The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies

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Summary

A decade ago, 158 refineries operated in the United States and its territories and sporadic refinery outages led many policy makers to advocate new refinery construction. Fears that crude oil production was in decline also led to policies promoting alternative fuels and increased vehicle fuel efficiency. Since the summer 2008 peak in crude oil prices, however, the U.S. demand for refined petroleum products has declined, and the outlook for the petroleum refining industry in the United States has changed.

In response to weak demand for gasoline and other refined products, refinery operators have begun cutting back capacity, idling, and, in a few cases, permanently closing their refineries. By current count, 124 refineries now produce fuel in addition to 13 refineries that produce lubricating oils and asphalt. Even as the number of refineries has decreased, operable refining capacity has actually increased over the past decade, from 16.5 million barrels/day to over 18 million barrels/day. Cyclical economic factors aside, U.S. refiners now face the potential of long-term decreased demand for their products. This is the result of legislative and regulatory efforts that were originally intended, in part, to accommodate the growing demand for petroleum products, but which may now displace some of that demand. These efforts include such policies as increasing the volume of ethanol in the gasoline supply, improving vehicle fuel efficiency, and encouraging the purchase of vehicles powered by natural gas or electricity.

Since the Clean Air Act Amendments, 15 distinctly formulated boutique fuels are required in portions of 12 states. H.R. 392, the Boutique Fuel Reduction Act of 2009, would further amend` the Clean Air Act to add temporary waivers for boutique fuels due to unexpected problems with distribution and give EPA authority to reduce the number of boutique fuels. The 2005 Energy Policy Act created the Renewable Fuel Program to substitute increasing volumes of renewable fuel for gasoline. The 2007 Energy Independence and Security Act expanded the program to cover transportation fuels in general, extended the program to calendar year 2022, and increased the target volume to 36 billion gallons renewable fuel annually. The 2008 Food, Conservation and Energy Act of 2008 reduced some of the federal subsidies and tax breaks favoring ethanol production. A 2007U.S. Supreme Court ruling found that EPA has the authority under the Clean Air Act to regulate carbon dioxide (CO2) emissions from automobiles. Though the ruling applied to automobiles, it had wider implications. In response to the FY2008 Consolidated Appropriations Act (H.R. 2764; P.L. 110-161), EPA issued the Mandatory Reporting of Greenhouse Gases Rule that requires suppliers of fossil fuels or industrial greenhouse gases (GHG), manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG emissions to submit annual reports to EPA. H.R. 2454, The American Clean Energy and Security Act of 2009 (passed in the House June 26, 2009) would amend the Clean Air Act by establishing a “cap-and-trade” system designed to reduce greenhouse gas emissions (GHG) and would cap emissions from refineries and allow trading of emissions permits (“allowances”). As proposed, H.R. 2454 would require U.S. refiners to purchase emission credits for both their stationary emissions and the subsequent combustion of their fuels (predominantly consumed in the transportation sector). S. 3663, introduced in August 2010, would establish a Natural Gas Vehicle and Infrastructure Development Program to promote natural gas as an alternative transportation fuel in order to reduce domestic oil use.

The prospect of declining motor-fuel demand may persuade operators to idle, consolidate, or permanently close refineries.

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Introduction

The U.S. petroleum refining industry experienced what some have called a "golden age" during the years 2004-2007. During this period, the demand for petroleum products, especially gasoline, increased rapidly both in the United States and world markets. Refiners found favorable price-spreads between heavy and light crude oils as well as between crude oil and refined products. The industry operated plants at nearly maximum capacity and posted record profit levels. Unexpected events such as hurricanes that shut down Gulf Coast refineries, concerns over "peak oil" production, and crude oil price speculation likely contributed to spikes in gasoline prices. During the period, many policy makers expressed the concern that U.S. refining capacity was not increasing rapidly enough to keep up with the expected growth in demand for petroleum products.

U.S. gasoline consumption began declining in 2008, by almost 99 million barrels from the previous year, and another 10 million barrels in 2009.[1] Paradoxically, the United States began importing more gasoline—81 million barrels in 2009.[2] U.S. renewable fuel production (in the form of ethanol) exceeded 256 million barrels, and ethanol imports added nearly 4.6 million barrels.[3]

The concern has now shifted to fears that refining overcapacity may exist in the United States, as the state of, and the outlook for, the petroleum refining industry have changed significantly. Current market conditions have resulted in lower capacity utilization rates and refinery closures. These most recent changes in the conditions facing the industry are consistent with a past performance that has been cyclic. However, mandates for a renewable fuel standard (RFS) and increased corporate average fuel economy (CAFE) could influence permanently reduced refining capacity in coming years.

During an era of increasing crude oil prices and concerns for declining domestic crude oil production, many policy makers advocated energy self-sufficiency. Renewable fuels offered the promise of at least offsetting an increasing demand for transportation fuel. Now, though, the prospect of declining motor-fuel demand may mean that the use of more renewable fuels may influence operators to idle, consolidate, or permanently close refineries.

This report begins by looking at the current production capacity of the refineries operating in the United States, and the sources and changes in crude oil supply. It then examines the changing characteristics of petroleum and petroleum product markets and identifies the effects of these changes on the refining industry, including tax considerations. The report concludes with discussion of the policy and regulatory factors that are likely to affect the structure and performance of the industry during the next decade.

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[1] Gasoline consumption, as reported by the U.S. Energy Information Administration, includes blended ethanol.

[2] Reported as 80,882 thousand barrels by EIA.

[3] Reported as 256,149 thousand barrels of fuel ethanol produced and 4,614 thousand barrels imported by Energy Information Administration, *Petroleum Supply Monthly*, February 2010, Table 2 p. 11, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_monthly/psm.html.

Background—Refineries and Capacity

After a volatile decade marked by record crude oil prices and profit margins, U.S. refiners now face the prospect of possibly long-term decreased demand for their products. Refiners are responding by cutting costs, reducing capacity utilization, and closing facilities.

A decade ago, 158 refineries operated in the United States and its territories. By the Congressional Research Service's count, the number has declined to 124 refineries that process crude oil into fuels, and in addition, 13 refineries that produce lubricating oils and asphalt.[4] These numbers include three refinery complexes, each made up of two formerly independent refineries joined by pipeline.

Although the number of refineries has decreased, operable refining capacity has increased over the past decade from 16.5 million barrels/day to over 18 million barrels/day. By the Energy Information Administration's (EIA) definition, "operable capacity" includes both operating refineries and idle refineries which shut down temporarily for repair or "turn around" for seasonal adjustment in the product slate (for example, reformulating gasoline from winter to summer blends). In addition, some refinery operators have indefinitely idled their refineries to wait for improving demand.[5]

Petroleum Administration for Defense Districts

During World War II, the War Department (now the Department of Defense) delineated "Petroleum Administration for Defense Districts" (PADD) to facilitate oil allocation. At one time, refineries in each PADD processed crude oil and distributed petroleum products for use in the district. The high rate of merchant-marine tankers lost to Nazi submarines operating along the Eastern seaboard prompted construction of the Virginia and Colonial product pipelines to link the Gulf Coast with the Northeast United States. A network of crude oil and petroleum product pipelines now interlinks the PADDs, making them interdependent.

Crude oil sourcing for U.S. refineries varies over time, but in general, the PADD 1 (East Coast) refineries process crude oil shipped from all over the world. PADD 2 (Midwest) and PADD 4 (Rocky Mountains) increasingly depend on crude oil produced and moved by pipeline from Canada and PADD 3 (Gulf Coast) as well as production from the Rocky Mountain states. PADD 3, the largest refining region, obtains crude oil from the Gulf Coast outer continental shelf, Mexico, Venezuela, and the rest of the world. Permitting issues currently stall a pipeline that would deliver Canadian syncrude (from oil sands) to Gulf Coast Refineries. PADD 5 (West Coast) obtains crude oil primarily from Alaska (by tanker) and California, and through imports. No crude oil pipelines link PADD 1 or PADD 5 with the rest of the country.

[4] To arrive at this number, CRS used U.S. Energy Information Administration and the Environmental Protection Agency sources, and then cross-correlated information that refinery operators published on their corporate web pages and in financial statements. CRS also geo-located the refinery sites by using online imagery and mapping tools.

[5] The Energy Information Administration defines idle capacity as a component of operable capacity that is not in operation and not under active repair, but capable of being placed in operation within 30 days; and capacity not in operation but under active repair that can be completed within 90 days.

Most of the country's gasoline is refined in the Gulf Coast (PADD 3), which makes up nearly 45% of the U.S. refining capacity with 45 refineries processing more than 8 million barrels per day (bbl/d). It is followed by the Midwest (PADD 2) and the West Coast (PADD 5) in refining capacity.[6] The East Coast (PADD 1) has been losing capacity, with gasoline imports meeting a growing portion of demand. **Figure 1** below breaks-out refining capacity by PADD.

A 95,000-mile network of petroleum product pipelines serves most of the United States. This network, separate from the network of crude oil pipelines, distributes refined products to balance the demand and supply conditions in each region. Regional differences in mandated fuel gasoline specifications, however, limit the flexibility of distribution by pipeline. Additionally, PADD 5 is largely isolated from the rest of the United States, especially from the large refineries in PADD 3, resulting in a market that has exhibited higher prices and reduced availability under some market conditions.

Figure 1. Fuel Refining Capacity by Petroleum Administration for Defense Districts

Barrels/day

PADD	Fuel Refineries	Bbl/Day
1	12	2,083,000
2	25	3,579,000
3	44	8,802,100
4	15	614,750
5	27	3,251,200
Total	123	18,330,050

Source: CRS.

Note: During World War II, the then-War Department delineated PADDs to facilitate oil allocation.

Refinery Closures

After crude oil prices peaked in the summer of 2008, the U.S. demand for refined petroleum products began to decline. In response, U.S. refiners began cutting back capacity and in some cases temporarily idled or permanently closed refineries.

[6] Texas—4,747,179 bbl/day and Louisiana—2,992,123 bbl/day.

Valero closed its Delaware City (DE) refinery in late 2009 and furloughed 550 workers.[7] In April 2010, Valero sold the refinery to Connecticut-based PBF Energy Partners LLC (Petroplus) for $220 million. Valero will reportedly write off more than $1.7 billion of assets.[8] PBF plans to invest another $125 million to $150 million in refurbishing the refinery with plans to reopen it in the spring of 2011.[9] Sunoco permanently closed its Eagle Point (NJ) refinery in early 2010 and furloughed 400 workers. [10] Sunoco had purchased Eagle Point in 2004 for about $250 million. In 2010, Western Refining idled its 16,800 bbl/day refinery in New Mexico and its 70,000 bbl/day Yorktown (VA) refinery.

Operable Refineries

Figure 2 through **Table 5,** below, identify operable fuel refineries by PADD.

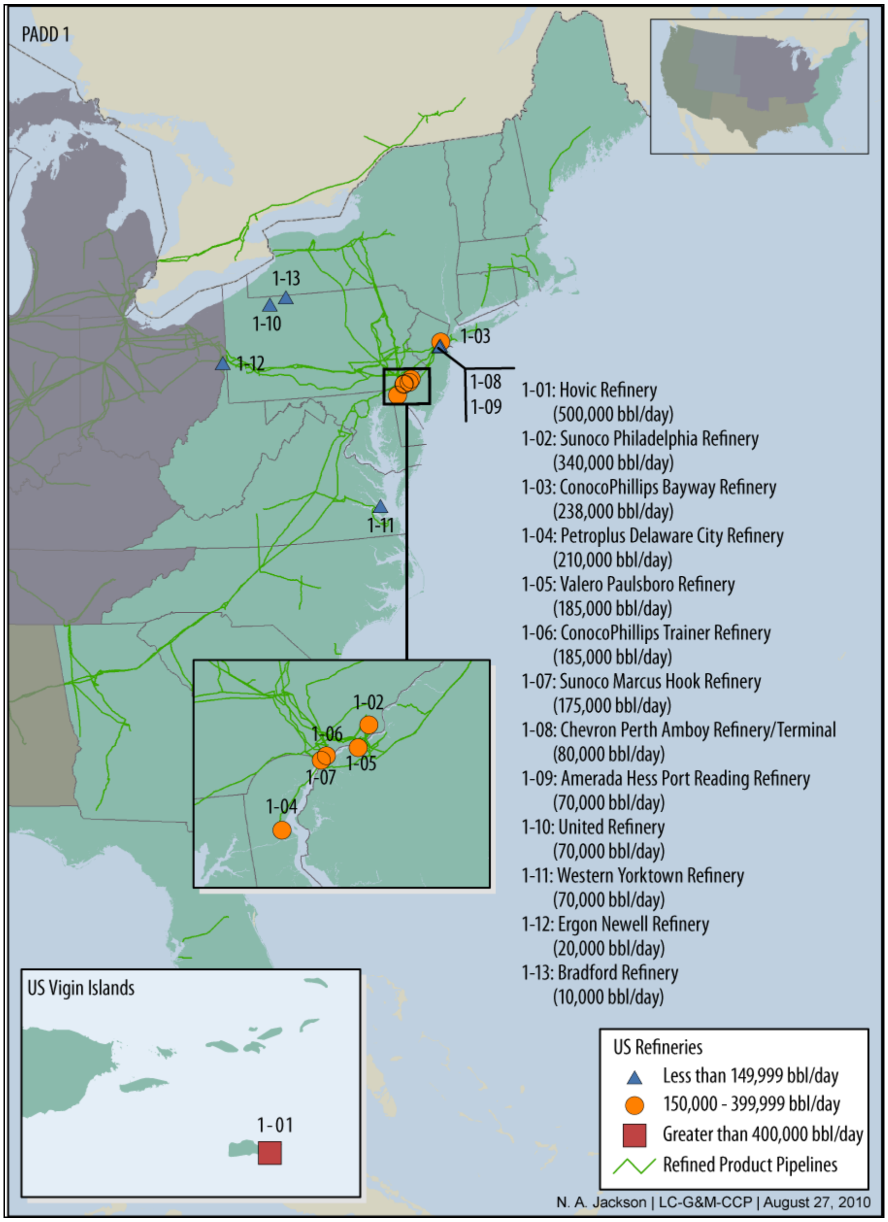
[7] Jeff Montgomery, "Valero refinery in Delaware City to close permanently," *The News Journal*, November 20, 2009.

[8] Jeff Montgomery, "Valero announces sale of Delaware City Refinery," *The News Journal*, April 8, 2010.

[9] Steve Goldstein, "Petroplus rallies on deal to buy Delaware refinery," *Wall Street Journal*, April 9, 2010, Market Watch.

[10] "Sunoco idles Eagle Point refinery, furloughs 400 workers, cuts dividend," *The Associated Press*, October 6, 2009.

Figure 2. Operable Refineries in PADD 1



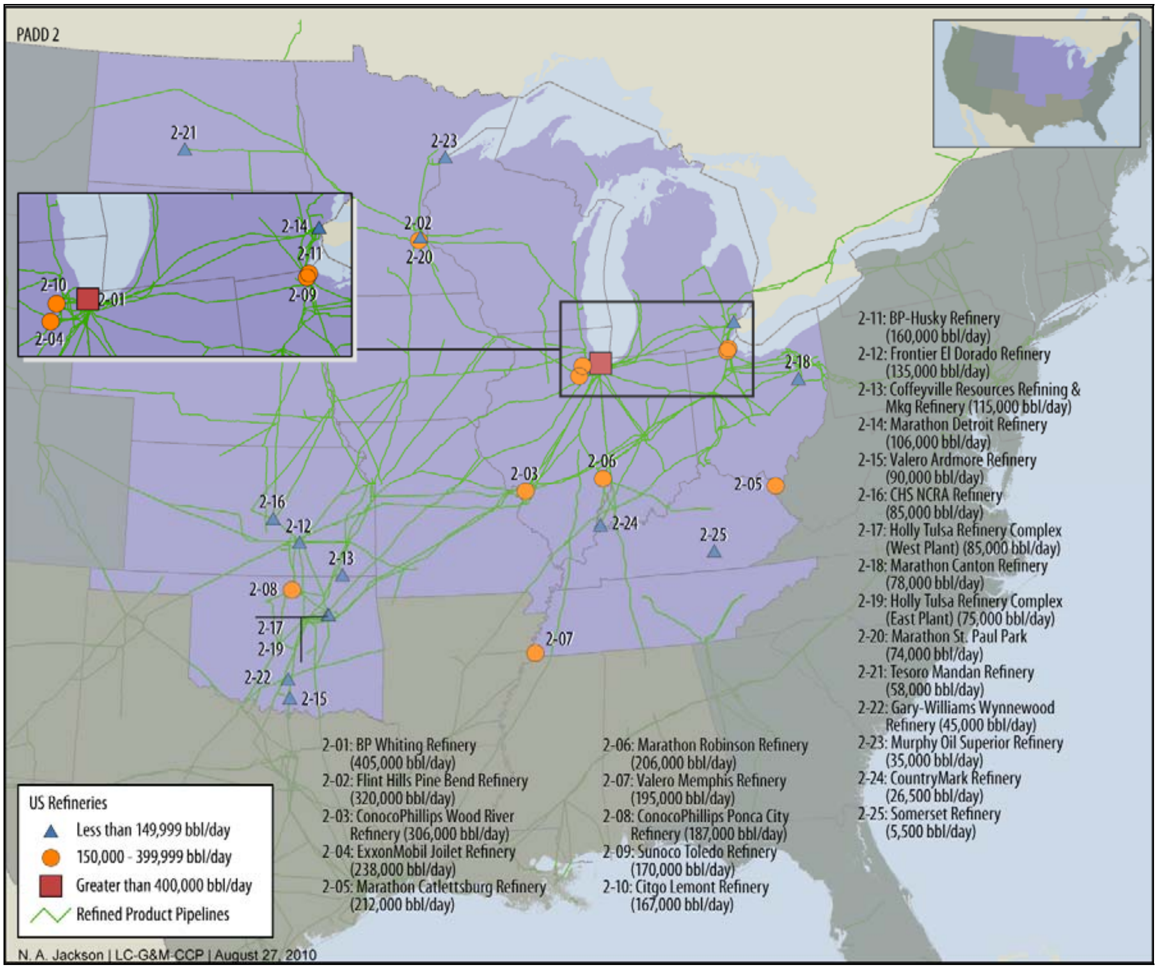
PADD #	Facility	City	State	Zip	Bbl/day
1-01	Hovic Refinery	Kingshill, St Croix	VI	00851	500,000
1-02	Sunoco Philadelphia Refinery	Philadelphia	PA	19145	340,000
1-03	ConocoPhillips Bayway Refinery	Linden	NJ	07036	238,000
1-04	Petroplus Delaware City Refinery*	Delaware City	DE	19270	210,000
1-05	Valero Paulsboro Refinery	Paulsboro	NJ	08066	185,000
1-06	ConocoPhillips Trainer Refinery	Trainer	PA	19061	185,000
1-07	Sunoco Marcus Hook Refinery	Marcus Hook	PA	19601	175,000
1-08	Chevron Perth Amboy Refinery/Terminal	Perth Amboy	NJ	08861	80,000
1-09	Amerada Hess Port Reading Refinery	Port Reading	NJ	07064	70,000
1-10	United Refinery	Warren	PA	16365	70,000
1-11	Western Yorktown Refinery*	Yorktown	VA	23692	70,000
1-12	Ergon Newell Refinery	Newell	WV	26050	20,000
1-13	Bradford Refinery	Bradford	PA	16701	10,000
				Total	**2,153,000**

Source: Refiner publications.

Notes: The Eagle Point Refinery, which closed in 2010, is not included on this map.

* Petroplus plans to reopen the idled Delaware City refinery in 2011. Western announced August 5, 2010, that it would idle its Yorktown refinery but continue to operate it as a terminal.

Figure 3. Operable Refineries in PADD 2

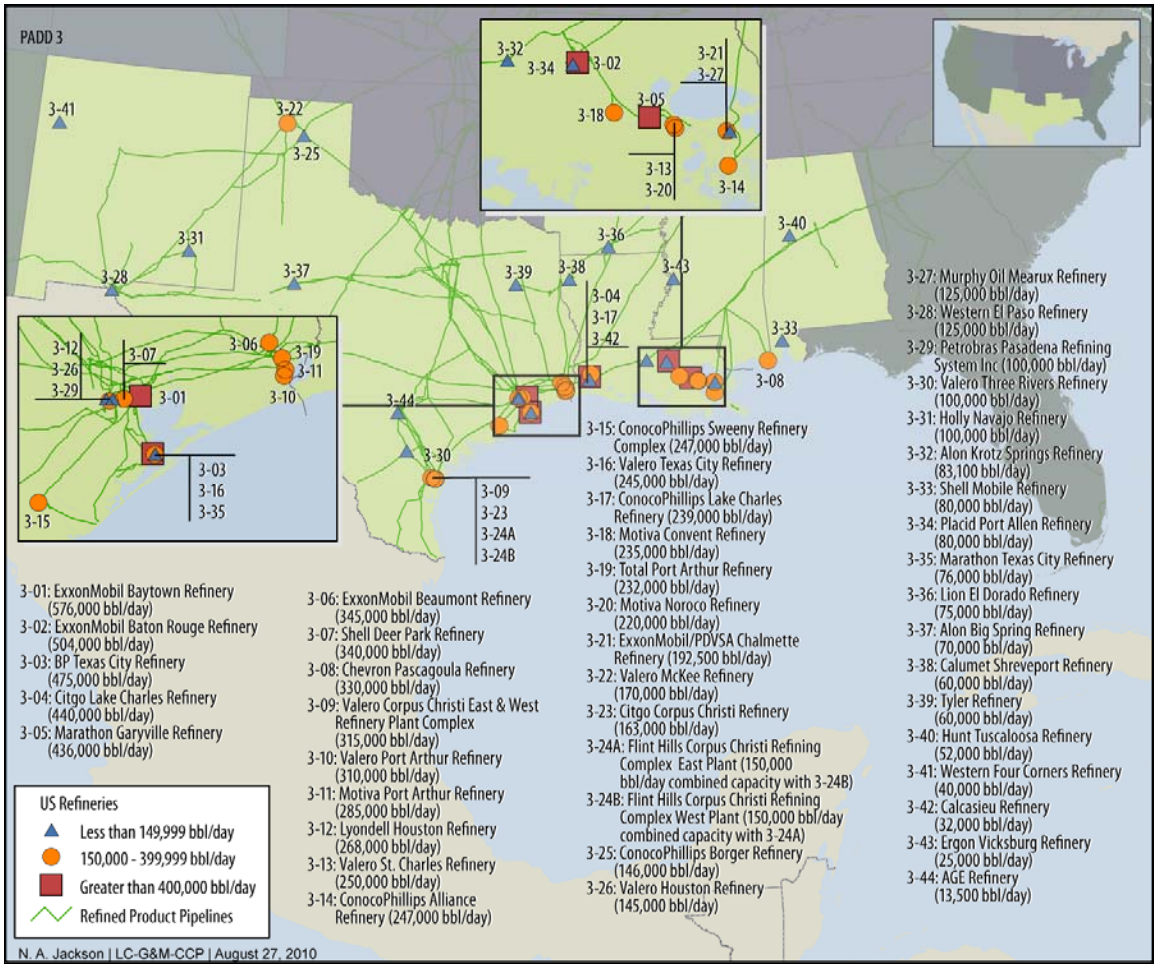


PADD #	Facility	City	State	Zip	Bbl/day
2-01	BP Whiting Refinery	Whiting	IN	46394	405,000
2-02	Flint Hills Pine Bend Refinery	Rosemont	MN	55068	320,000
2-03	ConocoPhillips Wood River Refinery	Roxana	IL	60284	306,000
2-04	ExxonMobil Joliet Refinery	Drummond	IL	60410	238,000
2-05	Marathon Catlettsburg Refinery	Catlettsburg	KY	41129	212,000
2-06	Marathon Robinson Refinery	Robinson	IL	62454	206,000
2-07	Valero Memphis Refinery	Memphis	TN	38109	195,000
2-08	ConocoPhillips Ponca City Refinery	Ponca City	OK	74601	187,000
2-09	Sunoco Toledo Refinery	Toledo	OH	43607	170,000
2-10	Citgo Lemont Refinery	Lemont (Chicago)	IL	60439	167,000
2-11	BP-Husky Refinery	Oregon/Toledo	OH	43616	160,000
2-12	Frontier El Dorado Refinery	El Dorado	KS	67042	135,000
2-13	Coffeyville Resources Refining & Mkg Refinery	Coffeyville	KS	67337	115,000
2-14	Marathon Detroit Refinery	Detroit	MI	48217	106,000
2-15	Valero Ardmore Refinery	Ardmore	OK	73401	90,000
2-16	CHS NCRA Refinery	McPherson	KS	67460	85,000
2-17	Holly Tulsa Refinery Complex (West Plant)	Tulsa	OK	74107	85,000

2-18	Marathon Canton Refinery	Canton	OH	44706	78,000
2-19	Holly Tulsa Refinery Complex (East Plant)	Tulsa	OK	74107	75,000
2-20	Marathon St. Paul Park Refinery	Saint Paul Park	MN	55071	74,000
2-21	Tesoro Mandan Refinery	Mandan	ND	58544	58,000
2-22	Gary-Williams Wynnewood Refinery	Wynnewood	OK	73098	45,000
2-23	Murphy Oil Superior Refinery	Superior	WI	54880	35,000
2-24	CountryMark Refinery	Mount Vernon	IN	47620	26,500
2-25	Somerset Refinery	Somerset	KY	42501	5,500
				Total	**3,579,000**

Source: Refiner publications.

Figure 4. Operable Refineries in PADD 3

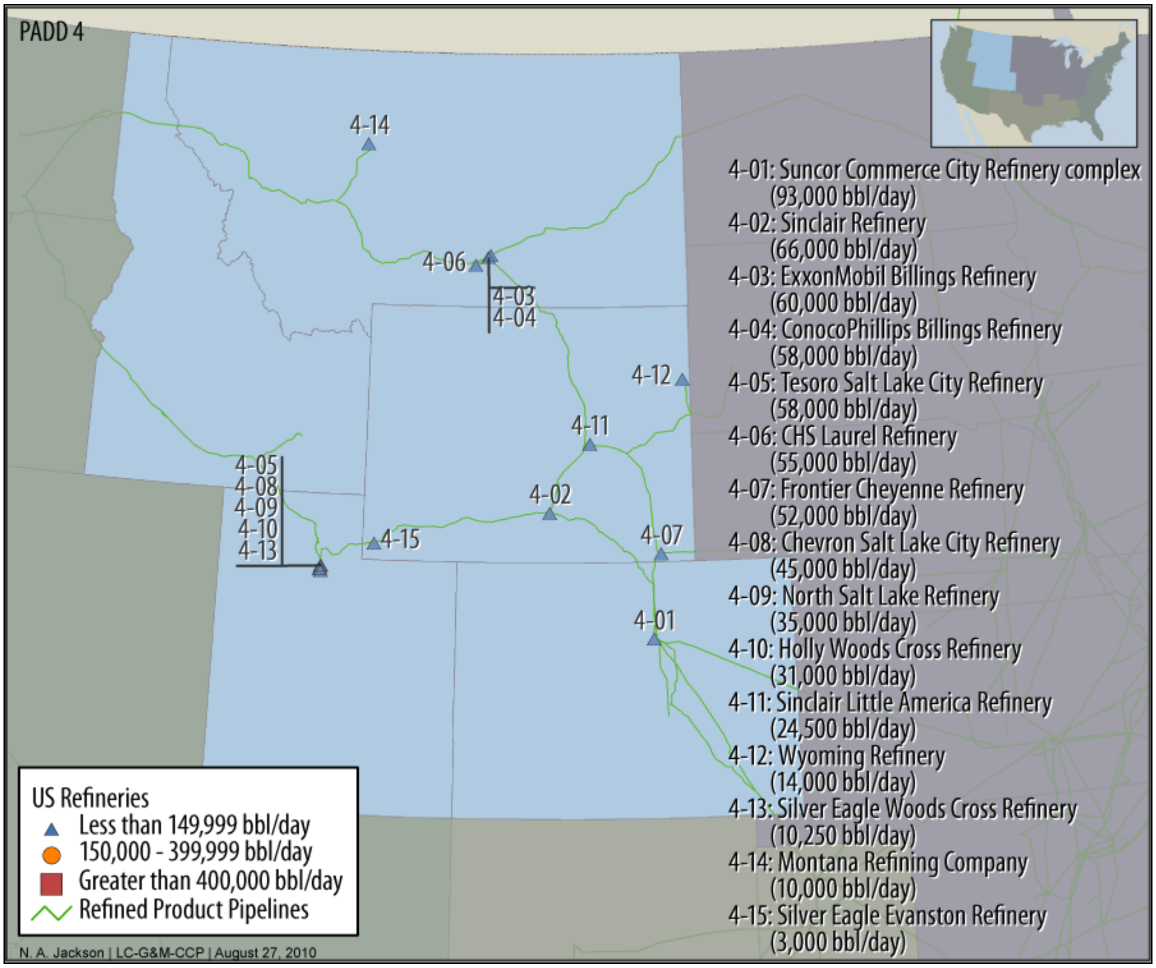


PADD #	Facility	City	State	Zip	Bbl/day
3-01	ExxonMobil Baytown Refinery	Baytown	TX	77520	576,000
3-02	ExxonMobil Baton Rouge Refinery	Baton Rouge	LA	70805	504,000
3-03	BP Texas City Refinery	Texas City	TX	77590	475,000
3-04	Citgo Lake Charles Refinery	Lake Charles	LA	70601	440,000
3-05	Marathon Garyville Refinery	Garyville	LA	70051	436,000
3-06	ExxonMobil Beaumont Refinery	Beaumont	TX	77703	345,000
3-07	Shell Deer Park Refinery	Deer Park	TX	77636	340,000
3-08	Chevron Pascagoula Refinery	Pascagoula	MS	39581	330,000
3-09	Valero Corpus Christi E. & W. Refinery Complex	Corpus Christi	TX	78407	315,000
3-10	Valero Port Arthur Refinery	Port Arthur	TX	77640	310,000
3-11	Motiva Port Arthur Refinery	Port Arthur	TX	77641	285,000
3-12	Lyondell Houston Refinery	Houston	TX	77017	268,000

PADD #	Facility	City	State	Zip	Bbl/day
3-13	Valero St. Charles Refinery	Norco	LA	70079	250,000
3-14	ConocoPhillips Alliance Refinery	Belle Chasse	LA	70037	247,000
3-15	ConocoPhillips Sweeny Refinery Complex	Sweeny	TX	77463	247,000
3-16	Valero Texas City Refinery	Texas City	TX	77590	245,000
3-17	ConocoPhillips Lake Charles Refinery	Westlake	LA	70669	239,000
3-18	Motiva Convent Refinery	Convent	LA	70723	235,000
3-19	Total Port Arthur Refinery	Port Arthur	TX	77642	232,000
3-20	Motiva Norco Refinery	St. Charles Parrish	LA	70079	220,000
3-21	ExxonMobil/PDVSA Chalmette Refinery	Chalmette	LA	70043	192,500
3-22	Valero McKee Refinery	Sunray	TX	79086	170,000
3-23	Citgo Corpus Christi Refinery	Corpus Christi	TX	78047	163,000
3-24A 3-24B	Flint Hills Corpus Christi Refining Complex E. Flint Hills Corpus Christi Refining Complex W.	Corpus Christi	TX	78408	150,000
3-26	ConocoPhillips Borger Refinery	Borger	TX	79007	146,000
3-27	Valero Houston Refinery	Houston	TX	77012	145,000
3-28	Murphy Oil Meraux Refinery	Meraux	LA	70075	125,000
3-29	Western El Paso Refinery	El Paso	TX	79905	125,000
3-30	Petrobras Pasadena Refining System Inc	Pasadena	TX	77506	100,000
3-31	Valero Three Rivers Refinery	Three Rivers	TX	78701	100,000
3-32	Holly Navajo Refinery	Artesia	NM	88210	100,000
3-33	Alon Krotz Springs Refinery	Krotz Springs	LA	70750	83,100
3-34	Shell Mobile Refinery	Saraland	AL	36571	80,000
3-35	Placid Port Allen Refinery	Port Allen	LA	70767	80,000
3-36	Marathon Texas City Refinery	Texas City	TX	77590	76,000
3-37	Lion El Dorado Refinery	El Dorado	AR	71730	75,000
3-38	Alon Big Spring Refinery	Big Spring	TX	79720	70,000
3-39	Calumet Shreveport Refinery	Shreveport	LA	71109	60,000
3-40	Tyler Refinery	Tyler	TX	75702	60,000
3-41	Hunt Tuscaloosa Refinery	Tuscaloosa	AL	35401	52,000
3-42	Western Four Corners Refinery	Gallup/Jamestown	NM	87347	40,000
3-43	Calcasieu Refinery	Lake Charles	LA	70605	32,000
3-44	Ergon Vicksburg Refinery	Vicksburg	MS	39183	25,000
3-45	AGE Refinery	San Antonio	TX	78205	13,500
				Total	**8,802,100**

Source: Refiner publications.

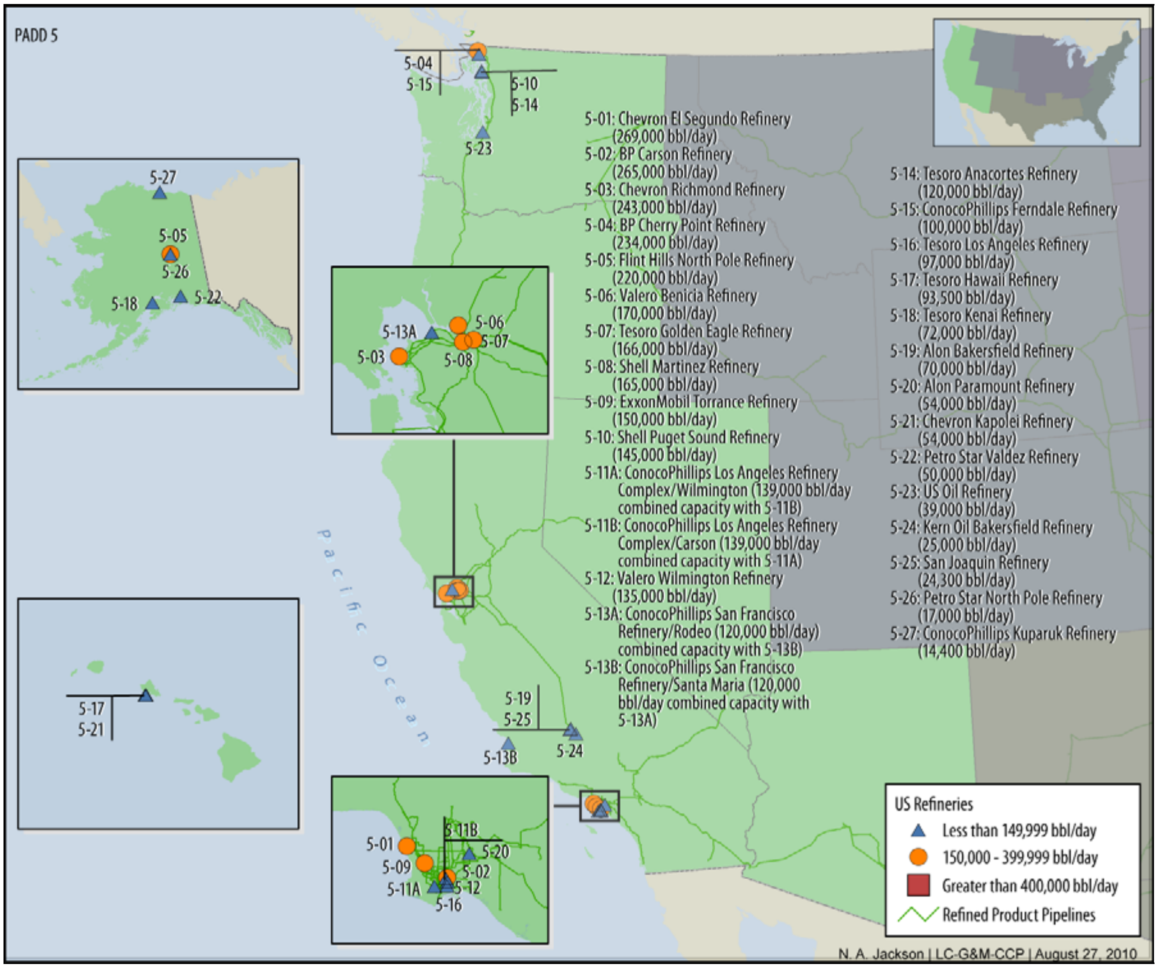
Figure 5. Operable Refineries in PADD 4



PADD #	Facility	City	State	Zip	Bbl/day
4-01	Suncor Commerce City Refinery Complex	Commerce City	CO	80022	93,000
4-02	Sinclair Refinery	Sinclair	WY	82334	66,000
4-03	ExxonMobil Billings Refinery	Billings	MT	59101	60,000
4-04	ConocoPhillips Billings Refinery	Billings	MT	59101	58,000
4-05	Tesoro Salt Lake City Refinery	Salt Lake City	UT	84103	58,000
4-06	CHS Laurel Refinery	Laurel	MT	59404	55,000
4-07	Frontier Cheyenne Refinery	Cheyenne	WY	82007	52,000
4-08	Chevron Salt Lake City Refinery	Salt Lake City	UT	84116	45,000
4-09	North Salt Lake Refinery	North Salt Lake	UT	84054	35,000
4-10	Holly Woods Cross Refinery	Woods Cross	UT	84087	31,000
4-11	Sinclair Little America Refinery	Casper/Evansville	WY	82609	24,500
4-12	Wyoming Refinery	Newcastle	WY	82701	14,000
4-13	Silver Eagle Woods Cross Refinery	Woods Cross	UT	84087	10,250
4-14	Montana Refining Company	Great Falls	MT	59404	10,000
4-15	Silver Eagle Evanston Refinery	Evanston	WY	82930	3,000
				Total	**614,750**

Source: Refiner publications.

Figure 6. Operable Refineries in PADD 5



PADD #	Facility	City	State	Zip	Bbl/day
5-01	Chevron El Segundo Refinery	El Segundo	CA	90245	269,000
5-02	BP Carson Refinery	Los Angeles	CA	90745	265,000
5-03	Chevron Richmond Refinery	Richmond	CA	94802	243,000
5-04	BP Cherry Point Refinery	Blaine	WA	98230	234,000
5-05	Flint Hills North Pole Refinery	North Pole	AK	99705	220,000
5-06	Valero Benicia Refinery	Benicia	CA	94510	170,000
5-07	Tesoro Golden Eagle Refinery	Martinez	CA	94553	166,000
5-08	Shell Martinez Refinery	Martinez	CA	94553	165,000
5-09	ExxonMobil Torrance Refinery	Torrance	CA	90509	150,000
5-10	Shell Puget Sound Refinery	Anacortes	WA	98221	145,000
5-11A	ConocoPhillips Los Angeles Refinery Complex/ Wilmington	Wilmington	CA	90744	139,000
5-11B	ConocoPhillips Los Angeles Refinery Complex/ Carson	Carson	CA	90745	
5-12	Valero Wilmington Refinery	Wilmington	CA	90744	135,000
5-13A	ConocoPhillips San Francisco Refinery/Rodeo Facility	Rodeo	CA	94572	120,000
5-13B	ConocoPhillips San Francisco Refinery/Santa Maria Facility	Arroyo Grande	CA	93420	
5-14	Tesoro Anacortes Refinery	Anacortes	WA	98221	120,000
5-15	ConocoPhillips Ferndale Refinery	Ferndale	WA	98248	100,000
5-16	Tesoro Los Angeles Refinery	Wilmington	CA	90744	97,000
5-17	Tesoro Hawaii Refinery	Kapolei	HI	96707	93,500
5-18	Tesoro Kenai Refinery	Kenai	AK	99611	72,000

PADD #	Facility	City	State	Zip	Bbl/day
5-19	Alon Bakersfield Refinery	Bakersfield	CA	93308	70,000
5-20	Alon Paramount Refinery	Paramount	CA	90723	54,000
5-21	Chevron Kapolei Refinery	Kapolei	HI	96707	54,000
5-22	Petro Star Valdez Refinery	Valdez	AK	99686	50,000
5-23	US Oil Refinery	Tacoma	WA	98421	39,000
5-24	Kern Oil Bakersfield Refinery	Bakersfield	CA	93307	25,000
5-25	San Joaquin Refinery	Bakersfield	CA	93308	24,300
5-26	Petro Star North Pole Refinery	North Pole	AK	99705	17,000
5-27	ConocoPhillips Kuparuk Refinery	Kuparuk	AK	99734	14,400
				Total	**3,251,200**

Source: Refiner publications.

Notes: The ConocoPhillips San Francisco Refinery comprises two facilities inked by a 200-mile pipeline—the Santa Maria facility located in Arroyo Grande, CA, and the Rodeo facility in the San Francisco Bay Area. The Santa Maria facility upgrades heavy crude oil for final processing in the San Francisco Bay facility. The Santa Maria facility is not on the map.

The ConocoPhillips Los Angeles Refinery Complex is composed of two facilities linked by a five-mile pipeline. The Carson facility serves as the front end of the refinery by processing crude oil, and Wilmington serves as the back end by upgrading the products.

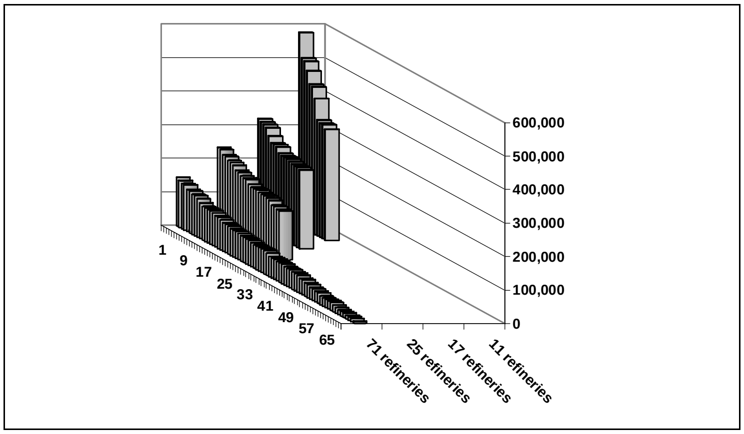
Refinery Capacity Distribution

A different picture of the refining industry base emerges when examining the distribution of capacity. As **Figure 7** shows, a quarter of U.S. refining capacity is concentrated in a few, larger refineries, reflecting economies of scale that yield decreasing per barrel costs. For example, Royal Dutch Shell PLC plans to double the size of the oil refinery it operates with a Saudi partner in Port Arthur, Texas. This would make it the largest refinery in the United States and one of the largest in the world.[11] ConocoPhillips has plans to expand its Wood River Refinery in Illinois to increase the volume of Canadian heavy crude it can handle, but has run into regulatory hurdles over the use of best available technology under the Clean Air Act. Eleven of the 124 refineries provide one quarter of total U.S. refining capacity. ExxonMobil operates the top two refineries (with a combined capacity exceeding 1 million bbl/day), followed by BP, Petrovesa (PDV), Sunoco, Chevron, Deer Park, and WRB.

[11] Texas Gulf Coast Online, *Shell Plans Major Expansion of Texas Gulf Coast Refinery*, http://www.texasgulfcoastonline.com/News/tabid/86/ctl/ArticleView/mid/466/articleId/72/Default.aspx.

Figure 7. Distribution of U.S. Refinery Capacity

Barrels per Calendar Day



Source: EIA Table 5. Refiners' Total Operable Atmospheric Crude Oil Distillation Capacity as of January 1, 2009, as adjusted by CRS.

Notes: Each quartile represents roughly 4.7 million barrels per calendar day of total refining capacity.

These eleven refineries are among the largest and most complex in the United States, if not the world, as their owners have added new processes to convert lower value residuum (formerly used as heavy heating oil) to high-value gasoline. Typically, this involves adding fluid or delayed cokers. European refineries, by comparison, employ less complex processes than U.S. refineries on average, as they produce more diesel fuel. (For a further discussion of refinery complexity and processes, refer to **Appendix A**.)

Changes in Crude Oil Supply and Demand

The crude oil input to U.S. refineries has decreased almost 8% compared to five years ago, reflecting reduced demand for petroleum products. In 2009, refineries consumed an average 14.3 million barrels per day of crude oil. (Refer to **Table 1**.) Roughly one-third of this input was U.S.-produced in 2009. The balance came from imports supplied by Canada, Saudi Arabia, Mexico, Nigeria, Iraq, and other smaller producers (See **Figure 8**). Canada has become the United States' leading crude oil supplier through its increasing production from oil sands.[12]

[12] CRS Report RL34258, *North American Oil Sands: History of Development, Prospects for the Future*, by Marc Humphries.

Table 1. Refinery Crude Oil Input

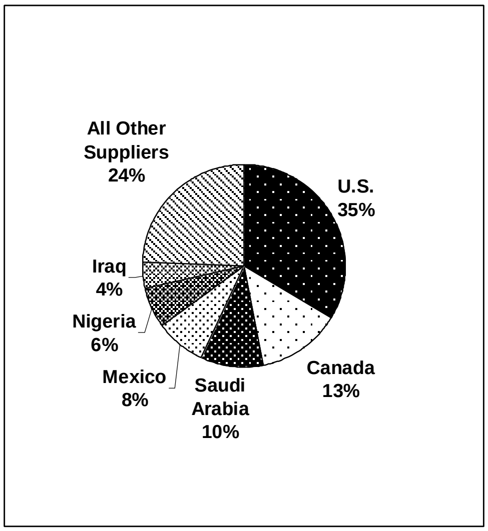
(million barrels)

Year	Daily	Annual	Annual Input Change
2004	15.5	5,663.9	
2005	15.2	5,555.3	-108.6
2006	15.2	5,563.4	+8.1
2007	15.1	5,532.1	-32.3
2008	14.7	5,361.3	-170.8
2009	14.3	5,224.3	-137.0

Source: EIA Petroleum Navigator, Petroleum Supply Annual; Refinery and Blender Net Inputs of Crude Oil; http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1_historical.html.

Figure 8. U.S. Crude Oil Supply

2008



Source: Based on EIA U.S. Crude Oil Imports, June 29, 2009. http://tonto.eia.doe.gov/dnav/pet/pet_move_impcus_a2_nus_epc0_im0_mbbl_a.htm

Over the last 25 years, the °API gravity of imported crude oils has been decreasing while average sulfur content has been increasing. °API gravity, a measure developed by the American Petroleum Institute, expresses the "lightness" or "heaviness" of crude oils on an inverted scale.[13] With a diminishing supply of light sweet (low sulfur) crude oil, U.S. refineries have had to invest in multi-million dollar processing-upgrades to convert lower-priced heavier sour crude oils to high-value products such as gasoline, diesel, and jet fuel. Refer to **Table 2** for a comparison of various crude oil °API gravities and sulfur contents.

[13] API gravity scale: light - greater than 30º; medium - 22º to 30º; heavy - less than 22º; and extra heavy -below 10º. Formula: (141.5 ÷ relative density of the crude [at 15.5°C or 60°F]) - 131.5.

Table 2. °API Gravity and Sulfur Content of Representative Crude Oils

Crude Oil	°API Gravity	%Sulfur
West Texas Intermediate	40	0.30
Alaska North Slope	29.5 – 29	1.10
Strategic Petroleum Reserve sweet/sour	40 – 30	0.5 – 2.0
NYMEX Deliverable Grade Sweet Crude Oil	42 – 37	<0.42
Canadian Sweet/Sour	37.7 – 37.5	0.42 – 0.56
Canadian Alberta Syncrude	38.7	0.19
Saudi Arabia Arab Extra Light / Heavy	37.2 – 27.4	1.15 – 2.8
Mexico Maya/Olmeca	39.8 – 22.2	0.80 – 3.30
Nigeria Bonny Light	33.8	0.30
Iraq Basra Light	34 –35	1.5
Venezuela Tia Juana Light/Heavy	31.8 – 18.2	1.16 – 2.24
North Sea Brent Blend	38 – 39	0.37

Source: NYMEX.

Notes: °API gravity is the American Petroleum Institute's measure of specific gravity of crude oil or condensate in degrees. The measuring scale is calculated as Degrees API = (141.5 / sp.gr.60 deg.F/60 deg. F) - 131.5. Higher API degree indicates lighter, and generally higher priced, crude oils.

Crude Oil Prices

The longstanding benchmark for pricing crude oil futures contracts traded on the New York Mercantile Exchange (NYMEX) has been West Texas Intermediate (WTI) crude oil; a high-quality crude oil with a 39.6° API gravity (making it a "light" crude oil) and a 0.24% sulfur content (making it a "sweet" crude oil). North Sea Brent crude oil, a 38°-39° API gravity light sweet crude oil but with higher sulfur content than WTI, is a global benchmark for other crude oil grades and is widely used to determine crude oil prices in Europe and in other parts of the world.[14] Brent is typically refined in Northwest Europe, and also is exported to the U.S. Gulf and East Coasts.

WTI on average is priced about $1-$2 per barrel above North Sea Brent crude, and $2-$4 per barrel above the Organization of the Petroleum Exporting Countries (OPEC) "basket" of crude prices.[15] OPEC collects price data on a basket of crude oils it produces, and uses the average prices for these oil streams to develop an OPEC reference price for monitoring world oil markets.[16] OPEC's reference basket consists of eleven crude streams representing the main export crudes of all its member countries, weighted according to production and exports to the main markets.[17] According to OPEC, the basket crude has a 32.7º API gravity, making it heavier than

[14]Commodity Online, http://www.commodityonline.com/commodities/energy/brentcrudeoil.php.

[15] On a daily basis the pricing relationships between these can vary greatly.

[16] PetroStrategies, http://www.petrostrategies.org/Graphs/OPEC_Basket_Crude_Oil_Prices.htm.

[17] The OPEC basket crude oil streams in the basket are: Saharan Blend (Algeria), Minas (Indonesia), Iran Heavy (Islamic Republic of Iran), Basra Light (Iraq), Kuwait Export (Kuwait), Es Sider (Libya), Bonny Light (Nigeria), Qatar Marine (Qatar), Arab Light (Saudi Arabia), Murban (UAE) and BCF 17 (Venezuela).

WTI or Brent, and a 1.77% sulfur content, making it sourer. Both of these characteristics tend to make it less valuable than WTI or Brent crude. With the diminishing availability of sweet crudes worldwide, U.S. refiners have increasingly turned to heavier sour crudes, and many refineries have upgraded to refine heavier, sourer crudes.

At the beginning of the U.S. invasion of Iraq in March 2003, the spot price for a barrel of WTI crude oil was $28.11, and generally rose during the course of the Iraq War. On a monthly basis, the spot market price of WTI peaked at $133.88 per barrel in June 2008.[18] By February 2009, the price had declined to $39.09 per barrel, only to rise to around $75 per barrel by the end of 2009 and into 2010.

Beside the political uncertainty introduced by the Iraq War, economists have suggested other reasons for the observed price volatility in crude oil markets, including political tensions in Africa and other regions, financial speculation, currency hedging, inflation hedging, excess demand, supply tightness, and a host of other factors. Widely publicized and debated concerns regarding global "peak oil" production may have contributed to speculation in the oil futures market.[19] Because the U.S. dollar serves as the reference price currency for oil in the world market, some oil analysts link the peak in oil prices in mid-2008 to the dollar's weakness at the time. As a result, the oil price rise was much less pronounced when measured in other major currencies.[20]

Although crude oil represents the primary input and cost factor in refinery operations, the relationship between the price of crude oil and the profit margin in refining is neither simple nor direct.[21] Rising crude oil prices increase primary refining costs and can tighten refining profit margins. However, if product prices rise proportionally to crude oil prices, as they did in 2008, refiners effectively pass cost increases on to consumers. Because of the short-term price insensitivity of demand when gasoline prices rise, the revenue derived from the sale of gasoline and other petroleum products is likely to increase in these market conditions, even as total costs are likely to decrease because the volume of oil passing through the refinery declines. These factors can permit refiners to maintain or even increase profits during periods of high crude oil prices. The situation differs if less oil is passing through the refinery due to weak product demand. In that event, product prices and profits may fall in tandem as capacity utilization declines.

The multiplicity of oil prices, which reflect the quality of various crude oils, further complicates the linkage between oil prices and the refining profitability. Generally, lighter crude oils command a price premium over heavier oils, as discussed earlier in this report. The size of the price premium tends to vary as relative supply availability changes and as refiners adapt refineries to use lower cost crude oil stocks. The price spread between light and heavy crude oils, shown in **Table 3**, shrank by almost $10 per barrel between 2006 and 2009.

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[18] On a yearly basis, the average price per barrel of WTI rose every year from 2003 through 2008. The daily peak was attained in July 2008, at over $145 per barrel. See WTI Spot Price data at http://www.eia.gov.

[19] For background on the subject of peak oil see Kenneth S. Deffeyes, *Beyond Oil: The View from Hubbert's Peak* (Farrar, Straus and Giroux, 2005).

[20] Steve Hawkes, "Oil nears $100 mark as crude reaches yet another record," *Times Online*, October 30, 2007, http://business.timesonline.co.uk/tol/business/industry_sectors/natural_resources/article2767141.ece.

[21] Crude oil generally represents over 50% of the cost of gasoline, the most important refinery product in the United States.

Table 3. Light/Heavy Crude Oil Price Spread

$ per barrel

Year	Spread
2006	15.51
2007	12.88
2008	14.85
2009	5.60

Source: Energy Information Administration.

Notes: CRS based calculations on North American crude oils, West Texas Intermediate, and Mexican Maya crude.

During the period of high oil prices from 2004 through 2008, heavy crude oils sold at a large discount relative to light crude. The relative tightness in the light crude market, coupled with the price discounts for heavy crude, induced refiners to invest in facilities and processes that would make refineries more able to process heavy crude oils and take advantage of these favorable price spreads. These investments declined in profitability after oil prices fell and the price premium narrowed. In February of 2009, the price-spread declined to a low of $1.93 per barrel, and stayed below $9 per barrel every month in 2009. By September of 2010 the price-spread was $7.95 per barrel.

Demand Conditions

The demand for crude oil is derived from the demand for petroleum products. For example, if consumers demand more gasoline, refiners may purchase and process more crude oil. Afterwards, refiners might adjust their product slate, within technological limits, to yield more gasoline from each barrel of crude oil. (Refer to **Appendix A** for a discussion of refining fundamentals.)

The demand for gasoline itself may depend upon the price of gasoline and the income level of consumers. However, in the short run, the responsiveness of gasoline demand to variations in price is quite low. Estimates of the short-run price elasticity for gasoline are in the range of -0.25 or less.[22] This value implies that if the price of gasoline rises by 1.0% the result is likely to be only a ¼ % decline in the quantity of gasoline demanded. Consumers may have difficulty reducing their demand for gasoline in the short-run, as commuting distance, automobile fuel-efficiency, and other commitments make it hard to lower consumption quickly. They may respond to higher gasoline prices by reducing expenditures on other goods or increasing household debt levels. The demand for gasoline also depends on consumer's income growth, and perhaps, as well, on the fraction of consumer's disposable income accounted for by gasoline purchases. The average estimate of income elasticity for gasoline demand in the United States is about 1.0, meaning that a 1% increase in income is associated with a 1% increase in spending on gasoline. Taken together, these elasticity values imply that gasoline demand may increase, even in an

[22] Price elasticity of demand is calculated as the percent change in quantity demanded divided by a specified percentage change in price. The result is a pure number (not measured in any units) that expresses the responsiveness of quantity demanded to changes in the price of the product. A formula to determine price elasticity is e= (percentage change in quantity) / (percentage change in price).

environment of high or rising prices, as long as the effect of higher incomes outweighs the effect of higher prices.

This condition appears to have been in place in the United States, and much of the world, during the first half of 2008, as well as much of the 2003-2008 period in general. However, after the third quarter of 2008 when U.S. gasoline prices had peaked at over $4.00 per gallon, an economic recession coupled with expectations of reduced income growth began moderating the demand for gasoline. After a 0.35% growth in gasoline demand in 2007, demand declined 2.9% the following year, as **Table 4** shows.

Table 4. United States Gasoline Consumption 2006-2009

(million barrels per year)

Year	Consumption	Change volume	Change percent
2006	3,377.2		
2007	3,389.3	12.1	0.35%
2008	3,290.1	-99.0	-2.90%
2009	3,280.0	-10.1	-0.30%

Source: Energy Information Administration.

Notes: Gasoline consumption is a measure of product supplied as finished motor gasoline. It includes refinery and blender net production, and imports.

The nearly 3% reduction in gasoline demand, as experienced during the 2007-2008 recession years, may seem minor compared to demand reductions in other industries. Nonetheless, it was sufficient to create the current weak market conditions (characterized by reduced capacity utilization rates, refinery closures, and weak profitability) that the refining industry faces today.

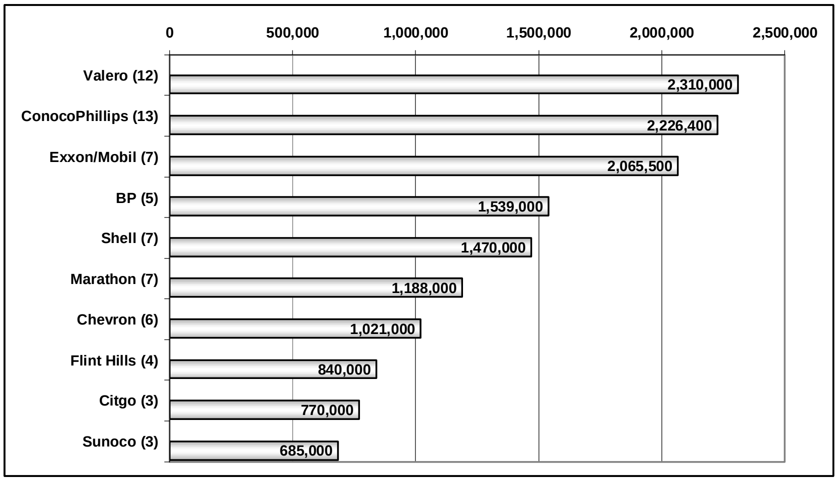
In the longer term, even when income growth returns, the outlook for the gasoline demand in the United States will be constrained by changing attitudes toward petroleum usage, regulations to increase automobile fuel efficiency standards, and regulations mandating the expanded use of alternative fuels in motor transportation.

Profitability

There are 45 firms refining petroleum in the United States. The top 10 refiners—Valero, Conoco Phillips, ExxonMobil, BP, Shell, Marathon, Chevron, Flint Hills, Citgo, and Sunoco—account for more than 75% of total U.S. refining capacity, as shown in **Figure 9**. The top ten firms operate half of the U.S. fuel refineries, a combined 68 out of 124 refineries (including currently idled refineries).

Figure 9. Major Refiners by Capacity

Barrels per Calendar Day



Source: CRS compiled from refiner published information, August 2010.

Notes: Figures in parenthesis indicate number of refineries owned. The top ten refiners represent roughly 75% of the total fuel refining capacity, some 18.5 million barrels per calendar day. This excludes topping and lubricating oils. The privately held Koch Industries owns Flint Hills Resources. The Venezuelan oil company Petrovesa owns Citgo.

The top six integrated oil companies—ConocoPhillips, ExxonMobil, BP, Shell, Marathon, and Chevron—engage in all phases of the oil business from producing and refining their own oil to transporting it and marketing at retail. Valero, the largest independent refiner and marketer, does not own petroleum reserves. The top six integrated firms plus the top two independent refiners and marketers also make up over 50% of U.S. refining capacity, and control the largest refineries.[23]

Their overall financial performance offers a measure of the profitability in refining and marketing in general. The comparative financial performance for the period 2006 through 2009 is presented in **Table 5**. The decline in net income over the period is attributable to several factors, including the combination of high crude oil prices and weak demand. The high inventories of gasoline and diesel fuel depressed product prices relative to the cost of crude oil, which further reduced refining profit margins.[24] In addition, the narrowing price spread between light and heavy crude reduced the refining margin and contributed to earlier capital investments failing to generate expected returns.

Table 5. Refiners' Net Income, 2006-2009

(million dollars)

Company	2006	2007	2008	2009
ExxonMobil	8,454	9,573	8,151	1,781

[23] Downstream operations include refining and marketing. Not all petroleum products are marketed by the large oil companies. Some retail outlets are company owned, some privately owned.

[24] Refining margins are the difference between the value of refined products derived from a barrel of crude oil and the cost of refining that barrel. The gross margin subtracts only the cost of crude oil, while the net margin includes all other operational costs as well as crude oil.

Company	2006	2007	2008	2009
BP	5,667	3,569	4,176	4,517
Shell	6,989	6,624	446	3,054
ConocoPhillips	4,481	5,923	2,322	37
Chevron	3,973	3,502	3,429	565
Marathon	2,795	2,077	1,179	464
Valero	5,461	5,234	-1,131	-1,982
Sunoco	979	891	776	-329

Source: *Oil Daily, Profit Profile Supplements,* various issues, 2007-2010.

Notes: Data in the table is downstream net income, which includes income derived from refining and marketing. Privately owned Flint Hills and Venezuelan owned Citgo do not publish financial reports.

All six of the major integrated oil companies have experienced mixed returns, but in all cases, their net incomes in 2009 were lower than in 2006. Valero and Sunoco, independent refiners and marketers, experienced losses.

Capital Investment

Refiners undertake capital investment for a variety of reasons, for example, expanding existing or creating new production facilities, implementing new or enhanced technology, or regulatory compliance. Facility expansion and new technology implementation are indicators that the industry expects increasing demand and economic growth.

Capital improvement and expansion require that an initial outlay of funds in the current time-period be offset by earnings that might accrue far into the future. If this stream of appropriately discounted future earning is greater than the initial outlay, then a capital investment project qualifies for inclusion in the capital budget.[25] Because the estimated earnings stream embodies management's forecast of the industry's future economic potential, increasing capital budgets imply expectations of healthy profitability, while declining budgets imply a weak profit outlook.

Capital spending in the U.S. refining sector has been declining, as **Table 6** shows. A 22% decline from 2008 through 2009 is expected to be followed by an almost 50% decline from 2009-2010. Combined with refinery closures discussed in this report, this data suggests that the industry does not see a need to expand, or even maintain, production capacity in the United States.

Table 6. U.S. Refining Industry Capital Budget Expenditures, 2008-2010

(billions of dollars)

Year	2005	2006	2007	2008	2009	2010
Expenditure	7.2	9.0	8.3	13.0	10.1	5.3

Source: *Oil and Gas Journal,* Week of March 1, 2010, p. 26.

[25] This method, which is widely employed by economists and financial analysts, is referred to as *Net Present Value*. An alternative measure is calculation of the internal rate of return to a hurdle rate, usually the company cost of capital.

Refinery Investment and Petroleum Product Imports

While imports of crude oil have been an important part of the U.S. energy supply picture for decades, the importance of petroleum product imports has also been rising. Oil companies can meet the demand for petroleum products, such as gasoline, in three basic ways. They can build new refineries, using either domestic or imported crude oil. This strategy puts refinery investment in competition with the companies' other capital projects, but offers the possibility of relatively large increases in supply.

Alternatively, an oil company can expand the capacity of existing refineries. Investment in expanded capacity can run parallel to investments made to keep existing refinery assets in compliance with environmental and other regulations affecting the industry. Expansions can usually be brought on line faster than new refineries due to simplified permitting requirements, but have the disadvantage of augmenting capacity in smaller steps.

Instead of investing in new refineries or expanding existing ones, an oil company might choose to meet petroleum product demand by importing finished, or partially finished, products from other areas of the world. The advantage of this approach is twofold. The imported products can be introduced, relatively quickly, into the domestic market with no requirement for additional capital spending. The imports can be easily expanded, or contracted, should the need arise. Reliance on foreign sources for petroleum products as well as crude oil adds an additional dimension to concerns of energy dependence, even though prices of these products may be the same in domestic and foreign markets.

Cost is likely to determine an oil company's decision on which alternative to use to meet demand variations. If products available on the world market can meet mandated domestic specifications and are available at competitive prices, importing them gives an oil company flexibility while avoiding the long-term commitment of expanding existing, or constructing new capacity.

A look at U.S. total motor gasoline imports over the 2004-2009 period shows that they averaged about 11% of the roughly 9 million barrels per day finished motor gasoline products supplied to U.S. consumers (see **Table 7**). Total petroleum products imports made up about 17% of domestic consumption. The effects of the recession can be seen in the reduced level of imports in 2008 and 2009. Adjustments in imports to reflect reduced demand are likely to be accomplished with fewer losses in domestic employment and economic dislocations than refinery closures.

Table 7. Gasoline Imports Vs. Total Gasoline Supplied

(Thousand Bbl/Day)

Product	2004	2005	2006	2007	2008	2009
Finished Motor Gasoline Imports	496	603	475	413	302	223
Motor Gasoline Blending Component Imports	451	510	669	753	789	719
Total Gasoline Imports Subtotal	947	1,113	1,126	1,166	1,091	942
Total Finished Motor Gasoline Supplied	9,105	9,159	9,253	9,286	8,989	8,997
Total Petroleum Product Imports	3,057	3,588	3,589	3,437	3,132	2,678

Source: U.S. Energy Information Administration, U.S. Imports by Country of Origin, http://www.eia.gov/dnav/pet/pet_move_impcus_d_nus_Z00_mbbl_a.htm; and Refiner Motor Gasoline Sales Volumes http://www.eia.gov/

dnav/pet/pet_cons_refmg_d_nus_VTR_mgalpd_a.htm, Product Supplied http://www.eia.gov/dnav/pet/pet_cons_psup_dc_nus_mbblpd_a.htm.

Notes: Other products include fuel oils, pentanes, LPG, unfinished oils, oxygenates, fuel ethanol, kerosene, naphtha, waxes, and lubricants.

Tax Considerations[26]

Provisions adopted in the Energy Policy Act of 2005 (EPAct05; P.L. 109-58) allowed taxpayers to expense 50% of qualified investments in refinery assets.[27] Congress adopted this provision to address concerns that domestic refineries would not have the capacity to meet anticipated growth in domestic fuel demand; a condition that has since reversed. The potential for fuel price spikes also rises when domestic refineries operate at near capacity, as there may be insufficient spare capacity to make up for a refinery outage.

The provisions allowing taxpayers to partially expense investments in refinery assets was initially enacted on a temporary basis.[28] Specifically, taxpayers making qualified investments in domestic refinery property used to refine liquid fuel from crude oil (or other qualified fuels) were eligible for the tax deduction if a binding contract for construction of the qualified property had been entered into by January 1, 2008.[29] Further, under EPAct05, it was required that qualifying property be placed in service prior to January 1, 2012. The Emergency Economic Stabilization Act of 2008 (EESA; P.L. 110-343) extended the under-contract and placed-in-service deadlines, such that the incentive is now available for refineries that entered into a binding construction contract before January 1, 2010, and will be placed in service by January 1, 2014.

Allowing taxpayers to expense part of their investment in refinery property reduces the cost of construction, encouraging additional refinery investment. Allowing 50% of refinery investments to be expensed, rather than depreciated over the normal 10-year life, reduces the cost of construction by approximately 5% for taxpayers in the 35% tax bracket.[30] Since the provision is temporary, there is an incentive to speed up the investment in refinery capacity so as to qualify for the tax incentive. Nevertheless, the incentive to speed up investment is limited, because the effective price discount is small. Investing in excess capacity that would not otherwise be desirable would either leave the plant idle or provide too much output and lower prices and profits for a period of time. The latter cost should be at least as big as the cost of remaining idle.

[26] Molly Sherlock, Analyst in Economics, contributed to this section of the report.

[27] Internal Revenue Code (IRC) § 179C. Under the Modified Accelerated Cost Recovery System (MACRS), petroleum refining assets are depreciated over a 10-year period using a double declining balance method.

[28] For additional background information on energy tax issues, see CRS Report R40999, *Energy Tax Policy: Issues in the 111th Congress*, by Molly F. Sherlock and Donald J. Marples and CRS Report R41227, *Energy Tax Policy: Historical Perspectives on and Current Status of Energy Tax Expenditures*, by Molly F. Sherlock.

[29] Existing refineries may qualify if the installation of new property increases the refinery's capacity by at least 5% or increases the percentage of total throughput attributable to qualified fuels such that it equals or exceeds 25%. All qualifying property must be in compliance with applicable environmental laws on the placed-in-service date.

[30] The present value of a 10-year, double declining balance depreciation per dollar of investment is $0.74 with an 8% nominal discount rate. For every dollar expensed, the benefit of expensing is to increase the present value of deductions by $0.26, and since half of the investment is expensed, the value is $0.13. Multiplying this value by 35% leads to a 4.6% benefit as a share of investment. The value would be larger with a higher discount rate. For example, at a 10% discount rate, the benefit would be 5.4%. The benefit is smaller for firms facing lower tax rates or those with limited tax liability.

With a 5% price discount, the interest cost of carrying excess capacity or losing profits could offset the tax credit's value.

The estimated reduction in federal receipts associated with provisions allowing taxpayers to expense 50% of qualified investments in refinery assets is presented in **Table 8**. Over the five-year 2009 through 2013 budget window, estimates suggest this provision will cost \$3.4 billion.[31]

Table 8. Tax Expenditures for Provisions Allowing Partial Expensing of Refinery Investments

billions of dollars

	2008	2009	2010	2011	2012	2013
Revenue Loss	0.4	0.5	0.7	0.8	0.7	0.6

Source: Joint Committee on Taxation

Notes: Tax expenditures are estimate federal revenue losses associated with special tax provisions.

Policy Considerations

The conventional gasoline refined today has changed considerably since the Clean Air Act of 1970 prohibited lead additives, and later amendments created demand for oxygenated gasoline and reformulated gasoline (RFG). Each of the three formulations of gasoline (conventional, oxygenated and reformulated) is available in at least three grades (87, 89-mid grade, and 91+ super) and the volatility is adjusted for winter/summer and northern/southern driving conditions. (Other properties such as Reid Vapor Pressure, octane, and cetane are discussed in **Appendix A**.)

Reformulated Gasoline

The Clean Air Act, as amended in 1990, directed the Environmental Protection Agency (EPA) to designate areas not complying with national ambient air quality standards (NAAQS) as ozone "nonattainment areas."[32] Cities with the worst smog pollution are required to reduce harmful emissions that cause ground-level ozone by using reformulated gasoline (known as RFG), which is blended to burn cleaner by reducing smog-forming and toxic pollutants during the summer ozone season. Reformulated gasoline undergoes additional processing to remove volatile components that contribute most to air pollution, and to make it less prone to evaporation. It also contains chemical oxygen, known as oxygenate, to improve combustion.

Since the Clean Air Act Amendments, a growing number of distinct types of gasoline ("boutique fuels") have entered the supply chain. Currently, 15 distinctly formulated boutique fuels are required in portions of 12 states (see **Figure 10**). In addition to the federal RFG standards, State Implementation Plans to improve air quality require low-Reid Vapor Pressure conventional

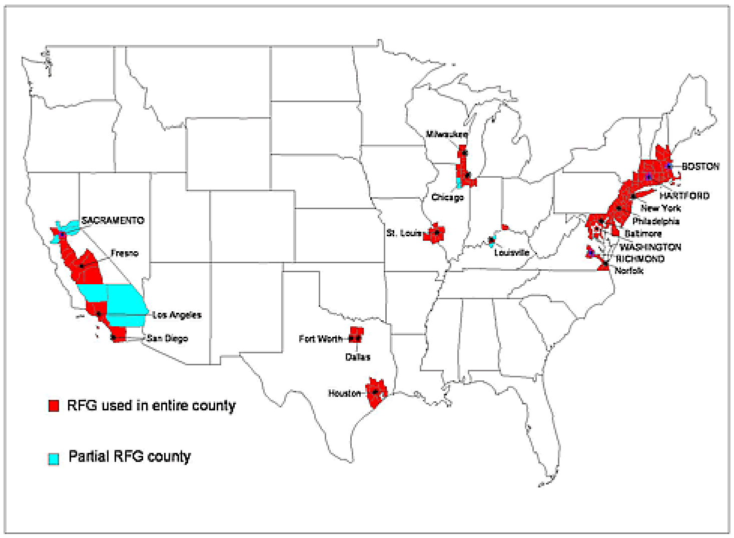
[31] U.S. Congress, Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 2009-2013*, committee print, 111th Cong., 2nd sess., January 11, 2010, JCS-1-10.

[32] Section 181 of the act required EPA to classify each area as a marginal, moderate, serious, severe or extreme ozone nonattainment area. EPA classified all areas that were designated as in nonattainment for ozone at the time of the enactment of the 1990 Amendments, except for certain "nonclassifiable" areas (56 FR 56694,(1) November 6, 1991).

gasoline (referred to as "low-RVP"). (Refer to **Appendix B** for a discussion of RVP and other fuel properties.) California mandates a cleaner fuel than federal RFG (referred to as California RFG, or CaRFG), and the Midwestern states require a unique ethanol-blended RFG.

In analyzing the proliferation of gasoline types, EIA concluded in 2002 that: "... the general impact of an increasing number of distinct gasoline fuels with smaller demands and, in some cases, served by fewer suppliers has been to reduce the flexibility of the supply and distribution system to respond to unexpected supply/demand shifts."[33] The prospect that more refineries may sit idle or permanently close due to decreased demand could further reduce that flexibility.

Figure 10. Map of Reformulated Gasoline Areas



Source: EPA.

Notes: Currently, 12 states have 15 boutique fuels. Alaska and Hawaii do not have RFG areas.

To reduce the proliferation of boutique fuels, the 2005 Energy Policy Act[34] amended the Clean Air Act (in 42 U.S.C. 7545) by limiting them to the number existing as of September 1, 2004.

H.R. 392, the Boutique Fuel Reduction Act of 2009, would further amend the Clean Air Act Section 211(c)(4)(C)(ii)II) to add temporary waivers for unexpected problems with distribution or delivery equipment necessary for transporting fuel or fuel additives. Amendments to Section 211(c)(4)(C) would give the EPA Administrator authority to reduce the number of boutique fuels after determining that a particular fuel is no longer included in a state implementation plan or is identical to a federally approved fuel.

Between 1992 and 2005, EPA also mandated oxygenated fuel blends to reduce ground-level ozone and smog. Much of the gasoline sold in the United States during that period was blended with up to 10% methyl tertiary-butyl ether (MTBE) as the oxygenate in almost all RFG outside of

[33] Energy Information Administration, *Analysis of Selected Transportation Fuel Issues Associated with Proposed Energy Legislation - Summary*, September 2002, http://www.eia.doe.gov/oiaf/servicerpt/fuel/gasoline.html.

[34] Subtitle C—Boutique Fuels Sec. 1541. Reducing the Proliferation of Boutique Fuels.

the Midwest, while ethanol was used in the Midwest. Both MTBE and ethanol served several functions: as an oxygenate in RFG, as an octane booster, and as a volume extender in conventional gasoline.[35] Groundwater contamination concerns and the State of California's ban on MTBE as a gasoline additive left ethanol as the most popular fuel oxygenate. MTBE was produced and added at the refinery. However, ethanol's corrosive nature makes long-distance shipment of ethanol mixed into gasoline impractical. In consequence, ethanol (produced mostly from corn fermentation) is blended with gasoline at the storage terminal where the fuel is dispensed to the fuel tank truck. The shift from MTBE to ethanol thus contributed to a reduction in refinery production.

Renewable Fuel Program /Alternative Fuels

During an era of increasing crude oil prices and concerns for declining domestic crude oil production, many policy makers advocated energy self-sufficiency. Renewable fuels offered the promise of, at least, offsetting an increasing demand for transportation fuel. Now, though, the prospect of declining motor-fuel demand may mean that the use of more renewable fuels may influence operators to idle, consolidate, or permanently close refineries.

Congress created the Renewable Fuel Program under Title XV of the Energy Policy Act of 2005 (EPAct—P.L. 109-58) to substitute increasing volumes of renewable fuel for gasoline. The U.S. Environmental Protection Agency (EPA) has the statutory authority for administering the National Renewable Fuel Standard (RFS) program. The act set a target production volume of 7.5 billion gallons of renewable fuels for calendar year 2012. The 2007 Energy Independence and Security Act (EISA) expanded the program to cover transportation fuels in general, extended the program to calendar year 2022, and increased the target volume to 36 billion gallons renewable fuel annually (857 million barrels annually or 2.3 Million bbl/d) (see **Table 9** below).

Table 9. EISA Renewable Fuel Volume Requirement

Year	Cellulosic Biofuel Requirement Billion Gallons	Biomass-based Diesel Requirement Billion Gallons	Advanced Biofuel Requirement Billion Gallons	Total Renewable Fuel Requirement Billion Gallons	Total Renewable Fuel Requirement Million Barrels
2008	n/a	n/a	n/a	9.00	214
2009	n/a	0.50	0.60	11.10	264
2010	0.10	0.65	0.95	12.95	308
2011	0.25	0.80	1.35	13.95	332
2012	0.50	1.00	2.00	15.20	362
2013	1.00	a	2.75	16.55	394
2014	1.75	a	3.75	18.15	432
2015	3.00	a	5.50	20.50	488
2016	4.25	a	7.25	22.25	530
2017	5.50	a	9.00	24.00	571

35 Environmental Protection Agency, *Status and Impact of State MTBE Bans*, http://www.eia.doe.gov/oiaf/servicerpt/mtbeban/pdf/mtbe.pdf.

Year	Cellulosic Biofuel Requirement Billion Gallons	Biomass-based Diesel Requirement Billion Gallons	Advanced Biofuel Requirement Billion Gallons	Total Renewable Fuel Requirement Billion Gallons	Total Renewable Fuel Requirement Million Barrels
2018	7.00	a	11.00	26.00	619
2019	8.50	a	13.00	28.00	667
2020	10.50	a	15.00	30.00	714
2021	13.50	a	18.00	33.00	786
2022	16.00	a	21.00	36.00	857
2023+	b	b	b	b	

Source: EPA Renewable Fuel Standard http://www.epa.gov/otaq/fuels/renewablefuels/

Notes: 1 barrel = 42 gallons.

a. To be determined by EPA through a future rulemaking, but not less than 1.0 billion gallons.

b. To be determined by EPA through a future rulemaking.

The 2010 requirement of nearly 13 billion gallons of renewable fuels represents more than 9% of 2009 gasoline consumption.

Under current EPA rules, ethanol is blended up to 10% by volume in retail gasoline (E10) and 85% in E85 fuel for use in flex-fuel vehicles (FFV). On October 13, 2010, the EPA partially granted Growth Energy's waiver request application submitted under section 211(f)(4) of the Clean Air Act.[36] The partial waiver allows the sale of gasoline that contains ethanol up to 15% by volume (E15) for use in 2007 and newer model year vehicles. EPA denied the waiver to use E15 in vehicles older than model year 2000, and is deferring a decision on using E15 in model years 2001 through 2006. The E15 fuel must be sold from a separate pump, as is E85. The new ruling would appear to be at odds with the EPAct 2005 provision that limits the proliferation of boutique fuels.

EPA is finalizing RFS regulations for 2011 with specific annual volumes for cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel requirements. Although current ethanol production capacity is more than adequate to meet current blending goals, increased biofuel production faces a number of economic, land use, and policy barriers. The feasibility of expanding current ethanol production by another 1 million bbl/d is linked to the ethanol industry's ability to expand under escalating feedstock prices and economic conditions that discourage capital investment. Congress is also looking toward cellulosic ethanol to meet much of the RFS requirements. However, cellulosic ethanol production has technological barriers to overcome before commercial-scale plants can begin operating.

[36] EPA, *Partial Grant and Partial Denial of Clean Air Act Waiver Application Submitted by Growth Energy to Increase the Allowable Ethanol Content of Gasoline to 15 Percent; Decision of the Administrator,* October 13, 2010, http://www.epa.gov/otaq/regs/fuels/additive/e15/e15-waiver-decision.pdf.

Subsidies and/or Tax Breaks for Renewable Fuel

Some of the federal subsidies and tax breaks favoring ethanol production were reduced by Title XV of the Food, Conservation and Energy Act of 2008 (P.L. 110-246). The ethanol blender tax credit of $0.51 per gallon (which applies to all ethanol blends, including imports) was reduced to $0.45 per gallon in January 2009 under Section 15331 of the act. The $0.54 per gallon import tariff on ethanol, which effectively offsets the blender tax credit when imported ethanol is blended into gasoline in the United States, is set to expire at the end of 2010 under Section 15333 of the act.

Under the strong motor fuel demand conditions that existed when the Food, Conservation, and Energy Act was passed, ethanol was considered to be a means of extending the volume of refined transportation fuels, particularly after the elimination of MTBE. Since then, ethanol has begun to displace refined fuel, albeit under subsidy. If the renewable fuel volume mandate is met by 2022, and the $0.45 per gallon subsidy were to remain in place, the RFS goal of 857 million barrels could represent a $16.2 billion annual subsidy to displace 564 million barrels of refined gasoline (on an energy equivalent basis).[37]

Carbon Emissions/Greenhouse Gas Rules

In 2007, the United States Supreme Court ruled that EPA has the authority under the Clean Air Act to regulate carbon dioxide (CO_2) emissions from automobiles, and directed EPA to conduct a thorough scientific review.[38] After the ordered review, EPA issued a proposed finding, in April 2009, that greenhouse gases contribute to air pollution that may endanger public health or welfare.[39] Though the finding pertained to automobile emissions, it has wide ranging implications.

In response to the FY2008 Consolidated Appropriations Act (H.R. 2764; P.L. 110-161), EPA issued the Mandatory Reporting of Greenhouse Gases Rule.[40] The rule requires suppliers of fossil fuels or industrial greenhouse gases, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG emissions to submit annual reports to EPA.[41] The rule includes final reporting requirements for 31 of the 42 emission sources listed in the proposal. EPA plans to finalize additional source categories listed in the proposal in 2010. The rule establishes the basis for future legislation and regulations that could cap GHG emissions from refineries as well as other industrial sources.

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[37] Assumes that one barrel of refined crude oil can yield up to 46% gasoline.

[38] *Massachusetts et al. v. Environmental Protection Agency*, 549 U.S. 497 (Supreme Court of the United States, April 2, 2007).

[39] The Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act was signed on April 17, 2009. On April 24, 2009, the proposed rule was published in the Federal Register (www.regulations.gov) under Docket ID No. EPA-HQ-OAR-2009-0171.

[40] The final rule was published in the Federal Register (www.regulations.gov) under Docket ID No. EPA-HQ-OAR-2008-0508-2278. The rule became effective December 29, 2009.

[41] The gases covered by the proposed rule are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), sulfur hexafluoride (SF_6), and other fluorinated gases including nitrogen trifluoride (NF_3) and hydrofluorinated ethers (HFE).

The American Clean Energy and Security Act of 2009

H.R. 2454—*The American Clean Energy and Security Act of 2009* (passed in the House June 26, 2009) would amend the Clean Air Act by establishing a "cap-and-trade" system designed to reduce greenhouse gas emissions (GHG) and would cap emissions from refineries and allow trading of emissions permits ("allowances"). Over time, H.R. 2454's provisions would reduce the cap to 83% of current emissions, forcing industries to reduce emissions by that amount (cap) or purchase allowances from others who would have reduced emissions more than required or offsets from eligible entities not covered by the cap (trade). The bill would allocate the refining industry only 2% of the total emission allowances for the entire U.S. economy.

Petroleum refineries emit approximately 205 million metric tons of CO_2 annually, which (according to the new EPA rule) represents approximately 3% of the U.S. GHG emissions. The cost of complying with the new EPA rule could be minimal, but the cost of complying with "cap and trade" provisions of H.R. 2454 or similar legislation could be disruptive to the refining industry according to recent analyses by the consulting firm Wood Mackenzie and the Energy Policy Research Foundation, Inc.[42]

As proposed, H.R. 2454 would require U.S. refiners to purchase emission credits for both their stationary emissions and the subsequent combustion of their fuels (predominantly consumed in the transportation sector). U.S. refiners could face competitive disadvantages with refined petroleum products imported from countries where refinery greenhouse-gas emissions are treated differently. In Wood McKenzie's analysis, U.S. refiners would need to purchase roughly 2,000 million credits in 2015, whereas European Union refiners who export their products (predominantly gasoline) to the United States would only need to purchase 3 million allowances.

Clean Energy and Oil Accountability Act of 2010

S. 3663, introduced in August 2010, would establish a Natural Gas Vehicle and Infrastructure Development Program to promote natural gas as an alternative transportation fuel in order to reduce domestic oil use (see Title XX—Natural Gas Vehicle And Infrastructure Development). The program would also offer incentives to convert or repower conventionally fueled vehicles to operate on compressed natural gas (CNG) or liquefied natural gas (LNG).[43]

Natural gas is abundant in the United States and has already been introduced as a transportation fuel for intra-city buses, principally as means of reducing air emissions. U.S. automobile manufactures marketed passenger vehicles modified to run on compressed natural gas in the 1990s. [44]

U.S refineries currently produce 1,386.5 million barrels of diesel fuel annually. Approximately 5.3 trillion cubic feet (tcf) of natural gas would be needed to replace this fuel, as S. 3663

[42] Alan Gelder, *The (potentially) Disruptive Impact of Carbon on US Refiners*, Wood Mackenzie, October 27, 2009, http://www.woodmacresearch.com/cgi-bin/wmprod/portal/energy/highlightsDetail.jsp?oid=1611276.

[43] The provision shares objectives similar to the Pickens Plan, which proposes to shift over-the-road trucks and municipal buses from diesel fuel to natural gas. http://www.pickensplan.com.

[44] For further information refer to CRS Report RS22971, *Natural Gas Passenger Vehicles: Availability, Cost, and Performance*, by Brent D. Yacobucci.

proposes.[45] In 2008, the United States produced 20.8 tcf of natural gas. To displace its diesel fuel with natural gas, the United States would need to increase natural gas production by more than 25%. This does not take into consideration policies aimed at replacing coal-based electricity generation with natural gas, nor any lost efficiency in converting diesel engines to natural gas.

A refined barrel of 35º API crude can yield about five gallons of diesel fuel, or 12% of the barrel. Displacing all diesel fuel consumption with natural gas represents about two million bbl/day in refining capacity. Refineries cannot cut back diesel production without cutting back on production of gasoline and other refined products. Assuming no decreased gasoline demand, refiners would likely export the excess diesel or market it as heating oil.

Vehicle Efficiency/Mileage Rules

The 2007 Energy Independence and Security Act (EISA) amended the "corporate average fuel efficiency" (CAFE) standards. By 2020, a manufacturer's combined fleet of passenger and non-passenger vehicles must achieve an average 35 mpg. The American Council on an Energy-Efficient Economy estimates that the new standard will save 2.4 million bbl/d by 2030, the equivalent of 13% of the current U.S. refinery output. The EPA and the National Highway Transportation Safety Administration (NHTSA) recently published final rules to implement the first phase of these new standards. Further, they have announced their intention to improve fuel efficiency and reduce greenhouse gas (GHG) emissions for commercial trucks and to adopt the second phase of GHG and fuel economy standards for light-duty vehicles.

Economists have recognized that improving energy efficiency releases an economic reaction that partially offsets the original energy savings, a "rebound effect."[46] According to the National Highway Traffic Safety Administration (NHTSA),

> improving a vehicle's fuel economy reduces its fuel cost per mile driven. In response to the reduced per-mile cost of driving a more fuel-efficient vehicle, some buyers will increase the amount of driving they do, although the precise magnitude of this response is uncertain. Thus imposing stricter fuel economy standards can increase the annual number of miles driven ."[47]

Research on the magnitude of the rebound effect in light-duty vehicles dating to the early 1980s concluded that a statistically significant rebound effect occurs when vehicle fuel efficiency improves.[48]

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[45] The heat content of diesel fuel (139,000 Btu per gallon) refined in 2008 (1,386.5 million barrels) is roughly: (*Eq. 1*) 0.67 × 1,386.5 million bbls × 42 gal./ bbl × 139,000 Btu/gal × therm/100,000 Btu = 5.423 therms. The equivalent volume of natural gas (1,028 Btu per cubic foot) needed to replace the diesel fuel is: (*Eq. 2*) 5,423,239 million Btu ÷ 1,028 Btu/ ft^3 = 5,275.5 million cubic feet.

[46] Kenneth Small and Kurt Van Dender, *The Effect of Improved Fuel Economy on Vehicle Miles Traveled: Estimating the Rebound Effect Using U.S. State Data, 1966-2001*, University of California Energy Institute, Policy and Economics Series, UC Berkeley, CA, September 21, 2005, http://escholarship.org/uc/item/1h6141nj.

[47] National Highway Traffic Safety Administration, *Corporate Average Fuel Economy Compliance and Effects Modeling*, DOT HS 811 112, April 2009, p. 24, http://www.nhtsa.gov/DOT/NHTSA/Traffic%20Injury%20Control/Articles/Associated%20Files/811112.pdf.

[48] National Highway Traffic Safety Administration, *Corporate Average Fuel Economy for MY2012-MY2016 Passenger Cars and Light Trucks*, August 2009, p. 355, http://www.nhtsa.gov/DOT/NHTSA/Rulemaking/Rules/Associated%20Files/MY2012-2016_CAFE_PRIA.pdf.

Mathematically, the rebound effect is equal to the elasticity of average vehicle use with respect to fuel cost per mile driven, although the rebound effect is customarily expressed as a positive percentage. NHTSA found that two-thirds of all rebound estimates it reviewed fell in the range of 10% to 30%.[49] NHTSA also cited recent evidence "that the rebound effect has been declining over time, and may decline even further over the immediate future if income rises faster than gasoline prices." In light of the various study results NHTSA reviewed, it elected to use a 10% rebound effect in its analysis of fuel savings and other benefits from higher CAFE standards for MY2012-MY2016 vehicles. The EPA has chosen a more conservative 5% effect.

Will rebound—that is, increased driving—stimulate additional demand for refined petroleum products, or will renewable fuel mandates offset the demand? The legal mandate for increased ethanol consumption further complicates the effort to improve vehicle fuel efficiency. For example, on the basis of energy content it would take roughly 1.39 gallons of E85 to move a vehicle the same distance as one gallon of gasoline.[50]

With EPA's partial Clean Air Act waiver allowing the sale of E15, drivers may see further decreases in vehicles' advertised mile-per-gallon (MPG) ratings. The blend wall increase may further challenge automobile manufacturers to meet the new CAFE standards and possibly erode demand for refined products.

Conclusion

The petroleum refining industry has a long history of cyclical performance. The most recent downturn closely followed a period many identified as the "golden age" of refining. Cycles in the industry have been historically related to movements in the price of oil, which is the primary cost element in refinery operations, and this will likely remain true in the future.

More urgently, the refining industry faces structural challenges from recent government regulations that aim at directly reducing the demand for the industry's output. Higher gas mileage standards for automobiles, increased ethanol content in gasoline blends, and the expansion in the use of pure bio-fuels suggest that even if economic conditions encourage a period of increasing demand for transportation fuels, the need for refined petroleum products will not necessarily increase proportionately. Electric vehicles, if adopted on a large-scale basis, could reduce the demand for liquid transportation fuels of all types.

These policies were intended, in part, to accommodate the growing demand for refined petroleum products. Now, though, the prospect of declining motor-fuel demand means that the use of more renewable fuels could influence operators to idle, consolidate, or permanently close refineries. This possibility may help explain why some refiners do not see a need to expand, or even maintain, production capacity in the United States.

Because of market forces, technological changes, and regulatory pressures on the refining industry, additional refineries are likely to close even as some of the more technologically complex and efficient refineries are likely to expand. If a trend toward even larger refineries emerges, this could lead to concentration in the industry at least on the national level. In the event

[49] NHTSA, August 2009, p. 356

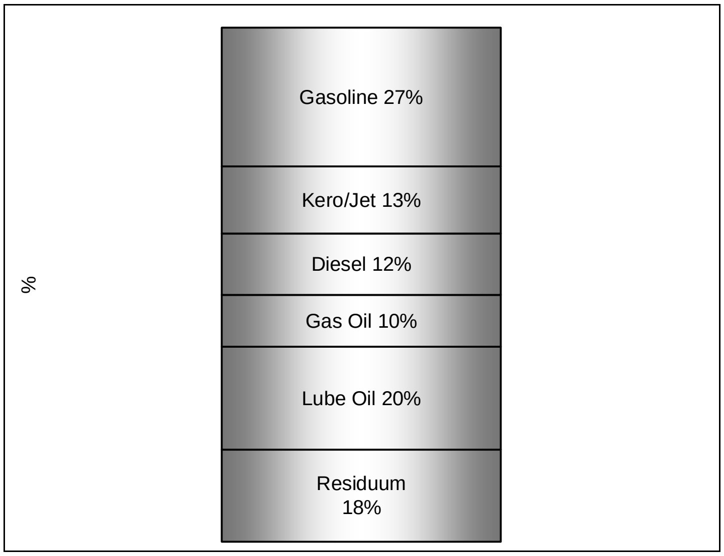
[50] E85 has 81,800 BTUs/gal) compared to gasoline's 114,100 BTUs/gal.

such adjustments occur, Congress may wish to monitor competitive conditions in oil refining, and in particular the impact of consolidation on the prices and less choice facing consumers.

Appendix A. Petroleum and Refining Fundamentals

Crude oil contains natural components in the boiling range of gasoline, kerosene/jet fuel and diesel fuel. A typical 35° API crude, oil as shown in **Figure A-1**, might contain 27% of the hydrocarbons in the range of gasoline and 13% of the hydrocarbons in the range of kerosene and jet fuel. Average crude oils tend to have more paraffin in the gasoline range and more aromatics and asphaltic in the residuum.

Figure A-1. 35° API Crude Oil Composition



Source: Petroleum Geochemistry and Geology, 1979.

Notes: For illustrative purposes only. Does not represent a specific crude oil assay.

A conventional refinery distills crude oil into various fractions, according to boiling point range, before further processing. In order of their increasing boiling range and density, the distilled fractions are:

Table A-1. Crude Oil Fractions and Boiling Ranges

Fraction	Boiling Range °F
Residuum	1,050° +
Gas-oil	520° — 1,050°
Kerosene/Jet/ Diesel	380° — 520°
Gasoline /Naphtha	90° — 380°
Fuel Gases	Below 90°

Source: CRS.

Notes: Gasoline's molecular weight is based on the number of carbon atoms, in range of C5 toC10; middle-distillate fuels like kerosene, jet, and diesel range from C11 to C18.

Crude oil may contain 10%-40% gasoline, and early refineries directly distilled a straight-run gasoline (light naphtha) of low-octane rating.[51]

A hypothetical refinery may "crack" a barrel of crude oil into two-thirds gasoline and one-third distillate fuel (kerosene, jet, and diesel), depending on the refinery's configuration, the slate of crude oils refined, and the seasonal product demands of the market.[52]

Conventionally refined gasoline, diesel, and jet fuels are complex mixtures of hydrocarbons that include paraffins, naphthenes, and aromatics (which give fuel its unique odor).[53]

Crude oil processing begins in a refinery's atmospheric distillation unit. The refinery's "name plate capacity," usually expressed as barrels per calendar day or barrels per stream day (see **Figure A-2**), describes the volume of crude oil that flows through a refinery's atmospheric distillation unit. This is the initial refining stage that separates crude oil into gasoline, kerosene, diesel fuel and heavier petroleum components on the basis of their boiling range. There, the "straight-run" petroleum fractions in the boiling ranges of gasoline, naphtha, kerosene, diesel, and jet fuel condense and separate. Heavier fractions are cracked with catalysts and hydrogen to produce more gasoline range (C5+) blending stock, and low-octane paraffins are converted into high-octane aromatics (octane is discussed below). Other processes such as alkylation produce branched chain hydrocarbons in the gasoline range.

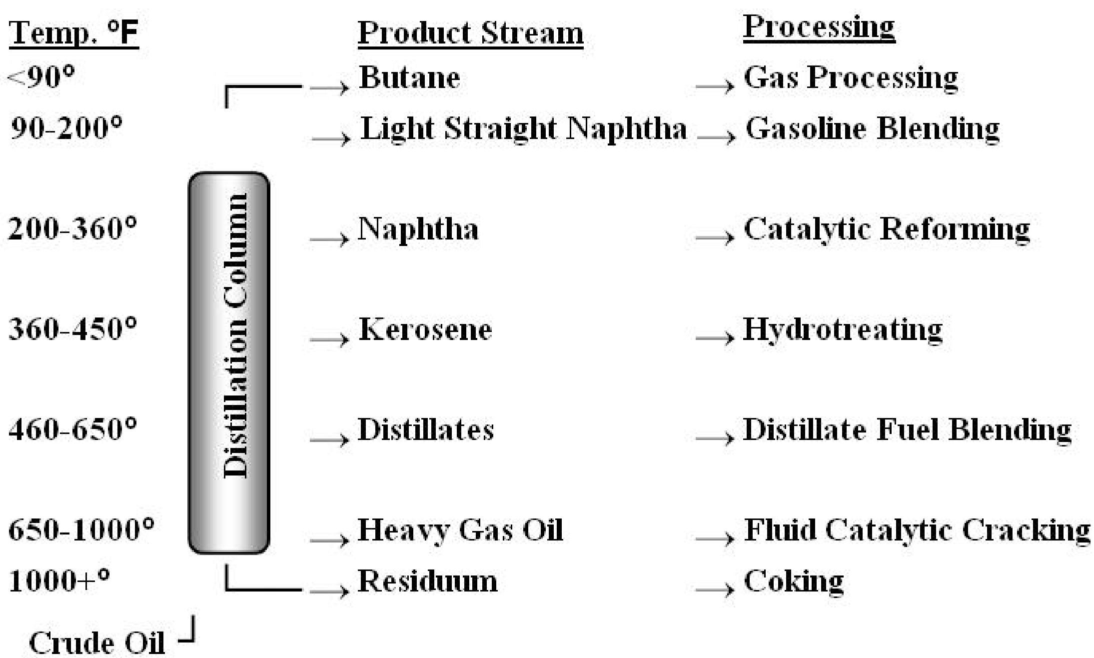
Generally, refineries are set up to run specific grades of crude oil, for example light sweet or heavy sour. Light sweet crude is particularly desirable as a feedstock for gasoline refining because its lighter-weight hydrocarbons make it easier to refine. Heavier crude oils require more complex processing than light crudes, and sour crudes require desulfurization. Refineries upgraded to process heavier crudes cannot readily switch back to lighter oils and run at normal capacity.

[51] Octane number refers to the gasoline property that reduces detrimental knocking in a spark-ignition engine. In early research, iso-octane (C8-length branched hydrocarbon molecules) caused the least knock and was rated 100. Cetane number refers to a similar property for diesel fuel, for which normal hexadecane ($C_{16}H_{34}$) is the standard molecule.

[52] The term "crack spread" refers to the 3-2-1 ratio of crude-gasoline-distillate. The crack spread and the 3-2-1 crack is a hypothetical calculation used by the New York Mercantile Exchange for trading purposes.

[53] James H. Gary and Glenn E. Handwerk, *Refining Petroleum—Technology and Economics*, 4th Ed., Marcel Dekker, Inc., 2001.

Figure A-2. Distillation Column



Source: CRS.

Distillation Unit: Heats crude oil until it boils vaporizes. Each hydrocarbon rises to a tray at a temperature just below its own boiling point. There, it cools and turns back to a liquid. The lightest fractions are liquefied petroleum gases (propane and butane) and the petrochemicals used to make plastics and other products. Next come gasoline, kerosene, and diesel fuel. Heavier fractions are used as home heating oil and as fuel in ships and factories. Still heavier fractions are made into lubricants and waxes. The remains, which include asphalt, are known as "residuals."

Fluid Catalytic Cracker: "Cat cracking" is a refining process used to manufacture gasoline. The process uses intense heat, low pressure, and powdered catalyst to accelerate the chemical reaction of the heavy fractions into smaller gasoline molecules.

Selective Hydrocracker: Partially converts diesel-range material into gasoline, propane and butane via a chemical reaction that uses high temperatures and pressures in a catalyst-containing reactor.

Alkylation Plant: Converts light hydrocarbons to heavier hydrocarbons more compatible as gasoline components for high-octane gasoline.

Catalytic Reforming: A process for upgrading low octane naphtha to a high octane gasoline blending component, reformate. Important by-products of this process include hydrogen, benzene, toluene, and xylenes.

Delayed Coker: Converts petroleum pitch into petroleum coke and gas oils for processing in other units to higher quality, higher value diesel fuel and gasoline.

Gas Oil Hydrotreater: Provides for removal of sulfur and nitrogen from various products, making them more suitable for conversion feed to other process units.

Gas Plants: Collect gases from processing units (hydrocracker, hydrotreater, reformer, coker, cat cracker) and separate volatiles into appropriate product streams.

Sulfur Recovery Unit: Recovers sulfur from refinery streams as elemental sulfur for sale as end-use products.

Catalytic cracking, coking, and other conversion units, referred to as secondary processing units, have enabled refineries to produce more high-value products, such as gasoline, from a barrel of crude oil and process heavier crude oils; see **Table A-2**. These processing units add to a refinery's complexity and can actually increase the volume of its output. These processes also require a supply of hydrogen, typically derived from natural gas.

Table A-2. Refinery Types and Process

Refinery Type	Processes	Complexity
Coking	Add coking/resid destruction (delayed coking process) to run medium/sour crude oil.	9
Cracking	Add vacuum distillation and catalytic cracking process to run light sour crude to produce light and middle distillates.	5
Hydroskimming	Atmospheric distillation, naphtha reforming and desulfurization process to run light sweet crude and produce gasoline.	2
Topping	Separate crude oil into constituent petroleum products by atmospheric distillation; produce naphtha but no gasoline.	1

Source: Reliance Industries, Ltd., "Types of Refinery & Nelson's Complexity."

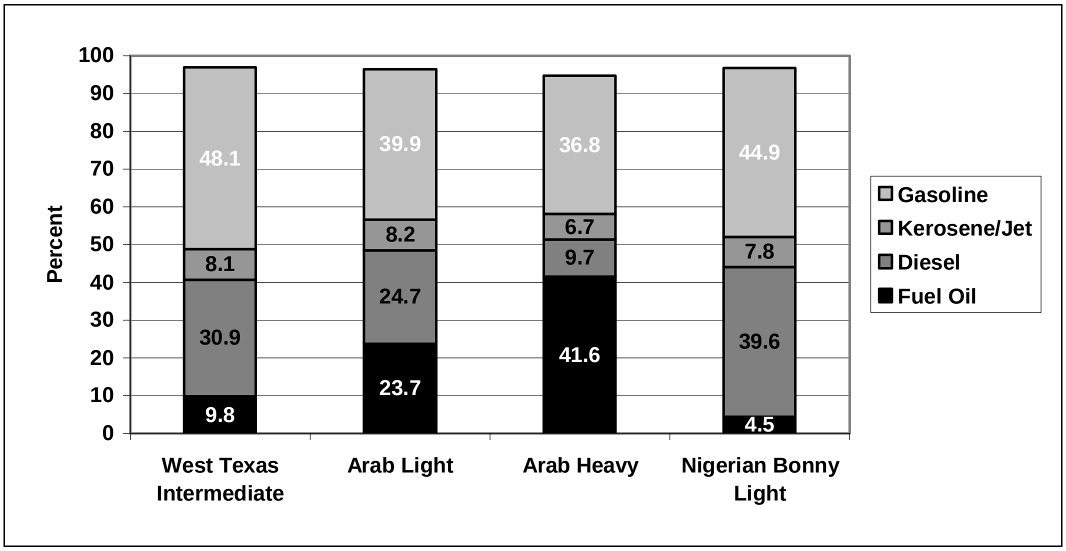
Notes: Complexity, as denoted above, is based on the Nelson Complexity Index, which rates the proportion of secondary processes to primary distillation (topping) capacity. Nelson's index varies from about 2 for hydroskimming refineries to about 5 for cracking refineries, and over 9 for coking refineries While the average index for U.S. refineries is 10, only 52 have coking capacity (accounting for the Delaware City refinery closure, this represent 3.485 million barrels per day capacity).[54] By and large, U.S. refineries have become the most complex in the world in order to convert low-value residuum, formerly used as heavy heating oil, to high-value gasoline. European refineries, in comparison, are less complex than U.S. refineries on average, being geared toward more producing diesel fuel.

[54] Oil & Gas Journal, 2006 U.S. Refining Survey, December 19, 2005.

A typical refinery yields a limited supply of jet and diesel fuel depending on the type of crude oil processed, see **Figure A-3**. Gulf Coast (Texas and Louisiana) may yield up to 8% jet fuel, and over 30% diesel. These refineries have an average complexity of 12 to 13, which is above the national average of 9.5.

Figure A-3. Gulf Coast Refinery Yields

Percent (%)



Source: Data used from Energy Intelligence, *The International Crude Oil Refining Handbook*, 2007. http://www.energyintel.com

Notes: Winter yields shown.

Appendix B. Important Fuel Properties

Reid Vapor Pressure

Vapor pressure is an important physical property of both automotive and aviation gasoline, affecting starting, warm-up, and tendency to vapor lock with high operating temperatures or high altitudes. EPA regulates the vapor pressure of gasoline sold at retail stations during the summer ozone season (June 1 to September 15) to reduce evaporative emissions from gasoline that contribute to ground-level ozone and diminish the effects of ozone-related health problems. Shifting to gasoline with lower Reid vapor pressure (RVP) reduces emissions. The Reid Method refers to American Society for Testing and Materials (ASTM) standard test method D 323-08 for measuring the vapor pressure of petroleum products. RVP varies from 8.7 in the summer to 11.5 in the winter.

Octane

Higher octane-number fuels better resist engine "knock"—the sound caused by fuel prematurely igniting during compression. In early gasoline research, the least knock resulted from using iso-octane, which arbitrarily received a rating of 100.[55] Isooctane refers to a branched "isomer" in the paraffin series having eight carbons (C_8H_{18}).[56] The straight-chain isomer in this series, n-octane, has a rating -19. Modern formulated gasoline ranges in octane from 87 to 93, achieved by blending various petroleum distillates, reforming gasoline-range hydrocarbons, and adding oxygenates such as ethanol to boost octane-number.

Cetane

The standard for rating diesel fuel's ease of auto-ignition during engine compression is based on "cetane"—a straight-chain hydrocarbon in the paraffin series with the common name of n-hexadecane. It consists of 16 carbon atoms with three hydrogen atoms bonded to the two end carbons and two hydrogens bonded to each of the middle carbons; written as $C_{16}H_{34}$. Pure cetane received the number 100 for rating purposes. Diesel fuel cetane-number ranges from 40 to 45 in the United States to as high as 55 in Europe (where high-speed diesel engines are prevalent in light-duty passenger vehicles). Diesel fuel formulation blends straight-run cut distillates with cracked stock (heavier fractions) to meet standardized specifications developed by the American Society for Testing and Materials (ASTM International) and EPA.

Sulfur

As now regulated by EPA (40 C.F.R. 80.520), diesel fuel must contain less than 15 parts-per-million (ppm) sulfur—referred to as ultra-low-sulfur diesel (ULSD). Conventionally refined aviation jet fuel may contain as high as 3,000 ppm sulfur. However, as it has been used in blending winter diesel fuel to lower the gel point, it has had a practical limit of 500 ppm (the previous EPA limit for diesel). It is uncertain whether EPA may promulgate future rules on jet

[55] John M. Hunt, Petroleum Geochemistry and Geology, W. H. Freeman and Co., 1979. p. 51.

[56] Or more correctly 2,2,4-trimethylpentane.

fuel sulfur-content, thus limiting its use in blending winter ULSD. Despite its detrimental environmental effects, sulfur contributes to the "lubricity" of fuel. Under reduced sulfur, engines wear out sooner. Fuel can be blended with additives to make up for the loss of sulfur lubricity and engines can be manufactured from tougher materials, as has been the case in the EPA mandated transition from low-sulfur diesel (500 ppm) to ultra-low-sulfur diesel (15 ppm). Average annual sulfur content in all gasoline dropped from about 300 ppm in 1997 to about 90 ppm in 2005.

Exhaust Emissions

Diesel engines characteristically emit lower amounts of carbon monoxide (CO) and carbon dioxide (CO_2) than gasoline engines, but they emit higher amounts of nitrogen oxides (NOx) and particulate matter (PM). NOx is the primary cause of ground-level ozone pollution (smog) and presents a greater problem, technically, to reduce in diesel engines than PM. The CO, NOx, and PM emissions for gasoline and diesel engines are regulated by the 1990 Clean Air Act amendments (42 U.S.C. 7401-7671q).

Appendix C. Glossary

Motor Gasoline (Finished). A complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines. Motor gasoline (as defined in ASTM Specification D 4814 or Federal Specification VV-G-1690C) has a boiling range of 122º to 158º F at the 10% percent recovery point, and a 365º to 374º F boiling range at the 90% recovery point. "Motor Gasoline" includes conventional gasoline, all types of oxygenated gasoline (including gasohol), and reformulated gasoline, but excludes aviation gasoline. Volumetric data on blending components, such as oxygenates, are not counted in data on finished motor gasoline until the blending components are blended into the gasoline. Note: E85 is included only in volumetric data on finished motor gasoline production and other components of product supplied.

> **Conventional Gasoline.** Finished motor gasoline not included in the oxygenated or reformulated gasoline categories. Note: This category excludes reformulated gasoline blendstock for oxygenate blending (RBOB) as well as other blendstock.
>
> **Reformulated Gasoline.** Finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under Section 211(k) of the Clean Air Act. It includes gasoline produced to meet or exceed emissions performance and benzene content standards of federal-program reformulated gasoline even though the gasoline may not meet all of the composition requirements (e.g., oxygen content) of federal-program reformulated gasoline. Note: This category includes Oxygenated Fuels Program Reformulated Gasoline (OPRG). Reformulated gasoline excludes Reformulated Blendstock for Oxygenate Blending (RBOB) and Gasoline Treated as Blendstock (GTAB).

Blendstock for Oxygenate Blending (RBOB). Specially produced reformulated gasoline blendstock intended for blending with oxygenates downstream of the refinery where it was produced. Includes RBOB used to meet requirements of the federal reformulated gasoline program and other blendstock intended for blending with oxygenates to produce finished gasoline that meets or exceeds emissions performance requirements of Federal reformulated gasoline (e.g., California RBOB and Arizona RBOB). Excludes conventional gasoline blendstocks for oxygenate blending(CBOB).

RBOB for Blending with Alcohol. Motor gasoline blending components intended to be blended with an alcohol component (e.g., fuel ethanol) at a terminal or refinery to raise the oxygen content.

Fuel Ethanol (E10). Blends of up to 10% by volume anhydrous ethanol (200 proof) (commonly referred to as the "gasohol waiver").

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