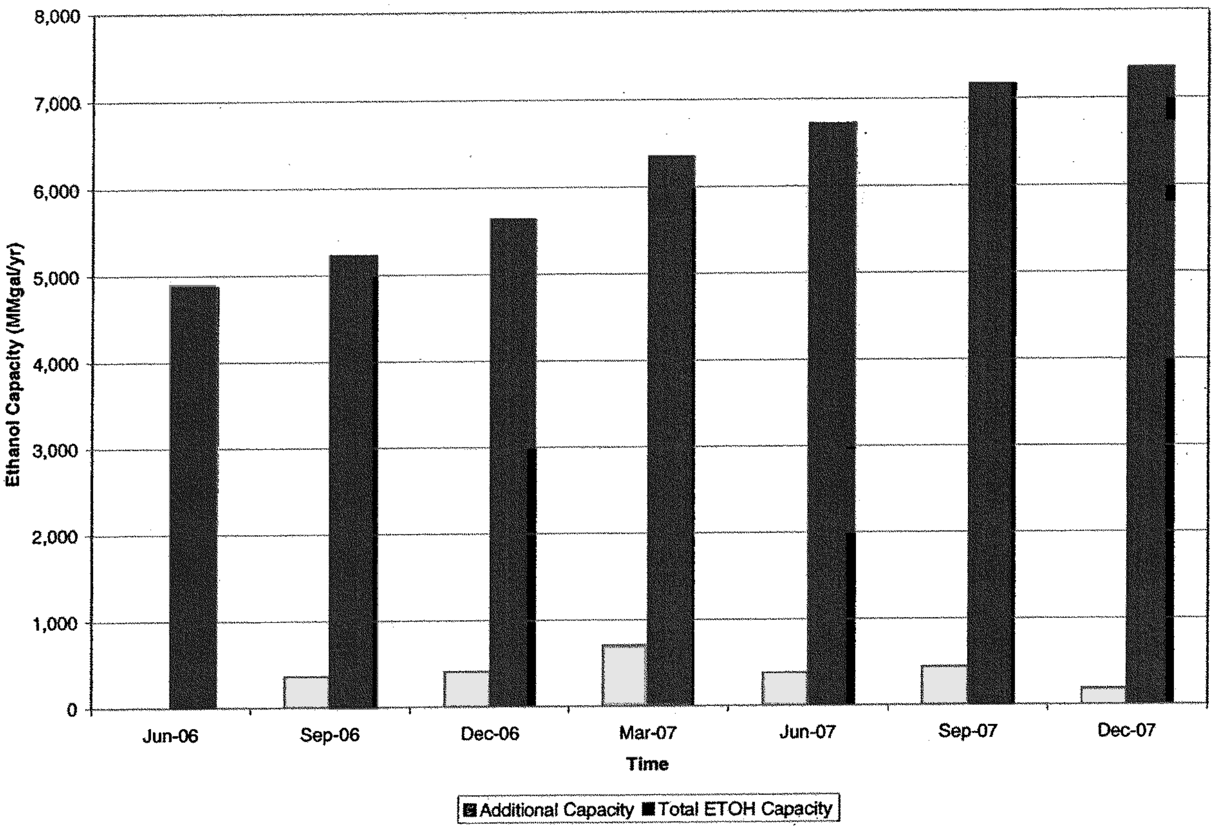
TABLE VI.A.2–1.—UNDER CONSTRUCTION U.S. ETHANOL PLANT CAPACITY—Continued

	2006 ETOH baseline		New construction		Plant expansions		2006 baseline + UC[a]	
	MMGal/yr	Plants	MMGal/yr	Plants	MMGal/yr	Plants	MMGal/yr	Plants
Total	4,872	102	2,218	39	259	9	7,349	141

[a] Under Construction.

A select group of builders, technology providers, and construction contractors are completing the majority of the construction projects described in Table VI.A.2–1. As such, the completion dates of these projects are staggered over approximately 18 months, resulting in the gradual phase-in of ethanol production shown in Figure VI.A.2–2.

Figure VI.A.2-2
Estimated Phase-In of Under Construction U.S. Plant Capacity



Source: April 6, 2006 Biofuels Journal: Ethanol Plants Under Construction in the United States and Canada (supplemented by ethanol producer website information)

As shown in Table VI.A.2–1 and Figure VI.A.2–2, once all the construction projects currently underway are complete (estimated by December 2007), the resulting U.S. ethanol production capacity would be over 7.3 billion gallons. Together with estimated biodiesel production (300 million gallons by 2012), this would be more than enough renewable fuel to satisfy the 2012 renewable fuel requirement (7.5 billion gallons) contained in the Act. However, ethanol production is not expected to stop here. There are more and more ethanol projects being announced each day. Many of these potential projects are at various stages of planning, such as conducting feasibility studies, gaining city/county approval, applying for permits, applying for financing/fundraising, or obtaining contractor agreements. Other projects have been proposed or announced, but have not entered the formal planning process. If all these plants were to come to fruition, the combined domestic ethanol production could exceed 20 billion gallons as shown in Table VI.A.2–2.

TABLE VI.A.2–2.—POTENTIAL U.S. ETHANOL PRODUCTION PROJECTS

	2006 baseline + UC[a]		Planned		Proposed		Total ETOH potential	
	MMGal/yr	Plants	MMGal/yr	Plants	MMGal/yr	Plants	MMGal/yr	Plants
PADD 1	0.4	1	250	3	1,005	21	1,255	25
PADD 2	7,010	128	1,940	15	7,508	90	16,458	233
PADD 3	60	2	108	1	599	9	767	12
PADD 4	155	5	0	0	815	14	970	19
PADD 5	124	5	128	2	676	18	928	25
Total	7,349	141	2,426	21	10,603	152	20,378	314

[a] Under Construction.

However, although there is clearly a great potential for growth in ethanol production, it is unlikely that all the announced projects would actually reach completion in a reasonable amount of time. There is no precise way to know exactly which plants would come to fruition in the future; however, we've chosen to focus our further discussions on only those plants which are under construction or in the final planning stages (denoted as ''planned'' above in Table VI.A.2–2). The distinction between ''planned'' versus ''proposed'' is that as of June 2006 planned projects had completed permitting, fundraising/financing, and had builders assigned with definitive construction timelines whereas proposed projects did not.

As shown in Table VI.A.2–2, once all the under construction and planned projects are complete (by 2012 or sooner), the resulting U.S. ethanol production capacity would be 9.8 billion gallons, exceeding the 2012 EIA demand estimate (9.6 billion gallons). This forecasted growth would double today's production capacity and greatly exceed the 2012 renewable fuel requirement (7.5 billion gallons). In addition, domestic ethanol production would be supplemented by imports, which are also expected to increase in the future (as discussed in DRIA Section 1.5).

Of the 60 forecasted new ethanol plants (39 under construction and 21 planned), all would (at least initially) rely on grain-based feedstocks. Of the plants, 56 would rely exclusively on corn as a feedstock. As for the remaining plants: Two would rely on both corn and milo, one would process molasses and sweet sorghum, and the last would start off processing corn and then transition into processing bagasse, rice hulls, and wood.

Under the Energy Act, the RFS program requires that 250 million gallons of the renewable fuel consumed in 2013 and beyond meet the definition of cellulosic biomass ethanol. As discussed in Section III.B.1, the Act defines cellulosic biomass ethanol as ethanol derived from any lignocellulosic or hemicellulosic matter that is available on a renewable or recurring basis including dedicated energy crops and trees, wood and wood residues, plants, grasses, agricultural residues, fibers, animal wastes and other waste materials, and municipal solid waste. The term also includes any ethanol produced in facilities where animal or other waste materials are digested or otherwise used to displace 90 percent of more of the fossil fuel normally used in the production of ethanol.

Of the 60 forecasted plants, only one is expected to meet the definition of ''cellulosic biomass ethanol'' based on feedstocks. The planned 108 MMgal/yr facility would start off processing corn and then transition into processing bagasse, rice hulls, and wood (cellulosic feedstocks). It is unclear as to whether this facility would be processing cellulosic material by 2013, however there are several other facilities that could potentially meet the Act's definition of cellulosic ethanol based on plant energy sources. In total, there are seven ethanol plants that burn or plan to burn renewable feedstocks to generate steam for their processes. As shown in Table VI.A.1–2, two existing plants burn renewable feedstocks. One plant burns a combination of coal and biomass and the other burns syrup from the production process. Together these existing plants have a combined ethanol production capacity of 99 MMgal/yr. Additionally, there are four under construction ethanol plants which plan to burn renewable fuels. One plant plans to burn a combination of coal and biomass, two plants plan to rely on manure/syngas, and the other plans to start up burning natural gas and then transition to biomass. Together these under construction facilities have a combined ethanol production capacity of 87 MMgal/yr. Finally, a planned 275 MMgal/yr ethanol production facility plans to burn a combination of coal, tires, and biomass. Depending on how much fossil fuel is displaced by these renewable feedstocks (on a plant-by-plant basis), a portion or all of the aforementioned ethanol production (up to 461 MMgal/yr) could potentially qualify as ''cellulosic biomass ethanol'' under the Act. Combined with the 108 MMgal/yr plant planning to process renewable feedstocks, the total cellulosic potential could be as high as 569 MMgal/yr in 2013. Even if only half of this ethanol were to end up qualifying as cellulosic biomass ethanol, it would still be more than enough to satisfy the Act's cellulosic requirement (250 million gallons).[41]

3. Current Ethanol and MTBE Consumption

To understand the impact of the increased ethanol production/use on gasoline properties and in turn overall air quality, we first need to gain a better understanding of where ethanol is used today and how the picture is going to change in the future. As such, in addition to the production analysis presented above, we have completed a parallel consumption analysis comparing current ethanol consumption to future predictions.

In the 2004 base case, 3.5 billion gallons of ethanol[42] and 1.9 billion gallons of MTBE[43] were blended into gasoline to supply the transportation sector with a total of 136 billion gallons of gasoline.[44] A breakdown of the 2004 gasoline and oxygenate consumption by PADD is found below in Table VI. A.3–1.

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[41] We anticipate a ramp-up in cellulosic ethanol production in the years to come so that capacity exists to satisfy the 2013 Act's requirement (250 million gallons of cellulosic biomass ethanol). Therefore, for subsequent analysis purposes, we have assumed that 250 million gallons of ethanol would come from cellulosic biomass sources by 2012.

[42] EIA Monthly Energy Review, June 2006 (Table 10.1: Renewable Energy Consumption by Source, Appendix A: Thermal Conversion Factors).

[43] File containing historical RFG MTBE usage obtained from EIA representative on March 9, 2006.

[44] EIA 2004 Petroleum Marketing Annually (Table 48: Prime Supplier Sales Volumes of Motor

TABLE VI.A.3–1.—2004 U.S. GASOLINE & OXYGENATE CONSUMPTION BY PADD

PADD	Gasoline MMgal	Ethanol		MTBE [a]	
		MMgal	Percent	MMgal	Percent
PADD 1	49,193	660	1.34	1,360	2.76
PADD 2	38,789	1,616	4.17	1	0.00
PADD 3	20,615	79	0.38	498	2.42
PADD 4	4,542	83	1.83	0	0.00
PADD 5 [b]	7,918	209	2.63	19	0.23
California	14,836	853	5.75	0	0.00
Total	135,893	3,500	2.58	1,878	1.38

[a] MTBE blended into RFG.

[b] PADD 5 excluding California.

As shown above, nearly half (or about 45 percent) of the ethanol was consumed in PADD 2 gasoline, not surprisingly, where the majority of ethanol was produced. The next highest region of use was the State of California which accounted for about 25 percent of domestic ethanol consumption. This is reasonable because California alone accounts for over 10 percent of the nation's total gasoline consumption and all the fuel (both Federal RFG and California Phase 3 RFG) has been assumed to contain ethanol (following their recent MTBE ban) at 5.7 volume percent.[45] The bulk of the remaining ethanol was used in reformulated gasoline (RFG) and winter oxy-fuel areas requiring oxygenated gasoline. Overall, 62 percent of ethanol was used in RFG, 33 percent was used in CG, and 5 percent was used in winter oxy-fuel.[46]

As shown above in Table VI.A.3–1, 99 percent of MTBE use occurred in PADDs 1 and 3. This reflects the high concentration of RFG areas in the northeast (PADD 1) and the local production of MTBE in the gulf coast (PADD 3). PADD 1 receives a large portion of its gasoline from PADD 3 refineries who either produce the fossil-fuel based oxygenate or are closely affiliated with MTBE-producing petrochemical facilities in the area. Overall, 100 percent of MTBE in 2004 was assumed to be used in reformulated gasoline.[47]

In 2004, total ethanol use exceeded MTBE use. Ethanol's lead oxygenate role is relatively new, however the trend has been a work in progress over the past few years. From 2001 to 2004, ethanol consumption more than doubled (from 1.7 to 3.5 billion gallons), while MTBE use (in RFG) was virtually cut in half (from 3.7 to 1.9 billion gallons). A plot of oxygenate use over the past decade is provided below in Figure VI.A.3–1.

The nation's transition to ethanol is linked to states'' responses to recent environmental concerns surrounding MTBE groundwater contamination. Resulting concerns over drinking water quality have prompted several states to significantly restrict or completely ban MTBE use in gasoline. At the time of this analysis, 19 states had adopted MTBE bans. A list of the states with MTBE bans is provided in DRIA Table 2.1–4.

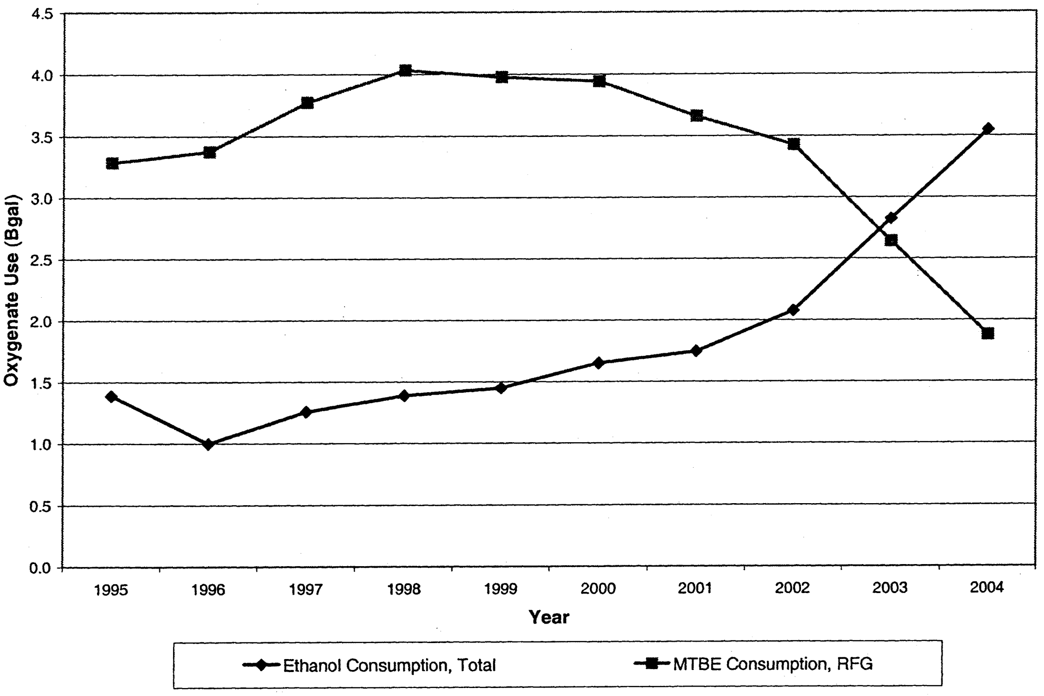
Gasoline by Grade, Formulation, PAD District, and State).

[45] Based on conversation with Dean Simeroth at California Air Resources Board (CARB).

[46] For the purpose of this analysis, except where noted, the term pertains to Federal RFG plus California Phase 3 RFG (CaRFG3) and Arizona Clean Burning Gasoline (CBG).

[47] 2004 MTBE consumption was obtained from EIA. The data received was limited to states with RFG programs, thus MTBE use was assumed to be limited to RFG areas for the purpose of this analysis.

Figure VI.A.3-1
U.S. Oxygenate Use Over Time



Source: Energy Information Administration[48]

4. Expected Growth in Ethanol Consumption

As mentioned above, ethanol demand is expected to increase well beyond the levels contained in the renewable fuels standard (RFS) under the Act. With the removal of the oxygenate mandate for reformulated gasoline (RFG),[49] all U.S. refiners are expected to eliminate the use of MTBE in gasoline as soon as possible. In order to accomplish this transition quickly (by 2006 or 2007 at the latest) while maintaining gasoline volume, octane, and mobile source air toxics emission performance standards, refiners are electing to blend ethanol into virtually all of their RFG.[50] This has caused a dramatic increase in demand for ethanol which, in 2006 is being met by temporarily shifting large volumes of ethanol out of conventional gasoline and into RFG areas. By 2012, however, ethanol production will have grown to accommodate the removal of MTBE without the need for such a shift from conventional gasoline. More important than the removal of MTBE over the long term, however, is the impact that the dramatic rise in the price of crude oil is having on demand for renewable fuels, both ethanol and biodiesel. This has dramatically improved the economics for renewable fuel use, leading to a surge in demand that is expected to continue. In the Annual Energy Outlook (AEO) 2006, EIA forecasted that by 2012, total ethanol use (corn, cellulosic, and imports) would be about 9.6 billion gallons[51] and biodiesel use would be about 0.3 billion gallons at a crude oil price forecast of $47 per barrel. This ethanol projection was not based on what amount the market would demand (which could be higher), but rather on the amount that could be produced by 2012. Others are making similar predictions, and as discussed above in VI.A.2, production capacity would be sufficient. Therefore, in assessing the impacts of expanded use of renewable fuels, we have chosen to evaluate two different future ethanol consumption levels, one reflecting the statutory required minimum, and one reflecting the higher levels projected by EIA. For the statutory consumption scenario we assumed 7.2 billion gallons of ethanol (0.25 of which was assumed to be cellulosic) and 0.3 billion gallons of biodiesel. For the higher projected renewable fuel consumption scenario, we assumed 9.6 billion gallons of ethanol (0.25 of which is once again assumed to be cellulosic) and 0.3 billion gallons of biodiesel. Although the actual renewable fuel volumes consumed in 2012 may differ from both the required and projected volumes, we believe that these two scenarios provide a reasonable range for analysis purposes.[52]

In addition to modeling two different future 2012 ethanol consumption levels, two scenarios were considered based on how refineries could potentially respond to the recent removal of the RFG oxygenate mandate. In both cases, the impacted RFG areas did not change

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[48] Total ethanol use based on EIA Monthly Energy Review, June 2006 (Table 10.1: Renewable Energy Consumption by Source, Appendix A: Thermal Conversion Factors). MTBE use in RFG also provided by EIA (file received from EIA representative on March 9, 2006). Reported 2004 MTBE use has been adjusted from 2.0 to 1.9 Bgal based on assumption of timely implementation of CA, CT, and NY MTBE bans on 1/1/04 (EIA reported a slight delay and thus showed small amounts of MTBE use in these states in 2004).

[49] Energy Act Section 1504, promulgated on May 8, 2006 at 71 FR 26691.

[50] Based on discussions with the refining industry.

[51] AEO 2006 Table 17 Renewable Energy Consumption by Sector and Source shows 0.80 quadrillion BTUs of energy coming from ethanol in 2012. A parallel spreadsheet provided to EPA shows 2012 total ethanol use as 628.7 thousand bbls/day (which works out to be 9.64 billion gallons/yr).

[52] As a comparison point for cost and emissions analyses, a 2012 reference case of 3.9 billion gallons of ethanol was also considered. The reference case is described in Section II.A.1 (above) and a complete derivation is contained in DRIA Section 2.1.3.

from the 2004 base case.[53] In the maximum scenario (''max-RFG''), refineries would continue to add oxygenate (ethanol) into all batches of reformulated gasoline. In this case, refineries currently blending MTBE (at 11 volume percent) would be expected to replace it with ethanol (at 10 volume percent). In the minimum scenario (''min-RFG''), we predict some refineries would respond by using less (or even zero) ethanol in RFG based on the minimum amount needed to meet volume, octane, and/or total toxics performance requirements. Applying the max-RFG and min-RFG criteria resulted in a total of four different 2012 ethanol consumption control cases:

1. 7.2 billion gallons of ethanol, maximum amount used in RFG areas;
2. 7.2 billion gallons of ethanol, minimum amount used in RFG areas;
3. 9.6 billion gallons of ethanol, maximum amount used in RFG areas; and
4. 9.6 billion gallons of ethanol, minimum amount used in RFG areas.

The seasonal RFG assumptions applied in 2012 (in terms of percent ethanol marketshare) are summarized below in Table VI.A.4–1. The rationale behind these selected values are explained in DRIA Section 2.1.4.2.

TABLE VI.A.4–1.—2012 RFG AREA ASSUMPTIONS

RFG areas	ETOH-blended gasoline (% market share)[a]			
	Min-RFG scenario	Max-RFG scenario		
		Summer (percent)	Winter (percent)	Summer (percent)
PADD 1	0	100	100	100
PADD 2	50	100	100	100
PADD 3	0	25	100	100
California[b]	25	100	100	100
Arizona[c]	0	100	100	100

[a] Percent marketshare of E10, with the exception of California (E5.7 year-round) and Arizona (E5.7 summer only).
[b] Pertains to both Federal RFG and California Phase 3. RFG.
[c] Pertains to Arizona Clean Burning Gasoline (CBG).

Once we determined how much ethanol was likely to be used in RFG areas (by PADD), we systematically allocated the remaining ethanol into conventional gasoline. First it was apportioned to winter oxy-fuel areas. In the 2004 base case, there were 14 state-implemented winter oxy-fuel programs in 11 states. Of these programs, 9 were required in response to non-attainment with the CO National Ambient Air Quality Standards (NAAQS) and 4 were implemented to maintain CO attainment status.[54] By 2012, 4 areas are expected to be redesignated to CO attainment status and discontinue oxy-fuel use and 2 areas are predicted to discontinue using oxy-fuel as a maintenance strategy. Accordingly, a reduced amount of ethanol was allocated to oxy-fuel areas in 2012. The remaining ethanol was distributed to conventional gasoline (CG) in different states based on a computed ethanol margin (rack gasoline price minus ethanol delivered price adjusted by miscellaneous subsidies/penalties). The methodology is described in DRIA Section 2.1.4.3.

The main difference in the four resulting ethanol consumption scenarios was how far the ethanol penetrated the conventional gasoline pool. A summary of the forecasted 2012 ethanol consumption (by control case, fuel type and season) is found in Table VI.A.4–2.

TABLE VI.A.4–2.—2012 FORECASTED U.S. ETHANOL CONSUMPTION BY SEASON

2012 Control case	Ethanol consumption (MMgal)						
	CG		OXY[a]	RFG[b]		Total	
	Summer	Winter	Winter	Summer	Winter	Summer	Winter
7.2 Bgal/Max-RFG	1,269	1,537	72	1,932	2,389	3,201	3,999
7.2 Bgal/Min-RFG	2,144	2,571	72	244	2,168	2,388	4,812
9.6 Bgal/Max-RFG	2,356	2,830	73	1,941	2,400	4,297	5,303
9.6 Bgal/Min-RFG	3,223	3,881	73	246	2,178	3,468	6,132

[a] Winter oxy-fuel programs.
[b] Federal RFG plus Ca Phase 3 RFG and Arizona CBG.

As expected, the least amount of ethanol was consumed in conventional gasoline in the 7.2 billion gallon control case when a maximum amount was allocated to RFG. Similarly, the most ethanol was consumed in CG in the 9.6 billion gallon control case when a minimum amount was allocated to RFG. For more information on the four resulting 2012 control cases, refer to DRIA Section 2.1.4.6.

B. Overview of Biodiesel Industry and Future Production/Consumption

1. Characterization of U.S. Biodiesel Production/Consumption

Historically, the cost to make biodiesel was an inhibiting factor to production in the U.S. The cost to produce biodiesel was high compared to the price of petroleum derived diesel fuel, even with consideration of the benefits of subsidies and credits provided by Federal and state programs. Much of the demand occurred as a result of mandates from states and local municipalities, which required the use

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[53] For a list of the Federal RFG areas, refer to DRIA Table 2.2–1.

[54] Refer to DRIA Table 2.1–2.

of biodiesel. However, over the past couple years biodiesel production has been increasing rapidly. The combination of higher crude oil prices and greater Federal tax subsidies has created a favorable economic situation. The Biodiesel Blenders Tax Credit programs and the Commodity Credit Commission Bio-energy Program, both subsidize producers and offset production costs. The Energy Policy Act extended the Biodiesel Blenders Tax Credit program to 2008. This credit provides about one dollar per gallon in the form of a Federal excise tax credit to biodiesel blenders from virgin vegetable oil feedstocks and 50 cents per gallon to biodiesel produced from recycled grease and animal fats. The program was started in 2004 under the American Jobs Act, spurring the expansion of biodiesel production and demand. Historical estimates and future forecasts of biodiesel production in the U.S. are presented in Table VI.B.1–1 below.

TABLE VI.B.1–1.—ESTIMATED BIODIESEL PRODUCTION

Year	Million gallons per year
2001	5
2002	15
2003	20
2004	25
2005	91
2006	150
2007	414
2012	303

Source: Historical data from 2001–2004 obtained from estimates from John Baize " The Outlook and Impact of Biodiesel on the Oilseeds Sector" USDA Outlook Conference 06. Year 2005 data from USDA Bioenergy Program *http://www.fsa.usda.gov/daco/bioenergy/2005/FY2005ProductPayments,* Year 2006 data from verbal quote based on projection by NBB in June of 2006. Production data for years 2007 and higher are from EIA's AEO 2006.

With the increase in biodiesel production, there has also been a corresponding rapid expansion in biodiesel production capacity. Presently, there are 65 biodiesel plants in operation with an annual production capacity of 395 million gallons per year.[55] The majority of the current production capacity was built in 2005, and was first available to produce fuel in the last quarter of 2005. Though capacity has grown, historically the biodiesel production capacity has far exceeded actual production with only 10–30 percent of this being utilized to make biodiesel, see Table VI.B.1–2.[56]

TABLE VI.B.1–2.—U.S. PRODUCTION CAPACITY HISTORY[a]

	2001	2002	2003	2004	2005	2006
Plants	9	11	16	22	45	53
Capacity (million gal/yr)	50	54	85	157	290	354

[a] Capacity Data based on surveys conducted around the month of September for most years, though the 2006 information is based on survey conducted in January 2006.

2. Expected Growth in U.S. Biodiesel Production/Consumption

In addition to the 53 biodiesel plants already in production, as of early 2006, there were an additional 50 plants and 8 plant expansions in the construction phase, which when completed would increase total biodiesel production capacity to over one billion gallons per year. Most of these plants should be completed by early 2007. There were also 36 more plants in various stages of the preconstruction phase (i.e. raising equity, permitting, conceptual design, buying equipment) with a capacity of 755 million gallons/year. As shown in Table VI.B.2–1, if all of this capacity came to fruition, U.S. biodiesel capacity would exceed 1.8 billion gallons.

TABLE VI.B.2–1.—PROJECTED BIODIESEL PRODUCTION CAPACITY

	Existing plants	Construction phase	Pre-construction phase
Number of plants	53	58	36
Total Plant Capacity, MM Gallon/year	354	714	754.7

For cost and emission analysis purposes, three biodiesel usage cases were considered: A 2004 base case, a 2012 reference case, and a 2012 control case. The 2004 base case was formed based on historical biodiesel usage (25 million gallons as summarized in Table VI.B.1.1). The reference case was computed by taking the 2004 base case and growing it out to 2012 in a manner consistent with the growth of gasoline.[57] The resulting 2012 reference case consisted of approximately 28 million gallons of biodiesel. Finally, for the 2012 control case, forecasted biodiesel use was assumed to be 300 million gallons based on EIA's AEO 2006 report (rounded value from Table VI.B.1.1). Unlike forecasted ethanol use, biodiesel use was assumed to be constant at 300 million gallons under both the statutory and higher projected renewable fuel consumption scenarios described in VI.A.4. EIA's projection is based on the assumption that the blender's tax credit is not renewed beyond 2008. If the tax credit is renewed, the projection for biodiesel demand would increase.

C. Feasibility of the RFS Program Volume Obligations

This section examines whether there are any feasibility issues associated with the meeting the minimum renewable fuel requirements of the Energy Act. Issues are examined with respect to

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[55] NBB Survey April 28, 2006 "Commercial Biodiesel Production Plants."

[56] From Presentation "Biodiesel Production Capacity," by Leland Tong, National Biodiesel Conference and Expo, February 7, 2006.

[57] EIA Annual Energy Outlook 2006, Table 1.

renewable production capacity, cellulosic ethanol production capacity, and distribution system capability. Land resource requirements are discussed in Chapter 7 of the RIA.

1. Production Capacity of Ethanol and Biodiesel

As shown in sections VI.A. and VI.B., increases in renewable fuel production capacity are already proceeding at a pace significantly faster than required to meet the 2012 mandate in the Act of 7.5 billion gallons. The combination of ethanol and biodiesel plants in existence and planned or under construction is expected to provide a total renewable fuel production capacity of over 9.6 billion gallons by the end of 2012. Production capacity is expected to continue to increase in response to strong demand. We estimate that this will require a maximum of 2,100 construction workers and 90 engineers on a monthly basis through 2012.

2. Production Capacity of Cellulosic Ethanol

Beginning in 2013, a minimum of 250 million gallons per year of cellulosic ethanol must be used in gasoline. The Act's definition of cellulosic, however, includes corn based ethanol as long as greater than 90% of the process energy was derived from animal wastes or other waste materials. As discussed in section VI.A. above, we believe that of the ethanol plants currently in existence, under construction, or in the final stages of planning there is likely to be more than 250 million gallons per year of ethanol produced from plants which meet these alternative definitions for cellulosic ethanol.

However, this is not to say that ethanol produced from cellulose will not be part of the renewable supply by 2012. As far as we know there is currently only one demonstration-level cellulosic ethanol plant in operation in North America; it produces 1 million gallons of ethanol per year (Iogen a privately held company, based in Ottawa, Ontario, Canada). However, the technology used to produce ethanol from cellulosic feedstocks continues to improve. With the grants made available through the Energy Act, we expect several cellulosic process plants will be constructed and an ever increasing effort will naturally be made to find better, more efficient ways to produce cellulosic ethanol.

To produce ethanol from cellulosic feedstocks, pretreatment is necessary to hydrolyze cellulosic and hemicellulosic polymers and break down the lignin sheath. In so doing, the structure of the cellulosic feedstock is opened to allow efficient and effective enzyme hydrolysis of the cellulose/hemicellulose to glucose and xylose. The central problem is that the α-linked saccharide polymers in the cellulose/hemicellulose structure prevent the microbial fermentation reaction. By comparison, when corn kernels are used as feedstock, fermentation of the starch produced from the corn kernels which have α-linked saccharide polymers takes place much more readily. An acid hydrolysis process was developed to pretreat cellulosic feedstocks (through hydrolysis which breaks up the β-links), but it continues to be prohibitively expensive for producing ethanol.

Some technologies that are being developed may solve some of the problems associated with production of ethanol from cellulosic sources. Specifically, one problem 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. Now, glucose and xylose can be co-fermented—hence, the present-day terminology: Weak-acid enzymatic hydrolysis and co-fermentation. In addition, several research groups, using recently developed genome modifying technology, have been able 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.

Cellulosic biomass can come from a variety of sources. Because the conversion of cellulosic biomass to ethanol has not yet been commercially demonstrated, we cannot say at this time which feedstocks are superior to others. In particular, there is only one cellulosic ethanol plant in North America (Iogen, Ottawa, Ontario, Canada). To the best of our knowledge, the technology that Iogen employs is not yet fully developed or optimized. Generally, the industry seems to be moving toward a process that uses dilute acid enzymatic prehydrolysis with simultaneous saccharification (enzymatic) and co-fermentation.

3. Renewable Fuel Distribution System Capability

Ethanol and biodiesel blended fuels are not shipped by petroleum product pipeline due to operational issues and additional cost factors. Hence, a separate distribution system is needed for ethanol and biodiesel up to the point where they are blended into petroleum-based fuel as it is loaded into tank trucks for delivery to retail and fleet operators. In cases where ethanol and biodiesel are produced within 200 miles of a terminal, trucking is often the preferred means of distribution. For longer shipping distances, the preferred method of bringing renewable fuels to terminals is by rail and barge.

Modifications to the rail, barge, tank truck, and terminal distribution systems will be needed to support the transport of the anticipated increased volumes of renewable fuels. These modifications include the addition of terminal blending systems for ethanol and biodiesel, additional storage tanks at terminals, additional rail delivery systems at terminals for ethanol and biodiesel, and additional rail cars, barges, and tank trucks to distribute ethanol and biodiesel to terminals. Terminal storage tanks for 100 percent biodiesel will also need to be heated during cold months to prevent gelling. In the past the refining industry has raised concerns regarding whether the distribution infrastructure can expand rapidly enough to accommodate the increased demand for ethanol. The most comprehensive study of the infrastructure requirements for an expanded fuel ethanol industry was conducted for the Department of Energy (DOE) in 2002.[58] The conclusions reached in that study indicate that the changes needed to handle the anticipated increased volume of ethanol by 2012 will not represent a major obstacle to industry. While some changes have taken place since this report was issued, including an increased reliance on rail over marine transport, we continue to believe that the rail and marine transportation industries can manage the increased growth in demand in an orderly fashion. This belief is supported by the demonstrated ability for the industry to handle the rapid increases and redistribution of ethanol use across the country over the last several years as MTBE was removed. The necessary facility changes at terminals and at retail stations to dispense ethanol containing fuels have been occurring at a record pace. Given that future growth is expected to progress at a steadier pace and with greater advance warning in response to economic drivers, we anticipate that the distribution system will be able to respond appropriately. A discussion of the costs associated making the changes discussed above is

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[58] ''Infrastructure Requirements for an Expanded Fuel Ethanol Industry,'' Downstream Alternatives Inc., January 15, 2002.

contained in section VII.B. of this preamble.

VII. Impacts on Cost of Renewable Fuels and Gasoline

This section examines the impact on fuel costs resulting from the growth in renewable fuel use between a base year of 2004 and 2012. We note that based on analyses conducted by the Energy Information Administration (EIA), renewable fuels will be used in gasoline and diesel fuel in excess and independent of the RFS requirements. As such, the changes in the use of renewable fuels and their related cost impacts are not directly attributable to the RFS rule. Rather, our analysis assesses the broader fuels impacts of the growth in renewable fuel use in the context of corresponding changes to the makeup of gasoline. These fuel impacts include the elimination of the reformulated gasoline (RFG) oxygen standard which has resulted in the refiners ceasing to use the gasoline blendstock methyl tertiary butyl ether (MTBE) and replacing it with ethanol. We also expect that by ending the use of MTBE that the former MTBE feedstock, isobutylene, will be reused to produce increased volumes of alkylate, a moderate to high octane gasoline blendstock. Thus, in this analysis, we are assessing the impact on the cost of gasoline and diesel fuel of increased use of renewable fuels, the cost savings resulting from the phase out of MTBE and the increased cost due to the production of alkylate.

As discussed in section II., we chose to analyze a range of renewable fuels use. In the case of ethanol's use in gasoline, the lower end of this range is based on the minimum renewable fuel volume requirements in the Act, and the higher end is based on AEO 2006. At both ends of this range, we assume that biodiesel consumption will be the level estimated in AEO 2006. We analyzed the projected fuel consumption scenario and associated program costs in 2012, the year that the RFS is fully phased-in. The volumes of renewable fuels consumed in 2012 at the two ends of the range are summarized in Table VII–1.

TABLE VII–1.—RENEWABLE FUELS VOLUMES USED IN COST ANALYSIS

	Renewable fuels consumption in 2012 (billion gallons)	
	Low	High
Corn Ethanol	6.95	9.35
Cellulosic Ethanol	0.25	0.25
Biodiesel	0.30	0.30
Total Biofuel Consumption	7.5	9.90

We have estimated an average corn ethanol production cost of $1.20 per gallon in 2012 (2004 dollars) in the case of 7.5 billion gallons per year (bill gal/yr) and $1.26 per gallon in the case of 9.9 bill gal/yr. For cellulosic ethanol, we estimate it will cost approximately $1.65 in 2012 (2004 dollars) to produce a gallon of ethanol using corn stover as a cellulosic feedstock. In this analysis, however, we assume that the cellulosic requirement will be met by corn-based ethanol produced by energy sourced from biomass (animal and other waste materials as discussed in Section III.B of this preamble) and costing the same as corn based ethanol produced by conventional means.

We estimated production costs for soy-derived biodiesel of $2.06 per gallon in 2004 and $1.89 per gal in 2012. For yellow grease derived biodiesel, we estimate an average production cost of $1.19 per gallon in 2004 and $1.10 in 2012.

The impacts on overall gasoline costs with and without fuel consumption subsidies resulting from the increased use of ethanol and the corresponding changes to the other aspects of gasoline were estimated for both of these cases. The 7.5 bill gal/yr case would result in increased total costs which range from 0.33 cents to 0.41 cents per gallon depending on assumptions with respect to ethanol use in RFG and butane control constraints. The 9.9 bill gal/yr case would result in increased total costs which range from 0.93 to 1.05 cents per gallon. The actual cost at the fuel pump, however, will be decreased due the effect of State and Federal tax subsidies for ethanol. Taking this into consideration results in ‘‘at the pump’’ decreased costs (cost savings) ranging from 0.82 to 0.89 cents per gallon for the 7.5 bill gal/yr case and ‘‘at the pump’’ decreased costs ranging from 0.98 to 1.08 cents per gallon for the 9.9 bill gal/yr case. We ask for comment on these derived costs as well as on the analysis methodology used to derive these costs, and refer the reader to Section 7 of the DRIA which contains much more detail on the cost analysis used to develop these costs.

A. Renewable Fuel Production and Blending Costs

1. Ethanol Production Costs

a. *Corn Ethanol.* A significant amount of work has been done in the last decade on surveying and modeling the costs involved in producing ethanol from corn, to serve business and investment purposes as well as to try to educate energy policy decisions. Corn ethanol costs for our work were estimated using a model developed by USDA in the 1990s that has been continuously updated by USDA. The most current version was documented in a peer-reviewed journal paper on cost modeling of the dry-grind corn ethanol process,[59] and it produces results that compare well with cost information found in surveys of existing plants.[60] We made some minor modifications to the USDA model to allow scaling of the plant size, to allow consideration of plant energy sources other than natural gas, and to adjust for energy prices in 2012, the year of our analysis.

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 credits represents about 50% of the final per-gallon cost, while utilities, capital and labor comprise about 20%, 10%, and 5%, respectively. For this work, we used corn price projections from USDA of $2.23 per bushel in 2012 for the 7.2 bill gal/yr case, and an adjusted value of $2.31 per bushel for the 9.6 bill gal/yr

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[59] Kwaitkowski, J.R., McAloon, A., Taylor, F., Johnston, D.B., Industrial Crops and Products 23 (2006) 288–296.

[60] Shapouri, H., Gallagher, P., USDA's 2002 Ethanol Cost-of-Production Survey (published July 2005).

case.[61] The adjustment at the higher volume case was taken from work done by FAPRIand EIA. [62] [63] Prices used for DDGS were $65 per ton in the 7.2 bill gal/yr case and $55 per ton in the 9.6 case, based on work by FAPRI and EIA.[64] Energy prices were derived from historical data and projected to 2012 using EIA's AEO 2006.[65] While we believe the use of USDA and FAPRI estimates for corn and DDGS prices is reasonable, additional modeling work is being done for the final rulemaking using the Forestry and Agricultural Sector Optimization Model described further in Chapter 8 of the RIA.

The estimated average corn ethanol production cost of $1.20 per gallon in 2012 (2004 dollars) in the case of 7.2 bill gal/yr and $1.26 per gallon in the case of 9.6 bill gal/yr represents the full cost to the plant operator, including purchase of feedstocks, energy required for operations, capital depreciation, labor, overhead, and denaturant, minus revenue from sale of co-products. It does not account for any subsidies on production or sale of ethanol. This cost is independent of the market price of ethanol, which has been related closely to the wholesale price of gasoline for the past decade.[66] [67]

Under the Energy Act, starch-based ethanol can be counted as cellulosic if at least 90% of the process energy is derived from renewable feedstocks, which include plant cellulose, municipal solid waste, and manure biogas.[68] It is expected that 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 corn ethanol meeting cellulosic criteria, we assume that the costs will not be significantly different from conventionally produced corn ethanol. We believe this is reasonable because these processes will simply be corn ethanol plants with additional fuel handling mechanisms that allow them to combust waste materials for process energy instead of natural gas. We expect them to be in locations where the very low or zero cost of the waste material or biogas itself will likely offset the costs of hauling it and/or the additional capital for processing and firing it, making them cost-competitive with conventional corn ethanol plants. Furthermore, 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. Based on these factors, we have assigned starch ethanol made using this cellulosic criteria the same cost as ethanol produced from corn using conventional means.

b. *Cellulosic Ethanol.* 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.[69] Although the 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 and USDA used a modified version of the model 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 the analysis for this proposed rule. Because there were no operating plants that could provide real world process design, construction, and operating data for processing cellulosic ethanol, NREL had considered modeling the plant based on assumptions associated with a first-of-a-kind or pioneer plant. The literature indicates that such models often underestimate actual costs since the high performance assumed for pioneer process plants is generally unrealistic.

Instead, the NREL researchers assumed that the corn stover plant was an N_{th} generation plant, *e.g.*, not a pioneer plant or first-or-its kind, built after the industry had been sufficiently established to provide verified costs. The corn stover plant was normalized to the corn kernel plant, *e.g.*, placed on a similar basis.[70] It is also reasonable to expect that the cost of cellulosic ethanol would be higher than corn ethanol because of the complexity of the cellulose conversion process. Recently, process improvements and 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.

We calculated fixed and variable operating costs using percentages of direct labor and total installed capital costs. Following this methodology, we estimate that producing a gallon of ethanol using corn stover as a cellulosic feedstock would cost $1.65 in 2012 (2004 dollars).

c. *Ethanol's Blending Cost.* Ethanol has a high octane value of 115 (R+M)/2 which contributes to its value as a gasoline blendstock. As the volume of ethanol blended into gasoline increases from 2004 to 2012, refiners will account for the octane provided by ethanol when they plan their gasoline production. This additional octane would allow them to back off of their octane production from their other gasoline producing units resulting in a cost savings to the refinery. For this cost analysis, the cost savings is expressed as a cost credit to ethanol added to the production cost for producing ethanol.

We obtained gasoline blending costs on a PADD basis for octane from a consultant who conducted a cost analysis for a renewable fuels program using an LP refinery cost model. LP refinery models value the cost of octane based on the octane producing capacity for the refinery's existing units, by

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[61] USDA Agricultural Baseline Projections to 2015, Report OCE–2006–1.

[62] EIA NEMS model for ethanol production, updated for AEO 2006.

[63] Food and Agricultural Policy Research Institute (FAPRI) study entitled "Implications of Increased Ethanol Production for U.S. Agriculture", FAPRI–UMC Report #10–05.

[64] Food and Agricultural Policy Research Institute (FAPRI) U.S. and World Agricultural Outlook, January 2006, FAPRI Staff Report 06–FSR 1.

[65] Historical data at *http://tonto.eia.doe.gov/dnav/pet/pet_pri_allmg_d_nus_PTA_cpgal_m.htm* (gasoline), *http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm* (natural gas), *http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls* (electricity), *http://www.eia.doe.gov/cneaf/coal/page/acr/table28.html* (coal); EIA Annual Energy Outlook 2006, Tables 8, 12, 13, 15; EIA Web site.

[66] Whims, J., Sparks Companies, Inc. and Kansas State University, "Corn Based Ethanol Costs and Margins, Attachment 1" (Published May 2002).

[67] Piel, W.J., Tier & Associates, Inc., March 9, 2006 report on costs of ethanol production and alternatives.

[68] Energy Policy Act of 2005, Section 1501 amending Clean Air Act Section 211(o)(1)(A).

[69] Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis Current and Futuristic Scenarios, Robert Wooley, Mark Ruth, John Sheehan, and Kelly Ibsen, Biotechnology Center for Fuels and Chemicals Henry Majdeski and Adrian Galvez, Delta-T Corporation; National Renewable Energy Laboratory, Golden, CO, July 1999, NREL/TP–580–26157.

[70] Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks; A Joint Study Sponsored by: USDA and USDOE, October 2000, NREL/TP–580–28893, Andrew McAloon, Frank Taylor, Winnie Yee, USDA, Eastern Regional Research Center Agricultural Research Service; Kelly Ibsen, Robert Wooley, National Renewable Energy Laboratory, Biotechnology Center for Fuels and Chemicals, 1617 Cole Boulevard, Golden, CO 80401–3393; NREL is a USDOE Operated by Midwest Research Institute Battelle Bechtel; Contract No. DE–AC36–99–GO10337.

added capital and operating costs for new octane producing capacity, and based on purchased gasoline blendstocks. The value of octane is expressed as a per-gallon cost per octane value, and ranges from 0.38 cents per octane-gallon in PADD 2 where lots of ethanol is expected to be used, to 1.43 cents per octane-gallon in California. Octane is more costly in California because the Phase 3 RFG standards restriction aromatics content which also reduces the use of a gasoline blendstock named reformate—a relatively cheap source of octane. Also, California's Phase 3 RFG distillation restrictions tend to limit the volume of eight carbon alkylate, another lower cost and moderately high octane blendstock.

Another blending factor for ethanol is its energy content. Ethanol contains a lower heat content per gallon than gasoline. Since refiners blend up their gasoline based on volume, they do not consider the energy content of its gasoline, only its price. Instead, the consumer pays for a gasoline's energy density based on the distance that the consumer can achieve on a gallon of gasoline. Since we try to capture all the costs of using ethanol, we consider this effect. Ethanol contains 76,000 British Thermal Units (BTU) per gallon which is significantly lower than gasoline, which contains an average of 115,000 BTUs per gallon. This lower energy density is accounted for below in the discussion of the gasoline costs.

2. Biodiesel Production Costs

We based our cost to produce biodiesel fuel on a range estimated from the use of USDA's and NREL's biodiesel computer models. Both of these models represent the continuous transesterification process for converting vegetable soy oil to esters, along with the ester finishing processes and glycerol recovery. The models estimate biodiesel production costs using prices for soy oil, methanol, chemicals and the byproduct glycerol. The models estimate the capital, fixed and operating costs associated with the production of soy based biodiesel fuel, considering utility, labor, land and any other process and operating requirements.

Each model is based on a medium sized biodiesel plant that was designed to process raw degummed virgin soy oil as the feedstock, yielding 10 million gallons per year of biodiesel fuel. USDA estimated the equipment needs and operating requirements for their biodiesel plant 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. The NREL model is also based on process simulation software, though the results are adjusted to reflect NREL's modeling methods.

The production costs are based on an average biodiesel plant located in the Midwest using soy oil 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 production costs are based on a plant that makes 10 million gallons per year of biodiesel fuel.

The model is further modified to use input prices for the feedstocks, byproducts and energy prices to reflect the effects of the fuels provisions in the Energy Act. Based on the USDA model, for soy oil-derived biodiesel we estimate a production cost of $2.06 per gallon in 2004 and $1.89 per gal in 2012 (in 2004 dollars) For yellow grease derived biodiesel, USDA's model estimates an average production cost of $1.19 per gallon in 2004 and $1.10 in 2012 (in 2004 dollars). In order to capture a range of production costs, we compared these cost projections to those derived from the NREL biodiesel model. With the NREL model, we estimate biodiesel production cost of $2.11 per gallon for soy oil feedstocks and $1.28 per gallon for yellow grease in 2012, which are slightly higher than the USDA results.

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 111 cents per gallon for soy derived biodiesel and 60 to 78 cents per gallon for yellow grease biodiesel 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 expires in 2008 if 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.

3. Diesel Fuel Costs

Biodiesel fuel is blended into 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 under two scenarios, with refinery diesel prices as forecasted by EIA's AEO 2006 with crude at $47 a barrel and with refinery diesel prices based on $70 per barrel crude oil.

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 2004 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 biodiesel volume is used as transport fuel, neglecting minor uses in the heating oil market.

For the AEO scenario, 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 $90 million per year, which equates to a reduction in fuel cost of about 0.15 c/gal.[71] Without the subsidy, the transport diesel fuel costs are increased by $118 million per year, or an increase of 0.20 c/gal for transport diesel fuel. With crude at $70 per barrel, including the biodiesel blenders subsidy, results in a cost reduction of $184 million per

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[71] 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.

year, or a reduction of 0.31 c/gal for the total transport diesel pool. Without the subsidy, transport diesel costs are increased by $25 million per year, or 0.04 c/gal.

B. Distribution Costs

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.[72] That study provided the foundation 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 to meet the requirements of the RFS in 2012. Distribution costs are evaluated here for the case where the minimum volume of ethanol is used to meet the requirements of the RFS (7.2 bill gal/yr) and for the projected case where the volume of ethanol used is 9.6 bill gal/yr. The 2012 reference case against which we are estimating the cost of distributing the additional volume of ethanol needed to meet the requirements of the RFS is 3.9 billion gallons.

a. *Capital Costs To Upgrade Distribution System For Increased Ethanol Volume.* The 2002 DOE study examined two cases regarding the use of renewable fuels for estimating the capital costs for distributing additional ethanol. The first assumed that 5.1 bill gal/yr of ethanol would be used in 2010, and the second assumed that 10 bill gal/yr of ethanol would be used in the 2015 timetable. We interpolated between these two cases to provide an estimate of the capital costs to support the use of 7.2 bill gal/yr of ethanol in 2012.[73] The 10 bill gal/yr case examined in the DOE study was used to represent the projected case examined in today's rule of 9.6 bill gal/yr of ethanol.[74] Table VII.B.1.a–1 contains our estimates of the infrastructure changes and associated capital costs for the two ethanol use scenarios examined in today's rule. Amortized over 15 years, the total capital costs equate to approximately one cent per gallon. We performed a sensitivity analysis where we increased reliance on rail use at the expense of barge use in transporting ethanol. The costs were relatively insensitive, increasing to just 1.1 cents per gallon.

TABLE VII.B.1.A–1.—ESTIMATED ETHANOL DISTRIBUTION INFRASTRUCTURE CAPITAL COSTS ($M) RELATIVE TO A 3.9 BILLION GALLON PER YEAR REFERENCE CASE

	7.2 billion gallons (per year)	9.6 billion gallons (per year)
Fixed Facilities:		
Retail	24	44
Terminals	142	246
Mobile Facilities:		
Transport Trucks	38	50
Barges	30	52
Rail Cars	104	161
Total Capital Costs	317	542

b. *Ethanol Freight Costs.* The DOE study contains ethanol freight costs for each of the 5 PADDs. The Energy Information Administration translated these cost estimates to a census division basis.[75] We took the EIA projections and translated them into State-by-State ethanol freight costs. In conducting this translation, we accounted for increases in the cost in transportation fuels used to ship ethanol by truck, rail, and barge. We estimate that the freight cost to transport ethanol to terminals would range from 5 cents per gallon in the Midwest, to 18 cents per gallon to the West Coast, which averages 9.2 cents per gallon of ethanol on a national basis.

We estimate the total cost for producing and distributing ethanol to be between $1.30 and $1.36 per gallon of ethanol, on a nationwide average basis. This estimate includes both the capital costs to upgrade the distribution system and freight costs.

2. Biodiesel Distribution Costs

The volume of biodiesel used by 2012 under the RFS is estimated at 300 million gallons per year. The 2012 baseline case against which we are estimating the cost of distributing the additional volume of biodiesel is 28 million gallons.[76]

For the purposes of this analysis, we are assuming that to ensure consistent operations under cold conditions all terminals will install heated biodiesel storage tanks and biodiesel will be transported to terminals in insulated tank trucks and rail cars in the cold seasons.[77] Due to the developing nature of the biodiesel industry, specific information on biodiesel freight costs is lacking. The need to protect biodiesel from gelling during the winter may marginally increase freight costs over those for ethanol. Counterbalancing this is the likelihood that biodiesel shipping distances may be somewhat shorter due to the more geographically dispersed nature of biodiesel production facilities. In any event, the potential difference between biodiesel and ethanol freight costs is likely to be small and the cost of distributing biodiesel does not appreciably affect the results of our analysis. Therefore, we believe that

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[72] Infrastructure Requirements for an Expanded Fuel Ethanol Industry, Downstream Alternatives Inc., January 15, 2002.

[73] See Chapter 7.3 of the Draft Regulatory Impact Analysis associated with today's rule for additional discussion of how the results of the DAI study were adjusted to reflect current conditions in estimating the ethanol distribution infrastructure capital costs under today's rule.

[74] For both the 7.2 bill gal/yr and 9.6 bill gal/yr cases, the baseline from which the DOE study cases were projected was adjusted to reflect a 3.9 bill gal/yr 2012 baseline.

[75] Petroleum Market Model of the National Energy Modeling System, Part 2, March 2006, DOE/EIA–059 (2006), *http://tonto.eia.doe.gov/FTPROOT/modeldoc/m059(2006)-2.pdf.*

[76] 2004 baseline of 25 million gallons grown with diesel demand to 2012.

[77] See section VI.C. in today's preamble regarding the special handling requirements for biodiesel under cold conditions.

estimated freight costs for ethanol of 9.2 cents per gallon adequately reflects the freight costs for biodiesel for this analysis.

The capital costs associated with distribution of biodiesel will be somewhat higher per gallon than those associated with the distribution of ethanol due to the need for storage tanks, barges, tanker trucks and rail cars to be insulated and in many cases heated. We estimate that to handle the increased biodiesel volume will require a total capital cost investment of $49,813,000, which equates to about 2 cents per gallon of new biodiesel volume.

We estimate the total cost for producing and distributing biodiesel to be between $2.00 and $2.22 per gallon of biodiesel, on a nationwide average basis. This estimate includes both the capital costs to upgrade the distribution system and freight costs.

C. Estimated Costs to Gasoline

To estimate the cost of increased use of renewable fuels, the cost savings from the phase out of MTBE and the production cost of alkylate, we developed our own spreadsheet cost model. As described above in Section VI.A, the cost analysis is conducted by comparing a base year before the Energy Act's fuel changes to a modeled year with the fuel changes. We used 2004 as the base year. We grew the 2004 gasoline demand to 2012 to create a reference case assuming that the 2004 fuel demand scenario remained the same (fuel quality remained constant). The sum of fuel changes, including the increased use of ethanol, the phase-out of MTBE and the conversion of a part of the MTBE feedstocks to alkylate, is all assumed to occur by 2012 and is compared to the 2012 reference case. This analysis considers the production cost, distribution cost as well as the cost for balancing the octane and RVP caused by these fuel changes.

In addition to assessing the cost at 7.2 and 9.6 billion gallons of total ethanol use in gasoline, we considered that ethanol could be used at different levels in RFG. Instead of picking a single point for ethanol use in RFG, we assessed a range (see Section VI.A above). At the high end of the range, ethanol is used in RFG in both summer and winter. At the low end of the range, ethanol is still used in wintertime RFG, but to only a very limited extent in summertime RFG. The lower rate of ethanol use in summertime RFG may occur because the RVP increase associated with ethanol will cause refiners to incur a cost to further control the volatility of their summertime RFG.

1. RVP Cost for Blending Ethanol Into Summertime RFG

Blending ethanol into summertime RFG causes about a 1 PSI (pounds per square inch) increase in RVP. To enable this gasoline to continue to be sold into the summertime RFG market, this vapor pressure increase must be accounted for by adjusting the RVP of the base gasoline. The vapor pressure adjustment is made by reducing of volume of pentanes in the gasoline boiling that comes from the fluid catalytic cracking unit (FCCU). To reduce the pentane content FCC naphtha, refiners would likely have to add a distillation column called a depentanizer, where pentanes and lighter hydrocarbons are removed from the hydrocarbon feed and drawn off the top of the column while the heavier C6+ hydrocarbons are removed from the bottom. While the pentanes would be removed from the summertime RFG pool, they are expected to be reblended into either summertime CG or wintertime CG and RFG. To rebalance the RVP of the nonsummertime RFG pool or wintertime RFG or CG pool caused by relocated pentanes, butanes are estimated to be removed from the gasoline pool. When ethanol is blended into summertime RFG, about 10 percent of the base gasoline is lost due to the removed pentanes. We believe that refiners would reblend these removed pentanes into summertime CG or wintertime CG and RFG and rebalance the RVP of the gasoline pool into which the pentanes are being reblended by removing butanes, thus reducing the volume loss to one fifth of that if the pentanes were permanently removed. There is an opportunity cost to removing butanes from gasoline. In 2004 butanes sold into the butane market were valued 36 cents per gallon less than gasoline, however, this opportunity cost would be much greater if pentanes were permanently removed from gasoline.

We developed cost estimates for adding and operating a new depentanizer distillation column for the removal of pentanes from FCC naphtha in each refinery. The feed rate for an average FCC unit was estimated by PADD and ranged from 7 to 35 thousand barrels per day. Once the capital and operating costs were estimated, the total costs were averaged over the entire gasoline pool, which ranged from about two to three times the volume of FCC naphtha. When ethanol is being blended newly into summertime RFG, the capital and operating costs will both apply. However, when we model ethanol coming out of a summertime RFG market, we only reduce the depentanizer operating costs since the capital costs are sunk.

Our analysis showed that the RVP blending costs for blending ethanol into summertime RFG ranges from 1 to 1.4 cents per gallon of RFG. If the ethanol is coming out of summertime RFG, which occurs in some of the scenarios that we modeled, there would be a cost savings of 0.8 to 1.2 cents per gallon of RFG.

In the cost of refinery gasoline section below, we took into account that butanes have a lower energy density compared to the gasoline pool from which the butanes were removed. This energy content adjustment will offset some of the cost for removing the butanes. Butane's energy density is 94,000 BTUs per gallon compared to 115,000 BTU per gallon for gasoline.

For further details on RVP reduction costs, see Section 7.4.2 of the RIA.

2. Cost Savings for Phasing Out Methyl Tertiary Butyl Ether (MTBE)

The Energy Act rescinded the oxygen standard for RFG and when the provision took effect, U.S. refiners stopped blending MTBE into gasoline. When MTBE use ended, the operating costs for operating those plants also ceased. The total costs saved for not operating the MTBE plants is calculated by multiplying the volume of MTBE no longer blended into gasoline with the operating costs for the plants producing that MTBE.

We determined the operating costs saved by shutting down these plants. The volumetric feedstock demands and the operating costs factors for each of these MTBE plants are taken from literature. We estimated the MTBE operating costs to be $1.40 per gallon for captive and ethylene cracker plants, $1.48 per gallon for propylene oxide plants and $1.55 per gallon for merchant operating costs. Weighted by the percentages for domestic MTBE production, the average cost savings for no longer producing MTBE is estimated to be $1.46 per gallon.

We also credited MTBE for its octane blending value. MTBE has a high octane value of 110 (R+M)/2 which increases its value compared to gasoline. This high octane value partially offsets its production cost. The cost of octane is presented above in subsection VII.(A)(1)(c) and is applied to the difference in octane value between MTBE and the average of the various gasoline grades (88 (R+M)/2). Accounting for MTBE's octane value reduces its cost down to $1.27 to $1.38 per gallon depending on the PADD. When accounting for the volume of

MTBE removed, we also adjust for its energy content, which is 93,500 BTU per gallon.

For further information on costs savings due to MTBE phaseout, see Section 7.4.3 of the RIA.

3. Production of Alkylate From MTBE Feedstocks

Discontinuing the blending of MTBE into U.S. gasoline is expected to result in the reuse of most of the primary MTBE feedstocks, isobutylene, to be used to produce alkylate. Alkylate is formed by reacting isobutylene together with isobutane. Prior to the establishment of the oxygen requirement for RFG, this isobutylene was, in most cases, used to make alkylate. Another option would be for reacting isobutylene with itself to form isooctene which would likely be hydrogenated to then form isooctane. However, our cost analysis found that alkylate is a more cost-effective way to reuse the isobutylene, even after considering isooctane's higher octane content. The cost for converting to alkylate is estimated to be $1.42 per gallon for captive (in-refinery) plants and ethylene cracker plants, $1.46 per gallon for propylene oxide plants and $1.52 per gallon for merchant MTBE plants. We believe that the cost for converting merchant MTBE plants to alkylate is too high to support its conversion, thus the conversion cost is estimated to be $1.43 per gallon, the average of the conversion costs for captive, ethylene cracker and propylene oxide MTBE plants. This projected percent of MTBE plant conversion results in 0.84 gallons of alkylate produced for each gallon of MTBE no longer produced.

The alkylate production cost is adjusted by PADD to account for the blending octane of alkylate, which varies by 1 to 2 cents per gallon depending on the value of octane in each PADD. Including its octane value, the cost of producing alkylate varies from $1.38 to $ 1.41 per gallon.

For further information on production of alkylate from MTBE feedstocks, see section 7.4.4 of the RIA.

4. Changes in Refinery Produced Gasoline Volume and Its Costs

In the sections above, we estimated changes in gasoline volume and the cost associated with those volume changes for ethanol, MTBE, alkylate and butane. As these various gasoline blendstocks are added to or removed from the gasoline pool, they affect the refinery production of gasoline (or oxygenate blendstock).

To estimate the changes in refinery gasoline production volumes, it was necessary to balance the total energy production of each control case to the reference case. The energy content of the reference case was estimated by multiplying the volumetric energy content of each gasoline pool blendstock, including MTBE, ethanol and refinery produced gasoline, by the associated gallons.

The increase or decrease in ethanol content in summertime RFG assumed under the different scenarios resulted in the change in the volumes of butane in RFG as described above. We identified that the increase or decrease in ethanol in wintertime RFG and CG could cause reductions or increases in the amount of butanes blended into wintertime gasoline. Wintertime gasoline is limited in vapor pressure by the American Standard for Testing Materials (ASTM) RVP and V/L (vapor-liquid) standards. According to a refiner with extensive refining capacity, and also Jacobs Engineering, a refining industry consulting firm, refineries are blending their wintertime gasoline up to those standards today and are limited from blending more butane available to them. If this is the case, for each gallon of summertime RFG and wintertime RFG and CG blended with ethanol 2 percent of the base gasoline volume would be lost in terms of butane removed. However, some refineries may have room to blend more butane. Also, we are aware that some states offer 1 PSI waivers for blending of ethanol into wintertime gasoline, presumably to accommodate splash blending of ethanol.[78] Consequently, it may be possible to accommodate the 1 PSI vapor pressure increase without forcing the removal of some or all of this butane. For this reason we assessed the costs as a range, on the upper end assuming that butane content would have to be removed to account for new ethanol blended into summertime RFG and wintertime RFG and CG , and on the low end assuming only that blending of ethanol into summertime RFG cause butanes to be removed.

For estimating the volume of butane which must be removed from the gasoline because of the addition of ethanol, we assumed that ethanol will be used at 10 volume percent except for California where it would continue to be used at 5.7 volume percent. Development of the estimates for winter vs. summer ethanol consumption for the control cases is discussed in Chapter 2.1 of the RIA. For the reference case, we estimated that 55 percent of the ethanol would be used in the winter and 45 percent in the summer. Table VII.C.4–1 summarizes the summertime RFG and wintertime RFG and CG volumes of ethanol and estimated change in butane content.

TABLE VII.C.4–1.—ESTIMATED CHANGES IN U.S. SUMMERTIME RFG ETHANOL VOLUMES AND THEIR IMPACT ON BUTANE BLENDING INTO GASOLINE

[Million gallons in 2012]

	Reference case	7.2 Bil gals max RFG	7.2 Bil gals min RFG	9.6 Bil gals max RFG	9.6 Bil gals min RFG
Summertime RFG Ethanol	1,155	1,932	244	1,932	244
Wintertime RFG & CG Ethanol.	2,178	3,999	4,812	5,303	6,132
Change in Butane		−140 to −456	164 to −297	−140 to −690	164 to −535

The change in volume of ethanol, MTBE, alkylate, and butane for each control case is adjusted for energy content. The volume of refinery gasoline is then adjusted to maintain the same energy content as that of the reference gasoline pool. The refinery gasoline production is estimated by dividing the BTU content of gasoline, estimated to be 115,000 BTU per gallon, into the total amount of BTUs for the entire gasoline pool after accounting for the BTUs of the other blendstocks. The BTU-balanced gasoline pool volumes for each control case are shown in Table

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[78] Most people are aware of the 1 PSI RVP waiver that ethanol is provided for the summertime, but some states offer a similar waiver to ethanol for wintertime blending as well.

VII.C.4–2. The changes are shown for both assumptions with respect to the need to remove butane from winter gasoline to accommodate more ethanol blending.

TABLE VII.C.4–2.—ESTIMATED 2012 VOLUMES

[Million gallons]

	7.2 Bil gals, max RFG		7.2 Bil gals, min RFG		9.6 Bil gals, max RFG		9.6 Bil gals, min RFG	
Total Ethanol	7,200		7,200		9,600		9,600	
Increase in Ethanol	3,302		3,302		5,702		5,702	
Change in MTBE	−2091		−2091		−2091		−2091	
New Alkylate	1,763		1,764		1,764		1,764	
Butane Removed in Winter	Yes	No	Yes	No	Yes	No	Yes	No
Change in Butane	−456	−140	−297	164	−690	−140	−535	164
Gasoline	143,486	143,228	143,357	142,980	142,092	141,642	141,965	141,394
Change in Gasoline	−1,873	−2,131	−2,002	−2,379	−3,267	−3,716	−3,394	−3,965
Change in Gasoline (%)	−1.3	−1.5	−1.4	−1.6	−2.2	−2.6	−2.3	−2.7

Based on our estimated impacts on volumes shown in table VII.C.4–2, refinery produced gasoline demand will be reduced by a range of 1.3 percent to 2.7 percent compared to the reference case, which would result in less imported finished petroleum products and/or less crude oil use. The projected impacts on refinery-produced gasoline demand depend on the volume of new ethanol blended into gasoline, on the volume of ethanol blended into summertime RFG and on whether butane blending into wintertime gasoline will be affected or not. To put this reduction in refinery-produced gasoline volume in perspective, the yearly annual growth in gasoline demand in this country is about 1.7 percent.

The cost for changes to refinery produced gasoline volume is assumed to be represented by the bulk price of gasoline in each PADD from EIA's 2004 Petroleum Marketing Annual. The 2004 gasoline cost is adjusted to 2012 using the ratio of the projected crude oil price in 2012 of $47 per barrel to that in the 2004 base case of $41 per barrel. The cost for distributing the gasoline to terminals is added on, which is estimated to be 4 cents per gallon. The estimated cost for producing and distributing gasoline to terminals (wholesale price at the terminal rack) ranges from $1.30 per gallon in the Gulf Coast, to $1.53 per gallon in California.

Crude oil prices are much higher today which decreases the relative cost of producing and blending in more ethanol into gasoline. For this reason, we conducted a sensitivity analysis assuming that crude oil is priced at around $70 per barrel. Since this is only a sensitivity analysis, we simply ratioed the gasoline production costs, MTBE and alkylate feedstock costs and butane value upwards by the same ratio. The ratio is determined by the projected increase in the wholesale gasoline price relative to the increase in crude oil price. We extrapolated this relationship to crude oil priced at $70 per barrel compared to the price in 2004 which was $41 per barrel, which results in about a 1.4 ratio factor. We did not adjust other costs and assumptions which are much less sensitive to the price of crude oil and therefore not likely to change much (e.g., distribution costs, refinery utility costs, incremental octane costs, and ethanol production costs). At a $70 per barrel crude oil price, the cost for production and distribution of gasoline to the terminal ranges from $2.05 in the Gulf Coast to $2.43 per gallon in California.

For further information on gasoline cost see section 7.4.5 in the RIA.

5. Overall Impact on Fuel Cost

We combined the costs and volume impacts described in the previous sections to estimate an overall fuel cost impact due to the changes in gasoline occurring with the projected fuel changes. This aggregated cost estimate includes the costs for producing and distributing ethanol, the blending costs of ethanol in summertime RFG, ending the production and distribution of MTBE, and reusing the MTBE feedstock isobutylene for producing alkylate, reducing the content of butane in summertime RFG and wintertime gasoline and for reducing the volume of refinery-produced gasoline. We also present the costs for the scenario that butanes would not need to be removed when ethanol is blended into wintertime gasoline. The costs for each control case are estimated by multiplying the change in volume for each gasoline blendstock, relative to the reference case, times its production, distribution and octane blending costs.

The costs of these fuels changes are expressed two different ways. First, we express the cost of the program without the ethanol consumption subsidies in which the costs are based on the total accumulated cost of each of the fuels changes. The second way we express the cost is with the ethanol consumption subsidies included since the subsidized portion of the renewable fuels costs will be not be represented to the consumer in its fuels costs paid at the pump, but instead by being paid through the state and Federal tax revenues. For both cases we express the costs with and without butanes being removed due to changes in wintertime blending of ethanol. We evaluated the fuel costs using ranges in different assumptions to bound the many uncertainties in the cost analysis (see the DRIA for more discussion concerning the cost uncertainties).

a. *Cost without Ethanol Subsidies.* Table VII.C.5.a–1 summarizes the costs without ethanol subsidies for each of the four control cases, including the cost for each aspect of the fuels changes, and the aggregated total and the per-gallon costs for all the fuel changes.[79] This estimate of costs reflects the changes in gasoline that are occurring with the expanded use of ethanol, including the corresponding removal of MTBE. These costs include the labor, utility and other operating costs, fixed costs and the capital costs for all the fuel changes expected. We excluded Federal and state ethanol consumption subsidies

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[79] 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.

which avoids the transfer payments caused by these subsidies that would hide a portion of the program's costs.

caused by these subsidies that would hide a portion of the program's costs.

TABLE VII.C.5.A–1.—ESTIMATED COST WITHOUT ETHANOL CONSUMPTION SUBSIDIES ($47/BBL CRUDE)

[million dollars, except where noted]

	7.2 Bil gals, max RFG		7.2 Bil gals, min RFG		9.6 Bil gals, max RFG		9.6 Bil gals, min RFG	
Adding Ethanol	3,769		3,837		6,852		6,897	
RFG RVP Cost	72		−74		72		−74	
Eliminating MTBE	−2,821		−2,821		−2,821		−2,821	
Adding Alkylate	2,520		2,520		2,521		2,521	
Butane Removed in Winter	Yes	No	Yes	No	Yes	No	Yes	No
Changing Butane Volume	−439	−133	−275	174	−667	−133	−510	174
Additional Gasoline Production	−2,484	−2,826	−2,638	−3,141	−4,350	−4,948	−4,507	−5,270
Total Cost Excluding Subsidies	619	582	548	496	1,606	1,542	1,507	1,426
Per-Gallon Cost Excluding Subsidies (cents per gallon)	0.41	0.38	0.38	0.33	1.05	1.01	0.99	0.93

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. $0.5 billion to around $1.6 billion in the year 2012. Expressed as per-gallon costs, these fuel changes would cost the U.S. 0.3 to just over 1 cent per gallon of gasoline.

b. Gasoline Costs Including Ethanol Consumption Tax Subsidies. Table VII.C.5.b–1 expresses the total and per-gallon gasoline costs for the four control scenarios 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. The costs are presented for the case that ethanol causes butanes to be withheld from the wintertime gasoline pool, and for the case that the blending of butanes remains unchanged.

TABLE VII.C.5.B–1.—ESTIMATED COST INCLUDING SUBSIDIES ($47/BBL CRUDE)

[million dollars, except where noted]

	7.2 Bil Gals Max RFG		7.2 Bil Gals Min RFG		9.6 Bil Gals Max RFG		9.6 Bil Gals Min RFG	
Butane Removed in Winter	Yes	No	Yes	No	Yes	No	Yes	No
Total Cost without Subsidies	619	582	548	496	1,606	1,542	1,507	1,426
Federal Subsidy	−1,684	−1,684	−1,684	−1,684	−2,908	−2,908	−2,908	−3,908
State Subsidies	−180	−180	−173	−173	−189	−189	−176	−176
Total Cost Including Subsidies	−1,245	−1,282	−1,308	−1,361	−1,491	−1,555	−1,578	−1,657
Per-Gallon Cost Including Subsidies (cents/gallon)	−0.82	−0.84	−0.86	−0.89	−0.98	−1.02	−1.03	−1.08

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 suggests that the fuel industry and consumers will see a 0.8 to 1.1 cent per gallon decrease in the apparent cost of producing gasoline with these changes to gasoline.

c. *Cost Sensitivity Case Assuming $70 per Barrel Crude Oil.* As described above, we analyzed a sensitivity analysis with the future price of crude oil remained at today's prices which is around $70 per barrel. This analysis was conducted by applying about a 1.4 multiplication factor times the 2004 gasoline production costs, MTBE and alkylate feedstock costs and butane value. This factor was derived by examining the historical association between increasing wholesale gasoline prices with increasing crude oil prices. We did not adjust the distribution costs, any of the utility costs, octane value and ethanol prices based on the assumption that these would change much less and therefore we kept them the same as that used in the primary analysis. The cost results of the sensitivity analysis are provided with and without the ethanol consumption subsidies in Table VII.C.5.c–1.

TABLE VII.C.5.C–1.—ESTIMATED COSTS FOR CRUDE OIL PRICED AT $70 PER BARREL

[Million dollars and cents per gallon]

	7.2 Bil gals, max RFG		7.2 Bil gals, min RFG		9.6 Bil gals, max RFG		9.6 Bil gals, min RFG	
Butane Removed in Winter	Yes	No	Yes	No	Yes	No	Yes	No

TABLE VII.C.5.C–1.—ESTIMATED COSTS FOR CRUDE OIL PRICED AT $70 PER BARREL—Continued

[Million dollars and cents per gallon]

Total Cost without Subsidies ($million)	−171	−187	−223	−245	222	196	138	105
Per-Gallon Cost without Subsidies (c/gal)	−0.11	−0.12	−0.15	−0.16	0.15	0.13	0.09	0.07
Total Cost Including Subsidies ($million)	−2,035	−2,051	−2,080	−2,102	−2,875	−2,901	−2,945	−2,978
Per-Gallon Cost Including Subsidies (c/gal)	−1.34	−1.35	−1.37	−1.38	−1.88	−1.90	−1.93	−1.95

If crude oil stays priced at around $70 per barrel, the cost of these fuel changes would decrease significantly. In fact, we estimate that the 7.2 billion gallon ethanol case would result in a cost savings to the U.S. even if butanes are removed from the wintertime gasoline pool when ethanol is added. When considering the ethanol subsidies, the incentive to blend in ethanol becomes much stronger at today's crude oil prices likely causing a rapid increase in ethanol production volume.

VIII. What Are the Impacts of Increased Ethanol Use on Emissions and Air Quality?

In this section, we evaluate the impact of increased production and use of renewable fuels on emissions and air quality in the U.S., particularly ethanol and biodiesel. In performing these analyses, we compare the emissions which would have occurred in the future if fuel quality had remained unchanged from pre-Act levels to those which will be required under the Energy Policy Act of 2005 (Energy Act or the Act). This approach differs from that traditionally taken in EPA regulatory impact analyses. Traditionally, we would have compared future emissions with and without the requirement of the Energy Act. However, as described in Section VI, we expect that total renewable fuel use in the U.S. in 2012 to exceed 7.5 billion gallons even in the absence of the RFS program. Thus, a traditional regulatory impact analysis would have shown no impact on emissions or air quality.

Strictly speaking, if the same volume and types of renewable fuels are produced and used with and without the RFS program, the RFS program is having no impact on emissions or air quality. However, levels of renewable fuel use are increasing dramatically relative to both today and the recent past, with corresponding impacts on emissions and air quality. We believe that it is appropriate to evaluate these changes here, regardless of whether they are occurring due to economic forces or Energy Act requirements.

In the process of estimating the impact of increased renewable fuel use, we also include the impact of reduced use of MTBE in gasoline. It is the increased production and use of ethanol which is facilitating the removal of MTBE while still producing the required volume of RFG which meets both commercial and EPA regulatory specifications. Because of this connection, we found it impractical to isolate the impact of increased ethanol use from the removal of MTBE.

A. Effect of Renewable Fuel Use on Emissions

1. Emissions From Gasoline Fueled Motor Vehicles and Equipment

Several models of the impact of gasoline quality on motor vehicle emissions have been developed since the early 1990's. We evaluated these models and selected those which were based on the most comprehensive set of emissions data and developed using the most advanced statistical tools for this analysis. Still, as will be described below, significant uncertainty still exists as to the effect of these gasoline components on emissions from both motor vehicle and nonroad equipment, particularly from the latest models equipped with the most advanced emission controls. Pending adequate funding, we plan to conduct significant vehicle and equipment testing over the next several years to improve our estimates of the impact of these additives and other gasoline properties on emissions. The results of this testing will not be available for inclusion in the analyses supporting this rulemaking. We hope that the results from these test programs will be available for reference in the future evaluations of the emission and air quality impacts of U.S. fuel programs required by the Act.[80]

The remainder of this sub-section is divided into three parts. The first evaluates the impact of increased ethanol use and decreased MTBE use on gasoline quality. The second evaluates the impact of increased ethanol use and decreased MTBE use on motor vehicle emissions. The third evaluates the impact of increased ethanol use and decreased MTBE use on nonroad equipment emissions.

a. *Gasoline Fuel Quality.* For this proposal, we estimate the impact of ethanol use on gasoline quality using fuel survey data obtained by Alliance of Automobile Manufacturers (AAM) from 2001–2005.[81] We estimate the impact of removing MTBE from gasoline based on refinery modeling performed in support of the RFG rulemaking. We plan to update these estimates for the FRM using refinery modeling which is currently underway. In general, as shown in Table VIII.A.1.a–1, adding ethanol to gasoline is expected to reduce levels of aromatics and olefins in conventional gasoline, as well as reduce mid and high distillation temperatures (e.g., T50 and T90). RVP is expected to increase, as most areas of the country grant ethanol blends a 1.0 RVP waiver of the applicable RVP standards in the summer. With the exception of RVP, the effect of removing MTBE results in essentially the opposite impacts. Please see Chapter 2 of the DRIA for a detailed description of the methodologies used and the specific changes in projected fuel quality.

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[80] Subject to funding.

[81] Alliance of Automobile Manufacturers North American Fuel Survey 2005. For the final rule, we intend to supplement this empirical approach with the results of refinery modeling which might better capture all of the effects of ethanol blending on gasoline quality.

TABLE VIII.A.1.A–1.—CG FUEL QUALITY WITH AND WITHOUT OXYGENATES

Fuel parameter	Typical 9 RVP CG	MTBE CG blend	Ethanol CG blend
RVP (psi)	8.7	8.7	9.7
T50	218	206	186
T90	332	324	325
Aromatics (vol%)	32	25.5	27
Olefins (vol%)	7.7	7.7	6.1
Oxygen (wt%)	0	2	3.5
Sulfur (ppm)	30	30	30
Benzene (vol%)	1.0	1.0	1.0

The effect of adding ethanol and removing MTBE on the quality of RFG is expected to very limited. RFG must meet stringent VOC, NO_X and toxics performance standards. Thus, the natural effects of MTBE and ethanol blending on gasoline must often be addressed through further refining. The largest differences are expected to exist in terms of the distillation temperatures, due to the relatively low boiling point of ethanol. Other fuel parameters are expected to be very similar. For this analysis we have assumed no changes to fuel parameters other than ethanol and MTBE content for RFG.

b. *Emissions from Motor Vehicles.* We use the EPA Predictive Models to estimate the impact of gasoline fuel quality on exhaust VOC and NO_X emissions from motor vehicles. These models were developed in 2000, in support of EPA's response to California's request for a waiver of the RFG oxygen mandate. These models represent a significant update of the EPA Complex Model. However, they are still based on emission data from Tier 0 vehicles (roughly equivalent to 1990 model year vehicles). We based our estimates of the impact of fuel quality on CO emissions on the EPA MOBILE6.2 model. We base our estimates of the impact of fuel quality on exhaust toxic emissions (benzene, formaldehyde, acetaldehyde, and 1,3-butadiene) primarily on the MOBILE6.2 model, updated to reflect the effect of fuel quality on exhaust VOC emissions per the EPA Predictive Models. Very limited data are available on the effect of gasoline quality on PM emissions. Therefore, the effect of increased ethanol use on PM emissions can only be qualitatively discussed.

In responding to California's request for a waiver of the RFG oxygen mandate in 2000, we found that both very limited and conflicting data were available on the effect of fuel quality on exhaust emissions from Tier 1 and later vehicles.[82] Thus, we assumed at the time that changes to gasoline quality would not affect VOC, CO and NO_X exhaust emissions from these vehicles. Very little additional data has been collected since that time on which to modify this assumption. Consequently, for our primary analysis for today's proposal we have maintained the assumption that changes to gasoline do not affect exhaust emissions from Tier 1 and later technology vehicles.

There is one recent study by the Coordinating Research Council (CRC) which assessed the impact of ethanol and two other fuel properties on emissions from twelve 2000–2004 model year vehicles (CRC study E–67). The results of this program indicate that emissions from these late model year vehicles may be at least as sensitive to changes to these three fuel properties as Tier 0 vehicles on a percentage basis.[83] However, because this study is the first of its kind and not all relevant fuel properties have yet been studied, in our primary analysis we continue to assume that exhaust emissions from Tier 1 and later vehicles are not sensitive to fuel quality. Based on the indications of the CRC E–67 study, we also conducted a sensitivity analysis where the exhaust VOC and NO_X emission impacts for all vehicles were assumed to be as sensitive to fuel quality as Tier 0 vehicles (*i.e.*, as indicated by the EPA Predictive Models).

We base our estimates of fuel quality on non-exhaust VOC and benzene emissions on the EPA MOBILE6.2 model. The one exception to this is the effect of ethanol on permeation emissions through plastic fuel tanks and elastomers used in fuel line connections. Recent testing has shown that ethanol increases permeation emissions, both by permeating itself and increasing the permeation of other gasoline components. This effect was included in EPA's analysis of California's most recent request for a waiver of the RFG oxygen requirement, but is not in MOBILE6.2.[84] Therefore, we have added the effect of ethanol on permeation emissions to MOBILE6.2's estimate of non-exhaust VOC emissions in assessing the impact of gasoline quality on these emissions.

No models are available which address the impact of gasoline quality on PM emissions. Very limited data indicate that ethanol blending might reduce exhaust PM emissions under very cold weather conditions (*e.g.*, –20 F to 0 F). Very limited testing at warmer temperatures (*e.g.*, 20 F to 75 F) shows no definite trend in PM emissions with oxygen content. Thus, for now, no quantitative estimates can be made regarding the effect of ethanol use on direct PM emissions.

Table VIII.A.1.b–1 presents the average per vehicle (2012 fleet) emission impacts of three types of RFG: Non-oxygenated, a typical MTBE RFG as has been marketed in the Gulf Coast, and a typical ethanol RFG which has been marketed in the Midwest.

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[82] The one exception was the impact of sulfur on emissions from these later vehicles, which is not an issue here due to the fact that renewable fuel use is not expected to change sulfur levels significantly.

[83] The VOC and NO_X emissions from the 2000–2004 model year vehicles are an order of magnitude lower than those from the Tier 0 vehicles used to develop the EPA Complex and Predictive Models. Thus, a similar impact of a fuel parameter in terms of percentage means a much smaller impact in terms of absolute emissions.

[84] For more information on California's request for a waiver of the RFG oxygen mandate and the Decision Document for EPA's response, see *http://www.epa.gov/otaq/rfg_regs.htm#waiver.*

TABLE VIII.A.1.B–1.—EFFECT OF RFG ON PER MILE EMISSIONS FROM TIER 0 VEHICLES RELATIVE TO A TYPICAL 9PSI RVP CONVENTIONAL GASOLINE [a]

Pollutant	Source	Non-Oxy RFG (percent)	11 Volume percent MTBE	10 Volume percent ethanol
Exhaust Emissions				
VOC	EPA Predictive Models	–7.7	–11.1	–12.9
NO_X		–1.7	2.4	6.3
CO	MOBILE6.2	–24	–28	–32
Exhaust Benzene	EPA Predictive and Complex Models	–18	–30	–35
Formaldehyde		7	11	2
Acetaldehyde		7	–8	143
1,3-Butadiene		22	2	–7
Non-Exhaust Emissions				
VOC	MOBILE6.2 & CRC E–65	–30	–30	–18
Benzene	MOBILE6.2 & Complex Models	–5	–15	–7

[a] Average per vehicle effects for the 2012 fleet during summer conditions.

As can be seen, the oxygenated RFG blends are predicted to produce a greater reduction in exhaust VOC and CO emissions than 9 RVP conventional gasoline, but a larger increase in NO_X emissions. This comparison assumes that all gasoline meets EPA's Tier 2 gasoline sulfur standard of 30 ppm. Prior to this program, RFG contained less sulfur than conventional gasoline and produced less NO_X emissions. Non-exhaust VOC emissions with the exception of permeation are roughly the same due to the fact that the RVP level of the three blends is the same. However, the increased permeation emissions associated with ethanol reduces the overall effectiveness of ethanol RFG.

An increase in ethanol use will also impact emissions of air toxics. We evaluated effects on four air toxics affected by fuel parameter changes in the Complex Model-benzene, formaldehyde, acetaldehyde and 1,3-butadiene. The most notable effect on toxic emissions in percentage terms is the increase in acetaldehyde with the use of ethanol. Acetaldehyde emissions more than double. However, as will be seen below, base acetaldehyde emissions are low relative to the other toxics. Thus, the absolute increase in total emissions of these four air toxics is still relatively low.

Table VIII.A.1.b–2 presents the effect of blending either MTBE or ethanol into conventional gasoline while matching octane.

TABLE VIII.A.1.B–2.—EFFECT OF MTBE AND ETHANOL IN CONVENTIONAL GASOLINE ON TIER 0 VEHICLE EMISSIONS RELATIVE TO A TYPICAL NON-OXYGENATED CONVENTIONAL GASOLINE [a]

Pollutant	Source	11 Volume percent MTBE	10 Volume percent ethanol [b]
Exhaust VOC	EPA Predictive Models	−9.2	−7.4
NO_X		2.6	7.7
CO [c]	MOBILE6.2	−6/−11	−11/−19
Exhaust Benzene	EPA Predictive and Complex Models	−22	−27
Formaldehyde		+10	+3
Acetaldehyde		−8	+141
1,3-Butadiene		−12	−27
Non-Exhaust VOC	MOBILE6.2	0	+17
Non-Exhaust Benzene	MOBILE6.2 & Complex Models	−10	+13

[a] Average per vehicle effects for the 2012 fleet during summer conditions.
[b] Assumes a 1.0 psi RVP waiver for ethanol blends.
[c] The first figure shown applies to normal emitters; the second applies to high emitters.

As was the case with the RFG blends, the two oxygenated blends both reduce exhaust VOC and CO emissions, but increase NO_X emissions. The MTBE blend does not increase non-exhaust VOC emissions, but the ethanol blend does due to the commonly granted waiver of the RVP standard. Both blends have lower exhaust benzene and 1,3-butadiene emissions. As above, ethanol increases non-exhaust benzene and acetaldehyde emissions.

The exhaust emission effects shown above for VOC and NO_X emissions only apply to Tier 0 vehicles in our primary analysis. For example, MOBILE6.2 estimates that 34% of exhaust VOC emissions and 16% of NO_X emissions from gasoline vehicles in 2012 come from Tier 0 vehicles. In the sensitivity analysis, these effects are extended to all gasoline vehicles. The effect of RVP on non-exhaust VOC emissions is temperature dependent. The figures shown above are based on the distribution of temperatures occurring across the U.S. in July.

c. *Nonroad Equipment.* To estimate the effect of gasoline quality on emissions from nonroad equipment, we used EPA's NONROAD emission model. We used the 2005 version of this model, NONROAD2005, which includes the effect of ethanol on permeation emissions from most nonroad equipment.

Only sulfur and oxygen content affect exhaust VOC, CO and NO_X emissions in NONROAD. Since sulfur level is assumed to remain constant, the only difference in exhaust emissions between conventional and reformulated gasoline is due to oxygen content. Table VIII.A.1.c–1 shows the effect of adding 11 volume percent MTBE or 10 volume percent ethanol to non-oxygenated gasoline on these emissions.

TABLE VIII.A.1.C–1.—EFFECT MTBE AND ETHANOL ON NONROAD EXHAUST EMISSIONS

Base fuel	4-Stroke engines		2-Stroke engines	
	11 Volume percent MTBE	10 Volume percent ethanol	11 Volume percent MTBE	10 Volume percent ethanol
Exhaust VOC	−9	−15	−1	−1
Non-Exhaust VOC 0	0	26	0	26
CO	−13	−21	−8	−12
NO_X	+24	+37	+12	+18

As can be seen, higher oxygen content reduces exhaust VOC and CO emissions significantly, but also increases NO_X emissions. However, NO_X emissions from these engines tend to be fairly low to start with, given the fact that these engines run much richer than stoichiometric. Thus, a large percentage increase of a relative low base value can be a relatively small increase in absolute terms.

Evaporative emissions from nonroad equipment are impacted by only RVP, and permeation by ethanol content. Both the RVP increase due to blending of ethanol and its permeation effect cause non-exhaust VOC emissions to increase with the use of ethanol in nonroad equipment. The 26 percent effect represents the average impact across the U.S. in July for both 2-stroke and 4-stroke equipment. We updated the NONROAD2005 hose permeation emission factors for small spark-ignition engines and recreational marine watercraft to reflect the use of ethanol.

For nonroad toxics emissions, we base our estimates of the impact of fuel quality on the fraction of exhaust VOC emissions represented by each toxic on MOBILE6.2 (*i.e.,* the same effects predicted for onroad vehicles). The National Mobile Inventory Model (NMIM) contains estimates of the fraction of VOC emissions represented by the various air toxics based on oxygenate type (none, MTBE or ethanol). However, estimates for nonroad gasoline engines running on different fuel types are limited, making it difficult to accurately model the impacts of changes in fuel quality. In the recent NPRM addressing mobile air toxic emissions, EPA replaced the toxic-related fuel effects contained in NMIM with those from MOBILE6.2 for onroad vehicles.[85] We follow the same methodology here. Future testing could significantly alter these emission impact estimates.

2. Diesel Fuel Quality: Biodiesel

EPA assessed the impact of biodiesel fuel on emissions in 2002 and published a draft report summarizing the results.[86] At that time, most of the data available was for pre-1998 model year onroad diesel engines. The results are summarized in Table VIII.A.2–1. As shown, it indicated that biodiesel tended to reduce emissions of VOC, CO and PM. The NO_X emission effect was more variable, showing a very small increase on average.

TABLE VIII.A.2–1.—EFFECT OF 20 VO% BIODIESEL BLENDS ON DIESEL EMISSIONS (%)

Pollutant	2002 draft EPA study (percent)	Recent test results	
		Engine testing	Vehicle testing
VOC	−21	−12% (−35% to +14%)	+10% (−33% to +113%)
CO	−11	−14% (−28% to +1%)	+4% (−11% to +44%)
NO_X	+2	+1% (−3% to +6%)	+2% (−1% to +9%)
PM	−10	−20% (−31%+6%)	−3% (−57% to +40%)

We collected relevant engine and vehicle emission test data developed since the time of the 2002 study. The results of our analysis of this data are also shown in Table VIII.A.2–1. There, we show the average change in the emissions of each pollutant across all the engines or vehicles tested, as well as the range of effects found for each engine or vehicle. As can be seen, the variability in the emission effects is quite large, but the results of the more recent testing generally corroborate the findings of the 2002 study. Refer to DRIA Tables 3.1–15 and 3.1–16, and their corresponding discussion, for more detail on the data in the above table.

Overall, data indicating the effect of biodiesel on emissions is still quite limited. The emission effects also appear to be dependent on the load and speed of the engine (or driving cycle and vehicle type in the case of vehicle testing). However, the data are too limited to determine the specific way in which this occurs. Also, with the implementation of stringent NO_X and PM emission standards to onroad and nonroad diesels in the 2007–2010 timeframe, any effect on a percentage basis will rapidly decrease in magnitude on a mass basis as base emission inventory level decreases. As additional testing is performed over the next several years we will update this assessment.

3. Renewable Fuel Production and Distribution

The primary impact of renewable fuel production and distribution regards ethanol, since it is expected to be the

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[85] 71, **Federal Register,** 15804, March 29, 2006.

[86] ''A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions,'' Draft Technical Report, U.S. EPA, EPA420–P–02–001, October 2002. *http://www.epa.gov/otaq/models/biodsl.htm.*

predominant renewable fuel used in the foreseeable future. We approximate the impact of increased ethanol and biodiesel production, including corn and soy farming, on emissions based on DOE's GREET model, version 1.6. We also include emissions related to distributing the renewable fuels and take credit for reduced emissions related to distributing displaced gasoline and diesel fuel. These emissions are summarized in Table VIII.A.3–1.

TABLE VIII.A.3–1.—WELL-TO-PUMP EMISSIONS FOR PRODUCING AND DISTRIBUTING RENEWABLE FUELS

[Grams per gallon ethanol or biodiesel][a]

Pollutant	Ethanol	Biodiesel
VOC	3.6	41.5
CO	4.4	25.1
NO_X	10.8	44.3
PM10	6.1	1.5
SO_X	7.2	7.5

[a] Includes credit for reduced distribution of gasoline and diesel fuel.

At the same time, areas with refineries might experience reduced emissions, not necessarily relative to current emission levels, but relative to those which would have occurred in the future had renewable fuel use not risen. However, to the degree that increased renewable fuel use reduces imports of gasoline and diesel fuel, as opposed to the domestic production of these fuels, these reduced refinery emissions will occur overseas and not in the U.S.

Similarly, areas with MTBE production facilities might experience reduced emissions from these plants as they cease producing MTBE. However, many of these plants may be converted to produce other gasoline blendstocks, such as iso-octane or alkylate. In this case, their emissions are not likely to change substantially.

B. Impact on Emission Inventories

We use the NMIM to estimate emissions under the various ethanol scenarios on a county by county basis. NMIM basically runs MOBILE6.2 and NONROAD2005 with county-specific inputs pertaining to fuel quality, ambient conditions, levels of onroad vehicle VMT and nonroad equipment usage, etc. We ran NMIM for two months, July and January. We estimate annual emission inventories by summing the two monthly inventories and multiplying by six.

As described above, we removed the effect of gasoline fuel quality on exhaust VOC and NO_X emissions from the onroad motor vehicle inventories which are embedded in MOBILE6.2. We then applied the exhaust emission effects from the EPA Predictive Models. In our primary analysis, we only applied these EPA Predictive Model effects to exhaust VOC and NO_X emissions from Tier 0 vehicles. In a sensitivity case, we applied them to exhaust VOC and NO_X emissions from all vehicles. Regarding the effect of fuel quality on emissions of four air toxics from nonroad equipment (in terms of their fraction of VOC emissions), in all cases we replaced the fuel effects contained in NMIM with those for motor vehicles contained in MOBILE6.2. The projected emission inventories for the primary analysis are presented first, followed by those for the sensitivity analysis.

1. Primary Analysis

The national emission inventories for VOC, CO and NO_X in 2012 with current fuels (i.e., "reference fuel") are summarized in Table VIII.B.1–1. Also shown are the changes in emissions projected for the two levels of ethanol use (i.e., "control cases") described in Section VI and the two different cases for ethanol use in RFG.

TABLE VIII.B.1.–1.—2012 EMISSIONS NATIONWIDE FROM GASOLINE VEHICLES AND EQUIPMENT UNDER SEVERAL ETHANOL USE SCENARIOS—PRIMARY ANALYSIS

[Tons per year]

Pollutant	Inventory	Change in inventory in control cases			
	Reference case	7.2 Billion gallons of ethanol	9.6 Billion gallons of ethanol		
		Minimum RFG use	Maximum RFG use	Minimum RFG use	Maximum RFG use
VOC	5,837,000	31,000	8,000	57,000	29,000
NO_X	2,576,000	19,000	20,000	40,000	39,000
CO	64,799,000	−843,000	−1,229,000	−1,971,000	−2,319,000
Benzene	177,000	−6,000	−3,000	−11,000	−8,000
Formaldehyde	40,200	300	0	800	500
Acetaldehyde	19,800	6,200	5,000	9,600	8,500
1,3-Butadiene	18,200	−500	−300	−800	−600

Both VOC and NO_X emissions are projected to increase with increased use of ethanol. However, the increases are small, generally less than 2 percent. Emissions of formaldehyde are also projected to increase slightly, on the order of 1–3 percent. Emissions of 1,3-butadiene and CO are projected to decrease by about 1–4 percent. Benzene emissions are projected to decrease by 2–6 percent. The largest change is in acetaldehyde emissions, an increase of 25–48 percent, as acetaldehyde is a partial combustion product of ethanol.

CO also participates in forming ozone, much like VOCs. Generally, CO is 15–50 times less reactive than typical VOC. Still, the reduction in CO emissions is roughly 20–140 times the increase in VOC emissions in the four scenarios. Thus, the projected reduction in CO emissions is important from an ozone perspective. However, as described above, the methodology for projecting the effect of ethanol use on CO emissions is inconsistent with that for exhaust VOC and NO_X emissions. Thus, comparisons between changes in VOC and CO emissions are particularly uncertain.

In addition to these changes in emissions due to ethanol use, biodiesel use is expected to have a minor impact on diesel emissions. Table VIII.B.1–2 shows the expected emission reductions associated with an increase in biodiesel fuel use from the reference case of 28 million gallons in 2012 to approximately 300 million gallons per year in 2012. This represents an increase from 0.06 to 0.6 percent of onroad diesel fuel consumption. In terms of a 20 percent biodiesel blend

(B20), it represents an increase from 0.3 to 3.2 percent of onroad diesel fuel consumption.

TABLE VIII.B.1–2.—ANNUAL EMISSIONS NATIONWIDE FROM ONROAD DIESELS IN 2012

[Tons per year]

	Reference inventory: 28 mill gal biodiesel per year	Change in emissions Inventory: 300 mill gal biodiesel per year
VOC	135,000	−800
NO_X	1,430,000	800
CO	353,000	−1,100
Fine PM	27,000	−100

As can be seen, the emission impacts due to biodiesel use are roughly two orders of magnitude smaller than those due to ethanol use.

There will also be some increases in emissions due to ethanol and biodiesel production. Table VIII.B.1–3 shows estimates of annual emissions expected to occur nationwide due to increased production of ethanol. These estimates include a reduction in emissions related to the distribution of the displaced gasoline.

TABLE VIII.B.1–3.—ANNUAL EMISSIONS NATIONWIDE FROM ETHANOL PRODUCTION AND TRANSPORTATION

[Tons per year]

	Reference inventory	Increase in emissions	
		7.2 Billion gallons of ethanol	9.6 Billion gallons of ethanol
VOC	15,929	12,744	22,301
NO_X	47,716	38,173	66,802
CO	19,389	15,511	27,144
PM_{10}	27,094	21,675	37,931
SO_X	31,760	25,408	44,464

As can be seen, the potential increases in emissions from ethanol production and transportation are of the same order of magnitude as those from ethanol use, with the exception of CO emissions. The vast majority of these emissions are related to farming and ethanol production. Both farms and ethanol plants are generally located in ozone attainment areas.

Table VIII.B.1–4 shows estimates of annual emissions expected to occur nationwide due to increased production of biodiesel. These estimates include a reduction in emissions related to the distribution of the displaced diesel fuel.

TABLE VIII.B.1–4.—ANNUAL EMISSIONS NATIONWIDE FROM BIODIESEL PRODUCTION AND TRANSPORTATION

[Tons per year]

Pollutant	Reference inventory: 28 mill gal biodiesel per year	Change in emissions Inventory: 300 mill gal biodiesel per year
VOC	1,300	12,700
NO_X	1,400	13,600
CO	800	7,200
PM_{10}	50	1,000
SO_X	200	1,800

The potential emission increases related to biodiesel production and distribution are generally much smaller, with the possible exception of VOC emissions. Again, these emissions are generally expected to be in ozone attainment areas.

2. Sensitivity Analysis

The national emission inventories for VOC and NO_X in 2012 with current fuels are summarized in Table VIII.B.2–1. Here, the emission effects contained in the EPA Predictive Models are assumed to apply to all vehicles, not just Tier 0 vehicles. Also shown are the changes in emissions projected for the two cases for future ethanol volume and the two cases of ethanol use in RFG. CO emissions are the same as in the primary analysis, as they are not affected by the EPA Predictive Models.

TABLE VIII.B.2–1.—2012 EMISSIONS NATIONWIDE FROM GASOLINE VEHICLES AND EQUIPMENT UNDER SEVERAL ETHANOL USE SCENARIOS: SENSITIVITY ANALYSIS

[Tons per year]

Pollutant	Inventory	Change in inventory in control cases			
	Reference case	7.2 Billion gallons of ethanol		9.6 Billion gallons of ethanol	
		Minimum RFG use	Maximum RFG use	Minimum RFG use	Maximum RFG use
VOC	5,775,000	4,000	−8,000	14,000	−5,000
NO_X	2,610,000	49,000	45,000	95,000	89,000
CO	64,799,000	−843,000	−1,229,000	−1,971,000	−2,319,000
Benzene	175,000	−9,000	−5,000	−14,000	−10,000
Formaldehyde	39,300	0	−200	300	0
Acetaldehyde	19,200	5,800	4,700	9,000	8,000
1,3-Butadiene	17,900	−600	−400	−1,100	−800

The overall VOC and NO_X emission impacts of the various ethanol use scenarios change to some degree when all motor vehicles are assumed to be sensitive to fuel ethanol content. The increase in VOC emissions either decreases substantially or turns into a net decrease due to a greater reduction in exhaust VOC emissions from onroad vehicles. However, the increase in NO_X emissions gets larger, as more vehicles are assumed to be affected by ethanol. Emissions of the four air toxics generally decrease slightly, due to the greater reduction in exhaust VOC emissions.

3. Local and Regional VOC and NO_X Emission Impacts in July

We also estimate the percentage change in VOC and NO_X emissions from gasoline fueled motor vehicles and equipment in those areas which actually experienced a significant change in ethanol use. Specifically, we focused on areas where the market share of ethanol blends was projected to change by 50 percent or more. We also focused on summertime emissions, as these are most relevant to ozone formation. Finally, we developed separately estimates for: (1) RFG areas, including the state of California and the portions of Arizona where their CBG fuel programs apply, (2) low RVP areas (i.e., RVP standards less than 9.0 RVP, and (3) areas with a 9.0 RVP standard. This set of groupings helps to highlight the emissions impact of increased ethanol use in those areas where emission control is most important.

Table VIII.B.3–1 presents our primary estimates of the percentage change in VOC and NO_X emission inventories for these three types of areas. While ethanol use is going up in the vast majority of the nation, ethanol use in RFG areas under the ''Minimum Use in RFG'' scenarios is actually decreasing compared to the 2012 reference case. This is important to note in order to understand the changes in emissions indicated.

TABLE VIII.B.3–1.—CHANGE IN EMISSIONS FROM GASOLINE VEHICLES AND EQUIPMENT IN COUNTIES WHERE ETHANOL USE CHANGED SIGNIFICANTLY—PRIMARY ANALYSIS

Ethanol use	7.2 Billion gallons		9.6 Billion gallons	
Ethanol use in RFG	Minimum	Maximum	Minimum	Maximum
RFG Areas				
Ethanol Use	Down	Up	Down	Up.
VOC	1.6%	0.4%	1.6%	0.4%.
NO_X	−5.2%	2.4%	−5.2%	2.4%.
Low RVP Areas				
Ethanol Use	Up	Up	Up	Up.
VOC	3.1%	3.2%	4.1%	3.5%.
NO_X	4.1%	6.0%	4.8%	4.4%.
Other Areas				
Ethanol Use	Up	Up	Up	Up.
VOC	4.1%	4.1%	5.4%	4.4%.
NO_X	4.6%	6.0%	5.8%	4.8%.

As expected, increased ethanol use tends to increase NO_X emissions. The increase in low RVP and other areas is greater than in RFG areas, since the RFG in the RFG areas included in this analysis all contained MTBE. Also, increased ethanol use tends to increase VOC emissions, indicating that the increase in non-exhaust VOC emissions exceeds the reduction in exhaust VOC emissions. This effect is muted with RFG due to the absence of an RVP waiver for ethanol blends. The reader is referred to Chapter 2 of the DRIA for discussion of how ethanol levels will change at the state-level.

Table VIII.B.3–2 presents the percentage change in VOC and NO_X

emission inventories under our sensitivity case (*i.e.*, when we apply the emission effects of the EPA Predictive Models to all motor vehicles).

TABLE VIII.B.3–2.—CHANGE IN EMISSIONS FROM GASOLINE VEHICLES AND EQUIPMENT IN COUNTIES WHERE ETHANOL USE CHANGED SIGNIFICANTLY—SENSITIVITY ANALYSIS

	7.2 Bgal Min	7.2 Bgal Max	9.6 Bgal Min	9.6 Bgal Max
RFG Areas				
Ethanol Use	Down	Up	Down	Up.
VOC	2.6%	0.2%	2.6%	0.2%.
NO_X	−9.0%	4.7%	−9.0%	4.7%.
Low RVP Areas				
Ethanol Use	Up	Up	Up	Up.
VOC	2.1%	2.1%	3.1%	2.5%.
NO_X	8.2%	10.6%	9.8%	8.9%.
Other Areas				
Ethanol Use	Up	Up	Up	Up.
VOC	3.4%	3.4%	4.6%	3.7%.
NO_X	8.4%	10.1%	10.3%	8.8%.

Directionally, the changes in VOC and NO_X emissions in the various areas are consistent with those from our primary analysis. The main difference is that the increases in VOC emissions are smaller, due to more vehicles experiencing a reduction in exhaust VOC emissions, and the increases in NO_X emissions are larger.

C. Impact on Air Quality

We estimate the impact of increased ethanol use on the ambient concentrations of two pollutants: ozone and PM. Quantitative estimates are made for ozone, while only qualitative estimates can be made currently for ambient PM. These impacts are described below.

1. Impact of 7.2 Billion Gallon Ethanol Use on Ozone

We use a metamodeling tool developed at EPA, the ozone response surface metamodel (Ozone RSM), to estimate the effects of the projected changes in emissions from gasoline vehicles and equipment for the 7.2 billion gallon ethanol use case. The changes in diesel emissions are negligible in comparison. We did not include the estimated changes in emissions from renewable fuel production and distribution, because of their more approximate nature. Their geographical concentration also makes it more difficult to simulate with the Ozone RSM.

The Ozone RSM was created using multiple runs of the Comprehensive Air Quality Model with Extensions (CAMx). Base and proposed control CAMx metamodeling was completed for the year 2015 over a modeling domain that includes all or part of 37 Eastern U.S. states, plus the District of Columbia. For more information on the Ozone RSM, please see the Chapter 5 of the DRIA for this proposal.

The Ozone RSM limits the number of geographically distinct changes in VOC and NO_X emissions which can be simulated. As a result, we could not apply distinct changes in emissions for each county. Therefore, two separate runs were made with different VOC and NO_X emissions reductions. We then selected the ozone impacts from the various runs which best matched the VOC and NO_X emission reductions for that county. This models the impact of local emissions reasonably well, but loses some accuracy with respect to ozone transport. No ozone impact was assumed for areas which did not experience a significant change in ethanol use. The predicted ozone impacts of increased ethanol use for those areas where ethanol use is projected to change by more than a 50% market share are summarized in Table VIII.C.1–1. As shown in Table 5.1–2 of the DRIA, national average impacts (based on the 37-state area modeled) which include those areas where no change in ethanol use is occurring are considerably smaller.

TABLE VIII.C.1–1.—IMPACT ON 8-HOUR DESIGN VALUE EQUIVALENT OZONE LEVELS (PPB) [a]

	Primary Analysis		Sensitivity Analysis	
	Min RFG Use	Max RFG Use	Min RFG Use	Max RFG Use
Minimum Change	−0.030	−0.025	−0.180	0.000
Maximum Change	0.395	0.526	0.637	0.625
Average Change [b]	0.137	0.171	0.294	0.318
Population-Weighted Change [b]	0.134	0.129	0.268	0.250

[a] In comparison to the 80 ppb 8-hour ozone standards.

[b] Only for those areas experiencing a change in ethanol blend market share of at least 50 percent.

As can be seen, ozone levels generally increase to a small degree with increased ethanol use. This is likely due to the projected increases in both VOC and NO_X emissions. Some areas do see a small decrease in ozone levels. In our primary analysis, where exhaust emissions from Tier 1 and later onroad vehicles are assumed to be unaffected by ethanol use, the population-weighted increase in ambient ozone levels in those areas where ethanol use changed significantly is 0.129–0.134 ppb. Since the 8-hour ambient ozone standard is 80 ppb, this increase represents about 0.16 percent of the standard, a very small percentage.

In our sensitivity analysis, where exhaust emissions from Tier 1 and later onroad vehicles are assumed to respond to ethanol like Tier 0 vehicles, the population-weighted increase in ambient ozone levels is roughly twice as high, or 0.250–0.268 ppb. This increase represents about 0.32 percent of the standard.

There are a number of important caveats concerning these estimates. First, the emission effects of adding ethanol to gasoline are based on extremely limited data for recent vehicles and equipment. Second, the Ozone RSM does not account for changes in CO emissions. As shown above, ethanol use should reduce CO emissions significantly, directionally reducing ambient ozone levels in those areas where ozone formation is VOC-limited. (Ozone levels in areas which are NO_X-limited are unlikely to be affected by a change in CO emissions.) The Ozone RSM also does not account for changes in VOC reactivity. With additional ethanol use, the ethanol content of VOC should increase. Ethanol is less reactive than the average VOC. Therefore, this change should also reduce ambient ozone levels in a way not addressed by the Ozone RSM, again in those areas where ozone formation is predominantly VOC-limited.

Moving to health effects, exposure to ozone has been linked to a variety of respiratory effects including premature mortality, hospital admissions and illnesses resulting in school absences. Ozone can also adversely affect the agricultural and forestry sectors by decreasing yields of crops and forests. Although the health and welfare impacts of changes in ambient ozone levels are typically quantified in regulatory impact analyses, we do not evaluate them for this analysis. On average, the changes in ambient ozone levels shown above are small and would be even smaller if changes in CO emissions and VOC reactivity were taken into account. The increase in ozone would likely lead to negligible monetized impacts. We therefore do not estimate and monetize ozone health impacts for the changes in renewable use due to the small magnitude of this change, and the uncertainty present in the air quality modeling conducted here, as well as the uncertainty in the underlying emission effects themselves discussed earlier.

2. Particulate Matter

Ambient PM can come from two distinct sources. First, PM can be directly emitted into the atmosphere. Second, PM can be formed in the atmosphere from gaseous pollutants. Gasoline-fueled vehicles and equipment contribute to ambient PM concentrations in both ways.

As described above, we are not currently able to predict the impact of fuel quality on direct PM emissions from gasoline-fueled vehicles or equipment. Therefore, we are unable at this time to project the effect that increased ethanol use will have on levels of directly emitted PM in the atmosphere.

PM can also be formed in the atmosphere (termed secondary PM here) from several gaseous pollutants emitted by gasoline-fueled vehicles and equipment. Sulfur dioxide emissions contribute to ambient sulfate PM. NO_X emissions contribute to ambient nitrate PM. VOC emissions contribute to ambient organic PM, particularly the portion of this PM comprised of organic carbon. Increased ethanol use is not expected to change gasoline sulfur levels, so emissions of sulfur dioxide and any resultant ambient concentrations of sulfate PM are not expected to change. Increased ethanol use is expected to increase NO_X emissions, as described above. Thus, the possibility exists that ambient nitrate PM levels could increase. Increased ethanol is generally expected to increase VOC emissions, which could also impact the formation of secondary organic PM. However, some VOC emissions, namely exhaust VOC emissions, are expected to decrease, while non-exhaust VOC emissions are expected to increase and the impact on PM is a function of the type of VOC emissions.

The formation of secondary organic PM is very complex, due in part to the wide variety of VOCs emitted into the atmosphere. Whether or not a specific gaseous VOC reacts to form PM in the atmosphere depends on the types of reactions that VOC undergoes, which in turn can depend on other pollutants present, such as ozone, NO_X and other reactive compounds. The relative mass of secondary PM formed per mass of gaseous VOC emitted can also depend on the concentration of the gaseous VOC and the organic PM in the atmosphere. Most of the secondary organic PM exists in a continually changing equilibrium between the gaseous and PM phases. Both the rates of these reactions and the gaseous-PM equilibria depend on temperature, so seasonal differences can be expected.

Recent smog chamber studies have indicated that gaseous aromatic VOCs can form secondary PM under certain conditions. These compounds comprise a greater fraction of exhaust VOC emissions than non-exhaust VOC emissions, as non-exhaust VOC emissions are dominated by VOCs with relatively high vapor pressures. Aromatic VOCs tend to have lower vapor pressures. As increased ethanol use is expected to reduce exhaust VOC emissions, emissions of aromatic VOCs should also decrease. In addition, refiners are expected to reduce the aromatic content of gasoline by 5 volume percentage points as ethanol is blended into gasoline. Emissions of aromatic VOCs should decrease with lower concentrations of aromatics in gasoline. Thus, emissions of gaseous aromatic VOCs could decrease for both reasons.

Overall, we expect that the decrease in secondary organic PM is likely to exceed the increase in secondary nitrate PM. In 1999, NO_X emissions from gasoline-fueled vehicles and equipment comprised about 20% of national NO_X emissions from all sources. In contrast, gasoline-fueled vehicles and equipment comprised over 60% of all national gaseous aromatic VOC 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.

EPA currently utilizes the CMAQ model to predict ambient levels of PM as a function of gaseous and PM emissions. This model includes mechanisms to predict the formation of nitrate PM from NO_X emissions. However, it does not currently include any mechanisms addressing the formation of secondary organic PM. EPA is currently developing a model of secondary organic PM from gaseous toluene emissions. We plan to incorporate this mechanism into the CMAQ model in 2007. The impact of other aromatic compounds will be added as further research clarifies their role in secondary organic PM formation. Therefore, we expect to be able to quantitatively estimate the impact of decreased toluene emissions and increased NO_X emissions due to increased ethanol use as part of future analyses of U.S. fuel requirements required by the Act.

IX. Impacts on Fossil Fuel Consumption and Related Implications

Renewable fuels have been of significant interest for many years due to their ability to displace fossil fuels, which have often been targeted as primary contributors to emissions of greenhouse gases such as carbon dioxide and national energy concerns such as dependence on foreign sources of petroleum. Because significantly more renewable fuel is expected to be consumed over the next few years than has been consumed in the past, there is increased interest in the degree to which their increased use will impact greenhouse gas emissions and fossil fuel consumption.

Based on our analysis, we estimate that increases in the use of renewable fuels will reduce fossil fuel consumption and GHG emissions as shown in Table IX–1 in 2012. The results represent the percent reduction in total transportation sector emissions and energy use. The ranges result from different cases evaluated of the amount of renewable fuel (7.5 billion gallons versus 9.9 billion gallons) that will actually be produced in 2012.

TABLE IX–1.—LIFECYCLE IMPACTS OF INCREASED RENEWABLE FUEL USE RELATIVE TO THE 2012 REFERENCE CASE

	7.5 Billion case [a]	9.9 Billion case [b]
Percent Reduction in Transportation Sector Petroleum Energy Use	1.0	1.6
Percent Reduction in Transportation Sector Fossil Fuel Energy Use	0.5	0.8
Percent Reduction in Transportation Sector GHG Emissions	0.4	0.6
Percent Reduction in Transportation Sector CO_2 Emissions	0.6	0.9

[a] 7.2 billion gallons of ethanol.
[b] 9.6 billion gallons of ethanol.

This section provides a summary of our analysis of the fossil fuel impacts of the RFS rule.

A. Lifecycle Modeling

Although the use of renewable fuels in the transportation sector directly displaces some petroleum consumed as motor vehicle fuel, this displacement of petroleum is in fact only one aspect of the overall impact of renewable fuels on fossil fuel use. Fossil fuels are also used in producing and transporting renewable feedstocks such as plants or animal byproducts, in converting the renewable feedstocks into renewable fuel, and in transporting and blending the renewable fuels for consumption as motor vehicle fuel. To estimate the true impacts of increases in renewable fuels on fossil fuel use, modelers attempt to take many or all these steps into account. Similarly, energy is used and GHGs emitted in the pumping of oil, transporting the oil to the refinery, refining the crude oil into finished transportation fuel, transporting the refined gasoline or diesel fuel to the consumer and then burning the fuel in the vehicle. Such analyses are termed lifecycle or well-to-wheels analyses.

A variety of approaches are available to conduct lifecycle analysis. This variety largely reflects different assumptions about (1) the boundary conditions and (2) the estimates of input factors. The boundary conditions determine the scope of the analysis. For example, a lifecycle analysis could include energy required to make farm equipment as part of the estimate of energy required to grow corn. The agency chose a lifecycle analytic boundary that encompasses the fuel-cycle and does not include the example used above. Differing estimates on input factors (e.g. amount of fertilizer to grow corn) can also affect the results of the lifecycle analysis.

For this proposed rulemaking, we have made use of a fuel-cycle model, GREET,[87] developed at Argonne National Laboratory (ANL) under the sponsorship of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE). GREET has been under development for several years and has undergone extensive peer review through multiple updates. Of the available sources of information on lifecycle analyses of energy consumed and emissions generated, we believe that GREET offers the most comprehensive treatment of the transportation sector. For instance, GREET provides lifecycle assessments for ethanol made from corn and cellulosic materials, biodiesel made from soybean oil, and petroleum-based gasoline and diesel fuel. Thus GREET provides a means for calculating the relative greenhouse gas (GHG) and petroleum impacts of renewable fuels that displace conventional motor vehicle fuels. For this proposal, we used version 1.7 of the GREET model, with a few modifications to its input assumptions as described in more detail below.

We do not believe that it would be appropriate at this time to base the regulatory provisions for this rule on lifecycle modeling, as described in more detail in Section III.B.4. Although the GREET model does provide a peer-reviewed source for lifecycle modeling, a consensus on all the assumptions, including point estimates, that are used as inputs into that model does not exist.[88] Also, given the short timeframe available for the development of this proposal, we have not had the opportunity to initiate the type of public dialogue on lifecycle modeling that would be necessary before such analyses could be incorporated into a regulatory framework. We have therefore chosen to use lifecycle modeling only as a means to estimate the impacts of the increased use of renewable fuel.

In addition to the GREET model tool, EPA has also developed a lifecycle modeling tool that is specific to individual fuel producers. This FUEL-CO2 model is intended to help fuel producers estimate the lifecycle greenhouse gas emissions and fossil energy use for all stages in the development of their specific fuel. EPA will evaluate whether the FUEL-CO2 model would be an appropriate tool for fuel providers who wish to demonstrate their actual reductions in greenhouse gas emissions and fossil energy use. This may also be the best way for ethanol producers to quantify the benefits of their renewable process energy use when qualifying corn ethanol as cellulosic biomass ethanol (an option for ethanol producers, stipulated in the Act).

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[87] Greenhouse gases, Regulated Emissions, and Energy use in Transportation.

[88] See Chapter 6.1.2 of the RIA for further discussion of input assumptions used for the GREET modeling. Also see IX.A.2 of this preamble section for a discussion about the differing estimates.

1. Modifications to GREET Assumptions

GREET is subject to periodic updates by ANL, each of which results in some changes to the inputs and assumptions that form the basis for the lifecycle estimates of emissions generated and energy consumed. These updates generally focus on those input values for those fuels or vehicle technologies that are the focus of ANL at the time. As a result there are a variety of other inputs related to ethanol and biodiesel that have not been updated in some time. In the context of the RFS program, we determined that some of the GREET input values that were either based on outdated information or did not appropriately reflect market conditions under a renewable fuels mandate should be examined more closely, and updated if necessary.

In the timeframe available for developing this proposal, we chose to concentrate our efforts on those GREET input values for ethanol that had significant influence on the lifecycle emissions or energy estimates and that were likely to be based on outdated information. We reviewed the input values only for ethanol made from corn, since this particular renewable fuel is likely to continue to dominate the renewable fuel pool through at least 2012. For cellulosic ethanol and biodiesel the GREET default values were used in this proposal. However, we have also initiated a contract with ANL to investigate a wider variety of GREET input values, including those associated with the following fuel/feedstock pathways:

- Ethanol from corn.
- Ethanol from cellulosic materials (hybrid populars, switchgrass, and corn stover).
- Biodiesel from soybean oil.
- Methanol from renewable sources.
- Natural gas from renewable sources.
- Renewable diesel formulations.

The contract focuses on the potential fuel production developments and efficiency improvements that could occur within the time-frame of the RFS program. The GREET input value changes resulting from this work are projected to be available in the fall of 2006, not in time for this proposal, but they will be incorporated into revised lifecycle assessments for the final rule.

We did not investigate the input values associated with the production of petroleum-based gasoline or diesel fuel in the GREET model for this proposal. However, the refinery modeling discussed in Section VII will provide some additional information on the process energy requirements associated with the production of gasoline and diesel under a renewable fuels mandate. We will use information from this refinery modeling for the final rule to determine if any GREET input values should be changed.

A summary of the GREET corn ethanol input values we investigated and modified for this proposal is given below. We also examined several other GREET input values, but determined that the default GREET values should not be changed for a variety of reasons. These included ethanol plant process efficiency, corn and ethanol transport distances and modes, corn farming inputs, CO_2 emissions from corn farming land use change, and byproduct allocation methods. Our investigation of these other GREET input values are discussed more fully in Chapter 6 of the RIA. The current GREET default factors for these other inputs were included in the analysis for this proposal.

a. *Wet-Mill Versus Dry Mill Ethanol Plants.* The two basic methods for producing ethanol from corn are wet milling and dry milling. In the wet milling process, the corn is soaked to separate the starch, used to make ethanol, from the other components of the corn kernel. In the dry milling process, the entire corn kernel is ground and fermented to produce ethanol. The remaining components of the corn are then dried for animal feed (dried distillers grains with solubles, or DDGS). Wet milling is more complicated and expensive than dry milling, but it produces more valuable products (ethanol plus corn syrup, corn oil, and corn gluten meal and feeds). The majority of ethanol plants in the United States are dry mill plants, which produce ethanol more simply and efficiently. The GREET default is 70 percent dry mill, 30 percent wet mill.

For this analysis, we expect most new ethanol plants will be dry mill operations. That has been the trend in the last few years as the demand for ethanol has grown, and our analysis of ethanol plants under construction and planned for the near future has verified this. Therefore, it was assumed that essentially all new ethanol facilities would be dry mill plants.

b. *Coal Versus Natural Gas in Ethanol Plants.* The type of fuel used within the ethanol plant for process energy, to power the various components that are used in ethanol production (dryers, grinders, heating, etc.) can vary among ethanol plants. The type of fuel used has an impact on the energy usage, efficiency, and emissions of the plant, and is primarily determined by economics. Most new plants built in the last few years have used natural gas. Based on specific situations and economics, some new plants are using coal. In addition, EPA is promoting the use of combined heat and power, or cogeneration, in ethanol plants to improve plant energy-efficiency and to reduce air emissions. This technology, in the face of increasing natural gas prices, may make coal a more attractive energy source for new ethanol plants.

GREET assumes that 20 percent of plants will be powered by coal. However, our review of plants under construction and those planned for the near future indicates that coal will only be used for approximately 10% of the plants. This is the value we assumed in GREET for our analysis. However, as new plants are constructed to meet the demands of the RFS, this percentage is expected to go up. Future work in preparation for the final rule will evaluate the potential trends for combined heat and power and coal as process fuel.

c. *Ethanol Production Yield.* It is generally assumed that 1 bushel of corn yields 2.7 gallons of ethanol. However, the development of new enzymes continues to increase the potential ethanol yield. We used a value of 2.71 gal/bu in our analysis. This value represents pure ethanol production (*i.e.* no denaturant). This value is consistent with the cost modeling of corn ethanol discussed in Section VII.

2. Controversy Concerning the Ethanol Energy Balance

Although we have made use of lifecycle impact estimates from ANL's GREET model, there are a variety of lifecycle impact analyses from other researchers that provide alternative and sometimes significantly different estimates. The lifecycle energy balance for corn-ethanol, in particular, has been the subject of numerous and sometimes contentious debates.

Several metrics are commonly used to describe the energy efficiency of renewable fuels. We have chosen to use displacement indexes for this proposal because they provide the least ambiguous and most relevant mechanism for estimating the impacts of renewable fuels on GHGs and petroleum consumption. However, other metrics, such as the net energy balance and energy efficiency, have more commonly been used in the past. The use of these metrics has served to complicate the issue since they do not involve a direct comparison to the gasoline that the ethanol is replacing.

Among researchers who have studied the lifecycle energy balance of corn-ethanol, the primary differences of opinion appear to center on fossil energy associated with fertilizers, the energy required to convert corn into ethanol, and the value of co-products. As a result of these differences, the net energy balance has been estimated to be somewhere between −34 and +31 thousand Btu/gal, and the energy efficiency has been estimated to be somewhere between 0.6 and 1.4.[89] A concern arises in cases where a researcher concludes that the net energy balance is negative, or the energy efficiency is less than 1.0. Such cases would indicate that the fossil energy used in the production and transportation of ethanol exceeds the energy in the ethanol itself, and this is generally interpreted to mean that lifecycle fossil fuel use negates the benefits of replacing gasoline with ethanol. However, since the metrics used do not actually compare ethanol to gasoline, such interpretations are unwarranted.

The primary studies that conclude that the energy balance is negative were conducted by Dr. David Pimental of Cornell University and Dr. T. Patzek of University of California, Berkeley [90] [91]. Many other researchers, however, have criticized that work as being based on out-dated farming and ethanol production data, including data not normally considered in lifecycle analysis for fuels, and not following the standard methodology for lifecycle analysis in terms of valuing co-products. Furthermore, several recent surveys have concluded that the energy balance is positive, although they differ in their numerical estimates.[92] [93] [94] Authors of the GREET model have also concluded that the lifecycle amount of fossil energy used to produce ethanol is less than the amount of energy in the ethanol itself. Based on our review of all the available information, we have concluded that the energy balance is indeed positive, and we believe that the GREET model provides an accurate basis for quantifying the lifecycle impacts.

B. Overview of Methodology

The GREET model does not provide estimates of energy consumed and emissions generated in total, such as the total amount of natural gas consumed in the U.S. in a given year by ethanol production facilities. Instead, it provides estimates on a national average, per fuel unit basis, such as the amount of natural gas consumed for the average ethanol production facility per million Btus of ethanol produced. As a result we could not use GREET directly to estimate the nationwide impacts of replacing some gasoline and diesel with renewable fuels.

Instead, we used GREET to generate comparisons between renewable fuels and the petroleum-based fuels that they displace. These comparisons allowed us to develop displacement indexes that represent the amount of lifecycle GHGs or fossil fuel reduced when a Btu of renewable fuel replaces a Btu of gasoline or diesel. In order to estimate the incremental impacts of increased use of renewable fuels on GHGs and fossil fuels, we combined those displacement indexes with our renewable fuel volume scenarios and GHG emissions and fossil fuel consumption data for the conventional fuels replaced. For example, to estimate the impact of corn-ethanol use on GHGs, these factors were combined in the following way:

$$S_{\text{GHG,corn ethanol}} = R_{\text{corn ethanol}} \times LC_{\text{gasoline}} \times DI_{\text{GHG,corn ethanol}}$$

Where:

$S_{\text{GHG,corn ethanol}}$ = Lifecycle GHG emission reduction relative to the 2012 reference case associated with use of corn ethanol (million tons of GHG).

$R_{\text{corn ethanol}}$ = Amount of gasoline replaced by corn ethanol on an energy basis (Btu).

LC_{gasoline} = Lifecycle emissions associated with gasoline use (million tons of GHG per Btu of gasoline).

$DI_{\text{GHG,corn ethanol}}$ = Displacement Index for GHGs and corn ethanol, representing the percent reduction in gasoline lifecycle GHG emissions which occurs when a Btu of gasoline is replaced by a Btu of corn ethanol.

Variations of the above equation were also generated for impacts on all four endpoints of interest (emissions of CO2, emissions of GHGs, fossil fuel consumption, and petroleum consumption) as well as all three renewable fuels examined (corn-ethanol, cellulosic ethanol, and biodiesel). Each of the variables in the above equation are discussed in more detail below. Section 6 of the DRIA provides details of the analysis.

1. Amount of Conventional Fuel Replaced by Renewable Fuel (R)

In general, the volume fraction (R) represents the amount of conventional fuel no longer consumed—that is, displaced—as a result of the use of the replacement renewable fuel. Thus R represents the total amount of renewable fuel used under each of our renewable fuel volume scenarios, in units of Btu. We make the assumption that vehicle energy efficiency will not be affected by the presence of renewable fuels (i.e., efficiency of combusting one Btu of ethanol is equal to the efficiency of combusting one Btu of gasoline).

Consistent with the emissions modeling described in Section VII, our analysis of the GHG and fossil fuel consumption impacts of renewable fuel use was conducted using three volume scenarios. The first scenario was a base case representing 2004 renewable fuel production levels, projected to 2012. This scenario provided the point of comparison for the other two scenarios. The other two renewable fuel scenarios for 2012 represented the RFS program requirements and the volume projected by EIA. In both scenarios, we assumed that the biodiesel production volume would be 0.3 billion gallons based on an EIA projection, and that the cellulosic ethanol production volume would be 0.25 billion gallons based on the Energy Act's requirement that 250 million gallons of cellulosic ethanol be produced starting in the next year, 2013. The remaining renewable fuel volumes in each scenario would be ethanol made from corn. The total volumes for all three scenarios are shown in Table IX.B.1–1. For the purposes of calculating the R values, we assumed the ethanol volumes are 5% denatured, and the volumes were converted to total Btu using the appropriate volumetric energy content values (76,000 Btu/gal for ethanol, and 118,000 Btu/gal for biodiesel).

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[89] A net energy balance of zero, or an energy efficiency of 1.0, would indicate that the full lifecycle fossil fuels used in the production and transportation of ethanol are exactly equal to the energy in the ethanol itself.

[90] Pimentel, David ''Ethanol Fuel: Energy Balance, Economics, and Environmental Impacts are Negative'', Vol. 12, No. 2, 2003 International Association for Mathematical Geology, Natural Resources Research.

[91] Pimentel, D.; Patzek, T. ''Ethanol production using corn, switchgrass, and wood; biodiesel production using soybean and sunflower.'' Nat. Resour. Res. 2005, 14 (1), 65–76.

[92] Hammerschlag, R. ''Ethanol's Energy Return on Investment: A Survey of the Literature 1990—Present.'' Environ. Sci. Technol. 2006, 40, 1744–1750.

[93] Farrell, A., Pelvin, R., Turner, B., Joenes, A., O'Hare, M., Kammen, D., ''Ethanol Can Contribute to Energy and Environmental Goals'', Science, 1/27/2006, Vol. 311, 506–508.

[94] Hill, J., Nelson, E., Tilman, D., Polasky, S., Tiffany, D., ''Environmental, economic, and energetic costs and benefits of biodiesel and ethanol biofuels'', Proceedings of the National Academy of Sciences, 7/25/2006, Vol. 103, No. 30, 11206–11210.

TABLE IX.B.1–1.—VOLUME SCENARIOS IN 2012

[billion gallons]

	Reference case	RFS required volume: 7.5 B gal	Projected volume: 9.9 B gal
Corn-ethanol	3.9	6.95	9.35
Cellulosic ethanol	0.0	0.25	0.25
Biodiesel	0.028	0.3	0.3
Total volume	3.928	7.5	9.9

Since the impacts of increased renewable fuel use were measured relative to the 2012 reference case, the value of R actually represented the incremental amount of renewable fuel between the reference case and each of the two other scenarios.

2. Lifecycle Impacts of Conventional Fuel Use (LC)

In order to determine the lifecycle impact that increased renewable fuel volumes may have on any particular endpoint (fossil fuel consumption or emissions of GHGs), we also needed to know the conventional fuel inventory on a lifecycle basis. Since available sources of GHG emissions are provided on a direct rather than a lifecycle basis, we converted these direct emission and energy estimates into their lifecycle counterparts. We used GREET to develop multiplicative factors for converting direct (vehicle-based) emissions of GHGs and energy use into full lifecycle factors. Table IX.B.2–1 shows the total lifecycle petroleum and GHG emissions associated with direct use of a Btu value of gasoline and diesel fuel.

TABLE IX.B.2–1.—LIFECYCLE EMISSIONS AND ENERGY (LC VALUES)

	Gasoline	Diesel
Petroleum (Btu/Btu)	1.11	1.10
Fossil fuel (Btu/Btu)	1.22	1.21
GHG (Tg-CO_2-eq/QBtu)	99.4	94.5
CO_2 (Tg-CO_2/QBtu)	94.2	91.9

3. Displacement Indexes (DI)

The displacement index (DI) represents the percent reduction in GHG emissions or fossil fuel energy brought about by the use of a renewable fuel in comparison to the conventional gasoline or diesel that the renewable fuel replaces. The formula for calculating the displacement index depends on which fuel is being displaced (i.e. gasoline or diesel), and which endpoint is of interest (e.g. petroleum energy, GHG). For instance, when investigating the CO_2 impacts of ethanol used in gasoline, the displacement index is calculated as follows:

$$DI_{CO_2} = 1 - \frac{\text{lifecycle } CO_2 \text{ emitted for ethanol in g/Btu}}{\text{lifecycle } CO_2 \text{ emitted for gasoline in g/Btu}}$$

The units of g/Btu ensure that the comparison between the renewable fuel and the conventional fuel is made on a common basis, and that differences in the volumetric energy content of the fuels is taken into account. The denominator includes the CO_2 emitted through combustion of the gasoline itself in addition to all the CO_2 emitted during its manufacturer and distribution. The numerator, in contrast, includes only the CO_2 emitted during the manufacturer and distribution of ethanol, not the CO_2 emitted during combustion of the ethanol.

The combustion of biomass-based fuels, such as ethanol from corn and woody crops, generates CO_2. However, in the long run the CO_2 emitted from biomass-based fuels combustion does not increase atmospheric CO_2 concentrations, assuming the biogenic carbon emitted is offset by the uptake of CO_2 resulting from the growth of new biomass. As a result, CO_2 emissions from biomass-based fuels combustion are not included in their lifecycle emissions results and are not used in the CO_2 displacement index calculations shown above.

Using GREET, we calculated the lifecycle values for energy consumed and GHGs produced for corn-ethanol, cellulosic ethanol, and soybean-based biodiesel. These values were in turn used to calculate the displacement indexes. The results are shown in Table IX.B.3–1. Details of these calculations can be found in Chapter 6 of the RIA. As noted previously, different models can result in different estimates. For example, whereas GREET estimates a net GHG reduction of about 26% for corn ethanol compared to gasoline, the previously cited works by Farrell et al. estimates around a 13% reduction.

TABLE IX.B.3–1.—DISPLACEMENT INDEXES DERIVED FROM GREET

	Corn ethanol (percent)	Cellulosic ethanol (percent)	Biodiesel (percent)
$DI_{Petroleum}$	92.3	92.7	84.6
$DI_{Fossil\ Fuel}$	40.1	96.0	47.9
DI_{GHG}	25.8	98.1	53.4

TABLE IX.B.3–1.—DISPLACEMENT INDEXES DERIVED FROM GREET—Continued

	Corn ethanol (percent)	Cellulosic ethanol (percent)	Biodiesel (percent)
DI_{CO_2}	43.9	110.1	56.8

The displacement indexes in this table represent the impact of replacing a Btu of gasoline or diesel with a Btu of renewable fuel. Thus, for instance, for every Btu of gasoline which is replaced by corn ethanol, the total lifecycle GHG emissions that would have been produced from that Btu of gasoline would be reduced by 25.8 percent. For every Btu of diesel which is replaced by biodiesel, the total lifecycle petroleum energy that would have been consumed as a result of burning that Btu of diesel fuel would be reduced by 84.6 percent.

Note that our DI estimates for cellulosic ethanol assume that the ethanol in question was in fact produced from a cellulosic feedstock, such as wood, corn stalks, or switchgrass. However, the definition of cellulosic biomass ethanol given in the Energy Act also includes ethanol made from non-cellulosic feedstocks if 90 percent of the process energy used to operate the facility is derived from a renewable source. In the context of our cost analysis, we have assumed this latter definition of cellulosic ethanol. Further discussion of this issue can be found in Chapter 1, Section 1.2.2 of the RIA.

C. Impacts of Increased Renewable Fuel Use

We used the methodology described above to calculate impacts of increased use of renewable fuels on consumption of petroleum and fossil fuels and also on emissions of CO_2 and GHGs. This section describes our results.

1. Fossil Fuels and Petroleum

We used the equation for S above to calculate the reduction associated with the increased use of renewable fuels on lifecycle fossil fuels and petroleum. These values are then compared to the total U.S. transportation sector emissions to get a percent reduction. The results are presented in Tables IX.C.1–1 and IX.C.1–2.

TABLE IX.C.1.–1.—FOSSIL FUEL IMPACTS OF INCREASED USE OF RENEWABLE FUELS IN THE TRANSPORTATION SECTOR IN 2012, RELATIVE TO THE 2012 REFERENCE CASE

	RFS Required volume: 7.5 Bgal	Projected volume: 9.9 Bgal
Reduction (quadrillion Btu)	0.2	0.3
Percent reduction	0.5	0.8

TABLE IX.C.1.–2.—PETROLEUM IMPACTS OF INCREASED USE OF RENEWABLE FUELS IN THE TRANSPORTATION SECTOR IN 2012, RELATIVE TO THE 2012 REFERENCE CASE

	RFS Required volume: 7.5 Bgal	Projected volume: 9.9 Bgal
Reduction (billion gal)	2.3	3.9
Percent reduction	1.0	1.6

2. Greenhouse Gases and Carbon Dioxide

One issue that has come to the forefront in the assessment of the environmental impacts of transportation fuels relates to the effect that the use of such fuels could have on emissions of greenhouse gases (GHGs). The combustion of fossil fuels has been identified as a major contributor to the increase in concentrations of atmospheric carbon dioxide (CO_2) since the beginning of the industrialized era, as well as the build-up of trace GHGs such as methane (CH_4) and nitrous oxide (N_2O). This lifecycle analysis evaluates the impacts of renewable fuel use on greenhouse gas emissions.

The relative global warming contribution of emissions of various greenhouse gases is dependant on their radiative forcing, atmospheric lifetime, and other considerations. For example, on a mass basis, the radiative forcing of CH_4 is much higher than that of CO_2, but its effective atmospheric residence time is much lower. The relative warming impacts of various greenhouse gases, taking into account factors such as atmospheric lifetime and direct warming effects, are reported on a CO_2-equivalent basis as global warming potentials (GWPs). The GWPs used by GREET were developed by the UN Intergovernmental Panel on Climate Change (IPCC) as listed in their Third Assessment Report [95], and are shown in Table IX.C.2–1.

TABLE IX.C.2–1.—GLOBAL WARMING POTENTIALS FOR GREENHOUSE GASES

Greenhouse gas	GWP
CO_2	1
CH_4	23
N_2O	296

Greenhouse gases are measured in terms of CO_2-equivalent emissions, which result from multiplying the GWP for each of the three pollutants shown in the above table by the mass of emission for each pollutant. The sum of

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[95] IPCC "Climate Change 2001: The Scientific Basis", Chapter 6; Intergovernmental Panel on Climate Change; J. T. Houghton, Y. Ding, D. J. Griggs, M. Noguer, P. J. van der Linden, X. Dai, C. A. Johnson; and K. Maskell, eds.; Cambridge University Press. Cambridge, U. K. 2001. *http://www.grida.no/climate/ipcc_tar/wg1/index.htm.*

impacts for CH_4, N_2O, and CO_2, yields the total effective GHG impact.

We used the equation for S above to calculate the reduction associated with the increased use of renewable fuels on lifecycle emissions of CO_2. These values are then compared to the total U.S. transportation sector emissions to get a percent reduction. The results are presented in Table IX.C.2–2.

TABLE IX.C.2–2.—CO_2 EMISSION IMPACTS OF INCREASED USE OF RENEWABLE FUELS IN THE TRANSPORTATION SECTOR IN 2012, RELATIVE TO THE 2012 REFERENCE CASE

	RFS Required volume: 7.5 Bgal	Projected Volume: 9.9 Bgal
Reduction (million metric tons CO_2)	12.6	19.8
Percent reduction	0.6 %	0.9 %

Carbon dioxide is a subset of GHGs, along with CH_4 and N_2O as discussed above. It can be seen from Table IX.B.3–1 that the displacement index of CO_2 is greater than for GHGs for each renewable fuel. This indicates that lifecycle emissions of CH_4 and N_2O are higher for renewable fuels than for the conventional fuels replaced. Therefore, reductions associated with the increased use of renewable fuels on lifecycle emissions of GHGs are lower than the values for CO_2. The results for GHGs are presented in Table IX.C.2–3.

TABLE IX.C.2–3.—GHG EMISSION IMPACTS OF INCREASED USE OF RENEWABLE FUELS IN THE TRANSPORTATION SECTOR IN 2012, RELATIVE TO THE 2012 REFERENCE CASE

	RFS Required volume: 7.5 Bgal	Projected Volume: 9.9 Bgal
Reduction (million metric tons $CO_{2\text{-eq.}}$) ..	9.0	13.5
Percent reduction	0.4%	0.6%

D. Implications of Reduced Imports of Petroleum Products

This section only considers the impacts on imports of oil and petroleum products. Expanded production and use of renewable fuels could have other economic impacts such as on the exports of agricultural products like corn. See section X of the preamble for a discussion on agricultural sector impacts.

In 2005, the United States imported almost 60 percent of the oil it consumed. This compares to just over 35 percent oil imports in 1975.[96] Transportation accounts for 70% of the U.S. oil consumption. It is clear that oil imports have a significant impact on the U.S. economy. Expanded production of renewable fuel is expected to contribute to energy diversification and the development of domestic sources of energy. We consider whether the RFS will reduce U.S. dependence on imported oil by calculating avoided expenditures on petroleum imports. Note that we do not calculate whether this reduction is socially beneficially, which would depend on the scarcity value of domestically produced ethanol versus that of imported petroleum products.

To assess the impact of the RFS program on petroleum imports, the fraction of domestic consumption derived from foreign sources was estimated using results from the AEO 2006. In section 6.4.1 of the DRIA we describe how fuel producers change their mix in response to a decrease in fuel demand. We do not expect the projected reductions in petroleum consumption (0.3 to 0.57 Quads) to impact world oil prices by a measurable amount. We base this assumption on the overall size of worldwide petroleum demand and analysis of the AEO 2006 cases. As a consequence, domestic crude oil production for the 7.5 or 9.9 cases would not be expected to change significantly versus the RFS reference case. Thus, petroleum reductions will come largely from reductions in net petroleum imports. This conclusion is confirmed by comparing the AEO 2006 low macroeconomic growth case to the AEO 2006 reference case, as discussed in the RIA 6.4.1. The AEO 2006 shows that for a reduction in petroleum demand on the order of the reductions estimated for the RFS, net imports will account for approximately 95% of the reductions. However, if petroleum reductions were large enough to impact world oil prices, the mix of domestic crude oil, imports of finished products, and imports of crude oil used by fuel producers would change. We discuss this uncertainty in more detail in section 6.4.1 of the RIA and solicit comments to the extent by which the RFS may have a price effect and impact the imports of crude oil and refined products.

We quantified the fraction of net petroleum imports that would be crude oil versus finished products. Comparison of same cases in the AEO 2006 shows that finished products initially compose all the net import reductions, followed by imported crude oil once reductions in consumption reach beyond 1.2 Quads of petroleum product. However, there is significant uncertainty in quantifying how refineries will change their mix of sources with a decrease in petroleum demand, particularly at the levels estimated for the RFS. For example, a comparison between the AEO low price case (as opposed to low macroeconomic growth case) and the reference case would yield a 50–50 split between product and crude imports. We believe that the actual refinery response could range between these two points, so that finished product imports would compose between 50 to 100% of the net import reductions, with crude oil imports making up the remainder. For the purposes of this rulemaking, we show values for the case where net import reductions come entirely from imports of finished products, as shown below in Table IX.D–1. We compare these reductions in imports against the AEO projected levels of net petroleum imports. The range of reductions in net petroleum imports are estimated to be between 1 to 2%, as shown in Table IX.D–2.

TABLE IX.D–1.—REDUCTIONS IN IMPORTS OF FINISHED PRODUCTS

[barrels per day]

Cases	2012
7.5	145,454
9.9	240,892

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[96] Davis, Stacy C.; Diegel, Susan W., Transportation Energy Data Book: 25th Edition, Oak Ridge National Laboratory, U.S. Department of Energy, ORNL–6974, 2006.

TABLE IX.D–2.—PERCENT REDUCTIONS IN PETROLEUM IMPORTS COMPARED TO AEO2006 IMPORT PROJECTIONS

Cases	2012
7.5	1.1%
9.9	1.7%

One of the effects of increased use of renewable fuel is that it diversifies the energy sources used in making transportation fuel. To the extent that diverse sources of fuel energy reduce the dependence on any one source, the risks, both financial as well as strategic, of potential disruption in supply or spike in cost of a particular energy source is reduced.

To understand the energy security implications of the RFS, EPA will work with Oak Ridge National Laboratory (ORNL). As a first step, ORNL will update and apply the approach used in the 1997 report Oil Imports: An Assessment of Benefits and Costs, by Leiby, Jones, Curlee and Lee.[97] This paper was cited and its results utilized in previous DOT/NHTSA rulemakings, including the 2006 Final Regulatory Impact Analysis of CAFE Reform for Light Trucks.[98] This approach is consistent with that used in the Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards Report conducted by the National Research Council/National Academy of Sciences in 2002. Both reports estimate the marginal benefits to society, in dollars per barrel, of reducing either imports or consumption. This ''oil premium'' approach emphasizes identifying those energy-security related costs that are not reflected in the market price of oil, and which may change in response to an incremental change in the level of oil imports or consumption.[99]

Since the 1997 publication of this report changes in oil market conditions, both current and projected, suggest that the magnitude of the ''oil premium'' may have changed. Significant factors that should be reconsidered include: Oil prices, current and anticipated levels of OPEC production, U.S. import levels, potential OPEC behavior and responses, and disruption likelihoods. ORNL will apply the most recently available careful quantitative assessment of disruption likelihoods, from the Stanford Energy Modeling Forum's 2005 workshop series, as well as other assessments [100]. ORNL will also revisit the issue of the macroeconomic consequences of oil market disruptions and sustained higher oil prices. Using the ''oil premium'' calculation methodology which combines short-run and long-run costs and benefits, and accounting for uncertainty in the key driving factors, ORNL will provide an updated range of estimates of the marginal energy security implications of displacing oil consumption with renewable fuels. The results of this work effort are not available for this proposal but will be part of the assessment of impacts of the RFS in the final rule. Although not directly applicable, financial economics literature has examined risk diversification. The agency is interested in ways to examine changes in risks associated with diversifying energy sources in general and solicits comments as such.

We also calculate the decreased expenditures on petroleum imports and compare this with the U.S. trade position measured as U.S. net exports of all goods and services economy-wide. All reductions in petroleum imports are expected to be from finished petroleum products rather than crude oil. The reduced expenditures in petroleum product imports were calculated by multiplying the reductions in gasoline and diesel imports by their corresponding price. According to the EIA, the price of imported finished products is the market price minus domestic local transportation from refineries and minus taxes.[101] An estimate was made by using the AEO 2006 gasoline and distillate price forecasts and subtracting the average Federal and state taxes based on historical data.[102]

We compare these avoided petroleum import expenditures against the projected value of total U.S. net exports of all goods and services economy-wide. Net exports is a measure of the difference between the value of exports of goods and services by the U.S. and the value of U.S. imports of goods and services from the rest of the world. For example, according to the AEO 2006, the value of total import expenditures of goods and services exceeds the value of U.S. exports of goods and services to the rest of the world by $695 billion for 2006 (for a net export level of minus $695 billion).[103] This net exports level is projected to diminish to minus $383 billion by 2012. In Table IX.D–3, we compare the avoided expenditures in petroleum imports versus the total value of U.S. net exports of goods and services for the whole economy for 2012. Relative to the 2012 projection, the avoided petroleum expenditures due to the RFS would represent 0.9 to 1.5% of economy-wide net exports.

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[97] Leiby, Paul N., Donald W. Jones, T. Randall Curlee, and Russell Lee, Oil Imports: An Assessment of Benefits and Costs, ORNL–6851, Oak Ridge National Laboratory, November 1, 1997. (*http://pzl1.ed.ornl.gov/energysecurity.html*).

[98] US DOT, NHTSA 2006. ''Final Regulatory Impact Analysis: Corporate Average Fuel Economy and CAFE Reform for MY 2008–2011 Light Trucks,'' Office of Regulatory Analysis and Evaluation, National Center for Statistics and Analysis, March. (*http://www.nhtsa.dot.gov/staticfiles/DOT/NHTSA/Rulemaking/Rules/Associated%20Files/2006_FRIAPublic.pdf*).

[99] For instance, the 1997 ORNL study gave a range for the ''oil premium'' $0 to $13 per barrel (adjusted to $2004) based on 1994 market conditions. The actual value depended on assumptions about the market power of foreign exporters and the monopsony power of the U.S., the risk of future oil price shocks and the employment of hedging strategies, and the connections between oil shocks and GNP.

[100] Stanford Energy Modeling Forum, Phillip C. Beccue and Hillard G. Huntington, 2005. ''An Assessment of Oil Market Disruption Risks,'' FINAL REPORT, EMF SR 8, October 3. (*http://www.stanford.edu/group/EMF/publications/search.htm*).

[101] EIA (September 1997), ''Petroleum 1996: Issues and Trends'', Office of Oil and Gas, DOE/EIA–0615, p. 71. (*http://tonto.eia.doe.gov/FTPROOT/petroleum/061596.pdf*)

[102] The average taxes per gallon of gasoline and diesel have stayed relatively constant. For 2000–2006, gasoline taxes were $0.44/gallon ($2004) while for 2002–2006, diesel taxes were $0.49/gallon. The average was taken from available EIA data (*http://tonto.eia.doe.gov/oog/info/gdu/gasdiesel.asp*).

[103] For reference, the U.S. Bureau of Economic Analysis (BEA) reports that the 2005 import expenditures. on energy-related petroleum products totaled $235.5 billion (2004$) while petroleum exports totaled $13.6 billion—for a net of $221.9 billion in expenditures. Net petroleum expenditures made up a significant fraction of the $591.3 billion current account deficit in goods and services for 2005 (2004$). (*http://www.bea.gov/*)

TABLE IX.D–3.—AVOIDED PETROLEUM IMPORT EXPENDITURES FOR 2012

[$2004 billion]

AEO2006 total net exports	RFS Cases	Avoided expenditures in petroleum imports	Percent versus total net exports (Percent)
−$383	7.5	3.5	0.9
	9.9	5.8	1.5

X. Agricultural Sector Economic Impacts

As described in more detail in the Draft Regulatory Impact Analysis accompanying this proposal, we plan to evaluate the economic impact on the agricultural sector. However, due to the timing of that analysis, it will not be completed until the final rule. In the meantime, we briefly describe here (and in more detail in the draft RIA) our planned analyses and the sources of assumptions which could critically impact those assessments. Finally, we ask for specific comment on the best sources of information we use in these analyses.

We will be using the Forest and Agricultural Sector Optimization Model (''FASOM'') developed over the past 30 years by Bruce McCarl, Texas A&M University and others. This is a constrained optimization model which seeks to allocate resources and production to maximize producer plus consumer surpluses. We have consulted with a range of experts both within EPA as well as at our sister agencies, the U.S. Departments of Agriculture and Energy and they support the use of this model for assessing the economic impacts on the agricultural sector of various renewable fuel pathways evaluated in this rule. The objective of this modeling assessment is to predict the economic impacts that will directly result from the expanded use of farm products for transportation fuel production. We anticipate that the growing demand for corn for ethanol production in particular but also soybeans and other agricultural crops such as rapeseed and other oil seeds for biodiesel production will increase the production of these feedstocks and impact farm income. The additional corn to produce ethanol may come from several sources, including (1) more intensive cultivation of existing land that currently produces corn, (2) switching production from soybean and cotton to corn, (3) additional acres of land being cultivated, or (4) diversion from corn exports. The implications to U.S. net exports and environment effects partially depend on which source supplies more corn. Eventually various cellulose sources such as corn stover and switchgrass for cellulose-based ethanol production may well become highly demanded and also significantly impact the agricultural sector.

Using the FASOM model, we will estimate the direct impact on farm income resulting from higher demand for corn and soybeans, for example. Additionally, we will estimate impacts on farm employment. Since we expect the higher demand for feedstock will increase both the supply and cost of feedstock, we will also consider how the higher renewable fuel feedstock cost impacts the cost of other agricultural products (corn and soy meal are important sources not only for directly making food for human consumption but also as feed for farm animals). As an estimate of the impact on corn and soybeans prices, we are relying on the estimates provided by the U.S. Department of Agriculture [104] rather than using the FASOM model to derive these price impacts. Additionally, we will rely on the Energy Information Agency's estimates for fuel mix in predicting the amount of ethanol and biodiesel in the fuel pool. Other than these external constraints, we expect to use FASOM as the basic model for estimating economic impacts on farm sector and how these might more generally impact the U.S. economy. Note that this FASOM analysis is a partial equilibrium analysis, focusing almost exclusively on impacts in the U.S. agricultural sector. As a result, it cannot be utilized to make broader assessments of net social benefits resulting from this rulemaking, which for example would require evaluation of the transfer payments to farmers and ethanol producers from consumers and refiners.

XI. Public Participation

We request comments on all aspects of this proposal. The comment period for this proposed rule will be November 12, 2006. Comments can be submitted to the Agency through any of the means listed under **ADDRESSES** above.

We will hold a public hearing on October 13, 2006. The public hearing will start at 10 a.m. (Central) at the Sheraton Gateway Suites Chicago O'Hare, 6501 North Mannheim Road, Rosemont, Illinois 60018. If you would like to present testimony at the public hearing, we ask that you notify the contact person listed under **FOR FURTHER INFORMATION CONTACT** above at least ten days beforehand. You should estimate the time you will need for your presentation and identify any needed audio/visual equipment. We suggest that you bring copies of your statement or other material for the EPA panel and the audience. It would also be helpful if you send us a copy of your statement or other materials before the hearing.

We will arrange for a written transcript of the hearing and keep the official record of the hearing open for 30 days to allow for the public to supplement the record. You may make arrangements for copies of the transcript directly with the court reporter.

XII. Administrative Requirements

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order (EO) 12866, (58 FR 51735, October 4, 1993) this action is a ''significant regulatory action'' because of the policy implications of the proposed rule. Even though EPA has estimated that renewable fuel use through 2012 will be sufficient to meet the levels required in the standard, the proposed rule reflects the first renewable fuel mandate at the Federal level. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction

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[104] ''USDA Agricultural Baseline Projections to 2015.''

Act, 44 U.S.C. 3501 et seq. The Information Collection Request (ICR) document prepared by EPA has been assigned EPA ICR number 2242.01.

The information is planned to be collected to ensure that the required amount of renewable fuel is used each year. The credit trading program required by the Energy Act will be satisfied through a program utilizing Renewable Identification Numbers (RIN), which serve as a surrogate for renewable fuel consumption. Our proposed RIN-based program would fulfill all the functions of a credit trading program, and thus would meet the Energy Act's requirements. For each calendar year, each obligated party would be required to submit a report to the Agency documenting the RINs it acquired, and showing that the sum of all RINs acquired were equal to or greater than its renewable volume obligation. The Agency could then verify that the RINs used for compliance purposes were valid by simply comparing RINs reported by producers to RINs claimed by obligated parties. The Agency will then calculate the total amount of renewable fuel produced each year.

For fuel standards, Section 208(a) of the Clean Air Act requires that manufacturers provide information the Administrator may reasonably require to determine compliance with the regulations; submission of the information is therefore mandatory. We will consider confidential all information meeting the requirements of Section 208(c) of the Clean Air Act.

The annual public reporting and recordkeeping burden for this collection of information is estimated to be 3.1 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements which have subsequently changed; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

A document entitled ''Information Collection Request (ICR); OMB–83 Supporting Statement, Environmental Protection Agency, Office of Air and Radiation,'' has been placed in the public docket. The supporting statement provides a detailed explanation of the Agency's estimates by collection activity. The estimates contained in the docket are briefly summarized here:

Estimated total number of potential respondents: 4,945.

Estimated total number of responses: 4,970.

Estimated total annual burden hours: 15,560.

Estimated total annual costs: $2,911,000, including $1,806,240 in purchased services.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques, EPA has established a public docket for this rule, which includes this ICR, under Docket ID number EPA–OAR–2005–0161. Submit any comments related to the ICR for this proposed rule to EPA and OMB. See the **ADDRESSES** section at the beginning of this notice for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after publication in the **Federal Register**, a comment to OMB is best assured of having its full effect if OMB receives it by October 30, 2006. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act

1. Overview

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201 (see table below); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. The following table provides an overview of the primary SBA small business categories potentially affected by this regulation:

Industry	Defined as small entity by SBA if:	NAICS codes[a]
Gasoline refiners	≤1,500 employees and a crude capacity of ≤125,000 bpcd[b]	324110

[a] North American Industrial Classification System.
[b] barrels of crude per day.

2. Background—Small Refiners Versus Small Refineries

Title XV (Ethanol and Motor Fuels) of the Energy Policy Act provides, at Section 1501(a)(2) [42 U.S.C. 7545(o)(9)(A)–(D)], special provisions for ''small refineries'', such as a temporary exemption from the standards until calendar year 2011. The Act defines the term ''small refinery'' as ''* * * a refinery for which the average aggregate daily crude oil throughput for a calendar year * * * does not exceed 75,000 barrels.'' This term is different from a small refiner, which is what the Regulatory Flexibility Act is concerned with. A small refiner is a small business that meets the criteria set out in SBA's regulations at 13 CFR 121.201; whereas a small refinery, per the Energy Policy Act, is a refinery where the annual crude throughput is less than or equal to 75,000 barrels (i.e., a small-capacity refinery), and could be owned by a larger refiner that exceeds SBA's small entity size standards.

Previous EPA fuel regulations have afforded regulatory flexibility provisions to small refiners, as we believe that refineries owned by small businesses generally face unique economic challenges, compared to larger refiners. As small refiners generally lack the resources available to larger companies (including those larger companies that own small-capacity refineries) to raise capital for any necessary investments for meeting regulatory requirements, these flexibility provisions were provided to reduce the disproportionate burden on those refiners that qualified as small refiners.

3. Summary of Potentially Affected Small Entities

The refiners that are potentially affected by this proposed rule are those that produce gasoline. For our recent proposed rule ''Control of Hazardous Air Pollutants From Mobile Sources'' (71 FR 15804, Wednesday, March 29, 2006), we performed an industry characterization of potentially affected gasoline refiners; we used that industry characterization to determine which refiners would also meet the SBA definition of a small refiner under this proposal. From the industry characterization, we determined that there were 20 gasoline refiners that met the definition of a small refiner. Of these 20 refiners, 17 owned refineries that also met the Energy Policy Act's definition of a small refinery.

4. Impact of the Regulations on Small Entities

As previously stated, many aspects of the RFS program, such as the required amount of annual renewable fuel volumes, were specified in the Energy Policy Act. As shown above in Table III.D.3.c–2, the annual projections of ethanol production exceed the required annual renewable fuel volumes. When the small refinery exemption ends, it is anticipated that there will be over one billion gallons in excess RINs available. We believe that this large volume of excess RINs will also lower the costs of this program. If there were a shortage of RINs, or if any party were to 'hoard' RINs, the cost of a RIN could be high; however with excess RINs, we believe that this program will not impose a significant economic burden on small refineries, small refiners, or any other obligated party. Further, we have determined that this proposed rule will not have a significant economic impact on a substantial number of small entities.

When the Agency certifies that a rule will not have a significant economic impact on a substantial number of small entities, EPA's policy is to make an assessment of the rule's impact on any small entities and to engage the potentially regulated entities in a dialog regarding the rule, and minimize the impact to the extent feasible. The following sections discuss our outreach with the potentially affected small entities and proposed regulatory flexibilities to decrease the burden on these entities in compliance with the requirements of the RFS program

5. Small Refiner Outreach

Although we do not believe that the RFS program would have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities. We held meetings with small refiners to discuss the requirements of the RFS program and the special provisions offered by the Energy Policy Act for small refineries.

The Energy Policy Act set out the following provisions for small refineries:

- A temporary exemption from the Renewable Fuels Standard requirement until 2011;
- An extension of the temporary exemption period for at least two years for any small refinery where it is determined that the refinery would be subject to a disproportionate economic hardship if required to comply;
- Any small refinery may petition, at any time, for an exemption based on disproportionate economic hardship; and,
- A small refinery may waive its temporary exemption to participate in the credit generation program, or it may also ''opt-in'', by waiving its temporary exemption, to be subject to the RFS requirement.

During these meetings with the small refiners we also discussed the impacts of these provisions being offered to small refineries only. As stated above, three refiners met the definition of a small refiner, but their refineries did not meet the Act's definition of a small refinery; which naturally concerned the small refiners. Another concern that the small refiners had was that if this rule were to have a significant economic impact on a substantial number of small entities a lengthy SBREFA process would ensue (which would delay the promulgation of the RFS rulemaking, and thus provide less lead time for these small entities prior to the RFS program start date).

Following our discussions with the small refiners, they provided three suggested regulatory flexibility options that they believed could further assist affected small entities in complying with the RFS program standard: (1) That all small *refiners* be afforded the Act's small *refinery* temporary exemption, (2) that small refiners be allowed to generate credits if they elect to comply with the RFS program standard prior to the 2011 small refinery compliance date, and (3) relieve small refiners who generate blending credits of the RFS program compliance requirements.

We agreed with the small refiners'' suggestion that small refiners be afforded temporary exemption that the Act specifies for small refineries. Regarding the small refiners' second and third suggestions regarding credits, our proposed RIN-based program will automatically provide them with credit for any renewables that they blend into their motor fuels. Until 2011, small refiners will essentially be treated as oxygenate blenders and may separate RINs from batches and trade or sell these RINs.

6. Conclusions

After considering the economic impacts of today's proposed rule on small entities, we certify that this action will not have a significant economic impact on a substantial number of small entities.

While the Energy Policy Act provided for a temporary exemption for small refineries from the requirements of today's proposed rule, these parties will have to comply with the requirements following the exemption period. However, we still believe that small refiners generally lack the resources available to larger companies, and therefore find it necessary to extend the small refinery temporary exemption to all small refiners. Thus, we are proposing to allow the small refinery temporary exemption, as set out in the Act, to all qualified small refiners. In addition, past fuels rulemakings have included a provision that, to qualify for EPA's small refiner flexibilities, a refiner must have no more than 1,500 total corporate employees and have a crude capacity of no more than 155,000 bpcd (slightly higher than SBA's crude capacity limit of 125,000 bpcd). To be consistent with these previous rules, we are also proposing to allow those refiners that meet these criteria to be considered small refiners for this rulemaking. Lastly, we are proposing that small refiners may separate RINs from batches and trade or sell these RINs prior to 2011 if the small refiner operates as a blender

We continue to be interested in the potential impacts of this proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under Section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, Section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of Section 205 do not apply when they are inconsistent with applicable law. Moreover, Section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted.

Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under Section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that this rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. EPA has estimated that renewable fuel use through 2012 will be sufficient to meet the required levels. Therefore, individual refiners, blenders, and importers are already on track to meet rule obligations through normal market-driven incentives. Thus, today's rule is not subject to the requirements of Sections 202 and 205 of the UMRA.

This rule contains no Federal mandates for State, local, or tribal governments as defined by the provisions of Title II of the UMRA. The rule imposes no enforceable duties on any of these governmental entities. Nothing in the rule would significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have Federalism implications.'' ''Policies that have Federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This proposed rule does not have Federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.''

This proposed rule does not have tribal implications, as specified in Executive Order 13175. This rule would be implemented at the Federal level and collectively apply to refiners, blenders, and importers. EPA expects these entities to meet the standards on a collective basis through 2012 even without imposition of any RFS obligations on any individual party. Tribal governments will be affected only to the extent they purchase and use regulated fuels. Thus, Executive Order 13175 does not apply to this rule. EPA specifically solicits additional comment on this proposed rule from tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045: ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under Section 5–501 of the Order has the potential to influence the regulation. This proposed rule is not subject to Executive Order 13045 because it does not establish an environmental standard intended to mitigate health or safety risks and because it implements specific standards established by Congress in statutes.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This rule is not a ''significant energy action'' as defined in Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

EPA expects the provisions to have very little effect on the national fuel supply, since normal market forces alone are promoting greater renewable fuel use than required by the RFS mandate. Nevertheless, the rule is an important part of the nation's efforts to reduce dependence on foreign oil. We discuss our analysis of the energy and supply effects of the increased use of renewable fuels in Sections VI and X of this preamble.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This proposed rulemaking does not involve technical standards. Therefore, EPA is not considering the use of any voluntary consensus standards.

XIII. Statutory Authority

Statutory authority for the rules proposed today can be found in section 211 of the Clean Air Act, 42 U.S.C. 7545. Additional support for the procedural and compliance related aspects of today's proposal, including the proposed recordkeeping requirements, come from Sections 114, 208, and 301(a) of the CAA, 42 U.S.C. 7414, 7542, and 7601(a).

List of Subjects in 40 CFR Part 80

Environmental protection, Air pollution control, Fuel additives, Gasoline, Imports, Incorporation by reference, Labeling, Motor vehicle pollution, Penalties, Reporting and recordkeeping requirements.

Dated: September 7, 2006.

Stephen L. Johnson,

Administrator.

40 CFR part 80 is proposed to be amended as follows:

PART 80—REGULATION OF FUELS AND FUEL ADDITIVES

1. The authority citation for part 80 continues to read as follows:

Authority: 42 U.S.C. 7414, 7542, 7545, and 7601(a).

2. Section 80.1100 is revised to read as follows:

§ 80.1100 How is the statutory default requirement for 2006 implemented?

(a) *Definitions.* The definitions of § 80.2 and the following additional definitions apply to this section only.

(1) *Renewable fuel.* (i) *Renewable fuel* means motor vehicle fuel that is used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to operate a motor vehicle, and which:

(A) Is produced from grain, starch, oil seeds, vegetable, animal, or fish materials including fats, greases, and oils, sugarcane, sugar beets, sugar components, tobacco, potatoes, or other biomass; or

(B) Is natural gas produced from a biogas source, including a landfill, sewage waste treatment plant, feedlot, or other place where decaying organic material is found.

(ii) The term ''renewable fuel'' includes cellulosic biomass ethanol, waste derived ethanol, biodiesel, and any blending components derived from renewable fuel.

(2) *Cellulosic biomass ethanol* means ethanol derived from any lignocellulosic or hemicellulosic matter that is available on a renewable or recurring basis, including dedicated energy crops and trees, wood and wood residues, plants, grasses, agricultural residues, fibers, animal wastes and other waste materials, and municipal solid waste. The term also includes any ethanol produced in facilities where animal wastes or other waste materials are digested or otherwise used to displace 90 percent or more of the fossil fuel normally used in the production of ethanol.

(3) *Waste derived ethanol* means ethanol derived from animal wastes, including poultry fats and poultry wastes, and other waste materials, or municipal solid waste.

(4) *Small refinery* means a refinery for which the average aggregate daily crude oil throughput for a calendar year (as determined by dividing the aggregate throughput for the calendar year by the number of days in the calendar year) does not exceed 75,000 barrels.

(5) *Biodiesel* means a diesel fuel substitute produced from nonpetroleum renewable resources that meets the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel derived from animal wastes (including poultry fats and poultry wastes) and other waste materials, or biodiesel derived from municipal solid waste and sludges and oils derived from wastewater and the treatment of wastewater.

(b) *Renewable fuel standard for 2006.* The percentage of renewable fuel in the total volume of gasoline sold or dispensed to consumers in 2006 in the United States shall be a minimum of 2.78 percent on an annual average volume basis.

(c) *Responsible parties.* Parties collectively responsible for attainment of the standard in paragraph (b) of this section are refiners (including blenders) and importers of gasoline. However, a party that is a refiner only because he owns or operates a small refinery is exempt from this responsibility.

(d) *EPA determination of attainment.* EPA will determine after the close of 2006 whether or not the requirement in paragraph (b) of this section has been met. EPA will base this determination on information routinely published by the Energy Information Administration on the annual domestic volume of gasoline sold or dispensed to U.S. consumers and of ethanol produced for use in such gasoline, supplemented by readily available information concerning the use in motor fuel of other renewable fuels such as cellulosic biomass ethanol, waste derived ethanol, biodiesel, and other non-ethanol renewable fuels.

(1) The renewable fuel volume will equal the sum of all renewable fuel volumes used in motor fuel, provided that:

(i) One gallon of cellulosic biomass ethanol or waste derived ethanol shall be considered to be the equivalent of 2.5 gallons of renewable fuel; and

(ii) Only the renewable fuel portion of blending components derived from renewable fuel shall be counted towards the renewable fuel volume.

(2) If the nationwide average volume percent of renewable fuel in gasoline in 2006 is equal to or greater than the standard in paragraph (b) of this section, the standard has been met.

(e) *Consequence of nonattainment in 2006.* In the event that EPA determines that the requirement in paragraph (b) of this section has not been attained in 2006, a deficit carryover volume shall be added to the renewable fuel volume obligation for 2007 for use in calculating the standard applicable to gasoline in 2007.

(1) The deficit carryover volume shall be calculated as follows:

$$DC = Vgas^{*} (Rs - Ra)$$

Where:

DC = Deficit carryover in gallons of renewable fuel.

Vgas = Volume of gasoline sold or dispensed to U.S. consumers in 2006, in gallons.

Rs = 0.0278.

Ra = Ratio of renewable fuel volume divided by total gasoline volume determined in accordance with paragraph (d)(2) of this section.

(2) There shall be no other consequence of failure to attain the standard in paragraph (b) of this section in 2006 for any of the parties in paragraph (c) of this section.

3. Section 80.1101 is added to read as follows:

§ 80.1101 Definitions.

The definitions of § 80.2 and the following additional definitions apply for purposes of this subpart.

(a) *Cellulosic biomass ethanol* means either of the following:

(1) Ethanol derived from any lignocellulosic or hemicellulosic matter that is available on a renewable or recurring basis, which includes any of the following:

(i) Dedicated energy crops and trees.

(ii) Wood and wood residues.

(iii) Plants.

(iv) Grasses.

(v) Agricultural residues.

(vi) Animal wastes and other waste materials.

(vii) Municipal solid waste.

(2) Ethanol made at facilities at which animal wastes or other waste materials are digested or otherwise used onsite to displace 90 percent or more of the fossil fuel that is combusted to produce thermal energy integral to the process of making ethanol and which comply with the recordkeeping requirements of § 80.1151(a)(4).

(b) *Other waste materials* means either of the following:

(1) Waste materials that are residues rather than being produced solely for the purpose of being combusted to produce energy (e.g., residual tops, branches, and limbs from a tree farm could be waste materials while wood chips used as fuel and which come from plants grown solely for such purpose would not be waste materials).

(2) Waste heat that is captured from an off-site combustion process (e.g., furnace, boiler, heater, or chemical process).

(c) *Otherwise used* means either of the following:

(1) The direct combustion of the waste materials to make thermal energy.

(2) The use of waste heat as a source of thermal energy.

(d) *Waste derived ethanol* means ethanol derived from either of the following:

(1) Animal wastes, including poultry fats and poultry wastes, and other waste materials.

(2) Municipal solid waste.

(e) *Biogas* means methane or other hydrocarbon gas produced from decaying organic material, including landfills, sewage waste treatment plants, and animal feedlots.

(f) *Renewable fuel.* (1) Renewable fuel is motor vehicle fuel that is used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to operate a motor vehicle, and is produced from either of the following:

(i) Grain.

(ii) Starch.

(iii) Oilseeds.

(iv) Vegetable, animal or fish materials including fats, greases and oils.

(v) Sugarcane.

(vi) Sugar beets.

(vii) Sugar components.

(viii) Tobacco.

(ix) Potatoes.

(x) Other biomass; or is natural gas produced from a biogas source, including a landfill, sewage waste treatment plant, feedlot, or other place where decaying organic material is found.

(2) The term ''Renewable fuel'' includes cellulosic biomass ethanol, waste derived ethanol, biodiesel (mono-alkyl ester), non-ester renewable diesel, and blending components derived from renewable fuel.

(3) Small volume additives less than 1.0 percent of the total volume of a renewable fuel shall be counted as part of the total renewable fuel volume.

(4) A fuel produced by a renewable fuel producer that is used in boilers or heaters is not a motor vehicle fuel, and therefore is not a renewable fuel.

(g) *Blending component* has the same meaning as ''Gasoline blending stock, blendstock, or component'' as defined at § 80.2(s), for which the portion that can be counted as renewable fuel is calculated as set forth in § 80.1115(a).

(h) *Motor vehicle* has the meaning given in Section 216(2) of the Clean Air Act (42 U.S.C. 7550).

(i) *Small refinery* means a refinery for which the average aggregate daily crude oil throughput for the calendar year 2004 (as determined by dividing the aggregate throughput for the calendar year by the number of days in the calendar year) does not exceed 75,000 barrels.

(j) *Biodiesel (mono-alkyl ester)* means a motor vehicle fuel or fuel additive which:

(1) Is registered as a motor vehicle fuel or fuel additive under 40 CFR part 79;

(2) Is a mono-alkyl ester;

(3) Meets ASTM D–6751–02a;

(4) Is intended for use in engines that are designed to run on conventional diesel fuel, and

(5) Is derived from nonpetroleum renewable resources (as defined in paragraph (o) of this section).

(k) *Non-ester renewable diesel* means a motor vehicle fuel or fuel additive which:

(1) Is registered as a motor vehicle fuel or fuel additive under 40 CFR part 79;

(2) Is not a mono-alkyl ester;

(3) Is intended for use in engines that are designed to run on conventional diesel fuel; and

(4) Is derived from nonpetroleum renewable resources (as defined in paragraph (o) of this section).

(l) *Biocrude* means plant oils or animal fats that are used as feedstocks to any production unit in a refinery that normally processes crude oil to make gasoline or diesel fuels.

(m) *Biocrude-based renewable fuels* are renewable fuels that are gasoline or diesel products resulting from the processing of biocrudes in atmospheric distillation or other process units at refineries that normally process petroleum-based feedstocks.

(n) *Importers*, for the purposes of this subpart only, are those persons who:

(1) Are considered importers under § 80.2(r); and

(2) Are persons who bring gasoline into the 48 contiguous states of the United States from areas that have not chosen to opt in to the program requirements of this subpart (per § 80.1143).

(o) *Nonpetroleum renewable resources* include, but are not limited to, either of the following:

(1) Plant oils.

(2) Animal fats and animal wastes, including poultry fats and poultry wastes, and other waste materials.

(3) Municipal solid waste and sludges and oils derived from wastewater and the treatment of wastewater.

(p) *Export of renewable fuel* means:

(1) Transfer of a batch of renewable fuel to a location outside the United States; and

(2) Transfer of a batch of renewable fuel from the contiguous 48 states to Alaska, Hawaii, or a United States territory, unless that state or territory has received an approval from the Administrator to opt-in to the renewable fuel program pursuant to § 80.1143.

(q) *Renewable Identification Number (RIN)*, is a unique number generated to represent a volume of renewable fuel in accordance with § 80.1126.

(r) *Standard-value* is a RIN generated to represent renewable fuel with an equivalence value up to and including 1.0.

(s) *Extra-value RIN* is a RIN generated to represent renewable fuel with an equivalence value greater than 1.0.

(t) *Batch-RIN* is a RIN that represents a batch of renewable fuel containing multiple gallons. A batch-RIN uniquely identifies all of the gallon-RINs in that batch.

(u) *Gallon-RIN* is a RIN that represents an individual gallon of renewable fuel.

§§ 80.1102–80.1103 [Added and Reserved]

4. Sections 80.1102 and 80.1103 are added and reserved.

5. Sections 80.1104 through 80.1107 are added to read as follows:

§ 80.1104 What are the implementation dates for the Renewable Fuel Standard Program?

The RFS standards and other requirements of this subpart are effective beginning the day after [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**.

§ 80.1105 What is the Renewable Fuel Standard?

(a) The annual value of the renewable fuel standard for 2007 shall be 3.71 percent.

(b) Beginning with the 2008 compliance period, EPA will calculate the value of the annual standard and publish this value in the **Federal Register** by November 30 of the year preceding the compliance period.

(c) EPA will base the calculation of the standard on information provided by the Energy Information Administration regarding projected gasoline volumes and projected volumes of renewable fuel expected to be used in gasoline blending for the upcoming year.

(d) EPA will calculate the annual renewable fuel standard using the following equation:

$$\mathrm{RFStd_i} = 100 \times \frac{\mathrm{RFV_i} - \mathrm{Cell_i}}{(\mathrm{G_i} - \mathrm{R_i}) + (\mathrm{GS_i} - \mathrm{RS_i}) - \mathrm{GE_i}}$$

Where:

$\mathrm{RFStd_i}$ = Renewable Fuel Standard in year i, in percent.

$\mathrm{RFV_i}$ = Nationwide annual volume of renewable fuels required by section 211(o)(2)(B) of the Act (42 U.S.C. 7545) for year i, in gallons.

$\mathrm{G_i}$ = Amount of gasoline projected to be used in the 48 contiguous states, in year i, in gallons.

$\mathrm{R_i}$ = Amount of renewable fuel blended into gasoline that is projected to be used in the 48 contiguous states, in year i, in gallons.

$\mathrm{GS_i}$ = Amount of gasoline projected to be used in noncontiguous states or territories (if the state or territory opts-in) in year i, in gallons.

$\mathrm{RS_i}$ = Amount of renewable fuel blended into gasoline that is projected to be used in noncontiguous states or territories (if the state or territory opts-in) in year i, in gallons.

$\mathrm{GE_i}$ = Amount of gasoline projected to be produced by exempt small refineries and small refiners in year i, in gallons (through 2010 only).

$\mathrm{Cell_i}$ = Beginning in 2013, the amount of renewable fuel that is required to come from cellulosic sources, in year i, in gallons (250,000,000 gallons minimum).

(e) Beginning with the 2013 compliance period, EPA will calculate the value of the annual cellulosic standard and publish this value in the **Federal Register** by November 30 of the year preceding the compliance period.

(f) EPA will calculate the annual cellulosic standard using the following equation:

$$\mathrm{RFCell_i} = 100 \times \frac{\mathrm{Cell_i}}{(\mathrm{G_i} - \mathrm{R_i}) + (\mathrm{GS_i} - \mathrm{RS_i})}$$

Where:

$\mathrm{RFCell_i}$ = Renewable Fuel Cellulosic Standard in year i, in percent.

$\mathrm{G_i}$ = Amount of gasoline projected to be used in the 48 contiguous states, in year i, in gallons.

$\mathrm{R_i}$ = Amount of renewable fuel blended into gasoline that is projected to be used in the 48 contiguous states, in year i, in gallons.

$\mathrm{GS_i}$ = Amount of gasoline projected to be used in noncontiguous states or territories (if the state or territory opts-in) in year i, in gallons.

$\mathrm{RS_i}$ = Amount of renewable fuel blended into gasoline that is projected to be used in noncontiguous states or territories (if the state or territory opts-in) in year i, in gallons.

$\mathrm{Cell_i}$ = Amount of renewable fuel that is required to come from cellulosic sources, in year i, in gallons (250,000,000 gallons minimum).

§ 80.1106 To whom does the Renewable Volume Obligation apply?

(a)(1) An obligated party is a refiner or blender which produces gasoline within the 48 contiguous states, or an importer which imports gasoline into the 48 contiguous states.

(2) If the Administrator approves a petition of Alaska, Hawaii, or a United States territory to opt-in to the renewable fuel program under the provisions in § 80.1143, then ‘‘obligated party’’ shall include any refiner or blender which produces gasoline within that state or territory, or an importer which imports gasoline into that state or territory.

(b)(1) For each calendar year starting with 2007, any obligated party is required to demonstrate, pursuant to § 80.1127, that they have satisfied the Renewable Volume Obligation for that calendar year, as specified in § 80.1107(a), except as otherwise provided in this section.

(2) The deficit carryover provisions in § 80.1127(b) only apply if all of the requirements specified in § 80.1127(b) are fully satisfied.

(c) Any blender whose sole blending activity in a calendar year is to blend a renewable fuel (or fuels) into gasoline, RBOB, CBOB, or diesel fuel is not required to meet the renewable volume obligation specified in § 80.1107(a) for that gasoline for that calendar year.

§ 80.1107 How is the Renewable Volume Obligation calculated?

For the purposes of this section, all reformulated gasoline, conventional gasoline and blendstock, collectively called ‘‘gasoline’’ unless otherwise specified, is subject to the requirements under this subpart, as applicable.

(a) The Renewable Volume Obligation for an obligated party is determined according to the following formula:

$\mathrm{RVO_i} = \mathrm{RFStd_i} \times \mathrm{GV_i} + \mathrm{D_{i-1}}$

Where:

$\mathrm{RVO_i}$ = The Renewable Volume Obligation for a refiner, blender, or importer for calendar year i, in gallons of renewable fuel.

$\mathrm{RFStd_i}$ = The renewable fuel standard for calendar year i from § 80.1105, in percent.

$\mathrm{GV_i}$ = The non-renewable gasoline volume, determined in accordance with paragraphs (b), (c), and (d) of this section, which is produced or imported, in year i, in gallons.

$\mathrm{D_{i-1}}$ = Renewable fuel deficit carryover from the previous year, per § 80.1127(b), in gallons.

(b) The non-renewable gasoline volume for a refiner, blender, or importer for a given year, $\mathrm{GV_i}$, specified in paragraph (a) of this section is calculated as follows:

$$\mathrm{GV_i} = \sum_{x}^{n} \mathrm{G_x} - \sum_{x}^{n} \mathrm{RB_x}$$

Where:

x = Batch.

n = Total number of batches of gasoline produced or imported.

$\mathrm{G_x}$ = Total volume of gasoline produced or imported, per paragraph (c) of this section, in gallons.

$\mathrm{RB_x}$ = Total volume of renewable fuel blended into gasoline, in gallons.

(c) For the purposes of this section, all of the following products that are produced or imported during a calendar year are to be included in the volume used to calculate a party's renewable volume obligation under paragraph (a) of this section, except as provided in paragraph (d) of this section:

(1) Reformulated gasoline.

(2) Conventional gasoline.

(3) Reformulated gasoline blendstock for oxygenate blending (''RBOB'').

(4) Conventional gasoline blendstock that becomes finished conventional gasoline upon the addition of oxygenate (''CBOB'').

(5) Gasoline treated as blendstock (''GTAB'').

(6) Blendstock that has been combined with other blendstock or finished gasoline to produce gasoline.

(d) The following products are not included in the volume of gasoline produced or imported used to calculate a party's renewable volume obligation under paragraph (a) of this section:

(1) Any renewable fuel as defined in § 80.1101(f).

(2) Blendstock that has not been combined with other blendstock or finished gasoline to produce gasoline.

(3) Gasoline produced or imported for use in Alaska, Hawaii, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Marianas, unless the area has opted into the RFS program under § 80.1143.

(4) Gasoline produced by a small refinery that has an exemption under § 80.1141 or an approved small refiner that has an exemption under § 80.1142 during the period that such exemptions are in effect.

(5) Gasoline exported for use outside the United States.

(6) For blenders, the volume of finished gasoline, RBOB, or CBOB to which a blender adds blendstocks.

(e) *Compliance period.* (1) For 2007, the compliance period is [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**] through December 31, 2007.

(2) Beginning in 2008, and every year thereafter, the compliance period is January 1 through December 31.

§§ 80.1108–80.1114 [Added and Reserved]

6. Sections 80.1108 through 80.1114 are added and reserved.

7. Section 80.1115 is added to read as follows:

§ 80.1115 How are equivalence values assigned by renewable fuel producers?

(a) Each gallon of a renewable fuel shall be assigned an equivalence value. The equivalence value is a number assigned to every renewable fuel that is used to determine how many gallon-RINs can be generated for a batch of renewable fuel according to § 80.1126. Equivalence Values for certain renewable fuels are assigned in paragraph (d) of this section. For other renewable fuels, the equivalence value shall be calculated using the following formula:

$$EV = (R / 0.931) * (EC / 77,550)$$

Where:

EV = Equivalence Value for the renewable fuel.

R = Renewable content of the renewable fuel. This is a measure of the portion of a renewable fuel that came from a renewable source, expressed as a percent, on an energy basis, of the renewable fuel that comes from a renewable feedstock.

EC = Energy content of the renewable fuel, in Btu per gallon (lower heating value).

(b) Technical justification and approval of calculation of the Equivalence Value.

(1) Producers of renewable fuels must prepare a technical justification of the calculation of the Equivalence Value for the renewable fuel including a description of the renewable fuel, its feedstock and production process.

(2) Producers shall submit the justification to the EPA for approval.

(3) The Agency will review the technical justification and assign an appropriate Equivalence Value to the renewable fuel based on the procedure in paragraph (c) of this section.

(c) The equivalence value is assigned as follows:

(1) A value rounded to the nearest tenth if such value is less than 0.9.

(2) 1.0 if the calculated equivalence value is in the range of 0.9 to 1.2.

(3) 1.3, 1.5, or 1.7, for calculated values over 1.2, whichever value is closest to the calculated equivalence value, based on the positive difference between the calculated equivalence value and each of these three values, except as specified in paragraphs (c)(4) and (c)(5) of this section.

(4) 2.5 for cellulosic biomass ethanol that is produced on or before December 31, 2012.

(5) 2.5 for waste derived ethanol.

(d) Equivalence values for some renewable fuels are as given in the following table:

TABLE 1 OF § 80.1115.—EQUIVALENCE VALUES FOR SOME RENEWABLE FUELS

Renewable fuel type	Equivalence value (EV)
Cellulosic biomass ethanol and waste derived ethanol produced on or before December 31, 2012	2.5
Ethanol from corn, starches, or sugar	1.0
Biodiesel (mono-alkyl ester)	1.5
Non-ester renewable diesel	1.7
Butanol	1.3
ETBE from corn ethanol	0.4

§§ 80.1116—80.1124 [Added and Reserved]

8. Sections 80.1116 through 80.1124 are added and reserved.

9. Sections 80.1125 through 80.1131 are added to read as follows:

§ 80.1125 Renewable Identification Numbers (RINs).

Each RIN is a 34 character numerical code of the following form:

YYYYCCCCFFFFFBBBBBRRDKSSSSSS EEEEEE

(a) YYYY is the calendar year in which the batch of renewable fuel was produced or imported. YYYY also represents the year in which the RIN was originally generated.

(b) CCCC is the registration number assigned according to § 80.1150 to the producer or importer of the batch of renewable fuel.

(c) FFFFF is the registration number assigned according to § 80.1150 to the facility at which the batch of renewable fuel was produced or imported.

(d) BBBBB is a serial number assigned to the batch which:

(1) Is chosen by the producer or importer of the batch such that no two batches have the same value in a given calendar year;

(2) Begins with the value 00001 for the first batch produced or imported by a facility in a given calendar year; and

(3) Increases sequentially for subsequent batches produced or imported by that facility in that calendar year.

(e) RR is a number representing the equivalence value of the renewable fuel.

(1) Equivalence values are specified in § 80.1115.

(2) Multiply the equivalence value by 10 to produce the value for RR.

(f) D is a number identifying the type of renewable fuel, as follows:

(1) D has the value of 1 if the renewable fuel can be categorized as cellulosic biomass ethanol.

(2) D has the value of 2 if the renewable fuel cannot be categorized as cellulosic biomass ethanol.

(g) K is a number identifying the type of RIN as follows:

(1) K has the value of 1 if the batch-RIN is a standard-value RIN.

(2) K has the value of 2 if the batch-RIN is an extra-value RIN.

(h) SSSSSS is a number representing the first gallon associated with a batch of renewable fuel.

(i) EEEEEE is a number representing the last gallon associated with a batch of renewable fuel. EEEEEE will be identical to SSSSSS in the case of a gallon-RIN. Assign the value of EEEEEE as described in § 80.1126.

§ 80.1126 How are RINs assigned to batches of renewable fuel by renewable fuel producers or importers?

(a) *Regional applicability.* (1) Except as provided in paragraph (b) of this section, every batch of renewable fuel produced by a facility located in the contiguous 48 states of the United States, or imported into the contiguous 48 states, must be assigned a RIN.

(2) If the Administrator approves a petition of Alaska, Hawaii, or a United States territory to opt-in to the renewable fuel program under the provisions in § 80.1143, then the requirements of paragraph (a)(1) of this section shall also apply to renewable fuel produced or imported into that state or territory beginning in the next calendar year.

(b) *Volume threshold.* Pursuant to § 80.1154, producers with renewable fuel production facilities located within the United States that produce less than 10,000 gallons of renewable fuel each year, and importers that import less than 10,000 gallons of renewable fuel each year, are not required to generate and assign RINs to batches of renewable fuel. Such producers and importers are also exempt from the registration, reporting, and recordkeeping requirements of §§ 80.1150 through 80.1152. However, for those producers and importers that voluntarily generate and assign RINs, all the requirements of this subpart apply.

(c) *Generation of RINs.* (1) The producer or importer of a batch of renewable fuel must generate the RINs associated with that batch. However, a producer of a batch of renewable fuel for export is not required to generate a RIN for that batch if that producer is also the exporter and exports the renewable fuel.

(2) A party generating a RIN shall specify the appropriate numerical values for each component of the RIN in accordance with the provisions of § 80.1125 and this paragraph (c).

(3) Standard-value RINs shall be generated separately from extra-value RINs, and distinguished from one another by the K component of the RIN.

(4) When a standard-value batch-RIN or an extra-value batch-RIN is initially generated by a renewable fuel producer or importer, the value of SSSSSS in the batch-RIN shall be 000001 to represent the first gallon in the batch of renewable fuel.

(5) *Generation of standard-value batch-RINs.* (i) Except as provided in paragraph (c)(5)(ii) of this section, a standard-value batch-RIN shall be generated to represent the gallons in a batch of renewable fuel. The value of EEEEEE when a batch-RIN is initially generated by a renewable fuel producer or importer shall be determined as follows:

(A) For renewable fuels with an equivalence value of 1.0 or greater, the value of EEEEEE shall be the standardized volume of the batch in gallons.

(B) For renewable fuels with an equivalence value of less than 1.0, the value of EEEEEE shall be the applicable volume, in gallons, calculated according to the following formula:

$$V_a = EV * V_s$$

Where:

V_a = Applicable volume of renewable fuel, in gallons, for use in designating the value of EEEEEE.
EV = Equivalence value for the renewable fuel per § 80.1115.
V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons.

(ii) For biocrude-based renewable fuels, a standard-value batch-RIN shall be generated to represent the gallons of biocrude rather than the gallons of renewable fuel. The value of EEEEEE shall be the standardized volume of the biocrude in gallons.

(6) *Generation of extra-value batch-RINs.* (i) Extra-value batch-RINs may be generated for renewable fuels having an equivalence value greater than 1.0.

(ii) The value for EEEEEE in an extra-value batch-RIN when a batch-RIN is initially generated by a renewable fuel producer or importer shall be the applicable volume of renewable fuel calculated according to the following formula:

$$V_a = (EV - 1.0) * V_s$$

Where:

V_a = Applicable volume of renewable fuel, in gallons, for use in designating the value of EEEEEE.
EV= Equivalence value for the renewable fuel per § 80.1115.
V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons.

(7) *Standardization of volumes.* In determining the standardized volume of a batch of renewable fuel for purposes of generating standard-value batch-RINs or extra-value batch-RINs, pursuant to paragraphs (c)(5) and (c)(6) of this section, the batch volumes shall be adjusted to a standard temperature of 60 °F.

(i) For ethanol, the following formula shall be used:

$$V_{s,e} = V_{a,e} * (-0.0006301 \times T + 1.0378)$$

Where:

$V_{s,e}$ = Standardized volume of ethanol at 60 °F, in gallons.
$V_{a,e}$ = Actual volume of ethanol, in gallons.
T = Actual temperature of the batch, in °F.

(ii) For biodiesel (mono alkyl esters), the following formula shall be used:

$$V_{s,b} = V_{a,b} * (-0.0008008 \times T + 1.0480)$$

Where:

$V_{s,b}$ = Standardized volume of biodiesel at 60 °F, in gallons.
$V_{a,b}$ = Actual volume of biodiesel, in gallons.
T = Actual temperature of the batch, in °F.

(iii) For other renewable fuels, an appropriate formula commonly accepted by the industry shall be used to standardize the actual volume to 60 °F.

(d) *Assignment of batch-RINs to batches.* (1) The producer or importer of a batch of renewable fuel must assign standard-value RINs to the batch of renewable fuel that those batch-RINs represent.

(2) The producer or importer of a batch of renewable fuel may assign extra-value batch-RINs to the batch of renewable fuel that those batch-RINs represent.

(3) A batch-RIN is assigned to a batch when the batch-RIN is recorded in a prominent location on a product transfer document assigned to that batch of renewable fuel per § 80.1153.

§ 80.1127 How are RINs used to demonstrate compliance?

(a) *Renewable volume obligations.* (1) Except as specified in paragraph (b) of this section, each party that is obligated to meet the Renewable Volume Obligation under § 80.1107, or an exporter of renewable fuels, must demonstrate that it has acquired sufficient RINs to satisfy the following equation:

$$(\Sigma RINVOL)_i + (\Sigma RINVOL)_{i-1} = RVO_i$$

Where:

$(\Sigma RINVOL)_i$ = Sum of all acquired gallon-RINs that were generated in year i and are being applied towards the RVO_i, in gallons.
$(\Sigma RINVOL)_{i-1}$ = Sum of all acquired gallon-RINs that were generated in year i–1 and are being applied towards the RVO_i, in gallons.

RVO_i = The Renewable Volume Obligation for the obligated party or renewable fuel exporter for calendar year i, in gallons.

(2) For compliance for calendar years 2009 and later, the value of $(\Sigma RINVOL)_{i-1}$ may not exceed a value determined by the following inequality:

$$(\Sigma RINVOL)_{i-1} \leq 0.20 * RVO_i$$

Where:

$(\Sigma RINVOL)_{i-1}$ = Sum of all acquired gallon-RINs that were generated in year i–1 and are being applied towards the RVO_i, in gallons.

(3) RINs may only be used to demonstrate compliance with the RVO for the calendar year in which they were generated or the following calendar year. RINs used to demonstrate compliance in one year cannot be used to demonstrate compliance in any other year.

(4) A party may acquire a RIN only if that RIN is obtained in accordance with §§ 80.1128 and 80.1129.

(5) Gallon-RINs that can be used for compliance with the RVO shall be calculated from the following formula:

$$RINVOL = EEEEEE - SSSSSS + 1$$

Where:

RINVOL = Gallon-RINs associated with a batch-RIN, in gallons.

EEEEEE = Batch-RIN component identifying the last gallon associated with the batch of renewable fuel that the batch-RIN represents.

SSSSSS = Batch-RIN component identifying the first gallon associated with the batch of renewable fuel that the batch-RIN represents.

(b) *Deficit carryovers.* (1) An obligated party or an exporter of renewable fuel that fails to meet the requirements of paragraph (a)(1) of this section for calendar year i is permitted to carry a deficit into year i + 1 under the following conditions:

(i) The party did not carry a deficit into calendar year i from calendar year i − 1.

(ii) The party subsequently meets the requirements of paragraph (a)(1) of this section for calendar year i+1.

(2) A deficit is calculated according to the following formula:

$$D_i = RVO_i - [(\Sigma RINVOL)_i + (\Sigma RINVOL)_{i\,-}1]$$

Where:

D_i = The deficit generated in calendar year i that must be carried over to year i+1 if allowed pursuant to paragraph (b)(1)(i) of this section, in gallons.

RVO_i = The Renewable Volume Obligation for the obligated party or renewable fuel exporter for calendar year i, in gallons.

$(\Sigma RINVOL)_1$ = Sum of all acquired gallon-RINs that were generated in year i and are being applied towards the RVO_i, in gallons.

$(\Sigma RINVOL)_{i\,-}1$ = Sum of all acquired gallon-RINs that were generated in year i − 1 and are being applied towards the RVO_i, in gallons.

§ 80.1128 General requirements for RIN distribution.

(a) *RINs assigned to batches of renewable fuel.* (1) Except as provided in § 80.1129 and paragraph (a)(3) of this section, as title to a batch of renewable fuel is transferred from one party to another, a batch-RIN that has been assigned to that batch according to § 80.1126(d) must remain assigned to an equivalent renewable fuel volume having the same equivalence value.

(i) A batch-RIN assigned to a batch shall be identified on product transfer documents representing the batch pursuant to § 80.1153.

(ii) Any documentation used to transfer custody of or title to a batch from one party to another must identify the batch-RINs assigned to that batch.

(2) If two or more batches of renewable fuel are combined into a single batch, then all the batch-RINs assigned to all the batches involved in the merger shall be assigned to the final combined batch.

(3) If a batch of renewable fuel is split into two or more smaller batches, any batch-RINs assigned to the parent batch must likewise be split and assigned to the daughter batches.

(i) If the Equivalence Value for the renewable fuel in the parent batch is equal to or greater than 1.0, then there shall be at least one gallon-RIN for every gallon in each of the daughter batches.

(ii) If the Equivalence Value for the renewable fuel in the parent batch is less than 1.0, then the ratio of gallon-RINs to gallons in the parent batch shall be preserved in all daughter batches.

(iii) For purposes of this paragraph (a)(3), the volume of each parent and daughter batch shall be standardized to 60 °F pursuant to § 80.1126(c)(7).

(b) *RINs not assigned to batches of renewable fuel.* (1) *Unassigned RIN* means one of the following:

(i) It is a RIN that contains a K value identifying it as an extra-value RIN and was not assigned to a batch of renewable fuel by the producer or importer of that batch; or

(ii) It is a RIN that was separated from the batch to which it was assigned in accordance with § 80.1129.

(2) Any party that has registered pursuant to § 80.1150 can hold title to an unassigned RIN.

(3) Unassigned RINs can be transferred from one party to another any number of times.

(4) An unassigned batch-RIN can be divided by its holder into two batch-RINs, each representing a smaller number of gallon-RINs if all of the following conditions are met:

(i) All RIN components other than SSSSSS and EEEEEE are identical for the parent and daughter RINs.

(ii) The sum of the gallon-RINs associated with the two daughter batch-RINs is equal to the gallon-RINs associated with the parent batch.

§ 80.1129 Requirements for separating RINs from batches.

(a)(1) Separation of a RIN from a batch means termination of the assignment of the RIN from a batch of renewable fuel.

(2) A RIN that has been assigned to a batch of renewable fuel according to § 80.1126(d) may be separated from a batch only under one of the following conditions:

(i) A party that is an obligated party according to § 80.1106 may separate any RINs that have been assigned to a batch if they own the batch.

(ii) Except as provided in paragraph (a)(2)(v) of this section, any party that owns a batch of renewable fuel shall have the right to separate any RINs that have been assigned to that batch once the batch is blended with gasoline or diesel to produce a motor vehicle fuel.

(iii) Any party that exports a batch of renewable fuel shall have the right to separate any RINs that have been assigned to the exported batch.

(iv) Except as provided in paragraph (a)(2)(v) of this section, any renewable fuel producer that owns a batch of renewable fuel shall have the right to separate any RINs that have been assigned to that batch if the renewable fuel is designated as motor vehicle fuel in its neat form and is used as motor vehicle fuel in its neat form.

(v) RINs assigned to batches of biodiesel (mono-alkyl esters) can only be separated from those batches once the biodiesel is blended into diesel fuel at a concentration of 80 volume percent biodiesel or less.

(b) Upon separation from its associated batch, a RIN shall be removed from all documentation that:

(1) Is used to identify custody or title to the batch; or

(2) Is transferred with the batch.

(c) RINs that have been separated from batches of renewable fuel become unassigned RINs subject to the provisions of § 80.1128(b).

§ 80.1130 Requirements for exporters of renewable fuels.

(a)(1) Any party that exports any amount of renewable fuel shall acquire sufficient RINs to offset a Renewable Volume Obligation representing the exported renewable fuel.

(2) Only exporters located in the applicable region described in § 80.1126(a) are subject to the requirements of this section.

(b) *Renewable Volume Obligations.* An exporter of renewable fuel shall determine its Renewable Volume Obligation from the volumes of the batches exported.

(1) A renewable fuel exporter's total Renewable Volume Obligation shall be calculated according to the following formula:

$$RVO_i = \Sigma(VOL_k * EV_k) + D_{i-1}$$

Where:

k = Batch.

RVO_i = The Renewable Volume Obligation for the exporter for calendar year i, in gallons of renewable fuel.

VOL_k = The standardized volume of batch k of exported renewable fuel, in gallons.

EV_k = The equivalence value for batch k.

D_{i-1} = Renewable fuel deficit carryover from the previous year, in gallons.

(2)(i) For exported batches of renewable fuel that have assigned RINs, the equivalence value may be determined from the RR component of the RIN.

(ii) If a batch of renewable fuel does not have assigned RINs but its equivalence value may nevertheless be determined pursuant to § 80.1115(d) based on its composition, then the appropriate equivalence value shall be used in the calculation of the exporter's Renewable Volume Obligation.

(iii) If the equivalence value for a batch of renewable fuel cannot be determined, the value of EV_k shall be 1.0.

(3) If the exporter of a batch of renewable fuel is also the producer of that batch, and no RIN was generated to represent that batch, then the volume of that batch shall be excluded from the calculation of the Renewable Volume Obligation.

(c) Each exporter of renewable fuel must demonstrate compliance with its RVO using RINs it has acquired pursuant to § 80.1127.

§ 80.1131 Treatment of invalid RINs.

(a) *Invalid RINs.* An invalid RIN is a RIN that:

(1) Is a duplicate of a valid RIN;

(2) Was based on volumes that have not been standardized to 60 °F;

(3) Has expired;

(4) Was based on an incorrect equivalence value; or

(5) Was otherwise improperly generated.

(b) In the case of RINs that have been determined to be invalid, the following provisions apply:

(1) Invalid RINs cannot be used to achieve compliance with the transferee's Renewable Volume Obligation, regardless of the transferee's good faith belief that the RINs were valid.

(2) The refiner or importer who used the invalid RINs, and any transferor of the invalid RINs, must adjust their records, reports, and compliance calculations as necessary to reflect the deletion of invalid RINs.

(3) Any valid RINs remaining after deleting invalid RINs, and after an obligated party applies valid RINs as needed to meet the RVO at the end of the compliance year, must first be applied to correct the invalid transfers before the transferor trades or banks the RINs.

(4) In the event that the same RIN is transferred to two or more parties, the RIN will be deemed to be invalid, and any party to any transfer of the invalid RIN will be deemed liable for any violations arising from the transfer or use of the invalid RIN.

(5) A RIN will not be deemed invalid where it can be determined that the RIN was properly created and transferred.

§§ 80.1132–80.1140 [Added and Reserved]

10. Sections 80.1132 through 80.1140 are added and reserved.

11. Sections 80.1141 through 80.1143 are added to read as follows:

§ 80.1141 Small refinery exemption.

(a)(1) Pursuant to § 80.1107(d), gasoline produced by a refiner at a small refinery is qualified for an exemption from the renewable fuels standards of § 80.1105 if that refinery meets the definition of a small refinery under § 80.1101(i) for calendar year 2004.

(2) This exemption shall apply through December 31, 2010, unless a refiner chooses to opt-in to the program requirements of this subpart (per paragraph (g) of this section) prior to this date.

(b)(1) To apply for an exemption under this section, a refiner must submit an application to EPA containing the following information:

(i) The annual average aggregate daily crude oil throughput for the period January 1, 2004, through December 31, 2004 (as determined by dividing the aggregate throughput for the calendar year by the number 365);

(ii) A letter signed by the president, chief operating or chief executive officer of the company, or his/her designee, stating that the information contained in the application is true to the best of his/her knowledge, and that the company owned the refinery as of January 1, 2006; and

(iii) Name, address, phone number, facsimile number, and E-mail address of a corporate contact person.

(2) Applications must be submitted by September 1, 2007.

(c) Within 60 days of EPA's receipt of a refiner's application for a small refinery exemption, EPA will notify the refiner if the exemption is not approved or of any deficiencies in the application. In the absence of such notification from EPA, the effective date of the small refinery exemption is 60 days from EPA's receipt of the refiner's submission.

(d) If EPA finds that a refiner provided false or inaccurate information on its application for a small refinery exemption, the exemption will be void ab initio upon notice from EPA.

(e) If a refiner is complying on an aggregate basis for multiple refineries, any such refiner may exclude from the calculation of its Renewable Volume Obligation (under § 80.1107(a)) gasoline from any refinery receiving the small refinery exemption under paragraph (a) of this section.

(f)(1) The exemption period in paragraph (a) of this section shall be extended by the Administrator for a period of not less than two additional years if a study by the Secretary of Energy determines that compliance with the requirements of this subpart would impose a disproportionate economic hardship on the small refinery.

(2) A refiner may at any time petition the Administrator for an extension of its small refinery exemption under paragraph (a) of this section for the reason of disproportionate economic hardship.

(3) A petition for an extension of the small refinery exemption must specify the factors that demonstrate a disproportionate economic hardship and must provide a detailed discussion regarding the inability of the refinery to produce gasoline meeting the requirements of § 80.1105 and the date the refiner anticipates that compliance with the requirements can be achieved at the small refinery.

(4) The Administrator shall act on such a petition not later than 90 days after the date of receipt of the petition.

(g) At any time, a refiner with an approved small refinery exemption under paragraph (a) of this section may waive that exemption upon notification to EPA.

(1) A refiner's notice to EPA that it intends to waive its small refinery exemption must be received by November 1.

(2) The waiver will be effective beginning on January 1 of the following calendar year, at which point the gasoline produced at that refinery will be subject to the renewable fuels standard of § 80.1105.

(3) The waiver must be sent to EPA at one of the addresses listed in paragraph (m) of this section.

(h) A refiner that acquires a refinery from either an approved small refiner (under § 80.1142) or another refiner with an approved small refinery exemption under paragraph (a) of this section shall notify EPA in writing no later than 20 days following the acquisition.

(i) Applications under paragraph (b) of this section, petitions for hardship extensions under paragraph (f) of this section, and small refinery exemption waivers under paragraph (g) of this section shall be sent to one of the following addresses:

(1) *For U.S. mail:* U.S. EPA—Attn: RFS Program, Transportation and Regional Programs Division (6406J), 1200 Pennsylvania Avenue, NW., Washington, DC 20460; or

(2) *For overnight or courier services:* U.S. EPA, Attn: RFS Program, Transportation and Regional Programs Division (6406J), 1310 L Street, NW., 6th floor, Washington, DC 20005.

§ 80.1142 What are the provisions for small refiners under the RFS program?

(a)(1) A refiner qualifies for a small refiner exemption if the refiner does not meet the definition of a small refinery under § 80.1101(i) but meets all of the following criteria:

(i) The refiner produced gasoline at the refinery by processing crude oil through refinery processing units from January 1, 2004 through December 31, 2004.

(ii) The refiner employed an average of no more than 1,500 people, based on the average number of employees for all pay periods for calendar year 2004 for all subsidiary companies, all parent companies, all subsidiaries of the parent companies, and all joint venture partners.

(iii) The refiner had a corporate-average crude oil capacity less than or equal to 155,000 barrels per calendar day (bpcd) for 2004.

(2) The small refiner exemption shall apply through December 31, 2010, unless a refiner chooses to opt-in to the program requirements of this subpart (per paragraph (g) of this section) prior to this date.

(b) To apply for an exemption under this section, a refiner must submit an application to EPA containing all of the following information for the refiner and for all subsidiary companies, all parent companies, all subsidiaries of the parent companies, and all joint venture partners; approval of an exemption application will be based on all information submitted under this paragraph and any other relevant information:

(1) (i) A listing of the name and address of each company location where any employee worked for the period January 1, 2004 through December 31, 2004.

(ii) The average number of employees at each location based on the number of employees for each pay period for the period January 1, 2004 through December 31, 2004.

(iii) The type of business activities carried out at each location.

(iv) For joint ventures, the total number of employees includes the combined employee count of all corporate entities in the venture.

(v) For government-owned refiners, the total employee count includes all government employees.

(2) The total corporate crude oil capacity of each refinery as reported to the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), for the period January 1, 2004 through December 31, 2004. The information submitted to EIA is presumed to be correct. In cases where a company disagrees with this information, the company may petition EPA with appropriate data to correct the record when the company submits its application.

(3) A letter signed by the president, chief operating or chief executive officer of the company, or his/her designee, stating that the information contained in the application is true to the best of his/her knowledge, and that the company owned the refinery as of January 1, 2006.

(4) Name, address, phone number, facsimile number, and e-mail address of a corporate contact person.

(c) Applications under paragraph (b) of this section must be submitted by September 1, 2007. EPA will notify a refiner of approval or disapproval of its small refiner status in writing.

(d) A refiner who qualifies as a small refiner under this section and subsequently fails to meet all of the qualifying criteria as set out in paragraph (a) of this section will have its small refiner exemption terminated effective January 1 of the next calendar year; however, disqualification shall not apply in the case of a merger between two approved small refiners.

(e) If EPA finds that a refiner provided false or inaccurate information on its application for small refiner status under this subpart, the small refiner's exemption will be void ab initio upon notice from EPA.

(f) If a small refiner is complying on an aggregate basis for multiple refineries, the refiner may exclude those refineries from the compliance calculations under § 80.1125.

(g) (1) An approved small refiner may, at any time, waive the exemption under paragraph (a) of this section upon notification to EPA.

(2) An approved small refiner's notice to EPA that it intends to waive the exemption under paragraph (a) of this section must be received by November 1 in order for the waiver to be effective for the following calendar year. The waiver will be effective beginning on January 1 of the following calendar year, at which point the refiner will be subject to the renewable fuels standard of § 80.1105.

(3) The waiver must be sent to EPA at one of the addresses listed in paragraph (i) of this section.

(h) A refiner that acquires a refinery from another refiner with approved small refiner status under paragraph (a) of this section shall notify EPA in writing no later than 20 days following the acquisition.

(i) Applications under paragraph (b) of this section shall be sent to one of the following addresses:

(1) *For U.S. Mail:* U.S. EPA—Attn: RFS Program, Transportation and Regional Programs Division (6406J), 1200 Pennsylvania Avenue, NW., Washington, DC 20460; or

(2) *For overnight or courier services:* U.S. EPA, Attn: RFS Program, Transportation and Regional Programs Division (6406J), 1310 L Street, NW., 6th floor, Washington, DC 20005.

§ 80.1143 What are the opt-in provisions for noncontiguous states and territories?

(a) A noncontiguous state or United States territory may petition the Administrator to opt-in to the program requirements of this subpart.

(b) The petition must be signed by the Governor of the state or his authorized representative (or the equivalent official of the territory).

(c) The Administrator will approve the petition if it meets the provisions of paragraphs (b) and (d) of this section.

(d)(1) A petition submitted under this section must be received by the Agency by October 31 for the state or territory to be included in the RFS program in the next calendar year.

(2) A petition submitted under this section should be sent to one of the following addresses:

(i) *For U.S. Mail:* U.S. EPA–Attn: RFS Program, Transportation and Regional Programs Division (6406J), 1200 Pennsylvania Avenue, NW., Washington, DC 20460; or

(ii) *For overnight or courier services:* U.S. EPA, Attn: RFS Program, Transportation and Regional Programs

Division (6406J), 1310 L Street, NW., 6th floor, Washington, DC 20005.

(e) Upon approval of the petition by the Administrator—

(1) EPA shall calculate the standard for the following year, including the total gasoline volume for the state or territory in question.

(2) Beginning on January 1 of the next calendar year, all gasoline producers in the state or territory for which a petition has been approved shall be obligated parties as defined in § 80.1106.

(3) Beginning on January 1 of the next calendar year, all renewable fuel producers in the State or territory for which a petition has been approved shall, pursuant to § 80.1126(a)(2), be required to generate RINs and assign them to batches of renewable fuel.

§§ 80.1144–80.1149 [Added and Reserved]

12. Sections 80.1144 through 80.1149 are added and reserved.

13. Sections 80.1150 through 80.1154 are added to read as follows:

§ 80.1150 What are the registration requirements under the RFS program?

(a)(1) Any obligated party as defined in § 80.1106 and any exporter of renewable fuel that is subject to a renewable fuels standard under this subpart, as of [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], must provide EPA with the information specified for registration under § 80.76, if such information has not already been provided under the provisions of this part. In addition, for each import facility, the same identifying information as required for each refinery under § 80.76(c) must be provided. Registrations must be submitted by no later than [DATE 90 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**].

(2) Any obligated party, as defined in § 80.1106, or any exporter of renewable fuel that becomes subject to a renewable fuels standard under this subpart after the date specified in paragraph (a)(1) of this section, must provide EPA the information specified for registration under § 80.76, if such information has not already been provided under the provisions of this part, and must receive EPA-issued company and facility identification numbers prior to engaging in any transaction involving RINs. Additionally, for each import facility, the same identifying information as required for each refinery under § 80.76(c) must be provided.

(b)(1) Any producer of a renewable fuel that is subject to a renewable fuels standard under this subpart as of [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], must provide EPA the information specified under § 80.76, if such information has not already been provided under the provisions of this part, by no later than [DATE 90 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**] .

(2) Any producer of renewable fuel that becomes subject to a renewable fuels standard under this subpart after the date specified in paragraph (b)(1) of this section, must provide EPA the information specified for registration under § 80.76, if such information has not already been provided under the provisions of this part, and must receive EPA-issued company and facility identification numbers prior to generating or creating any RINs.

(c) Any party not covered by paragraphs (a) and (b) of this section must provide EPA the information specified under § 80.76, if such information has not already been provided under the provisions of this part, and must receive EPA-issued company and facility identification numbers prior to owning any RINs.

(d) Registration shall be on forms, and following policies, established by the Administrator.

§ 80.1151 What are the recordkeeping requirements under the RFS program?

(a) Beginning with [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], any obligated party as defined under § 80.1106 or exporter of renewable fuel that is subject to the renewable fuels standard under § 80.1105 must keep all the following records:

(1) The applicable product transfer documents under § 80.1153.

(2) Copies of all reports submitted to EPA under § 80.1152(a).

(3) Records related to each transaction involving the sale, purchase, brokering, and trading of RINs, which includes all the following:

(i) A list of the RINs owned or transferred.

(ii) The parties involved in each transaction including the transferor, transferee, and any broker or agent.

(iii) The location, time, and date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(4) Records related to the use of RINs, by facility, for compliance, which includes all the following:

(i) Methods and variables used to calculate the Renewable Volume Obligation pursuant to § 80.1107.

(ii) List of RINs surrendered to EPA used to demonstrate compliance.

(iii) Additional information related to details of RIN use for compliance.

(5) Verifiable records of all the following:

(i) The amount and type of fossil fuel and waste material-derived fuel used in producing on-site thermal energy dedicated to the production of ethanol at plants producing cellulosic ethanol as defined in § 80.1101(a)(2).

(ii) The equivalent amount of fossil fuel (based on reasonable estimates) associated with the use of off-site generated waste heat that is used in the production of ethanol at plants producing cellulosic ethanol as defined in § 80.1101(a)(2).

(b) Beginning with [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], any importer or producer of renewable fuel as defined under § 80.1101(e) must keep all the following records:

(1) The applicable product transfer documents under § 80.1153.

(2) Copies of all reports submitted to EPA under § 80.1152(b).

(3) Records related to the generation of RINs, for each facility, including all of the following:

(i) Batch Volume.

(ii) RIN number as assigned under § 80.1126.

(iii) Identification of those batches meeting the definition of cellulosic biomass ethanol.

(iv) Date of production or import.

(v) Results of any laboratory analysis of batch chemical composition or physical properties.

(vi) Additional information related to details of RIN generation.

(4) Records related to each transaction involving the sale, purchase, brokering, and trading of RINs, including all of the following:

(i) A list of the RINs acquired, owned or transferred.

(ii) The parties involved in each transaction including the transferor, transferee, and any broker or agent.

(iii) The location, time, and date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(c) Beginning with [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], any party, other than those parties covered in paragraphs (a) and (b) of this section, that owns RINs must keep all of the following records:

(1) The applicable product transfer documents under § 80.1153.

(2) Copies of all reports submitted to EPA under § 80.1152(c).

(3) Records related to each transaction involving the sale, purchase, brokering, and trading of RINs, including all of the following:

(i) A list of the RINs acquired, owned, or transferred.

(ii) The parties involved in each transaction including the transferor, transferee, and any broker or agent.

(iii) The location, time, and date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(d) The records required under this section and under § 80.1153 shall be kept for five years from the date they were created, except that records related to transactions involving RINs shall be kept for five years from the date of transfer.

(e) On request by EPA, the records required under this section and under § 80.1153 must be made available to the Administrator or the Administrator's authorized representative. For records that are electronically generated or maintained, the equipment or software necessary to read the records shall be made available; or, if requested by EPA, electronic records shall be converted to paper documents which shall be provided to the Administrator's authorized representative.

§ 80.1152 What are the reporting requirements under the RFS program?

(a) Beginning with [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], any obligated party as defined in § 80.1106 or exporter of renewable fuel that is subject to the renewable fuels standard under § 80.1105, and continuing for each year thereafter, must submit to EPA annual reports that contain the information required in this section and such other information as EPA may require:

(1) A summary report of the annual gasoline volume produced or imported, or volume of renewable fuel exported, and whether the party is complying on a corporate (aggregate) or facility-by-facility basis. This report shall include all of the following:

(i) The obligated party's name.

(ii) The EPA company registration number.

(iii) The EPA facility registration number(s).

(iv) The production volume of finished gasoline, RBOB as defined in § 80.1107(c) and CBOB as defined in § 80.1107(c).

(v) The renewable volume obligation (RVO), as defined in § 80.1127(a) for obligated parties and § 80.1130 for exporters of renewable fuel, for the reporting year.

(vi) Any deficit RVO carried over from the previous year.

(vii) Any deficit RVO carried into the subsequent year.

(viii) The total number of RINs used for compliance.

(ix) A list of all RINs used for compliance.

(x) Any additional information that the Administrator may require.

(2) A report documenting each transaction of RINs traded between two parties, shall include all of the following:

(i) The submitting party's name.

(ii) The submitter's EPA company registration number.

(iii) The submitter's EPA facility registration number(s).

(iv) The compliance period,

(v) Transaction type (e.g. purchase, sale).

(vi) Transaction date.

(vii) Trading partner's name.

(viii) Trading partner's EPA company registration number.

(ix) Trading partner's EPA facility registration number.

(x) RINs traded.

(xi) Any additional information that the Administrator may require.

(3) A report that summarizes RIN activities for a given compliance year shall include all of the following information:

(i) The total prior-years RINs carried over into the current year (on an annual basis beginning January 1).

(ii) The total current-year RINS acquired.

(iii) The total prior-years RINs acquired.

(iv) The total current-year RINs sold.

(v) The total prior-years RINs sold.

(vi) The total current-year RINs used.

(vii) The total prior-years RINs used.

(viii) The total current-year RINs expired.

(ix) The total prior-years RINs expired.

(x) The total current-year RINs to be carried into next year.

(xi) Any additional information that the Administrator may require.

(4) Reports shall be submitted on forms and following procedures as prescribed by EPA.

(5) Reports shall be submitted by February 28 for the previous compliance year.

(6) All reports must be signed and certified as meeting all the applicable requirements of this subpart by the owner or a responsible corporate officer of the obligated party.

(b) Beginning with [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], any producer or importer of a renewable fuel that is subject to the renewable fuels standard under § 80.1105, and continuing for each year thereafter, must submit to EPA annual reports that contain all of the following information:

(1) An annual report that includes all of the following information on a per-batch basis, where ''batch'' means a discreet quantity of renewable fuel produced and assigned a unique RIN:

(i) The renewable fuel producer's name.

(ii) The EPA company registration number.

(iii) The EPA facility registration number(s).

(iv) The 34 character RINs generated for each batch according to § 80.1126.

(v) The production date of each batch.

(vi) The renewable fuel type as defined in § 80.1101(f).

(vii) Information related to the volume of denaturant and applicable equivalence value.

(viii) The volume produced.

(ix) Any additional information the Administrator may require.

(2) A report documenting each transaction of RINs traded between two parties, shall include all of the following information:

(i) The submitting party's name.

(ii) The submitter's EPA company registration number.

(iii) The submitter's EPA facility registration number(s).

(iv) The compliance period.

(v) Transaction type (e.g. purchase, sale).

(vi) Transaction date.

(vii) Trading partner's name.

(viii) Trading partner's EPA company registration number.

(ix) Trading partner's EPA facility registration number;

(x) RINs traded.

(xi) Any additional information the Administrator may require.

(3) A report that summarizes RIN activities for a compliance year shall include all of the following information:

(i) The total prior-years RINs carried over into the current year (on an annual basis beginning January 1).

(ii) The total current-year RINs generated.

(iii) The total current-year RINS acquired.

(iv) The total prior-years RINs acquired.

(v) The total current-years RINs sold.

(vi) The total prior-years RINs sold.

(vii) The total current-years RINs expired.

(viii) The total prior-years RINs expired.

(ix) The total current-year RINs to be carried into next year.

(x) Any additional information the Administrator may require.

(4) Reports shall be submitted on forms and following procedures as prescribed by EPA.

(5) Reports shall be submitted by February 28 for the previous year.

(6) All reports must be signed and certified as meeting all the applicable

requirements of this subpart by the owner or a responsible corporate officer of the renewable fuel producer.

(c) Any party, other than those parties covered in paragraphs (a) and (b) of this section, who owns RINs must submit to EPA annual reports that contain all of the following information:

(1) A report documenting each transaction of RINs traded between two parties shall include all of the following:

(i) The submitting party's name.

(ii) The submitter's EPA company registration number.

(iii) The submitter's EPA facility registration number(s).

(iv) The compliance period.

(v) Transaction type (e.g. purchase, sale).

(vi) Transaction date.

(vii) Trading partner's name.

(viii) Trading partner's EPA company registration number.

(ix) Trading partner's EPA facility registration number.

(x) RINs traded.

(xi) Any additional information the Administrator may require.

(2) A report that summarizes RIN activities for a compliance year shall include all of the following information:

(i) The total prior-years RINs carried over into the current year (on an annual basis beginning January 1).

(ii) The total current-year RINS acquired.

(iii) The total prior-years RINs acquired.

(iv) The total current-years RINs sold.

(v) The total prior-years RINs sold.

(vi) The total current-years RINs expired.

(vii) The total prior-years RINs expired.

(viii) The total current-year RINs to be carried into next year.

(ix) Any additional information the Administrator may require.

(3) Reports shall be submitted on forms and following procedures as prescribed by EPA.

(4) Reports shall be submitted by February 28 for the previous year.

(5) All reports must be signed and certified as meeting all the applicable requirements of this subpart by the owner or a responsible corporate officer of the renewable fuel producer.

§ 80.1153 What are the product transfer document (PTD) requirements for the RFS program?

(a) Any time that a person transfers ownership of renewable fuels subject to this subpart, and when RINs continue to accompany the renewable fuel, the transferor must provide to the transferee documents identifying the renewable fuel and assigned RINs which include all of the following information as applicable:

(1) The name and address of the transferor and transferee.

(2) The transferor's and transferee's EPA company registration number.

(3) The transferor's and transferee's EPA facility registration number.

(4) The volume of renewable fuel that is being transferred.

(5) The location of the renewable fuel at the time of transfer.

(6) The date of the transfer.

(7) The RINs assigned to the volume of renewable fuel that is being transferred.

(b) Except for transfers to truck carriers, retailers or wholesale purchaser-consumers, product codes may be used to convey the information required under paragraphs (a)(1) through (a)(4) of this section if such codes are clearly understood by each transferee. The RIN number required under paragraph (a)(7) of this section must always appear in its entirety.

§ 80.1154 What are the provisions for renewable fuel producers and importers who produce or import less than 10,000 gallons of renewable fuel per year?

(a) Renewable fuel production facilities located within the United States that produce less than 10,000 gallons of renewable fuel each year, and importers who import less than 10,000 gallons of renewable fuel each year, are not required to generate RINs or to assign RINs to batches of renewable fuel. Such producers and importers that do not generate and/or assign RINs to batches of renewable fuel are exempt from the following requirements of subpart K, except as stated in paragraph (b) of this section:

(1) The registration requirements of § 80.1150:

(2) The recordkeeping requirements of § 80.1151; and

(3) The reporting requirements of § 80.1152.

(b) Renewable fuel producers and importers who produce or import less than 10,000 gallons of renewable fuel each year and that generate and/or assign RINs to batches of renewable fuel are subject to the provisions of §§ 80.1150 through 80.1152.

§§ 80.1155–80.1159 [Added and Reserved]

14. Sections 80.1155 through 80.1159 are added and reserved.

15. Sections 80.1160 through 80.1165 are added to read as follows:

§ 80.1160 What acts are prohibited under the RFS program?

(a) *Renewable fuels producer or importer violation.* Except as provided in § 80.1154, no person shall produce or import a renewable fuel that is not assigned the proper RIN value or identified by a RIN number as required under § 80.1126.

(b) *RIN generation and transfer violations.* No person shall do any of the following:

(1) Improperly generate a RIN (i.e., generate a RIN for which the applicable renewable fuel volume was not produced).

(2) Transfer to any person an invalid RIN or a RIN that is not properly identified as required under § 80.1125.

(c) *RIN use violations.* No person shall do any of the following:

(1) Fail to acquire sufficient RINs, or use invalid RINs, to meet the party's renewable fuel obligation under § 80.1127.

(2) Fail to acquire sufficient RINs to meet the party's renewable fuel obligation under § 80.1130.

(d) *Causing a violation.* No person shall cause another person to commit an act in violation of any prohibited act under this section.

§ 80.1161 Who is liable for violations under the RFS program?

(a) *Persons liable for violations of prohibited acts.* (1) Any person who violates a prohibition under § 80.1160(a) through (c) is liable for the violation of that prohibition.

(2) Any person who causes another person to violate a prohibition under § 80.1160(a) through (c) is liable for a violation of § 80.1160(d).

(b) *Persons liable for failure to meet other provisions of this subpart.* (1) Any person who fails to meet a requirement of any provision of this subpart is liable for a violation of that provision.

(2) Any person who causes another person to fail to meet a requirement of any provision of this subpart is liable for causing a violation of that provision.

(c) *Parent corporation liability.* Any parent corporation is liable for any violation of this subpart that is committed by any of its subsidiaries.

(d) *Joint venture liability.* Each partner to a joint venture is jointly and severally liable for any violation of this subpart that is committed by the joint venture operation.

§ 80.1162 [Reserved]

§ 80.1163 What penalties apply under the RFS program?

(a) Any person who is liable for a violation under § 80.1161 is subject a to civil penalty of up to $32,500, as specified in sections 205 and 211(d) of the Clean Air Act, for every day of each such violation and the amount of economic benefit or savings resulting from each violation.

(b) Any person liable under § 80.1161(a) for a violation of § 80.1160(c) for failure to meet a renewable fuels obligation or causing another party to fail to meet a renewable fuels obligation during any averaging period, is subject to a separate day of violation for each day in the averaging period.

(c) Any person liable under § 80.1161(b) for failure to meet, or causing a failure to meet, a requirement of any provision of this subpart is liable for a separate day of violation for each day such a requirement remains unfulfilled.

§ 80.1164 What are the attest engagement requirements under the RFS program?

In addition to the requirements for attest engagements under §§ 80.125 through 80.133, and other applicable attest engagement provisions, the following annual attest engagement procedures are required under this subpart.

(a) The following attest procedures shall be completed for any obligated party as stated in § 80.1106(b) or exporter of renewable fuel that is subject to the renewable fuel standard under § 80.1105:

(1) *Annual summary report.* (i) Obtain and read a copy of the annual summary report required under § 80.1152(a)(1) which contains information regarding:

(A) The obligated party's volume of finished gasoline, reformulated gasoline blendstock for oxygenate blending (RBOB), and conventional gasoline blendstock that becomes finished conventional gasoline upon the addition of oxygenate (CBOB) produced or imported during the reporting year;

(B) Renewable volume obligation (RVO); and

(C) RINs used for compliance.

(ii) Obtain documentation of any volumes of renewable fuel used in gasoline during the reporting year; compute and report as a finding the volumes of renewable fuel represented in these documents.

(iii) Agree the volumes of gasoline reported to EPA in the report required under § 80.1152(a)(1) with the volumes, excluding any renewable fuel volumes, contained in the inventory reconciliation analysis under § 80.133.

(iv) Verify that the production volume information in the obligated party's annual summary report required under § 80.1152(a)(1) agrees with the volume information, excluding any renewable fuel volumes, contained in the inventory reconciliation analysis under § 80.133.

(v) Compute and report as a finding the obligated party's RVO, and any deficit RVO carried over from the previous year or carried into the subsequent year, and verify that the values agree with the values reported to EPA.

(vi) Obtain documentation for all RINs used for compliance during the year being reviewed; compute and report as a finding the RIN numbers and year of generation of RINs represented in these documents; and agree with the report to EPA.

(2) *RIN transaction report.* (i) Obtain and read a copy of the RIN transaction report required under § 80.1152(a)(2) which contains information regarding RIN trading transactions.

(ii) Obtain contracts or other documents for all RIN transactions with another party during the year being reviewed; compute and report as a finding the transaction types, transaction dates and RINs traded; and agree with the report to EPA.

(3) *RIN activity report.* (i) Obtain and read a copy of the RIN activity report required under § 80.1152(a)(3) which contains information regarding RIN activity for the compliance year.

(ii) Obtain documentation of all RINs acquired, used for compliance (including current-year RINs used and previous-year RINs used) transferred, sold, and expired during the year being reviewed; compute and report as a finding the total RINs acquired, used for compliance, transferred, sold, and expired as represented in these documents; and agree with the report to EPA.

(b) The following attest procedures shall be completed for any renewable fuel producer:

(1) *Annual batch report.* (i) Obtain and read a copy of the annual batch report required under § 80.1152(b)(1) which contains information regarding renewable fuel batches.

(ii) Obtain production data for each renewable fuel batch produced during the year being reviewed; compute and report as a finding the RIN numbers, production dates, types, volumes of denaturant and applicable equivalence values, and production volumes for each batch; and agree with the report to EPA.

(iii) Verify that the proper number of RINs were generated for each batch of renewable fuel produced, as required under § 80.1126.

(iv) Obtain product transfer documents for each renewable fuel batch produced during the year being reviewed; report as a finding any product transfer document that did not include the RIN for the batch.

(2) *RIN transaction report.* (i) Obtain and read a copy of the RIN transaction report required under § 80.1152(b)(2) which contains information regarding RIN trading transactions.

(ii) Obtain contracts or other documents for all RIN transactions with another party during the year being reviewed; compute and report as a finding the transaction types, transaction dates, and the RINs traded; and agree with the report to EPA.

(3) *RIN activity report.* (i) Obtain and read a copy of the RIN activity report required under § 80.1152(b)(3) which contains information regarding RIN activity for the compliance year.

(ii) Obtain documentation of all RINs owned (including RINs created and acquired), transferred, sold and expired during the year being reviewed; compute and report as a finding the total RINs owned, transferred, sold and expired as represented in these documents; and agree with the report to EPA.

(c) For each averaging period, each party subject to the attest engagement requirements under this section shall cause the reports required under this section to be submitted to EPA by May 31 of each year.

§ 80.1165 What are the additional requirements under this subpart for gasoline produced at foreign refineries?

(a) *Definitions.* The following definitions apply for this section:

(1) *Foreign refinery* is a refinery that is located outside the United States, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands (collectively referred to in this section as "the United States").

(2) *Foreign refiner* is a person that meets the definition of refiner under § 80.2(i) for a foreign refinery.

(3) *RFS–FRGAS* is gasoline produced at a foreign refinery that has received a small refinery exemption under § 80.1141 or a small refiner exemption under § 80.1142 that is imported into the United States.

(4) *Non-RFS–FRGAS* is one of the following:

(i) Gasoline produced at a foreign refinery that has received a small refinery exemption under § 80.1141 or a small refiner exemption under § 80.1142 that is not imported into the United States.

(ii) Gasoline produced at a foreign refinery that has not received a small refinery exemption under § 80.1141 or small refiner exemption under § 80.1142.

(b) *General requirements for RFS–FRGAS foreign small refiners.* (1) A foreign refiner that has a small refinery exemption under § 80.1141 or a small refiner exemption under § 80.1142 must designate, at the time of production, each batch of gasoline produced at the foreign refinery that is exported for use in the United States as RFS–FRGAS; and

(2) Meet all requirements that apply to refiners who have received a small refinery or small refiner exemption under this subpart.

(c) *Designation, foreign refiner certification, and product transfer documents.* (1) Any foreign refiner that has received a small refinery exemption under § 80.1141 or a small refiner exemption under § 80.1142 must designate each batch of RFS–FRGAS as such at the time the gasoline is produced.

(2) On each occasion when RFS–FRGAS is loaded onto a vessel or other transportation mode for transport to the United States, the foreign refiner shall prepare a certification for each batch of RFS–FRGAS that meets the following requirements:

(i) The certification shall include the report of the independent third party under paragraph (d) of this section, and the following additional information:

(A) The name and EPA registration number of the refinery that produced the RFS–FRGAS;

(B) [Reserved]

(ii) The identification of the gasoline as RFS–FRGAS; and,

(iii) The volume of RFS–FRGAS being transported, in gallons.

(3) On each occasion when any person transfers custody or title to any RFS–FRGAS prior to its being imported into the United States, it must include the following information as part of the product transfer document information:

(i) Designation of the gasoline as RFS–FRGAS; and

(ii) The certification required under paragraph (c)(2) of this section.

(d) *Load port independent testing and refinery identification.* (1) On each occasion that RFS–FRGAS is loaded onto a vessel for transport to the United States the small foreign refiner shall have an independent third party:

(i) Inspect the vessel prior to loading and determine the volume of any tank bottoms;

(ii) Determine the volume of RFS–FRGAS loaded onto the vessel (exclusive of any tank bottoms before loading);

(iii) Obtain the EPA-assigned registration number of the foreign refinery;

(iv) Determine the name and country of registration of the vessel used to transport the RFS–FRGAS to the United States;

(v) Determine the date and time the vessel departs the port serving the foreign refinery; and

(vi) Review original documents that reflect movement and storage of the RFS–FRGAS from the foreign refinery to the load port, and from this review determine:

(A) The refinery at which the RFS–FRGAS was produced; and

(B) That the RFS–FRGAS remained segregated from Non-RFS–FRGAS and other RFS–FRGAS produced at a different refinery.

(2) The independent third party shall submit a report to:

(i) The foreign small refiner containing the information required under paragraph (d)(1) of this section, to accompany the product transfer documents for the vessel; and

(ii) The Administrator containing the information required under paragraph (d)(1) of this section, within thirty days following the date of the independent third party's inspection. This report shall include a description of the method used to determine the identity of the refinery at which the gasoline was produced, assurance that the gasoline remained segregated as specified in paragraph (i)(1) of this section, and a description of the gasoline's movement and storage between production at the source refinery and vessel loading.

(3) The independent third party must:

(i) Be approved in advance by EPA, based on a demonstration of ability to perform the procedures required in this paragraph (d);

(ii) Be independent under the criteria specified in § 80.65(e)(2)(iii); and

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities, facilities, and documents relevant to compliance with the requirements of this paragraph (d).

(e) *Comparison of load port and port of entry testing.* (1)(i) Any small foreign refiner and any United States importer of RFS–FRGAS shall compare the results from the load port testing under paragraph (d) of this section, with the port of entry testing as reported under paragraph (j) of this section, for the volume of gasoline, except as specified in paragraph (e)(1)(ii) of this section.

(ii) Where a vessel transporting RFS–FRGAS off loads this gasoline at more than one United States port of entry, the requirements of paragraph (e)(1)(i) of this section do not apply at subsequent ports of entry if the United States importer obtains a certification from the vessel owner that the requirements of paragraph (e)(1)(i) of this section were met and that the vessel has not loaded any gasoline or blendstock between the first United States port of entry and the subsequent port of entry.

(2) If the temperature-corrected volumes determined at the port of entry and at the load port differ by more than one percent, the United States importer shall include the volume of gasoline from the importer's RFS compliance calculations.

(f) *Foreign refiner commitments.* Any small foreign refiner shall commit to and comply with the provisions contained in this paragraph (f) as a condition to being approved for a small refinery or small refiner exemption under this subpart.

(1) Any United States Environmental Protection Agency inspector or auditor must be given full, complete and immediate access to conduct inspections and audits of the foreign refinery.

(i) Inspections and audits may be either announced in advance by EPA, or unannounced.

(ii) Access will be provided to any location where:

(A) Gasoline is produced;

(B) Documents related to refinery operations are kept; and

(C) RFS–FRGAS is stored or transported between the foreign refinery and the United States, including storage tanks, vessels and pipelines.

(iii) Inspections and audits may be by EPA employees or contractors to EPA.

(iv) Any documents requested that are related to matters covered by inspections and audits must be provided to an EPA inspector or auditor on request.

(v) Inspections and audits by EPA may include review and copying of any documents related to:

(A) The volume of RFS–FRGAS;

(B) The proper classification of gasoline as being RFS–FRGAS or as not being RFS–FRGAS;

(C) Transfers of title or custody to RFS–FRGAS;

(D) Testing of RFS–FRGAS; and

(E) Work performed and reports prepared by independent third parties and by independent auditors under the requirements of this section, including work papers.

(vi) Inspections and audits by EPA may include interviewing employees.

(vii) Any employee of the foreign refiner must be made available for interview by the EPA inspector or auditor, on request, within a reasonable time period.

(viii) English language translations of any documents must be provided to an EPA inspector or auditor, on request, within 10 working days.

(ix) English language interpreters must be provided to accompany EPA inspectors and auditors, on request.

(2) An agent for service of process located in the District of Columbia shall be named, and service on this agent constitutes service on the foreign refiner or any employee of the foreign refiner for any action by EPA or otherwise by the United States related to the requirements of this subpart.

(3) The forum for any civil or criminal enforcement action related to the provisions of this section for violations of the Clean Air Act or regulations promulgated thereunder shall be governed by the Clean Air Act, including the EPA administrative forum where allowed under the Clean Air Act.

(4) United States substantive and procedural laws shall apply to any civil or criminal enforcement action against the foreign refiner or any employee of the foreign refiner related to the provisions of this section.

(5) Submitting an application for a small refinery or small refiner exemption, or producing and exporting gasoline under such exemption, and all other actions to comply with the requirements of this subpart relating to such exemption constitute actions or activities covered by and within the meaning of the provisions of 28 U.S.C. 1605(a)(2), but solely with respect to actions instituted against the foreign refiner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign refiner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(6) The foreign refiner, or its agents or employees, will not seek to detain or to impose civil or criminal remedies against EPA inspectors or auditors, whether EPA employees or EPA contractors, for actions performed within the scope of EPA employment related to the provisions of this section.

(7) The commitment required by this paragraph (f) shall be signed by the owner or president of the foreign refiner business.

(8) In any case where RFS–FRGAS produced at a foreign refinery is stored or transported by another company between the refinery and the vessel that transports the RFS–FRGAS to the United States, the foreign refiner shall obtain from each such other company a commitment that meets the requirements specified in paragraphs (f)(1) through (f)(7) of this section, and these commitments shall be included in the foreign refiner's application for a small refinery or small refiner exemption under this subpart.

(g) *Sovereign immunity.* By submitting an application for a small refinery or small refiner exemption under this subpart, or by producing and exporting gasoline to the United States under such exemption, the foreign refiner, and its agents and employees, without exception, become subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States without limitation based on sovereign immunity, with respect to actions instituted against the foreign refiner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign refiner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(h) *Bond posting.* Any foreign refiner shall meet the requirements of this paragraph (h) as a condition to approval as benzene foreign refiner under this subpart.

(1) The foreign refiner shall post a bond of the amount calculated using the following equation:

$$\text{Bond} = G * \$\ 0.01$$

Where:

Bond = Amount of the bond in United States dollars.

G = The largest volume of gasoline produced at the foreign refinery and exported to the United States, in gallons, during a single calendar year among the most recent of the following calendar years, up to a maximum of five calendar years: the calendar year immediately preceding the date the refinery's application is submitted, the calendar year the application is submitted, and each succeeding calendar year.

(2) Bonds shall be posted by:

(i) Paying the amount of the bond to the Treasurer of the United States;

(ii) Obtaining a bond in the proper amount from a third party surety agent that is payable to satisfy United States administrative or judicial judgments against the foreign refiner, provided EPA agrees in advance as to the third party and the nature of the surety agreement; or

(iii) An alternative commitment that results in assets of an appropriate liquidity and value being readily available to the United States, provided EPA agrees in advance as to the alternative commitment.

(3) Bonds posted under this paragraph (h) shall—

(i) Be used to satisfy any judicial judgment that results from an administrative or judicial enforcement action for conduct in violation of this subpart, including where such conduct violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413);

(ii) Be provided by a corporate surety that is listed in the United States Department of Treasury Circular 570 ''Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds'' and

(iii) Include a commitment that the bond will remain in effect for at least five years following the end of latest annual reporting period that the foreign refiner produces gasoline pursuant to the requirements of this subpart.

(4) On any occasion a foreign refiner bond is used to satisfy any judgment, the foreign refiner shall increase the bond to cover the amount used within 90 days of the date the bond is used.

(5) If the bond amount for a foreign refiner increases, the foreign refiner shall increase the bond to cover the shortfall within 90 days of the date the bond amount changes. If the bond amount decreases, the foreign refiner may reduce the amount of the bond beginning 90 days after the date the bond amount changes.

(i) *English language reports.* Any document submitted to EPA by a foreign refiner shall be in English language, or shall include an English language translation.

(j) *Prohibitions.* (1) No person may combine RFS–FRGAS with any Non-RFS–FRGAS, and no person may combine RFS–FRGAS with any RFS–FRGAS produced at a different refinery, until the importer has met all the requirements of paragraph (k) of this section.

(2) No foreign refiner or other person may cause another person to commit an action prohibited in paragraph (j)(1) of this section, or that otherwise violates the requirements of this section.

(k) *United States importer requirements.* Any United States importer of RFS–FRGAS shall meet the following requirements:

(1) Each batch of imported RFS–FRGAS shall be classified by the importer as being RFS–FRGAS.

(2) Gasoline shall be classified as RFS–FRGAS according to the designation by the foreign refiner if this designation is supported by product transfer documents prepared by the foreign refiner as required in paragraph (c) of this section. Additionally, the importer shall comply with all requirements of this subpart applicable to importers.

(3) For each gasoline batch classified as RFS–FRGAS, any United States

importer shall have an independent third party:

(i) Determine the volume of gasoline in the vessel;

(ii) Use the foreign refiner's RFS–FRGAS certification to determine the name and EPA-assigned registration number of the foreign refinery that produced the RFS–FRGAS;

(iii) Determine the name and country of registration of the vessel used to transport the RFS–FRGAS to the United States; and

(iv) Determine the date and time the vessel arrives at the United States port of entry.

(4) Any importer shall submit reports within 30 days following the date any vessel transporting RFS–FRGAS arrives at the United States port of entry to:

(i) The Administrator containing the information determined under paragraph (k)(3) of this section; and

(ii) The foreign refiner containing the information determined under paragraph (k)(3)(i) of this section, and including identification of the port at which the product was off loaded.

(5) Any United States importer shall meet all other requirements of this subpart for any imported gasoline that is not classified as RFS–FRGAS under paragraph (k)(2) of this section.

(l) *Truck imports of RFS–FRGAS produced at a foreign refinery.* (1) Any refiner whose RFS–FRGAS is transported into the United States by truck may petition EPA to use alternative procedures to meet the following requirements:

(i) Certification under paragraph (c)(2) of this section;

(ii) Load port and port of entry testing under paragraphs (d) and (e) of this section; and

(iii) Importer testing under paragraph (k)(3) of this section.

(2) These alternative procedures must ensure RFS–FRGAS remains segregated from Non-RFS–FRGAS until it is imported into the United States. The petition will be evaluated based on whether it adequately addresses the following:

(i) Provisions for monitoring pipeline shipments, if applicable, from the refinery, that ensure segregation of RFS–FRGAS from that refinery from all other gasoline.

(ii) Contracts with any terminals and/or pipelines that receive and/or transport RFS–FRGAS that prohibit the commingling of RFS–FRGAS with Non-RFS–FRGAS or RFS–FRGAS from other foreign refineries.

(iii) Attest procedures to be conducted annually by an independent third party that review loading records and import documents based on volume reconciliation, or other criteria, to confirm that all RFS–FRGAS remains segregated throughout the distribution system.

(3) The petition required by this section must be submitted to EPA along with the application for a small refinery or small refiner exemption under this subpart.

(m) *Additional attest requirements for importers of RFS–FRGAS.* Importers of RFS–FRGAS, for each annual compliance period, must arrange to have an attest engagement performed of the underlying documentation that forms the basis of any report or document required under this subpart. The attest engagement must comply with the procedures and requirements that apply to importers under §§ 80.125 through 80.130, and other applicable attest engagement provisions, and must be submitted to the Administrator of EPA by August 31 of each year for the prior annual compliance period. The following additional procedures shall be carried out for any importer of RFS–FRGAS.

(1) Obtain listings of all tenders of RFS–FRGAS. Agree the total volume of tenders from the listings to the gasoline inventory reconciliation analysis in § 80.128(b), and to the volumes determined by the third party under paragraph (d) of this section.

(2) For each tender under paragraph (m)(1) of this section, where the gasoline is loaded onto a marine vessel, report as a finding the name and country of registration of each vessel, and the volumes of RFS–FRGAS loaded onto each vessel.

(3) Select a sample from the list of vessels identified in paragraph (m)(2) of this section used to transport RFS–FRGAS, in accordance with the guidelines in § 80.127, and for each vessel selected perform the following:

(i) Obtain the report of the independent third party, under paragraph (d) of this section, and of the United States importer under paragraph (k) of this section.

(A) Agree the information in these reports with regard to vessel identification and gasoline volume.

(B) Identify, and report as a finding, each occasion the load port and port of entry volume results differ by more than the amount allowed in paragraph (e) of this section, and determine whether the foreign refiner adjusted its refinery calculations as required in paragraph (e) of this section.

(ii) Obtain the documents used by the independent third party to determine transportation and storage of the RFS–FRGAS from the refinery to the load port, under paragraph (d) of this section. Obtain tank activity records for any storage tank where the RFS–FRGAS is stored, and pipeline activity records for any pipeline used to transport the RFS–FRGAS prior to being loaded onto the vessel. Use these records to determine whether the RFS–FRGAS was produced at the refinery that is the subject of the attest engagement, and whether the RFS–FRGAS was mixed with any Non-RFS–FRGAS or any RFS–FRGAS produced at a different refinery.

(4) Select a sample from the list of vessels identified in paragraph (m)(2) of this section used to transport RFS–FRGAS, in accordance with the guidelines in § 80.127, and for each vessel selected perform the following:

(i) Obtain a commercial document of general circulation that lists vessel arrivals and departures, and that includes the port and date of departure of the vessel, and the port of entry and date of arrival of the vessel.

(ii) Agree the vessel's departure and arrival locations and dates from the independent third party and United States importer reports to the information contained in the commercial document.

(5) Obtain separate listings of all tenders of RFS–FRGAS, and perform the following:

(i) Agree the volume of tenders from the listings to the gasoline inventory reconciliation analysis in § 80.128(b).

(ii) Obtain a separate listing of the tenders under this paragraph (m)(5) where the gasoline is loaded onto a marine vessel. Select a sample from this listing in accordance with the guidelines in § 80.127, and obtain a commercial document of general circulation that lists vessel arrivals and departures, and that includes the port and date of departure and the ports and dates where the gasoline was off loaded for the selected vessels. Determine and report as a finding the country where the gasoline was off loaded for each vessel selected.

(6) In order to complete the requirements of this paragraph (m) an auditor shall:

(i) Be independent of the foreign refiner or importer;

(ii) Be licensed as a Certified Public Accountant in the United States and a citizen of the United States, or be approved in advance by EPA based on a demonstration of ability to perform the procedures required in §§ 80.125 through 80.130 and this paragraph (m); and

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities and documents relevant to compliance with the requirements of §§ 80.125 through 80.130 and this paragraph (m).

(n) *Withdrawal or suspension of foreign refiner status.* EPA may withdraw or suspend a foreign refiner's small refinery or small refiner exemption where—

(1) A foreign refiner fails to meet any requirement of this section;

(2) A foreign government fails to allow EPA inspections as provided in paragraph (f)(1) of this section;

(3) A foreign refiner asserts a claim of, or a right to claim, sovereign immunity in an action to enforce the requirements in this subpart; or

(4) A foreign refiner fails to pay a civil or criminal penalty that is not satisfied using the foreign refiner bond specified in paragraph (g) of this section.

(o) *Additional requirements for applications, reports and certificates.* Any application for a small refinery or small refiner exemption, alternative procedures under paragraph (l) of this section, any report, certification, or other submission required under this section shall be—

(1) Submitted in accordance with procedures specified by the Administrator, including use of any forms that may be specified by the Administrator.

(2) Be signed by the president or owner of the foreign refiner company, or by that person's immediate designee, and shall contain the following declaration: ''I hereby certify: (1) That I have actual authority to sign on behalf of and to bind [NAME OF FOREIGN REFINER] with regard to all statements contained herein; (2) that I am aware that the information contained herein is being Certified, or submitted to the United States Environmental Protection Agency, under the requirements of 40 CFR part 80, subpart K, and that the information is material for determining compliance under these regulations; and (3) that I have read and understand the information being Certified or submitted, and this information is true, complete and correct to the best of my knowledge and belief after I have taken reasonable and appropriate steps to verify the accuracy thereof. I affirm that I have read and understand the provisions of 40 CFR part 80, subpart K, including 40 CFR 80.1165 apply to [NAME OF FOREIGN REFINER]. Pursuant to Clean Air Act section 113(c) and 18 U.S.C. 1001, the penalty for furnishing false, incomplete or misleading information in this certification or submission is a fine of up to $10,000 U.S., and/or imprisonment for up to five years.''

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