CHAPTER ELEVEN

HYDROCARBON LIQUIDS

EXECUTIVE SUMMARY

Hydrocarbon liquids, primarily from petroleum, are the predominant supply for transportation in the United States and around the world. This chapter summarizes the current and future state of the U.S. hydrocarbon liquid supply chain as well as the breadth and competitiveness of this fuel pathway. The potential for new technology, new sources of hydrocarbon liquids, potential for greenhouse gas (GHG) reduction, and continued improvement in the existing supply chain highlight the significant benefits of this energy pathway. The key findings are listed below:

- Hydrocarbon liquids are expected to play a key role in the future U.S. transportation system while also facilitating use of biofuels through integrated products and by providing key infrastructure.
- Hydrocarbon liquids have properties that make them high-quality transportation fuels and allow the supply chain to operate at large scale and efficiency, which reduces cost. A well-established distribution system ensures widespread availability.
- The supply outlook for the United States and North America has improved in recent years. Oil production in the United States and Canada is expected to continue to increase with unconventional oil from tight oil, heavy oil, and oil sands playing an increasing role.
- Global oil demand growth is focused in developing countries. Demand in the United States and other Organisation for Economic Co-operation and Development (OECD) countries is forecast to be stable or decline as increased vehicle efficiency outweighs growth in end-user demand.
- U.S. oil imports have decreased since 2005 and are forecast to continue to decline slowly to 2035. Key factors in reducing imports are recent reductions in demand, limiting future demand growth, and increasing U.S. oil and biofuels production. Further reductions in imports are possible with improved vehicle efficiency or further increases in U.S. oil production facilitated by greater access to resources. Canada is the largest source of U.S. imports and is expected to become even more predominant in the future.
- Long-term development of alternative hydrocarbon liquids (gas-to-liquids, coal-to-liquids, oil shale) will require higher prices than are currently forecast, unless capital costs are reduced significantly. However, a large potential resource exists to augment petroleum supply.
- Life-cycle energy use and GHG emissions are mainly from customer fuel use. Vehicle efficiency improvement and other demand reduction steps can substantially reduce GHG emissions and petroleum imports.
- U.S. refineries are some of the most complex in the world, producing high-quality transportation fuels. U.S. refineries have been and will continue to be improved by technology, which improves efficiency, product quality, and feedstock utilization.
- Light-duty vehicle efficiency and increased biofuel use are likely to reduce gasoline demand, while distillate demand is expected to grow. Depending on demand assumptions, a wide range of future outcomes is forecast. As demonstrated through previous cycles, the refining industry should be able to manage changes in product demand over time.

- The U.S. refined product infrastructure provides efficient and low-cost product distribution. The system has a backbone of high-volume pipelines, supplemented by barge transport, with the final distribution via truck to retail locations. This system, with the exception of pipelines, has been adapted to handle ethanol and biodiesel.
- The technical challenge for pipeline operators is to allow the existing pipeline infrastructure to ship ethanol and other biofuels while minimizing the risk to pipeline integrity and product quality. Some combination of ethanol unit trains and pipeline gathering hubs may become a critical factor in minimizing the cost for transporting ethanol and other biofuels.

HYDROCARBON LIQUIDS OVERVIEW AND SUPPLY CHAIN

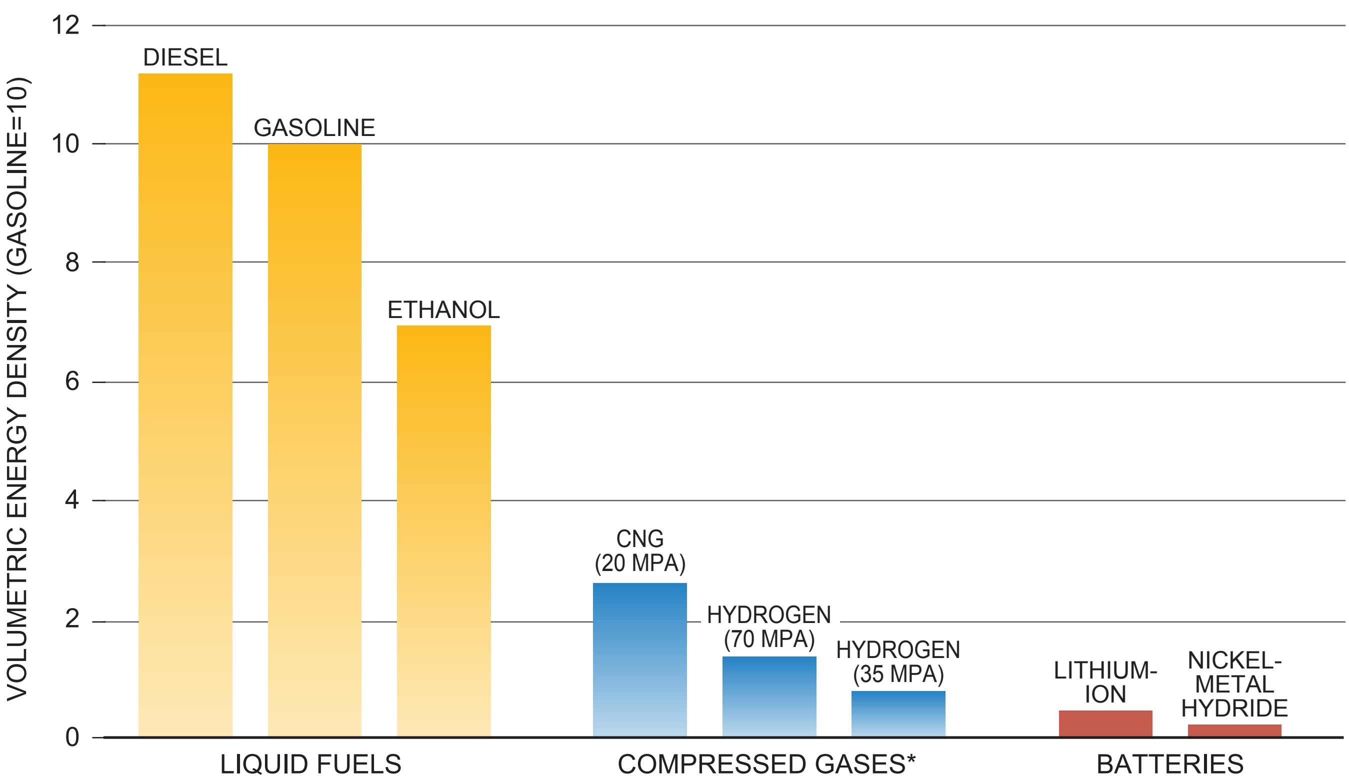
Introduction

Hydrocarbon liquids have unique properties that make them high-quality transportations fuels. One of the most significant properties is energy density, which is compared to other transportation energy sources in Figure 11-1. Other desirable characteristics include:

- Liquid form, easy to transport
- Adjustable combustion characteristics for use in a wide range of engines
- Consumer familiarity/risk acceptance.

In addition to utility, hydrocarbon liquids have advantages due to scale, relatively low cost, and widespread availability. The demand for hydrocarbon liquids continues to be large in most future outlooks because the cost of competing technologies is high. (Key items impacting demand are economic growth, fuel prices, vehicle efficiency, government action, and a variety of end-user preferences.)

This chapter covers hydrocarbon liquids as transportation fuels including: current state of the supply chain, future outlooks, role of natural gas and coal-to-liquids, and technology and infrastructure issues. The impact of an alternative case with



*MPA = megapascals.

Figure 11-1. *Energy Density*

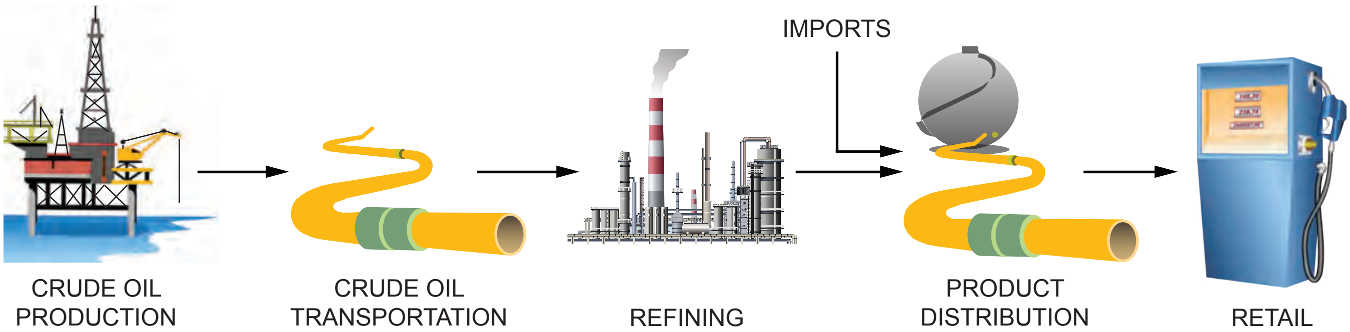


Figure 11-2. *Simplified View of Hydrocarbon Liquid Supply Chain*

reduced demand for highway vehicle fuels is also investigated.

Hydrocarbon Liquid Supply Chain

The United States has a comprehensive supply chain for the production, transportation, and processing of crude oil and distribution of refined petroleum products, as illustrated in Figure 11-2. The oil supply chain has been the primary energy pathway for transportation in the United States over the last 100 years and is constantly improving as new technologies are incorporated and in response to market factors. The U.S. supply chain continues to evolve as producing technology is applied to new unconventional oil plays. The scale of the supply chain is large and touches every corner of the country. For example, approximately 168,000 miles of pipeline combine to deliver crude oil from producing fields and import hubs to refineries and products from refineries to distribution terminals. This infrastructure combined with linkage to an even larger global supply chain provides efficiency and diversity. Due to ease of transport, hydrocarbon liquids can be shifted globally and regionally in response to market forces and disruptions.

U.S. transportation fuel demand is approximately 14 million barrels per day (MMB/D). According to the Energy Information Administration's (EIA) Annual Energy Outlook 2010 (AEO2010), gasoline for light-duty vehicles is 61% of the total. Although biofuel volumes have grown, petroleum-based hydrocarbons represent more than 95% of current supply on an energy content basis. A key trait of the hydrocarbon supply chain has been its improvement and adaptability over time. The hydrocarbon supply chain has a long record of employing technology to improve efficiency in finding, producing, and refining oil and in distributing products. These efficiencies occurred to meet growing customer demand for transportation fuels.

Hydrocarbon Liquid Supply Options

A major issue confronting hydrocarbon liquids is the development of new resources to meet increasing global demand and to replace declining production in older fields.

Conventional Oil and Natural Gas Liquids

Conventional oil is a liquid produced from wells drilled into underground reservoirs. Natural gas liquids (NGL) are gases at subsurface conditions and are a by-product of natural gas production. Both can be used to produce transportation fuels. A wide range of exploration, drilling, and production technologies continue to advance. These technologies enable identification of new resources and allow more costly resources to become economic. Improved drilling allows development of previously unavailable resources such as ultra-deep and shale reservoirs, as well as previously inaccessible offshore resources. Additionally deepwater production has grown significantly in the last few decades through an expanding array of advanced engineering structures such as tension-leg platforms, spars, floating production systems and subsea producing systems. The assessment of global oil production in the 2011 NPC *Prudent Development* study updates prior work done by the Council in the 2007 *Hard Truths* study. Both remain relevant today and the reader is referred to these studies for further information on supply and demand issues.

Unconventional Oil/Heavy Oil

Unconventional oils are petroleum liquids in accumulations that were not historically available to the supply chain due to low quality or restricted flow. Unconventional oil sources were traditionally more expensive than conventional resources but due to increasing oil price and technology improvements are becoming more competitive. Development of new unconventional oil plays is having a large impact on the U.S. supply chain leading to increased supply and investment. Unlike conventional oil, unconventional resources are most heavily concentrated in North and South America. North American unconventional resources include Canadian oil sands, Canadian heavy oil, U.S. oil sands, Canadian and U.S. tight oil, and U.S. oil shale. The Venezuela Orinoco Heavy Oil Belt is the predominant unconventional resource in South America. Application of technology is improving the prospects for development of unconventional oil, and such resources are playing an increasing role in North American oil production. The reader is referred to the 2011 NPC *Prudent Development* report for a more complete analysis on unconventional hydrocarbon supply and demand.

Domestic and North American Oil Production

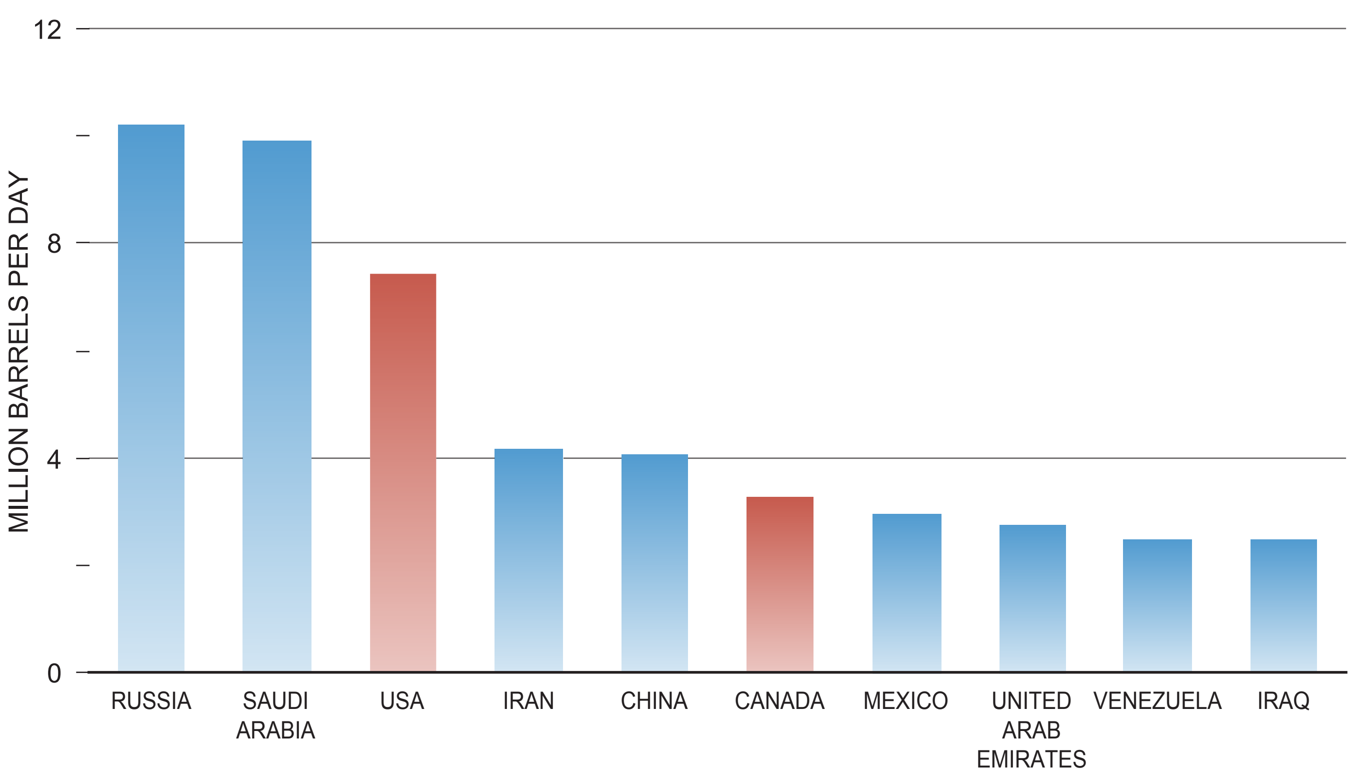
The United States is now the third largest daily producer after Saudi Arabia and Russia (see Figure 11-3).[1] Recently there has been an upturn in U.S. oil production, reversing a long declining trend (see Figure 11-4). This is primarily due to unconventional production. Canadian production has been on a long-term uptrend due to increased production of oil sands.

Supply Sources Outside of North America

Crude Oil Imports

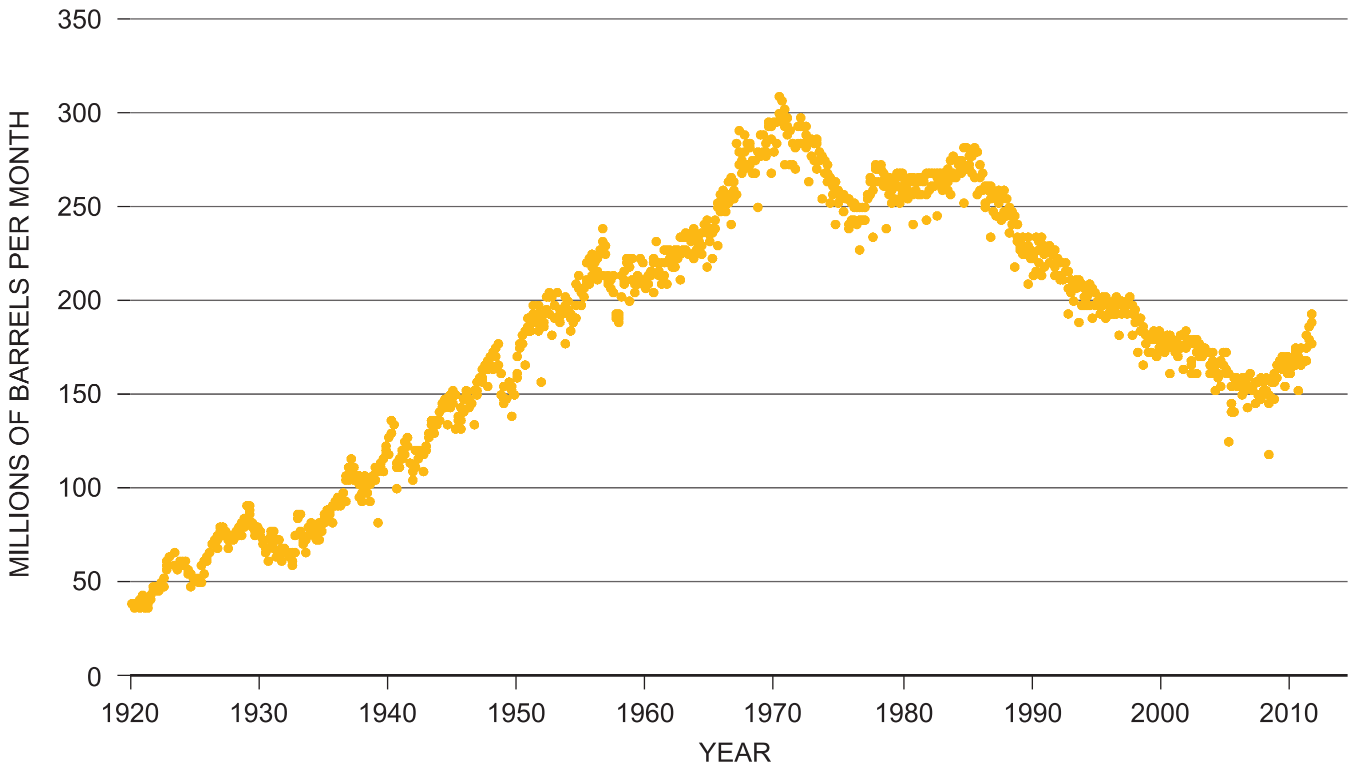
The United States imports hydrocarbon liquids including crude oil and refined products and blendstocks. Because there are so many different varieties and grades of crude oil, buyers and sellers have found it easier to refer to a limited

1 BP, *BP Statistical Review of World Energy,* June 2011.



Source: BP Statistical Review of World Energy.

Figure 11-3. *Main Oil Producing Countries*



Source: U.S. Energy Information Administration.

Figure 11-4. *Monthly U.S. Field Production of Crude Oil*

number of benchmark crude oils. Other varieties are then priced according to their quality relative to these benchmarks. Brent crude oil from the UK North Sea is generally accepted to be the world benchmark. In the Arabian Gulf, Dubai crude oil is used as a benchmark. In the United States, the benchmark is West Texas Intermediate (WTI). The Organization of Petroleum Exporting Countries (OPEC) has its own reference known as the OPEC basket price, which is an average of 15 different crude oils.

Crude oil is similar to other traded commodities that respond to supply and demand. Hydrocarbon liquid markets are global and deep. The global market is not entirely free as the OPEC cartel tries to influence market factors. The stated OPEC goal is to keep the basket price within a predetermined range by adjusting the amount of oil it provides. Macroeconomic factors affect the behavior of commodity prices. Studies stressing a structural approach to commodity price determination have found that two (demand-side) variables did well in explaining the variation of commodity prices: the state of the business cycle in industrial countries and the real exchange rate of the U.S. dollar.[2] Although commodity prices are subject to wide swings, they are self-correcting as prices send clear signals to producers and suppliers.

Large global markets and the fungible nature of crude oil and the hydrocarbon products allow for rapid and relatively low-cost responses to changes in market demand. A diverse supply promotes price competition and using the lowest cost/most efficient supplies first provides economic advantage to the world economy. Competing energy pathways, such as biofuels or gas-to-liquids must demonstrate their cost competitiveness versus conventional hydrocarbon liquid imports.

U.S. conventional crude oil supply has been produced continuously for 100 years. Over the past 20 years, U.S. oil demand has increased while U.S. oil production has decreased, leading to an increase in oil imports. Recently, however, this trend has

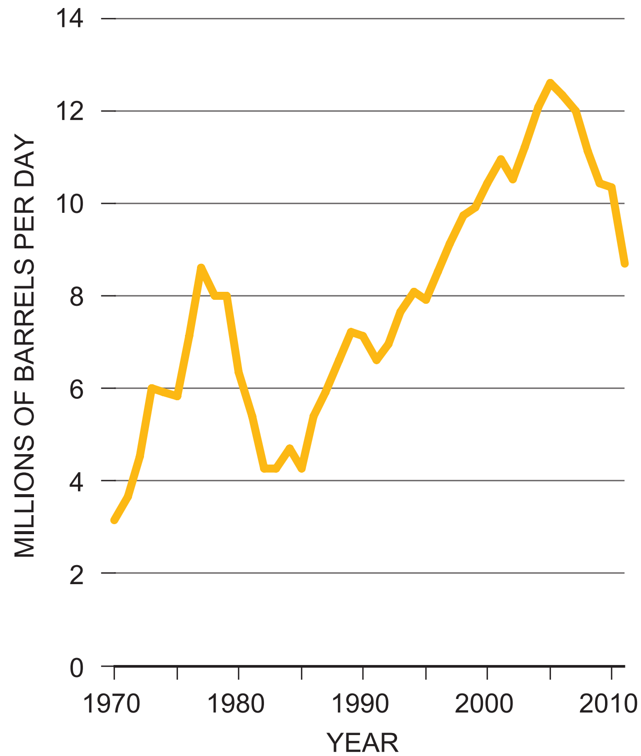
2 Eduardo Borensztein and Carmen M. Reinhart, *The Macroeconomic Determinants of Commodity Prices,* University of Maryland, June 1994.

reversed due to reduced demand and an increase in U.S. liquids production. Oil imports during 2011 averaged about 8.7 MMB/D, which is 3.8 MMB/D lower than the 2005 peak (see Figure 11-5). The sources of crude oil used in the United States are geographically diverse, with the predominant sources being domestic production, imports from Canada and Mexico, supplemented by Saudi Arabia, Iraq, Nigeria, and other sources (see Figure 11-6).[3] The role of Canada has been steadily increasing and is now the largest source of imported oil to the United States. This trend is forecast to continue as production from Canadian oil sands increases. Imports will continue, due to their relative cost, unless the United States discovers material new domestic fields or technology breakthroughs occur.

Product Imports

The United States is largely self-sufficient in terms of refinery production of transportation fuel. Product imports into the United States are dependent

3 Congressional Research Service, *The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies,* November 2010.



Source: U.S. Energy Information Administration.

Figure 11-5. *U.S. Annual Oil Imports*

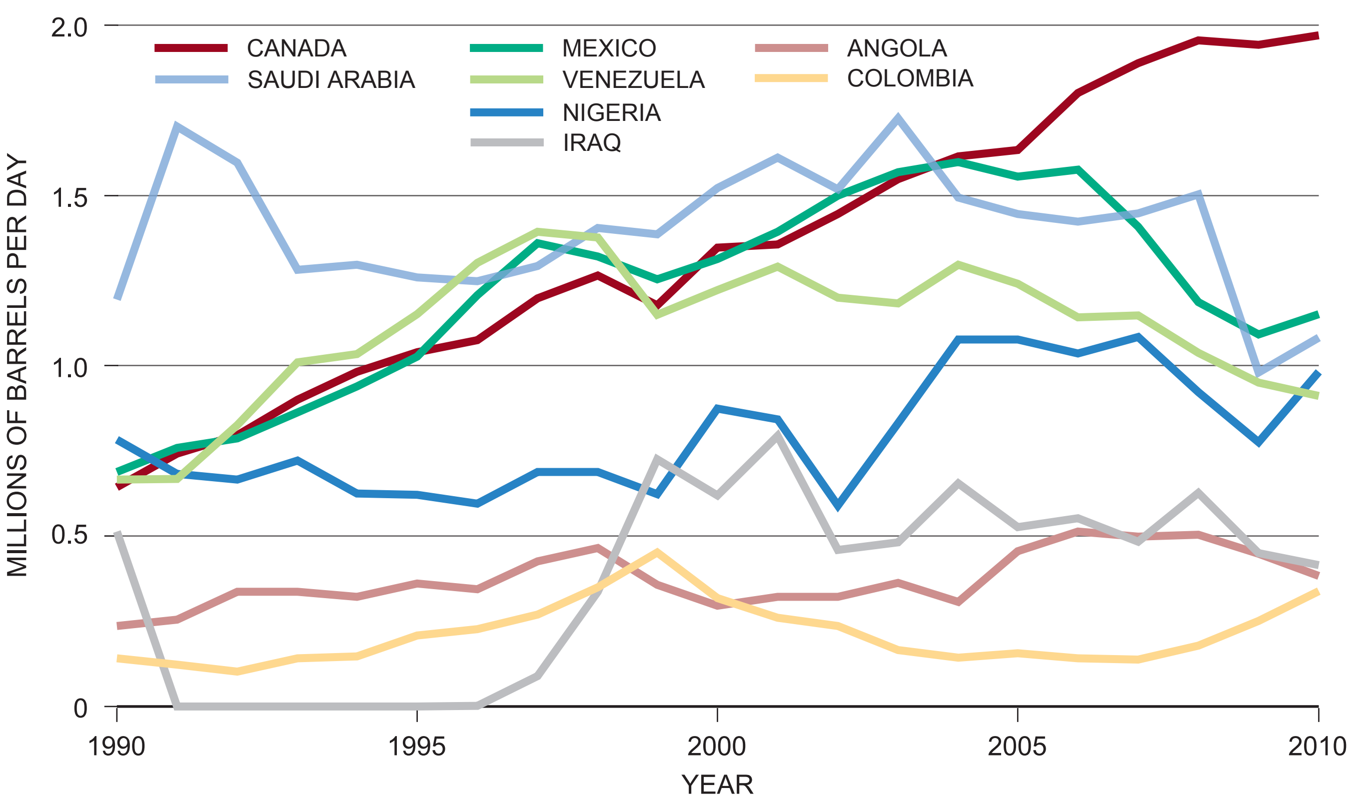


Figure 11-6. *U.S. Oil Imports by Source Country*

on the relative economics of domestic and foreign refining centers. The United States has historically been a net importer of gasoline and other products, generally importing less than 10% of its refined products need. Recently, however, the United States has become a net exporter of petroleum products, as shown by negative net imports in Figure 11-7. The competitiveness of U.S. refining, lower U.S. demand for transportation fuels, and strong distillate demand outside the United States have been the biggest factors. The shift highlights the flexibility of the U.S. refining industry to respond to changes in market demand.

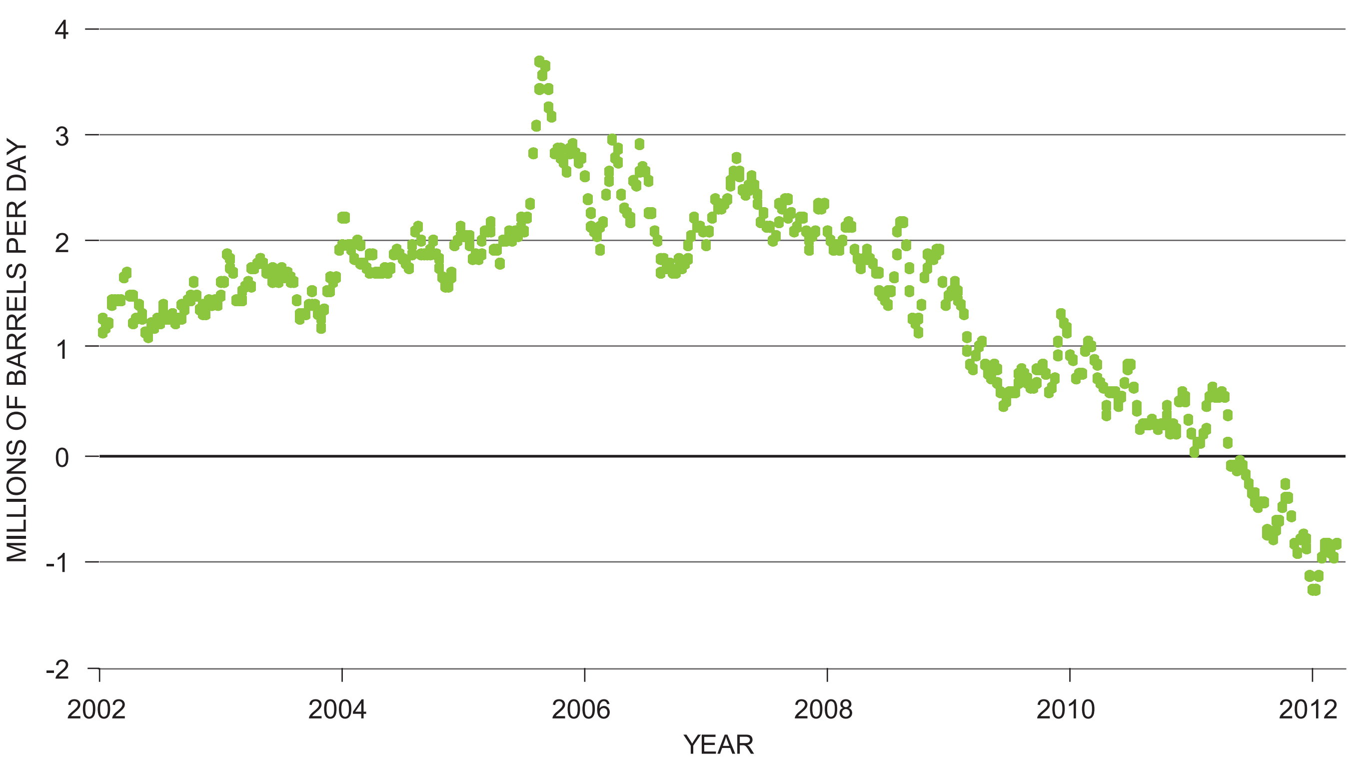
Biofuels are a competing but complementary supply chain to hydrocarbon liquids that intersects at the hydrocarbon product terminal. The ability to incorporate biofuels provides additional supply diversity. Biofuels have been subsidized in the United States for many years and have been recently mandated in two rounds of energy legislation via the renewable fuel standard (RFS) illustrated in Figure 11-8. The biofuel categories under RFS are defined based on GHG performance or feedstock source. Currently almost all gasoline in the United States contains 10% corn ethanol while biodiesel makes up roughly 2% of U.S. diesel. RFS mandates increasing use of biofuels in the future.

Other Potential Sources of Hydrocarbon Liquids

Liquefied petroleum gas (LPG) and liquids produced from gas and coal provide alternative sources of liquid fuels. Non-LPG pathways are generally more costly and not widely used but offer a future potential for domestic production based on substantial U.S. coal and natural gas reserves.

LPG

LPG is mainly propane with small amounts of other C3 and C4 hydrocarbons. LPG is a by-product of natural gas processing and crude oil refining. LPG is a gas at atmospheric conditions and is stored in liquid form in pressurized tanks at approximately 2–20 bars (30–300 psi) depending on propane/butane composition and storage temperature. LPG is widely available in the United States and is used



Source: U.S. Energy Information Administration.

Figure 11-7. *U.S. Net Imports of Total Petroleum Products (Four-Week Running Average)*

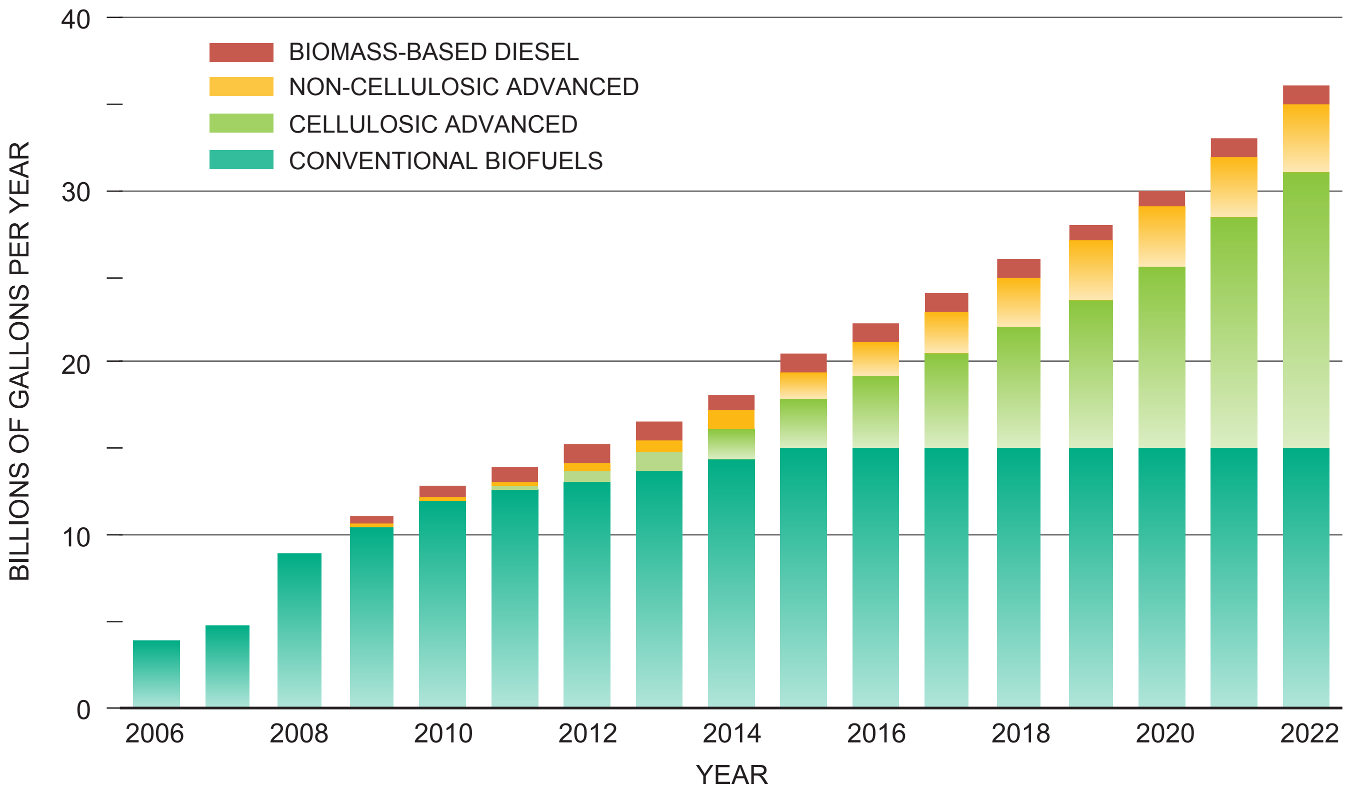


Figure 11-8. *U.S. Biofuels Renewable Fuel Standard*

for many purposes. Relatively small volumes have been used as transportation fuels. Globally over 13 million vehicles used LPG in 2008, with annual use of over 7 billion U.S. gallons.

LPG fuel tanks for vehicles are heavier than gasoline or distillate, but lighter than compressed natural gas (CNG). LPG has lower energy density compared to gasoline, but higher than CNG and provides intermediate vehicle range. LPG vehicles are more expensive (around $1,000–$2,000) than equivalent gasoline-powered vehicles due mainly to the extra cost for fuel tanks.

LPG is used in spark-ignition engines, generally in vehicles that have been converted from gasoline use. LPG's high octane rating (around 105) means that compression ratio can be increased without causing pre-ignition. Currently there is no original equipment manufacturer (OEM) production of LPG vehicles, only conversions from gasoline vehicles.

LPG has GHG emissions that are about 10% lower than gasoline and similar to CNG. In a purpose-built vehicle, LPG can offer very low emission characteristics for non-GHG pollutants.

LPG use as a transportation fuel is limited by LPG supply, infrastructure, and competing uses for LPG. With the increase in shale gas production in the United States, additional volumes may become available as a by-product of gas production. In its 2011 Annual Energy Outlook (AEO2011), the EIA forecast an increase in production of natural gas liquids in the United States of 0.9 MMB/D by 2035. A portion of this volume could potentially allow increased LPG volumes in transportation.

Gas-to-Liquids (GTL)

Gas-to-liquids is a general term for processes that convert natural gas to hydrocarbon liquids. There are several GTL processes, and the one illustrated in Figure 11-9 uses Fischer-Tropsch (FT) technology. This process first converts natural gas to synthesis gas, which is a mixture of carbon monoxide and hydrogen. The FT process converts this synthesis gas into mainly long-chain paraffin hydrocarbons and distillates that are cracked into conventional transportation fuels. The process has a high distillate yield and also produces a lighter fraction that can be used as a gasoline blending component or as a feedstock for chemicals production. The process energy efficiency in converting natural gas to liquid products is 58–65%.[4] There are GTL plants operating in Malaysia, South Africa, and Qatar, with additional plants under construction in Qatar and Nigeria.

Natural gas can also be converted to other transportation fuels such as methanol, dimethyl ether (DME), or methanol-to-gasoline (MTG). Both methanol and DME require significant fueling and vehicle infrastructure investments, which makes them less attractive than other liquid fuels produced from natural gas. Commercial production of methanol is well established. Methanol can be used in vehicles as a low-level blend with gasoline. It has higher vapor pressure than gasoline and is less water tolerant, which may make it less suitable for use in a low-level blend. Methanol can also be used as a high-level blend with gasoline, but requires more extensive vehicle upgrading for use in a flexible-fueled-vehicle than ethanol. Since U.S. gasoline fuels currently contain up to 10% ethanol, addition of methanol would result in excessive fuel oxygen content. Therefore methanol would likely displace ethanol in the gasoline blend. DME has high cetane and can substitute for diesel in compression ignition engines but would require significant vehicle and distribution infrastructure addition due to high vapor pressure (similar to LPG) and use of pressurized tanks. Methanol and DME are intermediaries in the MTG process, which results in high octane gasoline and LPG. FT diesel and MTG have an advantage in producing hydrocarbon liquids that can be readily incorporated into the existing infrastructure as finished fuels or blendstocks.

4 Carmine L. Iandoli and Signe Kjelstrup, "Exergy Analysis of a GTL Process Based on Low-Temperature Slurry F-T Reactor Technology with a Cobalt Catalyst," *Energy Fuels* 21, no. 4 (2007): pages 2317-2324.

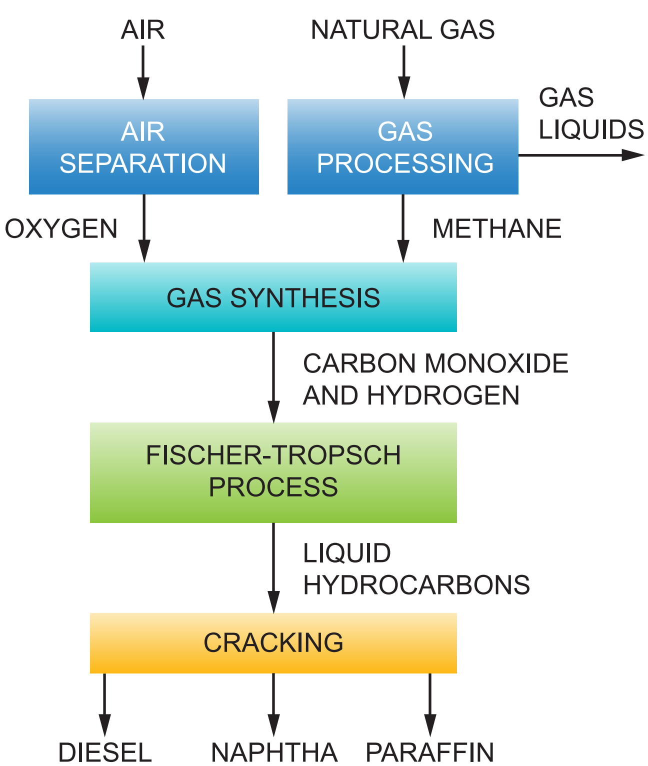
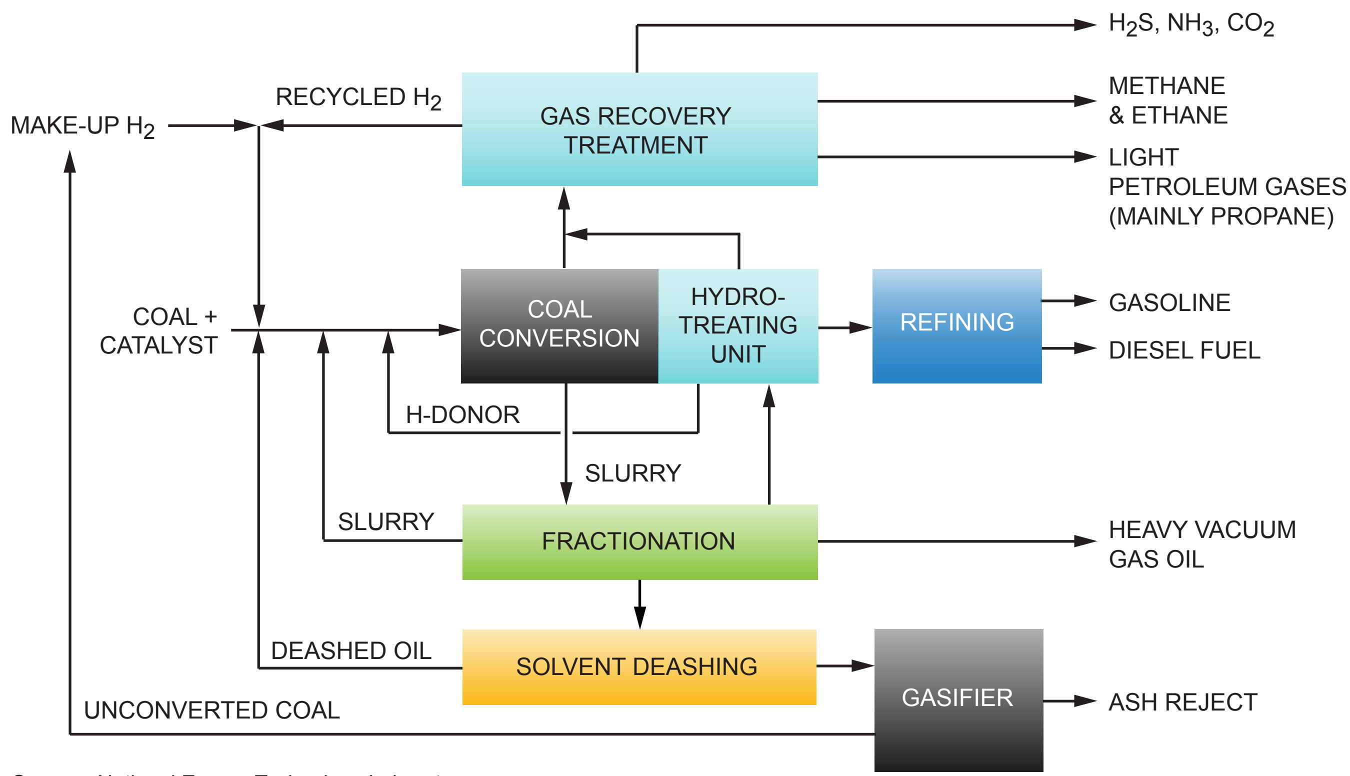


***Figure 11-9.** Simplified Process Flow of Gas-to-Liquids*

The commercial viability of these technologies is contingent on a number of variables, such as competing energy prices (a low gas price relative to oil benefits gas conversion), risk threshold, capital cost and return on capital requirements. Gas conversion may hold long-term promise due to the growing extent of the "shale gas" resource in the United States. Potential future production and economic comparisons are discussed later in this chapter.

Coal-to-Liquids (CTL)

Alternative hydrocarbon liquids can also be derived from coal. There are two main technologies available for coal conversion: indirect and direct liquefaction. Indirect liquefaction is similar to GTL. Coal is transformed into synthesis gas and then converted to liquid hydrocarbon fuels using the processes described above (FT diesel, MTG, methanol, DME). The direct liquefaction process shown in Figure 11-10 involves addition of hydrogen to coal to increase the hydrogen-to-carbon ratio from ~0.8 in coal to ~1.8 typical of various petroleum products. The potential for CTL is contingent on a number of factors: coal and petroleum prices, risk threshold, capital cost, and return on capital requirements. Coal is generally the least expensive fossil fuel but capital costs for CTL are higher than GTL due to extra steps needed to convert solid coal to synthesis gas. There are commercial CTL plants in China and South Africa, but no commercial plants in the United States even though the United States



Source: National Energy Technology Laboratory.

Figure 11-10. *Simplified Process Flow of Coal to Liquids*

has a significant coal resource. The relative economics of this technology are covered in a subsequent discussion.

Combined Coal- and Biomass-to-Liquids (CBTL)

In this process, mixtures of coal and biomass are converted into liquid transportation fuels. The plant operates like a CTL plant except that biomass is gasified in addition to the coal. Coal provides the necessary scale, which improves economics compared to stand-alone biomass-to-liquids processes. Consolidating and transporting biomass is expensive, so the biomass fraction is generally limited to 15% of total input.

Oil Shale

U.S. oil shale represents one of the largest unconventional hydrocarbon deposits in the world, with an estimated two trillion barrels of oil-in-place. The best deposits are found in the Green River Formation in Colorado, Utah, and Wyoming. Since there is no commercial production, it is difficult to estimate potential resources. "Oil shale" is a misnomer as the hydrocarbon in place is not present as oil. It is kerogen, an organic precursor of oil that has not yet undergone the full transformation to oil and gas. In order for the resource to be useful, the kerogen must be transformed into liquid petroleum by retorting processes that use heat and pressure (see Figure 11-11). Although the resource is large, the NPC does not expect it to play a major role in U.S. production over the next 25 years. Investigation of production techniques at pilot scale is required to address economic and environmental issues associated with oil shale development.

Supply Cost Curves

Supply curves describe the amount of resource of a particular type that is available relative to the costs required to develop that resource. The global supply curve for hydrocarbon liquids developed by the International Energy Agency's (IEA) World Energy Outlook 2008 is shown in Figure 11-12. Production cost uncertainty is largest for the unconventional resources at the center and right of the figure.

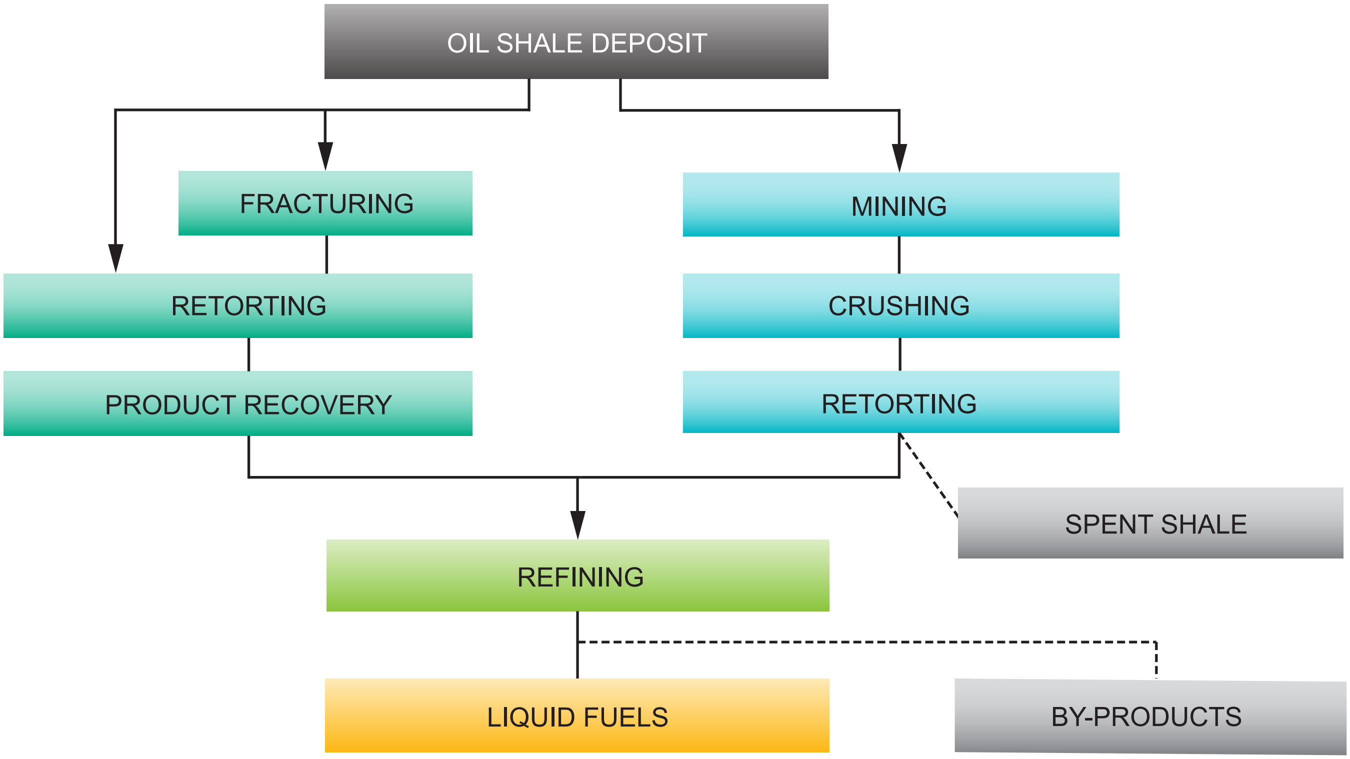
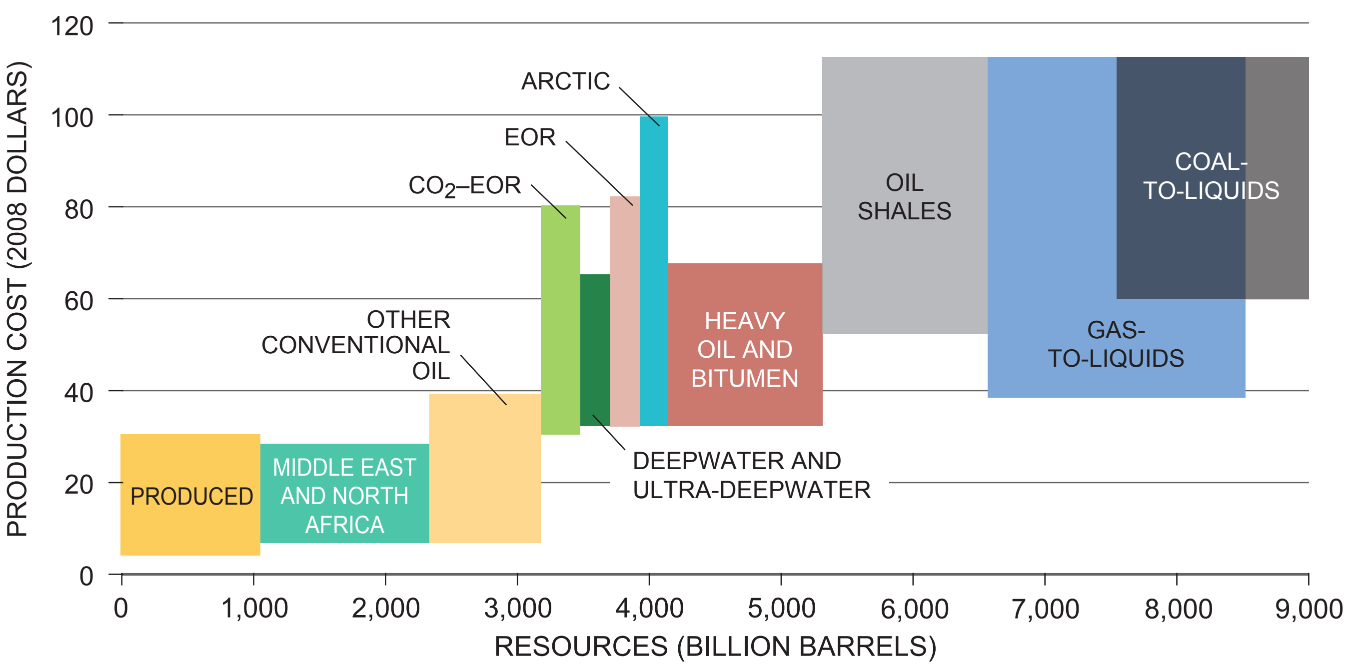


Figure 11-11. *Simplified Process Flow of Oil Shale*



Note: The figure shows the availability of oil resources as a function of the estimated production cost. Cost associated with CO_2 emissions is not included. There is also a significant uncertainty on oil shales production cost as the technology is not yet commercial. The shading and overlapping of the gas-to-liquids and coal-to-liquids segments indicates the range of uncertainty surrounding the size of these resources, with 2.4 trillion shown as a best estimate of the likely total potential for the two combined.

Source: International Energy Agency, *World Energy Outlook 2008*, © OECD/IEA 2008.

Figure 11-12. *Long-Term Oil-Supply Cost Curve*

The amount of hydrocarbon resources that can be brought to market may be as high as 9 trillion barrels, compared to roughly 1 trillion barrels that have already been produced. The lowest cost conventional production is in the Middle East and North Africa. Oil shales, GTL, and CTL represent the most costly supply.

The hydrocarbon liquid supply curve provides a benchmark for competing fuel technologies. Costs of oil shale and XTL (gas-, coal-, and biomass-to-liquids) may be competitive with potential fuel pathway alternatives in the center of the supply curve. The abundance of hydrocarbon liquid resources combined with the existing infrastructure of refining, pipelines, and dispensing makes hydrocarbon liquids a formidable incumbent in the future of transportation fuels.

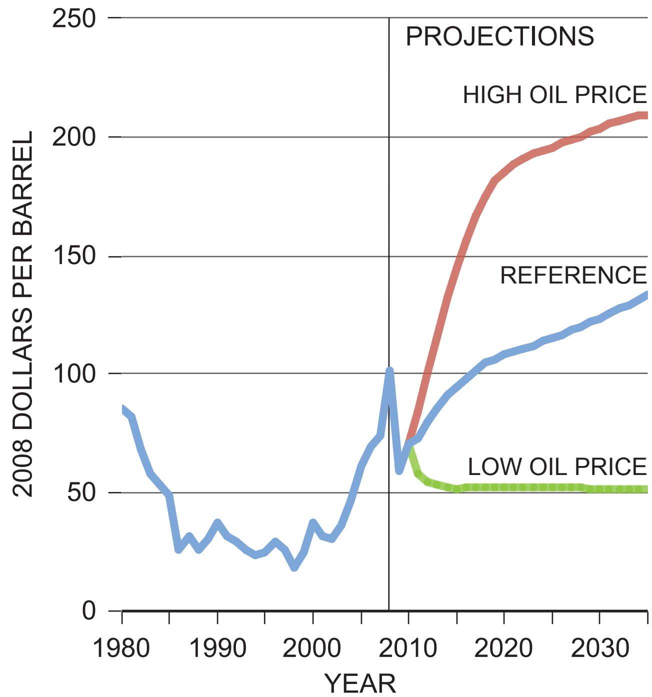
FUTURE PETROLEUM SUPPLY AND DEMAND

Supply and demand outlooks are published annually by the EIA and the IEA. Additionally, the National Petroleum Council conducted a study of North American resources, titled *Prudent Development: Realizing the Potential for North America's Abundant Natural Gas and Oil Resources,* which was published in 2011. The NPC study included forecasts from EIA and IEA as well as a wide range of industry organizations and consultants to develop low, medium, and high scenarios for North American oil production.

There is considerable uncertainty in projecting future behavior of energy markets, which increases with the length of the outlook. Outlooks are based on a set of assumptions regarding economic growth, oil prices, government action, and other factors. The reader is referred to the NPC *Prudent Development* report for more full discussion on petroleum supply and demand.

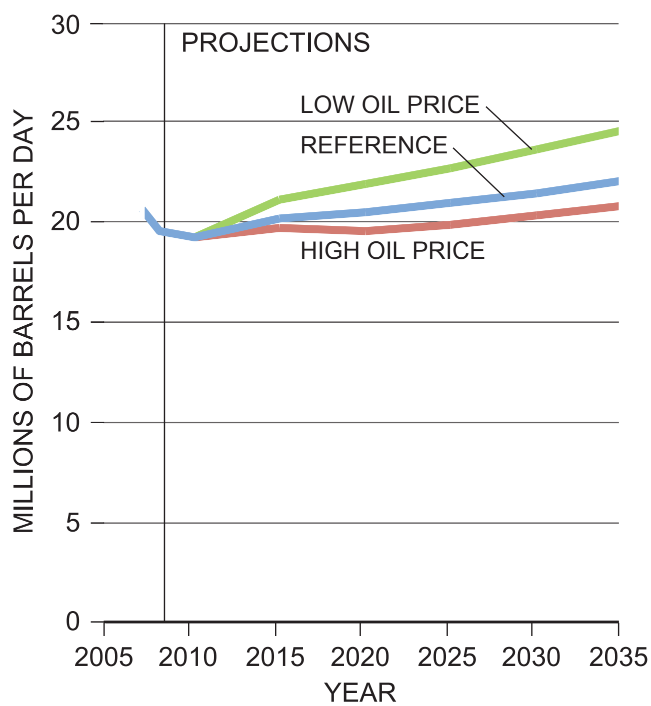
Price Assumptions

AEO2010 oil price cases, shown in Figures 11-13 through 11-16, represent alternative, internally consistent scenarios. In general, EIA and IEA price scenarios are similar. Demand, production, and imports of liquid fuels are all sensitive to the assumed long-term path of oil prices. Demand is reduced in the high price scenario while domestic



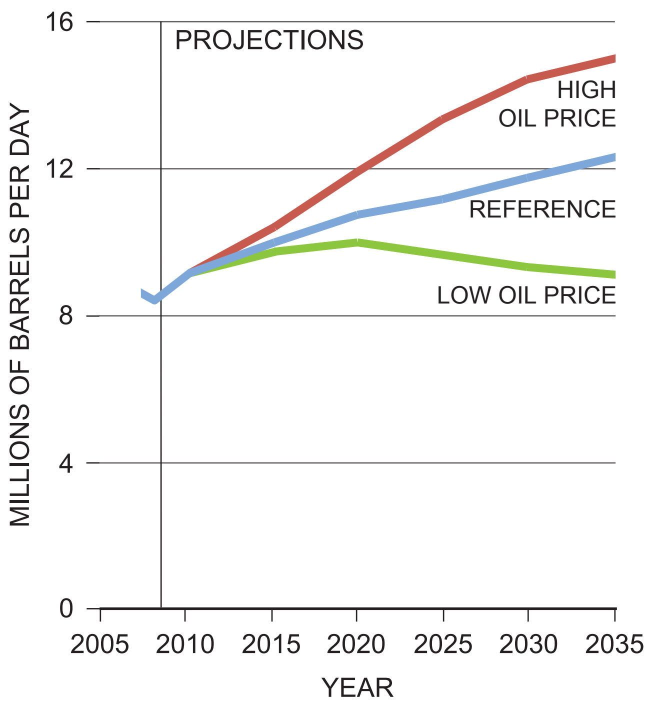
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2010.*

***Figure 11-13.** Liquids Outlook over Price Scenarios in AEO2010 – Average Annual World Oil Prices*



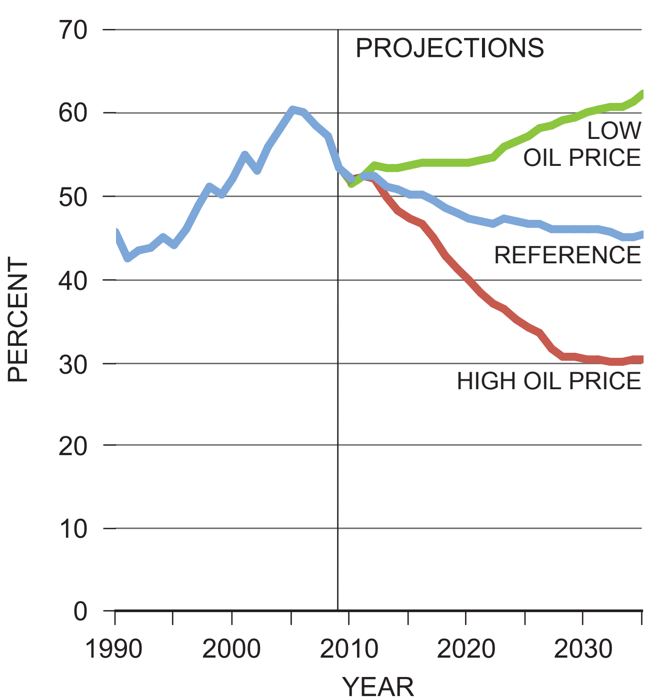
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2010.*

***Figure 11-14.** Liquids Outlook over Price Scenarios in AEO2010 – U.S. Liquids Consumption*



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2010*.

Figure 11-15. *Liquids Outlook over Price Scenarios in AEO2010 – U.S. Liquids Production*



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2010*.

Figure 11-16. *Liquids Outlook over Price Scenarios in AEO2010 – U.S. Liquids Imports*

production increases, thereby lowering crude imports. U.S. supply is more sensitive to assumed prices than demand.

Global Supply and Demand

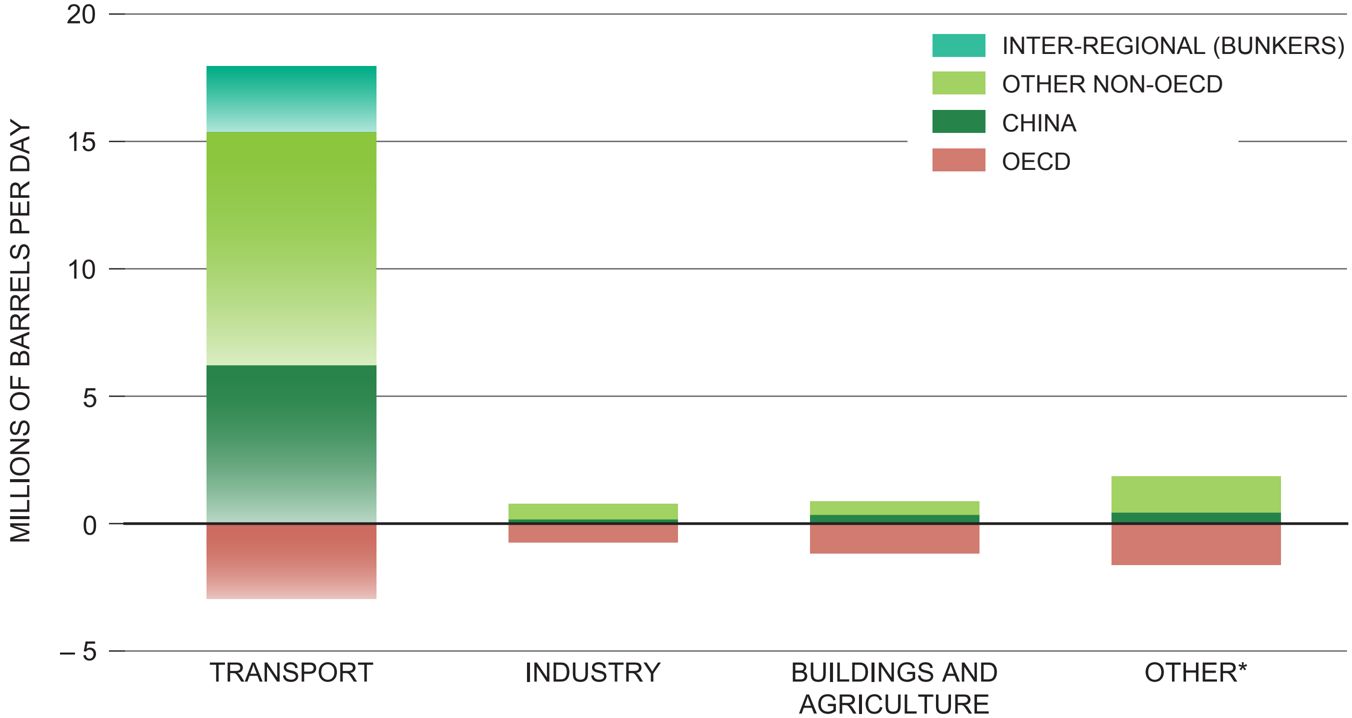
According to the IEA, future demand growth for hydrocarbon liquids is focused in the developing world, where large increases in end-user demand overwhelm efficiency gains (see Figure 11-17). China alone accounts for almost half of the projected growth in transportation-related oil demand over the next 25 years. In contrast, use of oil in mature OECD countries is forecast to decrease as increasing efficiency outweighs relatively slow growth in end-user demand. Meeting the increase in non-OECD oil demand is a major challenge for the global hydrocarbon liquid supply chain.

More recent EIA and IEA outlooks have tended to forecast lower global oil production in future years. This reflects difficulty in increasing conventional production combined with reduced demand projections due to higher prices, slower economic growth, and increased regulation of vehicle fuel economy. Unconventional liquids play a growing role in all global outlooks. Figure 11-18 from the AEO2010 outlook illustrates the potential of unconventional liquid supply.

North American Oil Supply

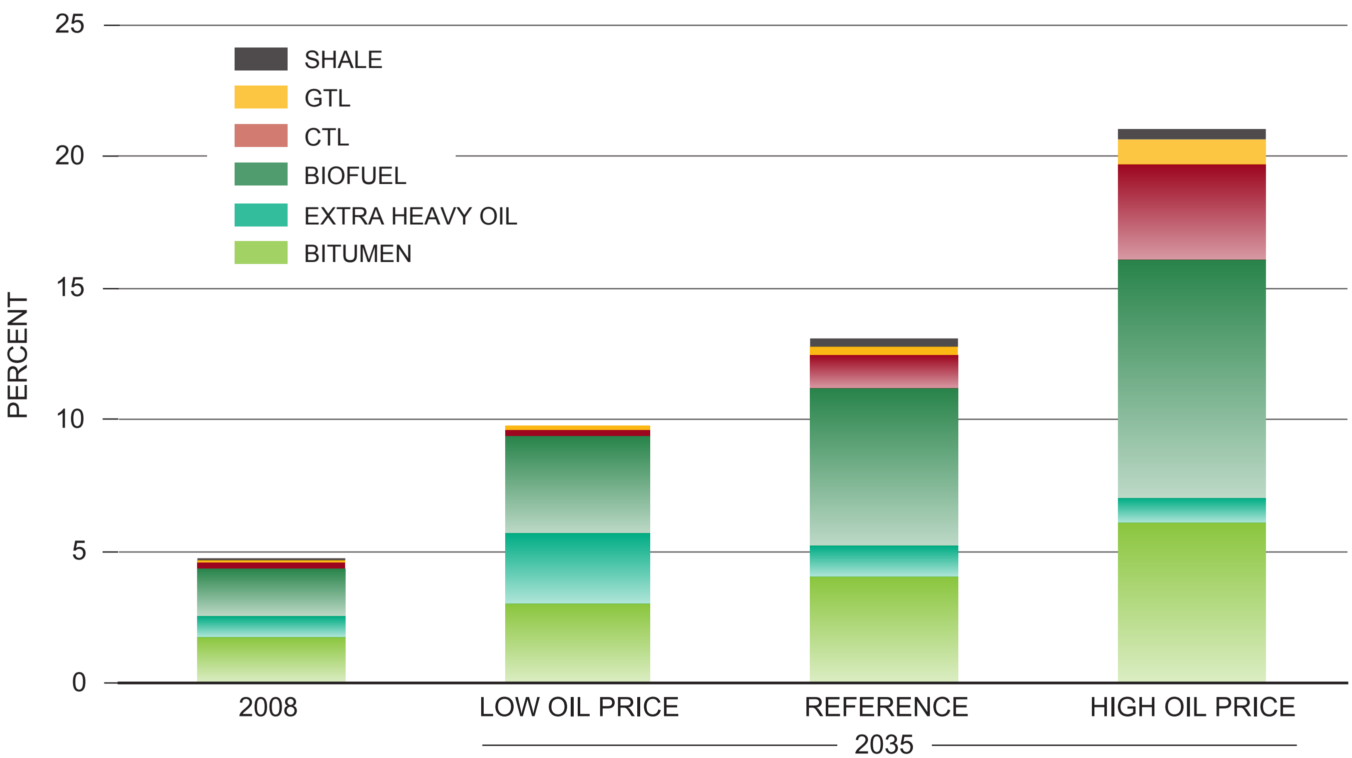
Oil production forecasts for the United States and North America have become more positive in recent years. There has been a steady upward revision in projected future U.S. oil production as new unconventional oil plays continue to develop. Long-term growth in oil production can come from several existing and new North American supply sources including tight oil, offshore oil, Arctic oil, oil sands and oil shale. The AEO2011 calls for U.S. and North American production to increase through 2035. This is consistent with the NPC *Prudent Development* study, which also indicates that North American production could potentially double by 2035 in a high-side scenario as shown in Figure 11-19. Large increases in Canadian oil production are expected due to increases in oil sands production.

The NPC *Prudent Development* study also categorized U.S. shale gas as a potential game changer.



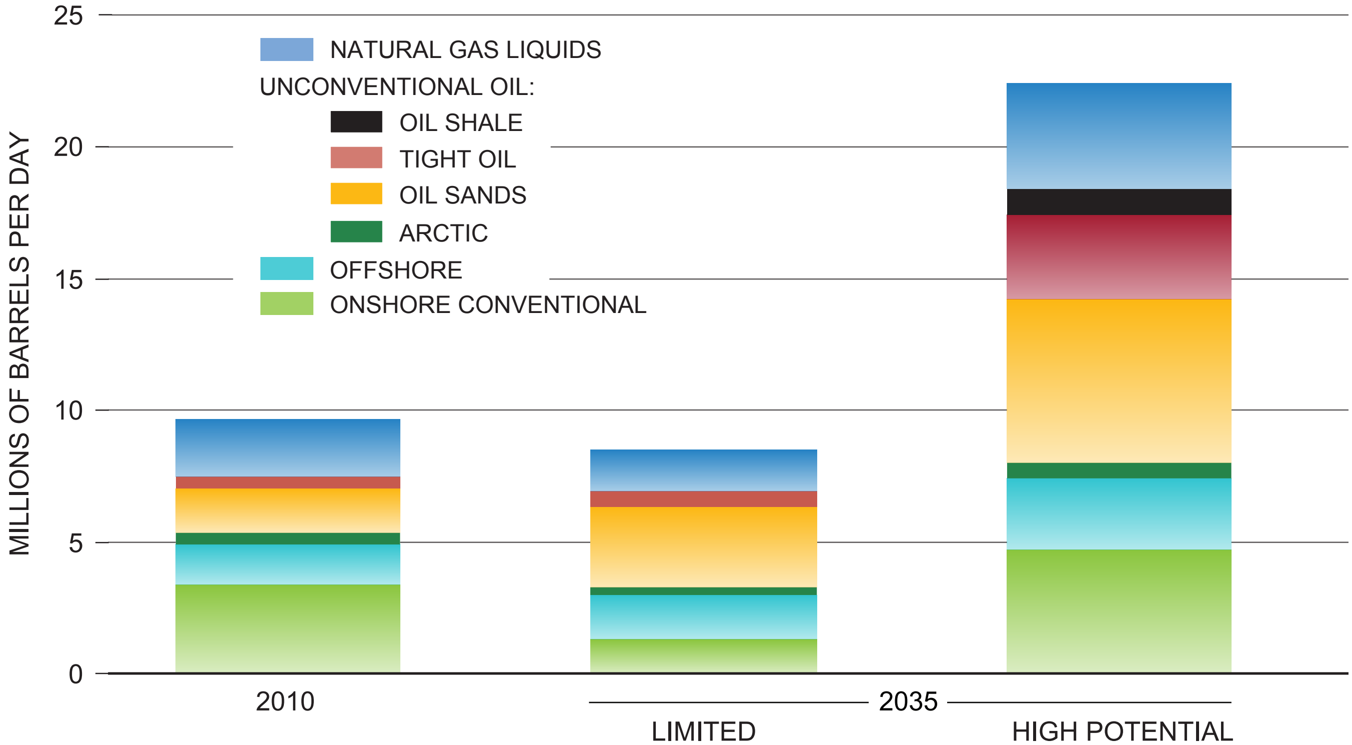
* Includes power generation, other energy sector, and non-energy use.
Source: International Energy Agency, *World Energy Outlook 2010*, © OECD/IEA 2010.

Figure 11-17. *Change in Oil Demand from 2010 to 2035 by Sector and Region*



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2010.*

Figure 11-18. *Unconventional Hydrocarbon Liquids in AEO2010 Oil Price Cases*



Notes: The oil supply bars for 2035 represent the range of potential supply from each of the individual supply sources and types considered in this study. The specific factors that may constrain or enable development and production can be different for each supply type, but include such factors as whether access is enabled, infrastructure is developed, appropriate technology research and development is sustained, an appropriate regulatory framework is in place, and environmental performance is maintained.

In 2010, oil demand for the U.S. and Canada combined was 22.45 million barrels per day. Thus, even in the high potential scenario, 2035 supply is lower than 2010 demand, implying a continued need for oil imports and participation in global trade.

Source: Historical data from Energy Information Administration and National Energy Board of Canada. Projections from National Petroleum Council, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, 2011.

Figure 11-19. *U.S. and Canadian Oil Production Projections*

Increased natural gas production is also expected to result in increased production of natural gas liquids. LPG, butane, and natural gasoline are all potential transportation fuels either as blendstocks or in specialized vehicles.

Supply and Demand Balance and Imports

As shown in Figure 11-20, the EIA forecasts that U.S. liquid fuel use remains near its present level through 2035 (AEO2012 Early Release). Oil imports are projected to decrease due to increases in U.S. petroleum and biofuel supply, which outpaces the small increase in demand. The EIA outlook does not include proposed light-duty vehicle CAFE (corporate average fuel economy) and GHG standards, which would reduce light-duty demand and further reduce petroleum imports.

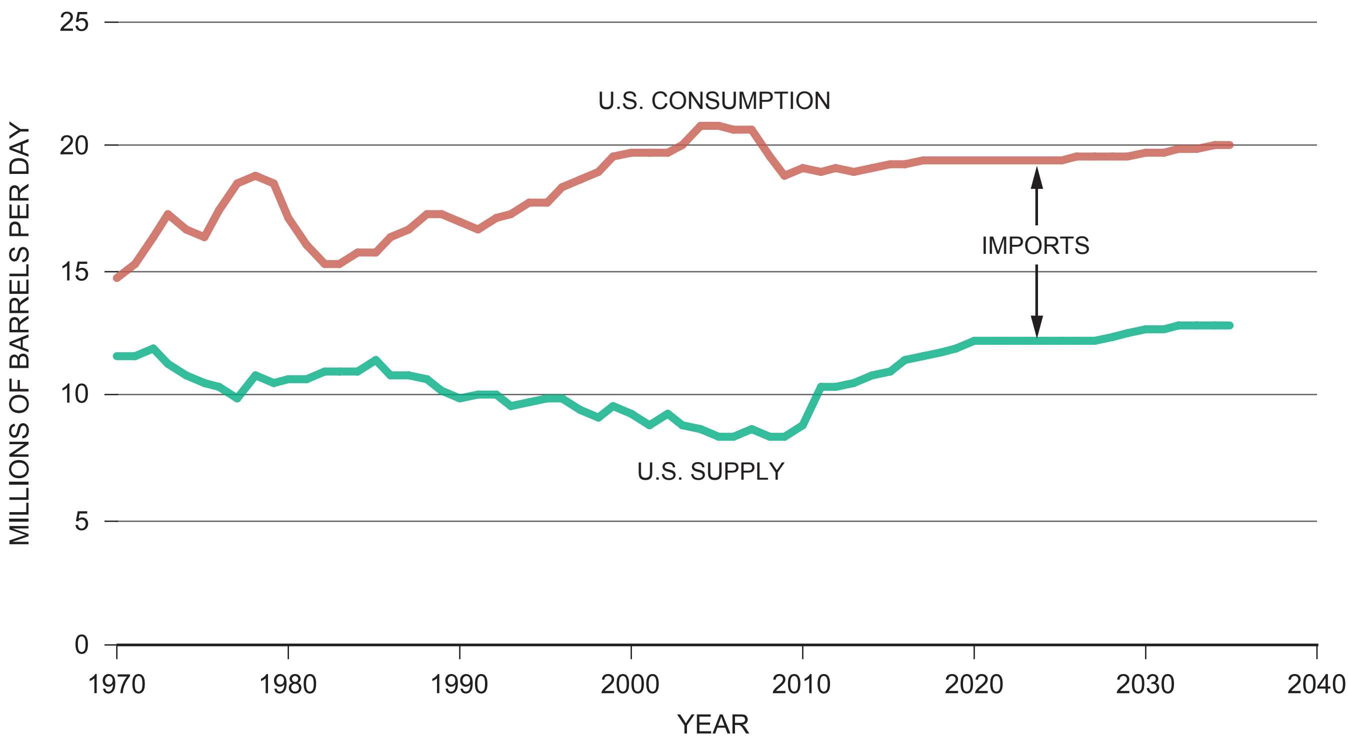
Transportation Demand

Additional detail in transportation fuel demand is shown in Figure 11-21. The EIA projects decreasing gasoline demand to 2035 while diesel and jet fuel are forecast to increase slightly. The role of biofuels also increases.

REFINING

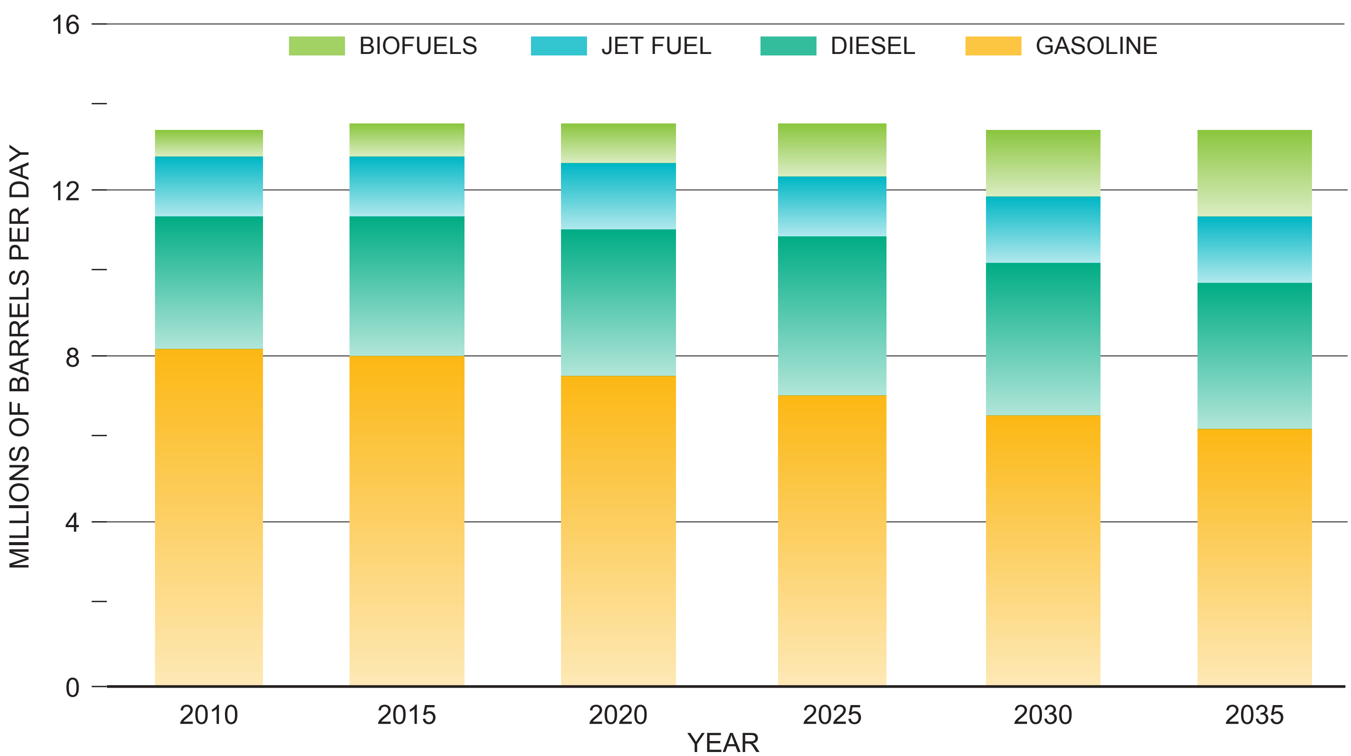
Refining Technology

U.S. refineries are some of the most highly complex in the world, producing high-quality transportation fuels and undergoing continual upgrades to



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2012 Early Release*.

Figure 11-20. *Liquid Supply and Demand Balance in AEO2012 Early Release*



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2012 Early Release*.

Figure 11-21. *Transportation Fuel Projection in AEO 2012 Early Release* improve efficiency, product quality, and feedstock utilization.

Background. Liquid hydrocarbon fuels must have known and consistent properties for specific types of combustion systems. Manufacturing products at very large scale and at the molecular level makes refining unique and requires a wide range of technologies.

In addition to transportation fuels, the refining sector provides a number of products that play an essential role in the economy.[5]

- **Petrochemicals.** The refining sector is closely integrated with petrochemicals. The exchange of feedstocks and products between refineries and petrochemicals plants improves competitiveness in industrial clusters such as the U.S. Gulf Coast.

- **Industrial Materials.** The refining industry also plays a role in other industrial value chains: asphalt for road construction and roofing, lubricants for use in transportation and industry, high-quality petroleum coke for use in the metals industry, waxes, solvents, and other products. Many of these specialty products are difficult to manufacture and highly specialized.

Refining Processes. Refinery processes can be divided into six categories:

1. **Separation of Crude Oil.** Separates crude into materials with narrower boiling range.

2. **Restructuring Hydrocarbon Molecules.** Restructuring processes change molecular size or structure in a variety of ways. Some processes break apart bigger molecules while others combine small gas molecules to make liquids, and others change molecular structure. Examples are listed in Table 11-1.

3. **Treating.** Treating processes are used to remove contaminants such as sulfur, nitrogen, and heavy metals, which are present in crude oil, from various streams.

4. **Blending Hydrocarbon Products.** Many streams are blended to make gasoline and other hydrocarbon products.

5. **Auxiliary Operating Facilities.** These units support operation of the primary processing units by providing inputs like hydrogen or processing by-products.

6. **Refinery Off-Site Facilities.** These facilities provide utilities, logistics, and safety.

Table 11-1 shows the six categories of refinery processes. A detailed discussion is in Appendix C, "History and Fundamentals of Refining Operations," of the June 2000 NPC report *U.S. Petroleum Refining*.

Refinery Schematic. Refinery units are carefully integrated to provide high product yield with minimum waste and energy consumption. While each refinery is unique, refineries can be classified into three broad groups based on processing complexity, which in turn determines ability to convert crude oil into lighter transportation fuels. Hydro-skimming refineries contain a crude oil distillation unit (CDU) and naphtha reformers, which increase gasoline octane and produce hydrogen that can be used in desulfurization units. Medium conversion, or cracking, refineries have the same elements plus fluid catalytic cracking (FCC) and alkylation units, which allows greater conversion of crude oil to transportation fuels. High conversion refineries also have cokers, hydrocrackers, and hydrogen plants, as shown in Figure 11-22. High conversion refineries are common in the United States and convert large proportions of crude oil feedstock to transportation fuels and have greater ability to upgrade heavy or sour crude oil. Integration and optimization becomes more important as the number of process streams increase. Modern refineries contain networks of sensors, logic devices, and computers to control and optimize the complex reactions and flows within and among process and for logistics and planning of crude oil inputs and product output.

Industry State

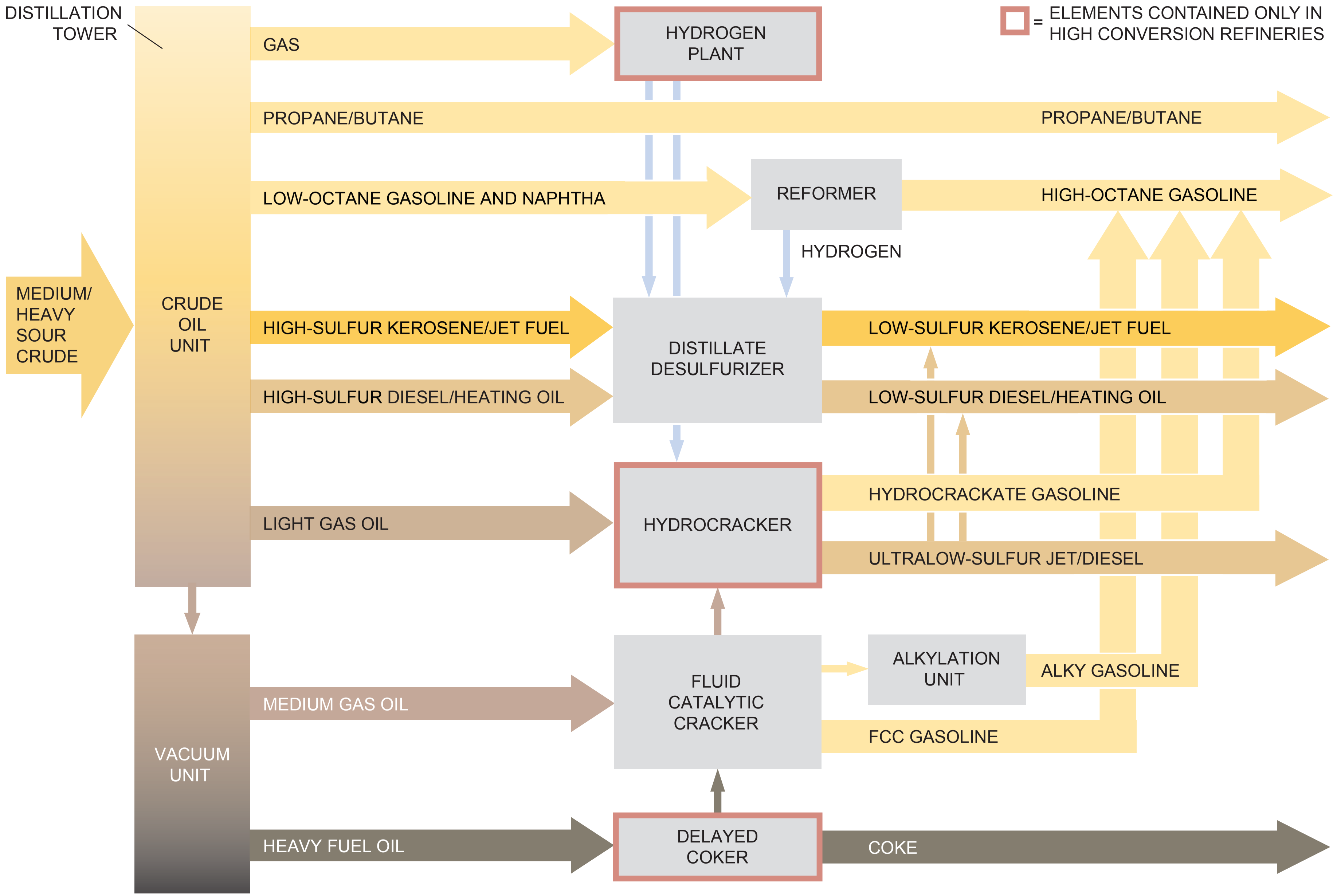
Geographic Distribution. Refining capacity is generally based on CDU capacity with units of thousand barrels per day. The majority of U.S. refineries are geographically concentrated into several large refining centers, called Petroleum

5 Europia, White Paper on EU Refining, 2011.

Separation	Molecule Restructuring	Treating	Product Blending	Auxiliaries	Off-Sites
Desalting & Dewatering Atmospheric Distillation Vacuum Distillation	Conversion • Thermal Cracking – Steam Cracking – Visbreaking – Coking • Catalytic Cracking – Fluid Catalytic Cracking Hydrocracking Combining • Alkylation • Polymerization Modifying • Catalytic Reforming • Isomerization • Ethers Manu-facture	Hydroprocessing Amine Treating Sweetening Solvent Extraction Bitumen Production Wax, Lube, and Grease Manufacturing	Motor Gasoline • Reformate • Alkylate • Straight-Run Gasoline • FCC Gasoline • Coker Gasoline • Butane • Oxygenates • Additives Jet Fuel • Kerosene • Straight-Run Virgin Distillates • Naphtha Diesel Fuel • Virgin Distillates • Cycle Oil Distillate Fuel Oil Residual Fuels Lubes • Refined Base Stock • Additives Asphalt • Residual Base Stock • Additives Liquefied Petroleum Gas (LPG) Petrochemical Feedstocks • Benzene • Toluene • Ethane • Ethylene • Propane • Propylene • Naphtha • Gas Oils Petroleum Solvents	Hydrogen Production Light Ends Recovery Acid Gas Treating Sour Water Stripping Sulfur Recovery Tail Gas Treating Wastewater Treatment	Storage Tanks Steam Generation Power Generation Flare & Blowdown Systems Cooling Water Systems Receiving & Distribution Systems Refinery Fire Control Systems Garages Maintenance Shops Storehouses Laboratories Necessary Office Buildings

Source: Appendix C, "History and Fundamentals of Refining Operations," in NPC report *U.S. Petroleum Refining,* June 2000.

Table 11-1. *Six Categories of Refinery Processes*



Source: Valero (website), Industry Fundamentals, "Basics of Refining and Coking," January 2011, http://www.valero.com/InvestorRelations/Pages/IndustryFundamentals.aspx.

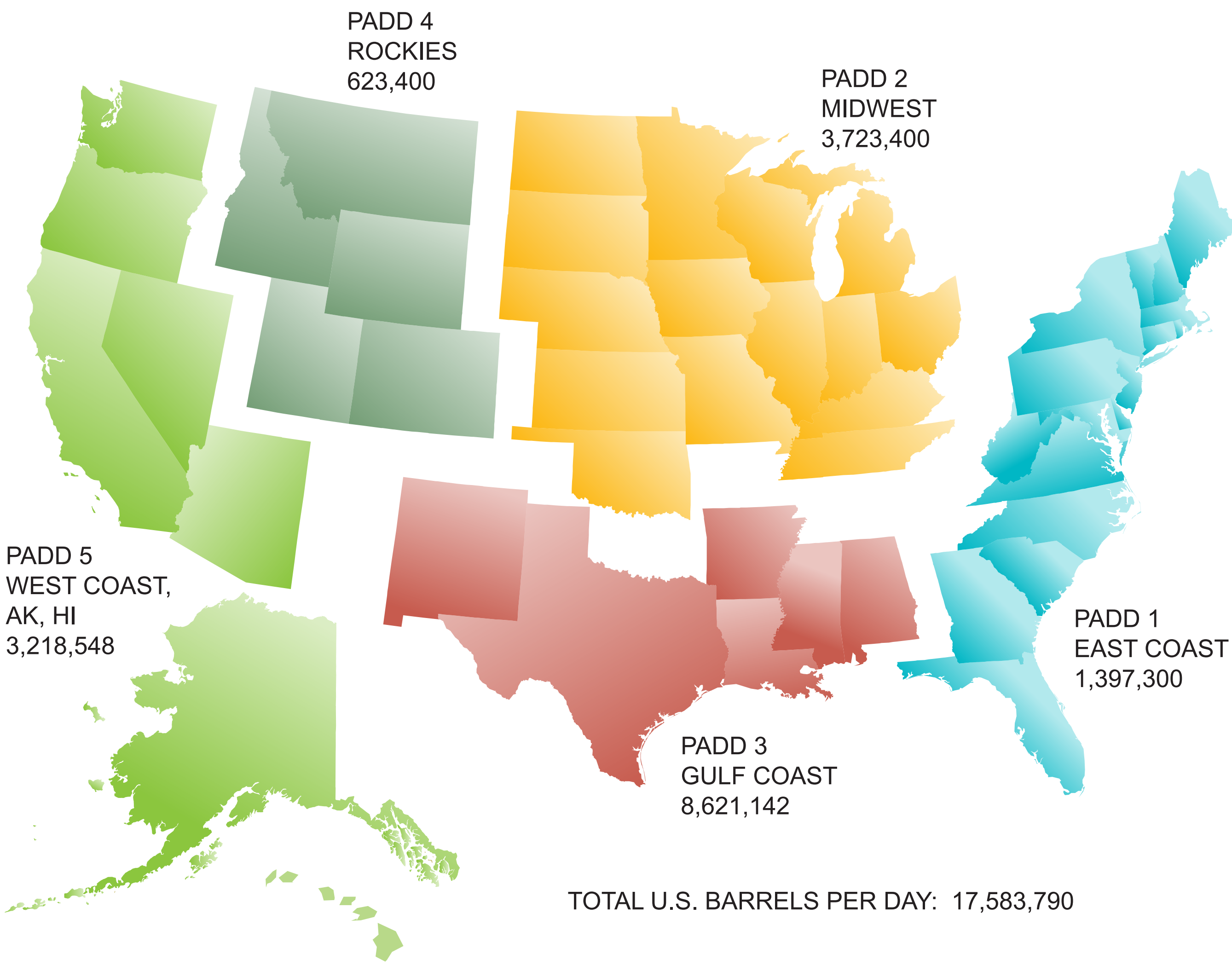
Figure 11-22. *Simplified Process Flow Diagram for High Conversion (Coking/Resid Destruction) Refinery*

Administration for Defense Districts, or PADDs, with boundaries and capacity as shown in Figure 11-23.

Capacity and Size Distribution. As of January 1, 2010, the EIA reported U.S. refining capacity of 17.6 MMB/D from a total 148 refineries, which represents a capacity growth of 2 MMB/D, while number of refineries has decreased from 205. This trend toward fewer, large refineries continues. The largest 11 refineries make up one-quarter of U.S. capacity. The smallest 71 refineries also total approximately one-quarter of U.S. capacity.

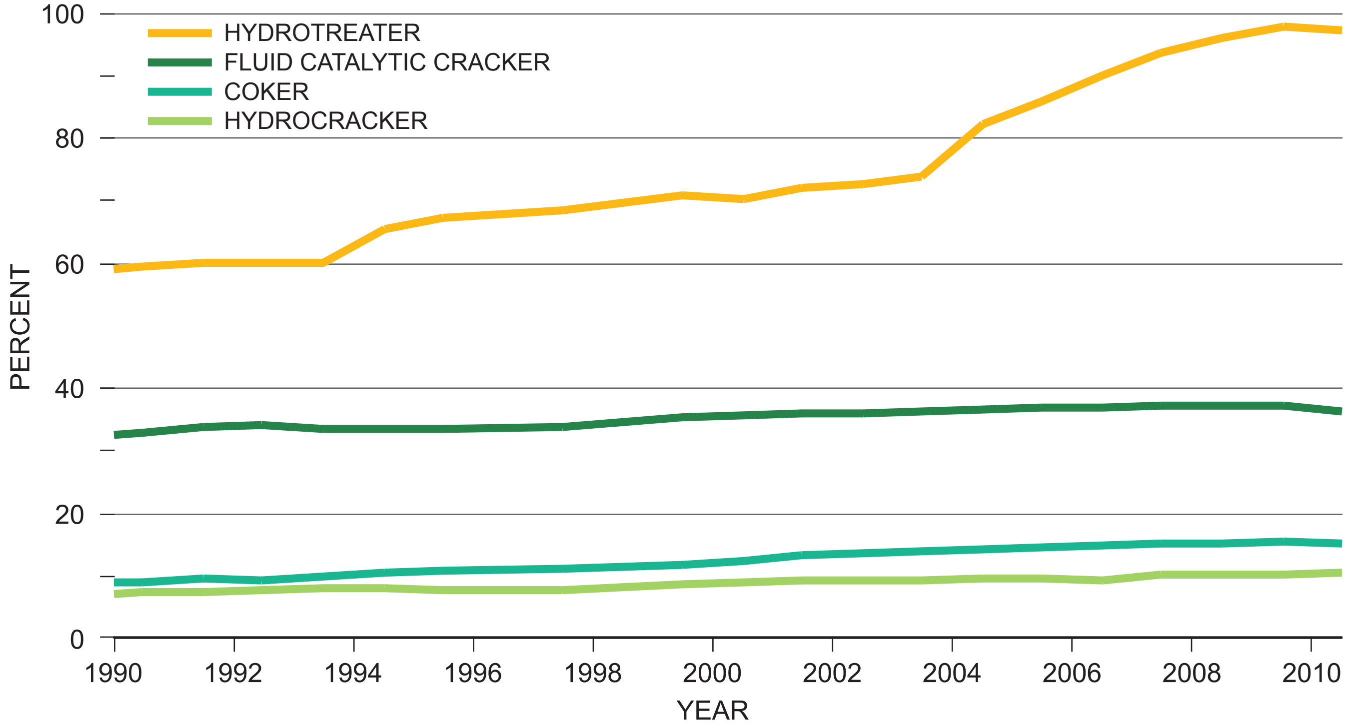
Complexity. As additional conversion units are added to a refinery, ability to convert heavier feedstock into transportation fuels increases. As shown in Figure 11-24, U.S. conversion capability has increased over the last 20 years. U.S. coker capacity has grown by 68%, hydrocracker capacity by 44%, FCC capacity by 13%, and hydrotreating capacity by 68% over the period.

Product Quality Improvement. The qualities of hydrocarbon produced by refiners have improved over time to meet regulatory standards and the evolution of the transportation fleet. Increasingly, hydrocarbon fuel product specifications are driven



Note: During World War II, the then-War Department delineated PADDs to facilitate oil allocation.
Source: U.S. Energy Information Administration, "Number and Capacity of Petroleum Refineries," as of January 1, 2010.

Figure 11-23. *Fuel Refining Capacity by Petroleum Administration for Defense District (Barrels per Day)*

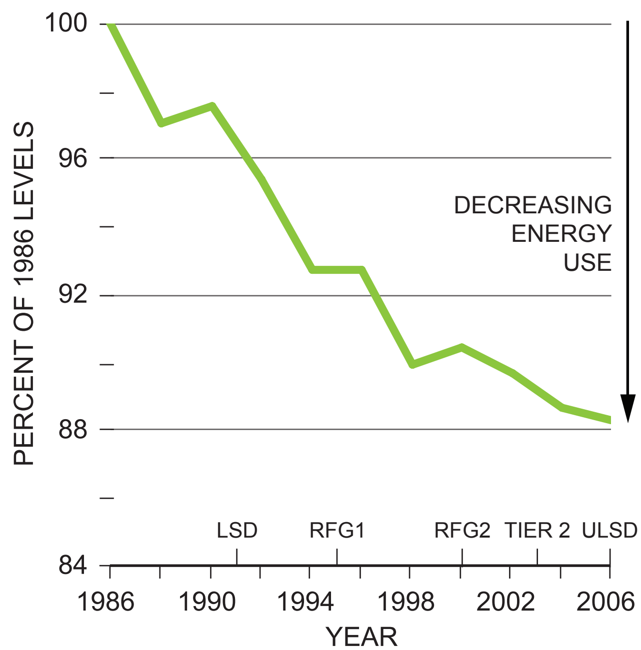


Source: U.S. Energy Information Administration, "Number and Capacity of Petroleum Refineries."

Figure 11-24. *Conversion Process Capacity as Percent of Crude Oil Distillation Unit*

by vehicle technical requirements and environmental regulations that have significantly reduced vehicle emissions over the past 40 years. The ability of refiners to adapt to the regulations has been well established; however, sometimes significant capital funds are required.

Efficiency Improvements by Refiners. Refiners have reduced energy consumption through efficiency improvements, energy integration, and efficiency investments. Improvement comes from numerous small items as well as larger projects like cogeneration and advanced catalyst technology. Today refining is highly efficient, with roughly 90% of energy in crude oil remaining in finished products.[6] Since 1986, the refining sector has improved its energy efficiency by roughly 0.6% per year (see Figure 11-25). Efficiency gains slowed after 1998 as cleaner fuel standards were adopted, which required additional processing for sulfur reduction and other specification changes.



Note: Fuel Regulations: LSD = Low-Sulfur Diesel; RFG = Reformulated Gasoline; TIER 2 = Low-Sulfur Gasoline; ULSD = Ultra-Low-Sulfur Diesel

Source: Solomon Associates.

Figure 11-25. *U.S. Refinery Energy Intensity Index*

6 GREET Model: The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model, Argonne National Laboratory, http://greet.es.anl.gov/.

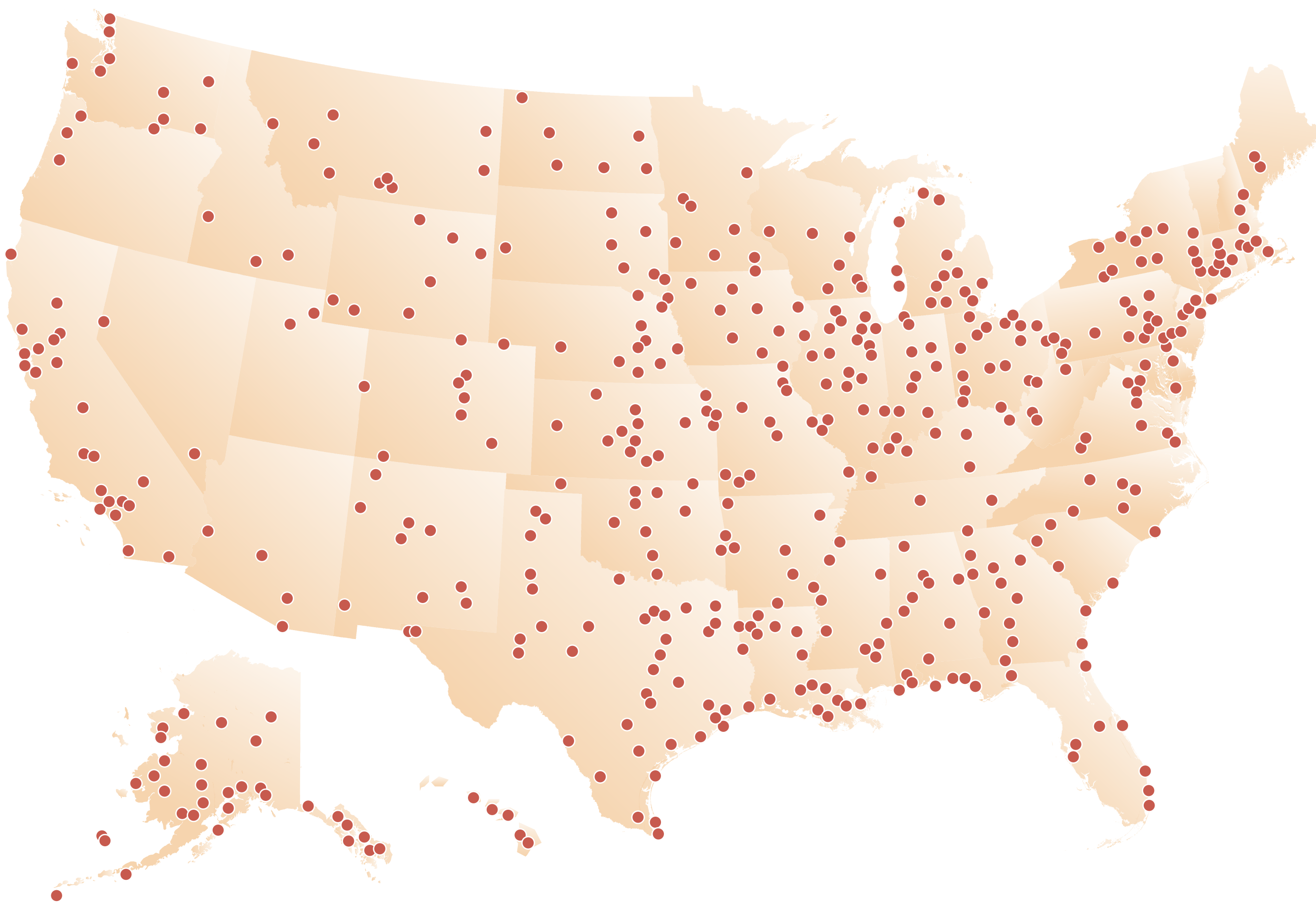
Refinery Capability to Adapt to Shifting Feedstock Mix/Quality. Crude oil varies in a number of properties including sulfur, density, acidity, and others. Refineries have limited ability to change crude oil inputs and are often designed and optimized to run nearby or readily available crudes. Changing crude oil feedstock properties usually requires capital investment. A recent example is upgrades to certain Midwest refineries to process Canadian crude from oil sands.

DISTRIBUTION INFRASTRUCTURE

The U.S. refined product distribution system has historically adapted to provide the most efficient and lowest cost product transportation to the U.S. consumer and it will continue to adapt in the foreseeable future. The distribution system has a backbone of large, high volume pipelines, supplemented by water movements. The final part of the journey is via truck from terminals to fuel marketers and retail locations. This system, with the exception of pipelines, has been adapted to handle ethanol and biodiesel. Ethanol also takes advantage of rail movements where feasible.

Throughout the early decades of the petroleum industry, refined products were manufactured at relatively small refineries located close to product markets. During World War II, vulnerability of tanker shipments and the growing demand for petroleum products led to the development of large pipelines to move products to the East Coast from refining centers along the Gulf Coast. Shortly thereafter, pipelines were constructed in the Midwest and West. Approximately 75% of the existing pipeline infrastructure was constructed between 1940 and 1980.

The distribution of hydrocarbon liquid product terminals has grown to span the entire country, as



Source: IRS Active Fuel Terminals.

Figure 11-26. *Major U.S. Product Terminals*

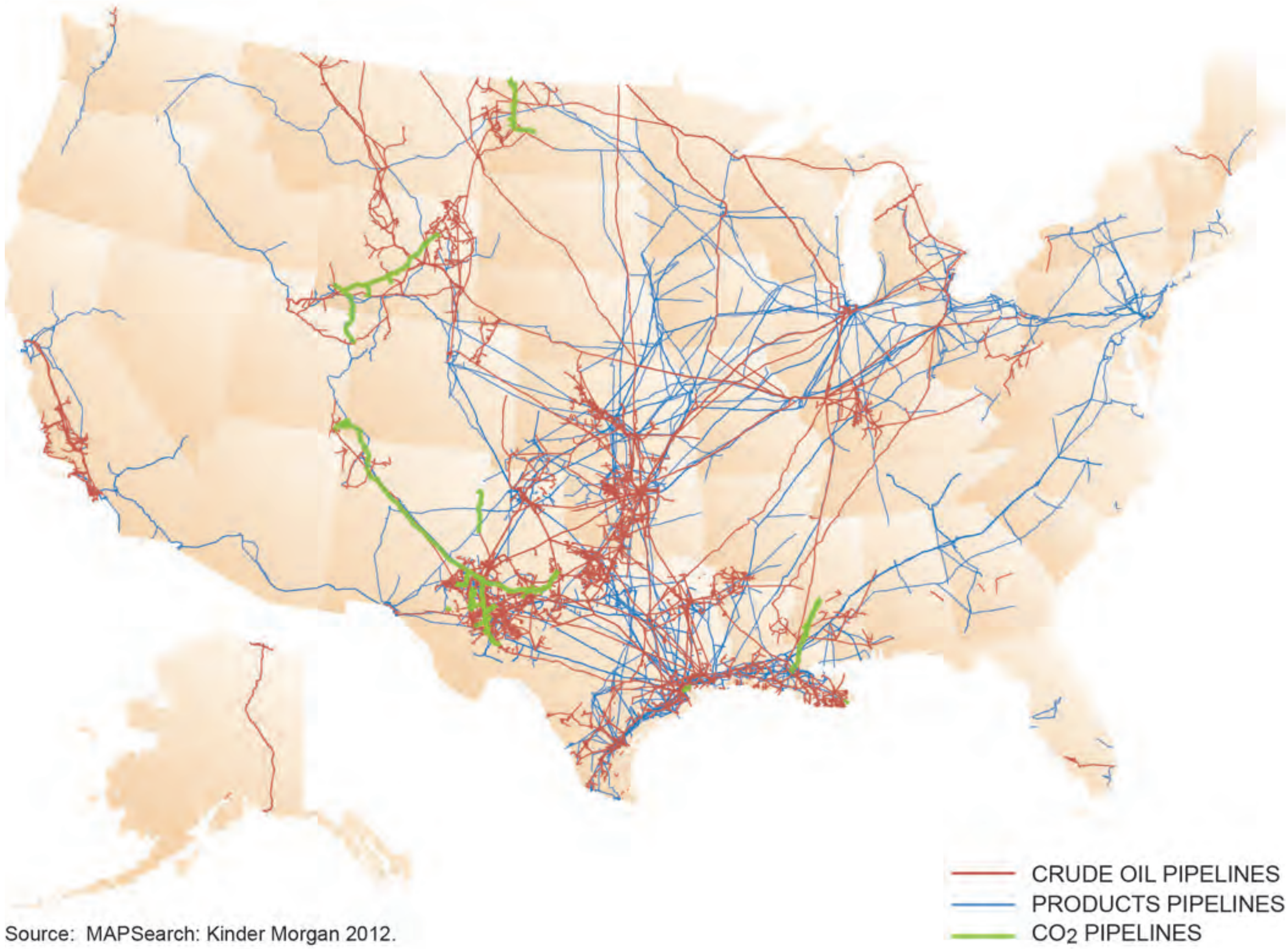


Figure 11-27. *Major U.S. Pipelines*

shown in Figures 11-26 and 11-27. These terminals are located in demand centers and along pipeline routes to deliver hydrocarbon fuels and biofuels to the end customer. The legacy value of these terminals is significant, for a competing energy pathway to replicate this coverage and redundancy is a very large hurdle.

Over time, the transportation of petroleum products has become more complex. For pipeline operators, the proliferation of product grades for gasoline and diesel are a complicating factor that required expanding the number of segregations. These segregations create additional complexity in managing product quality and integrity (Figure 11-28).

Depending upon the specifications of adjacent batches, it may be possible to downgrade the commingled product interface between two batches into a succeeding lower quality material (such as premium gasoline into regular gasoline). Downgrading from one batch to another cannot always occur. In those situations it becomes necessary to segregate the interface (called transmix) and arrange for it to be sent back to the refinery or other processing facility.

Today, pipelines are controlled by the use of computers often referred to as programmable logic controllers (PLCs). The data from the PLCs are transferred by secured wide-area network to a centralized database. The data are then compiled and formatted in such a way that a control room operator can make decisions to start or stop the pipeline, adjust flow rates, raise or reduce the operating pressure, as well as open and close valves. The system of computers and the communications network is collectively referred to as a Supervisory Control

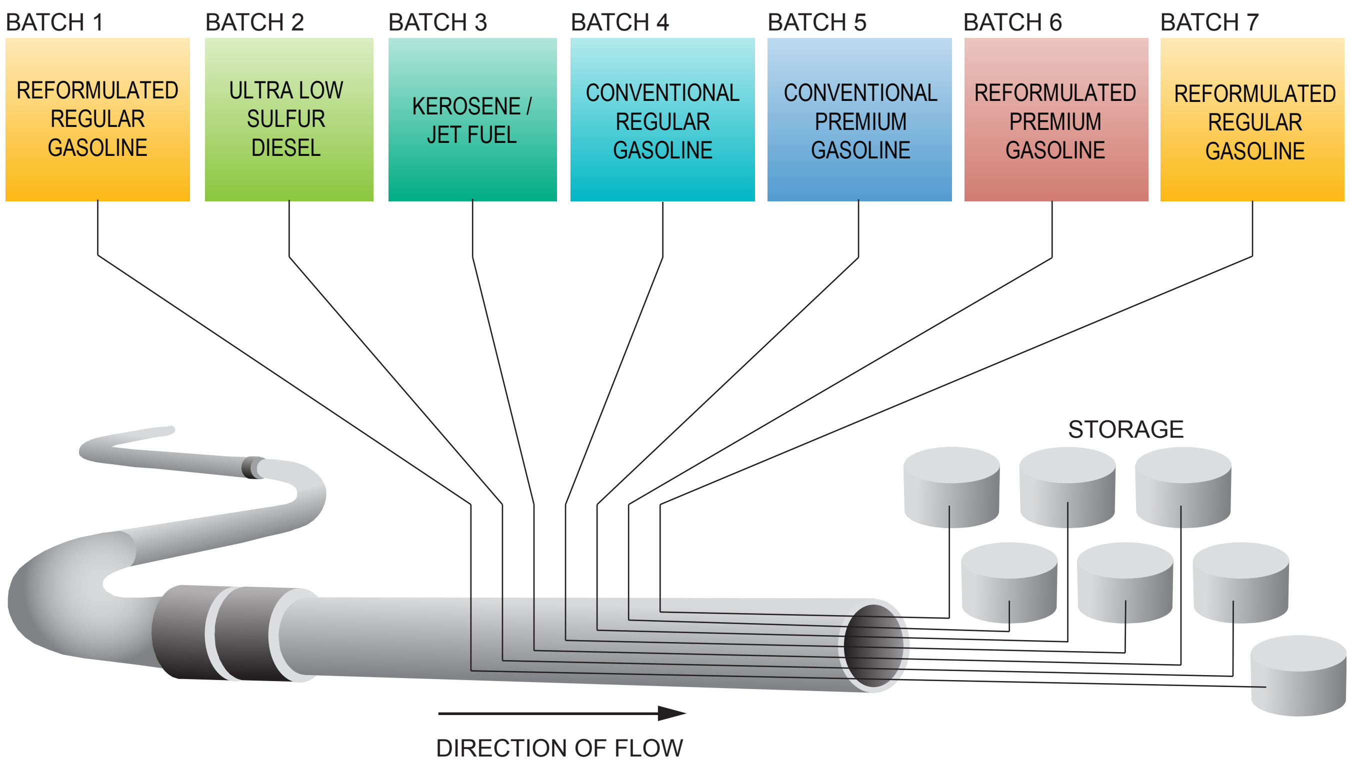


Figure 11-28. *Typical Refined Products Pipeline Batch Sequencing*

and Data Acquisition (SCADA) system. The SCADA system can also feed various real time data into business computers to support pipeline scheduling, product accounting, and other business functions (Figure 11-29).

Although pipelines are the primary source for transporting crude oil and refined petroleum products, water carriers, railroads, and trucks are also important components. However, the ability to continuously move large volumes of crude oil and refined products over great distances have made pipelines the most efficient mode of transportation. Likewise, the economics when transporting products by pipeline are also favorable. The relative shares of refined product movements by mode are shown in Figure 11-30.

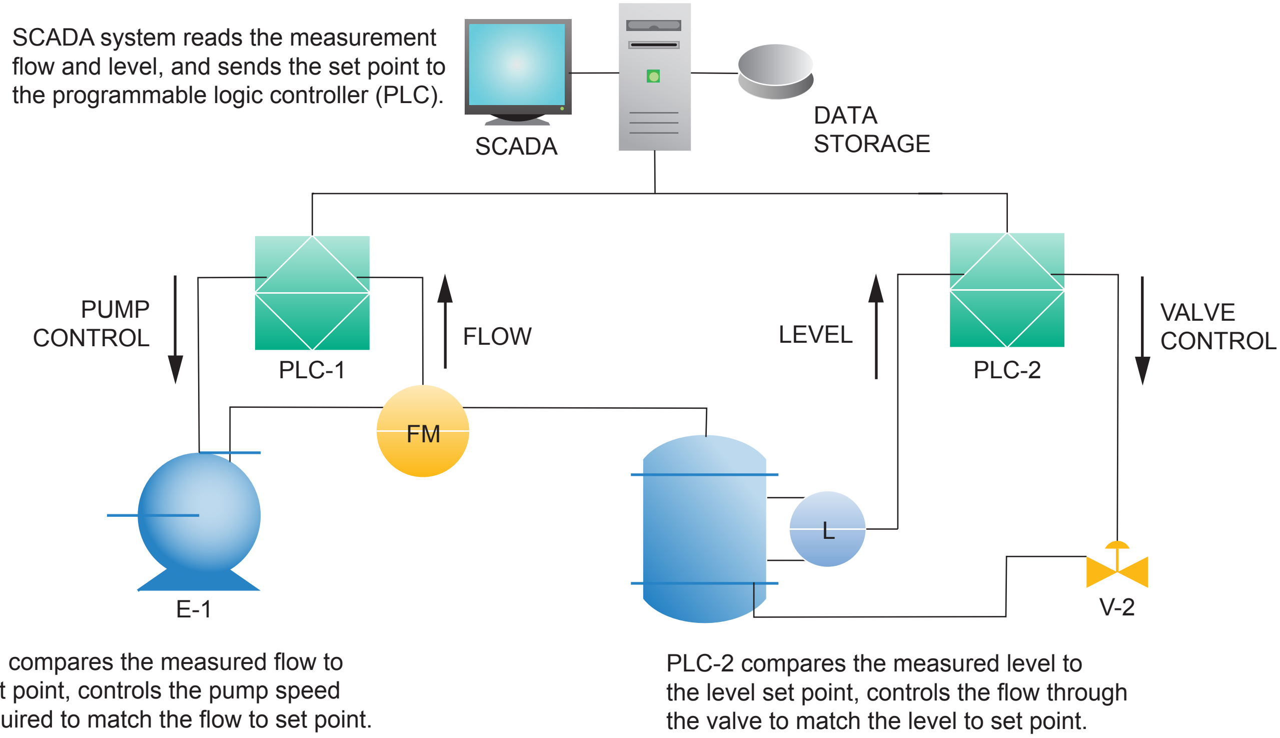
Oil Pipelines – State of the Industry

Pipelines accounted for 71% of all petroleum transportation in 2008, up from approximately 54% in 1990.[7] Water carriers provided the second highest level of ton-miles in 2008, 16% of crude oil, and 27% of petroleum products.

Ethanol Impact on Infrastructure

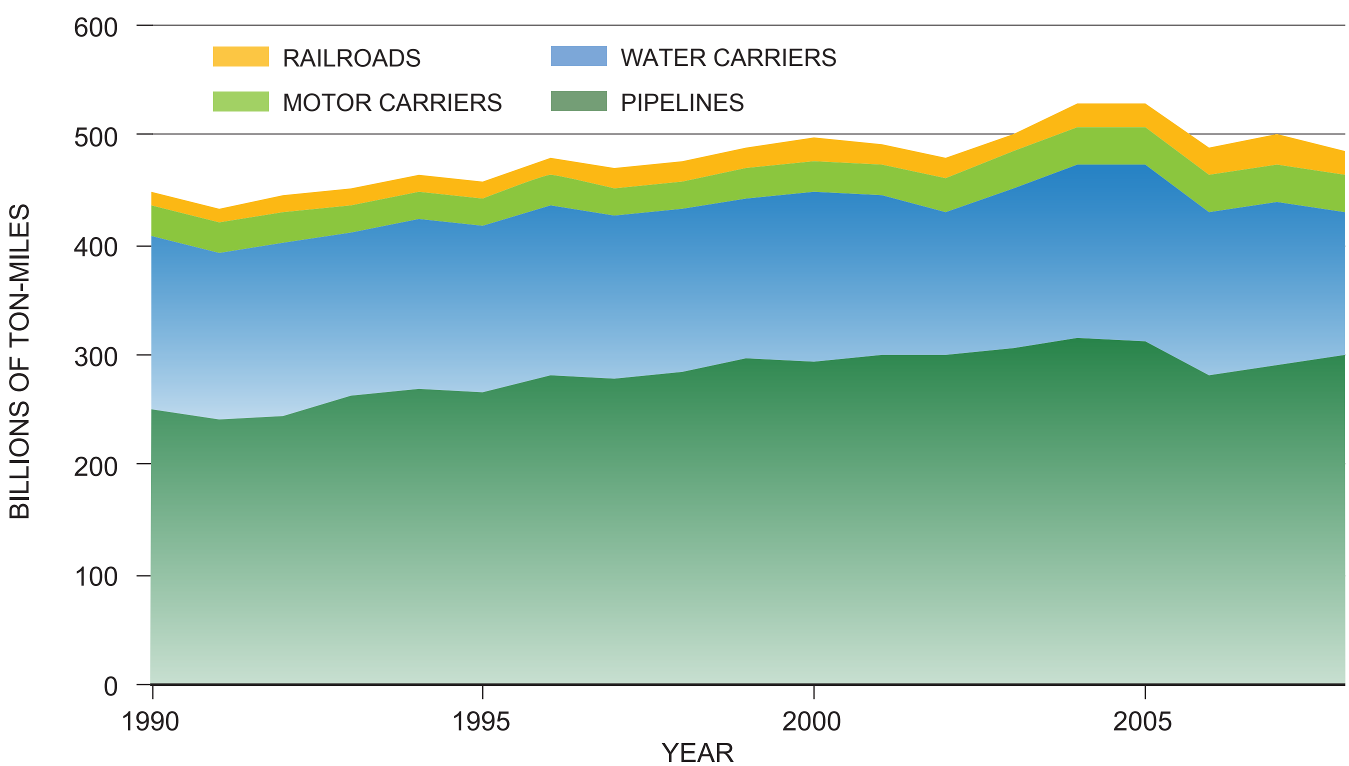
The volumes and the percentage of products transported within the Association of Oil Pipe Lines (AOPL) data do not include ethanol. Pipeline operators have been reluctant to ship ethanol, or gasoline-ethanol blends on a commercial scale due to ethanol's corrosive properties and water solubility. Ethanol will clean the internal surfaces of a pipeline and can result in the pipeline becoming more susceptible to internal stress corrosion cracking, which is difficult to detect and manage. Likewise, ethanol has an affinity for moisture and is completely soluble in water. Water enters the pipeline system through terminal and refinery tank roofs and can be dissolved in fuels during the refining process. If the ethanol or gasoline-ethanol blend picks up water in the pipeline, it could "phase separate" resulting in off-specification product. An E10 gasoline-ethanol blend can typically contain up to 0.5 volume percent water at 60°F before phase separation occurs. Lesser amounts of water

7 Association of Oil Pipe Lines, *Report on Shifts in Petroleum Transportation: 1990–2009,* February 2012.



Source: Kinder Morgan.

Figure 11-29. *SCADA System*



Source: Association of Oil Pipe Lines.

Figure 11-30. *Total Petroleum Product Movement* can induce separation at lower temperatures. Also, lower blend levels of ethanol such as 5.7% or 7.7% tolerate less water.

Trains, trucks, and water carriers are the primary means by which ethanol is transported from origin to market. The majority of the ethanol production is in the Midwest, with the heaviest demand along the East Coast, West Coast, and Southeast. In 2005, approximately 75% of ethanol produced was transported by rail.[8] Implementation of the Renewable Fuel Standard calls for ethanol consumption to increase to 36 billion gallons (2.4 MMB/D) in 2022.

The ability to ship ethanol by pipeline or unit trains will be important to ensuring quick and affordable ethanol shipments. Unit trains are a more efficient mode of transportation than single manifest cars; however, the transportation of ethanol from trans-loading facilities to terminals by truck may become problematic in terms of highway congestion and air emissions.

Technology improvements to address ethanol's water affinity and corrosion issues could result in the wider use of pipelines to transport ethanol. The construction of new pipeline infrastructure or the expansion of existing pipeline infrastructure can be costly when considering right-of-way acquisition, intermediate tanks and terminals, as well as permits. Although this section of the report focuses on ethanol, the same issues are present when discussing the introduction, infrastructure, and logistics of other biofuels.

To improve overall efficiency, the combination of unit trains to transport ethanol by bulk from the Midwest to existing pipeline gathering hubs, where the product could then be transported by pipeline directly into terminals, may become a cost-effective solution.

FUTURE STATE OF HYDROCARBON LIQUIDS TO 2050

The current scale and efficiency of the global hydrocarbon liquid supply chain is expected to be maintained throughout the outlook period, but there are several important issues as discussed below.

Conventional Infrastructure

Resources

As discussed previously, conventional oil is increasingly located in remote areas or geographically concentrated in a few countries with large remaining resources. Access to these resources, technology development, and safe and environmentally sound operations are critical to meeting projected increases in demand. Unconventional resources are also important, with technology development to reduce cost and improve environmental performance an important challenge. Issues associated with resource development are covered in the NPC *Prudent Development* report.

Impact of Outlooks on Product Demand and Refining

The crude oil production profiles shown in Figure 11-19 foresee an increase in North American unconventional oil production. The crude oil slate shift will provide an incentive for upgrading of heavy crude oil in existing infrastructure. The most efficient disposition of this heavy crude oil production will likely be in existing high conversion refineries discussed previously in this chapter.

As the crude oil profiles change, so will the demand barrel as illustrated in the Reference and Alternative scenarios shown in Figure 11-31. The AEO2012 Early Release and the IEA outlooks show the potential pressure on refined gasoline from a volume and yield perspective due to light-duty fleet efficiency, increased biofuels, and growth in diesel for medium-/heavy-duty vehicles. The challenge for refining will be to make the product slates required by customer demands. Although the changes are substantial in some outlooks, they occur over a very long period, giving industry time to respond. The flexibility of the refinery fleet to manage this shift will be discussed in the next section.

Refinery Capability to Address Shape of Barrel Shifts

The U.S. refining industry has responded in the past to changing customer demand by shifting refinery yields. Recently, U.S. refineries have increased distillate yield, from 31.9% in 1995 to 36.3% in

8 Holly Jessen, "Riding the Rails," *Ethanol Producer Magazine,* October 2006.

Figure 11-31. *Demand Shifts in Various Outlooks versus 2010*

2009, while gasoline yield has been flat (see Figure 11-32). The result has been a higher overall yield of gasoline and diesel, with an increasing diesel fraction (see Figure 11-33).

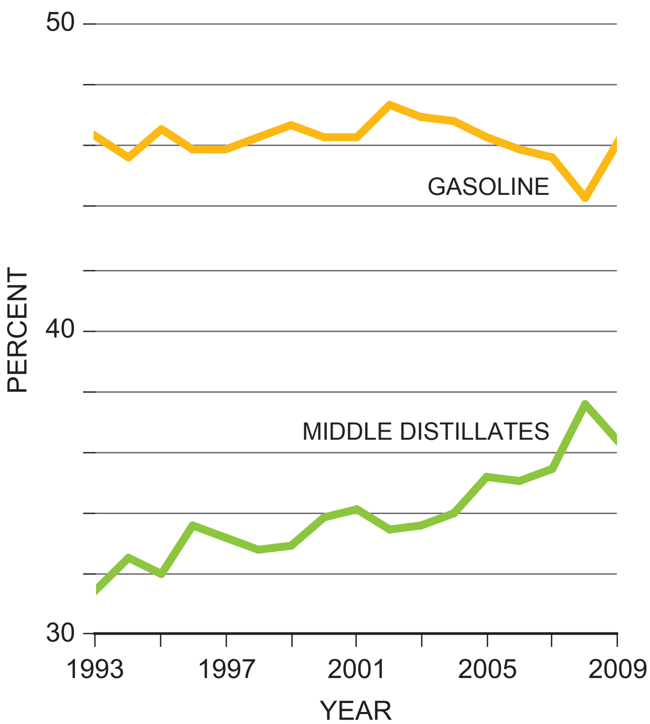
Utilization of refinery process units has declined in recent years due to capacity additions and reductions in demand (see Figure 11-34). The AEO 2010 Reference Case postulates that 1.5 MMB/D of existing refining capacity would be taken out of service by 2020, and refining utilization falls to 80% from 85%. The alternative reduced demand outlooks would imply even greater sparing of refinery capacity.

The results of an EIA study show that U.S. refineries have the ability to increase annual average distillate yields on crude oil and unfinished oil inputs 3 to 5% with no or small investments for distillation improvements. When planned hydrocracking increases are taken into consideration, the increase could be in the range of 4 to 8%.[9]

There should be no near-term constraint in meeting slowly increasing distillate consumption, given the capability to adjust to market demands as evidenced in previous cycles and recent additions to capacity. In fact, distillate yield increases will likely enable U.S. refiners to increase distillate exports when economics are attractive.

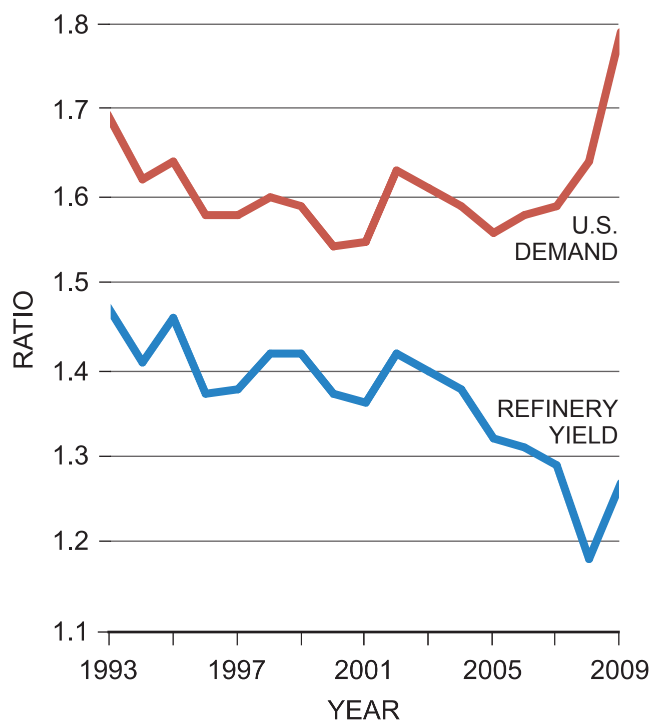
In conclusion, the impact to 2050 for the refining circuit will likely be increased unconventional oil feedstock, and a flat or declining demand barrel that shifts from gasoline to distillate. Industry's history in the recent past of managing such challenges

9 U.S. Energy Information Administration, "Atlantic Basin Refining Dynamics from U.S. Perspective," presentation by Joanne Shore and John Hackworth at Platts 4th Annual European Refining Markets Conference, September 2010.



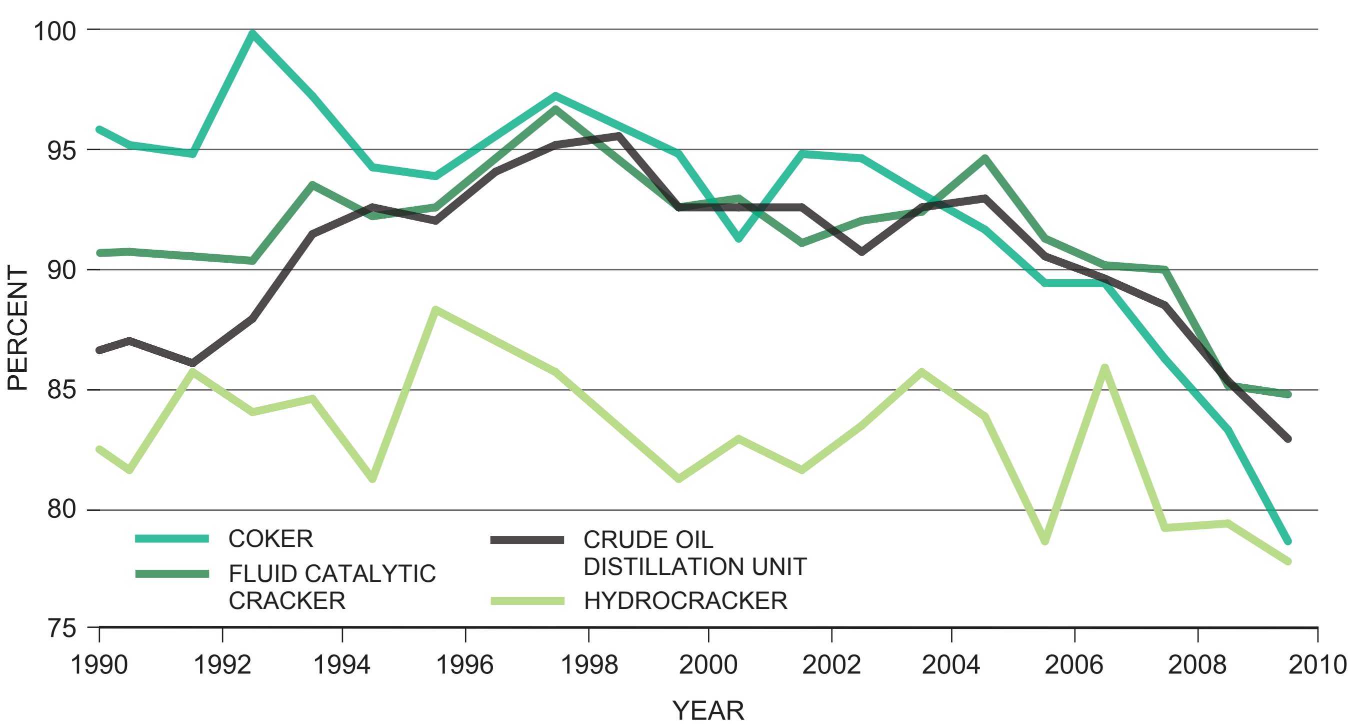
Sources: U.S. Energy Information Administration.

Figure 11-32. *U.S. Refinery Gasoline/ Distillate Yields*



Source: U.S. Energy Information Administration.

Figure 11-33. *U.S. Gasoline/ Middle Distillate Ratios*



Source: U.S. Energy Information Administration, "Number and Capacity of Petroleum Refineries."

Figure 11-34. *Utilization of Crude Oil Distillation and Major Conversion Units* indicates future revisions will be successfully accomplished.

Infrastructure Investment

According to the IEA's 2010 World Energy Outlook, very large infrastructure investments will be needed globally to meet projected future oil demand, roughly $8 trillion over a 25-year period, as shown in Table 11-2. Most of the investment will occur outside OECD countries to find and develop new sources of oil production. Spending in the United States is projected to be only 11% of the global total. The total cost of new infrastructure is roughly $10 per barrel produced and processed over the 25-year outlook period.

Capital Demand – Conventional Refining

While infrastructure spending in the United States is a relatively small fraction of the global total, it is important for the efficiency and reliability of the U.S. supply chain. EIA projects a reduction of overall U.S. refining capacity to 2035 after peaking in 2012. Refinery capital investment will be required to:

- Upgrade capacity to meet increasing diesel demand
- Increase production of low sulfur distillate and marine fuel
- Process heavy crudes
- Meet potential regulatory requirements.

	Conventional Production	Unconventional Production	Refining	Total*	Annual Average
OECD	**1,284**	**283**	**244**	**1,811**	**70**
North America	973	263	121	1,358	52
United States	*721*	*51*	*95*	*868*	*33*
Europe	286	2	85	373	14
Pacific	25	17	38	80	3
Non-OECD	**5,004**	**262**	**735**	**6,001**	**231**
E. Europe/Eurasia	1,173	15	81	1,270	49
Caspian	*539*	*4*	*13*	*555*	*21*
Russia	*624*	*9*	*44*	*676*	*26*
Asia	396	58	450	904	35
China	*222*	*34*	*220*	*475*	*18*
India	*57*	*11*	*139*	*207*	*8*
Middle East	821	39	105	965	37
Africa	1,254	20	39	1,313	51
Latin America	1,361	129	60	1,549	60
Brazil	*984*	*5*	*30*	*1,019*	*39*
World*	**6,288**	**545**	**979**	**8,053**	**310**
European Union	*117*	*0*	*81*	*198*	*8*

* World total includes an additional $241 billion investment in inter-regional transport infrastructure.
Source: International Energy Agency, *World Energy Outlook 2010,* 2010.

Table 11-2. *Cumulative Investment in Oil Supply Infrastructure by Region and Activity in the New Policies Scenario, 2010–2035 ($ Billion in Year-2009 Dollars)*

Biofuels, Coal, and Gas Infrastructure

Hydrocarbon liquids facilitate use of biofuels by providing product integration that is seamless to the customer and by providing key distribution infrastructure. However, increasing use of biofuels raises a number of issues in the distribution system that might cause additional capital and complexity for the hydrocarbon liquids supply chain.[10] There are no insurmountable technical barriers for fuel infrastructure development to allow increasing biofuel use.

Biofuels

E10–E85 Infrastructure Issues

- **E10 Blendwall.** Volumes of biofuel required under RFS will exceed the amount that can be achieved with E10, the historical ethanol limit. Higher ethanol blending volumes will require vehicle and fueling infrastructure investments.
- **E15.** In November 2010, the Environmental Protection Agency (EPA) granted a waiver request to allow vehicles model year 2007 and newer to use E15. In January 2011, EPA extended this approval to cover all vehicles model year 2001 and newer. There are a number of implementation issues. From an infrastructure standpoint, the lack of suitable station hardware for holding and dispensing E15 will slow introduction. The partial nature of the vehicle waiver also complicates introduction and may confuse customers. As of June 2012, vehicle manufacturers have not endorsed E15 use in existing vehicles.
- **E85.** The main issue is a lack of service station and vehicle infrastructure. While this is not a challenge in the long term, it will delay introduction.

Service Station Infrastructure for Mid- and High-Level Ethanol Blends

The use of mid- and high-level ethanol blends will require investment in service station and other fuel distribution infrastructure. Dispensing of gasoline and ethanol-gasoline blends is regulated for safety, accuracy, and security by federal, state, and local governments. In the United States, Underwriters Laboratories (UL) is the recognized national testing laboratory for fuel dispensing equipment. UL has developed three certification categories, which cover up to E10 (UL 87), mid-level blends up to E25 (87A-E25), and high-level blends up to E85 (87A-E85).[11] Federal law and most local jurisdictions require use of UL certified equipment. Most service stations do not have equipment that has been UL certified for ethanol contents above 10%. Generally retailers will have to purchase and install new equipment before they can market mid- or high-level ethanol blends. When upgrading equipment during the normal course of business, it may be prudent for retailers to install E85 capability to provide flexibility to handle any possible future ethanol concentration.

Major service station components that may need to be upgraded include: fuel dispensers, pumps, piping, and storage tanks. A wide range of costs is possible, depending on service station design and how much equipment needs to be replaced. Replacing a single dispenser costs $17,000 to $40,000.[12] To replace underground equipment involves permitting and higher costs. Costs for a single dispenser and storage tank range from $71,000 to $185,000. Costs would be higher to upgrade an entire station. A typical station has four or more dispensers and two or more storage tanks.

There were 161,000 service stations in the United States in 2008, equivalent to 0.65 fueling stations per 1,000 vehicles.[13] A typical dispenser lifetime is 10 years, while a storage tank can last 30 years.

The total nationwide costs could be in excess of $10 billion for upgrading to mid- or high-level ethanol blends depending on the equipment installed, the number of stations that decide to upgrade, and where stations are in the normal equipment upgrade cycle. Typical service station volume is

10 Congressional Research Service, *Intermediate-Level Blends of Ethanol in Gasoline, and the Ethanol "Blend Wall,"* October 2010.

11 Clean Fuels Foundation and the Nebraska Ethanol Board, In cooperation with the U.S. Department of Agriculture, *E85 and Blender Pumps: A Resource Guide to Ethanol Refueling Infrastructure,* 2011.

12 National Association of Convenience Stores, *Challenges Remain Before E15 Usage is Widespread,* 2011; Petroleum Equipment Institute, *Compatibility Assessment Survey,* 2008; U.S. Environmental Protection Agency, *Draft Regulatory Impact Analysis: Changes to Renewable Fuel Standard Program,* Section 4.2.1.1.6, March 2009; and American Petroleum Institute, API RFS2 Comments, Attachment 4: E85 Retail Fueling Cost Study, 2009.

13 U.S. Department of Energy, Oak Ridge National Laboratory, "Chapter 4" in *Transportation Energy Data Book.*

around 1,000,000 gallons per year, so cost per gallon over equipment lifetime is relatively low on the order of a penny per gallon, but impacts on short-term station profitability could be significant. This estimate is in agreement with EPA's estimate that service station upgrades would cost 1.2 cents per E85 gallon dispensed.[14]

Renewable Fuel Transportation and Processing in Conventional Liquid Hydrocarbon Infrastructure

Ethanol and fatty acid methyl ester (FAME) biodiesel are not currently blended in refineries or shipped in most pipelines. This increases transportation cost relative to gasoline and diesel. To improve distribution economics, biofuels would require additional processing either in stand-alone units or potentially as a refinery feedstock.

Use of biomass-derived feedstock in refineries raises a number of issues. First, such stocks contain significant amounts of oxygen that must be rejected as water that refineries are not designed to handle. Second, pyrolysis of biomass to produce bio-oil yields many unstable compounds that refineries are not designed to process or remove. Third, many bio-derived nitrogen and oxygen compounds are poisons to the catalysts employed in the refining process. In addition, removal of the nitrogen, oxygen, sulfur, and unstable compounds requires hydrogen, which will increase supply costs at a refinery. Finally, bio-components that are co-processed in refineries do not receive tax credits received by biofuel producers. These hurdles will limit the amount of biomass-derived feedstock existing refining infrastructure can handle.

Potential for Hydrocarbon Liquids Production from Coal and Gas Resources

The conditions under which a large domestic industry to convert gas, coal, and biomass to liquids (XTL) might develop were investigated. Because few such plants have been constructed worldwide, there is considerable long-term uncertainty in the economics of XTL relative to petroleum and the large potential resource.

14 U.S. Environmental Protection Agency, *Draft Regulatory Impact Analysis: Changes to Renewable Fuel Standard Program,* Section 4.2.1.1.6, May 2009.

Economics of GTL, CTL, and CBTL

To investigate the economics of XTL, information on plant attributes was collected and updated and models employed to estimate plant economics. The tight engineering and construction market has resulted in escalations of capital costs for major energy projects and creates difficulty in accurately estimating capital costs.

There is a considerable range of estimates of capital costs for the GTL plants that have been built and for those still in construction or in the planning stage. This range is between about \$35,000/daily barrel for the Sasol Oryx plant that was constructed over 5 years ago and about \$200,000/daily barrel for the Escravos plant in Nigeria. The Escravos project is expected to cost \$8.4 billion for 33,000 barrels per day of GTL liquids product, and is 70% complete (although it was originally expected to cost ~\$3 billion).[15] The large Shell Pearl GTL plant that has recently completed construction in Qatar will produce 140,000 barrels per day of FT fuels and about 120,000 barrels per day of natural gas liquids. This plant is expected to cost in the region of \$18 billion.[16] There are many reasons for this large range including plant size, location, timing, project scope, products, gas processing needed, financing assumptions, etc. To attempt to address the impact of this range on the required selling price (RSP) of the fuels, a base capital expense (Capex) and a high Capex were used in the economics. Table 11-3 shows the Capex values and other major economic assumptions used in the analysis for a plant designed to produce 50,000 barrels per day of diesel fuel and naphtha. The costs listed in the table for the base case are consistent with recent studies by the National Academy of Sciences and the National Energy Technology Laboratory but are somewhat higher than EIA, while those for the high case are closer to recent plant construction experience at Escravos and Pearl. Because investment in these plants would be considered high risk, the economics are based on a capital recovery factor of 20%.

Figures 11-35 and 11-36 show estimates of the RSP of diesel fuel produced from CTL and CBTL plants sized to produce 50,000 barrels/day of diesel fuel and naphtha based on the capital costs

15 Zeus Intelligence, *Zeus Syngas Refining Report,* March 1, 2011.

16 Shell (website), "Pearl GTL: An Overview," 2011

	GTL	CTL	CBTL
Base Capex $/Daily Barrel	70,000	150,000	157,000
High Capex $/Daily Barrel	180,000	300,000	314,000
Capital Recovery Factor %	20	20	20
Capacity Factor %	90	90	90
O&M Cost % of Capex	5	5	5
HHV Efficiency %	60	50	50
Feedstock Value Range	5-10$/million BTU Natural Gas	$35-$70/Ton Coal	$35-$70/Ton Coal $71/Dry Ton Biomass

Table 11-3. *Key Variables for XTL Comparisons*

above. Carbon capture and storage (CCS) is used to capture the carbon dioxide produced during the conversion process. Note that CCS has a moderate impact on plant costs representing about 10% of capital expense. The base CTL capital cost is assumed to be $150,000/daily barrel and the high Capex is $300,000/daily barrel. If the coal price is $1.50/million BTU (equivalent to about $35 per ton) the RSP on a crude oil equivalent basis would be $120/barrel for the base Capex. For the high Capex case it would be over $220/barrel. The base CBTL capital cost is assumed to be $157,000/ daily barrel and the red line shows the high Capex case ($314,000/daily barrel). If the coal price is $1.50/ million BTU (equivalent to about $35 per ton) the RSP on a crude oil equivalent basis would be about $130/barrel for the base Capex. For the high Capex case, it would be over $230/barrel. In all cases, the

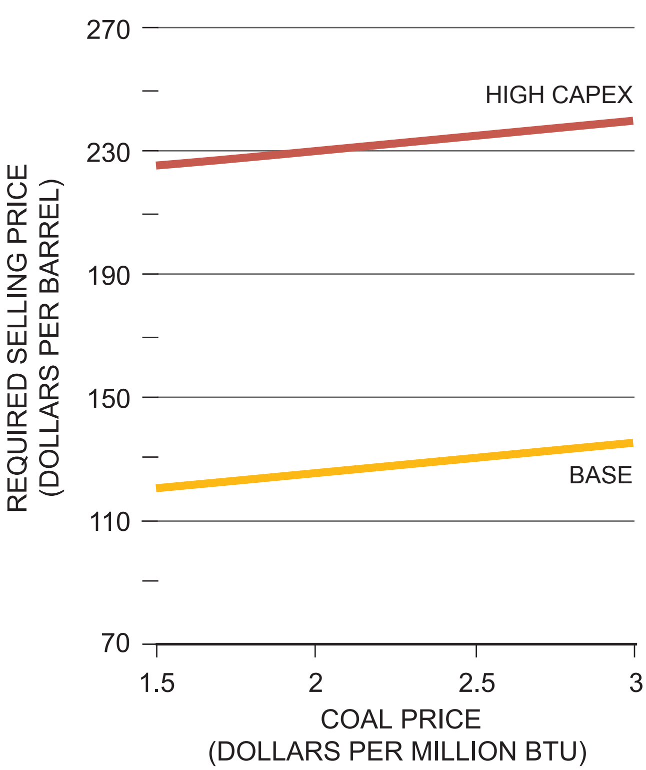


Figure 11-35. *Required Selling Price of Diesel on a Crude Oil Equivalent Basis for CTL*

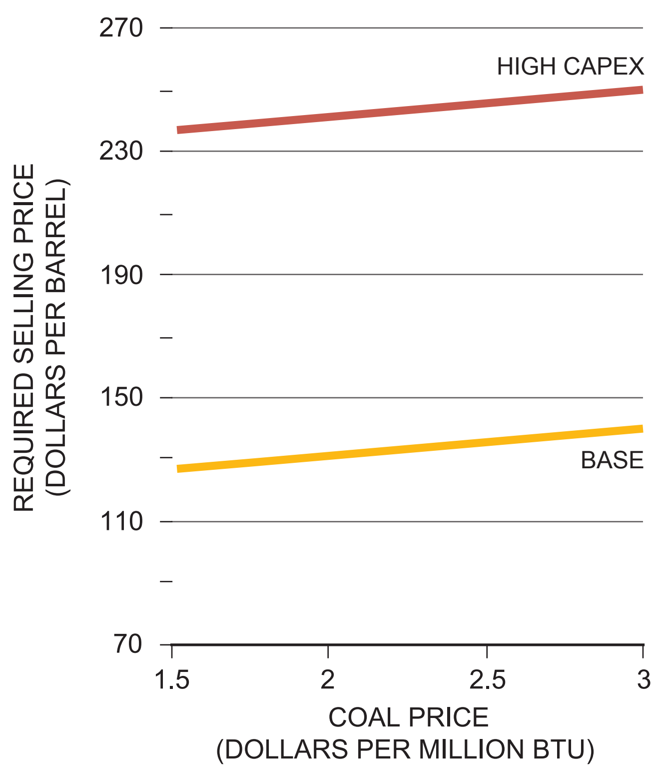


Figure 11-36. *Required Selling Price of Diesel on a Crude Oil Equivalent Basis for CBTL*

biomass feedstock cost was assumed to be constant at $71/dry ton.

The assumptions regarding Capex have a large effect on the RSP and hence on the economic viability of CTL and CBTL. Note that coal provides the necessary scale, which improves economics compared to stand-alone BTL. Transporting biomass is expensive so a BTL plant would operate at much smaller scale and much higher $/barrel capital cost than the CBTL plant analyzed here.

Figure 11-37 shows estimates of the RSP of diesel fuel (crude oil equivalent basis) produced from a GTL plant sized to produce 34,000 barrels per day of diesel and naphtha from about 300 million standard cubic feet per day of natural gas. With natural gas at $5.00/million BTU, the cost for diesel from a GTL plant with a capital cost of $70,000/daily barrel is estimated to be about $90/barrel. If natural gas prices escalate to $10/million BTU, then the RSP on a crude oil equivalent basis increases to about $130/barrel. Costs are much higher for the high Capex case.

Potential Supply Curves for XTL

Figure 11-38 shows two potential diesel fuel supply curves for XTL to 2050. The gold curve uses the low capital cost case, and red the high cost case. Both cases assume the AEO2010 Reference Case for oil, gas, and coal pricing. As discussed above, projected volumes are sensitive to capital costs and relative costs of petroleum, gas, and coal. In the low capital cost case, a sizeable XTL industry develops producing 2 MMB/D of diesel by 2050. This represents 65% of U.S. highway diesel in the Reference Case and 26% of all distillate and would have a significant impact on oil imports and refining. Using the AEO2010 price outlook, GTL is more economic than CTL or CBTL. Roughly 70% of the XTL is from GTL. However, under the high Capex case, no XTL is produced. As expected, forecast oil prices also impact projected volumes. With low oil prices, no XTL is produced under the low oil price case, while 3 MMB/D is produced under the high oil price scenario. Based on this analysis, XTL can be considered a backstop that could supplement petroleum under certain economic conditions.

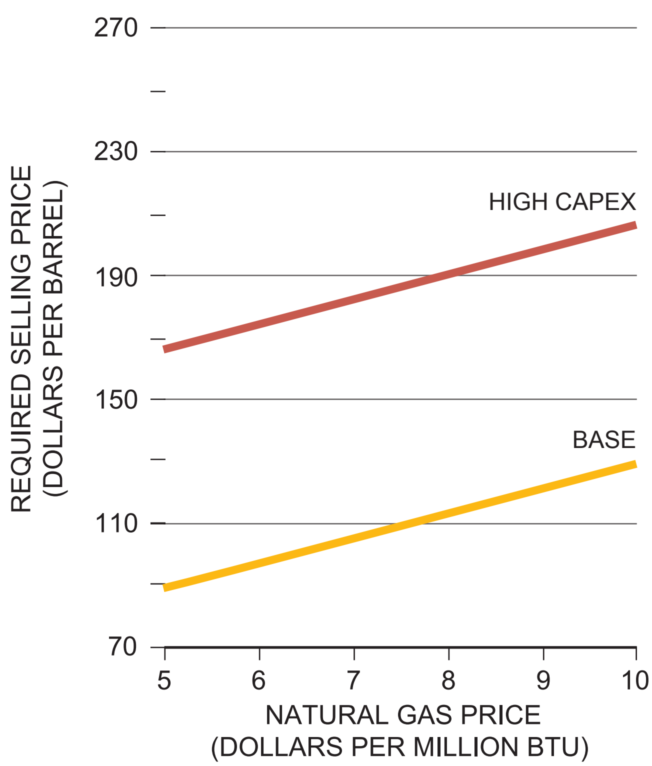


***Figure 11-37.** Required Selling Price of Diesel on a Crude Oil Equivalent Basis for GTL*

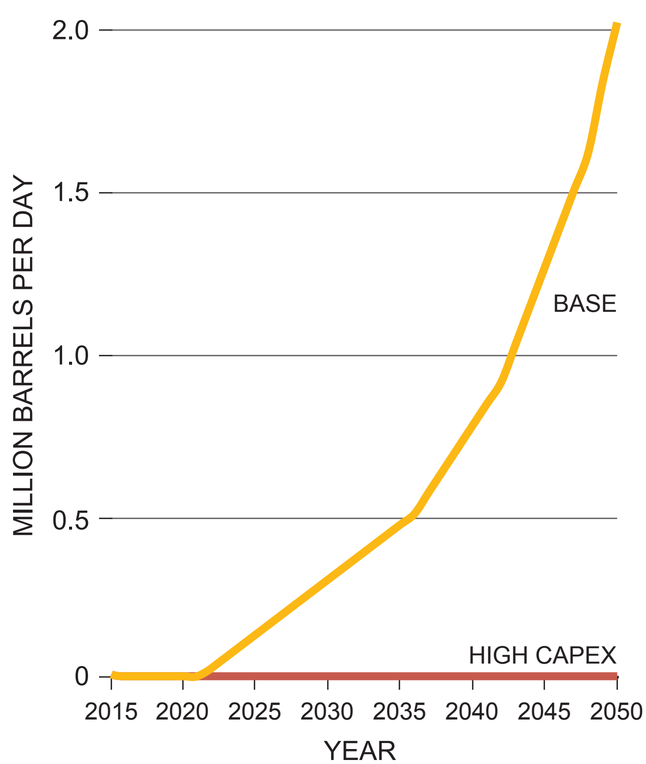


Figure 11-38.
XTL Supply Curves

Fuel	Crude Oil Material Transport	Refining Process and Capacity	Product Distribution Pipeline/Terminal/ Outlet
Oil sands	Geographic pipeline capacity required to transport syncrude to existing refineries.	Upgrades to conventional processes required.	Drop-in
CTL – indirect	Scale to support geographic pipeline capacity likely required to transport to existing refineries.	Distillate product requires very little further processing; gasoline requires upgrade.	Drop-in
CTL – direct	Scale to support geographic pipeline capacity likely required to transport to existing refineries.	Product requires significant upgrading/ hydrotreating capacity.	Drop-in
BTL, XTL	Scale to support geographic pipeline capacity may be an issue. Truck/ rail transport would be a significant logistics hurdle.	Depending on conversion process used, may range from near drop in to significant upgrade capacity required.	Drop-in
Shale	Scale to support geographic pipeline capacity may be an issue. Truck/ rail transport would be a significant logistics hurdle and CO_2 penalty.	Likely to require significant upgrading/ hydrogenation capacity.	Drop-in
Pyrolysis oil from bio	As-produced material may not be suitable for pipeline; on-site upgrading required. Scale to support geographic pipeline capacity may be an issue. Truck/ rail transport would be a significant logistics hurdle and CO_2 penalty.	Significant upgrading/ hydrogenation (oxygen rejection) capacity and technology required. Front end processing through crude units will require upgrading.	Drop-in
Renewable diesel	Scale to support geographic pipeline capacity may be an issue. Truck/ rail transport would be a significant logistics hurdle and CO_2 penalty.	Significant upgrading/ hydrogenation (oxygen-rejection) capacity required.	Drop-in
Biodiesel (fatty acid methyl ester)	Efficient transport, e.g. pipeline, complicated by fragmented manufacturing locations and lack of compatibility with existing hydrocarbon pipelines. Truck/rail transport would be a significant logistics hurdle and cost and CO_2 penalty.	n/a	Need to address compatibility issues in existing product pipelines (jet tailback). Requires investment in terminal blending. Cold weather operational limitations.
E15-EX Ethanol	Efficient transport, e.g. pipeline, complicated by fragmented manufacturing locations and lack of compatibility with existing hydrocarbon pipelines. Truck/rail transport would be a significant logistics hurdle and cost and CO_2 penalty.	n/a	Requires terminal blending. Increased E15-EX may require significant upgrades to terminal facilities for blending and storage.

Table 11-4. *Alternative/Renewable Capital Infrastructure Requirements*

Production is much more likely if capital costs are relatively low, similar to National Research Council and other studies, while production is unlikely if capital costs are more like recent project experience.

Capital Required for Alternative and Renewable Fuel Pathways

Production of alternative and renewable fuels will require varying levels of capital investment to integrate into the existing hydrocarbon fuels distribution system. This investment is above and beyond that required for fuel production and will depend upon whether the product meets current fuel specifications when used in existing infrastructure at high concentrations (neat) or as a blend product. Such fuels are referred to as "drop in" fuels. Specific capital required to establish alternative and renewable fuel manufacture is described elsewhere in this report. A qualitative summary of the infrastructure integration capital required for each fuel pathway is shown in Table 11-4.

Considering the large lower-cost resource base, and the legacy investment in refineries, existing infrastructure, and plentiful dispensing network, hydrocarbon liquids can be expected to continue to provide the majority of transportation fuel for the outlook period.

GHG Emissions and Reduction

GHG emissions associated with use of hydrocarbon liquids are best analyzed on a well-to-wheel (WTW) basis, which includes emissions associated with production, refining, transportation, and use of hydrocarbon liquids. WTW GHG emissions for gasoline, as predicted by the GREET model, are shown in Figure 11-39. The petroleum life-cycle upstream of the vehicle is efficient and most of the energy content of petroleum is retained in the finished fuel such that over 80% of GHG emissions are associated with vehicle fuel use. Most of the remainder results from fuel production, which includes refining and product transportation. Feedstock production from crude oil production and transportation has the smallest emissions. As shown in Figure 11-39, improving vehicle efficiency can lower per-mile emissions significantly. Any reduction in demand reduces both vehicle and fuel-cycle emissions upstream of the vehicle.

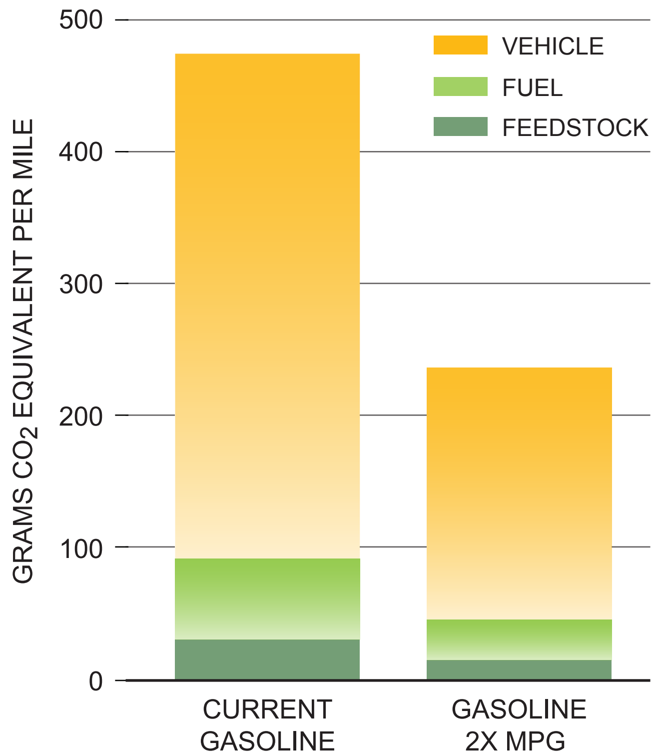
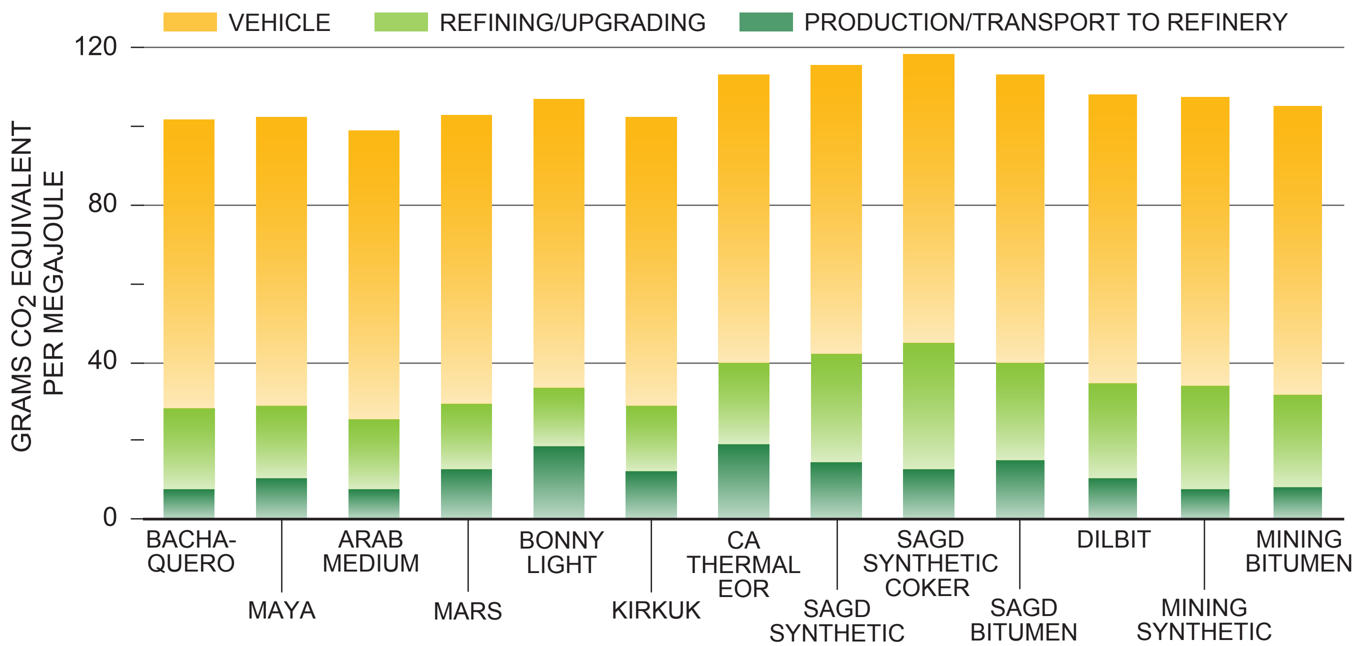


Figure 11-39. *Light-Duty Vehicle Well-to-Wheel GHG Emissions for Gasoline – GREET Model*

GHG emissions for petroleum upstream of the vehicle vary somewhat depending on how oil is produced, transported, and refined. Emissions associated with unconventional oil production are typically larger than conventional oil production due to added energy for production and upgrading. In some parts of the world, natural gas associated with oil production is flared, which produces additional GHG emissions. The GREET model represents an average of the U.S. situation, which uses 9.4% as the Canadian oil sand fraction of U.S. crude oil supplies. Complex refineries, described in the Refining section of this chapter, tend to use more energy and have higher GHG emissions due to added process units. This is balanced, however, by the higher fraction of transportation fuels produced per barrel refined in complex refineries.

Figure 11-40 illustrates the differences in GHG emissions among petroleum sources, including a variety of oil sand production pathways. Emissions from oil sands are slightly higher than conventional production, but there is overlap between the highest conventional fields and the lowest oil sands



Note: g/MJ measures the grams of CO_2 equivalent GHGs emitted per megajoule of reformulated gasoline consumed, after accounting for all emissions from producing and refining the crude or bitumen into reformulated gasoline blending stock, plus all emissions from transporting the gasoline to the sevice station, and burning the gasoline in vehicles.

Sources: The Conference Board of Canada; Alberta Innovates – Energy and Environment Solutions.

Figure 11-40. *Well to Wheels Emissions for Selected Crude Oils*

pathways. Some conventional fields have emissions that are similar to oil sands.

GHG Reduction in Petroleum Pathway

According to a 2010 EPA report, although the potential for reducing emissions in the hydrocarbon liquid supply chain is relatively small compared to the fuel carbon content, there are emission reduction strategies for refining. Most options improve efficiency and reduce energy use. As discussed previously, there has been an ongoing improvement in refining energy efficiency. Further improvement could come from more efficient combustion, equipment (pumps, compressors, etc.) and lighting, reduced heat losses, and a variety of other measures. Generally, these items are small individually and so must be approached in a systematic manner, hence the value of energy management systems, which are already widely in use in refining. The large steam requirements for refining operations make refineries excellent candidates for combined heat and power (CHP). Refineries represent one of the largest industry sources of CHP today, with 103 active plants with a capacity of 14.6 gigawatts.[17] While CHP systems are already in use at the majority of the 145 U.S. refineries, there are opportunities to add CHP or to repower existing plants making them larger and more efficient.

Increased biofuel blending can lower transportation GHG depending on the source of the biofuel. Low-level biofuel blends leverage the existing fuel distribution and vehicle infrastructure, providing an advantage compared to alternatives that require a new infrastructure. There are no major technical limitations to increased biofuel use, but significant investments in distribution and vehicle infrastructure will be needed depending on the biofuel produced.

Carbon sequestration could produce reductions in GHG emissions from refinery and thermal oil production but is expected to be very costly.

17 U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, October 2010.

Current cost estimates for electric power plant coal CCS for the Nth-of-a-kind plant are \$60–\$100/ton of CO_2 avoided.[18] CCS for refining emissions is expected to be significantly more costly than power generation CCS because the CO_2 streams are typically smaller scale and more widely distributed than those from large power plants. Carbon sequestration may be more easily applied to GTL and other non-petroleum pathways, however, due to the presence of a concentrated CO_2 stream as discussed below.

GHG produced in transportation of crude oil and petroleum products are best addressed by using the most efficient transportation modes, which are marine and pipeline. As previously discussed, most petroleum transportation is already by these modes. Increased use of trucks to accommodate biofuels or other new fuels could increase GHG, however.

Gasoline Octane

Increased gasoline octane can improve vehicle fuel economy by allowing use of higher engine compression ratio. Only new vehicles that are designed for the higher octane would benefit significantly. Producing higher octane increases energy use and GHG emissions in refineries. The overall effect of changing octane should be evaluated on a WTW basis that includes both vehicle and refinery effects. A WTW study in Japan found a net increase in vehicle plus refinery GHG for an octane increase from 90 to 95 RON (research octane number).[19]

XTL GHG Emissions

Table 11-5 lists the petroleum ratio for a variety of XTL pathways. The petroleum ratio is defined as the life-cycle GHG emissions of producing and using the XTL fuel divided by the life-cycle emissions of petroleum-derived fuel. Petroleum ratio greater than 1.0 indicates XTL pathways with GHG emissions higher than petroleum, and petroleum ratio less than 1.0 indicates XTL pathways with lower emissions than petroleum. Without sequestration, GTL and especially CTL have higher emissions than petroleum due to higher energy use in fuel production and in the case of coal higher fuel carbon content. However, since XTL produces a concentrated stream of CO_2, sequestration would be more cost-effective compared to utility sources. In this case, XTL can have GHG emissions lower than petroleum. Use of biomass in CBTL provides a small additional reduction relative to CTL with or without CCS; however, the reduction is limited by the small 15% fraction of biomass to the total CBTL feedstock cost.

Transportation 2050 Discussion

As discussed above, demand reduction can produce the largest reductions of GHG in the hydrocarbon liquid pathway. To illustrate the potential benefits and to discuss potential issues, an alternative scenario was developed with reduced demand based on improved vehicle efficiency. The scenario was based on a target of 50% improvement in light-duty and 25% improvement in heavy-duty fuel efficiency per vehicle mile traveled (VMT) by 2050.[20] As expected, the alternative scenario produced a 23–27% reduction in highway vehicle energy, petroleum use, and GHG compared to the reference case. (See Table 11-6 and Figures 11-41 and 11-42.) The largest reductions were in light-duty vehicle GHG emissions, consistent with the greater improvement in vehicle efficiency. By 2050,

18 H. S. Kheshgi, et al., "Perspectives on CCS Cost and Economics," SPE International Conference on CO_2 Capture, Storage, and Utilization, New Orleans, LA, November 2010.

19 Japan Clean Air Program (JCAP). 4th JCAP Conference, June 1, 2005, Session 2; and 5th JCAP Conference, February 22, 2007, Session 1.

20 Laboratory for Energy and Environment, MIT, *Factor of Two: Halving the Fuel Consumption of New US Automobiles by 2035,* 2007; USEPA, NHTSA, CARB, *Interim Joint Technical Assessment Report: Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards for Model years 2017-2025,* September 2010; and USEPA and NHTSA, *Draft Regulatory Impact Analysis, Proposed Rulemaking to Establish Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles,* October 2010.

Technology	CTL (No CCS)	CTL (CCS)	CBTL* (No CCS)	CBTL* (CCS)	GTL (No CCS)	GTL (CCS)
Petroleum Ratio	~2.2	~0.9-1.0	~1.9	~0.8-0.9	~1.1	~0.9
* CBTL plants co-feed 15 weight % biomass.						

Table 11-5. *Life-Cycle GHG Emissions for XTL Relative to Petroleum*

	2010	Refer-ence 2050	Alter-native 2050	Delta Ref.--> Alt.
Energy Use % Relative 2010	–	+33%	-2%	-26%
Petroleum Use % Relative 2010	–	+15%	-12%	-23%
GHG (million metric tons)	–	+28%	-6%	-27%
% Gasoline of Petro-leum	80	73	65	-11%
% Ethanol in Gasoline Pool	9.5	18	25	+37%

Table 11-6. *Highway Vehicle Metrics – Reference and Alternative Cases*

light-duty vehicle GHG emissions were 22% lower than 2010. (See Figure 11-43 for highway vehicle GHG emissions in both cases.) The efficiency gains also result in a large decrease in petroleum imports, approximately 4 MMB/D below the reference case. The reference and alternative cases were based on the AEO2010. The more recent AEO2012 Early Release is projecting roughly 20% less VMT than the AEO2010. Combining the slower VMT growth in the more recent projection with improved vehicle fuel economy would produce even larger reductions in energy use, GHG, and petroleum imports. Even larger GHG reductions could be achieved by the following: increase vehicle efficiency further; change vehicle power, size, or other characteristics; reduce the growth in highway VMT; fuel substitution; or reduced GHG in the petroleum pathway.

Note that the alternative case only considered highway vehicles. Inclusion of non-highway vehicles would dilute the percentage improvement values. Modal substitution, increased efficiency, and fuel substitution are potential measures for air, rail, and marine sectors.

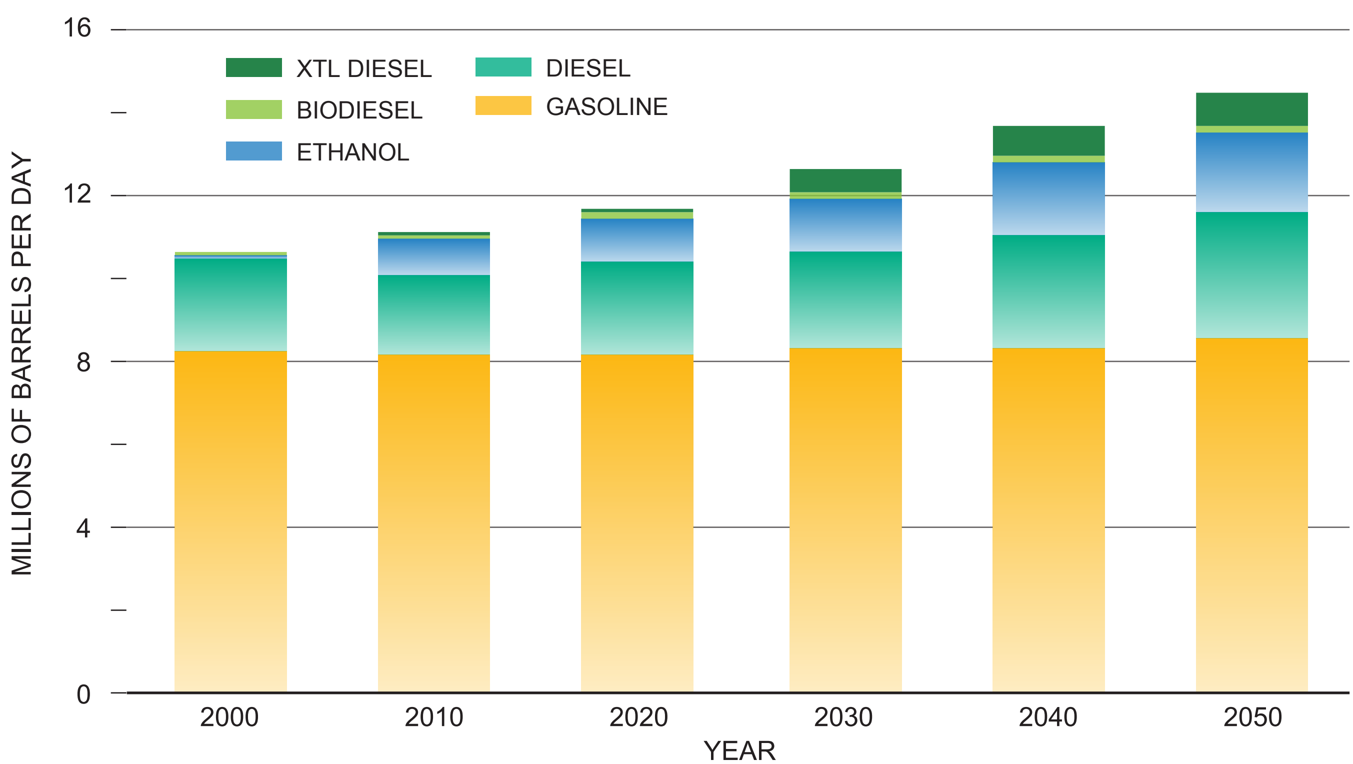


Figure 11-41. *Highway Vehicle Fuel Use – Reference Case (Based on AEO2010)*

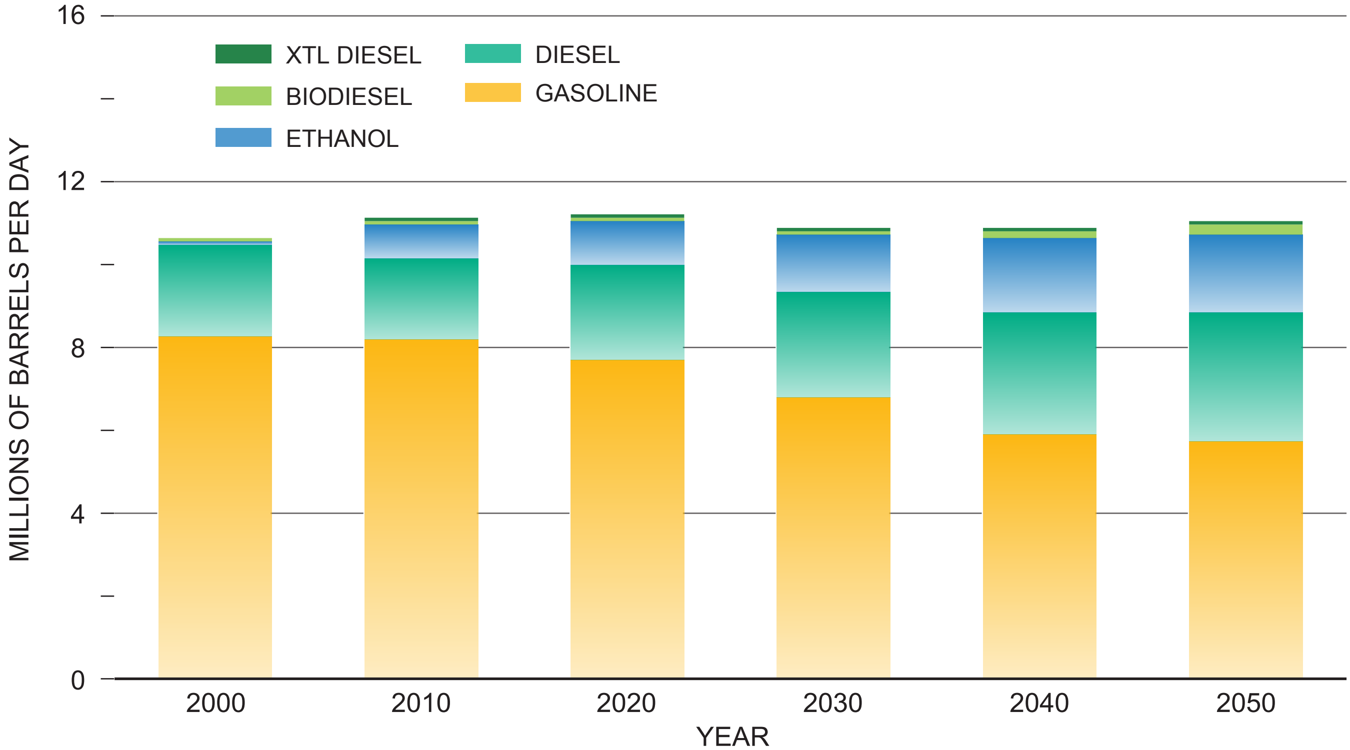


Figure 11-42. *Highway Vehicle Fuel Use – Alternative Case*

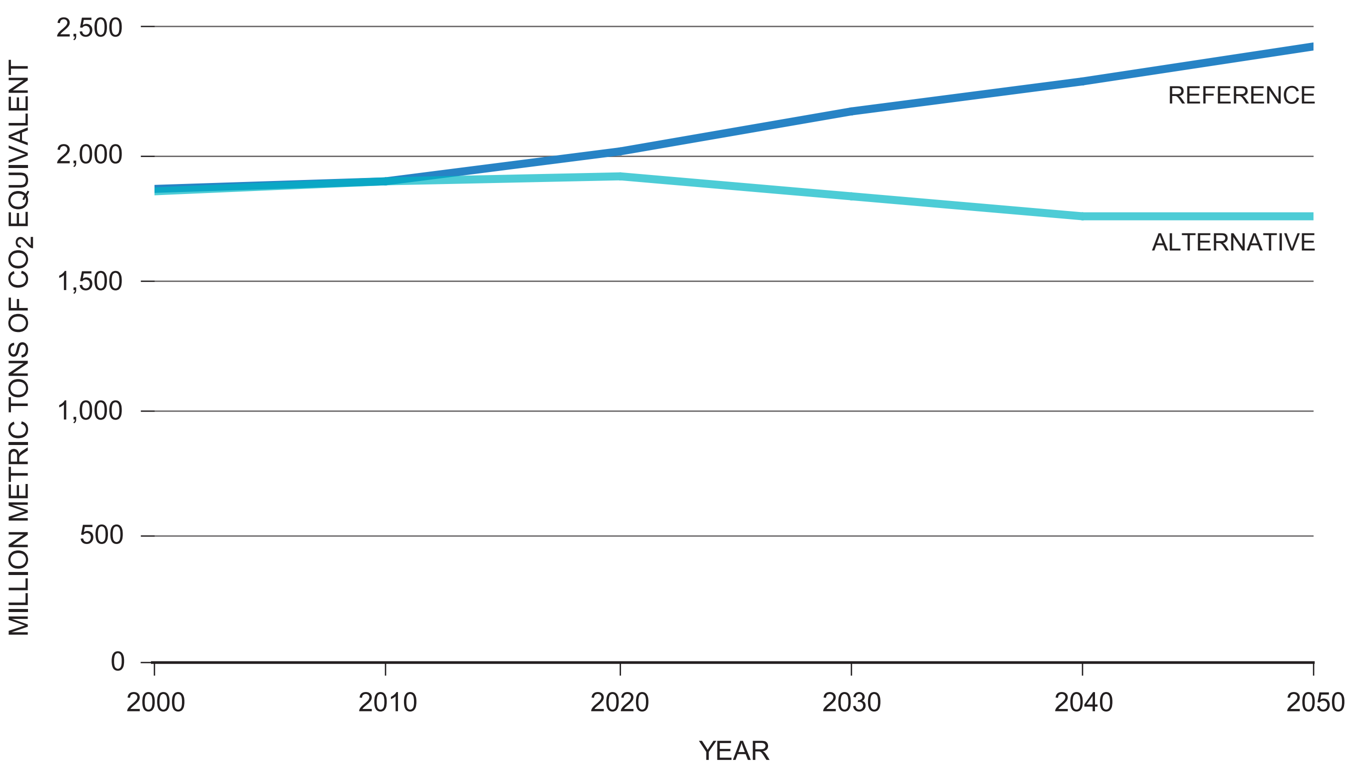


Figure 11-43. *Highway Vehicle GHG Emissions – Reference and Alternative Cases*

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