Regulatory Impact Analysis: Renewable Fuel Standard Program

Chapter 7 Estimated Costs of Renewable Fuels, Gasoline and Diesel

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Chapter 7: Estimated Costs of Renewable Fuels, Gasoline and Diesel

This section describes our methodology for estimating the cost impacts of increased production, distribution, and blending of renewable fuels, including corn and cellulosic ethanol and biodiesel. Detailed information is given on expected changes to the nation's fuel distribution system, as well as changes in refining processes that will likely occur as larger volumes of ethanol are blended into gasoline. The impact of subsidies is also addressed.

7.1 Ethanol

This subsection provides a description of the analysis we conducted for estimating the cost of corn and cellulosic ethanol. Our analysis indicates that corn ethanol will cost $1.32 per gallon to produce (2004 dollars) in 2012. We also estimated that using cellulosic feedstock, the production costs for ethanol would be approximately $1.65 per gallon (2004 dollars). By 2012 this cellulosic cost may decline with breakthroughs and advances in technology. Based on reports from a variety of sources and discussions we held with members of academia as well as those directly involved in the industry, we believe several hurdles still have to be overcome in the production of large volumes of cellulosic derived ethanol. However, it appears that good progress continues to be made and we remain optimistic that cellulosic ethanol will become increasingly important in the future.

7.1.1 Corn Ethanol

Of the new ethanol production capacity expected to be built, according to Section 1.2.2 of this RIA, less than three percent combined is expected to be produced from cellulosic feedstocks or in plants that differ significantly from dry mill corn ethanol plants. Several plants will be able to utilize other starchy feedstocks besides corn, such as milo, barley, wheat, and sorghum. However, corn is the primary feedstock, and therefore, the following analyses will focus on dry mill starch ethanol production.

7.1.1.1 Engineering and Construction Requirements for Corn Ethanol Plants

To meet the RFS Case goal of 6.7 billion gallons per year (Bgal/y) of ethanol in 2012 from the October 2006 capacity of 5.2 Bgal/yr, 1.5 Bgal/yr of additional capacity will have to be constructed.[79] If we consider that it is likely that at least 9.6 Bgal/yr of actual ethanol capacity will come on-line by 2012 (EIA Case), the annual capacity increase is 4.4 Bgal/yr. Our industry characterization work considering plants that are either under construction or are planned to be constructed in the next 2-3 years suggests the average new plant size will be 81 million gallons per year (MMgal/yr) (including a small number of expansions).

[79] For details on current and expected ethanol capacity, refer to Section 1.2 of this RIA. Note that volumes considered cellulosic are also included here, since we believe that virtually all near-term cellulosic ethanol production will be from starch-based feedstocks that meet the alternative definition in the Act (discussed further in Section 7.1.1.2).

Based on conversations with representatives from design-build firms working in this field, as well as material from public sources, each new plant requires design engineering work lasting about six months followed by construction lasting 12-14 months before plant startup is possible, resulting in a total project timeline of 18-20 months. The design phase for a basic 50 MMgal/yr plant is expected to require the attention of about 12 engineers full time, and the construction phase will employ an average of about 125-150 workers each day. To correlate these figures with requirements for an 81 MMgal/yr plant, the number of construction personnel (150) were scaled proportionally, while the number of engineering personnel were assumed to be constant.

These figures provide a basis for estimating the personnel requirements of the total volume needed to meet the expected volumes. Over the six-year build-up period, a maximum of 970 construction workers and 30 engineers would be required on a monthly basis for the RFS case, while for the EIA case, these numbers increase to 2,328 and 75, respectively.

These figures simply estimate the number of workers required at the final assembly stage of the plant, and do not capture many more personnel hours that will go into designing and constructing vessels, pipe fittings, control systems, and other pieces of equipment that will be installed and brought online by the plant construction crews. A report produced by one consultant suggested that expansion of the ethanol industry was responsible for more than 65,000 construction jobs in 2005.[IIIII]

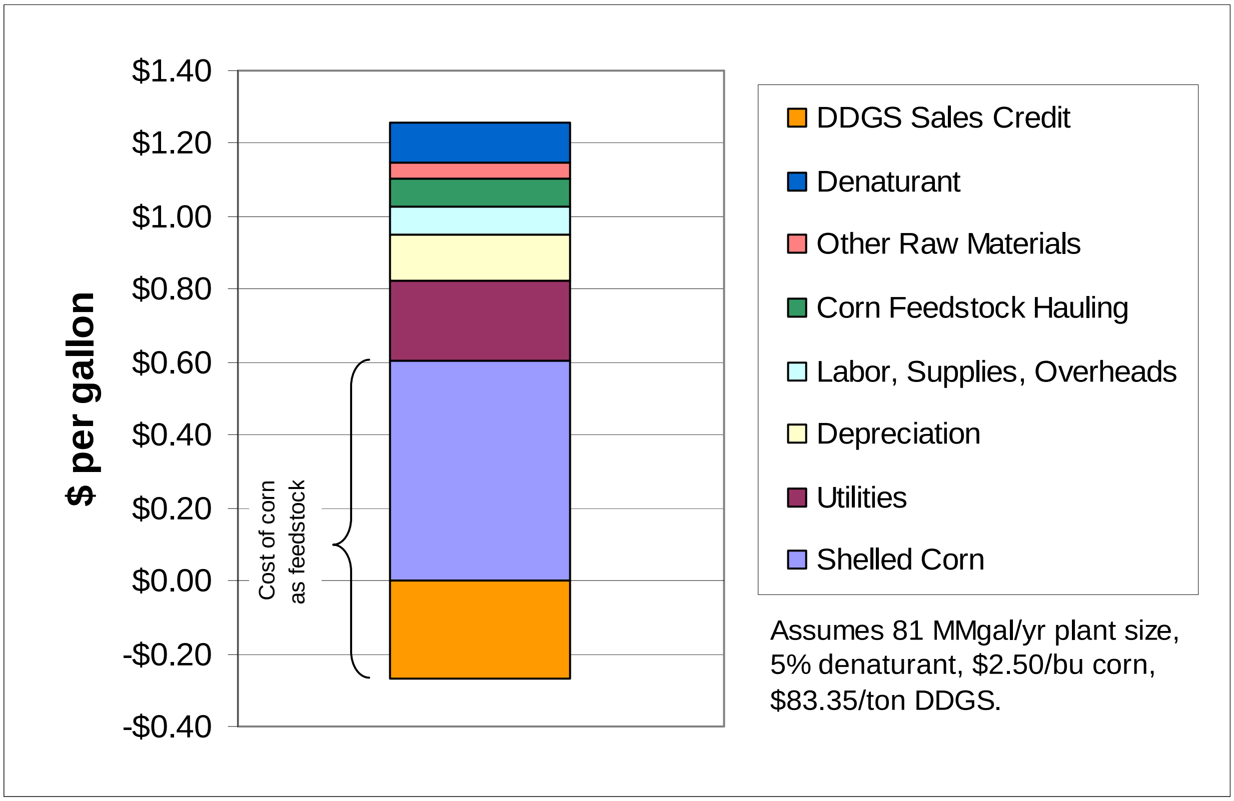
7.1.1.2 Corn Ethanol Production Costs

Corn ethanol costs for our work were estimated using a model developed by USDA that was documented in a peer-reviewed journal paper on cost modeling of the dry-grind corn ethanol process.[JJJJJ] It produces results that compare well with cost information found in surveys of existing plants.[KKKKK]

The USDA model is for a 40 MMgal/yr corn plant producing ethanol with a primary co-product of distillers dried grains with solubles (DDGS). The ethanol yield used in the model is 2.87 gallons per bushel with 5.0% gasoline denaturant. The model is based on work done in chemical process simulation software to generate equipment sizes, stream flowrates, and material and energy balances. These results were then put together with feedstock, energy, and equipment cost information in a spreadsheet format to arrive at a final per-gallon cost estimate. Although the model is current in terms of technology, yields, and capital estimates, we made some modifications to allow estimation of costs for ethanol plants of different sizes and operating under different energy and feedstock prices. We believe that these updates, in combination with the industry and supplier surveys done by USDA in developing the model, result a reasonable estimate for projected ethanol production costs.

We estimate an average corn ethanol production cost of $1.26 per gallon in 2012 (2004 dollars) for the RFS case and $1.32 per gallon for the EIA case. The cost of ethanol production is most sensitive to the prices of corn and the primary co-product, DDGS. Utilities, capital, and labor expenses also have an impact, although to a lesser extent. Corn feedstock minus DDGS sale credit represents about 48% of the final per-gallon cost, while utilities, capital and labor comprise about 19%, 9%, and 6%, respectively. For this work, we used corn and DDGS price projections generated by the Forestry and Agricultural Sector Optimization Model, which is described in Chapter 8.1.1 of this RIA. Corn and DDGS prices are given there in Table 8.1-1. Figure 7.1-1 shows the cost breakdown for production of a gallon of ethanol. Note that this production model does not account for the cost to pelletize or ship the DDGS. Those costs are external and are expected to increase the price of DDGS an end user located far from the plant. More details are given in Section 8.1.1 where the FASOM model is discussed.

Figure 7.1-1.
Cost Breakdown of Corn Ethanol Production (2004$).



The ability to address plant scaling in the model was accomplished by applying an engineering scaling factor to all plant equipment. In past rulemakings involving modifications to refineries we have used a material scaling factor of 0.65. This factor is applied as an exponent to the ratio of the new size to the original size, the result of which is then multiplied by the original capital cost. However, there is information suggesting that a general factor may be considerably higher for ethanol plants. Based on a recent journal publication, a factor of 0.84 was used in this work.[LLLLL] With this factor, the model indicates that the change in per-gallon production cost due to economies of scale is very small over the range of typical plant sizes, on the order of $0.02 between 40 and 100 MMgal/yr. In this analysis we used an average new plant size of 81 MMgal/yr, derived from our industry characterization work in Chapter 1.

We also added functions to estimate the per-gallon cost impact of coal combustion as a process energy source rather than natural gas. Our industry characterization work suggests that about 14% of ethanol production from new plants being constructed will use coal for the process energy source, so the effect on average costs is relatively small. Capital cost used for an 81 MMgal/yr gas-fired plant was $99 million (2004$). For the coal system versus natural gas, additional requirements were estimated at $45 million in capital for the same size plant, as well as one additional operator per shift and 10% additional electric utility use. These figures should be considered conservative estimates, and were based on information from press releases as well as a conversation with staff of a company that designs and builds ethanol plants. Additionally, we adjusted the thermal efficiency of coal combustion processes downward by 13% relative to natural gas, and electricity consumption upward by 10% to reflect operational differences in the processes.[MMMMM] Using this information in the model, the cost savings is about $0.04 per gallon of ethanol for a coal-fired plant compared to natural gas firing. The results presented here are a weighted average of coal and gas production costs (using 14% coal).

Under the Energy Act, starch ethanol can be counted as cellulosic if at least 90% of the process energy is derived from animal wastes or other waste materials.[NNNNN] It is expected that the vast majority of the 250 million gallons per year of cellulosic ethanol production required by 2013 will be made using this provision. While we have been unable to develop a detailed production cost estimate for ethanol from corn which meets cellulosic criteria, we assume that the costs will not be significantly different from conventionally produced corn ethanol. We believe this is reasonable because to the extent that these processes are utilized, we expect them to be in locations where the very low or zero cost of the feedstock or biogas itself will likely offset the costs of hauling the material and the additional capital for handling and combusting it. In addition, because the quantity of ethanol produced using these processes is still expected to be a relatively small fraction of the total ethanol demand, the sensitivity of the overall analysis to this assumption is also very small.

In general, energy prices used in the model were taken from historical EIA data for 2004 and scaled according the ratios of 2004-2012 price forecasts published in the Annual Energy Outlook 2006. [OOOOO,PPPPP] The prices used in the modeling are shown in Table 7.1-2. Several sensitivity cases were run using the model, and the results are shown in Table 7.1-3. Input values in this table were chosen to give a significant margin around current and anticipated future prices.

Table 7.1-2.
Energy Prices Used for Ethanol Cost Modeling for 2012 (2004$)

Natural Gas[a] $/MMBtu	Coal[a] $/MMBtu	Electricity[a] $/kWh	Natural Gasoline[b] $/gal
6.16	1.94	0.044	1.36

[a] Historical data based on averages for Iowa, Illinois, Minnesota, and Nebraska
[b] Natural gasoline (or natural gas liquids) is the typical denaturant used in ethanol production, since it is cheaper than finished gasoline. The price used was based on its value being 20 cents per gallon below wholesale gasoline.

Table 7.1-3.
Energy and Feedstock Price Sensitivities (2004$)

Natural Gas = $6.00/MMBtu			Natural Gas = $12.00/MMBtu		
Corn $/bu	DDGS $/ton	Ethanol $/gal	Corn $/bu	DDGS $/ton	Ethanol $/gal
$2.00	$50.00	$1.18	$2.00	$50.00	$1.35
	$100.00	$1.02		$100.00	$1.19
	$150.00	$0.86		$150.00	$1.03
$2.50	$50.00	$1.36	$2.50	$50.00	$1.52
	$100.00	$1.20		$100.00	$1.36
	$150.00	$1.04		$150.00	$1.20
$3.00	$50.00	$1.53	$3.00	$50.00	$1.70
	$100.00	$1.37		$100.00	$1.54
	$150.00	$1.21		$150.00	$1.38
$3.50	$50.00	$1.71	$3.50	$50.00	$1.87
	$100.00	$1.55		$100.00	$1.71
	$150.00	$1.39		$150.00	$1.55
$4.00	$50.00	$1.88	$4.00	$50.00	$2.04
	$100.00	$1.72		$100.00	$1.88
	$150.00	$1.56		$150.00	$1.72
$5.00	$50.00	$2.23	$5.00	$50.00	$2.39
	$100.00	$2.07		$100.00	$2.23
	$150.00	$1.91		$150.00	$2.07
$6.00	$50.00	$2.58	$6.00	$50.00	$2.74
	$100.00	$2.42		$100.00	$2.58
	$150.00	$2.26		$150.00	$2.42

7.1.2 Cellulosic Ethanol

7.1.2.1 How Ethanol Is Made from Cellulosic Feedstocks

It is not clear when the first processes to produce ethanol from cellulosic biomass were discovered. While ethanol produced from starch can be traced historically to ancient times, cellulosic derived ethanol appears to have been investigated in the 1800's. Until recently, the demand for fuel ethanol has been somewhat limited, and not sufficient to support a cost-competitive, commercial process to convert cellulose into ethanol.

With the increasing demand for fuel ethanol during the past few years, good progress has been made toward producing ethanol from cellulosic feedstocks. Interest in ethanol has continued to grow, initially fostered in part from EPA's reformulated gasoline (RFG) regulations that required such gasoline to contain a minimum of 2 percent oxygen by weight in the fuel. This minimum oxygen requirement has recently been revoked by EPA in response to the Energy Act, which revised the Clean Air Act requirement for oxygen in RFG. The Renewable Fuel Standard (RFS) continues to create a demand for ethanol. Likewise, there is an additional incentive to produce cellulosic ethanol because the Energy Act mandates that, starting in 2013, renewable fuels used in gasoline must include.

There is a wide variety of government and renewable fuels industry research and development programs dedicated to improving our ability to produce renewable fuels from cellulosic feedstocks. There are at least three completely different approaches to producing ethanol from cellulosic biomass, sometimes referred to as “platforms”. The first is based on what NREL refers to as the “sugar platform,”[80] which refers to pretreating the biomass, then hydrolyzing the cellulosic and hemicellulosic components into sugars, and then fermenting the sugars into ethanol. Corn grain is a nearly ideal feedstock for producing ethanol by fermentation, especially when compared with cellulosic biomass feedstocks. Corn grain is easily ground into small particles, following which the exposed starch which has α-linked saccharide polymers is easily hydrolyzed into simple, single component sugar which can then be easily fermented into ethanol. By comparison, the biomass lignin structure must be either mechanically or chemically broken down to permit hydrolyzing chemicals and enzymes access to the saccharide polymers. The central problem is that the cellulose/hemicellulose saccharide polymers are β-linked which makes hydrolysis much more difficult. Simple microbial fermentation used in corn sugar fermentation is also not possible, since the cellulose and hemicellulose (6 & 5 carbon molecules, respectively) have not been able to be fermented by the same microbe. We discuss various pretreatment, hydrolysis and fermentation technologies, below. The second and third approaches have nothing to do with pretreatment, acids, enzymes, or fermentation. The second is sometimes referred to as the “syngas” or “gas-to-liquid” approach; we will call it the “Syngas Platform.” Briefly, the cellulosic biomass feedstock is steam-reformed to produce syngas which is then converted to ethanol over a Fischer-Tropsch catalyst. The third approach uses plasma technology.

Technologies that are currently being developed may solve some of the problems associated with producing cellulosic ethanol. Specifically, one problem, mentioned previously, with cellulosic feedstocks is that the hydrolysis reactions produce both glucose, a six-carbon sugar, and xylose, a five-carbon sugar (pentose sugar, $C_5H_{10}O_5$; sometimes called “wood sugar”). Early conversion technology required different microbes to ferment each sugar. Recent research has developed better cellulose hydrolysis enzymes and ethanol-fermenting organisms.[81] Now, glucose and xylose can be co-fermented—hence, the terminology, weak-acid enzymatic hydrolysis and co-fermentation. In addition, at least one group is researching the use of recently developed genome modifying technology to produce a variety of new or modified enzymes and microbes that show promise for use in a process known as weak-acid, enzymatic-prehydrolysis [82]

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[80] *Enzyme Sugar Platform (ESP), Project Next Steps National Renewable Energy,* Dan Schell, FY03 Review Meeting; Laboratory Operated for the U.S. Department of Energy by Midwest Research Institute • B NREL, Golden, Colorado, May 1-2, 2003; U.S. Department of Energy by Midwest Research Institute • Battelle • Bechtel

[81] “Purdue yeast makes ethanol from agricultural waste more effectively.” Purdue News, June 28, 2004; Writer: Emil Venere, (765) 494-4709, venere@purdue.edu; source: Dr. Nancy Ho, (765) 494-7046, nwyho@ecn.purdue.edu.

[82] *DOE Genomics: GTL Roadmap, Systems Biology for Energy and Environment*, U.S. Department of Energy, Office of Science, Office of Biological and Environmental Research, Office of Advanced Scientific Computing Research, Germantown, MD 20874-1290, August 2005; DOEGenomesToLife.org/roadmap; downloadable as whole or in sections.

7.1.2.2 Difficulties in Estimating Capital and Operating Costs for New or Pioneer Process Plants

Many years ago the petroleum and chemical process industries learned that it can be financially problematic to scale-up a bench or laboratory scale process to a full commercial sized operation. There are simply too many process variables that act one way at a batch rate of one- or two-gallons per day, or even 100-gallons per day, but then act a completely different way in a continuous, 70,000 gallon per day operation. Under these, admittedly somewhat extreme expectations, there is also absolutely no reasonable way to optimize a process. We expect that at least pilot or demonstration size projects will be necessary before a fully commercial sized, reasonably optimized plant can be constructed.

The petroleum and chemical process industries have also learned that if a different feedstock, with similar, but at the same time sufficiently different characteristics, becomes available, it is nearly always necessary to make several pilot plant runs before the feedstock in introduced into the process. There are a wide variety of potential cellulosic feedstocks, such as switch grass, forest thinnings, municipal waste, wood chips, and corn stover (corn stalks). The physical characteristics of these materials, such as size, composition, and density vary widely. As a result, there could be significant differences in the process configurations, as well as differences in the enzyme "cocktails" required to hydrolyze and convert each of them into ethanol. Compositional and density variations may require different reactor residence times for each feedstock, which will impact throughput. Many of the process streams will actually be slurries of the feedstock. It is also quite likely that each slurry stream will have its own flow and compositional characteristics. The flow characteristics of any slurry, under real operating conditions, must be well understood in order to properly design an optimum system. Additionally, valve and pump types, sizes, and materials of construction, as well as line sizes and configurations, may vary. Apart from the various process issues, questions also remain regarding which of the feedstocks is actually the best in terms of ethanol yield per dollar.

Consequently, we believe a good deal more process data is necessary before a reasonably accurate cost to design, engineer, and build a commercial scale cellulosic based ethanol plant can be expected. At the present time, there is only one cellulosic ethanol plant in North America (Iogen[QQQQQ] a privately held company, based in Ottawa, Ontario, Canada). On February 28, 2007, however, the Department of Energy (DOE) announced that it will provide grants of up to $385 billion for six biorefinery projects over the next four years. These facilities are expected to produce more than 130 million gallons of celluloic ethanol per year. As additional information on these future facilities are made available, EPA will have more information on process design from which we will better be able to project production costs for cellulosic ethanol.

Although the industry seems to be moving down several different pathways, one of the more mature process being tested and improved uses dilute acid enzymatic prehydrolysis with simultaneous saccharification (enzymatic) and co-fermentation. Because there is more publicly available information about this process, the model we used incorporates this type of process to estimate the cost of producing ethanol from corn stover. We chose corn stover because it is ubiquitous and because of the likelihood it will eventually be used as a feedstock.

In 1999, the National Renewable Energy Laboratory (NREL) published a report outlining its work with the USDA to design a computer model of a plant to produce ethanol from hardwood chips.[RRRRR] Although the cellulosic model was originally prepared for hardwood chips, it was meant to serve as a modifiable-platform for ongoing research using cellulosic biomass as feedstock to produce ethanol. Their long-term plan was that various indices, costs, technologies, and other factors would be regularly updated.

NREL modified the model in order to compare the cost of using corn-grain with the cost of using corn stover to produce ethanol. We used the corn stover model from the second NREL/USDA study for this analysis. Because there are no operating plants that could potentially provide real world process design, construction, and operating data for processing cellulosic ethanol, NREL had originally considered modeling the plant based on assumptions associated with a pioneer plant. Such assumptions would likely result in costs significantly higher than corn ethanol plants due to the higher level of uncertainty in both the design and engineering as well as the final construction and operating costs. The literature indicates that such models often underestimate actual costs since the high performance assumed for pioneer process plants is generally unrealistic.

The NREL analysis assumed that the corn stover plant was an N^{th} generation plant, built after the industry had been well enough established to provide verified costs. The corn stover plant was normalized to the corn kernel plant, e.g., placed on a similar basis. Additional costs for risk financing, longer start-ups, and other costs associated with first-of-a-kind or pioneer plants were not included in the study.[SSSSS] It is also reasonable to expect the cost of cellulosic ethanol will be higher than corn ethanol because of the complexity of the cellulose conversion process. During the recent past, process improvements and other advancements in corn production have considerably reduced the cost of producing corn ethanol. We also believe it is realistic to assume that cellulose-derived ethanol process improvements will be made and that one can likewise reasonably expect that as the industry matures, the cost of producing ethanol from cellulose will also decrease.

7.1.2.3 Methods, Data Sources, and Assumptions

For our analysis, we used the spreadsheet model that NREL developed for its comparison of the costs of producing ethanol from corn grain and corn stover.[83] We believe NREL's approach was reasonable and well thought out. They also had an outside engineering firm validate their work, to the extent possible. The Delta-T Corporation (Delta-T) assisted in preparing, reviewing, and estimating costs for the process design. Delta-T worked with NREL process engineers to review all the process design and equipment costs (with the exclusion of wastewater treatment and the burner-boiler system, which were reviewed by Merrick Engineering and Reaction Engineering, Inc., respectively). For the plant areas that are actively

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[83] The first, woodchip-plant study was designed to produce 52.2 million gallons of ethanol per year from about 2,200 tons per day (350 operating days per year; 15 days for downtime, including turn-around) of woodchips. The second study normalized the original woodchip plant into the corn stover plant to produce 25 million gallons of ethanol per year (about 1,235 wet tons per day), in 1999 dollars. The adjustments included feedrate and feedstock volume and cost adjustments; equipment sizes with adjustments to capital and installation costs, and the cost of capital, labor, and process chemicals, including denaturant.

being investigated under DOE programs (e.g., prehydrolysis, cellulase enzyme production, and simultaneous saccharification and co-fermentation), Delta-T used the results of the DOE sponsored research to identify process design criteria and equipment requirements. These were used as a basis for sizing and costing major equipment components in the facility. The results of Merrick Engineering's work on wastewater treatment and REI's work on the burner/boiler were also included.[TTTTT] The NREL model used the Aspen Plus™ process simulator to calculate the flows and the heat and material balances for the process. We decided to use the NREL spreadsheet corn stover model, as is, since we did not have access to the Aspen Plus™ model nor to all the input. Rather, we left the feedrate, yields, and streams flows as they were, but adjusted equipment capital and installation costs, and utility, chemical, and labor costs to 2004 dollars. We used the same indices used by NREL to update their corn stover study; however, we used actual costs and indices for 2004 where possible. For example, in their 2000 calculations, NREL had extrapolated the Chemical Engineering Plant Cost Index and the Chemical Cost Index through 2012. However, we used actual 2004 data rather than the extrapolated data.

We did not change the corn stover cost. Several issues remain to be settled regarding the amount of stover that should be left in place and how it should be gathered, baled, and shipped. We found cost ranges of from $25 per dry ton to $45 per dry ton. For purposes of this analysis we used the $35 per dry ton that NREL assumed in its analysis.

For the analysis, we calculated the annual production cost in dollars per gallon of fuel ethanol. The annual production cost includes equipment straight-line depreciation for the life of the plant (10 years), and variable costs, labor, supplies and overhead, minus any by-product credits. Gasoline for denaturant and diesel for bulldozers to move the stover were projected into 2012 prices using IEA's AEO 2006[UUUUU] report. The market selling price minus the annual production cost is the before-tax profit. We calculated variable operating costs using NREL's best estimate of quantities of chemicals and additives based on their laboratory work. NREL calculated fixed costs using industry standards for percentages of direct labor (indirect labor was 40% of direct labor and overhead was 60% of total labor); other operating supplies, insurance, etc. totaled 3.25% of total installed cost. According to the analysis three major cost categories made up the majority of the total production cost: feeds stock – 31.2%; fixed costs – 23.8%; and depreciation (reflects installed capital cost of equipment) – 33.8%.

As previously stated, several feedstock issues remain to be settled, not least being which of the many available feedstocks will be the best or most efficient. We chose an average cost of $35 per dry ton; we don't believe the cost will rise and as a result of the research that is currently under way, there is reason to expect it to come down a little. On the other hand, several researchers have indicated switch grass may be better than corn stover; others point to forest wastes, etc. In the end, the best feedstock will likely be the one that is readily available and close to the plant; gathering, baling, and hauling continue to be important issues that will definitely impact the viability of a feedstock. Equipment cost reductions may have a significant impact on future costs. For example, there appear to be reasons to expect significant savings from purchasing enzymes rather than growing them onsite. Another issue that remains to be investigated is whether a particular kind of feedstock can be processed using one type of technology while a different kind may require the use of a completely different technology.

7.1.2.4 Results and Discussion

Given the limitations we've already discussed, and perhaps others, we determined that it would have cost approximately $1.65 in 2012 (2004 dollars) to produce a gallon of ethanol using corn stover as a cellulosic feedstock.

The provisions offering grants and shared financing included in Title XV of the Energy Act[VVVVV] will likely encourage process development work to generate the necessary construction and operating cost estimates. We assume the results produced by the above referenced NREL study are accurate and reasonable given the state of our current knowledge.

7.2 Biodiesel and Renewable Diesel Production Costs

7.2.1 Overview of Analysis

We based our estimate for the cost to produce biodiesel on the use of USDA's, NREL's and EIA's biodiesel computer models, along with estimates from engineering vendors that design biodiesel plants. Biodiesel fuel can be made from a wide variety of virgin vegetable oils such as canola, corn oil, cottonseed, etc. though, the operating costs (minus the costs of the feedstock oils) for these virgin vegetable oils are similar to the costs based on using soy oil as a feedstock, according to an analysis by NREL[84]. Biodiesel costs are therefore determined based on the use of soy oil, since this is the most commonly used virgin vegetable feedstock oil, and the use of recycled cooking oil (yellow grease) as a feedstock. Production costs are based on the process of continuous transesterification, which converts these feedstock oils to esters, along with the ester finishing processes and glycerol recovery. The models and vendors data are used to estimate the capital, fixed and operating costs associated with the production of biodiesel fuel, considering utility, labor, land and any other process and operating requirements, along with the prices for feedstock oils, methanol, chemicals and the byproduct glycerol.

The USDA, NREL and EIA models are based on a medium sized biodiesel plant that was designed to process raw degummed virgin soy oil as the feedstock. Additionally, the EIA model also contains a representation to estimate the biodiesel production cost for a plant that uses yellow grease as a feedstock. In the USDA model, the equipment needs and operating requirements for their biodiesel plant were estimated through the use of process simulation software. This software determines the biodiesel process requirements based on the use of established engineering relationships, process operating conditions and reagent needs. To substantiate the validity and accuracy of their model, USDA solicited feedback from major biodiesel producers. Based on responses, they then made adjustments to their model and updated their input prices to year 2005. The NREL model is also based on process simulation software, though the results are adjusted to reflect NREL's modeling methods, using prices based on year 2002. The origin of the EIA model is not known, though it is based on 2004 prices. The output for all of these models was provided in spreadsheet format. We also use engineering vendor

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[84] NREL Presentation "U.S. Biodiesel Feedstock Supply" June 2004.

estimates as another source to generate soy oil and yellow grease biodiesel production costs. These firms are primarily engaged in the business of designing biodiesel plants.

The production costs are based on a 10 million gallon per year biodiesel plant located in the Midwest using feedstock oils and methanol, which are catalyzed into esters and glycerol by use of sodium hydroxide. Because local feedstock costs, distribution costs, and biodiesel plant type introduce some variability into cost estimates, we believe that using an average plant to estimate production costs provides a reasonable approach. Therefore, we simplified our analysis and used costs based on an average plant and average feedstock prices since the total biodiesel volumes forecasted are not large and represent a small fraction of the total projected renewable volumes.

The models and vendor estimates are further modified to use input prices for feedstocks, byproducts and energy that reflect the effects of the fuels provisions in the Energy Act. In order to capture a range of production costs, we generated cost projections from all of the models and vendors. We present the details on these estimates later in this section.

For soy oil biodiesel production, based on the USDA model, we estimate a production cost of $2.06 per gallon in 2004 and $1.89 per gal in 2012 (in 2004 dollars). With the NREL model, we estimate soy oil biodiesel production costs of $2.28 and $2.11 per gallon in 2004 and 2012, respectively, which is slightly higher than the USDA results. The EIA model generated soy oil based costs of $2.33 and $ 2.15/gal, while the engineering vendor's costs averaged $2.27 and $2.09/gal, in years 2004 and 2012, respectively.

For yellow grease derived biodiesel, we used the EIA and vendor estimates and generated a range of costs, as discussed later. The total production costs ranged from $1.24 to $1.60/gal in 2004, and from $1.11 to $1.56 for year 2012.

Table 7.2-1.
Summary of Production Costs for Biodiesel made from Soy Oil, per Gallon (2004 cents)

	Total Production Cost	Subsidized Production Cost	Feed	Capital	Reagent and Chemicals	Labor	Energy/Utilities
USDA	189	89	156	11.3	12.7	5.0	4.8
NREL	211	111	165	17.0	17.0	6.0	7.4
EIA	215	115	161	14.4	NA	NA	16.0
PSI-Lurgi	220	120	174	18.8	12.6	8.2	5.5
Superior Process Technologies	224	124	175	11.7	16.5	7.6	5.0

Table 7.2-2.
Summary of Production Costs for Biodiesel made from Yellow Grease, per Gallon (2004 cents)

	Total Production Cost	Subsidized Production Cost	Feed	Capital	Reagent and Chemicals	Labor	Energy/Utilities
EIA	138	88	80	14.4	NA	NA	16.9
Superior Process Technologies	167	117	114	14.7	18.3	8.7	9.0

With the current Biodiesel Blender Tax Credit Program, producers using virgin vegetable oil stocks receive a one dollar per gallon tax subsidy while yellow grease producers receive 50 cents per gallon, reducing the net production cost to a range of 89 to 115 c/gal for soy oil and 61 to 106 c/gal for yellow greased derived biodiesel fuel in 2012. This compares favorably to the projected wholesale diesel fuel prices of 138 cents per gallon in 2012, signifying that the economics for biodiesel are positive under the effects of the blender credit program, though the tax credit program will expire in 2008 if it is not extended. Congress may later elect to extend the blender credit program, though, following the precedence used for extending the ethanol blending subsidies. Additionally, the Small Biodiesel Blenders Tax credit program and state tax and credit programs offer some additional subsidies and credits, though the benefits are modest in comparison to the Blender's Tax credit.

7.2.2 Inputs to and Results of USDA's Model

We used USDA's biodiesel model as a source to generate an estimate for the cost to produce biodiesel fuel. The model is in spreadsheet format with inputs in 2005 dollars, and contains all of the capital and operating costs for a plant to produce 10 million gallons per year of biodiesel fuel.

7.2.2.1 Feedstock Costs

Feedstock prices are the largest component in generating production costs for biodiesel fuel. For soy oil prices, we used prices based on USDA's 2006 Outlook, which has forecasted soy oil prices considering production of biodiesel under EPAct 2005. USDA's Outlook is a national forecasting analysis that models the effects of demand for farm products and farm product prices for soy beans, soy bean oil, corn and other farm commodities. The 2006 Outlook estimated soy oil prices considering the demand of soy oil derived biodiesel fuel at approximately 160 MM gallons per year in 2006 and 312 MM gallons a year in 2007[85]. This is in close proximity to EIA's soy oil derived biodiesel volume projection of 135 MM gals and 265 MM gals in 2006 and 2007, respectively. We therefore used the soy oil prices from USDA's Outlook to determine biodiesel production costs. The USDA does not forecast yellow grease prices, so we assumed that yellow grease feedstocks costs would maintain the same relative historical pricing differential to virgin soy oil. In the past, some analysis has shown that yellow

[85] Per USDA phone discussion 6/22/06

grease has sold for about half the price of soy oil[86]. The resulting feedstock costs to make a gallon of biodiesel under projected volumes for RFS are in Table 7.2-3.

Table7.2-3.
Projected Prices of Feedstock (2004 Dollars per Gallon)

Marketing Year	Soy Oil[a]	Yellow Grease
2004	1.71	0.86
2012	1.56	0.78

[a]Production of Biodiesel assumed to consume 7.42 lbs of soy oil per gallon. USDA prices in 2012 are adjusted to 2004 dollars to account for inflation, using GDP index of 109.7 in year 2004 and 130.8 in year 2012.

7.2.2.2 Capital Costs

For capital costs we used USDA's total installed capital cost of $10.66 MM for a 10 MM gallon per year plant. This estimate was determined by the USDA, using a detailed analysis to generate costs for equipment needs, installation, land, engineering and construction work, buildings, utility needs, contingencies, startup costs etc. The USDA model is based on 2005 dollars, so we adjusted the numbers to 2004 values using the GDP index. Per the USDA method, the total installed capital costs on a per gallon basis was amortized on a 10 year straight line depreciation rate using a facility dependent cost of 10 percent times the capital costs. Maintenance charges, insurances and facility supply costs were also calculated as percentages of the capital. The total of all of these are equal to 16 cents per gallon.

7.2.2.3 Operating Costs

The total operating expenses were 20 and 18 c/gal for a soy based biodiesel plant in 2004 and 2012, respectively. The operating cost included a 4 cent per gallon offset from sale of the glycerol product at a price of 5 cents/lb. The operating costs include values for utilities, feed reagents, manpower and were based on the USDA's model. The components of the operating costs are discussed below.

7.2.2.4 Utility and Labor Costs

We estimated utility costs using energy requirements from USDA's model and adjusted the inputs to match the energy and electricity prices for the Midwest, using prices from EIA's AEO. The cost for steam was estimated using the price of natural gas. Each pound of steam was produced from heating water, which required 810 British Thermal Units (BTUs) per pound of steam. Additionally, the steam costs are estimated assuming that the BTUs to make steam are increased by a factor of two, to account for steam distribution efficiency losses, treatment of boiler water to prevent fouling, maintenance and other miscellaneous costs. The utility requirements per gallon of biodiesel and energy prices are presented in Tables 7.2-4 and 7.2-5

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[86]Energy Information Administration NEMS Petroleum Marketing Model Documentation page J-2

Table 7.2-4.
Utility Requirements per Gallon Biodiesel[a]

Medium Pressure Steam, lbs	4.0
Electricity, kWh	0.10
Cooling Tower Water, lbs	96.1

[a]Utilities per USDA model from the production of biodiesel from soy oil.

Table 7.2-5.
Midwest Energy Prices per Year (in 2004 $)

Year	2004	2012
Electricity, $/kWh	0.046	0.044
Natural gas, $/MM BTU	7.16	6.16

Labor costs include the salaries and benefits for personnel to operate a biodiesel plant. This was estimated in the USDA model, though the labor costs were in 2005 dollars, which we adjusted to 2004 dollars using the GDP price index. The resulting labor costs are 5 cents per gallon of produced biodiesel fuel.

7.2.2.5 Chemical Reagents

Another operating expense, the production of biodiesel also requires the use of chemicals and chemical reagents, as these act as a catalyst in the transesterification process. Additionally, methanol is required as it is the feedstock that is chemically combined with soy oil and yellow grease during the transesterification process, yielding the biodiesel product. The amount of chemicals and methanol required to make a gallon of biodiesel are listed in Table 7.2-6.

Table 7.2-6.
Reagent Requirements

Reagent	Annual Requirement, lbs per gallon
Water	0.0323
Hydrochloric acid	0.0185
Methanol	0.8006
Sodium Methoxide	0.0231
Sodium Hydroxide	0.0031

For the prices of chemical reagents, we used prices that were supplied in USDA's 2005 model and adjusted them to 2004 dollars. Additionally, since we have no forecasting mechanism we assumed that the chemical reagent prices remained unchanged in 2012.

However, we estimated methanol prices, as the cost for this feedstock is a significant component of the total operating costs. For our analysis, we generated values by use of a correlation that calculates methanol's price as a function of the price of natural gas[87]. In 2004 and 2012, using Midwest natural gas prices, we estimated methanol prices of 13.1 and 11.6 cents per pound, respectively. All other chemical prices, we assumed were constant over time and are in Table 7.2-7.

Table 7.2-7.
Reagent Prices (in 2004 $)

Reagent	Prices, $/lb
Hydrochloric acid	0.167
Sodium Methoxide	1.358
Sodium Hydroxide	0.273

7.2.2.6 Glycerol Byproduct

The feedstock cost credit for the glycerin by product in our modeling work was 5 cents per pound, based on recent pricing trends, assuming that additional glycerol generated from expansion of biodiesel production will continue to keep prices low. The model, like many biodiesel plants, produces a crude 80% glycerin stream, which is usually sold to glycerin refiners for purification. In the past, crude glycerin has sold for around $0.15 / pound. Because of the increase in biodiesel production around the world, however, the crude glycerin market has become saturated and the price is now around $0.05 / pound. As more biodiesel capacity comes on line, this price may very well drop further, though other markets for the use of glycerol are likely to develop because glycerol is a platform chemical used throughout industry. We assumed that the current glycerin pricing environment will continue in the future. For our cost estimation, the byproduct glycerin was sold at 5 cents per pound, reflecting current saturated market and low pricing conditions. The income from sale of the byproduct glycerin lowered biodiesel production costs by 2 percent and 4 percent for soy oil and yellow grease derived biodiesel fuel, respectively.

The total biodiesel production costs derived using the USDA's model are summarized in Table 7.2-8

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[87] Per EIA paper "MTBE Production Economics" Tancred C. M. Lidderdale, methanol price cents per gallon = 15.79 + 0.099 *natural gas price ($ per million BTU)

Table7.2-8.
Projected Production Costs for Biodiesel by Feedstock per Gallon
(2004 Dollars)

Marketing Year	Soy Oil
2004	2.06
2012	1.89

7.2.3 Inputs to and Results of NREL's Biodiesel Model

We used NREL's biodiesel model as another source to generate an estimate for the cost to produce biodiesel fuel. Similar to the USDA's model, the NREL biodiesel model also represents a continuous transesterification process that uses sodium hydroxide and methanol to convert soy oil to biodiesel and which has the finishing processes for biodiesel and glycerol. The model is in spreadsheet format, and contains all of the capital and operating costs for a plant to produce 10 million gallons per year of biodiesel fuel. We again simplified our analysis, and used the NREL model to estimate production costs for an average biodiesel plant that makes 10 MM gallon per year. To make the results directly comparable to USDA's model, we used energy costs in the Midwest, and based the analysis on production of soy oil derived biodiesel.

Based on the results of the NREL model, we estimate that the total production costs to make soy oil derived biodiesel fuel are $2.28 and $2.11 per gallon for years 2004 and 2012, respectively. This is 22 cents more per gallon than the estimate derived from USDA's model. The components that make up our NREL estimate are discussed in the sections that follow.

7.2.3.1 Feedstock Costs

The feedstock costs increase because the NREL model assumes 7.87 pounds of soy oil are required to make a gallon of biodiesel fuel. This is slightly higher than the pounds required by the USDA model, though the difference may be due to each model being based on soy oils with differing chemical structures, i.e. more esters, differing densities. The higher amount of soy oil required by the NREL model raises the production costs for biodiesel by about 10 cents per gallon for feedstock costs alone, versus the USDA model. The feedstock costs are summarized in Table7.2-9.

Table7.2-9.
Projected Prices of Feedstock (2004 Dollars per Gallon)

Marketing Year	Soy Oil
2004	181.0
2012	165.2

7.2.3.2 Capital Costs

The total capital cost in the NREL model account for all of the costs for building a plant, including but not limited to the expenses for equipment, tanks, installation costs, engineering, tanks, construction, land and site development, start up and permitting charges. These costs do not account for expenses incurred from maintenance, insurance and taxes, however. The total capital coats for a plant are $14.8 million in 2002 dollars, which we adjusted to 2004 dollars using the GDP price index. The capital costs were amortized assuming a seven percent return on investment, resulting in a cost of 17 cents per gallon. All of the economic factors used for amortizing the capital costs are summarized in Table 7.2-10.

Table 7.2-10.
Economic Factors Used in Deriving the Capital Cost Amortization Factor

Amortization Scheme	Depreciation Life	Economic and Project Life	Federal and State Tax Rate	Return on Investment (ROI)	Resulting Capital Amortization Factor
Societal Cost	10 Years	15 Years	0%	7%	0.11

7.2.3.3 Operating Costs

The total operating costs are 31 and 30 cents per gallon for years 2004 and 2012, respectively. These costs are not directly comparable to those from the USDA model, as fixed operating cost are included in the operating costs for the NREL model, while the USDA model accounts for fixed costs in the capital estimate. The operating cost for the NREL analysis includes items for utilities, reagents, manpower, insurance, taxes, general administration and maintenance costs, though do not account for capital costs. Additionally, the sale of the glycerol byproduct (80% strength) generated income of 4 cents per gallon of produced biodiesel, using glycerol price of 5 cents per pound. The cost associated with insurance, taxes, general administration and supplies incur a cost of 2.4 cents per gallon of biodiesel. The remaining components of operating costs for the NREL modeling analysis are discussed below.

7.2.3.4 Utility and Labor

The utility costs were estimated using the energy requirements in the NREL model along with the same prices for energy, steam and electricity, as those used in our USDA analysis. The utility requirements per gallon of biodiesel fuel are listed in Table 7.2-11

Table 7.2-11.
Utility Requirements per Gallon of Biodiesel

Natural Gas, SCF	2.0
Medium Pressure Steam, lbs	3.2
Electricity, kWh	0.1
Cooling Tower Water, lbs	8.3

The NREL model accounts for the salaries of 4 employees per shift to run and maintain the plant. In addition to salaries for these personnel, the labor expenses also accounted for employee fringe benefits and the cost for a plant supervisor. The resulting labor costs are 6 cents for each gallon of biodiesel.

7.2.3.5 Chemical Reagents

The NREL model also requires the use of the same chemicals and chemical reagents that are used in the USDA model. The amount of chemical reagents in the NREL model, however, reflect the use of diluted hydrochloric acid (HCl) and sodium methoxide for the biodiesel production process. Hydrochloric acid is listed as being at 33 percent strength, which we assumed also applied to the strength of sodium methoxide, since the amount of HCl in the model is reflective of about one third the value of the USDA's model. For the chemical and reagents prices, we used the same pricing values as those in our USDA modeling analysis. The resulting total chemical and reagent costs on a per gallon basis are about 17 cents for each gallon of biodiesel fuel produced. All of the required chemicals and reagents for the production of biodiesel are presented on an undiluted basis in Table 7.2-12.

Table 7.2-12.
Reagent Requirements

Reagent	Annual Requirement, lbs per gallon
Water	3.4646
HCl[a]	0.0098
Methanol	0.6037
$NAOCH_3$[a]	0.0338
Sodium Hydroxide	0.1901

[a]HCl is Hydrochloric acid, $NAOCH_3$ is sodium methoxide.

The total biodiesel production costs derived from the NREL model are summarized in Table 7.2-13.

Table 7.2-13.
Projected Production Costs for Biodiesel by Feedstock per Gallon
(2004 dollars)

Marketing Year	Soy Oil[a]
2004	2.28
2012	2.11

[a]Production consumes 7.87 lbs of soy oil per gallon of biodiesel. USDA prices in 2012 are adjusted to 2004 dollars to account for inflation, using GDP index of 109.7 in year 2004 and 130.8 in year 2012.

7.2.4 EIA NEMS Model for Biodiesel

We also estimated production costs using the biodiesel plant representation in EIA's NEMS model. This biodiesel model is in spreadsheet format and has the aggregated cost components for an average soy oil and yellow grease based biodiesel plant. We could not locate written documentation that describes the basis for these models, though we will assume for our analysis that it represents an average biodiesel plant.

EIA's model requires 7.65 lbs/gal of soy oil and yellow grease feedstock to produce a gallon of biodiesel fuel. Using the oil feedstock costs as discussed in section 7.2.2.1, feed stock costs for soy oil are $1.76/gal and $1.61/gal for 2004 and year 2012, respectively, while yellow grease feedstock costs are $0.88/gal and $0.80/gal for years 2004 and 2012, respectively.

The EIA model does not provided specific individual cost components for biodiesel production, though it does have an estimate for total energy, operating and capital costs for both plant types. Capital costs are estimated at 14.4 cents/gal in 2004 for both plant types, which we assumed contains all of costs associated with building a plant, along with the depreciation and capital payoff costs. The energy costs are provided in the model on an aggregated basis and do not contain the individual amounts of natural gas, electricity and steam used by a plant. The model, though, has the total energy needs in year 2004, which are 13.7 c/gal for soy oil and 14.5 cents/gal for yellow grease. For 2012, we determined the energy costs by adjusting the 2004 aggregate energy cost by the EIA projected price change of natural gas in the Midwest from 2004 to 2012, resulting in an energy cost of 16.0 and 16.9 cents/gal for soy oil and yellow grease, respectively. All of the other operating costs are represented by an aggregate number, which in year 2004 is 32.6 and 34.5 cent/gal for soy oil and yellow grease, respectively. This cost represents all of the operating costs not associated with energy and capital requirements. For our analysis, we assume that this cost does not change in 2012. We used a glycerin price of 5 c/lb, which generates income and offsets operating cost by 4 c/gal.

The net production cost for yellow greases (minus feedstock costs) is about 3 c/gal more than the net production cost for soy based biodiesel, indicating the extra cost incurred for the yellow grease process. The resulting total production cost are presented in Table 7.2-14

Table7.2-14.
Projected Production Costs for Biodiesel by Feedstock per Gallon
(2004 Dollars)

Marketing Year	Soy Oil[a]	Yellow Grease
2004	2.33	1.47
2012	2.15	1.38

[a]Production consumes 7.65 lbs of soy oil per gallon of biodiesel. USDA prices in 2012 are adjusted to 2004 dollars to account for inflation, using GDP index of 109.7 in year 2004 and 130.8 in year 2012.

7.2.5 Vendor Production Estimates for Biodiesel

We used engineering vendor estimates as another source to generate the cost to produce biodiesel fuel. For this, we used engineering details from two firms, Superior Technologies and PSI-Lurgi Engineering Inc. These engineering vendors are engaged in the business of designing, constructing and building biodiesel plants. The biodiesel production processes provided by these firms are also based on the continuous transesterification process, using sodium hydroxide and methanol to convert soy oil and yellow grease to biodiesel, along with the finishing processes for biodiesel and glycerol, similar to the other models. The vendors generated estimates of the total cost to build and operate a biodiesel plant, providing the requirements for the equipment, energy, capital and operating. We adjusted these estimates to a 2004 year costs basis for comparative purposes, and used energy costs in the Midwest.

The vendor estimates we used for PSI-Lurgi are those listed in the report "Economic Feasibility of Producing Biodiesel in Tennessee" [88]. The biodiesel plant in this analysis was sized for soy oil feedstock, based on a 13 MM gallon per year plant, which we assumed is directly comparable to the 10 MM gallon plant used in the USDA, NREL and EIA models. In making this comparison, we relied on a report[89] from Superior Process Technologies to generate the production costs to make biodiesel from soy oil and yellow grease. This report has the various cost components for a 10 MM gallon per year plant.

The total soy oil based biodiesel production cost estimate for year 2004 is $2.20/gal and $2.34/gal for PSI-Lurgi and Superior Technology, respectively with an average cost of $2.27/gal. For 2012, we project the soy oil production cost from both vendors would average approximately $2.09 gal. The Superior Technology's yellow grease biodiesel production cost is $1.66/gal in 2004.

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[88] "Economic Feasibility of Producing Bio-diesel in Tennessee" AIM-AG Agri-Industry Modeling & Analysis Group, 2002

[89] Superior Process Technologies, " Biodiesel Plant Economics and Process Description", 8/18/06

7.2.5.1 PSI-Lurgi estimate of Biodiesel Costs

The feedstock costs assume that 7.569 pounds of soy oil are required to make a gallon of biodiesel fuel. The resulting feedstock cost is 174.1 cents/gal for year 2004 . We adjusted all other cost items in the PSI estimate from a 2002 year to 2004 basis, scaling by the relative change of GDP, though the costs for reagent needs and utilities are adjusted using the methods as discussed in the following sections.

7.2.5.2 Capital Costs

The total capital cost provided in the estimate account for all of the costs for building a plant, though excluding maintenance costs, similar to the capital requirements in the NREL model. The total capital coats for a plant are $19.7 million in 2004 dollars, which we adjusted from 2002 dollars. The capital costs were amortized assuming a seven percent return on investment, resulting in an annualized cost of 16.7 cents per gallon. The economic factors used for amortizing the capital costs are the same as those listed in Table 7.2-8.

7.2.5.3 Operating Costs

The total operating costs are 29 cents per gallon for year 2004, excluding capital charges. The cost associated with insurance, taxes and general administrations is 7.3 cents per gallon, while the cost for maintenance is 2 cents/gal. The sale of the glycerol byproduct at 80% strength generates incomes of 4 cents per gallon of produced biodiesel, assuming a glycerol price of 5 cents per pound. The remaining components of operating costs are discussed below.

7.2.5.4 Utility and Labor

The utility costs were estimated using the energy requirements presented in Table 3.1 of the report, along with the same prices for energy, steam and electricity, as those used in our 2004 model analysis. The total utility requirements are 5.5 cents per gallon. The utility requirements per gallon of biodiesel fuel are listed in Table 7.2-15.

Table 7.2-15.
Utility Requirements per Gallon of Biodiesel

Natural Gas, SCF	0
Medium Pressure Steam, lbs	3.92
Electricity, kWh	0.093
Cooling Tower Water, lbs	200.7

The PSI-Lurgi estimate accounts for the salaries of 4 employees per shift to run and maintain the plant. In addition to salaries for these personnel, the labor expenses also accounted for employee fringe benefits. The resulting labor costs are 6.3 cents for each gallon of biodiesel. In addition to these costs, the SG&A expenses are estimated at 6.3 c/gal.

7.2.5.5 Chemical Reagents

The PSI-Lurgi estimate also requires the same chemicals and chemical reagents in the USDA/NREL models. We assumed that the hydrochloric acid and the sodium methoxide used in the PSI estimate is 33% strength, as the prices listed in the study are reflective of being on a diluted basis. We also assumed that the price for the amount of caustic soda required is on an undiluted basis. We adjusted the prices for the chemical and reagents using the 2004 year pricing values used in our USDA/NREL modeling analysis, though the price of phosphoric acid was adjusted using the GDP index. The resulting total chemical and reagent costs on a per gallon basis are about 12.6 cents for each gallon of biodiesel fuel produced. All of the required chemicals and reagents for the production of biodiesel are presented on an undiluted basis in Table 7.2-16.

Table 7.2-16.
Reagent Requirements

Reagent	Annual Requirement, lbs per gallon
Water	1.666
HCl[a]	0.026
Methanol	0.700
$NAOCH_3$[a]	0.038
Caustic Soda / Sodium Hydroxide	0.04
Phosphoric Acid	0.013

[a]HCl is Hydrochloric acid, $NAOCH_3$ is sodium methoxide.

The total soy oil based biodiesel production costs derived from the PSI-Lurgi are $2.20 dollars in year 2004.

7.2.6 Superior Process Technologies Estimate

The Superior feedstock costs assume that 7.60 pounds of soy oil and yellow grease are required to make a gallon of biodiesel fuel, which results in a feedstock cost of 175 cents/gal for year 2004 for soy oil and 87.5 c/gal for yellow grease, using the feedstock costs in section 7.2.2.1. We adjusted all other cost items in the Superior estimate from a 2006 year to 2004 basis, adjusting the cost by the relative change of GDP, though the costs for reagent needs and utilities are adjusted using the methods as discussed below.

7.2.6.1 Capital Costs

The total capital coats for a soy oil based plant are $10.7 million, while the costs for a yellow grease plant are $13.4 million, in 2004 dollars. These costs are inclusive of the amount needed for a new plant, which is similar to the other biodiesel estimates. The capital costs were amortized assuming a seven percent return on investment, resulting in a cost of 11.7 cents per gallon and 14.7 cents per gallon for a soy oil and yellow grease based plant, respectively.

7.2.6.2 Operating Costs

The total operating costs, excluding capital charges are 47 and 64 cents per gallon for soy oil and yellow grease plants in year 2004, respectively. Insurance, taxes, rent and local taxes incur a cost of about 6 and 7 cents per gallon, for soy oil and yellow grease, respectively. The costs for maintenance, plant overhead costs and supplies account for about 16.0 and 21.5 cents/gal, for soy oil and yellow grease. The sale of the glycerol byproduct at 80% strength generates incomes of 4 cents per gallon of produced biodiesel, assuming glycerol price of 5 cents per pound. The remaining components of operating costs are discussed below.

7.2.6.3 Utility and Labor

The overall utility costs were provided, though the specific amounts of natural gas, electricity were not provided for the 10 MM gallon plant. We adjusted the Superior utility cost estimate from a 2006 year to a 2004 year basis, using the relative price change of natural gas and electricity, assuming that natural gas supplies 90 percent of the energy, and electricity supplies the remaining 10 percent. The resulting energy requirement is 5.0 and 8.6 cents per gallon, for soy oil and yellow grease, respectively.

The estimate accounts for personnel cost to run and maintain the plant, including laboratory, plant supervisory and administration costs. The overall labor costs on a 2004 year basis are 7.6 and 12.8 cents for each gallon of biodiesel, for soy oil and yellow grease, respectively.

7.2.6.4 Chemical Reagents

The Superior vendor estimate also requires the same chemicals and chemical reagents as used in the USDA/NREL models and Tennessee study. The total chemical reagent cost from Superior on a 2006 year reagent pricing basis is 18.1 and 20.1 c/gal, respectively for soy and yellow grease plants. Superior provided the prices for each of the chemicals, though the specific amounts of each chemical were not provided for the soy oil based estimate. We therefore, adjusted the total chemical reagent cost to a 2004 year basis, assuming the demands for reagent as documented in the PSI-Lurgi estimate. The resulting reagent costs on a 2004 year basis are 16.5 and 18.3 cents/gal, for soy oil and yellow grease. The Superior prices for the required chemicals and reagents are presented in Table 7.2-17.

Table 7.2-17.
Superiors Reagent Prices

Reagent	Dollar / lb
$NAOCH_3$ [a] (25% solution)	0.50
HCl [a] (32%)	0.091
Methanol	0.146
Phosphoric Acid (75%)	0.42
Caustic Soda / Sodium Hydroxide (50%)	0.14

[a]HCl is Hydrochloric acid, $NAOCH_3$ is sodium methoxide.

The total resulting biodiesel production costs derived from Superior Process description and engineering estimate is $2.34 and $ 1.66 per gallon for soy oil and yellow grease derived biodiesel respectively, in year 2004. Yellow greases net production cost (minus feedstock costs) are about 20 c/gal more than the net production cost for soy based biodiesel.

7.2.7 Yellow Grease Production Costs

Yellow grease's production cost is higher than soy oil produced biodiesel fuel, due to the extra capital and operating costs required to remove contaminants in the grease feedstock. In the prior sections, the EIA and Superior analysis indicated that the yellow grease production cost for biodiesel is higher than the production cost based on use of soy oil, excluding the feedstock costs. The EIA analysis showed that yellow grease's production cost is 3 c/gal higher, while the Superior results showed that the yellow grease's production cost is about 20 c/gal higher than soy oil production costs. Both of these provide a measurement of the extra production costs (excluding feedstock) associated with making biodiesel from yellow grease versus soy oil.

In this section, we use the EIA and Superior results to generate yellow grease costs as inputs to the models, adjusting the soy oil production costs to reflect the extra cost for producing yellow grease. We assume the same feedstock costs for yellow grease as those listed in section 7.2.2.1, and that it takes 7.6 lbs of yellow grease to produce a gallon biodiesel fuel. Table 7.2-18, contains the resulting yellow grease production costs based on the EIA and Superior analyses.

Table 7.2-18.
Yellow Grease Costs Based on EIA and Superior Results

	EIA 2004	Superior 2004	EIA 2012	Superior 2012
USDA, c/gal	124	141	111	128
NREL, c/gal	138	155	131	148
EIA, c/gal	143	160	132	149
Vendor avg, c/gal	142	159	139	156
Average	136.8	153.8	128.3	145.2

We averaged all of the yellow grease results, and generated an average production cost of $1.45/gal in 2004 and $1.37/gal in 2012 for yellow grease derived biodiesel.

7.2.8 Biodiesel Blending Credit Programs

There are numerous credit and incentive programs that encourage the blending of biodiesel. These programs reimburse blenders and producers for adding biodiesel to transport diesel fuel, which acts to lower the production costs and makes the production of biodiesel more economically competitive with petroleum derived diesel fuel. There are several federal/nationwide biodiesel credit programs that offer subsidies for blending or use of biodiesel as a transport diesel fuel which are discussed below.

The Commodity Credit Commission Bio-energy Program is an existing program that expires at the end of fiscal year 2006, though due to a funding shortfall the program will terminate on July 31, 2006. This program was administered by the USDA and pays biodiesel producers grants when the economics to produce biodiesel are poor. The stipend is determined based on available funding and the volume of renewable fuel that can receive the credit. For historical purposes, the payments in 2004 and 2005 averaged about 107 and 50 c/gal of fuel produced, respectively. For the first half of 2006, the credit on a per gallon basis is reduced further, as the payment is diluted by increased production volume of fuels available to receive the credit.

The Energy Act extended the Biodiesel Blenders Tax Credit program to the end of year 2008. This program was created under the American Jobs Creation Act of 2004 which created an excise tax credit that can be claimed by anyone who blends biodiesel into transport diesel fuel. Under this program, blenders may claim a credit against the applicable federal motor fuels excise tax for blends containing biodiesel. According to IRS guidelines, the credit may be claimed by anyone who adds biodiesel into diesel fuel at a level greater than 0.1 percent in the final blend. The full credit for biodiesel made from virgin vegetable oils and animal fats is $1.0 per gallon, while biodiesel derived from recycled grease receives 50 cents/gallon. A blender with more excise tax credits than taxes owed can receive a refund from the IRS. Additionally, under the current program, imported biodiesel and fuel made from imported feedstocks can also receive the credit.

The Income Tax Credit Alternative is a program that is also available. This program does not require any blending of biodiesel, though it does offers allow a similar excise tax credit as in the blenders tax credit program. The excise tax can only be taken against actual income, however, which makes the program less economically attractive than the blenders' credit program.

The Energy Act also created the Small Biodiesel Blenders Tax credit program. Under this program, a credit of 10 c/gal is available to small producers who make biodiesel fuel from virgin vegetable oils. This stipend is limited to companies with annual production volumes less than 60 MM gallons per year, using the aggregated capacity from all production sites for an individual company. The maximum payment per company is capped at $15 MM per year and the program is set to expire at the end of year 2008.

In addition to the federal programs, there are state and local programs that offer state fuel tax exemptions, tax credits, and incentives that are more modest.

7.3 Distribution Costs

7.3.1. Ethanol Distribution Costs

There are two components to the costs associated with distributing the volumes of ethanol necessary to meet the requirements of the Renewable Fuels Standard (RFS): 1) the capital cost of making the necessary upgrades to the fuel distribution infrastructure system, and 2) the ongoing additional freight costs associated with shipping ethanol to terminals. The most comprehensive study of the infrastructure requirements for an expanded fuel ethanol industry was conducted for the Department of Energy (DOE) in 2002.[wwwww] This study provides the foundation for our estimates of the capital costs associated with upgrading the distribution infrastructure system as well as the freight costs to handle the increased volume of ethanol needed in 2012. Distribution costs are evaluated here for the RFS and EIA cases.

7.3.1.1 Capital Costs to Upgrade the Ethanol Distribution System

The 2002 DOE study examined two cases regarding the use of renewable fuels. The first case assumed that 5.1 Bgal/yr of ethanol would be used in 2010, and the second case assumed that 10 Bgal/yr of ethanol would be used in 2015. We interpolated between these two cases to provide the foundation for our estimate of the capital costs to support the use of 6.67 Bgal/yr of ethanol in 2012 (the RFS case). The 10 Bgal/yr case from the DOE study was used as the foundation to estimate the capital costs under the EIA case. For both the 6.67 Bgal/yr and 9.64 Bgal/yr cases, we adjusted the results from the DOE study to reflect a 3.9 Bgal/yr 2012 ethanol use baseline. Table 7.3-1 contains our estimates of the infrastructure changes and associated capital costs for the two ethanol use scenarios examined in today's rule.[90]

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[90] These capital costs will be incurred incrementally during the period of 2007-2012 as ethanol volumes increase. For the purpose of this analysis, we assumed that all capital costs will be incurred in 2007.

Table 7.3-1.
Ethanol Distribution Infrastructure Capital Costs
Relative to a 3.9 Billion Gallon per Year Reference Case

	RFS Case (6.67 Bgal/yr)	EIA Case (9.64 Bgal/yr)
New Terminal Blending Systems for Ethanol		
Number of terminals	243	515
Capital cost	$73,044,000	$154,530,000
New Ethanol Storage Tanks at Terminals		
Number of tanks	168	370
Capacity	1,526,000 barrels	3,415,000 barrels
Capital cost	$21,939,000	$48,803,000
Terminal Storage Tanks Converted to Ethanol		
Number of tanks	44	83
Capacity	319,000 barrels	592,000 barrels
Capital cost	$931,000	$1,739,000
Terminals Using Ethanol for the First Time[a]		
Number of terminals	212	453
Capital cost	$4,238,000	$9,065,000
New Rail Delivery Facilities at Terminals		
Number of terminals	42	76
Capital cost	$14,869,000	$27,127,000
Retail Facilities Using Ethanol for First Time[a]		
Number of retail facilities	33,600	74,820
Capital cost	$19,824,000	$44,146,000
New Tractor Trailer Transport Trucks		
Number of Trucks	209	435
Capital Costs	$24,027,000	$50,075,000
New Barges		
Number of new barges	11	23
Capital cost	$21,475,000	$43,204,000
New Rail Cars		
Number of new rail cares	2,024	3,491
Capital cost	$172,012,000	$296,729,000
Total Capital Costs	$352,361,000	$675,418,000
Capital Costs Attributed to Terminal and Retail (i.e. fixed) Facilities	$134,847,000	$285,410,000
Capital Costs Attributed to Mobile Facilities (tank trucks, rail cars, & barges)	$217,514,000	$390,008,000

[a] Terminal and retail facilities using ethanol for the first time will need to make various modifications to ensure the compatibility of their systems with ethanol.

Our estimated capital costs in this final rule differ from those in the proposal for several reasons. First, the volume for the RFS case was updated to reflect the fuel rule provisions. Second, we adjusted our estimate of capital costs from those in the proposal to reflect an increase in the cost of rail tank cars and barges since the DOE study was conducted. Third, we are assuming a 30 percent increase in the reliance on rail versus marine transport over that projected in the DOE study. The 2002 DOE study estimated that 53 percent of the increase in ethanol volume shipped between PADDs would be carried by barge and 47 percent by rail. For the purposes of this analysis, we assumed that 30 percent of the increased volume in ethanol shipments that were projected to be carried by barge in the DOE study would instead be carried by rail. This equates to 37 percent of the increase in ethanol shipments being carried by barge and 63 percent by rail. To provide a conservatively high estimate of the potential economic impact, we assumed that this shift translates into a 30 percent increase in rail infrastructure costs. This incorporates the increased cost to prepare additional terminals to receive ethanol by rail, and to provide a sufficient number of additional rail tank cars for ethanol transport. The actual increase in rail infrastructure costs may be somewhat lower given improvements in the efficiency of ethanol transport by rail.

Amortized over 15 years at a 7 percent cost of capital, the total capital costs (of $352,361,000 under the RFS case and 675,418,000 under the EIA case) equates to an annual cost of approximately $38,687,000 under the RFS case and $74,157,000 under the EIA case. This translates to approximately 1.4 cents per gallon of new ethanol volume under the RFS case and 1.2 cents per gallon under the EIA case. Under both cases, approximately 0.5 cents per gallon is attributed to mobile facilities and the remainder to fixed facilities.

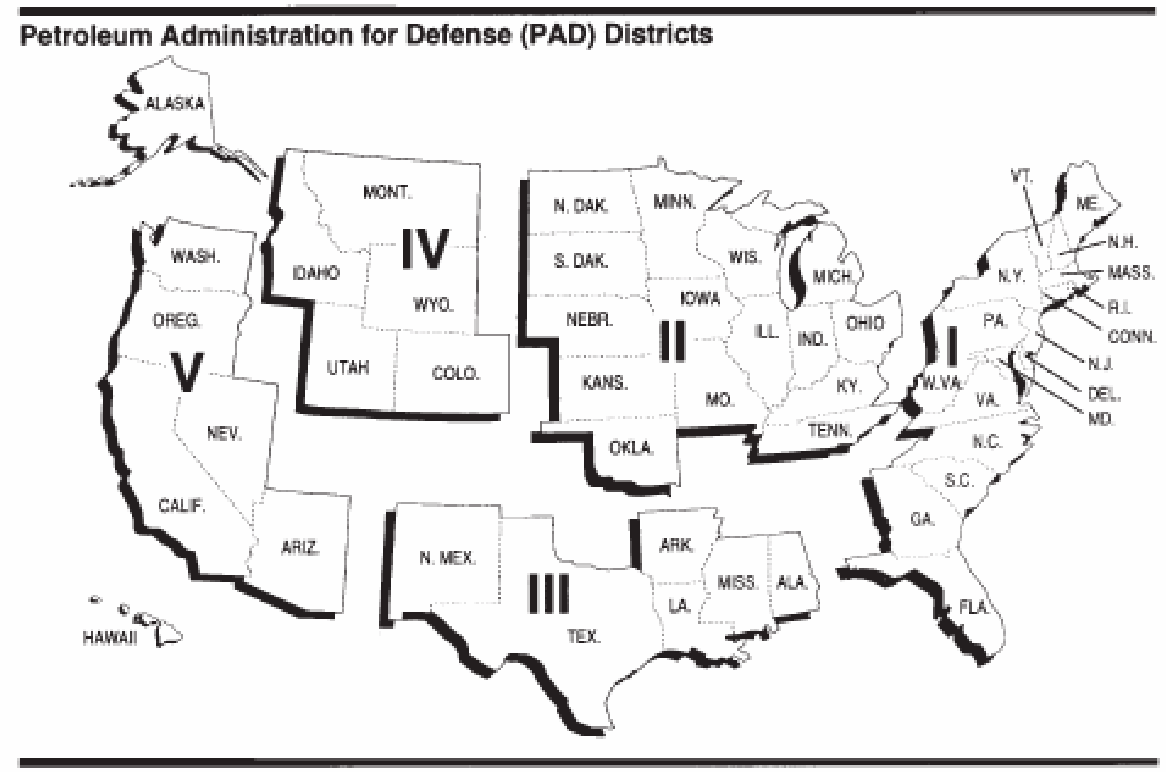
7.3.1.2 Ethanol Freight Costs

The 2002 DOE study contains estimated ethanol freight costs for each of the 5 PADDs. These estimated costs are summarized in the following Table 7.3-2.[XXXXX] A map of the PADDs is contained in Figure 7.3-1.

Table 7.3-2.
Estimated Ethanol Freight Costs from the 2002 DOE Study

PADD	5.1 billion gallons per year (cents per gallon)	10.0 billion gallons per year (cents per gallon)
1	11.1	7.2
2	4.3	2.4
3	6.6	5.8
4	4.7	7.4
5	12.7	10.7
National Average	7.7	5.7

Figure 7.3-1.
PAD District Definitions.

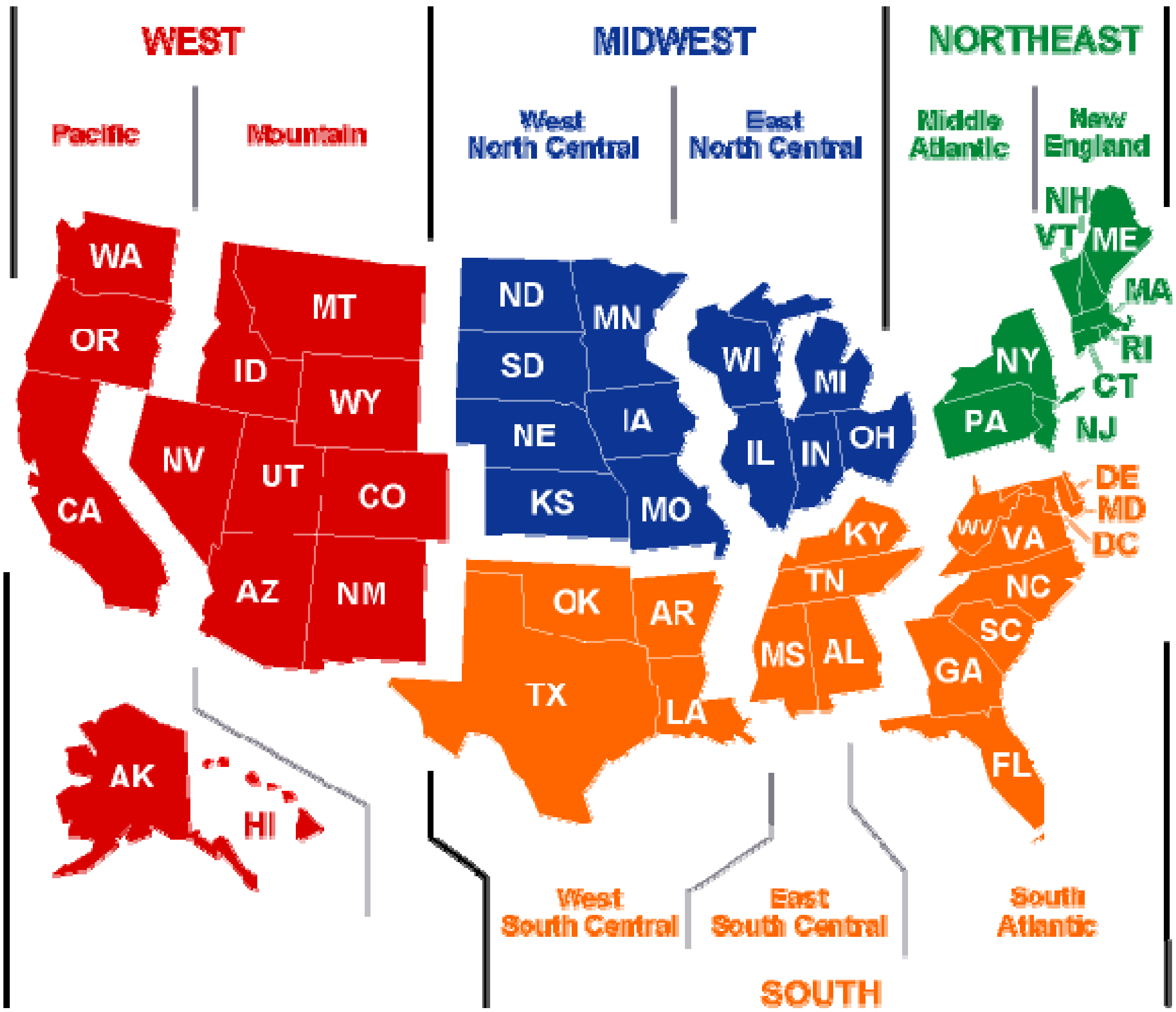


The Energy Information Administration (EIA) translated the cost estimates from the 2002 DOE study to a census division basis.[YYYYY] A summary of the resulting (EIA) ethanol distribution cost estimates are contained in the following Table 7.3-3. A map of the census divisions is contained in Figure 7.3-2.

**Table 7.3-3.
EIA Estimated Ethanol Freight Costs
(derived from the 2002 DOE Study)**

Census Division		Freight Cost (cents per gallon)
From	To	
East North Central	New England	9.8
East North Central	Middle Atlantic	9.8
East North Central	East North Central	4
East North Central	South Atlantic	9.8
East North Central	East South Central	4.7
East North Central	Pacific	14.0
West North Central	New England	11.4
West North Central	Middle Atlantic	11.4
West North Central	East North Central	4
West North Central	West North Central	4
West North Central	South Atlantic	11.4
West North Central	East South Central	4.7
West North Central	West South Central	4.7
West North Central	Mountain	4.5
West North Central	Pacific	13.0

Figure 7.3-2.
Census Divisions



We took the EIA projections and translated them into State-by-State ethanol freight costs. For the purposes of this analysis, all ethanol was assumed to be produced in the East and West North Central Census Divisions (corresponding closely to PADD 2). We believe that this is a reasonable approach because the cost of shipping corn feedstock from PADD 2 to ethanol plants located outside of PADD 2 will typically negate any potential reduction in freight cost from reduced shipping distances for ethanol or dried distiller grains. The vast majority of ethanol plants planned for outside of PADD 2 are projected to begin operation using corn supplied from PADD 2.[91] Many have stated plans to transition to local feedstocks. However, we believe that such a transition will typically not be accomplished within the timeframe considered by this

[91] Hawaii is a special case because plants potentially located there will use local feedstocks from their initial start up date.

analysis (i.e. 2012). Other local considerations may provide a unique cost advantage to locating a plant outside of PADD 2. One such consideration might be that if by locating a plant outside of PADD 2 the ethanol producer could avoid the need to dry the distiller grains it produces and sell the wet distiller grains to a local market. Although this might result in a significant cost savings, it is unclear the extent to which this will be possible given the short shelf life of wet distiller grain (~3 days). Also, any potential cost savings might be offset by the relatively lower price that can be negotiated for wet versus dry distiller grains. In any event, there is insufficient data at this time to evaluate the extent to which such local conditions may result in an advantage in lower freight costs for ethanol plants outside of PADD 2. Further, our projection of where new ethanol production plants might be located indicates that only 10 percent of production capacity could be located outside of PADD 2. Thus, any potential freight cost advantage that might be enjoyed by such plants would not likely have a significant impact on our national analysis. Furthermore, to the extent that the location of ethanol plants outside of PADD 2 imparts a savings in ethanol distribution costs, this would suggest that our estimates of ethanol freight costs in this rule are conservatively high.

Ethanol consumed within census divisions belonging to PADD 2 was assumed to be transported by truck, while distribution outside of these areas was assumed to be by rail, ship, and/or barge. A single average distribution cost for each destination census division was generated by weighting together the 2012 freight costs given for each mode in both source census divisions according to their volume share. These cents per gallon figures were first adjusted upward by 10 percent to reflect the increased cost of transportation fuels used to ship ethanol since the 2002 DOE study, and then additional adjustments were applied to some individual states based on their position within the census division. In the case of Alaska and Hawaii, differences in ethanol delivery prices from the mainland were inferred from gasoline prices.

For some states, different freight costs for ethanol supplied to large hub terminals versus small satellite terminals was estimated. The reasoning behind this is that large shipments of ethanol shipped from the Midwest by barge, ship, and/or unit train will often be initially unloaded at hub terminals for further distribution to satellite terminals. In cases where redistribution from a hub to a satellite terminal doesn't take place, the volume of ethanol shipped directly from the producer to a lesser volume ("satellite") terminal will also incur a higher freight rate than ethanol shipped to a larger-volume "hub" terminal. The largest adjustment was applied to the Rocky Mountain States since they are generally large in area and additional expense is required to transport freight through higher elevations and rugged terrain. Smaller adjustments were applied to states that are smaller, flatter, or have access by navigable waterways. The states to which an adjustment was not applied were generally in the Midwest or were so small as to not warrant different distribution costs. Given the large number of ethanol plants in the Midwest, we do not believe that there are substantial differences in the cost of distributing ethanol with that area.

We made several adjustments in our estimates of ethanol freight costs from those in the proposal. First, the differential cost of shipping ethanol to satellite terminals versus hub terminals was increased to better reflect the additional costs incurred in either redistributing the ethanol from a hub to a satellite terminal, or of shipping ethanol directly from the producer to the satellite terminal in a lesser volume. The estimated additional freight cost of shipping ethanol to satellite terminals versus hub terminals is contained in the following Table 7.3-4.

Table 7.3-4.
Additional Freight Cost to Deliver Ethanol to a Satellite Terminal Compared to a Hub Terminal

States	cents per gallon
OH	2
AL, AR, FL, GA, KY, LA, MD, ME, MS, NC, NH, NY, OK, OR, PA, SC, TN, VA, VT, WA, WV	4
AK, AZ, CO, ID, NM, NV, TX, UT, WY	5

Another change that we made from the proposal was with respect the volume of ethanol we estimated would be delivered to hub versus satellite terminals. The proposal assumed a 50/50 spit. For this final rule, we project that all of the ethanol volume blended into reformulated gasoline would be used in urban areas served by hub terminals. The percentage of ethanol blended into conventional gasoline that is used in an urban area (and hence delivered to a hub terminal) versus that used in a rural area (and hence delivered to a satellite terminal) was based on our analysis of the percentage of vehicle miles traveled in urban versus rural areas.[92]

The final change from the proposal pertains to our consideration of the cost of shipping ethanol from the production plant to the rail head / marine terminal either for large volume shipment by unit train or marine shipment to hub terminals, or for shipment at single car rates via multiple-product trains directly to satellite terminals. Our review of current ethanol freight rates conducted in response to a comment on the proposed rule indicates that we did not adequately account for this added cost in the proposal. Chicago is a primary ethanol gathering point from producers for further distribution. A 4 cent per gallon conveyance fee is charged to account for delivery of ethanol from the production plant gate to the Chicago Board of Trade delivery point for taking ethanol. This includes train shipments, loading costs, and other miscellaneous fees. Based on this information, we have added 4 cents per gallon to our ethanol freight estimates.

Our estimates of the State-by-State ethanol freight costs under the RFS and EIA cases are contained in Tables 7.3-5 and 7.3-6. National and PADD average freight costs under both the RFS and EIA cases are contained in Table 7.3-7. We are assuming that these freight costs do not include the costs associated with the recovery of capital for the distribution facility changes that are necessary to accommodate the increased volume of ethanol. This may tend to overstate distribution costs to some extent because some capital recovery may be incorporated into the 4 cent per gallon conveyance fee. The inclusion of rail tank car lease fees also suggests that these estimated freight costs may be conservatively high given that rail car lease fees incorporate a capital recovery and profit margin.

[92] See Chapter 2 of this RIA for additional discussion of our estimate of the percentage of ethanol that will be used in urban versus a rural areas

Table 7.3-5.
State-by-State Ethanol Freight Costs

State	PADD	Ethanol Freight Cost*: (cents per gallon)			
		Hub Terminal	Satellite Terminal	Average Freight Cost**	
				RFS Case	EIA Case
Connecticut	1	15.4	15.4	15.4	15.4
Maine	1	17.4	21.4	20.0	20.0
Massachusetts	1	15.4	15.4	15.4	15.4
New Hampshire	1	16.4	16.4	16.4	16.4
Rhode Island	1	15.4	15.4	15.4	15.4
Vermont	1	16.4	16.4	NA***	16.4
New Jersey	1	15.4	15.4	15.4	15.4
New York	1	15.4	19.4	15.4	15.7
Pennsylvania	1	12.4	16.4	13.8	13.7
Delaware	1	15.4	15.4	15.4	15.4
District of Columbia	1	15.4	15.4	NA***	15.4
Florida	1	12.4	16.4	14.0	14.0
Georgia	1	15.4	19.4	NA***	17.4
Maryland	1	15.4	15.4	NA***	15.4
North Carolina	1	15.4	19.4	NA***	NA***
South Carolina	1	15.4	19.4	NA***	NA***
Virginia	1	15.4	19.4	NA***	15.4
West Virginia	1	15.4	19.4	NA***	NA***
Illinois	2	4.4	4.4	4.4	4.4
Indiana	2	5.4	5.4	5.4	5.4
Michigan	2	6.4	6.4	6.4	6.4
Ohio	2	5.4	7.4	6.6	6.6
Wisconsin	2	4.4	4.4	4.4	4.4
Iowa	2	3.4	3.4	3.4	3.4
Kansas	2	4.4	4.4	4.4	4.4
Minnesota	2	4.4	4.4	4.4	4.4
Missouri	2	4.4	4.4	4.4	4.4
Nebraska	2	4.4	4.4	4.4	4.4
North Dakota	2	5.4	5.4	5.4	5.4
South Dakota	2	4.4	4.4	4.4	4.4
Kentucky	2	6.2	10.2	7.1	7.3
Tennessee	2	6.2	10.2	8.7	8.7
Oklahoma	2	8.3	12.3	NA***	11.1

* Freight rates from PADD 2 production facilities
** Hub and satellite freight rates were volume weighted to arrive at an average freight rate.
*** No significant ethanol use. See Chapter 2 of this RIA regarding our estimates of where ethanol will be used.

Table 7.3-5.
State-by-State Ethanol Freight Costs (continued)

State	PADD	Ethanol Freight Cost*: (cents per gallon)			
		Hub Terminal	Satellite Terminal	Average Freight Cost**	
				RFS Case	EIA Case
Alabama	3	11.2	15.2	14.0	14.0
Mississippi	3	10.2	14.2	13.9	13.9
Arkansas	3	11.3	16.3	15.0	15.0
Louisiana	3	11.3	15.3	13.8	13.8
Texas	3	14.3	19.3	14.3	16.0
New Mexico	3	16.4	21.4	19.0	19.6
Colorado	4	14.4	19.4	NA***	17.0
Idaho	4	19.4	24.4	NA***	22.8
Montana	4	17.4	22.4	21.8	21.8
Utah	4	17.4	22.4	NA***	20.5
Wyoming	4	16.4	21.4	NA***	20.8
Arizona	5	19.4	24.4	20.3	20.5
Nevada	5	20.4	25.4	21.1	22.3
Alaska	5	45.5	50.5	NA***	NA***
Hawaii	5	40.5	40.5	NA***	40.5
Oregon	5	20.5	24.5	20.5	20.5
Washington	5	20.5	24.5	21.9	21.9
California	5	20.5	20.5	20.5	20.5

* Freight rates from PADD 2 production facilities.
** Hub and satellite freight rates were volume weighted to arrive at the average freight rate.
*** No significant ethanol use. See Chapter 2 of this RIA regarding our estimates of where ethanol will be used.

Table 7.3-6.
National and PADD Average Ethanol Freight Costs

	Ethanol Freight Cost* (cents per gallon)	
	RFS Case	EIA Case
National Average	11.3	11.9
PADD 1	14.9	15.1
PADD 2	5.1	5.3
PADD 3	14.6	15.2
PADD 4	21.8	19.8
PADD 5 excluding AK & HI	20.6	20.7
PADD 5 including AK & HI	20.6	22.1

* Freight rates from PADD 2 production facilities.

The national average ethanol freight cost of 11.3 cents per gallon under the RFS case and 11.9 cents per gallon under the EIA case translates to an annual freight cost for the additional volume of ethanol used in 2012 of $313,123,000 and $678,300,000 respectively. Adding in the annualized capital costs, results in a total annual ethanol distribution cost of 351,810,000 or 12.7 cents per gallon under the RFS case and $752,457,000 or 13.1 cents per gallon under the EIA case.[93]

7.3.2 Biodiesel Distribution Costs

The volume of biodiesel used by 2012 under the RFS is estimated at 300 million gallons per year. The 2012 reference case against which we are estimating the cost of distributing the additional volume of biodiesel needed to meet the requirements of the RFS is 30 million gallons.[94]

The capital costs associated with distribution of biodiesel are higher per gallon than those associated with the distribution of ethanol due to the need for storage tanks, blending systems, barges, tanker trucks and rail cars to be insulated and in many cases heated during the winter months.[95] In the proposal, we estimated that that these capital costs would be approximately $50,000,000. We adjusted our estimate of these capital costs for this final rule based on additional information regarding the cost to install the necessary storage and blending equipment at terminals and the need for additional rail tank cars for biodiesel.[96] We now estimate that handling the increased biodiesel volume will require a total capital cost investment of $145,500,000 which equates to about 6 cents per gallon of new biodiesel volume.[97]

In the proposal, we estimated that the freight costs for ethanol adequately reflect those for biodiesel as well. In response to comments, we sought additional information regarding the freight costs for biodiesel. This information indicates that freight costs for biodiesel are typically 30 percent higher than those for ethanol which translates into an estimate of 15.5 cents per gallon for biodiesel freight costs.[98]

Including the cost of capital recovery for the necessary distribution facility changes, we estimate the cost of distributing biodiesel to be 21.5 cents per gallon.

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[93] All capital costs were assumed to be incurred in 2007 and were amortized over 15 years at a 7 percent cost of capital.

[94] See Chapter 1 of this RIA regarding the 2012 reference case.

[95] See Chapter 1.3 of the Regulatory Impact Analysis associated with today's rule for a discussion of the special handling requirements for biodiesel under cold conditions.

[96] Information on biodiesel facility costs was obtained from a number of biodiesel blenders on the condition that the specific source of such information would not be identified. Biodiesel rail tank cars typically have a capacity of 25,500 gallons as opposed to 30,000 gallons for an ethanol tank car. Thus, additional tank cars are need to transport a given volume of biodiesel relative to the same volume of ethanol.

[97] Capital costs will be incurred incrementally over the period of 2007-2012 as biodiesel volumes increase. For the purpose of this analysis, all capital costs were assumed to be incurred in 2007 and were amortized over 15 years at a 7 percent cost of capital.

[98] This is based on our review of publicly available biodiesel and ethanol freight rates from CSX and BNSF rail at www.csx.com and www.bnsf.com , on information regarding the lease rates for biodiesel versus ethanol freight cars considering the smaller size of biodiesel tank cars, and on discussions with biodiesel distributors. The estimated ethanol freight costs were increased by 30 percent to arrive at the estimate of biodiesel freight costs.

7.4 Gasoline and Diesel Blendstock Costs

The previous sections of this chapter have presented estimates of the cost of producing and distributing ethanol and biodiesel. In this section, we summarize the results of refinery modeling conducted by Jacobs Consultancy under contract to EPA. Jacobs's used the Haverly Linear Programming (LP) model to conduct the analysis. This model is widely used by the refining industry, consultants, engineering firms and government agencies to analyze refinery economics, refinery operations, fuel quality changes, refinery capital investments, environmental changes and demand changes. The Haverly model uses Jacobs's Refining Process Technology Database to represent refining operations

The modeling was conducted to analyze the effect of the increased renewable fuel use on the production costs and composition of the nation's gasoline and diesel fuel. The refinery modeling output described in this section includes the changes in volumes and capital investments as well as the resulting capital and fixed operating costs, the variable costs, and the total of all these costs. The costs are expressed in 2006 dollars and capital costs are amortized at 7% before tax return on investment (ROI). The costs for the RFS and EIA cases are expressed incremental to the reference case. We first report the results of the RFS case, followed by the results of the EIA case.

7.4.1 Description of Refinery Modeling Cases Modeled

The modeling cases were set up to analyze the RFS and EIA cases described in Chapter 2. The primary renewable fuel modeled was ethanol in gasoline, while considering a fixed production amount of biodiesel as projected by EIA in 2012. Along with the increased use of renewable fuels, the analyses for the RFS and EIA cases both include the elimination of the RFG oxygen content standard and the resulting removal of MTBE from the U.S. gasoline market. These scenarios both assume the current Mobile Source Air Toxics standard (MSAT1) is in place. The effects of the MSAT2 standard are modeled in that rulemaking which has just recently been made final.

Jacobs conducted a Linear Programming (LP) modeling analysis of the refining industry for the various RFS scenarios using a model developed by Haverly's LP technology. The modeling was set up to analyze the extent to which ethanol will be used in CG versus RFG by region and the resulting effects on gasoline composition. The refining industry was modeled based on five aggregate complex refining regions, representing PADD's 1, 2, 3, 4 & 5 together minus California and California separately. All of the PADDS were modeled simultaneously together in the LP model, in order to balance and meet the national gasoline and fuel demands.

7.4.1.1 RVP

The analysis modeled summer and winter seasons, with all gasoline types including California RFG, Federal RFG, 7.0, 7.8 RVP controlled areas and 9.0 CG. The control cases consisted of the minimum renewable fuel volume as specified by EPAct and discussed in Chapter 2 and the 2006 AEO projection of 9.6 billion gallons of ethanol per year in 2012.

Winter gasoline RVP levels were adjusted higher than EPA data, to account for refiner RVP reporting inaccuracies from use of the complex model in the winter season. (Some refiners reported lower RVP levels than actually produced, as the complex model has a fixed upper reporting limit of 8.8 in the winter season.)

7.4.1.2 Base case (2004)

The base case was established by modeling fuel volumes for 2004. Information was based on process capacities from Oil and Gas Journal, EIA data and gasoline emissions and property data from EPA. Fuel property data for this base case was built off of 2004 refinery batch reports provided to EPA; however, the base case assumed sulfur standards based on gasoline data in 2004, not with fully phased in of Tier 2 gasoline standards at the 30 ppm level. In addition we assumed the phase-in of 15 ppm sulfur standards for highway, nonroad, locomotive and marine diesel fuel. The supply/demand balance for the U.S. was based on gasoline volumes from EIA and the California Air Resources Board (CARB). Our decision to use 2004 rather than 2005 as the baseline year was because of the refinery upset conditions associated with the Gulf Coast hurricanes in 2005.

7.4.1.3 MSAT1 Provisions for Refinery Cases in 2012

For CG and RFG, gasoline qualities were modeled to assure Complex model Phase 2 calculations seasonal and annual compliance, taking into account the elimination of the oxygen requirement for RFG; (by PADD and California), and under MSAT1 gasoline standards. Incremental gasoline volumes above the 2004 base case volumes for each PADD were allowed to conform to less stringent toxics performance standards as allowed by the MSAT1 provisions. For this, the MSAT 1 PADD constraints were calculated using gasoline data from 1998-2000 EPA batch reports, considering that new incremental volumes of gasoline above the 1998-2000 annual average would comply with MSAT1 provisions, as predicated by EPact 2005. The following tables show the resulting conventional and RFG gasoline MSAT1 baseline constraints, which was applied to gasoline produced for the cases modeled in year 2012.

Table 7.4-1.
Conventional Gasoline MSAT 1 2012 Baseline Data

	Exhaust Toxics mg/mi*	NOx mg/mi*
PADD 1	88.33	1,440.84
PADD 2	92.79	1,432.57
PADD 3	88.79	1,438.76
PADD 4 & 5, excluding California	99.85	1,414.00

*mg/mi is milligram per mile.

Table 7.4-2.
RFG Gasoline MSAT 1 2012 Baseline Data

	Total Toxics mg/mi*	Toxics Percent Reduction
PADD 1	75.11	27.39
PADD 2	80.11	22.56
PADD 3	74.74	27.75
PADD 4 & 5, excluding California	NA	NA

*mg/mi is milligram per mile.

7.4.1.4 Reference case (2012)

The reference case was based on modeling the base case, using 2012 fuel prices, and scaling the 2004 fuel volumes to 2012 based on growth in fuel demand. In addition, we scaled MTBE and ethanol upward, in proportion to gasoline growth, and assumed the RFS program would not be in effect. For example, if the PADD 1 gasoline pool MTBE oxygen was 0.5 wt% in 2004, the reference case assumed it should remain at 0.5 wt%. Finally, we assumed the MSAT 1 standards would remain in place as would the RFG oxygen mandate. We assumed the crude slate quality in 2012 is the same as the baseline case.

7.4.1.5 Control cases (2012)

Two control cases were run for 2012. The assumptions for the control cases are summarized below:

- Control Case 1 (RFS case): 6.7 billion gallons/yr (BGY) of ethanol in gasoline; it reflects the renewable fuel mandate. In addition, it is assumed that no MTBE is in gasoline, MSAT1 is in place, the 1 psi waiver for CG containing 10 volume percent ethanol remains in effect for all states where it currently applies, the RFS is in effect, and there is no RFG oxygenate mandate.

- Control Case 2 (EIA case): Same as Control Case 1, except that the ethanol volume in gasoline is 9.6 BGY.

7.4.2 Assumptions made for Refinery Modeling

7.4.2.2 Fuels Production and Demand

The production of and demand for gasoline and other refinery fuels in the reference and control cases were based on EIA's AEO 2006 projections for year 2012 . The modeling also was set up to meet demand based on terminals' sales in each refining area, using EIA fuel sales data. The LP modeling accounted for inter-PADD transfers of finished products and gasoline blendstocks from refiners, to meet demand at terminals, based on historical transfer data from EIA, including CBOB and RBOB. Both the RFS and EIA control cases did not model any production of biodiesel fuel in fulfilling transportation diesel fuel demand.

7.4.2.3 Ethanol

The control cases were based on fixed national ethanol volumes as specified in Chapter 2. For the control cases, however, the LP modeling analysis used ethanol blending economics and ethanol distribution costs to allocate ethanol to each PADD, and to allocate ethanol use in CG and RFG grades of gasoline. Additionally, the modeling assumed that all ethanol added to gasoline is match-blended for octane by refiners in the reference and control cases, while splash blending of ethanol was assumed as appropriate for the base case using EPA gasoline data.

The price of ethanol was based on the 2004 yearly average price spread between regular conventional gasoline sold on spot market in Houston and ethanol sold on spot market on Chicago Board of Trade (CBOT). This was used to determine a Midwest ethanol production price. To derive ethanol prices for all other PADDs outside the Midwest, the Midwest ethanol production price was then adjusted for transportation costs to deliver ethanol from the Midwest to end use terminals (see section 7.3 for additional details). The price of ethanol was also adjusted to account for the 51 cent/gal rebate from the Federal subsidies, but did not account for the impact of state subsides.

The reference and control cases where modeled assuming that ethanol CG blends are entitled to the 1.0 psi RVP waiver during the summer (i.e., for all 9.0 RVP and low RVP control programs) so as to assess the impact on summertime butane removal.

7.4.2.4 Processes and Capital

All changes in refining capital was assessed at a 15% Return on Investment (ROI) after taxes, which was adjusted to 7 % ROI before taxes. Crude and other input prices were based on Jacobs' projection of refinery margins and crude prices in 2012 cases, which was also based on the historical price spreads of fuels between PADDS, using information from EIA's 2004 price information tables, Platts, and AEO 2006, see the Jacob's report for the petroleum fuel prices used in the modeling analysis.

7.4.3 Results of Refinery Modeling

7.4.3.1 Summary of Changes in Refinery Inputs and Outputs to the RFS Case

There are a number of changes in individual and overall volume for specific gasoline blendstocks between the RFS case and reference case based on the refinery model results. The changes include the increased blending of ethanol, the removal of MTBE, and the increased volumes of isooctane, isooctene and alkylate from the reuse of isobutylene formerly used to produce MTBE. The isooctane and isooctene are produced by merchant MTBE plants that formerly produced MTBE from mixed butanes, ethylene crackers, and propylene oxide plants as determined by a survey of how those plants are being converted to produce other gasoline blendstocks. The alkylate is produced from the isobutylene previously used to produce MTBE at captive (refinery-based) MTBE plants. The total volume of these gasoline blend stocks is summarized in Table 7.4-3 for both the reference case and RFS case adjusting the volume of ethanol and MTBE to reflect their gasoline energy-equivalent volumes.

Table 7.4-3.
Comparison of Ethanol, MTBE, Isooctane, Isooctene, and Alkylate Volumes by PADD for the RFS Case and Reference Case (barrels per day)

Case	Gasoline Blendstock	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	USA
Reference Case	Ethanol	57,620	114,900	5,242	20,676	58,934	257,372
	MTBE	54,887	0	122,474	0	0	177,360
	Isooctane/Isooctene	200	200	200	200	200	1,000
	Gasoline-equivalent Volume	82,687	76,034	102,864	13,846	39,096	314,527
RFS Case	Ethanol	139,224	201,989	23,091	17,853	53,004	435,160
	MTBE	0	0	0	0	0	0
	Isooctane/Isooctene Alkylate from MTBE	11,042	200	212,177	200	21,484	245,103
	Gasoline-equivalent Volume	102,930	133,513	227,417	11,983	56,466	532,308
	Change in Gasoline Equivalent Volume	20,243	57,479	124,553	-1,863	17,370	217,781

As the bottom row in Table 7.4-3 shows, the gasoline-equivalent volumes for the aggregated volume of these gasoline blendstocks are expected to increase as we compare the RFS case to the reference case. It is this net increase in gasoline blendstock volume that is expected to result in a net reduction in petroleum consumption.

The addition of ethanol to wintertime gasoline, and to summertime RFG, will cause an increase of approximately 1 psi in RVP that needs to be offset to maintain constant RVP levels. An obvious means that refiners could choose to offset the increase in RVP is to reduce the butane levels in their gasoline. To some extent, the modeling results showed some occurrences of that, but it also did not report an overall increase in butane sales as a result of the increased use of ethanol.

To convert the captive MTBE over to alkylate, after the rejection of methanol, refiners will need to combine one molecule of refinery produced isobutane with the isobutylene that was the feedstock for MTBE. The use of the isobutane will reduce the RVP of the gasoline pool from which it comes, helping to offset the RVP impacts of ethanol. Also, the increased production of alkylate provides a low RVP gasoline blendstock that offsets a portion of the cracked stocks produced by the fluidized catalytic cracker unit. Other means that the refinery model used to offset the high blending RVP of ethanol includes purchasing gasoline components with lower RVP, producing more poly gasoline which has low RVP and selling more high-RVP naphtha to petrochemical sales.

In Table 7.4-4, we summarize the inputs into and gasoline outputs from the refinery model separate from the ethanol and converted MTBE blendstocks summarized above. The summary shows that crude oil and vacuum gas oil and residual fuel purchases are expected to decrease about 1 percent averaged over all the PADDs. The refinery model also estimates that the volume of purchased gasoline components will increase in most PADDs. These gasoline components include renewable blendstocks for ethanol blending (RBOB), which is a very low

RVP gasoline blendstock. A likely reason for the increased gasoline blendstock volumes over purchased crude oil purchases is that the refinery model is seeking to purchase low RVP blendstocks to offset the volatility impacts of ethanol, as opposed to having to crack crude oil which produces more volatile four carbon compounds. Table 7.4-4 also shows the volume of gasoline projected to be produced for both the RFS case and reference case. We adjusted the gasoline volume for the RFS case to reflect the same energy density of the gasoline reported for the reference case. While the national energy-adjusted gasoline production levels for RFS case are about the same as the reference case, the energy adjusted gasoline production levels vary significantly by PADD. The refineries in PADDs 1 and 2 are projected to produce more gasoline in the RFS case compared to the reference case, while the refineries in PADD 3 are projected to produce less gasoline in the RFS case.

Table 7.4-4.
Summary of Refinery Model Input and Output Volumes by PADD for the RFS Case and Reference Case (barrels per day)

Case	Crude Oil and Gasoline	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	USA
Reference Case	Crude Oil	1,823,008	3,650,044	9,071,056	1,529,442	1,952,560	18,026,111
	VGO and Residual Fuel	152,467	59,552	680,329	0	27,400	919,748
	Gasoline Component Inputs	144,293	69,233	144,782	49,247	51,475	459,030
	Gasoline Volume	1,378,811	2,398,179	4,004,675	778,262	1,184,533	9,744,461
	Gasoline Energy Content	5.012	4.997	5.093	5.019	5.024	5.044
RFS Case	Crude Oil	1,762,018	3,579,232	9,071,056	1,520,709	1,952,560	17,885,576
	VGO and Residual Fuel	75,044	59,552	680,329	0	40,707	855,631
	Change in Crude oil and VGO/resid	-138,413	-70,812	0	-8,733	13,307	-204,651
	Inputs	200,272	69,233	178,080	49,247	67,146	563,979
	Change in Gasoline Component Inputs	55,979	0	33,298	0	15,672	104,949
	Gasoline	1,483,535	2,584,977	3,753,849	765,880	1,184,533	9,772,775
	Gasoline Energy Content	4.951	4.957	5.073	5.015	5.046	5.016
	Total Gasoline at Constant Energy	1,465,385	2,564,330	3,739,352	765,181	1,189,801	9,719,422
	Volume at Constant Energy	86,573	166,151	-265,323	-13,081	5,268	-25,039

The addition of ethanol, the phase out of MTBE and the reuse of former MTBE feedstocks to make other gasoline blendstocks is expected to change the capital investments that would otherwise occur if these changes were not made. Table 7.4-5 summarizes the change in refinery unit throughputs by PADD comparing the RFS case to the reference case.

Table 7.4-5.
Change in the Refinery Unit Capacities by PADD between the RFS Case and Reference Case (thousand barrels per day)

Unit or Category	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	USA
Crude Tower	-61	-71	0	-9	0	-141
Vacuum Tower	-22	-32	0	-2	0	-56
Sats Gas Plant	-13	-12	6	-2	0	-21
Unsats Gas Plant	-38	-19	0	-4	3	-59
FCC DeC5 Tower	-8	-3	56	-4	-9	33
FCC	-130	-61	0	-16	2	-205
FCC Splitter	-97	-5	116	-8	3	9
Hydrocracker	0	0	0	0	-6	-6
Delayed Coker	-13	-16	0	0	3	-27
Visbreaker	0	0	0	0	-3	-3
Thermal Naphtha Splitter	-2	-2	0	0	0	-3
CRU Reformer	0	8	48	0	0	56
SRU Reformer	0	0	0	0	-4	-4
BTX Reformer	0	0	0	0	0	0
C4 Isomerization	-13	0	1	0	-2	-14
C5/C6 Isomerization	0	3	-57	15	-26	-65
HF Alkylation	0	-1	1	0	0	0
H2SO4 Alkylation	-22	0	59	-1	-3	33
Dimersol	0	0	0	-2	0	-2
Cat Poly	1	0	18	0	0	19
Isooctane	0	0	0	0	0	0
DHT - Total	0	1	22	5	-1	28
DHT 2nd RCT - Total	0	3	2	5	0	10
DHT Arom Saturation	0	0	0	0	-4	-4
NHT - Total Fd	-9	3	-13	-1	-4	-23
NHT - Isom/Thermal Fd	-9	-5	-61	0	0	-75
NHT - Reformer Fd	0	8	48	0	-4	52
CGH - Generic	-81	-34	-42	-4	0	-161
CGH - Olefin Sat'n	0	0	0	0	28	28
FCCU Fd HDT	-39	0	0	0	0	-39
LSR Splitter	-12	-32	0	0	-6	-50
LSR Bz Saturator	-6	-15	0	0	-2	-22
Reformate Saturator	-2	-24	0	0	-4	-30
SDA	0	0	0	0	0	0
MTBE	-5	0	-114	0	0	-119
TAME	0	0	0	0	0	0
Hydrogen Plant - Total BSCF	-11	1	-75	3	-27	-109
Lube Unit	0	0	0	0	0	0
Sulfur Plant	-276	-298	138	-13	81	-368
Fuel System - Fuel Oil	0	0	0	0	0	0
Fuel System - CO2 (BLb/Day)	-18	-9	-5	-1	-2	-35
Utilities - Steam (Blbs)	-22	-12	-17	0	-6	-58
Utilities - Steam Vent (Blbs)	0	0	0	0	0	0
Utilities - Power (Mwh)	-715	-226	749	1	-133	-324
Utilities - Cooling H2O (Bgal)	-213	-93	-156	-14	-27	-502

Most of the capacity throughput changes are negative, reflecting the decreased processing of crude oil and vacuum gas oil and decreased downstream refining units as projected by the refinery model. Of the negative throughput changes, the large reduced volume of the fluidized catalytic cracker is important. As discussed above, the refinery model likely chose to decrease the fluidized catalytic cracker throughput to crack less heavy hydrocarbons to light hydrocarbons, producing less four-carbon compounds to offset the volatility impacts of ethanol. There are several units which show throughput capacity increases, primarily in PADD 3. PADD 3 refineries will have a substantial loss in octane because of the removal of a substantial volume of MTBE, but the refinery model did not choose to blend much ethanol in PADD 3. Instead, the refinery model chose to make additional alkylate from the captive MTBE plants formerly operating in PADD 3, and blend in isooctene from the conversion of merchant MTBE plants. The refinery model also added some reformer capacity to make up the balance of octane loss. The refinery model added depentanizer capacity mostly in PADD 3 to enable the blending of ethanol into RFG.

Refiners can also control the gasoline production and quality by adjustments they can make to several of their refinery conversion units. Refiners can adjust the conversion of their FCC and hydrocracker units, and change the severity of their reformers. Table 7.4-6 contains the percent conversions and severities of these units.

Table 7.4-6.
Comparison of Key Refinery Unit Operations by PADD between the RFS Case and Reference Case (percent)

Case	Refinery Unit Operations	PADD 1	PADD 2	PADD 3	PADD 4/5	CA
Reference Case	FCCU Conversion	73	74	74	71	75
	Continuous Reformer Severity	99	99	97	0	0
	Semi-Regen Severity	0	0	0	94	95
	Hydrocracker Conversion	80	80	85	85	85
RFS Case	FCCU Conversion	72	74	74	71	75
	Continuous Reformer Severity	100	96	97	0	0
	Semi-Regen Severity	0	0	0	93	96
	Hydrocracker Conversion	80	80	85	85	85

The refinery model maintains the same FCC unit conversion percentage for the RFS case compared to the reference case, except for PADD 1 which showed a small decrease in FCC unit conversion. For all PADDs, hydrocracker conversion percentage remains the same. Continuous reformer severity is projected to increase slightly in PADD 1 likely because of the octane loss caused by the removal of MTBE from the RFG pool which is not completely made up by the increased ethanol volume there. In PADD 2 where a lot of ethanol is being blended, reformer severity decreases significantly from 99 RON to 96 RON. Reformer severity remains the same in PADD 3. Reformer severity is projected to increase slightly in California due to an anticipated small decrease in ethanol. Finally, reformer severity is projected to decrease slightly in PADDs 4 and 5 despite the small decrease in ethanol there.

These changes in refinery unit throughputs are associated with changes in capital investments. Table 7.4-7 summarizes the projected change in capital investments between the reference case and the RFS control case. Table 7.4-7 shows that incremental to the reference case, refiners are expected to reduce their capital investments by $5.8 billion compared to business as usual. Most of the reduction occurs in PADDs 1 and 2 where large volumes of ethanol, and other gasoline blendstocks, are expected to enter the gasoline pool. Of course, this capital cost decrease is countered by the $2.3 billion in capital costs being incurred to build new ethanol plants and put into place the distribution system required to distribute the new ethanol.

Table 7.4-7.
Comparison of Capital Expenditures by PADD between the RFS Case and Reference Case (million dollars)

	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	U.S. Total
Unit	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case
Crude Tower	-228.6	0.0	0.0	0.0	0.0	-228.6
Vacuum Tower	-141.4	0.0	0.0	2.6	0.0	-138.7
Sats Gas Plant	-101.2	-13.6	-1.8	2.6	-22.7	-136.8
Unsats Gas Plant	-280.1	-225.5	-2.5	-29.5	-1.0	-538.6
FCC DeC5 Tower	17.4	-52.0	54.3	-16.6	0.0	3.1
FCC	-1426.9	-1160.4	0.0	-103.8	0.0	-2691.0
FCC Splitter	-144.2	-37.0	49.5	-6.6	0.0	-138.3
Hydrocracker	0.0	0.0	0.0	0.0	0.0	0.0
H-Oil Unit	0.0	0.0	0.0	0.0	0.0	0.0
Delayed Coker	0.0	0.0	0.4	0.0	0.0	0.4
Visbreaker	-0.1	-0.1	0.0	0.0	0.0	-0.2
Thermal Naphtha Splitter	0.0	0.0	0.0	0.0	0.0	0.0
CRU Reformer	0.0	0.0	0.0	0.0	0.0	0.0
SRU Reformer	0.0	0.0	0.0	23.9	0.0	23.9
BTX Reformer	0.0	0.0	2.4	0.0	0.0	2.4
C4 Isomerization	0.0	0.0	28.9	0.0	-60.6	-31.7
C5/C6 Isomerization	0.0	0.0	0.0	153.7	0.0	153.7
HF Alkylation	0.0	0.0	0.0	0.0	0.0	0.0
H2SO4 Alkylation	-698.3	0.0	607.5	0.0	0.0	-90.9
Dimersol	0.0	0.0	0.0	-23.3	-25.0	-48.3
Cat Poly	29.0	0.0	100.3	0.0	0.0	129.3
Isooctane	0.0	0.0	0.0	0.0	0.0	0.0
DHT - Total	1.6	0.0	217.8	32.0	11.2	262.6
DHT 2nd RCT - Total	0.0	11.0	6.1	21.1	0.0	38.2
DHT Arom Saturation	0.0	0.0	0.0	0.0	0.0	0.0
NHT - Total Fd	-39.7	0.0	0.0	69.3	0.0	29.6
CGH - Generic	-472.8	-154.5	-139.5	-70.3	0.0	-837.2
CGH - Olefin Sat'n	0.0	0.0	0.0	0.0	160.5	160.5
FCCU Fd HDT	-525.0	0.0	0.0	0.0	0.0	-525.0
LSR Splitter	0.0	-47.2	0.0	0.0	0.0	-47.2
LSR Bz Saturator	-44.7	-151.7	0.0	0.0	0.4	-196.0
Reformate Saturator	-8.2	-272.4	0.0	0.0	-47.3	-328.0
Reformate Splitter	-4.4	-142.7	0.0	0.0	-8.8	-155.9
SDA	0.0	0.0	0.0	0.0	0.0	0.0
MTBE	0.0	0.0	-175.4	0.0	0.0	-175.4
TAME	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen Plant	-109.6	2.2	-196.1	-7.4	-58.3	-369.2
Lube Unit	0.0	0.0	0.0	0.0	0.0	0.0
Sulfur Plant	-1.9	-2.8	0.0	-0.1	0.1	-4.7
Merox Jet	0.0	0.0	0.0	0.0	0.0	0.0
Merox Diesel	0.0	0.0	0.0	0.0	0.0	0.0
BTX Reformer - Tower feed	0.0	0.0	0.0	0.0	0.0	0.0
BTX Reformer - Extract feed	0.0	0.0	0.0	0.0	0.0	0.0
Total Capital Costs $MM	-4,179	-2,247	552	48	-51	-5,878

7.4.3.2 Summary of Changes in Refinery Inputs and Outputs to the EIA Case

The EIA case has some similarities to the RFS case. The MTBE is still estimated to no longer be blended into gasoline, and the former MTBE feedstocks are converted over to other low-RVP gasoline blendstocks. The annual volume of ethanol blended into gasoline, however, is almost 3 billion gallons higher. This increased volume of ethanol is expected to be spread over all the PADDs, although PADD 3 is projected to absorb the most. The much increased volume of very high octane ethanol is expected to slightly reduce the consumption of the gasoline blendstocks produced from former MTBE feedstocks. The net gasoline-equivalent volume increase by ethanol and other gasoline blendstock changes is expected to be over 100 thousand barrels per day. Table 7.4-8 contains the volumes of these gasoline blendstocks by PADD.

Table 7.4-8.
Comparison of Ethanol, MTBE, Isooctane, Isooctene, and Alkylate Volumes by PADD for the EIA Case and Reference Case (barrels per day)

Case	Gasoline Blendstock	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	USA
Reference Case	Ethanol	57,620	114,900	5,242	20,676	58,934	257,372
	MTBE	54,887	0	122,474	0	0	177,360
	Isooctane/Isooctene	200	200	200	200	200	1,000
	Gasoline-equivalent Volume	82,687	76,034	102,864	13,846	39,096	314,527
EIA Case	Ethanol	161,821	255,512	117,722	32,113	59,055	626,223
	MTBE	0	0	0	0	0	0
	Isooctane/Isooctene Alkylate from MTBE	11,042	200	200,119	200	17,010	228,571
	Gasoline-equivalent Volume	117,844	168,838	277,816	21,395	55,986	641,878
	Change in Gasoline Equivalent Volume	35,157	92,804	174,952	7,548	16,889	327,351

Table 7.4-9 summarizes the inputs into and gasoline outputs from the refinery model separate from the ethanol and converted MTBE blendstocks summarized in Table 7.4-12 above. Crude oil and vacuum gas oil and residual fuel purchases are expected to decrease about 1.7 percent averaged over all the PADDs. The refinery model also estimates that the volume of purchased gasoline components will increase incrementally over the RFS case. It seems that a likely reason for the increased gasoline blendstock volumes over purchased crude oil purchases is that the refinery model is seeking to purchase low RVP blendstocks to offset the volatility impacts of ethanol, as opposed to having to crack crude oil which produces more volatile four carbon compounds. Table 7.4-15 also shows the energy-adjusted volume of gasoline projected to be produced for both the RFS case and reference case. The national energy-adjusted gasoline production levels for EIA case is somewhat lower than the reference case which suggests that the crude oil savings described above are somewhat overstated. The refineries in PADDs 1 and 2 are projected to produce much more gasoline in the EIA case compared to the reference case, while the refineries in PADD 3 are projected to produce much less gasoline in the EIA case.

Table 7.4-9.
Summary of Refinery Model Input and Output Volumes by PADD for the EIA Case and Reference Case (barrels per day)

Case	Crude Oil and Gasoline	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	USA
Reference Case	Crude Oil	1,823,008	3,650,044	9,071,056	1,529,442	1,952,560	18,026,111
	VGO and Residual Fuel	152,467	59,552	680,329	0	27,400	919,748
	Gasoline Component Inputs	144,293	69,233	144,782	49,247	51,475	459,030
	Gasoline Volume	1,378,811	2,398,179	4,004,675	778,262	1,184,533	9,744,461
	Gasoline Energy Content	5.012	4.997	5.093	5.019	5.024	5.044
EIA Case	Crude Oil	1,667,893	3,539,369	9,058,059	1,528,255	1,952,560	17,746,134
	VGO and Residual Fuel	97,621	59,552	675,959	0	41,194	874,325
	Change in Crude oil and VGO/resid	-209,962	-110,675	-17,368	-1,188	13,794	-325,398
	Gasoline Component Inputs	208,809	69,233	166,023	49,247	62,913	556,224
	Change in Gasoline Component Inputs	64,516	0	21,240	0	11,438	97,194
	Gasoline	1,602,258	2,584,977	3,657,519	775,512	1,184,533	9,804,799
	Gasoline Energy Content	4.924	4.922	5.042	5.000	5.042	4.988
	Total Gasoline at Constant Energy	1,574,007	2,546,302	3,620,530	772,501	1,188,742	9,695,751
	Change in Total Gasoline Volume at Constant Energy	195,196	148,123	-384,145	-5,761	4,208	-48,710

The addition of ethanol, the phase out of MTBE and the reuse of former MTBE feedstocks to make other gasoline blendstocks is expected to change the capital investments that would otherwise occur if these changes were not made.

Table 7.4-10 summarizes the change in refinery unit throughputs by PADD comparing the EIA case to the reference case.

Table 7.4-10.
Change in the Refinery Unit Capacities by PADD between the EIA Case and Reference Case (thousand barrels per day)

Unit or Category	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	USA
Crude Tower	-155	-111	-13	-1	0	-280
Vacuum Tower	-63	-50	12	4	0	-97
Sats Gas Plant	-17	-20	-20	0	1	-56
Unsats Gas Plant	-37	-28	-6	-7	3	-74
FCC DeC5 Tower	-7	0	40	-6	-9	17
FCC	-130	-90	-18	-24	3	-260
FCC Splitter	-99	0	82	-12	3	-27
Hydrocracker	0	0	0	0	-7	-7
Delayed Coker	-10	-25	-7	0	3	-39
Visbreaker	3	3	1	0	-3	3
Thermal Naphtha Splitter	-1	-3	-1	0	0	-5
CRU Reformer	-15	-19	-109	0	0	-143
SRU Reformer	0	0	0	-1	-3	-4
BTX Reformer	0	0	0	0	0	0
C4 Isomerization	-13	3	0	0	-2	-12
C5/C6 Isomerization	0	-14	-93	-3	-30	-140
HF Alkylation	0	-3	1	0	0	-2
H2SO4 Alkylation	-22	0	49	-1	-5	22
Dimersol	0	0	0	-2	3	1
Cat Poly	0	0	18	0	0	19
Isooctane	0	0	0	0	0	0
DHT - Total	-24	-3	-66	16	0	-78
DHT 2nd RCT - Total	0	-15	17	15	0	17
DHT Arom Saturation	0	0	0	0	-4	-4
NHT - Total Fd	-32	-27	-145	-1	-3	-208
NHT - Isom/Thermal Fd	-17	-7	-36	0	0	-60
NHT - Reformer Fd	-15	-19	-109	-1	-3	-147
CGH - Generic	-81	-53	26	-6	0	-114
CGH - Olefin Sat'n	0	0	0	0	29	29
FCCU Fd HDT	-39	0	0	0	0	-39
LSR Splitter	-12	-32	0	0	-6	-50
LSR Bz Saturator	-6	-15	0	1	-2	-21
Reformate Saturator	-3	-24	0	0	-5	-32
SDA	-3	0	0	0	0	-3
MTBE	-5	0	-114	0	0	-119
TAME	0	0	0	0	0	0
Hydrogen Plant - Total BSCF	-34	7	4	4	-30	-49
Lube Unit	0	23	0	0	0	23
Sulfur Plant	-340	-551	-261	-4	86	-1,070
Fuel System - Fuel Oil	0	0	0	0	0	0
Fuel System - CO2 (BLb/Day)	-20	-13	-10	-2	-2	-47
Utilities - Steam (Blbs)	-25	-12	-28	-3	-7	-75
Utilities - Steam Vent (Blbs)	0	0	0	0	0	0
Utilities - Power (Mwh)	-1,029	-582	-98	40	-168	-1,837
Utilities - Cooling H2O (Bgal)	-246	-128	-256	-24	-28	-682

Most of the capacity throughput changes are negative, reflecting the decreased processing of crude oil and vacuum gas oil and decreased downstream refining units as projected by the refinery model. Of the negative throughput changes, the reduced volume of the fluidized catalytic cracker is important. As discussed above, the refinery model likely chose to decrease the fluidized catalytic cracker throughput to crack less heavy hydrocarbons to light hydrocarbons, producing less four-carbon compounds to offset the volatility impacts of ethanol. The reduction in FCC unit throughput is relatively less for the EIA case than it was for the RFS case. There are several units which show throughput capacity increases, primarily in PADD 3. PADD 3 refineries will have a substantial loss in octane because of the removal of a substantial volume of MTBE. Unlike the RFS case, however, much of the ethanol is projected to be blended into PADD 3's gasoline pool making up for the octane loss. This can be seen in Table 7.4-15 as reformer and alkylation throughputs volumes are projected to be lower for the EIA case. The refinery model added depentanizer capacity mostly in PADD 3 to enable the blending of ethanol into RFG.

Refiners can also control the gasoline production and quality by adjustments they can make to several of their refinery conversion units. Refiners can adjust the conversion of their FCC and hydrocracker units, and change the severity of their reformers. Table 7.4-11 contains the percent conversions and severities of these units.

Table 7.4-11.
Comparison of Key Refinery Unit Operations by PADD between The EIA Case and Reference Case (percent)

Case	Refinery Unit Operations	PADD 1	PADD 2	PADD 3	PADD 4/5	CA
Reference Case	FCCU Conversion	73	74	74	71	75
	Continuous Reformer Severity	99	99	97	0	0
	Semi-Regen Severity	0	0	0	94	95
	Hydrocracker Conversion	80	80	85	85	85
EIA Case	FCCU Conversion	72	74	74	71	75
	Continuous Reformer Severity	100	94	96	0	0
	Semi-Regen Severity	0	0	0	93	97
	Hydrocracker Conversion	80	80	85	85	85

The refinery model maintains the same FCC unit conversion percentage for the RFS case compared to the reference case, except for PADD 1 which showed a small decrease in FCC unit conversion. For all PADDs, hydrocracker conversion percentage remains the same. Continuous reformer severity is projected to increase slightly in PADD 1 despite the ethanol blended into that PADD's gasoline. In PADD 2 where a lot of ethanol is being blended, reformer severity decreases significantly from 99 RON to 94 RON. Reformer severity is projected to decrease slightly in PADD 3 due to the large volume of ethanol being blended into the gasoline in that PADD. Reformer severity is projected to decrease slightly in California due to an anticipated small increase in ethanol. Finally, reformer severity is projected to decrease slightly in PADDs 4 and 5 due to the increase in ethanol there.

These changes in refinery unit throughputs are associated with changes in capital investments. Table 7.4-12 summarizes the projected change in capital investments between the reference case and the EIA control case. Table 7.4-12 shows that incremental to the reference case, refiners are expected to reduce their capital investments by $7.3 billion compared to business as usual. Most of the reduction occurs in PADDs 1 and 2 where large volumes of ethanol, and other gasoline blendstocks are expected to enter the gasoline pool. Of course, this capital cost decrease is countered by the estimated $6.5 billion in capital costs incurred to build new ethanol plants and put into place the distribution system that the new ethanol requires.

Table 7.4-12.
Comparison of Capital Expenditures by PADD between the EIA Case and Reference Case (million dollars)

	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	U.S. Total
Unit	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case
Crude Tower	-453.8	0.0	0.0	0.0	0.0	-453.8
Vacuum Tower	-295.0	0.0	103.7	8.9	0.0	-182.4
Sats Gas Plant	-115.9	-13.6	-55.8	0.1	-23.4	-208.7
Unsats Gas Plant	-275.6	-261.5	-20.1	-49.6	2.5	-604.4
FCC DeC5 Tower	17.7	-58.9	50.9	-18.5	0.0	-8.8
FCC	-1426.9	-1160.4	-68.1	-331.7	0.0	-2987.1
FCC Splitter	-147.0	-48.7	46.6	-9.6	0.0	-158.7
Hydrocracker	0.0	0.0	0.0	0.0	0.0	0.0
H-Oil Unit	0.0	0.0	0.0	0.0	0.0	0.0
Delayed Coker	0.0	0.0	-185.9	0.0	0.0	-185.9
Visbreaker	7.2	6.2	0.0	0.0	0.0	13.4
Thermal Naphtha Splitter	0.0	0.0	-0.3	0.0	0.0	-0.3
CRU Reformer	0.0	0.0	0.0	0.0	0.0	0.0
SRU Reformer	0.0	0.0	0.0	-2.6	0.0	-2.6
BTX Reformer	0.0	0.0	1.8	0.0	0.0	1.8
C4 Isomerization	0.0	0.0	0.0	0.0	-60.6	-60.6
C5/C6 Isomerization	0.0	0.0	0.0	-56.6	0.0	-56.6
HF Alkylation	0.0	0.0	0.0	0.0	0.0	0.0
H2SO4 Alkylation	-715.4	0.0	497.6	0.0	0.0	-217.8
Dimersol	0.0	0.0	0.0	-17.9	7.8	-10.1
Cat Poly	4.3	0.0	114.9	0.0	0.0	119.2
Isooctane	0.0	0.0	0.0	0.0	0.0	0.0
DHT - Total	-169.8	0.0	-219.5	93.2	21.6	-274.6
DHT 2nd RCT - Total	0.0	-165.3	105.6	138.0	0.0	78.3
DHT Arom Saturation	0.0	0.0	0.0	0.0	0.0	0.0
NHT - Total Fd	-39.7	0.0	0.0	-1.9	0.0	-41.7
CGH - Generic	-471.6	-179.5	102.0	-77.1	0.0	-626.1
CGH - Olefin Sat'n	0.0	0.0	0.0	0.0	161.0	161.0
FCCU Fd HDT	-525.0	0.0	0.0	0.0	0.0	-525.0
LSR Splitter	0.0	-47.2	0.0	0.0	0.0	-47.2
LSR Bz Saturator	-44.7	-151.7	0.0	21.9	0.4	-174.0
Reformate Saturator	-19.2	-272.4	0.0	0.0	-49.9	-341.6
Reformate Splitter	-20.1	-142.7	0.0	0.0	-10.1	-172.9
SDA	0.0	0.0	0.0	0.0	0.0	0.0
MTBE	0.0	0.0	-175.4	0.0	0.0	-175.4
TAME	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen Plant	-188.5	22.9	6.6	54.2	-58.3	-163.2
Lube Unit	0.0	0.0	0.0	0.0	0.0	0.0
Sulfur Plant	-2.5	-2.8	-0.2	0.0	0.1	-5.4
Merox Jet	0.0	0.0	0.0	0.0	0.0	0.0
Merox Diesel	0.0	0.0	0.0	0.0	0.0	0.0
BTX Reformer - Tower feed	0.0	0.0	0.0	0.0	0.0	0.0
BTX Reformer - Extract feed	0.0	0.0	-0.1			
Total	-4,882	-2,476	304	-249	-9	-7,311

7.4.3.3 Adjustments to the LP Refinery Model's Cost Estimate

We made several adjustments to the costs directly estimated by the LP refinery cost model for the RFS and EIA cases which are included in the costs reported below. One adjustment made was to adjust the costs based on the ethanol prices used in the LP cost model to reflect the ethanol production costs estimated and reported above in section 7.1.1. This adjustment resulted in much lower ethanol costs to refiners because Jacobs largely based its ethanol prices on ethanol's octane costs instead of its historical price relationship to gasoline, which is much lower. We also adjusted the ethanol distribution costs from those used in the LP refinery cost study, which roughly corresponded to those used for the proposed rule cost analysis, to those estimated for the final rule as discussed above in section 7.3.1. In Table 7.4-13 we summarize the ethanol production and distribution costs used in the LP refinery cost model and those we estimated for the final rule.

Table 7.4-13
Ethanol Price and Distribution Costs used in the LP Refinery Model versus Those used for the Final Rule Cost Analysis (cents per gallon)

		Case	PADD 1	PADD 2	PADD 3	PADD 4/5 ex CA	CA
Prices used in LP Refinery Cost Model	Ethanol Price in Midwest	RFS and EIA Case	158	158	158	158	158
	Ethanol Distribution Cost	RFS and EIA Case	12	0	10	17	18
	Ethanol Price in PADD	RFS and EIA Case	170	158	168	175	176
Costs used in Final Cost Analysis	Ethanol Production Cost	RFS Case	126	126	126	126	126
		EIA Case	131	131	131	131	131
	Ethanol Distribution Cost	RFS and EIA Case	16	6.5	16	23	22
	Ethanol Cost in PADD	RFS Case	142	132.5	142	149	148
		EIA Case	147	137.5	147	154	153

Another adjustment we made to the costs directly estimated by the LP refinery cost model was to add a cost for distributing gasoline. The refinery cost model did not include distribution costs for gasoline for moving the gasoline from the refinery to the terminal. We assigned gasoline distribution costs to be 4 cents per gallon applied as a cost savings to the gasoline-equivalent volume of ethanol blended into each PADD's gasoline, since this roughly corresponded to the volume of gasoline displaced by the ethanol.

7.4.3.4 Estimated Costs

7.4.3.4.1 Estimated Costs for the RFS Case

Table 7.4-14 summarizes the costs for the RFS case excluding federal and state ethanol consumption subsidies. The costs are reported by different cost component as well as aggregated total and the per-gallon costs.[99] This estimate of costs reflects the changes in gasoline that are occurring with the expanded use of ethanol, including the corresponding removal of MTBE and reuse of MTBE feedstocks. The operating costs include the labor, utility and other operating costs and are a direct output from the refinery model. These costs are adjusted to reflect ethanol's production cost plus distribution costs instead of the ethanol prices used in the refinery cost model. The fixed costs are 3 percent of the capital costs. The costs associated with lower energy density gasoline are accounted for using the fractional change in energy density shown in Table 7.4-4, multiplied times the wholesale price of gasoline. By excluding the federal and state ethanol consumption subsidies in the table, we avoid the transfer payments caused by these subsidies that would hide a portion of the program's costs.

Table 7.4-14.
Summary of RFS Case Costs without Ethanol Consumption Subsidies
(million dollars per year and c/gal, except as noted; 2004 dollars, 7% ROI before taxes)

	RFS Case 6.7 Billion Gals Incremental to Reference Case
Capital Costs ($MM)	**-5,878**
Amortized Capital Costs ($MM/yr)	-647
Fixed Operating Cost ($MM/yr)	-178
Variable Operating Cost ($MM/yr)	-201
Lower Energy Density Gasoline ($MM/yr)	1,848
Total Cost ($MM/yr)	**823**
Capital Costs (c/gal)	-0.40
Fixed Operating Cost (c/gal)	-0.11
Variable Operating Cost (c/gal)	-0.12
Lower Energy Density Gasoline (c/gal)	1.13
Total Cost Excluding Subsidies (c/gal)	**0.50**

[99] EPA typically assesses social benefits and costs of a rulemaking. However, this analysis is more limited in its scope by examining the average cost of production of ethanol and gasoline without accounting for the effects of farm subsidies that tend to distort the market price of agricultural commodities.

Our analysis shows that when considering all the costs associated with these fuel changes resulting from the expanded use of ethanol that these various possible gasoline use scenarios will cost the U.S. $820 million in the year 2012. Expressed as per-gallon costs, these fuel changes would cost the U.S. 0.50 cent per gallon of gasoline.

Table 7.4-15 expresses the total and per-gallon gasoline costs for the RFS case with the federal and state ethanol subsidies included. The federal tax subsidy is 51 cents per gallon for each gallon of new ethanol blended into gasoline. The state tax subsidies apply in 5 states and range from 1.6 to 29 cents per gallon. The cost reduction to the fuel industry and consumers are estimated by multiplying the subsidy times the volume of new ethanol estimated to be used in the state.

Table 7.4-15.
Estimated RFS Case Cost including Ethanol Consumption Subsidies
(million dollars per year and cents per gallon; 2004 dollars, 7% ROI before taxes)

	RFS Case 6.7 Billion Gals Incremental to Reference Case
Total Cost ($MM/yr)	823
Federal Subsidy ($MM/yr)	-1376
State Subsidies ($MM/yr)	-5
Revised Total Cost ($MM/yr)	**-558**
Per-Gallon Cost Excluding Subsidies (c/gal)	0.50
Federal Subsidy (c/gal)	-0.84
State Subsidies (c/gal)	-0.003
Total Cost Including Subsidies (c/gal)	**-0.34**

The cost including subsidies better represents gasoline's production cost as might be reflected to the fuel industry as a whole and to consumers "at the pump" because the federal and state subsidies tends to hide a portion of the actual costs. Our analysis estimates that the fuel industry and consumers will see a 0.34 cent per gallon decrease in the apparent cost of producing gasoline for the RFS case.

7.4.3.4.2 Estimated Costs for the EIA Case

Table 7.4-16 summarizes the costs for the EIA case. The costs in this table exclude federal and state ethanol consumption subsidies. The costs are reported by different cost components as well as the aggregated total and the per-gallon costs. This estimate of costs reflects the changes in gasoline that are occurring with the much expanded use of ethanol, including the removal of MTBE and reuse of MTBE feedstocks. The operating costs include the labor, utility and other operating costs and are a direct output from the refinery model, adjusted for ethanol's production cost at this higher volume including ethanol distribution costs. The fixed costs are 3 percent of the capital costs. The costs associated with lower energy density gasoline, as shown in Table 7.4-9, are estimated by the fractional change in energy content times the wholesale price of gasoline. The increment of the EIA case to the RFS case indicates the economic impact of the additional volume of ethanol between the two cases.

Table 7.4-16.
Summary of EIA Case Costs without Ethanol Consumption Subsidies
(million dollars per year and c/gal, except as noted; 2004 dollars, 7% ROI before taxes)

	EIA Case 9.6 Billion Gals Incremental to Reference Case	EIA Case 9.6 Billion Gals Incremental to RFS Case
Capital Costs ($MM)	**-7,311**	**-1,433**
Amortized Capital Costs ($MM/yr)	-804	-158
Fixed Operating Cost ($MM/yr)	-222	-43
Variable Operating Cost ($MM/yr)	-491	-290
Lower Energy Density Gasoline ($MM/yr)	3,255	1407
Total Cost ($MM/yr)	**1739**	**915**
Capital Costs (c/gal)	-0.49	-0.10
Fixed Operating Cost (c/gal)	-0.14	-0.03
Variable Operating Cost (c/gal)	-0.30	-0.18
Lower Energy Density Gasoline (c/gal)	1.98	0.86
Total Cost Excluding Subsidies (c/gal)	**1.06**	**0.56**

Our analysis shows that when considering all the costs associated with these fuel changes resulting from the expanded use of subsidized ethanol that these various possible gasoline use scenarios will cost the U.S. $1,740 million in the year 2012 for the EIA case. Expressed as per-gallon costs, these fuel changes would cost the U.S. about 1.1 cents per gallon of gasoline. The incremental volume of ethanol added between the RFS and EIA cases is expected to cost $915 million in the year 2012, resulting in a 0.56 cent per gallon cost.

Table 7.4-17 expresses the total and per-gallon gasoline costs for the EIA case with the federal and state ethanol subsidies included. The federal tax subsidy is 51 cents per gallon for each gallon of new ethanol blended into gasoline. The state tax subsidies apply in 5 states and range from 1.6 to 29 cents per gallon. The cost reduction to the fuel industry and consumers are estimated by multiplying the subsidy times the volume of new ethanol estimated to be used in the state.

Table 7.4-17.
Estimated EIA Case Cost including Ethanol Consumption Subsidies
(million dollars per year and cents per gallon; 2004 dollars, 7% ROI before taxes)

	EIA Case 9.6 Billion Gals Incremental to Reference Case	EIA Case 9.6 Billion Gals Incremental to RFS Case
Total Cost ($MM/yr)	1739	915
Federal Subsidy ($MM/yr)	-2865	-1489
State Subsidies ($MM/yr)	-31	-26
Revised Total Cost ($MM/yr)	**-1158**	**-600**
Per-Gallon Cost Excluding Subsidies (c/gal)	1.06	0.56
Federal Subsidy (c/gal)	-1.74	-0.90
State Subsidies (c/gal)	-0.02	-0.02
Total Cost Including Subsidies (c/gal)	**-0.71**	**-0.37**

The cost including subsidies better represents gasoline's production cost as might be reflected to the fuel industry as a whole and to consumers "at the pump" because the federal and state subsidies tends to hide a portion of the actual costs. Our analysis estimates that the fuel industry and consumers will see a 0.71 cent per gallon decrease in the apparent cost of producing gasoline for the EIA case. Incremental to the RFS case, the consumer would be expected to see a 0.37 cent per gallon price decrease "at the pump."

7.4.3.4.3 Sensitivity Cost Analyses for the RFS and EIA Cases

In Table 7.1-5 above, we presented various corn-ethanol production cost estimates based on varying corn and dried distillers grain prices. We entered a range of low and high production ethanol cost estimates from that table into our cost spreadsheet created from the output from the LP refinery cost modeling. The range of ethanol production costs that we chose represents a reasonable bound around the possible range of future ethanol production costs. This allowed us to estimate the cost of using ethanol at these other possible ethanol production costs at the ethanol volumes analyzed for the RFS and EIA cases. We present these costs in Table 7.4-18. We did not conduct sensitivity analyses around higher or lower crude oil prices.[100]

[100] This sensitivity analysis conducted at lower and higher ethanol production costs can also be used as a surrogate for a sensitivity analysis of higher and lower crude oil prices. Analyzing a lower ethanol cost is similar to analyzing a higher crude oil price with ethanol production costs at the levels we analyzed them at which was 126 and 131 cents per gallon, and vice versa for our sensitivity analysis at the higher ethanol production cost.

Table 7.4-18.
Summary of the Sensitivity Cost Analysis at Higher and Lower Ethanol Production Costs (Costs in 2012, 2004 dollars, 7% ROI before taxes)

Ethanol Production Cost		Units	Costs RFS Case	Costs EIA Case
0.86	Cost without Subsidies	$MM/yr	-260	-846
		c/gal	-0.16	-0.52
	Cost with Subsidies	$MM/yr	-1640	-3740
		c/gal	-1.00	-2.28
2.04	Cost without Subsidies	$MM/yr	2930	5784
		c/gal	1.79	3.53
	Cost with Subsidies	$MM/yr	1546	2890
		c/gal	0.95	1.76

7.4.4 Impact on Diesel Prices

Biodiesel fuel is added to highway and nonroad diesel fuel, which increases the volume and therefore the supply of diesel fuel and thereby reduces the demand for refinery-produced diesel fuel. In this section, we estimate the overall cost impact, considering how much refinery based diesel fuel is displaced by the forecasted production volume of biodiesel fuel. The cost impacts are evaluated considering the production cost of biodiesel with and without the subsidy from the Biodiesel Blenders Tax credit program. Additionally, the diesel cost impacts are quantified with refinery diesel prices as forecasted by Jacobs's which are based on EIA's AEO 2006.

We estimate the net effect that biodiesel production has on overall cost for diesel fuel in year 2012 using total production costs for biodiesel and diesel fuel. The costs are evaluated based on how much refinery based diesel fuel is displaced by the biodiesel volumes as forecasted by EIA, accounting for energy density differences between the fuels. The cost impact is estimated from a 2012 year basis, by multiplying the production costs of each fuel by the respective changes in volumes for biodiesel and estimated displaced diesel fuel. We further assume that all of the forecasted bio-diesel fuel volume is used as transport fuel, neglecting minor uses in the heating oil market.

For this analysis, the production costs for biodiesel fuel are based on the costs generated using the USDA, NREL, EIA and the design vendors estimates in the preceding sections. We average these results to developed costs for soy oil and yellow grease feedstocks. Additionally, the production costs are based on EIA's projection in 2012 that half of the total biodiesel volume will be made from soy oil feedstock with the remaining volume being produced from yellow grease. To these estimates, we add distribution costs of 21.5 c/gal to the biodiesel production costs, reflecting the distribution estimates derived in section 7.3.2. For the refinery diesel production costs in 2012, we used the projected wholesale national average diesel price of 160 c/gal projected by the Jacobs' pricing forecast. Distribution costs of 4 c/gal were added to the Jacobs's wholesale diesel price projection, to account for the additional costs to move diesel fuel from the wholesale market to end use terminals.

Our estimate for the reduction in refinery produced diesel fuel is based on EIA's forecast for approximately 300 MM gallons of biodiesel in 2012, along with the 2012 Reference Case year biodiesel production volume of 28 MM gallons. With this and accounting for differences in energy density between biodiesel and diesel fuel, we estimate in 2012 that the additional biodiesel production reduces the need for 250 MM gallons of refinery produced diesel fuel. Table 7.4-19 contains the energy densities used in this analysis.

Table 7.4-19.
Energy Content of Fuels per Gallon

Fuel	Lower Heating Value (BTU/gallon)
Biodiesel	117,093
Refinery Produced Diesel	128,700

For all RFS case scenarios, the net effect of biodiesel production on diesel fuel costs, including the biodiesel blenders' subsidy, is a reduction in the cost of transport diesel fuel costs by $114 MM per year, which equates to a fuel cost reduction of about 0.20 c/gal[101]. Without the subsidy, the transport diesel fuel costs are increased by $91 MM per year, or an increase of 0.16 c/gal.

7.5 Other Potential Economic Impacts

Ideally, we would prefer to assess all economic and environmental impacts of increased ethanol use and decreased fossil fuel use in a holistic manner. Such an analysis is beyond the scope of this RIA. However, we can approximate some of the impacts of increased ethanol production and use, and we can discuss other impacts qualitatively. The preceding discussion quantifies the impact of expanded use of renewable fuels on the cost of gasoline and diesel fuel. It does so by quantifying the direct costs of ethanol production, as well as the direct costs of state and federal tax subsidies for the renewable fuels, which are financed through tax payments. There are many other economic impacts associated with the use of renewable fuels and the fossil fuels they replace which go well beyond the scope of the analysis conducted for the RIA. We have not attempted to quantify all of them here. For example, increased renewable fuel production and use may have adverse impacts on surface and ground water quality and soil erosion, while decreased fossil fuel, distribution and use may have positive impacts. To quantify the economic impact associated with this would require extensive analysis of the likely responses of farmers to the increased demand for renewable fuels, the cost of actions taken to remedy the impacts, and the cost of any resulting health and welfare impacts.

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[101] Based on EIA's AEO 2006, the total volume of highway and off-road diesel fuel consumed in 2012 was estimated at 58.9 billion gallons.

Furthermore, the renewable fuel production costs assumed in our analysis do not reflect the entire cost to society associated with the production of the corn and soybean feedstocks used in their production due other state and federal agricultural policies. Direct payments, counter-cyclical payments, marketing loans, and subsidized crop insurance are all examples of policies outside of this rulemaking that impact the price of corn and soybeans that are not reflected in the production cost for ethanol and biodiesel, but do impact costs borne by consumers indirectly through taxes. Quantifying the incremental impacts of this rulemaking on the effects of these pre-existing programs would represent a significant challenge. However, the challenge is complicated even more by the direct and indirect economic support provided for the production, supply, and distribution of the fossil fuels which would be replaced by these renewable fuels. Again, any assessment of the overall costs to society for increase renewable use would have to look at the economic support provided across the entire fuel supply. Such an analysis is well beyond the scope of this RIA.

Despite our inability to fully capture all the potential impacts on the cost to society of increased renewable fuel use, two potential impacts were touched on briefly in our analysis, and these are discussed in this subsection.

Economic Impacts of Emission Changes

As discussed in Chapters 4.1 and 5.1, we estimate that there may be an increase in emissions and a corresponding small increase in ozone resulting from the expanded use of renewable fuels. Our vehicle and equipment emission estimates are highly uncertain, however, given the lack of data in particular on vehicles and engines complying with the latest standards. However, to the extent that there are emission and ozone increases resulting from the expanded use of renewable fuels, there can be a cost associated with them. In some cases, areas that see an increase in emissions resulting from renewable fuel use may be forced to take other actions to offset these emission increases. In other cases, particularly in attainment areas, the impact, while not affecting attainment, may adversely impact air quality and human health. It is difficult to provide any quantitative estimate of what the mitigation costs might be to offset emission increases, or to quantify the health impacts resulting from the air quality impacts. Not only are the emission and air quality impacts highly uncertain, but they are also very location dependent. While we have made projections on where the ethanol use may rise or fall for the purposes of estimating nationwide fuel cost impacts and potential emissions impacts, these projections are much less reliable when trying to predict specific local air quality impacts.

Despite all of the above caveats, we have attempted to provide a rough estimate of the potential national-level cost impacts; As a surrogate for additional emission control costs in nonattainment areas and potential health impacts in attainment areas, we looked at the potential health costs associated with the secondary nitrate PM resulting from the decreases in NOx emissions estimated in previous EPA rules. We note again that we actually expect an overall decrease in ambient $PM_{2.5}$ formation due to the increased use of ethanol in fuel (See Chapter 5.2).[102] Thus, we expect most areas to have lower health impact costs and certainly lower abatement costs related to PM control.

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[102] Overall, we expect that the decrease in secondary organic PM is likely to exceed the increase in secondary nitrate PM. In 2006, NO_x emissions from gasoline-fueled vehicles and equipment comprise about 37% of national NO_x

In recent rulemakings we monetized PM emission impacts, including those resulting from changes in secondarily formed $PM_{2.5}$ due to NOx emission changes. Using this information as a guide, we provide a screening-level estimate of the monetized PM-related health impacts associated with an increase in NOx emissions associated with the final rule. For this analysis, we derived a dollar-per-ton value based on recent benefits modeling conducted for the Clean Air Nonroad Diesel Rule (CAND).[ZZZZZ] This value ($8,000 in PM-related monetized health impacts per ton of NOx reduced) is based on air quality modeling conducted in 2004 for the CAND rule. This benefits transfer method is consistent with approaches used in other recent mobile and stationary source rules.[103] We refer the reader to the final CAND RIA for more details on this benefits transfer approach. The dollar-per-ton value represents monetized health impacts in 2015 (in year 2000 dollars).

We combined the dollar-per-ton estimate of monetized health effects with the projected 2015 emission changes presented in Table 4.4-1, which includes emissions from gasoline vehicles and equipment and renewable fuel production and distribution. We estimate that the potential $PM_{2.5}$-related monetized impact associated with NOx emissions from increased use of ethanol to be up to $290 million for the RFS control scenario, and up to $340 million for the EIA control scenario. Note that this impact is based on monetized changes in health effects, including changes in mortality risk, chronic bronchitis, nonfatal heart attacks, respiratory hospital admissions, asthma attacks, and other minor health endpoints. It is also important to point out that this value does not represent the cumulative monetized health impacts associated with the potential PM changes associated with the future use of ethanol described above.

This estimate is subject to a number of additional caveats. The dollar-per-ton values reflect specific geographic patterns of emissions reductions and specific air quality and benefits modeling assumptions which are derived from previous analyses and will not match those associated with increased ethanol use in fuel for two reasons. One, the geographical distribution of the emission sources affected by increased ethanol use differs from that addressed in the CAND rulemaking. Two, the CAND rule was national in scope and the emission reductions were spread out across the entire nation. Increased ethanol use will be very geographically focused. Many major population centers will not experience an increase in ethanol use as their fuel already contains ethanol. Care should be taken when applying these estimates to emission reductions that occur in any specific location, since the dollars-per-ton for emission reductions in specific locations may be very different than the national average. Given these caveats and the

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emissions from mobile sources. In contrast, gasoline-fueled vehicles and equipment comprise almost 90% of national gaseous aromatic VOC mobile source emissions. The percentage increase in national NO_x emissions due to increased ethanol use should be smaller than the percentage decrease in national emissions of gaseous aromatics. Finally, in most urban areas, ambient levels of secondary organic PM exceed those of secondary nitrate PM. Thus, directionally, we expect a net reduction in ambient PM levels due to increased ethanol use. However, we are unable to quantify this reduction at this time.

[103] See: Clean Air Nonroad Diesel final rule (69 FR 38958, June 29, 2004); Nonroad Large Spark-Ignition Engines and Recreational Engines standards (67 FR 68241, November 8, 2002); Final Industrial Boilers and Process Heaters NESHAP (69 FR 55217, September 13, 2004); Final Reciprocating Internal Combustion Engines NESHAP (69 FR 33473, June 15, 2004); Final Clean Air Visibility Rule (EPA-452/R-05-004, June 15, 2005); Ozone Implementation Rule (70 FR 71611, November 29, 2005).

potential decrease in ambient $PM_{2.5}$ due to the decrease in aromatic fuel content, we can not say for certain in which direction the total monetized PM-related health impact will be. In reality there may be an overall reduction in PM-related health costs, despite the increase due to increased NOx emissions.