A Tale of Cane and Corn:

Evaluating Compliance Opportunities for Brazilian Sugarcane Ethanol under a Low Carbon Fuel Standard (LCFS)

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It is the purpose of this paper to investigate the potential for Low Carbon Fuel Standard (LCFS) compliance to be achieved using Brazilian Sugarcane ethanol. This was first done finding the true effects of the policy in California to date and then by modelling abatement costs and feasibility under various scenario assumptions. Since its implementation in California, it was found the policy has incentivized relatively higher Sugarcane ethanol blends (5.4% higher relative to the control) and increased E85 infrastructure to the point where E15-E20 blends could be possible in the near future. The model which this paper proposes then found that if E15 blending is possible by 2020, full compliance could be achieved via Sugarcane ethanol blending at a relatively low compliance cost ($112/Ton$CO_2$), with only minor improvements in Biodiesel blends and credit banking necessary. If the state is still constrained by the E10 blend wall in 2020, compliance will be more difficult, requiring additional investments in other low-CI fuels as well as B15-B20 Biodiesel blends. Compliance in 2030 will be costlier, and, even at E20 blending, would still require increased credit banking from other low-CI fuels as well as higher Biodiesel blends (B30) and an LCFS credit price of at least $202/Ton$CO_2$. The marginal abatement costs of Sugarcane ethanol blending, are, however, highly subject to RFS RIN pricing, as well as CARBOB prices and average Carbon Intensity values for Sugarcane ethanol.

Executive Summary

Under California's Low Carbon Fuel Standard (LCFS), Brazilian Sugarcane ethanol is presented as much less carbon-intensive than Corn ethanol. This leads to a much higher credit banking potential for California blenders who opt to import Sugarcane ethanol from their southern neighbors rather than bringing in American Corn ethanol. With many other states, such as Oregon and Washington, turning towards the LCFS for their own transportation fuel standards, significant academic interest has been generated into how the policy could incentivize relatively higher blends of Sugarcane ethanol than a standard RFS, and whether Sugarcane ethanol could be the key to compliance under the tough carbon reduction requirements presented by the LCFS. It is the interest of this paper to address these concerns by analyzing the feasibility of LCFS compliance using Brazilian Sugarcane ethanol.

1. What levels of ethanol blending will be possible in California by 2020 and 2030?
    - 1.1. Ethanol Blending
    - 1.2. E85 Investment
    - 1.3. Sugarcane Ethanol Replacement
2. What levels of Sugarcane ethanol blending would be necessary to achieve full compliance, and at what cost?
    - 2.1. Required Abatement from Sugarcane Ethanol
    - 2.2. Modeling Marginal Costs
    - 2.3. Marginal Abatement Costs
    - 2.4. Sensitivity Analyses

An answer to the first question is necessary so as to contextualize the feasibility of the levels of required Sugarcane ethanol blending found in question 2. In this first part of the paper, California's ethanol blending before and after the LCFS was compared to an 8-state control group. While the results of these regressions remained somewhat inconclusive, it became evident that the stagnation in ethanol blending since 2010 is largely due to the state reaching the 10% "blend wall" relatively sooner than most other states. It is for this reason that this was followed by another regression, this time looking at the state's expansion in E85 infrastructure compared to the same 8-state control group. Here it became clear that the LCFS has pushed California to add 51-102 E85 stations, thus demonstrating a relatively larger push towards the state surpassing the blend wall, making the possibility of E15-E20 blends a possibility in California's future. A further regression also found that so far, Sugarcane ethanol's portion in California's ethanol mix has likely been increased to the tune of 5.4% due to the LCFS.

The second question will be answered in several parts. First, the paper will seek to find what levels of Sugarcane ethanol blending would be necessary in order to achieve abatement under various compliance scenarios. I then propose a model by which to model Corn and Sugarcane ethanol marginal costs and resulting abatement costs at given levels of production. It is perhaps these marginal production and abatement cost models which represent the most significant contribution of this paper to the literature, as they propose a framework by which to investigate not only the feasibility of LCFS compliance using these biofuels, but also the sensitivity of compliance costs with regards to federal policies, fuel prices and LCFS legislation.

Using these models, I found that under baseline carbon intensity (CI) assumptions, 2020 and 2030 compliance using Sugarcane ethanol would only be possible assuming E15 gasoline, along with a 0-25% increase in credit banking and B15-B20 Diesel blending by 2020 and E25 blends and a 100-125% increase in credit banking and B30-B50 Diesel blends by 2030. Under these assumptions, baseline compliance costs would be between $40-112/ton CO_2 in 2020 and $23-202/ton CO_2 in 2030. If average CI assumptions are altered, though, the potential for full compliance could be very different. A 20-point increase in Sugarcane ethanol's average carbon intensity would leave compliance entirely unfeasible, even under the most optimistic scenario, while a 20-point decrease could make 2020 compliance far easier, with significant reductions in required ethanol blends as well as total compliance costs.

These compliance costs of carbon abatement are subject to an array of intervening factors, such as the Renewable Fuel Standard (RFS) and California Gasoline (CARBOB) prices. Without the presence of the RFS, the cost of compliance using Sugarcane ethanol in 2020 would likely increase by 115-383% and decrease by 58-193% if RIN prices were to increase by 100%. At the same time, the presence of high gasoline prices could reduce compliance costs by 57-198%, while low gasoline prices could increase compliance costs by 68-225%.

Table of Contents

Summary of Graphs, Tables and Figures

1. Background

Ever since the advent of the Kyoto Protocol, most of the world's developed economies have been grappling with the question of how best to limit and/or reduce carbon emissions within their borders without infringing on private sector growth and overall economic development. Most signatories of the Protocol believed that the creation of a market for carbon credits rather than a tax on emissions would be the best way to do this, and thus the Kyoto Mechanism was born. This cap and trade mechanism has served as the model for the European Trading Scheme (EU ETS) within EU nations – the single largest emissions trading scheme – as well as various emissions trading systems among the other major ratifiers of the protocol.

For the US, who signed but never ratified the treaty, the question remains on how best to address the issue of emissions reduction. Within the transportation fuel sector, the Renewable Fuel Standard serves as the federal framework for emissions reduction through the incentivizing of higher renewable fuel blends. With this program, the United States aims to displace over a quarter of US fuel with biofuels by 2022, with different production targets for 4 classes of renewable fuels: cellulosic biofuel (0.1 billion gallons in 2010 to 16.0 bgal in 2022), biodiesel (0.65 bgal in 2010 to 1.0 bgal in 2022), advanced biofuels (0.95 bgal in 2010 to 21.0 bgal in 2022), and conventional biofuel (12.0 bgal in 2010 to 15.0 bgal in 2022). Under the RFS, each renewable fuel batch is assigned a Renewable Identification Number (RIN), with different types of RINs for the different classes of biofuels, while fossil fuels produced or imported to the US carry with them a Renewable Volume Obligation (RVO), which can be nullified either through the blending of renewable fuels (and thus the acquisition of their associated RINs) or the purchase of "detached RINs" from the open market.

Some states, such as California, have attempted to establish their own carbon reduction schemes to go beyond the RFS and its perceived weaknesses. California's Low Carbon Fuel Standard presents a novel new method of achieving desired emissions reductions. Through the LCFS, each fuel present in the state's transportation fuel sector is assigned a "Carbon Intensity" value (CI) based on its total CO2 emitted across its lifecycle; from production to transportation to consumption. The state then establishes benchmark CI values for each given year, with the goal of achieving a 10% reduction in carbon emissions by 2020 and a Scoping Plan in place to extend the Standard to reach 18% reductions by 2030.

Each fuel with a CI above the annual benchmark value generates a credit deficit, which must be balanced through the purchase of credits. Any fuel with a CI below this benchmark generates a credit surplus, which can be traded on the open market. The LCFS and RFS represent radically different credit trading systems aimed at the transportation fuel sector, and their credit markets move in extremely different ways. Today, however, many states are attracted to the CI benchmarking system and have been turning to California's LCFS as a model for replication. In 2016, Oregon began enforcement of its "Clean Fuels Program", representing the second Low Carbon Fuel Standard to come to fruition in the United States. With Washington's HB 2338 – which proposes a LCFS for the state – gaining house committee approval as of January of 2018, more state-level Low Carbon Fuel Standards could be on the way.

All of this begs the question of how the Low Carbon Fuel Standard may provide different blending incentives for various biofuels. Biofuels which were virtually indistinguishable at the regulatory level under the Renewable Fuel Standard may now have significant credit generation differences. There are particularly wide carbon intensity differences among ethanol varieties, depending in large part on their respective feedstock. With ethanol representing the lion's share of American alternative transportation fuels as well as a vital part of the US agricultural economy, it is thus of particular interest to better understand how the LCFS may effect American Corn ethanol's competiveness against its most formidable international rival: Brazilian Sugarcane ethanol. This paper will seek to analyze how California's Low Carbon Fuel Standard affected the state's total ethanol blending as well as its relative demand for Sugarcane ethanol. It will then propose a theoretical framework with which to model and describe marginal costs and marginal carbon abatement costs between the two biofuels under the Low Carbon Fuel Standard.

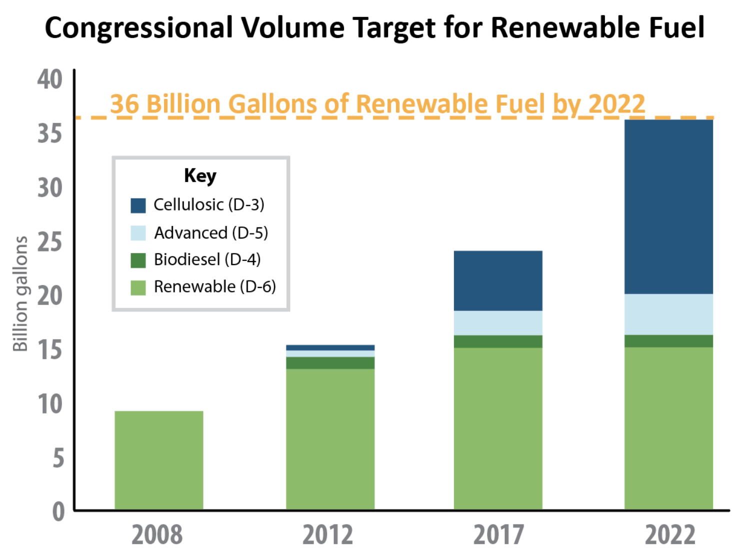
1.1 Regulatory Framework

The Renewable Fuel Standard

The Renewable Fuel Standard can trace its birth to the Energy Policy Act of 2005. Among a host of other policy changes (ranging from clean coal initiatives to an extension in daylight savings time), the 2005 Act established a Renewable Fuel Program which was to mandate an increase in renewable fuel blending from a minimum 4.0 billion gallons in 2006 to at least 7.5 billion gallons in 2012. This provision of the act came to be known as the Renewable Fuel Standard, or RFS1. A significant change was brought about with the passing of the Energy Independence and Security Act of 2007, which extended and expanded RFS1 to put in place the framework for today's Renewable Fuel Standard (RFS2). With RFS2, biofuel volume requirements were increased to 36 billion gallons and the timeline extended out to 2022. RFS2 simultaneously identified and isolated four separate biofuel classes: Biomass-based diesel (defined as a diesel substitute made from renewable feedstocks which demonstrate lifecycle greenhouse gas (GHG) reductions of at least 50%), Cellulosic biofuels (a biofuel made from cellulose, hemicellulose, or lignin nonfood-based renewable feedstocks with 60%+ GHG reductions), Advanced biofuels (a biofuel made with cellulosic or "advanced" feedstocks with 50%+ GGH reductions), and "Conventional" biofuels (a starch-derived biofuel; i.e. corn or sorghum) with 20%+ GHG reduction. Corn ethanol is classified as a Conventional biofuel and, as of 2010, Sugarcane ethanol is considered an Advanced biofuel.

Under the new ruling, the total renewable fuel mandate of 36 billion gallons was to be achieved through separate volume requirements for each of these biofuel classes. Cellulosic biofuel blending was to increase from 0 billion gallons (bgal) in 2009 to 16.0 bgal in 2022, Biodiesel from 0.5 bgal in 2009 to 1.0 bgal in 2022, Advanced biofuels from 0.6 bgal in 2010 to 21.0 bgal in 2022, and Conventional biofuels from 12.0 bgal in 2010 to 15.0 bgal in 2022 (see Figure A). The production or import of any these biofuels carries with it the generation of a Renewable Identification Number (RIN), with different RINs assigned to biofulinkeels from the different mandate classes (D3 RINs for Cellulosic biofuels, D4 for Biodiesel, D5 for Advanced biofuels, D6 for Conventional biofuels and D7 for Cellulosic diesel). Each RIN corresponds to a batch (gallon) of its respective biofuel.

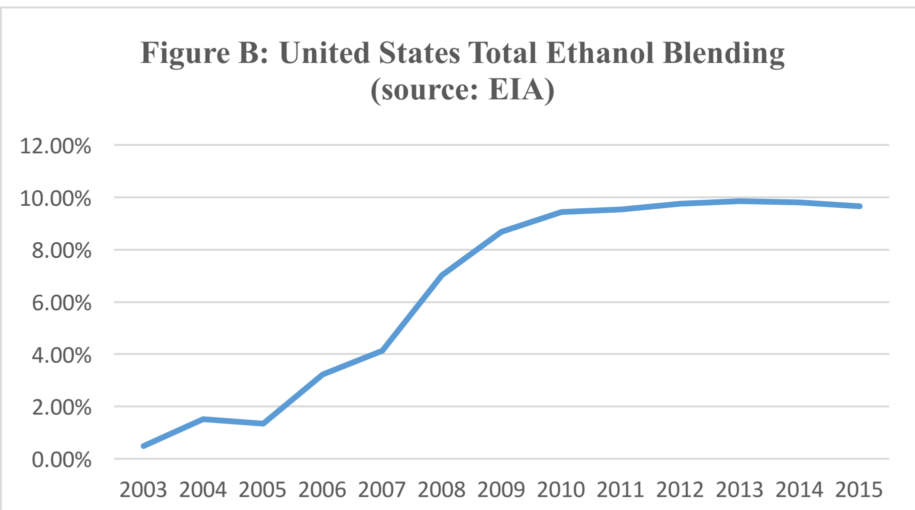
Figure A (source: EPA)



In order to enforce these requirements, renewable volume obligations (RVOs) are generated for each domestic fuel producer by multiplying their production or import volume by the annual blending ratios set for each of the 4 mandate classes and adding any RVO deficits from previous years. Any biofuel blending above the producer's RVO allows the producer to "detach" RINs and sell them on the open market. In order to fulfill RVOs, producers must either purchase and blend biofuels or buy detached RINs from the open market. When RINs are bought and sold on the open market, their value will depend on the market forces which dictate their supply and demand. Because of the nature of the RFS, with its different production growth targets for different biofuel classes, the markets for different RINs will inherently differ.

*RFS Effects on Ethanol Blendin*g

As Figure B demonstrates, Ethanol blending grew at a solid pace before quite dramatically tabling off at the so-called "blend wall" of 10% ethanol (E10). This represents the maximum level of ethanol which regular gasoline can hold. In the Unites States, most vehicles are not equipped to burn gasoline with blends higher than E10-E15, with most car manufacturers only providing warranty for their vehicles to consume gasoline blends of E10 or lower, despite the EPA clearing E15 usage for all models produced in 2001 or later (Schnepf & Yacobucci, 2010). In fact, as of 2017, less than 2% of US gas stations sold E85 (51-85% ethanol), and only 4% of gasoline-powered vehicles were flex fuel capable (able to burn ethanol blends of E10-E85), with estimates of only a 1.3% increase in the flex-fuel vehicle fleet between 2017 and 2050 (AFDC, EIA). The 2016 RVOs required



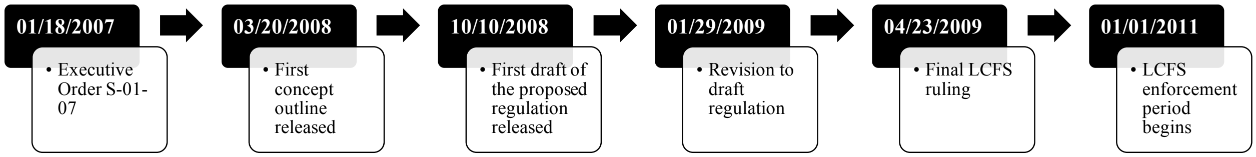
biofuel blending at levels equivalent to 14.2% of total gasoline and diesel fuel production, a blend which is significantly higher than the E10 barrier. When the RFS RVO mandates require ethanol blending above this 10% threshold, paths around the blend wall must be explored.

The general academic consensus is that the primary method by which to reach RFS RVO mandates is through expanded E85 availability and consumption. De Gorter and Drabik (2015) put forward three primary strategies to overcome the blend wall: 1. discounting consumer E85 prices enough to incentivize flex-fuel vehicle purchases, 2. discounting the producer E85 price enough to incentivize expanded E85 infrastructure, and/or 3. Using D4 (biodiesel) RINs to fulfill D5 and D6 RVOs. These sentiments are echoed by Pouliot & Babcock (2014), Whistance et al. (2015), de Gorter et al. (2013), Good & Irwin (2014) and Moschini et al. (2017), who all contend that an increased presence of E85 in the market represents the most feasible path towards RVO compliance. Pouliot & Babcock (2014) believe that the existing flex-fuel vehicle fleet can accommodate more than 15 billion gallons of ethanol (the 2022 conventional biofuel mandate) without necessitating significant decreases in E85 prices. The paper contends that current FFV owners are not currently using high levels of E85 primarily due to access constraints (i.e. distance/awareness of E85 stations). It thus holds that the simple expansion of E85 stations will increase E85 consumption by current FFV owners, and allow for the 2022 mandate to be reached. This view is supported by Aguilar et al.'s 2015 study which surveyed 2300 people nationwide to find that at price equivalence, consumers prefer ethanol-blended fuels. Only one fifth of the study's respondents indicated unwillingness to purchase ethanol-blended fuels, and many of the respondents were largely unaware of the commercial availability of E85 and other ethanol blends greater than E10. On the other side of the coin, Liao et al.'s 2016 survey of current flex-fuel vehicle owners found that only 50% of FFV owners currently use E85, with this low figure driven primarily by a lower willingness to pay for higher ethanol blends rather than by access constraints. This lends credence to the argument that E85 expansion must be driven by reduced costs of E85.

This argument is furthered by Whistance et al. (2015), whose paper finds that higher RIN prices are necessary to pave the path towards E85 expansion. The paper contends that once E85 prices become comparable to E10 prices on a per megajoule basis, consumers will begin adopting E85. This view is supported by Lade & Bushnell (2016), whose research finds complete RIN pass-through to retail E85 prices, meaning that RINs act as an effective price-setter for E85. It is for this reason that de Gorter & Drabik (2015) define RIN prices as the cost to overcome the blend wall. The paper further finds that at higher mandate obligations, the price of E85 declines to 0 while the price of RINs increase in turn. These findings are furthered by Pouliot & Babcock (2015), who in their paper find that as the RVO increases past a binding mandate (found to be 12.08 gallons), E85 prices decrease while RIN prices increase dramatically. At a mandate of 14 billion gallons, the paper finds 61% of E85 retail price to be held in RIN value.

If RIN prices represent the cost to overcome the blend wall, their inherent volatility certainly does not make them the most reliable metric. In addition to their already unpredictable nature, prices are subject to dramatic policy shocks (Lade et al. 2016). Whenever a proposal or announcement is released regarding revisions to the RVO mandates, the RIN markets react with dramatic price declines. If we are to accept the existing literature's propositions that consistently high RIN prices are necessary to incentivize wide-spread E85 adoption, RIN price shocks and inherent market volatility could make it extremely difficult to sustain prices that encourage an outwards expansion of the blend wall.

California Low Carbon Fuel Standard



On January 18, 2007, Governor Arnold Schwarzenegger signed Executive Order S-01-07, announcing a target for the state of California to reach a 10% reduction in carbon intensity of transportation fuels by 2020, prescribing the establishment of a "Low Carbon Fuel Standard" to achieve this reduction (California Office of the Governor, 2007). An initial workgroup proposal was released on March 20, 2008, providing the renderings for the LCFS's future framework, with the first completed draft of the regulation released in October of that year (CARB, March 2008) (CARB, October 2008). In a March 2009 report made in preparation for a public hearing to consider the proposed LCFS, the California Air Resources Board laid out its reasons for proposing the new standard. The Board claimed that the RFS alone would not achieve the state's desired GHG reduction targets as it is too narrow in its biofuels classifications and methods of emissions reduction. Unlike the RFS, the LCFS regulates all transportation fuels; both biofuels and non-biofuels, and incentivizes continued innovation in the biofuels sector through the reduction of individual producer CI values (CARB, March 2009). Following revisions in January of 2009 to include specific carbon intensity valuation criteria, a final rulemaking document was released in April of that year (CARB, January 2009) (CARB, April 2009). It was with this document that the Low Carbon Fuel Standard – a new and novel approach to carbon emissions reduction – was born.

Under the Low Carbon Fuel Standard, the average carbon intensity (or GHG emissions per unit of energy) of gasoline would have to be reduced from 95.61 grams of CO_2 emitted per megajoule expended (gCO_2e/MJ) in 2011 to 86.27 gCO_2/MJ in 2020. Carbon intensity calculations and thus the 2020 target would later be revised in 2011 and again in 2015 to a final goal of 88.62 gCO2e/MJ, with an extended proposal to increase this carbon reduction target to 18% carbon intensity reductions by 2030.

Rather than separating individual biofuels into a handful of discrete biofuel categories like the RFS, the LCFS seeks to value the "pathway carbon intensity" of every fuel that enters its borders. These Carbon Intensity values account for all of the GHGs emitted throughout the entire lifecycle of a fuel, from production to transportation to consumption. Carbon intensity values are pinpointed down to a facility-level. In other words, one producer can have different carbon intensity (CI) values among two of its facilities producing the same biofuel. Using the state's annual benchmark carbon intensity (which declines annually before reaching the 2020 goal), each fuel producer generates a credit surplus by blending a fuel from a facility with a CI below that year's benchmark or a deficit by blending a fuel with a CI above the benchmark. These surplus CI points are then traded as credits (priced in $ per MT CO2 abated) on the same open market to allow those with a CI deficit to be in compliance.

Whereas under the RFS all D3, D4, D5 and D6 biofuels are seen as equals among their peers but distinct between classes, the LCFS places every biofuel on the same scale and credit market, and assigns each independent fuel a unique and independent CI value based off of its specific carbon abatement potential. The carbon intensity of corn ethanol, for example, can range anywhere from 53 to 86 gCO2e/MJ, depending on its facility and the method by which it was produced. This makes a significant difference, as in 2020 the former will generate 35.62 gCO2 of credits whereas the latter will only generate 2.6.

By structuring itself around a fixed carbon reduction obligation rather than a biofuel volume obligation, the LCFS sidesteps many of the problems surrounding the RFS's production mandates. Whereas the RFS imposes increased ethanol blending via mandated biofuel volume obligations, blenders under the LCFS can reach compliance levels simply by replacing more carbon intensive ethanol varieties with their less carbon intensive counterparts.

LCFS Effects on Ethanol Blending

The feasibility and implications of the Low Carbon Fuel Standard have become the subject of significant scrutiny among the academic community, especially considering the existing difficulties with the RFS. It was partially for this reason that some early studies, such as Holland et al. (2007) cited the potential for LCFS credit prices as high as $307-$2,702 per ton of CO2 emitted. The general consensus agrees that significant investment in low-CI ethanol varieties will be necessary to reach required levels of carbon abatement, with much, if not most, of this abatement coming from either cellulosic or Sugarcane abatement.

The California Air Resources Board's own 2011 review report acknowledges that Brazilian Sugarcane ethanol could play a "key role" in reaching CI targets, though likely at some cost, and to an extent that will likely be determined by the status/feasibility of cellulosic ethanol (CARB, 2011). It further postulates that Brazilian Sugarcane ethanol could constitute 20-68% of the ethanol blend mix, with the scale of the figure largely dependent on the feasibility of cellulosic ethanol production. Whistance et al. (2017), Christensen & Hobbs (2016), Chen & Fan (2013), Zhang et al. (2010), Lade & Lin (2013), Morrison (2011) and Malins et al. (2015) all come to similar conclusions. In Chen & Fan's (2013) LCFS compliance scenarios, high levels of Brazilian sugarcane ethanol imports are used to reach required CI reduction targets up until what they call the "cellulosic breakthrough" (predicted to be reached ~2018), at which point cellulosic ethanol displaces Sugarcane ethanol as the primary means by which to reach carbon abatement.

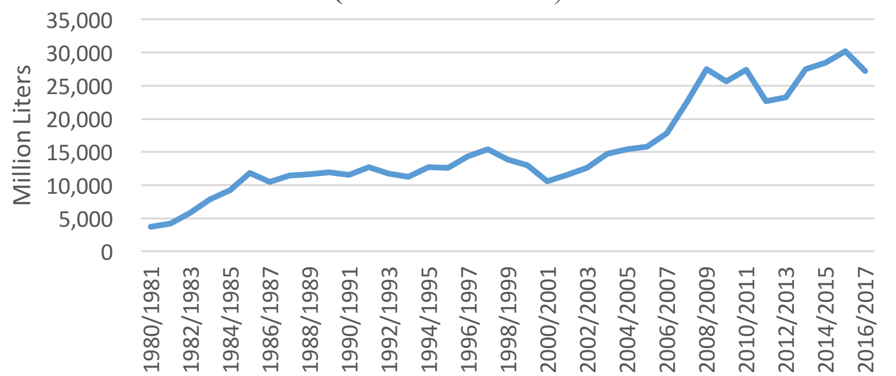
Morrison (2011) similarly predicts that any delay in the reaching of this cellulosic breakthrough would require large increases in Brazilian Sugarcane ethanol blending. Zhang et al. (2010) are somewhat pessimistic regarding the feasibility of cellulosic ethanol, holding that the LCFS is likely to lead to a high level of dependence on Brazilian Sugarcane ethanol, barring any significant investments in cellulosic ethanol research and/or technologies. ICF (2013) predicts that "attractive pricing" as well as a high probability of increases in Brazilian exports could lead to 350-500 million gallons of Brazilian Sugarcane ethanol blending by 2020. Similarly, in the 5 compliance scenarios put forward by Malins et al. (2015), Sugarcane ethanol makes up between 8 and 60% of non-cellulosic ethanol blending in 2020, and as much as 80% of the non-cellulosic blend by 2030.

Many of the compliance scenarios put forth in the relevant literature run into issues when one considers the blend wall. Zhang et al. (2010) find that in order for abatement to be met via Sugarcane ethanol blending, 6.58 billion gallons of ethanol would have to be imported from Brazil – a figure which they state requires 33-41% ethanol blending. They further add that this figure could only be met via large increases in E85 infrastructure, with at least 35% of all vehicles on the road being flex-fuel capable. Lade & Lin (2013) expand on this point, arguing that the LCFS requires either increases in corn starch or Sugarcane ethanol and/or increased fuel prices paired with reduced fuel consumption. Regardless, they argue that higher credit prices are sure to come, and that prices of a certain magnitude could incentivize a breach in the blend wall by incentivizing consumers to purchase FFVs via relatively lower E85 prices.

The Brazilian Sugarcane Ethanol Import Program

As of 2015, Brazilian sugarcane ethanol comprised almost 28% of global ethanol production, making it the second most important player in the global trade after the United States. The nation's abundance of sugarcane and top global position in the market for raw sugar led to early investments in fuel ethanol infrastructure in response to gasoline price shocks during the 1973 oil crisis. By the late 1970s, mandatory ethanol blend requirements were already in place in Brazil (Budny & Sotero, 2007). It was at this point that the Brazilian Ethanol program, Proálcool, began encouraging blending of ethanol at E20 levels. At the time, the Brazilian vehicle fleet was composed almost entirely of standard gasoline vehicles. Thus Proálcool's strategy became two-fold: 1. spread technologies which would allow normal gasoline engines to burn higher blends of ethanol, and 2. encourage consumers to purchase pure ethanol (E100) powered engines. Due to general consumer reticence in regards to purchasing E100 engines, Brazilian ethanol production remained somewhat stagnant into the early 2000s (see figure C).

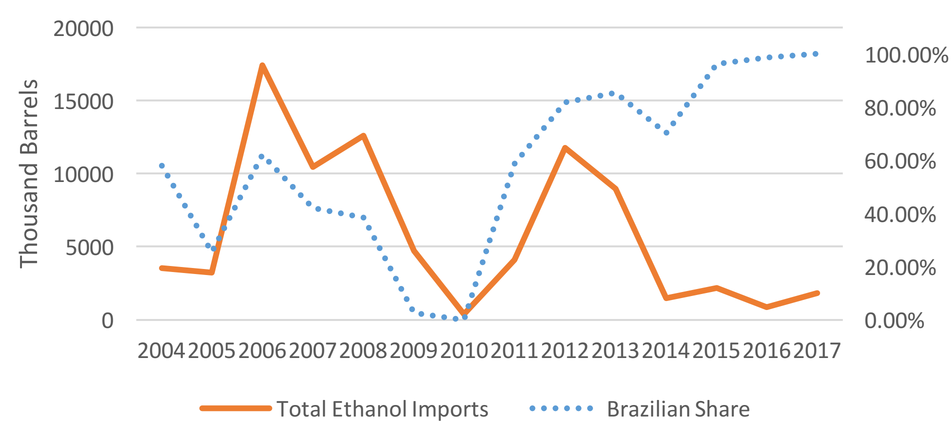
Figure C: Total Brazilian Ethanol Production (source: UNICA)



All of this would change in 2003, with the introduction of flex-fuel vehicles. The entrance of the Volkswagon Gol 1.6 Total Flex into the Brazilian market would forever change the nation's vehicle fleet. When faced with the vehicular constraints posed by Proálcool's policies, consumers readily adapted themselves to flex-fuel technology. The rapid adoption of these vehicles brought on increased demand for higher ethanol blends by both producers and regulators (this spike in production in 2003 can be visualized in figure C). By 2007, almost 90% of the country's vehicle's sold were flex-fuel capable, with this figure rising to 96% in 2017 (source: UNICA data). Today, 74% of the Brazilian vehicle fleet is Flex-Fuel capable, with most gasoline-only vehicles standing as remnants of the pre-2003 era, thus leaving them likely to be phased out of the national fleet in coming decades. With flex-fuel vehicles becoming the norm in Brazil, the concept of a blend wall became obsolete and the possibilities for ethanol blending became limitless. Today, all retail gasoline stations must carry blends of 18-27.5% ethanol, with a government ethanol mandate of 27% of gasoline (E27) as of March, 2015 (USDA FAS).

Because of its history of ethanol production, Brazil has long been the primary exporter of ethanol into the United States (see figure D), with Brazilian ethanol making up 100% of US ethanol imports in 2017. It is for this reason that for much of its history, Brazilian ethanol was seen as a threat to the US's less-developed, burgeoning corn ethanol industry, and was thus treated with protectionist policies.

Figure D: Brazilian Share of Total US Ethanol Imports (source: EIA)



This was made most evident by the US's imposition of a $0.54 specific tariff on ethanol beginning in 1980. From its inception, the tariff proved to be quite controversial. As famed economist Joseph Stiglitz put it in 2006: "Perhaps the most outrageous example [of an escalating tariff] is America's $0.54 per gallon import tariff on ethanol, whereas there is no tariff on oil and only a $0.50 tax on gasoline… foreign producers can't compete unless their costs are $1.05 per gallon lower than those of American producers" (Stiglitz, 2006).

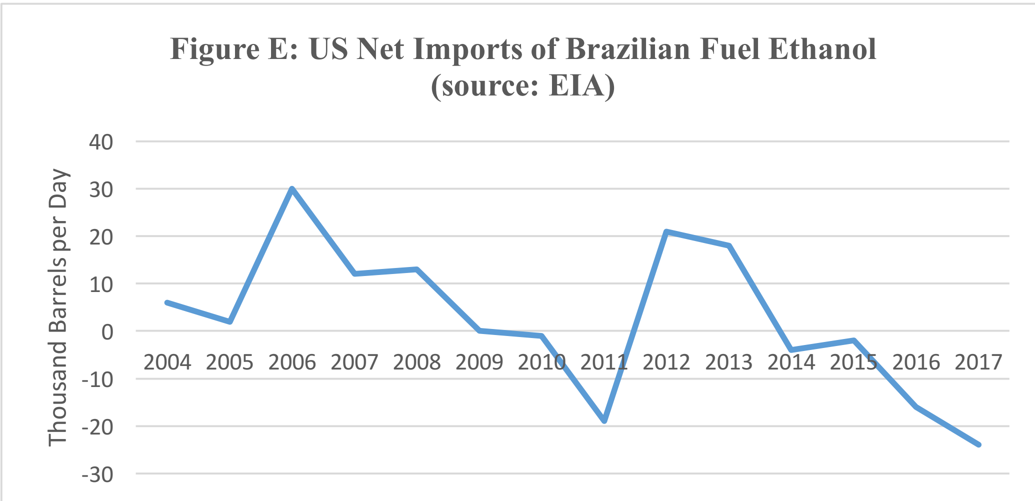
The economics of the import tariff thus became the subject of a significant amount of literature discussing American ethanol's competitiveness when faced with the threat of Brazilian imports. De Gorter & Just (2010) put forth the argument that discriminatory trade measures such as subsidies or tariffs could more than offset the benefits of ethanol mandates. This sentiment is echoed by De Gorter & Just (2008) as well as De Gorter et al. (2009), which claim that a tariff reduces the terms of trade of both American ethanol imports as well as American corn exports, with an ideal mandate including neither a tax credit on domestic production nor a tariff on imports. Devados & Kuffel (2010) went so far as to call the tariff "punitive", instead calling for a subsidy on imports to help blenders meet their RVOs. Elobeid & Tokgoz (2008) find that while a tariff would lead to a reduction in ethanol price and an increase in American ethanol consumption, it wouldn't all be positive, as it would simultaneously lead to a reduction in US ethanol production.

Additionally, since the EPA changed its mandate class in 2010, Sugarcane ethanol has benefitted from its classification as a D5 "Advanced" biofuel under the RFS, rather than a D6 "Conventional" biofuel like Corn ethanol. It could thus be hypothesized that the expiration of the ethanol tariff and tax credit in 2011 ushered in a new era of Brazilian imports. This was not the case. In fact, in 2009- 2010 a significant shift occurred in US-Brazil ethanol trade dynamics, with the US becoming a net exporter of fuel ethanol to Brazil (see figure E). This can be explained by 3 primary factors:

1. The US hits the blend wall

2. Brazilian demand outpaces supply

3. FOB Price reversal



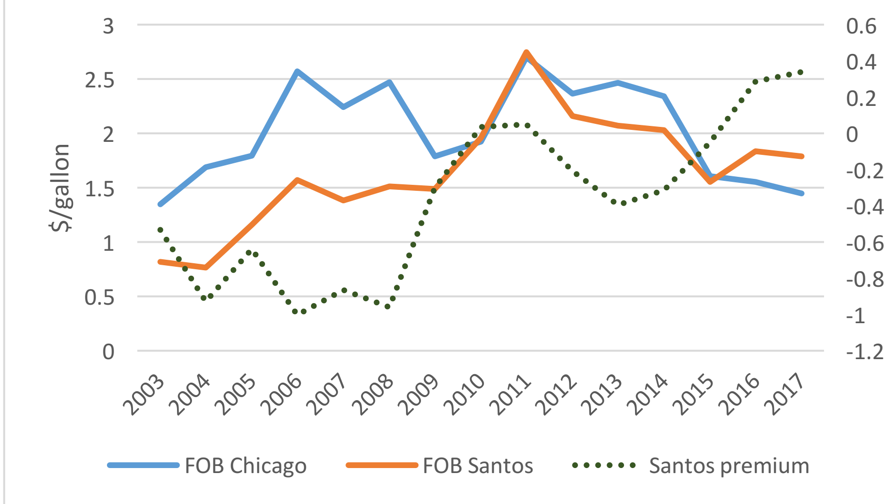
As the US began nearing the E10 blend wall (see figure B), American producers began seeking ways around their domestic demand constraint. With new increases in production efficiency and increased global interest in biofuels, they found an international demand for the low octane prices which American ethanol offered. From there, the American ethanol export program was born.

Simultaneously, high prices in the global market for raw sugar led to many Brazilian mills finding more profitability in selling Sugar rather than converting it to Ethanol. This combined with low sugar stocks due to poor sugarcane harvests, bad weather, and reduced investment in Sugarcane mills, led to a plateau in Brazilian ethanol production and thus a failure to meet local demand (Chum et al., 2014). The United States then stepped in to provide exports to the EU as well as 150 million liters of exports to Brazil to help the country fill it's overwhelming demand.

With all of this going on, a pricing shift took place between Sugarcane ethanol and Corn ethanol, as FOB Santos prices (the benchmark for Brazilian Sugarcane ethanol prices) closed in on the historically higher FOB Chicago prices (benchmark for US Corn ethanol prices), with

Santos prices overtaking Chicago for the first time in 2010 (see figure F). At the same time, D5 and D6 RIN prices converged, typically trading only pennies apart. The convergence and reversal in the

Figure F: FOB Santos vs. FOB Chicago Ethanol Prices (source: UNICA, USDA)



Santos-Chicago premium meant that without an incentive in RIN price differentials, blenders in the US would find little benefits in a Brazilian import program.

As Lade & Lin (2013) and Zhang et al. (2010) have demonstrated, the LCFS could present an opportunity for renewal in American imports of Brazilian ethanol and a reversal in recent trade trends. With the incentive of greater credit banking by blending Sugarcane ethanol, credit prices of a certain magnitude could incentivize the replacement of Corn ethanol with Sugarcane ethanol in local blends.

Additionally, because Brazilian demand is dictated by a blind mandate (meaning it does not discriminate between ethanol varieties), a relative price advantage in Corn ethanol could lead to increases in trade between the two countries, with the US importing large amounts of Brazilian Sugarcane ethanol and in turn exporting Corn ethanol to Brazil. Whistance et al. further this argument in their 2017 paper, making the point that the CI differential between American and Brazilian ethanol combined with Brazil's blend mandate and a relatively unimportant price differential could lead to an increase in two-way trade of fuel ethanol.

1.2 Research Questions

1. How has the LCFS affected California Ethanol blending?

This paper will first seek to understand the true impact of the LCFS on California ethanol blending and investment in E85 infrastructure. This will seek to answer the question of whether or not the LCFS has incentivized a breach in the blend wall, or at least strides therein. By looking at total ethanol blending in California versus the rest of the country before and after the policy, it will be possible to answer the question of whether or not the state has been making a relatively larger push towards blending ethanol in quantities beyond the E10 blend wall.

Following the findings of de Gorter & Drabik (2015), Pouliot & Babcock (2014), Whistance et al. (2015), de Gorter et al. (2013), Good & Irwin (2014) and Moschini et al. (2017), who all hold that ethanol blending beyond the E10 blend wall will primarily come from expanded E85 infrastructure, this paper's analysis will be furthered via an analysis of how E85 availability changed in California following the announcement and implementation of the LCFS.

This will be followed by an investigation of how the LCFS has changed California's ethanol blend mix relative to the rest of the country. In other words, has the policy incentivized relatively higher levels of Brazilian Sugarcane ethanol blending? This will be done by analyzing the state's imports of Brazilian ethanol before and after the policy, versus the import habits of the rest of the country during the same time period.

2. Is LCFS Compliance via Sugarcane Ethanol Blending feasible?

By first proposing a function for total required abatement, it will be possible to find necessary abatement from Sugarcane ethanol at a given Carbon reduction target. The paper will also put forth functions by which to model the marginal abatement costs of Corn and Sugarcane ethanol at varying levels of abatement (blending). It will then be possible to determine the feasibility of reaching required abatement targets via Sugarcane ethanol blending under various compliance scenarios.

2. Methods

2.1 LCFS Ethanol Blending Effects

Total Ethanol Blends

This paper first seeks to answer how the LCFS has influenced total ethanol blending and whether or not it has generated significant enough investment into E85 infrastructure to push blending past the E10 blend wall. As such, the first part of this question will look towards total ethanol blending in California before and after the policy, while the second part of this question will look at the addition of E85 gas pumps in California versus the rest of the country before and after the LCFS (sources: EIA, AFDC, FHWA).

Total Ethanol Blending

The basic framework for the first regression will be structured as:

$$Blend_{st} = \beta_0 + \beta_1\alpha + \beta_2\tau + \beta_3\delta + \varepsilon_{st}$$

$$Blend_{st} = \beta_0 + \beta_3\delta + \beta_4\rho + u_s + \lambda_t + \varepsilon_{st}$$

β_0 is representative of the constant, or in other words the control group's average blending before the policy.

α is a dummy variable representing the post-LCFS time period, while β_1 is the coefficient representative of the difference between the pre and post periods, with data spanning from 2002 to 2016. The regression will be run with 3 different scenario assumptions for the start of the "post-LCFS" period and resultant activation of the α dummy variable.

1. The first regression will define "LCFS enactment" as occurring with Schwarzenegger's signing of Executive Order S-01-07 in January of 2007, and will thus have α equal to 1 in 2007 and every year subsequent to 2007.
2. The second regression will define the post-LCFS period as any year during which the LCFS was an enforceable policy. Because the regulatory enforcement period began on January 1st, 2011, this regression will have α equal to 1 in 2011 and every year subsequent to 2011.
3. The third regression will discard all data within the "regulatory drafting period," defined as occurring between the LCFS's initial legislative proposal in January of 2007 and its official enforcement in January of 2011. As such, this regression will have α equal to 0 in all years prior to 2007 and equal to 1 following January 1st, 2011.

τ is a dummy variable representing the treatment variable, California, while the β_2 coefficient represents the difference between the treatment and control group. The treatment will be indexed against an 8-state control, consisting of Arizona, New York, Washington, Pennsylvania, North Carolina, Colorado, Florida and Texas. These states were selected on the basis of 3 criteria: gasoline consumption trends, vehicle-miles travelled (per capita mileage), and distance from ethanol producing regions. These states are all somewhat similar to California on these 3 bases, while simultaneously representing a large enough geographic diversity that could help control for large-scale regional effects.

δ is equal to $\alpha * \tau$, or in other words, represents the treatment variable, California, in the post-LCFS period. β_3 thus represents the difference-in-difference coefficient, and can be interpreted as representing the effect which the LCFS had on ethanol blending.

Following this, the regression will be adapted to account for changes in state gasoline taxation rates as well as fixed year and state effects, which will yield the equation: $Y_{st} = \beta_0 + \beta_3\delta + \beta_4\rho + u_s + \lambda_t + \varepsilon_{st}$, with ρ representing state gasoline taxation rates and β_4 the coefficient for the effect of gas tax on ethanol blending. u_s *and* λ_t represent the state and year fixed effects, respectively.

E85 Infrastructure

$$E85_{st} = \beta_0 + \beta_1\alpha + \beta_2\tau + \beta_3\delta + \varepsilon_{st}$$

$$E85_{st} = \beta_0 + \beta_3\delta + \beta_4\rho + \beta_5\gamma + u_s + \lambda_t + \varepsilon_{st}$$

The same regression structure as the one used for total blending will be adapted to this time look at the LCFS's effects on number of gas stations offering E85. Thus, all variables will remain the same, but the outcome will now be expressed in terms of E85 offerings, with an additional control variable, γ, for state gasoline consumption.

Sugarcane Ethanol Replacement

The second question which this paper seeks to address involves the potential for increased blending of Sugarcane ethanol under the LCFS, and more specifically the potential for displacement of high-CI ethanol varieties – namely Corn ethanol – by lower CI Brazilian Sugarcane ethanol. It will thus look at how Sugarcane ethanol's part in the total ethanol blend ratio changed following the enactment of the LCFS, with the outcome variable measured as Brazilian ethanol imports divided by total ethanol consumption (source: EIA).

$$SC_{st} = \beta_0 + \beta_1\alpha + \beta_2\tau + \beta_3\delta + \varepsilon_{st}$$

$$SC_{st} = \beta_0 + \beta_3\delta + u_s + \lambda_t + \varepsilon_{st}$$

In addition to the different outcome variable, adjustments to the initial regression will be made in regards to the measurement of the treatment and control groups, as well as to the time variable, α.

Because there are a limited number of ports equipped for large-scale fuel imports, and inter-state ethanol movements are difficult to control for, Sugarcane ethanol consumption will be measured on the basis of a given state's Petroleum Administration for Defense District (PADD). The PADDs represent five state groupings which are used by the EIA for the purposes of fuel data collection and dispersion. It is assumed that not all fuel arriving in a given port will be blended and consumed in that given state, and thus the use PADDs as a variable measure enables the regression to control for inter-regional movement of Brazilian Sugarcane ethanol. If, for example, a blender in Nebraska wanted to purchase Brazilian Sugarcane ethanol, the ethanol would have to first be imported via a coastal port, such as Houston, before reaching its final destination in Nebraska. Though the ethanol was imported via Texas, it was consumed in Nebraska. The EIA provides data on ethanol exports from PADD 3 (Texas) to PADD 2 (Nebraska) which would enable increased accuracy when calculating the consumption figures for PADD 3.

The PADDs of interest to this regression thus represent the three coastal regions through which Brazilian Sugarcane ethanol is imported. These include PADD 1 (East Coast)[1], PADD 3 (Gulf Coast)[2], and PADD 5 (West Coast)[3]. The treatment group will be represented by PADD 5, which includes California and 6 other west coast states. PADD 5 Sugarcane ethanol consumption is seen as an accurate proxy for California's Sugarcane ethanol consumption for two primary reasons. For one, California makes up the majority of PADD 5's fuel consumption, accounting for around 67% of total PADD 5 ethanol consumption since 2003. Additionally, the vast majority of PADD 5 Brazilian ethanol imports have entered the region via California ports, with 94% of PADD 5's total Brazilian ethanol imports coming in through either San Francisco or Los Angeles since the import program's inception in 2003/2004. Additionally, PADD 5's ethanol exports have remained at or near 0 since 2003, indicating that all Brazilian Sugarcane ethanol imported into PADD 5 is consumed in PADD 5.

The time variable α will be modified in this regression, to be activated on a slightly different schedule to that used in the regressions for total ethanol blending and E85 infrastructure. The three scenario assumptions will include, as in the last case, one scenario with a "post-LCFS" period following regulatory enforcement in 2011, as well as one scenario with a

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[1] PADD 1 includes: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, Delaware, District of Columbia, Maryland, New Jersey, New York, Pennsylvania, Florida, Georgia, North Carolina, South Carolina, Virginia, and West Virginia.
[2] PADD 3 includes: Alabama, Arkansas, Louisiana, Mississippi, New Mexico, and Texas.
[3] PADD 5 includes: California, Alaska, Arizona, Hawaii, Nevada, Oregon and Washington.

pre-LCFS period preceding Executive Order S-01-07 in 2007 and post-LCFS period following enforcement in 2011. It will also, however, include a scenario assumption in which "post-LCFS" is defined as the period following the first LCFS draft revision on January 29, 2009, as it was in this document that Brazilian Sugarcane ethanol and Corn ethanol were first assigned prospective Carbon Intensity values, with Sugarcane ethanol assigned a significantly lower CI value than Corn ethanol. It is for this reason that January of 2009 can be seen as the point at which blenders first saw that Brazilian Sugarcane ethanol could provide greater credit banking potential than Corn ethanol.

In this regression's three scenario assumptions, time variable α will thus be equal to 1 for the following time periods for each respective scenario regression:

1. Post-LCFS period defined as: 2009 onwards
2. Post-LCFS period defined as: 2011 onwards
3. Pre-LCFS defined as: before 2007, post-LCFS: 2011 onwards

2.2 Modeling Sugarcane Ethanol's Abatement Potential

Sugarcane ethanol's carbon abatement potential under the LCFS will assume a blend wall constraint and thus requires full displacement of Corn ethanol for each gallon of Sugarcane ethanol added to the blend. In other words, assuming current blending is operating at the blend wall, the blending of an additional 1 billion gallons of Sugarcane ethanol would require the loss of 1 billion gallons of Corn ethanol from the state's total gasoline blend. Total abatement will thus be modeled as a function of carbon abatement gained via Sugarcane ethanol replacement less the total abatement lost by displacing Corn ethanol plus abatement from biodiesel and the total credit bank. Written as a function of total abatement from Sugarcane ethanol, this function reads:

$Abatement_{Sugarcane\ Ethanol} = (Total\ Required\ Abatement) +$
$(loss\ of\ Corn\ Abatement) - (Net\ Biodiesel\ Abatement) - (Credit\ Bank)$, where:

$Total\ Required\ Abatement$ is equal to the total amount of CO2 which must be abated by the given target date. If, for example, the target is to reduce the average carbon intensity of gasoline by 10gCO2/MJ, total abatement will be equal to $10\ {}^{gCO_2}/_{MJ} \times$
$(Total\ Gasoline\ Consumption)$, with gasoline consumption expressed in MJ.

$Abatement_{Sugarcane\ Ethanol}$ represents the carbon abatement via Sugarcane ethanol blending which is necessary to reach the given total abatement target.

$Loss\ of\ Corn\ Abatement$ is equivalent to the amount of carbon abatement achieved by the Corn ethanol which is to be displaced. If, for example 1 billion gallons of Sugarcane ethanol are to be blended, then 1 billion gallons of Corn ethanol which have already been achieving a certain level of abatement will be replaced. This figure is thus representative of the level of abatement which had previously been achieved by this now displaced Corn ethanol.

$Net\ Biodiesel\ Abatement$ represents surplus credits from biodiesel blending (with the term "biodiesel" encompassing both Biodiesel and Renewable Diesel), which can be used to fulfill gasoline credit requirements. ICF (2013) and Christensen & Hobbs (2017) hold that Biodiesel and Renewable Diesel blending will likely hold an important role in reaching LCFS abatement target, with Christensen & Hobbs (2016) harping on biodiesel's important role in LCFS compliance, calling for rapid increases (up to at least B20) in biodiesel and renewable diesel blending by 2020. ICF (2013) further states that the diesel blending can fulfill this important abatement role, as there is "significant potential" for large amounts of credits to be generated via relatively small quantities of biodiesel and renewable diesel. It is thus of particular interest to understand how different levels of biodiesel blending could impact the need for abatement from Sugarcane ethanol blending.

Abatement from biodiesel blending can be represented as:

$$Net\ Biodiesel\ Abatement = (Real\ Biodiesel\ Abatement) - (Required\ Biodiesel\ Abatement)$$

In this equation, Real Biodiesel Abatement represents the true abatement from Biodiesel as well as abatement from Renewable Diesel, assuming a current blend ratio of 39.69% Biodiesel (BD) and 60.31% Renewable Diesel (RD). It can thus be expressed as:

$$Real\ Biodiesel\ Abatement = \left[(CI_{Diesel} - CI_{BD}) * \left((0.3969 * (Blend)) * (Total\ Diesel)\right)\right] + \left[(CI_{Diesel} - CI_{RD}) * \left((0.6031 * (Blend)) * (Total\ Diesel)\right)\right]$$, where:

CI_{Diesel} represents the reference carbon intensity value for standard diesel, CI_{BD} the average carbon intensity for CARB-registered biodiesel producers, and CI_{RD} the average carbon intensity of CARB Renewable Diesel.

$Blend$ represents the combined percentage of total California retail diesel ($Total\ Diesel$) which is either BD (Biodiesel) or RD (Renewable Diesel), with 0.3969 and 0.6031 representing the BD and RD blend adjustments, respectively. Thus, a B12 (20% biodiesel) blend, for example, will be assumed to be constituted of ($.3969 * 0.12$) 4.76% BD and ($.6031 * 0.12$) 7.24% RD.

Required Biodiesel Abatement is calculated using Biodiesel CI reduction targets, which are on a different schedule than those for gasoline. Thus, the example from the above section could be modified to $Required\ Biodiesel\ Abatement = (CI\ reduction) \times (Total\ Diesel\ Consumption)$, with Total Diesel Consumption again expressed in megajoules.

The difference between "Real" and "Required" biodiesel abatement, thus represents "Net Biodiesel Abatement". If this value is positive, it signifies a credit surplus from biodiesel blending, while a negative value represents a credit deficit from biodiesel blending. Any credit surplus can be used to help fulfill the gasoline abatement targets, thus reducing the abatement required via Sugarcane ethanol blending. Any credit deficit in biodiesel blending would have the inverse effect, requiring increased abatement within the gasoline market, and thus increased Sugarcane ethanol blending.

The $Credit\ Bank$ is the sum of excess carbon abatement to-date. In other words, it represents net credit generation for every year precedent to the present. This can be seen as a proxy for credit generation in sugarcane ethanol and biodiesel, as well as other low-CI transportation.

2.3. Abatement Scenarios

Required abatement from Sugarcane ethanol will be modeled under the following scenarios, the first two of which are relatively pessimistic, the third the baseline, and the final two relatively optimistic:

1. 2020: Credit surplus exhausted (no credit bank); B12 Diesel
   2030: Net deficits greater than credits (-50% credit bank); B12 Diesel
2. 2020: Credit surplus reduced by factor of 25%; B12 Diesel
   2030: Credit surplus exhausted; B20 Diesel
3. 2020: Credit surplus unchanged; B12 Diesel ***(Baseline)***
   2030: Credit surplus reduced by factor of 25%; B20 Diesel
4. 2020: Credit surplus unchanged; B15 Diesel
   2030: Credit surplus increased by 100%; B30 Diesel
5. 2020: Credit surplus increased by 25%; B20 Diesel
   2030: Credit surplus increased by 125%; B50 Diesel

Scenario 1 borrows from Lade & Lin (2013) and Christen & Hobbs (2016), and assumes that credit banking was not sufficient in the early days of the LCFS, with the credit bank reaching its maximum at the end of 2016, being totally exhausted by 2020, and then accruing net deficits by 2030. It additionally assumes that Diesel blends will not see any further innovation, and will rather remain unchanged at 12% Biodiesel/Renewable Diesel (B12). Scenario 2 assumes an extended timeline for credit bank exhaustion, with credit surplus reduced by a factor of 25% by 2020, and reaching complete exhaustion by 2030. It further assumes that

Biodiesel/Renewable Diesel blending will remain unchanged in 2020, before reaching the 20% target set forth by Christensen & Hobbs (2016) by 2030. Scenario 3 represents the baseline, and thus assumes no change in credit banking before 2020, with a 50% reduction by 2030. It assumes standard growth in Diesel blends from B12 in 2020 up to B20 by 2030. Scenario 4 assumes slightly higher Biodiesel/Renewable Diesel blending at the 2020 and 2030 targets, as well as a 100% increase in credit surplus by 2030 thanks to investment in other low CI fuels, high biodiesel abatement, and/or increases in electric vehicles. Scenario 5 is an optimistic take on Scenario 4, with slightly higher Biodiesel/Renewable Diesel blending as well as a larger credit bank.

Sensitivity Analyses

RFS and RINs Prices

In both of their papers, Christensen & Hobbs (2016) and Whistance et al. (2017) find a high level of codependence between the compliance costs of the LCFS and RFS. It is for this reason that marginal abatement costs at 2020 and 2030 targets will be calculated given different RIN price scenarios. They will first be calculated under the assumption that the RFS does not exist and thus RIN prices are $0. Next they will be calculated given reduced RIN prices, then at similar rates of increase.

CARBOB Prices

Using the California Energy Commission's oil price projections, marginal abatement costs will be calculated at the low, mid and high projections put forth by the commission. Under the "low" projection, oil prices will be 36% lower than current levels by 2020 and 20% lower than today by 2030. The "mid" scenario projects current prices at 2020 and a 30% increase by 2030. The "high" projection has oil prices increasing by 30% by 2020 and 100% by 2030.

CI Revisions

CARB has revised pathway carbon intensities several times since the implementation of the LCFS (notably in 2011, 2013, and 2015). Every time there is a revision to these CI values, the abatement potential of each given fuel type inherently changes. Additionally, the LCFS could incentivize a natural change in average fuel CI by causing a shift in preference towards relatively less carbon intensive producers of a given fuel type. Given the LCFS's high potential exposure to CI revisions, the abatement model will be recalculated under CI revisions of $\pm 20\ gCO_2/MJ$.

2.4. Marginal Abatement Cost

$$Marginal\ Abatement\ Cost = \frac{\frac{Cost_{LCF}}{EER} - Cost_{ref}}{CI_{ref} - \frac{CI_{LCFS}}{EER}} \times \frac{907185\ grams}{1\ ton}\ \text{(expressed in \$/tonCO2 abated)}$$

The marginal abatement cost curves are meant to represent the marginal cost of each additional ton of CO2 abated by blending a given Low-Carbon Fuel (LCF) instead of regular gasoline. In other words, it represents the cost to prevent the emission of an additional unit of CO2 by blending a given low-carbon fuel instead of regular gasoline. It is thus calculated by first finding the cost to blend one megajoule of a given LCF instead of the reference fuel (calculated using the price differential between the fuel types), then finding how many grams of CO2 were abated by replacing gasoline with the LCF (Yeh et al., 2009). In the above formula, all variables are fixed except for $Cost_{LCF}$, which represents the marginal cost of production of the low carbon fuel. Higher levels of abatement require higher levels of production of a given LCF, which will inherently change the marginal cost of the fuel. The fixed variables are defined as follows:

$Cost_{ref}$ is defined as the marginal cost of the reference fuel, in this case CARBOB, California's reformulated variety of standard RBOB gasoline. Using an average price of $2.26/gallon for Los Angeles Reformulated RBOB gasoline between 2003 and 2015, this variable can be fixed at $0.017/MJ (assuming each Gasoline Gallon Equivalent (GGE) is equal to 131.6 MJ).

CI_{ref} represents the carbon intensity, or quantity of CO2 released per megajoule expended, of the reference fuel. According to the California Air Resources Board's fuel pathways reference sheet, the average carbon intensity of CARBOB gasoline is 99.78 gCO2/MJ.

CI_{LCF} is the carbon intensity of the Low-Carbon Fuel for which the MAC is being calculated. For the purposes of our analyses these LCFs are corn and sugarcane ethanol. According to the California Air Resources Board, the carbon intensities of corn ethanol and sugarcane ethanol are 72.5 gCO2/MJ and 46.6 gCO2/MJ, respectively. These values were found by taking the mean pathways carbon intensity values of all CARB-registered Corn and Sugarcane ethanol production facilities.

EER, or Energy-Economy Ratio is a unit-less measure meant to reflect the relative efficiency of a vehicle's drive train when displacing a reference fuel with an LCF. The EER values relative to gasoline for both corn and sugarcane ethanol are 1.

$Cost_{LCF}$, or the cost of the Low-Carbon Fuel, represents the cost at a given level of carbon abatement for the given biofuel whose marginal abatement cost is being calculated. The models used to generate marginal cost curves for corn and sugarcane ethanol production will be further discussed later.

The idea behind this model is to serve as a proof of concept for the LCFS. In other words, if two biofuels are the same price, the one which emits relatively less CO2 will have a greater incentive to be blended. If, for example, the $Cost_{LCF}(fuel\ 1)$ and $Cost_{LCF}(fuel\ 2)$ with carbon intensity values of 20 and 40 gCO2/MJ, respectively, are found to both be \$0.020/MJ, the marginal abatement cost for fuel 2 will be higher than that of fuel 1 (\$50/tonCO2 abated for fuel 2 vs. \$37.50/tonCO2 abated for fuel 1). This means that at a credit price of \$40/tonCO2, a blender will have an incentive to blend only fuel 1, as it will generate a surplus \$2.5/tonCO2 abated by blending fuel 1 versus a loss equivalent to \$10/tonCO2 abated when blending fuel 2.

This paper will model LCFS marginal abatement costs for Corn and Sugarcane ethanol under two scenarios: MAC_0 and MAC_{10}, in which MAC_0 is the "year 0" scenario, or the marginal abatement costs under current capacity and feedstock constraints. The MAC_{10} scenario represents a 10 year marginal abatement cost forecast assuming 5% annual production capacity growth and feedstock production growth modeled according to trends to date. MAC_0 will thus be used to model compliance costs under the 2020 target, with MAC_{10} used for the proposed 2030 target.

2.5. Modeling Marginal Costs for Selected Biofuels

$$MC_{LCF} = (operational\ \&\ capital\ costs)x + (secondary\ feedstock\ costs)x + (primary\ feedstock\ costs)x - (co-product\ returns)x + (capacity\ installation\ costs)(\delta)x + (California\ basis)x$$

Operational and capital costs refer to the general costs of keeping the plant running such as labor, maintenance and machinery costs, and regular capital expenditures such as interest payments, land, etc.

Secondary feedstock costs refer to the costs of chemicals and other commodities aside from the primary feedstocks which are necessary for the biofuel production process. These include the chemicals used in the chemical underpinnings of the ethanol itself, such as denaturant and various enzymes, as well as the commodities/utilities necessary for the basic functioning of the plant, such as natural gas and electricity.

The primary feedstock costs are the costs of the actual underlying crop/product from which a given biofuel is produced (i.e. corn, sugarcane). Because the American and Brazilian ethanol industries are the primary consumers of corn and sugarcane, the markets for these feedstocks are inextricably intertwined with their biofuel markets down the chain. In 2016, 36% of American Corn and 57% of Brazilian Sugarcane was cultivated for ethanol production (USDA ERS, UNICA). Because of this, any shifts in ethanol production can have a significant impact on demand for that ethanol's primary feedstock and resultantly, on its prices. It is for this reason that primary feedstock costs will be modeled as a function of their usage in ethanol production.

Co-product returns represent the value of byproducts or regulatory credits generated through the ethanol production process. These include Renewable Identification Numbers (RINs), Distiller's Grains (DDGs), and any other products which can be sold at a gain to the ethanol producer and contribute to non-ethanol revenue for the plant. This value is thus negative in the marginal cost formula.

Capacity installation costs (CIC) are the fixed construction costs necessary to install an extra gallon of plant capacity. In other words, it represents the added cost required to produce the

1 gallon of ethanol above the maximum quantity which existing plants can handle. δ is a dummy variable which is activated at production values greater than or equal to maximum possible production levels under current (Year 0) capacity constraints (CC_0). This means that it is not a recurring cost, and will only be paid the year that capacity is expanded. Any future marginal cost curve will have δ equal to 0 at the quantity of production reached in the year prior.

In the MAC_0 scenario δ will be binary, with values equal to 1 at all production levels above the maximum installed capacity constraint (CC_0) and 0 at any production levels below this constraint. This is because in a year 0 scenario, any production above the current capacity constraint, CC_0, would require immediate capacity installation at costs equal to the given biofuel's CIC.

For the MAC_{10} scenario, δ will be activated at current capacity constraints and will increase gradually until it is equal to 1 at the forecasted 10-year capacity constraint (assuming 5% annual capacity growth). In other words, in the MAC_{10} model, δ will equal 0.1 at year 1 maximum capacity (with year 1 max capacity $= 1.05^1 * CC_0$), 0.2 at year 2 maximum capacity, and so on, before reaching 1.0 at the 10-year maximum capacity. This means that CIC marginal costs in the MAC_{10} scenario at a given level of production (x) can be rewritten as:

$$Capacity\ Installation\ Cost_{10\ year} = CIC * \frac{\ln\left(\frac{x}{CC_0}\right) / \ln(1.05)}{10}$$

The California basis represents the additional costs incurred when getting a biofuel onto the market in California. This includes taxes, tariffs and logistical expenses.

This general formula can then be adapted to the specific Low-Carbon Fuel for which the marginal cost is being calculated.

Marginal Cost of Corn Ethanol

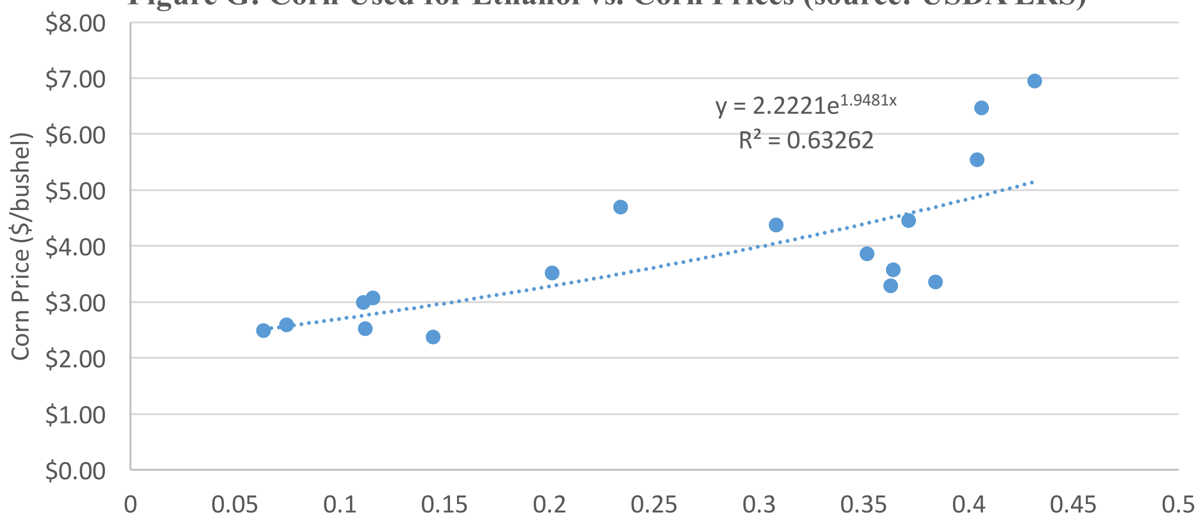
In the case of corn ethanol, this formula can be further refined to include the following in each cost category:

Operational & Capital Cost Assumptions: Industry estimates for annual operational costs of a standard dry-mill 100 Million Gallon per Year (MGY) ethanol plant find this variable cost to be around $0.21 per gallon (Gordon et al., 2008) (Irwin, 2017). This accounts for the non-corn, non-chemical costs to keep a plant running. These include materials maintenance and services (32% of operational expenses), taxes and insurance (32%), labor (12%), repairs (12%), and variable supply needs and other miscellaneous expenditures (12%) (biofuel production costs). For the purposes of this model, this value will remain fixed at $0.21/gallon.

Secondary Feedstock Cost Assumptions: There are two primary secondary feedstocks necessary in the dry-mill corn ethanol production process: Natural Gas and denaturant. Other secondary feedstocks include water and enzymes. Assuming the dry mill process requires 30 cubic feet of natural gas per gallon of ethanol produced, and a 5-year average industrial natural gas price of $\$4.29/1000ft^3$ (EIA), the variable cost of natural gas can be fixed at $0.1287/gallon. Variable denaturant prices are typically computed as being 2% of the wholesale price of CBOB (Irwin, 2017). Using this formula and a 2-year average price of $2/gallon for CBOB, we can estimate denaturant costs to be around $0.04/gallon. The cost of water is built into plant operational expenses while variable enzyme prices are negligible and will thus not be included in the model. Total secondary feedstock costs are thus calculated as being $0.1687/gallon of ethanol produced.

Primary Feedstock Cost Assumptions: Ever since the advent of "Big Ethanol" in America, the country's corn industry has often been at the whim of ethanol producers. Ethanol producers have in fact accounted for an average of 38% of all US corn purchases since 2008 (USDA ERS). With US corn exports absolutely dominating the international trade (accounting for an average of 60% of global corn exports from 2003-2008, and slightly less since), the US ethanol industry is the major player in global corn's buy-side dynamics. Because of this, any shifts in ethanol

Figure G: Corn Used for Ethanol vs. Corn Prices (source: USDA ERS)



production can have tremendous impacts on demand for Corn and thus on Corn prices. It is for this reason that the primary feedstock cost must be modeled to account for changes in ethanol production. As figure G demonstrates, corn usage for ethanol since 2000 correlates strongly with wholesale corn prices, with the relationship found to have a correlation coefficient of 0.75. The exponential function demonstrated in the figure fits these data with an R^2 of 0.63. It is for this reason that the primary feedstock costs for corn ethanol production will be modeled with the function $MC_{Corn} = 2.2221e^{1.9481(\frac{C_e}{C_T})}$, with C_e equal to Corn usage for Ethanol and C_T equal to total Corn production in a given harvest year, or, in other words, the feedstock constraint (the maximum amount of corn which could possibly be used to produce ethanol). Assuming a plant conversion efficiency of 2.80 bushels of corn per gallon of ethanol and current total Corn production of 14.54 billion bushels, this function can be readjusted to reflect the cost of corn at a given level of ethanol production and the current feedstock constraint with $MC_{Corn} = 2.2221e^{1.9481(\frac{x}{40.73})}$, where x is equal to ethanol production (in billions of gallons) and 40.73 bgal equal to maximum ethanol production under the current feedstock constraint of 14.54 billion bushels of corn. A limit will additionally be imposed at this feedstock constraint. In the MAC(10) scenario the feedstock constraint is expanded by 2.49% annually, based off of growth in Corn production to date.

Co-Product Return Assumptions: Dry-mill corn ethanol produces two primary physical co-products (Dried Distillers Grains with Solubles and Corn Oil) and one primary regulatory co-product (D6 RINs). Dried Distillers Grains (DDGS) are the spent cereals from the dry-mill ethanol production process which represent a protein and nutrient-rich feed grain used in a host of animal rations. The dry-mill process is estimated to produce between 16 and 20 pounds of DDGS per bushel of corn used, with higher estimates typically accounting for higher than 10% moisture content (Irwin, 2017, Crago et al., 2010, APEC, 2010). Using a 5-year average price of $120/ton for 10% moisture Nebraska DDGS (USDA AMS) and 16 pounds of 10% moisture DDGS produced per bushel of corn, we can thus estimate DDGS returns to be around $0.31/gallon of ethanol. Corn Oil produced in the dry-mill process can be used as a food-grade cooking oil or as a secondary feedstock for biodiesel production. The ethanol production process yields around 0.55 pounds of Corn Oil per bushel of corn (Irwin, 2017). Assuming an average retail price of \$0.25/pound (USDA AMS), Corn Oil yields returns of about \$0.049 per gallon of ethanol produced.

Due to corn ethanol's classification as a conventional biofuel (D6) under the RFS, regulatory co-product returns can be quantified with D6 Renewable Identification Number (RIN) prices. Recent prices have been quite volatile, but this paper will use a recent average price of \$0.67 per credit, with 1 credit generated per gallon of D6 biofuel produced (OPIS). This places the regulatory co-product return for Corn Ethanol at \$0.67/gallon. This leaves total co-product returns, both physical and regulatory, at \$1.029 netback for each gallon of Corn ethanol produced.

Capacity Installation Cost Assumptions: The fixed cost of construction is estimated to be slightly over \$210 million for a 100 MGY dry-mill plant (Irwin, 2017, Gordon et al., 2008). A fixed price of \$2.11 per gallon of installed capacity will thus be used as the average capacity installation cost of a standard dry-mill corn ethanol production facility. Current nameplate capacity for US dry-mill corn ethanol plants is 14.232 billion gallons, though plants can typically produce at up to 20% above nameplate capacity. δ, the dummy variable used to represent the existing capacity constraint, CC_0, will thus be activated at 17.0784 billion gallons of production. The figure above demonstrates how CIC marginal costs differ in the MAC_0 and MAC_{10} scenarios due to the differing δ values at production levels CC_0 and CC_{10}.

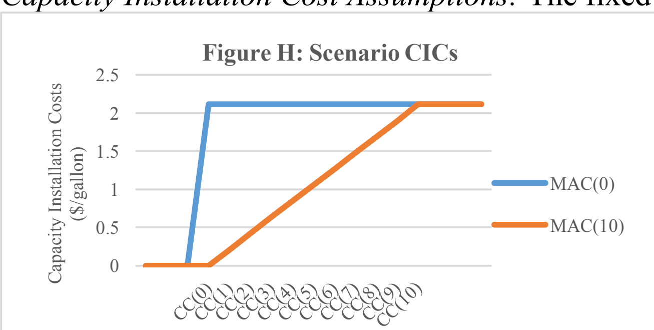
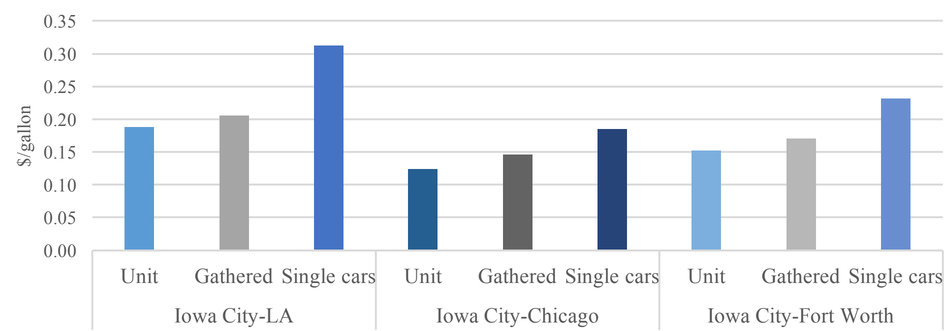


Figure H: Scenario CICs

California Basis Assumptions: Ethanol in California typically sells at a significant premium over other states, with a basis (difference between the local spot market and standard futures price) that is consistently among the highest in the nation. Included in the basis valuation are differences in transportation costs and tax rates. Ethanol rail transportation to California costs between \$0.19 and \$0.31 per gallon. As the figure demonstrates, single car rail – which is the most common method of transportation for fuel ethanol – between Iowa and Los Angeles is around \$0.31/gallon, a \$0.13 premium to Chicago and \$0.08 premium to Fort Worth. This, combined with higher fuel taxes in California relative to the rest of the country (\$0.30/gallon on gasoline and blended ethanol and \$0.15/gallon on unblended ethanol), leads to a fixed California basis value of approximately \$0.24/gallon of corn ethanol.

Figure I: Ethanol Rail Tariffs



Source: USDA AMS, Union Pacific, BNSF Railway

The complete marginal cost curve for Corn ethanol can thus be defined as:

$$MC_{Corn\ Ethanol} = (0.21)_{OC}x + (0.1687)_{SFC}x + (2.2221e^{1.9481\left(\frac{x}{40.73}\right)})_{PFC}x - (1.029)_{CPR}x + \delta(2.11)_{CIC}x + (0.24)_{CB}x$$

Marginal Cost of Sugarcane Ethanol

Operational & Capital Cost Assumptions: Operating and capital cost estimates for Brazilian sugarcane ethanol plants are cited at between \$0.35 and \$0.43/gallon (biofuel production cost) (Sonoda et al., 2016) (Crago et al., 2010). This operating and capital cost is broken down into machinery (43% of total operating & capital expenses), capital remuneration (26.2%), labor (18.5%), and land (12.3%) (Sonoda et al., 2016). For the purposes of this paper, an upper limit estimate of \$0.43 of operating and capital expenses per gallon produced will be used.

Secondary Feedstock Cost Assumptions: The production of Sugarcane ethanol requires chemicals and enzymes and utilities similar to those used in corn ethanol. The cost of chemicals (such as denaturant) and enzymes (~\$0.10/gallon) plus the cost of energy and utilities (~\$0.03/gallon) brings the combined secondary feedstock cost to around \$0.13 per gallon produced (biofuel production cost).

Primary Feedstock Cost Assumptions: To an even greater extent than the US Corn ethanol industry, the Brazilian Sugarcane ethanol industry dominates demand for Brazilian Sugarcane. Since 2004, an average of 54% of all sugarcane in Brazil has been cultivated for use in ethanol (CEPEA/ESALQ). With Brazilian exports making up 81% of the global Raw Sugar trade, it is clear that the ethanol industry's demand for sugarcane can have a very significant impact on global Sugarcane prices (OEC). In order to account for any changes in sugarcane prices due to changes in corn prices, a similar method to that used for Corn ethanol's primary feedstock cost was used. By generating a regression between annual share of Sugarcane used in ethanol and

Sugarcane prices, an exponential relationship equivalent to $MC_{Sugarcane} = 0.4685e^{1.9641(\frac{S_e}{S_T})}$, with S_e equal to Sugarcane usage for ethanol and S_T equal to total Sugarcane production in a given harvest year, or, in other words, the feedstock constraint (the maximum amount of Sugarcane which could possibly be used to produce ethanol). Assuming a plant conversion efficiency of 80 liters of ethanol (21.13 gallons) per ton of Sugarcane and current total Sugarcane production of 667 Million MT of Sugarcane, this function can be readjusted to reflect the cost of corn at a given level of ethanol production and the current feedstock constraint with $MC_{Sugarcane} = 0.4685e^{1.9641(\frac{x}{14.09})}$, where x is equal to ethanol production (in billions of gallons) and 14.09 bgal equal to maximum ethanol production under the current feedstock constraint of 667 MMT of Sugarcane. A limit will additionally be imposed at this feedstock constraint. In the MAC(10) scenario the feedstock constraint is expanded by 2.12% annually based off of growth trends in Sugarcane ethanol acreage to date.

Co-Product Return Assumptions: Sugarcane's primary physical co-product is bagasse – the pulpy Sugarcane remains left once ethanol has been extracted – and its regulatory co-product upon entering US soil is D5 RINs. Bagasse can be used to generate bioelectricity, which can then be sold back to the grid. Depending on the turbine system, bagasse can yield electricity to the magnitude of 100-121 kwh/ton (Bezerra & Ragauskas, 2016). Assuming that bagasse represents 30% of sugarcane weight, and an average Brazilian electricity price of $0.10/kwh, bagasse bioenergy can generate returns of $11/ton of bagasse, or $0.156 per gallon of Sugarcane ethanol produced.

Sugarcane ethanol benefits from being classified as an advanced biofuel (D5) under the RFS, rather than a conventional D6 biofuel like Corn ethanol. This implies generally higher regulatory co-product returns, which can be quantified with D5 Renewable Identification Number (RIN) prices. Though D5 RIN prices have historically tracked D6 RIN prices very closely, D5 RINs have recently begun trading at a slight premium, thus, for the purposes of this paper, a recent average price of $0.77 per credit will be used, with 1 credit generated per gallon of D5 biofuel produced (OPIS). This places the regulatory co-product returns for Sugarcane Ethanol at $0.77/gallon. Total co-product returns, both physical and regulatory, are thus $0.926 netback for each gallon of Sugarcane ethanol produced.

Capacity Installation Cost Assumptions: Construction of a standard 108 Million Liter per Year (MLY) Sugarcane ethanol plant in Brazil is estimated to cost around $74 million, with this cost broken down into land and site development, construction, working capital/inventory, railroad and rolling stock, and safety adjustments (biofuel production cost). This can be readjusted to a fixed capacity installation cost equal to $2.59 per gallon of newly installed capacity. With current Brazilian nameplate capacity at 10.7 billion gallons per year, and assuming Brazilian sugarcane ethanol plants can operate at up to 110% of nameplate capacity, the current maximum capacity constraint, CC_0, is assumed to be 11.8 billion gallons per year, leading this to be the production level at which δ is activated. MAC_0 and MAC_{10} CIC values will follow theoretical paths similar to those for Corn ethanol, as visualized in the figure shown in the above section, but will be capped at $2.59/gallon rather than $2.11/gallon.

California Basis Assumptions: The basis calculation includes tariffs, taxes and logistical costs of getting Sugarcane ethanol to California. Using standard Santos to New York Harbour ethanol shipping costs of $0.1363/gallon (Argus), we assume Santos to Los Angeles to cost around

\$0.17/gallon. This is calculated using distance estimates of 5000 nautical miles between Santos and New York Harbor and 7000 nautical miles between Santos and Los Angeles (marinetraffic.com). Assuming that around 60% of shipping costs are distance-dependent, this places the Santos-Los Angeles shipping route at slightly greater than a \$0.03 premium to the Santos-New York route (Gordon et al., 2008). The excise tax on all ethanol with less than or equal to 15% gasoline blended (aka E85-E100) is currently pegged at half of the state's gasoline tax rate of \$0.30/gallon, thus putting it at \$0.15/gallon of ethanol (AFDC). Ever since the US government lifted its \$0.54/gallon specific ethanol tariff in 2011, ethanol imports have been subject only to the standard 1.9-2.5% ad valorem tariff on non-beverage alcohol (1.9% if denatured, 2.5% if undenatured) (USITC). We will thus assume a tariff rate equal to 1.9% of the FOB Santos value of the ethanol. In other words, the tariff is equal to $0.019 * (operational\ \&\ capital\ costs)x + (secondary\ feedstock\ costs)x + (primary\ feedstock\ costs)x - (Bagasse\ returns)x + (capacity\ installation\ costs)(\delta)x$. Thus, it is equal to 1.9% of the marginal cost of the ethanol before accounting for returns from D5 RINs or any of the components of the California-specific costs (basis). The model thus assumes total basis costs equal to: \$0.3163 + 0.019(MC FOB Santos).

The complete Brazilian Sugarcane ethanol marginal cost curve is assumed to be:

$$MC_{Sugarcane\ Ethanol} = (0.43)_{OC}x + (0.13)_{SFC}x + (0.4685e^{1.9641(\frac{x}{14.09})})_{PFC}x - (0.92)_{CPR}x + \delta(2.59)_{CIC}x + (0.3163 + 0.019(0.404 + \delta(2.59)x + 0.4685e^{1.9641\left(\frac{x}{14.09}\right)}))_{CB}x$$

3. Results

Ethanol Blending

As can be visualized in Table 1, regression 1, which didn't include fixed effects or control variables, yielded positive and statistically significant β_3 values (the difference in difference coefficient) at the 0.01 level under all 3 Post-LCFS scenario assumptions. These values vary from 0.032 for post-2007 (A), 0.044 for post-2011 (B) and 0.049 for the pre-2007/post-2011 (C). This can be interpreted as an indication that ethanol blending increased 3.2-4.9% more for California than for the 8-state control following the LCFS. Regression 2, however, indicates that fixed state and year effects account for a significant portion of the relationship between the LCFS and ethanol blending, with coefficient values now entirely negative and only statistically significant at the 0.05 level under the post-2007 (A) scenario assumption. Regression 3, which adds a control for differences in state gasoline taxation rates, shows that gasoline taxation rates do not have a significant effect on ethanol blending.

As far as E85 infrastructure is concerned, regression 1 demonstrates that with no fixed effects or control variables, the addition of the LCFS yielded positive and statistically significant β_3 values at the 0.01 level under all 3 Post-LCFS scenario assumptions, with coefficient values varying between 40.18 under scenario assumption A, 65.62 for B, and 64.09 for C. The addition of state and year fixed effects in regression 2 slightly reduced these coefficient values, but they remain positive and statistically significant at the 0.05 level for scenario assumption A and the 0.01 level for scenario assumptions B and C. Regression 3, which adds a control for total gasoline consumption, yields coefficient values of 51.71 (A), 66.70 (B), and 91.93 (C), which are all statistically significant at the 0.01 level. The addition of a control for gasoline taxation rates in regression 4 slightly reduces the coefficient value for scenario assumption A to 50.91, while increasing the coefficients for B and C to 72.60 and 102.15, respectively. Regression 1 thus estimates that the LCFS led to the addition of between 40.18 and 65.62 E85 pumps, with regression 3 placing this figure between 51.7 and 91.93, and regression 4 at 50.91-102.15 pumps.

Table 1

Total Ethanol Blending

Assumptions:
Regression (1): No fixed effects or controls
Regression (2): Includes fixed state and year effects
Regression (3): Includes fixed state and year effects; controls for gas taxation

1.A Executive Order S-01-07 (pre vs. post January 2007)

	(1)	(2)	(3)
CA Post-LCFS	0.0317377**	-0.0176798*	-0.0192897*
	(0.0121485)	(0.0076188)	(0.0082082)
Tax			0.0001878
			(0.0003485)
Observations	126	126	126
R^2	0.0576	0.8941	0.8944

1.B LCFS Enforcement Period (pre vs. post January 2011)

	(1)	(2)	(3)
CA Post-LCFS	0.0439957**	-0.0074641	-0.0086793
	(0.0159813)	(.0077807)	(0.0093793)
Tax			0.0000934
			(0.0003983)
Observations	126	126	126
R^2	0.0576	0.8896	0.8896

1.C LCFS Drafting Period Omission (pre January 2007 vs. post January 2011)

	(1)	(2)	(3)
CA Post-LCFS	0.0493828**	-0.0157468	-0.0149413
	(0.0170569)	(0.0082495)	(0.010372)
Tax			-0.0000566
			(0.0004366)
Observations	99	99	99
R^2	0.0795	0.9105	0.9105

*Indicates statistical significance at the 0.05 level
**Indicates statistical significant at the 0.01 level

Table 2

E85 Station Offerings

Assumptions:
Regression (1): No fixed effects or controls
Regression (2): Includes fixed state and year effects
Regression (3): Includes fixed state and year effects; controls for gas consumption
Regression (4): Includes fixed state and year effects; controls for gas consumption and taxation

2.A Executive Order S-01-07 (pre vs. post January 2007)

	(1)	(2)	(3)	(4)
CA Post-LCFS	40.19754**	26.98182*	51.71269**	50.91103**
	(12.19599)	(12.6879)	(9.950947)	(10.08084)
Gas			0.0013794**	0.0014421**
			(0.0002136)	(0.0002405)
Tax				0.2574345
				(0.448122)
Observations	144	144	126	126
R^2	0.0711	0.7466	0.8122	0.8128

2.B LCFS Enforcement Period (pre vs. post January 2011)

	(1)	(2)	(3)	(4)
CA Post-LCFS	65.61522**	36.95238**	66.69709**	72.59632**
	(14.62714)	(11.5934)	(9.164651)	(9.87738)
Gas			0.0015548**	0.0014326**
			(0.0001967)	(0.0002109)
Tax				-0.6696375
				(0.4349903)
Observations	144	144	126	126
R^2	0.1241	0.7577	0.8436	0.8472

2.C LCFS Drafting Period Omission (pre January 2007 vs. post January 2011)

	(1)	(2)	(3)	(4)
CA Post-LCFS	64.08961**	40.30655**	91.92742**	102.1541**
	(16.03361)	(13.84569)	(10.30606)	(10.84713)
Gas			0.0019705**	0.0017832**
			(0.0002078)	(0.0002158)
Tax				-1.103369*
				(0.4542229)
Observations	117	117	99	99
R^2	0.1220	0.7640	0.8828	0.8912

*Indicates statistical significance at the 0.05 level
**Indicates statistical significant at the 0.01 level

Sugarcane Ethanol Blending

The results of the Sugarcane ethanol regression demonstrate that prior to the inclusion of PADD and year fixed effects, the difference in difference coefficient is in fact slightly negative, with values of -0.016 for the post-2009 assumption (A), -0.004 for post-2011 (B) and -0.011 for pre-2007/post-2011 (C), though none of these values are statistically significant at the 0.05 level. Once fixed region and time effects are accounted for, the coefficients turn positive, implying that the LCFS increased the fraction of Sugarcane ethanol in the total ethanol blend. These coefficient values range from 0.041 (A) to 0.040 (B) and 0.054 (C), with only scenario C (pre-2007/post-2011) having statistical significance at the 0.05 level. This can be taken to mean that the LCFS led to a 4.0-5.4% increase in Brazilian Sugarcane ethanol's share in the total ethanol blend.

Table 3

Sugarcane Ethanol Blending

Assumptions:
Regression (1): No fixed effects or controls
Regression (2): Includes fixed state and year effects

3.A First LCFS Draft Revision (pre vs. post January 2009)

	(1)	(2)
CA Post-LCFS	-0.0162674	0.0412729
	(0.016106)	(0.0209251)
Observations	39	39
R^2	0.0268	0.7277

3.B LCFS Enforcement Period (pre vs. post January 2011)

	(1)	(2)
CA Post-LCFS	-0.0042894	0.0396912
	(0.0205635)	(0.0198049)
Observations	39	39
R^2	0.0012	0.7290

3.C LCFS Drafting Period Omission (pre January 2007 vs. post January 2011)

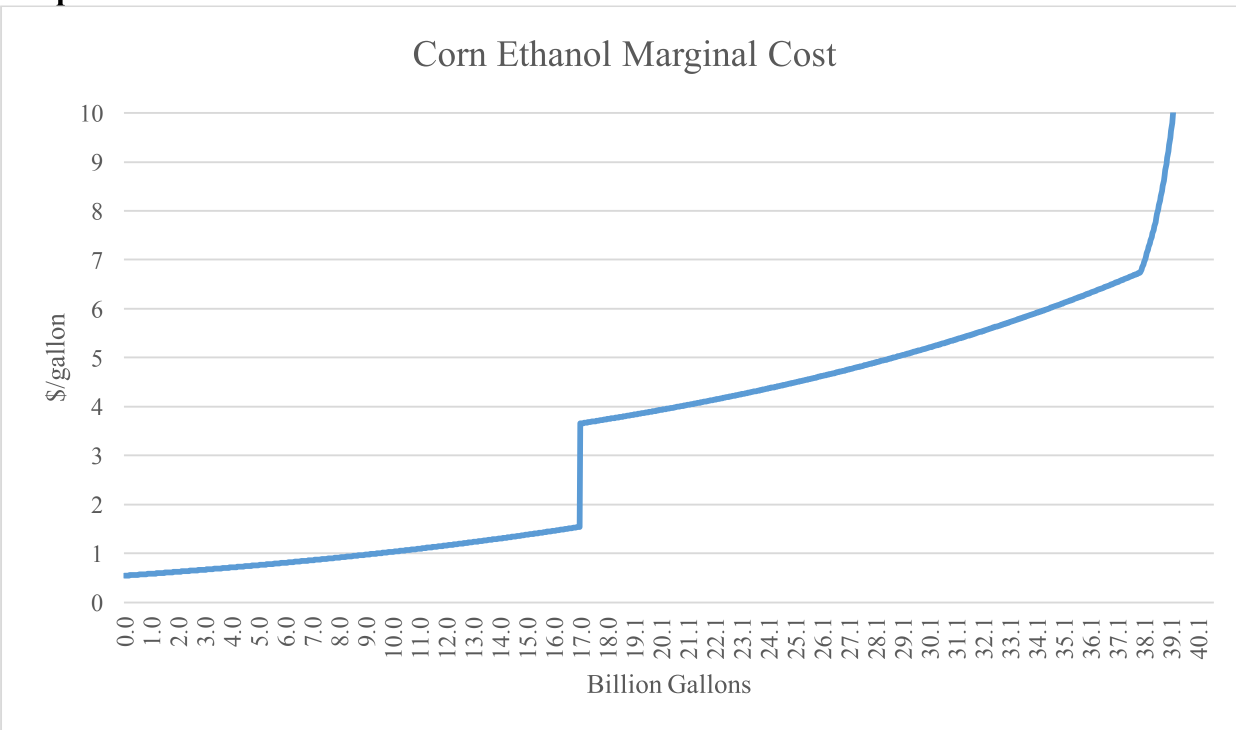
	(1)	(2)
C4	-0.0106824	0.0537416*
	0.023088	(0.0235141)
	30	30
	0.0076	0.7500

*Indicates statistical significance at the 0.05 level
**Indicates statistical significant at the 0.01 level

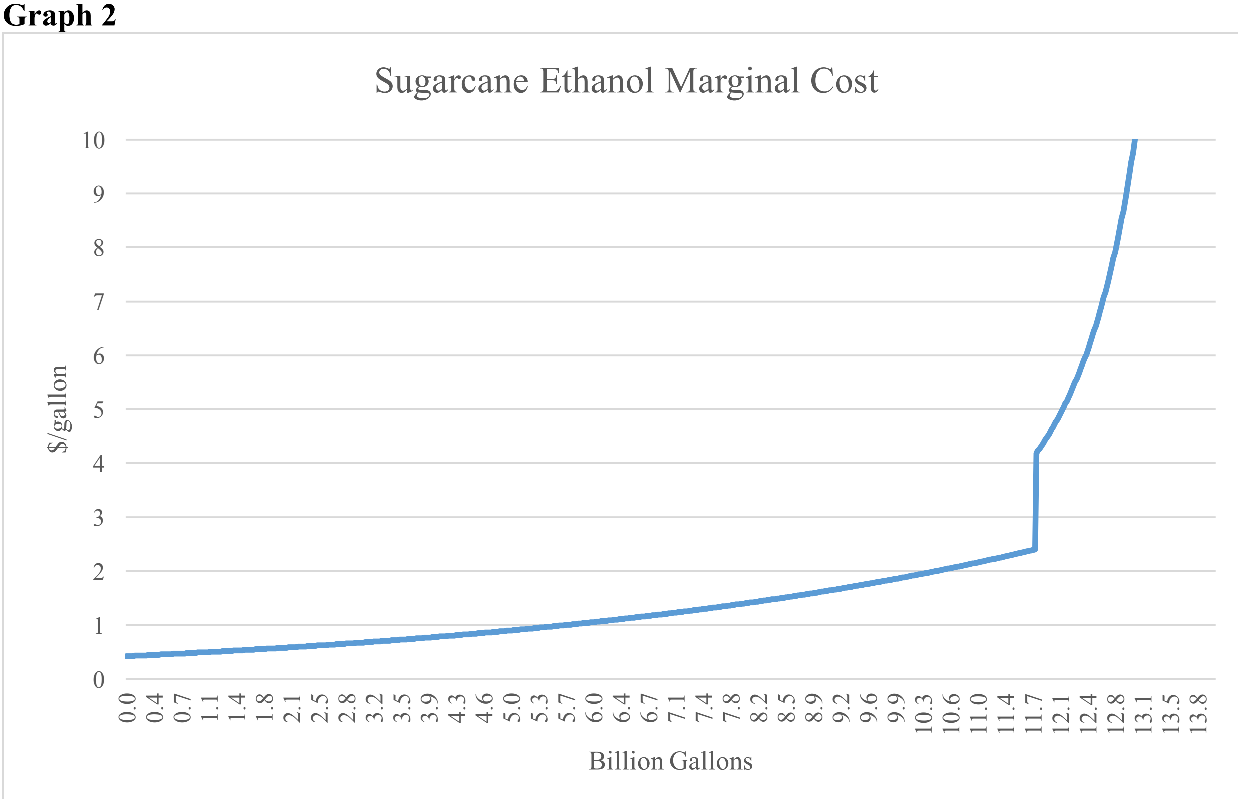
Marginal Cost Curves (Graphs 1 & 2)

The Marginal Cost curves generated from the equations in section 2.3 demonstrate the expected costs of Corn and Sugarcane ethanol at a given level of production. Using current production figures of 14.5 billion gallons of Corn ethanol (USDA NASS) and 7.59 billion gallons of Sugarcane ethanol (UNICA), the model predicts marginal costs to be equivalent to $1.32 for Sugarcane ethanol and $1.34 for Corn ethanol. While these figures may seem somewhat low, it should be considered that they include RIN value pass-through, which is not typically accounted for in FOB pricing, as RIN prices have been found to be passed directly onto retail gasoline consumers (Lade & Bushnell, 2016). As such, the marginal costs found via this model account for the RFS and in turn understate the true marginal cost of production. At current capacity constraints of 17 bgal and 11.77 bgal for Corn and Sugarcane ethanol, respectively, the marginal costs rise to $3.66 for Sugarcane ethanol and $4.19 for Corn ethanol under MC_0, the cost curve used to find the 2020 marginal abatement costs. Under the MC_{10} assumption, which assumes 5% annual capacity growth and 2.3% and 2.5% annual feedstock growth for Sugarcane and Corn ethanol, respectively, this change in price due to capacity installation growth is spread across a 10 year period. As Graph 2 demonstrates, Sugarcane ethanol reaches its maximum feedstock constraint before full capacity growth is reached.

Graph 1



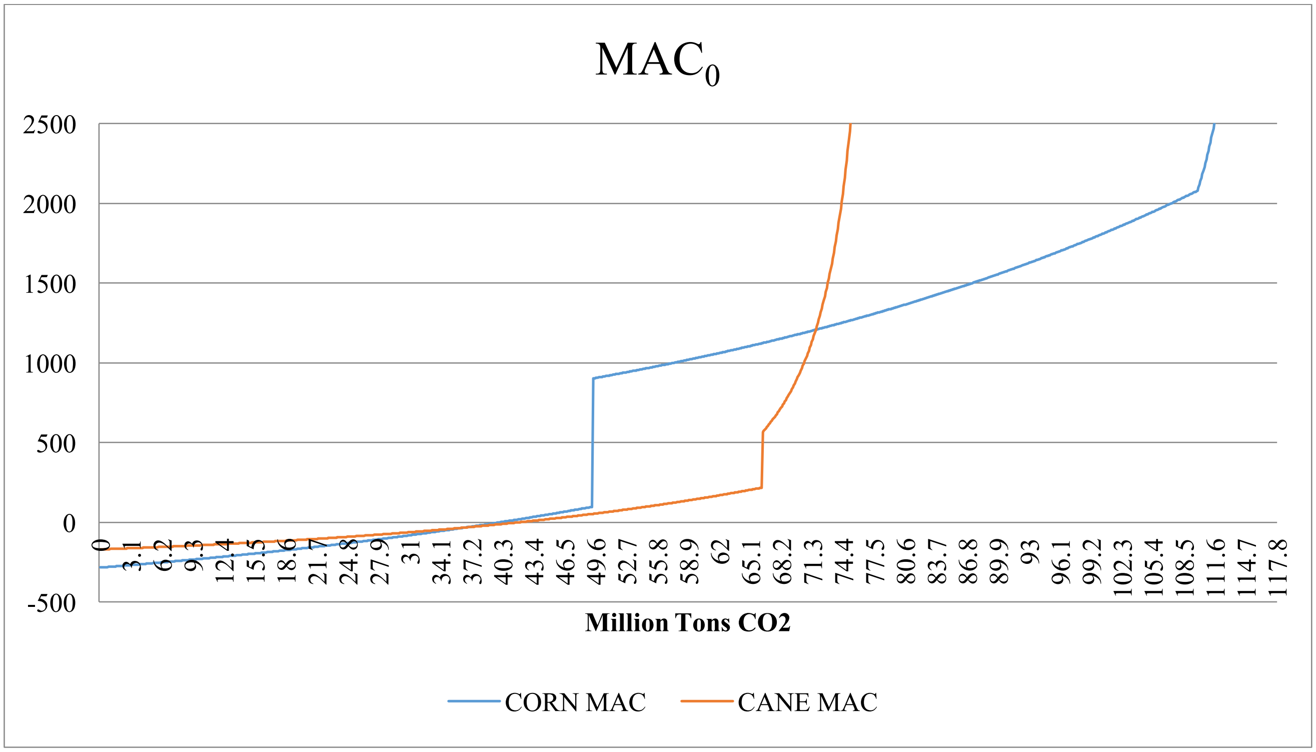
Graph 2



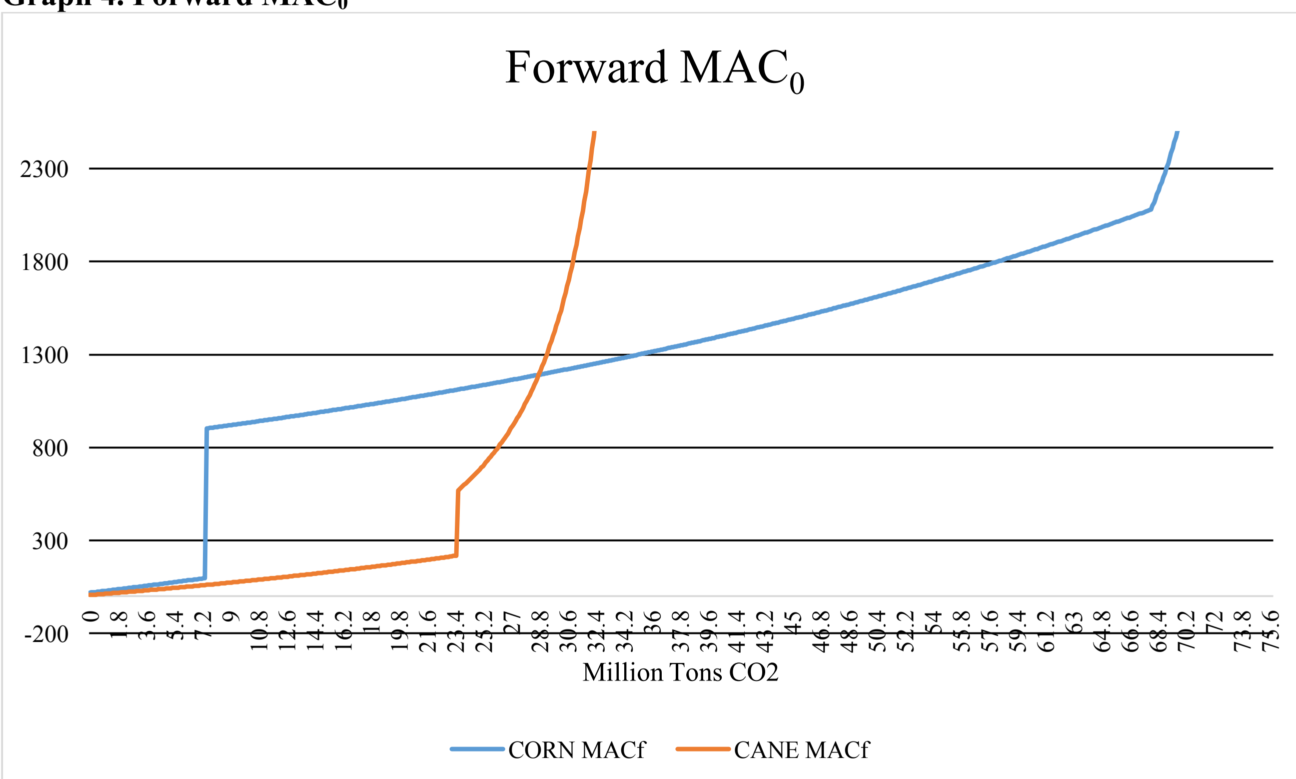
Marginal Abatement Cost Curves

As the models in Graphs 3 and 5 demonstrate, the MAC_0 and MAC_{10} abatement cost curves show that there is incentive to abate 41.85 million tons of CO2 via Sugarcane ethanol production and 40 million tons via Corn ethanol production without the presence of the LCFS. This translates into 7.42 billion gallons of Sugarcane ethanol and 13.83 billion gallons of Corn ethanol – figures which are slightly under true production of 7.59 billion gallons and 14.5 billion gallons for Sugarcane and Corn ethanol, respectively. These "natural" production levels are the points at which the marginal costs for corn and sugarcane ethanol reach the marginal cost of the reference fuel, CARBOB. In other words, at production levels lower than this, both Corn and Sugarcane ethanol are relatively cheaper than CARBOB, and blenders are thus incentivized to purchase them, regardless of any credit markets. At current production levels, the costs of marginal abatement rise to $19.34 for Corn ethanol and $6.38 for Sugarcane ethanol. Assuming that increased California ethanol blending does not displace current blending (in other words, any ethanol that California purchases will be produced on top of existing production), a $6.38 or $19.34 credit would be required in order to incentivize the blending of an additional gallon of Sugarcane or Corn ethanol. Graphs 4 and 6 demonstrate these "forward abatement costs", or, the MAC curves assuming current production levels as the baseline. These demonstrate that the compliance costs for Sugarcane ethanol are lower than those for Corn ethanol, until the Sugarcane feedstock constraint is reached, but would require LCFS credits of varying prices in order to incentivize production at the necessary levels of abatement.

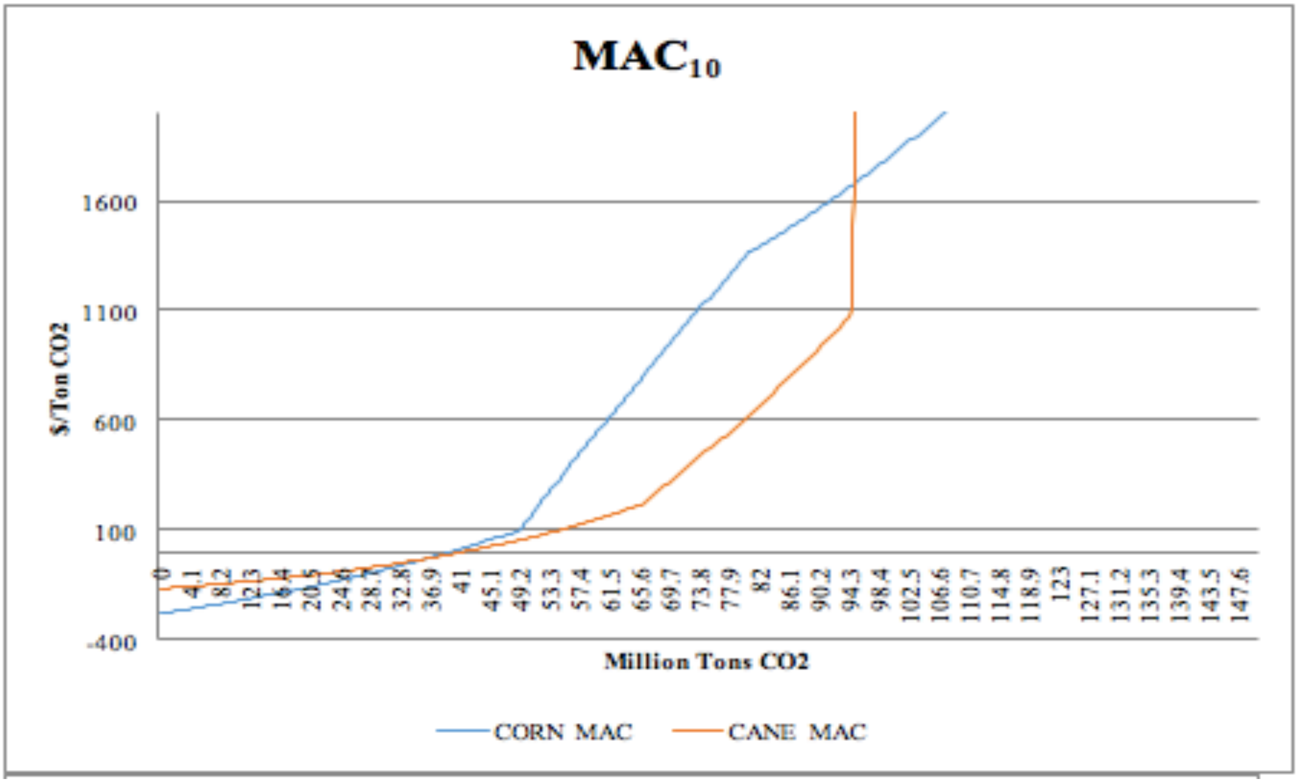
Graph 3. 2020 Marginal Abatement Cost (MAC_0)



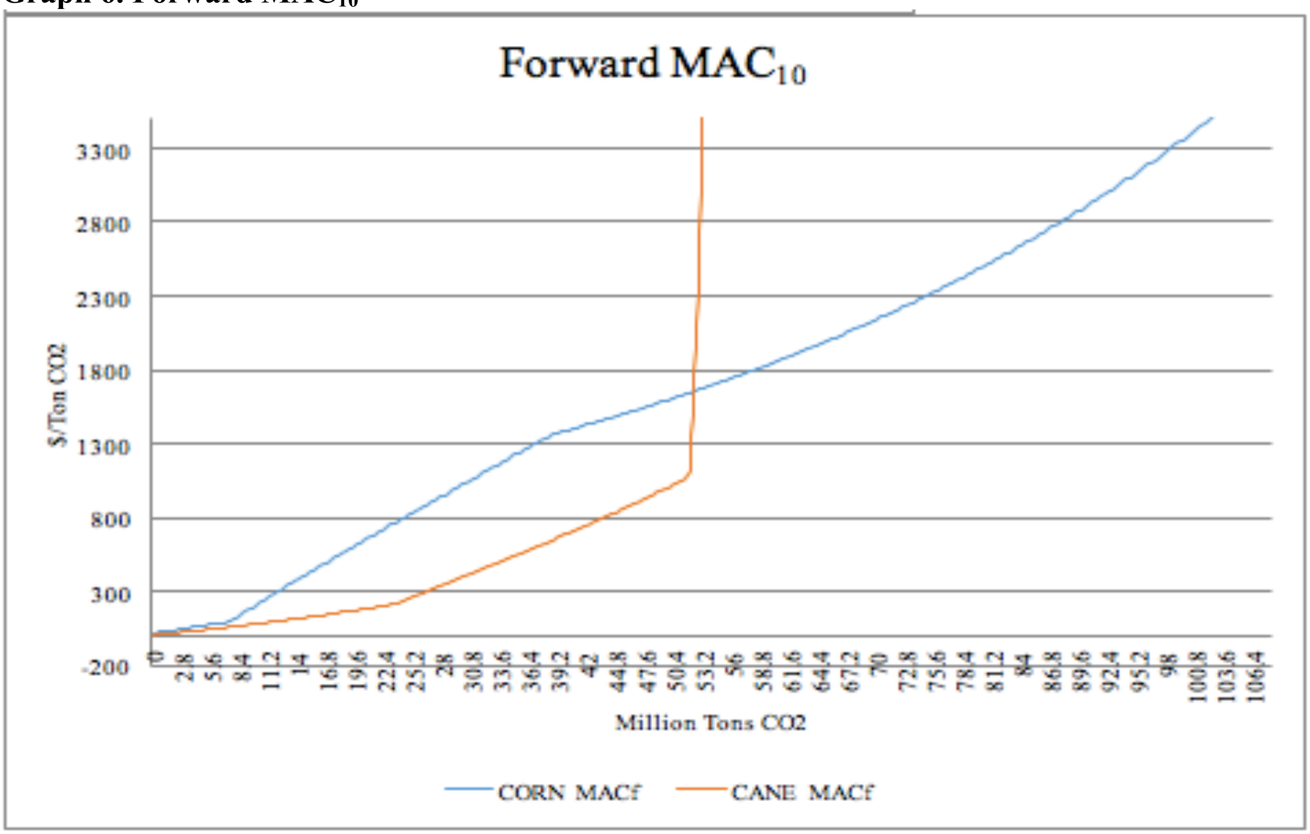
Graph 4. Forward MAC_0



Graph 5. 2030 Marginal Abatement Cost (MAC_{10})



Graph 6. Forward MAC_{10}



Marginal Abatement Scenarios

Table 4. Baseline Compliance Model

	2020				2030			
Scenario	Blend	% Cane	MAC_{Sugar}	MAC_{Corn}	Blend	% Cane	MAC_{Sugar}	MAC_{Corn}
1	41.3%	100%	*$12,120**	-	98.82%	100%	N/A	-
2	23.89%	100%	$185	-	80.48%	100%	N/A	-
3	18.08%	100%	$133	-	63.07%	100%	*$13,103**	-
4	15.56%	100%	$112	-	25.63%	100%	$202	-
5	10%	53.55%	$40	$39	10%	28.91%	$23	$51

*Indicates a price which exists on the artificially imposed feedstock limit

All marginal abatement cost scenarios model compliance from the end of 2016 onwards. In other words, the CI is seen as being reduced by 7.88 points by 2020, and 16.56 points by 2030. Scenario 1 – which is relatively pessimistic and assumes credit surplus exhaustion and no innovation in biodiesel – would require 17.4 million tons of CO2 abatement via ethanol by 2020, which would necessitate 6.33 billion gallons of Sugarcane ethanol production. It should be noted that these 17.4 million tons of abatement from ethanol translate to 35.7 million tons of abatement from Sugarcane ethanol. This is because it is assumed that if this abatement were not coming from sugarcane ethanol, then it would have been achieved via corn ethanol blending. As such, a gallon of sugarcane ethanol is replacing a gallon of corn ethanol which could have been fulfilling a certain quantity of CO2 abatement. At these required Sugarcane ethanol production levels, which are quite close to the maximum feedstock constraint, the ethanol blend would have to be 41.3%, with a compliance cost of over $12,000. In 2030, the ethanol blend would have to increase to almost 100%, with required Sugarcane ethanol production beyond the maximum feedstock constraint.

At the baseline, Scenario 2 requires ethanol blending at around 23.9% in 2020 and 80.5% in 2030, with a compliance cost of $185 in 2020 and unfeasible compliance in 2030 (required production above Sugarcane ethanol's maximum feedstock constraint). Scenario 3, which represents baseline biodiesel blending and credit banking assumptions, requires 18.08% ethanol blending in 2020 and 63.07% blending in 2030, with credit prices of $133 and $13,103, respectively. Scenario 4 would require only marginal increases in blending in 2020 and 2030, and would carry reduced compliance cost burdens – with required credit prices of $112 in 2020 and $202 in 2030. Scenario 5 – the most optimistic in terms of biodiesel blending and credit banking – is the only scenario that could achieve all required abatement while operating within a 10% blend wall constraint. Under this scenario, blending would remain underneath 10%, with only 53.6% Sugarcane ethanol in 2020 and 28.9% in 2030, and credit price requirements declining from $40 in 2020 to $23 in 2030. At the same time, because Sugarcane ethanol blending would not have to be 100%, Corn ethanol, which is making up the rest of the ethanol blend, would have an abatement cost of $39 in 2020 and $51 in 2030, at required production levels.

RFS Interaction (Table 5)

	Scenario	2020 MAC_{Sugar}	2020 MAC_{Corn}	2030 MAC_{Sugar}	2030 MAC_{Corn}
1. No RFS	1	*$12,120***	-	N/A	-
	2	$338	-	N/A	-
	3	$286	-	*$13,103**	-
	4	$265	-	$355	-
	5	$193	$294	$177	$306
2. RIN Price Reduction 2020: -25% 2030: -50%	1	*$12,120**	-	N/A	-
	2	$223	-	N/A	-
	3	$171	-	*$13,103**	-
	4	$150	-	$282	-
	5	$78	$102	$104	$175
3. RIN Price Increase 2020: +100% 2030: +200%	1	*12,120**	-	N/A	-
	2	$108	-	N/A	-
	3	$56	-	*$13,103**	-
	4	$35	-	$52	-
	5	-$37	-$89	-$127	-$208

Without the presence of a Renewable Fuel Standard, compliance costs would increase dramatically. Under the baseline scenario (3), credit prices would have to increase by 115% relative to the baseline in 2020. Even in the most optimistic scenario (5), compliance costs would increase by 383% for Sugarcane ethanol and 654% for Corn ethanol in 2020, and by 670% and 500% for Sugarcane and Corn ethanol, respectively in 2030. Assuming that D5 and D6 RIN prices fall by 25% by 2020 and 50% by 2030, credit prices would still have to dramatically increase to account for the reduced “value” of the two biofuels. Only in a scenario in which RIN prices increase by 100% before 2020 and 200% by 2030, would compliance costs fall somewhat substantially. In this scenario, baseline (scenario 3) abatement costs would fall by 57.9% in 2020, but would still be unfeasible by 2030. Optimistic abatement requirements (scenario 5) would actually find abatement costs which would still be negative for both Corn and Sugarcane ethanol in both 2020 and 2030. Required blending for both biofuels under this scenario would actually be below their given production equilibrium. This is because the increased RIN value would translate into lower marginal costs for both fuels, and at this relatively low level of blending, would find marginal costs of production which are lower than the CARBOB reference fuel price.

CARBOB Price Interaction (Table 6)

	Scenario	2020		2030	
		MAC_{Sugar}	MAC_{Corn}	MAC_{Sugar}	MAC_{Corn}
Low	1	*$12,210*$*	-	N/A	-
	2	$276	-	N/A	-
	3	$224	-	*$13,103*$*	-
	4	$203	-	$255	-
	5	$130	$215	$77	$145
Mid	1	*$12,120*$*	-	N/A	-
	2	$185	-	N/A	-
	3	$133	-	*$13,103*$*	-
	4	$112	-	$130	-
	5	$40	$39	-$49	-$100
High	1	*$12,044*$*	-	N/A	-
	2	$110	-	N/A	-
	3	$57	-	*$13,103*$*	-
	4	$37	-	-$47	-
	5	-$39	-$108	-$225	-$443

Similarly to what was demonstrated via the RFS interaction, compliance costs are highly dependent on reference fuel (CARBOB) prices. Under relatively low CARBOB prices, compliance costs increase dramatically, with a credit price requirement which is 68.4% higher for the baseline scenario (3) in 2020. For the two most feasible 2020 compliance scenarios (4 & 5), Sugarcane ethanol marginal abatement costs would rise to $130-$203, representing compliance cost increases of 81-225%. Additionally, the marginal abatement cost of Corn ethanol under scenario 5 would increase from $39 in the baseline, to $215 under this "low CARBOB" price assumption, meaning that the cost of blending Corn ethanol would also be dramatically affected by the shift in gasoline price.

At the same time, an assumption using high CARBOB prices would lead to a 57% reduction in compliance costs for the baseline and a 67% and 198% reduction for scenarios 4 and 5, respectively. Because all CEC CARBOB price predictions anticipate a moderate to high increase in gasoline prices by 2030, the CARBOB price interaction would most likely only cause major difficulties with 2020 compliance, and are instead more likely to facilitate compliance in 2030 via slight increases in CARBOB gasoline prices.

Carbon Intensity Value Interaction (Table 7)

		2020				2030			
	Scenario	Blend	% Cane	MAC_{Sugar}	MAC_{Corn}	Blend	% Cane	MAC_{Sugar}	MAC_{Corn}
+20	1	181.3%	100%	-	-	99%	100%	-	-
	2	104.9%	100%	-	-	80.7%	100%	-	-
	3	79.4%	100%	-	-	63.3%	100%	*$32,928**	-
	4	68.3%	100%	-	-	26%	100%	$329	-
	5	24.4%	100%	$304	-	15.7%	100%	$180	-
-20	1	23.3%	100%	$131	-	55.8%	100%	$525	-
	2	13.5%	100%	$70	-	45.5%	100%	$486	-
	3	10%	98.5%	$52	$20	35.7%	100%	$306	-
	4	10%	84.7%	$45	$24	14.7%	100%	$76	-
	5	10%	30%	$18	$50	10%	19.5%	$13	$55

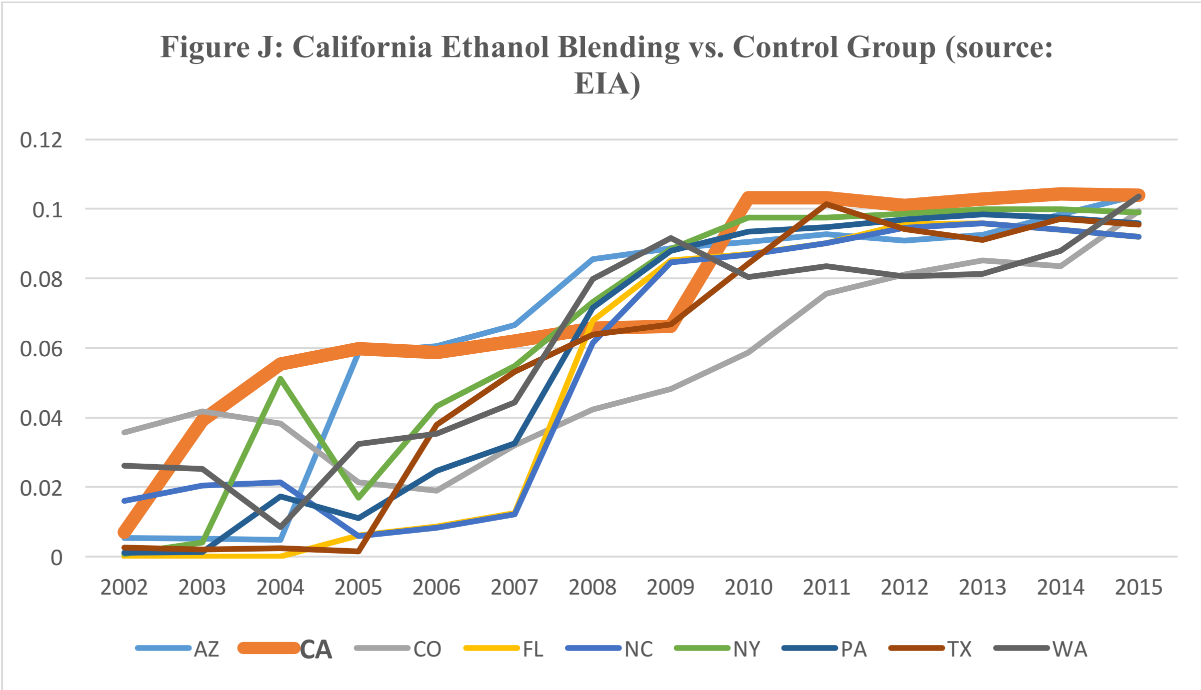
All previous compliance assumptions used current Pathway carbon intensity values of 72.5 gCO2/MJ for Corn ethanol and 46.6 for Sugarcane ethanol. These figures, however, shift quite frequently, as CARB audits and reassigns individual producer CI values. Because of this, it is useful to understand how abatement requirements and prices shift with a given addition or subtraction of CI points. In this sensitivity analysis, Sugarcane ethanol's CI was first increased from its current average by 20 points to 66.6, then reduced by 20 points to 26.6. Adding 20 points to the CI value made abatement in scenarios 1-4 unfeasible, with blending requirements above Sugarcane ethanol's current feedstock constraint. In fact, scenarios 1 and 2 would require ethanol blending alone to be greater than current California gasoline consumption. In other words, all of the state's gasoline would have to be composed of ethanol, and then some more ethanol would have to be consumed on top of that. Even the most optimistic scenario, scenario 5, would require greater than E20 blends in 2020 and at least E15 blends in 2030.

If Sugarcane ethanol's carbon intensity were to be reduced by 20 points, compliance would become significantly easier, as now relatively fewer quantities of the biofuel would achieve greater levels of abatement. In fact, full compliance in 2020 would be possible without breaching the E10 blend wall under scenarios 3-5, as well as under scenario 2 under an E15 blend wall. 2030 compliance would still be difficult, with E10 blending possible under scenario 5 and E15 blending possible under scenario 4. Under every scenario, however, 2030 abatement targets can be achieved without surpassing Sugarcane's maximum feedstock constraint. Despite this, ethanol blending would have to reach very high targets (35-56% levels) under Scenarios 1-3 in order to make compliance possible. Compliance costs in every scenario are greatly reduced across the board, with baseline (scenario 3) credit price requirements reduced by 61% for 2020 targets.

Discussion

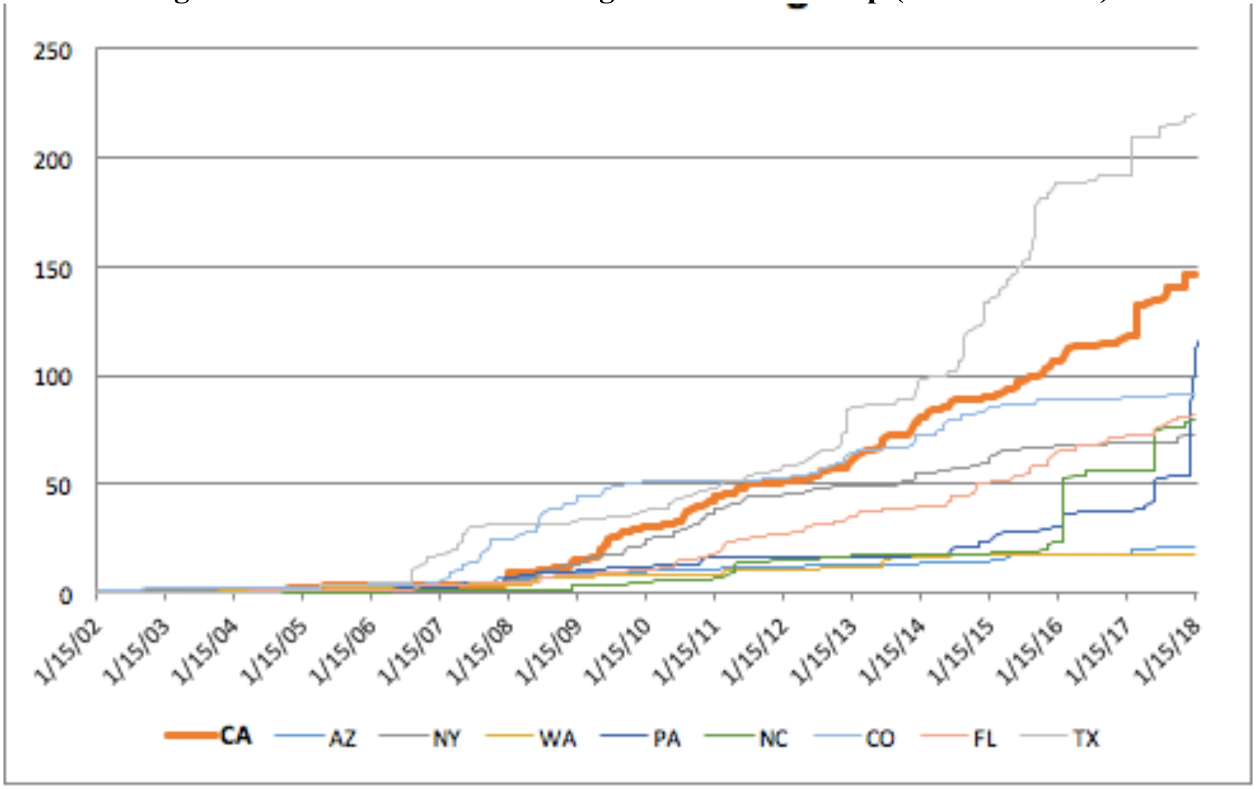
Ethanol Blending

It is difficult to extrapolate any concrete conclusions from the results of the regressions analyzing total ethanol blending for California (Table 1). Though regression 1 yielded positive, statistically significant coefficients, the addition of state and year fixed effects in the second regression completely upended these coefficient values, with all three turning negative and only scenario 1 (post-2007) finding statistical significance at the 0.05 level. Perhaps the most useful tool with which to analyze these puzzling results is a visual representation of total blending in California versus the 8-state control group (see Figure J). As is made evident in this figure, California gasoline reached the 10% blend wall in 2010, before any of the states from the control group. California blending has since remained suspended near the E10 blend wall, making only marginal pushes upwards in the past 7 years. This indicates that California had been making relatively larger advances in ethanol blending prior to reaching the 10% threshold. It is for this reason that an investigation into the state's E85 infrastructure investments is of particular interest, as it could indicate the state's potential for moving to overcome this E10 blending threshold in the future.



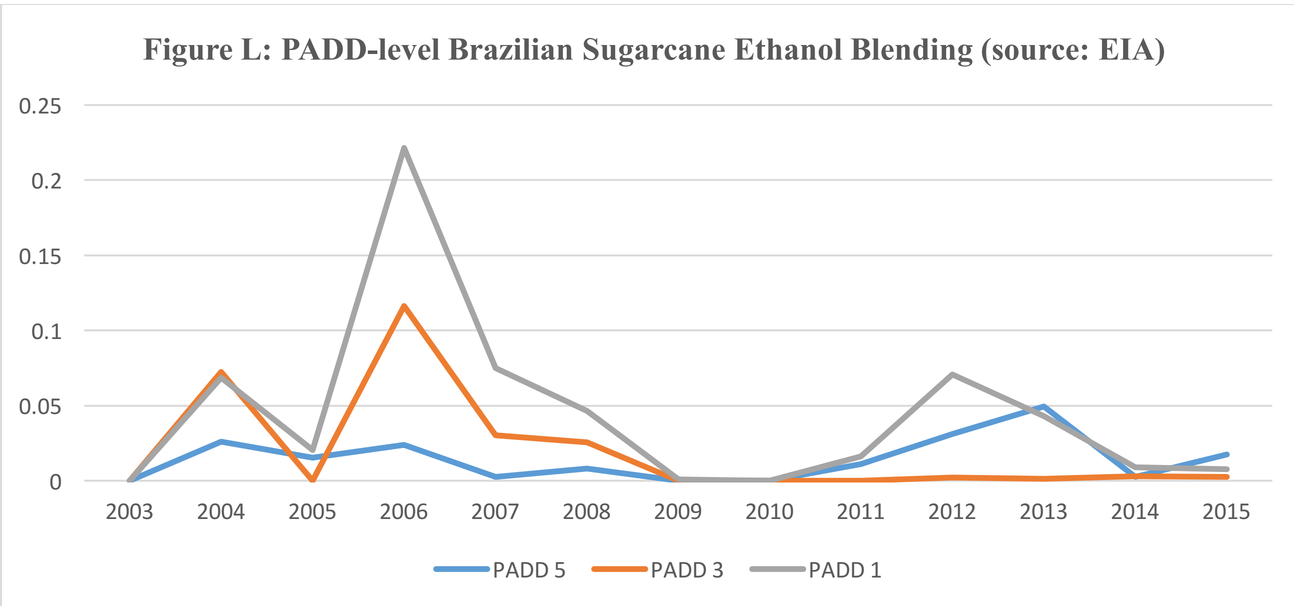
The regressions from Table 2 all seem to indicate that California has, in fact, made relatively larger investments into expanded E85 infrastructure compared to the 8-state control, with the LCFS accounting for the addition of 51 to 102 more gas stations offering E85 in California relative to other states. Figure K shows that California began investing in E85 pumps at about the same time as most other states (with the exception of Colorado and Texas, who both had earlier starts), but broke away in early 2009, maintaining a consistently high pace of E85 station growth since then. If California continues to expand its E85 infrastructure at such an advanced pace, it is perhaps not unfeasible for the state to surpass the blend wall and achieve E15+ blending in the coming years.

Figure K: California E85 Offerings vs. Control Group (source: AFDC)



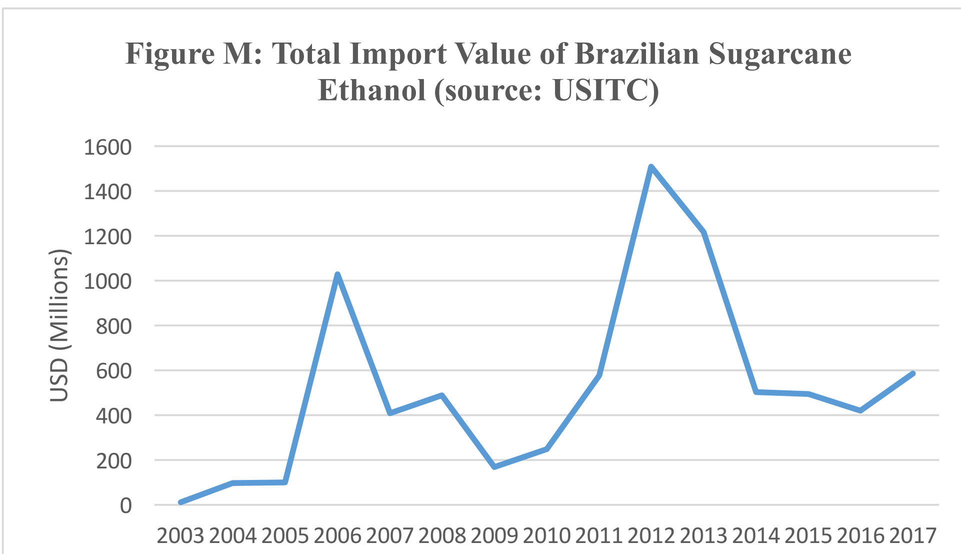
Sugarcane Ethanol Blending

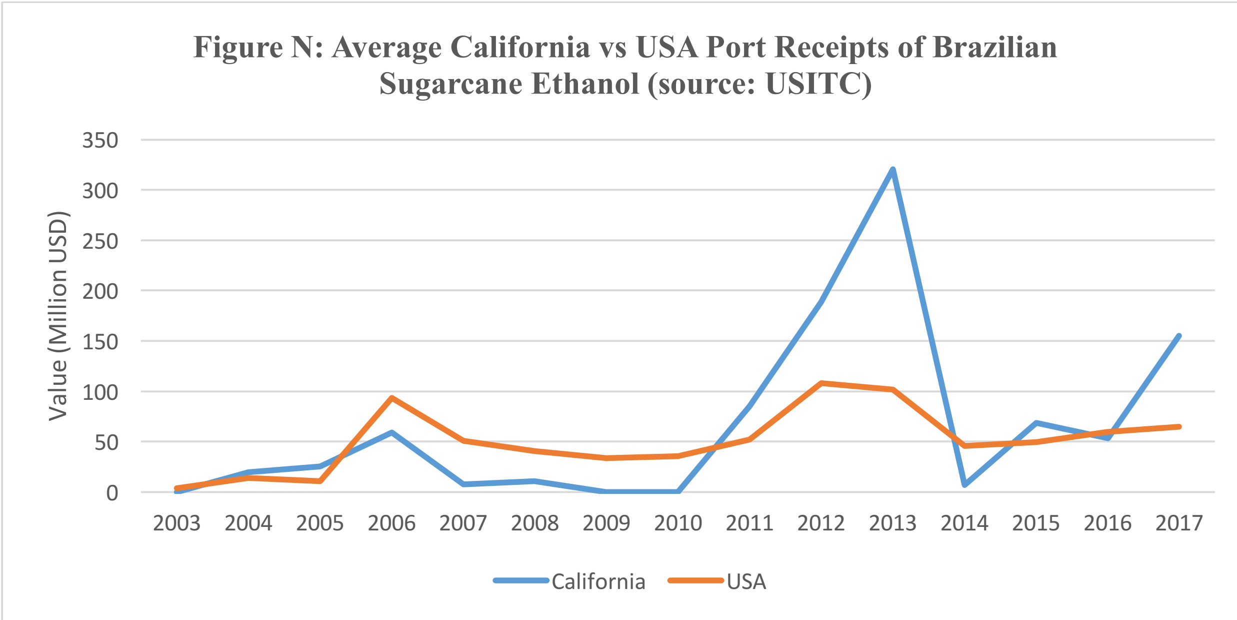
The regressions on Table 3 indicate that, while PADD 5 imported relatively larger amounts of Sugarcane ethanol, it was typically not at levels which can be seen as statistically significant. It is perhaps best, however, to analyze these figures with a visual aid of what was going on with Brazilian Sugarcane ethanol imports at the time. Figures D and L show that, across the board, imports from Brazil fell off dramatically in 2007 before reaching 0 in 2010, and only began recovering in 2011. This falls in line with Chum et al.'s (2014) findings that poor investment in Sugarcane mills combines with high raw sugar prices led to outsized local demand for Sugarcane ethanol and a dramatic decline in the Brazilian export market. With this in mind, the most robust regressions would most likely be those which do not include the "LCFS drafting period" from 2007 to 2010 (Table 3.C). It so happens that the only regression which yielded a statistically significant outcome at the 0.05 level was regression 3.C.2, which used this pre-2007 vs. post-2011 difference in difference and included fixed year and PADD effects. Under these conditions, the regression yielded a coefficient of 0.054, which can be interpreted to mean that the LCFS resulted in PADD 5 adding 5.4% more Brazilian Sugarcane Ethanol into the total Ethanol blend compared to the 8-state control.



It is worth noting the limits of using PADD-level trade data. Because California shares PADD 5 with 6 other states, it is impossible to control for how much sugarcane ethanol was blended by which state. It can be inferred, however, that the majority was consumed by California, as California ports received almost all of PADD 5's Brazilian ethanol imports during this time period (~94%). It is thus likely that the PADD-level Sugarcane ethanol blending figures somewhat understate California's state-specific Sugarcane ethanol blend. CARB began publishing data on ethanol blending by feedstock beginning in 2011, and as such it became possible to look at California's Sugarcane ethanol as a fraction of the total ethanol blend mix from this point forward. Here it becomes evident that, at least from 2011 onwards, California's Sugarcane ethanol blending was significantly higher than that of the rest of PADD 5, with a mean of 9% Sugarcane ethanol in the blend mix since 2011, compared to an average of 2% for PADD 5 as a whole.

It should also be noted that PADD-level trade data does not extend beyond 2015, and thus none of these regressions include Brazilian Sugarcane import data beyond this point. Using CARB's California-specific fuel data, though, it can be seen that in the 3rd quarter of 2017, Sugarcane ethanol made up slightly more than 16% of the state's Ethanol blend – levels which are significantly higher than in 2015, or any other year included in these regressions. This is despite 2017 presenting the largest premium in Brazilian Sugarcane ethanol (Figure F) to date. With a current FOB Santos-FOB Chicago premium of around $0.34/gallon, it would be anticipated that Brazilian Sugarcane ethanol imports would decline dramatically in favor of the relatively cheaper domestic Corn ethanol. Figure M shows that the value of total Brazilian ethanol imports for the United States as a whole has been somewhat lower than the highs seen in previous years ever since the reversal in the Santos premium in 2014/15. Figure N furthers this, showing that since 2015, California ports have consistently





outpaced the average value of United States ports' receipts of Brazilian ethanol. It can thus be inferred that the relationships found in the regressions in Table 3 could be substantially strengthened if years following 2015 were included.

Marginal Abatement Requirements

Under the baseline, Scenario 1 would require very high ethanol blends of 41.3% by 2020 and 98.8% by 2030. Additionally, at these levels of blending, Sugarcane ethanol production would be at the crop's maximum feedstock limit in 2020 and beyond the maximum feedstock constraint by 2030. In other words, even if all of Brazil's possible Sugarcane production, from current production onwards, went into California ethanol blends, it would still be impossible for necessary production to be achieved. As such, scenario 1 is entirely unfeasible. Scenario 2 would require slightly greater than E20 blends by 2020 (23.9% ethanol), and over 80% ethanol by 2030. As such, it would potentially be possible to achieve required abatement by 2020, given significant investment in E85 infrastructure, but would be entirely impossible in 2030. Scenario

3, or the baseline assumption, reaches similar conclusions. Assuming B12 diesel and an unchanged credit bank by 2020, full compliance could be possible with an E20 blend of pure Sugarcane ethanol. In 2030, however, assuming a slight reduction in credit banking (25% loss) and an increase in biodiesel blending (to B20), compliance becomes impossible, as it would require 63% ethanol blending, and thus would necessitate Sugarcane production on the maximum production limit. Full compliance under scenarios 1-3 would thus be either difficult, at best, or nearly impossible, at worst, to achieve.

Scenarios 4 and 5, however, represent compliance scenarios in which full abatement via Sugarcane ethanol could be possible, though only under a given set of circumstances. Scenario 4, which assumes an unchanged credit surplus and B15 diesel blends by 2020, would require pure Sugarcane ethanol to be blended at E15 levels with credit prices of at least $112 in 2020 in order to achieve full compliance. In 2030, scenario 4 assumes a 100% increase in credit surplus and B30 diesel blends, which would require E25 blends of pure Sugarcane ethanol and a credit price of at least $202 in order to reach full LCFS compliance. Scenario 4 could be possible given several circumstances. Firstly, in order for ethanol blends of E15 and E25 to be possible by 2020 and 2030, respectively, a larger investment would have to be made into E85 infrastructure. As Table 2 demonstrates, the LCFS has pushed California to make a relatively larger push towards adding E85 pumps in its gas stations. Considering this, it is possible that E15 blending could be achieved by 2020 and, with a slightly increased expansion effort, it would not be unfathomable for E20-E25 levels to be reached by 2030. Additionally, scenario 4 would require the credit bank to remain stable by 2020 and then increase by 2030. This could possibly be achieved by relatively small levels of cellulosic ethanol production, or, more likely, via an increase in electric vehicles and biomethane as a feedstock. Biodiesel blends of B15 by 2020 and B30 by 2030 would likely require significant investments into increased Renewable Diesel production. Though most Diesel engines can only handle blends of Biodiesel at certain levels, Renewable Diesel can be blended at high levels without requiring major engine alterations. As such, any Diesel “blend wall” can far more easily be surpassed than the gasoline blend wall. Considering this, scenario 5’s assumptions of B20 Diesel blends in 2020 and B50 in 2030, along with 25% and 125% increases in credit banking by 2020 and 2030, respectively, are not unfathomable. Scenario 5’s optimistic abatement assumptions would only require E10 ethanol blends, with only 53.6% of ethanol in 2020 and 28.9% in 2030 composed of Sugarcane ethanol. The rest of the blend mix could remain as Corn ethanol. As the table shows, the marginal abatement costs of the Corn and Sugarcane ethanol which would make up the blend mix under this assumption would both be around $40 in 2020, indicating an almost perfect blend equilibrium. In 2030, however, the marginal abatement cost of Sugarcane ethanol would only be $23, whereas corn ethanol would be $51. This can be taken to mean that even once required abatement levels are reached, there would be an incentive to blend Sugarcane ethanol above this required level, as its compliance cost is still less than that of Corn ethanol. As such, the credit banking incentive still makes it a more attractive blend alternative than Corn ethanol.

RFS Interaction

The findings for how compliance costs might change under different RFS assumptions indicate a high level of co-dependence between RFS and LCFS compliance. Without the presence of the RFS, LCFS compliance using Sugarcane ethanol becomes far less feasible, with credit price requirements rising to $193-$12,000+. Under the baseline scenario, this translates to a 115% price increase, and in the most optimistic compliance scenario a 383% increase. These figures are even greater than those put forward by Christensen & Hobbs (2016), who predict a 50% increase in LCFS credit prices without the presence of an RFS. It should be noted, however, that this paper's model only looks at the credit price change necessary to incentivize similar levels of blending. Thus, this 115-383% gain price requirement can be interpreted to mean that abatement by Sugarcane ethanol would be significantly more expensive without the existence of the RFS, and blenders could instead turn to relatively cheaper alternatives in order to reach required abatement levels. Even a slight reduction in RIN credit prices could translate to massive increases in compliance costs for Sugarcane ethanol blenders. A 50% increase in RIN prices, on the other hand, would translate to a 57.9% reduction in LCFS compliance costs under the baseline scenario and up to a 193% reduction in the most optimistic scenario (5) for Sugarcane ethanol blenders in 2020.

These figures tend to support existing academic consensus that LCFS compliance is closely tied with RFS compliance, with RIN prices playing directly into LCFS credit prices. As such, abatement via Sugarcane ethanol blending is far more feasible under any scenario in which D5 RIN prices are relatively high. The baseline scenario in this model assumed only a $0.10 premium in D5 over D6 RIN prices. This is largely because D5 (advanced biofuels – Sugarcane ethanol) and D6 (conventional biofuels – Corn ethanol) RIN prices have typically tracked very closely together, only beginning to diverge slightly in 2017. As of the beginning of 2018, however, D6 RIN prices began falling dramatically while D5 RINs remained relatively stable. By March of 2018, the D5-D6 premium stood at $0.40 – a differential which is significantly higher than that accounted for in the model. If this is indicative of what is to come in the future, then the MAC curves for Corn and Sugarcane ethanol could begin shifting further apart, with the marginal abatement cost of Corn ethanol rising relative to that of Sugarcane ethanol. In such a world, blenders would find even higher profitability by replacing Corn ethanol with Sugarcane ethanol. If, for example, the price of D5 RINs was to increase by 50% while the price of D6 RINs decreased by 50% from the model's baseline assumptions, we could anticipate a marginal abatement cost at 0 blending of -$70 for Sugarcane ethanol and $146 for Corn ethanol – figures which have a significantly wider spread than the baseline of $6 and $19 for Sugarcane and Corn ethanol, respectively. This can be taken to mean if D5 and D6 RIN prices were to continue to diverge in such a manner, Sugarcane ethanol would bring blenders significantly greater value thanks to the much higher value of their attached RINs.

CARBOB Price Interaction

The compliance costs of Sugarcane ethanol blending are also quite dependent on the price of the reference fuel – CARBOB gasoline. In a scenario in which CARBOB prices remain relatively "low" in 2020 and 2030, credit prices could increase by 81-225% in 2020 and 26-235% by 2030. In the "mid-price scenario," compliance costs would not change by 2020, but would decrease by 36-313% in 2030. Under the "high-price" scenario, abatement costs would decrease by 67-198% for scenarios 4 and 5 in 2020, and 123-1078% by 2030 under these same two scenarios. The same way that compliance costs are extremely sensitive to shifts in RIN prices, they also change dramatically based off of the price of the reference fuel. This is, of course, to be expected, as each gallon of Sugarcane ethanol is displacing a given gallon of gasoline. If the gasoline is far cheaper than this ethanol, then the credit price necessary to incentivize this replacement would have to be significantly higher, and vice versa. It is worth emphasizing, though, that under scenarios 1-3, blending would remain extremely difficult regardless of CARBOB or RIN prices in 2020 and would still be most likely impossible in 2030.

These price sensitivities which have been described are thus based primarily off of scenarios 4-5, and partially scenario 3, for 2020 and exclusively scenarios 4 and 5 for 2030.

Carbon Intensity Value Interaction

Because all of the aforementioned assumptions use the current average carbon intensities of Corn and Sugarcane ethanol (72.5 and 46.6, respectively), it is worth noting that these values are subject to change, and have, in fact, changed in the past. If, for example, blenders begin focusing on relatively more or less carbon intensive fuel producers, or if CARB audits and reassigns producer CI values, these figures can very easily shift upwards or downwards. In fact, in the original 2009 LCFS Draft Revision, Sugarcane Ethanol had a CI value 20 points higher than the one it occupies today. It is for this reason that it's particularly interesting to understand the effects which CI revisions can have on required abatement levels as well as compliance costs. As Table 7 demonstrates, an increase of Sugarcane ethanol carbon intensity of 20 points results in almost completely unfeasible abatement targets, with only scenario 5 in 2030 having some potential for success (assuming E15 ethanol blending and a credit price requirement of $180.

The inverse would be the case if Sugarcane ethanol's average CI value were to be reduced by this same factor. Assuming a reduction of 20 CI points to an average carbon intensity of 26.6 gCO_2/MJ, scenarios 2-5 would all be feasible in 2020. Scenario 2 would require E15 ethanol blending, with compliance costs of $70, while full compliance could be achieved in scenarios 3-5 without passing the E10 blend wall. Scenario 3 would require 98.5% of the ethanol mix to be composed of Sugarcane ethanol, with accompanying compliance costs of $52 for Sugarcane ethanol, and $20 for Corn ethanol. Because the MAC for Corn ethanol would be relatively lower than that of Sugarcane ethanol in this scenario, the compliance target would be necessary in order to incentivize Sugarcane ethanol replacement. Scenario 4 would similarly require 84.7% of the blend mix to be Sugarcane ethanol, with accompanying marginal abatement costs of $45 for Sugarcane ethanol and $24 for Corn ethanol. Thus, similarly to Scenario 3, Scenario 4 necessitates a compliance incentive, as in equilibrium, relatively more Corn ethanol would be blended until the point of equilibrium were to be found (the point where $MAC_{Corn} = MAC_{Sugarcane}$). In scenario 5, however, only 30% of the blend mix would have to be composed of Sugarcane ethanol, and Sugarcane ethanol's compliance costs would be lower than those of Corn ethanol ($18 vs. $50, respectively), leading to the assumption that even greater levels of Sugarcane ethanol would be blended, even after compliance targets have been reached. Only scenarios 4 and 5 would be feasible in 2030, with scenario 4 possible assuming a baseline of E15 gasoline and credit prices of $76/TonCO$_2$. Scenario 5 would be possible in 2030 under E10 blending constraints, with only 20% of the ethanol mix displaced by Corn ethanol, and at credit price requirements of $13 for Sugarcane ethanol and $55 for the Corn ethanol remaining in the blend mix.

This can all be taken to mean that, while compliance would likely be unfeasible if CI values were pushed up dramatically, compliance would become far easier if Sugarcane ethanol were to face a downwards CI revision. Under a downwards CI revision assumption of -20gCO$_2$/MJ, compliance would be possible under 4 of the 5 scenarios in 2020 (scenarios 2-5) and 2 of the 5 scenarios in 2030 (scenarios 4 & 5), at relatively low costs of compliance.

Conclusion

This paper represents a complete investigation into the full potential for LCFS compliance using Brazilian Sugarcane ethanol. In the first part of this paper it was found that, while California has been constrained by the E10 blend wall in recent years, it has been making relatively substantial pushes towards expanding its E85 infrastructure. Borrowing from de Gorter & Drabik (2015), Pouliot & Babcock (2014), Whistance et al. (2015), de Gorter et al. (2013), Good & Irwin (2014) and Moschini et al. (2017), who all hold that investment in E85 infrastructure represents the key to achieving greater than E10 ethanol blends, this can be taken to mean that the LCFS has pushed California relatively closer to a point which would allow consistent blend levels above the 10% barrier. Additionally, this paper has found that even within this E10 constraint, the LCFS has incentivized relatively greater replacement of Corn ethanol by Sugarcane ethanol in California's ethanol blend mix.

Following these findings, this paper modeled the potential carbon abatement paths and prices for LCFS compliance using Sugarcane Ethanol. It was found that under baseline RIN price, CARBOB price, and CI value assumptions, compliance in 2020 and 2030 would only be possible given certain scenario assumptions. If the credit surplus remains unchanged and Diesel blending increase from current B12 blends (12% Biodiesel and Renewable Diesel) to B15 blends by 2020, then full compliance via Sugarcane ethanol blending will be possible at a compliance cost of \$112/TonCO_2, assuming the E85 infrastructure is in place to allow for E15 blends. If the E85 infrastructure necessary for E15 blends is not yet in place by 2020, full compliance under the baseline assumptions would only be possible if the credit bank is increased by up to 25% and biodiesel blending increases to B15/B20 levels, with a minimum credit price of \$40/TonCO_2. In 2030, full compliance at E10 blending would only be possible with credit prices of \$23+, Diesel blends of around B50, and a greater than 120% increase in the existing credit bank. If, however, the E85 infrastructure is in place so as to allow for E20 ethanol blends, full compliance in 2030 would be possible at a cost of \$202/TonCO_2, with Diesel blends of B30 and a 100% increase in credit banking.

These results are, however, highly sensitive to any changes in the RFS, gasoline (CARBOB) prices, and/or any revisions to the average pathway carbon intensity (CI) of Sugarcane ethanol. Without the existence of an RFS (and thus assuming RIN prices of \$0), the cost of LCFS compliance using Sugarcane ethanol could increase by 118-383% by 2020 and 26-235% by 2030. In turn, any increase in RIN prices could dramatically reduce the cost of compliance using Sugarcane ethanol. Similarly, compliance costs are highly co-dependent on the costs of CARBOB gasoline, with any reduction in gas prices causing dramatic upswings in the cost of compliance. Additionally, the model is extremely sensitive to any changes in the average carbon intensity of Sugarcane ethanol – any revision upwards could make compliance via Sugarcane ethanol entirely unfeasible, while a revision downwards could make compliance significantly easier.

It is safe to say that the LCFS creates an incentive for Sugarcane ethanol blending which would otherwise not exist under the RFS alone. In order for full LCFS compliance in gasoline markets to be achieved via Sugarcane ethanol blending, some advances will likely have to be made in E85 infrastructure. If E85 infrastructure is not expanded to a point which would allow E15+ blending in 2020/2030, then significant pushes will have to made into electrical vehicles and alternative, non-ethanol fuel varieties so as to increase credit banking, while Biodiesel and Renewable Diesel blends will likely have to be increased to at least B15+ levels. This being said, compliance will still depend largely on the given LCFS credit markets, as the marginal abatement cost of Sugarcane ethanol has the potential to swing dramatically due to any changes in RIN prices, CARBOB prices, or average CI values.

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