Renewable Natural Gas as a Solution to Climate Goals: Response to California's Low Carbon Fuel Standard

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28 February 2017

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Abstract
Natural gas is a growing portion of transportation fuel consumed in California. While natural gas has a slight environmental benefit relative to the use of conventional liquid fuels, such as gasoline and diesel, the environmental performance of natural gas can be greatly improved by procurement from renewable sources. Yet renewable natural gas (RNG) production is too expensive to compete with fossil natural gas in the absence of policy intervention. I consider the impacts of the LCFS policy on four pathways of RNG production: (1) dairy manure, (2) municipal solid waste, (3) wastewater treatment plants, and (4) landfill gas. Using a novel dataset of California RNG supply estimates, I construct a static, multi-market, partial equilibrium model of the California fuels markets to evaluate the supply response of RNG to existing California fuel policy, the Low Carbon Fuel Standard (LCFS). I also evaluate policy response of natural gas from fossil sources, gasoline, ethanol, diesel, and biodiesel fuels. Additionally, I apply a method of modeling consumer fuel switching to accurately reflect the extent to which fuel substitution is possible in the short term. I assess the economic surplus, climate, and RNG response to the LCFS policy and compare the policy efficiency of the LCFS to a hypothetical carbon tax. My findings indicate that the LCFS policy is sufficient to incentivize substantial quantities of RNG production; enough to supply the entire market for vehicular natural gas. Further, the LCFS is less efficient than a carbon tax, but when combined with a price ceiling, the policy approaches the efficiency of a carbon tax as the LCFS policy become more stringent.

Key words
renewable natural gas, methane abatement, fuel standards, multi-market partial equilibrium

JEL Codes
Q4, Q18, Q42, Q5

***Working Paper.**

Transportation in the United States is almost entirely powered by fossil fuels and is responsible for significant contributions to greenhouse gas emissions (Pachauri et al., 2014). Transportation is the subject of myriad emission-reducing policies and regulations e.g. those addressing fuel economy,[1] tailpipe emissions,[2], and the mandated blending of biofuel in the gasoline supply.[3] While these programs have largely been successful, transportation remains a major source of greenhouse gas (GHG) emissions, making up 26% of all emissions in the United States.[4] Efforts to further reduce the climate footprint of transportation through the use of additional biofuels have been inhibited by the "blend wall"; the technological limitation precluding blends of over 10% ethanol from use in most gasoline engines. For many other alternative fuels, significant adoption depends upon the transformation of the vehicle fleet, which will take many years given the long vehicle replacement interval. Natural gas provides a real possibility for near-term reductions in transportation emissions, particularly through the employment of natural gas produced from renewable sources.

While natural gas makes up a small portion of fuel consumption, it is steadily growing mostly due to low prices of natural gas. Adoption of natural gas freight vehicles is already employed by several major freight fleets such as Cisco, Pepsi, Walmart, Frito-Lay, HEB, Trimac Transportation, Truck Tire Service Corporation (TTS), Verizon, UPS, AT&T, Food Lion, and Ryder (Jaffe et al., 2015). This phenomenon of expansion of natural gas into the heavy-duty trucking sector has been studied in Krupnick (2011) and Knittel (2012). The current level of vehicular natural gas consumption presents a ready market for the introduction of renewable natural gas (RNG).[5] RNG is considered to be an extremely low-carbon (in some cases negative carbon) fuel because it is produced via the recovery of methane that would otherwise emit into the atmosphere and its consumption displaces the consumption of fossil natural gas. Methane is a potent greenhouse gas having approximately 25 times the impact on climate as CO_2.[6] Therefore, capturing fugitive emissions of methane,

[1] The Energy Policy and Conservation Act of 1975 (EPCA) (Pub.L. 94163, As Amended Through P.L. 11367), Enacted December 26, 2013.

[2] Clean Air Act Amendments of 1977 (91 Stat. 685, Pub.L. 95-95).

[3] Energy Policy Act of 2005 (119 Stat. 594, Pub.L. 109-58), Enacted August 8, 2005.

[4] U.S. Greenhouse Gas Inventory Report: 1990-2014. https://www.epa.gov/ghgemissions/us-greenhouse-gas-inventory-report-1990-2014.

[5] U.S. Energy Information Administration, California Natural Gas Vehicle Fuel Consumption, http://www.eia.gov/dnav/ng/hist/na1570_sca_2a.htm.

[6] IPCC Fourth Assessment Report: Climate Change 2007: Working Group I: The Physical Science Basis. https://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html.

converting them into less harmful CO_2 via combustion, and displacing the combustion of fossil natural gas significantly reduces GHG emissions.

The most promising RNG production pathways are the capturing and upgrading of (1) landfill gas and the anaerobic digestion and upgrading of (2) dairy manure, (3) municipal solid waste, and (4) waste water at waste water treatment plants (WWTP). Recent California legislation specifically targets the reduction of methane from the dairy and waste management sectors. California State Bill 1383 (2016) requires these industries to reduce their methane emissions by 40% relative to 2013 levels by 2030. This amounts to a reduction of roughly 12.7 million metric tonnes of CO_2 equivalent from the dairy and landfill sectors combined.[7] The extent to which RNG production can achieve this goal, the quantity of RNG that can be produced and introduced into transportation, and the degree to which emissions can be reduced is largely unknown. To answer these questions, I rely upon a novel dataset of estimates of California RNG supplies by Parker (2016). The cost of production of RNG is much greater than the current price of fossil natural gas. No RNG can be expected to be supplied without policy intervention. RNG Supply curve estimates are presented i Figure 1. I evaluate the response of California RNG production to an existing California transportation policy, the Low Carbon Fuel Standard (LCFS).

The Low Carbon Fuel Standard sets a target for the carbon intensity (quantity of greenhouse gas emitted per unit of energy consumed) of the transportation sector. Consumption of fuels which have carbon intensities above (below) this target generates deficits (credits). Deficits must be offset by purchases of credits. The carbon intensity target is set exogenously by the state and the price of credits is determined endogenously by the supply and demand for credits in the LCFS credit market. I first present a demonstrative, analytical model to illustrate the features of the LCFS policy and how its operation compares to a carbon tax, which is more widely understood. The analytical model indicates that the response of RNG is highly sensitive to the endogenously determined credit price in the LCFS credit market. Evaluation of RNG supply response to LCFS policy requires a robust model which includes an endogenous determination of credit price.

In this paper, I construct a numerical, static, multi-market, partial-equilibrium model of Cali-

[7] California Air Resources Board, 2016 Edition California Greenhouse Gas Inventory for 2000-2014 by Sector and Activity.

fornia transportation fuels. The model considers the markets for gasoline, diesel, ethanol, biodiesel, natural gas, and renewable natural gas. The fuels considered make up 99.9% of California's transportation fuel consumption. In this model, I estimate the quantity, price, economic surplus, and emissions responses of these fuels to the LCFS policy instrument. The numerical model includes many extensions that build upon previous efforts to model LCFS policy. First, by relying on the novel dataset created by Parker (2016), I include natural gas and RNG which have been absent from previous studies. Second, I extend beyond a two-fuel gasoline-ethanol model as employed by Holland, Hughes and Knittel (2009) and Lade and Lin Lawell (2015*a*,*b*) to a more comprehensive consideration of the California fuels market. By expanding beyond gasoline and ethanol, I capture the impact of other major conventional fuels on the LCFS credit market and provide a more complete representation of credit price determination. Third, rather than assume perfect substitution of vehicle fuels, I impose constraints that reflect the limitations of the existing vehicle fleet. That is, I adopt the methodology by Anderson (2010) to model consumer choice fuel switching between gasoline and E85 and adapt this method to the diesel-biodiesel market. Lastly, I model the implementation as it exists in California, rather than consider a hypothetical LCFS policy. Therefore, the results are directly relevant to policymakers.

To evaluate the economic efficiency of the LCFS policy, I compare it to a hypothetical alternative first-best policy, a carbon tax. The hypothetical carbon tax I consider applies to all sectors of the economy. Consequently, this carbon tax fully realizes the full lifecycle advantage of negative carbon fuels. Typically, a carbon tax prices the positive content of carbon in a fuel. Fuels that that have negative carbon intensity assessments due to the full lifecycle accounting would simply be exempted from the tax. The carbon tax considered in this analysis allows for the full lifecycle analysis of fuels to be employed. The apparent subsidization of negative carbon fuels under the carbon tax is the manifestation of avoided taxation elsewhere in the economy. This choice is justified due to the passing of SB 1383 which specifically targets the sectors likely to yield fuels with negative carbon intensities for reduction in methane emissions.

The extensions in this paper which expand upon existing LCFS modeling efforts reveal consequences of the policy not otherwise possible. The choice of partial-equilibrium approach covering the comprehensive set of transportation fuels with fuel choice limited by existing technology allows for a more realistic determination of endogenous credit prices. Models including only gasoline and ethanol do not capture the impact of diesel fuel on the demand for credits or the impact of biodiesel, natural gas, or RNG on the supply of credits and thus have an incomplete view of the credit market. Further, models which allow for perfect substitution between fuels implicitly assume complete fuel choice flexibility by all vehicles. The assumption of perfect substitution may have merit in the very long term, but it is not ideal in understanding market response from the current equilibrium. In the short term, the choices of vehicle fuel a consumer may consider are constrained by the technological limitations of their existing vehicle. A partial-equilibrium model is better aimed at capturing short-term implications of policy on the existing equilibrium.

The numerical model shows that large quantities of renewable natural gas can be supplied given the existing specification of the LCFS. Industry groups argue that the new legislation has imposed "unachievable" requirements (Dumas, 2016). However, I find RNG from dairy and municipal solid waste sources can supply the entire market for vehicular natural gas in the near term. This will avoid 2. million metric tonnes of CO_2e, meeting about 16% of the SB 1383 goal in the near term.

The numerical model additionally reveals two interesting features of the California LCFS policy. First, I find an extremely narrow window of intensity targets that yield an interior solution to the credit market equilibrium. As Borenstein et al. (2015) note in their work on cap-and-trade, the inelasticity of the supply of credits yields a situation where an interior solution for credit price above zero and below the ceiling occurs only under a very narrow range of carbon intensity targets. In the case of the LCFS, the inelasticity of supply of credits is due to the scarcity of low-carbon fuels and the vehicle technology limitations on their adoption. The LCFS policy is likely to result in extreme price outcomes. The price ceiling could bind under carbon intensity targets scheduled for as early as 2017.

The second policy revelation highlights the relative efficiency of the LCFS policy as compared to the hypothetical carbon tax. Previous literature has shown the LCFS to be economically inefficient relative to a carbon tax (Holland, Hughes and Knittel, 2009; Lade and Lin Lawell, 2015*a*). If the unpriced emissions are the only externality in the fuels market, then a carbon tax set to the social cost of carbon is the most economically efficient policy (Lade and Lin Lawell, 2015*a*). As previous literature suggests, the numerical model reveals the LCFS policy is economically less efficient than a carbon tax at all specifications of carbon intensities considered. However, the results of my model reveal that in the California implementation which includes a price ceiling, the performance gap between the LCFS policy and a carbon tax decreases as the policy becomes more stringent which corroborates the finding by Lade and Lin Lawell (2015*b*). The LCFS policy approaches the efficiency of the carbon tax. When coupled with a price ceiling, a carbon tax can be considered a special case of a LCFS policy when the intensity target is set to zero and where the price ceiling serves as the price of carbon.

The following section provides a broad overview of transportation fuels in California and major policies in place governing transportation fuels. Section 2 provides background on the LCFS policy and details the carbon intensity assessment procedure, credit and deficit generation, and trading in the credit market. Section 3 presents an analytical model of LCFS in contrast to a carbon tax to highlight the differences in policy operation. Section 4 describes the numerical model and parameter calibration. Section 5 presents the results of the numerical model detailing the supply response of RNG to the LCFS, changes in emissions and economic surpus, and comparison of policy efficiency relative to a hypothetical carbon tax and Section 6 discusses these results. Section 7 concludes.

1 Background

In this section, I provide a broad background of the types of fuels consumed in transportation in California, some of the important production pathways that produce these fuels, and the consumption share of the major fuels. Here, I indicate in relative terms which fuels have greater and lesser impacts on the climate. A more thorough description of the carbon intensities of each fuel and how they are employed in the LCFS and carbon tax policies is provided in Section 2.1. I also provide a brief background on the major transportation and related policies that target emissions.

The overwhelming majority of transportation fuel consumed in California is derived from petroleum and fossil sources. According to the California Air Resources Board (2016), the 2015 California fuel consumption mix is 71% gasoline, 21% conventional diesel fuel,[8] 6% ethanol, 2% biodiesel and renewable diesel, 1% natural gas, less than 0.10% electricity, and almost zero hydrogen fuel. Gaso-

[8]Conventional diesel fuel is derived from petroleum and is typically known simply as "diesel" or "fossil diesel."

line mainly serves the passenger light-duty vehicle market and diesel mainly serves the freight and heavy-duty market (California Energy Commission, 2016*a*; Davis, Diegel and Boundy, 2016).

Gasoline and diesel are fossil fuels and are considered to be high-carbon fuels. The combustion of gasoline and diesel releases CO_2 and other greenhouse gases that would otherwise have not been emitted had the fuels remained in place in the form of unextracted, uncombusted crude oil. Fossil fuels in general are responsible for 78% of the total GHG emission increase between 1970 and 2010 and are specifically targeted for reduction by government and intergovernmental agencies as a way to avoid climate change (Pachauri et al., 2014).

Ethanol is a plant-derived fuel that substitutes imperfectly with gasoline. The climate impact of ethanol fuel relative to fossil fuel varies depending on the feedstock and efficiency of the production path. This is reflected in how the U.S. Environmental Protection Agency classifies biofuels. Ethanol produced from corn starch is classified as conventional biofuel and has the smallest climate benefit relative to fossil gasoline. Sugarcane and corn stover feedstocks produce what is classified as advanced biofuel, yielding a larger overall reduction in greenhouse gases. Lastly, ethanol produced from grasses, wood matter, and crop residue is classified as cellulosic biofuel which yields the greatest overall reductions in greenhouse gas emissions (U.S. Environmental Protection Agency, 2016).

Ethanol enters the transportation market primarily as a gasoline-ethanol blend. Nearly all gasoline sold in the United States is sold as a 10% ethanol blend known as E10 (Energy Information Administration, 2016*a*). With few exceptions, all gasoline vehicles on the road can run on a gasoline-ethanol blend containing up to 10% ethanol. Not all vehicles can run on blends greater than 10% ethanol and thus, this presents an upper limit to the concentration of ethanol that can be mixed into the blend which is sold for broad consumption. A subset of vehicles operating today are equipped with "flex-fuel" technology that allows the use of blends containing up to 85% ethanol, E85. Only about 10% of vehicles in operation are equipped with flex-fuel technology which limits the capability of E85 to replace gasoline fuel consumption (Energy Information Administration, 2016*b*).

Biodiesel and renewable diesel are the available alternatives to diesel fuel that can be utilized in existing diesel engines. Biodiesel substitutes almost perfectly for diesel. Generally speaking, any diesel-powered vehicle can run on biodiesel (Wang et al., 2000). Renewable diesel is a perfect substitute for diesel fuel; all diesel vehicles can run on renewable diesel. The market penetration of biodiesel does not face the same technological limitations as exhibited in flex-fuel vehicles in the gasoline-ethanol market. Since both biodiesel and renewable diesel are produced from biomass, their carbon intensities are much lower than conventional diesel fuel. I make the simplifying assumption to treat these fuels as the same fuel in the policy response model.

Natural gas currently comprises a small portion of California fuel consumption and mainly serves the same vehicle classes as diesel fuel. Most applications of natural gas are in medium- and heavy-duty vehicles such as garbage trucks or delivery trucks. A major limitation of natural gas fuel is the limited availability of refueling stations. Most of the natural gas vehicles in operation today employ a return-to-base refueling strategy. These vehicles leave the vehicle depot, complete a route, and refuel behind-the-gate upon return. Wider adoption of natural gas fuel requires the development of a more widespread refueling network and a greater adoption of natural gas vehicles. It is an excellent candidate to be a substitute for diesel fuel over the long-term. It has the benefit of reducing emissions in the road freight sector as well as from the dairy and landfill sectors of the economy. In its June 2013 report, Citigroup projects a shift of heavy-duty trucking into natural gas could add 2.5 to 6.7 billion cubic feet per day of vehicular natural gas consumption by 2030 (Morse et al., 2013).[9] Of this growth in vehicular natural gas consumption, approximately 400 to 1,000 bcf per year can be attributed to California.[10]

Natural gas can be produced from a variety of sources. The vast majority of natural gas is produced from fossil sources; though it can also be produced from renewable sources such as captured landfill gas or the anaerobic digestion of dairy manure, municipal solid waste, or waste water. Landfills naturally emit methane as the waste in place decomposes over time. Most landfills in California fall under regulation that requires them to capture the natural emissions of methane and burn off or "flare" the gas or use it to create electricity or transportation fuel.[11] The option of employing the captured gas in electricity generation is limited due to new legislation limiting emissions from stationary electricity generation sites (Jaffe et al., 2016). While flaring is certainly

[9] 1 bcf of natural gas is equal to 1 million mmBTU of natural gas.

[10] Attribution of 43.5% of natural gas consumption based on California's 2015 share of total U.S. vehicular natural gas consumption (Energy Information Administration, 2016*d*).

[11] Landfill Rule of the Clean Air Act, Section 111. `https://www3.epa.gov/ttn/atw/landfill/landfv2.pdf`.

the cheapest way to convert methane into the less potent CO_2, it does not displace any fossil fuel consumption and the routine use of flaring is discouraged. California has signed on to the World Bank Initiative to end the routine flaring of methane gas by 2030.[12] While the initiative focuses on the oil and gas industry, it is reasonable to assume that policymakers in California will aim to end the practice elsewhere. For these reasons, Parker assumes RNG production to be directly injected into the pipeline system in his supply estimation (Parker, 2016). Another option to reduce the methane output of landfills is the anaerobic digestion of organic waste matter, municipal solid waste (MSW). By diverting organic matter from being contributed into a landfill and, instead, feeding it into a purpose-built anaerobic digester, the organic material can be converted into methane more efficiently.

The anaerobic digestion of manure from dairies and feedlots in California provides the opportunity to substantially reduce methane emissions. Agriculture makes up about 8% of California GHG emissions and livestock productions makes up two-thirds of the emissions from agriculture. Presently, livestock producers face no requirement to collect and flare the methane emissions of their herds. As in the case of landfills, I do not expect flaring to be a viable mechanism to abate methane emissions in the future given California's adoption of the World Bank Initiative on reducing routine flaring. In contrast to the MSW pathway, manure has a significantly lower methane yield which leads to higher costs of conversion (Parker, 2016).

The last pathway considered is the anaerobic digestion of waste water. Waste water treatment plants already have anaerobic digesters in place for the purpose of reducing the nutrient load of the effluent stream. The supply estimate for the WWTP pathway considers WWTP sites with anaerobic digesters in place that are not currently generating electricity.

Regardless of the production pathway, all RNG must be cleaned of pollutants, upgraded to pipeline standards, and injected into the pipeline system. The cost to clean and upgrade gas varies depending on the source of the gas. For instance, the collection of landfill gas includes the collection of CO_2 and ambient air along with the methane which must be removed before the gas can meet pipeline quality standard. Injection into the pipeline network requires the construction of a pipeline

[12] World Bank Zero Routine Flaring by 2030 Initiative. http://www.worldbank.org/en/programs/zero-routine-flaring-by-2030.

spur from the production site to the nearest natural gas transmission line as well as the construction of a pipeline interconnect. Capital expenditure on cleaning and upgrading gas as well as connecting to the pipeline network is a considerable fixed cost which leads to economies of scale in RNG production. Within each pathway, typically the largest production sites can produce gas at the lowest per unit cost because the fixed costs are distributed over a larger volume of production.

On September 19, 2016, the California State Legislature adopted SB 1383 which requires the 40% reduction of methane and other emissions relative to 2013 levels from landfill and dairy sources. The bill specifically mentions the the production of biomethane (RNG) via digesters and direct injection into the pipeline network as a solution to emissions reduction. The legislation also mandates the 50% reduction of landfill disposal of organic waste by 2020 and the 75% reduction by 2030 indicating a policy preference for the MSW pathway.

Electricity supplies less than 0.1% of the energy consumed in transportation and hydrogen fuel provides less than 0.0001% of transportation energy. Increasing the market share of hydrogen and electricity as vehicle fuels is predicated on the expansion of refueling infrastructure and turnover of the passenger vehicle fleet, both of which require long timelines. Modeling the LCFS impact on long-term transition of fleet technology is beyond the scope of this analysis.

There are numerous policies in place governing transportation fuels in the United States. The oldest of the major policies is the Corporate Average Fuel Economy (CAFE) standard which addresses vehicle fuel economy. CAFE was first introduced in 1975 in response to the 1973 Oil Embargo.[13] Specifically aimed at reducing fuel demand in order to lessen the impact of the Oil Embargo, the CAFE standards yield increases in average miles-per-gallon and as a result, reductions in emissions per mile. The CAFE standard sets a standard for production-weighted average fuel economy that vehicle makers must achieve. If a vehicle manufacturer fails to achieve the standard, they may either purchase credits from manufacturers that over-comply, or pay a penalty proportional to the degree to which they fail to meet the standard times the size of their vehicle fleet.[14] The CAFE standards have increased the average fuel economy of vehicles for sale in the United

[13] Trasnportation.gov, "Corporate Average Fuel Economy (CAFE) Standards," https://www.transportation.gov/mission/sustainability/corporate-average-fuel-economy-cafe-standards.

[14] Cite Federal Register Vol 76. No. 179. Sept 15, 2011. http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/2011-20740.pdf.

States, but do not address the carbon content of fuel itself.

The Renewable Fuel Standard (RFS) was implemented in the Energy Policy Act of 2005 and expanded in the Energy Independence and Security Act of 2007.[15,16] The RFS requires the blending of renewable fuel into transportation fuel at increasing quantities. Presently, the RFS requires renewable fuel to make up about 10% of transportation fuel.[17] The RFS requires a growing portion of the renewable fuel mandated to enter the market to be made from advanced biofuel and from cellulosic biofuel. The RFS policy faces numerous barriers to success. Historically, the biofuel industry has failed to meet the scheduled cellulosic biofuel requirements necessitating reductions in the cellulosic requirement.[18] Advanced biofuel has largely been obtained by imports of Brazilian sugar-cane ethanol. The upper bound of ethanol concentration in gasoline blends, "the blend-wall," is being reached and limits the expansion of additional ethanol concentrations (Schnepf and Yacobucci, 2010). An additional criticism facing the RFS is the inflexibility of the program to market changes. The quantity of ethanol the RFS requires to be blended in to transportation fuel is inflexible to changes in supply and demand of ethanol production inputs. Carter, Rausser and Smith (2016) show the RFS policy exacerbated the price impact of the 2012 drought on corn prices.

2 Low Carbon Fuel Standard Policy Mechanism

In this section, I describe the LCFS policy, its background in California, implementations in other locales, and the operation of the LCFS policy mechanism. For the policy mechanism, a description of the carbon intensity assessments is presented first. A description of the credit and deficit generation process follows. Lastly, this section ends with a description of credit trade and credit price determination.

California's LCFS policy was enacted by Gov. Schwarzenegger via Executive Order S-1-07 in 2007. The LCFS regulation was approved by the administrative body, the California Air Resources Board, in 2009, the regulation went into effect in 2011, and the regulation was re-adopted in 2015.

[15] Energy Policy Act of 2005. http://energy.gov/sites/prod/files/2013/10/f3/epact_2005.pdf.

[16] Energy Independence and Security Act of 2007. https://www.congress.gov/bill/110th-congress/house-bill/6/text.

[17] EPA RFS Standards. https://www.epa.gov/renewable-fuel-standard-program/renewable-fuel-annual-standards.

[18] EIA Biofuels Issues and Trends.

The drafting of the regulation is largely based on technical and policy analysis of Farrell and Sperling (2007*a*,*b*). The LCFS policy has the stated goal of reducing the carbon intensity of transportation fuel by 10% by 2020.[19] LCFS policies are also in place in Oregon, British Columbia, and the European Union. The Oregon Clean Fuels Program requires the reduction of transportation fuel carbon intensity by 10% over 10 years.[20] The British Columbia Renewable & Low Carbon Fuel Requirements Regulation requires the reduction of the average carbon intensity of transportation fuels by 10% relative to 2010 levels by 2020.[21] The European Union Fuel Quality Directive requires the reduction in average carbon intensity of transportation fuels by 6% by 2020.[22]

The implementation of a Low Carbon Fuel Standard requires the determination of two parameters, the carbon intensity target and the credit price. For a given carbon intensity target, the sale of fuels with carbon intensities above the target generates deficits and and the sale of fuels with an intensity below the target generates credits, both according to the degree to which their carbon intensity deviates from the target. Next, a price for credits must be established. The implementation in California is designed to be "revenue neutral." That is, the state determines the carbon intensity target and provides a market in which participants can trade credits. In the LCFS credit market, high-carbon fuel providers purchase credits from low-carbon fuel providers. High-carbon fuel providers must purchase enough credits to offset the deficits generated by their fuel sales. The LCFS credit price results from the market equilibrium that equates credits with deficits. This policy is considered "revenue neutral" since wealth is transferred from high-carbon fuel producers to low-carbon fuel producers.

The revenue neutrality of this policy has one important caveat. As a cost containment measure, a price ceiling is imposed on credits at $200 per metric tonne of CO_2e. At this price, an unlimited supply of credits is available from the state agency. It is important to note that credits are generated in terms of avoided metric tonnes of carbon dioxide equivalent, CO_2e. That is, the avoidance of

[19] California Air Resources Board. Low Carbon Fuel Standard: Background Information. `https://www.arb.ca.gov/fuels/lcfs/lcfs.htm`.

[20] The Oregon Clean Fuels Program passed Oregon State legislature in 2009 via HB 2186 and the regulation was approved for implementation in 2015 via SB 324. `http://www.deq.state.or.us/aq/cleanFuel/`

[21] The Renewable & Low Carbon Fuel Requirements Regulation was enacted in 2008. `http://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/renewable-low-carbon-fuels`.

[22] European Commission Climate Action. `http://ec.europa.eu/clima/policies/transport/fuel/index_en.htm`.

greenhouse gases other than CO_2 are weighted based on their global warming potential relative to CO_2. Sales of credit by the state agency does result in revenue to the government, but language in the regulation requires these fund to be spent on alternative fuel investment.

Lastly, credits can be banked and carried forward into the future to offset future deficits. Literature on commodity storage suggests that allowing for credit banking will bias credit prices upward in the near-term time horizon (Brennan, 1958). In the numerical model in this paper, I do not examine the consequences of banking permits for future use. Rubin and Leiby (2013) includes this feature in their analysis of LCFS compliance scenarios and finds that banking smooths out compliance costs.

2.1 LCFS Carbon Intensities

The overall goal for the Low Carbon Fuel Standard is to reduce the average carbon intensity of transportation fuel use. Carbon intensity targets for the years 2011 to 2020 are set forth in the LCFS Final Regulation order and are presented in Table 1. The carbon intensity targets are based on achieving a 10 percent reduction in carbon intensity of both gasoline and diesel fuels by 2020.[23]

Table 1: Average Carbon Intensity Requirements (gCO_2e/MJ)

Year	Fuels that Compete with Gasoline	Fuels that Compete with Diesel
2010	Reporting Only	Reporting Only
2011	95.61	94.47
2012	95.37	94.24
2013	97.96	97.05
2014	97.47	97.05
2015	96.48	97.05
2016	95.49	99.97
2017	94.00	98.44
2018	92.52	96.91
2019	91.03	94.36
2020+	89.06	91.81

Source: California Code of Regulation Title 17, §95484

[23]The average carbon intensity requirements for years 2011 and 2012 reflect reductions from base year (2010) using the CI for crude oil supplied to California refineries in 2006. The average carbon intensity requirements for years 2013 to 2015 reflect reductions from revised base year (2010) CI values using the CI for crude oil supplied to California refineries in 2010. In 2015 the LCFS was readopted and the CI modeling updated. The average carbon intensity requirements for years 2016 to 2020 reflect reductions from revised base year (2010) CI values.

Carbon intensity values of alternative fuels pathways are established in one of two ways. First, for a set of core fuel pathways, the California Air Resources Board has established the carbon intensity values and they are listed in the LCFS Final Regulation.[24] Fuel providers can either accept the carbon intensity that matches their pathway (if one exists) or they may seek approval of additional fuel pathways or sub-pathways by submitting an Method 2 Carbon Intensity Application where their specific pathway's carbon intensity is assessed.[25]

In this paper, I rely on the carbon intensity values reported in the LCFS Final Regulation for the municipal solid waste, wastewater treatment plant, and landfill sources.[26] Since the carbon intensity value of RNG from the anaerobic digestion of manure is not available in the LCFS Final Regulation, I rely on the only approved pathway for dairy digester biogas.[27] Carbon intensity values are presented in Table 2.

Table 2: Carbon Intenstity Values of Fuel Pathways

Fuel Pathway	Carbon Intensity $\frac{g\,CO_2e}{MJ}$
Diesel[a]	102.01
Gasoline[a]	99.78
E10[a,d]	98.00
E85[a,d]	84.67
Biodiesel	35.44
Fossil CNG[b]	78.37
Landfill CNG[b]	46.42
WWTP CNG[a]	19.34
MSW CNG[a]	-22.93
Dairy CNG[c]	-276.24

[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, §95488, Table 7.
[c]Method 2B Application CalBio LLC, Dallas, Texas, Dairy Digester Biogas to CNG.
[d]California Air Resources Board Media Request, July 28, 2016.

The carbon intensities for each fuel listed in Table 2 are the Well-to-Wheels (WTW) value or

[24]California Code of Regulation Title 17, §95488, Table 6.
[25]California Air Resources Board, Low Carbon Fuel Standard - Method 2 Carbon Intensity Applications, `http://www.arb.ca.gov/fuels/lcfs/2a2b/2a-2b-apps.htm`
[26]California Code of Regulation Title 17, §95488, Tables 6 and 7.
[27]Method 2B Application CalBio LLC, Dallas Texas, Dairy Digester Biogas (Bakersfield, CA) to CNG (Pathway Code: CNG056), approved January 22, 2016, `http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/Calbio-122115.pdf`

the full lifecycle value of emissions accounting for all upstream emissions known as Well-to-Tank (WTT), and all vehicular emissions known as Tank-to-Wheels (TTW). Upstream emissions include all steps involved in feedstock production and transport, and finished fuel production, transport, and dispensing. The carbon intensity of gasoline and diesel are roughly the same at about 100 grams of CO_2e per megajoule ($g\,CO_2e/MJ$). The carbon intensity of natural gas is about 20 percent less than gasoline and diesel on a per-unit-of-energy basis. This is why natural gas is sometime referred to as "clean burning" in relation to gasoline and diesel. The carbon intensity is largely dependent on the molecular carbon content of the fuel.[28] I compute E10 and E85 carbon intensities to be 98.0 and 84.67 gCO_2e/MJ, respectively, based on the carbon intensity of gasoline per California Code of Regulations (2015) as well as the 2015 average carbon intensity of ethanol fuel per the California Air Resources Board (2016). I rely on the carbon intensity for biodiesel of 35.44 gCO_2e/MJ based on the 2015 volume weighted average carbon intensity of biodiesel and renewable diesel.

2.2 LCFS Credit/Deficit Generation

The mechanism by which credits and deficits are generated depend not only on the carbon intensity of the fuel in question and the carbon intensity target specified by statute, but also the efficiency with which the fuel is utilized. Each fuel is assigned an energy economy ratio (EER) relative to gasoline or diesel fuel. Different vehicle powertrains use the energy in fuel to varying degrees of efficiency. While a plug-in electric vehicle may use energy three to four times as efficiently as a gasoline powered vehicle, a natural gas powered truck is only 90 percent as efficient as a diesel powered truck in terms of miles per unit of energy.[29] An assessment of compliance outlooks prepared by ICF International (2013) indicates the vast majority of natural gas fuel will be used in heavy duty and off-road applications and, consequently, I employ the 0.9 EER to the natural gas transport sector in the policy response model.

After establishing carbon intensities of fuel pathways, the average carbon intensity target and energy economy ratios, fuel providers then generate LCFS credits (deficits) according to the formula

[28]Natural gas, CH_4, has a lower ratio of carbon to hydrogen than gasoline, C_8H_{18}, or diesel, $C_{12}H_{23}$, and therefore, fewer carbon emissions per unit of energy.

[29]California Code of Regulation Title 17, §95485, Table 5.

$$Credits = \left(CI_{target} - \frac{CI_{fuel\,pathway}}{EER_{fuel}} \right) \times E \times C \tag{1}$$

where $Credits$ are in metric tonnes of CO_2e, CI_{target} is equal to the the average carbon intensity requirement for that year, $CI_{fuelpathway}$ is the carbon intensity value for the fuel pathway, EER_{fuel} is the energy economy ratio for the fuel, E is the quantity of energy supplied in megajoules, and $C = 10^{-6} \frac{MT}{g}$ is a constant to convert credits from units of grams of CO_2e to metric tonnes of CO_2e. Deficits are generated as negative credits.

2.3 LCFS Credit Market Equilibrium

The third and final aspect of the Low Carbon Fuel Standard policy intervention is resolving the credit market equilibrium. High-carbon fuel providers are obligated to comply with the LCFS and they generate deficits according to the formula in Equation 1. Obligated parties must then purchase an equal amount of offsetting credits from producers of low-carbon fuels. The market price of credits is determined by trading so credits equal deficits. There is an important caveat to the calculation of the credit market equilibrium. As a cost containment measure, the LCFS sets a maximum credit price of $200 per credit. At this price, credits may be purchased directly from the state.

Figure 2 illustrates a simplified credit market where the credit generating fuel consists of fossil and renewable natural gas and the deficit generating fuel consist only of diesel. In this model, the credit market clears where the quantity of deficits generated equals the quantity of credits generated. This condition is equivalent to equating the value of deficits generated to the value of credits generated. In Figure 2, the shaded area in the each panel represents the value of credits (deficits) generated. The credit price that equates the value of credits sold to offset deficits clears the market.

3 Analytical Model

In Figure 3, I present a simplified model of the credit generating market. Let the target average carbon intensity be 95 gCO_2e. In that case, fossil natural gas with its carbon intensity of 78.37 will generate LCFS credits as its EER-adjusted carbon intensity falls below this target. Fossil natural gas will generate 0.0084 LCFS credits per mmBTU which I denote by $\alpha_F = 0.0084\frac{MT\,CO_2e}{mmBTU}$.[30] Now consider a hypothetical renewable natural gas pathway with a carbon intensity of 50 gCO_2e; fuel from this representative pathway will generate 0.0416 LCFS credits per mmBTU, $\alpha_R = 0.0416\frac{MT\,CO_2e}{mmBTU}$. The renewable fuel generates roughly five times as many LCFS credit as fossil natural gas for the same quantity of energy. The per-mmBTU subsidy received by each pathway is $\tau\alpha_i$, where τ is the LCFS credit price per metric ton of CO_2e and i signifies the pathway. In this case, the RNG pathway will receive five times the subsidy as fossil gas per unit of energy for the same LCFS credit price.

Figure 3 shows the market for natural gas in transportation as it is impacted by the LCFS policy. Demand for natural gas fuel is shown as D_{NG} and there is no distinction made between the different pathways of natural gas fuel from the consumer's perspective. Supply of the renewable fuel is represented by S_R and supply of fossil natural gas is represented by S_F. The initial equilibrium occurs at point A. I assume the supply of fossil natural gas is perfectly elastic because the LCFS program affects only natural gas used in transportation and the transportation share makes up less than one percent of total natural gas consumption in California.[31] In the absence of the LCFS program, demand for natural gas in transportation is satisfied entirely by fossil natural gas, the lowest cost pathway to provide this fuel.

Next, I introduce the LCFS policy where credits are trading at τ dollars per $MT\,CO_2e$. In that case, fossil natural gas generates $\tau\alpha_F$ dollar per mmBTU in LCFS credit value which shifts the supply curve down by $\tau\alpha_F$ to S'_F. The renewable natural gas pathway generates $\tau\alpha_R$ dollar per mmBTU in LCFS credit value which shifts the supply curve down to S'_R. After the introduction of the policy with a credit price of τ, the equilibrium price of natural gas falls from P to P' yet the subsidy on renewable natural gas is insufficient to incentivize production of renewable natural gas at the price P'. The equilibrium occurs at point B. By doubling the LCFS credit price to 2τ, the fossil natural gas supply curve shifts to S''_F, the renewable natural gas supply curve shifts to S''_R,

[30]Under a 95 CI target, fossil natural gas will generate $\left(95 - \frac{78.37}{0.9}\right) \times 10^{-6} = 0.00000792$ LCFS credits per MJ or approximately 0.0084 LCFS credits per mmBTU based on 1,055 MJ per mmBTU.

[31]California Energy Commission, Energy Almanac, Supply and Demand of Natural Gas in California, `http://energyalmanac.ca.gov/naturalgas/overview.html`.

and the equilibrium to point shifts from B to C. In this case, renewable natural gas supplies Q_R at point D and fossil gas makes up the remainder $Q''_C - Q_R$. In this example, it requires a substantial credit price for renewable natural gas to be supplied to the market which highlights the sensitivity of RNG production to LCFS credit price.

Now suppose instead of the LCFS policy as the instrument to reduce GHG emissions, I introduce a hypothetical carbon tax and evaluate its impact on the natural gas and RNG transportation fuels. This hypothetical carbon tax relies on the same carbon intensity assessments as in the previous example of this analytical model. Using the carbon intensity values as in the previous example, $CI_F = 78.37$ and $CI_R = 50$, the fossil natural gas will generate 0.0919 metric tons of CO_2e per mmBTU, $\beta_F = 0.0919$ and renewable natural gas will generate 0.0586 metric tons of CO_2e per mmBTU, $\beta_R = 0.0586$. A carbon tax of τ dollars per metric ton of CO_2e will increase the price of each pathway, i, by $\tau\beta_i$ dollars per mmBTU. In Figure 4, I present the RNG response to a carbon tax equal to τ and 2τ as in Figure 3. Before any tax is imposed, the market clears at point A. After imposing a carbon tax of τ dollars per metric ton of CO_2e, the market clears at point B and the tax is not sufficient to induce any RNG production. With a carbon tax of 2τ the market clears at point C and the tax does induce some RNG production of Q_R at point D. Notice also that the overall consumption of natural gas fuel from any pathway has decreased from Q_C to Q''_C. The carbon tax achieves emissions reductions in two ways. First, it reduces consumption of natural gas altogether by increasing the price of fuel. Second, it induces switching out of fossil natural gas and into renewable natural gas resulting from the tax correcting the relative prices in line with the relative carbon intensities.

The analytical model illustrates the sensitivity of RNG production to LCFS credit prices in particular, and the importance of credit price on quantity response of all fuels in general. A modeling approach which examines the LCFS policy implications under the exogenous choice of credit price fails to capture the important consequences of the LCFS credit price. Even an examination of LCFS policy response to the exogenous choice of credit price that examines the entire range of credit prices from \$0 to \$200 per metric tonne of CO_2e does not provide any information regarding the likelihood of outcome.

4 Numerical Model

In order to capture the important consequences of the LCFS credit price and to assess the LCFS policy impact, I construct a static, multi-market, numerical model of all the major transportation fuels and calibrate this model to actual 2015 California transportation fuel data. I evaluate the response to LCFS policy specification of target carbon intensity of 100 down to 85 gCO_2e/MJ and over the full range of credit prices from \$0 to \$200 per metric tonne of CO_2e. To compare the economic efficiency of the LCFS policy, the numerical model also evaluates the response to a hypothetical carbon tax which relies on the same carbon intensity assessments as employed in the LCFS regulation. The carbon tax is evaluated under carbon prices ranging from \$0 to \$200 per metric tonne CO_2e. This numerical model accounts for deficit generation by the high-carbon, conventional fuels California Reformulated Gasoline (E10, a gasoline-ethanol blend containing 10% ethanol) and diesel and examines the credit generation by the low-carbon, alternative fuels E85 (a gasoline-ethanol blend containing 85% ethanol), bio- and renewable-diesel, natural gas, and RNG. This comprehensive view of the transportation fuels market provides a more complete view of the market of supply and demand for LCFS credits. These fuels together made up 99.9% of transportation fuel in California reporting to the LCFS program in 2015 (California Air Resources Board, 2016).[32] Further, I impose a number of constraints regarding how fuel switching may occur between markets.

I am examining the policy impact in the near- to intermediate-term horizon which precludes the examination of vehicle choice and fleet turnover. Changing the makeup of technologies employed in California's vehicle fleet can lead to much larger adoption of alternative, low-carbon fuels. However, this transition will take place over the long-term and is left for future work. My analysis reveals interesting policy consequences that will manifest in the near-term, before the possibility of any substantial transition of the vehicle fleet technology makeup. Since the numerical model is based on a partial-equilibrium model in the short-term, I do not allow for perfect substitution between vehicle fuels as has been employed in previous analyses of the impact of LCFS policy. Rather, I impose the constraint the the markets are separated into three groups which allow for substitution within

[32]The remaining 0.1% of transportation fuel is composed of hydrogen and electricity.

group, but not between groups. These fuel groups are the gasoline-ethanol blend group containing E10 and E85 fuels, the diesel group which contains conventional diesel and bio/renewable diesel, and the natural gas group which contains fossil natural gas and RNG.

The evaluation of these deficit and credit generating fuels introduce new complexities into the model that are not featured in the fossil/renewable natural gas fuel switching decision. Since renewable natural gas is nearly identical to fossil natural gas, there is no energy-density disadvantage to consider when choosing one fuel over the other. Further, RNG is injected into the pipeline network and is immediately comingled with fossil natural gas. There is no guarantee that a consumer purchasing RNG for their vehicle will receive physical molecules of natural gas produced from renewable pathways. The consumer may not even know if their refueling station has contracted to deliver RNG or not, as the decision takes place behind the scenes between refueling station operators and RNG producers.

The fuel switching decision between E10 and E85 and between diesel and bio/renewable diesel happens at the individual driver level. Unlike the case of renewable natural gas, a consumer must explicitly decide to purchase E85 for their vehicle rather than E10 (similarly for biodiesel over diesel). Since E85 contains about 25% less energy than E10, the decision to purchase E85 depends on the energy-adjusted relative price of the fuels, the inconvenience of finding an E85 station, the inconvenience of more frequent refueling, but also, the possible satisfaction of purchasing a "green" fuel (Anderson, 2010). The consumption of E85 is limited to a subset of gasoline-powered vehicles known as "flex-fuel" vehicles (Energy Information Administration, 2016*b*). There are about 100 million flex-fuel vehicles on the road in the United States overall, but only about 10% of these vehicles actually run on E85 (Energy Information Administration, 2016*b*). The characteristics of the diesel/biodiesel fuel switching decision are similar to that of the E10/E85 market. Biodiesel contains about 10% less energy than conventional diesel, users of biodiesel face the same inconvenience of lower availability of biodiesel refueling stations and requiring more frequent refueling, and also users may benefit from the satisfaction of purchasing "green" fuel. The key difference between the diesel-biodiesel market and the E10-E85 is that all diesel engines can run on biodiesel.

To model the fuel switching behavior for these fuel types, I employ the methodology developed by Anderson (2010) and expand this method from the E10-E85 fuels market to the diesel-biodiesel market. Anderson considers an individual household utility function where utility is quasilinear in fuel. The utility function is specified as

$$U(e, g, x) = v(e + rg) + x, \tag{2}$$

where $v(\cdot)$ is strictly increasing and strictly concave, e is consumption of E85, g is consumption of E10, x is consumption of all other goods, and r is the rate at which the household converts gallons of gasoline to gallons of ethanol-equivalent. In this specification, E85 and E10 are perfect substitutes. Given the budget constraint

$$y - p_e e - p_g g - x = 0, \tag{3}$$

where the price of x is normalized to 1, each individual household will be at a corner solution consuming either only ethanol or only gasoline. Whether a household is consuming ethanol or gasoline is determined by their value of r and the ratio of prices of gasoline and ethanol, p_g/p_e. When $r < p_g/p_e$, the household will consume ethanol exclusively. For a household that cares only about mileage, their value of r will equal the relative mileage of E10 over E85 and the household will simply choose the fuel that is cheaper on a cost-per-mile basis. However, other considerations affect a household's decision whether or not to purchase ethanol. The inconvenience of finding refueling stations that offer E85 as well as the need to make more frequent refueling stops when running E85 can dissuade a household from choosing the fuel, yielding a higher value for r, suggesting the household will avoid E85 even when in cases where it is the cheaper fuel per mile. Conversely, if a household places more weight on the "green" aspects of ethanol fuel, this will yield a value for r below the mileage ratio.

The share of households choosing ethanol is then determined by the distribution of r, $h(r)$, the ratio of prices, p_g/p_e, and the portion of vehicles that are of flex-fuel technology, ϕ. Households with a value of r less than p_g/p_e will consume ethanol exclusively. The share of fuel that is consumed as ethanol is given by the cdf of r, $H(r)$, evaluated at p_g/p_e multiplied by the share of vehicles capable of consuming ethanol, ϕ.

4.1 Model Calibration

The numerical model is calibrated to parameterize the supply and demand equations of each fuel and to calibrate the parameters that govern fuel switching as per the Anderson model in accordance with the fuel groups I specify. I calibrate the model to observed 2015 California equilibrium data for prices, quantities, alternative-fuel-capable vehicle shares, alternative fuel choice fractions, and carbon intensities.

For natural gas, I rely on the California citygate price in December 2015 of \$3.00/mmBTU per the Energy Information Administration (2016*c*) and the 2015 consumption in transportation quantity of 17 billion cubic feet per the California Energy Commission (2016*b*). For E10 and diesel, I rely on the California 2015 average prices of \$3.22/gallon and \$3.02/gallon respectively from the Energy Information Administration (2016*e*) and the consumption quantities of 15.1 billion gallons and 3.5 billion gallons per the California Air Resources Board (2016) and California Board of Equalization (2016). For E85, I rely on the California 2015 average price of \$2.66/gallon per E85Prices (2016) and consumption quantity of 11.1 million gallons per Elam et al. (2015) as of 2014. The price of biodiesel of \$3.40/gallon was obtained from the Department of Energy as the national October 2015 price (Bourbon, 2016) and the consumption quantity of biodiesel of 291 million gallons is per the California Air Resources Board (2016).[33]

The share of gasoline powered vehicles in California which are capable of running on E85 is quite low. Nationally, about ten percent of gasoline vehicles are equipped with "flex-fuel" technology enabling the use of E85. In California, the share of vehicles with flex-fuel technology may be as low as 6.6 percent. In this study, I choose the value of ten percent as the share of gasoline vehicles with flex fuel technology, ϕ_{flex_fuel}. All diesel engines can run on biodiesel without modification; therefore, the share of biodiesel capable vehicles, $\phi_{biodiesel}$, is 1.0 (Wang et al., 2000).

The last consideration of the fuel switching model is to calibrate the distribution of $r_{ethanol}$, the rate of conversion of gasoline to ethanol-equivalent gallons, and $r_{biodiesel}$, the rate of conversion of diesel to biodiesel-equivalent gallons. I calibrate the distribution of $r_{ethanol}$ for the gasoline-ethanol market, by setting the mean of the distribution equal to the mileage ratio of E10 to E85 and

[33]Quantity information for biodiesel is based on the sum of biodiesel and renewable diesel sold in California in 2015.

Table 3: California Fuel Market Parameters

Variable	Description	Value
Price of Natural Gas	P_{NG}	\$3.00/mmBTU
Price of E10 blend	P_{E10}	\$3.22/gal
Price of E85 blend	P_{E85}	\$2.66/gal
Price of Diesel	P_d	\$3.02/gal
Price of Biodiesel	P_b	\$3.40/gal
Quantity of Natural Gas	Q_{NG}	17 billion cubic feet
Quantity of E10 blend	Q_{E10}	15.1 billion
Quantity of E85 blend	Q_{E85}	11.1 million gallons
Quantity of Diesel	Q_d	3.5 billion gallons
Quantity of Biodiesel	Q_b	291 million gallons
Share E85-enabled vehicles	$\phi_{flex-fuel}$	10%
Share biodiesel-enabled	$\phi_{biodiesel}$	100%
E85 choice fraction	$H\left(\frac{P_g}{P_e}\right)$	1.38%
Biodiesel choice fraction	$H\left(\frac{P_d}{P_b}\right)$	7.78%

computing the variance based on the observed share of E85 fuel consumed at the observed California E10-E85 price ratio, 1.138 percent. This calibration procedure yields the distribution $r_{ethanol} \sim N(1.35, 0.0612)$.[34] I follow the same procedure for the diesel market and find the distribution $r_{biodiesel} \sim N(1.1, 0.1491)$ at the observed price ratio of diesel to biodiesel and the observed share of biodiesel of 7.78 percent.

The model calibration inputs are summarized in Table 3. While there is a sizable literature devoted to estimating the price elasticity of gasoline demand, there is a gap where it applies to estimating the price elasticity of demand of natural gas as a transportation fuel. Further, estimates of the price elasticity of demand for diesel are much less common than those for gasoline. Based on two commonly cited studies of the price elasticity of diesel, I establish a range of -0.7 to -0.07 (Dahl, 2012; Johansson and Schipper, 1997).

Consistent with the gasoline elasticity estimate meta-analyses of Espey (1996), Dahl and Sterner (1991), and Graham and Glaister (2004), as well as more recent estimates by Hughes, Knittel and Sperling (2006) and Lin and Prince (2013) I employ a price elasticity of demand of -0.2 for all fuels

[34]This distribution compares to the distribution specified by Andersen of $r \sim N(1.35, 0.10)$ which was calibrated to the Minnesota market.

in consideration in this study.

4.2 Natural Gas Group Calibration

The basis of my estimate of supply of renewable natural gas is the forthcoming work by Parker (2016). A more detailed description is provided in Appendix A. Renewable natural gas has been addressed in previous analyses of LCFS policy only in terms of scenarios-based analyses that make an exogenous assumption on the portion of the natural gas transportation market that will be fueled by RNG.[35] This paper is the first to employ estimates of RNG supply in terms of market response to fuels policy. For the supply of fossil natural gas, I assume it to be perfectly elastic at the equilibrium price of $3.00/mmBTU. I assume the supply to be perfectly elastic because I am only considering the supply of natural gas for use in transportation which makes up less than one percent of California total natural gas consumption.

I assume demand to be linear and to have an elasticity of -0.2 at the equilibrium price of $3.00 per mmBTU and equilibrium quantity of 17 billion cubic feet per year.[36]

4.3 Gasoline-Ethanol Blend Group Calibration

The calibration of the gasoline-ethanol blend market containing the E10 and E85 fuels requires the specification of parameters that govern the demand and supply for both fuels, plus the mechanism governing fuel switching between the two blend options. Aggregate E85 demand is specified as the product of (1) number of households, (2) the share which have flex-fuel vehicles, (3) the fraction that choose E85, and (4) the average per household consumption of E85. The aggregate ethanol demand equation is

$$Q_e\left(P_e, P_g\right) = N\phi H\left(\frac{P_g}{P_e}\right)\bar{q}\left(P_e\right), \tag{4}$$

where $\bar{q_e}\left(P_e\right)$ is the expected per household consumption of E85 for households that choose E85. The type of fuel is determined by the ratio of prices, and the extent of consumption is determined

[35] See for instance ICF International (2013).

[36] Natural gas price elasticity of demand is consistent with Arora (2014) estimate of overall natural gas price elasticity of demand.

Table 4: Gasoline-Ethanol Aggregate Demand Parameters

Parameter	Value
$\bar{Q}_e$: intercept	11,707,317,086
$\bar{Q}_e$: slope	-733,541,170
$\bar{Q}_g$: intercept	15,978,179,173
$\bar{Q}_g$: slope	-827,027,907

by the absolute price.

I then simplify equation 4 to

$$Q_e\left(P_e, P_g\right) = \phi H\left(\frac{P_g}{P_e}\right)\bar{Q}_e\left(P_e\right), \tag{5}$$

where $\bar{Q}_e\left(P_e\right) = N\bar{q}\left(P_e\right)$, and specifies the aggregate demand for E85 fuel given all households choose E85, ϕ reduces this demand to only households that have the technology to choose E85, and $H\left(\frac{P_g}{P_e}\right)$ reduces the demand further to only those households that do choose E85. I set the elasticity of unconstrained aggregate demand, $\bar{Q}_e\left(P_e\right)$, to -0.2 as described in Section 4.2. Lastly, I calibrate the linear function for $\bar{Q}_e\left(P_e\right)$ such that the demand curve has an elasticity of -0.2 at the observed price of E85 and the equilibrium quantity yields a quantity that, once multiplied by ϕ and $H\left(\frac{P_g}{P_e}\right)$ at the observed price ratio, equals the observed E85 consumption.

I repeat the procedure for the E10 market to calibrate the equation

$$Q_g\left(P_e, P_g\right) = \left[1 - \phi H\left(\frac{P_g}{P_e}\right)\right]\bar{Q}_g\left(P_g\right), \tag{6}$$

where $\bar{Q}_g\left(P_g\right)$ specifies the aggregate demand for E10 fuel given all households choose that fuel type. The resulting parameters for the unconstrained aggregate demand equations for E10 and E85 are specified in Table 4.

The supply of both E10 and E85 are assumed to be linear, with elasticities of 0.3 based on the estimate of gasoline supply elasticity of 0.289 by Coyle, DeBacker and Prisinzano (2012) and the estimate of ethanol supply elasticity of 0.258 by Luchansky and Monks (2009).

Table 5: Diesel-Biodiesel Aggregate Demand Parameters

Parameter	Value
$\bar{Q}_b$: intercept	4,485,595,997
$\bar{Q}_b$: slope	-219,882,157
$\bar{Q}_d$: intercept	4,554,569,534
$\bar{Q}_d$: slope	253,031,641

4.4 Diesel-Biodiesel Calibration

I specify the fuel switching model of the diesel-biodiesel model in a similar fashion to the E10-E85 market described in Section 4.3. It is important to note that there are two drop-in replacements for diesel fuel, biodiesel and renewable diesel. Both of which are produced from biomass. I make the simplifying assumption to treat both biodiesel and renewable diesel as the same diesel alternative fuel and do not distinguish between the two in our fuel switching model. As in Section 4.3, I specify the aggregate biodiesel demand equation to be

$$Q_b\left(P_b, P_d\right) = \phi_{biodiesel} H\left(\frac{P_d}{P_b}\right) \bar{Q}_b\left(P_b\right), \tag{7}$$

and the aggregate diesel demand equation to be

$$Q_d\left(P_b, P_d\right) = \left[1 - \phi_{biodiesel} H\left(\frac{P_d}{P_b}\right)\right] \bar{Q}_d\left(P_d\right), \tag{8}$$

where the parameters for the unconstrained aggregate demand equations for biodiesel, $\bar{Q}_b$, and diesel, $\bar{Q}_d$, are presented in Table 5. The supply of both diesel and biodiesel are assumed to be linear, with elasticities of 0.3 based on the estimates for gasoline and ethanol stated above.

5 Results

I present the results of market response to the LCFS policy and estimate credits and deficits generated under combinations of intensity target and credit price over their relevant ranges. Next, I present the likely path of credit prices in the LCFS credit market under scheduled intensity targets. Given the likely path of credit prices, I then present the implications on economic surplus and greenhouse gas mitigation at the equilibrium outcomes under the intensity target range of 100 down to 85 gCO_2e/MJ. I comment on the potential for the LCFS to encourage the production of renewable natural gas and the possibility of the dairy and landfill sectors to meet the new regulatory requirements. For the carbon tax, I present implications on economic surplus and greenhouse gas mitigation under carbon prices ranging from \$0 to \$200 per metric tonne of CO_2e. Lastly, I compare the efficiency of these policies in terms of the emission reduction per dollar of deadweight loss at the equilibrium outcomes of each policy.

5.1 LCFS Policy Impact

The nature of the LCFS policy requires the evaluation of policy response across not only each possible LCFS credit price (\$0 to \$200), but also across the relevant range of carbon intensity targets (100 to 85 gCO_2e/MJ). Given the quantity of credits and deficits generated at each combination of intensity target and credit price, I determine the resultant credit market equilibrium. Figure 5 illustrates the credit market equilibrium under a carbon intensity of 95.25 gCO_2e/MJ. In this figure, the supply of credits equals the demand for credits at a price of just over \$150 per LCFS credit. This illustrates the need for a comprehensive model incorporating all major fuels to determine credit price. Under each specification of carbon intensity target, the model identifies the equilibrium LCFS credit price.

I find an extremely narrow window of intensity targets that yield an interior solution to the credit market equilibrium. That is, at choices of carbon intensity target greater than or equal to the current average carbon intensity in the transportation sector, no adjustment is required to meet the target. For intensity targets slightly below the current average carbon intensity, credits are sold to holders of deficits at a price which equates credits and deficits. In this instance, the credit market resolves at an interior solution above zero and below the price ceiling. Further, there is a carbon intensity target such that at the maximum credit price, the supply of credits from low-carbon fuels is insufficient to meet demand for credits by the consumption of high-carbon fuels. At this carbon intensity targets and all intensity targets below, the carbon price resolves at the price ceiling and some portion of credits are purchased directly from the government. As noted in Borenstein et al.

(2015), the scarcity of low-carbon fuels and the vehicle technology limitations on their adoption yields a situation where the window of market response is limited. The most likely outcomes are a zero credit price, or a price that binds at the ceiling set by statute. Figure 6 shows the path of credit prices as the carbon intensity target declines from 100 to 85 gCO_2e/MJ and indicates the scheduled intensity targets. Note that the intensity target scheduled for as soon as 2017 yields a credit price binding at the ceiling.

Once the credit price binds at the ceiling, the realized average carbon intensity of the transportation sector fails to meet the intensity target specified by the government. Additionally, the policy ceases to be revenue-neutral as the shortfall in availability of credits is met by sales of credits by the government.

In Figure 7, I present the equilibrium distributional impacts of the LCFS policy as a function of the carbon intensity target. The revenue neutrality of the policy is evident in the lower-left panel of the diagram. In this panel, the change to taxpayer surplus due to the policy is steady at zero until the credit price ceiling is met and the state becomes a vendor of credits. Below this binding intensity target, the revenue to the government steadily increases as the policy become more stringent and the market must increasingly rely on the state as a source of credits. Producers and consumer are made worse off by this policy in general, but the impact varies by fuel and pathway. Producers of low-carbon fuels benefit greatly from this policy at the expense of producers of high-carbon fuels. Similarly, consumers of natural gas fuel see large benefits in terms of lower fuel price relative to their gasoline-consuming counterparts which suffer increased costs of fuel. Lastly, the lower right panel of the figure shows the total economic impact of the policy before accounting for the value of avoiding emissions. In Section 5.4, I discuss carbon savings and cost to avoid carbon.

5.2 Policy Implications on Renewable Natural Gas

The California dairy and waste management industries have been specifically targeted for reducing their methane emissions by recent legislation SB 1383. These industries must reduce their methane emissions by 40% relative to 2013 levels by 2030. This amounts to a reduction of roughly 12.7 million metric tonnes of CO_2 equivalent from the dairy and landfill sectors combined. The main approach dairies and landfills can pursue to avoid methane is to capture the gas, upgrade by removing pollutants and ambient air, and inject into the pipeline network. This is the process I evaluate in my model and is the methane reduction strategy specifically mentioned in the legislation.

Representative supply curves of renewable and fossil gas are presented in Figure 1. They show that renewable natural gas is much too expensive to compete against fossil natural gas. These pathways for natural gas production require some form of support relative to fossil gas in order to encourage production. The supply of RNG in response to the LCFS policy is presented in Figure 8 and the quantity of methane avoided is presented in figure 9. Given the incentives provided by the LCFS, the scheduled carbon intensity targets and the likely credit prices, dairies and landfills can reduce up to 16% of methane emissions in the short-term, upon construction of the anaerobic digester and pipeline capital. The extent of methane reduction is mainly limited by the capacity of the natural gas vehicle fleet to consume RNG. In the longer-term, as vehicles switch into natural gas fuel, these required reduction in methane emissions can certainly be attained given the existing policy instrument and incentives for renewable natural gas production.

5.3 Carbon Tax Policy Impact

I present the distributional impacts of the carbon tax policy in Figure 10. Here, the taxpayers are enriched at the expense of losses to producer and consumer surplus. The losses to consumers and producers outweigh the gains to tax revenue leading to deadweight loss to the economy. The loss to the economy grows as the price on carbon increases. Within the producer and consumer groups, the transfer of wealth from producers and consumers of high-carbon fuels to their low-carbon counterparts is greatly diminished relative to the LCFS policy scenario. Again, the value of avoiding greenhouse gas emissions is not included in the measure of cost to the economy. Valuing the cost of avoiding carbon is addressed in the following subsection.

5.4 Policy Comparison

In this section, I describe the complexity of comparing the LCFS and carbon tax policy instruments, present my basis for comparison, and describe the relative performance of these policy instruments.

In order to compare the LCFS and carbon tax policies, they must first be placed on equal footing. For instance, a carbon tax of $100 per tonne is not directly comparable with an LCFS policy with credit prices trading at $100 per tonne and a non-zero intensity target. Though they have the same price per tonne of CO_2e generated, the mechanism by which they measure emissions is not equal. The LCFS will understate the emissions by high-carbon fuels and overstate the savings of low-carbon fuels.

The relevant metric to compare the efficiency of these policies is cost to the economy per quantity of CO_2e avoided. That is, dollars of deadweight loss per metric tonne of CO_2e avoided. Figure 11 presents the policy efficiency in terms of $\$DWL/MT\,CO_2e\,avoided$ plotted against the quantity of avoided emissions for the equilibrium results of both policies. The policy efficiencies can then be directly compared for a given reduction in CO_2e by comparing the cost per unit to avoid that quantity of emissions. To achieve a five million metric tonne reduction in CO_2e, the LCFS can achieve this at a cost of $100 per tonne, whereas a carbon tax can achieve the same reduction for a cost of about $25 per tonne. However, as the policies become more stringent and the carbon reductions increase, the performance gap between the LCFS and the carbon tax shrinks. This result provides further evidence to what is suggested in Lade and Lin Lawell (2015*b*) that the efficiency of an LCFS policy with a hard cap on prices can improve as the intensity target decreases.

6 Discussion

By relying on the novel dataset of RNG supply estimates and constructing a model of LCFS response which includes the endogenous determination of credit price, I am able to assess the RNG supply response to LCFS policy. I find that as the LCFS policy is currently specified, credit prices will likely reach levels that will incentivize large quantities of RNG production. Under likely LCFS credit price outcomes, RNG can supply the entire California vehicular natural gas market with about 5.1 billion cubic feet per year from dairy, about 14.8 bcf/year from MSW, and about 2.5 bcf/year from WWTP RNG production. The LCFS yields a larger RNG production response than a carbon tax. The substantial production of RNG will lead to a reduction of 2.0 million metric tonnes of CO_2e emissions from the dairy and MSW sources which meets about 16% of the required emissions reductions required under SB 1383.

It is important to highlight the lack of production of RNG from landfill gas. Landfill gas has the lowest cost of production and is the closest to being able to produce competitively against fossil natural gas. However, the carbon intensity of landfill gas, while lower than that of fossil natural gas, is much higher than the carbon intensity of RNG produced from either MSW sources or from dairy sources. As discussed in Section 5.1, the range of intensity targets which will generate an interior solution for the credit price is very small and the most likely outcome for credit price is to bind at the price ceiling of $200 per metric tonne of CO_2e under most intensity targets. Given such a high LCFS credit price and the much lower carbon intensities of MSW and dairy RNG, the LCFS policy greatly reduces the cost of production of these sources of RNG in contrast to landfill gas. Landfill gas receives a much smaller effective subsidy due to the fact that it generates few credits per unit of energy. Just as RNG production displaces fossil natural gas, landfill natural gas is also displaced by the less carbon intensive sources of RNG.

The quantity of RNG produced is constrained by the demand for vehicular natural gas fuel. Under high LCFS credit prices, a much greater quantity could be produced profitably, but is not produced because use of RNG outside of transportation fuel does not generate LCFS credits. Expanding the use of natural gas in transportation can lead to substantial increases in RNG production, and therefore, methane emission reductions beyond what is presented in the short-term model in this paper.

As has been established in the literature before,[37] I too find that the LCFS policy is less economically efficient than an alternative carbon tax. However, the presence of a price ceiling provides many improvements over an unconstrained LCFS policy as was considered in Holland, Hughes and Knittel (2009). Given the limited supply of LCFS credits, the equilibrium credit price is highly sensitive to specification of carbon intensity targets. Therefore, reductions in carbon intensity target below the current average carbon intensity in transportation yields rapidly increasing credit price outcomes. Under intensity targets scheduled for as early as 2017, the LCFS credit price will bind at the price ceiling. The price ceiling limits the price of LCFS credits from resolving at unreasonably high prices and provides certainty to the market. Participants in the fuels markets can reasonably

[37]See Holland, Hughes and Knittel (2009) and Lade and Lin Lawell (2015*a*).

assume that credit prices will remain at or near the price ceiling until a large scale transformation of the California vehicle fleet occurs. Credit price certainty will encourage greater investment into low-carbon fuel production and research and development (Sandmo, 1971). However, just as noted in the carbon tax versus cap-and-trade debate, certainty in credit prices (compliance costs) comes at the expense of giving up certainty in carbon reductions (Metcalf, 2009; Krugman, 2010).

Under a binding credit price ceiling, I show the economic efficiency of the LCFS policy rapidly improving and approaching the efficiency of the hypothetical carbon tax. The main source of inefficiency in the LCFS policy is that the carbon intensity target is set greater than zero meaning that the policy subsidizes fuels which, while still under the target, have positive levels of emissions. As the intensity targets decrease, the efficiency gap between the LCFS and the carbon tax decreases.

7 Conclusion

Natural gas is a rapidly growing transportation fuel and while fossil sourced natural gas may not have a significant climate benefit relative to liquid fuels like diesel and gasoline, renewable sources of natural gas have clear advantages in terms of avoiding extremely harmful methane emissions. The production of RNG from organic matter that would otherwise emit methane into the atmosphere can dramatically reduce greenhouse gas emissions. However, RNG production is very expensive relative to the production of fossil natural gas. Depending on the value placed upon avoiding greenhouse gas emissions, RNG production can be a worthwhile endeavor.

California's LCFS policy as it exists can incentive substantial quantities of RNG production. RNG produced from dairy and MSW sources can supply the entire market for vehicular natural gas. This amounts to a 1.6 million metric tonne reduction in emissions from the livestock industry and a 0.4 million metric tonne reduction in emissions from the waste management sector of the economy achieving about 16% percent of their reductions required by 2030.

While often criticized as an inefficient policy instrument, I find the LCFS policy approaches the efficiency of a carbon tax, the first-best alternative, when combined with a credit price ceiling. As the LCFS policy becomes more stringent and the carbon intensity target decreases, the economic inefficiency of the LCFS policy quickly decreases.

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A RNG Supply Estimation

The renewable natural gas supply estimates that I rely upon in this paper are based on the estimates presented in Jaffe et al. (2016) and forthcoming work by Parker (2016). The supply estimation focuses on the four most promising pathways for RNG production; dairies, landfill, wastewater treatment plants, and municipal solid waste streams. The estimation procedure begins with assessing the resource potential of each pathway for all possible production sites in California. Based on the site-specific resource potential a techno-economic model of RNG production technologies is employed to estimate the cost of production and RNG yield at each site. 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. Lastly, the quantity and costs from each site are aggregated to generate supply curves for each RNG production pathway. In this analysis, Parker (2016) makes the simplifying assumptions of overnight construction, certainty in product price and technological performance over lifetime of investment, all potential entrants require the same rate of return on investment, and that all RNG is injected into transmission pipelines. On-site vehicle refueling is not considered.

The resource potential for the dairy industry is based on the location and size of dairy herds in 2011 and 2012, obtained from Central Valley Regional Water Quality Control Board and the Santa Anna Regional Water Quality Control Board. These data 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 0.09 to 103.25 million cubic feet per year for the smallest to the largest dairy. Each dairy is considered to operate independently.

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 dry tons per year of this resource could be utilized if it can be economically separated from the waste stream (Wiliams, Jenkins and Kaffka, 2015). 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 billion cubic feet (bcf) of RNG potential. This 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 (CalRecycle, 2015) to assign tipping fees across space. The tipping fees range from \$21 to \$34 per wet ton in the base case. The resource assumed to be available at the landfills where it is currently disposed and anaerobic digesters are sited throughout the state to minimize the combined transport and conversion cost using the Geospatial Bioenergy Systems Model (Parker et al., 2010; Tittmann et al., 2010).

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. The potential for RNG production from WWTP with anaerobic digesters (but no energy production) was analyzed.

Landfill gas is estimated based on current landfill gas production rates from the EPAs Landfill Methane Outreach Program (LMOP, 2015). 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 52 bcf per year or about three quarters of the resource estimated by California Biomass Collaborative using disposal rates for the state as a whole.

Dairy and MSW anaerobic digesters have separate cost functions due to the significantly different qualities of the feedstock. Cost functions for the two digesters types can be found in Table A1. The estimate for dairy digesters is based on the cost function found in Faulhaber, Raman and Burns (2012) that was fitted to the EPA's AgSTAR project database for plug-flow anaerobic digesters. The cost function was adjusted to remove costs associated with electricity production and increased by 30% to account for the higher cost of digesters in California. In a case study, Summers and

Williams (2013) found California digesters to be 30% more expensive than the average digesters of the same size and type found in the AgSTAR database (EPA AgSTAR, 2009). Biomethane production is assumed to be 4.3 million British thermal units (mmBTU) per dry ton of manure. The cost function 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 also adjusted by subtracting the cost of power generation equipment. The MSW digesters are limited to facility sizes less than 200,000 tons per year, which is the size of a large landfill operation in CA, due to practical feasibility for siting and permitting of the facility. For comparison, the largest current facility in California is 90,000 tons per year.

Table A1: Costs of RNG Production and Upgrading Facilities

Technology	Capital Cost ($)	Operating Cost ($/yr)	Capacity Notes
Dairy Digester	15,826 capacity$^{0.59}$	0.05Capital + 20,000	dry tons of manure per year
MSW Digester	1,666,500 capacity$^{0.54}$	162,772 capacity$^{0.6}$	1,000 tons per year of MSW input
RNG Upgrading		333,177 capacity$^{0.64}$	flow rate of RNG (mmBTU/hr)

The costs of upgrading biogas, including construction of a pipeline interconnect is developed from Electrigaz (2011) and public comments to the California Public Utilities Commission (CPUC). The costs include the clean-up to the pipeline specification, compression and injection station with the necessary monitoring equipment. For the purposes of estimating the costs across the hundreds of sources in California, Parker 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, the cost function is modified 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 distance from each production site to the nearest natural gas transmission pipelines were calculated using ArcGIS 10.3. The distance found is the shortest straight-line path between the production site and the pipeline. Since pipelines are unlikely to travel the shortest path due to rights of way, terrain, and other considerations, a tortuosity factor of 1.3 is included in the estimate. 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, Cabe and Stout (2011) to 2014 dollars. The cost for each facility is then dependent on their distance to the pipeline.

Supply curves of RNG produced from (1) dairy gas, (2) municipal solid waste, (3) wastewater treatment plants, and (4) landfill gas as well as natural gas from fossil sources are presented in Figure 1. The price of natural gas from fossil sources is based on the California citygate price December 2015 of $3.00/mmBTU per the United States Energy Information Administration. The price of natural gas from fossil sources is the important benchmark against which renewable natural gas competes. Methane from fossil sources and from renewable sources are indistinguishable from a consumer's point of view. Without addressing the externality of carbon emissions, no consumer would have any incentive to purchase renewable natural gas for more than the cost of the cheapest source of methane available, fossil natural gas. The private costs of production for each of the RNG sources we consider exceed the price of fossil natural gas. RNG from landfill gas is the closest source to profitable production when natural gas prices are around $3.00/mmBTU. However, the lowest cost source of RNG is $6.61/mmBTU, over double the price of fossil gas. The lowest cost source of RNG from the other three sources are $8.81/mmBTU for gas from wastewater treatment, $14.01/mmBTU for gas from municipal solid waste, and $26.41/mmBTU for dairy gas. The combined supply available under $10.00/mmBTU from all four sources of RNG is 33.9 bcf per year. Under $20.00/mmBTU, the combined supply of RNG available is 66.5 bcf per year. The total RNG supply possible at any price is 94.0 bcf per year.

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Figure 1: Renewable Natural Gas Supply Curve Estimates

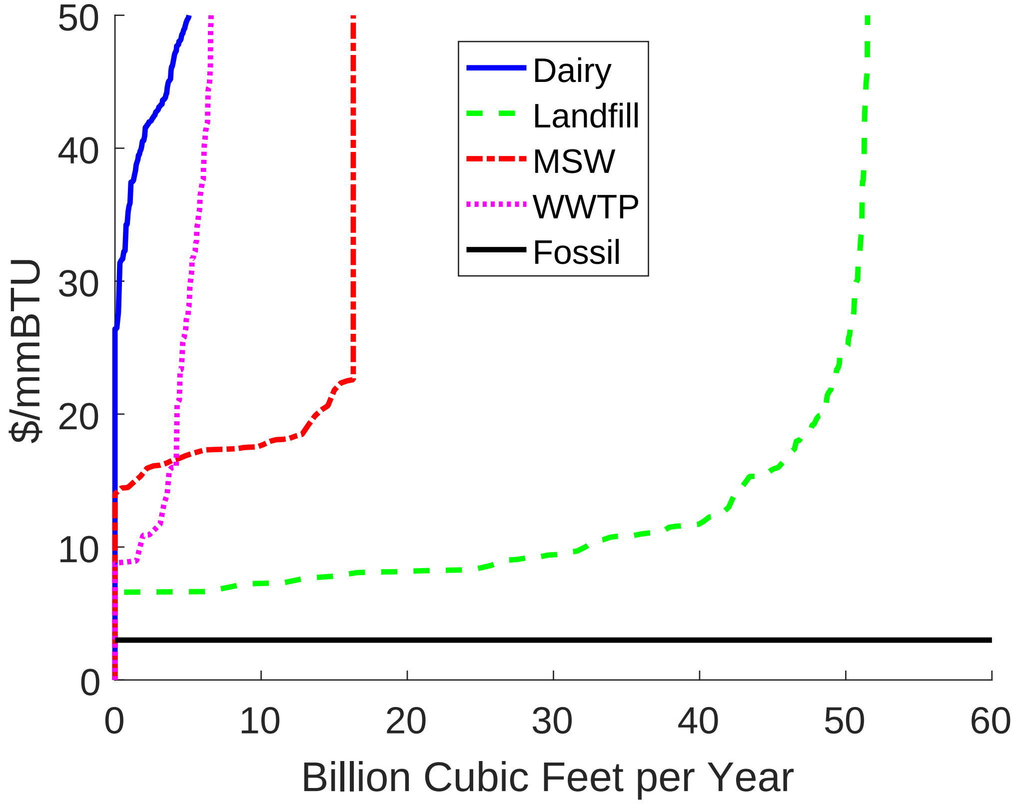
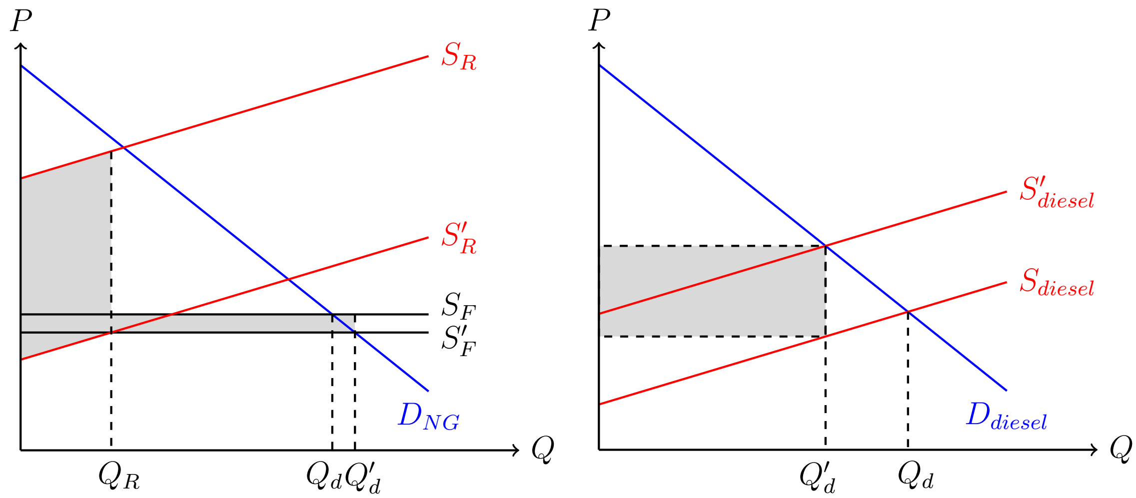


Figure 2: Credit Market Equilibrium



Credit Generating Market **Deficit Generating Market**

Figure 3: RNG Response to LCFS Credit Prices

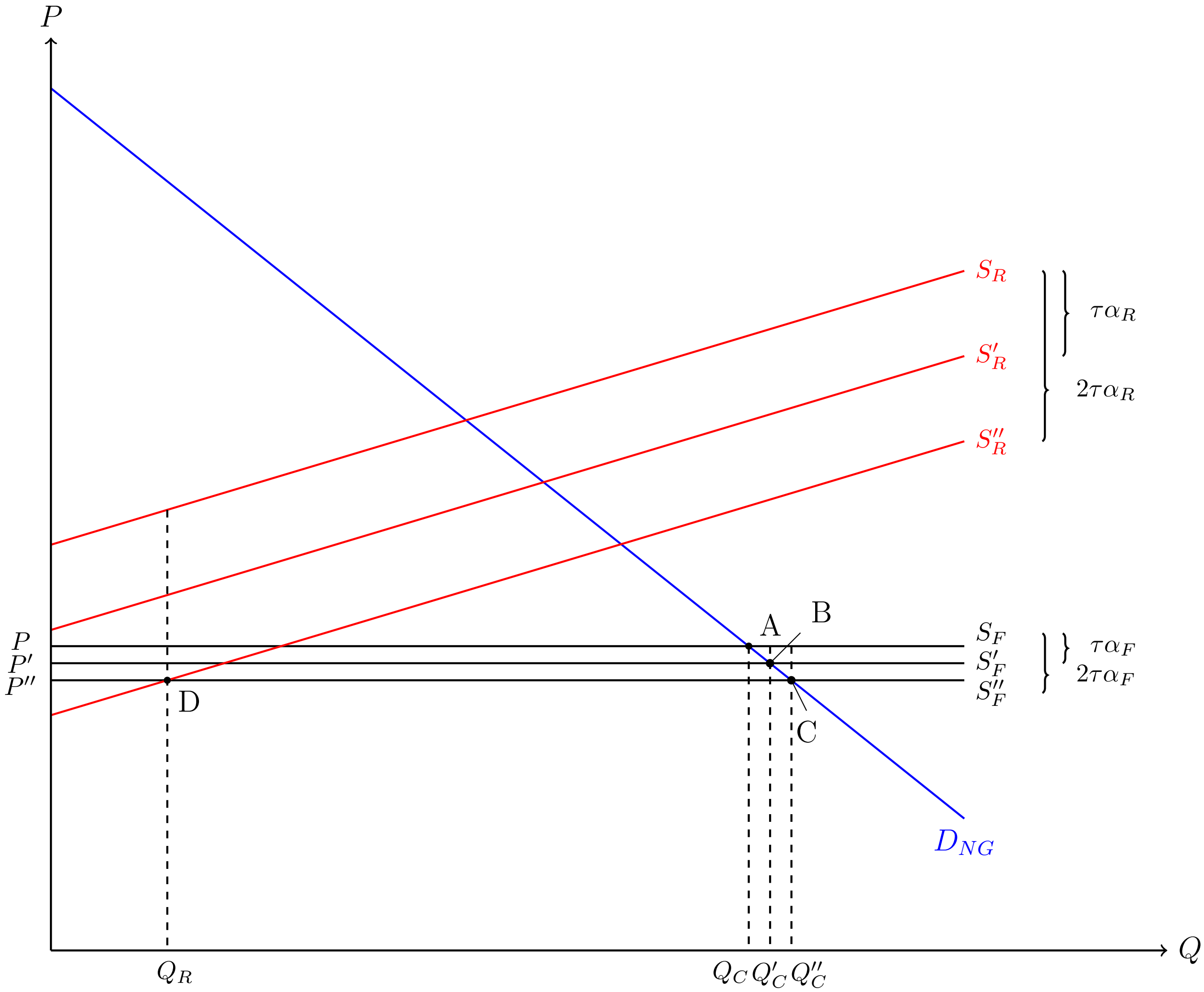


Figure 4: RNG Response to Carbon Tax

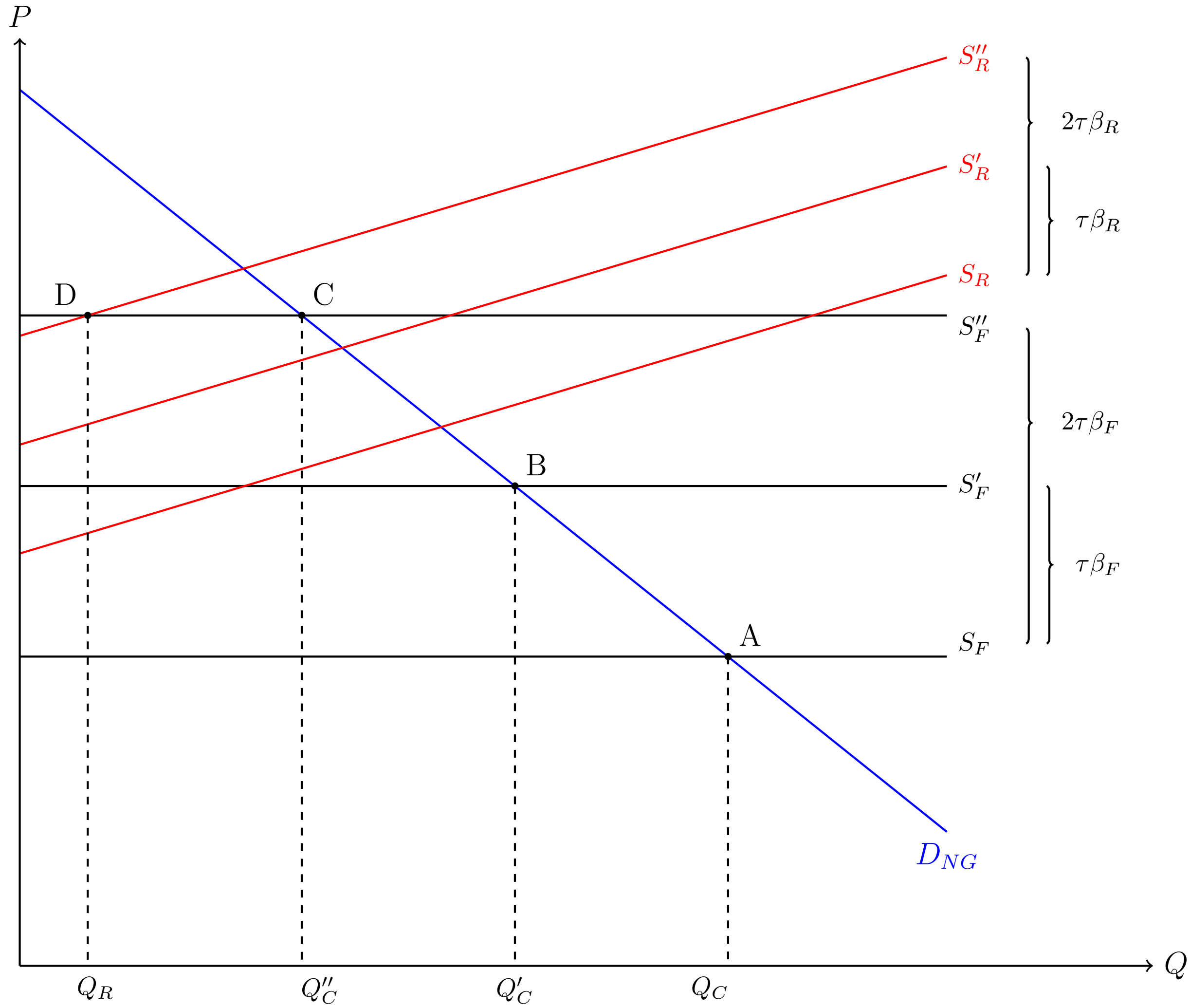


Figure 5: LCFS Credit Market Equilibrium

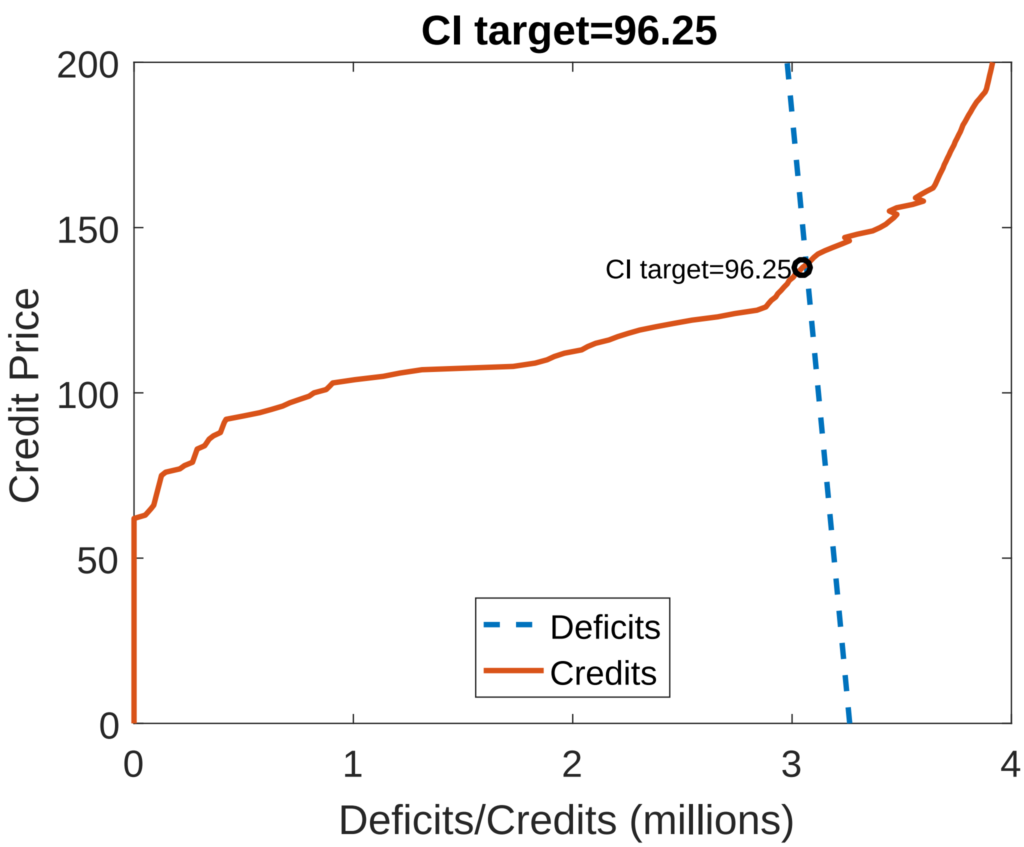


Figure 6: LCFS Credit Market Equilibria

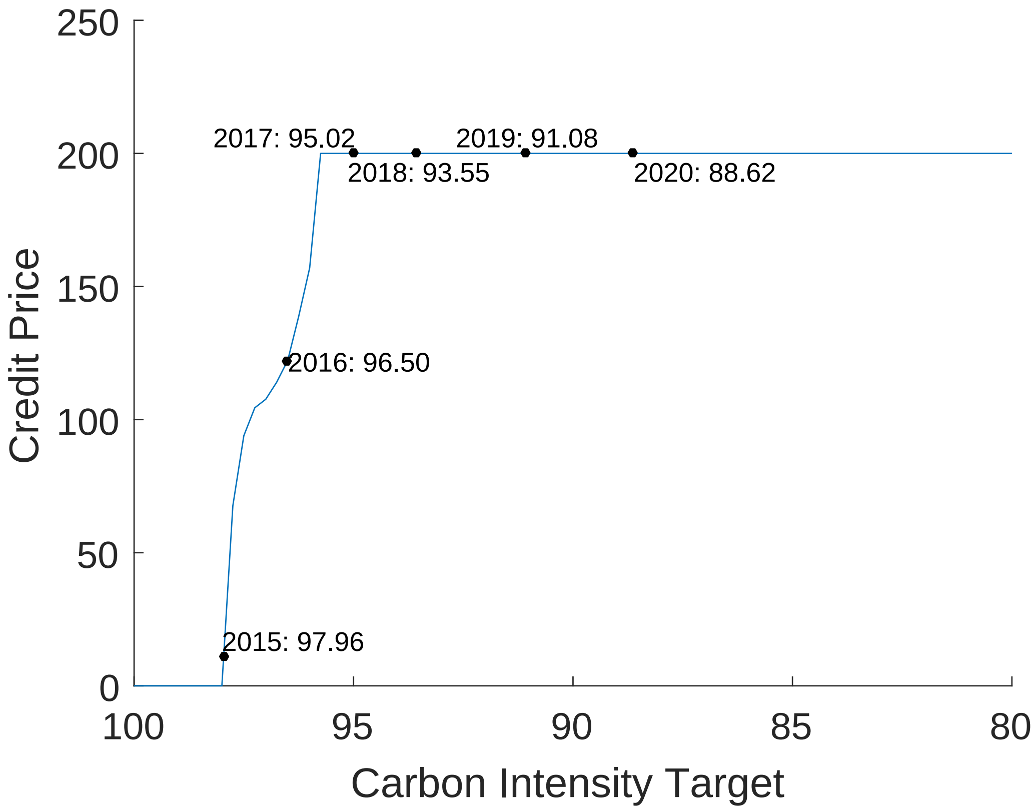


Figure 7: Equilibrium Economic Impact under LCFS by Carbon Intensity Target

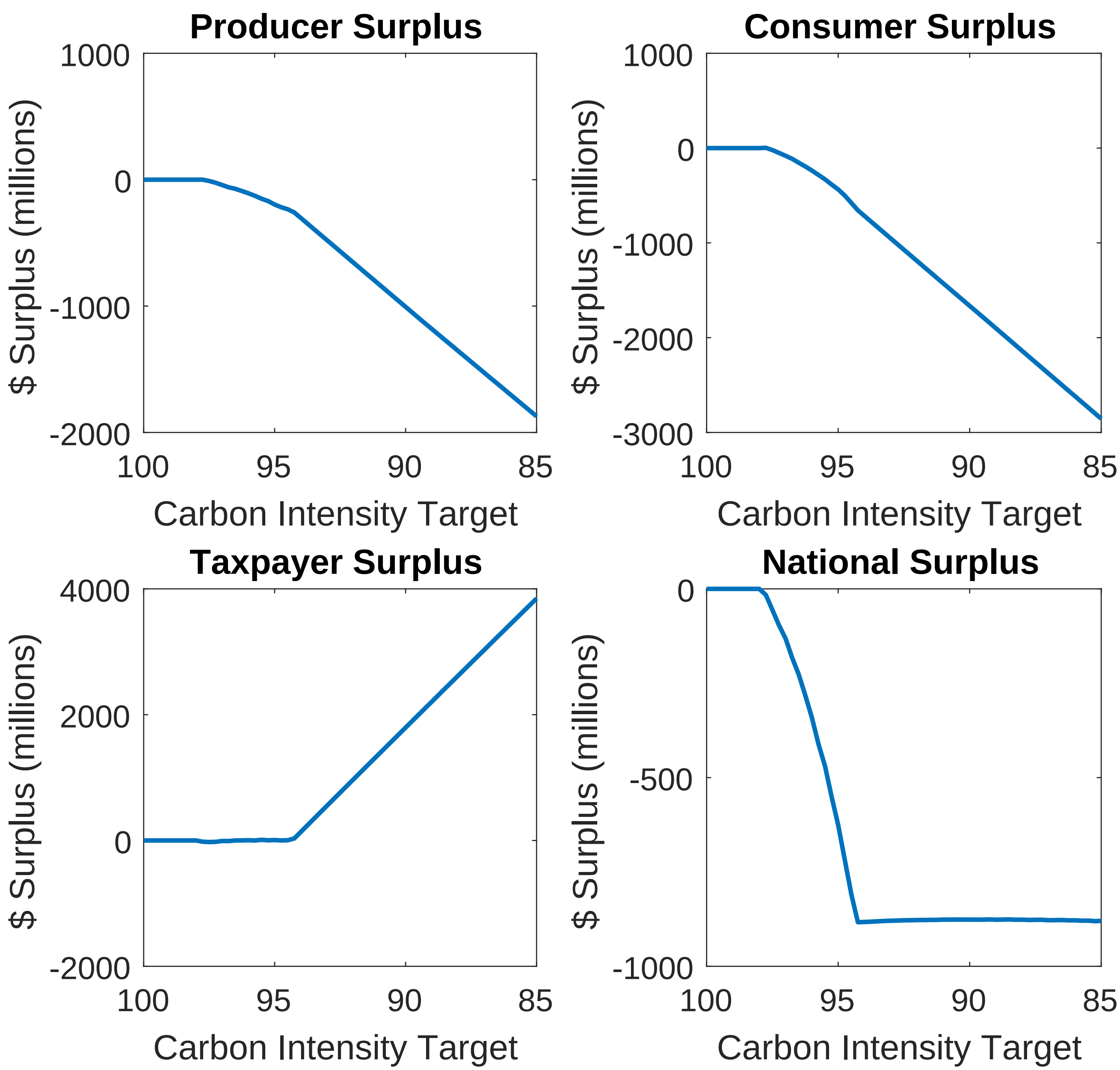


Figure 8: RNG Supplied under LCFS by Carbon Intensity Target

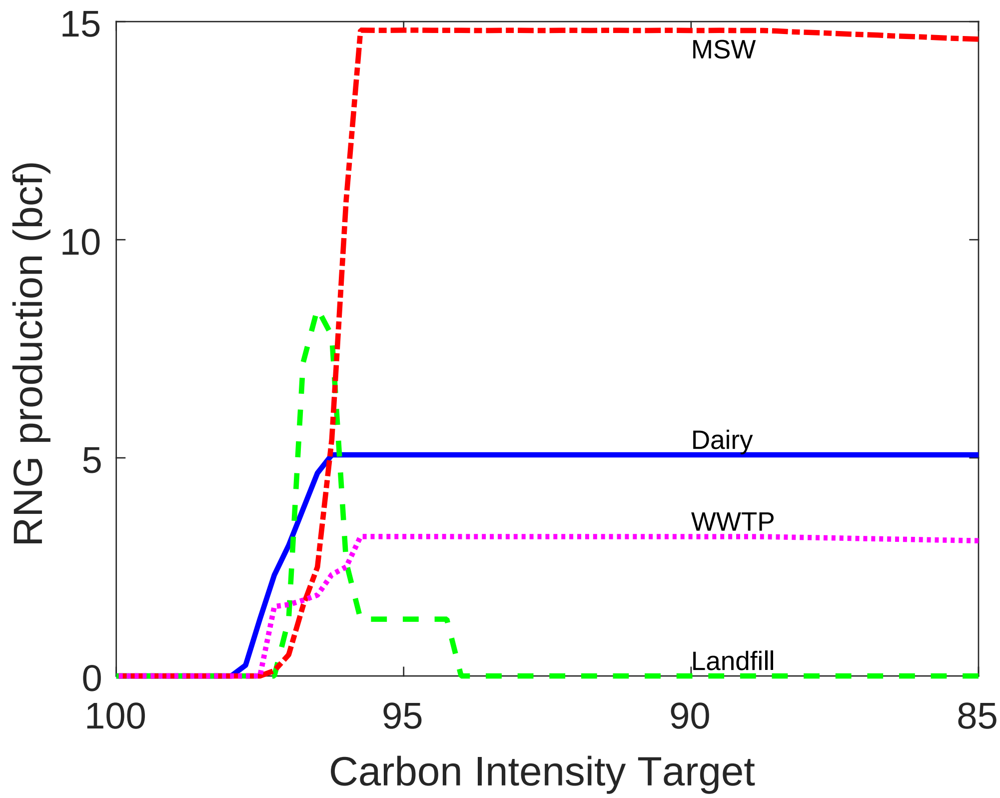


Figure 9: RNG Emissions Savings under LCFS by Carbon Intensity Target

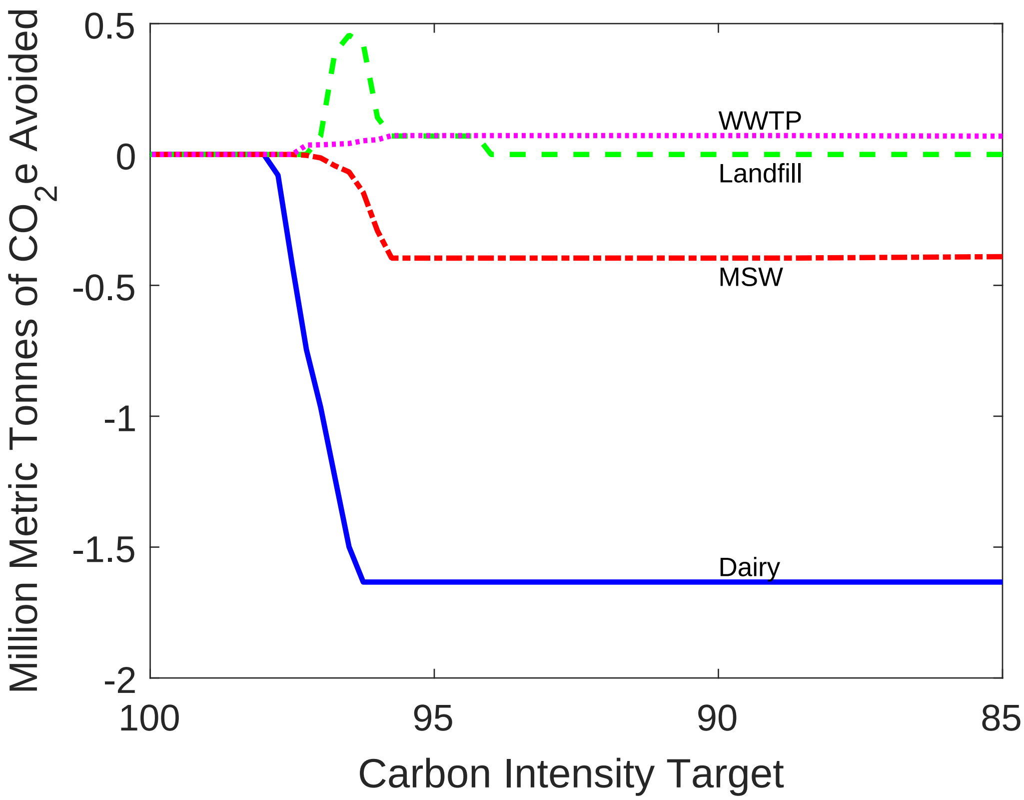
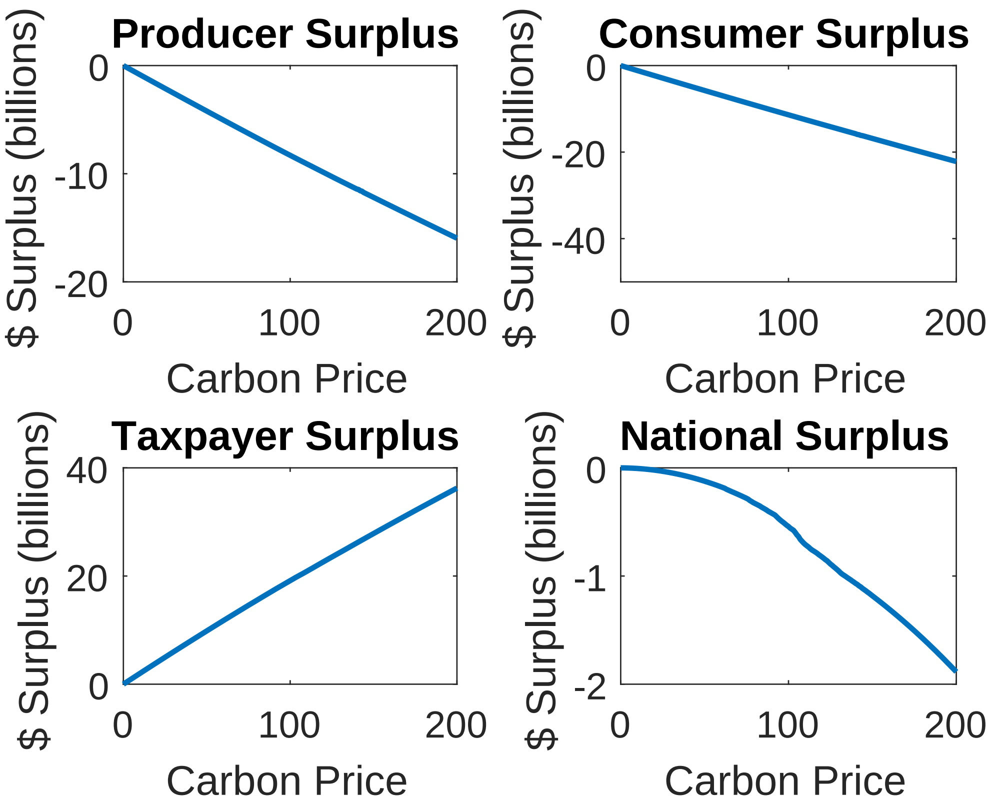


Figure 10: Economic Impact under Carbon Tax



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