Regulatory Impact Analysis: Renewable Fuel Standard Program

Chapter 1
Industry Characterization

Assessment and Standards Division
Office of Transportation and Air Quality
U.S. Environmental Protection Agency

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Chapter 1: Industry Characterization

1.1 Transportation Fuel Providers

1.1.1 Petroleum Refiners

As of the end of 2005, there were 142 crude oil refineries operating in the United States, representing a total of 16.4 million barrels/day of refining capacity. (These refineries produce gasoline and other products and are a separate category than "blender refiners" that do not process crude oil, but make gasoline from blendstocks.) The greatest number of refineries per PADD is in PADD 3 (the Gulf Coast region) which has 52 operating refineries as of the end of 2005. This PADD also has the greatest refining capacity, at 7.9 million barrels per day. Table 1.1-1 presents the refineries and their crude oil production capacity, and identifies the PADD where the refinery is located.

Table 1.1-1.
Refining Capacity by Individual Refinery
(crude oil processing basis)

Company	Capacity (MMbbls/cd)	PADD
Conoco Phillips	**2.2**	
Wood River, IL	*0.31*	*2*
Belle Chasse, LA	*0.25*	*3*
Sweeny, TX	*0.25*	*3*
Westlake LA	*0.24*	*3*
Linden, NJ	*0.24*	*1*
Ponca City OK	*0.19*	*2*
Trainer, PA	*0.19*	*1*
Borger TX	*0.15*	*3*
Wilmington CA	*0.14*	*5*
Ferndale WA	*0.10*	*5*
Rodeo CA	*0.08*	*5*
Billings MT	*0.06*	*4*
Valero Energy Corp.	**2.0**	
Port Arthur TX	*0.26*	*3*
Memphis TN	*0.18*	*2*
Lima OH	*0.15*	*2*
Texas City TX	*0.21*	*3*
Corpus Christi TX	*0.14*	*3*
Houston TX	*0.08*	*3*
Sunray TX	*0.16*	*3*
Three Rivers TX	*0.09*	*3*
Norco LA	*0.19*	*3*
Paulsboro NJ	*0.16*	*1*
Benecia CA	*0.14*	*5*
Wilmington CA	*0.01*	*5*
Ardmore OK	*0.08*	*2*
Wilmington CA	*0.08*	*5*

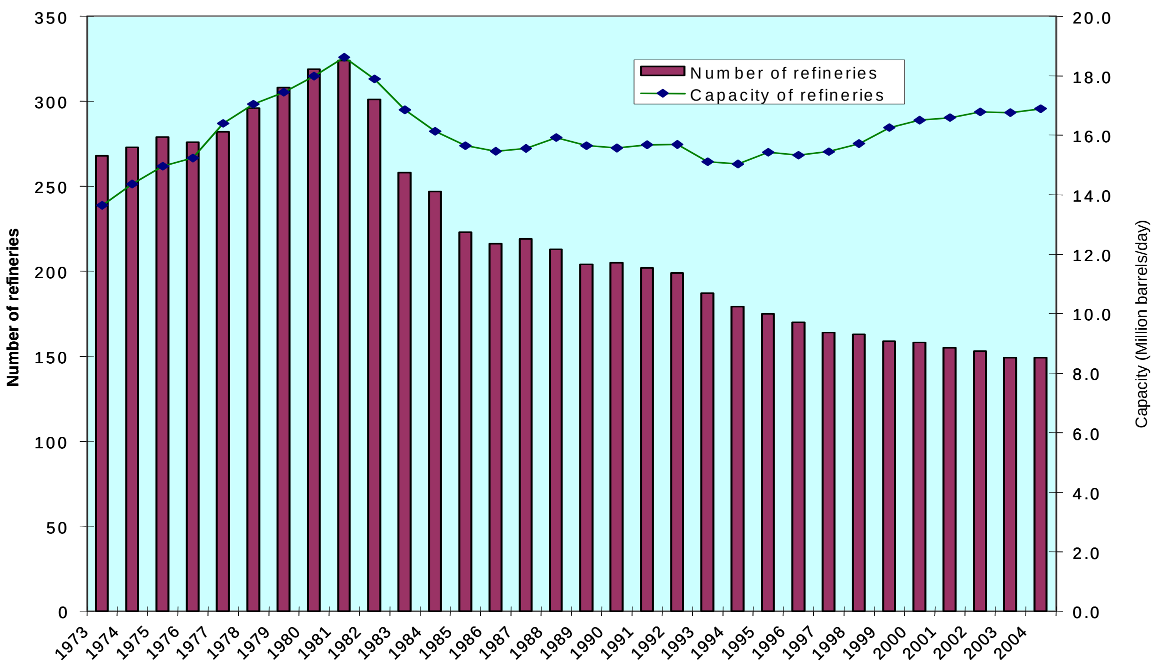
Company	Capacity (MMbbls/cd)	PADD
Krotz Springs LA	*0.08*	*3*
Exxon Mobil Corp.	**2.0**	
Baytown TX	*0.56*	*3*
Baton Rouge LA	*0.50*	*3*
Beaumont TX	*0.34*	*3*
Joliet IL	*0.24*	*2*
Torrance CA	*0.15*	*5*
Billings MT	*0.06*	*4*
Chalmette, LA	*0.19*	*3*
BP PLC	**1.5**	
Texas City TX	*0.44*	*3*
Whiting IN	*0.41*	*2*
Toledo OH	*0.13*	*2*
Los Angeles CA	*0.26*	*5*
Ferndale WA	*0.23*	*5*
Chevron Corp.	**0.9**	
Pascagoula MS	*0.33*	*3*
El Segundo CA	*0.26*	*5*
Richmond CA	*0.24*	*5*
Honolulu HI	*0.05*	*5*
Salt Lake City UT	*0.05*	*4*
Marathon Oil Corp.	**1.0**	
Garyville LA	*0.25*	*3*
Cattlettsburg KY	*0.22*	*2*
Robinson IL	*0.19*	*2*
Detroit MI	*0.10*	*2*
Canton OH	*0.07*	*2*
Texas City TX	*0.07*	*3*
Saint Paul Park MN	*0.07*	*2*
Sunoco, Inc.	**0.58**	
Marcus Hook PA	*0.18*	*2*
Toledo OH	*0.16*	*2*
Westville NJ	*0.15*	*1*
Tulsa OK	*0.09*	*2*
PDV America, Inc.	**0.81**	
Citgo; Lake Charles LA	0.43	*3*
Citgo, Lemont IL	0.17	*2*
Citgo; Corpus Christi TX	0.16	*3*
Koch Industries	**0.57**	
Corpus Christi TX	*0.29*	*3*
Saint Paul MN	*0.28*	*2*
Motiva Enterprises LLC	**0.76**	
Port Arthur TX	*0.29*	*3*
Convent LA	*0.24*	*3*
Norco LA	*0.23*	*3*
Tesoro Corp.	**0.51**	
Anacortes WA	*0.12*	*5*
Salt Lake City UT	*0.06*	*4*

Company	Capacity (MMbbls/cd)	PADD
Martinez CA	*0.17*	*5*
Kapolei HI	*0.09*	*5*
Kenai AK	*0.072*	*5*
Royal Dutch/Shell Group	**0.82**	
Martinez CA	*0.16*	*5*
Anacortes WA	*0.15*	*5*
Wilmington CA	*0.10*	*5*
Saraland AL	*0.08*	*3*
Deer Park, TX	*0.33*	*3*
Lyondell Chem. Co. (Houston)	**0.27**	*3*
Total SA (Port Arthur, TX)	**0.23**	*3*
Sinclair Oil	**0.17**	
Tulsa OK	*0.07*	*2*
Sinclair WY	*0.07*	*4*
Evansville WY	*0.03*	*4*
Murphy Oil	**0.15**	
Meraux LA	*0.12*	*3*
Superior WI	*0.03*	*2*
Frontier Oil	**0.15**	
El Dorado KS	*0.11*	*2*
Cheyenne WY	*0.04*	*4*
Cenex Harvest States, Inc.	**0.14**	
McPherson KS	*0.08*	*2*
Laurel MT	*0.06*	*4*
Coffeyville Acquisitions (Coffeyville KS)	**0.11**	*2*
Navajo Refining Corp.	**0.11**	
Artesia NM	*0.07*	*3*
Woods Cross UT	*0.03*	*4*
Great Falls MT	*0.01*	*4*
Pasadena Refining Systems (Pasadena TX)	**0.10**	*3*
Giant Industries, Inc.	**0.10**	
Yorktown VA	*0.06*	*1*
Gallup NM	*0.02*	*3*
Bloomfield NM	*0.02*	*3*
Big West Oil (North Salt Lake UT)	**0.10**	*4*

Source: Table 5 in Energy Information Administration, Refinery Capacity 2006 found at http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/refinery_capacity_data/current/table5.pdf

Refining capacity has steadily increased in the U.S. due to increased demand for petroleum products, with gasoline representing approximately 45 percent of product demand. Refining capacity (crude oil input) was about 14 million bbls/day in 1973 and 17 million bbls/day in 2005. While refining capacity has increased, however, the number of refineries has decreased as less economical refineries have been forced to close. (Many of these came into existence for a very short time due to oil price supports in the 1970's.) In the 1970's, the number of refineries in the U.S. was approximately 270 and has decreased by 47 percent. Figure 1.1-1 shows the number of refineries and total capacity in the U.S. from 1973 through 2004.

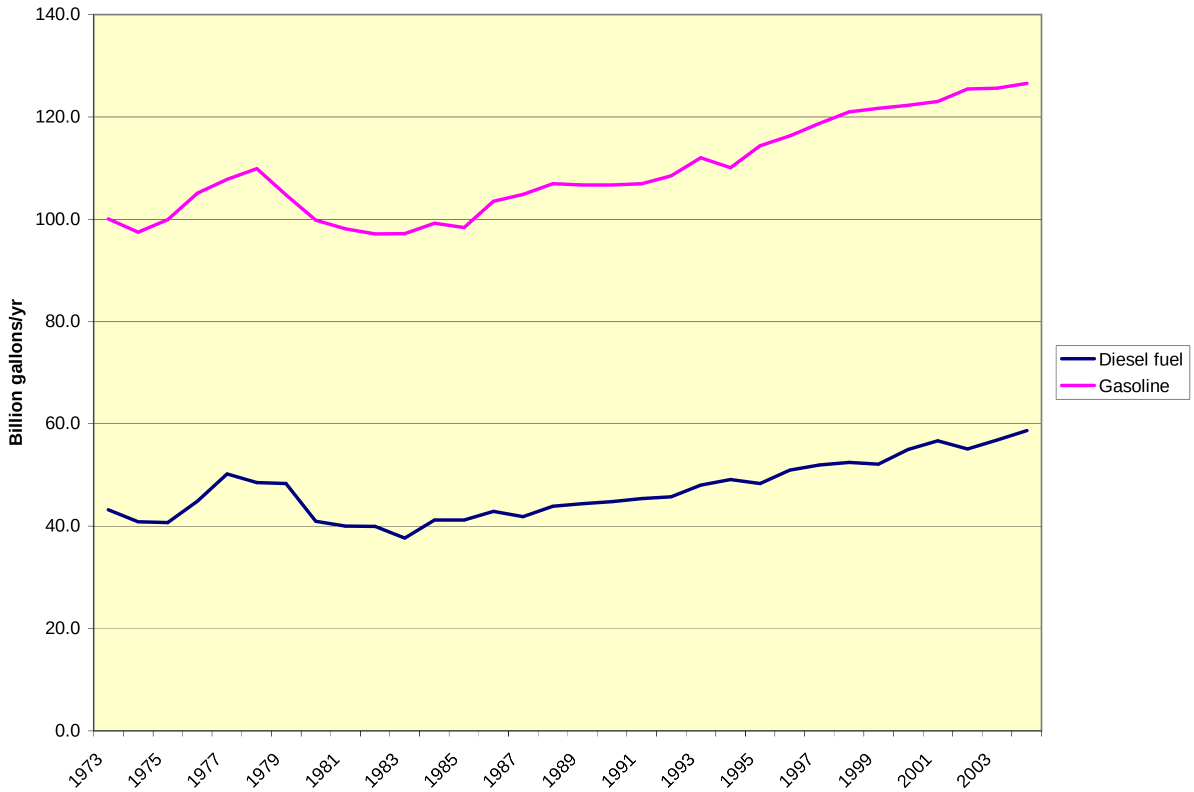
Figure 1.1-1.
Number of Refineries and Total Capacity in the U.S. from 1973-2004



Source: EIA; Annual Energy Report, 2005 (Table 5.9)

The increase in capacity combined with the decrease in amount of refineries and the increased demand for gasoline and diesel fuels, has resulted in an increase in the average utilization rate of refineries. In the 1970's, the utilization rate ranged from 84 to 94 percent. In the last ten years, however, the utilization rate has ranged from 91 to 96 percent. Refineries therefore have to produce more with less overall capacity. The amount of gasoline and diesel produced by U.S. refiners has steadily increased. Since 1973 through 2004, gasoline and diesel production has increased 27 and 36 percent, respectively. Figure 1.1-2 shows the change in gasoline and diesel production from 1973 through 2004

Figure 1.1-2.
Amount of Gasoline and Diesel Fuels Produced in the U.S.



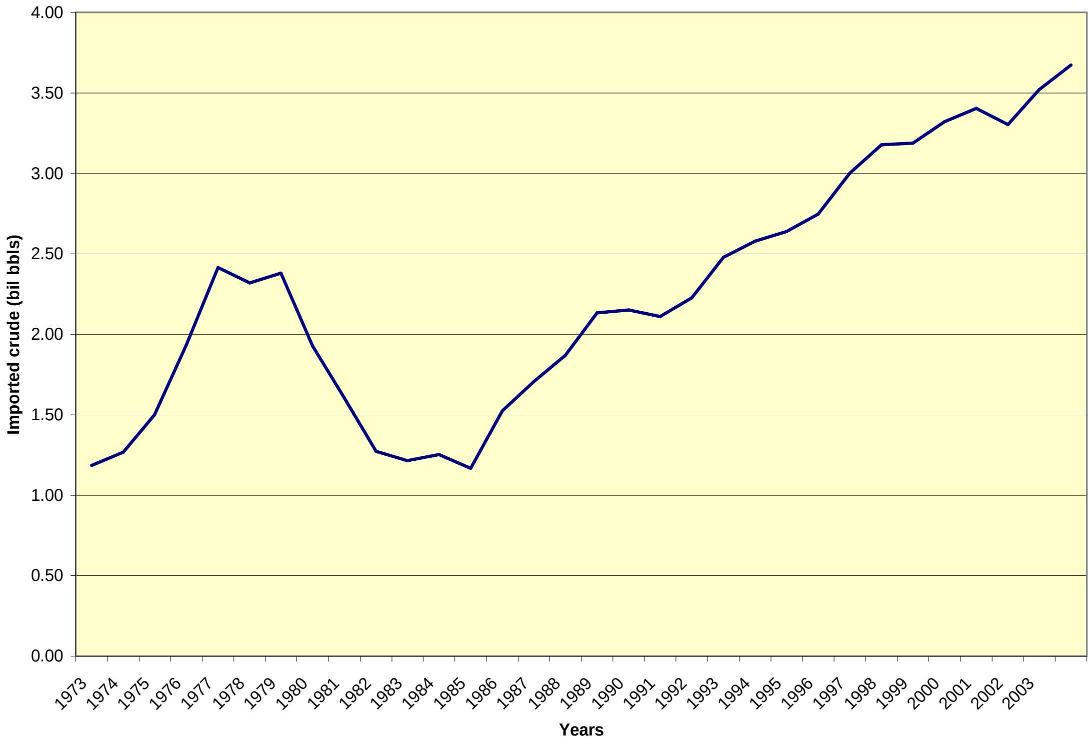
Source: EIA Annual Energy Report, 2005; Table 5.8

1.1.2 Petroleum Imports

The decrease in U.S. refining capacity discussed in Section 1.1.3, has resulted in increases in the amount of gasoline and diesel fuels imported into the U.S. As of 2004, 5.4 and 11.5 percent of the total respective volumes of gasoline and diesel consumed in the U.S. were imported.

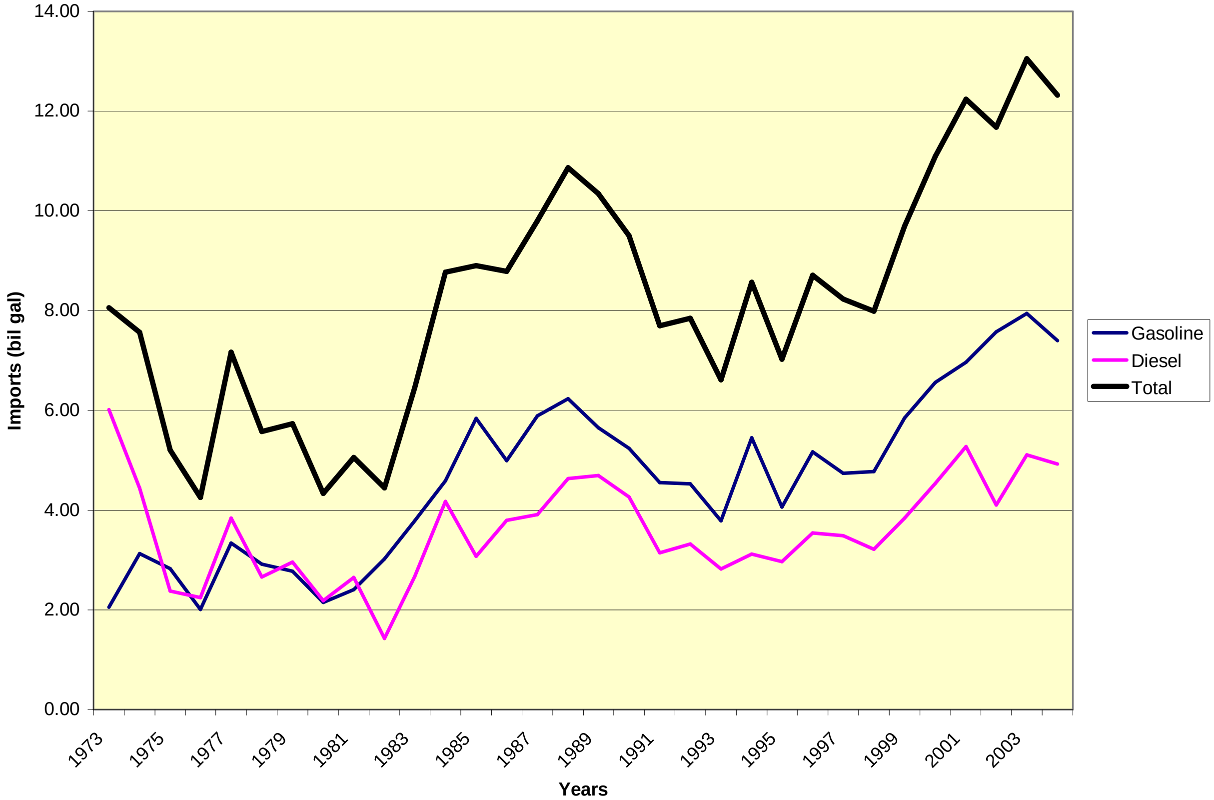
Today, the United States imports approximately 70 percent of all petroleum products used, with two-thirds of these products being used for transportation. From 1973 to 2004, the amount of crude oil imported has increased from 1.2 to 3.7 billion barrels per year, a tripling of volume, representing an average annual increase of about 6 percent. Over the same time period, the amount of gasoline imported has increased from 2 to 7.4 billion gallons per year, more than three times the amount of volume. The amount of diesel imported in the same time period decreased slightly from 6 to 5 percent. Figures 1.1-3 and 1.1-4 show the increase in crude oil and gasoline/diesel fuel imports, respectively, from 1973 to 2004.

Figure 1.1-3.
Increase in Crude Oil Imports from 1973-2004



(Source: Annual Energy Outlook, 2005; Energy Information Administration)

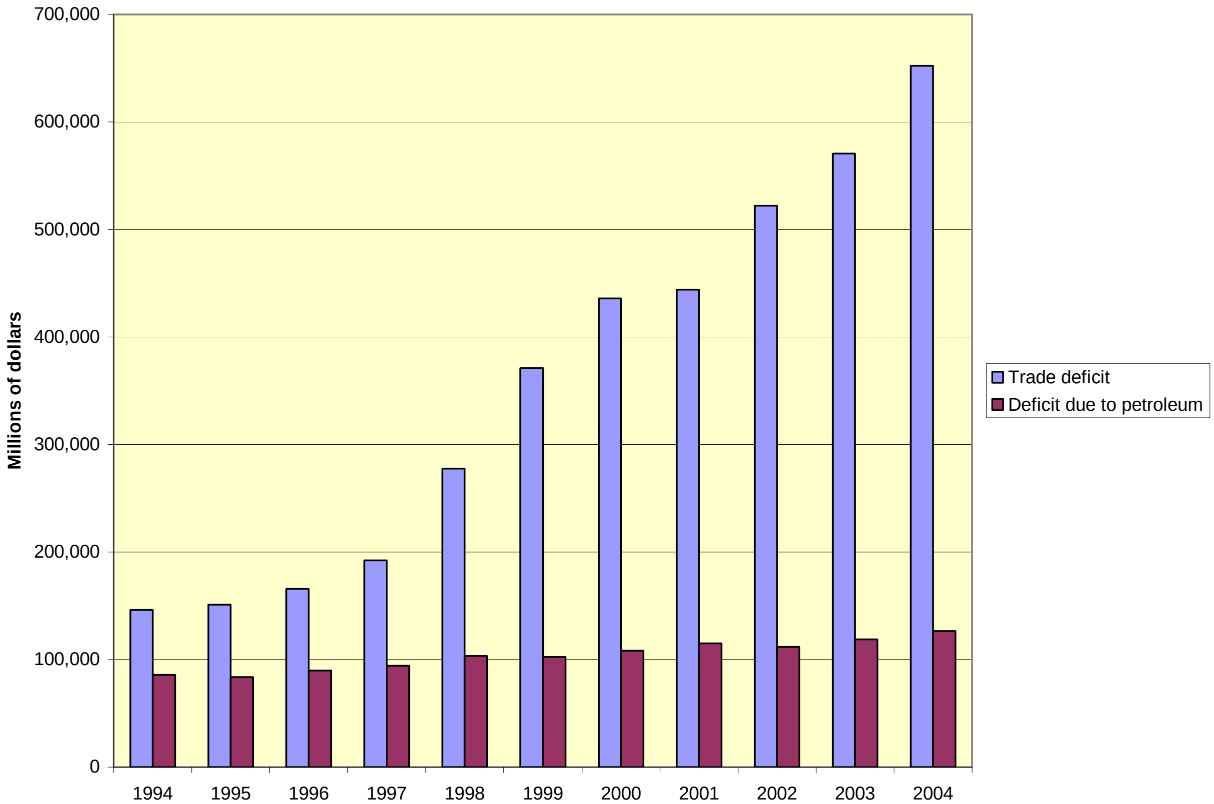
Figure 1.1-4.
Change in Volumes of Imported Gasoline and Diesel fuels (1973-2004)



Source: Annual Energy Outlook, 2005; Energy Information Administration

Approximately twenty percent of our trade deficit is from imported petroleum products, a deficit which reached $782 billion in 2005. Figure 1.1-5 shows the trade deficits from 1994 through 2004 (earlier data on petroleum imports is not available from the U.S. Census web site at this time). While the overall contribution of petroleum imports to the total deficit is decreasing as shown in Figure 1.1-5, this is due to a more rapid growth in the total deficit from other goods and services. The portion of the deficit due to petroleum imports by itself is increasing by approximately 4 percent per year. Over the last 25 years, the cumulative cost of imported crude oil has reached $2.0 trillion in 2005 dollars.

Figure 1.1-5.
U.S. Trade Deficit and Portions Due to Petroleum Imports
1994-2004
(Millions of dollars, chain weighted to 2000)



Source: U.S. Census Bureau, Foreign Trade Statistics, 2006

The amount of import facilities in the U.S. has stayed relatively constant since the U.S. EPA has been requiring such facilities to register. In 1995 there were a total of 39 such facilities in the U.S. The amount has remained relatively constant, in the 50's since that time and as of 2004 there were 53 such facilities registered with U.S. EPA. The great majority of such facilities are located in PADD 1; as of 2004, 35 facilities were in PADD 1, and a total of 18 in the other four PADDs.

1.2 Renewable Fuel Production

While the definition of renewable fuel in the Act does not limit compliance with the standard to any one particular type of renewable fuel, ethanol is currently the most prevalent renewable fuel blended into motor vehicle fuels today. Biodiesel represents another form of renewable fuel, which while not as widespread as ethanol use (in terms of volume), has been increasing in production capacity and use over the last several years. Ethanol and biodiesel are expected to continue to dominate renewable fuel use in the timeframe when the RFS rule will be phasing in.

1.2.1 Current U.S. Ethanol Production

1.2.1.1 Overview

There are currently 110 ethanol production facilities in the United States with a combined production capacity of 5.2 billion gallons per year[1]. This baseline, or starting point, for this regulatory impact analysis is based on U.S. ethanol production facilities operational as of October 2006.[2ABCDE]

Approximately 92 percent of today's ethanol production capacity is produced exclusively from corn, mainly from a dry-milling process. The remainder is derived from corn/grain blends, cheese whey, and other starches. The majority of ethanol plants are located in Midwest where the bulk of corn is produced. PADD 2 accounts for just over 5 billion gallons (or 96 percent) of the total U.S. ethanol production. Leading the Midwest in ethanol production are Iowa, Illinois, Nebraska, Minnesota, and South Dakota which together represent 76 percent of the total domestic product. In addition to the concentration of facilities located in PADD 2, there are also a sprinkling of ethanol plants situated outside of the Midwest as far west as California and as far south as Georgia.

1.2.1.2 Ethanol Feedstocks & Processing Technologies

All of the ethanol currently produced today comes from grain or starch-based feedstocks that can easily be broken down into ethanol via traditional fermentation processes. The primary feedstock is corn, although grain sorghum (milo), wheat, barley, beverage waste, cheese whey, and sugars/starches are also fermented to make fuel-grade ethanol.

The majority of ethanol (almost 92 percent by volume) is produced exclusively from corn. Most of the corn originates from the Midwest and most of the ethanol is produced in PADD 2 close to where the corn is grown. However, several corn-ethanol plants are also situated outside the traditional "corn belt". In California, Colorado, New Mexico, and Wyoming corn is shipped from the Midwest to supplement locally grown grains or in some cases, serve as the sole feedstock. As for the remaining ethanol, almost eight percent is produced from a blend of corn and/or similarly processed grains (milo, wheat, or barley) and less than one percent is

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[1] This analysis does not consider ethanol plants that may be located in (or planned for) the Virgin Islands or U.S. territories.

[2] The October 2006 ethanol production capacity baseline was generated based on the June 2006 NPRM plant list and updated on October 18, 2006 based on a variety of data sources including: Renewable Fuels Association (RFA), Ethanol Producer Magazine (EPM), ICF International, BioFuels Journal, and ethanol producer websites. The baseline includes small-scale ethanol production facilities as well as former food-grade ethanol plants that have since transitioned into the fuel-grade ethanol market. Where applicable, current ethanol plant production levels have been used to represent plant capacity, as nameplate capacities are often underestimated.

produced from waste beverages, cheese whey, and sugars/starches combined. A summary of ethanol production by feedstock is presented in Table 1.2-1.

Table 1.2-1.
2006 U.S. Ethanol Production by Feedstock

Plant Feedstock	Capacity MMgy	% of Capacity	No. of Plants	% of Plants
Cheese Whey	8	0.1%	2	1.8%
Corn[a]	4,780	91.6%	90	81.8%
Corn, Barley	40	0.8%	1	0.9%
Corn, Milo[b]	244	4.7%	8	7.3%
Corn, Wheat	90	1.7%	2	1.8%
Milo, Wheat	40	0.8%	1	0.9%
Sugars, Starches	2	0.0%	1	0.9%
Waste Beverages[c]	16	0.3%	5	4.5%
Total	**5,218**	**100.0%**	**110**	**100.0%**

[a]Includes two facilities processing seed corn and another facility processing corn which intends to transition to corn stalks, switchgrass, and biomass in the future.
[b]Includes one facility processing small amounts of molasses in addition to corn and milo.
[c]Includes two facilities processing brewery waste.

There are two primary plant configurations for processing grains into ethanol: dry mill and wet mill. A summary of the processing technologies used by today's ethanol plants is found below in Table 1.2-2.

Dry mill plants simply grind the entire kernel and feed the flour into the fermentation process to produce ethanol. At the end, the unfermentable parts are recovered as distillers' grains along with a soluble liquid containing vitamins, minerals, fat and protein. The distillers' grains are concentrated with the solubles stream to make a single co-product, referred to as distillers' grains with solubles (DGS). The co-product is either sold wet (WDGS) or more commonly dried (DDGS) to the agricultural market as animal feed. If the feed is going to be used by local markets, it's usually sold wet precluding the need for process dryers. However, if the feed is going to be shipped (usually by train) to more distant locations, the product is usually dried to facilitate storage and transportation.

Wet mill plants typically separate the kernel into four products: starch, gluten feed, gluten meal, and oil. The starch is used in a fermentation process the same as in dry mill plants, while the gluten, oil, and other co-products are sold into food and agricultural markets. Production of these multiple streams is more capital-intensive than the dry milling process, and thus wet mill plants are generally more expensive to build and tend to be larger in size.

Table 1.2-2.
2006 U.S. Ethanol Production by Processing Technology

Processing Technology	Capacity MMgy	% of Capacity	No. of Plants	% of Plants
Dry Milling	4,057	77.7%	92	83.6%
Wet Milling	1,137	21.8%	10	9.1%
Other[a]	25	0.5%	8	7.3%
Total	**5,218**	**100.0%**	**110**	**100.0%**

[a]Plants that do not process traditional grain-based crops and thus do not require milling. This category includes plants processing cheese whey, sugars & starches, or waste beverages.

As shown above in Table 1.2-2, dry milling is the most predominant production process used by today's ethanol plants. Of the 102 facilities processing corn and/or other similarly processed grains, 92 utilize dry milling technologies and the remaining 10 plants rely on wet milling processes (refer to Table 1.2-3 below). The remaining "other" eight plants listed above process waste beverages, cheese whey, or sugars/starches and operate differently than their grain-based counterparts. These facilities do not require milling and instead operate a simpler enzymatic fermentation process.

Table 1.2-3.
2006 U.S. Grain Ethanol Production - Wet Mill Plants

Ethanol Plant	Location	Capacity MMgy
Archer Daniels Midland[a]	Cedar Rapids, IA	300
Archer Daniels Midland[a]	Clinton, IA	150
Archer Daniels Midland	Columbus, NE	90
Archer Daniels Midland[a]	Decatur, IL	250
Archer Daniels Midland	Marshall, MN	40
Aventine Renewable Energy	Pekin, IL	100
Cargill, Inc.	Eddyville, IA	35
Cargill, Inc.	Blair, NE	85
Grain Processing Corp	Muscatine, IA	20
Tate & Lyle	Loudon, TN	67
Total		**1,137**

[a]Estimated ADM plant capacities

In addition to grain and starch-to-ethanol production, another method exists for producing ethanol from a more diverse feedstock base. This process involves converting cellulosic materials such as bagasse, wood, straw, switchgrass, and other biomass into ethanol. Cellulose consists of tightly-linked polymers of starch, and production of ethanol from it requires additional steps to convert these polymers into fermentable sugars. Scientists are actively pursuing acid and enzyme hydrolysis as well as gasification to achieve this goal, but the technologies are still not fully developed for large-scale commercial production. As of October 2006, the only known cellulose-to-ethanol plant in North America was Iogen in Canada, which produces approximately one million gallons of ethanol per year from wood chips. Several companies have announced plans to build cellulose-to-ethanol plants in the U.S., but most are still in the research and development or pre-construction planning phases. The majority of the plans involve converting bagasse, rice hulls, wood, switchgrass, corn stalks, and other agricultural waste or biomass into ethanol. For more a more detailed discussion on future cellulosic ethanol plants and production technologies, refer to RIA Sections 1.2.3.6 and 7.1.2, respectively.

1.2.1.3 Ethanol Plant Energy Sources

Ethanol production is a relatively resource-intensive process that requires the use of water, electricity, and steam. Steam needed to heat the process is generally produced onsite or by other dedicated boilers. Of today's 110 ethanol production facilities, 101 burn natural gas, 7 burn coal, 1 burns coal and biomass, and 1 burns syrup from the process to produce steam[3]. Our research suggests that 11 plants currently utilize co-generation or combined heat and power (CHP) technology, although others may exist. CHP is a mechanism for improving overall plant efficiency. Whether owned by the ethanol facility, their local utility, or a third party; CHP facilities produce their own electricity and use the waste heat from power production for process steam, reducing the energy intensity of ethanol production. A summary of the energy sources and CHP technology utilized by today's ethanol plants is found below in Table 1.2-4.

Table 1.2-4.
2006 U.S. Ethanol Production by Energy Source

Plant Energy Source	Capacity MMgy	% of Capacity	No. of Plants	% of Plants	CHP Tech.
Coal	1,042	20.0%	7	6.4%	2
Coal, Biomass	50	1.0%	1	0.9%	0
Natural Gas[a]	4,077	78.1%	101	91.8%	9
Syrup	49	0.9%	1	0.9%	0
Total	**5,218**	**100.0%**	**110**	**100.0%**	**11**

[a]Includes three facilities burning natural gas which intend to transition to coal or biomass in the future.

1.2.1.4 Ethanol Production Locations

The majority of domestic ethanol is currently produced in the Midwest within PADD 2 – where most of the corn is grown. Of the 110 U.S. ethanol production facilities, 100 are located in PADD 2. As a region, PADD 2 accounts for about 96 percent (or over five billion gallons) of domestic ethanol production, as shown in Table 1.2-5.

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[3] Facilities were assumed to burn natural gas if the plant fuel type was not mentioned or unavailable.

Table 1.2-5.
2006 U.S. Ethanol Production by PADD

PADD	Capacity MMgy	% of Capacity	No. of Plants	% of Plants
PADD 1	0.4	0.0%	1	0.9%
PADD 2	5,012	96.0%	100	90.9%
PADD 3	30	0.6%	1	0.9%
PADD 4	105	2.0%	4	3.6%
PADD 5	71	1.4%	4	3.6%
Total	**5,218**	**100.0%**	**110**	**100.0%**

Leading the Midwest in ethanol production are Iowa, Illinois, Nebraska, Minnesota, and South Dakota with capacities of 1.62, 0.71, 0.61, 0.55, 0.49 billion gallons, respectively. Together, these five states' 70 ethanol plants account for 76 percent of the total domestic ethanol production. However, although the majority of ethanol production comes from PADD 2, there are a growing number of plants situated outside the traditional corn belt. In addition to the 15 states comprising PADD 2, ethanol plants are currently located in California, Colorado, Georgia, New Mexico, and Wyoming. Some of these facilities ship in feedstocks (namely corn) from the Midwest, others rely on locally grown/produced feedstocks, while others rely on a combination of the two. A summary of ethanol production alphabetically by state is found in Table 1.2-6.

Table 1.2-6.
2006 U.S. Ethanol Production by State

State	Capacity MMgy	% of Plants	No. of Plants	% of Capacity
California	71	1.4%	4	3.6%
Colorado	93	1.8%	3	2.7%
Georgia	0.4	0.0%	1	0.9%
Iowa	1,618	31.0%	25	22.7%
Illinois	706	13.5%	6	5.5%
Indiana	122	2.3%	2	1.8%
Kansas	219	4.2%	8	7.3%
Kentucky	38	0.7%	2	1.8%
Michigan	155	3.0%	3	2.7%
Minnesota	546	10.5%	16	14.5%
Missouri	155	3.0%	4	3.6%
North Dakota	51	1.0%	2	1.8%
Nebraska	606	11.6%	12	10.9%
New Mexico	30	0.6%	1	0.9%
Ohio	3	0.1%	1	0.9%
Oklahoma	2	0.0%	1	0.9%
South Dakota	493	9.4%	11	10.0%
Tennessee	67	1.3%	1	0.9%
Wisconsin	233	4.5%	6	5.5%
Wyoming	12	0.2%	1	0.9%
Total	**5,218**	**100.0%**	**110**	**100.0%**

In addition to the domestic ethanol production described above, the U.S. also receives a small amount of ethanol from other countries. A discussion on ethanol imports is found in Section 1.5

1.2.1.5 Ethanol Producers and Marketers

The U.S. ethanol industry is currently comprised of a mixture of corporations and farmer-owned cooperatives (co-ops). More than half (or 60) of the plants are owned by corporations and the remainder (50 plants) are farmer owned co-ops. On average, a U.S. ethanol production facility has a mean plant capacity of about 47 million gallons per year. In general, plants owned by corporations ("company-owned") are above average in size while farmer-owned co-ops are below average. Similarly, company-owned plants tend to have a much broader range in ethanol production levels than farmer-owned co-ops. A summary of these results is presented in Table 1.2-7.

Table 1.2-7.
2006 U.S. Ethanol Production by Plant Ownership

Plant Ownership	No. of Plants	Production Capacity, MMgy			
		Total	Avg	Min	Max
Company-Owned[a]	60	3,315	55	0.4	300
Farmer-Owned	50	1,903	38	3	60
Total	**110**	**5,218**	**47**	**0.4**	**300**

[a]Includes ethanol producers with public offerings.

Based on the dominating number of company-owned plants and their above-average production size, company-owned plants account for nearly 64 percent of the total domestic product. Further, more than 50 percent of today's U.S. ethanol production capacity comes from plants owned by just 6 different companies. A list of the top six ethanol producing companies and their respective plant capacities is found in Table 1.2-8.

Table 1.2-8.
2006 Top Six U.S. Ethanol Producers

Company[a]	Capacity MMgy	No. of Plants
Archer Daniels Midland	1,070	7
Broin	838	18
VeraSun Energy	230	2
Hawkeye Renewables, LLC	200	2
Global / MGP Ingredients	190	3
Aventine Renewable Energy	150	2
Total	**2,678**	**34**

[a]Includes majority and minority plant ownership.

Over 80 percent of today's U.S. ethanol production is sold to the gasoline industry by eight marketing companies[4]. A list of the top eight ethanol marketers and their respective marketing capacities based on plant affiliations is found in Table 1.2-9. The remaining ethanol is marketed by Kinergy Marketing, The Andersons, Murex International, Noble Americas, and other small marketing companies.

[4] Based on information obtained from ethanol marketer websites, ethanol producer websites, and conversations with ethanol marketers/producers.

Table 1.2-9.
2006 Top Eight U.S. Ethanol Marketers

Marketing Company	Capacity MMgy[a]	No. of Plants
Archer Daniels Midland	1,172	9
Ethanol Products	991	22
Renewable Products Marketing Group	612	15
Aventine Renewable Energy	666	14
Eco-Energy	325	5
Provista (formerly UBE)	217	5
Cargill, Inc.	120	2
Abengoa Bioenergy	110	3
Total	**4,212**	**75**

[a]Volumes based on marketing agreements and respective ethanol plant capacities

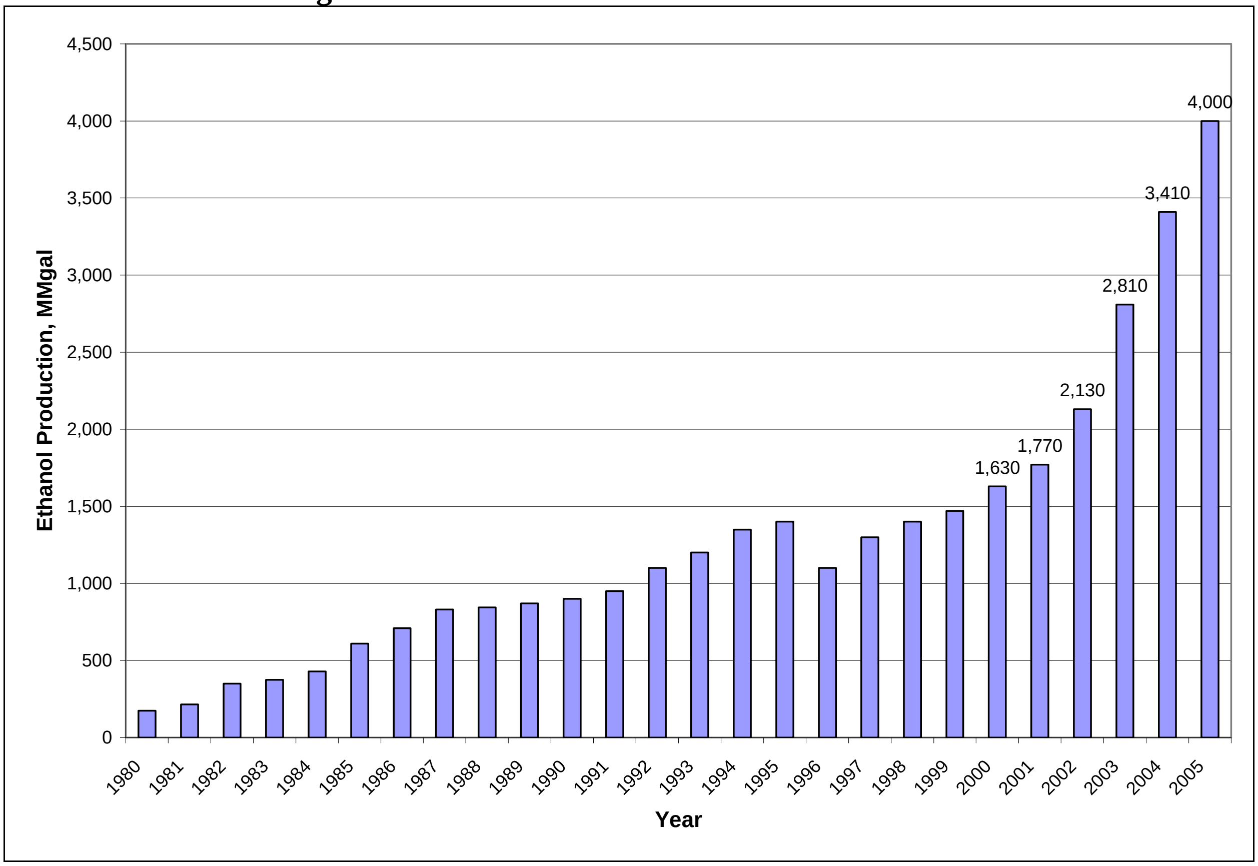
1.2.2 Forecasted Growth in Ethanol Production

1.2.2.1 Overview

Over the past 25 years, domestic fuel ethanol production has steadily increased due to environmental regulation, federal and state tax incentives, and market demand. More recently, ethanol production has soared due to the phase out of MTBE, an increasing number of state ethanol mandates, and elevated crude oil prices. As shown in Figure 1.2-1, over the past three years, domestic ethanol production has nearly doubled from 2.1 billion gallons in 2002 to 4.0 billion gallons in 2005. For 2006, the Renewable Fuels Association is anticipating about 4.7 billion gallons of domestic ethanol production[5].

[5] Based on RFA comments received in response to the proposed rulemaking, 71 FR 55552 (September 22, 2006).

Figure 1.2-1. U.S. Ethanol Production Over Time



Source: Renewable Fuels Association, From Niche to Nation: Ethanol Industry Outlook 2006

EPA forecasts that domestic ethanol production will continue to grow into the future. In addition to the past impacts of federal and state tax incentives, as well as the more recent impacts of state ethanol mandates and the removal of MTBE from all U.S. gasoline, crude oil prices are expected to continue to drive up demand for ethanol. As a result, the nation is on track to exceed the renewable fuel requirements contained in the Act, as explained below.

1.2.2.2 Expected Increases in Plant Capacity

Today's ethanol production capacity (5.2 billion gallons) is already exceeding the 2007 renewable fuel requirement (4.7 billion gallons). In addition, there is another 3.4 billion gallons of production capacity currently under construction.[6FGH] A summary of the new construction and plant expansion projects currently underway (as of October 2006) is found in Table 1.2-10.

[6] Under construction plant locations, capacities, feedstocks, and energy sources as well as planned/proposed plant locations and capacities were derived from a variety of data sources including Renewable Fuels Association (RFA), Ethanol Producer Magazine (EPM), ICF International, BioFuels Journal, and ethanol producer websites.

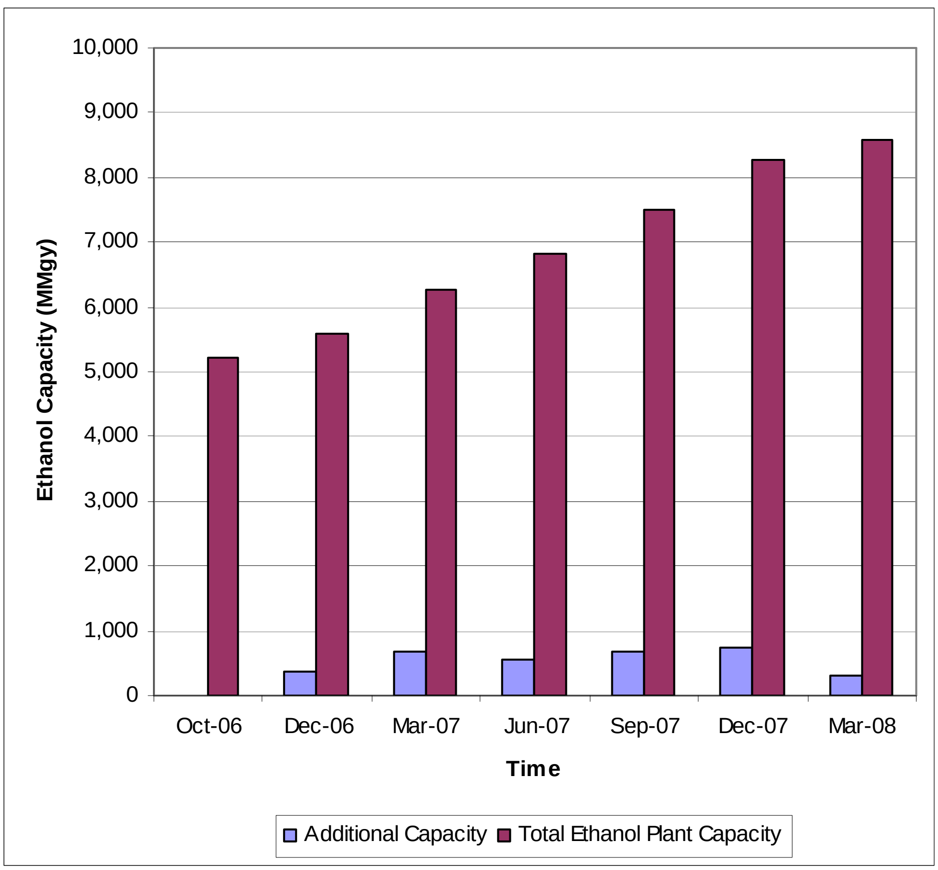
Table 1.2-10. Under Construction U.S. Ethanol Production Capacity

PADD	Oct. 2006 Baseline MMgy	Oct. 2006 Baseline Plants	Under Const. MMgy[a]	Under Const. Plants	Base + Under Const. MMgy[a]	Base + Under Const. Plants
PADD 1	0.4	1	115	1	115	2
PADD 2	5,012	100	2,764	39	7,776	139
PADD 3	30	1	230	3	260	4
PADD 4	105	4	50	1	155	5
PADD 5	71	4	198	3	269	7
Total	**5,218**	**110**	**3,357**	**47**	**8,575**	**157**

[a]Includes plant expansions

A select group of builders, technology providers, and construction contractors are completing the majority of the construction projects described in Table 1.2-10. 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 1.2-2[7].

Figure 1.2-2. Estimated Phase-In of Under Construction Plant Capacity



[7] Construction timelines based on information obtained from press releases and ethanol producer websites.

As shown in Table 1.2-10 and Figure 1.2-2, once all the construction projects currently underway are complete (estimated by March 2008), the resulting U.S. ethanol production capacity would be about 8.6 billion gallons. Without even considering forecasted biodiesel production (discussed below in 1.2.5), this would be more than enough renewable fuel to satisfy the 2012 RFS requirements (7.5 billion gallons). However, ethanol production is expected to continue to grow. There are more and more ethanol projects being announced each day. These potential projects are at various stages of planning from conducting feasibility studies to gaining local approval to applying for permits to financing/fundraising to obtaining contractor agreements. Together these potential projects could result in an additional 21 billion gallons of ethanol production capacity (as shown in Table 1.2-11).

Table 1.2-11.
Other Potential U.S. Ethanol Production Capacity

	Base + Under Const.		Planned		Proposed	
PADD	**MMgy[a]**	**Plants**	**MMgy[a]**	**Plants**	**MMgy[a]**	**Plants**
PADD 1	115	2	548.0	8	934	21
PADD 2	7,776	139	4,633	44	11,722	136
PADD 3	260	4	250	4	876	14
PADD 4	155	5	100	1	783	14
PADD 5	269	7	232	8	775	23
Subtotal	**8,575**	**157**	**5,763**	**65**	**15,090**	**208**
Total[b]			**14,339**	**222**	**29,428**	**430**

[a]Includes plant expansions
[b]Total including existing plus under construction plants.

Although there is clearly a great potential for ethanol production growth, it is highly unlikely that all the announced projects would actually reach completion in a reasonable amount of time, or at all, considering the large number of projects moving forward. Since there is no precise way to know exactly which plants will come to fruition in the future, we have chosen to focus our subsequent discussion on forecasted ethanol production on plants which are likely to be online by 2012.[8] This includes existing plants as well as projects which are under construction (refer to Table 1.2-10) or in the final planning stages (denoted as "planned" in Table 1.2-11). The distinction between "planned" versus "proposed" is that as of October 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 1.2-11, once all the under construction and planned projects are complete, the resulting U.S. ethanol production capacity would be 14.3 billion gallons. This volume, expected to be online by 2012, exceeds the EIA AEO 2006 demand estimate (9.6 billion gallons by 2012, discussed more in RIA Section 2.1.4.1). The forecasted growth would nearly triple today's production capacity and greatly exceed the 2012 RFS requirement (7.5 billion

[8] A more detailed summary of the plants we considered is found in a March 5, 2007 note to the docket titled: RFS Industry Characterization – Ethanol Production.

gallons). While our forecast represents ethanol production capacity (actual production could be lower), we believe it is still a good indicator or what domestic ethanol production could look like in the future. In addition, we predict that domestic ethanol production will continue to be supplemented by imports in the future. A more detailed discussion on future ethanol imports is found in Section 1.5.

1.2.2.3 Changes in Feedstocks & Processing Technologies

Of the 112 forecasted new ethanol plants (47 under construction and 65 planned), 106 would rely on grain-based feedstocks. More specifically, 89 would rely exclusively on corn, 13 would process a blend of corn and/or similarly processed grains (milo or wheat), 3 would process molasses, and 1 would process a combination of molasses and sweet sorghum (milo). Of the remaining six plants (all in the planned stage), four would process cellulosic biomass feedstocks and two would start off processing corn and later transition to cellulosic materials. Of the four dedicated cellulosic plants, one would process bagasse, one would process a combination of bagasse and wood, and two would process biomass. Of the two transitional corn/cellulosic plants, one would ultimately process a combination of bagasse, rice hulls, and wood and the other would ultimately process wood and other agricultural residues. In addition to the forecasted new plants described above, an existing corn ethanol plant plans to expand production and transition to corn stalks, switchgrass, and biomass in the future.

A summary of the resulting overall feedstock usage (including current, under construction, and planned projects) is found in Table 1.2-12. A discussion on how the plants predicted to process cellulosic feedstocks would help the nation meet the Act's cellulosic biomass ethanol requirement is found in Section 1.2.2.6

Table 1.2-12. Forecasted 2012 U.S. Ethanol Production by Feedstock

Plant Feedstock	Capacity MMgy	% of Capacity	No. of Plants	% of Plants
Bagasse	7	0.1%	1	0.5%
Bagasse, Wood	2	0.0%	1	0.5%
Bagasse, Wood, Rice Hulls[a]	108	0.8%	1	0.5%
Biomass	55	0.4%	2	0.9%
Cheese Whey	8	0.1%	2	0.9%
Corn[b]	12,495	87.1%	178	80.2%
Corn, Barley	40	0.3%	1	0.5%
Corn, Milo[c]	1,132	7.9%	20	9.0%
Corn, Wheat	235	1.6%	3	1.4%
Corn Stalks, Switchgrass, Biomass[a]	40	0.3%	1	0.5%
Milo, Wheat	40	0.3%	1	0.5%
Molasses[d]	52	0.4%	4	1.8%
Sugars, Starches	2	0.0%	1	0.5%
Waste Beverages[e]	16	0.1%	5	2.3%
Wood Agricultural Residues[a]	108	0.8%	1	0.5%
Total	**14,339**	**100.0%**	**222**	**100.0%**

[a]Facilities plan to start off processing corn.
[b]Includes two facilities processing seed corn.
[c]Includes one facility processing small amounts of molasses in addition to corn and milo.
[d]Includes one facility planning to process sweet sorghum (milo) in addition to molasses.
[e]Includes two facilities processing brewery waste.

As shown above, the majority of future plants are predicted to process grains (namely corn). Similarly, the vast majority of plants are expected to pursue dry milling technology. Our analysis does not foresee any new wet mill facilities, with the exception of a new 100 MMgy wet mill plant that is planned for Fort Dodge, IA and a 37 MMgy plant expansion project that is underway in Loudon, TN. Further, we do not predict that there will be any new plants processing cheese whey, waste beverages, or sugars/starches (which do not require milling). The forecasted cellulosic feedstock plants (described in more detail in Section 1.2.2.7) will not require milling. However, these facilities will require complex forms of pretreatment (described in more detail in Section 7.1.2) to break down the lignocellulosic and hemicellulosic polymers into fermentable sugars. A summary of the resulting overall feedstock processing technology utilization is found below in Table 1.2-13.

Table 1.2-13.
Forecasted 2012 U.S. Ethanol Production by Processing Technology

Processing Technology	Capacity MMgy	% of Capacity	No. of Plants	% of Capacity
Dry Milling	12,668	88.3%	192	86.5%
Wet Milling	1,274	8.9%	11	5.0%
Other[a]	397	2.8%	19	8.6%
Total	**14,339**	**100.0%**	**222**	**100.0%**

[a]Plants that do not process traditional grain-based crops and thus do not require milling. This category includes plants processing cheese whey, sugars & starches, or waste beverages as well as plants that plan to process molasses or cellulosic feedstocks.

1.2.2.4 Changes in Plant Energy Sources

Of the 112 forecasted new plants, 100 would burn some amount of natural gas - at least initially. More specifically, 91 plants would rely exclusively on natural gas; two would rely on a combination of natural gas, bran and biomass; one would burn a combination of natural gas, distillers' grains and syrup; and six would start off burning natural gas and later transition to coal. As for the remaining 12 plants, three would burn manure-derived methane (biogas); seven would rely exclusively on coal; one would burn a combination of coal and biomass; and one would burn a combination of coal, tires and biomass. In addition to the new ethanol plants, three existing plants currently burning natural gas are predicted to transition to alternate boiler fuels in the future. More specifically, two plants plan to transition to biomass and one plans to start burning coal.

Our research suggests that seven of the new plants (mentioned above) would utilize combined heat and power (CHP) technology, although others may exist. Three of the new CHP plants would burn natural gas, three would burn coal, and one would burn a combination of coal, tires, and biomass. Among the existing CHP plants, two are predicted to transition from natural gas to coal or biomass at this time. Overall, the net number of CHP ethanol plants would increase from 11 to 18. A summary of the resulting overall plant energy source utilization is found below in Table 1.2-14. A discussion on how the plants predicted to burn waste materials could help the nation meet the Act's cellulosic biomass ethanol requirement is found in Section 1.2.2.6.

Table 1.2-14. Forecasted 2012 U.S. Ethanol Production by Energy Source

Plant Energy Source	Capacity MMgy	% of Capacity	No. of Plants	% of Plants	CHP Tech.
Biomass[a]	112	0.8%	2	0.9%	1
Coal[b]	2,095	14.6%	21	9.5%	6
Coal, Biomass	75	0.5%	2	0.9%	0
Coal, Biomass, Tires	275	1.9%	1	0.5%	1
Manure Biogas[c]	144	1.0%	3	1.4%	0
Natural Gas	11,275	78.6%	189	85.1%	10
Natural Gas, Bran, Biomass	264	1.8%	2	0.9%	0
Natural Gas, Distillers' Grain, Syrup	50	0.3%	1	0.5%	0
Syrup	49	0.3%	1	0.5%	0
Total	**14,339**	**100.0%**	**222**	**100.0%**	**18**

[a]Represents two existing natural gas-fired plants that plan to transition to biomass.

[b]Includes two plants planning on burning lignite coal or coal fines. Includes one existing plant currently burning natural gas that plans to transition to coal. Includes six new plants that will start off burning natural gas and later transition to coal.

[c]Includes one facility planning on burning cotton gin in addition to manure biogas.

1.2.2.5 Changes in Ethanol Production Locations

Once all the forecasted ethanol projects are complete, 87 percent of the domestic production capacity would originate from PADD 2, followed by PADDs 1, 3, 5, and 4 (all contributing less than 5 percent). A summary of the findings is found below in Table 1.2-15.

Table 1.2-15.
Forecasted 2012 U.S. Ethanol Production by PADD

PADD	Capacity MMgy	% of Capacity	No. of Plants	% of Plants
PADD 1	663	4.6%	10	4.5%
PADD 2	12,409	86.5%	183	82.4%
PADD 3	510	3.6%	8	3.6%
PADD 4	255	1.8%	6	2.7%
PADD 5	501	3.5%	15	6.8%
Total	**14,339**	**100.0%**	**222**	**100.0%**

While PADD 2 ethanol production is expected to more than double (from 5.0 to 12.4 billion gallons), this represents a decrease in Midwest marketshare (from 96 to 87 percent). This predicted shift in marketshare is attributed to the growing number of ethanol plants located outside the cornbelt. Arizona, Florida, Hawaii, Louisiana, New York, Oregon, Pennsylvania and Texas are scheduled to join the 19 ethanol producing states described in Table 1.2-5. A summary of future ethanol production by state is found below in Table 1.2-16.

Table 1.2-16.
Forecasted 2012 U.S. Ethanol Production by State

State	Capacity MMgy	% of Plants	No. of Plants	% of Capacity
Arizona	55	0.4%	1	0.5%
California	244	1.7%	7	3.2%
Colorado	243	1.7%	5	2.3%
Florida	80.0	0.6%	2	0.9%
Georgia	150.4	1.0%	3	1.4%
Hawaii	59.2	0.4%	5	2.3%
Iowa	3,016	21.0%	38	17.1%
Illinois	1,606	11.2%	16	7.2%
Indiana	855	6.0%	11	5.0%
Kansas	569	4.0%	13	5.9%
Kentucky	38	0.3%	2	0.9%
Louisiana	110	0.8%	2	0.9%
Michigan	212	1.5%	4	1.8%
Minnesota	882	6.2%	20	9.0%
Missouri	382	2.7%	6	2.7%
New York	325	2.3%	4	1.8%
North Dakota	251	1.7%	5	2.3%
Nebraska	2,543	17.7%	31	14.0%
New Mexico	30	0.2%	1	0.5%
Ohio	420	2.9%	7	3.2%
Oklahoma	112	0.8%	3	1.4%
Oregon	143	1.0%	2	0.9%
Pennsylvania	108	0.8%	1	0.5%
South Dakota	953	6.6%	16	7.2%
Tennessee	109	0.8%	2	0.9%
Texas	370	2.6%	5	2.3%
Wisconsin	463	3.2%	9	4.1%
Wyoming	12	0.1%	1	0.5%
Total	**14,339**	**100.0%**	**222**	**100.0%**

1.2.2.6 Meeting the Cellulosic Ethanol Requirement in 2013

The Energy Policy Act of 2005 (the Energy Act or the Act) requires that 250 million gallons of the renewable fuel consumed in 2013 and beyond meet the definition of cellulosic biomass ethanol. 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.

As discussed above in Section 1.2.2.3, there are seven "planned" ethanol plants planning on processing cellulosic feedstocks in the future. A summary of these facilities is found below in Table 1.2.17.

Table 1.2-17. Potential Cellulosic Feedstock Plants

Ethanol Plant	Location	Plant Feedstock	Capacity MMgy	Status
Worldwide Energy Group[a]	Kaumakani, HI	Bagasse	7	Planned
Celunol Corp.[b]	Jennings, LA	Bagasse, Wood	2	Planned
GS Agrifuels Corporation[c]	Memphis, TN	Biomass	5	Planned
Xethanol Coastal LLC	Augusta, GA	Biomass	50	Planned
Bionol	Lake Providence, LA	Corn then Bagasse, Rice Hulls, Wood	108	Planned
Xethanol Corporation	Blairstown, IA	Corn then Corn Stalks, Switch Grass, Biomass	40	Planned[d]
BioEnergy International	Clearfield County, PA	Corn then Wood, Agricultural Residues	108	Planned
Total Cellulosic Ethanol Potential Based on Plant Feedstocks			**320**	

[a]Company also/formerly known as Clearfuels Technology
[b]Company also/formerly known as BC International
[c]Project also/formerly known as Mean Green Biofuels
[d]Includes 5 Mmgy existing plant capacity plus 35 MMgy planned expansion.

It is unclear whether the above-mentioned cellulosic feedstock plants would be online and capable of producing 250 million gallons of ethanol by 2013 to meet the Act's cellulosic biomass ethanol requirement. However, as described above in Section 1.2.2.4 there are 12 facilities that burn or plan to burn waste materials to power their ethanol plants in the future. These facilities, summarized below in Table 1.2.18, could also potentially meet the definition of cellulosic biomass ethanol under the Act.

Table 1.2-18. Potential Waste Energy Plants

Ethanol Plant	Location	Plant Energy Source	Capacity MMgy	Status
Corn LP	Goldfield, IA	Coal, Biomass	50	Existing
E Caruso Ethanol	Goodland, KS	Coal, Biomass	25	Under Construction
Archer Daniels Midland	Columbus, NE	Coal, Tires, Biomass	275	Planned
E3 Biofuels, LLC	Mead, NE	Manure Biogas	24	Under Construction
Harrison Ethanol, LLC	Cadiz, OH	Manure Biogas	20	Planned
Panda Ethanol	Hereford, TX	Manure Biogas, Cotton Gin	100	Under Construction
Central Minnesota Ethanol Co-op	Little Falls, MN	Natural Gas then Biomass	22	Existing
Chippewa Valley Ethanol Co.	Benson, MN	Natural Gas then Biomass	90	Existing[a]
Ethanex at SEMO Port	Cape Girardeau, MO	Natural Gas, Bran, Biomass	132	Planned
Ethanex Southern Illinois[b]	Benton, IL	Natural Gas, Bran, Biomass	132	Planned
Green Plains Renewable Energy[c]	Superior, IA	Natural Gas, Distillers Grain, Syrup	50	Under Construction
Corn Plus, LLP	Winnebago, MN	Syrup	49	Existing
Total Cellulosic Ethanol Potential Based on Plant Energy Sources			**969**	

[a]Includes 45 MMgy existing plant capacity plus 45 MMgy planned expansion.
[b]Joint venture with Star Ethanol
[c]Project also/formerly known as Superior Ethanol

Depending on how much fossil fuel is displaced by burning these waste materials (on a plant-by-plant basis), a portion or all of the above-mentioned 969 MMgy ethanol production capacity could potentially qualify as "cellulosic biomass ethanol" under the Act. Combined with the additional 320 MMgy of ethanol production capacity from plants processing cellulosic feedstocks, the overall cellulosic ethanol potential could be as high as 1.3 billion gallons. Even if only one fifth of this ethanol were to end up qualifying as cellulosic biomass ethanol or come to fruition by 2013, it would be more than enough to satisfy the 250 million gallon requirement specified in the Act.[9]

1.2.3 Current Biodiesel Production

Biodiesel is defined in several sections of the Act, which we have used in formulating our definition for the regulations, which call for meeting ASTM specifications. Biodiesel is registered with the EPA for commercial sale and is legal for use at any blend level in both highway and nonroad diesel engines although most engine manufacturers will only honor the warranty if biodiesel is used in blends of 2, 5 or, in some limited circumstances, 20 percent.

Biodiesel can be made from almost any vegetable or animal fat, with most of the world's production coming from plants oils, notably soy bean and rapeseed (canola) oil. Biodiesel fuel production is rapidly increasing in many regions of the world. The choice of the feedstock oil used to make it is dependent upon the vegetable oils and fat supplies that are economically available. For the U.S. market, there are many potential plant oil feedstocks that can be used to make biodiesel, including soybean, peanut, canola, cottonseed and corn oil. Biodiesel can also be made from animal fats such used restaurant grease (yellow grease) and tallow. Though, typically for the U.S. market, soybean oil has been the primary major feed stock supply, followed by use of yellow grease and animal tallow.

The resulting biodiesel product can be used as a fuel for diesel engines with minor modifications and is commonly blended with refinery produced diesel fuel. Raw vegetable and animal oils consist of fatty acids and glycerine products. Though these oils can directly be used in engines and give good short term performance, this is highly discouraged as their use can cause severe engine problems. This is primarily due to the raw oils forming engines deposits, with coking and plugging in engine injectors nozzles, piston rings, lubricating oil, etc. This happens due to polymerization of the triglycerides in the raw oils as the fuel is combusted. Therefore, it is necessary to convert the raw oils into a form of esters or biodiesel which prevents these issues. The biodiesel production process converts the raw vegetable and animal oils into esters, though the virgin oils themselves are sometimes (inappropriately) referred to as biodiesel. The production process called transesterification consists of adding methanol or ethanol to the virgin vegetable oil and animal oil, in the presence of a catalyst such as sodium or potassium hydroxide, resulting in esters or biodiesel and a byproduct glycerol. A subsequent step is usually

[9] We anticipate a ramp-up in cellulosic ethanol production in the years to come so that capacity exists to satisfy the Act's 2013 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.

needed, however, to remove glycerin, catalysts and other compounds, to allow the biodiesel to meet the required ASTM specifications.

Biodiesel blends such as B2, B5 and in some cases B20, can be used in existing engines without modification, and most engines exhibit no performance problems with the use of biodiesel, though this depends on the blend and the season. However, engine fuel filters may need to be changed more often, and there may be cold temperature operations due to biodiesel's higher cloud point. As a result most engine manufacturers will only recognize their warranties if biodiesel is used in low concentrations. Biodiesel produced from vegetable oil has practically zero amounts of sulfur and aromatics and a high cetane value, thus making it a good for blending into 15 ppm highway and offroad diesel fuel, though biodiesel made from yellow grease and animal fat may contain about 24 ppm of sulfur[I]. Biodiesel also has good lubricity qualities and can be used in concentration (~2 vol%) as a lubricity-enhancing additive for conventional diesel.

1.2.4 Forecasted Biodiesel Production

Biodiesel production has been increasing rapidly over the past five years and is projected to continue at a high rate in part because of the Renewable Fuel Standard (RFS) program. This expansion has primarily been driven by better economics, due to the recent large increase in diesel prices associated with the run up in crude prices, along with the Biodiesel Blenders Tax Credit programs and the Commodity Credit Commission Bio-energy Program, both of which subsidize producers and offset production costs. The Act extended the Biodiesel Blenders Tax Credit program to year 2008, which 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. This program was started in 2004 under the American Jobs Act. The existing Commodity Credit Commission Bio-energy Program also pays biodiesel producers grants when the economics to produce biodiesel are poor; the program averaged about one dollar per gallon in 2004. Recent payments through the Commodity Credit program have been reduced, however, and the program is expiring in fiscal year 2006. Historically, the cost to make biodiesel was an inhibiting factor to production. 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. Mandates from states and local municipalities that require the use of biodiesel in transport fuels are another factor which is expanding the use of biodiesel.

In 2005 approximately 91 million gallons of biodiesel were produced in the U.S. based on program payments to biodiesel producers under USDA's Bio-energy Program. This volume represents approximately 0.15 percent of all diesel fuel consumed in the domestic market. EIA projects the future production volume to expand to 414 million gallons per year in 2007 and then decrease to about 303 MM gallons per year in 2012, assuming that the biodiesel blender tax credits program expires in 2007 (see Table 1.2-19).

Table 1.2-19. Estimated Biodiesel Production[a]

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

[a] 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. Year 2006 data from verbal quote based on projection by NBB in June of 06. 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 85 biodiesel plants in operation with an annual production capacity of 580 million gallons per year[J]. The majority of the current production capacity was built in 2005 and 2006, and was first available to produce fuel in the later part of 2005 and in 2006. Though the 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 1.2-20.

Table 1.2-20. U.S. Production Capacity History

	2001	**2002**	**2003**	**2004**	**2005**	**2006**
Plants	9	11	16	22	45	85
Capacity (MM gals/yr)	50	54	85	157	290	580
Production, (MM gals/yr)	5	15	20	25	91	150
Capacity Utilization for Biodiesel, %	10	28	24	16	31	26

Note: Capacity Data based on surveys conducted.

Excess production capacity is not easily quantified, though since some of these plants may not run at full rate all of the time and may be "idled" for certain days of the week, seasons, time of day, etc. The capacity can be classified into two types of producers; capacity dedicated to biodiesel production and capacity available from the ole-chemical industry. The plants that primarily operate in the ole-chemical industry produce esters for use in the chemical industry. These plants are swing producers of biodiesel, which means that when the economics are favorable they can shift their operations and make biodiesel esters instead of products for the ole-chemical market.[10] The capacity from the ole-chemical industry produces mono-alkyl esters using a similar transesterification process, with the ester products being sold for to make plasticizers, soaps, paints, solvents and other industrial uses. Additionally, the biodiesel production capacity volumes may be optimistic, as this is not officially tracked. The capacities listed here are those based on each company's self reported volumes to the National Biodiesel Board and may have some inaccuracies due to informal reporting procedures.

We anticipate that future capacity additions will be geared more towards production of biodiesel for use as transportation fuel, rather than serving primarily the oleochemicals markets. As of September 2006, there were 65 plants in the construction phase and 13 existing plants that are expanding their capacity. All of this new capacity when installed would provide about 1.4 billion gallons per year of additional throughput capacity. Table 1.2-21 presents the data for the biodiesel plant capacities per the categories discussed.

Table 1.2-21. Biodiesel Plant Capacities

	Existing Plants	**Construction Phase**
Number of Plants	85	78
Total Plant Capacity, (MM Gallon/year)	580	1,400

Considering that it takes 12 to 18 months to construct a biodiesel plant (from the time of project feasibility analysis to startup date), a large portion of the capacity in the construction phase in late 2006 will be available to produce fuel in 2007.[K] Data on biodiesel plant construction reveals most of the new capacity that is currently being constructed is expected to be online and producing fuel in 2006 or by end of 2007. Therefore, the existing capacity plus the capacity in the construction phase totals an aggregate amount of about two billion gallons per year. Though there is no volume mandate for biodiesel fuel under the RFS program, the total capacity available from new and existing plants exceeds EIA's projected biodiesel volume of 414 MM in 2007 and 303 MM in 2012 by a wide margin.

The plants in the construction phase are larger than existing biodiesel plants, with average capacity of existing plants at 8.4 MM gallons per year, while plants in construction phase are

[10] Oleochemicals are derived from biological fats and oils using hydrolysis or alcoholysis with products of fatty acid esters and glycerol.

averaging 20.9 MM gallons per year, as presented in Table 1.2-22. The distribution of biodiesel plants by size and number of companies within each size range are presented in Table 1.2-23.

Table 1.2-22. Average Plant Capacity by Feedstock (MM gallons per year)

Feedstock	Existing*	Construction*
Canola		57.5
Multi Feedstock	6.0	16.7
Other Vegetable	2.0	
Recycled Cooking Oil	0.5	1.0
Soybean Oil	8.8	19.3
Tallow	5.0	

Table 1.2-23. Biodiesel Plant Size versus Number of Companies

Plant Size (MM gallons per year)[a]	Existing Plants	Construction Phase
<1.00	9	5
1.0- 5.0	28	9
5.0-10.0	17	10
10.0 to 15 .0	9	7
15.0 to 20.0	2	3
20.0+	10	28
Average Plant Size	8.4	20.9

[a]Total capacity of plants in each category; existing plants are 580 MM gal/yr while those in the construction phase are 1,400 MM gal/yr.

Because newer plants are likely to be larger than existing plants, have better technology and may have greater alignment with feedstock and feed sources, some of the older plants may operate at an economic disadvantage once the new plants come on line. At the moment, it is not possible to predict actual biodiesel production based on capacity, since in the past the capacity was used at rates less than maximum. Thus, how excess production capacity evolves will be dictated by economics, profitability, and fuel demand.

The majority of existing biodiesel plant capacity is located in the middle and Midwestern parts of the country and use soy bean oil as the feedstock. The other plants are scattered with locations based on the east and west coasts, with feedstocks based on use of soybean, canola and other oils as well as yellow grease as the feedstock. The new plants are being built to process a wider variety of feedstocks, with multi-feedstock and recycle grease capability. The feedstocks for these plants are listed in Table 1.2-24.

Table 1.2-24. Feedstock Selection for Biodiesel Producers

Feedstock	Existing	Construction
Camelia		
Canola		2
Cottonseed	1	
Multi Feedstock	29	29
Palm Oil		
Recycled Cooking Oil	7	3
Soybean oil	39	36
Tallow/Poultry Fat	2	
Unknown	7	8

1.2.5 Baseline and Projected Biodiesel Volumes for Analysis

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 1.2-16). 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 diesel fuel (described in Section 2.1.3). The resulting 2012 reference case consisted of approximately 30 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 1.2-16). Unlike forecasted ethanol use (described in 2.1.4), biodiesel use was assumed to be constant at 300 million gallons under both the statutory and higher projected renewable fuel consumption scenarios.

1.3 Renewable Fuel Distribution

1.3.1 Current Renewable Fuel Distribution System

Ethanol and biodiesel blended fuels are not currently shipped by petroleum product pipeline due to operational issues and additional cost factors.[L] The ability to ship by pipeline is also limited because the sources of ethanol and biodiesel are frequently not in the same locations as the sources of gasoline and petroleum-based diesel fuel. 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. Ethanol and biodiesel can either be added by "splash blending" where the renewable is added separately to the tank truck, or by in-line injection where the renewable is injected into the petroleum fuel stream as it is being dispensed into the tank truck. Ethanol and biodiesel are sometimes added to petroleum-based fuels downstream of the terminal, but this accounts for little of the total volume of used.

In cases where ethanol and biodiesel are produced within 200 miles of a terminal, trucking is often the preferred means of distribution. However, most renewable fuel volumes are produced at greater distances from potential centers of demand. For longer shipping distances, the preferred method of bringing renewable fuels to terminals is by rail and barge. Dedicated pipelines have not been used to distribute renewable fuels to terminals due to the high cost of installing new pipelines, the relatively large shipping volumes that would be needed to justify such expenditures, and the fact that renewable fuel production facilities tend to be relatively numerous and dispersed.

The relatively low volumes of ethanol used prior to 2002 constrained the ability of the distribution system to efficiently move ethanol to distant markets. Ethanol shipments by rail were typically made on an individual car basis. Under such an approach, small groups of rail cars travel to market as part of trains that carry other goods. This approach results in relatively high transportation costs, longer transit times, and potential delays in delivery. Substantial improvements in the efficiency of distributing ethanol by rail are being made due the need to move large volumes of ethanol over long distances as a consequence of the elimination of MTBE in California, New York, and Connecticut beginning in 2004. The use of unit trains, sometimes referred to as "virtual pipelines" reduces delivery costs, shortens delivery times, and improves reliability. Unit trains are composed entirely of approximately 100 rail cars containing ethanol. Ethanol shipped by unit trains is delivered to hub terminals for further distribution to other terminals by barge and tank truck.

Substantial volumes of ethanol can potentially be shipped down the Mississippi river by barge for temporary storage in New Orleans.[M] From New Orleans, ethanol can be loaded onto ocean transport for delivery to the East and West Coast. There is also potential to move ethanol via the Missouri and Ohio as well as other river systems and the Great Lakes. Marine shipments of ethanol require a relatively large minimum shipment size, determined by the minimum size of the marine tank compartment.[11] Similar to the case for "unit trains", there are also efficiencies in dedicating whole barges, barge tows, or marine tankers to ethanol distribution. The increased demand for ethanol has made it possible to better benefit from these efficiencies of scale.

The use of inland barges to transport ethanol from production facilities is in large part driven by whether there is river access at such facilities. Historically, corn prices tend to be higher near river systems that serve as arteries for the export of corn than at inland locations distant from these river systems. To take advantage of lower corn prices at inland locations and to avoid competing for corn with grain elevators that serve the export market, all of the new ethanol production facilities that have been built since 1999 have been built at inland locations.[N]

[11] River barges typically have a capacity of 10,000 barrels. Ocean barges typically have a capacity of 20,000 barrels. Barges are sometimes subdivided into 2 or 3 compartments.

Consequently, the majority of the growth in ethanol freight volumes since 1999 has been in the rail sector.

1.3.2 Changes to the Renewable Fuel Distribution System Due to Increased Demand

This section addresses that changes that we expect will take place in the renewable fuel distribution system in response to the anticipated increase in demand for such fuels through 2012. There may be some limited opportunity to ship renewable fuels by pipeline in the future as demand increases. However, because of the constraints discussed previously (see section 1.3.1), we believe that rail and barge are likely to remain the predominant means of transportation. The 2002 DOE Study also reached this conclusion.[O] While this constraint on the ability to ship ethanol and biodiesel by pipeline presents logistical challenges that result in additional transportation costs, the need to transport these alternative fuels by other means may work to the overall advantage of the fuel distribution system. Petroleum product pipelines are nearing capacity. Thus, it seems likely that the pipeline distribution system will find it increasingly difficult to keep pace with annual increases in the demand for transportation fuels. Displacing some of the volume of transportation fuels from the pipeline distribution system through the use of ethanol and biodiesel will relieve some of this strain.

Small volume rail shipments made on a by-car basis are likely to remain an important feature in supplying markets that demand limited volumes. However, as the demand for ethanol increases we anticipate that the expansion of the use of unit trains will continue, and that this will be a significant means of bringing ethanol to distant markets. There has been some expansion of capacity at existing ethanol plants with river access and some new plants are projected to be built with river access. However, we anticipate that most new ethanol capacity will not have river access. In addition, at least one new ethanol plant slated for production that does have river access is planning to move its ethanol to market via rail. Nevertheless, in cases where rail is the means to transporting ethanol to hub terminals, marine transport can play an important role in further distribution to satellite terminals.

Substantial improvements to the rail, barge, tank truck, and terminal distribution systems will be needed to support the transport of the volumes of renewable fuels necessary to meet the requirements of the RFS program. These improvements include the addition of a significant number of additional rail cars, and tank trucks. Additional marine barges will also be needed. To facilitate the increased use of unit trains, new rail spurs will be needed at terminals. Terminals will also need to add facilities to store and blend ethanol. In addition, those terminals and retail facilities that had not previously handled ethanol blended fuel will need to make certain one-time upgrades to ensure the compatibility of their systems with ethanol. These types of changes have been occurring as demand for ethanol and biodiesel has grown rapidly over the last several years, and there is no reason to suspect that they would not continue as demand continues to warrant it. The costs associated with these changes are discussed in Chapter 7.3 of this RIA.

The most comprehensive study of the infrastructure requirements for an expanded fuel ethanol industry was conducted for the Department of Energy (DOE) in 2002 .[P] The conclusions reached in this study indicate that the changes needed to handle the increased volume of ethanol required under the RFS will not represent a major obstacle to industry.[12] While some changes have taken place since this report was issued (as discussed below), we continue to believe that the rail and marine transportation industries can manage the increased growth in an orderly fashion. This belief is supported by the demonstrated ability of the industry to handle the rapid increases and redistribution of ethanol use across the country over the last several years as MTBE was removed. Given that future growth in ethanol use is expected to take place in an orderly fashion in response to economic drivers, we anticipate that the distribution system will be able to respond appropriately.

The use of unit trains has accelerated beyond that anticipated in the 2002 DOE report, leading to the more efficient distribution of ethanol by rail. As a result, rail has taken a relatively greater role in the transportation of new ethanol volumes as compared to shipment by barge than was projected in the report. Thus, there is likely to be a relatively greater demand on the rail distribution system and somewhat less demand on the marine distribution system than was projected in the DOE study.

The 2002 DOE study estimated that the increase in the volume of ethanol shipped by rail needed to facilitate the use of 10 billion gallons of ethanol annually would represent an increase in total tank car loadings of 0.33 percent. The increase in tank car loadings for Class I railroads was estimated at 4.75 percent. The DOE report concluded that this increase is relatively modest by railroad industry standards and could be accommodated given the available lead time. The DOE study estimated that the increase in demand on barge movements due to the need to carry an increased volume of ethanol would equate to a one percent increase in the total tonnage moved by barge. Given that on the one hand relatively few new ethanol plants are projected to be cited with river access, and that on the other hand barge is expected to play an important role in redistributing ethanol from rail hub terminals, we estimate that the increase in barge movements will be 30 percent less than that projected in the 2002 DOE study. This equates to an increase in total tank car loadings of 0.44 percent rather than the 0.33 percent projected in the DOE study. We believe that this relatively modest potential increase in the demand on the rail distribution system can be accommodated without major difficulty given the available lead time.

Although, the 2002 DOE study generally concluded that the projected one percent increase in the demand on the river barge industry could be accommodated without major difficulty, it highlighted two potential concerns. The report noted that delays are already being experienced at locks on the Mississippi river. The question was raised regarding how the projected increase of one percent in river traffic due to increased ethanol shipments might be accommodated at these locks. The report also raised concerns regarding the availability of sufficient marine vessels capable of traveling between two ports in the United States (Jones Act compliant vessels). Given that it appears that there will be less demand placed on the river barge industry to transport ethanol than was projected in the 2002 DOE study, the concerns raised in the study regarding the capability of the inland waterway system to cope with the increased traffic associated with shipping the anticipated new volume of ethanol will be less pronounced.

[12] See section 7.3 of this RIA regarding the projected costs of the necessary infrastructure improvements.

At the present time, the industry is experiencing a shortage of tractor trailers and drivers to transport ethanol. The boom in demand for truck transport is due to a number of factors, including the precipitous removal of MTBE from gasoline and its replacement by ethanol[13] which has taken place when the demand for truck transport was already growing at a rapid place due to the increased imports. The implementation of EPA's ultra-low sulfur diesel (ULSD) program this summer may also cause an increase in the demand for tank trucks if more trucks must be dedicated to ULSD service. Given the gradual increase expected from year to year in ethanol production, we anticipate that the industry will be able to add sufficient additional tank truck service in an orderly fashion without undue burden.

The necessary facility changes at terminals and at retail stations to dispense ethanol containing fuels have been occurring at a record pace due to the removal of MTBE from gasoline. The use of ethanol has also become more economically attractive due to higher gasoline prices. Now that MTBE has been removed, a more steady increase in the use of ethanol is anticipated over time. This will also allow for a smooth transition for terminals and retail operators.

The volumes of biodiesel that are expected to be used by 2012 to comply with the RFS will be relatively modest (approximately 300,000,000 gallons). Consequently, we anticipate that biodiesel will continue to be distributed to terminals by tank truck and by individual rail car shipments. One hundred percent biodiesel (B100)[14] forms wax crystals when the temperature falls to 35 to 45 degrees Fahrenheit.[15] Thus, storage tanks for B100 need to be heated to maintain flow-ability during the cold seasons. Shipping vessels used to transport B100 such as barges, rail cars, and tank truck containers also typically must either be insulated (and sometimes heated) during the cold season or alternatively facilities can be provided at the terminal to reheat the vessel prior to delivery. Biodiesel that is blended with diesel fuel and enhanced with cold flow additives (if needed) can have comparable cold flow performance to petroleum based diesel fuel.[16]

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[13] MTBE is typically blended with gasoline at the refinery. MTBE production plants are often located nearby to refineries allowing transport to the refinery by dedicated pipeline. In cases where, the sources of MTBE are more distant from the refinery, barge and rail are the preferred means of transport and relatively little MTBE is transported by truck.

[14] The concentration of biodiesel in a biodiesel blend is indicated by the number following the "B" designation. For example, B99.9 indicates a biodiesel blend containing 99.9 percent biodiesel, and B80 indicates a blend containing 80 percent biodiesel. Manufactures of biodiesel sometimes blend in one tenth of one percent diesel fuel into biodiesel to create B99.9 prior to shipping the fuel to terminals to create more dilute biodiesel blends so that the producer can claim the biodiesel tax credit (pursuant to Internal Revenue Service requirements).

[15] The point at which wax crystals form is referred to as the cloud point. The cloud point of B100 varies depending on the feed stock used in its production.

[16] The relatively low concentration biodiesel blends that are typically used in vehicles (up to 20% biodiesel) can be formulated to have comparable cold flow performance to petroleum based diesel fuel. Thus, there is no need to heat such biodiesel blends in vehicle fuel tanks.

As temperatures fall during the cold seasons, some terminals currently avoid the need for heated B100 tanks and facilities to heat shipping vessels by accepting progressively less concentrated biodiesel blends (for final blending to produce fuels for use in vehicles). During the warm seasons, such terminals typically accept B100 or B99.9. As the weather grows colder, the terminal might switch to accepting B80 and during the coldest parts of the year might accept B50 (that contains 50 percent number one diesel fuel). The need for insulated tank trucks and tank cars is also sometimes avoided if transit times are brief by shipping warmed biodiesel. We believe that as the volume of biodiesel grows, most terminals will opt to receive B100 (or B99.9) year round for blending into diesel fuel for the consistency in operations which this practice offers. A number of terminals are already following this practice. These terminals have installed heated storage tanks for biodiesel and insist that biodiesel be delivered in insulated tank trucks (or rail cars) so that it may be pumped into the terminal storage tank without concern about the potential need for reheating. The cost of the necessary heated and/or insulated equipment is not insignificant. However, the modest additional volumes that will need to be shipped via rail and tank truck due to the use of biodiesel do not materially affect the conclusions reached above regarding the ability of the fuel distribution system to cope with the increased volumes of renewable fuels.

1.4 Blenders

1.4.1 Ethanol Blending

Ethanol is miscible with water, and thus can introduce water into the distribution system causing corrosion and durability problems as well as fuel quality problems. For this reason, ethanol is blended downstream at terminals or into tank trucks.

The distribution of ethanol is described in more detail in Section 1.3. Briefly, ethanol producers provide ethanol either directly to terminals, to marketers or to terminals that are owned by refiners. In the first case, ethanol is provided to terminals that are owned entities other than refining companies. They receive ethanol from the ethanol producer, and gasoline from any number of refiners. The blenders then add ethanol to the gasoline at the terminal. For RFG, the terminals receive the blendstock for RFG, called Reformulated Blendstock for Oxygenate Blending or RBOB, to which they add the amount of ethanol called for on the Product Transfer Document that accompanies such shipments. Once the ethanol is added to the RBOB, the product becomes a finished gasoline (RFG) and is sent via truck to retailers. For conventional gasoline (CG) ethanol is also added and shipped to retailers. The tracking mechanism for CG is not as detailed as it is for RFG, however. The majority of ethanol that is blended into CG has historically been “splash-blended” although an increasing volume of ethanol is being blended into special blends of conventional gasoline (e.g. sub-octane), or “match blended”. Finally, a very small amount is blended as E85.

1.4.2 Biodiesel Blending

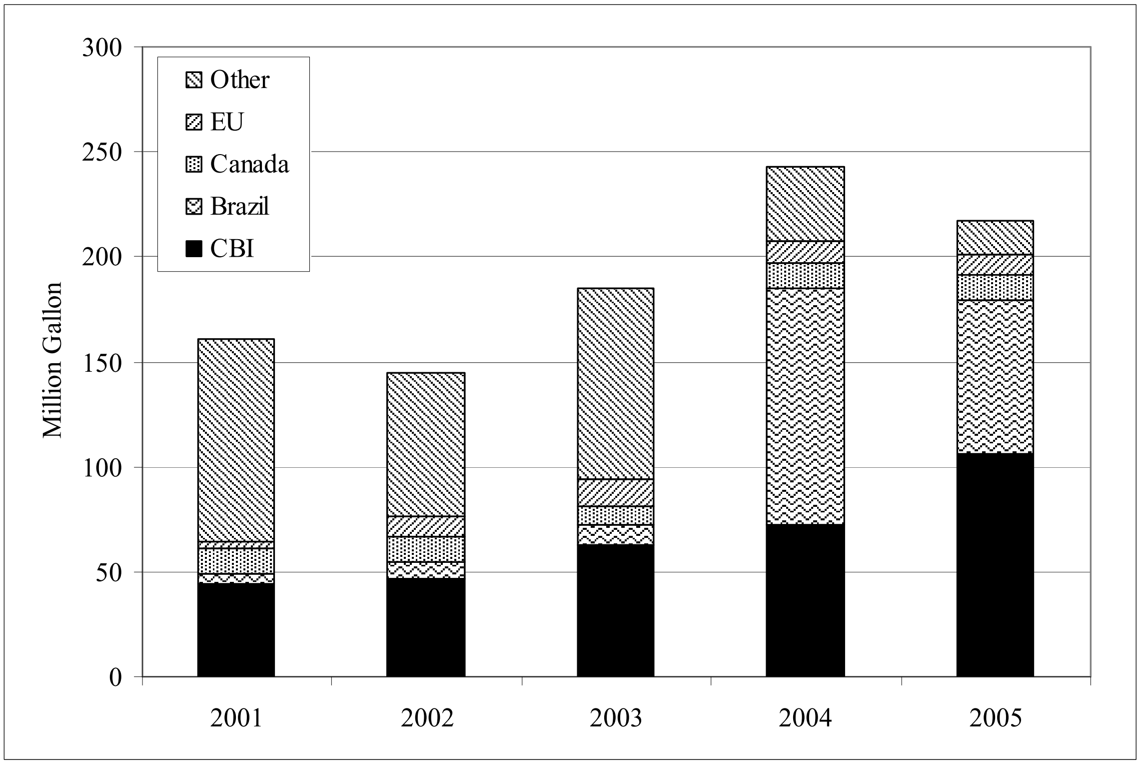
Biodiesel generally leaves the production facility in its neat form and is shipped by truck to locations where it can be blended with conventional diesel fuel. The blending generally occurs at centralized distribution points such as terminals, although it also sometimes occurs within tank trucks themselves. Biodiesel is only rarely used in its neat (unblended) form.

1.5 Imports/Exports of Renewable Fuel

Since the early 1980s, the U.S. has maintained a 54 cent per gallon tariff on imported ethanol, primarily to offset the blending tax subsidy of the same magnitude that had been put in place to support alternative energy production and domestic agriculture. Legislation and agreements implemented since then have waived or significantly reduced the tariff on imports from Canada, Mexico, and about two dozen Central American and Caribbean nations covered by the Caribbean Basin Initiative (CBI). Under the Caribbean Basin Economic Recovery Act, which created the CBI, these countries can export ethanol duty free to the U.S. at a rate up to 7% of the U.S. fuel alcohol market; quantities above this limit have additional stipulations for feedstocks being grown within the supplying country.

Historically, the CBI nations have had little ethanol production capacity of their own but have supplemented it by importing Brazilian ethanol and re-exporting it to the U.S. duty free. More recently, with the rapid phase-out of MTBE and the high price of ethanol, it has become economically viable to import significant quantities of ethanol directly from other nations despite the tariff. Brazil, currently the largest ethanol producing nation in the world, has become the largest single country supplier to the U.S. market. As shown in Figure 1.5-1, total imports have increased more than 30% in 2004-5 over the previous three-year average.

Figure 1.5-1. Historic U.S. Ethanol Import Volumes and Origins[a]



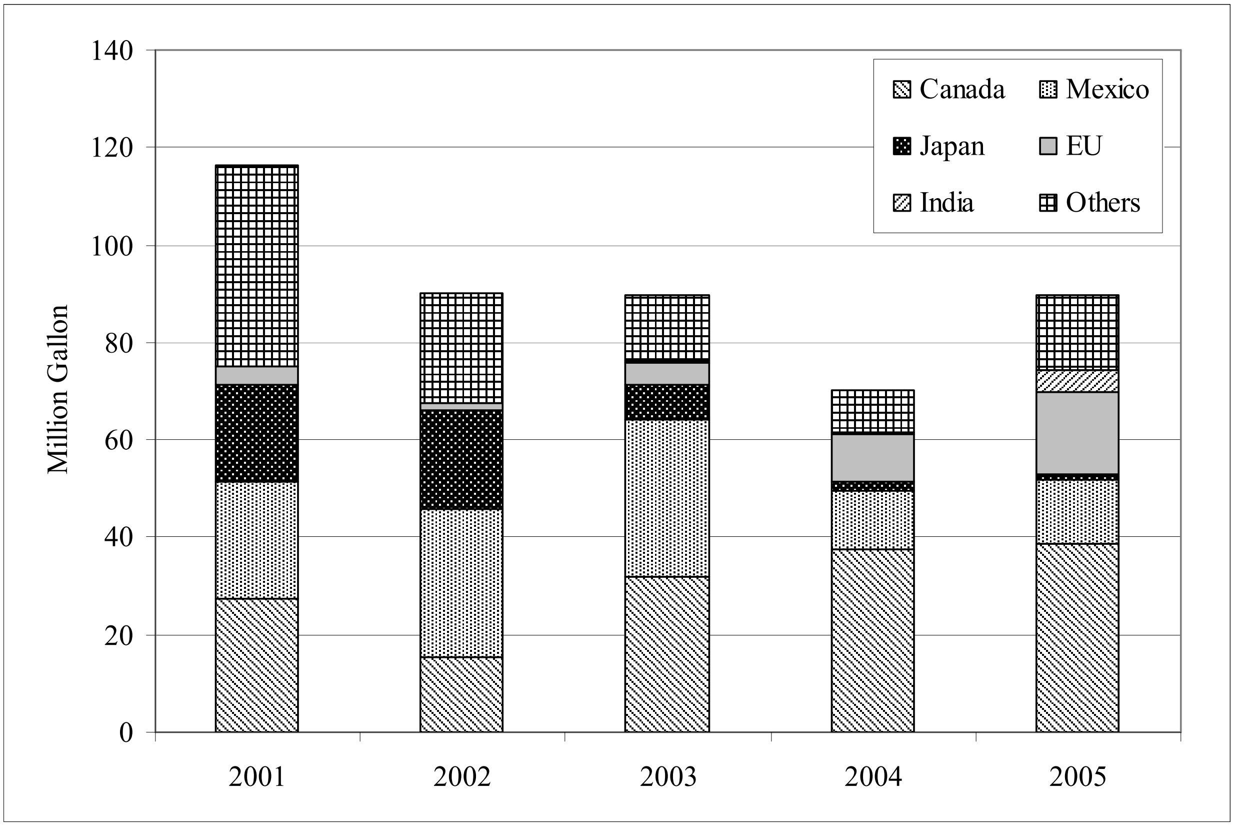
[a] F.O. Licht, "World Ethanol Markets, The Outlook to 2015" (2006). Gross imports (does not account for export volumes) including hydrous, dehydrated, and denatured volumes.

Going forward, as domestic ethanol production capacity increases rapidly, its price is expected to fall back into the historic range of 30-40 cents per gallon above gasoline (before blending subsidy). This is expected to once again make direct imports from Brazil and other full-tariff producers less attractive, and to decrease total imports. According to a current report by F.O. Licht, U.S. net import demand is estimated to be around 300 million gallons per year by 2012, being supplied primarily through the CBI, with some direct imports from Brazil during times of shortfall or high price.[Q]

Changes in the production and trade climate may influence this however. The Caribbean countries with duty free status are seeing both internal and foreign investment to increase ethanol production capacity significantly over the next several years, making more cheap imports available. It is unclear at this point what volume of ethanol will be supplied through these channels.

On the export side, the U.S. has averaged about 100 million gallons per year since 2000, mostly to Canada, Mexico, and the E.U. Figure 1.5-2 shows historical U.S. exports. There is a trend over the past five years of exporting larger quantities to fewer countries, with declining volumes to Asia and increasing volumes to the E.U. and India. The demand for ethanol in all these areas remains strong, and it appears that Asian imports from Brazil and China are making up for the decrease in U.S. ethanol moving into the region.

Figure 1.5-2. Historic U.S. Ethanol Export Volumes and Origins[a]



[a] F.O. Licht, "World Ethanol Markets, The Outlook to 2015" (2006). Gross exports (does not account for import volumes), includes hydrous, dehydrated, and denatured volumes.

These numbers are expected to increase modestly as more production comes online, with more dramatic increases possible during periods of depressed domestic prices or stock surges. Looking out over the next decade, the E.U. has a biofuels directive in place that will bolster demand, and Japan and South Korea are expected to increase their use of biofuels steadily as well. World ethanol production is projected to grow from the current 10 billion gallons per year to more than 25 in 2015, and the international biofuels markets are just beginning to take shape. During this period we can expect significant changes in who is supplying and who is demanding as the players determine their places and forge agreements on subsidies and tariffs. As of 2005, the U.S. became largest ethanol producing nation, eclipsing Brazil, and ample foreign markets will be available if conditions are right.