Final Draft Report

on

The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute

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Prepared for the California Air Resources Board and the California Environmental Protection Agency

Amy Myers Jaffe, Principal Investigator

STEPS Program, Institute of Transportation Studies, UC Davis

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SUSTAINABLE TRANSPORTATION ENERGY PATHWAYS

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Team

Coordinators/Lead Researchers:

Amy Myers Jaffe, PI

Rosa Dominguez-Faus

Contributing Researchers:

Nathan Parker

Daniel Scheitrum

Justin Wilcock

Marshall Miller

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ABSTRACT

The emergence of natural gas as an abundant, inexpensive fuel in the United States has raised the possibility of using natural gas in transportation. Growth in natural gas fueling infrastructure improves the prospects for the development of a commercially viable renewable natural gas (RNG) industry in the state of California, with distribution into the existing transportation fueling system.

The development of alternative fuels that have low greenhouse gas and criteria pollutant emissions, such as renewable natural gas, are vital for the state of California to meet climate change and air quality goals. This study examines the feasibility of producing large quantities of renewable natural gas fuels for use in transportation in California. The study's results indicate that there are substantial sources of RNG in California that are commercially competitive with existing fossil fuel-based transportation fuels because carbon externalities are taken into consideration in the California market through existing programs such as the Low Carbon Fuel Standard (LCFS) and the U.S. Renewable Fuels Standard (RFS).

At current credit prices including California's LCFS and the U.S. federal RIN credits, up to 82 billion cubic feet per year (bcf/y) of RNG supply could be attractive for private investment at competitive rate of return in developing RNG sources from landfill, dairy, municipal solid waste and waste-water sites combined. We find that the LCFS credit of $120 per metric tonne of CO_2, if taken alone enables up to 14 bcf of RNG into the transportation fueling infrastructure over the study period, 6.3 bcf from landfill, 1.5 bcf from waste-water treatment, 1.75 bcf from municipal solid waste, and 4.3 bcf from dairy. The analysis also shows that increasing tipping fees for municipal solid waste can influence private investment in RNG. To be specific, increased tipping fees and carbon credits could create an incentive to produce more RNG since the municipality could save both the cost of the tipping fees and receive LCFS credits with a combined value providing over $13.00 per mmBTU of price support subsidy. Tipping fees are unique to the MSW RNG pathway and preventing MSW sites from capturing the tipping fees would make a straightforward waste to landfill option more expensive and less commercially viable. A potential ban to landfilling would be equivalent in our modeling to an extremely high tipping fee that would increase the appeal of converting the waste to biogas. All dollar values are in 2015 dollars.

Landfill gas is the largest potential source of RNG. With carbon credits or other financial incentives, such as LCFS and RFS RINs, of at least $3.75 per mm BTU, large landfill could produce 6.3 billion cubic feet per year of RNG. However, if the gas from landfills and waste water treatment plants at a particular site require more upgrading or more expensive. The study investigates the impact of California's quality standards for RNG and distance to central distribution systems on the level of investment in certain kinds of RNG. Upgrading costs are significant for all technologies but the range in upgrading costs is directly resulting from the range of biogas production scales. The dairies are especially limited in their ability

to achieve the scale required to bring the cost of upgrading into an economically viable range. One key conclusion of the study's comparison of costs is that clustering of the dairies is very important to lowering the cost of RNG by 60% compared with non-clustered systems using the same digester technology.

Finally, the study investigates the sensitivity of features influencing the climate performance of RNG on a life cycle analysis basis. Analysis reveals that vehicle produced methane emissions constitute a larger influence of overall carbon performance for LNG than in CNG. Use of landfill gas on-site instead of being sent elsewhere via pipeline reduces carbon emissions by up to 67%, indicating a clear climate benefit to avoiding pipeline transmission. For wastewater treatment plant biogas and manure renewable natural gas shifting LCA analysis from flaring to venting brings a substantial reduction in carbon intensity of RNG.

Overall, this study demonstrates that regulatory policy, combined with market pricing of environmental externalities, should be sufficient to attract new entrants to the renewable natural gas business in California.

EXECUTIVE SUMMARY

California will need high volumes of alternative fuels that have low greenhouse gas emissions to be able to meet its climate change and air quality goals. One such potential fuel is renewable natural gas. Existing biomass resource assessments suggest that there is a substantial resource base in California that could be tapped to build a renewable natural gas industry in the state. Such resources include manure, food waste, landfill gas, wastewater treatment sludge, forest and agricultural residues, and organic municipal solid waste. Technologies under consideration include capture and upgrading for landfill gas and anaerobic digestion for all other resources. Biogas resulting from anaerobic digestion or collection of landfill gas requires clean-up and upgrading in order to produce a vehicle fuel or to be blended in to the commercial fossil natural gas pipeline network.

The possible development of California's renewable natural gas resources comes at a time when the traditional fossil fuels natural gas industry is expanding its supply and infrastructure into the transportation sector. Liquefied natural gas (LNG) fueling stations for heavy trucks now exist in over a dozen locations around the state of California and continue to expand. California represents about 71% of U.S. LNG truck refueling facilities and about 200,000 gallons/day of LNG were trucked into California in the mid-2000s.

California has the potential to produce approximately 90.6 billion cubic feet (bcf) per year (750 million gasoline gallon equivalents (gge) per year) of renewable natural gas from dairy, landfill, municipal solid waste, and wastewater treatment plant sources.

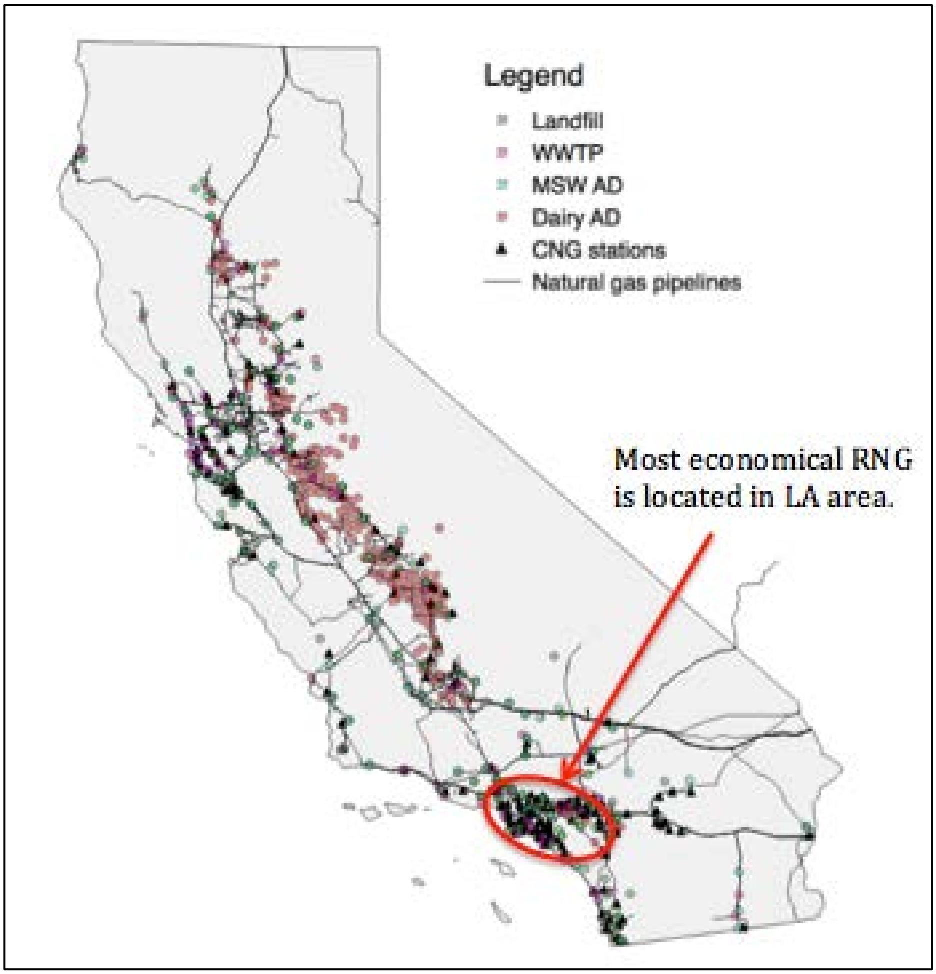

Figure 1. Circles sites indicate most economically viable production sites for RNG

We produced cost curves for California RNG using technical estimates of resource availability and technology performance. We then incorporated these cost curves into our spatial model by determining the quantity of renewable natural gas that could be supplied under different competitive landscapes. We first consider scenarios that begin temporally in 2013 at commodity natural gas prices of roughly $3.00/mmBTU and extending over a decade or two into the future when the competing fuel is fossil natural gas at prices available in the natural gas futures and derivatives market. Those derivatives prices generally ranged from $2.80 per mmBTU and $4.15 mmBTU over the modeling period. All costs and prices in our model are in 2015 constant dollars.

Calculations take into consideration not only the commodity price for fossil natural gas and diesel fuel versus the cost for different sources of RNG but also capital expenditures, a commercial rate of return for capital deployed, taxes, incentives and operational and maintenance expenses throughout the entire infrastructure supply chain from feed source to fueling station. Calculations consider the most commercially optimal combination of technologies, equipment, feedstocks, and size/scale of facilities to meet rising demand for transportation fuel for major trucking routes in the state.

We compare available RNG commercial supply against natural gas vehicle (NGV) demand estimated in our trucking model under various scenarios to determine the portion of NG truck fuel that can be supplied by RNG sources and provide a profitable rate of return to investors. We do not calculate how much RNG volume might remain on agriculture sites to meet internal demand as we consider this volume to be somewhat limited and aim to measure the potential for large scale injections into California's transportation fuel system. The scenarios we considered are variations of initial penetration rate of NG trucks, low, medium, and high diesel prices, and we specifically consider how changes in carbon credits, subsidies and tipping fee structures for waste collection would influence the outcomes for how much RNG might be deployed into the California trucking fuel market.

In today's conditions of low fossil natural gas prices, adoption of natural gas truck technology can be commercially feasible when fossil natural gas trades at a favorable price discount to diesel. We find that there are substantial sources of RNG in California that are commercially competitive with existing fossil fuel-based transportation fuels because carbon externalities are taken into consideration in the California market through existing programs such as the Low Carbon Fuel Standard (LCFS) and Renewable Fuels Standard (RFS).

Our calculations show that RNG can achieve significant market penetration of 14 BCF of RNG into the transportation fueling infrastructure by the 2020s with California's Low Carbon Fuel Standard (LCFS) credits at current levels of \$120 per metric ton of CO_2. Higher volumes are possible, as LCFS credits become more valuable and technological learning and scale economies lower upfront capital costs. When considering the additional credit from the U.S. Federal Renewable Fuels Standard (RFS) RINs of \$1.78 per gallon of ethanol equivalent (\$23.32 per mmBTU), the volume is higher at 82.8 BCF per year. However, RNG has only very recently been qualified to generate cellulosic biofuel D3 RINs which have been the most expensive RIN category. The price of D3 RINs have been extremely expensive as biofuel producers had failed to meet cellulosic biofuel production targets and thus elevated the D3 RIN price due to scarcity of qualifying fuel. Since the category of cellulosic fuel has expanded to include RNG, D3 RIN prices are starting to decline as the scarcity of qualifying fuel eases. Required levels of price support for RNG production pathways are presented in Table 1 below.

Table 1. Levels of price support required to incentivize production by pathway

	Support Required to Incentivize Production over $3.00/mmBTU market price (2015$)	
RNG Production Pathway	$ per mmBTU	$ per gasoline gallon equivalent
MSW	$11.50	$1.38
Landfill	$3.75	$0.45
WWTP	$5.90	$0.71
Dairy	$26.00	$3.15

One implication of our results is that credit market programs such as the LCFS play a central role in influencing private capital to select the most cost effective sources of renewable natural gas into the market. In a market that prices fuels taking into account their carbon intensity such as California, some of the higher capital costs for RNG as compared to fossil natural gas can be mitigated.

Based on these values for a low carbon fuel credit, our model finds that the combined California RNG production (all four sources of gas) increases from 0.5 bcf to 14 bcf per year in the 2020s, which correspond to 85% of all natural gas used in transportation in California in 2015, estimated in 16,467 million cubic feet of natural gas[1]. From the 14bcf projected total, 6.3 bcf would come from landfill, 1.5 from waste-water treatment, 1.75 from municipal solid waste (MSW) 9m, and 4.3 from dairy. Adding in credits from the Federal Renewable Fuels Standard of $1.78 per gallon of ethanol equivalent all four sources of gas increases from 0 bcf to 82.8 bcf, which would be equal to five times the current transportation NG used in California, of which 50.8 bcf is from landfill and 5.6 bcf from waste-water treatment, 16.3 bcf from municipal solid waste, and 10.1 bcf from dairy.

The cost differentials for various RNG pathways reflect differences in the level of specialized technology and infrastructure that is needed to bring the biogas to commercial commodity quality standards. For RNG from dairies and municipal solid waste, greenfield AD facilities must be constructed from scratch whereas the collection and upgrading equipment needed for landfill and WWTP is less capital intensive. The relatively low methane yields of manure also contribute to making manure RNG less competitive. Capital costs of AD are about a third of total capital requirements while the other two thirds are upgrading and injection infrastructure costs. The gas from landfills and waste water treatment plants may require more upgrading or more expensive monitoring equipment than we have assumed in our estimates in order to meet California gas quality standards.

One implication of the cost variability of the various RNG pathways is that credit market programs such as the LCFS play a central role in influencing private capital to select the most cost effective sources of renewable natural gas into the market. Market players are currently considering these wide variations in costs for various sources for RNG at different locations and applications to decide which resources will carry the most attractive return on private capital. To date, there is some evidence that markets are clearing the most cost effective investments first and that technology improvement, scale economies and learning by doing will enhance this process more robustly over time.

In considering the economics of RNG from municipal solid waste for transportation, an additional feature is the level of landfill tipping fees. Landfill tipping fees vary widely. In some cases in California, tipping fees of $126 per ton exist. Any change in the level of landfill tipping fees will have a material impact on the quantity of RNG from MSW that could be economically diverted to a digester. For example, if current tipping fees were 20% higher than today, RNG production from MSW sources that could be used in a municipal digester would increase from 1.75 to 12.4 bcf per year under a $120 per metric tonne of CO_2e LCFS credit price. In other words, increased tipping fees and carbon credits could create an incentive to produce more RNG since the municipality could save both the cost of the tipping fees and receive a LCFS credits with the combined value providing over $13.00 per mmBTU of price support subsidy. Thus in making the economic decision to build or expand a digester, the municipality would consider both the savings from not having to pay tipping fees, as well as the value of the credit from the LCFS market. The higher the tipping fee, the more cost savings could be considered in the calculation about the ultimate economics from diverting MSW waste to a digester instead of paying to dispose of it in a landfill.

Higher tipping fee structures could be created through California government policy by creating limits to the amount of MSW that can be accepted at landfills at optimum locations for digesters and RNG fuel use, thereby reducing supply of that service and thereby raising its price. A tax on landfill operations would not necessarily be able to be passed on to consumers of landfill services, if sufficient competition would force landfill operators to reduce underlying tipping fees to make room for the tax. The State could also mandate a state-wide fixed tipping fee for MSW that would be high enough to stimulate digester economics and higher diversion of MSW to digesters to make RNG.

1 INTRODUCTION

California will need high volumes of alternative fuels that have low greenhouse gas emissions to be able to meet its climate change and air quality goals. One such potential fuel is renewable natural gas (RNG). RNG is produced from organic materials or waste streams. The lifecycle emissions for RNG have the potential to be lower than the emissions of fossil natural gas.

Renewable natural gas is rich in methane that is produced from organic materials or waste streams and can be processed so that it meets existing fossil natural gas pipeline and vehicle specifications. When burned in vehicles, RNG emits similar levels of greenhouse gases as fossil fuels, but different upstream processes result in an overall reduction of lifecycle GHG emissions due to methane capture, and avoided upstream emissions.

If abundant, inexpensive fossil natural gas leads to significant increases in the natural gas vehicles market. In the freight sector, RNG could potentially help improve the climate performance of such a market. The emergence of natural gas as an abundant, inexpensive fuel in the United States has raised the possibility of using natural gas in transportation. Major corporations are already investing billions of dollars to build infrastructure to feed natural gas into the U.S. trucking industry and expand the use of natural gas in fleets. In the state of California, natural gas fueling infrastructure is expanding, especially in and around the ports of Los Angeles and Long Beach.

Existing biomass resource assessments suggest that there is a substantial resource base in California that could be tapped to build a renewable natural gas industry in the state. Such resources include manure, food waste, landfill gas, wastewater treatment sludge, forest and agricultural residues, and organic municipal solid waste, converted into biogas via anaerobic digestion, and cleaned and upgraded into pipeline quality biomethane.

RNG can be delivered to vehicles either locally near the production facility or through long distance pipeline distribution. While local usage may provide niche markets for a small volume of RNG, local demand may be too limited to enable commercial feasibility of investments in RNG infrastructure. Some kinds of RNG may require large scale production to achieve economies of scale to lower costs. RNG is then transported in long distance pipelines to reach fueling locations that represent significant demand levels.

RNG is not the only fuel that can be made from biomass feedstocks. Biodiesel, dimethyl ether (DME), and even composting can be seen as a competing use for feedstocks for RNG. Carreras-Sospedra (2013) suggests that conversion of biomass for RNG for vehicle use may achieve lower impacts on air quality and climate protection than some other uses[2].

The economics of producing RNG must also consider other uses for the biomaterials. Value for RNG derived from landfill or municipal solid waste collection can be derived from waste by three primary mechanisms: tipping fees, recycling and generating energy from waste. Because of the high demand for energy and fuel, converting biomaterials to fuel presents a high value potential for it, allowing for capture of both lucrative tipping fees and revenues from the sales of fuels. Zero waste initiatives that arise from governments, environmental and civic groups encourage reduction of waste through recycling, or reuse.

There are several waste streams that are hard to eliminate and therefore are good candidates for conversion to fuel such as WWTP, and forest and agricultural residues. For agricultural waste, alternative uses may be more complex. Some biowaste may be able to be sold as a feedstock product or used or recycled on site. In other cases, agricultural producers may be paying a service fee to have waste removed from their premises in which case the waste stream represents a cost.

Generally speaking, the process for creating RNG is more costly than extracting fossil natural gas. This can create challenges to commercial scalability of RNG. If volumes are not sufficiently large, the cost for RNG processing equipment to remove impurities (clean up) and to improve energy content (conditioning) can be a barrier to commercial feasibility. One aspect of the high costs for pipeline injection is the testing and verification required to meet pipeline owner specifications. Another commercial barrier is pipeline interconnections costs for feeder pipelines from RNG sourced gas. California has higher interconnection costs for RNG feeder pipelines than other states. California also has the most restrictive standards for RNG injection (testing, mixing, compression, etc.).

Recently the California Public Utility Commission (CPUC) instituted a biomethane monetary incentive program to offset some portion of the interconnection costs in the state. This adjustment is expected to help facilitate the commerciality of some kinds of locally sourced RNG. To date, much of the RNG currently being used in California comes from out of state suppliers. Regulatory barriers have given out of state RNG facilities a head start in displacing in-state resources and working down the cost/learning curve for RNG generation.

1.1 RNG Pathways

There are various technologies being developed to capture the value in RNG. They include:

1.1.1 Landfill gas to energy

Landfill gas to energy (LGTE) is a method of capturing the naturally occurring methane from the breakdown of waste in a landfill. One solution for dealing with this methane is to simply flare it off breaking it down into less harmful gases. However, due to the potential energy source of this gas, technologies have been developed to capture this gas and convert it into energy.

1.1.2 Anaerobic Digestion- Wet (dairy waste) and dry (food waste)

Anaerobic digestion (AD) of organic waste is the process of taking organic material (yard clippings, food waste, food soiled papers or biological waste) and allowing the natural decomposition to occur in an anaerobic environment. This process produces methane, which is then captured and processed for fuel or energy usage. Anaerobic digestion may be operated at a range of solids concentrations. Dry (high solid waste) tends to be less capital intensive to process into methane than wet sources because it has higher energy content per unit of waste and requires less infrastructure and clean up.

Yebo Li, Stephen Park, Jiyung Zhu (2010)[3] discuss the advantages of solid state anaerobic digestion compared to liquid anaerobic digestion. The author's literature review notes that a wide range of organic solids found in municipal, industrial, and agricultural wastes can be used in solid-state anaerobic digestion. One study demonstrated that food wastes with 20% total solids (TS) that were digested in a two phase system at 37 degrees C, 87% to 90% of the solids were reduced, and 90% of the initial volatile solid (VS) was converted to biogas. Additionally, the methane yield reached 86-88% of the biochemical methane potential. In another trial, 70% food waste, 20% fecal matter, 10% green algae were co-digested at 37 degrees C and a biogas yield of 90% was achieved. Steam pre-treatment of corn stover at 190 degrees C for 5 minutes using SO2 as an acid catalyst has been shown to give high sugar yields. The authors also note that biogas yields are materially affected by characteristics of MSW, and that the digestate of MSW generally requires landfill or incineration.

1.1.3 Gasification- Standard and plasma

Waste can also be gasified through systems that converting a feedstock (MSW, biomass, coal etc.), through high temperature thermal decomposition in a low oxygen environment, into synthesis gas. High- temperature and plasma gasification are currently the dominant technologies being developed.

Gasification typically occurs at temperatures ranging from 480-1,650°C (900-3,000F°). Gasification has been in place for over 60 years in refining, chemicals, and energy production. The syngas produced can be then processed into a variety of other products including heat, energy or fuel. There may be some pretreatment of the feedstock required before gasification can occur. This varies between different technologies, and the feedstock used. Pretreatment can include sorting out recyclable materials, shredding or resizing the material, and drying the material[4,5]. High temperature gasification can convert multiple types of feedstock into syngas with minimal residual metal and slag (an inert, glass-like material). This can be done with a fluidized bed (typically glass or salt), moving bed, fixed bed, and entrained flow[6,7]. This technology may require some drying, presorting and grinding of materials before introduction into the gasification unit.

Plasma gasification uses a plasma torch, created by an electric current passed between two electrodes. This generates extremely high temperatures in the reaction chamber ranging from 930 to 1,200 °C (1,700 to 2,200°F). These temperatures break down the material with virtually no emissions. As with standard gasification technologies a slag byproduct is produced in the process[8]. The high temperatures enable both standard and plasma gasification plants to process regulated or hazardous wastes such as medical waste, waste from steelmaking and chlorine-containing waste[9].

A common application tied to gasification is Fischer-Tropsch fuel to liquid conversion technology. This process converts syngas to diesel and other liquid transportation fuels. Gasification has primarily been used to process coal and biomass. The application of municipal solid waste as a feedstock is a relatively new development. Because this study focuses on synergies and competition with fossil natural gas infrastructure, our investigation does not include gasification technologies that produce biodiesel fuel.

1.2 Natural Gas Vehicle Market and Incentives

The possible development of California's renewable natural gas resources comes at a time when the traditional fossil fuels natural gas industry is expanding its supply and infrastructure into the transportation sector.

Liquefied natural gas (LNG) fueling stations for heavy trucks now exist in over a dozen locations around the state of California and continue to expand. California represents about 71% of U.S. LNG truck refueling facilities and about 200,000 gallons/day of LNG were trucked into California in the mid-2000s. Volumes have been growing steadily in recent years, and LNG fueling facilities now exist in Tulare, Fontana, Lodi, Lost Hills, San Diego, Aurora and Ripon, with planned new facilities in Coachella and Colton. California is the leading state in LNG trucking, according to the U.S. Department of Energy, with station locations focusing initially on U.S. interstate routes from Los Angeles to Houston and Las Vegas as well as to Chicago and Atlanta.

In the United States, there were 250,000 natural gas vehicles on the road in a variety of applications in 2013, from which only about 4,000 of the NG vehicles were medium- and heavy-duty trucks according to the European Natural Gas Vehicles Association[10]. The United States has 900 compressed natural gas (CNG) fueling sites of which a little under half are public. In its report, "Energy 2020: Trucks, Trains and Automobiles"[11] Citigroup projects that a shift to liquefied natural gas (LNG) for heavy trucking could eliminate 1.2 to 1.8 million barrels a day (mbd) of U.S. diesel demand by 2030 and 3.4 million b/d globally.

About half of the total natural gas consumed in transportation was destined to freight trucks[12]. Only one automobile manufacturer, Honda Motor Co., had previously offered natural gas passenger cars for sale in the United States, but the vehicle failed to capture a large market base and was taken off the market in 2015. Of the quarter of a million natural gas vehicles operating in the United States, the majority are in service for municipal and commercial fleets, including 14,000 buses and 230 passenger vehicles. Many other are in taxi fleets.

Figure 2 shows the range of policies used to stimulate natural gas vehicles use and investment in the United States. A number of states are offering incentives to support the expansion of natural gas as a transportation fuel. Pennsylvania, home to the rich Marcellus shale gas basin, recently announced the Natural Gas Development Program that would provide $20 million over three years to convert or acquire heavy-duty vehicles that run on compressed natural gas (CNG) and tailored the Alternative Fuel Infrastructure Grant to support mid duty vehicles conversion and fueling infrastructure financing through the Alternative and Clean Energy Fund.

The state of Oklahoma, in another example, instituted a 75% subsidy on CNG fueling stations as part of its goal to facilitate the use of natural gas in commercial vehicles[13]. To promote the use of natural gas in transportation, Oklahoma brought together vehicle manufacturers (OEMs), station providers and natural gas producers to create a coordinated effort that would overcome chicken and egg infrastructure issues, at least for CNG networks in the state. The state orchestrated bulk government purchasing orders of natural gas vehicles from the major automakers at a discounted level while offering a 75% station cost subsidy to station developers in exchange for a commitment to construct a credible number of fueling stations. There are currently close to 30 natural gas fueling stations in Oklahoma.

In February 2009, then Governor Jon Huntsman announced that Utah would increase the state's NGV fueling infrastructure[14]. The state offered incentives to drivers to offset the higher price for the NGV vehicle and Questar offered financing and lease programs to customers to support the economics of the conversions. As a result, Utah has 99 natural gas fueling stations, public and private, many of which are located along primary highway corridors to support the fuel requirements of heavy-duty trucks.

Several incentives have been available for natural gas vehicles in California. The Alternative and Renewable Fuels and Vehicle Technology Program (ARFVTP) by the California Energy Commission (CEC) offer incentives to reduce purchase price of new on-road Natural Gas Vehicles[15]. Natural Gas Vehicle Incentive Project (NGVIP), funded by ARFVTP and administered by University of California Irvine, provided incentives of up to $25,000 per vehicle. About $10 million were allocated and $9.4 million were committed in a waiting list[16].The Carl Moyer Memorial Air Quality Standards Attainment Program (Carl Moyer Program) grant funding administered by local air districts also supports the purchase of cleaner-than-required engines and equipment[17]. 2014 saw the passing of the bill "California Clean Truck and Bus and Off Road Vehicle and Equipment Technology Program". Under this law, part of the Greenhouse Gas Reduction Fund would be allocated to technology development, demonstration, pre-commercial pilots, and early commercial deployment Zero or Near-Zero medium- and heavy-duty trucks, with 20% of the program money until 2018 (50% between 2018 and 2023) going to heavy duty trucks[18]. The allocation for clean trucks is estimated at $23 million, but current budget shortfalls might affect the final amount[19]. The Alternative Fuel Data Center[20] and Seekingalpha websites provide a detailed list of subsidies for NGVs or natural gas stations[21].

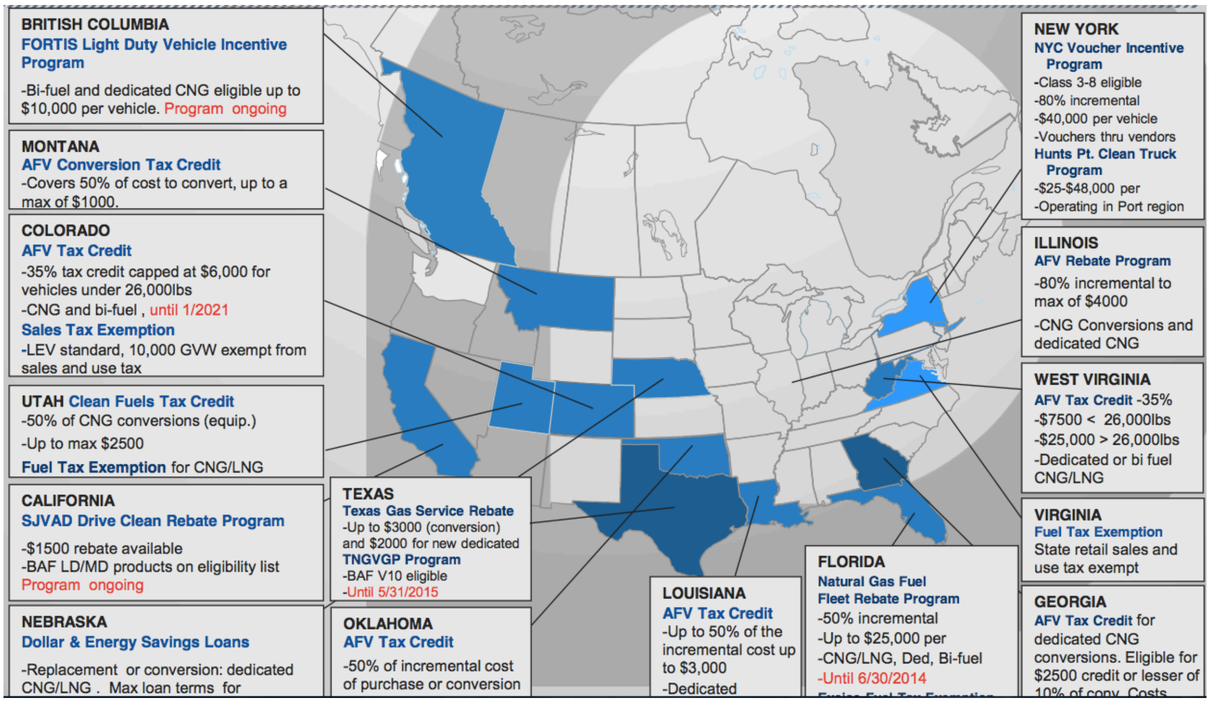

Figure 2. Available State Incentives for Natural Gas Vehicles.
Source: Transportation Energy Partners

1.3 Renewable Natural Gas as Attractive Heavy-Duty Fuels

Increasingly, long distance trucking is changing from patterns where a single vehicle with a single driver traverses the entire country to a hub and spoke operation where more localized fleets handle part of a longer journey for modular containers. This new transport paradigm means more trucks return to a local home base in the evening, not only improving the lifestyles of drivers but also creating more opportunities to fuel and maintain fleets from a home base. This emerging “relay race” model to daily regional operations with a home base is conducive to a shift to fossil and renewable natural gas for commercial fleets. This new operational pattern has implications for California because it makes it easier to direct fuel policies for the state, even if shipments starting in California will extend to other parts of the United States. That is because a hub and spoke system means localized fleets in California can operate with one set of class 8 tractor/trucks and then the same container trailers holding cargo originating in California can continue on to other more distant parts of the U.S. using different tractor/trucks that may run on conventional fuels. In other words, California trucks can have a higher rate of alternative fuels utilization than most of the rest of the country and still participate in the business of national goods movements.

While interested in attractive fuel cost differentials and demand of cleaner transportation from customers, the trucking industry has to date been reluctant to take the plunge on expensive equipment upgrades to natural gas. The logistics sector operates on thin margins and tight schedules and fueling station density is a critical issue. Barring large incentives, the conversion of heavy duty fleets to a new fuel is unlikely to take place rapidly because only 200,000 to 240,000 new vehicles come on the road each year. At present only 14% of fleets operate any vehicles on alternative fuels[22]. Fleet owners worry that supply chains for natural gas vehicles are not yet sufficiently robust to avoid higher maintenance costs than traditional diesel vehicles.

1.4 Synergies with Natural Gas Infrastructure

Prior to studying RNG, we have assessed the potential of fossil natural gas to serve as a major fuel for trucking in the state of California. Our research reveals that the conditions for natural gas fueling infrastructure in the state of California are more commercially attractive than in other parts of the country. The flow of freight traffic on California highways is higher than on many other national routes, and a high percentage of the state's freight movement is concentrated on the I-5 corridor, limiting the number of stations needed to cover major routes inside the state. California also has higher diesel prices than in other parts of the country, again providing a more favorable commercial incentive for fuel switching. We find that firms can achieve a 12 percent rate of return[1] on investment in natural gas fueling stations in California, once the network of long distance trucking running on natural gas were to reach a penetration rate of 6,000 vehicles, about twice as high as today's fleet. This result confirms the possibility that some subsidization of natural gas trucks would be effective in promoting a state-wide fueling network.

A key aspect of the model is testing whether certain regional networks could prove more profitable than others in the short run and lay the groundwork for expansion over time to a more comprehensive national network. Our analysis of the U.S. regions shows that, under current market 0.1% LNG national truck penetration, California and the U.S. Great Lakes region, which have a relatively high level of demand and traffic density, could play a key role in the network development (Figure 3).

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[1] This rate of return was selected based on standard industry practice as determined by extensive interviews with oil industry executives, natural gas fueling companies, equipment manufacturers and industry consultants.

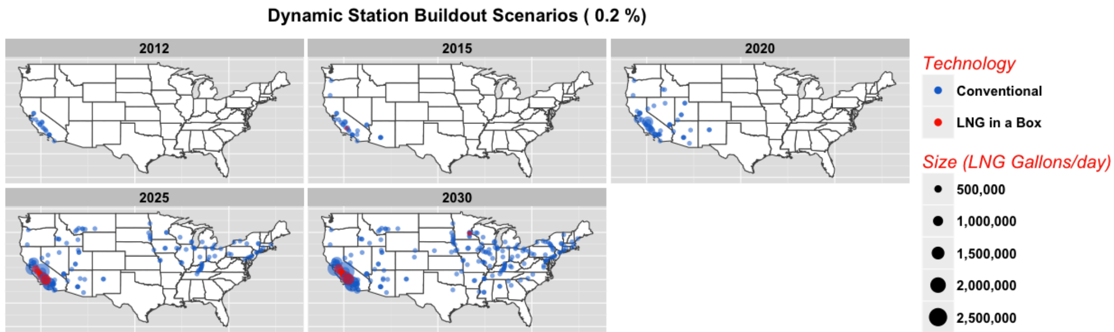

Figure 3. LNG station build-out under 0.2% initial market penetration

1.5 California as a Profitable Refueling Network Opportunity

Our results indicate that for the California network to operate profitably under the optimal configuration, conventional station technology of the smallest capacity should be deployed. We find that the number of stations in those regions would intensify as these regional networks become more commercial. The existence of a solitary main trucking artery in the state of California could create a profitable opportunity to build-out a commercial LNG fueling network for a relatively small investment of around $90 million. This would be the case if the number of LNG trucks on the road in the United States were to double from the current 3,000 trucks to 6,000. More specifically, it would cost roughly $10 million to construct all the LNG stations shown in Figure 3 in our model year 2012, and roughly $80 million to construct all the micro-LNG liquefaction plants needed to service the stations.

Detailed flow rates vary by year but under our base scenario we find that the Los Angeles region initially has the highest demand for LNG fuel at 3.2 million LNG gallons, followed by Fresno at 2.5 million LNG gallons, Bakersfield at 2.1 million LNG gallons, and San Jose, 1.4 million LNG gallons. Lebec, Lost Hills, and Sacramento areas achieve flows of 1.1 million LNG gallons with other areas such as San Diego and Commerce seeing smaller demands (Figure 4).

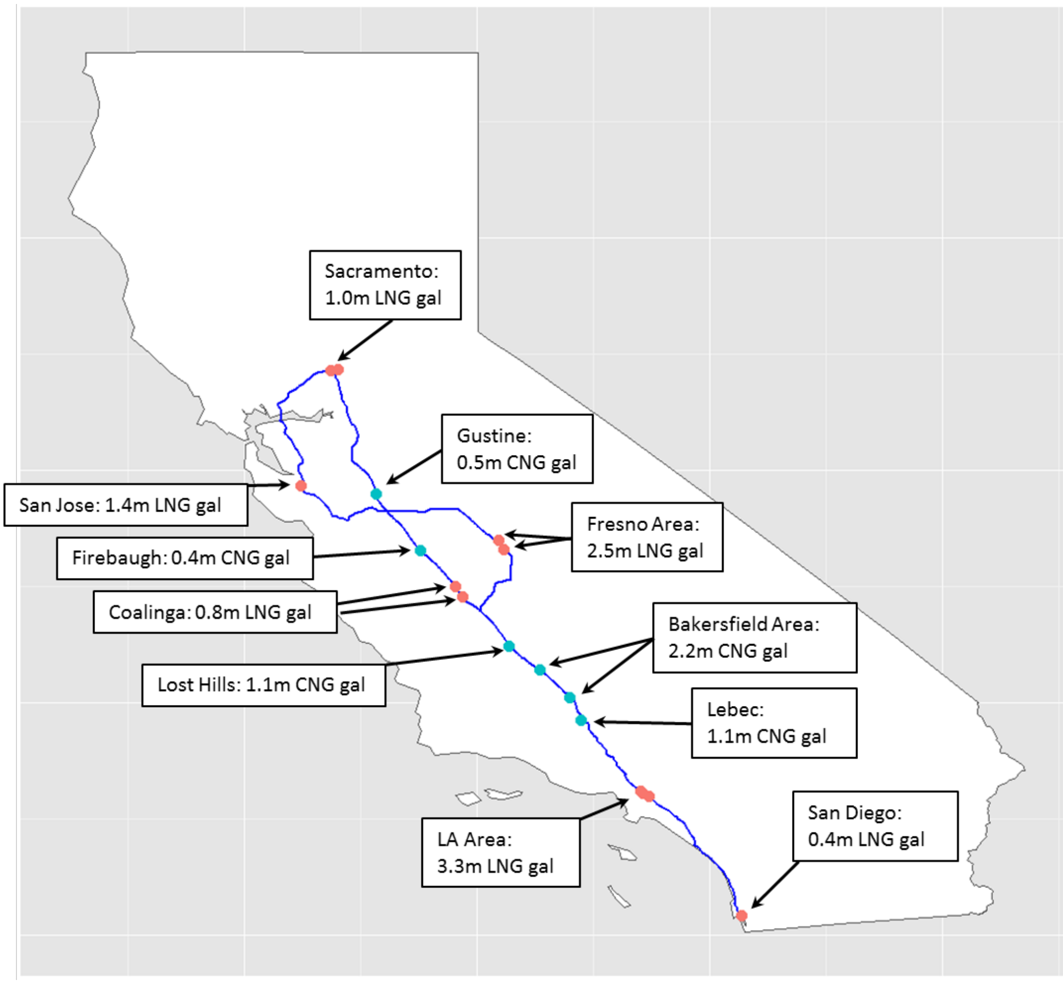

Figure 4. Initial locations of LNG (red dots) and CNG (blue dots) refueling infrastructure and route deployment. Annual gallons of LNG and CNG fuel delivered at outset- 0.2% Penetration Rate. No Subsidy.

Under a 50% station cost subsidy case (Figure 5) initial flows of natural gas through Los Angeles increase significantly to 3.8 million LNG gallons and through Fresno modestly to 2.7 million LNG gallons. But other locations are not greatly impacted by government assistance in the short run. By 2025, the base case projects flows through Los Angeles would be 1.1 billion LNG gallons, rising to 1.3 billion LNG gallons with a scenario that includes 50% subsidy to station construction costs. Under a high diesel price scenario where diesel prices return to high levels seen at peak prices in 2008, volumes around the state are not significantly higher in the immediate run. However, by 2025, flows across California under the high diesel scenario are much greater than under either the base case or 50% subsidy scenarios. California already has several LNG fueling stations, including two at the port of Long Beach. Under a scenario where CNG is a ready alternative to LNG and diesel fuel, our results show that CNG would be favored at many locations, including Gustine, Firebaugh, Lost Hills, Bakersfield, and Lebec. The addition of a 50% station subsidy broadens the locations for CNG stations to Coalinga and between Lost Hills and Lebec. See Figure 5.

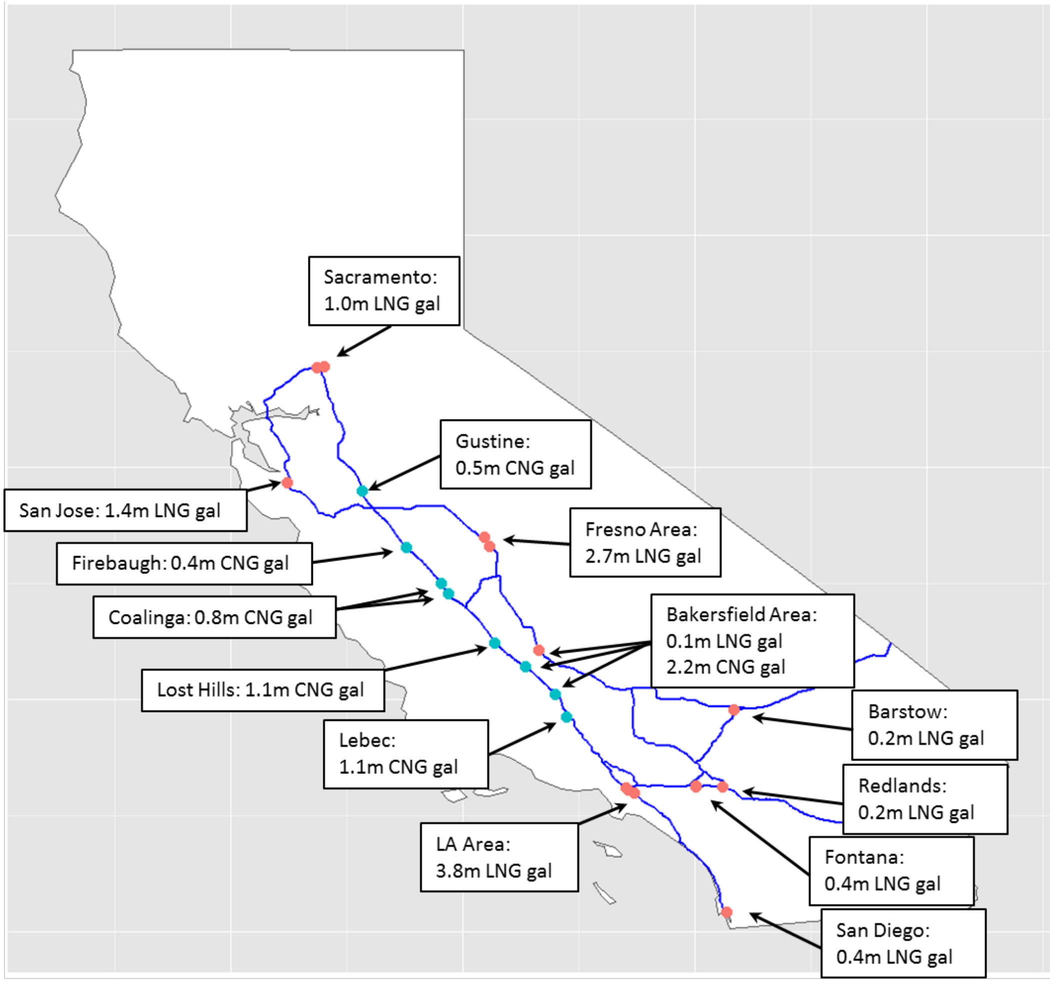

Figure 5. Initial locations of LNG and CNG refuelling infrastructure and route deployment. Annual gallons of LNG and CNG fuel delivered at outset- 0.2% Penetration Rate. 50% Subsidy.

The California example demonstrates that station investors should be looking first and foremost for high volume routes where truckers have fewer routing options than in other parts of the country. It also confirms the corporate strategy being undertaken by fuel providers and truck manufacturers to focus marketing efforts on large corporate fleets. In this strategy, large early adopters could make a limited route such as California's Interstate 5 a commercially viable, cost-effective place to introduce LNG and CNG as an alternative fuel especially around Port of Los Angeles, Fresno and Bakersfield. The concept that a handful of large fleets could commit to substantial purchases of LNG trucks in a particular regional market finds evidence in today's commercial climate. For example, the United Postal Service (UPS) ordered about 700 gas tractors in 2013, showing the viability of getting adoption of the additional trucks via a fleets purchasing model.

1.6 SUSTAINABLE FUEL POTENTIAL

A California network receives an extra financial boost from the existence of a liquid carbon pollution market that qualifies for credits of natural gas fuel use and thus we believe it could be feasible for the state of California to try to promote a natural gas fueling infrastructure network that could prove to scale to commercially sustainable operations.

However, the use of fossil natural gas as a trucking fuel still produces significant greenhouse gas emissions. We find that replacement of this fossil natural gas with renewable natural gas can improve the climate performance of trucking operations in California when compared to diesel fuel.

The potential to avert upstream methane emissions that would otherwise have been emitted makes the use of renewable natural gas very interesting. Lee and Sumner (2014)[23] investigate greenhouse gas emissions reduction options from California's agricultural sector. They estimate that 8.5 million metric tonnes (MMT) of CO_2e is emitted from farms with anaerobic systems in California and conclude that manure management to reduce methane emission and other GHGs can be solved by simply covering manure lagoons and flaring the methane. However, they compare the cost assumptions for eight studies on the topic and conclude that converting the methane to biogas to use in replacement of fossil fuels is costly and not likely to be commercially feasible without large subsidies.

JJ Owen, E Kebreab, and W Silver (2014)[24] estimate that converting to anaerobic digesters could reduce total methane emissions by 7.7 Tg CO_2e. Cuellar and Webber (2008)[25] estimate that 51 to 118 MMT of CO_2e results from livestock manure emissions and can be captured to generate 970 bcf of renewable electricity per year. Given the climate benefits, we test how much fossil natural gas could be replaced with RNG for the California natural gas fueling infrastructure network.

G. Saur and A Millbrandt (2014)[26] estimate that the U.S. total methane potential in raw biogas is about 16 million tons, but net availability is more limited at 6.2 million tons. The authors breakdown the biogas supply by source with landfill biogas as the largest potential source of 2,455 thousand tonnes per year out of 10,586 total methane potential and 1,927 tonnes per year from waste water treatment plants out of 2,339 total methane potential. Animal manure raw biogas is estimated at 1,842 tonnes per year available out of a total of 1,905 tonnes per year. The estimate for total potential of industrial, institutional and commercial sources of biogas (IIC) is estimated at 1.2 million tonnes annually and illustrated below in Figure 6.

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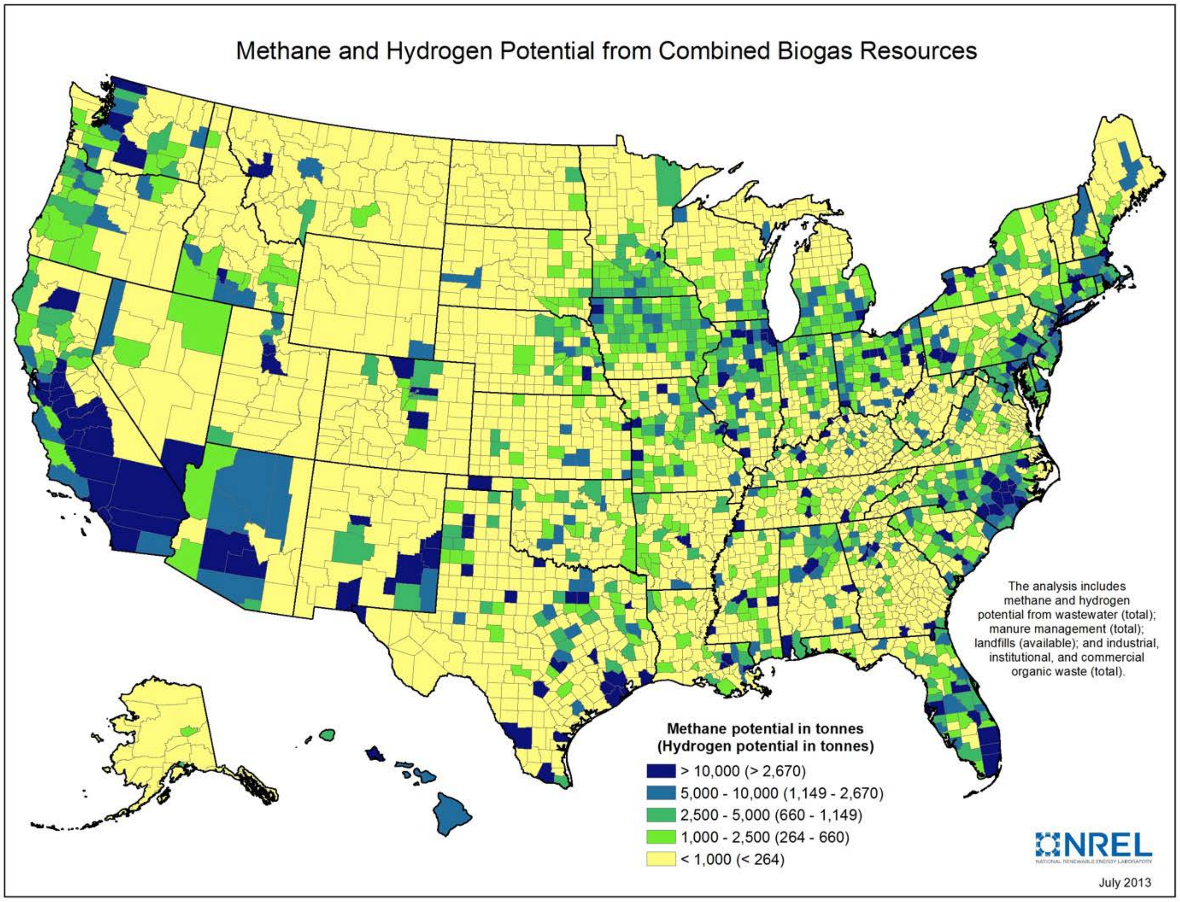

Figure 6. Combined Methane and Hydrogen Potential (Tonnes) adopted from G Saur and A Milbrandt (2014)

Figure 6 shows the methane and hydrogen potential from all combined sources. The figure shows how some counties in California have a large potential for methane and hydrogen production from biogas, Arizona also has large resources and has the additional benefit of connecting to California by pipeline as a transit state for fossil natural gas shipments to California. Large resources are also present in western New Mexico that might also be accessible to pipelines to California. Already, some biogas resources from Texas are being injected into the pipeline to California.

In terms of specific kinds of resources, G. Saur and A Millbrandt (2014) find that methane and hydrogen from wastewater treatment is most concentrated in the U.S. eastern seaboard and along the Great Lakes region, but California also has substantial methane and hydrogen potential from wastewater biogas (Figure 7)

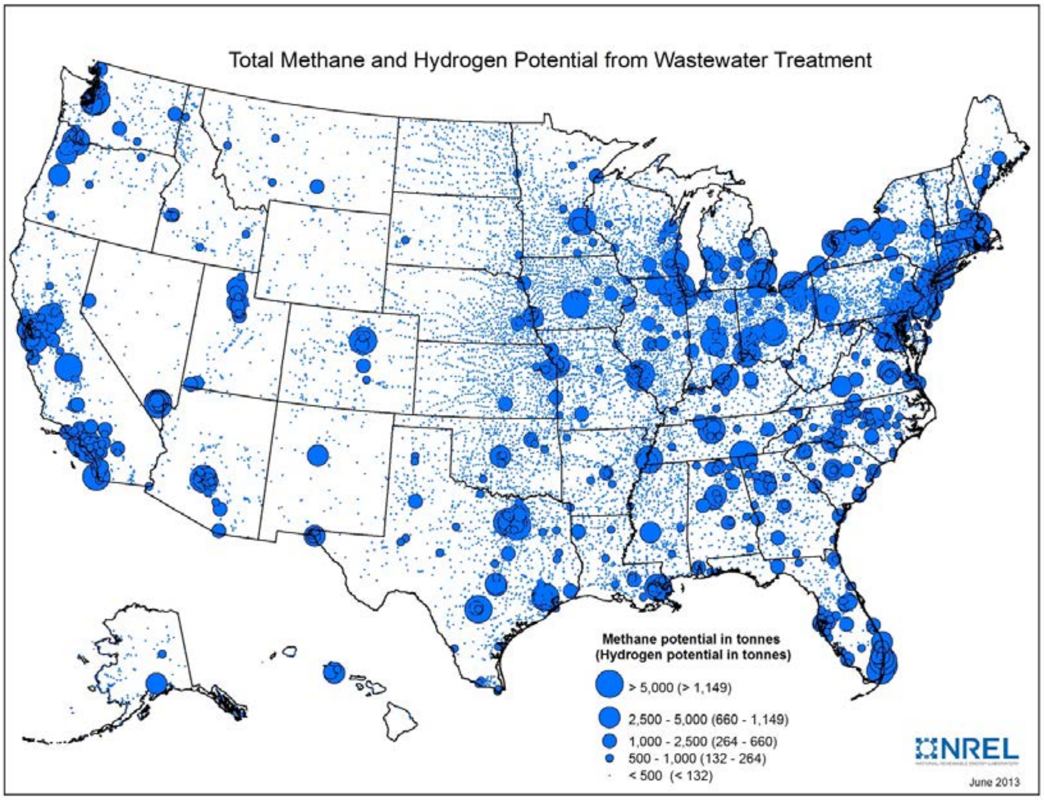

Figure 7. Wastewater Methane and Hydrogen Potential (Tonnes)
adopted from G Saur and A Milbrandt (2014)

G. Saur and A Millbrandt (2014) also survey the U.S. potential for renewable methane and hydrogen to be produced from landfills and find extensive resources across much of the United States, with Texas and California providing many large candidate sites (Figure 8).

The authors find that eight of the 25 largest candidate sites are located in California including three in Los Angeles, one in Orange, one in Stanislaus, two in Alameda, and one in Kings Counties. There are also two large candidate sites in Maricopa County, Arizona. Kings and Stanislaus counties are also candidate sites for methane production from animal manure. Merced also has a large candidate site potential for methane produced from animal manure. But the study notes that farm sizes tend to be small in California's central valley and therefore the "economic feasibility of anaerobic digestion at dairy farms with fewer than 1,000 cows might hinge on air and water regulations as well as other technical factors."

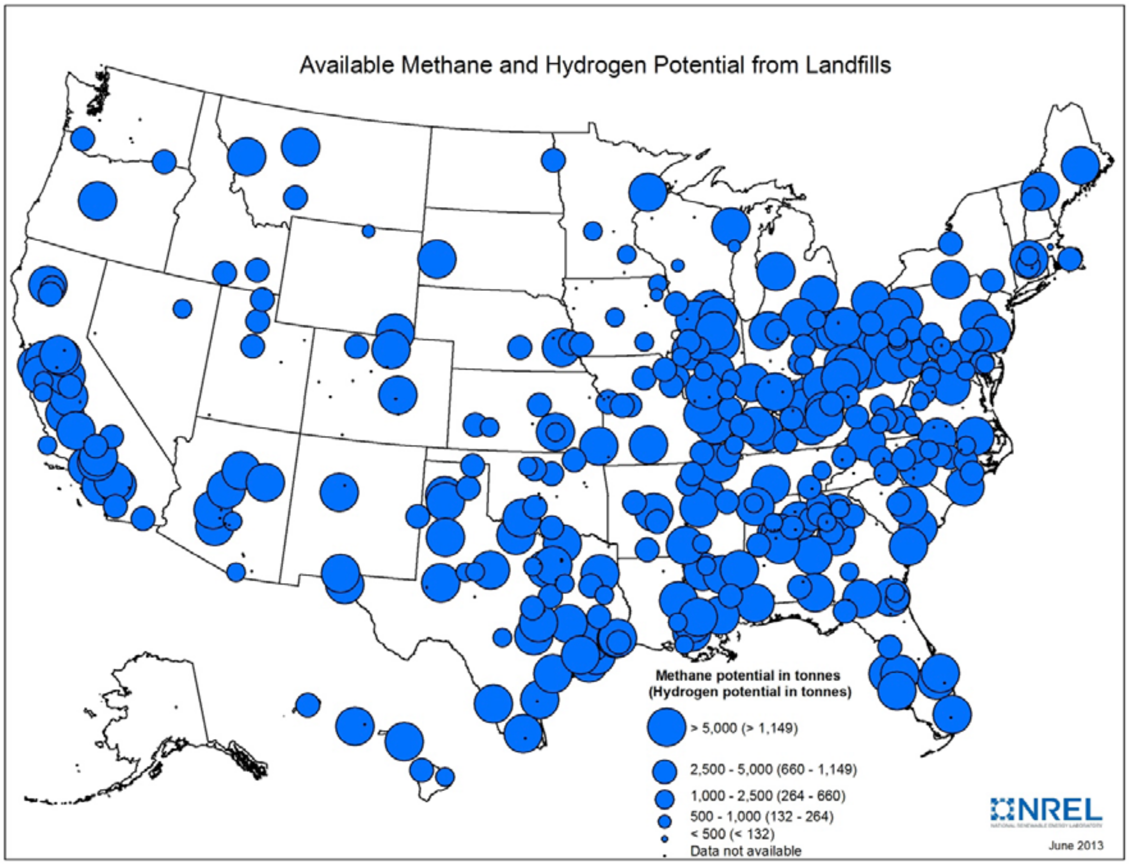

Figure 8. Landfill Methane and Hydrogen Potential (Tonnes) adopted from G Saur and A Milbrandt (2014)

Methane and hydrogen potential from organic waste from industrial, institutional and commercial sites is smaller than other sources at only 1.2 million tons annually (Figure 9).

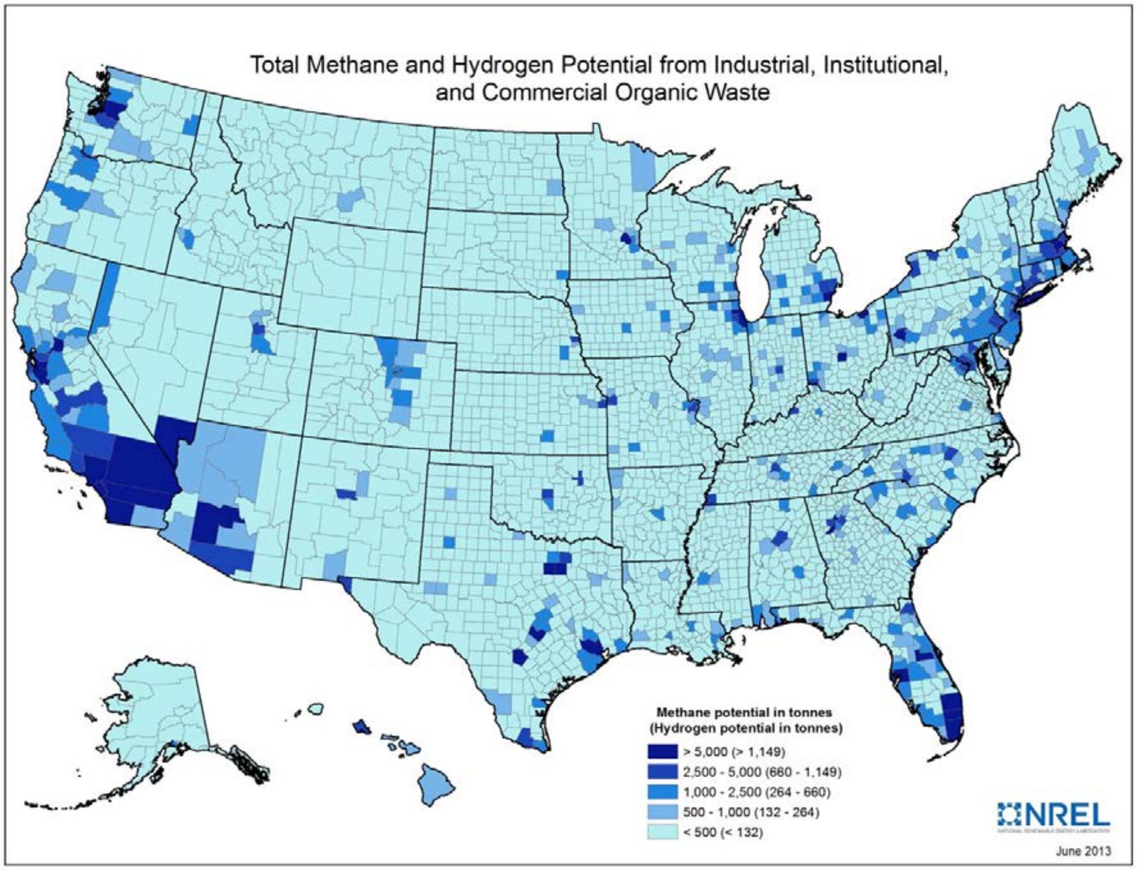

Figure 9. Organic Waste Methane and Hydrogen Potential (Tonnes) adopted from G Saur and A Milbrandt (2014)

Twenty percent of U.S. national supply comes from the top 20 candidate locations including Los Angeles, Orange, San Diego, Santa Clara, Riverside and San Bernadino counties. Other major cities with large IIC resource potential are Houston and Dallas in Texas and Maricopa in Arizona.

Ken Krich et al (2005)[27] investigate biomethane from dairy waste and conclude that there is sufficient volume of biomethane from cows to fuel existing natural gas vehicles in California but that electricity generation from biogas is more cost effective than upgrading biogas to biomethane. Tuna and Hulteberg (2013)[28] find that renewable natural gas is less costly than production costs for ethanol from woody biomass.

2 MATERIALS AND METHODS

Development of alternative fuels that have low greenhouse gas emissions and low criteria pollutant emissions, such as renewable natural gas, are vital for the state of California to meet climate change and air quality goals. Thus, we examine the feasibility of producing large quantities of renewable natural gas fuels for use in California and what percentage of this volume could replace fossil natural gas in the California trucking industry.

To do this, first we identify the overall resource potential inside the state of California and calculate feedstock supply curves based on best available data on feasibility and cost estimates for each possible source for RNG. We include costs of both anaerobic digestion and capture and upgrading of the biogas from a variety of source material including manure, food waste, waste water, landfill gas, agricultural residues and forest residues (Table 2).

Table 2. Resource categories for economic analysis

Stationary	Transportable
Landfill Gas	Food and green waste
Waste Water Treatment Biogas	Forest residues
Dairy manure	Agricultural residues

We identify which commercial RNG resources might have access to locations where fossil natural gas is being distributed or may be distributed in the future for use in trucking. This mapping activity provides new information about the potential role of incumbent infrastructure and expanding investments in the fossil fuel industry in enabling a large scale renewable natural gas industry that could transition supplies for the trucking industry from fossil fuel-based fuels to renewable natural gas. We study the optimal locations for production of renewable natural gas for use in transportation, based on profit maximization to give policy makers improved information about where government intervention might best be utilized to accelerate and expand low carbon renewable natural gas into the California fuels market.

2.1 Renewable Natural Gas Resource Assessment

This study develops supply curves for renewable natural gas in California using technical estimates of resource availability and technology performance. The world described by these supply curves is one where investments in infrastructure are operating under certainty of prices for products and performance of the technology. All entities in possession of the resource have interest in participating in the market with the same rate of return. Calculation of the potential reflects an overnight build assumption where the industry can quickly build out all profitable investment without delays or constraints on capital or skilled labor. In the real world of course, these factors can delay implementation of profitable projects. All RNG produced is injected into transmission pipelines, as no local refueling is considered here.

The methodologies for assessment were tailored to the characteristics of the specific resources that can be converted into RNG. Some resources are stationary where the resource is difficult or impractical to move for the purpose of aggregation while other resources are either already collected on trucks (MSW) or highly dispersed but can be transported at relatively low cost (forest/agricultural residues). The analysis of the stationary sources takes the resource potential at a location as given and calculates the cost of producing RNG from that supply point. For dairy manure, the supplies of RNG at a given source are small but the sources are close together. A clustering analysis was performed for dairies to capture the potential for aggregating biogas in a local pipeline network for centralized upgrading and injection. The analysis of transportable resources utilizes the Geospatial Bioenergy System Model (GBSM)[29,30,31] to optimally locate and size facilities to produce RNG from those resources based on the costs of procuring, transporting and converting the resource to RNG (Figure 10).

For stationary resources, a resource assessment is developed from the best available data sources to provide a technical potential for producing a given resource at a given location. The cost of accessing the resource is also an estimate. For example, the production of biogas at a waste-water treatment facility can be estimated based on the average flow rate. The cost of accessing the supply is either zero as collection and flaring is otherwise required or the opportunity cost of using the bio-gas in producing an alternative product. Next, techno-economic models of the RNG production technologies are used to estimate the cost of producing RNG at each location. The cost of accessing the natural gas transmission pipeline via a dedicated pipe installed to the nearest transmission line is calculated using ArcGIS to find the distance between the point source and the pipeline. Finally, the supplies and costs from each point source are aggregated to create a supply curve for a given resource type. The supply curve gives the cumulative supply that can be produced below a certain cost.

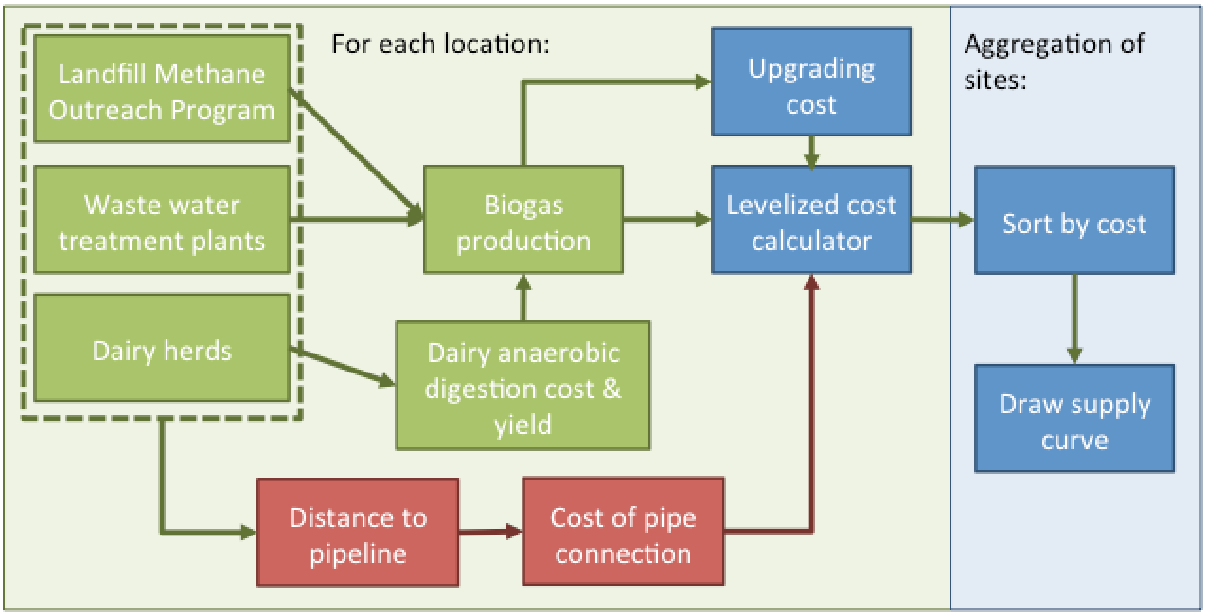

Figure 10. Supply curve method flow chart.

A greedy algorithm was developed for aggregating dairy biogas resources for centralized upgrading and injection into the natural gas pipeline network. The algorithm uses the stationary source assessment methodology to find the most promising individual dairies for siting RNG production. Working from the most promising site, the algorithm adds neighboring dairies to a centralized biogas upgrading and injection facility. The neighboring dairy that would provide biogas at the lowest cost is added first. Additional dairies are added to the cluster until adding another dairy would increase the cost of RNG production for the cluster as a whole. The algorithm moves to the next best single dairy that has not been assigned a cluster and begins to build another cluster. This process continues until all dairies have been added to a cluster or were found to not benefit from clustering. This methodology does not provide the absolute minimum cost for RNG as more optimal configurations of clusters could likely be found but it does follow a reasonable logic. Algorithm matches a system where there is a lead dairy developing a clustered upgrading and injection facility that is working with neighboring dairies to produce the lowest cost RNG.

For transportable resources, the initial resource assessment is similar to finding the technical resource availability at a given location and the cost of accessing it. The GBSM uses this resource base along with a set of potential locations for production facilities, the cost of transportation, techno-economic models of the conversion technology, and the cost of pipeline access to find the profit-maximizing configuration of RNG production facilities and allocation of resources to those facilities. GBSM is a mixed integer, linear programming model with an objective to maximize the profit from producing biomass-based fuels. The cost and production potential for individually-sited production facilities can be used to produce a supply curve for a given resource type.

The supply curves for individual resource types are aggregated to produce an aggregate supply curve. Sensitivity analysis can be performed using this framework on the various costs in the system, potential resource limitations, or regional differences in policies that may impact prices or costs.

In the next section, we discuss the technology cost assumptions in the assessment. After that we discuss the individual resource assessments, and finally the results.

2.1.1 Technology Cost Assumptions

2.1.1.1 Anaerobic Digesters at Dairies

Anaerobic digesters for animal manures and MSW have separate cost functions due to the significantly different qualities of the feedstock and the objectives and constraints of the industries with control over the resources. These costs are in addition to the upgrading/injection and distribution pipeline costs discussed below.

Dairy digesters serve as part of a manure management system. There are a variety of designs but two general systems are considered here, covered lagoons and reactor or tank digesters which include complete mix and plug flow reactors. Covered lagoons are earthwork lagoon that are lined and covered with impermeable material to create a digester. It has the advantages of lower capital and the potential for retrofit for dairies with existing lagoons, which accounts for 60% of the state's dairy herd. The tank digesters offer higher biomethane yields but at a higher capital cost from the construction of an above ground tank system. As of May 2015, there are 199 operational dairy digesters in the United States according to the EPA's AgStar database[32]. In California there are 20 digester projects, 13 of which are covered lagoon digesters. Only five of the projects nationwide utilize the biogas for production of CNG.

There is a wide range of estimates for dairy digester cost. Some of the factors causing the diversion are due to local parameters including regulations and environmental factors. Two estimates have been made from the national AgSTAR database. The most widely used is a linear regression of the capital costs as a function of the number of cows on the farm[33]. A study by Iowa State University found a power function curve fit the data better[34]. The national average costs estimates are a poor match for Californian projects. UC Davis reported cost functions informed by proposed California projects and studies that was significantly higher than the functions based on the AgSTAR database[35]. These estimates of dairy digester costs are shown in Figure 11. The UC Davis study includes an estimate for covering existing lagoons and flaring the biogas. This estimate is higher than the AgSTAR estimate for a covered lagoon digester. For this study, we have deflated the UC Davis cost estimates somewhat while keeping the comparative difference the same (“Covered Lagoon” and “Tank” curves in Figure 12).

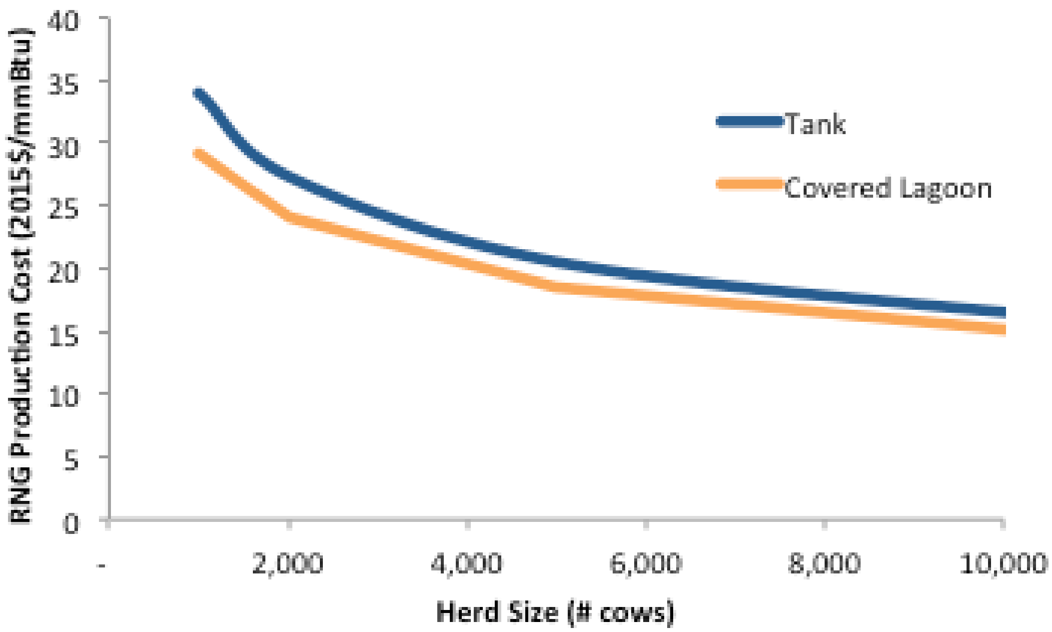

Figure 11. Economies of scale for dairy digesters.

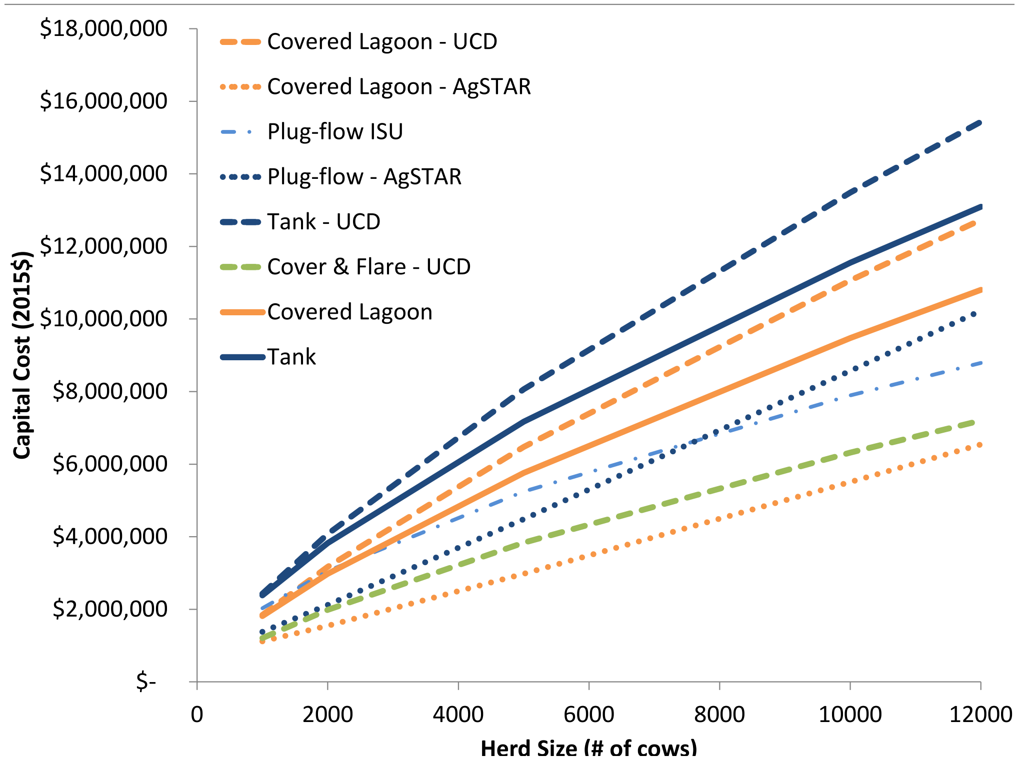

Figure 12. Estimates of dairy digester capital cost.

2.1.1.2 FOOD AND GREEN WASTE ANAEROBIC DIGESTERS

The cost of production for food waste and green waste digesters demonstrate strong economies of scale as seen in Figure 13. Our estimate for MSW digesters is fitted to data from Rapport et al (2008) with the costs updated to 2014 dollars. Biomethane production is assumed to be 2.16 mmBTU/wet ton of waste digested based on the composition of food and green waste currently landfilled that could be made available to digesters. The costs were adjusted to be biogas production by subtracting the cost of power generation equipment. It is important to note that these costs are non-feedstock.

The food/green waste AD scenario limits the facility size to 200,000 tons per year (tpy), which is the size of a large landfill operation in California, due to practical feasibility for siting and permitting of the facility. For comparison, the size of the Zero Waste Energy facility located in San Jose is 90,000 tpy.

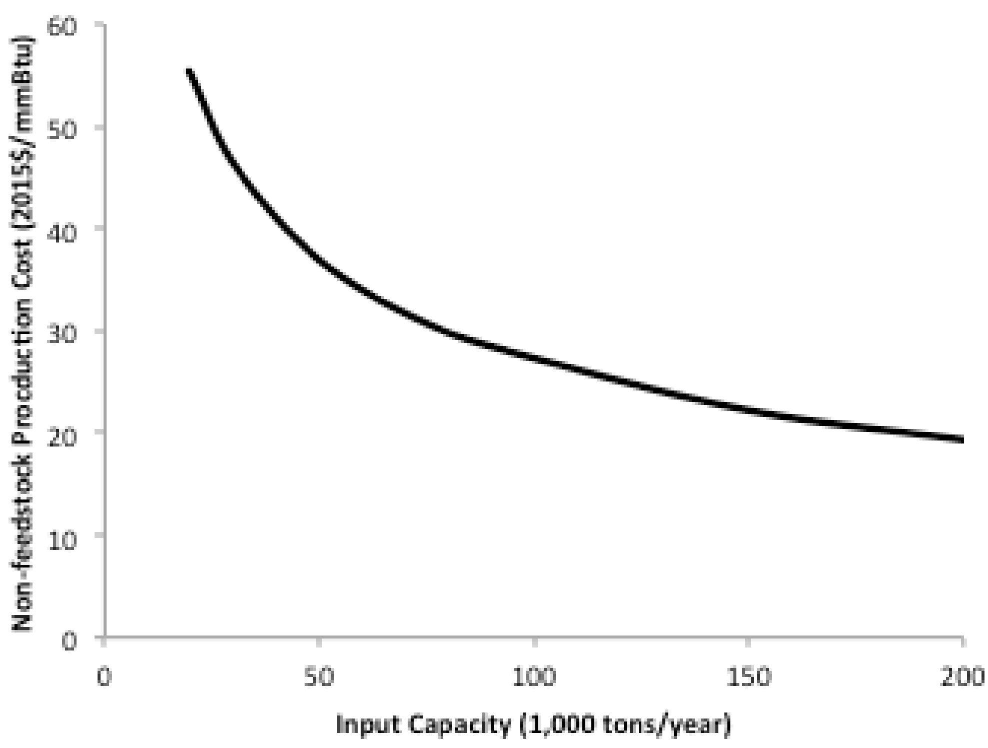

Figure 12. Economies of scale for MSW digesters (excluding tipping fees).

2.1.1.3 Biogas clean-up and upgrading

The cost of upgrading biogas to RNG and the injection station for pipeline injection demonstrate significant economies of scale. The cost for biogas upgrading including an injection station is shown in Figure 14 below with our estimate developed from Electrigaz (2011) and public comments to the CPUC. The Electrigaz study considered upgrading of biogas and injection of RNG into the existing natural gas pipeline in Ontario, Canada for three sizes of landfills, three sizes of dairy digesters, two industrial digesters and one size of waste water treatment plant.

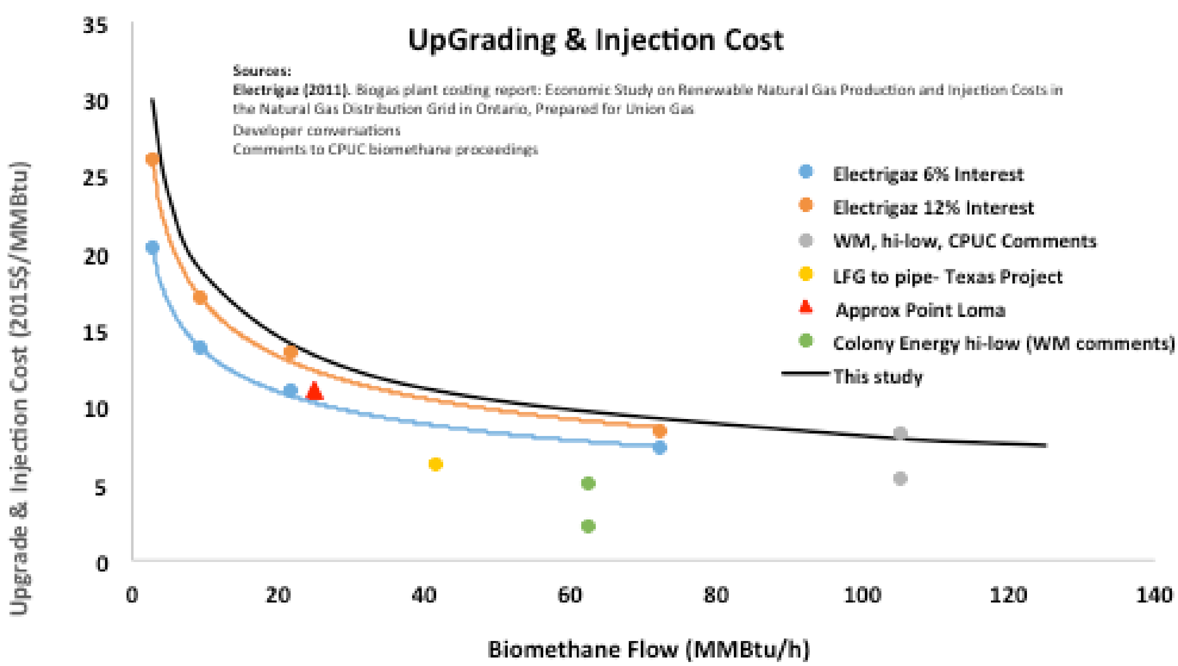

Figure 13. Upgrading and injection cost curve fit to the Electrigaz (2011) study.

The costs include the clean-up to the pipeline specification shown in Table 3. Each individual case had a unique configuration of clean-up/upgrading equipment.

For the purposes of estimating the costs across the hundreds of sources in California, we did not analyze each site to provide a unique clean-up configuration recommendation for each site but rather fitted a cost curve to the data from the Electrigaz study to give a good estimate of the cost while taking into account the scale of the resources at a given location. In addition, we have modified the cost function to account for higher costs of interconnection in California based on industry comments to the CPUC. The cost of capital was adjusted to reflect a 12% rate of return. The curve fit is shown in Figure 14 above.

Using a Canadian report (Electrigaz, 2011) for estimating the cost of upgrading biogas to pipeline quality raises some issues given California's stringent pipeline standards. The properties of the RNG in the study here are given in the table below. Of note, the oxygen limit in the study is higher than California's standard (0.4 mol% compared to 0.1 mol% for the standard). These cost estimates were used due to lack of data at the time of analysis for the cost of meeting the California standard across a wide range of biogas resources and scales of operation.

Table 3. Specification of RNG used in the analysis

Physical Properties	Upper Content Limit	Units
Heating Value (MJ/m3 101.325 kPa, 15C, Dry)	*36.0 to 40.2*	*MJ/M3*
Carbon monoxide	*0.5*	*mol%*
Carbon Dioxide	2	mol%
Oxygen	0.4	mol%
Hydrogen Sulphide	7	mg/M3
Sulpher (in total)	100	mg/M3
Mercaptans or Methyl Mercaptan	5	mg/M3
Water Content	80	mg/M3
Hydrocarbon Dew Point	-10	°C
Gas Interchangeability	YT, flashback, lifting factors range of permiting according to AGA Research bulletin No.36	
Temperature	43	°C
Particulates	shall be commercially free of	
Bacteria	shall be commercially free of	
Hydrogen	Trace	
Ammonia	shall be commercially free of	
Chlorinated & Fluorinated Compounds	shall be commercially free of	
Heavy Metals	shall be commercially free of	
Siloxanes	shall be commercially free of	
Aromatics	shall be commercially free of	

Sand, dust, gums, crude oils, lub. Oils, liquids, chemicals or compounds used in the production, treatment, compression or deshydratation of the gas or any other objectable substance present in sufficient quantity so as to render the Gas toxic, unmerchantable or cause injury to or interference with the Gas pipelines, regulators, meter or other appliances through which it flows, or their operation

2.1.1.4 PIPELINE TO INJECTION STATIONS

Pipeline costs are estimated at $1 million per mile based on updating the EPA Region 9 natural gas pipeline costs for 2 to 8 inch pipelines found in Brown et al (2011) to 2014 dollars. The cost for each facility is then dependent on their distance to the pipeline.

The distance from each dairy to the nearest natural gas transmission pipelines were calculated using ArcGIS 10.3. The distance found is the shortest straight-line path between the dairy and the pipeline. For example the fraction of manure resources versus the distance to a NG pipeline is shown for California dairies in Figure 15. We have included a tortuosity factor of 1.3 in estimating the required pipeline length as the pipeline route will not be the shortest path due to terrain, land use and land ownership factors. Pipeline routing is beyond the scope of this work.

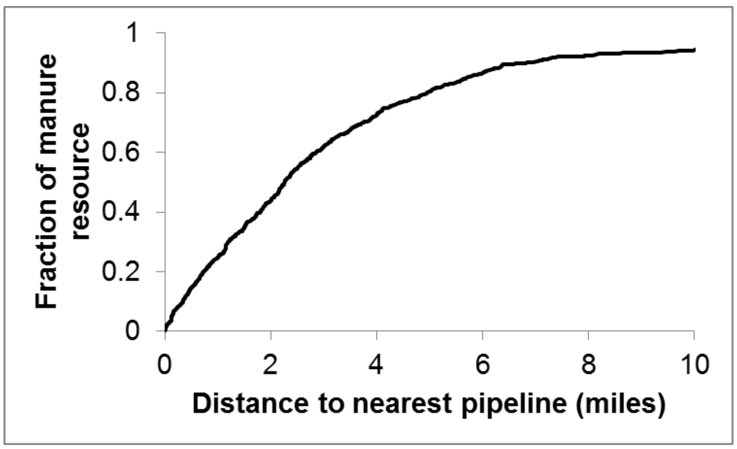

Figure 14. Distance to nearest pipeline from California dairies.

2.1.2 FEEDSTOCK RESOURCE ASSESSMENTS

Each type of resource has a unique footprint in California and the methods of estimating the local availability of the resources vary between these resource types.

2.1.2.1 ANIMAL MANURES

The California Biomass Collaborative (CBC) estimates the gross production of manures of 11.9 million bone dry tons (bdt) per year from the agricultural animal population. The majority of this resource is not available as manures deposited in fields are not feasible to collect. Rough technical availability factors used in the CBC resource estimate by animal type reduces the resource to 4.4 million BDT/yr. Dairy manures make up 82% of this resource estimate and are the focus of the work here. The biogas produced from the manure resource can be used to produce distributed electricity or heat and power instead of RNG.

There are no dairy digesters producing electricity in California though many exist elsewhere in the country.

Data on the location and size of dairy herds in 2011 and 2012 were obtained from Central Valley Regional Water Quality Control Board and the Santa Ana Regional Water Quality Control Board, which represent 96% of the total dairy herd of the state. Dairies in California range in size from 10 to nearly 11,000 mature cows. This manure represents a technical RNG production potential ranging from 100 to 100,000 mmBTU per year for the smallest to the largest dairy. The dairy manure density in California is mapped in Figure 16. There is a concentration of dairies in the San Joaquin Valley where the majority of the resource is located.

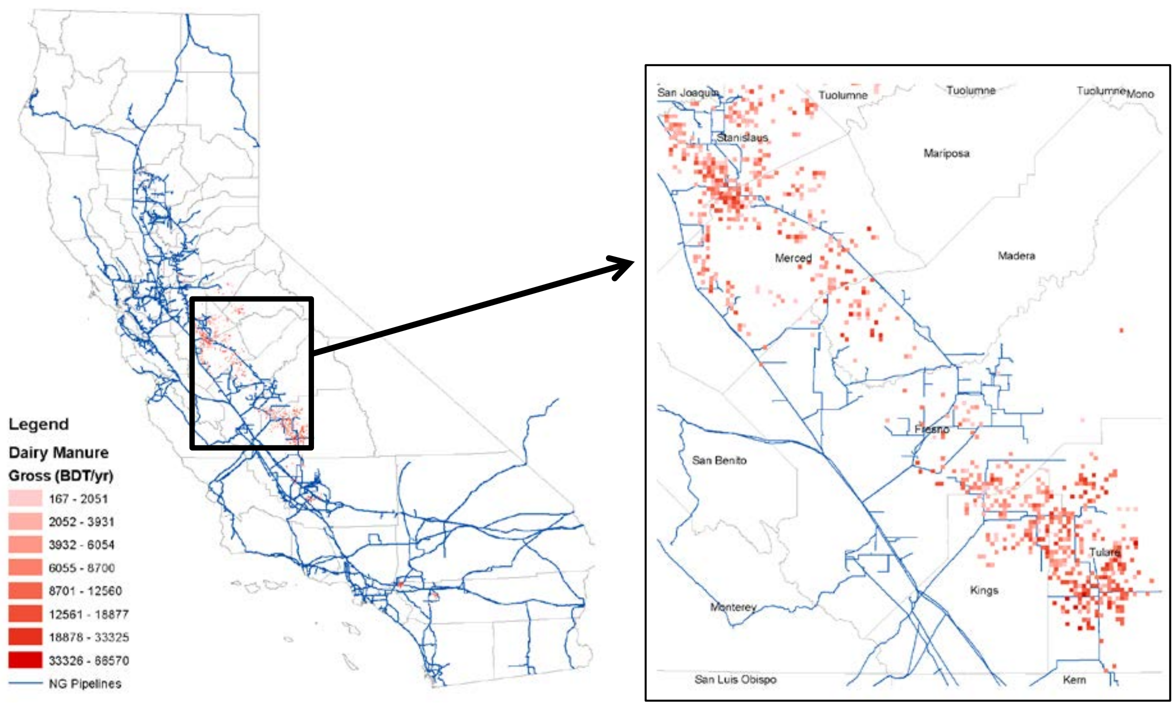

Figure 15. Concentration of Dairy Manure Production in California

2.1.2.2 Waste-water Treatment Biogas

Many of the waste-water treatment plants in California use anaerobic digestion to reduce the nutrient load. This results in biogas that can be upgraded to renewable natural gas. Of the 150 waste-water treatment plants in the California Association of Sanitation Agencies with anaerobic digesters, 56 are currently producing heat and power for the facility from their biogas and 8 are producing heat. These facilities with energy production currently produce roughly 4 bcf year of biomethane. The potential for RNG production from WWTP with anaerobic digesters (but no energy production) was analyzed.

Waste-water treatment plants with excess capacity in their digesters could increase production of biogas by supplementing the digester feed with additional digestible material. Waste fats, oils and grease supplementation have the potential to greatly increase biogas production as they produce more methane per volume compared to typical waste water. Food waste could also be used to supplement the digester feed.

An additional opportunity exists for switching existing combined heat and power facilities to produce RNG due to air quality regulations. The majority of existing facilities use reciprocating engines for the production of heat and power. These systems have high air pollutant emissions compared to large scale natural gas combined cycle power plants and would be difficult and expensive to meet tighter air quality regulations.

The biogas production from each of the waste water treatment plants was estimated using the reported average flow rate of waste water acquired from the California Association of Sanitation Agencies. A factor of biogas production per throughput of waste water was applied to each facility to estimate the total biogas and also the methane production potential. The factor used here is 1.15 ft3 of biogas produced per 100 gallons of waste water processed with a methane content of 65%.

2.1.2.3 LANDFILL GAS

The production of landfill gas depends on the quantity, composition of material deposited in the landfill, and the humidity and packing conditions in the landfill. The more material in a landfill, the more methane it will generate; further, the more organic material in a landfill the more methane it will generate. The decomposition, which produces methane, is generally modeled as an exponential decay function. As time passes, methane yields will be lower[36]. Ideally, a resource assessment of landfill gas would use historical landfill disposal data and projections of future disposal to generate a projection of landfill gas production over time for each landfill in the state. For this project, we take a more coarse approach using current landfill gas production rates from the EPA's Landfill Methane Outreach Program (LMOP)

The LMOP has collected a database of landfills in the country. In this database, an estimate of current landfill gas production is made for the majority of the landfills. In California, 147 of 314 landfills in the database have an estimate of landfill gas production. These 147 landfills contain 92% of the reported waste in place in landfills in California. The total production of methane from these landfills is approximately 82 bcf per year or about three fourths of the resource estimated by California Biomass Collaborative using disposal rates for the state as a whole. About 55% of this production or roughly 45 bcf is being converted to electricity and the remaining 37 bcf is collected and flared.

2.1.2.4 Food and Green Waste

Food and green wastes can be intercepted before the landfill to produce RNG at a dedicated MSW anaerobic digester. The California Biomass Collaborative estimates that 1.2 million bdy/yr of this resource could be utilized if it can be economically separated from the waste stream[35]. Exploiting this resource can be done in two ways – source separation and mixed digestion of a sorted waste stream. These resources are best suited for anaerobic digestion due to high moisture content and high biodegradability. The currently landfilled food waste and green waste represents 8 bcf of RNG potential.

The food and green waste resource is modeled spatially as being available at the landfills where they are currently disposed. The quantity of total landfill disposal at each landfill in the state is taken from the Solid Waste Information Systems (SWIS) database, and the food and green wastes fractions are applied based on the most recent waste characterization study. This resource is assumed to generate a tipping fee for the facility that receives it. We have used regional average tipping fees from the CalRecycle 2015 report on tipping fees across California[37] to assign tipping fees across space. The tipping fees range from $21 to $34 per ton in the base case.

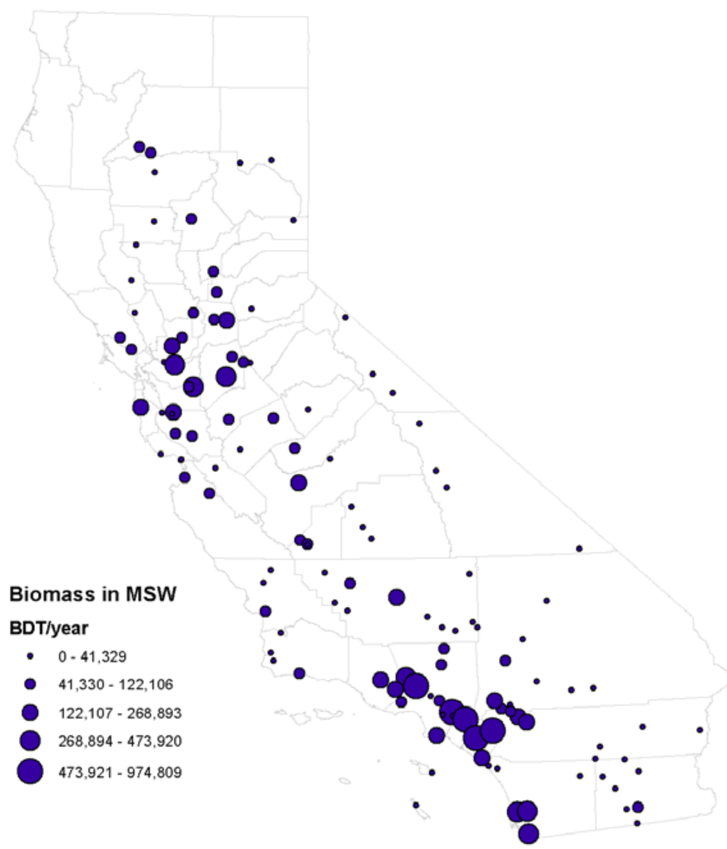

Figure 16. Concentration of MSW resources in California

2.1.2.5 Woody biomass

The high resolution California resource assessment has been updated using county level data from the most recent California Biomass Collaborative Resource Assessment[35]. Woody biomass sources considered were from California agriculture and forestry wastes.

Principal sources of woody biomass from agriculture in California are residues and removals of orchards and vineyards. The California Biomass Collaborative estimates that there are 6.2 million bdt of crop residues and processing wastes generated in the state. Of this they estimate that 4.6 million BDT is technically available. The majority of this resource is produced from 5 crops (almonds, pistachios, walnuts, citrus (aggregated) and grapes). Limiting our analysis to these crops reduces the total technically available resource considered in the modeling to 4.3 million bdt.

The resource assessment is performed at the county level using county agricultural commissioner reports on the total area planted in each crop. To allocate the resource at a higher spatial resolution we have used the Pesticide Use Report (PUR) data, which reports pesticide use and crop area at the section level of resolution. The crop areas reported by the two sources do not match exactly. To correct for this discrepancy, the county commissioner data were used to scale the PUR data so that the total crop area within each county matches the areas reported by the county commissioners. The locations of the processing facilities were unknown. For modeling purposes the processing wastes were assumed to be located in the fields. Figure 18 shows the spatial layout of agricultural biomass.

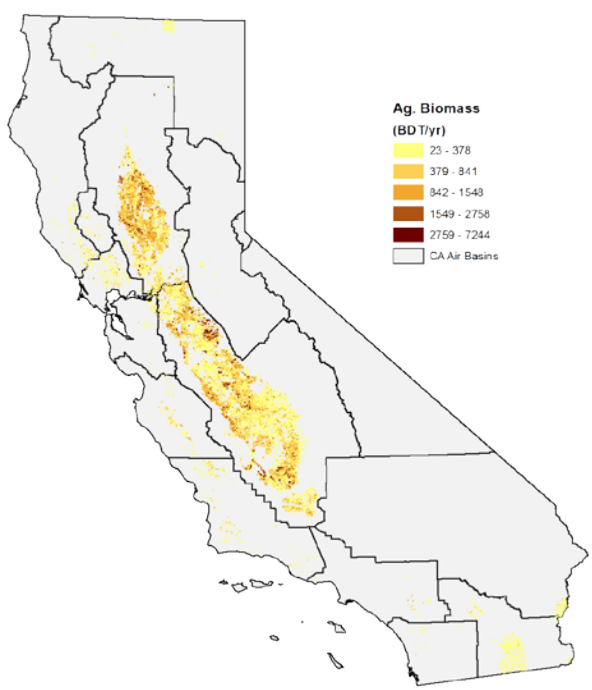

Figure 17. Map of Agricultural Biomass in California

The four main categories of forestry biomass are logging slash, mill residues, biomass from forest thinning and stand improvement operations, and chaparral. Mill residues were computed by factoring timber harvest data. Logging slash, mill residues, and forest thinnings are already in commercial use as fuel for power generation. Harvesting of chaparral has not been conducted on a large scale in California so far.

Estimates of forest residue in California have a wide range. The California Department of Forestry and Fire Protection (CALFIRE) developed an assessment in 2005 by applying a realistic but limited number of commercial thinning and fuel reduction prescriptions at a very high spatial resolution of a 100-meter grid[38]. This assessment has been the basis for California Biomass Collaborative assessments since 2005. Tittmann et al (2008)[39] used the data from the CALFIRE assessment and the Fuel Reduction Cost Simulator[40] to develop a high-resolution resource assessment that includes the cost of acquisition. These assessments produce high estimates of forest biomass because they do not account for limits on the industry capacity for implementing the prescriptions along with other factors.

A national assessment of forest biomass by United States Forest Service (USFS) applies constraints to the production of forest products based on historical activities within a county[41] (Skog et al, 2008). The assessment results in estimates of biomass volume that is less than half the CALFIRE estimate but is only available at the county resolution. We have used the USFS resource assessment but scaled it to a 5-kilometer grid using the high resolution data set from Tittmann. The downscaling of the assessment is particularly important in the California context where counties are large and irregularly shaped. Distributing the resource uniformly across a county would result in large estimates of forest availability in the Central Valley as counties from the Valley extend into the Sierras. Figure 19 shows the estimate of forest residue that is available for less than $50/BDT at the forest landing.

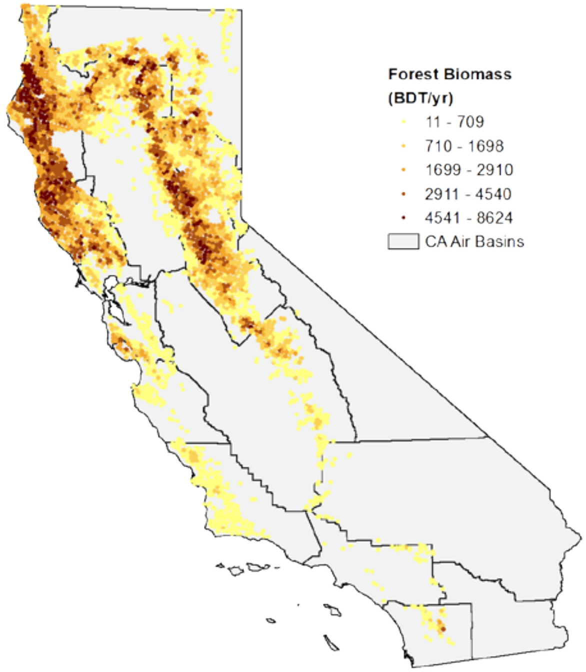

Figure 18. Forest Residue Estimate for California

2.1.2.6 Integration of RNG into the existing natural gas network Methodology

To model the potential for natural gas demand in the transportation sector, we employ the ITS-Davis model of natural gas refueling infrastructure for Class 8 Heavy-Duty trucks.[42] In this model, at roughly five-year increments from 2012 to 2030, we model natural gas refueling location and pathway choice, truck traffic and portion of that traffic that is made by natural gas trucks, and the price differential between diesel and natural gas fuel, to inform natural gas truck adoption in the next period.

We create a modeling framework that utilizes spatial mapping of existing major California highways and refueling infrastructure for long-haul trucks to make infrastructure planning decisions. Spatial network theory and network analysis is utilized to generate all of the spatial information that is needed to calculate the profitable trucking corridors to establish a natural gas refueling infrastructure.

Our spatial optimization model is designed to determine the most profitable transportation networks and locations for natural gas flows into transportation markets in California using the spatial infrastructure data, and to compare costs for transportation of natural gas by source, distribution method, and other market development costs. We consider the two alternative NG delivery routes. The first delivery route is the conventional LNG pathway. In the conventional pathway, natural gas is delivered from the supply site to a liquefaction plant via pipeline. After it is liquefied, it is delivered by truck to a refueling station and put into a storage tank.[2] LNG is then dispensed out of the storage tank at the refueling station. The second delivery route is the CNG pathway. In this pathway, natural gas is delivered from the supply site directly to the refueling station via pipeline. At the refueling station, natural gas is then compressed onsite and dispensed as CNG.

At each candidate refueling station site, we consider the cost of dispensing natural gas on a per LNG gallon basis taking into account station capital cost, operating and management cost, feed-stock cost, trucking cost, pipeline transport and construction costs, and lastly, electricity cost. These costs were collected through extensive interviews with equipment manufacturers and suppliers, NG fueling system operators and investors as well as from data provided by consultant studies and interviews with consultants, industry specialists and government regulators who study these networks. At each candidate site, we select the technology and capacity that minimizes the delivered per gallon price. This comprehensive assessment tool is aimed to simulate the potential volumetric capacity for the natural gas transportation market in the United States, as well as to choose the optimal location of new and existing fueling facilities subject to this simulated volumetric capacity.

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[2] We assume that trucking costs are $10/mile per truckload with a typical truckload equal to 12,420 LNG gallons. Therefore, we use $0.00085 per mile per gallon as our estimate cost of delivering LNG by truck.

We solve our model at roughly five-year increments from 2012 to 2030.[3] At each of these five stages during the time horizon, we update the station specific LNG demand and then solve for the optimal choice of new station construction and existing station upgrades taking the current state of the LNG infrastructure as given.

2.1.3 Constraints

In addition, one unique feature that we must address is to explicitly consider vehicle range. LNG fuel contains roughly 60% of the energy density of diesel fuel, which makes LNG trucks' range limited when compared with traditional diesel trucks. In the optimization model, when selecting candidate refueling station sites, we include the constraint that stations along a route are only constructed if the route taken as a whole is profitable and that the route can be feasible. The profitability constraint does not require that each station is profitable, but rather if there are unprofitable stations along a route, the more profitable stations must earn enough to compensate for the stations operating at a loss. Secondly, the feasibility constraint requires that stations must be no farther apart than the maximum range of LNG trucks. It is this feasibility constraint that sometimes leads to the construction of unprofitable stations in order to ensure that a route can be traversed by LNG vehicles. However, the profitability constraint requires that the losses incurred by unprofitable stations are at least offset by profits at more financially successful stations.

2.1.4 Optimization

The optimization model chooses the optimal locations, technologies, and capacities for LNG stations from a set of existing diesel truck stops.[4] A binary decision making process will decide whether or not to construct a natural gas fueling options at any given diesel truck stop. The model selects the type of LNG station based on the optimal options for liquefaction plants, from a set of existing candidate locations and related fueling station locations within its commercially profitable sphere of operation. These candidate locations are selected as point locations near pipelines with the highest number of interconnections and from existing petroleum terminal locations. During the solution process, the model implicitly decides the extent to which natural gas is piped and LNG trucked at any point in the supply chain in order to maximize total system profits. Lastly, the model decides the quantity delivered between supply source and the destination NG station where demand is fulfilled.

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[3] We solve our model for the years 2012, 2015, 2020, 2025, and 2030.

[4] LNG refueling station locations are chosen from the set of existing diesel locations for tractability purposes. Choosing locations from a finite set allows the model to solve much more quickly than allowing free choice of location.

2.1.5 Natural Gas Vehicle Adoption

To determine the amount of new demand for natural gas fuel that can emerge in any given year, a trucking demand model was developed to represent the constraints on demand growth through the natural rate of truck turnover and the economic competitiveness of LNG across the distribution of truck use. The demand for LNG from trucking is tied to the turnover of trucks in the market and the competitiveness of LNG as a fuel, including both the cost of the truck and the cost of the fuel.

To calculate the volume of trucks converting to LNG, the truck fleet turnover rate uses historical data on the distribution of the truck fleet by model year in 2012, the survival of trucks as they age, and a sales-to-scrap ratio to grow the fleet over time.

For each year, a set percentage of trucks of a given age are scrapped based on historical survival rate of trucks. Historically 50% of trucks are scrapped by the time they are 16 years old and very few trucks survive to age 30.[43] The fleet grows by using a sales/scrap ratio. For 2012-2020 the ratio is assumed to be 1.1 and for 2021-2030 it is assumed to be 1.2.[44] These assumptions increase the size of the truck fleet from 3.2 million in 2012 to 3.8 million trucks in 2030.

Older trucks stay in operation, but they shift to lower mileage applications so their contribution to the energy demand (% of truck miles traveled) is less than their population suggests. To capture the distribution of truck miles by age and use, we use the Vehicle Inventory and Use Survey from 2002. The 2002 data are the most recently available data available to assess truck miles between trucks of different classifications.

We are able to use our calculation of the distribution of use to determine the percent of truck miles traveled by trucks in each age group, which can then be applied in the fleet turnover model to determine the fraction of truck miles that are traveled by trucks in each model year. This allows us to track the influence of new trucks over time on the potential LNG market share.

The decision to purchase LNG trucks instead of diesel trucks is represented in the model by a discounted 3-year payback rule. Three years is selected based on the commercial practices of large scale fleet operators. It is typical industry practice to purchase new vehicles every three years and then to resell the vehicle into the secondary market. Because our projections for demand for NG vehicles are based on new vehicle purchasing, we consider this standard duration for vehicle turnover in our calculations. Based on interviews with owners of large truck fleets, we assume that purchasers will want to have the higher cost for a natural gas vehicle to be paid back during the operation of the vehicle prior to its resale in the secondary market. In the model, if LNG trucks offer a 3-year or less payback, then the LNG truck is purchased. Otherwise, the diesel truck is purchased. As discussed, this decision is based on the overall pattern of the purchasing decisions for new vehicles in the heavy duty sector. The payback is sensitive to the cost of the LNG truck, annual mileage of the truck, the relative fuel economy, and the maintenance costs differential. The model finds the price gap between diesel and LNG that makes LNG the better deal, so while diesel price is important it is not a parameter in the model. The broad distribution of annual travel for new trucks found in the VIUS 2002 data leads to a demand curve for LNG trucks as a function of the diesel-natural gas price differential, holding all other parameters constant. At small price gaps only the trucks with the highest travel will find LNG competitive, but as the price gap grows larger, percentages of the new truck buyers will find LNG attractive.

2.1.6 Delivered Fuel Demand

With all of the above components of the model calculated, we are finally able to compute estimated natural gas fuel dispensed at each station within California in both LNG form and CNG form. The amount of fuel demanded is calculated as the annual truck traffic, multiplied by the station specific penetration rate of natural gas vehicles, divided by the fuel efficiency of natural gas trucks. With the fuel demand, we are then able to compare the quantity of natural gas that we estimate to be consumed by the Heavy-Duty Trucking sector, and the amount that can be supplied by RNG sources.

2.1.7 Supply of RNG

Our study period begins in 2013 and extends into the 2020s. We consider the volume of RNG that can be commercially feasible under market conditions where the price of commodity natural gas starts at $3 per mmBTU and follows the price curve for future years available in the commodity futures and derivatives markets, which at the time of the study was being undertaken generally ranged from between $2.80 per mmBTU and $4.15 per mmBTU. This represents a market price that is available to be locked in by commercial investors and is the price competition point for businesses and investors considering making capital allocations for RNG production and distribution systems. Given the stable forecast of natural gas prices in the futures market, and due to the opportunity to lock in prices via hedging, we consider a stable price of natural gas at $3.00 per mmBTU in 2015 dollars. All cost figures in consideration in this report are updated to 2015 constant dollars. Future use of this report will require updating from 2015 dollars to current dollars at the time of use.

Under existing alternative fuels support programs like the LCFS, a substantial portion of natural gas consumption in the transportation sector can be satisfied by RNG if current carbon credit prices persist into the future.

The portion of natural gas transportation fuel that is supplied from RNG sources depends entirely on how quickly and extensively natural gas fuel demand expands. We consider a variety of scenarios based on different initial penetration rates of NG vehicles, varying diesel prices, and the level of LCFS credits that is available to facilitate RNG production. Even with the benefit of carbon credits, our scenario analysis shows that even as the natural gas trucking sector grows, commercial cost barriers, including high clean up and interconnection charges inside California, will limit the portion of the increased fuel demand that can be filled by renewable natural gas sources. Specific details are found below in our discussion of modeling results.

2.1.8 Spatial Distribution of RNG Sites

The supply of RNG is split roughly 50-50 between Northern and Southern California. Most dairy sites are situated in the Central Valley and most landfill sites are situated inland from the coast in Southern California. Municipal solid waste sites and wastewater treatment plant sites are distributed throughout California.

2.2 LCA SENSITIVITY METHODOLOGY

California's Low Carbon Fuel Standard (LCSF) was originally adopted in 2009[45]. The law specifies that carbon credits are granted when a company produces a fuel with a carbon intensity that falls below the specified regulated annual target. The carbon credit is proportional to the magnitude of reductions and thus depends on the carbon intensity of each fuel. Originally, the Air Resources Board (ARB) produced a lookup table with carbon intensity estimates of each fuel (Method 1 values)[46]. Additionally, users could submit their own pathway estimates using guidelines in Method 2A/2B[47].

Both Method 1 and Methods 2A/2B values were estimated utilizing the model CA-GREET1.8b version. CA_GREET is a life cycle analysis (LCA) model originally developed by Argonne National Lab (ANL) and known as GREET but adapted to California by ARB. M1 and M2A/2B values are due to expire at the end of 2016. After that, new estimates will have to be produced with the newer version CA-GREET2.0. Changes in the new version are documented in the "CA-GREET 2.0 Supplemental Document and Tables of Changes"[48]. ARB continues to provide a lookup table for a limited number of fuels, and producers continue to have the option submitting their own estimates as long as they are produced with CA-GREET2.0.

We have used carbon intensity values from ARB's new lookup table[49] (Table 4) when testing the effect of LCFS credit on the commerciality of renewable natural gas potential in this report (see " Renewable Natural Gas Response to the Low Carbon Fuel Standard" section).

Table 4. Carbon Intensity lookup values by ARB 2016 using CA-GREET2.0

Fuel Pathway	Carbon Intensity $\frac{gCO_2e}{MJ}$
Diesel*	102.01
Gasoline*	99.78
Fossil CNG†	78.37
Landfill CNG†	46.42
WWTP CNG*	19.34
MSW CNG*	-22.93
Dairy CNG‡	-276.24

*California Code of Regulation Title 17, §95488, Table 6. Carbon intensity for WWTP is the average of two WWTP pathways.
†California Code of Regulation Title 17, §95488, Table 7.

†Method 2B Application CalBio LLC, Dallas Texas, Dairy Digester Biogas to CNG.

It should be noted, however, that there is sufficient variability in RNG production pathways to grant a large group of possible values. While such variations are characteristic of LCA in general, bioenergy systems are particularly diverse. As Cherubini notes for bioenergy systems, "Differences are due to several reasons: type and management of raw materials, conversion technologies, end-use technologies, system boundaries and reference energy system"[50].

To begin our discussion of the life cycle analysis of bioenergy, therefore, we believe it is useful to lay out some of the major differences that are encountered. In this section, we use the CA-GREET2.0 model to test the sensitivities in the carbon intensity calculations.

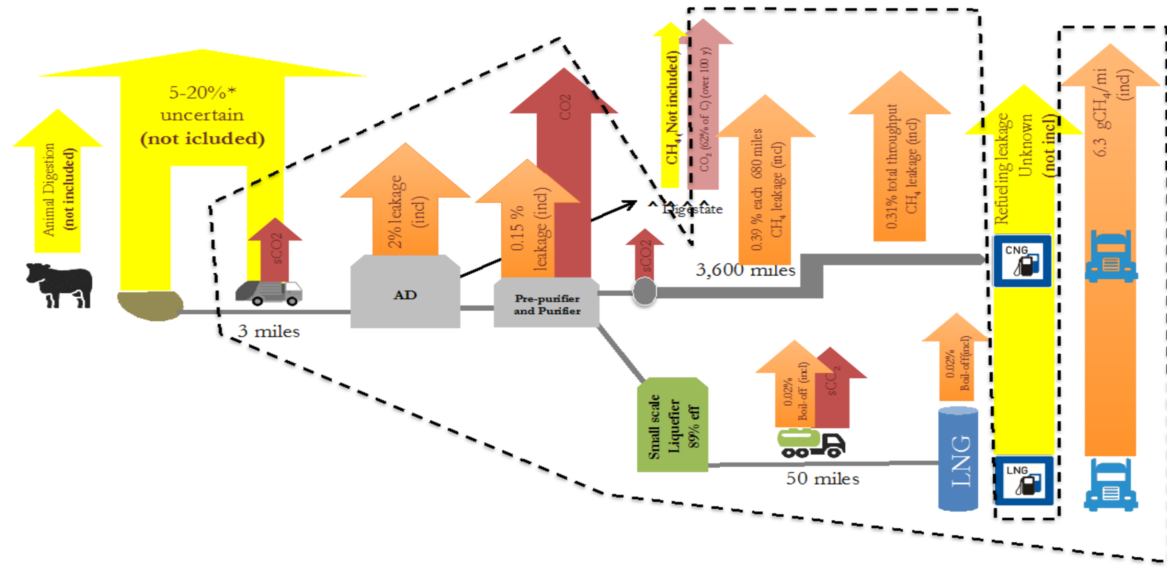
2.2.1 CA-GREET2.0

In the LCFS readopted in 2015, fuel pathways are grouped into either Tier 1 or Tier 2 and slightly different versions of the model are used to calculate Tier 1 and Tier 2 CIs. These versions contain the same data tables but differ in how the carbon intensities are calculated. The Tier 1 version is called CA-GREET2.0-T1, while the Tier 2 version is called CA-GREET2.0-T2, and they are collectively referred to as "CA-GREET 2.0."[51]. Tier 1 includes 23 common conventionally produced first-generation fuels (starch- and sugar-based ethanol, biodiesel, renewable diesel, CNG, LNG). Tier 2 includes next-generation fuels (cellulosic alcohols, hydrogen, drop-in fuels, etc.) or first-generation fuels produced using innovative production processes. We use the CA-GREET2.0-T1 version (downloaded June 2016) for our sensitivity analysis. It must be noted that ARB might use CA-GREET2.0-T2 or other approaches such as the "ARB Compliance Offset Program"[52] in the case of renewable natural gas fuels and differences in results might arise.

2.2.2 Assumptions Affecting LCA Results

2.2.2.1 System Boundaries

Well-to-wheels analyses aim at including all aspects in the fuel supply chain. However, this is not practical since some data are non-existent or uncertain and some boundaries to what is being modelled must be set. The model used in this report, CA-GREET2.0, will include emissions from energy use (red in Figure 20) in manure management operations, but methane leakage (yellow/orange in Figure 20) from those are uncertain[53] and not included. This is also the case in refueling operations. The system boundary is shown in dashed line in Figure 20.



*"Waste-to-Wheel Analysis of Anaerobic-Digestion-Based Renewable Natural Gas Pathways with the GREET Model" by Jeongwoo Han, Marianne Mintz, and Michael Wang Center for Transportation Research Energy Systems Division, Argonne National Laboratory September 2011. ANL/ESD/11-6

Figure 19. System boundaries used in GREET and CA-GREET marked with dashed black line. Energy-related CO_2 emissions (red) and methane leakage (Orange). Uncertain volumes in yellow.

2.2.2.2 Reference and Counterfactual

Collecting and using biogas avoids emissions that would have occurred if the organic waste had been left to rot. It is the avoided emissions what makes renewable natural gas a negative carbon fuel but how negative depends on the change of fate of the material in the current versus avoided situation. In the well-to-wheels (WTW) analysis of renewable natural gas, the carbon footprint is calculated by subtracting the avoided emissions (defined in the reference case) from the emissions associated with the new use (alternative case or counterfactual). In this report, the counterfactual is used as transportation fuel (either on-site or off-site), but the reference case depends on the type of feedstock and what kind of emissions management was already in place.

In the case of landfill gas, the reference case could be: 1) gas is vented, 2) gas is flared, or 3) gas is used for electricity generation that displaces electricity from the grid. Flaring is a management strategy that reduces carbon emissions by approximately nine-fold[5] (assuming a 100 year GWP of methane of 25 (mass based), and given that oxidizing one gram of CH_4 produces 2.75g of CO_2 mole of CH_4,). An even better outcome can be achieved if the landfill

[5] Complete oxidization of one mole of CH_4 produces one mole of CO_2. However, the molecular weight of CO_2 is about three times higher than that of CH_4 (16 for CH_4, and 44 grams for CO_2). The net effect is calculated by dividing the 25 GWP by the 2.75 equivalent produced mass, resulting in about a nine-fold reduction in the final greenhouse effect of the gas emitted.

gas is burned for electricity generation since some useful work can be obtained in exchange of emissions. Since 1996, landfills with a permitted capacity greater than 2.5 million cubic meters or 2.5 million megagrams of waste must control their air emissions by capturing the landfill gas[54] and then flare it or use it as a fuel for electricity generation, or transportation. However, new stationary source limits for NOx are making power generation from biogas less attractive, therefore producing renewable natural gas as a fuel is an alternative with growing potential.

For any given unit of gas collected, there is a larger opportunity of emissions reduction if the gas is generated in smaller landfills where the gas would otherwise be vented. However, although less than half of the 2,434 landfills in the United States have flaring equipment in place, those constitute 85% of the solid waste landfilled in the country[55] (Table 5).

Table 5. Number of landfills and amount of solid waste landfilled, with and without flaring equipment based on LMOP Database

	Number of landfills	**Solid Waste Landfilled (billion tons)**
Landfills without flaring equipment	1,349	1.1
Landfills with flaring equipment	1,085	6.1
Total	2,434	7.2

The reference case for municipal solid waste is landfilled. The counterfactual would be separating the MSW and sending it to an anaerobic digester for RNG production. Higher emissions are associated with a separate waste collection line but the anaerobic digester produces also higher conversion and collection efficiencies than uncontrolled landfill digestion. The organic (digestible) portion is typically comprised of food waste and green waste. The State of California has a target to reduce landfilling of solid waste by 75 percent in 2020, with a new proposal on the table for diverting 90 percent of organics from landfills through source reduction and organics recycling by 2025 (80 percent reduction from current levels)[56].

The reference case in CAGREET2.0 for Dairy manure is storage in lagoons with capture and flare of methane. However, producers can now use the CARB Livestock Offset Verification

Protocol, for crediting the avoided venting of methane. The counterfactual is collecting the manure and transporting it to an anaerobic digester for biogas production[6].

The reference case for forest and agricultural waste is being left to rot naturally (which could act both as a carbon sink or source- the literature is extensive on this, and is also depends on the type of soil/climate) or could be collected for fire prevention in the case of forests or to produce biomass for pellets or composite wood.

2.2.2.3 Upstream Methane Leakage

Natural gas systems leak methane, the main component of natural gas. RNG will also leak methane at a rate of approximately 1% at the anaerobic digester, during storage, and throughout the distribution system if injected into the natural gas pipeline. Refueling station leakage is not included in either GREET or CA-GREET due to uncertainty in measurements. If natural gas is stored as LNG, additional boil-off effects must be included. In GREET, boil-off from storage tanks is assumed to be 1% with 80% recovery. Leakage in transmission is 0.39% of throughput for each 680 miles, while distribution leakage is fixed (not distance dependent) at 0.31%. (Table 6)

Table 6. Methane leakage affecting renewable natural gas pathways

	Methane leakage
Digester	1%
Transmission and Storage – CH_4 Venting and Leakage (distance-dependent)	0.39% for each 680 miles
Distribution – CH_4 Venting and Leakage (not distance- dependent)	0.31%
LNG storage boil-off	1% (with 80% recovery rate)
Refueling station	N/A
Vehicle methane slip	See TTW section below

[6] The default anaerobic digester system in GREET is a covered unheated lagoon, but other, more complex and higher efficiency options exist at the expense of cost and energy inputs. Those include a mixed lagoon, horizontal plug flow or mixed plug flow

2.2.2.4 EFFICIENCIES

Efficiencies in different processes such as collection, liquefaction, compression or even flaring must be factored in the LCA calculation. Landfill collection efficiencies vary between 50 and 90% (average value of 75% used in GREET) and during flaring, 99.9% of the methane is oxidized to CO_2 (Table 7)

Perhaps the most impactful efficiency is, however, the vehicle fuel economy. Not only fuel economy affects the tank-to-wheel (TTW) emissions, which is important because majority of WTW emissions are contributed by the vehicle. This is a particularly sensitive value in the case of medium and heavy-duty applications that operate at different duty cycles. For example, a typical garbage truck might yield 2-3 miles per diesel gallon (mpdg) whereas a long haul trucks might see a better fuel economy at 6 miles per gallon of diesel equivalent (mpgd) or even 8 mpdg for some of the latest model engines. In applications where RNG or fossil natural gas are substituting for diesel, typically a 10% fuel economy penalty is assumed for the natural gas trucks to account for energy efficiency differences between spark ignition (used in NG trucks) and the more efficient compression ignition (used in diesel trucks) engines. This 10% penalty is not applicable when natural gas substitutes for gasoline, as both natural gas and gasoline run in spark ignition trucks. Vehicle efficiency values used in this analysis are discussed in the tank-to-wheel section below. The parameter in LCFS that adjusts for this efficiency loss is the Energy Efficiency Ratio (EER).

Table 7. Efficiency values assumed in CA-GREET2.0 for processes occurring in the renewable natural gas supply chain

	Efficiency
LFG collection	75% (50-90%)
Methane oxidation at the flare	99.9%
Liquefaction	89% (small scale liquefier)
Boil-off collection	80%
Generator (using RNG)	28-44%
ICE (spark-ignition reciprocating engines) to generate electricity	33% (rich burn) 44% (lean-burn)
Combustion turbines	29-40%
Compressor	80% (pipeline) and 65% (fuel station)
Spark ignition engine in truck	90% of compression ignition

2.2.2.5 TRANSMISSION AND DISTRIBUTION DISTANCES

Default transmission distance in CA-GREET2.0 is 3,600 miles of pipeline and leakage of 0.39% for each 680 mi. This represents the largest possible distance traveled in North America and thus covers any renewable natural gas possibly sold in California. Distribution distances are not relevant as distribution leakage in CA-GREET2.0 is assumed at 0.31% of total throughput. LNG can be liquefied at a large liquefaction facility (3,600 miles of pipeline assumed) or liquefied on site with a small liquefier, and hauled by truck as a liquid 50 miles to a refueling station. An alternative to injecting the biomethane into the pipeline is to use it on-site. If used on-site for transportation, it is either liquefied or compressed to about 3,600-4,000 psi with an electric compressor (or with a landfill gas fueled generator if in a landfill or with marginal California electricity mix for the rest of feedstocks).

2.2.2.6 VEHICLE SPECIFICATION

The total carbon intensity of fuels is highly influenced by what happens during vehicle operations, also called “tank-to-wheel” (TTW)[57]. Although, this might not be the case in some of the biogas pathways (the avoided upstream emissions dominate the total estimate), the part contributed by the vehicle is still important. Vehicle emissions and vehicle fuel economy can vary depending on vehicle class and drive cycle. This is particularly true when a fuel is primarily in medium and heavy-duty operations, which show more operational variability than the light-duty sector.

In this exercise, we look solely at heavy-duty C8 long haul operations, which we believe will be the most significant large-scale application for RNG in the California transportation sector[58] (Figure 21). In this regards and due to the impact of fuel specifications in the overall analysis, our WTW results might differ from the values in the lookup tables for the LCFS, which applies to all vehicle sizes and classes and thus represents the California natural gas fleet weighted average rather than C8-specific calculations made for this report. Likewise, the sensitivity results presented in this report might be different if calculated for smaller trucks or any other type of vehicle.

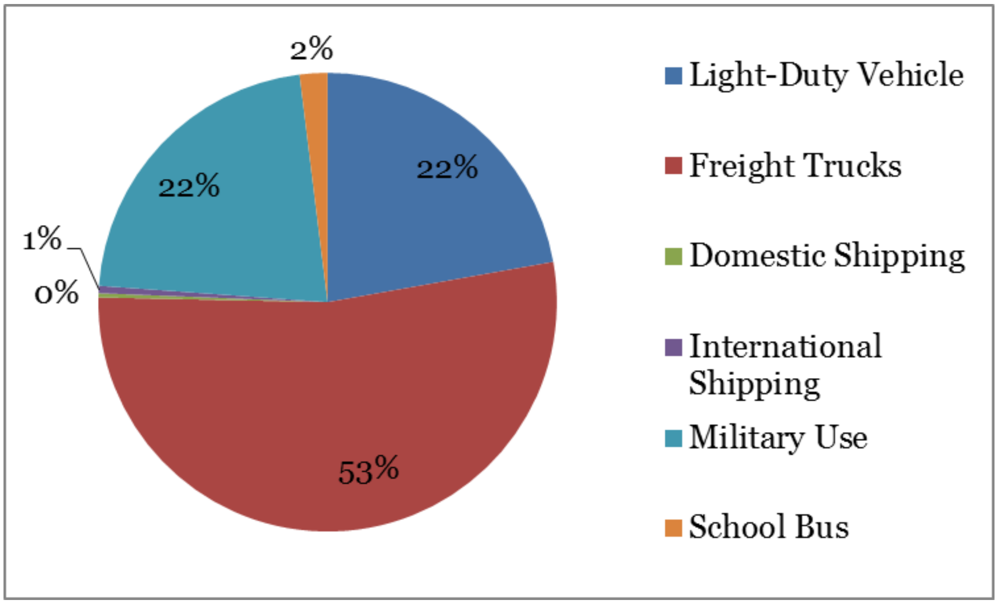


Figure 20. Transportation use of natural gas in U.S. in the year 2014, by mode[59].

As Table 8 shows, our analysis assumes a fuel economy of 4.8 miles per diesel gallon equivalent (mpdge) for spark ignition natural gas C8 long haul trucks (a 10% reduction versus compression ignition), independently of whether natural gas is stored as CNG or LNG[7]. This is in contrast to CA-GREET2.0 C8 long-haul truck fuel economy of 23,586 (BTU/mi)[60] (5.4mpdge) and in contrast to California's heavy duty fleet average used by CARB of 36,279 BTU/mi (3.5 mpdge) for CNG and 33,868 BTU/mi (3.7 mpdge) for LNG.

Methane leakage from the vehicle also varies across transportation applications, as it depends on engine configuration and drive cycle. Vehicle methane leakage occurs at the exhaust and the crank-case. We assume an average of 6.3 gCH_4/mi for natural gas spark ignition vehicles and 0.07gCH_4/mi for diesel based on conversations with engine manufactures. These would

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[7] The distinction of CNG and LNG refers to how it is stored (compressed or liquefied). Either way the fuel enters the engine in the form of gaseous natural gas, and thus the storage distinction does not affect engine performance. Engine performance depends on the type of engine (i.e., spark or compression ignition). Both CNG and LNG can run in both spark ignition engine (most typical for natural gas) or in a compression-ignition started engine developed by Cummins (i.e., the HPDI). Spark ignition engines typically have a 10% efficiency penalty respect to compression ignition. Natural gas fuels should use an efficiency correction only when a spark ignition engine substitutes a diesel one. Examples include when a typical spark ignition natural gas engines substitutes a diesel engine. It would not be the case when spark ignition natural gas engines substituting gasoline, or when diesel is substituted with natural gas with an HPDI engine. GREET1 (2015) was the first GREET version to include a separate heavy-duty vehicle tab. In this tab, one can specify vehicle specs, such as fuel economy and methane slip, independently of fuel type. Care must be made when using any model based on earlier versions of GREET1 2015.

translate to about 235.42 g CH_4/mmBTU for natural gas vehicles[8]. This is in contrast to CA-GREET defaults of 198 gCH_4/mmBTU for C8 long-haul trucks, and to LCFS fuel-weighted fleet average of 203.308 and 207.23 gCH_4/mmBTU[60] for CNG and LNG respectively[9]. These vehicle emissions are independent of whether the source of natural gas is fossil or renewable.

Our industry-suggested vehicle methane slip value is more than double the value typically included in the GREET models, but manufacturers argue that significant reductions can theoretically be achieved. Methane leakage occurs at the crank-case and in the exhaust. Crank-case leakage can technically be eliminated. Exhaust methane slip is harder to control, as it depends on combustion temperature, which must be tuned with catalysts for NOx emission reduction. Westport has recently certified a truck with significantly lower NOx and CH_4 emissions[61], but this would be a 8.9 L engine that might be too small for the long haul applications investigated in this study.

Table 8. Fuel economy and methane slip assumptions in this and other analyses

	This analysis (C8 long-haul trucks)	**CA-GREET2.0 (C8 long haul trucks)**	**ARB (California heavy duty fleet average)**
Fuel Economy of NGVs running on CNG	4.8 mpdge (26,760 Btu/mi)	5.4 mpdge (23,787Btu/mi)	3.5 mpdge (36,279 Btu/mi)
Fuel Economy of NGVs running on LNG	4.8 mpdge (26,760 Btu/mi)	5.4 mpdge (23,787 Btu/mi)	3.7 mpdge (33,868 Btu/mi)
Methane slip of NGVs running on CNG	6.3 g CH_4/mi (235 g CH_4/mmBtu)	4.7 g CH_4/mi (198 g CH_4/mmBtu)	13.70 g CH_4/mi (203 g CH_4/mmBtu)
Methane slip of NGVs running on LNG	6.3 g CH_4/mi (235 g CH_4/mmBtu)	4.7 g CH_4/mi (198 gCH_4/mmBtu)	and 207.23 (207 g CH_4/mmBtu)

[8] 6.3 g/mi * 4.8 mi/dge * 1dge/128,450 BTU = 235.42 g/mmBTU

[9] As described earlier, CNG and LNG are storage options, and should not affect engine specifications. There is, however, a habit of considering CNG a substitute of gasoline, and LNG a substitute of diesel. This implies no difference in engine type between CNG and gasoline but a difference LNG with diesel. In reality, both CNG and LNG are being used in spark ignition in heavy duty, and both are substituting diesel, thus vehicle specs (fuel economy and methane slip) should reflect this.

2.2.2.7 Choice of Global Warming Potential

GWP is a normalization parameter that allows for comparison of greenhouse gases that have different climate forcing and different atmospheric lifetimes. For example, methane has a higher global warming potential (GWP) than CO_2 but it has a shorter atmospheric lifetime. Thus, warming is greater in the near future and smaller in the distant future, as methane levels dissipate after a few decades. CO_2, however, has a lower global warming potential in the short-term, but dissipates more slowly over centuries. Depending on the time frame chosen (typically either 20 or 100 years) the GWP values vary for GHGs relative to CO_2, but new scientific discoveries support reconsideration of the GWP values used even within a given timeframe[62].

Table 9. Evolution of GWP over the different IPCC Assessment Reports (ARs)

	AR2 (1995)		AR3 (2001)		AR4 (2007)[10]		AR5 (2014)	
	20y	**100y**	**20y**	**100y**	**20y**	**100y**	**20y**	**100y**
CO_2	1	1	1	1	1	1	1	1
CH_4	56	21	62	23	72	25	85	30
N_2O	280	310	275	296	289	298	264	265

Although ARB provides a lookup table with the carbon intensities of a few fuels, LCFS requires fuel producers to submit producer and pathway-specific carbon intensities of most fuels. These will be estimated primarily with CA-GREET2.0. In this analysis, we take this model (downloaded in February 2016) and use it to estimate the carbon intensity of different biogas combinations of type of feedstock (landfill, manure, and WWTP) and storage type (CNG or LNG) for class 8 heavy-duty long haul trucking.

We describe an RNG baseline scenario for each feedstock, and modify one input at a time to highlight sensitivity of outcomes per variable factors.

[10] For LCFS purpose, ARB uses100-year values of 25 based on AR5 (IPCC 2007)

2.2.3 BASELINE CASE AND SCENARIOS

We describe the RNG baseline case as follows:

- In the case of manure, about 13% of the carbon is converted to biogas in the anaerobic digester, a 100% of which is flared (Figure 22).
- In the case of WWTP, 44% of the biogas is flared and 55% used in a boiler, with the remaining 1% as leaks to the atmosphere (Figure 23)
- In the manure counterfactual, 21% is converted into biogas, from which about one fifth goes to a boiler and about 77% goes to cleanup and 1% is leaked. Of the cleaned gas 37% is used in CHP and 62% is used as a transportation fuel.
- In the case of a small (5 million gallons a day) meso-1stage WWTP biogas, 21% of the carbon in the sludge is converted to biogas in the anaerobic digester. About 13% of the biogas is sent to a boiler and 86% is cleaned up to transportation uses.
- The baseline of all pathways is calculated using a 100yGWP of 25.
- Vehicle specs in all pathways are 4.8 miles per diesel gallon and 6.3 g CH_4/mile.
- In all pathways, the renewable natural gas is injected into the pipeline and can travel up to 3,600 miles (largest distance possible in the United States to the final refueling location.

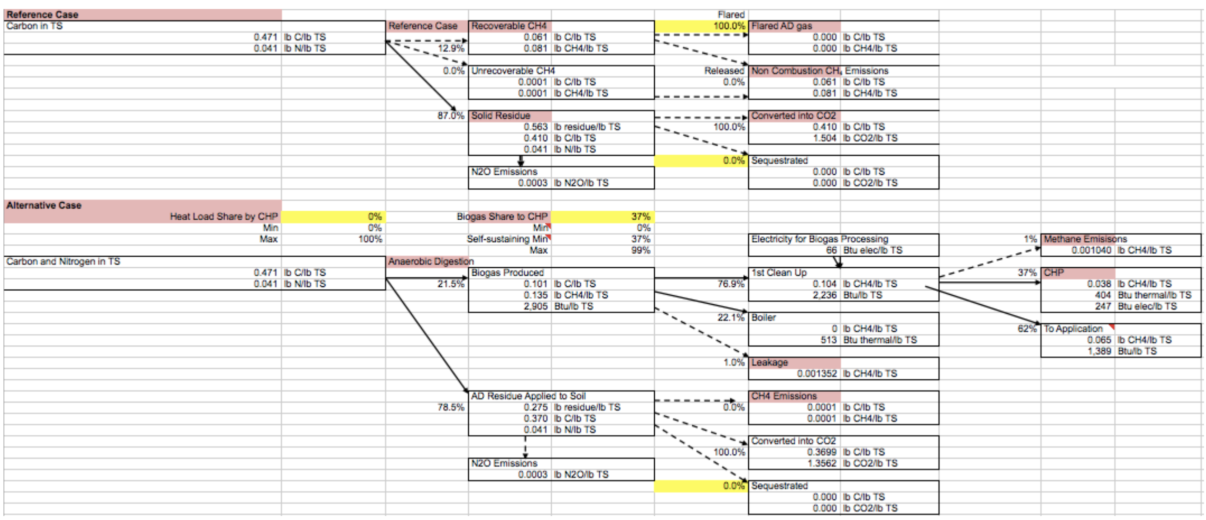

Figure 21. Reference and alternative (counterfactual) cases for manure gas in the baseline.

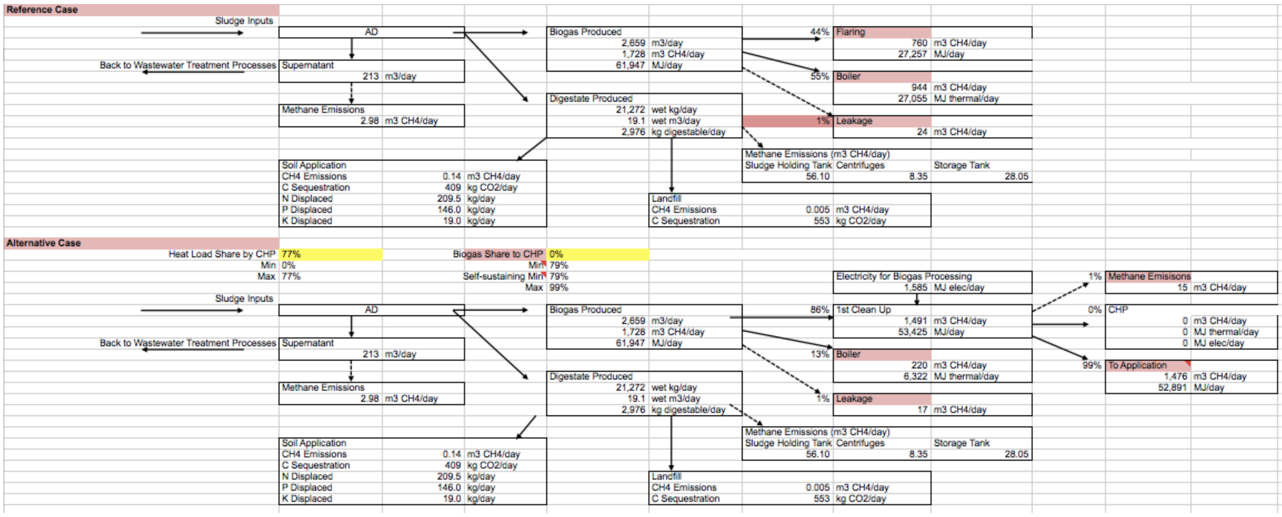

Figure 22. Reference and alternative (counterfactual) cases for WWTP gas in baseline.

In addition to the baseline, a series of scenarios will be tested. These scenarios include choices of climate parameters, such as GWP values, elimination of methane emissions from the car, change of reference case from flared to vented, and changes in anaerobic digester configurations.

Scenarios Tested. We modify the baseline scenario one input at a time and test the effect of the following options:

- CNG is used on-site instead off-site via injection into the pipeline. This will test the effect of transmission leakage (assumed as 0.39% for each 680 mi for 3,600 miles) and distribution (0.31% of total throughput).
- The 100y Global Warming Potential (GWP) of methane: We vary between the IPCC 2007 value (i.e., 25) and the more recent IPCC value (i.e., 30).
- For manure digestion, we tried several designs: Covered Lagoon, Horizontal Plug Flow and Mixed Plug Flow.
- Methane slip in the vehicle (which is the amount of methane emitted from the truck during vehicle operations) is completely eliminated.
- We test alternative reference cases where the biogas would have been vented instead of flared (Figure 24, Figure 25).

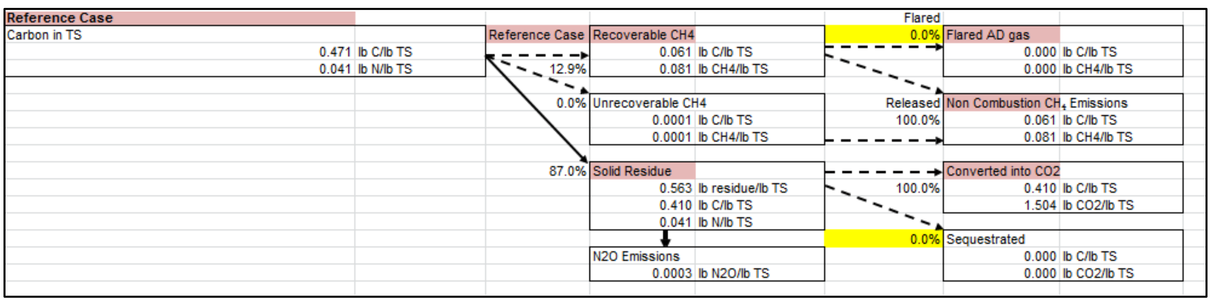

Figure 23. Reference case for manure gas in vented (instead of flared) scenario.

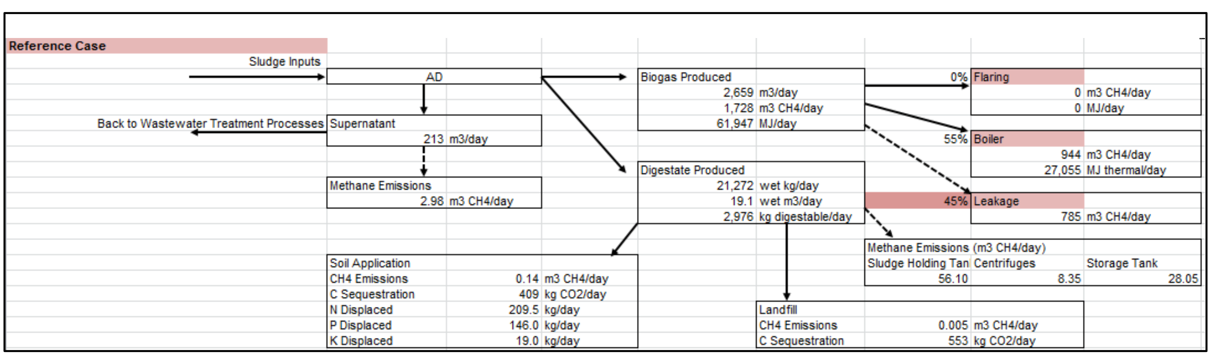

Figure 24. Reference case for WWTP gas in vented (instead of flared) scenario.

Table 10. Sensitivity test by type of feedstock

	Landfill	**Manure**	**WWTP**
On-site use as fuel rather off-site	✓	✓	✓
100yGWP of 30 instead of 25	✓	✓	✓
Reference is vented instead of flared		✓	✓
Covered lagoon instead of Complete mixed reactor		✓	
HPF instead of Complete Mix		✓	
MPF instead of Complete Mix		✓	

3 RESULTS

3.1 LCA SENSITIVITY RESULTS

As discussed, we test a variety of sensitivities for renewable natural gas (RNG) by modifying an RNG baseline scenario one input at a time. The baseline scenario is specified as off-site transportation use (travels via transmission pipeline 3,600mi- the largest distance possible for any North American RNG) by C8 heavy-duty trucks with a methane slip of (6.3 gCH_4/mi) and fuel economy (4.8 mpg). The fate of gas in the reference case in WWTP is 53% flared (rest goes to boiler), 100% flared in the case of landfill and 11% flared (88% to boiler and 1% leaked) in the case of WWTP and 12% Carbon recovered as CH_4 and flared in the case of manure. We use a100yGWP (global warming potential) of 25 for methane. The basic digester type is complete mix.

The sensitivity analysis performed in landfill gas (Figure 26) shows increasing GWP from 25 to 30 increases the carbon intensity of landfill CNG and LNG by 11%. Eliminating methane slip (i.e., all methane produced in the vehicle) reduces the carbon intensity by 9% in the case of CNG and 12% in the case of LNG. This discrepancy suggests the vehicle part has a larger influence in the case of LNG than in CNG. When landfill CNG was used on-site instead of being sent elsewhere via pipeline, carbon emissions can be reduced up to 67% (largest distance traveled), indicating a clear climate benefit of not injecting into the pipeline.

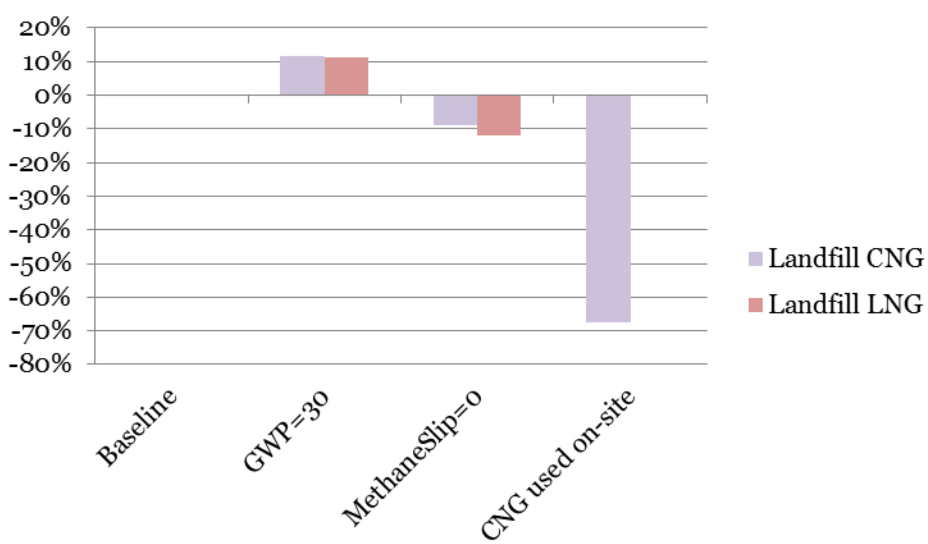

Figure 25. Sensitivity Analysis Results for Landfill Gas with CA-GREET2.0

In the case of wastewater treatment plant biogas (Figure 27), increasing the GWP to 30 had an effect under 7%, while eliminating vehicle methane slip reduced the carbon intensity by 15% in the case of CNG and 35% in the case of LNG, suggesting the LNG pathway is more affected by vehicle emissions than the CNG pathway. The reference case used in the baseline of WWTP biogas is 18% of the carbon in the sludge is converted to methane in the anaerobic digestion. From this methane produced, 55% is used in the boiler to provide energy used in the plant, 44% is flared and 1% is leaked. When this reference case is changed so the 44% is now vented, the carbon intensity is reduced by 516% in the case of CNG and 1,160% in the case of LNG. This is due to the fact that a larger climate impact is avoided if the reference case was going to be vented. The LNG pathway is affected by this change to a larger extent than CNG, indicating that the avoided emissions part of the calculation is also proportionally larger in the case of LNG. The carbon intensity of WWTP CNG can be reduced up to 60% when used on-site rather than injected into the pipeline.

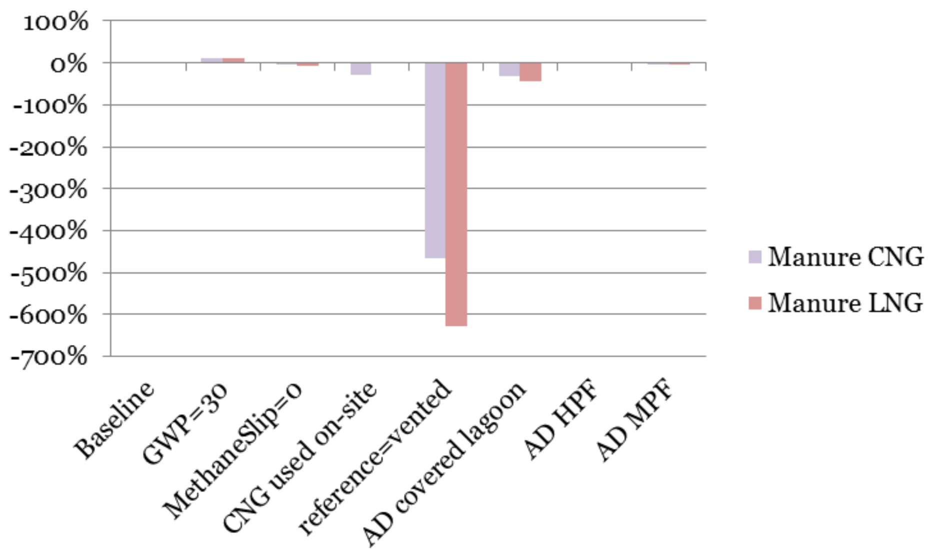

Figure 26. Sensitivity Analysis Results for WWTP RNG with CA-GREET 2.0.

Manure renewable natural gas (Figure 28) shows about a 10% larger carbon intensity when the global warming potential is changed from 25 to 30. Eliminating methane slip reduces the carbon intensity by 5%. When CNG is used on site rather than injected into the pipeline, a reduction of up to 27% could be achieved. The reference case in the baseline is defined as 12% of the manure being converted to methane, which is all flared. When the reference case is changed to vented instead of flared, a reduction in the carbon intensity of 466% in CNG and 629% in LNG is achieved. When the type of anaerobic digester is changed from the complete mixed used in the baseline to a covered lagoon, a reduction of 30% and 43% in the carbon intensities of CNG and LNG is achieved. This is despite the fact that covered lagoons have maximum conversion efficiencies of 70%, which are about one fifth lower than the other possible configurations complete mix, MPF and HPF, but unlike the other digester configurations, covered lagoons do not electricity or heat and thus overall reductions are reduced. Based on this modeling results converting a complete mix to HPF or MPF had no significant effect.

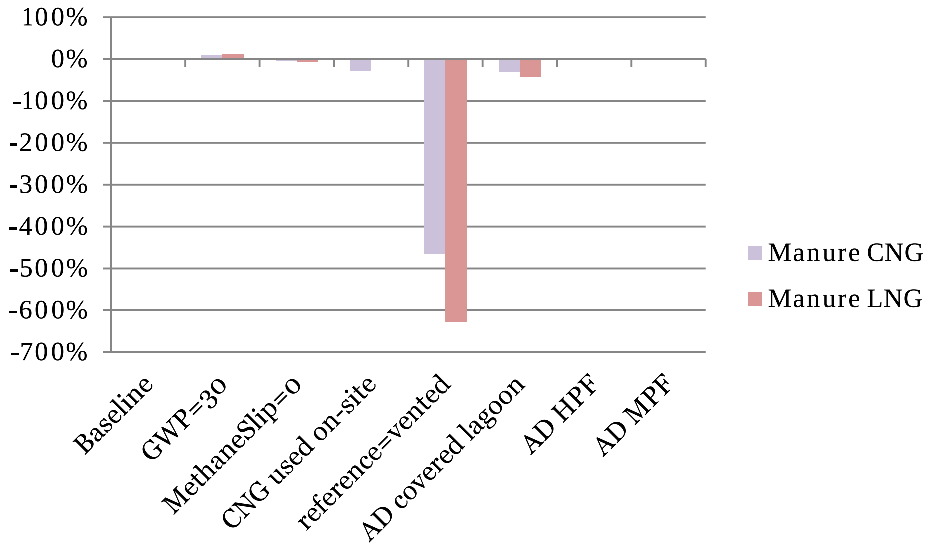

Figure 27. Sensitivity analysis of Manure renewable natural gas with CA-GREET2.0

These sensitivity analyses highlight variations that result from different configurations of RNG pathways or modeling assumptions. On-site use of the renewable natural gas eliminates the methane leakage from transmission and distribution of the CNG in the pipeline system, but the impact was bigger in landfill and WWTP gas than in manure. In the case of manure converting to a covered lagoon suggest a larger effect than eliminating the upstream emissions from transmission and distribution. Elements that affect vehicle emissions affect LNG to a larger extent than CNG, indicating LNG in the model is affected by vehicle contributions more than CNG. Regulating vehicles to reduce methane slip could potentially improve the environmental performance of the RNG to CNG and LNG pathway, our analysis suggests. Gains in the LNG pathway are slightly larger when methane slip is eliminated.

In general, our sensitivity analysis demonstrates that ARB's current policy of requesting each RNG producer to submit their own pathway estimates is sound policy and will allow regulators to provide the best oversight of carbon intensity of the RNG industry. It is important for policy makers also to be aware that differences in how global warming potential is made can alter modeling results and therefore it is important to understand this difference when comparing results from different academic and consulting studies.

Our study confirms that the deployment of renewable natural gas into the California fuels system will be climate friendly in large measure because avoided emissions are a significant contributor to a negative carbon intensity of renewable natural gas. If the original waste methane was vented instead of flared, the avoided emissions are particularly salient and the environmental outcome more positive for the use of RNG fuel.

3.2 California Renewable Natural Gas Technical Potential

We estimate that California's renewable natural gas resource base contains up to 90.6 bcf per year of renewable natural gas supply that can be assessed as technically produceable. Landfill gas has the largest potential for producing RNG and the largest potential for producing RNG at costs that do not exceed $10/mmBtu. At this price, we estimate that commercial production could reach roughly 33 bcf/yr of RNG a year, including 31.6 bcf from landfill gas and 1.75 bcf from WWTP (Figure 29). The lowest costs are found for those facilities with large landfill gas production that are also near the natural gas transmission pipeline. As is characteristic of the supply curves created from a spatial engineering economic analysis, even for this relatively competitive RNG supply source, there is a level of output at which the supply curve turns upward. These supplies represent smaller or remote sources, which are prohibitively expensive to convert to RNG.

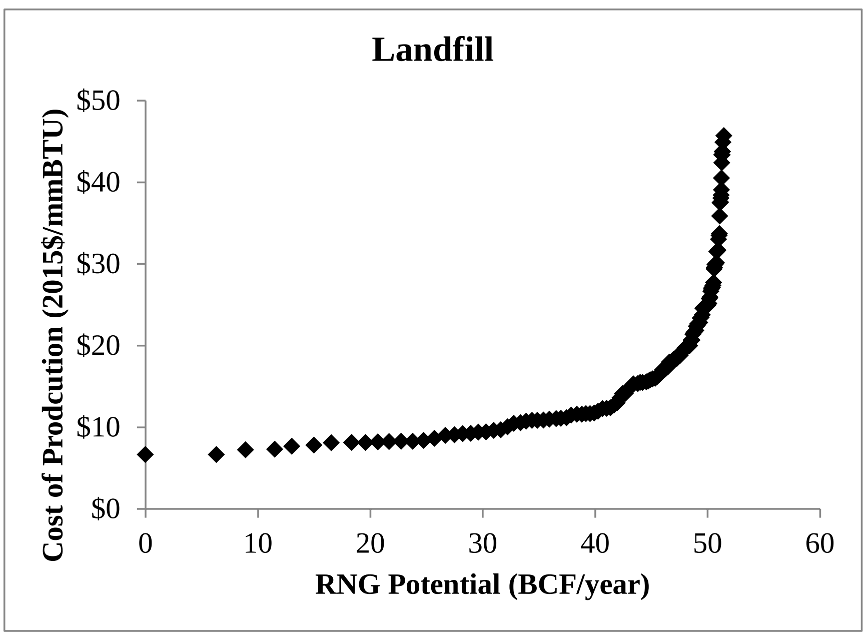

Figure 28. Supply curve estimated for RNG potential from California landfill gas

This same principle of an upwardly supply economies curve applies to the entire resource base for RNG across the state. As Figure 26 shows, the supply curve of RNG from all four sources considered, swing sharply upward at about 70 bcf/yr, or roughly 75% of the total potential of 90.6 bcf/yr.

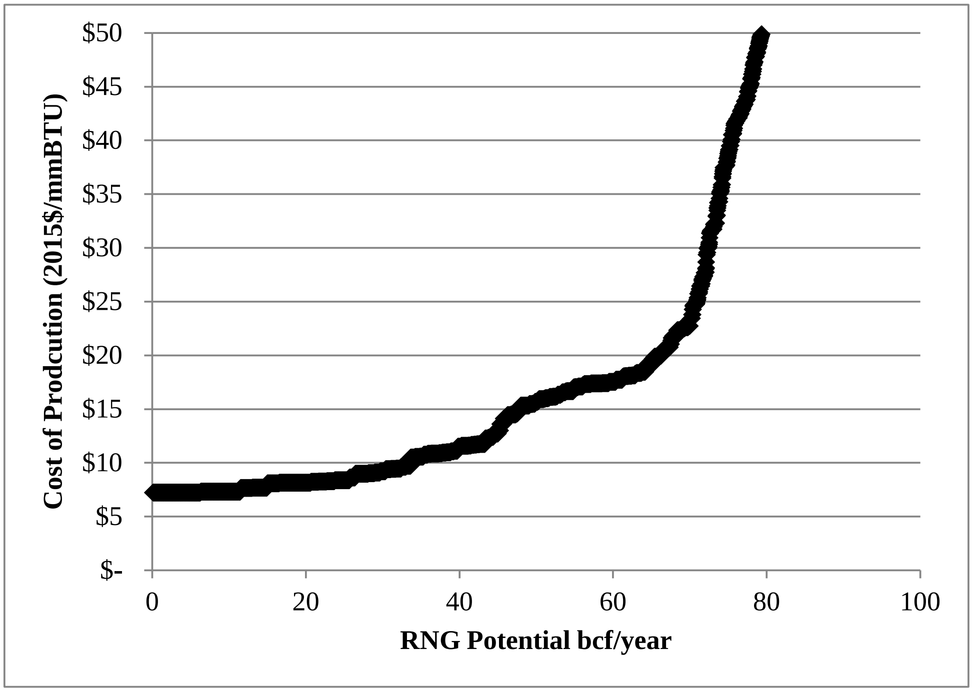

Figure 29. Combined source supply curve of RNG

The potential for RNG production from WWTP with anaerobic digesters (but assuming no energy production) was analyzed. The cost of clean-up and pipeline injection was considered at each location. It was found that 1.5 bcf per year of RNG could be economically viable to produce with an RNG price equivalent of $9/mmBTU, mainly from two of the most prolific and lower cost facilities analyzed (the Hyperion Treatment Plant near LAX and Sanitation of LA County – Joint Water Pollution Control Plant in Carson, CA). The cost of RNG from WWTP as a function of RNG potential is shown is Figure 31b. The costs start to quickly increase as the large facilities near pipelines are exploited and smaller or more remote facilities need to be utilized to bring in more supply.

The cost of RNG from the anaerobic digestion of food and green waste fractions of MSW as a function of RNG potential is shown is Figure 31c. It was found that an RNG price equivalent of $15/mmBTU could bring 1.3 bcf per year of the resource into the market. Most commercially viable sites include those where facilities are sited in areas of high tipping fees with a local resource base that allows for the maximum scale facility to be built. There is a large relatively flat region of the supply curve between 2 bcf/yr and 10 bcf/yr where we estimate that RNG could be produced for the price/cost equivalent between $16/mmBTU and $18/mmBTU. It should be noted that as this resource is utilized out of the landfills either for energy production or compost production, the long-term landfill gas production will ultimately decline. This means fewer fugitive emissions at landfills but also lower potential for high volume, economically viable costs for using that landfill gas over time.

An estimate of the cost for the landfill gas pathway to produce RNG is shown in Figure 31d. The collection, upgrading and injection cost estimate for this pathway has costs of around \$6.50-15.00/mmBTU to produce the majority of the resource of more than 50 bcf per year.

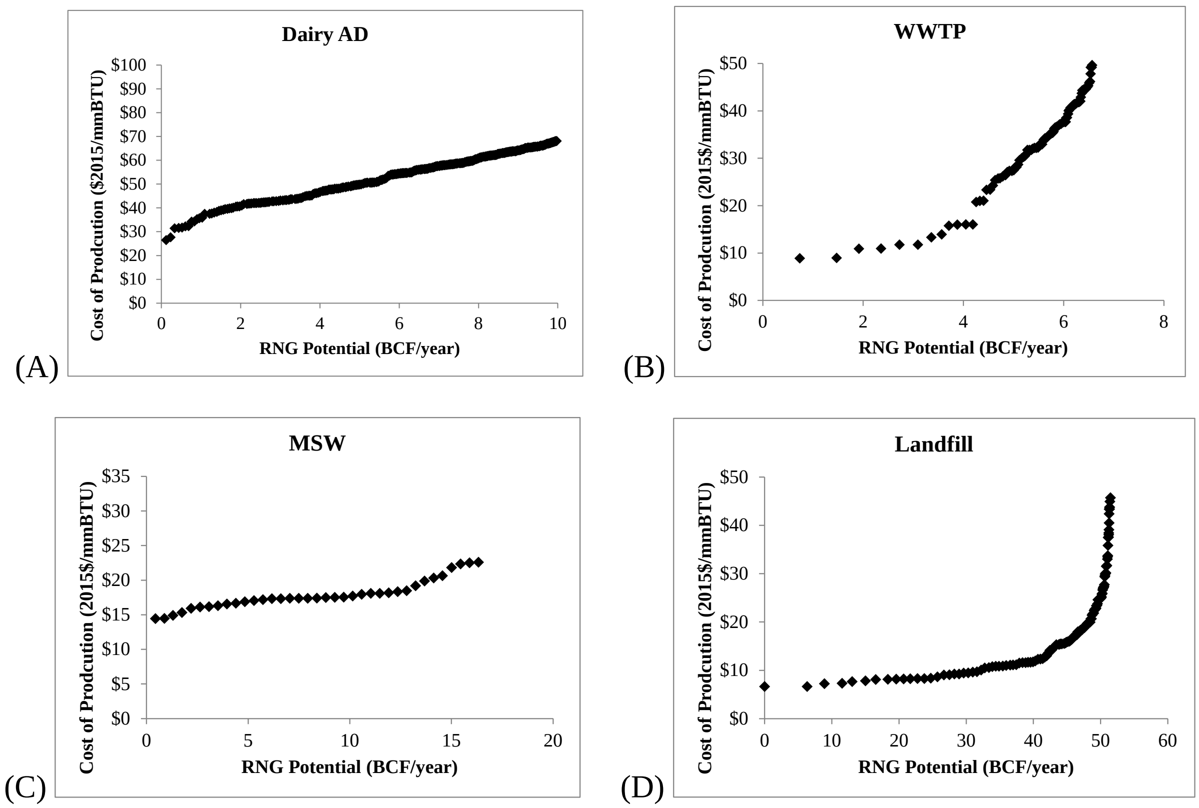

Figure 30. Supply curves estimated for RNG from (A) dairy manures, (B) waste water treatment plants, (C) food and green waste digesters and (D) landfills

Manure management using anaerobic digesters is most economical for facilities with a large concentration of collected manures with current markets and technologies. The total resource is therefore influenced by geography where smaller or distant locations may require collection and injection costs that are economically prohibitive. Clustering several locations together to supply one facility can greatly improve the economics of producing RNG from dairy manures. Estimated are the cost of installing a digester with clean up and injection in the pipeline of RNG at 1,369 dairies in California. This is not a complete data set of California manure sources but it represents 82% of the total technical resource according to the California Biomass Collaborative[35]. The estimation is made with the assumption that RNG needs to pay for the full operation of the digesters. The value of co-products and co-benefits are not included. As seen in Figure 31a, it requires the equivalent of a RNG price of $33.50/mmBTU to bring in 1 bcf per year of this resource.

There are large reductions in methane release by using anaerobic digesters as opposed to uncovered lagoons. If reduction of these methane emissions is considered as part of the baseline then it is appropriate to compare RNG production against flaring of biogas produced in covered lagoons. The co-products of digestion are generally improved soil amendments and fertilizers. The degree to which AD increases the economic value of a reference system of manure management will depend on market factors in the agricultural lands surrounding the dairy.

The dairy RNG supply curve used in the analysis was estimated with clustered dairies using tank digesters. This configuration gave the lowest cost RNG across much of the supply curve. The higher cost of the digester is overcome by higher biogas yields which both spread the cost over a higher production volume and allows for larger upgrading and injection facilities to be built. The economies of scale in the upgrading and injection facilities are important for the tank digesters becoming the lower cost option.

Sensitivity to dairy digester type and clustering is show in Figure 32. Clustering of the dairies is very important to lowering the cost of RNG by 60% compared with non-clustered systems using the same digester technology. Two cost curves were run for covered lagoons. In one the full cost of the lagoon construction is included. This results in consistently higher costs than the clustered tank digesters. The difference is less than 10% for RNG volumes below 5 bcf/yr. The second cost function assumes existing lagoons can be covered and the resulting biogas can be upgraded. This significantly lowers the cost of the digesters but has a smaller impact on the total cost of production. This estimate is slightly below the tank digester estimate for volumes under 5 bcf/yr but rises above it at volumes over 8 bcf/yr. This scenario is not accurate for the 40% of the California dairy herd that does not currently use lagoons for manure management. The true supply curve for covered lagoons is likely to lie between the two estimates. The three cluster scenarios provide estimates that are within 20% of each other, which is within the uncertainty bounds for this type of estimation. The use of the clustered tank digester curve can be considered as indicative of any clustered dairy scenario.

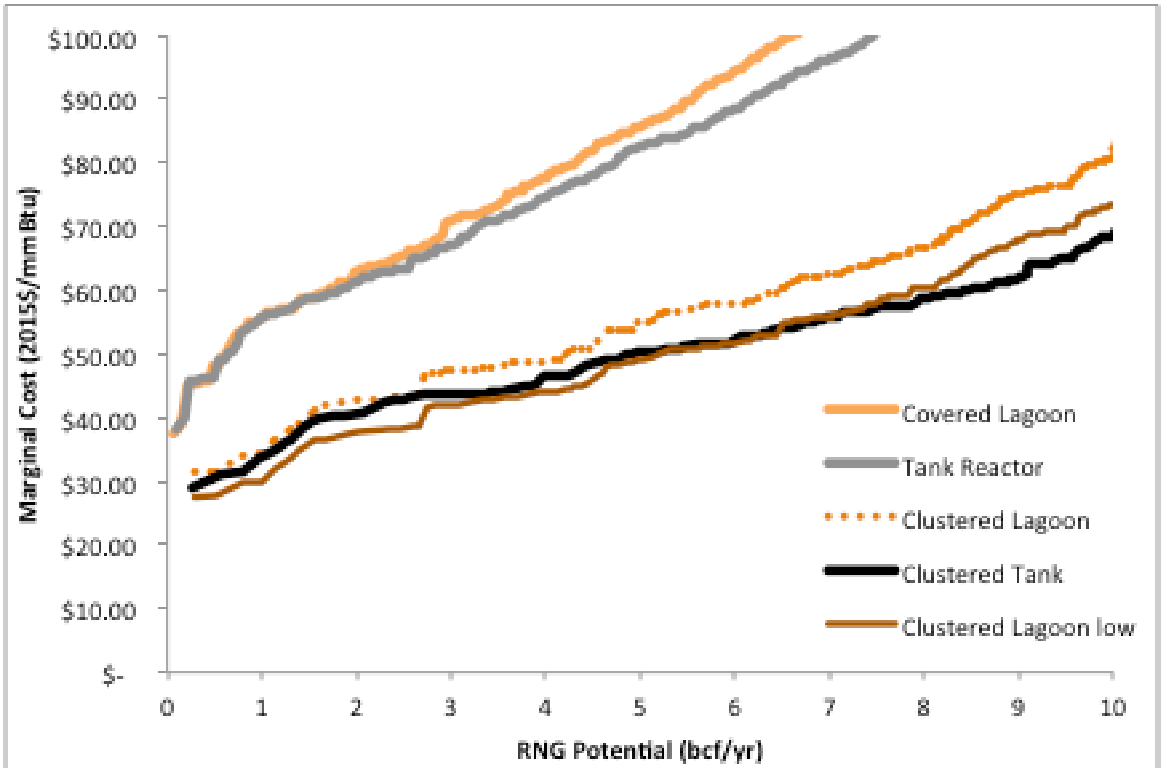

Figure 31. Dairy RNG productivity by Technology

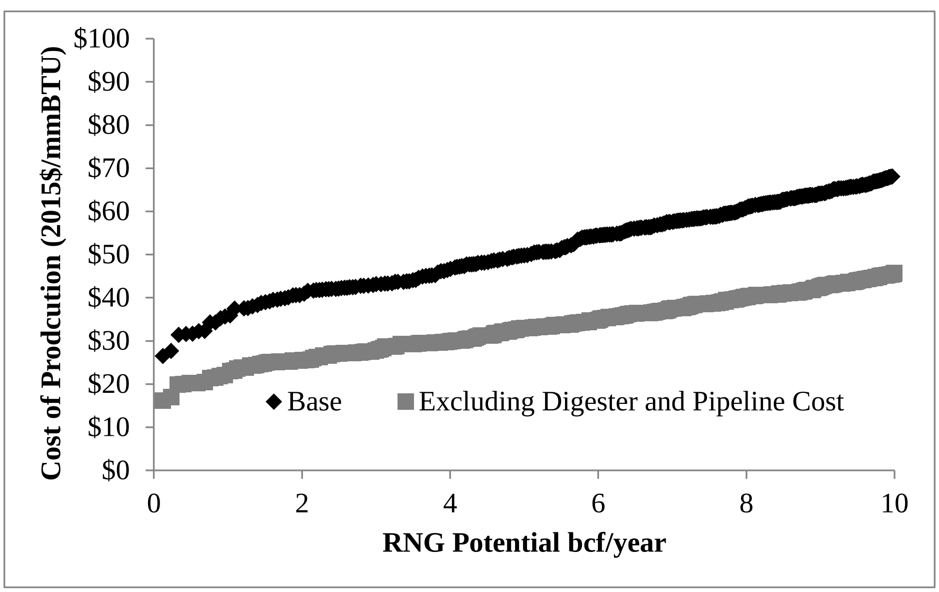

Figure 32. Supply curve for RNG from dairy manure including the cost of digesters (Base) and excluding the cost of digesters and pipelines

3.3 Cost components

Table 11 gives a breakdown of the range of costs for the feedstock, conversion, upgrading and distribution (pipeline connection) for the four paths toward RNG considered. Three paths are assumed to have zero feedstock costs as the biogas is already collected in the landfill and wastewater cases and the manure is already collected in the dairy case. The anaerobic digestion of MSW collects tipping fees resulting in negative feedstock costs that greatly improve the economics of the system. Similarly, conversion cost is a significant fraction of the total cost for paths requiring new digesters (dairy and MSW AD). The upgrading costs are significant for all technologies. The range in upgrading costs is directly resulting from the range of biogas production scales. There are some very large landfill gas sources that could drive down the cost of RNG upgrading through economies of scale but these are limited. The dairies are especially limited in their ability to achieve the scale required to bring the cost of upgrading into an economically viable range. Finally, the pipeline connection costs are extremely diverse per source location and range from three cents per mmBTU to over $500 per mmBTU. This is only the pipe cost as the injection station is included in the upgrading cost. This cost is driven by both the distance to the natural gas pipeline and the scale of the RNG resource. For larger resources, the fixed capital investment of installing a pipe is spread over a larger lifetime production of RNG.

Table 11. Summary of RNG cost components by pathway in 2015$/mmBTU

Pathway	Feedstock[11]	Conversion	Upgrading/ Injection	Pipeline Connection
Landfill	-	-	6 to 43	<0.01 to 300
Dairy AD	-	13 to 100	10 to 180	0.03 to 500
Waste water biogas	-	-	9 to 90	0.02 to 3,000
MSW AD	-15 to -712	19 to 20	10	0.05 to 1

[11] Feedstock costs for WWTP and dairy manures are assumed to be zero as systems are in place to collect the manures/biogas as part of the existing operation.

[12] Based on regional average tipping fees from CalRecycle (2015).

Figure 34 to Figure 37 show the supply curves of the different feedstocks distinguishing between cost components. Dairies (Figure 34) and MSW (Figure 35) need to build AD from scratch whereas landfill (Figure 36) and WWTP (Figure 37) already have the conversion process in place.

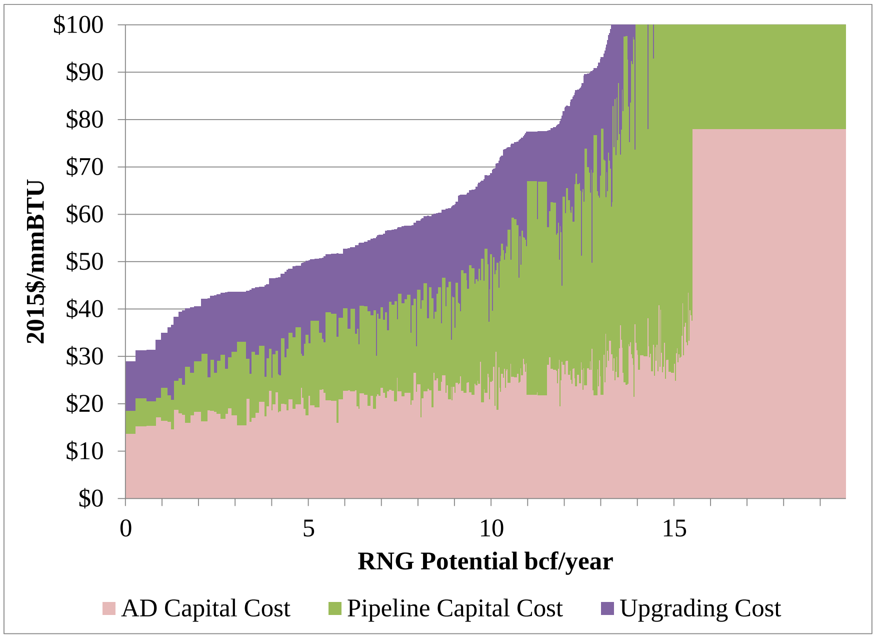

Figure 33. Supply curve and component cost for dairies

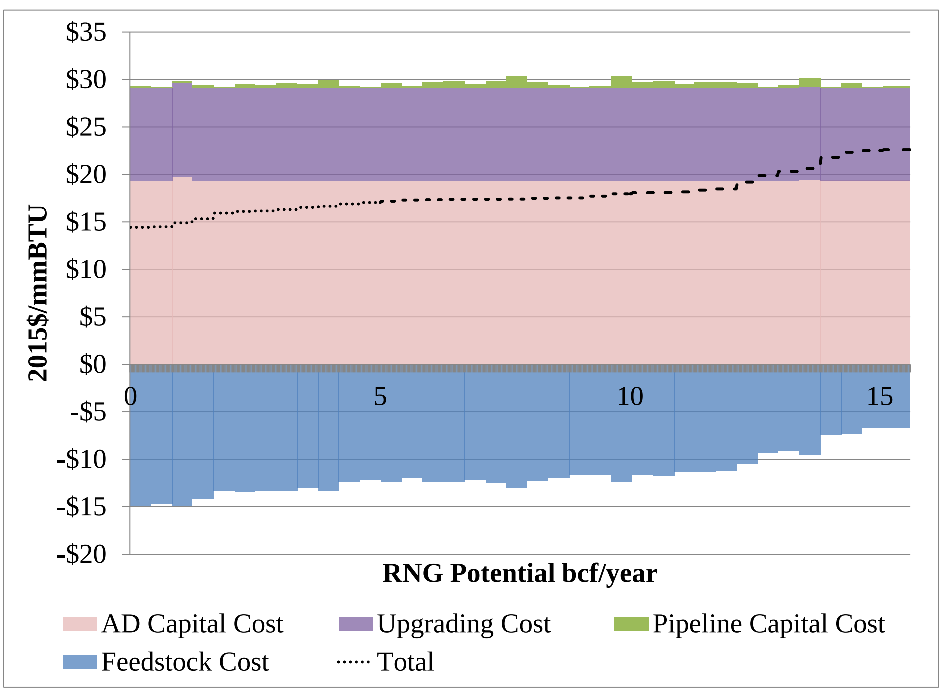

Figure 34. Supply curve and component cost of MSW

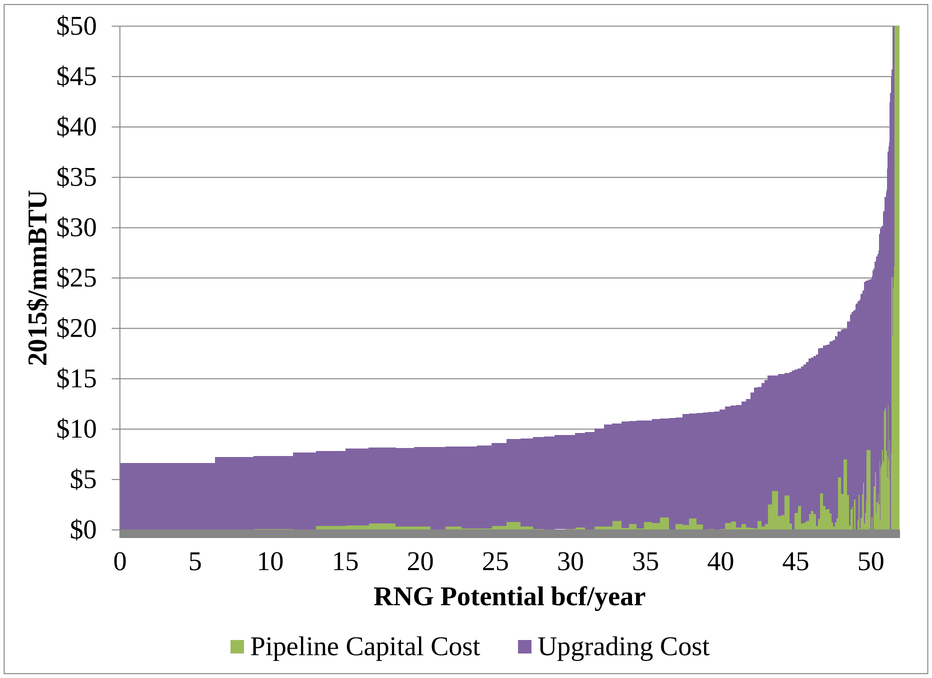

Figure 35. Supply curve and component cost for landfills

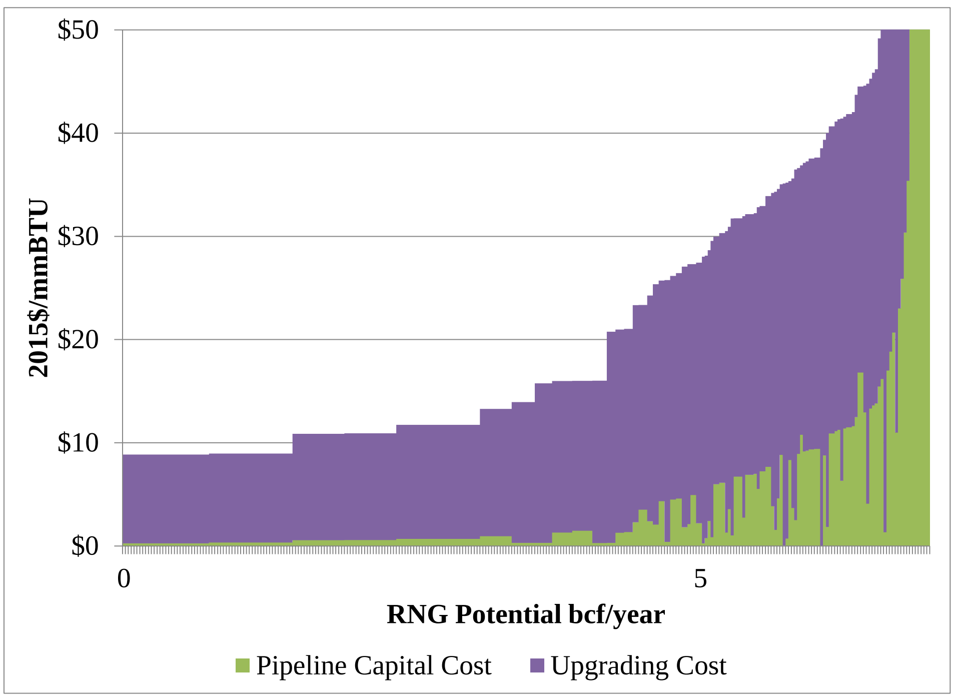

Figure 36. Supply curve and component cost for WWTP

In dairies and MSW, capital costs of AD are about a third of the total while the two other thirds are upgrading and injection costs. MSW costs are offset by advantageous tipping fee avoidance. Tipping fees are unique to the MSW RNG pathway and preventing MSW sites from capturing the tipping fees would make a straightforward waste to landfill option more expensive and less commercially viable. A potential ban to landfilling would be equivalent in our modeling to an extremely high tipping fee that would increase the appeal of converting the waste to biogas.

Landfill gas is the largest potential source of RNG. With carbon credits or other financial incentives, such as LCFS and RFS RINs, of at least $3.75 per mm BTU, large landfill could produce 6.3 billion cubic feet per year of RNG. However, if the gas from landfills and waste water treatment plants at a particular site require more upgrading or more expensive monitoring equipment than we have assumed in our estimates in order to meet California's gas quality standards, the carbon credit needed would be higher.

We consider the level of carbon credits needed to offset the high biogas upgrading costs for wastewater treatment plants and large capital costs for dairy digesters in a series of sensitivity analyses discussed in the next section. Pricing of carbon pollution externalities are likely to be needed for RNG from wastewater treatment or dairies to attract private investment in these industry pathways.

3.4 California Renewable Natural Gas Commercial Potential and Locations

At a historical average market price for natural gas of around \$3.00/mmBTU, RNG production would need to be facilitated with carbon credits or other financial incentives to provide private investors with a commercial return. All potential sources are presented below in Figure 38.

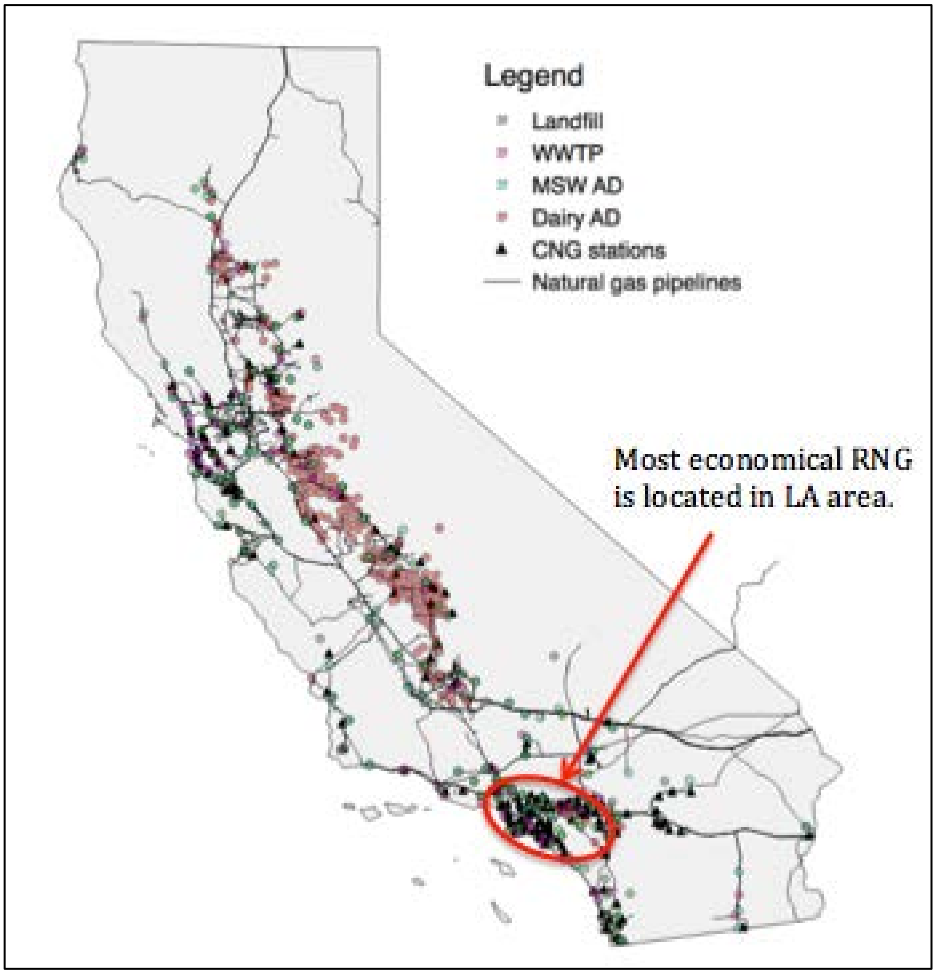

Figure 37. RNG Potential Sites in California.

The price of natural gas is a major factor that influences the viability of RNG as a source of transportation fuel. To attract private investment for much of California's renewable natural gas sources, RNG must be able to fetch about \$10/mmBTU or more, including its market price combined with carbon credits and other incentives. Chances are, given now ample sources for fossil natural gas in the United States and Canada in the aftermath of the shale gas revolution, the California wholesale natural gas market is unlikely to reach a $10/mmBTU price level for fossil natural gas entering the state from Texas, Colorado or Canada, the three most likely sources for fossil natural gas supplies to the state[63]. Moreover, if fossil natural gas were to come into scarce supply, for example, in a case where hydraulic fracturing was banned in many locations, very expensive fossil natural gas might have higher value in other applications, curbing demand for all forms of natural gas in trucks.

In today's conditions of low natural gas prices, adoption of natural gas truck technology can be attractive if natural gas trades at a favorable price discount to diesel of roughly $1.00 dge or more. Under market conditions of sustained low natural gas prices such as $3.00 mmBTU or below, the existence of mechanisms to price the externalities of carbon pollution can contribute to stimulating large private investment in RNG. We assess the level of RNG that can be facilitated at different levels of carbon credit pricing.

3.5 Renewable Natural Gas Response to the Low Carbon Fuel Standard

California has introduced policy aiming to reduce carbon emissions in the transportation sector and the program is now beginning to take effect. The Low Carbon Fuel Standard (LCFS) assigns a carbon intensity (CI) value to each fuel according to the source and also sets a target of average carbon intensity for the transportation sector as a whole. Fuels with a carbon intensity above the target generate deficits by the amount of the difference between the fuel's CI and the target CI. Fuels with carbon intensity below the target generate credits based on the difference between the fuel's CI and the target CI. Credits are then sold to firms that have accumulated deficits, and the market clears when the credit price equates the number of generated credits to deficits. In such a market, for a given credit price, credits can be thought of as a subsidy on low-carbon fuel and deficits can be thought of as a tax on high-carbon fuel. Since the credit is dependent on the degree to which a fuel falls below the target, the effective subsidy per unit of RNG differs depending on whether the RNG was sourced from dairy gas, landfill gas, municipal solid waste, or digestion in a wastewater treatment plant. In the table below are the carbon intensities of the four sources of RNG, as well as fossil natural gas, diesel, and the 2020 CI target for reference.

Table 12. LCFS Carbon Intensity Values and Credit Price Impacts on RNG

Fuel Type	Specific Source	Carbon Intensity Values			Carbon Benefit Relative to Fossil Gas	LCFS Credit Benefit to RNG ($/mmBTU)			RIN Benefit
		(gCO_2e/MJ)\1	(gCO_2e/mmBTU)\2	(metric tonne CO_2e/mmBTU)	(metric tonne CO_2e/mmBTU)	$10 credit	$120 credit	$200 credit	$1.78 per gallon ethanol equivalent
Diesel	Diesel[a]	102.01	107,709	0.108					
Target	2020 Target[b]	91.81	96,939	0.097					
CNG	CA CNG via pipeline[c]	78.37	82,749	0.083			$0.00		
CNG	Landfill gas[c]	46.42	49,013	0.049	0.034	$0.34	$4.05	$6.75	$23.32
CNG	Dairy Digester Biogas to CNG[d]	-276.24	-291,674	-0.292	0.374	$3.74	$44.93	$74.88	$23.32
CNG	MSW Digester Gas to CNG[a]	-22.93	-24,211	-0.024	0.107	$1.07	$12.84	$21.39	$23.32
CNG	WWTP AD to CNG[a]	19.34	20,421	0.020	0.062	$0.62	$7.48	$12.47	$23.32

[a] California Code of Regulation Title 17, §95488, Table 6. Carbon intensity for WWTP is the average of two WWTP pathways.

[b] California Code of Regulation Title 17, §95484.

[c] California Code of Regulation Title 17, §95488, Table 7.

[c] Method 2B Application CalBio LLC, Dallas Texas, Dairy Digester Biogas to CNG.

In order to evaluate the per mmBTU carbon credit to each of the sources of RNG, we first compute the carbon intensity of each fuel in terms of metric tonne CO_2e/mmBTU. We then compute the carbon benefit of the RNG fuels relative to fossil natural gas. Since fossil natural gas also has a carbon intensity below the target, it will also generate credits that effectively lowering its price to consumers relative to oil based fuels. For RNG, it is the carbon intensity below that of fossil natural gas which will be captured by the producers and thus encourage RNG production. Therefore, we calculate the LCFS price support to RNG based on the amount by which the RNG source carbon intensity falls below that of fossil natural gas in terms of metric tonne CO_2e/mmBTU and multiply that by choices of credit price in terms of $/metric tonne CO_2e in order to determine the $/mmBTU carbon credit. These credits are detailed in Table 12 above. To capture a range of market conditions, we evaluate LCFS credits prices of $100, $120, and $200 per metric ton CO_2e as well as current RIN prices of $1.78 per gallon of ethanol equivalent.

The monthly average LCFS credit price at the end of 1Q2016 was around $120/metric tonne CO_2e[64]. At this level of CO_2e credit price, an effective incentive of $4.00 to $4.25 per mmBTU is comprised into the economics of investing in production of landfill gas. For dairy gas, the effective incentive is much higher at roughly $45 per mmBTU, because conversion of dairy manure makes a large contribution to eliminating otherwise vented carbon emissions. The level of incentive created by the LCFS for MSW gas is $12.75 per mmBTU and is $7.50 per mmBTU on RNG from wastewater treatment plants.

RIN credits are also available but have been volatile and thus are harder to assess for impact on long term influence on the economics of RNG. Renewable natural gas delivered as transportation fuel now qualifies for D3 (cellulosic biofuel) RINs which have been trading at $1.78 per gallon of ethanol equivalent in 2016. On a per mmBTU basis, these RINs would be worth $23.32 to renewable natural gas producers.

We calculate that under an LCFS credit of $120 per metric ton of CO_2e and assuming RIN level of $1.78 per D3 RIN, RNG production from landfill gas increases from 0 bcf to 50.1 bcf per year, production from waste-water treatment increases from 0 bcf to 5.6 bcf per year, from municipal solid waste increases from 0 bcf to 16.3 bcf per year, and from dairies increases from 0 bcf to 10.1 bcf per year.

To stimulate a large scale capital investment, we calculate the MSW sites would require financial incentives such as carbon credits or other incentives of at least $11.50/mmBTU, WWTP would require at least $5.90/mmBTU, dairy at least $26.00/mmBTU, far larger than the limited $3.75/mmBTU carbon credit that drives investment in RNG development from landfill gas. On a gasoline gallon equivalent these levels would range from $0.45 per gallon to $3.15 per gallon.

Table 13. Levels of price support required to incentivize production by pathway

	Support Required to Incentivize Production over $3.00/mmBTU market price (2015$)	
RNG Production Pathway	$ per mmBTU	$ per gasoline gallon equivalent
MSW	$11.50	$1.38
Landfill	$3.75	$0.45
WWTP	$5.90	$0.71
Dairy	$26.00	$3.15

3.6 Sensitivity of MSW RNG to Avoided Tipping Fees

In considering the economics of RNG from municipal solid waste for transportation, an additional feature influencing the profitability of investment is the level of landfill tipping fees. Landfill tipping fees can be as high as $126 per ton in some cases in California. Any change in the level of landfill tipping fees will have a material impact on the quantity of RNG from MSW that could be economically diverted to a digester. For example, if current tipping fees were 20% higher than today, RNG production from MSW sources that could be used in a municipal digester would increase from 1.75 to 12.4 bcf per year under a $120 LCFS credit price. In other words, a municipality could save both the cost of the tipping fees and receive the LCFS credit value of $13.00 per mm/BTU. Thus in making the economic decision to build or expand a digester, the municipality would consider both the savings from not having to pay tipping fees, as well as the value of the credit from the LCFS market. The higher the tipping fee, the more cost savings could be considered in the calculation about the ultimate economics from diverting MSW waste to a digester instead paying to dispose of it in a landfill.

Higher tipping fee structures could be created through California government policy by creating limits to the amount of MSW that can be accepted at landfills at optimum locations for digesters and RNG fuel use, thereby reducing supply of that service and thereby raising its price. Tax policy on MSW might be less effective since a simple tax on landfill operations would not necessarily be able to be passed on to consumers of landfill services, if sufficient competition would force landfill operators to reduce underlying tipping fees to make room for the tax. The State could mandate a state-wide fixed tipping fee target floor for MSW that would be high enough to stimulate digester economics and higher diversion of MSW to digesters to make RNG.

The results to our scenario sensitivity analysis are displayed in the tables below. Absolute RNG commercial volumes are shown in Table 14 and as a portion of all natural gas fuel supplied into freight transportation are presented in Table 10. As the values in Tables 9 & 10 show, carbon credits are an important element influencing the volume of gas from renewable sources that is likely to be commercially attractive to private investors in the NG transportation market.

Table 14. Summary of RNG supply under a combination of initial penetration rates and different diesel scenarios (in billion cubic feet)

	RNG Fuel Supplied billion cubic feet					
	No Carbon Pricing Business as Usual			RNG with LCFS + RINs		
Initial Penetration Rate	Low Diesel Prices	Moderate Diesel Prices	High Diesel Prices	Low Diesel Prices	Moderate Diesel Prices	High Diesel Prices
0.1%	-	-	-	-	4.07	7.81
0.2%	-	-	-	15.16	667.86	1,332.07
0.3%	-	-	-	64.75	1,573.20	1,573.20
0.5%	-	-	-	134.24	1,573.20	1,573.20
1.0%	-	-	-	548.03	1,573.20	1,573.20

Table 15. Summary of RNG supply under a combination of initial penetration rates and different diesel scenarios (as a percentage of NG fuel demand)

	RNG as a Percentage of Supplied NG Fuel Demand					
	No Carbon Pricing (Business as Usual)			RNG with $120 LCFS + RINs		
Initial Penetration Rate	Low Diesel Prices	Moderate Diesel Prices	High Diesel Prices	Low Diesel Prices	Moderate Diesel Prices	High Diesel Prices
0.1%	0.0%	0.0%	0.0%	N/A	100.0%	100.0%
0.2%	0.0%	0.0%	0.0%	100.0%	93.8%	54.1%
0.3%	0.0%	0.0%	0.0%	100.0%	50.4%	42.2%
0.5%	0.0%	0.0%	0.0%	100.0%	41.4%	35.8%
1.0%	0.0%	0.0%	0.0%	100.0%	37.4%	34.6%

In today's commercial conditions where there is a LCFS credit of $120 per metric ton of CO_2e and assuming RIN level of $1.78 per D3 RIN and relatively low expansion of NG trucks, it may be possible for RNG to fill the entire current and near term fossil natural gas freight network. Under longer term scenarios where market conditions are conducive to a more extensive expansion of NG trucks, renewable sources will have difficulty competing commercially compared to competitively-priced fossil natural gas and probably reach 34.6% of NG fuel.

4 DISCUSSION

Advances in drilling technology have opened up large reserves of fossil natural gas in the United States, raising the possibility of abundant, inexpensive supplies for the coming decades. The large potential for domestic natural gas production is prompting interest in new end-use applications to create demand. While the current number of natural gas vehicles in California and the United States is relatively small, the trucking sector has been identified as a key sector for deployment of natural gas fuel. While the economics may favor natural gas trucks, fueling vehicles with fossil natural gas could be problematic in the long term, given concerns about climate change. Substituting natural gas for diesel fuel is not expected to lower carbon emissions sufficiently to meet California's long run climate change goals. One potential solution is to supplement and eventually replace fossil natural gas with renewable natural gas.

This study considers various market conditions and their impact on the level of RNG supply that might be considered commercially attractive to private investors by ensuring a sufficient return on capital to stimulate large scale investment.

A key conclusion to this analysis is that California's current program of carbon credits can be effective in stimulating private investment in renewable natural gas sources. This conclusion suggests that current market mechanisms can and are encouraging private capital to commit to RNG as a low carbon fuel source in the state and that public finance may not be as necessary to launch some supply sources in this sector as in other comparatively more expensive alternative fuels. However, some RNG supply sources are more expensive than others due to their lack of scale economies, distance to common pipeline injection locations or high cleanup costs. Dairy manure is one of the biogas sources that have more costly clean up and injection costs than other RNG sources and may see less volumes coming into the NG fuel system in the current market conditions where wholesale prices for fossil natural gas are relatively low.

Our analysis suggests that among the various sources of RNG that could be used for transportation, landfill gas is the largest potential source of RNG and has the greatest potential for commercial scale up. We find that an LCFS credit price of as low as $90 would enable landfills located in Los Angeles, San Diego, Irvine, Sacramento and Livermore to provide significant volumes of low carbon fuel for California. In other words, the low carbon fuel standard credits have been trading at levels that are sufficient to encourage production of landfill gas in transportation to substitute away from fossil natural gas or diesel. One factor that could discourage landfill gas RNG-production even when credits are sufficient to support landfill gas production is lack of certainty in long term credit prices. Credit prices have fluctuated widely since they have been available and parties investing in landfill gas production that are counting on support from LCFS credits would have a strong desire to enter into long-term contracts to fix the credit prices. Finding counterparties in the forward market for LCFS credits beyond current year has been at times more difficult than expected, thwarting the kind of large scale capital investment that can really drive scale up development of local RNG supply.

This study highlights the commercial potential for landfill gas to be converted to RNG for transportation near the Los Angeles market as among the most economically attractive investments to the private sector. The following map shows the optimum locations for natural gas fueling infrastructure.

Figure 38. Potential Locations of LNG (red dots) and CNG (blue dots) refueling infrastructure and route deployment

As discussed, the economics of producing RNG also involves other uses for the biomaterials. Value can be derived from waste by three primary mechanisms: tipping fees, recycling, and generating energy from waste. Because of the high demand for energy and fuel, converting biomaterials to fuel presents a high value potential for it, allowing for capture of both lucrative tipping fees and revenues from the sales of fuels. Zero waste initiatives that arise from governments, environmental and civic groups encourage reduction of waste through recycling, or reuse. But there are several waste streams that are hard to eliminate and therefore are good candidates for conversion to fuel such as WWTP, forest and agricultural residues, and manures.

Our analysis also identifies the strict standards for injection of natural gas from renewable sources as a potential barrier to large scale development of in-state RNG supply. If volumes are not sufficiently large, the cost for RNG processing equipment to remove impurities (clean up) and to improve energy content (conditioning) can be prohibitive. One aspect of the high costs for pipeline injection is the testing and verification required to meet pipeline owner specifications. California also has higher interconnection costs for RNG feeder pipelines than other states. California also has the most restrictive standards for RNG injection (testing, mixing, compression, etc). Recently the CPUC instituted a biomethane monetary incentive program to offset some portion of the interconnection costs in the state, but generally speaking, much of the RNG currently being used in California comes from out of state suppliers who can inject out of state RNG supply more cheaply into common natural gas transmission lines in other state jurisdictions for export to California as part of the blended general fossil natural gas stream. Out of state producers of RNG can, thereby, still collect California carbon credits as “foreign” suppliers to the state of a low carbon fuel. Thus, these regulatory barriers have given out of state RNG facilities a head start in displacing in-state resources and working down the cost/learning curve for RNG generation.

Geographically, the resource base of RNG is split roughly 50-50 between Northern and Southern California. Most dairy sites are situated in the Central Valley and most landfill sites are situated inland from the coast in Southern California. Municipal solid waste sites and wastewater treatment plant sites are located throughout California. The current highest end-use utilization potential for RNG is mainly in Southern California, mainly in and around Los Angeles.

In today’s conditions of low natural gas prices, adoption of natural gas truck technology can be attractive if natural gas trades at a favorable price discount to diesel. We find that even though the capital costs for developing natural gas from renewable sources is higher, there is still a substantial volume of RNG supply sources that can be cost competitive, depending on the price of carbon credits available to investors and operators. However, the absolute level and predictability of that level of carbon credits will be a major factor in investor’s decision making regarding market signals of the profitability between different upstream sources of methane feedstock. Figure 40 illustrates these competitive market pressures and the relative competitiveness of various sources of renewable natural gas sources.

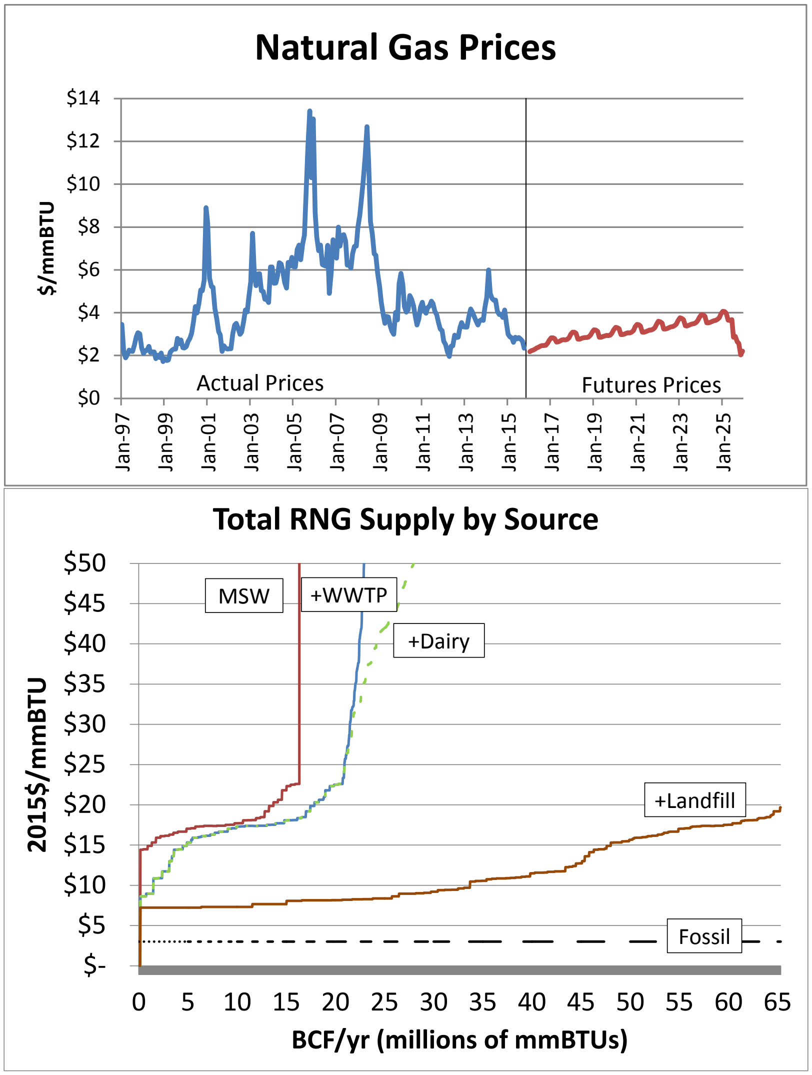

Figure 39. Natural gas prices and RNG supply curves

We have tested what level of carbon credits or other financial incentives would be required to accelerate the availability of RNG to fill the current fossil natural gas fuel long distance trucking system in California and the future expansion of that network into the 2020s under a scenario where natural gas prices are about $3.00 per mmBTU and roughly $1.00 per dge lower than diesel. To date, California's Low Carbon Fuel Standard (LCFS), which currently trades around $120 per tonne, is helping bridge the commerciality of RNG in existing networks.

We model the continuation of a $120 LCFS credit which is an effective financial incentive of between $4 per mmBTU for landfill gas into the existing and future fossil natural gas fueling infrastructure through the 2020s. We find that the LCFS credit enables up to 14 bcf of RNG into the transportation fueling infrastructure over the study period, 6.3 bcf from landfill, 1.5 bcf from waste-water treatment, 1.75 bcf from municipal solid waste, and 4.3 bcf from dairy. A

\$120/metric tonne CO_2e credit price translates into an incentive of \$4.00 to \$4.25 per mmBTU on the production of landfill gas. Under this assumption of \$120/metric tonne CO_2e low carbon fuel credit, California RNG production from landfill gas increases from 0 bcf to 14 bcf per year in the 2020s.

To stimulate a capital investment, we calculate the MSW sites would require a financial incentive larger than the \$4.00 to \$4.25 mmBTU rate available through the low carbon fuel standard credits. To incentivize private investment in MSW sites a carbon credit and/or other incentives would have to be twice as large at around \$11.50/mmBTU. This is in contrast to landfill gas which is economically viable under incentives totally just \$3.75/mmBTU. By comparison, WWTP would require incentives valued at \$5.90/mmBTU or more and RNG from dairy waste needs the largest credits of \$26.00/mmBTU or more. In terms of gasoline gallon equivalents, these credit levels would range from \$0.45 per gallon to \$3.15 per gallon. In other words, the low carbon fuel standard credits alone are not yet sufficiently high to incentivize large scale production of RNG from MSW or dairy resources. However, adding in additional credits, such as the federally mandated RINs or in the case of MSW factoring in tipping fees, facilitates more private investment in RNG, our analysis shows. These results are presented in Table 16.

Table 16. Levels of price support required to incentivize production by pathway

	Support Required to Incentivize Production over \$3.00/mmBTU market price (2015\$)	
RNG Production Pathway	\$ per mmBTU	\$ per gasoline gallon equivalent
MSW	\$11.50	\$1.38
Landfill	\$3.75	\$0.45
WWTP	\$5.90	\$0.71
Dairy	\$26.00	\$3.15

Under conditions where higher credit prices than \$120 for CO_2e tonne are available to stimulate larger volumes of RNG, conversion of some existing electricity production to RNG production for fuel would likely take place and this will constrain some of the volumes that might otherwise be converted to fuel.

Capital costs for RNG from dairies is substantially higher than those for RNG from other sources such as landfill and water waste treatment plants. Processing of wet manure requires additional greenfield infrastructure and upgrading processes that are more expensive than those needed for methane collecting and upgrading at landfills, for example. Capital costs of AD are about a third of the total while the two other thirds are upgrading and injection costs. We caution that some gas from landfills and waste water treatment plants may require more upgrading or more expensive monitoring equipment at individual locations than we have assumed in our estimates in order meet California gas quality standards.

In considering the economics of RNG from municipal solid waste for transportation, an additional feature is the level of landfill tipping fees. Landfill tipping fees can be as high as $126 per ton in some cases in California. Any change in the level of landfill tipping fees will have a material impact on the quantity of RNG from MSW that could be economically diverted to a digester. For example, if current tipping fees were 20% higher than today, RNG production from MSW sources that could be used in a municipal digester would increase from 1.75 to 12.4 bcf per year under a $120 LCFS credit price. In other words, a municipality could save both the cost of the tipping fees and receive the LCFS credit value of $13.00. Thus in making the economic decision to build or expand a digester, the municipality would consider both the savings from not having to pay tipping fees, as well as the value of the credit from the LCFS market. The higher the tipping fee, the more cost savings could be considered in the calculation for the ultimate economics from diverting MSW waste to a digester instead of paying to dispose of it in a landfill.

Higher tipping fee structures could be created through California government policy by creating limits to the amount of MSW that can be accepted at landfills at optimum locations for digesters and RNG fuel use, thereby reducing supply of that service and thereby raising its price. A straightforward tax on landfill operations may be less effective. A tax on landfill operations would not necessarily be able to be passed on to consumers of landfill services, as if there is sufficient competition in the waste industry landfill business, it would force landfill operators to reduce underlying tipping fees to make room for the tax. The State could also mandate a state-wide fixed tipping fee for MSW that would be high enough to stimulate digester economic viability, and thus higher diversion of MSW to digesters to make RNG. Banning or limiting additional future access to landfill for municipal solid waste streams would also indirectly increase the tipping fees at remaining facilities.

5 SUMMARY AND CONCLUSIONS

Development of alternative fuels that have low greenhouse gas emissions and low criteria pollutant emissions are vital for the state of California to meet climate change and air quality goals. The emergence of natural gas as an abundant, inexpensive fuel in the United States has expanded interest among private investors in infrastructure surrounding the use of natural gas as a transportation fuel. Major corporations are investing billions of dollars to build infrastructure to feed natural gas in the U.S. trucking industry and expand the use of natural gas in fleets. Municipalities are also investing in alternative fuels for vehicle fleets including compressed natural gas (CNG).

In California, investment in natural gas fueling infrastructure is expanding especially in and around the ports of Los Angeles and Long Beach. We investigated whether this growth in natural gas fueling infrastructure improves the prospects for the development of a large scale renewable natural gas industry in the state that could utilize existing transportation fueling system infrastructure.

There are extensive RNG resources that could be tapped in California. We estimate that California's renewable natural gas resource base contains up to 90.6 bcf per year of renewable natural gas supply that can be assessed as technically producible.

We find that at today's levels, carbon credit markets in California are sufficient to encourage investment by the private sector in in-state renewable natural gas resources development, especially for landfill gas. Under the current values for the low carbon fuel credit market, California RNG production from landfill gas could rise to as much as 14 bcf per year in the 2020s in the trucking sector. We find that an LCFS credit price of as low as $90 would enable landfills located in Los Angeles, San Diego, Irvine, Sacramento and Livermore to provide significant volumes of low carbon fuel for California.

Credit market programs such as the LCFS play a central role in influencing private capital to select the most cost effective sources of renewable natural gas into the market. The wide variation in costs for various sources for RNG at different locations and applications suggest that the private sector and market forces may be best equipped to evaluate the optimum combination of projects and various feedstock options. The private sector is well positioned to consider these wide variation in costs for various sources for RNG at different locations and applications and to decide which resources will carry the most attractive return on private capital. To date, there is some evidence that markets are clearing the most cost effective investments first and that technology improvement, scale economies and learning by doing will enhance this process more robustly over time.

The cost differentials for various RNG pathways reflect differences in the level of specialized technology and infrastructure that is needed to bring the biogas to commercial commodity quality standards. For RNG from dairies and municipal solid waste, greenfield AD facilities must be constructed from scratch whereas the collection and upgrading equipment needed for landfill and WWTP is less capital intensive. Capital costs of AD are about a third of total capital requirements while the other two thirds are upgrading and injection infrastructure costs. The gas from landfills and waste water treatment plants may require more upgrading or more expensive monitoring equipment than we have assumed in our estimates in order to meet California gas quality standards.

In today's commercial conditions where there is a LCFS credit of $120 per metric ton of CO_2e and assuming RIN level of $1.78 per D3 RIN and relatively low expansion of NG trucks, we find that it may be possible for RNG to fill the entire current and near term fossil natural gas freight network. Under longer term scenarios where market conditions are conducive to a more extensive expansion of NG trucks, renewable sources will have difficulty competing commercially compared to competitively-priced fossil natural gas and probably reach only 7% of NG fuel unless additional market intervention is promoted.

More specifically, we calculate that under an LCFS credit of $120 per metric ton of CO_2e and assuming RIN level of $1.78 per D3 RIN, RNG production from landfill gas increases from 0 bcf to 50.1 bcf per year, waste-water treatment increases from 0 to 5.6 bcf, municipal solid waste increases from 0 to 16.3 bcf, and dairy gas increases from 0 to 10.1 bcf yielding 82.1 bcf per year total.The price support from D3 RINs is substantial providing extra financial incentives of over $23 per mmBTU. This is partly a consequence of very high D3 RIN prices due to the failure of biofuel producers to meet production targets yielding a scarcity in qualifying fuel. The criteria of fuel which qualify for D3 RINs has recently been expanded to include RNG. As the market adjusts to accommodate the new qualifying fuel, it is likely that D3 RIN prices will fall in the future due to the easing of scarcity in qualifying fuel.

Our study identifies California's high inter-connection fees and clean-up and upgrading costs for raw RNG as a continued barrier to large scale RNG development and production, especially from agricultural sources. In particular, dairy farms can face more expensive logistical and capital costs for collecting and converting methane. For dairies, clean up and injection costs can represent up to two thirds of total required investment. Any policy to regulate emissions from the dairy sector must take this heavy financial burden into consideration.

California waste disposal tipping fees are relatively low compared to the volume of waste disposed in the state. Our research reveals the sensitivity to the level of tipping fees to the diversion of municipal solid waste to digesters. California should make a more detailed study of tipping fee pricing structures and their impact on the development of renewable natural gas for transportation. For example, if current tipping fees were 20% higher than today, RNG production from MSW sources that could be used in a municipal digester would increase from 1.75 to 12.4 bcf per year under a $120 LCFS credit price.

All sources of RNG could be used to produce electricity instead of transportation fuels. Existing production capacity is currently consuming about half of the WWTP biogas resource and 16% of the landfill gas resource. Several factors have changed the economic calculation for the best use of biogas resources. The recent increase in the value of RNG as a transportation fuel from the RFS and the LCFS makes RNG more attractive. Increasingly stringent air quality standards are making distributed electricity production from biogas more expensive. Lower costs from competing sources of renewable electricity, such as wind and solar, reduces the demand for higher cost electricity from biogas. Local conditions, such as heat demands, RNG demand and local air quality, will alter the economic tradeoff between the competing use of biogas and are beyond the scope of this study.

Large scale production of renewable natural gas will improve the environmental performance of the natural gas fuel transportation system. We find that depending on the counterfactual of alternative uses of biowaste, RNG lowers the carbon intensity of trucking operation and thereby can improve the carbon footprint of trucks currently operating on fossil natural gas, or that of trucks which can be converted from diesel fuel or gasoline. Using the fuel on-site has a significant positive impact and reduces the carbon footprint of RNG from any source.

In general, our sensitivity analysis demonstrates that ARB's current policy of requesting each RNG producer to submit their own pathway estimates is sound policy and will allow regulators to provide the best oversight of carbon intensity of the RNG industry. In considering incentives for digester technologies, policy makers will want to consider size of facilities as material to environmental contribution to emissions reductions.

Our study confirms the benefit of deployment of renewable natural gas into the California fuels system will be climate friendly in large measure because avoided emissions are a significant contributor to a negative carbon intensity of renewable natural gas. If the original waste methane was vented instead of flared, the avoided emissions are particularly salient and the environmental outcome more positive for the use of RNG fuel. This is relevant for dairy manure in particular, when methane has been freely vented.

6 RECOMMENDATIONS

This study highlights the commercial potential for landfill gas to be converted to RNG for transportation near the Los Angeles market. The following map shows the optimum locations for natural gas fueling infrastructure. For other locations, biogas might best be used to power onsite machinery and vehicles and also to generate electricity or combined heat and power.

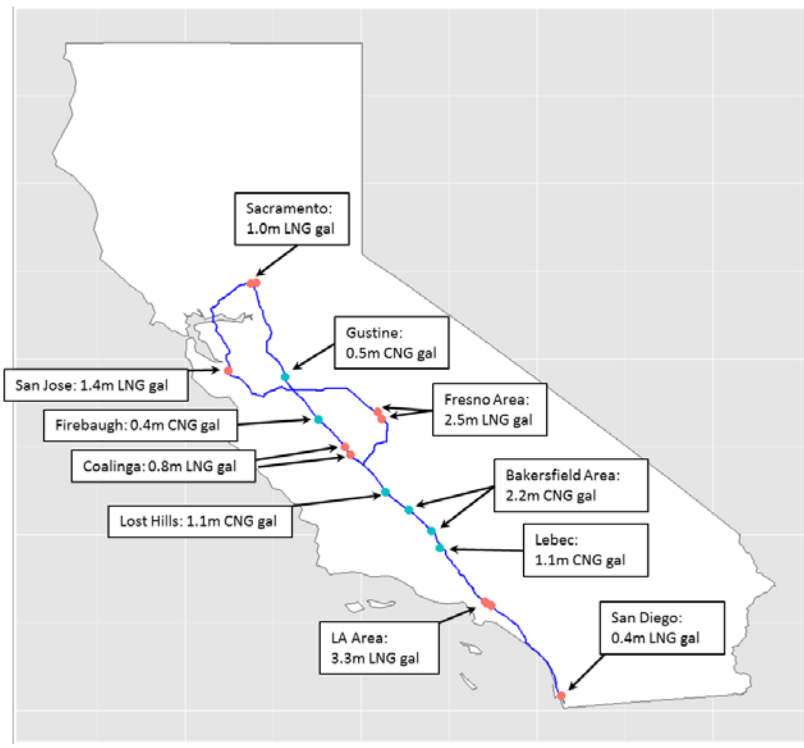

Figure 40. Potential Locations of LNG(red dots) and CNG (Blue dots) refueling infrastructure and route deployment

Our results demonstrate that carbon credit markets can be effective in incentivizing private investment in RNG resources. Therefore, we do not believe that public investment in RNG resources will be necessary to create a market for RNG in the state of California. However, high inter-connection fees and clean-up and upgrading costs for raw RNG continue to be a barrier to large scale RNG development and production, especially from agricultural sources. In particular, dairy farms can face more expensive logistical and capital costs for collecting and converting methane. For dairies, clean up and injection costs can represent up to two thirds of total required investment. Any policy to regulate emissions from the dairy sector must take this heavy financial burden into consideration. We recommend that the state intensify its ongoing study on how to lower inter-connection fees and also work with pipeline operators in the state to consider whether there is a technical solution to any of the strict injection quality standards currently thwarting large scale RNG injection into the fossil pipeline transmission system.

Authors also recommend that a new investigation of the role of tipping fees in the commerciality of RNG could yield new insights on how to best promote RNG investment beyond the current carbon credit markets. Since California waste disposal tipping fees are relatively low compared to the volume of waste disposed in the state, a review of tipping fee policy could potentially identify an additional area where policy could be adjusted to promote RNG development. Our research reveals the sensitivity to the level of tipping fees to the diversion of municipal solid waste to digesters. California should undertake a more detailed study of tipping fee pricing structures and their impact on the development of renewable natural gas for transportation.

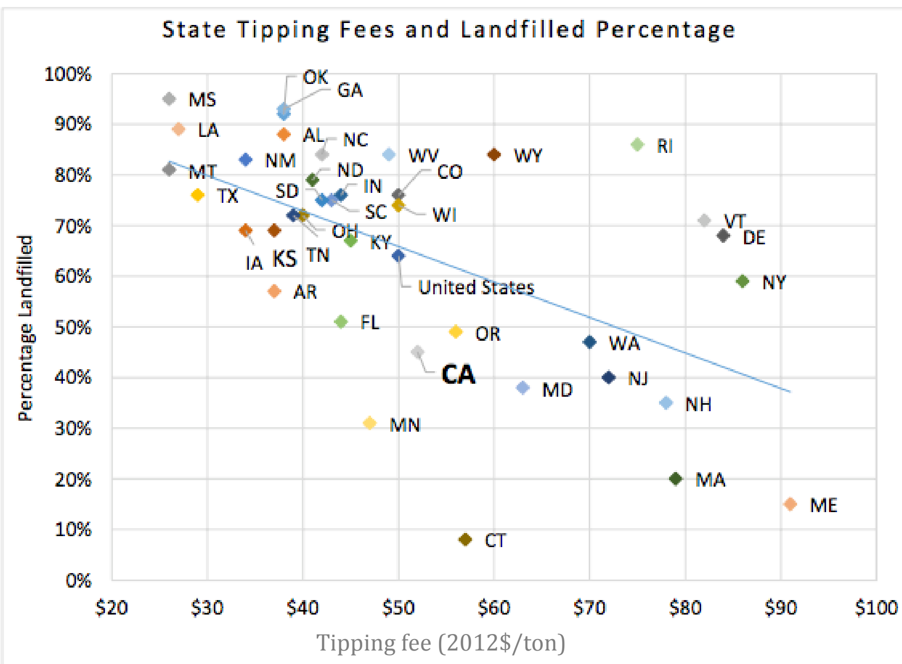

Figure 41. Tipping fees (2012$/ton) and landfilled percentage in each state based on CalRecycle, 2015.

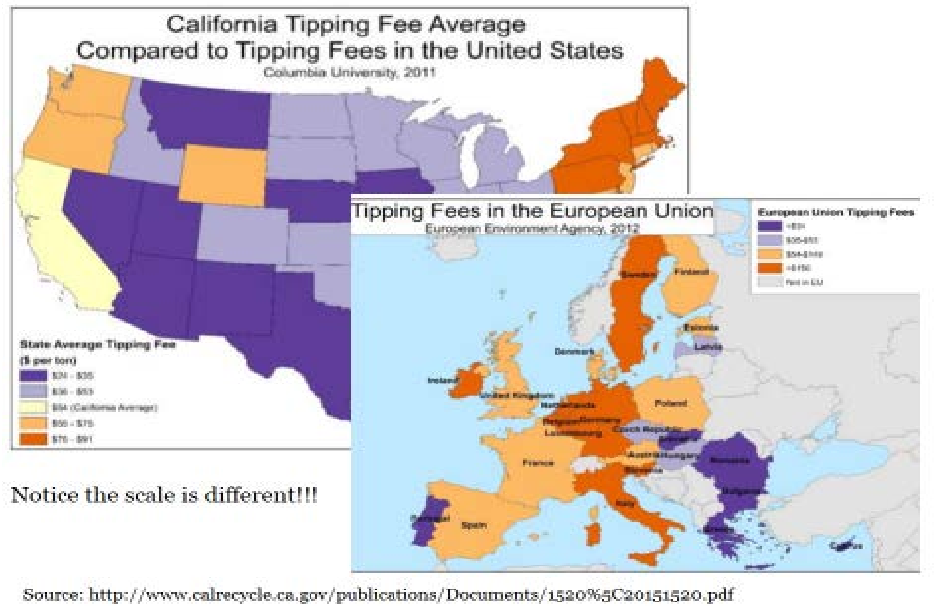

Figure 42. Tipping fees in the U.S. and in Europe (CalRecycle, 2015)

The large commercial potential of municipal solid waste as a source for RNG for transportation also suggests a more detailed study on the comparative LCA impacts of alternative use pathways that would allow policy makers to optimize policy incentives.

Once this study on LCA of RNG sources is completed, the state could initiate a more comprehensive landfill policy for best climate impact. There are two important issues from a climate perspective when considering policies to encourage RNG production from waste streams. The first consideration is to determine the optimal destination for waste based on greenhouse gases. Should waste be delivered to landfills to emit methane gas and capture the gas in an indirect system, or should organic waste be separated and diverted directly into digesters to extract methane gas in a closed system? The diversion and conversion of organic waste into methane gas is already occurring in several cities in California. For instance, in San Jose, Zero Energy Waste has constructed the largest dry anaerobic digester in the world and processes up to 90,000 tons per year of organic waste otherwise destined for a landfill.

We find that the sector that would need the most government intervention to attract private investment will be RNG to be produced specifically from dairy manure sources. We find that the most cost effective location to build or subsidize digester systems would be in key locations near the most cost effective sources of RNG and natural gas fueling infrastructure in and around Los Angeles. Clustering dairy sources is critical to achieving a return on investment that could be viable to private capital.

Finally, more investment in RNG would be enabled if liquidity in trading in multi-year LCSF credits could be promoted. We recommend the CEC or ARB initiate a study on how to incentivize more market players to trade LCSF credits on a multi-year basis to facilitate capital investment based on multi-year supply contracts for RNG or whether a state entity could participate more pro-actively in market making in outer year credits.

7 GLOSSARY OF TERMS

AD – Anaerobic Digester
bcf – billion cubic feet
bdt – Bone dry tons
Bbl – Barrels (of oil, diesel, etc.)
CA-GREET California modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model
CI – Carbon Intensity
Class 8 Tractor/Truck - A vehicle with a GWVR exceeding 33000 lb (14969 kg) These include tractor trailer tractors as well as single-unit dump trucks of a GVWR over 33,000 lb; such trucks typically have 3 or more axles.
CNG – Compressed Natural Gas
CO2e – Carbon Dioxide Equivalent
CPUC – California Public Utilities Commission
dge – Diesel Gallon Equivalent
EER – Energy efficiency ratio
CNG – Compressed natural gas
g/mi – Grams per mile
g/MJ – Grams per megajoule
GBSM – Geospatial Bioenergy System Model
Gge – Gasoline Gallon Equivalent
GHG – Greenhouse gas
GJ – Gigajoule
LCA – Life cycle analysis
LCFS – Low-carbon fuel standard
LGTE – Landfill gas to energy
LMOP – Landfill Methane Outreach Program
LNG – Liquefied natural gas
Mbd- million barrels a day
methane slip- total methane leakage in the tank-to-wheels, from crack-case and vehicle exhaust.
mmBTU – million British Thermal Units
MMT – Million metric tons
Mpgd or mpdge – Miles per diesel gallon or miles per diesel gallon equivalent
MMT – Million metric tonnes
MSW – Municipal Solid Waste
NGV- natural gas vehicle
RNG – Renewable Natural Gas
SLCP – Short lived climate pollutants
STEPS – Sustainable Transportation Energy Pathways
SWIS – Solid Waste Information Systems
Tg – Teragrams
Tpy – Tons per Year
TTW – Tank-to-Wheels
WTT – Well-to-Tank
WTW – Well-to-Wheels
WWTP – Wastewater Treatment Plant

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