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TRANSPORTATION ENERGY FORECASTS AND ANALYSES FOR THE 2011 INTEGRATED ENERGY POLICY REPORT

CALIFORNIA
ENERGY COMMISSION
Edmund G. Brown, Jr., Governor

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Table of Contents

List of Figures

List of Tables

ABSTRACT

For the *2011 Integrated Energy Policy Report*, California Energy Commission staff has prepared a subordinate draft report that provides long-term forecasts of state transportation energy demand and price as well as analyses of supply and projected ranges of transportation fuel and crude oil import requirements. These forecasts support analysis of petroleum reduction and efficiency measures, introduction and commercialization of alternative fuels, transportation fuel infrastructure requirements, and energy diversity and security. The projections and analysis indicate a potential need for targeted expansion of import infrastructure, particularly marine import facilities, to offset declining in-state oil production, growing demand in California, Nevada, and Arizona for transportation fuels, and requirements for potential new sources of renewable fuels. The magnitude of future contributions from efficiency improvements and various emerging transportation fuels and technologies is highly uncertain. Staff found that efficiency and emerging fuels and technologies can potentially displace significant amounts of petroleum, which will reduce the need for petroleum-specific infrastructure enhancements. However, many of these alternative fuels, in particular renewable fuels, may require their own additional segregated import facilities, including pipelines and storage tanks. Moreover, transportation-related industries must develop the means of distributing these emerging fuels (including electricity, hydrogen, and natural gas) through public retail refueling and recharging sites and home refueling and recharging systems and aligning the installation of these sites and technologies with the rollout of appropriate numbers of vehicles.

KEYWORDS

California demand forecasts, transportation energy, gasoline, diesel, jet fuel, crude oil production, renewable fuels, alternative fuels, fuel imports, crude oil imports, marine import infrastructure, refining capacity, consumer preference, pipeline exports, retail refueling infrastructure, fuel prices, light-duty vehicles, medium- and heavy-duty vehicles

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EXECUTIVE SUMMARY

Background

Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002), requires the California Energy Commission to conduct "assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices to develop policies for its *Integrated Energy Policy Report."* The Energy Commission develops long-term projections of California transportation energy demand that supports its analysis of petroleum reduction and efficiency measures, introduction and commercialization of alternative fuels, transportation fuel infrastructure requirements, and energy diversity and security.

This report summarizes the transportation energy demand forecasts, quantifies the petroleum and petroleum product-equivalent supply needs to meet the forecasted transportation energy demand, and identifies emerging constraints on transportation fuels infrastructure required to meet California's future transportation fuel demand. California's petroleum infrastructure is composed of the import and export system for petroleum, petroleum products, and renewable blendstocks; in-state refineries and biofuel production facilities; and the distribution and storage network, made up of pipelines, trucks, rail, and storage tanks, that move petroleum, petroleum products, and renewable blendstocks to and from in-state refineries and to the refueling infrastructure. Increasingly, this transportation energy system will accommodate emerging renewable and alternative fuels that have their own sources of supply, as well as separate import, distribution, and retail refueling and recharging infrastructure.

While the Energy Commission expects consumption of transportation energy in California to increase in the future under a variety of fuel price and regulatory conditions, there are substantial uncertainties associated with the future contributions of various renewable and alternative transportation fuels and technologies. These emerging fuels are expected to displace substantial amounts of petroleum, which would reduce the need for petroleum-specific infrastructure enhancements. However, each of these alternative fuels has its own set of marketing, supply, infrastructure, and regulatory challenges affecting market penetration. Moreover, transportation-related energy industries must develop the means of distributing these emerging fuels through public retail refueling and recharging sites and home refueling and recharging systems and aligning the installation of these systems with the rollout of appropriate numbers of vehicles.

Selected Findings

Historic Transportation Fuel Trends

- California gasoline consumption was relatively constant, changing by only about 0.2 percent - from 40.6 million gallons a day in 2009 to 40.7 million gallons a day in 2010. U.S. gasoline consumption rose from 377.9 million gallons per day in 2009 to 379.4 million gallons a day in 2010. California's percentage of total U.S. gasoline consumption was 10.7 percent in 2010.

- California per capita gasoline consumption fell from 1.36 gallons per day in 1990 to 1.04 in 2010, a 23.5 percent decrease. From 2000 to 2010 this decrease is accompanied by a decline in per capita vehicle miles traveled while prior to 2000 declines seem to be a result of increased vehicle efficiency.

- From 2004 to 2009 California consumers purchased fewer large vehicles (sport utilities and trucks) and a larger percentage of smaller vehicles (compacts, midsize, full-size, etc.). Small vehicle purchases grew from 19.6 to 30 percent, trucks dropped from 13.3 to 8.5 percent, and sports utilities dropped from 9.1 to 4.8 percent of all new vehicles sold in California. These changes were at least in part due to increased fuel prices over that time period, which rose from $1.92 per gallon (in nominal dollars) for gasoline in the second quarter of 2004 to $4.12 in the third quarter of 2008.

- From 2001 to 2009, registered hybrid vehicles grew from 0.03 percent of the California light duty vehicle fleet to 1.5 percent, diesel vehicles increased from 1.4 to 1.7 percent, and flex fuel vehicles increased from 0.42 to 1.54 percent.

- Diesel consumption appears to be related to California real per capita Gross State Product with per capita Gross State Product increasing 1.8 percent and diesel sales increasing by 2.7 percent from 2004 to 2007. Declines for Gross State Product in 2008 of 1.2 percent and in 2009 of 4.8 percent accompany declines in diesel consumption of 8.3 and 8.8 percent, respectively, for those years. Diesel sales rose from 2.6 billion gallons in 2009 to 2.6 billion gallons in 2010 as Gross State Product rose 0.6 percent.

- California jet fuel consumption rose from 188,000 barrels per day in 2009 to 203,000 barrels per day in 2010, largely a result of a 2.9 percent increase in passenger totals.

- After ethanol, natural gas is the most consumed alternative fuel for transportation use in California, with electricity consumption ranked third.

- The number of natural gas powered buses in California rose from just under 1,400 in 2000 to over 11,000 in 2009. In 2009, roughly 10 percent of all buses were powered by natural gas.

California Transportation Fuel Demand Forecasts

- Staff's preliminary (unadjusted for the revised federal Renewable Fuel Standards) forecast of total California annual gasoline consumption is estimated to fall 4.8 percent compared to 2009 in the Low Petroleum Demand Scenario to 14.1 billion gallons by 2030, largely as a result of high fuel prices, efficiency gains, and competing fuel technologies. In the preliminary forecast of annual gasoline consumption in the High Petroleum Demand Scenario, the recovering economy and lower relative fuel prices lead to gasoline demand growing to 16.9 billion gallons in 2030, 14.3 percent above 2009 levels.

- After evaluating the impact of the federal revised Renewable Fuel Standards, and taking into consideration California's proportional share of federal gasoline volumes, staff estimates the final forecast of gasoline consumption in the Low Petroleum Demand Scenario will decline from 2009 by 21.0 percent to 11.7 billion gallons by 2030. This is substantially lower than the preliminary estimate prior to the revised Renewable Fuel Standards compliance and is primarily caused by the increased consumption of E85, a blend of 85 percent ethanol and 15 percent gasoline, as the primary means of Renewable Fuel Standard compliance. The final revised Renewable Fuel Standards proportional-share adjusted annual gasoline consumption in the High Petroleum Demand Scenario grew by only 3.6 percent by 2030 to 15.3 billion gallons.

- In the preliminary forecast for E85, total annual consumption in the Low Petroleum Demand Scenario increases from 13.2 million gallons in 2009 to 48.8 million gallons in 2030. In the preliminary forecast for the High Petroleum Demand Scenario, annual E85 consumption increases to 64.3 million gallons by 2030.

- The final forecast of California's annual E85 consumption, taking into account the revised Renewable Fuel Standards proportional California share of renewable fuel volumes, increases in the Low Petroleum Demand Scenario to 3.2 billion gallons by 2030, a dramatic increase over the preliminary consumption estimate. In the High Petroleum Demand Scenario, the annual consumption of E85 increases to 2.2 billion gallons by 2030. In both scenarios, increased E85 consumption is contingent upon availability of adequate vehicles and infrastructure.

- In the preliminary forecast of California diesel fuel, total annual consumption increases 26.6 percent by 2030 from 2009 levels in the Low Petroleum Demand Scenario to 4.1 billion gallons, largely because of continued economic growth through 2030. In the High Petroleum Demand Scenario, which assumes a higher rate of economic growth, total annual diesel consumption increases 56.8 percent from 2009 levels to 5 billion gallons.

- The final revised Renewable Fuel Standards proportional-share adjusted total diesel consumption forecast increases 24.9 percent from 2009 levels in the Low Petroleum Demand Scenario to 4 billion gallons by 2030. In the High Petroleum Demand Scenario, total annual diesel consumption increases 53.8 percent from 2009 levels to 4.9 billion gallons. As with the final gasoline consumption values, the reductions in diesel demand are the result of increased biofuel consumption to comply with the federal Renewable Fuel Standards regulations, in this case, biomass-based diesel fuels.

- Between 2009 and 2030, staff expects that jet fuel demand in California will increase by 29.8 percent to 3.8 billion gallons in the Low Petroleum Demand Scenario, and 67.3 percent to 4.8 billion gallons in the High Petroleum Demand Scenario.

- Between 2009 and 2030, staff expects that annual transportation electricity will increase from 120 gigawatt hours to 1,070 gigawatt hours in the Low Petroleum Demand Scenario. In the High Petroleum Demand Scenario the annual transportation electricity consumption is forecast to increase to 1,060 gigawatt hours. The increase in both scenarios is the result of substantial market penetration of plug-in hybrid electric vehicles, and to a lesser extent, battery electric vehicles.

- Between 2009 and 2030, staff expects annual transportation consumption of natural gas to increase 86.7 percent to 243 million gasoline gallon equivalents in the Low Petroleum Demand Scenario. In the High Petroleum Demand Scenario the annual transportation consumption of natural gas increases 96 percent to 256 million gasoline gallon equivalents by 2030. In the Low Petroleum Demand Scenario transportation natural gas consumption growth reflects travel mode responses to high petroleum fuel prices in the near term and competition of alternatives in the latter years of the forecast.

- Based on recent survey of automakers' strategy for complying with the Zero Emission Vehicle mandate, there could be rapid increase in the number of fuel cell vehicles in California. Between 2012 and 2017, an anticipated 53,000 fuel cell vehicles are expected in California.

Policies and Regulations

Renewable Fuel Standards 2

- The revised federal Renewable Fuel Standards will require more renewable fuels, primarily ethanol, and to a lesser extent biodiesel. Under the Low Petroleum Demand Scenario for gasoline, the final forecast of total ethanol demand in California rises from 1.5 billion gallons in 2010 to 2.7 billion gallons by 2020. Under the High Petroleum Demand Scenario for gasoline, the final forecast of total ethanol demand in California rises about the same -- from 1.494 billion gallons in 2010 to 2.7 billion gallons by 2020.
- Staff estimates that ethanol demand in California due to RFS 2 requirements will exceed an average of 10 percent by volume in all gasoline sales between 2012 and 2013, depending on the gasoline demand growth rates. However, it is unlikely that the low-level ethanol blend limit in California will be greater than the current 10 percent by

volume (E10) before 2015 or later, even if the U.S. Environmental Protection Agency ultimately grants permission for United States refiners and marketers to go to a gasoline blend of 85 percent gasoline and 15 percent ethanol (E15).

- Availability of E85 will need to increase dramatically to ensure that sufficient volumes of E85 can be sold to keep pace with the revised Renewable Fuel Standards requirements. Assuming California reformulated gasoline continues to be limited to 10 percent ethanol and ethanol is the predominant renewable fuel used to comply with the revised Renewable Fuel Standards, E85 sales in California are forecast to rise from 13 million gallons in 2010 to 1.7 billion gallons in 2020 and 3. 2 billion gallons by 2030. However, the pace of this expansion may be hindered due to a variety of infrastructure challenges and disincentives.
- Depending on the amount of fuel sold for a typical E85 dispenser, California would require between about 4,800 and 36,000 E85 dispensers by 2022. To put that figure in perspective, there were approximately 42,050 total retail fuel dispensers in the entire state during 2008. Between 2009 and 2030 the E85 dispenser infrastructure costs could range from $241.4 million to $7.2 billion.
- Over the near-term, the greatest challenge to expanded use of ethanol as E85 is an adequate and timely build-out of E85 retail fueling infrastructure. E85 retail infrastructure is expensive. Costs for installing a new underground storage tank, dispenser, and appurtenances range between $50,000 and $200,000. This level of investment is between 1.5 and 6 times greater than the total annual profit of a typical retail station (for both fuel and non-fuel commodities). The Renewable Fuel Standards regulations do not have any requirements that retail station owners and operators make available E85 for sale to the public. Refiners, importers, and blenders have an obligation to collectively market mandated volumes of renewable fuels, but retail station operators do not have an obligation to assist in marketing large amounts of E85. Financial assistance from industry or government agencies may be required to install the number of E85 dispensers needed to supply adequate volumes of E85. It is estimated that, at a minimum, an average of 530 E85 dispensers per year would need to be installed in California between 2014 and 2022, costing between $27 million and $106 million per year.
- California's number of registered flex fuel vehicles would need to increase from over 450,000 vehicles in 2010 to at least 2 million flex fuel vehicles by 2020 and 5 million by 2030 to enable an adequate market for the projected volumes of E85 needed to meet the federal Renewable Fuel Standards.
- It is unlikely that there will be sufficient cellulosic ethanol capacity in place to fully meet the revised federal Renewable Fuel Standards obligations on the schedule adopted in legislation. The U.S. Environmental Protection Agency is required to set the cellulosic biofuel standard each year based on the volume projected to be available during the following year, and it has reduced the required amount for 2011 and is in the process of revising the 2012 volumes.

- Under the Low Petroleum Demand Scenario, the final forecast of biomass-based diesel proportional-share ("proportional-share" refers to California's proportional share of renewable fuel consumption under the RFS2) ranges from 14.5 million gallons annually in 2010 to 56 million gallons by 2030. Under the High Petroleum Demand Scenario – the final forecast of biodiesel proportional share ranges from 14.5 million gallons in 2010 to 96.7 million gallons by 2030.

Low Carbon Fuel Standards and High Carbon Intensity Crude Oil

- California refiners desire to process a mix of crude oil that is economically optimal based on their individual refinery configuration, the desired ratio of gasoline and diesel fuel that the marketing department is targeting, and minimizing their acquisition costs for crude oil supplies.
- Some crude oils require more energy to produce, whether through thermally enhanced recovery methods, excessive flaring, bitumen mining, or preprocessing. Since the LCFS takes into consideration the full lifecycle of fuels, it identifies these crudes as High Intensity Crude Oils (HCICOs) and recognizes that their use in California refineries generates incremental GHG deficits when compared to standard crudes. Refiners can use HCICOs, but they would need to offset the incremental carbon debt. Therefore, the HCICO provision in the LCFS will discourage significant use of HCICOs in California's refineries.
- The HCICO provision has the potential to affect the crude oil selection decisions of California refiners. However, the HCICO provision is not expected to restrict access to crude oil supplies in a way that could significantly impact fuel supply, but it could impact refiner profitability and the ultimate cost of petroleum fuel in California.
- Energy Commission staff initial screening of 248 Marketable Crude Oil Names found that 74 percent by volume of the crude oils were non-HCICOs. A crude oil was labeled a "potential" High Carbon Intensity Crude Oil if it was: from a country that had an average flaring intensity greater than the threshold set by the California Air Resources Board; or was from a source field (either partially or wholly) that was using thermally enhanced oil recovery; or was from a bitumen mine; or was from an upgrading facility in Canada or Venezuela.
- Approximately 16.5 percent of the foreign crude oil receipts by California refineries during 2010 might potentially be classified as High Carbon Intensity Crude Oils, accounting for 8.0 percent of total crude oil use during the year. Replacing a portion of the existing crude supplies and instead using other sources of crude oil could lead to increased crude acquisition costs.
- Achieving these emission reductions will be a challenge for two reasons: oil producers outside of California have alternative markets to sell their crude oil; and the California crude oil market is too small (between 1.2 and 2.1 percent of world market) to justify an investment to reduce the carbon intensity of crude oil production operations.

Low Carbon Fuel Standard and Ethanol Fuel Types

- The Low Carbon Fuel Standard is intended to decrease California's reliance on petroleum based transportation fuel and concurrently impact the mix of ethanol and other types of renewable and alternative transportation fuels that will be used in California. Traditional relatively high carbon intensity biofuels such as average corn-based ethanol and biodiesel will still have a role, but will eventually lose market share to other fuels with lower carbon intensity including a wide variety of renewable hydrocarbons, natural gas, electricity and hydrogen. Introduction of a large amount and variety of these new alternative fuels which have low lifecycle carbon emissions is essential if obligated parties are to maintain compliance with the LCFS regulation through 2020.
- There are many potential compliance pathways for the LCFS. In order to assess the range of implications for these pathways in its proposed analysis, Energy Commission staff has been working with ARB staff to identify reasonable assumptions about use of credits for electric vehicle charging, biofuel concentrations allowed in gasoline and diesel, and California ethanol and biodiesel production capacity, applying to all cases of LCFS compliance. The analysis will also include assumptions for quantities of ethanol and biodiesel used relative to RFS2 compliance, availability and use of cellulosic and advanced biofuels, availability and use of specific feedstocks having superior carbon intensity values, and building of excess credits, among other factors.
- Potential LCFS compliance costs could fall into three categories: use of more expensive renewable fuels than would otherwise be used under RFS2; an additional price premium for lower carbon intensity fuels (the lower the CI, the higher the premium); and market-clearing prices of LCFS credits sold to obligated parties. Over the long-term these increased costs could be passed through to consumers and businesses.
- Twenty-two other states are developing or considering LCFS rules, either singly or in regional groups, with cumulative totals of gasoline and diesel use in 2009 of 55.4 billion gallons and 23.2 billion gallons, respectively, totals that are substantially more than California consumption. If such rules are adopted in a significant number of these states, competition and prices for desirable fuels and feedstocks will increase, as would the environmental benefits of more widespread use of low-carbon fuels.

Ethanol Blenders Excise Tax Credit and Import Tariff

- Continuation of the Volumetric Ethanol Excise Tax Credit policy may no longer be necessary to encourage ethanol use in the United States since the RFS2 mandates have relegated discretionary use to the E85 market. According to the U.S. Government Accountability Office, Elimination of the Volumetric Ethanol Excise Tax Credit could increase gasoline excise tax revenue to the federal government by nearly $6 billion per year, absent any other changes in excise fuel tax rates.
- Minimizing importation fees for types of lower carbon renewable fuels that would assist in achieving compliance with the state's Low Carbon Fuel Standard could help to lower

the incremental costs of the regulation. Further, elimination of the tariff could also reduce the cost for obligated parties throughout the rest of the United States to comply with the Advanced Biofuels portion of the revised Renewable Fuels Standards.

Fuel Economy Standards

- Corporate Average Fuel Economy Standards for on-road 2010 cars and light-duty trucks exceeded Corporate Average Fuel Economy requirements, achieving 33.4 miles per gallon for cars and 24.8 miles per gallon for light trucks.
- The National Highway Transportation Safety Administration set fuel economy standards for model years 2012-2016 cars and light trucks, which will increase to 35.5 miles per gallon by the 2016 model year. Fuel economy rules for model year 2017-2025 cars and light trucks are being finalized currently, and are expected to be set to reach 54.5 miles per gallon by the 2025 model year
- The 2014-2018 model years face the first fuel efficiency standards for medium- and heavy-duty vehicles. The standards have the potential to save approximately 500 million barrels of oil over the life of vehicles sold during the 2014 to 2018 period and result in cost savings of $34.6 billion. Compared to 2010 baselines, fuel consumption will have to be reduced by 7 to 15 percent, with the exception of big rigs with sleeper cabs, which are required to obtain a 20 percent reduction.
- By 2017 tractor-trailers (big rigs) will have to reduce fuel consumption by 7 to 20 percent, compared to 2010 baselines.
- The establishment of Corporate Average Fuel Economy standards for heavy-duty pickup trucks and vans will require an average improvement in fuel consumption of 10-15 percent per vehicle by 2017, compared to 2010 baselines.

Ozone Standards

- The U.S. Environmental Protection Agency is in the process of reconsidering its current 8-hour Ozone standard from 0.075 to a value between a range of 0.060 parts per million and 0.070 parts per million. Uncertainty regarding specific values has in turn generated uncertainty regarding the potential impact of these standards for California and the neighboring states.
- The primary impact of more stringent ozone standards for California transportation fuel supplies over the early and middle portions of the forecast period could potentially be limited to reduced demand for gasoline. This occurs through improved fuel economy of the existing fleet and the displacement of petroleum with increased use of renewable fuels and vehicles that do not require gasoline (especially electric and hydrogen vehicles).
- A switch to year round and statewide application of Cleaner Burning Gasoline, in Arizona, could increase exports from California refineries by up to 600 million gallons per year or 39 thousand barrels per day.

Canada's Renewable Fuel Standard

- During the next couple of years, incremental ethanol demand to meet Canadian Renewable Fuel Standards compliance will be sourced from corn-based ethanol plants in the United States. Since the Canadian Renewable Fuel Standards regulations do not mandate specific types of ethanol, this standard will not create competing demand for other types of lower carbon-intensity ethanol that will be needed to meet California's Low Carbon Fuel Standards requirements.

Renewable and Alternative Fuels

Ethanol

- Ethanol use in California gasoline increased from an average concentration of between 6 and 7 percent by volume in 2009 to 10 percent in 2010, primarily due to federal regulations mandating greater use of renewable fuels and transition to a revised state reformulated gasoline regulation. For forecasting purposes we have assumed 10 percent blending for 2010 but recognize that some refiners and other marketers have the flexibility to use lower concentrations in their proprietary systems.
- Federal mandates, such as the revised Renewable Fuel Standards, in conjunction with the state's Low Carbon Fuel Standard are expected to compel increased quantities of ethanol and biodiesel use in California over the next several years, including a longer-term move to renewable hydrocarbons that will begin to displace a portion of the gasoline and diesel fuel used for transportation.
- Ethanol demand set a record in June 2010 of 88 thousand barrels per day. The demand for ethanol is expected to continue growing over the forecast period due to mandated blending quantities stipulated by the federal revised Renewable Fuel Standards.
- The United States is not expected to remain a large net exporter of ethanol over the next several years. Foreign sources of ethanol (from Brazil and Caribbean Basin Initiative countries) are expected to play a more pivotal role as demand for ethanol with lower carbon intensity grows in response to the California Low Carbon Fuel Standard and the Renewable Fuel Standards Advanced Biofuels requirements.
- Despite the recent poor economics for operating domestic ethanol plants, production capacity of conventional ethanol is expected to be adequate over the next several years. Domestic ethanol production capacity is already sufficient to meet the starch based biofuel revised Renewable Fuel Standards requirement of 12.6 billion gallons for 2011, 13.2 billion gallons for 2012, 13.8 billion gallons for 2013, and even the 14.4 billion gallons for 2014.
- Currently, three of the five California corn-based ethanol facilities are operating with a collective production capacity of nearly 170 million gallons per year. Two of the California facilities remain idle with a combined capacity of 71 million gallons per year. The remaining two idle ethanol plants are temporarily closed due to poor economic operating conditions (costs are exceeding revenue streams).

- Production of ethanol in Brazil is determined by the interrelationship between various factors: minimum blending levels in gasoline as set by its Ministry of Agriculture; world sugar market demand, balances, and prices; outcome of sugarcane growing season; and the potential value of ethanol exports. Based on the interaction of these market components, supplies of ethanol available to export from Brazil can vary significantly on a year-to-year basis. Over the last five years (2006 through 2010), Brazil has exported between 0.55 billion and 1.35 billion gallons of ethanol.
- Even if Brazilian ethanol supplies were sufficient to allow significant volumes of exports. Brazilian exporters of ethanol to the United States must pay two types of import duties, an ad valorem tax equivalent to 2.5 percent of the ethanol transaction price and a secondary import duty of 54 cents per gallon, which could result in higher ethanol prices in California. There is bipartisan discussion in Congress to repeal the tax and tariff, as well as the tax subsidies for domestic corn ethanol production.
- Staff anticipates that California's logistical infrastructure for the importation and distribution of ethanol will need to continue to be modified to enable a greater quantity and flexibility of ethanol imports within the next 6 to 18 months. Currently, most of the ethanol used in California is imported from corn-based ethanol plants in the Midwest. The majority of these imports are via unit trains that consist of between 90 and 112 rail cars.
- Kinder Morgan began accepting only base gasoline that will be used to blend E10 at all of their California distribution terminals on January 11, 2010. The majority of gasoline distributed throughout California moves through some portion of the Kinder Morgan pipeline systems and refiners want to ensure that the type of gasoline they produce is compatible (to allow for volume exchanges and increased flexibility during unplanned refinery outages).
- The majority of fuel ethanol in the United States is produced in facilities that use corn as the primary feedstock. As the demand for mandated use of ethanol continues to grow, so too does the demand for corn as a feedstock. Corn use to produce ethanol is forecast to set a record of 5.075 billion bushels for 2011.

Biodiesel

- Under the Low Petroleum Demand Scenario, the final forecast of biomass-based diesel proportional-share ("proportional-share" refers to California's share of renewable fuel consumption under the revised Renewable Fuel Standards) ranges from 14.5 million gallons in 2010 to 56 million gallons by 2030. Under the High Petroleum Demand Scenario – the final forecast of biodiesel proportional-share ranges from 14.5 million gallons in 2010 to 96.7 million gallons by 2030.
- If biodiesel use incentivized by California's Low Carbon Fuel Standard reached 10 percent by volume, biodiesel demand could reach 427 million gallons by 2020 and 502 million gallons by 2030. Further, B20 levels would infer biodiesel demand levels in California of 765 million gallons by 2020.
- As is the case with ethanol, increasing levels of biodiesel blended with conventional diesel fuel do pose some challenges that would need to be addressed to ensure biodiesel could be used at concentrations of up to 20 percent by volume. Currently, the biodiesel infrastructure is inadequate to accommodate widespread blending of biodiesel even at concentrations as low as B5. However, with sufficient lead-time (12 to 24 months), distribution terminal modifications could be undertaken and completed to enable an expansion of biodiesel use.
- The revised Renewable Fuel Standards regulations call for a minimum use of 1.0 billion gallons per year of biomass-based diesel fuel in 2012, increasing to 1.28 billion gallons in 2013. As of July 2011, there was more than 2.4 billion gallons of biodiesel production capacity for all United States' operating facilities. It appears as though there may be sufficient domestic sources of biodiesel production facilities to meet the revised Renewable Fuel Standards requirements for several years.
- According to the National Biodiesel Board there are 16 biodiesel production facilities in California with an annual production capacity of 84.5 million gallons. These production capacity volumes are sufficient to supply California's total revised Renewable Fuel Standards proportional-share of biodiesel. However, the increased demand for biodiesel incentivized by the Low Carbon Fuel Standards scenarios could necessitate substantial imports from either domestic or foreign sources.
- To help ensure adequacy of biodiesel distribution capability for meeting increased demand levels associated with the revised Renewable Fuel Standards and the state's Low Carbon Fuel Standard, construction of biodiesel storage tanks at a minimum of 50 percent of California's distribution terminals over the next couple of years would likely be necessary. Costs for such an undertaking could amount to between $25 million and $50 million.
- Assuming sufficient spare production capacity throughout the United States to meet the potential increase in California biodiesel demand, it is likely that most of the incremental biodiesel will originate from facilities located outside the state. This means that imports of biodiesel may be necessary via rail and/or marine vessel. Currently, there are no biodiesel rail facilities designed to handle unit trains. Ultimately, biodiesel unit train

receipt capability may not be necessary due to demand levels that may be too low to justify the expense. It is more probable that rail receipts of biodiesel will be transferred to tanker trucks via transloading, as is the case with the Kinder Morgan ethanol transloading project in Northern California.

- Assuming biodiesel fuel blends in California do not exceed the B20 level over the foreseeable future, retail station modifications should be negligible to accommodate such increased concentrations. However, for those retail locations that want to dispense B99 or B100, storage of biodiesel at these concentrations in an underground storage tank may not be permissible at this time per the California State Water Resources Control Board.
- Not all original equipment manufacturers allow biodiesel bends in excess of B5. This limitation is also imposed by some companies that provide extended motor vehicle warranties. Until this warranty issue is covered, retail station operators may be reluctant to offer B20 for sale at all of their dispensers. Therefore, a dedicated underground storage tank and retail dispenser may have to be installed for B20 blends. This could result in significantly higher retail infrastructure costs to achieve widespread biodiesel penetration in California above B5 levels.

Potential Emerging Fuels

- Of the emerging renewable transportation fuels, only biomethane and renewable diesel are or are likely to be produced in commercial quantities or sufficient volumes to comply with Low Carbon Fuel Standard. California output of renewable fuels is small compared to both worldwide renewable fuel production and California conventional fuel production.
- Biomethane is a gaseous fuel that is a perfect substitute for either compressed or liquefied natural gas, both of which are used as diesel substitutes. Biomethane is relatively well-established as a renewable fuel. There have not been any known commercial transactions within California: all biomethane currently used as transportation fuel is consumed by the producer. The nature of biomethane production and infrastructure may limit the development of a robust market for biomethane as a transportation fuel.
- Due to absence of an existing biomethane market, there is almost no information available on cost projections, although its commercial potential is heavily dependent upon the price of natural gas, for which it is a perfect substitute.
- There are two upcoming regulations that could influence a commercial scale production of hydrogen fuel in California. The first regulation is the Clean Fuels Outlet which requires regulated parties to provide outlets of hydrogen to meet the needs of fuel cell vehicles. The second regulation is SB1505, also called Environment and Energy Standards for Hydrogen, which will require the hydrogen produced for motor vehicle use meet greenhouse gas, criteria pollutant, toxic emission and renewable requirements.
- SB1505 will require the hydrogen produced in California to contain 33 percent renewable resources. This will likely increase demand for emerging renewable

transportation fuels such as biomethane, which is expected to serve as replacements for compressed natural gas or liquefied natural gas. Staff anticipates that SB1505 will likely increase the demand for biomethane to approximately 300 million standard cubic feet in compressed form or about 4 million gallons in liquid form by 2017. With an additional increase in demand by 2030, it is expected that the demand for biomethane could increase to about 4 billion standard cubic feet or 45 million gallons.

- Hydrogen has the potential to be a common alternative fuel. Although it does not occur free in nature, it can be reformed from natural gas and any renewable biogas or landfill gas and can be derived through the electrolysis of water. It is produced in mass quantities and is trucked or piped for use in food processing and in petroleum refining processes. Used in fuel cell passenger vehicles and forklifts, it reduces well-to-wheel criteria pollutant and greenhouse gas emissions relative to all internal combustion engine cars on the road today.
- Butanol is notable because it can be used as an ethanol substitute and has properties that make it more desirable as transportation fuel: it has higher energy content, is less likely to evaporate, and attracts less water, as well as other advantages.
- Renewable diesel, renewable jet fuel, and renewable gasoline are appealing because they are renewable fuels identical to the petroleum-based products they would replace. Although none of these are currently produced in California in commercial volumes, today there are commercial plants with sufficient capacity to enable California to comply with the Low Carbon Fuel Standard.
- Algae-based processes can produce a variety of fuels, depending on the algae strain: biodiesel, renewable diesel, renewable gasoline, renewable jet fuel, and ethanol have at least been proposed for algae processes. Production of algae-based biofuels remains in the research and development stage.
- Algae can grow in water of all types, including wastewater and saline groundwater. Within California the Imperial Valley best meets growing conditions and has been the location of algae-based fuel facilities. Compared to other purpose-grown fuels, algae possess the potential to produce a significant amount of fuel from a relatively small area. Algae grown on 1 percent to 3 percent of the total United States cropping area would be enough to produce 50 percent of transportation fuel needs.

Alternative Vehicle Refueling Infrastructure

- Residential chargers for single and multi-family dwellings will be the primary method of charging for most plug-in electric vehicles. In 2011 the Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program committed funding for over 1,000 home rechargers, and 4,800 public charging stations.
- Fast Charging Electric Vehicle Stations are anticipated to be needed in large numbers to accommodate growing numbers of plug-in electric vehicles; however, it is not clear yet to what extent Level 1 and Level 2 public recharging stations will be necessary.

- One of the primary challenges to the penetration of light-duty natural gas vehicles is the lack of available refueling infrastructure. New compressed natural gas home refuelers are now being sold for home use.
- The aging compressed natural gas stations and equipment in California do not meet today's fleet refueling needs and some are approaching their useful life. Upgrading and replacing existing older equipment, especially high- pressure storage tanks and lines will be a growing need to ensure adequate, reliable, and safe compressed natural gas fuel.
- As of August 2011 there were less than 10 hydrogen stations in California with a total dispensing capacity of 315,000 kilograms per year. A kilogram has the same energy as a gallon of gasoline. In 2011 more than 11 hydrogen stations were co-funded by the Energy Commission, with 740,000 kg per year of new hydrogen retail capacity.
- New hydrogen station designs are resulting in significantly reduced station costs, yet these costs are still many times greater than traditional gasoline or diesel dispensing stations.

Crude Oil Supply

- California refineries processed 607 million barrels (1.7 million barrels per day) of crude oil in 2010. The largest percentage of this crude oil was obtained from foreign sources (47.7 percent), followed by California sources (38.1 percent), with the balance from Alaska (14.2 percent).
- California's annual crude oil production was approximately 224 million barrels during 2010, averaging approximately 613,000 barrels per day. The decline of California crude oil production has continued since 1985, when crude oil production peaked at 424 million barrels per year. Since 1985, California crude oil production has declined by 47.2 percent; Alaska, by 67.2 percent; and the rest of the United States, by 28.2 percent. California crude oil production is forecast to continue declining at a rate of between 2.2 and 3.1 percent per year.
- Due to the projected reduction in demand for the petroleum fraction of gasoline in California resulting from increased use of renewable fuels and improvement in light-duty vehicle fuel efficiency, it is unlikely that there will be any significant expansion of existing refining distillation capacity in California over the forecast period. However, it is possible that refining projects designed specifically to increase the yield of diesel fuel might be pursued.
- The High Case for crude oil imports yields an increase of 60 million barrels per year more in 2020 and 104 million barrels per year more by 2030. In this case, increased crude oil imports are solely the result of continued steady decline of California's crude oil production since refining distillation capacity remains fixed over the forecast period.
- The Low Case for crude oil imports yields an increase of 14 million barrels per year more in 2020 and 22 million barrels per year more by 2030. In this case, increased crude oil imports are dramatically lower when compared to the High Case, primarily because

of the assumed reduction in refining capacity of approximately 170 thousand barrels per day by the end of the forecast period.

- The possibility that some of California's refining capacity could be reduced over time as part of refinery asset consolidation was considered a very low probability during previous *Integrated Energy Policy Report* cycles. However, the possibility of a refinery closing in California is now assumed to be a higher probability based on: recent announcements made by several oil companies; an assumption that California refinery operating costs are higher than other regions of the United States.
- Staff calculated 5 to 47 additional crude oil tanker arrivals per year by 2015, 8 to 86 by 2020, and 12 to 149 additional arrivals per year by 2030.
- The incremental crude oil storage capacity needed in California would amount to between 0.4 million and 2.7 million barrels by 2015; between 0.6 million and 5.0 million barrels by 2020; and between 1.0 million and 8.6 million barrels of storage capacity by 2030.
- The High Case for imports necessitates the need for expanded capability to receive greater volumes of crude oil imports within the next four to five years so that refiners would be able to operate their facilities at high enough utilization rates to produce sufficient supplies of transportation fuels to meet the needs of California consumers and businesses.
- Currently, there are two petroleum import infrastructure projects in Southern California that are at various stages of development. The first site is Berth 408 at Pier 400 in the Port of Los Angeles. The second project is referred to as Pier Echo located at Berth T126 in the Port of Long Beach. Based on Energy Commission analysis, the Southern California market may only require one of these import facilities to be constructed over the forecast period, not both.
- The moratoria areas off the coast of California were estimated by Minerals Management Services to contain between 5.8 billion and 15.8 billion barrels of undiscovered technically recoverable resources crude oil. Over half of this estimated crude oil resource is located in federal waters off the coast of Southern California.
- If the lifting of the Outer Continental Shelf moratoria remains in effect and development proceeds as forecast by U.S. Department of Energy off the coast of California, this activity could significantly impact the crude oil import forecast, such that waterborne imports of crude oil would actually be less than they were in 2010, regardless of scenario.
- Two projects that have been recently proposed off the coast of California could result in additional quantities of crude oil being produced from existing offshore platforms. The potential production was estimated at 8,000 to 27,000 barrels per day of additional crude oil that could have been produced from the Tranquillon Ridge Project, but seems to be on hold after loss of California political support last year. Crude oil production could from the other project (Platform Hogan) could begin as early as 2013 and yield a maximum of 3,500 barrels per day or roughly 1.3 million barrels per year by 2020. This

volume of additional production has the potential to reduce the crude oil forecast by 9.3 percent in 2020 under the Low Case and by 2.2 percent under the High Case.

CHAPTER 1: Introduction to Transportation Energy Forecasts

Transportation Energy Analyses

As required by SB 1389 (Bowen, Chapter 568, Statutes of 2002), the California Energy Commission conducts "assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices." The Energy Commission reports these assessments and forecasts in its *Integrated Energy Policy Report* (*IEPR*), which it adopts every odd-numbered year (Public Resources Code [PRC] §25302[d]).

Transportation energy demand and fuel price forecasts support several state energy policy and program activities, including alternative vehicle and fuel technology analysis for the Alternative and Renewable Fuel and Vehicle Technology Program (Assembly Bill 118, Nuñez, Chapter 750, Statutes of 2007) (ARFVTP), petroleum use reduction and efficiency assessments, transportation energy infrastructure requirements assessments, and analysis of energy diversity and security. Since the *2009 IEPR*, the Low Carbon Fuel Standards (LCFS) has begun to be implemented by the California Air Resources Board (ARB), the federal Renewable Fuels Standards (RFS) have been revised, and the U.S. Environmental Protection Agency (U.S. EPA) has proposed new corporate average fuel economy (CAFE) standards for 2017-25. The LCFS sets carbon reduction standards that will affect the types of fuels that can be sold in California, particularly renewable fuels. The revised renewable fuel standards (RFS2) mandates the volumes and types of renewable fuels that must be used nationally, with states required to meet proportional-share volumes. The new fuel economy rules are being assessed to determine how they will be implemented in the state and how they can be integrated into fuel demand and technology forecasts.

While the Energy Commission expects consumption of transportation energy in California to increase in the future under a variety of fuel price and regulatory conditions, there are substantial uncertainties associated with the future contributions of various renewable and alternative transportation fuels and technologies. These emerging fuels are expected to substantially displace amounts of petroleum, which would reduce the need for petroleum-specific infrastructure enhancements. However, each of these alternative fuels has its own set of supply, infrastructure, and regulatory issues affecting market penetration. Moreover, transportation-related energy industries must develop the means of distributing these emerging fuels through public retail refueling and recharging sites and home refueling and recharging systems. The installation of these systems must be aligned with the rollout of appropriate numbers of vehicles.

This staff draft report provides preliminary transportation energy forecasts and analyses for the *2011 IEPR* with a focus on the implications of future transportation energy demand for California's existing transportation fuels marine and other import facilities, as well as the state's retail refueling infrastructure. Available time and resources dictate that staff focuses on those issues that appear to have the most pressing near-term consequences, namely the intersection of complex state and federal renewable fuel rules that prescribe percentages and volumes of renewable fuels consumed, particularly ethanol and biodiesel. Expectations for the penetration of other alternative fuels are also presented and analyzed. In areas where technical and data constraints have limited quantitative analysis, staff has attempted to provide qualitative assessments based on existing information.

Summary of Staff Findings

Historic Transportation Fuel Trends

- California gasoline consumption was relatively constant, changing by only about 0.2 percent - from 40.6 million gallons a day in 2009 to 40.7 million gallons a day in 2010. U.S. gasoline consumption rose from 377.9 million gallons per day in 2009 to 379.4 million gallons a day in 2010. California's percentage of total U.S. gasoline consumption was 10.7 percent in 2010.

- California per capita gasoline consumption fell from 1.36 gallons per day in 1990 to 1.04 in 2010, a 23.5 percent decrease. From 2000 to 2010 this decrease is accompanied by a decline in per capita vehicle miles traveled (VMT), while prior to 2000 declines seem to be a result of increased vehicle efficiency.

- California gasoline light duty vehicle fleet fuel economy increased from 19.94 to 20.56 miles per gallon from 2004 to 2009, a 3 percent increase.

- From 2004 to 2009 California consumers purchased fewer large vehicles (sport utilities and trucks) and a larger percentage of smaller vehicles (compacts, midsize, full-size, etc.). Small vehicle purchases grew from 19.6 to 30 percent, trucks dropped from 13.3 to 8.5 percent, and sports utilities dropped from 9.1 to 4.8 percent of all new vehicles sold in California. These changes were at least in part due to increased fuel prices over that time period, which rose from $1.92 per gallon (in nominal dollars) for gasoline in the second quarter of 2004 to $4.12 in the third quarter of 2008.

- From 2001 to 2009, registered hybrid vehicles grew from 0.03 percent of the California light duty vehicle fleet to 1.45 percent, diesel vehicles increased from 1.4 to 1.7 percent, and flex fuel vehicles (FFVs), which are vehicles that can use gasoline containing any concentration of ethanol up to 85 percent (E85), increased from 0.42 to 1.54 percent.

- Diesel consumption appears to be related to California real per capita Gross State Product (GSP) with per capita GSP increasing 1.8 percent and diesel sales increasing by

2.7 percent from 2004 to 2007. Declines for GSP in 2008 of 1.3 percent and in 2009 of 4.8 percent accompany declines in diesel consumption of 8.3 and 8.8 percent, respectively, for those years. Diesel sales rose from 2.58 billion gallons in 2009 to 2.6 billion gallons in 2010 as GSP rose 0.6 percent.

- In 2009, diesel powered vehicles represented 60 percent of all vehicles registered in California with a Gross Vehicle Weight Rating (GVWR) of 3 or higher. Diesel vehicles were also 77 percent of vehicles with GVWR 5 and higher, and 92 percent of GVWR 7 and higher.

- California jet fuel consumption rose from 188,000 barrels per day in 2009 to 203,000 barrels per day in 2010, largely a result of a 2.9 percent increase in passenger totals.

- In 2008, California experienced a 0.6 percent drop in per person income and an average rise in ticket price of 6.8 percent. This relative increase in the price of air travel corresponded with a decline in departures and jet fuel consumption in California.

- After ethanol, natural gas is the most consumed alternative fuel for transportation use in California, with electricity consumption ranked third. Historical consumption data for transportation electricity and natural gas are prone to large fluctuations; it is unclear whether these changes are caused by economic and policy conditions, or result from data collection issues.

- The number of natural gas powered buses in California rose from just under 1,400 in 2000 to over 11,000 in 2009. In 2009, roughly 10 percent of all buses were powered by natural gas.

- After comparing consumption figures of alternative fuels to vehicle counts information, alternative fuel consumption in California appears to be driven by state air quality policies and federal petroleum reduction standards. The South Coast Air Quality Management District (SCAQMD) policy on fleet vehicle purchases is one of the most significant. Over 70 percent of alternative fueled medium- and heavy-duty vehicles are government owned.

California Transportation Fuel Demand Forecasts

- Staff's preliminary (unadjusted for RFS2) forecast of total California annual gasoline consumption is estimated to fall 4.8 percent compared to 2009 in the Low Petroleum Demand Scenario to 14.1 billion gallons by 2030, largely as a result of high fuel prices, efficiency gains, and competing fuel technologies. In the preliminary forecast of annual gasoline consumption in the High Petroleum Demand Scenario, the recovering economy and lower relative fuel prices lead to gasoline demand growing to 16.9 billion gallons in 2030, 14.3 percent above 2009 levels.

- After evaluating the impact of the federal revised Renewable Fuel standards, and taking into consideration California's proportional share of federal gasoline volumes, staff estimates the final forecast of gasoline consumption in the Low Petroleum Demand Scenario will decline from 2009 by 21.0 percent to 11.7 billion gallons by 2030. This is substantially lower than the preliminary estimate prior to the revised Renewable Fuel Standards compliance and is primarily caused by the increased consumption of E85, a blend of 85 percent ethanol and 15 percent gasoline, as the primary means of Renewable Fuel Standard compliance. The final revised Renewable Fuel Standards proportional-share adjusted annual gasoline consumption in the High Petroleum Demand Scenario grew by only 3.6 percent by 2030 to 15.3 billion gallons.
- In the preliminary forecast of E85, the total annual consumption in the Low Petroleum Demand Scenario increases from 13.2 million gallons in 2009 to 48.8 million gallons in 2030. In the preliminary forecast for the High Petroleum Demand Scenario, annual E85 consumption increases to 64.3 million gallons by 2030.
- The final forecast of California's annual E85 consumption, taking into account the revised Renewable Fuel Standards proportional California share of renewable fuel volumes, increases in the Low Petroleum Demand Scenario to 3.2 billion gallons by 2030, a dramatic increase over the preliminary consumption estimate. In the High Petroleum Demand Scenario, the annual consumption of E85 increases to 2.2 billion gallons by 2030. In both scenarios, increased E85 consumption is contingent upon availability of adequate vehicles and infrastructure.
- In the preliminary forecast of California diesel fuel, total annual consumption increases 26.6 percent by 2030 from 2009 levels in the Low Petroleum Demand Scenario to 4.1 billion gallons, largely because of continued economic growth through 2030. In the High Petroleum Demand Scenario, which assumes a higher rate of economic growth, total annual diesel consumption increases 56.8 percent from 2009 levels to 5 billion gallons.
- The final RFS2 proportional-share adjusted total diesel consumption forecast increases 24.9 percent from 2009 levels in the Low Petroleum Demand Scenario to 4 billion gallons by 2030. In the High Petroleum Demand Scenario, total annual diesel consumption increases 53.8 percent from 2009 levels to 4.9 billion gallons. As with the final gasoline consumption values, the reductions in diesel are the result of increased biofuel consumption to comply with the federal RFS regulations, in this case, biomass-based diesel fuels.
- Between 2009 and 2030, staff expects that jet fuel demand in California will increase by 29.8 percent to 3.7 billion gallons in the Low Petroleum Demand Scenario, and 67.3 percent to 4.8 billion gallons in the High Petroleum Demand Scenario.
- Between 2009 and 2030, staff expects that annual transportation electricity will increase from 120 gigawatt hours to 1,070 gigawatt hours in the Low Petroleum Demand Scenario. In the High Petroleum Demand Scenario the annual transportation electricity consumption is forecast to increase to 1,060 gigawatt hours. The increase in both

scenarios is the result of substantial market penetration of plug-in hybrid electric vehicles, and to a lesser extent, battery electric vehicles.

- Between 2009 and 2030, staff expects annual transportation consumption of natural gas to increase 86.7 percent to 243 million gasoline gallon equivalents in the Low Petroleum Demand Scenario. In the High Petroleum Demand Scenario the annual transportation consumption of natural gas increases 96 percent to 256 million gasoline gallon equivalents by 2030. In the Low Petroleum Demand Scenario transportation natural gas consumption growth reflects travel mode responses to high petroleum fuel prices in the near term and competition of alternatives in the latter years of the forecast.
- Based on recent survey of automakers' strategy for complying with the Zero Emission Vehicle mandate, there could be rapid increase in the number of fuel cell vehicles in California. Between 2012 and 2017, an anticipated 53,000 fuel cell vehicles are expected in California.

Policies and Regulations

Revised Renewable Fuel Standards

- The revised federal Renewable Fuel Standards will require more renewable fuels, primarily ethanol, and to a lesser extent biodiesel. Under the Low Petroleum Demand Scenario for gasoline, the final forecast of total ethanol demand in California rises from 1.5 billion gallons in 2010 to 2.7 billion gallons by 2020. Under the High Petroleum Demand Scenario for gasoline, the final forecast of total ethanol demand in California rises about the same -- from 1.5 billion gallons in 2010 to 2.7 billion gallons by 2020.
- Staff estimates that ethanol demand in California due to RFS2 requirements will exceed an average of 10 percent by volume in all gasoline sales between 2012 and 2013, depending on the gasoline demand growth rates. However, it is unlikely that the low-level ethanol blend limit in California will be greater than the current 10 percent by volume (E10) before 2015 or later, even if the U.S. EPA ultimately grants permission for United States refiners and marketers to go to a gasoline blend of 85 percent gasoline and 15 percent ethanol (E15).
- Availability of E85 will need to increase dramatically to ensure that sufficient volumes of E85 can be sold to keep pace with the revised Renewable Fuel Standards requirements. Assuming California reformulated gasoline continues to be limited to 10 percent ethanol and ethanol is the predominant renewable fuel used to comply with the revised Renewable Fuel Standards, E85 sales in California are forecast to rise from 13 million gallons in 2010 to 1.7 billion gallons in 2020 and 3. 2 billion gallons by 2030. However, the pace of this expansion may be hindered due to a variety of infrastructure challenges and disincentives.
- Depending on the amount of fuel sold for a typical E85 dispenser, California would require between 4,828 and 35,928 E85 dispensers by 2022. To put that figure in perspective, there were approximately 42,050 total retail fuel dispensers in the entire

state during 2008. Between 2009 and 2030 the E85 dispenser infrastructure costs could range from $241.4 million to $7.2 billion.

- Over the near-term, the greatest challenge to expanded use of ethanol as E85 is an adequate and timely build-out of the necessary E85 retail fueling infrastructure. E85 retail infrastructure is expensive. Costs for installing a new underground storage tank, dispenser, and appurtenances range between $50,000 and $200,000. This level of investment is between 1.5 and 6 times greater than the total annual profit of a typical retail station (for both fuel and non-fuel commodities). The federal Renewable Fuel Standards regulations do not have any requirements that retail station owners and operators make available E85 for sale to the public. Refiners, importers, and blenders have an obligation to collectively market mandated volumes of renewable fuels, but retail station operators do not have an obligation to assist in marketing large amounts of E85. Financial assistance from industry or government agencies may be required to install the number of E85 dispensers needed to supply adequate volumes of E85. It is estimated that, at a minimum, an average of 530 E85 dispensers per year would need to be installed in California between 2014 and 2022, costing between $27 million and $106 million per year.
- If the base gasoline blendstock to produce E85 is something other than California reformulated blendstock for oxygenate blending (CARBOB) for E10 blending, additional segregated storage tanks would be required throughout the production and distribution infrastructure to accommodate this new gasoline blendstock.
- California's number of registered flex fuel vehicles would need to increase from over 450,000 vehicles in 2010 to at least 2 million flex fuel vehicles by 2020 and 5 million by 2030 to enable an adequate market for the projected volumes of E85 needed to meet the Renewable Fuel Standards.
- It is unlikely that there will be sufficient cellulosic ethanol capacity in place to fully meet the revised federal Renewable Fuel Standards obligations on the schedule adopted in legislation. The U.S. Environmental Protection Agency is required to set the cellulosic biofuel standard each year based on the volume projected to be available during the following year, and it has reduced the required amount for 2011 and is in the process of revising the 2012 volumes.
- Under the Low Petroleum Demand Scenario, the final forecast of biomass-based diesel proportional-share ("proportional-share" refers to California's share of renewable fuel consumption under the RFS2) ranges from 14.5 million gallons in 2010 to 56 million gallons by 2030. Under the High Petroleum Demand Scenario – the final forecast of biodiesel "proportional-share" ranges from 14.5 million gallons in 2010 to 96.7 million gallons by 2030.

Low Carbon Fuel Standards and High Carbon Intensity Crude Oil

- The use of steam for thermally enhanced oil recovery (TEOR) requires additional energy that increases the carbon footprint for crude oil that uses this type of extraction technique. California has one of the highest concentrations of TEOR crude oil production in the world, accounting for nearly 47 percent of the state's total crude oil production during 2008 and approximately 17 percent of the total crude oil processed by California refineries during the same year.

- California refiners desire to process a mix of crude oil that is economically optimal based on their individual refinery configuration, the desired ratio of gasoline and diesel fuel that the marketing department is targeting, and minimizing their acquisition costs for crude oil supplies.
- Some crude oils require more energy to produce, whether through thermally enhanced recovery methods, excessive flaring, bitumen mining, or preprocessing. Since the LCFS takes into consideration the full lifecycle of fuels, it identifies these crudes as High Intensity Crude Oils (HCICOs) and recognizes that their use in California refineries generates incremental GHG deficits when compared to standard crudes. Refiners can use HCICOs, but they would need to offset the incremental carbon debt. Therefore, the HCICO provision in the LCFS will discourage significant use of HCICOs in California's refineries.
- The HCICO provision has the potential to affect the crude oil selection decisions of California refiners. However, the HCICO provision is not expected to restrict access to crude oil supplies in a way that could significantly impact fuel supply, but it could impact refiner profitability and the ultimate cost of petroleum fuel in California.
- Energy Commission staff initial screening of 248 Marketable Crude Oil Names found that 74 percent by volume of the crude oils were non-HCICOs. A crude oil was labeled a "potential" High Carbon Intensity Crude Oil if it was: from a country that had an average flaring intensity greater than the threshold set by the California Air Resources Board; or was from a source field (either partially or wholly) that was using thermally enhanced oil recovery; or was from a bitumen mine; or was from an upgrading facility in Canada or Venezuela.
- Approximately 16.5 percent of the foreign crude oil receipts by California refineries during 2010 might potentially be classified as High Carbon Intensity Crude Oils, accounting for 8.0 percent of total crude oil use during the year. Replacing a portion of the existing crude supplies and instead using other sources of crude oil could lead to increased crude acquisition costs.
- Achieving these emission reductions will be a challenge for two reasons: oil producers outside of California have alternative markets to sell their crude oil; and the California crude oil market is too small (between 1.2 and 2.1 percent of world market) to justify an investment to reduce the carbon intensity of crude oil production operations.

LCFS and Ethanol Fuel Types

- The Low Carbon Fuel Standard is intended to decrease California's reliance on petroleum based transportation fuel and concurrently impact the mix of ethanol and other types of renewable and alternative transportation fuels that will be used in California. Traditional relatively high carbon intensity biofuels such as average corn-based ethanol and biodiesel will still have a role, but will eventually lose market share to other fuels with lower carbon intensity including a wide variety of renewable hydrocarbons, natural gas, electricity, and hydrogen. Introduction of a large amount and variety of these new alternative fuels which have low lifecycle carbon emissions is essential if obligated parties are to maintain compliance with the LCFS regulation through 2020.

- There are many potential compliance pathways for the LCFS. In order to assess the range of implications for these pathways in its proposed analysis, Energy Commission staff has been working with ARB staff to identify reasonable assumptions about use of credits for electric vehicle charging, biofuel concentrations allowed in gasoline and diesel, and California ethanol and biodiesel production capacity, applying to all cases of LCFS compliance. The analysis will also include assumptions for quantities of ethanol and biodiesel used relative to RFS2 compliance, availability and use of cellulosic and advanced biofuels, availability and use of specific feedstocks having superior carbon intensity values, and building of excess credits, among other factors.
- Potential LCFS compliance costs could fall into three categories: use of more expensive renewable fuels than would otherwise be used under RFS2; an additional price premium for lower carbon intensity fuels (the lower the CI, the higher the premium); and market-clearing prices of LCFS credits sold to obligated parties.
- Twenty-two other states are developing or considering LCFS rules, either singly or in regional groups, with cumulative totals of gasoline and diesel use in 2009 of 55.4 billion gallons and 23.2 billion gallons, respectively, totals that are substantially more than California consumption. If such rules are adopted in a significant number of these states, competition and prices for desirable fuels and feedstocks will increase, as would the environmental benefits of more widespread use of low-carbon fuels.

Ethanol Blenders Excise Tax Credit and Import Tariff

- Continuation of the Volumetric Ethanol Excise Tax Credit (VEETC) policy may no longer be necessary to encourage ethanol use in the United States since the RFS2 mandates have relegated discretionary use to the E85 market. According to the United States Government Accountability Office (U.S. GAO), elimination of the VEETC could increase gasoline excise tax revenue to the federal government by nearly $6 billion per year, absent any other changes in excise fuel tax rates.
- Minimizing importation fees for types of lower carbon renewable fuels that would assist in achieving compliance with the state's Low Carbon Fuel Standard could help to lower the incremental costs of the regulation. Further, elimination of the tariff could also reduce the cost for obligated parties throughout the rest of the United States to comply with the Advanced Biofuels portion of the revised Renewable Fuels Standards.

Fuel Economy Standards

- Corporate Average Fuel Economy (CAFE) Standards for on-road 2010 cars and light-duty trucks exceeded Corporate Average Fuel Economy requirements, achieving 33.4 miles per gallon for cars and 24.8 miles per gallon for light trucks.

- The National Highway Transportation Safety Administration (NHTSA) set fuel economy standards for model years 2012-2016 cars and light trucks, which will increase to 35.5 miles per gallon by the 2016 model year. Fuel economy rules for model year 2017-2025 cars and light trucks are being finalized currently, and are expected to be set to reach 54.5 miles per gallon by the 2025 model year
- Fuel Economy rules for model year 2017-2025 cars and light trucks are being finalized currently, but have so far been set to reach 54.5 MPG by the 2025 model year
- The 2014-2018 model years face the first fuel efficiency standards for medium- and heavy-duty vehicles. The standards have the potential to save approximately 500 million barrels of oil over the life of vehicles sold during the 2014 to 2018 period and result in cost savings of $34.6 billion. Compared to 2010 baselines, fuel consumption will have to be reduced by 7 to 15 percent, with the exception of big rigs with sleeper cabs, which are required to obtain a 20 percent reduction.
- By 2017 tractor-trailers (big rigs) will have to reduce fuel consumption by 7 to 20 percent, compared to 2010 baselines.
- The establishment of CAFE standards for heavy-duty pickup trucks and vans will require an average improvement in fuel consumption of 10-15 percent per vehicle 2017, compared to 2010 baselines.
- Standards for vocational vehicles require 7 to 10 percent reductions in fuel consumption by 2017, compared to 2010 baselines.

Ozone Standards

- The U.S. EPA is in the process of reconsidering its current 8-hour Ozone standard from 0.075 to a value between a range of 0.060 parts per million (ppm) and 0.070 ppm. Uncertainty regarding specific values has in turn generated uncertainty regarding the potential impact of these standards for California and the neighboring states.
- The primary impact of more stringent ozone standards for California transportation fuel supplies over the early and middle portions of the forecast period could potentially be limited to reduced demand for gasoline. This occurs through improved fuel economy of the existing fleet and the displacement of petroleum with increased use of renewable fuels and vehicles that do not require gasoline (especially electric and hydrogen vehicles).
- A switch to year round and statewide application of Cleaner Burning Gasoline (CBG), in Arizona, could increase exports from California refineries by up to 600 million gallons per year or 39 thousand barrels per day (TBD).
- The impact from any potential changes to Nevada gasoline specifications are expected to have a minimal impact on California refiners that will likely be off-set by additional gasoline shipped to Las Vegas, Nevada, from refineries located in Salt Lake City, Utah, via the new petroleum product pipeline (UNEV).

Canada's Renewable Fuel Standard

- During the next couple of years, incremental ethanol demand to meet Canadian RFS compliance will be sourced from corn-based ethanol plants in the United States. Since the Canadian RFS regulations do not mandate specific types of ethanol, this standard will not create competing demand for other types of lower carbon-intensity ethanol that will be needed to meet California's LCFS requirements.

Renewable and Alternative Fuels

Ethanol

- Ethanol use in California gasoline increased from an average concentration of between 6 and 7 percent by volume in 2009 to 10 percent in 2010, primarily due to federal regulations mandating greater use of renewable fuels and transition to a revised state reformulated gasoline regulation. For forecasting purposes we have assumed 10 percent blending for 2010 but recognize that some refiners and other marketers have the flexibility to use lower concentrations in their proprietary systems.
- Use of renewable and other alternative fuels in the United States and California is expected to continue growing, primarily as a consequence of federal and state regulations mandating ever-increasing levels of renewable content in gasoline and diesel fuel, carbon reduction rules, and incentives for increasing alternative fuel consumption.
- Federal mandates, such as RFS2, in conjunction with the state's LCFS are expected to compel increased quantities of ethanol and biodiesel use in California over the next several years, including a longer-term move to renewable hydrocarbons that will begin to displace a portion of the gasoline and diesel fuel used for transportation.
- Ethanol demand set a record in June 2010 of 88 TBD. The demand for ethanol is expected to continue growing over the forecast period due to mandated blending quantities stipulated by the federal RFS2.
- The United States is not expected to remain a large net exporter of ethanol over the next several years. Foreign sources of ethanol (from Brazil and CBI countries) are expected to play a more pivotal role as demand for ethanol with lower carbon intensity grows in response to the California LCFS and the RFS Advanced Biofuels requirements.
- As of June 2011 there was an estimated 472 million gallons of idle ethanol production capacity in the United States, about 3.2 percent of total production capacity of 14.65 billion gallons.
- Despite the recent poor economics for operating domestic ethanol plants, production capacity of conventional ethanol is expected to be adequate over the next several years. Domestic ethanol production capacity is already sufficient to meet the starch based biofuel RFS2 requirement of 12.6 billion gallons for 2011, 13.2 billion gallons for 2012, 13.8 billion gallons for 2013, and even the 14.4 billion gallons for 2014.
- Currently, three of the five California corn-based ethanol facilities are operating with a collective production capacity of nearly 170 million gallons per year. Two of the California facilities remain idle with a combined capacity of 71 million gallons per year.

The remaining two idle ethanol plants are temporarily closed due to poor economic operating conditions (costs are exceeding revenue streams).

- Brazilian ethanol production is also tied closely with the production of sugar from the cane juice. This means that ethanol plants in Brazil can adjust the ratio of ethanol-to-sugar in reaction to local ethanol demand/prices, export ethanol market economics, and world sugar demand/prices.

- Production of ethanol in Brazil is determined by the interrelationship between various factors: minimum blending levels in gasoline as set by its Ministry of Agriculture; world sugar market demand, balances, and prices; outcome of sugarcane growing season; and the potential value of ethanol exports. Based on the interaction of these market components, supplies of ethanol available to export from Brazil can vary significantly on a year-to-year basis. Over the last five years (2006 through 2010), Brazil has exported between 0.55 billion and 1.35 billion gallons of ethanol.

- Even if Brazilian ethanol supplies were sufficient to allow significant volumes of exports. Brazilian exporters of ethanol to the United States must pay two types of import duties, an ad valorem tax equivalent to 2.5 percent of the ethanol transaction price and a secondary import duty of 54 cents per gallon, which could result in higher ethanol prices in California. There is bipartisan discussion in Congress to repeal the tax and tariff, as well as the tax subsidies for domestic corn ethanol production.

- Staff anticipates that California's logistical infrastructure for the importation and distribution of ethanol will need to continue to be modified to enable a greater quantity and flexibility of ethanol imports within the next 6 to 18 months. Currently, most of the ethanol used in California is imported from corn-based ethanol plants in the Midwest. The majority of these imports are via unit trains that consist of between 90 and 112 rail cars.

- Kinder Morgan began accepting only base gasoline that will be used to blend E10 at all of their California distribution terminals on January 11, 2010. The majority of gasoline distributed throughout California moves through some portion of the Kinder Morgan pipeline systems and refiners want to ensure that the type of gasoline they produce is compatible (to allow for volume exchanges and increased flexibility during unplanned refinery outages).

- Marine imports of ethanol to California have been limited over the last several years due primarily to an abundance of ethanol production capacity in the United States and the import tariff for most sources of foreign ethanol.

- Currently, no ethanol is shipped through any petroleum product pipelines that are also used to transport gasoline, diesel, or jet fuel. Kinder Morgan has demonstrated that ethanol can be successfully shipped in batches through their pipeline segment in Florida. However, this practice is unlikely to be extended to California over the near to mid-term due to the increased age and complexity of the existing California pipeline system, as well as a higher probability of water in the pipeline system due to changes in the pipeline elevation (hydraulic profile).

- The majority of fuel ethanol in the United States is produced in facilities that use corn as the primary feedstock. As the demand for mandated use of ethanol continues to grow, so too does the demand for corn as a feedstock. Corn use to produce ethanol is forecast to set a record of 5.075 billion bushels for 2011.

Biodiesel

- Under the Low Petroleum Demand Scenario, the final forecast of biomass-based diesel proportional-share ranges from 14.5 million gallons in 2010 to 56 million gallons by 2030. Under the High Petroleum Demand Scenario – the final forecast of biodiesel "proportional-share" ranges from 14.5 million gallons in 2010 to 96.7 million gallons by 2030.
- If biodiesel use incentivized by California's Low Carbon Fuel Standard reached 10 percent by volume, biodiesel demand could reach 427 million gallons by 2020 and 502 million gallons by 2030. Further, B20 levels would infer biodiesel demand levels in California of 765 million gallons by 2020.
- As is the case with ethanol, increasing levels of biodiesel blended with conventional diesel fuel do pose some challenges that would need to be addressed to ensure biodiesel could be used at concentrations of up to 20 percent by volume. Currently, the biodiesel infrastructure is inadequate to accommodate widespread blending of biodiesel even at concentrations as low as B5. However, with sufficient lead-time (12 to 24 months), distribution terminal modifications could be undertaken and completed to enable an expansion of biodiesel use.
- RFS2 regulations call for a minimum use of 1.0 billion gallons per year of biomass-based diesel fuel in 2012, increasing to 1.28 billion gallons in 2013. As of July 2011, there was more than 2.4 billion gallons of biodiesel production capacity for all U.S. operating facilities. It appears as though there may be sufficient domestic sources of biodiesel production facilities to meet the RFS2 requirements for several years.

- Production of biodiesel in the United States dramatically increased in response to federal legislation that included a $1 per gallon blending credit for all biodiesel blended with conventional diesel fuel that went into effect in 2005, but declined in 2009 and 2010 with the temporary loss of that subsidy in conjunction with poor production economics (high feedstock costs relative to market price of diesel fuel). Output is expected to rebound as refiners and other obligated parties strive to meet biodiesel blending requirements mandated by RFS2 and could set a record level of production during 2011.

- Significant quantities of biodiesel were exported between 2007 and 2009 due to more attractive wholesale prices and U.S. exporters' use of the dollar-per-gallon biodiesel blenders' credit. Biodiesel exports have grown from nearly 9 million gallons in 2004 to a peak of more than 677 million gallons in 2008. After peaking in 2008, a declining percentage of total U.S. biodiesel supply has been exported. In 2010, export volumes represented 32 percent of total U.S. biodiesel supplies (production combined with imports). That portion is forecast to be even lower in 2011 as obligated parties under the RFS2 strive to utilize a minimum of 800 million gallons of biodiesel.

- According to the National Biodiesel Board there are 16 biodiesel production facilities in California with an annual production capacity of 84.5 million gallons. These production capacity volumes are sufficient to supply California's total revised Renewable Fuel Standards proportional-share of biodiesel. However, the increased demand for biodiesel incentivized by the Low Carbon Fuel Standards scenarios could necessitate substantial imports from either domestic or foreign sources.

- Europe continues to be the dominant producer of biodiesel in the world, estimated to produce approximately 65 percent of the global biodiesel production in 2009. This foreign source of biodiesel spare production capacity is more than sufficient to meet any incremental demand for biodiesel that may be necessary by obligated parties in California to help achieve compliance with the LCFS requirements.

- To help ensure adequacy of biodiesel distribution capability for meeting increased demand levels associated with the RFS2 and the state's LCFS, construction of biodiesel storage tanks at a minimum of 50 percent of California's distribution terminals over the next couple of years would likely be necessary. Costs for such an undertaking could amount to between $25 million and $50 million.

- Assuming sufficient spare production capacity throughout the United States to meet the potential increase in California biodiesel demand, it is likely that most of the incremental biodiesel will originate from facilities located outside the state. This means that imports of biodiesel may be necessary via rail and/or marine vessel. Currently, there are no biodiesel rail facilities designed to handle unit trains. Ultimately, biodiesel unit train receipt capability may not be necessary due to demand levels that may be too low to justify the expense. It is more probable that rail receipts of biodiesel will be transferred to tanker trucks via transloading, as is the case with the Kinder Morgan ethanol transloading project in Northern California.

- Availability of marine facilities is limited and would need to be made available if meaningful volumes of biodiesel were to be imported via marine vessel. However, there is sufficient domestic biodiesel production capacity to supply California's anticipated needs over the near to mid-term that could reasonably be delivered in rail cars, rather than marine vessels.

- Assuming biodiesel fuel blends in California do not exceed the B20 level over the foreseeable future, retail station modifications should be negligible to accommodate such increased concentrations. However, for those retail locations that want to dispense B99 or B100, storage of biodiesel at these concentrations in an UST may not be permissible at this time per the California State Water Resources Control Board (SWRCB).

- Not all original equipment manufacturers allow biodiesel bends in excess of B5. This limitation is also imposed by some companies that provide extended motor vehicle warranties. Until this warranty issue is covered, retail station operators may be reluctant to offer B20 for sale at all of their dispensers. Therefore, a dedicated UST and retail dispenser may have to be installed for B20 blends. This scenario could result in significantly higher retail infrastructure costs to achieve widespread biodiesel penetration in California above B5 levels.

Potential Emerging Fuels

- Biomethane is a gaseous fuel that is a perfect substitute for either compressed or liquefied natural gas, both of which are used as diesel substitutes. Biomethane is relatively well-established for a renewable fuel. There have not been any known commercial transactions within California: all biomethane currently used as transportation fuel is consumed by the producer. The nature of biomethane production and infrastructure may limit the development of a robust market for biomethane as a transportation fuel.
- Due to absence of an existing biomethane market, there is almost no information available on cost projections, although its commercial potential is heavily dependent upon the price of natural gas, for which it is a perfect substitute.
- There are two upcoming regulations that could influence a commercial scale production of hydrogen fuel in California. The first regulation is the Clean Fuels Outlet which requires regulated parties to provide outlets of hydrogen to meet the needs of fuel cell vehicles. The second regulation is SB1505, also called Environment and Energy Standards for Hydrogen, which will require the hydrogen produced for motor vehicle use meet greenhouse gas, criteria pollutant, toxic emission and renewable requirements.
- SB1505 will require the hydrogen produced in California to contain 33 percent renewable resources. This will likely increase demand for emerging renewable transportation fuels such as biomethane, which is expected to serve as replacements for compressed natural gas or liquefied natural gas. Staff anticipates that SB1505 will likely increase the demand for biomethane to approximately 300 million standard cubic feet in compressed form or about 4 million gallons in liquid form by 2017. With an additional increase in demand by 2030, it is expected that the demand for biomethane could increase to about 4 billion standard cubic feet or 45 million gallons.
- Hydrogen has the potential to be a common alternative fuel. Although it does not occur free in nature, it can be reformed from natural gas and any renewable biogas or landfill gas and can be derived through the electrolysis of water. It is produced in mass quantities and is trucked or piped for use in food processing and in petroleum refining processes. Used in fuel cell passenger vehicles and forklifts, it reduces well-to-wheel criteria pollutant and greenhouse gas emissions relative to all internal combustion engine cars on the road today.

- Butanol is notable because it can be used as an ethanol substitute and has properties that make it more desirable as transportation fuel: it has higher energy content, is less likely to evaporate, and attracts less water, as well as other advantages.
- Renewable diesel, renewable jet fuel, and renewable gasoline are appealing because they are renewable fuels identical to the petroleum-based products they would replace. Although none of these are currently produced in California in commercial volumes, today there are commercial plants with sufficient capacity to enable California to comply with the LCFS.
- Most discussions of renewable fuels center on fuels rather than fuel-producing processes, but algae is typically a process rather than a fuel. Algae-based processes can produce a variety of fuels, depending on the algae strain: biodiesel, renewable diesel, renewable gasoline, renewable jet fuel, and ethanol have at least been proposed for algae processes. Production of algae-based biofuels remains in the research and development stage.
- Algae can grow in water of all types, including wastewater and saline groundwater. Within California the Imperial Valley best meets growing conditions and has been the location of algae-based fuel facilities. Compared to other purpose-grown fuels, algae possess the potential to produce a significant amount of fuel from a relatively small area. Algae grown on 1 percent to 3 percent of the total United States cropping area would be enough to produce 50 percent of transportation fuel needs.

Alternative Vehicle Refueling Infrastructure

- Residential chargers for single and multi-family dwellings will be the primary method of charging for most plug-in electric vehicles (PEVs) and battery electric vehicles. In 2011 the ARFVTP committed funding for over 1,000 home rechargers, and 4,800 public charging stations.
- Fast Charging Electric Vehicle (EV) Stations are anticipated to be needed in large numbers to accommodate growing numbers of plug-in electric vehicles; however, it is not clear yet to what extent Level 1 and Level 2 public recharging stations will be necessary.
- One of the primary challenges to the penetration of light-duty natural gas vehicles (NGVs) is the lack of available refueling infrastructure. New compressed natural gas (CNG) home refuelers are now being sold for home use.
- The aging CNG stations and equipment in California do not meet today's fleet refueling needs and some are approaching their useful life. Upgrading and replacing existing older equipment, especially high pressure storage tanks and lines will be a growing need to ensure adequate, reliable, and safe CNG fuel.
- As of August 2011 there were less than 10 hydrogen stations in California with a total dispensing capacity of 315,000 kilograms per year. A kilogram has the same energy as a gallon of gasoline. In 2011 11 hydrogen stations were co-funded by the Energy Commission, adding 740,000 kg per year of new hydrogen retail capacity.

- New hydrogen station designs are resulting in significantly reduced station costs, yet these costs are still many times greater than traditional gasoline or diesel dispensing stations.
- Existing retail diesel stations are adequate for selling Biodiesel fuels up to B20 blends. The current California Underground Storage Tank regulations allows B5 blends, and impediments to storing B6-B20 blends are anticipated to be resolved by the industry by 2012.

Crude Oil and Petroleum Product Supply

- California refineries processed 607 million barrels (1.7 million barrels per day) of crude oil in 2010. The largest percentage of this crude oil was obtained from foreign sources (47.7 percent), followed by California sources (38.1 percent), with the balance from Alaska (14.2 percent).
- California's annual crude oil production was approximately 224 million barrels during 2010, averaging approximately 613,000 barrels per day.
- The decline of California crude oil production has continued since 1985, when crude oil production peaked at 424 million barrels per year. Since 1985, California crude oil production has declined by 47.2 percent; Alaska, by 67.2 percent; and the rest of the United States, by 28.2 percent.
- California crude oil production is forecast to continue declining at a rate of between 2.2 and 3.1 percent per year.
- Due to the projected reduction in demand for the petroleum fraction of gasoline in California resulting from increased use of renewable fuels and improvement in light-duty vehicle fuel efficiency, it is unlikely that there will be any significant expansion of existing refining distillation capacity in California over the forecast period. However, it is possible that refining projects designed specifically to increase the yield of diesel fuel might be pursued.
- The High Case for crude oil imports yields an increase of 60 million barrels per year more in 2020 and 104 million barrels per year more by 2030. In this case, increased crude oil imports are solely the result of continued steady decline of California's crude oil production since refining distillation capacity remains fixed over the forecast period. Staff has elected to use a flat distillation capacity growth rate of zero percent per year over the forecast period in conjunction with the higher utilization rate of 89.8 percent (from 2000 through 2010), and the higher rate of 3.1 percent for California crude oil production decline to yield the upper range for projected crude oil imports
- The Low Case for crude oil imports yields an increase of 14 million barrels per year more in 2020 and 22 million barrels per year more by 2030. In this case, increased crude oil imports are dramatically lower when compared to the High Case, primarily because of the assumed reduction in refining capacity of approximately 170 TBD by the end of the forecast period.

- Staff modified three assumptions as part of the forecast of crude oil imports under the Low Case. The first was to assume a less steep decline rate for California crude oil production of approximately 2.1 percent per year, rather than 3.1 percent decline rate used in the High Case scenario. The second modified assumption was to use a slightly lower utilization rate of 87.6 percent that was the average from 2007 through 2010. The third assumption that California refining capacity would remain level over the forecast period was also modified as part of this scenario.
- The possibility that some of California's refining capacity could be reduced over time as part of efinery asset consolidation was considered a very low probability during previous *IEPR* cycles. However, the possibility of a refinery closing in California is now assumed to be a higher probability based on: recent announcements made by several oil companies; an assumption that California refinery operating costs are higher than other regions of the United States.
- California refiners are expected to incur additional operating costs over the near-term that competitors outside of the state will not experience that will likely impact their profitability and further increase the likelihood of refinery consolidation in California. Examples include potential additional costs of compliance associated with California's AB 32, LCFS, and HCICO requirements.
- Based on recent historical trends, staff assumed that 60 percent of the incremental crude oil imports over the forecast period would be delivered to marine terminals in Southern California, with the balance (40 percent) handled by marine berths in the San Francisco Bay Area.
- Staff calculated 5 to 47 additional crude oil tanker arrivals per year by 2015, 8 to 86 by 2020, and 12 to 149 additional arrivals per year by 2030.
- The incremental crude oil storage capacity needed in California would amount to between 0.4 million and 2.7 million barrels by 2015; between 0.6 million and 5.0 million barrels by 2020; and between 1.0 million and 8.6 million barrels of storage capacity by 2030.
- The High Case for imports necessitates the need for expanded capability to receive greater volumes of crude oil imports within the next four to five years so that refiners would be able to operate their facilities at high enough utilization rates to produce sufficient supplies of transportation fuels to meet the needs of California consumers and businesses.
- Petroleum marine terminals in the Ports of Los Angeles and Long Beach have periodically come under pressure either to be shuttered or relocated to make way for other types of port commercial activity that generates greater revenue per acre per year for the respective port authorities who allow oil companies to operate under long-term leases that have staggered expiration dates.
- "Spare" import capacity is a subjective term that fails to incorporate circumstances by which one or more existing marine terminals are temporarily out of service due to damage inflicted by a natural disaster (earthquake, tsunami, etc.) or an act of terrorism.

In other words, spare capacity to import greater quantities of crude oil should also be viewed as a type of insurance policy that would help ensure continuity of operations for these types of plausible contingencies.

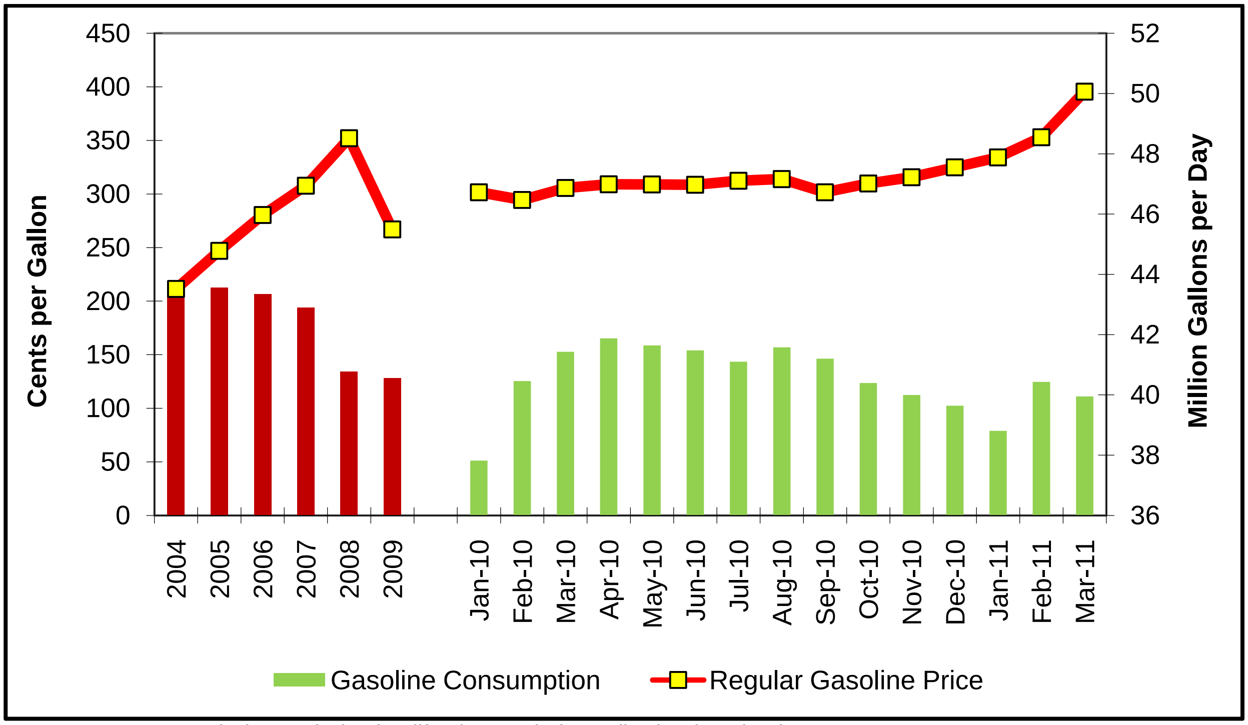
- Currently, there are two petroleum import infrastructure projects in Southern California that are at various stages of development. The first site is Berth 408 at Pier 400 in the Port of Los Angeles. The second project is referred to as Pier Echo located at Berth T126 in the Port of Long Beach. Based on Energy Commission analysis, the Southern California market may only require one of these import facilities to be constructed over the forecast period, not both.
- The moratoria areas off the coast of California were estimated by Minerals Management Services (MMS) to contain between 5.8 billion and 15.8 billion barrels of Undiscovered Technically Recoverable Resources (UTRR) crude oil. Over half of this estimated crude oil resource is located in federal waters off the coast of Southern California.
- If the lifting of the Outer Continental Shelf (OCS) moratoria remains in effect and development proceeds as forecast by United States Department of Energy (U.S. DOE) off the coast of California, this activity could significantly impact the crude oil import forecast, such that waterborne imports of crude oil would actually be less than they were in 2010, regardless of scenario.
- There are two projects that have been recently proposed off the coast of California that could result in additional quantities of crude oil being produced from existing offshore platforms. The potential production was estimated at 8,000 to 27,000 BPD of additional crude oil that could have been produced from the Tranquillon Ridge Project, but seems to be on hold after loss of California political support last year. Crude oil production could from the other project (Platform Hogan) could begin as early as 2013 and yield a maximum of 3,500 BPD or roughly 1.3 million barrels per year by 2020. This volume of additional production has the potential to reduce the crude oil forecast by 9.3 percent in 2020 under the Low Case and by 2.2 percent under the High Case.

CHAPTER 2: Historic Transportation Fuel Trends

California’s transportation fuel demand has changed over time in response to growth in population, variation in fuel prices, evolving vehicle and fuel technologies, the health of the economy, and environmental regulations. These changes have collectively influenced the choice of transportation mode, vehicle ownership (number and type), and driving behavior. Crude oil and fuel price volatility, the Cash for Clunkers program, and the 2008 recession are among the recent factors that have influenced transportation fuel consumption. For example, West Texas crude oil prices rose to over $140 per barrel in July 2008, before declining sharply to just above $30 in December 2008, but have since tripled to over $90 in June 2011. During that same time, the California unemployment rate has risen from 5.9 percent in January of 2008, to a high of 12.5 percent in December 2010, adding to consumer difficulties in dealing with the rapid changes in fuel prices.

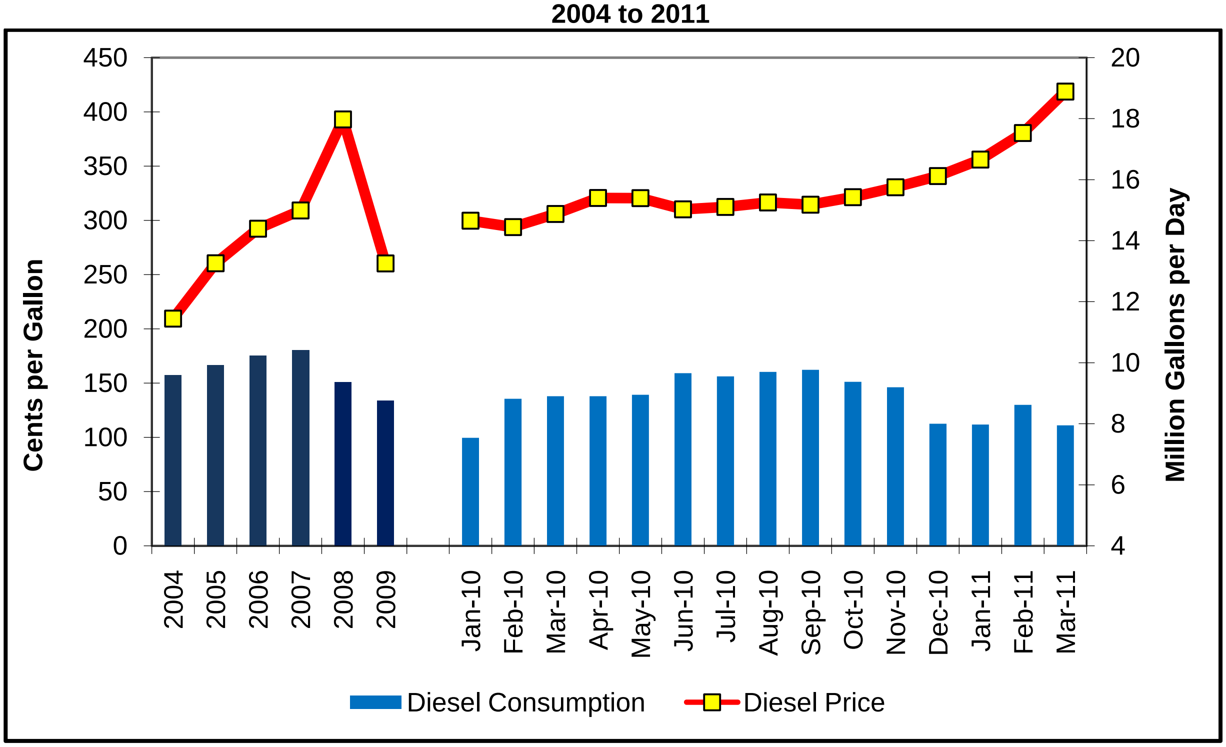
In 2004, gasoline, diesel, and jet fuel consumption was 15.9 million, 3.5 million, and 3.4 million gallons respectively. By 2010, gasoline, diesel, and jet fuel consumption fell to 14.8 million, 3.3 million, and 3.1 million gallons. In Figure 2-1, gasoline consumption for the first three months of 2011 is on par with 2010 levels, with January and February of 2011 consumption being stronger than the same months in 2010, but March 2011 is weaker than the previous year’s consumption. Figure 2-2 displays the same trend for diesel consumption.

**Figure 2-1: California Gasoline Consumption and Average Price
2004 to 2011**



Source: Energy Commission analysis of California Board of Equalization (BOE) sales reports

**Figure 2-2: California Diesel Consumption and Average Price
2004 to 2011**

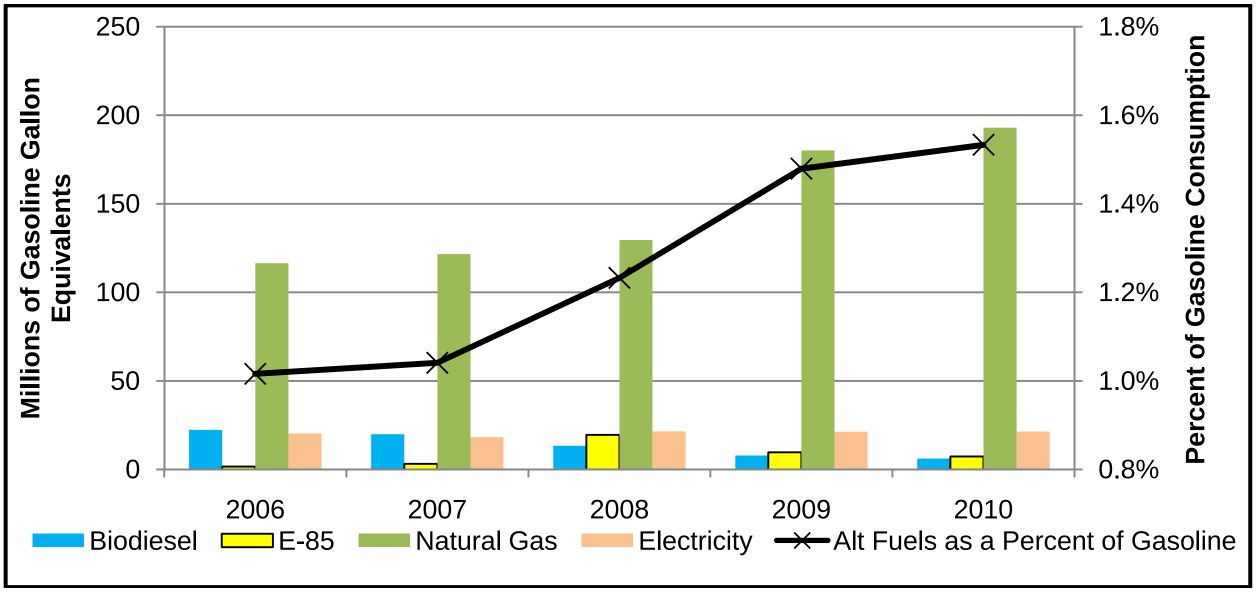


Source: California Energy Commission analysis of BOE sales reports

While alternative fuels continue to increase their penetration into the transportation fuels market, their combined consumption as a percent of gasoline consumption remain under 1.6

percent. Figure 2-3 displays Energy Commission staff estimates of alternative fuel consumption, with natural gas being the most consumed alternative fuel for transportation purpose on a gasoline-gallon equivalent (GGE) basis.

Figure 2-3: California Alternative Transportation Fuel Consumption 2006 to 2010



Source: California Energy Commission analysis

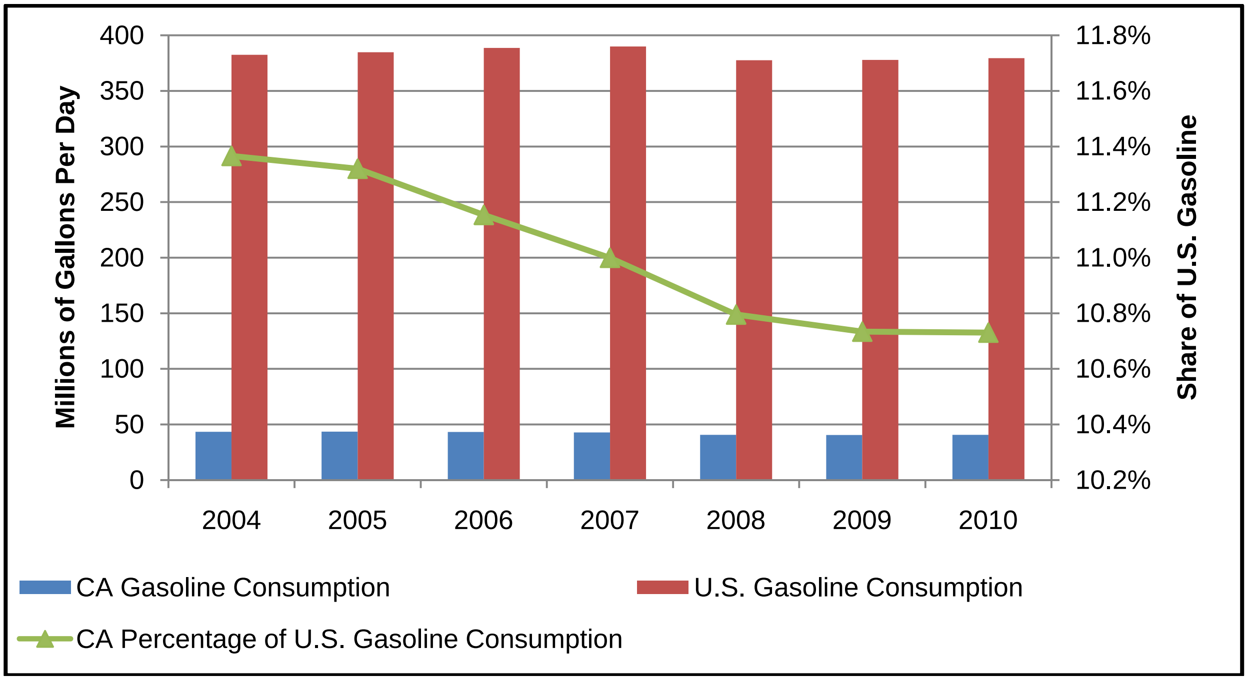
The rest of this chapter discusses historic changes in fuel consumption for gasoline, diesel, jet fuel, and for alternative fuels used for transportation purposes. Much of the analysis presented focuses on changes in economic and demographic factors in comparison to fuel consumption. While compliance with the federal RFS2 and LCFS is imminent, these regulations had little impact during this period. Estimates for alternative fuels are presented at the end of the chapter, but comparative analysis with economic and demographic factors was not done, due to data collection ambiguities and ongoing efforts to improve data collection. Instead staff analysis indicates that consumption of these fuels is mostly determined by government policy decisions.

Historic Gasoline Demand

On a per gallon basis, gasoline is the most used transportation fuel in California. Within the transportation sector, gasoline is primarily used by light-duty vehicles and in 2009, 98 percent of the light-duty vehicle fleet was powered by gasoline, of which 82 percent was for personal use.[1] With this strong link to personal ownership, gasoline demand is primarily influenced by household travel behavior. Factors that influence gasoline consumption include income, fuel prices, VMT, unemployment, population, vehicle stock, and fuel efficiency.

Gasoline consumption in California reached a peak of 43.5 million gallons per day in 2005, while the United States reached a peak of 390 million gallons per day in 2007. Figure 2-4 shows that since 2005 gasoline use in California steadily declined to 40.6 million gallons per day in 2009, falling at an annual average rate of 1.76 percent.[2] During that same period, United States gasoline consumption declined to 377.9 million gallons per day in 2009, falling at an annual average rate of 0.45 percent. In 2010, gasoline consumption increased for both the United States and California to 379.4 and 40.7 million gallons per day, respectively. California's percentage of total U.S. gasoline consumption decreased from 11.4 percent in 2002 to 10.7 percent in 2009 and 2010.

Figure 2-4: U.S. and California Gasoline Sales, 2002 to 2010

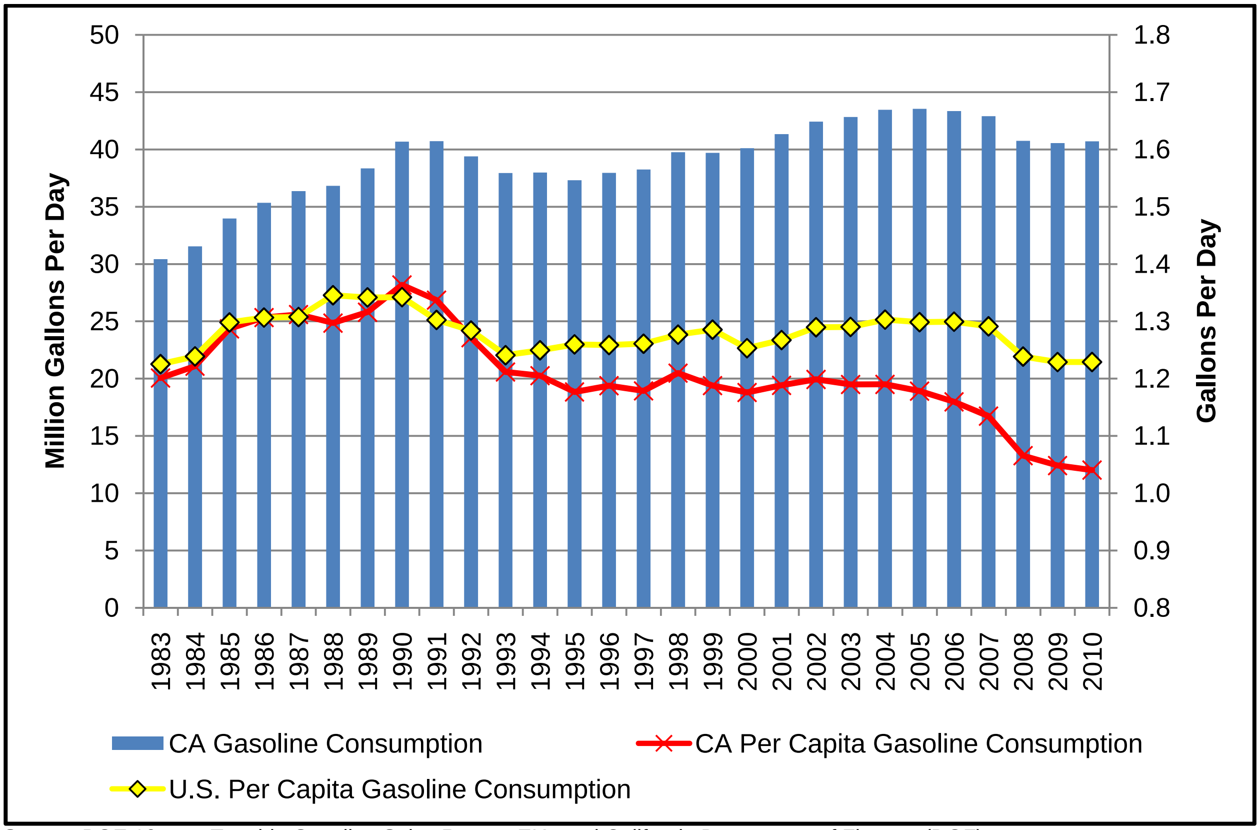


Source: BOE 10 year Taxable Gasoline Sales Report and data from the Energy Information Administration (EIA)

Figure 2-5 shows that while daily gasoline consumption in California fluctuated around the 40 million gallon mark from 1990 to 2010, per capita consumption declined. In 1990, California per capita gasoline use peaked at 1.36 gallons per day and has since fallen to 1.04 gallons in 2010. This drop was similar for the 16 year and older population, which dropped from 1.8 gallons per day in 1990 to 1.34 gallons per day in 2010 (Figure 2-6). This was a 25.2 percent drop in California per capita gasoline consumption and a 23.7 percent drop in California per 16 and older gasoline consumption. United States per capita gasoline use has exceeded California since 1992 and the difference has been steadily increasing through 2010.

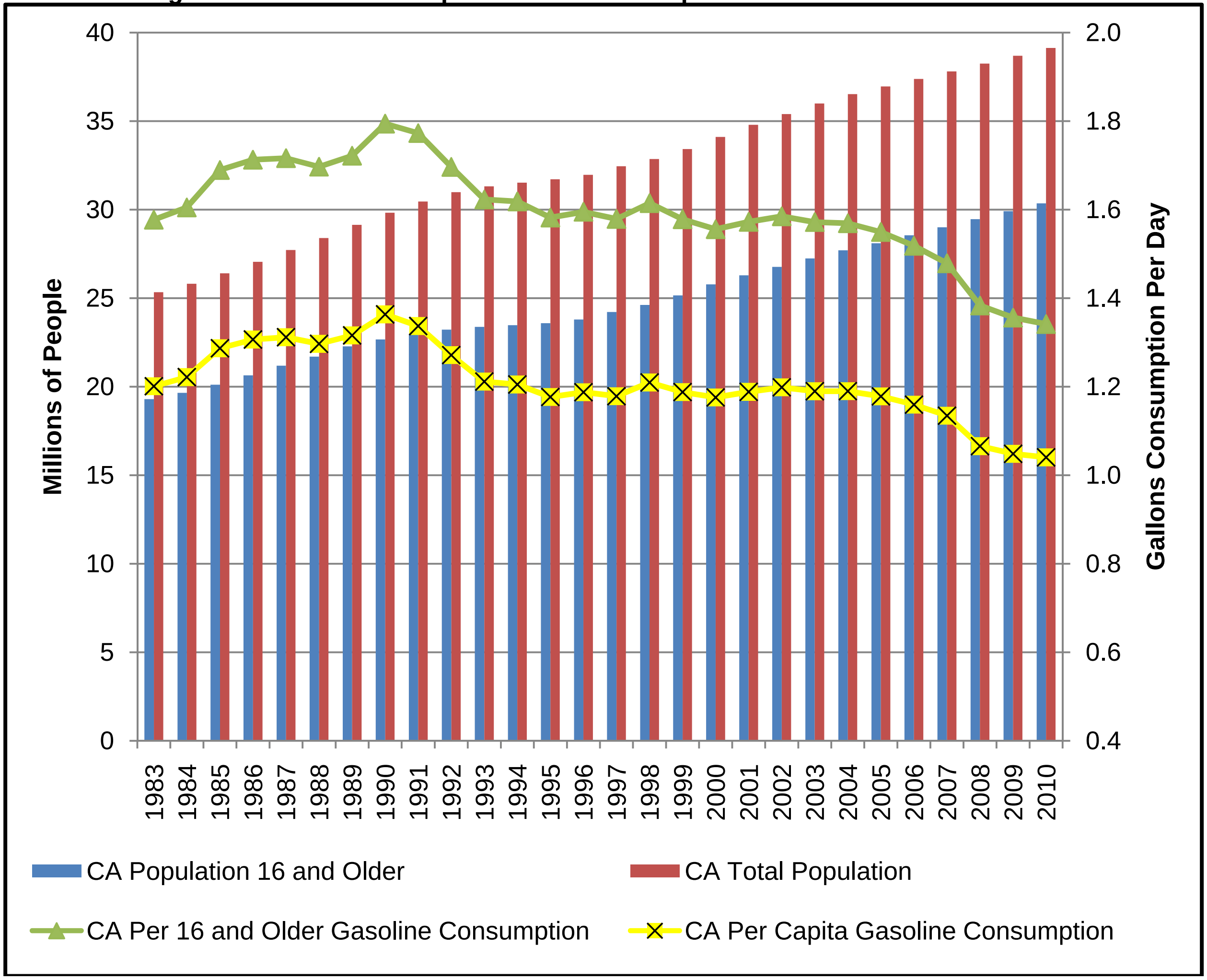
Figure 2-6 shows that from 1983 to 2010 California's population grew at roughly 511,000 people per year, for a total increase of 54.5 percent. From 1990 to 2005, California's population grew by 23.9 percent, while total gasoline consumption grew by only 7.1 percent, and per capita gasoline use declined 13.6 percent. From 2005 to 2010, California population increased 5.9 percent, gasoline consumption declined 6.5 percent, and per capita use of gasoline declined 11.7 percent.

Figure 2-5: United States and California Gasoline Sales and Per Capita Gasoline Consumption, 1983 to 2010



Source: BOE 10 year Taxable Gasoline Sales Report, EIA, and California Department of Finance (DOF)

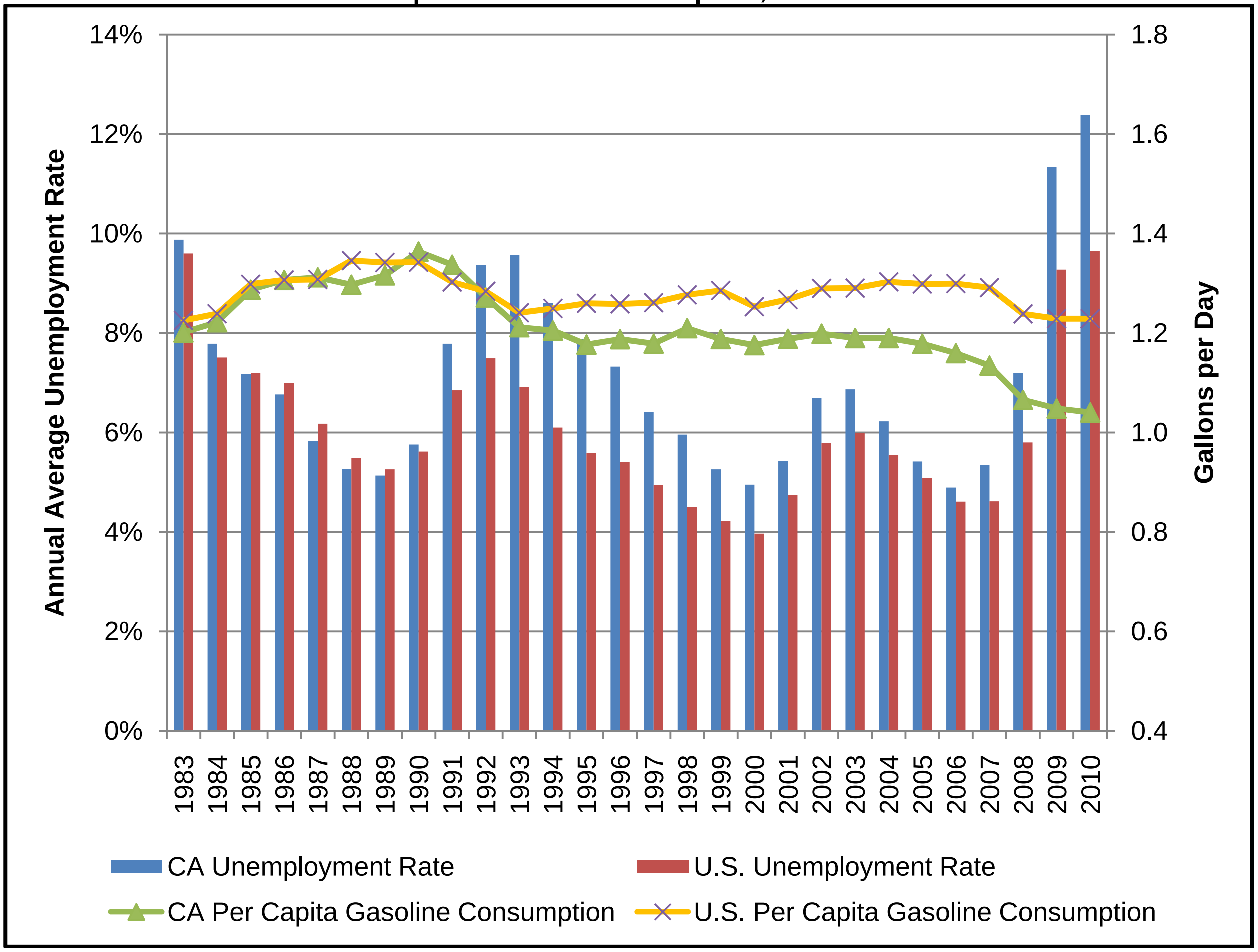
Figure 2-6: California Population and Per Capita Gasoline Use 1983 to 2010



Source: BOE 10 Year Taxable Gasoline Sales Report, EIA, and DOF

Possibly contributing to California's falling per capita gasoline consumption relative to the United States is California's higher unemployment rate, as fewer people commuting to work results in a lowering of per capita gasoline consumption. Figure 2-7 shows that the unemployment rate and per capita gasoline consumption are almost the same for the United States and California from 1983 to 1990. While declining unemployment from 1990 to 2000 matches modest increases in per capita gasoline consumption for the United States, California per capita gasoline consumption levels off. These trends generally persist beyond 2000 regardless of the fluctuations in unemployment, although per capita fuel use in the state and nationally did drop significantly with the most recent sharp increases of unemployment starting in 2007. While these results indicate a possible relationship between unemployment and per capita gasoline consumption, other influences should be considered as well.

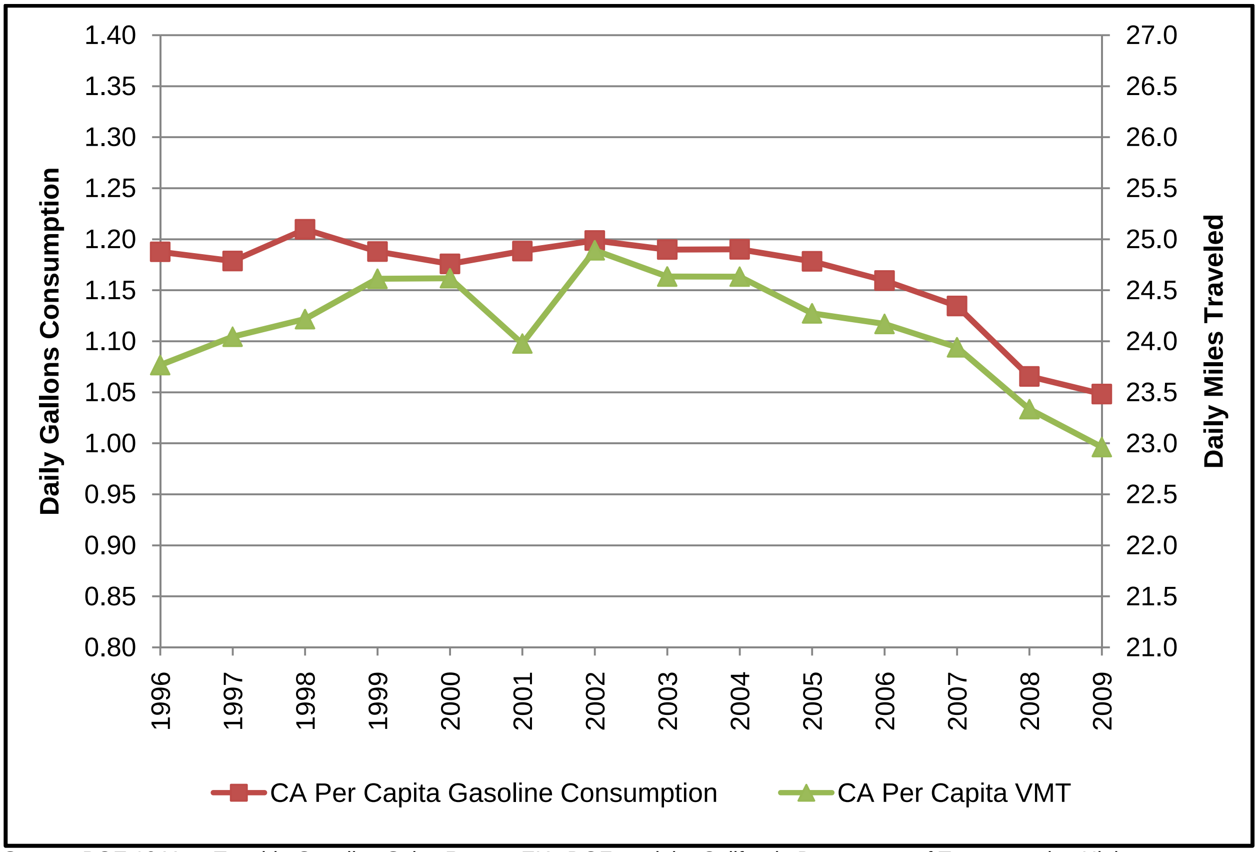
Figure 2-7: United States and California Annual Average Unemployment Rates and Per Capita Gasoline Consumption, 1983 to 2010



Source: United States Bureau of Labor Statistics, BOE 10 year Taxable Gasoline Sales Report, EIA, and DOF

Also possibly influencing gasoline consumption would be changes in driving behavior represented by changes in VMT shown in Figure 2-8.[3] From 1996 to 2007, California total VMT increased 17 percent, but the per capita VMT decreased 3 percent, going from 23.8 miles per day in 1996, to 24.9 miles per day in 2002, and then falling to 23 miles per day in 2009. From 1996 to 2004, per capita gasoline consumption remained steady at 1.2 gallons per day, until it begins to decline to 1.05 gallons per day in by 2009, matching the fall in per capita VMT. From 2004 to 2009, the decrease in per capita VMT appears to be related to the decrease in per capita gasoline use. It may also be the result of increased fleet fuel economy, which staff estimates to have increased from 19.94 to 20.56 miles per gallon for gasoline and hybrid vehicles (a 3 percent increase) from 2004 to 2009.

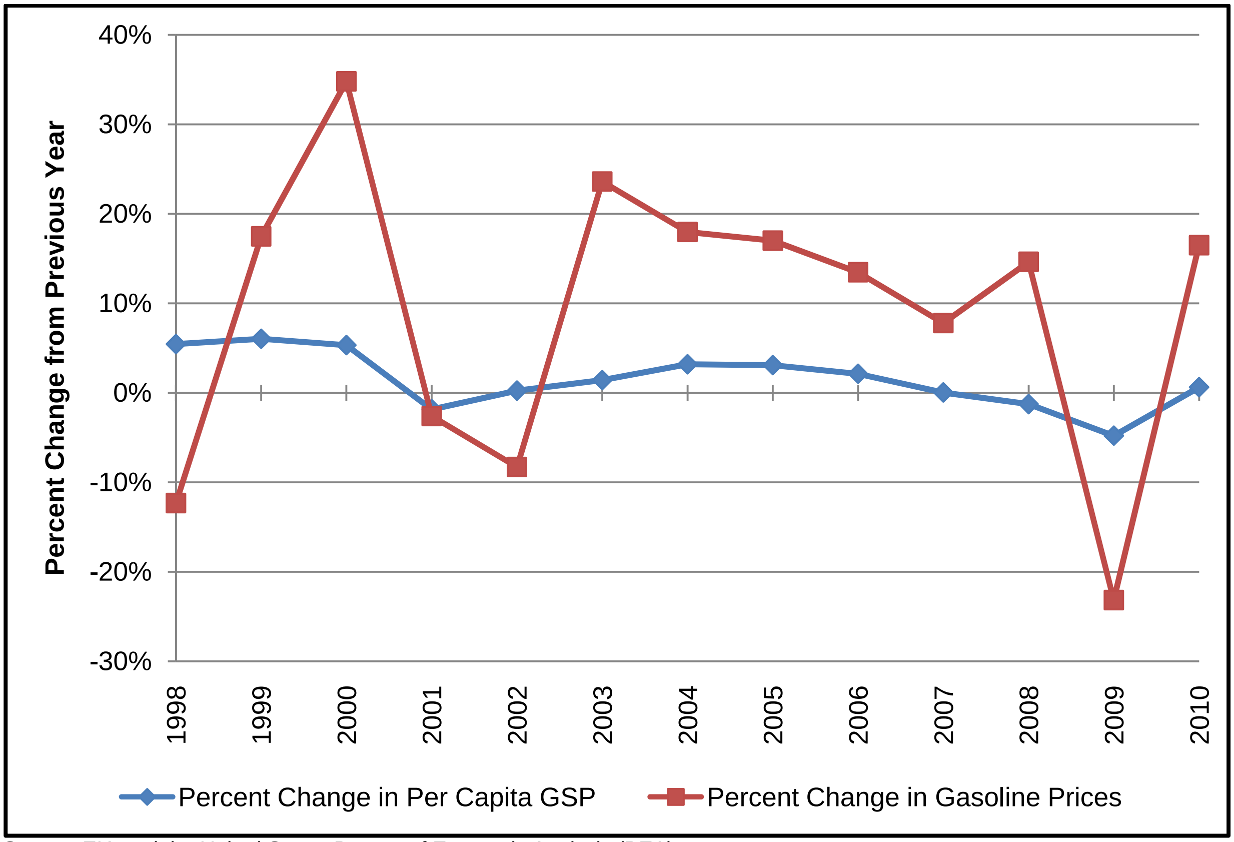
Figure 2-8: California Per Capita Vehicle Miles Traveled and Per Capita Gasoline Use 1996 to 2009



Source: BOE 10 Year Taxable Gasoline Sales Report, EIA, DOF, and the California Department of Transportation Highway Performance Monitoring System

While increased unemployment may explain the decline in per capita VMT and gasoline consumption between 2007 and 2009, it cannot explain the general decline in both of these figures from 2002 to 2007. One possible explanation for this decline is the increase in gasoline prices relative to the income of California residents. Figure 2-9 shows that gasoline prices grew, on average, ten times faster per year than income between 2003 and 2008 (the average rate of growth in per capita income was 1.44 percent and the average rate of growth for gasoline prices was 15.75 percent). These contrasting growth rates imply an increase in gasoline share of household expenditures over that time period, which may further explain the decline in per capita VMT as gasoline becomes relatively more expensive. A sharp decrease in prices did ease this burden for consumers in 2009 as prices fell on average 23 percent, but in 2010 prices rose 16.5 percent while income grew only 0.6 percent.

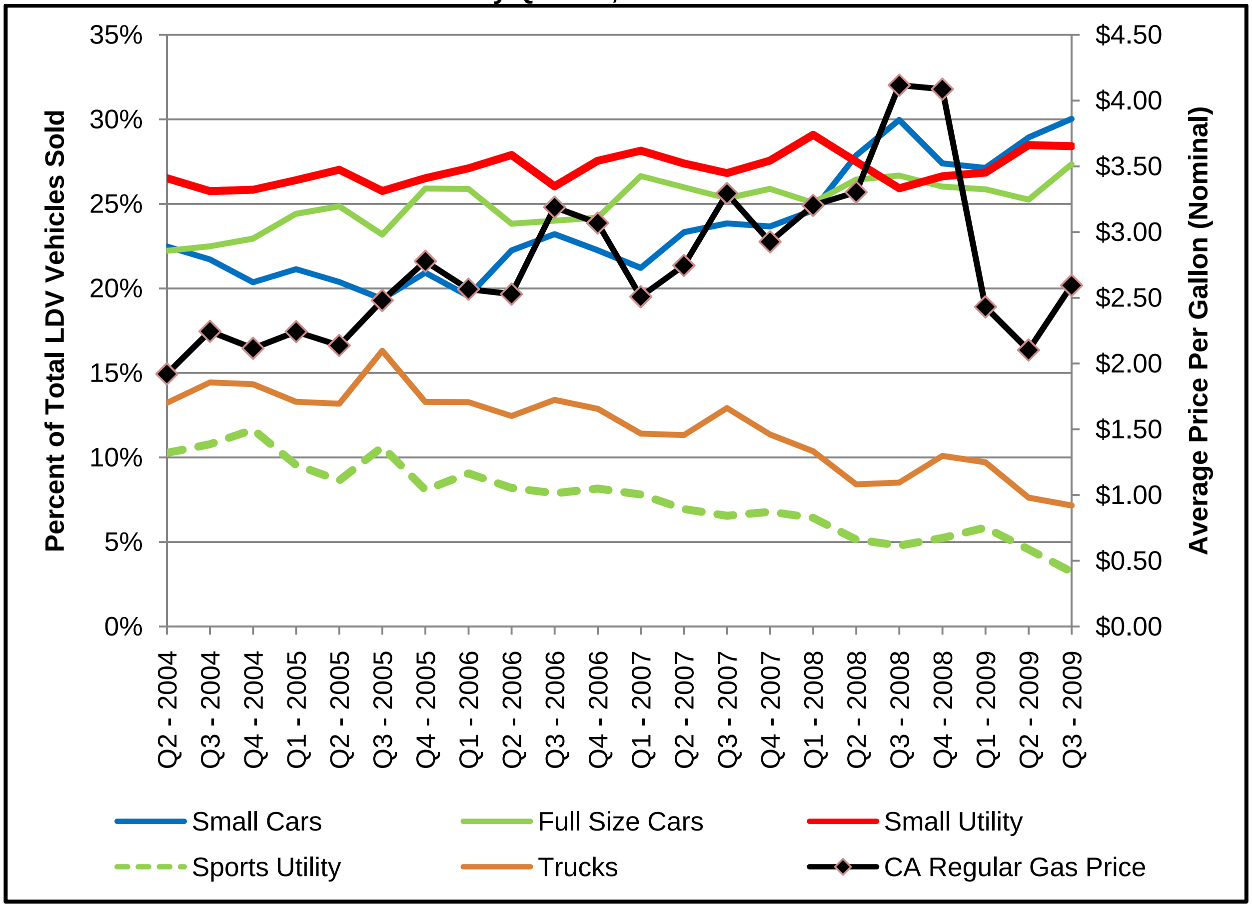
Figure 2-9: Percent Change in California Per Capita GSP and Gasoline Prices 1998 to 2010



Source: EIA and the United States Bureau of Economic Analysis (BEA)

Contributing to the decline in per capita gasoline consumption as well is fuel efficiency, represented in Figure 2-10 as the change in vehicle sales by vehicle grouping. Likely in response to changes in fuel prices, from 2004 to 2009 California consumers bought fewer large vehicles (sport utilities and trucks) and more small vehicles (compacts, midsize, full-size, etc.), improving the average fuel economy of the California light-duty fleet. From the first quarter of 2006 until the third quarter of 2008, average gasoline prices increased from $2.57 per gallon to $4.12. During the same period, the small vehicle group grew from 19.6 to 30 percent of all new vehicles sold in California and remained the top selling vehicle group over the next 4 quarters. Over the same time period, trucks dropped from 13.3 to 8.5 percent and sports utilities dropped from 9.1 to 4.8 percent of all new vehicles sold in California. These trends continued into the third quarter of 2009, with small and full size cars accounting for 57 percent, and the sports utility vehicles and trucks at just over 10 percent of new vehicles sold.

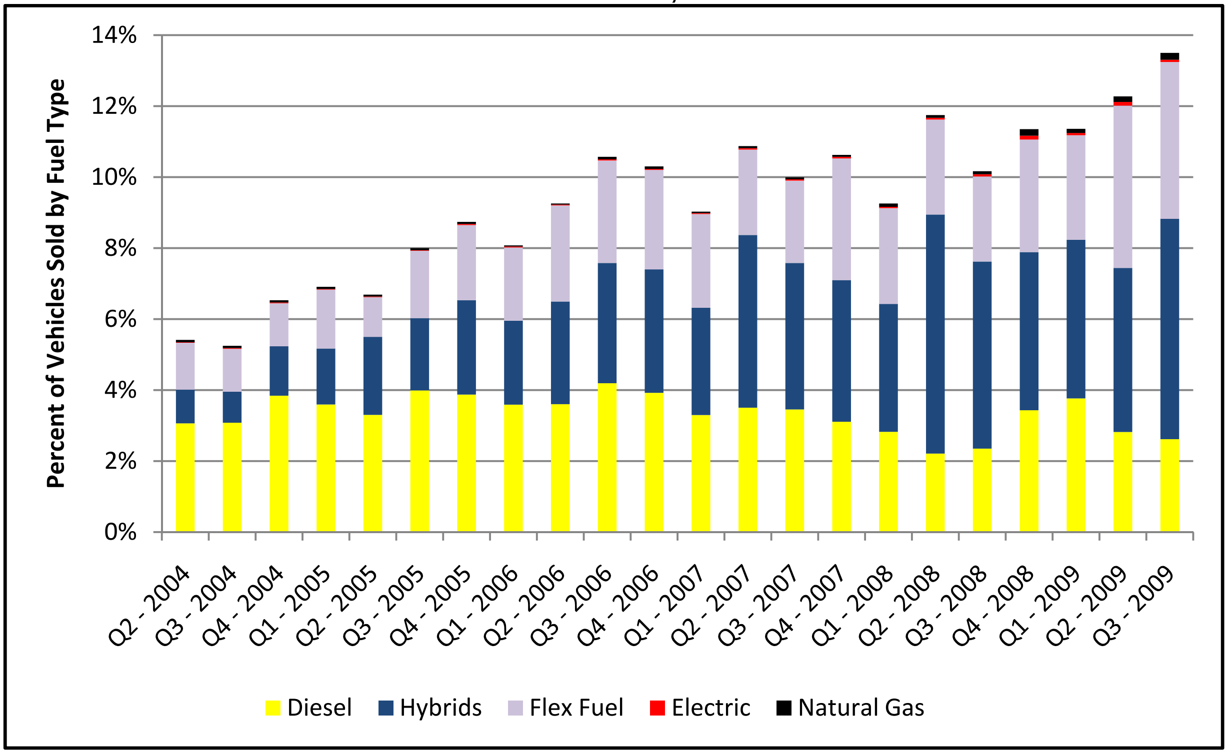
Figure 2-10: Percent of New Vehicles Sold in California by Vehicle Group and Gasoline Prices by Quarter, 2004 to 2009



Source: California Department of Motor Vehicles (DMV) Database and California Energy Commission analysis

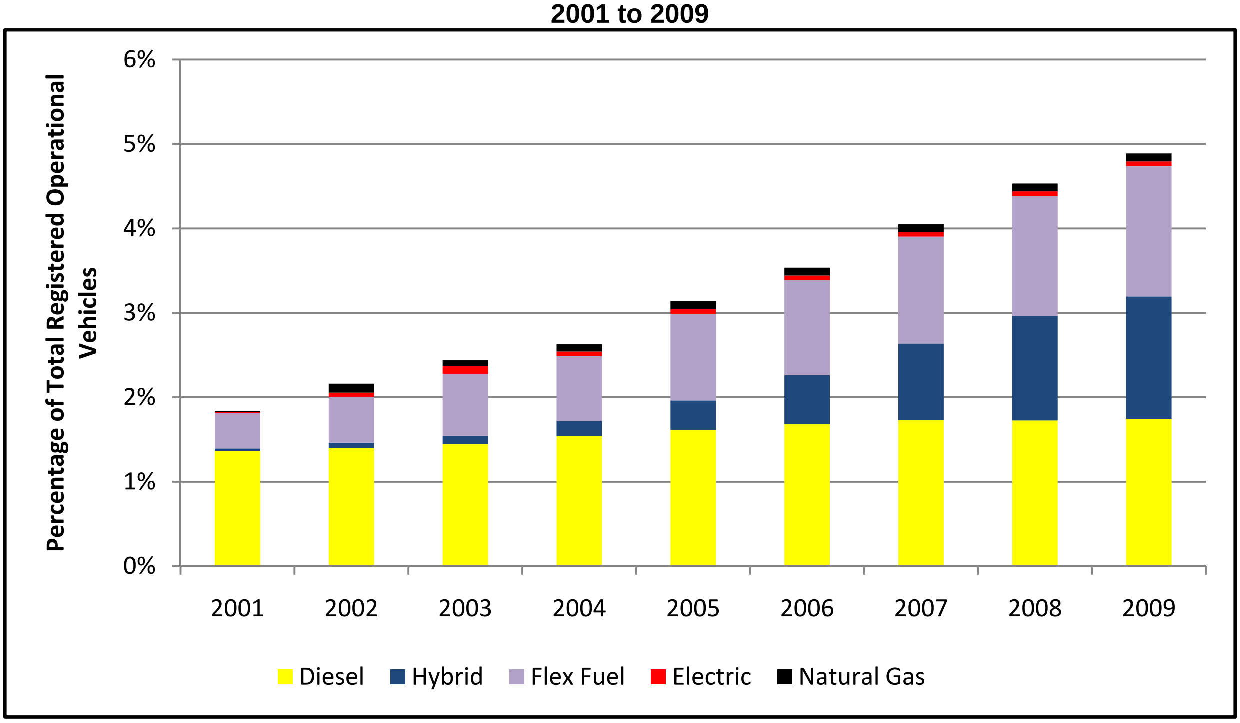
Along with the shift away from larger vehicles, California motorists have become more inclined to purchase alternative fuel vehicles in recent years. From the first quarter of 2006 until the third quarter of 2009, traditional gasoline fueled vehicles fell from 91.9 to 86.47 percent of all new vehicle purchases (Figure 2-11). Hybrid vehicles gained the most, with sales increasing from 2.4 to 6.21 percent of all new vehicles sold during the same time frame, while FFVs increased from 2.1 to 4.4 percent of the new vehicle sales. From 2001 to 2009, registered hybrid vehicles grew from 0.03 percent of the fleet to 1.45 percent, diesel increased from 1.37 to 1.73 percent, and FFVs increased from 0.42 to 1.54 percent (Figure 2-12 and Table 2-1).

Figure 2-11: Percent of New Vehicles Sold in California by Fuel Type and Quarter for All Vehicle Sizes, 2004 to 2009



Source: DMV Database and California Energy Commission analysis

Figure 2-12: Percent of California Registered Operational Light-Duty Vehicles 2001 to 2009



Source: DMV Database and California Energy Commission analysis

Table 2-1: Californian Registered Operational Light-Duty Vehicles 2001 to 2009

Light-Duty Vehicle Counts						
	Gasoline	**Diesel**	**Hybrid**	**Flex Fuel**	**Electric**	**Natural Gas**
2001	22,779,246	316,872	6,609	97,611	2,905	3,082
2002	23,384,639	334,313	15,159	129,734	11,963	25,682
2003	24,516,071	364,411	24,182	183,546	23,399	17,228
2004	24,785,578	391,950	45,263	195,752	14,425	21,269
2005	25,440,904	424,137	91,438	269,857	13,947	24,471
2006	25,741,051	449,305	154,165	300,806	14,071	24,919
2007	25,815,758	465,654	243,729	340,910	13,956	25,196
2008	25,654,102	463,631	333,020	381,584	14,670	24,810
2009	25,240,074	462,936	384,567	409,636	15,031	24,819
Compound Average Growth Rate	**1.29%**	**4.85%**	**66.19%**	**19.64%**	**22.81%**	**29.79%**

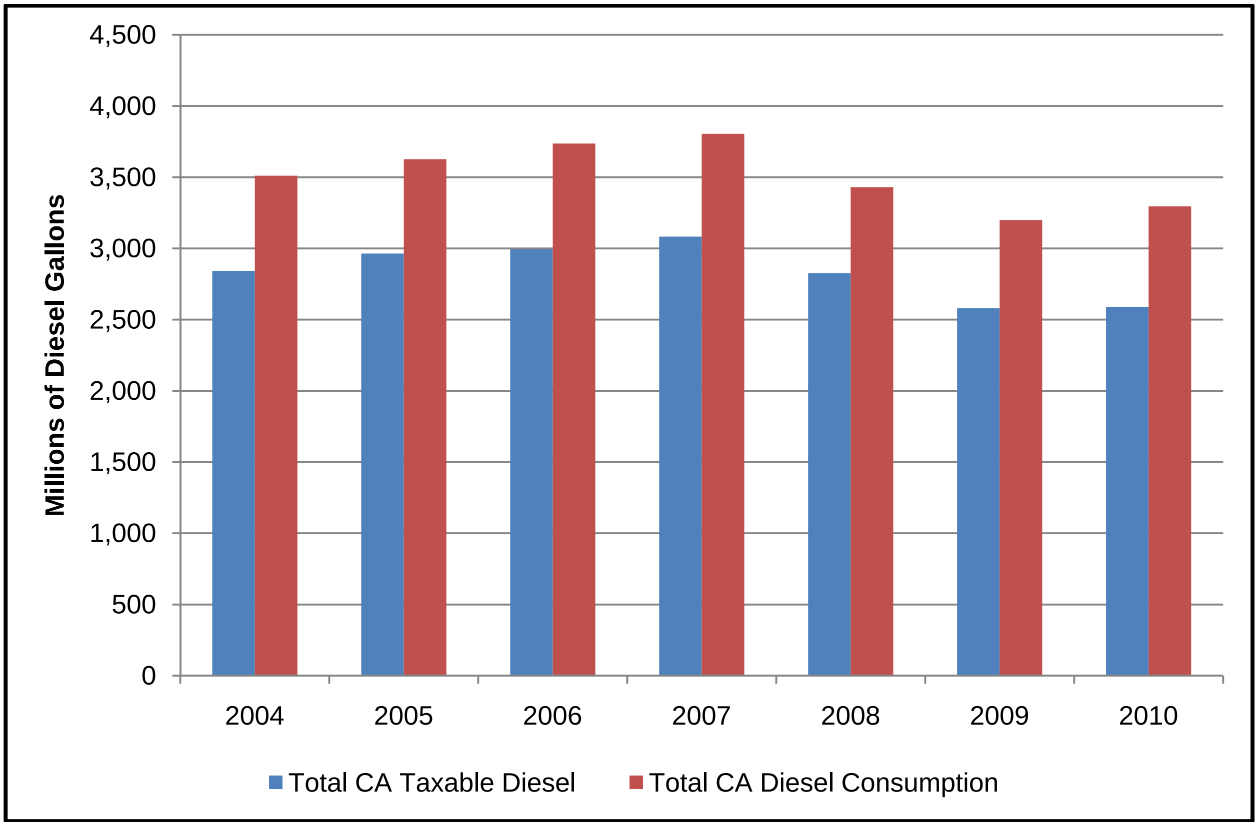
Source: DMV Database and California Energy Commission analysis

Historic Diesel Demand

Diesel fuel is primarily used by commercial entities in large freight shipping vehicles, such as railroad engines and on-road tractor-trailers, and in agricultural, transit, and construction vehicles, creating a strong link between diesel consumption and economic activity. Other factors that may impact diesel fuel consumption include population, fuel price, and average diesel fuel economy of the California and United States vehicle fleets. Increased use of alternative-fueled vehicles, such as liquefied natural gas (LNG), and CNG, could also displace diesel consumption, but their use has been primarily limited to transit vehicles and to some construction and refuse vehicles, which has not historically accounted for a large portion of diesel consumption.

Figure 2-13 shows that California taxable diesel sales rose from 2.8 to 3.1 billion gallons between 2004 and 2007, growing at an average rate of 2.73 percent a year. After 2007 diesel sales fell to just over 2.58 billion gallons by 2009, a rate of decrease of roughly 8.5 percent per year, with taxable diesel sales rising slightly in 2010 to 2.59 billion gallons. The difference between total diesel sales and the taxable diesel sales in Figure 2-13 shows the non-taxable diesel consumption (of which the largest portion is dyed diesel).[4] From 2004 to 2010 the non-taxable diesel sales were roughly 19 percent of total diesel consumption and averaged about 675 million gallons a year, and fluctuated with the demand for taxable diesel sales.

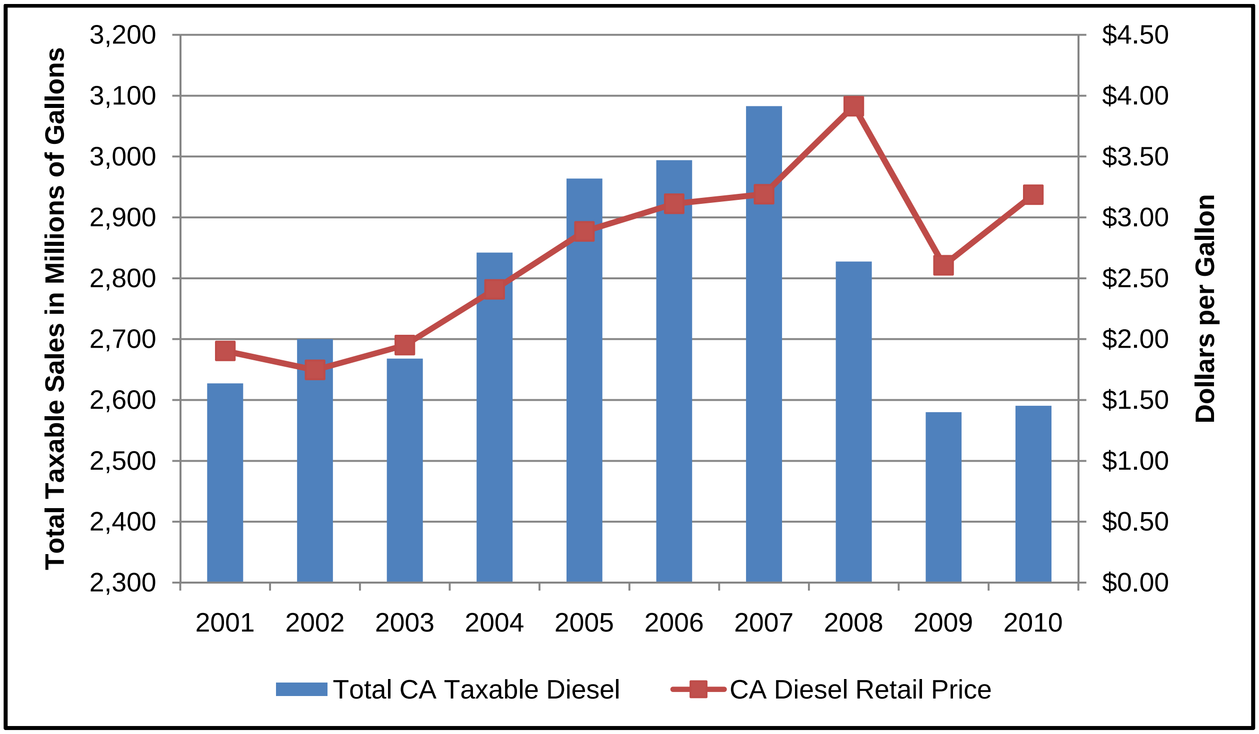
Figure 2-13: California Taxable and Total Diesel Sales 2004 to 2010



Source: BOE Taxable Diesel Sales, 10 Year Report

From 2001 to 2010, taxable diesel sales seem to show some responsiveness to price. During this time period, nominal diesel prices rose from a statewide average of $1.54 per gallon to $3.92 per gallon in 2008, with a dramatic fall in 2009 to $2.61 per gallon. After adjusting for inflation[5], diesel prices grew at an average rate of 5.9 percent a year between 2001 and 2010. As shown in Figure 2-14, from 2001 to 2003 higher diesel prices match years of lower diesel sales totals and vice versa. This relationship fades from 2004 to 2007 as prices increased at an average rate of 12.9 percent a year and taxable diesel sales grew at an average rate of 2.7 percent. But as diesel prices spiked by 22.7 percent to an annual average price of $3.91 per gallon in 2008, diesel sales fell dramatically. Yet, while price seems to account for some of the changes in taxable diesel sales, the data indicate that other factors also influence overall diesel demand.

Figure 2-14: California Taxable Diesel Sales & California Average Real Retail Diesel Prices, 2001 to 2010

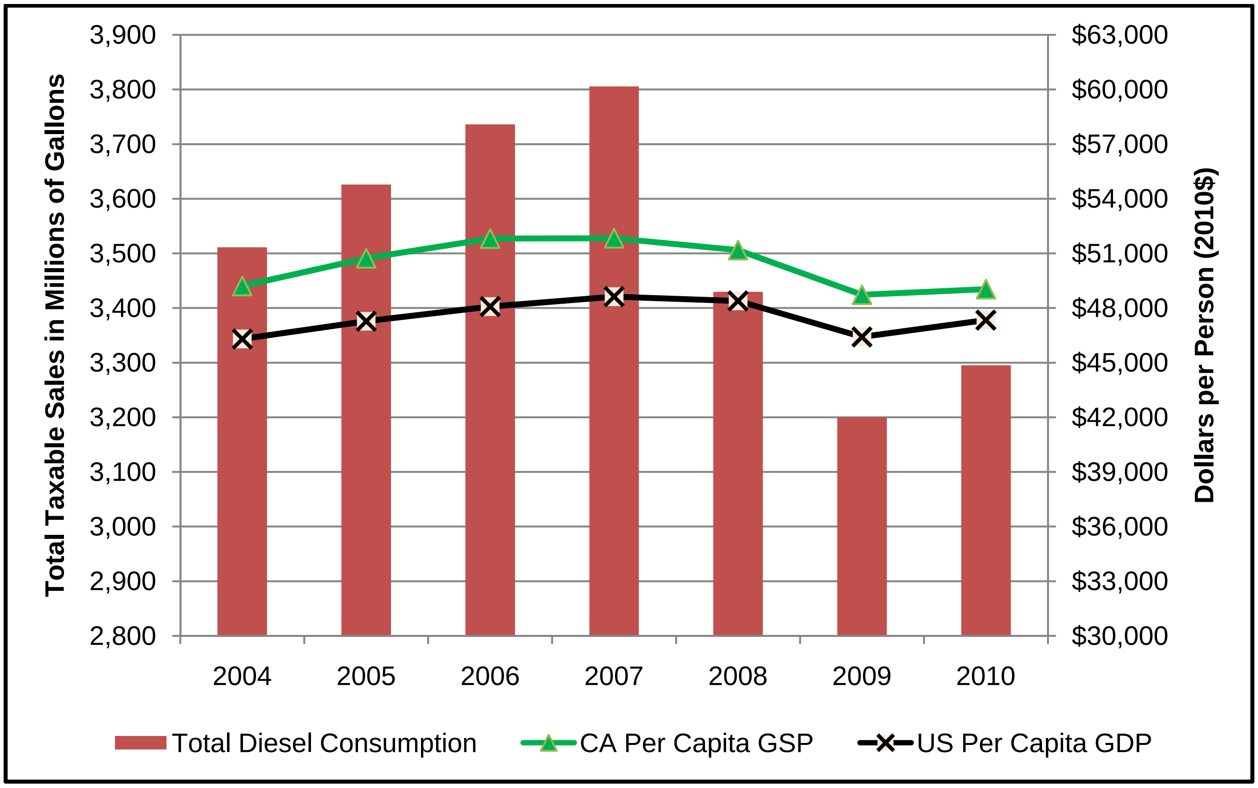


Source: BOE Taxable Diesel Sales, 10 Year Report, EIA On-Highway Diesel Prices

Due to its many commercial applications, diesel is currently the most common fuel for heavy- and medium-duty vehicles in California. In 2009, diesel powered vehicles represented 60 percent of all vehicles (regardless of fuel type) registered in California with a GVWR of 3 or higher. This percentage becomes even greater the higher the GVWR, with 77 percent of vehicles with GVWR 5 and higher, and 92 percent GVWR 7 and higher being diesel powered in 2009. While diesel does have light-duty vehicle applications, only 46 percent of the diesel fleet was light-duty vehicles with 80 percent of those vehicles weighing more than 8,500 pounds (pickups and vans).[6] Table 2-2 displays diesel powered vehicles counts for GVWR 3 to 7 as well as diesel power light-duty vehicles.

With the high concentration of diesel vehicles in heavy- and medium-duty applications, it is not surprising that diesel fuel usage would be related to economic activity. Figure 2-15 shows that, as California real per capita GSP increased from 2004 to 2007 by an average annual rate of 1.8 percent, total diesel sales increased by an average annual rate 2.7 percent. As California per capita GSP decreased by 1.26 percent from 2007 to 2008, diesel sales decreased by 8.3 percent. Likewise, California per capita GSP declined 4.8 percent from 2008 to 2009, before increasing 0.63 percent into 2010, while taxable diesel sales decreased 8.8 percent from 2008 to 2009, before increasing 0.41 percent into 2010. Since fewer goods will be purchased during periods of declining income, the shipping of goods to meet inventory and purchasing needs, and therefore the use of diesel fuel, would also decline. Although increased fuel economy of the diesel fleet would lower diesel fuel consumption, the high correlation of per capita GSP and gross domestic product (GDP) to diesel consumption suggests that declining diesel use was caused by the recent recession.[7]

Figure 2-15: Diesel Consumption and California & United States Per Capita Income 2001 to 2009



Source: California Energy Commission Analysis, BEA

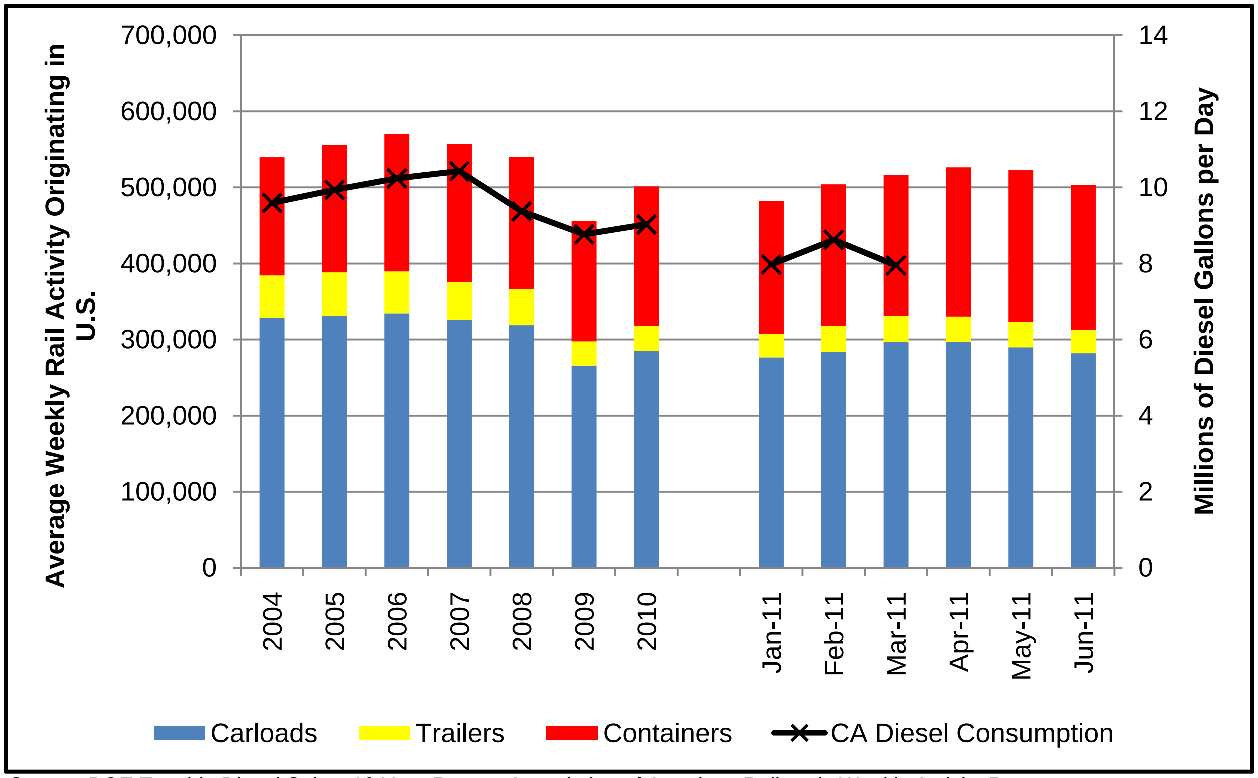
Table 2-2: California Medium- & Heavy-Duty Vehicle Counts, 2000 to 2009

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Total Registered Vehicles (LDV, MDV, & HDV)- All Fuel Types	23,452,693	24,029,290	24,770,432	26,014,352	26,306,356	27,194,069	27,642,889	27,893,303	27,828,930	27,458,229
Total Diesel Vehicles (LDV, MDV, & HDV)	686,903	704,754	757,785	818,615	863,290	944,698	1,005,894	1,060,166	1,036,569	1,016,406
GVWR 3 Vehicle - All Fuel Types	311,783	331,742	331,813	328,046	281,718	284,590	294,140	295,552	295,005	283,939
GVWR 4 Vehicle - All Fuel Types	101,307	104,033	118,055	125,111	131,844	155,011	156,144	160,982	159,711	154,235
GVWR 5 Vehicle - All Fuel Types	24,804	26,931	41,319	47,080	50,488	54,421	59,385	63,298	64,383	65,034
GVWR 6 Vehicle - All Fuel Types	137,835	132,758	144,565	137,936	142,920	168,070	178,382	189,846	186,898	182,872
GVWR 7 Vehicle - All Fuel Types	94,210	92,421	93,965	97,001	96,087	91,976	93,512	93,270	87,311	83,210
GVWR 8 Vehicle - All Fuel Types	138,573	131,219	137,709	149,745	148,511	166,716	170,519	179,508	158,883	147,186
Diesel GVWR 3 Vehicle	50,405	56,328	69,614	81,205	88,096	99,124	112,812	123,844	128,315	128,104
Diesel GVWR 4 Vehicle	33,529	36,572	40,867	43,769	47,068	53,579	57,746	60,673	61,193	58,936
Diesel GVWR 5 Vehicle	11,796	14,104	16,904	19,631	23,062	26,693	31,194	35,293	37,054	38,255
Diesel GVWR 6 Vehicle	78,032	77,484	85,713	84,231	88,633	105,185	112,351	119,792	117,836	115,776
Diesel GVWR 7 Vehicle	80,925	80,098	81,666	83,682	84,006	83,111	85,472	86,883	81,281	77,609
Diesel GVWR 8 Vehicle	130,239	123,296	128,708	141,686	140,475	152,869	157,014	168,027	147,259	134,790

Source: California Energy Commission analysis of the DMV Database

Economic activity also drives railroad traffic and Figure 2-16 shows how per overall United States railroad traffic and total California diesel sales are related. An increase of 3.3 percent for all railroad activity from 2004 to 2007, matches with years of higher total diesel consumption and higher per capita GSP (seen in Figure 2-15). Lower traffic years, such as 2007 to 2009 (an 18.2 percent cumulative fall for that time period) aligns with years of lower diesel consumption. While the Energy Information Administration's (EIA) adjusted sales of distillate fuel oil by end use totals indicate that railroad use only averaged 7.5 percent of total diesel consumption from 2004 to 2008, railroad activity is highly interconnected with on-road consumption and supports the expectation that changes in United States rail activity have indirect effects on other uses of diesel.[8]

Figure 2-16: Average Week Rail Activity & BOE Diesel Sales 2001 to 2011

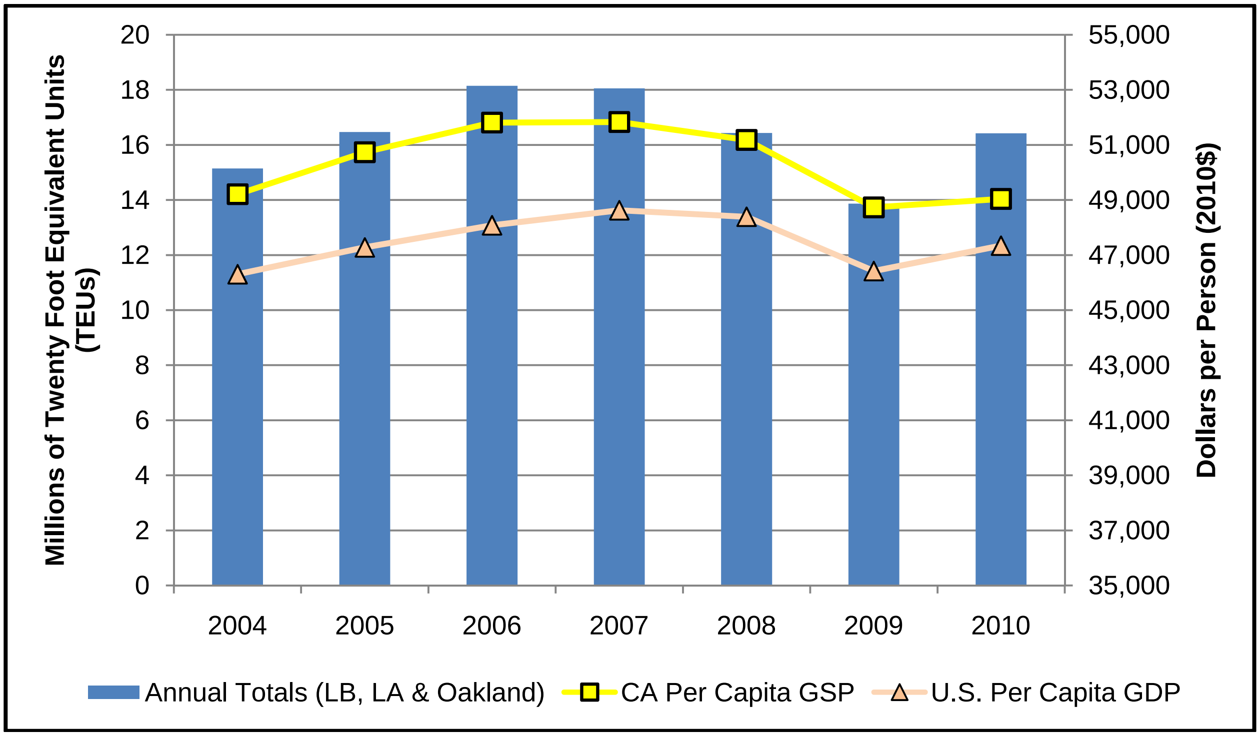


Source: BOE Taxable Diesel Sales, 10 Year Report, Association of American Railroads Weekly Activity Reports

The decreases in 2008 and 2009 for rail activity are also seen in container traffic in California ports. Port activity is linked to diesel consumption through trucking and railroad transport moving cargo away from the ports. Figure 2-17 shows that port container activity steadily increased from 15.14 million twenty-foot equivalent units (TEUs) in 2004, to a peak in 2006 and 2007 of roughly 18 million TEUs. This increase in activity is matched by increases in California per capita GSP and United States per capita GDP that rise from $49,210 and $46,303 to $51,835 and $48,630 in 2007, respectively.[9] In 2008 when the California per capita GSP fell to $51,182, California port activity also dropped to 16.4 million TEUs, implying a link between GSP and total port activity. When compared to Figure 2-15, as the port activity and per capita GSP figures fall, diesel demand falls as well in response to the lower port activity. In 2009, port traffic continued to fall to 13.8 million TEUs and total California diesel sales fell from 3.43

billion gallons in 2008 to 3.2 billion gallons in 2009. The 2010 growth in port container traffic was the first since 2006, with port activity rising to near the 2008 total of 16.4 million TEUs.

Figure 2-17: California Port Activity with California & United States Per Capita Income 2001 to 2010



Source: American Association of Port Authorities, Port of Long Beach, Port of Los Angeles, and Port of Oakland Statistics

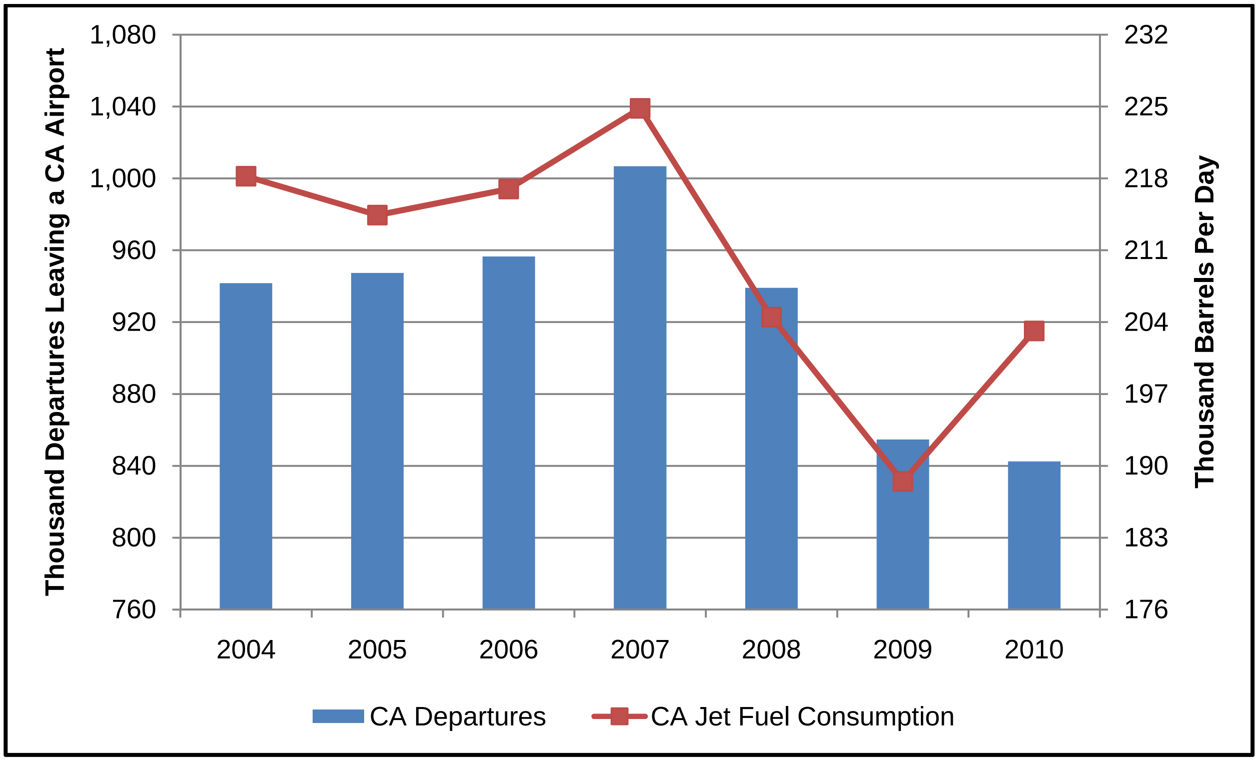
Staff believes that it is likely that the recent decline in diesel demand is the result of the recession that began in 2008. Indicators such as port activity, railroad activity, and GSP, show a drop in activity in 2008 and 2009 that matches the decline in diesel sales for the same time periods. While these indicators seem to describe a portion of the reason that diesel rose and fell in the 2000 to 2010 decade, the simple relationship between California per capita GSP and total diesel sales was the most strongly correlated. The explanation of lower per person income resulting in less overall cargo movement, spread across the different types of freight modes that would use diesel fuel, such as trucking and railroad, seems to be supported by the data.

Historic Jet Fuel Demand

Consumption of jet fuel is a result of demand for air travel and air cargo shipping. Indicators to assess in analyzing jet fuel consumption include population, income, average ticket price, total departures, and fuel used per passenger departure. Since turnover rates are very low for the U.S. commercial air fleet, fuel efficiency gains from new plane turnover or engine upgrades are assumed to be minimal. In recent years, United States passenger air travel averaged 93 percent of all common carrier plane departures. From 2004 to 2010, the number of passengers flying in commercial airplanes increased, even as aggregate plane departures fell by 12 percent in total. With the fall in United States plane departures, United States jet fuel consumption decreased from 1.63 to 1.30 million barrels per day, between 2004 and 2009, before increasing to 1.42 million barrels per day in 2010.[10]

In California, jet fuel consumption matched several of the same patterns found in United States jet fuel consumption. Figure 2-18 shows that the number of passenger-carrying planes departing California airports increased from roughly 942,000 departures in 2004 to roughly 1,010,000 departures in 2007, before falling to 842,000 departures in 2010. While departures decreased 16 percent from 2007 to 2010, jet fuel consumption declined 9.6 percent, with a large increase between 2009 and 2010.[11]

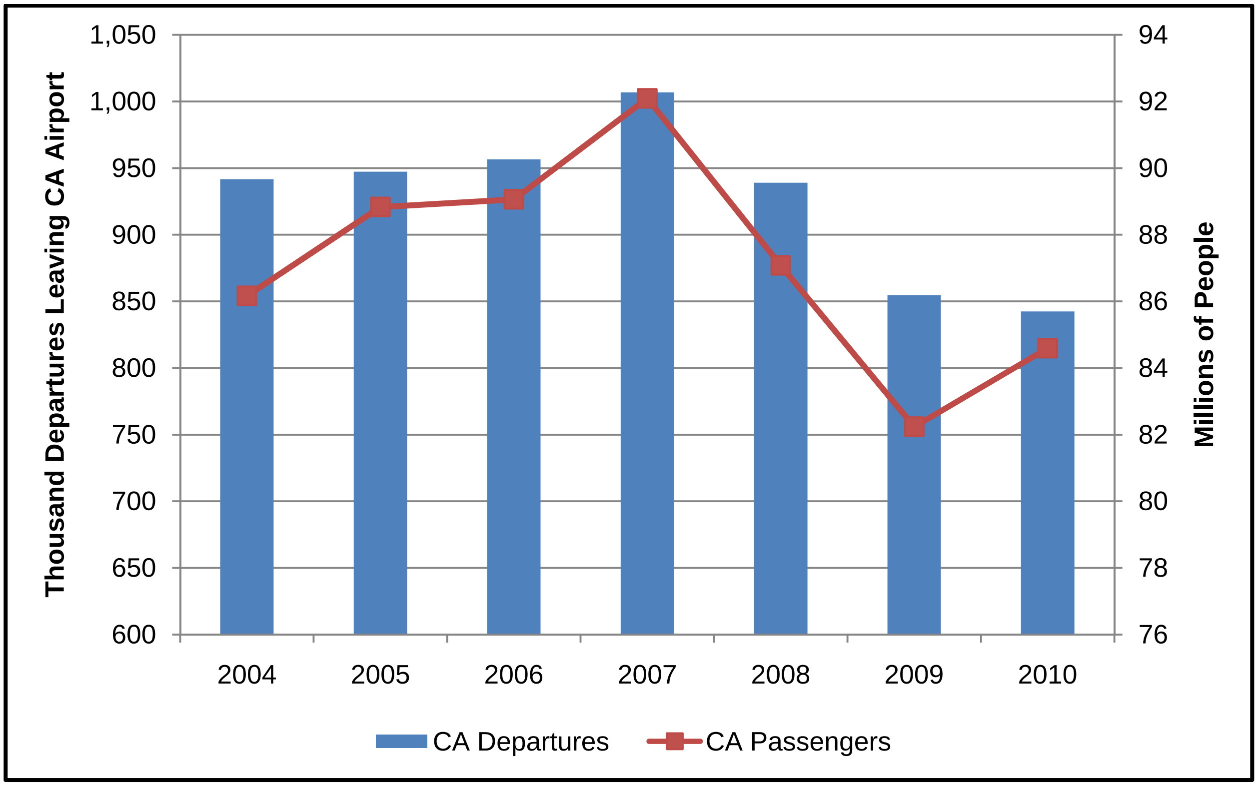
Figure 2-18: California Plane Departures and Jet Fuel Consumption 2004 to 2010



Source: Bureau of Transportation Statistics TranStats and California Energy Commission

One reason for the decrease in the number of planes departing Californian airports is the number of passengers demanding flights. Figure 2-19 shows that in 2004, roughly 86 million passengers departed from California airports. That number increased to 92 million in 2007 before declining to 84.5 million passengers in 2010. Like departures, passenger totals have increased and decreased with California jet fuel consumption. While the number of passengers and departures has been trending together since 2004, the number of passengers per departure has been steadily increasing. In 2004, flights originating in California averaged 91.5 passengers per departure. By 2010 that number had risen to 100.4 passengers per departure.

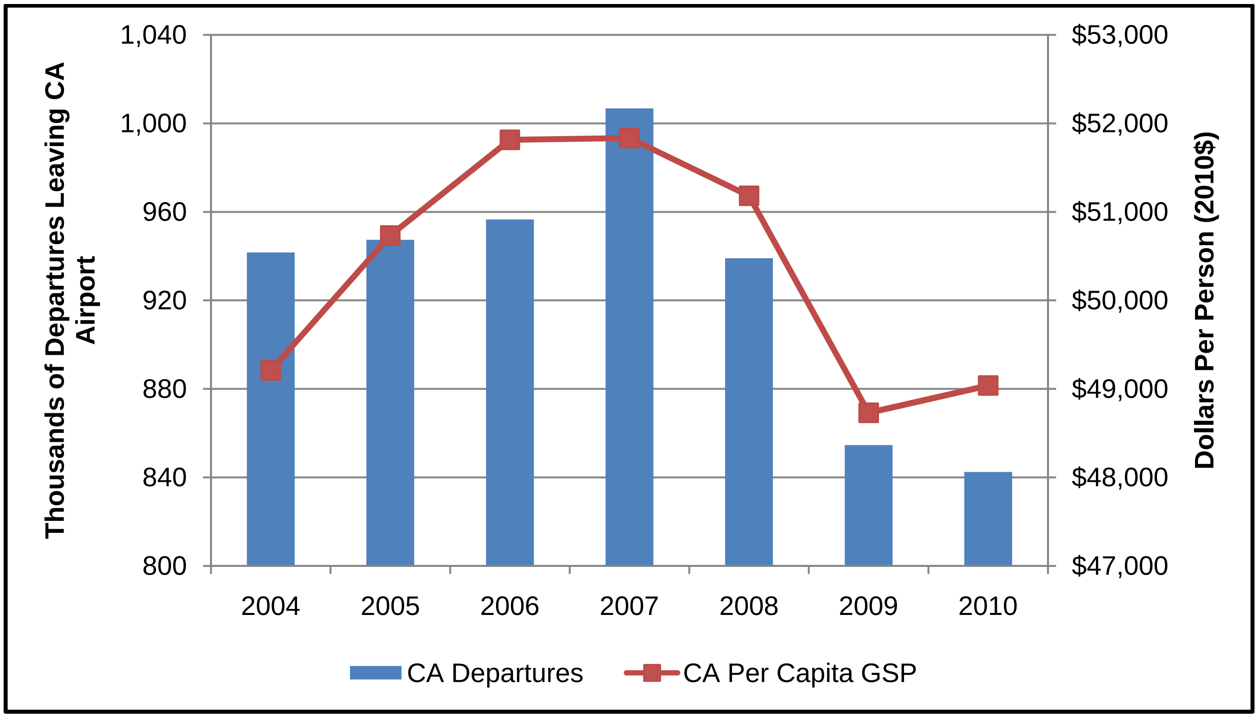
Figure 2-19: Origin California Airport Passengers and Departures 2004 to 2010



Source: Bureau of Transportation Statistics TranStats

Another reason for changes in aircraft departures and jet fuel consumption are changes in income. As shown in Figure 2-20, between 2004 to 2007 California per capita gross GSP rose at an average growth rate of 1.7 percent per year, with the number of departures leaving California airports increasing at an average growth rate of 2.25 percent per year.[12] The decline in departures from 2007 to 2010 was matched by a decrease in personal income, as per capita GSP fell 5.4 percent. While the increase in departures from 2004 to 2007 is noticeable, increases in 2005 and 2006 were not as large. Also apparent in this graph is that the decrease in income for Californians closely tracked the fall in departures from 2007 to 2009.

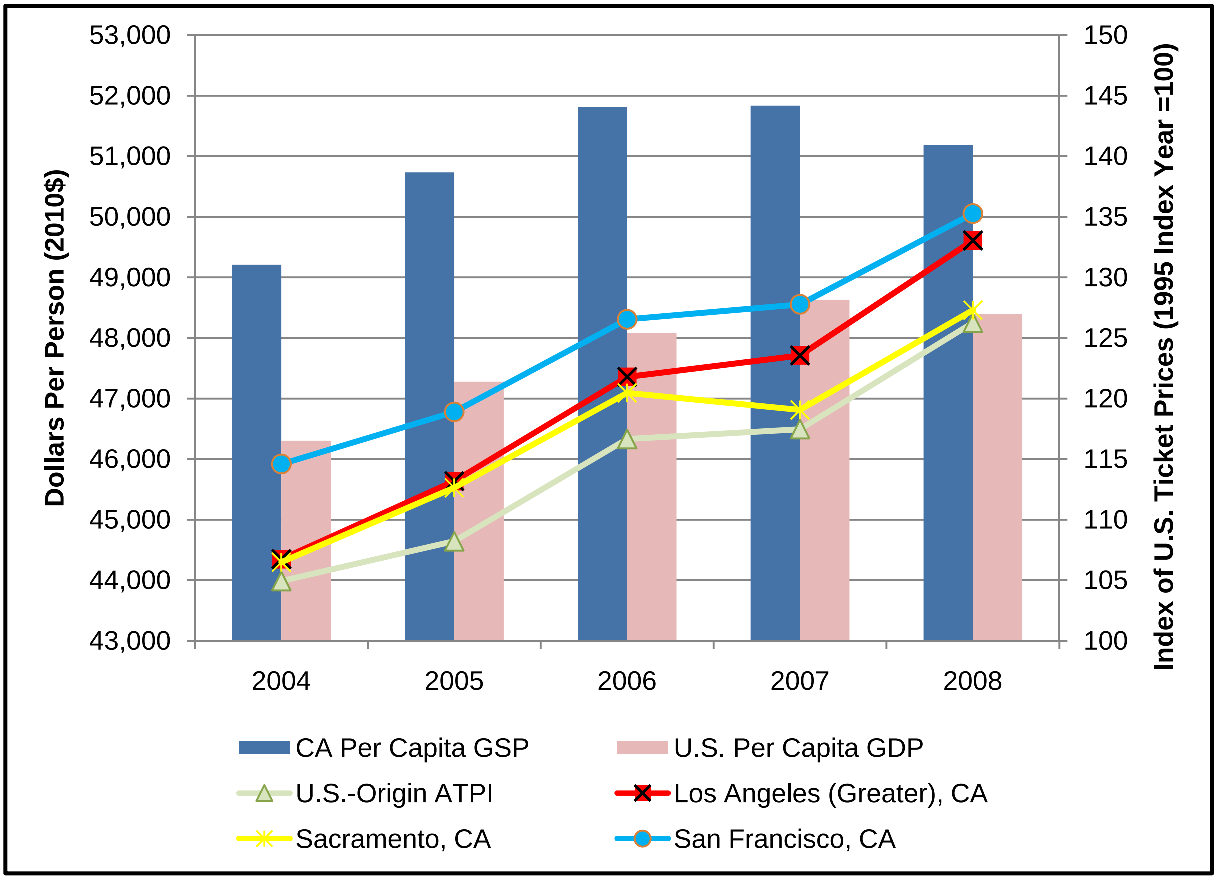
Figure 2-20: California Passenger Departures and Californian Per Capita GSP
2004 to 2010



Source: Bureau of Transportation Statistics TranStats and BEA

Figure 2-21 shows California per capita GSP and United States per capita GDP, as well as air travel price indices for the United States (average), Greater Los Angeles Area, Sacramento, and San Francisco airports. Between 2004 and 2007, ticket prices for flights involving airports in the Greater Los Angeles Area, Sacramento, and San Francisco all rose at an average rate of 4.2 percent. Most of this increase occurred from 2004 to 2006, with the average change in ticket prices from 2006 into 2007 being only 0.4 percent. When comparing changes in ticket prices to the change in per person income, it becomes apparent that increases in income were being offset by increases in ticket price from 2004 to 2006, leading to lower demand for flights in California. But in 2007, as income increased and ticket prices remained constant, air travel becomes relatively less expensive and a rise in departures and jet fuel consumption occurred. Like the large upswing in departures and fuel consumption in 2007, the declines in 2008 seem to be influenced by the income and ticket price differential as well. In 2008, Californians experienced a 0.6 percent drop in per person income and an average rise in ticket price of 6.8 percent. This relative increase in the price of air travel corresponded with a decline in the level of departures to roughly 2004 totals, which cut jet fuel consumption considerably. Figure 2-21 also illustrates California ticket prices tend to be higher than the U.S. average, with San Francisco being the most expensive.

Figure 2-21: California per Capita GSP and Air Travel Price Indices
2004 to 2008



Source: Bureau of Transportation Statistics TranStats and BEA

Like gasoline and diesel demand, there are indications that the recent decline in California jet fuel demand was a result of the recession that began in 2008. Indicators such as ticket prices, departures, passenger enplanements, and per capita GSP show a drop in activity in 2008 and 2009 that matches the decline in jet fuel consumption for those years. Per capita income relative to ticket prices seems to be best explanatory factor when analyzing short-term fluctuations in jet fuel consumption and plane departures.

Alternative Fuels

Retail sales of alternative fuels, including compressed natural gas, biodiesel, E85, and electricity, have grown in recent years yet remain a small share of transportation fuels use in California. Table 2-3 displays California Board of Equalization (BOE) retail fuel sales totals for biodiesel and E85, and staff estimates of natural gas and electricity consumption for transportation purposes.[13] The table shows that natural gas is the most used alternative fuel, with combined electricity consumption ranked second. The table also shows significant fluctuations in the sales of these fuels. It is unclear whether these changes are caused by economic and policy conditions, or result from data collection issues. These issues include: insufficient dedicated metering infrastructure for electric vehicles from which to obtain data leaves only a bottom-up calculation method for deriving on-road electricity consumption; new BOE reporting procedures for biodiesel and E85 sales makes the early years of data suspect as retailers learn to properly fill out forms; and only a 2006 report from the California Public Utilities Commission (CPUC) with which to calibrate bottom-up derivations of natural gas for transportation consumption.

Table 2-3: California Alternative Fuel Estimates for Transportation Consumption 2006 to 2010

Fuel Consumption For Transportation Purposes	2006	2007	2008	2009	2010
Biodiesel (native gallon)	19,610,347	17,459,058	11,702,110	6,921,124	5,398,081
E85 (native gallon)	2,227,327	4,366,914	26,648,447	13,204,070	9,979,885
Natural Gas (GGE)	106,857,111	111,424,023	118,551,539	138,291,091	147,857,131
Electricity – On-Road Light-Duty Vehicles (GGE)	7,430,047	7,405,692	8,030,186	8,545,887	8,266,272
Electricity –On Road MD/HD Transit Vehicles (GGE)	3,902,890	3,863,521	4,131,559	4,309,838	4,232,264
Electricity –Rail Transit Vehicles (GGE)	15,660,110	13,665,525	16,586,978	16,036,290	NTD data not available

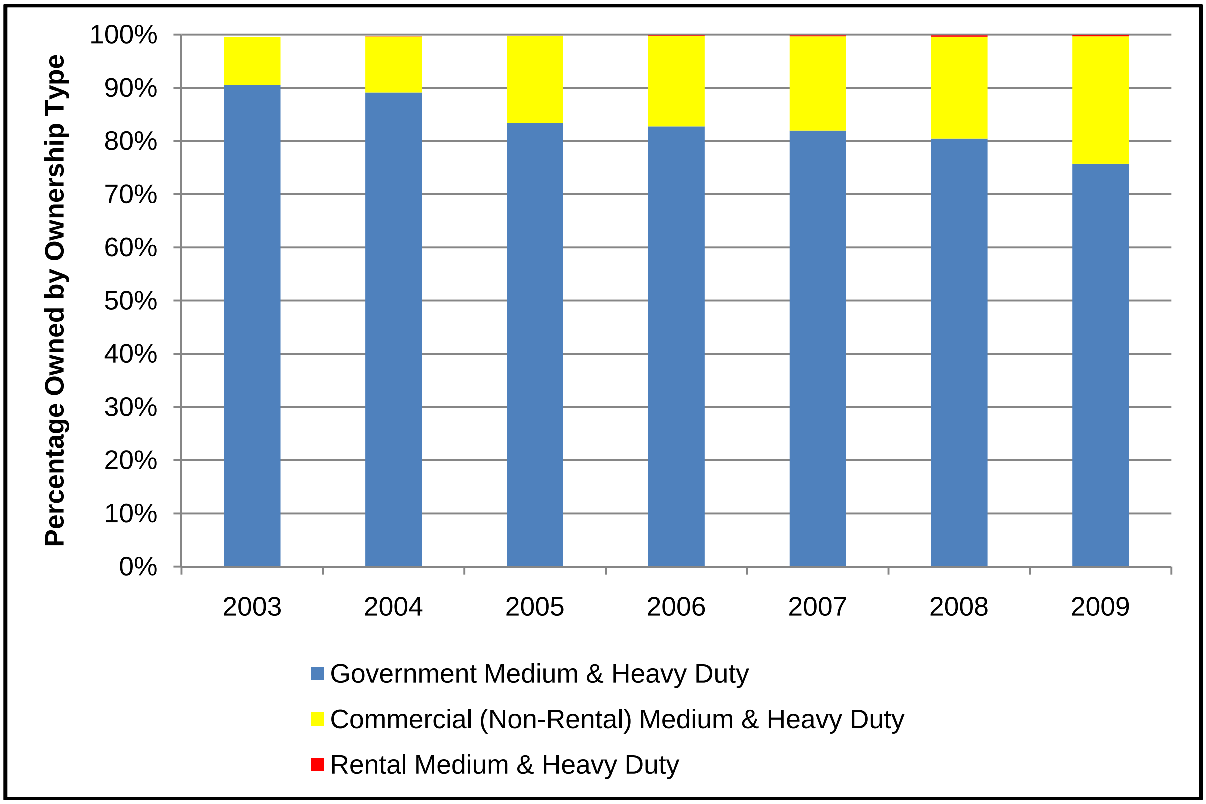
Source: California Energy Commission analysis, National Transit Database, California Public Utilities Commission, BOE

Currently, the primary difficulty Energy Commission staff experiences when attempting its own collection of consumption data for the Petroleum Industry Information Reporting Act (PIIRA) (including gasoline and diesel as well as alternative fuels) is locating dispensing stations for all of these fuels (both publically and privately accessible), because there is no central repository for California transportation station locations. Both the California Water Board and all Air Quality Management District's (AQMD) have regulations in place to collect station location information for tanks and dispensers, but the information collected is often incomplete. Another difficulty is that the Energy Commission would need resources to expand data collection efforts to commercial and government fleets, which are believed to be the primary consumers of alternative fuels, as explained below. U.S. DOE efforts, especially their TransAtlas tool, have helped staff in this regard but these efforts are also far from complete.[14] It should also be noted that while BOE sales numbers on fuels form the basis of consumption figures presented in this chapter, that information is collected at the fuel terminal level and it is unclear how much of the fuel is truly sold at retail level. BOE also doesn't track electricity and natural gas consumption, forcing staff to collect data from other sources like the CPUC which is not required to segregate consumption for transportation use in its data.

After comparing consumption figures of alternative fuels to vehicle counts information, alternative fuel consumption seem to be driven by California air quality policies and federal petroleum reduction policies. Light-duty alternative fuel consumption for E85 has been in response to federal CAFE regulations which incentivizes the production and sales of FFV models. Consumer consumption of biodiesel appears to be motivated by energy security and environmental concerns. However, staff estimates that eighty to ninety percent of the alternative fuel consumption occurs in heavy-duty applications. This make the SCAQMD policy on fleet vehicle purchases one of the most significant drivers of alternative fuel consumption in California today.

The SCAQMD, an air district covering Orange County and the urban portions of Los Angeles, Riverside, and San Bernardino counties, is estimated to contain roughly 50 percent of the California population. In the summer of 2000, SCAQMD issued clean fleet rules requiring fleet operators of 15 or more vehicles, including school buses, transit buses, trash trucks, airport shuttles, taxis, and heavy-duty utility trucks, to buy clean-fueled vehicles when replacing their fleets. This rule greatly affected government and commercial transit fleets operating in the South Coast air basins, helping to raise the number of natural gas powered buses in California from just under 1,400 to over 11,000 in 2009. These rules effectively resulted in a ban on the sale of diesel-powered buses throughout the 5 county SCAQMD regions. Figure 2-22 shows the percentage of natural gas medium- and heavy-duty vehicles owned by government and commercial entities in California from 2003 to 2009. As seen in the figure, these entities owned over 99 percent of all natural gas medium- and heavy-duty vehicles over that time-period. While the percentage of government ownership of natural gas vehicles has declined over this time, the number of vehicles owned by state and local governments has roughly doubled. During 2003 to 2009, government and commercial ownership of all natural gas vehicles has risen from just under 65 percent to over 70 percent in 2009.

Figure 2-22: Percentage of Natural Gas Medium- and Heavy-Duty Vehicles by Ownership Type 2003 to 2009



Source: DMV Database and California Energy Commission analysis.

Local government agencies within the SCAQMD have also implemented their own policies to purchase and operate clean alternative-fuel vehicles. For example, the Los Angeles County Metropolitan Transportation Authority adopted its Alternative Fuel Initiative in 1993, which directed future transit bus purchases to alternative-fuel buses. Orange County Transportation Authority, Omnitrans, Riverside Transit Agency, and Sunline Transit Agency also instituted similar policies. Table 2-4 displays information on the driving factors behind alternative fuel consumption and vehicle purchases.

Table 2-4: On-Road Alternative Fuel Consumption Drivers 2000-2010

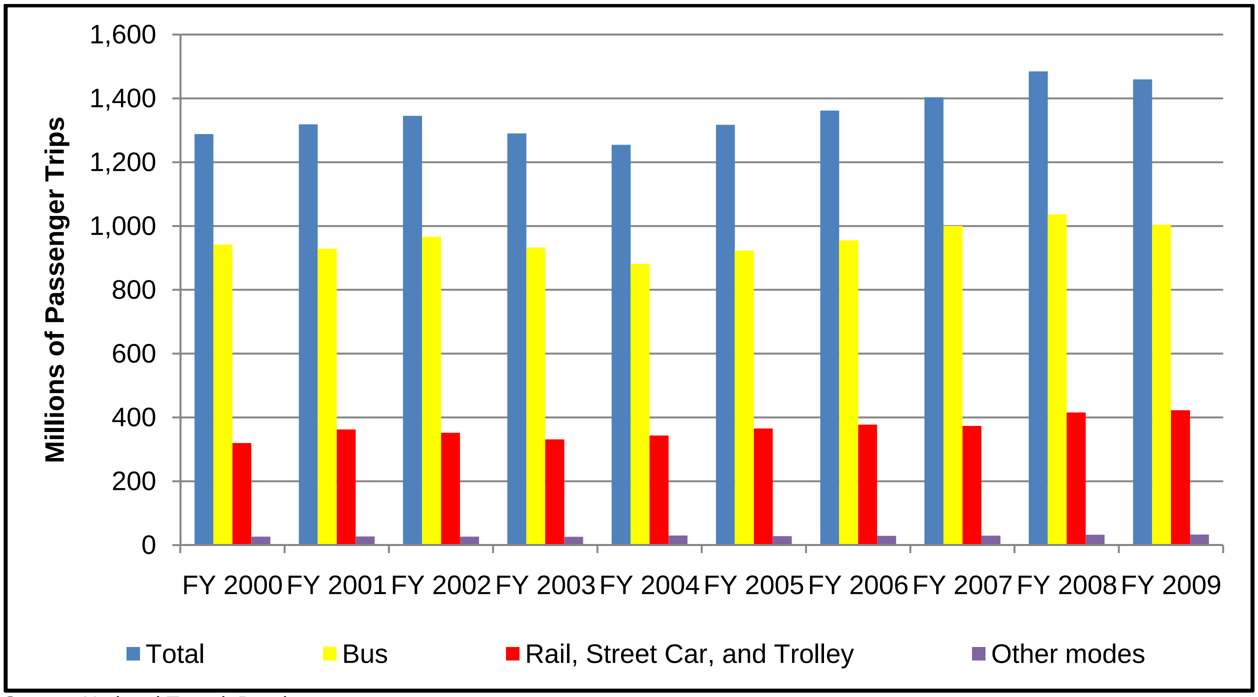
Fuel Type	Light-Duty Vehicles	Medium- and Heavy-Duty Vehicles
Biodiesel	Grass roots consumer demand Federal Governmental Subsidy	Federal Energy Policy Act compliance option
E85	Grass roots consumer demand Federal CAFE FFV provisions Federal subsidy lowering fuel cost	No current medium- and heavy-duty vehicles offerings can use E85 Post 2010, models are anticipated to be released
Natural Gas	Federal CAFE CNG provisions Single occupants allowed to use carpool lanes	South Coast Air Quality Management District - Rule 1192 Air Resources Board Public Transit Rule Federal Energy Policy Act
Electricity	Grass roots consumer demand	Transit trolley buses using overhead electrical powered, 95% are in San Francisco, 5% in Santa Barbara
Propane	Declining vehicle numbers	South Coast Air Quality Management District - Rule 1192

Source: California Energy Commission

At the federal level, the United States Energy Policy Act (EPAct), administered by the DOE, was designed to reduce dependence on foreign oil supplies and increase the use of alternative fuel vehicles.[15] As of 1997, federal and state fleet operators have been required to purchase alternative fuel vehicles as a percentage of new vehicle acquisitions. This percentage started at 10 to 33 percent depending on fleet and gradually increased over time. EPAct alternative fuel vehicle purchase requirements rose to 75 to 90 percent by the years 2000 and 2002, respectively.

On February 24, 2000, ARB approved a statewide regulation that will reduce the air pollution impacts of large diesel powered urban transit buses (greater than 33,000 pounds GVWR). The regulation requires reductions in particulate matter and Nitrogen Dioxide (NOx) fleet emissions by urban transit bus operators and more stringent exhaust emission standards applicable to engine manufacturers. To implement this regulation, urban transit bus fleet operators are required to choose between two different compliance paths: the diesel path or the alternative fuel path. As with the SCAQMD, data on transit fleet operators seems to indicate that many fleet operator choose the alternative fuel path by purchasing more natural gas vehicles. With these fleet purchasing policies driving the purchases of new medium- and heavy-duty vehicles, it easy to see why a large portion of alternative fuel consumption is driven by transit agency activity. Staff estimates that roughly 40 to 45 percent of total California alternative transportation fuels are used by transit entities, based on comparison of alternative consumption figures and the National Transit Database (NTD) fuel consumption estimates. One likely reason why natural gas is the most used alternative fuel is that from fiscal year 2000 to 2009, bus travel accounted for roughly 70 percent of all urban transit passenger trips, while light rail, streetcar, and trolleys use electricity accounted for only 27 percent. Analysis of the California Department of Motor Vehicles (DMV) database indicates that roughly 10 percent of all buses are powered by natural gas, which has been growing since 2000. Figure 2-23 displays NTD estimates for all transit passenger trips.

Figure 2-23: California Transit Passenger Trips
Fiscal Year 2000 to 2009



Source: National Transit Database

Chapter 3: California Transportation Fuel Demand Forecasts

Staff has prepared forecasts of transportation fuel demand to 2030 using demand forecasting models for commercial light-duty vehicle travel, urban and intercity travel (including public transit), freight movement, and passenger and freight aviation. These demand models are behavioral models that respond to changes in economic and demographic variables, and to changes in vehicle attributes and fuel prices (see Appendix A for more detail). These models use projected inputs from a number of sources in order to develop fuel demand forecasts. Estimating future transportation fuel demand requires staff to contend with uncertainties in future economic and market conditions, human behavior, and the regulatory and policy environment, therefore the forecasts must be viewed in this context. Staff has developed multiple scenarios to allow for many of these uncertainties.

Fuel supply models used by staff are accounting models that do not directly respond to projected changes in economic conditions and prices. Demand forecasting models are amenable to the economic and policy scenarios described below, and generate forecasts that are referred to in this report as preliminary demand forecasts. These preliminary demand forecasts are then "post processed" to account for other policies that have not been incorporated into the models, as well as assess supply and infrastructure limitations, in order to create a balance between supply and demand. The post processed demand forecasts are referred to in this report as final demand forecasts.

Models and scenarios are defined differently by different offices and agencies for infrastructure and other planning and policy analysis purposes. For instance, the Electricity Demand Analysis Office (DAO) forecast of high demand for electric vehicles helps assess adequacy of electricity supply to prevent outages. In contrast, the Fossil Fuels Office (FFO) is concerned with ensuring an adequate fuel distribution system as well as meeting petroleum reduction goals. Therefore the higher demand for electric vehicles resulting from low petroleum demand from FFO will not be the same as the high EV demand forecast from DAO, as the two scenarios are defined differently. The Emerging Fuels and Technologies Office (EFTO) and the Public Interest Energy Research (PIER) Program develop market projections that are based on growth trends and/or information from individual suppliers of alternative and renewable fuels and vehicles, whereas FFO's fuel and vehicle demand forecasts are based on vehicle surveys of household and commercial consumers, as well as consultants' projected vehicle attributes that integrate assessment of market demand into their model of vehicle supply. Public and private entities using staff forecasts need to attend not only to the difference between preliminary and final demand noted above, but also to the differences between scenario definitions, methods, inputs, and assumptions used for forecasts by different offices within the Energy Commission and outside agencies and organizations.

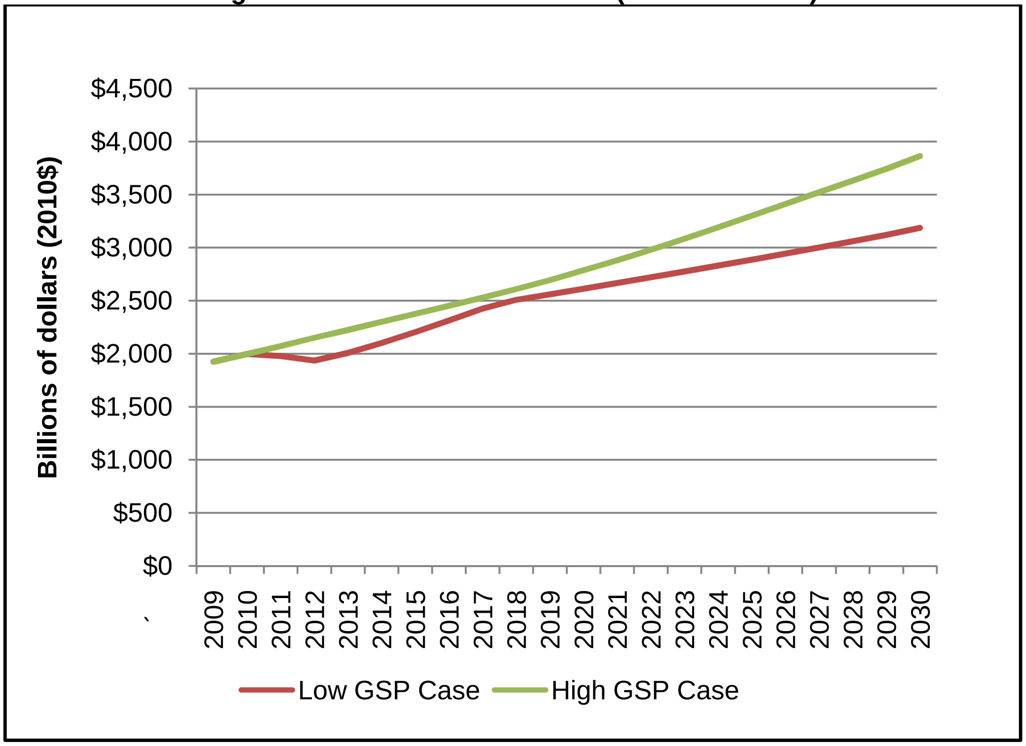
Forecast Uncertainties

In addition to uncertainties inherent in the data and specifications used in estimating any forecasting model, there are uncertainties associated with the public and private sector projections used as inputs to these models. Changes in consumer preference, the regulatory environment, land-use patterns, and fuel and vehicle technology, as well as crude oil and transportation fuel price fluctuations also add to the uncertainties of fuel demand forecasts in an increasingly globalized economy.

There are uncertainties in the projections of crude oil and transportation fuel prices, economic growth, and demographic and technological trends that are used in developing fuel demand forecasts. Moreover, many of the events that shape energy markets in the short-term cannot be anticipated, including weather, geopolitical disruptions, and strikes. Nor can longer-term developments in transportation technologies, demographics, and resources markets be foreseen with certainty. Staff has adopted scenarios that address key uncertainties in crude oil and transportation fuel prices, economic growth patterns, and federal and state regulations for current *IEPR* projections.

There are significant differences among economists concerning future growth rates in the economy, and there are fluctuations in the expectations of domestic and global economic performance as evidenced by the dramatic changes in the Dow Jones Industrials Average in August 2011. Staff has used two sources in creating the range of plausible economic outcomes. The boundaries of economic growth are defined by Moody's economy.com estimates for the low-income case, and IHS Global Insight estimates for the high-income case. Personal income, GSP, employment, and sectoral growth rates used in forecasting fuel and travel demand correspond with each of the separate economic growth cases. Figure 3-1 illustrates a fluctuating growth rate in the Low Income case, but a steady growth rate in the High Income case. By 2030, the high GSP is 21 percent higher than the low GSP. These two income scenarios are consistent with those used by DAO.

Figure 3-1: Gross State Product (in 2009 dollars)

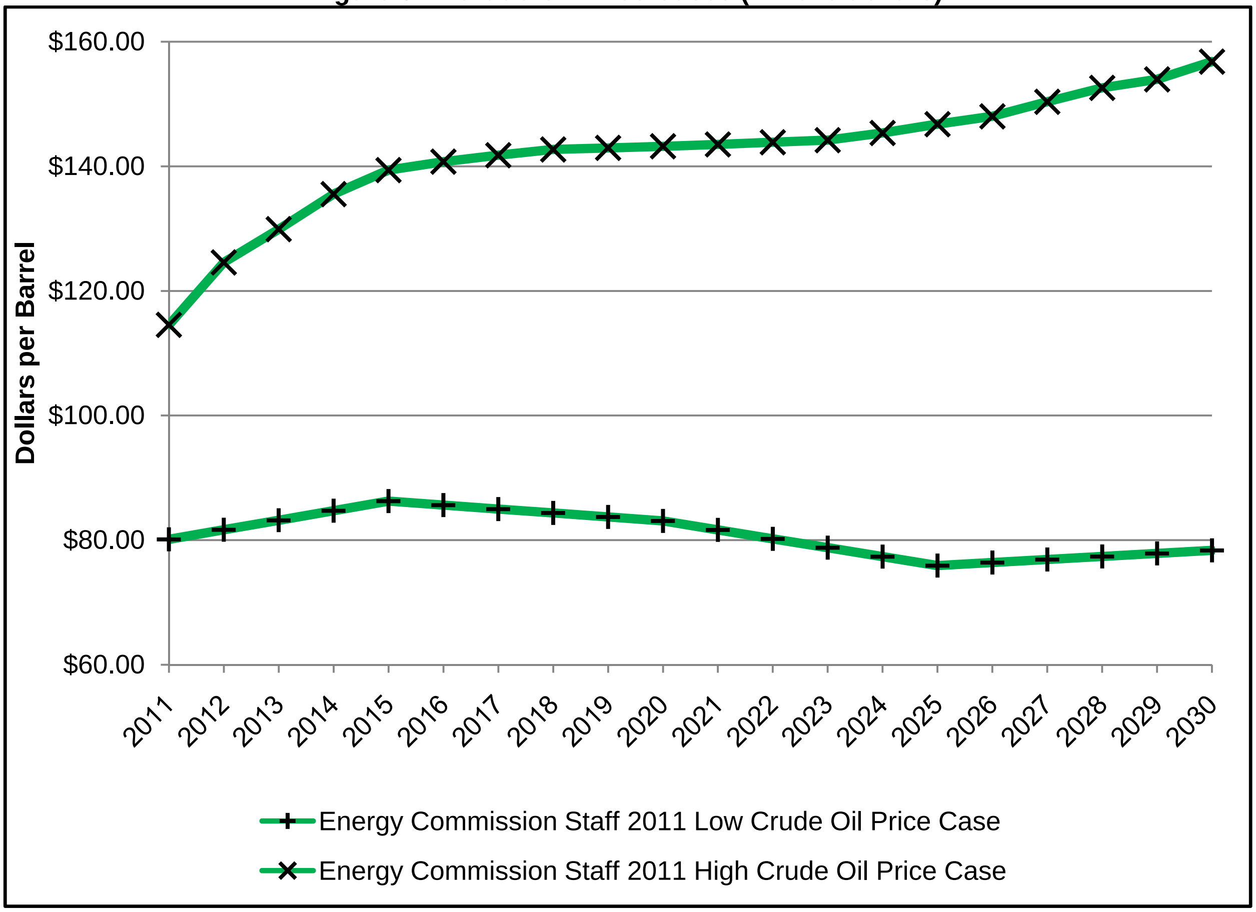


Source: Moody's economy.com (Low GSP Case) and IHS Global Insight (High GSP Case)[16]

Moreover, there are further uncertainties associated with population growth in the state as a result of differing estimates of birth rates and in- and out-migration. For instance, the DOF and United States Census Bureau have different estimates of long-term state population growth. However, in conformance with other Energy Commission forecasts, the transportation energy demand forecast is based only on the DOF population forecast.

Crude oil prices are determined by multiple factors that shape global oil demand and supply, including world economic growth, availability of resources, investment in production, technology development, Organization of Petroleum Exporting Countries quotas, disruptions in oil producing regions, currency exchange rates, commodity speculation, and weather. Staff has developed two price scenarios, discussed at the *2011 IEPR Joint Committee Workshop on Economic, Demographic, and Energy Price Inputs for Electricity, Natural Gas, and Transportation Fuel Demand Forecasts* on February 24, 2011. These oil price forecasts are illustrated in Figure 3-2 and the range of transportation fuel price forecasts that result from them are discussed in more detail in Appendix B, in order to account for the range of uncertainties introduced by these factors.

Figure 3-2: Crude Oil Price Cases (in 2010 dollars)



Source: California Energy Commission staff analysis of EIA and IHS Global Insight Forecasts

There are multiple uncertainties related to both fuel and vehicle production technologies. While technologies do exist to produce fuels and vehicles of many different types, economic feasibility will ultimately determine success in the market. Staff has solicited outside expertise to develop projections of the vehicle attributes for conventional, renewable, and alternative fueled vehicles, but these projections are limited to the makes and models with expected market penetration of 20,000 or more. The absence of a long enough history and wide enough markets for these alternative and emerging vehicles and transportation fuels has limited the consensus and added to the uncertainties associated with staff's analysis, beyond the uncertainties introduced by the current economic conditions. In addition, the rollout of emerging technologies, such as electric, natural gas, and hydrogen vehicles, will have to occur in concert with the installation of appropriate refueling infrastructure in order to increase the use of these alternative fuels, as will be discussed in later sections.

The potential for long-term changes in land use patterns will also add uncertainty to the transportation fuel demand forecasts. In response to different rules and regulations, including SB375 (Steinberg; Chapter 728, Statutes of 2008), multiple planning agencies are adopting policies to increase density and reduce personal vehicle usage. The degree to which these policies and standards will be adopted and implemented and succeed in meeting their intended goal remains uncertain. Staff forecasts do not directly account for these uncertainties.

Increasing environmental concerns have led California to adopt a number of rules and regulations aimed at reducing harmful emissions. The latest in a series of approved and/or implemented rules and regulations is the LCFS (see chapter 4 for more details). There are also proposed new fuel economy standards to be fully implemented by 2017 that will for the first time include medium- and heavy-duty vehicles (see chapter 4). There are uncertainties not only with respect to future standards, but also about the implementation of the ones that are currently adopted. To account for these uncertainties the staff has developed two policy cases (see Table 3-1). These policy cases currently assume no change in the existing rules and standards. However, the July 2011 agreement on the 2017-2025 Federal fuel economy standards (see chapter 4) as well as the additional ruling by ARB, due in October 2011, will be incorporated into the final revisions of the transportation fuel forecasts.

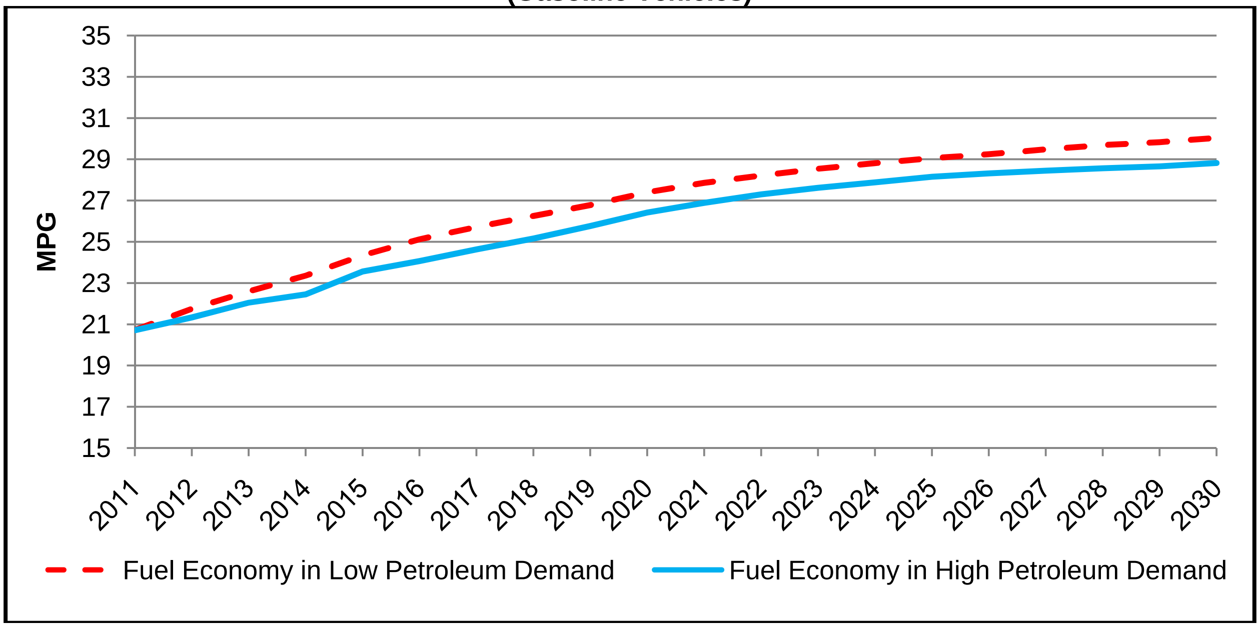
Table 3-1: Policy Cases

Policy Case		Vehicle Technology Case Fuel Efficiency Cost			LCFS	RFS II	ZEV Mandate[17]	CA Pavley[18]	2011-2016 Light-Duty Vehicle CAFE Standards	Medium- & Heavy-Duty Freight Fuel Economy	Aircraft Fuel Economy
		EPA	NAS	Manufacturer							
Preliminary Forecast	1		X				X	X	X	Low	Low
	2		X				X	X	X	High	High
Final Forecast	1		X			X	X	X	X	Low	Low
	2		X			X	X	X	X	High	High

Source: California Energy Commission

Staff has used the following fuel economy projections as the basis for different policy cases. Figure 3-3 provides a simple (not weighted by vehicle stock) average MPG for new gasoline light-duty vehicles associated with different crude oil price, policy, and economic growth scenario combinations, as described in the next section.

Figure 3-3: Light-Duty Vehicle Average* Fuel Economy Case Projections (Gasoline Vehicles)

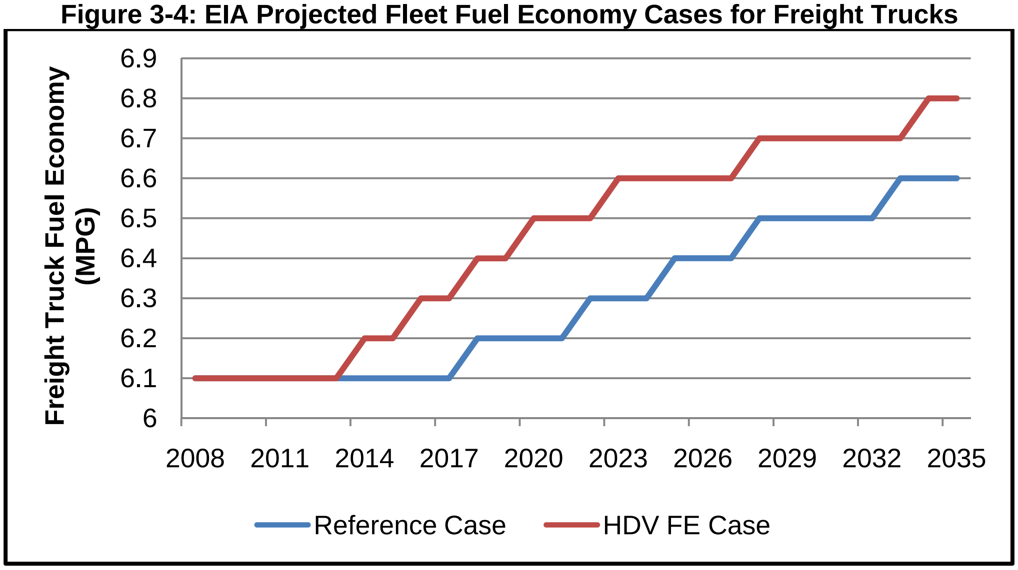


Source: ICF International projections for Energy Commission petroleum demand scenarios.
*Simple average for all vehicle classes, NOT weighted by vehicle stock in each class.

These fuel economy projections for gasoline vehicles show continous improvement in fuel economy through 2030, in all scenarios, but fuel economy projections for other vehicles are higher and remain constant after 2025.

Staff has also used EIA's projections of different fleet average fuel economy for freight trucks to create different cases for fuel economy improvement for these vehicles. Figure 3-4 depicts the changes in freight truck fuel economy through 2035.

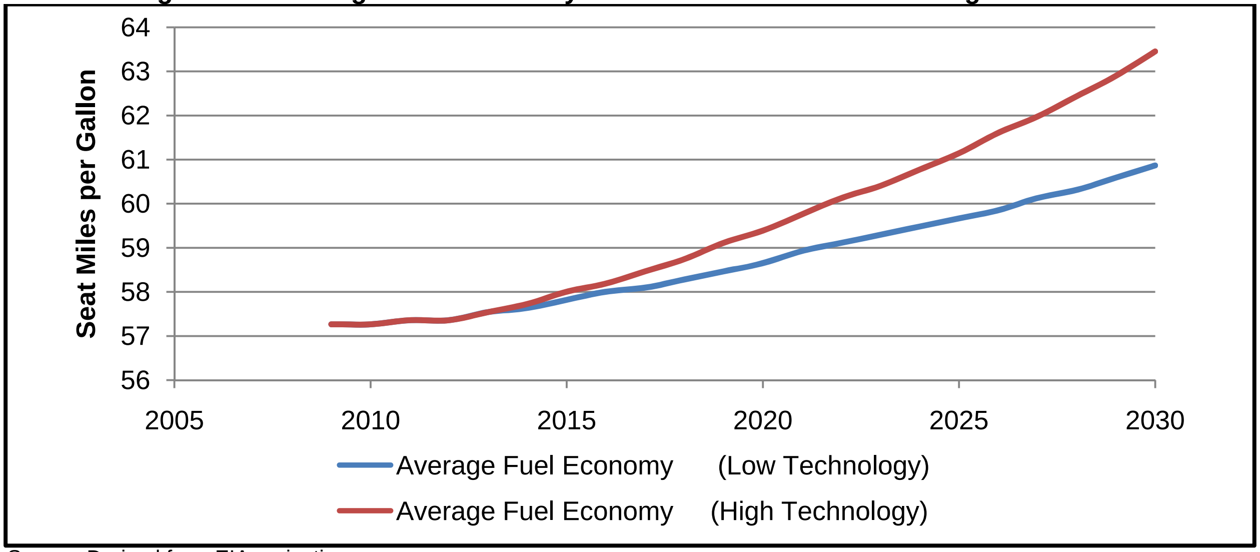
Figure 3-4: EIA Projected Fleet Fuel Economy Cases for Freight Trucks



Source: EIA

Likewise, staff used EIA technology cases to create two fuel economy cases for different aircraft classes in the aviation model, as illustrated in Figure 3-5.

Figure 3-5: Average* Fuel Economy cases for Commercial Passenger Aviation



Source: Derived from EIA projections

* Simple average for all aircraft classes, NOT weighted by aircraft stock

Both policy cases assume that currently implemented laws and regulations will be in effect through the forecast period. Some of these regulations, such as the fuel economy standards, have been quantified specifically for inclusion in different policy cases and to assess their impact on the preliminary demand forecast. All of the regulations and standards considered in different policy cases are statewide policies and standards, and do not explicitly include local policies and regulations. Some statewide policies, such as Low Emission Vehicle III (LEVIII) are not included in the analysis. It is important to note, however, that the mandated affects of some of the statewide regulations on scenario outcomes, in particular the Zero Emission Vehicle (ZEV) rules, are evaluated within the model and are reflected in the preliminary demand forecast. Others, such as the LCFS and RFS2, are evaluated outside the forecasting models, through post processing of the preliminary demand forecast and their impact is reflected in the final demand forecast.

The starting point for the final forecast is the assumption of compliance with LCFS and RFS2 requirements, followed by with evaluation of compliance, and arriving at the final forecast.

Scenario Definitions

Movements of people and goods generally increase with low fuel prices, and decrease with high fuel prices, all else held equal. These movements also increase with higher economic activity and income, and decrease with declines in the level of economic activity. On the other hand, stricter fuel economy regulations and low carbon fuel standards will lower demand for petroleum based fuels.

Staff has combined business-as-usual assumptions, reflecting known technological and demographic trends, with different plausible economic and regulatory conditions to define a small set of scenarios for petroleum fuel demand trends. These scenarios will generate a range of forecasts that are not intended to represent predictions of what will happen but rather what might happen, given various implicit and explicit assumptions about important variables.

Uncertainties associated with crude oil and fuel price forecasts, economic forecasts, and the regulatory environment are addressed by developing scenarios. Uncertainties in other model inputs, such as demographic projections, are not expressly accounted for, using instead a single projection.

The Energy Commission staff generates low and high price forecasts for California transportation fuels, as detailed in Appendix B. Staff has also used the low and high economic output forecasts, as described above. These different case conditions for transportation fuel prices, economic growth, and varying policies are aligned to produce a High Petroleum Demand Scenario and a Low Petroleum Demand Scenario. These two scenarios are intended to frame plausible upper and lower boundaries for petroleum based transportation fuel demand. The focus on petroleum demand is in response to multiple policies and goals aimed at reducing petroleum demand due to economic, environmental and energy security concerns.

Low Petroleum Demand Scenario – High petroleum-related fuel price forecasts (including high E85 prices) with comparatively low natural gas and electricity prices prevail through the forecast period. Under these conditions staff also assumes that low economic growth rates prevail through the forecast period. The influence of existing Federal CAFE standards for 2011—2016 are examined, as well as the proposed 2017-2025 Federal CAFE standards, each being in effect through our forecast period.

High Petroleum Demand Scenario – Low petroleum-related fuel price forecasts (including low E85 prices) with comparatively high natural gas and electricity prices prevail through the forecast period. Staff assumes that high economic growth rates prevail through the forecast period, with only the Federal CAFE standards for 2011—2016 assumed to be in effect.

Table 3-2 shows the set of conditions that apply in the two petroleum demand scenarios.

Table 3-2: Scenario Definitions

Petroleum Fuel Demand Scenarios	Fuel price cases		Economic Output Cases	Policy Cases
	Petroleum Fuels (gasoline, diesel, E85, B5, propane)	Natural gas & electricity		
High Petroleum Demand	Low Price	High Price	High Income	(1) Low Technology
Low Petroleum Demand	High Price	Low Price	Low Income	(2) High Technology

Source: California Energy Commission

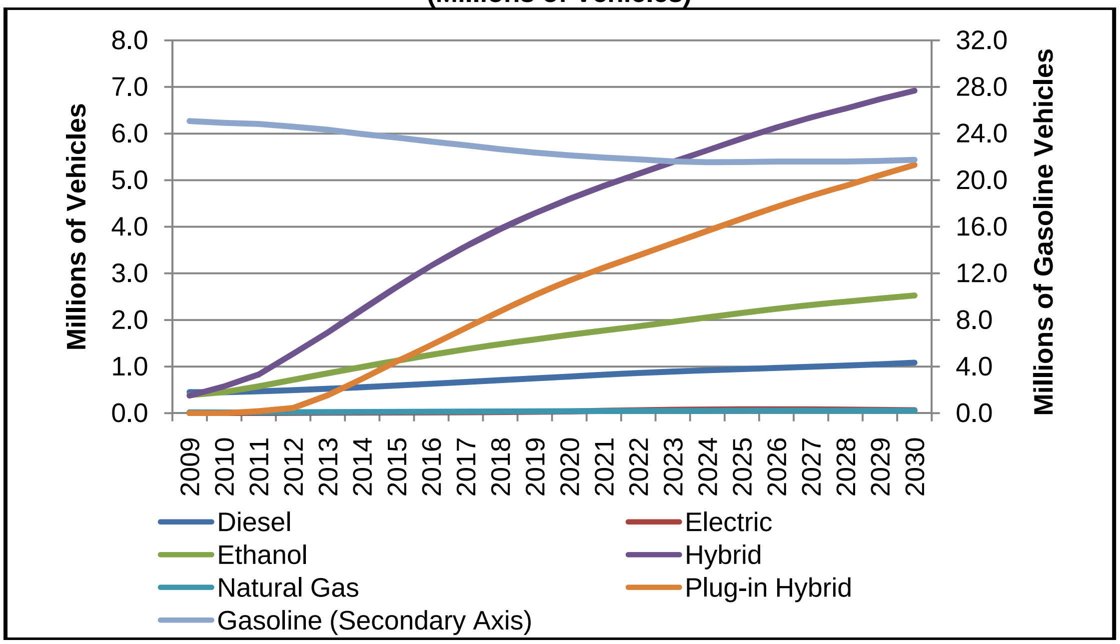
Forecast Results for the Demand Scenarios

Light –Duty Vehicle Forecast

Vehicle sales have declined significantly in response to recession and high fuel prices. In the near term the continued recession will impact the adoption of incrementally expensive alternative technologies. Over the forecast, hybrids and plug-in hybrid vehicles still see a substantial increase and reflect the consumer preferences for these types of vehicle technologies identified in the 2009 California Vehicle Survey. Diesel and FFVs are adopted at moderate levels while full electric and natural gas vehicles never appreciably gain market share.

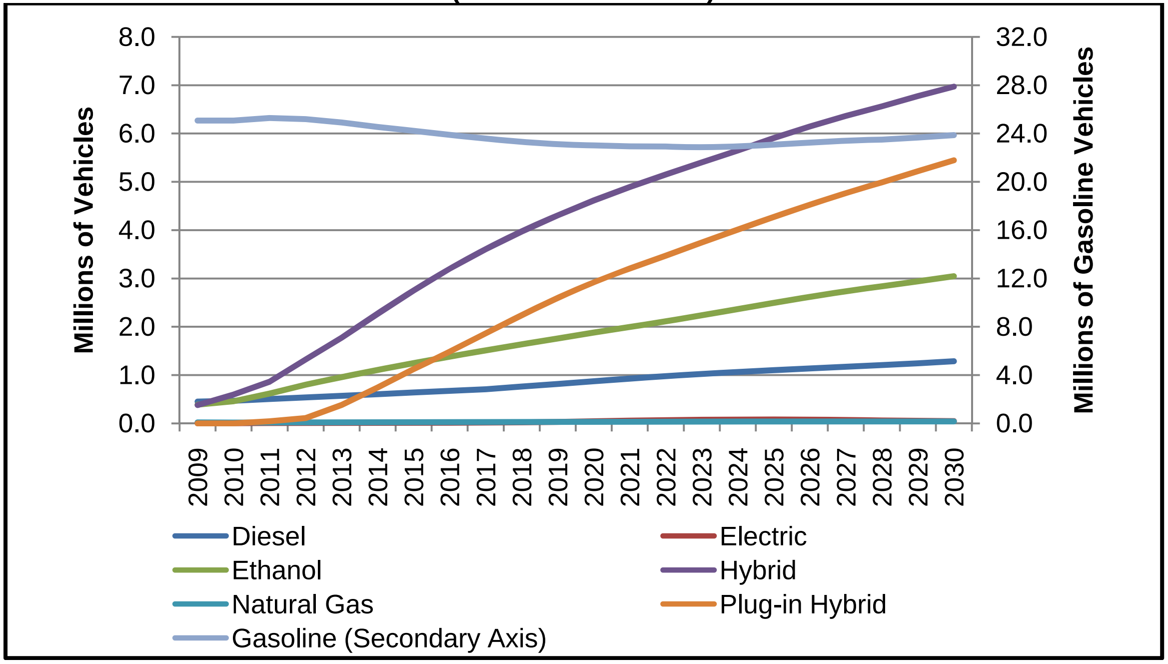
Figure 3-6 and Figure 3-7 illustrate the extent to which vehicles change over the forecast period in the Low and High Petroleum Demand Scenarios, respectively.

Figure 3-6: California Vehicle Demand Forecast Low Petroleum Demand Scenario (Millions of Vehicles)



Source: California Energy Commission

Figure 3-7: California Vehicle Demand Forecast High Petroleum Demand Scenario (Millions of Vehicles)

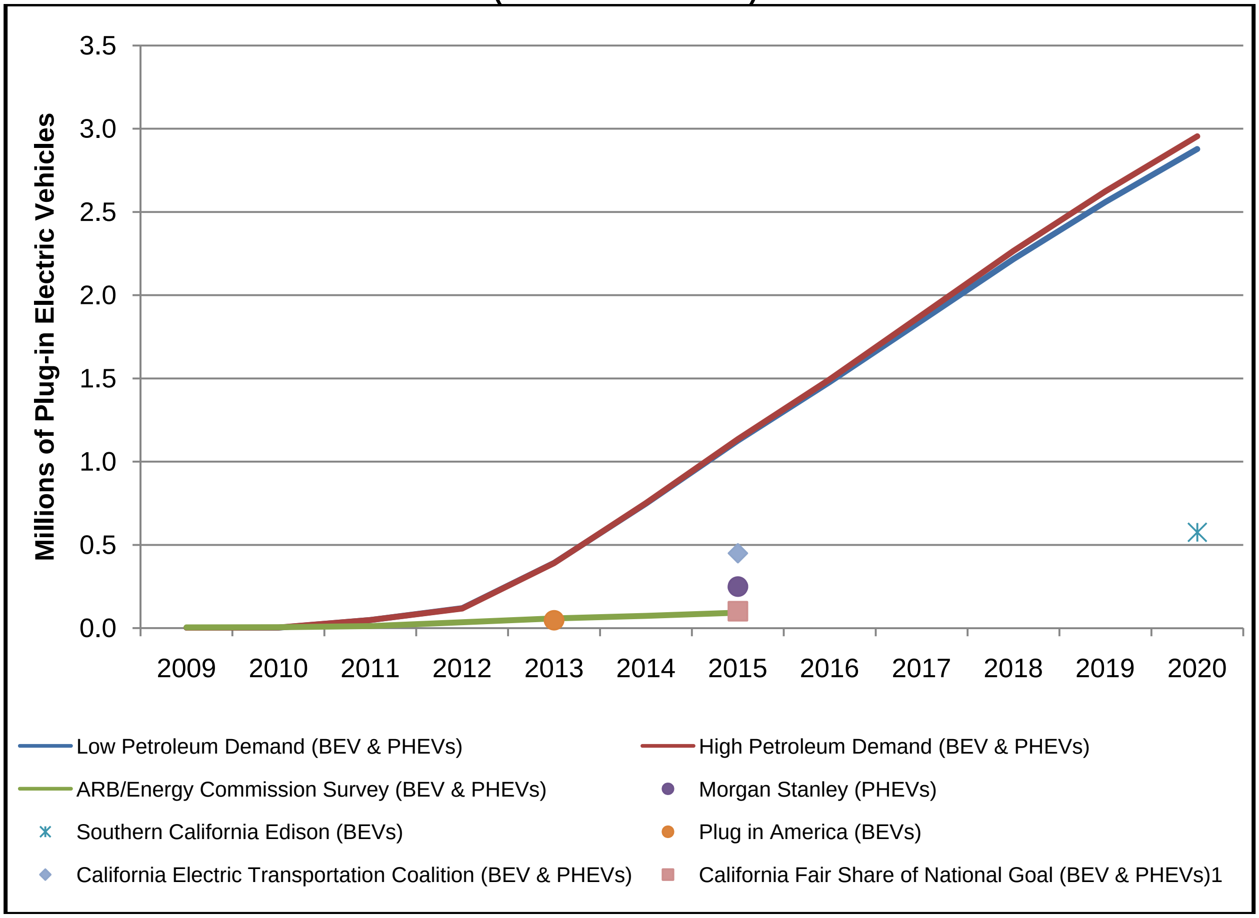


Source: California Energy Commission

In each of the two demand scenarios, plug-in electric vehicles have been adjusted to comply with expected upcoming ZEV program requirements. Since the Energy Commission has not included an analysis of hydrogen vehicles in the forecasts, it is assumed that the needed minimum number of fuel cell vehicles will enter the market to comply with the updated ZEV program. Surveys of vehicle original equipment manufacturers (OEM) performed by the Fuel Cell Partnership and the Energy Commission/ARB in 2009 to characterize potential market penetrations of fuel cell vehicles revealed manufacturers expected to deploy 53,000 fuel cell vehicles in California by 2015-17.[19]

Estimates for future plug-in electric vehicles vary and include a high estimate of 450,000 plug-in electric vehicles from the California Electric Transportation Coalition. The recent Energy Commission AB 118 Investment Plan includes estimates from various sources of projected plug-in electric vehicles which have been overlaid with the Low and High Demand plug-in electric vehicles population forecasts in Figure 3-8.

Figure 3-8: California Plug-in Electric Vehicles, Projections, and Estimates by Source (Millions of Vehicles)



Source: California Energy Commission analyses and 2010-11 AB 118 Investment Plan

Although it appears the forecasted vehicle stock is significantly higher than the reported estimates, this growth rate is consistent with consumer survey preferences and is primarily composed of the plug-in hybrid electric vehicles (PHEVs). Additionally, assumptions on the range, incremental costs, and other vehicle attributes are not available for the PHEV projections from other sources, complicating any direct comparisons.

Gasoline Demand Forecast

Between 2009 and 2030, total gasoline consumption in California falls by 4.8 percent in the preliminary Low Petroleum Demand Scenario as increased efficiency, continued fleet hybridization and dieselization, and the introduction of alternative fuels reduce gasoline demand. In the High Petroleum Demand Scenario, the recovering economy and lower fuel prices lead to the continued growth in total state gasoline demand through the forecast, increasing 14.31 percent between 2009 and 2030. Table 3-3 reports the preliminary forecast of gasoline demand for light-duty vehicles in California, and Table 3-4 and Figure 3-9 show preliminary forecast of total gasoline demand.

Table 3-3: Preliminary California Light-Duty Vehicle Gasoline Demand Forecast (Gallons)

Year	Low Petroleum Demand Scenario	Percent Change from Prior Year	High Petroleum Demand Scenario	Percent Change from Prior Year
2009	14,216,707,634		14,216,707,634	
2015	12,824,193,691	-1.15%	13,822,514,103	-0.63%
2020	12,352,572,898	-1.01%	13,428,238,901	-0.24%
2025	11,752,289,452	-0.76%	13,417,076,579	0.25%
2030	11,554,086,773	-0.06%	13,774,895,021	0.77%
CAGR	-0.98%		-0.15%	

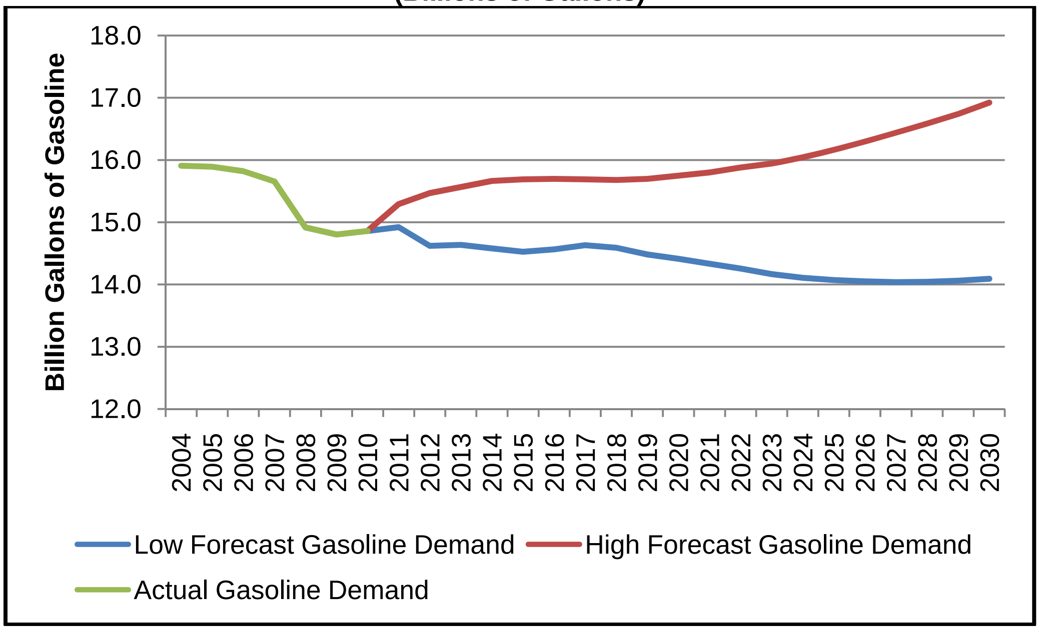
Source: California Energy Commission

Table 3-4: Preliminary California Total Gasoline Demand Forecast (Gallons)

Year	Low Petroleum Demand Scenario	Percent Change from Prior Year	High Petroleum Demand Scenario	Percent Change from Prior Year
2009	14,804,119,733		14,804,119,733	
2015	14,525,940,335	-0.37%	15,689,915,914	0.16%
2020	14,413,047,312	-0.48%	15,749,737,362	0.33%
2025	14,069,642,509	-0.26%	16,166,020,834	0.77%
2030	14,091,913,882	0.23%	16,922,642,875	1.08%
CAGR	-0.23%		0.64%	

Source: California Energy Commission

Figure 3-9: Preliminary California Total Gasoline Demand Forecast (Billions of Gallons)



Source: California Energy Commission

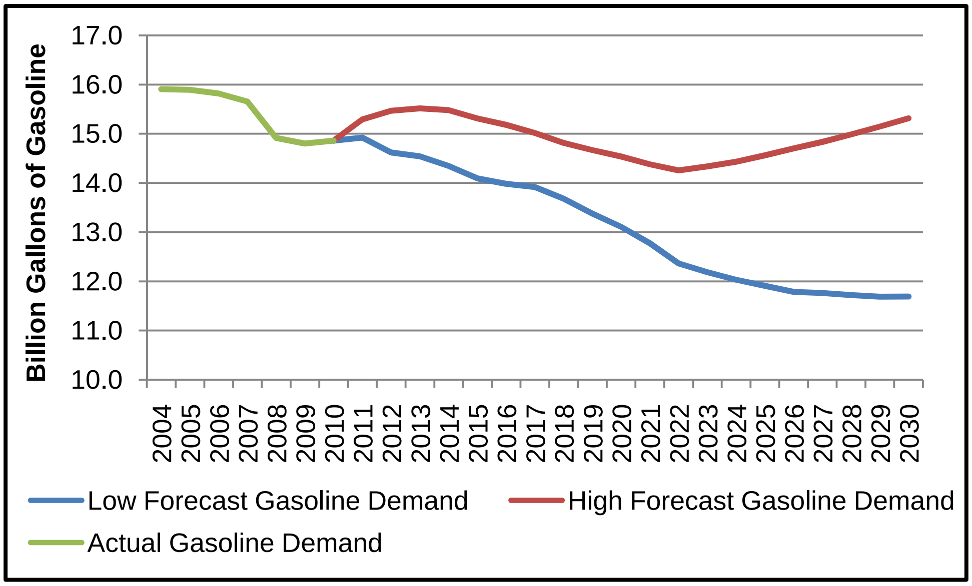
The final fuel demand forecast incorporates the impacts of RFS2. For gasoline demand, this resulted in a decline of 21.0 percent in the Low Petroleum Demand Scenario from 2009 to 2030 and a 3.5 percent increase in gasoline demand in the High Petroleum Demand Scenario over that period. Incorporating RFS2 requirements into the forecast diverted gasoline to biofuel based products, including E10 purchased in California after 2010 and as E85. High blends of ethanol require specialized vehicles, such as FFVs, that are compatible with the use of high ethanol blends and dedicated dispensers. For the final forecasts, staff assumed that both the vehicle supply and infrastructure exist to allow compliance with the federal regulations. Table 3-5 provides the final gasoline demand forecast through 2030. The compound annual average growth rate (CAGR) was -1.12 percent in the Low Petroleum Demand Scenario and 0.6 percent in the High Petroleum Demand Scenario. Figure 3-10 shows the total gasoline demand forecast for California.

Table 3-5: Final California Total Gasoline Demand Forecast (Gallons)

Year	Low Petroleum Demand Scenario	Percent Change from Prior Year	High Petroleum Demand Scenario	Percent Change from Prior Year
2009	14,804,119,733		14,804,119,733	
2015	14,095,132,101	-1.76%	15,314,441,926	-1.09%
2020	13,110,424,364	-2.00%	14,539,812,677	-0.88%
2025	11,908,787,432	-1.03%	14,562,979,288	0.91%
2030	11,690,919,080	0.02%	15,317,068,304	1.12%
CAGR	-1.12%		0.16%	

Source: California Energy Commission

Figure 3-10: Final California Total Gasoline Demand Forecast (Billions of Gallons)



Source: California Energy Commission

Diesel Demand Forecast

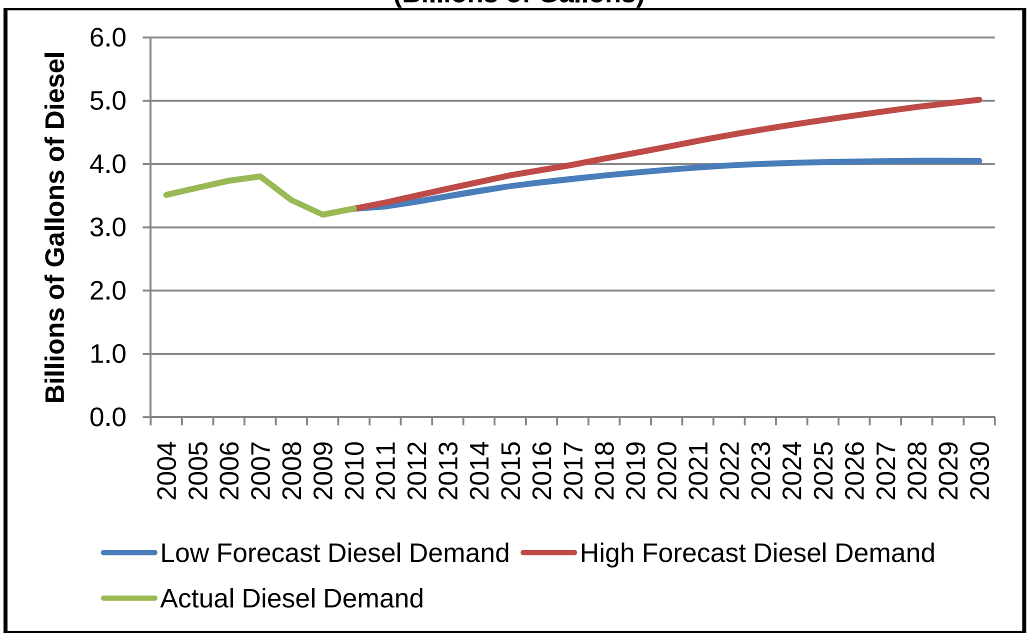
The diesel demand forecast encompasses four primary areas: truck and rail freight goods movement, residential and commercial light-duty vehicle transportation, urban and intercity public transit, and off-road use of diesel (mostly in construction and agriculture). Of these four sectors, goods movement is by far the most significant, representing over 62 percent of all diesel consumption in 2009. Table 3-6 and Figure 3-11 show the preliminary forecast of California total diesel demand. Between 2009 and 2030, total diesel demand is forecast to increase by 26.7 percent in the Low Petroleum Demand Scenario and 55.0 percent in the High Petroleum Demand Scenario. Increased growth in the economy over the forecast period including increased import and export activities leads to the growing diesel demand. This increase is mitigated by increasing federal fuel efficiency improvements for medium- and heavy-duty vehicles in the near-term. However, steady economic growth and the lack of substantive alternatives for freight movement lead to the persistent forecast demand increases.

Table 3-6: Preliminary California Diesel Demand Forecast (Gallons)

Year	Low Petroleum Demand Scenario	Percent Change from Prior Year	High Petroleum Demand Scenario	Percent Change from Prior Year
2009	3,200,244,414		3,200,244,414	
2015	3,653,923,080	2.22%	3,823,541,973	2.83%
2020	3,908,746,258	1.07%	4,271,106,212	2.21%
2025	4,030,311,368	0.24%	4,693,633,187	1.52%
2030	4,053,333,032	-0.03%	5,017,085,417	1.12%
CAGR	1.13%		2.16%	

Source: California Energy Commission

Figure 3-11: Preliminary California Total Diesel Demand Forecast (Billions of Gallons)



Source: California Energy Commission

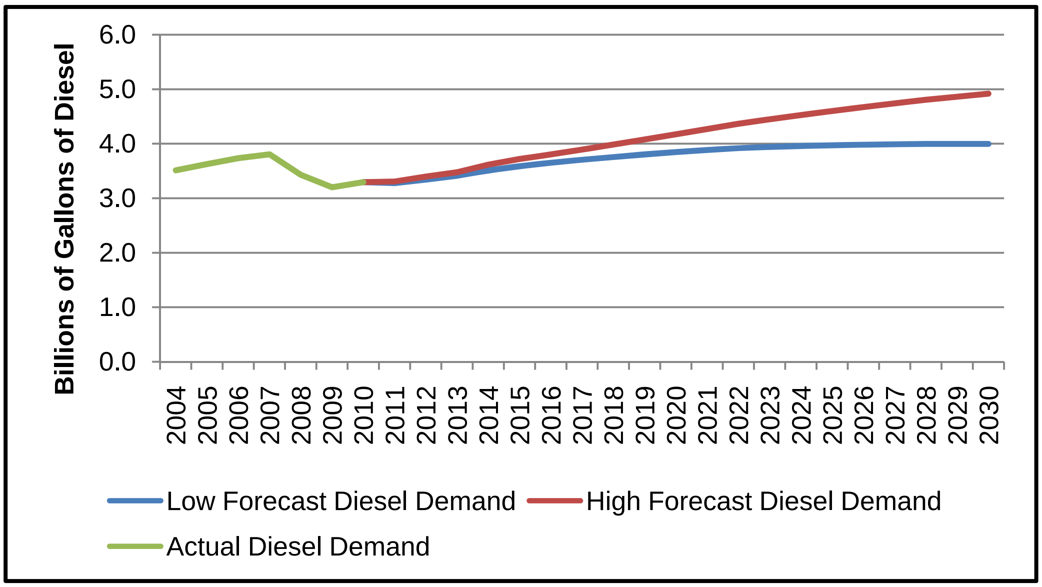
Like gasoline, consumption of diesel in California will be influenced by the federal RFS2 program. The final total diesel consumption grows 24.9 percent in the Low Petroleum Demand Scenario and 53.8 percent in the High Petroleum Demand Scenario. The CAGRs are slightly lower than the preliminary diesel demand numbers at 1.06 percent for the Low Petroleum Demand Scenario and 2.07 percent in the High Petroleum Demand Scenario. In the case of diesel, volumes are being displaced by low blends of biomass based diesel products such as biodiesel. Under the federal regulations, only certain products can qualify as a biomass-based diesel complying product. Currently biodiesel can be blended at up to 5 percent and provide enough capacity to account for the added volumes of biomass based diesel. RFS2 does not reduce diesel as significantly as gasoline because it requires a low volume for compliance as discussed in Chapter 4. Table 3-7 and Figure 3-12 provide the final forecast of diesel demand in the Low and High Petroleum Demand Scenarios.

Table 3-7: Final California Total Diesel Demand Forecast (Gallons)

Year	Low Petroleum Demand Scenario	Percent Change from Prior Year	High Petroleum Demand Scenario	Percent Change from Prior Year
2009	3,200,244,414		3,200,244,414	
2015	3,590,196,125	2.24%	3,722,299,264	2.97%
2020	3,846,538,236	1.10%	4,173,298,178	2.26%
2025	3,970,930,097	0.27%	4,599,739,029	1.55%
2030	3,996,283,655	-0.01%	4,920,712,414	1.12%
CAGR	1.06%		2.07%	

Source: California Energy Commission

Figure 3-12: Final California Total Diesel Demand Forecast (Billions of Gallons)



Source: California Energy Commission

High Ethanol Blends (E85) Demand Forecast

The preliminary E85 demand forecast includes residential and commercial light-duty vehicle transportation consumption of E85. The high overall rate of increase for this fuel is directly related to the number of fueling stations available within California. The Energy Commission forecasted number of stations increases from 35 stations in 2009 to 980 stations in 2030. The Energy Commission, through the AB118 program, is funding the installation of E85 stations in California. These additional stations have been included in the preliminary E85 forecast and incorporated into the RFS2 analysis. Table 3-8 and Figure 3-13 show the total preliminary

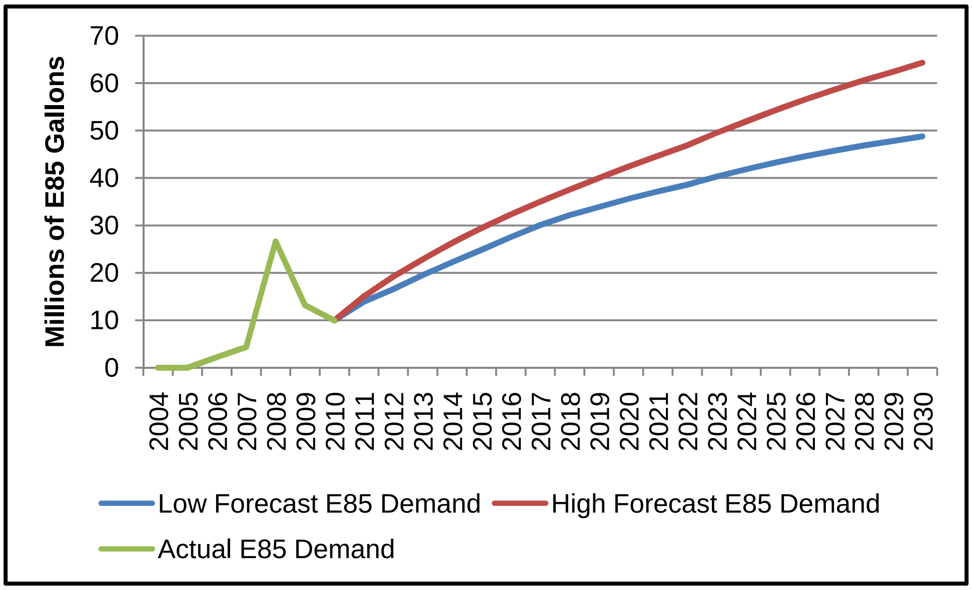
California E85 demand forecast. These results are considered preliminary because they do not comply with RFS2.

Table 3-8: Preliminary California High Ethanol Blend (E85) Demand Forecast (Gallons)

Year	Low Petroleum Demand Scenario	Percent Change from Prior Year	High Petroleum Demand Scenario	Percent Change from Prior Year
2009	13,204,070		13,204,070	
2015	24,841,148	11.66%	29,366,677	11.68%
2020	35,624,945	5.05%	42,410,749	6.08%
2025	43,242,112	3.42%	54,276,581	4.58%
2030	48,796,371	2.02%	64,314,117	3.08%
CAGR	6.42%		7.83%	

Source: California Energy Commission

Figure 3-13: Preliminary California High Ethanol Blend (E85) Demand Forecast (Millions of Gallons)



Source: California Energy Commission

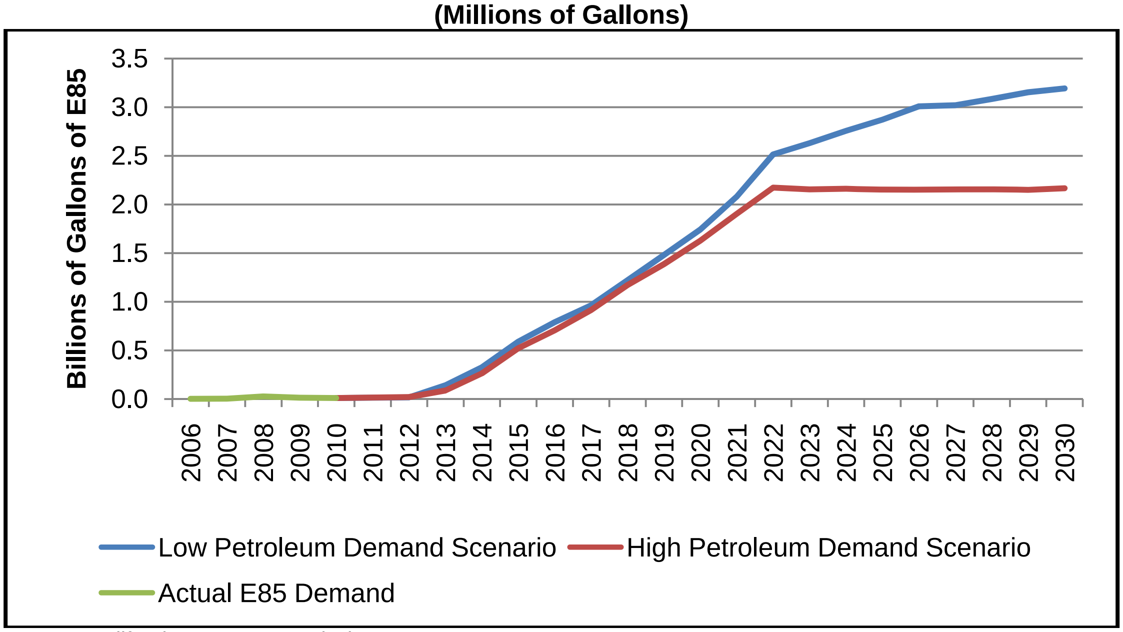
Energy Commission staff has interpreted RFS2 compliance to be addressed primarily through the use of ethanol. The volume of ethanol blended into gasoline cannot exceed 10 percent under current California regulations. However, blend concentrations of ethanol can reach much higher levels. In the assessment of E85 consumption in California, staff assumes that any ethanol volume needed for RFS2 compliance which exceeds the 10 percent blending level would be sold using E85. Table 3-9 and Figure 3-14 present the final E85 demand forecasts for the Low and High Petroleum Demand Scenarios and show the substantial increase in E85 consumption due to the RFS2 requirements. It should be noted that the forecasted volumes presented are blended at an annual average of 79.2 percent ethanol by volume to account for regional and seasonal variations in blending.

Table 3-9: Final California High Ethanol Blend (E85) Demand Forecast (Gallons)

Year	Low Petroleum Demand Scenario	Percent Change from Prior Year	High Petroleum Demand Scenario	Percent Change from Prior Year
2009	13,204,070		13,204,070	
2015	588,844,483	80.68%	520,927,805	98.29%
2020	1,740,986,241	17.62%	1,626,413,803	17.33%
2025	2,872,179,385	4.18%	2,152,938,370	-0.34%
2030	3,192,118,551	1.27%	2,166,292,079	0.77%
CAGR	29.87%		27.49%	

Source: California Energy Commission

Figure 3-14: Final California High Ethanol Blend (E85) Demand Forecast (Millions of Gallons)



Source: California Energy Commission

Transportation Electricity Demand Forecast

The transportation electricity demand forecast represents three primary sectors: residential and commercial light-duty vehicle transportation and urban public transit. The majority of early electricity demand for the transportation sector is attributable to electric rail in urban transit. Through the latter years of the forecast, PHEVs and EVs consume a larger portion of the transportation electricity demand, reaching over 79 percent of transportation electricity demand in both cases by 2030. The Low Electricity Demand Case results from the High Petroleum Demand Scenario and has lower oil prices, higher electricity prices, and lower numbers of electric vehicles when compared to the High Electricity Demand Case (Low Petroleum Demand

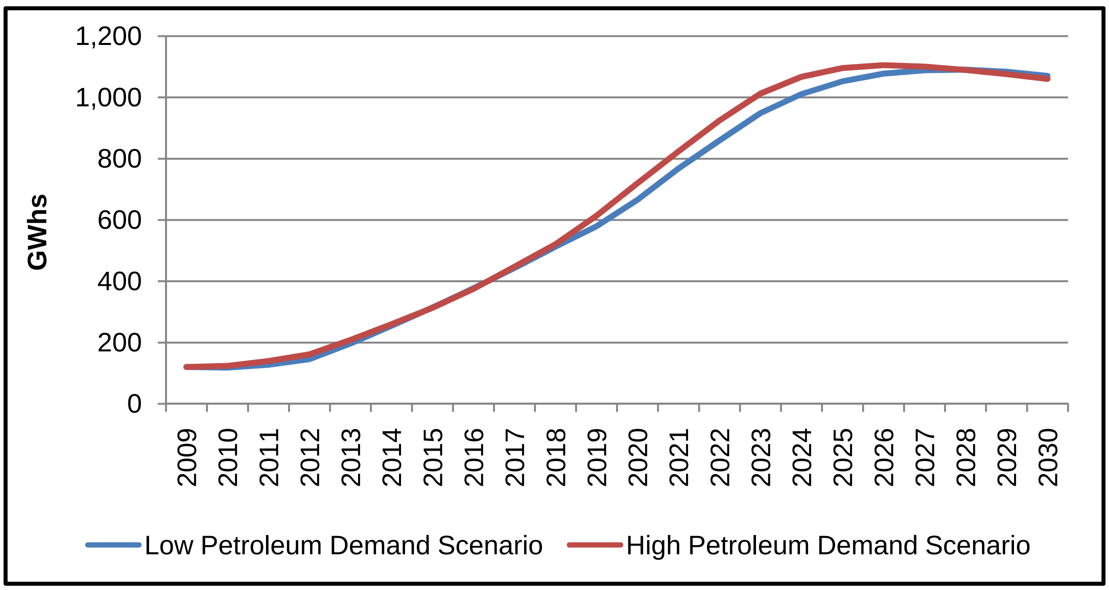
Scenario). As electricity consumption is not influenced by RFS2, Table 3-10 and Figure 3-15 show the final total California transportation electricity demand forecast.

Table 3-10: California Transportation Electricity Demand Forecast (KWhs)

Year	Low Petroleum Demand Scenario	Percent Change from Prior Year	High Petroleum Demand Scenario	Percent Change from Prior Year
2009	120,399,988		120,399,988	
2015	315,280,594	24.31%	313,201,235	20.62%
2020	665,244,976	14.84%	719,785,975	17.26%
2025	1,052,346,700	4.12%	1,095,500,400	2.67%
2030	1,070,069,181	-1.27%	1,060,286,712	-1.43%
CAGR	10.96%		10.92%	

Source: California Energy Commission

Figure 3-15: California Transportation Electricity Demand Forecast (GWhs)



Source: California Energy Commission

Transportation Natural Gas Demand Forecast

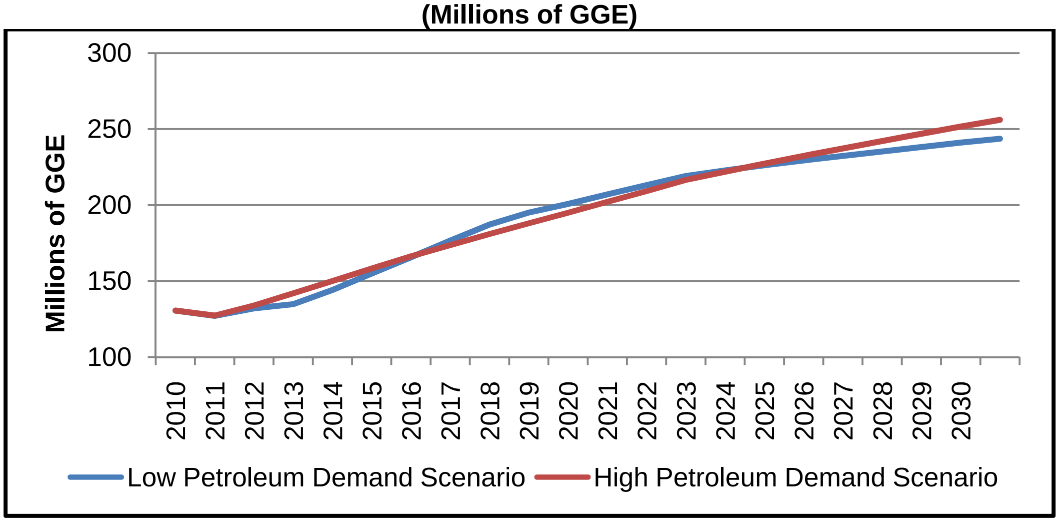
The transportation natural gas demand forecast represents three primary sectors: residential and commercial light-duty vehicle transportation and urban public transit. Of these sectors, urban public transit is most significant, representing over 87.7 percent of all consumption in 2009. The Low Natural Gas Demand Case results from the High Petroleum Demand Scenario and has lower oil prices, higher natural gas prices, and lower numbers of natural gas vehicles when compared to the High Natural Gas Demand Case (Low Petroleum Demand Scenario). In the Low Petroleum Demand Scenario, changing travel mode choices increases consumption of natural gas in the near term reflecting additional public transportation use. Later in the forecast, competing alternative technologies results in a slower natural gas consumption rate. Table 3-11 and Figure 3-16 show the total California natural gas transportation demand forecast.

Table 3-11: California Transportation Natural Gas Demand Forecast (GGE)

Year	Low Petroleum Demand Scenario	Percent Change from Prior Year	High Petroleum Demand Scenario	Percent Change from Prior Year
2009	130,574,240		130,574,240	
2015	165,642,890	6.83%	166,369,708	5.06%
2020	206,997,529	3.13%	202,192,152	3.71%
2025	229,165,223	1.24%	232,120,370	2.04%
2030	243,653,145	1.03%	256,084,851	1.75%
CAGR	3.02%		3.26%	

Source: California Energy Commission

Figure 3-16: California Transportation Natural Gas Demand Forecast (Millions of GGE)



Source: California Energy Commission

Jet Fuel Demand Forecast

Since jet fuel is formulated to national and international standards, jet fuel demand forecasts do not take into account California greenhouse gas (GHG) standards but do incorporate high and low jet fuel price scenarios as well as two aviation fuel efficiency forecast cases. High jet fuel prices and fuel efficiency imputed from United States Federal Aviation Administration (FAA) projections are assumed in the Low Petroleum Demand Scenario. Low jet fuel prices and the FAA fuel efficiency performance targets are assumed in the High Petroleum Demand Scenario. Staff did not attempt to project military jet fuel use, so military consumption is excluded from the forecast. Table 3-12 and Figure 3-17 show the low and high jet fuel demand projections.

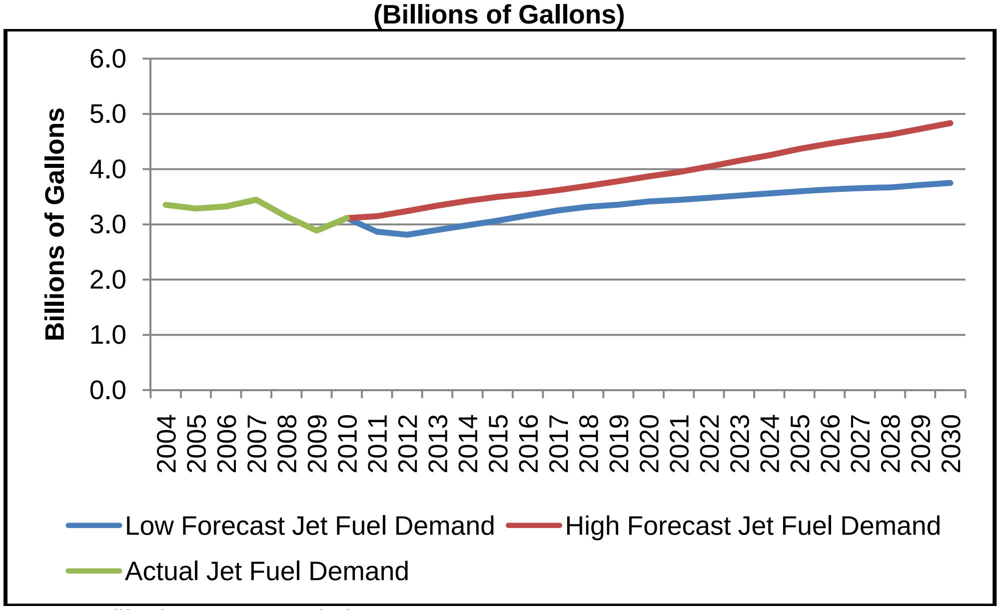
Between 2007 and 2030 staff expects that jet fuel demand in California will increase by 28.5 percent to 3.7 billion gallons in the low demand scenario and 63.6 percent to 4.7 billion gallons in the high demand scenario.

Table 3-12: California Jet Fuel Demand Forecast (Gallons)

Year	Low Petroleum Demand Scenario	Percent Change from Prior Year	High Petroleum Demand Scenario	Percent Change from Prior Year
2009	2,889,312,636		2,889,312,636	
2015	3,066,666,787	2.78%	3,499,797,157	2.16%
2020	3,415,602,323	1.74%	3,868,770,890	2.27%
2025	3,599,683,923	1.12%	4,367,788,428	2.70%
2030	3,750,829,359	1.03%	4,833,458,111	2.23%
CAGR	1.25%		2.48%	

Source: California Energy Commission

Figure 3-17: California Jet Fuel Demand Forecast (Billions of Gallons)



Source: California Energy Commission

Analysis of Scenario Outcomes

In general, the early years of the transportation energy demand forecasts represent a recovery from the current recessionary economic conditions. Because the economic and demographic projections used in these forecasts indicate the return of reasonably healthy economic growth and steady population growth, the trends for the freight and aviation sectors tend to resume historical patterns of increases in fuel demand. Gasoline demand in the light-duty sector, however, is more heavily influenced by the introduction of competing technologies, efficiency improvements, and by higher projected fuel prices. As a result, the forecasted gasoline demand tends to decline in later years. In addition, the RFS2 evaluation presented in Chapter 4 leads to an even more significant decline in gasoline demand over the forecast as biofuels are anticipated to become more prevalent in response to regulations.

CHAPTER 4: Policies and Regulations

Renewable Fuels Standard – Increased Demand for Ethanol and Biodiesel

As required by the Energy Independence and Security Act of 2007 (EISA), the RFS program was altered to require the sale of 30 billion gallons of renewable fuels by 2020 and 36 billion gallons by 2022.[20] The U. S. EPA continued accepting comments on its Notice of Proposed Rulemaking (NOPR) until September 25, 2009.[21] The Final Rule for RFS2 was issued on March 26, 2010.[22] On December 10, 2010, the U.S. EPA issued the Final Rule for various program amendments.[23] The RFS2 requires all obligated parties (refiners, importers, and blenders) to achieve minimum renewable fuel use each year either through actual use (blending) or purchase of Renewable Identification Number (RIN) credits from other market participants who blended a greater quantity of renewable fuel than was required by the RFS2 regulation. Refiners and importers determine their Renewable Volume Obligation (RVO) each calendar year that is calculated from the RFS percentage assigned by the U.S. EPA prior to November 30th of the preceding year.[24] For 2011, the RFS obligation is 8.01 percent, assuming that 13.95 billion gallons of renewable fuel will be blended into gasoline and diesel fuel. These obligations include "proportional-share" blending of four different categories of renewable fuels through actual use or purchase of appropriate RINs (see Table 4-1).[25]

Table 4-1: U.S. RFS2 Requirements (2008 to 2030)

			Advanced Biofuels			
Year	Total Renewable Fuel Requirement Bil. Gallons	Starch Derived Biofuel Bil. Gallons	Cellulosic Biofuels Bil. Gallons	Other Advanced Biofuels Bil. Gallons	Biomass Based Diesel Bil. Gallons	Total Advanced Biofuels Bil. Gallons
2008	9.00	9.00				0.00
2009	11.10	10.50		0.10	0.50	0.60
2010	12.95	12.00	~~0.10~~ **0.0065**	~~0.20~~ **0.294**	~~0.65~~ **1.15**	0.95
2011	13.95	12.60	~~0.25~~ **0.0066**	~~0.30~~ **0.543**	0.80	1.35
2012	15.20	13.20	~~0.25~~ **0.0035 - 0.0126**	~~0.50~~ **0.987 - 0.997**	1.00	2.00
2013	16.55	13.80	1.00	0.75	~~1.00~~ **1.28**	2.75
2014	18.15	14.40	1.75	1.00	1.00	3.75
2015	20.50	15.00	3.00	1.50	1.00	5.50
2016	22.25	15.00	4.25	2.00	1.00	7.25
2017	24.00	15.00	5.50	2.50	1.00	9.00
2018	26.00	15.00	7.00	3.00	1.00	11.00
2019	28.00	15.00	8.50	3.50	1.00	13.00
2020	30.00	15.00	10.50	3.50	1.00	15.00
2021	33.00	15.00	13.50	3.50	1.00	18.00
2022	36.00	15.00	16.00	4.00	1.00	21.00
2023	36.00	15.00	16.00	4.00	1.00	21.00
2024	36.00	15.00	16.00	4.00	1.00	21.00
2025	36.00	15.00	16.00	4.00	1.00	21.00
2026	36.00	15.00	16.00	4.00	1.00	21.00
2027	36.00	15.00	16.00	4.00	1.00	21.00
2028	36.00	15.00	16.00	4.00	1.00	21.00
2029	36.00	15.00	16.00	4.00	1.00	21.00
2030	36.00	15.00	16.00	4.00	1.00	21.00

Source: U.S. Environmental Protection Agency and Energy Commission modifications. Red font indicates **revisions.**

The U.S. EPA is required to evaluate cellulosic and advanced biofuel availability by November 30 of each year to determine if the minimum target levels in the RFS2 statute can be met. If not, either or both of the target levels are lowered and the new minimum volumes for cellulosic and advanced biofuels that obligated parties are required to meet for the following calendar year are published in the Federal Register.[26] The revisions in Table- 4-1, denoted in red font, are the results of this annual review.

Progress of cellulosic ethanol production capacity has fallen significantly short of government and various expert projections. Production costs far in excess of corn-based ethanol are the likely cause for the shortfall compared to expectations. As consequence of this lack of progress, the U.S. EPA has repeatedly down-sized the cellulosic biofuels requirement for the years 2010 through 2013. Instead of the original mandated quantity of 600 million gallons of cellulosic biofuels between 2010 and 2012, the U.S. EPA has been compelled to dramatically reduce this requirement to between 16.6 million and 25.7 million gallons.[27] Further, it appears that there have not been any RINs generated from cellulosic biofuels through June 2011.[28] The fact that no cellulosic RINs have been generated as part of the RFS2 program does not necessarily mean that there has not been any cellulosic biofuel production in the United States. It just means that if there has been cellulosic biofuel production, the fuel produced cannot be used towards meeting the cellulosic requirements under RFS2 because the facilities have not yet registered as part of the U.S. EPA Moderated Transaction System (EMTS).

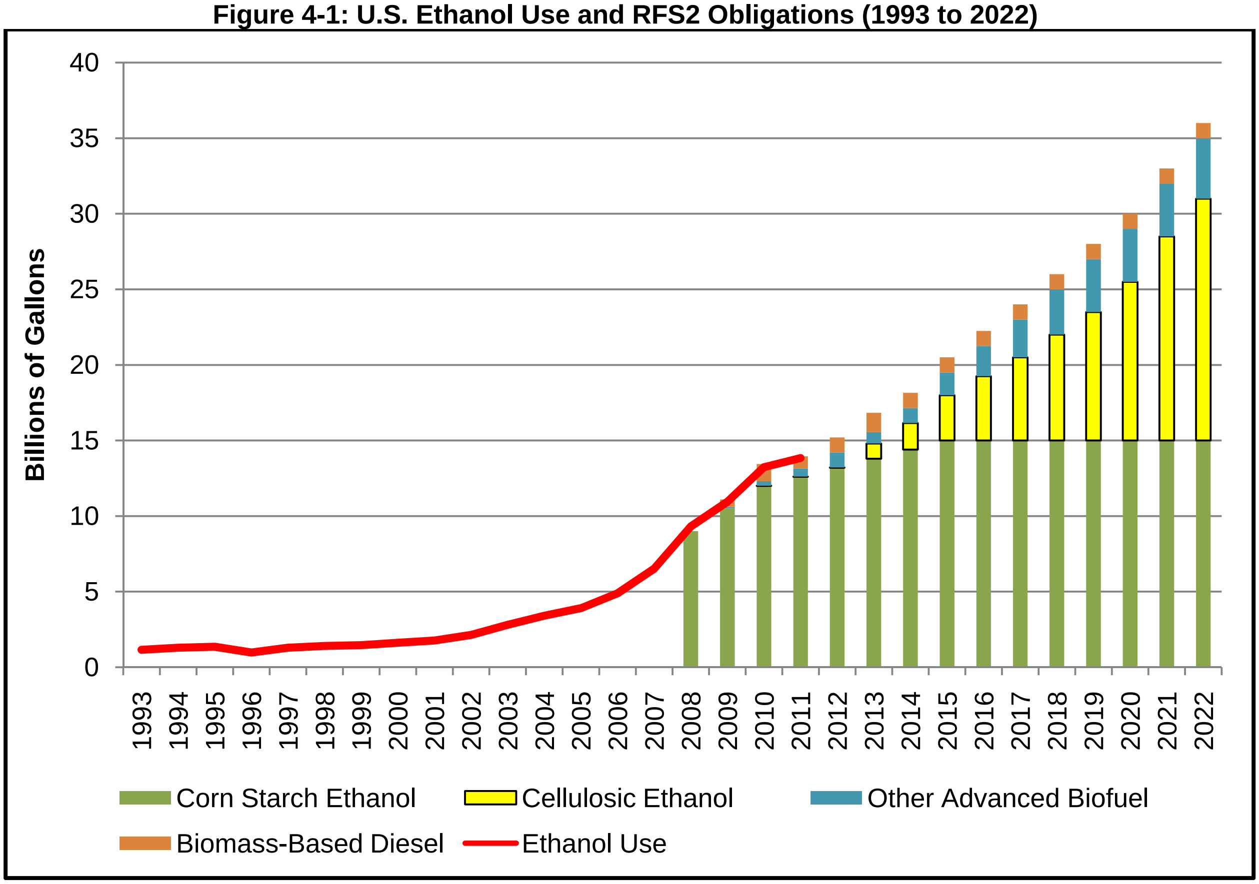
Currently, it is unclear why no RFS2 complying production has been reported. In their December 9, 2010 Final Ruling, the U.S. EPA listed five companies currently online that could produce 6 million gallons of fuel to satisfy the cellulosic biofuel requirements in 2011.[29] These companies were: DuPont Danisco in Vonore, Tennessee; Fiberight in Blairstown, Iowa; KL Energy in Upton, Wyoming; KiOR in Houston, Texas; and Range in Soperton, Georgia. Four of those companies were also evaluated by the EIA with their estimates showing that 3.9 million gallons of cellulosic ethanol could be produced in 2011. One reason these companies may not be registering the RINs produced from this commercial production of cellulosic ethanol could be that the fuel being produced does not meet the U.S. EPA's specification for a motor vehicle fuel, a requirement to meet RFS2, found in Code of Federal Regulations under Title 40, part 79. Another reason could be that this fuel is not being used as a motor vehicle fuel, thus also not meeting the RFS2 compliance.[30]

While production for 2011 may not occur, obligated parties under RFS2 can still comply with the standard by purchasing waiver credits. Per Section 211(o)(7)(D) of the Clean Air Act, whenever the U.S. EPA is required to set "the applicable volume of cellulosic biofuel at a level lower than that specified in the Act, the U.S. EPA is to provide a number of cellulosic credits for sale that is no more than the U.S. EPA-determined applicable volume. Congress also specified the formula for calculating the price for such waiver credits: Adjusted for inflation, the credits must be offered at the price of the higher of 25 cents per gallon or the amount by which $3.00 per gallon exceeds the average wholesale price of a gallon of gasoline in the United States." In 2010, the value of these credits to comply with the 6.5 million gallon target was $1.56 per credit and 12,186 of these credits were purchased, totaling $19,010.16, with the rest of the compliance being satisfied by RFS cellulosic biofuel credits. In 2011, no RFS credits can be applied to compliance and if no RIN credits are created, 6.6 million credits will need to be purchased at $1.13 a credit, totaling $7.458 million. For 2012, the credit waiver value will be posted in November of 2011.

The U.S. EPA should consider convening a forum to ascertain the primary causes for lack of progress regarding growth of cellulosic biofuel production capacity. As part of this proceeding, the U.S. EPA should consider modifications to the program that may include significant revisions to the various RFS2 category requirements. Scaling back the cellulosic requirements in conjunction with increasing the Advanced Biofuel volumes by an identical quantity is one approach that should be considered. Discussions should also include possible increase of the Starch-based Biofuel component of RFS2 with appropriate analysis of potential impacts that such a change could have on agricultural, animal feedstock, and food markets related to corn and other potentially displaced grain crops.

The estimated ethanol use in 2010 was 13.23 billion gallons or 930 million gallons greater than the RFS2 requirement for last year and is projected by staff to be about 690 million gallons more for 2011 based on an estimated ethanol use of 13.84 billion gallons. Figure 4-1 shows the progression of ethanol use in the United States and the RFS2 obligations through 2022, including the latest revisions to the cellulosic and advanced biofuel requirements.

Figure 4-1: U.S. Ethanol Use and RFS2 Obligations (1993 to 2022)



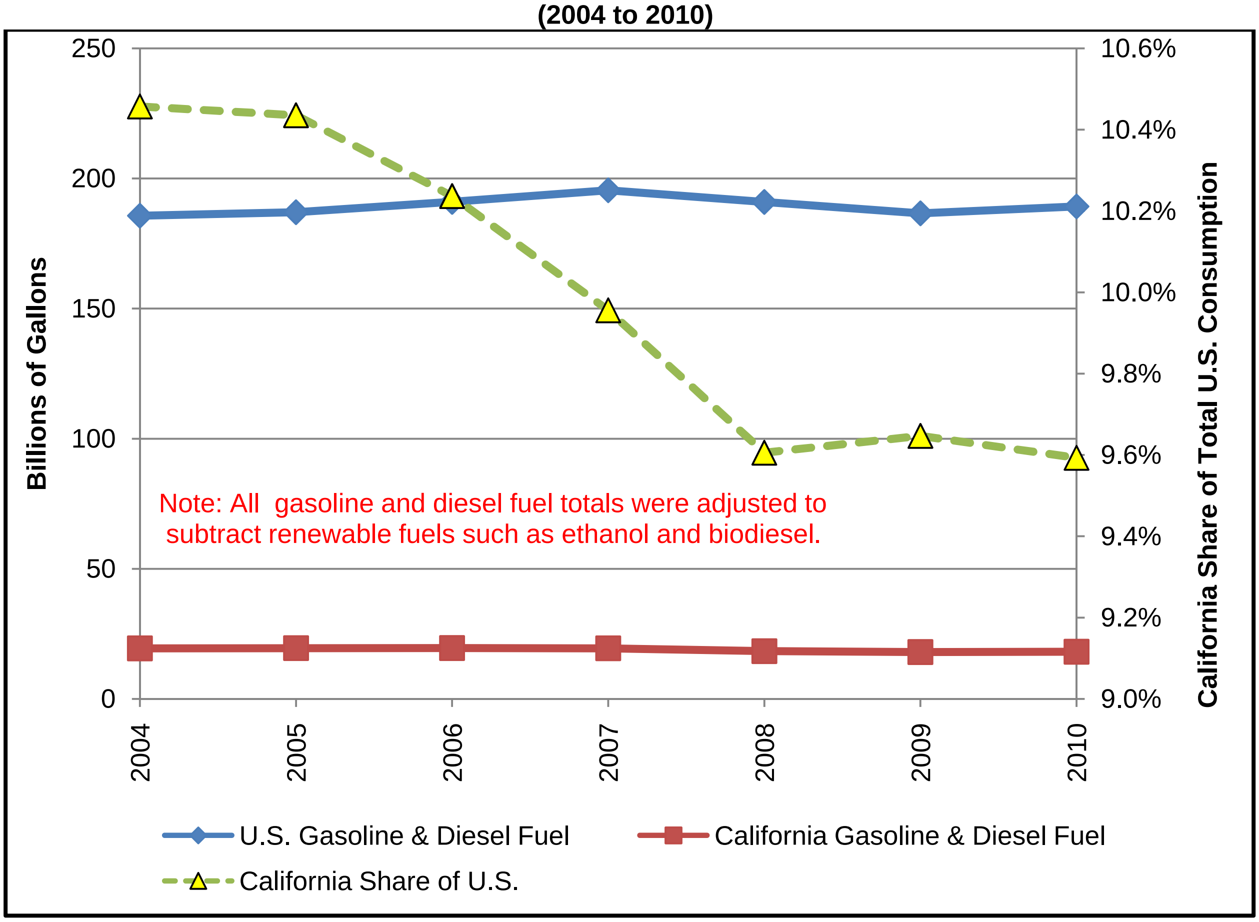
Sources: EIA, U.S. EPA, and California Energy Commission analysis.

California Proportional Share from RFS2

To determine what quantity of renewable fuel might be needed in California to comply with RFS2, staff had to determine what the "proportional-share" RFS2 obligation might be under both Low and High Petroleum Demand Scenarios for gasoline over the forecast period. Although compliance with RFS2 by refiners, importers, and blenders can include acquisition of RIN credits and over-compliance on a company basis in other areas of the United States outside California, for this part of the analysis, staff assumed that all obligated parties in California would be complying by blending their "proportional-share" of renewable fuels within the state's borders. This approach will yield more of a "worst case" infrastructure assessment but still recognizes that the forecasted demand for ethanol and biodiesel necessitated by RFS2 could be a bit less than presented in this report.

The first step was to figure out what the "proportional-share" should be for the various types of renewable fuels mandated under RFS2 standards. Staff analyzed California's gasoline and diesel fuel demand relative to the totals in the United States, less the renewable fuel portion.[31] California's share of United States gasoline and diesel fuel consumption has averaged 9.84 percent between 2004 and 2010, but has continued to decline over that same period (see Figure 4-2).

Figure 4-2: United States & California Motor Vehicle Fuel Consumption (2004 to 2010)



Sources: EIA, BOE, and California Energy Commission analysis.

To meet the regulatory necessities of RFS2 over the forecast period, staff calculated California's proportional-share by comparing the Energy Commission combined gasoline and diesel fuel demand forecasts to that of the Low Oil Price and the Extended Policy Cases from EIA's *2011 Annual Energy Outlook* that was revised in April 2011.[32] This calculated California share of gasoline and diesel fuel demand was then applied to each of the four RFS2 renewable fuel annual minimum requirements (refer back to Table 4-1.) to determine how much ethanol and biodiesel would be necessary to achieve "proportional-share" compliance with RFS2. For 2023 through 2030, RFS2 annual domestic requirements were held fixed at the 2022 levels. However, staff recognized that RFS2 regulations note that values post 2022 may be adjusted and could be higher than the values used by staff in this forecast analysis. Under the Low Petroleum Demand Scenario for gasoline, total ethanol demand in California is forecast to rise from 1,344 million gallons in 2010 to 2,791 million gallons by 2020. Under the Low Petroleum Demand Scenario for diesel fuel, minimum biodiesel demand in California is forecast to grow from 42.3 million gallons in 2010 to 62.2 million gallons by 2020. (See Table 4-2.)

Table 4-2: California Renewable Fuel Requirements (2008 to 2030)
Low Petroleum Demand Scenario

Year	California Share Ethanol Fuel Requirement Bil. Gallons	Starch Derived Biofuel Bil. Gallons	Advanced Biofuels			
			Cellulosic Biofuels Bil. Gallons	Other Advanced Biofuels Bil. Gallons	Biomass Based Diesel Bil. Gallons	Total Advanced Biofuels Bil. Gallons
2008	0.973	0.973	0.000	0.000	0.000	0.000
2009	1.179	1.168	0.000	0.011	0.033	0.044
2010	1.344	1.311	0.011	0.022	0.042	0.075
2011	1.407	1.348	0.001	0.058	0.053	0.112
2012	1.453	1.350	0.001	0.102	0.063	0.166
2013	1.575	1.398	0.101	0.076	0.079	0.256
2014	1.712	1.437	0.175	0.100	0.063	0.337
2015	1.910	1.469	0.294	0.147	0.064	0.505
2016	2.069	1.461	0.414	0.195	0.064	0.672
2017	2.210	1.442	0.529	0.240	0.063	0.832
2018	2.405	1.443	0.673	0.289	0.063	1.025
2019	2.596	1.442	0.817	0.337	0.063	1.217
2020	2.791	1.444	1.010	0.337	0.062	1.410
2021	3.045	1.427	1.285	0.333	0.062	1.679
2022	3.374	1.446	1.542	0.386	0.061	1.989
2023	3.454	1.480	1.579	0.395	0.061	2.034
2024	3.547	1.520	1.621	0.405	0.060	2.087
2025	3.632	1.557	1.660	0.415	0.059	2.135
2026	3.735	1.601	1.707	0.427	0.059	2.193
2027	3.744	1.604	1.711	0.428	0.058	2.197
2028	3.794	1.626	1.734	0.434	0.058	2.225
2029	3.848	1.649	1.759	0.440	0.057	2.256
2030	3.882	1.664	1.775	0.444	0.056	2.275

Source: California Energy Commission analysis

Under the High Petroleum Demand Scenario, total ethanol demand in California is forecast to rise from 1,343 million gallons in 2010 to 2,836 million gallons by 2020. Under the High Petroleum Demand Scenario, minimum biodiesel demand in California is forecast to grow from 71 million gallons in 2010 to 98 million gallons by 2020 (Table 4-3).

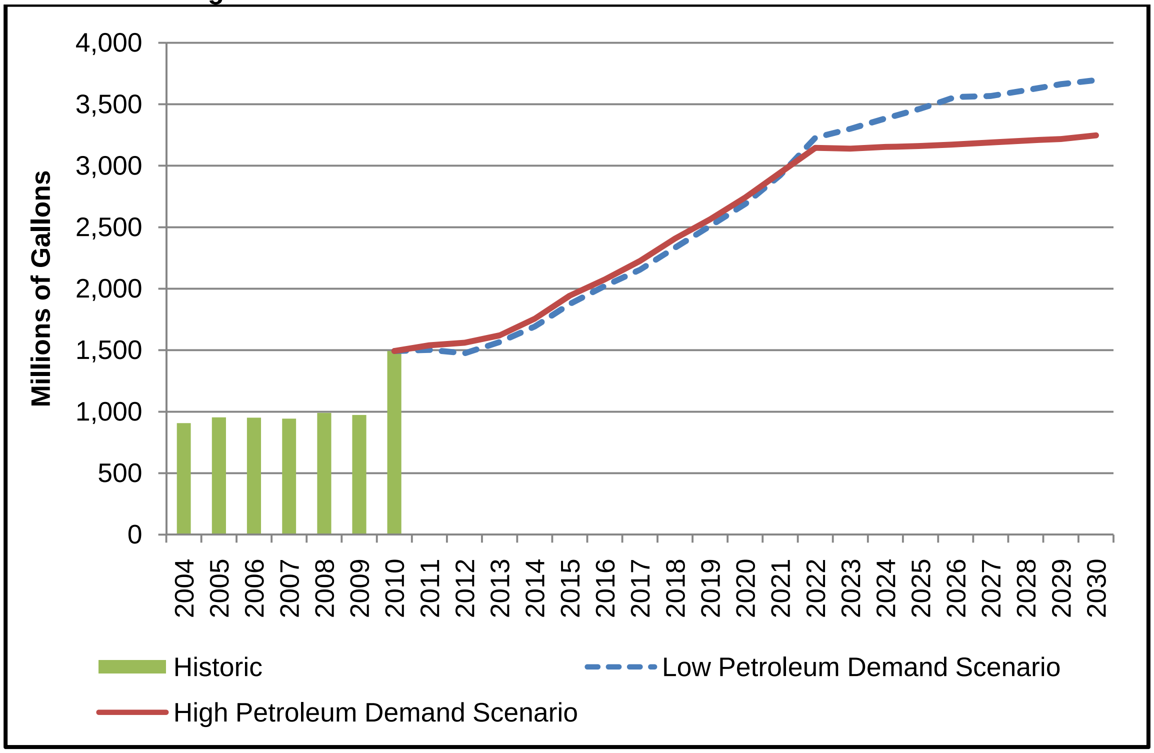
Table 4-3: California Renewable Fuel Requirements (2008 to 2030)
High Petroleum Demand Case

Year	California Share Ethanol Fuel Requirement Bil. Gallons	Starch Derived Biofuel Bil. Gallons	Advanced Biofuels			
			Cellulosic Biofuels Bil. Gallons	Other Advanced Biofuels Bil. Gallons	Biomass Based Diesel Bil. Gallons	Total Advanced Biofuels Bil. Gallons
2008	0.973	0.973	0.000	0.000	0.000	0.000
2009	1.179	1.168	0.000	0.011	0.056	0.067
2010	1.343	1.310	0.011	0.022	0.071	0.104
2011	1.394	1.336	0.001	0.058	0.085	0.143
2012	1.505	1.398	0.001	0.106	0.106	0.213
2013	1.627	1.444	0.105	0.078	0.134	0.317
2014	1.772	1.488	0.181	0.103	0.103	0.387
2015	1.974	1.519	0.304	0.152	0.101	0.557
2016	2.118	1.495	0.424	0.199	0.100	0.723
2017	2.279	1.486	0.545	0.248	0.099	0.892
2018	2.476	1.486	0.693	0.297	0.099	1.090
2019	2.645	1.470	0.833	0.343	0.098	1.274
2020	2.836	1.467	1.027	0.342	0.098	1.467
2021	3.055	1.432	1.289	0.334	0.095	1.718
2022	3.272	1.402	1.496	0.374	0.093	1.963
2023	3.265	1.399	1.492	0.373	0.093	1.959
2024	3.279	1.405	1.499	0.375	0.094	1.968
2025	3.286	1.408	1.502	0.376	0.094	1.972
2026	3.298	1.413	1.508	0.377	0.094	1.979
2027	3.315	1.421	1.515	0.379	0.095	1.989
2028	3.330	1.427	1.522	0.381	0.095	1.998
2029	3.342	1.432	1.528	0.382	0.095	2.005
2030	3.373	1.446	1.542	0.385	0.096	2.024

Source: California Energy Commission analysis.

California's "proportional-share" RFS2 obligations are forecast to significantly increase the quantity of ethanol used in the state over the forecast period. The projected ethanol demand increase is greatest under the Low Petroleum Demand Scenario, more than doubling to 2.0 billion gallons by 2016 before peaking at 3.8 billion gallons by 2030. Figure 4-3 depicts ethanol demand growth in California between 2004 and 2030.

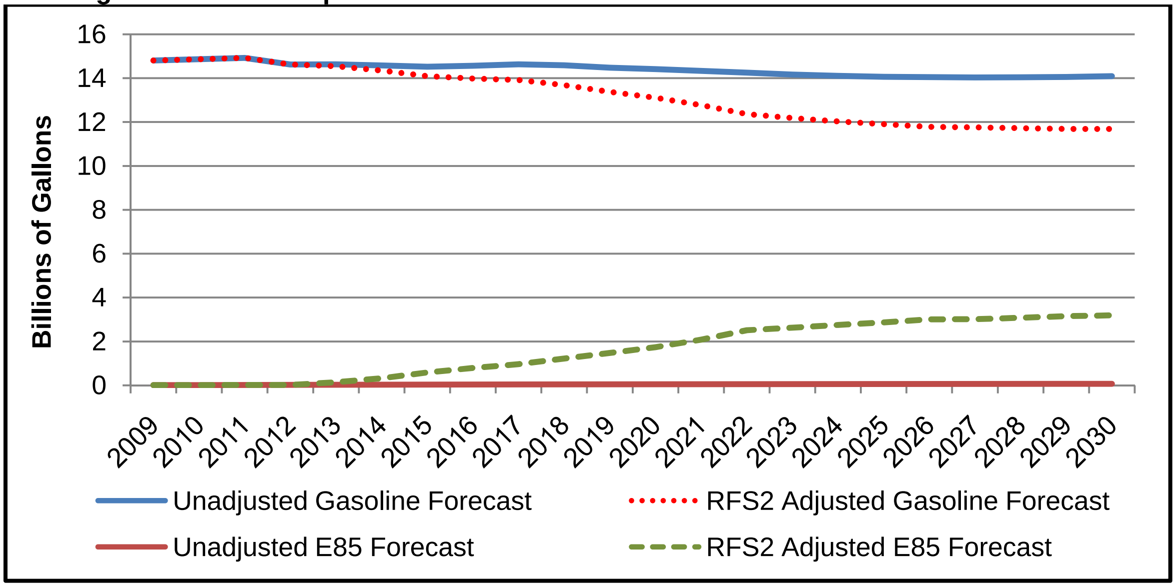
Figure 4-3: California Historical and Forecast Ethanol Demand



Source: California Energy Commission analysis.

The federally mandated use of ever-increasing quantities of ethanol over the forecast period will dampen the outlook for gasoline demand further than will higher fuel economy standards alone. Figure 4-4 illustrates how the Energy Commission's Low Petroleum Demand Scenario gasoline consumption projections decrease 22 percent by 2030 as a consequence of higher ethanol use mainly in the form of greatly increased sales of E85 that will be necessitated by the RFS2 requirements.

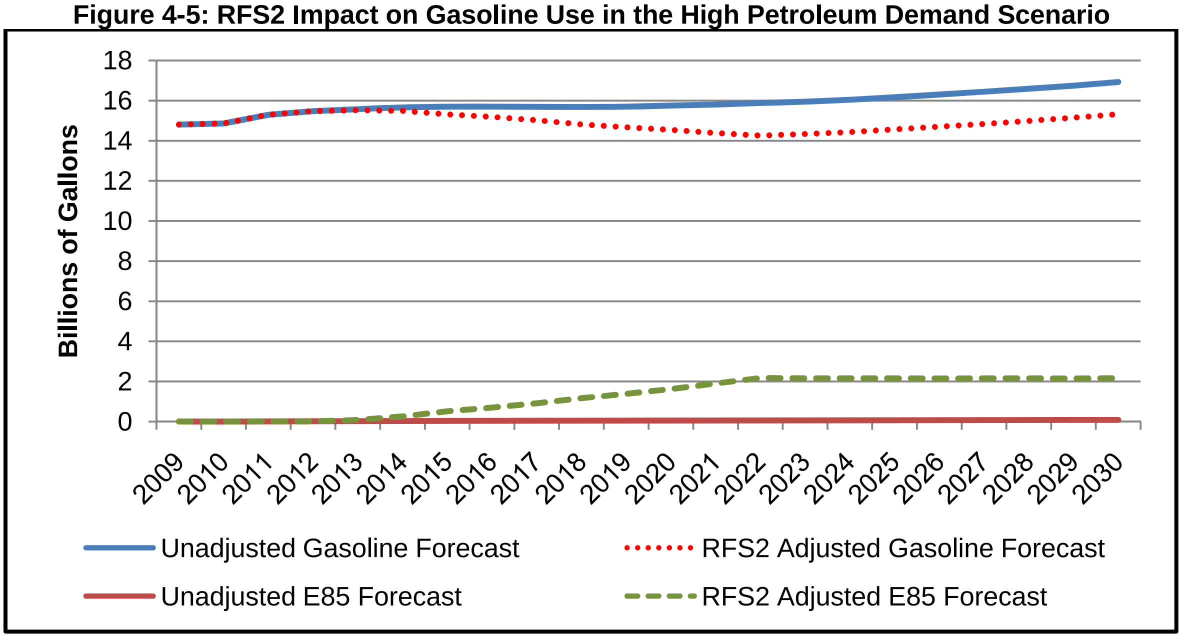
Figure 4-4: RFS2 Impact on Gasoline Use in the Low Petroleum Demand Scenario



Source: California Energy Commission analysis.

The impact on the High Petroleum Demand Scenario is slightly less, decreasing the initial outlook 9.0 percent by 2030 as illustrated by Figure 4-5.

Figure 4-5: RFS2 Impact on Gasoline Use in the High Petroleum Demand Scenario



Source: California Energy Commission analysis.

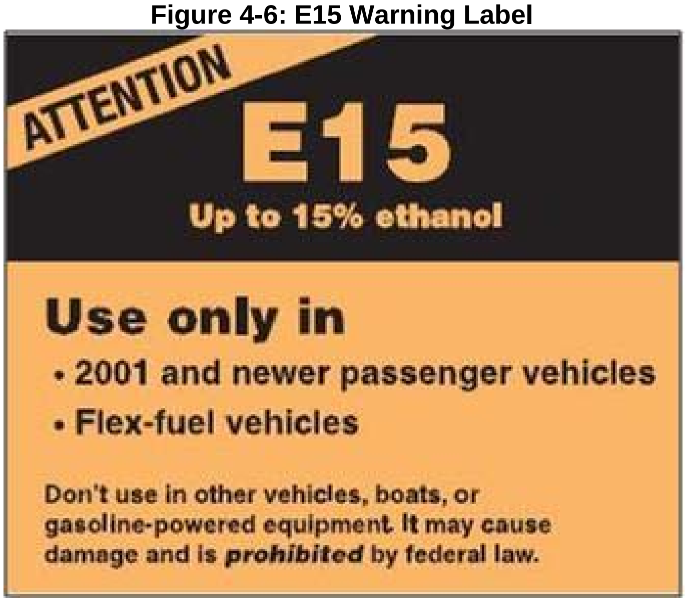
Greater use of ethanol in California could be accomplished by (1) adoption of new upper limits for low-level ethanol blends in excess of the current E10 standard, or (2) increased sales of E85. Experts generally recognize that there are potential vehicle operability and emission issues that need to be addressed before the low-level cap on ethanol blends in gasoline (referred to as the *blend wall*) can be increased to levels greater than 10 percent.[33]

Ethanol Blend Wall

Staff estimated that ethanol demand in California will eclipse an average of 10 percent by volume in all gasoline sales between 2012 and 2013, depending on gasoline demand growth rates. Original equipment manufacturers (OEMs) generally have motor vehicle warranties that are voided if the owner uses gasoline with more than 10 percent by volume ethanol. OEMs are concerned about potential harm to the catalyst in their vehicles. A recent study conducted on behalf of the University of Minnesota, however, suggests existing vehicles could operate at slightly higher ethanol concentrations without undue operational or emissions problems.[34] The U.S. DOE conducted vehicle testing of intermediate ethanol blends (E15 and E20) to measure effects on vehicle emissions, catalysts, and engine durability. This group has released a revised report that did not identify any significantly detrimental issues.[35] Lastly, the U.S. EPA was petitioned by Growth Energy to allow the ethanol blend wall to be increased to E15.[36]

The U.S. EPA has considered the request to allow a higher concentration of ethanol in low-level gasoline and made a determination that E15 may be used in light-duty vehicles that are newer than model year 2001 but this is not mandated.[37] The regulation is estimated by U.S. EPA to include 67.2 percent of the existing fleet of vehicles and goes into effect on August 24, 2011.[38] This decision also includes a provision to require labeling of gasoline dispensers with sufficient information to warn consumers with older vehicles as to the potential consequences of using E15 in their vehicles.[39] Figure 4-6 provides a copy of the proposed warning label.

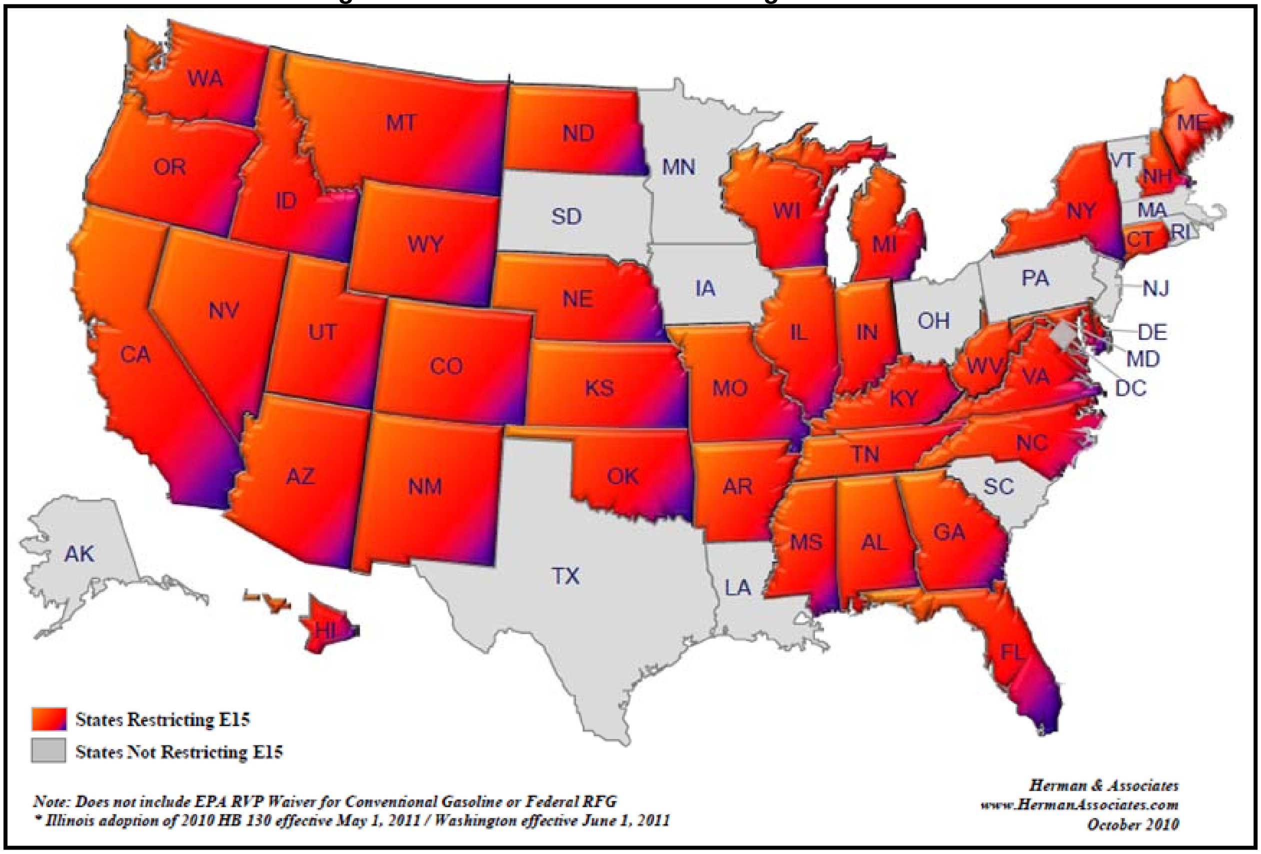
Figure 4-6: E15 Warning Label



Source: U.S. EPA

However, there are several other challenges that would need to be overcome before E15 could begin to achieve significant penetration into the United States transportation fuels market. Some of the more significant challenges include: potential voiding of OEM vehicle warranties; no liability protection provided by Congress against misfueling and potential vehicle damage claims for vehicles prior to model year 2001; and E15 blending restrictions by majority of states. Figure 4-7 illustrates the states that have some form of regulation that that either prohibit or have various restrictions regarding the sale of E15 gasoline blends. In time, it is possible for these challenges to be overcome in some areas of the United States.

Figure 4-7: States With E15 Blending Restrictions



Source: Herman & Associates.

California's revised reformulated gasoline specifications (referred to as the revised Predictive Model) went into effect on January 1, 2010. Information used to develop mathematical relationships between various gasoline properties (such as sulfur and oxygen content) and vehicle emissions (both evaporative and tailpipe) did not include gasoline with blends of ethanol greater than 10 percent by volume. As such, this ARB regulation would have to be modified before E15 blends could be considered for use in the state. Since this process would require several years to complete (if this path were to be pursued) and the outcome is uncertain, staff has assumed in this analysis that E10 will remain the practical upper limit in California gasoline low-level blends over the foreseeable future, although E15could potentially show up in the California fuels market after 2015.

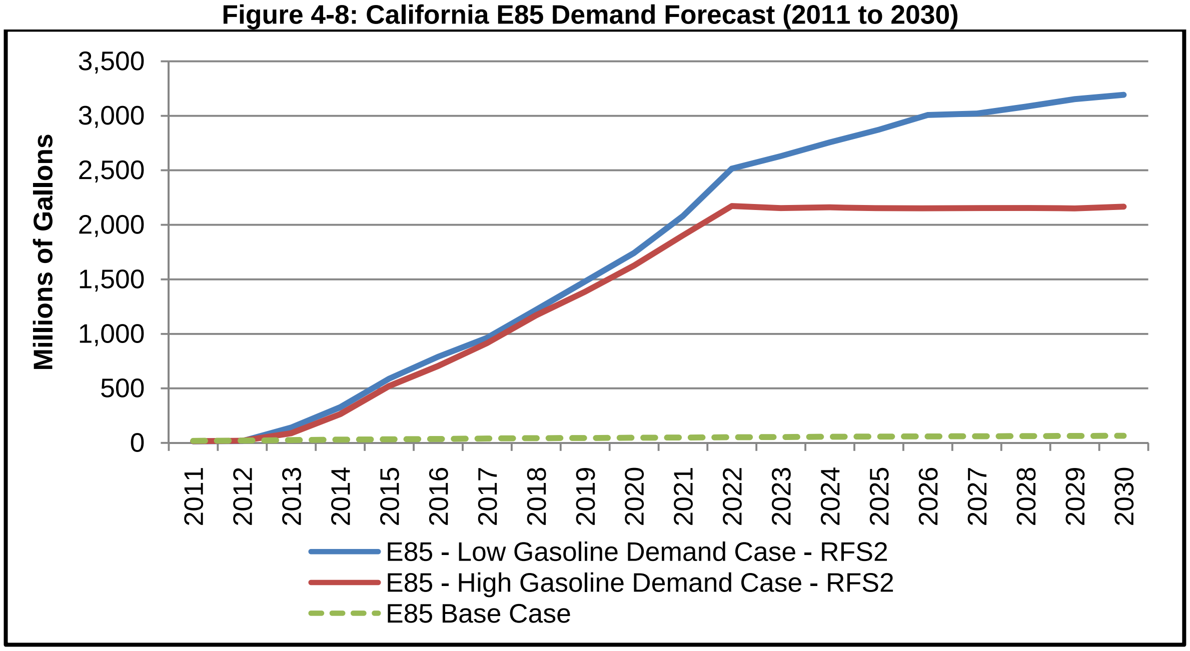
Increased Ethanol Use in Gasoline – E85

Since the ethanol blend wall in California is assumed to remain at 10 percent by volume over the forecast period, the only reasonable means of using more ethanol in transportation fuels is to increase the sales of E85. As of October 2009, there were nearly 409,636 registered FFVs in California which could use either gasoline or E85.[40] Although there is a large population of FFVs in California, there are a modest but growing number of retail stations that offer E85. As of July

2011, there were at least 64 stations that offered E85 to the public.[41] Staff expects that the quantity of E85 sold in California will increase in response to higher levels of mandated ethanol use due to the RFS2. However, the pace of this expansion may be inadequate to achieve compliance due to a variety of infrastructure challenges and disincentives.

There are several challenges to expansion of E85 sales in California. Availability of E85 will need to increase dramatically to ensure that sufficient volumes of E85 can be sold to keep pace with RFS2 requirements. Assuming a 10 percent ethanol blend wall, E85 sales in California are forecast to rise from 13.2 million gallons in 2009 to 1,741 million gallons in 2020 and 3,192 million gallons by 2030 under the Low Petroleum Demand Scenario for gasoline. Figure 4-8 shows the annual E85 forecast for both the Low and High Petroleum Demand Scenarios.

Figure 4-8: California E85 Demand Forecast (2011 to 2030)



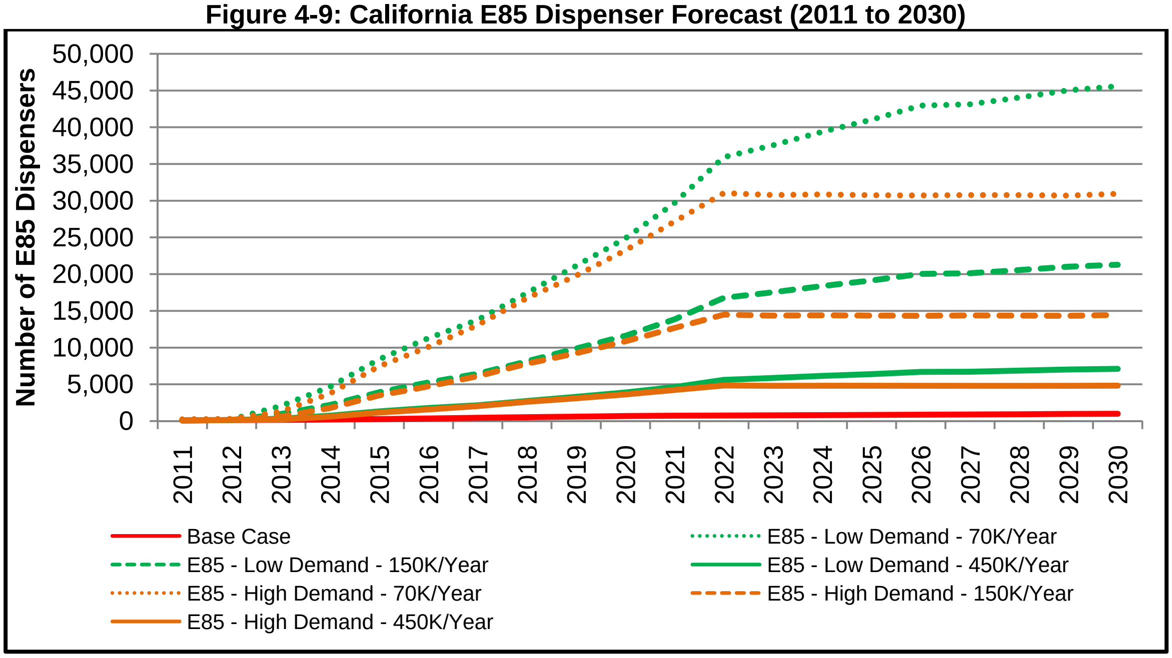
Source: California Energy Commission analysis.

However, the proposed RFS2 regulations do not require that retail station owners and operators make available E85 for sale to the public. Refiners, importers, and blenders have an obligation to comply with the RFS2 standards, but retail station operators do not have any obligation. This is an apparent "disconnect" in the RFS2 policy that could easily result in a retail infrastructure that is inadequate to handle the necessary increase in E85 sales.

Another potential issue is what type of base gasoline will be necessary to blend with ethanol to produce E85 to meet ASTM minimum RVP requirements. If the blendstock is something other than CARBOB for E10 blending, additional segregated storage tanks would be required throughout the production and distribution infrastructure to accommodate this new gasoline blendstock.

To calculate the number of retail stations that would need to offer E85, staff had to first estimate the number of E85 dispensers that would need to be operating. This quantity of E85 dispensers can vary depending on the annual statewide demand for E85 and the average annual distribution of E85 per dispenser. Depending on the average quantity of fuel sold by a typical E85 dispenser, California could require between 4,828 and 35,928 E85 dispensers by 2022. To put that estimated number of new dispensers into perspective, there were a total of approximately 42,050 retail dispensers in California during summer of 2008 for all fuel types.[42] The average annual distribution of transportation fuel per fuel dispenser in California between July 1, 2007, and June 30, 2008, is estimated at 452,000 gallons. However, staff estimates that a dispenser that sells only one type of fuel sold an average of between 150,000 and 175,000 gallons over this same period.[43] Actual per-station E85 annual sales figures for Minnesota are much lower, averaging about 74,000 gallons.[44] The impact of lower annual throughput and minimum per-gallon margins necessary to make a profit are discussed later in this section. Figure 4-9 depicts the growth in E85 dispenser availability over the forecast period that would be necessary to distribute sufficient volumes of E85 to help comply with RFS2.

Figure 4-9: California E85 Dispenser Forecast (2011 to 2030)



Source: California Energy Commission analysis.

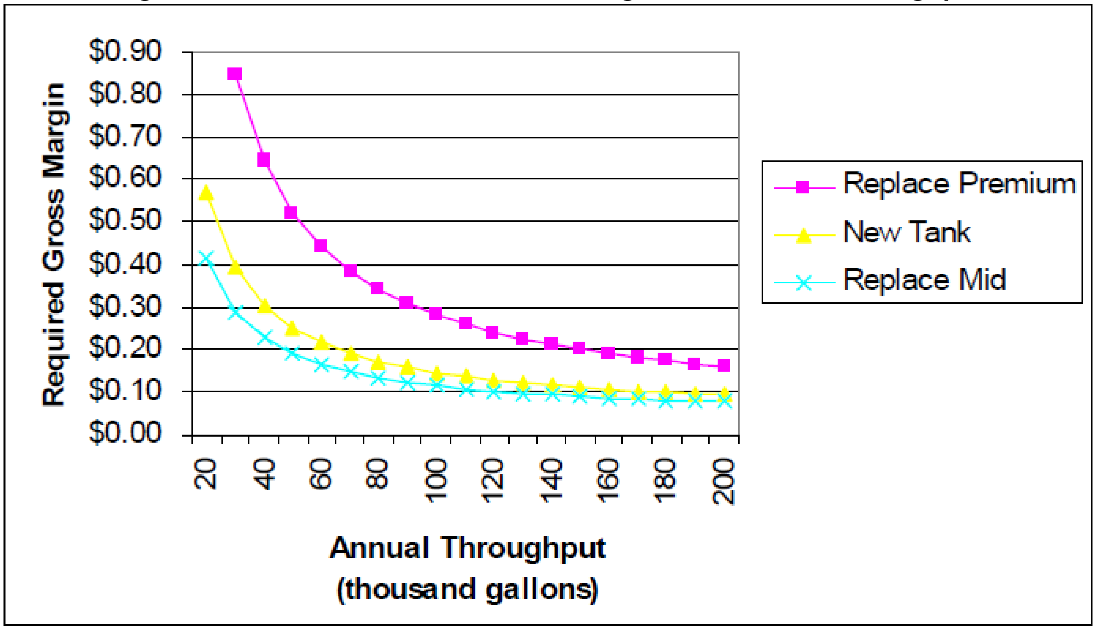
The significant increase in E85 dispenser availability at California retail stations has a potential challenge or increased difficulty associated with equipment approval. Most (if not all) retail dispensers have been certified by Underwriters Laboratories (UL) or are assembled using UL-approved parts and components. Since June 2011, UL has certified multiple dispensers and equipment for the purpose of E85 distribution. However, it is uncertain how the low number of certified dispensers and equipment are influencing the installation of E85 dispensers in California since retailers have been selling E85 since 2006. It is possible that variances or waivers are being granted for E85 equipment submitted for approval by local jurisdictions that have oversight.

E85 retail infrastructure is expensive. Costs for installing a new UST, dispenser, and appurtenances range between $50,000 and $200,000.[45] More recently in California, costs have been estimated at between $226,500 and $442,500 per existing retail station location.[46] Statewide, the E85 retail infrastructure investment costs could be as low as $749 million to upwards of $20.8 billion between 2011 and 2020. Between 2011 and 2030 the E85 dispenser infrastructure costs could range from $3.1 billion to $101.8 billion. The California Energy Commission's AB118 program has funded the installation of 85 E85 stations at a total funding level of $16.5 million[47]. One approach to reduce this anticipated infrastructure cost is for the California Legislature to consider requiring new building code standards that all gasoline-related equipment (underground storage tanks, dispensers, associated piping, and so on) be E85-compatible for construction of any new retail stations or replacement of any gasoline-related equipment beginning January 1, 2013. This approach would increase the likelihood of success of renewable fuel penetration policy goals.

Costs can also be reduced if an existing UST is used to store and dispense the E85. Dedicated mid-grade and premium storage tanks are two examples, although each option has additional complications. The mid-grade replacement option is estimated to cost only $20,000 but requires a station that has a dedicated mid-grade gasoline tank.[48] The portion of retail stations in California that still have dedicated mid-grade USTs is estimated at no more than 30 percent.[49] This option in California is limited and will decline in the future since new retail stations do not normally install a dedicated mid-grade UST. The National Renewable Energy Laboratory (NREL) also examined a scenario whereby a retail station owner uses a dedicated premium grade gasoline UST to store and dispense E85. This option will likely eliminate premium and mid-grade gasoline sales at a retail station. It should also be noted that premium grade gasoline sales usually command the highest profit margin. A retail station owner would have to believe that the E85 margins would be even higher when compared to premium gasoline for this business strategy to be a viable option.

NREL conducted modeling to assess various factors that can impact profitability of a decision to modify an existing retail station to dispense E85. Figure 4-10 shows the three options (new tank, use of existing mid-grade tank, and use of existing premium tank) and the per-gallon level of margin required to sustain profitability over a wide range of annual E85 fuel throughput. The graph illustrates that the new tank and mid-grade tank options are similar, while the premium option requires higher margins at any level of throughput.

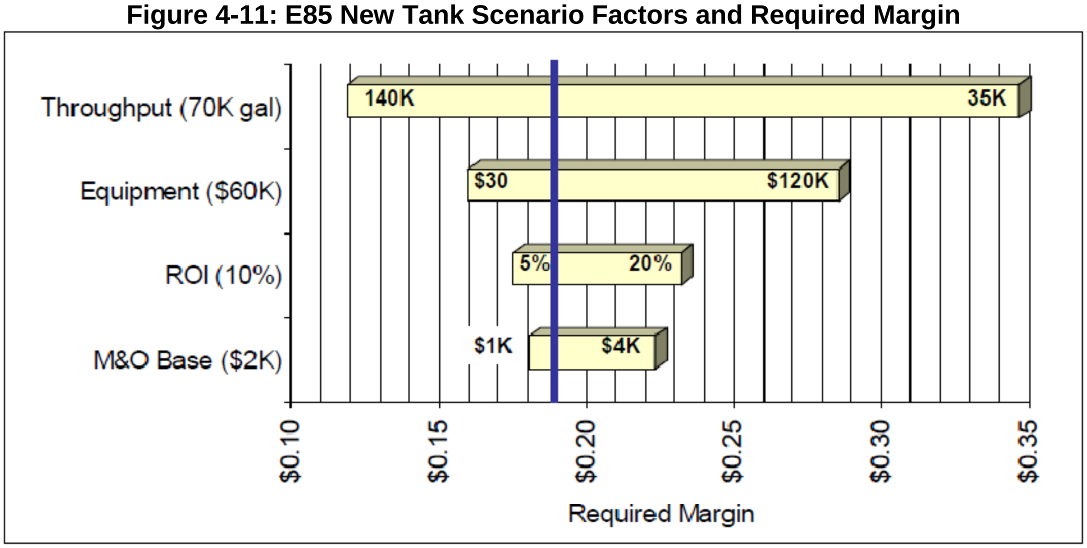
Figure 4-10: E85 Business Scenario Margins and Annual Throughput



Sources: NREL Technical Report TP-540-41590, Dec. 2007, Figure 5, page 13.

The actual level of E85 sales is probably the most important variable for determining the per-gallon margin necessary to be profitable. Variation in the actual cost of equipment is the second most important variable. Figure 4-11 shows how the level of margin required to be profitable changes as the various factors are adjusted upward or downward.

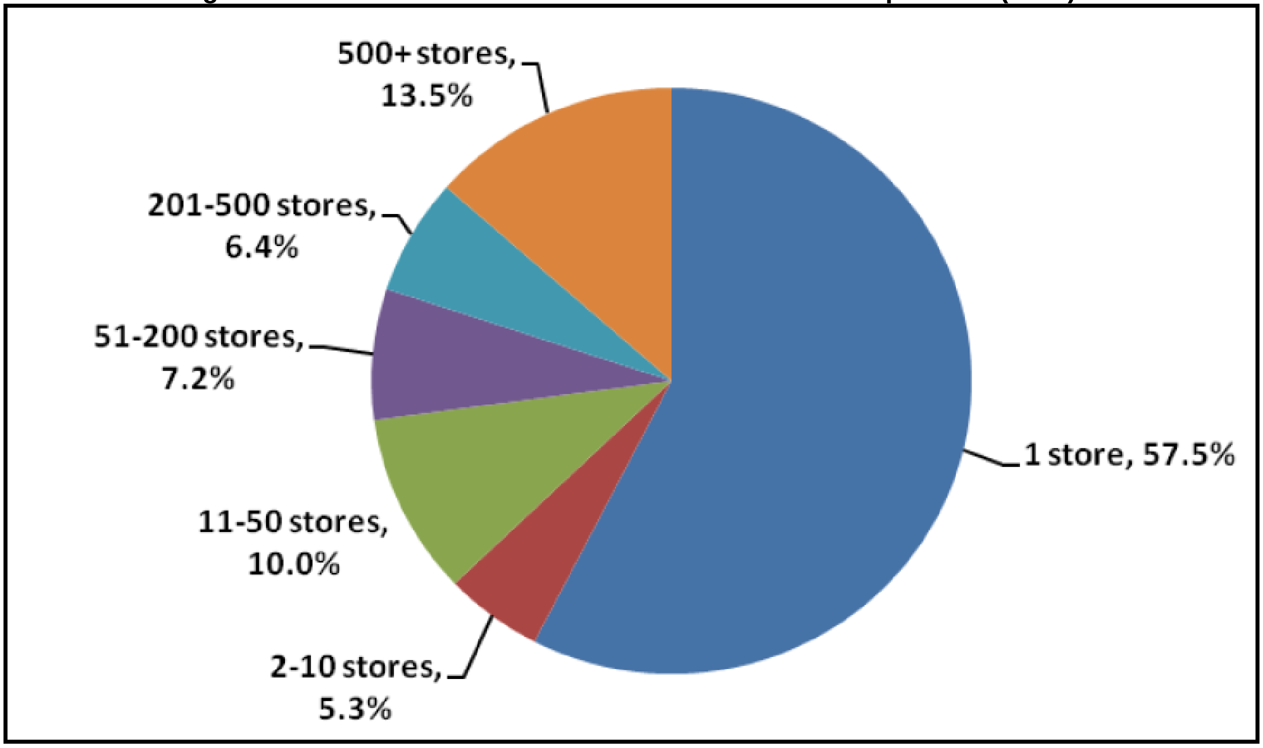
Figure 4-11: E85 New Tank Scenario Factors and Required Margin



Sources: NREL Technical Report TP-540-41590, Dec. 2007, Figure 6, page 15.

Most retail station owners and operators could have a difficult time obtaining sufficient resources to finance this type of work. Nearly 58 percent of retail stations in the United States are owned and operated by someone who has one store. (See Figure 4-12).[50] Large oil companies are actually reducing the number of retail stations they own and operate.

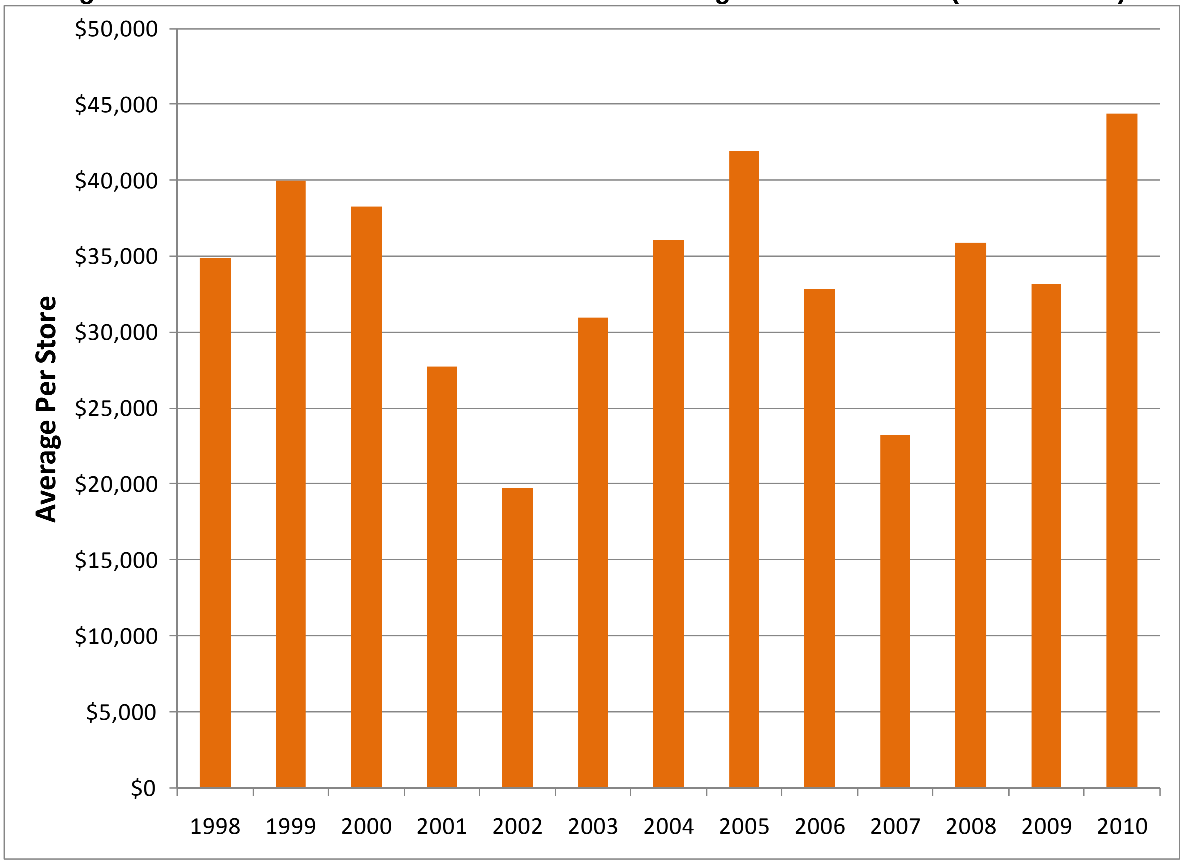
Figure 4-12: United States Convenience Store Ownership Profile (2010)



Sources: National Association of Convenience Stores (NACS) and TDLinx Official Industry Store Count, Feb. 2011.

Once again, there is no obligation to install E85 dispensers nor is there a strong financial incentive for a typical retail station owner. During 2010, approximately 80 percent of the gasoline sold to the public nationwide was through convenience stores.[51] These places of business have continued to be profitable over the last decade, averaging nearly $32,600 per store pre-tax profits between 2001 and 2010.[52] Figure 4-13 shows that these pre-tax profits are not steady but can fluctuate over time. It is possible that because most stations are operated by a sole proprietor and pre-tax profits are historically less than $40,000 per year, voluntary installation of a new E85 retail dispenser, UST, and associated piping is a business proposition that would be difficult to justify. In fact, the majority of retail locations that have recently installed E85 dispensers in California have done so with either partial or complete financial assistance from other funding sources.[53] Over the near term, the greatest challenge to expanded use of ethanol is an adequate and timely build-out of the necessary minimum E85 retail fueling infrastructure capability. It is estimated that, at a minimum, an average of 545 E85 dispensers *per year* would need to be installed in California between 2014 and 2022, costing between $27 million and $218 million per year

Figure 4-13: United States Convenience Store Average Pre-Tax Profits (1998 to 2010)



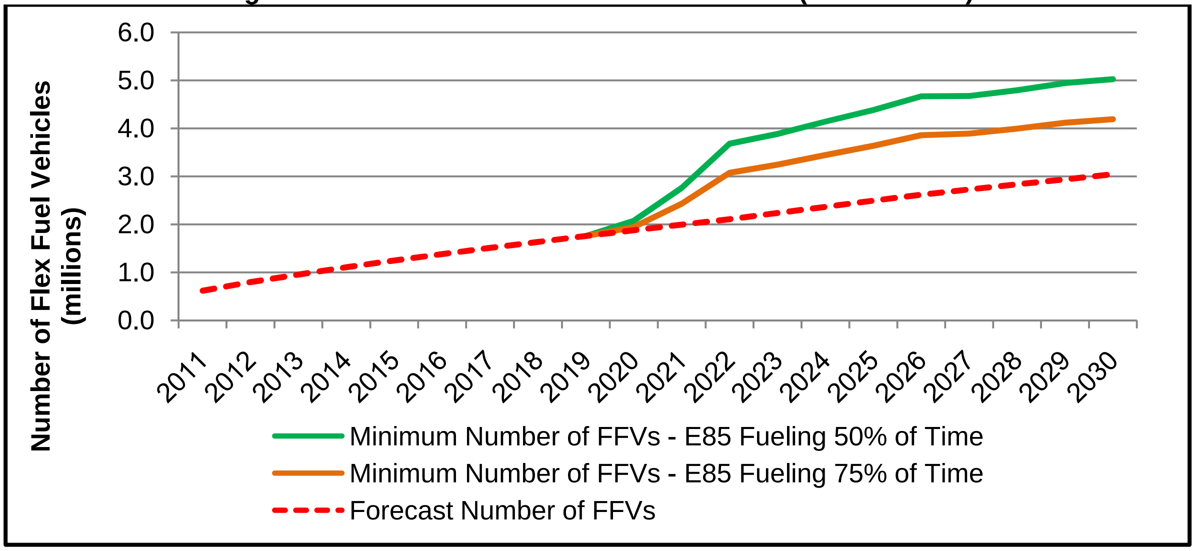
Sources: NACS State of the Industry Report data and 2011 press release.

However, the state should continue to provide as much assistance as available resources permit to help increase the likelihood of successful E85 availability. One such example is providing financial resources to help develop the retail fueling infrastructure at the early stages of E85 growth. The Energy Commission's AB118 funding allocations have included money for this type of infrastructure.

E85 Demand and Flexible Fuel Vehicle Forecast

Along with the forecasted rise of E85 sales in California, there is a commensurate rise in the number of FFVs that would be necessary to use greater volumes of E85. The FFV forecast depends on the total demand for E85, the fuel economy of FFVs, the average number of VMT per FFV, and the frequency of E85 fueling by a typical FFV owner. Based on these interrelated factors, the FFV population would need to grow from approximately 455,188 vehicles in 2010 to as many as 2.1 million FFVs by 2020 and 5.0 million by 2030. Figure 4-14 shows the FFV forecast for Low Petroleum Demand Scenario that yielded the higher E85 demand levels. The lower FFV forecasts assume that FFV owners elect to use E85 for the majority of each fueling event (75 percent of the time). The higher numbers of FFVs would be required if owners fueled with E85 at least 50 percent of the time.

Figure 4-14: California FFV Demand Forecast (2011 to 2030)



Source: California Energy Commission analysis

Based on these FFV forecast trends, a significantly greater number of FFVs will need to be sold in California than are assumed in the base case as soon as 2020. Most automakers are believed to have committed to producing up to half of their new vehicle models as FFV-compliant by 2012, contingent upon an adequate fueling infrastructure.[54] However, the ability of automobile manufacturers to produce an even greater portion of their new models as FFVs for sale in California could be challenged due to increasingly stringent emission standards and higher fuel economy standards.

Flexible Fuel Vehicles – Technical and Policy Challenges

New vehicles offered for sale in California have to include an increasing percentage of models that meet super–ultra-low-emission vehicle (SULEV) and Partial Zero Emission Vehicle (PZEV) evaporative emission standards. Compliance with these standards may be a technical challenge for FFVs.[55] These technical challenges are currently limiting the number of new vehicles that can be offered for sale as FFVs.[56] Regulations adopted by ARB designed to reduce emissions from new vehicle models (both tailpipe and evaporative), along with revised ZEV standards, will require automobile manufacturer compliance with more stringent emission standards and growing percentage of ZEV and PZEV sales.[57] Both of these sets of standards may create significant challenges for greater introduction of FFVs. The upper limit of FFV availability for new vehicle sales and incremental cost of California vehicle emission standards is unknown at this time.

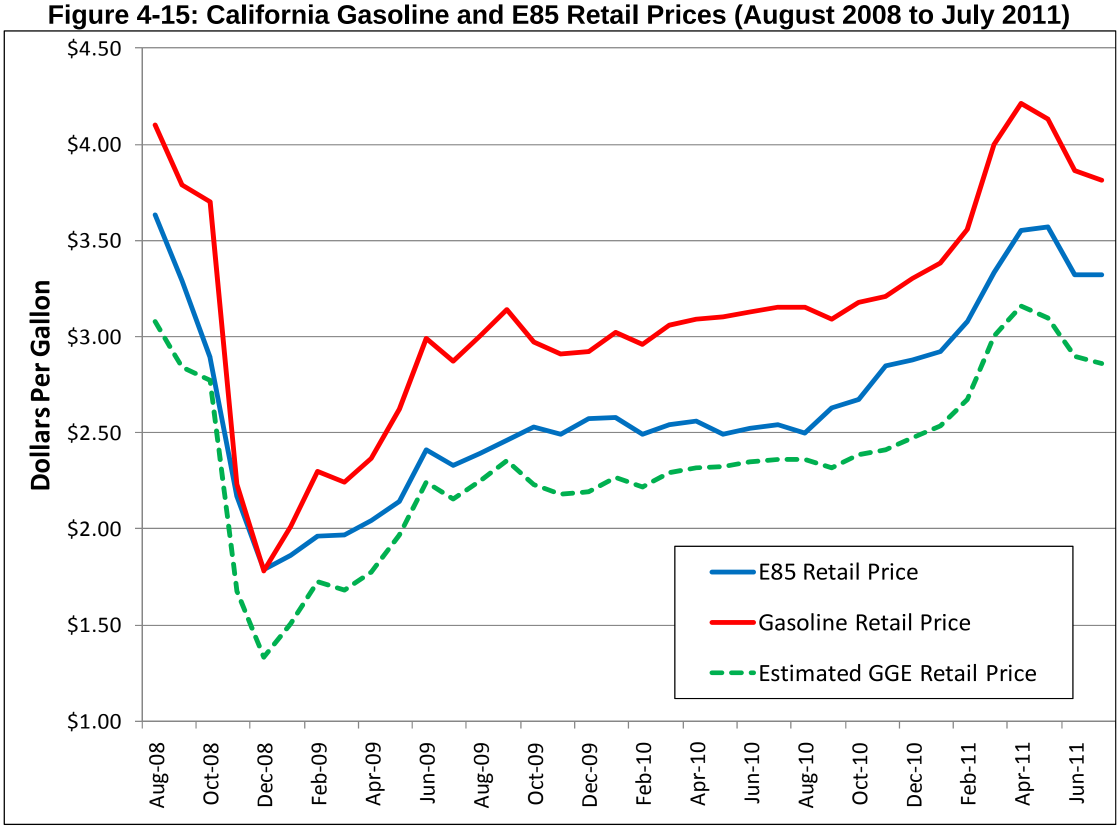
CAFE standards for passenger cars and light trucks were recently updated for model years 2012 through 2016.[58] Most recently, NHTSA and the U.S. EPA announced an intention to move forward with developing more stringent CAFE standards for model year 2017 through 2025 passenger vehicles and light-duty trucks.[59] One potential implication of these regulations is that the mix of new vehicles offered for sale will need to achieve ever-higher fuel economy standards. As such, vehicle manufacturers may plan to offer certain makes and models of more fuel-efficient vehicles, such as: PHEV, fuel cell, direct injection diesel, and electric vehicles.

None of these vehicles are FFVs. It is possible that vehicle manufacturer marketing decisions might preclude FFVs, setting the stage for a potential shortfall of new FFV vehicle availability in California in sufficient numbers to help meet compliance with the RFS2 renewable fuel obligations. This potential policy conflict should be examined in greater detail to determine if a potential FFV availability shortfall could occur.

E85 Pricing Issues

A growing market for E85 necessitated by ever-increasing mandated use of ethanol will need to adjust to the fact that E85 has less energy per gallon when compared to a gallon of E10. This energy difference can reduce the number of miles traveled per gallon from between 23 and 28 percent.[60] As such, the retail price of a gallon of E85 would need to be an equivalent percentage less than a retail gallon of E10 to ensure that an FFV operator would receive a gallon of equal value. For example, if a gallon of E10 was priced at $3.50, a gallon of E85 would need to be priced at between $2.52 and $2.70. However, in actual practice, FFV motorists in California have been consistently overpaying on an energy basis for E85 fuel. Figure 4-15 tracks California average retail prices for both gasoline and E85 at retail stations that offer both types of fuels.[61] Staff has also included a GGE price for E85 based on an average fuel economy difference of 75 percent. As the chart indicates, consumers were paying more per gallon for E85 than the fuel economy equivalent price by an average of 26 cents per gallon during 2010 and an average of 41 cents per gallon more during the first 7 months of 2011. The overpayment ranged between 14 and 47 cents per gallon over this period of time.

Figure 4-15: California Gasoline and E85 Retail Prices (August 2008 to July 2011)



Sources: E85Prices.com and California Energy Commission analysis.

As California sales of E85 increase, there should be steps taken to help ensure that FFV motorists are receiving adequate pricing information at retail stations to put them in a position of making more informed fuel purchase decisions. Over time, FFV consumers may elect, on average, to pay a premium for E85 above the GGE price. It is recognized that gasoline energy content varies on a seasonal basis, as well as from one refinery to the next. As such, GGE pricing through the use of an exact fuel economy equivalency ratio is not feasible and the use of an average equivalency factor could introduce significant variation about the true fuel economy differential at any point in time. Further, FFVs may exhibit fuel economy variability between various models. As an alternative method to provide California consumers with additional information, the Legislature should consider requiring retail station owners to affix labels on each face of E85 retail dispensers with language similar to "the fuel economy of an FFV using E85 is approximately 23 to 28 percent less when compared to E10."

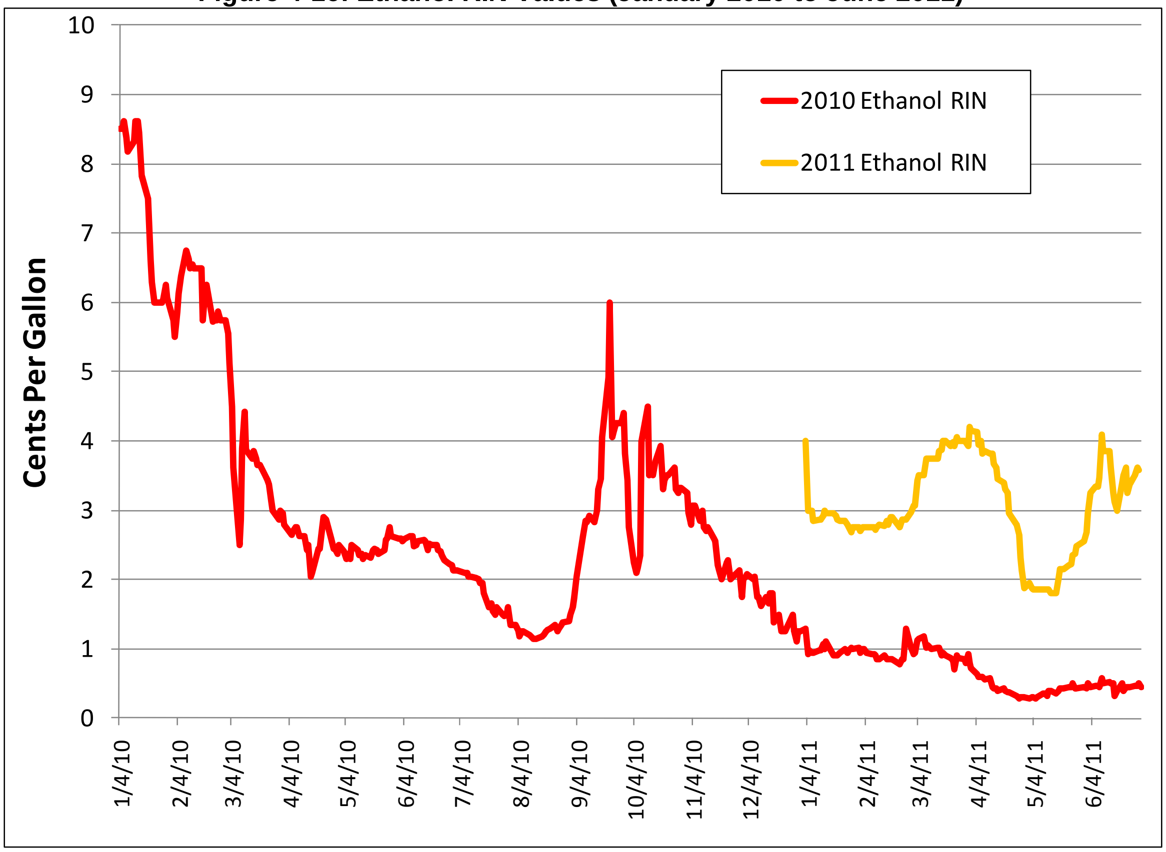
The lower fuel economy of E85 and resulting need to discount the price of this fuel to attract a sufficient level of demand implies that the suppliers of ethanol will need to consistently discount the wholesale price of E85. The need to provide consistently discounted ethanol for E85 blending could place downward pressure on ethanol wholesale prices and further depress ethanol producer profitability. This is one of the reasons that several ethanol producer stakeholders are pushing to have the ethanol blend wall increased from 10 to 15 percent by volume so that ethanol can be sold at or near gasoline values rather than being discounted. It should be noted that, in a non-mandated market setting, E85 retail stations and availability of FFVs allow for a type of ethanol pricing "floor," meaning that as the discount between ethanol and gasoline increases, the economic incentive to blend additional volume of E85 on a discretionary basis rises allowing a greater quantity of ethanol to be sold into the fuel market (higher demand for ethanol producers). However, this discretionary market scenario will likely not develop as E85 sales in California will need to increase significantly to maintain compliance with mandated RFS2 "proportional-share" blending requirements. One possible exception to this outlook is the potential economic benefit of excess RINs.[62]

To comply with RFS2, production of a renewable fuel must have an accompanying RIN to certify that it meets U.S. EPA standards and to track the sale or importation of that renewable fuel. This 38-digit code tracks things such as the facility and company that made the fuel, when it was made, and what type of fuel it is. The number also denotes whether the RIN credit has been detached from the fuel (thus can only be used for RFS2 compliance) or has fuel volumes still attached to the RIN credit. To track these RINs and the trading of them for compliance purposes, the U.S. EPA created EMTS. All generated renewable fuels for motor vehicle use must be tracked through the EMTS in order to have renewable fuel production count toward RFS2 compliance. Using this system, producers, traders, and obligated parties can track the sale and the generation of RIN credits for the different RFS2 complying fuels. While the system is not a "trading house" for these fuels, all transactions of RINs and the fuels attached to them must be entered into the system to be considered valid. The U.S. EPA requires that both parties of a RIN trade record the trade in the EMTS within five business days.

Excess RIN credits have an economic value that has fluctuated between 0.3 and 8.5 cents per gallon (cpg) between January 2010 and June 2011.[63] (See Figure 4-16). RIN values have averaged

3.2 cpg during 2010 and averaged 3.1 cpg for the first half of 2011. However, these RIN credit levels may not be sufficient to overcome the economic value of the fuel economy differential (80 to 98 cpg for $3.50 gasoline), even if one assumes that the blenders receiving the RIN credit revenue will be willing to pass some of that money back through to ethanol producers in the form of higher wholesale ethanol prices.

Figure 4-16: Ethanol RIN Values (January 2010 to June 2011)



Source: Oil Price Information Service (OPIS).

It is clear from recent history that excess RIN credits can be viewed by the holder as an additional revenue stream that can be used to help offset costs and maintain sufficient profit levels. However, the party who holds title to the RINs can be unclear, and this uncertainty complicates compliance strategies for various parties.[64] E85 blending in California is currently a practice involving other marketers who are not refiners. In this circumstance, the non-refiner blender can accrue RIN credits and their associated economic value that can be sold to RIN aggregators, refiners, or other obligated parties.

As California transitions to increased sales of E85 necessitated by RFS2, an imbalance between refiners' ethanol blending obligations and actual ethanol blending could widen if other market participants are the entities primarily blending and delivering the E85 to retail. Under this scenario, refiners would need to purchase an increasingly greater number of excess RIN credits to ensure compliance. In fact, the RINs embodied in the E85 could also be passed along to the retailer, who has no obligation to blend ethanol. Either way, it is likely that the cost of acquiring these RIN credits will be passed along to consumers in the form of higher prices over the long term by those parties forced to acquire excess credits (such as refiners). However, the incremental cost for traditional ethanol is quite low (less than 5 cents per gallon) due to an excess supply of corn-based ethanol. In the future, the cost of compliance for other types of renewable fuels could be greater due to a combination of scarcer supply and significantly higher RIN credits for cellulosic ethanol.

Low Carbon Fuel Standards and High Carbon Intensity Crude Oils

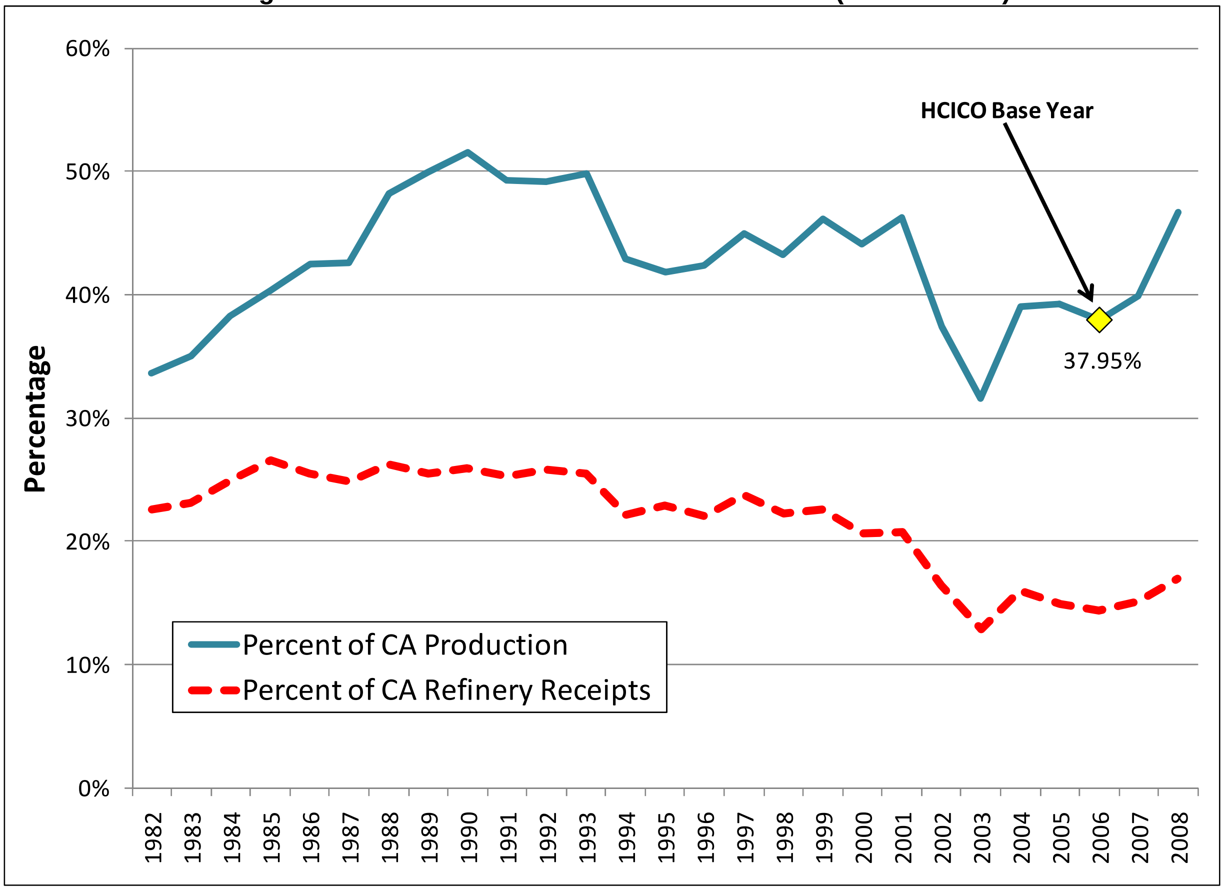
The ARB has included provisions to the LCFS that regulates the use of new crude oil types that have significantly higher carbon intensities associated with their production when compared to the average mix of crude oil used by refineries in California during 2006 These types of crude oils are referred to as High Carbon Intensity Crude Oils (HCICOs).[65] The purpose of this provision of the LCFS is to ensure that any rise in petroleum-related lifecycle emissions due to a movement of crudes with high extraction emissions is captured in the LCFS and mitigated. Currently, ARB has temporarily delayed enforcement of this provision pending development of a more detailed process to separate HCICOs from non-HCICOs. As part of this effort, Energy Commission staff performed an assessment of world crude oil types to determine what portion of MCONs were potential HCICOs, for the use of which refiners in California would have to either compensate or defer purchase for processing in California.

Crude Oil Production Techniques

Globally, crude oil production involves primary and secondary forms of extraction techniques. Primary crude oil production usually involves drilling wells and allowing the natural underground pressure to force the crude oil to the surface or the installation of pumps to move the crude oil to the surface for collection and processing. These types of crude oil operations can be either onshore or offshore. A second type of crude oil production activity involves more effort to extract the crude oil from a reservoir or deposit. These techniques involve various forms of enhanced oil recovery, upgrading, and even extracting crude from bitumen mines.

Enhanced oil recovery (EOR) can include such approaches as: water flooding, injection of steam, use of chemicals, and even the injection of natural gas and carbon dioxide.[66] The use of steam for TEOR requires additional energy that increases the carbon footprint for crude oil that uses this type of extraction technique. California has one of the highest concentrations of TEOR crude oil production in the world, accounting for nearly 47 percent of the state’s total crude oil production during 2008 and approximately 17 percent of the total crude oil processed by California refineries during the same year.[67] Figure 4-17 depicts how the portion of TEOR production has shifted between 32 percent and 52 percent of California production since 1982.

Figure 4-17: California TEOR Production Share (1982 to 2008)



Sources: California Energy Commission analysis of California Division of Oil, Gas & Geothermal Resources data.

In other cases, very heavy crude oil is partially processed at a facility called an "upgrader" to produce a synthetic form of crude oil with more desirable properties for refiners to process.[68] Countries that have significant upgrading capacity for producing syncrudes are Canada and Venezuela.[69] These operations require additional forms of energy (steam and electricity) to create these syncrudes, which is why crude oils of this type are likely to be classified as HCICOs.

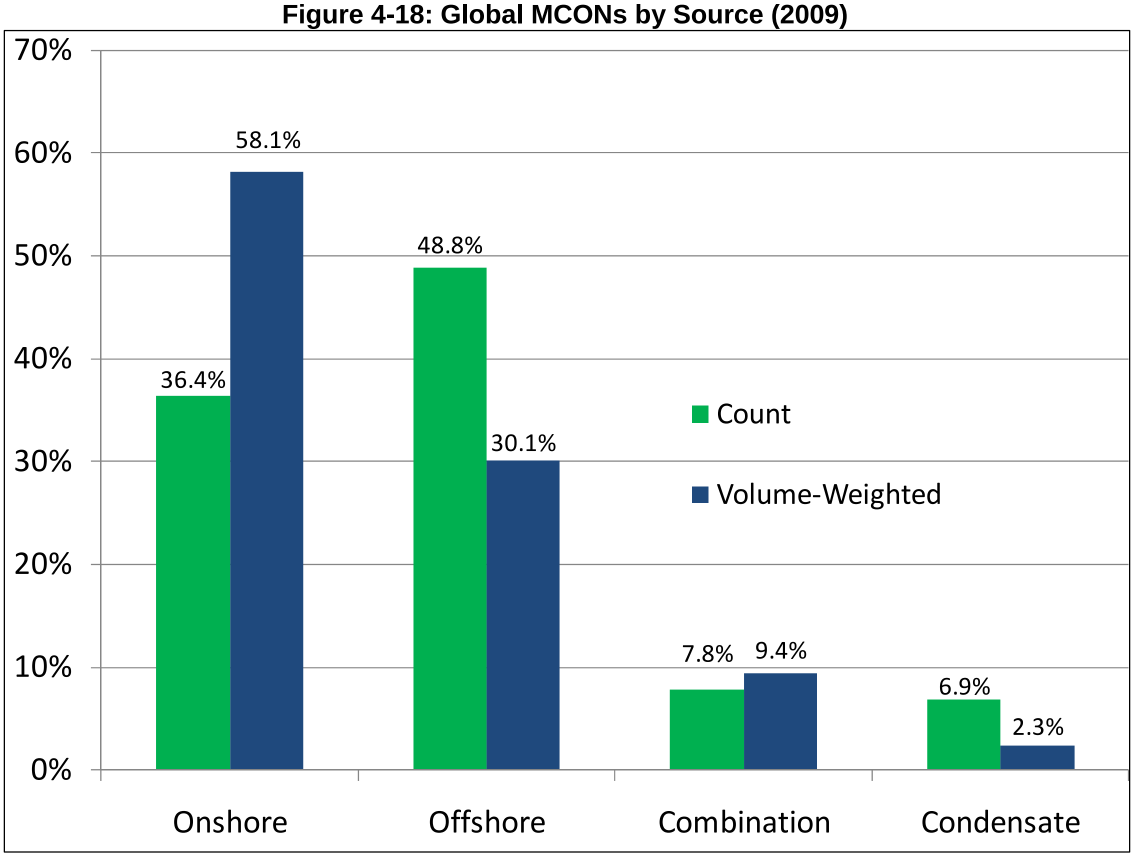
One of the more energy-intensive crude oil production techniques involves the extraction of bitumen from open mines. The bitumen requires processing to extract the petroleum from the non-petroleum material. Canada is the only country that operates bitumen mines in their oil sand deposits, with recoverable reserves estimated at 170 billion barrels.[70]

Another activity associated with the production of crude oil is the flaring of associated natural gas from both primary and secondary operations. The natural gas is normally burned when natural gas collection infrastructure and/or availability of local markets is insufficient to warrant an investment to cease flaring operations. When the flaring activity is widespread, the associated carbon emissions can be significant. It is for this reason that ARB has also proposed that when a type of crude oil originates from a country that has an average flaring intensity greater than 10 standard cubic meters per barrel, the MCON should be assumed to be a potential HCICO, unless additional information can be submitted by a company that demonstrates the flaring intensity for a specific MCON is below the threshold.[71]

Global Crude Oils by Type

Energy Commission staff performed analysis to compile a list of crude oil types that were commonly marketed globally, characterized by their method of production. Further, that list of MCONs was initially screened to identify how many MCONs could be easily excluded from a listing of potential HCICOs. Figure 4-18 breaks down the 217 MCONs by crude oil production source for 2009.[72]

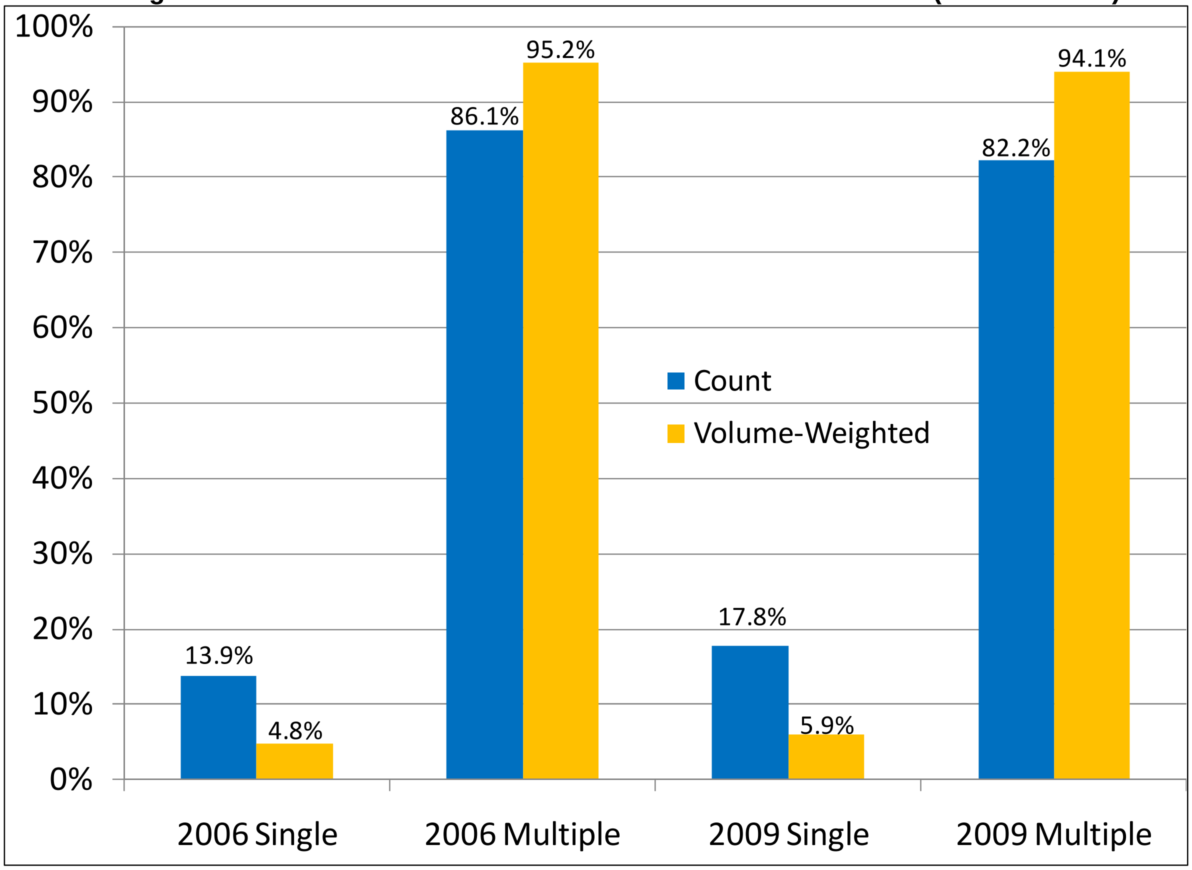
Figure 4-18: Global MCONs by Source (2009)



Source: California Energy Commission analysis of multiple information resources.

As the chart illustrates, the majority of MCONs are from offshore sources, but the majority of volume is from onshore sources. This means that average volume contribution by MCON is greater from onshore sources. The majority of the crude oils sold on the world market consist of blends from multiple field sources. This practice is usually necessary to provide adequate volumes sufficient to warrant infrastructure to export the oil and to maintain specific crude oil properties. Figure 4-19 illustrates the portion of MCONs that are from single fields versus those that are from multiple field sources.

Figure 4-19: Marketable Crude Oil Names – Field Concentration (2006 vs. 2009)



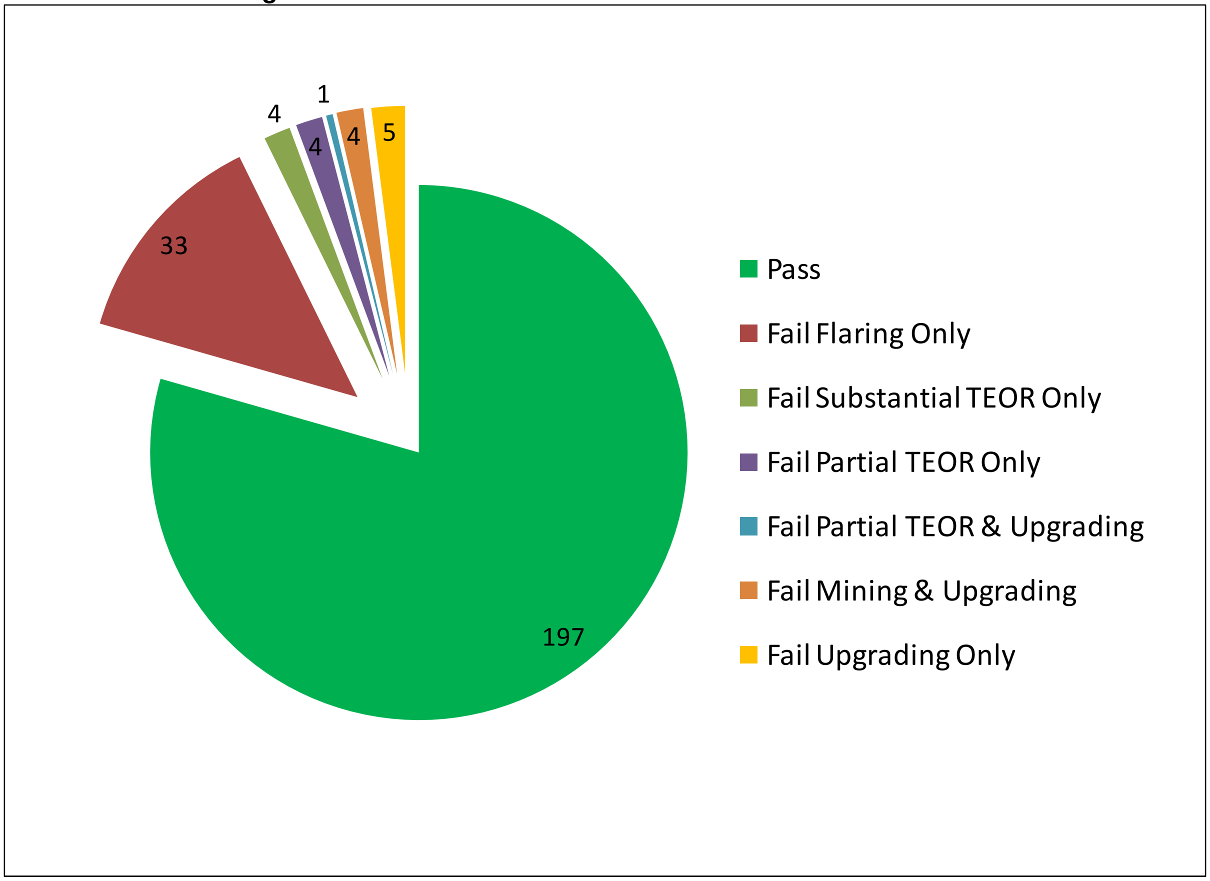
Source: California Energy Commission analysis of multiple information resources.

California refiners are already attempting to process a specific mix of crude oil that is economically optimal based on their individual refinery configuration, the proper ratio of gasoline and diesel fuel that the marketing department is targeting, and the acquisition costs for the various crude oil types. The HCICO provision has the potential to affect the crude oil selection decisions of California refiners. However, the HCICO provision is not expected to restrict access to crude oil supplies in a way that could significantly impact fuel supply, but it could impact refiner profitability and the ultimate cost of petroleum fuel in California.

The LCFS does not prohibit the use of HCICOs. However the petroleum fuels derived from such crudes would be of a higher carbon intensity (CI) than typical gasoline and diesel petroleum components, and these higher carbon emissions would need to be offset by greater use of low-CI alternative fuels. This increase in CI is substantial, and once the HCICO provisions are fully implemented it is unlikely that California refiners will elect to continue using significant percentages of HCICO in their crude mix because of this increased difficulty of off-setting the additional carbon emissions.

Energy Commission staff conducted an initial screen of 248 MCONs available globally during 2006-2010 to identify what portion were potential HCICOs. A crude oil was labeled a potential HCICO if it was from a country that had an average flaring intensity greater than the threshold set by ARB; or was from a source field (either partially or wholly) that was using TEOR; or was from a bitumen mine; or was from an upgrading facility in Canada or Venezuela. Figure 4-20 shows the numbers of potential HCICOs by type from this initial screening work.

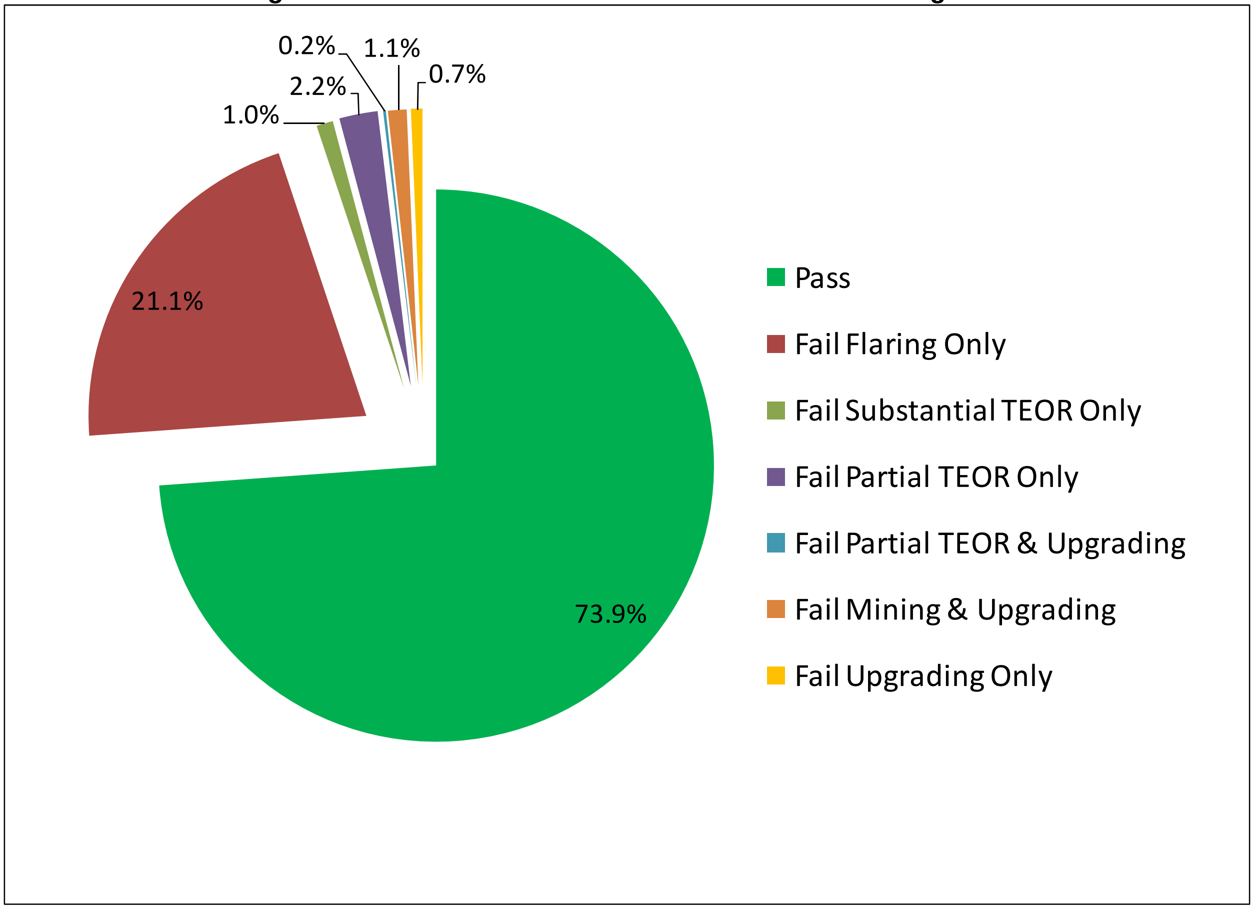
Figure 4-20: Marketable Crude Oil Names – Potential HCICOs



Source: California Energy Commission analysis of multiple information resources.

Figure 4-21 illustrates how the portions shift when adjusted by relative production volumes of each MCON.

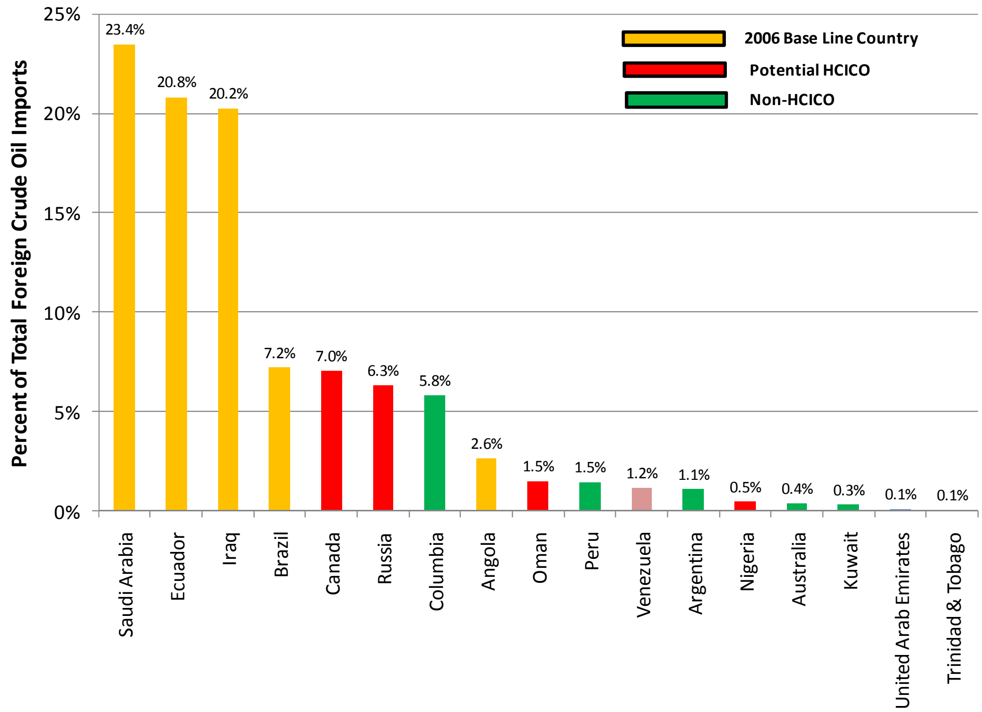
Figure 4-21: MCONs – Potential HCICOs – Volume Weighted



Source: California Energy Commission analysis of multiple information resources.

Although 74 percent of the MCONs that were initially screened passed, 26 percent of the crude oils were characterized as potential HCICOs in need of further analysis to determine which of these are also non-HCICOs. Some of the crude oil used by California refiners during 2010 was also identified by Energy Commission staff to be potential HCICO. Figure 4-22 depicts the various foreign crude oil sources and identifies the estimated volume that was potentially HCICO.

Figure 4-22: California Foreign Crude Oil Imports (2010)



Source: California Energy Commission analysis of multiple information resources.

As the chart shows, approximately 16.5 percent of the foreign crude oil receipts by California refineries during 2010 were potentially affected by the HCICO provisions, accounting for 8.0 percent of total crude oil use during the year. While it is clear that adequate other sources of crude that is not subject to the HCICO provisions of the LCFS are available, obtaining alternative crude oils than those used recently in California refineries could lead to increased crude costs and lower refinery margins.

Implementation of the Proposed HCICO Provision

The HCICO provision is designed to "encourage emission reduction activities from these HCICO sources".[73] Achieving these emission reductions will be a challenge for two reasons: oil producers outside of California have alternative markets to sell their crude oil; and the California crude oil market is too small to justify an investment to reduce the carbon intensity of crude oil production operations. Oil producers in other countries may not be "captured" by this regulation and forced to comply because they have alternative markets to sell their crude oil and would have no need to modify their production techniques solely due to the HCICO provision in California. The Energy Commission is forecasting that between 384 million and 408 million barrels of crude oil will be imported from foreign and Alaska sources during 2015. Even if one assumes that this entire quantity of waterborne crude oil were a potential market for oil producers outside the state, these quantities of additional crude oil are quite small in comparison to the current global crude oil demand forecast for 2012 of 91 million barrels per day or 33.3 billion barrels per year.[74] Even if the global crude oil demand remains flat through 2015, California's potential market represents a maximum of 1.2 percent.[75] From another perspective, the Energy Commission is forecasting that incremental crude oil imports for California will range between 9 million and 38 million barrels *per year* by 2016. On an incremental basis, California's potential market by 2016 represents a maximum of 2.1 percent of world total incremental demand for crude oil by 2016.[76]

Companies may not invest significant amounts of money to reduce the amount of energy (and carbon) required to bring their crude oil to market *solely* for getting below the threshold of a HCICO if that same company will not receive any additional premium payment for their lower-carbon crude oil. Rather, companies are making investments in many different countries that have a sufficient return on investment (ROI) achieved by either: lowering their production costs; capturing natural gas that is being flared (to sell for an additional revenue stream and/or reduce the costs incurred from paying a flaring fee); or avoiding carbon taxes imposed by a local jurisdiction or country. These projects have a secondary benefit of reducing carbon emissions.

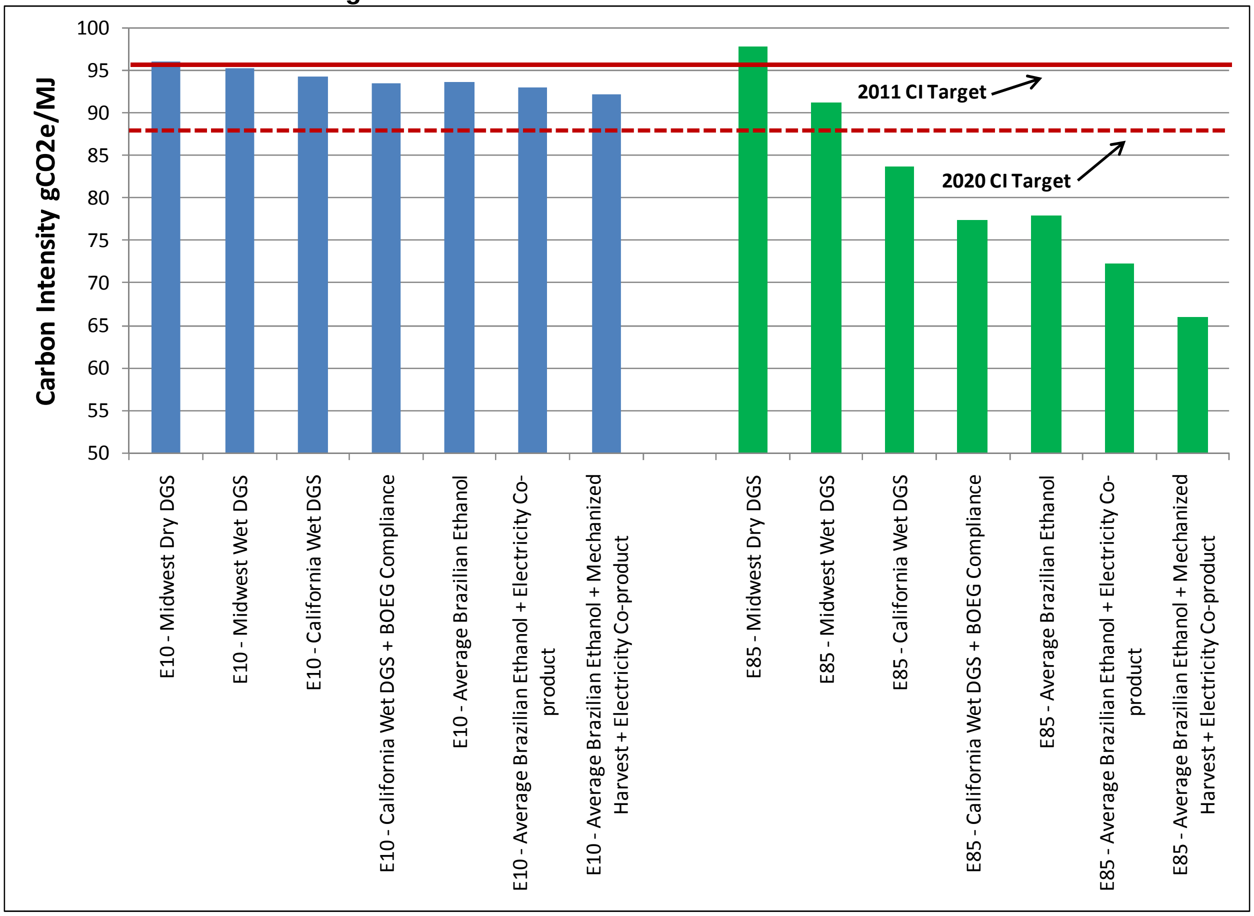
Low Carbon Fuel Standard: Identification of Potential Challenges and Changing Mix of Renewable Fuel Types

The ARB adopted the LCFS regulations in 2009. The regulation requires a reduction in the average carbon intensity (or CI, as measured by both direct and indirect life cycle carbon emissions) of California transportation fuel of 10 percent between the baseline year 2010 and 2020.[77] The baseline CI for 2010 is set for both diesel and for gasoline based on the composition of those fuels in 2010. The LCFS is designed to incent a progressive shift to lower-CI fuels in California. The LCFS provides incentives to displace petroleum fuels with lower CI renewable fuels, and fuels such as natural gas, electricity, and hydrogen that have CIs lower than the 2020 LCFS standards. No fuels are prohibited under the LCFS, but fuels with CIs above the LCFS standard create carbon deficits, which must be offset with an equal amount of carbon credits created by the marketing of lower-CI fuels. Traditional biofuels with relatively high CIs, such as corn-based ethanol and biodiesel, will continue to have a role over the next several years, but will eventually need to significantly reduce their CIs in the future to maintain major shares of the California market. The use of new types of liquid fuels (renewable hydrocarbons with very low carbon intensity) and an increased penetration of electricity and natural gas in the transportation sector is expected under the LCFS to generate the LCFS carbon credits needed by obligated parties to achieve compliance with the regulation through 2020.

The average per-gallon carbon intensity of gasoline and diesel fuel, as expressed in terms of grams of carbon dioxide equivalent per megajoule (gCO2e/MJ), must be reduced each year until achieving a total 10 percent reduction by 2020. The ARB has identified carbon intensity (CI) values for multiple types of transportation fuels based on production processes used to create the fuels, the energy required to distribute the fuels to retail stations, and carbon dioxide equivalent emissions produced by vehicles when the fuel is consumed.[78] In addition, ARB has calculated the additional carbon emissions attributable to indirect activities such as the planting of additional acres of agricultural crops in other countries to compensate for greater use of these crops in the United States for transportation fuels, referred to as Indirect Land Use Changes or ILUC.[79]

Refiners, importers, and large marketers are obligated parties under LCFS regulations. Each quarter, these parties must report their sales of gasoline and diesel fuel, as well as the volumes and types of renewable fuels (such as ethanol and biodiesel) that are blended with petroleum fuels. Compliance is determined by calculating the carbon deficits and credits generated during each annual compliance period. Carbon debits are accrued when an obligated party sells a transportation fuel with average carbon intensity greater than the CI standard for a particular year. The CI for petroleum diesel and the petroleum portion (CARBOB) of gasoline are set at the baseline CI which is slightly higher (about 0.25 percent) than the LCFS standard in 2011. Since the standard continues to decline each year, the carbon deficits are larger for each gallon of CARBOB or diesel fuel sold. In general, carbon credits are earned when an obligated party uses a renewable fuel with a lower CI than the target for a particular year. Carbon credits can also be purchased from other refiners or other transportation fuel providers who generate credits from such activities as the charging of an electric vehicle and the use of biogas as a transportation fuel. Figure 4-23 compares the finished gasoline and E85 blends with the 2011 and 2020 CI target values. This chart is not intended to reflect how obligated parties would comply with the standard, as described above, but is meant to be an illustrative comparison as to the carbon intensity of various blends of gasoline-related fuels relative to the initial and final CI targets.

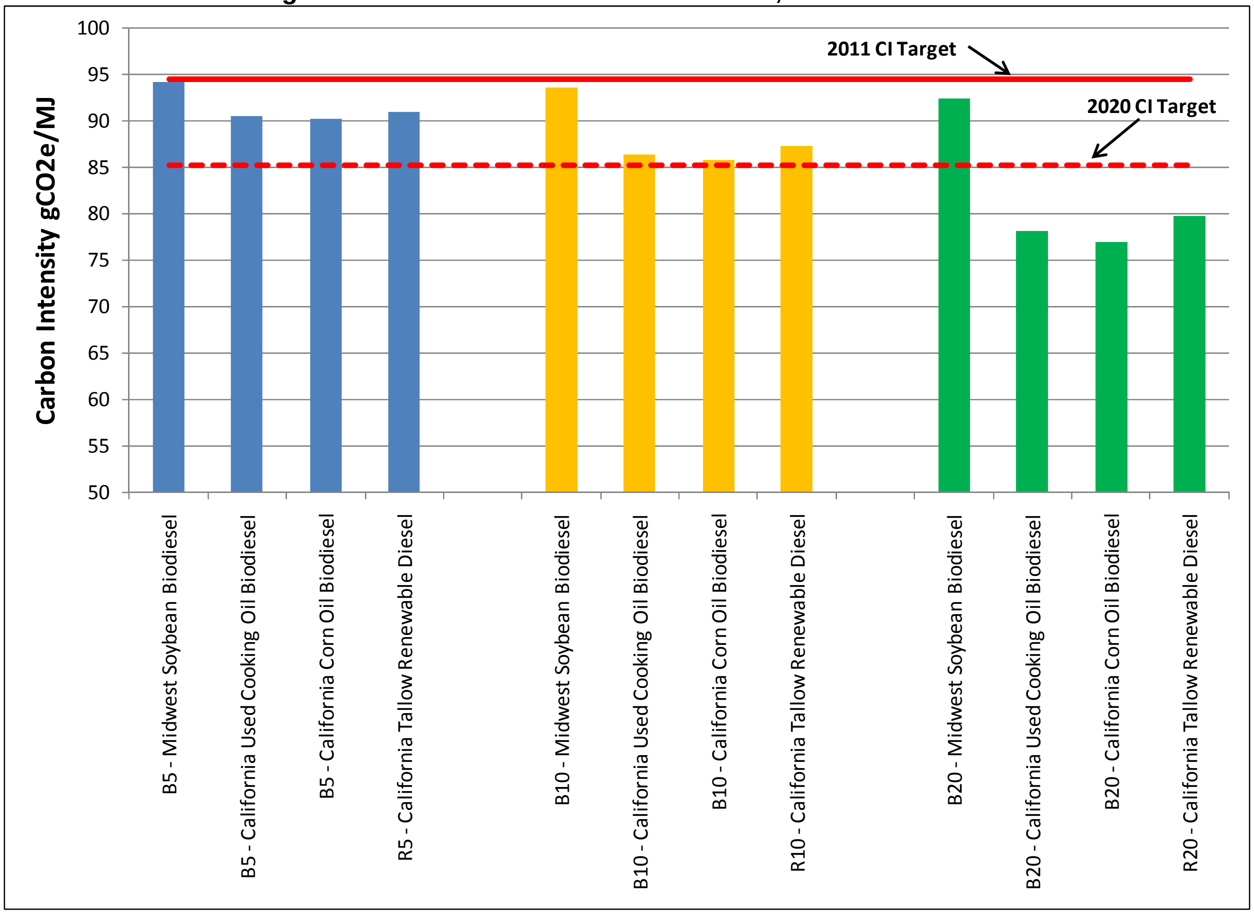
Figure 4-23: LCFS Gasoline Blends – E10 & E85



Sources: California Energy Commission analysis of ARB data.

Figure 4-24 compares the various biodiesel and renewable diesel blends with the 2011 and 2020 CI target values. This chart is not intended to reflect how obligated parties would comply with the standard, as described above, but is meant to be an illustrative comparison as to the carbon intensity of various blends of diesel fuels relative to the initial and final CI targets.

Figure 4-24: LCFS Diesel Fuel Blends – 5, 10 & 20 Percent



Sources: Energy Commission analysis of California Air Resources Board data.

It should be noted that there are several challenges to use of higher biodiesel blends due to: inadequate volumes of specific fuel types (lack of sufficient national feedstock availability); lack of infrastructure compatibility for higher biodiesel concentrations; warranty concerns for biodiesel blends in excess of 10 percent; and an identification of increased oxides of nitrogen (NO_x) that have been identified by ARB at the higher biodiesel blends that could preclude meaningful expanded use of biodiesel to help meet the LCFS requirements for diesel fuel.[80] The NO_x issue is a significant hurdle for expanded biodiesel use to comply with the LCFS obligations since the primary mitigation strategy initially proposed by ARB involves the use of renewable diesel in a ratio of four parts to one when biodiesel is used in concentration greater than five percent by volume.[81]

Low Carbon Fuel Standard Analysis – Assumptions & Approach

Energy Commission staff is working with ARB staff in the Board's first comprehensive assessment of implementation of the LCFS. Part of this effort is the assessment of the likely availability of varying quantities and types of renewable fuels and other alternative fuels that might be used to comply with the LCFS regulation over the first half of the forecast period. This analysis is ongoing at this time, and results are not yet available for inclusion in this report. The preliminary results of the scenario analysis will be presented at the September 9, 2011 Transportation Committee workshop. This analysis is grouped into four cases or scenarios that are described below. The results of each case analysis should not be interpreted as a forecast as to how obligated parties, in aggregate, will behave in their biofuel choice decisions. These cases are designed to determine potential compliance outcomes based on the preferential use of lower carbon intensity biofuels in conjunction with use of electricity and natural gas credits under varying supply availability assumptions, as described below. Because of the non-prescriptive nature of the LCFS, it will be very difficult to make firm projections on the fuel mix that will evolve so analysis of several feasible scenarios will be needed. The basic Energy Commission assumptions proposed for all of the LCFS analysis cases are as follows:

- All carbon credits generated by the charging of electric vehicles in our forecast are assumed captured and purchased by obligated parties each year, regardless if all of these credits are eligible for use in the program.
- The concentration of fuel ethanol in finished gasoline is limited to 10 percent by volume over the forecast period. The concentration of fuel ethanol for use in flexible fuel vehicles is an average of 79.2 percent by volume.[82]
- The concentration of biodiesel used in diesel fuel is limited to 10 percent by volume until the end of 2015, at which point the maximum concentration, if necessary, can be raised to a maximum of 20 percent by volume.
- California ethanol production volumes throughout the forecast period are blended into California gasoline until the point that continued use becomes counterproductive to achieving compliance. Pacific Ethanol's Madera facility resumes operation by January 2012 and all of the California ethanol facilities enrolled in the California Ethanol Producer Incentive Program (CEPIP)[83] complete their modifications to achieve compliance with the Biorefinery Operational Enhancement Goals (BOEG)[84] by 2015 that results in a lower CI for their ethanol output. Maximum volume available is calculated as 210 million gallons of ethanol per year under the zero production capacity growth evaluations. In cases where production capacity grows, the maximum available capacity is 210 million gallons in 2012 then grows in the following years.
    - 2011 - 170 million gallons @ 80.70 gCO2e/MJ
    - 2012-2014 - 210 million gallons @ 80.70 gCO2e/MJ
    - 2015 & beyond - 210 million gallons @ 72.00 gCO2e/MJ

- California renewable diesel production volumes throughout the forecast period are blended into California diesel fuel. The total volume available is based on the maximum production capacity for those California facilities that have either completed or have pending certifications for their carbon intensity pathways, except for the current year (see below). In the case where production capacity does not grow, the following are the production capacities and the carbon intensities used to perform the evaluation for Case 1 and Case 2. In the cases where production capacity grows, the maximum production capacity would increase after 2012, but never exceed an upper limit of 47.9 million gallons per year. Conditions for Case 3 and Case 4 allow this capacity to increase to 300.0 million gallons per year, if necessary.
    - 2011 – 6.1 million gallons @ 19.65 gCO2e/MJ
    - 2012 & beyond – 15.3 million gallons @ 19.65 gCO2e/MJ
- California biodiesel production volumes throughout the forecast period are blended into California diesel fuel until the point that continued use becomes counterproductive to achieving compliance. The total volume available is based on the maximum production capacity for those California facilities that have either completed or have pending certifications for their carbon intensity pathways. The only exception to this set of assumptions is for biodiesel sourced from corn oil. In the case where production capacity does not grow, the following are the production capacities and the carbon intensities used to perform the evaluation for Case 1 and Case 2. In the cases where production capacity grows, the maximum production capacity would increase after 2012, but never exceed an upper limit of 66.0 million gallons per year for biodiesel produced from corn oil. Conditions for Case 3 and Case 4 allow this capacity to increase to 160.0 million gallons per year, if necessary.
    - 2011 – zero gallons @ 5.90 gCO2e/MJ
    - 2012-2014 – 12.5 million gallons @ 5.90 gCO2e/MJ
    - 2015 & beyond – 25.0 million gallons @ 5.90 gCO2e/MJ
- Any use of biodiesel in California in excess of the RFS2 "fair share" volumes initially calculated as part of the Low and High Demand scenarios is assumed to displace petroleum-based diesel fuel (on an energy-equivalent basis) and its associated annual carbon debt.
- Any use of renewable diesel in California is assumed to displace petroleum-based diesel and its associated annual carbon debt on an energy-equivalent basis.
- Any use of biomass-to-liquid (BTL) gasoline in California is assumed to displace petroleum-based gasoline (CARBOB) and its associated annual carbon debt on an energy-equivalent basis.

Case 1: No Excess Credit Build and Biofuel Availability Limit

For purposes of the Case 1 analysis, Energy Commission staff assumes that obligated parties will attempt to balance carbon debits and credits on an annual basis using biofuels with varying carbon intensities. The initial maximum volumes of biofuels available for use in California for Case 1 are assumed to be the aggregate production capacity totals for biorefinery facilities that have either completed or have pending registrations, including the exceptions noted in the underlying assumptions. No cellulosic biofuels are assumed available for this scenario. Case 1 also includes analysis that allows these production capacities to be gradually increased over the forecast period by 5 percent and 10 percent per year. The quantity of ethanol used in this case is not to exceed California's RFS2 fair share volume. The quantity of biodiesel can rise to a level in excess of California's RFS2 fair share volume, but not exceed 10 percent by volume through 2015 and 20 percent by volume for 2016 and the remainder of the forecast period.

Case 2: No Excess Credit Build, RFS2 Fair Share Advanced Fuels Use & Biofuel Availability Limit

For purposes of the Case 2 analysis, Energy Commission staff assumes that obligated parties will attempt to balance carbon debits and credits on an annual basis using biofuels with varying carbon intensities. The quantity of ethanol used in this case is not to exceed California's RFS2 fair share volume. The quantity of biodiesel can rise to a level in excess of California's RFS2 fair share volume, but not exceed 10 percent by volume through 2015 and 20 percent by volume for 2016 and the remainder of the forecast period. Other conditions for Case 2 that differ from Case 1 are as follows:

- Cellulosic biofuels are used for the first time, including cellulosic ethanol, gasoline and diesel fuel. These volumes are limited in quantity to *California's fair share portion* of the projected availability as forecast by the EIA's Annual Energy Outlook 2011 *Low Oil Pric*e and *Extended Policy* scenarios, rather than the higher levels stipulated by Congress as part of the annual RFS2 cellulosic biofuels obligations.
- Volumes of sugarcane ethanol are limited to the aggregate production capacity totals for biorefinery facilities that have either completed or have pending registrations, nearly 1.53 billion gallons. However, those facilities that have a CI designation of 66.40 gCO2e/MJ are assumed to convert to mechanized harvesting and the associated lower CI of 58.20 gCO2e/MJ beginning in 2012.
    - 914.0 million gallons production capacity @ 73.40 gCO2e/MJ
    - 610.0 million gallons production capacity @ 66.40 gCO2e/MJ
- Maximum volumes of *all other* biofuels available for use in California are assumed to be the aggregate production capacity totals for biorefinery facilities that have either completed or have pending registrations, including the exceptions noted in the base assumptions. These production volumes limits can be increased by as much as 10 percent per year.

Case 3: No Excess Credit Build, United States RFS2 Cellulosic Capacity & Selected Other Biofuel Supply Availability Limit

For purposes of the Case 3 analysis, Energy Commission staff assumes that obligated parties will attempt to balance carbon debits and credits on an annual basis using biofuels with varying carbon intensities. The quantity of ethanol used in this case is not to exceed California's RFS2 fair share volume. The quantity of biodiesel can rise to a level in excess of California's RFS2 fair share volume, but not exceed 10 percent by volume through 2015 and 20 percent by volume for 2016 and the remainder of the forecast period. Other conditions for Case 3 that differ from Case 1 and Case 2 are as follows:

- Cellulosic biofuels are used, including cellulosic ethanol, gasoline and diesel fuel. These volumes are limited in quantity to 50 percent of the *total national projected availability* as forecast by the EIA's Annual Energy Outlook 2011 *Low Oil Pric*e and *Extended Policy* scenarios, rather than the higher levels stipulated by Congress as part of the annual RFS2 cellulosic biofuels obligations.
- Volumes of sugarcane ethanol may exceed aggregate production capacity totals for biorefinery facilities that have either completed or have pending registrations. Those facilities that have a CI designation of 66.40 gCO2e/MJ are assumed to convert to mechanized harvesting and the associated lower CI of 58.20 gCO2e/MJ beginning in 2012.[85] Further, the volume available of this lower-CI Brazilian ethanol may increase to as much as 1.50 billion gallons beginning in 2014 and grow by up to 10 percent per year, if necessary, over the forecast period.
- Use of **renewable diesel fuel sourced from inedible tallow** through 2014 is limited to production capacity of facilities with completed or pending registrations. Production capacity available for 2015 through 2016 is increased by an incremental volume that diverts all of the inedible tallow used as feed for livestock and poultry. The production capacity is allowed to increase to 50 percent of the theoretical national feedstock limit for inedible tallow of 219.4 million gallons beginning 2017 and remain at that limit for the remainder of the forecast.
    - 2011 – 6.1 million gallons @ 19.65 gCO2e/MJ
    - 2012-2014 – 15.3 million gallons @ 19.65 gCO2e/MJ
    - 2015-2016 – 47.9 million gallons @ 19.65 gCO2e/MJ
    - 2017 & beyond – 219.4 million gallons @ 19.65 gCO2e/MJ
- Use of **biodiesel sourced from corn oil** is assumed to not be available for 2011. The volume available for 2012 through 2014 is assumed to be 50 percent of maximum capacity for registered facilities. The volume available for 2015 through 2016 is increased to the quantity of corn oil equivalent to the average annual exports from the United States between 2009 and 2010. The production capacity is allowed to increase to 50 percent of the theoretical national average annual limit for corn oil production that

occurred during 2009 and 2010 or 160.0 million gallons beginning 2017 and remain at that limit for the remainder of the forecast.

  - 2011 – zero gallons @ 5.90 gCO2e/MJ
  - 2012-2014 – 12.5 million gallons @ 5.90 gCO2e/MJ
  - 2015-2016 – 66.0 million gallons @ 5.90 gCO2e/MJ
  - 2017 & beyond – 160.0 million gallons @ 5.90 gCO2e/MJ

- Use of **biodiesel sourced from used cooking oil** is assumed to not be available for 2011. The volume available for 2012 through 2014 is assumed to be 50 percent of maximum capacity for registered facilities. The volume available for 2015 through 2016 is increased to 100 percent of maximum capacity for registered facilities. The production capacity is allowed to increase to 200 percent of the maximum capacity for registered facilities or 155.1 million gallons beginning 2017 and remain at that limit for the remainder of the forecast. It is assumed that the pathway for this biofuel does not require "cooking" and is sourced from within California. However, it is acknowledged that some portion of this type of feedstock could be processed outside the state, a step that would incur an additional carbon intensity increase of 1.77 gCO2e/MJ. But the CI value for this case analysis was kept at the lower level.
  - 2012-2014 – 38.8 million gallons @ 11.76 gCO2e/MJ
  - 2015-2016 – 77.6 million gallons @ 11.76 gCO2e/MJ
  - 2017 & beyond – 155.1 million gallons @ 11.76 gCO2e/MJ

Case 4: Excess LCFS Credit Build and Increased Use of BTL Fuels

For purposes of the Case 4 analysis, Energy Commission staff assumes that obligated parties will attempt to over-comply with the regulation in the earlier years as a strategy of building excess credits to use in later years since LCFS credits have no expiration date. The quantity of ethanol used in this case is not to exceed California's RFS2 fair share volume. The quantity of biodiesel can rise to a level in excess of California's RFS2 fair share volume, but not exceed 10 percent by volume through 2015 and 20 percent by volume for 2016 and the remainder of the forecast period. Other conditions for Case 4 that differ from the previous cases are as follows:

- A maximum quantity of 50 percent of the national cellulosic biofuels supply is assumed available for use in California beginning in 2012.
- Quantity of sugarcane ethanol is intentionally maximized to exceed LCFS compliance demand levels as soon as 2012. This type of biofuel is assumed to be the lowest CI of 58.20 gCO2e/MJ and will be allowed to reach 1.0 billion gallons during 2012, with supply available for California obligated parties assumed to grow by up to 10 percent per year, if necessary, over the forecast period.

- Quantity of biodiesel sourced from used cooking oil is allowed to increase at a more rapid rate than Case 3 and allowed to rise to a higher maximum production capacity. As was the condition in Case 3, it is assumed that the pathway for this biofuel does not require "cooking" and is sourced from within California. However, it is acknowledged that some portion of this type of feedstock could be processed outside the state, a step that would incur an additional carbon intensity increase of 1.77 gCO2e/MJ. But the CI value for this case analysis was kept at the lower level.
    - 2012 – 38.8 million gallons @ 11.76 gCO2e/MJ
    - 2013 – 77.6 million gallons @ 11.76 gCO2e/MJ
    - 2014 – 155.1 million gallons @ 11.76 gCO2e/MJ
    - 2015-2016 – 310.0 million gallons @ 11.76 gCO2e/MJ
    - 2017 & beyond – 750.0 million gallons @ 11.76 gCO2e/MJ
- If obligated parties are unable, in aggregate, to achieve full compliance with the LCFS standards, staff will calculate the quantity of BTL gasoline and BTL diesel fuel that would be necessary to achieve full and continued compliance with the standard.

Availability of Specific Types of Biofuels

A number of biofuels have superior carbon intensity values that will be desirable to obligated parties trying to achieve compliance with the California LCFS. However, the potential production volumes for these fuels will ultimately be limited to availability of the necessary feedstocks.

Inedible Tallow Renewable Diesel (R100)

Currently, the inedible tallow renewable diesel production capacity for facilities with completed and pending registrations is 15.3 million gallons per year. The theoretical availability of renewable diesel produced from inedible tallow is estimated at between 47.9 and 438.8 million gallons per year for the entire United States. The lower estimate of 47.9 million gallons assumes the average annual volume of inedible tallow used to feed animals for the period 2009-2010 in the United States is instead converted to renewable diesel.[86] The upper estimate of 438.8 million gallons assumes the average annual production volume of United States inedible tallow for 2009-2010 is instead entirely converted to renewable diesel.[87]

Corn Oil Biodiesel (B100)

Currently, the corn oil biodiesel production capacity for facilities with completed and pending registrations is 25 million gallons per year. However, this single facility has not produced any biodiesel using corn oil as a feedstock. The availability of biodiesel produced from corn oil is estimated at between 66.0 and 319.5 million gallons per year for the entire United States. The lower estimate of 66.0 million gallons assumes the average annual export volume of corn oil for 2009-2010 from the United States is instead converted to biodiesel.[88] The upper estimate of 319.5 million gallons assumes the average annual production volume of United States corn oil for

2009-2010 is instead entirely converted to biodiesel.[89] This is probably unrealistic since refined corn oil is used to produce higher value products such as salad or cooking oil. But additional corn oil could be produced if more ethanol facilities installed corn oil extraction equipment at an unknown cost. The ARB estimates that for every 100 gallons of ethanol produced from corn between 6 percent and 7 percent of that volume could be extracted in the form of corn oil using two extraction systems.[90] This means that the theoretical upper limit of corn oil from corn-based ethanol plants could range between 900 million and 1.05 billion gallons per year.[91]

Used Cooking Oil Biodiesel (B100)

Currently, the used cooking oil biodiesel production capacity for facilities with completed and pending registrations is 77.6 million gallons per year. The theoretical availability of biodiesel produced from used cooking oil could be as great as 3.0 billion gallons per year for the entire United States, if one assumes that the waste oil from every hotel and restaurant is collected and processed into biodiesel.[92] This scenario is doubtful due to the inverse relationship between collection costs and size of supply. For purposes of this analysis, staff assumes that no more than 25 percent (750 million gallons) of biodiesel from used cooking oil would be available for 2017 and beyond.

Costlier Biofuels

LCFS compliance costs will likely fall into three categories; an additional price premium for lower carbon intensity fuels (the lower the CI, the higher the premium); use of more expensive renewable fuels (such as Brazilian sugarcane ethanol); and market-clearing prices of LCFS credits sold to obligated parties. Over the long-term, these increased costs could be passed through to consumers and businesses in the form of more expensive gasoline, E85, and diesel fuel. Staff is continuing an assessment of these incremental costs and will continue working with California Air Resources Board staff to better understand the information resources available and interpretation of this pricing data as to how the various biofuel incremental costs could or should apply to LCFS analysis. Energy Commission staff intends to provide a more thorough description and quantification at the September 9, 2011 public workshop. Brief examples of these incremental costs are provided below for illustrative purposes only.

Carbon Intensity Price Premium

Lower carbon intensity biofuels are expected to command a price premium depending on how low the CI is when compared to gasoline or diesel fuel. Currently, there is only one source of CI differential pricing information available to use as a reference point, daily Midwest corn ethanol prices published by the Oil Price Information Service (OPIS). Based on the OPIS data between January and June of 2011, the price premium has averaged 1.34 cents per gallon between two different types of Midwest ethanol produced from corn. Based on their respective carbon intensity values, the differential premium could amount to an increased price of various types of ethanol that could range between 2 and 10 cents per gallon of fuel ethanol. If these actual price increases were to occur the potential impact on E10 prices would be between 0.2 and 1.0

cents per gallon, while the potential impact on E85 prices could range between 1.3 and 7.6 cents per gallon.[93]

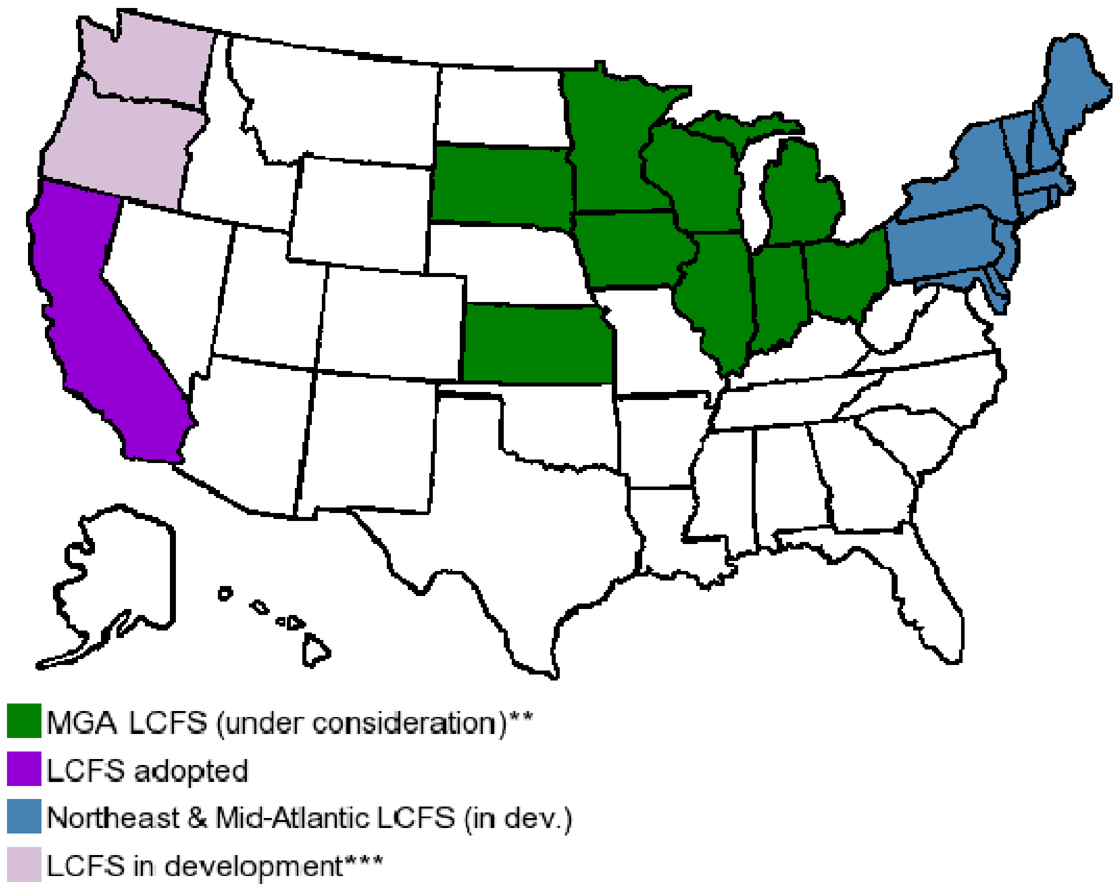
More Expensive Biofuels – Brazilian Ethanol

LCFS compliance strategies by obligated parties over the mid-term could involve the use of Brazilian ethanol that has some of the lowest CI values of commercially-available gasoline substitute biofuels. However, the calculated delivered price of Brazilian ethanol to California has been quite high over the last 18 months, estimated at an average of $1.04 per gallon greater compared to ethanol delivered to California from the Midwest during 2010 and estimated at an average of $1.75 per gallon greater compared to ethanol delivered to California from the Midwest during the first six months of 2011. Part of the reason for the recent price increase has been the tightening of Brazilian ethanol market, the increased price of world sugar prices, and higher sugarcane costs for Brazilian mills. If these recent incremental price differences were to be sustained at these levels, the potential impact on E10 prices for blends using Brazilian ethanol could range between 10.4 cents per gallon and 17.5 cents per gallon. The potential impact on E85 prices could be greater, ranging between 83 cents per gallon and $1.39 per gallon.

Issues Associated with LCFS Expanded to Other Areas of United States

At this time, California is the only state with a Low Carbon Fuel Standard (LCFS) program in place. A number of states are developing or considering LCFS programs, either individually or as a bloc[94] (see Figure 4-25). This section briefly describes those programs which have not yet been implemented and their status.

Figure 4-25: LCFS Programs in the United States



Source: Pew Center on Global Climate Change.

Oregon

- LCFS program was enacted by the Oregon Legislature in 2009 as part of House Bill 2186.[95]
- Uses ARB as a base, modified for Oregon fuels market.[96]
- Draft rules developed January 2011[97]; final proposed rules to be considered Dec 2011
- 2013 is first compliance year; 10 percent GHG reduction achieved by 2022; timeframes may be pushed back a year if implementation issues warrant.[98]
- Does not cover propane, which was specifically excluded from HB2186.[99]
- Exempts farm and logging trucks.[100]

Washington

- Executive Order 09-05 directs Department of Ecology [101]to investigate the development of a LCFS plan.
- Uses ARB as a base

- Final GHG plan developed in 2010 noted "a number of questions that we will continue to assess before making a recommendation to the Governor on whether or not we believe Washington should implement [an LCFS program] [102]."

- Final report on LCFS published February 2011[103]. Plan assumes carbon intensity "will be reduced 10 percent from 2007 levels by 2023, with reductions beginning in 2014.[104]"

Northeast & Mid-Atlantic States

- Represents Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont.[105]

- Program tied in to Northeast States for Coordinated Air Use Management (NESCAUM)[106], an independent 501(c) (3) organization.[107]

- Signed Memorandum of Understanding in December 2009 to collaborate on a LCFS.[108]

- Memorandum published December 2010[109] noted that draft program framework was expected to be made available to stakeholders early 2011, but this document is not on NESCAUM website.[110]

Midwestern Governors Association

- Represents Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Ohio, South Dakota and Wisconsin.[111]

- Advanced Transportation Fuels Advisory Group currently undertaking studies and discussions of Low Carbon Fuels Policy.[112]

- 2010 Low Carbon Fuels Policy Document presented May 2-3, 2011; alternative approaches document also presented.[113]

- Recommendations use 2005 as baseline for reductions and 10 percent reductions within 10 years of implementation.[114]

All of these regions represent a significant quantity of gasoline and diesel fuel, when compared to California. This large portion of transportation fuel demand is important when assessing potential implications for LCFS compliance. A major consideration for other states and regions considering implementation of LCFS-like regulations is the supply of biofuels necessary to help achieve compliance, regardless of cost. Table 4-4 lists the other states considering LCFS-like programs and their relative consumption estimates for gasoline and diesel fuel.

Table 4-4: Gasoline and Diesel Fuel Consumption – Selected States (2009)

State	Diesel Fuel MM Gals	Gasoline MM Gals	State	Diesel Fuel MM Gals	Gasoline MM Gals
California	3,797	15,023	New Hampshire	323	722
Connecticut	949	1,525	New Jersey	1,231	4,250
Delaware	126	445	New York	2,764	5,725
Illinois	1,823	4,973	Ohio	1,978	5,027
Indiana	1,495	3,091	Oregon	781	1,554
Iowa	924	1,667	Pennsylvania	2,512	5,116
Kansas	752	1,323	Rhode Island	239	399
Maine	559	672	South Dakota	311	449
Maryland	827	2,915	Vermont	206	336
Massachusetts	1,260	2,797	Washington	1,063	2,722
Michigan	1,084	4,620	Wisconsin	1,000	2,524
Minnesota	995	2,554	Totals (Ex. CA)	23,201	55,406

Legend:

LCFS adopted

LCFS in development

Midwestern Governors' Association LCFS (under consideration)

Northeast & Mid-Atlantic LCFS (in development)

Sources: California figures – BOE. All other states - State Energy Data from EIA.

The California LCFS compliance analysis presented earlier in this section illustrate the various strategies that obligated parties are anticipated to pursue. These actions will result in the need for substantial quantities of specific types of renewable fuels. In the cases that achieve compliance for the longest period of time, the calculated volumes required by California obligated parties either approach or nearly approach the entire national supply of renewable fuels with low enough carbon intensity. The incremental demand for these same fuels that would result if any other region of the United States carried out implementation of an LCFS-like program would, at a minimum, increase competition and raise the market-clearing prices of these biofuels. Based on the figures provided in the table above, the states considering implementation of LCFS-like regulations equate to 3.7 times the quantity of gasoline consumed in California and 7.2 times the quantity of diesel fuel consumed in California during 2009. Implementation of LCFS-like regulations outside of California would need to be accompanied by an unprecedented expansion of low carbon intensity fuels, likely in the form of biomass-to-liquid gasoline and diesel fuel, in order that sufficient incremental supplies of the appropriate biofuels be available, all at an unknown cost to consumers and businesses.

Ethanol Blenders Excise Tax Credit and Import Tariff

Refiners and marketers that have used ethanol in the gasoline they sell have long enjoyed a benefit of the federal tax code that has excused a portion of the federal excise tax owed on gasoline. In addition, domestic ethanol producers have enjoyed a benefit of import protectionism in the form of a tariff and an ad valorem tax applied to most sources of foreign ethanol. This section discusses these policies and the potential implications if eliminated.

Ethanol Blenders Excise Tax Credit

The Energy Tax Act of 1978 established that blenders of ethanol in gasoline at a concentration of 10 percent by volume, referred to as gasohol, were excused from the full amount of federal excise tax owed on a gallon of gasoline that at the time was 4 cents per gallon.[115] This excise tax credit has undergone a number of revisions over the years culminating in the Volumetric Ethanol Excise Tax Credit (VEETC) that was created by the American Jobs Creation Act of 2004.[116] The VEETC was reduced from 51 cents to 45 cents per gallon by the 2008 Farm Bill. This is not an ethanol producer subsidy, rather a federal excise tax credit for refiners and marketers who blend ethanol in gasoline. If ethanol is used at a concentration of E10, the federal excise tax owed on gasoline of 18.4 cents per gallon would be reduced by 10 percent of the 45 cent-per-gallon credit or 4.5 cents per gallon of E10.[117]

The primary intent of enacting an excise tax credit for ethanol was to allow blenders (refiners and gasoline marketers) to realize a lower net blending cost (market price less the excise tax credit), thus allowing greater revenues for ethanol producers since the market price would have been lower without the excise blenders credit. When this federal legislation was originally enacted as part of the Energy Tax Act of 1978, the ethanol industry was just getting started. Over the years, proponents of the VEETC have claimed that this provision is necessary to ensure a maximum use of ethanol in the market by offering a lower-priced gasoline blending component for discretionary blending of ethanol. However, with the enactment of new federal legislation mandating increasing minimum levels of biofuel use through the federal RFS2, the amount of discretionary ethanol blending opportunities have been dramatically reduced such that the concentration of ethanol in all gasoline in the United States has averaged 9.53 percent for the first four months of 2011.[118] Therefore, the primary justification of retaining the VEETC has largely been rendered moot.

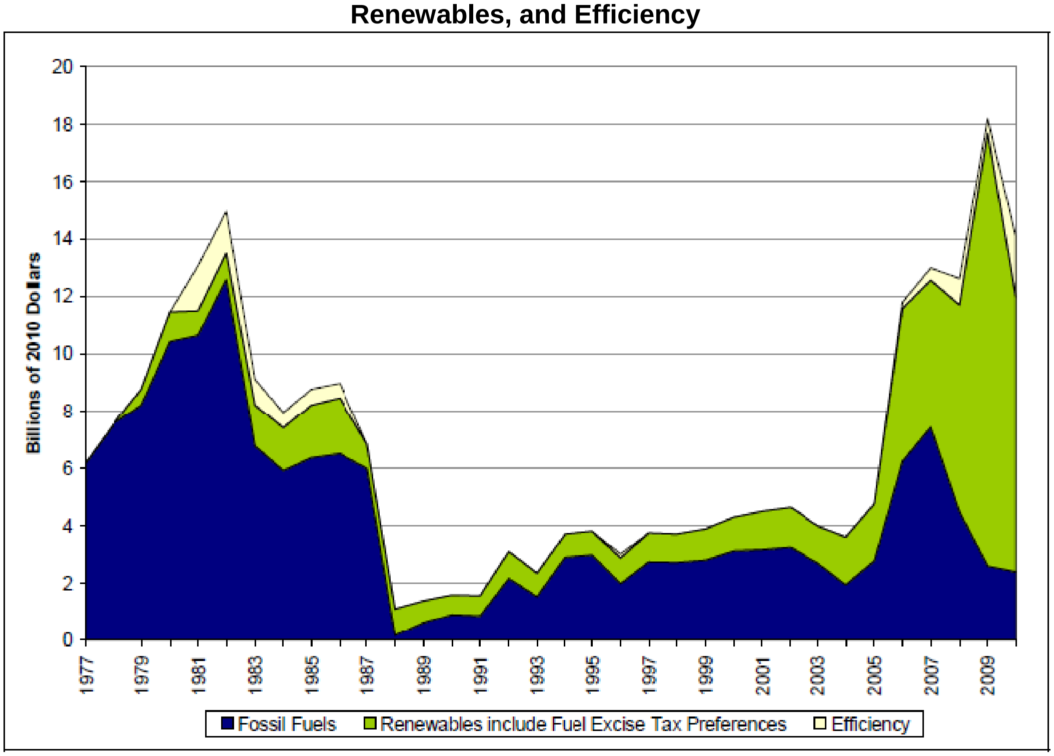
Demand for ethanol today is primarily a consequence of the RFS2 minimum use mandates. It is unlikely that the loss of the VEETC will decrease ethanol use since refiners and marketers are using it because they have to comply with the federal mandate, not because the price of ethanol may or may not be less than that of gasoline. According to the U.S GAO: "*When the RFS is binding, removal of the VEETC would not affect ethanol consumption but would eliminate the tax credit benefit to motor fuel blenders, motor fuel purchasers, and ethanol producers*."[119] Gasoline in California contains 10 percent ethanol. Changes in the cost of ethanol over time do not impact this concentration in gasoline. Changes in ethanol demand are a direct consequence of changing gasoline demand that is primarily influenced by the strength or weakness of the state's economy and near-term retail price movements. The only current discretionary use of ethanol in

California is for the marketing of E85. However, this practice is limited to roughly 50 retail locations and modest sales volumes that are estimated to be about 10 million gallons during 2010.[120]

Elimination of the VEETC could result in a higher cost for refiners and gasoline marketers. The extent of this price increase solely as consequence of the VEETC elimination is uncertain, but likely not to exceed the full magnitude of the credit, 45 cents per gallon.[121] If so, gasoline blended at an ethanol concentration of 10 percent by volume could increase by up to 4.5 cents per gallon as refiners and gasoline blenders attempt to pass along this cost increase to consumers over the long-term. Other studies of eliminating the VEETC have concluded that ethanol prices for refiners and gasoline marketers will increase, but not by the full amount because ethanol producers will expect to see a drop in the price they receive. However, these studies assume that the use of ethanol is discretionary, rather than the scenario of a *de facto* mandatory use situation that the California market is under.

Since the VEETC excuses a portion of the federal fuel excise tax owed to the United States Treasury when gasoline is blended with ethanol, the federal government receives less revenue. The excise tax credit for ethanol blending and other forms of tax expenditures for fossil fuels and energy efficiency have reduced revenue to the federal government by more than $10 billion per year since 2005. Figure 4-26 shows the annual revenue decrease by category of program since 1977.[122]

Figure 4-26: Revenue Losses from Tax Expenditures and Excise Tax Provisions: Fossil Fuels, Renewables, and Efficiency



Source: United States Congressional Research Service calculations using Joint Committee on Taxation and Office of Management and Budget tax expenditure estimates.

According to a recent report released by the U.S. GAO, "the VEETC will cost $5.7 billion in forgone revenues in 2011."[123] If the VEETC were to continue beyond the current sunset date of December 31, 2011, the annual cost to the Treasury could rise to $6.75 billion by 2015.[124]

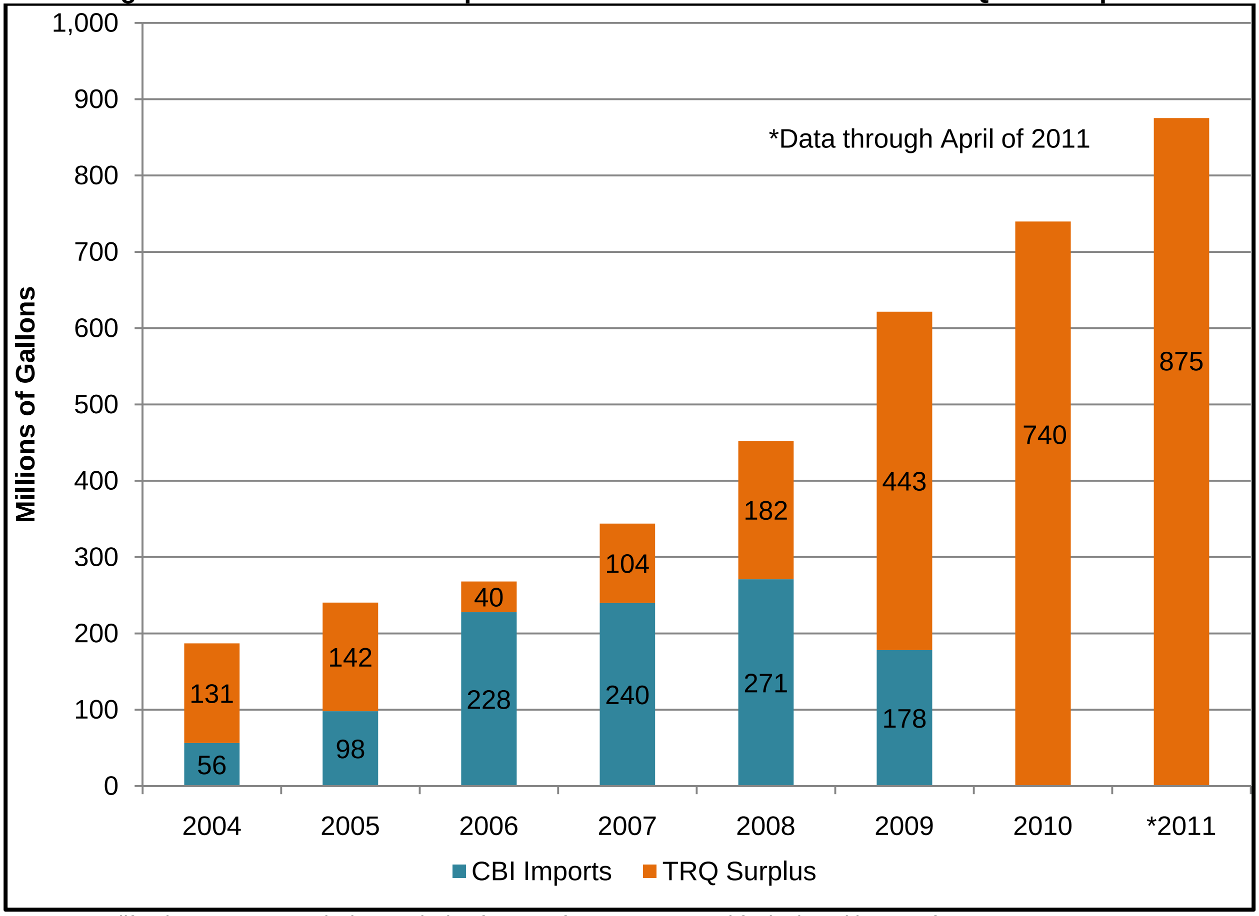
Continuation of the VEETC policy is no longer necessary to encourage ethanol use in the United States since the RFS2 mandates have relegated discretionary use to the E85 market. Elimination of the VEETC will increase gasoline excise tax revenue to the federal government by nearly $6 billion per year, absent any other changes in excise fuel tax rates.

Ethanol Import Tariff

Most exporters of ethanol to the United States must pay two types of import duties, an ad valorem tax equivalent to 2.5 percent of the ethanol transaction price and a secondary import duty of 54 cpg. Assuming ethanol is selling for $2 per gallon, the combined import duties for Brazilian ethanol would amount to 59 cents per gallon (ad valorem of 5 cpg + secondary import tariff of 54 cpg).[125] This form of protectionism increases the cost of supplying ethanol to the United States market and is a type of trade challenge not applied to other types of transportation fuel-related foreign imports such as crude oil, gasoline, jet fuel, and diesel fuel. The only exception to these duties is ethanol imported from a group of countries identified under the Caribbean Basin Initiative (CBI).[126]

Ethanol imports from CBI countries may be imported into the United States duty-free at quantities no greater than 7 percent of the previous federal fiscal year United States fuel ethanol consumption quantity (ending September 30).[127] The United States International Trade Commission (U.S. ITC) announces the duty-free quota for each calendar year. The current fuel ethanol quota for 2011 has been set at an upper limit of 875.4 million gallons. Figure 4-27 shows the annual CBI imports and duty-free tariff rate quota (TRQ) surplus between 2004 and 2011 (through April).

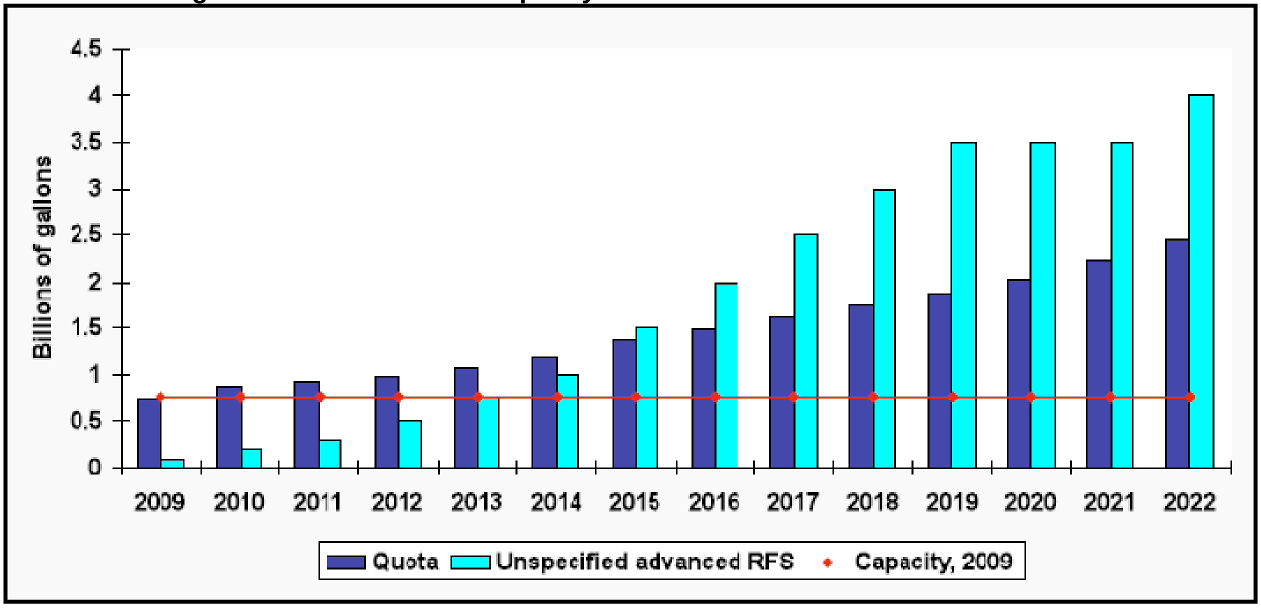
Figure 4-27: United States Imports of CBI Ethanol and the Tariff Rate Quota Surplus



Sources: California Energy Commission analysis of quotas from U.S. ITC and fuel ethanol imports from EIA

As the chart illustrates, duty-free imports of ethanol from CBI countries do not normally reach their limit, especially during 2010 when CBI imports did not occur due to surplus ethanol supply in the United States at lower prices compared to these Caribbean countries. Unlike ethanol plants in the United States and Brazil, the CBI facilities are primarily designed to process hydrous ethanol in a manner that eliminates most of the water in the ethanol mixture such that the resulting output achieves compliance with anhydrous ethanol specifications, the type of ethanol that can be blended with gasoline in the United States. The total processing capacity in five CBI countries is over 700 million gallons per year.[128] The majority of the hydrous ethanol processed by these facilities originates in Brazil.[129] CBI ethanol could play a role in California's LCFS, by providing a source of fuel ethanol that has lower carbon intensity compared to Midwest corn-based ethanol, but higher carbon intensity compared to Brazilian ethanol from sugar cane.[130] CBI ethanol also is characterized as an Advanced Biofuel under the RFS2 regulations. The more favorable carbon footprint for CBI ethanol means that there could be demand under RFS2 and the LCFS, depending on market prices relative to Brazilian ethanol. Figure 4-28 shows the estimated increase in the quota for CBI ethanol based solely on the RFS2 minimum volume mandates as interpreted by the International Trade Commission.[131]

Figure 4-28: CBI Ethanol Capacity and RFS2 Advanced Biofuels Demand



Sources: U.S. ITC, Doug Newman presentation, March 9, 2009.

The information in the chart indicates that CBI ethanol production capacity will remain greater than the RFS2 minimum demand levels for Advanced Biofuels over the next several years, as well as within the forecast duty-free volume quotas. Further, the Caribbean Ethanol Producers believe that CBI facilities could expand to meet the continued growth in Advanced Biofuels demand such that Brazilian hydrous ethanol can be exported duty-free to the United States, via processing at CBI dehydrating facilities.[132] However, economics of CBI ethanol production in competition with ethanol market prices in the United States and Brazil will ultimately dictate what portion of the RFS2 and LCFS lower carbon intensity ethanol demand will be sourced from this region. The fate of the import tariff will play a large role in the competitive position and continued viability of the CBI ethanol processing facilities.[133]

Domestic ethanol prices would have to rise significantly in order for Brazilian ethanol to become economically attractive. For example, the price of ethanol in Brazil averaged 86 cents per gallon *higher* than California ethanol price during the first six months of 2011. Most recently the price differential has narrowed to only 12 cents per gallon higher than California ethanol during June of 2011.[134] However, a more accurate cost comparison is the price of California ethanol versus the estimated price of Brazilian ethanol delivered to California, including shipping costs and the import tariffs, assuming they are not repealed. In order for Brazilian ethanol to be an economically viable alternative for a California refiner or gasoline marketer during June of 2011, the domestic price would have to rise by the 12 cents, as well as another 76 cents to over $3.74 per gallon to cover the import tariff (54 cpg), duties, and transportation costs.

Since the ethanol price that producers receive is expected to decline with a repeal of the VEETC, it is unlikely that Brazilian ethanol imports will become a more economically viable option over the near-term. In fact, due to excess production capacity, the ethanol prices in the United States have been sufficiently low during 2010 that exporting ethanol to foreign destinations has been a profitable option for some United States ethanol producers. In fact, the United States exported a record quantity of ethanol during 2010, nearly 400 million gallons, or roughly 3 percent of domestic production during 2010. Until the end of 2009, the United States had been importing ethanol to help meet demand. Through the first five months of 2011, the trends of 2010 have continued, with low domestic ethanol prices and 393 million gallons of ethanol exported from the United States.[135]

Lately, a variety of stakeholders have been calling for the elimination of this ethanol import tariff, especially in light of the increased demand for Brazilian ethanol that is likely to materialize as a consequence of the federal RFS Advanced Biofuels requirement and California's LCFS for gasoline carbon intensity. Modeling work assessing the potential impact of removing the 2.5 percent ad valorem and the secondary import tariff suggest that the price of ethanol in the United States could be reduced from between 2.5 to 14 percent, a potential benefit to consumers.[136] Put another way, if the import tariff and ad valorem tax had been eliminated, the estimated cost to provide Brazilian ethanol to California during June of 2011 could have been approximately 62 cents per gallon less.

Elimination of the import tariff and ad valorem tax could decrease the cost of importing Brazilian ethanol to California. Minimizing importation fees for types of renewable fuels that will be in high demand to help achieve compliance with the state's LCFS could help to lower the incremental costs of the regulation for consumers and businesses. Further, elimination of the tariff could also reduce the cost for obligated parties throughout the rest of the United States to comply with the Advanced Biofuels portion of RFS2. However, elimination of the import tariff could impact the economics of CBI ethanol facilities to such an extent as to result in their closure. It is uncertain what portion of the reduced cost of importing Brazilian ethanol by eliminating the tariff would be potentially offset by a reduction in ethanol production capacity from CBI countries.

Fuel Economy Standards

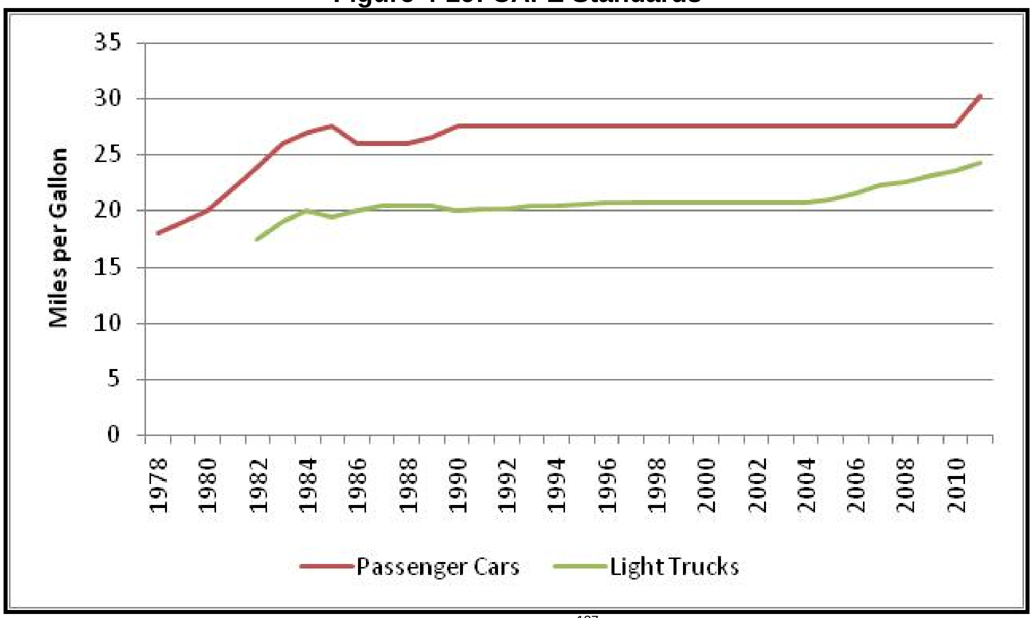
Vehicles are divided into two broad classes of vehicles, based on weight, that are generally used for different purposes and use substantially different amount of fuels. Although there are some overlaps, generally speaking, light-duty vehicles are used mostly for personal transportation, and the heavy-duty vehicles are used for commercial movement of people and goods as well as performing commercial activities. These differences determine the type and application of fuel economy standards to different classes of vehicles. Light-duty vehicles have long been subject to fuel economy standards and have a track record to assess their compliance, but medium and heavy- duty vehicle fuel economy standards have only been proposed.

Light-Duty Vehicles

CAFE standards for vehicles were first established in 1975 and currently require that new vehicles sold meet a minimum fuel efficiency standard expressed in miles per gallon of fuel. The mix of vehicles manufacturers' sales will determine each manufacturer's average fuel economy using a harmonic average. NHTSA sets the standards to conserve energy, but considers technological feasibility and cost. These standards are set at higher levels for light-duty vehicles, than the light truck standard.

The fuel economy standard for cars has increased in 2011 after remaining constant at 27.5 MPG for 21 years. The CAFE standards for light trucks were constant at 20.7 MPG for nine years before gradually increasing to 24.2 in 2011, as can be seen in Figure 4-29. Until 1991, light-duty truck fuel standards were set separately for two-wheel drive vehicles and four-wheel drive vehicles, but since then the same standard has been applied to all light-duty trucks. This change allowed the manufacturers to compute the fuel economy standard for their light- duty truck fleet as a whole.

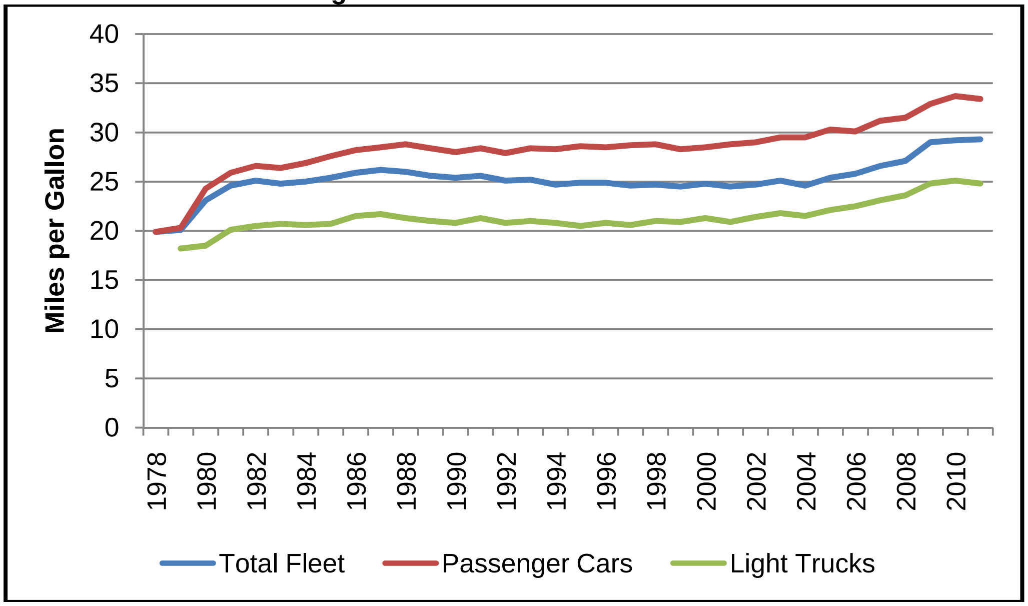
Figure 4-29: CAFE Standards



Source: NHTSA, "Summary of Fuel Economy Performance"[137]

For model year 2011, the standard is currently at 30.2 MPG for cars and 24.2 MPG for light trucks. However, the actual MPG for on-road model year 2010 cars and light trucks calculated by NHTSA exceeded the requirements, achieving 33.4 MPG for cars and 24.8 MPG for light trucks, as displayed in Figure 4-30 below. When manufacturers exceed the fuel economy standards, they receive credits that they can either save or use to comply with the standards in previous model years. However, they may only carry forward the credits for five years or back three years.

Figure 4-30: National Fleet CAFE

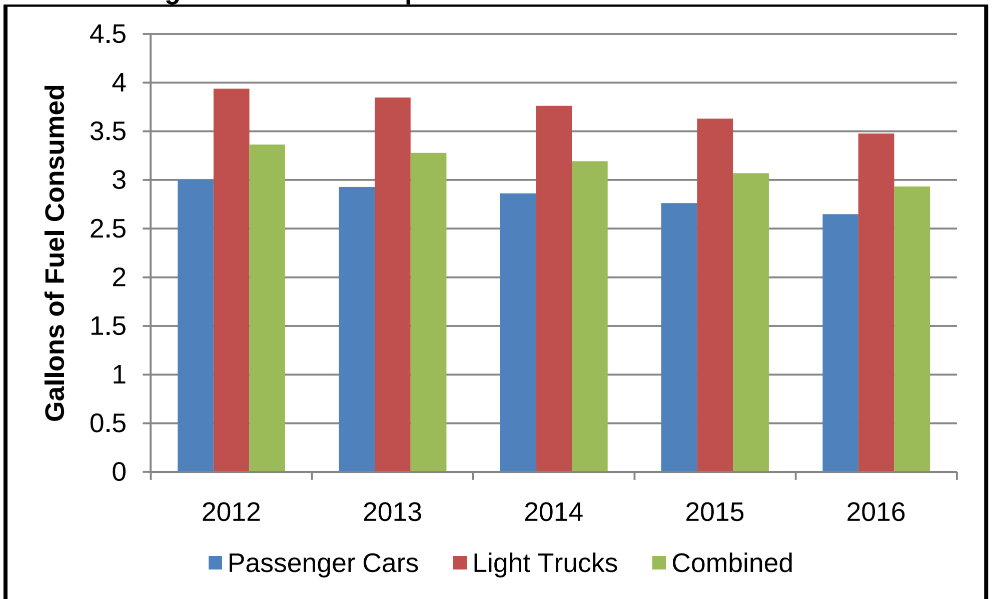


Source: NHTSA, "Summary of Fuel Economy Performance"

The method by which NHTSA identified vehicles subject to fuel economy standards used gross vehicle weight as the criteria, for vehicles up to 8500 pounds.[138] This weight-based rating system allowed manufacturers to add weight to a vehicle so that it will fall in a different vehicle category with lower fuel economy standards. Beginning in the 2008 model year, NHTSA adopted a new method that will no longer differentiate between cars and trucks and will instead use the vehicle footprint to evaluate compliance with standards for both. Footprint refers to the wheelbase, the distance between the front and rear axle, multiplied by the track width, which is the distance between the center of the tires. A footprint standard also allows vehicles in similar market segments to be grouped together. NHTSA allowed for a transition period for model years 2008 to 2011 in which manufacturers could choose between the reformed CAFE standards, which use the footprint methodology, or the unreformed CAFE standards based on weight based classes of vehicles. Starting with 2012 model years, manufacturers can only use the footprint method.

For model years 2012-2016, fuel economy standards under the National Program, which includes NHTSA and U.S. EPA rules, are set to increase to 35.5 MPG by the 2016 model year. NHTSA forecasts that the new CAFE standards, over the life of the 2012-16 vehicles, will save 61 billion gallons of fuel, which is almost one third of total United States fuel consumption in 2010[139]. The cars and light trucks combined fuel usage per 100 miles is 3.36 gallons for model year 2012[140] while it decreases to 2.93 gallon for model year 2016 (see Figure 4-31). Assuming a constant fuel price, this translates into a 12.8 percent decline in expense for consumers to purchase the fuel. The lifetime benefits for the CAFE standards are projected at $182 billion[141], which includes fuel savings, and the total cost will be $52 billion. These costs include higher vehicle prices, which are projected to increase by $434 for model year 2012 vehicles and $926 for model year 2016[142].

Figure 4-31: Gallons per 100 Miles with CAFE Standards



Source: NHTSA[143]

The fuel economy standards for model years 2012-16 reflect rules that comply not just with CAFE standards, but with the U.S. EPA's GHG emission requirements as well. Under the regulations, ARB agreed not to create separate and different vehicle GHG emission requirements for light-duty vehicles until 2016. However, ARB is still considering setting stricter vehicle GHG requirements for model year 2017 and later, while at the same time, the United States and NHTSA are developing fuel economy and tailpipe emission rules for 2017-25 model years. Although final details for the rules won't be available until September 2011, NHTSA and U.S. EPA have determined that the average fleet fuel economy will reach 54.5 miles per gallon by the 2025 model year.[144] To achieve this, the program requires that fuel economy improvements will average 5 percent per year for cars and 3.5 percent for light trucks through 2021; from 2022 to 2025, both cars and light trucks will average a 5 percent improvement[145]. To meet these improvements, the agencies believe that manufacturers will build vehicles with lighter materials, develop smaller engines, and incorporate more fuel-efficient engine technology. This corresponds to an increase in vehicle costs of $800 to $3,500 and fuel savings between $5,000 to $7,000[146], depending on the vehicle technologies and assumptions. NHTSA and U.S. EPA will finalize the rules by July 31, 2012.

Medium- and Heavy-Duty Fuel Economy Standards

While light-duty vehicles have had fuel efficiency standards for quite some time, the 2014-2018 model years are subject to the first such standards for medium- and heavy-duty vehicles. These include the largest pickup trucks and vans, semi trucks, and all types and sizes of work trucks and buses. The standards have the potential to save approximately 500 million barrels of oil over the life of vehicles sold during the 2014 to 2018 period and result in cost savings of $34.6 billion. It is important to note that the standards cover both engines and the complete vehicle. For purposes of this regulation, the heavy-duty vehicle fleet includes all on-road vehicles rated at a gross vehicle weight at or above 8,500 pounds, and the engines that power them, except those covered by the current GHG emissions and CAFE standards for model years 2012-2016. Heavy-duty engines affected by the standards would generally be those that are installed in commercial medium- and heavy-duty trucks and buses. Trailers are not covered under these standards.[147] NHTSA proposed fuel economy standards that are tailored to each of three main regulatory vehicle categories: combination tractors (big rigs), heavy-duty pickup trucks and vans, and vocational vehicles. These standards use two types of measures: payload-dependent gallon per 100-mile standards for large pickups and vans; and gallon per 1,000 ton-mile standards for vocational vehicles and combination tractors. These measures account for the fact that more fuel is burned in moving heavier loads than in moving lighter loads.[148]

For combination tractors NHTSA is establishing standards for nine categories of combination tractors based on three attributes: weight class, cab type, and roof height. As an example, by 2017, sleeper cabs will have to reduce fuel consumption by 15 to 20 percent and day cabs by 7 to 11 percent, compared to 2010 baselines.[149]

CAFE standards will be established for heavy-duty pickup trucks and vans, similar to the approach taken for light-duty vehicles. Each manufacturer's standard for a model year would depend on its sales mix, with higher capacity vehicles (payload and towing) having higher target levels, with an added adjustment for four-wheel drive vehicles. The standards require an average improvement in fuel consumption of 15 percent per diesel vehicle and 10 percent per gasoline vehicle by 2017, compared to 2010 baselines.[150]

Vocational vehicles consist of a wide variety of truck and bus types including delivery, refuse, utility, dump, cement, transit bus, shuttle bus, school bus, emergency vehicles, motor homes, and tow trucks. NHTSA will regulate chassis manufacturers for this segment and divide it into three regulatory subcategories: Light-Heavy (Class 2b through 5), Medium-Heavy (Class 6 and 7), and Heavy Heavy (Class 8), which is consistent with the engine classification. The standards require 7 to 10 percent reductions in fuel consumption by 2017, compared to 2010 baselines.[151]

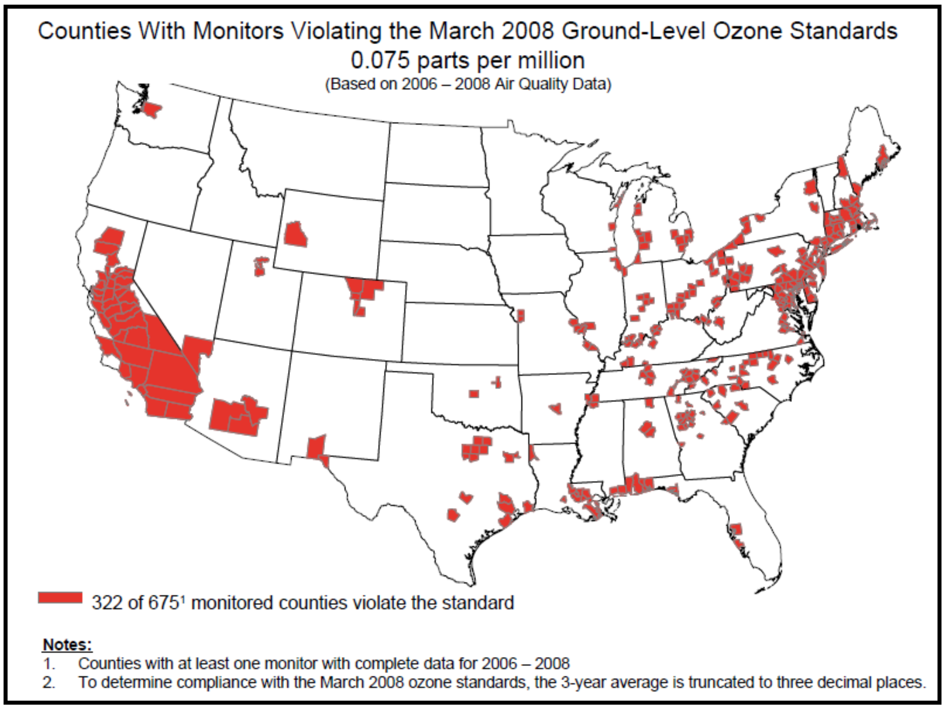
Clean Air Act of 1970 - Revision of the 8-Hour Ozone Standard and Potential Impact on Transportation Fuel Regulations

Background and Timeline

Pollution reduction is one of the factors that policymakers consider when developing a fuel specification standard. At ground-level ozone (O_3)[152] is a prime ingredient of photochemical smog and is a significant contributor to various respiratory illnesses[153] and vegetation damage. While some ozone is naturally present at ground level, significant artificial ozone is generated when various gases (known as ozone precursors) combine in the presence of sunlight[154]. Ozone emissions are regulated by the U.S. EPA under the Clean Air Act of 1970 via the National Ambient Air Quality Standard (NAAQS)[155], which requires periodic review and revision.

The primary standard[156] for ozone is a particular concentration threshold (measured in ppm), above which the "3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed[157]." In 1997, the U.S. EPA set this threshold at 0.084 ppm, a standard which was attained by Arizona and Nevada but not California. In March 2008, the U.S. EPA issued a promulgation lowering the threshold to 0.075 ppm[158]. Figure 4-32 depicts the counties that have violated this proposed standard.

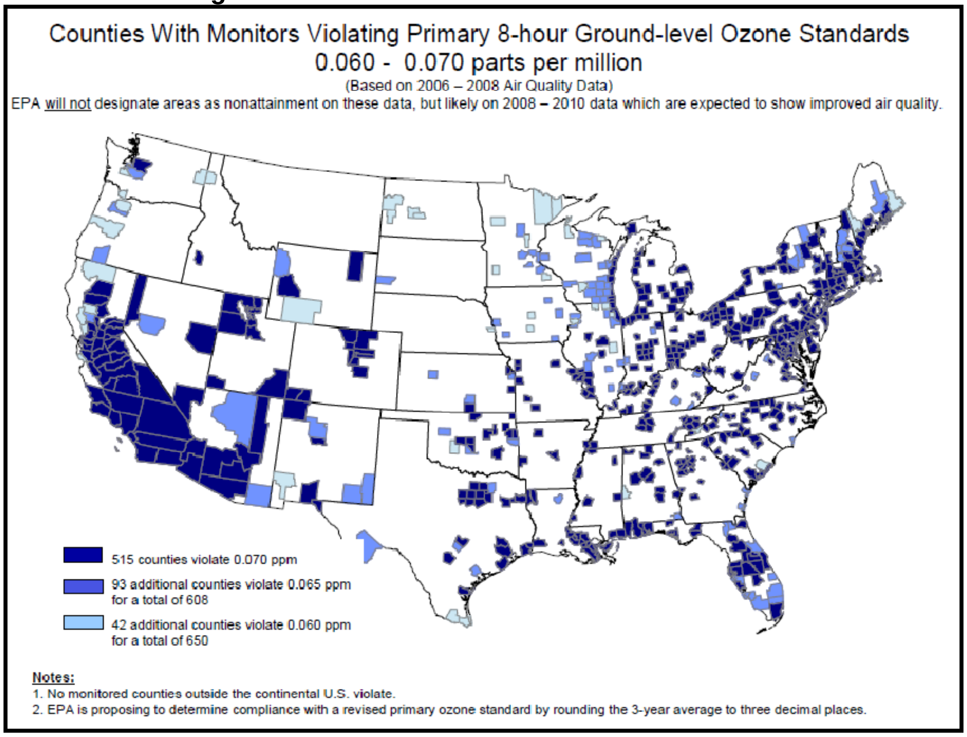
Figure 4-32: U.S. EPA March 2008 Ozone Standard



Source: U.S. EPA

A number of states and environmental groups filed suit in federal courts challenging U.S. EPA's new standard on the grounds that the decision did not go far enough in curbing ozone emissions and protecting the health of the public[159]. In response, the U.S. EPA announced it would reconsider the 2008 standard[160] and subsequently announced that it will set the standard within a range of 0.060 ppm to 0.070 ppm[161]. See Figure 4-33 to see how many additional counties in the Southwest could be drawn in to the more stringent standard. A final decision on the reconsideration was expected by July 29, 2011[162]. However, U.S. EPA has since delayed this ruling indefinitely, pending an interagency review[163].

Figure 4-33: U.S. EPA Revised Ozone Standard



Source: U.S. EPA

The responsibility for achieving compliance with NAAQS falls largely on individual states, which are required to identify which regions within their borders are out of compliance with the new standard and develop a State Implementation Plan (SIP), detailing actions necessary to achieve the new target by the specified deadline[164]. These comprehensive plans include an evaluation of all ozone sources, but the majority of ozone emissions originate from the transportation sector.

The overall impact of the impending NAAQS reconsideration on the transportation sector will depend greatly on which value within the 0.060 ppm to 0.070 ppm range the U.S. EPA decides upon. California, much of which already exceeds the current 0.075 ppm standard by a considerable margin[165], will face considerable challenges under the new standard. Further, some of the areas of California facing the worst ozone emissions have been granted waivers extending the time they have to come into compliance to as far as 2024[166], ensuring that these challenges will last well into the next decade. There are multiple strategies available to states that can be pursued to help achieve compliance with more stringent ozone standards. These include additional emission controls on stationary sources, more stringent vehicle emission standards, and modifications to existing gasoline regulations designed to yield a reduction in ozone-forming compounds from the existing and future fleet of cars and trucks.

If the ozone standards are lowered and the neighboring states of Arizona and Nevada elect to modify their respective gasoline regulations, then the portion and type of gasoline that they import from refineries in California could be altered from their current level. Neither Nevada nor Arizona have any refineries operating in their respective states that produce gasoline –

Nevada receives nearly all of its gasoline from refineries located in California, while Arizona receives about half with the balance provided from refineries located in New Mexico and Texas. If, for example, the portion of gasoline shipped to Arizona from refineries in California were to increase due to adoption of more stringent gasoline specifications, these additional exports would in effect increase the demand on California refineries for regional transportation fuel supply.

Impact on California

Due to California's unique climate, geography and size, it faces the worst ozone emissions challenge in the nation. The ARB, which is responsible for producing California's SIP, has determined nearly the entire state to be out of attainment with the current ozone standard[167]. The SCAQMD has the worst ozone concentrations, with 8-hour ozone concentrations as high as 0.123 ppm in 2010[168]. Changes in vehicle technology and fuel specifications contributed to a dramatic reduction in ozone from the levels seen in the 1980s. However, the State will need to take increasingly stronger and more costly measures to bring its ozone emissions under control. In California's most recent SIP (adopted in 2007), ARB outlined a number of ozone reduction strategies, including[169]:

- Encouraging the modernization of California vehicles (including automobiles, trucks, and locomotives).
- Implementing expanded and more stringent smog checks, and more frequent smog checks of older vehicles.
- Standards for off-road mobile sources, such as lawn and garden equipment, recreational vehicles and boats, and construction equipment.
- Large diesel, gasoline, and LPG gas equipment, where authority is split between California and the federal government.
- Expectation of future technologies to bring further ozone reductions.

In addition to these measures and as earlier discussed, ARB has reclassified the South Coast region as an "extreme" designated area, giving the area more time to come into NAAQS compliance. It is expected that other areas, such as the Sacramento and San Joaquin Valleys, will be given similar designations as well to push back their respective attainment deadlines.

Much of the reduction in ozone (and in turn smog) has come from increasingly stricter regulations in automobile manufacturing. However, a large number of older vehicles not manufactured under these stricter standards are more polluting and remain on California highways. For example, data from DMV indicates that in 2009, over four million of the twenty-seven million light-duty vehicles registered in California were from model year 1993 or earlier, and approximately one million are from model year 1986 and earlier. In addition to the ozone reduction associated with modernizing the state's vehicle population, the accelerated replacement of older cars with newer vehicles will increase overall fuel efficiency, which may in turn reduce overall fuel demand. None of the above-referenced strategies for reducing ozone formation involve modifications to California's existing fuel regulations (both gasoline and diesel fuel). Therefore, the primary impact of more stringent ozone standards for California transportation fuel supplies over the early and middle portions of the forecast period could potentially be limited to reduced demand for gasoline. This occurs through improved fuel economy of the existing fleet and the displacement of petroleum with increased use of renewable fuels and alternative-fuel vehicles that do not require gasoline (especially electric and hydrogen vehicles).

Impact on Arizona and Nevada and Implications for California

In response to the March 2008 NAAQS ozone concentration limit of 0.075 ppm, Arizona communicated to the U.S. EPA that it intends to declare the entire state in compliance with the current standards, with the exception of the area surrounding Phoenix[170]. However, supporting documents revealed that a large portion of the state may be out of compliance depending on which value within the 0.060 ppm to 0.070 ppm range the U.S. EPA chooses for its reconsideration.

Like California, Arizona has a number of potential measures at its disposal for mitigating ozone emissions. One of the more effective measures currently employed is the use of Arizona Cleaner Burning Gasoline (CBG), a blend of gasoline with lower ozone precursor emissions than conventional gasoline. CBG is used in Phoenix during the summer season, when ozone concentration is at a maximum; other regions in the state may continue to use conventional gasoline. If much of Arizona is deemed to be out of compliance with the revised NAAQS, a statewide, year-round conversion to CBG may be one type of strategy Arizona adopts as part of its revised SIP.

Arizona currently obtains approximately 30 percent of its CBG from California refineries; the remaining 70 percent is from refineries located in New Mexico and Texas via the eastern pipeline network, including the Longhorn Pipeline operated by Magellan[171]. However, increasing CBG production and importation from the east may prove difficult if Magellan, as expected, decides to reverse the flow of the Longhorn Pipeline. This means that any additional CBG production will likely be obtained from refineries in California. At current demand levels, this would translate to an extra 600 million gallons of fuel annually from refineries in California[172].

In Nevada, the situation may not be as problematic. Currently, the only area in Nevada considered to be in nonattainment is Clark County (the area surrounding Las Vegas). A NAAQS standard of 0.065 ppm is projected to put the Reno-Sparks metropolitan area into nonattainment as well. Nevada's ozone mitigation strategy relies largely on the use of a specialized gasoline formulation used in the Las Vegas area. The Reno-Sparks area currently uses conventional gasoline but may also be required to transition to the Las Vegas gasoline standard if the Reno-Sparks area is declared to be in nonattainment. However, Nevada could also elect to only modify a portion of their gasoline regulations, a reduction in the volatility standard[173]. This would reduce the quantity of blendstocks used to produce gasoline for Nevada and cause a relatively small reduction in supply. The pending start of operations of the UNEV pipeline is expected to provide a new source of gasoline and diesel fuel for Nevada that could offset any potential gasoline supply impacts that a reduction in the volatility standard might cause for the refiners sending gasoline to Reno and Las Vegas.[174]

Canada's RFS

Canada has adopted regulations that mandate increasingly greater use of renewable fuels in their gasoline and diesel fuel, passed by the Canadian Senate on June 26, 2008.[175] The Canadian Renewable Fuels Standard (CRFS) is discussed in this report since it has the potential to increase demand and competition for renewable fuels that may be needed to help achieve compliance with RFS2, as well as California's LCFS.[176]

The regulation requires that all refiners and importers have an average annual renewable fuel content equal to at least 5 percent of the volume of gasoline that they produce or import, commencing on December 15, 2010.[177] Unlike the federal RFS2, the Canadian regulation does not mandate the use of specific types of ethanol, instead allowing flexibility to utilize any approved type.[178] Certain provinces in Canada already have specific ethanol blending requirements (see Table 4-5) that are estimated to generate an ethanol demand of about 1.3 billion liters (343.4 million gallons) in 2010.[179] Based on gasoline sales figures for the provinces with mandates, Energy Commission staff estimates that minimum mandated Canadian ethanol demand was 372 million gallons in 2010.[180] However, the use of ethanol in Canada may be greater than the minimum mandates, estimated to be 1.687 billion liters (446 million gallons) during 2010 by the Foreign Agricultural Service of the U.S. Department of Agriculture (USDA).[181]

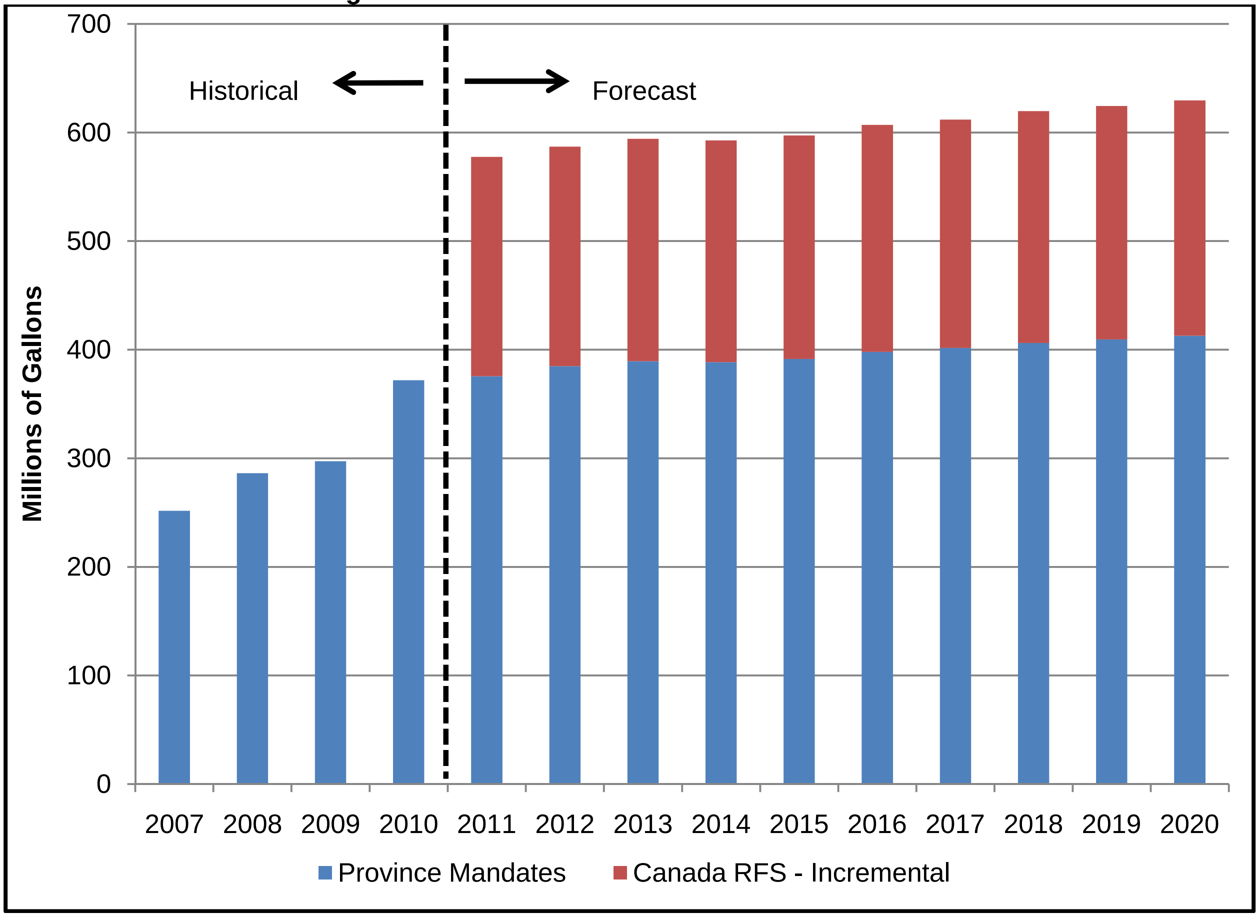
Table 4-5: Canada Province Mandates

Province	Gasoline - Renewable Portion	Start Year
Ontario	5.0%	2007
Saskatchewan	7.5%	2007
Manitoba	8.5%	2008
British Columbia	5.0%	2010

Source: Canada Gazette

To determine what additional ethanol may be required in Canada over the next several years, staff quantified the requirements for the provincial mandates and compared those to the estimated amount of ethanol required to achieve Canadian RFS compliance. The National Energy Board (NEB) of Canada forecasts demand for end-use sectors. Based on the most recent forecast available, Energy Commission staff used the Canadian High Price scenario trends to estimate the increase in gasoline demand and associated incremental demand for ethanol in Canada as consequence of their CRFS obligations and rising fuel demand (see Figure 4-34).[182]

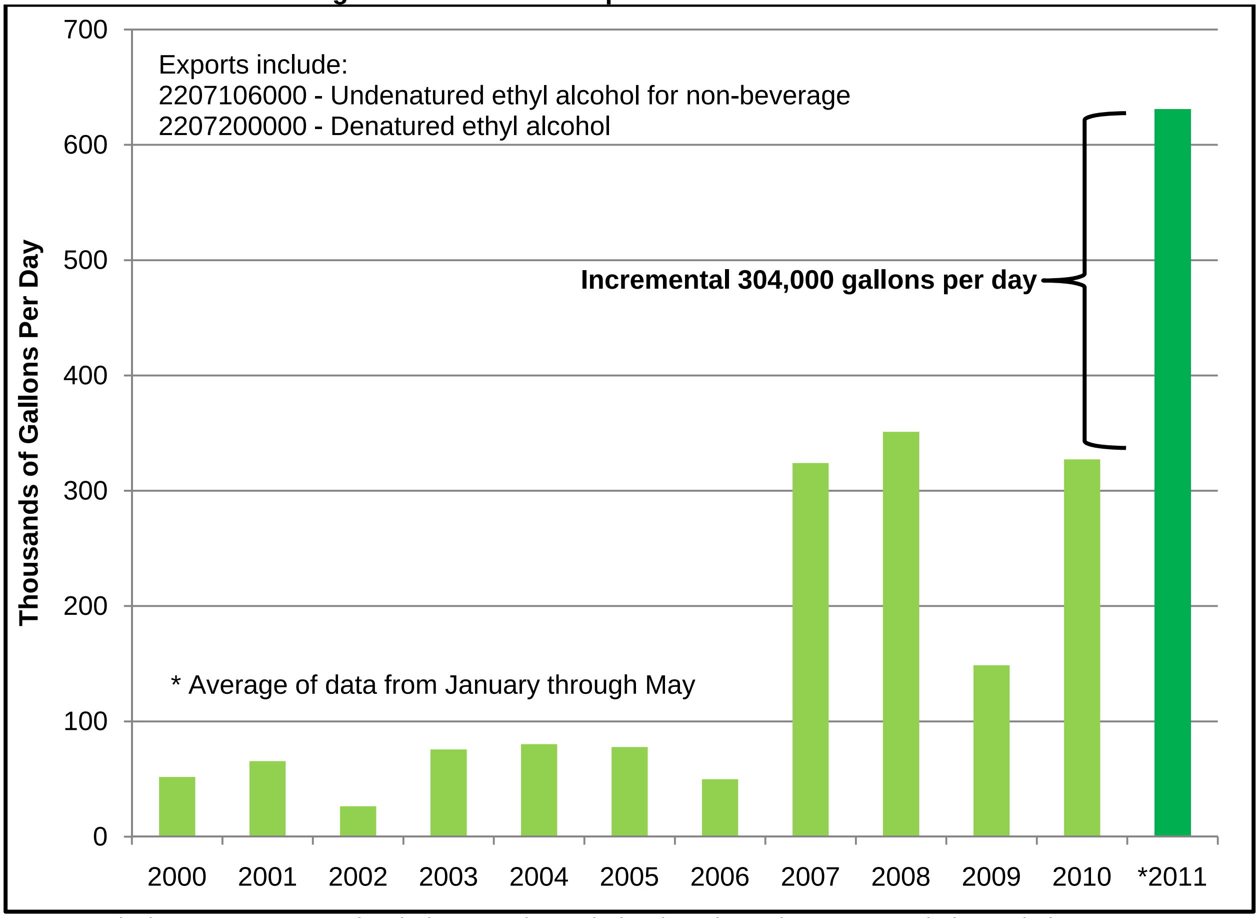
Figure 4-34: Canada Ethanol Demand 2007-2020



Sources: Canada National Energy Board data and California Energy Commission analysis.

Ethanol demand in Canada for 2011 is estimated to reach roughly 578 million gallons, including an incremental 202 million gallons (553,000 gallons more per day for 2011 compared to 2010) to achieve minimum compliance with the CRFS mandates solely with the use of ethanol. According to information provided as part of the regulatory analysis, average incremental renewable fuel demand is estimated at 794 million liters (210 million gallons) per year between 2011 and 2034 compared to 2010 levels.[183] The question of primary interest is how much ethanol might need to be imported from the United States to help achieve compliance over the next several years. Current ethanol production capacity in Canada is roughly 1.894 billion liters (500.3 million gallons) per year.[184] Assuming Canadian ethanol plants operate at full capacity, net imports of ethanol would need to reach at least 78 million gallons during 2011 or average about 214,000 gallons per day. However, according to the Foreign Agricultural Service (FAS), Canada's ethanol production is estimated to average 1.35 billion liters (357 million gallons) during 2011 or roughly 71 percent of capacity.[185] Ethanol exports from the United States to Canada are currently averaging approximately 631,000 gallons per day during the first 5 months of 2011.[186] Figure 4-35 depicts exports of ethanol from the United States to Canada between January 2000 and May 2011.

Figure 4-35: Ethanol Exports to Canada 2000-2011



Sources: United States Department of Agriculture, Foreign Agricultural Service and Energy Commission analysis

Canada's average ethanol imports from the United States for the first five months of 2011 are slightly higher than the upper level estimated by staff, an indication that Canadian ethanol plants are not operating at full capacity. The incremental imports average of 304,000 gallons per day, compared to 2010, is lower than the incremental ethanol volume calculated to meet the CRFS, possibly suggesting that the use of ethanol was already greater than the minimum provincial requirements.

In summary, during the next couple of years, incremental ethanol demand to meet CRFS compliance will be sourced from corn-based ethanol plants in the United States. Since the CRFS regulations do not mandate specific types of ethanol, this standard will not create competing demand for other types of lower carbon-intensity ethanol that will be needed to meet California's LCFS requirements.

Chapter 5: Renewable and Alternative Fuels

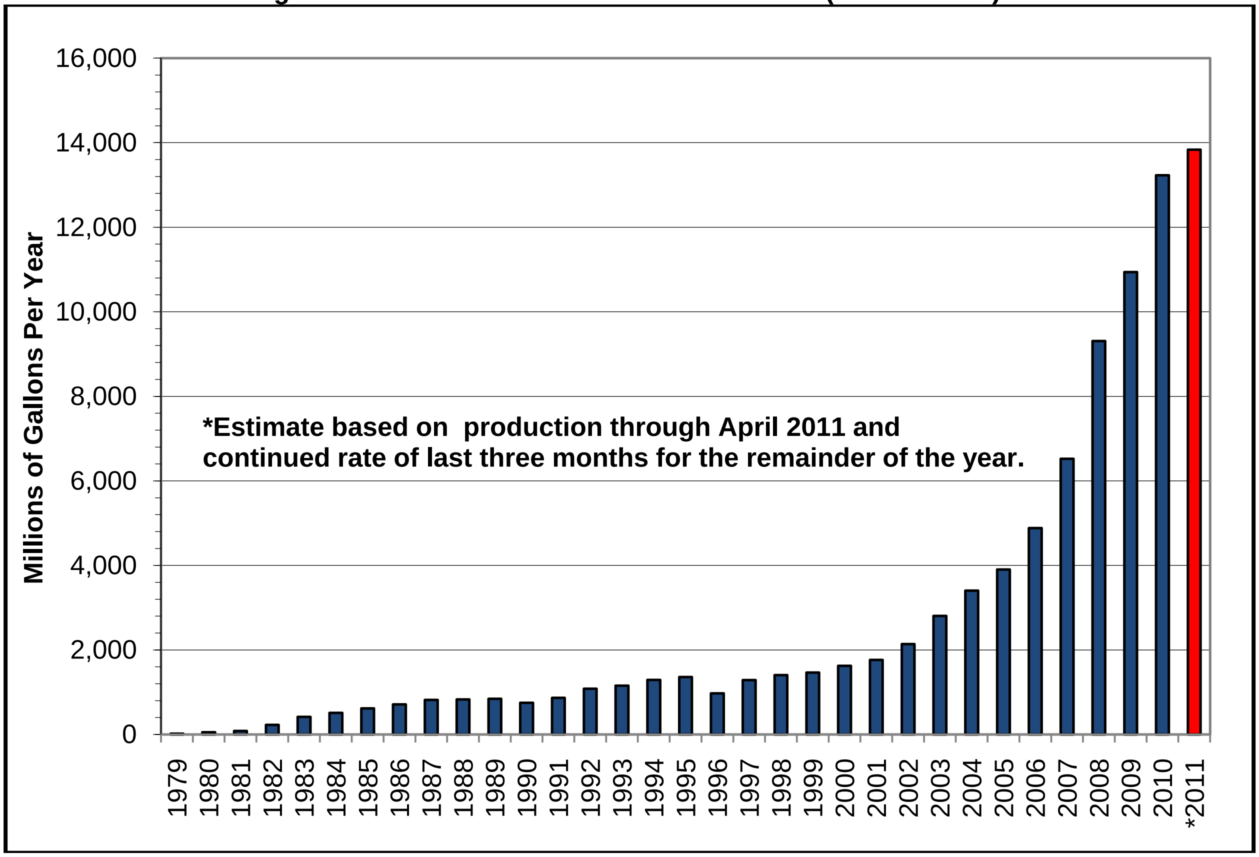
Use of renewable and other alternative fuels in the United States and California is expected to continue growing, primarily as a consequence of federal and state regulations mandating ever-increasing levels of renewable content in gasoline and diesel fuel, carbon reduction rules, and incentives for increasing alternative fuel consumption. However, these are several unresolved issues that have yet to be addressed regarding adequacy of both additional supplies and the requisite infrastructure to receive and distribute increased quantities of ethanol and biodiesel to California consumers. Likewise, there are numerous challenges to developing adequate vehicle production and sales, refueling infrastructure, and technical standards that would enable increased use of natural gas, electric, and other alternative fuels in transportation.

This chapter will provide historical information, regulatory context, supply assessments, and identification of infrastructure challenges that could endanger adequacy of transportation fuel supplies for California motorists and businesses. Available time and resources dictate that staff focuses on those issues that appear to have the most pressing near-term consequences, namely the intersection of complex state and federal renewable fuel rules that prescribe percentages and volumes of renewable fuels consumed, particularly ethanol. Other fuels will be discussed, but with the understanding that the time, dialogue, and research needed to fully quantify their contributions to petroleum and carbon reduction, and the challenges to their adoption, are limited. However, staff is committed to developing these analyses in future work as resources and time permit and seeks an open and ongoing discussion with stakeholders to work to that end.

Ethanol Overview

Ethanol (normally referred to as denatured fuel ethanol) has a long history as a transportation fuel in the United States. The Ford Model T, first manufactured in 1908, was designed with an engine that operated on gasoline, kerosene, or ethanol.[187] The use of ethanol as a motor vehicle fuel was modest from the early 1900s through the late 1930s. Declining prices of gasoline, relative to ethanol, decreased ethanol's role in transportation fuel for the next several decades until the oil price shocks of the 1970s spurred government action and intervention.[188] Federal assistance in the form of tax credits and loan guarantees resulted in a resurgence of the United States ethanol industry from "practically zero" in 1978 to more than 210 million gallons by 1982.[189] Figure 5-1 shows the annual progression of ethanol production in the United States between 1979 and 2010, including an estimate for 2011.[190]

Figure 5-1: United States Ethanol Production (1979 to 2011)

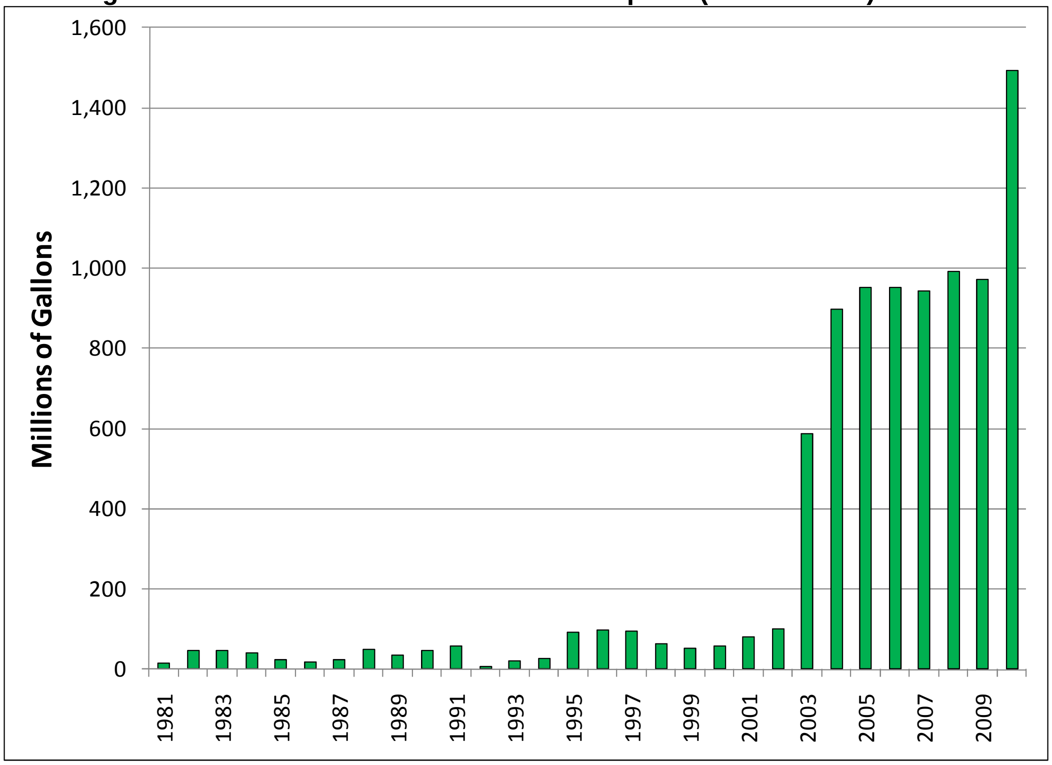


Sources: U.S. Department of Agriculture (USDA) and EIA

Beginning in 1980, ethanol's use for blending in gasoline at concentrations of E10, or gasohol, began to gain acceptance in somewhat limited quantities. However, further action by Congress mandated increased use of ethanol to help reduce formation of carbon monoxide beginning in November 1992 via the Wintertime Oxygenate Program administered by the U.S. EPA.[191] Beginning in January 1995, federal reformulated gasoline regulations took effect that required year-round use of oxygenates (chemicals containing oxygen that are added to fuels, especially gasoline, to make them burn more efficiently) in roughly one-third of the nation's gasoline.[192] The ARB adopted reformulated gasoline regulations specific to California that required all gasoline sales to meet the new standard beginning March 1, 1996.[193] Oxygenates for these federal and state programs included ethers (such as Methyl tertiary butyl ether [MTBE] and Tertiary Amyl Methyl Ether [TAME]) and ethanol. The majority of the industry elected to use MTBE, but ethanol was used to blend with a portion of the wintertime oxygenated and reformulated gasoline markets. By the end of the 1990s, ethanol demand in the United States had increased to 1.4 billion gallons per year.

The phase-out of MTBE (due to ground water contamination concerns) and passage of the RFS are the most recent events that resulted in a further expansion of ethanol use as a transportation fuel. The transition to ethanol and away from MTBE began in California following Governor Gray Davis' decision to eliminate its use due to concerns of potential widespread contamination of drinking water sources.[194] The practice of reducing use of MTBE spread to other areas of the country and by January 2005 the transition away from MTBE was completed, leaving ethanol as the only viable oxygenate. Figure 5-2 shows consumption of ethanol in California since 1981.

Figure 5-2: California Fuel Ethanol Consumption (1981 to 2010)



Sources: United States Federal Highway Administration (U.S. FHA), BOE) and California Energy Commission analysis

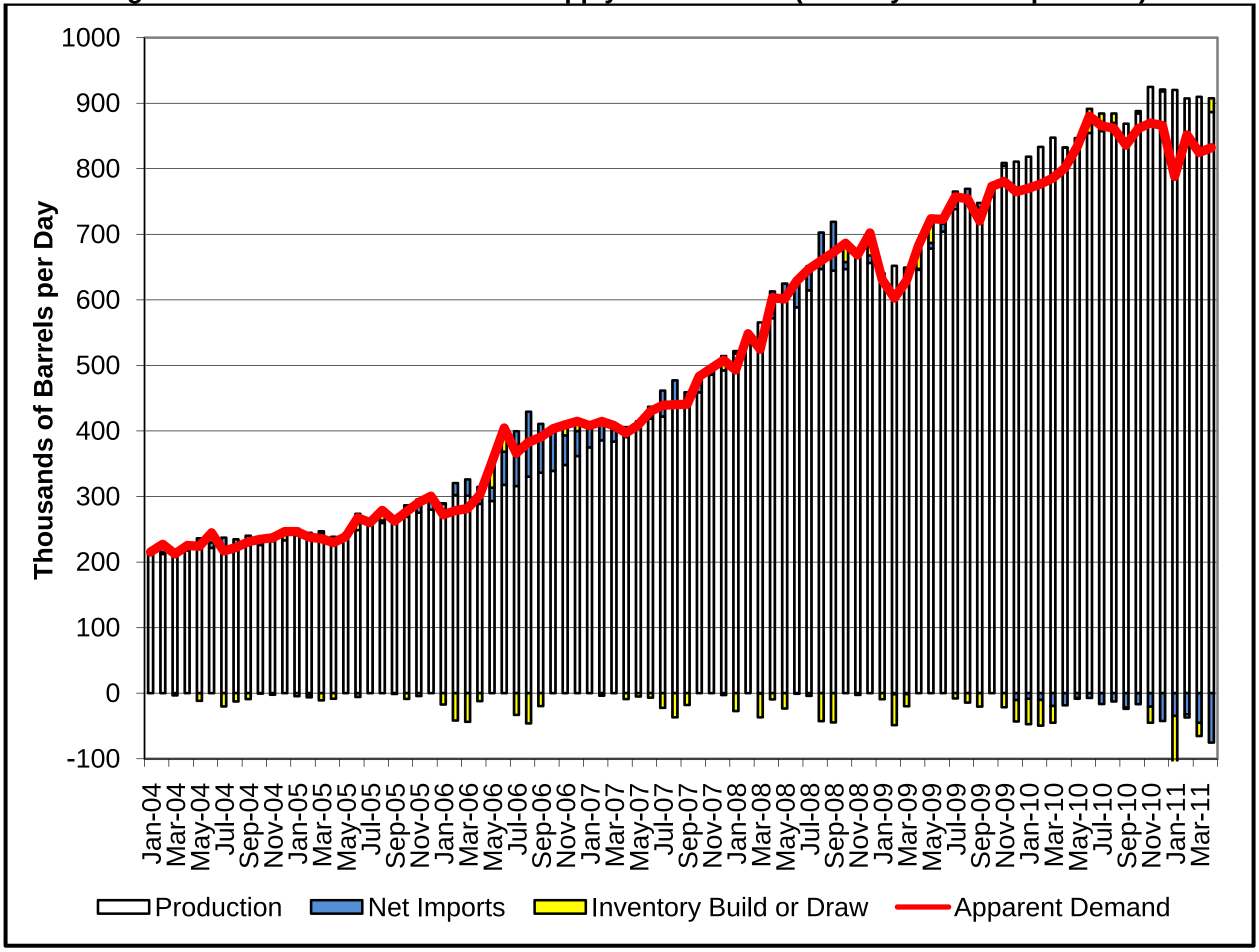
Congress took additional steps to expand ethanol's use by initially mandating minimum levels of blending through the RFS provisions of the Energy Policy Act of 2005, followed by an increase of these mandated levels through specific provisions of EISA. These federal mandates in conjunction with the state's LCFS are expected to compel increased quantities of ethanol and biodiesel use in California over the next several years, including a longer-term move to renewable hydrocarbons that will begin to displace a portion of the gasoline and diesel fuel used for transportation.

Ethanol Supply Outlook

U.S. Ethanol Supply Outlook and Issues

Increasing demand for ethanol as a transportation fuel has been met by expansion of domestic production capacity, fluctuating quantities of imported ethanol, and inventory build or draws as necessary to balance out demand. Figure 5-3 shows supply and demand for U.S. ethanol between January 2004 and April 2011. Ethanol demand set a record in June 2010 of 880 TBD.[195] The demand for ethanol is expected to continue growing over the forecast period due to mandated blending quantities stipulated by the federal RFS2.

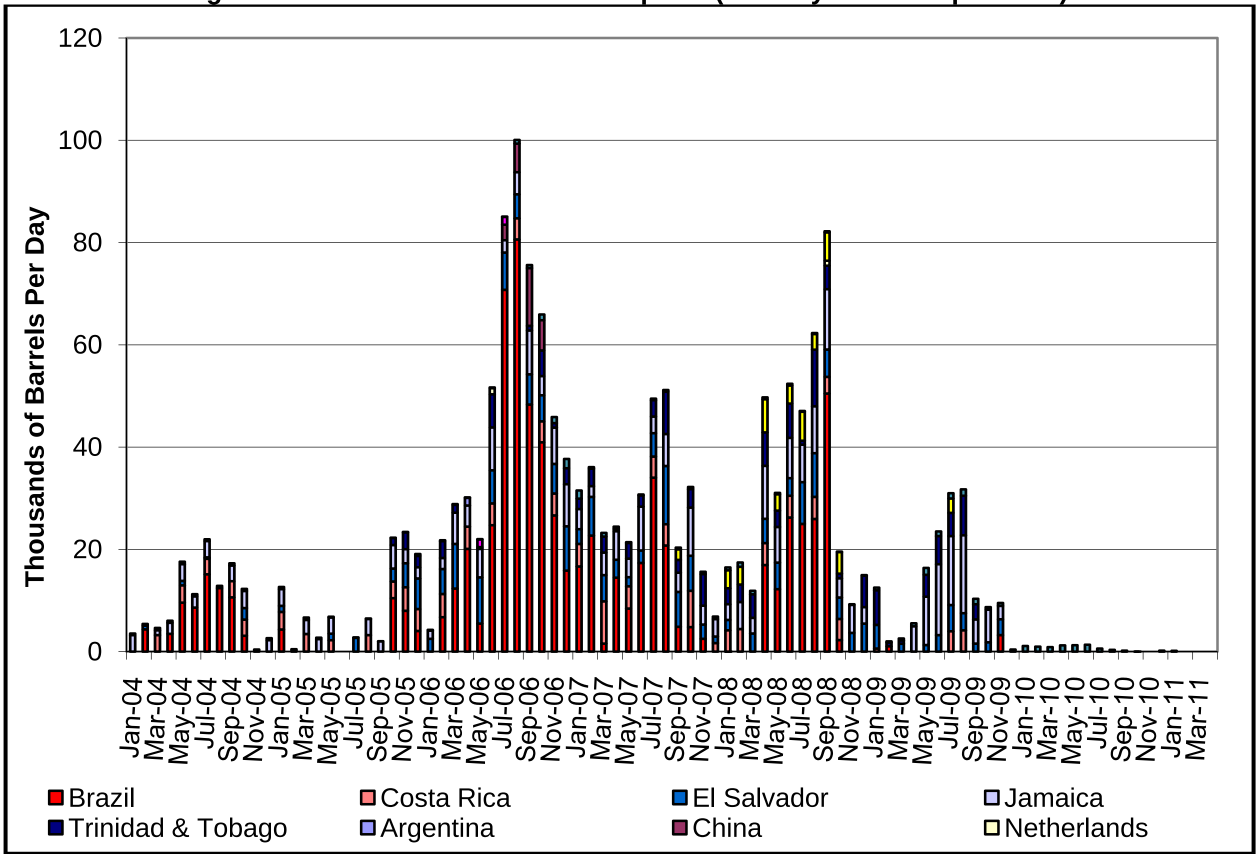
Figure 5-3: United States Ethanol Supply and Demand (January 2004 to April 2011)



Sources: EIA and California Energy Commission analysis.

As the chart indicates, net imports of ethanol have been negative over the last year as the United States has become a large exporter due to excess domestic supply and low prices relative to export destinations. However, the United States is not expected to remain a large net exporter of ethanol over the next several years. Foreign sources of ethanol (from Brazil and CBI countries) are expected to play a more pivotal role as demand for ethanol with lower carbon intensity grows in response to the California LCFS and the RFS Advanced Biofuels requirements. Figure 5-4 shows monthly United States imports of ethanol between January 2004 and April 2011.[196]

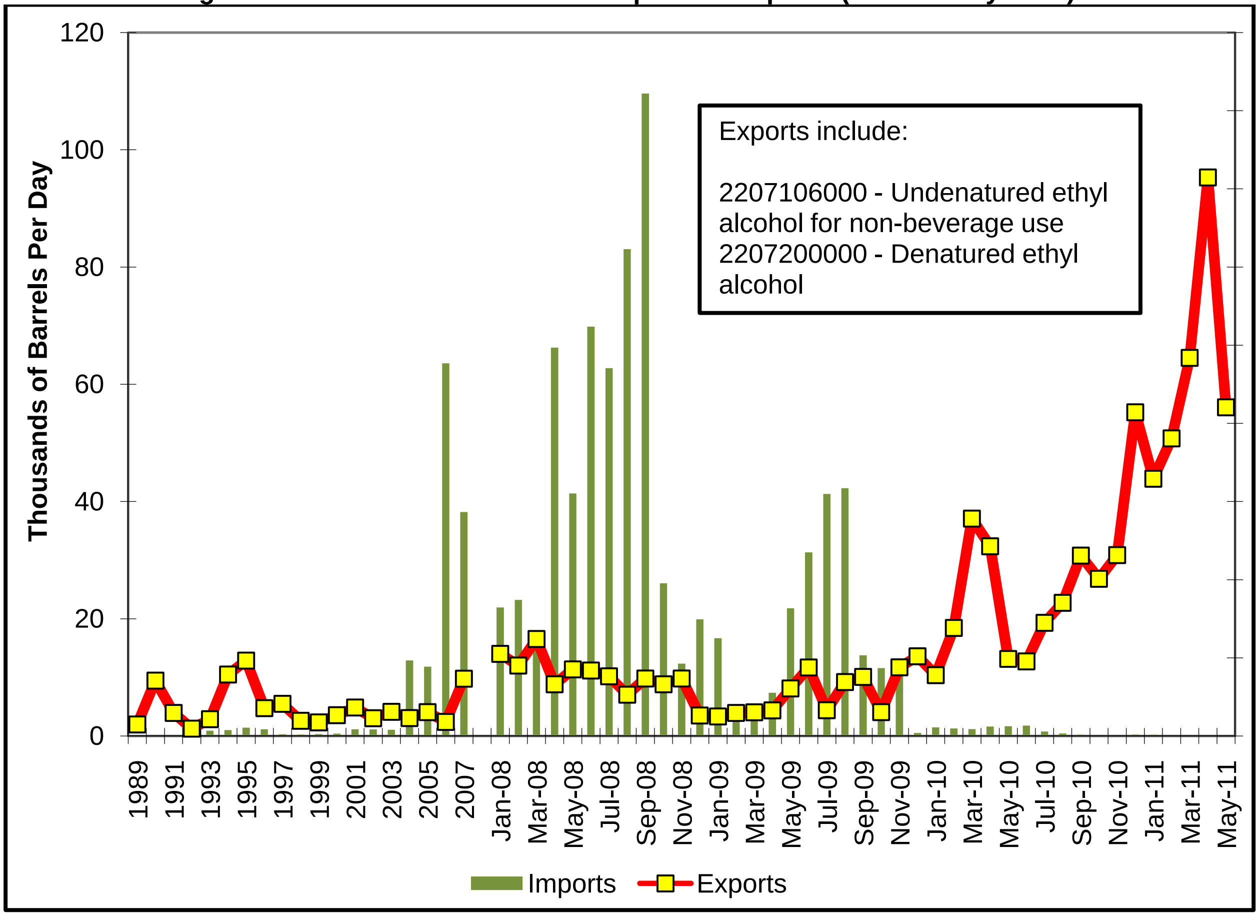
Figure 5-4: United States Ethanol Imports (January 2004 to April 2011)



Sources: EIA and California Energy Commission analysis

Ethanol imports peaked at 100 TBD during August 2006. The oversupply of domestic ethanol and relatively low prices in the United States have nearly eliminated ethanol imports and resulted in record averages of 25.9 TBD of ethanol exports by the United States during 2010 and an even higher export total during the first five months of 2011, averaging 62.1 TBD (see Figure 5-5).[197]

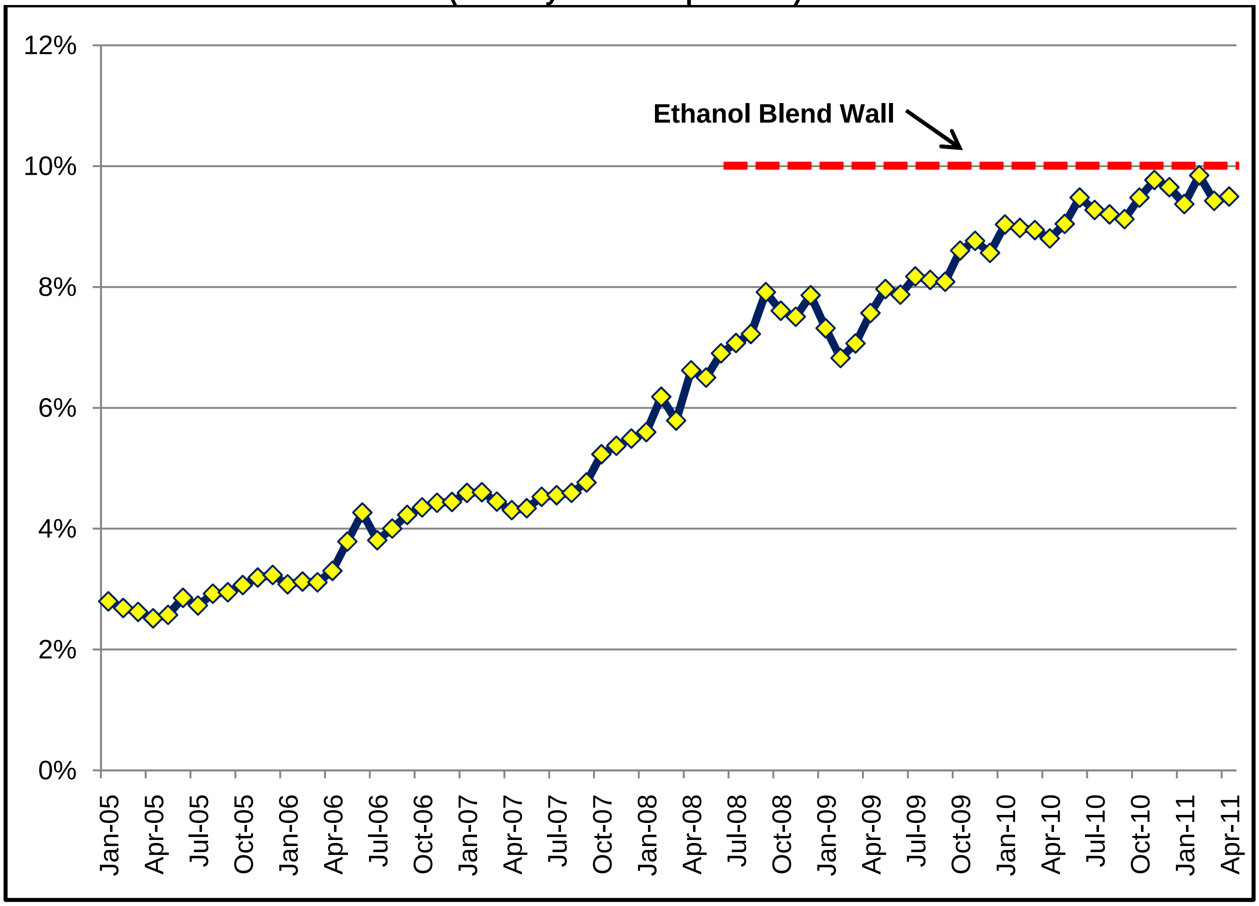
Figure 5-5: United States Ethanol Imports & Exports (1989 to May 2011)



Sources: EIA, USDA Global Agricultural Trade System (GATS), and California Energy Commission analysis

Increasing production of ethanol in response to federal biofuel use mandates over the last several years has resulted in a growing percentage of this renewable fuel displacing gasoline. When measured as a concentration in finished motor gasoline, ethanol use has steadily grown from approximately 3 percent by volume during 2005 to 9.5 percent by volume by April 2011, with a peak of 9.85 percent during February 2011 (see Figure 5-6). The average concentration of ethanol in finished gasoline appears to have reached a plateau of less than 10 percent. This is understandable since most states have regulations that place a cap on the amount of ethanol in gasoline or the quantity of oxygen derived from the ethanol. This upper limit is referred to as the ethanol "blend wall" and is discussed in greater detail later in the "E15 Waiver" section of the report. Regardless of the extent of success as a result of the federal E15 waiver, ethanol use is expected to continue rising as obligated parties strive to comply with the RFS2 increasing renewable fuel mandates. Greater use of ethanol in gasoline can and is being achieved through increased sales of E85.

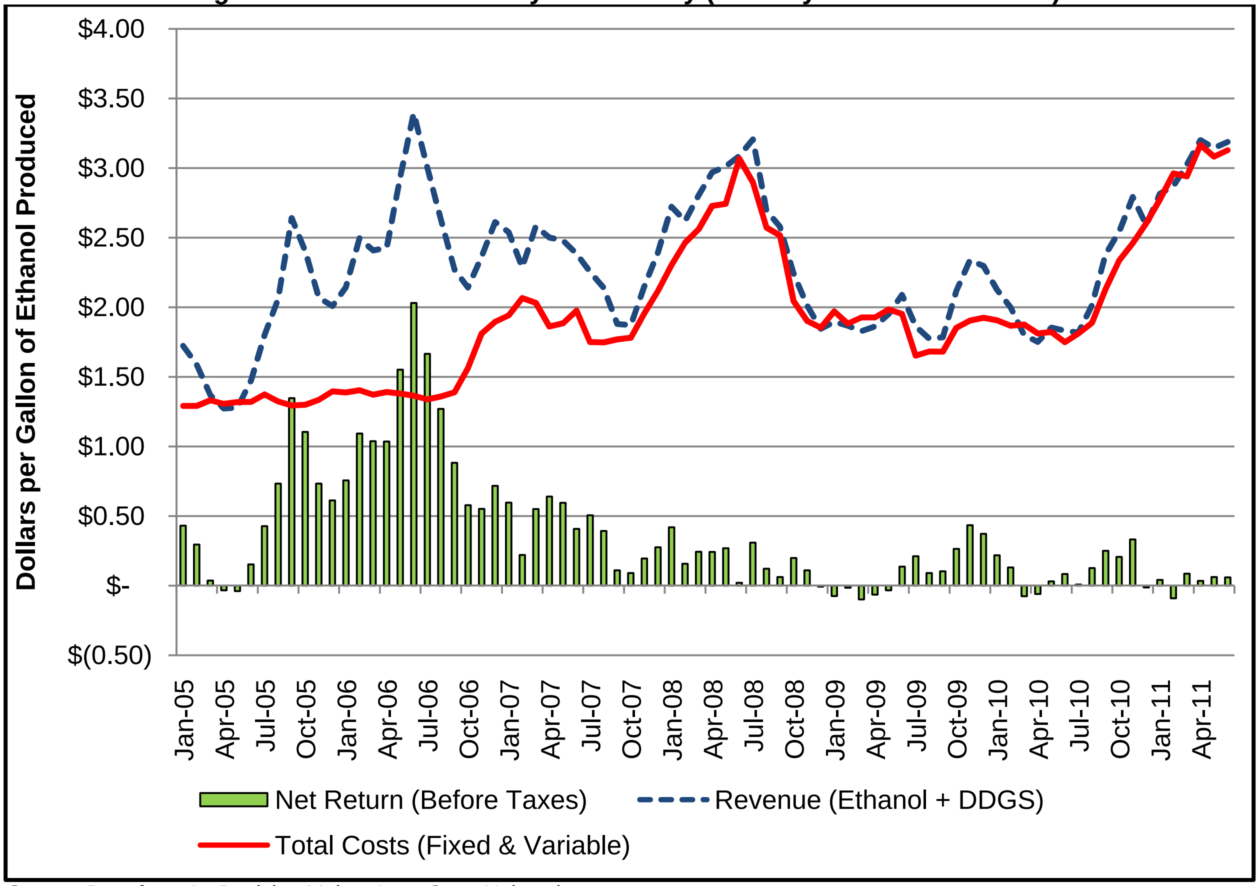
Figure 5-6: United States Ethanol Concentration in Finished Gasoline (January 2005 to April 2011)



Sources: California Energy Commission analysis of EIA data

The domestic ethanol industry has been under economic pressure over the last couple of years due to excess supply capacity and feedstock costs increasing at a greater pace than revenue streams from fuel ethanol and by-products such as distillers grains with solubles (DGS). Figure 5-7 tracks an aggregate measure of ethanol plant gross margins by using data generated by an economic model developed by Ag Decision Maker of Iowa State University that is intended to capture all of the revenue and costs associated with a typical ethanol plant.[198]

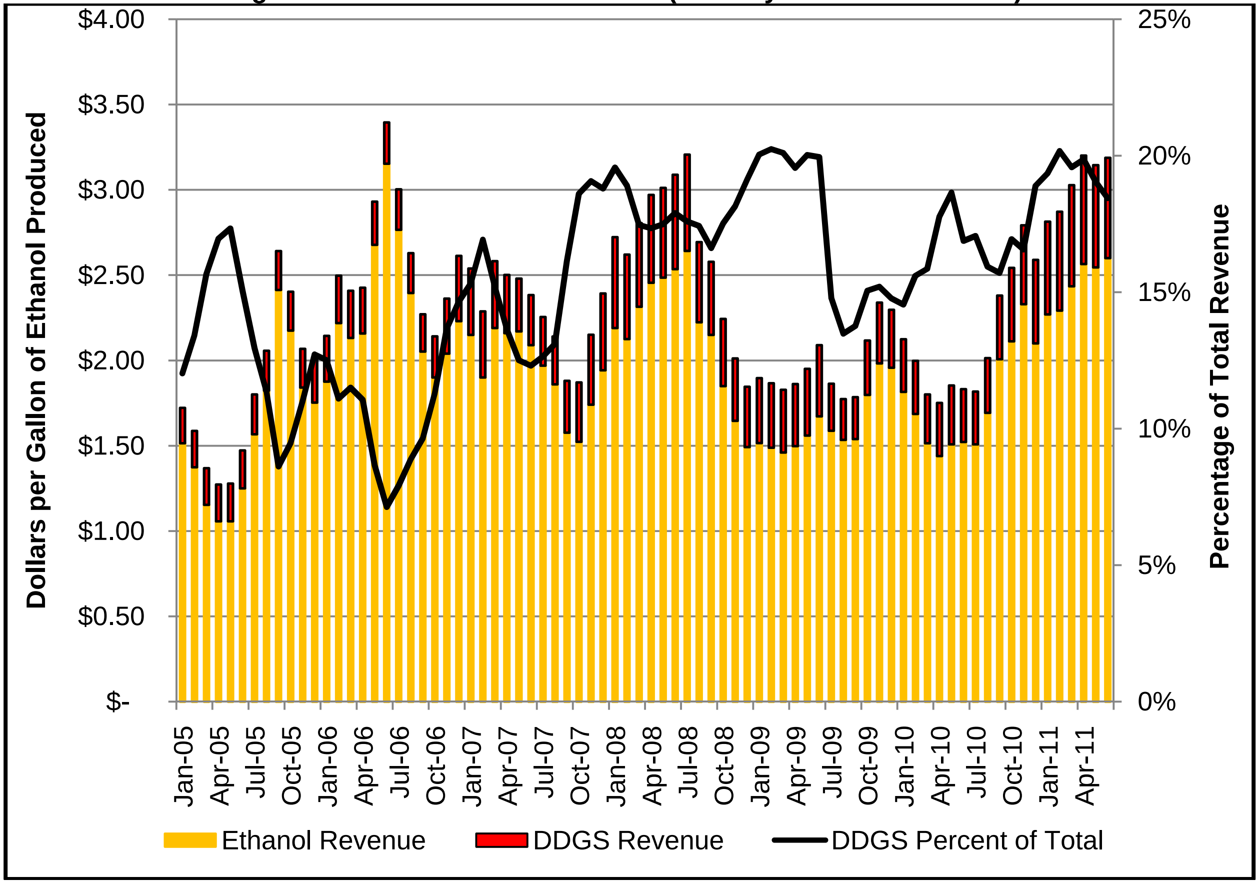
Figure 5-7: Ethanol Industry Profitability (January 2005 to June 2011)



Source: Data from Ag Decision Maker, Iowa State University.

The chart illustrates that profitability of ethanol plants has declined significantly since 2006, primarily as consequence of rising corn costs. Ethanol plants obtain revenue from the sale of fuel ethanol and to a lesser extent, co-products of ethanol production. The primary co-product is distiller's grains solubles that can be dried to remove most of the water (referred to as dry distillers grains with solubles [DDGS]) so that the product can be transported and stored for long periods. Most of the DDGS is sold as feed to the cattle industry.[199] It should be noted that the DGS produced by California ethanol facilities is not dried (referred to as wet DGS [WDGS]) since feedlot customers are close to the ethanol plants, reducing the need for longer-term transportation and storage. Wet DGS uses less energy to produce (less natural gas for drying), yielding a lower carbon footprint when compared to ethanol dry mills in the Midwest. The importance of these ethanol plant co-products is highlighted in Figure 5-8 that shows the growing share of DDGS revenue over the last couple of years, a development that has allowed ethanol plants to remain profitable during periods of record-high corn prices. During the first 6 months of 2011, estimated DDGS revenue has averaged 19.4 percent of total estimated revenues for ethanol plants, while averaging only 16.7 percent for all of 2010.

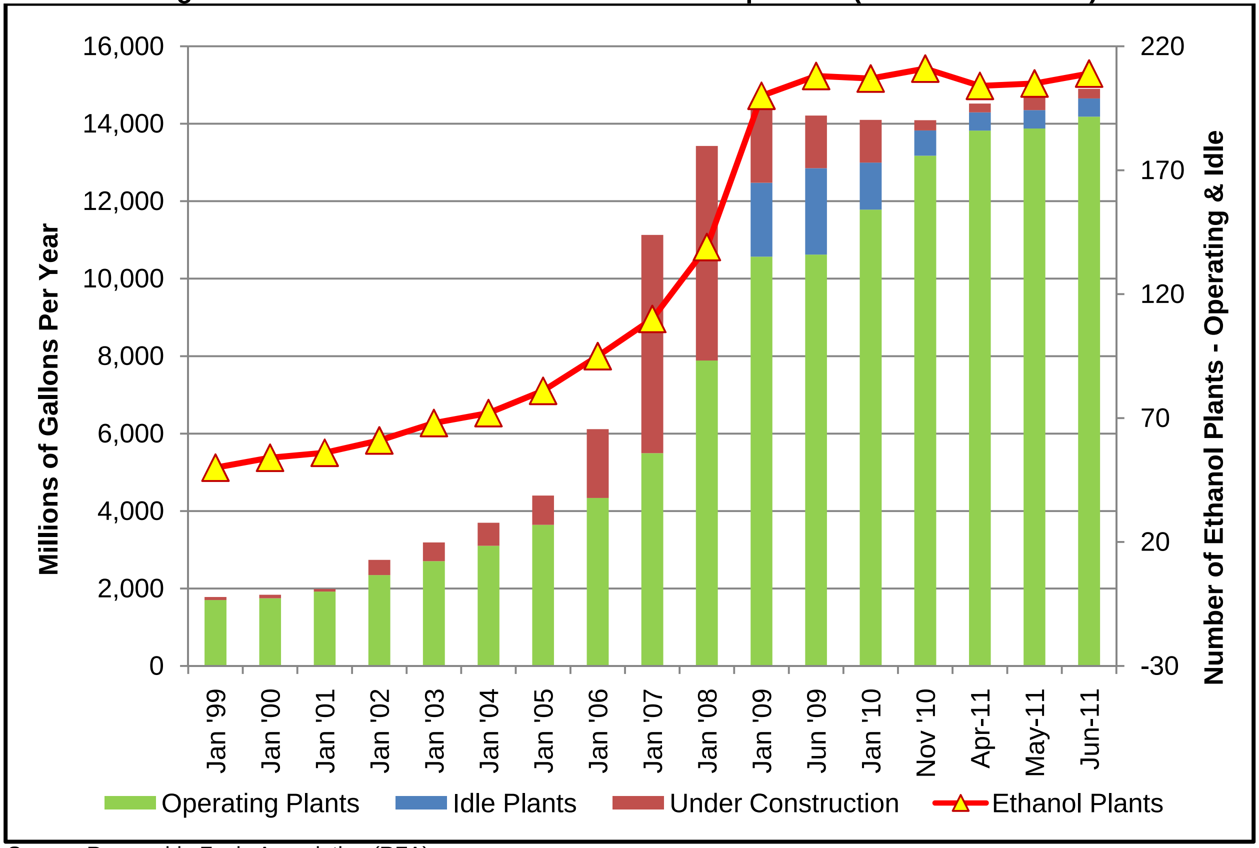
Figure 5-8: Ethanol Plant Revenue (January 2005 to June 2011)



Source: Data from Ag Decision Maker, Iowa State University.

This development is expected to be temporary as demand for ethanol is forecast to continue increasing over the next several years as consequence of the federal RFS regulation. In time, the oversupply of ethanol could be reduced, and the profitability of the industry will likely continue to improve. However, the extreme volatility of the corn market over the last couple of years does increase uncertainty of profitability and puts less competitive ethanol producers at a heightened risk of temporary closure or even bankruptcy filing. The ethanol market has experienced other periods of economic difficulties associated with changing cost structures, market price differentials between gasoline and ethanol, and evolving markets for various coproducts.[200] As of June 2011 there was an estimated 472 million gallons of idle ethanol production capacity in the United States, about 3.2 percent of total production capacity of 14.65 billion gallons.[201] Figure 5-9 shows the annual ethanol plant capacity for the United States broken down by operating, idle, and under construction, along with the number of ethanol facilities. The overwhelming majority of these facilities use corn as their sole or primary feedstock. The pace of construction and expansion of additional ethanol plants that use corn for a feedstock has slowed because the RFS2 regulations allow obligated parties to use a maximum 15.0 billion gallons of year by 2015 of that type of ethanol. Refiners and marketers can use even greater quantities of conventional ethanol but they would not earn additional RFS2 compliance credits.

Figure 5-9: U.S. Ethanol Plant Numbers and Capacities (1999 to June 2011)



Source: Renewable Fuels Association (RFA)

Despite the recent poor economics for operating domestic ethanol plants, production capacity of conventional ethanol is expected to be adequate over the next several years. Domestic ethanol production capacity is already sufficient to meet the starch-based biofuel RFS2 requirement of 12.6 billion gallons for 2011, 13.2 billion gallons for 2012, 13.8 billion gallons for 2013, and even the 14.4 billion gallons for 2014.

California Ethanol Supply Outlook and Issues

Currently, three of the five California corn-based ethanol facilities are operating with a collective production capacity of nearly 170 million gallons per year.[202] Two of the California facilities remain idle with a combined capacity of 71 million gallons per year.[203] The remaining two idle ethanol plants are temporarily closed due to poor economic operating conditions (costs are exceeding revenue streams).

The Pacific Ethanol facility in Madera may be able to resume operations sometime later in 2011. However, for this analysis, all California facilities that are currently idle are assumed to be fully operational at their rated nameplate capacity of nearly 71 million gallons per year beginning January 2013. Total combined California ethanol production capacity by that time will reach 241 million gallons per year. Future projects to develop ethanol production that would qualify for Advanced Biofuels and Cellulosic classification continue to be permitted and discussed. However, none of these proposed projects has yet to begin construction. The potential production capacity for advanced biofuels ethanol production in California is estimated by staff at approximately 502 million gallons per year. The majority of these facilities would use sugar cane as the primary feedstock. With regard to cellulosic ethanol production projects, there are nine facilities that have been discussed with a combined capacity of 168 million gallons per year. Although these incremental volumes of planned ethanol production are significant, there remains substantial uncertainty concerning the viability of these projects under current poor ethanol economic conditions. Over the near-to mid-term period, it is likely that some of these facilities will begin construction. Since the magnitude of incremental production and timing of new facility operations is highly uncertain, staff has elected to exclude these estimated production capacity volumes from in-state ethanol availability. Over time, some portion of this planned capacity is expected to come on-line, but probably only a lesser percentage of the total within the next five years

Brazil Ethanol Supply Outlook and Issues

Ethanol from Brazil is produced from sugarcane, rather than corn. Since sugarcane cannot be stored once harvested, ethanol production in Brazil occurs seasonally, necessitating storage of ethanol sufficient to last until the following harvest cycle.[204] Brazilian ethanol production is also tied closely with the production of sugar from the cane juice. This means that ethanol plants in Brazil can adjust the ratio of ethanol-to-sugar in reaction to local ethanol demand/prices, export ethanol market economics, and world sugar demand/prices. In contrast, most United States ethanol producers do not have the flexibility to alter ethanol production by switching to another product. Ethanol production in the United States is adjusted by altering the quantity of corn processed. Table 5-1 compares the differences in the ethanol industry between Brazil and the United States.

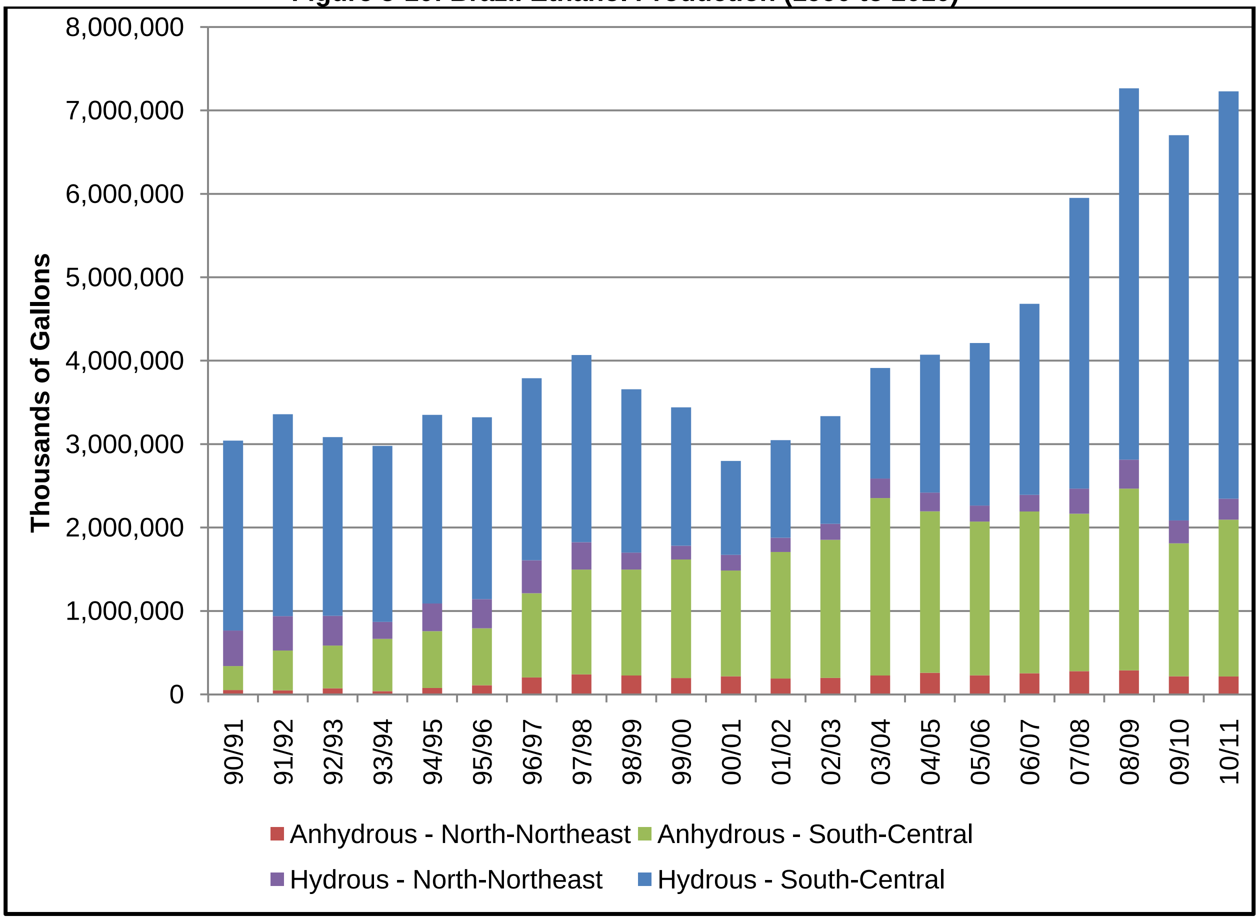
Table 5-1: Brazil and United States Ethanol Operations – 2010

2010 Comparison	Brazil	United States
Number of Ethanol Plants	162	209
Combined Number of Ethanol & Sugar Mill Facilities	251	
Total Ethanol Plants	413	209
Total Ethanol Production (Billions of Gallons)	7.2	13.2
Average Plant Production (Millions of Gallons/Year)	17.5	63.2
Ethanol Production Per Acre of Feedstock (Gallons)	655.5	424.9
Ethanol Plant Operation	Seasonal	Year-round
Long-Term Feedstock Storage	No	Yes

Sources: Various and California Energy Commission analysis.[205]

As is the case in the United States, Brazil ethanol production has continued to increase, rebounding from a down year to reach an output level of 7.23 billion gallons during 2010 (see Figure 5-10). Brazil produces two different types of ethanol, hydrous and anhydrous. Hydrous ethanol contains water in concentrations up to 5.6 percent by volume.[206] This type of ethanol is used in FFVs designed to operate on fuels containing ethanol between 24 and 100 percent by volume (E100). Hydrous ethanol is also exported to other countries (especially in the Caribbean) that further process the ethanol to remove most of the water (dehydration step) before sending to the United States, duty free under the CBI.[207] All ethanol produced in Brazil in the initial steps of processing contains water that must be removed to a level of less than 0.5 percent by volume if the ethanol is destined for low-level gasoline blends in Brazil or final export destinations. Once this dehydration step has been completed, the resulting product is referred to as anhydrous ethanol. This type of ethanol is suitable for blending with gasoline for use in low-level blends of up to 25 percent in Brazil and up to 10 percent by volume in the United States.[208]

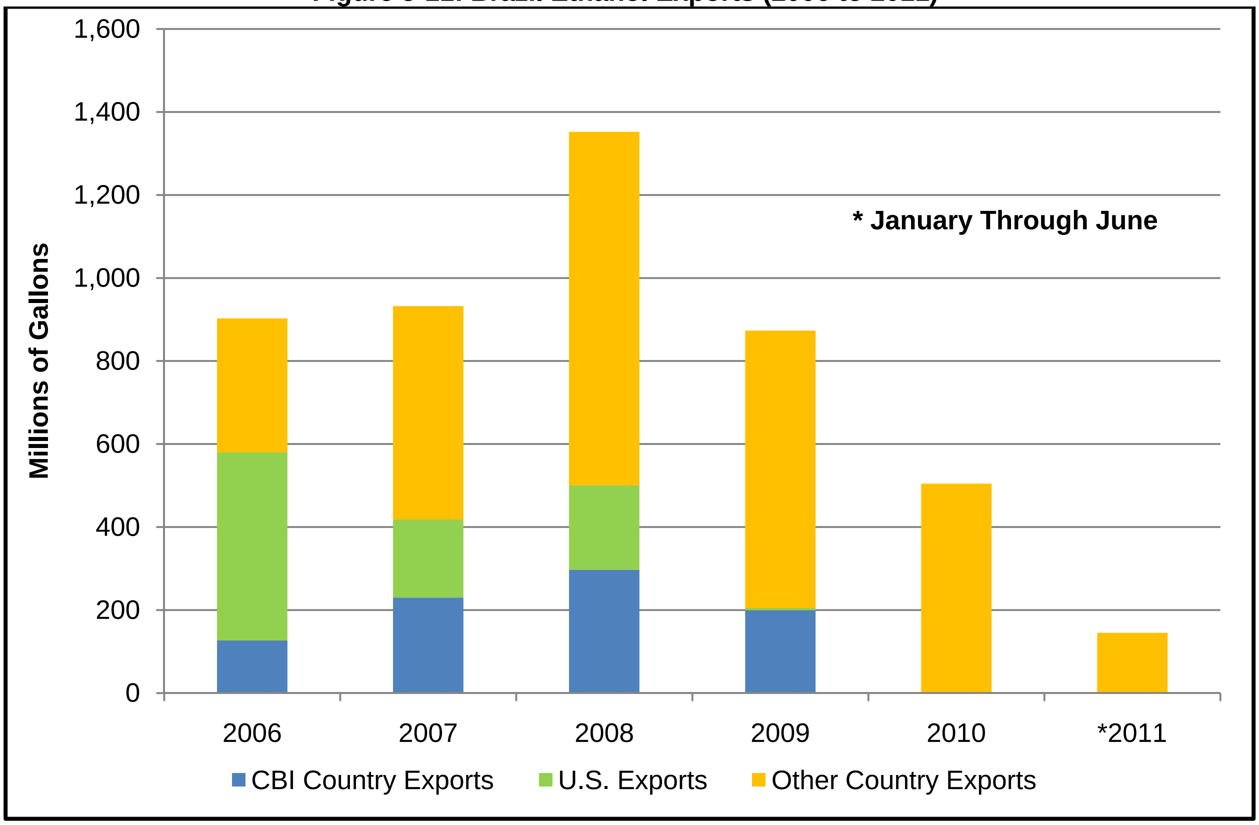
Figure 5-10: Brazil Ethanol Production (1990 to 2010)



Sources: UNICA, MAPA, USDA FAS, and California Energy Commission analysis

Production of ethanol in Brazil is determined by the interrelationship between various factors: minimum blending levels in gasoline as set by its Ministry of Agriculture; world sugar market demand, balances, and prices; outcome of sugarcane growing season; and the potential value of ethanol exports. Based on the interaction of these market components, there may or may not be ample excess supplies of ethanol available to export from Brazil in any given year. Over the last five years (2006 through 2010), Brazil has exported between 0.55 billion and 1.35 billion gallons of ethanol (see Figure 5-11).[209]

Figure 5-11: Brazil Ethanol Exports (2006 to 2011)

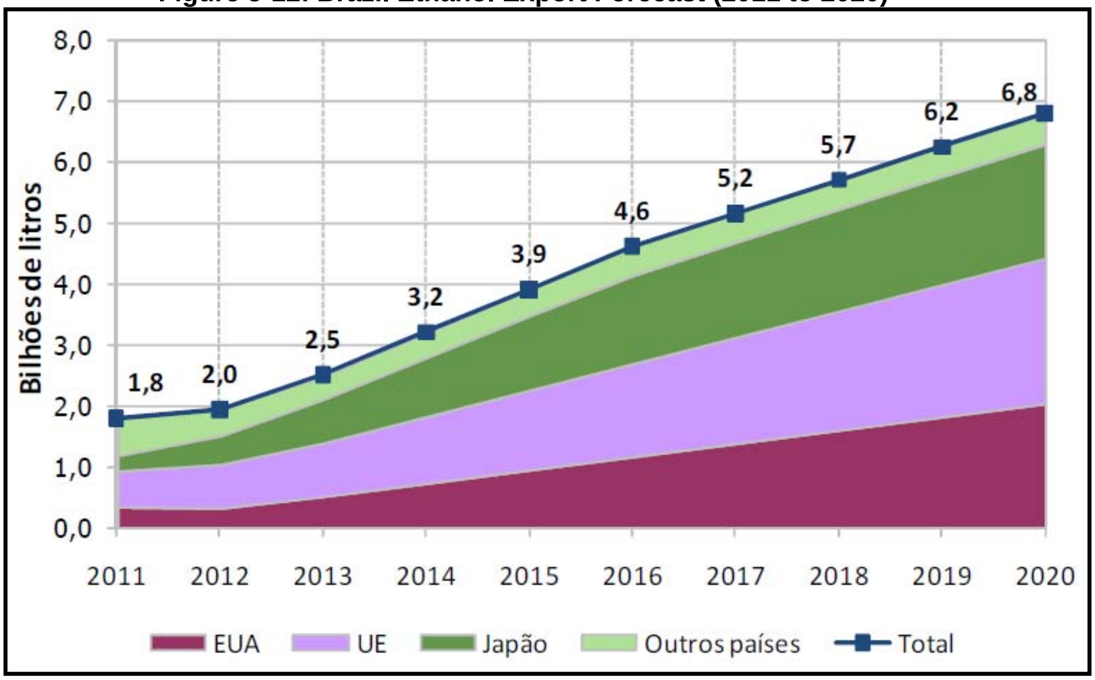


Sources: UNICA, Secex, and California Energy Commission analysis.

The significant drop in ethanol exports during 2010 and the first half of 2011 was a reflection of scarce ethanol supplies in Brazil accompanied by high prices that made export opportunities less attractive than previous years. Most Brazilian exports of ethanol in 2010 and 2011 were obligated volumes under longer-term contracts. This recent confluence of circumstances (high local prices, tight supply, and thin export market) is troubling in light of the demand for Brazilian ethanol that is foreseen to help meet the advanced biofuels minimum standards of the RFS2 and the lower carbon intensity fuel need of California's LCFS. For example, the non-biodiesel portion of the RFS2 advanced biofuels requirement for 2012 is approximately 1.0 billion gallons, followed by up to 1.75 billion gallons in 2013, a quantity of ethanol that Brazil has never achieved for total exports to all other countries, let alone exports to the United States.[210]

Even if Brazilian ethanol supplies were sufficient to allow significant volumes of exports, the price could be costly. Brazilian exporters of ethanol to the United States must pay two types of import duties, an ad valorem tax equivalent to 2.5 percent of the ethanol transaction price and a secondary import duty of 54 cents per gallon (refer to the Ethanol Tariff section of the Policies and Regulations chapter for more detailed information). Tight ethanol supplies in Brazil over the last 18 months, combined with the import tariffs, equate to a cost of delivering Brazilian ethanol to California that would have been an average of $1.04 per gallon more than the price of Midwest ethanol delivered to California during 2010 and an average of $1.47 more per gallon during the first 6 months of 2011.[211]This form of protectionism increases the cost of supplying ethanol to the U.S. market and is a type of trade challenge not applied to other types of transportation fuel-related foreign imports such as crude oil, gasoline, jet fuel, and diesel fuel. The amount of excess ethanol that may be available to import from Brazil over the next several years is forecasted to grow to between 480 million and 1.8 billion gallons by 2020, a substantial reduction from the export forecast from two years earlier.[212] Figure 5-12 illustrates estimates from the Empresa de Pesquisa Energética or Energy Planning Agency of the Ministry of Mines and Energy of Brazil (EPE). The units of the chart are billions of liters, while "EUA" is the designation for the United States, "UE" for the European Union, "Japão" for Japan, and "Outros países" for Other Countries.

Figure 5-12: Brazil Ethanol Export Forecast (2011 to 2020)

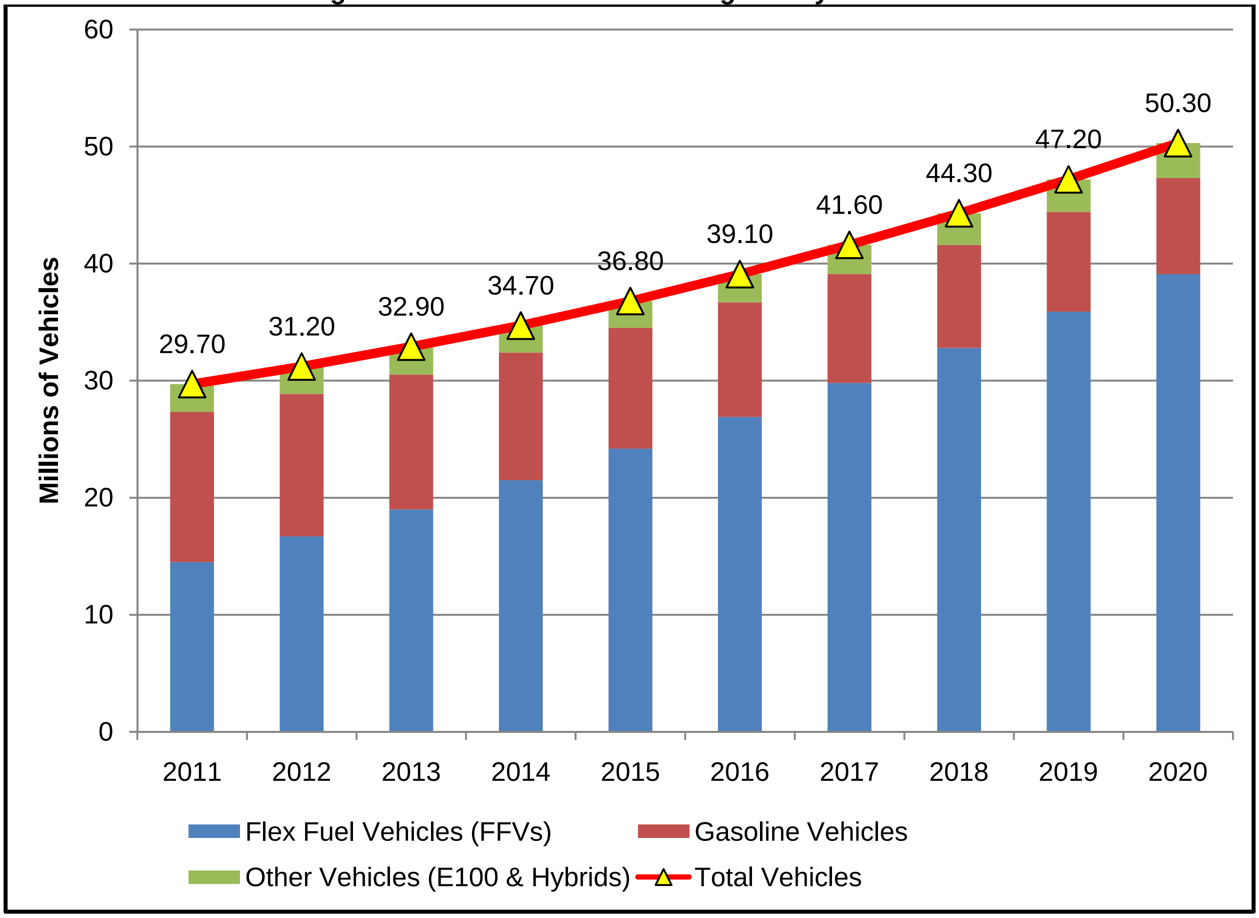


Source: EPE

Future availability of ethanol for export from Brazil will also depend on the permissible range of ethanol that can be blended with gasoline. As stated earlier in this section, the maximum concentration of ethanol in gasoline is currently 26 percent by volume. Due to the tight ethanol market in Brazil over the last 18 months and the resulting high local ethanol prices and need to import additional ethanol supplies from outside the country, Brazilian officials have taken steps to reduce the lower limit of ethanol from 20 percent down to 18 percent.[213] This change, if promulgated into Brazilian law, is estimated to reduce anhydrous ethanol demand by 250 million liters (66 million gallons) for every percentage point reduction in the limit. If the assumed ethanol blend level is at the upper limit of 25 percent and a reduction down to 18 percent is actually carried out, the additional ethanol that would be made available could range between a low of 500 million and a high of 1.75 billion liters (130 million to 460 million gallons).

Brazil's ethanol demand is forecast to rise 10.8 percent per year between 2010 and 2020.[214] This strong growth is in large part due to the tremendous growth of FFVs in Brazil as depicted in Figure 5-13.[215]

Figure 5-13: Forecast of Brazil Light-Duty Vehicles

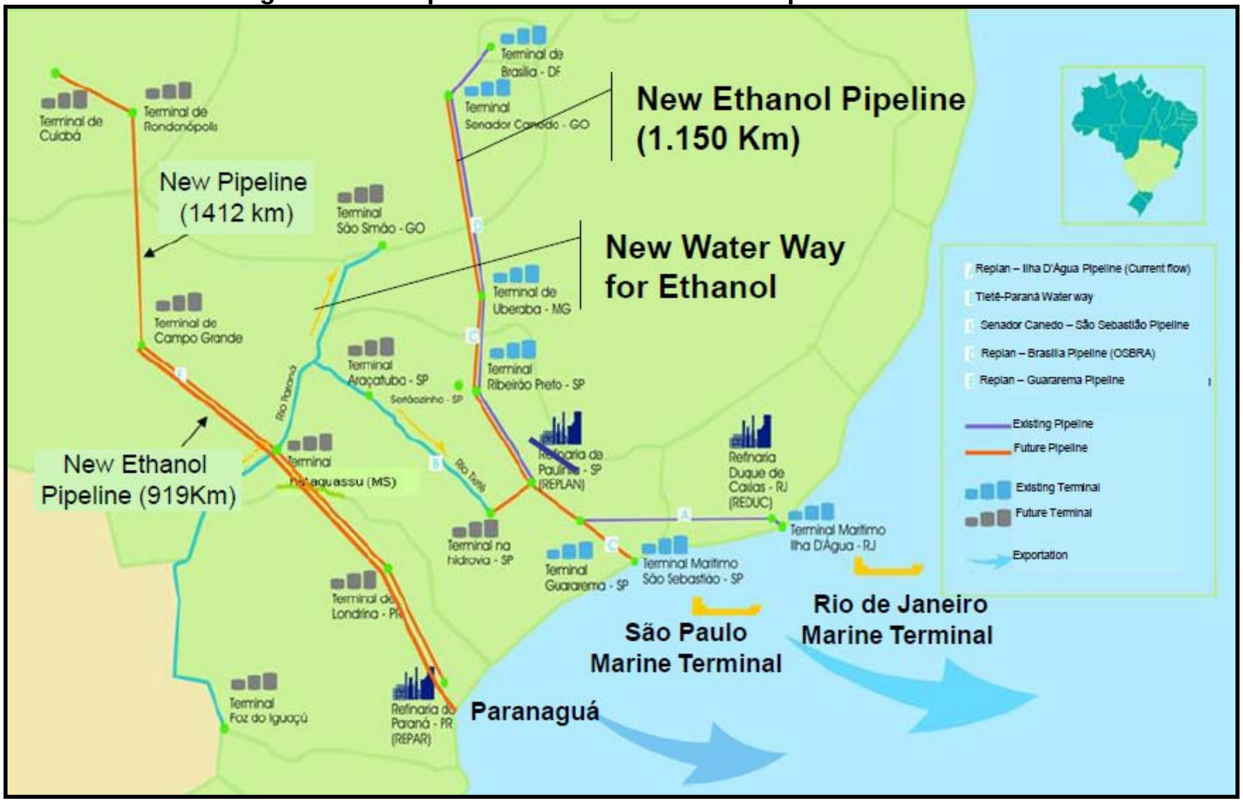


Source: EPE.

Brazil's ability to supply significant quantities of ethanol to the United States and California from excess production output over the next couple of years is highly uncertain. However, it should be possible for Brazil to examine the possibility of developing a system of ethanol exchange whereby Brazil ships sugarcane-based ethanol to the United States and takes back Midwestern corn-based ethanol in the same marine vessel.[216] This type of contingency plan, referred to as the Sao Paulo-Houston shuffle, would help ensure adequate supplies of ethanol that meet the RFS2 advanced biofuel standards and the LCFS low carbon requirements.

Brazil continues to develop an infrastructure that is designed to increase the quantity of ethanol that can be exported to destinations such as the United States. In fact, Brazil is the only country that transports ethanol over significant distances via pipelines that are also used to ship petroleum products. Figure 5-14 shows the existing and expanded infrastructure associated with an expansion of ethanol exports.[217]

Figure 5-14: Expansion of Brazil Ethanol Export Infrastructure



Source: Petrobras presentation.

California Ethanol Logistics Outlook and Issues

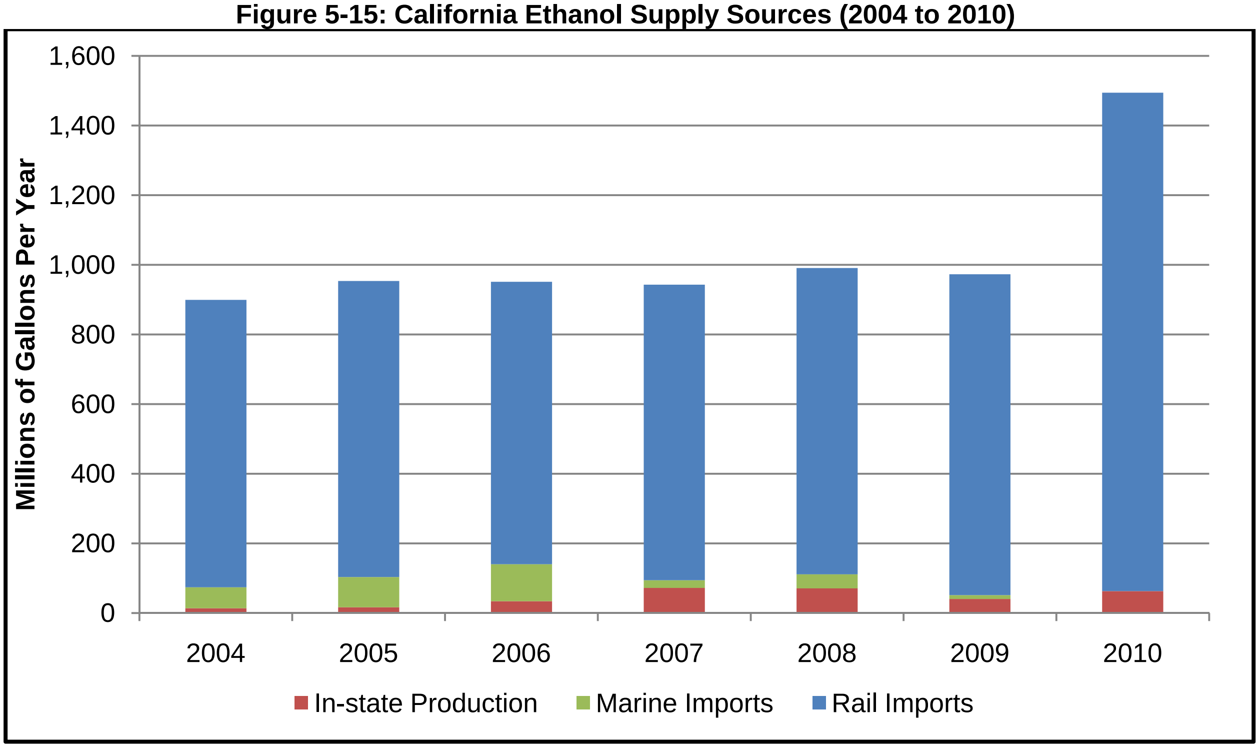
It is clear that the quantity of ethanol used in California transportation fuels will continue to increase over the next couple of years as refiners and other marketers react to higher levels for ethanol that will be mandated by the RFS2 requirements. In addition, the California LCFS is expected to further complicate matters by pushing obligated parties to select types of ethanol that have lower carbon intensities. At this time, ethanol produced from sugarcane in Brazil is the type of commercially available ethanol that has the lowest carbon intensity. As such, it is anticipated that California's logistical infrastructure for the importation and distribution of ethanol will need to continue to be modified to enable a greater quantity and flexibility of ethanol imports within the next 6 to 18 months.

Ethanol Rail Logistics

Currently, most of the ethanol used in California is imported from corn-based ethanol plants in the Midwest. The majority of these imports are via unit trains that consist of between 90 and 112 rail cars. This method of rail delivery is efficient in terms of transit time and costs as the unit trains usually receive priority use of the tracks and can transverse the distance from source to destination without stopping. There are two facilities in Southern California that are capable of receiving unit trains of ethanol. The first facility is in Carson and is referred to as the Lomita Rail Off-loading Terminal.[218] The facility has demonstrated a throughput of 22,300 barrels per day in the recent past or roughly an ethanol receipt capability of approximately 342 million gallons per year. [219] The second facility, referred to as the West Colton Rail Terminal, is operated by U.S. Development Group (USDG). The operation has an ethanol receipt capacity of 15,000 barrels per day or nearly 230 million gallons per year.[220] Staff estimates that these two facilities could handle up to 100 percent of Southern California's rail receipts of ethanol.[221] Northern California also has a comparable type of rail receipt facility like Carson where unit trains can be received and the ethanol transloaded directly to tanker trucks.[222] The facility is located in Richmond and has been operational since March 2010.[223]

California can also receive ethanol via a combination of manifest rail cars and ocean-going marine vessels with the balance of ethanol supplies obtained from California ethanol facilities. Figure 5-15 breaks down the sources of ethanol for California over the last seven years.[224] During this period, rail imports have accounted for an average of 90.8 percent of California ethanol supply, followed by marine imports (4.9 percent) and in-state production (4.3 percent). During 2010, rail imports represented 95.8 percent, followed by higher in-state production (4.2 percent). There were no marine imports of ethanol during 2010 due to unfavorable economics in foreign source countries.

Figure 5-15: California Ethanol Supply Sources (2004 to 2010)



Sources: EIA, BOE and California Energy Commission analysis

Ethanol Distribution Terminal Logistics

Kinder Morgan began accepting only base gasoline that will be used to blend E10 at all of their California distribution terminals on January 11, 2010.[225] The majority of gasoline distributed throughout California moves through some portion of the Kinder Morgan pipeline systems and refiners want to ensure that the type of gasoline they produce is compatible (to allow for volume exchanges and increased flexibility during unplanned refinery outages). That need, in conjunction with growing RFS2 renewable fuel requirements, is why California's gasoline market switched to E10 during the first quarter of 2010.

Kinder Morgan completed its project to enable the receipt of ethanol unit trains into the Richmond area.[226] Unlike the unit train facility in Southern California, this facility is designed to transfer the ethanol directly from the rail cars to the tanker trucks via a process called transloading.[227] Completion and operation of this project helped ensure that Northern California had sufficient capacity to receive ethanol via rail cars to accommodate the increase to E10 blending during the first quarter of 2010. However, as discussed earlier, the LCFS is expected to drive refiners and other obligated parties to seek out types of ethanol with lower carbon intensities, such as sugar cane ethanol from Brazil and dehydrated hydrous ethanol processed in CBI countries. This anticipated import requirement could be necessary as early as the beginning of 2012.

Ethanol Marine Logistics

Marine imports of ethanol to California have been limited over the last several years due primarily to an abundance of ethanol production capacity in the United States and the import tariff for most sources of foreign ethanol. Consequently, the capacity to receive significant quantities of ethanol via marine vessel has not been needed. However, that situation could be altered due to the changing mix of ethanol sources and the potential impact on marine import infrastructure requirements. At this time, it is uncertain how much incremental ethanol could be imported into California via marine vessel. Over the short term, operators of marine import facilities could commit additional storage tanks for receiving ethanol imports. The conversion of storage tanks from one type of service (gasoline, diesel, or jet fuel) to ethanol service does not pose a technical difficulty. These types of decisions would reduce the ability of individual marine facility operators to import other petroleum products, unless overall import capacity was to increase.

If California is to transition to greater use of Brazilian ethanol, there are two pathways for this foreign ethanol to enter California: marine vessels directly from Brazil and rail shipments from another marine terminal outside California. Along these lines, Primafuel has received permits to construct a new marine terminal in Sacramento that is designed to import up to 400 million gallons of ethanol per year.[228] However, two years have passed and construction has not been initiated. Reticence on the part of potential customers appears to be the primary hurdle at this time. The proposed Sacramento renewable fuels hub terminal would greatly increase the marine ethanol import capability of Northern California such that there should be sufficient capacity to receive Brazilian ethanol over the near to mid-term period. Additional imports of Brazilian ethanol into California could also be accomplished via unit trains originating in another port city outside California. For example, ethanol from Brazil could be imported through the Houston ship channel and transferred to rail cars before delivery to California. Kinder Morgan is pursuing just such an endeavor that is referred to as the Deer Park Rail Terminal project.[229] Phase 2 of this project is conditional on customer demand, but could be operational within 6 to 12 months of developing long-term agreements with refiners and other marketers. Development of this type of capability would increase the likelihood that sufficient capacity could be in place to import significant quantities of Brazilian ethanol.

Ethanol Trucking Logistics

Although California receives the majority of ethanol via rail cars from outside the state, only a few gasoline distribution facilities have the capability to handle rail cars full of ethanol. Instead, the overwhelming majority of California's distribution terminals that dispense gasoline receive all of the ethanol needed for blending via tanker truck deliveries that originate at the primary ethanol rail receipt hub terminals. As California moved to E10 during 2010, the trucking industry and terminals operators responded to the increased throughput of ethanol at California's distribution terminals without any temporary logistical difficulties. Over the next several years, ethanol demand will continue to grow, but at a more gradual pace than was experienced during the transition to E10. As such, the trucking logistics to handle future growth in ethanol demand are not expected to pose a challenge.

Ethanol Pipeline Logistics

The last portion of the ethanol logistics distribution infrastructure involves the pipelines used to transfer transportation fuels from refineries to distribution terminals. Currently, no ethanol is shipped through any petroleum product pipelines that are also used to transport gasoline, diesel, or jet fuel. Kinder Morgan has demonstrated that ethanol can be successfully shipped in batches through their pipeline segment in Florida.[230] However, this practice is unlikely to be extended to California over the near to mid-term due to the increased age and complexity of the existing California pipeline system, as well as a higher probability of water in the pipeline system due to changes in the pipeline elevation (hydraulic profile).[231] If over a longer period ethanol shipments do become an operational reality in California, the primary impact on ethanol logistical operations would be the reduction in truck trips from ethanol receipt hubs to all of the distribution terminals. However, the shipment of ethanol through California pipeline segments would also displace shipment capacity for other transportation fuels in those portions of the pipeline infrastructure at or near pumping capacity. In time, Kinder Morgan and other pipeline companies could make modifications to their pipeline distribution systems to increase pumping capacities if ethanol pipeline shipments were to occur in California.

This discussion would not be complete without mentioning a recent proposal to construct a pipeline dedicated solely to ethanol shipments. A pipeline company (Magellan Midstream Partners, LLP) and an ethanol company (POET) have signed a joint development agreement to "continue assessing the feasibility of constructing a dedicated ethanol pipeline". The project is designed to gather ethanol from ethanol facilities located in the Midwest and transport the renewable fuel as far as 1,700 miles to the Northeast United States.[232] The U.S. DOE conducted a feasibility study for hypothetical dedicated ethanol pipeline from the Midwest to the East Coast markets.[233] One of the major findings from the study was that:

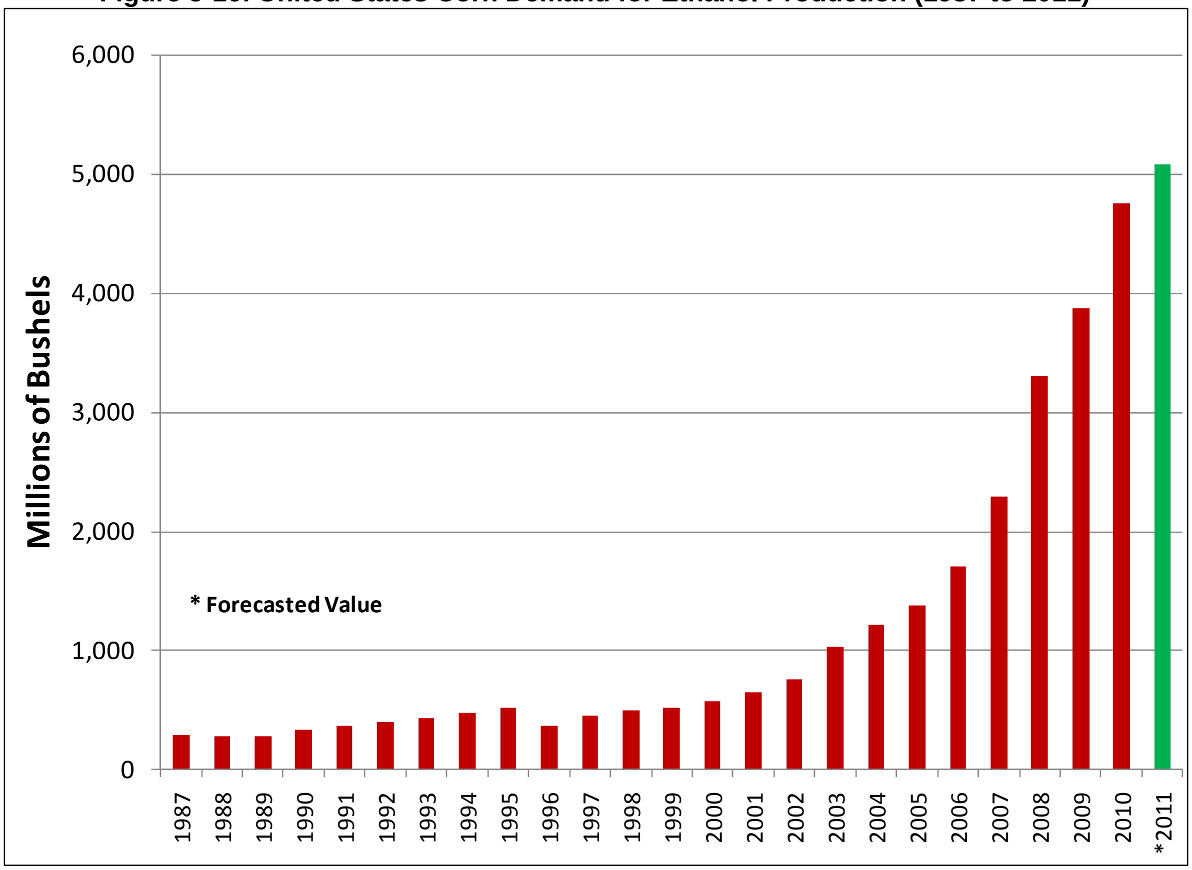
Based on the assumed ethanol demand volume (2.8 bgy) and a project construction cost of $4.25 billion, the pipeline would need to charge an average tariff of 28 cents per gallon, substantially more than the *current average rate for ethanol transport across current modes (rail, barge, and truck) along the same corridor (19 cents per gallon).*[234]

A similar concept for a dedicated pipeline in California would also likely be economically unattractive since California does not have a large concentration of ethanol plants that normally sell their ethanol to markets that are over 1,000 miles distant.

Renewable Fuels and Agriculture

The majority of fuel ethanol in the United States is produced in facilities that use corn as the primary feedstock. As the demand for mandated use of ethanol continues to grow, so too does the demand for corn as a feedstock. Figure 5-16 illustrates the quantity of corn that was used annually to produce ethanol since 1987. Corn use to produce ethanol is forecast to set a record of 5.075 billion bushels for 2011.

Figure 5-16: United States Corn Demand for Ethanol Production (1987 to 2011)



Source: USDA - National Agricultural Statistics Service

During the earlier years of ethanol, corn demand for producing ethanol was a small percentage of total use. However, the portion of corn required to produce ethanol has been increasing at an accelerated pace and accounted for approximately 35.7 percent of total use in 2010 and a forecasted 38.0 percent for 2011[235] Figure 5-16 shows the increasing use over the last 24 years.

Other Potential Agriculture Issues

Various concerns regarding increased water use and higher fertilizer application rates associated with corn have been voiced by some stakeholders. Based on the most recent agriculture census by the USDA (updated in September 2009), the majority of corn is grown without the use of any irrigated water, solely dependent on rainfall during the growing season. In 2007, only 15.3 percent of corn acres were irrigated with the balance (84.7 percent) receiving no irrigated water.[236] It is not known if expanded production of corn will occur as a result of an even higher ratio of irrigated acres over the forecast period. Assuming the ratio remains fairly constant, increasing corn production due to higher mandated ethanol demand should primarily occur through expansion of dry cropping, rather than through increased irrigation. With regard to fertilizer use, staff examined USDA statistics and noted that the application rate per acre of corn for nitrogen has increased 7.7 percent between 1980 and 2010, while the average corn yield has increased 67.9 percent over the same period.[237] The continued improvement of corn yields is primarily a consequence of other improvements unrelated to increased use of nitrogen per acre.

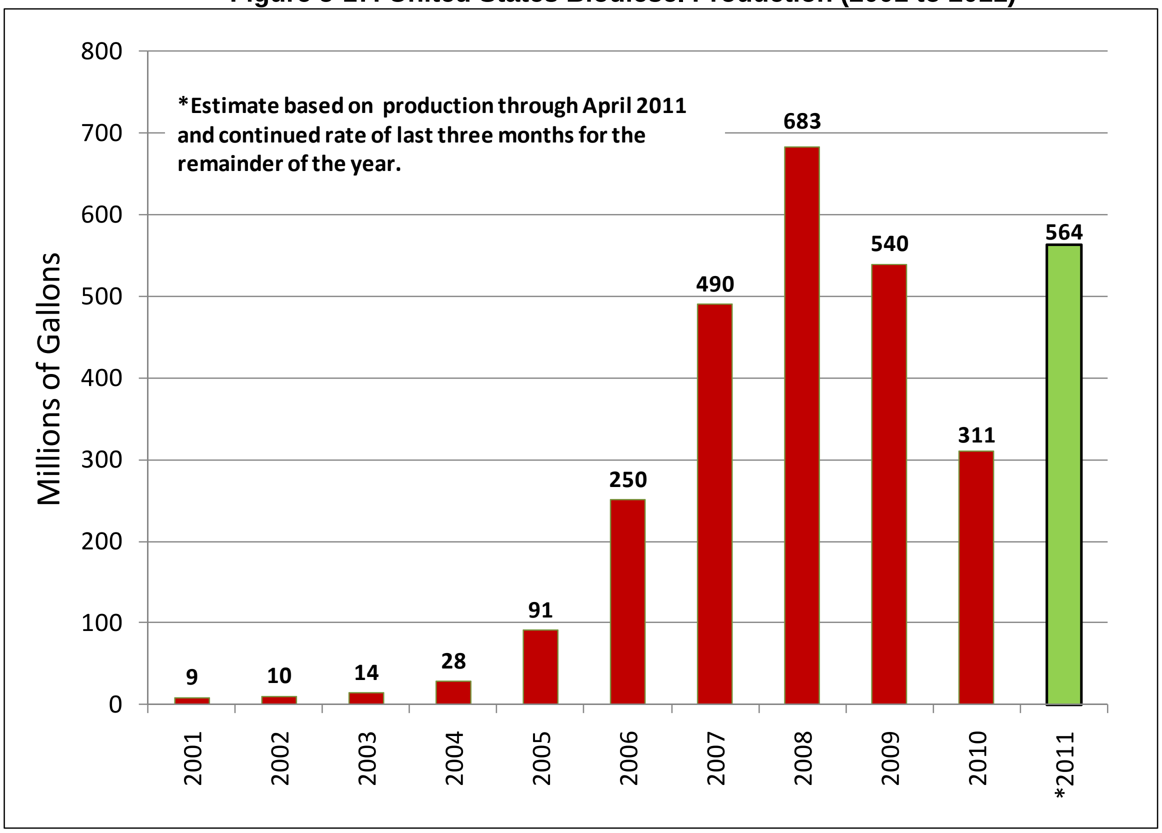
Biodiesel Overview

Biodiesel is a general term used to describe mixtures of diesel fuel with varying concentrations (between 2 and 20 percent) of biomass-based distillate. Early use of biomass-based distillate dates back to at least 1900, when Rudolph Diesel used peanut oil in a diesel engine at the World's Fair in Paris.[238] The earliest reference to biodiesel (ethyl esters of palm oil) is from a 1937 Belgium patent, followed by application in a commercial urban bus route between Brussels and Leuven, Belgium, during the summer of 1938.[239] Biodiesel use continued up through World War II as a necessity brought about by shortage and security. Increased availability of relatively inexpensive petroleum-based diesel fuel essentially eliminated biodiesel use until a resurgence spurred by the 1990 Clean Air Act Amendments and the Energy Policy Act of 1992.[240] Currently, retail sales of biodiesel in California are quite modest but could likely increase due to the state LCFS. The federal RFS2 is not expected to mandate any significant growth in biodiesel demand itself.

Blenders of biodiesel are permitted to vary the concentration in diesel fuel depending on which standard is adhered to for the final blend. Low-level biodiesel blends can range from 2 to 5 percent of B100 mixed with the conventional diesel fuel to meet American Society for Testing and Materials (ASTM) international specification D975. Higher blends of B100 between the range of 6 and 20 percent by volume must meet ASTM international specification D7467.[241] A survey of biodiesel producers in the United States was conducted in 2004 to identify the properties of both B100 and B20.[242] A survey was carried out in March and April 2007 to test the quality of biodiesel blends being sold at retail.[243] A subsequent study of B20 obtained from retail stations and fleet operators during the summer of 2008.[244] The overwhelming majority of the samples complied with all or most ASTM standards prevailing at the time of the respective surveys. However, there was a consistent finding of biodiesel concentration variability in low-level blends.

Production of biodiesel in the United States dramatically increased (see Figure 5-17) in response to federal legislation that included a $1 per gallon blending credit for all biodiesel blended with conventional diesel fuel that went into effect in 2005, but declined in 2009 and 2010 with the temporary loss of that subsidy in conjunction with poor production economics (high feedstock costs relative to market price of diesel fuel).[245] Output is expected to rebound as refiners and other obligated parties strive to meet biodiesel blending requirements mandated by RFS2 and could set a record level of production during 2011.

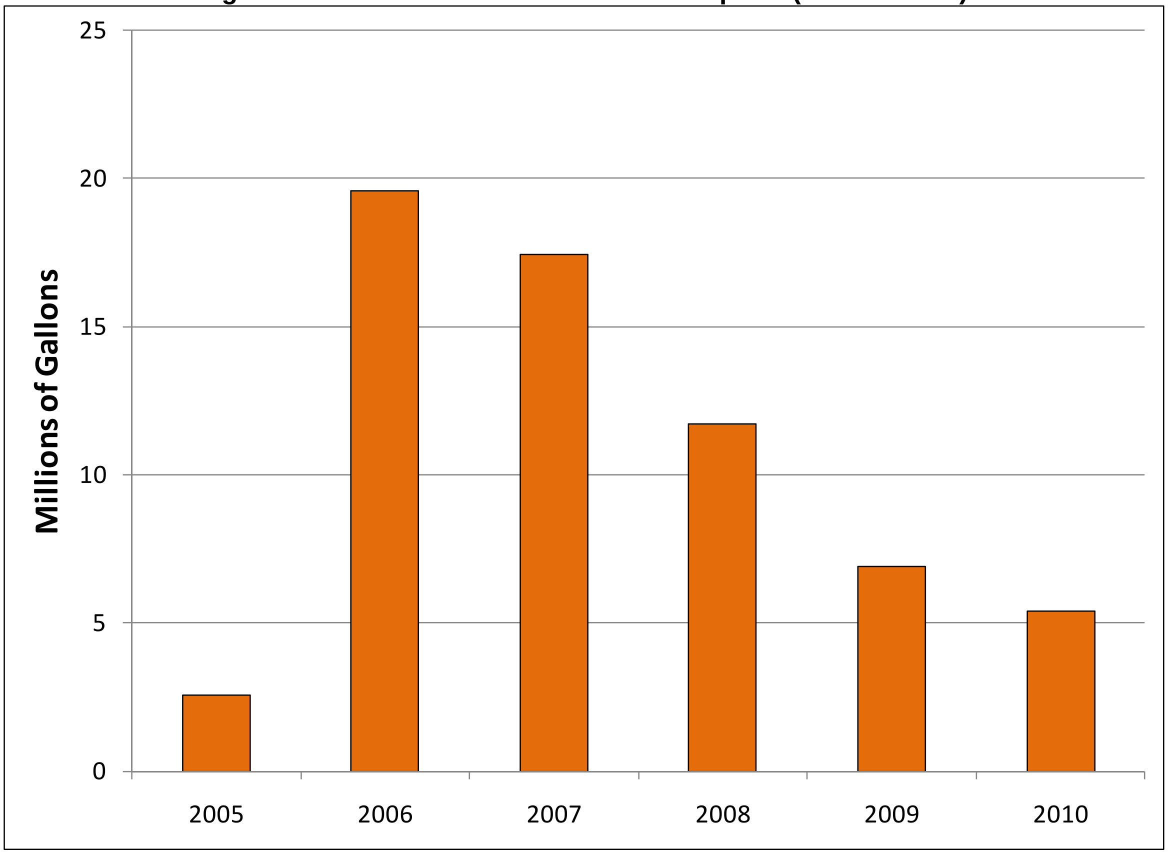
Figure 5-17: United States Biodiesel Production (2001 to 2011)



Source: EIA

Biodiesel use in California has been modest over the last several years due to an inadequate level of distribution infrastructure (lack of storage tanks at terminals) and varying approaches and interpretations of regulations controlling the concentration of biodiesel that is permissible in USTs. As such, biodiesel use in California is estimated to be no higher than 20 million gallons over the last several years as depicted in Figure 5-18. Biodiesel use is expected to increase in California as the distribution and retail infrastructure improves, storage tank issues are fully resolved, and obligated parties under the state's LCFS turn to greater quantities of biodiesel to help achieve compliance with their sales of diesel fuel.

Figure 5-18: California Biodiesel Consumption (2005 to 2010)



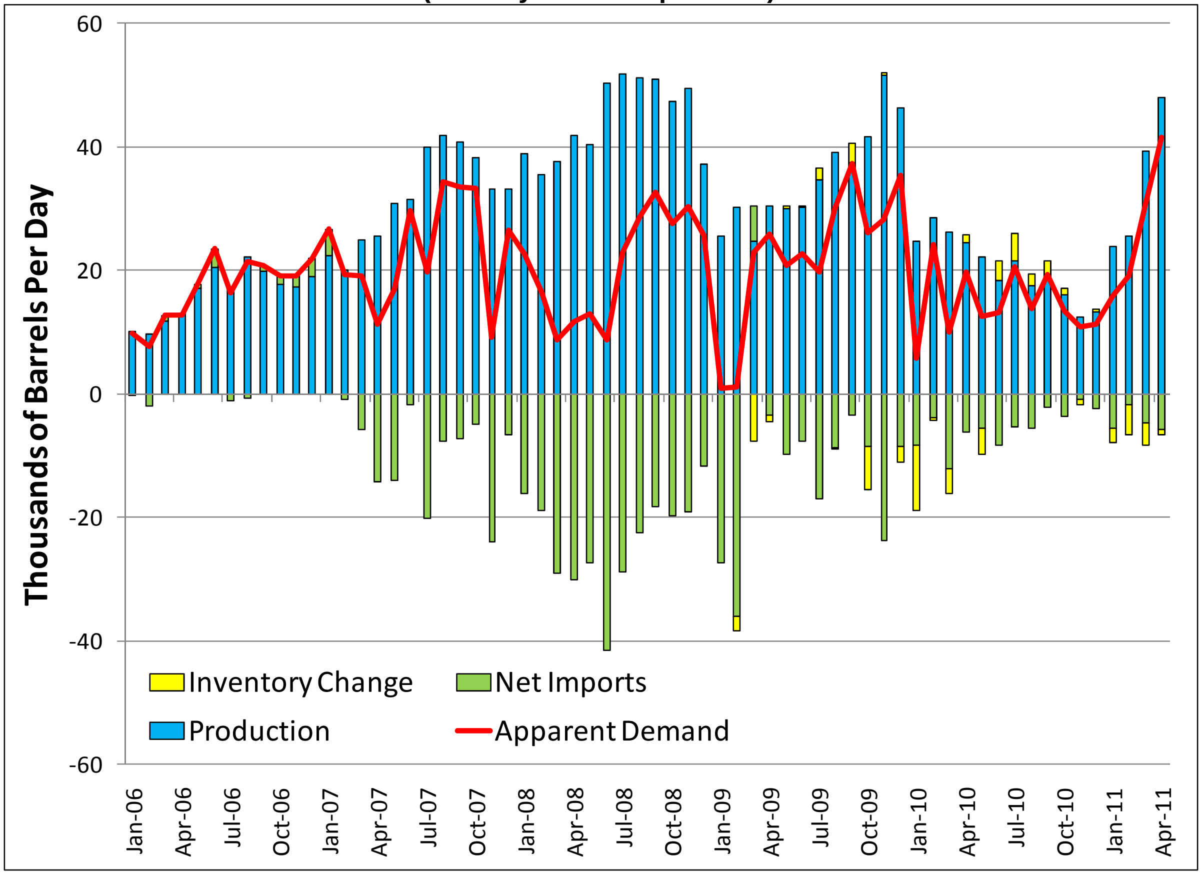
Source: BOE

Biodiesel Supply Outlook

United States Biodiesel Supply Outlook and Issues

Demand for biodiesel as a transportation fuel has been erratic, primarily a consequence of changing subsidy policies and expensive feedstock costs. Figure 5-19 shows supply and demand for U.S. biodiesel between January 2004 and April 2011. Biodiesel consumption set a record in April 2011 of 41.5 TBD.[246] The demand for biodiesel is expected to continue growing over the forecast period due to mandated blending quantities stipulated by the federal RFS2.

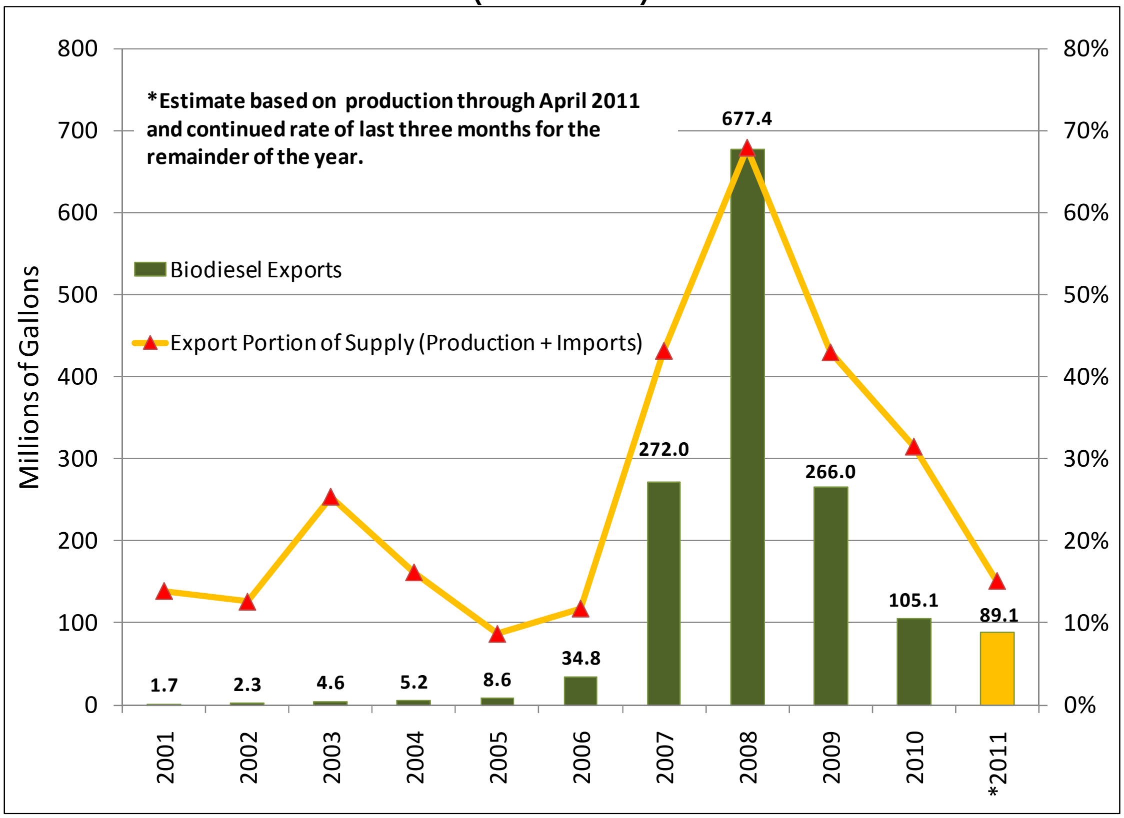
Figure 5-19: United States Biodiesel Supply and Demand (January 2006 to April 2011)



Sources: EIA and California Energy Commission analysis

Significant quantities of biodiesel were exported between 2007 and 2009 due to more attractive wholesale prices and United States exporters' use of the dollar-per-gallon biodiesel blenders' credit (see Figure 5-20.) Biodiesel exports have grown from nearly 9 million gallons in 2004 to a peak of more than 677 million gallons in 2008.[247] After peaking in 2008, a declining percentage of total United States biodiesel supply has been exported. In 2010, export volumes represented 32 percent of total United States biodiesel supplies (production combined with imports). That portion is forecast to be even lower in 2011 as obligated parties under the RFS2 strive to utilize a minimum of 800 million gallons of biodiesel.

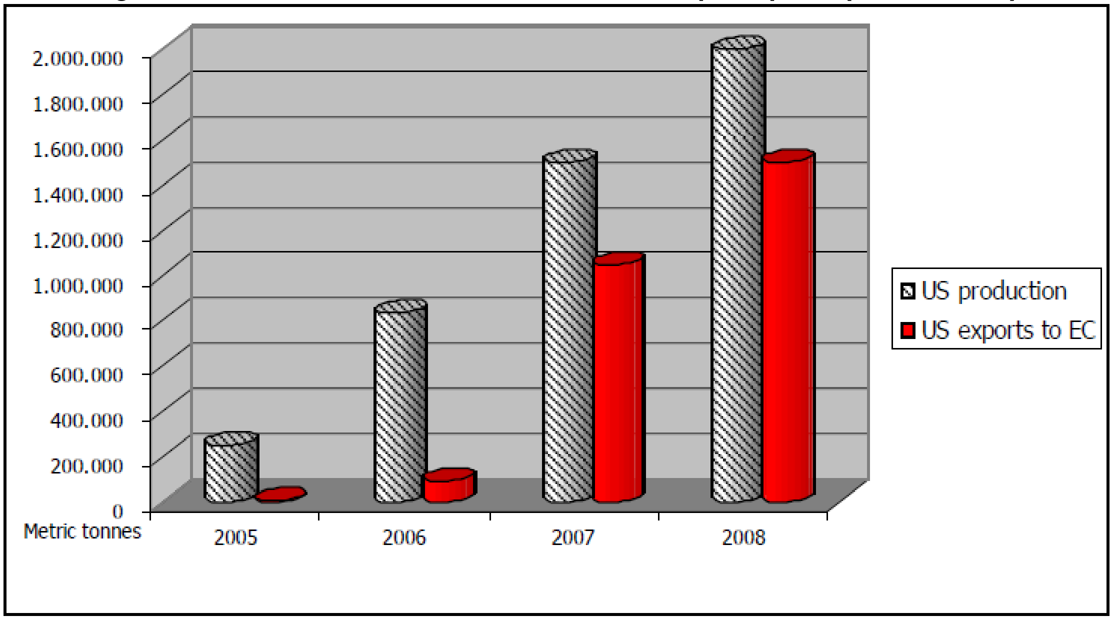
Figure 5-20: United States Biodiesel Exports and Percentage of Total Supply (2001 to 2011)



Source: EIA

According to the European Biodiesel Board (EBB), a significant quantity of the United States biodiesel production was exported to European Union countries during 2007 and 2008 (see Figure 5-21).[248] The continuous flow of biodiesel exports to Europe from the United States was not sustained since the European Union took action to apply a combination of import duties (both countervailing and anti-dumping) that were approved in July 2009 for a period of five years.[249] These new tariffs are designed to compensate for the economic advantage gained by United States biodiesel exporters from the dollar-per-gallon blenders' credit.[250] As consequence of these actions, United States exports of biodiesel have declined back to an average of 15.4 percent of supply based on the first four months of 2011. In fact, U.S. exports of biodiesel to the European Union (EU) all but vanished in 2010, replaced by Argentina (61 percent) and Malaysia (25 percent).[251]

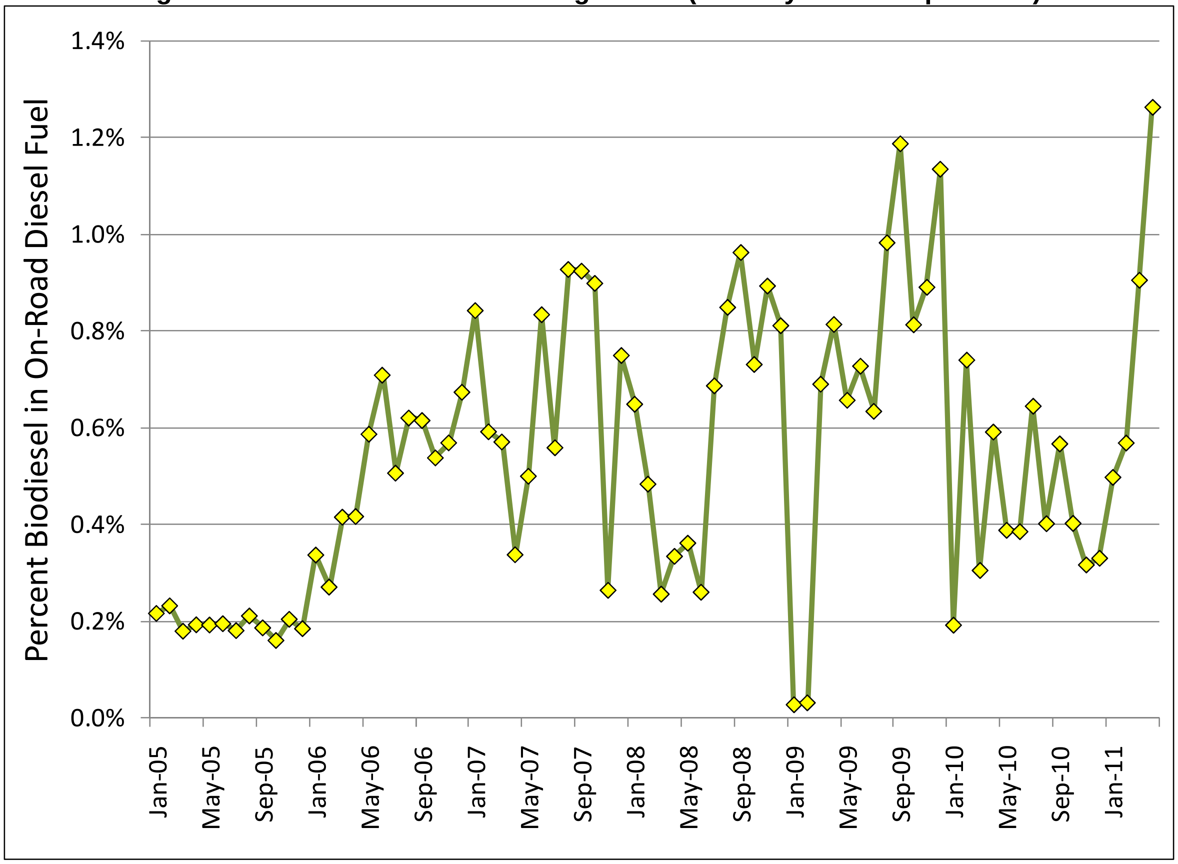
Figure 5-21: U.S. Biodiesel Production and Europe Exports (2005 to 2008)



Source: European Biodiesel Board (EBB) – approximately 300 gallons of biodiesel per metric tonne

The reduced exporting of domestic biodiesel production from the United States to Europe resulted in biodiesel blending levels that have fluctuated between 0.2 and 1.2 percent as illustrated by Figure 5-22. Absent the large increase of biodiesel exports, blending levels in the United States could have increased to an average of 1.29 percent during 2008, rather than the actual 2008 average of 0.61 percent. However, the application of the EU tariffs resulted in a decrease of biodiesel exports but not an increase of the average biodiesel concentration in the United States as production and use levels declined with the temporary loss of the biodiesel blenders' credit and less desirable blending economics. Only since the beginning of 2011 have use levels started to climb due to the reinstatement of the blenders credit and the need to meet RFS2 biomass-based diesel minimum use levels. In fact, the average concentration of biodiesel in United States diesel during April 2011 reached 1.26 percent, an all-time record. Over the next couple of years, production and use of biodiesel are expected to continue to grow due to even higher levels as mandated by the RFS2 regulations.

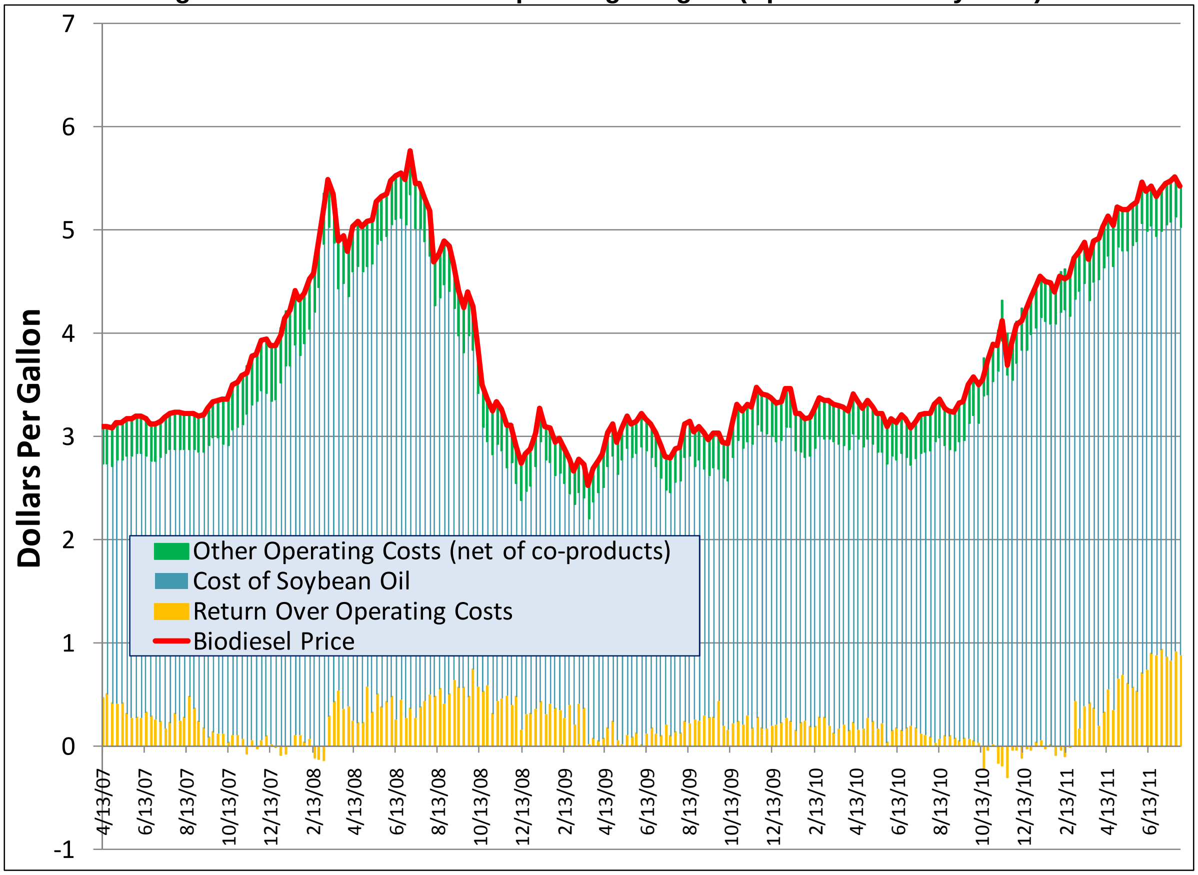
Figure 5-22: U.S. Biodiesel Blending Levels (January 2005 to April 2011)



Sources: EIA and California Energy Commission analysis.

The domestic biodiesel industry has been under economic pressure over the last couple of years due to: excess supply capacity of more than 1.5 billion gallons; temporary loss of a $1 per gallon blenders' credit; and expensive feedstock costs. Figure 5-23 tracks an aggregate measure of a biodiesel plant operating return from data collected and analyzed by the Center for Agriculture and Rural Development (CARD) that is intended to capture all of the revenue and costs associated with a typical biodiesel plant.[252] As is the case with ethanol, it is anticipated that these poor biodiesel production economics are temporary and will continue to improve as demand for biodiesel grows through the RFS2 mandates and the LCFS necessity to reduce the per-gallon carbon intensity of diesel fuel in California.

Figure 5-23: U.S. Biodiesel Operating Margins (April 2007 to July 2011)



Source: Center for Agricultural and Rural Development, University of Iowa.

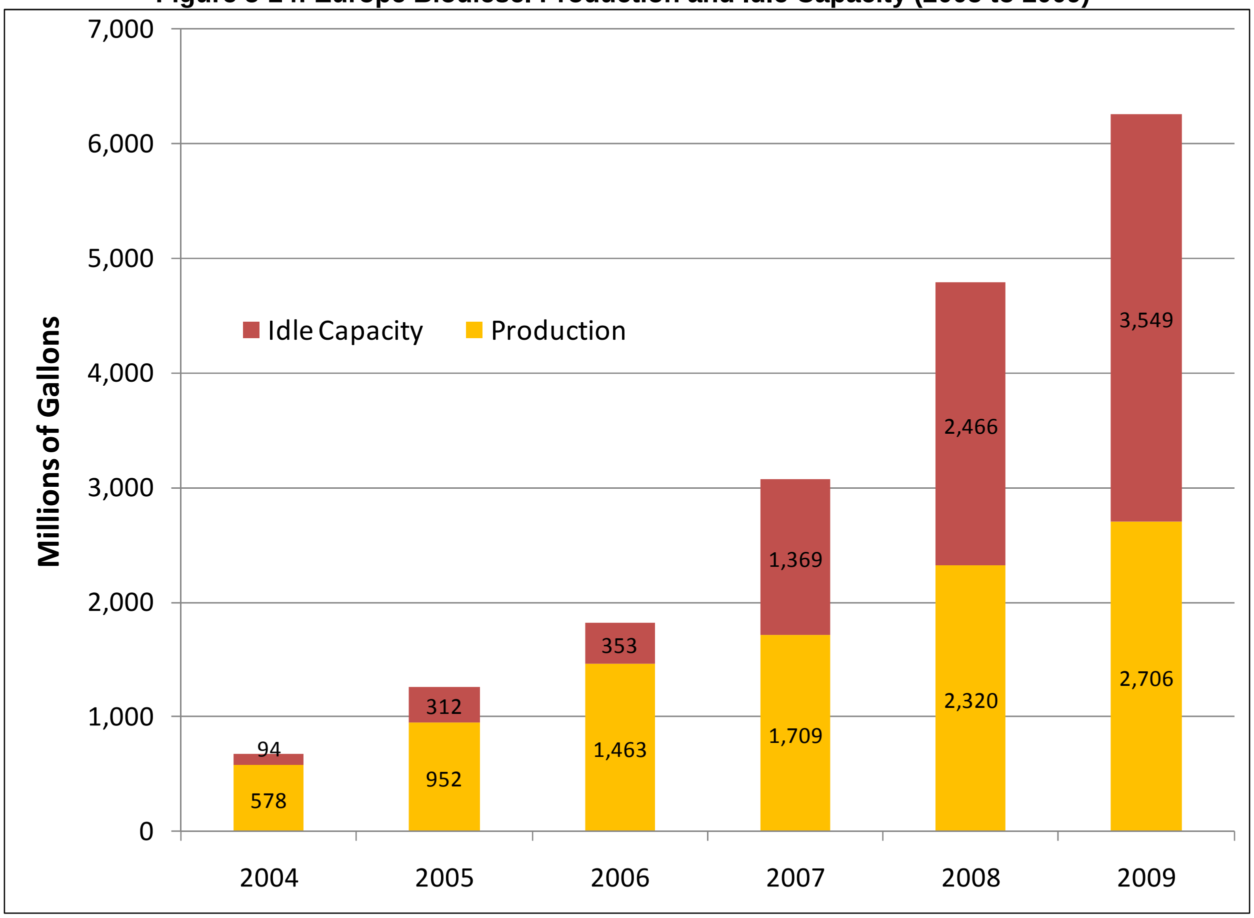
Summary of Biodiesel Supply Outlook and Issues

The RFS2 regulations call for a minimum use of 1.0 billion gallons per year of biomass-based diesel fuel in 2012, increasing to 1.28 billion gallons in 2013.[253] As of July 2011, there was more than 2.4 billion gallons of biodiesel production capacity for all United States operating facilities.[254] It appears as though there may be sufficient domestic sources of biodiesel production facilities to meet the RFS2 requirements for several years.

According to the NBB, there are 16 biodiesel production facilities in California with an annual production capacity of 84.5 million gallons.[255] These production capacity volumes are sufficient to supply California's total RFS2 "proportional-share" of biodiesel. However, the increased demand for biodiesel under various LCFS scenarios will require quantities that exceed the state's production capacity, necessitating imports from either domestic or foreign sources.

Europe continues to be the dominant producer of biodiesel in the world, estimated to produce approximately 65 percent of the global biodiesel production in 2009.[256] Between 2004 and 2009, biodiesel production in the EU has increased from 578 million gallons to 2.7 billion gallons. Over the same period, production capacity has increased from 678 million gallons per year to 6.25 billion gallons per year (see Figure 5-24).[257] The growing spare capacity of EU biodiesel facilities may be a reflection of poor market economics in the face of less expensive and heavily subsidized imports.[258] This foreign source of biodiesel spare production capacity is more than sufficient to meet any incremental demand for biodiesel that may be necessary by obligated parties in California to help achieve compliance with the LCFS requirements.

Figure 5-24: Europe Biodiesel Production and Idle Capacity (2005 to 2009)



Sources: EBB and California Energy Commission analysis

California Biodiesel Logistics Outlook and Issues

Infrastructure requirements for biodiesel are similar to those of ethanol in that biodiesel needs to be transported from points of production (both inside and outside California) to initial redistribution hubs via rail and marine vessels. Once inside California, the biodiesel would then need to be hauled to distribution terminals that dispense diesel fuel destined for truck stops and other retail locations. Although similar in need, the biodiesel infrastructure has not been developed to the same extent as that of ethanol primarily because there has not been any meaningful increase in the use of biodiesel to date. It is likely that changing circumstances could require a sizable increase in the use of biodiesel and a commensurate development of the associated distribution infrastructure to ensure adequacy of diesel fuel supplies for California. Currently, the biodiesel infrastructure is inadequate to accommodate widespread blending of biodiesel even at concentrations as low as B5. However, with sufficient lead time (12 to 24 months), modifications could be undertaken and completed to enable an expansion of biodiesel use.

Biodiesel Distribution Terminal Logistics

Biodiesel is blended with diesel fuel as the tanker truck is loaded before delivery to the retail station. As such, the biodiesel must be stored in segregated tanks. Unlike ethanol, only a few distribution terminals have biodiesel storage capabilities due to significantly lower demand levels when compared to ethanol. This circumstance appears to be the most significant challenge to near-term increased use of biodiesel. To help ensure adequacy of biodiesel distribution capability for meeting increased demand levels associated with the RFS2 and the state's LCFS, construction of biodiesel storage tanks at a minimum of 50 percent of California's distribution terminals over the next couple of years would likely be necessary. Costs for such an undertaking could amount to between $25 million and $50 million. At this time, biodiesel use is discretionary and at very low concentrations (on average). That situation is expected to change as refiners and other marketers in California move to comply with both the RFS2-mandated biodiesel blending requirements and the additional volumes that will be one of the strategies employed to reduce the per-gallon carbon intensity of diesel fuel per the LCFS.

Distribution terminal modifications will need to be made over the near to mid-term to help ensure sufficient volumes of biodiesel will be available for blending with conventional diesel fuel. New storage tanks will need to be constructed in most cases, although in some situations an existing storage tank can be converted from one type of fuel to biodiesel at a significantly lower cost and time frame. However, this approach would not be viable for most distribution terminals since all or most of the existing storage tanks are already being continuously used. If a terminal operator needs to install a new storage tank, the process to obtain a permit can be lengthy (as long as 12 to 18 months).

Biodiesel Rail Logistics

The majority of biodiesel use in California is believed to originate from production facilities located within the state. Approximately 5.4 million gallons of biodiesel was used as transportation fuel during 2010, less than 7 percent of the state's biodiesel production capacity. Over the next several years, biodiesel volumes are expected to increase. It is possible that biodiesel demand levels could exceed 10 or even 20 percent of total diesel fuel used in the transportation sector. Assuming sufficient spare production capacity throughout the United States to meet this potential increase in California biodiesel demand, it is likely that most of the incremental biodiesel will originate from facilities located outside the state. This means that imports of biodiesel may be necessary via rail and/or marine vessel. Currently, there are no biodiesel rail facilities designed to handle unit trains. Ultimately, biodiesel unit train receipt capability may not be necessary due to demand levels that may be too low to justify the expense. It is more probable that rail receipts of biodiesel will be transferred to tanker trucks via transloading, as is the case with the Kinder Morgan ethanol transloading project in Northern California.

Biodiesel Marine Logistics

Periodically, biodiesel has been imported into California by marine vessels. Due to cargo sizes that are smaller than ethanol, the storage tank requirements to unload the biodiesel are more modest. Optimal storage tank sizes are less than 10 thousand to 50 thousand barrels in size. Smaller storage tanks at marine terminals are normally reserved for lubricants, specialty solvents, and other chemicals that have limited demand volumes. Based on conversations with various biodiesel importers, these types of storage tank accommodations at marine import facilities are limited. In fact, a marine terminal in Southern California that was recently closed had been used periodically for importation of biodiesel. Availability of marine facilities is limited and would need to be made available if meaningful volumes of biodiesel were to be imported via marine vessel. However, as was previously discussed, there is sufficient domestic biodiesel production capacity to supply California's anticipated needs over the near to mid-term that could reasonably be delivered in rail cars, rather than marine vessels.

Biodiesel Truck Logistics

As is the case with ethanol logistics, few distribution terminals have the ability to receive shipments via rail. Therefore, most or all of the biodiesel would first need to be delivered to distribution terminals via tanker trucks to segregated storage tanks. Since the volume and associated trucking requirements are less than that of ethanol, incremental trucking requirements should not be as pressing. For example, assuming an incremental 300 million gallons per year of biodiesel was being transported to California distribution terminals, approximately 50 additional tanker trucks may be necessary (assuming two trips per truck per day). Although the additional trucking requirements may be modest, most distribution terminals would need to be modified so that the biodiesel could be received and transferred to segregated storage tanks at the terminals (a capability that all of the terminals have for ethanol today). This ultimate capability will require both time and an unknown capital expense to complete.

Biodiesel Pipeline Logistics

As biodiesel use continues to grow in the United States, so too do strategies for reducing the transportation costs of biodiesel. By far, pipeline delivery costs are the lowest of any of the primary methods of delivery, usually one tenth (1/10) of the cost compared to tanker truck delivery.[259] Pipeline distribution companies have recently initiated shipments of biodiesel blends in portions of certain pipeline networks. One such example is the recent distribution of B5 in portions of Kinder Morgan's Plantation Pipeline located in the Southeastern United States.[260] However, there are operational restrictions that limit this practice. The primary concern of transporting biodiesel blends in mixed petroleum product pipeline systems is the potential contamination with jet fuel. At present, Kinder Morgan is restricting biodiesel blend shipments to portions of their pipeline system that do not handle any jet fuel. Since all of the

Kinder Morgan petroleum product pipeline systems in California are used to ship jet fuel, it is unlikely that this practice could be adopted for use in this state. Over time, if the potential concern of jet fuel contamination with biodiesel can be overcome, the primary logistical impact would be the reduced needs for delivery of biodiesel to distribution terminals via tanker trucks.

Biodiesel Retail Logistics

Retail diesel fuel dispensers and USTs are certified to handle diesel fuel that contains biodiesel at concentrations of up to 5 percent by volume. However, these same USTs have not received independent testing organization approvals for biodiesel blends greater B5 and up to B20. To provide additional time for these approvals to be developed, the SWRCB issued emergency regulations that took effect on June 1, 2009, that allowed for a 36-month variance from this UST requirement.[261] This action has removed a potential challenge to expanded use of biodiesel in California. Assuming biodiesel fuel blends in California do not exceed the B20 level over the foreseeable future, retail station modifications should be negligible to accommodate such increased concentrations. However, for those retail locations that want to dispense B99 or B100, storage of biodiesel at these concentrations in an UST may not be permissible at this time per the SWRCB. Therefore, retailers still have the option to store B99 or B100 in an aboveground storage tank (AGT). Installation of a new AGT would be significantly more expensive than using an existing UST that is currently used to store and dispense diesel fuel.

Biodiesel Blend Wall

It is likely that the LCFS will necessitate increased use of biodiesel in California beyond the minimum "proportional-share" volumes calculated for RFS2 compliance. As is the case with ethanol, increasing levels of biodiesel blended with conventional diesel fuel pose some challenges that would need to be addressed to ensure biodiesel could be used at concentrations of up to 20 percent by volume. In addition to the UST issues previously cited, there is a lack of warranty coverage for biodiesel blends in excess of B5. Not all original equipment manufacturers allow biodiesel bends in excess of B5. This limitation is also imposed by some companies that provide extended motor vehicle warranties.[262] Until this warranty issue is covered, retail station operators may be reluctant to offer B20 for sale at all of their dispensers. Therefore, a dedicated UST and retail dispenser may have to be installed for B20 blends.[263] This scenario could result in significantly higher retail infrastructure costs to achieve widespread biodiesel penetration in California above B5 levels.

Potential Emerging Fuels

Emerging Transportation Fuels: Technology, Production, and Supply

Renewable fuels are a subset of alternative fuels that are made from renewable feedstock, typically of biological origin, such as corn, soybeans, wood, and a variety of waste products including food waste, municipal solid waste (MSW), and landfill deposits. All renewable fuels except biomethane and renewable hydrogen are liquid fuels that would be used as substitutes for gasoline or diesel. Biomethane is a gaseous fuel that is a perfect substitute for either compressed or liquefied natural gas, both of which are used as diesel substitutes.

Of the emerging renewable transportation fuels, only biomethane and renewable diesel have been produced in commercial quantities or are likely to be produced in sufficient volumes to help comply with the LCFS. There is a great deal of effort going into research and development of other fuels, but at present a great deal of uncertainty surrounds the future viability of these projects.

Biomethane

Biomethane is relatively well-established for a renewable fuel, although its use as a transportation fuel has been limited. There have not been any known commercial transactions within California and all biomethane currently used as transportation fuel is consumed by the producer. The nature of biomethane production and infrastructure constrains the development of a robust market for biomethane as a transportation fuel. Production is typically located at a site that provides feedstock, and these are usually somewhat remote. Infrastructure for transport of biomethane is simply a gas pipeline owned by a utility. This is convenient because utilities are ready purchasers of biomethane, which they use to meet RPS requirements. Although convenient for producers and utilities, this limits the use of biomethane as transportation fuel.

Currently almost all biomethane produced as a transportation fuel within California is produced by anaerobic digestion, which is a commercialized "off-the-shelf" technology that generally has no technology risk. The digesters can be as simple as a landfill or lagoon with an elastic cover to collect the biogas produced from anaerobic digestion of cow manure or other waste material. Tanks can also be used to contain anaerobic digesters, and wells can be drilled into landfills to collect landfill gas. There has been some progress in gasifying waste materials to produce a synthetic gas or syngas that is further purified to produce pipeline-ready biomethane, but this is a new technology in the United States and is still in the pilot stage.

Of the four options for biomethane producers—on-site electricity generation, sale to a utility for electricity generation, on-site production of transportation fuel, and sale for transportation fuel— the latter is often the least attractive. On-site electricity generation is appealing for any producer that consumes power on a regular basis since relatively little clean up of the gas is required and no pipeline connection or marketing is necessary.[264] Sale to the electric utility is straightforward if a pipeline is within economical distance of the production facility. Transportation fuel is attractive if it is consumed on-site, typically by the producer. If it is not consumed on-site, it must be put into the pipeline to reach the consumer, and if the gas is going into the pipeline, it is less costly to sell it to the utility than to market it to vehicle fleets as transportation fuel. However, the Hayden Act of 1988 effectively prohibits injection of landfill gas into a pipeline.[265]

There are three primary types of biomethane producers: wastewater treatment plants, dairies, and landfills. Currently 22 wastewater treatment plants in California use biogas for power or heat.[266] Although not as widespread, production by dairies has in the past been used primarily for electricity generation, but recent restrictions have prevented this.[267] The organic fraction of

MSW, currently comprising up to 40 percent of all waste sent to landfills in California, could be diverted for biomethane production.[268] Currently 73 landfills in California burn it for heat or electricity generation[269], but only three clean it to produce biomethane for transportation fuel.

The Frank R. Bowerman Landfill in Orange County has a plant that produces the equivalent of 800,000 gallons of diesel annually from waste biogas[270]. In Livermore, the Altamont Landfill is currently the largest landfill gas-to-LNG project in the world and is producing the equivalent of 2.6 million gallons of diesel annually to be used in Waste Management's refuse trucks. The Puente Hills Landfill produces the equivalent of 350,000 gallons of diesel annually for use by the landfill's water trucks and other vehicles.[271] In addition, dairies could use biomethane for off-road agricultural vehicles such as tractors, combines, and threshers, as well as on-road vehicles including pickup trucks and milk trucks. The Hilarides Dairy in Lindsey, California, for instance, uses biomethane to fuel two milk trucks.

California's waste streams have a gross production potential of 124 BCF per year and a technical potential of 23 BCF per year, equivalent to 185 million diesel-gallon equivalent (DGE),[272] representing about 7 percent of the state's on-road diesel fuel usage. Some feedstocks currently in use or planned for use in California demonstration projects include diverted organic material from post-recycled municipal solid waste streams, animal manure, woody biomass from urban green waste and from forest fuels management activities, agricultural residues, food waste, and waste from a rendering plant. Municipal solid waste (MSW) is one of the largest of these waste streams available in California for conversion to biomethane. Approximately 39 million tons of MSW are landfilled annually, and about 22 percent of that is suitable for anaerobic digestion. CalRecycle supports the diversion of organic matter from landfills, requiring 50 percent reduction of organics in the waste stream by 2020 and encouraging the development of alternative energy and biofuels[273]. When diverted from landfills, the organic fraction of MSW has over eight times the energy production potential per ton of landfilled waste[274]. Due to absence of an existing biomethane market, there is almost no information available on cost projections, although its commercial potential is heavily dependent upon the price of natural gas, for which it is a perfect substitute.

Other Renewable Fuels

Of the other emerging renewable fuels, biobutanol is notable because it can be used as an ethanol substitute and has properties that make it more desirable as transportation fuel: it has a higher energy content, is less likely to evaporate, and attracts less water, as well as other advantages. Currently testing is underway on retrofitted corn ethanol plants. If successful, the potential capacity for biobutanol production would be substantial in California and the rest of the United States.

Renewable diesel, renewable jet fuel, and renewable gasoline are appealing because they are renewable fuels identical to the petroleum-based products they would replace. Consequently, they are sometimes also referred to as "drop-in" fuels. Only renewable diesel is currently produced in commercial quantities and might be available in the volumes needed for compliance with the LCFS.

Renewable diesel can be made from a variety of feedstocks and is typically processed in a refining facility where the feedstocks are transformed into a diesel fuel through hydrocracking and hydrogenation. The refinery-based process produces a renewable diesel fuel that is chemically identical to diesel fuel, requiring no modifications for infrastructure or diesel engines.

Although there is currently no commercial production in California and no pilot plants ready to scale-up to commercial scale, there is the possibility that plants with proven technology could be built in California similar to those currently in operation elsewhere in the United States and in other countries. Dynamic Fuels has a renewable diesel plant with a capacity of 75 million gallons per year in Louisiana that uses non-food grade animal fats and greases obtained from Tyson foods.[275] Neste Oil has the capacity to produce 550 million gallons per year at biorefineries in Finland, Singapore, and the Netherlands.[276] Neste uses palm oil and palm oil byproducts, along with waste and by-products from the food industry that are unsuitable for human consumption. Neste Oil currently buys practically all the waste animal fat available in Finland. The company also procures animal fat from other EU countries, as well as from Australia and New Zealand, and some canola (rapeseed) oil. Possible future feedstocks include jatropha, camelina, and soybean oils.[277]

Although renewable diesel refineries are substantially larger than the biodiesel plants currently operating in California, obtaining sufficient feedstock can be a challenge. This is one reason that, if built in California, renewable diesel refineries are most likely to be built on the coast, hence accessible to imported feedstock, with the fuel then transported via pipeline throughout the state. Renewable diesel is more costly than petroleum-based diesel, but the cost can be at least partially offset by selling RINs.

Although renewable diesel fuel is chemically identical to diesel fuel, requiring no modifications to retail infrastructure or diesel engines, segregated wholesale rack infrastructure may be needed for renewable diesel. Renewable diesel, however, has recently been found to be similar to conventional fuel in conforming to ASTM D975. The State Water Board is expected to accept this finding and allow renewable diesel in USTs at retail facilities, without the prohibition that is applied to biodiesel. Renewable diesel is also expected to reduce NOx, and is being tentatively proposed as potential NOx mitigation for biodiesel use.

Propel Fuels is currently working to bringing non-ester renewable diesel into California, establishing relationships with renewable diesel producers, and working with State regulators to address issues associated with the fuel's storage in underground tanks. ARB is adopting a carbon intensity value appropriate for Non-Ester Renewable Diesel from a fuel similar to Dynamic Fuels' estimated at 19 gCO2e/MJ, equivalent to an 80 percent GHG reduction over the

2011 California diesel fuel baseline. Further product and emissions testing can begin once these issues are resolved.

Algae-Based Fuel Processes

Producing renewable fuels from algae involve processes that require a feedstock and carbon dioxide, which can then produce a variety of fuels, depending on the algae strain. Biodiesel, renewable diesel, renewable gasoline, renewable jet fuel, and ethanol have all been proposed for algae processes. Production of algae-based biofuels remains in the research and development stage. A wide variety of processes are being researched, and little is known about algal processes compared to other biofuel processes.[278] Algae are organisms that grow in water. They include microalgae and cyanobacteria (both microscopic) and macroalgae (seaweed). Different types of algae are grown depending on the type of fuel to be produced. Algae can be grown with light in open mixed or unmixed ponds or in enclosed plastic bags or tubes (known as photobioreactors). They can also be grown without light and fed a carbon source, such as sugars, to generate new biomass (heterotrophic cultivation).[279]

The best locations for growing algae are in the Southwest and Florida, near fossil fuel plants with waste carbon dioxide. The number of annual average cumulative sun hours should be at least 2800, the annual average daily temperature should be at least 55 F, and the number of annual average freeze-free days should be at least 200.[280] Algae can grow in water of all types, including wastewater and saline groundwater. When grown to produce oil, the yield is from 1000 to 6500 gallons per acre per year. Within California, the Imperial Valley best meets these conditions, and it is the location of algae-based fuel facilities.

Compared to other purpose-grown fuels, algae processes have the potential to produce a significant amount of fuel from a relatively small area. Algae grown on 1 percent to 3 percent of the total United States cropping area would be enough to produce 50 percent of transportation fuel needs.[281]

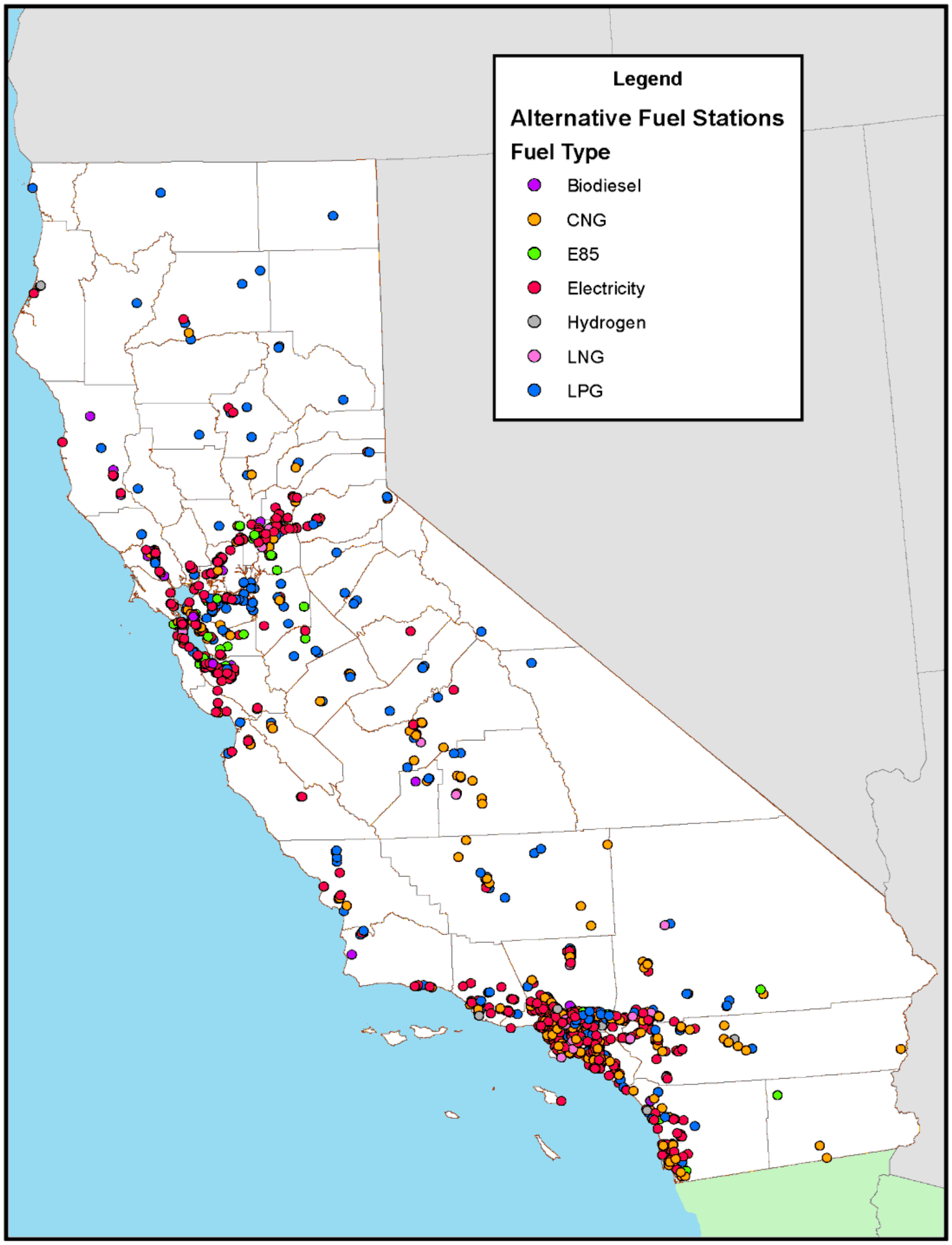
The National Algal Biofuels Technology Roadmap provides a literature review of production costs, which reveals that many estimates are dated and use widely different basic assumptions. It notes, however, "that a combination of improved biological productivity and fully integrated production systems can bring the cost down to a point where algal biofuels can be competitive with petroleum at approximately $100 per barrel."[282]

Algae processes are not as advanced as most other processes. Converting algae to biofuel requires the algae be harvested and dewatered, and then the oil or carbohydrates extracted. These processes are energy-intensive and expensive. By one count there are 28 hurdles to algae cultivation, including oil recovery, biofuel production temperature control, carbon dioxide availability and transport, resistance to invasion in open ponds, and dewatering methods.[283] Additionally research is needed in biology, algae strain development, scale-up, biorefineries, and whole-system design. An important area of product research is algae-based production of "drop-in" transportation fuels, meaning that they require no additional processing. The focus here is on large molecule fuels such as gasoline, jet fuel, and diesel. Production may be economically feasible only if combined with production of bulk chemicals, food, and feed ingredients. Sustainable, commercial production of algae-based biofuels may require another ten to fifteen years of development.[284] Although fuel produced by algal processes has been successfully tested in a variety of vehicles,[285] and many companies hope to supply consumers, for the foreseeable future there are currently no known facilities in the United States that will be producing fuel in the volumes needed for compliance with California's LCFS.

Alternative Transportation Refueling Infrastructure

Alternative fuels refer to all fuels with less than 90% gasoline or 100% diesel and include both biomass based and fossil based liquid fuels, as well as other forms of energy, such as: CNG, E85, propane/ LPG, biodiesel (20% bio, 80% diesel), electricity, hydrogen, and LNG. In recent years, substantial investments have been made in public retail and fleet refueling infrastructure, as mapped on Figure 5-25. Some of these alternative fuels are used mostly for heavy-duty vehicles, such as LNG, while others are used mostly for light-duty vehicles, defined as the passenger cars, light trucks, vans, and sport utility vehicles with up to 10,000 GVWR. Home and/or workplace refueling options are available for some of these alternative fuels, namely natural gas and electricity, and primarily in the light-duty vehicle market. These home refueling stations typically have a long refill time (up to 10 hours). An example of this technology is the "PHILL" fuel maker which compresses natural gas from a standard utility gas line for use in a CNG vehicle. The new PHILL unit is expected be sold in North America within the next several months[286], making home refueling more accessible for natural gas vehicle owners. Home compressor stations typically cost $4,500 plus installation cost and last 6,000 hours, roughly 4.5 years of use, and supplying 3,000 gasoline gallons equivalent before a $2,000 overhaul is required.[287]

Figure 5-25: California Public Retail and Fleet Alternative Fuel Stations



Source: U.S. DOE

Residential chargers for single and multi-family dwellings will be the primary method of charging for most PEVs including both battery electric and plug-in hybrid vehicles. There are three general types of chargers known as level 1, level 2, and fast chargers. Home recharging for PEVs historically cost $2,500 per installation plus roughly $1,200 labor and permit cost; however, these costs are dropping. Recently, Ford announced a partnership with Best Buy offering a Level 2 charging station for owners of the new Ford Focus battery electric vehicle (BEV) for roughly $1,500 for a standard installation—about one-third less than competitors' systems.[288]

Plug-In Electric Vehicle Charging Infrastructure Plans

Over the 2011-2012 period there will be significant investment in California's charging infrastructure. The Federal government's ARRA funds matched with Energy Commission program funds in California and other private and public funding are available to support PEV charging infrastructure for the deployment of PEVs in California. Table 5-2 summarizes the planned deployment of PEV charging infrastructure in four strategic PEV regions: the nine-county Bay Area, the San Diego and Los Angeles Regions, and the Sacramento Region.

Table 5-2: PEV Public Charging Infrastructure Deployment by California Region[289]

Region	Existing	Planned		
	Public/Commercial Stations	Public/Commercial Points[290]	DC Fast Charge Stations	Battery Switch
S.F. Bay Area	96	916	55	5
Los Angeles	237	972		
San Diego	16	1,452	60	
Sacramento	56	494		
Other	28	3	2	
Total	433	3,837	117	5

Source: California Energy Commission and Nissan

In the San Diego and Los Angeles regions, Energy Commission program funds of $8 million and ARRA cost-share funds of $39.35 million will be used to deploy 2,452 Level 2 chargers and 60 fast-charging stations in residential and commercial sites. This deployment will support the introduction of 1,000 Nissan Leafs in the near term, and eventually up to 5,000 Leafs. The Energy Commission also recently awarded funds to the SoCal Collaborative for $840,750 to upgrade and install at least 315 upgrades and new electric vehicle supply equipment (EVSE) for fleets and public locations throughout the Los Angeles Metropolitan Region.

The Energy Commission will also fund Coulomb Technologies with $5 million in federal American Recovery and Reinvestment Act (ARRA) match share to install and upgrade up to 1,290 Level 2 public chargers in the Bay Area, Sacramento and the Los Angeles areas. The Association of Bay Area Governments is awarded about $1.5 million with additional local match share to install about 413 charge points, of which 171 are Level 1, 223 are Level 2 chargers, and 19 are fast chargers. This award will supplement the Bay Area Air Quality Management District (BAAQMD) two-phased infrastructure deployment. The first phase is for $1.3 million for 402 EVSE's 6 fast chargers and one battery switch station to be installed by the end of 2011. The second phase is a $3.9 million award for 2,750 Level 2 residential chargers (with a $700 incentive per charger) provided by Coulomb (500), Aerovironment (500), Clipper Creek (250) and Ecotality (1,500 as part of the "EV Project"). Also included are 30 corridor fast chargers by mid-2012. [291] Remaining funds will be used for additional residential or commercial chargers based on the results of a regional analysis of PEV infrastructure.

The permitting, installation, and inspection process for residential charging infrastructure vary by community and for each installation but, on the whole, it is currently complex, costly, and protracted. Although the actual charging panels may take only a few hours to install, the entire process from order to installation depends on a series of site visits including the utility company, licensed electrician, city permitting office, and city building inspector which can take more than 4 weeks. Regions are currently brainstorming to find ways to streamline the process and reduce the time for installation. It is also important to provide education to local government jurisdictions that often lack knowledge about the permitting process for PEV charging infrastructure and provide assistance to permit and inspection offices facing workforce reductions. The California PEV Collaborative has identified the following actions that can help to streamline the process: [292]

- Coordinate among auto dealers, electrical contractors, utilities, and local authorities to minimize red tape
- Designate local contacts to respond to consumer questions about PEV charging
- Develop automated inspection reporting executed at the time of inspection
- Develop clear installation procedures and disseminate widely using the clearinghouse and other mechanisms
- Develop online applications for local inspections and permitting
- Establish 24-hour phone or Internet-based scheduling for inspections
- Establish set fees and consolidate inspections
- Prioritize applications for residential charging equipment in the permit review process
- Provide customers information about installation incentives, costs, options, and trade-offs through an information clearinghouse or other mechanisms, such as PEV consultations
- Seek compliance from nationally recognized testing laboratories, such as UL, for dual-meter adapters

Charging station costs vary depending on the level of service, location, type of station, and installation requirements, including electrical upgrading requirements. Estimated costs of charging stations are shown in Table 5-3.

Table 5-3: Estimated Costs for Charging Stations

Level	Location	Equipment	Installation
1	Single Residence	$30- $200 (charge cord only, included at no cost to consumer with BEV/PHEV) when an accessible household plug (e.g., in a garage or adjacent to a driveway) with a ground fault interrupter is already available	$400-$1000+ may be necessary depending on difficulty of installing a new circuit at the desired location, but in most cases, owners with sufficient panel capacity would opt for a more capable 220 V AC Level 2 installation instead of a Level 1 dedicated circuit because the additional installation cost is only marginally higher.
2	Residential, Apartment Complex, or Fleet Depot	3.3 kW EVSE (each): $300-$4,000 6.6 kW EVSE (each): $400- $4,000	3.3- 6.6 kW installation cost: $400-$2,300 without wiring/service panel upgrade, or $2,000-$5,000 with panel upgrade.
2	Public	$400-$3,800+ for each EVSE	$3,000- $7,000+ installation cost, varying significantly with distances from service entrance and number of EVSEs installed.
3	Public	$8,000-$50,000 for fast chargers	

Source: NHTSA, and ARB, September 2010

Residential In-Home Charging

One of the attractions of PEVs compared to internal combustion engine vehicles is the convenience of home charging instead of fueling at a gas station. ICF International estimates that in the early market, roughly 95 percent of charging will either be at home or at fleet facilities.[293] According to Southern California Edison, 40 percent of homes are likely to rely on Level 1 charging, and 60 percent will likely opt for Level 2 charging.[294] Surveys show that consumers strongly prefer home charging and rarely use public chargers.[295,296] Most PHEVs can charge from a typical 120 V household outlet (Level 1); however Level 1 charging for a typical BEV, such as a Nissan Leaf for example, would provide only 4 to 5 miles of range per hour of charging. Level 1, however, may be sufficient for consumers that drive relatively few miles each day and don't require faster charging daily. Many consumers would prefer Level 2 charging, which would provide 12 to 15 miles per hour of charging. [297] Charging at Level 2 may require an electrical panel upgrade, adequate wiring to the charging location, EVSE equipment, and city and county permits for any electrical or land use changes. A large percentage of homes will require the installation of a 220/240 V plug in their garages or parking shelters. This installation is an additional cost that will extend the payback period for PEVs.

- Several automakers are teaming up with charging infrastructure companies as their PEVs roll-out. General Motors (GM) is partnering with SBX to provide Volt customers with Level 2 chargers and one-stop shopping, setting up permits, providing rebates, and sending out the electrical contractor. The charger cost is $490 (with installation costs about $1,500) and takes four to six hours to install. Nissan is partnering with ECOtality in the San Diego and Los Angeles regions to provide home installation of Level 2 chargers as part of its initial rollout. Mitsubishi will partner with Eaton and Best Buy to sell and install Level 2 home charging stations. The Best Buy "Geek Squad" will handle the consultation and installation for the charging units, including coordination with third-party licenses electrical contractors, if needed.

- The broad consensus is that residential charging is the highest priority for deployment because consumers like the convenience and it encourages charging during periods of off-peak electrical demand.[298] The Energy Commission will consider providing PEV consumers with incentives to help defray the cost of home EVSE.

Natural Gas Vehicle Refueling Infrastructure

One of the primary challenges to the penetration of natural gas vehicles is the lack of available refueling infrastructure. Until this problem is addressed, the use of natural gas vehicles will likely be confined to medium- and heavy-duty vehicles, which can use CNG/LNG stations on a regular route. Fueling infrastructure for natural gas vehicles in California includes a combination of public and/or private access, CNG and/or LNG dispensing, and fast fill or time fill for CNG dispensing.[299] The number of stations is presented in Table 5-4.

Table 5-4: Natural Gas Fueling Stations

	Publicly Accessible Stations	Private Access Stations
CNG	140	424
LNG	13	19

Source: California Natural Gas Vehicle Coalition, U.S. DOE Alternative Fuels and Advanced Vehicles Data Center

Table 5-5 presents Energy Commission estimates of current natural gas infrastructure costs, based on the station's size (measured in standard cubic feet per minute [scfm] for CNG and gallon capacity for LNG). All of the prices for CNG stations are presumed to include fast fill dispensers, which may not be necessary for certain applications (such as those that return to a designated station overnight). To reduce these estimated station costs, the federal government offers a tax credit for up to 30 percent of the cost, not to exceed $30,000, if the station is installed in 2011.

Table 5-5: Natural Gas Infrastructure Costs

Infrastructure Type	Estimated Cost Range[300]
Small CNG Station (≤ 500 scfm)	$600,000 - $1,500,000
Medium CNG Station (500-2,000 scfm)	$1,200,000 - $3,500,000
Large CNG Station (≥ 2,000 scfm)	$3,000,000 - $5,000,000
Large LNG Station (≥ 15,000 gallons storage capacity) With Combined CNG dispensing	$1,000,000 - $2,200,000
Home Fueling	$3,600[301]

Source: Gladstein, Neandross & Associates, California Energy Commission

Self-contained dispensing systems, such as the Galileo Nanobox, also offer the option to provide small fuel dispensers at existing fuel stations. This significantly reduces the cost of new natural gas fueling infrastructure by using existing land, concrete infrastructure, and canopies. The

Energy Commission has invested $5,741,388 for the installation of 20 new stations or upgrades to existing stations across the state; 16 CNG stations, 3 LNG stations, and 1 combination station. Some of these stations include multiple dispensers at the same site. Each of these installations was targeted to match the fueling needs of particular fleets and natural gas customers.

Discussions with vehicle manufacturers, fuel providers, local air districts, and other program stakeholders revealed that additional investment in natural gas infrastructure is critical to the adoption of natural gas vehicles and market transformation for this alternative fuel.[302] Seed money for regional planning for natural gas fueling infrastructure may also be needed.[303] Fuel accessibility is one of the key considerations for fleet managers for the purchase of natural gas vehicles. Increased demand for clean fuel alternatives to gasoline and diesel along with regulatory requirements, such as the SCAQMD Fleet Rule, has driven an increase in natural gas infrastructure by private investors.

The combination of CNG and LNG dispensing at a single station is particularly attractive because LNG can be vaporized and pressurized into CNG with conventional pumps using less energy than it takes to compress pipeline gas into CNG. These stations also allow the station owner to serve different markets using much of the same support equipment, such as canopy and pavement, without a significant difference in the cost of the station. These combination stations also support the corridor approach to refueling, making CNG and LNG available along major goods movement corridors to support regional and interstate trucking operations. Industry and government strongly support the corridor refueling concept. The Interstate Clean Transportation Corridor (ICTC) project, supported by the U.S. DOE, employs public and private partnerships to expand alternative fuel vehicle use and refueling station access throughout the Western United States.[304] The ICTC has successfully developed 23 natural gas refueling stations in California and Nevada. The ICTC continues to work to build a sustainable corridor of LNG refueling stations along the I-15, I-80, and I-5 corridors connecting Southern California, Salt Lake City, and Northern California to support the movement of goods by alternative fuel heavy-duty trucks throughout the Western United States. Several of the stations proposed for funding by the Energy Commission will directly support corridor refueling along I-10, I-5, SR-99, and other in-state goods movement corridors.

Recent federal funding further demonstrates government and industry support to expand refueling infrastructure along goods movement corridors. One example of many is the U.S. DOE's award of nearly $5.6 million for a LNG station in Las Vegas, Nevada, that will provide a 700-mile LNG fueling corridor along one of the nation's most heavily traveled truck routes for the movement of various goods.[305]

The aging stations and equipment in California do not meet today's fleet refueling needs. Many fleet owners involved in goods movement are concerned with the bottom line, which, in part, depends on the reliability of fueling equipment and the time it takes to refuel their fleets. In the *2010-11 Investment Plan*, the Energy Commission dedicated $2 million to natural gas station upgrades for public fleets, particularly school districts and local governments. While the Energy

Commission has not yet issued a solicitation for this allocation, this funding will likely be substantially oversubscribed based on conversations with managers of existing stations, especially those serving school district bus fleets and growing transit fleets.

Recognizing that market transformation for natural gas will occur only when range anxiety and fleet fueling operations are addressed, the Energy Commission allocated $8 million to support the installation of new natural gas fueling infrastructure and upgrades to existing infrastructure. This funding will be closely tied toward identifiable needs in LNG and CNG fueling infrastructure, focusing primarily on long-haul LNG goods movement corridors and pairing new CNG stations with high-volume fleets that make a concerted effort to convert from diesel to CNG. Based the Energy Commission's cost share for the 20 natural gas station projects funded from the infrastructure solicitation, this funding will support roughly 30 new stations and/or existing station upgrades.

Hydrogen Refueling Stations

Hydrogen has the potential to be a common alternative fuel. Although it does not occur free in nature, it can be reformed from natural gas and any renewable biogas or landfill gas and can be derived through the electrolysis of water. It is produced in mass quantities and is trucked or piped for use in food processing and in petroleum refining processes. Used in fuel cell passenger vehicles and forklifts, it reduces well-to-wheel criteria pollutant and greenhouse gas emissions relative to all internal combustion engine cars on the road today.

Currently, there are roughly 250 hydrogen fuel cell vehicles (FCVs) operating in California in 2011, but only 15 were registered in California in 2009. These vehicles use stored hydrogen, which is combined with oxygen from the atmosphere through an electrochemical reaction to produce electricity, which is then used to power an electric motor. Like BEVs, FCVs produce no tailpipe emissions and store the hydrogen fuel in on-board pressure tanks. Today's FCVs hold enough hydrogen in their on-board tanks to support driving ranges of roughly 250 miles. Current refueling is relatively quick, taking about 3-5 minutes per fill for a 700 bar tank.

In the July 2011 *2011-2012 Investment Plan for the Alternative and Renewable Fuel and Vehicle Technology Program* report, the Emerging Fuels and Technology Office identifies that the high cost of the technology remains a major challenge for this fuel and vehicle technology. It also states that vehicle production and fueling infrastructure are still at a pre-commercial stage, where industry cannot take advantage of economies of scale benefits that come with commercial production volumes. However, there are indicators that cost is decreasing on both the vehicle and fuel infrastructure side. Energy Commission staff discussions with OEMs indicates that FCVs are reaching the $100,000 mark and several OEMs plan to lease vehicles to the public at more publicly attractive lease rates. The Energy Commission has also seen the cost per fueling station decrease, from a range of $3 million to $6 million to a range of $1 million to $2.5 million, over only a few years.[306] This was made possible due to modular designs and strategically designed fuel production and distribution models.[307]

As part of its investment strategies for the *2011-2012 Investment Plan*, the California Energy Commission is funding projects that support hydrogen fueling infrastructure driven by the fuel demand of pre-commercial FCVs deployed by automakers in California. Subsequent to the *2008-2010 Investment Plan*, the Energy Commission provided $22 million to establish hydrogen infrastructure based on information available from public agencies, public and private organizations, and other stakeholders. Through a competitive solicitation released in June 2010, 11 stations, totaling $15.7 million (Table 5-6), were awarded funding. Eight of the stations represent new installations, and three are upgrades. Once these awards are finalized and grant agreements are developed, construction and upgrades of the stations will begin. These stations were selected because they were strategically located in areas where automakers have committed to significant numbers of FCV deployments over the next three years, with nine of the stations located in the greater Los Angeles area, one near San Francisco International Airport, and one in the Sacramento area.

Table 5-6: Awarded Hydrogen Stations and applicant estimated GHG benefits

	Dispensing Capacity (kg/day)	W-T-W GHG %	Total Match Funding	Commission Funding
Gaseous Delivery Hydrogen Refueling Station Deployment Program	1440	44%	$21,780,585	$11,231,733
West Sac and Laguna Niguel Hydrogen Fueling Stations	480	47%	$5,226,935	$3,920,198
SFO West Bay Hydrogen Fueling Complex	240	47%	$3,168,291	$567,003
Total	2160		**$30,175,811**	**$15,718,934**

Source: California Energy Commission

Along with its light-duty vehicle applications, FCV has made inroads into the medium- and heavy-duty sector as well. Indentified within the *2011-2012 Investment Plan*, there are currently two transit hubs in California that own and operate hydrogen-operated buses. SunLine in Thousand Palms and AC Transit in Oakland (together with a consortium of five transit agencies around the Bay Area) both operate hydrogen fueling stations and FCV buses. SunLine has one bus fueling station, and the AC Transit's old station in Oakland is closed and will be replaced by a new station in the same location, which is funded by local, state, and federal sources. An additional station is being built by AC Transit in Emeryville. To temporarily bridge the refueling needs gap, mobile trailers are currently being used to fuel demonstration fleets in areas that do not have permanent hydrogen station access. These mobile fuelers are skid-mounted with a tube trailer and can be easily moved for a greater level of flexibility of location.

The ARB continues to support hydrogen station development. The Clean Fuels Outlet Regulation (California Code of Regulations Title 13, Chapter 8) was developed in 1990 to support the California Low Emission Vehicle (LEV) Standard. The regulation put in place a requirement for petroleum fuel providers to develop a system of ethanol, methanol, and natural gas dispensing facilities once a threshold of LEV vehicles using these fuel types came to market.

In 2009, the ARB began investigating the possible modification of this regulation to address the lack of fueling infrastructure available for vehicles meeting the ZEV Regulation, which has superseded the LEV Regulation. To meet the fueling needs of the ZEV fleet, the regulation would require fuel providers to develop a network of hydrogen fueling stations once the threshold of fuel cell vehicles is reached (currently 20,000 vehicles). In 2011, the ARB has begun to investigate extending this regulation to the battery electric vehicle market. The Board is expected to meet in the 4th quarter of 2011 to either approve staff's recommended changes or to direct staff on additional modifications to this regulation.

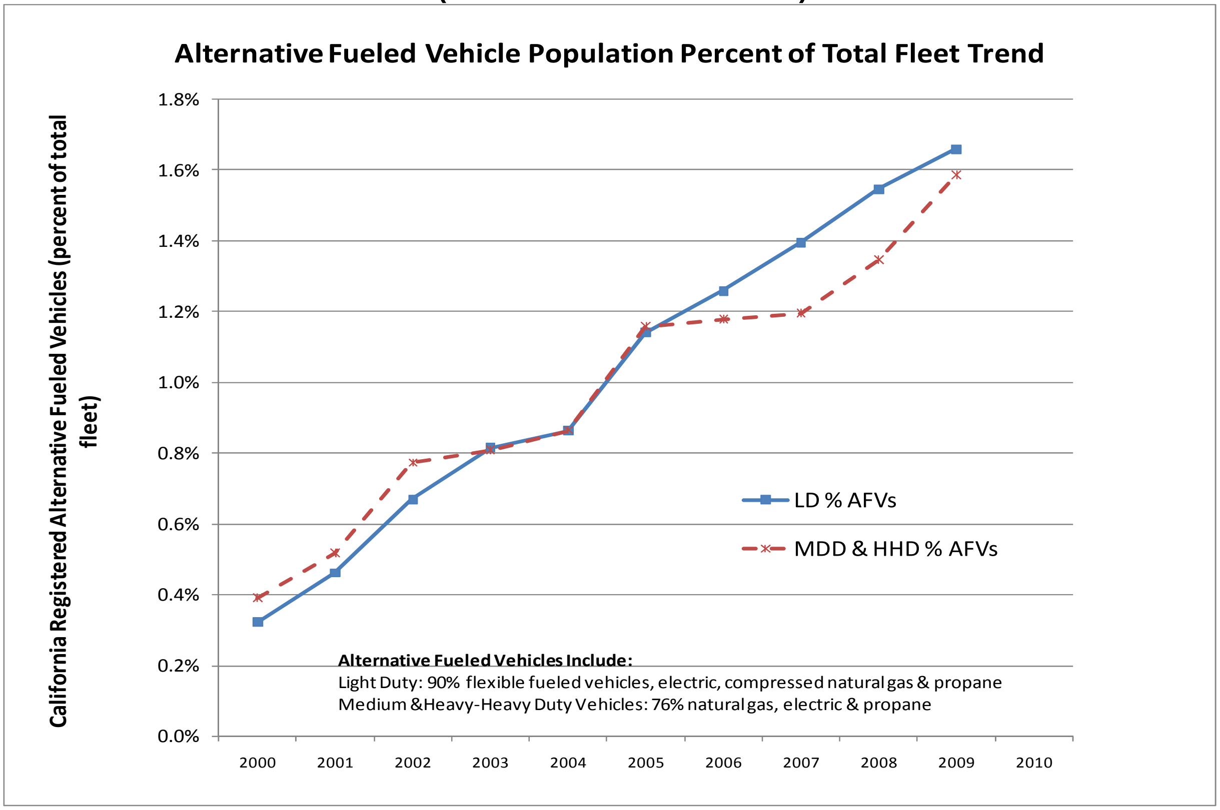
Another regulation is SB1505, also called Environment and Energy Standards for Hydrogen, which will require the hydrogen produced for motor vehicle use meet greenhouse gas, criteria pollutant, toxic emission and renewable requirements. SB1505 will require the hydrogen produced in California to contain 33 percent renewable resources. This will likely increase demand for emerging renewable transportation fuels such as biomethane, which is expected to serve as replacements for compressed natural gas or liquefied natural gas. Staff anticipates that SB1505 will likely increase the demand for biomethane to approximately 300 million standard cubic feet in compressed form or about 4 million gallons in liquid form by 2017. With an additional increase in demand by 2030, it is expected that the demand for biomethane could increase to about 4 billion standard cubic feet or 45 million gallons.

Finally, the *2011-2012 Investment Plan* describes the Energy Commission efforts in supporting a contract with CDFA Division of Measurement Standards (DMS), which is funding activities to develop and establish retail fuel quality standards for hydrogen. This contract will establish testing procedures and quality standards for commercially available gaseous hydrogen as a transportation fuel and is a critical first step in developing competitive marketplace for California's hydrogen dispensing infrastructure. To further support hydrogen infrastructure development, the Energy Commission funded CDFA/DMS to develop retail fuel quality standards for hydrogen and a type approval for measuring and dispensing hydrogen for sale in California.[308] The same contract will allow CDFA/DMS to prepare the groundwork to establish a standard for the commercial measurement of gaseous hydrogen for vehicles and other refueling applications. These efforts will help remove one of the major obstacles to commercialization of hydrogen as a transportation fuel and help develop the fueling infrastructure.

Alternative Fueled Vehicles Availability

Light- and heavy-duty alternative fueled vehicles have been steadily growing as a percent of California's total fleet. Figure 5-26 shows the historic trend of alternative fueled vehicles as a percent of the total vehicle population (see chapter 2 for distribution of medium- and heavy-duty vehicles between public and private sectors).

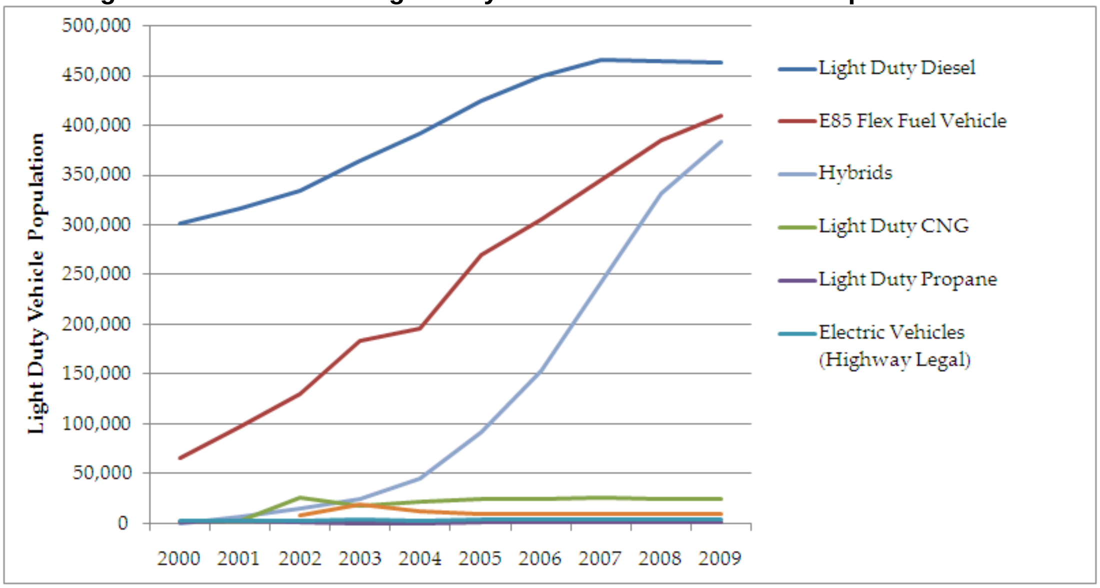
Figure 5-26: California Alternative Fueled Vehicle Population (Percent of Total Fleet Trend)



Source: California Energy Commission analysis of DMV database

Figure 5-27 shows the light-duty vehicle population of alternative fueled and other petroleum reduction vehicles. Of the top three significantly growing petroleum reduction light-duty vehicle options, the only alternative fueled vehicle is the E85 FFV. The other alternative fueled light-duty vehicles did not appreciably grow from 2000 to 2009.

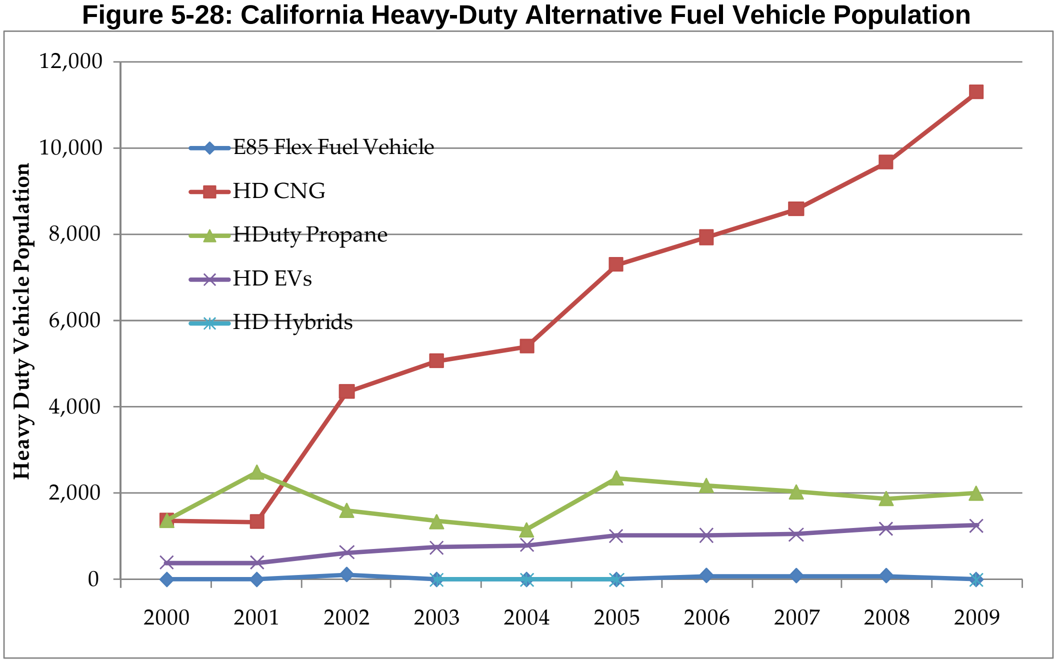
Figure 5-27: California Light-Duty Alternative Fuel Vehicle Population



Source: California Energy Commission Analysis of DMV database

Figure 5-28 shows the California Heavy-Duty Alternative Fueled Vehicle Population trends from 2000 to 2009. Heavy-duty natural gas vehicles make up over 76 percent of the total alternative fueled vehicles.

Figure 5-28: California Heavy-Duty Alternative Fuel Vehicle Population



Source: California Energy Commission analysis of DMV database

Alternative fueled light-duty vehicles, hybrids, and light-duty diesel cars (petroleum reduction vehicles) have been steadily increasing since 1998. Table 5-7 list the light-duty vehicles models listed on the United States Fuel Economy Guide over the years. FFV's represent the largest share of the growth accounting for 95 percent of all light-duty alternative fueled vehicles and 70 percent of all alternative fueled and petroleum reduction vehicle expansion.

Table 5-7: Alternative Vehicle Models Offered 1998 – 2011

	FFVs	Hybrids	Diesels	CNG	Electric Vehicles	Fuel Cells	Propane	Plugin Hybrids	Total
1998	0	0	9	2	0	0	0		11
1999	8	0	5	6	8	0	5		32
2000	11	*1*	4	7	0	0	0		23
2001	21	*2*	3	10	4	0	2		42
2002	23	*2*	4	8	4	0	2		43
2003	35	*2*	4	8	1	1	2		53
2004	34	7	5	15	0	2	2		65
2005	36	10	8	5	0	2	0		61
2006	35	16	6	0	0	3	0		60
2007	59	19	7	1	0	1	0		87
2008	61	22	7	1	0	0	0		91
2009	90	25	6	1	1	2	0		125
2010	75	31	11	1	0	2	0		120
2011	139	41	13	2	3	2	0	1	201

Source: U.S. EPA Fuel Economy Guides 1998-2011.

CHAPTER 6: Petroleum Supply

Crude Oil Supply - Overview, Imports Forecast, and Associated Issues

California's 20 refineries processed more than 1.7 million barrels a day of crude oil in 2010. These facilities are the primary source of transportation fuels for California, Nevada, and Arizona. Over the next several years, the amount of crude oil required in California could remain relatively steady, although the sources of crude oil are expected to continue shifting as California's oil production continues to decline. However, the continual trend of increasing quantities of crude oil imports could be altered by a contraction of California refining capacity or a resumption of offshore exploration and production in California state and federal OCS waters. The likelihood that a resumption of offshore exploration and production will alter the trajectory of crude oil imports over the near to mid-term period is debatable, since it would require several years of sustained effort to realize tangible results. However, over the longer term, the potential impact on crude oil imports of this scenario can be more significant and is presented later in this chapter for comparison.

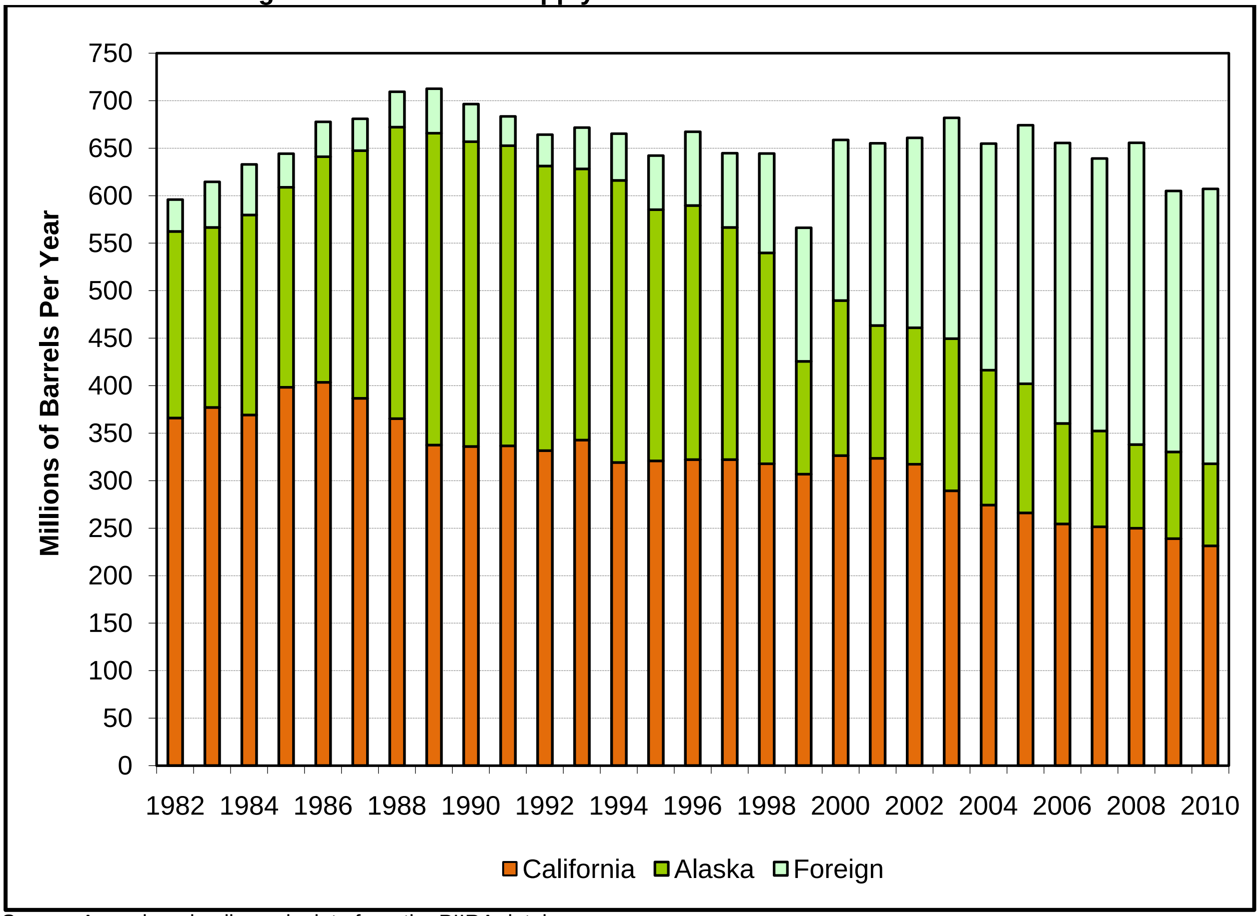
Two factors primarily determine the quantity of crude oil imported into California: the declining production from California crude oil fields and the gradual expansion or contraction of refining capacity in the state. Staff developed the forecast of crude oil imports for the state by analyzing trends for both of these factors over approximately the last decade and by making some assumptions going forward over the forecast period. Rather than working toward a single forecast, staff took the approach that a forecasted range of crude oil imports would be more useful in providing reasonable boundaries of incremental crude oil imports. This approach yielded a Low and High Case for crude oil imports.

The Low Case for crude oil imports first assumes that the decline rate of California crude oil production is less steep than the average rate of depletion experienced over the last decade. In addition, the gradual growth of California refinery capacity to process crude oil, often referred to as refinery creep, is assumed to *decrease* over the forecast period. This is due primarily to a projected decline of gasoline demand in the state that is expected to lead to refinery consolidation in California. These two projections combine to yield a forecast for crude oil imports that is at the lower end of the spectrum. To develop a High Case crude oil import forecast, staff assumed that the depletion of California crude oil sources would continue at a higher rate and that refinery distillation capacity is assumed to remain flat over the forecast period.

Historical California Crude Oil Production and Import Sources

California refineries processed 607 million barrels (1.7 million barrels per day) of crude oil in 2010. The majority of this crude oil was obtained from foreign sources (47.7 percent), followed by California sources (38.1 percent), with the balance from Alaska (14.2 percent). Figure 6-1 illustrates the various sources of crude oil used in California refineries since 1982.

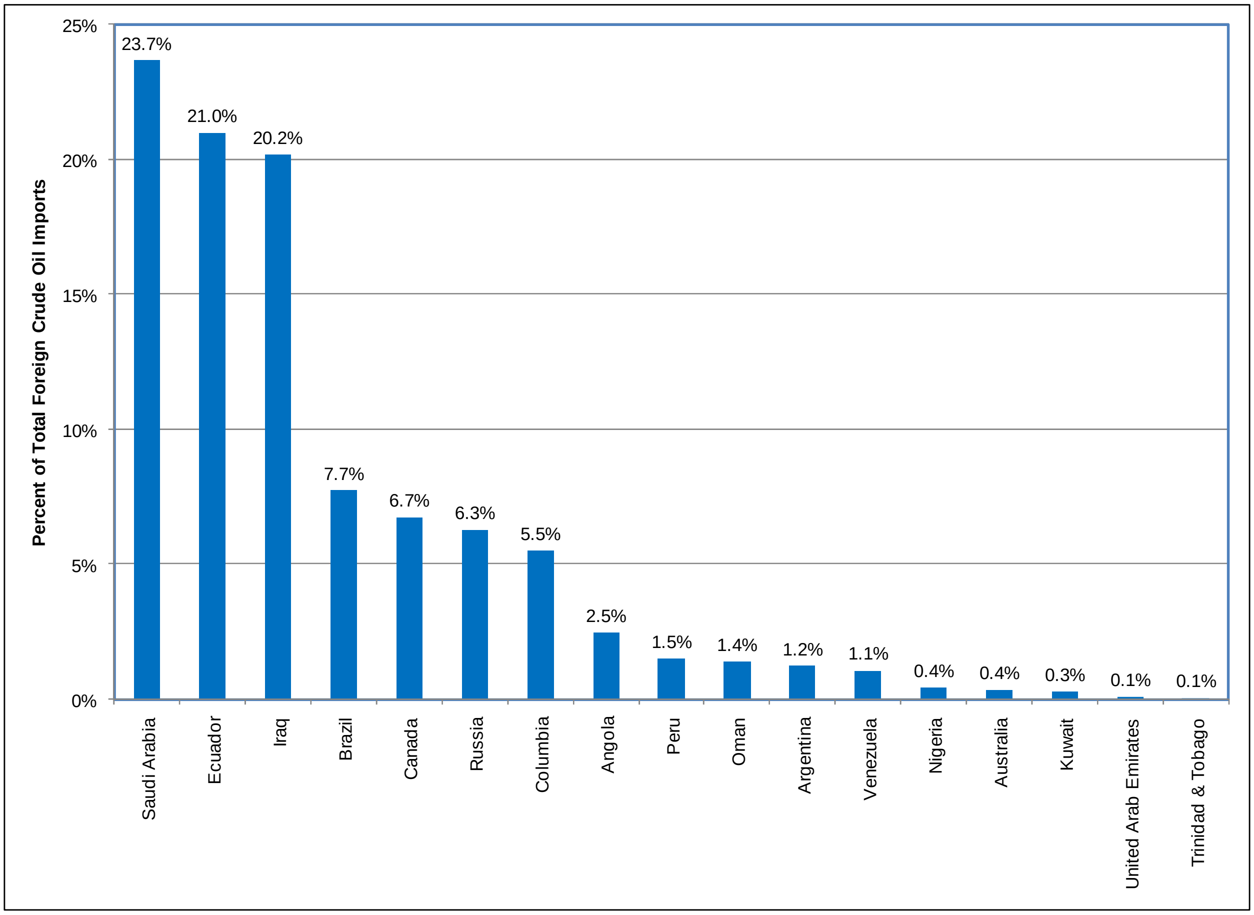
Figure 6-1: Crude Oil Supply Sources for California Refineries



Source: Annual crude oil supply data from the PIIRA database.

Figure 6-1 also shows that foreign-sourced crude oil is increasing to displace declining quantities of California and Alaska crude oil sources. The top five sources of foreign crude oil imports during 2010 were Saudi Arabia, Ecuador, Iraq, Brazil, and Canada. All of the source countries for 2010 and their respective percentage of total foreign imports are presented in Figure 6-2. A complete list of all countries and associated volumes from 2000 through 2010 is located in Appendix C.

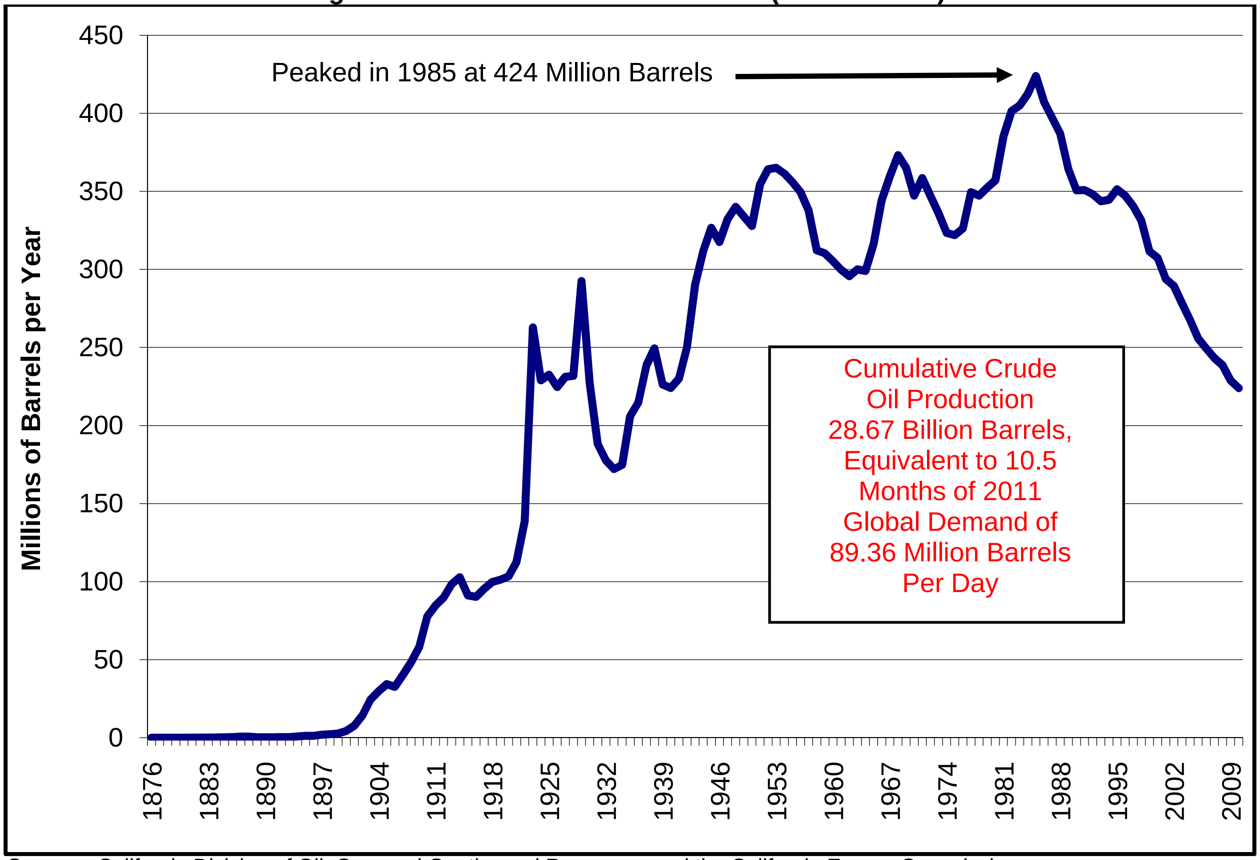
Figure 6-2: California - Foreign Oil Imports for 2010



Source: EIA – Company Level Imports

The decline of California crude oil production has persisted since 1985, when crude oil production peaked at 424 million barrels per year. California crude oil production began in the early 1860s with "production" obtained from horizontal shafts dug into the sides of hills that contained oil seeps.[309] The first oil producing well was drilled in Humboldt County near Petrolia. Since then, technological advances in crude oil exploration and production have enabled companies to obtain crude oil from deeper reservoirs and extract nearly tar-like oil using TEOR (steam injection). Most of California's crude oil producing fields are mature, such as those in Kern County, and have been producing oil for more than 100 years. Over time, the drilling and extraction of crude oil results in diminishing output from wells. As Figure 6.3 illustrates, the production of California crude oil has peaked and will likely continue to decline over the foreseeable future. The primary question is at what rate California's crude oil production will decline over the next 20 years?

Figure 6-3: California Oil Production (1876 to 2010)

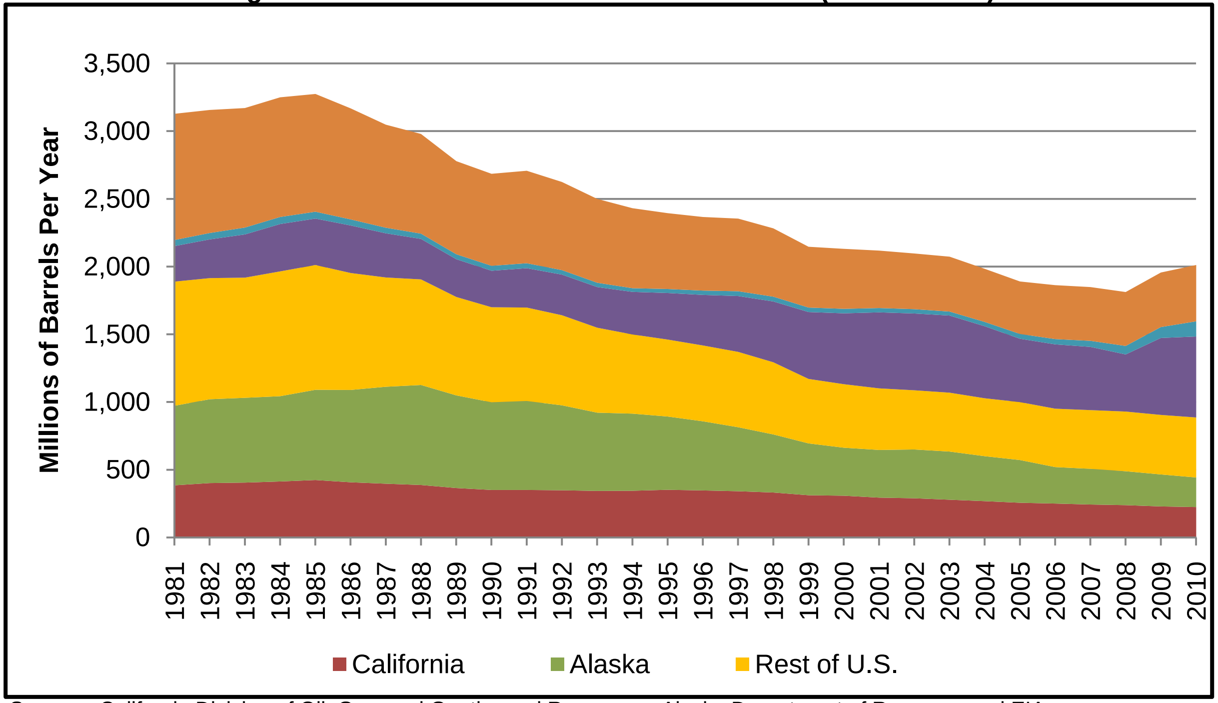


Sources: California Division of Oil, Gas, and Geothermal Resources and the California Energy Commission.

United States and California Crude Oil Production Trends

Since the late 1980s, crude oil production for California has been declining at a steady pace, while the decline rate for United States production has only recently been reversed due to increased output in North Dakota, Texas, and the federal OCS waters of the Gulf Coast.[310] Since 1985, California crude oil production has declined by 47.2 percent; Alaska, by 67.2 percent; and the rest of the United States, by 28.2 percent. During 2010, United States crude oil production totaled a little more than 2.0 billion barrels or an average of 5.51 BPD. Annual United States oil production is slightly over 200 million barrels higher than the low point of 2008. California's annual crude oil production was approximately 223.93 million barrels during 2010, averaging approximately 613,000 BPD. Figure 6-4 breaks down United States crude oil production by selected sources between 1981 and 2010.

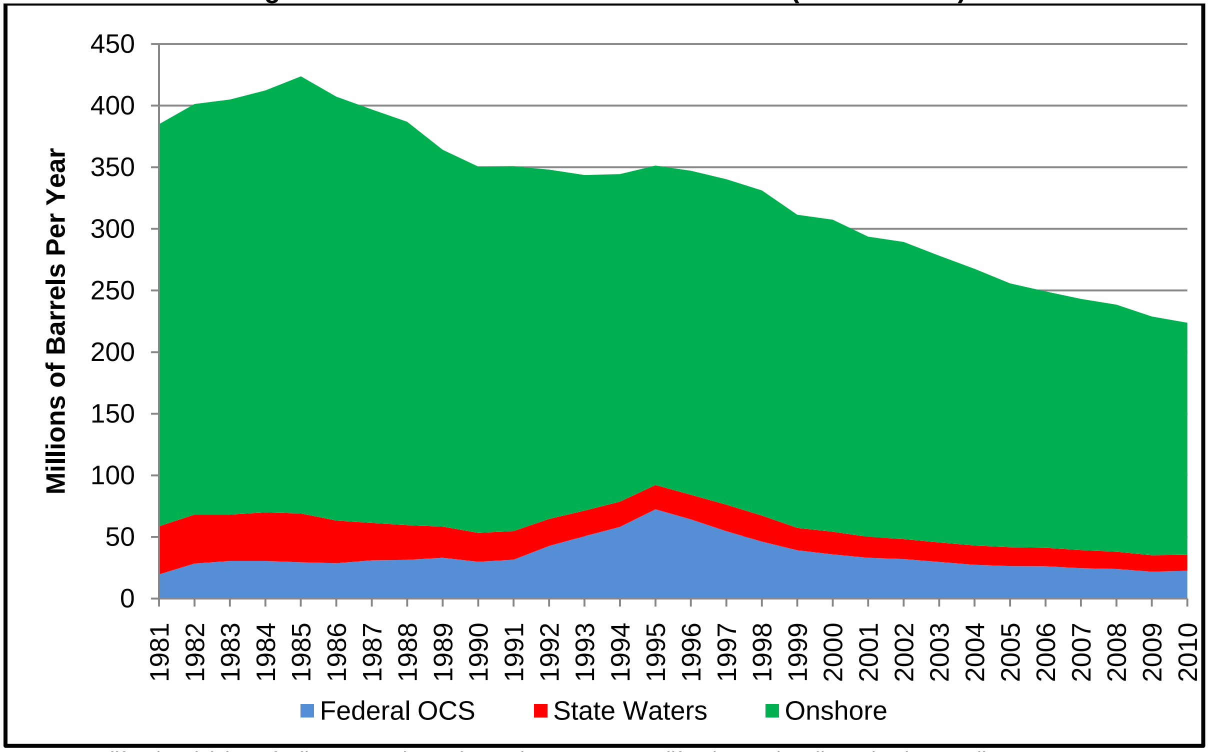
Figure 6-4: United States Crude Oil Production (1981 to 2010)



Sources: California Division of Oil, Gas, and Geothermal Resources, Alaska Department of Revenue, and EIA

Figure 6-5 illustrates California's crude oil production over the same period from three sources: onshore, state offshore waters, and federal OCS.

Figure 6-5: California Crude Oil Production (1981 to 2010)

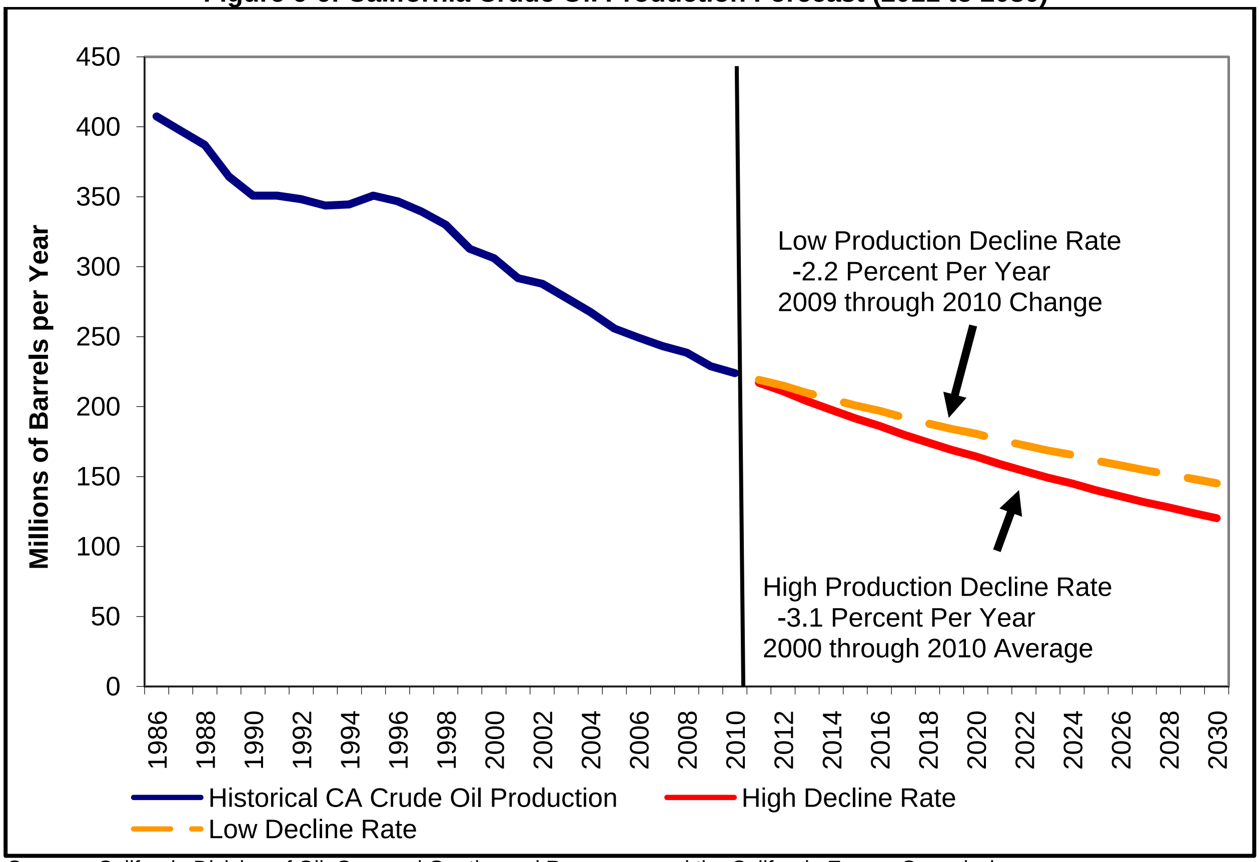


Source: California Division of Oil, Gas, and Geothermal Resources California Crude Oil Production Decline Rates

One factor that contributes to increasing volumes of imported crude oil over time is the steady decline of California crude oil production. As local quantities of crude oil diminish, refiners must compensate by importing additional volumes from sources outside the state. Since Alaska crude oil production has declined at an even greater rate than California production, refiners must seek substitute crude oil from foreign sources.

Figure 6-6 shows the historical and projected crude oil production levels based on a range of decline rates. The higher production decline rate is a trend based on the last decade of historical data, an average decline rate of 3.2 percent per year. The less steep decline rate of 2.2 percent per year is based on the most recent two years of statistics.

Figure 6-6: California Crude Oil Production Forecast (2011 to 2030)



Sources: California Division of Oil, Gas, and Geothermal Resources and the California Energy Commission

California Refinery Operational Assumptions- Processing Capacity, Utilization Rates, and Refinery Projects

The capacity to process crude oil at California refineries, how that level may change over time, the rate at which refineries operate, and the status of other types of refinery expansion projects are important factors that impact the forecast for imports of crude oil into the state.

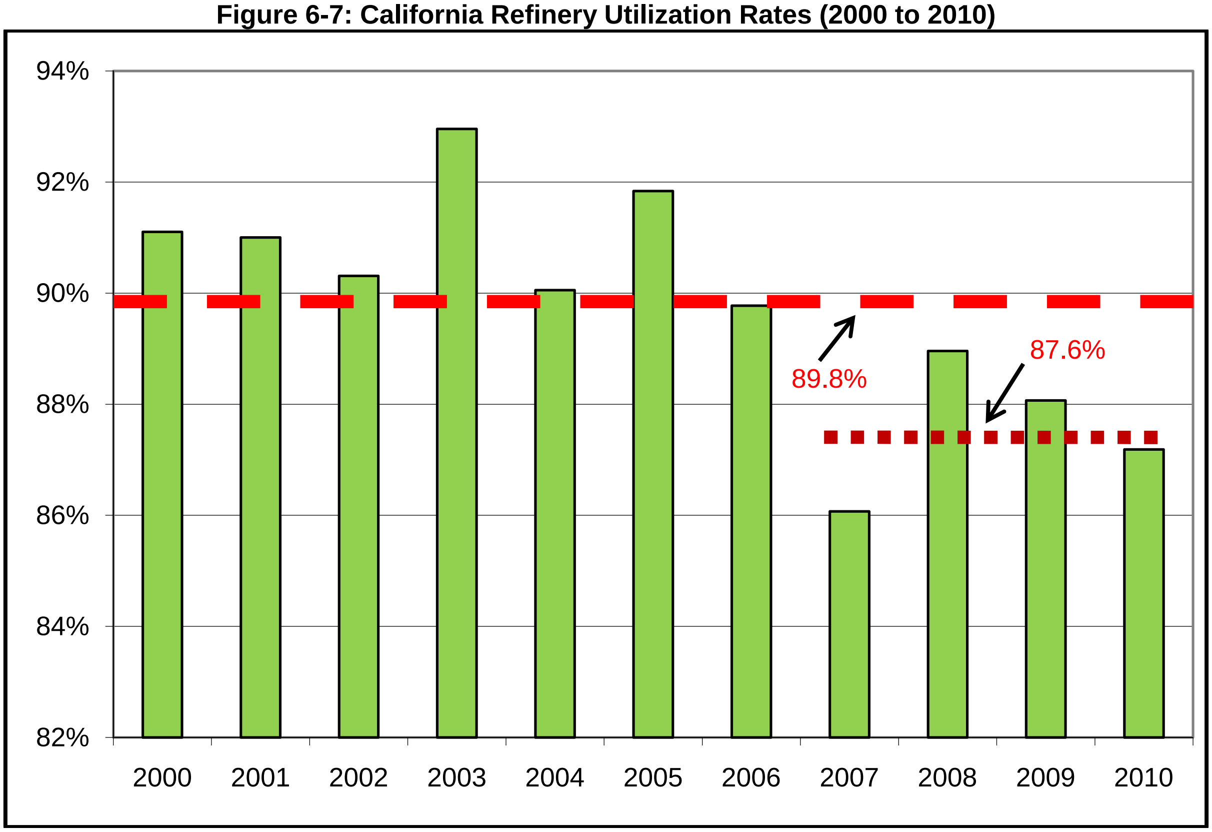
California Refinery Distillation Capacity

In the initial processing step, atmospheric distillation process units convert crude oil to a variety of petroleum blendstocks that are combined to form gasoline, diesel, and jet fuel. Occasionally, a refiner may elect to expand slightly the capacity of its crude oil distillation equipment or other process units if the project meets environmental guidelines and can be justified as having a sufficient economic return for the cost of the project. This gradual increase of distillation capacity—*refinery creep*—is one of the primary factors that can contribute to changing levels of California crude oil imports. Operating capacity for California refineries was approximately 1.86 million barrels per calendar day for 2010.[311] Over the forecast period, total in-state operating distillation capacity was not increased in response to the restart of the Alon USA refinery in Bakersfield [312]

California Refinery Utilization Rates

Since refineries do not process crude oil when the distillation units are undergoing maintenance or are temporarily out of service from an unplanned refinery outage, their utilization rates (a measure of actual crude oil processed per day relative to the maximum capacity of the equipment) will be at a level of less than 100 percent. For all of the refineries operating in California since 2000, the combined utilization rate has averaged 89.9 percent. However, that level has dropped to 87.6 percent over the last 4 years, likely due to declining demand for gasoline and poorer refining margins compared to earlier periods (see Figure 6-7).

Figure 6-7: California Refinery Utilization Rates (2000 to 2010)



Sources: EIA, PIIRA database, and California Energy Commission analysis

Status of California Refinery Projects

Refining projects identified during the *2009 IEPR* included Chevron's Energy and Hydrogen Renewal Project at its Richmond refinery and the Clean Fuels Project (CFP) at Big West's Bakersfield refinery. Since that time, the Chevron project has been scaled back from its original scope. [313] The deleted portion of the project would have increased the production of gasoline by approximately 300,000 gallons per day or about 7,140 barrels per day.[314] Chevron proceeded with the project until construction was halted by litigation with 50 percent of the work completed. Chevron submitted a conditional use permit application to the City of Richmond during May of 2011.[315] The Revised Project will now only include the new hydrogen plant. The City of Richmond will be responsible for preparing a revised Environmental Impact Report (EIR) to comply with the litigation.[316] Energy Commission staff assumes that completion of this project will not result in an increase of transportation fuel production from this facility.

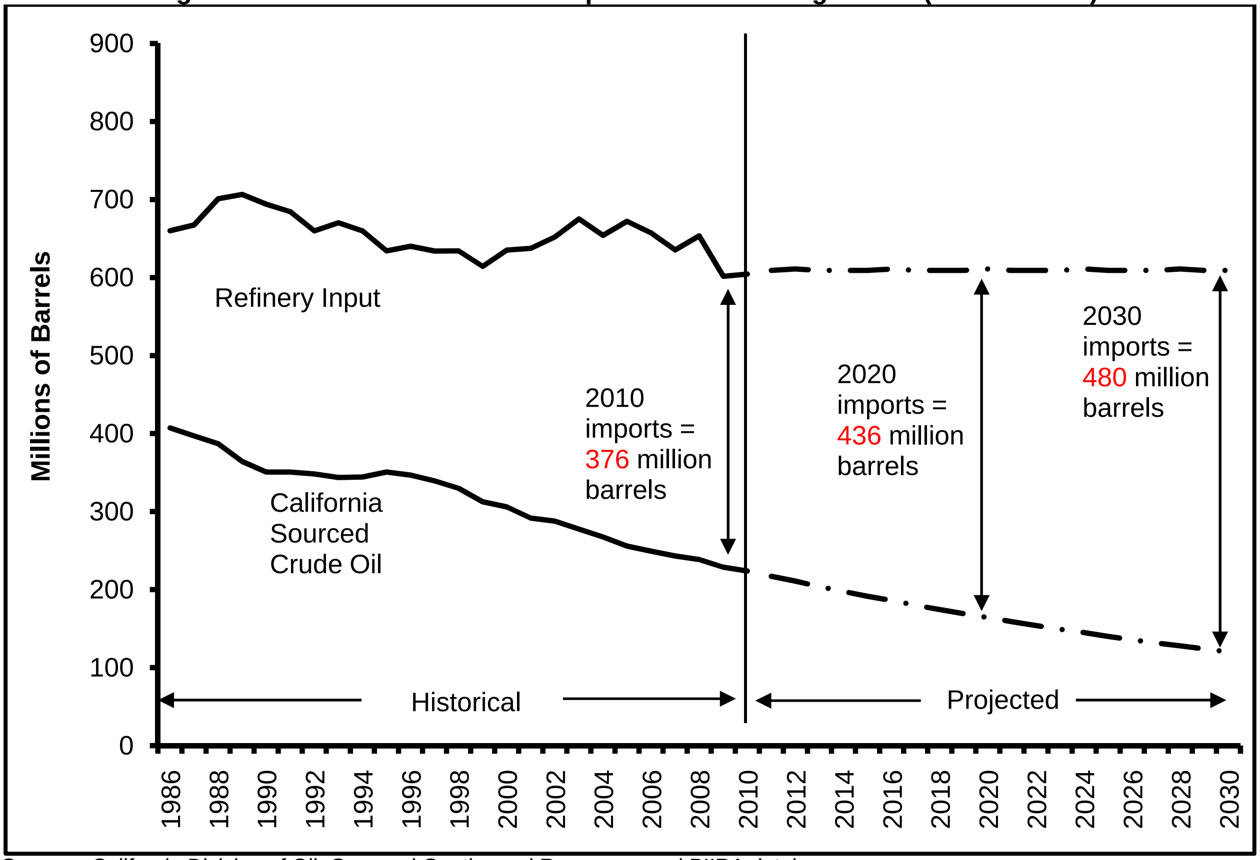
Since the *2009 IEPR*, the Big West refinery has been sold to Alon USA Energy.[317] The company completed work on a hydrocracker project and resumed operations at the facility during June of 2011.[318] The unique aspect of this facility is that no crude oil is being processed to produce gasoline and diesel fuel. Rather, the company uses partially processed crude oil or gas oils as their feedstock. The refinery's crude oil distillation capacity is assumed to be zero for purposes of calculating utilization rates and forecasting crude oil imports for California. Due to the projected reduction in gasoline demand for California resulting from increased use of renewable fuels and improvement in light-duty vehicle fuel efficiency, it is unlikely that there will be any significant expansion of existing refining distillation capacity in California over the forecast period. The only exception to that assumption is the possibility of refining projects designed specifically to increase the yield of diesel fuel. Historically, the capacity of California refineries to process crude oil has gradually increased. Staff has assumed that this historical refinery creep will not continue as part of the base assumptions used in the primary analysis of imports and exports of refined transportation fuels.

California Crude Oil Import Forecasts

High Crude Oil Import Case

Staff has elected to use a flat distillation capacity growth rate of zero percent per year over the forecast period in conjunction with the higher utilization rate of 89.8 percent (from 2000 through 2010), and the higher rate of 3.1 percent for California crude oil production decline to yield the upper range for projected crude oil imports (see Figure 6-8).

Figure 6-8: California Crude Oil Import Forecast – High Case (2011 to 2030)



Sources: California Division of Oil, Gas, and Geothermal Resources and PIIRA database.

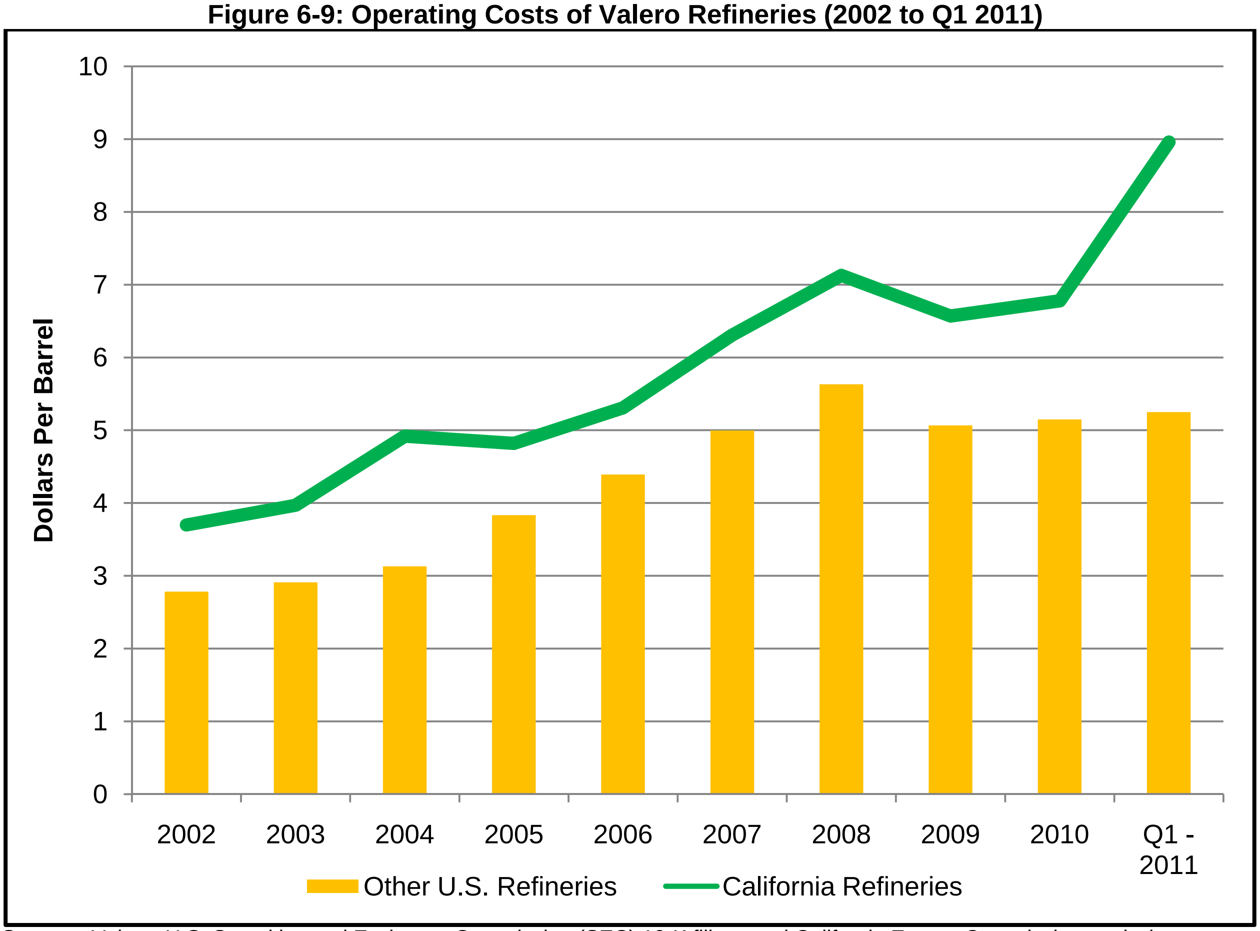
The High Case for crude oil imports yields increases compared to 2010 of 60 million barrels per year by 2020 and 104 million barrels per year by 2030. In this case, increased crude oil imports are solely the result of continued steady decline of California's crude oil production since refining distillation capacity remains fixed over the forecast period. This High Case outlook is substantially lower than the one presented as part of the *2009 IEPR*, primarily because increasing refining capacity was assumed in that earlier case. The 2009 analysis estimated that additional crude oil imports would be 113 million more barrels per year by 2020 and 190 million more barrels per year by 2030.[319] Potential impacts on the crude oil import forecast of additional offshore exploration and production activities is discussed in the "Alternative Assumptions" section of this chapter.

Low Crude Oil Import Case

Staff modified three assumptions as part of the forecast of crude oil imports under the Low Case scenario. The first was to assume a less steep decline rate for California crude oil production of approximately 2.1 percent per year, rather than 3.1 percent decline rate used in the High Case scenario. The second modified assumption was to use a slightly lower utilization rate of 87.6 percent that was the average from 2007 through 2010. The third assumption that California refining capacity would remain level over the forecast period was also modified as part of this scenario.

The possibility that some of California's refining capacity could be reduced over time as part of some refinery asset consolidation was considered a very low probability during previous *IEPR* cycles. However, the possibility of a refinery closing in California is now assumed to be of higher probability based on: recent announcements made by several oil companies; an assumption that California refinery operating costs are higher than other regions of the United States; and additional operating costs that California refiners will incur over the near and mid-term.[320] The cost of refining operations in California is assumed to be greater compared to other regions of the United States, resulting in a heightened risk of refinery consolidation in a scenario of decreasing gasoline demand and escalating refining operating costs from other state regulatory programs. Few companies provide public information to make such a demonstration. Figure 6-9 illustrates the difference in operating costs for Valero, the largest refining company in the United States.[321]

Figure 6-9: Operating Costs of Valero Refineries (2002 to Q1 2011)

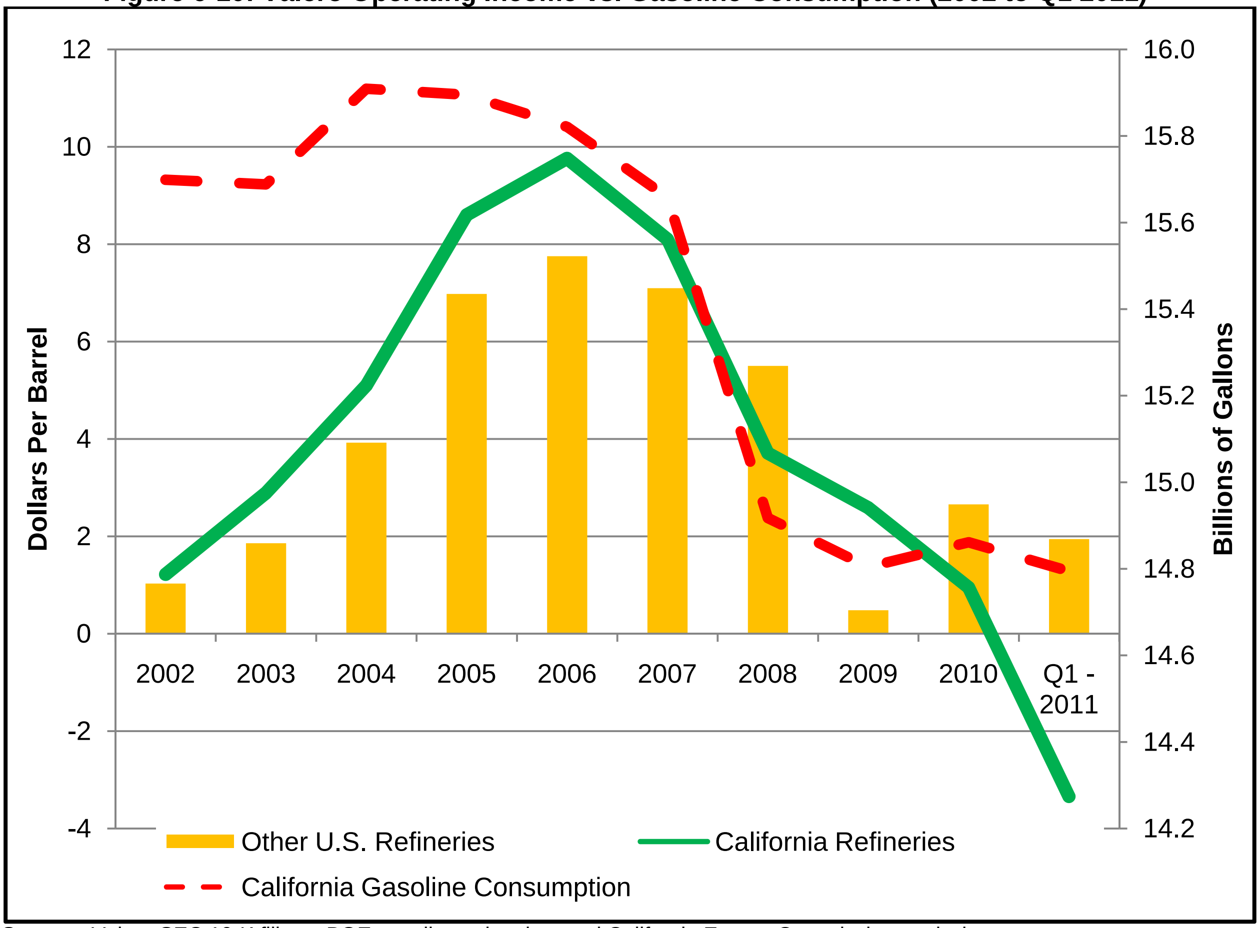


Sources: Valero, U.S. Securities and Exchange Commission (SEC) 10-K filings and California Energy Commission analysis

The Energy Commission does not currently have the authority to mandate California refiners to routinely submit sufficient types of refinery-specific cost information to verify staff's assumption of higher operating costs relative to other regions in the United States for all of the other companies that operate refineries in the state. The Energy Commission's PIIRA regulations would need to be modified to enable mandatory reporting of this type of information to enable staff to periodically quantify and publicly report the aggregated magnitude of this difference in California refinery operating costs.

As mentioned earlier, gasoline demand in California is forecast to decline. California refineries were designed, in part, to maximize gasoline production. As such, operating income (difference between refining margin and total operating costs) can be negatively impacted by declining gasoline demand. Figure 6-10 shows this relationship for Valero's operating income and California gasoline consumption since 2002.

Figure 6-10: Valero Operating Income vs. Gasoline Consumption (2002 to Q1 2011)

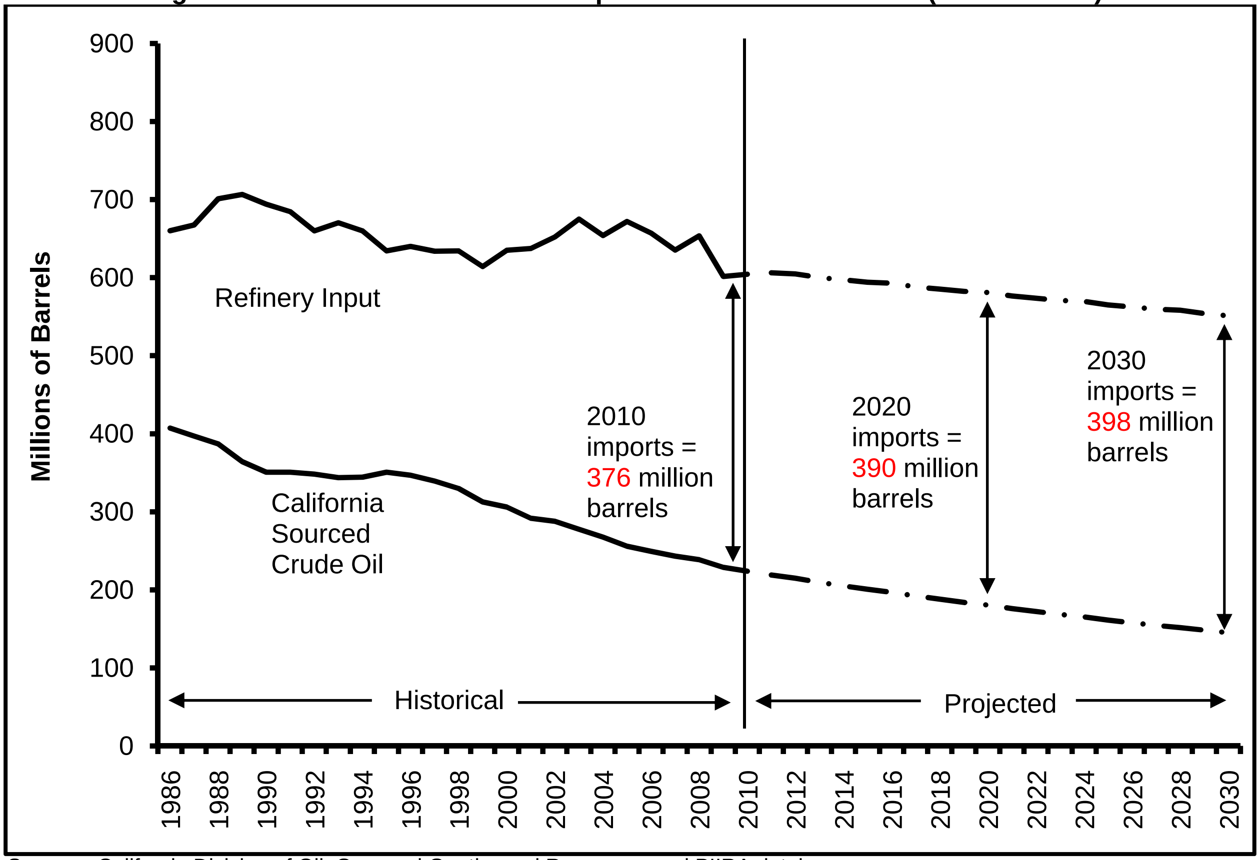


Sources: Valero SEC 10-K filings, BOE gasoline sales data and California Energy Commission analysis

Lastly, California refiners are expected to incur additional operating costs over the near-term that competitors outside of the state will not experience that will likely impact their profitability and further increase the risk of refining consolidation in California. Examples include compliance costs associated with California's AB32, LCFS, and HCICO requirements.

Staff has elected to use a declining rate for California refinery distillation capacity of 0.5 percent per year over the forecast period in conjunction with a less steep rate for California crude oil production decline of 2.2 percent per year and the lower utilization rate of 87.6 percent to yield the lower range for projected crude oil imports (see Figure 6-11).

Figure 6-11: California Crude Oil Import Forecast – Low Case (2011 to 2030)



Sources: California Division of Oil, Gas, and Geothermal Resources and PIIRA database

The Low Case for crude oil imports compared to 2010 projects an increase of 14 million barrels per year more in 2020 and 22 million barrels per year more by 2030. In this case, increased crude oil imports are dramatically lower when compared to the High Case, primarily because of the assumed reduction in refining capacity of approximately 170 TBD by the end of the forecast period. Staff acknowledges that any conversion of a California refinery to a product terminal would not occur over a multi-year period of time, but would instead appear as a step-down in refining capacity during a single year. This means that the forecast crude oil imports for the mid-term could be lower than shown in the chart above, but similar to those at the end of the forecast period.

This Low Case outlook is substantially lower than the one presented as part of the *2009 IEPR*, primarily due to an assumption of decreasing refining capacity that was used for this scenario. Additional crude oil imports estimated in that earlier work were 55 million more barrels per year by 2020 and 91 million more barrels per year by 2030.[322] Potential impacts on the crude oil import forecast of additional offshore exploration and production activities is discussed in the "Alternative Assumptions" section of this chapter.

The use of different rates for crude oil production decline, refinery creep, and utilization rates can significantly alter the estimated range of incremental crude oil imports. Table 6-1 combines the various factors and results into a single table for the near-term (2015), mid-term (2020) and longer-term (2030) periods of the forecast.

Table 6-1: Import Projections for Entire State

Incremental California Crude Oil Imports - Millions of Barrels						
Distillation Capacity Growth Rate	Utilization Rate of 87.6% Oil Production Decline - 2.2%			Utilization Rate of 89.8% Oil Production Decline - 3.1%		
	2015	2020	2030	2015	2020	2030
Zero Percent				32	60	104
- 0.5 Percent	8	14	22			

Source: California Energy Commission analysis of PIIRA data

The next step in the analysis involved an estimate of the portion of the incremental crude oil imports for the entire state that would be delivered to Northern and Southern California, respectively. Based on recent historical trends, staff assumed that 60 percent of the incremental crude oil imports over the forecast period would be delivered to marine terminals in Southern California, with the balance (40 percent) handled by marine berths in the San Francisco Bay Area.[323] Table 6-2 shows how the incremental import projections for Southern California can vary by changing the assumed rates for crude oil production decline and refinery creep.

Table 6-2: Import Projections for Southern California

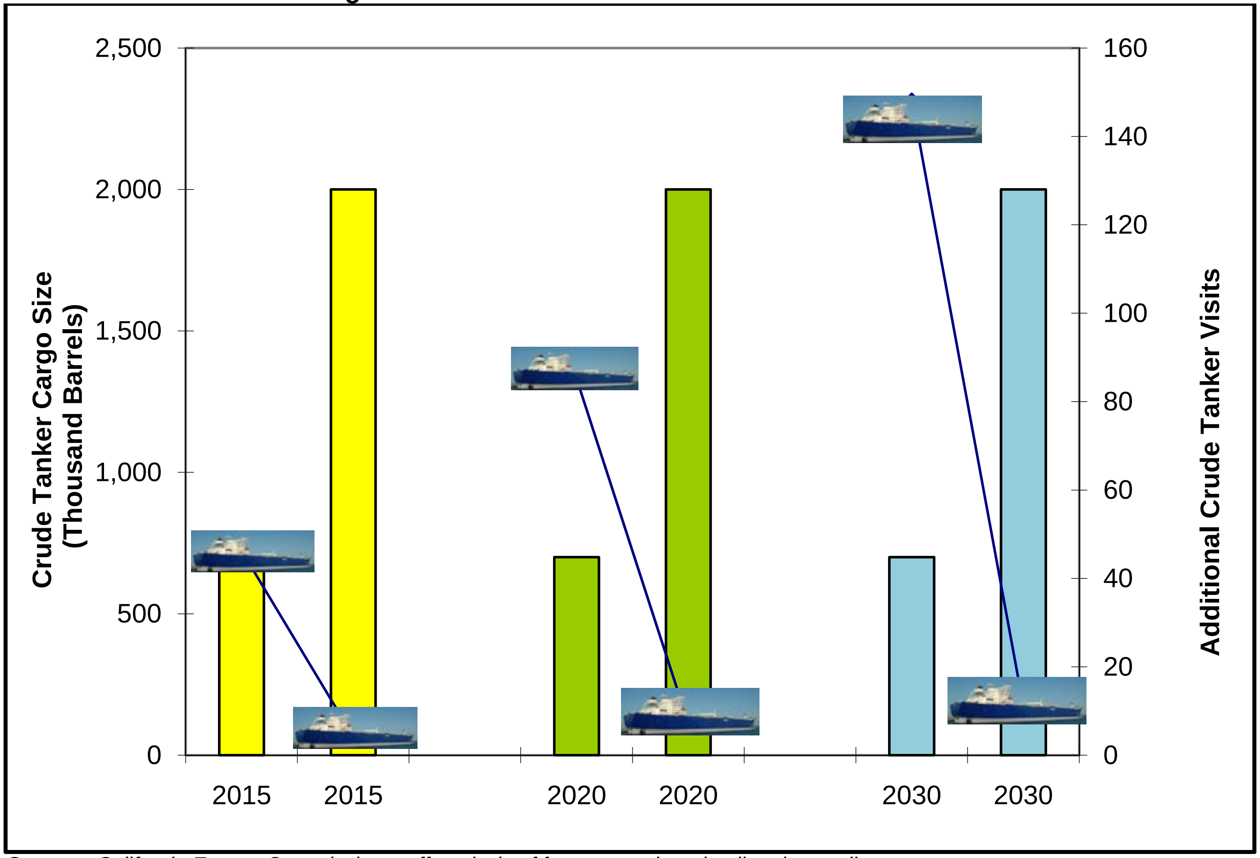
Incremental **Southern California** Crude Oil Imports - Millions of Barrels						
Distillation Capacity Growth Rate	Utilization Rate of 87.6% Oil Production Decline - 2.2%			Utilization Rate of 89.8% Oil Production Decline - 3.1%		
	2015	2020	2030	2015	2020	2030
Zero Percent				19	36	62
- 0.5 Percent	5	9	13			

Source: California Energy Commission

Crude Oil Tankers–Incremental Voyages

The increased imports of crude oil are expected to result in a greater number of marine vessels (referred to as crude oil tankers) arriving in California ports. Staff has examined recent import information to determine an average cargo size per crude oil tanker import event. For calculating additional crude oil tanker trips, staff used an upper limit of 2 million barrels of cargo capacity per import event and a lower limit of 700,000 barrels capacity. The upper limit represents the storage capacity of a very large crude carrier (VLCC). The lower range is the capacity of typical foreign crude oil tankers, referred to as Aframax (80,000 to 119,000 deadweight tonnage). This scenario assumed that the bulk of the incremental imports of crude oil over the near term will originate from foreign sources and be transported on Aframax marine vessels. Using these two estimates for crude oil tanker capacity, staff calculated 5 to 47 additional crude oil tanker arrivals per year by 2015, 8 to 86 by 2020, and 12 to 149 additional arrivals per year by 2030. The broad range for the estimate is a consequence of the large difference in capacity between the Aframax and VLCC storage capacities, as well as the annual incremental crude oil import forecast differences between the High and Low Cases.[324] Figure 6-12 depicts the broad range of incremental crude oil tanker import events at various points of the forecast. The vertical axis on the left side is for the size of the crude oil tanker cargo capacity, while the vertical axis on the right side is for the number of additional crude oil tanker visits in a specific year at some point during the forecast period.

Figure 6-12: Incremental Crude Oil Tanker Visits



Sources: California Energy Commission staff analysis of forecast and crude oil tanker attributes.

Crude Oil Storage Capacity–Future Expansion

The importation of incremental volumes of crude oil will not only necessitate an increased number of crude oil tanker visits, but will also require a larger storage tank capacity for the marine facilities receiving the additional cargoes. The Energy Commission staff has calculated additional storage tank capacity that would have to be constructed to handle the incremental imports of crude oil. This scenario assumes that most of the existing marine terminals are at or near maximum operating capacity. Two incremental storage tank throughput rates were used to calculate the additional crude oil storage tank capacity estimates.

The first rate uses a design capacity throughput similar to the proposed crude oil import project at Berth 408 in San Pedro Harbor, approximately 1 million barrels of storage capacity per 23 million barrels of imports per year.[325] The second rate assumes a slower cycling of the storage tanks, yielding a conversion rate of about 1 million barrels of storage capacity per 12 million barrels of imports per year. Based on these assumptions, the incremental crude oil storage capacity needed in California would amount to between 0.4 million and 2.7 million barrels by 2015; between 0.6 million and 5.0 million barrels by 2020; and between 1.0 million and 8.6 million barrels of storage capacity by 2030. Nearly 60 percent of this incremental storage capacity will need to be constructed in Southern California, where spare land for such projects is at a premium.

Based on the results from the two cases developed for incremental crude oil imports for California, staff believes that the High Case necessitates the need for expanded capability to receive greater volumes of crude oil imports within the next four to five years. Absent an expansion of incremental import capability, there would be an increased risk of a constrained crude oil import infrastructure that could endanger the ability of refiners to operate their facilities at high enough utilization rates to produce sufficient supplies of transportation fuels to meet the needs of California consumers and businesses.

California's marine import infrastructure for crude oil has demonstrated that a little more than 400 million barrels per year can be received, as was the case during 2005 and 2008 when 408 million and 406 million barrels of oil were imported, respectively. Since waterborne imports of crude oil (from Alaska and foreign sources) during 2010 amounted to nearly 376 million barrels, there should, in theory, be a minimum of about 32 million barrels of spare import capability. This means, simplistically, that the Low Case for imports could be met by existing crude oil import infrastructure.

However, this conclusion could be nullified if any of the existing crude oil import infrastructure were to be closed down due to pressures to convert some of these marine terminals to other uses, such as cargo container import facilities. Petroleum marine terminals in the Ports of Los Angeles and Long Beach have periodically come under pressure either to be shuttered or relocated to make way for other types of port commercial activity that generates greater revenue per acre per year for the respective port authorities who allow oil companies to operate under long-term leases that have staggered expiration dates. To quote from an earlier Energy Commission report: *Efforts to expand existing petroleum infrastructure or to create additional infrastructure have been met with stiff resistance from some local community members, elected politicians, and port representatives. Objections include concerns over increased air pollution, increased truck traffic, aesthetic objections to the sight of storage tanks, perceived safety threat to nearby communities, and competition for diminishing spare land that is coveted by community members for park/recreational development and port representatives for expansion of cargo container handling facilities.*[326]

In addition, "spare" import capacity is a subjective term that fails to incorporate circumstances by which one or more existing marine terminals are temporarily out of service due to damage inflicted by a natural disaster (earthquake, tsunami, etc.) or an act of terrorism. In other words, spare capacity to import greater quantities of crude oil should also be viewed as a type of insurance policy that would help ensure continuity of operations for these types of plausible contingencies.

Currently, there are two petroleum import infrastructure projects in Southern California that are at various stages of development. The first site is Berth 408 at Pier 400 in the Port of Los Angeles. This facility is designed to receive up to 350 TBD of crude oil and contain 4 million barrels of new crude oil storage tanks.[327] Figure 6-13 shows the proposed location for Berth 408 on Pier 400.

Figure 6-13: Berth 408 Location in Port of Los Angeles

Source: Pacific Energy Partners (PEP)

The environmental and permit review process for this project was initiated in 2003.[328] After development of a draft Environmental Impact Report (DEIR) and draft Environmental Impact Statement (DEIS) by the Army Corps of Engineers and the Port of Los Angeles, the Board of Harbor Commissioners approved the Pier 400, Berth 408 project's DEIR/DEIS in the fourth quarter of 2008, and the Los Angeles City Council approved the Pier 400, Berth 408 project's DEIR/DEIS in the second quarter of 2009.[329] The most recent development has been the completion of a Value Engineering Study by Pacific LA Marine Terminal LLC (PLAMT), the current business organization backing this project.[330] The last two major steps that need to be completed prior to finalizing design and beginning construction include a completion of the lease agreement with the Port of Los Angeles, and long-term agreements with prospective customers.[331] The facility could be operational within 29 months of those last major hurdles being overcome.[332]

The Port of Long Beach issued a Request for Proposal (RFP) on May 21, 2010 to receive bids on a project referred to as Pier Echo located at Berth T126.[333] Pier Echo is intended to be a new marine terminal designed to receive imports of crude oil, as well as serve the local transportation fuel market by enabling imports and exports of petroleum and renewable fuels. Vopak has been selected as the winning bidder for the RFP. The scope and capacity of the terminal has yet to be finalized, but will likely be similar to throughput design of Pier 400 and sufficient to handle the incremental crude oil import forecast volumes from our High Case analysis. Based on Energy Commission analysis, the Southern California market may only require one of these import facilities to be constructed over the forecast period, not both.

Alternative Assumptions – Impact on Crude Oil Import Forecast

Crude oil imports for California refiners could be less than initial staff projections indicate under a different scenario of expanded exploration and production off of California's coast. Expanded offshore drilling and production remain a contentious issue, especially in light of last year's oil spill in the Gulf of Mexico from BP's Macondo well tragedy that accounted for the greatest accidental release of crude oil in world history, approximately 4.9 million barrels or about 206 million gallons.[334] For comparison, the *Exxon Valdez* spill during 1989 in Alaska amounted to approximately 10.8 million gallons. The previous record for largest accidental spill of crude oil was 140 million gallons released from the Ixtoc 1 oil well leak in the Gulf of Mexico (Mexico waters) between June 3, 1979 and March 23, 1980.[335] The previous largest spill in U.S. waters was back on February 29, 1968, when the tanker *Mandoil* sank in the Pacific Ocean, near Warrenton, Oregon, releasing an estimated 12.8 million gallons.[336] The single biggest spill off the coast of California was from the blowout of a Union Oil Company offshore well located 5.5 miles southeast of Santa Barbara on January 28, 1968. The well was not capped until February 7, 1968 and is estimated to have released about 4.2 million gallons of crude oil to the environment.[337]

In the wake of the BP oil spill, significant change has come to the federal regulatory structure that oversees offshore oil and gas activities. The MMS has been replaced, in part, by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE).[338] The next sections in this chapter are intended to provide a summary of oil production potential from offshore California, along with an assessment of how the High and Low Case crude oil forecast results might be impacted.

Timing and Supply Potential of Expanded Offshore Drilling Scenario

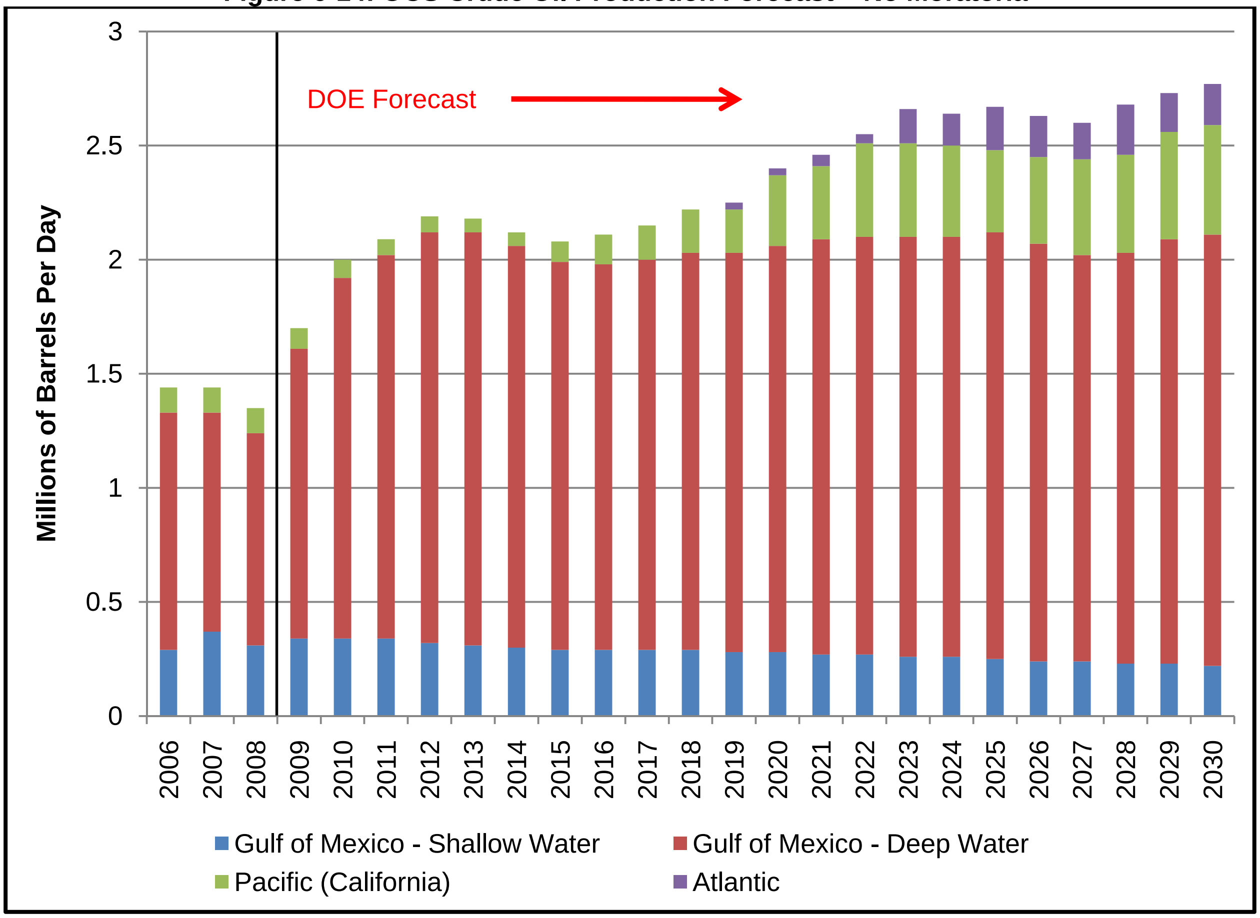
The federal moratoria for drilling in federal OCS waters expired when Congress took no action to reinstate the ban before the new federal fiscal year began on October 1, 2008. Before that date, the MMS initiated a new five-year lease process that included the OCS moratoria areas. The moratoria areas off the coast of California were estimated by MMS to contain between 5.8 billion and 15.8 billion barrels of UTRR crude oil.[339] Over half of this estimated crude oil resource is located in federal waters off the coast of Southern California. However, the federal MMS estimated that between 53 and 78 percent of these reserves would be economically recoverable based on crude oil prices ranging from $60 to $160 per barrel.[340]

Once an oil company is a successful recipient of a lease, it would be able to initiate the processes to develop an exploration plan, obtain the necessary capital, construct the drill rigs, drill exploratory wells, assess drill results and mapping analysis, construct a drilling platform, drill production wells, and construct pipelines from the platform to onshore facilities before new crude oil production could begin. Due to the lengthy federal regulatory process and the numerous developmental steps, it is no surprise that the EIA estimates that it could take up to 10 years for new crude oil production to begin from the moratoria OCS areas.[341]

The U.S. DOE has estimated the pace and quantity of additional crude oil production that could be achieved from expanded drilling in federal OCS waters for the lower 48 states. The incremental quantities are illustrated in Figure 6-14. Under this scenario, OCS crude oil production is forecast to increase from 1.35 million barrels per day in 2008 to approximately 2.77 million barrels per day by 2030. New production associated with lifting of the moratoria is assumed to begin in 2015, since the process to develop these new areas could require at least five years. Compared to 2014, crude oil production would increase from 2.12 million barrels per day to 2.77 million barrels per day by 2030, approximately 650,000 barrels per day higher by the end of the forecast period. The majority (65 percent by 2030) of this incremental OCS crude oil production is forecast by the U.S. DOE to occur in the Pacific region (essentially California). In fact, nearly 74 percent of the cumulative incremental crude oil production is forecast to originate from the Pacific (California) OCS region, 1.5 billion barrels of the total 2.1 billion barrels incremental crude oil production between 2014 and 2030.

If federal, state, and local governments were to pursue such an expanded drilling scenario, a new infrastructure of offshore oil production platforms, interconnecting pipelines, crude oil trunk lines, and pump stations would likely be required to achieve this forecast level of incremental crude oil production. It is unknown what portion of the untapped economically recoverable crude oil OCS reserves are close to any of the existing 22 offshore platforms (in federal OCS waters) such that directional drilling could be employed to increase production without constructing any new platforms and associated infrastructure.[342] However, it is unlikely that these OCS crude oil reserves could be completely accessed without the construction of new infrastructure that is currently undetermined in scope and cost.

Figure 6-14: OCS Crude Oil Production Forecast – No Moratoria



Source: California Energy Commission staff analysis of data from the U.S. DOE Office of Petroleum Reserves

Impact on California Crude Oil Import Forecast of Lifting OCS Moratoria

If the lifting of the OCS moratoria remains in effect and development proceeds as forecast by U.S. DOE off the coast of California, the incremental crude oil production could have a significant impact on the forecast of crude oil imports, as illustrated in Table 6-3.

Table 6-3: Moratoria Scenario – Import Projections for Entire State

Incremental California Crude Oil Imports - Millions of Barrels						
Distillation Capacity Growth Rate	Utilization Rate of 87.6% Oil Production Decline - 2.2%			Utilization Rate of 89.8% Oil Production Decline - 3.1%		
	2015	2020	2030	2015	2020	2030
Zero Percent				21	-32	-50
- 0.5 Percent	-3	-77	-131			

Source: U.S. DOE OCS forecast and California Energy Commission analysis

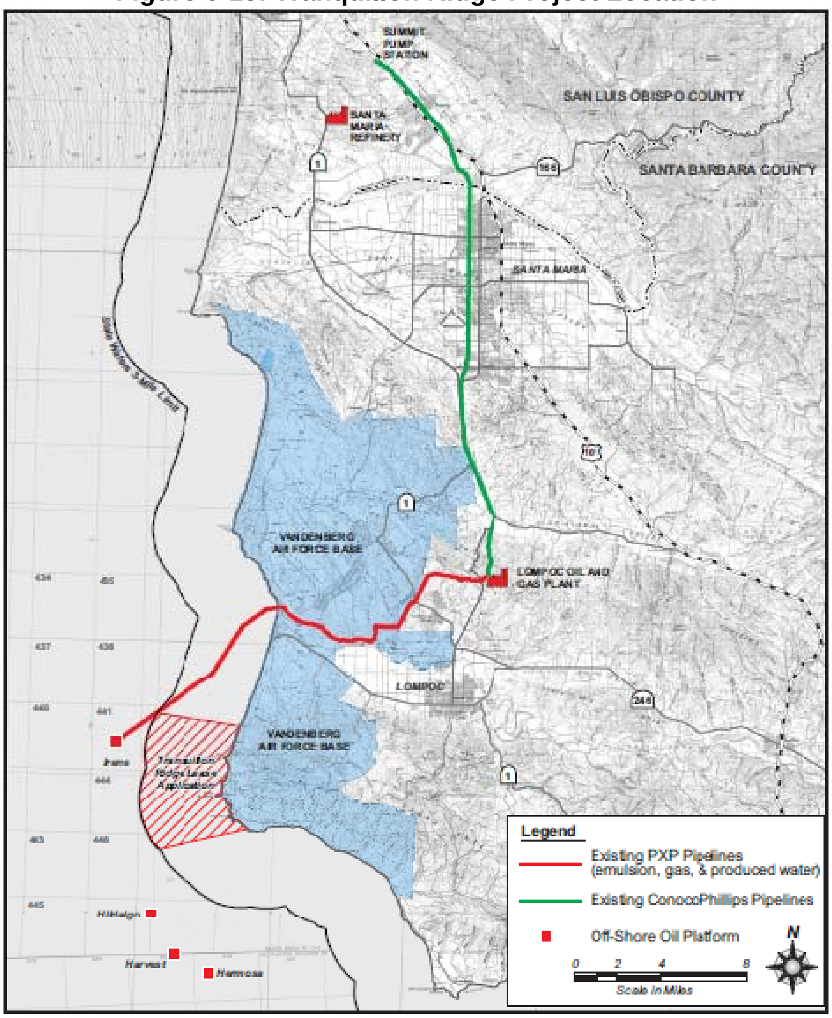
The negative figures in Table 6-3 indicate that resumption of new crude oil drilling and production activities off the coast of California in federal OCS waters could significantly impact the crude oil import forecast, such that waterborne imports of crude oil would actually be less than they were in 2010, regardless of scenario.

Impact on California Crude Oil Import Forecast of Renewed Drilling in California State Waters

Although the scenario of expanded drilling off of California's coast in OCS waters is a contentious and complicated process that would entail a significant period to achieve any tangible results (if allowed to proceed), there are two projects that have been recently proposed off the coast of California that could result in additional quantities of crude oil being produced from existing offshore platforms.

The Plains Exploration and Production Company was pursuing a project in 2010 that involved drilling additional wells from its existing Platform Irene (that lies in federal OCS waters off of Vandenberg Air Force Base) into a crude oil field referred to as Tranquillon Ridge (Figure 6-15).[343]

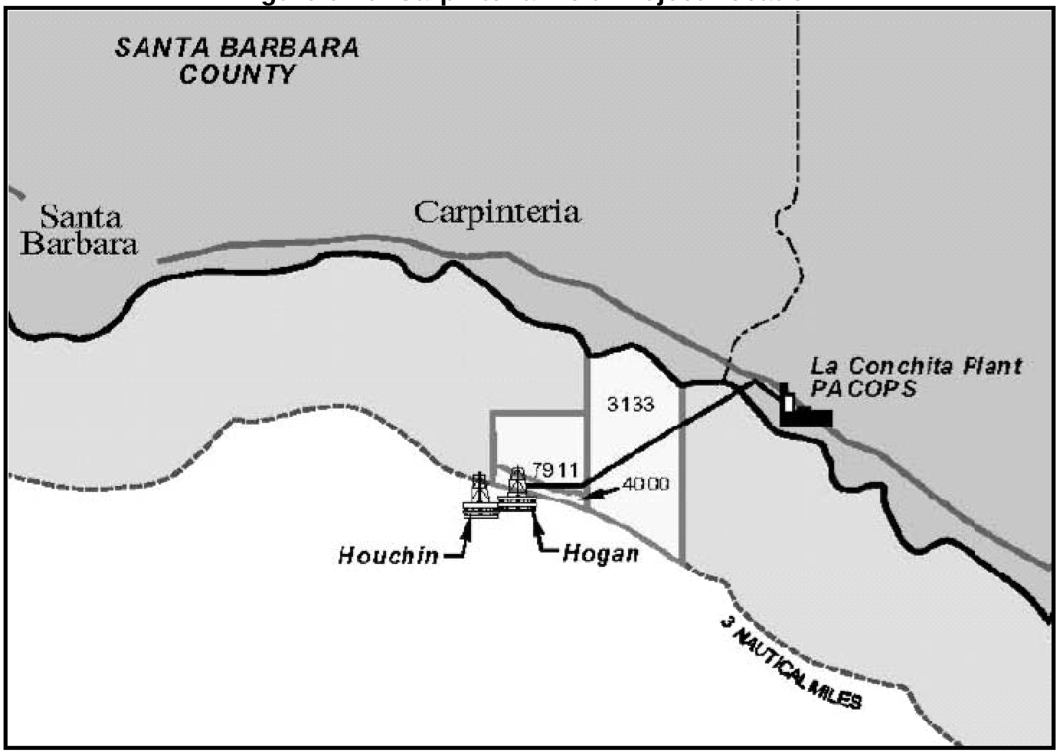
Figure 6-15: Tranquillon Ridge Project Location



Source: County of Santa Barbara Planning and Development, Final EIR, Figure 2-1 page 2-29, April 2008

However, following the BP Gulf of Mexico spill, Governor Schwarzenegger dropped his support and the project seems to be on hold at the time of this writing.[344] The potential production was estimated at 8,000 to 27,000 BPD of additional crude oil that could have been produced from the Tranquillon Ridge Project.[345] More recently, Carone Petroleum Corporation continues to pursue a project to drill into Carpinteria Field is located offshore southern California from an existing offshore platform in federal OCS waters (see Figure 6-16).[346]

Figure 6-16: Carpinteria Field Project Location



Source: Revision to Development and Production Plan – Platform Hogan Carpinteria Offshore Field, Pacific Operators Offshore LLC (PACOPS) Signal Hills Services Inc., Revision No. 4, February 2011.

According to the California State Lands Commission (SLC), additional crude oil production could from Platform Hogan could begin as early as 2013 and yield a maximum of 3,500 BPD or roughly 1.3 million barrels per year by 2020.[347] Based on these maximum production estimates, this project has the potential to reduce the crude oil forecast by 9.3 percent in 2020 under the Low Case and by 2.2 percent under the High Case.

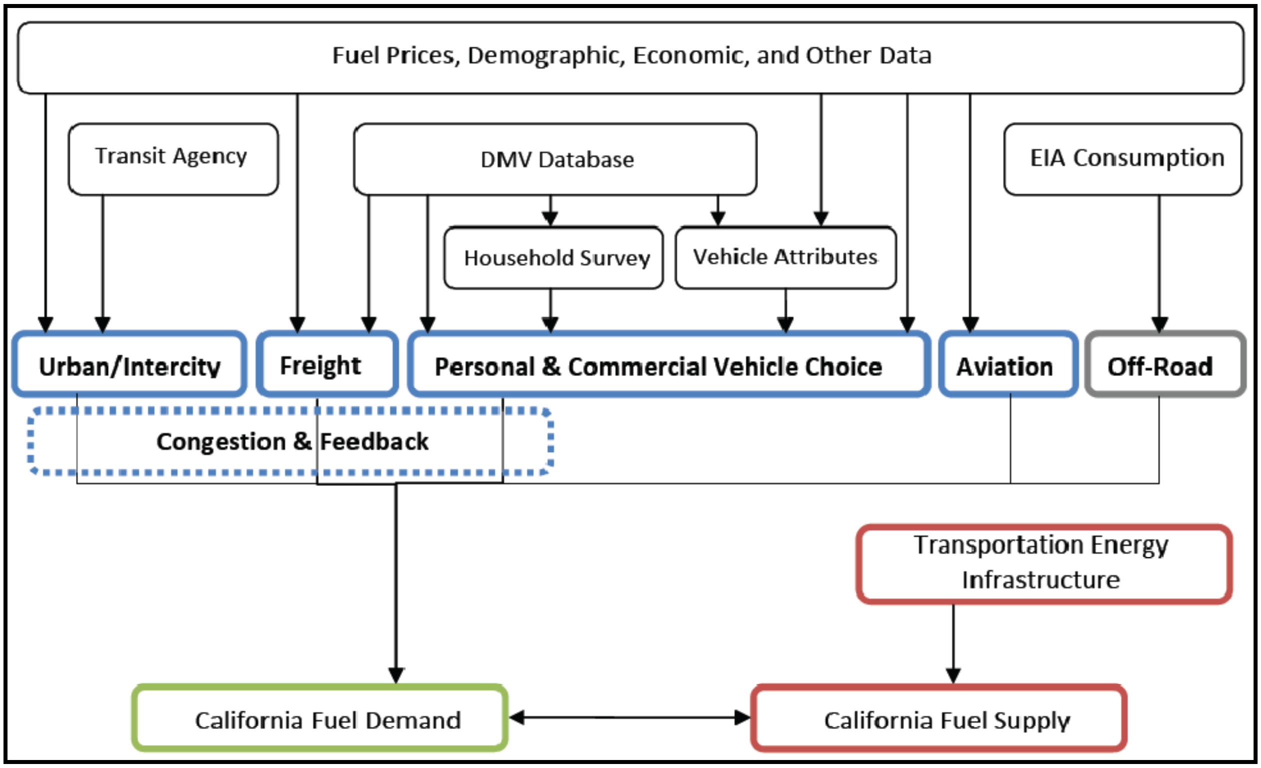
Petroleum Product Import Forecast

The petroleum product import forecast was not completed in time for inclusion into this staff draft report. In order to get the rest of the report to reviewers and stakeholders in a timely manner before the September 9, 2011 Transportation Committee workshop, if time permits this material will have to be prepared separately and presented at the workshop. The methods used in the preparation of this analysis and related discussion, however, will be similar to those used in the *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report*.[348]

APPENDIX A: TRANSPORTATION FUEL DEMAND FORECASTING METHODS

As part of the *2011 IEPR*, staff will produce long-term annual transportation fuel demand forecasts using a set of integrated forecasting models. These models cover four distinct transportation sectors: light-duty vehicle demand, personal ground travel (urban and intercity), goods movement, and aviation travel. Relationships and data flow between these models are illustrated in Figure A-1. A new congestion module also interacts with both urban and commercial light-duty vehicle travel as well as freight movement. Each model forecasts transportation fuel demand for different transportation sectors and, with the exception of aviation and congestion, they are updates of models and methods used in previous years' *IEPR* forecasts. In some cases, the models have been changed to allow for new input values, but the forecasting methods have remained consistent with previous forecasts. Significant changes have been made to the past Urban and Intercity Transit Models, to transform them into Urban and Intercity travel demand models. The new Aviation models forecast demand for jet fuel for both freight and passenger air travel. Additionally, various inputs and assumptions to the models have been updated.

Figure A-1: Transportation Energy Data Flow Diagram



The following are general descriptions of each of the models to be used for the *2011 IEPR* transportation fuel demand forecast.

Light-Duty Vehicle Demand Models

Light-duty vehicles are primarily used for personal movement by household and commercial sectors. Light-duty vehicle demand is captured by two separate models: Personal Vehicle Choice (PVC) and Commercial Vehicle Choice (CVC) models. PVC and CVC forecasting models generate forecasts of vehicle stock and average fuel economy by vehicle and fuel types. There are 105 vehicle classes in these models, comprised of 15 vehicle styles and 7 fuel types. The 7 fuel types include gasoline, diesel, E85, CNG, Hybrid, Full Electric, and PHEVs.

CVC also generates vehicle mileage forecasts for the commercial light-duty vehicle sector; however, the personal vehicle miles travelled forecast for household vehicles is generated in the urban and intercity travel demand models.

PVC and CVC are discrete choice models, and their dynamic nature is defined by the impact of vehicle stock in one year on the vehicle stock of the subsequent year. The coefficients for these models were estimated using the Energy Commission's 2009 California Household and Commercial Vehicle Survey (2009 California Vehicle Survey) conducted by Abt SRBI. The *2011 IEPR* used the statewide version of the model estimated for three household categories of one, two and 3+ vehicle households, in contrast with *2009 IEPR* forecast which was estimated for one and 2+ vehicle households. Parameter values follow the same general direction that was described in the *2009 IEPR*. All versions of the model were estimated using the 2009 vehicle survey data.

ICF International is the source for key model inputs including projections of key vehicle attributes such as fuel economy, vehicle price range, and acceleration. The United States Census Bureau American Community Survey, DOF, and Moody's Economy.com are the sources of household demographic and economic data inputs in the models. Other key inputs include DMV registered on-road vehicle counts and transportation fuel prices.

California Travel Demand Models

Two models generate travel demand forecasts for California households and one model generates demand for light-duty vehicle travel by the commercial sector. Urban and Intercity Travel Demand Models generate projections of transit ridership, passenger miles, and VMT for public transit and personal automobile vehicle use, as well as fuel consumption estimates. Urban travel revolves around mode choices between personal automobile, bus, and rail modes, while intercity travel requires mode choice between personal auto, bus, rail and air travel. These models estimate the effects of changes in transit fares, service policies, automobile fuel economy, fuel prices, population, employment, and income on transportation energy consumption. The urban travel model can also estimate the effectiveness of policies designed to save energy by promoting diversions from automobiles to transit.

Commercial vehicle choice model generates the forecast of light-duty vehicle travel demand based on the stock of commercial light-duty vehicles and the level of economic activity in different economic sectors.

Economic and demographic data used in these models are consistent with input data used in the vehicle choice models. Urban transit specific data inputs to the model are derived from the NTD, and an Energy Commission staff survey of public transit agencies in California, as well as the California Department of Transportation's 2000 California Household Travel Survey.

California Freight Transportation Energy Demand Model

The California Freight Transportation Energy Demand Model projects the volume of ground freight transported by medium-/heavy-duty vehicles and rail, medium-/heavy-duty vehicle stock, VMT, and fuel consumption for four types of fuels used in this sector. Fuel price projections, growth projections for 42 commodities, and growth projections of industrial activity in 14 economic sectors drive the output. Industrial activities projections are used to account for on-road medium- and heavy-duty vehicle movements that are not directly related to commodity movement, such as mining, construction, and public utility trucks.

The California Freight Transportation Energy Demand Model takes disaggregated base year data that includes VMT, ton-miles, truck stock, average payload, commodity growth, economic activity projections, and fuel price inputs to forecast goods movements. These inputs are then distributed to different modes by a modal diversion model. The modal diversion model allocates the transportation of these goods to either rail or road vehicle modes based on transportation costs, travel time, shipment size.

California Civil Aviation Jet Fuel Demand Model

Staff has utilized two separate aviation models; one for freight aviation and another for passenger travel. Freight aviation's main drivers are GDP and jet fuel prices. The passenger aviation model generates forecasts of intrastate, interstate, and international air travel demand for both personal and business passengers. Economic and demographic projections, as well as the Bureau of Transportation Statistics base year data on passenger and aircraft origin and destination travel, passenger load factor, and aircraft capacity for aircraft classes are the inputs to the model that generates the jet fuel demand forecast. General aviation fuel consumption is projected in proportion to population growth.

Congestion Module

The Congestion module uses a Road Congestion Index published by the Texas Transportation Institute, alongside VMT from the Urban and Freight models to generate a forecast year Travel Time Index (TTI). The module then uses index to compute travel times in forecast years and subsequently influence personal travel in the Urban and commercial light-duty vehicle models and the ground goods movement in the Freight module. This module was not used in the *2011 IEPR* forecast, but congestion has influenced the forecasting outcome.

APPENDIX B: CALIFORNIA TRANSPORTATION FUEL PRICE CASES

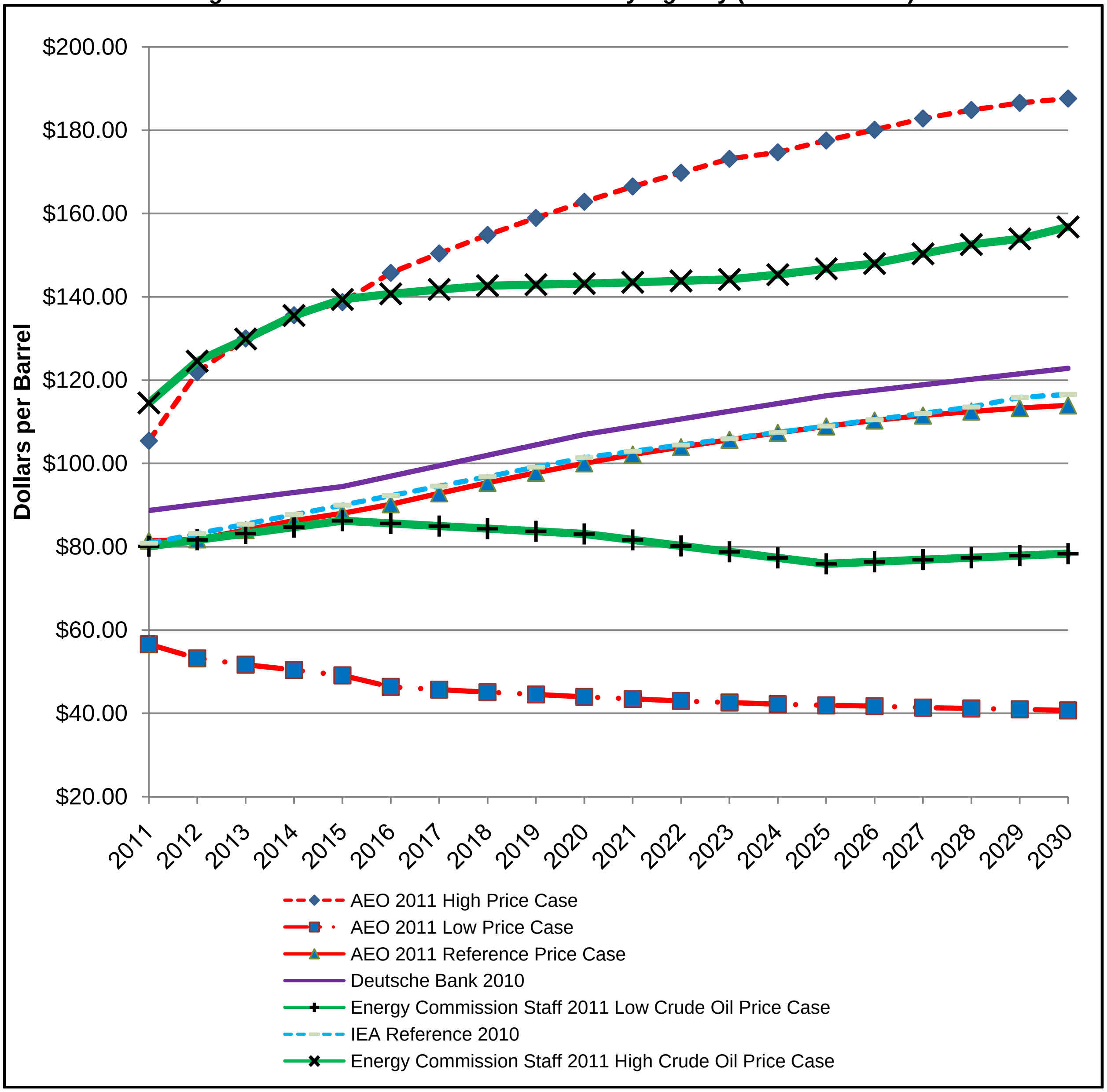
Summary

Staff has developed High and Low Fuel Price Cases for California transportation fuels based on the review of crude oil and fuel price forecasts, data, and analysis from other organizations. The Energy Commission's resulting High Fuel Price Case starts at $4.22 per gallon for gasoline and $4.31 for diesel in 2011, increases to $4.84 and $4.96, respectively, in 2015, and then continues to rise to $5.26 and $5.42 by 2030 (all prices are reported in 2010 dollars).[349] The Energy Commission's Low Fuel Price Case starts at $3.26 per gasoline gallon and $3.28 per diesel gallon in 2011, climbs to $3.41 and $3.44 in 2015, and then declines gradually to $3.22 and $3.24 per gallon, respectively, by 2030. Price cases for other transportation fuels, including E85, biodiesel (B5), propane, electricity, CNG, and hydrogen, are discussed later in this appendix.

Crude Oil Price Projections Assumptions

Staff has based California-specific High and Low Case regular-grade gasoline and diesel price forecasts on crude oil price forecasts. The United States refiner acquisition cost (RAC) of imported crude oil, as defined and measured by EIA, is used as a proxy for crude oil prices. This index is the average price of all imported crude oil and is roughly $3 to $10 per barrel less than the average for higher-quality imported light sweet oil.[350] Both the High Crude Oil Price Case and the Low Crude Oil Price Case projections were developed by Energy Commission staff after review of crude oil price forecasts from other organizations. The Low Crude Oil Price case remains unchanged from the February 2011 *Transportation Fuel Price Cases and Demand Scenarios* report.[351] The High Fuel Price Case was increased in response to stakeholder feedback from the February 24th workshop and to account for recent events affecting oil supplies in North Africa and the Middle East, as well as the continuing weakness in the dollar during the February to June time period. Figure B-1 compares the 2011 Energy Commission staff crude oil price cases and crude oil price projections from other organizations. Table B-1 displays Energy Commission staff's High and Low Crude Oil Price Cases in both nominal and real dollars.

Figure B-1: Crude Oil Price Forecasts by Agency (in 2010 dollars)



Source: EIA and California Energy Commission

Table B-1: California Energy Commission Staff's Crude Oil Price Cases (Real and Nominal Dollars per Barrel)

Year	Real 2010		Nominal	
	Energy Commission High Price Case	Energy Commission Low Price Case	Energy Commission High Price Case	Energy Commission Low Price Case
2011	$114.54	$80.12	$115.47	$80.77
2012	$124.57	$81.65	$126.99	$83.24
2013	$129.89	$83.19	$134.64	$86.23
2014	$135.54	$84.72	$143.08	$89.44
2015	$139.39	$86.26	$150.13	$92.90
2016	$140.74	$85.62	$154.64	$94.08
2017	$141.78	$84.98	$159.01	$95.31
2018	$142.70	$84.35	$163.42	$96.59
2019	$142.95	$83.71	$167.07	$97.83
2020	$143.21	$83.07	$170.81	$99.08
2021	$143.51	$81.64	$174.45	$99.24
2022	$143.86	$80.21	$178.05	$99.27
2023	$144.20	$78.77	$181.70	$99.26
2024	$145.36	$77.34	$186.48	$99.22
2025	$146.76	$75.90	$191.69	$99.14
2026	$148.01	$76.39	$196.84	$101.59
2027	$150.36	$76.88	$203.73	$104.17
2028	$152.58	$77.37	$210.60	$106.79
2029	$153.95	$77.86	$216.53	$109.51
2030	$156.81	$78.35	$224.57	$112.21

Source: California Energy Commission

Petroleum Transportation Fuel Price Projection Assumptions

Staff established relationships between crude oil and retail fuel prices using monthly RAC crude oil price and retail gasoline and diesel price data. The January 2003 to December 2010 period was analyzed due to MTBE-free reformulated gasoline becoming the dominant gasoline refined and used in the state during this time. This difference is referred to as the "crude oil-to-retail" price margin (i.e. combining what are often referred to as refiner and dealer margins) and has varied between $0.40 and $1.40 in 2010 dollars for regular gasoline, and between $0.39 and $1.35 for diesel, since 2003. The last step in generating a final retail price forecast for each of the fuels is to add excise and sales taxes and fees. In the case of regular-grade gasoline, combined federal and state excise taxes (including fuel use and UST levies) totaled $0.557, and sales tax was estimated at 3.25 percent (2.25 percent state sales tax with a 1 percent local sales tax).[352] For diesel, the federal excise taxes are $0.244 and the state excise taxes $0.156. In the case of diesel, however, $0.136 of the state excise tax is not subject to sales tax and therefore was added after sales tax was computed and included. Sales tax to be used for diesel price is estimated at 10 percent, composed of 9 percent state and 1 percent local sales taxes.

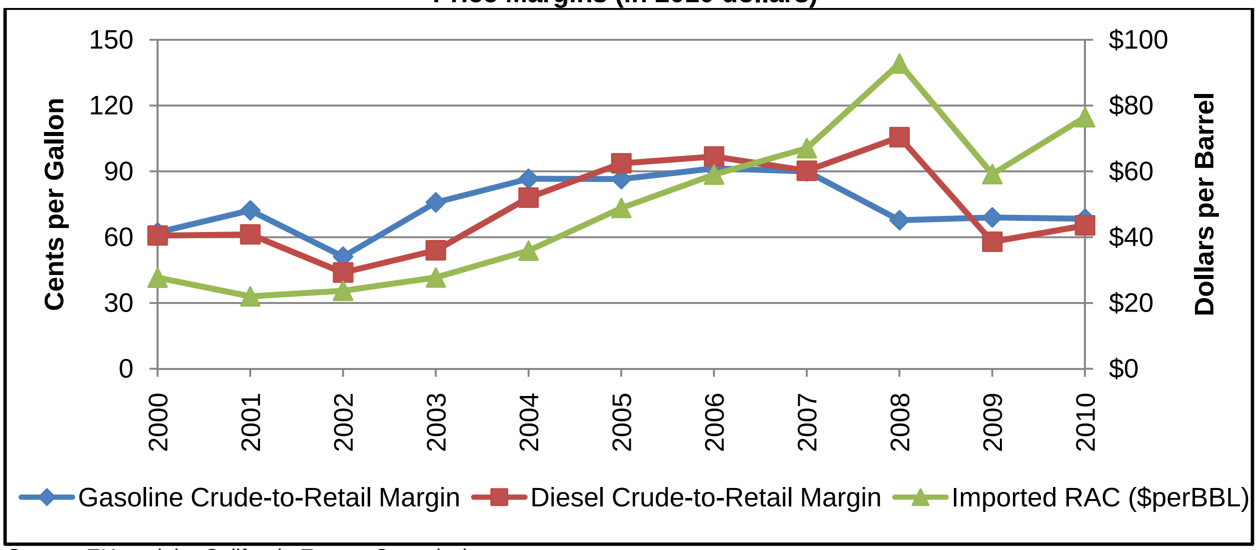
Table B-2 and Figure B-2 displays the price margins and fuel taxes used with the High and Low Crude Oil Price Cases to generate final retail regular gasoline and diesel prices.

Table B-2: Price Margins and Taxes Used in Fuel Price Cases (2010 cents per gallon)

Fuel Price Case	Crude-to-Retail Margin	Federal Excise Tax	State Excise Tax	Underground Storage Tank Tax	State and Local Sales Tax
High Gasoline Price Margin	79.9	18.4	35.3	2	3.25%
High Diesel Price Margin	83.9	24.4	13.6	2	10%
Low Gasoline Price Margin	68.4	18.4	35.3	2	3.25%
Low Diesel Price Margin	76.3	24.4	13.6	2	10%

Source: California Energy Commission

Figure B-2: Imported Refiner Acquisition Cost (RAC), Gasoline and Diesel Crude-to-Retail Price Margins (in 2010 dollars)

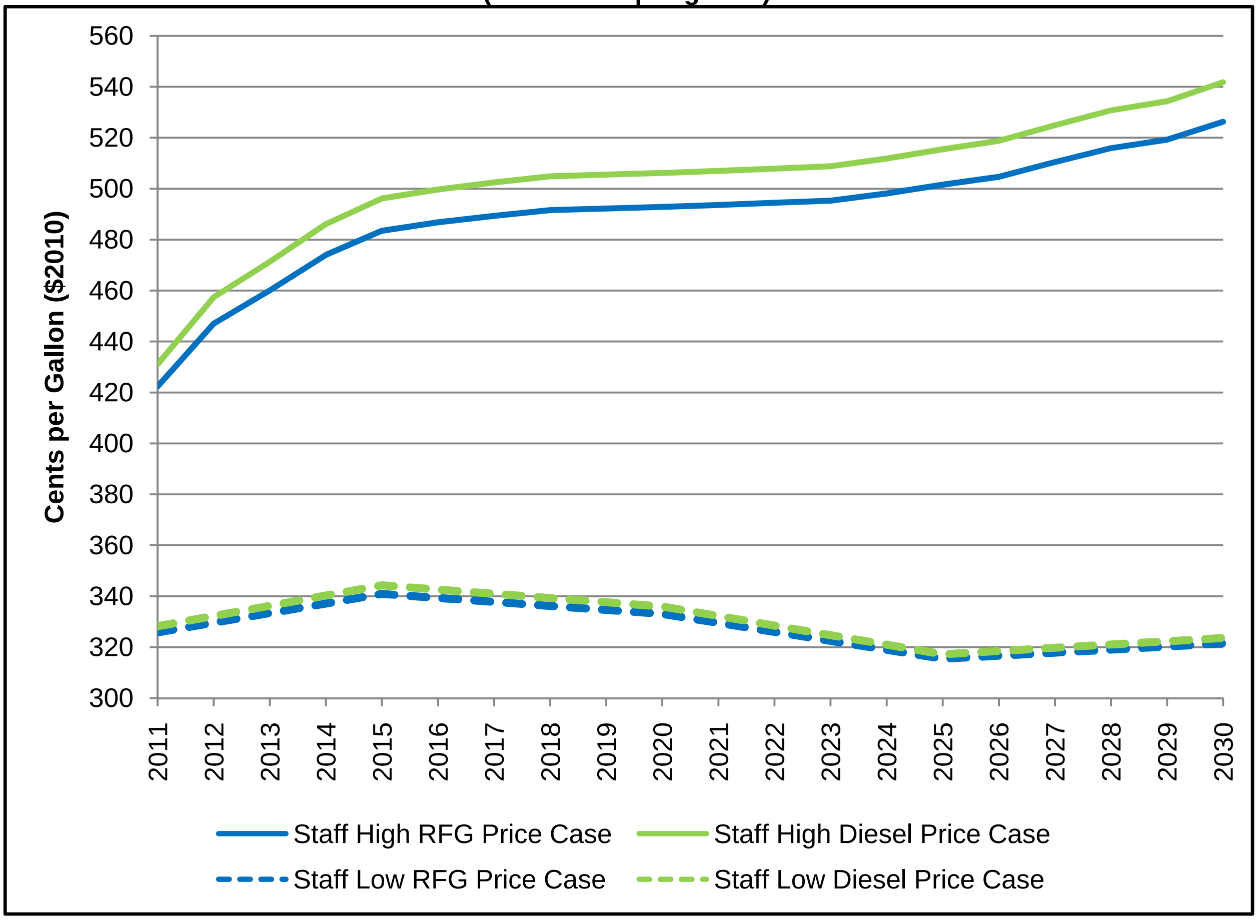


Source: EIA and the California Energy Commission

California Petroleum Fuel Price Forecasts

Figure B-3 and Table B-3 show the proposed California retail fuel price cases in 2010 cents per gallon for regular-grade California gasoline and California diesel fuel using the assumptions outlined above. These retail price cases are generated by adding the price margin and the corresponding tax estimates for each fuel type to the corresponding imported crude oil price cases. The High Crude Oil Price Case estimates were used to generate the Energy Commission's High Fuel Price Case. Likewise, for the Low Fuel Price Case, the Low Crude Oil Price Case was used. Figure B-4 shows the retail fuel price cases in nominal dollars.

Figure B-3: California Gasoline and Diesel Price Cases (2010 cents per gallon)



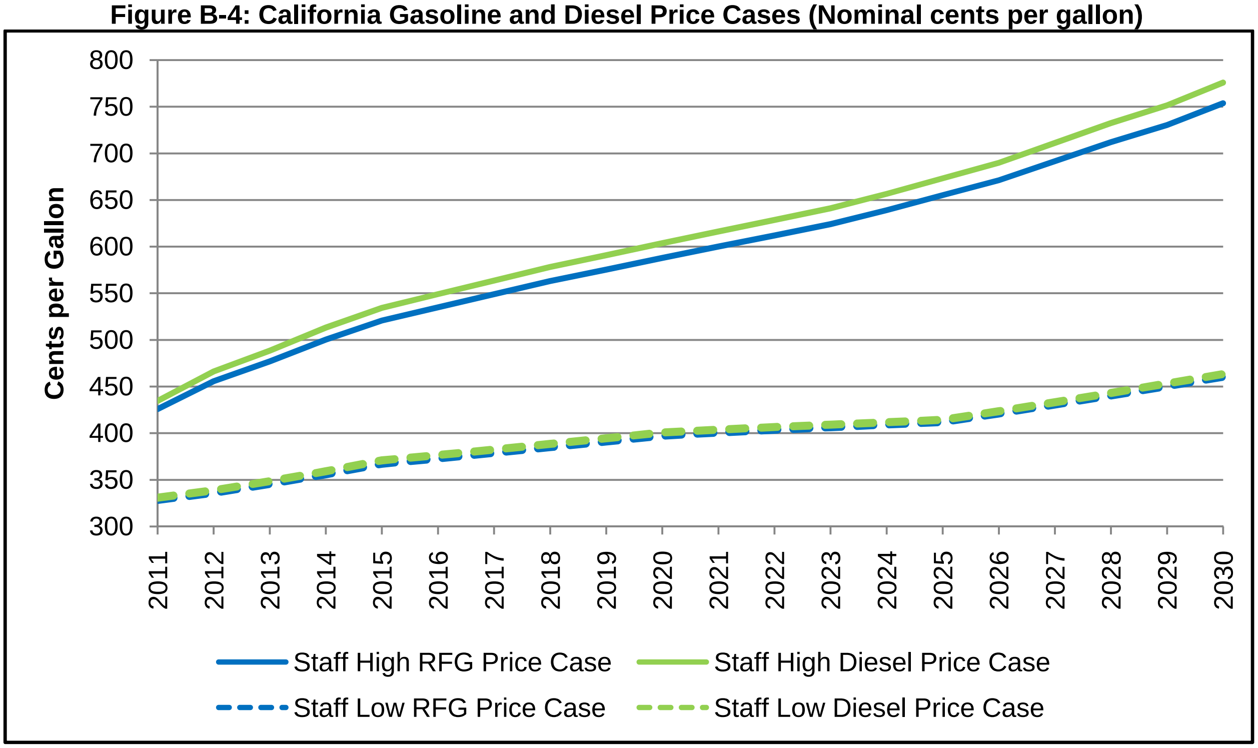
Source: California Energy Commission

Table B-3: Retail Gasoline and Diesel Price Cases (2010 cents per gallon)

Year	Regular Gasoline		Diesel	
	High Price	Low Price	High Price	Low Price
2011	422	326	431	328
2012	447	330	457	332
2013	460	333	471	336
2014	474	337	486	340
2015	484	341	496	344
2016	487	339	500	343
2017	489	338	502	341
2018	492	336	505	339
2019	492	335	506	338
2020	493	333	506	336
2021	494	330	507	332
2022	494	326	508	328
2023	495	323	509	325
2024	498	319	512	321
2025	502	315	516	317
2026	505	317	519	319
2027	510	318	525	320
2028	516	319	531	321
2029	519	320	534	322
2030	526	322	542	324

Source: California Energy Commission

Figure B-4: California Gasoline and Diesel Price Cases (Nominal cents per gallon)



Source: California Energy Commission

Alternative Transportation Fuel Price Forecasts

During the *2009 IEPR* cycle, staff developed price cases for the following alternative transportation fuels: E85, B20, transportation electricity rates, CNG, LNG, hydrogen, and propane. These price cases were used as inputs in scenarios for vehicle manufacturer offerings and for fuel demand for that *IEPR* cycle. In the current report, estimates for B20 have been changed to B5, the more common fuel supplied in the California market. Moreover, there are a high percentage of diesel vehicle offerings with warranties that do not cover a diesel fuel with over 10 percent biomass derived diesel. LNG price cases have also been dropped, because of an insignificant share of the LNG fueled vehicles in the California transportation market and the uncertainty on how the fuel will be brought to market.[353] High and Low Price Cases were developed after consultation with other offices within the Energy Commission regarding all of these fuel types.

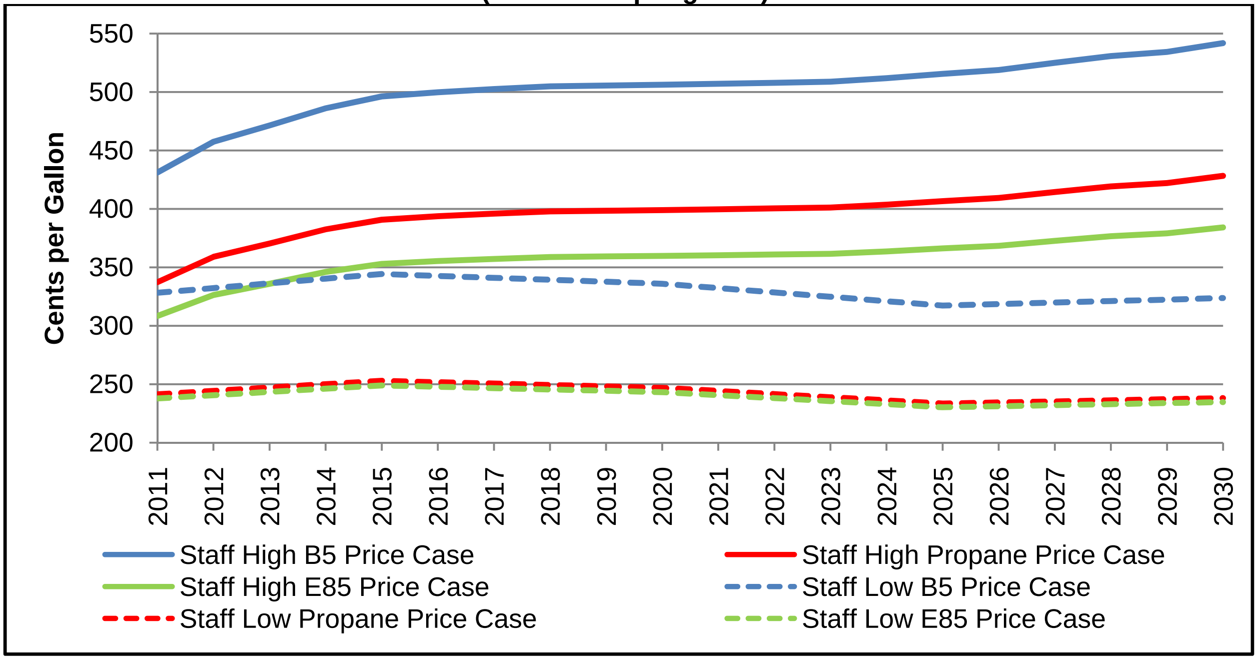
Renewable Fuels and Propane

High and Low Price Cases for E85, B5, and propane for transportation use are based on the corresponding High and Low Price Cases for crude oil. The E85 price cases are based on its GGE price (price divided by 1.37), thus effectively making it the same price as gasoline on an energy-content basis. This assumption was made since flex fuel vehicles can also use gasoline and thus E85 is a substitute for gasoline for these consumers. Since E85 is directly competing with gasoline, consumers will eventually base their purchasing decisions on the fuel economy realized per gallon, driving the price to this energy content equivalency.

In the case of B5, analysis of OPIS' renewable fuel reports indicates that B5 has been sold at values similar to that of regular diesel prices on the West Coast. Given the short period of data available (February 2008 to November 2010) to determine if consumers place a premium or discount on this product, staff has determined that for projection purposes it can be priced at the same value as regular diesel due to the high degree of substitution between the two fuels.

Transportation propane prices were projected based on the price link assumption between EIA's PADD V wholesale propane price and the RAC of crude oil. From 2003 to 2008, the wholesale propane prices averaged 84 percent of RAC. This ratio was applied to the High Crude Oil Price Cases to develop the high estimates of wholesale propane prices. Staff used a similar method to develop the low price estimates but based it on the 2008 to 2010 average propane wholesale to RAC price ratio of 73 percent. This ratio was applied to the Low Crude Oil Price Case to obtain the low estimates of wholesale propane prices. EIA data on the PADD V wholesale-to-retail price margins were then used to estimate a price margin of $0.58 (2003 to 2005 data, in 2010 dollars). Only one wholesale-to-retail margin will be used for both high and low cases due to non-reported years in the EIA data. Table B-4 and Figure B-5 display E85, B5, and propane retail transportation price cases for 2011 to 2030.

**Figure B-5: California E85, B5, and Propane Fuel Price Cases
(2010 cents per gallon)**



Source: California Energy Commission

**Table B-4: California Petroleum-Related Alternative Transportation Fuel Retail Price Cases
(2010 cents per gallon)**

Year	E85		B5		Propane	
	High Price	Low Price	High Price	Low Price	High Price	Low Price
2011	308	238	431	328	337	241
2012	326	241	457	332	359	244
2013	336	243	471	336	370	247
2014	346	246	486	340	382	250
2015	353	249	496	344	391	253
2016	355	248	500	343	394	252
2017	357	247	502	341	396	250
2018	359	245	505	339	398	249
2019	359	244	506	338	398	248
2020	360	243	506	336	399	247
2021	360	241	507	332	400	244
2022	361	238	508	328	400	241
2023	362	235	509	325	401	239
2024	364	233	512	321	404	236
2025	366	230	516	317	407	233
2026	368	231	519	319	409	234
2027	373	232	525	320	414	235
2028	377	233	531	321	419	236
2029	379	234	534	322	422	237
2030	384	235	542	324	428	238

Source: California Energy Commission

Natural Gas Transportation Fuels

Staff developed final High and Low Price Cases for transportation-use CNG and hydrogen using Henry Hub natural gas price cases provided by the Energy Commission's Electricity Supply Analysis Division and the fixed margin methodology established in the *2009 IEPR*. Like the other fuels, margins have been updated to reflect current conditions.

For CNG, the High Price Case margin was calculated from the historical 1997-2009 cost differential between California Citygate natural gas prices and Henry Hub natural gas prices, which was $0.051 per therm. The Low Price Case margin was calculated from the 2003-2009 period and was $0.023 per therm. Current PG&E Schedule G-NGV2 natural gas pricing margins are then added to obtain the final retail price. This schedule and the methodology to produce final transportation CNG prices can be found in the February 2011 *Transportation Fuel Price Cases and Demand Scenarios* report. See Table B-5 for margin and tax values.

Natural gas continues to be the primary feedstock needed for manufacturing hydrogen and is the basis for the hydrogen price cases. In staff's projection methodology, natural gas is the only cost that is variable over time in this forecast. All other costs are held constant in real terms over the projection period for both the high and low price cases. This projection uses the same Citygate natural gas price forecast as the CNG analysis. Production costs, compression costs, and retail costs are then summed and an 8.25 percent sales tax[354] is included for the final hydrogen fuel price. No state or federal excise taxes are included in the price estimates. Currently these taxes are not imposed on hydrogen vehicle fuel, but future market penetration of this fuel could lead to the inclusion of these fair-use taxes. This methodology remains unchanged from the February 2011 *Transportation Fuel Price Cases and Demand Scenarios* report. See Table B-5 for margin and tax values.

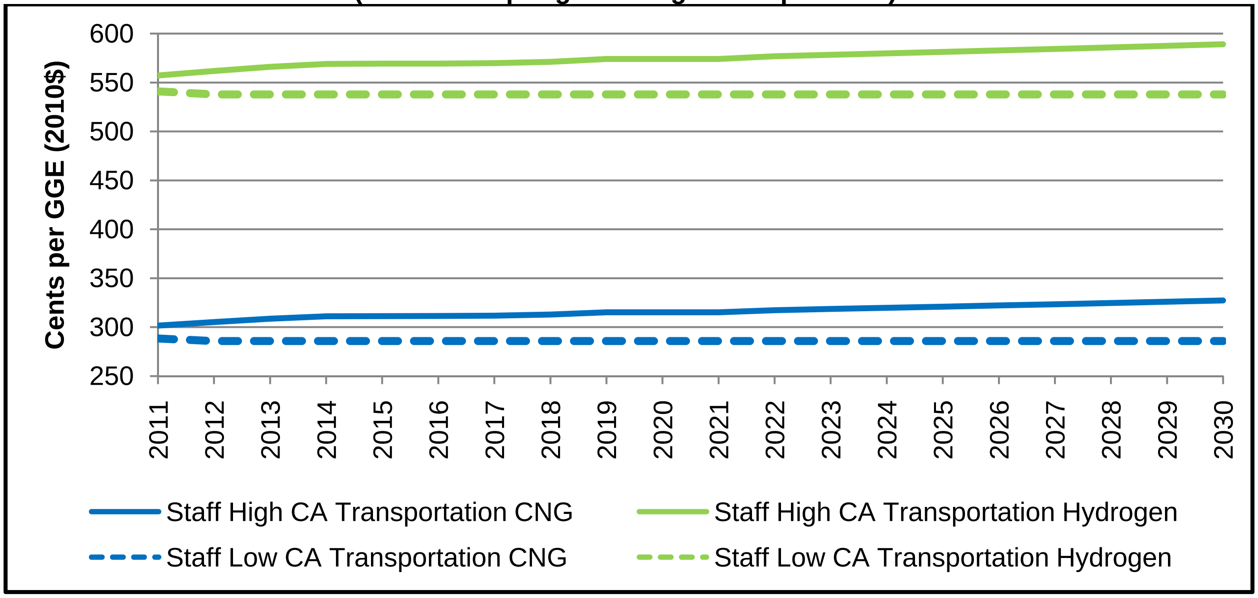
Figure B-6 and Table B-6 displays final retail transportation use CNG and hydrogen price cases.

Table B-5: Natural Gas Based Transportation Fuel Margins and Taxes for Staff Price Cases (2010 cents per gasoline gallon equivalent)

	CNG High Margin (GGE)	CNG Low Margin (GGE)	Hydrogen (GGE)
Wholesale Margin	$1.65	$1.61	$1.25
Retailer Margin & Excise Taxes	$0.52	$0.52	$3.06
Sales Tax	8.25%	8.25%	8.25%

Source: California Energy Commission

Figure B-6: California Transportation CNG and Hydrogen Fuel Price Cases (2010 cents per gasoline gallon equivalent)



Source: California Energy Commission

Table B-6: California Transportation CNG and Hydrogen Fuel Price Cases (2010 cents per gasoline gallon equivalent)

Year	Transportation CNG		Transportation Hydrogen	
	High Price	Low Price	High Price	Low Price
2011	302	288	557	541
2012	305	286	562	538
2013	309	286	566	538
2014	311	286	569	538
2015	311	286	569	538
2016	311	286	569	538
2017	312	286	570	538
2018	313	286	571	538
2019	315	286	574	538
2020	315	286	574	538
2021	315	286	574	538
2022	317	286	577	538
2023	319	286	578	538
2024	320	286	580	538
2025	321	286	581	538
2026	322	286	583	538
2027	323	286	584	538
2028	325	286	586	538
2029	326	286	588	538
2030	327	286	589	538

Source: California Energy Commission

Transportation Electricity Rates

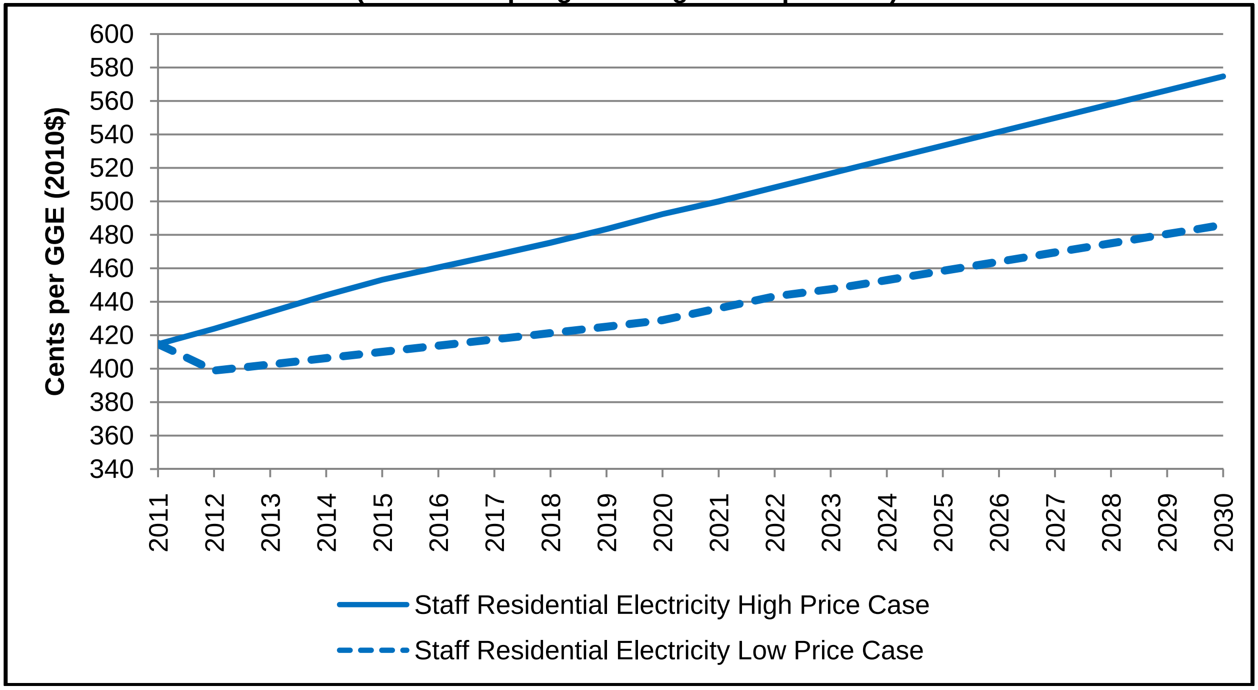
Transportation electricity prices are based on the current residential electric vehicles rates for Pacific Gas & Electric (PG&E), Sacramento Municipal Utilities District, San Diego Gas & Electric, Los Angeles Department of Water & Power, and Southern California Edison (SCE). In 2009, these 5 utilities comprised nearly 90 percent of all California residential electricity consumption and are the largest based on consumption. Using the current utility rate structures, and the assumptions described below, the consumption weighted average transportation electricity price for California is 12.6 cents per kilowatt hour (KWh) in 2010. This value will be increased by at least two different annual growth rates which will be consistent with the Electricity Supply Analysis Division's preliminary electricity price scenarios.

As with past *IEPR* analyses, updated rate schedules were used for all utilities. In the case of tiered rates for PG&E and SCE, only PG&E had a single meter rate, residential schedule E-9 Rate A. For the E-9 Rate A rate schedule, all additional electric consumption from vehicle use was used to calculate the overall electric rate, since electric vehicles were assumed to increase the overall household electricity consumption. For the duel meter rates, electricity consumption is charged separately from household consumption, but uses the same monthly baseline allotment. To account for California seasonal driving patterns, additional monthly consumption for the electric vehicle was estimated at 181 KWhs for summer months and 169 KWhs for winter months and is accounted for in the final prices. Additionally, the following assumptions were made in staff's estimated price for 2010.

- The electric vehicle charging profile will be the same for all plug-in electric vehicles and will be 88 percent off-peak, 8 percent partial-peak, and 4 percent on-peak. This charging profile will not be influenced by changes or differences in rate structures.
- For PG&E, average household consumption is the simple average of overall consumption divided by the number of customers in the climate zone.
- PG&E's E-9 Rate B was used for all households which were not restricted from, or had questionable access to, duel metering. This amounts to approximately 70 percent of households in PG&E's service area based on data collected by Energy Commission staff. The remaining 30 percent of households will use PG&E's Rate A.
- The final statewide transportation electricity price was weighted using historic electricity consumption trends and seasonal driving trends.

Figure B-7 and Table B-7 displays final retail transportation electricity price cases.

Figure B-7: California Transportation Electricity Price Cases (2010 cents per gasoline gallon equivalent)



Source: California Energy Commission

Table B-7: California Transportation Electricity Price Cases (2010 cents per gasoline gallon equivalent)

Year	Residential Electricity	
	High Price	Low Price
2011	415	415
2012	424	399
2013	434	403
2014	444	406
2015	453	410
2016	461	414
2017	468	418
2018	475	421
2019	483	425
2020	492	429
2021	500	436
2022	508	443
2023	517	447
2024	525	453
2025	533	458
2026	542	464
2027	550	469
2028	558	475
2029	566	480
2030	575	486

Source: California Energy Commission

APPENDIX C: CRUDE OIL IMPORTS AND FORECASTS

Table C-1: California Foreign Crude Oil Imports by Country (Thousand Barrels)

Country	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
ANGOLA		3,127	17,552	8,414	6,014	12,912	14,979	21,038	7,775	13,562	7,040
ARGENTINA	6,993	7,030	12,834	7,504	8,119	6,213	3,484	2,174	2,976	4,667	3,523
AUSTRALIA	5,557	8,248	5,841	7,646	4,360	650			2,088	585	1,033
AZERBAIJAN								1,523		530	
BOLIVIA					260	246	299	307	642	922	
BRAZIL				953	1,893	12,474	17,938	22,453	26,078	25,054	22,061
BRUNEI	651	1,613	392	1,778	725	417					
CAMEROON							337				
CANADA		1,977	3,559	4,421	2,826	4,942	2,450	5,320	9,401	13,765	19,247
CHAD					2,293		1,285	3,885	355	375	
CHINA, PEOPLES REP	835	664					210	554	702		
COLOMBIA	1,237	1,988	2,190	1,828	4,062	4,180	9,362	11,813	19,860	15,578	15,749
CONGO (BRAZZAVILLE)		399									
ECUADOR	36,862	23,871	27,410	39,318	50,631	67,705	71,174	55,456	62,507	46,507	59,947
EQUATORIAL GUINEA			1,958	583		1,846	1,040	866			
GABON			1,973								
INDONESIA	4,110	2,401	5,222	2,959	2,792			168	166		
IRAQ	51,249	54,307	39,512	37,371	51,119	34,160	56,163	57,788	76,225	50,583	57,651
KUWAIT	5,766	1,728	3,808	3,343	277	1,403		300	3,105	2,997	799
LIBYA						581					
MALAYSIA	2,910	118	1,194			418	1,123				
MEXICO	14,858	18,288	18,533	16,469	14,284	19,316	15,473	9,214	1,175		
NIGERIA		312		1,084		946	736	5,447	2,766		1,245
NORWAY		37	385				497	1,168	1,531		
OMAN		5,444	6,060	2,835	321	2,985	6,326	4,400	4,009	9,425	4,008
PERU	1,494	2,524	1,128	2,447	383	1,501	962	1,841	2,684	5,698	4,279
QATAR			3,194								
RUSSIA								2,219	837	993	17,937
SAUDI ARABIA	30,544	42,726	36,256	83,477	86,051	95,507	86,976	72,296	82,969	67,478	67,590
THAILAND										1,332	
TRINIDAD & TOBAGO								1,060		359	180
UNITED ARAB EMIRATES	477	4,723	3,505	3,645	639	2,110		925	450	4,819	295
VENEZUELA	3,014	5,183	321	1,725	711	2,140	4,120	4,706	3,802	5,379	3,072
VIETNAM	2,367	974		291		399	1,883			159	
YEMEN	9,802	8,702	7,884	2,000		1,050	2,658	1,157			
Grand Total	**178,726**	**196,384**	**200,711**	**230,091**	**237,760**	**274,101**	**299,475**	**288,078**	**312,103**	**270,767**	**285,656**

Source: EIA, company-level imports

GLOSSARY

AC	Alternating current
AGT	Aboveground storage tank
AQMD	Air Quality Management District
ARB	California Air Resources Board
ARFVTP	Alternative and Renewable Fuel and Vehicle Technology Program
ARRA	American Recovery and Reinvestment Act
ASTM	American Society for Testing and Materials
B5	Diesel fuel containing 5 percent biodiesel by volume
B6	Diesel fuel containing 6 percent biodiesel by volume
B20	Diesel fuel containing 20 percent biodiesel by volume
B99	Diesel fuel containing 99 percent biodiesel by volume
B100	Diesel fuel containing 100 percent biodiesel by volume
BAAQMD	Bay Area Air Quality Management District
BEA	Bureau of Economic Analysis
BCF	Billion cubic feet
BEV	Battery electric vehicle
BOE	California Board of Equalization
BOEG	Biorefinery Operational Enhancement Goals
BOEMRE	Bureau of Ocean Management, Regulation and Enforcement
BPD	Barrels per Day
BTL	Biomass-to-liquid
CAFE	Corporate Average Fuel Economy
CAGR	Compound average Annual growth rate
CARBOB	California Reformulated Blendstock for Oxygenate Blending
CARD	Center for Agriculture and Rural Development
CBI	Caribbean Basin Initiative
CBG	Cleaner Burning Gasoline
CEPIP	California Ethanol Producer Incentive Program
CFP	Clean Fuels Project
CI	Carbon intensity
CNG	Compressed natural gas
CPG	Cents per gallon
CRFS	Canadian Renewable Fuels Standard
CVC	Commercial Vehicle Choice
DAO	Electricity Demand Analysis Office
DDGS	Dry distillers grains with solubles
DEIR	Draft Environmental Impact Report
DEIS	Draft Environmental Impact Statement
DGE	Diesel-gallon equivalent
DGS	Distillers grains with solubles
DMS	Division of Measurement Standards

DMV	California Department of Motor Vehicles
DOF	California Department of Finance
E10	A blended transportation fuel product that is 90 percent gasoline and 10 percent denatured ethanol by volume
E15	A blended transportation fuel product that is 85 percent gasoline and 15 percent denatured ethanol by volume
E85	A blended transportation fuel product that is 15 to 23 percent gasoline and 77 to 85 percent denatured ethanol by volume
E100	A transportation fuel product that is 100 percent gasoline
EBB	European Biodiesel Board
EFTO	Emerging Fuels and Technology Office
EIA	Energy Information Administration
EIR	Environmental Impact Report
EISA	Energy Independence and Security Act of 2007
EMTS	United States Environmental Protection Agency Moderated Transaction System
EOR	Enhanced oil recovery
EPAct	United States Energy Policy Act
EPE	Energy Planning Agency of the Ministry of Mines and Energy of Brazil
EU	European Union
EV	Electric vehicle
EVSE	Electric vehicle supply equipment
FAA	United States Federal Aviation Administration
FAS	Foreign Agricultural Service
FCV	Fuel cell vehicle
FFO	Fossil Fuels Office
FFV	Flex fuel vehicle
GATS	Global Agricultural Trade System
GDP	Gross Domestic Product
GM	General Motors
GGE	Gasoline-gallon Equivalent
GHG	Greenhouse gas
GSP	Gross State Product
GWhs	Gigawatt hours
GVWR	Gross Vehicle Weight Rating
HCICO	High Carbon Intensity Crude Oil
ICTC	Interstate Clean Transportation Corridor
IEPR	Integrated Energy Policy Report
ILUC	Indirect land use changes
kW	Kilowatt
KWh	Kilowatt hour
LCFS	Low Carbon Fuel Standard

LEV	Low emission vehicle
LEVIII	Low Emission Vehicle III Mandate
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MAPA	Brazilian Ministry of Agriculture
MCON	Marketable Crude Oil Name
MMS	Minerals Management Services
MPG	Miles per Gallon
MSW	Municipal solid waste
MTBE	Methyl tertiary butyl ether
NAAQS	National Ambient Air Quality Standard
NACS	National Association of Convenience Stores
NBB	National Biodiesel Board
NEB	National Energy Board
NESCAUM	Northeast States for Coordinated Air Use Management
NGV	Natural gas vehicle
NHTSA	National Highway Transportation Safety Administration
NOPR	Notice of Proposed Rulemaking
NOx	Nitrogen Dioxide
NREL	National Renewable Energy Laboratory
NTD	National Transit Database
O_3	Ozone
OCS	Outer Continental Shelf
OEM	Original Equipment Manufacturer
OPIS	Oil Price Information Service
PACOPS	Pacific Operators Offshore LLC
PEV	Plug-in electric vehicle
PEP	Pacific Energy Partners
PG&E	Pacific Gas & Electric
PHEV	Plug-in hybrid electric vehicle
PIER	Public Interest Energy Research
PIIRA	Petroleum Industry Information Reporting Act
PLAMT	Pacific LA Marine Terminal LLC
Ppm	Parts per million
PVC	Personal Vehicle Choice
PZEV	Partial Zero Emission Vehicle
RAC	Refiner acquisition cost
RFA	Renewable Fuels Association
RFP	Request for Proposal
RFS	Renewable Fuel Standards
RFS2	Revised Renewable Fuel Standards
RIN	Renewable Identification Number
ROI	Return on investment

RVO	Renewable Volume Obligation
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SCFM	Standard cubic feet per minute
SEC	Securities and Exchange Commission
SIP	State Implementation Plan
SLC	California State Lands Commission
SULEV	Super ultra low emission vehicle
SWRCB	California State Water Resources Control Board
TAME	Tertiary amyl methyl ether
TBD	Thousand barrels per day
TEOR	Thermally enhanced oil recovery
TEU	Twenty foot equivalent unit
TTI	Travel time index
TRQ	Tariff Rate Quota
U.S. DOE	United States Department of Energy
U.S. EPA	United States Environmental Protection Agency
U.S. FHA	United States Federal Highway Administration
U.S. GAO	United States Government Accountability Office
U.S. ITC	United States International Trade Commission
UL	Underwriters Laboratories
UNEV	Pipeline running between Las Vegas, Nevada and Salt Lake City, Utah
UNICA	União da Indústria de Cana-de-Açúcar', the Brazilian Sugarcane Industry Association
USDA	United States Department of Agriculture
USDG	United States Development Group
UST	Underground storage tank
UTRR	Undiscovered Technically Recoverable Resources
V	Volt
VEETC	Volumetric Ethanol Excise Tax Credit
VLCC	Very large crude carrier
VMT	Vehicle miles traveled
W-T-W	Well-to-wheel
WDGS	Wet distillers grains with solubles
ZEV	Zero emission vehicle

ENDNOTES

[1] 98 percent is the sum of traditional gasoline powered, hybrid, and flex fuel vehicle percentages of the total LDV fleet. Personal ownership is determined through Energy Commission analysis of the DMV database.
[2] All annual average growth rates for Chapter 2 are calculated using a compound average growth rate method. Gasoline sales are assumed to be same as consumption for analysis purposes.
[3] VMT figures produced by the California Department of Transportation's Highway Performance Monitoring System (HPMS) found at: http://www.dot.ca.gov/hq/tsip/hpms/datalibrary.php
[4] Dyed diesel is defined by the California Tax Code as: "…diesel fuel that is dyed under United States Environmental Protection Agency or the Internal Revenue Service rules for high sulphur diesel fuel or low sulphur diesel fuel or any other requirements subsequently set by the United States Environmental Protection Agency or the Internal Revenue Service and considered destined for nontaxable, off-highway uses."
[5] Diesel prices were converted into 2010 dollars using the California CPI index on the Department of Finance web site. Index found at: http://www.dof.ca.gov/HTML/FS_DATA/LatestEconData/FS_Price.htm
[6] A Light Duty Vehicle is defined as a vehicle under 10,000 pounds.
[7] The correlation between California per capita GSP and taxable diesel & dyed diesel sales from 2003 to 2008 was measured at 0.915.This number was produced using a standard correlation calculation with the number 1 indicating perfect correlation and 0 indicating absolutely no correlation. The California per capita GSP elasticity of California taxable diesel sales was estimated to be 2.5 using a 2001 to 2008 data set. The R^2 of this regression estimation function was 0.96 and the beta coefficient was statistically significant at a 99 percent confidence level. Please note that while there seems to be a strong relationship between these two items, the short time period of the analysis and the lack of accounting for other possible confounding factors make this less than conclusive. Regression function was specified as: $\ln(Taxable\ Diesel\ Sales) = \beta_1 * \ln(CA\ Per\ Capita\ GSP) + \beta_2 * \ln(CA\ Annual\ Average\ Diesel\ Price) + \varepsilon$
[8] http://www.eia.gov/dnav/pet/pet_cons_821dsta_dcu_SCA_a.htm
[9] Per capita GSP figures are in inflation adjusted 2010 dollars.
[10] U.S. Jet Fuel consumption numbers come from the Energy Information Agency (EIA) website. Short Term Energy Outlook (STEO) historic numbers were used and are found at: http://www.eia.doe.gov/emeu/steo/pub/cf_tables/steotables.cfm?tableNumber=9&loadAction=Apply+Changes&periodType=Annual&startYear=1996&endYear=2011&startMonthChanged=false&startQuarterChanged=false&endMonthChanged=false&endQuarterChanged=false&noScroll=true
[11] California jet fuel consumption estimates are calculated based on CEC analysis.
[12] Californian per capita gross state product figures collected from the Bureau of Economic Analysis (BEA) at: http://www.bea.gov/index.htm.
[13] Total electricity use by transit vehicles was obtained from NTD. On-road MD/HD transit vehicle electricity consumption was estimated by staff and subtracted from the total to obtain rail consumption.
[14] TransAtlas tool can be found at: http://maps.nrel.gov/transatlas
[15] EPAct – U.S. Code, Title 42, Sections 13211 to 13264
[16] For Moody's economy.com see http://www.economy.com/home/products/us-states-metros.asp?src=left-nav and for IHS Global Insight see http://www.ihs.com/products/global-insight/
[17] The California Zero Emission Vehicle (ZEV) Program estimated compliance scenario as revised by ARB
[18] Assembly Bill 1493 (Pavley, Chapter 200, Statutes of 2002)
[19] Table 11,2009 and 2010 Fuel Cell Vehicle Survey on p. 52 of the *2011-12 Investment Plan for the Alternative and Renewable Fuel and Vehicle Technology Program,* CEC-600-2011-006-SD, February2011; http://www.energy.ca.gov/2011publications/CEC-600-2011-006/CEC-600-2011-006-SD.PDF
[20] United States Environmental Protection Agency, "Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Proposed Rule," *Federal Register*, Vol. 74, No. 99, May 26, 2009. A link to the document is as follows: http://www.epa.gov/OMS/renewablefuels/rfs2_1-5.pdf
[21] United States Environmental Protection Agency, "Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Extension of Comment Period," *Federal Register*, Vol. 74, No. 128, pp. 32091-02, July 7, 2009. A link to the document is as follows: http://www.epa.gov/fedrgstr/EPA-AIR/2009/July/Day-07/a15947.pdf

[22] United States Environmental Protection Agency, "Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Final Rule" *Federal Register*, Vol. 75, No. 58, pp. 14669–15320, March 26, 2010. A link to the document is as follows: http://edocket.access.gpo.gov/2010/pdf/2010-3851.pdf

[23] United States Environmental Protection Agency, "Regulation of Fuels and Fuel Additives: Modifications to Renewable Fuel Standard Program; Final Rule" *Federal Register*, Vol. 75, No. 244, pp. 79964–79978, December 21, 2010. A link to the document is as follows: http://edocket.access.gpo.gov/2010/pdf/2010-31910.pdf

[24] United States Environmental Protection Agency, "Renewable Fuel Standard for 2009, Issued Pursuant to Section 211(o) of the Clean Air Act," *Federal Register*, Vol. 73, No. 226, November 21, 2008. A link to the document is as follows: http://www.epa.gov/fedrgstr/EPA-AIR/2008/November/Day-21/a27613.pdf

To quote from the specific portion of the regulation from page 70643:

"This standard is calculated as a percentage, by dividing the amount of renewable fuel that the Act requires to be used in a given year by the amount of gasoline expected to be used during that year, including certain adjustments specified by the Act. In this notice we are publishing an RFS of 10.21% for 2009. This standard is intended to lead to the use of 11.1 billion gallons of renewable fuel in 2009, as required by the Energy Independence and Security Act of 2007 (EISA). As discussed below, we expect the 11.1 billion gallons of renewable fuel required in 2009 to include approximately 0.5 billion gallons of biodiesel and renewable diesel."

[25] United States Environmental Protection Agency, "Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Proposed Rule," *Federal Register*, Vol. 74, No. 99, page 24953, May 26, 2009. A link to the document is as follows: http://www.epa.gov/OMS/renewablefuels/rfs2_1-5.pdf

To quote from the specific portion of the regulation:

"In order for an obligated party to demonstrate compliance, the percentage standards would be converted into the volume of renewable fuel each obligated party is required to satisfy. This volume of renewable fuel is the volume for which the obligated party is responsible under the RFS program, and would continue to be referred to as its Renewable Volume Obligation (RVO). Since there would be four separate standards under the RFS2 program, there would likewise be four separate RVOs applicable to each refiner, importer, or other obligated party."

[26] *EPA Finalizes 2011 Renewable Fuel Standards*, U.S. EPA, notice number EPA-420-F-10-056, November 2010, page 2. A link to the notice is as follows: http://www.epa.gov/otaq/fuels/renewablefuels/420f10056.pdf

[27] The cellulosic biofuel requirement for 2010 was reduced from 100 million to 6.5 million gallons. See *EPA Finalizes Regulations for the National Renewable Fuel Standard Program for 2010 and Beyond*, U.S. EPA, notice number EPA-420-F-10-007, February 2010, page 1. A link to the notice is as follows: http://www.epa.gov/otaq/renewablefuels/420f10007.pdf

The cellulosic biofuel requirement for 2011 was reduced from 250 million to 6.6 million gallons. See *EPA Finalizes 2011 Renewable Fuel Standards*, U.S. EPA, notice number EPA-420-F-10-056, November 2010, page 2. A link to the notice is as follows: http://www.epa.gov/otaq/fuels/renewablefuels/420f10056.pdf

The cellulosic biofuel requirement for 2012 was reduced from 500 million to between 3.45 million and 12.9 million gallons. See *EPA Proposes 2012 Renewable Fuel Standards and 2013 Biomass-Based Diesel Volume*, U.S. EPA, notice number EPA-420-F-11-018, June 2011, page 2. A link to the notice is as follows: http://www.epa.gov/otaq/fuels/renewablefuels/420f11018.pdf

[28] U.S. EPA, RFS2 EPA Moderated Transaction System (EMTS) Informational Data. A link to this information is as follows: http://www.epa.gov/oms/fuels/renewablefuels/compliancehelp/rfsdata.htm#2010

[29] Final Ruling posted in the Federal Register at: http://edocket.access.gpo.gov/2010/2010-30296.htm

[30] A renewable fuel is defined as a "motor vehicle fuel that is used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to operate a motor vehicle" found in Code of Federal Regulations under Title 40, part 80, subpart K, 80.1100.

[31] RFS2 RVO formula only uses the petroleum-based portion of gasoline and on-road diesel fuel as part of the calculation. United States Environmental Protection Agency, "Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Proposed Rule," *Federal Register*, Vol. 74, No. 99, pages 24954 through 24955, May 26, 2009. A link to the document is as follows: http://www.epa.gov/OMS/renewablefuels/rfs2_1-5.pdf

[32] *Annual Energy Outlook 2011*, Energy Information Administration, DOE/EIA-0383(2011), April 2011. A link to the report is as follows: http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf. Staff use the Low Oil Price and Extended Policy cases as the basis of the RFS2 evaluation.

A link to that information is as follows:

Extended Policy Case Liquid Fuels Supply and Disposition Table:
http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2011&subject=0-AEO2011&table=11-AEO2011&region=0-0&cases=extended-d031011a
Low Oil Price Case Liquid Fuels Supply and Disposition Table:
http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2011&subject=0-AEO2011&table=11-AEO2011&region=0-0&cases=lp2011lno-d022511a
The Liquid Fuels Supply and Disposition Table contains the EIA projections for gasoline and diesel fuel.

[33] *Mid-Level Blend Ethanol: Challenges, Opportunities & Testing Follow Through,* James Frusti, Chrysler LLC, Joint IEPR and Transportation Committee Workshop on Transportation Fuel Infrastructure Issues, California Energy Commission, Sacramento, California, April 14-15, 2009. A copy of this presentation may be viewed at the following link: http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/presentations/Day-1/09-Frusti_James_Mid-Level_Ethanol_Blends.pdf

[34] University of Minnesota, Department of Mechanical Engineering, *Demonstration and Driveability Project to Determine the Feasibility of Using E20 as a Motor Fuel,* November 4, 2008. A link to the study is as follows: http://www.mda.state.mn.us/~/media/Files/renewable/ethanol/e20drivability.ashx

[35] Oak Ridge National Laboratory, *Effects of Intermediate Ethanol Blends on Legacy Vehicles and Small Non-Road Engines, Report 1*, publication number ORNL/TM-2008/117, February 2009. A link to the report is as follows: http://www.nrel.gov/docs/fy09osti/43543.pdf

[36] Deadline for submitting comments on the E15 waiver request was extended from May 21 to July 20, 2009. "Notice of Receipt of a Clean Air Act Waiver Application To Increase the Allowable Ethanol Content of Gasoline to 15 Percent; Extension of Comment Period," *Federal Register*, Vol. 74, No. 96, May 20, 2009, page 23704. A link to the notice is as follows: http://www.epa.gov/fedrgstr/EPA-AIR/2009/May/Day-20/a11785.pdf

[37] United States Environmental Protection Agency, "Regulation To Mitigate the Misfueling of Vehicles and Engines With Gasoline Containing Greater Than Ten Volume Percent Ethanol and Modifications to the Reformulated and Conventional Gasoline Programs; Final Rule," *Federal Register*, Vol. 76, No. 142, July 25, 2011. A link to the document is as follows: http://www.gpo.gov/fdsys/pkg/FR-2011-07-25/pdf/2011-16459.pdf

[38] There are an estimated 224.7 million cars and light-duty trucks in the United States in 2011, of which 151.0 million are newer than MY 2001. United States Environmental Protection Agency, "Regulation To Mitigate the Misfueling of Vehicles and Engines With Gasoline Containing Greater Than Ten Volume Percent Ethanol and Modifications to the Reformulated and Conventional Gasoline Programs; Proposed Rule," *Federal Register*, Vol. 75, No. 213, November 4, 2010, Table VI.C.3-1, page 68074. A link to the document is as follows: http://edocket.access.gpo.gov/2010/pdf/2010-27446.pdf

[39] A link to the E15 label requirement is as follows: http://www.epa.gov/otaq/regs/fuels/additive/e15/index.htm#mitigate

[40] All of these registered vehicles (409,636) were in the light-duty class. The majority of these FFVs were either a variation of some type of sport utility vehicles (32.4 percent), pickup trucks (33.0 percent) or vans (14.4 percent).

[41] Number of locations according to E85Prices.com on July 31, 2011. A link to the site is as follows: http://e85prices.com/california.html

[42] *Fuel Delivery Temperature Study*, California Energy Commission, Commission Report CEC-600-2009-002-CMF, March 2009, page 57. A link to the document is as follows: http://www.energy.ca.gov/2009publications/CEC-600-2009-002/CEC-600-2009-002-CMF.PDF

[43] Staff estimates that there are a total of between 217,000 and 252,000 meters at nearly 10,000 retail fuel stations throughout California. On average, each meter is estimated as having dispensed between 75,000 and 87,500 gallons of transportation fuel during the period July 1, 2007 through June 30, 2008. Further assuming that a dispenser designed to dispense only one type of fuel would be equipped with two meters, the average fuel distribution during this period for such a dispenser is calculated at between 150,000 and 185,000 gallons. The lower estimate for number of meters at retail motor fuel locations originated from the California Division of Measurement Standards, County Monthly Report (CMR) summary for period July 1, 2007, through June 30, 2008. The higher estimate was derived by staff as part of its work associated with the Fuel Temperature study. As a point of reference, it is further estimated that each fuel dispenser in California distributed an average of 452,000 gallons of transportation fuel over the same period of time. The average distribution level is significantly higher than the "single-fuel" dispenser average because most dispensers are designed to sell three grades of gasoline and will include six meters per dispenser, rather than two. Dispensers that also sell diesel fuel (along with the three grades of gasoline) will normally have eight meters per dispenser (four for each side or face).

[44] *E85 Retail Business Case: When and Why to Sell E85*, C. Johnson and M. Melendez, National Renewable Energy Laboratory, Technical Report NREL/TP-540-41590, December 2007, page 20. A link to this report is as follows: http://www.afdc.energy.gov/afdc/pdfs/41590.pdf

[45] National Association of Convenience Stores (NACS) and the Society of Independent Gasoline Marketers of America (SIGMA), Letter to Congress, March 27, 2006, page 2. A copy of the document may be accessed at the following link: http://www.sigma.org/pdf/E85-Mandates.pdf. According to the National Commission on Energy Policy's (NCEP) recent report: "Replacing an entire system can be expected to cost substantially more than $150,000 per facility depending upon the market." *Task Force on Biofuels Infrastructure*, NCEP, May 2009, Appendix B, page 53; available from http://www.energycommission.org/ht/a/GetDocumentAction/i/10232; Internet; accessed on August 2, 2009. Additional cost estimates for both new and retrofit scenarios are provided in the following brief paper: *Cost of Adding E85 Fueling Capability to Existing Gasoline Stations: NREL Survey and Literature Search,* National Renewable Energy Laboratory, Publication NREL/FS-540-42390, March 2008. A link to this document is as follows: http://www.afdc.energy.gov/afdc/pdfs/42390.pdf

[46] August 9, 2011, Gary Yowell phone conversation with Robert L. Bowen, DGS, Project Director, Project Management Office of DGS and review of completed retail E85 stations funded through Grant Agreement Number ARV-09-006.

[47] Summary provided in the 2011 AB 118 Investment Plan.

[48] *E85 Retail Business Case: When and Why to Sell E85*, C. Johnson and M. Melendez, National Renewable Energy Laboratory, Technical Report NREL/TP-540-41590, December 2007, Appendix C, page 41. A link to this report is as follows: http://www.afdc.energy.gov/afdc/pdfs/41590.pdf

[49] *Fuel Delivery Temperature Study*, California Energy Commission, CEC-600-2009-002-CMF, page 59. A link to this study is as follows: http://www.energy.ca.gov/2009publications/ENERGY COMMISSION-600-2009-002/ENERGY COMMISSION-600-2009-002-CMF.PDF

[50] Based on data for 2010, 57.5 percent of the convenience stores were owned and operated by someone who only had one station. A link to this information and more is at the following link: http://www.nacsonline.com/NACS/Resources/campaigns/GasPrices_2011/Documents/GasPriceKit2011.pdf

[51] National Association of Convenience Stores, NACS Online, Fact Sheets, Motor Fuels, Motor Fuel Sales, posted June 3, 2011. A link to the fact sheet is as follows: http://www.nacsonline.com/NACS/News/FactSheets/Motor%20Fuels/Pages/MotorFuelSales.aspx

[52] National Association of Convenience Stores, *NACS State of the Industry Report of 2007 Data* (1998 – 2007 data), December 2008, 2009 press release (2008 data), and 2010 press release (2009 data). Press release: *Convenience Store Sales Show Strong Growth in 2010*, NACS, April 6, 2011. A link to the press release is as follows: http://www.pbaa.net/index.php?option=com_k2&view=item&id=137:convenience-store-sales-show-strong-growth-in-2010&tmpl=component&print=1

[53] One such example of government funding is the California Air Resources Board Alternative Fuel Incentive Program created through Assembly Bill 1811 (Laird, Chapter 48, Statutes of 2006). This activity was designed to provide $25 million "for the purposes of incentivizing the use and production of alternative fuels." A link to the ARB site is as follows: http://www.arb.ca.gov/fuels/altfuels/incentives/incentives.htm.

An example of a specific station in Brentwood that received grant money from this program (approximately $580,000) is as follows: *California Has New E85 Station Open to the Public*, Dimitri Stanich, California Air Resources Board, February 26, 2008. A link to the press release is as follows: http://www.arb.ca.gov/newsrel/nr022608.htm. The list of additional California programs that may provide other funding opportunities for prospective E85 retail station owners can be viewed at the following link: http://www.afdc.energy.gov/afdc/progs/state_summary.php/CA

Finally, the 2009 American Recovery and Reinvestment Act (Section 1123) provides for a tax credit of up to $50,000 per business through 2010 that can be applied to the installation of E85 dispensers. The specific language to the Section 1123 provisions are found on page 47 at the following link: http://thomas.loc.gov/home/h1/Recovery_Bill_Div_B.pdf

[54] *Mid-Level Blend Ethanol: Challenges - Opportunities & Testing Follow Through*, James Frusti, Chrysler, April 14, 2009, slide 11. A link to this presentation is as follows: http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/presentations/Day-1/09-Frusti_James_Mid-Level_Ethanol_Blends.pdf

[55] *GM Update on Flex-Fuel Vehicle Challenges in CA*, James Ehlmann and Clay Okabayashi, General Motors, June 24, 2008, slides 4 through 8. A link to this presentation is as follows: http://www.netl.doe.gov/publications/proceedings/08/clean-cities-ca/pdfs/6.24Tues/Ehlmann%20%26%20Okabayashi%20-%20GM.pdf

[56] Ibid. slide 9.

[57] *The California Low-Emission Vehicle Regulations - With Amendments Effective April 17, 2009*, California Air Resources Board. A link to this document is as follows: http://www.arb.ca.gov/msprog/levprog/cleandoc/cleancomplete_lev-ghg_regs_3-09.pdf

The revised zero emission vehicle standards describe the multiple and complex compliance options for vehicle manufacturers. Some of these compliance pathways can include the increased sales of PZEVs. Hearing Date: 03/27/08, Adopted: 12/17/08. A link to this Final Regulation Order – Part 5 is as follows: http://www.arb.ca.gov/regact/2008/zev2008/zfrop5.pdf

For a historical summary of the ZEV regulation evolution, please refer to the following document: "Learning From California's Zero-Emission Vehicle Program," Louise Wells Bedsworth and Margaret R. Taylor, *California Economic Policy*, Volume 3, Number 4, September 2007. A link to the document is as follows: http://www.ppic.org/content/pubs/cep/EP_907LBEP.pdf

[58] United States Environmental Protection Agency and the National Highway Traffic Safety Administration (NHTSA), "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule," *Federal Register*, Vol. 75, No. 88, May 7, 2010. A link to the document is as follows: http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/CAFE-GHG_MY_2012-2016_Final_Rule_FR.pdf

[59] *2017-2025 Model Year Light-Duty Vehicle GHG Emissions and CAFE Standards: Supplemental Notice of Intent*, EPA and NHTSA, July 29, 2011. A copy of the supplemental notice is as follows: http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/2017-2025_CAFE-GHG_Supplemental_NOI07292011.pdf

[60] *E85 Retail Business Case: When and Why to Sell E85*, C. Johnson and M. Melendez, National Renewable Energy Laboratory (NREL), Technical Report NREL/TP-540-41590, December 2007, Appendix E, page 43. A link to this report is as follows: http://www.afdc.energy.gov/afdc/pdfs/41590.pdf

[61] Retail prices obtained from E85Prices.com, California price chart. A link to this site is as follows: http://e85prices.com/california.html

[62] "Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Proposed Rule," U.S. Environmental Protection Agency, *Federal Register*, Vol. 74, No. 99, May 26, 2009, pp. 24920-1. A link to the proposed rule is as follows: http://www.epa.gov/OMS/renewablefuels/rfs2_1-5.pdf

[63] Excluding the 2010 RIN credit values during 2011, the lowest RIN credit was 1.1 cents per gallon.

[64] An overview of the RIN requirements and some of the complicating factors are contained in the following paper: *The Changing RINs Landscape*, Oil Price Information Service (OPIS), 2009. A link to a copy of this document is as follows: http://www.scribd.com/doc/17121722/Briefing-on-RINs-Renewable-Identification-Numbers

[65]*Crude Oil Screening Workgroup Objectives*, Draft, California Air Resources Board, First Crude Oil Screening Workgroup Meeting, March 29, 2010. A link to the document is as follows: http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/032910crude_oil_ws_obj.pdf

Page2 contains a definition that High Carbon Intensity Crude Oil "means any crude oil that has a total production and transport carbon intensity value greater than 15.00 gCO2e/MJ".

[66] A detailed description of various Enhanced Oil Recovery techniques, trends and recent status is contained in *Enhanced Oil Recovery: An Update Review*, Vladimir Alvarado and Eduardo Manrique, *Energies* 2010, 3, 1529-1575, published August 27, 2010. A link to the publication is as follows: http://www.mdpi.com/1996-1073/3/9/1529/pdf

[67] *2008 Annual Report of the State Oil & Gas Supervisor*, California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, Publication No. PR06, 2009, page3. A link to the document is as follows: ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2008/0101summary1_08.pdf

[68] *Talk About Upgrading and Refining*, fact sheet, Government of Alberta, July 2011. A link to the document is as follows: http://www.energy.gov.ab.ca/Oil/pdfs/FSRefiningUpgrading.pdf

[69] Canada currently has 6 upgraders in operation with a combined bitumen processing capacity of 1.2 million barrels per day according to *Existing and Proposed Canadian Commercial Oil Sands Projects*, Strategy West Inc., January 2011. A link to the report is as follows: http://www.strategywest.com/downloads/StratWest_OSProjects_2011_01.pdf

[70] *Talk About Oil Sands*, fact sheet, Government of Alberta, April 2011. A link to the document is as follows: http://www.energy.alberta.ca/OilSands/pdfs/FactSheet_OilSands.pdf

[71] *Determining Carbon Intensity Values for Fuels Derived from Crude Oil, Interim Crude Oil Screening Process*, California Air Resources Board, February 11, 2011. A link to the document is as follows: http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/021711lcfs-hcico-arb-proposal.pdf

[72] For a complete description of the various information resources used to perform the crude oil analysis see: *Results of Crude Oil Marketing Name Analysis*, Gordon Schremp, California Energy Commission, Crude Oil Screening - General Meeting Presentation. A link to the presentation is as follows: http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/090910cec.pdf

[73] *Low Carbon Fuel Standard Proposed Amendments*, California Air Resources Board, July 22, 2011, slide 65. A link to the presentation is as follows: http://www.arb.ca.gov/fuels/lcfs/regamend/072211lcfs_regamend_pres.pdf

[74] *Market Report Highlights*, International Energy Agency (IEA), July 13, 2011. A link to this report is as follows: http://omrpublic.iea.org/currentissues/high.pdf

[75] This calculation assumes that California's maximum total crude oil import need for 2015 of 408 million barrels is divided by the forecasted global crude oil demand value of 33.21 billion barrels (based on a daily demand estimate of 91.0 million barrels per day).

[76] This calculation assumes that California's maximum incremental crude oil import need for 2016 of 38 million barrels is divided by the forecasted global incremental crude oil demand value of 1.8 billion barrels (based on a daily incremental demand estimate of 4.91 million barrels per day between 2010 and 2016). This comparison uses the lower crude oil demand estimate from the low-GDP case from IEA's Medium-Term Oil Market Report. *IEA Report Looks at Oil, Gas Market Prospects Through 2016*, International Energy Agency, press release, June 16, 2011. A link to the press release is as follows: http://www.iea.org/press/pressdetail.asp?PRESS_REL_ID=417

[77] A link to the California Air Resources Board website that contains background information and regulations is as follows: http://www.arb.ca.gov/fuels/lcfs/lcfs.htm

[78] *Carbon Intensity Lookup Table for Gasoline and Fuels that Substitute for Gasoline*, California Air Resources Board, Table 6, updated January 6, 2011. A link to this table is as follows: http://www.arb.ca.gov/fuels/lcfs/010611lcfs_lutables.pdf

[79] *California's Low Carbon Fuel Standard, An Update on the California Air Resources Board's Low Carbon Fuel Standard Program*, California Air Resources Board, October 2009, pages 14 to 15. A link to this document is as follows: http://www.arb.ca.gov/fuels/lcfs/100609lcfs_updated_es.pdf

[80] Biodiesel NO_x issues raised by ARB are, in part, based on information provided by U.S. EPA that illustrates an increase in biodiesel blends. *A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions*, Draft Technical Report, U.S. Environmental Protection Agency, report number EPA420-P-02-001, October 2002, Figure ES-A, page ii. A link to the report is as follows: http://www.epa.gov/oms/models/analysis/biodsl/p02001.pdf

The ARB provides a more extensive description of the NO_x increase issue and results of their literature review in the following workshop presentation, titled *Biodiesel and Renewable Diesel Rulemaking 2nd Public Workshop*, Lex Mitchell and Bob Okamoto, California Air Resources Board, May 19, 2010. A link to the presentation is as follows: http://www.arb.ca.gov/fuels/diesel/altdiesel/100519BiodieselWorkshopPresColor.pdf

[81] *Concept Paper for Biodiesel and Renewable Diesel Rulemaking*, California Air Resources Board, January 20, 2010. A link to this draft proposal is as follows: http://www.arb.ca.gov/fuels/diesel/altdiesel/100120biodieselconceptpaper.pdf

[82] Concentration of fuel ethanol is an average value for each calendar year.

[83] *Alternative and Renewable Fuel and Vehicle Technology Program, Solicitation Number PON-09-607, Subject Area: California Ethanol Producer Incentive Program*, California Energy Commission, June 7, 2010. A link to the document is as follows: http://www.energy.ca.gov/contracts/PON-09-607/PON-09-607_Ethanol_Application_Manual.pdf

[84] *Alternative and Renewable Fuel and Vehicle Technology Program, Solicitation Number PON-09-607, Subject Area: California Ethanol Producer Incentive Program*, Addendum 3, California Energy Commission, August 25, 2010, pages 2 through 3. A link to the document is as follows: http://www.energy.ca.gov/contracts/PON-09-607/PON-09-607_Addendum_03.pdf

[85] The carbon intensity (CI) value for Brazilian sugarcane ethanol using average production processes is 73.40 gCO2e/MJ. This value includes both direct emissions and other indirect effects (such as changes in land use). If the Brazilian sugarcane-based ethanol production has electricity cogeneration from the burning of bagasse (sugarcane residue), the CI drops to 66.40 gCO2e/MJ. If mechanized harvesting is also included along with electricity generation, the CI value drops further to 58.20 gCO2e/MJ.

Average Midwestern ethanol produced from corn has a carbon intensity value of 99.40 gCO2e/MJ by comparison. Ethanol produced using corn at an average California facility has a carbon intensity value of between 80.70 and 88.9 gCO2e/MJ, depending on whether or not the distillers grain with solubles (DGS) co-product is wet or dry. California Air Resources Board, Modified Regulation Order, Table 6, page 43, posted July 20, 2009. A link to the document is as follows: http://www.arb.ca.gov/regact/2009/lcfs09/lcfsmodtxt.pdf

[86] Inedible tallow use as a feed is defined as "…shipments for consumption of inedible tallow and grease for use in livestock and poultry feed." Source of information is *Fats and Oils: Production, Consumption, and Stocks*, Form M311K, U.S. Census Bureau, 2010 Summary, June 2011, Tables 4A and 4B. A link to the file is as follows: http://www.census.gov/manufacturing/cir/historical_data/m311k/m311k1013.xls

Conversion of inedible tallow to renewable diesel uses the following assumptions:
Each 1.17 pounds of inedible tallow can yield 1.00 pounds of renewable diesel fuel according to *Detailed California-Modified GREET Pathway for Renewable Diesel Produced in California from Tallow (U. S. Sourced)*, California Air Resources Board, Release Date: July 20, 2009, page 26. A link to the document is as follows: http://www.arb.ca.gov/fuels/lcfs/072009lcfs_tallow_rd.pdf
Density of renewable diesel from inedible tallow is assumed to be 2,948 grams per gallon which converts to 6.50 pounds per gallon. Ibid, page 26.
[87] *Fats and Oils: Production, Consumption, and Stocks*, Form M311K, U.S. Census Bureau, 2010 Summary, June 2011, Table 2. A link to the file is as follows: http://www.census.gov/manufacturing/cir/historical_data/m311k/m311k1013.xls
Conversion of inedible tallow to renewable diesel uses the identical assumptions from the previous end note.
[88] Ibid., Table 8a. Corn oil exports definition "Represents crude and once-refined oil only; excludes exports of fully refined oil."
[89] Ibid.
[90] *California Modified GREET Pathway for the Production of Biodiesel from Corn Oil at Dry Mill Ethanol Plants*, California Air Resources Board, Release Date: December 14, 2010, page 8. A link to the document is as follows: http://www.arb.ca.gov/fuels/lcfs/2a2b/internal/121410lcfs-cornoil-bd-rpt.pdf
[91] This range assumes that the upper limit of corn-based ethanol production will be 15.0 billion gallons per year, the maximum volume that may be used by obligated parties under the federal RFS2 program. 6 percent of this volume equates to 900 million gallons of corn oil biodiesel and 7 percent equates to 1.05 billion gallons of corn oil biodiesel.
[92] *Learn About Biodiesel*, U.S. EPA, Region 9. A link to this site is as follows: http://www.epa.gov/region9/waste/biodiesel/questions.html
[93] Assumes that the average fuel ethanol concentration in E85 is 79.2 percent by volume.
[94] Pew Center on Global Climate Change, "Low Carbon Fuel Standard," February 11, 2011. A link to the document is as follows: http://www.pewclimate.org/sites/default/modules/usmap/pdf.php?file=8009
[95] Oregon House Bill 2186, June 25, 2009. A link to the bill is as follows: http://www.leg.state.or.us/09reg/measpdf/hb2100.dir/hb2186.en.pdf
[96] Oregon Department of Environmental Quality, "Low Carbon Fuel Standard," 2011. A link to the document is as follows: http://www.deq.state.or.us/aq/committees/lowcarbon.htm
[97] Oregon Department of Environmental Quality, "Oregon Low Carbon Fuel Standards: Advisory Committee Process and Program Design," January 25, 2011. A link to the document is as follows: http://www.deq.state.or.us/aq/committees/docs/lcfs/reportFinal.pdf
[98] Ibid, page 18
[99] Oregon Department of Environmental Quality, "Oregon Low Carbon Fuel Standards: Advisory Committee Process and Program Design," January 25, 2011, Page 10. A link to the document is as follows: http://www.deq.state.or.us/aq/committees/docs/lcfs/reportFinal.pdf
[100] HB 2186, Section 6.4.
[101] Executive Order 09-05, "Washington's Leadership on Climate Change," May 21, 2009. A link to the executive order is as follows: http://www.ecy.wa.gov/climatechange/2009EO/2009EO_signed.pdf
[102] Washington Department of Ecology, "Path to a Low-Carbon Economy: An Interim Plan to Address Washington's Greenhouse Gas Emissions, December 2010, Page 3. A link to the document is as follows: http://www.ecy.wa.gov/pubs/1001011.pdf
[103] Washington Department of Ecology, "A Low Carbon Fuel Standard in Washington: Informing the Decision," February 18, 2011. A link to the document is as follows: http://www.ecy.wa.gov/climatechange/docs/fuelstandards_finalreport_02182011.pdf
[104] Ibid, Page vii.
[105] Pew Center on Global Climate Change, "Low Carbon Fuel Standard," February 11, 2011. A link to the document is as follows: http://www.pewclimate.org/sites/default/modules/usmap/pdf.php?file=8009
[106] NESCAUM, "Low Carbon Fuels,". A link to the website is as follows: http://www.nescaum.org/topics/low-carbon-fuels

[107] NESCAUM, "NESCAUM Overview,". A link to the overview is as follows: http://www.nescaum.org/about-us/overview
[108] M. Jodi Rell et al, "Northeast and Mid-Atlantic Low Carbon Fuel Standard," Memorandum of Understanding, December 30, 2009. A link to the MOU is as follows: http://www.nescaum.org/documents/lcfs-mou-govs-final.pdf
[109] NESCAUM, "Update on the Regional Low Carbon Fuel Standard Initiative," December 29, 2010. A link to the document is as follows: http://www.nescaum.org/documents/lcfs-end-of-year-statement.pdf/
[110] NESCAUM, "Low Carbon Fuels,". A link to the website is as follows: http://www.nescaum.org/topics/low-carbon-fuels
[111] Pew Center on Global Climate Change, "Low Carbon Fuel Standard," February 11, 2011. A link to the document is as follows: http://www.pewclimate.org/sites/default/modules/usmap/pdf.php?file=8009
[112] Midwestern Governors Association, "Alternative Transportation Fuels," 2011. A link to the website is as follows: http://www.midwesterngovernors.org/fuels.htm
[113] Midwestern Governors Association Advanced Transportation Fuels Advisory Group, "Alternative Policies to Reduce GHG Intensity of Fuels in the Midwest, 2011. A link to the website is as follows: http://www.midwesterngovernors.org/Fuels/Meeting1/Alternative_Approaches_to_LCFP.pdf
[114] Energy Security and Climate Stewardship Platform for the Midwest: Low Carbon Fuel Policy Advisory Group Recommendations, 2010. A link to the document is as follows: http://www.midwesterngovernors.org/Publications/LCFPagDoc.pdf

[115] *The Tax Treatment of Alternative Transportation Fuels*, CRS Report for Congress, Salvatore Lazzari, 97-195 E, Updated March 19, 1997. A link to the report is as follows: http://ncseonline.org/nle/crsreports/transportation/trans-6.cfm
[116] A detailed history of the VEETC development may be reviewed at the following: Stephen McDonald, *Why VEETC Is Not Enough: Protecting the National Highway Transportation Infrastructure*, 30 Wm. & Mary Envtl. L. & Pol'y Rev. 731 (2006), http://scholarship.law.wm.edu/wmelpr/vol30/iss3/6
[117] A breakdown of the current federal excise tax rate on various ethanol concentrations and all other transportation and heating fuels may be viewed at the following link: http://www.mpca.org/newsletters/2010/attachments/010311_PMAA_RR_1-3-11.pdf
[118] Energy Commission staff analysis of ethanol production, inventory, import and export data from the Energy Information Administration (EIA) and USDA Foreign Agricultural Service
[119] *Biofuels: Potential Effects and Challenges of Required Increases in Production and Use*, U.S. Government Accountability Office, report number GAO-09-446, August 2009, page 99. A link to the document is as follows: http://www.gao.gov/new.items/d09446.pdf
[120] Information provided to the Energy Commission by the California State Board of Equalization (BOE) indicated that E85 sales totaled 9,979,885 gallons during 2010.
[121] Ibid, page 99.
[122] *Energy Tax Policy: Historical Perspectives on and Current Status of Energy Tax Expenditures*, Molly F. Sherlock, Congressional Research Service (CRS), May 2, 2011, Figure 6, page 24. A link to the report is as follows: http://leahy.senate.gov/imo/media/doc/R41227EnergyLegReport.pdf
[123] *Opportunities to Reduce Potential Duplication in Government Programs, Save Tax Dollars, and Enhance Revenue*, U.S. Government Accountability Office, report number GAO-11-318SP, March 2011, page 60. A link to the document is as follows: http://www.gao.gov/new.items/d11318sp.pdf
[124] Ibid, page 59.
[125] *Harmonized Tariff Schedule of the United States (2009) – Supplement 1*, United States International Trade Commission, July 1, 2009, subheading 2207.10.60, page 1006. Citation for the 2.5 percent ad valorem fee on undenatured ethyl alcohol intended for nonbeverage use in the United States.
Harmonized Tariff Schedule of the United States (2009) – Supplement 1, United States International Trade Commission, July 1, 2009, subheading 9901.00.50, page 2558. Citation for the secondary import tariff of 14.27 cents per liter or 54.08 cents per gallon (cpg) on ethyl alcohol intended for fuel use in the United States. A link to the Harmonized Tariff Schedule document is as follows: http://www.usitc.gov/publications/docs/tata/hts/bychapter/0910htsa.pdf
[126] The Caribbean Basin Initiative or CBI is an economic development program designed, in part, to allow specific types of goods imported into the United States duty-free or at reduced tariff structures. A lengthy description of

the program and eligible countries is contained in: "Guide to the Caribbean Basin Initiative," U.S. Department of Commerce, International Trade Commission, 2000 Edition. A link to the document is as follows: http://www.ita.doc.gov/media/Publications/pdf/cbi2000.pdf

[127] *The Impact of the Caribbean Basin Economic Recovery Act, Nineteenth Report 2007-2008*, U.S. International Trade Commission, Publication 4102, September 2009, footnote 29, page 1-6. A link to the document is as follows: http://www.usitc.gov/publications/332/pub4102.pdf

[128] *Enhancing Regional Cooperation Under the CBI: Challenges and Opportunities of the U.S. Ethanol Policy*, Doug Newman, U.S. International Trade Commission, March 11, 2009, slide number 8. A copy of the presentation may be viewed at the following link: http://www.bioenergywiki.net/images/0/05/DNewman.pdf

[129] *Ethanol and the Caribbean Basin Initiative*, Caribbean Ethanol Producers, June 2011. A link to this document is as follows: http://www.caribbeanethanolproducers.com/doc/CBI%20Summary%203-June%202011.docx

[130] *Table 6, Carbon Intensity Lookup Table for Gasoline and Fuels that Substitute for Gasoline*, California Air Resources Board, revised 01/06/2011. A link to the table is as follows: http://www.arb.ca.gov/fuels/lcfs/010611lcfs_lutables.pdf

[131] Doug Newman, slide number 26.

[132] *Ethanol Mandates in the U.S. and the Caribbean Basin Initiative*, Caribbean Ethanol Producers, June 2011, Exhibit III. A link to the document is as follows: http://www.caribbeanethanolproducers.com/doc/CBI_ETHANOL%20Mandates%20in%20the%20US.docx

[133] Support Alternative to Preserve Ethanol Production in the Caribbean Basin, Caribbean Ethanol Producers, June 2011. A link to the document is as follows: http://www.caribbeanethanolproducers.com/doc/CBEPA%20One%20Page%2062111.pdf

[134] Delivered ethanol price to Los Angeles averaged $2.84 per gallon during June of 2011, while the price of anhydrous ethanol in Santos, Brazil averaged $2.97 per gallon during the same period. Brazilian ethanol prices may be viewed at the following link: http://www.cepea.esalq.usp.br/english/ethanol/?id_page=243

[135] USDA Foreign Agricultural Service's Global Agricultural Trade System (GATS), Harmonized (HS-10) data for undenatured ethyl alcohol for non-beverage use (code 2207106000) and for denatured ethyl alcohol (code 2207200000). A link to the GATS site is as follows: http://www.fas.usda.gov/gats/ExpressQuery1.aspx

[136] *Removal of U.S. Ethanol Domestic and Trade Distortions: Impact on U.S. and Brazilian Ethanol Markets*, Amani Elobeid and Simla Tokgoz, Center for Agricultural and Rural Development, Iowa State University, Working Paper 06-WP 427, October 2006 (Revised), page 22. A link to the document is as follows: http://www.card.iastate.edu/publications/DBS/PDFFiles/06wp427.pdf

The lower estimate of 2.4 percent U.S. ethanol price reduction is from the following Working Paper: *The Economics of U.S. Ethanol Import Tariffs with a Consumption Blend Mandate and Tax Credit*, Harry de Gorter and David R. Just, Department of Applied Economics and Management, Cornell University, Ithaca, New York, February 7, 2008, Table 2, page 24. Note that the 2.4 percent reduction of the U.S. ethanol price is for 2015 and is under a scenario of mandated ethanol use, removal of the import tariff, and retention of the 45 cpg ethanol blenders' tax credit. A link to this working paper is as follows: http://papers.ssrn.com/sol3/Delivery.cfm/SSRN_ID1097106_code328474.pdf?abstractid=1024532&mirid=5

[137] National Highway Traffic Safety Administration "Summary of Fuel Economy Performance," p 3, <http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/2011_Summary_Report.pdf>

[138] National Highway Traffic Safety Administration, "EPA and NHTSA Propose First-Ever Program To Reduce Greenhouse Gas Emissions and Improve Fuel Efficiency of Medium- and Heavy-Duty Vehicles: Regulatory Announcement," p 3, <http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/CAFE_2014-18_Trucks_FactSheet-v1.pdf>

[139] From EIA's US Product Supplied data. Gasoline and Diesel fuel consumed by the US for 2010 is 196.7 billion gallons.

[140] National Highway Traffic Safety Administration, "NHTSA and EPA Establish New National Program to Improve Fuel Economy and Reduce Greenhouse Gas Emissions for Passenger Cars and Light Trucks," p 5. <http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/CAFE-GHG_Fact_Sheet.pdf>

[141] National Highway Traffic Safety Administration, "NHTSA and EPA Establish New National Program to Improve Fuel Economy and Reduce Greenhouse Gas Emissions for Passenger Cars and Light Trucks," p 5. <http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/CAFE-GHG_Fact_Sheet.pdf>

[142] National Highway Traffic Safety Administration, "NHTSA and EPA Establish New National Program to Improve Fuel Economy and Reduce Greenhouse Gas Emissions for Passenger Cars and Light Trucks," p 5, <http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/CAFE-GHG_Fact_Sheet.pdf>.

[143] National Highway Traffic Safety Administration, "NHTSA and EPA Establish New National Program to Improve Fuel Economy and Reduce Greenhouse Gas Emissions for Passenger Cars and Light Trucks," p 5. <http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/CAFE-GHG_Fact_Sheet.pdf>

[144] National Highway Traffic Safety Administration, "President Obama Announces Historic 54.5 mpg Fuel Efficiency Standard," <http://www.nhtsa.gov/About+NHTSA/Press+Releases/2011/President+Obama+Announces+Historic+54.5+mpg+Fuel+Efficiency+Standard>

[145] Rascoe, Ayesha and Seetharaman, Deepa, "Obama Unveils Sharp Increase in Auto Fuel Economy," Reuters, July 29, 2011, <http://www.reuters.com/article/2011/07/29/us-usa-autos-standards-idUKTRE76S4AR20110729?type=companyNews>

[146] National Highway Traffic Safety Administration,NHTSA and EPA Announces a First Step in the Process for Setting Future Fuel Economy and Greenhouse Gas Standards for Passenger Cars and Light Trucks, p 3, <http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/FactSheet_%20NOI_TAR.pdf>

[147] National Highway Traffic Safety Administration. Fact Sheet on Fuel Efficiency and GHG Emission Program for Medium- and Heavy-Duty Vehicles, pp 1-4. http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/CAFE_2014-18_Trucks_FactSheet-v1.pdf

[148] Ibid, pp 3-4.

[149] National Highway Traffic Safety Administration 49 CFR Parts 523, 534, and 535 [EPA–HQ–OAR–2010–0162; NHTSA–2010–0079; FRL–9219–4]; RIN 2060–AP61; RIN 2127–AK74. Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles, p 74225. http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/MD-HD_fuel_efficiency-GHG_NPRM_11302010.pdf

[150] NHTSA Fact Sheet, pp 5-6.

[151] Ibid, p 6.

[152] It should be noted that ground-level ozone is a separate issue entirely from the ozone layer. The ozone layer exists several miles above ground level and provides protection from ultraviolet radiation, while ground-level ozone remains close to the surface of the Earth and is a pollutant. See, for example, <http://www.epa.gov/airquality/gooduphigh/ozone.pdf> for more information.

[153] Environmental Protection Agency, "National Ambient Air Quality Standards for Ozone," Federal Register, Vol. 85, No. 11, p. 2949, January 19, 2010, <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2005-0172-7239>, accessed on June 16, 2011.

[154] Environmental Protection Agency, "Final Ozone NAAQS Regulatory Impact Analysis," p. 2-1, March 2008, < http://www.regulations.gov/#!documentDetail;D=OSHA-2010-0034-0661>, accessed on June 21, 2011.

[155] Environmental Protection Agency, "Final Ozone NAAQS Regulatory Impact Analysis," p. 2-1, March 2008, < http://www.regulations.gov/#!documentDetail;D=OSHA-2010-0034-0661>, accessed on June 21, 2011.

[156] In addition to the primary standard, the EPA enforces a secondary weighted standard, known as W126. The formulation of this standard is technically complex and has not been considered for purposes of this report. See, for example, <http://www.epa.gov/ttn/naaqs/standards/ozone/data/2007_07_ozone_staff_paper.pdf>, page 483 for more information.

[157] Environmental Protection Agency, "National Ambient Air Quality Standards (NAAQS)," July 7, 2011, <http://www.epa.gov/air/criteria.html>, accessed on July 12, 2011.

[158] Environmental Protection Agency, "National Ambient Air Quality Standards for Ozone," Federal Register, Vol. 73, No. 60, p. 16483, March 27, 2008, <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2005-0172-7205>, accessed on June 16, 2011.

[159] Environmental Protection Agency, "National Ambient Air Quality Standards for Ozone," Federal Register, Vol. 85, No. 11, p. 2944, January 19, 2010, <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2005-0172-7239>, accessed on June 16, 2011.

[160] Environmental Protection Agency, "National Ambient Air Quality Standards for Ozone," Federal Register, Vol. 75, No. 11, p. 2940-2941, January 19, 2010, <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2005-0172-7239>, accessed on June 16, 2011.

[161] Environmental Protection Agency, "Summary of the Updated Regulatory Impact Analysis (RIA) for the Reconsideration of the 2008 Ozone National Ambient Air Quality Standard (NAAQS)," p. S1-1, January 12, 2010, <http://www.epa.gov/ttnecas1/regdata/RIAs/s1-supplemental_analysis_summary11-5-09.pdf>, accessed on June 16, 2011.

[162] Environmental Protection Agency, "Integrated Review Plan for the Ozone NAAQS Review," p. 1-13, April 2001,< http://www.epa.gov/ttn/naaqs/standards/ozone/data/2011_04_OzoneIRP.pdf>, accessed on June 16, 2011.

[163] Edgar Ang, "Update: EPA Delays Introduction of Proposed Tighter Ozone Standards," Oil Price Information Service, July 26, 2011.

[164] Environmental Protection Agency, "National Ambient Air Quality Standards for Ozone," Federal Register, Vol. 75, No. 11, p. 2941, January 19, 2010, <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2005-0172-7239>, accessed on June 16, 2011.

[165] Environmental Protection Agency, "Final Ozone NAAQS Regulatory Impact Analysis," p. 3-9, March 2008, < http://www.regulations.gov/#!documentDetail;D=OSHA-2010-0034-0661>, accessed on June 21, 2011.

[166] Environmental Protection Agency, "Designation of Areas for Air Quality Planning Purposes; California; San Joaquin Valley, South Coast Air Basin, Coachella Valley, and Sacramento Metro 8-Hour Ozone Nonattainment Areas; Reclassification," Federal Register Vol. 75, No. 86, p. 25515, May 5, 2010, <http://www.regulations.gov/#!documentDetail;D=EPA-R09-OAR-2011-0046-0045>, accessed on July 11, 2010.

[167] California Air Resources Board, "2010 Area Designations for State Ambient Air Quality Standards," 2010, <http://www.arb.ca.gov/desig/adm/2010/state_ozone.pdf>, accessed on June 23, 2011.

[168] South Coast Air Quality Management District, "Historic Air Quality Trends," June 9, 2011, <http://www.aqmd.gov/smog/o3trend.html>, accessed on June 23, 2011.

[169] California Air Resources Board, "Statewide Air Quality Plan," April 26, 2007 < http://www.arb.ca.gov/planning/sip/2007sip/2007sip.htm>, accessed on June 16, 2011.

[170] Arizona Department of Environmental Quality, "Arizona Air Quality Designations," ES-1, March 12, 2009, <http://www.epa.gov/ozonedesignations/2008standards/rec/letters/09_AZ_rec.pdf>, accessed on June 21, 2011.

[171] Yantorno, Duane, conference call, June 22, 2010.

[172] Arizona Department of Weights and Measure, "Transportation Fuels Report for 2009," p. 12-17, August 8, 2010.

[173] Striejewske, William, conference call, June 26, 2010.

[174] Further details on the UNEV pipeline are contained in the Pipeline section of this report.

[175] Regulations were contained in Bill C-33, An Act to amend the Canadian Environmental Protection Act, 1999. A description of the bill may be viewed at the following link: http://www.parl.gc.ca/About/Parliament/LegislativeSummaries/bills_ls.asp?lang=E&ls=c33&Parl=39&Ses=2&source=library_prb

[176] A more detailed description of the Canadian RFS and various provincial renewable fuel mandates is contained in *Canada Biofuels Annual - 2010*, USDA Foreign Agricultural Service, Global Agricultural Information Network (GAIN), Report number CA11036, July 5, 2011. A link to the report is as follows: http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Ottawa_Canada_07-05-2011.pdf

[177] Canada Gazette, Vol. 144, No. 18, September 1, 2010. A link to the regulation is as follows: http://www.gazette.gc.ca/rp-pr/p2/2010/2010-09-01/html/sor-dors189-eng.html

[178] Ibid.

[179] *Building on Our Strengths: An Inventory of Current Federal, Provincial, and Territorial Climate Change Policies*, Bollinger and Roberts, Canada West Foundation, February 2008, pages 10-11. A link to the document is as follows: http://cwf.ca/pdf-docs/publications/building-on-our-strengths-report-2008.pdf

[180] Annual gasoline sales figures obtained from *The Supply and Disposition of Refined Petroleum Products in Canada*, Catalogue no. 45-004-X, Statistics Canada. A link to the 2010 annual report is as follows: http://publications.gc.ca/collections/collection_2011/statcan/45-004-X/45-004-x2010012-eng.pdf

[181] *Canada Biofuels Annual - 2010*, USDA Foreign Agricultural Service, Global Agricultural Information Network (GAIN), Report number CA11036, July 5, 2011, Table 4, page 12. A link to the report is as follows: http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Ottawa_Canada_07-05-2011.pdf

[182] *2009 Reference Case Scenario: Canadian Energy Supply and Demand to 2020, Appendices*, National Energy Board, July 2009. A link to the document is as follows: http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2009/rfrnccsscnr2009ppndc-eng.pdf

[183] Canada Gazette.
[184] Ethanol Producer Magazine, Canada ethanol plant list as of June 17, 2011. A listing of the 16 facilities currently operational may be viewed at the following link: http://www.ethanolproducer.com/plants/listplants/Canada/
[185] *Canada Biofuels Annual - 2010*, USDA Foreign Agricultural Service, Table 4, page 12.
[186] USDA Foreign Agricultural Service's Global Agricultural Trade System (GATS), Harmonized (HS-10) data for undenatured ethyl alcohol for non-beverage use (code 2207106000) and for denatured ethyl alcohol (code 2207200000). A link to the GATS site is as follows: http://www.fas.usda.gov/gats/ExpressQuery1.aspx
[187] Wikipedia, "Ford Model T"; available at http://en.wikipedia.org/wiki/Ford_Model_T.
[188] U.S. General Accounting Office, *Importance and Impact of Federal Alcohol Fuel Tax Incentives*, GAO/RCED-84-1, Washington D.C.: Government Printing Office, June 1984, page 1. http://archive.gao.gov/d6t1/124476.pdf
[189] Ibid, page1.
[190] Ethanol production data from 1981 through April of 2011 obtained from the Energy Information Administration (EIA). http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPOOXE_YOP_NUS_1&f=M
Estimates of ethanol production prior to 1981 obtained from various sources published by the U.S. Department of Agriculture (USDA).
[191] The federal requirement was one of the programs contained in the 1990 Clean Air Act Amendments. The California Air Resources Board promulgated regulations to meet compliance with the winter oxygenate program. A review of that program is summarized in: *An Overview of the Use of Oxygenates in Gasoline*, California Air Resources Board, September 1998. http://www.arb.ca.gov/fuels/gasoline/pub/oxyrprt.pdf
[192] The U.S. Environmental Protection Agency published the Final Rule for their reformulated gasoline regulations in the Federal Register (FR) on February 16, 1994 (59 FR 7716). Roughly 70 percent of California's gasoline sales were estimated to occur within the mandated federal reformulated gasoline (RFG) geographic regions of the state. http://www.epa.gov/fedrgstr/EPA-AIR/1996/November/Day-13/pr-23839DIR/Other/fuel.txt.html
[193] The California Air Resources Board adopted reformulated gasoline regulations on November 22, 1991, referred to as CaRFG Phase 2 regulations. http://www.arb.ca.gov/fuels/gasoline/carfg2/carfg2.pdf
[194] Governor Davis issued Executive Order D-5-99 on March 25, 1999, directing various state agencies to develop regulations to eliminate the use of MTBE in California. Part of that order directed the California Energy Commission to "develop a timetable for the removal of MTBE from California gasoline not later than December 31, 2002." http://www.arb.ca.gov/fuels/gasoline/carfg3/eod0599.pdf
On July 1, 1999, the Energy Commission issued its report, *Timetable for the Phaseout of MTBE From California's Gasoline Supply*, which found that the phase-out deadline of December 31, 2002, could not be advanced. http://energyarchive.ca.gov/mtbe/documents/1999-07-01_300-99-003.PDF
Additional analysis by the Energy Commission and consultants working for the Energy Commission determined that the original phase-out deadline should be extended an additional year. As a consequence of this new analysis and other sources of information, Governor Davis issued Executive Order D-52-02 on March 14, 2002, delaying the final MTBE phase-out deadline until January 1, 2004. http://www.calgasoline.com/EOD52-02.PDF
[195] Apparent demand for ethanol is calculated by summing production and imports, subtracting exports and adjusting for changes in inventory levels. The U.S. Energy Information Administration (EIA) is the source for the data. http://www.eia.gov/dnav/pet/pet_pnp_oxy_dc_nus_mbbl_m.htm
A link to the monthly fuel ethanol inventory data is http://www.eia.gov/dnav/pet/pet_stoc_typ_d_nus_SAE_mbbl_m.htm
[196] Data is sourced from EIA's Imports by Country of Origin information. http://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_epooxe_im0_mbbl_m.htm
[197] Data for exports of ethanol from the United States is obtained from the USDA's Foreign Agricultural Service's Global Agricultural Trade System (GATS) using the Harmonized (HS-10) product group information. http://www.fas.usda.gov/gats/default.aspx
[198] A link to the ethanol profitability plant model, assumptions and data is http://www.extension.iastate.edu/agdm/energy/xls/d1-10ethanolprofitability.xls
The data used to create the chart is contained in the tab marked "Returns per Gal.".
[199] A more detailed description of distillers grains with solubles (both dry and wet), their compositions and uses are contained in the following publication: *Corn Processing Co-Products Manual, A Review Of Current Research On Distillers Grains and Corn Gluten*, Nebraska Corn Board and the University of Nebraska-Lincoln, 2005. http://beef.unl.edu/byprodfeeds/05CORN-024_CoProducts.pdf

[200] A more detailed historical examination of ethanol markets is presented in Paul Gallagher's paper: *Roles for Evolving Markets, Policies, and Technology Improvements in U.S. Corn Ethanol Industry Development*, Federal Reserve Bank of St. Louis, Regional Economic Development, Volume 5, Number 1, 2009. http://research.stlouisfed.org/publications/red/2009/01/Gallagher.pdf

[201] According to the Renewable Fuels Association (RFA), as of June 23, 2011, there was 14.654 billion gallons of ethanol production capacity in the United States. Only 471 million gallons of capacity is idle, while another 356 million gallons of incremental production capacity is either undergoing expansion or is under construction. http://www.ethanolrfa.org/bio-refinery-locations/

[202] The following ethanol plants are currently operating: Pacific Ethanol in Stockton, Calgren Renewable Fuels in Pixley, and AE Biofuels in Keyes.

[203] The two idle California ethanol plants are Pacific Ethanol in Madera and Altra Biofuels in Goshen.

[204] Harvest of sugarcane in Brazil normally begins in April and is usually completed during November.

[205] The most recent compilation of ethanol sugar and plants in Brazil from the Brazil Ministry of Agriculture indicates that there are a total of 413 facilities that produce ethanol (251 sugar/ethanol plants and 162 ethanol-only plants). There are also 19 facilities on the list that only produce sugar. Information is current as of August 30, 2010. http://www.uff.br/enzimo/arquivos/arqix003.pdf

Please note that the list is in Portuguese. All sugar/ethanol facilities are referred to as "Mista," ethanol-only facilities as "Álcool," and sugar mills as "Açúcar."

[206] *An Overview of the Brazilian Sugarcane Industry*, Marcos Jank, UNICA, November 13, 2008, slide 10. A link to the presentation is as follows: http://english.unica.com.br/download.asp?mmdCode=9C382A63-916C-41E8-A4F9-381C6B60C60C

[207] The Caribbean Basin Initiative or CBI is an economic development program designed, in part, to allow specific types of goods imported into the United States duty-free or at reduced tariff structures. A lengthy description of the program and eligible countries is contained in: "Guide to the Caribbean Basin Initiative," U.S. Department of Commerce, International Trade Commission, 2000 Edition. A link to the document is as follows: http://www.ita.doc.gov/media/Publications/pdf/cbi2000.pdf

[208] The Brazil Ministry of Agriculture sets the ratio of ethanol in low-level gasoline blends each year based on the market outlooks for both sugar and ethanol. The maximum blend limit is 26 percent by volume.

The Brazilian Ethanol Programme: Impacts on World Ethanol and Sugar Markets, Tatsuji Koizumi, Commodities and Trade Division of the Food and Agriculture Organization of the United Nations (FAO), June 24, 2003, page 2. A link to this document is as follows: ftp://ftp.fao.org/docrep/fao/006/ad430e/ad430e00.pdf

This working paper also contains a good summary of the history of Brazil's ethanol program.

[209] Country destination for Brazilian ethanol exports is not yet available for all of 2010 and any portion of 2011. However, during the first six months of 2010, only 8 million of the total 176 million gallons of exports were to CBI countries (about 4.6 percent). Total exports from 2010 and the first six months of 2011 are from the Boletim Mensal dos Conbustíveis Reonváveis nº 42 - junho de 2011, page 18. A link to this bulletin is as follows: http://www.mme.gov.br/portalmme/opencms/spg/galerias/arquivos/publicacoes/boletim_mensal_combustiveis_renovaveis/Boletim_DCR_nx_042_-_junho_de_2011.pdf

[210] The advanced biofuels portion of the RFS2 requirement for 2013 could be "up to" 1.75 billion gallons, assuming that the cellulosic biofuels portion is significantly down-sized again by EPA due to inadequate cellulosic production capacity in place by the fall of 2012.

[211] Refer to the Ethanol Tariff section of the Policies and Regulations chapter for more details on the costs.

[212] *Plano Decenal de Expansão de Energia*, Empresa de Pesquisa Energética (EPE), June 2011. A link to this document in Portuguese is as follows: http://www.epe.gov.br/PDEE/20110602_1.pdf

The EPE ethanol export forecast is from Graph 110 on page 245 of this report.

[213] *New Brazil Policies May Not Prevent Rising Ethanol Prices, Analyst Says*, Bloomberg, Apr 29, 2011. A link to the article is as follows: http://www.bloomberg.com/news/2011-04-29/new-brazil-policies-may-not-prevent-rising-ethanol-prices-analyst-says.html

[214] *Plano Decenal de Expansão de Energia*, Empresa de Pesquisa Energética (EPE), June 2011, Table 15, page 33. A link to this document in Portuguese is as follows: http://www.epe.gov.br/PDEE/20110602_1.pdf

[215] Ibid. The light duty vehicle forecast data is from Graph 7 on page 44 of this report.

[216] Marine vessels loaded with Brazilian anhydrous ethanol can discharge their cargo in Houston and then load their vessel with Midwest anhydrous ethanol for the voyage back to Brazil.

[217] *The Brazilian Experience on Biofuels*, Luthero Winter Moreira, Petrobras, April 2008, slide 11. A link to the PowerPoint presentation is as follows: http://www.google.com/url?sa=t&source=web&cd=2&ved=0CB4QFjAB&url=http%3A%2F%2Fwww.arc.fiu.edu%2Fwhix%2Fdoc%2FChilePresentations%2FPanel%25203%2FLUTHERO%2520WINTER%2520MOREIRA%2520Seminario%2520sobre%2520Energia%2520Renov%25C3%25A1vel%2520-%2520C.ppt&rct=j&q=brazil%20ethanol%20Luthero%20Winter&ei=SwYyTqjMMMrjiAKm47G6CA&usg=AFQjCNE1xVZN22L8pUcM6Xa9RZEppvhodA&cad=rja

[218] A link to details associated with the Kinder Morgan Lomita rail off-loading facility is as follows: http://www.kindermorgan.com/business/terminals/ethanol/e-Lomita2010May.pdf

[219] The Lomita facility was averaging 22,300 barrels per day of ethanol receipts during 2007 according Kinder Morgan. See *Biofuels Houston Summit III* presentation, October 20-21, 2008, slide 20. A link to this presentation is as follows: http://www.braziltexas.org/attachments/contentmanagers/1/Kinder%20Morgan%20BF2008.pdf

[220] A link to the U.S. Development Group site for all terminals, including the West Colton facility, is as follows: http://www.us-dev.com/terminals.php

[221] Staff estimates that rail imports of fuel ethanol for all of Southern California totaled approximately 34,900 barrels per day during 2010, equivalent to the ethanol demand in Southern California for that year.

[222] Additional details associated with the Richmond transloading facility may be viewed at the following link: http://www.kindermorgan.com/business/terminals/ethanol/e-Richmond2010May.pdf

[223] Kinder Morgan Energy Partners, L.P., Form 10-K, U.S. Securities and Exchange Commission, for the fiscal year ended December 31, 2010, page 29. A link to the filing is as follows: http://www.kindermorgan.com/investor/KMP_2010_annual_report_financials.pdf

[224] Rail imports are derived by subtracting California fuel ethanol production and marine imports from the estimated demand.

[225] Kinder Morgan PowerPoint presentation, January 28, 2010, slide 16. A link to the presentation is as follows: http://www.kindermorgan.com/investor/presentations/2010_Analysts_Conf_06_Products_Pipes.pdf

[226] Kinder Morgan PowerPoint presentation, May 11, 2011, slides 4 and 5. A link to the presentation is as follows: http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-11_workshop/presentations/Kinder_Morgan.pdf

[227] For a description of an ethanol transloading terminal operation (Norfolk Southern ethanol transloading facility in Alexandria, Virginia), refer to the following presentation: *Ethanol Transloading*, City of Alexandria, Presentation to City Council, May 27, 2008. A link to this presentation is as follows: http://alexandriava.gov/special/transloading/docs/EthanolTransloadingPresentation052708.pdf

[228] *Renewable Fuel Terminal Infrastructure*, Rahul Iyer, Primafuel, California Energy Commission Workshop, April 14, 2009, slide 8. A copy of this presentation is as follows: http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/presentations/Day-1/05-Lyer_Rahul_Primafuel_ENERGY COMMISSION_EnergyInfrastructureWorkshop.pdf

[229] Kinder Morgan PowerPoint presentation, May 11, 2011, slides 2 and 3. A link to the presentation is as follows: http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-11_workshop/presentations/Kinder_Morgan.pdf

[230] "KMP Begins Commercial Operations of Ethanol Transportation on Central Florida Pipeline System," Kinder Morgan press release, December 2, 2008. A copy of the press release may be viewed at the following link: http://phx.corporate-ir.net/phoenix.zhtml?c=119776&p=irol-newsArticle&ID=1231520&highlight

[231] *Joint Integrated Energy Policy Report and Transportation Committee Workshop on Transportation Fuel Infrastructure Issues*, transcript, Ed Hahn comments, Kinder Morgan, April 14, 2009, pp. 201-4. A link to the transcript is as follows: http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/2009-04-14_Transcript.pdf

[232] "POET Joins Magellan Midstream Partners to Assess Dedicated Ethanol Pipeline," POET press release, March 16, 2009. A link to this press release is as follows: http://www.poet.com/discovery/releases/showRelease.asp?id=155

[233] *Report to Congress, Dedicated Ethanol Pipeline Feasibility Study*, U.S. Department of Energy, March 2010. A link to the study is as follows: http://www1.eere.energy.gov/biomass/pdfs/report_to_congress_ethanol_pipeline.pdf

[234] Ibid., page iv.

[235] "Total Use" is referred to by USDA as "Total Disappearance" and is composed of "Domestic Use" and "Exports". "Domestic Use" includes the following categories: Food, Alcohol, and Industrial use; Seed use; and Feed and Residual use. *Feed Grains Data: Yearbook Tables, Corn: Food, Seed, and Industrial Use*, Table 4, USDA, Economic Research Service. A link to the source is as follows: http://www.ers.usda.gov/data/FeedGrains/Table.asp?t=04

[236] Corn using irrigated water totaled 13.16 million acres in 2007, while non-irrigated corn amounted to 73.09 million acres. Since irrigated corn has a higher yield, the percentage of corn produced from irrigated acres is slightly higher, approximately 16.9 percent for the same year. *2007 Census of Agriculture*, United States

Department of Agriculture, Table 32, page 26, updated September 2009. A link to the document is as follows: http://www.agcensus.usda.gov/Publications/2007/Full_Report/Volume_1,_Chapter_1_US/usv1.pdf
[237] Most recent complete year of fertilizer data for U.S. corn acres is 2010. Nitrogen application for fertilized corn was 130 pounds per acre in 1980, 138 pounds per acre in 2005, and 140 pounds per acre in 2010. *U.S. Fertilizer Use and Price*, USDA Economic Research Service, Table 10, updated May 27, 2011. A link to the data is as follows: http://www.ers.usda.gov/Data/FertilizerUse/Tables/FertilizerUse.xls
Corn yield in 1980 was 91.0 bushels per acre, 147.9 bushels per acre in 2005, and 152.8 bushels per acre in 2010. *Crop Production Historical Track Records*, USDA, National Agricultural Statistics Service, April 2011, page 26. A link to the document is as follows: http://usda.mannlib.cornell.edu/usda/current/htrcp/htrcp-04-26-2011.pdf
[238] *Historical Perspectives On Vegetable Oil-based Diesel Fuels*, Gerhard Knothe, Inform, Volume 12, November 2001, pp. 1103-4. A link to this article is as follows: http://www.biodiesel.org/resources/reportsdatabase/reports/gen/20011101_gen-346.pdf
[239] Ibid. page 1107.
[240] Ibid. page 1105.
[241] National Renewable Energy Laboratory, *Biodiesel Handling and Use Guide*, fourth edition, publication number NREL/TP-540-43672, revised January 2009, page 23. A link to the revised document is as follows: http://www.nrel.gov/docs/fy09osti/43672.pdf
[242] National Renewable Energy Laboratory, *Survey of the Quality and Stability of Biodiesel and Biodiesel Blends in the United States in 2004*, publication number NREL/TP-540-38836, October 2004, pages 18, 49, and 50. A link to the survey is as follows: http://www.nrel.gov/docs/fy06osti/38836.pdf
[243] *Quality Survey of Biodiesel Blends Sold at Retail Stations*, Haiying Tang, et al, Elsevier, available online June 2, 2008. A link to the research paper is as follows: http://www.eng.wayne.edu/user_files/414/file/Quick_Upload/Quality%20survey%20of%20biodiesel%20blends%20sold%20at%20retail%20stations%282%29.pdf
[244] National Renewable Energy Laboratory, *Analysis of Biodiesel Blend Samples Collected in the United States in 2008*, publication number NREL/TP-540-46592, March 2010. A link to the survey is as follows: http://www.nrel.gov/vehiclesandfuels/npbf/pdfs/46592.pdf
[245] The $1-per-gallon volumetric biodiesel blenders credit originated in the JOBS Act of 2004 legislation. This portion of the act was intended to encourage increased biodiesel production, higher blending into diesel fuel, and the creation of additional agricultural jobs. The following link to a National Biodiesel Board Issue Brief contains additional specifics and Internal Revenue Service provisions: http://www.biodiesel.org/news/taxincentive/Biodiesel%20Tax%20Credit%20NBB%20Issue%20Breif.pdf
The blenders credit was allowed to expire by Congress at the end of 2009 and was not re-instated until late 2010. The blenders credit is currently due to expire at the end of 2011. For additional details see *President Obama Signs Bill Extending Biodiesel Tax Incentive Into Law*, Biodiesel.org, December 17, 2010. A copy to the article is as follows: http://www.biodiesel.org/news/taxcredit/default.shtm
[246] Apparent demand for biodiesel is calculated by summing production and imports, subtracting exports and adjusting for changes in inventory levels. The U.S. Energy Information Administration (EIA) is the source for the data. A link to the monthly biodiesel data is as follows: http://www.eia.gov/totalenergy/data/monthly/
[247] Energy Information Administration, Monthly Energy Review. A link to the information under the Renewable Energy section is as follows: http://www.eia.gov/totalenergy/data/monthly/#renewable
[248] European Biodiesel Board press release, Figure II, page 2, July 15, 2009. A link to the press release is as follows: http://www.ebb-eu.org/EBBpressreleases/EBB%20press%20release%202008%20prod%202009%20cap%20FINAL.pdf
[249] The European Commission conducted a nine-month investigation and concluded that the application of countervailing and anti-dumping tariffs for U.S. biodiesel exports to Europe was necessary to "level the playing field" for European biodiesel producers. The new tariffs became effective on March 13, 2009. On July 1, 2009, the Council of the European Union adopted these provisions for a period of five years. A link to the countervailing tariff decision is as follows: http://register.consilium.europa.eu/pdf/en/09/st11/st11080.en09.pdf
The link to the anti-dumping tariff decision is as follows: http://register.consilium.europa.eu/pdf/en/09/st11/st11084.en09.pdf
[250] However, some biodiesel producers and exporters soon realized that the addition of even small quantities of petroleum diesel fuel (approximately 1 percent by volume) enabled them to obtain the blenders credit for nearly all of the export volume. The increased exports of biodiesel originating from the United States prompted the decision by the European Union to impose sufficiently high off-setting tariffs to help ensure a more level playing field for their own biodiesel producers. See *EBB Strongly Condemns the Unfair Subsidized US Biodiesel Exports and*

Stands Ready for Legal Action, European Biodiesel Board, October 16, 2007. A copy of the press release from the European Biodiesel Board is as follows: http://www.ebb-eu.org/EBBpressreleases/Press%20release%20B99%20FINAL.pdf

[251] *The EU Biodiesel Industry in Changing Times*, Raffaello Garofalo, European Biodiesel Board, presentation to the World Biofuels Market, Rotterdam, March 23, 2011, slide 21. A link to the presentation is as follows: http://www.sari-energy.org/PageFiles/What_We_Do/activities/worldbiofuelsmarkets/Presentations/GlobalBiodieselRoundtable/Raffaello_Garofalo.pdf

[252] A link to the biodiesel profitability tracking assumptions and data is as follows: http://www.card.iastate.edu/research/bio/tools/hist_bio_gm.aspx

[253] *EPA Proposes 2012 Renewable Fuel Standards and 2013 Biomass-Based Diesel Volume*, EPA, Regulatory Announcement, June 2011, page 3. A link to the announcement is as follows: http://www.epa.gov/otaq/fuels/renewablefuels/420f11018.pdf

[254] National Biodiesel Board, plant list. A link to this information is as follows: http://www.biodiesel.org/buyingbiodiesel/plants/showall.aspx

[255] Ibid.

[256] *Global Biodiesel Production and Market Report*, Biodiesel Magazine, September 1, 2010. A link to the article is as follows: http://www.biodieselmagazine.com/articles/4447/global-biodiesel-production-and-market-report

[257] Statistics from the European Biodiesel Board (EBB). A link to the annual biodiesel production capacity figures in metric tonnes is as follows: http://www.ebb-eu.org/prev_stats_capacity.php

[258] *2009-2010: EU biodiesel Industry Restrained Growth in Challenging Times*, press release, European Biodiesel Board, July 22, 2010, page 2. A link to the EBB press release is as follows: http://www.ebb-eu.org/EBBpressreleases/EBB%20press%20release%202009%20prod%202010_capacity%20FINAL.pdf

[259] Estimates from Cybus Capital Markets LLC range from 2 cents per gallon (cpg) for pipeline transportation, 5 cpg via barge, 10 cpg via rail, and 20 cpg via tanker truck. *Biofuels Houston Summit III* presentation, Kinder Morgan, October 20-21, 2008, slide 23. A link to this presentation is as follows: http://www.braziltexas.org/attachments/contentmanagers/1/Kinder%20Morgan%20BF2008.pdf

[260] "KMP Completes First Commercial Shipment of Biodiesel in U.S. on Plantation Pipe Line," Kinder Morgan press release, June 30, 2009.A link to this press release is as follows: http://phx.corporate-ir.net/phoenix.zhtml?c=119776&p=irol-newsArticle&ID=1303436&highlight=

[261] A link to a copy of the SWRCB regulatory action and Office of Administrative Law (OAL) approval are as follows: http://www.waterboards.ca.gov/water_issues/programs/ust/regulatory/biodiesel/oal_file2009_0521_02e.pdf

[262] Valero Energy Corporation Comments on the Draft 2009 Integrated Energy Policy Report (IEPR) Docket No. 09-IEP-1K, Valero Energy Corporation, John Braeutigam, September 4, 2009, pp. 2-3. A link to this document is as follows: http://www.energy.ca.gov/2009_energypolicy/documents/2009-08-24_workshop/comments/2009-09-04_Valero_Energy_Corporation_TN-53150.PDF

[263] Ibid., page 2.

[264] www.energy.ca.gov/biomass/landfill_gas.html

[265] www.energy.ca.gov/biomass/landfill_gas.html . California Codes, Health And Safety Code sections 25420-25422.

[266] www.energy.ca.gov/research/renewable/biomass/anaerobic_digestion

[267] San Joaquin Air Pollution Control District rules 2201 and 4308. See Dave Warner, "Permitting Issues for Anaerobic Digesters in the San Joaquin Valley For the California Energy Commission Workshop on Biopower in California" April 21, 2009. www.energy.ca.gov/2009_energypolicy/documents/2009-04-21_workshop/presentations/

[268] Mark Leary, Deputy Director, Department of Resources, Recycling and Recovery. "Letter from Cal Recycle Regarding Draft 2010-2011 AB118 Investment Plan," March 9, 2010. See Docket Log at http://www.energy.ca.gov/2009-ALT-1/documents/index.html

[269] Tom Frankiewicz. April 21, 2009. "Landfill Gas Energy Potential in California: Presentation to California Energy Commission. US Environmental Protection Agency Landfill Methane Outreach Program.

[270] Prometheus Energy, Liquid Natural Gas, LNG, from Landfill Gas. http://www.prometheus-energy.com/whatwedo/landfillgas.php.

[271] www.lacsd.org/about/solid_waste_facilities/puente_hills/default.asp

[272] Ken Krich, Biomethane from Dairy Waste: A Sourcebook for the production and use of Renewable Natural Gas in California. Technical potential is based on physical system constraints including but not limited to agronomic and ecological requirements, terrain limitation, and inefficiencies in collection and handling.

[273] CalRecycle's "Strategic Directive 6.1" identifies a reduction of the amount of organics in the waste stream by 50 percent by 2020.
[274] One ton of organic waste landfilled has a 65 kW potential while one ton of MSW has a 550 kW potential. Energy Commission meeting with CalRecycle, 28 October 2010.
[275] Dynamic Fuels is a joint venture of Tyson Foods and Syntroleum. See www.syntroleum.com
[276] http://www.nesteoil.com/default.asp?path=1,41,11991,12243,12335,12337
[277] http://www.nesteoil.com/default.asp?path=1,41,11991,12243,15658
[278] (S&T)^2 Consultants, Inc. 2009. The Addition of Algae and Jatropha Biodiesel to GHGenius. Page 20.
[279] U.S. DOE 2010, National Algal Biofuels Technology Roadmap. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Biomass Program. Visit http://biomass.energy.gov for more information.
[280] Ibid, pages 76-81.
[281] Chisti, Yusuf. 2007. "Biodiesel from microalgae," *Biotechnology Advances,* volume 25, page 296.
[282] U.S. DOE 2010. *National Algal Biofuels Technology Roadmap*. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Biomass Program, page 104.
[283] Pienkos, Philip T, National Renewable Energy Lab, 2007. "The Potential of Biofuels From Algae." Presentation given at the Algae Biomass Summit. www.nrel.gov/docs/fy08osti/42414.pdf, slide 16. Accessed 10/20/2010.
[284] Wijffels, Rene H. and Maria J. Barbosa. 2010. "An Outlook on Microalgal Biofuels," *Science*, August 13 2010, vol. 329, pages 796-799.
[285] For example, the U.S. Navy has successfully tested Solazyme's algae-derived jet fuel and marine diesel.
[286] Phone conservation with Michael Eaves, Clean Energy on January 6, 2011
[287]BRC fuel Maker Again Selling Phill Home CNG Fuel Station, March 7, 2011.
http://www.autoobserver.com/2011/03/brc-fuelmaker-again-selling-phill-home-cng-fuel-station.html
[288] PR Newswire, "Ford Working With Best Buy to Offer Focus Electric Charging Station Sales, Installation and Support," 1/10/11.
[289] Based on estimates of known deployments planned through 2013. This may not include all planned chargers.
[290] Some of these may be charging stations that have more than one charge point.
[291] Karen Schkolnick, Bay Area Air Quality Management District, February 2, 2011
[292] California Plug-in Electric Vehicle Collaborative, "Taking Charge: Establishing California Leadership in the Plug-in Electric Vehicle Marketplace," http://www.evcollaborative.org/evcpev123/wp-content/uploads/2010/07/Taking_Charge_final2.pdf
[293] ICF International Draft Report, "Technical Analysis for Alternative and Renewable Fuel and Vehicle Technology Program," September 2010.
[294] Summary of Southern California Edison Comments on the CPUC Order Instituting Rulemaking to Consider Alternative-Fueled Vehicle Tariffs, Infrastructure and Policies to Support California's Greenhouse Gas Emissions Reduction Goals, Morton Blatt, December 2009
[295] Characterizing Consumers' Interest in and Infrastructure Expectations for Electric Vehicles: Research Design and Survey Results. EPRI, Palo Alto, CA, and Southern California Edison, Rosemead, CA: 2010.
[296] BMW, Presentation by Andreas Klugescheid given at the October 19, 2010, Joint Energy Commission and PEV Collaborative PEV Infrastructure Workshop.
[297] *Electrification Roadmap, Revolutionizing Transportation and Achieving Energy Security***,** Electrification Coalition, November 2009.
[298] October 19, 2010, Joint Energy Commission Staff and Statewide PEV Collaborative PEV Infrastructure Joint Workshop, Residential Panel discussion.
[299] Fast fill and time fill refer to the speed at which a natural gas vehicle is refueled. Fast fill dispensers can perform a complete fill within several minutes. Time fill dispensers require several hours, often overnight. However, fast fill dispensers require more expensive equipment and maintenance. Fast fill dispensers are the only practical type of dispensers for public retail fueling stations, which necessarily serve multiple vehicles each day. However, time fill stations are expected to be more economical for dedicated fleet users.
[300] Estimates based on submitted proposals as well as discussions with industry representatives.
[301] *Consumers Reports*, March 2008, "Review of the 2008 Honda GX."
[302] Industry meetings with Freightliner, Kenworth, Navistar, Westport, December 2010 – January 2011.

[303] Comments submitted by the California Center for Sustainable Energy, Energy Commission Docket Number 10-ALT-1, June 3, 2011.

[304] Interstate Clean Transportation Corridor, "About the Interstate Clean Transportation Corridor," http://ictc.gladstein.org/aboutictc.html.

[305] Department of Energy, "Secretary Chu Announces Nearly $300 Million in Clean Cities Grants to Support Clean Fuels, Vehicles, and Infrastructure Development," http://www.energy.gov/7843.htm.

[306] Based on information from proposals received by the Energy Commission under PON-09-608.

[307] The *2011-2012 Investment Plan for the Alternative and Renewable Fuel and Vehicle Technology Program* report: http://www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-600-2010-001-CTF

[308] A "type approval" is granted to a product that meets a minimum set of regulatory, technical and safety requirements. Generally, type approval is required before a product is allowed to be sold.

[309] *Oil and Gas Production History in California*, Division of Oil, Gas, and Geothermal Resources (DOGGR), undated. ftp://ftp.consrv.ca.gov/pub/oil/history/History_of_Calif.pdf

[310] According to crude oil production statistics from the Energy Information Administration (EIA), crude oil production output for these three areas increased by a combined average of 675,000 barrels per day when compared to 2008. Over this same period of time, crude oil production from all other areas of the United States declined by a combined average of 113,000 barrels per day. http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm

[311] Capacity total for the atmospheric distillation process units of all operating California refineries, as of January 1, 2010, was obtained from the *Refinery Capacity Report*, Energy Information Administration,Table 1. http://205.254.135.24/petroleum/refinerycapacity/archive/2010/table1.pdf

[312] As of July 2009, the Big West refinery in Bakersfield was temporarily idled as a consequence of the Chapter 11 filing and subsequent business decisions of the parent company, Flying J. The refinery was purchased by Alon USA Energy, completing the acquisition on June 2, 2010. The company resumed operations at the Bakersfield facility during June 2011. However, the company will operate the refinery using gas oils as a feedstock, rather than crude oil. This means that the idle atmospheric distillation capacity of this facility was not included in the total operating refining capacity over the forecast period.

[313] *Chevron Energy and Hydrogen Renewal Project*, Draft Environmental Impact Report, State Clearinghouse No. 2005072117, City of Richmond Project No. 1101974, Volume 1, pp. 3-32 to 3-34. http://www.ci.richmond.ca.us/DocumentView.aspx?DID=2729

[314] Ibid., page 1-1.

[315] *Chevron Richmond Refinery Revised Renewal Project, Conditional Use Permit/Amended EIR Application*, Chevron CUP Application to the City of Richmond Planning Division, May 23, 2011. http://www.ci.richmond.ca.us/DocumentView.aspx?DID=7207

[316] Additional details of the Revised Project and status of the City of Richmond EIR are available from http://www.ci.richmond.ca.us/index.aspx?NID=2450

[317] *Alon USA Announces Acquisition of Bakersfield Refinery From Flying J*, Alon USA Press Release, June 2, 2010. http://www.alonusa.com/index.cfm?FuseAction=Page&PageID=1000024&ArticleID=158

[318] *Alon USA Announces Completion of Hydrocracker Project at Bakersfield*, Alon USA Press Release, June 27, 2011. http://phx.corporate-ir.net/phoenix.zhtml?c=190387&p=irol-newsArticle_Print&ID=1580095&highlight

[319] *2010 Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report*, Gordon Schremp, Aniss Bahreinian, and Malachi Weng-Gutierrez, California Energy Commission, report number CEC-600-2010-002-SF, May 2010, page 141. http://www.energy.ca.gov/2010publications/CEC-600-2010-002/CEC-600-2010-002-SF.PDF

[320] Recent comments from ConocoPhillips and BP illustrate that California refineries have been characterized as ether less competitive or non-core, relative to other refining assets held by these companies. ConocoPhillips comments also indicate that an unsuccessful sales attempt could result in a refinery being converted to a terminal. ConocoPhillips has announced plans to shed 500 thousand barrels per day of refining assets that if unsuccessful, could result in conversion to terminal for some of these refineries as referenced in the following quote: "Now, moving forward, the big challenge is how do we reduce our refining footprint. And there are a number of ways we do that. There's obviously the sale, the outright sale, which we're going through right now with Wilhelmshaven in Germany. If the sales aren't successful, there is the conversion to the terminals.", comments by Willie Chiang, Senior Vice President –RMT & Commercial, ConocoPhillips, 2011 Analyst Meeting, March 23, 2011, New York, NY,

page 24.
http://www.conocophillips.com/EN/investor/presentations_ccalls/Documents/Analyst%20Meeting%202011%20Transcript.pdf
According to an article in Oil Express, UBS banking managers are referenced as believing that "two of the five non-core U.S. refining assets targeted for sales could be in California." *ConocoPhillips Tells Bank Five U.S. Refineries for Sale*, Oil Express, June 20, 2011 – Vol. XXXIV, Issue No. 24, page 1. http://www.opisnet.com/news/sample/sampleoe.pdf
BP has recently announced plans to sell some refining assets that include their refinery in Carson, California. The stated reason is that: "Parts of the US Fuels Value Chain portfolio does not meet our strategic hurdles. So we have announced our intention to exit the Texas City refinery and the Southern West Coast Fuels Value Chain, including the Carson refinery, by the end of 2012, subject to obtaining relevant approvals." *Strengthening Safety, Restoring Trust, Building Value*, Lamar McKay, Chairman & President, BP America Inc., Howard Weil Energy Conference, New Orleans, Louisiana, March 28, 2011, page 13.
http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/S/Howard_Weil_Speech_28_March_2011.pdf

[321] The total operating costs used in the analysis include both the operating expenses, depreciation and amortization expenses as provided in the Refining Operating Highlights by Region section of the 10-K filings. Average operating cost values for the "Other U.S. Refineries" were volume-weighted based on the throughput volumes for each of the specific regions.
http://www.valero.com/InvestorRelations/FinancialReports_Filings_Statements/Documents/VEC%202010%20Form%2010-K%20FINAL.pdf

[322] *2010 Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report*, Gordon Schremp, Aniss Bahreinian, and Malachi Weng-Gutierrez, California Energy Commission, report number CEC-600-2010-002-SF, May 2010, page 140. http://www.energy.ca.gov/2010publications/CEC-600-2010-002/CEC-600-2010-002-SF.PDF

[323] Over the last four years (2007 through 2010), the portion of crude oil waterborne receipts (Alaska and foreign sources) into California that have been imported through marine terminals in Southern California has averaged 59.7 percent of the total waterborne crude oil imports to the state.

[324] Additional information concerning marine vessel tanker definitions and sizes can be obtained by reviewing a presentation by Pacific Energy Partners at http://www.pacificenergypier400.com/pdfs/TANKERS/TankerBusEmissions.pdf
Another resource that includes descriptions and definitions for all types of marine tankers (both crude oil and petroleum products) can be viewed at http://www.globalsecurity.org/military/systems/ship/tanker-types.htm

[325] The crude oil import facility proposed by Pacific Energy Partners has a design capacity of 4 million barrels of crude oil storage and a daily import capability of up to 250,000 barrels per day of crude oil. These storage capacities and throughput design equate to 1 million barrels of storage per 23 million barrels of imports per year. Additional project information is located at http://www.pacificenergypier400.com/index2.php?id=3

[326] *Transportation Energy Forecasts for the 2007 Integrated Energy Policy Report*, Draft Staff Report, California Energy Commission, report number CEC-600-2007-009SD, July 2007, page 46.
http://www.energy.ca.gov/2007publications/CEC-600-2007-009/CEC-600-2007-009-SD.PDF

[327] An overview of Berth 408 at Per 400 and its throughput capacity may be viewed at
http://www.pacificenergypier400.com/index2.php?id=2
A detailed description of the storage facilities, including total capacity, may be viewed at
http://www.pacificenergypier400.com/index2.php?id=25

[328] Pacific Energy Partners (PEP) filed a project development application with the Port of Los Angeles in March 2003. http://www.pacificenergypier400.com/index2.php?id=2

[329] Pacific Energy Partners, "next steps" information may be viewed at
http://www.pacificenergypier400.com/index2.php?id=4

[330] *Pier 400 Berth 408 - Value Engineering Study*, Pacific LA Marine Terminal LLC, October 19, 2010.
http://www.slc.ca.gov/division_pages/mfd/Prevention_First/Documents/PF2K10%20LAYOUT/Pier%20400%20Berth%20408%20Value%20Engineering%20Study.pdf

[331] Ibid., slide number 46.

[332] Ibid., slide number 41.

[333] *Pier Echo RFP Changes*, Port of Long Beach, May 19, 2010.
http://www.polb.com/civica/inc/displayblobpdf2.asp?BlobID=7341

[334] *Assessment of Flow Rate Estimates for the Deepwater Horizon / Macondo Well Oil Spill*, National Incident Command, Interagency Solutions Group, Flow Rate Technical Group, U.S. Department of the Interior, March 10, 2011, page 8. http://www.doi.gov/deepwaterhorizon/loader.cfm?csModule=security/getfile&PageID=237763

[335] *Ixtoc Oil Spill Assessment, Final Report, Executive Summary*, ERCO/Energy Resources Company, March 19, 1982, page 1. http://invertebrates.si.edu/mms/reports/IXTOC_exec.pdf

[336] *History of Major Oil Spills*, Table 2. http://www.scribd.com/doc/6667687/History-MAJOR-Oil-Spills

[337] *Oil Spill Case Histories, 1967-1991, Summaries of Significant U.S. and International Spills*, National Oceanic and Atmospheric Administration (NOAA), report number HMRAD 92-11, September 1992, page 162. http://response.restoration.noaa.gov/book_shelf/26_spilldb.pdf

[338] A description of the new agency and its responsibilities may be viewed at http://www.boemre.gov/aboutBOEMRE/

[339] *Survey of Available Data on OCS Resources and Identification of Data Gaps*, U.S. Department of Interior, Mineral Management Services, Report MMS 2009-015, May 2009, Appendix C, Table C-1, page C-2. http://www.boemre.gov/5-year/PDFs/45-DayReportAvailableDataOnOffshoreResources.pdf

An historical assessment of crude oil reserves and production in the most active OCS region, the Gulf of Mexico, is contained in the following report: *Estimated Oil and Gas Reserves Gulf of Mexico, December 31, 2005*, U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Regional Office, May 2009, Table 6, page 45. http://www.gomr.mms.gov/PDFs/2009/2009-022.pdf

[340] Ibid., page 5.

[341] A link to EIA's assessment is http://www.eia.doe.gov/oiaf/aeo/otheranalysis/ongr.html

[342] A list and location of all of the offshore crude oil and natural gas production platforms in state and federal waters off the coast of California is described by the BOEMRE, a division of the Department of the Interior. http://www.boemre.gov/omm/Pacific/offshore/platforms/platformintro.htm

[343] Information associated with the Plains All American project may be viewed at http://www.t-ridgefacts.com/t-ridge-project/

[344] *Arnold Schwarzenegger Abandons Tranquillon Ridge*, Calitics, Robert Cruickshank, May 3, 2010. http://www.calitics.com/diary/11621/arnold-schwarzenegger-abandons-tranquillon-ridge

[345] Energy Commission estimate based on information obtained from California State Lands Commission and County of Santa Barbara presentations. The CSLC staff estimate of Tranquillon Ridge production is more conservative than the one Aspen prepared on behalf of the County of Santa Barbara. CSLC estimate from the Commission Informational Hearing, Tranquillon Ridge Field, January 6, 2009. http://archives.slc.ca.gov/Meeting_Summaries/2009_Documents/01-06-09/ITEMS_AND_EXHIBITS/R01Exhibit.pdf

The Aspen estimate was obtained from Figure 2-3 of the Final EIR released on March 27, 2008. http://www.countyofsb.org/energy/documents/projects/TranqRidgeFinalEIR/index.htm

Energy Commission staff analysis of these two information resources has derived estimated incremental cumulative crude oil production from Tranquillon Ridge of between 60 and 110 million barrels for the first 12 years of the project.

[346] *Proposed Development of the Carpinteria Field State Oil and Gas Reserves*, California State Lands Commission, public update letter, April 27, 2011. http://www.slc.ca.gov/Division_Pages/DEPM/DEPM_Programs_and_Reports/Carpinteria_Field_Redevelopment/PDF/Carone%20_Update_04272011.pdf

[347] Ibid., page 2.

[348] http://www.energy.ca.gov/2010publications/CEC-600-2010-002/CEC-600-2010-002-SF.PDF

[349] All real prices used in this work are in 2010 dollars, using the December 2010 EIA deflator series reported in the 2011 AEO Early Release.

[350] The subset of premium light sweet oil constitutes a relatively small percentage of the oil actually refined in the United States or California, but prices for it are those most commonly referred to in the media.

[351] Report found at: http://www.energy.ca.gov/2011publications/CEC-600-2011-001/CEC-600-2011-001.PDF

[352] Sales tax rate reflects recent changes in the fuel tax structure due to the California Gas Tax Swap that started July, 1 of 2010. The diesel tax structure is scheduled to change on July 1, 2011. Both changes are intended to be revenue neutral and excise tax rates will be changed in future years based on gasoline and diesel consumption.

[353] EIA estimates less than 2,000 LPG vehicles operated in California in 2008. This would represent only roughly 6% of the total natural gas fleet per Energy Commission estimates of natural gas vehicles in California. http://www.eia.doe.gov/cneaf/alternate/page/atftables/afv_atf.html#inuse

[354] State sales tax of 7.25 percent and 1 percent local sales tax.