CHAPTER 12. Technological Barriers

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12.1 Background, Objectives, and Approach

An assessment of the required infrastructure for producing and distributing fuels from the four feedstocks under consideration—citrus, sugar cane, algae and cottonseed— was benchmarked against the existing infrastructure for conventional fuels. By analyzing the infrastructure requirements (number of acres, quantities of water, miles of pipelines, number of processing plants (e.g. distilleries), distribution hubs, retail outlets, storage tanks, etc.) and evaluating a range of market penetration targets for 2030, infrastructure investments can be estimated. For a particular market penetration, the infrastructure is estimated and by moving backwards; reasonable adoption profiles to reach the 2030 targets were determined.

To provide context for these infrastructure development scenarios, a series of historical fuel transitions were examined. These are described in Section 12.2. These historical analyses will be followed by evaluations of market penetration targets in Section 12.3 and infrastructure needs in Section 12.4.

12.2 Historical Case studies of Fuel Transitions

12.2.1 Introduction

The U.S. liquid fuels sector has undergone numerous transitions over the last several decades. Major transitions in the sector are reviewed, with a focus on identifying the following characteristics and parameters:

- motivating factors, such as environmental, public health, economic, and energy security priorities;
- pertinent market and policy mechanisms that drove change;
- penetration rates into the fuel market;
- infrastructure changes made in the petroleum industry, distribution and retail networks, and end use industry (i.e., engine and vehicle manufacturers);
- infrastructure investments and economic impacts;
- impediments encountered during the transitions.

Based on the findings, key lessons from these case studies are discussed. The Section begins with a review of major transitions in the motor gasoline sector, starting with the transition to unleaded gasoline and is followed by a review of sulfur reduction transitions in the distillate fuel oil (DFO) sector. The section concludes with a discussion of the implications of transitions, with the goal of identifying lessons that have relevance to a transition to biofuels.

12.2.2 U.S. Motor Gasoline Sector

12.2.2.1 Leaded to Unleaded Gasoline

The introduction of unleaded gasoline in the U.S. spanned nearly 20 years following the passage of the Clean Air Act (CAA) of 1970. The following discussion does not attempt to provide a full historical account of the leaded gasoline history. However, as noted by Sperling and Dill nearly 20 years ago (Sperling and Dill, 1988): "[The] government-orchestrated transition to unleaded gasoline serves as a model for the United States and other countries for the introduction of nonpetroleum fuels." As the U.S. works to introduce greater volumes of biofuels in the coming decade(s), key features of this transition merit examination.

Leaded gasoline made its entry into the transportation fuel market in the early 1920s as a consequence of the phenomenon known as engine knock. Although not a common problem with engines of that day, engine knock prevented the development of more efficient and powerful high-compression engines (Seyforth, 2003). "Knock" is the name given to the noise that is transmitted through the engine when spontaneous ignition of a portion of the unburned fuel-air mixture occurs before the piston is at top-dead-center. Intense and sustained knock can result in a range of symptoms, from minor ones, such as overheating, loss of power, and reduced efficiency, to complete and immediate engine failure (Heywood, 1988). Engine knock can be prevented by using fuels with higher octane ratings[1], through engine redesign, or a combination of the two.

A solution to the knock problem would allow engines to operate at higher compression ratios leading to greater power output and fuel efficiency. With this goal in mind, a team of scientists and engineers at the GM Corporation, headed by Thomas Midgley, Jr., were tasked with solving the problem. Using the periodic table of the elements as their guide, the team of researchers resorted to the method of elimination to identify various chemical components that would reduce the tendency to knock. They eventually discovered the anti-knock quality of lead, specifically in the form of tetraethyl lead (TEL), an organometallic compound with the formula $(CH_3CH_2)_4Pb$ (Seyforth, 2003). The precise mechanism by which TEL controls knock is not fully known; it is generally agreed that the compound decomposes into lead oxide and inhibits the reaction that leads to auto-ignition of the fuel-air mixture (Heywood, 1988).

Although other additives were being researched at the time, it seems that no other additive could compete on price. Researchers had experimented with low percentage additives, such as TEL and other organometallics, and high percentage additives, such as benzene and alcohols[2]. In fact, Midgley and his team carried out extensive research with high percentage blends and favored ethanol, even over TEL. However, the supply of ethanol in the 1920s and the production and use of alcohol during the prohibition era presented major obstacles (Seyforth, 2003).

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[1] The ability of a fuel to resist knock is indicated by its octane number: higher octane numbers indicate greater resistance to knock.

[2] Low-percentage additives serve to inhibit knock when blended in very small quantities with gasoline, e.g., from parts-per-million levels to less than 2% by volume. High-percentage additives must be blended in much greater quantities, e.g., 10% to 20% by volume.

The first public sale of ‘ethyl’ gasoline—the marketing name given to leaded gasoline—occurred on February 1, 1923 in Dayton, OH at 25 cents per gallon (regular gas cost 21 cents per gallon). By 1936, 90 percent of the gasoline sold in the U.S. contained TEL; by 1963 this figure had risen to greater than 98 percent (Seyforth, 2003). Leaded gasoline paved the way for high performance engines that automobile manufacturers sought to manufacture. But, as illustrated in Figure 12.1, the use of lead in gasoline quickly dropped in the early 1970s.

Figure 12.1. Consumption of lead in gasoline dropped rapidly after 1970 (Seyforth, 2003).

Mounting concerns about urban air pollution led to the passage of the CAA of 1970 and the establishment of the Environmental Protection Agency (EPA). The CAA introduced rules requiring new automobiles (starting in 1975) to use catalytic converters to control emissions of carbon monoxide (CO), nitrogen oxides (NOx), and hydrocarbons (HCs). Unleaded gasoline was a must for vehicles equipped with catalytic converters since various trace metals, including lead, inactivate the catalyst (Heywood, 1988). Though the toxic nature of lead in the environment had gradually gained the attention of the public in parallel, it was the desire to preserve catalyst lifetimes, as opposed to reducing emissions of lead, that initially motivated the switch to unleaded gasoline.

Section 211 (c)(1) of the CAA gives the EPA’s Administrator broad authority to “control or prohibit the manufacture…or sale of any fuel additive” if its emission products (1) cause or contribute to “air pollution which may be reasonably anticipated to endanger the public health or welfare,” or (2) “will impair to a significant degree the performance of any emission control device or system…in general use” (EPA, 1985). Since the use of leaded gasoline “will impair to a significant degree” the performance of catalytic converters, the second condition was used by the EPA to mandate the phase out of lead. EPA later accelerated the phase out of lead in the 1980s based on the first condition.

12.2.2.1.1 The Phasing Out of Lead in Gasoline

The initial phase down of lead was mandated through so-called 'command-and-control' measures taken by the EPA. On July 1, 1974, the EPA required all retailers that sold 200,000 gallons or more of gasoline to provide unleaded gasoline and design fuel nozzles so that cars with catalytic converters could accept only unleaded gasoline. Similarly, car manufacturers were required to design tank filler inlets to accept only unleaded gasoline and to apply "Unleaded Gasoline Only" labels on cars equipped with catalytic converters, which would arrive on the market with 1975 models (Kerr and Newell, 2003; Newell and Rogers, 2003).

To further promote the production of unleaded gasoline, EPA implemented performance standards requiring refineries to decrease average lead content of all gasoline (i.e., a pooled average of lead content in leaded and unleaded gasolines). These performance standards took effect on October 1, 1979, and required a pooled average of 0.5 grams of lead per gallon for individual facilities. The standards were less stringent for small refineries (see Table 12.2 for details) since small facilities were apparently less capable of producing gasoline without lead[3]. This averaging method provided refiners with the incentive to increase unleaded production while not necessarily removing lead from their leaded gasoline. Total lead usage decreased as old vehicles were retired and replaced by new vehicles equipped with catalytic converters (Kerr and Newell, 2003; Newell and Rogers, 2003).

The next set of rules, implemented on November 1, 1982, limited the allowable content of lead in leaded gasoline to a quarterly average of 1.1 grams per gallon of leaded gasoline (gplg). Small refineries again faced less stringent standards until 1983. This new rule no longer allowed the averaging, or pooling, of leaded and unleaded gasoline production, thereby forcing a true reduction in the concentration of lead in leaded gasoline (Kerr and Newell, 2003; Newell and Rogers, 2003).

Despite the progress made in removing lead from gasoline, evidence on the health effects of lead in the environment was mounting. Between 1983 and 1985, the EPA conducted an extensive cost-benefit analysis of further tightening the standards to 0.1 gplg by 1988. In 1985, the EPA released a Regulatory Impact Analysis (RIA) estimating benefits in four major categories: blood pressure-related health effect in adult males due to lead; children's health and cognitive effects associated with lead; damages caused by excess emissions of HC, NOx, and CO from misfueled vehicles[4]; and impacts on maintenance and fuel economy of vehicles fueled with leaded gasoline (EPA, 1985).
The various benefits of the lead phase out were monetized and compared to estimated costs that would be borne by the refining industry to meet the 0.1 gplg standard. Table 12.1 summarizes the results of the cost-benefit analysis. Despite the substantial costs that would be placed on the refining industry, the EPA estimated that the benefits would outweigh the costs by as much as 10

[3] Section 12.2.1.2 provides details on the approaches taken by refiners to meet the increasingly stringent performance standards, and to produce unleaded gasoline with performance characteristics similar to leaded gasoline.
[4] Misfueling refers to the use of leaded gasoline in vehicles equipped with catalytic converters. Although some vehicle owners were concerned about knock, misfueling was attributed primarily to price differentials between leaded and unleaded gasoline at the retail level. Despite the smaller tank inlet fittings on new vehicles, owners could easily remove the fitting and thus fill their tanks with the cheaper and more familiar leaded gasoline.

to 1 (EPA, 1985). On January 1, 1985, the new rule was introduced, phasing lead down to 0.1 gplg at the start of 1986.

To help ease the transition for refineries, the EPA permitted both trading and banking of lead permits through a system of inter-refinery averaging. Trading of lead credits among refineries was allowed from late 1982 through the end of 1987, after which each refinery was required to comply with the 0.1 gplg standard. Banking was allowed only from 1985 to 1987. This marketable permit system alleviated some of the financial burden facing small refineries, and it allowed the refining industry a measure of flexibility in allocating the reduction among firms and in allocating investments over time, resulting in a more cost-effective reduction (Kerr and Newell, 2003; Newell and Rogers, 2003).

On January 1, 1996, the EPA banned the sale of leaded fuel for use in on-road vehicles. The EPA allowed the continued sale of leaded fuel for off-road uses, including aircraft, racing cars, farm equipment, and marine engines (EPA, 1996). Through a combination of command-and-control and market-based policy mechanisms, the EPA successfully removed lead from gasoline in the U.S. over a period of two decades. Although other nations successfully transitioned to unleaded gasoline in a matter of years, the U.S. acted as the first mover on this issue and has since served as an example for other nations.

During the two decades of phasing out lead, a price differential existed between leaded and unleaded gasoline (see Figure 12.2). This differential raised concerns among economists, who were involved in the 1985 EPA study, that the study's model was underestimating the cost of replacing lead as an octane enhancer. The EPA model estimated that unleaded gasoline would cost approximately 2 cents per gallon more to produce; this estimate was consistent with various indicators in the market, such as the price at which lead permits were trading and prices on the wholesale markets. Most of the increase took place at the retail level, where leaded gasoline was advertised at a lower price (Nichols, 1997).

Borenstein estimated that overall price differences due to both price discrimination and differential production costs slowed the phase out of leaded gasoline by about 4 years (Borenstein, 1993). Differential taxation policies, in combination with phase out mandates, contributed to the more rapid adoption of unleaded gasoline in many European nations in the 1980s and 90s (Hammar and Lofgren, 2004).

The effect of the CAA and EPA policies on lead in gasoline is very simply summarized in Figure 12.3—a chart illustrating the adoption rate of unleaded gasoline in the motor gasoline market. Table 12.2 provides a chronological summary of the lead standards.

Table 12.1. Results of the EPA Cost-Benefit Analysis estimated that costs to the refining industry would be outweighed by various benefits (millions of 1983 dollars) (EPA, 1985). The abrupt increase in net benefits from 1985 to 1986 occurs due to the lead standard being reduced from 0.5 to 0.1 gplg.

Monetized Benefits	1985	1986	1987	1988	1989	1990	1991	1992
Children's health effects	223	600	547	502	453	414	369	358
Adult blood pressure	1,724	5,897	5,675	5,447	5,187	4,966	4,682	4,691
Conventional pollutants	0	222	222	224	226	230	239	248
Maintenance	102	914	859	818	788	767	754	749
Fuel economy	35	187	170	113	134	139	172	164
Total Monetized Benefits	2,084	7,821	7,474	7,105	6,788	6,517	6,216	6,211
Total Refining Costs	96	608	558	532	504	471	444	441
Net Benefits	1,988	7,213	6,916	6,573	6,284	6,045	5,772	5,770
Net Benefits Excluding Blood Pressure	264	1,316	1,241	1,125	1,096	1,079	1,090	1,079

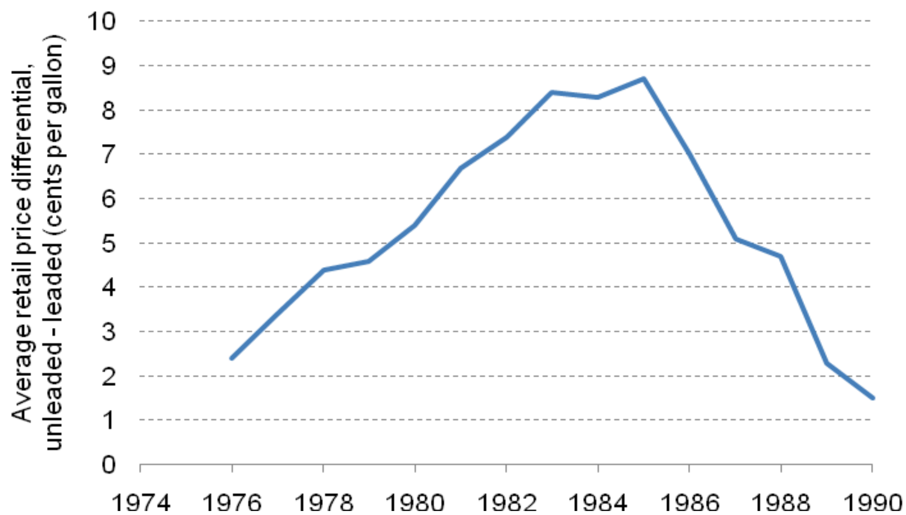


Figure 12.2. Unleaded gasoline was priced at a premium over leaded gasoline during the transition to unleaded gasoline (EIA, 2007).

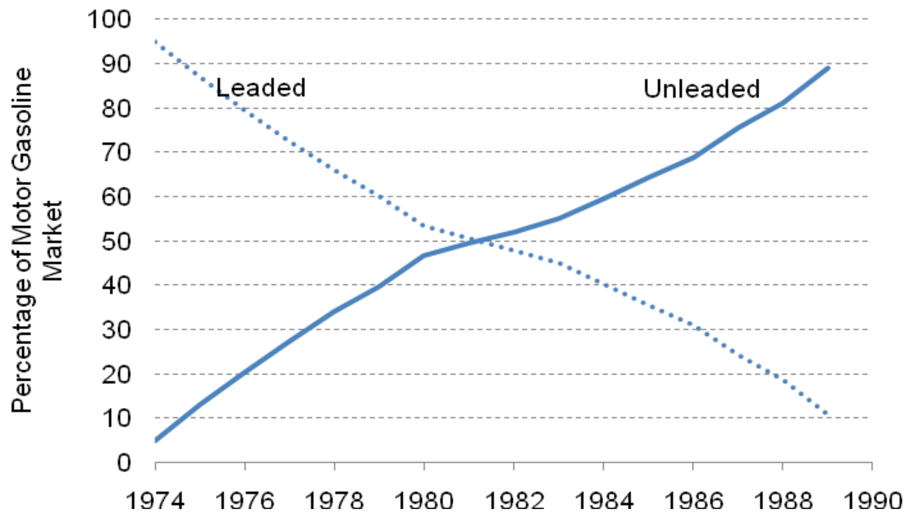


Figure 12.3. The transition to unleaded gasoline spanned over 15 years (Sperling and Dill, 1988; EIA, 1983-1990; EIA, 1990; EIA, 2009j).

Table 12.2. Lead standards promulgated by the EPA from 1974-1996 (Kerr and Newell, 2003; Newell and Rogers, 2003).

Deadline	Standard	Small Refinery Exceptions
July 4, 1974	Gasoline retailers must offer unleaded gasoline for use in cars with catalytic converters.	
October 1, 1979	Refineries must not produce gasoline averaging more than 0.5 glpg per quarter, pooled (leaded and unleaded).	Small refineries (≤ 50 MBD crude oil capacity, owned by company with ≤ 137.5 MBD capacity) are subject to less stringent standard of 0.8-2.65 glpg varying by capacity.
November 1, 1982	Refineries must meet a leaded gasoline standard of 1.1. Inter-refinery averaging of lead rights is permitted among large refineries and among small refineries, but not between refineries of different sizes.	Very small refineries (≤ 10 MBD gasoline production, owned by company with ≤ 70 MBD production) are subject to a less stringent pooled standard of 2.16 or 2.65 varying by capacity.
July 1, 1983	Very small refineries are also subject to a standard of 1.1 (leaded). Averaging is permitted among all refineries.	
January 1, 1985	During 1985 only, refineries are permitted to 'bank' excess lead rights for use in a subsequent quarter.	
July 1, 1985	The standard is reduced to 0.5 (leaded).	
January 1, 1986	The standard is reduced to 0.1 (leaded).	
January 1, 1988	Inter-refinery averaging and withdrawal of banked lead usage rights are no longer permitted. Each refinery must comply with the 0.1 standard.	
January 1, 1996	Lead additives in motor gasoline are prohibited.	

Note: glpg = grams of lead per gallon; MBD = thousand barrels per day.

12.2.2.1.2 Impacts to Industry

Up to this point, only the history of leaded gasoline and the policies used to phase out lead have been discussed. The impacts on industry, including refiners, distributors and marketers, and automobile manufacturers are addressed next.

At the time, the catalytic converter was viewed as the only technology available to the automotive industry to meet the new emissions requirements under the CAA. Since catalytic converters are rendered ineffective when exposed to lead, the automotive industry became a major proponent of unleaded gasoline. In addition, the use of unleaded gasoline was expected to lower vehicle maintenance costs and increase fuel economy (Sperling and Dill, 1988). It is interesting to note that the EPA RIA included these benefits (see Table 12.1). The reduced maintenance costs, enjoyed by vehicle owners, were a direct result of the elimination of lead and the associated impacts that lead has on exhaust system components, spark plugs, and oil quality.

Before 1975, the petroleum industry had concerns that after making large capital investments to produce unleaded gasoline it would then find that there was little demand for the new product. The automotive industry smoothed this transition by producing pre-1975 vehicles that could operate on either fuel, helping to initiate a market for the new fuel. These ‘dual-fuel’ vehicles were designed with slightly lower compression ratios and were upgraded with exhaust valves with improved metallurgy to mitigate concerns about valve seat wear (Sperling and Dill, 1988).

The removal of lead did not negate the need for refiners to boost octane in gasoline. Refiners had (and still have) two basic options for increasing the octane of gasoline without lead additives. They can employ the more intensive refining techniques of alkylation, isomerization, catalytic cracking and reforming to produce hydrocarbons with higher octane (e.g. benzene and other aromatics, and branched paraffins). The other approach is to utilize alternative additives, such as methyl tertiary-butyl ether (MTBE), ethyl tertiary-butyl ether (ETBE), and alcohols such as methanol and ethanol (Sperling and Dill, 1988; Newell and Rogers, 2003). According to Newell and Rogers, a combination of these approaches was utilized to make up for the lost octane.

Prior to any regulation being in place, there were many attempts made at estimating these anticipated costs. In 1967, API estimated that the transition to unleaded gasoline would cost refiners a total of $4.2 billion (Anon, 1967). The study estimated that overall average production costs of gasoline would increase about 2 cents per gallon. In 1971, a consultant study for the EPA stated, “the most significant impact of a lead removal program on the domestic petroleum industry is the requirement that more capital be spent on refineries over the next 10 years”. Other estimates ranged from about $4 billion to $6 billion (Sperling and Dill, 1988).

The 1985 EPA RIA provided a very comprehensive assessment of the costs that would be required by the industry in reducing lead content from 1.1 to 0.1 gplg. Again referring to Table 12.1, the EPA estimated that the new rule would cost the refining industry approximately $500 million per year from 1985 to 1992 (in 1983 dollars). The EPA estimated that these refining costs would translate into a production cost increase of 2 cents per gallon over leaded gasoline, which falls in line with API’s estimate from 1967.

A study completed by the Energy Information Administration (EIA) that reviewed the state of the refining industry in the 1980s helps to explain the difficulty in assessing the costs directly attributable to the phase out of lead (EIA, 1990):

> The overall financial performance and investment patterns for the refining/marketing sector in the 1980’s were heavily influenced by several factors, including the decontrol of

> domestic crude oil prices in 1981, the severe drop in crude oil prices in 1986, changes in product demand and crude oil supply, and the introduction of more stringent environmental regulations.
>
> Factors which drove the rise in investment throughout the decade include shifting product demand away from heavy fuel oils to light products, the increased availability of high-sulfur crude oils, the price spread between light and heavy crude oils, and restrictions on lead content. The anticipation of additional environmental regulations governing motor gasoline vapor pressure and reducing the sulfur content of diesel fuel were other factors that induced investments.

The "restrictions on lead content" were but one of many challenges facing the industry in the 1980s. Although these excerpts illustrate the difficulty in assigning specific costs to the lead standards, it is worthwhile to present data on investments made by the industry during this time period. Figure 12.4 shows the annual investments made by FRS refineries[5] from the late 1970s to the late 1980s. FRS refineries accounted for 75 to 80% of total domestic refining capacity during the 1980s, and therefore act as a good surrogate for the industry as a whole. Annual investments ranged from approximately \$1.5 billion to \$5 billion (constant 1982 dollars). By comparing the annual EPA cost estimates (Table 12.1) against the actual investments made by the industry, it is possible to conclude that investments needed to meet lead standards made up a significant portion of overall industry investments during this time period.

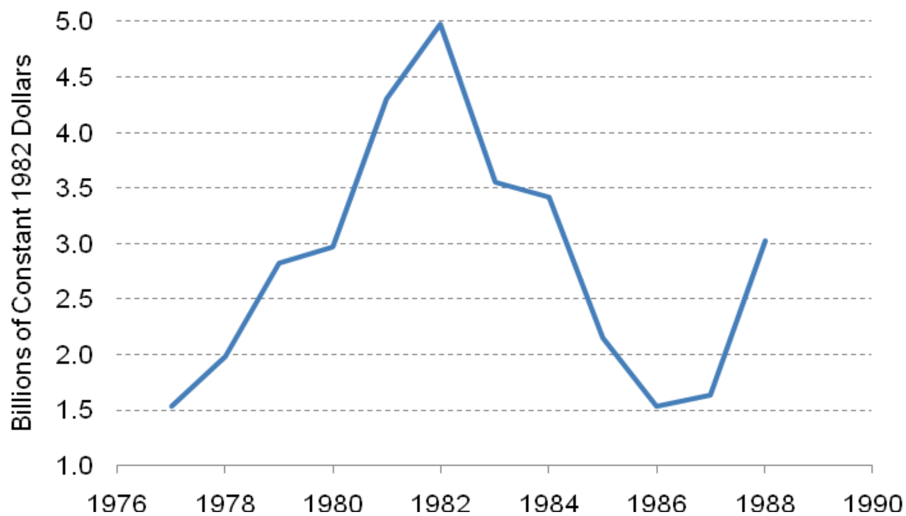


Figure 12.4. Investments in Domestic Petroleum Refining for FRS Companies ranged from \$1.5 to \$5.0 billion annually during the transition to unleaded gasoline, which spanned from approximately 1975 through 1990 (EIA, 2009b).

Despite the lack of technical challenges facing the distribution and marketing system (unleaded and leaded gasoline were both compatible with pipelines, tanks, tanker trucks, railcars, etc.), there were many logistical challenges associated with the delivery and storage of both leaded and

[5] FRS companies include those refineries that report financial data through EIA's Financial Reporting Systems (FRS).

unleaded gasoline. For example, precautions had to be taken to ensure that unleaded gasoline met the EPA standards; pipeline procedures had to be modified to minimize contamination; and separate storage facilities were necessary throughout the distribution system. At the retail level, as mentioned previously, new dispensing nozzles had to be designed and installed for fueling unleaded vehicles. According to Sperling and Dill, the total cost of adapting the distribution system to unleaded gasoline was large but never specified; however, because thousands of companies were involved, the costs were widely distributed. Costs incurred at retail stations alone, not including the distribution system, were estimated in 1978 at $5,951 per outlet (Sperling and Dill, 1988).

In summary, it is very challenging, if not impossible, to accurately quantify the investments made in the industry during the transition to unleaded gasoline that can be directly attributed to the phase out of lead. Based on the information presented above, a crude approximation would suggest that total investments over two decades could have ranged from as little as $4 billion to greater than $10 billion dollars. This estimate would equate to approximately $10 billion to greater than $20 billion in present day dollars. The EPA had estimated that costs would average approximately $500 million per year (in 1983 dollars), equating to $1.1 billion per year in present day dollars.

12.2.2.2 High-Octane Hydrocarbons in Gasoline

As discussed in the previous section, as lead additives were reduced in leaded gasoline, and eliminated in unleaded gasoline, refiners sought ways to recover the octane lost through the removal of lead additives. Changes in gasoline composition were necessary. Refiners reverted to using high-octane hydrocarbons such as alkylated aromatics, olefins, and branched paraffins. Oxygenated compounds also increase octane and were being utilized as early as the late 1960s. Initially, refiners turned to butane, and other short-chain or lower paraffins[6], and aromatics[7] to boost octane. Lower paraffins, such as butane, provided a cost-effective way to enhance octane by boosting the octane at relatively low concentrations (NRC, 1999). However, these lower paraffins evaporate readily and volatilize other reactive hydrocarbons in gasoline. Both summer and winter gasolines followed an upward trend in vapor pressure until approximately 1989 when there was a rapid drop for summer gasolines in response to federal vapor pressure regulations (discussed below). Figure 12.5 illustrates these trends in vapor pressure, which were directly related to the content of butane and other lower paraffins in gasoline used to meet octane demands throughout the 1980s (Gibbs, 1996).

[6] Paraffins are alkane hydrocarbons with the general formula C_nH_{2n+2}.
[7] Aromatics are hydrocarbon compounds containing one or more benzene rings.

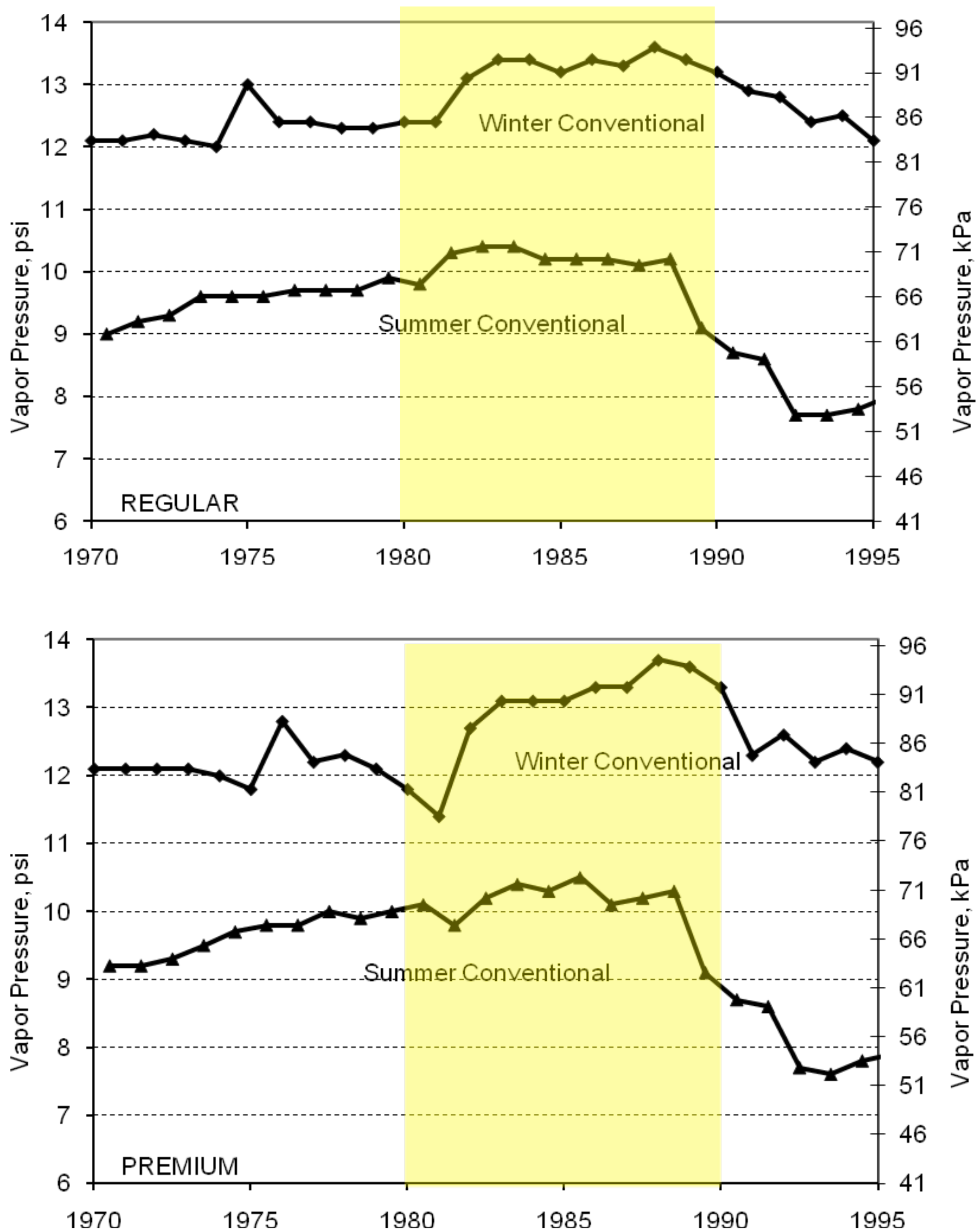


Figure 12.5. U.S. National average vapor pressure trends for regular (top panel) and premium (bottom panel) grade gasolines serve as a surrogate for the use of lower paraffins in gasoline (Dickson, 1970-2008).

Some of the worst ozone excursions on record were observed during the summer of 1988. These events led to speculation that evaporation of high-volatility summer gasoline was a major contributor to the VOC emissions that gave rise to these ozone excursions. Following initiatives taken by individual states, the EPA promulgated a rule setting vapor pressure (i.e., volatility) limits on gasoline sold during the ozone season throughout the nation starting in 1989; these limits were redefined and tightened for 1992 and later years (NRC, 1999). Under the CAA Amendments of 1990, the EPA promulgated the Phase I and II Volatility Regulations for Gasoline and Alcohol Blends. Phase I and II Volatility Regulations required gasoline Reid Vapor Pressure (RVP)[8] not to exceed 10.5/9.5/9.0 and 9.0/7.9 psi, respectively, depending on the state and month. The more stringent limits (e.g., Phase II Regulation of 7.9 psi) are often applied in the summer months when gasoline volatility increases due to higher average ambient temperatures. Gasoline containing ethanol at 9 to 10% by volume was given a 1.0 psi allowance (e.g., Phase II Regulations increase to 10.0/8.9 psi), due to the low-level blended fuel having a higher volatility relative to gasoline alone (EPA, 2008b). California led the nation by enacting similar volatility regulations starting in 1971.

Although the lower paraffins helped to recover some of the octane rating, refiners sought additional high-octane components to further boost octane. Unleaded regular- and premium-grade gasolines had substantially higher aromatics content than the leaded grades they replaced. Figure 12.6 illustrates these trends in aromatics content in gasoline. Following an initial increase, aromatics content followed a slight downward trend through the 1980s and 1990s. Gibbs partially attributes this reduction to dilution caused by the increased use of oxygenates for octane enhancement and to meet federal oxygenated gasoline requirements (Gibbs, 1996).

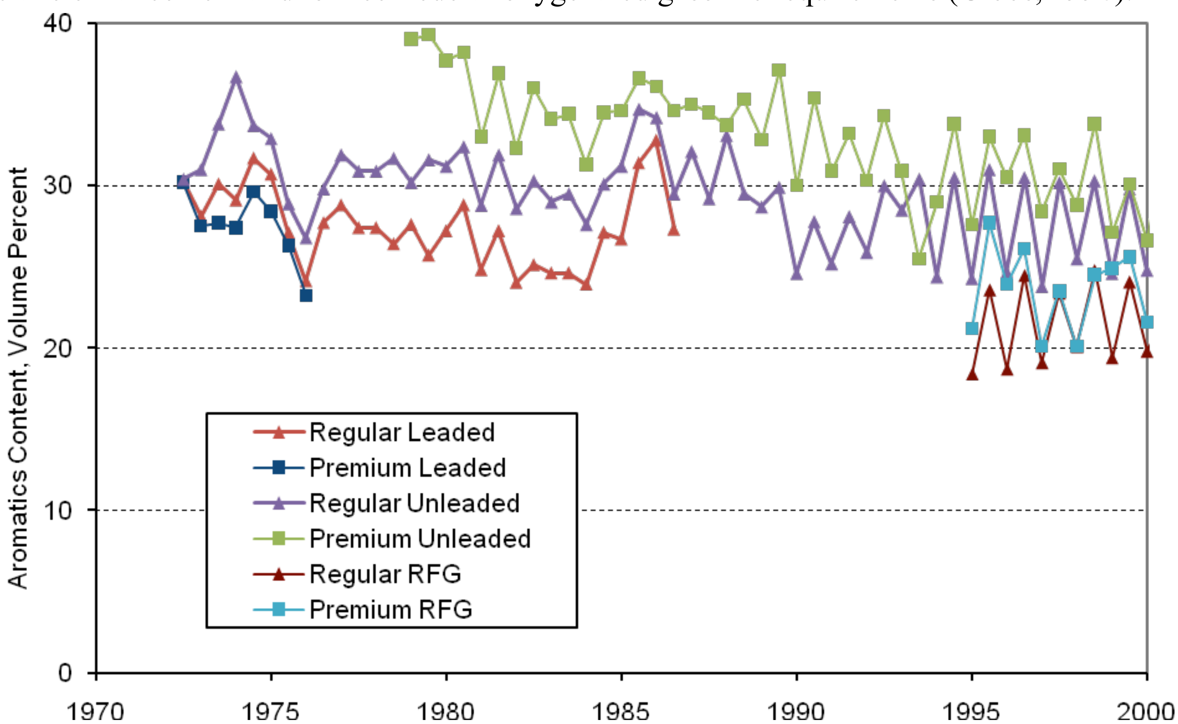


Figure 12.6. U.S. National average aromatics content was higher in the unleaded gasolines that replaced leaded gasolines (Dickson, 1970-2008), e.g., regular unleaded has a higher aromatics content relative to regular leaded from 1973 through 1986.

The impacts of these fuel modifications on the motor gasoline sector were confined to the refining industry. The altered composition of gasoline, with an increased content of lower paraffins and aromatics, did not impact the distribution, retail, and end use stages of the motor

[8] RVP is a common measure of gasoline volatility based on the test method ASTM D323.

gasoline supply chain. Refiners, in their drive to recover the octane lost through the reduction and removal of lead additives, revamped their operations to alter the formulation of gasoline. The necessary investments made by the refiners to initially recover the octane of gasoline during the lead phase down through the use of higher octane hydrocarbons are likely encompassed within the refinery investments made throughout the 1980s, as discussed in the prior section on the transition to unleaded gasoline. No attempt was made to quantify the economic costs attributable to these fuel modifications.

12.2.2.3 Oxygenates in Gasoline

The two most common oxygenates used as additives in gasoline are methyl-tertiary butyl ether, or MTBE ($CH_3OC(CH_3)_3$), and ethanol (C_2H_5OH). These oxygenates are used to increase the octane rating of gasoline and to reduce the formation of air pollutants, such as carbon monoxide (CO). Alternative, less common oxygenates include methanol (CH_3OH), tertiary-amyl methyl ether (TAME), ethyl-tertiary butyl ether (ETBE), and di-isopropyl ether (DIPE). These oxygenates have been far less common in the gasoline pool, aside from a short-lived interest in methanol as a gasoline substitute and oxygenate during the 1980s. Figure 12.7 shows the total amount of oxygenate consumed in the US from 1980 to present day, relative to the total motor gasoline supply. The data might slightly underestimate the total oxygenate as this data set includes only the ethanol and MTBE supply. Regardless, the total oxygenate supply has grown from essentially 0% to over 7% of the total motor gasoline supply in the last three decades. The figure also illustrates a transition that occurred during the first decade of the 21st century—the transition from MTBE to ethanol as the primary oxygenate additive in gasoline. This transition will be discussed further in the next section.

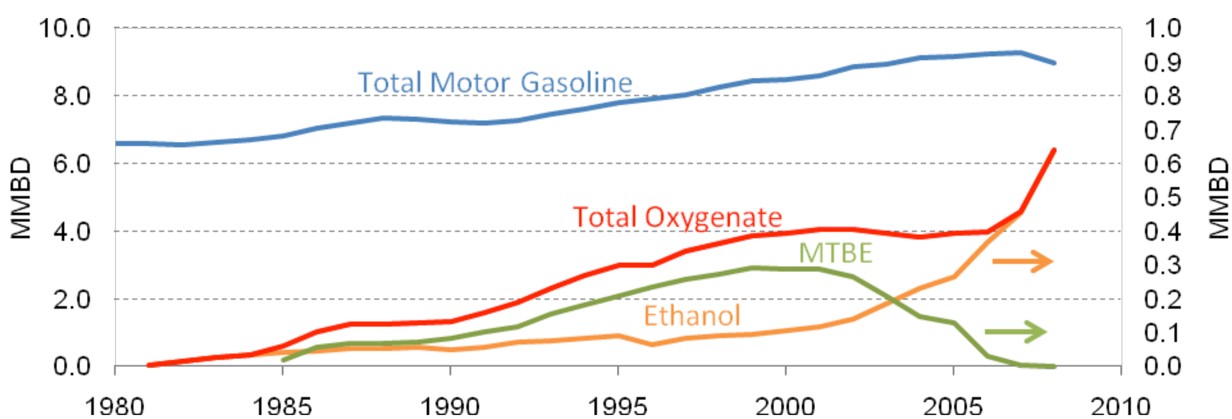


Figure 12.7. Total oxygenate supply has grown steadily for three decades to make up a substantial share of the motor gasoline sector (Davis and Diegel, 2004; Table 2.10, EIA, 2009g; EIA, 2009h; EIA, 2009i; EIA, 2009j). All data series represent the product supply consumed in the U.S. in million barrels per day (MMBD): total motor gasoline is plotted with the left axis, the oxygenates are plotted with the right axis.

Along with the high-octane hydrocarbons, oxygenated compounds were being used in small quantities as high-octane blending components as early as the late 1960s. The EIA apparently did not track oxygenate production or supply in the motor gasoline sector prior to the 1980s, possibly a reflection of the small quantities used prior to 1980. As the lead phase down progressed through the 1980s, and refiners worked to maintain the octane performance of gasoline, the regulation of fuel properties was substantially expanded with the passage of the CAA Amendments of 1990 (CAAA 1990). The CAAA 1990 mandated the Federal Reformulated Gasoline (RFG) program and the Federal Oxygenated Fuels (Oxyfuels) program. The RFG program commenced in late 1994 (Phase I) and was made more stringent in 2000 (Phase II); the Oxyfuels program started in 1992. The California Air Resources Board (CARB) implemented its own RFG program, which commenced in 1992, nearly 3 years prior to the Phase I program promulgated by the EPA. CARB also mandated wintertime oxygen content starting in 1992 (EPA, 2008a; Gibbs, 1996; NRC, 1999). By mandating the use of oxygenates, these programs rapidly expanded the use of oxygenated compounds in motor gasoline during the 1990s (see Figure 12.7).

Like the volatility regulations, the Oxyfuels program was justified based on the success of winter gasoline oxygenate programs established by some states in the late 1980s (NRC, 1999). This program seeks to lower motor-vehicle emissions of CO to avoid nonattainment of the National Ambient Air Quality Standards (NAAQS) for CO, and to help nonattainment areas move towards attainment. Because CO pollution is typically more severe in the winter months[9], the Oxyfuel program requires gasoline to contain 2.7 percent oxygen content (by weight) during the wintertime. When the Oxyfuel program commenced in 1992, 36 areas[10] implemented the program; only 8 areas implemented the program during the winter of 2007/2008 (EPA, 2008f). Ethanol has served as the additive of choice for most oxyfuel areas (EPA, 1999).

In contrast, the RFG programs tend to regulate gasoline sold during the summer ozone season. The programs set content requirements for oxygen, benzene, and aromatics, and requires reductions in levels of NOx, toxics, and VOC emissions relative to a 1990 fuel baseline. These programs (Federal and CA) are aimed at reducing light-duty vehicle (LDV) emissions of VOC, CO, NOx, and air toxics. According to the EPA, RFG is gasoline that is blended such that it significantly reduces VOC and air toxics emissions compared to conventional gasoline. Since the fuel properties of RFG are well within those exhibited by conventional gasoline, the EPA explained, when introducing the program, that the RFG program is a "new program", but that RFG is not a "new gasoline" (EPA, 1995c). Nine metropolitan areas were initially mandated under the RFG program, although any nonattainment areas are able to voluntarily opt in to the program. Prior to 2006, the RFG program required a minimum of 2.1 percent oxygen by weight (average). Figure 12.8 illustrates the rapid introduction of RFG in the motor gasoline sector. Following its introduction in December 1994, RFG use rapidly grew to over 30% of the sector by 1996; RFG continues to comprise approximately one third of the motor gasoline volume, with that share increasing slowly since 1996.

[9] In the winter months, lower temperatures during engine start up and cold operation can result in incomplete combustion, leading to the formation of CO emissions. Adding oxygenates to gasoline is thought to reduce emissions of CO, although the overall emissions benefits of gasoline oxygenates have been questioned. See, e.g., Ozone-Forming Potential of Reformulated Gasoline, National Academies, 1999 http://www.nap.edu/catalog.php?record_id=9461

[10] In regulatory terms, "area" refers to metropolitan statistical area (MSA) and consolidated metropolitan statistical area (CMSA), both of which are comprised of one or more counties.

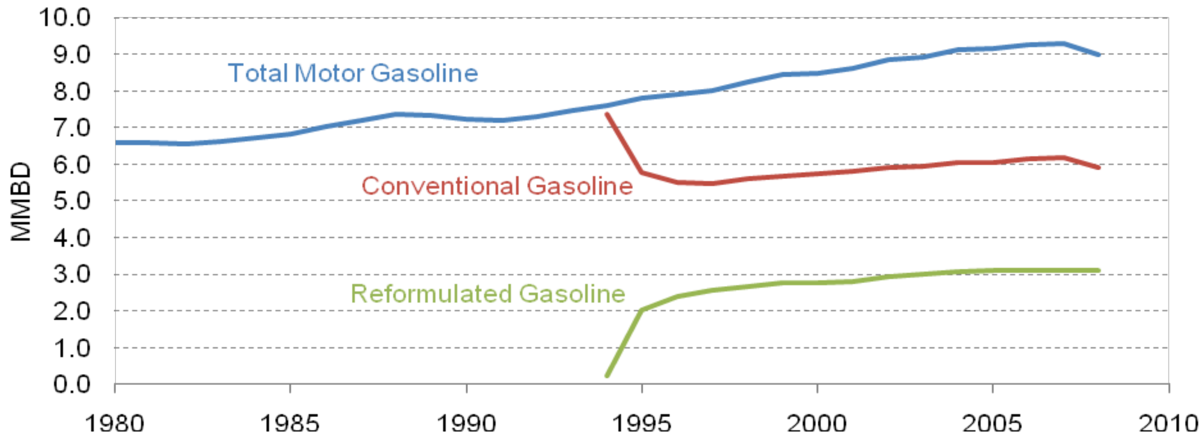


Figure 12.8. The RFG program currently comprises over one third of the motor gasoline market, with conventional gasoline comprising the remainder (EIA, 2009j).

The quantity of oxygen in a fuel is typically expressed in terms of the percent by volume of oxygenated additive (i.e., vol % additive) or the percent of oxygen in the fuel by weight (i.e., wt % oxygen). The later quantity is used to specify oxygen content requirements in the RFG programs. MTBE has a higher molecular weight relative to ethanol, yet both have only one oxygen atom in their structures. Therefore, a greater volume percentage of MTBE is needed to obtain the same weight percent of oxygen than when blending with ethanol. Table 12.3 lists the amounts of ethanol and MTBE (by volume) needed to produce gasoline with a particular oxygen content. To meet a specified percent of oxygen by weight, ethanol is blended at about 50% less volume percentage relative to MTBE. The RFG program mandated approximately 2% oxygen by weight, which requires 5.7% ethanol by volume and 11.2% MTBE by volume (NRS, 1999). These volumetric differences can have important implications on possible infrastructure changes.

Table 12.3. The volume of MTBE needed to produce a specified oxygen content in gasoline is nearly double that of ethanol (NRC, 1999).

Wt % Oxygen	Vol % Ethanol	Vol % MTBE
1.0	2.85	5.6
1.5	4.3	8.3
2.0	5.7	11.2
2.5	7.1	13.9
3.0	8.6	16.7
3.5	10.1	18.9

Prior to the introduction of regulations mandating the inclusion of oxygenates in gasoline, the use of oxygenates was quite limited. Refiners used conventional refining processes to produce high-octane hydrocarbons for blending with gasoline in order to recover the octane performance provided by lead additives. These processes, such as catalytic cracking, catalytic reforming, and isomerization, can often be more economical than those used to produce oxygenates. However, as the Oxyfuel and RFG programs were implemented, MTBE quickly became a dominant oxygenate in the gasoline pool.

According to the EPA, Arco Petroleum began selling an RFG-like gasoline in California in the late 1980s as a replacement for leaded gasoline. Arco's "EC-1" fuel, which utilized MTBE as an additive, was formulated specifically for older vehicles with high compression ratios that needed high octane gasoline. Other petroleum refiners began to follow suit. When CAA legislation was being debated in 1990, a number of provisions called for the use of alternative fuels to aid in reducing emissions. As a substitute for these non-petroleum fuels provisions, the petroleum and oxygenate industries argued in favor of an RFG program. Arguing that significant fleet turnover would be required to achieve emission reductions through the use of alternative fuels, they explained that RFG would be effective immediately in reducing emissions in the existing LDV gasoline fleet (EPA, 1995a).

The petroleum industry favored MTBE for several reasons. First, the feedstocks used to produce MTBE are hydrocarbons—normal butane and methane. Methane is used to produce methanol; normal butane is isomerized to produce isobutylene; methanol and isobutylene are then reacted to form MTBE. Normal butane is a hydrocarbon present in both crude oil and wet natural gas, while methane is the primary hydrocarbon in natural gas. Second, MTBE can be blended with gasoline at a refinery and distributed through the existing infrastructure with no modifications. Therefore, the existing fuels industry loses little market share and experiences little disruption in operations when MTBE is used as an oxygenate additive in RFG; only a small shift from petroleum to natural gas is required to produce the additive. With the petroleum and oxygenate industries helping to implement the RFG program in the CAAA of 1990, MTBE use rapidly increased through the 1990s (see Figure 12.7). Estimates of the total amount of oxygenate in RFG and volumes of MTBE and ethanol as oxygenates in RFG, from the program's inception in late 1994 through present day, are shown in Figure 12.9.

In addition to increasing the use of oxygenates, the RFG program reduced aromatics content in the overall gasoline pool. Referring back to Figure 12.6, the aromatics content of premium and regular RFG is reduced relative to the average unleaded gasoline trends.

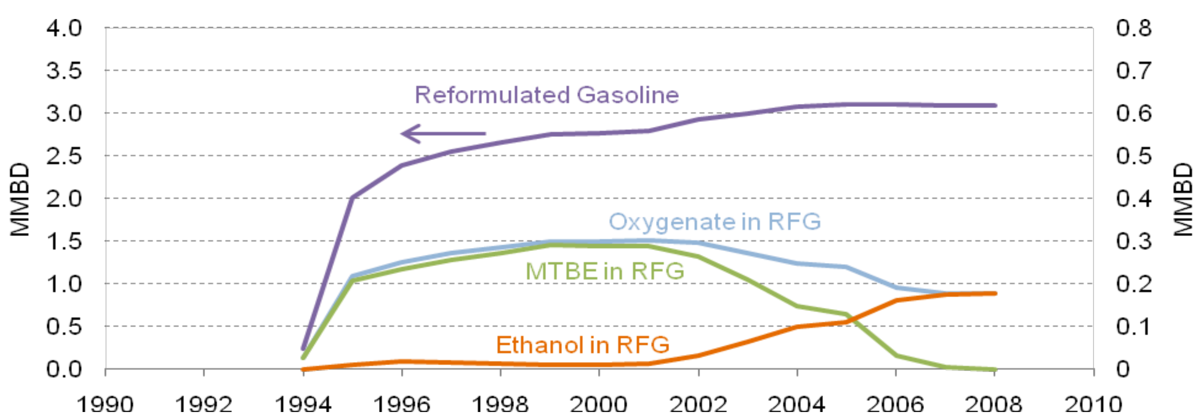


Figure 12.9. MTBE served as the predominant oxygenate in RFG throughout the 1990s (Davis and Diegel, 2004, Table 2.10; EIA, 2009g; EIA, 2009h; EIA, 2009i; EIA, 2009j). This figure does not account for the quantities of ethanol and MTBE consumed in the Oxyfuels program; data on the consumption of oxygenates in the Oxyfuels program could not be identified. To create this chart, it was assumed that the entire MTBE supply is blended in RFG with the balance being supplied by ethanol.

12.2.2.4 MTBE to Ethanol as the Dominant Gasoline Oxygenate

As MTBE became more ubiquitous throughout much of the nation's gasoline infrastructure, evidence of drinking water contamination—particularly in groundwater supplies—led to concern over its continued use. In 1999, the seminal report, "Achieving Clean Air and Clean Water: The Report of the Blue Ribbon Panel on Oxygenates in Gasoline (EPA, 1999)," marked the beginning of the end of MTBE's dominance of the gasoline oxygenate market—MTBE consumption reached its peak of 0.29 MMBD that same year and declined rapidly thereafter (see Figures 12.7 and 12.9). The independent Blue Ribbon Panel, appointed by then EPA Administrator, Carol Browner, found that detections of MTBE in drinking water primarily resulted in consumer odor and taste concerns and that MTBE had been found, in rare cases, at levels above the EPA's drinking water advisory and state standards. The Panel made the following recommendations, stressing that the actions should be implemented as "a single package" in order to simultaneously maintain air quality benefits and improve water quality protection without impacting the cost and supply of gasoline (EPA, 1999; EPA, 2008c):

- remove the requirement for 2% oxygen in RFG from the CAA;
- enhance water protection programs (over 20 specific actions were specified);
- reduce MTBE use nationwide;
- maintain air quality benefits of RFG;
- support further research on MTBE and its alternatives.

The EPA worked to implement several recommendations made by the Blue Ribbon Panel. The agency supported legislation in Congress to phase down the use of MTBE as a fuel additive in gasoline and promote renewable fuels like ethanol (EPA, 2008c). However, no federal legislation aimed specifically at limiting MTBE use was ever passed. Despite legislative inaction at the federal level, individual states implemented limits and bans on MTBE to prevent further contamination of water supplies. As of August 2007, 25 states had taken actions to limit or ban the use of MTBE and other similar oxygenates (e.g., other ethers) in gasoline (EPA, 2007). Although Congress never passed legislation related to the use of MTBE, the Energy Policy Act (EPAct) of 2005 included a provision to eliminate the RFG oxygen content requirement from the CAA, as recommended by the Panel. The EPA proceeded to amend the RFG regulations, effectively removing the oxygen content requirement on May 5, 2006 (EPA, 2006). With the elimination of the oxygen content requirement, refiners can produce RFG in the most cost-effective manner, either with or without an oxygen component.

Prior to the amendment of RFG regulations, most oil companies had announced their intent, and were already taking actions, to remove MTBE from their gasoline by the summer driving season of 2006 (EIA, 2006a). As refiners phased out their use of MTBE as an oxygenate additive in gasoline, domestically-produced, corn-based ethanol quickly became the primary substitute. With favorable federal and state tax incentives supporting domestic ethanol production, the refining industry turned to ethanol for RFG production to (1) maintain octane performance, (2) achieve air toxics reduction requirements, and (3) make up for lost volume (from the MTBE phase out) (Green, 2008). In addition, refiners were wary about turning to alternative ethers (e.g. ETBE) that might pose water contamination concerns similar to those evidenced by the use of MTBE.

Figure 12.7 illustrates the overall transition from MTBE to ethanol as the dominant oxygenate in the motor gasoline sector, while Figure 12.9 illustrates this transition within the RFG portion of the sector. In 2008, 47 thousand barrels per day (MBD) of MTBE were produced in the US solely for export markets—no MTBE was consumed domestically.

As with the phase down of lead additives in gasoline, concerns arose about the phase down of MTBE as an oxygenate additive in gasoline (Pegg, 2006; Platts, 2006). Much of this concern stemmed from a report published by the EIA in March 2006, titled, "Eliminating MTBE in Gasoline in 2006," which warned that the rapid transition from MTBE to ethanol could "increase the potential for supply dislocations and subsequent price volatility on a local basis (EIA, 2006a)." The EIA warning, aimed mostly at the East Coast and Texas RFG regions, pointed to several potential drivers for the supply and price concerns (EIA, 2006a). First, a net loss of gasoline production capacity would occur due to changes needed in RFG blendstocks to accommodate the differing properties of ethanol, particularly with its higher vapor pressure. Second, ethanol production capacity and distribution challenges were expected to create a tight ethanol market in the short term. Third, since ethanol would be blended solely at terminal facilities, limited resources and permitting problems would hinder gasoline suppliers' ability to install the necessary equipment for the storage and blending of ethanol. Finally, a shortfall in (RFG) import sources might occur due to their inability to deliver RFG without MTBE or to produce the high-quality blendstock needed for ethanol blending.

With respect to the removal of the RFG oxygen content requirement, Lyondell Chemical, the nation's top MTBE Manufacturer at the time, responded to the EPA rule, captured in the headline of an article published by Green Car Congress: "Top MTBE Manufacturer Slams EPA Ruling on Oxygenated Fuels (Green, 2006; Lyondell, 2006)." Well before the EPA ruling, Lyondell included a dissenting opinion in the Blue Ribbon Panel's "Achieving Clean Air and Clean Water" report in 2000. Based on the recommendations made by the Panel, Lyondell estimated that the recommended alternatives to MTBE would "impose an unnecessary additional cost of 1 to 3 billion dollars per year (3-7 c/gal. RFG) on consumers and society without quantifiable offsetting social benefits or avoided costs with respect to water quality in the future (EPA, 1999)." In Lyondell's response to the EPA ruling (to remove the RFG oxygen content requirement) in 2006, the company estimated that the "direct impact on the United States economy will be $6-$13 billion over a two-month spike, and a sustained increase of $350-$700 million per year (excluding impact of reduced economic activity due to higher gasoline prices) (Green, 2006)." As with the Ethyl Corporation's experience during the lead phase down, Lyondell held a major stake in the MTBE industry and would be severely impacted by the MTBE phase down.

It is not entirely clear whether Lyondell's estimated impacts to the economy and the EIA's warnings were ever realized during the rapid transition from MTBE to ethanol. Figure 12.10 plots the trend in national average (real and nominal) gasoline prices from 2005 through 2007. Although the national average price may conceal evidence of localized price aberrations, it is clear that the phase out of MTBE and transition to ethanol did not cause gasoline prices to skyrocket—the average price appears to follow the normal summer driving season price increase that is experienced annually in the US. The peak in nominal price during the summer of 2006 increased by less than 8 cents relative to that of 2005; the peak in real prices were nearly identical (EIA, 2009e).

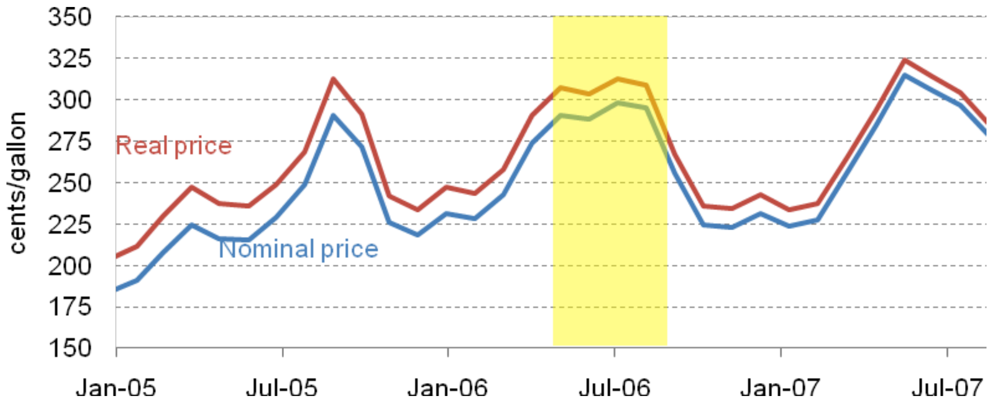


Figure 12.10. National average gasoline prices (real and nominal) during the summer of 2006 (shaded box) followed the normal summer driving season price hike (EIA, 2009e), despite a rapid transition from MTBE to ethanol as an oxygenate.

In contrast to Lyondell's concerns, a report prepared in March 2000 for the Governor's Ethanol Coalition—in response to the Blue Ribbon Panel report—stated that a transition from MTBE to ethanol would not result in increased gasoline prices and would result in positive economic impacts (Urbanchuk, 2000):

> The cost to add the new ethanol capacity to replace MTBE is estimated at nearly $1.9 billion. The level of construction activity associated with this expansion combined with the increased demand for corn and other grain to produce the additional ethanol will add $11.7 billion to real GDP by 2004, increase household income by $2.5 billion, and generate more than 47,800 new jobs throughout the entire economy.

During a hearing before the Senate Environment and Public Works Committee in March 2006, the president of the Renewable Fuels Association, Bob Dinneen, explained that the industry had anticipated the transition and would be capable of handling the short-term challenges associated with the rapid increase in ethanol demand (Pegg, 2006). In a letter to the EIA, in response to the EIA's 2006 report on the transition, Mr. Dinneen explained that domestic ethanol producers, combined with ethanol imports, would be capable of meeting the new demand required by the RFG market (Dinneen, 2006; RFA, 2006b). Two months later, in a hearing before the Energy and Commerce Committee, Mr. Dinneen suggested that the transition was nearly complete, and that the industry had continued to provide an adequate supply of gasoline without increasing prices (RFA, 2006a):

> As refiners have made the decision to remove MTBE from gasoline, ethanol has been there to replace the lost octane and volume of MTBE, without sacrificing the air quality benefits of the RFG program or increasing consumer costs. The transition from MTBE to ethanol is now largely complete, and is a testament to what can be accomplished when oil refiners, gasoline marketers and ethanol producers work together for the benefit of consumers.

To address the distribution challenges associated with moving ethanol to market, Dinneen explained that the ethanol industry had aggressively developed a “Virtual Pipeline.” This “pipeline” moves ethanol through components of the distribution system that are compatible with the fuel: the rail system, barges, and trucks. By improving the logistics of ethanol distribution, the ethanol industry was able to efficiently move their product to new demand regions (i.e., RFG markets) during the transition without the aid of the petroleum pipeline infrastructure.

During an April 2006 press conference, EIA Administrator Guy Caruso stated that consumers should expect gasoline prices to be 25 cents higher than the previous summer’s average, but attributed 19 cents of that increase to high crude oil prices and that the transition from MTBE to ethanol would increase prices by “just a few pennies (RFA, 2006c).” The April 2006 Short-Term Energy Outlook attributed the expected price increase to several drivers (EIA, 2006b):

> Gasoline prices are expected to increase because of higher cost of crude oil compared with last year and the increase in production and distribution costs associated with Tier 2 gasoline and the phaseout of MTBE.

As with the transition from leaded to unleaded gasoline, identification of the true costs and impacts attributable to the transition from MTBE to ethanol is convoluted by the many factors that were simultaneously affecting the gasoline sector.

The removal of the RFG oxygen content requirement and state bans on MTBE were major drivers in the expanded use of ethanol. However, the EPAct of 2005 included an additional provision—the Renewable Fuels Standard (RFS) program—that would help to guarantee a major market for domestically-produced ethanol, and other biofuels.

12.2.2.5 Ethanol as a Gasoline Substitute

The initial version of the RFS was implemented in two separate final rules by the EPA. Due to the limited timeframe following the passage of the EPAct of 2005, the EPA implemented the standard as set forth in the EPAct of 2005 on December 30, 2005 for the year 2006 only. The agency then finalized the rule for 2007 and beyond on May 1, 2007. Shortly thereafter, the EISA of 2007 was passed, which substantially expanded the requirements of the program. The EPA is still in the process of finalizing the final rule, but has based the 2008 and 2009 volume requirements on the new requirements set forth by the EISA of 2007 (EPA, 2008e). Following the transition from MTBE to ethanol, the RFS has further spurred the growth of the ethanol industry. Figures 12.7 and 12.11 plot the increasing consumption of ethanol in recent decades.

Figures 12.9 and 12.11 approximate the quantity of ethanol used as an oxygenate additive in RFG. Although the RFG oxygen content requirement has been stricken from the CAA since May 2006, this approximation serves to illustrate the minimum amount of ethanol needed to replace the oxygen content previously supplied by MTBE. The approximation is based on the minimum volume percentage of ethanol needed to produce RFG with 2% oxygen by weight. Referring back to Table 12.3, an RFG with 5.7% ethanol by volume is needed to provide the oxygen content supplied with 11.2% MTBE by volume. These differing volume percentage requirements explain the reduced volume of ethanol needed to produce RFG with 2% oxygen by weight, relative to MTBE.

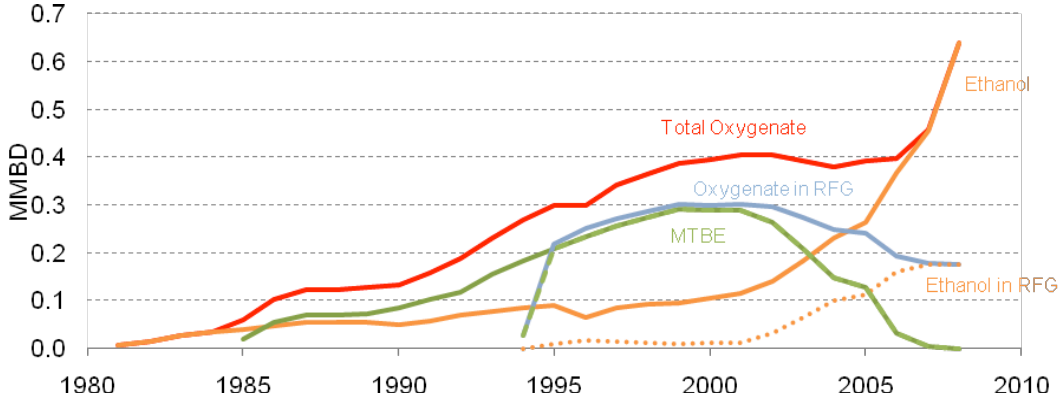


Figure 12.11. Ethanol has increasingly served as a substitute for gasoline, rather than simply a substitute for MTBE (Davis and Diegel, 2004, Table 2.10; EIA, 2009g; EIA, 2009h; EIA, 2009i EIA, 2009j).

In Figure 12.11, the gap between the data series 'Ethanol' and 'Ethanol in RFG' represents the volume of ethanol consumed as a substitute for gasoline. Although ethanol is an oxygen containing compound—an oxygenate—it is increasingly serving as a direct substitute for crude-based gasoline[11]. Today, most gasoline suppliers blend RFG, and, increasingly, conventional gasoline (CG), with approximately 10% ethanol by volume (E10) for several reasons: (1) the VEETC federal tax incentive has encouraged E10 blends; (2) the vapor pressure of gasoline-ethanol blends peaks near the 5.7% blend point, dropping thereafter; and (3) the RFS program mandates ever increasing volumes of renewable fuels, which all obligated parties such as gasoline blenders, must meet annually. The future growth of the ethanol consumption is examined later in this Task report.

12.2.2.6 Summary of Motor Gasoline Transitions

Although this overview of the motor gasoline sector does not account for all changes or modifications in gasoline composition over the last several decades, such as gasoline sulfur reductions (e.g., Tier 2 Gasoline Program), it has served to highlight several major transitions that have occurred and the implications associated with such transitions (discussed in further detail below). Table 12.4 summarizes the regulations that helped to drive transitions in the motor gasoline sector. These actions taken at the federal and state (primarily California) levels have yielded significant modifications to gasoline over the last several decades. Figure 12.12 captures the overall growth in the motor gasoline sector along with several major transitional trends that have occurred: the transition from leaded to unleaded gasoline, the introduction of oxygenate additives in gasoline, the transition from MTBE to ethanol, and the expanded use of ethanol as a crude-based gasoline substitute.

[11] It should be noted that a portion of the ethanol not used as a substitute for MTBE in RFG is actually consumed in (wintertime) oxyfuel areas. Although a significant share of ethanol demand might have been driven by the oxyfuel program in the early 1990s, as mentioned previously, the number of areas implementing the program has dropped substantially since its initial implementation in 1992. Data on the volume of ethanol consumed in oxyfuel areas have not been identified by the author.

Table 12.4. Federal (EPA) and California (CARB) motor gasoline regulations have aimed to eliminate lead additives, reduce fuel volatility, reduce air pollutants, and mandate oxygenates and renewable fuels content in gasoline.

Year	Agency	Regulation
1971	CA	Vapor Pressure 9.0 psi Max summer months
1974	US	Unleaded Gasoline required in service stations
1977	CA	Lead phase down
1980	US	Lead phase down
1989	US	Phase I Volatility Regulations – 10.5/9.5/9.0 psi max summertime
1992	CA	Vapor Pressure Phase I – 7.8 psi max summertime; part of California Reformulated Gasoline Program, Phase I (1992-1996)
1992	CA	Wintertime oxygen content – 1.8-2.2 wt %
1992	US	Phase II Volatility Regulations – 9.0/7.8 psi max summertime
1992	US	Federal Oxygenated Fuels (Oxyfuels) Program – 2.7 wt % min
1994	CA	Required all gasoline to be unleaded
1995	US	Federal Reformulated Gasoline, Phase I (1995-1999)
1996	US	Lead banned for highway fuel
1996	CA	California Reformulated Gasoline Program, Phase II
2000	US	Federal Reformulated Gasoline Program, Phase II
2006	US	Renewable Fuel Standard (EPAct 2005)
2006	US/CA	CA and Federal RFG oxygen content requirement removed (EPAct 2005)
2009	CA	Low Carbon Fuel Standard
2009	US	Renewable Fuel Standard 2 (EISA 2007)

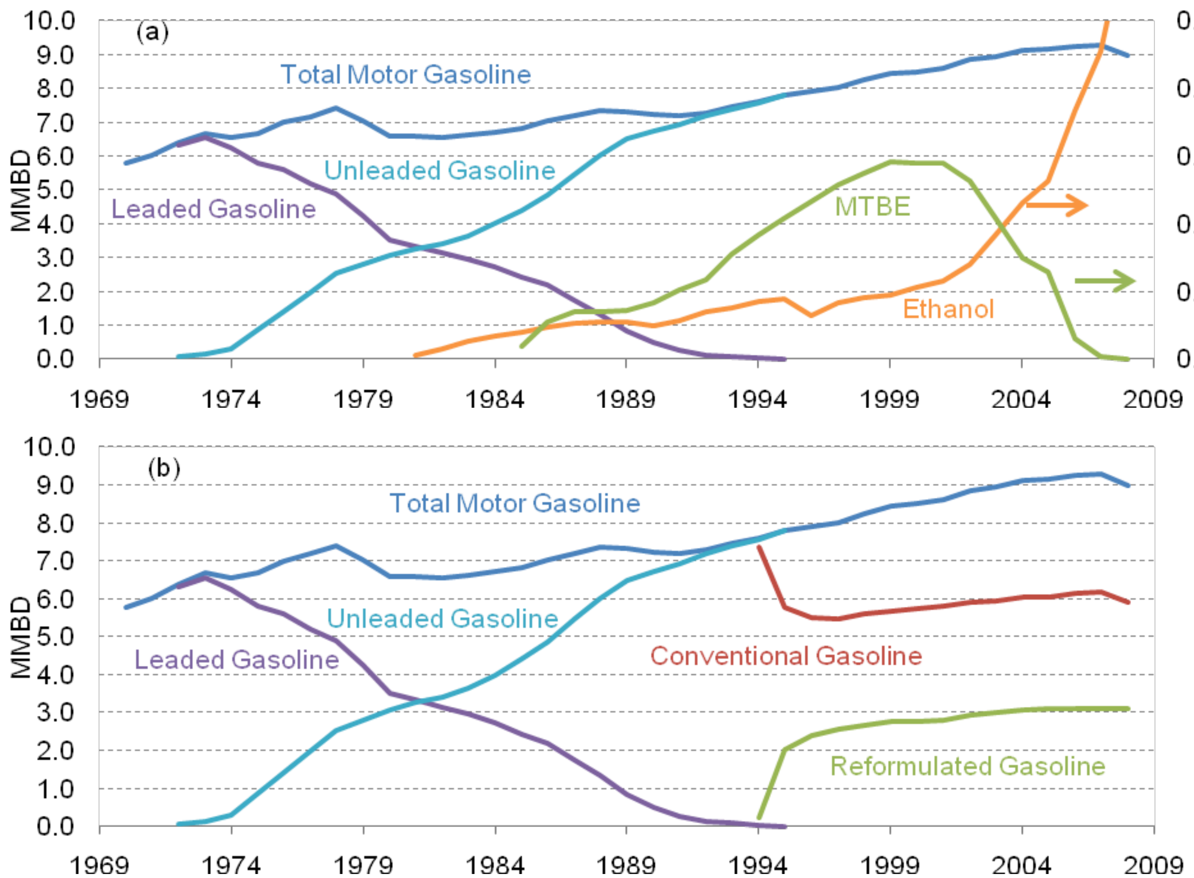


Figure 12.12. Trends in the US motor gasoline sector illustrate the numerous transitions that have occurred over the last several decades (Davis and Diegel, 2004, Table 2.10; EIA, 1983-1990; EIA, 1990; EIA, 2009g; EIA, 2009h; EIA, 2009i EIA, 2009j; Sperling and Dill, 1988). Both panels (a) and (b) illustrate the transition from leaded to unleaded gasoline. Panel (a) shows the growth in MTBE consumption and subsequent transition to ethanol, while panel (b) shows the introduction of RFG.

12.2.3 U.S. Distillate Sector

The following discussion focuses on transitions in the U.S. distillate fuel oil (DFO) sector that have yielded significant reductions in sulfur content of finished distillate fuels (e.g. diesel) over the last two decades[12]. Distillate fuel oil, as defined in this report, includes distillate fuel oils no. 1, 2, and 4, which are differentiated by their boiling ranges[13]. These fuels are used primarily in diesel-powered equipment (i.e., diesel fuel) and heating oil applications (i.e., fuel oil). This

[12] Although there have been additional transitions in the composition of distillate fuels, sulfur stands as the most significant transition in this fuel sector, and is often compared to the removal of lead from gasoline, despite sulfur being a naturally-occurring element in crude oil.
[13] This definition is based on the DFO classification used by the EIA: "A general classification for one of the petroleum fractions produced in conventional distillation operations. It includes diesel fuels and fuel oils. Products known as No. 1, No. 2, and No. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. Products known as No. 1, No. 2, and No. 4 fuel oils are used primarily for space heating and electric power generation." See http://tonto.eia.doe.gov/dnav/pet/TblDefs/pet_cons_psup_tbldef2.asp

classification of fuels also includes several alternative distillate fuels: biodiesel, renewable diesel, and synthetically-derived liquid fuels (e.g., biomass-, gas-, and coal-to liquids).

Sulfur is one of several heteroatoms found in limited quantities (<1%) in crude oil. The level of sulfur content varies greatly depending on the reservoir from which the crude is produced. Sweet crude oil is defined as petroleum that contains less than 0.5% sulfur by weight; petroleum containing higher levels of sulfur is defined as sour crude oil. Due to increasingly stringent regulations aimed at reducing sulfur content in distillate fuels (and gasoline), as discussed below, sweet crude oils are highly demanded by petroleum refiners, as they require less processing relative to sour crudes.

12.2.3.1 Introduction of LSD

The regulation of the concentration of sulfur in distillate fuels began on October 1, 1993 (EPA, 2000b). The EPA amended the CAA, Section 211, limiting the concentration of sulfur in motor vehicle (i.e., on-highway) diesel fuel to no more than 0.05% by weight (i.e., 500 parts per million (ppm) sulfur limit)[14]. This amendment to the CAA was made in response to concerns expressed by the heavy-duty (HD) diesel engine manufacturers prior to the March 15, 1985 promulgation of particulate matter (PM) emission standards for HD diesel engines. The engine manufacturers were concerned that sulfur in diesel fuel, which forms sulfates in engine exhaust, could plug aftertreatment devices, which, at the time, were thought to be needed to meet the new PM standards. In addition, sulfur could limit performance of the catalyst and particulate sulfate emissions generated by high-sulfur fuel could make it challenging to meet the standards (Lidderdale, 1993). To ensure that sulfur in diesel fuel would not prevent the engine manufacturers from meeting the standards for 1994 and later model years, CAAA 1990 mandated refiners to reduce the sulfur content in on-highway diesel fuel. The mandate, which did not apply to off-highway diesel fuel and heating oil, required that distillates not meeting the standard be distinguished from low-sulfur diesel (i.e., 500 ppm sulfur limit) through the use of dyes (EPA, 2000a; Lidderdale, 1993). At the time, the low-sulfur diesel fuel (LSD) standard impacted approximately 47% of the DFO sector (refer to Figure 12.13) (EIA, 2008). Figures 12.14 and 12.15 illustrate the introduction of LSD in the DFO sector. By 1994, LSD's share of the sector had increased to nearly 60%; in 2004, LSD comprised over 72% of the DFO supply in the U.S. (EIA, 2009j).

[14] The regulation also required a minimum cetane index of 40 and maximum aromatics content of 35%.

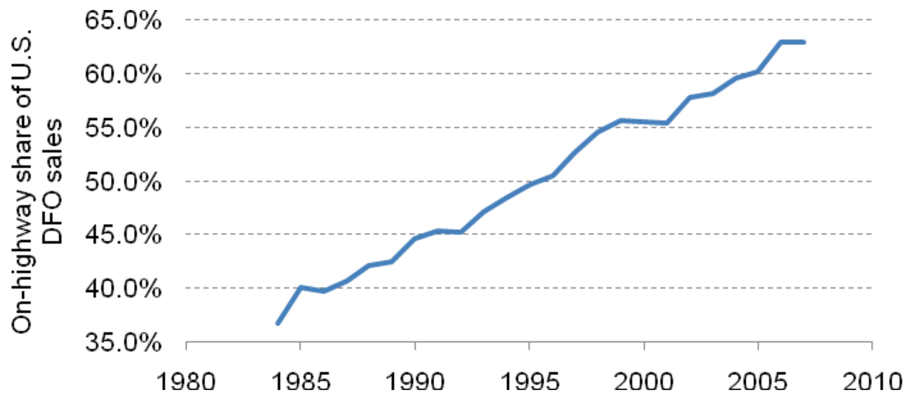


Figure 12.13. The on-highway diesel fuel market has increased its share of the DFO sector by nearly 30% since the 1980s, comprising nearly 65% of the sector in 2007 (EIA, 2008).

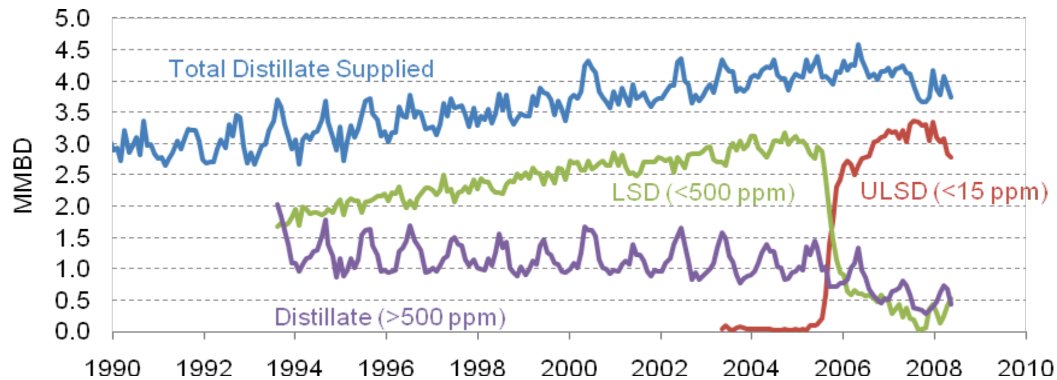


Figure 12.14. The distillate fuel oil (DFO) sector has undergone two transitions, i.e., reductions, in sulfur content (Note: data are monthly averages) (EIA, 2009j).

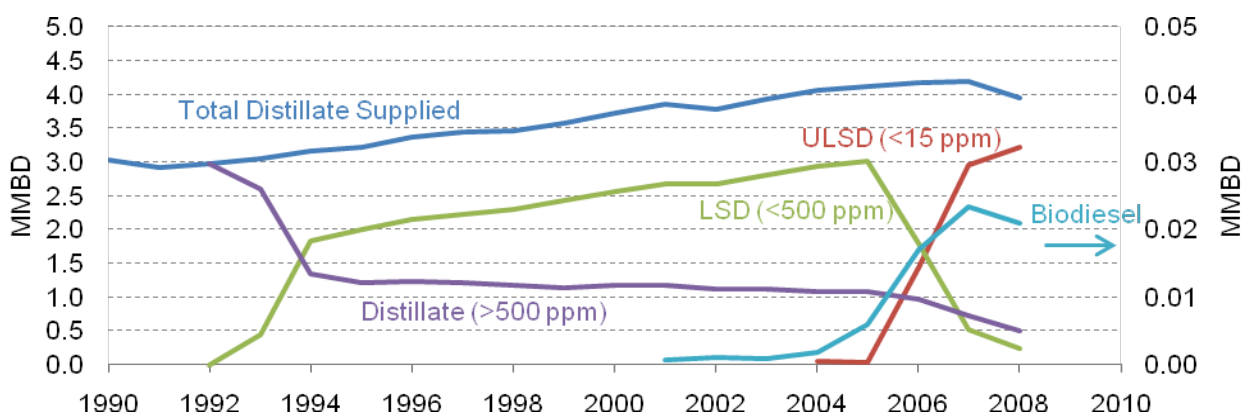


Figure 12.15. The DFO sector has seen little incorporation of renewable fuels. Biodiesel production has increased rapidly in recent years, yet supplies an insignificant share of the DFO sector (Note: data are annual averages) (EIA, 2009d; EIA, 2009j).

12.2.3.2 Transition to ULSD

Just seven years after promulgating the LSD requirement, the EPA released its final rulemaking on HD Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements in December 2000, which, when implemented, would mandate another significant reduction in diesel fuel sulfur content. Once again, the need to limit sulfur in diesel fuel was forced by new emissions standards. The purpose of the HD Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements, otherwise known as the 2007 HD Highway Rule, is to significantly reduce emissions of NOx and PM from HD diesel engines and vehicles that use diesel fuel (EIA, 2001). The EPA intended the rule to be technology forcing—by significantly limiting the primary criteria pollutants from diesel engines (i.e., NOx and PM), advanced emission control devices would become integral components of diesel engine systems (NRC, 2006).

During development of the rule, it was thought that diesel engines would need to be equipped with aftertreatment devices capable of driving PM and NOx emissions below the regulated levels; advances in fuel system and in-cylinder combustion technologies alone were not expected to achieve the deep emission reductions required by the rule. The primary technology proposed for controlling PM emissions was the diesel-particulate filter (DPF). Like the catalytic converters on gasoline-powered engines, which required the elimination of lead from gasoline, DPF performance is impacted by trace elements, including sulfur. Likewise, to control NOx emissions, engine manufacturers were looking to NOx adsorbers, whose catalysts are also rendered ineffective by sulfur. Therefore, to allow the manufacturers to develop and commercialize these emission control technologies, a further reduction in diesel fuel sulfur content was deemed necessary.

Like the lead phase down, the EPA justified the further reduction in sulfur content—to 0.0015% by weight (15 ppm sulfur limit)—based on the second criterion of Section 211(c)(1) of the CAA, which states that the EPA may mandate fuel controls if "the emission products of the fuel will significantly impair emissions control systems in general use or which would be in general use were the fuel control to be adopted." Since sulfur in diesel fuel exhaust "will significantly impair emissions control systems" thought to be necessary to meet the new emission standards, the EPA adopted the ultra-low-sulfur diesel fuel (ULSD) requirement (i.e., maximum 15 ppm sulfur). But, the EPA also justified this ruling on the first criterion, which allows for fuel controls if "the emission products of the fuel cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare." The EPA justified the sulfur reduction based on this criterion based on sulfate emissions contributing to PM pollution (EPA, 2000b).

Originally, the 2007 Highway Rule required refiners and importers to produce ULSD starting June 1, 2006; the new fuel was required to be at terminals by July 15, 2006, and at retailers and wholesalers by September 1, 2006 (EIA, 2001). However, as the ULSD transition approached, the diesel fuel industry raised concerns about their ability to supply ULSD throughout the entire distribution system by the required deadlines. The EPA responded by extending the deadlines for terminals and retailers by 45 days, pushing the implementation dates back to September 1 and October 15, 2006, respectively; some additional transition dates related to sulfur limits were extended as well (EPA, 2008d).

The rule implemented a phase-in option, the "temporary compliance option," allowing refiners and importers to continue to supply up to 20% of the highway diesel fuel market with LSD through May 2010, with the remaining 80% meeting the new ULSD standard. Like the lead phase down, the EPA implemented an averaging, banking, and trading program, through which refineries could receive and trade credits for meeting certain ULSD production levels; the trading program will end in May 2010, coinciding with the conclusion of the aforementioned optional phase-in period. In addition, and once again mimicking the lead phase down, the rule includes hardship provisions for small refiners, defined as refiners with up to 1,500 corporate employees that had a crude oil capacity of 155,000 barrels or less per day in 1999 (EIA, 2001). Each of these flexibility provisions and extensions was put in place to ease the transition to ULSD, which would become a major undertaking for the diesel fuel industry.

Figures 12.14 and 12.15 illustrate the introduction of ULSD in the DFO sector. When the new fuel was introduced, the highway diesel fuel market comprised 63% of the sector, over 15% more than at the time of the LSD introduction (EIA, 2008). By 2007, the first full year that ULSD was in commerce, the fuel comprised 70% of the DFO supply in the U.S., leaving LSD with only a 12% share of the market. The next year, in 2008, ULSD made up 87%, leaving LSD with only 6% of the market (EIA, 2009j). The remainder of the market continues to be supplied with "standard" distillate having no limit on sulfur content. The phase-in option, allowing for 20% of highway diesel fuel to be supplied with LSD through May 2010, was not fully utilized. That is, the transition occurred faster than was required by regulations.

12.2.3.3 Impacts of the Sulfur Reduction Transitions

As with transitions in the motor gasoline sector, the sulfur reduction transitions in the DFO sector had significant ramifications for the refining industry, distribution and retail industry, and engine manufacturers.

The refining industry has several approaches for reducing the sulfur content in diesel fuel. According to the EIA, there exist 4 primary options for producing fuel with lower sulfur (Lidderdale, 1993):

- intensify the operation of new or existing catalytic hydrotreating units;
- increase production of low-sulfur distillates from catalytic hydrocracking units;
- limit diesel fuel blending to low-sulfur internal refinery streams; and
- import low-sulfur diesel.

The most viable options for reducing sulfur are through hydrotreating of distillate fuel or hydrocracking of heavy fuels. Increasing the amount of sulfur to be removed (that is, reducing the allowable concentrations of sulfur in the refined fuel) requires refiners to operate these units under more severe conditions (i.e., increased hydrogen volume, higher pressure and temperature, longer residence time). These intensified operating conditions, in turn, shorten catalyst life and reduce unit capacity. Therefore, desulfurization capacity would need to be increased to produce lower-sulfur fuels at the required volumes.

Prior to the LSD transition, the EIA examined the potential impacts to the refining and distribution industry as a result of the new fuel control mandated by the EPA. Increased capital and operating expenses associated with the production of the new fuel, coupled with increased logistical demands placed on the distribution infrastructure in handling multiple distillate fuels, led the EIA to estimate that LSD would sell for a premium of 3 to 4 cents per gallon over other distillate fuels, namely, heating oil and other high-sulfur distillate fuels. At the time, refineries were producing a single distillate fuel that satisfied the requirements for both diesel fuel and heating oil, since the restrictions on these fuels were so similar. With a new sulfur control applied to on-highway diesel fuel, refiners would be faced with the decision of whether to segregate this new fuel from other distillates. Segregation of fuel streams could reduce capital and operating expenses associated with expanded desulfurization capacity, yet these cost reductions could be more than offset by the increased costs associated with the additional infrastructure needed to handle separate product streams within the refinery. The EIA report suggested that due to these cost burdens, segregation of fuels among different refineries was quite possible. Refiners lacking the resources needed to produce LSD could focus on producing only high-sulfur distillates for the off-highway and heating oil markets, leaving the on-highway LSD market to larger refineries with spare desulfurization capacity and/or greater resources to expand this capacity (Lidderdale, 1993).

Aside from impacts to the refining and distribution industry, the end use segment of the supply chain also experienced impacts from the transition to LSD. Although the engine manufacturers advocated sulfur reductions, which were needed to meet the new PM standards, this modification of diesel fuel did not simply limit sulfur content. The intensified desulfurization processes needed to produce LSD reduced the content of aromatics and other high-molecular weight hydrocarbons. The reduction of these hydrocarbon compounds had two impacts on engine operation. First, these hydrocarbon compounds serve as natural lubricity agents critical to the operation of diesel engine fuel systems (e.g., fuel pumps and injector components). The new LSD, with its reduced content of these lubricating compounds, caused wear issues in diesel engine fuel systems—primarily in fuel pumps. Second, this altered composition of LSD caused fuel system seals to lose their set. When these seals, made with various rubbers and elastomers (e.g., nitrile), are initially exposed to high-sulfur diesel, they swell to a certain set; when these seals are later exposed to LSD, the seal swell will reduce. During the transition to LSD, this characteristic of fuel system seals created widespread cases of leaking fuel pumps. Diesel engines that went into operation following the introduction of LSD did not experience this problem; since the seals were never exposed to the high-sulfur diesel, their set was established with the new fuel. Similar lubricity and seal integrity issues manifested themselves from 1993 to 1994 (G. Adebayo, personal communication with M. O'Donnell, 2007) (John Deere, 2009). Fortunately, the industry anticipated the accompanying reduction in lubricating properties and took the necessary precautions by adding lubrication additives to the finished ULSD product (G. Adebayo, personal communication with M. O'Donnell, 2007). The EPA even included this additional cost burden in their RIA of the 2007 Highway Rule, estimating a cost of 0.2 cents per gallon for lubricity additives in ULSD (EIA, 2001; EPA, 2000b).

Following the issuance of the 2007 Highway Rule final rulemaking, the EIA conducted an analysis of the costs and impacts associated with the transition to ULSD (EIA, 2001). The analysis estimated that refiners would be burdened with new investments ranging from $6.3 to

$9.3 billion through 2011. The study compiled a range of estimates made by various industry groups, agencies, and laboratories. The estimated refinery capital investments ranged anywhere from $3.0 to $13.2 billion (1999 dollars), illustrating the significant uncertainties associated with the costs of this mandated transition[15]. Some of the uncertainties, as identified by the EIA, included:

- rate of development of refinery and pipeline testing technology;
- supply of personnel, thick-walled reactors, and reciprocating compressors (for the expansion of desulfurization capacity);
- behavior of the new fuel in the pipeline infrastructure; and
- cost recovery in the pipeline industry.

The cost estimates mentioned above did not include impacts to the distribution industry. Due to the optional phase-in provision, the distribution industry is responsible for simultaneously handling LSD, ULSD, and high-sulfur distillate fuel through 2010. This flexibility provision, although helpful to some refiners, places a burden on the distribution industry. Capital investments in infrastructure and additional operating costs would be needed to handle multiple products. In addition, the distribution industry had expressed concerns about contamination of ULSD with higher-sulfur distillates resulting in significant volumes of ULSD being downgraded to a higher-sulfur fuel (with lower market value).

Despite these burdens placed on the refining, distribution, and retail industry, the on-highway ULSD fuel transition seems to have been a success with minimal, isolated instances of supply disruptions and price aberrations (Jenson, 2006; Nguyen, 2006). By October 2006, an EIA senior analyst explained, "Our understanding is that the transition is essentially complete (Nguyen, 2006)." Relative to 2005 prices, the national average (retail) diesel price did not exhibit any noteworthy increases during 2006 when the EPA deadlines associated with the ULSD transition were reached (see Figure 12.16). Again, these national average prices may conceal evidence of localized price volatility.

The ULSD transition occurred during the same time frame as the transition from MTBE to ethanol in motor gasoline. ***The fuel industry successfully managed two major fuel transitions more or less simultaneously in the two largest markets of the U.S. liquid fuels sector.***

[15] The EPA estimated that the refining industry would face $5.3 billion in capital investments in the 2007 Highway Rule RIA. Due to the rule's focus on diesel engine emissions reductions, and not simply diesel fuel sulfur control, a detailed review of the RIA and cost-benefit analysis is not provided. The 2007 Highway Rule RIA can be downloaded from the following EPA webpage: http://www.epa.gov/otaq/highway-diesel/regs/2007-heavy-duty-highway.htm

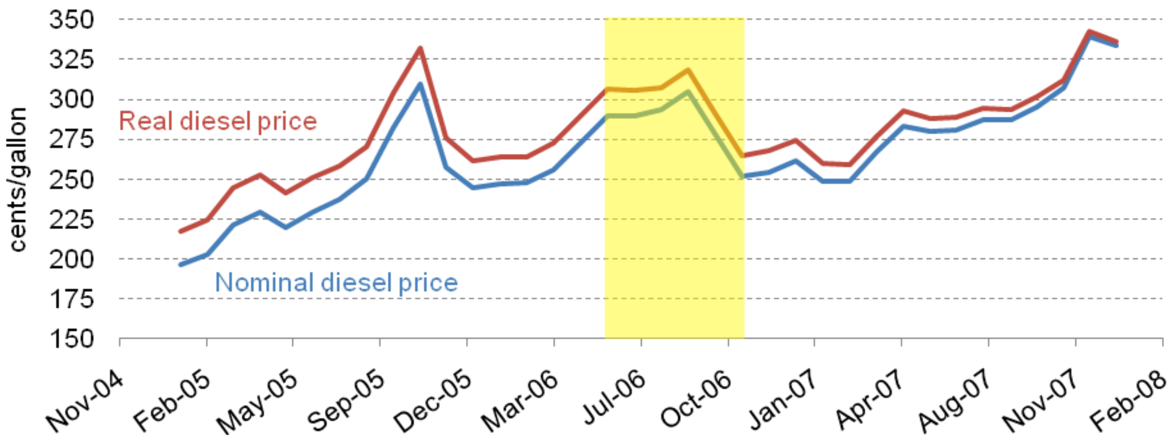


Figure 12.16. National average retail diesel prices (real and nominal) during the ULSD transition (shaded box) followed a slightly longer seasonal increase than the prior year (EIA, 2009e).

For the fledgling biodiesel industry, the introduction of ULSD was embraced as a marketing opportunity. Although the biodiesel industry had been growing rapidly, it was supplying a rather insignificant share of the DFO sector. Prior to the ULSD transition, in 2005, the biodiesel industry's share of the DFO sector stood at less than one-quarter of one percent (see Figure 12.15). Due to the reduced lubricity in ULSD, and corresponding need to recover the lubricity with additives, the biodiesel industry attempted to push its product as a solution to this problem. According to results compiled by the National Biodiesel Board (NBB), low-level blends of biodiesel can significantly improve the lubricity of diesel fuels. Blending low-sulfur diesel fuels with as little as 2% biodiesel restores the lubricating properties exhibited by higher-sulfur diesels (NBB, 2002). Although the industry may have benefited from this new market opportunity, the industry continues to supply a small share of the DFO sector.

As a result of the diesel fuel sulfur reductions (and gasoline sulfur restrictions), the sulfur production capacity of U.S. refineries has expanded significantly over the last two decades. Figure 12.17 shows the annual sulfur production capacity of U.S. refineries in 1,000 short tons per day. This byproduct of the refining industry has impacted traditional sulfur markets. In 2000, it was reported that the last domestic Frasch sulfur mine closed, ending discretionary sulfur production in the U.S. As a result, domestic users of sulfur (e.g., fertilizer production) now rely on the production of recovered elemental sulfur from petroleum refineries. While the cause and effect of DFO desulfurization and mine closures is difficult to establish analytically, it is worth noting that similar trend has occurred globally, as other nations and regions have placed similar limits on sulfur content in liquid fuels (USGS, 2001).

Depending solely on byproduct sulfur, rather than direct sulfur sources (i.e., mining), can add volatility to the sulfur market. Disruptions to refining activities can ultimately limit sulfur availability. For example, in 2005, total U.S. sulfur production was down 5% from the previous year due to the active hurricane season in the Gulf Coast regions, which resulted in major refinery shutdowns (USGS, 2006). Therefore, if petroleum products demand were to be significantly reduced in the future, through increased use of alternative fuels, for example, the sulfur industry may need to return to traditional reserves (i.e., mined sulfur) to maintain supplies.

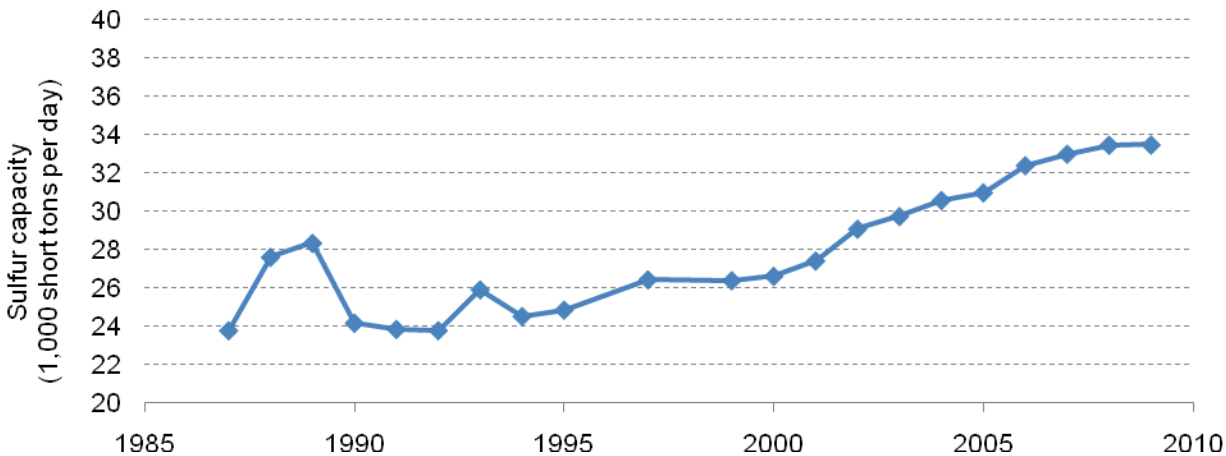


Figure 12.17. U.S. refinery sulfur production capacity has increased due to fuel sulfur content restrictions (EIA, 2009f).

12.2.4 Implications of Transitions

A concise summary of major transitions in the U.S. liquid fuels sector is presented in Tables 12.5 and 12.6. Transitions in the motor gasoline and DFO sectors are summarized according to their time frame (and approximate duration), key drivers and regulations, and impacts to the fuel supply chain infrastructure. The infrastructure changes in each segment of the fuel supply chain are differentiated according to major (M), minor (m), and negligible (-) impacts. The motor gasoline sector includes the transition from leaded to unleaded gasoline, the use of high octane hydrocarbons in gasoline, the mandated use of oxygenate additives in gasoline, the transition from MTBE to ethanol as the predominant oxygenate additive in gasoline, and the ongoing growth of ethanol as a direct substitute for crude-based gasoline. The DFO sector includes the two reductions in sulfur content in diesel fuel: the introduction of LSD, and the introduction of and transition to ULSD.

Defining the time frame and duration of a given transition is not so straight forward. Since many of these transitions involve a growth phase, or market penetration, followed by a phase down, or market reduction/elimination, the definition of the transition duration is debatable. For example, the introduction of oxygenate additives in gasoline covers the significantly expanded use of oxygenates due to state and federal mandates on gasoline composition. Oxygenates were being used as early as the 1960s; they continue to be used today. Yet the time frame for this transition is defined here as the late 1980s through 2006. The expanded use of oxygenates, through mandates, did not begin until the late 1980s when some states implemented wintertime oxygenated fuels programs. The majority of mandated use of oxygenates ended in 2006 when the EPA amended the CAA to eliminate the oxygenate requirement from the RFG program. Oxygenates are still used in RFG, but are no longer mandated; the continued use of ethanol in RFG is a strategic decision made by gasoline suppliers. The Oxyfuel program is still implemented in some areas, but its extent has diminished significantly since being established on a federal level in 1992. Overall, the expanded use of oxygenates to satisfy gasoline composition requirements is defined in this thesis as spanning approximately two decades from the late 1980s to the late 2000s. However, the transition time to introduce oxygenates was much shorter, but is difficult to define.

Although the issue of infrastructure implications is more complicated than simple indications of the supply chain segments impacted by a given transition, Tables 12.5 and 12.6 succinctly illustrate the range of segments impacted by transitions. For example, the burden of using high-octane hydrocarbons to recover octane rating in gasoline was isolated to the refining industry. Crude-oil production, distribution, retail, and end use were not directly affected by this fuel modification implemented by refiners. On the other hand, the expanded use of ethanol as a substitute for crude-based gasoline is impacting all segments of the gasoline supply chain: feedstock production shifts from crude oil to biomass (e.g., corn); fuel production shifts from oil refineries to biorefineries (e.g., corn distilleries); distribution is limited to the aforementioned "virtual pipeline;" retailers are responsible for handling a new product with associated material compatibility issues; and as higher blends of ethanol are incorporated into gasoline (e.g., E85), alternative technologies are required in motor gasoline-powered vehicles (i.e., flex-fuel vehicles). Though the simple 'X' indications in the table summaries do not provide detailed insights into infrastructure impacts, they do indicate the reach of a given transition's impacts throughout the supply chain.

These historical transitions represent the uncertainty and diversity of future transition pathways in the liquid fuels sector (e.g., a transition to biofuels), and raise the following questions when looking forward:

- What are the key takeaways and lessons learned from these case studies?
- Are there any generalizable trends or patterns that emerge from these transitions?
- As we look to the future in this sector, with new regulations that mandate the increased use of renewable fuels, what might we expect, or how can we better anticipate the varied implications of this ongoing biofuels transition?
- How can we apply lessons and experiences from past transitions moving forward?
- How do these findings help to identify barriers that may exist in current policies, market conditions (i.e., economic factors), the structure of today's industries, or the state of technology, etc, which could impede a transition to biofuels?

Table 12.5. Transitions in the motor gasoline sector are characterized by their timing, drivers, and infrastructure implications. Infrastructure changes are differentiated by major (M), minor (m), and negligible (-) impacts..

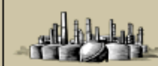
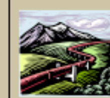
Sector	Transition	Time Period; Duration	Drivers; Regulations	Infrastructure Implications				
				Production 	Refining 	Distribution 	Retail 	End use 
Motor Gasoline	Leaded to Unleaded Gasoline	1974 ~ 1995 ~20 years	Policy; Lead additives impair catalytic converters, Toxicity; CAA 1970, CAAA 1990	-	m	m	M	M
	High Octane Hydrocarbons (Butane, Aromatics) in Gasoline	1980 ~ 1990 (span) 1~2 years	Market and Policy Initially used by refiners to recover octane in gasoline; Volatility regulations and RFG program put in place; State programs, CAAA 1990	-	m	-	-	-
	Oxygenates in Gasoline	1980s ~ 2006 (variable)	Market and Policy; Initially used by refiners to boost octane in unleaded; RFG and Oxygenated Fuels Programs; State programs, CAAA 1990	m	m	m	-	-
	MTBE to Ethanol as Gasoline Oxygenate	1999 ~ 2006 <10 years	Policy and Legal; MTBE use leads to drinking water contamination; State bans on MTBE, Refiner liability concerns	M	M	m	-	-
	Ethanol as a Gasoline Substitute (≤ E10)	1980s ~ 2010 20~30 years	Policy (and Market); Renewable Fuel Standard Program; EPAct 2005, EISA 2007	M	M	M	-	-
	Ethanol as a Gasoline Substitute (≥ E10)	2010 ~ ? >20 years (?)	Policy (and Market?); Renewable Fuel Standard Program; EISA 2007	M	M	M	M	M

Table 12.6. Transitions in the DFO sector are characterized by their timing, drivers, and infrastructure implications. Infrastructure changes are differentiated by major (M), minor (m), and negligible (-) impacts.

Sector	Transition	Time Period; Duration	Drivers; Regulations	Infrastructure Implications				
				Production 	Refining 	Distribution 	Retail 	End use 
Distillate Fuel Oil (DFO)	Low-Sulfur Diesel (<500ppm)	1993~ 1994 ~2 years intro 1993~2006 >10 years total	Policy; PM standards require fuel sulfur reduction; CAAA 1990		m	m	-	m
	Ultra-Low-Sulfur Diesel (<15ppm)	2006~2007 ~ 1 year	Policy; PM and NOx standards; Sulfur impairs diesel emission control devices; Sulfate emissions contribute to PM; 2007 HD Highway Rule (CAA)		m	m	-	m

Table 12.7 The duration of fuel transitions has varied with the extent of infrastructure implications. Infrastructure changes are differentiated by major (M), minor (m), and negligible (-) impacts. Transitions are ordered (approximately) from shortest to longest duration. Refer to Tables 2-5 and 2-6 for a listing of the drivers and regulations of transitions.

Sector	Transition	Time Period; Duration	Infrastructure Implications				
			Production 	Refining 	Distribution 	Retail 	End use 
Motor Gasoline	High Octane Hydrocarbons (Butane, Aromatics) in Gasoline	1980 ~ 1990 (span) 1~2 years (?)	-	m	-	-	-
DFO	Ultra-Low-Sulfur Diesel (<15ppm)	2006~2007 ~1 year	-	m	m	-	m
DFO	Low-Sulfur Diesel (<500ppm)	1993~ 1995 ~2 years	-	m	m	-	m
Motor Gasoline	Oxygenates in Gasoline	1980s ~ 2006 (variable)	m	m	m	-	-
Motor Gasoline	MTBE to Ethanol as Gasoline Oxygenate	1999 ~ 2006 <10 years	M	M	m	-	-
Motor Gasoline	Leaded to Unleaded Gasoline	1974 ~ 1995 ~20 years	-	m	m	M	M
Motor Gasoline	Ethanol as a Gasoline Substitute (≤ E10)	1980s ~ 2010 20~30 years	M	M	M	-	-
Motor Gasoline	Ethanol as a Gasoline Substitute (≥ E10)	2010 ~ ? >20 years (?)	M	M	M	M	M

As an example, Sperling and Dill provided several explanations for the successful transition to unleaded gasoline, which can be summarized as follows (Sperling and Dill, 1988):

- New technologies are bound to experience problems out of the gate, yet new fuels and vehicles must exhibit high levels of quality.
- Government must be certain it can enforce standards. If a large number of players are involved in a particular segment of the market, the ability to enforce standards is diminished. Misfueling was identified as the major failing of the transition to unleaded gasoline, and can be attributed to the inability to monitor the large number of vehicle owners.
- Widespread support. The national commitment to air quality improvements during the 1970s bolstered the adoption of unleaded gasoline.
- Concentration of authority and responsibility in one organization allows for the effective development of strategies and coordination of activities. In the transition to unleaded gasoline, the EPA was the federal agency coordinating the promulgation of rules and regulations affecting all sectors of the industry.
- Reduction of uncertainty and risk in the marketplace allows for a stable environment for investment and participation by industry and consumers. Cooperation between government and industry to standardize technologies, use incentives and mandates to encourage fuel production, and follow established timetables all contributed to the successful transition to unleaded gasoline.

As mentioned at the beginning of this chapter, Sperling and Dill suggested that the government-coordinated transition to unleaded gasoline serves as a “model for the United States and other countries for the introduction of nonpetroleum fuels.” They further suggested that the transition “faced the same type of obstacles as would any other new fuel, dissimilar to petroleum, such as alcohols, gaseous hydrocarbons, and hydrogen.” On the other hand, none of the major transitions that have occurred in the liquid fuels sector, as summarized in Tables 12.5 and 12.6, have involved a fuel substitution, or interfuel substitution. Stated alternatively, it can be argued that these transitions have been nothing more than fuel modifications of the same base fuels (i.e., crude-based gasoline and distillates) used predominantly to power the same base engine technologies (i.e., spark- and compression-ignition internal combustion engines). Interestingly, in a book published the same year as Sperling and Dill’s aforementioned journal article on the unleaded gasoline transition, Sperling seems to concur with this alternative view (Sperling, 1988):

> [I]nterfuel substitution has in fact resulted in substantial reductions in petroleum consumption in industrial, residential, commercial, and electric utility activities. Coal, natural gas, nuclear power, and more decentralized sources such as solar heat, wind power, geothermal energy, and small hydroelectric plants have supplanted petroleum in many activities, but not in transportation. In the transportation sector there has been practically no interfuel substitution (p. 19).

Each transition in a given sector (e.g., motor gasoline) has resulted in an incremental change of the same technology or base fuel. Therefore, the transitions that have occurred in these sectors (i.e., motor gasoline or DFO) could be viewed as a continuum of change, or ongoing evolution, of a given technological system.

Exceptions to this fuel modification viewpoint could be the introduction of oxygenate additives in gasoline and the transition from MTBE to ethanol that ensued. MTBE, derived from natural gas and petroleum, allowed for a portion of the motor gasoline feedstock supply to shift from petroleum to natural gas. Ethanol, derived mostly from corn starch, allows for a shift from petroleum to agricultural commodities (and their associated inputs). For these oxygenate transitions, the feedstock shifts have been minimal at best. Moving forward, as greater volumes of biofuels are incorporated into the liquid fuels sectors, this shift away from petroleum feedstocks could become substantial, edging towards a true fuel substitution. As will be shown in later in this Task report, this shift is already resulting in a reduction in crude-based gasoline in the motor gasoline sector (i.e., "peak gasoline") (Gold and Campoy, 2009).

This dearth of fuel substitutions should not nullify the lessons and findings from historical transitions in the sector. The liquid fuels sector is comprised of a well-established network of industries and accompanying infrastructures, supported by and integrated with regulations, practices, and institutions. A transition to biofuels in the liquid fuels sector will not occur independently or in isolation from this system. Understanding how previous transitions progressed and altered this established sector is critical to understand future transitions. But, acknowledging the limitations of such an analysis is just as important when considering the implications of an interfuel substitution in the liquid fuels sector.

The following key lessons were derived from the review of historical transitions in the U.S. liquid fuels sector:

- transitions are common;
- transitions have variable infrastructure implications;
- transitions exhibit variable time scales;
- transitions are better understood through an integrated view of vehicles and fuels;
- transitions are analyzed differently when system boundaries are expanded and expansion of boundaries to a full life cycle can prevent unintended consequences

These lessons are discussed below.

12.2.4.1 Transitions are common

Dynamic technological systems (e.g., the transportation sector) commonly undergo change (Grubler, 1990; Grubler, 2003; Marchetti and Nakicenovic, 1979). The liquid fuels sector, a complex technological system, is continually changing in response to new economic, regulatory, or technological conditions. Reviewing major transitions in the motor gasoline and DFO sectors, shows that change is common.

Moving forward, energy security and climate change might serve as drivers to the adoption of alternatives to petroleum-derived liquid fuels, such as biofuels. Although society cannot fully predict the outcomes of a transition to biofuels, the path forward may be better navigated through an enhanced understanding of historical transitions. In this respect, the historical record implies that key corporations in the existing liquid fuel infrastructure must make important contributions to any substantial change. Thus, it is not surprising that many of these companies are leading a possible future increase in the use of biofuels.

12.2.4.2 Transitions have variable infrastructure implications

Tables 12.5 and 12.6 summarize the extent of infrastructure implications associated with fuel transitions in the motor gasoline and DFO sectors, respectively. For each segment of the fuel supply chain, changes to the infrastructure are differentiated by major (M), minor (m), and negligible (-) impacts. Although infrastructure impacts cannot be fully represented with these simple, qualitative indications, they do allow for quick comparisons of fuel transitions according to the number of segments impacted, and the extent of those impacts.

For example, the burden of using high-octane hydrocarbons to recover octane rating in gasoline was isolated to the refining industry. Crude-oil production, distribution, retail, and end use were not directly affected by this fuel modification implemented by refiners. Since the fuel modifications did not require an expansion of fuel refining capacity, the impact to refining is categorized as minor (m). On the other hand, the transition to ethanol as a gasoline substitute (≤ E10) has had major impacts on several segments of the fuel supply chain. Ethanol, being produced primarily from grain corn, has shifted a portion of motor gasoline feedstock away from crude oil. Fuel production capacity has expanded with the construction of ethanol production facilities, i.e. corn distilleries. The distribution of ethanol has relied on the development of a "virtual pipeline," comprised of rail, barge, and truck distribution networks. The impacts to each of these segments (production, refining, and distribution) are considered to be major (M). However, ethanol is still consumed primarily in the form of low-level blends (≤ E10). Therefore, impacts to the retail and end use segments have been negligible (-).

Table 12.7 presents the same information as Tables 12.5 and 12.6, but orders the transitions according to approximate durations, from shortest to longest. Interestingly, the durations align well with the number of segments impacted in the fuel supply chain infrastructure, and the extent of those impacts (i.e., major, minor, or negligible). The variability of time scales exhibited by transitions is discussed further in the next section.

12.2.4.3 Transitions exhibit variable time scales

The time periods listed in Tables 12.5 and 12.6 illustrate the variability in time scales of transitions. The transition to unleaded gasoline took approximately 20 years, with lead additives finally being eliminated from on-highway gasoline in 1995. At the other end of the spectrum, the introduction of ULSD, and even the initial introduction of LSD, took approximately one year. The transition duration for LSD is listed as greater than 10 years in Table 12.6 to encompass the introduction of LSD through to the subsequent replacement of LSD by ULSD.

The transition to unleaded gasoline had major implications throughout the supply chain, and was one of the first major transitions in the motor gasoline sector. Refiners needed to alter operations to recover the octane that had been provided by lead additives. During the transition, when both leaded and unleaded gasolines were available, the distribution and retail network had to adapt to supply multiple fuels. Vehicle manufacturers altered engine designs with lower compression ratios due to the anticipated reduction in octane rating of gasoline. The transition impacted the entire motor gasoline supply, not just specific segments, as seen with the use of oxygenate additives in gasoline. Oxygenate additives were used in the formulation of RFG and wintertime oxyfuel. These fuels were (and are still) supplied to specific geographic locations, and overwhelmingly to large demand centers, like the Northeast states and California. It has been argued that the transition to unleaded gasoline in the U.S. could have occurred at a more accelerated pace (Borenstein, 1993; Hammar and Lofgren, 2004). Many nations, particularly in the EU, completed the transition to unleaded gasoline in less than a decade (Hammar and Lofgren, 2004).

On the other hand, the sulfur reduction transitions in the DFO sector occurred rapidly. These transitions impacted a majority of the DFO sector: LSD comprised over 72% of the DFO supply at its peak in 2004, while ULSD made up 87% of the supply in 2008. With the reduction of sulfur, no major performance-enhancing properties of the fuel were altered (e.g., cetane). This factor stands in sharp contrast to the important role that lead additives played in the gasoline market (i.e., to boost octane). Refiners were required to reduce sulfur content, but did not need to recover any critical combustion-performance properties. When the market realized that the desulfurization processes reduced the content of aromatics and higher-molecular weight hydrocarbons, small quantities of lubricity additives were simply added to the fuel to recover the lubricating properties of these hydrocarbon compounds. In the case of the ULSD transition, the distribution and retail network had expressed concerns about the 80/20 phase-in option, allowing ULSD and LSD to coexist in the market through 2010. By accelerating the phase-in of ULSD, and accompanying phase-out of LSD, the market has limited the impacts of handling multiple products. If the refiners are capable of producing enough of the new fuel (i.e., ULSD), the distribution and retail industry faces fewer obstacles and will more efficiently deliver the new fuel to the consumer. The overall size of the DFO sector may have played a role in the rate of these sulfur transitions as well. The DFO sector is less than one half the size of the motor gasoline sector: in 2008, an average of approximately 9 MMBD of motor gasoline was consumed, compared to approximately 4 MMBD of distillates. Even during the transition to unleaded gasoline, the size of the motor gasoline sector grew from approximately 6.5 to 7.5 MMBD.

The ethanol industry has grown at a rapid rate over the last decade as demand for this alcohol has been driven by several factors, namely, the biofuels mandates, tax credits, and elimination of MTBE from the gasoline supply. The future growth of this industry could be dependent upon a number of limiting factors. From the production side, previous transitions in the liquid fuels sector provide little insight.

These transitions did not result in significant shifts away from petroleum feedstocks. The production of ethanol, and other biofuels, will constitute such a shift. The magnitude of the shift is limited by the availability of biomass feedstocks. Previous transitions have not been hampered by overall limits in fuel production capacity, only in the capacity of specific processes within refineries. For example, during the sulfur reduction transitions, refineries were not limited by overall fuel production capacity, but rather by the capacity of desulfurization units in the existing refining capacity. The growth in biofuels production capacity, however, is not simply limited by how quickly plants can be built and commissioned, but by the development of new technologies.

Moreover, the biofuels mandates require that specific types of biofuels be produced, e.g., cellulosic ethanol, even as the technologies have yet to be fully developed on a commercial scale nor demonstrated in the market as the most appropriate solution. Therefore, the production aspect will be limited by both technology development and capacity growth and exacerbated by the risk that other emerging technologies may be the ultimate commercial choices.

It is likely that the distribution and retail network will also need to adapt. Currently, ethanol is not moved through the vast petroleum pipeline infrastructure due to ethanol's affinity for water and associated corrosive characteristics. As mentioned earlier, the distribution industry has expanded and optimized the use of existing train, barge, and trucking systems to develop a "virtual pipeline" for moving ethanol (RFA, 2006a). The efficacy of this virtual pipeline to distribute ethanol to the motor gasoline market could be diminished as the volume of ethanol expands in the coming years. Some pipeline operators are looking to adapt. For example, Kinder Morgan is shipping commercial volumes of ethanol through revamped pipelines in Florida (Anon, 2008; Meinhardt, J., 2008), and announced plans to distribute biodiesel blends through pipelines in the Southeast states (Williams, 2009). Magellan Midstream Partners and POET Energy are conducting a feasibility study of building a dedicated ethanol pipeline extending from South Dakota through the major ethanol producing regions of the corn belt, and finally to the Northeast states for delivery (POET, 2009).

At the retail level, most conventional and reformulated gasoline is currently blended with up to 10% ethanol, but, as the mandated volumes increase, retailers will be required to move greater volumes of ethanol. Currently, the only option available to retailers, other than E10, is E85. The rate at which retailers expand their offering of E85 will be a major limiting factor to the growth of ethanol as a gasoline substitute, and therefore might limit the transition[16].

Finally, the end use segment provides challenges as well. With the need to expand E85 offerings at the retail level, retailers will need a market for this fuel. To safely use this fuel without causing engine damage, consumers must own a flex-fuel vehicle (FFV). The fleet of FFVs must grow rapidly in order to consume the growing volumes of higher ethanol blends that must be pushed through the market to meet the mandates. Each of these factors throughout the fuel supply chain could influence the rate at which the ethanol industry expands.

This discussion, although focused on ethanol, illustrates that the characteristics of a particular biofuel influences the rate at which the fuel could penetrate the liquid fuels sector. The time scale of a biofuels transition will be influenced by a number of factors, and is dependent on the types of biofuels that are produced in the future.

12.2.4.4 Integrated view of vehicles and fuels

These historical transitions highlight the importance of developing an integrated view of vehicles and fuels. When considering the impacts of fuel transitions, those that impact the end use segment (i.e., vehicles) are at a significant disadvantage compared to those that can be

[16] As will be discussed in chapter 4, the nation's motor gasoline pool could reach a 10% limit in the next few years, requiring any increased consumption of ethanol to come in the form of E85.

introduced with minimal impact to the existing fleet of vehicles. A fuel transition requiring changes in the existing fleet can significantly impact transition duration because fleet turnover typically takes 15 years or more (Greene and Schafer, 2003). For example, a transition to hydrogen in the LDV fleet, which requires new energy conversion devices such as fuel cells along with on-board reforming and/or storage system, would undoubtedly require substantial time due to the need for fleet turnover (NRC, 2004). As mentioned previously, a transition to ethanol is not immune from this problem. In order to consume high blends of ethanol, FFV technology is necessary. Even if the technology does not incur significant costs relative to conventional vehicles, the fundamental barrier of fleet turnover still exists.

Viewing fuels and vehicles as a single technological system has been important to recent emissions reductions in the transportation sector. Prior to the implementation of the RFG program, vehicle manufacturers and oil companies jointly invested in a research program designed to quantify the emission impacts of changes in the formulation of gasoline. This joint research program, the Auto/Oil Air Quality Improvement Research Program (AQIRP), concluded that significant emission benefits were readily achievable (technologically and economically) through reformulated gasoline (EPA, 1995a; NRC, 1999). The program "sought to identify those fuels and formulations that could be most effective in reducing ozone precursors without compromising drivability or substantially increasing the cost (per gasoline or diesel equivalent range) of driving (NRC, 1999)." By viewing the fuel as a critical component of a single technological system, the fuel introduces new variables in the design of the overall operation of the system, allowing for new approaches to the reduction of emissions. Perhaps more important, the AQIRP sought solutions that would have minimal impacts to performance and cost.

This principle was carried forward when the 2007 Highway Rule was crafted to reduce NOx and PM emissions from HD diesel engines. With limits on sulfur content in diesel fuel, PM emissions are directly reduced, and the integration of aftertreatment devices into the overall engine system design—allowing for further reductions in PM and NOx—is enabled. Integrating the fuel into the overall system design allowed for a wider range of technological solutions to emissions challenges.

If the AQIRP principle is applied to the new challenges of mitigating climate change and improving energy security, rather than reducing criteria air pollutants, then a new research program would "seek to identify those fuels and formulations that could be most effective in reducing *lifecycle emissions* without compromising drivability or substantially increasing the cost (per gasoline or diesel equivalent range) of driving." As an added benefit, when the fuel is viewed together with the vehicle, impacts to the distribution and retail infrastructure are likely to be minimized. This principle assumes that solutions to the challenges of climate change and energy security exist within the current transportation paradigm, i.e., liquid fuels powering IC engines. While the solution to these new challenges might require a new paradigm, history shows that changes within the existing infrastructure, if possible, are likely to be quicker and more affordable than multi-decade infrastructure conversions across the end-to-end fuels system.

12.2.4.5 System boundaries and unintended consequences

The analysis of historical events is influenced by temporal, spatial, and sectoral boundaries, and if those boundaries are not chosen appropriately, unintended consequences can result, as illustrated by analyses of MTBE. For example, the potential for water contamination was not adequately considered as MTBE became a dominant fuel component. Analyzing potential technologies through a systematic lifecycle perspective has the potential to limit the occurrence and severity of unintended consequences. With this approach, the potential for shifting problems, whether through energy, economic, societal, or environmental costs, is limited.

Lifecycle assessment (LCA), while still evolving as a standard methodology, is a critical component in the evaluation of alternative fuels. Biofuels must meet specific lifecycle GHG reduction thresholds in order to qualify for the RFS program. This regulation serves as the nation's initial attempt to enforce LCA standards on any type of product or service (EPA, 2009a; EPA, 2009c). By comparing alternative fuels to conventional fuels on a lifecycle basis, the regulation aims to prevent the adoption of new fuels that have higher GHG emissions over the lifecycle of the fuel. With previous fuel-use regulations, which focused on specific criteria air pollutants (e.g., NOx, CO) at the end-use, the question of lifecycle emissions did not come into play. In the case of GHG emissions, the impacts are global; the source of emissions is irrelevant and accounting of emissions must take place throughout the fuel supply chain.

12.3 Biofuel Market Penetration

12.3.1 Introduction

Biofuels are being adopted in greater volumes in the U.S. liquid fuels sector; future volumes of adoption and the forms that those adoptions take will be influenced by many factors. Policies adopted at the federal and state levels, and by corporations and institutions, will play a major role in a transition to biofuels. The Renewable Fuels Standard (RFS) program has played has contributed to the recent growth in the favored segments of the biofuels sector. Table 12.8 summarizes the volume mandates of the RFS program as established by the Energy Independence and Security Act (EISA) of 2007. This program stands as a key driver in a transition to biofuels in the near term. By mandating annual consumption of biofuels, increasing to 36 billion gallons per year (bgy) in 2022, the program has the potential to alter the state of the U.S. liquid fuels sector.

Table 12.8. The RFS2 mandates annual consumption of biofuels through 2022 (EPA, 2009a; EPA, 2009c).

Year	Cellulosic Biofuel	Biomass-Based Diesel	Total Advanced Biofuel	Total Renewable Fuel
2009	0.00	0.50	0.60	11.10
2010	0.10	0.65	0.95	12.95
2011	0.25	0.80	1.35	13.95
2012	0.50	1.00	2.00	15.20
2013	1.00		2.75	16.55
2014	1.75		3.75	18.15
2015	3.00		5.50	20.50
2016	4.25		7.25	22.25
2017	5.50		9.00	24.00
2018	7.00		11.00	26.00
2019	8.50		13.00	28.00
2020	10.50		15.00	30.00
2021	13.50		18.00	33.00
2022	16.00		21.00	36.00

With the context of the RFS program as the key driver in a transition to biofuels in the liquid fuels sector, this Section examines multiple scenarios that help illustrate the range of futures and the uncertainty that exists in assessing such a transition. These scenarios also identify barriers that could hinder the market penetration of biofuels. The analysis will focus on fuel-specific issues; issues related to feedstocks are discussed elsewhere in this report.

As the RFS program mandates greater volumes of biofuels, there is substantial uncertainty facing the liquid fuels sector as to how such a transition will unfold. Ethanol derived from grain corn overwhelmingly dominates the biofuels sector today. Moving forward, the mix of biofuels being produced and consumed could change substantially. Different fuels have different implications as they penetrate the market. Therefore, understanding the barriers associated with the introduction of different fuels and fuel blends is critical. As illustrated by the review of historical fuel transitions in the previous Section, each new fuel requires different changes along segments of the fuel supply chain. This analysis identifies barriers that face a biofuels transition, including challenges that are unique to different types of biofuels. Since ethanol is currently the dominant biofuel in the U.S. today, and is poised to maintain this dominant role moving forward, substantial attention will be given to barriers facing the continued transition to ethanol in the motor gasoline sector.

A set of first-order projections, or scenarios, of the liquid fuels sector was developed using a model of the sector—the Liquid Fuels Transition (LiFTrans) model. Each scenario is based on the RFS mandate and is thus limited to the timeframe of the mandate, extending no further than 2022. They illustrate different pathways to meeting the requirements of the RFS mandate, producing no more or less than the mandated volumes. These scenarios differ based on the overall demand of liquid fuels, how the biofuels mandate is met (i.e., fuel mix), and other important factors such as ethanol blend limit. The scenarios serve as a starting point for evaluating the associated infrastructure implications for different fuels and penetration rates.

Before introducing the LiFTrans model, projections made by the Energy Information Administration (EIA) will be reviewed. The Annual Energy Outlook (AEO) 2009 projections of the motor gasoline and DFO sectors are presented. The updated 2009 reference case is presented first, followed by a brief review of alternative cases, which are based on differing assumptions related to economic growth and world oil prices. These projections serve as an input to the LiFTrans model, which will be used to generate a series of transition scenarios.

4.3.2 AEO projections

Each year, the EIA produces the AEO, a report detailing the agency's outlook on energy markets in the U.S. extending several decades into the future (e.g. AEO 2009 assesses energy markets through 2030). The National Energy Modeling System (NEMS) is the general equilibrium model used by EIA analysts to produce the quantitative projections presented in the AEO reports each year. The AEO includes projections of all sectors of the U.S. energy market, including the liquid fuels and transportation sectors. Table 11 of the AEO report, Liquid Fuels Supply and Disposition, serves as the input data for the charts presented below. The Liquid Fuels Supply and Disposition table includes data on annual volumes of liquid fuels consumed through 2030 in million barrels per day (MMBD). Several sets of data from this AEO data table are used as inputs.

12.3.2.1 AEO stimulus case

The reference case projection from the most recent AEO report, released in April 2009, referred to here as the "stimulus" case, was published following the initial release of AEO 2009 in order to reflect the provisions of the American Recovery and Reinvestment Act (ARRA) implemented in mid-February 2009 (EIA, 2009k). The initial publication of AEO 2009 in March 2009 was based on laws and regulation in place as of November 2008. Therefore, the stimulus case includes several important energy-related provisions that could affect energy markets and the overall macroeconomic outlook for the U.S. Some energy-specific provisions of the ARRA that were implemented in the modeling of the stimulus case that could impact the liquid fuels sector include the plug-in hybrid vehicle tax credit, electric vehicle tax credit, and loan guarantees for biofuels projects. In addition, the stimulus case includes updates to the Corporate Average Fuel Economy (CAFE) standards proposed by the National Highway Traffic Safety Administration (NHTSA) for light-duty vehicles (LDVs) through 2015. The EIA assumed that the standards would increase to 35 mpg on average in 2020, and remain constant thereafter.

Using the stimulus case, projections of the motor gasoline and DFO sectors through 2030 are presented and discussed below.

12.3.2.1.1 Motor Gasoline

The motor gasoline projection includes consumption of total motor gasoline, crude-based gasoline, total ethanol, and ethanol-gasoline blends through 2030. Data are taken from the Liquid Fuels Supply and Disposition table of the stimulus case, or Updated AEO2009 Reference Case Service Report (EIA, 2009c, Table 11). Figure 12.18 presents the motor gasoline projection from 2005 through 2030. Figure 12.19 presents the same data with historical data from the historical analyses presented in the previous section. This figure places the projected trends in the context of previous transitions and illustrates the growth in overall demand since 1970.

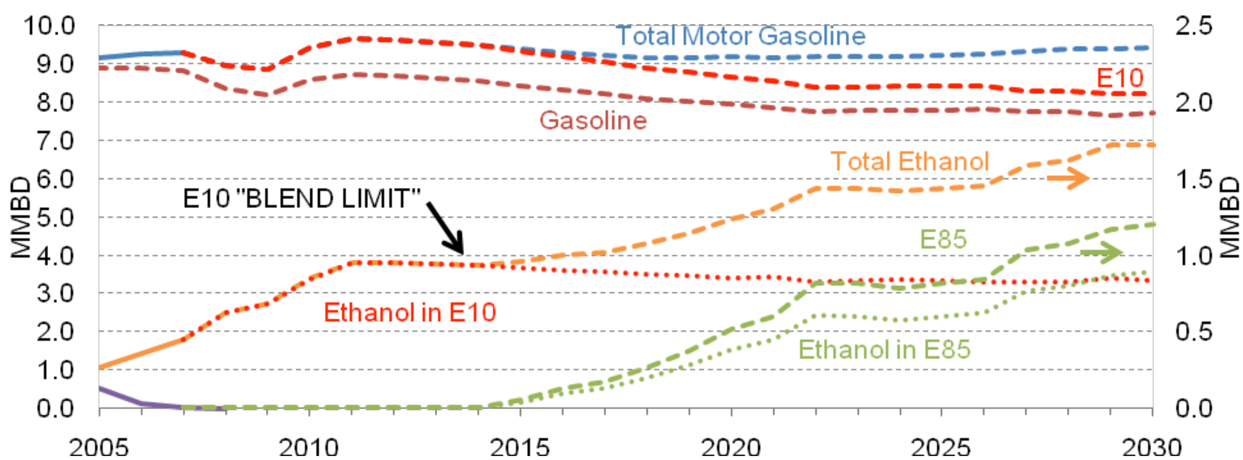


Figure 12.18. The AEO 2009 stimulus case projection of the motor gasoline sector through 2030 shows a transition to increased consumption of ethanol and E85, and decreased consumption of crude-based gasoline (i.e., Gasoline). The EIA projects total gasoline demand to plateau after 2010. The upper data sets (Total Motor Gasoline, E10, and Gasoline) are read from the left axis of the chart; the remaining data sets are read from the right. Gasoline represents all crude-based gasoline consumption, in both low-level blends (e.g., E10) and E85.

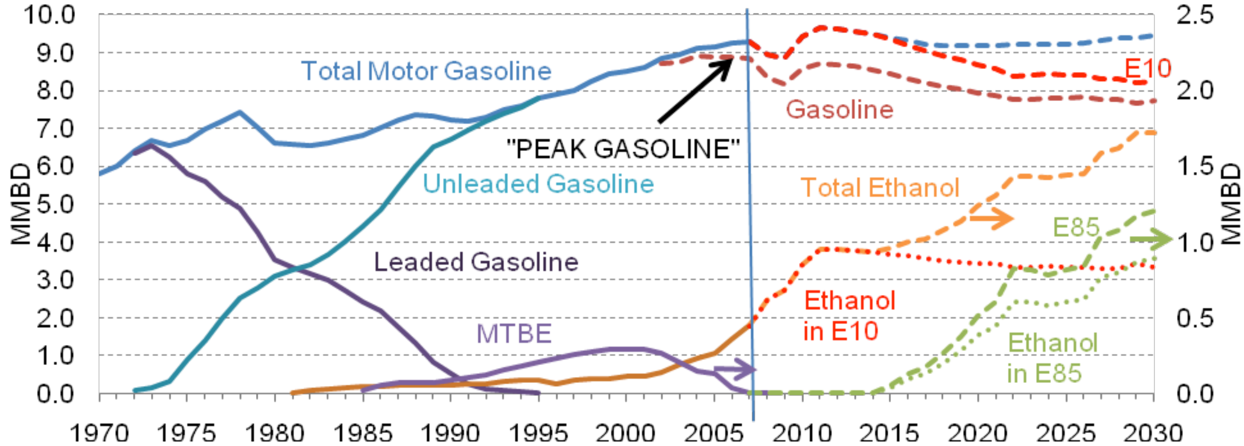


Figure 12.19. The AEO2009 stimulus case projection of the motor gasoline sector through 2030 is combined with historical trends starting in 1970. The leaded and unleaded gasoline data sets are read from the left axis of the chart; the MTBE data set is read from the right.

In this projection, the only alternative to crude-based gasoline is ethanol. Ethanol consumption continues to grow rapidly through 2011, remains constant until 2015, and resumes growth until 2022. The EIA assumes that after 2022, the RFS mandate will remain constant at 36 bgy. Total ethanol and crude-based gasoline (i.e. Gasoline) sum to the total motor gasoline supply. The projection shows that this total supply, or consumer demand, plateaus through 2030. With no growth in overall demand, and increasing ethanol demand, the demand for crude-based gasoline must fall. This reduction in crude-based gasoline demand creates what has been termed "peak gasoline," the point at which consumption of gasoline peaks and declines thereafter. According to the EIA, this peak occurred in 2007, when gasoline consumption reached 8.84 MMBD, or 135.5 bgy. Along with EIA analysts, many private consultants and oil industry executives have acknowledged the "peak gasoline" phenomenon. The EIA does not expect gasoline consumption to return to 2007 levels in the future (Gold and Campoy, 2009).

As total ethanol consumption increases, gasoline consumption does not decrease on a one-to-one, or barrel-to-barrel, basis. Since ethanol has a lower energy content compared to gasoline (76,330 and 115,261 Btu/gallon, respectively),[17] a greater volume of ethanol is required to replace a barrel of gasoline. For each volume unit of gasoline, 1.5 volume units of ethanol are required to replace the gasoline on an energy basis.

Figures 12.18 and 12.19 show trends in E10 and E85 consumption, along with the breakdown of ethanol consumed as E10 and E85. Summing the ethanol consumed as E10 and E85 gives the total ethanol consumption. Summing the E10 and E85 consumption gives the total motor gasoline consumption. The data series related to E10 (E10 and Ethanol in E10) represent the average blend level of ethanol and gasoline, not including E85. They represent volumes of blends less than or equal to 10%. These low-level blends can range from 0% to 10% ethanol in gasoline, and are sold as standard motor gasoline for all gasoline-powered vehicles and equipment. Currently, the Clean Air Act (CAA) limits the sale of gasoline to blends of ethanol no greater than 10%. The blend limit was established by a waiver to the "substantially similar"

[17] See Table 12.10.

rule under section 211(f) of the CAA (EPA, 1995b). This limit has been referred to as the "blend limit" or "blend wall." Once this limit is reached in the gasoline supply, all further increases in ethanol consumption must come in the form of E85 or other high level blends (>10%).[18]

E85 consumption is negligible until approximately 2014, at which point it begins a rapid growth trend that continues through 2022. In the same year, the 10% blend wall is reached (see Figure 12.18). After the blend wall is reached, further increases in ethanol consumption come in the form of E85. Additionally, as the volume of crude-based gasoline available for blending declines with increased total ethanol demand, ethanol consumed as E10 must inevitably decline. After the blend wall is reached, if the gasoline supply was blended to E10, there would not be enough gasoline available to incorporate the remaining ethanol into the market as E85. Therefore, E10 consumption must decline. This phenomenon is not simply a result of the blend wall, but is also based on the flat demand for total motor gasoline products in this projection. If total demand were to increase at a rate comparable to total ethanol demand (on an energy basis), then the market could continue to be supplied with E10, forgoing the need for ethanol to be consumed as E85.

In this projection, total motor gasoline demand on an energy basis is approximately equivalent in the years 2018 and 2030. As total ethanol consumption increases by 0.65 MMBD from 2018 to 2030, the ethanol consumed as E85 increases by 0.69 MMBD, while the ethanol consumed as E10 decreases by 0.04 MMBD. Even as the total energy demand remains flat during this time period, the total volume increases by 0.27 MMBD, from 9.18 to 9.44 MMBD, due to the lower volumetric energy content of ethanol. As ethanol comprises a greater percentage of the overall motor gasoline pool, a greater overall of volume of fuel must be supplied. By 2029, ethanol is consumed in greater volumes as E85 compared to E10. This transition is shown in Figures 12.18 and 12.19 when ethanol consumed as E85 increases above the ethanol consumed as E10.

The rate of market penetration of different fuels (e.g., E85) is also an important factor. For a given projection in total motor gasoline and ethanol demand, a required market penetration of E85 can be determined based on the 10% blend wall and an assumption that E85 consumption remains negligible until the blend wall has been reached. The rate at which E85 must penetrate the market determines the pace at which market transitions must occur (e.g., fleet of flex-fuel vehicles (FFVs) in the market, retailers capable of dispensing E85, etc). In this projection, E85 increases from approximately 0.5% of total motor gasoline volume in 2015 to 12.8% in 2030. This penetration rate requires the market to increase its capability to supply E85 from 0.05 MMBD (2.2 million gallons per day) to 1.20 MMBD (50.6 million gallons per day) in a span of 15 years.

12.3.2.1.2 Distillate Fuel Oil (DFO)

The DFO projection includes consumption of total distillate, crude-based distillate, non-crude-based distillate, bio-based distillate, and biodiesel through 2030. Bio-based distillate includes biodiesel and liquids-from-biomass; non-crude-based distillate includes bio-based distillate and coal-to-liquid distillate. Like the motor gasoline projection, data are taken from the Liquid Fuels Supply and Disposition table of the stimulus case, or Updated AEO2009 Reference Case Service Report (EIA, 2009c, Table 11). Figure 12.20 presents the DFO projection from 2005 through

[18] The "substantially similar" rule and ethanol blend limit are discussed in greater detail in section 12.3.4.2.

2030. Figure 12.21 presents the same data with historical data. Figure 12.21 places the projected trends in the context of historical transitions and illustrates the growth in overall distillate demand since 1990. Since the AEO projection does not differentiate between sulfur grades of distillate fuels, only historical trends of the grades of distillates are plotted.

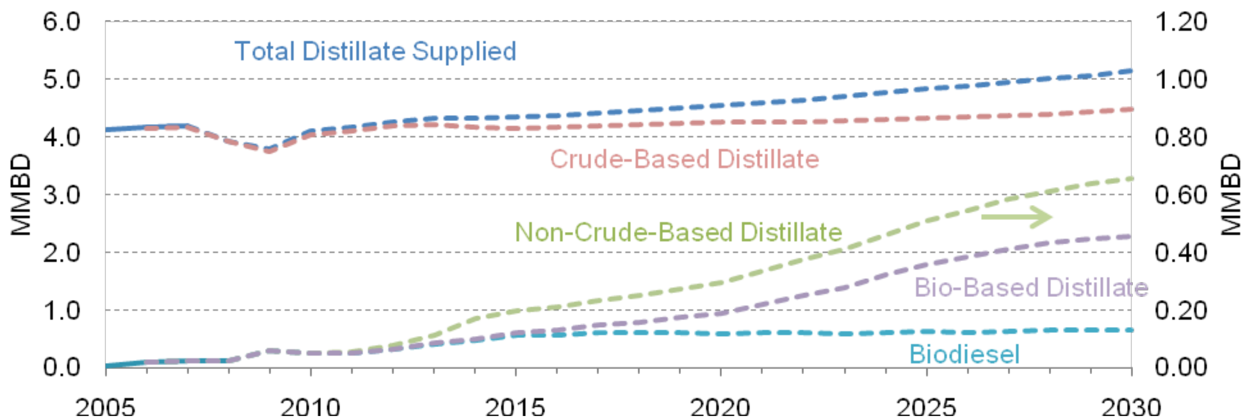


Figure 12.20. The AEO 2009 stimulus case projection of the DFO sector through 2030 shows increasing consumption of bio-based and other non-crude-based distillate fuels. Despite these increases, consumption of crude-based distillate continues to increase due to the rapid growth in overall distillate demand. The upper data sets (Total Distillate Supplied and Crude-Based Distillate) are read from the left axis of the chart; the remaining data sets are read from the right.

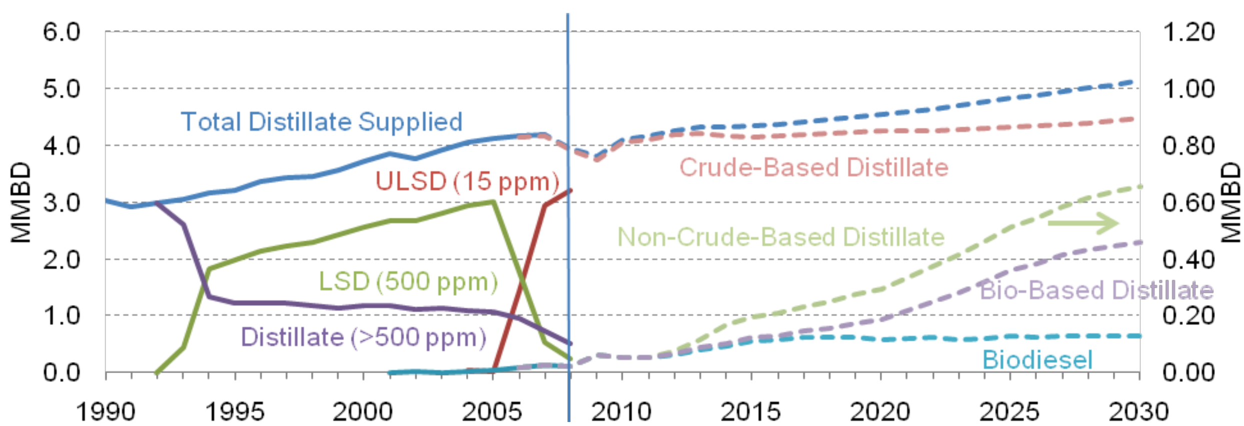


Figure 12.21. The AEO2009 stimulus case projection of the DFO sector through 2030 is combined with historical trends starting in 1990. The historical data sets are read from the left axis of the chart.

Bio-based distillates may come in the form of biodiesel (e.g., fatty-acid-methyl ester) or liquids-from-biomass. Liquids-from-biomass represent any biomass-derived distillate that is chemically identical to crude-based distillate, e.g. renewable diesel and biomass-to-liquid (BTL) fuels (e.g., FT diesel).[19]

[19] Renewable diesel (RD) is a diesel substitute derived from oil-based feedstocks through hydro-treating processes. BTL is a diesel substitute derived from various cellulosic feestocks through gasification and FT processes; it is also

With the modest penetration of biofuels and growth in total distillate demand starting in 2010, there is no evidence of a peak in crude-based distillate consumption through 2030. Therefore, the "peak gasoline" phenomenon observed in the motor gasoline sector is not anticipated in this projection. A transition in oil refinery operations would be required to supply the increasing market demand for distillates and reduced demand for gasoline.

In addition, no issues related to a "blend limit" or "blend wall" are anticipated. Diesel-engine manufacturers place limits on biodiesel use, but the projected volumes of biodiesel fall well below any concerns about reaching a blend wall during the timeframe of this projection. Biodiesel's share of the DFO pool grows to just under 3% in 2015, and holds this share through 2030. Currently, diesel engines are warranted to run on blends of biodiesel up to 5%, i.e., B5. This acceptance of B5 blends is reflected in the latest version of the ASTM distillate fuel oil specifications, D975 and 396, which allow for distillates to be blended with up to 5% biodiesel. The specifications ensure that a biodiesel-blended fuel meets all requirements of D975 or 396, and that the neat biodiesel, i.e., B100, used in the blend meets the ASTM biodiesel specification, D6751 (ASTM, 2008). Even if biodiesel demand grows beyond the 5% blend level, several diesel-engine manufacturers have warranted engines that are approved to operate on B20, and even B100 in a few instances (NBB, 2009), ensuring a larger market for biodiesel. The other bio-based distillates, e.g., renewable diesel and BTL, face no blend limitations. Ignoring the fact that these fuels are projected to comprise a minimal percentage of the DFO sector, these fuels are chemically identical to crude-based distillates, ensuring their unrestricted use in the current DFO infrastructure.

The EIA projection predicts that biofuels in the DFO sector will play a smaller role compared to ethanol's role in the motor gasoline sector. The final year of the RFS mandate—2022—serves as a useful point of comparison between the two sectors. On a volume basis, ethanol is projected to comprise 15.6% of the motor gasoline pool in 2022, while bio-based distillates are projected to comprise only 5.4% of the DFO pool. On an energy basis, ethanol is projected to provide 10.9% of the motor gasoline energy demand, substantially less than the volume contribution, again due to ethanol's lower energy content. Bio-based distillates are projected to provide 5.1% of the DFO energy demand, only slightly less than the volume contribution. The energy contents of biodiesel, renewable diesel, and BTL fuels are only slightly less than crude-based distillate (see Table 12.10). When considering the size of the motor gasoline sector (9.21 MMBD) relative to the DFO sector (4.64 MMBD), the role of ethanol can be seen to be even more substantial in the overall liquid fuels sector. Ethanol alone is projected to comprise over 10% of the volume of fuels consumed in the liquid fuels sector (motor gasoline and DFO); nearly 7% on an energy basis, again, in 2022.

In this EIA projection, 1.69 MMBD, or 25.8 bgy, of biofuels are consumed in 2022. This volume of biofuels consumption falls well short of the RFS mandate of 36 bgy in 2022. By 2030, the projected consumption of biofuels still falls short by nearly 3 bgy, reaching 33.4 bgy.

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known as cellulosic diesel or FT diesel. Both fuels are high-quality synthetic distillate substitutes with similar heating values.

12.3.2.2 AEO2009 alternative cases

The EIA does not base its annual outlook of energy markets on a single case. The AEO reports are based on several alternative cases in addition to the reference case. Alternative cases are analogous to the reference case model, but with altered high-level assumptions related to economic growth and world oil prices. The low and high oil price cases "define a wide range of potential price paths, reflecting different assumptions about decisions by OPEC members regarding the preferred rate of oil production and about the future finding and development costs and accessibility of conventional oil resources outside the United States." The low and high economic growth cases "were developed to reflect the uncertainty in projections of economic growth." The alternative cases are used to illustrate and assess the uncertainty and variability in energy market projections resulting from these altered assumptions (EIA, 2009b, Appendix E).

In this section, reference and alternative cases of AEO 2009 are presented, along with the updated AEO 2009 reference case, i.e., the *stimulus* case. A summary of AEO 2009 cases is provided in Table 12.9. For each case, the table lists the case name, description, and abbreviated identifier used to identify the cases throughout this chapter. Each of the alternative cases used in this chapter, and listed in Table 12.9, were released with the initial AEO 2009 publication from March 2009.

Table 12.9. The AEO 2009 alternative cases differ based on economic growth and world oil price assumptions (EIA, 2009b, Appendix E).

Case	Description	Identifier
Reference	Baseline economic growth (real GDP increases at 2.5%/year on average from 2007-2030), world oil price (world light, sweet crude oil prices reach $130/bbl in 2030, in 2007 dollars), and technology assumptions.	*ref*
Stimulus, or Updated Reference Case	Incorporates ARRA (i.e., economic stimulus bill) provisions into the AEO2009 reference case.	*stimulus*
High Oil Price	World light, sweet crude oil prices are about $200/bbl (2007 dollars) in 2030, compared to $130/bbl in reference case. Other assumptions are the same as reference case.	*hp*
Low Oil Price	World light, sweet crude oil prices are about $50/bbl (2007 dollars) in 2030, compared to $130/bbl in reference case. Other assumptions are the same as reference case.	*lp*
High Economic Growth	Real GDP increases at 3.0%/year on average from 2007-2030. Other assumptions are the same as in the reference case.	*hm*
Low Economic Growth	Real GDP increases at 1.8%/year on average from 2007-2030. Other assumptions are the same as in the reference case.	*lm*

Following the release of the *stimulus* case, additional energy policy changes have been announced, including further changes to CAFE standards and the passing of the Consumer

Assistance to Recycle and Save (CARS) Act of 2009, otherwise known as the "cash-for-clunkers" program. The CAFE standards, which were previously updated with the passing of the EISA of 2007, would have required an average fuel economy of 35 mpg in 2020. However, in May 2009, President Obama announced a new national fuel efficiency policy requiring an average fuel economy of 35.5 mpg in 2016. This policy unifies fuel efficiency policies at the federal and state levels, whereas the previous CAFE requirements would have differed from proposed California fuel efficiency standards (Office of the Press Secretary, 2009). The cash-for-clunkers program, passed in June 2009, provided federal funds for consumers to trade in inefficient "clunkers" for more fuel-efficient vehicles. The program was touted as a means for reducing emissions, increasing LDV fleet fuel economy, and stimulating auto sales. Congress ultimately appropriated $3 billion to the program, which resulted in the exchange of nearly 700,000 vehicles in less than one month (Johnson, 2009; NHTSA, 2009).

These programs, both aimed at increasing average fuel economy of the U.S. automotive fleet, will ultimately impact liquid fuels consumption. Since both were announced after the release of the AEO 2009 *stimulus* case, the projected impacts of these programs are not incorporated in any of the energy market projections listed in Table 12.8, which encompass the most recent AEO cases released by the EIA.

These recent policy changes illustrate the rapidity at which energy markets, and the wider economy, can evolve and change, and the uncertainty inherent in making energy market projections. Despite these recent changes, the AEO 2009 cases should not be viewed as irrelevant. The EIA developed the alternative cases explicitly to address potential changes in future conditions. Although the alternative cases do not alter low-level assumptions, like fuel economy standards, such changes can be assessed by examining the impacts of changing high-level assumptions. In the case of increased fuel economy standards, the consumption of oil might be reduced as a result of an increased average fuel efficiency of the LDV fleet. Such a scenario could be analogous, at least qualitatively for liquid fuel demand, to a high oil price case, which causes a reduction in liquid fuels consumption. The quantitative impact of a given program cannot be assessed, but overall qualitative trends can be viewed as similar to the alternative cases. Instead of attempting to revise the AEO projections to incorporate these recent policy changes, the alternative cases can be used to assess broad impacts and trends based on changes in overall liquid fuels demand.

12.3.2.2.1 Motor Gasoline

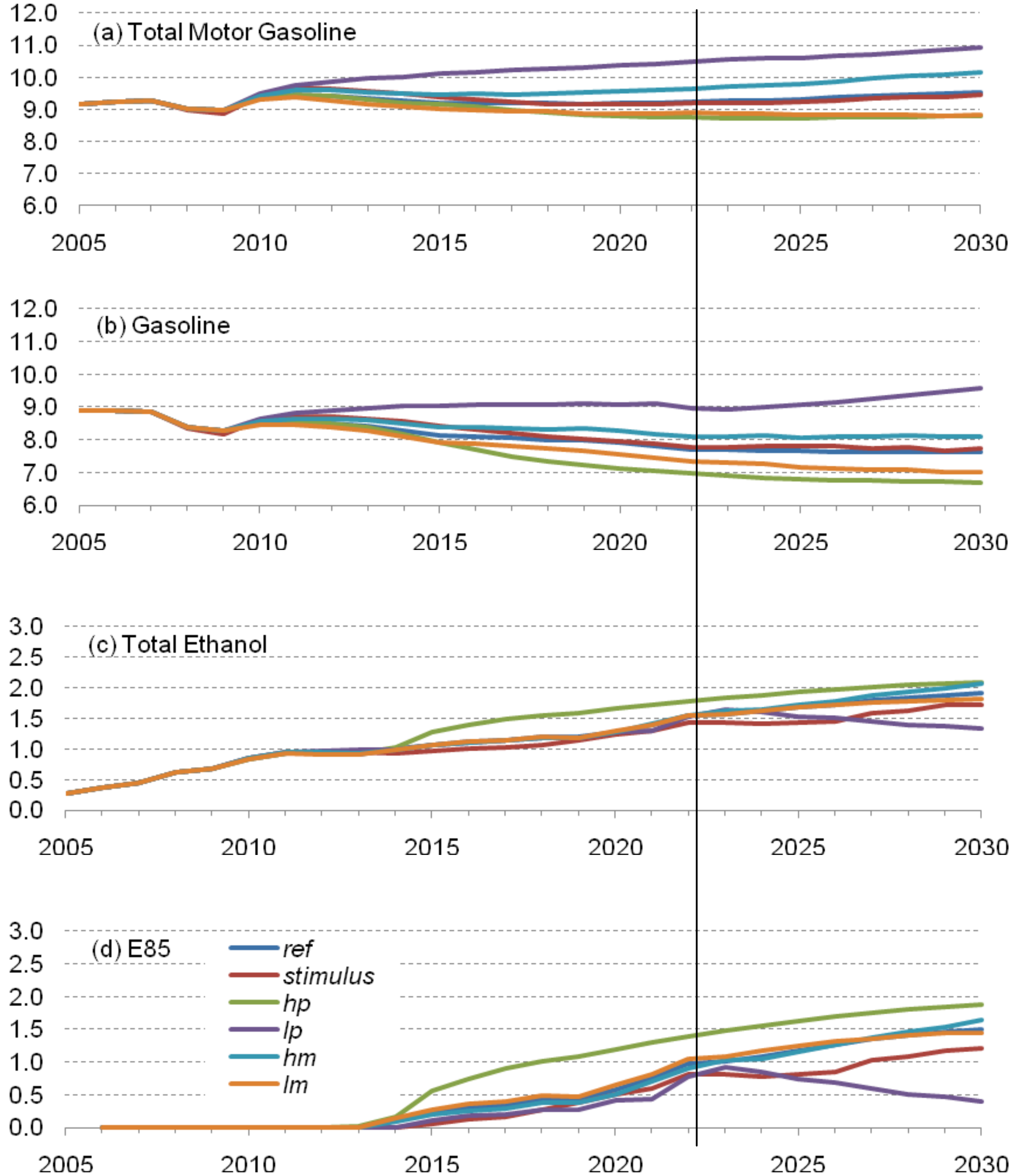
Rather than presenting all data sets from the alternative cases, figures are limited to individual data sets of total motor gasoline, crude-based gasoline, total ethanol, and E85 consumption through 2030. E10 consumption and ethanol consumed as E10 and E85 are omitted. For each data set, the five AEO 2009 cases are plotted along with the *stimulus* case. Data are taken from the Liquid Fuels Supply and Disposition table for each case (EIA, 2009b, Table 11; EIA, 2009c, Table 11). Figures 12.22 (a-d) present the motor gasoline projections from 2005 through 2030. Although the full data sets are presented through 2030, the variability through 2022 is of greater interest, as this coincides with the last year of the RFS. The year 2022 is identified by the vertical line crossing through Figures 12.22 (a-d).

Projections of total motor gasoline do not diverge appreciably until 2010. By 2022, the projections differ considerably—the high and low oil price cases, i.e., the *hp* and *lp* cases, range from 8.74 MMBD to 10.49 MMBD, or 134.0 bgy to 160.8 bgy, respectively. This difference represents a significant range of possibilities for the future of the motor gasoline sector through 2022. In the *lp* case, the sector would be required to supply the market with an additional 1.20 MMBD of motor gasoline products compared to 2007. On the other hand, the *hp* case would require the sector to shrink by 0.55 MMBD over the same 15 year period.

In all cases, crude-based gasoline continues to supply the majority of the motor gasoline market. Again, the *hp* and *lp* cases provide the greatest range of potential futures, with consumption of gasoline ranging from 6.96 MMBD to 8.96 MMBD, or 106.8 bgy to 137.3 bgy, respectively. Only the *lp* case shows a steady consumption of crude-based gasoline through 2022; all other cases show a reduction, ensuring that the "peak gasoline" phenomenon is likely to stand as an historical event, rather than a future occurrence.

If the *hp* case is ignored, total ethanol consumption varies by only 0.10 MMBD in the year 2022. However, total ethanol consumption ranges from 1.44 MMBD to 1.78 MMBD, or 22.0 bgy to 27.3 bgy, for the *stimulus* and *hp* cases, respectively. By assuming that the 15 bgy cap on the conventional biofuel category of the RFS is met in each case, then the range in consumption—5.3 bgy—would be based solely on projections of cellulosic ethanol production. With higher oil prices, additional marginal cellulosic ethanol facilities are able to come on line and supply the market. In the *lp* case, total ethanol consumption actually falls after 2023. With depressed oil prices, advanced biofuel technologies would take longer to develop and enter the market to compete economically with crude-based fuels and conventional biofuels.

E85 consumption varies widely in 2022, but, like total ethanol consumption, the *hp* case produces the greatest growth. In 2022, E85 consumption ranges from 0.77 MMBD to 1.39 MMBD, or 11.8 to 21.3 bgy, for the *lp* and *hp* cases, respectively. The high oil price yields a near doubling in E85 consumption compared to the low oil price assumption. By 2030, the *hp* case projects the consumption of E85 to be over four times that of the *lp* case. This wide range might seem at odds with the relatively small range in total ethanol consumption. However, ethanol and E85 consumption cannot be examined in isolation from total motor gasoline or crude-based gasoline consumption. In addition to the increased total ethanol consumption with higher oil prices, crude-based gasoline and total gasoline consumption fall. Therefore, ethanol must be blended increasingly as E85, rather than as E10, since less gasoline is available for blending. So, as high prices allow ethanol to capture market share from crude-based gasoline, total consumption also falls, requiring greater penetration of E85, or other high-level blends.



Figures 12.22 (a-d). The AEO2009 cases and *stimulus* case projections of (a) Total Motor Gasoline, (b) Crude-Based Gasoline, (c) Total Ethanol, and (d) E85 consumption illustrate the wide range of potential futures in the motor gasoline sector resulting from varied high-level assumptions. The vertical axes are in units of MMBD of product supplied.

12.3.2.2.2 DFO

Like the motor gasoline projections, figures are limited to 4 data sets: total distillate, crude-based distillate, non-crude-based distillate, and bio-based distillate consumption through 2030. Biodiesel consumption is omitted. For each data set, the five AEO 2009 cases are plotted along with the *stimulus* case. Data are taken from the Liquid Fuels Supply and Disposition table for each case (EIA, 2009b, Table 11; EIA, 2009c, Table 11). Figures 12.23 (a-d) present the DFO projections from 2005 through 2030. Again, the variability through 2022 is of greatest interest, as this coincides with the last year of the RFS. Like Figures 12.22 (a-d), the year 2022 is identified by the vertical line crossing through Figures 12.23 (a-d).

Total distillate consumption does not vary appreciably until after 2010. By 2022, the low and high economic (market) cases, i.e., the *lm* and *hm* cases, range from 4.34 MMBD to 5.07 MMBD, or 66.5 bgy to 77.8 bgy, respectively. In all cases, the total demand for distillate products is projected to increase. The *hm* case would require an additional 0.88 MMBD of distillate products compared to 2007.

Crude-based distillate maintains a substantial share of total distillate consumption through 2022, supplying over 90% of the market volume. Again, the *lm* and *hm* cases provide the greatest variation in potential futures, with crude-based distillate consumption ranging from 3.96 MMBD to 4.69 MMBD, or 60.7 bgy to 71.9 bgy, respectively. All cases project increasing demand for crude-based distillate products, except for the *hp* and *lm* cases, which show small reductions in demand. The *hm* case would call for an additional 0.52 MMBD of crude-based distillate over 2007 demand.

This trend differs substantially from the projected future of stagnation or contraction of demand for crude-based gasoline products. Gasoline is projected to maintain no more than 85% of the volume in the motor gasoline sector, and could fall below 80%. Oil refiners would be faced with the need reconfigure operations to provide for an increasing output of distillates, or at least a growing percentage of distillate output relative to gasoline in their product slate. Historically, U.S refiners have optimized operations to maximize gasoline consumption. This trend stands in contrast to European refiners, where refinery product slate is configured to optimize distillate production. Demand for distillate fuels has grown to such an extent in Europe that surplus gasoline production is exported to the U.S. As the U.S. shifts demand from gasoline to distillate fuels, both U.S. and European refiners could be impacted. European refiners could face a dwindling export market for gasoline (Acerra, 2008).

Comparison of the range of projections in total distillate to total motor gasoline consumption reveals that oil price assumptions (i.e., the *lp* and *hp* cases) have a greater impact on total motor gasoline (and crude-based gasoline) consumption, whereas economic assumptions (i.e., the *lm* and *hm* cases) have a greater impact on total distillate (and crude-based distillate) consumption. According to the EIA projections, demand in the DFO sector is heavily influenced by economic activity. Since distillate fuels are used overwhelmingly to power vital sectors of the economy (e.g., shipping and transportation of commodities and goods, construction, agriculture, etc), an increase or decrease in economic activity would result in an increase or decrease in distillate demand. On the other hand, demand in the motor gasoline sector is influenced more by oil prices. Since motor gasoline products are used primarily to fuel personal transportation, an increase or decrease in oil prices could serve to alter consumer driving habits and decrease or increase motor gasoline demand.

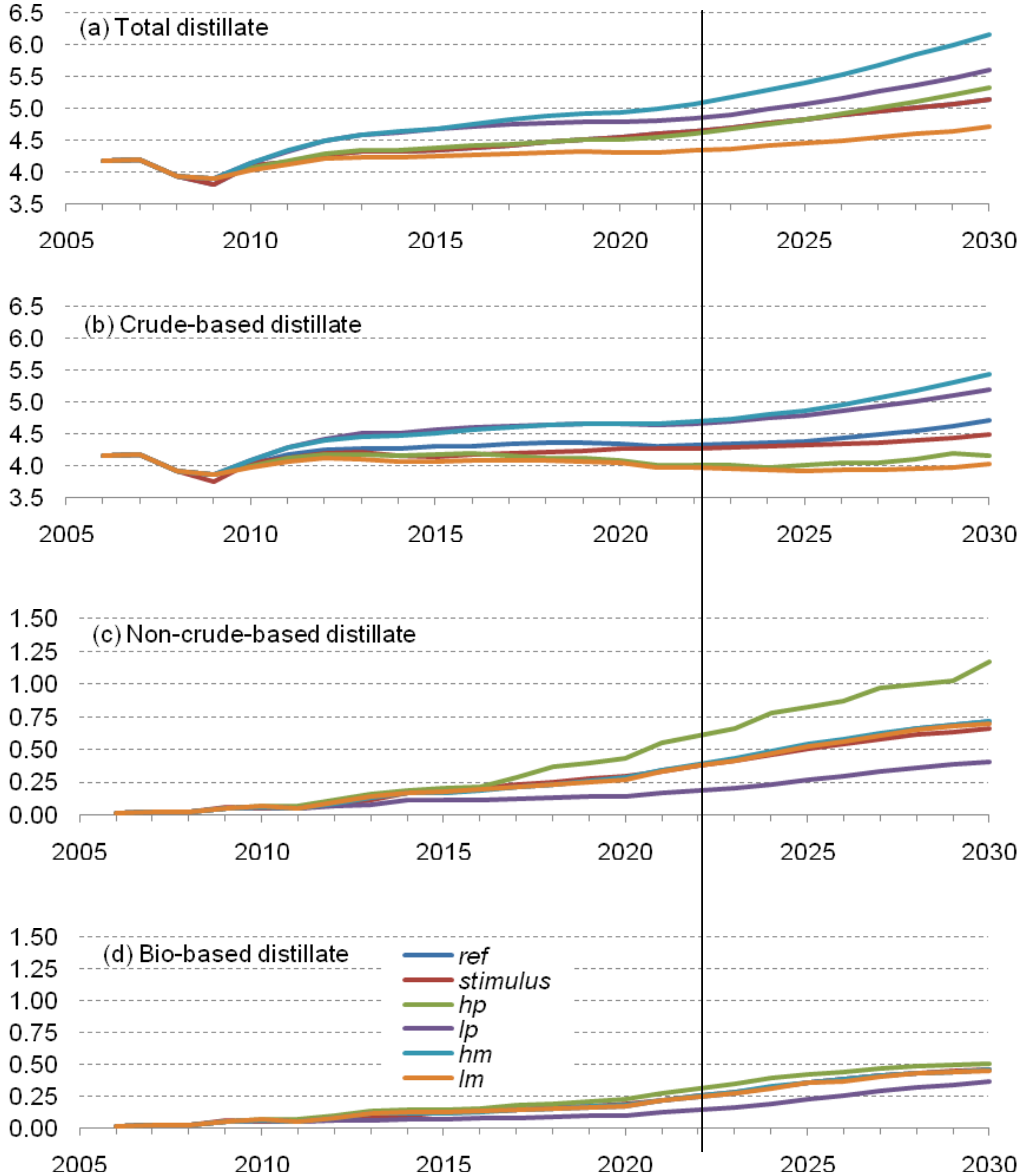
Consumption of non-crude-based distillate—distillate fuels derived from non-crude feedstocks—is projected to grow in all cases. The *lp* and *hp* cases result in substantial variation in consumption, ranging from 0.19 MMBD to 0.61 MMBD, or 2.9 bgy to 9.3 bgy, respectively. All cases represent significant growth from a market of 360 mgy in 2007. The *hp* case requires the supply of non-crude-based distillate fuels to increase by nearly 2,500% from 2007 through 2022. If the *hp* and *lp* cases are ignored, the remaining cases project very similar growth, increasing to approximately 0.38 MMBD, or 5.8 bgy, in 2022.

In 2022, bio-based distillate consumption ranges from 0.14 MMBD to 0.31 MMBD, or 2.2 to 4.8 bgy, respectively. Bio-based distillate is projected to supply only 3% to 7% of total distillate consumption on a volume basis. In contrast, ethanol is projected to capture 15% to 20% of the motor gasoline pool, again, on a volume basis. Despite the lower energy content of ethanol compared to crude-based gasoline, the gasoline substitute is projected to penetrate the market much more than bio-based substitutes in the DFO sector. In addition, when considering the size of the motor gasoline sector relative to the DFO sector, ethanol is projected to maintain its role as the nation's primary biofuel consumed in the liquid fuels sector. On a volume basis, consumption of bio-based distillates is projected to be 10% to 20% of total ethanol consumption in 2022.

For the alternative distillates, oil price assumptions drive growth since many of the alternatives, e.g., biodiesel, BTL, coal-to-liquids (CTL), etc, serve as marginal supplies. They are relatively expensive to produce. In order for these fuels to supply a substantial portion of the DFO market, oil prices need to climb to a point where the alternative technologies can be deployed and fuel production facilities can compete economically with conventional, crude-based fuels. The level of economic activity has little to no impact on the consumption of these fuels, as evidenced by the lack of variability between the economic cases and the reference and *stimulus* cases in Figures 12.23 (c, d).

Total liquid fuels consumption is projected to increase from 13.48 MMBD, or 206.7 bgy, in 2007 to a range in 2022 of 13.59 MMBD to 14.32 MMBD, or 208.3 bgy to 219.6 bgy, for the *lm* and *hm* cases, respectively. This range represents a growth of 100 MBD to 1 MMBD over a 15 year time period. In all cases, biofuels consumption is projected to fall short of the 36 bgy mandate in 2022, ranging from 25.8 bgy to 28.4 bgy, for the *lp* and *hp* cases, respectively. In 2030, all but the *lp* case are projected to slightly exceed 36 bgy of biofuels consumption.

Again, the oil price assumptions cause substantial variability in motor gasoline and biofuels consumption through 2022. This variability proves useful in the development of biofuels transition scenarios. Aside from the *stimulus* case, only the alternative oil price cases are used as inputs to the LiFTrans model. There are several reasons for moving forward with the *hp* and *lp* cases, which provide a greater range of total motor gasoline consumption. First, as explained above, ethanol is expected to continue its prominent role in the biofuels industry, with bio-based distillate consumption projected to fall well short of ethanol consumption in the foreseeable future. Second, ethanol is consumed in the motor gasoline sector, which will continue to be much larger than the DFO sector. Third, ethanol presents many unique challenges due to its fuel properties, whereas bio-based distillates are more easily integrated into the existing DFO supply and infrastructure.



Figures 12.23 (a-d). The AEO2009 cases and *stimulus* case projections of (a) Total distillate, (b) Crude-based distillate, (c) Non-crude-based distillate, and (d) bio-based distillate consumption illustrate the wide range of potential futures in the DFO sector resulting from varied high-level assumptions. The vertical axes are in units of MMBD of product supplied.

12.3.3 Liquid fuels transition (LiFTrans) model

The Liquid Fuels Transition (LiFTrans) model was developed as part of this project to explore potential pathways that could be followed in the liquid fuels sector to meet the requirements of the RFS through 2022. The model creates transition scenarios based on a limited set of user inputs. Scenario results include annual consumption of biofuels (e.g., ethanol, bio-based distillate), crude-based fuels, and total liquid fuels consumption for the motor gasoline and DFO sectors. Scenarios developed with the model can be presented in a format analogous to Figures 12.18 through 12.21. The overall structure and individual components (e.g., source data, user inputs, calculations, outputs) of the model are discussed in detail below. Assumptions related to each component of the model are stated explicitly. Implementation of the model in a spreadsheet application is also briefly discussed. Results of the model are included later in this task report.

12.3.3.1 Model structure

Figure 12.24 illustrates the basic components of the LiFTrans model. The model uses two primary demand, or fuel consumption, functions: total liquid fuels and biofuels. These demand functions are used for both the motor gasoline (MoGas) and DFO portions of the model. The total liquid fuels demand functions are derived from the AEO 2009 cases. The RFS program, which is assumed to be the primary driver of biofuels consumption through 2022, serves as the biofuels demand function. However, these data sources are not directly fed into the model. Several variables were created to increase model flexibility, allowing the user to alter assumptions and develop a range of alternative transition scenarios. These include the specification of annual biofuel volumes (by fuel type), motor gasoline blend limit, and total liquid fuels demand (from a set of AEO cases). In the following sections, data sources, user inputs, calculation procedures, model output, and model implementation are discussed.

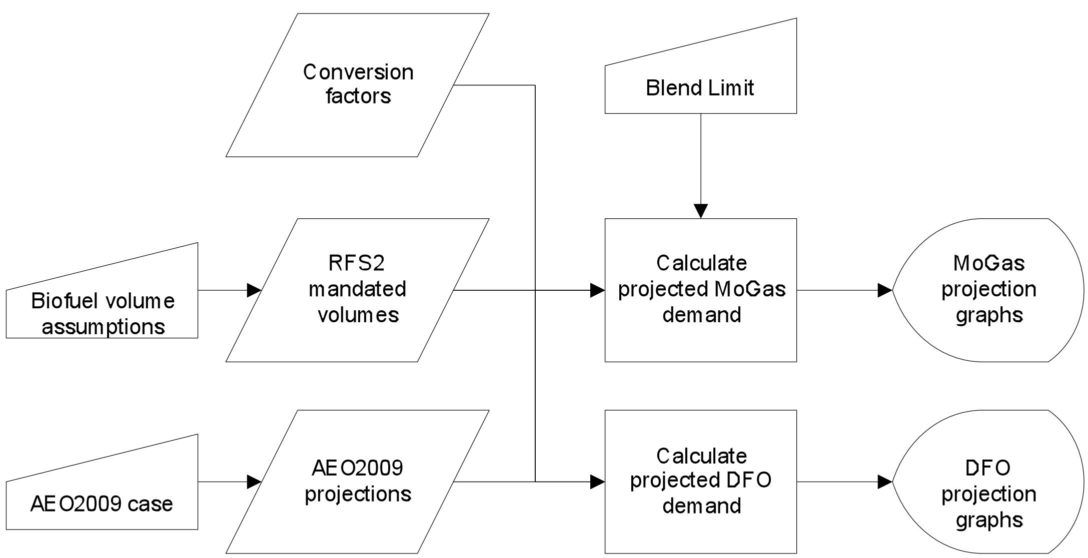


Figure 12.24. The flowchart illustrates the basic components (inputs, data, processes, outputs) of the LiFTrans model. Note that motor gasoline has been denoted as 'MoGas'.

12.3.3.2 Data sources

12.3.3.2.1 RFS2 mandated volumes

Table 12.9 shows the annual biofuel volumes mandated by the RFS program, along with a control case used by the EPA to analyze one plausible pathway to meeting the mandate.[20] The program specifies annual volumes of total renewable fuel (i.e., biofuel), and further specifies volumes of advanced biofuels—cellulosic biofuel, biomass-based diesel, and other advanced biofuel. As proposed in the RFS2 Notice of Proposed Rulemaking (NPRM), each biofuel category contributes on a per-gallon basis, i.e., the equivalence values defined in the original RFS program will no longer be used (EPA, 2009a). The EPA control case in Table 12.10 actually falls just short of the mandated 'other advanced biofuel' category from 2011 through 2022. For an explanation of this shortfall in the EPA control case, the reader is referred to section 1.2.5 of the EPA RFS2 DRIA document (EPA, 2009a).

The mandated biofuel volumes serve as a guide for the model user when developing a biofuel demand function. The biofuel demand function is discussed further below.

12.3.3.2.2 AEO2009 projections

Total liquid fuels demand functions are derived from the AEO 2009 cases. The motor gasoline demand function is derived from the Liquid Fuels Supply and Disposition tables of the AEO 2009 cases (EIA, 2009b, Table 11; EIA, 2009c, Table 11). Total motor gasoline supply includes both crude-based gasoline and ethanol, i.e., all liquid fuels consumed in gasoline-powered equipment. However, only total motor gasoline demand through 2022 is used as an input to the model. The DFO demand function is also derived from the Liquid Fuels Supply and Disposition tables of the AEO 2009 cases (EIA, 2009b, Table 11; EIA, 2009c, Table 11). DFO supply includes crude-based DFO, biodiesel, and various xTL (biomass (B)-, coal (C)-, and gas (G)-to-liquid) fuels. DFO is specified, by the EIA, as fuel oil nos. 1, 2, and 4. These distillate fuels are used primarily in diesel-powered equipment (excluding air transportation) and heating oil applications. Only total distillate demand through 2022 is used as an input to the model.

[20] The control case was developed and used by EPA analysts in the RFS2 Draft Regulatory Impact Assessment (DRIA).

Table 12.10. The EPA RFS2 DRIA control case serves as an example of one pathway to meeting the RFS mandate. All fuel values are in billion gallons per year (bgy)(EPA, 2009a).

	Advanced Biofuel										Non-Advanced Biofuel		
	Cellulosic Biofuel	(mandate)	Biomass-Based Diesel			(mandate)	Other Advanced Biofuel			(mandate)			(mandate)
Year	Cellulosic Ethanol		FAME Biodiesel	Non-Co-processed Renewable Diesel	sum		Co-processed Renewable Diesel	Imported Ethanol	sum		Corn Ethanol	Total Renewable Fuel	
2008		0.00				0.00				0.00			9.00
2009	0.00	0.00	0.50	0.00	0.50	0.50	0.00	0.50	0.50	0.10	9.85	10.85	11.10
2010	0.10	0.10	0.64	0.01	0.65	0.65	0.01	0.29	0.30	0.20	11.55	12.60	12.95
2011	0.25	0.25	0.77	0.03	0.80	0.80	0.03	0.16	0.19	0.30	12.29	13.53	13.95
2012	0.50	0.50	0.96	0.04	1.00	1.00	0.04	0.18	0.22	0.50	12.94	14.66	15.20
2013	1.00	1.00	0.94	0.06	1.00	1.00	0.06	0.19	0.25	0.75	13.75	16.00	16.55
2014	1.75	1.75	0.93	0.07	1.00	1.00	0.07	0.36	0.43	1.00	14.40	17.58	18.15
2015	3.00	3.00	0.91	0.09	1.00	1.00	0.09	0.83	0.92	1.50	15.00	19.92	20.50
2016	4.25	4.25	0.90	0.10	1.00	1.00	0.10	1.31	1.41	2.00	15.00	21.66	22.25
2017	5.50	5.50	0.88	0.12	1.00	1.00	0.12	1.78	1.90	2.50	15.00	23.40	24.00
2018	7.00	7.00	0.87	0.13	1.00	1.00	0.13	2.25	2.38	3.00	15.00	25.38	26.00
2019	8.50	8.50	0.85	0.15	1.00	1.00	0.15	2.72	2.87	3.50	15.00	27.37	28.00
2020	10.50	10.50	0.84	0.16	1.00	1.00	0.16	2.70	2.86	3.50	15.00	29.36	30.00
2021	13.50	13.50	0.83	0.17	1.00	1.00	0.17	2.67	2.84	3.50	15.00	32.34	33.00
2022	16.00	16.00	0.81	0.19	1.00	1.00	0.19	3.14	3.33	4.00	15.00	35.33	36.00

12.3.3.2.3 Conversion factors

The lower heating values (LHV) of the fuels represented in the model are listed in Table 12.11 (in Btu/gallon). Values are derived from those published in the Greenhouse Gas, Regulated Emissions, and Energy Use in Transportation (GREET) model (Wang, 2009). To simplify calculations, and to avoid the need to further specify fuel categories, the following assumptions are made with regards to the heating values.

Gasoline (crude-based) - Reformulated and conventional gasolines have slightly different heating values. To avoid the specification of these types of gasoline, an averaged value is used. RFG comprises approximately one-third of the gasoline pool, based on historical data from the EIA (EIA, 2009j). Therefore, the LHV for crude-based gasoline is weighted as follows:

$$LHV_{gasoline} = \frac{1}{3} \times LHV_{RFG} + \frac{2}{3} \times LHV_{CG}$$

DFO (crude-based) - DFO is comprised of several types of distillate, distinguished primarily by sulfur content. GREET includes two categories: conventional diesel and low-sulfur diesel. Although distillate could be further specified (e.g., conventional, LSD, ULSD), the LHV for crude-based DFO was weighted based on these two values. The weighting is based on historical data from the EIA, which shows that conventional diesel (>500 ppm) makes up just under one-fifth of the DFO pool. Regardless of this weighting, the LHVs differ by less than 1,000 Btu/gallon. The LHV for DFO is weighted as follows:

$$LHV_{DFO} = \frac{1}{5} \times LHV_{CD} + \frac{4}{5} \times LHV_{LSD}$$

Liquids from biomass - This category of fuel includes renewable diesel (RD) and BTL (or FT diesel). GREET provides one value for BTL, but provides two values for RD based on a SuperCetane RD and a UOP-HDO RD. The BTL and UOP-HDO RD heating values are nearly equivalent, and are averaged for the liquids from biomass LHV:

$$LHV_{RD/BTL} = \frac{1}{2} \times LHV_{BTL} + \frac{1}{2} \times LHV_{RD\,(UOP\text{-}HDO)}$$

Table 12.11. Lower-heating values are derived from the GREET model (Wang, 2009).

Fuel	LHV [Btu/gal]
gasoline	115,261
ethanol	76,330
diesel (DFO)	129,280
biodiesel	119,550
liquids from biomass (RD/BTL)	123,279
renewable gasoline	115,983

12.3.3.3 User inputs

12.3.3.3.1 AEO2009 case

The AEO 2009 *stimulus* case was used as a starting point to implement the model. In the current model implementation, the user can select amongst 6 different AEO cases: AEO 2009 reference, high- and low-oil price, high- and low-economic growth, and revised reference case based on the economic stimulus, i.e., *ref*, *hp*, *lp*, *hm*, *lm*, and *stimulus*, respectively.[21] The reference case serves as the default demand input.

Although these cases provide the user with a range of total demand, the model is restricted to EIA analysts' vision of the future. To allow for maximum flexibility, the model could be implemented to allow for user-specified demand functions for the motor gasoline and DFO sectors. However, since the AEO projections are widely referenced and utilized for energy planning, they set useful bounds on the demand function. Scenarios can be compared to actual AEO case projections to investigate the impacts that other inputs have on the projections (e.g., the impact of varying the ethanol blend limit).

12.3.3.3.2 Biofuel volume assumptions

For each mandated category of biofuel, several types of biofuels could potentially be used to meet the mandate. Table 12.10, as mentioned previously, shows the control case projection used by EPA analysts in the RFS2 DRIA. In this control case, the majority of the mandate is met with ethanol—cellulosic ethanol, imported Brazilian sugar-cane ethanol, and corn ethanol. The model allows the user to alter the types and quantities of fuels consumed on an annual basis, again, through 2022. For example, the cellulosic biofuel mandate could be partially met with cellulosic diesel (i.e., BTL), rather than exclusively cellulosic ethanol, as in the EPA control case. The RFS requirements do not serve as a strict input; rather, they serve as a guide for the user when developing a biofuel demand function. The user is not obligated to develop a demand function that meets all requirements of the RFS mandate. When the user-supplied biofuel demand function fails to meet the annual volume requirements for each biofuel category and in total, the model notifies the user. The implementation of this aspect of the model is discussed in later sections.

For each EPA-defined category of biofuel, the user must enter the annual volumes of fuels consumed. For example, for cellulosic biofuel, the user can specify annual volumes of cellulosic ethanol and/or cellulosic diesel (i.e., BTL) consumed in the MoGas and DFO sectors, respectively. Annual volumes must be entered in billion gallons per year.

12.3.3.3.3 Blend limit

This component of the model is a single variable used to specify the ethanol blend limit in the motor gasoline sector. The blend limit is the maximum percentage of ethanol that can be blended into conventional and reformulated gasolines (CG and RFG, respectively) for use in non-flex-fuel vehicles. The CAA currently limits the blend limit to 10% ethanol.[22] To incorporate the increasing volumes of ethanol into the gasoline pool, many ethanol-advocates are

[21] See Table 12.2 for a description of the alternative cases.
[22] Again, the ethanol blend limit is discussed further in section 12.3.4.2.

pushing for this limit to be increased to 15-20% (EPA, 2009a; Knoll, 2009). Therefore, the model was designed to allow the user to specify any value greater than or equal to 10% for the blend limit variable (up to 100%).

12.3.3.4 Model calculations

12.3.3.4.1 Calculate projected MoGas demand

The objective of this component is to calculate the annual volumes of total motor gasoline, crude-based gasoline, ethanol, motor gasoline (crude-based gasoline plus ethanol not blended as E85), and E85 from 2007 through 2022. The volumes of ethanol used in motor gasoline (e.g., E10) and E85 are also determined. Inputs include the assumed annual volumes of total ethanol used to meet the mandate, total MoGas demand, the blend limit, and heating values.

It is assumed that there is negligible demand for E85 until the blend limit is reached. Based on information from the EIA (2009b, Table 11), E85 is represented with a seasonally-averaged content of 74% ethanol by volume.[23] Due to the differences in energy content between gasoline and ethanol, an annual total motor gasoline energy demand is needed (i.e., the total motor gasoline demand function). This demand is derived from the user-specified AEO projection as follows:[24]

$$\text{TMG [MMBtuD]} = \text{E [MMBtuD]} + \text{G [MMBtuD]}$$

where:

$$\text{G [MMBtuD]} = \text{G [MMBD]} \times 42 \text{ gal/bbl} \times \text{LHV}_{\text{G}} \text{ [Btu/gal]}$$

$$\text{E [MMBtuD]} = \mathit{E} \text{ [MMBD]} \times 42 \text{ gal/bbl} \times \text{LHV}_{\text{E}} \text{ [Btu/gal]}$$

$$\text{G [MMBD]} = \text{TMG [MMBD]} - \mathit{E} \text{ [MMBD]}$$

$$\text{TMG [MMBD]} = \mathit{E85} \text{ [MMBD]} + \mathit{MG} \text{ [MMBD]}$$

E (Ethanol), *E85*, and *MG (Motor Gasoline)* [MMBD] are inputs from the AEO 2009 projections.

The total MoGas energy demand (from above) and assumed ethanol volume (from the biofuel demand function) are then used to determine the projection. The user-specified ethanol volume is converted to an ethanol energy demand as follows:

$$\text{E [MMBtuD]} = \text{E [MMBD]} \times 42 \text{ gal/bbl} \times \text{LHV}_{\text{E}} \text{ [Btu/gal]}$$

where:

$$\text{E [MMBD]} = \text{E (user specified) [bgy]} \times (10^3 / 42 \text{ gal/bbl} / 365 \text{ D/y})$$

[23] The volume of ethanol in E85 varies with the season to address cold start issues.
[24] Data series are represented with the following variables: Total Motor Gasoline (TMG), Ethanol (E), crude-based Gasoline (G), E85 (E85), Motor Gasoline, e.g., E10 (MG), Ethanol in E85 (EE85), Ethanol in Motor Gasoline (EMG), and blend limit (xx). Also, MMBtuD denotes million Btu per day.

To determine the crude-based gasoline energy demand, the ethanol energy demand is subtracted from the total MoGas energy demand:

G [MMBtuD] = TMG [MMBtuD] – E [MMBtuD]

The volume of crude-based gasoline can now be determined:

G [MMBD] = G [MMBtuD] / 42 gal/bbl / LHV_G [Btu/gal]

To determine the allocation of ethanol between motor gasoline and E85, recall the assumption that all ethanol is allocated to motor gasoline until the user-specified blend limit (xx) is reached. Using the known volumes of ethanol and crude-based gasoline, the following set of equations are solved to determine the volumes of E85 and motor gasoline:

$$E = xx \times MG + 0.74 \times E85$$

$$G = (1 - xx) \times MG + 0.26 \times E85$$

The above equations are solved for motor gasoline and E85 volumes:

$$MG = \frac{(E - 0.74 \times E85)}{xx}$$

$$E85 = \frac{G - \left(\frac{1}{xx} - 1\right) \times E}{0.26 - 0.74 \times \left(\frac{1}{xx} - 1\right)}$$

These equations assume that there is sufficient volume of ethanol, relative to the volume of crude-based gasoline, to have both motor gasoline and E85 supplied in the MoGas sector. When ethanol volumes are insufficient relative to crude-based gasoline, all ethanol is allocated to produce low-level motor gasoline blends. Finally, the ethanol allocated to each type of fuel, motor gasoline and E85, is determined:

EE85 [MMBD] = 0.74 × E85 [MMBD]

EMG [MMBD] = E [MMBD] – EE85 [MMBD]

The blend percentage in motor gasoline can be determined assuming an average blend-level nationwide:

xx = EMG [MMBD] / Exx [MMBD]

These calculations are completed for each year in the projection through 2022.

The energy-volume conversions assume that FFVs are not designed to optimize fuel consumption when fueled with ethanol-blends, e.g., E85. Engines can be designed (e.g., increase the compression ratio) to take advantage of the higher octane of ethanol to improve fuel economy (Agarwal and Whitaker, 2009; Christie and Stokes, 2008; Ruggiero, 2007).

12.3.3.4.2 Calculate projected DFO demand

The objective of this component is to calculate the annual volumes of total distillate fuel oil (DFO), crude-based DFO, biodiesel, and liquids from biomass from 2007 through 2022. Inputs include the assumed annual volumes of bio-based distillate used to meet the RFS2 mandate, total DFO demand, and heating values.

Due to the differences in energy content between the various fuels, an annual total DFO energy demand is needed (i.e., the total distillate demand function). This demand is derived from the user-specified AEO 2009 projection as follows:[25]

TDFO [MMBtuD] = DFO [MMBtuD] + BD [MMBtuD] + *xTL* [MMBtuD]

where:[26]

DFO [MMBtuD] = DFO [MMBD] × 42 gal/bbl × LHV_{DFO} [Btu/gal]

BD [MMBtuD] = *BD* [MMBD] × 42 gal/bbl × LHV_{BD} [Btu/gal]

xTL [MMBtuD] = *xTL* [MMBD] × 42 gal/bbl × LHV_{xTL} [Btu/gal]

DFO [MMBD] = *DFO* [MMBD] – *BD* [MMBD] – *xTL* [MMBD]

xTL [MMBD] = *GTL* [MMBD] + *CTL* [MMBD] + *BTL* [MMBD]

DFO (Distillate Fuel Oil), *BD (Biodiesel)*, *GTL (Liquids from Gas)*, *CTL (Liquids from Coal)*, and *BTL (Liquids from Biomass)* [MMBD] are inputs from the AEO 2009 projections.

The total DFO energy demand (from above) and assumed DFO substitute volumes (from the biofuel demand function) are then used to determine the projection. The CTL volumes are taken directly from the user-specified AEO 2009 case. The user-specified biofuel volumes are converted to energy demands as follows:

BD [MMBtuD] = BD [MMBD] × 42 gal/bbl × LHV_{BD} [Btu/gal]

RD/BTL [MMBtuD] = RD/BTL [MMBD] × 42 gal/bbl × $LHV_{RD/BTL}$ [Btu/gal]

where:

BD [MMBD] = BD (user specified) [bgy] × (10^3 / 42 gal/bbl / 365 D/y)

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[25] Data series are represented with the following variables: Total DFO (TDFO), crude-based DFO (DFO), Biodiesel (BD), non-crude-based DFO (NDFO), bio-based DFO (BDFO), and renewable diesel/biomass-to-liquid (RD/BTL).
[26] LHV_{xTL} is assumed to be equivalent to $LHV_{RD/BTL}$.

$$\text{RD/BTL [MMBD]} = \text{RD/BTL (user specified) [bgy]} \times (10^3 / 42 \text{ gal/bbl} / 365 \text{ D/y})$$

To determine the crude-based DFO energy demand, the DFO substitute energy demands are subtracted from the total DFO energy demand:[27]

$$\text{DFO [MMBtuD]} = \text{TDFO [MMBtuD]} - \text{BD [MMBtuD]} - \text{xTL [MMBtuD]}$$

where:

$$\text{xTL [MMBtuD]} = \text{RD/BTL [MMBtuD]} + \mathit{CTL} \text{ [MMBtuD]}$$

The volume of crude-based DFO can now be determined:

$$\text{DFO [MMBD]} = \text{DFO [MMBtuD]} / 42 \text{ gal/bbl} / \text{LHV}_{\text{DFO}} \text{ [Btu/gal]}$$

The non-crude-based DFO and bio-based volumes can then be determined:

$$\text{NDFO [MMBD]} = \text{BD [MMBD]} + \text{xTL [MMBD]}$$

$$\text{BDFO [MMBD]} = \text{BD [MMBD]} + \text{RD/BTL [MMBD]}$$

These calculations are completed for each year in the projection through 2022.

The current implementation of the model does not include a blend limit for the DFO sector. Such a limit would only apply to the blending of biodiesel in the DFO pool and not to synthetic (xTL) fuels. Biodiesel, an ester (e.g. fatty-acid methyl ester), is an oxygenated fuel having different properties than hydrocarbons. As discussed in earlier sections, the distillate fuel specifications, ASTM D975 and D396, were recently updated to allow for blending with up to 5% biodiesel by volume. These specifications require that the biodiesel blendstock (B100) meets the ASTM D6751 specification prior to blending, and that the resulting blend, up to B5, meets all aspects of D975 or D396. D975 is the specification for diesel fuel oils; D396 covers fuel oils (e.g. home heating) (ASTM, 2008).

These standards are developed by representatives of the existing fuel refiners and engine manufacturers. They are designed to assure interoperability between existing fuels and existing engines. If engine and fuel technology must change to most efficiently adapt to biofuels, the current standards must change.

Current production of biodiesel is well below a hypothetical nationwide 5% blend, and projections by the EPA show that oil-based feedstocks will be limited in the foreseeable future (EPA, 2009a), limiting the production of biodiesel below such a limit. Regardless, the model could be altered to allow for greater volumes of biodiesel and the ability to implement a blend limit. Since D975 and D396 allow for blends up to B5, such blends can be treated as standard crude-based DFO in the fuel infrastructure. For higher blends, manufacturers have various limitations on the use of biodiesel; some OEMs limit use to B5, while others allow for limited

[27] *CTL (Liquids from Coal)* demand is taken from the AEO 2009 projections.

use of blends up to B20, with a minority of manufacturers allowing for very restricted use of neat biodiesel (B100) (NBB, 2009). The synthetic fuels are not burdened with this issue since they are chemically similar to crude-based DFO hydrocarbons, and exhibit some properties that are more advantageous (e.g., higher cetane, ultra-low sulfur content, etc) (ISEE, 2009).

12.3.3.5 Model output format

Results can be presented in a format analogous to Figures 12.18 through 12.21. For the motor gasoline component, the output can be displayed graphically in a time series showing the following fuel volumes (in MMBD): Total MoGas, Gasoline (crude-based), E10, E85, Ethanol, and Ethanol in E10 and E85. Likewise, for the DFO component, the output includes the following fuel volumes (in MMBD): Total DFO, crude-based DFO, Biodiesel, Bio-based DFO, and Non-crude-based DFO.

12.3.6 Model implementation

The LiFTrans model is currently implemented as a spreadsheet model in Microsoft Excel. All data sources, user input interfaces, calculations, and outputs are contained in a single workbook. For each model run, the source workbook is saved as a new file, allowing the user to modify inputs while preserving the default model settings in the source workbook.

Data sources (AEO 2009 projection data, RFS mandated biofuel volumes, conversion factors) are organized in individual worksheets as data tables. Data from the Liquid Fuels Supply and Disposition table of each AEO 2009 case are organized in 6 worksheets. User input is solicited through individual worksheet cells. The AEO case is specified through a single cell, requiring the user to enter a number (0-5) to specify the desired case (*ref*, *stimulus*, *hp*, *lp*, *hm*, and *lm*, respectively). If the user enters a number greater than 5, or less than 0, the model defaults to the *ref* case. The biofuel volumes are also entered in worksheet cells, but the user must specify annual volumes from 2009 through 2020 for a range of fuel types. Within each EPA-defined fuel category, the user can select from several biofuels, e.g., cellulosic biofuel is divided into cellulosic ethanol and cellulosic diesel (i.e., BTL). The user may specify any volume for a given biofuel in a given year, regardless of the RFS volume requirements. However, the spreadsheet notifies the user when annual requirements for a given fuel category, or total biofuel requirement, are not met. This notification is made through a change in cell color via conditional formatting. The ethanol blend limit is input in a single cell as a numeric value from 10 up to 100, representing the maximum allowable percentage of ethanol in motor gasoline. If the user enters a value outside of this range, the model defaults to 10%.

The time series of fuel volumes calculated by the model are provided as data tables and figures. Several pre-made figures with variable time frames and sets of data series are available for immediate review. Scenario results can be viewed in combination with historical trends in the liquid fuels sector as well. Due to limitations in Microsoft Excel's plotting functions, data labels and axes often need to be readjusted when inputs are altered.

The simplicity of the LiFTrans model allows for a straightforward implementation in a single Excel workbook. Despite this simplicity, the model allows for a wide range of biofuel transition scenarios to be developed.

12.3.4 Biofuel transition scenarios

Using the LiFTrans model, a set of scenarios was developed. Most scenarios utilize the AEO 2009 *stimulus* case for the total liquid fuels demand functions; the *hp* and *lp* cases are the only other projections that serve as inputs to this set of scenarios. Although the biofuel demand function is defined differently for several of the scenarios, each of the assumed biofuel consumption trends meets the annual volume requirements of the RFS. All biofuels are assumed to meet or exceed the GHG reduction requirements specified for each fuel category, as dictated by the RFS program. For example, cellulosic ethanol or cellulosic diesel could be used to satisfy the cellulosic biofuel mandate as substitutes for gasoline or diesel, respectively. Both fuels are assumed to reduce lifecycle GHG emissions by at least 60% compared to the lifecycle emissions of 2005 petroleum baseline fuels displaced by the cellulosic biofuel, such as gasoline or diesel (EPA, 2009a).

Table 12.12 lists the transition scenarios with brief descriptions of each. The scenarios are discussed in detail in the following subsections. For each scenario, the model inputs (and accompanying assumptions) and results are presented. Scenario 1 serves as a base case that complies with the RFS mandate and satisfies the projected liquid fuels demand in the AEO 2009 *stimulus* case. The remaining scenarios build off of this base case with altered assumptions (i.e., altered model inputs).

Table 12.12. The following transition scenarios were developed with the LiFTrans model.

Scenario	Description
1	RFS compliance base case
2	Increased ethanol blend limit
3	Increased consumption of biofuels in the DFO sector
4	Increased consumption of non-ethanol biofuels in the MoGas sector
5	Variable liquid fuels demand (i.e., increased/decreased liquid fuels demand)

The model assumptions and inputs used to develop these scenarios could be combined in numerous additional combinations, creating a long list of narrowly-defined transition scenarios. For instance, a decreased total liquid fuels demand scenario (i.e., 5) could be combined with a high consumption of bio-based distillate fuels scenario (i.e., 3). Such a scenario would serve to illustrate the benefits of distributing biofuels consumption between the motor gasoline and DFO sectors in order to alleviate some of the implications associated with a rapid penetration of ethanol in a motor gasoline sector with reduced overall demand. However, the scenarios presented in this section, although limited, illustrate a wide range of characteristics of, and barriers to, a biofuels transition in the liquid fuels sector.

12.3.4.1 Scenario 1: RFS compliance base case

Scenario 1 serves as a base case. Total liquid fuels demand is derived from the AEO 2009 *stimulus* case (i.e., AEO case is set to 1, the *stimulus* case). The biofuel demand function is based on annual biofuel volumes from the EPA control case presented in Table 12.10. The ethanol blend limit is set to 10%, the current limit imposed by the CAA. This base case scenario is nearly analogous to the *stimulus* case projection. However, while the *stimulus* case projection shows a shortfall in biofuels consumption, this scenario meets the annual volume requirements of the RFS through 2022.

The EPA control case results in a transition scenario that is primarily based on increasing ethanol consumption in the motor gasoline sector—an "ethanol-centric" scenario. Conventional, corn-based ethanol is capped at 15 bgy in 2015. Cellulosic ethanol production expands to satisfy the annual cellulosic biofuel mandate, and ethanol imports from Brazil satisfy a majority of the other advanced biofuels category. Consumption of bio-based distillates grows slowly, as markets for oil-based feedstocks (e.g., vegetable oils, rendered animal fats, recycled cooking grease, etc) are expected to remain tight in the foreseeable future, according to the EPA (2009a). Figures 12.25 through 12.27 show the model results for scenario 1 from 2006 through 2022.

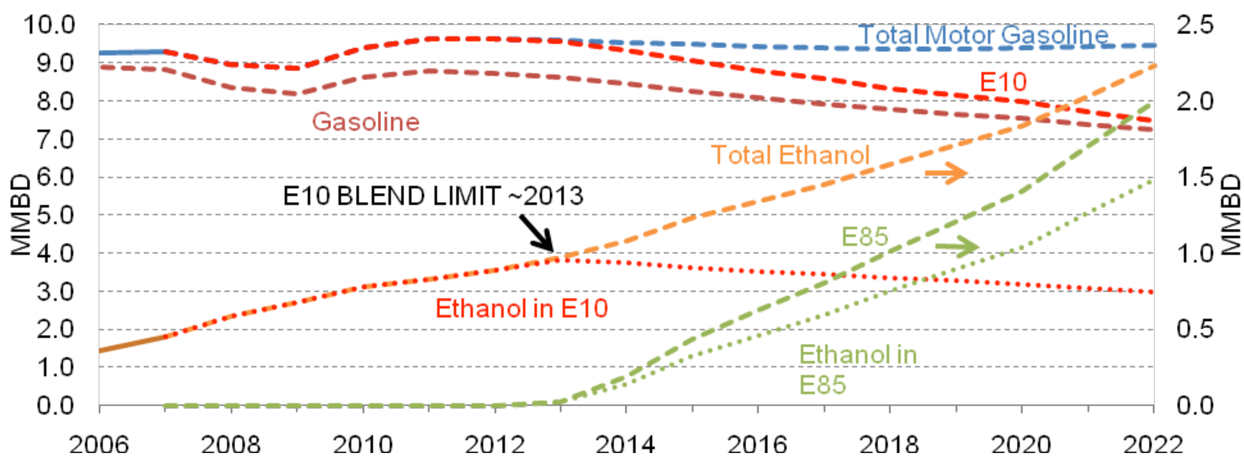


Figure 12.25. The base case scenario results in rapid penetration of ethanol in the motor gasoline sector. Crude-based gasoline consumption falls to 7.2 MMBD in 2022. The upper data sets (Total Motor Gasoline, E10, and Gasoline) are read from the left axis of the chart; the remaining data sets are read from the right.

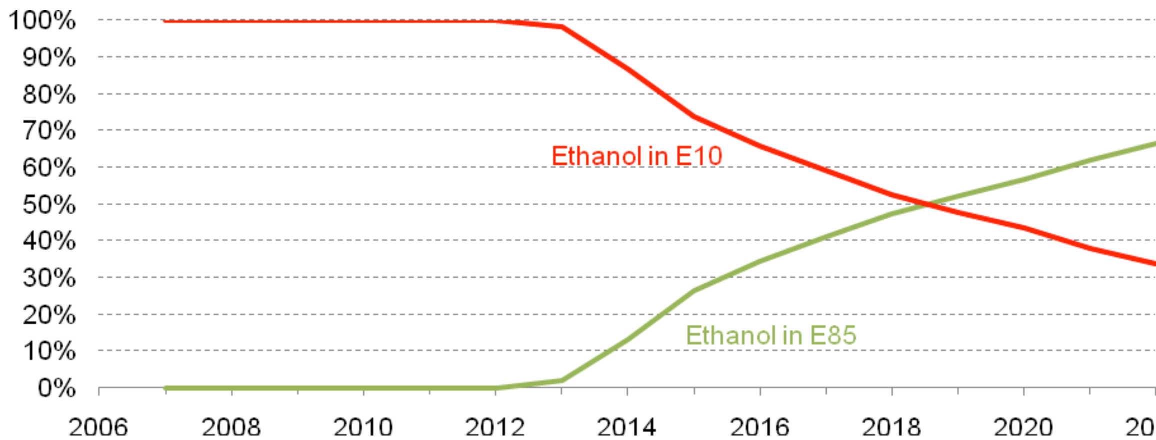


Figure 12.26. The rapid penetration of ethanol requires a transition in ethanol consumption; after the blend wall is reached in 2012, ethanol is increasingly consumed as E85 due to a shrinking crude-based gasoline supply. The left axis is the percentage of the ethanol supply blended in motor gasoline or E85.

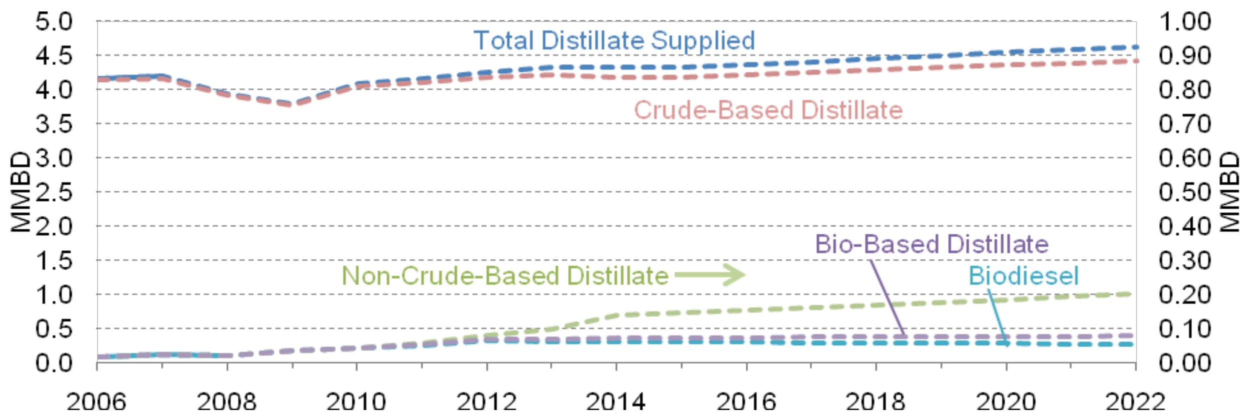


Figure 12.27. The base case scenario assumes a limited consumption of bio-based distillate, resulting in minimal displacement of crude-based distillate in the DFO sector. The upper data sets (Total Distillate Supplied and Crude-Based Distillate) are read from the left axis of the chart; the remaining data sets are read from the right. Recall that non-crude-based distillate includes bio-based distillate and CTL; bio-based distillate includes biodiesel and BTL/RD fuels. Unlike the gasoline projections, a blend wall for non-crude based distillate is not reached in these DFO projections.

Figure 12.25 illustrates the rapid penetration of ethanol into the motor gasoline sector. With flat demand for total motor gasoline, crude-based gasoline (i.e., Gasoline) consumption falls precipitously. Consumption falls from a recovered level of 8.80 MMBD in 2011 to 7.25 MMBD in 2022—a contraction of over 1.5 MMBD in just over 10 years. The 10% blend limit is reached in approximately 2013, requiring E85 to enter the market. As the crude-based gasoline supply shrinks and ethanol supply grows, ethanol must increasingly be blended as E85. By 2019, more ethanol is consumed as E85 than as motor gasoline (e.g., E10).

Recall that the model allocates all ethanol to motor gasoline blends (e.g., E10) on an annual basis until the blend limit is reached. In subsequent years, ethanol is allocated between motor gasoline blends and E85, keeping the motor gasoline blend level equal to the blend limit. This simplifying approach is based on the assumption that a negligible quantity of E85 enters the market prior to reaching the blend limit. This approach stands in contrast to analysis presented in the EPA RFS2 DRIA. EPA analysts assume that the E85 market expands prior to hitting the blend wall, such that an E85 infrastructure is being developed before the blend limit dictates the need for E85 in the motor gasoline sector (EPA, 2009a). As shown in Figure 12.22(d), EIA projections show negligible E85 penetration prior to 2013-2014, coinciding with the 10% blend limit. EIA analysts explain that penetration of E85 is delayed until more E85-compatible vehicles (i.e., FFVs) are in use and market infrastructure for E85 is expanded. The slow penetration of E85 hampers the overall growth in ethanol consumption, contributing to the shortfall projected by the EIA (EIA, 2009b). In this transition scenario, which meets the RFS mandate through rapid growth in ethanol consumption, the need for FFVs and E85 infrastructure is magnified.

Results for the DFO sector are shown in Figure 12.27. With constrained production of bio-based distillates in the EPA control case, biofuels supply less than 2% of total distillate demand (on a volume basis) in 2022, resulting in a minimal displacement of crude-based distillate.

12.3.4.2 Scenario 2: Increased ethanol blend limit

Scenario 2 examines the impacts of an increased ethanol blend limit. Since the blend limit variable only impacts results for the motor gasoline sector, results for the DFO sector are omitted.[28] All inputs and assumptions are analogous to scenario 1, expect for the blend limit variable, which is increased up to 20%. By altering the blend limit parameter while holding all other parameters constant, implications of the blend wall are revealed. Results for scenario 2 are presented in Figures 12.28 through 12.30.

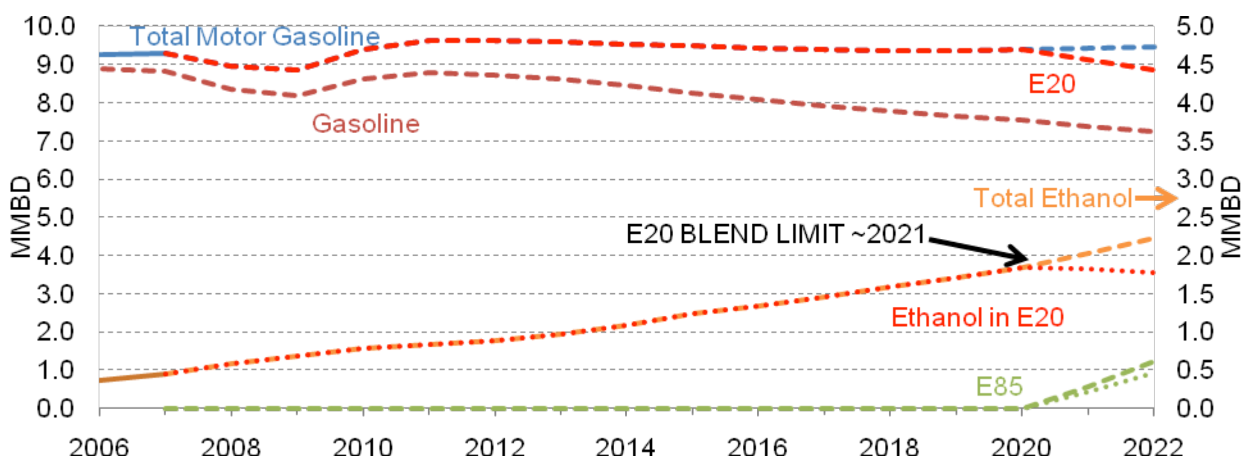


Figure 12.28. Increasing the blend limit from 10 to 20% (i.e., E20) delays the introduction of E85 by approximately 8 years. Note the change of scale on the right axis when compared to Figure 12.8. The upper data sets (Total Motor Gasoline, E10, and Gasoline) are read from the left axis of the chart; the remaining data sets are read from the right.

[28] For discussions on blend limits in the DFO sector, refer to section 12.3.3.4.2

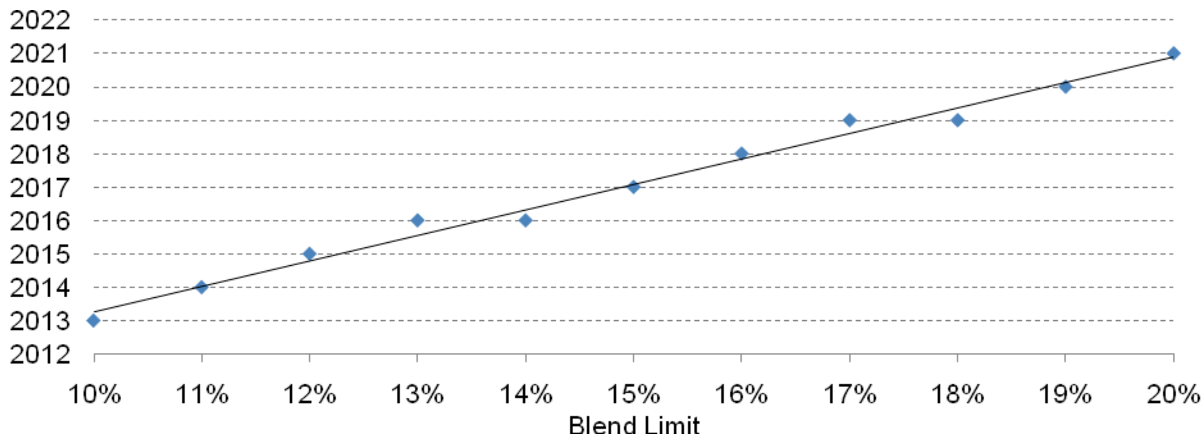


Figure 12.29. By increasing the blend limit variable from 10% to 20%, a relationship between the blend limit year and percentage is revealed. The left axis is the year when the blend limit is reached for a given blend limit percentage.

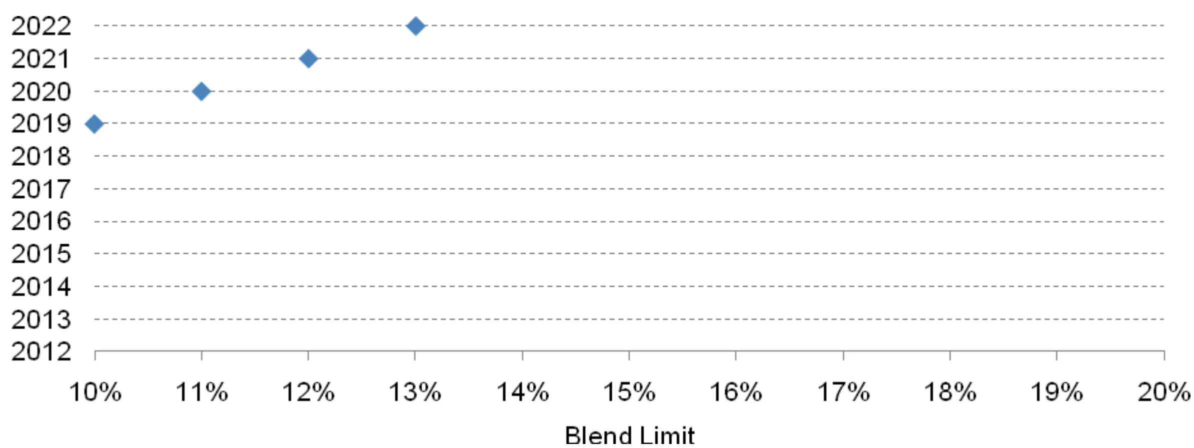


Figure 12.30. This figure shows the year at which ethanol consumption in E85 first exceeds ethanol consumption in motor gasoline for a given blend limit percentage. For example, a blend limit of 10% requires more ethanol to be consumed as E85 starting in 2019. When the blend limit exceeds 13%, the amount of ethanol blended as E85 never exceeds the amount blended in motor gasoline through 2022.

Recall that the data series labeled as 'E20' and 'Ethanol in E20' in Figure 12.28 do not represent volumes of E20 throughout the entire time series. Once the 20% blend limit is reach in 2021, the data do in fact represent a motor gasoline pool that is, on average, at a 20% blend. Prior to reaching the limit, the average blend level is less than 20%. Since this scenario is based directly on scenario 1, the average blend level in 2013 is 10%, the year the 10% blend limit is reached in scenario 1.

The impact of increasing the blend limit is shown in Figure 12.28. The 20% blend limit is reached around 2021, 8 years later than the 10% limit. With an increased blend limit, the need to develop an E85 market is delayed, and the amount of ethanol needed to be consumed as E85 is drastically reduced. In 2022, the 10% limit requires 1.5 MMBD of ethanol to be consumed as E85 (66% of total ethanol), while the 20% limit requires only 0.5 MMBD (20% of total ethanol).

Figure 12.29 was developed by increasing the blend limit variable from 10% to 20% in 1% increments and determining the year when the given blend limit is reached. Between the 10% and 20% limits, the relationship is essentially linear—the 15% limit is reached in 2017, the midpoint between the 10% and 20% limits. Figure 12.30, which also plots the blend limit percent on the horizontal axis, shows the year when ethanol consumption in E85 first exceeds that in motor gasoline. At a 10% blend limit, this occurs in 2019. If the limit is increased above 13%, a greater volume of ethanol is consumed in motor gasoline blends through 2022, i.e., the E85 market requires a smaller share of the total ethanol supply through 2022.

Currently, the CAA sets a 10% limit on ethanol in motor gasoline blends. In the CAA, the "substantially similar" rule limits oxygen content in motor gasoline fuels to 2.7% by weight (EPA, 1991):

> The allowable oxygen content for a "substantially similar" unleaded gasoline is…2.7 percent by weight, for blends of aliphatic alcohols and/or ethers, excluding methanol.

This oxygen limit equates to an ethanol-in-gasoline blend of 7.0% to 7.5%. A 10% blend results in an oxygen content of 3.7%, which exceeds the "substantially similar" rule by 1%. Ethanol blends are allowed to exceed the oxygen limit due to an approved waiver request under section 211(f) of the CAA (EPA, 1995b). In order to increase the limit beyond 10%, an amendment to the CAA or another waiver request must be approved. Growth Energy and 54 ethanol manufacturers submitted such a request on March 6, 2009, seeking a waiver for blends up to 15% (i.e., E15). The Administrator of the EPA was originally scheduled to grant or deny this request by December 1, 2009 (EPA, 2009a; EPA, 2009b)[29], however in late November, a decision was announced to delay a decision until mid 2010.

In the RFS2 DRIA, the analysis is primarily centered on an E10/E85 future. In addition, EPA analysts investigated the possibility of a waiver request to increase the blend limit. E15 and E20 blend limits. This analysis does not simply shift from an E10/E85 market to an E15/E85 or E20/E85 market. Instead, the EPA acknowledges that there may be a need to continue to supply E10 for legacy vehicles. Vehicle manufacturers warrant non-FFV vehicles to run on blends no greater than E10. Therefore, unless manufacturers grant approval for legacy vehicles to operate on blends greater than E10, the market must continue to have a sufficient supply of E10. The EPA assumes that such an approval would not be granted for the legacy fleet. Therefore, in their analysis, the motor gasoline supply consists of E10 for legacy vehicles, E15/E20 for Tier 2 or FFVs, and E85 exclusively for FFVs. Despite this complication, the average blend level of motor gasoline (not including E85) still increases. With a blend limit of 15-20%, the average blend level of motor gasoline would stand between 10% and 15-20%. Although a portion of the motor gasoline market might still need to be supplied with E10, by allowing greater penetration of mid-level blends (e.g., E15), the size of the E85 market is reduced. In the simple scenario presented above, the blend limit could represent the average blend level of motor gasoline, which

[29] On November 30, 2009, the EPA notified Growth Energy that the waiver request decision would be delayed until mid-year 2010, pending results from DOE vehicle test programs. The letter can be viewed here: http://www.growthenergy.org/static/docs/2009/11/letter_EPAtoGrowthEnergy.pdf

could be made up of blends ranging from 0-20%. Implications of altering the blend are discussed further in later sections.

12.3.4.3 Scenario 3: Increased consumption of bio-based distillate

Scenario 3 investigates the impacts of shifting biofuels consumption away from the motor gasoline sector by increasing bio-based distillate consumption. All inputs and assumptions are analogous to scenario 1, expect for the biofuel demand function. Two model runs were conducted as part of this scenario, presented below as scenarios 3(a) and 3(b). These scenarios depart from the "ethanol-centric" futures that are based on the biofuel assumptions of the EPA control case.

12.3.4.3.1 Scenario 3(a)

In this scenario, the cellulosic biofuel mandate is split evenly between cellulosic ethanol and cellulosic diesel (i.e., BTL) annually. For example, in 2015, the 3 bgy mandate is met with 1.5 bgy of ethanol and 1.5 bgy of BTL. In addition, the volumes of imported ethanol in the EPA control case are shifted entirely to the production of bio-based distillate (e.g., renewable diesel and/or BTL). Results are presented in Figures 12.31 through 12.34.

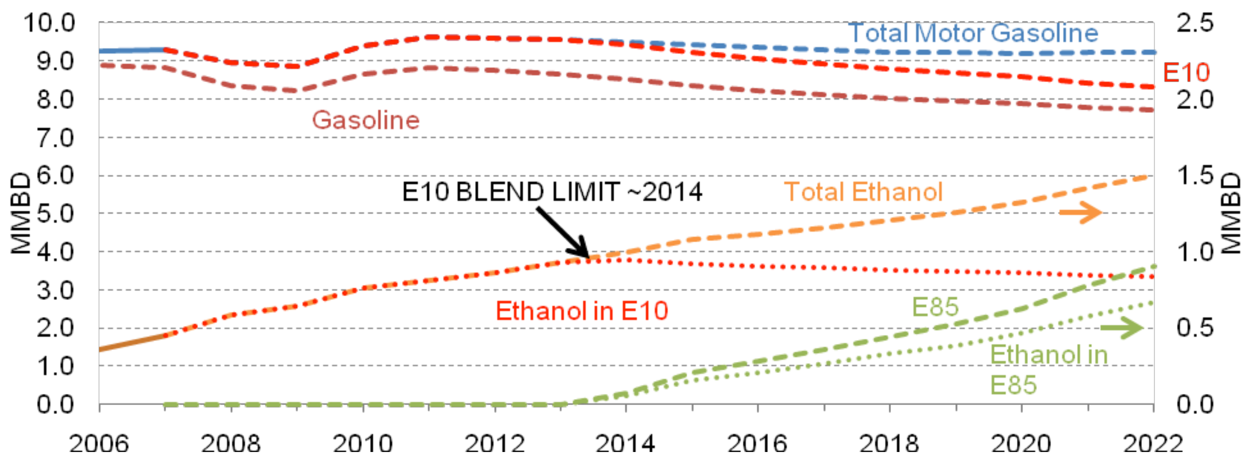


Figure 12.31. Total ethanol consumption is reduced due to the altered biofuel assumptions; only one half of the cellulosic biofuel requirement is met with ethanol. By diverting this biofuel consumption from the motor gasoline to the DFO sector, the blend limit is delayed by 1 year, the growth of the E85 market is reduced, and ethanol consumption in motor gasoline is greater than in E85 through 2022 (see Figure 12.33).

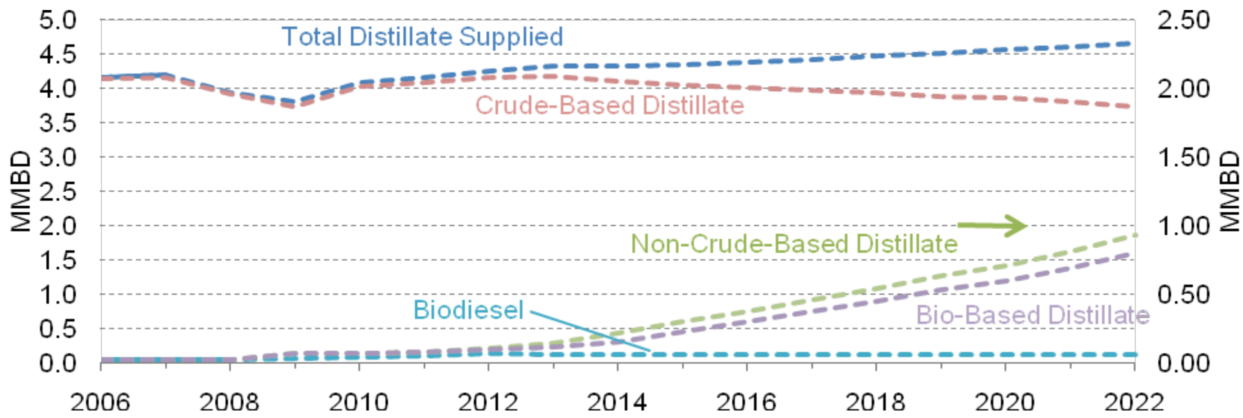


Figure 12.32. Scenario 3 assumes that one half of cellulosic biofuel consumption is met with cellulosic diesel (i.e., BTL). The increased supply of bio-based distillate results in a decrease in crude-based distillate demand after 2013, mimicking the "peak gasoline" phenomenon in the motor gasoline sector. Note the change of scale on the right axis when compared to Figure 12.27.

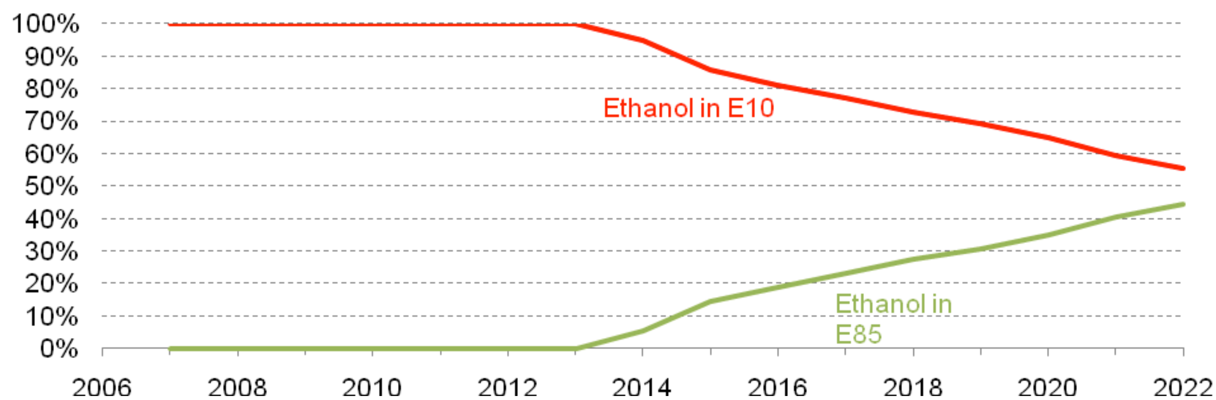


Figure 12.33. Ethanol consumption in motor gasoline (i.e., E10) is greater than in E85 through 2022 due to the reduced market penetration of cellulosic ethanol (and total ethanol). The left axis is the percentage of the ethanol supply blended in motor gasoline or E85.

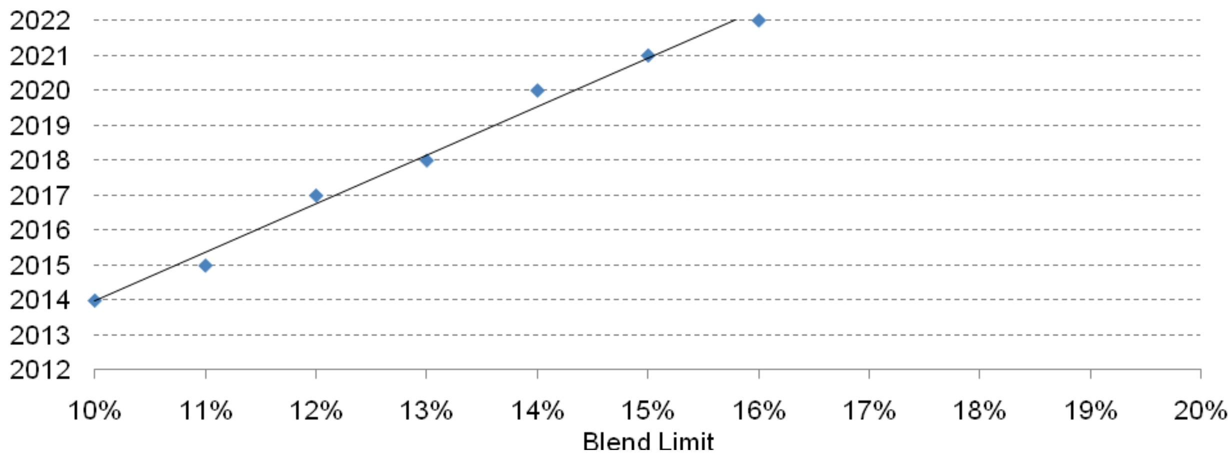


Figure 12.34. When compared to Figure 12.29, which is based on the base case scenario, the blend limit trend is shifted up and has a greater slope, i.e., the decrease in total ethanol consumption delays the blend limit year for a given blend limit percentage. If the blend limit is greater than or equal to 16%, no E85 market is needed through 2022.

Total ethanol consumption in 2022 is reduced by 0.5 MMBD to 1.5 MMBD when compared to scenario 1; with less total ethanol consumption, crude-based gasoline consumption does not decline as rapidly. The E10 blend limit is delayed by only 1 year to 2014. However, with slower growth in total ethanol consumption, the E85 market develops slowly, and the majority of the ethanol supply is consumed as motor gasoline (i.e., E10) through 2022 (see Figure 12.33). Figure 12.34 shows the results of increasing the blend limit above 10%. Like Figure 12.29, increasing the blend limit delays the year when the blend limit is reached. But, in this case, since total ethanol consumption grows more slowly than in scenario 2, a given increase in the blend limit percentage delays the blend limit year more rapidly. For example, when the blend limit is increased from 10% to 15% in this scenario, the blend limit year is delayed by 7 years (2014 to 2021). As shown in Figure 12.29, this same increase in the blend limit for scenario 2 causes a delay of only 4 years (2013 to 2017). For a blend limit greater than or equal to 16%, no E85 market is needed through 2022.

Results for the DFO sector are shown in Figure 12.32. In 2022, consumption of bio-based distillate is increased by more than 0.7 MMBD when compared to scenario 1. The growth in bio-based distillate consumption causes demand for crude-based distillate to subside after a peak in 2013. From 2013 to 2022, consumption of crude-based distillate is reduced by 0.3 MMBD. This drop in crude-based distillate mimics the "peak gasoline" phenomenon in the motor gasoline sector. In addition, for each gallon of ethanol replaced by bio-based distillates, a greater amount of the total liquid fuels energy demand is met, thereby reducing the total volume of liquid fuels consumption.[30] In 2022, this scenario results in a total liquid fuels volume of 13.89 MMBD compared to 14.10 MMBD for scenarios 1 and 2—a reduction of 212 MBD.

[30] Recall that the liquid fuels transition model is designed to satisfy the energy demanded by the motor gasoline and DFO sectors, not the volume, since different fuels have different energy contents.

4.4.3.2 Scenario 3(b)

Scenario 3(b) is analogous to 3(a) in all regards except that the annual volume mandate for cellulosic biofuel is met entirely with cellulosic diesel (i.e., BTL). For example, in 2015, the 3 bgy mandate is met with 3 bgy of BTL. Results are presented in Figures 12.35 and 12.36.

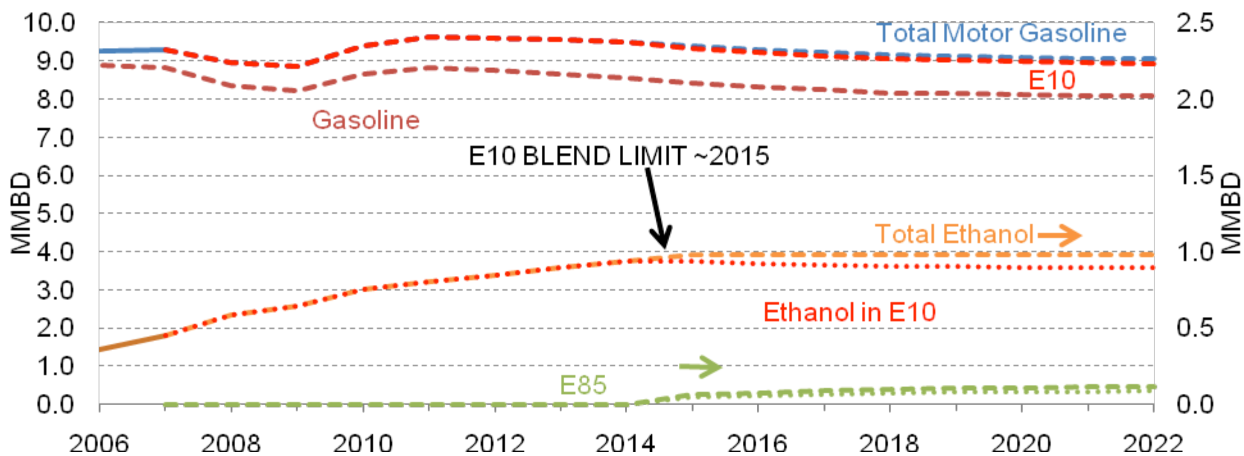


Figure 12.35. Total ethanol consumption plateaus in 2015 when the non-advanced biofuel, or conventional biofuel, category is capped at 15 bgy (~1 MMBD). With the entire cellulosic biofuel mandate shifted to the DFO sector, the ethanol supply does not grow beyond 2015.

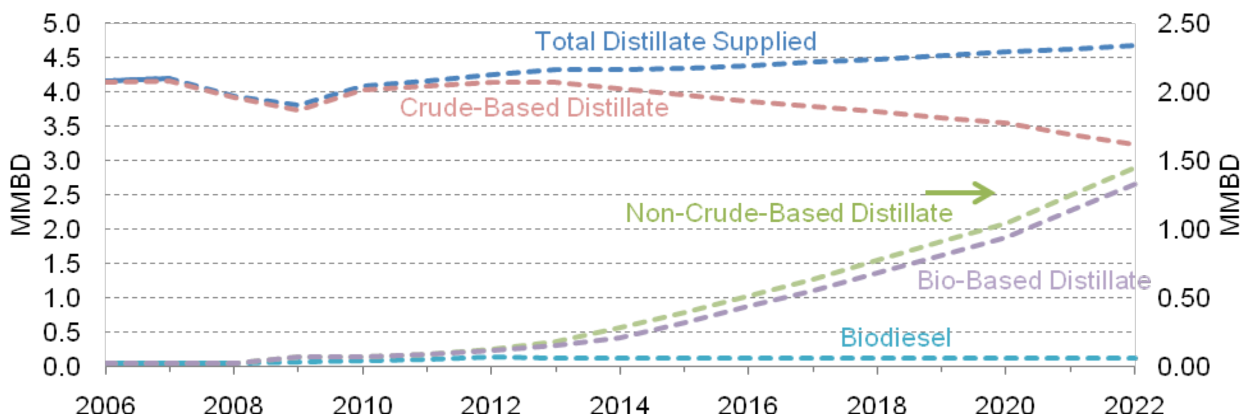


Figure 12.36. The bio-based distillate supply grows rapidly as cellulosic diesel is produced to meet the cellulosic biofuel mandate. Crude-base distillate consumption drops rapidly after 2013 and is 0.5 MMBD less in 2022 when compared to scenario 3(a). From 2013 to 2022, crude-based distillate consumption contracts by nearly 1 MMBD.

Results for scenario 3(b) exhibit the same trends as 3(a), except that these trends are magnified. Since the entire cellulosic biofuel mandate is met with BTL, total ethanol consumption stops growing after the conventional biofuel category is capped at 15 bgy (~1 MMBD) in 2015. Since total motor gasoline demand is nearly constant after 2015, consumption trends exhibit negligible change through 2022.

Unlike scenario 3(a), there is no blend limit chart (e.g., Figure 12.34) shown for scenario 3(b). If this chart is produced for scenario 3(b), only one data point would be shown—the 10% limit in

2015. Since the ethanol supply does not expand beyond 2015, an 11% limit is never reached in this scenario. By increasing the blend limit to 11%, an E85 market becomes unnecessary since all ethanol is able to be blended as motor gasoline (up to E11).

Rapid growth in bio-based distillate consumption results in a precipitous drop in crude-based distillate consumption after 2013, falling by nearly 1 MMBD from 2013 to 2022. With even more ethanol replaced by the higher energy containing bio-based distillate (i.e., BTL), total liquid fuels volume falls to 13.74 MMBD—a reduction of 364 MBD when compared to the "ethanol-centric" scenarios (1 and 2). This reduction in total liquid fuels volume results not only from the replacement of ethanol with bio-based distillate, but also from the need for crude-based gasoline to supply the energy demand in the motor gasoline sector that is no longer supplied by ethanol. This issue is illustrated by the slight reduction in total motor gasoline consumption (e.g., in 2022) when comparing scenarios 3(a) and (b), i.e., Figures 12.31 and 12.35.

12.3.4.4 Scenario 4: Increased consumption of non-ethanol bio-based gasoline

Scenario 4 is similar to scenario 3(b), except that the cellulosic ethanol is replaced by other bio-based gasoline substitutes, like renewable gasoline or biobutanol, rather than bio-based distillate. Only one model run was executed, with renewable gasoline replacing cellulosic ethanol in the biofuel demand function. A biobutanol scenario was not run through the model.

12.3.4.4.1 Renewable gasoline

When compared to the base case scenario, only the biofuel demand function is altered. The cellulosic biofuel mandate is met entirely with renewable gasoline rather than cellulosic ethanol. This change is based on the assumption that renewable gasoline, a bio-derived synthetic gasoline, is produced from cellulosic feedstocks and meets the lifecycle GHG emissions reduction target for cellulosic biofuel (60%). Since renewable gasoline is chemically identical to crude-based gasoline, the blend limit and infrastructure compatibility issues that face ethanol do no apply. The 10% blend limit still applies to the remaining ethanol supply, and total demand is still based on the AEO 2009 *stimulus* case.

Minor changes to the model calculations for the motor gasoline component were needed to execute the model run for this scenario. Renewable gasoline was not incorporated into the motor gasoline calculations in the base model. With energy content nearly identical to crude-based gasoline,[31] renewable gasoline is treated as an additional supply of crude-based gasoline. In the ethanol blend calculations, renewable gasoline and crude-based gasoline volumes are combined for blending with ethanol. However, since renewable gasoline is a biofuel, it still acts to reduce crude-based gasoline consumption.

Results for the motor gasoline sector are presented in Figures 12.37 and 12.38. DFO results are identical to scenario 1 since the inputs impact only the motor gasoline results; see Figure 12.27.

[31] Referring to Table 12.4, the LHVs of renewable gasoline and crude-based gasoline are 115,983 and 115,261 Btu/gallon, respectively.

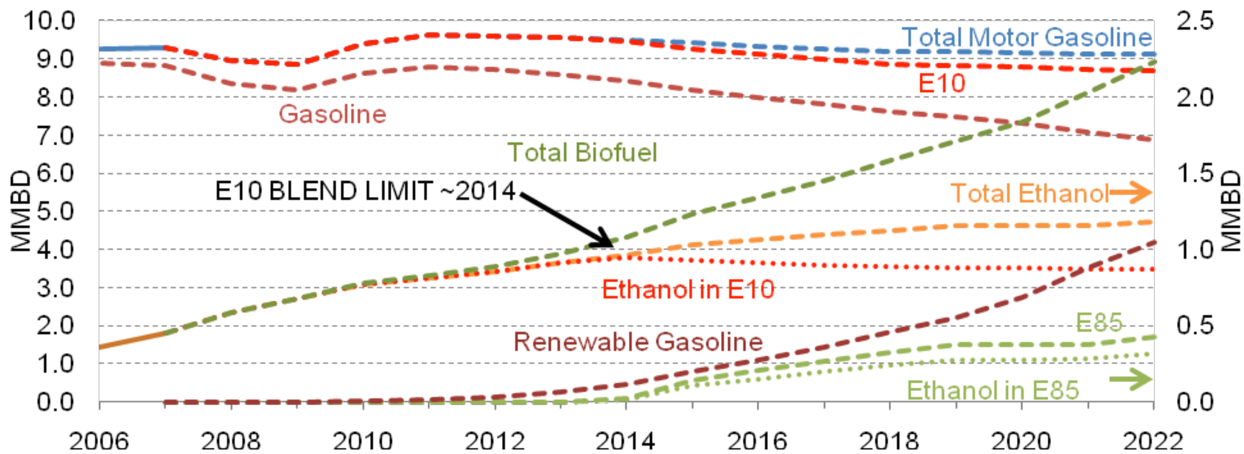


Figure 12.37. The renewable gasoline industry replaces the cellulosic ethanol industry in this scenario. The E10 blend limit is delayed by one year relative to the base case (i.e., scenario 1). However, with the slow growth in ethanol consumption after 2015, market penetration of E85 is reduced. The upper data sets (Total Motor Gasoline, E10, and Gasoline) are read from the left axis of the chart; the remaining data sets are read from the right.

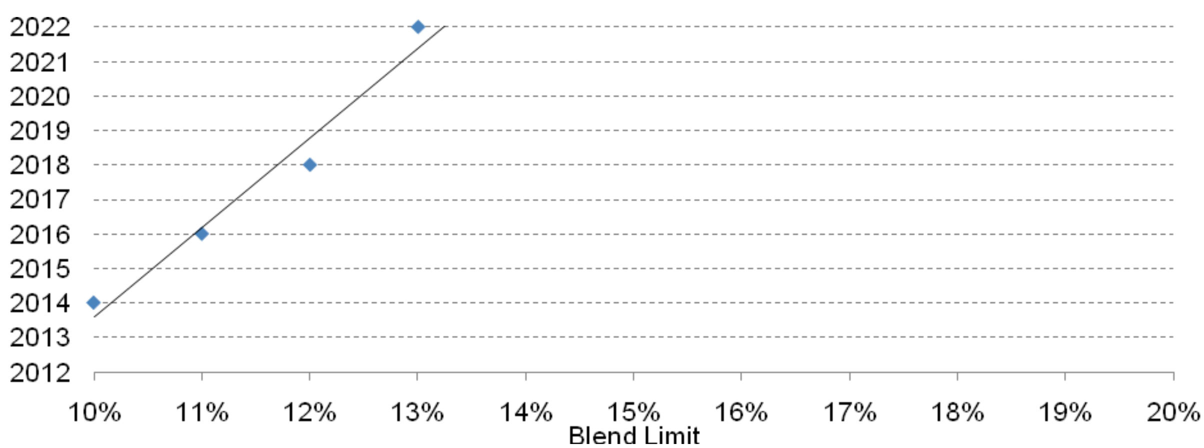


Figure 12.38. As biofuel consumption in the motor gasoline sector shifts from ethanol to renewable gasoline, the blend limit year is delayed for a given percentage when compared to the base case (see Figure 12.29). If the blend limit is greater than or equal to 13%, no E85 market is needed through 2022.

By substituting cellulosic ethanol with renewable gasoline, several changes occur. First, although the blend limit is delayed by only 1 year when compared to scenario 1, the slower growth in ethanol consumption in subsequent years results in a slow penetration of E85. With a smaller E85 market, more ethanol is consumed as motor gasoline (i.e., E10) through 2022. Second, increasing the blend limit delays the blend limit year very rapidly. As shown in Figure 12.38, an increase in the blend limit from 10% to 13% causes a delay of 8 years (2014-2022). Compared to scenario 2 (Figure 12.29), this same increase in the blend limit saves only 3 years (2013-2016). Again, when the blend limit year is delayed, the market entry of E85 is similarly delayed (and the size of the E85 market is limited). Third, due to the gallon-for-gallon replacement of ethanol with renewable gasoline, a greater reduction in crude-based gasoline consumption results when compared to scenario 1. Crude-based gasoline consumption falls to 6.89 MMBD in 2022, compared to 7.25 MMBD in the base case.

12.3.4.4.2 Biobutanol

Biobutanol has been cited as a gasoline substitute with more advantageous properties than ethanol. Biobutanol is the term given to butanol (i.e., C_4H_9OH) that is derived from biomass an intended for use as a fuel. The energy content of butanol is 99,837 Btu/gal (LHV) (Wang, 2009). Butanol's energy content is over 30% greater than that of ethanol (76,330 Btu/gal). Butanol also has a slightly higher density than ethanol. Integrating butanol blends into the motor gasoline sector could alleviate some of the challenges posed by ethanol (e.g., phase-separation in the presence of water). Advocates of butanol explain that the alcohol could be blended at higher percentages than ethanol before encountering material compatibility issues in vehicles and the distribution and retail infrastructure (Reardon and Silcock, 2007).

However, the "substantially similar" rule of the CAA currently limits butanol content in gasoline to 11.5% by volume (EPA, 1991). Recall from section 12.3.4.2 that the "substantially similar" rule limits oxygen content in unleaded gasoline to 2.7% by weight. Unlike ethanol, butanol has not been granted a waiver (EPA, 1995b). The ethanol waiver allows for 10% blends of ethanol by volume, which equates to an oxygen content of 3.7% by weight. If a butanol waiver was approved, allowing butanol to be blended with gasoline to a maximum oxygen content of 3.7% by weight, then butanol blends up to 16% would be permitted. The following equation is used determine the oxygen content of alcohol-gasoline blends:

$$\%\text{ O by wt.} = \frac{\left(\frac{\text{blend }\%}{100} * \rho_{\text{alcohol}} * \frac{16\text{ g}}{\text{MW}_{\text{alcohol}}}\right)}{\left(\frac{\text{blend }\%}{100} * \rho_{\text{alcohol}}\right) + \left(\left(1 - \frac{\text{blend }\%}{100}\right) * \rho_{\text{gasoline}}\right)}$$

$$3.7\%\text{ O by wt.} = \frac{\left(0.16 * 3065\,\frac{\text{g}}{\text{gal}} * \frac{16\text{ g}}{74\text{ g}}\right)}{\left(0.16 * 3065\,\frac{\text{g}}{\text{gal}}\right) + \left((1 - 0.16) * 2819\text{ g/gal}\right)}$$

Without an approved waiver request under section 211(f) of the CAA, butanol would likely do little to alter a biofuel transition in the motor gasoline sector. Compared to the 10% limit imposed on ethanol, the dynamics of a transition would be only slightly altered with an 11.5% limit imposed on butanol. With an approved waiver request, substituting ethanol with butanol on a gallon-for-gallon basis would delay the blend limit (from 10% to 16%) and limit the need for a high-blend market. Greater reductions in crude-based and total motor gasoline consumption would result from the increase in energy content when ethanol is replaced with butanol. However, since an ethanol industry is already established, the wholesale replacement of ethanol with butanol, at least in the near term, is improbable. If a butanol industry develops to supply the motor gasoline sector, questions could arise as to whether ethanol-gasoline blends could co-mingle with butanol-gasoline blends. In addition, the advantages of utilizing butanol as a fuel could be outweighed by the challenges of incorporating a second alcohol fuel into the motor gasoline supply.

In 2006, DuPont and BP publicly announced their plans to develop biobutanol for the commercial market. The two companies have been working jointly since 2003 to develop the fuel, and had planned to introduce the first commercial volumes of biobutanol in Europe in 2007 (Dupont, 2009). However, these plans appear to have been delayed, with a subsequent announcement explaining that "market development" quantities of biobutanol were to be introduced in the UK in early 2009 (Childs, 2007). A more recent announcement explains that BP is planning to produce commercial quantities of biobutanol from a facility in the UK by 2012/2013 (Trompiz, 2009).

4.3.4.5 Scenario 5: Variable liquid fuels demand

Total liquid fuels demand is based on the AEO 2009 *stimulus* case in scenarios 1-4. For this final set of scenarios, the impact of increasing/decreasing total liquid fuels demand is investigated. The *lp* and *hp* cases are used to alter the total liquid fuels demand function. The biofuel demand function is identical to the base case (i.e., scenario 1), and the blend limit is initially set to 10%. The effect of altering the blend limit is also assessed. Two model runs were executed, and are presented below as scenarios 5(a) and (b). The scenarios differ only in their specification of the AEO 2009 case: scenario 5(a) uses the *hp* case; scenario 5(b) uses the *lp* case.
Several factors could impact total liquid fuels demand in the coming decade:

- Deepened economic recession;
- Economic recovery and sustained growth;
- Increased electrification of the LDV fleet (e.g., HEV, PHEV, EV);
- Dieselization;
- Increased fuel efficiency standards (e.g., CAFE);
- Altered consumer behavior (e.g., reduction in VMT, increased use of mass transit);
- FFV production (and sales) rates.

Assessing the probability of occurrence and quantitative impacts of such factors in the liquid fuels sector is beyond the scope of this report. Rather than undertaking such an exercise, the simple scenarios presented below help to illustrate the general impacts that changes in total liquid fuels demand could have on a biofuels transition. Although the AEO 2009 *hp* and *lp* cases are based on altered assumptions related to future world oil prices, any number of the factors listed above could influence liquid fuels demand in qualitatively similar ways. In addition, the overarching design of the RFS mandate can be assessed by altering the total liquid fuels demand function. As a volume-based mandate, the RFS program requires an annually increasing volume of biofuels to be consumed, regardless of changes in total demand. This design influences how a biofuels transition will unfold in the next decade.

4.4.5.1 Scenario 5(a): Decreased liquid fuels demand

Scenario 5(a) derives total liquid fuels demand from the AEO 2009 *hp* case, bases the biofuel demand function on EPA control case volumes, and initially applies a 10% blend limit in the motor gasoline sector. Results are presented in Figures 12.39 through 12.43.

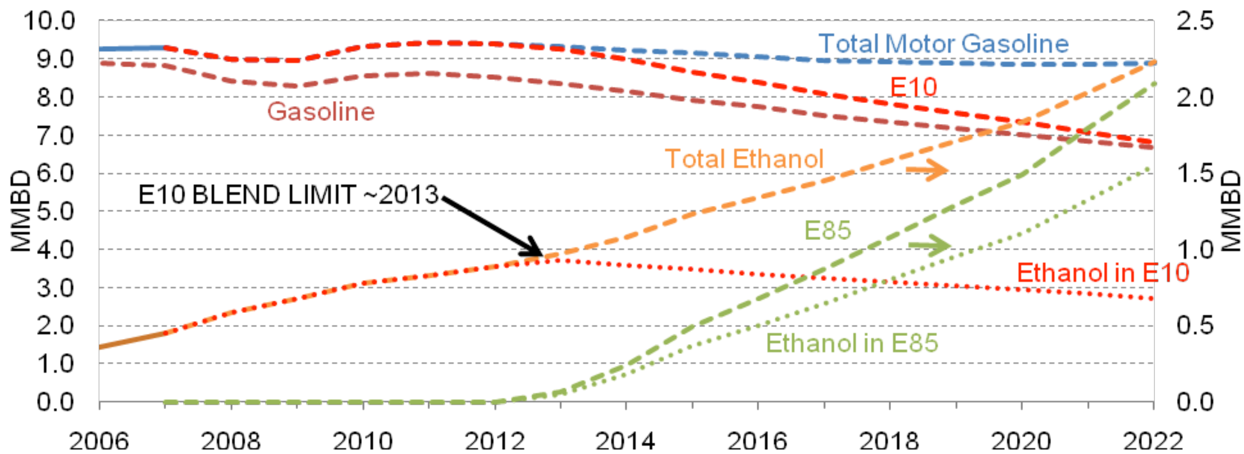


Figure 12.39. The AEO2009 *hp* case results in decreased total motor gasoline demand. Crude-based gasoline consumption falls rapidly compared to the base case (i.e., scenario 1). The upper data sets (Total Motor Gasoline, E10, and Gasoline) are read from the left axis of the chart; the remaining data sets are read from the right.

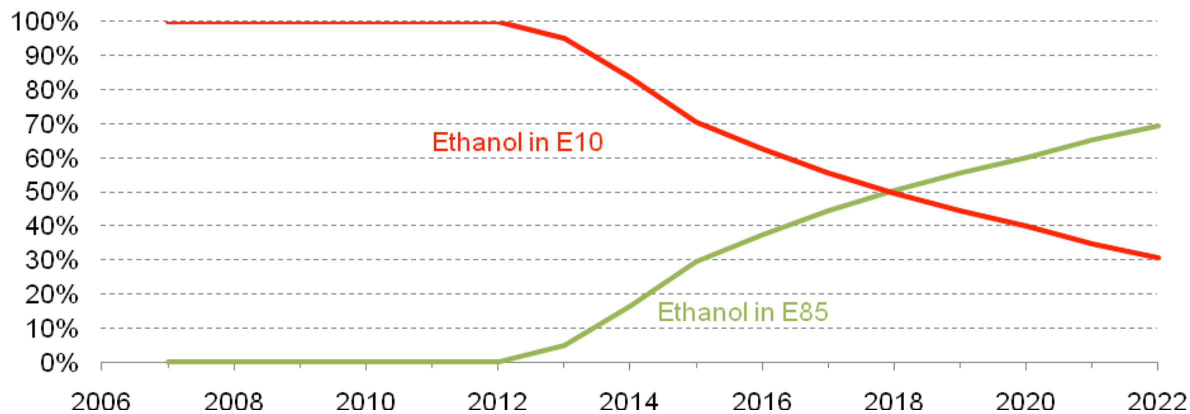


Figure 12.40. By 2018, more ethanol is consumed in E85 than in motor gasoline blends (e.g., E10). In 2022, ~70% of the ethanol supply is blended as E85. The left axis is the percentage of the ethanol supply blended in motor gasoline or E85.

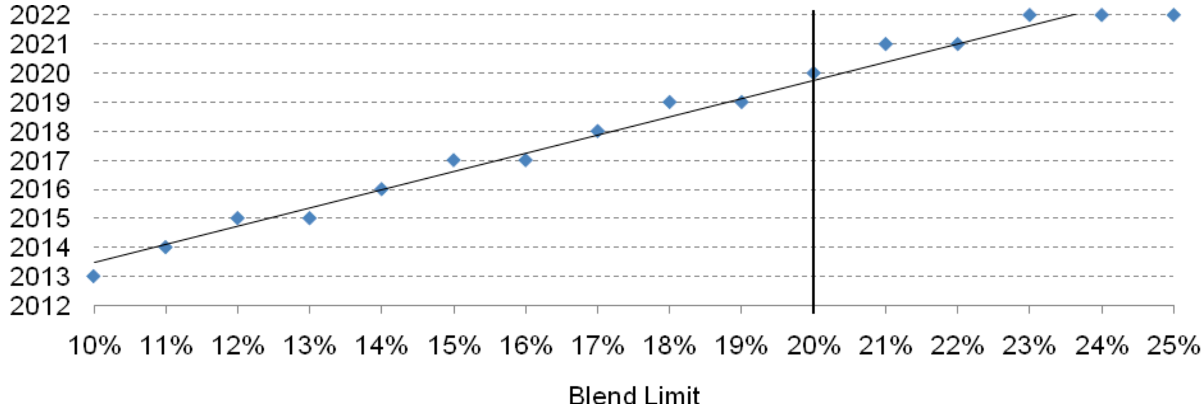


Figure 12.41. When compared to Figure 12.29, the blend limit year advances less for a given increase in the blend limit percentage. The blend limit must be increased beyond 25% to eliminate the need for an E85 market through 2022. The left axis is the year when the blend limit is reached for a given blend limit percentage.

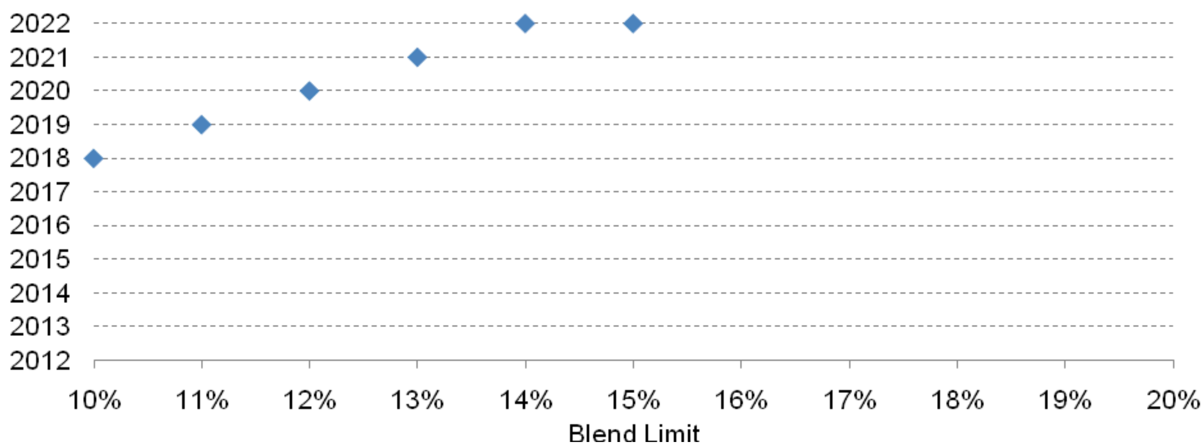


Figure 12.42. This figure shows the year at which ethanol consumption in E85 first exceeds ethanol consumption in motor gasoline (e.g., E10) for a given blend limit percentage (e.g., 10%).

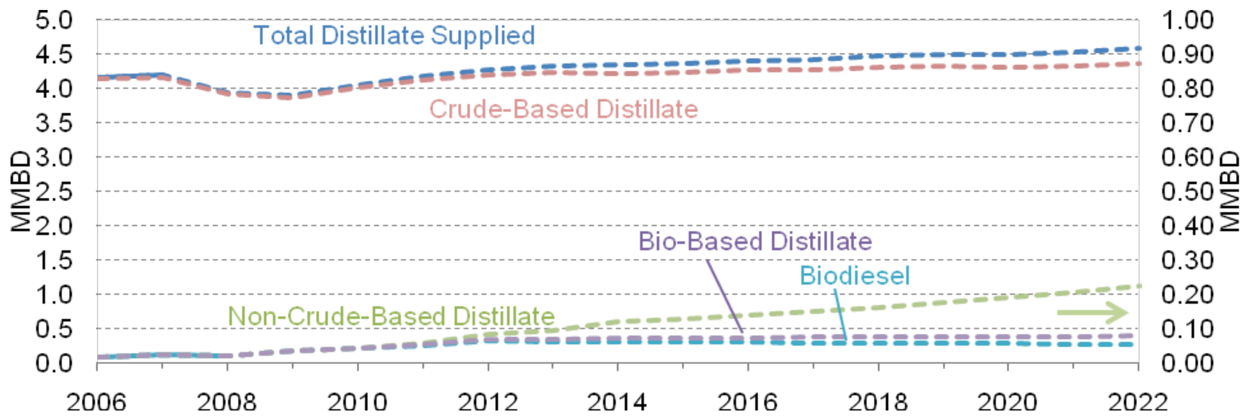


Figure 12.43. The AEO2009 *hp* case has little impact on total distillate demand. Since the EPA control case is used for biofuel demand assumptions, the DFO sector sees little penetration of biofuels, like scenario 1.

As shown in Figure 12.39, total motor gasoline demand falls below 9 MMBD in 2017. In scenario 1 (Figure 12.25), demand stays well above 9 MMBD, increasing to approximately 9.5 MMBD in 2020. The impacts of this reduced demand are immediately evident. As total ethanol consumption rises to satisfy the RFS, crude-based gasoline consumption falls rapidly, falling below 7 MMBD after 2020. By 2022, over 2 MMBD of crude-based gasoline demand is eliminated from its peak of nearly 9 MMBD. The 10% blend limit is still reached in 2013, but with falling total demand and increasing total ethanol consumption, the E85 market expands rapidly, requiring more ethanol than the motor gasoline market (i.e., E10) after 2017. By 2022, 70% of the ethanol supply is blended as E85 (see Figure 12.40). In 2022, ethanol supplies one-quarter of the volume in the motor gasoline sector.

By comparing Figure 12.41 to 12.29, the impact of increasing the blend limit is shown to differ little from the base case scenario. The 20% blend limit is reached in 2020, compared to 2021 in scenario 2. The blend limit must be increased beyond 25% to eliminate the need for an E85 market through 2022. The base case reaches this point when the blend limit is increased above 23%. Figure 12.42 shows that when the blend limit exceeds 15%, the amount of ethanol consumed as E85 never exceeds the consumption of ethanol in motor gasoline (e.g., E16) through 2022.

The AEO 2009 *hp* case has minimal impacts on total distillate demand. Since the biofuel demand function is again based on the EPA control case, there is little penetration of bio-based distillate. The impacts of a reduced distillate demand can be assessed by imagining the AEO 2009 *lm* case being combined with the biofuel demand function from either scenario 3(a) or (b). With growing consumption of bio-based distillate, and falling total distillate demand, crude-based distillate consumption would fall rapidly.

4.3.4.5.2 Scenario 5(b): Increased liquid fuels demand

Scenario 5(b) uses the AEO 2009 *lp* case for total liquid fuels demand, bases the biofuel demand function on EPA control case volumes, and initially applies a 10% blend limit in the motor gasoline sector. Results are presented in Figures 12.44 through 12.48.

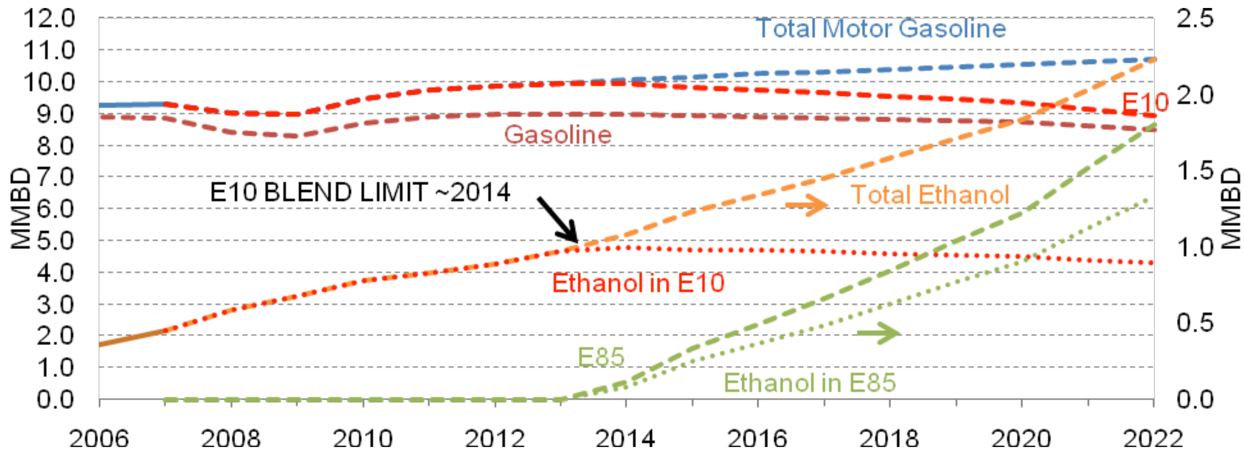


Figure 12.44. The AEO2009 *lp* case results in increased total motor gasoline demand. The 10% blend limit is delayed by one year, when compared to the *stimulus* and *hp* cases (i.e., scenarios 1 and 5a, respectively). Crude-based gasoline consumption remains nearly flat through 2022. Note the change of scale in the left axis when compared to Figure 12.25, or any other motor gasoline figure in this section. The upper data sets (Total Motor Gasoline, E10, and Gasoline) are read from the left axis of the chart; the remaining data sets are read from the right.

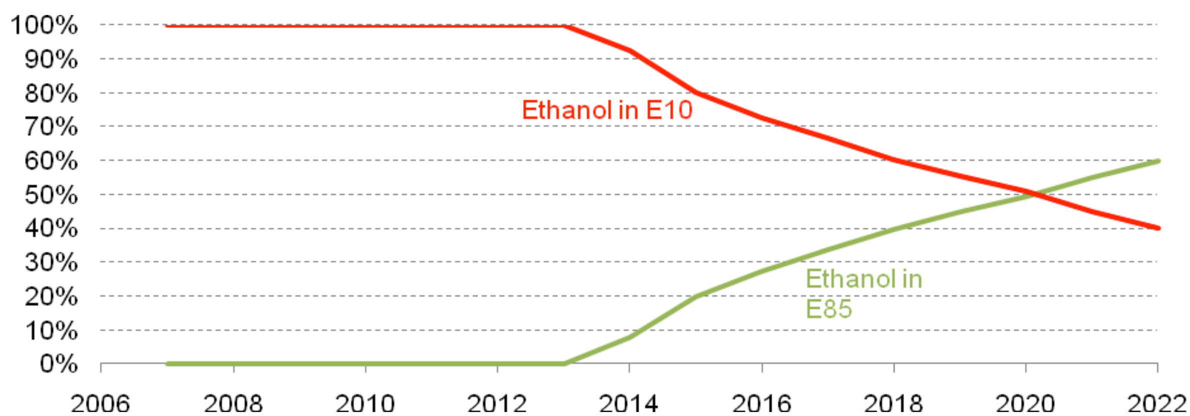


Figure 12.45. The growth in total motor gasoline demand delays the penetration of E85. More ethanol is consumed as E85 starting in 2020. In scenario 1, this transition occurs in 2019. The left axis is the percentage of the ethanol supply blended in motor gasoline or E85.

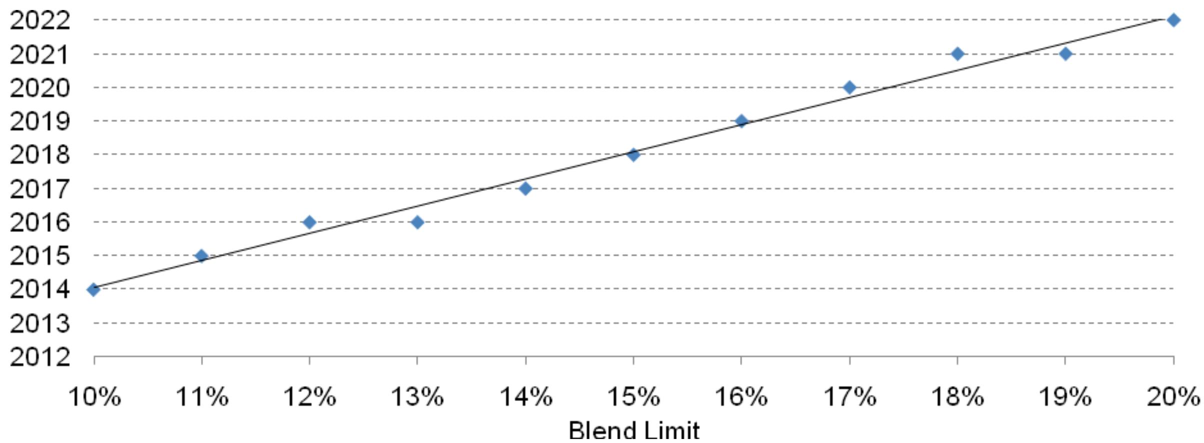


Figure 12.46. When compared to Figure 12.29, the blend limit year is delayed for a given percentage. The increased total motor gasoline demand provides a large supply of crude-based gasoline for blending with ethanol, thereby delaying the blend limit year. In this scenario, no E85 market is needed for a blend limit exceeding 20%. The left axis is the year when the blend limit is reached for a given blend limit percentage.

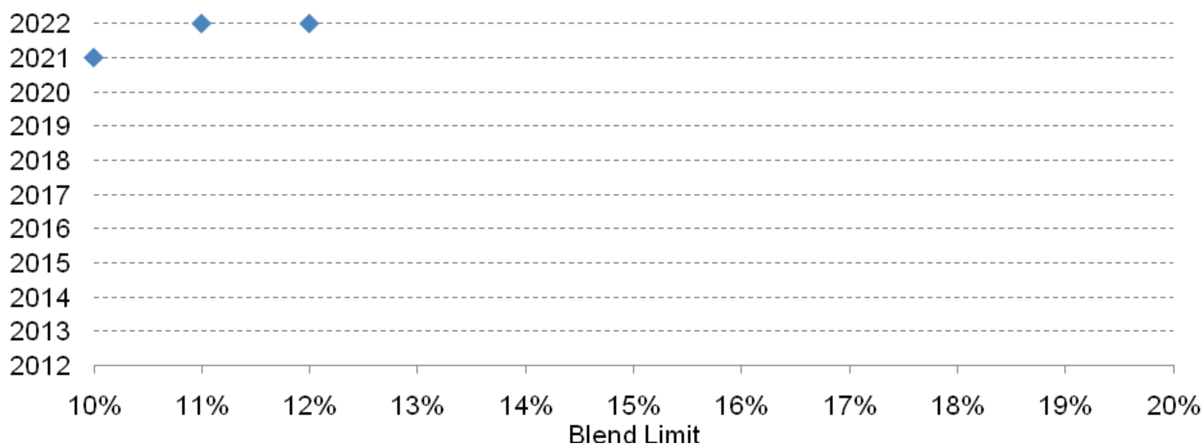


Figure 12.47. This figure shows the year at which ethanol consumption in E85 first exceeds ethanol consumption in motor gasoline for a given blend limit percentage (analogous to Figure 12.30). A blend limit of 10% requires more ethanol to be consumed as E85 starting in 2021. When the blend limit exceeds 12%, the amount of ethanol blended as E85 never exceeds the consumption of ethanol in motor gasoline through 2022.

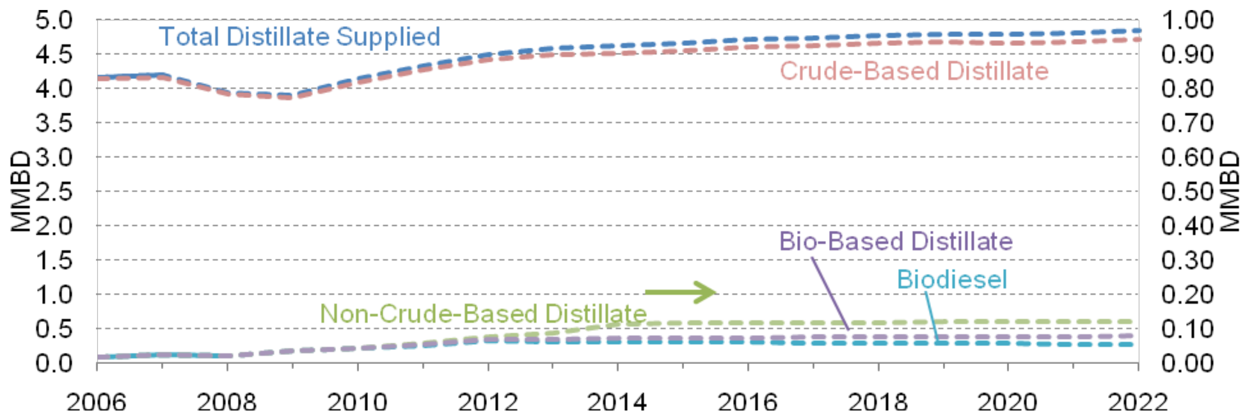


Figure 12.48. The AEO 2009 *lp* case has little impact on total distillate demand. Aside from a slight increase in total distillate demand, lower-crude prices cause total non-crude-based distillate consumption to fall due to reduced production of CTL. With equivalent bio-based distillate consumption, reduced CTL consumption, and increased total demand, crude-based distillate supplies nearly the entire distillate market through 2022.

As shown in Figure 12.44, total motor gasoline demand climbs above 10 MMBD in 2014. This demand exceeds 10.7 MMBD in 2022, compared to a demand of 9.5 MMBD in scenario 1. As total ethanol consumption increases with total demand, crude-based gasoline consumptions falls only slightly between 2012 and 2022, inching just below 8.5 MMBD in 2022. The E85 market expands at a slower pace as more crude-based gasoline is available for blending. By 2022, 60% of the ethanol supply is blended as E85 (see Figure 12.40). In 2022, ethanol supplies only 20% of the volume in the motor gasoline sector; this compares to 25% in scenario 5(a). Figures 12.46 and 12.47 show that increases in the blend limit have less overall impact on the transition, e.g., the 20% blend limit is reach in 2022, compared to 2020 in scenario 5(a). When the blend limit is increased beyond 13%, the amount of ethanol consumed as E85 never exceeds the consumption of ethanol in motor gasoline through 2022.

Aside from a reduction in CTL production, results for the DFO sector differ little from scenarios 1 and 5(a).

As illustrated by scenarios 5(a) and (b), the impact of the RFS program is dependent on total liquid fuels demand. Regardless of total demand, the RFS program mandates the same volumes of biofuels. When total demand falls, the liquid fuels sector undergoes a more rapid transition to biofuels, as evidenced by the rapid growth of the E85 market and sharp decline in demand for crude-based gasoline in scenario 5(a). When total demand increases, the transition unfolds more slowly, and demand for crude-based fuels remains strong. This later point is illustrated by the steady demand for crude-based gasoline in scenario 5(b).

12.3.5 Analysis and discussion

Margo Oge, Director of the EPA Office of Transportation and Air Quality (OTAQ), recently explained that the RFS mandate can be met in essentially three ways (Voegele, 2009): (1) increase the availability of E85 in the market in conjunction with increased production of FFVs;

(2) lessen the "incompatibility hurdle" through the production of synthetic fuels, or more compatible fuels, e.g., biobutanol, renewable diesel, renewable gasoline; or (3) increase the ethanol blend limit.

These three pathways are reflected in the scenarios presented in the previous section. Scenario 1, which is based on the EPA control case volumes, requires an increased consumption of E85 in the market. Scenario 2, which is also based on the EPA control case, is reflective of the third pathway suggested by Oge, requiring an increase in the ethanol blend limit. Oge's second pathway could play out like scenarios 3(a), 3(b), or 4, which are based on increasing the production of synthetic fuels that are compatible with existing infrastructure. Finally, scenarios 5(a) and (b), illustrate the first pathway suggested by Oge, but with altered total liquid fuels demand.

Each of these scenarios will require simultaneous technological and operational changes throughout the fuel supply chain, including logistics and supply of feedstocks, fuel production, distribution and retail networks, and end use (e.g., engine technologies). Like the historical transitions reviewed earlier in this task report, the extent of these impacts will vary for each scenario. These impacts depend on the nature of the fuels produced to meet the mandate, the status of the blend limit, and the overall demand for liquid fuels, among other factors. Tables 12.13 and 12.14 list each of the biofuel transition scenarios for the motor gasoline and DFO sectors, respectively, with the infrastructure implications of each scenario compared to the base case (i.e., scenario 1). The comparisons indicate whether the impacts to a particular segment of the supply chain will be greater than (+), less than (-), or approximately unchanged (~) when compared to the base case, along with a brief explanation of why the impacts differ relative to the base case. The infrastructure impacts (and barriers) associated with the base case are discussed first, followed by a review of the remaining scenarios, highlighting how the impacts might differ in each case.[32]

[32] Recall from the introduction of this chapter (section 12.1) that feedstock production and logistics are omitted from the scope of this analysis.

Table 12.13. Infrastructure implications in the MoGas sector are qualitatively compared to the base case for each scenario.

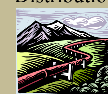
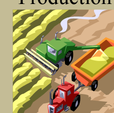
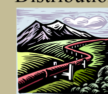
Sector	Transition scenario	Description	Ethanol, E85 (MMBD) in 2022	Infrastructure Implications				
				Production 	Refining 	Distribution 	Retail 	End use 
Motor Gasoline	Scenario 1	RFS compliance base case	2.227, 2.000	-	-	-	-	-
	Scenario 2	Increased ethanol blend limit (20%)	2.227, 0.615	(~) Same feedstock requirements	(~) Same ethanol production capacity required	(-) Ethanol needed for E85 blending reduced; less E85 storage capacity required	(-)/(~) E85 sales reduced, but still need to retail multiple blends	(-) Reduced E85 consumption (fewer FFVs)
	Scenario 3(a)	Increased bio-based distillates	1.500, 0.902	(-) Less cellulosic ethanol feedstock demand	(-) Less cellulosic ethanol fuel demand	(-) Less ethanol (and total motor gasoline volume) to distribute	(-) Ethanol blend sales reduced	(-) Reduced E85 consumption (fewer FFVs)
	Scenario 3(b)	Increased bio-based distillates (2)	0.978, 0.114	(-) No cellulosic ethanol feedstock demand	(-) No cellulosic ethanol fuel demand	(-) Less ethanol (and total motor gasoline volume) to distribution	(-) Ethanol blend sales reduced	(-) Minimal E85 consumption required
	Scenario 4	Renewable gasoline	1.183, 0.425	(~) Cellulosic feedstock still needed for renewable gasoline production (i.e., BTL)	(+) Renewable gasoline commercial production technologies come online	(-) Less ethanol (and total motor gasoline volume) to distribute	(-) Ethanol blend sales reduced, as ethanol is replaced by synfuel	(-) Reduced E85 consumption (fewer FFVs)
	Scenario 5(a)	Decreased liquid fuels demand	2.227, 2.090	(~) Same feedstock requirements	(~) Same ethanol production capacity required	(+)/(~) Ethanol needed for E85 blending increased; more E85 storage capacity	(+) E85 sales increase (more retail station conversions/upgrades)	(+) Increased E85 consumption (more FFVs and fleet turnover)
	Scenario 5(b)	Increased liquid fuels demand	2.227, 1.804	(~) Same feedstock requirements	(~) Same ethanol production capacity required	(-)/(~) Ethanol needed for E85 blending reduced; less E85 storage capacity	(-) E85 sales decrease (less retail station conversion/upgrades)	(-) Reduced E85 consumption (fewer FFVs or fleet turnover)

Table 12.14. Infrastructure implications in the DFO sector are qualitatively compared to the base case for each scenario.

Sector	Transition scenario	Description	Bio-based, crude-based distillate (MMBD) in 2022	Infrastructure Implications				
				Production 	Refining 	Distribution 	Retail 	End use 
Distillate Fuel Oil (DFO)	Scenario 1	RFS compliance base case	0.078, 4.426	-	-	-	-	-
	Scenario 2	Increased ethanol blend limit	0.078, 4.426	(~) Ethanol blend limit does not impact the DFO sector				
	Scenario 3(a)	Increased bio-based distillates	0.804, 3.733	(+) Cellulosic diesel (i.e., BTL) feedstock demand	(+) BTL commercial production technologies come online	(+) Distribution of bio-based distillate (compatible, but spatially dispersed supply)	(~) Sales of bio-based distillate increase (but compatible)	(~) Increased consumption of bio-based distillate (but compatible)
	Scenario 3(b)	Increased bio-based distillates (2)	1.326, 3.236	(+) Increased cellulosic diesel feedstock demand	(+) BTL commercial production technologies fully displace cellulosic ethanol production	(+) Distribution of bio-based distillate (compatible, but spatially dispersed supply)	(~) Sales of bio-based distillate increase (but compatible)	(~) Increased consumption of bio-based distillate (but compatible)
	Scenario 4	Renewable gasoline	0.078, 4.426	(~) Production of renewable gasoline does not impact the DFO sector				
	Scenario 5(a)	Decreased liquid fuels demand	0.078, 4.365	(~) Same feedstock requirements	(~) Same bio-based distillate production capacity required	(+)/(~) Increased percentage of distribution activities devoted to bio-based distillate	(~) Increased sales percentage of bio-based distillate (but compatible)	(~) Increased percentage of bio-based distillate (but compatible)
	Scenario 5(b)	Increased liquid fuels demand	0.078, 4.726	(~) Same feedstock requirements	(~) Same bio-based distillate production capacity required	(-)/(~) Decreased percentage of distribution activities devoted to bio-based distillate	(~) Decreased sales percentage of bio-based distillate (but compatible)	(~) Decreased percentage of bio-based distillate (but compatible)

12.3.5.1 Scenario 1: RFS compliance base case

Based on the EPA control case, this scenario aligns well with the pathway envisioned and analyzed by the EPA. This biofuels transition scenario requires greater volumes of ethanol consumption in the motor gasoline sector, with little increase in bio-based distillate consumption in the DFO sector. The changes required throughout the supply chain are discussed below, beginning with fuel production.

12.3.5.1.1 Fuel production

As ethanol consumption increases, the petroleum refining industry will be required to adapt as less demand for gasoline falls. As crude-based fuel demand shifts from gasoline to distillates, refiners could face the need to adjust operations away from a product slate currently optimized for gasoline production. Overall crude-based fuel demand could also fall, forcing refiners to make decisions related to refining capacity, possibly facing the need to shut down some current refineries (Gold and Campoy, 2009). These impacts are not isolated to U.S. refiners. As the gasoline market shrinks in the U.S., EU refiners could be faced with a shrinking export market (Acerra, 2008). The "peak gasoline" phenomenon could have other, far-reaching implications. For instance, as gasoline-tax revenues fall with demand, state and local government will be forced to search for new funding sources (Gold and Campoy, 2009).

As the industry sees its market share eroded by increased biofuels consumption, some petroleum companies will choose to enter the biofuels industry. There is already ample evidence of this trend. In March 2009, Valero, an independent oil refiner based in San Antonio, Texas, with plants and offices throughout the U.S. and Canada, purchased 7 ethanol plants from the Chapter 11 bankruptcy of VeraSun Energy Corporation (Gold and Campoy, 2009; Krauss, 2009b). Valero paid $477 million for the plants, which are located in South Dakota, Iowa, Minnesota, Nebraska, and Indiana. It was the first purchase of ethanol plants by a traditional refiner in the U.S. A spokesperson for the company explained that the purchase "represents a cost savings and a recognition on Valero's part that ethanol is going to be part of the fuel mix going forward" (Krauss, 2009b).

Several oil companies, rather than buying their way into the existing ethanol market, have formed internal renewable fuels departments and are reaching out to existing biofuel and biotechnology companies. BP has partnered with DuPont to develop biobutanol production technologies (Dupont, 2009; Krauss, 2009a). BP has also paired with Verenium Corporation, a small biofuel and biotechnology company based in Cambridge, Massachusetts, to scale up Verenium's cellulosic ethanol technologies for commercial production. BP intends to build a $250 million, commercial-scale, cellulosic ethanol plant in Florida based on this technology. In addition to the DuPont and Verenium ventures, BP has also entered the sugar cane ethanol market in Brazil. The president of BP's Biofuels unit, Phil New, explains the company's reasoning for entering the biofuels sector as follows (Krauss, 2009a): "We can see biofuels as being a really big potential reservoir…If the government is going to make a market happen, we need to be able to participate commercially in that market."

Shell has initiated partnerships with a number of small companies working on cellulosic ethanol technologies, algae-derived biofuels, and renewable gasoline (Krauss, 2009a). Chevron, ExxonMobil, and ConocoPhillips have also initiated biofuels research and development projects. Chevron has partnered with Weyerhaeuser to develop cellulosic ethanol from wood waste (Krauss, 2009a); ExxonMobil has launched a new program with Synthetic Genomics Inc. to produce biofuels from algae (ExxonMobil, 2009a; ExxonMobil, 2009b); ConocoPhillips ran a pilot project in 2008 using rendered animal fats produced by Tyson (ConocoPhillips, 2009). These examples serve as just a sampling of how the oil industry is venturing into the biofuels industry.

In the base case scenario, cellulosic ethanol production technology must be scaled up to produce 100 mgy in 2010, increasing to 16 bgy in 2022. Cellulosic ethanol is produced from lignocellulosic feedstocks, including forestry and agricultural residues (e.g., wood chips, corn stover), cover crops, perennial "energy" crops grown on marginal lands, and other waste streams (e.g. municipal solid wastes). By avoiding agricultural food commodities, the production of cellulosic ethanol has the potential to overcome or reduce some of the impacts associated with conventional (corn) ethanol production, e.g., competition with food and feed supplies, water consumption, and land use change. Ethanol can be produced from cellulosic feedstocks through a number of biochemical and thermochemical processes. Compared to conventional ethanol production, cellulosic production technologies are more complex technologically, requiring additional processing steps and process inputs. Detailed information and analyses of cellulosic feedstocks and biofuel production technologies are available in the literature (Aden, 2002; De La Torre Ugarte, et al, 2003; De La Torre Ugarte and Ray, 2000; DOE, 2009; EPA, 2009a; Hammerschlag, 2006; NRC, 2009; Perlack, 2005; Pimentel and Patzek, 2005; POLYSYS, 2008; The Royal Society, 2008; Sandor, Wallace, and Peterson, 2008; Schmer, 2008; Solomon, Barnes and Halvorsen, 2007; Wang, 2009.

A panel convened by the National Research Council (NRC)—America's Energy Future Panel on Alternative Liquid Transportation Fuels—assessed the current state of cellulosic ethanol production technologies and made several recommendations for promoting its development and eventual deployment on a commercial scale (NRC, 2009). Overall, the panel judged that cellulosic ethanol will be capable of commercial deployment before 2020, but not necessarily at the scale of 21 bgy. To gain the engineering and operational knowledge needed to reduce capital and operating costs of commercial-scale production facilities, the panel recommended that the federal government and industry pursue technology demonstration and small-scale commercial plants, which would provide detailed engineering and cost performance data. In tandem, processes specific to the production of cellulosic ethanol (e.g. feedstock pretreatment, enzymatic hydrolysis, fermentation, etc) need to be improved to reduce plant-level costs. The panel recommended that the federal government continue its support of research and development (R&D) of cellulosic ethanol technology, with program design and resource allocation based on a long-term perspective. In addition, the panel recommended that the R&D programs should be coupled with the pilot- and commercial-scale demonstrations and deployments to ensure that appropriate industrial-level issues are being addressed and new technologies are being continuously demonstrated.

Currently, there are no commercial-scale cellulosic ethanol production facilities in the nation (EPA, 2009a). However, several pilot scale projects are underway, or have been announced, along with plans and proposals to build commercial scale facilities in the near future.[33] The execution of these plans will hinge on the successful development of production technologies and the financing of the construction and operation of new facilities.

Based on an assessment by the EPA, there were 25 small cellulosic ethanol plants operating in April 2009, although most produce only small volumes of ethanol on an irregular basis. In order to meet the cellulosic biofuel mandate, production facilities will have to be financed and built at a rapid pace. The EPA, in their control case analysis, developed one scenario for building plants that would meet the annual cellulosic mandate. Figure 12.49 shows the required build rate and annually increasing ethanol industry capacity compared to the historical and ongoing build rate of conventional, starch ethanol plants (EPA, 2009a). The EPA scenario calls for 2-10 plants per year (40 mgy average capacity) from 2010-2013; 10-18 plants per year (80 mgy) from 2014-2017; and 20 plants per year (100 mgy) through 2022. This scenario produces a total cellulosic ethanol capacity of 16 bgy distributed among 186 facilities in 2022. In 2008, conventional plant construction peaked at 27 plants with an average capacity of 100 mgy.

Based on present and planned future capacity, there will be 163 conventional plants producing 15 bgy. The National Commission on Energy Policy (NCEP), a bipartisan group of energy experts, suggests that 60-100 new cellulosic biorefineries with 30-50 mgy capacity each are needed by 2015, and 300-500 by 2022, or approximately 25-45 new facilities per year through 2022 (NCEP, 2008).

When compared to the historical build rate of conventional plants, the cellulosic build rate is not unreasonable. However, cellulosic plants are to be based on technologies that have yet to be proven on a commercial scale, and will be run on feedstock supplies that are currently not produced, collected, stored, and distributed on a wide scale. The conventional ethanol industry has had the advantage of developing around a feedstock (i.e., corn) that is already produced, collected, stored, and distributed on a large scale. The logistics of siting these new plants also serves as a source of uncertainty. According to the NCEP, inbound and outbound transportation costs can amount to 20% of operating costs for biorefineries. Strategic siting of these facilities is dictated by proximity to transportation infrastructure (e.g., railroad) and feedstock radius (the maximum distance that feedstock is collected and transported to a given facility) (NCEP, 2008).

[33] The reader is referred to sections 1.4.3 and 1.5.3 of the EPA RFS2 DRIA. See http://www.epa.gov/otaq/renewablefuels/420d09001.pdf

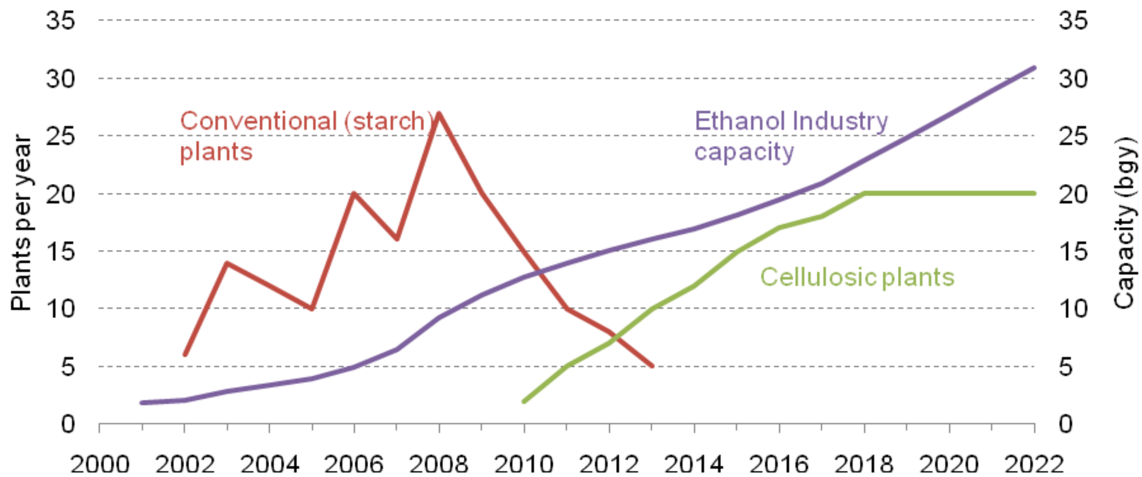


Figure 12.49. The EPA control case requires ethanol capacity to expand with the construction of cellulosic ethanol plants starting in 2010 and continuing through 2022 (EPA, 2009a). As discussed in section 1.3, the capacity of existing and proposed conventional facilities and those currently under construction is approximately 15 bgy, which is equivalent to the limit on conventional biofuels production imposed in 2015 by the RFS.

The EPA control case also foresees the need for increased imports of ethanol, increasing from 500 mgy in 2008 to over 3 bgy in 2022 (EPA, 2009a). Currently, the U.S. stands as the top producer of ethanol in the world, followed closely by Brazil. In 2008, the U.S. produced 9.2 billion gallons of ethanol, while Brazil produced approximately 6.5 billion gallons. The next closest producer is the EU, which produced well under 1 billion gallons in 2008 (RFA, 2009). The additional demand for ethanol imports by the U.S. from 2008 through 2022 alone would force Brazil to increase production by nearly 40%. When considering future demand for transportation fuels in Brazil, increased global demand for biofuels, and the current excise tax levied on ethanol imports to the U.S., the ability to secure an additional 2.5 bgy of ethanol imports stands as a major source of uncertainty in this scenario.

The NCEP cites state-specific fuel requirements and formulations as another source of uncertainty as ethanol consumption increases with the RFS mandate (NCEP, 2008). Currently, refiners that supply liquid fuels to the U.S. liquid fuels sector meet a range of fuel standards, typically dictated by state and federal air quality requirements. For example, as discussed in the historical fuel transition analyses, the CAA mandates the use of reformulated gasoline (RFG) in several metropolitan regions in the U.S. Another example is the wintertime Oxyfuel program, requiring gasoline supplied in the winter months to have increased oxygenate content as a means for reducing CO emissions. Figure 12.50, a map published in April 2007 by ExxonMobil, illustrates the geographical diversity of gasoline formulation requirements throughout the nation (Gardner, 2007). As ethanol penetrates the motor gasoline sector, and is blended in ever greater quantities throughout the nation's gasoline supply, refiners and blenders could face challenges in meeting the requirements of these various state-level fuel specifications and emission requirements. Refiners will be required to produce gasoline blend stocks (i.e., the crude-based gasoline blended with ethanol) that still meet the specifications even as the amount of ethanol blended into the gasoline supply increases. Meeting these requirements could reduce production and distribution efficiencies, ultimately impacting costs.

The NCEP suggests that some level of federal harmonization of fuel specifications could help to alleviate these challenges (NCEP, 2008). This is balanced by the fact that differing state requirements reflect the different geography, weather, stationary air pollution sources, and traffic densities for those states. Extensive analysis might be required to balance the benefits of reduced costs due to less variability against the realization that standards adequate for much of the country can be harmful in selected areas.

The remaining fuels produced in scenario 1 include limited quantities of biodiesel and other bio-based distillate, i.e., renewable diesel produced at standalone facilities or co-processed at existing crude oil refineries. Both fuels are produced from triglycerides (e.g., vegetable oils, rendered fats, waste grease, etc). The EPA limits the role of these fuels based on an assumption that the supply of bio-based oil feedstocks (i.e., triglycerides) will remain tight due to demand for other uses, e.g., food, over the span of the RFS program. Unless new, "advanced" feedstock sources, like algae, are developed in the near term, these fuels will continue to supply a minimal portion of the DFO sector (EPA, 2009a). Increased consumption of bio-based distillate in the DFO sector is discussed further in later sections.

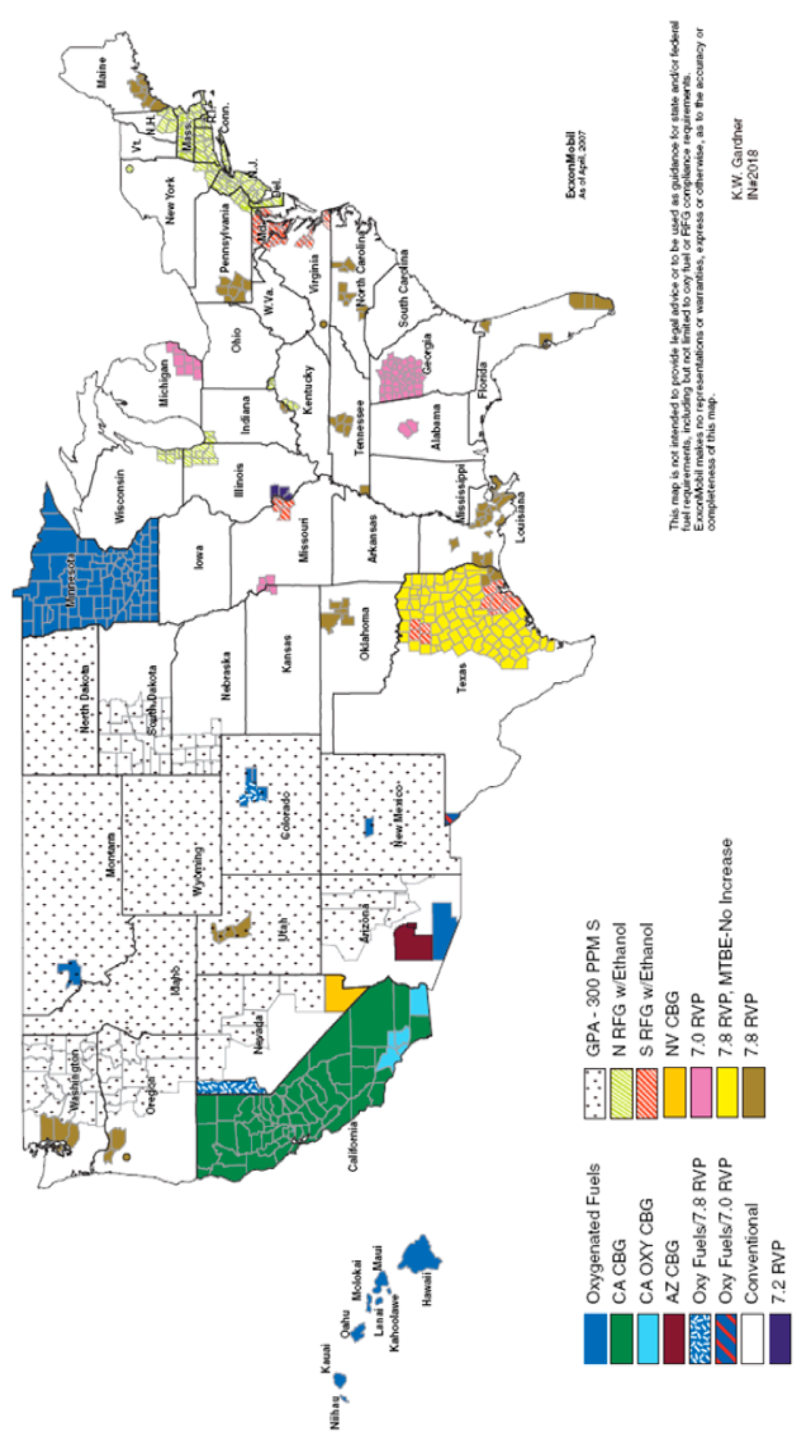


Figure 12.50. A map of U.S. gasoline requirements illustrates the geographic diversity of gasoline fuel formulations (Gardner, 2007).

12.3.5.1.2 Distribution

In scenario 1, ethanol comprises more than 90% of annual biofuels volume that must be distributed to end use markets through 2022. Currently, the majority of ethanol is produced in over 100 facilities scattered across the Midwest and Great Plains, i.e., the corn belt. Currently, about 60% of ethanol is transported by rail, 30% by truck, and 10% by barge (Peterson, Chin and Das, 2009). The demands placed on this "virtual pipeline" will only increase with further increases in ethanol production (Downstream Alternatives, Inc., 2002; EPA, 2009a; NCEP, 2008; RFA, 2006a). The NRC panel (i.e., America's Energy Future Panel) explains the challenge as follows (NRC, 2009):

> The need to expand the delivery infrastructure to meet a high volume of ethanol deployment could delay and limit the penetration of ethanol into the U.S. transportation fuels market. Replacing a substantial proportion of transportation gasoline with ethanol will require a new infrastructure for its transport and distribution. Although the cost of delivery is a small fraction of the overall fuel-ethanol cost, the logistics and capital requirements for widespread expansion could present many hurdles if they are not planned for well.

This problem is exacerbated by the fact that ethanol has a lower energy content relative to the crude-based gasoline it replaces. So, as ethanol increasingly displaces crude-based gasoline, the overall volume of fuel that must be distributed is greater than a business-as-usual scenario that would see little to no growth in ethanol consumption. So, unless total motor gasoline demand falls, the displacement of crude-based gasoline with ethanol will alone require the distribution infrastructure to expand.

Researchers at the Oak Ridge National Laboratory (ORNL) recently studied the distribution challenges associated with increasing production of ethanol based on the EPA control case (i.e., increasing to 34.14 bgy in 2022). They introduced the problems as follows (Peterson, Chin and Das, 2009):

> At current levels of shipments, biofuels represent less than 1% of total railcar ton-miles shipped in the United States. It is anticipated that renewable fuels are unlikely to have more than marginal impact on rail capacity or congestion. However, the rail system itself is subject to increasing capacity and congestion constraints that will impact all commodities shipped by rails, including biofuels. A lack of rail accessibility at biorefinery sites, the type of rail infrastructure accessible to biofuels producers, the current state of capacity and congestion on the U.S. rail network, and logistics and supply-chain management capabilities at biofuels producers are some of the issues related to the U.S. rail system that need to be addressed.

Using an infrastructure network model, the ORNL researchers analyzed the transportation of ethanol by domestic rail, barge, and truck distribution systems from ethanol plants to blending terminals. The analysis did not account for increased distribution activity associated with feedstock collection and transportation to biorefineries, and distribution of blended fuels from terminals to retail stations. They computed increases in spatially-resolved transportation activity (e.g., kton-miles); state-by-state and national average distribution costs; and rolling stock requirements (i.e., number of railcars, barges, and trucks) in 2022. A "distribution constraint analysis" was conducted to assess where stresses (e.g., delays due to increased congestion) in the distribution infrastructure could potentially arise due to the increased biofuels demand. The study found that ethanol shipments would continue to be moved predominantly by rail, increasing to approximately 90% in terms of ton-mile movements in 2022. Since biofuels make up only a small portion of overall movement of goods through the distribution infrastructure, demand in 2022 is expected to increase ton-mile movements by rail, barge, and truck by only 2.8%, 0.6%, and 0.13%, respectively, when compared to 2005 shipments. The national average ethanol distribution cost was estimated to be 6.8 cents/gallon in 2022, with state-by-state estimates ranging from 1.2 to 33.2 cents/gallon. In summary, the researchers found that future ethanol demand would have minimal impacts on transportation infrastructure overall. But, spatial impacts due to increases in rail traffic would require a significant level of investment. The assumed locations of biorefineries and distribution (i.e., blending) terminals were found to have significant impacts on transportation activity and distribution costs (Peterson, Chin and Das, 2009).

As the "virtual pipeline" continues to expand with ethanol production, railcar production could become a major constraint. It is estimated that 60-65% of new rail tank car orders are currently due to increased ethanol demand (Peterson, Chin and Das, 2009). According to Roger Ginder, professor of economics at Iowa State University, production backlogs for railcars have risen by approximately 400% since 2005, while production output has remained nearly flat. Ginder explains the problems as follows (Pentland, 2008):

> There are four major tank car manufactuers—GATX, Trinity, Union, and AFT…Some car manufacturers are booked for more than two years. Until growth in [ethanol] production capacity slows and/or turnaround times for ethanol tank cars increases, it will be difficult to reduce the backlog in orders.

A growing reliance on the rail, barge, and truck distribution systems is based on the assumption that pipelines will not be used to move any substantial amount of ethanol. If pipelines became an option for distributing ethanol, and other biofuels, then a Gulf Coast hub to collect and distribute biofuels, similar to today for petroleum-based fuels, could be favored, reducing impacts on the wider distribution system and reducing ethanol distribution costs (NCEP, 2008; Peterson, Cohin and Das, 2009). However, ethanol is typically not used in pipelines for several reasons (AOPL and API, 2007; NCEP, 2008; Sridhar, 2008):

- hygroscopic/hydrophilic nature of ethanol;
- tendency of water to separate from ethanol when blended with gasoline;
- potential for stress corrosion cracking of steel;
- compatibility with polymers used for pipeline coatings;
- compatibility with elastomers used for seals and gaskets;
- compatibility with drag-reducing agents;
- potential for mixing and reacting with other products delivered through pipelines.

The petroleum pipeline infrastructure was developed around an oil refining industry that is predominantly concentrated around the Gulf Coast region (e.g., Texas and Louisiana), and delivers finished products to major demand centers on the East and West Coasts. If the disadvantageous properties of ethanol are put aside, addressing the geographic disparity between the current ethanol supply and existing pipeline infrastructure becomes a major logistical problem.

However, these problems have not mitigated interest in moving ethanol through pipelines. Like oil producers, distribution companies have interest in moving new fuels through their systems as demand for conventional petroleum products declines. As noted in previous sections, Kinder Morgan ran trial shipments of ethanol, ethanol blends, and biodiesel blends in existing pipelines in Florida and the Southeast, and proceeded with commercial shipments of ethanol in Florida and announced plans to distribute biodiesel blends in the Southeast (Anon, 2008; Mahon, 2007; Meinhardt, J., 2008). Other pipeline and distribution companies and industry groups are conducting research on the transport of ethanol and other biofuels through existing pipelines (Energetics Incorporated, 2007; Sridhar, 2008). Even if this research enables distributors to overcome compatibility barriers, the question of geographic disparity and logistics remains.

Magellan Midstream Partners and POET, taking a different approach, are jointly conducting a feasibility study of building a dedicated ethanol pipeline from the Midwest to demand centers in the Northeast (POET, 2009). A map of the currently proposed pipeline is shown in Figure 12.51. This approach could address both the compatibility concerns with existing pipelines and the geographic disparity between existing pipeline networks and ethanol facilities. A dedicated ethanol pipeline will face significant barriers related to capital costs, the need to gather sufficient throughput from dispersed ethanol producers, and siting issues (AOPL and API, 2007). Robust markets and guaranteed long-term supply is needed to justify the financing of such a large-scale project. The siting of a dedicated ethanol pipeline would likely require eminent domain authority. According to the NCEP, this authority currently does not exist for ethanol pipelines (NCEP, 2008). Due to long permitting and right-of-way acquisition lead times, the NCEP believes that a decision to build a dedicated ethanol pipeline cannot be delayed beyond 2009, if pipeline distribution is to play a role in moving ethanol produced under the RFS.

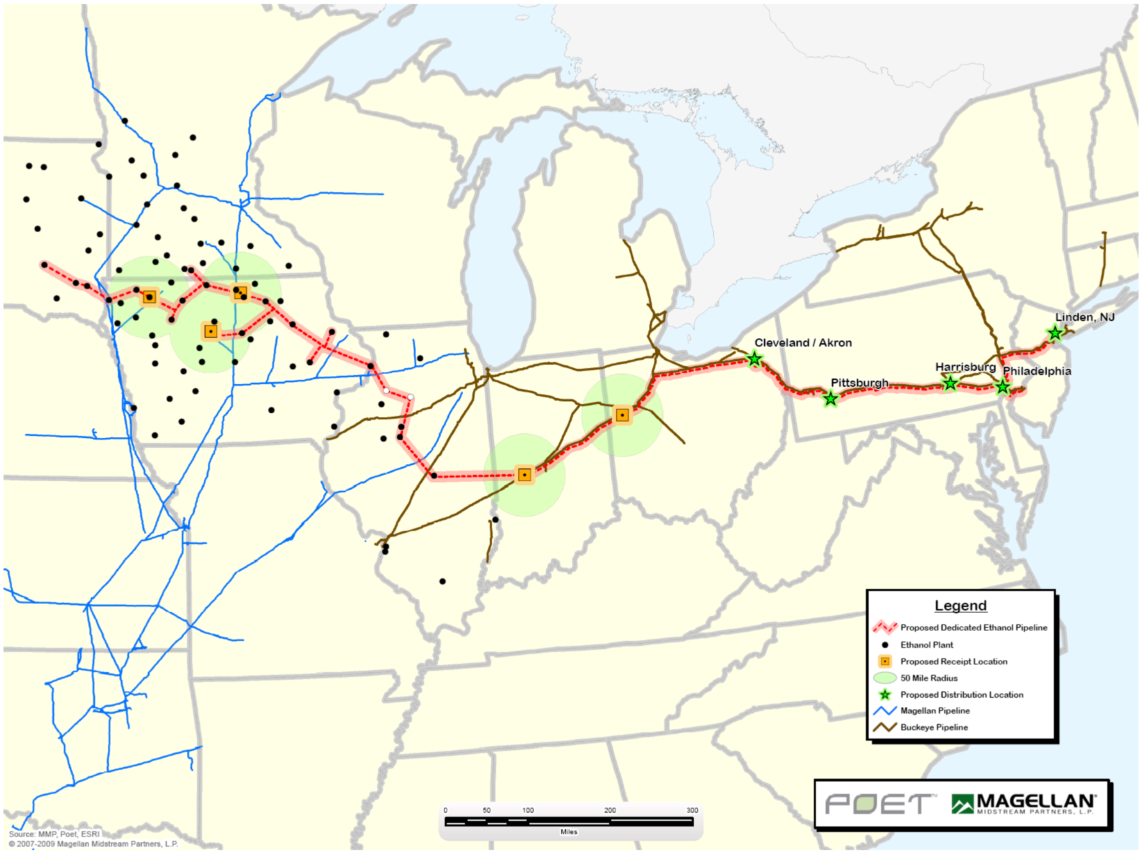


Figure 12.51. Magellan and POET are studying the feasibility of constructing and operating a dedicated ethanol pipeline, as illustrated in this map (Magellan Midstream Partners, POET Energy, and ESRI, 2009). The red-dashed line represents the proposed pipeline; solid-blue lines represent existing Magellan pipelines; solid-brown lines indicated existing Buckeye pipelines; yellow squares represented proposed ethanol receipt locations, surrounded by green circles indicating a 50 mile radius; black dots represent ethanol plants; and green stars are proposed distribution locations.

Distribution infrastructure could also be influenced by the development of the cellulosic ethanol industry. If new cellulosic ethanol plants are widely distributed across the nation, rather than being developed around existing facilities in the Midwest, then distribution on a regional or local scale could be more efficient. If the new facilities are sited near existing corn ethanol plants (e.g., to utilize corn stover and cover crops as feedstocks), then the dedicated pipeline route becomes more viable (NCEP, 2008). However, with cellulosic ethanol production technology under development, it is not clear what feedstocks will be favored by the industry.

To address the distribution challenges associated with the deployment of increasing volumes of ethanol, the NRC panel recommends the following:

> The U.S. DOE and the biofuels industry should conduct a comprehensive joint study to identify the infrastructure system requirements of, research and development needs in, and challenges facing the expanding biofuels industry.

Like the NCEP, the NRC panel stresses that the continued expansion of the "virtual pipeline" and the long-term potential of this system to accommodate increasing volumes of ethanol should be weighed against the potential benefits of pipeline delivery (dedicated or otherwise). Results from the ORNL study suggest that the "virtual pipeline" is capable of accommodating the increased volumes of ethanol and other biofuels. However, this analysis was based on the assumption that pipelines would not be an option. An analysis including that includes the pipeline option could help to address questions related to the use of pipelines in distributing ethanol in the future.

The NRC panel also recommends that any analysis of biofuels distribution should account for the "timing and role of advanced biofuels that are compatible with the existing…infrastructure." Scenarios 3 and 4, which are based on the increased production of advanced biofuels, serve to illustrate the impacts of shifting to biofuels that are compatible with existing infrastructure.

The infrastructure issue is highlighted by the chemical incompatibility of ethanol with existing petrochemical pipeline structure and the geographical incompatibility with the petrochemical pipeline and corn growing areas of the US. Other biofuels add to the risk of investing in improving this infrastructure. Not only does cellulosic ethanol add complexity to the future geographic incompatibility, but the growing industrial investment in algae is another confounding factor. Large scale biodiesel from algae could change the scenario for a profitable infrastructure significantly.

12.3.5.1.3 Retail and End Use

The analysis of the retail and end use segments of the fuel supply chain presented here focuses on the implications of storing and dispensing increased volumes of ethanol in the retail network, and the consumption of ethanol in motor-gasoline-powered vehicles.

In scenario 1, the motor gasoline sector is comprised of E10 and E85. As the 10% blend limit is approached, and ultimately reached, the retail network must be prepared to supply the market with an increasing volume of E85. Unlike E10, which is currently dispensed as conventional motor gasoline nationwide, E85 requires retailers to install new, or upgrade existing, storage and dispensing equipment. Since total motor gasoline demand is not expected to grow substantially through 2022, the supply of E85 will be moved predominantly through existing facilities. In 2008, the National Renewable Energy Laboratory (NREL) conducted a survey and literature review to assess the costs associated with adding E85 equipment to existing gasoline stations (Sperling and Dill, 1988). Table 12.15 shows the results of the NREL study. The first scenario, which involves the installation of a new storage tank and new or retrofit dispenser(s), is estimated to cost between $50,000 and $200,000. The second scenario, involving the conversion of an existing storage tank and installation of new or retrofit dispenser(s), is estimated to cost much less, ranging from $2,500 to $30,000. The table summarizes the major variables that influence the cost for each scenario, e.g., the number of dispensers, excavation and concrete work, etc. In 1978, it was estimated that the cost incurred by retail stations that made unleaded conversions was $5,951 per station (Sperling and Dill, 1988). In 2009 dollars, this cost equates to approximately $20,000, falling well within the range of costs to convert an existing tank to store E85. However, the NREL report explains that a declining number of stations could pursue this option (i.e., the second scenario), shifting the majority of E85 upgrades to the new tank scenario. The conversion option is only viable if a gasoline station can economically justify switching an existing tank to E85. With an average of 3.3 tanks per station, most retailers would be challenged to justify such a conversion, depending on the sales of fuels currently dispensed (e.g., premium, diesel, etc) relative to expected E85 sales. If retailers are not guaranteed a robust E85 market, then justifying the costs to add E85 equipment becomes a major challenge.

Table 12.15. The NREL compiled cost estimates for adding E85 equipment to existing gasoline stations, based on two scenarios: (1) adding a new tank and new or retrofit dispenser(s) and (2) converting an existing tank and installing new or retrofit dispenser(s) (NREL, 2008).

Scenario	Estimated Cost	Description	Major Variables Affecting Cost
New tank, new or retrofit dispenser(s)	$50,000-$200,000	Includes new storage tank, pump, dispenser(s), piping, electrical wiring, excavation, and concrete work	Dispenser needs, excavation, concrete work, sell backs, canopy, tank size, location, labor price, regulations/permitting
Convert existing tank, new or retrofit dispensers	$2,500-$30,000	Tank cleaning, replace non-compatible components in piping and dispensers	Dispenser needs, number of non-compatible components, location, labor price, regulations

Once retail stations decide to add E85 storage and dispensing equipment, either through new or converted equipment scenarios, the question of pricing must be addressed. Due to the lower energy content of ethanol, E85 has, on average, 22% less energy per gallon than E10. Assuming that this reduction in energy content per gallon translates directly into a 22% reduction in fuel economy for the end user, then the E85 sale price must be reduced to ensure "price parity" with E10. Table 12.16 presents the energy content of gasoline, ethanol, and various blends, along with example pricing to ensure price parity among fuels (based on equivalent energy content per unit cost). If the average price of straight crude-based gasoline is $2.59, E10 must be priced at $2.50, and E85 at $1.94 to ensure price parity. The table shows the required price spread as a percentage, which can be used to determine pricing parity as the price of fuels fluctuate. Figure 12.52 illustrates this trend graphically. As the average content of ethanol in motor gasoline reaches the 10% limit, the price spread would be based on the difference in price spreads for E10 and E85 (-22%) to ensure pricing parity (since straight crude-based gasoline, E0, would be unavailable at most retail stations). Since January 2009, the price spread between motor gasoline and E85 has fluctuated between 9% and 19%, and stands at approximately 14.5% as this report is written (E85Prices.com, 2009).

The pricing parity argument could be extended beyond a simple energy content argument. Due to the reduced energy content, and accompanying reduction in fuel economy, consumers choosing to fill up with E85 will be faced with more frequent trips to the refueling station. To compensate for this increased frequency of refueling, consumers could demand additional incentives, e.g., further reductions in E85 pricing. As discussed in the historical fuel transitions analyses, Borenstein estimated that the price differential between leaded and unleaded gasoline slowed the phase out of leaded gasoline by about 4 years (Figure 12.2 shows that unleaded gasoline was priced higher than leaded gasoline throughout the 15 year lead transition). This historical example suggests that the relative pricing of fuels could influence the transition to biofuels.

Table 12.16. To ensure price parity, the price of ethanol-gasoline blends must fall relative to crude-based gasoline as the ethanol content increases. The LHVs of gasoline and ethanol are taken from Table 12.11.

Fuel	LHV (Btu/gallon)	Example retail price	Price relative to gasoline	Price spread
gasoline	115,261	$ 2.59	$ -	0%
ethanol	76,330	$ 1.72	$ (0.87)	-34%
E85	86,452	$ 1.94	$ (0.65)	-25%
E10	111,368	$ 2.50	$ (0.09)	-3%
E15	109,421	$ 2.46	$ (0.13)	-5%
E20	107,475	$ 2.42	$ (0.17)	-7%

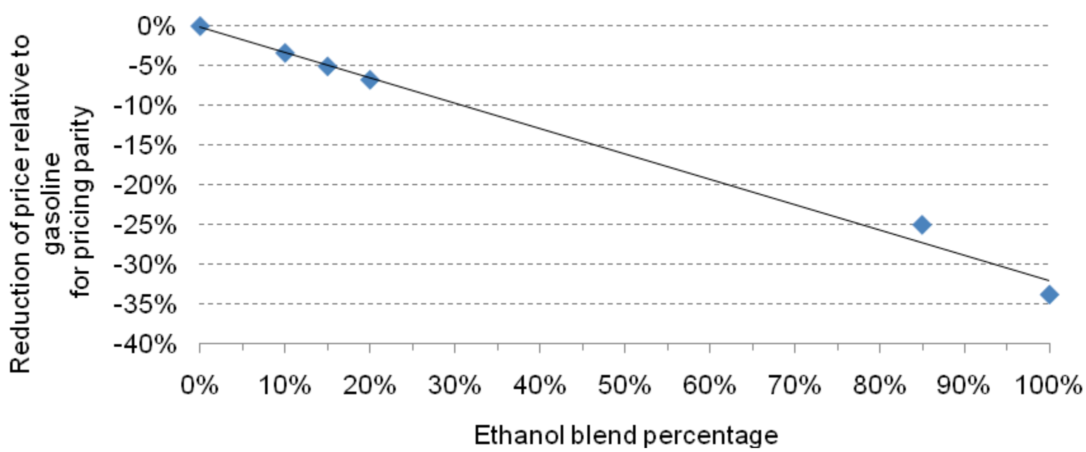


Figure 12.52. The price of ethanol blends must be reduced as the ethanol content increases in order to ensure price parity. The trend is not a perfectly linear relationship due to the seasonally-average content of ethanol in E85 (i.e., 74%).

Even if retail stations make the appropriate upgrades to store and dispense E85, and adjust pricing to incentivize purchases of the new fuel, end users must have equipment that is capable of operating on E85. The availability of vehicles capable of operating on higher-blends of ethanol (and customer demand for such vehicles) is a major source demand uncertainty (NCEP, 2008). Due to the physical and chemical properties of ethanol, gasoline-powered vehicles must be modified to operate on higher blends, such as E85. Systems requiring modification, and the extent of modifications, are dependent on the blend level and age of vehicle, as illustrated in Figure 12.53.

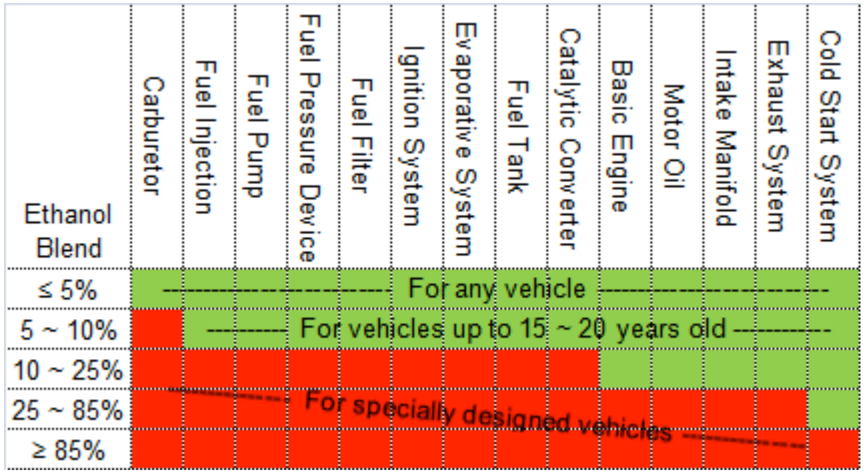


Figure 12.53. Vehicle and engine systems requiring modification depend on the ethanol blend level and vehicle age. Modifications are not necessary in boxes shaded green; modifications are probably necessary in red areas. For example, vehicles that are 15-20 years old probably require modifications to the carburetor when operating on blends greater than 5% (Joseph, Jr., 2007; The Royal Society, 2008).

Since scenario 1 is based on a motor gasoline sector supplied with E10 and E85, the only rows in Figure 12.53 that are of concern include ethanol blends up to 10% and blends greater than or equal to 85%. Aside from vehicles equipped with carburetors, fueling with E10 poses no challenges to the existing fleet of gasoline-powered vehicles. The remaining fuel, E85, must be consumed by specially designed vehicles, or flex-fuel vehicles (FFVs). Ford Motor Company explains that the following components and systems must be modified when upgrading an existing vehicle model to be flex-fuel capable (DiCicco, 2009):

- Engine components, including valves, valve seats, spark plugs, fuel injectors, direct-injection fuel pumps, cylinder head gaskets;
- Adjustment of controller calibrations for performance, emissions, on-board diagnostics (OBD), and cold start (at all blend levels);
- Fuel system components, including fuel tank, flow pump, fuel delivery lines.

Currently, vehicle manufacturers do not warrant the use of blends exceeding E10 in conventional (non-flex-fuel) vehicles, which is the limit imposed on motor gasoline by the CAA. However, domestic vehicle manufacturers have been producing flex-fuel vehicles (FFVs) capable of operating on blends up to E85 since about 1996. Figure 12.54 shows the number of light-duty FFVs in use (i.e., rolling stock), along with cumulative production of light- and medium-duty vehicles, from 1996 through 2008. The rolling stock estimates are derived from cumulative production data using vehicle survivability factors published by the NHTSA (Lu, 2006). In January 2008, approximately 6,250,927 FFVs were in operation in the U.S. LDV fleet. Figure 12.54 also plots EIA estimates of the number of FFVs actually fueled on E85 from 2003-2007 (EIA, 2009a). Due to the limited availability of E85 in the market, the vast majority of FFVs in use are not actually fueled with E85.

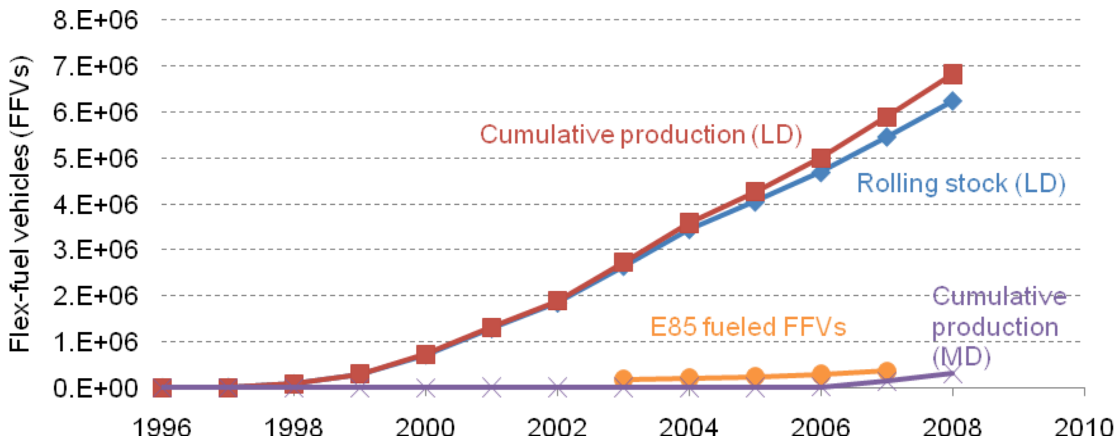


Figure 12.54. The cumulative production and rolling stock of light-duty FFVs have increased steadily since 1998 (EIA, 2009a; Lu, 2006). Due to limited availability of E85, the vast majority of in-use FFVs are not fueled with E85.

The dynamics of fleet turnover influence the rate at which FFVs enter the market—turnover of the U.S. LDV fleet typically takes 15 years or more (Greene and Schafer, 2003). If all LDVs sold in the U.S. starting in 2010 were FFVs, it would take until 2025 for the LDV fleet to be capable of operating nearly completely on E85. In scenario 1, E85's share of total motor gasoline (by volume) increases to just over 20% in 2022. In 2008, out of a total light-duty fleet of 232 million vehicles, 2.5%, or 6 million, were FFVs. The EIA projects that the total light-duty fleet will grow to 266 million in 2022 (EIA, 2009c, Table 58). If E85 fuel is assumed to fuel all FFVs, i.e., all consumers with FFVs always choose to purchase E85, then approximately 16% of the light-duty fleet must be comprised of FFVs in 2022, i.e., 42 million vehicles.[34] Over a 14 year period, the FFV population must grow by 42 million, while the entire light-duty fleet grows by only 34 million. This fleet turnover seems feasible, but it is based on a very optimistic assumption related to refueling.

The continued production and sale of FFVs is uncertain. In the RFS2 DRIA, the EPA analyzed 3 scenarios based on different assumptions related to FFV production rates, forecasted vehicle phase-out (i.e., fleet turnover), vehicle-miles traveled, and fuel economy estimates (EPA, 2009a). Using the EPA MOVES model, EPA analysts estimated that the maximum percentage of motor gasoline fuel that could feasibly be consumed by FFVs in 2022 is 30%. The analysis further assumed that FFVs would be evenly distributed throughout the nation, and that access to E85 would not be a constraint. However, the expansion of E85 infrastructure needed to ensure refueling access is also uncertain. The EPA defines "reasonable access" to E85 as one-in-four pumps offering the fuel in a given area.[35] The EPA estimated that reasonable E85 access must grow to encompass 70% of the nation by 2022.

In 2007, 164,292 conventional refueling stations were in operation in the U.S. (Davis, Diegel and Boundy, 2009), and 2,204 stations currently offer E85 (E85Prices.com, 2009). If the number of

[34] Due to the lower energy content of E85 relative to E10 (22% reduction), only 16% of the fleet could be exclusively fueled on E85.
[35] This definition is based on current access to diesel fuel, which is available at approximately one-in-four stations.

stations remains steady[36] through 2022, then 26,547 additional stations would need to add E85 to their fuel offerings, or approximately 2,000 per year through 2022. If reasonable access is defined as one-in-three stations offering E85, then 36,131 additional stations, or approximately 2,800 stations per year must add E85 access through 2022. From 2007 through 2009, the number of stations offering E85 has increased from 1,085 to 2,204, an increase of less than 600 stations per year. Based on these simple calculations, it is clear that E85 infrastructure must expand rapidly relative to recent growth in order to supply the market with sufficient access to and volume of E85 to meet the RFS mandate according to scenario 1, or the EPA control case.

Even if one-in-four stations offer E85 in 2022, the distribution of these stations relative to the distribution of FFVs in the LDV fleet remains uncertain. The NRC panel explains the problem that exists between the retail and end use segments as follows (NRC, 2009):

> Expansion of the flexible-fuel vehicle fleet needs to be complemented by presence of ethanol stations close to where the vehicles are used. Past policy that mandated the increased use of alternative-fuel vehicles did not result in reduced gasoline consumption, because ethanol pumps were not readily available in many areas where flexible-fuel vehicles were used. The close coupling of alternative fuels and alternative-fuel vehicles is an important practical consideration.

The panel recommends that "[f]uture policy measures need to take into account implementation of alternative-fuel vehicles, availability of alternative fuels, and proximity of vehicles to fueling stations to ensure an effective vehicle and fuel transition." Therefore, even if FFVs penetrate the market, E85 availability in the retail sector (in terms of volume and access) could hinder total ethanol consumption by limiting expansion of the E85 market. A stand alone volume mandate, met primarily through E10 and E85, could be hindered by a failure to address this coupling between the end use and retail segments of the fuel supply chain.

Overall, scenario 1 will require significant capital investments throughout the fuel supply chain, from new production facilities (e.g., cellulosic and conventional ethanol), expanded biofuels distribution capacity, and upgraded retail stations coupled with an increased population of FFVs. The projected capital investments required over the life of the RFS program, as estimated by the EPA, are show in Table 12.16. Since scenario 1 is based on the EPA control case, which serves as the basis for the EPA analysis, these cost estimates are worth reviewing here. The EPA explains the estimated capital investments as follows:

> The increased use of renewable and alternative fuels would require capital investments in corn and cellulosic ethanol plants, and renewable diesel fuel plants. In addition to producing the fuels, storage and distribution facilities along the whole distribution chain, including at retail, will have to be constructed for these new fuels. Conversely, as these renewable and alternative fuels are being produced, they supplant gasoline and diesel fuel demand which results in less new investments in refineries compared to business-as-usual.

[36] The number of conventional refueling stations has actually declined steadily since the 1990s, falling from 207,416 in 1993 to 164,292 in 2007. See (Davis et. al, 2009).

As shown in Table 12.17, nearly all investments are related to the expanded production and distribution of ethanol.

Table 12.17. The EPA estimated capital investments necessary over the life of the RFS program (based on the EPA control case, which is analogous to scenario 1) (EPA, 2009a).

Investment type	Capital Costs (billion dollars)
Corn ethanol plants	4.0
Cellulosic ethanol plants	50.1
Ethanol distribution	12.4
Bio-based distillate production and distribution	0.25
Petroleum refining industry (avoided investments)	-7.9
Total	58.9

12.3.5.2 Scenario 2: Increased ethanol blend limit

In scenario 2, the ethanol blend limit is increased from the regulated level of 10% to 20%. As discussed in earlier sections, the current 10% limit was established by a waiver request under section 211(f) of the CAA (EPA, 1995b). The limit can be increased only through an amendment to the CAA or with the approval of another waiver request. The EPA is currently reviewing a waiver request to increase the blend limit to 15%, which was submitted on March 6, 2009 by Growth Energy, an ethanol industry advocacy group, and 54 ethanol producers (EPA, 2009a; EPA, 2009b). [37]

The increased blend limit has been pursued as a means for incorporating more ethanol into the motor gasoline supply as the nation approaches the 10% limit in the coming years. The current rate of growth of E85 infrastructure and population of FFVs in the light-duty fleet may be insufficient to incorporate the growth in ethanol supply needed to meet the RFS. As shown in Figure 12.29, increasing the blend limit delays the year in which the blend limit is reached, delaying the need for E85 to supply a portion of the market. Although increasing the blend limit alone is not capable of meeting the RFS requirements (without the need for E85), it does have the potential to provide valuable time needed to expand the E85 and FFV infrastructure (EPA, 2009a).

The greatest impacts and concerns related to an increased blend limit fall in the retail and end use segments of the fuel supply chain. The E15 waiver request submitted in March 2009 saw immediate reactions from engine manufacturers, consumer advocacy groups, and various industry groups—ranging from the Alliance of Automobile Manufacturers to the Society of Independent Gasoline Marketers (SIGMA) and the National Association of Convenience Stores (NACS)—with concerns about potential damages to engines in vehicles and other gas-powered equipment, and the financial and legal implications facing the retail sector (Hughes and Etter, 2009; Jensen, 2009).

[37] On November 30, 2009, the EPA notified Growth Energy that the waiver request decision would be delayed until mid-year 2010, pending results from DOE vehicle test programs. The letter can be viewed here: http://www.growthenergy.org/static/docs/2009/11/letter_EPAtoGrowthEnergy.pdf

As mentioned in previous sections, engine manufacturers do not warrant the use of blends exceeding E10 in conventional (non-flex-fuel) vehicles, coinciding with the limit imposed on motor gasoline by the CAA. Only FFVs are warranted to run on blends exceeding 10%. Cars and trucks are not the only concern. Hundreds of millions of small gasoline-powered engines in lawnmowers, weed trimmers, chainsaws, etc, and small to large engines in various watercrafts could be affected by the use of intermediate ethanol blends. This is a fundamental problem in that the testing for engine-fuel compatibility has been done over a very limited range compared to the options available today. Very good solutions might exist outside of the tested compatibility ranges, but collaboration among the government, fuel suppliers, motor manufacturers, and university researchers is likely to be needed to develop confidence in new combinations. This collaborative effort is likely to require significant resources.

In anticipation of these concerns, the U.S. DOE initiated a government test program in the summer of 2007 to evaluate the potential impacts of intermediate ethanol blends on legacy vehicles and other engines, including small non-road engines (Knoll, 2009). The objective of the DOE program, conducted by researchers at DOE's ORNL, is to evaluate the effects of E15 and E20 on tailpipe and evaporative emissions, catalyst and engine durability, vehicle drivability, engine operability, and vehicle and engine materials. Results to date have shown that vehicles exhibit a loss of fuel efficiency equivalent with energy content of the fuel, and that regulated tailpipe emissions were “largely unaffected” by ethanol content. No obvious material compatibility issues were noted during testing, although such effects were not specifically characterized during initial testing.

A materials compatibility test program, to be conducted in collaboration with the Coordinating Research Council (CRC), will evaluate the durability of fuel-wetted components of fuel systems in non-FFVs when exposed to different intermediate ethanol blends, including impacts to plastics, elastomers, o-rings, and hose materials. When considering the current opposition from OEMs and consumer advocacy groups, the results of the test programs being funded and conducted by the DOE will be closely watched. To ensure the validity and support of this continuing program, the DOE plans to work closely with the EPA and various industry stakeholders to ensure that the test programs are conducted in a sound manner and targeted at providing the data needed to properly evaluate the effects of intermediate blends.

Similar concerns arise in the retail sector. Although fuel stations have been handling motor gasoline with ethanol up to 10%, questions remain as to whether existing equipment is compatible with intermediate blends. Many state and local fire codes require third party certification for fuel handling equipment, a task most often handled by Underwriters Laboratories (UL), an independent product safety certification organization. Existing fuel pumps, although safe with blends up to 15%, will not be approved for E15 by UL because E15 could actually represent a wider range of blends, including, e.g., E16. UL has stated that even if existing pumps could handle E15, the company cannot retroactively certify existing pumps. This leaves essentially two options for retailers: (1) sell fuel with incompatible equipment, or (2) replace existing equipment with approved, compatible equipment (Jensen, 2009). This problem applies not only to fuel pumps, but the entire range of fuel-wetted components in the fuel retail sector, e.g., storage tanks, fuel lines, dispenser nozzles, etc.

To allow for greater flexibility in selection of equipment that is compatible with various ethanol blends, UL recently announced a new certification path for fuel dispensers for mid-level blends up to E25 (UL, 2009). This new path provides manufacturers with three certification options, which, according to UL, allows manufacturers to "balance market needs and provide maximum flexibility as advances are made in the fuel industry." The three certification pathways cover gasoline and ethanol fuel blends up to E10, E85, and E25. Jeff Smidt, General Manager of Global Energy Business for UL, explains the reason for the third certification option as follows (UL, 2009):

> There is increased potential for different types of damage to materials and components at blends above E25 and, as a result, there are more stringent requirements for dispensers for use with these higher blend levels. This new mid-level option, up to E25, provides another certification path and can help facilitate the distribution of ethanol blends in the market.

Therefore, if the blend limit is increased, retailers will have an option to procure equipment that is certified for blends up to E25, rather than jumping to more expensive E85-compatible equipment.

One approach being advocated by ethanol industry groups is the increased use of so-called "blender pumps" at retail stations (Brekke, 2009). Blender pumps are comprised of two underground tanks, one with unleaded gasoline (i.e., E0), and one with E85. The system blends and dispenses the appropriate percentage of each fuel to create a customer-specified blend level ranging from 0% to 85%. Advocates of blender pumps explain that such systems provide the consumer with new choices at the pump, and benefits station owners by providing flexibility should an increase in the blend limit be approved. Currently, the benefit of blender pumps is mostly restricted to consumers with FFVs, since blends above E10 are only warranted for use in FFVs. If the blend limit is increased, blender pumps will enable retailers to immediately supply the market with intermediate blends. In addition, blender pumps could be helpful in providing options to retailers and consumer alike, in the selection of an ethanol blend that minimizes cost as the price spread between ethanol and gasoline fluctuates. For example, if the price spread increases dramatically, e.g., ethanol price is 34% less than gasoline, then the consumer could choose to fuel up on a high blend, e.g., E85. If the spread is narrow, then the consumer could choose to limit the amount of ethanol they blend into the fuel. Some retailers, echoing the concerns of engine and vehicle manufacturers, contend that the new pumps could encourage non-FFV owners to fuel with intermediate blends because ethanol is cheaper than conventional gasoline. Due to UL resistance to recertify existing equipment, and liability concerns facing retailers that choose to dispense higher blends with existing equipment, expanded use of blender pumps could be limited (NACS, 2009). Although blender pumps could provide flexibility to retail station owners, and more choices to consumers, the expenses associated with upgrading a station are likely to be analogous to the E85 costs presented in Table 12.15, since tank and dispenser conversions and/or replacements would be necessary.

A related challenge to be overcome is that all states regulate current gasoline sales by volume. Most states have processes in place to certify volumetric measurements on gasoline pumps. If the price is influenced by both the volume and the ethanol content, it is quite likely the states will need more sophisticated instrumentation and inspectors to help develop consumer acceptance.

The EPA, in a sensitivity analysis conducted in the RFS2 DRIA, considered the impacts of a waiver request being approved for E15 or E20 blends (EPA, 2009a). However, in their analysis, they assumed that legacy vehicles would continue to operate on E10, while Tier 2 vehicles[38] would be approved for blends up to E20. Therefore, the market would still have to provide E10, E15/20, and eventually E85. Since a portion of the market continues to be supplied with E10, the effects of increasing the blend limit are mitigated, e.g., the need for an E85 market is delayed less than if the entire supply of motor gasoline is blended to the increased blend limit. Ultimately, actions taken by OEMs will be crucial in determining whether the blend limit will be increased, and if it is increased, whether intermediate blends will be available to the entire fleet, or a limited segment (e.g., Tier 2 vehicles).

In the distribution network, the impacts of an increased blend limit could be varied. Overall, the impacts would be limited to blending/distribution terminals and delivery to retailers. Upstream of blending terminals, the distribution system would continue to operate as usual; denatured ethanol and gasoline blendstock would continue to be delivered separately to blending terminals. If the blend limit is increased, and is approved for the entire existing fleet of vehicles, i.e. the approval is not limited to Tier 2 vehicles, then the distribution system would only be required to adapt to an increasing blend level in motor gasoline. At blending terminals, equipment that is currently used to handle and store motor gasoline (up to E10) could be found to be incompatible with intermediate blends, requiring equipment upgrades. Shipping containers used to transport blended fuels to retailers, i.e., truck trailers, could face similar issues. If the blend limit is increased, but the approval is limited to Tier 2 vehicles (and FFVs), then the market would have to supply multiple fuels: E10, E15/E20, and eventually E85. Blending terminals could be faced with blending, storing, and distributing the additional intermediate blend. This determination would be based on the acceptance and growth of blender pumps at retail stations. If blender pumps are not installed widely, distribution networks would shoulder the burden of blending, storing, and distributing the intermediate blend. Otherwise, standard motor gasoline (E10) and E85 would continue to be distributed to retailers, as they would have the capability to supply intermediate blends with blender pumps.[39] In summary, impacts to the distribution segment of the fuel supply chain are dependent upon OEM approvals and the acceptance of blender pumps in the retail segment. By reducing the extent of the E85 market, increasing the blend limit has the potential to limit the number of terminals that would be required to blend, store, and distribute E85.

In addition to delaying the need to develop E85 infrastructure, and limiting the size of the E85 market, increasing the blend limit has the potential to (1) provide some flexibility in meeting the RFS and (2) limit the impacts of future policy changes. By limited the overall size of the E85 market, an increased blend limit provides some flexibility in the design of ethanol markets. For example, regions with a high concentration of ethanol producers could more aggressively develop E85 markets, by providing incentives for consumers to purchase FFVs and retail station

[38] Vehicles meeting the EPA Tier 2 requirements were first manufactured in the 2004 model year. See http://www.epa.gov/tier2/ for details.

[39] In section 1.7.1.3 of the EPA RFS2 DRIA, a retail configuration for dispending mid-level blends with existing retail infrastructure, as proposed by SIGMA/NACS, is presented. However, this configuration is still reliant on a distribution infrastructure capable of delivering motor gasoline (E10), an intermediate blend (E15/E20), and E85. The retail configuration allows retailers to avoid the need for blender pumps, while retaining the ability to offer regular, midgrade, and premium motor gasoline.

owners to install E85 equipment (or blender pumps). Outside of these E85 regions, intermediate blends could be integrated into existing infrastructure, limiting or negating the need for E85 markets.

By delaying the need for, and extent of, an E85 market, an increased blend limit could prevent significant capital investments in the fuel supply chain infrastructure from ending up as sunk costs, or stranded assets. For example, if advanced biofuel technologies develop in the coming years, allowing synthetic fuels to enter the market, the need for ethanol-compatible infrastructure would become unnecessary as ethanol is displaced by advanced biofuels.[40] The entire blend limit issue would become a non-issue if the fuels industry moves to advanced biofuels, which serve as "drop-in" replacements to crude-based gasoline. In addition, if the RFS mandate was to be suspended, or revised to require a more modest consumption of biofuels in the coming years, and thereby limiting or negating the need for E85, then sunk costs could, again, be avoided or minimized by delaying and limiting the extent of the E85 infrastructure.

Finally, it should be noted that the blend limit has no impact on the DFO sector, and thus does not affect the production, distribution, retail, and consumption of bio-based distillate.

12.3.5.3 Increased production of bio-based synthetic fuels

This section encompasses scenarios 3(a), 3(b), and 4, since all are based on the increased production of bio-based synthetic fuels (i.e., advanced biofuels), and limit the growth of the ethanol industry. As explained previously, advanced biofuels, which are compatible with existing infrastructure, have the potential to limit the need for an ethanol-compatible infrastructure and the associated capital investments.[41]

Cellulosic diesel, or Fischer-Tropsch (FT) diesel, supplies half of the cellulosic biofuel mandate in scenario 3(a), while the entire cellulosic mandate is met with cellulosic diesel in scenario 3(b). Cellulosic diesel is a BTL fuel. The term BTL is applied to any synthetic fuel that is made from biomass through a thermo-chemical pathway (Platform, 2009). Synthetic diesel can be produced from lignocellulosic feedstocks through gasification processes and the FT process. The FT process has been utilized to produce synthetic diesel with coal and natural gas feedstocks. Rather than following a fermentation pathway to produce cellulosic ethanol, synthetic diesel is produced by converting the lignocellulosic feedstocks first to synthesis gas, i.e., syngas, and then converting the syngas to liquid hydrocarbons via the FT process. The resulting hydrocarbons can be further refined through conventional petroleum refining processes, such as hydrocracking. Scenario 4 is analogous to 3(a), except that half of the cellulosic biofuel mandate is met with renewable gasoline. Like cellulosic diesel, renewable gasoline is produced with lignocellulosic feedstocks through a thermo-chemical pathway. Hydrocarbons produced from the FT process would require further upgrading with conventional petroleum refining processes.

Additional fuels are being developed that could contribute to this "compatibility" pathway. Renewable diesel is the term applied to hydrogenation-derived renewable diesel (HDRD), a

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[40] The increased production of bio-based synthetic fuels is discussed further in section 12.35.3.
[41] The development and use of biofuels that are compatible with existing engines and infrastructure aligns well with the integrated view of vehicle and fuels, as discussed in section 12.4.4.

high-quality, synthetic substitute to crude-based distillate. Renewable diesel is produced through the reaction of an oil-based feedstock (i.e., triglyceride) with excess hydrogen under high pressure and temperature to produce saturated hydrocarbons. This process can be run in an independent facility, or in existing oil refineries, and can even be operated with a blend of triglycerides and petroleum. Gasoline can be produced using similar processes, but, according to the U.S. DOE, this process is in early stages of development. A number of companies are working to develop HDRD production processes, including ConocoPhillips, Neste Oil, Petrobras, Syntroleum, and UOP-Eni (DOE, 2009). As mentioned previously, the availability of oil-feedstocks (e.g., vegetable oils, rendered animal fats, etc) for fuel production remains in question. The development of algae as a source of triglycerides could address this feedstock supply issue in the long term (Wogan, 2008). Algae are being researched as a potential feedstock for the production of a range of biofuels, including renewable diesel and gasoline, biocrude, and conventional biofuels, i.e., biodiesel and ethanol.

Any combination of advanced biofuels that satisfy the requirements of the RFS mandate could be developed to displace the expanded production of ethanol, as illustrated through scenarios 3(a), 3(b), and 4. However, a primary hurdle to the commercial production and market penetration of these fuels is the development of advanced fuel production technologies. The only liquid biofuels currently produced on a commercial scale are conventional starch ethanol and biodiesel. The technologies needed to produce BTL fuels (e.g., FT diesel, renewable gasoline), renewable diesel (HDRD), biobutanol, and even cellulosic ethanol, are still in research and development stages. In order to displace conventional biofuels, not only do advanced biofuels production technologies need to be proven on a commercial scale, but they must be capable of producing fuels that can compete on a cost basis with conventional biofuels, and conventional petroleum fuels.

The NRC panel, in a review of biochemical conversion pathways, acknowledges the importance of developing advanced biofuels from lignocellulosic feedstocks, and not limiting research and development to the production of ethanol (NRC, 2009):

> Future improvements in cellulosic technology that entail invention of biocatalysts and biological processes could produce fuels that supplement ethanol production in the next 15 years. In addition to ethanol, advanced biofuels (such as lipids, higher alcohols, hydrocarbons, and other products that are easier to separate than ethanol) should be investigated because they could have higher energy content and would be less hydroscopic than ethanol and therefore could fit more smoothly into the current petroleum infrastructure than ethanol.

The panel recommends that the federal government should support research focused on technologies that could convert biomass feedstocks directly to advanced biofuels that can be seamlessly integrated into the existing infrastructure. However, the panel acknowledges the challenges facing the large-scale commercial application of these immature technologies, and stresses the need for continued federal and industry support of R&D and demonstration programs.

In their review of thermochemical pathways (e.g., to produce FT diesel), the panel is more optimistic about the state of technology, but stresses the importance of technology demonstration, which is needed to support commercial-scale production (NRC, 2009):

> The advanced technologies for gasification, syngas cleanup, and Fischer-Tropsch synthesis have been demonstrated on a commercial scale. Their integration on the scale required to have a substantial impact on fuel production has not been demonstrated but is not considered a major issue.
>
> The technology for producing liquid transportation fuels from biomass...via thermochemical conversion has been demonstrated but requires additional development to be ready for commercial deployment.
>
> Key technologies should be demonstrated for biomass gasification on an intermediate scale…to obtain the engineering and operating data required to design commercial-scale synthesis gas-production units.

Based on the state of advanced biofuels production technologies, the ability of the industry to scale up production of these compatible biofuels to supply the increasing volumes mandated by the RFS program can be questioned. Although the scenarios that present such a pathway may not be reasonable in terms of initial market penetration, the benefits gained from the eventual increased production of these fuels should not be overlooked. The E10/E85 pathway to meeting the RFS will require substantial investments throughout the fuel supply chain infrastructure in order to distribute and consume a fuel that is incompatible with existing infrastructure. The capital investments made to support the increased production and distribution of ethanol, and increased fleet of FFVs to consume increasing volumes of E85, have the potential to end up as sunk costs if and when advanced biofuels technologies are scaled up. Advanced biofuels, which are compatible with existing infrastructure, could essentially render the ethanol (E85) infrastructure obsolete.

Setting aside the blend limit issue, these scenarios (3 and 4), when compared to the base case, present two potential pathways: (1) the nation limits the expansion of "first-generation" biofuels and the associated infrastructure investments until advanced biofuel technologies are developed and scaled up, thereby limiting the potential energy and environmental benefits associated with near-term biofuels consumption, or (2) push ahead with "first-generation", incompatible biofuels, i.e., ethanol, making substantial infrastructure investments that could potentially end up as sunk costs if advanced, "next-generation", compatible biofuels enter the market. This issue becomes a question of potential near-term energy and environmental benefits weighed against the costs to develop an infrastructure that would be rendered obsolete with the development of compatible biofuels in the future.

Although the benefits of synthetic fuels have been discussed throughout this section, some of the same distribution challenges facing conventional biofuels will need to be addressed. The production of synthetic fuels, being dependant on the same, or similar, feedstocks as conventional biofuels, will likely still occur in a large number of widely dispersed biorefineries. With an existing distribution system developed around the concentrated petroleum refining industry, the collection and distribution of this more dispersed supply of fuel remains a challenge. However, due to the removal of the "incompatibility hurdle," these fuels are capable of being seamlessly integrated into existing infrastructure, including pipelines. If the pipeline infrastructure is able to be utilized, a biofuels distribution system could be developed around the exiting petroleum distribution infrastructure. Fuels could be transported to the Gulf Coast through various transportation modes (e.g., barge), blended into finished products for various markets, and distributed via the existing pipeline infrastructure to destination terminals (NCEP, 2008; Peterson, Chin and Das, 2009).

An added benefit of synthetic fuels, aside from compatibility with infrastructure, is the higher energy content when compared to ethanol. The lower energy content of ethanol has implications in the distribution, retail, and end use segments, requiring a greater volume of liquid fuel to be transported and consumed relative to the gasoline it displaces. With energy contents nearly equivalent to crude-based gasoline and diesel, the synthetic fuels would be transported, stored, dispensed, and consumed in volumes equivalent to conventional crude-based fuels.

12.3.5.4 Scenario 5: Variable liquid fuels demand

Whereas the previous scenarios present alternative pathways to meeting the RFS, scenarios 5(a) and 5(b) illustrate the impacts of variable liquid fuels demand in a transition to increased consumption of biofuels. Both are identical to the base case, except that total liquid fuels demand is altered—decreased in 5(a) and increased in 5(b). Liquid fuels demand could be influenced by a number of factors, ranging from changes in economic conditions to altered energy policies and trends in the liquid fuels sector (e.g., increased electrification of the LDV fleet). These scenarios illustrate the implications of the RFS program being designed as a volume mandate, in that regardless of overall demand, the mandated consumption of biofuels remains unchanged.

If the objective of a biofuels transition is to reduce petroleum consumption and GHG emissions from the transportation sector, then more rapid reductions can be realized when total liquid fuels demand is reduced in combination with mandated increases in biofuels consumption. Policies aimed at reducing total liquid fuels demand, in combination with the RFS, could force the sector through a more rapid transition. Although absolute production and consumption of biofuels remains unchanged, the relative share of biofuels in the liquid fuels sector would grow more rapidly.

From a production perspective, the impacts would be no different than the base case as no change in regulations is assumed. The mandate still requires 36 bgy of biofuels by 2022, so the same increase in conventional and cellulosic ethanol facilities would be needed, along with the modest increase in bio-based distillate production. The distribution and retail infrastructure, built around petroleum products, would be faced with a more rapid penetration of E85. In order to consume the increased volume of E85, a greater percentage of the nation would require "reasonable access" to the fuel, requiring more blending terminals and retailers to be capable of handling and dispensing the fuel. Although these segments of the supply chain would face challenges with this more rapid transition, the reduced total demand presents some benefits. For example, as total liquid fuels demand falls, more of the existing storage capacity could be used to store denatured ethanol and various blends, rather than forcing terminals to expand storage capacity. With a rapidly growing E85 market, retailers would be presented with a more robust market, better justifying investments in E85 compatible equipment. In the end use segment, fleet turnover poses a significant challenge. As demand falls, and ethanol is increasingly supplied as E85, the population of FFVs would be required to grow more rapidly. However, if total liquid fuels demand declines as a result of reduced average VMT, the rate of fleet turnover could be reduced: as consumers drive less, their vehicles could remain in use for extended periods of time, slowing fleet turnover and the introduction of FFVs.

If total liquid fuels demand increases, relative to the base case, the situation is relatively unchanged. Many of the barriers and hurdles facing the liquid fuels sector are identical, or could potentially be mitigated due to the overall growth in the sector. With increased total demand, the rate of growth and size of the E85 market are reduced, requiring a smaller portion of the nation to have "reasonable access" to the fuel. Fewer terminals and retailers would be required to make the necessary upgrades to handle and dispense the new fuel. With a smaller E85 market, some retailers and terminals could find it more difficult to justify the investments needed to upgrade equipment. With less E85 needing to be consumed, fewer FFVs would be needed in the fleet, mitigating concerns related to fleet turnover. However, as total demand increases, the sector will be faced with increases in total capacity. When considering the fact that many parts of the liquid fuels distribution system already face capacity constraints (NCEP, 2008; Peterson, Chin and Das, 2009; Rabinow, 2004), the additional strain of adding capacity to handle biofuels, i.e., ethanol, could be an added burden. Due to the lower energy content of ethanol relative to crude-based gasoline, an increased supply of ethanol would force greater capacity expansions compared to an energy-equivalent increase in crude-based gasoline.

12.3.5.5 Uncertainty

The pace and success of technology development and advancements are a major source of uncertainty in a biofuels transition. In all scenarios considered in this work, conventional biofuels are capped at 15 bgy starting in 2015. The continued expansion of the biofuels industry is then reliant on advanced biofuels production technologies (and continued expansion of new biofuel feedstock supplies). This uncertainty in fuel supply impacts investment decisions not only in production facilities, but in all segments downstream in the supply chain. Uncertainty in the biofuels supply could serve as an incentive for stakeholders in the distribution and retail industry to withhold or delay necessary infrastructure investments. Vehicle manufacturers could be faced with consumers unwilling to shoulder the added costs associated with FFVs if the ethanol supply does not expand sufficiently to justify an E85 or other high-blend market. The investments required to support an E85 market are also put into question by the potential development of advanced, compatible biofuels technologies, which could cause such infrastructure investments to end up as stranded assets.

The magnitude of infrastructure investments also stands as a source of uncertainty. Estimating the costs of large scale projects is often a major challenge. New technology demonstration projects often face major cost overruns compared to initial cost estimates. Finally, continuity of energy policy is another source of uncertainty (NCEP, 2008; Sperling, 1987; Sperling, 1988). If policies are altered to favor one or another approach that would fail in the market, stakeholders may be hesitant, or unwilling to make the necessary investments to ensure a smooth transition.

The NCEP explains that “uncertainty therefore emerges as a key crosscutting barrier to the infrastructure investments that will be needed to allow for a smooth transition.” In order to reduce uncertainty and promote a stable market, the NCEP proposes the following policy measures as means for supporting the RFS mandate (NCEP, 2008):

- continuity of the RFS program;
- deployment of FFV and fuel distribution infrastructure (e.g., promoting FFVs on a timetable that coincides with mandated volumes);
- improve permitting processes throughout the supply chain;
- simplify and/or harmonize fuel specifications (e.g., eliminate state-level specifications);
- allocate federal resources for critical infrastructure investments (e.g., retail equipment).

These recommendations align well with the challenges facing the base case scenario, which satisfies the requirements of the RFS through and E10/E85 future. However, it should be expected that there will be interest in modifying current policies to also support pathways less reliant on an expanded ethanol industry.

12.3.6 Conclusions

Analyses of historical fuel transitions were performed to place barriers to potential transitions to biofuels into context. The historical analyses illustrated that fuel transitions are common and exhibit variable time scales. For example, the United States has experienced several fuels transitions: leaded to unleaded gasoline; diesel to low-sulfur diesel to ultra-low-sulfur diesel; and shifts in oxygenates from MTBE to ethanol. The ULSD transition occurred during the same time frame as the transition from MTBE to ethanol in motor gasoline, which means the fuel industry successfully managed two major fuel transitions more or less simultaneously in the two largest markets of the U.S. liquid fuels sector. Though price increases of fractions of a cent to a few cents per gallon were anticipated for these various transitions, it’s hard to determine whether these price increases in fact happened.

For the transition currently underway, ethanol has found significant market share as an oxygenate substitute for MTBE, and increasingly as a substitute for gasoline. Despite the success of ethanol, the DFO sector has seen little incorporation of renewable fuels. Biodiesel production has increased rapidly in recent years, yet supplies an insignificant share of the DFO sector.

The historical cases illustrate different time scales for fuel transitions. The transition to unleaded gasoline took approximately 20 years, with lead additives finally being eliminated from on-highway gasoline in 1995. By contrast, the introduction of ULSD, and even the initial introduction of LSD, took approximately one year. The transition to unleaded gasoline had major implications throughout the supply chain, and was one of the first major transitions in the motor gasoline sector. Refiners needed to alter operations to recover the octane that had been provided by lead additives. During the transition, when both leaded and unleaded gasolines were available, the distribution and retail network had to adapt to supply multiple fuels. Vehicle manufacturers altered engine designs with lower compression ratios due to the anticipated reduction in octane rating of gasoline. The transition impacted the entire motor gasoline supply, not just specific segments, as seen with the use of oxygenate additives in gasoline. Oxygenate additives were used in the formulation of RFG and wintertime oxyfuel. These fuels were (and are still) supplied to specific geographic locations, and overwhelmingly to large demand centers, like the Northeast states and California.

On the other hand, the sulfur reduction transitions in the DFO sector occurred rapidly. With the reduction of sulfur, no major performance-enhancing properties of the fuel were altered (e.g., cetane). This factor stands in sharp contrast to the important role that lead additives played in the gasoline market (i.e., to boost octane). Refiners were required to reduce sulfur content, but did not need to recover any critical combustion-performance properties. When the market realized that the desulfurization processes reduced the content of aromatics and higher-molecular weight hydrocarbons, small quantities of lubricity additives were simply added to the fuel to recover the lubricating properties of these hydrocarbon compounds. The phase-in period, allowing for 20% of highway diesel fuel to be supplied with LSD through May 2010, was not fully utilized. That is, the transition occurred faster than was required by regulations. (LSD to ULSD)

The analysis of historical events illustrated the importance of properly selecting temporal, spatial, and sectoral boundaries for analysis: if those boundaries are not chosen appropriately, unintended consequences can result. For example, in the MTBE case, the potential for water contamination was not adequately considered as it became a dominant fuel component. Analyzing potential technologies through a systematic lifecycle perspective has the potential to limit the occurrence and severity of unintended consequences. Moreover, when considering the lifecycle of a fuel, one aspect of the fuel transition that is important but often overlooked is a shifting market for byproducts. For example, ULSD standards led to large supplies of extra sulfur as a byproduct from the refining industry, affecting global sulfur prices for agricultural applications. As noted in other sections, by products are an important aspect to consider for economic production of fuels, and shifts in the availability of byproducts can have effects on the production prices of the fuels themselves, and on other markets.

These historical examples were used to inform forward-looking analyses about the looming transition during which biofuels would displace a substantial fraction of the liquid fuels consumed in the United States. Prior transitions were used to identify potential market penetration rates, possible infrastructure implications, and potential unintended consequences.

The Renewable Fuels Standard (RFS) program has played a crucial role in the recent growth of the ethanol industry, and stands as a key driver in a transition to biofuels in the near term. By mandating annual consumption of biofuels, increasing to 36 billion gallons per year (bgy) in 2022, the program has the potential to significantly alter the state of the U.S. liquid fuels sector. As the RFS program mandates greater volumes of biofuels, there is substantial uncertainty facing the liquid fuels sector as to how such a transition will unfold.

A set of six projections, or scenarios, of the liquid fuels sector was developed using a model of the sector—the Liquid Fuels Transition (LiFTrans) model, which was developed for this project (partly from the findings of the historical analysis) to explore potential pathways that could be followed in the liquid fuels sector to meet the requirements of the RFS through 2022. The scenarios illustrate different pathways to meeting the requirements of the RFS mandate, with total biofuels production that is no more or less than the mandated volumes. These scenarios differ based on the overall demand of liquid fuels, how the biofuels mandate is met (i.e., the mix of biofuels), and the status of the ethanol blend limit in the motor gasoline sector. The scenarios were used to evaluate the infrastructure implications associated with a biofuels transition, and illustrate the uncertainty that exists in assessing such a transition. The model incorporates corrections for energy density of various fuels while meeting requlatory volumetric production requirements. The model uses two primary demand, or fuel consumption, functions: total liquid fuels and biofuels. These demand functions are used for both the motor gasoline (MoGas) and DFO portions of the model. The total liquid fuels demand functions are derived from the AEO 2009 cases. The RFS program, which is assumed to be the primary driver of biofuels consumption through 2022, serves as the biofuels demand function.

The scenarios represent three basic pathways to meeting the RFS mandate: (1) increase the availability of E85 in the market in conjunction with increased production of FFVs; (2) lessen the "incompatibility hurdle" through the production of synthetic fuels, or more compatible fuels; or (3) increase the ethanol blend limit. In addition, the impact of variable total liquid fuels demand was illustrated (with scenario 5). As a volume-based mandate, the RFS program requires an annually increasing volume of biofuels to be consumed, regardless of changes in total demand.

For the reference case, E85 consumption is negligible until approximately 2014, when a 10% blend wall is reached. At that point consumption of E85 begins a rapid growth trend that continues through 2022. Prior to the blend wall, most increases in ethanol consumption are from E10. After the blend wall is reached, further increases in ethanol consumption come in the form of E85. Additionally, as the volume of crude-based gasoline available for blending declines with increased total ethanol demand, ethanol consumed as E10 must inevitably decline. After the blend wall is reached, if the gasoline supply was blended to E10, there would not be enough gasoline available to incorporate the remaining ethanol into the market as E85. Therefore, E10 consumption must decline. This phenomenon is not simply a result of the blend wall, but is also based on the flat demand for total motor gasoline products in this projection. Increasing the blend limit from 10 to 20% (i.e., E20) delays the introduction of E85 by approximately 8 years, and thereby spares significant infrastructure changes (including vehicle stock turnover, retail outlet retrofits, etc.).

If total demand were to increase at a rate comparable to total ethanol demand (on an energy basis), then the market could continue to be supplied with E10, forgoing the need for ethanol to be consumed as E85. Moreover, because of ethanol's lower energy density compared with gasoline, as ethanol comprises a greater percentage of the overall motor gasoline pool, a greater overall of volume of fuel must be supplied. Ethanol alone is projected to comprise over 10% of the volume of fuels consumed in the liquid fuels sector (motor gasoline and DFO); nearly 7% on an energy basis, again, in 2022.

For the diesel sector, with the modest penetration of biofuels and growth in total distillate demand starting in 2010, there is no evidence of a peak in crude-based distillate consumption through 2030. Therefore, the "peak gasoline" phenomenon observed in the motor gasoline sector is not anticipated in this projection. A transition in oil refinery operations would be required to supply the increasing market demand for distillates and reduced demand for gasoline.

In addition, no issues related to a “blend limit” or “blend wall” are anticipated. Diesel-engine manufacturers place limits on biodiesel use, but the projected volumes of biodiesel fall well below any concerns about reaching a blend wall during the timeframe of this projection.

Any pathway to a biofuels transitions will require simultaneous technological and operational changes throughout the fuel supply chain, which includes feedstock production, fuel production, distribution, retail, and end use. The extent of these impacts is influenced by the nature of the biofuels (e.g., chemical/physical properties, state of production technology, etc) produced to meet the mandate. Like the historical fuel transitions, different fuels force different changes throughout the fuel supply chain. In summary, each scenario, or alternative pathway to meeting the RFS mandate, has a set of tradeoffs facing the liquid fuels sector in a transition to biofuels. Each scenario presents a range of challenges, or barriers, which must be addressed to ensure a successful transition. While one scenario could potentially mitigate challenges associated with another scenario, most often other challenges arise. The production of bio-based synthetic fuels to displace ethanol production exemplifies these tradeoffs. By overcoming the “incompatibility hurdle,” synthetic fuels can limit or negate the significant infrastructure investments required to distribute increasing volumes of E85. However, the technologies needed to produce, and the infrastructure needed to collect, synthetic fuels have yet to be deployed on a commercial scale. While these advanced biofuels could limit capital investments that end up as stranded assets, the time needed to develop the necessary production technologies could delay and prolong a biofuels transition.

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