California's Low Carbon Fuel Standard:
Evaluation of the Potential to Meet and Exceed the Standards

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February 2, 2015

Contents

1. Regulatory Background

California's adoption of the Global Warming Solutions Act of 2006, also known as Assembly Bill (AB) AB32, set in motion a series of policies to reduce greenhouse gas (GHG) emissions in the state to 1990 levels by 2020 – roughly a 20 percent reduction – while also protecting public health. Under AB32, the California Air Resources Board (ARB) developed a series of GHG reduction strategies as part of a Scoping Plan for achieving the 2020 goal. For the transportation sector, the key programs ARB adopted include standards for cleaner, more efficient cars and trucks; a clean fuels standard; a cap-and-trade regulation; and established targets to reduce emissions through more sustainable, transit friendly and walkable communities.

The state's clean fuels standard, known as the Low Carbon Fuel Standard (LCFS), was adopted in 2009 as an early-action measure under AB32 and in furtherance of Executive Order S-01-07 by then Governor Arnold Schwarzenegger. In addition, in his recent fourth inaugural address, current Governor Jerry Brown provided targets for a series of new environmental goals for 2030, including reducing current petroleum use in cars and trucks by 50 percent.[1]

California's LCFS is a performance-based standard requiring petroleum refiners and other fuel providers to reduce the carbon-intensity of transportation fuels used in California by 10 percent by 2020. The carbon-intensity of each fuel is measured on a full lifecycle basis, which includes accounting for GHG emissions from production of a feedstock, transport, refining, distribution, and end-use combustion. Because the standard is technology-neutral, companies can earn LCFS "credits" any number of ways, including improving their processes or through switching to renewable feedstocks and inputs. Each LCFS credit represents one metric ton of reductions in GHG emissions. The LCFS is designed to include market-based features that allow LCFS credits to be sold, banked, or utilized to help meet the requirements.

2. Project Scope

To inform the dialogue about the re-adoption of the LCFS and establishment of revised annual compliance requirements, Promotum Inc., an independent technical and management consulting firm focused on fuels and chemicals, was commissioned by the Natural Resources Defense Council (NRDC), Union of Concerned Scientists (UCS) and the Environmental Defense Fund (EDF) to evaluate likely scenarios for compliance and the impact of credit values on incentivizing greater production and volumes of low Carbon Intensity (CI) fuels for sale in the state.[2]

[1] http://gov.ca.gov/news.php?id=18828
[2] The conclusions and views contained herein are solely those of the consultant and do not necessarily reflect those of NRDC, UCS, and EDF.

Promotum reviewed and analyzed fuel availability, prior supply studies, data from obligated parties (fuel suppliers) through quarterly reporting to the ARB, California Energy Commission (CEC) information, U.S. Energy Information Administration (EIA) data, and consulted with a wide number of industry participants with specific sector expertise to develop a forecast of supplies and a model of future low carbon fuel production.

As part of the creation of these scenarios we sought to incorporate the latest technology and commercialization developments. For example, 2014 saw the startup of the first two commercial scale cellulosic ethanol facilities in the U.S. with a third scheduled for launch in early 2015. We sought to understand how likely advances in technology would impact future cost of production. Ultimately, we looked at the impact of LCFS credit value both producing additional lower CI fuels in California, and on moving them into California.

For analytical purposes the study evaluated two scenarios: a Reference Case and Low Case.

- The Reference Case assumes the value of credits within the LCFS market remains at roughly $100 per metric ton reduction ($100/MT) over the 2015 to 2025 timeframe. This case is consistent with the estimate currently included in ARB's assessment under its regulatory analysis, provided as part of its 2014 staff report.
- The Low Case assumes a LCFS Credit Value below $50/MT. This case is consistent with credit values observed throughout 2014.[3]

3. Key Findings

The key findings of this study are:

Supply Potential

- **The petroleum industry can meet current LCFS compliance requirements through 2020 by taking advantage of the program's performance-based incentive for reducing greenhouse gas (GHG) emissions.** The LCFS credit system provides obligated parties sufficient incentive to reduce their carbon emissions in a timely manner. Promotum's analysis shows that a $100 per MT credit value, (an amount utilized by ARB for their regulatory proposal), provides sufficient incentive to achieve a 10% reduction in fuel carbon-intensity by 2020 through three mechanisms: (1) providing greater volumes of alternative fuels in California, (2) reducing the carbon-intensity of traditional fuels, and (3) reducing emissions at refineries and throughout the petroleum value chain.

[3] http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm

- **Diesel substitutes, lower carbon-intensity (CI) ethanol, and reductions in the carbon footprint across the petroleum value chain are primary pathways for meeting a 10% target.** Shifts toward lower-carbon feedstocks, including recycled fats and oils, and the production of cellulosic ethanol, including ethanol made from agricultural residue, will reduce carbon intensity. Using electricity as fuel for cars, trucks, and offroad sources such as trains will also significantly contribute to meeting the LCFS.

- **California can extend the LCFS beyond a 10% carbon-intensity (CI) reduction in 2020 to 15% in 2025.** At $100/MT there is sufficient biofuel supply and incentive to support an additional one percent per year reduction from 2020 through 2025.

- **Even under relatively low LCFS credit values, below the historical 2012 and 2013 credit value, California can meet existing requirements through 2020.** However, sustained low credit values may be insufficient to provide enough incentive to achieve a15% reduction by 2025.

Benefits

- **The LCFS program will contribute significantly to meeting California's goal of cutting petroleum use in half by 2030.** Alternative fuels use is increasing, up from supplying only 6% of transportation energy to 14% by 2020 and 20% by 2025. For diesel, much of the growth in demand for cleaner, alternative fuels will be met through biodiesel, renewable diesel, as well as natural gas including biomethane. Growth on the gasoline side will occur largely through increases in lower CI ethanol and electricity.

- **The LCFS is estimated to result in over 70 million metric tons of GHG emission reductions over the next five years through 2020**. Increasing the requirements to 15% by 2025 could generate 183 MMT CO_2e of reductions over the next ten years through 2025, equivalent to cutting the emissions of nearly five coal fired plants operating for ten years.[4]

Reduction Opportunities, Value Creation, and Economics

- **The petroleum industry can achieve a significant portion of the standard by reducing the carbon-intensity of gasoline and diesel through improvements at petroleum refineries and crude oil production facilities.** Just as alternative fuel companies can achieve reduced overall carbon-intensity though efficient production and

[4] U.S. EPA Greenhouse Gas Equivalencies Calculator. http://www.epa.gov/cleanenergy/energy-resources/calculator.html

processing, the petroleum sector has significant potential to reduce the CI of gasoline and diesel through energy efficiency improvements, integration of renewable energy inputs such as biomethane, and use of innovative technologies including solar thermal. This study estimates these three measures alone could result in a 1.5% reduction in carbon-intensity across petroleum-based gasoline and diesel by 2020, growing to a 3% reduction in CI by 2025.

- **Under the Reference Case of $100 per metric ton value, energy efficiency projects at refineries would be significantly more attractive to fuel suppliers.** Based on information generated by energy efficiency audits for California refineries' past and currently proposed projects, the LCFS credit value could more than double the operating savings at the facilities.[5] In addition to garnering operational savings associated with energy efficiency investments, refineries would be further incented under the LCFS to reduce the carbon-intensity of fuel products. Such improvements also allow fuel producers to forgo purchasing pollution permits under the state's cap-and-trade regulation.

- **Use of biomethane at refineries and crude oil facilities to displace fossil natural gas is a potentially attractive option to the reduce carbon-intensity of gasoline and diesel. Such uses are in addition to the use of biomethane in natural gas vehicles.** At the end of the Fall 2014, the LCFS incentive had resulted in an increase in the use of biomethane for natural gas vehicles to 40% of the mix, primarily from biogas capture at landfills.[6] However, a much greater volume of natural gas in California is currently consumed by refineries and crude oil facilities. Full substitution of this end-use with biomethane going forward would represent a potential of 12 MMT of reductions of carbon annually, such that even partial substitution could meet a significant portion of the LCFS.

- **Future capital and operating costs for cellulosic ethanol will decrease over time.** While it is possible for California entities to import hundreds of millions of gallons of ultra-low CI cellulosic ethanol at some point in the future, it is difficult to predict exactly when those gallons will be available. However, cellulosic technology providers have successfully reached commercial scale at some plants and the first wave build out is well underway. Future validation of the first wave of cellulosic production facilities will pave the way for financing of the second and third wave of cellulosic plants. It is widely

[5] Air Resources Board (2013), *Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources Refinery Sector Public Report*, Issued June 6, 2013. http://www.arb.ca.gov/cc/energyaudits/eeareports/refinery.pdf
[6] Air Resources Board (2014), *Low Carbon Fuel Standard Reporting Tool Quarterly Summaries*, http://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm.

expected, based on industry experience and learning, that the second wave and later facilities will have lower capital costs and improved efficiency.

- **Even remaining conservative on the timing and volumes for cellulosic ethanol in 2020, given the uncertainty of the second wave of production plants, other low-carbon fuels and technologies can provide sufficient credits under the scenarios evaluated.** Since the LCFS is technology-neutral performance based, and also includes an ability for parties to "bank" or save credits, regulated entities have enormous flexibility to comply. No single technology is required to generate the reductions needed.

- **Over-compliance over the 2015 to 2018 period will allow for compliance in later years through 2020**. The so-called "banking" provisions of the LCFS allow companies to flexibly utilize credits generated in earlier years to comply with future years. As of the end of 2014, parties registered within the LCFS have registered an over-compliance of approximately six million metric tons, with those credits banked for use in future years.[7]

Potential Barriers Moving Forward

- **The LCFS needs underlying regulatory stability to achieve a 10% reduction requirement by 2020 and a theoretical 15% requirement by 2025.** As a result of lawsuits brought against the state by oil and corn ethanol industry groups, the current LCFS reduction mandate has remained at a one percent (1%) CI reduction level since 2013, resulting in significant over-compliance with the standard. As the same time, LCFS credit prices have dropped from nearly $80 per ton in December of 2013 to $26 per credit in December of 2014.[8] Under a scenario where LCFS credit prices remain under $50/ton for 2016 and beyond, the sustained low credit price causes an insufficient market signal, with the overall LCFS market generating annual deficits beginning in 2018 and regulated industries fully using all banked credits by 2020. In 2020 and beyond, the LCFS would experience net cumulative deficits. Accordingly, for the LCFS to achieve full compliance, sufficient regulatory certainty must exist to provide a sufficient market signal to spur additional alternative fuel supplies.

- **Reductions in the carbon-intensity on the gasoline side will be slower than on the diesel side unless greater expansion of E15 and E85 occurs.** While credit values at $100/ton will be sufficient for production of low CI ethanol, further capital investments are needed to develop the next wave of cellulosic ethanol facilities. Furthermore, additional infrastructure investments will be needed to expand the use of low CI ethanol

[7] Air Resources Board (2014), *Low Carbon Fuel Standard Regulation: Initial Statement of Reasons*. December 31, 2014. http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm
[8] Information based on reporting of the credit values by ARB. http://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm.

beyond E10 (e.g. E15 or E85) and allow the industry to achieve a larger reduction. This includes ethanol producers overcoming limitations due to lack of upgraded ethanol infrastructure including tankage and blender pumps.

- **Long-term regulatory stability and firm commitment with both the Low Carbon Fuel Standard and the federal Renewable Fuels Standard is necessary for financing of new facilities**. Major investors are sensitive to regulatory instability and require long-term time horizons before financing major capital projects. Ensuring forward momentum will, at minimum, require the LCFS credit value to be sufficiently robust to achieve compliance.

4. Methodology

Promotum developed spreadsheets for each fuel technology. Where available we developed supply inputs based on prior studies and on discussions with industry experts and stakeholders. The modeling evaluated a Reference Case and Low Case, with calculations and accounting following ARB's methodology as presented in its regulatory analysis.[9]

For consistency we adopted ARB's baselines for gasoline and diesel CIs; forecasts for gasoline and diesel consumption; the proposed compliance curve from 2015 to 2020; and the banked LCFS credits estimated for 2014. For assumptions on CI, we used the CI look up table from ARB's *Initial Statement of Reasons* (ISOR) Appendix B "average annual CI assumptions." Using the CI values and forecasts, we calculated the overall compliance credits and deficits annually to evaluate compliance each year. Where available we utilized obligated party reporting (2013 and 2014) to ground the model, information that ARB makes publicly available.[10]

The fuel volume tables for the 2015 to 2025 period of study assume that refiners and fuel importers must reduce the lifecycle GHGs produced from gasoline and diesel. This includes crude oil production, transportation, refining, distribution, and combustion. LCFS deficits can be offset by blending lower CI gasoline and diesel substitutes, purchasing credits, utilizing banked credits, or generating credits directly from refinery investment projects or applying innovative technologies at crude oil production facilities. In cases where producers use blending as a compliance strategy, they will largely use ethanol and biodiesel. Additional credits accrue from electric vehicles, both fossil-based and bio-based natural gas (or biomethane), and hydrogen used for fuel cell vehicles. These categories are currently small but growing in their contributions to meeting the standard.

For each case we developed biofuel supply curves for 2015 to 2025. There are many pathways and approved biofuels, but the major substitutes include:

Major Gasoline Substitutes and Technologies	Major Diesel Substitutes and Technologies
Ethanol (Corn, Sorghum/Wheat, Sugar, Cellulosic)	Biodiesel (Soy, Corn Oil, Waste Grease/Used Cooking Oil, Animal Tallow)
Electricity	Renewable Diesel (similar feedstocks)
Petroleum Improvements	Compressed Natural Gas or Liquefied Natural Gas, (Fossil and biomethane)
Renewable Gasoline	Petroleum Improvements

[9] http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm
[10] http://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm

This report also examined potential GHG reductions in the petroleum value chain. Promotum believes there is significant opportunity to reduce the overall CI of traditional gasoline and diesel, principally by utilizing steam derived from biogas or solar thermal energy sources for Enhanced Oil Recovery (EOR) operations at the well head, substituting biomethane for fossil natural gas at refineries, and utilizing off-the-shelf energy efficiency technology and improved operations at refineries. Promotum did not evaluate use of carbon capture and sequestration (CCS) at petroleum facilities.

5. Scenarios

Promotum created two hypothetical cases to evaluate the effects of credit prices on potential achievement of LCFS targets. For each case, we calculated the LCFS deficits (MT CO_2e generated) produced by the petroleum value chain and the combustion of traditional gasoline and diesel. To this obligation, we added back the LCFS credits produced (MT CO_2e reduced) by substituting in biofuels and through reductions in emissions from the petroleum value chain. We then added previously banked credits before comparing the annual and cumulative total against ARB's compliance curve.

For purposes of the study, we assumed steady state average pricing for Low Carbon Fuel Standard credits. Based on these prices, we evaluated how much low carbon fuel could be produced or imported to California for each fuel type.

As a starting point for the biofuels portion of the scenario assessment, we started with the basic strategy of assuming the penetration of as much low CI substitute biofuel into the California fuels market as was available. This assessment took into account limitations in available supply or potential new capacity. We then backfilled needed fuel volumes with the best available corn ethanol and soy-based biodiesel - using compliance data filed quarterly with ARB to set starting levels of blended ethanol and biodiesel. The starting blend rate for ethanol was 10.6% (by volume) and about 2% for biodiesel.

To calculate the GHG reductions currently required by the LCFS, we used the currently proposed compliance schedule for 2016 through 2020 in ARB Staff's *Initial Statement of Reasons.* According to the analysis, by 2020 the LCFS requirements would effectively require enough credits to reach a 10% reduction in carbon-intensity for gasoline and diesel.

To calculate the GHG reductions required under an LCFS that extended to 2025, we extended the LCFS requirements to a 15% CI reduction, increasing at an additional rate of 1% per annum. Figure 1 shows the compliance requirements used for both scenarios.

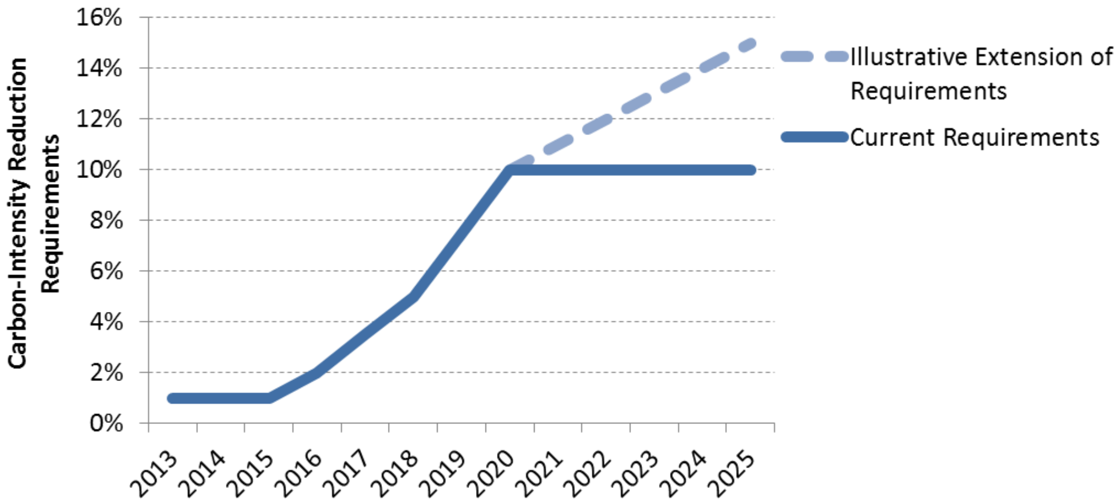

Figure 1: Current proposed requirements achieving 10% by 2020 and extension of requirements to 15% by 2025.

6. Issues and Considerations

Assessing the feasibility of LCFS reductions and differential credit values and the effect of those credit values on biofuel supplies is a considerable and complicated subject. We describe some of the complexities in the following section.

A. Internal LCFS Market Conditions

Since the program's inception, the credit values have experienced market fluctuations. Commodity market experts, such as at Argus, suggest the reasons for volatility encompass a number of factors[11]:

- Regulatory and legal uncertainty in the initial three years,
- Over-compliance occurring due to the low standard — one percent — maintained since 2013,
- A short spot market due to producers banking surplus credits in expectation of future shortfalls, and
- A thin LCFS credit market due to a limited numbers of buyers, sellers, and volumes of credits able to be bought and sold.

[11] *Argus White Paper: California Environmental Markets: Factors that Affect LCFS and GHG Trading,* Argusmedia.com

B. Combined Effects of the LCFS and the Renewable Fuel Standard

In addition, understanding the implications of the California GHG reduction measures must account for the federally mandated Renewable Fuel Standard (RFS) managed by the U.S. Environmental Protection Agency (EPA). The RFS requires increasing volumes of biomass-based fuels, with specific volumetric requirements for different categories of fuels meeting GHG reduction thresholds. Fuels that qualify are eligible to generate Renewable Identification Numbers (RINs), a serial number that both allows for tracking of fuel and allows for trading among parties. Like LCFS credits, RINs have a market value for those that own them. In addition, RINs become separable after biofuels are blended - meaning producers can choose to buy and retire RINs instead of blending biofuels themselves.

As a result, if the LCFS credit value plus RIN value exceeds transportation cost to California for a given gallon of biofuel, this should provide enough incentive for producers to make more biofuels and sell them into the California market. Figure 2 demonstrates how RINs and LCFS credit work in tandem to increase supplies of the biofuel.[12]

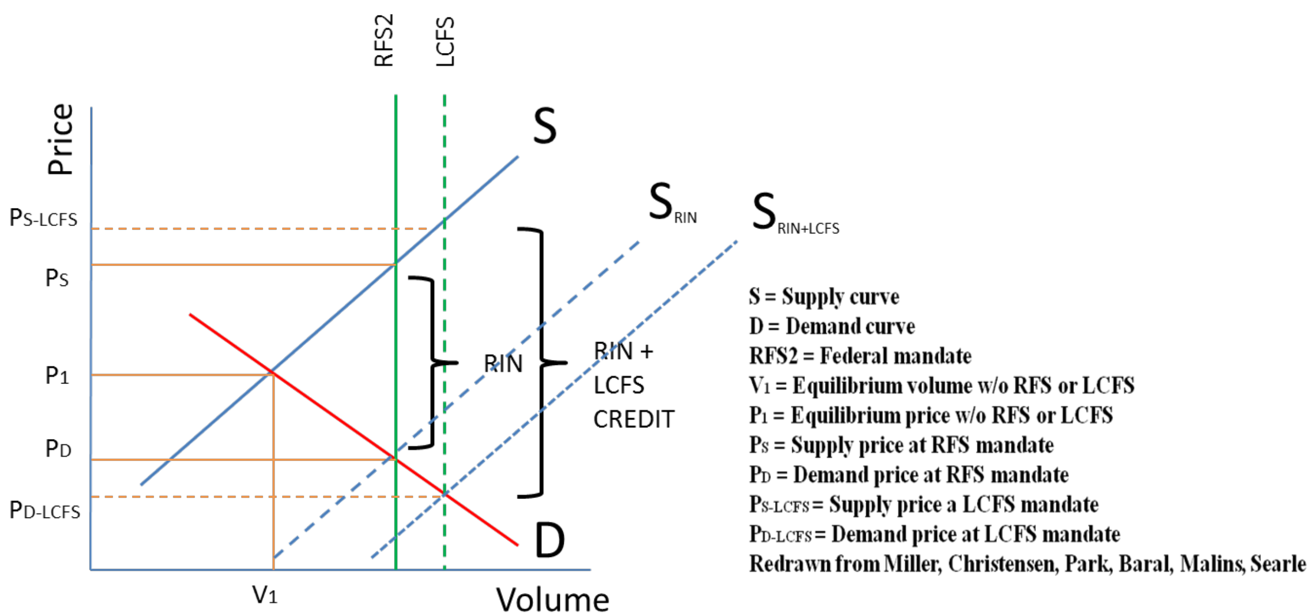

Figure 2: Biofuel economics of LCFS credits and RFS RINs.

[12] N. Miller et al (2013), *Measuring and addressing the investment risk in second-generation biofuels* industry, International Council on Clean Transportation, 2013. http://www.theicct.org/addressing-investment-risk-biofuels

C. Technology and infrastructure development

Notwithstanding the impact of overlapping LCFS and RIN credit prices, the market signal for Low-CI fuel development gets more complicated when considering the stages of technology development and production capacity for many low CI fuels (i.e. advanced biofuels). Based on present market conditions, it remains evident that much of the nation's prospective supply of low-CI fuels is still maturing. Significant infrastructure issues need to be addressed for many biofuels before the market is truly efficient with high price elasticity.

Under these circumstances technology developers are making investments in technology and capacity based on market expectations, including the future of the RFS and the LCFS programs in terms of regulatory certainty and the RIN and LCFS credit markets. The diagram below based on biofuel supply curves generated by Nathan Parker at UC Davis describes the situation graphically.[13] For our purposes we assumed that LCFS credit values will signal prospective suppliers in anticipation of a future efficient market.

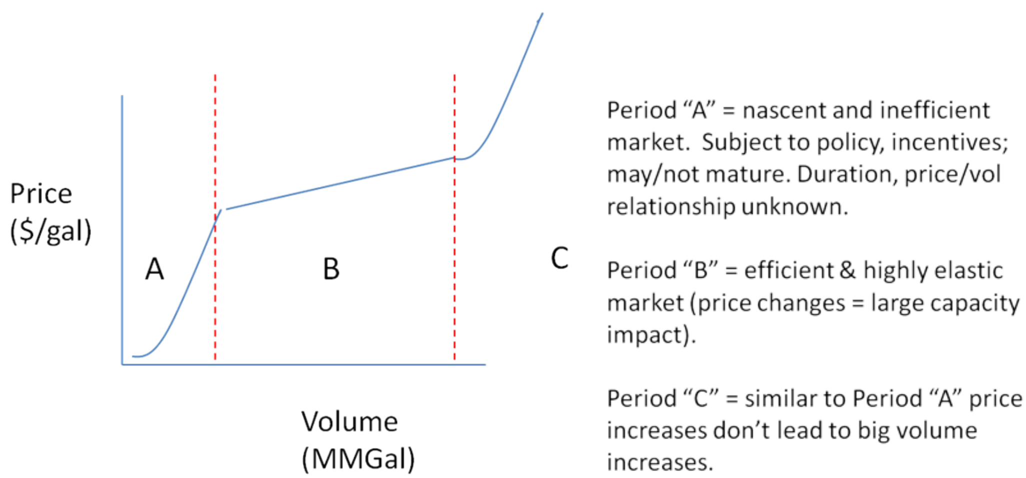

Figure 3: Biofuel supply at varying price points.

For each of our cases we estimated the biofuels volumes, which after analysis we believed would be available in California based on the LCFS credit value, constrained by our understanding of the current state of technology, infrastructure and U.S. or global forecast capacity. To understand the value of each biofuel to California we calculated how much each fuel resulted in reduced carbon dioxide emissions and then what additional value was associated with the fuel, on a dollar per gallon gasoline or diesel equivalent energy basis ($/gge or $/dge), depending on which fuel they substituted for.

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[13] N. Parker (2011), *Modeling Future Biofuel Supply Chains Using Spatially Explicit Infrastructure Optimization*, Dissertation, Univeristy of California, Davis. http://www.its.ucdavis.edu/research/publications/publication-detail/?pub_id=1471

D. LCFS incentive value for alternative fuels

Figure 4 translates LCFS credit value for gasoline and diesel substitutes to a dollar per gallon gasoline equivalent basis. The credit value range shown represents a low of \$50/MT CO_2e to a high of \$150/MT.

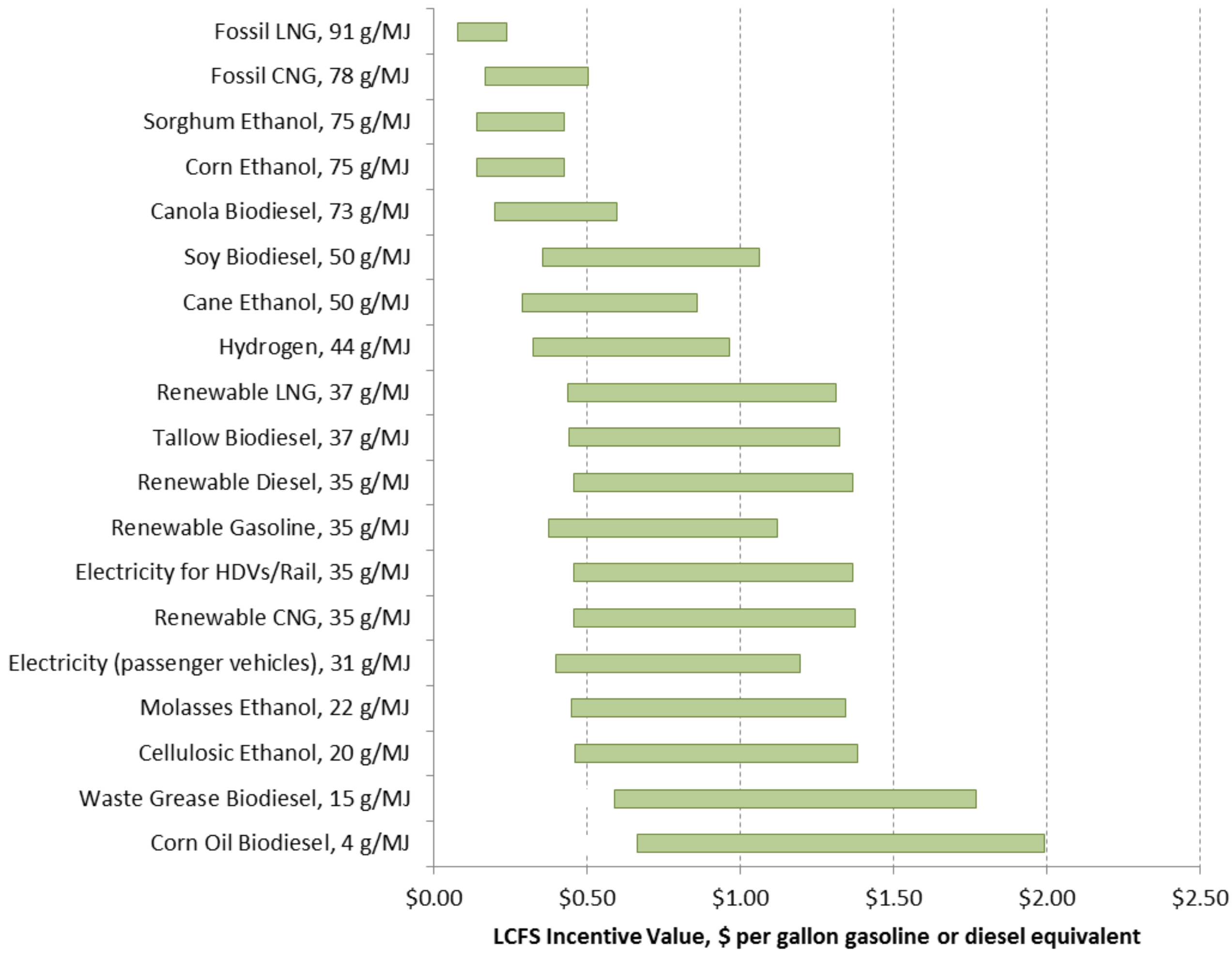

Figure 4: Incentive value provided by the LCFS. Range represents \$50 to \$150 per MT CO2e reduction.

As shown in Figure 4, the Reference Case of \$100 per MT reduced of CO_2e translates into an additional value of \$0.92/gallon for cellulosic ethanol. Theoretically, as long as the LCFS credit value together with the associated cellulosic RIN prices exceed transportation costs, we should see producers ramping up capacity and selling into California as well as California producers expanding and increasing production.

In the Low Case ($50/MT reduction), the value for cellulosic ethanol translates to $0.46/gallon in addition to the RIN value. Higher LCFS credit values, of course, are possible and would theoretically provide greater incentive for domestic production or greater importation. However, other factors, such as the state of technology development and availability for financing of new facilities, may be more critical in establishing necessary volumes than the incentive value of RINs and LCFS credits.

E. LCFS incentive value to reduce petroleum sector emissions

The LCFS also provides incentives and returns credit value to petroleum companies that choose to reduce lifecycle oil and gas emissions directly. These companies may generate credits by reducing the CI of crude oil production and refineries through greater use of energy efficiency, innovative technologies, or renewable inputs. Like other fuels, these investments can yield LCFS credits which have higher or lower value based on the overall credit price.

One example of the value of the LCFS for petroleum company investments can be extrapolated from self-reported data on energy efficiency investments by California petroleum refineries to the ARB. [14] As reported, there are over four hundred past and planned energy efficiency and co-generation projects at refineries in California, with a total capital cost of approximately $2,600 million - resulting in annual energy savings of about $200 million for refineries and 2.8 million metric tons of reduced GHGs.

Using past projects identified to ARB as an illustration, if refineries were to invest in future energy efficiency improvements that resulted in an additional 2.8 million metric tons of reductions and achieved the same annual operating savings, the additional LCFS credit value generated could be between $140 to $280 million dollars annually (at a $50 to $100/ton credit price respectively). In addition California refineries would avoid having to purchase permits, or allowances, within the state's cap-and-trade regulation to cover their remaining CO_2 emissions, yielding an additional cost saving of about $35 million annually, assuming current permit prices of just over $12 per ton. These savings, in theory, would increase the overall annual savings from $200 million (energy savings) to $375 to $515 million annually at refineries with the additional LCFS credit value and avoided need to purchase cap and trade pollution permits. While further analysis in this area is warranted to provide finer resolution on a project-specific basis, initial calculations suggest that the LCFS could more than halve the payback period for investments in energy efficiency projects in some cases, making these projects significantly more attractive for petroleum companies.

7. Key Outputs

Promotum's analysis incorporates three major mechanisms that drive reductions in the carbon intensity of transportation fuels. The first is to increase the volume of renewable fuels we

[14] http://www.arb.ca.gov/cc/energyaudits/eeareports/refinery.pdf

currently use (grow the market); the second is to improve the carbon-intensity (CI) of the fuel (improve the fuel in the market); and the third is reduce emissions directly at refineries and crude oil production facilities using energy efficiency, renewable energy, and innovative technologies. To achieve the greatest reductions, California will likely need to spur all three mechanisms to varying degrees.

In our estimate, compliance with the LCFS will result in the alternative fuels market growing to 14% of the transportation energy mix by 2020 and 20% by 2025. Constraints on growth include the E10 blend-wall as well as the rate at which biodiesel can expand and be utilized in California. More volumes of ethanol and biodiesel will be needed to achieve compliance. This means California will need to accelerate E15 and E85 deployment as well as biodiesel blends above B5 levels post 2017 based on the Reference Case scenario.

In terms of improving the carbon-intensity of fuels, achieving the LCFS will require migration toward lower-carbon feedstocks; improvements at the biofuel plant and at the agricultural level. The LCFS is already sending a market signal, but regulatory certainty is necessary to ensure sufficient value for technology improvements to continue.

Improvements along the petroleum value chain remains, to date, one of the largest untapped areas of potential for CI reductions across the existing fuel pool. While alternative fuels will increase in market share, the large majority of transportation fuels will remain petroleum-based over the timeframe. Even small changes in CI, when spread across large fuel volumes, will lead to significant reductions.

The analysis of the effects of credit prices demonstrates three findings. First, the LCFS credit value is an important factor in increasing low-carbon fuel supply and reductions in GHG emissions we can achieve. Second, ARB's regulatory analysis, showing credit prices around $100/ton, would be sufficient to allow for a 10% requirement to be met by 2020 while extending the standard to a 15% level by 2025. Third, if credit values remain low – as we saw in the past year, due to regulatory uncertainty– then sufficient incentive will not exist for low-carbon fuel production, and compliance beyond 2020 will be unlikely to occur.

Beyond the recent decreases in oil prices, the most significant barrier to the supply of low CI fuels in California remains uncertainty with the regulatory environment. Oil companies, alternative fuel companies, and other energy investors make large capital commitments and require enough time to achieve acceptable returns.

LCFS Reference Case:

Figure 5 demonstrates annual and cumulative credit balance over time for the Reference Case.

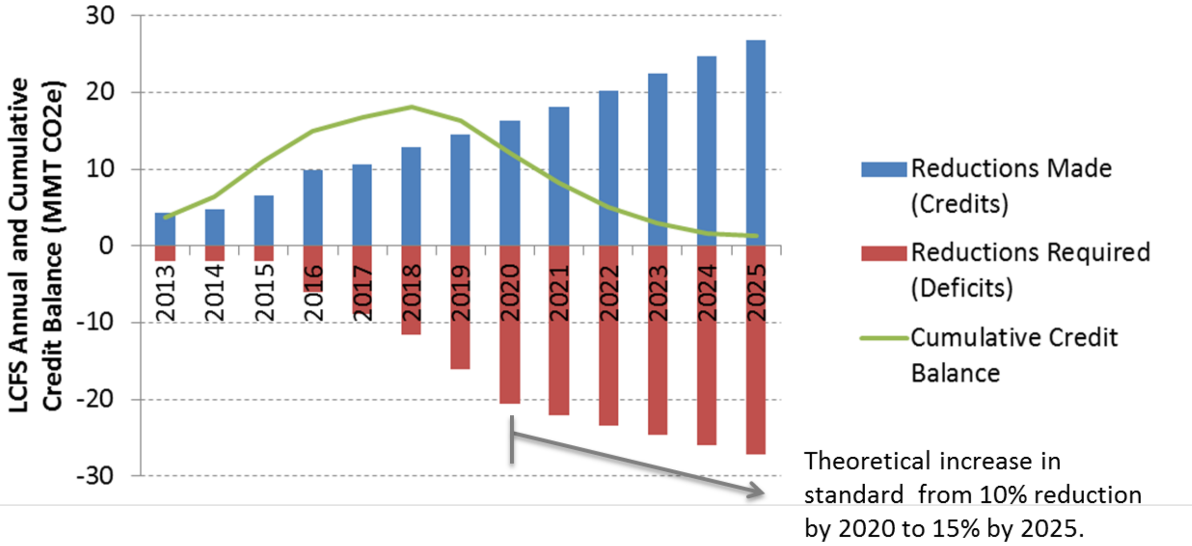

Figure 5: LCFS Annual Credit and Deficits, with the Cumulative Credit Balance (LCFS Reference Case).

The LCFS Reference Case is comprised of the following scenario:

- An LCFS credit value of $100/MT
- Assumes that the current requirement of 10% CI reductions by 2020 is increased to 15% CI reductions by 2025
- Biomass-based diesel, including biodiesel and renewable diesel, become a principal tool of compliance, taking advantage of underutilized production capacity and RIN and LCFS credit values to utilize waste greases, animal tallow, corn oil, and soy oil among other feedstocks.
- Blend rates of biodiesel grow to a 7% by volume mix in diesel (B7) by 2020 taking into account existing infrastructure constraints and restrictions on increased NOx. Blend rates increase to B12 in 2025 as the new NO_x control technologies on trucks are phased in by 2023.
- Direct emission reduction from the petroleum value chain make significant contributions to LCFS compliance
- Electricity used in passenger vehicles, as well as for off-road mobile and truck applications, also make significant contributions.
- Credit value is sufficient to incent the production and import of low CI cellulosic and sugarcane ethanol from existing facilities, but other factors related to investment and financing of new facilities, distribution infrastructure, and other issues limit availability.

The LCFS Low Case:

Figure 6 demonstrates annual and cumulative credit balance over time for the Low Case.

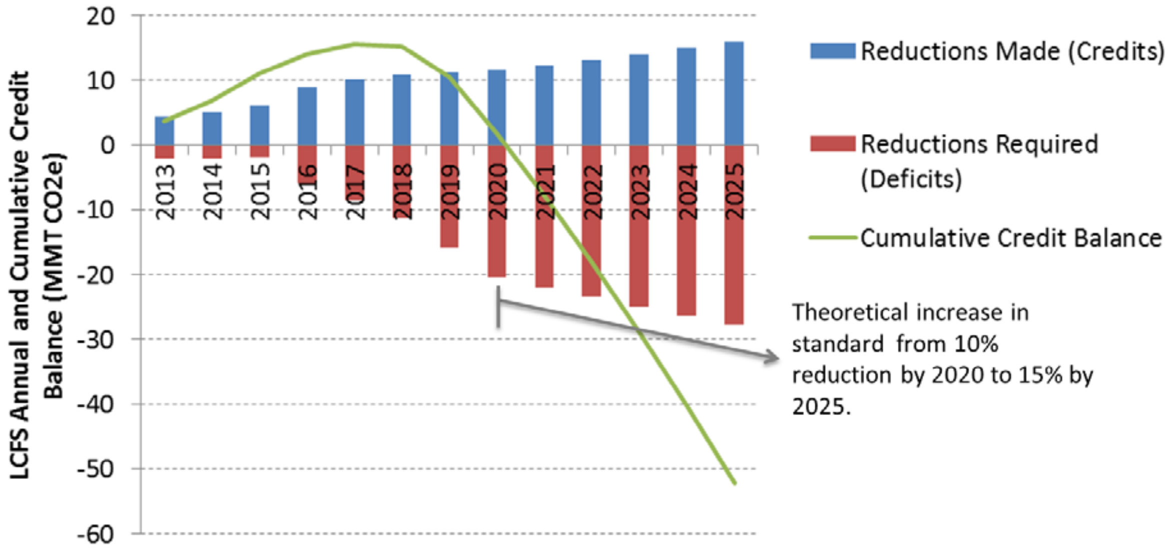

Figure 6: LCFS Annual Credit and Deficits, with the Cumulative Credit Balance (LCFS Low Case).

The LCFS Low Case is comprised of the following scenario:

- LCFS credit value below $50/MT
- Assumes that the current requirement of 10% CI reductions by 2020 is increased to 15% CI reductions by 2025
- Inexpensive and local waste based fuels come to the fore, which is positive, but under this scenario the incentive amount is not sufficient to persuade waste based biodiesel and renewable diesel producers to sell much more than the 2013/2014 volumes currently utilized in the state.
- California's LCFS market may achieve the Low Case scenario in the near term, but soy biodiesel (and other existing seed or vegetable oils) are not sufficiently incented to drive compliance.
- Absent large amounts of credits generated from diesel substitutes as in the Reference Case, greater ethanol demand occurs. In this scenario, a blend rate of 19% ethanol, including 2.5 billion gallons of mid-CI ethanol (e.g. corn, sorghum, wheat-based) would be required to achieve compliance in 2020.
- While there is enough ethanol production capacity, under a Low Case, significant investments in ethanol infrastructure to support E15 or E85 distribution are needed, including investments in storage tankage and retail blend pumps.
- In the Low Case, the LCFS incentives would be insufficient to allow for compliance beyond 2020.

Tables and additional descriptions of the compliance pathways are provided in the Appendices.

Appendix A: Description of compliance pathways

Reference Case ($100 per ton credit value)

Ethanol - Prior to the LCFS, requirements for reformulated gasoline to reduce smog – together with the federal RFS volume requirement – have effectively led to the growth in the use of ethanol to E10 levels. Corn-based ethanol has been the primary biofuel utilized in California. The LCFS has driven improvements in the carbon-intensity of the ethanol mix over the past three years. ARB has approved many ethanol pathways and the CIs of ethanol produced as well as imported into California continue to drop significantly. In our Reference Case we see a tapering of corn ethanol consumption starting in 2015, dropping steadily to 650 MMG in 2025 as other lower CI ethanol feedstocks and fuels become available.

Traditionally the US receives 50% to 60% of Brazil's cane ethanol exports and despite current challenges in the Brazilian marketplace, we expect imports of this low CI fuel to continue. These challenges, including sugar versus corn pricing and Brazil's domestic policies, will likely temper California's imports. Ultimately, we see consumption growing to 300 million gallons per year (MMGY) by 2020.

While it is easy to envision the importation of hundreds of million gallons of ultra-low CI cellulosic ethanol into California, it is difficult to predict exactly when those quantities will be available. Cellulosic ethanol (c-etoh) volumes remain highly uncertain.

Cellulosic technology providers have successfully reached commercial scale and the first wave build out is well underway. Based on separate estimates from Bloomberg New Energy Finance (2014) and Environmental Entrepreneurs (2015), about 220 million gallons per year of capacity of cellulosic ethanol is already built or forecasted to be completed by end of 2015, with about 100 million gallons of this capacity located in the U.S.[15] We expect availability of c-etoh to emerge in 2015 with the launch of the Abengoa, POET and DuPont facilities in the U.S. However, capacity utilization will likely be modest for the early years. Based on a healthy LCFS credit value and discussions with c-etoh technology providers, we expect a significant fraction of the available pool to make its way to California.

Coming validation will pave the way for financing of the second and third wave of cellulosic plants. At this time the facilities are more expensive and smaller than first generation ethanol plants. However, both capital and operating expenditures will decrease significantly over time as technology and operations improve. Cost of production estimates for cellulosic ethanol abound. Promotum reviewed publically available studies and analysis by academics as well as government agencies that incorporate theoretical cost models. In addition, Promotum spoke directly to several technology providers. We incorporated available data into our supply curves

[15] Bloomberg New Energy Finance data (http://about.bnef.com/). Environmental Entrepreneurs (2015), *Advanced Biofuel Market Report 2014*.

for the Reference Case and Low Case and this informed our thinking. We believe the estimates are conservative but reasonable.

US c-etoh facilities will largely be green field construction, scaling in modular fashion from 25 million gallons per year capacity followed by 50 and 75 MMGY plant capacities. Given issues around herbaceous feedstock transportation, achieving 100 MMGY capacity in any one plant is doubtful. Based on conversations with cellulosic ethanol technology providers we believe the price of cellulosic ethanol will fall on a fully loaded basis from $2.75/gallon today to about $1.70/gallon in 2030, including the cost of capital.

Electricity and Hydrogen –While internal combustion engine vehicles remain the current predominant technology on the road, automakers are rapidly investing in fuel efficient technologies, including various combinations of electric-drive vehicles, from plug-in hybrids to full battery electrics, even offering initial hydrogen fuel cell vehicles. As electric-drive vehicle sales continue to displace gasoline powered vehicles, demand for low CI electricity will increase and credits will be generated. We see electricity consumption almost quadrupling from 0.44GWhr in 2015 to 1.6GWhr in 2020 and nearly 4.4GWhr in 2025. For hydrogen, we believe the opportunities for fuel cell vehicles are good, but we have conservatively kept consumption at modest levels in the study, given potential hydrogen infrastructure constraints. We also note that improvements in the CI of electricity and hydrogen are expected, particularly if California meets targets to reach 50% renewable by 2030 in addition to the existing 33% Renewable Portfolio Standard requirements by 2020. To be conservative, however, we kept CI constant, as assumed in ARB Staff's *Initial Statement of Reasons*.

Petroleum Supply Chain Improvements – This study estimates GHG emission reductions in the petroleum value chain, including at the well head and refinery level will make up a significant percentage of overall compliance in the Reference Case.

Three technologies were included in this assessment using a study by TetraTech/NRDC (2014) as a starting point. These include use of solar thermal for steam generation in enhanced oil recovery, broader use of energy efficiency at refineries, and use of biomethane by the petroleum industry. These estimates may be conservative given the wider array of technologies available as well as industry experience with some of these technologies already.

For solar thermal, it is assumed that approximately 10% of the fossil natural gas used for steam injection projects is displaced in California by 2025. These estimates do not include an assessment of the potential for crude oil imported into the state, which currently represent 63% of the mix used in California, to utilize this technology. We estimate that by 2025, just over 0.7 MMT of reductions annually can be generated.

For refinery energy efficiency (EE) investments, it is assumed that at $100/ton, the incentive is sufficient to more than double the payback of EE, such that a reduction of 1.5% per year improvement in GHG emissions at refineries across the industry. We estimate that reductions from EE investments grow linearly from 2017 to 2025, reaching 4.3 MMT in annual reductions by 2025.

In terms of renewable energy inputs, we consider the use of biomethane to replace fossil natural gas at crude oil facilities, a fuel consumed at refineries, and a feedstock for hydrogen production utilized by refineries. We assume that 15% of the natural gas used by California crude oil and refining facilities could be displaced via biomethane purchases by 2020, growing to nearly 40% by 2025. The reductions would grow to 1.1 MMT annually by 2020 and 2.8 MMT annually by 2025. Significant volumes of biogas, which can be cleaned and processed into biomethane, are currently emitted, flared, or captured from landfills, dairy digesters, and waste-treatment facilities throughout the U.S.[16]

The study projects CI reductions, applied as credits for crude oil producers or refineries respectively, would be approximately 1.5% by 2020 and 3% by 2025 over the entire lifecycle of petroleum gasoline and diesel. This CI reduction level corresponds to 16% and 32% of the standard in 2020 and 2025 respectively being met in those years from direct petroleum supply measures. We believe the current environment of relatively low oil prices also lends itself to implementation of downstream projects, including refinery energy efficiency and GHG reduction projects, as other capital investments in the upstream and midstream are reduced in the U.S.

When combined, we see opportunities for 4.2MM MT of GHG reduction in 2020 reaching 8.8MM MT in 2025 from these three categories of technologies.

Renewable Diesel – We see opportunities for renewable diesel (R-Diesel) to play an important role in California's biofuel portfolio, based on existing domestic and international plant capacity, reaching 400 MMGY in 2020. This represents almost 50% of the ~850 million gallon global capacity, but is consistent with the estimates by the Air Resources Board staff in their regulatory analysis.[17] To some extent we have concerns with regard to the sustained availability of international supplies (~650 million gallons per year) and the high cost of new capacity. We do believe domestic capacity for hydrotreating waste oils will be constrained. We also believe there will be considerable competition for this capacity with military aviation fuel. Continued uncertainty around the US production tax credit will also inhibit financing capacity expansion.

Biodiesel – Biodiesel is a primary driver of compliance in the Reference Case. In California and the United States there are hundreds of millions of gallons of underutilized biodiesel production capacity. The technology is simple and mature, utilizes low carbon feedstocks and produces a low CI diesel substitute. We see an important opportunity to grow the blend rate beyond the currently anemic 2% levels by volume. Waste grease (used cooking oil),increasing volumes of corn oil biodiesel and soy biodiesel will contribute. We see total biodiesel consumption reaching 265 MMGY in 2020 and more than 500 MMGY in 2025.

[16] NREL (2013), *Biogas Potential in the United States*, NREL/FS-6A20-60178, October 2013, National Renewable Energy Laboratory, Energy Analysis, Golden, CO. Also see EPA Landfill Gas candidate project lists: http://www.epa.gov/lmop/projects-candidates/index.html.

[17] http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm

Availability of corn oil depends primarily on the penetration of necessary unit operations within corn wet mills. Starting from approximately 59% in 2015 we see penetration increasing to ~90% by 2025. We forecast 68 million gallons of inedible corn oil biodiesel reaching California in 2020 out of an estimated US pool of 475 million gallons and greater than 100 million gallons in 2025.

Biodiesel from used cooking oil (waste grease) will continue to make an important contribution to the BD pool. We estimate 51 million gallons will be available to California in 2020 and 77 million gallons in 2025. While the very low CI makes it particularly attractive, community collection by its nature will remain a constraint.

Swing biodiesel feedstock will come in the form of soy oil. While often spurned because of its nominal association with food, soy oil is separated, from soy protein prior to utilization. A healthy LCFS credit value overcomes traditional soy pricing problems, which have mothballed many biodiesel facilities and left many others operating below capacity. With an improving CI profile we predict 51 million gallons of soy biodiesel in the California market in 2020 and 77 million gallons in 2025. We do not see a big role for canola based biodiesel in the US or California.

Natural Gas – We expect natural gas usage in fleets to increase and used to comply with the LCFS. We also assume that an increasing share will come from biomethane captured from landfills and other sources, including anaerobic digestion and waste-treatment facilities. We find approximately 170 million diesel gallon equivalents of liquefied natural gas will be utilized by 2025 and 306 million diesel gallon equivalents of compressed natural gas being utilized. We assume approximately 80% of these volumes will be derived from biomethane sources by 2025, given the increased value for biomethane producers and current levels in California approaching 40%.

Low Case (less than $50 per ton credit value)

Ethanol – In a Low Case scenario, inexpensive corn, wheat, or sorghum based ethanol becomes the primary tool of compliance. Instead of the tapering we saw in the Reference Case, a dramatic increase in these feedstocks occurs, reaching blending level of 2.5 BGY in 2020, together with an additional 140 MMGY of low-CI ethanol. This represents an effective blend rate of 19%-21% in the years 2020-2025.

Electricity and Hydrogen – We find that similar levels of electricity and hydrogen consumption for the transportation sector will occur between the LCFS Reference and Low Case. However, we have not analyzed the use of electricity credits by utilities and the effects on the market, given the lack of current data.

Petroleum Supply Chain Improvements – Lower credit values decrease the incentive for refinery and well head improvements. Significant reductions still occur, reaching 2.1MMT in 2020 and 5 MMT in 2025, but the pace of implementation is slower.

Renewable Diesel – R-Diesel remains relatively expensive from 2015 to 2025 and lower LCFS credit values mean blending remains stuck at circa 2015 levels, approximately 100MMGY.

Natural Gas – While we find that NGV usage and natural gas demand for transportation to remain at similar levels to the Reference Case, we see a significant drop in biomethane use to only double from current levels, growing to only 30 MMGY (diesel equivalent).

Appendix B: Fuel Volumes and Carbon-Intensity Tables

Reference Case ($100 per ton credit value)

Reference Case														
Gasoline Replacements	**Units**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Corn Ethanol	mm gal	1,220	1,275	1,255	1,200	1,150	1,000	975	850	800	775	725	675	650
Cane Ethanol	mm gal	150	100	100	100	100	200	200	300	300	300	300	300	300
Diversified Ethanol (sorghu	mm gal	150	170	170	190	215	235	235	235	235	235	235	235	235
Cellulosic Ethanol	mm gal	0	0	5	25	35	45	55	65	75	85	95	105	115
Renewable Gasoline	mm gal	0	0	0	0	0	5	15	25	50	75	100	125	150
Hydrogen	mm gal GGE	0	0	2	5	8	11	15	21	25	30	36	44	52
Electricity for LDVs	1000 MWH	200	400	440	596	759	982	1,276	1,629	2,064	2,563	3,127	3,757	4,374
Total Ethanol (MM gal)		1,520	1,545	1,530	1,515	1,500	1,480	1,465	1,450	1,410	1,395	1,355	1,315	1,300
CARBOB (energy adjusted)		12,848	12,950	12,814	12,666	12,519	12,365	12,197	12,021	11,776	11,510	11,256	10,997	10,723
Gasoline As CARFG + E85		14,340	14,495	14,344	14,186	14,034	13,870	13,712	13,546	13,286	13,030	12,761	12,312	12,023
Ethanol (vol %)		10.60%	10.66%	10.67%	10.68%	10.69%	10.67%	10.68%	10.70%	10.61%	10.71%	10.62%	10.68%	10.81%
Diesel Replacements	**Units**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Soy Biodiesel	mm gal	5	5	5	15	30	85	105	135	175	215	255	285	300
Waste Grease Biodiesel (U(	mm gal	33	35	37	39	41	43	45	47	49	51	53	55	57
Corn Oil Biodiesel	mm gal	11	20	34	48	61	68	68	68	68	82	102	122	142
Tallow Biodiesel	mm gal	4	5	10	10	10	10	10	10	10	10	10	10	10
Canola Biodiesel	mm gal	6	5	5	5	5	5	5	5	5	5	5	5	5
Renewable Diesel	mm gal	118	107	180	260	290	320	360	400	400	400	400	400	400
LNG	mm gal DGE	28	26	30	30	30	30	30	30	30	30	30	30	30
CNG	mm gal DGE	61	70	70	70	70	70	70	70	70	70	70	70	70
Renewable LNG	mm gal DGE	5	5	30	39	51	63	76	90	100	110	120	130	140
Renewable CNG	mm gal DGE	6	11	45	59	77	94	114	136	156	176	196	216	236
Electricity for HDVs/Rail	1000 MWH	-	-	900	900	900	900	900	900	900	900	900	900	900
Total HD NG (DGEs)		100	112	175	198	228	257	290	326	356	386	416	446	476
Total Biodiesel (MM gal.)		59	70	91	117	147	211	233	265	307	363	425	477	514
Diesel (non-adjusted)		3,677	3,732	3,788	3,845	3,903	3,961	4,021	4,081	4,142	4,204	4,267	4,331	4,396
Diesel (energy adjusted)		3,404	3,447	3,324	3,253	3,222	3,162	3,128	3,082	3,074	3,054	3,029	3,014	3,014
Total biodiesel (vol %)		1.65%	1.93%	2.53%	3.21%	4.02%	5.03%	5.94%	6.94%	7.99%	9.01%	10.02%	11.09%	11.94%
Renewable Diesel (vol %)		3.29%	2.95%	5.01%	7.16%	7.92%	8.66%	9.67%	10.67%	10.58%	10.48%	10.38%	10.28%	10.18%

Petroleum Value Chain Reductions

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
MMT Reductions	-	-	-	0.4	0.4	1.3	2.3	3.2	4.2	5.3	6.5	7.6	8.8
CI reduction (g/MJ)	-	-	-	0.2	0.2	0.6	1.1	1.5	2.0	2.5	3.1	3.7	4.3

Low Case (Less than $50 per ton credit value)

Gasoline Replacements	**Units**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Corn Ethanol	mm gal	1,220	1,500	1,800	1,900	2,200	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
Cane Ethanol	mm gal	150	100	100	100	100	100	100	100	100	100	100	100	100
Diversified Ethanol (sorghu	mm gal	150	170	170	170	170	170	170	170	170	170	170	170	170
Cellulosic Ethanol	mm gal	0	0	5	25	35	35	35	35	35	35	35	35	35
Renewable Gasoline	mm gal	0	0	0	0	0	5	15	25	25	25	25	25	25
Hydrogen	mm gal GGE	0	0	2	5	8	11	15	21	25	30	36	44	52
Electricity for LDVs	1000 MWH	200	400	440	596	759	982	1,276	1,629	2,064	2,563	3,127	3,757	4,374
Total Ethanol (MM gal)		1,520	1,770	2,075	2,195	2,505	2,605	2,605	2,605	2,605	2,605	2,605	2,605	2,605
CARBOB (energy adjusted)		12,848	12,798	12,447	12,208	11,842	11,608	11,429	11,243	10,996	10,745	10,489	10,228	9,969
Gasoline As CARFG + E85		14,340	14,568	14,522	14,408	14,362	14,238	14,059	13,873	13,626	13,375	13,119	12,833	12,574
Ethanol (vol %)		10.60%	12.15%	14.29%	15.23%	17.44%	18.30%	18.53%	18.78%	19.12%	19.48%	19.86%	20.30%	20.72%
Diesel Replacements	**Units**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Soy Biodiesel	mm gal	5	5	5	5	5	5	5	5	5	5	5	5	5
Waste Grease Biodiesel (U	mm gal	33	35	37	39	41	43	45	45	45	45	45	45	45
Corn Oil Biodiesel	mm gal	11	20	34	48	61	61	61	61	61	61	61	61	61
Tallow Biodiesel	mm gal	4	5	10	10	10	10	10	10	10	10	10	10	10
Canola Biodiesel	mm gal	6	5	5	5	5	5	5	5	5	5	5	5	5
Renewable Diesel	mm gal	118	107	100	100	100	100	100	100	100	100	100	100	100
LNG	mm gal DGE	28	26	30	30	30	30	30	30	30	30	30	30	30
CNG	mm gal DGE	61	70	70	70	70	70	70	70	70	70	70	70	70
Renewable LNG	mm gal DGE	5	5	10	10	10	10	10	10	10	10	10	10	10
Renewable CNG	mm gal DGE	6	11	20	20	20	20	20	20	20	20	20	20	20
Electricity for HDVs/Rail	1000 MWH	-	-	900	900	900	900	900	900	900	900	900	900	900
Total HD NG (DGEs)		100	112	130	130	130	130	130	130	130	130	130	130	130
Total Biodiesel (MM gal.)		59	70	91	107	122	124	126	126	126	126	126	126	126
Diesel (non-adjusted)		3,677	3,732	3,788	3,845	3,903	3,961	4,021	4,081	4,142	4,204	4,267	4,331	4,396
Diesel (energy adjusted)		3,404	3,447	3,449	3,491	3,534	3,591	3,648	3,708	3,770	3,832	3,895	3,959	4,024
Total biodiesel (vol %)		1.65%	1.93%	2.50%	2.88%	3.25%	2.77%	3.13%	3.08%	3.03%	2.99%	2.94%	2.90%	2.85%
Renewable Diesel (vol %)		3.29%	2.95%	2.75%	2.70%	2.66%	2.62%	2.58%	2.54%	2.50%	2.46%	2.43%	2.39%	2.35%

Petroleum Value Chain Reductions

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
MMT	-	-	-	0.2	0.7	1.1	1.6	2.1	2.7	3.2	3.8	4.4	5.0
CI reduction (g/MJ)	-	-	-	0.1	0.3	0.5	0.8	1.0	1.3	1.5	1.8	2.1	2.4

Annual average carbon-intensity (g $CO2_e$/MJ)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Corn Ethanol	82.24	82.24	82.24	70.00	69.30	68.61	67.92	67.24	66.57	65.90	65.24	64.59	63.95
Cane Ethanol	72.5	72.5	72.5	40.0	39.5	39.0	38.5	38.0	37.5	37	36.5	36	35.5
Sorghum/Corn Ethanol	79.1	79.1	79.1	70.0	69.3	68.6	67.9	67.2	66.57	65.9	65.24	64.59	63.95
Misc Corn Ethanol	91.5	91.5	91.5	70.0	69.3	68.6	67.9	67.2	66.57	65.9	65.24	64.59	63.95
Sorghum/Corn/Wheat Ethanol	72.8	72.8	72.8	65.0	64.4	63.7	63.1	62.4	61.81	61.2	60.58	59.98	59.38
Cell. Ethanol[1]	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Molasses Ethanol	22.1	22.1	22.1	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
Renewable Gasoline[2]	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Hydrogen	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9
Electricity for LDVs	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Soy Biodiesel	83.3	83.3	50.0	49.5	49.0	48.5	48.0	47.5	47	46.5	46	45.5	45
Waste Grease Biodiesel	15.0	15.0	14.0	12.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Corn Oil Biodiesel	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Tallow Biodiesel	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2
Canola Biodiesel	62.6	62.6	62.6	73.2	73.2	73.2	73.2	73.2	73.2	73.2	73.2	73.2	73.2
Renewable Diesel	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
LNG	80.9	80.9	80.9	90.9	90.0	89.1	88.2	87.4	86.5	85.6	84.7	83.8	82.9
CNG	70	70	70	70	70	70	70	70	70	70	70	70	70
Renewable LNG	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Renewable CNG	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Electricity for HDVs/Rail	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9
CARBOB	99.2	99.2	99.2	100.6	100.6	100.6	100.6	100.6	100.6	100.6	100.6	100.6	100.6
CARB Diesel	98.0	98.0	98.0	102.8	102.8	102.8	102.8	102.8	102.8	102.8	102.8	102.8	102.8

8. About Promotum

Promotum is a technology based management consulting working at the convergence of fuels, chemicals and biologics. We are a team of standout engineers, scientists and accomplished MBAs, who are as passionate about science and technology as we are about business. By focusing on the convergence of energy, materials, and biology we deal daily with complex issues and disciplines. Promotum is growth focused helping clients enter new markets, evaluate or create them. Our expertise allows us to maximize results for our clients around the world. Promotum is headquartered in Cambridge, Massachusetts.

Functional Practices

- Business Development
- Business Strategy & Planning
- Corporate Development
- Competitive Intelligence
- Due Diligence
- Investment/Financial Analysis
- Licensing
- Market Analysis
- New Venture Creation
- Policy Analysis
- Technology Commercialization

Industrial Practices

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- Biomass to Energy
- Energy Efficiency
- Environmental Sciences
- GHG Life Cycle Analysis
- Green Chemicals
- Green Polymers
- Next Generation Fuels
- Next Generation Vehicles