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# QUADRENNIAL TECHNOLOGY REVIEW

## AN ASSESSMENT OF ENERGY TECHNOLOGIES AND RESEARCH OPPORTUNITIES



Chapter 7: Advancing Systems and Technologies  
to Produce Cleaner Fuels  
September 2015



## Issues and RDD&D Opportunities

- Fossil fuels account for 82% of total U.S. primary energy use.
- Each fuel has strengths and weaknesses in relation to energy security, economic competitiveness, and environmental responsibility identified in Chapter 1.
- Low-cost fuels can contribute to economic prosperity. Oil and gas can be low cost but can also have volatile prices; bioenergy technology costs have declined significantly, but further improvements are needed; and hydrogen costs vary significantly with the source energy used to create the hydrogen, with further reductions needed.
- Energy security requires stable, abundant domestic resources. Oil and gas have large resource bases for domestic production. Bioenergy has intermediate levels of potential supplies. Fossil energy and bioenergy sources have land use constraints and controversies unique to each. Hydrogen can be produced from any energy resource—fossil, nuclear, renewable—so it can be domestically produced.
- Meeting environmental goals requires reduction of greenhouse gas emissions and other externalities. Oil and gas have a poor carbon footprint and other environmental issues that require attention to carbon capture, utilization (where possible), and storage (CCS), as described in Chapter 4. Bioenergy can have a good carbon footprint, and when combined with CCS, can provide a net reduction of atmospheric carbon dioxide levels. Hydrogen can be carbon neutral or not, depending on the source of the energy to produce it and whether CCS is used.
- The economy will rely on a broad mix of fuels, balanced across their various strengths and shortcomings, during the transition from a high-carbon to a low-carbon economy.
- Research, development, demonstration, and deployment (RDD&D) can help address the shortcomings of these fuels while increasing economic competitiveness and energy independence.

# 7

## Advancing Systems and Technologies to Produce Cleaner Fuels

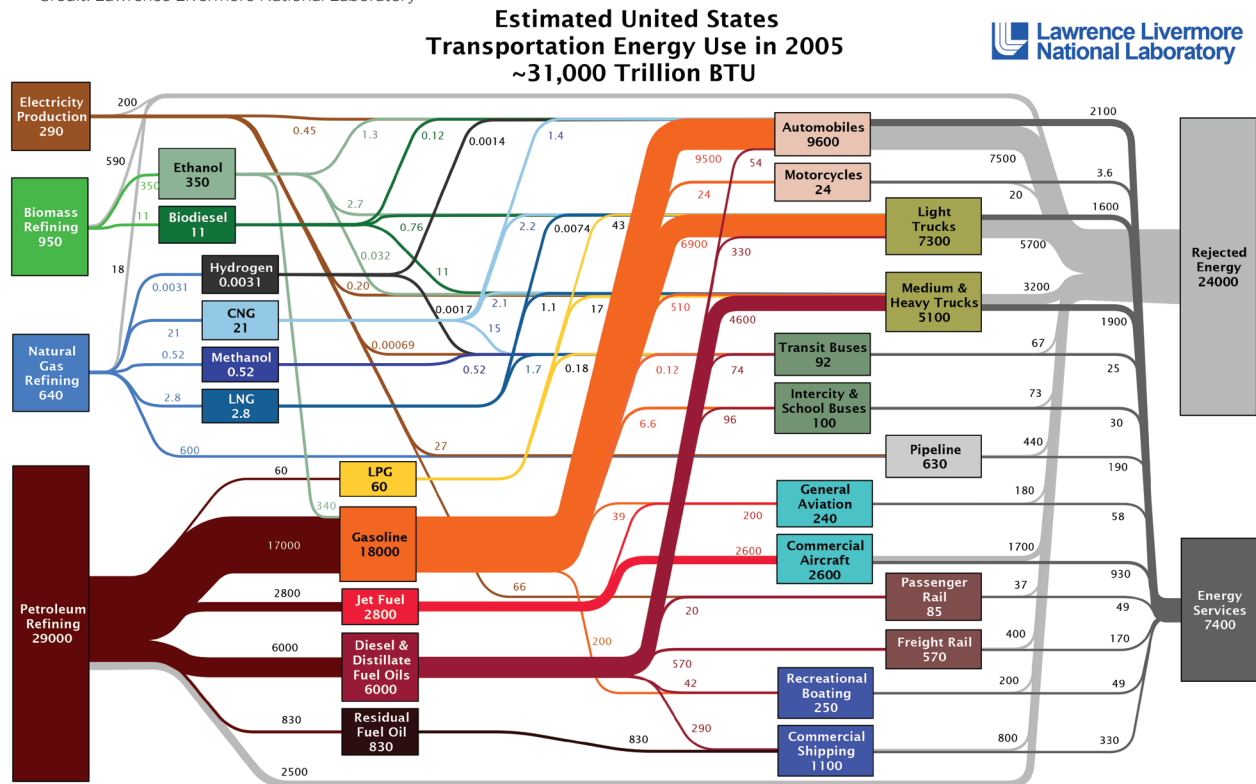
### 7.1 Introduction

Fuels play a critical role throughout our economy. In 2013, fuels directly supplied about 99% of the energy needed by our national transportation system, 66% of that needed to generate our electricity, 68% of that needed by our industry, and 27% of that needed by our buildings.<sup>1</sup>

For the purposes of this Quadrennial Technology Review (QTR), a “fuel” is defined as a carrier of chemical energy that can be released via reaction to produce work, heat, or other energy services. Fuel resources include oil, coal, natural gas, and biomass. The diversity of liquid and gaseous fuel use in the transportation sector is depicted in Figure 7.1. The source and mix of fuels used across these sectors is changing, particularly the rapid increase in natural gas production from unconventional resources for electricity generation and the rapid increase in domestic production of shale oil. Nuclear fuel and other energy resources, such as geothermal, hydropower, solar, and wind energy, are treated separately in Chapter 4.

**Figure 7.1** Sankey Diagram of Transportation Fuel Use

Credit: Lawrence Livermore National Laboratory



Source: LLNL 2011. Data is based on DOE/ORNL-6985(2010), July 2010. If this information or a reproduction of it is used, credit must be given to the Lawrence Livermore National Laboratory and the Department of Energy, under whose auspices the work was performed. All quantities are rounded to 2 significant digits and annual flows of less than 0.0005 trillion BTU are not included. Totals may not equal sum of components due to independent rounding. LLNL-TR-513773

Fossil fuels account for 82% of total U.S. primary energy use because they are abundant, have a relatively low cost of production, and have a high energy density—enabling easy transport and storage. The infrastructure built over decades to supply fossil fuels is the world's largest enterprise with the largest market capitalization.

While fuels are essential for the United States and the global economy, they also pose challenges:

- **Security:** Fuels should be available to the nation in a reliable, continuous way that supports national security and economic needs. Disruption of international fuel supply lines is a serious geopolitical risk.
- **Economy:** Fuels and the services they provide should be delivered to users and the markets at competitive prices that encourage economic growth. High fuel prices and/or price volatility can impede this progress.
- **Environment:** Fuels should be supplied and used in ways that have minimal environmental impacts on local, national, and global ecosystems and that enable their sustainability. Waste streams from fossil fuel production, such as produced water, and from fossil fuel use, such as carbon dioxide (CO<sub>2</sub>) emissions, are causing serious problems in many locations across the globe. Biofuels can raise potential land-use conflicts.

Each fuel type has advantages and disadvantages with respect to our nation's security, economy, and environment. Since these needs are vital to the national interest, it is essential to improve fuels in all three dimensions and maintain a robust set of options for rapidly changing conditions.

In the long term, to reduce U.S. greenhouse gas (GHG) emissions, significant deployment of carbon capture, utilization, and storage (CCS), coal/biomass to liquids (CBTL) and/or bioenergy with carbon capture and storage (BECCS) will be needed to enable fossil fuels to continue to be robust contributors to our nation's energy needs (CCS technology and economics is addressed in Chapter 4). Renewable fuels show promise, but biofuels face land constraints, and hydrogen production from renewables is currently expensive; significant research, development, demonstration, and deployment (RDD&D) remains to solve the challenges associated with scale and cost for these fuels.

In the near to mid term, multiple technological pathways need to be explored to serve as bridges to a low-carbon future. Particular focus should be given to interim technologies that help alleviate GHG challenges while minimizing embedded infrastructure changes that would inhibit the transition to sustainable solutions. Fuel sources such as natural gas and first generation biofuels, if utilized properly, could help enable this transition.

Each type of fuel has an associated system to produce the resource, upgrade, and transport it to a facility for cleanup and/or conversion into its final form for distribution to the end user. Although many of these steps are unique for each particular fuel, some do interconnect, particularly as they enter distribution systems. Here, three major fuel systems and a few alternatives will be discussed. Because the primary focus of this QTR is on RDD&D opportunities, processes for mature fuel systems for which there is no longer a federal role are not considered further here.

This chapter focuses on oil and gas and biomass production and conversion, hydrogen production, and a few alternatives such as CBTL with CCS, with a particular emphasis on fuels for transportation (e.g., automobiles, trucks, off-road vehicles, aircraft, ships). The transportation sector represents one-third of global energy use, one-third of global emissions, and nearly 90% of oil use. Because the fuels are carried on board, the challenges for weight, energy density, and storage are particularly difficult for fuels to meet. Transportation fuels—oil—also represent significant challenges with regard to domestic energy security, balance of trade, and environmental controls.

The United States currently consumes about 290 billion gallons per year of fuels, petrochemical products, and other commodities manufactured primarily from crude oil. Most of these fuels and products are used for transportation or for heavy equipment in the industrial sector. Table 7.1 shows the current composition of this market and anticipated future changes, as projected by the U.S. Energy Information Administration (EIA).

The United States has large reserves of oil, gas, and coal, with reserves of each among the top ten largest in the world. Recent technology developments have led to improved abilities to extract these fossil resources, particularly from unconventional sources, significantly impacting fuel prices in the United States. Increased domestic oil and gas production has brought the United States into production parity with Saudi Arabia, which has important security implications. However, generally increasing global demand is expected to exert upward pressure on market prices over time.

While fossil fuels have advantages from an economic and security perspective, their emissions of greenhouse gases, chiefly CO<sub>2</sub>, and methane (CH<sub>4</sub>), are the primary contributor to global warming. Potential impacts on water systems are also a growing concern. This has led to increased investment, development, and commercialization of fuels that would reduce climate, water, and/or other impacts.

**Table 7.1** Market Size of U.S. Liquid Fuels and Products (billion gallons/year)

	2013	2040 projected	Growth 2012–2040 (percent per year) <sup>a</sup>
Gasoline	136	108	-0.8%
Diesel	55	64	0.6%
LPG <sup>b</sup>	38	50	1.0%
Other <sup>c</sup>	31	37	0.7%
Jet fuel	22	29	1.0%
Residual fuel oil	5	4	-0.4%
<b>Total</b>	<b>291</b>	<b>295</b>	<b>0.1%</b>

Source: U.S. Energy Information Administration, 2015<sup>2</sup>

<sup>a</sup> Growth rate is a compound annual growth rate assuming geometric growth.

<sup>b</sup> Includes ethane, natural gasoline, and refinery olefins.

<sup>c</sup> Includes kerosene, petrochemical feedstocks, lubricants, waxes, asphalt, and other commodities.

Some fuels, such as hydrogen and alcohols, can be derived from both renewable and fossil resources. Hydrocarbon fuels that are compatible with the existing fossil fuel infrastructure can also be synthesized from renewable resources. These fuels have great potential as environmentally sound, sustainable, and domestic resources. To achieve economic parity with fossil fuels, more research is needed and potential environmental consequences will need to be addressed.

This chapter considers three primary fuel pathways—oil and natural gas, biomass, and hydrogen—their associated economic, security, and environmental concerns, and technology and industrial ecosystems. For each, current technology is reviewed and key RDD&D opportunities are identified that could help resolve their challenges. In the oil and gas sector, further research related to resource extraction could lower costs for producers as well as reduce some environmental impacts (Chapter 4). Biofuels can benefit from RDD&D across the entire value chain, from resources through conversion to a variety of refined products. Hydrogen can be produced via a variety of industrially proven technologies from fossil sources such as natural gas, but further RDD&D for producing hydrogen from renewables could lower costs and risks. Hydrogen’s other challenges include storage, transmission, and distribution infrastructure, fuel cell cost and durability, as well as economic

scale-up across the entire value chain. The chapter concludes with a brief survey of additional fuel pathways (CBTL, dimethyl ether, ammonia, etc.), each of which has intrinsic technological merit, but all of which also face challenges.

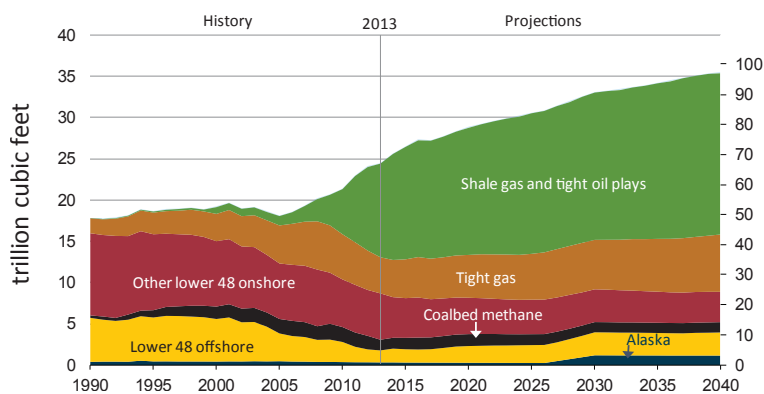
In addition to security concerns for imported oil and economic concerns over fuel prices and price volatility, environmental concerns are important for the entire global fuel enterprise. For fossil fuels used in buildings and some industries, CCS systems near the point of use may often not be possible. This provides motivation for converting fossil resources to low-carbon energy carriers, such as electricity or hydrogen, at a central location where CCS can be deployed, and then using these energy carriers at the distributed locations. Concurrently, development of carbon-neutral fuels utilizing biomass or renewable energy sources is needed. This chapter examines RDD&D opportunities associated with these transitions and their attendant challenges.

## 7.2 Oil and Gas

Until recently, U.S. oil production was in decline. Oil imports contributed more than half of domestic oil

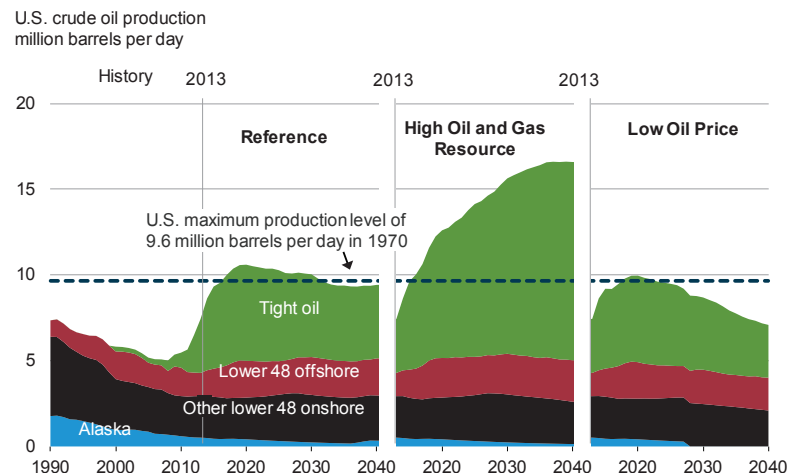
**Figure 7.2** Shale Resources Remain the Dominant Source of U.S. Natural Gas Production Growth<sup>6</sup>

Credit: U.S. Energy Information Administration



**Figure 7.3** Expected Gains in Tight Oil Production Drive Projected Growth in Total U.S. Crude Oil Production<sup>6</sup>

Credit: U.S. Energy Information Administration



consumption. Natural gas investment was moving toward expensive terminals to import natural gas. Today, the United States is the world's largest producer of oil and natural gas. It is exporting more refined products, and is on the path toward exporting liquefied natural gas (LNG).<sup>3</sup> Figure 7.2 demonstrates historic shale gas production and future production potential.

These considerable changes result primarily from technology developments in hydraulic fracturing and horizontal drilling that have allowed industry to produce oil and gas from low-permeability formations including shale and “tight” formations, often called “unconventional resources.” These advances were generated in part by DOE’s technological investments in the early 1980s, and in part by industry’s continued development and application of those technologies.<sup>4,5</sup> Together with increased work in rock mechanics and the understanding of fracture development and propagation

to enhance production, these technological advances have driven the rapid increase in production from unconventional resources. Figure 7.3 shows the projected growth from tight oil production.

Concurrent with these technological advances has been the drive to reduce the environmental impacts of oil and gas production, especially following public concerns about hydraulic fracturing onshore and the BP Deepwater Horizon incident offshore (Figure 7.4). Government mandates to increase safety and environmental stewardship have advanced safety regulations and practices, promoted development of safety cultures, and developed accident mitigation technologies. Industry has also responded with practices that reduce environmental and safety impacts and risks. However, ongoing environmental and safety challenges underscore the opportunity for continued RDD&D, particularly in those areas where there may be significant public benefit but industry may see no return—immediate or otherwise—on that investment.

## 7.2.1 Recent Technology Advancements

In 2011, the National Petroleum Council reported that the resource base for technically recoverable oil and gas was 2.3 quadrillion cubic feet of natural gas,<sup>8</sup> and 167 billion barrels of oil.<sup>9</sup> Advanced technology can help make these resources economically recoverable in an environmentally prudent way.

Progress in technology development over the last five to ten years, both offshore and onshore, has been focused in several distinct areas:

- Sophisticated data acquisition, processing, and visualization applied across the sector, from exploration to field maintenance and safe final plugging of wells
- Water conservation and protection, chiefly through treatments enabling water reuse, as well as use of brines and non-potable water in oil and gas applications
- Materials science, especially in cements and metals used for wellbore isolation and integrity
- Technologies to increase reservoir recovery factors; in particular, via stimulation

**Figure 7.4** BP Deepwater Horizon Oil Spill April 20, 2010<sup>7</sup>

Credit: U.S. Coast Guard



On April 20, 2010, the Macondo well—located about fifty miles from New Orleans in more than 5,000 feet of water, with a pay depth of greater than 18,000 feet subsea—blew out, costing the lives of eleven men and spilling more than four million barrels of crude oil into the Gulf of Mexico. A presidential commission identified the root causes to be associated with zonal isolation during cementing and the failure to create a competent barrier to uncontrolled flow. Other risk factors contributing to this disaster were associated with well monitoring equipment on the Deepwater Horizon, including data displays, and the lack of attentiveness to the risk resulting from deviation from the original designs for well construction.

- Combining increased oil and gas recovery with carbon sequestration in a technique known as CO<sub>2</sub> enhanced oil recovery (CO<sub>2</sub>-EOR)
- Oil spill prevention technology for operations in deep and ultra-deep waters
- Research and development (R&D) for operations in extreme environments, especially the Arctic, which contains significant oil and gas resources in environmentally sensitive areas

However, the most profound technical developments have been in the field of drilling and completions, including horizontal drilling and hydraulic fracturing.

### Onshore Well Construction: Drilling, Completion, and Stimulation

Technologies are being developed that will result in the need for fewer wells overall with far lesser impact on the surface and subsurface environments. Advances include reducing the drilling footprint through the use of drilling pads that allow multiple wells to be drilled from a single pad location.<sup>10</sup> Pad drilling can also enable rigs to be moved using railed systems. More recent technology has led to “walking rigs” that can travel from pad to pad under their own power.<sup>11</sup> New technologies provide more precise information about the subsurface location of oil and gas zones. Of key significance are technologies that allow operators to steer wells more precisely and with greater control.<sup>12</sup> Advances in the chemical formulations of drilling fluids have reduced their toxicity.<sup>13</sup>

There have also been technological advances in well completion and stimulation. Hydraulic fracturing of a single well at various points along the horizontal length in shale formations can dramatically increase initial production from new wells.<sup>14</sup> Advances in fracturing fluid technology plus technologies to treat flowback and produced water may enable production companies to recycle and/or reuse the same water for hydraulic fracturing and other operations depending on technology, transportation, and economic factors.<sup>15</sup>

Examples below of RDD&D for onshore and offshore completion technologies demonstrate how the above technology development areas have played a role in advancing hydrocarbon recovery and reducing environmental impact at the surface and in the subsurface.

### Offshore Well Construction and Operations

Drilling challenges in deep and ultra-deep water are different from those onshore because of the lower strength of these geologic formations, which can increase the risk of loss of well control. Technologies such as dual gradient and managed pressure drilling reduce this challenge, allowing for more controlled—and safer—drilling.

Much technology development has focused on oil spill prevention and mitigation. The Macondo/BP Deepwater Horizon incident focused attention on over-pressured zones and the integrity of the entire well construction system during the drilling process, particularly on the components of the system, such as casing, cement, and the seal that must be established between the rock and the well.<sup>16</sup> Progress has been made in expandable casing,<sup>17</sup> a technology that helps ensure integrity of the wellbore while allowing the well to maintain a larger diameter for a longer interval. This has been accompanied by advances in metallurgy and cement chemistry, resulting in downhole tubulars with lower fatigue and failure rates in the case of metallurgy,<sup>18</sup> and wellbores with enhanced integrity due to advances in cementing technology.<sup>19</sup>

Substantial research has been conducted, and is ongoing, for foamed cement<sup>20</sup> in applications where low density fluids and sealing materials are required, and for alternatives to traditional cement. Integrity monitoring of downhole tubulars and cement, in real time through the placement of downhole temperature and pressure sensors, has been introduced in an attempt to identify and mitigate potential failure.



As in the onshore sector, advances in logging-while-drilling and measurement-while-drilling,<sup>21</sup> including measurements at the drill bit, allow for greater precision in steering deviated and lateral wells, while identifying the potential for unexpected pressure anomalies.

Technological advances with regard to metallurgical options and analysis of fatigue and failure in metal components, especially with application to drilling risers (which connect the well to the drillship), are ongoing.<sup>22</sup> Existing metal properties are being examined<sup>23</sup> and new alloys are being studied and developed. Advances in remote inspection capabilities using remotely operated vehicles and autonomous underwater vehicles are being made.<sup>24</sup>

Blowout preventer design has been reexamined and new technology developed for control systems and sealing and cutting rams. In order to promptly contain the spill at or near the wellhead after a blowout or other loss of well control, industry has invested significant resources in subsea spill containment capabilities.<sup>25</sup>

Considerable progress has been made in subsea processing technologies, allowing processing of produced fluids at the seafloor to be sent from the field to gathering pipeline systems via subsea pumping systems. The corrosion caused by saltwater is another challenge unique to offshore production. Inspection of Gulf of Mexico facilities, especially older ones, is important for continuation of safe operations offshore. New technologies and analytical algorithms have been developed to allow subsea inspection of offshore facilities to identify failed or at-risk structural components.<sup>26</sup>

### Enhanced Oil Recovery (including CO<sub>2</sub>-EOR and ROZ)

Improved oil recovery (IOR) and EOR are technical strategies used to increase the amount of oil and/or gas recovered from a particular deposit. In the past, these terms have had more precise definitions, but now the terms are used more generally to indicate any technical activity that can increase the ultimate recovery from oil and gas reservoirs. These technologies generally include the injection of water, steam, gas, chemicals, or microbes, or other techniques to address some particular barrier in the reservoir that is preventing greater recovery of hydrocarbons. Each has its strengths and all have increased costs that affect project economics.

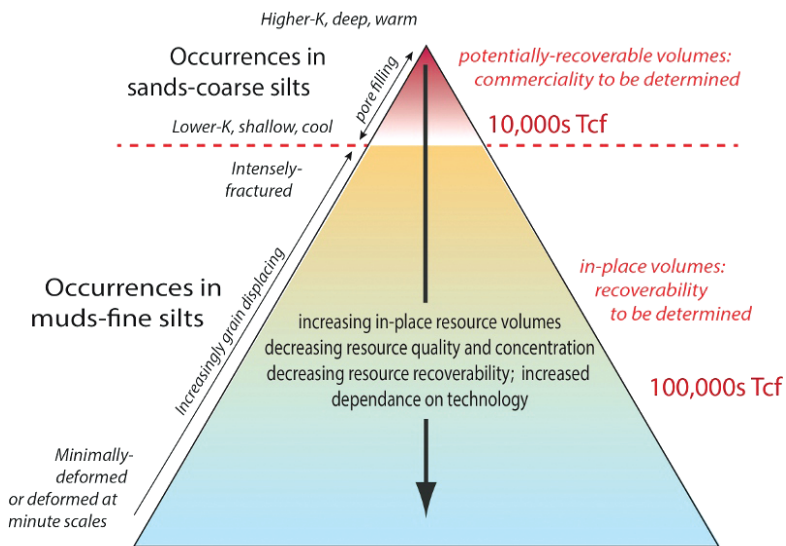
The potential application for CO<sub>2</sub>-EOR has gained interest because of the potential for sequestering CO<sub>2</sub> while improving recovery of hydrocarbons. In two common approaches, CO<sub>2</sub>, either naturally occurring or captured from industrial or power generation processes (anthropogenic CO<sub>2</sub>), is injected into oil bearing formations, either alternating with water (water-alternating-gas) or as a continuous flood in the reservoir. CO<sub>2</sub>-EOR has a lower carbon footprint compared to other EOR/IOR technologies, such as the use of steam. Currently, CO<sub>2</sub>-EOR accounts for about 300,000 barrels or almost 4% of U.S. daily production of crude oil.<sup>27</sup>

CO<sub>2</sub>-EOR is now being used to exploit recently identified residual oil zones (ROZ). ROZs exist in many mature fields and in migration fairways between fields. Within fields, residual oil can be found below the oil/water contact, or in areas that were bypassed in the normal production processes. CO<sub>2</sub>-EOR for producing oil in ROZs began in the 1990s. The oil in the ROZ is immobile (i.e., at irreducible saturation) and cannot be produced by primary or secondary recovery means. However, it does appear to respond well to CO<sub>2</sub>-EOR, and eight fields within the United States produce oil using this technique. It appears possible in some formations to produce oil with a near-zero carbon footprint.<sup>28</sup> More research would help industry understand the size and extent of ROZs, and how to minimize their carbon footprint. ROZ resources located predominantly in the Permian Basin have more than 250 billion barrels of oil in place.

## Natural Gas Hydrates

Traditional assessments of gas hydrate resources produce a wide range of very large estimates. Scientific drilling, experimental studies, and numerical simulation consistently indicate that high-concentration deposits in sand-rich sediments are amenable to traditional oil and gas exploration and production approaches.<sup>29</sup> The latest, but very poorly constrained, assessment of this portion of the gas hydrate resource pyramid (Figure 7.5)

**Figure 7.5** Gas Hydrate Resource Pyramid<sup>30</sup>



is on the order of ~100 trillion cubic feet (Tcf) in Alaska,<sup>31</sup> and perhaps 1,000s to 10,000 Tcf in the United States offshore. One global assessment reports an estimate of 40,000 Tcf in resource grade deposits worldwide,<sup>32</sup> the equivalent of more than 300 years of global gas consumption today.

Gas hydrate research continues to escalate internationally, with programs currently underway in the United States, Japan, Korea, India, and China. These efforts continue to improve the technologies for gas hydrate characterization via remote sensing and field sampling and analysis, and mature the

scientific understanding on the nature, occurrence, and dynamic development of gas hydrate systems. The most aggressive program is underway in Japan, where extensive past drilling has suggested ~200 Tcf of resource potential and enabled advanced characterization of prospective reservoirs off the nation's southeastern coast.

A series of scientific field production experiments conducted in the Arctic by Japan, the United States, and Canada has led to the identification of depressurization as the most promising base technology for gas production from gas hydrates. In 2013, Japan tested this approach for the first time in a deepwater setting with promising results, and has announced their plan for R&D. Detailed geologic descriptions of actual gas hydrate reservoirs have only recently been matched with advanced numerical simulation capabilities that honor the complex thermodynamics of gas hydrate dissociation.

Safety and environmental risks from gas hydrate production are comparable to those in all oil and gas production. Well control risks are more limited because of the shallow, low-pressure setting of gas hydrate reservoirs. Reservoir subsidence and resultant instability in overburden and at the seafloor is a risk that may be most relevant to gas hydrate production, particularly in marine applications, given the shallow and generally unconsolidated nature of most potential gas hydrate reservoirs.

### 7.2.2 Emerging Research Opportunities

Large strides in technology, safety, and environmental practices have been made, yet a set of persistent and emerging challenges remain, which points to a set of research opportunities (Table 7.2). Some opportunities are important to address in the near term, in part because of the driving needs of policymakers, regulators, and

**Table 7.2** Emerging Issues Around Hydrocarbon Production. Near term, medium term, and long term refer to potential outcomes with substantial impacts within the time frame.

Key research opportunities	Near term (2–5 years)	Medium term (5–10 years)	Long term (>10 years)
Environmentally sustainable drilling and completion technologies and methodologies <sup>33</sup>	✓		
Unconventional oil and gas environmental challenges	✓	✓	
Offshore and Arctic oil spill prevention	✓	✓	
Gas hydrates characterization			✓

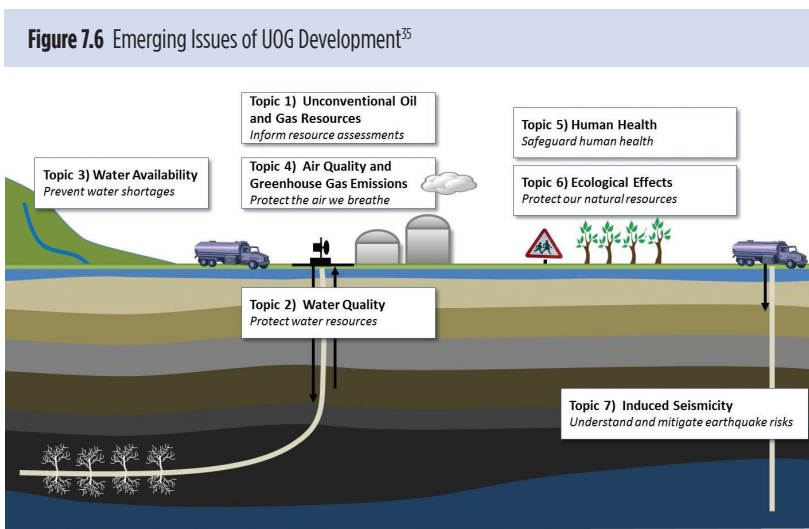
other public stakeholders. Other opportunities are less so, but may either dramatically improve environmental performance or dramatically increase resource availability.

In recognition of these emerging challenges, many groups in industry, government, and academia have highlighted potential RDD&D efforts, including the National Academy of Sciences; federal advisory groups such as the National Petroleum Council (NPC) and the Secretary of Energy Advisory Board; environmental organizations such as the Environmental Defense Fund, Natural Resources Defense Council, and World Resources Institute; and state governments. The oil and gas industry is engaged in significant but often proprietary RDD&D efforts. These challenges can be grouped and divided into the four themes discussed below.

### Environmentally Sound Drilling and Completions

#### “Golden Rules” or Best Practices

The International Energy Agency recently published a set of principles or “Golden Rules” applicable to operations in unconventional oil and gas (UOG).<sup>34</sup> These practices include measurement, disclosure, and engagement with stakeholders; prudent choice of drilling locations; proper well construction designed to protect the environment from wellbore fluids; prudent use of water resources; protection of air quality; and cognizance of the cumulative impacts of UOG development (Figure 7.6). The American Petroleum Institute also publishes standards outlining best practices for all significant activities associated with conventional and unconventional oil and gas development.<sup>36</sup> Analysis and research can help improve understanding of the costs and potential benefits associated with widespread deployment of these practices, and how much they could be improved to reduce risk to the environment in terms of methane (CH<sub>4</sub>) leakage, water quality and quantity, truck traffic, and the subsurface footprint.



### *Protection of Natural Waters (Groundwater)*

Protection of groundwater encompasses a range of biological, chemical, and physical systems for both surface (lakes and streams, as well as near-shore oceans) and subsurface waters (aquifers). Public concern regarding UOG development is related to potential water quality impacts on ecosystems and human well-being. Research opportunities in this area include improved quantitative evaluations of contaminant pathways in water resources that can be used to assess potential human and ecological health effects. Research would also help quantify understanding of water quality impacts over the entire cycle of UOG operations (site preparation, water acquisition, drilling, completion and fracturing, production, wastewater disposal, pipeline construction, and site closure), and how these impacts may vary over time and space and may be attributed to differences in UOG operations.

## Energy-Water Crosscutting Research

Understanding the true impacts of water used and produced during UOG operations is a key challenge. This is important because a small fraction of the estimated 151,000 wastewater injection wells permitted in the United States have documented incidents of felt seismic events resulting from injection activities.<sup>37</sup> A significant increase in these seismic events has been observed in central Oklahoma that is inconsistent with any natural processes; this increase is likely the result of wastewater injection associated with a rapid growth in oil and gas production.

RDD&D opportunities include reducing water use in UOG activities; such as developing treatment technologies for wastewater reuse or recycle. Understanding physical subsurface conditions and mitigation strategies that affect seismic events related to wastewater injection is essential.

DOE has established an integrated technology team, the Energy Water Technology Team, to identify and pursue crosscutting technology, data, modeling, analysis, and policy priorities relevant to the issues that crosscut energy production and water availability, use, treatment, and reuse.

### *Efficient and Reduced Use of Water*

Water is used in the drilling, completion, and stimulation (i.e. hydraulic fracturing) of oil and gas wells. Sometimes large volumes of water are produced with the oil and gas. Key challenges include understanding the true impacts of water withdrawn from surface and groundwater systems, and water produced during the active phase of a UOG operation. Produced and flowback wastewaters are important because instead of injection as wastewater,<sup>38</sup> they can potentially be reused for drilling or in hydraulic fracturing, thereby reducing total freshwater withdrawals. They may also be treated and returned to the environment, potentially reducing demands on the local water budget. Water coproduced with oil and natural gas can range from relatively clean to a high brine concentration depending on the geological setting in which it exists. Several companies produce water from their oil and gas operations of such a quality that it requires only limited treatment before it can be reused to hydraulically fracture other wells or for other production operations activities. Research questions relate to how UOG activities may: impact the quantity and availability of water required for hydraulic fracturing; possibly contaminate drinking water resources; and how new technology can mitigate or otherwise reduce the impact on ground and surface water resources. Research challenges and opportunities exist in a number of areas, including alternative water sources, reducing the volume of water used during hydraulic fracturing, technologies and approaches for beneficial treatments of produced water, and low-water to waterless hydraulic fracturing techniques.

### Waterless Stimulation

Several hydraulic fracturing methods that have been investigated in the past decades use little or no water, and some have been adopted into commercial practice. According to data contained in the *FracFocus* database, 609 stimulations were performed using compressed gases in the 2011–2012 time frame (less than 2%–3% of the hydraulic fracturing in the United States and 20%–30% of the hydraulic fracturing performed in Canada). Even though nitrogen- and carbon dioxide-based stimulation methods have been available since the 1970s, they still represent a niche share of the market. “Waterless” hydraulic fracturing fluids and techniques include nitrogen-based foam, CO<sub>2</sub>-based foam, CO<sub>2</sub>-sand fracturing, straight nitrogen- or straight CO<sub>2</sub>-based fracturing, gelled liquefied petroleum gas (LPG) fracturing, and liquefied natural gas (LNG) fracturing. Each has its own strengths, limitations, and costs. Continued RDD&D into improving the environmental performance and cost of these techniques could yield major environmental benefits.

## Subsurface Crosscutting Research

The many oil and gas wells that have been drilled to date have contributed immensely to current understanding of subsurface environments. Shared interests, for example, include wellbore integrity, which is important in subsurface extraction of resources, energy storage, disposition of civilian and defense waste streams, and the remediation of sites contaminated from past endeavors. Future oil and gas development would benefit from additional knowledge of the subsurface stress state in order to predict and control the growth of hydraulically induced fractures, re-opening of faults, and address concerns related to induced seismicity. Current capabilities to measure or infer the *in situ* stress directly do not provide a detailed picture of the variations in stress throughout the subsurface. To guide and optimize sustainable energy strategies while simultaneously reducing the environmental risk of subsurface injection, radically new approaches could help quantify the subsurface stress regime. DOE has established an integrated technology team—Subsurface Technology and Engineering Research—that includes the DOE offices involved in subsurface activities that are aligned with energy production/extraction, subsurface storage of energy and CO<sub>2</sub>, subsurface waste disposal, and environmental remediation.

## Other Environmental Challenges for Unconventional Oil and Gas

### Induced Seismicity

During 2014, Oklahoma surpassed Alaska and California in the number of annual earthquakes. Geophysicists have long known about the potential for human activity to cause seismic activity, from petroleum extraction to water reservoir impoundments and fluid injection into the subsurface. Changes in fluid volume and pore pressure through fluid injection can induce, and in fact, have induced, seismic events. Thus, the three stages of the UOG life cycle that could potentially cause such events are: 1) the disposal of UOG-produced and flowback wastewaters via deep injection wells, 2) long-term extraction of oil and gas, and 3) large-stage hydraulic fracturing. Current understanding suggests that the potential risk of felt or damaging earthquakes is greatest from wastewater disposal in deep injection wells.<sup>39</sup> Induced seismicity can also occur during other activities, such as enhanced geothermal systems and carbon dioxide, development, storage and operations. There is a need for more data and analysis to relate UOG operations to induced seismic events, to connect these events to specific operational parameters and geologic conditions, and to develop and assess possible mitigation options for use by technical and/or regulatory decision makers in an attempt to minimize seismic risks.

### *Truck Traffic and Alternatives*

UOG development sometimes occurs near communities previously unfamiliar with oil and gas operations. UOG operations involve the transport of equipment, fluids, and other materials, usually by trucks. As a result, truck traffic increases significantly in communities where increased developmental activities occur. The largest contributor to this increased truck traffic is the transportation of fracturing fluids to fields and produced water to disposal sites. Associated with increased truck traffic is increased noise, dust, and air emissions from the trucks. Community engagement can be important for mitigating community concerns. Research is needed to develop alternative methods of transporting fluids, technologies that use less or no water, and pollution and noise mitigation technologies.

### *Control of Methane Leaks*

CH<sub>4</sub> leakage during the production, distribution, and use of natural gas has the potential to undermine and possibly even reverse the GHG advantage that natural gas has over coal or oil.<sup>40</sup> This is because CH<sub>4</sub> is a potent GHG. Methane's lifetime in the atmosphere is much shorter than CO<sub>2</sub>, but CH<sub>4</sub> traps more radiation than CO<sub>2</sub>. The comparative impact of CH<sub>4</sub> on climate change is more than twenty times greater than CO<sub>2</sub> over a one hundred-year period<sup>41</sup> and eighty-six times greater over a twenty-year period.<sup>42</sup> The U.S. Environmental Protection Agency's (EPA) national *Greenhouse Gas Inventory* estimates that in 2012, CH<sub>4</sub> contributed roughly 10% of gross GHG emissions (on a CO<sub>2</sub>-equivalent basis) from U.S. anthropogenic sources, nearly one quarter of which were emitted by natural gas systems.<sup>43</sup> R&D to resolve these emissions sources with unambiguous and reconciled data is needed. Beyond that, technology is needed to reduce CH<sub>4</sub> leaks associated with pipelines and compressors in the midstream infrastructure, and to increase the operational efficiency of natural gas infrastructure as a whole. Research opportunities include improved pipeline inspection technologies; external monitoring technologies and real-time leak detection including sensors; "live" pipeline repair technologies; improved gas compression and compressor controls, and response time to changing demand profiles; and gas storage alternatives.

## Flaring of Associated Natural Gas<sup>40</sup>

Some tight oil production tends to be gas rich. Increased flaring occurs when associated natural gas cannot be economically captured and used (often due to lack of infrastructure). As a result, North Dakota has been flaring 30% or more of all the gas produced in the state. In comparison, the national average for gas flaring is less than 1% of marketed production. Flaring of associated gas from oil production is often allowed so that oil production can start, subsequent revenues can flow, associated taxes and fees can be paid, and prospective gas volumes can be estimated. Where appropriate, gas infrastructure—gathering lines, processing plants, and compressors—can be planned and eventually built.

New technologies that could use and convert into useful products methane that might otherwise be flared, remain an important technology challenge and RDD&D opportunity.

### *Reducing Subsurface Footprint*

Near- and long-term, cumulative environmental impacts of UOG development are dependent largely on the nature and pace of the development process and the geologic and geographic setting where development occurs. At present, industry is striving to increase the low recovery efficiencies typical of UOG development by employing increasingly intensive activities, including more closely spaced wells, stacked wells, and more

fracture stages per wellbore. Technological solutions that enable a prudent balance of maximum recovery efficiency with minimum development intensity require research. These include fit-for-purpose simulation tools, novel stimulation technologies (e.g., energetic stimulation materials), and improved process control systems. Such technology will need to be based on an improved scientific understanding of the fundamental nature of UOG reservoirs as well as the processes that govern the storage, release, and flow of hydrocarbons in response to alternative stimulation designs and approaches.

### Emerging Research Opportunities for Offshore Oil Spill Prevention

The offshore environment can be characterized by geologic, meteorologic, oceanographic, and hydrologic uncertainties that require better understanding to reduce the risk to the environment during oil and gas resource development. In the Gulf of Mexico, water depths of greater than 1,000 feet create substantial logistical and operational challenges. In the Arctic, extreme cold creates surface ice and other logistical issues (e.g., oil flow). Spill prevention is very important, and technologies are needed that ensure well control. A more detailed understanding of the geologic environment where hydrocarbons exist could prevent hazards from leading to failures. Technologies and processes that protect the environment during the drilling and completion of wells and the umbilicals and systems that bring the production to the surface could minimize potential environmental damage. Increased reliability of subsea systems could reduce both cost and environmental risks.

For example, protection of the environment at and below the seafloor during drilling and completion could be improved with novel designs and materials for better wellbore integrity, comprehensive knowledge of wellbore intervention and remediation technologies (pre- and post-decommissioning), and the advancement of capabilities for human interface with sophisticated technology and monitoring systems. Challenges associated with surface systems and umbilicals include large-scale system designs and technology to improve safety and long-term durability, and to increase automation in support of decision making.

As discussed in the recent NPC study *Arctic Potential*,<sup>44</sup> spill prevention is especially important in avoiding the need to implement a spill response in Arctic waters. Research priorities are similar to those for offshore Gulf of Mexico except that surface temperatures and the presence of ice require enhancements to surface systems and equipment to address drilling and production in extreme environments.

### Gas Hydrates: Assessment and Safe and Effective Production

Gas hydrate is a material very much tied to its environment—it requires very specific conditions to form and remain stable. Pressure, temperature, and availability of sufficient quantities of water and CH<sub>4</sub> are the primary factors controlling gas hydrate formation and stability, although geochemistry and the type of sediment also play a part. If the pressure and temperature are just right, free methane gas and water will form and sustain solid gas hydrate. Gas hydrates can be found in pipelines, in the subsurface, and on the seafloor.

Despite being a large resource (Figure 7.5), gas hydrates are far from a viable option for meeting potential domestic energy supply needs in the mid-term. To tap this resource, science and technology advancement on three fronts would be needed. First, the United States' resource must be more fully characterized and confirmed to better understand the opportunity and challenges. While the assessment of gas hydrate onshore in Alaska is relatively advanced, the bulk of the resource lies offshore. Although a joint industry drilling program by DOE, the U.S. Geological Survey (USGS) and the Bureau of Ocean Energy Management (BOEM), confirmed gas hydrate resource occurrence and exploration approaches in 2009,<sup>45</sup> these represent the only wells to validate the BOEM assessment of ~20,000 Tcf of resource-grade gas in the United States' Outer Continental Shelf.<sup>46</sup> This estimate is an order of magnitude more gas than the entire United States' technically recoverable natural gas resource base.<sup>47</sup>

Second, production approaches demonstrated over sufficient time frames can generate reliable estimates of gas/water production. Multiple long-term tests would identify and provide insight into potential production issues (such as sand production, seal integrity, and others). While depressurization will be the base technology for commercial applications, the optimal use of chemical, mechanical, and thermal stimulation could affect site-specific production levels significantly. Initial field experiments are likely to occur in the Arctic, with lessons learned subsequently demonstrated in the deepwater of the Gulf of Mexico. Commercial applications will also likely leverage drilling approaches tailored to the shallow depths at which gas hydrate occurs.

Third, concerns regarding gas hydrate's potential contribution to ongoing climate change must be addressed through continued integration of gas hydrate science into ocean process and global climate models. Gas hydrate geohazard issues, particularly on shallow arctic shelves, are an area of increasing concern.

There is currently little or no domestic industry investment in this area, either on a proprietary basis, or in collaboration with government. Effective collaboration between federal and state research, international research programs, and government agencies would improve any future research in this area.

In summary, the oil and gas sector has undergone significant changes due in large part to advanced technologies. Oil and gas are relatively low cost and represent a large, secure domestic resource. However, to ensure prudent development of the U.S. oil and gas resource base both onshore and offshore, technological advances are still needed to address the remaining challenges.

For UOG, this includes improving water and air quality, reducing the surface and subsurface footprint, and addressing induced seismicity. For water, the concern is protecting groundwater, reducing the amount of water used in UOG development, efficient use of water, and water-less stimulation. For induced seismicity, we need to understand the specific relationship between seismic events and UOG operations—is it related to the disposal of wastewater? Is it related to the size of the hydraulic fracturing treatment? Can faults be identified before they move? We need to understand these relationships and their mechanisms in order to predict and mitigate induced seismicity. Another important challenge is the intensity of development of UOG. The low recovery factor from these wells is leading to more frequent and more intensive stimulation. Understanding the scale and nature of UOG formations could help reduce this intensity, which in turn could lead to many environmental benefits, such as fewer wells, reduced water use, reduced truck traffic, and improved air quality.

Moving to the offshore, the challenges are associated with the complexity of dealing with deep water and deep formations in the Gulf of Mexico, and surface temperatures and ice in the Arctic. The technology opportunity space for oil spill prevention in the Gulf of Mexico includes understanding the geologic hazards in the subsurface before the drilling program is designed, and then being able to handle any anomalies during drilling. This intersection of the natural system with the engineered systems is the point of highest risk in oil and gas development. This risk is exacerbated when drilling through thousands of feet of water into pay zones that can be miles deep and located more than one hundred miles from shore. Once the well is in production, the risk continues. The umbilicals and the surface systems are subject to hurricanes on the surface, and to currents and corrosion subsea. Finally, many of the subsea and seafloor systems are automated, so reliability of the components is critical. Arctic development has significant challenges due to low temperatures, ice, and the remoteness of the location. The recent NPC study *Arctic Potential*<sup>48</sup> advises of the need “to validate technologies for improved well control...”

The issues affecting future supply from gas hydrates focus on two main concerns: 1) how to commercially produce certain hydrate deposits and 2) how to identify the conditions for stability of noncommercial hydrate deposits. The technology space to address these concerns is framed by three key thrusts: 1) characterization of the resource, 2) production approaches for commercial deposits, and 3) conditions of hydrate stability for noncommercial deposits.



Underlying all of these is the need to address carbon emissions to the atmosphere. Technology can help overcome some of the shortcomings associated with oil and gas during the transition to a low-carbon economy. More information on oil and gas is included in the Supplemental Information to this chapter.

## Federal Roles

The oil and gas industry is a mature, worldwide commercial entity. The federal role in this enterprise is necessarily focused on ensuring the public good and manifests itself in activities that protect the environment, improve safety, and contribute to the nation's energy security. The federal role includes partnering across industry on such activities as developing technologies in the public domain that can sustain domestic supply, minimize the footprint of operations by reducing the number of wells drilled, protect water and air quality, reduce the risk of oil spills, and mitigate the risk of pipeline leaks and fugitive emissions.

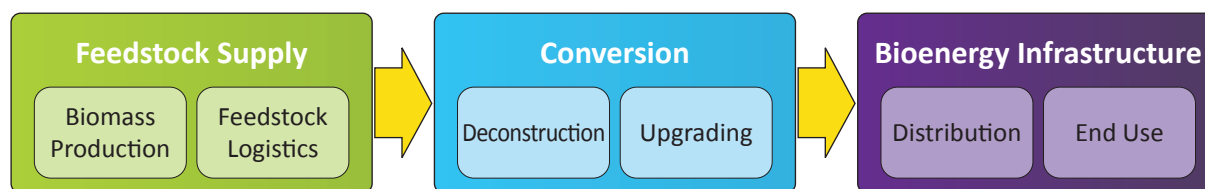
## 7.3 Bioenergy for Fuels and Products

### 7.3.1 Bioenergy Overview

Bioenergy can help meet the need for liquid fuel with lower emissions through production of biofuels and other bioproducts. This requires developing, producing, and collecting sustainable feedstocks, efficient conversion processes, and a competitive final fuel product that has the necessary physical and chemical properties. Properties that are required include appropriate energy content and characteristics for use, acceptable transport characteristics, ability to withstand temperature extremes, and storage suitability.

In general, bioenergy pathways consist of production and collection of feedstock supply; conversion of that feedstock through a wide variety of processes into the desired fuel; and distribution in the energy infrastructure for use (Figure 7.7). In addition, biogenic wastes (e.g., manures, biosolids [treated sewage], food wastes, and municipal solid waste) can be converted into liquid fuels and products. This section describes a variety of technologies across these generalized pathways and associated metrics used to assess the viability and desirability of these technologies.

**Figure 7.7** Overall Pathway for Production of Fuels from Biomass



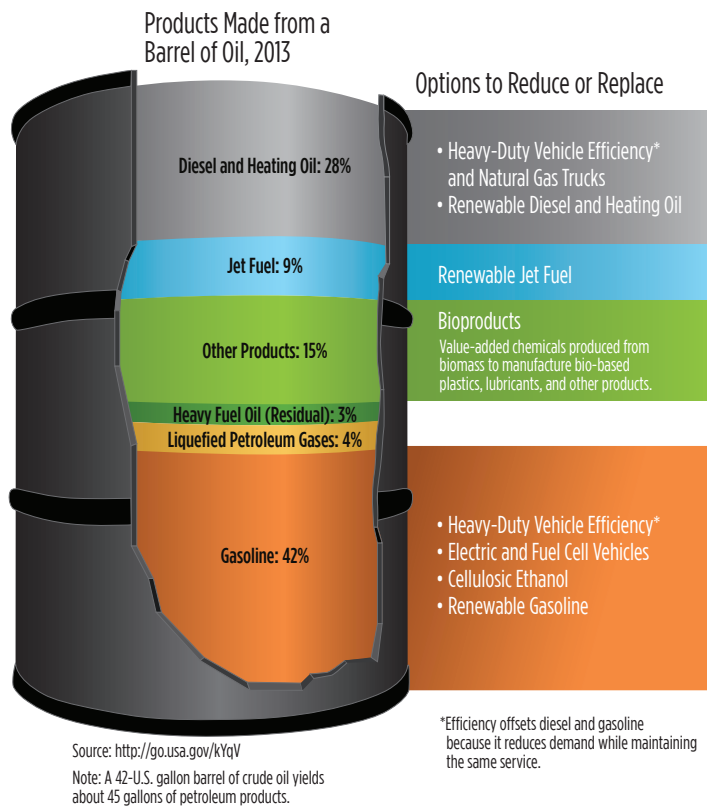
Bioenergy can provide options to replace oil, especially in challenging applications like aircraft fuels, diesel, and bioproducts that can substitute biomass for petroleum feedstocks (Figure 7.8). Renewable fuels are needed for reducing GHG emissions from these sectors because other approaches like electrification are not viable in the near term. A fuel that is compatible with existing infrastructure may increase the ability of the fuel to serve many needs and reduce barriers to deployment.

Bioenergy is considered renewable because it can be replenished through plant growth or use of waste streams. Carbon dioxide emitted from biofuel combustion is generally discounted as an emission because it was captured from the atmosphere in growing the biomass. Cultivation, production, collection, and processing of biomass into fuels and products often involves the use of fossil fuels, which means the resulting life-cycle

**Figure 7.8** R&D options are available to address most products from the whole barrel of oil. Bioenergy can address jet fuel and other products, two fractions that have few other substitutes.

Credit: U.S. Energy Information Administration

## Reducing and Replacing Petroleum Use



energy may not be completely renewable or emissions-free. Growth of biomass may also impact soil carbon or standing biomass. Challenges associated with large-scale utilization of biomass include the need for a large land area to grow biomass feedstocks, water and nutrient requirements for feedstock cultivation, and the impact of feedstock growth because of climate issues.

Life-cycle assessment (LCA) is a technique used to evaluate total energy use and GHG emissions associated with biofuels and compare energy pathway performances. Pathway emissions depend on factors such as the energy needs of the feedstock, logistics energy use, fertilizer requirements, conversion efficiency and chemistry, and biorefinery energy needs. R&D can identify ways to improve the conversion efficiency for many pathways. Fuels under development can reduce the life-cycle emissions

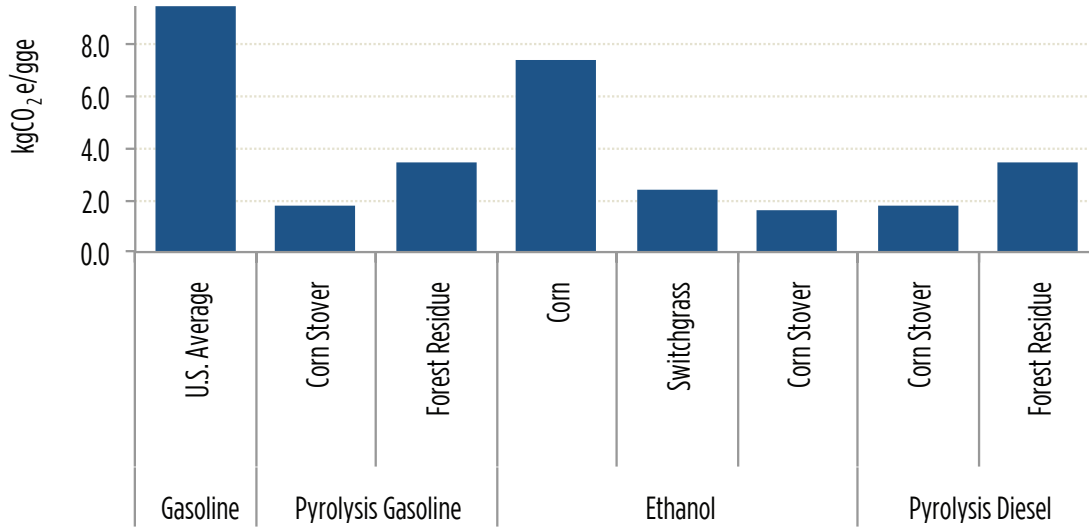
of GHGs in comparison to existing fossil-derived transportation fuels (Figure 7.10). Some topics, such as land-use change, can be challenging to include in an LCA framework and are a subject of ongoing research.

### Total Bioenergy Potential

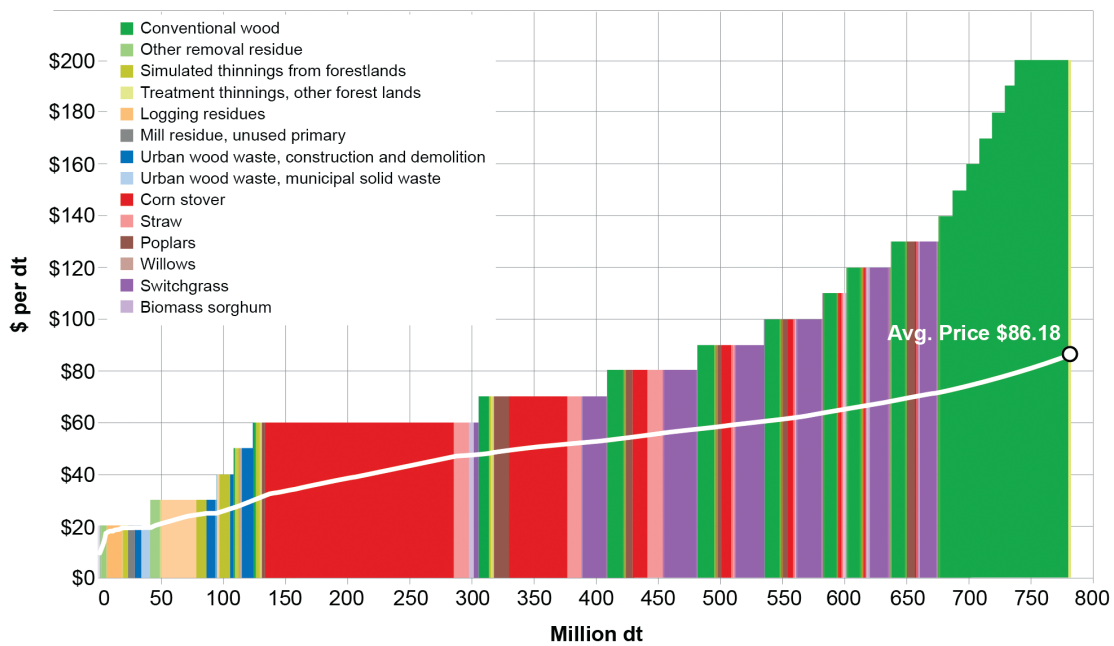
The total emissions reductions and petroleum displacement potential of biofuels and hydrogen depend on factors such as the total sustainable resource, the availability of a cost-effective resource, and the efficiency of conversion technologies (Figure 7.9). More than one billion dry tons of biomass may be available sustainably for use as bioenergy by 2030 (Figure 7.10 and Table 7.3).<sup>49</sup> With technology improvement and a mature market, this available bioenergy could provide approximately 58 billion gallons of fuels to replace gasoline, diesel, and jet fuel—produced from approximately 18 quadrillion British thermal units (Btu) of biomass feedstock by 2050.<sup>50</sup> Capturing this total potential would require significant success in RD&D and market deployment activities.

Even in high-usage scenarios, bioenergy would not supply sufficient energy to totally replace petroleum at current use levels. However, when combined with efficiency and other strategies in transportation (Chapter 8) and industry (Chapter 6), bioenergy can represent a key part of a clean energy future, especially by meeting

**Figure 7.9** Life-Cycle Greenhouse Gas Emissions of Selected Pathways. These are point estimates but significant uncertainty and geographic variation remains regarding the specific emissions associated with each technology or specific biorefinery. Data from Greenhouse Gases, Regulated Emissions and Energy Use in Transportation Model (GREET 2014).



**Figure 7.10** Total Estimated Sustainable Bioenergy Resource Potential Supply Curve at Marginal Prices Between \$20 and \$200 per Dry Metric Ton in 2022



**Table 7.3** Current and Future Potential Impacts of the Bioeconomy. As one possible scenario of potential biomass use in the future, the 2030 vision for the bioeconomy uses one billion dry metric tonnes of biomass—approximately 18 quads of primary energy—to produce the power, fuels, chemicals, and pellets listed below. The biofuels allocation is 14.6 billion gallons of ethanol, 21.8 billion gallons of advanced drop-in fuels, 5.5 billion gallons of jet/aviation fuels, and 15.9 billion gallons of diesel and heating oil, for a total of 58 billion gallons of liquid fuels, which would represent approximately 20% of current total annual petroleum use. Power generation of 90 billion kWh would represent about 2.5% of current electricity generation.<sup>51</sup>

Bioeconomy parameter	Current	Future potential
Biomass utilization	200 million dry metric tons (DMT)	1 billion DMT
Biopower production	30 billion kWh	90 billion kWh
	(22 million DMT)	(60 million DMT)
Biofuels production	15 billion gallons	58 billion gallons
	(164 million DMT)	(918 million DMT)
Biochemicals production	2.5 billion pounds	16 billion pounds
	(7 million DMT)	(44 million DMT)
Wood pellet production	14 billion pounds	34 billion pounds
	(7 million DMT)	(17 million DMT)

liquid fuel needs in uses like jet fuel that are challenging to replace. Conversion technologies need to be developed utilizing lignocellulosic feedstocks, waste materials, and algae that minimize land-use change and deforestation around the world.

### Impact of Success: Growing the Bioeconomy

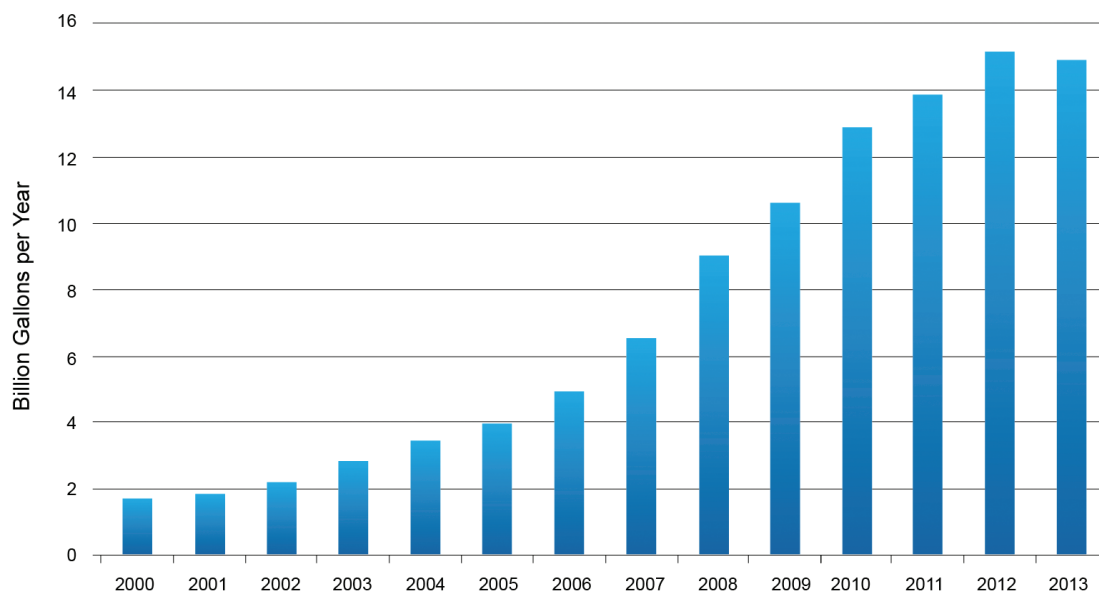
The bioeconomy has potential to provide jobs and economic opportunities, support a secure, renewable energy future, and contribute to improved environmental quality. While the United States has always maintained an active bioeconomy, the potential exists to expand it and use up to one billion dry tons of biomass annually producing renewable fuels, power, and products. This effort would require sustainable production of biomass feedstocks, construction of biorefineries and manufacturing facilities, market growth in biofuels and other biomass-derived products, and development of feedstock production to support the industry. Table 7.3 shows the current and anticipated outcomes from a fully mature bioeconomy.

Increasing utilization of a diverse blend of domestic resources including, renewable fuels such as biofuels, offers a pathway to increase energy security and reduce market uncertainty by increasing diversity.

#### 7.3.2 Current Status

While not as extensive as petroleum-based systems, biofuels have established markets, infrastructure, and industrial processes for production and use in the United States and worldwide. In some parts of the world, biofuels are competitive as a drop-in transportation fuel. In 2013, the United States produced 13.5 billion gallons of ethanol from 211 biorefineries for use as a transportation fuel. This development has scaled up rapidly from less than two billion gallons of capacity in 2000 (Figure 7.11).

**Figure 7.11** Growth in U.S. Ethanol Production Capacity (Source: Bioenergy Technology Office Multi Year Program Plan)<sup>52</sup>



Ethanol from corn remains the largest component of this market. It is consumed in the light-duty vehicle fleet as blends of ethanol/gasoline. Approved blends in the United States' market are E10 (10% ethanol, 90% gasoline, suitable for most vehicles in the road today), E15 (for 2001 and newer light-duty vehicles), and E85 (for flex-fuel vehicles). Biodiesel from soybean and waste oils is also being used in heavy-duty vehicles at blends up to B20, displacing approximately 2% of the diesel market.

Cellulosic biofuels, mandated by the Federal Renewable Fuel Standard and favored by the California Low Carbon Fuel Standard<sup>53</sup> have been slower to enter the market. Recently, there has been significant R&D progress that should lead to reductions in the production cost of biochemically produced cellulosic ethanol. To realize the benefits of this technology, more plants must be built at commercial scale (approximately 50 million gallons per year), and the current technologies must mature as the industry gains experience.

Four commercial-scale facilities have been constructed that can produce ethanol from lignocellulosic feedstocks (Abengoa—25 million gallons per year, DuPont—30 million gallons per year, INEOS—8 million gallons per year, and POET-DSM—25 million gallons per year). These facilities convert corn stover, citrus waste, and other types of agricultural residues into ethanol. Although these accomplishments are substantial and represent important benchmarks for technology demonstration, they remain a small part of the fuels market.

Three additional commercial-scale cellulosic biofuel projects (Emerald Biofuels, Fulcrum BioEnergy, and Red Rock Biofuels)<sup>54</sup> are in the construction phase. These projects will use municipal solid waste, waste oils and greases, and woody biomass to produce renewable jet fuel and renewable diesel. These fuels are nearly identical to their fossil-derived counterparts and are approved for blending at 50/50 levels with conventional jet fuel/diesel in the civil and military aviation sectors. Production from these facilities is expected to begin in 2017, and when fully operational, they will produce 100 million gallons/year of renewable diesel and jet fuel.

Despite recent progress, key barriers remain for advanced bioenergy technologies. Although there are more than seventeen million vehicles on the road that can use E85, various factors have limited E85 use in practice, and E15 is not yet widely deployed. This means that additional ethanol cannot simply be added to the fuel mix beyond the current 10%.

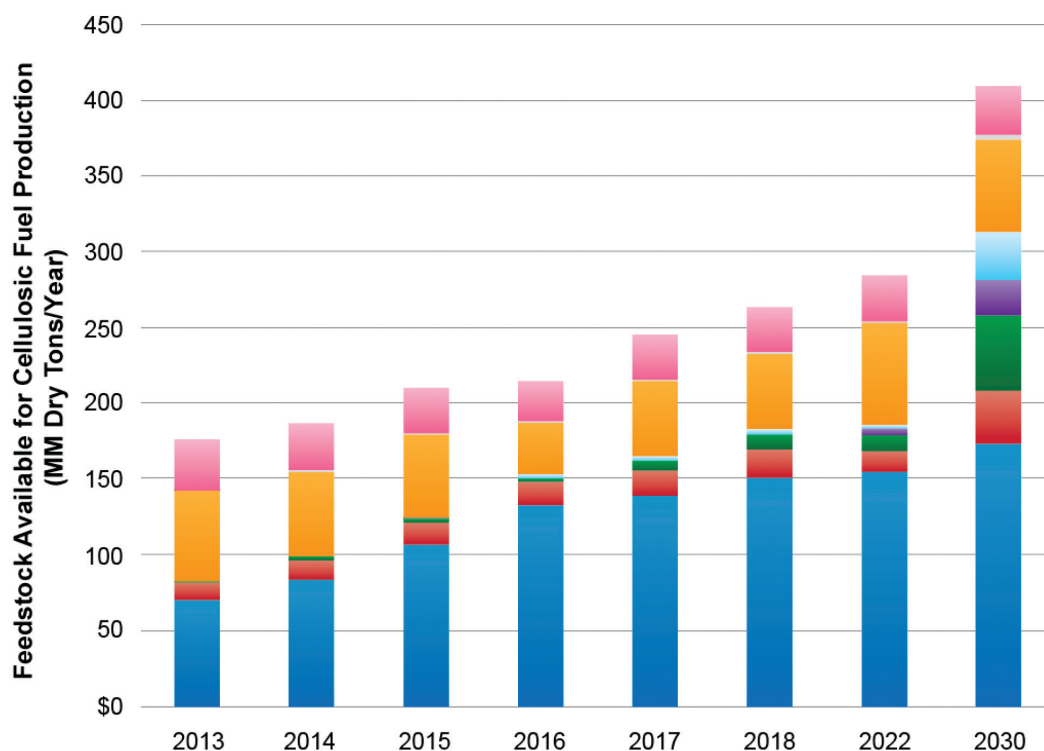
### 7.3.3 Feedstocks and Logistics

The sustainable supply of quality, cost-effective feedstocks is fundamental to growing the bioenergy industry. However, the inherently dispersed nature of biomass remains a central challenge. Four broad categories of feedstock are discussed here: 1) terrestrial feedstocks, 2) lignin, 3) algal feedstocks, and 4) waste feedstocks.

#### Terrestrial Feedstocks

About 200 million dry tons of biomass is currently used today. The largest energy use of biomass (44%) is in the industrial sector where wood/wood waste is used in paper mills to provide heat and steam via boilers. The transportation sector uses the next largest share of biomass (31%) in the form of corn-based ethanol and soybean-waste oils-based biodiesel. Corn and soybean harvesting, logistics, and collection systems are mature following many years of fine-tuning and development. The remaining biomass consumption is fuelwood in residential and commercial sectors. A small amount of biomass is consumed by the electric power sector. About 65% of the biomass is woody material and comes from forest sources. The delivered price for pulpwood ranges from \$30–\$40/green ton (Figure 7.12).

**Figure 7.12** Historical and Projected Volumes of Biomass Available at a Delivered Cost of \$80/Dry Metric Ton for Various Biomass Types, Accommodating Multiple Conversion Processes. NOTE: Higher projected volumes are attributable to a variety of factors, including increased biomass yields, capacity and efficiency improvements in logistics systems, and logistics strategies such as blending.



Today, a quality, affordable feedstock supply uses conventional logistics systems developed for traditional agriculture and forestry systems. These are designed to move biomass short distances for limited-time storage (less than one year). It appears that such systems are not well configured for a diverse, much larger set of feedstocks and their associated transportation requirements, especially in medium-to-low yield areas. Advanced, purpose-designed, economical systems designed to deliver feedstocks with predictable physical

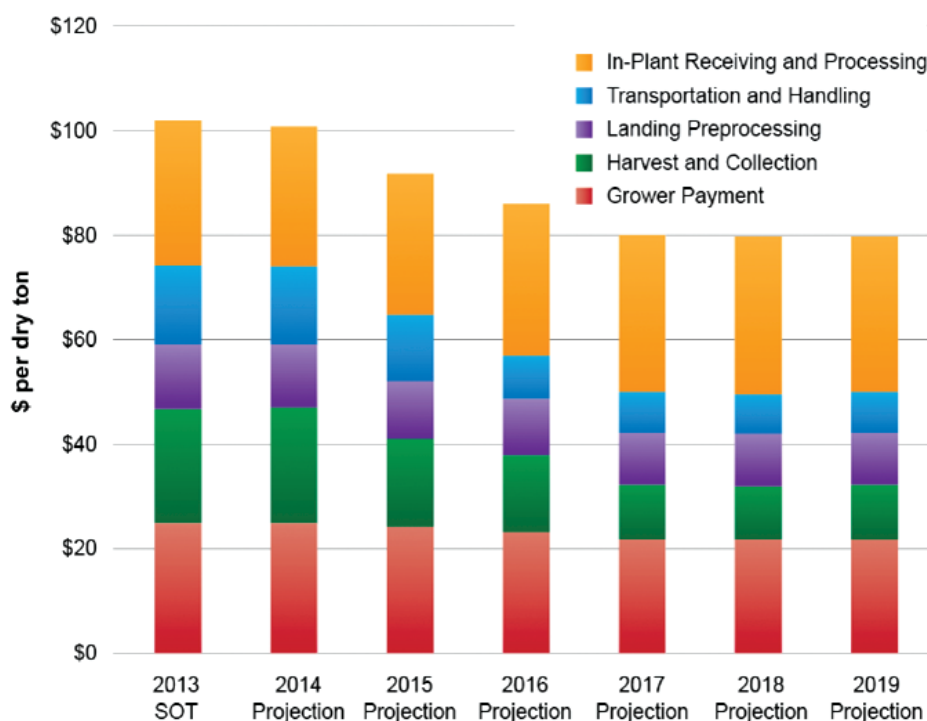
and chemical characteristics, longer-term stability during storage, and high-capacity bulk material handling characteristics can facilitate economic transport over longer distances and lower costs of biofuels. One approach to achieving this is applying preprocessing techniques, such as blending.<sup>55</sup>

Energy crops are produced primarily to be feedstocks for energy production—as opposed to agricultural or forest residue, which are byproducts of another commodity. Examples of energy crops include switchgrass, miscanthus, and energy cane. Farmgate price is defined as the price needed for biomass producers to supply biomass to the roadside. It includes, when appropriate, planting, maintenance (e.g., fertilization, weed control, pest management), harvest, and transport of biomass in the form of bales or chips (or other appropriate forms—e.g., billets, bundles) to the farmgate or forest landing.

Biomass price projections with quality information obtained from the Biomass Resource Library and Properties Database<sup>56</sup> have shown that gains in projected volumes can be realized by transitioning to a blended feedstock approach.

Traditionally, terrestrial feedstock logistics research has focused on improving conventional systems. Through 2012, conventional woody supply system costs were reduced by improving existing equipment efficiencies, adopting innovative ways of mitigating moisture content, and increasing grinder performance. Many researchers have since concluded that conventional feedstock supply systems would remain inadequate for a competitive biofuels industry, and focused on advanced logistical systems and nonideal feedstock supply areas to increase the total volume of material that could be processed, enable more biorefinery options, address quality, and meet the 2017 cost target of \$80 per dry ton delivered to the biorefinery inlet. Advanced systems could gradually bring in larger quantities of feedstock from an even broader resource base after 2017, as well as incorporate environmental impact criteria into availability determinations and continue to meet both quality requirements and the \$80 per dry ton cost target (Figure 7.13).

**Figure 7.13** Historical and Projected Delivered Woody Feedstock Costs, Modeled for Pyrolysis Conversion



Key: SOT = State of technology

A feedstock cost target of \$80 per dry ton is estimated to be sufficient to supply biomass that meets a set of required specifications (ash content, moisture, particle size distribution, amount of material) for fuel conversion facilities.<sup>57</sup> The cost includes a grower payment to the farmer to reflect the added inputs needed to grow and/or harvest the material. A conversion facility can expect to achieve an efficiency of about 70 gallons of fuel/dry ton. Feedstock cost of \$80 per dry metric ton adds about \$1.14 per gallon to the fuel conversion cost.

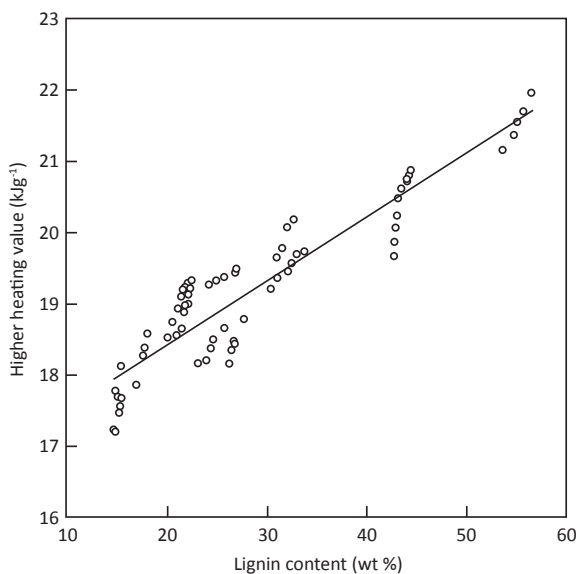
## Lignin

Lignin is a large molecule and component of woody biomass cell walls that gives wood its distinctive structure. A total resource availability of 300 billion metric tons of lignin exists in the biosphere,<sup>58</sup> making it one of the most abundant natural polymers on Earth. Assuming an energy content of 25 kJ/g, the renewable resource is equivalent to nearly 8,000 quads worldwide. Of course, only a small fraction of this energy can be used for bioenergy or bioproducts.

Burning wood for heat energy is among the oldest forms of human energy use. Commercial experience with lignin is also long-lived; in 1927, the Marathon Corporation began investigation into commercial uses for lignin other than as boiler fuel. Successive uses have included a diverse slate of products, from bulk chemicals like agricultural dispersants to specialty chemicals like vanillin. Other companies have recently developed injection molding substances from lignin (Tecnaro GmbH) and produced expanded polyurethane foam using lignin.

**Figure 7.14** Correlation Between Lignin and Energy Content in Biomass Samples<sup>59</sup>

Credit: Reprinted from Energy Conversion and Management, 42, Demirbas, A., Relationships between lignin contents and heating values of biomass, 183-188, Copyright (2001), with permission from Elsevier.



The higher heating value (HHV) of different types of biomass samples correlates with the sample's lignin content (Figure 7.14). For biofuel production, particularly through biochemical conversion technology routes, lignin is often an under-utilized biomass component due its digestion resistance. Most often it is used on-site at the biorefinery to generate energy and process heat. Lignin can make up as little as 15% of herbaceous plant composite and as high as 35% of some softwood species. Lignin is too high of a percentage of biomass to ignore for biofuel cost-competitiveness.

One solution to costs and logistical issues is blending. Feedstock blending allows a biorefinery to collect less of any one feedstock and thus move down the cost versus supply curve, enabling biorefineries to pay a lower average price. The blended feedstock concept is being explored by two lignocellulosic biomass conversion facilities: Abengoa in Kansas and POET in Iowa. Preliminary results suggest that blending multiple preprocessed feedstocks enables the acquisition of higher biomass volumes and reduces feedstock variability to meet biorefinery in-feed specifications, while delivering feedstock to the biorefinery at \$80/dry metric ton.



## Algae

Algal biomass includes micro- and macro-algae and cyanobacteria, all abundant in the earth's oceans and freshwater causeways. Because algae grow rapidly, and thus potentially could scale as a commercial feedstock, biofuels derived from algal biomass could contribute to a substantial domestic advanced biofuel market. Advantages of algae-derived biofuels include the ability to grow on nonarable land (including potentially offshore) and the ability to use brackish or saline water and grow on waste nutrients and effluents, including carbon dioxide from power plants. Algae may also have a limited concentration of ash (the inorganic components of biomass) and can accumulate significant amounts of lipid.

This high-lipid content has special merit for biorefining. Algal species that accumulate significant amounts of lipid in their cell structure are particularly well suited for economic conversion to hydrocarbon-based fuels such as renewable diesel and jet fuel. Research has the potential both to increase algal growth rates and maximize lipid content. However, algae have their own challenges. Depending on the setting and production system, production costs can be very high, and both water and micronutrient requirements can be substantial. R&D opportunities include reducing the cost of production of algal biomass and intermediates, developing cultivation and logistics systems for producing fuels and products at commercial scale, developing innovative dewatering technologies, and developing algal species that can survive and maintain high productivity in nonlined open pond algal farms. These costs must be substantially reduced for viable commercial competitiveness.<sup>60</sup>

Table 7.4 shows projected minimum fuel selling prices for algae-based biofuels based on reasonable yield assumptions derived from literature and technical projections. The greatest opportunity to reduce costs is in production systems through improved biomass yield and reduced cultivation capital costs. Achieving the 2022 projection requires the following: a fivefold improvement in biomass yield through increased productivity and extractable lipid content, a factor of two reduction in capital costs for pond construction (including removing pond liners from the design), and significant capital and operability improvements in the harvest and preprocessing steps.

**Table 7.4** Summary of Cost Contributions (\$/gallon of product) for the Algal Lipid Upgrading Design<sup>61</sup>

Unit operation	2010 state of technology	2014 projection	2018 projection	2022 projection
Feedstock	\$16.50	\$10.60	\$5.19	\$3.05
Conversion	\$1.72	\$1.56	\$1.11	\$1.11
Hydro-treating	\$1.84	\$1.84	\$1.84	\$0.29
Anaerobic digestion	\$0.68	\$0.65	\$0.47	-\$0.18
Balance of plant	\$0.00	\$0.00	\$0.00	\$0.08
<b>Total</b>	<b>\$20.74</b>	<b>\$14.66</b>	<b>\$8.61</b>	<b>\$4.35</b>

## Waste to Fuels

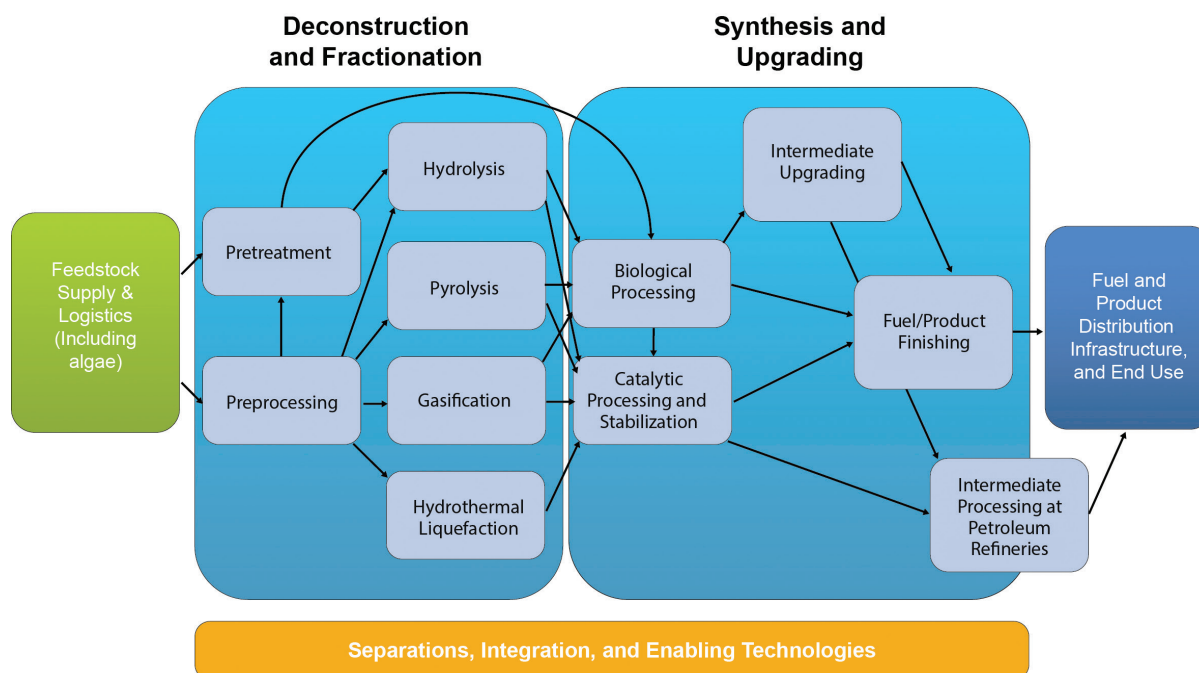
In addition to purpose-grown crops, municipal, industrial, and agricultural waste streams constitute a significant resource for the production of fuels, product precursors, heat, and electricity. Waste feedstocks have an inherently attractive quality—using them likely provides solutions to problems of waste management and disposal. Two facilities in the United States currently convert waste fats, oils, and greases into renewable diesel (Diamond Green Diesel facility in Louisiana—130 million gallons per year and REG’s plant in Geismar, Louisiana—75 million gallons per year of renewable diesel).

The *Biogas Opportunities Roadmap*, issued jointly by the U.S. Department of Agriculture, EPA, and DOE, estimates that the combination of biogas production from agricultural manure operations, landfills, and water resource recovery facilities could yield 654 billion cubic feet per year. If converted to electricity, the roadmap projects potential generation of more than 40 terawatt-hours, more than 1% of the United States’ current consumption according to the EIA. This figure is probably conservative, as it does not include organic industrial wastes. Biogas used in compressed or liquefied natural gas vehicles and biogas used to generate electricity to charge an electric vehicle both qualify as cellulosic biofuels under the Renewable Fuel Standard.

### 7.3.4 Conversion Pathways

Biological feedstocks and their intermediate products (e.g., crude bio-oils, syngas, and sugars) must be upgraded to produce a finished product. These finished products could be fuels or biochemicals, or could be stabilized intermediates suitable for finishing in a petroleum refinery or chemical manufacturing plant. To produce energy-dense, liquid transportation fuels, a variety of conversion technologies are being explored that can be combined into pathways from feedstock to product (Figure 7.15).

Figure 7.15 Conversion Pathways from Feedstock to Products

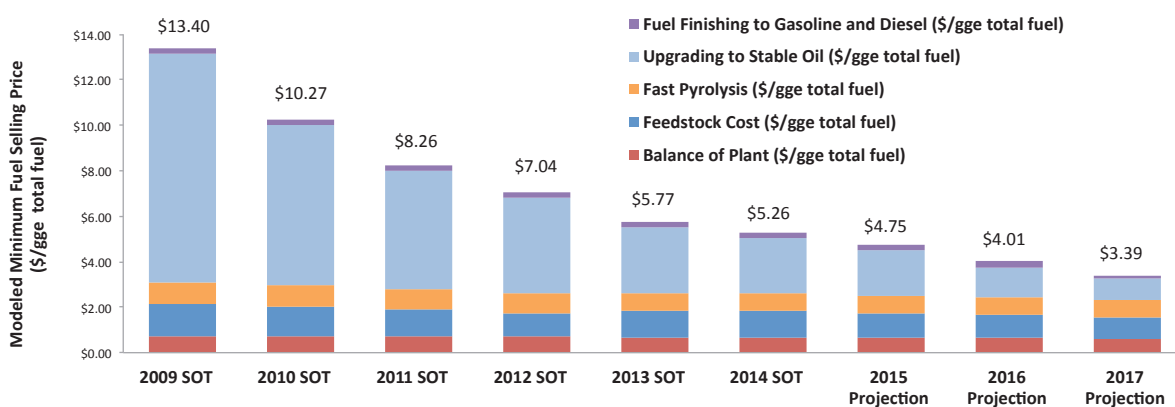


Historically these pathways have been roughly classified as either biochemical (using biological processes such as organisms or enzymes) or thermochemical (using chemical catalysis and chemistry) to reflect the primary catalytic conversion system employed as well as the intermediate building blocks produced. Generally, biochemical conversion technologies involve pathways that use sugars and lignin intermediates, while thermochemical conversion technologies involve pathways that use bio-oil and gaseous intermediates. Specific process variations impact performance (e.g., rate, selectivity, and yield), which determines economic viability and potential environmental impacts (e.g., life-cycle assessments).

## Conversion Process Steps

Conversion can be broken down into two parts: 1) deconstruction and fractionation, and 2) synthesis and upgrading. Figure 7.15 highlights key technologies within deconstruction and fractionation as well as synthesis and upgrading, which are linked to form a complete conversion pathway from feedstock to products. Research on multiple technologies along several pathways can address the broad range of physical and chemical characteristics of various feedstocks and reduce the risk that any specific technology could fail to reach commercial viability. Additionally, each linked set of conversion technologies results in the production of a unique product slate whose value will vary depending on market size and demand.

**Figure 7.16** Cost Projection Breakdown for the Fast Pyrolysis Design Case, 2009–2017



**Deconstruction and fractionation:** Deconstruction and fractionation processes break down biomass-derived polymeric feedstock into tractable intermediate streams. After preprocessing and/or pretreatment, deconstruction processes can be divided into two categories: high-temperature deconstruction (at or above 100°C) and low-temperature deconstruction.

Development of a variety of conversion technologies is necessary to address the broad range of physical and chemical characteristics of various biomass feedstocks. Preprocessing options include densification and blending of an expanded pool of feedstocks, and also impact conversion.

- **High-temperature deconstruction** encompasses pyrolysis, gasification, and hydrothermal liquefaction. Each of these approaches is a conventional chemical engineering process, but application to biomass feedstocks is relatively new, and issues of cost, feed systems, ash handling, and other engineering and material handling topics remain important.
- **Low-temperature deconstruction** is the breakdown of feedstock into intermediates by pretreatment followed by hydrolysis. In this context, pretreatment is the preparation of feedstock for hydrolysis and separation of feedstock into soluble and insoluble components. This process opens up the physical

structure of plant cell walls, revealing sugar polymers and other components. Hydrolysis is the breakdown of these polymers either enzymatically or chemically into their component sugars and/or aromatic monomers.

One conversion method, fast pyrolysis, has made important progress since 2009 and appears on track for market parity prices with ethanol in the next five years. The updated fast pyrolysis design case uses a blended, formatted woody feedstock to produce gasoline and diesel blendstock with costs modeled for n<sup>th</sup> plant biorefineries. This design case illustrates how the \$3 per gallon of gasoline-equivalent cost goal can be achieved by 2017.<sup>62</sup> The waterfall chart in Figure 7.16 shows that a 75% cost reduction is projected to be achieved from the 2009 state of technology (SOT) to the 2017 projection made possible by decreasing bio-oil upgrading costs through R&D efforts in catalyst improvement. In addition to large cost reductions, the renewable blendstocks produced are projected to have GHG reductions of greater than 60% compared to petroleum-based blendstocks.

### Thermochemical Conversion: Fuels and Petrochemicals

The thermochemical process used today for cellulosic conversion is gasification, including a gasifier, syngas cleanup, and catalytic fuel synthesis reactors. Significant process engineering improvements have been achieved within the gasifier and fuel synthesis steps, and technical improvements have been achieved in the syngas cleanup and catalytic fuels synthesis steps. Notable past breakthroughs have included the optimization of an indirectly heated fluidized bed gasifier; the development of tar- and methane-reforming catalysts that increased methane conversion to syngas from 20% to more than 80%; and development of catalysts and operational strategies for the conversion of syngas to mixed alcohols production. These key improvements have resulted in an increase in ethanol yield from 62 gallons to greater than 84 gallons per ton of biomass.

### Bioproducts

There are compelling economic and environmental reasons to pursue the development and manufacturing of biobased chemicals, in addition to fuels. The enabling research, technology development, and commercial demonstration of such technologies in the 1990s and early 2000s yielded substantial progress, outcomes, and commercial successes. These include the DuPont Tate and Lyle's 1,3-propanediol facility in Tennessee, Natureworks' polylactic acid facility in Nebraska, and the Myriant succinic acid facility in Louisiana. Each facility can generate more than a million pounds per year of renewable chemicals, effectively displacing fossil precursors of these materials.

Bioproduct markets are well developed, and the bioproducts compete directly with petroleum counterparts on a basis of cost and purity. Other bioderived chemicals may offer improved functionality compared to petroleum-derived chemicals. Such bioproducts may have an inherently higher value, but their markets will take time to develop, increasing risk.

Because biomass feedstocks are oxygenated compared to petroleum feedstocks, biofuels and many other market chemicals normally require reducing the oxygen content relative to biomass feedstocks. Conversely, other market chemicals are oxygenated—whether they are direct replacements, functional equivalents, or provide new functionality. In fact, many chemical products are functionally more similar to biomass than fuels (Figure 7.17).

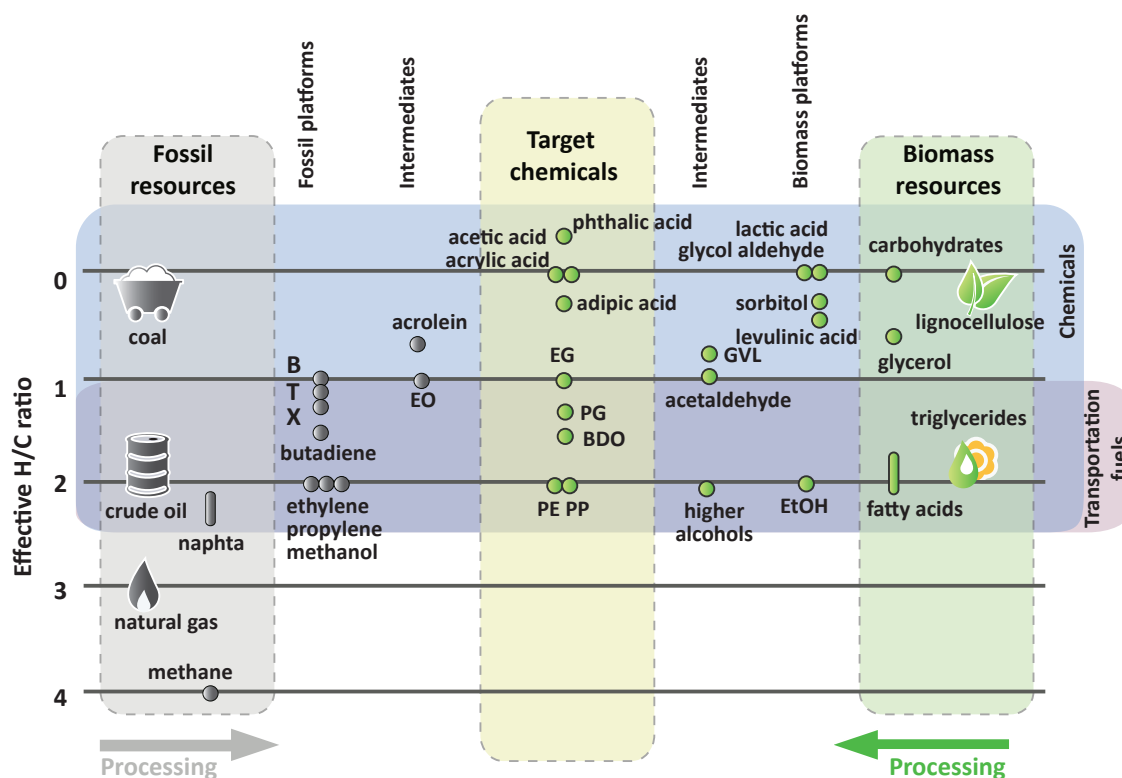
Overall, bioproducts have only a tiny presence in the market and much R&D is needed to realize their potential.

### Biochemical Conversion

Key agents in biochemical conversion are enzymes and microbial consortia. Biochemical conversion route costs have been significantly lowered through an approximately 90% reduction in enzyme cost enabled by development of new enzymes and enzyme cocktails. Development of microorganisms that can more effectively

**Figure 7.17** Producing oxygenated chemicals from olefins involves increasing the molecular weight via oxidation. Hence, the theoretical yield on a weight basis is greater than the weight of the olefin starting material. Biomass is different; because it is highly oxygenated, the molecular weight is usually decreased. On a weight basis, the theoretical yield is less than the weight of the starting sugar or biomass resource. Trying to match the oxidation state (or functional equivalency) can also be advantageous (most oxidized or most functional are presented on the right).

Credit: Vennestrøm, P. N. R., Osmundsen, C. M., Christensen, C. H. and Taarning, E., *Beyond Petrochemicals: The Renewable Chemicals Industry*. *Angewandte Chemie International Edition*, 50, 10502–10509 (2011). Reprinted with permission from John Wiley and Sons.



utilize multiple sugars also contributed to cost reductions. Key breakthroughs in biochemical process steps included the development of more efficient pretreatment processes, improved enzyme production and enzyme load methods, and more robust fermentation organisms that could use sugars in the presence of biomass-derived inhibitors. Many of these were demonstrated between 2001 and 2012.

The limited areas of biobased chemicals manufacturing available today are relatively mature and historically have used traditional sugars such as corn starch or sugar cane for feedstocks. The opportunity for expansion to new pathways should focus on the utilization of cellulosic sugars, lignin, and other renewable feedstocks.

Additional opportunities in biorefineries involve lignin as a feedstock (see Section 7.3.3). The lignin molecular structure itself suggests some applications, including aromatic chemicals and polymers, for applications that could include commodity chemicals currently produced from petroleum, such as benzene, toluene, and xylene, and potentially polymer applications, such as carbon fibers.<sup>63</sup>

In addition to these many applied research activities, important fundamental research is still required. For example, basic research is being conducted by the DOE Office of Science at three centers focusing on transformational breakthroughs (see textbox: *Fundamental Research: Bioenergy Research Centers*).

## Fundamental Research: Bioenergy Research Centers

DOE established three Bioenergy Research Centers (BRCs) in 2007 to accelerate transformational breakthroughs in the basic sciences needed to develop the cost-effective, sustainable, commercial production of cellulosic biofuels on a national scale. Directed fundamental RDD&D approaches focused on creating new energy crops, new methods for deconstructing the lignocellulosic material into chemical building blocks, and new metabolic pathways inserted into microbial hosts to produce ethanol and other hydrocarbon fuels.

The three centers engage national laboratories, academic institutions, and the private sector. The BRCs coordinate research on the entire pathway, from bioenergy crops to biofuel production. The center-scale approach allows technology development specialists to design automated pipelines that streamline workflows and increase research efficiencies. The BRCs offer an unusual opportunity for plant and microbial scientists to work with experts in chemical engineering, computational biology, analytical technology, and many other disciplines to test research ideas from proof-of-concept to field trials. The BRCs also develop intellectual property licensing agreements, partnerships, and targeted collaborative affiliations.

More information can be found at the website for each center:

- **The BioEnergy Science Center** (BESC; <http://bioenergycenter.org/besc/index.cfm>) is focused on the ability of plant cell walls to resist breakdown into their component cellulosic sugars.
- **Great Lakes Bioenergy Research Center** (GLBRC; <https://www.glbrc.org/>) aims to increase the energy density of grasses and nontraditional oil crops by understanding and manipulating the metabolic and genetic circuits that control accumulation of oils in plant tissues.
- **Joint Bioenergy Institute** (JBEI; <http://www.jbei.org/>) is applying synthetic biology to engineering microorganisms that convert sugars into advanced biofuels.

For more information on BRCs, visit <http://genomicscience.energy.gov/centers/BRCs2014HR.pdf>.

### 7.3.5 Fueling Infrastructure for Biofuels

The United States has about 160,000 retail gasoline stations, which distribute 134 billion gallons per year of motor gasoline. Most vehicles on the road today are approved to use E10, which can absorb about 13 billion gallons per year of ethanol. Corn-based ethanol production capacity of 15 billion gallons per year is saturating the gasoline market at E10 levels with the additional ethanol going into E85 and being exported to several countries (primarily Brazil). Ethanol in the form of E85 is available at about 2,600 retail stations.

While E85 has experienced growth over several years, the number of retail stations and the mismatch in the distribution of retail E85 stations and flex-fuel vehicles means slow growth in E85. On the other hand, the aviation sector consumes about 21 billion gallons per year of jet fuel. The United States' top thirty airports use more than 80% of the country's jet fuel. The delivery infrastructure associated with renewable jet fuel is significantly less challenging than the delivery infrastructure required with ethanol.

### 7.3.6 Research and Development Opportunities

Key research opportunities and timing are shown in Table 7.5. Cost competitiveness with conventional fuels and feedstocks is a key metric for each potential fuel production pathway. Satisfactory chemical composition and performance is also essential, and some renewable fuels offer benefits such as higher octane values.

**Table 7.5** Timing for Biomass Research Needs and Priorities

Research priorities	Near term (2–5 years)	Medium term (5–10 years)	Long term (>10 years)
Terrestrial feedstocks	✓	✓	
Algae			✓
Biochemical conversion		✓	✓
Thermochemical conversion	✓	✓	
Bioproducts	✓	✓	✓

Major focus areas for R&D are aviation biofuels, refinery integration, and bioproducts. New conversion processes (biochemical, thermochemical, and hybrid) need to be developed to produce renewable diesel and renewable jet fuel in a cost competitive manner from waste-based lignocellulosic biomass. Conversion processes can produce renewable diesel/jet blend-stocks that meet all relevant specifications and can be blended with conventional jet/diesel. An alternative approach is to produce a biocrude that can be used as a supplementary input (along with crude oil) to a refinery. There are significant compatibility issues associated with this approach, and refinery integration issues must be resolved for biocrudes produced from biomass via pyrolysis. These biocrudes have high oxygen content and are acidic. They need to be stabilized, transported, and minimally upgraded to ensure that they will not damage a petroleum refinery. If acceptable oil can be produced that will be suitable for integration into a refinery, the refinery can operate as usual with a supplemental volume of oil coming from biomass in addition to regular crude oil and use existing delivery infrastructure. The higher-value products (e.g., bio-succinic acid, 1,3-butadiene, animal feed, and fish feed) and use of existing infrastructure can help offset the cost of biofuels production.

Developing a uniform format blended feedstock would yield substantial benefits. One key criterion for building large integrated biorefineries is the biomass draw radius that, with conventional feedstocks, is limited to about seventy-five miles. An advantage of uniform format blended feedstocks would be the ability to transport biomass over longer distances, which would give significant flexibility to large biorefineries. Energy crops need to be developed that have high biomass yield (tons/acre), can be grown in temperate climates, can thrive on marginal soils, and have reduced input requirements such as water and fertilizer. Switchgrass and miscanthus are examples of crops that meet some of these criteria.<sup>64</sup>

Specific areas of interest in biochemical conversion include developing better pretreatment processes, creating lower-cost hydrolytic enzymes, developing new enzymes, limiting contaminants, and creating a tractable lignin stream. New microorganisms are needed that can tolerate high temperatures and highly acidic or basic conditions, that are tolerant of contaminants, and that can produce hydrocarbon-like fuels or precursors that can be easily converted to hydrocarbon fuels. A promising area of research involves extremophiles occurring in the natural environment, such as deep sea ocean thermal vents, thermal geysers, and hot springs. Microorganisms isolated from these environments can tolerate high temperatures and acidic conditions, and can obtain their metabolic energy from sulfur or other inorganic compounds instead of photosynthetically derived carbon dioxide molecules, which increases the range of available energy pathways.

In thermochemical conversion, key focus areas include developing a better understanding of the fundamentals of gasification, pyrolysis, and hydrothermal liquefaction processes, including reaction mechanisms; improving reactor designs; improving the quality of deconstructed intermediates; developing more robust catalysts and catalyst regeneration processes; and developing catalysts with improved specificity. Considerable R&D is

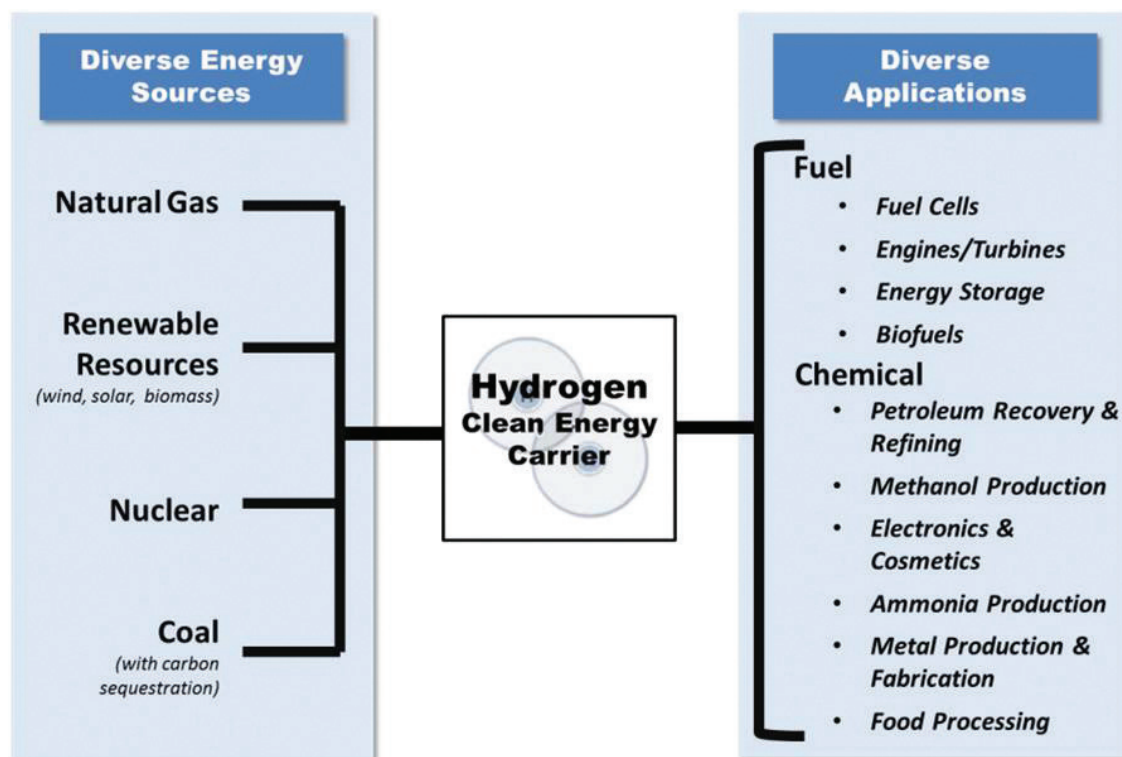
being conducted on catalyst life extension, easier regeneration of catalysts, and development of non-rare-earth catalysts. Discoveries in these areas will reduce the cost of upgrading raw bio-oils and make pyrolysis-derived biofuels cost competitive.<sup>65</sup>

## 7.4 Hydrogen Production and Delivery

As a clean fuel in the energy sector, hydrogen can be used in highly efficient fuel cells for transportation and stationary power applications, in internal combustion engines, and as an energy carrier and storage medium in grid modernization and other applications.<sup>66</sup> In the United States, more than 8,000 fuel cell forklifts and more than 5,000 fuel cell back-up power units have been deployed. In addition, light-duty fuel cell electric vehicles (FCEVs) are now becoming available for lease and for sale.<sup>67</sup> As discussed in Chapter 8, the use of hydrogen with FCEVs in the transportation sector can have a significant impact on reducing GHG emissions, with greater than 80% reductions achievable. Additionally, environmental and energy benefits of hydrogen and fuel cells in energy storage and in power sectors are detailed in Chapters 3 and 4, respectively.

Hydrogen is already a well established chemical commodity in various industrial sectors. Today, hydrogen is most commonly used as an industrial feedstock for refineries and ammonia production. The refinery and fertilizer industries have produced and used hydrogen for decades, and worldwide demand is increasing. The United States' hydrogen consumption, including imports, is more than 10 million tonnes per year, and worldwide consumption is approximately 23 million tonnes per year.<sup>68</sup> The United States currently produces about nine million tonnes annually, mainly from fossil fuels. This production volume is equivalent to a little more than one quadrillion Btus per year (1% of the United States' energy consumption)—enough to power at least 40 million FCEVs. For diverse industrial applications, hydrogen serves as a clean energy carrier that can be produced using a variety of domestic resources, as illustrated in Figure 7.18.

**Figure 7.18** Hydrogen Offers Important Long-Term Value as a Clean Energy Carrier

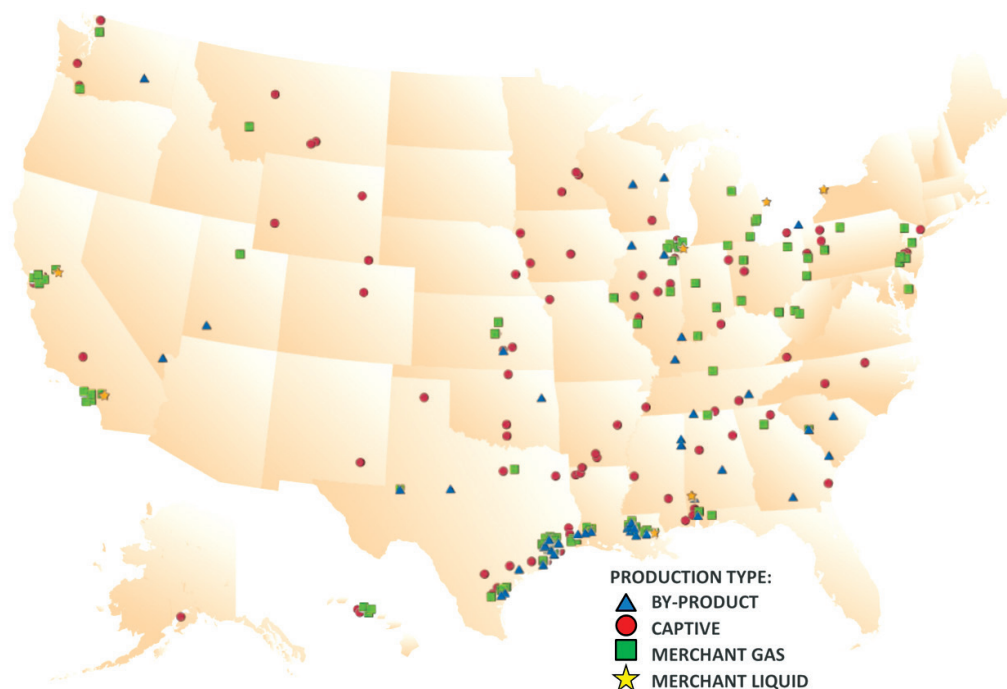




The majority of the world's hydrogen is currently produced at or near the petroleum refineries and ammonia plants that require it as a chemical feedstock. In North America, hydrogen is most commonly produced using steam methane reforming (SMR) of natural gas. According to the 2012 NPC Future Transportation Fuels Study, *Advancing Technology for America's Transportation Future*,<sup>69</sup> large hydrogen production facilities (>18,000 kg per day) exist in nearly every state in the United States, as illustrated in Figure 7.19. In other countries, such as China and India, coal is the primary feedstock.<sup>70</sup> In all these cases, carbon capture, use, and storage can be used to lower or remove the carbon footprint of the hydrogen produced through the reforming of fossil feedstocks, but this process is yet to be deployed at low cost and at scale.

**Figure 7.19** Existing Centralized Hydrogen Production Facilities in the United States (from the hydrogen chapter of the 2012 NPC Future Transportation Fuels Study)<sup>69</sup>

Credit: National Petroleum Council

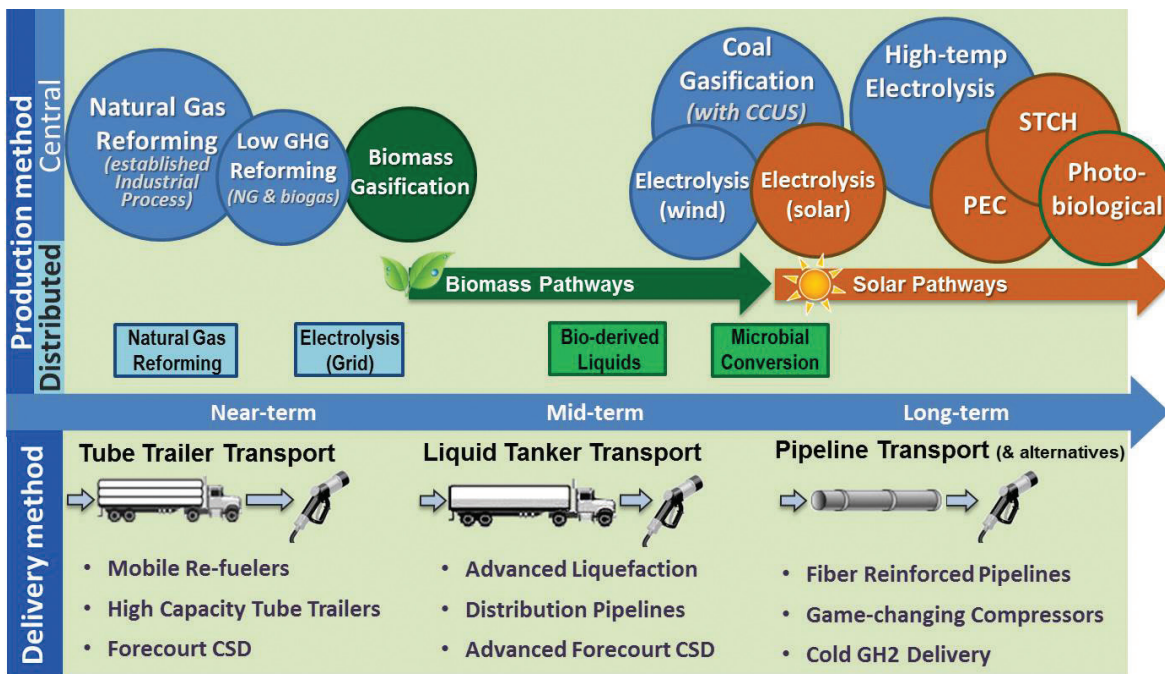


In the near term, the hydrogen production and delivery infrastructure demands of the emerging FCEV market need to be met. Leveraging the synergies between natural gas and hydrogen delivery infrastructure and existing hydrogen production capacity based on natural gas reforming can facilitate meeting these near term needs. In the long term, realizing the environmental and security benefits of hydrogen in the energy sector will require RDD&D of a portfolio of safe, low-cost, low-carbon hydrogen production and delivery methods relying on domestic resources.

### 7.4.1 Hydrogen Production and Delivery Technologies

Hydrogen for transportation fuel can be produced off-site at central facilities and transported to retail fueling stations or produced at the station through a wide variety of pathways represented in Figure 7.20. When hydrogen is produced at the station, it is referred to as distributed or forecourt production. At the retail refueling station, prior to dispensing to the vehicle, hydrogen is compressed to high pressure for onboard storage.<sup>71</sup>

**Figure 7.20** Many possible pathways for production and delivery of hydrogen exist. They vary in scale (semi-central to central production ranges from 50,000 to greater than 500,000 kg per day, while distributed production is up to 1,500 kg per day) and time frame for development, as well as in potential cost and GHG emissions.<sup>78</sup>



## Hydrogen Production

There are many different pathways to produce hydrogen.<sup>72</sup> Numerous low-carbon pathways include reforming of biomass or fossil fuels, such as natural gas and coal, with CCS; and the splitting of water using sustainable and/or renewable energy sources, such as nuclear, wind, solar, geothermal, and hydro-electric power. Most of the hydrogen production technologies fall into three general categories: thermal, electrolytic, and photolytic.

Thermal processes include reforming of natural gas or biofuels, gasification of coal and biomass, and thermochemical processes.<sup>73</sup> Reforming, the most widely deployed technology today, uses high-temperature steam (700°C–1000°C) to produce hydrogen from a methane source. Sources can include natural gas, biogas generated from various biogenic renewable sources, and biomass.<sup>74</sup> Reforming is suitable for both the central and distributed scale. Other thermochemical processes use heat (500°C–2000°C) to drive a series of chemical reactions that produce hydrogen from water. Thermochemical water-splitting processes are best suited for large-scale central production.

Electrolytic processes produce hydrogen and oxygen from water using electricity in an electrolyzer.<sup>75</sup> Electrolyzers can range in size from small, appliance-size equipment well suited for small-scale distributed hydrogen production, to large-scale, central production facilities. Hydrogen produced via electrolysis can result in minimal GHG emissions when low-carbon or zero-carbon electricity is used. Low-temperature electrolyzers are commercially available and are in use at some hydrogen fueling stations. High-temperature electrolysis systems, typically operated at temperatures greater than 750°C with higher electrical efficiency compared with lower temperature electrolyzers, are applicable for use at nuclear reactors and solar thermal facilities, taking advantage of the high-grade heat generated by these technologies.

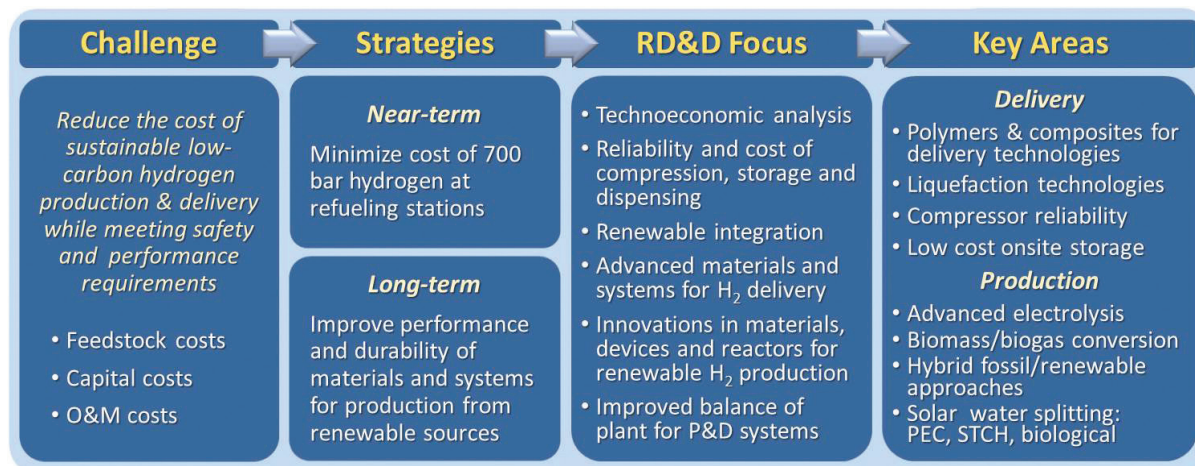
Photolytic processes use the energy in sunlight to separate water into hydrogen and oxygen and can be further classified into two general categories: photoelectrochemical (PEC) and photobiological. In PEC hydrogen production, specialized semiconductor devices harness sunlight to split water.<sup>76</sup> In photobiological production, specialized microorganisms, such as green algae and cyanobacteria, use the energy from sunlight to produce hydrogen.<sup>77</sup> These pathways have long-term potential for sustainable hydrogen production with low environmental impact but are in relatively early stages of R&D.

Alternatively, hydrogen can also be produced through microbial biomass conversion processes, which do not require light, such as fermentation or microbial electrolysis cells. These microbes can consume organic matter like corn stover or wastewater to produce hydrogen. This pathway could be suitable for central hydrogen production or even distributed production for waste stream feedstocks.

### Hydrogen Delivery

As seen in Figure 7.21, a wide range of hydrogen delivery technologies is available to serve existing and emerging markets. Hydrogen delivery includes the infrastructure required to move and store hydrogen from the point of production to the vehicle. This includes transmission, distribution, and refueling station operations. There are three main transmission and distribution pathways: pipeline, tube trailer, and liquid truck. The gaseous hydrogen transmission and distribution pathway is very similar to natural gas distribution today. Pipelines can be made with steel or fiber reinforced polymer pipe and operate at seventy to 100 bar. Gaseous tube trailers carry hydrogen in large, pressurized storage cylinders. These can either be steel cylinders at 180 bar or high-pressure composite cylinders that can carry hydrogen at pressures as high as 500 bar. Typical steel tube trailers can carry approximately 280 kilograms (kg), while the high-pressure tube trailers can carry close to 1,000 kg. Geologic storage is typically used in large-scale gaseous transmission and distribution.

**Figure 7.21** Hydrogen Production and Delivery RDD&D Opportunities and Key Focus Areas<sup>96</sup>



Hydrogen can be distributed as a liquid. During this process, the hydrogen is cooled below -253°C (-423°F) using liquid nitrogen and a series of compression and expansion steps. The cryogenic liquid hydrogen is then stored in large, insulated tanks, loaded into delivery trucks, and transported to the point of use or stored in vacuum-jacketed tanks until it is used. After on-site production or distribution to the point of use, the hydrogen goes through compression, storage, and dispensing at the retail fueling station in order to serve the vehicle market. The hydrogen in light-duty FCEV tanks is pressurized to 700 bar in order to store the approximately five

kg of hydrogen needed to enable a 300-mile vehicle range based on the mile per gallon of gasoline equivalent (mpgge) of today's FCEV within the space available onboard the vehicle.<sup>79,80</sup> The hydrogen is stored at 875–1,000 bar, which requires cooling during the compression process. It must be pre-cooled during dispensing to achieve a three- to five-minute fill time without overheating the storage tank. Therefore, thermal management is a key consideration in cost-effective station design. The heavy-duty vehicle market operates similarly, except that the hydrogen onboard the vehicles is stored at 350 bar rather than 700 bar since larger vehicles are less constrained with respect to space, and lower-pressure vessels provide a cost and weight advantage. This is current practice for transit buses, and it is expected that heavy-duty trucks would operate similarly.

### 7.4.2 Current Status and Accomplishments

Hydrogen production and delivery technologies span a range of development stages. A small number of hydrogen production technologies are currently used commercially or are approaching commercial readiness. These include natural gas and biogas reforming, as well as electrolysis. Other technologies, particularly renewable production pathways such as solar water splitting, require additional RDD&D.

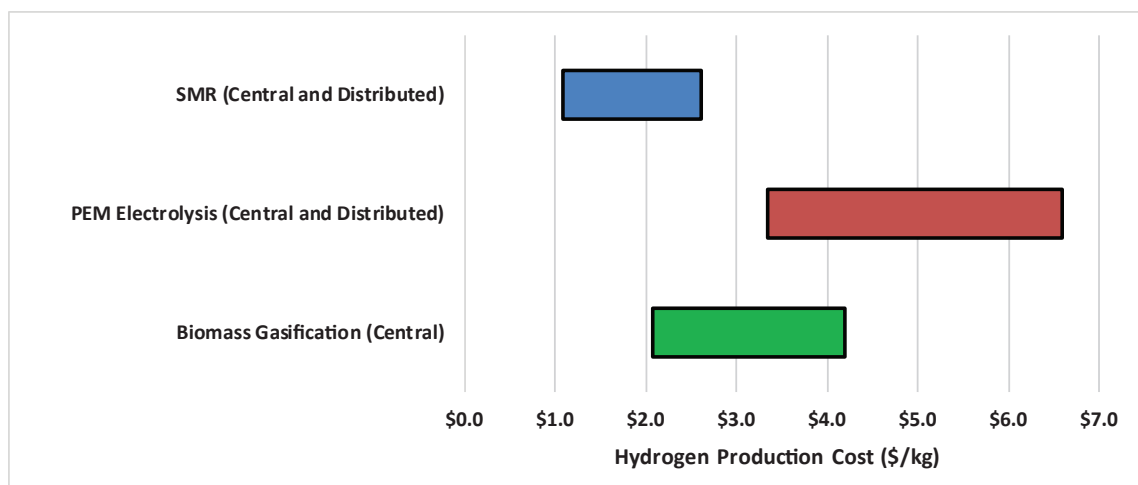
Recent technology advancements have reduced the cost of distributed hydrogen at retail fueling stations to less than \$4.50 per gallon of gasoline equivalent (gge) [assuming high-volume production and widespread deployment].<sup>81</sup> This applies to hydrogen produced by SMR and dispensed at 700 bar, and is valid over a wide range of natural gas prices. At the lower end of the range of natural gas prices, hydrogen cost drops below the 2020 target of less than \$4 per gge<sup>82</sup> for FCEV cost-competitiveness with other vehicle technologies.<sup>83</sup> For early markets, the interim target is less than \$7 per gge.<sup>84</sup> CCS would reduce the associated GHG emissions with the mature SMR pathway. Ongoing demonstration projects (e.g., a DOE-sponsored project at a hydrogen production facility in Port Arthur, Texas) that capture and store CO<sub>2</sub> from SMR plants are aimed at demonstrating the viability of this CCS approach, but widespread commercial deployment will depend on improvements in the benefit-cost ratio through further RDD&D. In the near term, low-carbon hydrogen can also be produced through reforming biogas (i.e., renewable natural gas), either through modified SMR, or using high temperature fuel cells that can simultaneously generate power, heat, and hydrogen (typically called combined heat, hydrogen, and power, or CHHP) with a lower carbon footprint than natural gas SMR.<sup>85</sup>

Electrolysis is also a commercial technology typically used today for small- to mid-scale hydrogen production, but scalable to larger megawatt-scale systems. There is growing interest, particularly in locations where emissions standards are in place (e.g., Europe, California), for pairing water electrolysis with “green” electricity as a way to use renewable electricity that otherwise would be curtailed during periods of low demand. Biomass gasification is a promising near-term technology that has not yet been commercialized at scale. Figure 7.22 summarizes the current range of production costs.<sup>86</sup> Through RDD&D in recent years, production costs have dropped from nearly \$6.50 per kg in 2006 to approximately \$5 per kg in 2013 for electrolysis, and from nearly \$3 per kg in 2006 to about \$2.50 per kg in 2013 for biomass gasification (at high volume).

Current industrial production capacity could potentially provide sufficient hydrogen fuel for early-market FCEV deployment.<sup>87</sup> Going forward, demand growth would require increased capacity, with a priority on hydrogen production from renewable and/or low-carbon pathways. To meet this demand, a portfolio of low-carbon hydrogen production pathways would be needed, including emerging options such as microbial biomass conversion, photobiological production, and solar-based thermo- and photoelectrochemical water-splitting, which require additional RDD&D to reach commercial readiness.

In all hydrogen production pathways, high conversion efficiencies are critical to reducing the hydrogen cost. To date, feedstock-to-hydrogen energy conversion efficiencies exceeding 70% have been demonstrated for SMR, while ~46% has been achieved in biomass gasification.<sup>89</sup> Hydrogen can also be produced by coupling

**Figure 7.22** Current Range of Hydrogen Production Costs (undispensed and untaxed, reported in \$/kg including feedstock and capital cost variability assuming high volume production and widespread commercialization)<sup>88</sup>



natural gas combined cycle power plants with water electrolysis systems. Conversion efficiencies of ~32% have been achieved with this approach using commercial low-temperature electrolyzers (including 67% electric-to-hydrogen electrolyzer efficiency, and 48% efficiency for the upstream natural gas combined cycle power plant), with efficiencies greater than 50% achievable using advanced high-temperature electrolyzers operating above 800°C.<sup>90</sup> Higher conversion efficiency reduces feedstock requirements and lowers cost. Continued RDD&D focused on improving efficiencies can reduce hydrogen costs in all the near- to longer-term technologies.

In conjunction with the current industrial production capacity to support early-market FCEV deployments, significant hydrogen delivery infrastructure is in place to serve the industrial market. The United States has more than 1,500 miles of hydrogen pipelines, primarily along the Gulf Coast.<sup>91</sup> The Praxair salt dome cavern on the Gulf Coast is one of the largest hydrogen storage systems in the world, with 1.4 billion cubic feet of working storage. California is the first state making significant investments in hydrogen infrastructure for the light-duty vehicle market, working to achieve a target of one hundred hydrogen refueling stations by 2020.<sup>92</sup> There will be twenty-eight stations open by the end of 2015 with twenty-three more stations planned to open in 2016.<sup>93, 94</sup>

High-pressure gaseous tube trailer delivery is the lowest-cost delivery method to serve the near-term vehicle market (Table 7.6). This is attributable to the decrease in compression required at the station when the gas is delivered at high pressure. Relatively small amounts of gaseous hydrogen can be transported short distances by high-pressure (up to 500 bar) tube trailers. A modern high-pressure tube trailer is capable of transporting nearly 1,000 kg of hydrogen. Gaseous transmission and distribution through pipelines remains the lowest-cost delivery option for large volumes of hydrogen. The high initial capital associated with this pathway constitutes a major barrier to the construction of new hydrogen pipelines.

The liquid hydrogen pathway is a well-developed and competitive method of providing hydrogen for high-demand applications that are beyond the reach of hydrogen pipeline supplies. It is more economical than gaseous trucking for high market demands (greater than 700 kg per day) and has longer delivery distances because a liquid tanker truck with a capacity of approximately 4,000 kg can transport more than four times the capacity of a 500-bar gaseous tube trailer. The nine existing liquefaction plants in North America vary in production size from 5,400-62,000 kg of hydrogen per day. Table 7.4 shows the current costs for a range of hydrogen delivery pathways at high volume.

**Table 7.6** Hydrogen Delivery Cost as a Function of Dispensed Gas Pressure and Delivery Pathway as Reported from the Hydrogen Delivery Scenario Analysis Model (to the nearest 0.05)<sup>95</sup>

Dispensing pathways	350 bar	700 bar
	Delivery costs (\$/kg hydrogen delivered and dispensed)	
Pipeline	4.45	4.85
Pipeline—tube trailer	3.15	3.20
Tube trailer	3.00	3.30
Pipeline—liquid tanker	N/A	3.75
Liquid tanker	N/A	3.25

### 7.4.3 RDD&D Opportunities

Cost reduction of at-scale technologies remains the key challenge in the production and delivery of hydrogen, particularly from low-carbon sources for use in fuel cell electric vehicles. The critical barriers and strategies for reducing the cost of hydrogen production and delivery are shown in Figure 7.23. Since high-volume market penetration is an essential factor for any cost reduction, lowering the cost of hydrogen for 700 bar refueling to accelerate the introduction of FCEVs into the market place is an important near-term requirement. Identifying RDD&D priorities will rely on techno-economic analysis and modeling to identify refueling station equipment and processes that can reduce refueling cost the most, along with cost mitigation approaches based on technology improvements. Broader RDD&D opportunities addressing longer-term needs include lowering the cost of hydrogen from renewable and low-carbon sources through process and materials development.

The thermal production processes such as bioderived liquid reforming, and coal and biomass gasification could achieve reduced capital cost through improved catalysts and low-cost separation and purification technologies. Electrolysis systems are another near-term hydrogen production pathway that requires additional research to reduce costs and improve efficiency, in particular. Currently, feedstock cost is the most significant contributor to the hydrogen cost from this pathway. As a result, it is important to focus on improving the process efficiency while reducing the capital cost. Development of load-following capability would provide more economical system operation during times of low demand. The cost of low-temperature electrolysis could be up to 10% lower if efficiency increased 10%, from 67% production efficiency to 74%. Chapter 4 discusses coal gasification cost and performance.

The costs of all emerging production pathways need to be significantly reduced for hydrogen to become a major contributor to transportation fuel. As material costs and performance improvements are needed for most of these pathways, promising areas of RDD&D with impacts on multiple pathways are high throughput/combinatorial approaches to enable rapid identification and development of promising materials systems as appropriate. PEC production requires RDD&D to develop materials with the appropriate band gap to both absorb sunlight and electrolyze water in a single device, while solar thermochemical hydrogen production pathways require identification and development of efficient and durable materials to design a cost-effective reactor system. Photobiological approaches require fundamental research in a number of areas such as direct water splitting using microalgae or cyanobacteria, and optimization of energy flows and electron flux. Microbial biomass conversion methods such as fermentation require research to improve hydrogen production yields and rates.

A high-temperature advanced nuclear reactor coupled with one of the high-temperature technologies (thermochemical cycles, electrolytic, and hybrid thermochemical/electrolytic) could achieve a thermal-to-hydrogen conversion efficiency of 45% to 55%. However, this technology is not yet ready for commercialization. There are challenges regarding the high temperature and the design of corrosion-resistant materials. To address these, system design development is needed to study the hydrogen plant and its relationship to the reactor, including configuration options and operating conditions, system isolation issues, and intermediate heat transfer loop design. Chapter 4 on power technologies contains a discussion on related nuclear energy RDD&D.

Hydrogen's low volumetric density poses a challenge with respect to the costs of storage and delivery, necessitating further RDD&D to improve the efficiency, cost, and reliability of compression, storage, and delivery technologies for 700-bar refueling. This can be achieved through researching new materials for high-pressure dynamic and static seals, developing new compression technologies such as linear motor, metal hydride, and thermal compressors, and demonstrating alternative refueling and control algorithms to lessen the burden on the station. Longer-term priorities in delivery include developing advanced technologies for liquefaction, geologic storage, and pipelines and pipeline compressors. Issues such as hydrogen embrittlement and safety clearly must be addressed; addressing these challenges requires continued materials compatibility RDD&D. With successful technology development, hydrogen delivery costs could be reduced by more than 50% (2020 target is less than \$2 per gge<sup>97</sup> versus today's cost of \$3–\$5/gge) that would enable economic competitiveness of hydrogen FCEVs with gasoline ICEs.

Figure 7.23 summarizes the near-, medium-, and long-term research areas. For both production and delivery technology pathways, it is necessary to continue developing and testing innovative materials, components, and systems.

**Figure 7.23** RDD&D areas and time frames for Hydrogen Production and Delivery

Research opportunities	Near term	Medium term	Long term
	(2–5 years)	(5–10 years)	(>10 years)
Compression and storage at fueling stations	■		
Distributed scale liquefaction and pipeline technologies	■		
High-pressure tube trailers	■		
Bioliqids reforming, biomass and coal gasification	■		
Sustainable, low-carbon hydrogen (e.g., biological, thermochemical, photo-electrochemical)	■		

The major challenge is to reduce the cost of producing and delivering hydrogen from renewable and low-carbon sources using a portfolio of technologies that are scalable, and that meet industrial performance and safety requirements. To reduce costs, continued RDD&D is needed to improve materials, systems, and scaled technologies for diverse hydrogen production and delivery options. Near-term cost reductions can be achieved by leveraging the synergies between natural gas and hydrogen delivery infrastructure and the existing hydrogen production capacity. This is important to support the early market deployment of FCEVs, and to promote development and deployment of the hydrogen production and delivery technologies and infrastructure needed to sustain market growth. The longer-term priority is to transition to the sustainable and low-carbon options for hydrogen production and delivery to fuel growing markets in the transportation, stationary heat and power, and energy storage sectors.

## 7.5 Other Alternative Transportation Fuels

Several alternatives to the three major classes of fuel discussed above (oil and gas, biofuels, and hydrogen) that have been and continue to be explored for potential environmental and security benefits. Most of these options emit fewer GHGs over production and use cycles and fewer criteria pollutants at the point of use. All can be produced from abundant domestic resources within the United States. To date, they all have some barriers to widespread deployment in the United States. Some of these barriers are inherent in the fuels (e.g. methanol's toxicity) while others require additional fundamental basic research. The DOE Office of Science actively supports the development of several transformational technologies through activities such as the Joint Center for Artificial Photosynthesis (see textbox: *Joint Center for Artificial Photosynthesis*).

### Joint Center for Artificial Photosynthesis

#### Fuels from Sunlight Energy Innovation Hub: Goals, Challenges, and Progress

Increased solar energy utilization is helping the United States meet growing energy demands. The ability to generate commercial fuels directly from sunlight holds great promise as a new innovation in energy production, potentially enabling fossil fuels to be replaced with solar fuels. Through the process of photosynthesis, plants and some microbes convert sunlight into energy-rich chemical fuels using the abundant feedstocks of water and carbon dioxide. It would be enormously beneficial to develop an artificial system capable of generating fuels directly from sunlight using just water and carbon dioxide in a manner analogous to the natural photosynthetic system. Despite decades of basic research advances, however, it is not yet possible to produce solar fuel generation systems with the required efficiency, scalability, and sustainability to be economically viable.

In 2010, DOE established the Fuels from Sunlight Energy Innovation Hub, the Joint Center for Artificial Photosynthesis (JCAP), which is focused on transformative advances needed to enable artificial photosynthesis. The goal of this multidisciplinary, multi-investigator, and multi-institutional effort is demonstrating systems that convert sunlight, water, and carbon dioxide into a range of commercially useful fuels. JCAP's overall approach is to develop robust concepts and designs for complete solar-fuels generators, define the essential assemblies of active components for the generators, and then discover or adapt materials needed to fabricate the assemblies.

More information on JCAP can be found at this website: <http://solarfuelshub.org>



## 7.5.1 Natural Gas as a Transportation Fuel

Natural gas fueled vehicles are a well-established, mature industry. Millions of natural gas vehicles are on the road worldwide today, yet, in the United States, only a small fraction of cars and trucks use natural gas. There are three principal ways in which natural gas is employed for vehicles: 1) as compressed natural gas (CNG), 2) as liquefied natural gas (LNG), or 3) converted via chemical processes into a liquid fuel. Historical barriers to expanded use of natural gas in vehicles include the lack of an infrastructure for distribution and vehicle fueling, the significant additional cost of vehicle hardware, such as natural gas fuel tanks, and uncertainty concerning natural gas prices over the long term.

### LNG for Long-Haul Trucks

Displacing diesel fuel with LNG in Class 8 long-haul trucks (18-wheelers travelling long routes) is of increasing interest within private industry. The lower cost of natural gas has the potential for significant fuel cost savings. Developing a fueling infrastructure for LNG long-haul trucks presents a significant challenge but is one the market is beginning to pursue. With a continued positive business case, private industry is beginning to make the investments needed for such an infrastructure.

### CNG for Fleets

Widespread adoption of CNG centralized fleets of light- and medium-duty vehicles is primarily hindered by the higher initial vehicle purchase price and large up-front infrastructure costs. Municipal buses, delivery vehicles, and other fleet vehicles have turned to natural gas primarily for air quality concerns, not because of economic advantages. Unlike long-haul trucks, such fleets do not travel as many miles or use as much fuel, which makes the payback period much longer. For medium-duty vehicles, the incremental cost typically takes twelve to fifteen years to recover out of a twenty- to thirty-year lifespan. Light-duty vehicles may never recover the initial incremental cost premium because of their shorter service life. There are also significant infrastructure costs that must be accounted for. A CNG station is required (\$400,000–\$1,000,000), and fleet maintenance facilities must be updated at additional cost to handle gaseous fuels.

### CNG for Private Vehicles

In the light-duty personal vehicle market, lack of a ubiquitous fueling infrastructure and high vehicle cost (relative to gasoline-fueled vehicles) combine to present an overwhelming challenge to mass market consumer acceptance. Today, there are roughly 160,000 gasoline service stations in the United States. Creating a similar nationwide infrastructure for natural gas refueling at even a fraction of those service stations would be prohibitively expensive (\$100 billion or more). Range limitations with natural gas represent an additional hurdle to widespread adoption.

### Chemical Conversion of Natural Gas to Liquid Fuels

Natural gas can be converted into liquid fuels using two main chemical processes, but neither is commercially available at scale in the United States. The first approach employs a widely used technology known as “Fischer-Tropsch” to produce a number of products, including diesel fuel. Additional discussions on this process can be found later in the section dealing with coal to liquids. Another approach is used to produce methanol from natural gas. Methanol is already produced from natural gas in very large quantities for industrial purposes, at costs roughly equivalent to gasoline. It could be used as a blend, much like ethanol, or converted to gasoline through a commercially available process.

## LNG/CNG Distribution

CNG stations receive fuel via a local utility line at a pressure lower than that used for vehicle fueling. The station compresses the gas to a higher pressure for vehicle fueling. Described below are the three types of CNG stations: fast-fill, time-fill, and combination-fill. The main structural differences are the amount of storage capacity, size of the compressor(s), and dispensing rate.

- **Fast-fill:** The compressor and storage capacity for fast-fill stations are designed such that drivers experience fill times similar to those for gasoline or diesel fueling stations.
- **Time-fill:** This equipment fills CNG vehicles over a period of hours and is typically used by fleets with vehicles that fuel at a central location each night. The time it takes to fuel a vehicle depends on the number of vehicles, the amount of fuel required, and the throughput of the compressor. Vehicles are unattended during the fueling process, which can take minutes to hours.
- **Combination-fill:** At combination-fill stations, users have the ability to time-fill or fast-fill vehicles on demand. Many fleets use the convenience of time-fill as the primary method of fueling, with fast-fill available as needed.

## Conclusion

While sales of natural gas-powered cars and trucks are small, the technology to build such vehicles is well known. The primary barriers to expanded use of natural gas in vehicles have been concerns about the future price of natural gas and the absence of an infrastructure to deliver the gas. Centrally fueled fleet vehicles (such as medium-duty trucks) offer the most mature market for using natural gas directly in the transportation sector, but this market represents a small percentage of our on-road fuel consumption. It would be significantly more complex to create an infrastructure that would allow a significant fraction of cars to operate on natural gas. In addition, there are climate concerns about methane and carbon emissions.

Technology improvements that could encourage expanded use of natural gas include the following:

- Cheaper onboard fuel storage and home-fueling compressors
- Broader range of available engine options for medium- and heavy-duty trucks
- Improved techniques for conversion of natural gas to conventional fuel (gas-to-liquids)

### 7.5.2 Ammonia and Carbon-Free Energy Carriers

Controlling carbon emissions from fossil energy resources will require systems for CCS. In the transportation fuels space, fossil resources can be converted to carbon-free energy carriers at a central location where CCS can be used, and then fuel can be distributed for use. The most common forms of such energy carriers currently recognized are electricity (discussed in Chapter 6) and hydrogen (discussed in Chapter 8).

An important question is what other carbon-free energy carriers might be used. One proposed option is ammonia. Along with hydrogen, ammonia has no carbon emission when combusted because it doesn't contain carbon. Existing infrastructure and current transportation energy systems are compatible with ammonia with relatively modest changes. Ammonia also has a high octane rating (about 120 versus gasoline at 86–93) and can be used in high compression engines. However, it has a relatively low energy density per gallon—about half of gasoline—so its fuel mileage is about half of gasoline's mileage. Issues also remain with toxicity, especially from ammonia vapor.

### 7.5.3 Coal (Biomass and Hybrid Systems) to Liquids

Coal-to-liquids (CTL) account for a small share of world liquids production but is expected to increase, assuming petroleum costs rise in the future. In particular, CTL accounted for the equivalent of 0.19 million

barrels per day in 2012. EIA<sup>98</sup> projects that number to grow to 1.12 million barrels per day by 2040. Nearly all of this increase is expected in China.

Historically, the CTL process has been used to convert coal into a substitute for liquid fuels in countries with a large coal resource and limited petroleum supplies. CTL includes both direct coal liquefaction technologies, and coal gasification combined with Fischer-Tropsch synthesis to produce liquid fuels. Following the oil crisis of the 1970s, significant coal liquefaction R&D was undertaken in Australia, Europe, Japan, and the United States, but much of this R&D was put on hold as oil prices stabilized from the mid-1980s through the 1990s. Owing to higher oil prices following that period, interest increased in CTL and biomass to liquids, including coprocessing coal and biomass (CBTL). China, in particular, has aggressively pursued conversion of CTL. Since 2005, China has developed three demonstration level CTL plants producing 4,500 barrels per day of products. Their largest CTL plant—producing 100,000 barrels per day—will be completed in 2016, and six more mega projects are scheduled. The most ambitious project will be the largest CTL plant in the world, producing four million tons per year.

Ongoing interest in reducing GHG emissions from energy production has resulted in increased effort to reduce GHGs from CTL production, since conversion results in GHG emissions significantly higher than conventional petroleum. Approaches for reducing GHGs include the following:

- Capturing and geologically storing CO<sub>2</sub> produced during the CTL process. This is attractive because 91% of CO<sub>2</sub> produced in the coal conversion process is in a concentrated stream that can be easily captured.
- Coprocessing coal and biomass to produce liquid fuels. Adding CCS to this CBTL process dramatically reduces GHGs because biomass conversion results in low GHGs, and when CCS is introduced, the biomass component becomes carbon negative.

A 2009 study<sup>99</sup> found that for a commercial process that converts coal into diesel fuel, coupling the process with carbon sequestration is relatively inexpensive, adding only seven cents per gallon. Furthermore, this small investment reduces the GHG emissions dramatically, from 147% above the petroleum-derived diesel baseline to 5% below it. The study looked at one technology enhancement (addition of an auto thermal reactor) that further reduced GHGs, but it did not consider ongoing R&D that will make the gasification process even more efficient and cost-effective.

Systems combining various inputs of biomass and coal, converting them at a central facility to liquid fuels and electric power, and using CCS on CO<sub>2</sub> released at that facility have been analyzed and these studies variously identify net positive, neutral, or negative carbon emissions.<sup>100</sup> The differences between cases depends on the balances of inputs and outputs. The fraction of input energy from biomass is a key factor as biomass draws CO<sub>2</sub> from the atmosphere during growth; then, when the biomass is converted to fuels and power, using CCS can enable a net drawdown of CO<sub>2</sub> from the atmosphere for that portion. This is balanced against the portion used as fuel for which CCS is not practical. Biomass feedstock costs increase with the scale of the conversion facility due to the large required collection areas and logistic costs, but the reduction in energy production costs for larger facilities can more than compensate for this over a wide range of cases, but is ultimately constrained by truck traffic congestion at the facility.<sup>101</sup> Research to reduce costs for smaller facilities and to improve biomass productivity and logistics could help address these factors.

#### 7.5.4 Fuel Methanol and Dimethyl Ether

Methanol (CH<sub>3</sub>OH), also known as wood alcohol, is considered an alternative fuel under the Energy Policy Act of 1992. Methanol was marketed in the 1990s as an alternative fuel for compatible vehicles. At its peak, nearly six million gasoline gallon equivalents of 100% methanol and 85% methanol/15% gasoline blends were used annually in alternative fuel vehicles in the United States. As an engine fuel, methanol has chemical and physical

fuel properties similar to ethanol. Methanol use in vehicles has declined dramatically since the early 1990s, and automakers no longer manufacture methanol vehicles in the United States, although it is still a popular fuel worldwide. It is generally produced by steam-reforming natural gas to create a synthesis gas. Feeding this synthesis gas into a reactor with a catalyst produces methanol and water vapor. Various feedstocks can produce methanol, but natural gas is currently the most economical in North America (in China, coal is preferred).

Methanol can be an alternative to conventional transportation fuels. The benefits of methanol include the following:

- **Lower production costs:** Methanol is inexpensive to produce relative to other alternative fuels.
- **Improved safety:** Methanol has a lower risk of flammability compared to gasoline.
- **Increased energy security:** Methanol can be manufactured from a variety of carbon-based feedstocks, such as natural gas and coal. Its use could also help reduce the United States' dependence on imported petroleum.

Dimethyl ether (DME) represents an alternative to CNG and LNG as a natural gas-derived transportation fuel. It can be synthesized from methanol via dehydration. In contrast to CNG, which requires onboard storage at high pressures (250 bar/3600 psi), and LNG, which requires low temperatures (-162°C), DME behaves like propane in that it is liquid at ambient temperatures and moderate pressures. Its combustion characteristics are well suited for use in diesel applications such as trucks, buses, and construction equipment. As a compression ignition fuel, DME is considered “clean burning” in that it is less likely to produce particulate (soot) emissions than diesel or bunker fuel. DME is also nontoxic and is not itself a GHG. DME has lower energy density (18.9 megajoules per liter), however, than diesel (37.3 megajoules per liter). Combustion studies and engine demonstrations of DME as a compression ignition fuel were performed throughout the 1990s, but further activity was halted when the price of natural gas increased nearly tenfold in 2000. Three important developments offer new research opportunities for DME: 1) the discovery of large domestic supplies of natural gas and subsequent price stabilization, 2) recent developments in advanced combustion regimes for engines, and 3) process developments to convert natural gas to DME in retail outlet quantities. By making and dispensing DME on-site, distribution through the existing natural gas infrastructure could provide a pathway to DME-fueled transportation with minimal infrastructure upgrades. Of course, the combustion products of DME include CO<sub>2</sub>, which must be controlled to address climate change.

## 7.6 Conclusion

Each fuel has strengths and shortcomings, and the fuel system must meet several challenging needs: economic prosperity requires low-cost fuels; energy security requires stable, abundant domestic resources; and meeting environmental goals requires reduction of greenhouse gas emissions and other externalities. This chapter explores options to address each of these challenges in oil and gas, in bioenergy for fuels, and in hydrogen production and distribution, as well as for other fuel options.

### Oil and Gas

Until recently, domestic oil and natural gas production was in decline, but because of technology advances in hydraulic fracturing, among others, the United States is now the world's largest producer of these fuels. While oil and gas are low cost, have good economics, are abundant, and support national security, they have a poor carbon footprint and other environmental challenges.

### Bioenergy for Fuels

Bioenergy from a variety of feedstocks can be converted to a wide variety of products and liquid fuels and offer the potential to significantly reduce the GHG emissions associated with liquid fuel use. While ethanol

from corn is an established industry, advanced pathways to use cellulosic, lignin, and waste inputs are just now beginning to enter the market but could scale up domestic low-carbon fuel production if key technology cost, scalability, and land use challenges can be met.

## Hydrogen

Hydrogen is an energy carrier that can be produced from a variety of energy resources. It is produced in large quantities today from natural gas. Technology options such as electrolysis from low-carbon electricity, direct reforming of fossil fuels with CCS, or production from biomass (possibly with CCS to achieve negative carbon emissions) can produce hydrogen for fuel with a very low carbon footprint from domestically available energy resources. Challenges include technology costs of these low-carbon resources, as well as distribution and fueling infrastructure.

## Future Prospects

The QTR identifies many opportunities for RDD&D to support the future of fuels in the United States. After several decades of generally flat (gas) or declining (oil) production, production of shale gas and oil has sharply increased in the United States in the past half-dozen years. Commercial production of cellulosic biomass fuels began in 2014 after many years of research and development. Public-private partnerships are now beginning to supply hydrogen for the new consumer FCEV market. Each of these fuels will pose tradeoffs—cost, performance, infrastructure, security, climate impact, and others—across different time frames. A strong understanding of the technological options in the fuels sector through the QTR can support an informed R&D strategy going forward (Table 7.7).

**Table 7.7** Summary of RDD&D Opportunities

Area	RDD&D opportunities
Oil and gas	<ul style="list-style-type: none"> <li>■ Minimizing the safety and environmental impacts of unconventional oil and gas development: protecting groundwater, increasing water availability, and protecting air quality</li> <li>■ Mitigating risk of offshore oil spills</li> <li>■ Reducing methane leaks associated with pipelines and compressors</li> <li>■ Understanding induced seismicity</li> <li>■ Develop understanding required for commercial production of natural gas from natural hydrate deposits</li> <li>■ Controlling carbon emissions with CCS where used at scale</li> </ul>
Bioenergy for fuels	<ul style="list-style-type: none"> <li>■ Reducing costs of feedstock production and improving logistics and conversion</li> <li>■ Producing and managing a consistent, aerobically stable suite of lignocellulosic feedstocks</li> <li>■ Improving enzymes and microorganisms for biochemical pathways and improving catalysts and processes for thermochemical pathways</li> <li>■ Producing high-value bioproducts and biobased inputs to chemicals</li> </ul>
Hydrogen	<ul style="list-style-type: none"> <li>■ Reducing costs of converting the end-to-end fuels infrastructure to accommodate hydrogen</li> <li>■ Reducing costs of hydrogen production from low- or zero-carbon resources</li> <li>■ Exploring new materials to improve efficiencies, performance, durability, cost, and safety</li> </ul>

## Chapter 7: Advancing Systems and Technologies to Produce Cleaner Fuels

# Technology Assessments

- 7A** Bioenergy Conversion
- 7B** Biomass Feedstocks and Logistics
- 7C** Gas Hydrates Research and Development
- 7D** Hydrogen Production and Delivery
- 7E** Natural Gas Delivery Infrastructure
- 7F** Offshore Safety and Spill Reduction
- 7G** Unconventional Oil and Gas

[See online version.]

## Supplemental Information

- Oil and Gas Technologies
- Subsurface Science and Technology

[See online version.]

### Endnotes

- <sup>1</sup> Energy Information Administration. “Annual Energy Outlook.” 2015; Table A2. Note: For industry and buildings, most of the energy not directly supplied by fuels is from electricity, for which upstream electricity-related generation and other losses are included in the total for energy use by the sector and in the calculation for the share of energy that direct fuel use provides.
- <sup>2</sup> Energy Information Administration, “Annual Energy Outlook.” 2015; Table 37.
- <sup>3</sup> As of June 24, 2015, the U.S. Department of Energy has granted final approval to export LNG to non-Federal Transit Administration countries from the following LNG Terminals: Sabine Pass LNG Terminal (2.2 Bcf/d), Freeport LNG Terminal (1.8 Bcf/d), Cameron LNG Terminal (1.7 Bcf/d), Dominion Cove Point (0.77 Bcf/d), Corpus Christi LNG Terminal (2.1 Bcf/d).
- <sup>4</sup> Energy Information Administration. “Annual Energy Outlook.” 2015.
- <sup>5</sup> National Research Council, Council on Benefits of DOE R&D on Energy Efficiency and Fossil Energy, Board on Energy and Environmental Systems, Division on Engineering and Physical Sciences. “Energy Research at DOE: Was it Worth It?,” 2001. *Energy Efficiency and Fossil Energy Research, 1978 to 2000*. 2001, p. 201.
- <sup>6</sup> Energy Information Administration. “Annual Energy Outlook.” 2015.
- <sup>7</sup> In Re: Oil Spill by the Oil Rig “Deepwater Horizon” in the Gulf of Mexico, on April 20, 2010, No. 10-2771 and No. 10-4536, Findings of Fact and Conclusions of Law, Phase Two Trial at 43-44 (E.D.L.A. Jan 15, 2015). Available at: <http://www2.epa.gov/sites/production/files/2015-01/documents/phase2ruling.pdf>.
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- <sup>9</sup> Ibid. Table 1-1 Natural Gas Resource Base, p. 65.

- <sup>10</sup> Energy Information Administration. “Today in Energy, September 11, 2012. Pad Drilling and Rig Mobility Lead to More Efficient Drilling.” Available at: <http://www.eia.gov/todayinenergy/detail.cfm?id=7910>.
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- <sup>14</sup> U.S. Department of Energy. “Modern Shale Gas Development in the United States: A Primer.” April 2009, p. ES-3.
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- <sup>16</sup> National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. Report to the President. “Deepwater: the Gulf Oil Disaster and the Future of Offshore Drilling.” Chapter 4.
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- <sup>76</sup> For more information, see <http://energy.gov/eere/fuelcells/photoelectrochemical-working-group>. High solar-to-hydrogen (STH) conversion efficiencies are possible in the emerging production pathways such as photoelectrochemical (PEC) water splitting. For example, a dual band gap PEC solar water splitting system, developed by stacking two materials in tandem, has an ideal theoretical efficiency of 41%, with a chemical solar-to-hydrogen conversion efficiency of 27% when including losses owing to the fraction of unused energy per absorbed photon (*Chemical Reviews* [110:11], 2010; pp. 6448-6449). To date, laboratory-scale demonstrations exceeding 15% STH have been achieved, but cost, durability, and scale-up issues remain (*Energy Environ. Sci.* [6], 2013; p. 1984).
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- <sup>88</sup> Feedstock cost ranges used in the case studies are \$4–\$10 per MMBTU for SMR, \$0.03–\$0.08 per kWh for PEM electrolysis, and \$40–\$120 per dry short ton for biomass gasification, consistent with the Fuel Cell Technologies Office Program Record #14005.
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