Carbon Metric:

AB 32 Transportation Measures

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Glossary of Terms and Organizations

AB 32	California's Global Warming Solutions Act of 2006, requiring the state to reduce greenhouse gas emissions to 1990 levels by 2020.
ACC	Advanced Clean Cars Program. The Advanced Clean Cars Program is a bundle of regulations that will limit smog forming pollution and GHG emissions using a combination of fuel economy standards and tailpipe emission standards. It includes what is referred to as Pavley 2 standards, the Zero Emission Vehicle Program, and the Clean Fuels Outlet.
BEV	Battery Electric Vehicle (e.g. a Nissan Leaf)
Biodiesel	Fuels derived from biomass feedstocks (typically vegetable oils) and produced via trans-esterification. Neat biodiesel (100 percent pure) cannot be utilized in most diesel engines. Biodiesel is typically blended into diesel fuels. Typical blend levels vary between 2 percent and 20 percent biodiesel (B2 and B20).
Biodistillate	A generic name for biomass derived diesel fuel substitutes. This includes biodiesel, renewable diesel (produced from vegetable oils through a hydrogenation process) and cellulosic diesel (produced from cellulosic biomass). Biodiesel can only be consumed as a blend with diesel; renewable and cellulosic diesel can be utilized on a neat basis.
Blend wall	The blend wall refers to the point at which ethanol production is equal to the maximum volume of ethanol that can be blended into gasoline. This refers to the current limit of ethanol that can be blended into gasoline for reformulated gasoline. Although the EPA has approved a waiver to blend up to 15 percent ethanol (by volume) in gasoline for vehicles produced after 2001, California currently restricts reformulated gasoline to 10 percent ethanol (by volume).
CARB	California Air Resources Board
CARBOB	California Reformulated Blendstock for Oxygenate Blending. California is what is referred to as a reformulated gasoline market. Reformulated gasoline consists of CARBOB and an oxygenator. The oxygenator is ethanol.
CAFE	Corporate Average Fuel Economy. Automobile manufacturers are required to comply with CAFE standards for light-duty vehicles and more recently, medium-duty vehicles. These standards impact the tailpipe emissions of vehicles, which mostly run on gasoline and diesel.

CEC	California Energy Commission
Citygate Price	Citygate typically refers to the point where natural gas is transferred from a transmission pipeline to a local utility. Typically, utilities take ownership of the natural gas at the citygate and then distribute the fuel to its customers.
CNG	Compressed Natural Gas. CNG is mainly used in medium- and heavy-duty vehicles. Because the gas is stored at high pressure for compression, large storage tanks are required on CNG vehicles.
CO_2	Carbon dioxide
CO_2e	Unit of measure for non-CO_2 GHG pollutants multiplied by an appropriate 100 year global warming potential value to arrive at a CO_2 equivalent value.
Criteria Pollutant	The Clean Air Act requires that U.S. EPA control ambient levels of six pollutants to protect public health. These pollutants are: particulate matter, ground-level ozone (smog), carbon monoxide, sulfur dioxide, nitrogen oxides and lead. Ground level ozone is limited through control of nitrogen oxide and volatile organic compound emissions.
EER	Energy Economy Ratio: ratio of fuel consumption per mile of gasoline vehicle divided by the fuel consumption per mile of the alternative fuel vehicle.
Ethanol	A fuel that can be utilized as a low level blend in gasoline vehicles and as a high level blend in flex fuel vehicles (FFVs). The U.S. EPA allows conventional gasoline vehicles to utilize up to a 10 percent blend in gasoline (up to 15 percent allowed for model years 2001 and newer). An 85 percent blend (E85) is utilized in flex fuel vehicles. Reformulated gasoline in California currently contains ~10 percent ethanol.
GHG	Greenhouse Gas. GHGs considered here include CO_2, CH_4 and N_2O.
FCV	Fuel cell vehicles. Fuel cell vehicles use electricity generated from hydrogen for propulsion and are more efficient than gasoline vehicles.
ILUC	Indirect Land Use Change. ILUC emissions can result from increased consumption of biomass fuels. For example, if consumption of soybean based biodiesel increases in the U.S., more soybeans will need to be grown somewhere in the world to replace those used for fuel. The emissions associated with clearing land (e.g. burning rain forests) to cultivate diverted soybeans are referred to as ILUC emissions.
LCFS	Low Carbon Fuel Standard. The LCFS requires a 10 percent reduction in the carbon intensity of transportation fuels by 2020. The carbon intensity of

a fuel is measure of its GHG emissions per unit of energy of fuel consumed on a Well-To-Wheels (WTW) basis

LEV	Low Emission Vehicle. California has regulated vehicle tailpipe emissions since 1990. The standards were first promulgated to reduce criteria air pollutants. Compliant vehicles were referred to as different types of LEVs.
mpg	miles per gallon. MPG is the metric of choice when measuring the efficiency of light-duty vehicles and is used to enforce CAFE standards.
NHTSA	National Highway Traffic Safety Administration
NPV	Net Present Value
Pavley 2	Pavley 2 is a proposed extension of the Pavley light duty GHG tailpipe standard for 2010-2016. In its current form, Pavley 2 is consistent with proposed Federal EPA light duty GHG standards and proposed NHTSA CAFE standards for 2017-2025.
PEV	Plug-in Electric Vehicle; includes both PHEVs and BEVs. Plug-in electric vehicles can be plugged in, whereby the electrical energy is stored in an onboard battery.
PHEV	Plug-in Hybrid Electric Vehicle (e.g. Chevy Volt). PHEV's are similar to hybrid electric vehicles (HEVs, e.g. the Toyota Prius) in that they have both a battery-electric motor and a gasoline engine. The PHEV battery capacity is larger and can be charged (plugged in).
Rack price	Rack price refers to the price which refiners sell their product to market. Buyers at the rack include wholesale gasoline sellers or even direct to retail infrastructure stations.
Renewable Diesel	Renewable diesel is a drop-in alternative fuel produced from renewable feedstocks. The fuel is referred to as a drop-in alternative because it is compatible with the existing pipeline and retail fueling infrastructure. There are many ways to produce renewable diesel e.g., by hydrogenating fatty acid methyl esters (biodiesel), pyrolysis, or the Fischer-Tropsch process.
RFS	Renewable Fuel Standard. The RFS was created by the Energy Policy Act (EPAct) of 2005 and modified under the Energy Independence and Security Act (EISA) of 2007. The standard requires a specified volume of renewable fuels to be blended into transportation fuels. The volumetric target started at 9 billion gallons in 2008 and increased to 36 billion gallons by 2022.

RIN	Renewable identification number. The RIN is a serial number assigned to each gallon of biofuel to track production, use, and trading as part of compliance with the federal Renewable Fuel Standard.
ZEV	Zero Emission Vehicle, currently considered to be BEVs and Hydrogen fuel cell vehicles.
ZEV Mandate	The ZEV Mandate was established in 1999 by CARB to force increased penetration rates of zero emission vehicles to reduce criteria pollutant emissions. Over the years, the mandate has been adjusted several times to reflect slower penetration than anticipated of ZEVs. In March 2008, the CARB Board directed staff to strengthen the requirements for 2015 and beyond by focusing solely on electric and hydrogen vehicles. Proposed modifications to the ZEV Mandate have been developed and published, but not yet approved.
TTW	Tank-to-Wheel emissions. TTW emissions are vehicle emissions and traditionally do not capture upstream emissions associated with fuel production and transport. In this analysis we include CO_2 emissions from electricity and hydrogen production in the TTW emissions to be consistent with the parallel analyses.
VMT	Vehicle miles travelled. VMT is generally reported on a daily or annual basis; it is typically used to determine fuel consumption for vehicles.
WTW	Well-to-Wheel emissions. WTW emissions include emissions associated with feedstock recovery and transport, fuel production and transport and vehicle emissions.

Executive Summary

Scope

Pacific Gas & Electric Company (PG&E) retained ICF International to determine the feasibility and cost of abatement of California's Low Carbon Fuel Standard (LCFS) regulation. Under LCFS, the California Air Resources Board (CARB) requires California fuel producers to reduce carbon intensity by at least ten percent by 2020, where carbon intensity is measured in grams per unit energy of fuel (gCO_2e/MJ) consumed on a full-fuel cycle or well-to-wheel (WTW) basis. The WTW estimate for GHG emissions is generally split into two parts: well-to-tank emissions and tank-to-wheel emissions. These are also referred to as upstream and downstream emissions, respectively. Well-to-tank or upstream emissions include emissions from processes such as crude oil or natural gas recovery, feedstock cultivation (for biofuels), transportation of refined products., and transmission or distribution of fuel (e.g., electricity). Tank-to-wheel or downstream emissions include emissions from the consumption of fuel to power a vehicle, such as combustion of gasoline, diesel, or natural gas in an internal combustion engine.

The LCFS does not stipulate how to reduce carbon intensity, rather it uses a crediting approach to require transportation fuels providers meet periodic intensity standards. Fuels less carbon-intensive than the standard will generate credits whereas fuels more carbon-intensive than the standard will result in deficits. Examples of less carbon-intensive gasoline and diesel alternatives include ethanol, bio-distillates, compressed natural gas, electricity and hydrogen. In other words, vehicles that run on biofuels (e.g., flexible fuel vehicles) or compressed natural gas, and advanced vehicle technologies such as plug-in hybrids, battery electric vehicles, and fuel cell vehicles that use hydrogen help reduce the carbon intensity of the transportation fuel sector. The gasoline fuel substitutes considered in our analysis include ethanol, electricity, and hydrogen; and to some extent compressed natural gas (CNG) for light-duty trucks and medium-duty trucks that consume gasoline. Gasoline vehicles are unable to run on ethanol alone and therefore must be blended with gasoline. California currently consumes a ten percent ethanol blend in reformulated gasoline. The diesel fuel substitutes considered in our analysis include biodiesel, renewable diesel, CNG, liquefied natural gas (LNG), and bio-methane.

Methodology

To analyze the feasibility and cost of the aforementioned alternatives, ICF developed an optimization model that considers a variety of compliance strategies based on each fuel's costs, incremental to gasoline or diesel, and its abatement potential. The model dynamically solves for a low-cost, lowest emission solution while considering inter-temporal trading and banking behavior. This is a critical aspect of the LCFS program because it provides an incentive for over-compliance in the early years of the regulation, when compliance strategies are potentially less costly.

ICF modeled LCFS compliance using the LCFS program's deficit and credit system i.e., gasoline consumption and diesel consumption yielded deficits and the introduction of lower carbon fuels yielded credits. Any fuel with a carbon intensity above the baseline for that year generated deficits and any fuel with a carbon intensity below the baseline for that particular year generated credits. This report describes emission reductions on a WTW basis and on a tank-to-wheel (TTW) or vehicle only basis. Although TTW emissions for electricity and hydrogen are traditionally assumed to be zero, we used an emission factor equivalent to the CO_2 emissions produced at the power plant and the hydrogen production plant, respectively. This assumption significantly decreases the estimated abatement for electricity and hydrogen when considered on a TTW basis; however it provides consistency with analyses of other energy-related program measures.

Change in the light-duty vehicle fleet due to Pavley 2 program measure and the Zero Emissions Vehicle (ZEV) mandate were factored into feasibility analysis of LCFS. We assume that the Pavley 2 standard is met through increased market penetration of more efficient vehicles and that the costs of conventional vehicles increase over time to comply with the standard according to estimates from CARB and the EPA. We model the ZEV Program using CARB's "most likely compliance scenario" which assumes that there are approximately 500,000 ZEVs on the road, whereby automobile manufacturers have maximized their ability to earn TZEV credits, and have deployed BEVs, and FCVs.

We report costs annually from 2011 to 2020 and include fuel costs, vehicle costs, and infrastructure costs. For example, for cellulosic ethanol, we quantified the net cost increase relative to consuming the equivalent amount of gasoline. The projected fuel cost increases include cost elements such as feedstock costs, production facility costs (e.g. bio-refinery construction costs, operations costs, and materials costs), and distribution costs (e.g., transporting ethanol to petroleum terminals).

Once we quantified annual net present value (NPV) GHG abatement and costs (high and low) for 2011 through 2020, we estimated cost per tonne reduced for each measure in 2020.

We developed two scenarios: a plausible low cost and plausible high cost scenario. For each scenario, we modified many variables—particularly those with the greatest uncertainty— to reflect potential constraints on the market. For instance, the price premium that cellulosic biofuels will require for deployment is unknown today because there are not commercial volumes available and no historical data exist. As a result of changes in the costs of various parameters, the supply potential of many alternative fuels was impacted. For instance, the volumes of sugarcane ethanol and cellulosic ethanol deployed in the optimization scenario were reduced in the plausible high scenario because of higher prices.

The parameters varied can be broadly categorized as follows: fuel costs, vehicle costs, and infrastructure costs. All low estimates were combined into the low case while all high estimates were combined to the high case to estimate a plausible range of abatement cost.

Conclusions

For illustrative purposes, we considered abatement costs in five different phases of the regulation, corresponding to a carbon intensity reduction target and a compliance year (as shown in Exhibit 1). Exhibit 2 and Exhibit 3 highlight the average unit abatement costs for the plausible low cost and plausible high cost scenarios, respectively. The WTW GHG reductions are shown on the horizontal axis; the thickness of each bar represents the GHG reductions attributable to that compliance increment. Note that LCFS compliance is achieved in the plausible low cost scenario, and it is not achieved in the plausible high cost scenario.

Exhibit 1. LCFS Compliance Targets in Phases

LCFS Phase	Carbon Intensity Reduction Target	Corresponding Years
Phase 1	0–1.0 percent	2011-2013
Phase 2	1.0–2.5 percent	2013-2015
Phase 3	2.5–5.0 percent	2015-2017
Phase 4	5.0–8.0 percent	2017-2019
Phase 5	8.0–10.0 percent	2019-2020

Exhibit 2. Abatement Curve for Plausible Low Cost Scenario

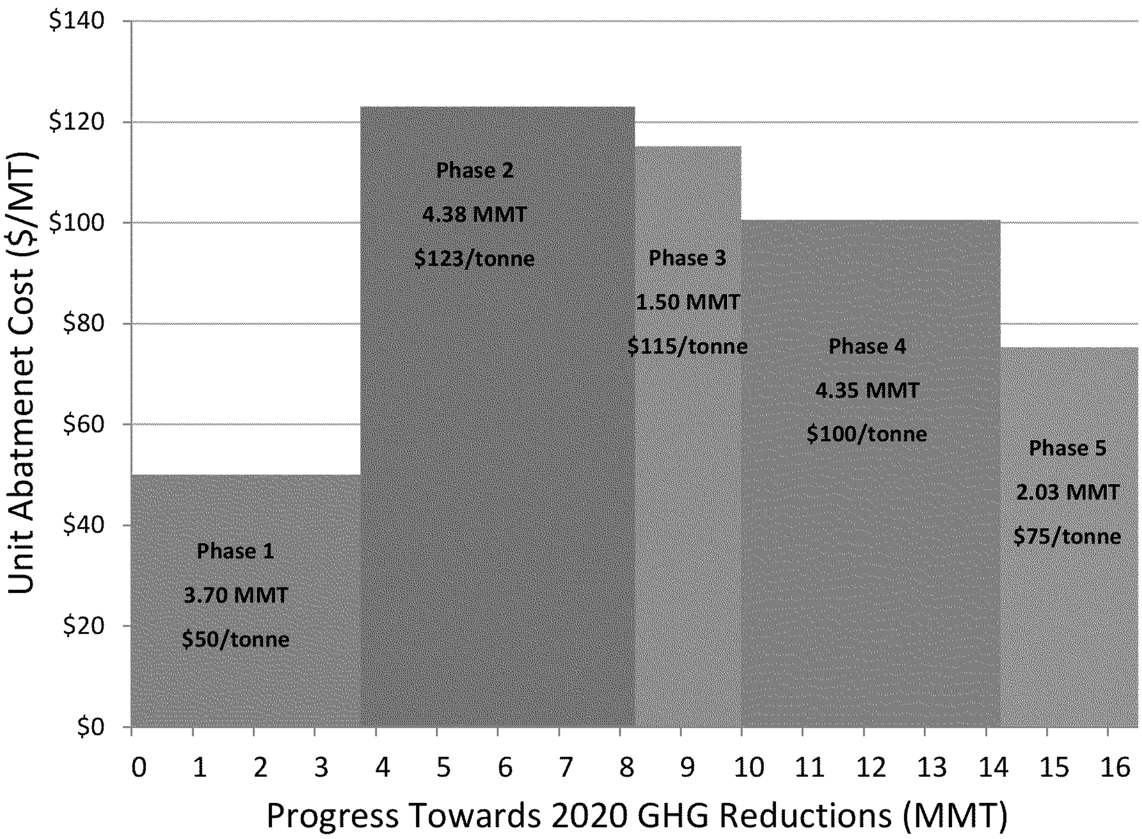

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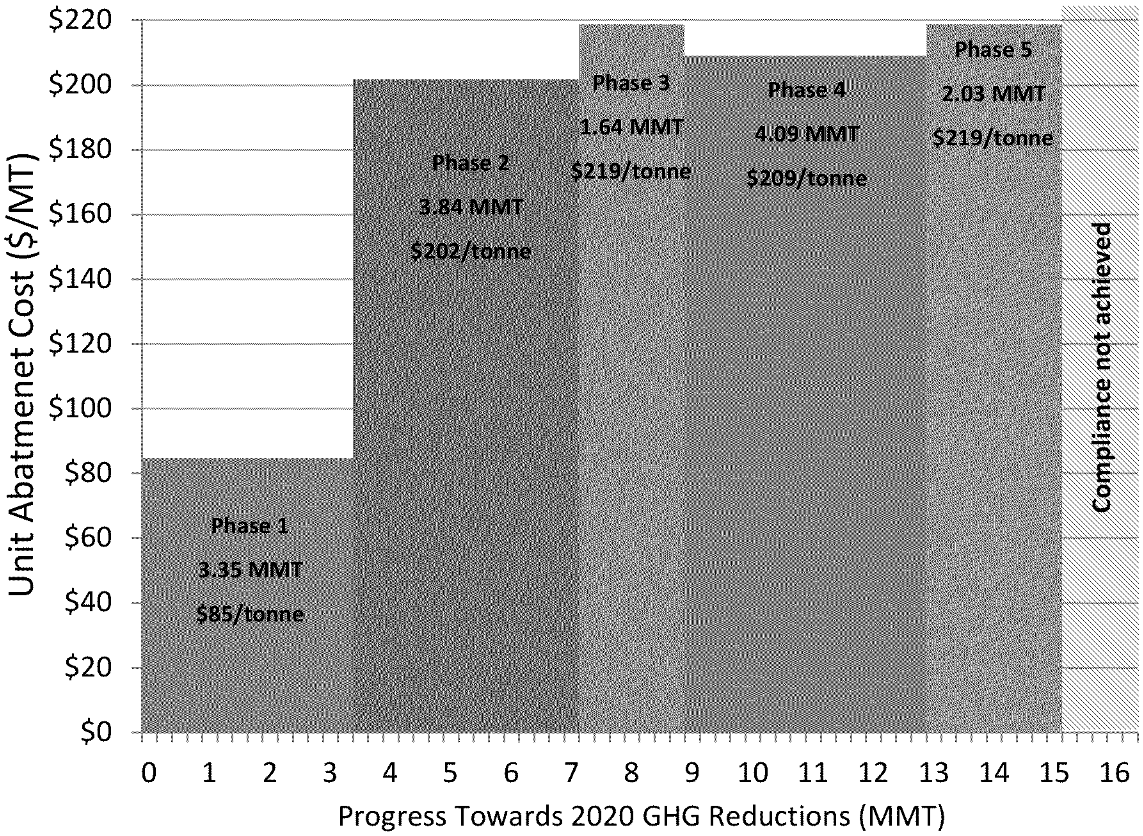
Exhibit 3. Abatement Curve for Plausible High Cost Scenario



Note: Compliance is not achieved in the Plausible High Cost Scenario

Exhibit 4. Average Abatement Costs for Plausible Low and Plausible High Cost Scenarios

Phases	Plausible Low Cost				Plausible High Cost			
	Reductions (in MMT CO_2e)		Costs (in $/MT)		Reductions (in MMT CO_2e)		Costs (in $/MT)	
	WTW	TTW	WTW	TTW	WTW	TTW	WTW	TTW
Phase 1 2011-2013	3.74	10.09	$50	$8	3.35	8.57	$85	$10
Phase 2 2013-2015	8.13	12.25	$123	$70	7.19	9.91	$202	$25
Phase 3 2015-2017	9.85	12.88	$115	$40	8.83	11.99	$219	$69
Phase 4 2017-2019	14.22	16.09	$100	$33	12.91	12.61	$209	$110
Phase 5 2019-2020	16.27	17.64	$75	$70	14.94	14.91	$219	$157
Average Unit Abatement Cost			**$94**	**$39**			**$182**	**$79**

Exhibit 5. Unit Abatement Costs and Marginal Abatement in 2020

Scenario	GHG Reductions (MT)	Avg Abatement Cost ($/tonne)	Abatement Cost of Last Increment ($/tonne)
Low Cost	16.27	$94	$75
High Cost	14.94	$182	$219

- ***Both scenarios rely significantly on over-compliance out to 2016 to comply by 2020***: Similar to any forward-looking analysis that relies on technological advances; this modeling exercise is limited by forecasted abatement potentials for multiple compliance strategies. The model is built using relatively conservative forecasts for the availability of very low carbon strategies (e.g., cellulosic biofuels from waste or bio-methane). As a result, the optimization model seeks out the lowest carbon, least cost pathway based on our current understanding of fuels that will be available at an estimated price in 2020. To some extent, the results represent our best estimates based on our understanding of what the market will look like in 2015 with a high degree of certainty and in 2020 with less certainty. In the case of 2015, we have a higher level of certainty regarding availability and pricing (e.g., biodiesel from corn oil). It is important to recognize the inherent uncertainty in these types of exercises given the challenge of forecasting out to 2020.
- ***GHG reductions in the diesel pool can make up for a shortfall in the gasoline pool***: The modeling exercise also suggests that the potential for GHG reductions in the diesel pool, through strategies such as corn-oil based biodiesel, renewable diesel, and natural gas, can help make up for a shortfall of credits in the gasoline pool. This is largely driven by the following:
  - There is little biodiesel consumption to date in California (less than 20 million gallons for the past couple of years),
  - There is significant potential for CNG to displace diesel in multiple diesel vehicle segments, and
  - Corn ethanol has a high carbon intensity that reduces motivation to blend with gasoline.
- ***Compliance with LCFS beyond 2020 will likely be challenging***: It is important to note that this analysis only considered the 2020 timeframe; therefore, complying with the LCFS beyond 2020 is outside of the scope of the modeling exercise. However, based on the number of deficits in the year 2020 for both scenarios, it will likely be challenging to comply with LCFS if the ten percent reduction in carbon intensity is kept constant beyond 2020.
- ***Compliance is not achieved in the high cost scenario***: As shown in Figure 1, the average unit abatement cost differs only by $88 per tonne but in the plausible high cost scenario, compliance with LCFS is not achieved. This is due to the higher costs introduced at the margins of the supply curves for low carbon biofuels, natural gas, and electric vehicles results in a shortfall of credits for LCFS compliance in 2020.

- ***The ZEV Mandate makes a small contribution towards LCFS compliance***: The ZEV Mandate does not come into effect until 2017 and using CARB's most likely compliance scenario, the program makes a nine to ten percent contribution towards LCFS compliance, largely as a result of a displacement credit awarded to electricity and hydrogen in the calculation used to quantify LCFS. As a result of this calculation, the impact of electricity and hydrogen towards compliance are disproportionate to their contribution towards GHG reductions, by factors ranging from 2.5 to 3.4.
- ***High degree of uncertainty regarding biofuel carbon intensities***: Biofuel carbon emission factors include a CARB estimate of Indirect Land Use Change (ILUC) emissions, which have a high degree of uncertainty. CARB is reviewing the ILUC emission factors for various crops including corn, soybeans, and sugarcane. Any changes in the current estimates of ILUC emissions would impact the abatement potential and abatement cost of biofuels.
- ***Sugarcane ethanol will most likely be a significant compliance pathway for LCFS because of its availability and price***: Despite concerns about importing sugarcane ethanol from Brazil and exporting corn ethanol for use in Brazil, without changes to the carbon intensity of corn ethanol, this "ethanol shuffle" will likely continue. In 2012, the US imported more than 500 million gallons of Brazilian sugarcane ethanol and 89 million gallons were delivered to California. Also, California imported 37 million gallons of sugarcane ethanol in 2011 for compliance with the LCFS and the federal renewable fuels standard (RFS2). The U.S is likely to increase net import of Brazilian sugarcane ethanol, with a shift in the import of the fuel towards California. Sugarcane ethanol imports are expected to fall somewhat in 2013 for the rest of the US as a result of the federal tax credit for biodiesel,[1] however, we continue to expect LCFS to be a significant driver for imports into California.
- ***Corn-oil based biodiesel is expected to play a major role in compliance with LCFS***: Based on the forecasted availability of supply, pricing, and low carbon intensity (4 g/MJ), corn oil-based biodiesel is expected to play a major role in compliance with the LCFS. A significant number of corn ethanol production facilities have already installed corn oil extraction equipment as of 2012, with an estimated nationwide production volume of 100 million gallons of corn oil based biodiesel by 2013 and about 720 million gallons by 2020.
- ***Natural Gas Vehicles (NGVs) will expand beyond niche applications and will generate a significant portion of LCFS credits***: We considered more than 25 different light, medium, and heavy duty vehicle segments for Natural Gas Vehicles (NGVs) that run on compressed natural gas (CNG) or liquefied natural gas (LNG). CNG and LNG have unit abatement costs across these sectors ranging from negative (in very high mileage scenarios) upwards of $1,000 per tonne (in very low mileage scenarios). The incremental pricing of the vehicle drives both the market potential and the unit abatement costs.

[1] This is somewhat confusing; however, sugarcane ethanol and biodiesel – although not competitors in the end-user market place – are competitive in the RFS2 regulatory compliance market. In 2012, it was cheaper to comply with RFS2 requirements using Brazilian sugarcane ethanol. With the reinstatement of the biodiesel tax credit through 2013, however, this will likely dampen imports to the rest of the country.

- The price differential between CNG or LNG and diesel fuel is generating significant interest in multiple market segments today. This has spurred significant investments in CNG and LNG infrastructure from companies such as Clean Energy. If vehicle and engine manufacturers respond to anticipated market demand by increasing their offerings and decreasing (even slightly) the upfront costs of vehicles, then natural gas consumption in the transportation sector is poised to increase significantly by 2020.
- For the plausible low cost scenario, the optimization model deployed vehicle applications with unit abatement costs less than $250 per tonne, which represents a significant portion of the medium-duty vehicle sector – which is a high mileage, high sales (more than 120,000 vehicles per year) segment.
- For the plausible high scenario, the increased cost of gasoline and diesel (and decreased availability of other low carbon options) enables a transition to natural gas in additional vehicle segments to help comply with LCFS.

- ***Plug-in Electric Vehicles will generate a smaller portion of LCFS credits***: In the plausible low scenario, PHEVs were deployed slightly above the baseline level of vehicles taken from CARB's most likely compliance scenario for the ZEV Program. Battery electric vehicles, however, were not deployed above the baseline scenario. In the plausible high cost scenario, neither PHEVs nor BEVs were deployed beyond the baseline level of vehicles taken from CARB's most likely ZEV compliance scenario. The low levels of PHEVs and BEVs in the high cost scenario are mainly a result of high vehicle costs (and with a phased out federal subsidy); and to a lesser extent, high costs for electric vehicle supply equipment.
- ***Fuel cell vehicles will not be deployed beyond the numbers projected by CARB***: Hydrogen provides about 40 percent GHG reduction benefit relative to gasoline, but the costs are significantly higher than any of the other strategies. As a result, fuel cell vehicles were not deployed in either the plausible low cost or high cost scenario beyond the number of vehicles projected in CARB's most likely ZEV compliance scenario.
- ***LCFS will have a modest impact on fuel prices***. The optimization model used in this study is not explicitly designed to estimate fuel prices at the pump or estimate the price of LCFS credits. The focus of this work is the feasibility of compliance and the associated unit abatement costs of compliance. However, based on the results of the modeling exercise and some assumptions regarding fuel pricing, we estimate the impacts of LCFS on fuel pricing by considering the increased costs associated with a) biofuel blending and b) potential exposure to the LCFS credit market:
  - In the plausible low scenario, gasoline prices will increase by $0.06–$0.26 per gallon and diesel prices will increase by about $0.32 per gallon.
  - In the plausible high scenario, gasoline prices will increase by about $0.12–$0.32 per gallon and diesel prices will increase by about $0.42 per gallon.
- ***Low carbon biofuels (e.g., cellulosic ethanol and corn oil biodiesel) will command a price premium through at least 2020:*** The demand for lower carbon biofuels, driven by LCFS compliance and RFS2 compliance, will significantly outstrip supply for the next several years. The production capacity of advanced biofuels is expected to increase significantly in

the next several years to hundreds of million gallons and we anticipate technological improvements that will lower the production costs of low carbon intensity biofuels. However, there will still be about 17 billion gallons of domestic corn ethanol production and soy-based biodiesel production. These other conventional biofuels will likely keep the rack prices higher for ethanol and biodiesel in the near-term future.

- ***There is potential for lower carbon biofuels to reduce production costs, however, this potential is largely a function of estimated feedstock costs***: Estimating production costs using a bottoms-up approach, it is conceivable that advanced biofuels will reduce production costs. Most of these reductions are attributable to feedstock costs that are lower than conventional biofuels. For instance, corn oil is cheaper than soybean oil. Similarly, most cellulosic biofuels are likely to be produced using waste products or energy crops such as corn stover, farmed wood, or energy grasses. Typically these feedstocks are not part of a commodity market, so the estimated production costs are dependent on assumptions regarding feedstock price and availability.

1. Methodology

The objective of this project was to determine the feasibility of the LCFS by considering plausible low and plausible high scenarios. The feasibility of the LCFS was assessed using an optimization model driven by the supply curves of multiple abatement measures for fuels that displace gasoline and diesel. We developed the costs associated with each strategy over the specific technology's lifetime. For instance, when considering a fuel and vehicle strategy, we assumed a ten-year vehicle lifetime. When infrastructure was required to be deployed, we assumed a 20-year lifetime. The following sections describe our calculations, provide an overview of the regulations we considered, review the compliance strategies from which the model is built, and discuss key assumptions we employed in the analysis.

1.1. Abatement Cost Equation

Equation 1 shows how we quantified greenhouse gas (GHG) abatement cost. We use the equation to estimate GHG abatement costs of AB 32 transportation sector proposed and final regulations. The numerator represents net costs including fuel, vehicle and infrastructure relative to the uncontrolled baseline case, referred to as the baseline case, in other words, the fuel and/or vehicle that would have been purchased or deployed in absence of the LCFS or other complementary standards. The denominator represents carbon emissions abated relative to the displaced technology, which includes both the vehicle and the fuel. The costs in the formula are the net present value (NPV) of annual net costs and actual annual net emissions abated for 2020. We used two cases to assess cost: high cost and low cost.

$$\text{Abatement Cost}\left(\frac{\$2010}{\text{tonne}}\right) = \frac{\text{Net Transportation Measure Cost (NPV, \$2010)}}{\text{Avoided Carbon Emissions (tonnes)}} \qquad (1)$$

The following paragraphs describe the calculation in more detail.

- **Numerator**: Estimate the fuel costs, vehicle costs and infrastructure costs for each AB 32 measure considered. We subtract the annual costs for the displaced fuel (e.g., gasoline and diesel) from each measure's costs to determine each measure's net cost.
- **Denominator**: Estimate the annual carbon emissions for each AB 32 measure considered and for the displaced fuel for 2020. We estimate carbon emissions by multiplying the total amount of each type of fuel consumed each year by its corresponding emission factor. The avoided carbon emissions are simply the carbon emissions for each measure less the displaced emissions. For each measure, we calculate the resulting annual avoided carbon emissions. We calculate avoided carbon emissions on a well-to-wheel (WTW) basis and a tank-to-wheel (TTW) basis.
- **Result**: To calculate the overall abatement cost ($/tonne) we divide the numerator by the denominator. In addition to the overall abatement values for each GHG measure evaluated, ICF determined the relative contribution of each alternative fuel and/or technology to the total abatement achieved and cost. Specifically, we determined the net costs and net

emission reductions attributable to increased consumption of each of the alternative fuels and increased penetration of more efficient vehicles.

In order to calculate the costs, we considered a California state total resource cost perspective. The following table shows the costs and benefits that were included in this analysis, as well as those that have been excluded.

Exhibit 6. Included / Excluded Costs in the CA Total Resource Perspective for Transportation Measures

Fuel pathway	Included Costs / Benefits	Excluded Costs / Benefits
Gasoline	Rack price of CARBOB	Fuel taxes and fees
Diesel	Rack price of ULSD	Fuel taxes and fees
Ethanol, E10	Rack price of ethanol	Fuel taxes and fees
Ethanol, E85	Rack price of ethanol E85 retail infrastructure	Fuel taxes and fees
Biodiesel, B5	Rack price of biodiesel Biodiesel storage terminals Fuel tax incentive (only in 2013)	Fuel taxes and fees Fuel tax incentive, post-2013
Biodiesel, B20	Rack price of biodiesel Biodiesel storage terminals B20 retail infrastructure	Fuel taxes and fees Fuel tax credit, post-2013
Renewable diesel	Rack price of renewable diesel	Fuel taxes and fees
Plug-in electric vehicles	Vehicle price Federal vehicle tax credit Avoided cost of electricity production	California vehicle rebate Retail price of electricity Transmission & Distribution reinforcement costs
Hydrogen fuel cell vehicles	Vehicle price Cost of hydrogen production	Fueling stations tax credits, post-2014
Natural gas (inc. CNG, LNG, biomethane)	Vehicle price Citygate price Fuel excise tax credit (only in 2013) C/LNG Refueling infrastructure	Fueling stations tax credits, post-2013 Fuel excise tax credit, post-2013

Note: We assume that the rack price of fuels such as ethanol and biodiesel reflect the production costs of these fuels– including factors such as feedstock costs, transportation costs, and biofuel production costs.

1.2. California Transportation Regulatory Environment

Pursuant to California's Global Warming Solutions Act (AB 32), the California Air Resources Board (CARB) is required to promulgate regulations and standards that will reduced the State's GHG emissions to 1990 levels by 2020. Because the transportation sector is responsible for a large portion of the State's emissions, the Scoping Plan includes a number of transportation-focused measures. These include measures to improve fuel economy, reduce tailpipe GHG emissions, increase the number of Zero Emission Vehicles (ZEV), and to reduce the carbon intensity of transportation fuels. The following paragraphs describe each of these strategies.

Light Duty Fuel Economy and GHG Standards

California's first attempt to limit GHG emissions from vehicles began with the 2002 passage of AB 1493 (Pavley) which limits light duty vehicle tailpipe GHG emissions. In September 2004 CARB formally adopted regulations to implement the Pavley rule and submitted a request to U.S. EPA to allow the State to regulate vehicle GHG emissions. After initially denying California's request, U.S. EPA granted a second request in 2009. CARB formally adopted amendments to the Pavley rule in 2009 to limit light duty tailpipe GHG emissions from new vehicles sold in California from 2009 through 2016. At the same time, the U.S. National Highway Traffic Safety Administration (NHTSA) modified light duty corporate average fuel economy (CAFE) standards such that they are now harmonized with California's Pavley rule (35.5 mpg by 2016). CARB subsequently agreed to subordinate the Pavley standard to the new CAFE standards.

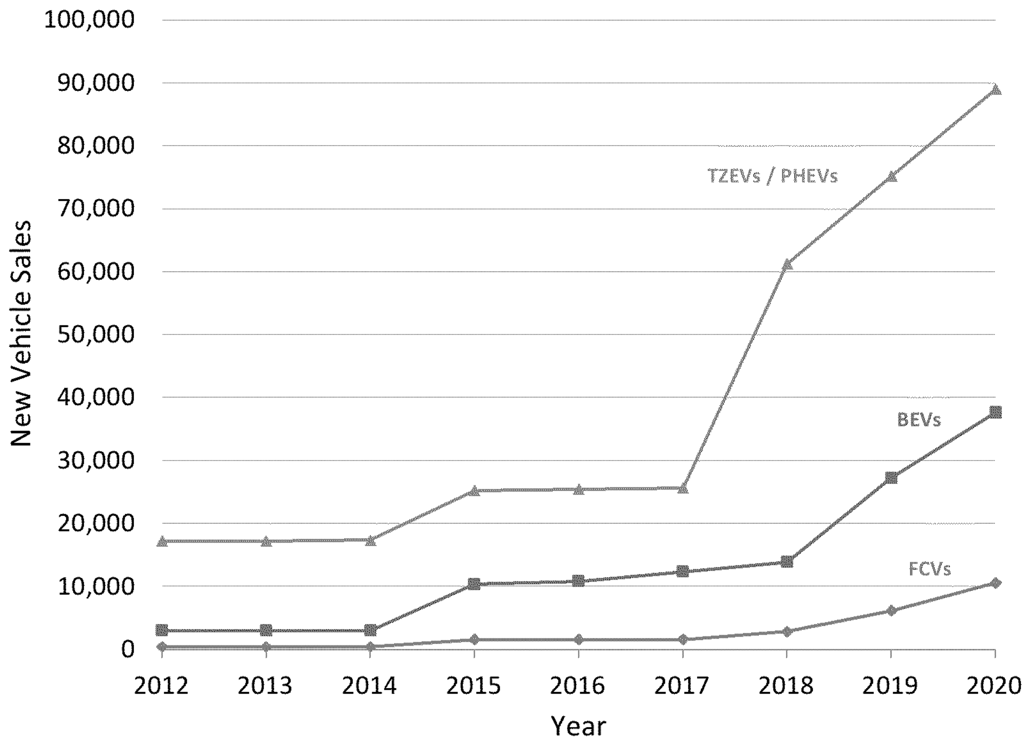
As part of the AB 32 Scoping Plan, CARB began development of the Advanced Clean Cars program. This program is essentially a combination of Low Emission Vehicle III (LEVIII) rulemaking and an update to the Zero Emission Vehicle (ZEV) Mandate. LEV III reduces tailpipe criteria pollutant and GHG emissions. The GHG portion is referred to as Pavley 2.

U.S. EPA and NHTSA worked in parallel to develop the new federal light duty GHG and fuel economy standards for 2017-2025. EPA's standard is equivalent to a fleet average of 54.5 miles per gallon (mpg). CARB agreed to subordinate the Pavley 2 portion of its Advanced Clean Cars Program to the federal standard (though the ZEV Program amendments will proceed independently).

ZEV Program

CARB established the ZEV Program in 1999 to increase penetration rates of zero emission vehicles to reduce criteria pollutant emissions. The mandate requires a certain percentage of light duty vehicles sold in California to be zero emission vehicles (ZEVs). Because of the limited availability of true ZEVs until recently, manufacturers were allowed to comply with the regulations by selling larger numbers of very low emitting vehicles. In March 2008, the CARB Board directed staff to strengthen the ZEV Program requirements for 2015 and beyond by focusing solely on electric and hydrogen vehicles. Proposed modifications to the ZEV Mandate have been accepted as part of the Advanced Clean Cars Program, dramatically increasing the requirements for sales of ZEVs beginning in 2018. Exhibit 7 provides light duty vehicle sales for CARB's most likely compliance scenario. Note that TZEV is equivalent to PHEVs. In our analysis period (2011-2020), the ratio of PHEVs to BEVs is weighted towards PHEVs, though in later years CARB projects that half of the electric vehicles will be BEVs and half will be PHEVs.

Exhibit 7. Most Likely Compliance Scenario for ZEV Program



Medium and Heavy Duty Fuel Economy Standards

In August of 2011, EPA and NHTSA finalized new GHG and fuel economy standards for new medium and heavy duty vehicles. New heavy duty big rig trucks must reduce fuel consumption 20 percent, medium duty trucks are required to reduce fuel consumption by 15 percent and vocational trucks (delivery, garbage, buses) must reduce consumption 10 percent by 2018.

Low Carbon Fuel Standard

The AB 32 Scoping Plan identifies California's Low Carbon Fuel Standard (LCFS) as an Early Action Item. The standard requires a ten percent reduction in transportation fuel carbon intensity by 2020, with the first reductions required in 2011. Carbon intensity is measured in gCO_2e per MJ of fuel and is quantified on a WTW basis. Although diesel has a lower carbon intensity than gasoline, it cannot be used as a substitute for gasoline to generate credits. For instance, it is likely that automobile manufacturers introduce more diesel vehicles in the light-duty vehicle market as a strategy to comply with fuel economy regulations. However, the diesel used in these vehicles to displace gasoline cannot be used to comply with the LCFS. Exhibit 3 illustrates the standard for each fuel pool. CARB quantifies and publishes carbon intensity values for all fuel pathways.

Exhibit 8. LCFS Compliance Schedule for Gasoline and Diesel, 2011-2020

Fuel	Average carbon intensity (gCO_2e/MJ)									
	11	12	13*	14	15	16	17	18	19	20
Gasoline	95.61	95.37	97.96	97.47	96.48	95.49	94.00	92.52	91.03	89.06
Diesel	94.47	94.24	97.05	96.56	95.58	94.60	93.13	91.66	90.19	88.23

* Note that CARB modified the baseline carbon intensity in 2012, which was originally an average of crude oil supplied to California refineries in 2006; the values from 2013 to 2020 reflect the updated average of crude oil supplied to California refineries in 2010.

2. Compliance Strategies Considered

2.1. Baseline Demand

The first step in the analysis was to define the forecasted demand for gasoline and diesel fuels. The forecasts of on-road gasoline and diesel fuel consumption account for relevant fuel economy or tailpipe standards (e.g., Pavley 2) as well as the increased vehicle miles traveled (VMT) attributable to the expansion of the fleet.

2.2. Alternative Fuel Consumption

For alternative fuel consumption, the following subsection reviews some of the key parameters and variables that ICF used to estimate the abatement costs and the abatement potential.

For a more detailed discussion regarding each fuel type, refer to Appendix A.

- A high-level overview of each fuel (and/or vehicle, as needed);
- Fuel production, broken down by feedstocks or source as appropriate, and associated limitations;
- Delivery of the fuel to the California market and associated limitations;
- Potential for consumption in California (on an annual basis); and,
- Contributions to GHG abatement.

Exhibit 9. Summary of Fuels Considered for Modeling LCFS Compliance

Fuel Type	CI (gCO_2e/MJ)	Expected Supply 2020	Exp. consumption in CA, 2020	Fuel Production	Delivery to CA	Key Advantages	Constraints & Barriers	Contribution to GHG abatement
Corn Ethanol, US	77 — 97	15 billion gallons	150 million gallons	Produced in Midwest	Via rail – Infrastructure is well developed	Relatively stable cost of production and abundance in volume	High carbon intensity leading to limited demand for blending	**Low**: Limited due to high carbon intensity values ascribed to Indirect Land Use Change
Corn Ethanol, CA	72 — 85	214 million gallons	214 million gallons	Produced in CA	n/a	Competitive CI values, local supplier; efficient production facilities	Limited production potential	**Low**: Limited due to small volumes
Sugarcane Ethanol	64 — 73	2.6 billion gallons	1 billion gallons	Produced in Brazil	Mainly via ship Some production via Caribbean Basin Initiative countries Also potential via rail from other US ports	Lower cost of production; significant export capacity; lower carbon intensity than corn ethanol	Export capacity is unclear; Brazilian domestic demand for fuel is strong; may be international demand for fuel from other regulatory drivers	**Very high**: projected to play a key role in compliance due to high volume and existing production capacity
Cellulosic Ethanol	25 — 35	520 million gallons	364 million gallons	Produced in US, outside of CA	Via rail – infrastructure is well developed.	Very low carbon intensity. Compatible with existing infrastructure for ethanol.	Technological breakthroughs are required to hit production targets.	**Moderate to High**: Potentially significant if volumes materialize as projected

Fuel Type	CI (gCO_2e/MJ)	Expected Supply 2020	Exp. consumption in CA, 2020	Fuel Production	Delivery to CA	Key Advantages	Constraints & Barriers	Contribution to GHG abatement
E85	depends on feedstock	Depends on RFS; other market drivers. 15 billion gallons of corn ethanol available.	500 million gallons	Produced in Midwest and CA	Via rail and tanker truck. Can use same infrastructure as E10.	Helps alleviate blend wall for ethanol in E10. There are vehicles on the road that can use fuel	Requires expanded retail infrastructure Although vehicles on the road, limited potential for expansion in CA	**Low**: Minor contribution because of low volume potential.
Biodiesel	4 — 83	2.5 billion gallons	625 million gallons	>15% produced in CA Produced in Midwest	At low level volumes (160-200M gallons), can be shipped via pipeline as B5. As blending increases, import additional product via rail.	At low volumes (B5), can use diesel infrastructure. Low consumption today – significant expansion potential	Higher fuel costs. Warranty concerns for higher blends. Higher blends require dedicated refueling infrastructure Some air quality concerns (B20).	**Very high**: Very significant; corn oil based biodiesel is a major compliance pathway because of low carbon intensity.
Renewable Diesel	20 — 82	520 million gallons	130 million gallons	Limited CA production Focused on US	Via pipeline	Generally low carbon intensity Fungible with existing diesel infrastructure	Higher fuel costs; limited supply of feedstock	**Low to moderate**: Depending on feedstock availability
CNG / LNG	11 — 78	n/a	800 million dge	North American NG, largely US	Via pipeline	Cheaper than diesel. Existing vehicle technology. Growing retail infrastructure	Limited vehicle offerings today in some key markets. Retail infrastructure is expensive.	**Moderate to very high**: Due to fuel savings.

Fuel Type	CI (gCO_2e/MJ)	Expected Supply 2020	Exp. consumption in CA, 2020	Fuel Production	Delivery to CA	Key Advantages	Constraints & Barriers	Contribution to GHG abatement
Plug-In Electric Vehicles	105—124	n/a	81 million gge	Electricity produced in California	Via transmission and distribution network of electrical grid	Very low carbon intensity. California early adopter market for PEVs.	Vehicle pricing remains high.	**Low**: Vehicle pricing remains high; increasingly important as ZEV Program takes effect.
Hydrogen Fuel Cell Vehicles	76—133	n/a	10 million gge	Produced in CA via steam reformation w/ some renewables	Produced on-site or centrally near stations	Low carbon intensity	Vehicle pricing, vehicle availability, fuel pricing, and fuel availability.	**Very Low**: Projected vehicle penetration in the given timeframe is very low.

2.3. Key Assumptions

Many assumptions have been made to arrive at annual GHG emissions and cost estimates for each measure considered. The three key categories of assumptions reviewed here include: GHG emission factors, fuel costs, and infrastructure costs.

GHG Emission Factors

Emissions are quantified with two different sets of emission factors: well-to-wheel (WTW) and tank-to-wheel (TTW). Traditionally, transportation fuels are compared on a WTW basis to ensure a fair comparison of benefits within the transportation sector. WTW emission factors include emissions associated with feedstock recovery and transport to the fuel production facility, fuel production, transport of the finished fuel to the refueling station, and vehicle emissions. The WTW factors include CO_2, CH_4 and N_2O emissions. The CH_4 and N_2O emissions are weighted using the most recent IPCC 100 year global warming potential factors and reported as CO_2 equivalent emissions (CO_2e).

To determine quantities of alternative fuels required to comply with the LCFS in our two scenarios, ICF used CARB's LCFS emission factors.[2] To calculate WTW emission abatement, we used these same factors for all fuels except electricity. For electricity we utilized a WTW emission factor (including all three pollutants) based on a natural gas-fired combined cycle combustion turbine power plant.[3]

To estimate TTW emission abatement, we included only the contribution from CO_2, and utilized just the vehicle portion of the CARB LCFS emission factors for all fuels except hydrogen and electricity. This ensures a fair comparison of benefits between the transportation and energy sectors. TTW emissions for electric vehicles and hydrogen fuel cell vehicles (FCVs) are generally assumed to be zero; PG&E requested that we include hydrogen production plant CO_2 emissions for hydrogen and natural gas combined cycle CO_2 emissions for electricity for consistency with the analyses of other energy sector program measures.

Exhibit 10 provides a subset of the emission factors utilized in the analysis. The carbon intensity values for electricity and hydrogen have been modified using an Energy Economy Ratio (EER). EER is the ratio of the energy consumption per mile of a gasoline vehicle divided by the energy consumption per mile of the alternative fuel vehicle. This enables hydrogen and electricity carbon intensity values to be compared on an equivalent basis with other fuels.

When comparing the WTW and TTW emission factors for fuels (Exhibit 10) we find that the biofuels have the largest difference in WTW and TTW emission factors. Therefore, when we consider emission reductions on a TTW basis, scenarios with more biofuel consumption will yield larger emission reductions than scenarios with lower biofuel consumption.

Finally, it is important to note that the emissions factors for biofuels include emissions associated with indirect land use change (ILUC). ILUC emissions can result from increased

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[2] CARB – updated pathways in Final Regulation Order.
[3] CEC AB1007 Well to Tank report

consumption of biomass based fuels. For example, if consumption of soybean biodiesel increases in the U.S., more soybeans will need to be grown somewhere in the world to replace soybeans used for fuel. The emissions associated with clearing land elsewhere to cultivate soybeans that were diverted elsewhere are referred to as ILUC emissions. These values have a high degree of uncertainty, and are currently under revision by CARB. If the values are reduced significantly, corn ethanol and soybean biodiesel could become important compliance fuels, significantly changing the compliance fuel mix. Lower corn ethanol and soybean biodiesel carbon intensity values would mean that compliance would likely be achieved with higher percentages of these conventional biofuels and lower imports of sugarcane ethanol, and less consumption of cellulosic biofuels, electricity, and CNG.

Exhibit 10. Sample GHG Emission Factors Used in Modeling

Fuel	WTW g CO_2e/MJ	TTW g CO_2/MJ
Gasoline Blendstock, CARBOB	99.18	72.90
Ultra Low Sulfur Diesel	98.03	74.10
Ethanol, US Corn	86.46	0.00
Ethanol, CA Corn Ethanol [a]	80.70	0.00
Ethanol, Brazil Sugarcane [b]	68.84	0.00
Ethanol, Cellulosic	29.00	0.00
Biodiesel, Soybeans	83.25	0.00
Biodiesel, FOGs	15.04	0.00
Biodiesel, Corn Oil	4.00	0.00
Renewable Diesel, FOGs	29.49	0.00
Renewable Diesel, cellulosic	37.20	0.00
CNG	68.00	55.70
Electricity [c,d]	41.30	31.90
Hydrogen (central plant, NG) [e]	57.80	32.00

[a] Declining through 2020 to 72 g/MJ; [b] Declining through 2020 to 64 g/MJ; [c] WTW from CEC AB1007 WTT report, TTW from E3; [d] After EER of 3.4 applied; [e] TTW from GREET model, after EER of 2.5 applied.

Fuel Pricing and Fuel Costs

There are several cost and pricing terms that we use throughout this report:

- ***Fuel production costs***: The costs to produce a fuel. These are typically characterized using bottom-up estimates of the individual cost elements. For example, consider conventional petroleum-based fuels and biofuels:
  - For petroleum-based fuels, the fuel production costs include the price paid for crude oil, the costs to refine the crude, and the costs to distribute the refined product.
  - For biofuels, the fuel production costs are built up as a function of feedstock costs, delivery costs of the feedstock to a biofuel production facility, the costs of operating a biofuel production facility (e.g., electricity, chemicals, and ingredients), and the costs to deliver the finished product to a blending terminal (where the fuel is blended with gasoline or diesel).
- ***Rack prices***: Rack price refers to the price that finished liquid fuels (e.g., gasoline, diesel, ethanol) are sold into the retailers market. Typically these finished fuels are sold to wholesale sellers or gas stations who then take the fuel to the market for consumer purchasing.
- ***Pump prices***: Pump prices refer to the price that consumers pay at the pump. These prices include the rack price paid by the retailer, a mark-up by the retailer (which includes profit, operating expenses, etc.), and any applicable taxes or fees.

There is significant potential for advanced biofuels (e.g. cellulosic ethanol, sugarcane ethanol) to reduce the production costs of gasoline and diesel substitutes relative to conventional biofuels (e.g., ethanol from corn or biodiesel from soybeans). For instance, the DOE's Biomass Program has projected a renewable gasoline or diesel (via pyrolysis) production cost of less than $2.50 per gallon by 2017.[4] Other studies have estimated the levelized cost of cellulosic ethanol as low as $2.00 per gallon.[5] For the sake of comparison, conventional biofuels such as corn ethanol and soy-based biodiesel have productions costs around $2.60 per gallon and $4.50 per gallon, respectively.[6]

However, it is important to note that reducing fuel production costs does not necessarily yield lower rack prices because the demand for lower carbon biofuels, driven by LCFS compliance and RFS2 compliance, will significantly outstrip supply for the next several years. While the production capacity of advanced biofuels is expected to increase significantly in the next several years in the hundreds of million gallons, there will still be about 17 billion gallons of corn ethanol production and soy-based biodiesel production. These other conventional biofuels will likely keep the rack prices higher for ethanol and biodiesel in the near-term future.

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[4] Haq, Z. Advanced Biofuels Cost of Production. Aviation Biofuels Conference, October 2012. Available online at: http://www1.eere.energy.gov/biomass/pdfs/aviation_biofuels_haq.pdf.
[5] Parker, N. Modeling Future Biofuel Supply Chains Using Explicit Infrastructure Optimization, UC Davis, PhD Thesis. January 2011.. Available online at: http://publications.its.ucdavis.edu/download_pdf.php?id=1471.
[6] These production costs are discussed in more detail in Appendix B.

For the purposes of calculating the unit abatement costs, we have focused on rack prices as they are the most consistent with the California total resource cost perspective. As noted previously, there is a growing body of research that demonstrates that there is significant potential to lower the production costs of advanced biofuels relative to conventional biofuels such as corn ethanol and soy-based biodiesel. However, we opted to use rack prices as the baseline for comparison because the finished fuel – ethanol or biodiesel – will be traded at some commodity price independent of the feedstock. Any premium that advanced biofuels receive at the rack will be a reflection of demand for advanced biofuels to comply with regulations such as the LCFS or RFS2. Although we did not use fuel production costs as an input for this analysis, we have outlined the cost elements and total production cost estimates for biofuel production in Appendix B.

We also use rack prices because they are analogous to parts of the retail chain for other fuels used in the transportation sector, including the citygate price for natural gas and the avoided cost of electricity.

We have considered pump prices in this analysis to the extent that they influence consumer behavior. For instance, in the case of electricity, the retail price of electricity compared to the retail price of gasoline yields a larger difference than the avoided cost of electricity compared to the rack price of gasoline. This is driven to some extent by the taxes and profit margins included in the retail price of gasoline, which are much higher on a per unit energy basis than the additional costs that are included in the retail price of electricity.

The pump prices that we use to determine the abatement potential of various compliance strategies are from CEC forecasts. There are potential feedback loops in fuel pricing that may arise from LCFS compliance (e.g., higher gasoline or diesel prices caused by LCFS may accelerate the introduction of alternative fuels). Some of these dynamics have been captured via an iterative approach to the modeling; however, the model does not have any dynamic mechanisms to account for this without user modifications.

The following subsections discuss the baseline for fuel pricing projections. In most cases, fuel pricing trends (as opposed to absolute fuel prices) from the CEC were used through 2020.[7]

Gasoline and Diesel Prices

Gasoline and diesel costs were derived from the average spot prices reported by Bloomberg for Los Angeles and San Francisco (see Exhibit 11 below).

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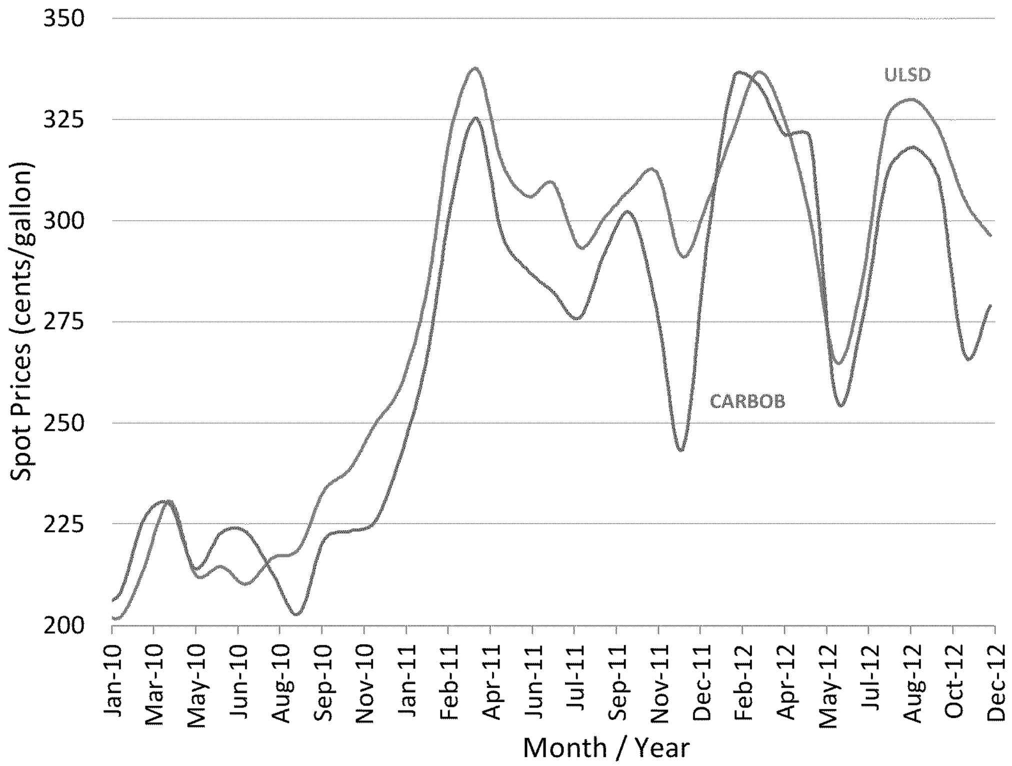
[7] California Energy Commission (CEC). "Transportation Energy Forecasts and Analyses for the 2011 Integrated Energy Policy Report." CEC, August 2011: Available at: http://www.arb.ca.gov/msprog/clean_cars/clean_cars_ab1085/cec-600-2011-007-sd.pdf

Exhibit 11. Spot prices (nominal) for CARBOB (red) and Ultra-low sulfur diesel (ULSD; blue)

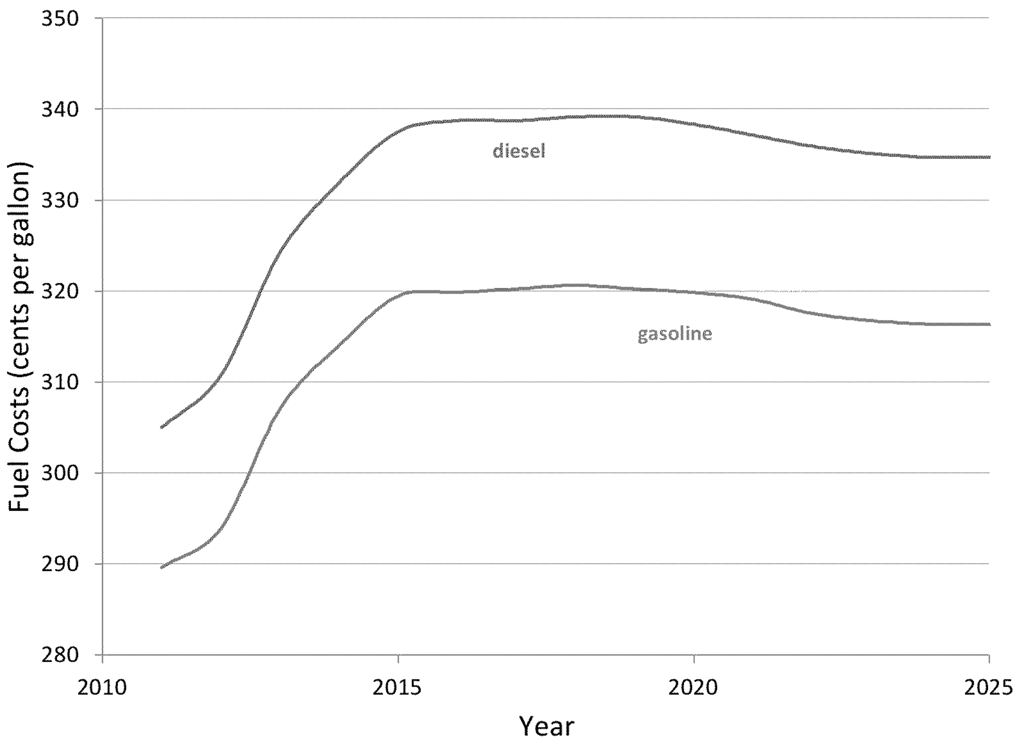


Source: Bloomberg, ICF analysis

As noted previously, these are fuel costs for gasoline and diesel, which do not include additional costs that the consumer will pay such as state tax, local taxes, and the mark-up from station owners.

For fuel pricing in future years, ICF used the average of fuel prices available from 2011 and 2012 (see previous graph), and used CEC forecasts to 2020 as shown in the figure below.

Exhibit 12. Forecasted Diesel and Gasoline Fuel Costs (in real dollars) in California



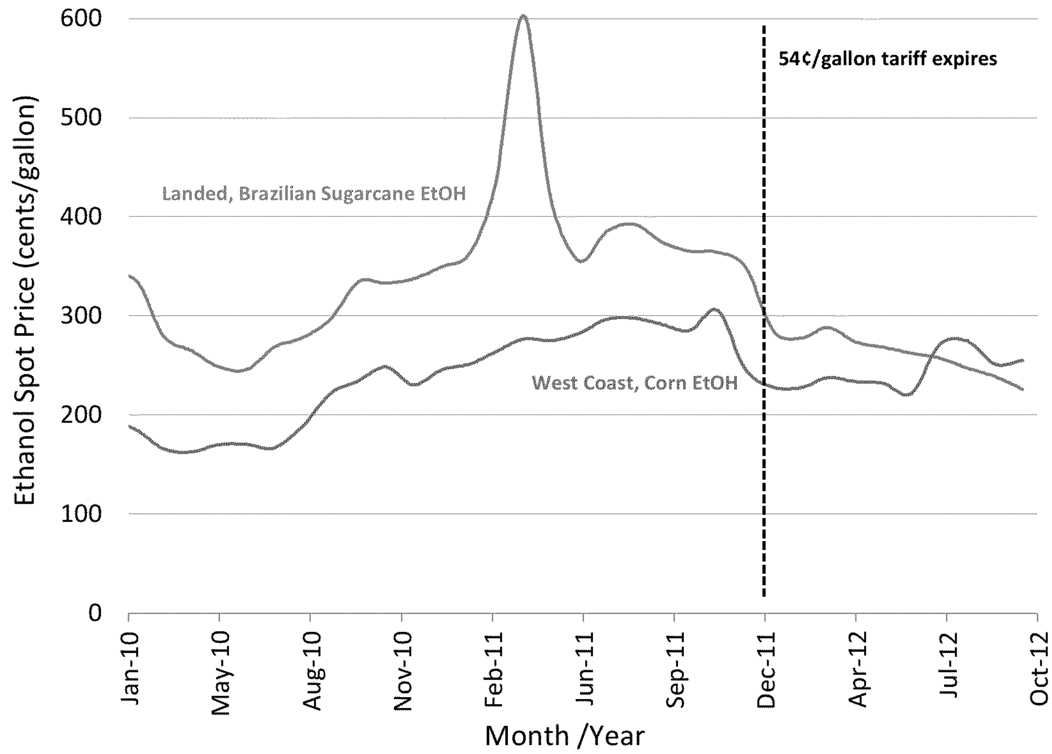
Source: California Energy Commission

Ethanol

The baseline fuel prices for ethanol are derived from spot prices from Bloomberg. The costs of production in California are comparable to other regions; most plants have switched to higher efficiency processes and use less water reducing fixed and variable operating costs. Based on ICF research, there is a small price premium for ethanol produced in California today because of the lower carbon intensity pathways for ethanol produced in California which have been approved by CARB.

Bloomberg includes prices for ethanol delivered to the West Coast via rail; however, for sugarcane ethanol, the prices are given for what is termed FOB Santos, which refers to the price of the shipment at the Port of Santos in Brazil. ICF added an estimated transportation cost of about 17 cents per gallon and a federally applied *ad valorem* tax of 2.5 percent.

Exhibit 13. Spot prices (in nominal dollars) for corn ethanol and sugarcane ethanol (from the Port of Santos) in California



Source: Bloomberg, ICF analysis

After excluding the tariff on ethanol that was in place before 2012, the price premium for sugarcane ethanol averages about 50 cents per gallon; however, the market saw a steady drop in ethanol prices from Brazil in 2012 with the price falling below that of corn ethanol. This was driven to some extent by lower corn crop yields in the US in 2012 as a result of drought conditions during the growing season. The price for sugarcane ethanol also includes the additional value of RINs – the market trading mechanism for biofuels under the RFS2 program. Brazilian sugarcane ethanol qualifies as an Advanced Biofuel whereas corn ethanol falls into the Renewable Fuels category. For 2012, reported RIN prices for Advanced Biofuels were approximately 35 cents per gallon compared to 5 cents per gallon for corn ethanol.

In the plausible low and high cost scenarios, ICF used the lowest and highest 12-month average of sugarcane ethanol prices, respectively, compared to corn ethanol prices reported by Bloomberg. This yields a price premium for sugarcane ethanol compared to corn ethanol of about 25 cents per gallon to 65 cents per gallon.

There is no historical basis to determine the fuel costs for cellulosic ethanol since there are no historical data on the prices that these fuels will command in the market. ICF assumed a fuel price premium (relative to corn ethanol) for cellulosic ethanol of $0.50 per gallon in the plausible low cost scenario. This cost was decreased over time. ICF assumed a fuel price premium of

$1.50 per gallon in the plausible high cost scenario. These price premiums are consistent with what CEC staff proposed in its LCFS analysis.[8]

Ethanol fuel price projections were linked to forecasted prices of corn as a feedstock, since corn ethanol will likely continue to drive the spot market prices for ethanol in the US market.

Biodiesel

Biodiesel prices were taken from Bloomberg, reported as an average for biodiesel rack prices in Los Angeles and San Francisco, as shown in Exhibit 14 below.

Exhibit 14. Rack prices (in nominal dollars) for biodiesel

Source: Bloomberg, ICF analysis

Although some feedstocks (e.g., corn oil or FOGs) have lower production costs than soybeans, ICF assumes that soy-based biodiesel will continue to be the primary driver for wholesale diesel rack prices.

Fats, waste oils, and greases (FOGs) have generally remained stable in price and exhibit limited volatility relative to other oilseed markets, such as soybean oil. The EPA estimates that waste oils will be available for $1.77 per gallon of biodiesel by 2022 (in $2010 dollars).[9]

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[8] See proceedings of the November 2011 Staff Workshop on the Role of Alternative Fuels in California's Transportation Energy Future, available online at: http://www.energy.ca.gov/2011_energypolicy/documents/#11142011.

Natural Gas

For CNG costs, we utilized both Annual Energy Outlook (AEO) price projections and the citygate price provided by E3. The AEO price is the citygate price plus the cost of compression, profits and taxes. We subtracted state taxes from the AEO price and then assumed half of the difference between the 2011 citygate cost and the AEO price without taxes is the compression cost. We then escalated this 2011 cost consistent with the E3 citygate natural gas costs through 2020.

For LNG costs, we assumed an additional cost of $0.60 per diesel gallon equivalent (dge), consistent with the reported difference between CNG and LNG reported during 2012 in the Alternative Fuel Price Report,[10] after accounting for small variations in the state excise taxes on CNG and LNG. The pricing differential between LNG and CNG is larger because the federal excise tax on LNG is equivalent to that of diesel (24.4 cents per gallon) whereas CNG is equivalent to that of gasoline (18.4 cents per gallon). After normalizing these on an energy basis, this is about 8.5 cents per dge.

Plug-in Electric Vehicles

Retail electricity rates for EV charging from the major utilities were used to determine the total cost of ownership for electric vehicles. These prices help determine the market potential for electric vehicles. The electricity costs used in the unit abatement cost calculation are avoided electricity costs, which were provided by E3.

Hydrogen Fuel Cell Vehicles

For hydrogen costs, we utilized the current cost from Sunline Transit and then escalated the cost each year according to forecasts from the CEC.

Infrastructure Costs

Assumptions regarding infrastructure costs incurred to allow the increased use of alternative fuels significantly affect the abatement costs of each compliance strategy. We developed infrastructure costs for increased ethanol, biodiesel, CNG, electricity, and hydrogen consumption. All of the costs presented below are reported as real costs in $2010.

Ethanol

For low-level blends of ethanol, we have included the costs of recouping infrastructure costs in the pricing of the fuel. For instance, the fueling costs include the cost of production facilities and transportation costs (e.g., trucks or rail to transport the finished product to blending terminals).

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[9] EPA, Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis, pgs. 765-766, Table 4.1-41; feedstock price in 2022 (assuming 7.7 lbs/gallon); http://www.epa.gov/otaq/renewablefuels/420r10006.pdf.

[10] These data are available online at: http://www.afdc.energy.gov/publications/#search/keyword/?q=alternativepercent20fuelpercent20pricepercent20report

For high-level blends of ethanol, we have included the costs of E85 infrastructure which will require the expansion of a skeletal refueling network of around 50 stations today. We use two estimates for the costs of E85 station installations:

- For retrofits at existing stations, we assume a cost of $125,000 to $150,000 per station.
- For new stations, this includes the costs of land, new fueling islands, USTs, pipes, electronics, etc., we assume a cost of $300,000 to $350,000.

Biodiesel

Similar to the case of low level blends of ethanol, we included the price of production facilities and transportation costs to blending terminals in the fuel pricing. However, for biodiesel we did account for the required expansion of biodiesel storage at petroleum terminals and refueling stations for B20.

- **Biodiesel Terminal Storage**

ICF conducted extensive research to estimate current levels of terminal storage capacity in California. ICF contacted more than 80 storage terminals in California and identified about 8-10 million gallons of existing storage capacity. Furthermore, during ICF's interviews, storage terminal staff indicated increased interest in biodiesel storage in recent months. The costs of expanding biodiesel storage capacity in California are based on the cost elements highlighted in Exhibit 15 below.

Exhibit 15. Cost elements for expand biodiesel terminal storage

Cost Element	Estimated Cost ($2010)
Terminal construction	$70/bbl
Terminal biodiesel blending equipment	$400,000 per terminal
Piping to terminal	$60,000 per terminal
Ancillary terminal costs	$50,000 per terminal

- **B20 Refueling Stations**

As the market for biodiesel expands, modifications will have to be made to the refueling infrastructure to accommodate higher blends of biodiesel i.e., B20. ICF used the following estimates for the retrofits to existing diesel fuel pumps and the addition of new biodiesel fueling islands:

  - For retrofits at existing stations, we assume a cost of $70,000 to $100,000 per station.
  - For new stations, we assume a cost $200,000 to $250,000 per station.

Compressed Natural Gas and Liquefied Natural Gas

ICF only considered CNG in applications where fueling would be centrally located or conducted on-road i.e., we did not consider the potential for any home refueling apparatus. We used an estimate of $2.15 million for a single station with a throughput of approximately 2,000 diesel gallon equivalents daily.

ICF only considered LNG in high mileage heavy-duty vehicle applications. Most of these are long-haul applications in which the driver needs to maximize the weight that can be hauled and the volume of available space for storage. In these cases, LNG is more attractive because more fuel can be stored on board at lower weight (which is advantageous for payload) and as a liquefied (rather than gaseous) fuel, it takes up less space (which is advantageous for volume).

Plug-in Electric Vehicles

The charging infrastructure for electric vehicles is referred to as electric vehicle supply equipment (EVSE). EVSE costs are primarily comprised of hardware, permitting, and installation costs. We consider the costs of deploying EVSE at homes and in non-residential applications. We considered the costs of Level 1 and Level 2 charging at home and Level 1, Level 2, and DC fast charging in non-residential applications (e.g., workplaces, retail centers, etc.).

- For most single-family homes, the electrical service available in the garage or through dedicated parking is likely suitable for Level 1 EVSE, which is designed for a 110 V connection. For Level 1 charging at a home, a PEV does not requires additional or special equipment - a simple cord and plug arrangement will suffice.
- For drivers that have PEVs with larger batteries, such as the Nissan LEAF, Level 2 charging will likely be required. The estimated costs for a Level 2 EVSE, including the hardware and installation are $900-2,350
- For non-residential charging infrastructure, we used the following estimates (with additional information available in Appendix A)
  - $5,600-14,000 per Level 2 EVSE unit
  - $17,000-42,000 per DC fast charging EVSE unit
  - For both Level 2 EVSE and DC fast charging EVSE, we assume multiple installations at a single site to reduce trenching and cutting costs. The costs shown in Exhibit 16 reflect these reduced costs as a result of multiple installations
- We did not consider any transmission and distribution reinforcement costs in this analysis. For instance, some studies have shown that clustering of electric vehicles will likely require local distribution upgrades. While we recognized these investments will likely be required as electric vehicles are deployed in greater numbers, these costs were not considered in this analysis.

Hydrogen Fuel Cell Vehicles

The infrastructure costs for hydrogen were based on data from the CEC; the deployment of hydrogen stations as part of AB 118 was factored into the analysis. ICF used an installation cost of $1.5 million for a station with 145 kg per day of hydrogen throughput.

California state agencies – including CARB and CEC – have made a significant investment in hydrogen fueling infrastructure: Over the last two years, the CEC has dedicated about $49 million of funding from the Alternative and Renewable Fuel and Vehicle Technology Program to hydrogen refueling stations. Based on information presented by CARB as part of ZEV, we estimate that between 50 and 65 hydrogen refueling stations will be required to support the forecasted deployment of hydrogen FCVs. Because state agencies have been investing so much money in hydrogen refueling infrastructure, we estimate that about 50 percent of the stations required to support the deployment of FCVs in the most likely compliance scenario will be funded by state programs. This impacts the unit abatement cost because we use a California resource perspective: Although this investment is significant, it is paid for using grant money from the Alternative and Renewable Fuel and Vehicle Technology Program, administered by the CEC. Because the program is funded by additional vehicle registration fees from California drivers, it is not included in the overall cost.

Financial Assumptions

The analysis period was defined as 2011 to 2020. Vehicle and infrastructure costs are annualized so that only the share of the costs utilized in the analysis period were considered. For vehicles, we assumed a life of 10-12 years, depending on the vehicle class and likely application. Note that to calculate fuel consumption, vehicle sales, vehicle turnover rates, annual mileage and fuel economy values provided in Appendix A were utilized. All infrastructure costs were amortized assuming a 20 year life.

All costs are represented in real 2010 dollars. Annual inflation was assumed to be 2 percent. The real discount rate, 5.66 percent, is applied to all flows: capital costs, avoided costs, and avoided emissions. (This equates to a nominal discount rate of 7.66 percent - PG&E's after-tax weighted average cost of capital at the time the analysis was conducted).

2.4. Variation in Low and High Cost Scenarios

Exhibit 16 lists the key parameters that are modified in the plausible low and high cost scenarios.

Exhibit 16. Low Cost and High Cost Assumptions (in $2010)

Fuel / Strategy	Cost Element	Low Cost Case	High Cost Case
Ethanol, E10 Fuel costs [a]	Corn ethanol, lower CI	+2-4 ¢/gallon	+4-6 ¢/gallon
	Sugarcane ethanol	+26 ¢/gallon	+74¢/gallon
	Cellulosic ethanol	+50 ¢/gallon decreasing in 2015	+150 ¢/gallon
Ethanol, E85 Refueling Equipment	Retrofits	$125,000	$150,000
	New stations	$300,000	$375,000
	Ratio of retrofits to new stations	40/60	20/80
Biodiesel, Fuel Costs [b]	Soy	--	--
	Corn oil	+25 ¢/gallon	+50 ¢/gallon
	FOGs	+25 ¢/gallon	+50 ¢/gallon
Biodiesel, Infrastructure Costs	Refueling infrastructure	$70,000	$100,000
	New stations	$200,000	$250,000
	Terminal storage	$120 million	$200 million
Renewable Diesel, Fuel Costs [b]	FOGs	+50 ¢/gallon	+100 ¢/gallon
	Cellulosic/waste	+50 ¢/gallon	+100 ¢/gallon
Natural Gas, Vehicle Costs	CNG, LNG vehicles	10 percent reduction by 2020	No vehicle price reductions
PEVs eVMT, vehicle costs, infrastructure costs	Electric vehicle miles traveled, PHEVs	+5 percent per year	+3 percent per year
	Vehicle costs	30% reduction by 2020	10% reduction by 2020
	Federal tax credit	Available through 2020	Phased out post-2018
	EVSE costs, L2 residential	$900	$2,350
	EVSE costs, L2 nonresidential	$2,500	$7,000
	EVSE costs, DC fast charging	$12,500	$20,000
Hydrogen FCVs	Vehicle costs	25% reduction by 2020	10% reduction by 2020

a. The cost increases for ethanol are relative to average corn ethanol, US.

b. The cost increases for biodiesel and renewable diesel are relative to biodiesel produced from soybeans.

3. Results

The following subsections highlight the findings based on a plausible low cost scenario and a plausible high cost scenario. In both cases, it is important to note that the model seeks to optimize compliance through the deployment of lower carbon fuels and advanced vehicle technologies. Compliance is defined as a net zero balance of credits in 2020. Compliance is achieved in the plausible low cost scenario; compliance is not achieved in the plausible high cost scenario. Our modeling exercise did not consider the feasibility of maintaining the ten percent carbon intensity reduction beyond 2020. Based on our modeling results, however, we expect compliance with a ten percent carbon intensity reduction beyond 2020 will be difficult without significant advances in the availability and pricing of lower carbon fuels and advanced vehicle technologies, or modifications to the design elements of the LCFS.

Exhibit 17. Average Abatement Costs for Plausible Low and Plausible High Cost Scenarios

Phases	Plausible Low Cost				Plausible High Cost			
	Reductions (in MMT CO_2e)		Costs (in $/MT)		Reductions (in MMT CO_2e)		Costs (in $/MT)	
	WTW	TTW	WTW	TTW	WTW	TTW	WTW	TTW
Phase 1 2011-2013	3.74	10.09	$50	$8	3.35	8.57	$85	$10
Phase 2 2013-2015	8.13	12.25	$123	$70	7.19	9.91	$202	$25
Phase 3 2015-2017	9.85	12.88	$115	$40	8.83	11.99	$219	$69
Phase 4 2017-2019	14.22	16.09	$101	$33	12.91	12.61	$209	$110
Phase 5 2019-2020	16.27	17.64	$75	$70	14.94	14.91	$219	$157
Average Unit Abatement Cost			**$94**	**$39**			**$182**	**$79**

3.1. Plausible Low Cost Scenario

Overview of costs

A mix of compliance strategies described below help to achieve the low cost scenario. Exhibit 18 and Exhibit 19 summarize the costs associated with compliance in the plausible low cost scenario. The unit abatement costs over time for each of the compliance pathways are shown in Exhibit 20.

Exhibit 18. Segmented Results for the Plausible Low Cost Scenario for 2020

Phase	Reductions (In MMT CO_2e)		Costs (In $/MT)	
	WTW	TTW	WTW	TTW
Phase 1 2011-2013	3.74	10.09	$50	$8
Phase 2 2013-2015	8.13	12.25	$123	$70
Phase 3 2015-2017	9.85	12.88	$115	$40
Phase 4 2017-2019	14.22	16.09	$100	$33
Phase 5 2019-2020	16.27	17.64	$75	$70
Average Unit Abatement Cost			**$94**	**$39**

Exhibit 19. Abatement Cost Curves by Phases in the Plausible Low Cost Scenario

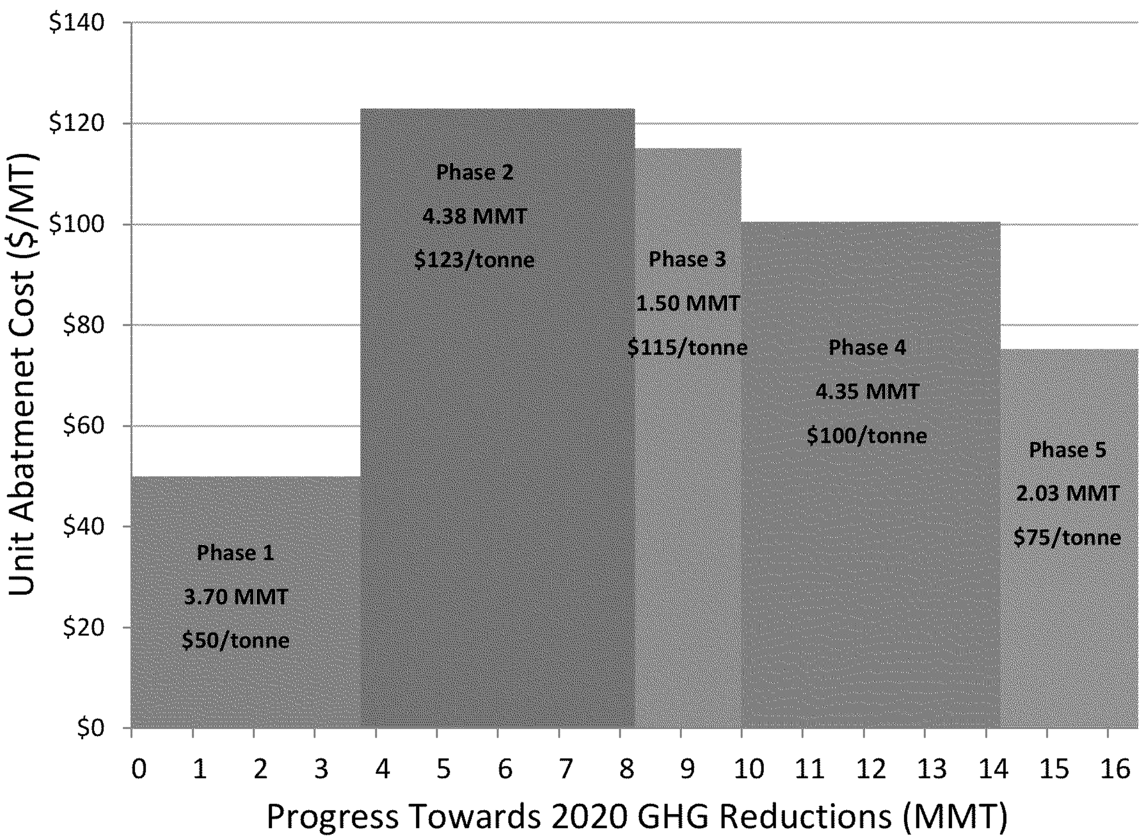


Exhibit 20. Abatement Cost Curves for Fuels in the Plausible Low Cost Scenario

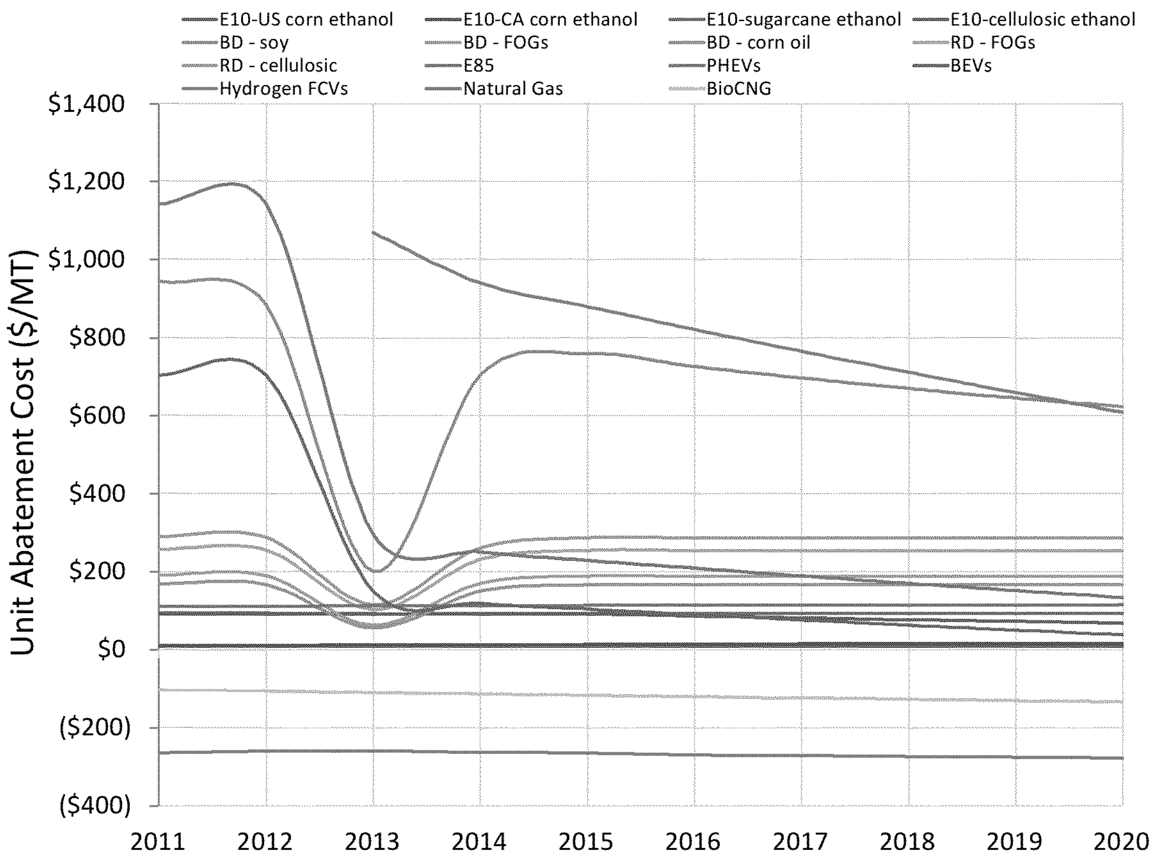


Exhibit 18 and Exhibit 19 show that abatement costs peak during the interim years of LCFS and then decrease slightly thereafter. The costs shown in Exhibit 20 highlight some of the reasons for the decreasing costs in the five-to-eight percent carbon intensity reduction requirement bin:

- Although we do not forecast significant changes in biofuel costs, we do forecast modest reductions in the carbon intensity of biofuels over time. For instance, the model includes carbon intensity reductions for Brazilian sugarcane ethanol because we assume a transition towards mechanized harvesting, which reduces the carbon intensity of that fuel significantly.
- The unit abatement costs include more significant investments in alternative fuel infrastructure in the earlier years in advance of more significant fuel deployment. These investments are required for E85, biodiesel, electric vehicles, CNG, and LNG.
- The costs of advanced vehicles decrease over time in the plausible low cost scenario.
  - For PEVs, battery improvements and volume manufacturing contribute to a 30 percent decrease by 2020.
  - For NGVs, the increased vehicle manufacturing volumes and modest improvements in cylinder technologies yield a 10 percent decrease by 2020.

The drop in abatement costs for biodiesel and renewable diesel (from various feedstocks) in 2013 is a result of the extension of the $1.00 per gallon federal tax credit for these fuels. Data from Bloomberg and other sources indicate that this tax credit yields significantly lower rack prices for biodiesel. Since the tax credit was only extended through the end of 2013, the rack pricing in our analysis reverts back to the higher pricing trend by 2014.

LCFS Compliance: Deficits/Credits, Fuel Volumes, and the Vehicle Mix

Balance of Deficits and Credits in the Plausible Low Cost Scenario

Exhibit 21 shows the percentage of credits generated by the various LCFS compliance pathways in the plausible low cost scenario. In any year during which the percentage of credits generated is greater than 100 percent, this indicates that credits are banked. In later years (2017-2020), these credits are used towards compliance (and indicated with the hatched out sections in those years).

Exhibit 21. Percentage of Credits Generated by Compliance Pathway in the Plausible Low Cost Scenario

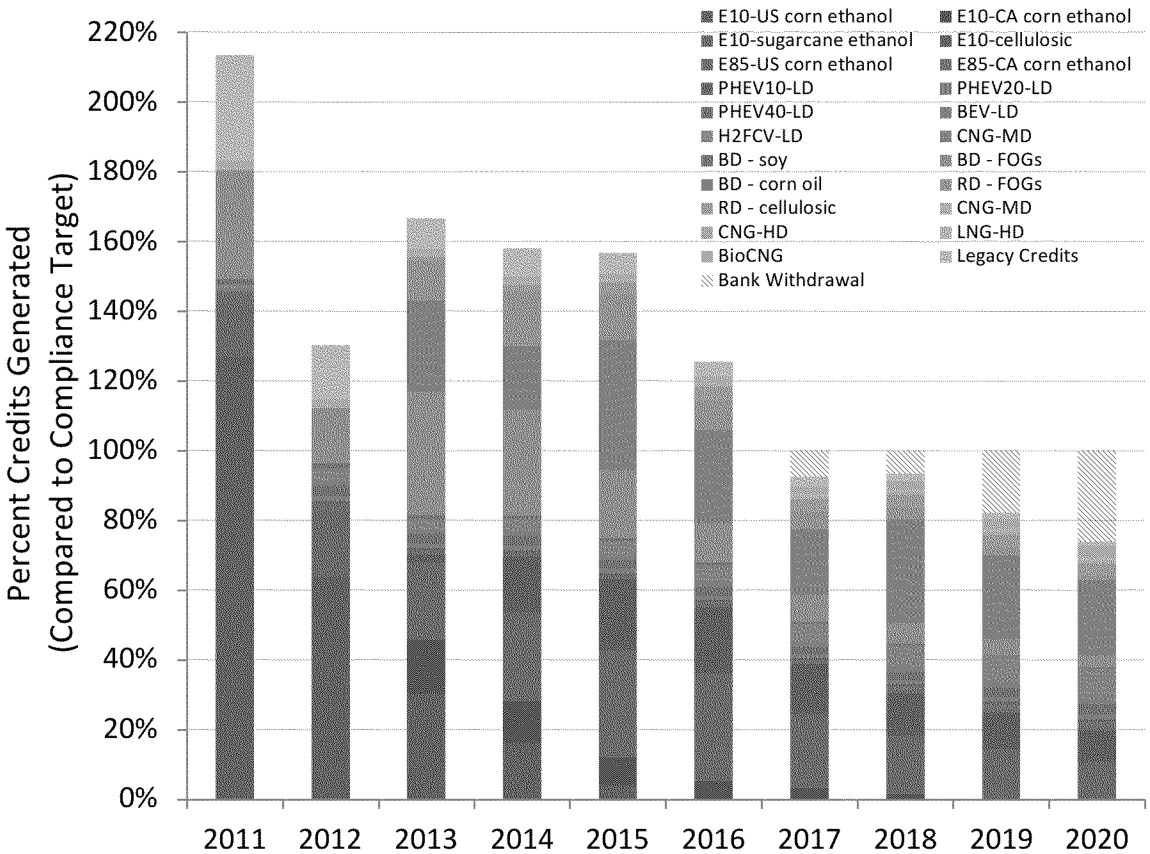
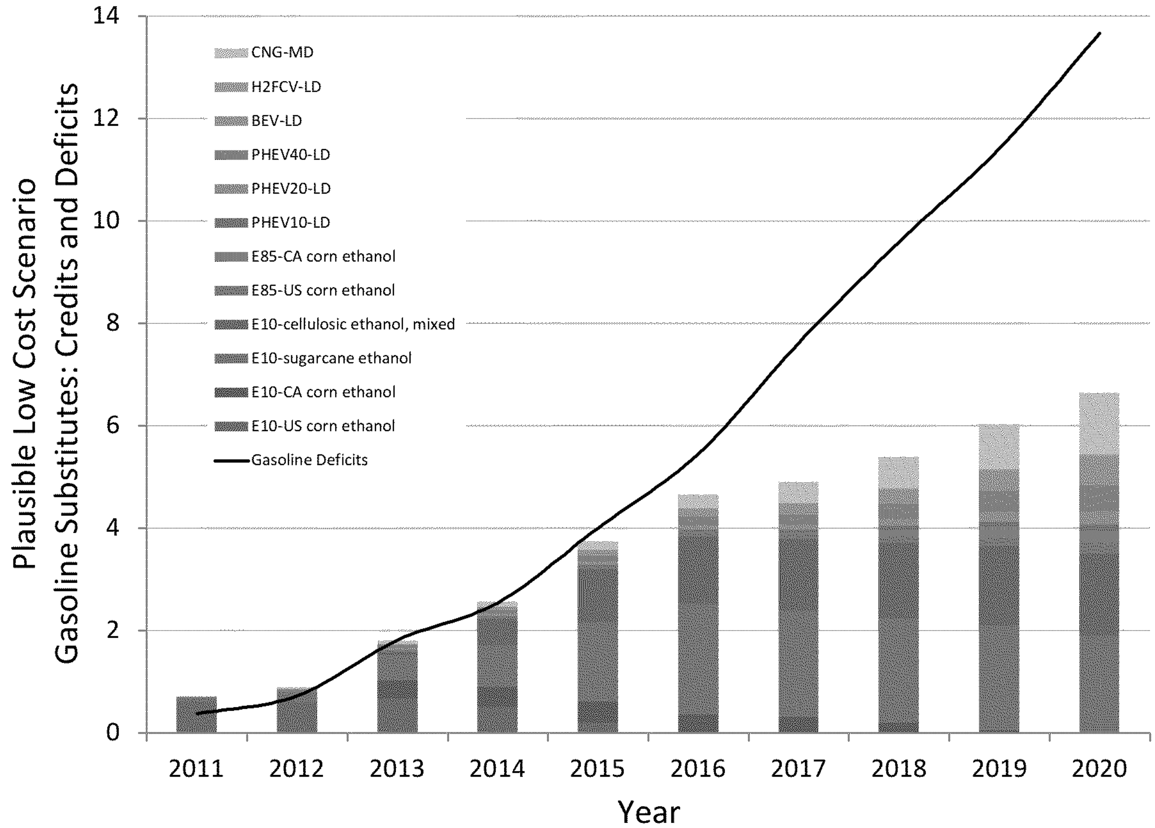


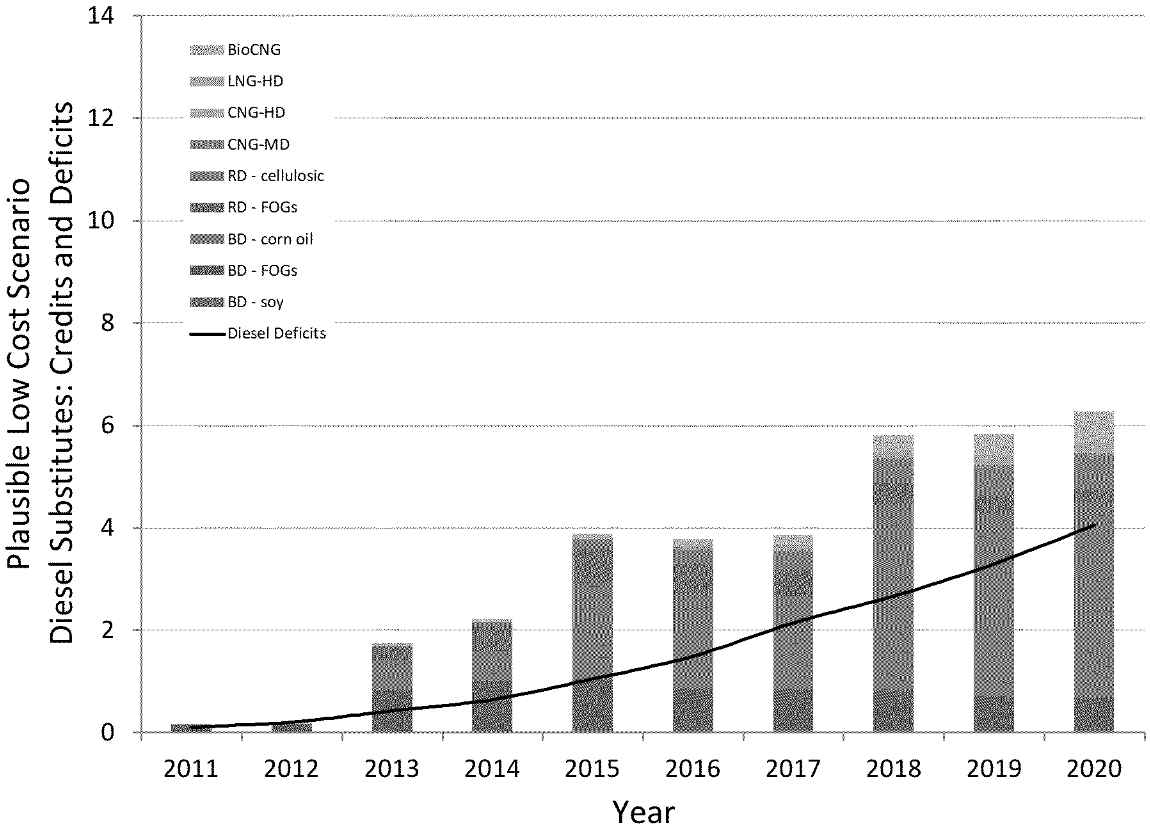
Exhibit 22 and Exhibit 23 show the annual balance of credits and deficits (in millions) in the gasoline and diesel pools, respectively. Notice that LCFS compliance depends heavily on diesel pool over-compliance. The black line in each graph shows the LCFS deficits as a result of gasoline and diesel consumption, respectively. Each block in the multi-colored column represents the credits generated by that compliance strategy in that year. For instance, the green and purple blocks, which feature prominently on an annual basis in the gasoline pool, represent the credits generated by Brazilian sugarcane ethanol and cellulosic ethanol, respectively. The light purple block at the top of the column that increases over time represents the credits generated by CNG consumption in medium-duty vehicles (that would have otherwise consumed gasoline).

Exhibit 22. Balance of Deficits and Credits in the Gasoline Pool, Plausible Low Cost Scenario



The green bar in Exhibit 22 represents the most prominent block of credits in the diesel pool. The green block represents the consumption of corn oil based biodiesel.

Exhibit 23. Balance of Deficits and Credits in the Diesel Pool, Plausible Low Cost Scenario



Transportation fuel volumes in the Plausible Low Cost Scenario

Exhibit 24 highlights the volumes of fuels in the gasoline and diesel fuel pools that are required to comply with the LCFS in the plausible low cost scenario.

Exhibit 24. LCFS Compliance Volumes for the Plausible Low Cost Scenario

Fuel / Compliance Strategy	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Gasoline fuel mix (CARBOB, PHEVs, BEVs, FCVs, CNG reported in million gge; E10 and E85 reported in million gallons)										
CARBOB	12,516	12,375	12,446	12,452	12,409	12,355	12,305	12,046	11,715	11,299
E10-US corn ethanol	1,354	1,287	957	738	311	0	0	0	0	0
E10-CA corn ethanol	0	0	200	202	204	191	178	120	31	0.00
E10-sugarcane ethanol	37	88	217	352	675	939	925	934	964	928
E10-cellulosic ethanol, mixed	0	0	9	92	189	243	264	285	306	328
E85-US corn ethanol	11	12	15	17	25	43	50	96	128	234
E85-CA corn ethanol	0	0	0	0	0	11	21	64	128	151
PHEV10-LD	0	0	1	1	1	2	2	3	4	5
PHEV20-LD	0	1	1	2	2	3	4	6	9	11
PHEV40-LD	0	1	2	3	5	7	8	12	17	23
BEV-LD	0	1	1	2	4	6	8	11	17	24
H2FCV-LD	0	0	0	0	1	1	1	2	3	5
CNG, MD	3	9	17	30	50	83	137	218	333	489
Diesel fuel mix (ULSD, CNG, LNG, BioCNG reported in million dge; BD and RD reported in million gallons)										
ULSD	3,253	3,320	3,243	3,269	3,190	3,234	3,254	3,112	3,124	3,073
BD – soy	5	10	15	15	20	30	30	30	30	30
BD – FOGs	15	15	80	99	103	83	83	83	72	72
BD - corn oil	0	0	50	50	163	163	163	329	329	359
RD – FOGs	0	0	28	55	74	66	58	49	40	31
RD – cellulosic	0	0	3	8	23	35	48	61	75	90
CNG-MD	0	1	1	2	4	6	10	16	25	37
CNG-HD	0	1	1	2	3	5	9	13	19	25
LNG-HD	6	8	10	16	24	45	71	101	132	175
BioCNG	1	2	3	5	7	13	21	32	46	66

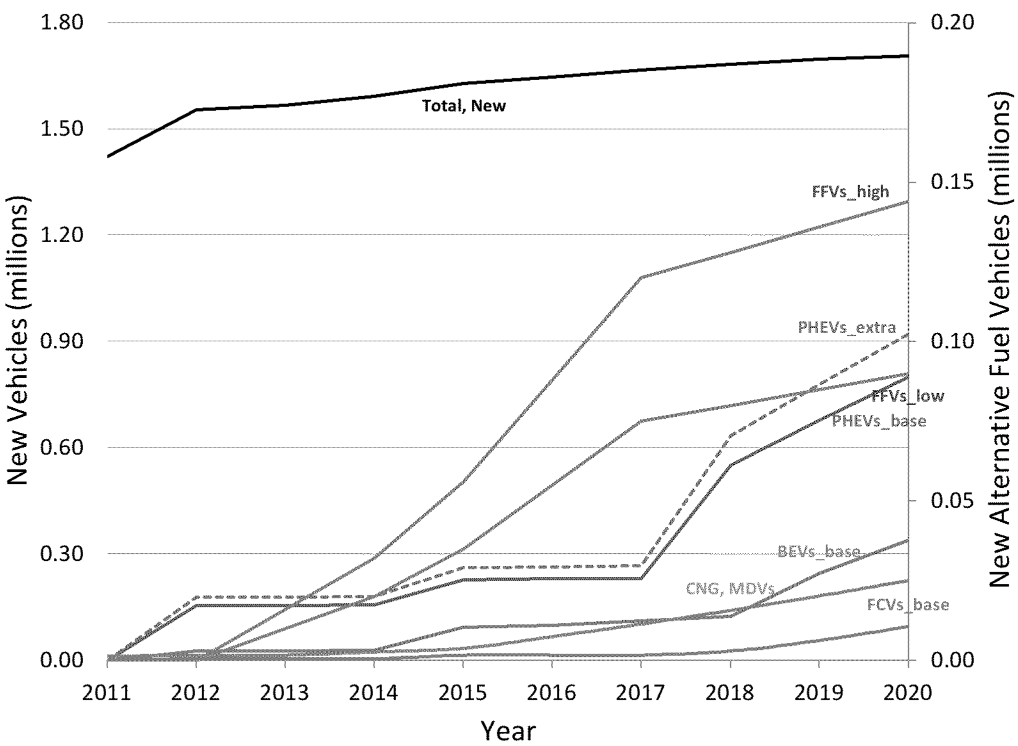
Vehicle Mix

Light- and Medium-Duty Vehicles

The impacts to the vehicle mix as a result of LCFS compliance in the plausible low cost scenario are discussed with regard to a) new vehicle sales and b) the total vehicle fleet. These two parameters help demonstrate the scope of changes on the vehicle side that will be required to deploy the fuel volumes highlighted previously. The total vehicle fleet in a given year is a function of a) new vehicle sales (i.e., vehicles added to the fleet), b) older vehicles that stay on the road (i.e., the fleet ages slightly), and c) the vehicles that are retired from the fleet (i.e., vehicles that are taken off the road).

Exhibit 25 below shows the new light-duty and medium-duty vehicle purchases for all new vehicles (black line, left axis) and for alternative fuel vehicles (right axis) over the analysis period. Note that the left scale is a factor of nine (9) larger than the right axis.

Exhibit 25. New Vehicles in the Light-duty and Medium-duty sectors, 2011-2020



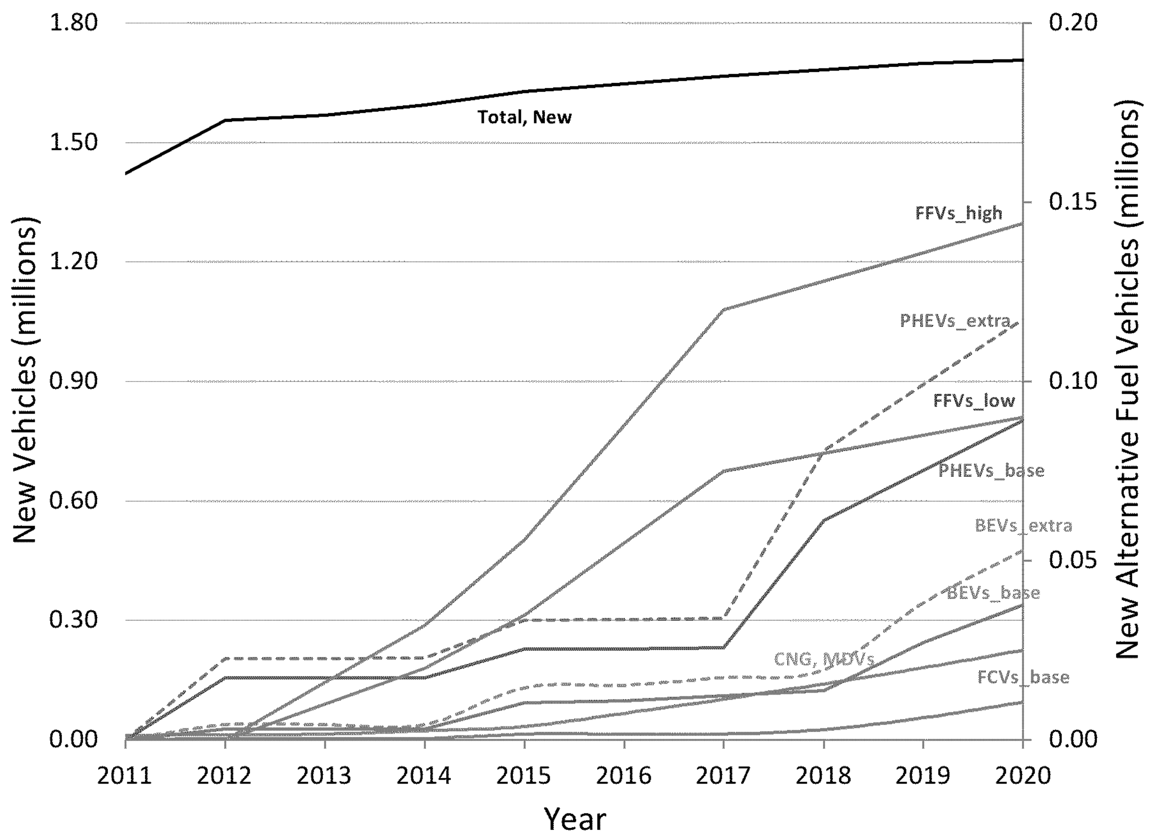
New vehicle purchases in the light- and medium-duty sectors (black line) increase from around 1.5 million vehicles in 2011 to around 1.7 million vehicles in 2020. The other alternative fuel vehicles deployed to consume the volumes of fuel in the plausible low cost scenario are:

- **FFVs that consume E85 (blue lines)**. The two blue lines for FFVs show a high and low scenario for FFV deployment depending on how frequently a driver will use E85.
- **CNG for medium-duty vehicles (orange line)**. The orange line at the bottom of the graph represents the deployment of new CNG medium-duty vehicles (not to be confused with medium heavy-duty vehicles).
- **ZEVs to comply with the ZEV program**. The model introduces a baseline number of PHEVs (red), BEVs (green), and FCVs (purple) to comply with the ZEV Program. Exhibit 25 labels vehicle deployment levels consistent with compliance with the ZEV program as "base." For instance, "FCVs_base" and "BEVs_base" are the baseline levels of these

vehicles introduced for compliance with the ZEV Program. In the plausible low cost scenario, the model introduces additional PHEVs at a rate shown by PHEVs_extra (dashed red line): The number of additional PHEVs introduced by model to the market is the difference between the line labeled “PHEV_base” and “PHEV_extra.”

By 2020, we forecast that about 21 percent of new vehicle purchases in the light- and medium-duty sectors will be alternative fuel vehicles, with the ZEV program accounting for eight percent. Exhibit 28 shows the impacts of these new vehicle purchases on the vehicle fleet mix over the time period.

Exhibit 26. Light- and Medium-duty Vehicle Fleet Estimates in the Low Cost Scenario



The left axis represents total vehicles purchases and corresponds to the black lines for light-duty automobiles (LDA) and light-duty trucks (LDT) as well as medium-duty vehicles (MDV; mainly trucks and vans). The right axis is a factor of 20 smaller than the axis on the left and corresponds to the total number of alternative fuel vehicles in the fleet by 2020.

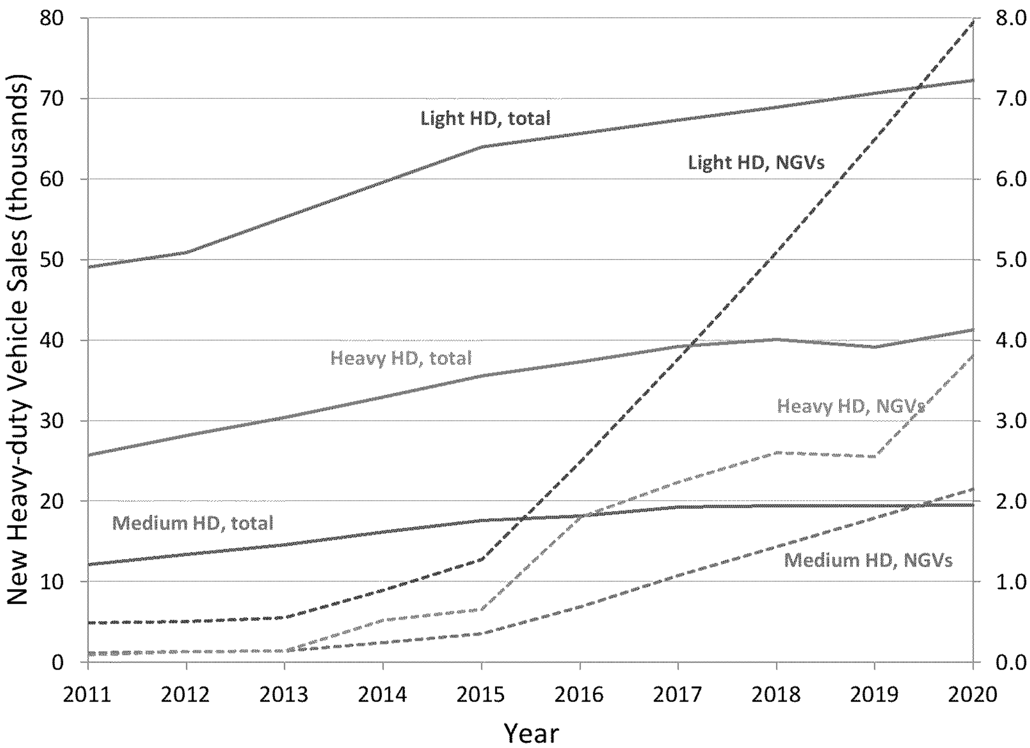
- We estimate that alternative fuel vehicles make up about seven percent of the total light- and medium-duty vehicle fleet by 2020.
- Flexible fuel vehicles (blue lines) comprise the highest percentage of alternative fuel vehicles. We estimate that the number of FFVs on the road will need to increase from about 450,000 on the road in 2011 to about 900,000-1,170,000 by 2020 in order to consume the forecasted volume of E85.

- NGVs in medium-duty applications account for 2 percent of the entire medium-duty vehicle fleet (about 4 million vehicles, lower black line) by 2020.
- The ZEV program accounts for 2 percent of the alternative fuel vehicles on the road; the modeling requires a small increase in PHEV sales (30 percent) and BEVs (40 percent) beyond CARB's most likely compliance scenario.

Heavy-Duty Vehicles

Exhibit 29 shows that new vehicle sales in the light-, medium-, and heavy-heavy-duty.[11] vehicle sectors are much lower than in the light-duty and medium-duty vehicle sectors. Natural gas represents the only alternative fuel vehicle available in the heavy-duty vehicle sector. The model primarily deploys biodiesel and renewable diesel to achieve compliance in the diesel pool. As a result of these fuels' introduction, there were not significant shifts in the new heavy-duty vehicle market.

Exhibit 27. New Vehicles in the Heavy-Duty sectors, 2011-2020



The left axis corresponds to the solid lines. The solid lines show that light-heavy-duty (LHD) vehicles (blue) have the largest annual sales of about 50,000 vehicles in 2011 and increase to 72,000 vehicles in 2020. Medium-heavy-duty (MHD; red line) and heavy-heavy-duty (HHD; green line) vehicles have lower annual sales of around 20,000 and 41,000 annually by 2020.

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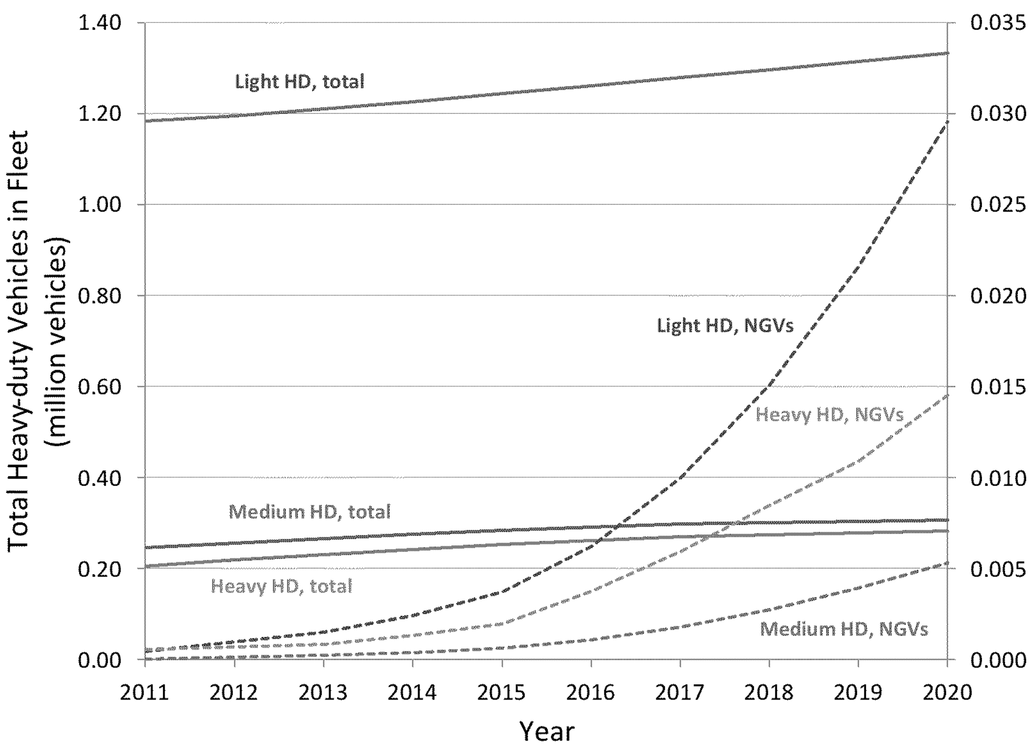
[11] Heavy-duty vehicles in California are defined as vehicles of gross vehicle weight rating (GVWR) of above 14,000 lbs. These vehicles are further classified into the following three categories: a) light-heavy duty, 14,000<LHD<19,500 lbs; b) medium- heavy duty, 19,500≤MHD≤33,000 lbs; and c) heavy-heavy duty, >33,000 lbs.

The right axis corresponds to the dotted lines. The dotted lines represent natural gas vehicle (NGV) purchases in the LHD, MHD, and HHD sectors. Note that the right axis is a factor of 33 times smaller than the left axis.

- Based on the persistent price differential between CNG or LNG and diesel, we forecast modest growth in the LHD (blue, dotted), MHD (red, dotted), and LHD (green, dotted) sectors. NGVs in the HD sector account for about ten percent of new vehicle sales by 2020: 11 percent in the LHD and MHD sectors and nine percent of new vehicles in the HHD.
- NGV sales in the HHD sector include vehicles that will run on both CNG and LNG. New vehicle sales in the HHD sector are slightly lower because there are several applications in the HHD sector for which neither CNG nor LNG vehicles would meet the duty-cycle demands required of the application.
- We do not distinguish between conventional CNG and biomethane consumption in NGVs in the LHD, MHD, or LHD sectors; therefore, there is no NGV category dedicated to biomethane vehicles.

Exhibit 28 shows the impacts of new NGV sales on the heavy-duty vehicle fleet by 2020.

Exhibit 28. Heavy-duty Vehicle Fleet Estimates in the Low Cost Scenario



As in the previous figures, the left axis corresponds to total vehicles in the fleet and the right axis (a factor of 40 smaller) corresponds to total alternative fuel vehicles in the fleet. NGVs in the LHD, MHD, and HHD sectors –with new vehicle sales representing ten percent of the fleet by 2020 – account for a forecasted three percent of the vehicle fleet by 2020.

LCFS Reductions in Phases

The following subsections review the anticipated market behavior according to the phase of reductions required by the LCFS. For the purposes of this analysis, the carbon intensity reductions have been grouped in the following phases:

Exhibit 29. Abatement Costs by Phase in the Plausible Low Cost Scenario

LCFS Phase	Carbon Intensity Reduction Target	Corresponding Years	Avg Unit Abatement Cost ($/tonne)
Phase 1	0–1.0 percent	2011-2013	$50
Phase 2	1.0–2.5 percent	2013-2015	$123
Phase 3	2.5–5.0 percent	2015-2017	$115
Phase 4	5.0–8.0 percent	2017-2019	$101
Phase 5	8.0–10.0 percent	2019-2020	$75
		Average Unit Abatement Cost	**$94**

In each of the following subsections, we present a handful of key takeaways followed by a more substantive discussion of these takeaways and other observations.

Phase 1: 0–1.0 percent reduction

- **The first phase of LCFS compliance is largely met by blending lower carbon corn ethanol into gasoline.** For the most part, the model includes reported consumption for 2011 and 2012 for fuels such as Brazilian sugarcane ethanol. The model also is calibrated to some extent based on the balance of credits reported by CARB, which indicate that there were nearly 1 million more credits than deficits in the market at the end of 2012.
- **By 2013, the model predicts a significant increase in Brazilian sugarcane ethanol and ramping up of California corn ethanol consumption – each representing more than 200 million gallons of production.** With a unit abatement cost of about $95/tonne in the plausible low cost scenario, Brazilian sugarcane ethanol is driving the average unit abatement cost in Phase 1 of LCFS compliance. Furthermore, it is important to note that the average unit abatement cost in Phase 1 of $53/tonne is based on significant banking in the model (i.e., over-compliance), with an estimated excess of more than 2.5 million credits by the end of Phase 1.
- **The model also includes modest consumption of biodiesel in Phase 1, increasing to nearly 4 percent of the diesel pool by the end of 2013 (equivalent to 135 million gallons).** Biodiesel can be made in-state or imported from out of state. Although much of California's biodiesel production has been idled in recent years, the availability of a dollar-per-gallon tax credit in 2013 and the increased pressure of LCFS compliance will likely increase utilization at these plants. The dollar-per-gallon tax credit also yields a significant drop in the unit abatement costs of biodiesel (regardless of feedstock) as shown in Exhibit

20. Even with these facilities operating at higher utilization rates, biodiesel will have to be imported into California. As noted previously, ICF considered several feedstocks for biodiesel and renewable diesel: Soybeans, corn oil, FOGs, and cellulosic or waste materials (for renewable diesel). The biodiesel consumed in Phase 1 is a mix of FOG-based biodiesel (47 percent), corn oil-based biodiesel (38 percent), and soy-based biodiesel (15 percent). We also estimate 35 million gallons of renewable diesel (from FOGs) consumption by the end of Phase 1.

- **By the end of Phase 1, the model deploys about 150 million dge of natural gas.** The unit abatement costs of natural gas consumption are lower in the earlier years – and generally negative due to estimated fuel cost savings – because the existing infrastructure of CNG and LNG will support the expanding market for at least Phase 1 and most of Phase 2 of LCFS compliance based on ICF estimates.

Phase 2: 1.0–2.5 percent reduction

- **In Phase 2, corn ethanol from outside of California will continue to be a significant blending component**, with little to no changes required in the existing infrastructure. The model continues to deploy Brazilian sugarcane ethanol in significant volumes (350 million gallons in 2014).
- **This phase represents the first significant introduction of cellulosic ethanol into California:** The model forecasts about 90 million gallons of cellulosic ethanol consumption in 2014, account for 11 percent of credits generated at a unit abatement cost of about $95/tonne. This is based on the assumption that there is sufficient production capacity online and able to be delivered to California.
- **By the end of Phase 2, the importance of a transition to corn oil-based biodiesel becomes more evident:** The compliance strategy accounts for 27 percent of all credits earned in 2015 after an increase to 195 million gallons consumed at a unit abatement cost of $150-170/tonne. By Phase 2, the tax credit for biodiesel blending has expired and the abatement costs are considerably higher. As a result, corn oil-based biodiesel and sugarcane ethanol drive the abatement costs in Phase 2.

The model forecasts biodiesel consumption will represent about 10 percent by volume of diesel consumption at the end of Phase 2. FOG-based biodiesel peaks at the conclusion of Phase 2 at around 110 million gallons, with another 92 million gallons of FOG-based renewable diesel. Even though these fuels have a rack price premium of $0.50-$1.00 per gallon, these fuels have unit abatement costs of about $160/tonne and $220/tonne. These unit abatement costs are attractive based on the limited availability of other low carbon fuels through Phase 2.

Natural gas is still only a small contributor in this phase of compliance, accounting for less than 5 percent of credits generated. Similarly, PEVs and hydrogen FCVs combined account for less than 2 percent of credits generated.

Phase 3: 2.5–5.0 percent reduction

The beginning of Phase 3 represents several significant transitions in the LCFS market:

- **Firstly, the average unit abatement cost for this Phase decreases due to the banking activity in years 2011-2016.** Even though the unit abatement costs of strategies deployed are higher, the optimization model simply cannot get the reductions required to achieve LCFS compliance without banking in the early years. If significant over-compliance is not achieved by 2016, then the ability of obligated parties to comply with the LCFS will be increasingly difficult and expensive as more credits are needed in later years (i.e., 2018-2020.
- **Secondly, Brazilian sugarcane ethanol consumption exceeds corn ethanol consumption in 2015 in the E10 market and by the end of Phase 3, corn ethanol from outside California is completely displaced from the E10 market.** Similarly, sugarcane ethanol starts to force corn ethanol from California out of the E10 market by 2016 to meet the increasingly stringent requirements of the LCFS. Furthermore, cellulosic ethanol consumption increases to nearly 265 million gallons by 2017.
- **Phase 3 also includes more significant natural gas consumption** – and the estimated unit abatement costs for many of NGV strategies range from -$300/tonne to -$200/tonne, with only modest introduction of new infrastructure. Rather, our estimates indicate that the existing infrastructure will increase capacity significantly before adding new stations. By 2017, the model forecasts that 7.1 percent of credits generated will be in NGV applications. This is sufficient to decrease the average unit abatement cost for compliance.

The corn ethanol that is displaced by lower carbon intensity ethanol is shifted to the E85 market, with an estimated 50 million gallons of E85 from corn by the end of Phase 3.

Corn oil-based biodiesel consumption is forecasted to remain flat at 165 million gallons based on estimated availability of supply to California; however, this consumption generates more than 20 percent of the credits in Phase 3. We also observe a slight shift in the consumption of FOG-based biodiesel to FOG-based renewable diesel: This is a function of availability of supply and lower infrastructure costs associated with transporting renewable diesel into California.

Finally, it is important to note that by the end of Phase 3 (2017), we anticipate that the infrastructure for biodiesel blending and storage for biodiesel, which is a barrier to expansion in the market, will have been expanded sufficiently to accommodate a statewide B20 market. In later years, this lowers the unit abatement cost for biodiesel fuels.

Phase 4: 5.0–8.0 percent reduction

- **Phase 4 represents the period in which the model begins to achieve compliance through the use of banked credits from previous years.** By 2018, the compliance strategies that the model identifies yield a net balance of nearly 1 million deficits.

The observations for Phase 4 are consistent with those made in Phase 3, with a handful of differences. For instance, the amount of corn oil-based biodiesel consumed effectively doubles to 330 million gallons by 2018. Overall, biodiesel consumption increases to about 12 percent by volume of diesel. Renewable diesel consumption is effectively flat at about 95-105 million gallons.

Apart from the significant change in corn oil-based biodiesel consumption, the model continues to deploy additional volumes of lower carbon ethanol (Brazilian sugarcane ethanol and cellulosic ethanol) in the E10 market. We also observe modest increases in E85 and natural gas (about 50 percent increases). We also observe consistent levels of biodiesel and renewable diesel consumption from other feedstocks such as soybeans, FOGs, and cellulosic materials.

- **Phase 4 does mark the beginning of more aggressive increases in electricity and hydrogen consumption in the transportation sector, largely driven by the ZEV Program.**

As was the case with the infrastructure for biodiesel blending in Phase 3, by the end of Phase 4, we forecast that the infrastructure for natural gas (consumed as either CNG or LNG) will have expanded sufficiently to support much higher consumption, thereby decreasing the unit abatement costs of these strategies slightly in later years.

Phase 5: 8.0–10.0 percent reduction

The net deficits increase significantly in Phase 5: 3.2 million deficits in 2019 and 5.9 million in 2020. The credits banked in earlier years are used to comply with the reductions required in Phase 5.

- **By Phase 5, the E10 market is entirely Brazilian sugarcane ethanol and cellulosic ethanol, which together account for about 30 percent of the credits generated.** The model forecasts volumes of 940 million gallons and 330 million gallons, respectively. With estimated unit abatement costs of $94/tonne and $167/tonne in 2020, these fuels are significant contributors to the average unit abatement cost.
- **In the later years of the program, the model deploys US corn ethanol and California corn ethanol into the E85 market** – with a 50 percent split in the marketplace by 2019. By 2020, lower carbon ethanol (i.e., sugarcane ethanol and cellulosic ethanol) displaces California corn ethanol from the E10 market. It is important to note that the optimization model does not necessarily capture the potential fluidity between these markets. The optimization model is calibrated assuming that blenders will seek the lowest carbon ethanol for blending because it is the lowest cost compliance option. If the expansion of E85 infrastructure does take place, as is included in the plausible low cost compliance scenario, then it is feasible that there is downward pressure on the abatement costs for lower carbon biofuels.

In Phase 5, the model forecasts E85 consumption to increase to 256 million gallons in 2019 and then a peak of 346 million gallons in 2020 – accounting for just 3.5 percent of the abatement costs in Phase 5. The ethanol in E85 is a mix of corn ethanol from California and corn ethanol from elsewhere in the US.

By the end of Phase 5 in 2020, the model includes biodiesel at 20 percent by volume in the diesel mix. The model is capped at 20 percent biodiesel by volume into the California market because this is typically the maximum volume that the majority of engine manufacturers will warranty their product. This may cause some issues regarding potential air quality concerns due to the potentially higher values of NOx emissions from biodiesel consumption, ICF has assumed that this barrier will not persist out to 2020.

- **The optimization model continues to be bullish on biodiesel from corn oil.** With a carbon intensity of 4 g/MJ, the opportunities for biodiesel from corn oil are significant. For the plausible low cost scenario, about 360 million gallons per year of corn oil based biodiesel are consumed by 2020. Even with a price premium of 50 cents per gallon, the $140/tonne abatement cost of corn oil based biodiesel is still attractive.
- **By the end of Phase 5, natural gas deployment is significant – accounting for 13 percent of credits earned.** The deployment is driven by increased vehicle sales in the medium-duty, LHD, MHD, and HHD vehicle segments. We forecast that NGV sales will increase to about 10-30 percent of new vehicle sales in each of these vehicle segments. As noted previously, the negative unit abatement costs for NGV applications in the model help lower the average unit abatement cost of compliance significantly and help contribute to the downward trend observed in Exhibit 19.
- **Although advanced vehicle technologies – including PHEVs, BEVs, and hydrogen FCVs – only account for 4.5 percent of credits generated in Phase 5 of compliance**, the unit abatement costs of these strategies are high – ranging from about $40/tonne (BEV) to about $600/tonne (hydrogen FCVs). As a result, the deployment of hydrogen for consumption in FCVs increases the average abatement cost for compliance.

The optimization model estimates about 39 million gge of electricity will be consumed by PHEVs and 24 million gge of electricity will be consumed by BEVs in 2020. By 2020, electricity consumption in the transportation sector will represent about one percent of the energy in the light-duty market. Due to the federal tax incentive for electric vehicles and the assumed decreases in vehicle costs, the optimization model accelerates the deployment of PHEVs by 2020 slightly, with an additional 53,000 vehicles on the road by 2020. PHEVs are also aided by the fact that the abatement costs do not include significant infrastructure costs. For instance, we assume that all BEVs will require a Level 2 EVSE for residential charging and substantial deployment of DC fast charging capabilities for trip extending purposes. On the other hand, in the plausible low cost scenario, we assume only modest upgrades as part of the unit abatement costs for PHEVs and only 40 percent of vehicle buyers will seek out a Level 2 charger at home..[12]The accelerated deployment of PHEVs will not help OEMs comply with the ZEV Program because the number of credits that can be earned from TZEVs is capped; however, the deployment of PHEVs will likely be a significant compliance strategy with more stringent (tailpipe) GHG emission standards.

With modest price reductions for BEVs out to 2020 and expensive infrastructure largely deployed by 2020, the deployment exceeds the levels required to comply with the ZEV Program

[12] Note that this 50 percent is slightly lower than what is reported today; however, most of the data available today are reported by Chevrolet Volt, a PHEV40. With the increased deployment of PHEV10 models (e.g., Toyota Prius Plug-in) and PHEV20 models (e.g., Ford C-MAX Energi), we anticipate that the proportion of consumers who install Level 2 charging will decrease substantially. We assumed 33 percent of PHEV10 and PHEV20 vehicles and 50percent of PHEV40 models will have Level 2 EVSE.

by nearly 40 percent. This may seem like a large number; however, with only modest sales targets through the ZEV Program in the early years, this is not a drastic shift towards light-duty vehicle electrification in the timeframe of this analysis.

By the end of Phase 5, the optimization model forecasts hydrogen consumption to account for less than 0.1 percent of energy consumed in the light-duty transportation sector, which is equivalent to about 5 million gge in 2020. Our forecasts do not include significant price reductions in hydrogen fuel cell vehicles by 2020 for the optimization model to incorporate this as a compliance strategy above-and-beyond the baseline deployment to comply with the ZEV program. Hydrogen FCVs account for about 0.7 percent of new light-duty vehicle sales and 0.2 percent of the light-duty vehicle fleet by 2020.

Tank-to-Wheel Costs

The focus of this analysis is on WTW reductions and costs; however, we have also included TTW reductions and costs to aid in comparisons to other aspects of the Carbon Metric study. The most significant difference between the WTW and TTW reductions and costs is for biofuels like ethanol and biodiesel. More specifically, fuels like corn ethanol and soy-based biodiesel – which account for a small percentage of reductions on a WTW basis – have a carbon intensity of 0 g/MJ. As a result, the emission reductions in the very first year (2011) are already large because of the volumes of ethanol that are consumed in reformulated gasoline. In other words, the initial tranche of reductions (11 MMT) is so inexpensive ($7/tonne) because it does not require significant investments in lower carbon biofuels or lower carbon alternative fuels.

The optimization model is designed to minimize costs and emissions on a WTW basis. Consequently, the results on a TTW basis can be confusing or misleading. For instance, the unit abatement costs of biodiesel increase for some feedstocks and decrease for others.

- Consider corn oil-based biodiesel: On a WTW basis, corn oil-based biodiesel has a very low carbon intensity of 4 g/MJ and displaces conventional diesel, which has a WTW carbon intensity of 98 g/MJ. However, on a TTW basis, corn-oil biodiesel and conventional diesel have carbon intensities of 0 g/MJ and 74.1 g/MJ, respectively. As a result, there are fewer GHG reductions at the same price. The optimization model deploys corn-oil-based biodiesel because of the significant reductions that are achieved on a WTW basis at a relatively attractive unit abatement cost, and because there is sufficient supply.
- On the other hand, the TTW unit abatement cost of soy-based biodiesel is lower than on a WTW basis. On a WTW basis, soy-based biodiesel has a carbon intensity of about 83 g/MJ, which yields a differential of about 15 g/MJ compared to conventional diesel. However, on a TTW basis the differential increases to 74 g/MJ, thereby decreasing the cost by a factor of 5. If the model were optimized to TTW reductions, then we would expect soy-based biodiesel to play a much more important role in compliance.

The unit abatement costs for natural gas are effectively unchanged on a TTW basis because the carbon intensity reductions are similar on a relative basis. In other words, the well-to-tank (WTT) portion of the WTW carbon intensity for natural gas is similar to that of conventional diesel and gasoline. As a result, you get similar reductions at the same price – yielding little to no change in the unit abatement cost.

On the other hand, electricity and hydrogen have higher unit abatement costs on a TTW basis because of the way we have accounted for upstream emissions as part of the TTW carbon intensity. Electricity and hydrogen have WTW carbon intensity differentials of 68 g/MJ and 42 g/MJ, respectively, compared to gasoline. On a TTW basis, in this analysis, these are reduced to 32 g/MJ each.

Due to all of the changes in the unit abatement costs of the various lower carbon fuels deployed, and considering that the model is optimized to WTW reductions, the results appear confusing on a TTW basis. In addition to the information presented previously in this subsection regarding the differences in abatements costs on a TTW basis, the major results are summarized briefly here (see Exhibit 18 for GHG emission reductions and corresponding abatement costs):

- Phase 1. The abatement costs are low in Phase 1 because compliance is achieved by blending corn ethanol into reformulated gasoline which has much higher GHG reductions on a TTW basis.
- Phase 2: In Phase 2, corn oil-based biodiesel plays a significant role in over-compliance and the abatement costs are higher for this fuel. However, Brazilian sugarcane ethanol, the other major fuel deployed to over-comply in the early years, has a lower abatement cost on a WTW basis, thereby driving the average abatement cost lower than in the WTW basis.
- Phase 3: Brazilian sugarcane ethanol and cellulosic ethanol combine to account for a significant portion of GHG reductions; in both cases, the TTW reductions for these fuels are higher than on a WTW basis, thereby decreasing unit abatement costs significantly.
- Phase 4: The deployment of lower carbon ethanol (e.g., cellulosic ethanol and Brazilian sugarcane ethanol) and the increased volumes of E85 (from corn ethanol) keep the unit abatement costs low, similar to Phase 3.
- Phase 5: There is a large increase in abatement costs in Phase 5 because the fuels that have higher TTW abatement costs reach their maximum deployed volumes, including: corn oil-based biodiesel, electricity, and hydrogen. Similarly, as an increasing number of advanced vehicle technologies – including electric vehicles and hydrogen fuel cell vehicles – are deployed (to comply with the ZEV Program), this puts slight downward pressure on lower carbon ethanol, which was previously keep the TTW unit abatement costs lower.

3.2. Plausible High Cost Scenario

Overview of Costs

A mix of compliance strategies described below help to achieve the low cost scenario. Exhibit 18 and Exhibit 19 summarize the costs associated with compliance in the plausible low cost scenario. The unit abatement costs over time for each of the compliance pathways are shown in Exhibit 20. Note that there are two different axes for the unit abatement costs shown in Exhibit 20. The unit abatement cost curves shown as a solid line correspond to the costs on the left axis; the unit abatement cost curves with a dotted line correspond to the costs on the right axis.

Based on ICF's modeling exercise, the high scenario yields an average unit abatement cost of $182; however, it does not achieve the emission reductions required by LCFS. The marginal abatement figures in this scenario are frequently above $600 per tonne (e.g., advanced vehicle technologies). The impacts of the modified parameters for each compliance strategy in this scenario are discussed in more detail in the subsections that follow.

Exhibit 30. Segmented Results for the Plausible High Cost Scenario for 2020

Phase	Reductions, tonnes		Costs, $/tonne	
	WTW	TTW	WTW	TTW
Phase 1 2011-2013	3.35	8.57	$85	$10
Phase 2 2013-2015	7.19	9.91	$202	$25
Phase 3 2015-2017	8.83	11.99	$219	$69
Phase 4 2017-2019	12.91	12.61	$209	$110
Phase 5 2019-2020	14.94	14.91	$219	$157
Average Unit Abatement Cost			**$182**	**$79**

Exhibit 31. Unit Abatement Cost Curves in the Plausible High Cost Scenario

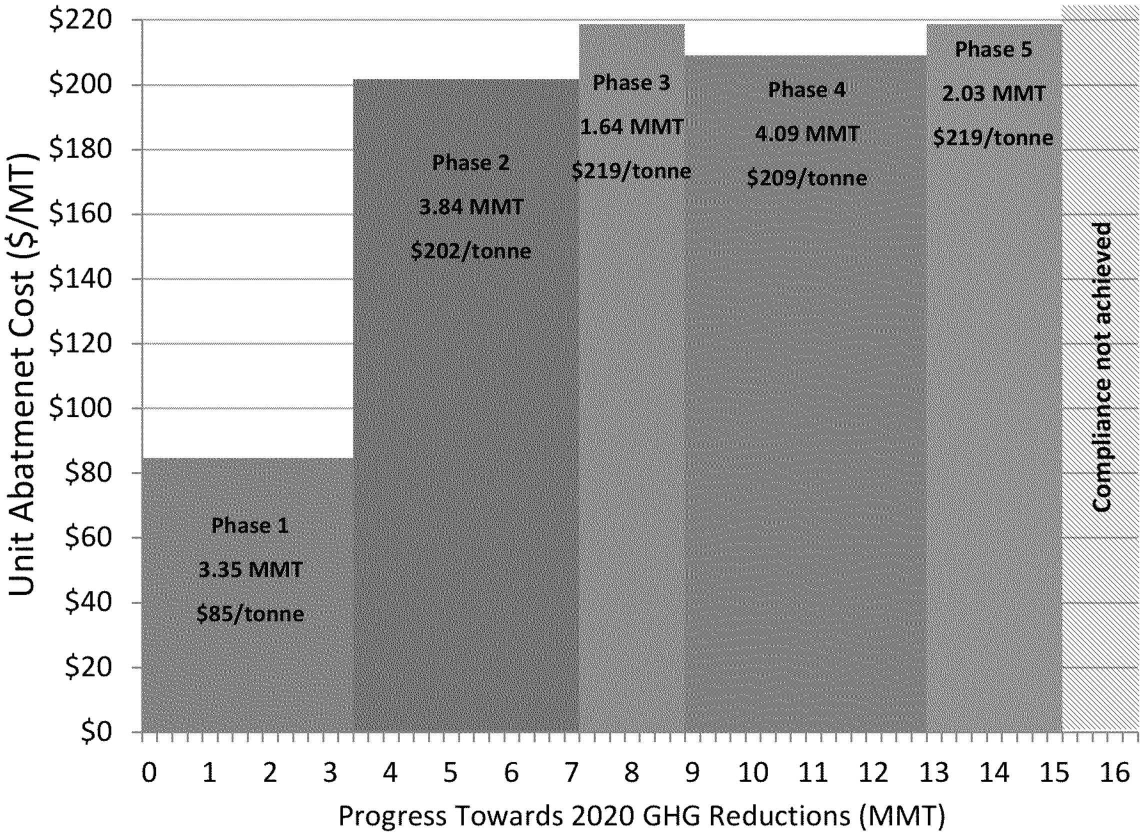
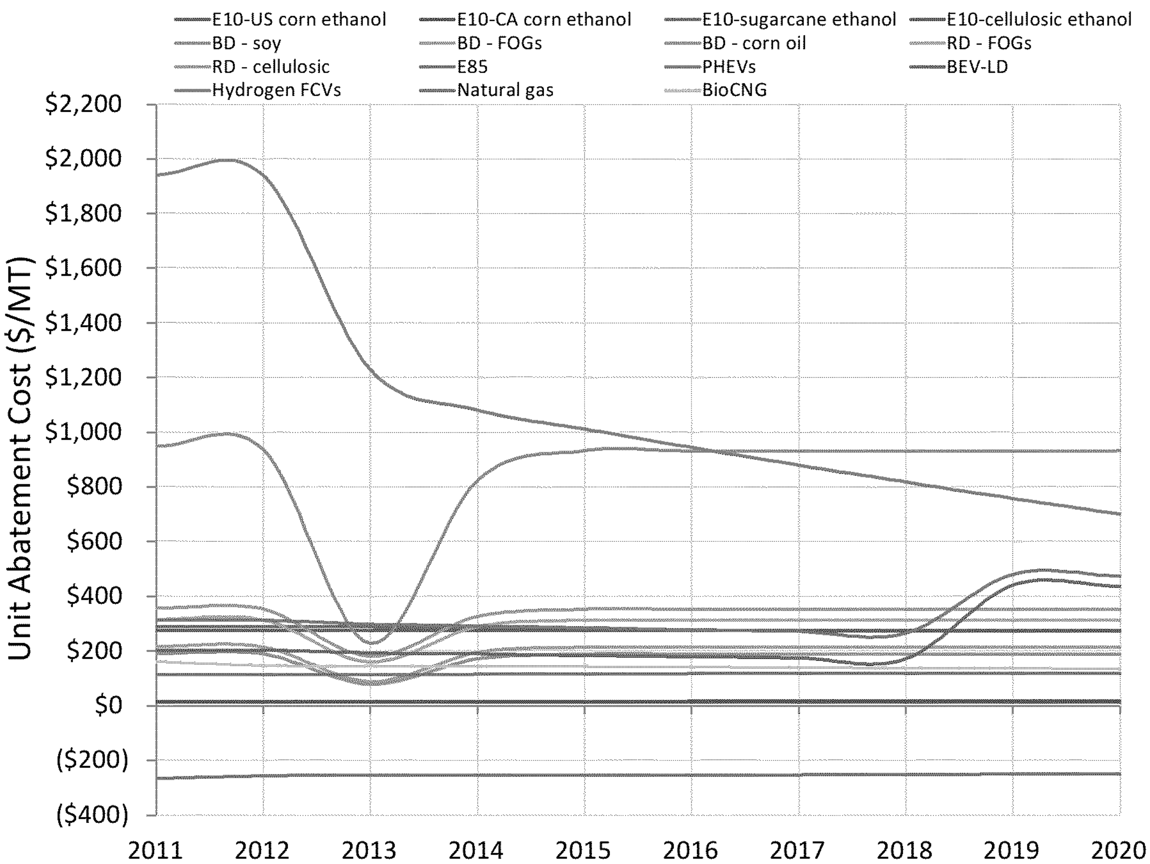


Exhibit 32. Unit Abatement Cost Curves, Plausible High Cost Scenario



LCFS Compliance: Deficits/Credits, Fuel Volumes, and the Vehicle Mix

Balance of Deficits and Credits in the Plausible High Cost Scenario

Exhibit 33 shows the percentage of credits generated by the various LCFS compliance pathways in the plausible high cost scenario. In any year during which the percentage of credits generated is greater than 100 percent, this indicates that credits are banked. In later years (2017-2020), these credits are used towards compliance (and indicated with the hatched out sections in those years). The percentage contributions towards compliance in the plausible high cost scenario are similar to those in the plausible low cost scenario.

Exhibit 33. Percentage of Credits Generated by Compliance Pathway in the Plausible High Cost Scenario

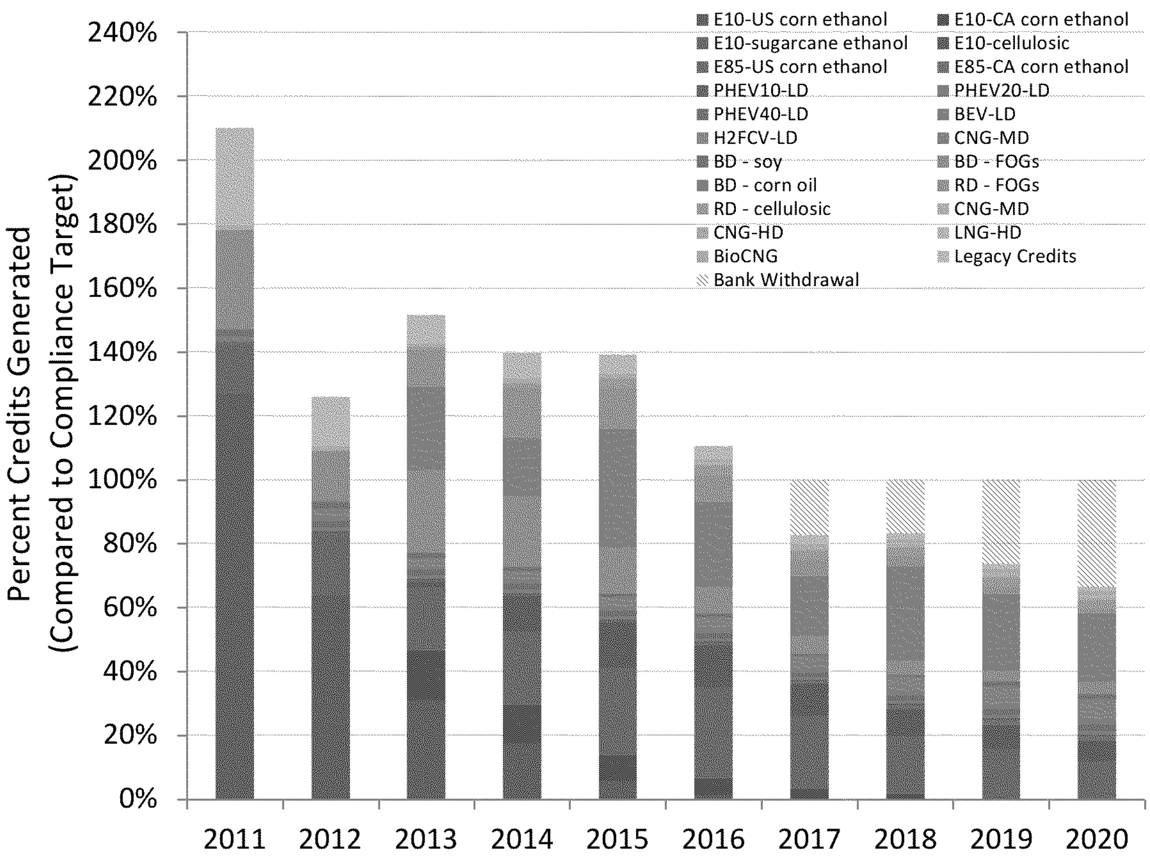


Exhibit 34 and Exhibit 35 show the balance of deficits and credits in the gasoline and diesel pool, respectively, in the plausible high cost scenario. It is not clear from these figures, however, the higher costs associated with this scenario push the model out of compliance with the LCFS. The model predicts a shortfall of about 6 million credits. Each credit is equivalent to one metric tonne. It is important to note that the shortfall of credits (or GHG reductions) is cumulative: In other words, the strategies in the plausible high cost scenario have annual GHG reductions that are about 1.0 MMT for the years 2015-2020.

Similar to the plausible low cost scenario, the model also optimizes costs and GHG reductions via over-compliance in the diesel pool. The black line in each graph shows the LCFS deficits as a result of gasoline and diesel consumption, respectively. Each block in the multi-colored column represents the credits generated by that compliance strategy in that year. For instance, the green and purple blocks, which feature prominently on an annual basis in the gasoline pool, represent the credits generated by Brazilian sugarcane ethanol and cellulosic ethanol, respectively. The light purple block at the top of the column that increases over time represents the credits generated by CNG consumption in medium-duty vehicles (that would have otherwise consumed gasoline).

Exhibit 34. Balance of Deficits and Credits in the Gasoline Pool, Plausible High Cost Scenario

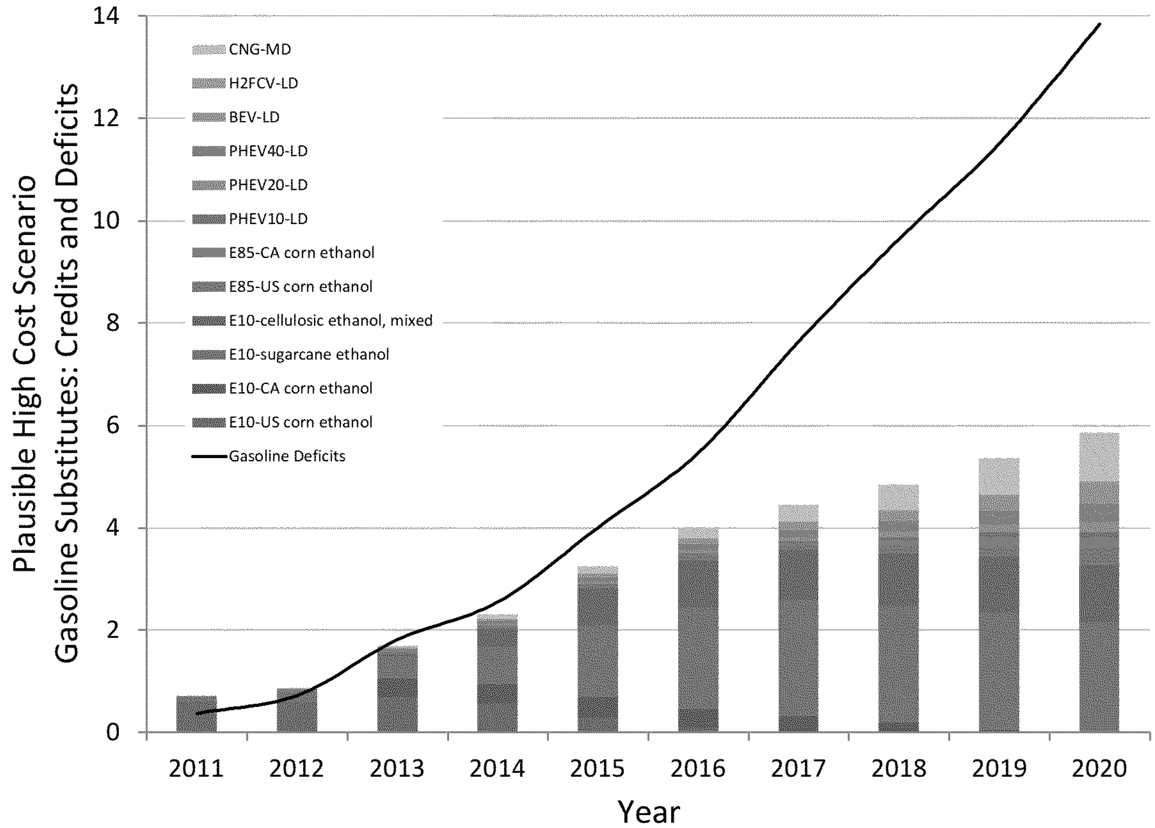
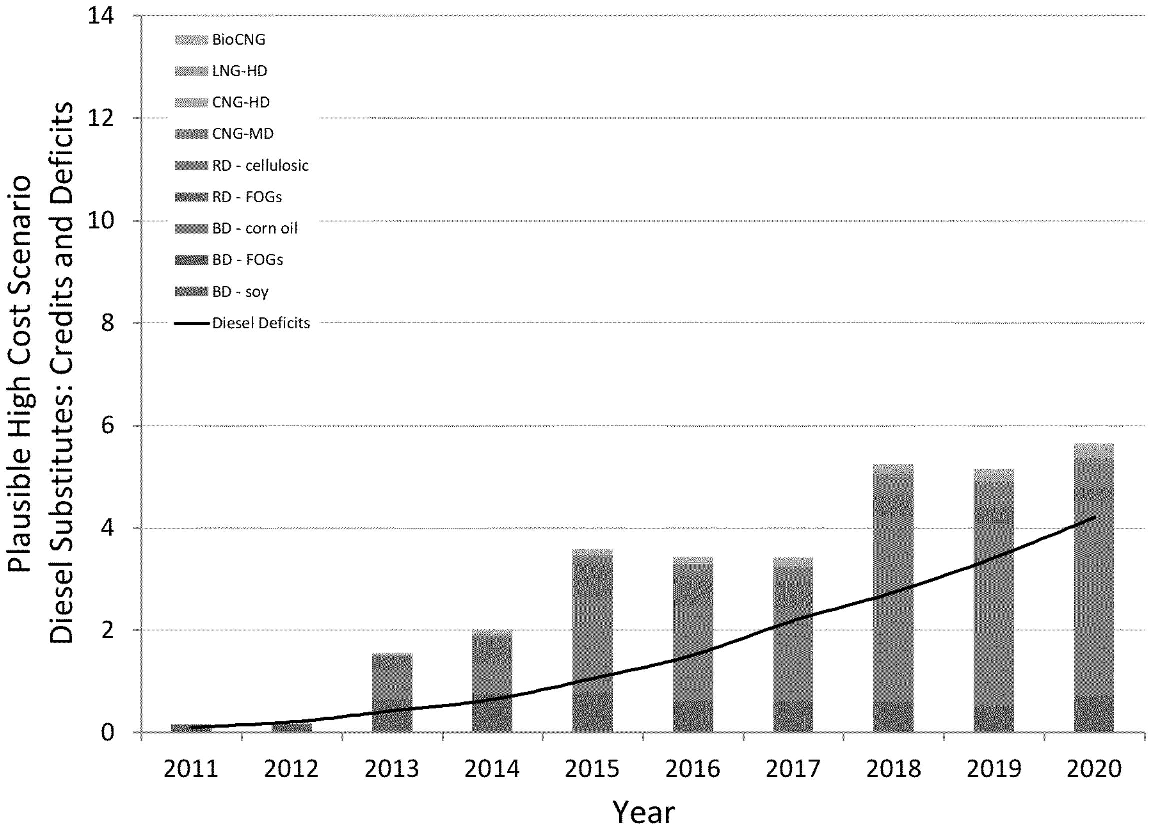


Exhibit 35. Balance of Deficits and Credits in the Diesel Pool, Plausible High Cost Scenario



Transportation fuel volumes in the Plausible High Cost Scenario

Exhibit 36 shows the volumes of fuels in the gasoline and diesel fuel pools deployed in the plausible low cost scenario.

Exhibit 36. LCFS Compliance Volumes for the Plausible High Cost Scenario

Fuel / Compliance Strategy	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Gasoline fuel mix (CARBOB, PHEVs, BEVs, FCVs, CNG reported in million gge; E10 and E85 reported in million gallons)										
CARBOB	12,516	12,379	12,454	12,464	12,428	12,384	12,348	12,113	11,814	11,440
E10-US corn ethanol	1,354	1,287	982	802	438	151	0	0	0	0
E10-CA corn ethanol	0	0	200	202	204	191	178	120	31	0
E10-sugarcane ethanol	37	88	195	317	608	866	1,011	1,028	1,069	1,044
E10-cellulosic ethanol, mixed	0	0	6	64	131	169	183	198	213	228
E85-US corn ethanol	11	12	15	17	25	43	50	96	128	234
E85-CA corn ethanol	0	0	0	0	0	11	21	64	128	151
PHEV10-LD	0	0	0	1	1	1	2	2	3	4
PHEV20-LD	0	0	1	1	2	3	3	5	7	9
PHEV40-LD	0	1	2	2	3	5	6	8	12	16
BEV-LD	0	0	1	1	3	4	6	8	12	17
H2FCV-LD	0	0	0	0	1	1	1	2	3	5
CNG-MD	2	7	14	24	40	67	110	175	267	391
Diesel fuel mix (ULSD, CNG, LNG, BioCNG reported in million dge; BD and RD reported in million gallons)										
ULSD	3,253	3,318	3,263	3,298	3,224	3,269	3,304	3,179	3,110	3,014
BD – soy	8	15	23	23	30	45	45	45	150	200
BD - FOGs	15	15	56	69	72	58	58	58	51	76
BD - corn oil	0	0	50	50	163	163	163	329	329	359
RD - FOGs	0	0	28	55	74	66	58	49	40	31
RD - cellulosic	0	0	3	6	18	28	39	49	60	72
CNG-MD	0	1	1	2	4	6	10	16	25	37
CNG-HD	0	1	1	1	2	4	6	9	14	19
LNG-HD	5	6	8	13	19	35	55	79	102	135
BioCNG	0	1	1	2	3	5	8	13	18	26

Vehicle Mix

Light- and Medium-Duty Vehicles

The changes to costs in the plausible high cost scenario yield small changes in new vehicle sales and the vehicle fleet compared to the plausible low cost scenario. The mix of light- and medium are summarized here:

- The volume of E85 deployed by the model is the same in the plausible high cost scenario as it was in the plausible low cost scenario. Therefore, there are no changes to the number of FFVs required to support the forecasted volumes.
- The number of NGVs in the medium-duty sector is slightly lower (about 20 percent) in the plausible high cost because: a) there are no vehicle price reductions and b) the infrastructure costs are higher.
- The number of ZEVs in the plausible high cost scenario is equivalent to CARB's most likely compliance scenario for the ZEV program. The vehicles prices are higher in the scenario and the federal tax credit for PEVs is phased out in 2018. The additional PHEVs that the optimization model deployed in the plausible low cost scenario are not deployed in this scenario.
- The number of hydrogen fuel cell vehicles is the same in the plausible high cost scenario as it was in the plausible low cost scenario.

Heavy-Duty Vehicles

Similar to the light- and medium- duty vehicle sectors, the changes in the plausible high cost scenario result in small changes in new vehicle sales and the vehicle fleet compared to the plausible low cost scenario. The HHD vehicle mix is summarized here:

- The number of NGVs deployed in the LHD, MHD, and HHD sectors is slightly lower (about 12 percent) in the plausible high cost because a) there are no vehicle price reductions and b) the infrastructure costs are higher. Together, these two factors increase the abatement costs for certain types of vehicles (as discussed in more detail below).

LCFS Reductions in Phases

The following subsections review the anticipated market behavior according to the phase of reductions required by the LCFS. The same five phases presented previously are used here:

Exhibit 37. Abatement Costs by Phase in the Plausible High Cost Scenario

LCFS Phase	Carbon Intensity Reduction Target	Corresponding Years	Avg Unit Abatement Cost ($/tonne)
Phase 1	0–1.0 percent	2011-2013	$85
Phase 2	1.0–2.5 percent	2013-2015	$202
Phase 3	2.5–5.0 percent	2015-2017	$219
Phase 4	5.0–8.0 percent	2017-2019	$209
Phase 5	8.0–10.0 percent*	2019-2020	$219
		Average Unit Abatement Cost	$182

* Compliance is not achieved in the plausible high cost scenario, so the 10 percent reduction is not met.

In each of the following subsections, we present a handful of key takeaways followed by a more substantive discussion of these takeaways and other observations.

The fuel volumes in the modeling of the plausible high cost scenario are similar to those that were forecasted by the model in the plausible low cost scenario. However, the volumes of fuels deployed in Phases 2 and Phase 3 are lower in many cases, thereby limiting over-compliance. Combined with lower availability of low carbon fuels in the later years (i.e., Phase 5), this leads to non-compliance and slightly lower GHG reductions.

The trend in average abatement costs through Phase 3 is the same as observed previously in the plausible low cost scenario. However, in the plausible high cost scenario, we observe a plateau of abatement costs. This is largely because there are fewer cost reductions assumed over time in the plausible high cost scenario. The most significant cost changes are as follows: the premium for cellulosic biofuel costs does not decrease, NGV costs do not decrease over time, and the PEV costs decrease less and the federal tax credit is eliminated by Phase 5.

The model still seeks over-compliance to the extent possible in earlier years due to the limited availability of lower carbon biofuels forecasted in later years. The excess credits are banked and used in the final two phases to achieve compliance. The following discussion of results focuses on the key differences observed in each of the five phases and the abatement measures driving the costs.

Phase 1: 0–1.0 percent reduction

- **Because the model relies extensively on actual data in the first phase of required reductions, there are no differences in the volumes deployed between the plausible low cost scenario and high cost scenario.** Although the model was developed using a similar consumption data for various fuels, there is still some uncertainty in the costs associated with many of the strategies. The higher costs in this scenario represent the upper bounds of costs from the research conducted (and discussed in more detail in Appendix A). For instance, the unit abatement cost of Brazilian sugarcane ethanol increased from about

$95/tonne to $290/tonne because the rack price premium was increased in the plausible high cost scenario (see Exhibit 16).

The higher rack prices of lower carbon biodiesel (e.g., from corn oil) also helps contribute to the more than doubling of the abatement cost in Phase 1 of the plausible high cost case compared to the plausible low cost case. Together with Brazilian sugarcane ethanol, biodiesel accounts for about 75 percent of the abatement costs in Phase 1.

Phase 2: 1.0–2.5 percent reduction

The higher costs in this scenario have an immediate impact on LCFS compliance in two ways:

- **Firstly, the compliance strategies that are available are more expensive. Secondly, the increased costs reduce the availability of fuels such as sugarcane ethanol and corn-oil based biodiesel.** As a result, not only do we observe higher abatement costs, the model is unable to bank sufficient credits by over-complying in this earlier phase. By the end of Phase 2, we already observe a 1.5 million decrease in the available credits compared to the plausible low cost scenario.
- **The model deploys a slightly lower volume of Brazilian sugarcane ethanol in the plausible high cost scenario because of the increase in fuel cost.** The higher cost of the fuel reduces the volume of Brazilian sugarcane ethanol slightly to 45 percent of the available export capacity estimated by the OECD. This higher cost is the result of what we assume will be robust demand market for sugarcane ethanol in Brazil, as well as a more constrained export market (e.g., to the European Union).

As noted previously in the discussion regarding the plausible low cost scenario, the expiration of the federal tax credit increases the abatement costs of biodiesel, regardless of the feedstock, significantly in Phase 2.

Brazilian sugarcane ethanol, cellulosic ethanol, and biodiesel account for about 80 percent of the abatement costs in Phase 2.

Phase 3: 2.5–5.0 percent reduction

- As was the case in the plausible low cost scenario, **the model maximizes over-compliance in early years and banks credits because there are fewer reductions available in Phase 4 and Phase 5.** The model primarily over-complies by blending the maximum amount of lower carbon biofuels available, including Brazilian sugarcane ethanol ~$275/tonne), cellulosic ethanol (~$275/tonne), corn oil-based biodiesel (~$190/tonne), and FOG-based biodiesel (~$215/tonne). Together, these fuels account for about 85% of the abatement costs in the plausible high cost scenario.

FOG-based biodiesel, much of which we anticipate will come from within California, peaks at 72 million gallons in 2015, representing a 20 percent reduction compared to the plausible low cost scenario. This is reduction is a result of the increased price of the fuel.

Phase 4: 5.0–8.0 percent reduction

- **The optimization model deploys similar levels of corn oil-derived biodiesel for the plausible high cost scenario.** Renewable diesel from FOGs and cellulosic or waste feedstocks are more expensive in the plausible high cost scenario. The volumes deployed in the plausible high cost scenario are decreased by 20 percent, peaking at 74 million gallons in 2015 for FOG-based renewable diesel and 72 million gallons in 2020 for cellulosic renewable diesel. These volumes represent 20 percent of the forecasted US production capacity of renewable diesel from FOGs and cellulosic feedstocks.

The higher assumed rack price of corn oil-based biodiesel (see Exhibit 16), however, yields a unit abatement cost of $160/tonne and an 8 percent reduction in the volume of corn oil-based biodiesel consumed in the diesel pool, peaking at 359 million gallons in 2020. This represents about 50 percent of the estimated available supply of corn oil-based biodiesel in the United States.

Phase 5: 8.0–10.0 percent reduction

- **The model forecasts a shortfall of 8.0 million credits available to comply with the LCFS by the end of Phase 5 in 2020.** As noted in the subsections above, this is largely due to insufficient lower carbon fuel availability in earlier years when the standard is not as stringent.

The higher costs reduce the consumption of cellulosic ethanol: The model forecasts about 230 million gallons of cellulosic ethanol in 2020, down from about 330 million gallons in the plausible low cost scenario, representing a 13 percent decrease.

The expansion of the E85 market forecasted in the plausible high cost scenario is the same as the plausible low cost scenario. The plausible high cost scenario also includes higher fueling station costs and a shift towards new fueling stations as opposed to retrofitting existing stations (as shown previously in Exhibit 16).

ICF forecasts CNG and LNG deployment in medium- and heavy-duty vehicle sectors to expand significantly in the 2015 to 2020 timeframe in the plausible high cost scenario. The higher vehicle costs and fueling station costs in the plausible high cost scenario yield about 400 million gge of CNG consumption in medium-duty trucks, an 18 percent reduction compared to the plausible low cost scenario. The higher vehicle costs increase the payback period compared to the plausible low cost scenario, thereby decreasing the potential new vehicle sales. Furthermore, with a lower volume of a fuel that has a significant negative unit abatement cost, the higher costs of blending biofuels and deploying advanced vehicle technologies are not offset as significantly as they were in the plausible low cost scenario.

The model forecasts similar reductions of natural gas consumption (as CNG and LNG) in the MHD and HHD sectors. Some vehicle types within these sectors have a less attractive payback period. For instance, the increased vehicle and infrastructure costs limit the deployment of MHD and HHD vehicles used in state (with GVWR greater than 26,000 lbs.[13]), public fleet trucks, and utility trucks. These vehicles tend to travel fewer miles and use less fuel. As a result, the payback period – which is the key parameter that we used to develop penetration rates – for these vehicles is longer, thereby reducing the potential sales. The lower sales result in lower consumption of CNG and LNG. The model forecasts about 60 million dge and 135 million dge of CNG and LNG consumption in 2020, a 15 percent reduction in the consumption of CNG and LNG in the MHD and HHD sectors compared to the plausible low cost scenario.

The optimization model estimates about 29 million gge of electricity will be consumed by PHEVs and 17 million gge by BEVs in the plausible high cost scenario. These levels of fuel consumption are consistent with our assumptions regarding the electric vehicle miles traveled by PHEVs and BEVs in CARB's most likely compliance scenario for the ZEV Program.

The primary driver for the increase in abatement costs per tonne between Phase 4 and Phase 5 is plug-in electric vehicles. Although plug-in electric vehicles only account for about 4 percent of GHG reductions in 2020, they account for about 20 percent of the costs, up from only 8 percent of the costs in Phase 4. The consumption of electricity is only down by about 5 million gge compared to the plausible low cost scenario; however, there are significant differences in the unit abatement costs between the two scenarios. Vehicle pricing is considerably higher in the plausible high cost scenario because of the phased out federal tax credit for plug-in electric vehicles and the smaller reduction in vehicle price over time. Similarly, the higher EVSE costs have an impact on the abatement cost as well. As a result of these changes, PHEVs and BEVs increase from around $200/tonne to $1,500-2,000 per tonne between the two scenarios.

There are no changes for the deployment of hydrogen fuel cell vehicles in the plausible high cost scenario compared to the plausible low cost scenario. The abatement costs are slightly higher, but do not make a significant contribution to the average abatement cost in Phase 5.

Tank-to-Wheel Costs

As noted previously, the focus of this analysis is on WTW reductions and costs; however, we have also included TTW reductions and costs to aid in comparisons to other aspects of the Carbon Metric study.

Due to the changes in the unit abatement costs of the various lower carbon fuels deployed, and considering that the model is optimized to WTW reductions, the results appear confusing on a TTW basis. In addition to the information presented previously in this subsection regarding the differences in abatements costs on a TTW basis, the major results are summarized briefly here (see Exhibit 30 for GHG emission reductions and corresponding abatement costs):

- Phase 1. The abatement costs are low in Phase 1 because it is largely corn ethanol blended into reformulated gasoline which has much higher reductions on a TTW basis.
- Phase 2: In Phase 2, corn oil-based biodiesel plays a significant role in over-compliance and the abatement costs are higher for this fuel.

[13] Categorized by CARB as T6 instate heavy in EMFAC2011.

- Phase 3: Brazilian sugarcane ethanol and cellulosic ethanol combine to account for a significant portion of GHG reductions; in both cases, the TTW reductions for these fuels are higher than on a WTW basis, thereby decreasing unit abatement costs. In the plausible high cost scenario, however, this decrease is not as significant as it was for the plausible low cost scenario. As a result, abatement costs continue to increase slightly. Moreover, corn oil-based biodiesel continues to play a significant role towards compliance and has a higher abatement cost on a TTW basis (as noted previously).
- Phase 4: Similar to Phase 3; however, corn oil-based biodiesel more than doubles between Phase 3 and Phase 4, displacing significant volumes (nearly 200 million gallons) of soy-based biodiesel. Cellulosic ethanol and Brazilian sugarcane ethanol volumes are effectively flat.
- Phase 5: There is a large increase in abatement costs in Phase 5 because the fuels that have higher TTW abatement costs reach their maximum deployed volumes, including: corn oil-based biodiesel, electricity, and hydrogen.

4. Discussion and Conclusions

The LCFS modeling results highlight the challenges and high costs of GHG abatement in the transportation sector. The results also show that LCFS feasibility depends significantly on assumptions today about future availability and cost of fuel supply available to meet the California market. To illustrate, consider that our assumptions in the plausible low cost scenario make LCFS feasible. However, modest modifications to those same supply and cost assumptions in the plausible high cost scenario show a shortfall in the GHG reductions required for LCFS compliance as the regulation is currently designed.

One of the primary shifts between the plausible low cost and plausible high cost scenario is the availability of carbon abatement from strategies that can have a material impact on the existing vehicle fleet. In other words, when the costs of biofuels are increased slightly, then the supply of biofuels that can be blended into the gasoline and diesel fuel mix and used in existing vehicles is lower. As a result, the model seeks additional reductions from other alternative fuels, requiring the introduction of new vehicles and infrastructure (e.g., PEVs or NGVs). Although the unit abatement cost is presented in NPV, and the potentially expensive vehicle costs or infrastructure costs can be amortized over many years, producers, suppliers, and end-users will often have to make significant investments based on paybacks over shorter-time periods. As a result, the supply curves for these alternative fuels are simply too steep to achieve compliance.

The most significant takeaways from this modeling exercise, relevant to both the plausible low and high cost scenarios, include the following:

- LCFS compliance depends on over-compliance in the earlier years of the regulation and on the use of what we have identified as free credits;
- Brazilian sugarcane ethanol and biodiesel from corn oil play a significant role in compliance;
- Both scenarios depend on the availability of cellulosic biofuels by 2014 with rapid expansion of production by 2015 and capacity expansion thereafter;
- The market for E85 is likely to increase significantly, but E85 demand depends on the availability of supply of low carbon biofuel for the E10 market; and,
- CNG and LNG in the medium- and heavy-duty sectors will play an important role in compliance, accounting for about 11-12 percent of credits generated between the two scenarios;
- The modeling exercise captures most (but not all) of the dynamics in a diversified transportation fuel market that we would expect – as the costs of abatement (and as a result, fuels) increases to meet compliance, the scope of compliance strategies broadens.

4.1. Over-compliance with LCFS required pre-2016

As noted previously, the modeling exercise identifies an important aspect of LCFS compliance: the likelihood of banking and trading LCFS credits. To some extent, uncertainty associated with the availability of lower carbon strategies in the future drives the optimization model's banking and trading. As a result, the optimization model seeks the lowest cost pathways in the near-term, with significant banking out to 2016 and trading in years 2017 to 2020. This occurs in both plausible low cost and plausible high cost scenarios modeled. Based on CARB's quarterly LCFS reports, this is exactly how the market is responding. For instance, through Q4 2012, about 1.3 million credits have been generated in the market. The optimization model was conservatively constrained based on these data. Moving forward, however, the optimization model does include creation of additional legacy credits. With about 120 million dge of CNG consumption in California prior to the implementation of the LCFS, the model implicitly assumes that CNG station owners will opt-in to the program by 2015. To date, CNG is generating around 40,000 credits on a quarterly basis; however, this is about 40-50 percent below what ICF anticipates could be earned if all the parties that could earn credits were to opt-in. ICF adjusted the optimization model assuming that by 2015 all parties that can earn LCFS credits will have opted into the LCFS market.

Over-compliance also helps explain the shape of the abatement cost curves shown previously, for example in Exhibit 19. The model seeks out reductions in the interim years of the compliance schedule (e.g., Phase 2 and Phase 3) to help achieve compliance by 2020. Even though these reductions are more expensive in the 2013-2016 timeframe, the optimization model has sufficient "foresight" to recognize that there is insufficient availability of low carbon fuels in later years. As a result of this constraint, the model over-complies in the early years and banks the credits generated to ensure compliance in later years. We observe similar activity in the plausible high cost scenario; however, the constraints imposed by higher costs yield insufficient availability of lower carbon fuels to meet the compliance schedule.

4.2. Brazilian sugarcane ethanol and corn oil biodiesel

Based on its carbon intensity, the availability of supply – as demonstrated by the 500 million gallons imported to the US last year – and fuel pricing, sugarcane ethanol will definitely play an important role towards compliance as the program is currently structured. We know the fuel can get to California and we know that the pricing is attractive enough to warrant importing it. The potential for cross-compliance with the RFS2 at the federal level using Brazilian sugarcane ethanol also serves to increase the likelihood of Brazilian sugarcane ethanol playing a significant part of LCFS compliance.

The sugarcane import volumes in 2012 to the US likely portend the potential for imports into California, despite the shifting dynamics of the RFS2 program. The uncertainty of the availability of lower carbon biofuels beyond 2015 will likely induce obligated parties to seek out over-compliance via strategies such as blending Brazilian sugarcane ethanol. It is also important to note that obligated parties in California will be able to use the volumes of sugarcane ethanol towards Advanced Biofuels credits; in the event that parties exceed their compliance volumes for RFS2, they may be able to recover some of the additional costs of sugarcane ethanol by selling RINs. Our model excluded RFS2 market dynamics and thus our results fail to reflect their potential costs.

The swapping of Brazilian sugarcane ethanol for US corn ethanol is likely to continue in the absence of affordable low carbon ethanol (e.g., cellulosic ethanol) or significant modification to the ILUC score for crop-based fuels. The "ethanol shuffle" is reminiscent of other unintended consequences of policy. For instance, when government officials in Mexico City introduced the *Hoy No Circula* program (Day Without a Car), certain vehicles were restricted from driving on certain days of the week. At the outset of the program, research demonstrated that some families purchased or kept a second used vehicle for driving purposes on their no driving days. As a result, it is theorized that vehicle miles traveled actually increased and the expected turnover of the fleet was slowed. Eventually, that program was fixed by coupling it with an emissions certification program. Unfortunately at this time, CARB lacks a comparable mechanism to capture the additional emissions attributable to potentially avoidable ethanol swapping – this would require the introduction of a complicated and controversial accounting system that penalizes imports or transportation of fuels into California beyond the emissions from transport already captured in the CA-GREET model.

Biodiesel from corn oil mirrors the role of Brazilian sugarcane ethanol in the diesel pool. With a best in LCFS carbon intensity of 4 g/MJ and the corn ethanol industry rapidly expanding the market for corn oil via the installation of extraction equipment, the barriers in the near-term future will be:

- The delivery infrastructure to California,
- Terminal storage of biodiesel for blending (at rates of five percent to 20 percent by volume); and,
- The build out of retail infrastructure to distribute B20 blends.

As noted previously, the cost of supplying large volumes of biodiesel, especially from corn oil, will require a significant upfront investment in the supply chain infrastructure. Although on a unit abatement cost basis, this does not add considerably to the dollar per tonne total because it is amortized over 20 years and millions of gallons of lower carbon biodiesel, it will still require an investment on the order of $120-200 million in the near-term future (i.e., before 2016).

4.3. Cellulosic biofuels required for compliance

Apart from sugarcane ethanol and biodiesel from corn oil, cellulosic biofuels will have to become available by 2014 in commercial quantities, followed by ramping up of production to nameplate capacity within the 12 months following availability. Thereafter, the market will require an expansion of at least one facility per year. The availability of lower carbon ethanol and diesel from waste, crop residues, or purpose grown energy crops is a controversial aspect of any analysis of the LCFS program. Despite our assessment that the LCFS is feasible in a plausible low cost scenario, this assessment is linked to the success of lower carbon biofuels – generating around 15 percent of total credits over the life of the program. Based on the investments to date and ICF's review of the likelihood of facilities planned – at various stages of construction, but all with financing – it is feasible that the volumes in the low cost scenario will be produced, and will be available to California. If by 2015, however, the market has not advanced significantly, and there are no other changes to the LCFS program, then this assessment will need to be revisited.

4.4. E85 under the LCFS

The market for ethanol is saturated today in California and the US as a result of reformulated gasoline, which is currently formulated assuming a 10 percent (by volume) blend of ethanol with CARBOB. The volume of ethanol produced in the United States, however, exceeds the maximum volume of ethanol that can be blended as E10 in reformulated gasoline markets. This is the so-called blend wall, whereby there is a mismatch between ethanol production and consumption.

In a market without carbon constraints, the shift to E85 is challenging. The ethanol market sees two prices – one to displace gasoline on a volumetric basis (E10) and another to displace gasoline on an energy basis (E85). In the former, 1 gallon of ethanol displaces 1 gallon of gasoline; in the latter, 1.2 gallons of ethanol displace 1 gallon of gasoline. The disconnect between these two markets when carbon is not constrained will always inhibit the expansion of E85: If the price of oil or gasoline goes up, then ethanol producers can generally sell their product at prices that are at least competitive with wholesale gasoline, regardless of production costs. However, ethanol producers selling into the E85 market, with a volume a mere fraction of the gasoline market are effectively capped based on the lower energy content of a gallon of ethanol compared to gasoline. When the price of the fuel also reflects the price of reducing carbon emissions in the fuels sector i.e., in a LCFS market; however, different types of ethanol have different pricing structures. This pricing differential becomes the driver for E85 consumption because of potentially lower pump prices.

The abatement cost of E85 as a compliance strategy includes a) the costs of the infrastructure required to distribute it and make it available at retail fueling centers and b) the ethanol that is used in E85. With a robust demand of about 400 million gallons of E85, we estimate that an additional 700 E85 stations will have to be built by 2020 (note: There are currently 56 E85 stations in California). Because the LCFS requires modest reductions in carbon intensity in the early years, and steeper reductions later as innovations and new investments bring more low carbon transportation fuels to market, ICF does not foresee a significant build out of E85 stations to be required until the 2016-2018 timeline. In ICF's calculation of the unit abatement cost of E85, the costs of E85 refueling stations are amortized over 20 years. However, fueling infrastructure providers will expect a return on investment in a much shorter time frame e.g., 2 years. In order to yield a return on investment, E85 must be priced competitively with reformulated gasoline. As a result, fueling infrastructure providers will seek out the lowest price ethanol. As noted previously, corn ethanol is forced out of the E10 market due to its high carbon intensity compared to sugarcane ethanol and cellulosic ethanol. However, it should have more attractive pricing than lower carbon ethanol in the E85 market because retailers will not have to pay the price premium that is anticipated for Brazilian sugarcane ethanol or cellulosic ethanol. As a result, the model assumes that E85 will largely consist of corn ethanol because we do not forecast sufficient expansion of production capacity and drastic reductions in the costs of ethanol from cellulosic or waste materials to put pressure on the price of corn ethanol.

4.5. Natural gas vehicles will play an important role

CNG and LNG providers are aggressively expanding their market share. For instance, CNG vehicles comprise up to 90 percent of new refuse haulers purchased in some parts of the US, including California. Although these are niche markets today, natural gas continues to be cheaper than diesel (and gasoline). As a result, we can expect to see more natural gas vehicles on the road. In the plausible low cost scenario, the modeling results in a significant expansion of the natural gas market, with an additional 700 million dge of natural gas (including CNG, LNG, and a modest amount of biomethane) consumption by 2020. Despite some of these options having higher than average unit abatement costs, from an end-user perspective, there is still an opportunity to save money – and that opportunity drives the assumed market penetration in various sectors.

4.6. Fuel pricing under the LCFS

The optimization model focuses primarily on abatement costs. As a result, the model fails to reflect explicitly some interactions between fuels and vehicles that affect fuel prices. For instance, the model may fail to illustrate how an increase in the price of Brazilian sugarcane ethanol may increase the consumption of E85 by increasing the price spread between reformulated gasoline (E10) and E85 (using a cheaper corn ethanol). Similarly, if there is a significant increase in the price of diesel as a result of biodiesel blending, then this will likely increase the demand for NGVs in the heavy-duty sector.

The optimization model is not explicitly designed to estimate fuel prices at the pump or estimate the price of LCFS credits. We have focused on the feasibility of compliance and the associated average unit abatement costs of compliance. However, based on the results of the modeling exercise we can make some estimates regarding fuel pricing. We made the following assumptions in the development of estimates for fuel pricing:

- Refiners and obligated parties would pass along the majority of the additional costs associated with blending biofuels to the end user (e.g., the consumer).
- Refiners and other obligated parties will seek to earn credits through biofuel blending. This assumption is implicit throughout the modeling exercise. Furthermore, we assumed that these same obligated parties would bank any credits from biofuel blending during the early years of over-compliance.
- Refiners and other obligated parties seeking credits will only go to the LCFS market after they have exhausted their supply of banked credits from blending biofuels.
- When they do have to go the LCFS credit market, refiners and other obligated parties seeking credits will spread the costs of compliance across the gasoline pool and not the diesel pool. The basis for this assumption is two-fold:
  - Biodiesel will have relatively higher rack prices compared to conventional diesel than ethanol does to conventional gasoline.
  - The goods movement sector, one of the most significant consumers of diesel fuel, is more sensitive to fuel pricing.

We recognize that these assumptions are an over-simplification of the potential market dynamics under the LCFS. In a competitive fuels market, refiners and other obligated parties will constantly seek to gain market share through aggressive fuel pricing and partnerships with ethanol producers. For instance, as a competitive measure, one refiner may be willing to reduce profit in the near-term by absorbing some of the anticipated additional costs of blending biofuels if it positions them to gain market share over a competitor. Despite the over-simplification of market dynamics, these assumptions enable us to make first-order estimates regarding the impacts of LCFS on fuel pricing.

The following factors should also be considered when considering the estimated impacts of LCFS on pump prices:

- The demand for reformulated gasoline decreases by about 6-7 percent in each scenario.
- The demand for diesel decreases by about 19 percent in each scenario, mainly because of the introduction of biodiesel and renewable diesel.

Exhibit 38 displays the estimated impacts of LCFS compliance on pump prices in 2020 for the plausible low cost and plausible high cost scenarios. The impact on pump prices is separated into the two components described above: 1) the additional costs of blending higher priced low carbon biofuels and 2) the costs of exposure to the LCFS credit market. As noted previously, we assume that refiners and other obligated parties will have to purchase credits from the LCFS credit market to offset deficits. This modeling exercise does not include a forecast of credit prices. The estimated impacts of LCFS on gasoline prices are shown as a range, reflecting low and high credit pricing scenarios. For the low credit pricing scenario, we used a value of $40 per credit; this is consistent with the values that have been reported in the LCFS market in early 2013..[14] In the high credit pricing scenario, we used a value of $300 per credit. Although we anticipate the pump price of gasoline and diesel to increase, drivers who use alternative fuels will likely experience significant cost savings, as shown in Exhibit 38.

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[14] ARB, 2012 LRT Quarterly Data Summary, 4Q 2012. Available online at: http://www.arb.ca.gov/fuels/lcfs/20130329_q4datasummary.pdf

Exhibit 38. Retail Fuel Pricing Forecasts for Conventional and Alternative Fuels [a]

Year	Gasoline							Diesel			E85 (gge)	CNG (dge)	Electricity [b] (gge)	H2 [c] (gge)
	Forecast	+ LCFS						Forecast	+LCFS					
		Plausible Low			Plausible High				Plausible Low	Plausible High				
		blending biofuels	LCFS credits		blending biofuels	LCFS credits								
			$40/credit	$300/credit		$40/credit	$300/credit							
2011	3.74	--	--	--	0.01	--	--	3.80	0.01	0.01	2.73	2.54	3.84	5.49
2012	3.89	--	--	--	0.01	--	--	3.95	0.01	0.02	2.84	2.54	3.81	5.50
2013	3.97	0.01	--	--	0.01	--	--	4.04	0.03	0.04	2.90	2.56	3.87	5.52
2014	4.06	0.01	--	--	0.03	--	--	4.13	0.12	0.12	2.96	2.57	3.93	5.54
2015	4.13	0.02	--	--	0.05	--	--	4.20	0.21	0.23	3.01	2.57	3.99	5.54
2016	4.13	0.03	--	--	0.07	--	--	4.22	0.21	0.23	3.02	2.57	4.05	5.54
2017	4.14	0.03	--	--	0.08	--	--	4.22	0.21	0.22	3.02	2.57	4.10	5.54
2018	4.14	0.03	--	0.02	0.08	0.01	0.10	4.22	0.30	0.32	3.02	2.58	4.14	5.55
2019	4.14	0.03	0.02	0.15	0.08	0.02	0.16	4.22	0.29	0.36	3.02	2.58	4.20	5.56
2020	4.13	0.03	0.03	0.24	0.09	0.03	0.24	4.21	0.32	0.42	3.02	2.58	4.26	5.56

Table Notes:

a. Retail fuel pricing estimates are reported as the average of the high and low cases forecasted by CEC in the 2011 IEPR documents. b. Retail electricity prices should be divided by 3.4 to account for the higher efficiency of electric vehicles compared to gasoline vehicles. c. Hydrogen retail prices should be divided by 2.5 to account for the higher efficiency of the fuel cell vehicles compared to gasoline vehicles.

As noted elsewhere, the unit abatement costs reported here represent the total resource costs associated with deploying each alternative fuel. These are not the same costs that drivers will pay when driving alternative fuel vehicles. The forecasted prices in Exhibit 38 indicate the prices that consumers will pay at the pump for various alternative fuels. For instance, drivers of electric vehicles will pay about $4.26 per gge. However, because electric motors are more efficient than gasoline engines, the price is actually $1.25 per gge. Similarly, hydrogen fuel cell vehicles are more efficient than conventional gasoline vehicles and consumers will pay the equivalent of about $2.22 per gge. These prices yield differences of at least $2.00–$3.20 per gge after accounting for the estimated increased pricing for gasoline at the pump.

We expect similar savings in the diesel sector for NGV drivers; although LCFS has the potential to increase diesel prices significantly, CNG may be have a price differential of about $2.00 per dge, up from $1.50 per dge today.

Appendix A – Summary of Alternative Fuel Assumptions

Ethanol

Ethanol is used primarily in low-level bends with California Reformulated Blendstock for Oxygenate Blending (CARBOB). It is currently blended at 10 percent by volume. Most ethanol produced in the US today comes from corn grown in the Midwest.

Ethanol can also be used in high-level blends, with 85 percent ethanol (by volume) blended with 15 percent gasoline, referred to as E85. E85 is consumed in flex-fueled vehicles (FFVs).

Ethanol is produced from a variety of feedstocks. For this analysis, ICF considered the following feedstocks:

- US corn ethanol
- California corn ethanol
- Brazilian sugarcane ethanol; and,
- Cellulosic ethanol

After we discuss these feedstocks, we discuss the consumption of ethanol as E85.

Corn Ethanol, US

Production

Corn ethanol is primarily produced in the Midwestern United States and is currently the most used alternative fuel in California. Corn ethanol is blended in at 10 percent as part of reformulated gasoline. Nearly 1.5 billion gallons of corn ethanol are consumed annually in California as an oxygenator in reformulated gasoline. For the purposes of our modeling exercise, there were no constraints imposed on corn ethanol imports from outside of California.

Delivery to California

Ethanol produced in the Midwest is delivered to California via rail. As noted above, with 1.5 billion gallons of corn ethanol consumed annually in California, the rail delivery infrastructure is well developed and no significant investment is required for expansion.

Potential Consumption in California

The market for corn ethanol in low level blends is effectively saturated today with the sale of reformulated gasoline. Any additional consumption of corn ethanol from outside of California will likely have to be consumed in a high level blend (E85); this is discussed in more detail below.

GHG abatement

The GHG abatement potential for corn ethanol from outside of California is limited. Although there are many pathways for corn ethanol, the major impediment to the limited GHG abatement potential of this fuel is so-called indirect land use change (ILUC) emissions that CARB has attributed to corn ethanol production. The lifecycle carbon intensity of corn ethanol includes an additional 30 g/MJ attributable to ILUC. The carbon intensity of corn ethanol from outside of California ranges from 77 g/MJ to 99 g/MJ (which is about the same intensity as gasoline). As a result, the GHG abatement potential of corn ethanol produced outside of California is constrained by the number of facilities that have made modifications to their production processes consistent with an existing pathway (in the range of 77-89 g/MJ) or to submit a new pathway.

Corn Ethanol, CA

Production

The majority of California's ethanol production facilities are considered destination plants i.e., the feedstock is shipped in from elsewhere (typically the Midwest) and the ethanol is produced on-site.

Delivery to California

The logical market for California ethanol production is California's reformulated gasoline market. The transport of the feedstock (generally corn) from the Midwest is the delivery mechanism for this fuel to California. The proximity of California' ethanol production facilities to blending racks – where ethanol is blended with CARBOB – makes it easier for producers to bring their product to market.

Potential Consumption in California

California currently has seven (7) ethanol production facilities with a combined nameplate production capacity of more than 250 million gallons. For ethanol produced in California, an upper limit of 254 million gallons per year of production was imposed based on research from the CEC. As recently as 2009, only 2 percent of California's ethanol production capacity was operational. However, with LCFS implementation and the switch to a full E10 market in January 2010, California facilities were operating at 70 percent capacity as recently as January 2012. We assume that all 254 million gallons per year of production will be available to the California market; we also assumed a modest cumulative increase of production capacity by one percent annually. These efficiency gains at plants are based on the potential for improvements such as those offered by Edeniq. Edeniq's Cellunators are reported to achieve up to two to four percent yield improvements at ethanol facilities. This annual increase yields annual production capacity of 272 million gallons of California ethanol by 2020.

GHG abatement

Corn ethanol produced in California has a lower carbon intensity, on average, than corn ethanol production facilities outside of California. The CEC has assumed – and ICF has confirmed via stakeholder outreach – that there is a plausible decrease in the carbon intensity of corn ethanol in California to 72 g/MJ; however, the pathways today have a carbon intensity of 77-84 g/MJ.

Many of California's facilities are seeking to introduce local feedstocks as a way to lower their carbon footprint. For instance, Pacific Ethanol reported that in the 3rd quarter of 2012, about 30

SB_GT&S_0767400

percent of its feedstock was sorghum. Similarly, Aemetis recently announced that it was idling production at its Keyes, California plant to upgrade the facility so that it can also operate using sorghum as a feedstock for ethanol production. This potential feedstock switching is also driven by the EPA's recent ruling (December 2012) that ethanol derived from sorghum qualifies as an Advanced Biofuel under the RFS2 program. This is critical to suppliers because sorghum-based ethanol will likely receive a price premium from suppliers looking to comply with both the LCFS and RFS2.

For the purposes of this analysis, we did not assume any feedstock switching at California's ethanol production facilities.

Brazilian Sugarcane Ethanol

Production

Most ethanol in Brazil is derived from sugarcane. This not only ties its ethanol to the seasonal oscillations of sugarcane harvest, but also drives the ethanol industry's economics in relation to the sugar industry and the larger sugarcane sector. Benefiting from a favorable climate and a national sugarcane ethanol promotion program lasting almost 40 years, Brazil's sugar and ethanol industries are highly developed. Brazil is currently the world's largest sugar producer and second largest ethanol producer behind the U.S.[15] In 2011, the country produced 6 billion gallons of ethanol from sugarcane (8.6 per cent of this amount was exported).

Brazil had 440 ethanol plants by the end of 2011 with an installed capacity of 11.3 billion gallons of ethanol.[16] Based on Brazil's production data for the 2009-2010 crop[17], the average crushing capacity of a sugarcane processing facility is about 1.5 million tons of sugarcane per year. At Brazil's current productivity level, this translates to about approximately 32 million gallons of ethanol per year if all cane is converted into ethanol. Currently, the ratio of sugarcane dedicated to sugar versus ethanol is about 50/50.[18]

Brazil's ethanol production capacity depends firstly on its sugarcane production potential. One of the frequently mentioned concerns is the impact of sugarcane development on land use. Brazil has a favorable climate and large quantities of land suitable for growing sugarcane, a necessary condition for it to become the world's largest sugarcane producer. Going forward, Brazil will likely continue to capitalize on this advantage as the country still has large quantities

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[15] OECD-FAO. "Agricultural Outlook: 2012-2021". OECD-FAO, 2012.

[16] U.S. Department of Agriculture (USDA). "Brazil Biofuels Annual: Annual Report 2012". USDA, August 2012: Washington, DC. Available at: http://gain.fas.usda.gov/Recentpercent20GAINpercent20Publications/Biofuelspercent20Annual_Saopercent20Paulopercent20ATO_Brazil_8-21-2012.pdf

[17] Companhia Nacional de Abastecimento (Conab). "Perfil do setor do açúcar e do álcool no Brasil" (in Portuguese). Conab, 2012. Available at: http://www.agricultura.gov.br/arq_editor/file/Desenvolvimento_Sustentavel/Agroenergia/estatisticas/producao/JUNHO_2012/Publicacoes/Perfilpercent20Sucroalcoleiropercent20-percent20safrapercent202009-10.pdf

[18] This is expected because the flexibility of the market in Brazil allows for a surplus in one market to be taken up in the other market. In other words, if the demand for sugar drops due to a surplus in the (global) market, more sugarcane is diverted to ethanol production.

of available land. Various studies estimate Brazil's additional land that could be used for sugarcane to be between 148 million and 894 million acres (in 2011, just under 20 million acres are used to grow sugarcane.[19]). The OECD forecast that we use in our analysis projects about 31.3 million acres of land for sugarcane in 2020[20], well below this range of estimates of Brazil's land potential.

Another concern is feedstock quality. Sugarcane has a 6-year cycle, i.e. sugarcane is harvested for five seasons after it is planted before the soil is "renewed". The highest productivity is usually recorded in the first year. The recent economic crisis has led to slower field renewal, in addition to reduced investment in mills, and thus lower productivity results.[21] Inclement weather may also wreak havoc on sugarcane harvest results. The 2010/11 season, which saw heavy rainfall, depressed the sugarcane harvest, raising sugar and ethanol prices. Investment in sugarcane crops may take 12-18 months to yield a return, so it may take some time to bring supply to normal levels.

Delivery to California

In 2012, Brazil exported approximately 800 million gallons of sugarcane ethanol, with about two thirds of that (533 million gallons) coming to the United States. The majority of Brazil's ethanol is exported from the Port of Santos and is either delivered to Los Angeles or San Francisco via tanker. It is also feasible for the ethanol to be imported via Houston and shipped to California via rail; however, it is unclear how common this practice is. For the purposes of our analysis, we assumed that ethanol is transported to California directly via tanker.

Brazilian sugarcane ethanol is also imported to the United States via countries in the Caribbean Basin Initiative (CBI). In this scenario, hydrous ethanol (i.e., ethanol with trace amounts of water) is exported to a country in the CBI, including Costa Rica, El Salvador, Guatemala, Jamaica, Nicaragua, and Trinidad & Tobago. Upon arrival in a CBI country, the trace water is removed from the ethanol and exported as anhydrous ethanol (i.e., ethanol without water) to the United States. Until 2011, the United States had an import tariff on Brazilian sugarcane ethanol of about 50 cents per gallon – mainly to offset the 50 cent per gallon tax credit that was given to entities that blended ethanol with gasoline. The tax credit helped spur the rapid growth of the ethanol production industry in the United States; however, the tariff on Brazilian sugarcane ethanol was implemented to protect corn ethanol producers from potential dumping of lower-cost sugarcane ethanol. The CBI countries came into play because the import tariff did not apply to them.

In 2011, 40 percent of the sugarcane ethanol imported into the US was via CBI countries. Even though the tax credit and import tariff expired at the end of 2011, about 15 percent of the ethanol that was imported into the United States still arrived from CBI countries in 2012. Furthermore, of the sugarcane ethanol imported to California, 35 percent was from CBI

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19 Ibid.
20 OECD-FAO. "Agricultural Outlook: 2012-2021". OECD-FAO, 2012.
21 OECD-FAO. "Agricultural Outlook: 2012-2021". OECD-FAO, 2012.

countries in 2012, up from 33 percent in 2011. ICF does not anticipate this trend to continue, however, it is clear that the pathway via CBI countries is still viable.

Potential Consumption in California

We know today that Brazil is aggressively pursuing an expansion of its export market for sugarcane ethanol, while also seeking to protect its sugar production industry at home. Most recently, Brazil reduced the amount of ethanol that is required to be blended into its transportation fuel mix from 25 percent to 20 percent, thereby putting downward pressure on its domestic market. This provides some protection for its sugar crop because the crop can be used as a feedstock or in sugar exports as a food product. Although these short-term changes do not have a material impact on our modeling exercise, they demonstrate the flexibility of Brazil's market and keen interest in expanding its export market.

Note that in other analyses, the export capacity of Brazilian sugarcane has been under-reported at around 500 million gallons. The 500 million gallons that were exported to the US in 2012 was a record; however, it was largely driven by compliance with RFS2 rather than the LCFS. The RFS2 – unlike the LCFS – has volumetric requirements for compliance. One of the renewable fuel categories is referred to as Advanced Biofuels. The RFS2, however, has a nested structure, and there is some overlap between categories. For instance, biodiesel has its own volumetric targets; however, when that target is achieved, excess biodiesel can be used towards compliance with the Advanced Biofuels target. Furthermore, a gallon of biodiesel is equivalent to 1.5 gallons of ethanol in the Advanced Biofuels category. Brazilian sugarcane ethanol is also an Advanced Biofuel. In other words, although one might think that Brazilian sugarcane ethanol is competing with corn ethanol, in 2012 it was used in lieu of biodiesel to comply with the Advanced Biofuels target. Obligated parties under RFS2 opted to import and blend Brazilian sugarcane ethanol because it was a cheaper compliance pathway than blending excess biodiesel. However, with the reintroduction of the biodiesel production tax credit as part of the so-called fiscal cliff deal in late 2012, the incentive to blend Brazilian sugarcane ethanol in place of biodiesel for compliance with the RFS2 will effectively be eliminated.

Exhibit 39 shows Brazil's production and consumption and capacity utilization of ethanol plants from 2008 to 2011. The decline in the country's production is directly related to the slowdown in capacity utilization from 70.9 percent in 2008 to 53.5 percent in 2011, due to heavy rainfall which adversely impacted sugarcane crops, causing an increase in sugar prices. It is notable that in 2011, in the face of the tight supply situation, while the export amount did not change (it increased slightly from 504 to 519 million gallons), Brazil's imports increased from over 20 million gallons to 300 million gallons to meet domestic demand (see Exhibit 40). This is because Brazil's ethanol industry is export dependent, even though domestic consumption still represents the most important market. The domestic demand left unmet due to the supply shortfall caused by exports could usually be satisfied with imports. Most of these imports, unsurprisingly, come from the U.S. where the blend wall has been increasing quantities of surplus corn ethanol (see more discussion in the corn ethanol section).[22] Brazil dropped its 20 percent tariff on imported ethanol in March 2010, effectively promoting this ethanol swap.[23]

Exhibit 39. Historical production, consumption, and capacity utilization of ethanol plants in Brazil[24]

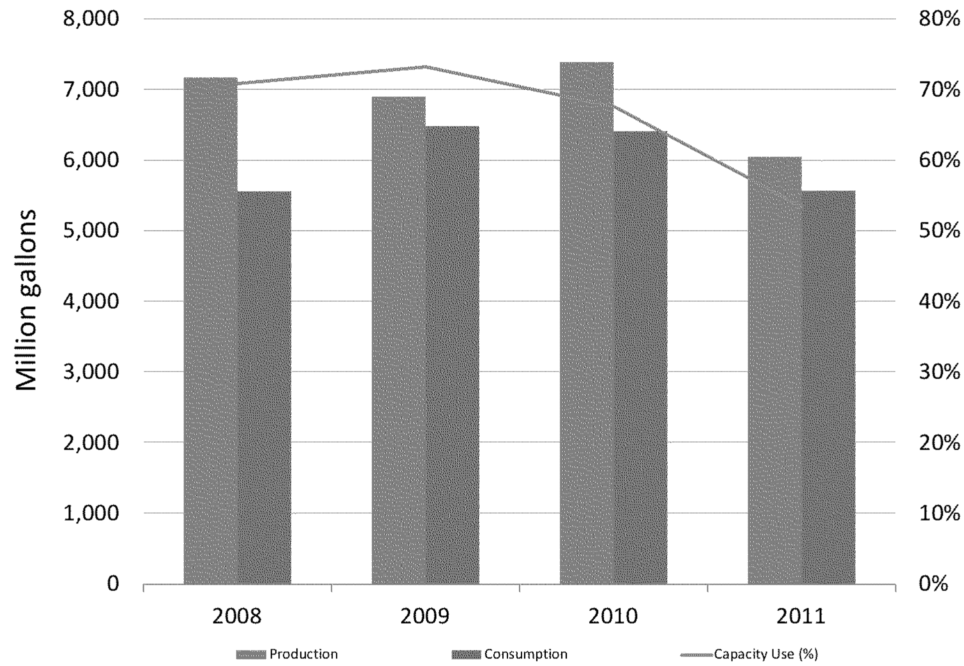


Exhibit 40. Exports and Imports of ethanol from/to Brazil

Exports (million gallons)	1,354	871	504	519	804
Imports (million gallons)	0	0	74	1,100	n/a

ICF used the OECD forecast to constrain our analysis for sugarcane ethanol exports because it is conservative with regard to production and consumption outlook as well as productivity in Brazil. Furthermore, it examines the export-oriented nature of Brazil's ethanol industry. For this

[22] The U.S. Energy Information Administration (EIA). "Development in US ethanol exports". EIA, July 18, 2012: Washington, DC. Available at: http://www.eia.gov/oog/info/twip/twiparch/120718/twipprint.html
[23] Jessen, Holly. "Ships passing in the night". Ethanol Producer Magazine, December 12, 2011. Available at: http://www.ethanolproducer.com/articles/8405/ships-passing-in-the-night
[24] U.S. Department of Agriculture (USDA). "Brazil Biofuels Annual: Annual Report 2012". USDA, August 2012: Washington, DC. Available at: http://gain.fas.usda.gov/Recentpercent20GAINpercent20Publications/Biofuelspercent20Annual_Saopercent20Paulopercent20ATO_Brazil_8-21-2012.pdf

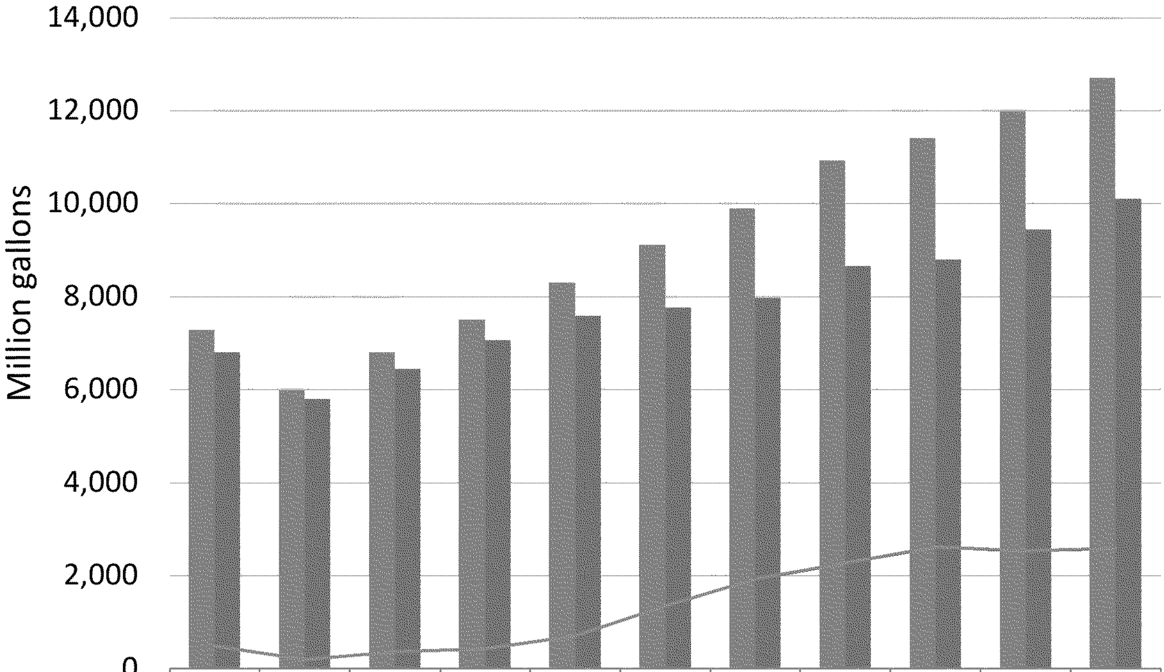
reason, the OECD outlook provides a reasonable estimate of how much ethanol Brazil would willingly make available for export, not just how much the country can produce.

Other outlooks we also considered included the FAPRI-ISU 2011 World Agriculture Outlook and Brazil's ten-year energy expansion plan.[25] The FAPRI-ISU outlook, which is based on a more optimistic yield assumption, presents a much higher trade balance for Brazil (nearly 4 billion gallons in 2020). Brazil's energy plan forecasts low export (1,797 million gallons in 2020)[26], which could be attributed to the fact that Brazil used AEO 2012 as an input into its models. A common theme across different outlooks is that Brazil will fulfill almost 100 per cent of future U.S. import demands. Considering no other countries currently have significant enough capacity and the lead time that it would take to deploy an infrastructure – including production facilities, distribution infrastructure, and export capabilities – to become a major supplier, it is reasonable to assume that moving forward, U.S. import demand will be met almost entirely by Brazil's sugarcane ethanol.

[25] FAPRI-ISU 2011 World Agriculture Outlook is available at http://www.fapri.iastate.edu/outlook/2011/. Brazil's ten year energy plan is available at: http://www.epe.gov.br/PDEE/20120302_1.pdf (in Portuguese)

[26] California Energy Commission (CEC). "Transportation Energy Forecasts and Analyses for the 2011 Integrated Energy Policy Report: Draft Staff Report". Page 159. CEC, August 2011. Available at: http://www.energy.ca.gov/2011publications/CEC-600-2011-007/CEC-600-2011-007-SD.pdf

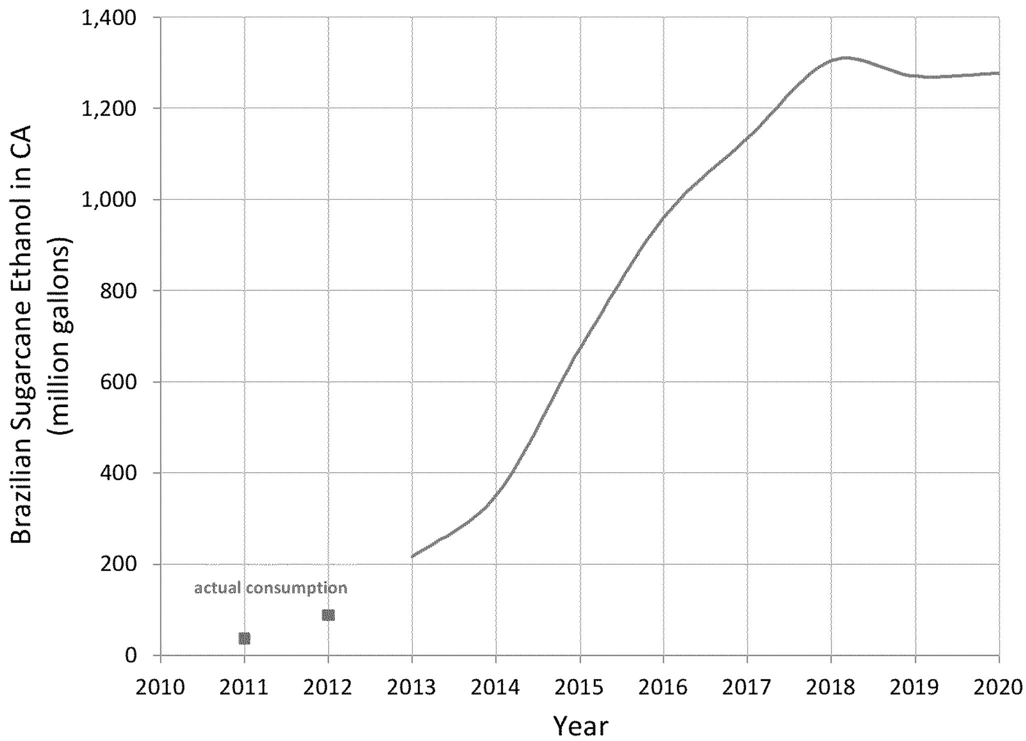
Exhibit 41. OECD forecast of Brazil's production, consumption and net export of ethanol



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Production	7,284	5,997	6,805	7,495	8,294	9,111	9,896	10,932	11,408	11,987	12,695
Consumption	6,795	5,796	6,440	7,061	7,590	7,761	7,972	8,661	8,797	9,444	10,103
Net export	489	201	365	435	704	1,350	1,924	2,271	2,611	2,543	2,592

Based on fuel import data from the Energy Information Administration (EIA), about 37 million gallons of Brazilian sugarcane ethanol were imported to California in 2011; and ICF estimates 88 million gallons of imports in 2012. For the purposes of this analysis, we assume that about 50 percent of Brazilian sugarcane exports will be available to the California market – reaching a maximum of nearly 1.3 billion gallons by 2020 (as shown in Exhibit 42 below)

Exhibit 42. Forecasted availability of Brazilian sugarcane ethanol in California (million gallons)



Source: OECD, ICF Analysis

Demand for Brazilian sugarcane ethanol in other markets with biofuels policies will limit the potential consumption in California. Most notably, the European Commission (EC) issued the Fuel Quality Directive (FQD), which requires a 6 percent reduction in the lifecycle carbon intensity of transportation fuels. The European Commission also has issued the Renewable Energy Directive (RED), which requires 10 percent renewable energy consumption in the transportation fuels market by 2020. Brazilian sugarcane ethanol is likely to play a significant role towards compliance with both of these directives. For instance, based on forecasts from the European Commission, some scenarios have as much as 1.5 billion gallons (5.9 billion liters) of sugarcane ethanol imported to the European Union by 2020 to help comply with the FQD.

There are barriers, however, to the European market that make the US market potentially more promising for ethanol producers in Brazil: Firstly, there is a tariff on ethanol imports into the EU of about 53 cents per gallon.[27] – considerably higher than the ad valorem tax (2.5 percent) that is imposed in the US, which is about 7 cents per gallon..[28] Secondly, ICF estimates that the transports costs to the US will continue to be cheaper than those same costs to the EU.

[27] The tariff is €0.102 per liter and was converted using current exchange rates for illustrative purposes.
[28] The ad valorem tax is applied at 2.5percent of the value of the imported product, so the tax paid will fluctuate as a function of ethanol prices paid FOB Santos. The 7 cents per gallon is an average based on data from 2010-2012.

GHG abatement

The GHG abatement potential of Brazilian sugarcane ethanol is significant. Even with an ILUC adder of 46 g/MJ to its carbon intensity, the pathways for Brazilian sugarcane ethanol range from 58-79 g/MJ. This is one of the major drivers for Brazilian sugarcane ethanol imports to California because it is one of the most cost-effective compliance pathways for refiners. Furthermore, the carbon intensity of the sugarcane ethanol only stands to improve moving forward: By 2014, sugarcane producers in Sao Paolo, for instance, will be required to switch from manual harvesting to mechanized harvesting – a process that reduces local air pollution (the fields are burned before manual harvesting) and reduces the average carbon intensity from 73 g/MJ to 58 g/MJ.

Cellulosic ethanol

Production

Production technologies for cellulosic ethanol are still under development. Several companies across the U.S. have developed demonstration plants, utilizing various technologies, which began operation as early as 2009. Moreover, several commercial-scale cellulosic ethanol plants are currently under construction with start-up dates as early as 2013. Although there has been progress in the development of cellulosic ethanol production, there are no commercial-scale plants currently operating in the U.S., and those under construction have faced significant delays since their initial public announcements. Not having a sufficient production track record remains to be the main commercialization challenge with cellulosic ethanol.

The amount of available feedstock may be a limiting factor in the production of cellulosic ethanol. In the U.S., corn is grown almost exclusively in the Midwest. The most recent Agricultural Census (2007) estimated the amount of cropland (the sum of land used for crops, idle land, and pasture available in the U.S.) to be 406 million acres..[29] Cropland acreage has been declining for the past 50 years since the land is being used for other developments. If th3e decline continues, the shortage of available cropland may be a constraint because feedstocks such as corn stover may not match its own demand from the cellulosic ethanol production facilities.

Delivery to California

There is already a supply infrastructure in place for cellulosic ethanol to be delivered to California. Although liquids are most economically transported over long distances through pipelines, due to the chemical properties of ethanol, this can be very difficult. First, special additives are required to prevent ethanol from corroding and cracking steel pipes. Second, water can seep into pipelines and get absorbed by the ethanol, which leads to fuel contamination. This problem can be eliminated by introducing dedicated pipeline infrastructure for ethanol; however, the costs of a parallel ethanol pipeline infrastructure would be high.

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[29] U.S. Department of Agriculture, 2007 Census of Agriculture (Washington, DC, June 2009), Vol. 1, Chapter 1, "U.S. National Level Data," Table 8, "Land: 2007 and 2002," web site http://www.agcensus.usda.gov/Publications/2007/Full_Report/Volume_1,_Chapter_1_US/st99_1_008_008.pdf

Furthermore, the current volumes of ethanol consumed do not warrant the level of investment that would be required to develop a dedicated pipeline for distribution. These technological and cost barriers result in higher transportation costs such as marine, railroad, and truck transport are relied upon instead. These alternative transportation modes need to have storage tanks that are made of biofuel-compatible materials in order to transport large volumes of biofuels to market. All of these options are commonplace today as a result of the expansion of the market for ethanol as an oxygenator in reformulated gasoline. In principle, cellulosic ethanol can simply replace the corn ethanol that is currently shipped to California for blending into gasoline. Today, many of the cellulosic ethanol production facilities under construction are mostly located in the Midwest (cropland for growing corn; with corn stover as a potential feedstock for cellulosic ethanol) and South regions of the U.S.

Because the cellulosic ethanol industry is not mature, it is difficult to determine if cellulosic ethanol producers will be able to use the existing infrastructure for ethanol delivery to California. Similar to corn ethanol and sugarcane ethanol, producers are highly sensitive to the proximity of feedstocks for ethanol production. As such, the delivery of the fuel to California will largely be dependent on where cellulosic ethanol production facilities will be deployed.

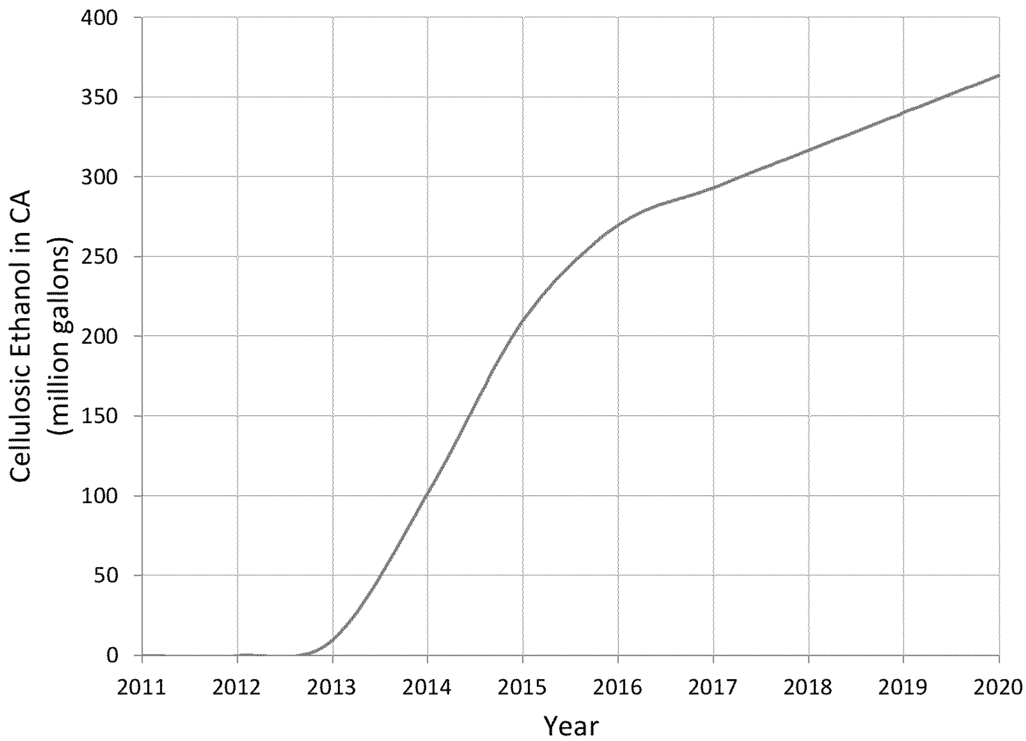
Potential Consumption in California

The scaling of production capacity of cellulosic ethanol to commercial scale was based on data from a recent market assessment conducted by Environmental Entrepreneurs (E2) and data from the EIA. Most cellulosic ethanol plants are outside of California; therefore, assumptions were made about the percent of the production capacity that would be available to California refineries considering proximity to a cost-effective distribution infrastructure (e.g., rail) and other regulatory drivers (e.g., RFS2).

E2 identified 27 facilities that are in some advanced stage of financing. These facilities – if completed as announced – would have a combined production capacity of more than 325 million gallons. E2 also identified another 14 demonstration facilities with stated production capacity of 10 million gallons. The uncertainty with respect to the number of facilities that complete for financing, along with technology driven delays cast considerable doubt regarding the likely production availability of cellulosic ethanol. There is also uncertainty regarding deliveries to the California market, primarily based on the location of the facilities. For instance, US EnviroFuels is building a facility in Highlands, Florida – it is unlikely that this fuel will be shipped to California, even with an LCFS-driven price premium. For the purposes of this analysis, about 50 percent of the projected volume in 2015 is expected to be available to California.

The estimated maximum consumption of cellulosic ethanol in California is shown in Exhibit 43 below.

Exhibit 43. Estimated Maximum Annual Consumption of Cellulosic Ethanol in California (million gallons)



Source: E2, CEC, EPA, ICF Analysis

GHG abatement

Cellulosic ethanol has the highest GHG abatement potential of the feedstocks for ethanol considered in this analysis. The primary reason for this is because cellulosic ethanol is generally derived from waste products or another feedstock (e.g., energy grasses) which will not have ILUC emissions. There are no approved CARB pathways for cellulosic ethanol; however, based on work presented by CEC and CARB, ICF estimated a carbon intensity of 29 g/MJ.

High-level blends, E85

Production

The ethanol used in E85 is produced via the same methodologies outlined in the previous subsections.

Delivery to California

E85 requires delivery via rail to California and then trucks to local retail stations because the fuel cannot be shipped via pipeline; as outlined previously, there are a variety of technical issues that preclude existing pipelines from using E85.

Potential Consumption in California

E85 is consumed in FFVs. Today, the CEC reports that there are about 450,000 FFVs on California roads. However, because the vehicles have bi-fuel capabilities and E85 is not available ubiquitously, consumption in California is currently limited. The CEC reports consumption of about 11-12 million gallons in California over the past couple of years.

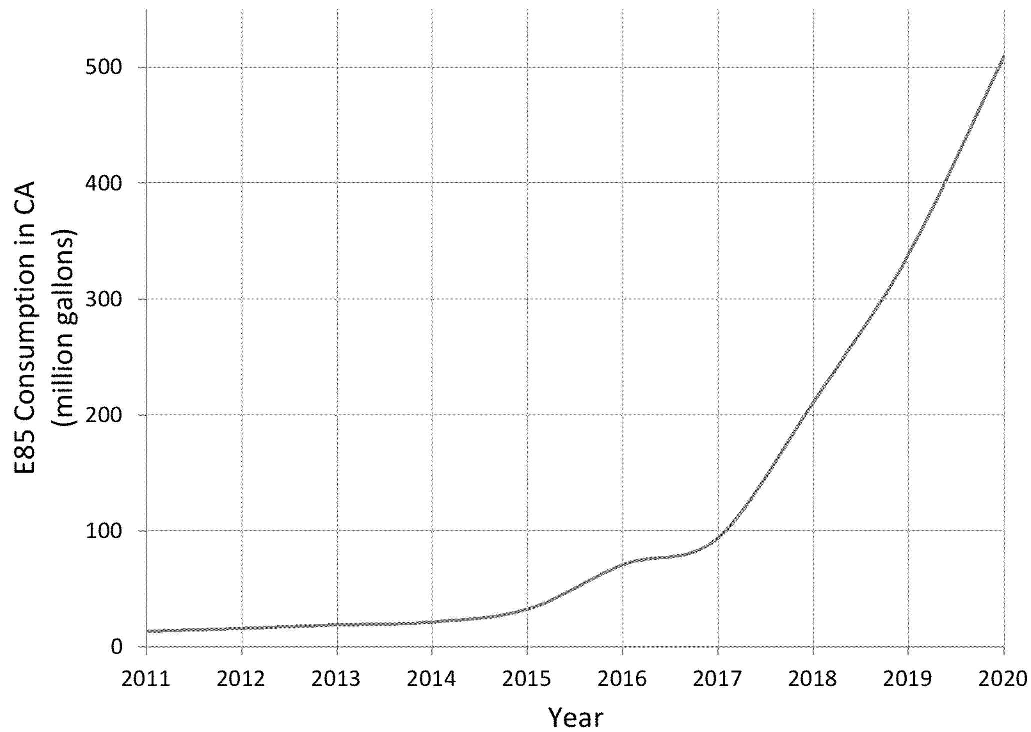
The potential consumption of E85 is limited by the a) the deployment of refueling infrastructure, b) the deployment of sufficient FFVs, and c) the price differential between E85 and gasoline.

- E85 refueling infrastructure. ICF research indicates that as many as 40 percent of refueling sites in California can be retrofitted with E85 pumps. This retrofit requires the introduction of a new underground storage tank for ethanol, the pumps, dispensers, monitoring equipment, lines from the tank to the fuel dispenser, and the electronics that enable credit card purchasing. This expansion, however, has already started with around 60 stations available today and another 80 stations to be deployed over the next 2-3 years as part of a grant from the CEC awarded to Propel. Outside of retrofits, E85 infrastructure can be deployed as standalone fueling islands, similar to gasoline fueling stations.
- FFV deployment. There are between 400,000 and 500,000 FFVs on the road today. This level of deployment indicates that theoretical consumption would peak around 190 to 240 million gallons.
  - Although the cost of FFVs is not a barrier – most industry estimates place the additional cost of manufacturing a FFV around $50-100 per vehicle – there is not a strong incentive for automobile manufacturers to make FFVs. Today, automobile manufacturers receive CAFE credits for deploying FFVs, so they typically absorb the additional cost. In other words, consumers do not see an increase in vehicle pricing. This CAFE credit has been the primary driver of FFVs to date; the fuel economy program has evolved into a GHG emissions standards program. After 2015, OEMs will need to demonstrate that an alternative fuel is actually being used in the FFVs to earn credits towards the GHG emissions standards. Although this is a barrier, the pathways for demonstrating E85 use are not prohibitively difficult given the potential for E85 in the California market.
  - Based on light-duty vehicle sales from 2012 reported by the California New Car Dealers Association (CNCDA), about 115,000-130,000 vehicles sold in California have FFV options. This does not mean that all of these vehicles sold were FFVs; rather, they had FFV models available. This represents about 8-10 percent of the market for light-duty vehicles and highlights one of the major challenges facing the E85 market: Of the top 10 top selling light-duty vehicles in California – Toyota Prius, Honda Civic, Toyota Camry, Honda Accord, Toyota Corolla, Honda CRV, the Ford F-Series, Nissan Altima, Hyundai Sonata, and Toyota Tacoma – only the Ford F-Series offers a FFV model. These 10 models account for nearly 25 percent of the market, and only 7 percent of those sales (or 2 percent of the entire market) has an FFV alternative.
- Pricing for E85 and gasoline. The pricing between E85 and gasoline is a complicated market dynamic because ethanol is also used at a rate of 10 percent in gasoline. As a result, there are two markets for ethanol producers – the low- and high-level blend markets. In order for

E85 to compete with gasoline, it has to be priced lower because it has less energy per gallon of fuel. In principle, a carbon market should help decouple the market for ethanol in a low level blend and high level blend. This dynamic is explore further in the results and discussion.

ICF used a forecasted E85 consumption scenario from the CEC as an upper limit for the modeling exercise, as shown in the figure below.

Exhibit 44. Estimated maximum consumption of E85 in California



Source: CEC, ICF analysis

GHG Abatement

As noted in previous subsections, the GHG abatement potential of ethanol is linked to the feedstock and the ILUC emissions factor. One of the advantages of the E85 market is that the reductions are not limited by the 10 percent blend wall. For illustrative purposes, consider a gallon of ethanol blended into gasoline and another gallon of ethanol blended into E85. The benefits of the gallon of ethanol blended into gasoline are spread out over 10 gallons of final product; whereas in the case of E85, 85 percent of the GHG reduction benefit is realized. The E85 market has significant GHG abatement potential; however, in the 2020 timeframe, it will be limited.

Biodiesel and Renewable Diesel

Biodiesel is a fatty acid methyl ester (FAME) that can be synthesized from vegetable oils, waste oils, fats, and grease. Renewable diesel is generally produced by upgrading FAME via hydrogenation to a product that meets the same ASTM standards as conventional diesel.

Biodiesel is generally used in low-level blends: biodiesel blended in at 5 percent by volume is considered the same as diesel and biodiesel blended at 20 percent by volume is the upper limit of blending for the majority of transportation applications due to vehicle warranty. Renewable diesel, however, is interchangeable with conventional diesel and does not have any blending limitations – it can be transported via pipeline, stored in the same facilities as diesel, and used without volume constraints in vehicle applications.

The following feedstocks for biodiesel were considered in our analysis:

- Soybeans,
- Corn oil, and
- Fats, Oils, and Greases (FOGs)

For renewable diesel, we considered the following feedstocks:

- FOGs, and
- Cellulosic materials or waste.

Biodiesel, Soy

Production

Currently, soybean oil is the primary feedstock for the majority of biodiesel produced in the United States. It is a well-established crop with a robust commodity market. Most biodiesel facilities that use soybeans as a feedstock are located in the Midwest, with similar growing conditions for corn.

Delivery to California

Biodiesel infrastructure requirements are similar to those of ethanol in that the fuel must be transported from production sites (inside and outside of California) to redistribution hubs via rail, truck, and marine vessels. After arriving in California, the biodiesel then moves to distribution terminals for blending with diesel before distribution to retail locations. Expansion of the biodiesel distribution infrastructure has moved at a much slower pace than that of ethanol, given the significantly lower demand levels.

Biodiesel is blended with diesel fuels in tanker trucks before delivery to retail service stations. Before blending, biodiesel must be stored in separate tanks. Few distribution terminals in California have biodiesel storage capabilities, largely due to low demand.

Potential Consumption in California

There is very limited consumption of biodiesel in California today (about 15-20 million gallons in 2012). California's biodiesel infrastructure is inadequate to meet increased biodiesel demand, even at B5 levels. With regard to storage, new storage tanks will be needed in most cases, with tanks requiring 12-18 months for permitting. Retrofitting existing storage tanks can lower costs and time required, though most existing storage is already in use, so this is not an option for most terminals.[30]

There are some air quality concerns at the higher rates of biodiesel blending; however, we do not consider these a barrier in this analysis. Biodiesel has a higher cetane number than diesel, which means that it burns at higher temperatures. Higher temperatures during combustion increase the formation of nitrogen oxides (NOx). NOx is a precursor to ozone formation and secondary particulate matter (PM) formation. The regions in California that have high ozone concentrations (one of the primary indicators of poor air quality) are generally considered NOx-limited, which means that NOx emissions drive ozone formation. In areas such as the South Coast Air Basin, biodiesel is not used in significant quantities because of these concerns.

The amount of soy-based biodiesel that could be consumed in California was not constrained in the model because the production capacity of plants in the US – upwards of 2 billion gallons – is sufficient to meet a significant increase in demand in California.

GHG abatement

The GHG abatement potential of soy-based biodiesel is limited because of ILUC emissions attributable to soy. Soybeans currently have an ILUC carbon intensity of 62 g/MJ, bringing the total carbon intensity of the product to 83 g/MJ. Despite its limited abatement potential, the availability of soy-based biodiesel makes it a potentially attractive compliance option for the LCFS; particularly if there are limitations on biodiesel produced from other feedstocks.

Biodiesel, Corn Oil

Production

Corn oil is a relatively small, but growing, feedstock for the biodiesel industry. As recently as 2010, about 10 percent of biodiesel produced in the US was produced using corn oil. The majority of corn oil predicted for future biodiesel production comes from non-edible oils extracted from distillers' grains in the ethanol production process. Corn oil extraction is a relatively new commodity for the majority of ethanol production facilities, but represents another high-value co-product. Corn oil is a byproduct of corn ethanol production and generally requires retrofitting an ethanol plant. However, anecdotal evidence suggests the payback on the equipment – reflecting the capital investment and current market prices for corn oil – is less than two years.

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[30] California Energy Commission (CEC). "Transportation Energy Forecasts and Analyses for the 2011 Integrated Energy Policy Report." CEC, August 2011: Sacramento, CA. Pp. 174-175. Available at: http://www.arb.ca.gov/msprog/clean_cars/clean_cars_ab1085/cec-600-2011-007-sd.pdf

Delivery to California

Corn oil-based biodiesel is delivered to California in the same way that soy-based biodiesel is: via rail and truck. The biodiesel can also be delivered as B5 via pipeline.

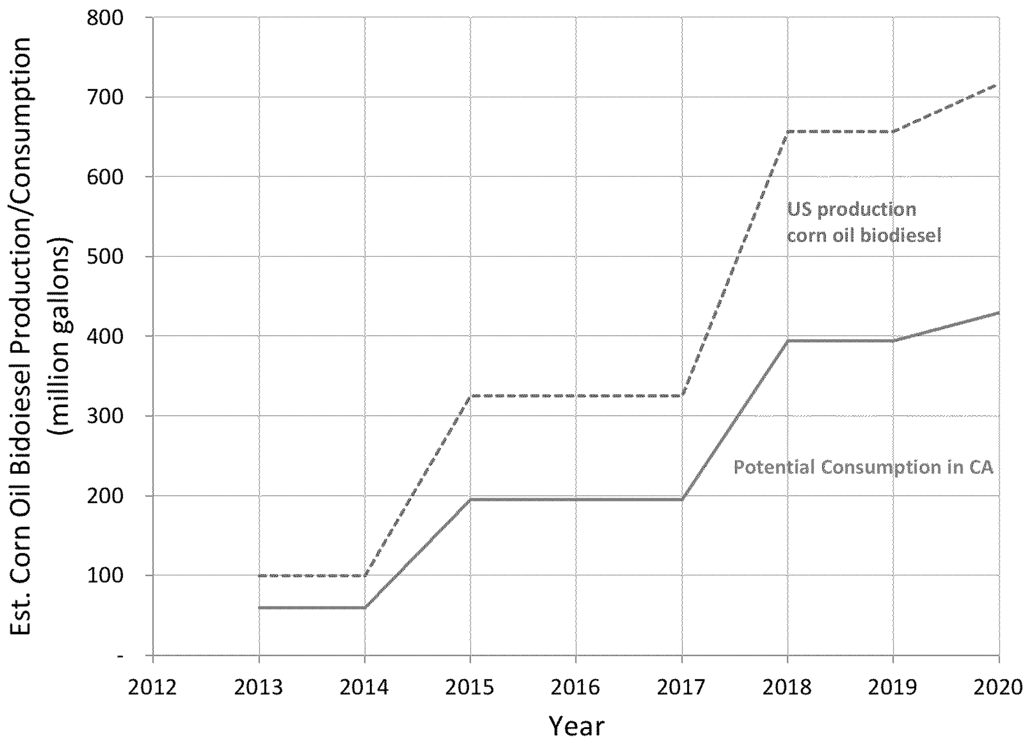
Potential Consumption in California

By the end of 2011, approximately 40 percent of ethanol production facilities in the US had corn oil extraction in place, and this likely increased further in 2012. ICF research indicates that nearly every corn ethanol production facility that can be retrofitted for corn oil extraction will have done so by the end of 2014. For example, Pacific Ethanol announced plans in November 2012 to install a corn oil extraction system at its Stockton, California plant. With a carbon intensity of just 4 g/MJ, biodiesel from corn oil is likely to be a major compliance pathway for LCFS.

The nationwide potential for corn oil is significant: with a yield of approximately 5-7 gallons of corn oil per 100 gallons of corn ethanol, the upper limit of nationwide production is 0.9-1.05 billion gallons. We estimate a lower volume of corn oil-based biodiesel production based on research from the EIA, reaching a peak of about 720 million gallons in 2020 (see Exhibit 45 below). Furthermore, we assume that about 60 percent of this will be available to California based on the LCFS as a significant driver and based on the anticipated location of production facilities that will process corn oil into biodiesel for rail shipment to California. California already imports a significant amount of ethanol via rail –more than 1 billion gallons annually – and we anticipate that this transportation infrastructure will support significant volumes of corn oil based biodiesel.

It is possible that we have over-stated the maximum capacity of biodiesel production using corn oil as a feedstock. For instance, one could make the argument that existing corn ethanol production facilities will switch feedstocks or modify to a cellulosic feedstock. The potential for feedstock switching or major production processing modifications cannot be predicted with good certainty today. Given the opportunity for corn ethanol facilities to produce a high value byproduct, they can improve the economics of their facilities – this opportunity is well understood today and anecdotal evidence from various industry stakeholders indicate significant shifts towards corn oil extraction for biodiesel production. And given the value of corn oil in the California market with such a low carbon intensity – of which there is currently no parallel at the national or other state level – it is feasible to assume that a significant percentage of the fuel will end up in the California market.

Exhibit 45. Estimated corn oil based biodiesel production in the US and consumption in California



GHG abatement

Corn oil based biodiesel has the highest GHG abatement potential of fuels considered in our analysis. With a carbon intensity of 4 g/MJ and no ILUC emissions – which are attributed to corn ethanol and not corn oil because corn oil is a byproduct of corn ethanol production – it is currently the lowest carbon fuel in the official CARB look-up tables. With such low levels of biodiesel consumption in California today – less than 20 million gallons annually for the last several years – a transition to B5, with corn oil based biodiesel blended exclusively for illustrative purposes, this is effectively a 4.8 percent reduction in the carbon intensity of diesel fuel, about half-way to 2020 compliance. And this only represents about 165-195 million gallons of corn oil based biodiesel being blended into conventional diesel. Assuming that corn oil based biodiesel is blended in at a rate of 20 percent with conventional diesel, then this represents a 19.2 percent reduction in carbon intensity in the diesel sector by 2020. Although these volumes are likely unachievable in the near-term, it demonstrates the GHG abatement potential of corn oil based biodiesel.

Biodiesel, FOGs

Production

Fats, oils, and greases are used to produce biodiesel in the same way that biodiesel and corn oil are used to produce biodiesel.

Delivery to California

FOGs-based biodiesel is delivered to California in the same way that other biodiesel products are delivered: via rail and truck. The biodiesel can also be delivered as B5 via pipeline. Many production facilities in California produce biodiesel from FOGs, so local distribution is typically done via truck.

Potential Consumption in California

About 15 million gallons of biodiesel from FOGs have been consumed over the past two (2) years in California. California has a production capacity of about 60 million gallons per year, with most of that coming from waste feedstocks. We estimate that the US has a production capacity around 350 million gallons of FOG-based biodiesel; however, not all of this will be accessible to California because the feedstock is much more dispersed than corn oil or soybeans, for instance. For this analysis, we assumed that 30 percent of the production capacity of FOG-based biodiesel would be available in California. The potential consumption of FOG-based biodiesel is discussed in more detail below in the consideration of renewable diesel.

GHG abatement

The GHG abatement potential of FOG-based biodiesel is high because FOGs are effectively waste products. The finished fuel has a carbon intensity of 15 g/MJ and there are no ILUC emissions. The major limitation for GHG abatement from FOG-based biodiesel is the limited production capacity due to limited feedstocks.

Renewable Diesel, Waste

Production

There are several types of renewable diesel. For instance, upgrading conventional biodiesel (FAME, as noted previously) via hydrogenation yields renewable diesel. In terms of chemical and physical properties, renewable diesel is similar to biodiesel, however, it meets the same ASTM[31] standards as conventional petroleum-based. The ASTM standards impact how the fuel can be transported, stored, and combusted. In the case of renewable diesel, because it meets the same ASTM standards as conventional diesel, it is not subject to the same infrastructure or vehicle limitations (i.e., it does not have a higher cetane number). In other words, renewable diesel is a drop-in replacement for petroleum-based diesel and therefore has a ready market. The largest constraint will be on the availability of renewable diesel. Since renewable diesel can be converted into jet fuel (unlike biodiesel) and bio-based chemicals, such as naptha, it is likely there will be competition for the fuel from other markets, which may be more profitable than the transportation fuels market.

Despite several major renewable diesel production companies being headquartered in California (e.g., Solazyme and Rentech), it is unclear how many production facilities will be

[31] ASTM, formerly the American Society for Testing and Materials, develops international standards for materials, products, systems, and services used in construction, manufacturing, and transportation.

located in the state in the future. Renewable diesel is considered a new advanced biofuel technology with a number of technical and economic constraints. Feedstock supply chain development will be the most significant technical constraint for renewable diesel over the next few years. To date, the majority of renewable diesel companies have co-located production facilities with readily available sources of feedstock, such as the Dynamic Fuels renewable diesel facility in Louisiana - a joint venture between Tyson Foods and Syntroleum.[32] Other production facilities generate their own sources of feedstock onsite, such as Solazyme, which converts plant sugars into oils by feeding the sugars to microalgae at several sites, including its first commercial production facility in Illinois.[33] As the industry develops, feedstock logistics will become more challenging, particularly for new feedstocks, such as energy grasses and algae oils, which do not have commodity markets or traditional supply chains.

Delivery to California

As noted elsewhere, renewable diesel will be transported via pipeline or tanker (if it is being imported). In either case, the infrastructure to support delivery of renewable diesel to California is sufficient for significant expansion should the product become available in larger volumes.

Potential Consumption in California

We estimate that 25 percent of estimated production capacity of renewable diesel will be available to California. Because there are no infrastructure constraints on renewable diesel, this is likely a conservative estimate; however, it is unclear how renewable diesel will be tracked when shipped via pipeline or the distances that producers will be willing to send renewable diesel via pipeline (because of the increased cost).

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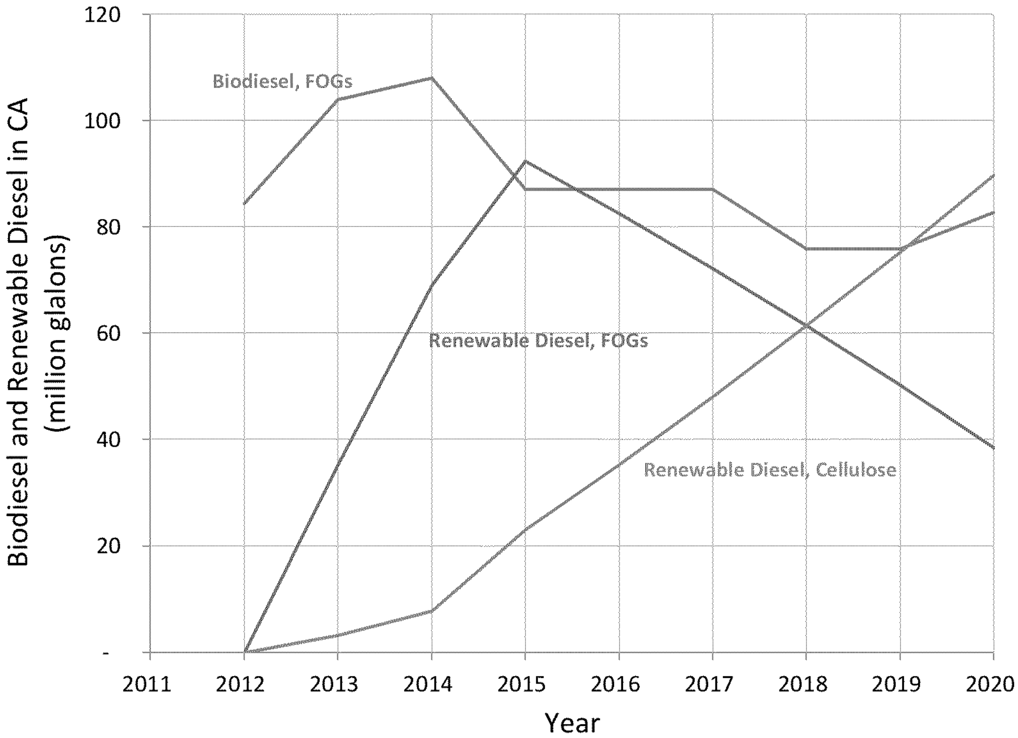
[32] Syntroleum, http://www.syntroleum.com.

[33] Solazyme, "Solazyme Announces Successful Commissioning of Integrated Renewable Oil Production Biorefinery in Peoria, Illinois," June 29, 2012 http://solazyme.com/media/2012-06-29.

Exhibit 46. Estimated Consumption of Biodiesel and Renewable Diesel from Waste Sources in California



The potential consumption of FOG-based biodiesel, renewable diesel and cellulosic diesel are shown in the figure above. The trends highlight the links between these markets. Firstly, we predict a shift in FOG-based biodiesel consumption towards renewable diesel consumption in the next 2-3 years, yielding the upward trend of renewable diesel (red line) and the downward trend for biodiesel (blue line). Similarly, as the potential for cellulosic diesel from waste materials, energy grasses or other feedstocks increases domestically, there are two shifts in the market: The first is a stabilization of the amount of FOGs used for biodiesel production and the second is the decrease in FOGs used to produce renewable diesel.

GHG abatement

The GHG abatement potential for renewable diesel is limited primarily by the volumes that can be delivered to California. With an ILUC emissions factor (and no infrastructure constraints) a mature renewable diesel market will be very appealing to obligated parties under LCFS. The average carbon intensity of renewable diesel produced using FOGs is about 30 g/MJ. The CARB look-up tables do not currently include a pathway for renewable diesel. Based on estimates from the CEC and CARB, ICF used a carbon intensity of about 37 g/MJ for cellulosic diesel.

Natural gas

ICF included several forms of natural gas in our modeling exercise, including compressed natural gas (CNG), liquefied natural gas (LNG), and biomethane. These are each described in more detail below. In the case of CNG and LNG, the gas is delivered via an extensive pipeline transmission and distribution infrastructure and compressed or liquefied on-site. LNG is either liquefied on-site for refueling or delivered to a fueling facility via truck.

Compressed Natural Gas

Potential Consumption in California

CNG was considered in trucks in the medium-duty and heavy-duty market segments. Although some industry stakeholders have indicated that CNG has potential in the light-duty vehicle market, we did not include this in our analysis.

CNG has significant potential in medium-duty trucks, which typically run on gasoline. Medium-duty trucks are attractive as a CNG application because they average more than 15,000 vehicle miles traveled annually and the conversion costs for vehicles are becoming more cost competitive. With the differential between gasoline or diesel and CNG prices expected to increase over time, the potential fuel savings is very attractive for end users. New medium-duty trucks sales in California are substantial, with estimated annual sales of about 150,000 in 2012 and increasing to nearly 230,000 by 2020.

The marketplace is responding to this potential rapidly. Westport Innovations, for instance, has conversion kits for Ford's F series of medium-duty trucks at a retail price of $9,500. Wesport's WiNG technology is a bi-fuel system that has been demonstrated and deployed with success in the F-250 and F-350 models; and Westport recently announced that they are expanding the offering to the F-450 and F-550 trucks. At that price, many consumers will see a two-to-three year payback period.

ICF also considered the potential of CNG in 27 different types of light-, medium-, and heavy-heavy duty trucks in the HD module of EMFAC2011. Of those 27 vehicle categories, five were not considered because natural gas engines were considered under-powered and would not be able to satisfy the duty cycles of the vehicle application. For instance, CNG is not a good application for many heavy-duty construction vehicles. Agricultural applications were also excluded due to the lack of fueling infrastructure in these locations. For the remaining 18 vehicle categories, ICF considered the annual VMT, annual fuel use, and price differential between CNG and diesel to determine the potential market penetration of the vehicles.

Between the medium- and heavy-duty vehicle sectors, ICF estimates that the potential consumption of CNG in California may displace up to 600 million gallons of diesel and gasoline (combined) by 2020 using modest vehicle penetration rates.

GHG abatement

CNG has a carbon intensity of 68 g/MJ and is an attractive compliance option because of the strong interest in the fuel today. Although end users are driven by the potential savings on the costs of ownership, CNG vehicles in the medium- and heavy-duty sector yield GHG reductions of 23-31 percent depending on the application.

Liquefied Natural Gas

Potential Consumption in California

ICF considered LNG consumption in 27 different types of light-, medium-, and heavy-heavy duty trucks in the HD module of EMFAC2011. LNG is introduced in vehicles that have annual mileage greater than 85,000 miles, as these vehicles are assumed to be operating in a long-haul application which requires both greater range and the reduced payload of storing LNG on-board. To determine the potential consumption in California, ICF considered the annual VMT, annual fuel use, and price differential between LNG and diesel to determine the potential market penetration of the vehicles.

There are currently more than 800 LNG trucks operating at the San Pedro Bay Ports in Southern California, supported by about 10 refueling facilities in the region. Natural gas providers have responded to increasing interest in the market with significant plans to deploy fueling infrastructure in California and across the United States. Clean Energy has been particularly aggressive in the announcement of its planned America's Natural Gas Highway – a plan to deploy 150 LNG fueling facilities nationwide by the end of 2013, with 75 already built. Shell has also been aggressive in the LNG market, partnering with both fueling infrastructure providers and engine manufacturers.

By 2020, data from EMFAC2011 indicates that there will be more than 23,000 heavy-duty trucks operating at the San Pedro Bay Ports and Port of Oakland, increasing for an estimated 16,000 in 2011. Similarly, there are another 3,200 long-haul trucks from out-of-state estimated to be on the road by 2020, up from 50 in 2011. These trucks are heavy fuel users and travel many miles. ICF estimates that up to 160 million gallons of LNG will be consumed annually by 2020 in the heavy-duty trucking sector assuming modest penetration of LNG vehicles into these key market segments.

GHG abatement

The abatement potential of LNG is similar to CNG; however, it has a slightly higher carbon intensity due to the energy required for liquefaction. The carbon intensity of the fuel is 78 g/MJ. A significant portion of the increased carbon intensity of LNG compared to CNG is offset by the efficiency of LNG vehicles compared to CNG vehicles. Under the LCFS, LNG vehicles used in a compression ignition engine do not take an energy efficiency penalty.

Biomethane

Production

Biomethane can be derived from a variety of sources, including but not limited to waste resources such as from landfills, wastewater treatment plants, food processing waste, and manure (e.g., at dairy farms). Biomethane can also be derived from purpose grown energy crops, or agriculture and forestry residue. Biomethane is generally produced via anaerobic digestion, whereby microorganisms breakdown organic matter in the absence of oxygen.

Facilities that are interested in producing biomethane generally introduce an anaerobic digester and a collections system.

According to the CEC, more than 70 landfills, 23 wastewater treatment facilities, and more than 12 dairies in California have the capacity to capture biomethane and use it for electricity generation, heating, or alternative fuel production.

- Landfill gas: Californians produce more than 42 million tons of waste per year; landfills produce a significant amount of landfill gas, which is primarily methane. As a general rule of thumb, one pound of municipal solid waste can produce about 0.1 standard cubic foot (scf) of landfill gas annually. The landfill gas is produced naturally as a result of the conditions at the facility, but requires a collection system. The collection system at landfills typically consists of wells that have been drilled and connected via a self-contained pipeline system. The gas is saturated with water in the collection process; in the next step of processing, the gas is dewatered, at which point the gas can be used in some applications (e.g., reciprocating engine). However, in order to be used in a transportation application, the gas needs to be upgraded further by removing excess carbon dioxide and sulfur dioxide in a scrubbing process.
- Wastewater treatment plants: The Department of Energy estimates that 3,500 of the largest wastewater treatment plants in the country are using anaerobic digesters – for wastewater treatment plants, the digesters help manage the levels of sludge significantly. In about half of the cases, the gas is captured and simply burned; however, in other cases, wastewater treatment facilities co-digest the sludge with organic wastes to produce a higher quality, higher energy content fuel. Plants that capture the higher quality methane typically combust it in an on-site combined heat and power (CHP) application. For every 100 gallons of wastewater, a plant has the potential to generate about 1 scf per day of biomethane.
- Dairy digesters: California is the largest dairy state in the US, with nearly 2 million cows collectively producing over 20,000 pounds of milk annually. The cows produce nearly 4 million bone dry tons of manure which requires careful management. The anaerobic digestion of waste and production of biomethane occurs naturally at covered piles or lagoons; introducing a digester and collection system enables the dairy to produce and capture biomethane. Most dairies use the capture biomethane on site and burn it to make electricity. The upgrading process is similar to the process for landfill gas: waste, sulfur-containing compounds (hydrogen sulfide), and water are removed.
- Municipal solid waste: Like landfilling, a municipal solid waste stream, especially those rich in organic materials, has the potential to generate a significant amount of biomethane. The EPA estimates that 25-33 percent of biomethane potential is lost at landfills as a result of the lag time between garbage disposal and the time that a collection system is operational; in the interim, the organic waste begins to decompose and emit methane.

Delivery to California

Biomethane can either be produced in California or injected into the natural gas pipeline outside of California and delivered via an energy provider.

Sourcing biomethane in California is potentially attractive; however, there are several challenges and barriers. Depending on the location of biomethane production facilities, it is conceivable that a dedicated pipeline would need to be constructed. This would cost about $100,000-$200,000 per mile.

There are currently policy constraints which prohibit the injection of biomethane captured from landfills into California pipelines; however, recent legislation (Assembly Bill 1900) requires the CPUC, CEC, and CARB to set standards for biomethane injection into the pipeline by the end of 2013.

Potential Consumption in California

The University of California, Davis has estimated that the theoretical potential of biomethane production in the entire state is 125 billion scf/year; however, the technical potential is a more modest 23 billion scf/year, equivalent to nearly 170 million dge. However, nearly two thirds of that potential (14 billion scf/year) is attributable to dairy waste in the state that is isolated from pipelines and other cost-effective delivery mechanisms.

ICF used an upper estimate of 15 million dge of biomethane production for transportation applications.

GHG abatement

The GHG abatement potential of biomethane is one of the primary drivers for interest in the fuel today: It has a carbon intensity of 11 g/MJ. With many industry observers expecting an expansion of natural gas consumption in the transportation sector, the medium- to long-term potential for biomethane is significant.

Plug-in Electric Vehicles

Plug-in electric vehicles include plug-in hybrid electric vehicles (PHEVs) and battery electric vehicles (BEVs). In both cases, vehicles are capable of being plugged into the electrical grid to power an onboard battery that is used in some capacity to propel the vehicle. For the purposes of this section, we did not include a discussion of electricity production or delivery to California. In the following subsections we address the potential consumption and GHG abatement of electricity used as a transportation fuel in PHEVs and BEVs.

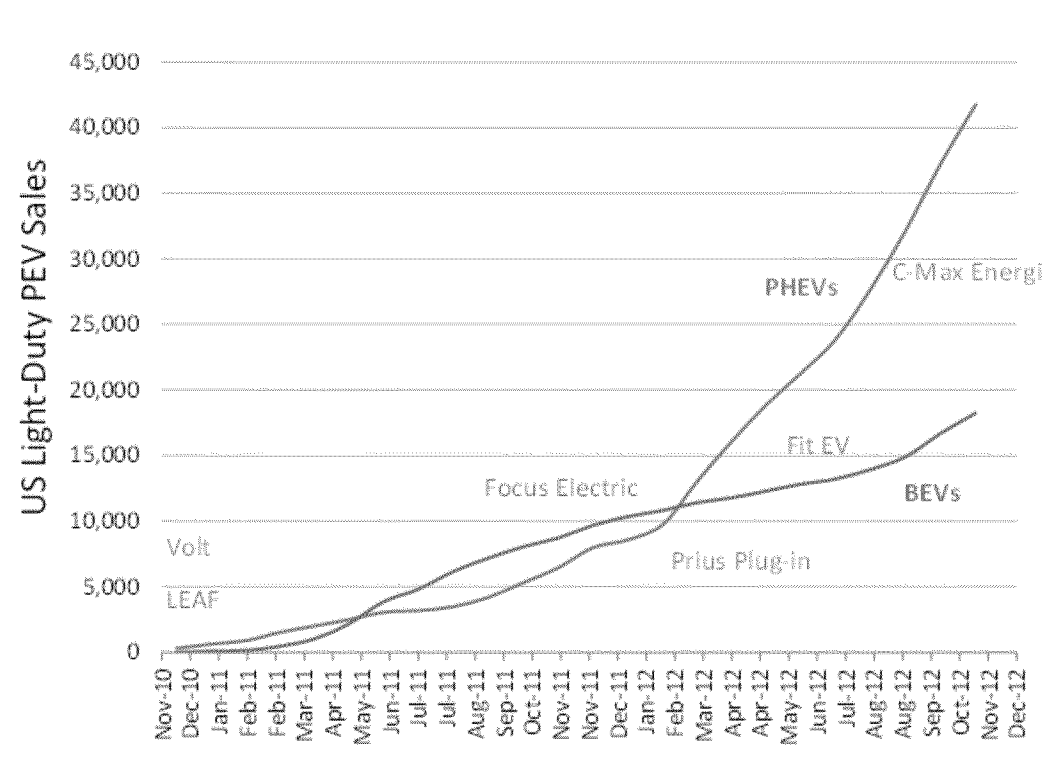
Plug-in Hybrid Electric Vehicles

Potential Consumption in California

The analysis considered PHEVs with a 10-, 20-, and 40-mile all-electric range in the light-duty sector. The percentages of electric VMT were based on assumptions from CARB and data presented by The EV Project.

As of February 2012, PHEVs have out-sold BEVs by a considerable margin nationwide (see the figure below). Based on announced model releases, ICF anticipates that PHEVs will continue to out-sell BEVs for the foreseeable future (e.g., to 2020 and beyond).

Exhibit 47. Cumulative Light-duty PEV Sales in the US



Note: the vehicle make and models listed in the graph indicate availability, not sales of that make/model.

For the purposes of this analysis, PHEVs were deployed at a baseline level consistent with CARB's most likely compliance scenario included in ZEV rulemaking process. This yields about 350,000 PHEVs on the road by 2020. Any additional PHEVs deployed in the market will likely be the result of aggressive vehicle pricing from automobile manufacturers as part of a compliance strategy with increasingly stringent tailpipe GHG standards.

GHG abatement

After accounting for the efficiency of electric vehicles, electricity has a carbon intensity of 31 g/MJ using the carbon intensity of marginal electricity generation in California, or about 30 percent of the carbon intensity of conventional gasoline.

The GHG abatement of electricity used in PHEVs is largely dependent on the travel behavior of drivers and the availability of charging infrastructure at retail locations, workplaces, and other commonly visited areas where charging may occur. For the purposes of this analysis, ICF assumed that drivers of PHEVs were able to travel on electricity 15 percent, 30 percent, and 60 percent of the time for PHEV10, PHEV20 and PHEV40. These values were increased slightly on an annual basis assuming modest investments in publicly available charging infrastructure.

Battery Electric Vehicles

Potential Consumption in California

Battery electric vehicles (BEVs) were introduced as part of the most likely compliance scenario presented by CARB as part of the Advanced Clean Cars Program. The scenario yields slightly more than 120,000 vehicles on the road by 2020. The charging profiles for BEVs were derived using data from The EV Project.

GHG abatement

As noted previously, the abatement potential of electricity is significant. However, the abatement potential for battery electric vehicles is limited in the timeframe of this analysis due to low penetration rates attributable to high upfront vehicles costs. The other current limitation on the GHG abatement of BEVs is their range; ICF assumed that BEVs traveled fewer miles than conventional gasoline vehicles because of range issues, thereby limiting the GHG abatement potential.

Infrastructure for PEVs

We assumed about 50 percent of PHEV buyers would install Level 2 EVSE. Chevrolet has reported in a variety of forums that about 50 percent of Volt drivers are opting for Level 1 charging. There are not many factors that will increase the cost of using Level 1 charging, unless a separate meter is required in order to take advantage of special PEV utility rates.

Most PEV manufacturers have partnered with suppliers to install Level 2 EVSE. For example, GM partnered with SPX, which sells EVSE from $490 to over $1,000. Nissan and Mitsubishi partnered with AeroVironment, which sells EVSE for about $1,100. Toyota partnered with Leviton, which sells EVSE from about $1,000. Retailers, such as Best Buy and Home Depot, sell Level 2 EVSE ranging from $750 to $1,000. Other suppliers sell EVSE well above $5,000,[34] but for the purposes of this analysis, a high estimate of $2,350 was used for Level 2 EVSE.

The range of installations costs is shown in the table below and reflects the hours required from a professional electrician at an estimated hourly rate of approximately $75 per hour. The number of hours worked depends on the level of difficulty to install the infrastructure. A new circuit box, conduit to the garage, and networking capabilities of the EVSE could increase the total costs of installation closer to $2,500.

[34] Plug-In America, "How Will You Charge Your Ride?" accessed November 14, 2012, http://www.pluginamerica.org/accessory-tracker?type=All&level=2&nrtl=All.

Exhibit 48. Estimated Level 2 EVSE costs at a single-family Home with dedicated parking

Cost Element	Low Estimate	High Estimate
Hardware	$500	$1,100
Permitting	$100	$250
Installation	$300	$1,000
Total	**$900**	**$2,350**

The installation of Level 1 EVSE at a MDU or workplace will likely require more equipment than an extension cord so an employer will likely need to meter electrical usage. If an employer choses to charge employees for EVSE use, AeroVironment estimates potential revenue of $520-838 per year per port, which could be a significant means of recouping installation costs.[35] The installation costs are much higher than for an installation at a single-family home because an office parking lot or garage may only have minimal wiring for lighting. The management or employer may elect to install multiple ports at the same time in which case the circuitry needs to be replaced and conduit laid to an area dedicated to PEV parking spots. Based on discussions with manufacturers and review of product literature, in addition to adding conduit, the trenching and concrete costs are necessary for signage, structure, access, and safety provisions.

A recent study by AeroVironment[36] notes the economics of workplace charging is more comparable to multi-family (or multi-dwelling units, MDU) charging than to single-family home charging because employers or building management are more likely to own the EVSE than the employees or tenants. Also, tenants and employees are more likely to be responsible for the operational costs. As a result, MDU and workplace charging will be discussed together. The table below summarizes the costs of MDU and workplace charging for Level 1 EVSE and Level 2 EVSE.

[35] Botsford, Charles, "The Economics of Non-Residential Level 2 EVSE Charging Infrastructure," pg. 5, accessed November 21, 2012, http://www.e-mobile.ch/pdf/2012/Economics_of_non-residential_charging_infrastructure_Charles-Botsford-EVS26.pdf.
[36] C. Botsford, "The Economics of Non-Residential Level 2 EVSE Charging Infrastructure," EVS26, Los Angeles CA, 2012.

Exhibit 49. Estimated costs for MDU and Workplace EVSE Installations.[37]

Cost Element	Level 1		Level 2		DC fast charge	
	Low	High	Low	High	Low	High
Hardware	$200	$500	$500	$2,000	$10,000	$30,000
Permitting	$100	$500	$100	$1,000	$500	$1,000
Installation	$500	$5,000	$2,000	$6,000	$3,500	$6,000
Trenching /Concrete [a]	$3,000	$25,000	$3,000	$25,000	$3,000	$25,000
Total, installed [b]	**$3,800**	**$11,000**	**$5,600**	**$14,000**	**$17,000**	**$42,000**
Networking (annual)	$120	$300	$120	$300	$120	$300
Maintenance	$100		$100		$100	

[a] The high cost scenario does not assume a $25,000 cost associated with trenching and concrete because this inflates the costs significantly and is considered more of an outlier than a true indication of the high cost that might be expected. Rather,the project team used a trenching cost of $5,000.

[b] The total cost does not include the annual costs associated with networking. These are shown for illustrative purposes only.

- We assumed a mix of Level 1 and Level 2 EVSE at residences to support PHEVs and BEVs.
- For nonresidential charging – including opportunity charging and workplace charging – we assumed levels of deployment consistent with research conducted by EPRI..[38]
- For DC fast charging to support BEVs, EVSE were deployed at levels consistent with research conducted by UC Davis. This results in about 400-600 fast chargers .[39] at 200-300 locations around California.

Hydrogen Fuel Cell Vehicles

Fuel cell vehicles use electricity to power the wheels, however, rather than using electrical energy from a battery, the energy is produced using a fuel cell powered by hydrogen. The following sections review hydrogen production and the potential for fuel cell vehicles in California.

Production

Hydrogen is typically produced via steam reformation of methane or electrolysis of water, generating hydrogen and oxygen.

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[37] Electric Transportation Engineering Corporation, "Electric Vehicle Charging Infrastructure Deployment Guidelines for Greater San Diego," pgs. 55-58, May 2010.

[38] Bowermaster, Dan, "How Much Electric Vehicle Charging Is Needed? Data and Results of Supportive Charging," Electric Power Research Institute, presented at California Plug-in Electric Vehicle Collaborative Meeting, August 15, 2012.

[39] Nicholas, M; Tal, G; Woodjack, J; and Turrentine, T. Statewide Fast Charging Scenarios, presented at EVS26 in Los Angeles, CA, May 2012.Available online at: http://phev.ucdavis.edu/research/evs-26/EVS26%20-%20Nicholas.pdf

Delivery to California

Hydrogen is generally produced at a centralized location and either compressed or liquefied – similar to natural gas – for delivery to a hydrogen fueling stations. When hydrogen is compressed, it is delivered via specialized high-pressure tube trailers; when it is liquefied, it is transported via specialized tankers. Generally, it is more cost effective to ship hydrogen long distances in liquefied form. In the near-term, however, most hydrogen will likely be sourced within 100-200 miles of refueling stations, which is sufficient for delivery via high pressure tube trailers.

Potential Consumption in California

Hydrogen fuel cell vehicles (FCVs) were introduced as part of the most likely compliance scenario presented by CARB as part of the Advanced Clean Cars Program. The scenario yields slightly more than 25,000 vehicles on the road by 2020.

GHG abatement

Hydrogen as a transportation fuel has significant GHG abatement potential, with a carbon intensity of 57 g/MJ after accounting for the efficiency of hydrogen fuel cell vehicles. However, FCVs are not unlikely to be deployed at a level significant enough to have a material impact on GHG abatement for LCFS.

Credits from Alternative Fuel Consumption pre-LCFS

Alternative fuels used before the implementation of the regulation (in 2010) are not factored into the baseline carbon intensity. As a result, lower carbon transportation fuels that were used in the marketplace prior to LCFS being enacted can simply earn credits by opting in (the obligated party that opts in to earn the credits varies with each fuel). ICF assumed that there is no additional cost attributable to the LCFS for these credits to become available on the market. The consideration of credits available at no cost was limited to compressed natural gas (CNG).

The CEC reports about 148 million gge of CNG was consumed in 2010. ICF assumed "like for like" replacement i.e., that even with turnover, this level of consumption would persist even in the absence of LCFS. To estimate the number of credits generated, this value was fixed through 2020. We also assumed that this volume of CNG was used to displace diesel, even though we know some of it likely was used in the light-duty sector. The carbon intensity compliance schedule for diesel is lower than gasoline, therefore, we consider our assumption conservative. Furthermore, based on LCFS reporting to date, it is evident that not all entities that should be earning credits as an obligated party supplying CNG have opted into the LCFS program. To adjust for this, ICF assumed that the number of credits that can be generated from existing CNG use will not be fully realized until 2015 (see Exhibit 50); in other words, all entities that can opt-in as regulated parties dispensing CNG, will opt-in by 2015

Exhibit 50. Estimated Credits to be Earned by Pre-Existing CNG Consumption

Fuel	Credits (Millions)									
	11	12	13	14	15	16	17	18	19	20
CNG	0.226	0.224	0.298	0.391	0.472	0.455	0.430	0.405	0.379	0.346

Although these credits are introduced into the market freely and help lower the overall cost of compliance slightly, they do not contribute towards GHG reductions.

Energy Conversion Factors

As noted previously, the LCFS is implemented using carbon intensity, a measure of GHG emissions per unit energy of fuel. However, we frequently discuss compliance strategies in terms of fuel consumption e.g., gasoline gallons or diesel gallons. This can lead to some confusion because the energy content of fuels varies considerably; furthermore, we considered liquid and gaseous transportation fuels as compliance strategies. The conversion factors in the table below should enable the reader to convert fuel volumes as needed.

Fuel	Energy Density	Units
CARBOB	119.53	MJ/gallon
Reformulated gasoline CARBOB 93.48%, by energy Ethanol, 6.52% by energy	115.63	MJ/gallon
Diesel (ULSD)	134.47	MJ/gallon
CNG	0.98	MJ/scf
LNG	78.83	MJ/gallon
Electricity	3.6	MJ/kWh
Hydrogen	120	MJ/kg
Ethanol (neat, denatured)	81.51	MJ/gallon
Biodiesel (neat)	126.13	MJ/gallon
E85 Ethanol, 85% by volume Gasoline, 15% by volume	87.213	MJ/gallon

In some cases the reader may need to convert between different units of energy. The table below includes the energy unit conversions and volumetric conversions for units mentioned throughout this report.

Value	Conversion
99,976	Btu per therm
1,055	MJ per Btu
1,000,000	grams per tonne
3,600	MWh per MJ
42	gallons per barrel

Appendix B – Biofuel Production Costs

The purpose of this analysis is to estimate biofuel production costs. This is accomplished by adopting a United States and Brazil "Resource Cost" perspective, expanding the California Resource cost perspective otherwise used in this analysis. The critical difference is that biofuel production and delivery costs are modeled on a bottoms up basis and not on a delivered to California basis. This is done for illustrative purposes, and in ICF's view, LCFS costs in this time frame, to 2020, using this approach are very unlikely.

As noted elsewhere, the costs used in this modeling exercise focused on rack prices for liquid fuels (gasoline, diesel, and biofuels), citygate prices for natural gas, avoided electricity costs, and a similar build-up of hydrogen fuel pricing. We also noted that there is potential for biofuels to reduce the costs of production in the long-term, if there is a transition towards very high volumes of advanced biofuels. Today, the price of biofuels in the US is largely set by corn ethanol and soy-based biodiesel. In order for next generation biofuels to decrease the rack prices of biofuels today, we would expect a drastic shift in the production potential of cellulosic or waste-based biofuels – upwards of billions of gallons of biofuels, not the hundreds of millions of gallons assumed in this report.

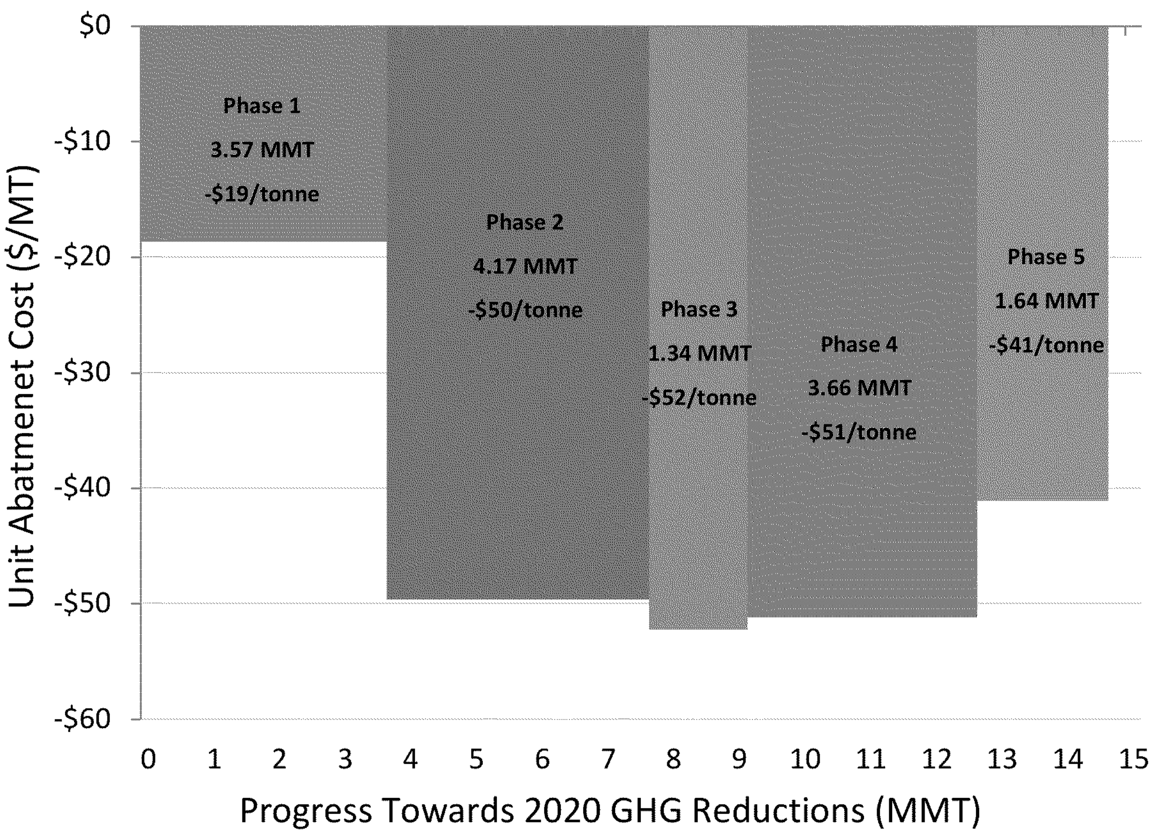
If one were to take a broader approach e.g., a US/Brazil total resource perspective, then the costs of the LCFS may look very different. It is important to note, however, that there are many dynamics which are not captured in this exercise. For instance:

- The shift to lower carbon corn ethanol is equivalent to cents per gallon based on ICF estimates in the plausible low and plausible high cost scenario; however, there is little indication that the production costs are considerably higher for these fuels. As a result, low carbon corn ethanol has effectively the same production cost as corn ethanol before LCFS was introduced. In other words, we essentially have a zero abatement cost for a transition to lower carbon intensity corn ethanol because the amortized costs of the investments required to reduce the carbon intensity of corn ethanol are small compared to the overall production cost.
- The premium that we included previously for sugarcane ethanol – a major pathway for compliance in our modeling exercise – is reduced significantly. Using the production cost outlook for biofuels ignores the market realities that have been observed over the last 2 years of the LCFS.
- The lower costs for corn oil biodiesel assume that there is no change in the price of corn oil as a feedstock. Today, corn oil (about 30-35 cents per pound) trades for considerably less than soy oil (about 50-55 cents per pound). Despite the lower cost of the feedstock, we have not observed a substantial shift in the cost of biodiesel rack prices. In the future, if biodiesel rack prices do not decrease substantially, then it is likely that corn oil prices may increase as corn oil producers seek to capture some of the margin that biodiesel producers are receiving at the rack.
- Most of the literature surrounding cellulosic biofuels – whether they be alcohols (e.g., ethanol) or drop-in replacements (e.g., renewable diesel or gasoline) – assume a given price

for the feedstock. Based on ICF's review of the literature, most studies fall around $50 per dry ton of material used in production. There is no market basis at this time for this assumption; however, it is safe to assume that if a market for a waste product or byproduct develops, that over time the price will fluctuate with supply and demand in considerably different ways than what are observed in the absence of that market today.

To illustrate the potential changes in the costs of the LCFS using bottoms-up estimates of production costs for biofuels, ICF performed a simple modeling exercise. We used the same cost assumptions as the plausible low cost scenario for all non-biofuels; however, for liquid biofuels – including ethanol and biodiesel – we used the production costs outlined in the subsequent sections instead of rack prices. The results of this exercise are shown in Exhibit 51. ICF cautions that these costs are not representative of what we expect to see in the market. Furthermore, the negative abatement costs in the transportation sector shown below are entirely a function of the perspective assumed and are not reflective of market realities.

Exhibit 51. Unit Abatement Costs for a Hypothetical Scenario using Biofuel Production Cost Estimates



The following sections outline the production costs that were used to develop these estimates.

Ethanol Production Costs

Ethanol is used primarily in low-level blends with California Reformulated Blendstock for Oxygenate Blending (CARBOB). It is currently blended at 10 percent by volume. Most ethanol produced in the US today comes from corn grown in the Midwest.

Ethanol can also be used in high-level blends, with 85 percent ethanol (by volume) blended with 15 percent gasoline, referred to as E85. E85 is consumed in flex-fueled vehicles (FFVs).

Ethanol is produced from a variety of feedstocks. For this analysis, ICF considered the following feedstocks:

- US corn ethanol
- California corn ethanol
- Brazilian sugarcane ethanol; and,
- Cellulosic ethanol

After we discuss these feedstocks, we discuss the consumption of ethanol as E85.

Corn Ethanol

ICF drew from the cost build-up that Iowa State University prepared.[40] The cost build-up for corn ethanol production has five main components:

- Feedstock: This is the primary cost driver for corn ethanol production.
- Other direct costs: Variable costs that fluctuate depending on production rates, but do not include the costs of direct inputs.
- Fixed costs: The costs associated with building and commissioning the production facility (labor, maintenance, etc.), and the resulting interest expense of debt used to finance the project.
- Chemicals and ingredients: The variable costs associated with direct inputs into the production process aside from corn feedstock.
- Freight and distribution costs: These distribution costs are the costs of moving ethanol, typically by rail, to storage terminals and/or blenders that mix the ethanol with gasoline to produce finished motor gasoline for wholesale distribution.

The table below shows the breakdown of productions costs for corn ethanol.

[40] *Ethanol Plant Profitability Calculator.* Extension Tool, Iowa State University. 2011. http://www.soc.iastate.edu/dpeters/pubs.html

Exhibit 52. Corn Ethanol Production Costs, Per Gallon

Cost Element	Cost per Gallon Ethanol	
	2015	2020
Feedstock	$1.68	$1.69
Chemicals & Ingredients	$0.18	$0.21
Other Direct Costs	$0.33	$0.38
Fixed Costs	$0.21	$0.22
Freight & Distribution	$0.13	$0.15
Total Cost	$2.53	$2.65

Feedstock

The main cost driver in corn ethanol production is the cost of corn, which comprises about two-thirds of the total cost of production (under current assumptions). The price of corn feedstock is based on the assumptions of Iowa State University's *Ethanol Plant Profitability Calculator*, which forecasts corn prices as hovering between $4.66 and $5.32/bushel through 2020. Moreover, there are slight improvements in assumptions for production productivity as more ethanol is yielded from each bushel of corn input (2.77 gallons/bushel in 2012 to 2.88 in 2020).

Other direct costs

These costs include water and water treatment, electricity, natural gas, waste management, maintenance, feedstock transportation, and other/unspecified costs. Water requirements are assumed to be 7 gallons/bushel of input (and corn inputs decrease over the period to 2020). The price of water and treatment grows at an annual rate of 3 percent (inflation). Electricity consumption is assumed to be 75 GWh each year and natural gas consumption is assumed to be 3.5 trillion Btu each year. Both projected fuel costs are based on the Energy Information Administration's (EIA) *Annual Energy Outlook* (AEO) fuel prices in the Pacific Region to the industrial sector..[41] Waste management, maintenance, and other/unspecified costs are based on corn input and default price assumptions from Iowa State's calculator that grow at inflation. Feedstock transportation costs are based on corn inputs, corn truck transport rates from Iowa State's calculator and growing at inflation, and assumed 15 miles for corn trucking.

Fixed Costs

This category is comprised of up-front costs, labor, interest on debt, and depreciation. Under current assumptions, land acquisition is $870,000, engineering is $20 million, and construction is $139.13 million (a total of $160 million). The capital structure is assumed to be 60 percent debt (10-year at 8 percent) and 40 percent equity. The debt ($96 million 2012 dollars) is repaid in equal annual installments (nominal) over 10 years to repay the present value of $96 million at

[41] The Pacific Region is Alaska, California, Hawaii, Oregon, and Washington.

8 percent interest. Annual depreciation is a straight-line expense and based on the total up-front costs (i.e. $160 million), a 20 year depreciation schedule, and 25 percent salvage value. Wages and salaries are based on 45 full-time employees making a 2010 salary of $45,000, which grows at inflation. Benefit costs are assumed to be 13 percent of wages and salaries each year. Management costs are assumed to be 10 percent of wages and salaries each year. Taxes are comprised of insurance trust taxes (10 percent of wages and salaries), state sales taxes (2.75 percent of costs for enzymes, yeasts, and chemicals), and local property taxes (90 percent of 1.75 percent property tax rate and total construction costs - $160 million, discussed in Fixed Costs). Currently, local sales taxes are assumed to be 0.

Chemicals and ingredients

This category includes the costs of enzymes, yeasts, chemicals: processing and antibiotics, chemicals: boiling and cooling, and denaturants. All these inputs to production are a function of corn input, and their base costs are provided by Iowa State's calculator and escalate at 3 percent.

Freight and distribution costs

The distribution cost for transporting ethanol from facilities to terminals/blenders is based on rail movements. The assumptions for the distribution costs include an annual production rate of 100 million gallons, a base rail charge from Iowa State's calculator that grows at inflation, and a distance of 200 miles to the rack market. For delivery to California on unit trains, this cost would clearly be higher. In general, the market price difference between the ethanol spot market in Los Angeles and Chicago mirrors the rail shipment cost.

Once delivered to California, additional costs are incurred for terminal storage fees at discharge hubs and then costs to transport the ethanol from the rail receipt hubs to delivery terminals across the state.

Brazilian Sugarcane Ethanol

Most ethanol in Brazil is derived from sugarcane. This not only ties its ethanol to the seasonal oscillations of sugarcane harvest, but also drives the industry's economics in relation to the sugar industry and the larger sugarcane sector, one that employs as many as 465,000 people in ethanol production alone.[42] and contributing $28.2 billion dollars (in 2008 dollars) to Brazil's GDP..[43] Benefiting from favorable weather and a national sugarcane ethanol promotion program lasting almost 40 years, Brazil's sugar and ethanol industries are highly developed. Brazil is currently the world's largest sugar producer and second largest ethanol producer behind the

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[42] Chaddad, Fabio. "UNICA: Challenges to Deliver Sustainability in the Brazilian Sugarcane Industry". International Food and Agribusiness Management Review, 2010. Available at: http://ageconsearch.umn.edu/bitstream/96332/2/20100040_Formatted.pdf

[43] Neves et al. "The Sugar-Energy Map of Brazil". Available at: http://sugarcane.org/resource-library/books/The%20Sugar%20Energy%20Map%20of%20Brazil.pdf

U.S.[44] In 2011, the country produced 6 billion gallons of ethanol from sugarcane (8.6 per cent of this amount was exported).

A typical sugarcane facility in Brazil consists of land for farming and distilleries capable of producing sugar and/or ethanol. Approximately 85 percent of these facilities can produce both, according to an Ernst & Young report.[45] The figure below summarizes the process of manufacturing ethanol from sugarcane. After sugarcane is harvested from the field, it is delivered to mills to prepare sugarcane juice. At this stage, the juice could be processed into sugar or fermented for ethanol production.

The table below highlights the major production cost elements discussed in more detail in the following subsections, including: feedstock, operating costs, financing costs, freight and distribution costs to the United States, and the recovered cost of byproducts.

Exhibit 53. Estimated Brazilian Sugarcane Ethanol Production Costs, Per Gallon

Cost Element	Cost per Gallon Ethanol	
	2015	2020
Feedstock	$1.18	$1.40
Operating Costs	$0.25	$0.29
Financing Costs	$0.11	$0.11
Freight & Distribution (to US)	$0.83	$0.97
Byproduct	($0.08)	($0.10)
Total Cost	$2.28	$2.67

Feedstock

The main driver of sugarcane production cost is feedstock price. According to the USDA, this constitutes 60 to 70 percent of current production costs, depending on the efficiency of the plant.[46] However, since feedstock prices can be volatile, the actual percentage might change over time. As described in the previous section, ethanol plants can procure feedstock needs from their own farms, and purchases from the open market can also be made. The price of feedstock paid by ethanol producers in the state of Sao Paulo is set based on an index produced by its Sugarcane, Sugar and Ethanol Growers Council (CONSECANA) based on

44 OECD-FAO. "Agricultural Outlook: 2012-2021". OECD-FAO, 2012.
45 Emst & Young Terco. "Sustainable Brazil: An outlook on the oil, ethanol and gas markets". Eamst & Young, 2012. Available at http://www.ey.com/Publication/vwLUAssets/Sustainable_Brazil_-_An_outlook_on_the_oil_ethanol_and_gas_markets/$FILE/Sustainable_Brazil_Oil_and_Gas.pdf
46 U.S. Department of Agriculture (USDA). "Brazil Biofuels Annual: Annual Report 2012". USDA, August 2012: Washington, DC. Available at: http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Sao%20Paulo%20ATO_Brazil_8-21-2012.pdf

sugar and ethanol prices.[47] This is also the sugarcane price in the OECD-FAO Agricultural Outlook used in this research.

Production

One of the advantages of sugarcane ethanol over corn ethanol is energy use in its production. The production process generates sufficient electricity for the whole operations so there is no need to draw from the grid.[48] Sometimes excess electricity is available to sell back to the grid. This is evolving into an important source of electricity for Brazil. Previous research estimates electricity from sugarcane production accounts for 3 per cent of Brazil's installed capacity in 2009 and this ratio may increase to 15 percent by 2020.[49] LCFS has a lower CI pathway for sugarcane ethanol with electricity co-product credit for facilities capable of exporting electricity back to the grid. Additionally, sugarcane ethanol requires no direct use of natural gas.

By-products

Bagasse is a residue of the ethanol production process. It is currently combusted to produce electricity for sugarcane mills and/or to sell back to the grid. It also has some potential for cellulosic ethanol and butanol production. Some pilot projects are in progress to explore this option.[50]

Molasses is a byproduct of sugar production. It could also be converted into ethanol. Currently about 25 percent of ethanol produced in Brazil is derived from molasses.[51]

Vinasse is a byproduct of the distillation process. It is rich in potassium and can be applied to cane fields as a fertilizer.[52]

Freight and distribution

Brazil's sugarcane industry faces serious constraints in its transportation infrastructure, relying primarily on trucks. The geographical distribution of mills and cumbersome logistics in Brazil, which involves transport from mills through various collection centers before getting to ports for export or to rack markets for domestic consumption might translate into over 600 miles of truck transportation for some regions.[53] This drives up Brazil's ethanol prices significantly. Petrobras

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47 OECD-FAO. "Agricultural Outlook: 2012-2021". OECD-FAO, 2012.

48 Chaddad, Fabio. "UNICA: Challenges to Deliver Sustainability in the Brazilian Sugarcane Industry". International Food and Agribusiness Management Review, 2010. Available at: http://ageconsearch.umn.edu/bitstream/96332/2/20100040_Formatted.pdf

49 Chaddad, Fabio. "UNICA: Challenges to Deliver Sustainability in the Brazilian Sugarcane Industry". International Food and Agribusiness Management Review, 2010. Available at: http://ageconsearch.umn.edu/bitstream/96332/2/20100040_Formatted.pdf

50 Biofuelschat. "Abengoa to build next-gen sugarcane ethanol plant". Biofuelschat, January 19, 2012. Available at: http://biofuelschat.com/topics/abengoa-build-next-gen-sugar-cane-ethanol-plant

51 U.S. Department of Agriculture (USDA). "Brazil's Ethanol Industry: Looking Forward". USDA, 2011: Washington, DC. Available at: http://www.ers.usda.gov/media/126865/bio02.pdf

52 Isaias de Carvalho Macedo. "Sugarcane's Energy". UNICA, May 2007: Sao Paulo, Brazil. Available at: http://sugarcane.org/resource-library/books/Sugar%20Canes%20Energy%20-%20Full%20book.pdf

53 U.S. Department of Agriculture (USDA). "Brazil's Ethanol Industry: Looking Forward". USDA, 2011: Washington, DC. Available at: http://www.ers.usda.gov/media/126865/bio02.pdf

recently cancelled one of its long-haul ethanol pipeline projects to make more domestically produced ethanol available for exports[54], even though the project is likely to significantly reduce transportation costs.

Ethanol exports are usually via marine transportation using chemical tankers. Petrobras reportedly use up to 48,000 deadweight tankers to transport ethanol[55]. For the purpose of this study we only focus on ethanol export logistics. The typical logistics involve the following stages: a) transport from mills to a collection center; b) transport between collection centers (this might depend on mill location); c) transport from a collection center to a Brazil port; and d) transport from a Brazil port to a US port. Previous research on transportation of Brazil's sugarcane ethanol to the US might use outdated information or does not consider the cost of moving ethanol to the West Coast (which can be very different from the East Coast). Therefore we constructed a transportation model to analyze possible transportation options for Brazil's sugarcane ethanol.

This analysis presents a hypothetical transportation situation as follows: a) the produced anhydrous ethanol (i.e., with no water) is transported from a mill in the Americo Brasiliense, Sao Paulo area to a collection center in Paulinia, Sao Paulo; b) it is then trucked to the port of Santos, Sao Paulo which represents about 70 percent of Brazil's ethanol exports; c) it is shipped to San Francisco though the Panama Canal on a 30,000 dwt vessel and d) finally the ethanol is trucked to terminals where it is blended with petroleum-based fuels.

The total truck distance in Brazil is 233 miles. Actual distances might be greater and/or smaller depending on the mill location. Note also that Sao Paulo is the main producing region in Brazil and also home to the port of Santos. As some production might come from more remote areas, this should be considered an optimistic estimate of the true average transportation cost. The size of the tanker is determined based on our analysis of actual ethanol tankers used in Brazil and the US. We have also considered the option of moving ethanol through the Strait of Magellan as well as to the Gulf Coast and then railed to California. However, these options are much less cost competitive. Pipeline transportation of ethanol in the US is not realistic at the moment (see more discussion in the corn ethanol section).

The total cost of transportation is estimated is \$0.34/gal or \$0.0038/MJ (assume 89 MJ/gallon).

Past applications for new sugarcane ethanol pathways (using Method 2A/2B) have come from Caribbean Basin Iniative (CBI) countries, rather than Brazil.[56] Brazilian producers have traditionally diverted some hydrous ethanol to the CBI countries for dehydration to take advantage of the duty-free treatment given to these countries. Because U.S. ethanol tariff was removed in December 2011, this complicated logistical arrangement may not persist in the longer term.

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[54] MarketWatch. "Brazil's Petrobras opts out of ethanol pipeline". MarketWatch, October 26, 2012: Sao Paulo, Brazil. Available at: http://www.marketwatch.com/story/brazils-petrobras-opts-out-of-ethanol-pipeline-2012-10-26

[55] Petrobras. "Transportation". Petrobras, 2009. Available at: http://www.petrobras.com.br/rs2009/en/relatorio-de-sustentabilidade/desempenho-operacional/transporte/

[56] "Summary: Method 2A/2B Applications and Internal Priority Pathways". Available at: http://www.arb.ca.gov/fuels/lcfs/2a2b/071112lcfs_apps_sum.pdf

Cellulosic ethanol

Production

Production technologies for cellulosic ethanol are still under development. Several companies across the U.S. have developed demonstration plants, utilizing various technologies, which began operation as early as 2009. Moreover, several commercial-scale cellulosic ethanol plants are currently under construction with start-up dates as early as 2013. Although there has been progress in the development of cellulosic ethanol production, there are no commercial-scale plants currently operating in the U.S., and those under construction have faced significant delays since their initial public announcements. Not having a sufficient production track record is the main commercialization challenge with cellulosic ethanol.

The amount of available feedstock may be a limiting factor in the production of cellulosic ethanol. In the U.S., corn is grown almost exclusively in the Midwest. The most recent Agricultural Census (2007) estimated the amount of cropland (the sum of land used for crops, idle land, and pasture available in the U.S.) to be 406 million acres..[57] Cropland acreage has been declining for the past 50 years since the land is being used for other developments. If the decline continues, the shortage of available cropland may be a constraint because feedstocks such as corn stover may not match its own demand from the cellulosic ethanol production facilities.

ICF considered the following steps in the production of cellulosic ethanol from corn stover:

- **Pretreatment and conditioning** – This entails the conversion of hemicellulose carbohydrates in the corn stover to soluble sugars (xylose, mannose, arabinose, and glucose) using hydrolysis reactions. To estimate these costs, the Harris Group obtained quotes for certain equipment and used its internal database for auxiliary equipment.
- **Enzymatic hydrolysis and fermentation** – This entails the conversion of cellulose into glucose using using cellulase enzymes. This process is known as enzymatic saccharification or enzymatic hydrolysis. To estimate these costs, NREL assumed that the plant uses separate (or sequential) hydrolysis and fermentation (SHF) with the most cost-effective material for the equipment.
- **Cellulase enzyme production** – This entails the production of cellulase, the enzyme used in the enzymatic hydrolysis and fermentation stage using aerobic fermentation. To estimate these costs, the Harris Group obtained quotes for certain equipment and used its internal database for auxiliary equipment. Additionally, NREL made the following assumptions:
  - The process was designed based on expert judgment without the input from enzyme companies.

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[57] U.S. Department of Agriculture, 2007 Census of Agriculture (Washington, DC, June 2009), Vol. 1, Chapter 1, "U.S. National Level Data," Table 8, "Land: 2007 and 2002," web site http://www.agcensus.usda.gov/Publications/2007/Full_Report/Volume_1,_Chapter_1_US/st99_1_008_008.pdf.

- Costs for concentration, stabilization, or transportation of the enzyme to the plant were not included.

- **Product, solids, and water recovery** – This entails separation of fermentation broth from Enzymatic hydrolysis and fermentation into water, anhydrous ethanol, and combustible solids. To estimate these costs, the Harris Group obtained quotes for certain equipment and used its internal database for auxiliary equipment.
- **Wastewater treatment** – This entails the treatment of the wastewater streams generated in the production of ethanol before recycling to the process or releasing to the environment. To estimate these costs, the Harris Group obtained quotes for certain equipment and used its internal database for auxiliary equipment.
- **Storage** - This entails bulk storage for process chemicals and the produced cellulosic ethanol. To estimate these costs, the Harris Group obtained quotes for certain equipment and used its internal database for auxiliary equipment.
- **Combustor, boiler, and regenerator** – This entails burning organic by-product streams to produce steam and electricity. To estimate these costs, the Harris Group obtained quotes for certain equipment and used its internal database for auxiliary equipment.
- **Utilities** – This entails the utilities required by this facility including cooling water, chilled water, plant and instrument air, process water, and the electricity usage throughout the plant. This does not include the steam provided by the Combustor, boiler, and regenerator. To estimate these costs, the Harris Group obtained quotes for certain equipment and used its internal database for auxiliary equipment.

ICF considered the following steps in the production of cellulosic ethanol from woody biomass:

- **Gasification** – This entails the conversion of a mixture of dried feedstock and steam to syngas and char. To estimate these costs, the Harris Group obtained quotes for certain equipment from Taylor Biomass Energy.
- **Gas Clean-up** – This entails the cleaning and cooling of syngas so it can be compressed and converted into alcohols. To estimate these costs, the Harris Group obtained quotes from Taylor Biomass Energy and TurboSonic.
- **Alcohol Synthesis, Syngas Compression, and Acid Gas Processing** – This entails the synthesis of mixed alcohols from syngas to catalytic conversion. To estimate these costs, the Harris Group gathered information from various sources including technology licensors, industrial suppliers, published literature, and Aspen computer software.
- **Alcohol separation** – This entails recovering alcohol products from the synthesis area and recycling unconverted material for improved overall conversion. To estimate these costs, the Harris Group gathered quotations from Delta-T Corporation and information from Aspen computer software.
- **Steam system and power generation** – This entails the production of steam through heat recovery from hot process streams throughout the plant.

- **Cooling water and other utilities** – This entails the utilities required by this facility including cooling water, chilled water, plant and instrument air, process water, and the electricity usage throughout the plant. This does not include the steam provided by the Combustor, boiler, and regenerator. To estimate these costs, the Harris Group obtained quotes for certain equipment and used its internal database for auxiliary equipment.

Feedstock

Corn stover and woody biomass were considered as feedstocks. The cost considered here include storing, homogenizing, and delivering the feedstock to the cellulosic ethanol production facility. ICF used the following estimates and assumptions from NREL:[58]

- The as-received corn stover feed requirement for the plant is 2,205 US dry tons/day.
- The refinery operates on the same schedule as the biomass depot: 24 hours a day, six days a week.
- Each truck trailer holds 10 U.S. tons of biomass which means to satisfy production and storage requirements, the plant must receive 12 trucks every hour.

The feedstock cost is estimated to be about $8.96/GJ (just under $60 per dry ton) using the Multi-Year Program Plan (MYPP) published by DOE's Office of the Biomass Program.

Freight and distribution

We assume that the freight and distribution costs for cellulosic ethanol are the same as corn ethanol.

Biodiesel and Renewable Diesel

Biodiesel is a fatty acid methyl ester (FAME) that can be synthesized from vegetable oils, waste oils, fats, and grease. Renewable diesel is generally produced by upgrading FAME via hydrogenation to a product that meets the same ASTM standards as conventional diesel.

Biodiesel is generally used in low-level blends: biodiesel blended in at 5 percent by volume is considered the same as diesel and biodiesel blended at 20 percent by volume is the upper limit of blending for the majority of transportation applications due to vehicle warranty. Renewable diesel, however, is interchangeable with conventional diesel and does not have any blending limitations – it can be transported via pipeline, stored in the same facilities as diesel, and used without volume constraints in vehicle applications.

The following feedstocks for biodiesel were considered in our analysis:

- Soybeans,
- Corn oil, and

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[58] National Renewable Energy Laboratory; Harris Group Inc. (2011). *Process Design and Economics for Biochemical Conversion of Lignocellulosic Biomass to Ethanol - Dilute-Acid Pretreatment and Enzymatic Hydrolysis of Corn Stover.* Available Online: http://www.nrel.gov/docs/fy11osti/47764.pdf

- Fats, Oils, and Greases (FOGs)

For renewable diesel, we considered the following feedstocks:

- FOGs, and
- Cellulosic materials or waste.

The tables below provide an overview of the production costs for the biodiesel and renewable diesel fuels (shown for 2015) discussed in more detail below.

Exhibit 54. Estimated Production Costs of Biodiesel and Renewable Diesel in 2015

Production Cost Element	Biodiesel			Renewable Diesel	
	Soybeans	FOGs	corn oil	FOGs	cellulosic
Feedstock	$3.77	$2.34	$1.36	$1.89	$1.56
Chemicals & Ingredients	$0.14	$0.14	$0.14	$0.17	$0.09
Other Direct Costs	$0.11	$0.11	$0.11	$0.07	$0.20
Fixed Costs	$0.26	$0.26	$0.26	$0.27	$1.23
Freight & Distribution	$0.20	$0.20	$0.20	$0.15	$0.15
Total	$4.48	$3.25	$2.07	$2.55	$3.23

Biodiesel

Feedstock

Cost of the feedstock varies by feedstock type. In the case of biodiesel we evaluated soybean oils, corn oils, Fats, Oils and Greases (FOGs), and algae oils.

Currently, soybean oil is the primary feedstock for the majority of biodiesel produced in the United States. It is a well-established crop with a robust commodity market. Soybean oil prices fluctuate depending on many outside variables. For example, soybean oil prices in 2012 have been widely influenced by drought conditions experienced in the Midwestern states. For purposes of this study, long-term projections to 2020 were derived from the USDA which provides feedstock prices ranging from $4.24 per gallon in 2012 to $3.92 per gallon in 2020..[59]

Corn oil is a relatively small, but growing, feedstock for the biodiesel industry. The majority of corn oil predicted for future biodiesel production comes from non-edible oils extracted from distillers' grains in the ethanol production process. Corn oil extraction is a relatively new commodity for the majority of ethanol production facilities, but represents another high-value co-product. For example, Pacific Ethanol announced plans in November 2012 to install a corn oil

[59] USDA, U.S. Soybean Long-Term Projections to 2022, p. 71 (in bushels), February 2012, http://www.ers.usda.gov/media/273331/oce121d_1_.pdf. University of Missouri, 7.7 lbs of unrefined soybean oil per gallon of biodiesel and 11.28 lbs. of soybean oil per bushel, http://www.fapri.missouri.edu/outreach/publications/2006/biofuelconversions.pdf.

extraction system at its Stockton, California plant. The additional income varies depending on market prices for corn oil and production yield but can run from 4 to 7 cents per gallon of ethanol produced.[60] The EPA estimates that corn oil will be available for $1.39 per gallon of biodiesel by 2022.[61]

Fats, waste oils, and greases (FOGs) have generally remained stable in price and are not prone to the wide fluctuations of other oilseed markets, such as soybean oil. The EPA estimates that waste oils will be available for $1.77 per gallon of biodiesel by 2022.[62]

Operations

The cost of operating a biodiesel production facility includes energy use, water use, chemicals (acids, bases, and catalysts), labor, maintenance, insurance and other resource costs. Biodiesel operation costs were derived using a profitability spreadsheet developed by the University of Iowa.[63] Given the comparable characteristics between feedstock types, operating costs were applied similarly among each fuel.

Installed Capacity

This includes the amortized cost of installing biofuel production facilities. The cost of building a facility will depend on its nameplate capacity, land acquisition and construction costs, property taxes, interest costs, depreciation level, and other capital expenditures. Amortized costs were derived using a profitability spreadsheet developed by the University of Iowa.[64] Given the comparable characteristics between feedstock types, amortized costs were applied similarly among each fuel.

Byproducts

The primary byproduct of biofuel production is glycerin. In recent years the glycerin market has been saturated by national and international biodiesel production facilities. Glycerin values were estimated at $0.03 per pound and derived from the profitability spreadsheet developed by the University of Iowa.[65]

Freight and distribution

Biodiesel infrastructure requirements are similar to those of ethanol in that the fuel must be transported from production sites (inside and outside of California) to redistribution hubs via rail, truck, and marine vessels. After arriving in California, the biodiesel then moves to distribution

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[60] The Record, "Stockton Ethanol Plan to Upgrade Facility," November 8, 2012, http://www.recordnet.com/apps/pbcs.dll/article?AID=/20121108/A_BIZ/211080319/-1/A_BIZ&template=printart.
[61] EPA, Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis, pg. 766, Table 4.1-41; feedstock price in 2022 (assuming 7.7 lbs/gallon), http://www.epa.gov/otaq/renewablefuels/420r10006.pdf.
[62] EPA, Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis, pgs. 765-766, Table 4.1-41; feedstock price in 2022 (assuming 7.7 lbs/gallon); http://www.epa.gov/otaq/renewablefuels/420r10006.pdf.
[63] University of Iowa, "Tracking Biodiesel Profitability spreadsheet," October 2012, http://www.extension.iastate.edu/agdm/articles/hof/HofJuly09.html.
[64] University of Iowa, "Tracking Biodiesel Profitability spreadsheet," October 2012, http://www.extension.iastate.edu/agdm/articles/hof/HofJuly09.html.
[65] University of Iowa, "Tracking Biodiesel Profitability spreadsheet," October 2012, http://www.extension.iastate.edu/agdm/articles/hof/HofJuly09.html.

terminals for blending with diesel before distribution to retail locations. Expansion of the biodiesel distribution infrastructure has moved at a much slower pace than that of ethanol, given the significantly lower demand levels.

Biodiesel is blended with diesel fuels in tanker trucks before delivery to retail service stations. Before blending, biodiesel must be stored in separate tanks. Few distribution terminals in California have biodiesel storage capabilities, largely due to low demand.

Renewable Diesel

Feedstock

Cellulosic feedstocks are wide ranging and cover everything from energy grasses to wood wastes. Wood waste prices are largely dependent on regional demand from other markets such as pulp-and-paper, wood pellets, biomass CHP, or other industries with wood boilers. Energy grasses are still an emerging industry and commodity markets have not yet been established. The EPA estimates cellulosic materials will be available in 2022 for an average of $64.70 per dry ton, or $1.56 per gallon.[66]

Operations

Two of the distinct differences between biodiesel and renewable diesel operations include energy and hydrogen use. Renewable diesel facilities use significantly more energy than traditional biodiesel facilities because of the high operating temperatures required for the processes. Hydrogen is another major input for hydrotreated renewable diesel products. Hydrogen costs are estimated between $0.15 and $0.17 per gallon or approximately 7 percent of the total production cost of the renewable diesel in 2022.[67]

Installed capacity

The amortized cost of installing biofuel production facilities was also difficult to define given the lack of information from existing renewable diesel operations. For purposes of our estimates for hydrotreated renewable diesel we used the costs provided by the EPA and derived from information provided by UOP and Syntroleum Corporation.[68] For purposes of our estimates for cellulosic biomass-to-liquids we used the costs provided by the EPA and derived from estimates from the National Renewable Energy Laboratory.[69]

Renewable diesel production facilities can either be distinct operations or built in conjunction with existing refineries. The cost of building a facility will depend on its nameplate capacity, land

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[66] EPA, Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis, pg. 769, Table 4.1-44; Cellulosic materials; http://www.epa.gov/otaq/renewablefuels/420r10006.pdf

[67] EPA, Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis, pgs. 765-766, Table 4.1-39 and Table 4.1-40; http://www.epa.gov/otaq/renewablefuels/420r10006.pdf

[68] EPA, Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis, pg. 765; http://www.epa.gov/otaq/renewablefuels/420r10006.pdf

[69] EPA, Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis, pgs. 767-769; http://www.epa.gov/otaq/renewablefuels/420r10006.pdf

acquisition and construction costs, property taxes, interest costs, depreciation level, and other capital expenditures.

Byproducts

The byproducts of biofuel production often have value in other markets, which lower the overall marginal cost of producing some biofuels. Renewable diesel does not have any significant or commercially-valuable byproducts. Unlike biodiesel, there is not a glycerin byproduct. For some biomass-to-liquid operations, it is possible to develop high value co-products, such as naptha.

Freight and distribution

Once the finished product is ready for the consumer, renewable diesel can be transported through existing diesel distribution infrastructure, meaning it will likely have similar transportation costs as diesel.