Prepared For:

Consumer Energy Alliance

Economic and Energy Impacts Resulting from a National Low Carbon Fuel Standard

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DISCLAIMER

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1. EXECUTIVE SUMMARY

As requested by the Consumer Energy Alliance, Charles River Associates (CRA)[1] has used its proprietary; state-of-the-art MRN-NEEM[2] modeling system to analyze the potential economic impacts of a nation-wide Low Carbon Fuel Standard (LCFS). This report presents the results of that analysis addressing the effect of a nation-wide LCFS on U.S. households, the transportation fuel market, the refinery sector, and the U.S. economy as a whole.

LCFS programs are moving ahead at the state level. As part of achieving the California Assembly Bill AB 32 emission targets, the California Air Resources Board (ARB) adopted a LCFS mandate in 2009 and will propose a final framework for the LCFS sustainability provision by 2011. Other states and regions are proposing their own LCFS mandates which take into consideration the California model and the nation-wide approach is being evaluated by regional organizations such as NESCAUM and the Midwestern Governors Association. The nation-wide LCFS mandate has also surfaced at the federal level where it was included in the Senate's Lieberman-Warner climate change bill in 2008 and in the House Waxman-Markey climate change bill in 2009 (although the LCFS provision was removed before the bill was passed by the House).

This study analyzed a nation-wide LCFS, which would begin in the year 2015 and achieve by the year 2025, a 10% reduction in the carbon intensity of transportation fuels relative to the base year. In this study, the economic impacts of the LCFS are measured relative to a reference case, which is based upon the Energy Information Administration's (EIA) 2010 Early Release Annual Energy Outlook (AEO), which incorporates a realistic outlook for the Renewable Fuel Standard 2 (RFS2). As such, the economic impacts determined in this analysis are in addition to any associated with RFS2.

Key assumptions characterizing low carbon fuels were based on a variety of literature sources. Emission factors were based upon the analyses of the U.S. Environmental Protection Agency (EPA)[3] and the ARB.[4] Relative costs of low carbon fuels were based on

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[1] CRA is a global consulting firm that has provided economic, financial, strategy and business management advice to public and private sector clients since 1965. CRA serves clients from offices on three continents.

[2] MRN-NEEM is CRA's proprietary combination of its Multi-Region National (MRN) model and its North American Electricity and Environment Model (NEEM).

[3] U.S. Environmental Protection Agency, "Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis", EPA-420-R-10-006, February 2010.

[4] California Environmental Protection Agency Air Resources Board, "Proposed Regulation to Implement the Low Carbon Fuel Standard," Volume 1, Staff Report: Initial Statement of Reasons, March 5, 2009.

the work of ARB.[5] Availability of low carbon fuels was based on a number of sources[6] including reports by EIA and EPA.

An important conclusion from this analysis is that adoption of a nation-wide LCFS will result in a price shock that will dramatically increase the cost of transportation to consumers and have long term effects on the economy by increasing transportation costs for all goods. The price shock – about a 30 to 80% increase in the cost of transportation fuels within 5 years of the time the LCFS is implemented -- is caused by the large increase in production of low carbon fuels required to achieve the reductions in emissions required by the standard. It is highly unlikely that it will be possible to produce sufficient quantities of fuel with sufficiently low emissions to meet the standard without drastically reducing the total amount of fuel consumed.

Low carbon fuels are like cream in a cup of coffee. If enough cream is not on the table to achieve the desired mix, then the only alternative is to reduce the amount of coffee in the cup. To reduce transportation fuel consumption sufficiently for the LCFS to be met requires very large increases in fuel prices, so that consumers will limit their driving and demand new vehicles that are much more costly and provide much higher fuel economy. Price increases for fuels used in commercial transportation will also be driven up, in order to reduce fuel use in trucking sufficiently to achieve the required reductions in emissions from fuels used in heavy duty gasoline and diesel engines.

These effects are paradoxical. The stated purpose of the LCFS is to be technology forcing,[7] and to bring new fuels into the market. Other policies designed for the purpose are intended to deal with vehicle design and consumer behavior, such as tighter fuel economy standards for new vehicles and urban planning and transportation policies to bring about modest reductions in travel demand. But the LCFS becomes a policy that drives large changes in consumer behavior and in new vehicle fuel economy because the targets are beyond reach with foreseeable fuel technology. None of these changes are likely to involve new technology, because again the time frame is too short to provide new transportation infrastructure or new vehicle technologies on a large scale. Thus the LCFS is turned into a policy that in effect rations gasoline until the required improvement in emissions per gallon is met.

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[5] California Environmental Protection Agency Air Resources Board, “Proposed Regulation to Implement the Low Carbon Fuel Standard,” Volume 1, Staff Report: Initial Statement of Reasons, March 5, 2009.

[6] Sources described in detail in section 4.3 Key Assumptions.

[7] The LCFS analyzed in this study is fully implemented ten years after initiation (2025). This is a relatively short period of time to allow for R&D that would be the basis for new fuel technology to succeed, technology scale-up issues to be resolved, and for wide spread commercial deployment of new technology.

The costs to consumers will be felt not only in their own cost of driving, but also because higher transportation costs will also be borne by businesses, the cost of goods and services purchased by consumers is likely to increase.

The following summarizes the main findings from the study.

1.1. Economic Impacts

A nation-wide LCFS would result in more expensive fuels and vehicles, which would increase the cost of transportation for consumers. Similarly, increased fuel costs will also increase costs in the trucking and commercial transportation sectors adding to the delivered cost of goods. These higher costs would likely reduce total consumption, employment, investment, and economic output.

Negative impacts on the energy sectors lead to economy-wide economic losses. Specific impacts of the legislation on economic performance include the following:

- By 2025, a nation-wide LCFS is estimated to cause a net loss of between 2.3 – 4.5 million total jobs from baseline levels. Regions around the U.S. would be disproportionately affected. The losses will not be evenly distributed across industrial sectors. These impacts include all so-called “green jobs” that will be created as a result of the LCFS.
- By 2025, the proposed legislation is estimated to reduce household annual purchasing power by $1,400 to $2,400 relative to 2010 income levels.
- By 2025, the proposed legislation is estimated to reduce investment by $200 to $320 billion relative to the baseline.
- By 2025, GDP, a commonly used measure of total economic activity, is estimated to decline below the baseline by approximately 2 to 3% or $410 to $750 billion.
- The impact on regional economic growth (GRP) from a nation-wide LCFS mandate will vary by location. Impacts on regional investment will follow a pattern similar to the GRP impacts.

The link between the cost of energy supply and the country’s economic performance is important to understanding the pattern of the study’s results and central to an assessment of the implications of a LCFS.

1.2. Energy Industry Impacts

Specific impacts of a LCFS on domestic energy markets include the following:

- By 2025, a LCFS is estimated to increase the cost of transportation fuels to consumers by 90% to 170% relative to the baseline.

- In order to keep the cost of transportation fuel from increasing even further in the year 2025, it will be necessary for low carbon fuel production to increase to more than 2.5 times the production forecasted in the baseline for the year 2015.
- By 2025, the higher cost of transportation fuel will cause drivers to reduce their driving by 9% to 14% relative to the baseline. Trucking ton-miles will be down by 9% to 13%.
- By 2025, refinery throughputs will decline by 4.0 to 5.8 million barrels per day (mmbd) resulting in the additional closing of 43 to 55 refineries with an associated loss of 4.6 to 6.5 million barrels of refining capacity.
- By 2025, a LCFS will cost about 21,000-33,000 direct refinery jobs and reduce ongoing refining investment by $2.1 to 3.2 billion/year.

1.3. Other

The remainder of the report is organized into five sections. Chapter 2 provides a detailed presentation of the study's impacts on the U.S economy, and energy industry. Chapter 3 provides a description of the nation-wide LCFS policy. Chapter 4 describes the methodology used to perform the analysis and discusses the key assumptions underlying the study. Appendix A describes the MRN-NEEM modeling system used in the analysis.

2. RESULTS

In this section impacts are presented as a range to reflect the uncertainty associated with the underlying assumptions. The two cases presented represent a reasonable upper and lower bound for the cost and emission factors associated with the low carbon fuels. The optimistic case reflects an optimistic view about both the ability of low carbon fuels to reduce emissions and the pace at which reductions in the cost of low carbon fuels occur. The pessimistic case presents a more conservative view of both assumptions. A detailed discussion of each of the underlying assumptions is presented in later in this report in the methodology section.

2.1. EFFECTS ON PERSONAL AND COMMERCIAL TRANSPORTATION, AUTO MANUFACTURERS AND FUEL SUPPLIERS

A LCFS is often seen as one of a triumvirate of policies, designed to affect carbon intensity of fuels, fuel economy of vehicles, and personal travel and commercial transportation. The LCFS is intended to address carbon intensity, CAFE standards for cars and trucks to address fuel economy, and a host of transportation-related policies to reduce vehicle miles travelled (VMT) and ton-miles or passenger-miles of commercial transportation.

The reality is not so simple. The LCFS will not only affect the carbon intensity, but will increase the cost of transportation to consumers and business. This will in turn reduce the VMT by automobiles and ton-miles of trucking. Consumers will purchase more expensive vehicles. These unintended consequences can be responsible for as much or more of the effects of the LCFS as are changes in carbon intensity measured by emissions per gallon of gasoline equivalent produced.

LCFS increases the supply and use of low carbon fuels while reducing the output of petroleum-based motor fuels and raises the cost of motor fuels to consumers. Indirectly, the LCFS reduces the demand for motor fuels in total, even though their carbon intensity is reduced. There are two routes by which the LCFS decreases total motor fuel demand. The LCFS raises the price of motor fuels to which motorists respond by driving less and by demanding improvements in the fuel economy of new vehicles. Which of these will dominate depends on the cost and availability of the low carbon substitutes that must replace gasoline and diesel to meet the LCFS and on the cost of improving fuel economy.

Under relatively optimistic assumptions about the cost and emission reduction potential of low carbon fuels, the primary route by which demand for motor fuels is reduced is through improvements in the fuel economy of new vehicles. One way this happens is through the greater use of plug-in hybrid electric vehicles (PHEVs), with the result that the majority of driving is done using electricity generated from low carbon sources. The other way this happens is that drivers demand liquid-fuel-powered vehicles with higher miles per gallon (MPG). Even with optimistic assumptions about the cost of the low carbon substitutes that must replace gasoline in order to achieve the LCFS, this mandate raises the cost of fuel so much that consumers demand new vehicles with fuel economy improvements even larger than those mandated by the current CAFE standards. This may also prove disruptive for U.S.

auto manufacturers as they will have to not only produce higher efficiency gasoline powered vehicles but more fuel-flexible vehicles (FFVs), compressed natural gas (CNG) powered vehicles, and PHEVs.

Under less optimistic assumptions, including higher cost and higher emission factors for low carbon fuels, compliance with the LCFS becomes even more difficult to achieve. The LCFS pushes the fuel system to the maximum availability of low carbon fuels, the demand for high mpg vehicles is even greater and only additional reductions in transportation fuel consumed can make it possible to meet the standard. This reduction occurs by destruction of travel demand represented as reductions in personal travel and ton-miles of freight. The reason for this greater demand destruction is that greater fuel costs and high emission factors for alternative fuels make it very expensive to meet the carbon-intensity standard without reducing the total amount of motor fuel demanded. This leads to motor fuel prices rising to levels that drive total fuel consumption down to a level such that the available low carbon fuels are sufficient to meet the standard.

To avoid gasoline rationing, CO_2 emissions per gallon of alternative fuels must show a large enough improvement over gasoline that it is possible to meet the standard without reducing total gallons of fuel consumed below levels that would be consumed absent the LCFS. How large an improvement is required depends on how much of the alternative fuel can be brought into the market. If a large volume of the alternative fuel can be brought into the market, then the reduction in CO_2 emissions per gallon of alternative fuel will only need to be as large as required to meet the LCFS standard. However, if the volume of alternative fuel that can be brought into the market is limited, then the reduction in CO_2 emissions per gallon of alternative fuel will need to be greater to offset the lower availability of alternative fuel. In any event, alternative fuels must provide at least the 10% improvement in emissions required by the LCFS. If this were the best any alternative fuel could do, then that alternative fuel would have to replace 100% of petroleum fuels. An alternative fuel that provided a 20% improvement would only have to replace 50% of petroleum based fuels, and so on.

Unfortunately, all alternative fuels that could be introduced by even 2025 will be limited in quantity. Each runs into different problems

- Ethanol of any kind runs into the blend wall problem that a maximum of 10% can be blended into fuel used in vehicles not specially designed for alcohol fuels.
- CNG runs into limits on penetration based on the need for a central fueling infrastructure.
- Advanced biofuels that can substitute directly for gasoline are extremely costly with current Fischer Tropsch biomass to liquids (BTL) technology and third generation technologies which are not yet developed to anything like a production prototype.
- Electric vehicles also have significant infrastructure requirements for large scale penetration, cannot substitute for all travel purposes, and are quite expensive when designed to substitute for average vehicles.

Thus it is fair to say that by the year 2025, it is impossible to bring to market sufficient quantities of new fuels with sufficiently low emission factors to meet the LCFS without reducing the total amount of transportation fuel consumed.

If the difference between the emission factor for low carbon fuels and petroleum based fuels is small, then the cost to consumers of transportation fuels must rise even further to stimulate the production of greater volumes of low carbon fuels while simultaneously discouraging total fuel consumption (the denominator of the fraction must be reduced until the standard is satisfied).

Under the pessimistic assumptions, meeting the LCFS would require even greater improvements in new car fuel economy to maintain travel in addition to the greater use of PHEVs. But even with those improvements, it is not economically feasible to achieve the LCFS standard without greater reductions in travel and transportation use. Fuel prices are driven higher in the pessimistic case, in order to bring about that reduction.

The harm to consumers and the overall economy thus comes from three sources:

- Higher cost of fuel, which translates into a higher cost of transportation services;
- Higher cost of new vehicles that must be paid to achieve greater fuel economy; and
- Loss of the value of transportation services foregone when the LCFS drives down total driving and ton-miles of freight.

Refiners are thus affected doubly by the LCFS. It has the intended effect of reducing the share of petroleum-based fuels in total motor fuel production, but it also has the unintended effect of reducing total motor fuel use in the U.S. Thus refiners face a shrinking share of a shrinking total market for motor fuel.

Refiners are affected by this loss in sales of petroleum-based fuels and also by the forced change in their product slates caused by the LCFS. No matter what assumptions are made about the cost and availability of low carbon fuels, refiners must cut back their output of gasoline and diesel fuel. This will affect both employment and investment in the refining industry.

Effects on the overall product slate differ with the availability and cost of substitutes. When PHEVs and low carbon fuels are available and have relatively low cost, most of the reduction in emissions required to meet the standard is concentrated on gasoline production in refineries. The available low carbon fuels and electricity substitute for both gasoline and diesel. The direct costs of the LCFS are concentrated on ordinary households who are consumers of gasoline for personal transportation. As a result, the largest refinery volume and percentage reduction is in gasoline.

When these gasoline and diesel substitutes are more expensive, the impacts on gasoline and diesel production and sales become much larger and more damage is done to commercial transportation and trucking in particular.

Auto and truck manufacturers are also likely to suffer from the effects of the LCFS on transportation demand. As costs of motor fuels rise and driving falls, new vehicle sales are also likely to drop off substantially until the size of the fleet falls to match lower personal driving and shrunken ton-miles of freight.[8]

Either way, consumers bear the added costs projected to result from a nation-wide LCFS. The LCFS is projected to result in fuel switching away from less costly conventional fuels towards more costly lower carbon alternatives. This would increase demand for these lower-carbon fuels, including natural gas and electricity if natural gas and electric vehicles are included in the LCFS, leading to higher costs. Further, costs for many other goods will be increased, as these higher costs of transportation fuels drive up the cost of transportation.

2.2. Economic Impacts

2.2.1. National Level Impacts

Non-Farm Employment

A nation-wide LCFS mandate would divert resources now used to produce goods and services enjoyed by consumers into the task of obtaining energy from sources that are more costly than petroleum. If consumers and businesses are forced to spend more on energy due to its higher costs, they would have less to spend on other goods and services causing decreases in demand for the quantities of goods and services produced by the economy. In addition, as the resources are diverted to more expensive energy sources, the productivity of labor will fall. Business activity is likely to contract relative to the levels that would have prevailed without mandate induced energy cost hikes. The demand for labor would weaken because employers would need to spend less on labor in order to supply the reduced amount of goods and services demanded by consumers. As a result, payments to labor are projected to decline relative to that which would have prevailed without the higher energy costs. This will be reflected in a combination of less employment, and lower wages for those workers not losing their job. While “green jobs” would be created, a large number of other jobs would be lost. The net result is a loss of social wealth.

Empirical experience suggests that wages do not immediately respond to new equilibrium levels, particularly if that entails a decline in wages. If real wages do not immediately fall to the new, lower market-clearing level, then there will be an excess supply of labor in the economy relative to what employers are willing to hire at those overly-high wage rates, and this leads to lay-offs and an increase in unemployment. The degree of unemployment that will occur depends on how much wages actually do fall towards the new market-clearing level. An exceedingly high amount of unemployment would be estimated under a LCFS if we were to assume that there would be no decline at all in real wages. And, as noted, if we

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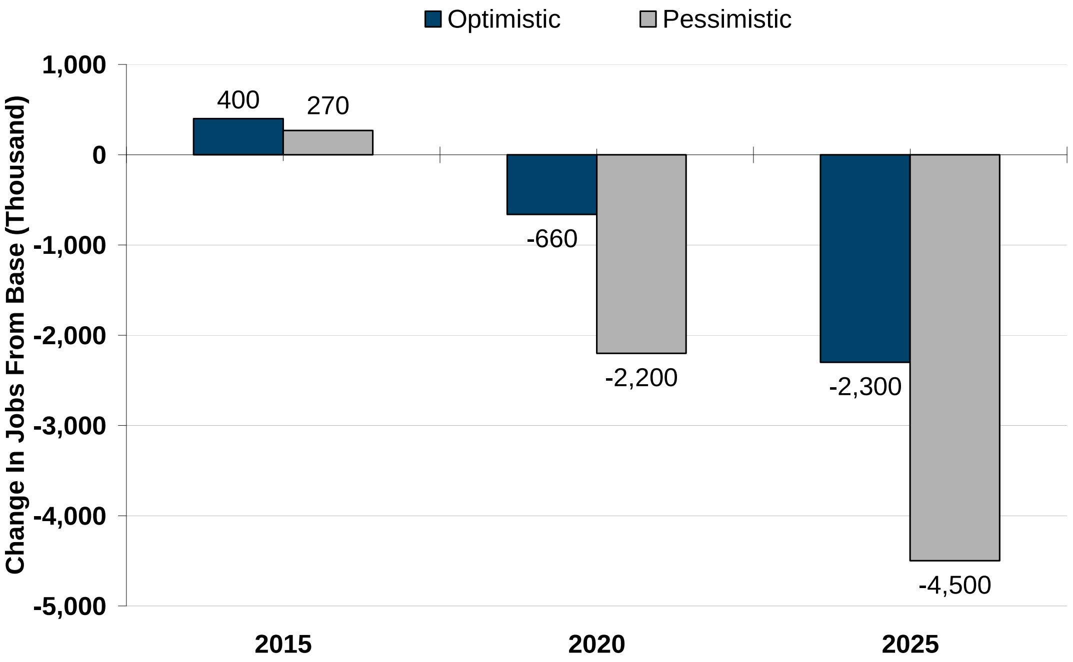
[8] See the CRA study on Industry Effects of the Kyoto Protocol for a discussion of this accelerator effect of an increase in fuel cost and fuel economy.

assume that workers would immediately absorb the full wage decline, there would be no involuntary job losses.

Figure 2-1 illustrates the employment impacts if three-quarters of the decline in the market-clearing wage rate is absorbed by workers immediately. In this case, the other quarter of the reduction in payments to labor has to be achieved by eliminating job positions. The actual number of job positions that would have to be shed depends on whether higher-paying or lower-paying jobs are the ones that are eliminated. In our calculation in the figure, we assume that jobs would be shed in equal proportions across the entire wage distribution, and report the loss in "average jobs." (The precise number of jobs would be lower if a LCFS would disproportionately affect the relatively higher-paid positions, and it would be higher if it would cause a disproportionate loss of lower-paid types of jobs.) Figure 2-1 shows that in 2025 there would be about 2.3 to 4.5 million fewer average jobs in the economy relative to what would otherwise have been possible but for the requirements of the LCFS.[9]

Figure 2-1: Projected changes to employment due to a nation-wide LCFS, assuming partial wage rate adjustments



Source: CRA Model Results, 2010

Because these estimated employment impacts are based on the general equilibrium requirement that total payments to labor must fall to the new, lower level that can be

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[9] The figure also shows modest job gains in 2015. These jobs result from the need to invest in low carbon biofuels and improved motor vehicles, which are required in later years. In addition, businesses accelerate production of goods and services early on as they know that conditions will be worse in the future.

supported by the reduced overall productivity of the entire economy, they are necessarily inclusive of all increases in so-called “green jobs” that will be created as a result of the proposed legislation.

Employment Impacts by Industrial Sector

The total job loss relative to the baseline in the U.S. by the year 2025 is projected to be between 2.3 and 4.5 million jobs. However, the losses will not be evenly distributed across industrial sectors. While some industries will gain jobs due to new “green jobs” and shifts in economic activities, most of the industrial sectors will experience reductions in employment relative to the baseline.

Employment impacts will vary by industrial sectors (Table 2-1) because the sectoral impacts are different. Under the nation-wide LCFS policy, the Services sector is projected to have about 1.7 to 3.1 million fewer jobs than in the baseline by the year 2025. Services sector employment reductions reflect the cumulative impact of businesses dealing with lower demand and facing higher costs for goods and services. The higher costs are associated with the increasing cost to transport goods. The services sector has relatively low wages compared to other sectors, so that these employment reductions are likely to affect low-wage jobs. Manufacturing and Other Heavy Industries will also be affected as their competitiveness relative to other foreign producers’ declines due to the increases in transportation costs. Commercial Transportation includes both trucking which experiences the direct impact of the nation-wide LCFS and air and water transportation, which is indirectly impacted. In this sector, job losses increase with time reflecting the increased stringency of the nation-wide LCFS mandate. Agriculture and Food Processing has small increases in employment due to the increased demand for agricultural products used for biofuel production, which is mostly offset by the shift of acreage from production of food crops to energy feedstock production. Energy sector job impacts reflect the combined effect of increased natural gas and electricity use by the transportation sector and the decline in the use of refined petroleum products. Motor Vehicles sector gains as a result of the need to develop and produce new higher cost electric powered vehicles (plug-in hybrid electric vehicles and dedicated electric vehicles) and CNG powered vehicles rather than new petroleum powered vehicles.

Table 2-1: Employment impacts by industrial sector (thousand jobs)

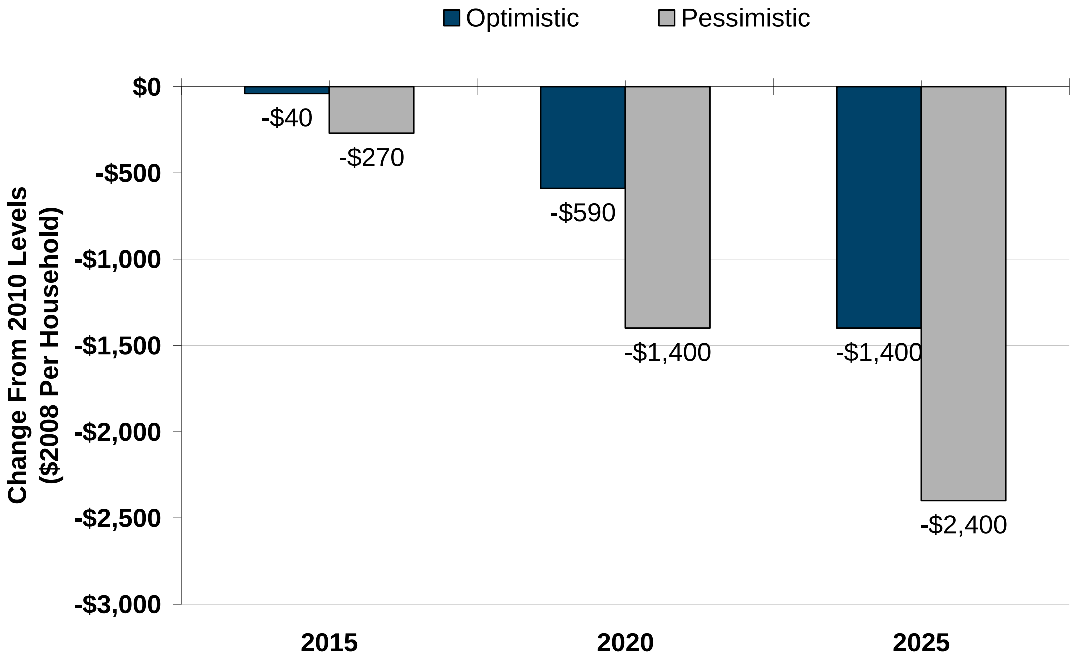
	2015		2020		2025	
	OPT	**PESS**	**OPT**	**PESS**	**OPT**	**PESS**
Energy	60	50	20	-10	-20	-70
Manufacturing and Other Heavy Industries	-10	-230	-430	-890	-810	-1,500
Agriculture and Food Processing	50	40	40	20	20	-40
Commercial Transportation Services	0	-20	-80	-160	-180	-280
Services	-10	-430	-920	-2,000	-1,700	-3,100
Motor Vehicles	320	860	700	900	400	470

Household Purchasing Power

Higher costs for transportation fuels generally mean that consumers must spend a larger percentage of their income to maintain their current level of household travel. Also, significant quantities of energy are needed to transport the many non-energy goods and services. The projected higher costs of these goods and services would be expected to magnify the loss in household purchasing power associated with the direct purchase of transportation services. At the same time, higher energy costs would likely lead to reduced worker productivity and lower wage earnings, while reduced returns on investment would tend to lower household income from savings and retirement funds. Figure 2-2 estimates the increasing erosion of household purchasing power that the nation-wide LCFS would likely cause.

The figure reveals the expected pattern of increasing losses through time. In 2020, the average household in the U.S. is estimated to experience a loss in annual purchasing power of roughly $590 to $1,400 relative to the baseline level, and by 2025, the average household's annual purchasing power is projected to decline by roughly $1,400 to $2,400 relative to the baseline level.

Figure 2-2: Projected changes to household annual purchasing power due to a nation-wide Low Carbon Fuel Standard, stated relative to 2010 income levels

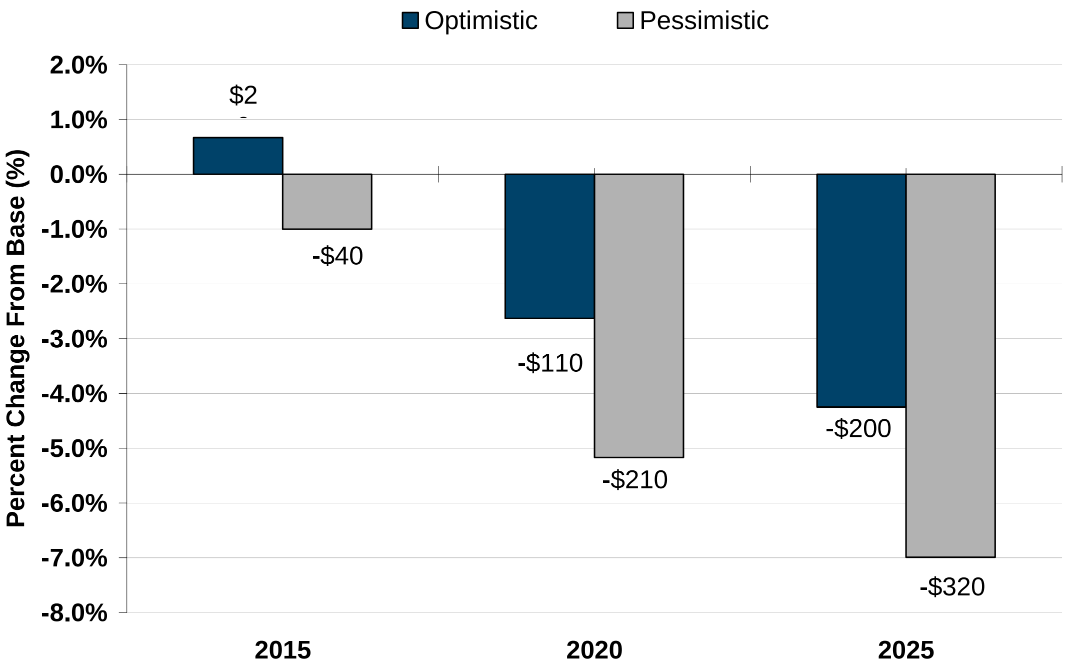


Source: CRA Model Results, 2010

Aggregate Investment

As household and business consumption fall, the demand for goods and services also tends to weaken; moreover, higher energy costs place upward pressure on the costs of goods. In combination these factors mean that fewer investments would be able to meet a profitability test, and they would tend to dampen demand for such investments. Figure 3.9 indicates that investment is projected to decline by 2.6 to 5.2% (or $110 to $210 billion) below the baseline level in 2020. By the year 2025, the impact becomes more severe as the nation-wide LCFS mandate is fully implemented. As a result, in 2025 investment is projected to decline by 4.2 to 7.0% (or $200 to $320 billion) below the baseline level. As with the employment losses, the impact would likely be uneven both across industries and among regions and would resemble that of employment losses. The investment increase in the optimistic case in 2015 reflects the decision by business to make investments before the market conditions become adverse as a result of the nation-wide LCFS.

Figure 2-3: Projected impact on aggregate U.S. investment due to a nation-wide Low Carbon Fuel Standard

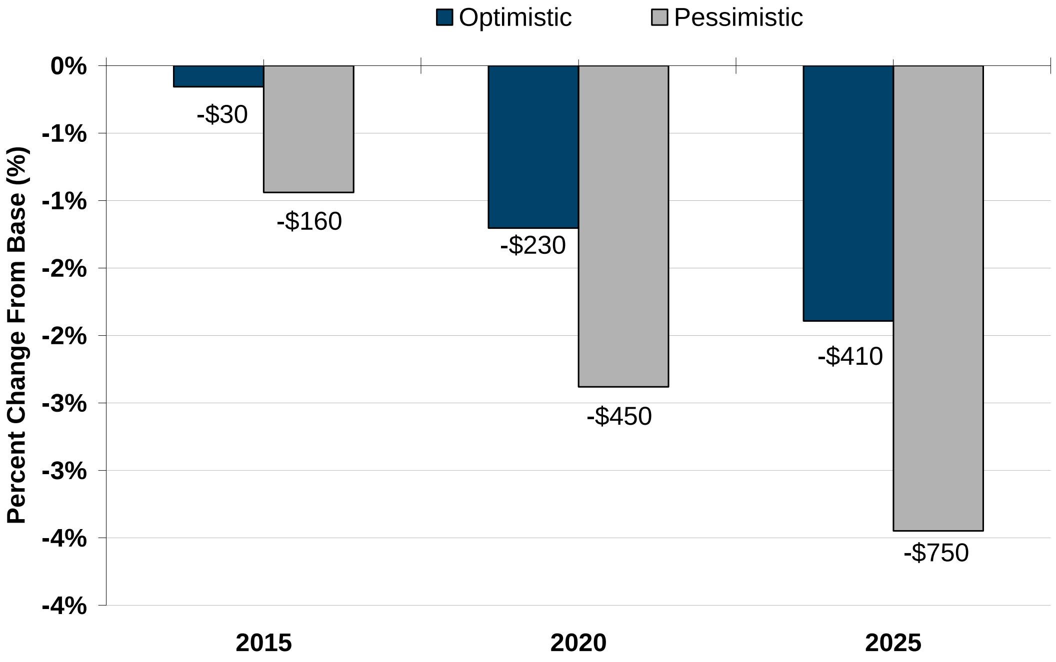


Source: CRA Model Results, 2010 Value in Billions of $2008

Gross Domestic Product

The estimated impacts on GDP would follow a similar pattern to that for consumption and employment. Higher costs for goods and lower household purchasing power interact. Employment and consumption would tend to fall. Total economic activity, measured as GDP, would also be expected to decline. By the year 2025 GDP is projected to decline by 1.9 – 3.4% (-410$ to -750$ billion) below baseline. Figure 2-4 illustrates the pattern of estimated GDP losses through time.

Figure 2-4: Projected Impact on aggregate GDP due to a nation-wide LCFS



Source: CRA Model Results, 2010

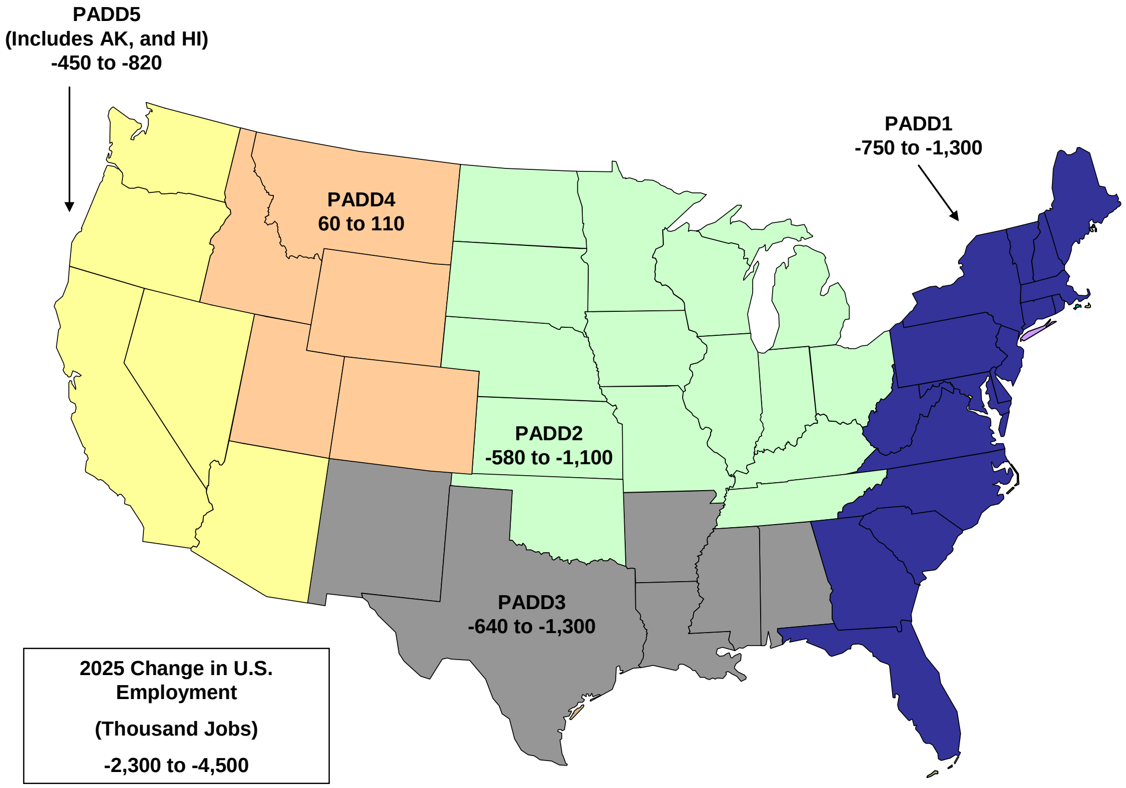
Value in Billions of $2008

2.2.2. PADD Level Impacts

Non-Farm Employment

Figure 2-5 indicates that the job losses projected from the provisions of the LCFS would be distributed throughout the country. In some cases, like commercial transportation, energy intensive activities are geographically widely dispersed. In other instances, like energy intensive manufacturing and petroleum refining/petrochemical production, activities are more geographically concentrated. PADD2 and PADD3 are particularly hard hit because of the great amount of refining in these PADDs. PADD1 and PADD5 economies depend less on energy production and so are less affected than PADD3 on a per capita or dollar basis. In PADD4 incomes are hit so hard by the decline in the refining industry and increases in the cost of transportation that the workers actually choose longer hours and second jobs in order to supplement their incomes. This shows up as an increase in jobs, but it also shows up as a significant reduction in leisure time available. Thus the increased hours of work are accompanied by a reduction in the quality of life.

Figure 2-5: Regional distribution of employment impacts due to a nation-wide LCFS

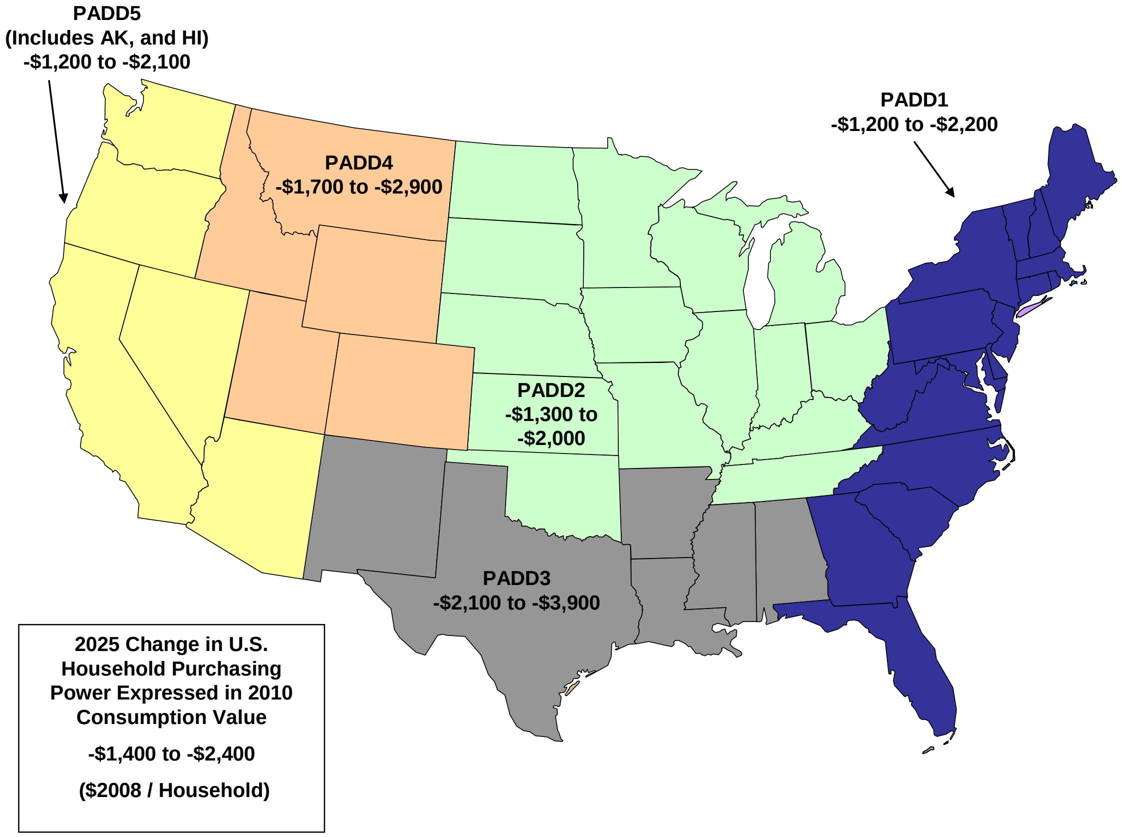


Source: CRA Model Results, 2010

Household Consumption

Higher energy costs generally mean that consumers must spend a larger percentage of their income to maintain their current level of household energy services. At the same time, significant quantities of energy are needed to produce and transport the many non-energy goods and services. The projected higher costs of these goods and services would be expected to magnify the loss in household purchasing power associated with the direct purchase of energy services. At the same time, higher energy costs would likely lead to reduced worker productivity and lower wage earnings, while reduced returns on investment would tend to lower household income from savings and retirement funds. Figure 2-6 estimates the regional erosion of household purchasing power that a nation-wide LCFS would likely cause through the combination of these factors.

Figure 2-6: Regional distribution of purchasing power impacts due to a nation-wide LCFS

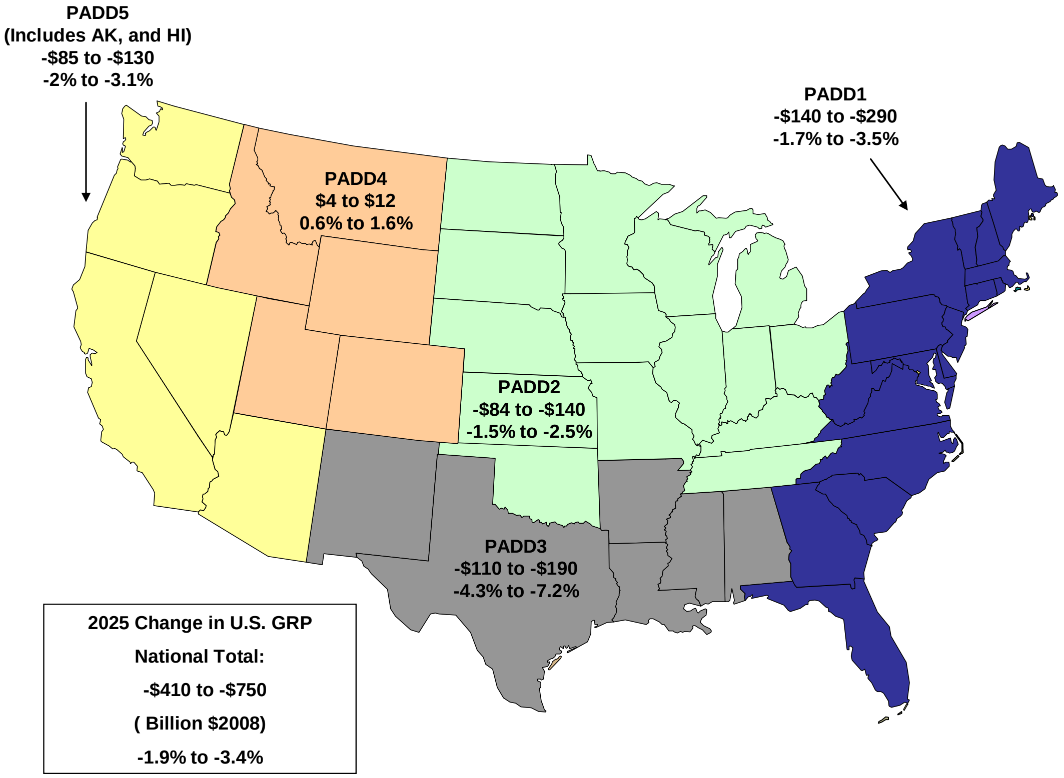


Source: CRA Model Results, 2010

Gross Regional Product (GRP)

Figure 2-7 illustrates that the impact on regional economic growth (GRP) from a nation-wide LCFS mandate will vary by location. The figure shows that four of the five PADD regions will be negatively impacted. This decrease in economic growth results from the higher prices that consumers will pay for transportation fuels, resulting in less demand for other goods and services (*i.e.*, a reduction in overall consumption). Less demand for goods and services leads to less investment required to produce the capital infrastructure necessary to support production. Both effects combine to reduce the level of GRP. PADD3 exhibits the largest negative impact on a percentage basis, reflective of the importance of the petroleum industry to that region's economy. PADDs 1, 2, and 5 exhibit significant negative impacts because the negative effects of the nation-wide LCFS mandate overwhelm any positive effects from the greater use of biofuels. Economic growth in the remaining region, PADD4, is slightly positive because of the relatively large investment that occurs in the region to support the increased biofuels production. In aggregate, the PADDs do not benefit from the nation-wide LCFS despite increases in biofuel and motor vehicle production because economic losses resulting from higher fuel costs outweigh these increases in biofuel production.

Figure 2-7: Regional distribution of gross regional product impacts due to a nation-wide LCFS

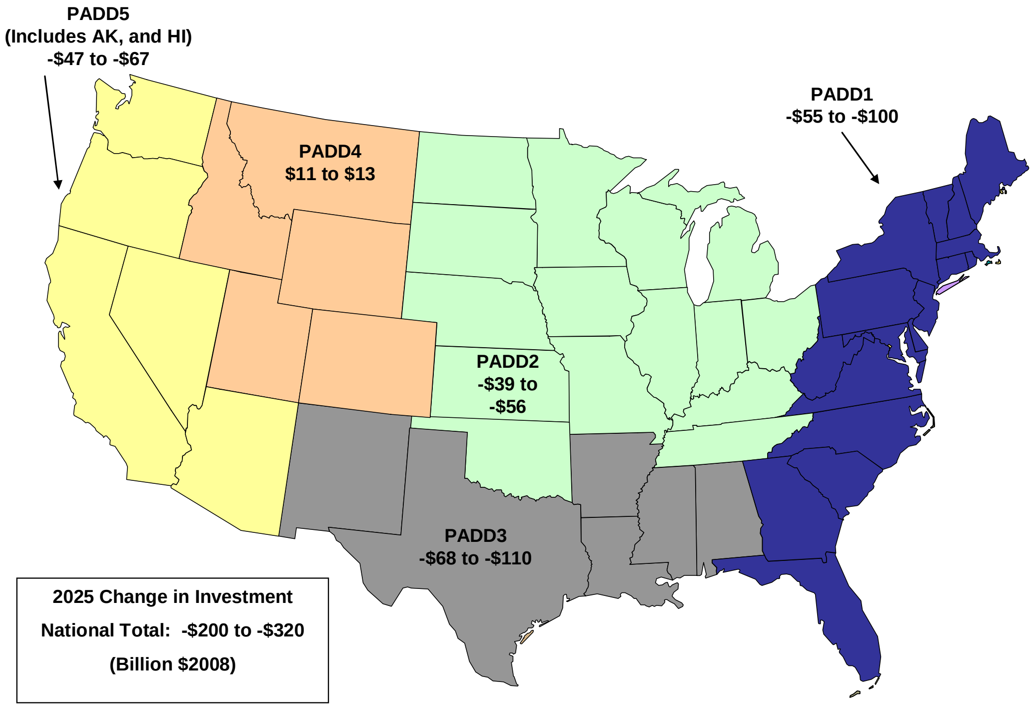


Source: CRA Model Results, 2010

Regional Investment

Figure 2-8 illustrates the regional impact on investment caused by a nation-wide LCFS policy. Similar to GRP impacts, investment is negatively impacted by a nation-wide LCFS policy for several reasons. As the policy slows economic growth, businesses have less need to invest. Higher energy costs reduce the overall return on investment in the economy, also leading to lower investment overall. The shrinking petroleum refining sector experiences disinvestment. The increased production of alternative fuels offsets these negative investment impacts to some degree, but for all except one PADD, the net effects are still negative. The exception is in PADD4 where investment in alternative fuels results in the positive net impact on investment in the PADD. In contrast, PADD3, the region whose economy has the largest petroleum component, is most negatively impacted because the significant decrease in the demand for petroleum products translates into less need for petroleum related investment. These results demonstrate that distributional impacts are significant with most regions of the country being negatively impacted.

Figure 2-8: Regional distribution of aggregate investment impacts due to a nation-wide LCFS



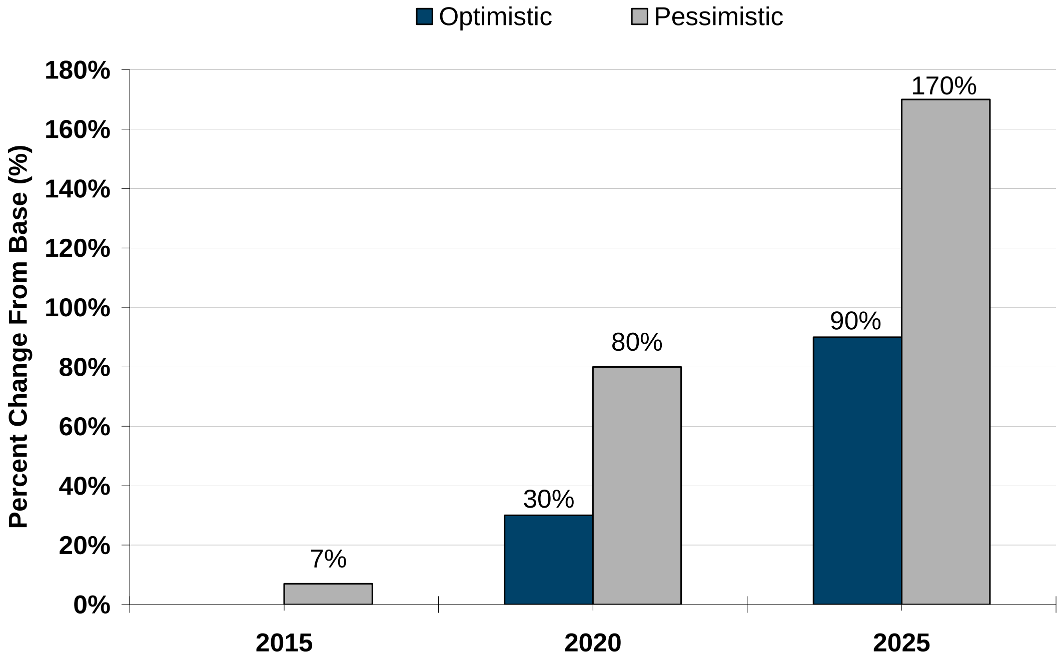
Source: CRA Model Results, 2010

2.3. Energy Industry Impacts

2.3.1. Cost of Transportation Fuels

Compliance with a LCFS will result in consumers experiencing higher costs for transportation fuels. There are two ways to comply with the LCFS mandate: first, increase the use of low carbon fuels in the transportation fuel pool and second, reduce the amount of petroleum in the transportation fuel pool. Low carbon fuels (biofuels) are more expensive than petroleum based transportation fuels resulting in higher costs to consumer. Even with aggressive forecasts for the use of biofuels it is still necessary to reduce the overall use of transportation fuels. This requires prices high enough to reduce demand to the permissible fuel supply, and like past gasoline supply disruptions means higher prices still.[10]

Figure 2-9: Percentage increase in the cost of transportation fuel as a result of a nation-wide LCFS



Source: CRA Model Results, 2010

Figure 2-9 shows the increase in the cost of transportation fuels with time for both the optimistic and pessimistic cases. The LCFS mandate becomes more stringent with time reducing carbon intensity by 1% in 2015, by 5% in 2020 and 10% in 2025. Consequently, the change in transportation fuel prices increases with time to reflect the greater degree of

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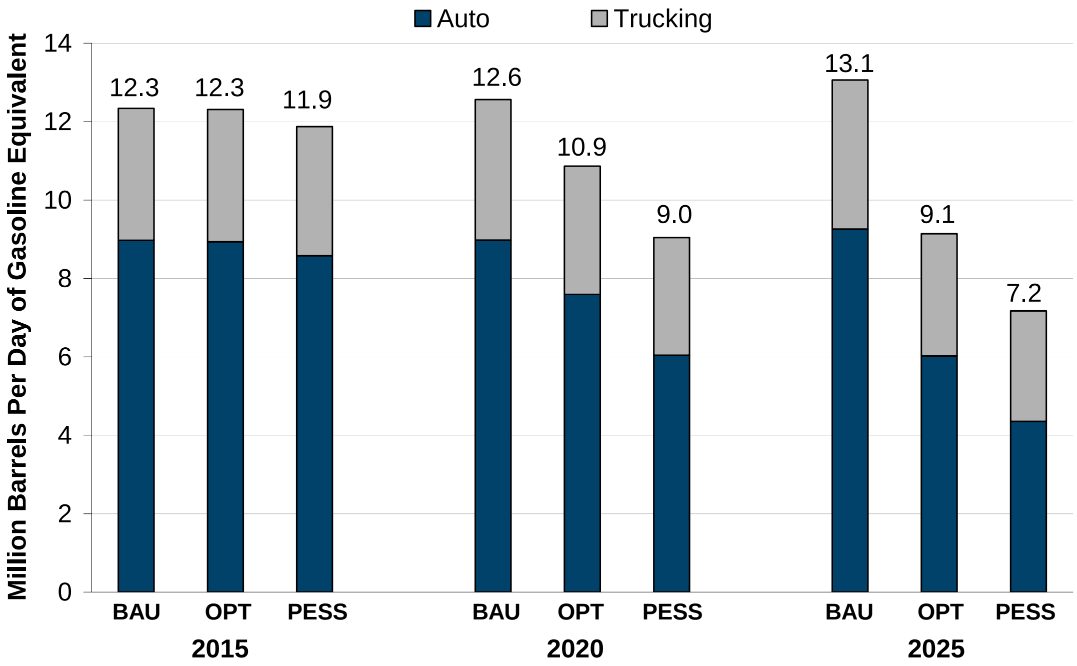
[10] Montgomery, W David, Robert E Baron, Mary K Weisskopf, “Potential Effects of Proposed Price Gouging Legislation on the Cost and Severity of Gasoline Supply Interruptions”, Journal of Competition Law and Economics, 2007, 3(3), 357-397.

severity of the mandate (in the optimistic case, the % increase rises from 0% in 2015 to 90% by 2025 and in the pessimistic case from 7% in 2015 to 170% by 2025). Furthermore, with a more pessimistic assumption for emissions from biofuels and a slower rate of improvement in biofuel technology the impact in the pessimistic case is greater than that of the optimistic case (for instance in 2025 the increase in price in the optimistic case is 90%, while that for the pessimistic case is 170%).

2.3.2. Demand for Transportation Fuels

Higher prices necessitated by the LCFS mandate result in less driving and lower overall transportation fuel demand. Figure 2-10 shows transportation fuel demand for both autos and trucks. As the price increases grow with time, in order to meet the more stringent LCFS mandate, demand for transportation fuels decrease. The pessimistic case exhibits larger impacts than the optimistic case because of the assumptions concerning emission factors and cost. A larger impact is realized in the auto sector than the trucking sector reflecting the greater responsiveness of personal driving to higher prices. By 2025, demand by autos has decreased by 35 to 52% relative to the baseline and for trucking by 18 to 26%. Driving is off by 9% to 14%. Most of the decrease in demand results from drivers switching to more fuel efficient vehicles, which are more expensive. Trucking is off by 9% to 13%; here too a significant portion of the decline is due to the introduction of more efficient vehicles.

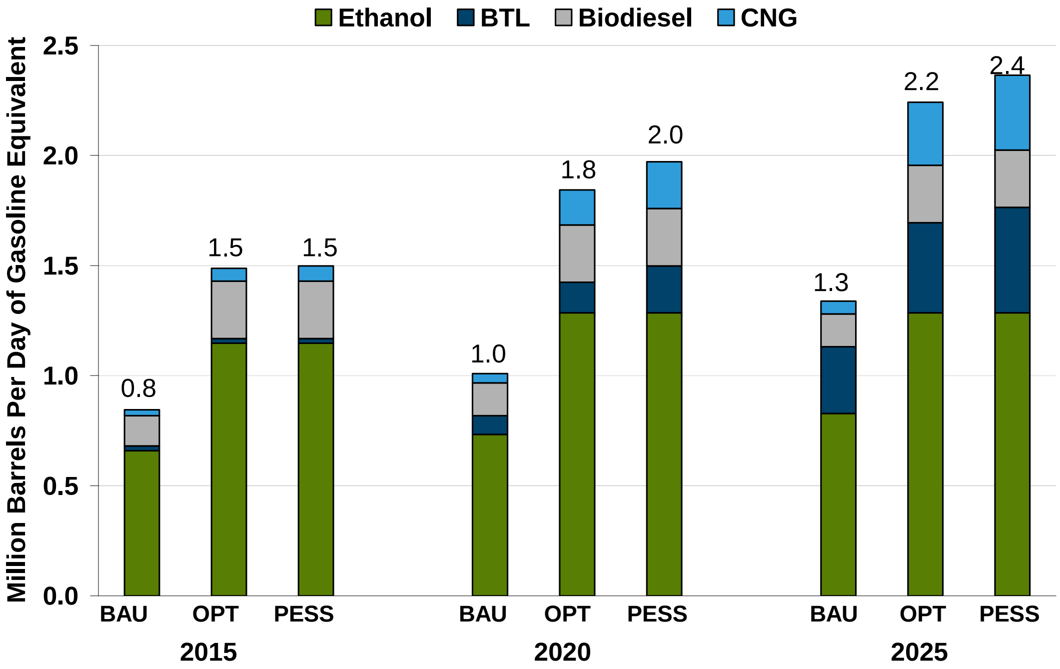
Figure 2-10: Total demand for transportation fuel (mmbd of Gasoline Equivalent)



Source: CRA Model Results, 2010

Figure 2-11 illustrates that despite the decline in overall driving and fuel use, the demand for low carbon fuels increases markedly. The demand for low carbon fuels increases with time and the increase in the LCFS relative to the base case increases decidedly as the LCFS mandate becomes more severe. By 2025, biofuel demand increases by about 80% compared to the baseline levels in 2025, and almost three times the baseline levels in 2015.

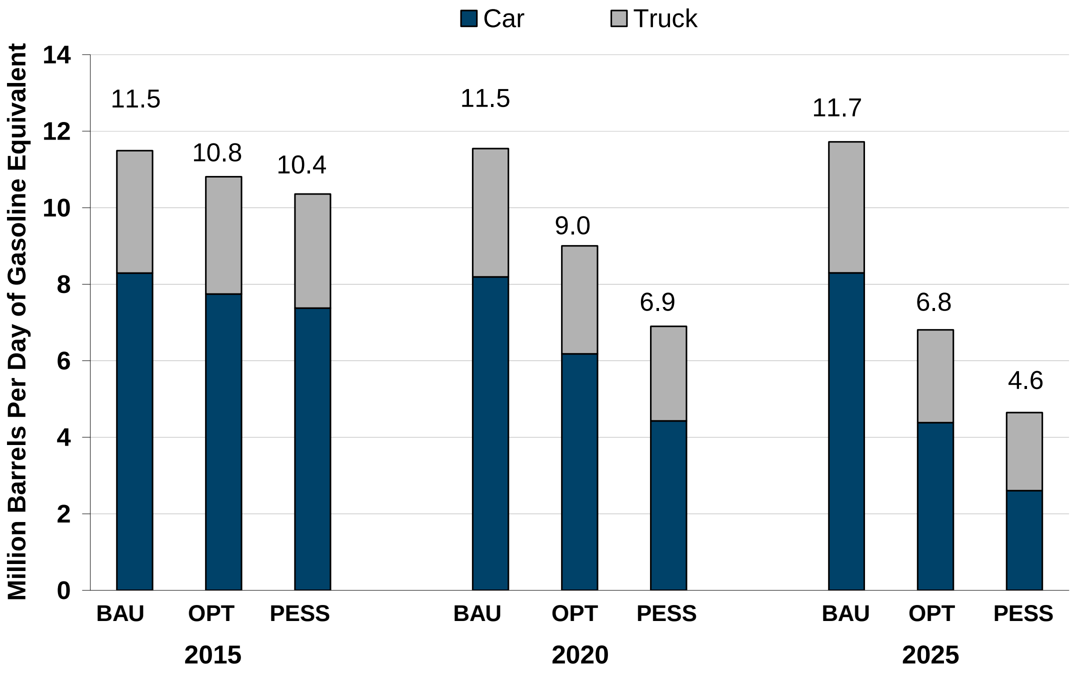
Figure 2-11: Demand for low carbon transportation fuels (mmbd of Gasoline Equivalent)



Source: CRA Model Results, 2010

As shown in Figure 2-12, Petroleum demand by autos and trucks is severely impacted by the LCFS mandate, declining 40% to 60% relative to the baseline in the year 2025. Substitution of low carbon fuels for petroleum in the transportation fuel pool for trucks accounts for about 14% to 18% of the decline. The remainder is demand destruction resulting from use of PHEVs, more fuel efficient vehicles and less driving.

Figure 2-12: Demand for petroleum transportation fuels (mmbd of Gasoline Equivalent)



Source: CRA Model Results, 2010

2.3.3. Refinery Industry Impacts

The U.S. Refining industry will be severely impacted by the LCFS mandate. Crude runs will be reduced by 27 to 40% in 2025 due to declining demand and substitution of low carbon fuels (Table 2-2). The impacts for crude runs are less severe in percentage terms than those for gasoline and diesel (Figure 2-10) because the directly impacted fuels, gasoline and diesel, only represent about half of refinery production.

Table 2-2: Impact of nation-wide LCFS on refinery crude runs

Crude Runs (thousand barrels per day)					
	2025			% Decline vs. BAU	
	BAU	OPT	PESS	OPT	PESS
PADD I	1,470	1,095	902	26%	39%
PADD II	3,135	2,063	1,770	34%	44%
PADD III	7,291	5,250	4,310	28%	41%
PADD IV	514	365	309	29%	40%
PADD V	2,213	1,847	1,522	17%	31%
Total U.S.	14,623	10,620	8,813	27%	40%

The amount of refining capacity would be significantly reduced as reduced crude runs force refiners to rationalize capacity to maintain acceptable levels of utilization. Assuming PADD-level utilization rates at the average levels of the last 25 years (1985 through 2009), refinery capacity in the U.S. would be reduced by 27 to 40% due to the LCFS impact (Table 2-3).

Table 2-3: Impact of nation-wide LCFS on refinery operating capacity

Refinery Capacity									
	Capacity (thousand barrels per day)				Decline (%)				
	2009	2025			2025 vs. 2009			2025 vs. BAU	
		BAU	OPT	PESS	BAU	OPT	PESS	OPT	PESS
PADD I	1,788	1,648	1,240	1,080	8%	31%	40%	25%	34%
PADD II	3,672	3,387	2,156	1,859	8%	41%	49%	36%	45%
PADD III	8,548	8,131	5,720	4,702	5%	33%	45%	30%	42%
PADD IV	622	561	411	364	10%	34%	42%	27%	35%
PADD V	3,216	2,446	2,060	1,658	24%	36%	48%	16%	32%
Total U.S.	17,845	16,173	11,586	9,662	9%	35%	46%	28%	40%

Note that these capacity reductions are in addition to closures of 1.5 mmbd over the period 2009 to 2025 in the Base Case (from 17.8 to 16.2 mmbd). PADDs II and V have the largest reduction in capacity versus current (2009) capacity. In terms of number of refineries, the LCFS will cause the closure of additional 43 to 55 refineries versus the base case by 2025 (Table 2-4). Because smaller, less complex refineries will be most likely to close, the number of refineries closed will be significantly larger than the crude run reduction or capacity closure would indicate. In the Pessimistic case, the number of refineries in 2025 is approximately one third of the current (2009) number.

Table 2-4: Impact of nation-wide LCFS on refinery retirements

Number of Refineries						
	2009	2025			Retirements Decline vs. BAU	
		BAU	OPT	PESS	OPT	PESS
PADD I	15	12	8	7	-4	-5
PADD II	27	20	9	7	-11	-13
PADD III	57	42	22	17	-20	-25
PADD IV	17	12	7	6	-5	-6
PADD V	34	21	18	15	-3	-6
Total U.S.	150	107	64	52	-43	-55

These additional refinery closures will cause approximately 21,000 to 32,000 direct job losses in the U.S. refining industry by 2025 (Table 2-5):

Table 2-5: Impact of nation-wide LCFS on refinery employment

Refinery Job Losses					
	2025 Job Losses			Job Losses vs. BAU	
	BAU	OPT	PESS	OPT	PESS
PADD I	700	2,600	3,600	1,900	2,900
PADD II	1,100	7,100	8,700	6,000	7,600
PADD III	2,800	14,000	20,000	11,200	17,200
PADD IV	200	700	1,000	500	800
PADD V	1,700	3,500	5,700	1,800	4,000
Total U.S.	6,500	27,900	39,000	21,400	32,500

As shown in Table 2-6, the refinery closures will also result in the loss of $2.2 to 3.3 billion per year, which represent a 25% to 39% reduction, in recurring capital expenditures for Health, Safety, Environment, maintenance and turnarounds, and profit improvement projects.

Table 2-6: Impact of nation-wide LCFS on refinery investment

Refinery Investment $MM/yr					
	2025			Decline vs. BAU	
	BAU	OPT	PESS	OPT	PESS
PADD I	$736	$545	$444	-$190	-$291
PADD II	$1,668	$1,061	$903	-$607	-$764
PADD III	$4,535	$3,435	$2,859	-$1,100	-$1,675
PADD IV	$250	$195	$174	-$55	-$76
PADD V	$1,502	$1,329	$1,109	-$173	-$393
Total U.S.	$8,690	$6,565	$5,490	-$2,125	-$3,200

2.3.4. Alternative Fuel Impacts

Alternative Fuel Investment

Increased production of low carbon fuels will require expansion of the capacity to produce and transport these fuels. Ethanol's chemical characteristics require that it receive special handling in order to segregate it from water and other contaminants. As a result, ethanol is transported by rail and truck rather than pipeline and must be stored in dedicated tankage. Consequently, new investment will need to occur in not only ethanol production facilities but also in the infrastructure for ethanol handling. Other low carbon fuels such as BTL and biodiesel will require investment additional production facilities to meet their increased demand. CNG facilities will need to be built requiring investment in station facilities to dispense natural gas taken from the pipeline (see Table 2-7).

Table 2-7: Cumulative capital investment in renewable fuels (billion 2008 dollars)

	Optimistic			Pessimistic		
	2011-2015	**2016-2020**	**2021-2025**	**2011-2015**	**2016-2020**	**2021-2025**
Ethanol	$24	$3	$0	$24	$3	$0
BTL	$0	$6	$6	$0	$10	$6
CNG	$1	$2	$3	$1	$3	$3
Biodiesel	$1	$0	$0	$1	$0	$0
Total	$25	$11	$9	$26	$16	$8

Investment in ethanol production facilities occurs early as ethanol is used in the early years to meet intermediate LCFS targets. Large investments occur in BTL and CNG in the later years. BTL investment magnitudes reflect the capital intensity of the process and the magnitude of the projects. CNG investments reflect the large amount of CNG that develops in the later years.

3. BACKGROUND

A nation-wide LCFS is a mandate designed to reduce carbon emissions from the transportation sector. It would require fuel suppliers to reduce the lifecycle greenhouse gas emissions of the transportation fuels sold in the U.S. on a per gallon equivalent basis. This policy is different than an emissions cap because it does not set a limit on total emissions directly but rather reduces the emissions rate by requiring fuel suppliers to reengineer their fuels to be less carbon intense than petroleum products (*i.e.*, have lower lifecycle greenhouse gas emissions on a per gallon equivalent basis). This mandate is typically implemented by progressively increasing carbon intensity reduction targets over time.

Options for complying with a LCFS boil down to fuel changes, vehicle changes or both. To some extent, changes can be made in the fuels used by the existing vehicle fleet. This involves blending renewable, lower carbon-emitting fuels such as cellulosic ethanol and biodiesel, into the transportation fuel supply pool. The amount of lower carbon-emitting fuels that can be introduced in this way depends on the tolerance of existing vehicles for ethanol or alternatives in their fuel. Current fuels regulations limit ethanol in gasoline to 10% by volume because the most existing vehicles are not designed to operate on higher levels. Therefore, there is a maximum volume of ethanol that can be added to the gasoline pool which is known as the “blend wall” (10% of the total gasoline pool). Blending ethanol into the transportation fuel supply pool can only go beyond this limit as flexible fuel vehicles are produced and enter the fleet. The blend wall constraint would not affect non-alcohol fuels such as gasoline or diesel substitutes from BTL processes, should they become available, but these fuels are likely to become available on a timetable much like that of fleet turnover.

Motor vehicles that could be incorporated into the vehicle supply pool in the future to expand the list of usable fuels that are characterized by lower carbon emissions also include PHEVs and battery operated electric vehicles (BEVs), when powered by electricity generated from a low carbon fuel source. Another possibility is CNG vehicles for fleets. For PHEVs and BEVs, electric utilities would be credited for selling electricity to power these vehicles. For CNG vehicles, natural gas suppliers would be credited for selling natural gas to CNG fleet users. Use of these fuels can only increase at the pace that vehicles designed for their use enter the fleet.

A LCFS would likely include mechanisms to allow for trading credits, providing additional flexibility and lowering the cost of compliance. For example, fuel suppliers would be able to purchase credits from electric utilities that supply low carbon electricity to PHEVs or BEVs or from natural gas suppliers selling CNG. This option would allow fuel suppliers to comply with the mandate in a potentially less expensive way than reengineering their fuel. Fuel suppliers would also be allowed to bank these credits for use in future years against future carbon reduction requirements.

Oil sands from Canada are the second largest known reserve of oil in the world. Although Canadian oil sands-derived crudes are no more carbon intensive than many conventional crudes processed in the U.S.,[11] the California LCFS and some other LCFS proposals attempt to account for the carbon emissions that are created during the processing of Canadian oil sands into synthetic crude oil or Diluted Bitumen without giving credit for local greenhouse gas emissions controls in Canada. This type of adjustment raises a complex set of issues including; emissions from extracting and transporting various types of internationally traded crudes, energy security, and the implications of NAFTA and WTO rules. Since these crude oil forms can be and are processed in refineries in the U.S., and since it is clear that California's final LCFS will and other regional LCFS proposals may assign an "emissions penalty" based on such a problematic life cycle emissions analyses, this study has modeled this particular "emissions penalty" feature of an LCFS policy.

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[11] Typical Heavy Crude And Bitumen Derivative Greenhouse Gas Life Cycles In 2007 prepared for Regional Infrastructure Working Group by T. J. McCann and Associates Ltd. November 16, 2001.

4. METHODOLOGY

The approach used for this analysis of a nation-wide LCFS is to first develop a reference case predicated on the EIA forecast from the 2010 Early Release AEO. A LCFS mandate would not be included in the reference case. Next, two scenarios are developed each of which contains the LCFS mandate. Both the reference case and the two scenarios are modeled with a forecast horizon of 2025. The two scenarios, the optimistic scenario and pessimistic scenario, are constructed to cover the potential range of uncertainty associated with a number of the key assumptions underpinning the analysis.

The nation-wide LCFS is assumed to begin implementation in the year 2015 and to achieve full implementation by the year 2025. The analysis assumes that by 2025, a nation-wide LCFS would mandate a reduction of 10% in the carbon intensity of transportation fuels relative to the nationwide carbon intensity in a base year. The base year is assumed to be the year 2015 with no LCFS mandate. Suppliers of transportation fuel have a number of options for complying with the nation-wide LCFS mandate. In general they can either alter their own mix of fuels to include greater portions of biofuels or they can purchase credits from electric utilities that generate these credits by supplying electricity to PHEVs or BEVs. The scenarios estimate the extent to which PHEVs or BEVs enter the market in response to the LCFS mandate and the amount of electricity that they consume. Suppliers can also comply with the mandate by changing their fuel product mix to include greater portions of low carbon fuels. This analysis considers several different types of low carbon fuels. Corn ethanol and sugarcane ethanol from Brazil are currently available options as components in a gasoline. The analysis also considers the introduction of more advanced biofuels that are not available in large quantities today. These advanced biofuels consist of cellulosic ethanol and BTL. CNG is also an option for fleets. Biodiesel is a potential substitute for petroleum diesel. The biodiesel analysis includes biodiesel made from soybean oil, waste grease from restaurant waste and waste grease from tallow (animal fat). It is assumed, perhaps optimistically, that an equal amount of each fuel measured on an energy basis provides the same transportation services. This implies, for example, that there are no issues of manufacturer’s warranties, stability in the vehicle tank, lubricity, or other subjective concerns with any of the substitute fuels.

4.1. BASE CASE

The reference case is based upon the EIA’s 2010 Early Release AEO.[12] Total baseline fuel consumption is consistent with the EIA forecast. The reference case includes the mix of transportation fuels (including biofuels) forecasted by EIA. The EIA has stated in its case description that it believes that it is unlikely that cellulosic biofuel volumes will reach stated

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[12] U.S. Energy Information Administration, “Annual Energy Outlook 2010 Early Release,” available at http://www.eia.doe.gov/oiaf/aeo/.

targets under RFS2.[13] For the reference case, we have relied upon EIA's analysis regarding the level of biofuels that are producible during the forecast period. In the reference case, cellulosic ethanol and biodiesel are introduced at volumes consistent with the EIA's forecast.

4.2. OPTIMISTIC AND PESSIMISTIC SCENARIOS

The two scenarios are constructed to cover the potential likely range of uncertainty associated with a number of the key assumptions underpinning the analysis. These include the full lifecycle emission rates for each biofuel, their production costs and availability. The "optimistic scenario" uses the emission reductions for biofuels reported by EPA[14] as well as advances in technologies that reduce biofuel costs and accelerate their commercial availability. The "pessimistic scenario" uses emission factors developed by the California ARB and assumes a slower pace for technology advances in reducing costs and increasing commercial availability.[15] Technology development, especially for advances of the scale required to meet the LCFS with fuels as cheap as gasoline, is a highly uncertain process and neither success nor failure can be predicted with confidence. Regulatory requirements may cause increased effort to be expended on R&D in directions that might lead to such innovations, but they cannot change the laws of nature or the unpredictability of research outcomes. Thus, the R&D breakthroughs required to achieve the "pessimistic scenario" might be the best that can be accomplished even under the lash of regulation. There is no way to know otherwise, leaving scenario analysis the only method that can evaluate potential consequences of regulation.

4.3. KEY ASSUMPTIONS

The scenarios were constructed based upon a number of key assumptions. The principal assumptions center on each fuel's emission factor, cost, and maximum allowable penetration. The calculation of emission factors for biofuels is an evolving process. Life cycle emissions must include not only the direct effects of burning the fuel, but also its indirect effects such as induced land-use changes. Furthermore, there may be co-products resulting from the production of the biofuel that also impact the energy balance. Because advanced biofuels are in a development phase, there is imprecise data regarding the cost to produce the fuels. Studies and pilot plants provide a source of information that is helpful but insufficient to accurately determine their costs. Also, given the development stage of these fuels, it is uncertain when and in what quantities they can be commercially produced.

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[13] U.S. Energy Information Administration, Peter Gross, "EIA's Long-Term Biofuels Outlook: Biofuels: Continuing Shifts in the Industry and the Long-Term Outlook," 2010 Energy Conference, Washington, DC, April 6, 2010.

[14] U.S. Environmental Protection Agency, "Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis", EPA-420-R-10-006, February 2010.

[15] California Environmental Protection Agency Air Resources Board, "Proposed Regulation to Implement the Low Carbon Fuel Standard," Volume 1, Staff Report: Initial Statement of Reasons, March 5, 2009.

Furthermore, the characterization of the emission credits that can be generated by electric utilities selling electricity to PHEVs and BEVs is complex. Issues arise concerning the source of electricity to power electric vehicles and the emissions factor associated with the vehicle and its source. Also, the emissions generated by transporting the electricity from the generating plant to the plug must be included.

Biofuels can be produced either domestically or overseas and then imported into the United States. Brazilian ethanol from sugar is an example of a potentially imported biofuel. It was necessary for the analysis to include an evaluation of the costs, volume potential and timing associated with bringing Brazilian sugar ethanol into the United States. The sections that follow provide a more detailed discussion of each of the key assumptions underlying this analysis.

4.3.1. Emission Factors by Fuel Type

Emission factors represent a very important set of assumptions underpinning this analysis. There exists controversy regarding what is the appropriate methodology for calculating life cycle emission factors particularly for biofuels. The life cycle emission factor must account for not only emissions created during the combustion process and the emissions generated during the conversion of biomass to biofuel, but also allow for credits and debits associated with co-products that result from the production process as well as impacts on the agricultural sector by which the biomass feedstock is produced. To further complicate this definition, these indirect impacts from co-products and agriculture can have both domestic and international impacts.

This study relied upon life cycle emission factors estimated by the EPA for the optimistic case, and the California ARB for the pessimistic case.

For the optimistic case, we relied upon EPA's regulatory impact analysis for their RFS2 program.[16] We reviewed EPA's analysis of emission factors and their sensitivity cases. In this analysis, for each biofuel we selected a mid-range value for the different cases that EPA presented.

Emission factors for corn ethanol were taken directly from EPA's latest estimates which used a 30-year lifecycle period. We chose the emission factors for the EPA case, which assumed the use of an average dry mill technology and natural gas as the fuel source. EPA's emission factors for corn ethanol ranged from 58 to 92 g CO_2e/MJ depending upon the technology and fuel source chosen. For sugar ethanol, we again chose a mid-range value from the EPA case which assumed no residue collection. EPA's emission factors for sugar ethanol ranged from 8 to 38 g CO_2e/MJ depending upon the scenario chosen. The cellulosic ethanol emission factor represents the direct and indirect emission effects from the biofuel. We used the EPA scenario which was based upon the use of corn stover as biomass and a thermo

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[16] U.S. Environmental Protection Agency, "Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis", EPA-420-R-10-006, February 2010.

chemical process. Cellulosic ethanol emissions are discussed in more detail later. EPA did not provide an emission factor for BTL, so we made a conservative assumption that BTL had the same emission factor as cellulosic ethanol. EPA also did not provide an emission factor for CNG so we relied upon a study by the California ARB.[17] For CNG we chose an emission factor calculated based upon natural gas received from an interstate pipeline as opposed to from other biomass sources such as landfill. The preponderance of natural gas used in the United States is a fossil fuel not a biomass fuel. Therefore, we used the direct emission factor.

For diesel and biodiesel, we also relied on the EPA study. We assumed diesel to be 100% petroleum and therefore, made no adjustments to its emission factor. For biodiesel, we considered two categories: soy-based (assumed to represent all virgin oils) and waste grease-based (assumed to include waste greases, corn oil and renewable diesel). In the EPA study, emissions factors for soy-bean based biodiesel varied from 28 to 40 g CO_2e/MJ. For the waste grease category, we assumed the listed waste grease emission factors reported by EPA.[18] We also included a BTL category which we assume produced a biomass diesel fuel. It was assumed to have the emission characteristics of cellulosic ethanol.

For the pessimistic case, we relied upon the analysis of California ARB.[19] Whenever the data allowed, for each of the biofuels we attempted to select a pathway which resulted in an emission factor which was in the mid-range of the possible outcomes.

For corn ethanol we used the emission factor for a Midwest average (80% dry mill, 20% wet mill with dry distilled grains with soluble), which had an emission factor of 99 g CO_2e/MJ. The emission factor for corn ethanol ranged from 90 to 121 (g CO_2e/MJ) depending upon the pathway. For sugar ethanol we chose the mid-range scenario with the average production technology with credits for electricity. The emission factor for this scenario is 66 g CO_2e/MJ. The emission factor for sugar ethanol ranged from 58 to 73 g CO_2e/MJ. For cellulosic ethanol we used another ARB study[20] which provided only one scenario, which assumed that cellulosic ethanol was produced from farmed trees by fermentation. For CNG we used the same case as was used in the optimistic case. For soy-based biodiesel we used an ARB

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[17] California Environmental Protection Agency Air Resources Board, “Proposed Regulation to Implement the Low Carbon Fuel Standard,” Volume 1, Staff Report: Initial Statement of Reasons, March 5, 2009.

[18] U.S. Environmental Protection Agency, “Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis”, EPA-420-R-10-006, February 2010.

[19] California Environmental Protection Agency Air Resources Board, “Proposed Regulation to Implement the Low Carbon Fuel Standard,” Volume 1, Staff Report: Initial Statement of Reasons, March 5, 2009.

[20] California Environmental Protection Agency Air Resources Board, “Detailed California-Modified GREET Pathway for Cellulosic Ethanol from Farmed Trees by Fermentation,” Version 2.1, Stationary Source Division, February 27, 2009, page 5.

study with conversion of Midwest soybeans to biodiesel using a FAME technology.[21] For waste grease, we used the ARB case that assumed some cooking of waste grease was required. The range of emission factor for waste grease biodiesel was 13 to 16 g CO_2e/MJ.

The emission factor for gasoline was intended to reflect the emissions produced from 100% petroleum based fuel (*i.e.*, 0% alcohol content). In order to calculate the gasoline emission factor, we used the ARB factor of 96 g/MJ as a starting point. This emission factor is based upon a gasoline mix containing both petroleum and alcohol (90% petroleum, 8% mid-west alcohol, 2% California alcohol). We adjusted the composition of the gasoline to 100% petroleum and recalculated the emission factor.

A summary of the emission factors used is presented below.

Table 4-1: Emission factors by fuel type (carbon intensity: grams CO_2e/MJ)

	Optimistic	Pessimistic
Gasoline	93	96
Corn Ethanol	73	99
Sugarcane Ethanol	36	66
Cellulosic Ethanol	7	20
CNG	68	68
Diesel	92	95
Soy-Based Biodiesel	40	83
Waste Grease Biodiesel	13	16
BTL Diesel	7	20

4.3.2. Cost and Introduction Rates for Biofuels

Relative biofuel cost estimates were based upon an ARB report,[22] which projected costs for a number of biofuels. The sugar ethanol estimates were consistent with other reports and include the 54 cents/gallon import tariff and 2.5% ad valorem tax.[23] Cellulosic ethanol is still undergoing process development thus the costs to produce this biofuel are dependent upon the degree and pace of technology improvement. At present, it is the most expensive of the biofuels. For CNG, CRA assumed costs include both the commercial delivery costs and the cost recovery necessary to justify the capital investment in the refueling station. These costs

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[21] California Environmental Protection Agency Air Resources Board, “Detailed California-Modified GREET Pathway for Conversion of Midwest Soybeans to Biodiesel (Fatty Acid Methyl Esters-FAME),” Version 3.0, Stationary Source Division, December 14, 2009, page 5.

[22] California Environmental Protection Agency Air Resources Board, “Proposed Regulation to Implement the Low Carbon Fuel Standard,” Volume 1, Staff Report: Initial Statement of Reasons, March 5, 2009, Table VIII-8, Lower-CI Fuel Costs.

[23] All ethanol qualifies for a 51 cents per gallon blending credit regardless of whether it is produced domestically (such as ethanol from corn) or imported (such as ethanol from sugar) but the tariff neutralizes the credit for imported.

are added as a premium to the price of natural gas which we then use as the CNG cost. Biodiesel costs for both waste grease and soybean were derived from the same ARB study,[24] indexed to the cost of corn ethanol. BTL biofuel was assumed to be equal in cost to cellulosic ethanol based upon an EPA study.[25] The relative costs of alternative fuels are summarized in Table 4-2.

Penetration rates and maximum volumes potentials for biofuels were derived from similar sources. The ethanol production limit is generally considered reached when it takes capacity away from food production. We have assumed that the EIA 2010 Early Release AEO Reference Case reaches this limit by 2025. Sugar ethanol import potential was estimated from a study from the Brazilian government,[26] which estimated total export potential of sugarcane ethanol out of Brazil. It was assumed that all Brazilian exports could potentially arrive in the United States. Cellulosic ethanol capacity was estimated based upon statements by EIA in the 2010 Early Release AEO.

Biodiesel capacity was estimated from a variety of sources. We derived our estimates of waste grease and corn oil potential from an EPA report.[27] Estimates for BTL were based upon the EIA 2010 Early Release AEO. The soybean potential was based upon the EPA and the Renewable Fuels Association.[28]

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[24] California Environmental Protection Agency Air Resources Board, "Proposed Regulation to Implement the Low Carbon Fuel Standard," Volume 1, Staff Report: Initial Statement of Reasons, March 5, 2009, Table VIII-8, Lower-CI Fuel Costs, page VIII-17.

[25] U.S. Environmental Protection Agency, "Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis", EPA-420-R-10-006, February 2010, page 782.

[26] Ministério de Minas e Energia ; Empresa de Pesquisa Energética, " Plano Nacional de Energia 2030," Brasília: MME: EPE, 2007.

[27] U.S. Environmental Protection Agency, "Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis", EPA-420-R-10-006, February 2010, page 190.

[28] U.S. Environmental Protection Agency, "Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis", EPA-420-R-10-006, February 2010.

National Biodiesel Board, "Biodiesel: Feedstock Supply", available at: http://www.biodiesel.org/resources/sustainability/pdfs/Achieving%201%20billion%20gallons%20of%20fuel%20While%20Protecting%20Valuable%20Feedstocks%20_June%209_.pdf.

Table 4-2: Relative costs of alternative fuels (cost relative to gasoline/diesel)

Optimistic Case	2015	2020	2025
Gasoline	1	1	1
Corn Ethanol	1.6	1.5	1.5
Sugarcane Ethanol	1.79	1.68	1.68
Cellulosic Ethanol	2.56	2.4	2.25
CNG	Premium to natural gas price		
Diesel	1	1	1
Soy-Based Biodiesel	1.76	1.65	1.65
Waste Grease Biodiesel	0.92	0.86	0.86
BTL Diesel	2.56	2.4	2.25

Pessimistic Case*	2015	2020	2025
Gasoline	1	1	1
Corn Ethanol	1.7	1.6	1.5
Sugarcane Ethanol	1.9	1.79	1.68
Cellulosic Ethanol	2.89	2.56	2.4
CNG	Premium to natural gas price		
Diesel	1	1	1
Soy-Based Biodiesel	1.87	1.76	1.65
Waste Grease Biodiesel	0.97	0.92	0.86
BTL Diesel	2.89	2.56	2.4

*Assumes 5-year delay in technology cost reductions

4.3.3. Brazilian Sugar Ethanol

In addition to domestic production, the United States imports ethanol from foreign sources; primarily from Brazil. In this analysis, CRA accounted for the potential volumes that could be imported given the market demand and the cost of imports relative to domestic fuels. CRA assumed that all imported ethanol comes from Brazil and that it is produced using sugarcane feedstock. In allowing for this renewable fuel in the model, CRA applied a different cost to Brazilian ethanol and set a limit on import volumes.

Currently, the United States imposes a 2.5% ad valorem tariff on foreign ethanol. In addition, U.S. petroleum product blenders are given tax credits for adding pure ethanol to their gasoline[29] of which could have been imported and later purchased by the blender. In order to prevent the U.S. government from subsidizing foreign ethanol production, there is an additional $0.54/gallon secondary tariff on imported ethanol.[30] These tariffs are assumed to be in place in all model years of this analysis. In addition to the tariffs, CRA assumes a

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[29] The American Jobs Creation Act of 2004 outlines current ethanol tax credits. See: http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_2005analysispapers/ajca.html.

[30] Some countries are exempt from this tariff. For example, under the Caribbean Basin Initiative (CBI), up to 7% of domestic ethanol production is not subject to a tariff so long as the fuel ethanol is derived from nations covered by the CBI. I do not include these volumes in this analysis. For more information, see: http://www.ethanol.org/index.php?id=78&parentid=26.

transportation cost from Brazil to the U.S. of $0.14/gallon, transportation cost from plant to port of $0.21/gallon and a port cost of $0.10/gallon. The final per gallon cost that is applied to sugarcane ethanol is that which is used in a report from the California ARB, which includes all of the above-mentioned costs.[31]

CRA also sets a limit on the total available sugarcane ethanol available to export from Brazil in each model year. The model then chooses the volume of imports in each year based on the economics of this fuel compared to others. For yearly forecasted export volumes from Brazil, CRA relied on the 2008 National Energy Plan report from the Empresa de Pesquisa Energética, the Brazilian government's energy research company.[32] Table 4-3 provides these limits for each year.

Table 4-3: Maximum volumes of sugarcane ethanol from Brazil allowed in MRN-NEEM (quads)

Year	Brazilian Ethanol Export Potential (Quads)
2010	0.15
2015	0.25
2020	0.41
2025	0.37

4.3.4. Cellulosic Ethanol Emissions

Cellulosic ethanol is generally considered to be the least carbon intensive of any biofuel currently in use or under development. Switchgrass and corn stover are the most common feedstocks for cellulosic ethanol, and the emissions resulting from converting them into ethanol are far less than those resulting from the production of corn ethanol. In determining an emissions factor for cellulosic ethanol, CRA relied upon a series of studies including EPA and ARB documents. As part of its rulemaking process for the second Renewable Fuels Standard as codified in the Energy Independence and Security Act of 2007 (EISA), EPA proposed new methodologies for conducting life cycle emissions analyses of biofuels. For example, EPA developed a new modeling framework that broadens the scope, or "system boundary," that defines precisely which portions of a product's lifecycle is considered when estimating its impact on emissions. EPA focused extensively on incorporating each fuel's impact on indirect emissions, or those emissions resulting from processes that do not result directly from the production of the fuel itself. In addition, EPA also incorporated the impact of co-products, or byproducts of the biofuel production process that have market value. The

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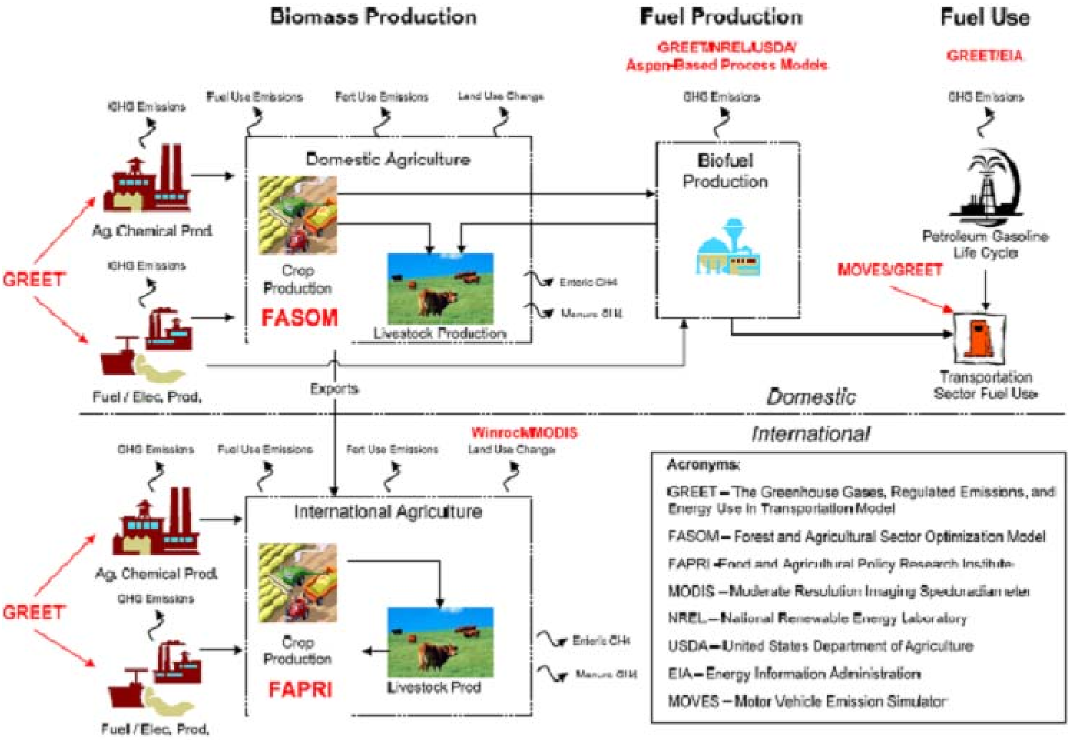
[31] California Environmental Protection Agency Air Resources Board, "Proposed Regulation to Implement the Low Carbon Fuel Standard," Volume 1, Staff Report: Initial Statement of Reasons, March 5, 2009, Table VIII-8.

[32] Ministério de Minas e Energia ; Empresa de Pesquisa Energética, " Plano Nacional de Energia 2030," Brasília: MME: EPE, 2007.

figure below is a schematic of how EPA defined the system boundary when estimating lifecycle emissions of biofuels.

Figure 4-1: EPA draft rule: system boundaries and models and data sources used[33]



EPA's approach to estimating indirect emissions is experimental and represents the cutting-edge of life cycle analyses for biofuels. In particular, its approach to estimating emissions resulting from changes in international agriculture and land use rely upon models that have not previously been used for such purposes. The implementation of these models results in estimates for cellulosic ethanol derived from switchgrass and corn stover that predict reductions in emissions of greater than 100% relative to a gasoline baseline.

EPA acknowledges that its methodology contains numerous uncertainties that have a material impact on results. As part of its rulemaking process, EPA has sought comments on various aspects of its estimates, particularly those related to its modeling of international agriculture and land use changes. EPA's results in this area are preliminary at best and, as a result, CRA did not rely upon them exclusively in determining a final emission factor for cellulosic ethanol for use in our analysis of a LCFS.

Another key assumption by EPA that resulted in emission factors greater than 100% reduction relative to gasoline relates to the accounting for co-products in the production of cellulosic ethanol.

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[33] U.S. EPA, Draft Regulatory Impact Analysis: Changes to Renewable Fuel Standard Program, Washington, D.C., May 2009, page 279. Available at http://www.epa.gov/otaq/renewablefuels/420d09001.pdf.

> *Conversion of cellulosic feedstocks (e.g., corn stover or switchgrass) to ethanol creates a net sequestration of carbon during the fuel production stage. Ethanol is fermented with the cellulosic portion of the biomass, while process energy is generated through the unfermentable portion (mainly lignin) of incoming biomass. Based on NREL estimates, the process is assumed to generate more than 8,000 Btu of excess electricity per gallon of ethanol produced. Biomass-fired electricity generation reduces GHG emissions by offsetting other forms of electricity production.*

The assumption that the entire amount of co-product would displace existing electricity generation is questionable. Instead, CRA chose to develop emissions factors based upon both EPA's proposed rule and outside studies. In the optimistic case, CRA chose a mid-range emission factor by using the EPA scenario based upon corn stover as feed to a thermochemical process. EPA presents other scenarios in which the range of emission factors varies from -27 to +26 (g CO_2e/MJ). For the pessimistic case, CRA relied upon the work of the ARB.[34] Their study presented a single point estimate of 20 (g CO_2e/MJ).

4.3.5. Canadian Crude

Although Canadian oil sands-derived crudes are no more carbon intensive than many conventional crudes processed in the U.S.,[35] the California LCFS and some other LCFS proposals attempt to account for the carbon emissions that are created during the processing of Canadian oil sands into synthetic crude oil or Diluted Bitumen, without giving credit for local greenhouse gas emissions controls in Canada. This type of adjustment raises a complex set of issues including; emissions from extracting and transporting various types of internationally traded crudes, energy security, and the implications of NAFTA and WTO rules. Since these crude oil forms can be and are processed in refineries in the U.S., and since it is clear that California's final LCFS will and other regional LCFS proposals may assign an "emissions penalty" based on such a problematic life cycle emissions analyses, this study estimates an additional "emissions penalty" by increasing the emission factor for petroleum products produced from Canadian synthetic crude oil or Diluted Bitumen that were produced from Canadian oil sands. These estimates of additional emissions are based upon life cycle analyses for synthetic crude.

In order to determine the increase in emission factor, it was necessary to estimate both the additional "emissions penalty" likely to be assigned to Canadian synthetic crude oil or Diluted Bitumen and the share of petroleum products consumed in the United States that was produced from Canadian crude oil. A review of the literature revealed several sources of data

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[34] California Environmental Protection Agency Air Resources Board, "Detailed California-Modified GREET Pathway for Cellulosic Ethanol from Farmed Trees by Fermentation," Version 2.1, Stationary Source Division, February 27, 2009, page 5.

[35] Typical Heavy Crude And Bitumen Derivative Greenhouse Gas Life Cycles In 2007 prepared for Regional Infrastructure Working Group by T. J. McCann and Associates Ltd. November 16, 2001.

on life cycle emissions from Canadian synthetic crude oil.[36] These sources provided a range of estimates from 5% to 15%. Based upon this review we decided to use a mid-range value which would result in approximately 10% increase in emissions relative to the average of other conventional crudes.

Next, a paper by Purvin and Gertz[37] was relied upon as a forecast for the level of Canadian Crudes processed in the United States. The forecast estimated Canadian Crude consumption in the United States by PADD. The Canadian crude import forecast was adjusted to an equivalent level of petroleum product production and used along with CRA model's forecast of petroleum product demand by PADD in order to calculate the Canadian share of petroleum product demand by PADD. The analysis determined that PADD II and PADD IV were likely to contain significant shares of Canadian petroleum in their consumption; 40% to 45%. Finally, adjusted emission factors were calculated using both the market share and emission factor data. It was assumed that there would be no substitution away from oil sands toward other crudes in these PADDs, only a shift in production across PADDs. The results, presented in Table 4-4, show that in order to reduce carbon intensity in 2025 to a level 10% below measured national carbon intensity in the base year 2015, PADD II and IV refiners need to accomplish an average 14% reduction from their regional carbon intensity, whereas PADD I, III, and V need only an average 7% reduction from their regional carbon intensity.

Table 4-4: Calculation of adjustment factors for motor gasoline and diesel fuel emission factors due to Canadian oil sand

	2015	**2020**	**2025**
PADD I	1	1	1
PADD II	1.06	1.07	1.07
PADD III	1	1	1
PADD IV	1.05	1.07	1.07
PADD V	1	1	1

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[36] TIAX LLC and MathPro Inc, "Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions," Prepared for Alberta Energy Research Institute, July 22, 2009.

Jacobs Consultancy Life Cycle Associates, "Life Cycle Assessment Comparison of North American and Imported Crudes," Prepared for Alberta Energy Research Institute, July 2009.

Issacs, Eddy, "Life Cycle Analysis- Exploring the Facts on Oil Sands Development," Alberta Energy Research Institute.

T.J. McCann and Associates Ltd., "Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles in 2007," Prepared for Regional Infrastructure Working Group, November 16, 2001.

[37] Wise, Thomas and David Wells, "Canadian Oil Sands Crudes: What Goes Where," National Petrochemical & Refiners Association, Annual Meeting, March 22-24, 2009.

4.3.6. Biomass Diesel

CRA modeled several types of biomass diesel in this study. The United States currently produces most of its biodiesel from either soybeans or waste oils. In addition, there is the possibility in the future of other forms of renewable diesel from either BTL or hydrogen processes.

EPA's most recent Renewable Fuel Standard (RFS2) mandates minimum production volumes of biomass diesel from 2010 to 2012 with levels for 2013 forward to be determined in the future. These biodiesel volumes must have a minimum of 50% reduction in Lifecycle Greenhouse Gas emissions from petroleum-based fuel. According to a recent lifecycle analysis of renewable fuels by the EPA, soybean and grease waste biodiesel have total lifecycle emission reductions of 56% and 86% respectively.[38]

The reference case for this study was calibrated against EIA AEO 2010 Early Release and closely mimicked EIA forecasts of biomass diesel production during the forecast period.

In the LCFS scenarios, the model could chose to produce increased levels of biomass diesel in order to achieve the LCFS target.

Like other renewable fuels modeled in this analysis, CRA set a maximum volume on the annual volume produced for soybean and waste oils biodiesel (see Table 4-4). These volumes were based on the EPA Regulatory Impact Analysis study.[39] The available volumes of waste oils were used principally to comply with the AEO forecast volumes.

Table 4-5: Maximum volumes of biodiesel allowed in MRN-NEEM (quads)

	Total Waste Oil Potential	Total Soybean Potential
2010	1.25	0.7
2015	1.25	2.5
2020	1.25	2.5
2025	1.25	2.5

4.3.7. Renewable Fuel Standard 2

EISA contained provisions which require EPA to implement a National Renewable Fuel Standard Program (RFS2). The legislation requires the EPA to set minimum annual limits on the volume of renewable fuel and advanced biofuel that must be contained in the transportation fuel pool. EPA can choose to adjust these limits by issuing credits if it appears that the production of some volumes of the biofuels is not commercially viable. Since there is

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[38] Over 100 years at a discount rate of 2% per year.

[39] U.S. Environmental Protection Agency, "Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis", EPA-420-R-10-006, February 2010.

some uncertainty regarding whether or not credits will be issued, particularly for cellulosic ethanol, this study follows the forecast of EIA in its 2010 Early Release AEO to determine the degree to which fuel suppliers are required to include biofuels in the transportation fuel pools.

Since this study is intended to analyze the incremental impacts of a nation-wide LCFS, the representation of the RFS2 provision is captured within the reference case.

4.3.8. PHEV and BEV Characterization

Cost and Performance Assumptions

CRA projected cost and performance assumptions over time for PHEV 40 and BEV 100 vehicles using the most recent industry reports and data on hybrids, PHEVs and BEVs. A PHEV 40 is a PHEV that has a range of up to 40 miles in electric-only mode. Similarly a BEV 100 is an all-battery vehicle that has a range of up to 100 miles. The assumptions for these two vehicle types represent costs and performance under current technology and under a future expected rate of technology progression.

The following cost and performance categories were examined as inputs to the MRN-NEEM model:

- Vehicle Cost Premium (excluding tax credits)
- Internal Combustion Engine (ICE) MPG
- Percentage of Time on Electric Engine
- Implied MPG
- Plug to Wheels Electricity Usage per Mile

Vehicle Cost Premium

The vehicle cost premium is the premium of a PHEV 40 or BEV 100 to a comparable-sized ICE light-duty vehicle. CRA assumed that the 2010 premium for a PHEV 40 would be best represented by a Chevy Volt relative to a mid-size car. Available articles suggest that the Chevy Volt might be priced between $40,000 and $42,000, which is approximately 100% more than a $20,000 mid-size car.[40]

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[40] USA Today, “GM builds first Chevy Volt, says production line practice run OK,” March 31, 2010, available at: http://content.usatoday.com/communities/driveon/post/2010/03/gm-finishes-building-first-chevy-volt-battery-car-using-production-tooling-says-the-practice-run-was-ok/1.

For a BEV 100, CRA assumed the 2010 premium be best represented by a Nissan Leaf relative to a high MPG compact-size car. For a comparable vehicle, we selected the Nissan Versa. The Nissan Leaf, priced at $34,000, is 319% more expensive than the Versa.[41]

CRA assumed that the cost premium for a PHEV 40 and BEV 100 would decline with time.

Internal Combustion Engine Miles per Gallon

The ICE's MPG is the MPG that the PHEV obtains when running in gasoline-only mode. For 2010, CRA assumed the ICE's MPG is equivalent to the 2010 On-Road New Light-Duty Vehicle MPG from the EIA's AEO 2010 Early Release increased by a factor of 32% to represent higher MPG ICEs in PHEV vehicles (EEA Study for WSPA).[42]

This ICE's MPG is not applicable for the BEV 100 since it is an all-electric vehicle.

Percentage of time on electric engine

The percentage of time on the electric engine represents the share of time that the electric engine powers the vehicle. This input can vary at the regional level down to the individual level based on driving habits. To derive a forecast for the percentage of time on the electric engine, CRA relied on a range of estimates in studies available.[43] We assumed that the PHEV 40 would operate 60% of the time in electric mode.

Implied MPG

The Implied MPG is the MPG that the PHEV achieves when running in both electric- and gasoline-only modes. The Implied MPG is calculated by dividing the ICE's MPG by one less the percentage of time in electric-only mode. This formula indicates that as the percentage of time in electric-only increases so does the Implied MPG.

This ICE's Implied MPG is not applicable for the BEV 100 since it is an all-electric vehicle.

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[41] USA Today, "GM builds first Chevy Volt, says production line practice run OK," March 31, 2010, available at: http://content.usatoday.com/communities/driveon/post/2010/03/gm-finishes-building-first-chevy-volt-battery-car-using-production-tooling-says-the-practice-run-was-ok/1.

US News, "Nissan Versa - What the Auto Press Say," November 19, 2009.

[42] Western States Petroleum Association, "Notice of Public Hearing to Consider Adoption of a Proposed Regulation to Implement the Low Carbon Fuel Standard (LCFS) – Western States Petroleum Association's Comments," April 21, 2009.

[43] MIT Joint Program on the Science and Policy of Global Change, "Prospects for Plug-in Hybrid Electric Vehicles in the United States and Japan: A General Equilibrium Analysis," Report No. 172, April 2009.

Plug to Wheels Electricity Usage per Mile

The Plug to Wheels Electricity Usage per Mile is expressed in kilowatt-hours per mile (kWh/mi). It represents the amount of electrical energy required to drive the vehicle in electric-only mode and takes into account the vehicle charging efficiency. CRA used an average Tank to Wheel Electricity Usage per mile of a PHEV 40 car and a PHEV 40 light-duty truck from an MIT study (Heywood 2007)[44] along with a charging efficiency of 85% to derive a 2010 estimate for a PHEV 40 Plug to Wheels Electricity Usage per Mile.

For a BEV 100, CRA assumed the 2010 Tank to Wheels Electricity Usage per Mile would be best represented by a Nissan Leaf, which is publicized to have a range of 100 miles on a 24 kWh battery.[45] Similar to the PHEV 40, we assumed an 85% charging efficiency to get to the Plug to Wheels Electricity Usage per Mile.

CRA projected an improvement of 0.5% per year in the Plug to Wheels Electricity Usage per Mile for both vehicle types. By 2050, the projections are very close to the optimistic projections for kWh/mi seen in literature.

4.3.9. Emission Reductions Achievable from PHEVs and BEVs

In order to develop carbon emission factors for the electricity used to charge PHEVs and BEVs, CRA relied upon its proprietary NEEM model. NEEM is a bottom-up model of the electric sector and is capable projecting unit-level outcomes such as generation, capacity additions, retirements, generation mix, fuel consumption, and air emissions. It was necessary to use NEEM to develop emission factors for three reasons. First, because the carbon intensity of electricity varies by region, a region-specific emission factors must be developed in order to allow for analysis of the impact on emissions by PHEVs and BEVs in different parts of the country. Since NEEM contains information about every generating unit in the U.S., the carbon intensity of electricity can be estimated for a specific region. Second, because the mix of generation changes over time as new generating units come on line and others retire, emission factors will change and must reflect the predominant mix in a given year. Because NEEM projects out to the year 2050, such estimates are feasible. Finally, since different types of units operate at different times of the day, emissions factors must be based upon the generation mix at the time of day when people are most likely to charge PHEVs and BEVs - night (or off-peak). NEEM contains a dispatch model that projects unit generation by peak and off-peak hours.

CRA used NEEM to project the off-peak generation mix by year in different regions, and assigned each of those regions by PADD. Table 4-6 illustrates the expected average heating rates for off-peak generation by PADD.

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[44] MIT, Laboratory for Energy and the Environment, “On the Road in 2035: Reducing Transportation’s Petroleum Consumption and GHG Emissions,” Report No. LFEE 2008-05 RP, July 2008.

[45] Nissan Leaf Webpage, available at:
http://www2.nissan-zeroemission.com/EN/LEAF/

Table 4-6: Average Heat Rate of Off-Peak Generation (million Btu per MWh)

PADD	2015	2020	2025	Average
PADD I	9.2	9.3	9.3	9.3
PADD II	10	10	9.9	9.9
PADD III	9.7	9.9	9.8	9.8
PADD IV	9.2	8.8	8.7	8.9
PADD V	6.6	6.5	6.5	6.5

CRA then used these results along with emission factor information about individual generating units to compute a generation-weighted average emission factor for all units in a given PADD for that year. Table 4-7 presents emission factors used in the LCFS analysis from electric generators by PADD.

Table 4-7: Average CO_2 Emission Factors of Off-Peak Generation (lbs per million Btu)

PADD	2015	2020	2025	Average
PADD I	111	119	124	118
PADD II	155	156	158	156
PADD III	146	155	160	154
PADD IV	179	170	174	175
PADD V	92	93	99	94

These factors provide a starting point for understanding the reduction in emissions achievable by PHEV and BEV in lieu of ICE vehicles. For this analysis, CRA calculated the percentage reduction in the emissions resulting from the production of one unit of energy outputted from the battery of an electric engine relative to emissions from a gasoline engine with the same energy output.

In order to develop a baseline level of emissions for a gasoline ICE in the pessimistic case, we relied upon a study by the California Air Resource Board[46] that estimated emissions from a gasoline engine at 96 grams of CO_2 per megajoule. For the optimistic case we relied upon the EPA study.[47]

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[46] California Environmental Protection Agency Air Resources Board, “California’s Low Carbon Fuel Standard: Final Statement of Reasons,” December 2009.

[47] U.S. Environmental Protection Agency, “Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis”, EPA-420-R-10-006, February 2010.

In order to calculate emission factors for PHEV and BEV we relied upon a formula developed by CARB[48] to calculate the effective displaced gasoline emissions. This formula is:

$$Displaced\ emissions = [Emis\ Rate_{gasoline} - (Emis\ Rate_{electric} / 3)]$$

The electric emission rate is divided by three as forecasted by ARB because electric engines are generally considered three times more efficient at converting energy into work than ICE. Using this formula, we calculated effective displaced emissions for both PHEVs and BEVs. For PHEVs, we assumed that 60% of the driving time is spent using the electric engine. See Table 4-8 for a summary of the results.

Table 4-8: PHEV and BEV emissions factors (grams CO_2e/MJ)

	Optimistic Case		**Pessimistic Case**	
	BEV	**PHEV**	**BEV**	**PHEV**
PADD I	52	68	52	70
PADD II	74	81	74	83
PADD III	71	80	71	81
PADD IV	85	88	85	89
PADD V	41	62	41	63

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[48] California Environmental Protection Agency Air Resources Board, "California's Low Carbon Fuel Standard: Final Statement of Reasons," December 2009.

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National Biodiesel Board, “Biodiesel: Feedstock Supply”, available at: http://www.biodiesel.org/resources/sustainability/pdfs/Achieving%201%20billion%20gallons%20of%20fuel%20While%20Protecting%20Valuable%20Feedstocks%20_June%209_.pdf.

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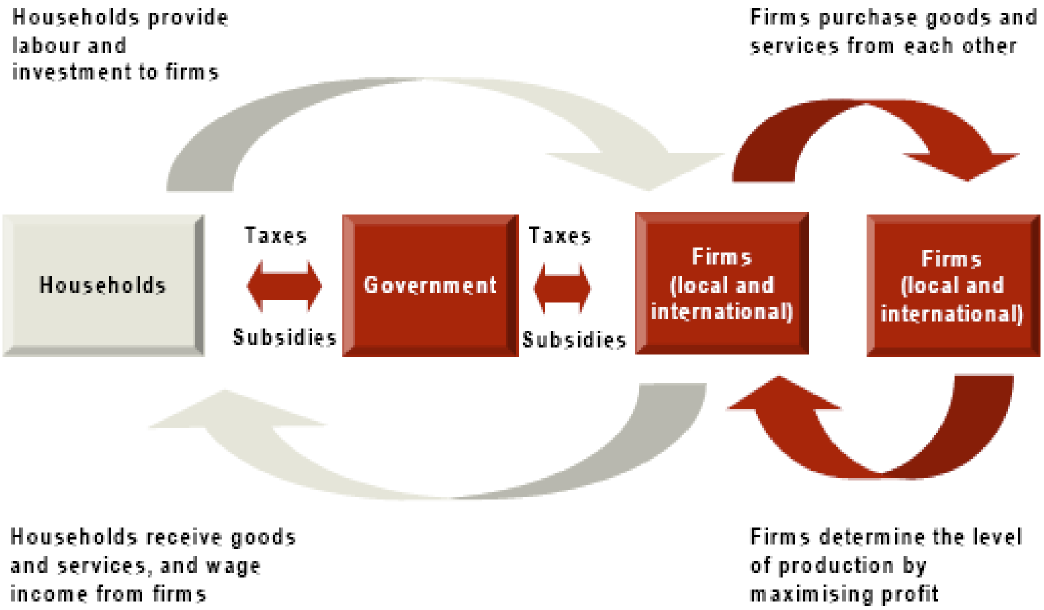
6. APPENDIX: MODEL FRAMEWORK

In conducting this analysis for the Consumer Energy Alliance, CRA combined two of its widely accepted state-of-the-art economic models: MRN and NEEM. MRN and NEEM are linked into one modeling system that has a detailed representation of the U.S. economy and hence allows for detailed analysis of the economic effects of a nation-wide LCFS.

6.1. OVERVIEW OF THE MRN SUB-MODEL

The top-down component of the integrated MRN-NEEM model is tailored from CRA's MRN model. MRN is a forward-looking, dynamic computable general equilibrium (CGE) model of the United States. It is based on the theoretical concept of an equilibrium in which macro-level outcomes (*e.g.*, consumption and investment) are driven by the decisions of self-interested consumers and producers. The basic structure of CGE models, such as MRN, is built around a circular flow of goods and payments between households, firms, and the government, as illustrated in Figure 6-1.

Figure 6-1: Circular flow of goods and services and payment figure



6.2. OVERVIEW OF THE NEEM SUB-MODEL

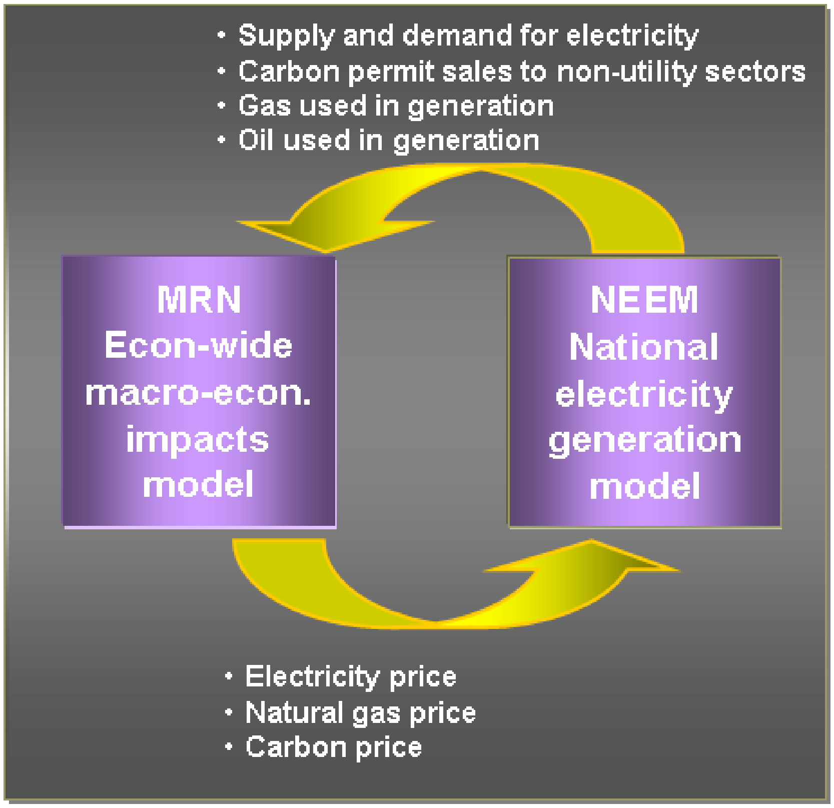
NEEM fills the need for a flexible, bottom-up partial equilibrium model of the North American electricity market that can simultaneously model both system expansion and environmental compliance over a 50-year time frame.

The model employs detailed unit-level information on all of the generating units in the United States and large portions of Canada. In general, coal units over 200 MW are represented individually in the model, and other unit types are aggregated. NEEM models the evolution of the North American power system, taking account of demand growth, available generation, environmental technologies, and environmental regulations both present and future. The North American interconnected power system is modeled as a set of regions that are connected by a network of transmission paths.

6.3. LINKING MRN AND NEEM

The MRN-NEEM integration methodology links the top-down and bottom-up models. The linking method utilizes an iterative process where the MRN and NEEM models are solved in succession, reconciling the equilibrium prices and quantities between the two. The solution procedure, in general, involves an iterative solution of the top-down general equilibrium model given the net supplies from the bottom-up energy sector sub-model followed by the solution of the energy sector model based on a locally calibrated set of linear demand functions for the energy sector outputs. The two models are solved independently using different solution techniques but linked through iterative solution points (see Figure 6-2).

Figure 6-2: MRN-NEEM iterative process[49]



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[49] A more complete documentation of the MRN-NEEM model is available on CRA's website. http://www.crai.com/uploadedFiles/RELATING_MATERIALS/Publications/BC/Energy_and_Environment/files/MRN-NEEM%20Integrated%20Model%20for%20Analysis%20of%20US%20Greenhouse%20Gas%20Policies.pdf.