Chapter 3
TECHNOLOGY

Abstract

Technology contributes significantly to both reducing energy demand growth and expanding and diversifying supply. Technological advances to extend conventional and expand unconventional fossil fuels are examined, along with technology breakthroughs that may reduce the cost, mitigate environmental drawbacks, and increase the volume potential of alternative energy sources. However, a majority of the U.S. energy-sector workforce—including skilled scientists, engineers, and technicians—is eligible to retire within the next decade and these workers must be replaced and new workers trained.

This chapter examines how technology can significantly improve energy-use efficiency in transportation and other sectors, while also expanding the energy industry's ability to find and produce resources. Expert teams assess commercial and environmental opportunities for conventional and unconventional hydrocarbons, biofuels, nuclear, and other energy sources, noting the time frames needed to bring promising new technologies to market. They also consider ways government and industry can cooperate to renew the vital energy workforce.

The outline of the Technology chapter is as follows:

- Key Findings
- Technology Development and Deployment
- Personnel Issues
- Carbon Capture and Sequestration
- Conventional Wells (including EOR and the Arctic)
- Exploration Technology
- Deepwater Technology
- Unconventional Natural Gas Reservoirs—Tight Gas, Coal Seams, and Shales
- Unconventional Hydrocarbons: Heavy Oil, Extra-Heavy Oil, and Bitumen
- Unconventional Hydrocarbons: Oil Shale
- Unconventional Hydrocarbons: Gas Hydrates
- Coal to Liquids
- Biomass Energy Supply
- Nuclear Outlook and Its Impact on Oil and Gas
- Transportation Efficiency.

The oil and natural gas industry has a long history of technological advancement, and today operates using materials, sensors, chemistry, and engineering that are marvels well beyond the limits envisioned by industry pioneers or, indeed, the general public (Figure 3-1). Many technical advances have been generated directly by research and development (R&D) in industry labs, through field trials, and by applied ingenuity.

Globally, the industry spends more than $6 billion annually on oil- and gas-related R&D. This spending is on the upswing, which will result in technological advances we can only imagine today. The percentage

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FIGURE 3-1. *Jackup Rig with Fracturing Stimulation Vessel in the Gulf of Mexico*

of that $6 billion that is focused on U.S.-specific needs is relatively small. R&D dollars, like capital expenditures, follow the most attractive opportunities, and these are increasingly found overseas. However, the U.S. industry has had some dramatic successes that point the way forward, confirming that there is a continuing role for the U.S. government in this area.

Deepwater technology, which has allowed us to tap into resources in the Gulf of Mexico at water depths exceeding 1,000 feet, is far greater than was imagined even a few years ago, and has significantly increased U.S. reserves and production. Coalbed methane, long considered a hazard to miners, is now a significant resource thanks to technology specifically applied after the U.S. government encouraged its development. In both of these cases, technology was not developed by U.S. government funding, but by industry pursuing opportunities and access to resources, which has made and continues to make a significant difference.

Government policy can affect how technologies are developed and implemented. For example, opening new areas for exploration stimulates R&D in technologies required to exploit those resources. Similarly, technologies that require new facilities, such as coal-to-liquids conversion plants or nuclear power plants, depend on establishing permitting and regulation procedures.

Several specific technologies highlighted in this chapter have potential for industry-government co-operation. These include advanced materials research in nanotechnology and in materials that can sustain high temperatures and high pressures, robotics, and metocean research.[1]

Enhanced oil recovery and carbon capture and sequestration (CCS) are activities for which significant advances are expected in the coming decades. Today, technology is developing to reduce the cost of separating carbon dioxide (CO_2) and to sequester large amounts of the gas in deep underground formations. Beyond today's biofuels, research breakthroughs are expected in second-generation crops and cellulosic ethanol production.

Advancements are being achieved by the industry that reduce environmental impacts, particularly in fragile and ecologically sensitive locations. "Greener" chemicals are being deployed throughout operations. Further cost reductions and technology to reduce environmental effects will be applied in heavy-oil reservoirs and later in oil shales in the western United States and elsewhere. Water and other resource demands increase significantly with many of these new developments, however, and in some regions these demands may become the largest factor limiting growth.

Clearly, a significant piece of the overall energy puzzle will be technology that increases the efficiency of energy use. This is an area rich in opportunity for both technology advancements and policy measures. It is, however, an area complicated by consumer preferences and diverse situations for technology's adoption. One can see this in the evolution of the U.S. auto fleet over the past decade, where technical improvements in drive-train efficiency have been mainly applied to increase performance rather than fuel economy. As with technology developments to increase supply,

1 Nanotechnology includes devices and materials whose size is in the range of 1 to 100 nanometers (billionths of a meter). Metocean is the "weather" of the offshore environment both above and below the surface of the water. The word is a contraction of "meteorology" (weather in the air) and "oceanology" (conditions below the surface of the water) and is used by all offshore industries.

clear regulatory signals by governments and economic opportunities by the private sector combine to accelerate technology advances. The U.S. refrigerator efficiency standard, which raised efficiency requirements and reduced energy consumption, is a good example of a clear success that could be duplicated. Lighting, building-energy efficiency, and electricity-grid improvements are all areas where ingenuity combined with smart policy would yield big efficiency gains.

While current R&D by the oil and natural gas industry, along with entrepreneurial start-ups funded by increased venture and equity capital, is on the upswing, U.S. government funding for oil and natural gas research is trending down. Department of Energy monies have been a significant funding source for U.S. universities and national laboratories. This funding is particularly important, as it enables students to pursue advanced degrees that are relevant and vital to our country's energy future. One of the most significant issues facing the U.S. energy industry is a critical shortage of engineers and scientists. This stems from the cyclical nature of the industry and by public perceptions, as well as reductions in the number of U.S. petroleum and geoscience degree departments, and industry demographics. More than 50 percent of the industry's current technical workforce is eligible for retirement within the next decade, creating an experience and skill shortage at a time when demand will be increasing. Solving this challenge will require cooperation among federal and state governments, academia, and industry if the United States is to continue its historical leadership in oil and natural gas technology development.

Topics are arranged in six broad groupings in this chapter. The first group contains two topics that are part of all the others—technology development and personnel issues—and one that is likely to be important for many of the others—carbon capture and sequestration. The second group describes exploration and production (E&P) activities that are current today: conventional resources (including enhanced oil recovery and arctic activities), exploration, and deepwater technologies. The third group comprises unconventional natural gas production in shale gas, coalbed methane, and tight gas sands (reservoirs with extremely low permeability). The fourth group includes unconventional hydrocarbon sources in heavy oil, oil shale, and methane hydrate. The fifth group describes alternative sources for liquid fluids from coal and biomass. The final group has two reports covering the effect that nuclear technology might have on the oil and natural gas sector, and the impact that technology improvements might have on transportation efficiencies.

Each section includes a description of the technology topic, information about the state-of-the-art within the topic, and, in many cases, the most important developments expected by 2010, 2020, and 2030. Details and technical discussions can be found in the individual Technology Topic Reports that are available on the CD that accompanies this report.

KEY FINDINGS

- The current and projected demographics of trained personnel in the broad U.S. energy industry indicate a shortage that is expected to worsen due to retirements in the next decade and beyond. The shortage affects both the E&P part of the business (upstream) and the refining part (downstream), construction, and other sectors, including the transportation industry. It ranges from skilled craftspeople through PhDs. Fewer academic departments are training students in petrotechnical areas now than in the 1980s. However, the problem is wider, with shortages of students in science, engineering, and mathematics. A similar situation exists for craft labor.
- Carbon capture and sequestration underground will facilitate the continued use of fossil fuels in an increasingly carbon-constrained world. CCS is technically achievable today, and has been demonstrated at a project level and applied in enhanced oil recovery. However, CO_2 has not been injected at the scales (both volumes and time periods) that will be necessary in the future.
- The prospect for advancements in technology is very good, but the Technology Task Group found no single, simple solution with the potential to provide energy security for the United States over the long term. The solution will involve as many of the available resources and potential technologies as can be developed and deployed.
- Technology can significantly improve transportation efficiency, particularly for light duty vehicles. Consumer preferences affect the deployment of technology in that sector, whereas a sound business case affects deployment in the other transportation sectors.

- Technology has had a significant impact on the industry's ability to find and produce resources. In exploration, 3D seismic technology created a boom in activity starting in the 1980s, driving down acquisition costs while improving the exploration success rate. In another area, after government policies were enacted in the 1980s, technologies were developed to understand and exploit coalbed methane, a resource that has been known since the beginning of the coal mining industry (Figure 3-2).

- Access to acreage with potential for economic oil and natural gas resources is itself a primary driver that encourages technology development. The onset of area-wide leasing for the U.S. Gulf of Mexico in the early 1980s led to significant acceleration of interest in deepwater regions.

- Commercializing technology in the oil and gas market is costly and time-consuming; an average of 16 years passes from concept to widespread commercial adoption.

- Recovery from existing and future resources is expected to improve because of continuing increases in the volume of the reservoir that is in proximity to a wellbore, thanks to both close well spacing and improved technologies such as multilateral horizontal wells. Environmental impact will continue to be reduced as technology allows operations with a smaller "footprint" and "greener" chemicals.

- Improved exploration and exploitation technology slowed the decline in discovery volumes. Although the future of exploration technologies is bright and the exploration success rate may continue to improve, it is still likely that the volumes of hydrocarbons discovered with time will continue to decrease.

- Unconventional natural gas resources in tight gas sands, coalbed methane, and gas shales have become commercial because of technological advances, and these new resources are likely to continue to be important.

- Technologies are available for production of heavy oil, extra-heavy oil, and bitumen, but these heavier crudes are in less demand than conventional oil because of the difficulty in processing to create refined products, and because fewer refineries have the capability to process them (Figure 3-3).

- Oil shales may become a commercial resource by 2020, although large-scale production is unlikely

FIGURE 3-2. *Land Rig in the Rocky Mountains*

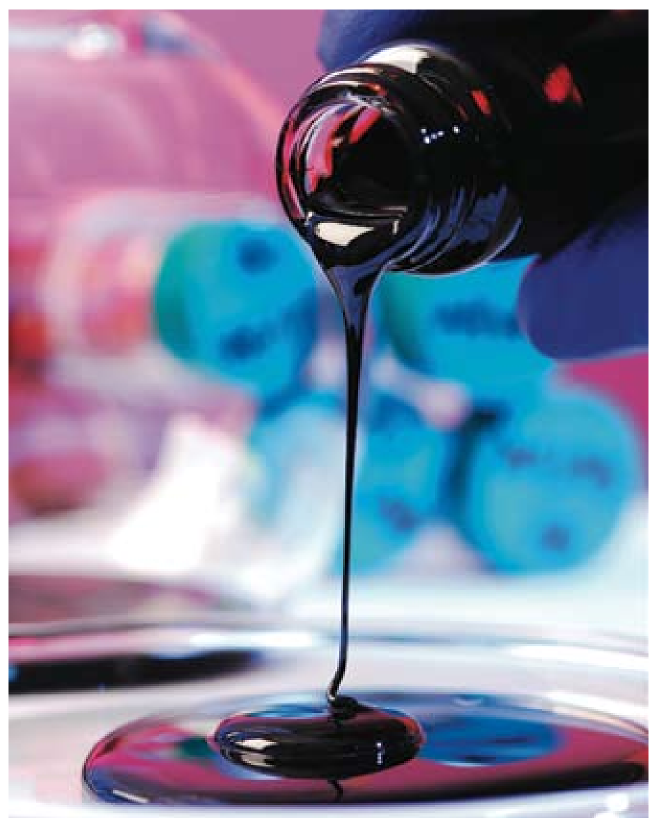

FIGURE 3-3. *Heavy Oil Sample*

until 2030. The technique used historically is surface processing in a high-temperature retort. An alternative process still in development, in situ conversion at lower temperature, has captured the industry's attention. In situ conversion technology is just emerging, so it is not yet clear which specific technologies can advance the state of the art over the coming decades.

- An economically viable method for production of natural gas from naturally occurring hydrate resources has not been developed. Hydrate sites are known to be in arctic areas, and in some marine locations in other parts of the world, but no efforts have been made to locate commercial marine deposits of hydrates in U.S. waters.
- Estimates for coal-to-liquids production are small relative to the overall petroleum market through 2030, for cost and environmental reasons.
- Biofuels face technological and logistics challenges before becoming a more significant part of the U.S. transportation fuel mix. Still required are efficient and scalable conversion techniques for cellulosic materials such as switchgrass, corn stover, and woody biomass; efficient transportation networks from field to plant; and ways to overcome water-supply shortages.
- Nuclear power plants provide base-load electrical power, whereas electricity generated using oil or natural gas is typically load-following. Therefore, if developed in the United States, growth of nuclear power will displace a much greater amount of coal-powered generation growth and a smaller amount of oil and natural gas generation.
- With many mature, marginal fields, the United States has specific R&D needs that have a lesser focus for the largest industry R&D organizations than the more prolific international prospects.

TECHNOLOGY DEVELOPMENT AND DEPLOYMENT

Since the beginning of the modern age of oil and natural gas, technology has played a fundamental role in supporting the efficient production of hydrocarbons. Oil and natural gas technologies are often destined for hostile, hard-to-reach environments such as deep offshore waters or in the high temperatures and pressures encountered at the bottoms of wells. Full-scale tests must be completed before a technology can be proved and the market will accept it. As a result, commercializing technology in oil and natural gas markets is costly and time-intensive; some studies indicate an average of 16 years from concept to commercialization. The Technology Development Topic Report examines both lessons from history and current trends in oil and natural gas technology development and deployment to make predictions for the coming years.

The sources of technology destined for the oil and natural gas markets have changed over time. Starting in the early 1980s, major oil and natural gas companies began to decrease their R&D spending, driven in large part by a decision to "buy versus build" new technology. Historically, independent oil and natural gas companies have spent little on R&D. Service companies have stepped in to partially fill the gap by increasing their R&D spending. There is little doubt that in the coming years, new technologies will be invented and applied to the global quest to maximize production from oil and natural gas reservoirs. As oil prices have risen over the past few years, so have R&D budgets, with the exception of U.S. government spending. The global industry will spend more than $6 billion on R&D, much of it in areas outside the United States.

The major oil and natural gas companies follow the best investment opportunities, including R&D, which are increasingly found overseas. This pursuit leaves U.S. onshore production largely in the hands of independent oil and natural gas companies. In a global marketplace, the service companies continue to respond to the needs of their worldwide customer base.

Being one of the most mature oil and natural gas producing countries, the United States has specific technology requirements compared with much of the rest of the world (Figure 3-4). More than 400,000 U.S. oil wells produce less than 10 barrels a day (of these, the average national production is 2.2 barrels per day). About 289,000 marginal natural gas wells produce less than 60 million cubic feet a day in the United States (an average of 16.7 million cubic feet per day per well). That is 17 percent of the oil and 9 percent of natural gas produced onshore in the United States.[2]

2 Interstate Oil and Gas Compact Commission, "Marginal Wells: Fuel for Economic Growth" (2006).

***FIGURE 3-4.** Pumping Units that Produce Oil from Low-Pressure Reservoirs*

Research is key to the survival of these marginal wells. Unfortunately, the small, independent producers who operate these wells rarely have the ability to conduct research, even though R&D might keep them producing for many more years. As a result, unless the technology requirements of the U.S. oil and natural gas business align with the needs of the rest of the world, there is a danger that U.S. interests may not be addressed adequately.

Figure 3-5 shows U.S. government R&D funding in recent years, split between oil and natural gas.[3] Research undertaken by national laboratories and universities usually leads to fundamental understanding and basic technologies. These technologies are typically applied by other entities such as oil and natural gas, service, or start-up companies.

However, the U.S. government proposal for fiscal year 2007 to terminate the oil and natural gas program within the Department of Energy leaves only $50 million in royalty receipts that were set aside in the Energy Policy Act of 2005. The bulk of the funds ($35 million) is set aside for ultra-deepwater and

3 Lawson, William F, "Who Will Fund America's Energy Future?" Interstate Oil and Gas Compact Commission report (2006).

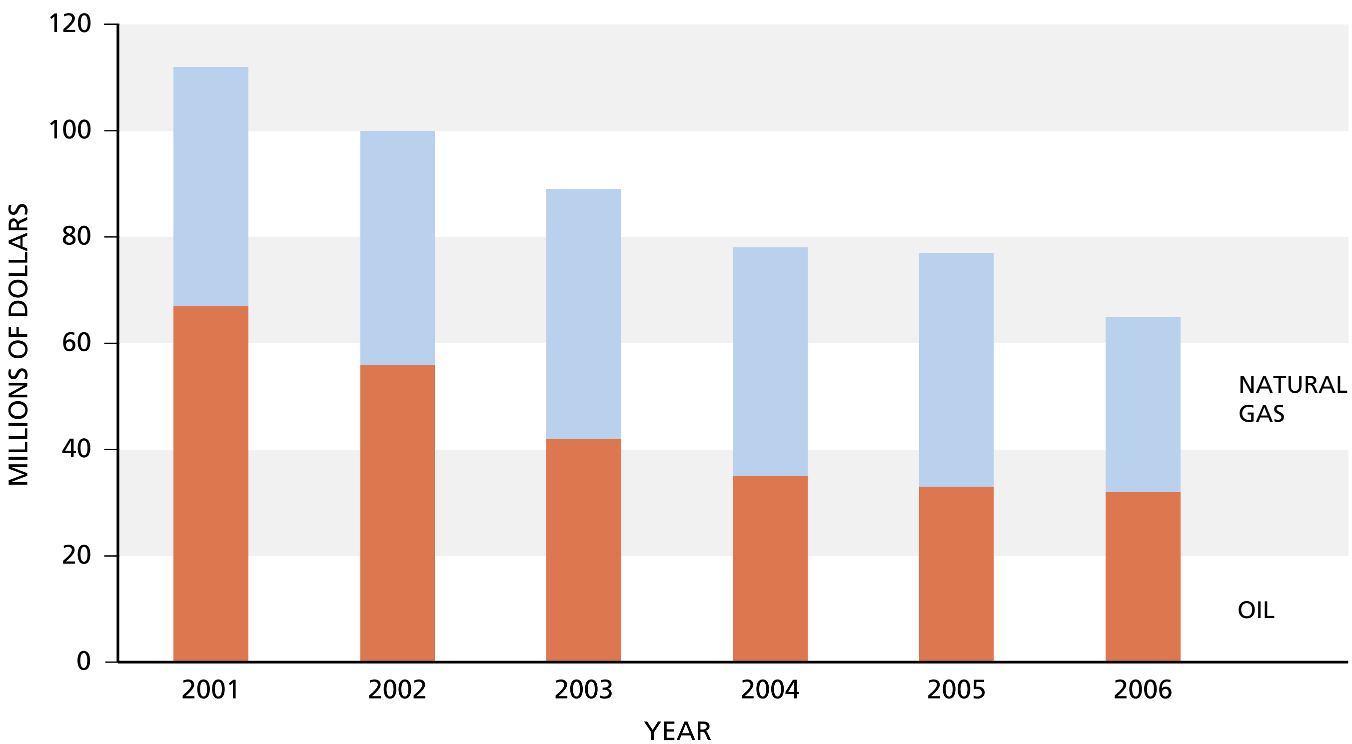

***FIGURE 3-5.** Oil and Natural Gas R&D Funds Provided by the U.S. Government*

unconventional-hydrocarbon research programs as part of the Research Partnership for a Secure Energy America (RPSEA). The remainder ($15 million) is set aside for an internal National Energy Technology Laboratory program and administrative funds.

Many successful research programs have featured accountability as a key attribute. Examples show that it is possible to leverage funding, such as the Ansari X prize for privately funded manned space flight, the Orteig prize to Lindbergh for his solo flight across the Atlantic, and the Board of Longitude prize for the 18th century invention of the marine chronograph that enabled navigators to determine longitude at sea.

PERSONNEL ISSUES

The exploration and production industry is currently in a boom cycle after an extended bust that lasted about 20 years. The current and projected demographics of trained personnel in the broad U.S. energy industry are disturbing, leading to a shortage that is expected to worsen and last for decades. This problem is pandemic, affecting upstream and downstream, construction, and other sectors including the transportation industry (Figure 3-6). Personnel shortages range from skilled craftspeople through PhDs. Within the E&P industry, the impending retirement and handoff to the next generation of employees has been referred to as the "big crew change;" the U.S. Department of Labor refers to it as the "demographic cliff."[4]

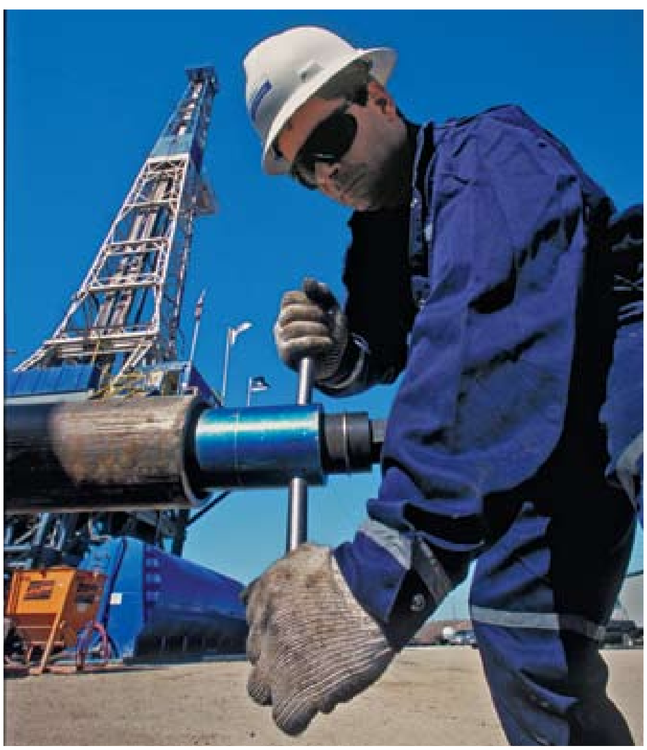

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FIGURE 3-6. Skilled worker on rig site

The majority of industry professionals are less than ten years from retirement eligibility. There are fewer academic departments in petrotechnical areas now than before the bust, and significantly fewer petrotechnical students are being trained to replace upcoming retirees. The industry's cyclical nature and its negative public image have kept the number of interested students low. Enrollment in petroleum engineering and geoscience departments of U.S. universities is down about 75 percent from its 1982 peak. However, the problem is wider, with a shortage of students in science, engineering, and mathematics. A similar situation exists for craft labor, with aggregate demand exceeding supply by an increasing margin over the next few years. Competition from other industries will intensify the shortage of personnel, which is exacerbated globally by an explosion in the rate of hiring by the industry in the past two years.

A study by Schlumberger Business Solutions in 2005 indicated a surplus of petrotechnical graduates in parts of the world, including Indonesia, Venezuela, and China, that is available to supply the areas with a deficit of graduates, such as the United States. However, a 2006 follow-up survey showed that the rapid increase in hiring has swamped even the ability of those countries to fill global needs. Even if the high rate of hiring lasts only a few years, language, culture, and immigration quotas pose barriers to a rapid flow of graduates from one part of the world to another.

Many E&P industry jobs can be (and are) filled by graduates of other engineering and scientific disciplines. However, the public's negative image of the industry makes recruiting those graduates difficult as well. The alternative of mid-career hiring is a negative-sum game when viewing the industry as a whole: although it helps one company, it does so to the detriment of another, and it is an expensive option.

Many of the Technology Task Group Topic Reports noted this problem as a barrier to implementing technological advances. For example, enabling development of coal-to-liquids technologies requires

4 U.S. Department of Labor, "Identifying and Addressing Workforce Challenges in America's Energy Industry," President's High Growth Job Training Initiative, U.S. DOL Employment Training Administration (March 2007).

additional coal miners, transportation crews, and plant personnel, both skilled and professional. Similar problems are noted for any substantial increase in biofuels production, shale oil development, carbon sequestration, and other areas.

CARBON CAPTURE AND SEQUESTRATION

It is likely that the world is moving into an era in which carbon emissions will be constrained. For a general discussion on carbon, see Chapter 5, "Carbon Management." Oil and natural gas contribute more than half the current, energy-related CO_2 emissions. In a carbon-constrained world, the use of oil, natural gas, and coal will be affected by policy measures to reduce carbon emissions. Carbon management will involve combining several measures to reduce CO_2 emissions, including improvements in the efficiency of energy use and the use of alternatives to fossil fuels such as biofuels, solar, wind, and nuclear power. However, to meet the energy demands of the nation, the United States will continue using fossil fuels, including coal, extensively over the next 50 years or more. To do so, and to extend the resource base to include unconventional hydrocarbons such as heavy oil, tar sands, and shale oil, it will be necessary, if carbon constraints are imposed, to capture and sequester a large fraction of the CO_2 produced by burning these fossil fuels.

Carbon capture and sequestration entails trapping CO_2 at the site where it is generated and storing it for periods sufficiently long (several thousand years) to mitigate the effect CO_2 can have on the Earth's climate. In this report, we only consider geological sequestration and do not discuss possible alternatives, such as deep-sea sequestration, which is fraught with environmental concerns and issues of public acceptance. Geological sequestration would target spent oil and natural gas reservoirs and deep saline formations; the potential capacity is discussed in the CCS Topic Report.

The technologies required for effective CCS are, by and large, viable. Projects continue at Sleipner field, the Weyburn enhanced oil recovery (EOR) project in Canada,[5] and the In Salah saline formation project in Algeria.[6] The hurdles to implementation are largely ones of integration at scale. Current possible scenarios of climate change predict that by 2030, the level of CO_2 to be mitigated could be 30 billion tons per year or more.[7, 8] Sequestering 5 billion tons of CO_2 each year would entail pumping volumes close to 100 million barrels per day of supercritical CO_2 into secure geological formations. This amounts to around a quarter of the volume of water currently pumped worldwide for secondary oil recovery. At the local level, sequestering CO_2 from a 1-gigawatt coal-fired power station would require pumping into the ground some 150,000 barrels per day of supercritical CO_2.[9] A power station of that size would generate electricity for about 700,000 typical American homes.

While the technologies for CCS are essentially available, in that capture and storage can be implemented now, extensive scope remains for improvement. In particular, the capture stage of CCS is key, and currently dominates the overall cost. Novel, lower-cost approaches to capture would have a significant effect on the implementation of CCS and would, in turn, greatly influence the usability of fossil fuels under carbon constraint. The CCS Topic Report discusses other areas where continued research is important:

- Fundamentals of storage, such as long-term physiochemical changes in the storage reservoir
- Characterization and risk assessment (faults, cap rocks, wells)
- Reservoir management for long-term storage
- Integration of fit-for-purpose measurement, monitoring, and verification
- Ability to inject CO_2 into formations
- Retention and leakage, such as leakage through wells.

It is also crucial at this stage to undertake an assessment of the total U.S. capacity for CO_2 sequestration.

5 Wilson M, Monea M. (Eds.), IEA GHG Weyburn CO_2 Monitoring & Storage Project Summary Report 2000-2004 (2004).

6 Riddiford, F, Wright, I, Espie, T, and Torqui, A, "Monitoring geological storage: In Salah Gas CO_2 Storage Project," GHGT-7, Vancouver (2004).

7 Pacala and Socolow, "Stabilization Wedges: Solving the Climate Problem for the next 50 Years with Current Technology," *Science* 305 (13 Aug. 2004): 968.

8 Third Assessment Report – Climate Change 2001, Intergovernmental Panel on Climate Change.

9 Socolow, R, "Can We Bury Global Warming?" *Scientific American* (2005).

While it is reasonable to expect that the combined capacity of existing hydrocarbon reservoirs and deep saline formations is large, a detailed understanding of the regional distribution of capacity throughout the United States is critically important.

It is important to note that there is no experience available with full-process integration, e.g., a coupled, large-scale coal-fired power plant with CCS. Several projects worldwide, most notably FutureGen in the United States and Zero-Gen in Australia, are in the process of designing and constructing an integrated large-scale power and CCS operation. Operating such facilities successfully is central to understanding the true economics and practical requirements for large-scale CCS.

Experience Basis	Significance	Limitations
CO_2 enhanced oil recovery (EOR)	> 30 years experience; injection >> 1 million tons CO_2/year	Very limited monitoring programs; questions of applicability of experience to saline formations
Acid gas injection	> 15 years experience injecting CO_2 and H_2S into over 44 geologic formations	Generally small volumes; very little publicly available technical information
Hazardous waste disposal/ underground injection control	…	Most hazardous waste is not buoyant or reactive
Natural gas storage	~100 years experience injecting natural gas into rocks	Limited monitoring; different chemistry; built for temporary storage
Natural analogs	Several large (> 50 trillion cubic feet) carbo-gaseous accumulations globally; proof of concept	Most at steady state, transient knowledge unavailable; limited geography and geology
Conventional oil and gas E&P	Nearly 150 years of technology and experience in predicting and managing buoyant fluids in crust	Hydrocarbon recovery has goals and needs which differ from those of carbon sequestration
Capture/gas separations technology	> 70 years separating CO_2 and other acid gases from gas streams, including at power plants	Costs still higher than preferred under widespread deployment; still no integration of large power plants with CCS
Large CO_2 storage projects	3 large-scale projects; > 6 pending before 2010	Still limited monitoring program; limited geologic representation
CO_2 pipelines and transportation	> 30 years experience at large scale; existing regulations likely to apply	None

TABLE 3-1. *Basis for Experience Relevant to Commercial Carbon Capture and Sequestration*

One activity in which CO_2 is pumped into reservoirs currently is enhanced oil recovery. This provides a proving ground for various techniques that are relevant to CCS, and can be implemented while other carbon-management solutions are under development. (A section of the Topic Report discusses the role of CO_2-EOR in the development of CCS technologies.) At present, CO_2-EOR is not directed towards effective storage of CO_2 but the techniques can be modified to improve carbon sequestration.

There is a growing scientific consensus that anthropogenic CO_2 is driving detrimental climate change.[10] Moreover, the Intergovernmental Panel on Climate Change (IPCC) Special Report on CCS indicates that including it in a mitigation portfolio could help stabilize CO_2 concentrations in the atmosphere (at double the pre-industrial level) with a cost reduction of 30 percent or more, compared to other approaches.[11] More recently, the UK's Stern Review estimated that the cost of meaningful mitigation—maintaining atmospheric levels of CO_2 at no more than double the pre-industrial levels—would amount to about 1 percent of global GDP.[12] Doing nothing, on the other hand, would likely incur a cost greater than

10 Oreskes, N, "The Scientific Consensus on Climate Change," *Science* 306 (3 Dec. 2004): 1686.

11 "IPCC Special Report on Carbon Dioxide Capture and Storage," Intergovernmental Panel on Climate Change, Interlachen (2005), available at http://www.ipcc.ch/.

12 "The Stern Review of the Economics of Climate Change," available at http://www.hm-treasury.gov.uk/independent_reviews/stern_review_economics_climate_change/stern_review_report.cfm.

Technology	Significance	Brief Discussion
CO_2-EOR	Natural arena for exploring CCS	Provides a direct commercial incentive to pumping CO_2 into a reservoir
Evaluation of CCS in association with coal-fired plant	Development of integration of required technologies	Projects in United States, Australia, and China to develop CCS with coal plants
Improved capture technologies	Key determinant of cost of CCS	Significant efforts in United States, Europe, and Japan to drive down cost of capture
Injection of CO_2 into subsurface formations	Demonstration of injection and test of storage	CO_2 currently injected at the million tons/year level
Development of models for subsurface migration of CO_2	Understanding of migration behavior underpins characterization and MMV	Combination of modeling and experiment (e.g., Sleipner) to establish CO_2 migration
Reservoir characterization for storage	Reservoir characterization techniques migrate to CO_2 storage estimates	Available techniques tested at several sites
Measurement, monitoring and verification (MMV)	Available MMV technologies applied to CO_2 injection and storage	Available techniques tested at several sites
Development of CO_2 resistant cements	Primary leakage path is likely to be existing wells	Improvements in resistance of cements to corrosion are currently being pursued

TABLE 3-2. *Summary of Carbon Capture and Sequestration Technologies in Priority Order*

Technology	Significance	Time Frame
Extensive CO_2-EOR with substantial CO_2 sequestration	Enhanced security of supply through better recovery	2010
Measurement, monitoring and verification (MMV) techniques	Necessary prerequisite for implementation	2010
Site characterization and risk assessment	Determination of site suitability for sequestration	2010
CO_2 leak remediation technology	Necessary for implementation of CO_2 storage	2010
Demonstration of coal-fired power with CCS	Establish precedent for the technology	2010
Assessment of U.S. CO_2 sequestration capacity	Primary requirement for siting power stations	<2020
Novel, inexpensive capture technology	Key cost determinant of CCS	<2020
Next-generation CO_2-EOR with maximum CO_2 storage	Increases usable CO_2 storage capacity in structurally confined geologic settings by three- to ten-fold	2020
Ubiquitous coal-fired power with CCS	Extensive power generation without CO_2 emissions	2020
Rig-site or sub-surface hydrocarbon processing to generate low-carbon fuels or feedstocks and recycle CO_2 within the reservoir or field for EOR followed by CCS	Keeps most of the carbon in or near the reservoir, simplifying CCS logistics and costs, enabling low carbon fuels/heat/power from oil and gas	2030

TABLE 3-3. *Summary of Carbon Capture and Sequestration Technologies in Time/Priority Order, with Time Frame to Commercial Use*

5 percent of world GDP, with a worst-case estimate of 20 percent, to ameliorate the damage caused by a deteriorating climate. These studies indicate that the financial risk to the nation of delaying action is now so high that a concerted emphasis on CCS is already strongly warranted.

Summary: Technical Issues

Tables 3-1, 3-2, and 3-3 describe the basis for experience relevant to commercial CCS, current technologies in priority order, and future technologies in time/priority order, with time scales to commercial use.

Technology today is well-understood and effective and can probably deliver what is needed. However, there are some outstanding technical issues:

- Novel, lower-cost capture technologies
- Integration and fit-for-purpose deployment of monitoring and verification
- Well-leakage characterization and mitigation
- Protocols for site characterization
- Technical basis for operational protocols and risk characterization.

Summary: Nontechnical Issues

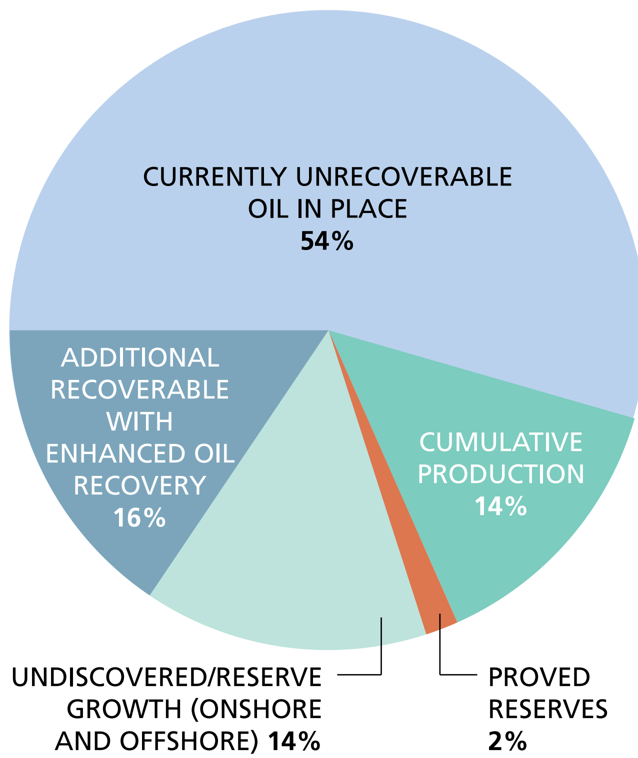
Given the scope of commercial CCS, there are many issues that are not technical, per se, but relate to technical readiness and ways to maximize early investment:

- There is a high likelihood of a critical gap in human capital. Currently, workers who can execute CCS are the same as those employed in oil and natural gas exploration and production. In a carbon-constrained economy, there will not be enough skilled workers to go around. This is particularly true for geoscientists, but also true for chemical and mechanical engineers.
- Development of a comprehensive set of energy policies and strategies is critical to provide certainty to make investment decisions.
- The legislative and regulatory framework within which CCS is conducted will have a major impact on how rapidly the technology is implemented and ultimately will determine whether CCS can effectively mitigate carbon emissions and provide access to future hydrocarbon supplies. A section of the CCS Topic Report is devoted to regulatory issues and details the various aspects of regulation that will be critical to the success of CCS.
- It is not clear that the science and technology programs in place today will provide answers required by regulators and decision makers. Greater dialogue between individuals working with technology and those developing a regulatory framework would help to reduce unnecessary regulation and guide R&D goals toward the most immediate needs.
- Infrastructure to transport CO_2, such as pipelines, is essential for commercial deployment. However, there is concern that pipelines for early project opportunities will not be able to carry additional future projects. Incentives and government action for this infrastructure can help to build networks sufficient to support large-scale, commercial CCS deployment in the United States.

CONVENTIONAL WELLS (INCLUDING EOR AND IN THE ARCTIC)

Large volumes of technically recoverable, domestic oil resources—estimated at 400 billion barrels—remain undeveloped and are yet to be discovered, from undeveloped remaining oil in place of over a trillion (1,124 billion) barrels (Figure 3-7). This resource includes undiscovered oil, stranded light oil amenable to CO_2-EOR technologies, unconventional oil (deep heavy oil and oil sands), and new petroleum concepts, such as residual oil in reservoir transition zones. As the leader in EOR technology, the U.S. oil industry faces the challenge of further applying this technology towards economically producing the more costly remaining domestic oil resources.

While pursuing this remaining domestic oil-resource base poses considerable economic risk and technical challenge to producers, developing the technical capability and infrastructure necessary to exploit this resource reduces our dependence on foreign energy sources and helps our domestic energy industry maintain worldwide technical leadership.



Source: Kuuskraa, V.A., "Undeveloped Domestic Oil Resources: The Foundation for Increasing Oil Production and a Viable Domestic Oil Industry," prepared for the U.S. Department of Energy, Office of Fossil Energy–Office of Oil and Natural Gas, Advanced Resources International (2006).

FIGURE 3-7. *Original, Developed, and Undeveloped Domestic Oil Resources*

The Conventional Wells Topic Report examines the current state of technology relating to conventional oil and natural gas wells, including enhanced oil recovery (EOR) and arctic resources, and makes projections on how technology could influence these businesses in the future (Figure 3-8).

The size and nature of the original, developed and undeveloped domestic oil resources are included in Table 3-4. Note that the domestic oil resources described in this report do not include oil shale. As points of comparison with this table, current proven crude-oil reserves are 22 billion barrels and annual domestic crude-oil production is about 2 billion barrels.

Of the 582 billion barrels of oil in place in discovered fields, 208 billion barrels already have been produced or proved, leaving behind 374 billion barrels. A significant portion of these 374 billion barrels is immobile or residual oil left behind (stranded) after application of conventional (primary and secondary) oil-recovery technology.[13] With appropriate EOR technologies, 110 billion barrels of this stranded resource from already discovered fields may become technically recoverable, although the conditions for economic recoverability will change over the study period to 2030.

Undiscovered domestic oil is estimated to be 360 billion barrels in place, with 119 billion barrels (43 billion barrels from onshore, 76 billon barrels from offshore) being recoverable with primary or secondary recovery. Application of advanced EOR could add another 60 billion barrels of technically recoverable resource from this category.

Future reserve growth in discovered oil fields could amount to 210 billion barrels of oil in place, with 71 billion barrels (60 billion barrels from onshore and 11 billion barrels from offshore) being recoverable with primary and secondary recovery. Application of advanced EOR could raise this technically recoverable volume by up to 40 billion barrels.

With advances in thermal EOR technology, domestic oil sands holding 80 billion barrels of resource in place could provide up to 10 billion barrels of future technically recoverable domestic oil resource.

13 Although the definitions vary, simply speaking, primary recovery comes from a reservoir's natural energy, while secondary recovery involves flooding with water or gas.

FIGURE 3-8. *Seismic Vessel in Iced-In Conditions*

The estimates of remaining, recoverable, domestic oil resources from undiscovered and reserve growth are from the national resource assessments by the United States Geological Survey (USGS) and the U.S. Minerals Management Service (MMS). The estimates of recoverable oil resources using EOR technology on stranded oil and oil sands are based on work by Advanced Resources International for DOE/Fossil Energy's Office of Oil and Natural Gas.

Since the preparation and publication of the Kuuskraa paper that provided a basis for this report, considerable additional work has been completed by the author's firm that further confirms the estimates of undeveloped U.S. oil resources. A total of 10 domestic oil basins and areas have now been assessed (up from the original 6). These 10 assessments indicate that the technically recoverable oil resource from application of "state-of-the-art" CO_2-EOR is 89 billion barrels. The earlier estimate of 80 billion barrels for applying EOR to the stranded light oil resource has been updated to 90 billion barrels (rounded off), as shown in Table 3-4.

Crude Oil Resources*	Original Oil In Place	Developed to Date		Remaining Oil In Place	Future Recovery†		
		Conventional Technology	EOR Technology		Conventional Technology	EOR‡ Technology	Total
Discovered	582	(194)	(14)	374	0	110	110
Light Oil	482	(187)	(2)	293	0	90	90
Heavy Oil	100	(7)	(12)	81	0	20	20
Undiscovered	360	0	0	360	119	60	179
Reserve Growth	210	0	0	210	71	40	111
Transition Zone	100	0	0	100	0	20	20
Tar Sands	80	0	0	80	0	10	10
Total	1,332	(194)	(14)	1,124	190	240	430

* Does not include oil shale.
† Technically recoverable resources rounded to the nearest 10 billion barrels.
‡ Based on ten basin-oriented assessments and residual oil zone resource potential highlighted in reports released by the Department of Energy Office of Fossil Energy in February 2006. V.A. Kuuskraa provided the updated EOR technology numbers for this table.

Sources: This table updates numbers from a table of U.S. oil resources recovery potential in a report from Advanced Resources International by V.A. Kuuskraa, "Undeveloped Domestic Oil Resources: The Foundation for Increasing Oil Production and a Viable Domestic Oil Industry," prepared for the U.S. Department of Energy's Office of Fossil Fuel in February 2006, and available at http://www.fossil.energy.gov/programs/oilgas/publications/eor_co2/Undeveloped_Oil_Document.pdf. The updated numbers are available from ARI at http://www.fossil.energy.gov/programs/oilgas/publications/eor_co2/G_-_Updated_U_S__Oil_Resources_Table_2-1.pdf. Note that the EIA estimates of remaining reserves are lower than those used here, see information in the NPC data warehouse and http://tonto.eia.doe.gov/dnav/pet/pet_crd_pres_dcu_NUS_a.htm.

TABLE 3-4. *Original, Developed, and Undeveloped Domestic Resources (Billions of Barrels)*

New work on the transition/residual oil zone resource documents the presence of 42 billion barrels of this category of oil in place in just three domestic oil basins (Permian, Big Horn, and Williston). Detailed reservoir simulation assessment shows that about 20 billion barrels of this oil in place could become technically recoverable by applying CO_2-EOR. This work provides support to the transition/residual oil zone resource estimate of 100 billion barrels in Table 3-4 and indicates that an important portion of this resource may become recoverable.

Finally, the author and his firm took an in-depth look at the additional oil recovery from applying "next-generation" CO_2-EOR technology. This work shows that combining: (1) advanced, high reservoir contact well designs; (2) mobility and miscibility enhancement; (3) large volumes of CO_2 injection; and (4) real-time performance feedback and process control technology could bring about "game changer" levels of improvement in oil recovery efficiency. This work provides support that a national average oil recovery efficiency target of 60 percent could become realistic, assuming a successful program of advanced technology development, affordable supplies of CO_2 and other EOR injectants, and appropriate risk-mitigation policies, such as federal and state tax incentives to help overcome the risk of applying these new technologies. The NPC studied EOR in 1976 and 1984, and raised great expectations for domestic EOR activity (projecting 3 million and 2 million barrels per day, respectively). These expectations have not been met. Peak domestic EOR

Technology	Time Frame	Discussion
Big increase in controlled reservoir contact	2015	Technologies allowing a continuing increase in the number of strategically placed horizontal wells will allow much greater commercial access to reserves.
Horizontal/multilateral/ fishbone wells	2020	Multiple, placed drainholes from a main wellbore will further extend commercial access to reserves.
Arthroscopic-well construction	2025	The ability to place drain holes to within feet of every hydrocarbon molecule in the formation allows the ultimate in recovery.
SWEEP (see, access, move)	2020	The combined technologies (including the four immediately below) allowing us to see, access, and move the hydrocarbons in the optimum way will bring a big increase to recoverable reserves.
Smart well (injection and production)	2015	The ability to control what fluids go where (at the wellbore).
Reservoir characterization and simulation	2015	Extending current technology to include simultaneous inversion of all measurements with a forward model.
Reservoir vision and management in real time	2020	Combining reservoir-scale measurements (pressure, seismic, electromagnetic, and gravity) in a joint inversion, with uncertainty and without data loss.
Mission control for everything	2020	Representation and control of the full system (subsurface and surface) allowing true optimization.
CO_2 flood mobility control	2020	Measurement and control of the CO_2 flood front is critical for successful implementation.
Steam-assisted gravity drainage (SAGD)/steam and alkaline-surfactant-polymer (ASP) technology	2030	Technologies to perfect and optimize SAGD operations (including the use of ASP) will be key to widespread economic exploitation of heavy oil.
Arctic subsea-to-beach technology	2020	Ice scouring of the seafloor surface presents a huge challenge to conventional approaches to subsea and subsea-to-beach operations.
Faster and more affordable, higher-definition, 3D seismic	2015	Quicker, better, cheaper could extend this already impressive specialized technology into universal use.

TABLE 3-5. *Summary of Highly Significant Technologies for Conventional Wells*

production occurred in 1992 at 761,000 barrels per day. Current activity is 680,000 barrels per day. In the interim, many technologies have been tried, but most failed. Two successes are CO_2-miscible floods and steam (cyclic, steam-assisted gravity drainage, and steam flood).

A broad portfolio of oil-recovery policies and technologies, plus targeted risk-mitigation incentives, would help industry convert these higher-cost, undeveloped domestic oil resources into economically feasible reserves and production. Table 3-5 lists the future technologies that study participants believed will provide the greatest impact on conventional wells, including EOR and arctic.

EXPLORATION TECHNOLOGY

Exploration technology has evolved significantly since 1859, when the first commercial oil well in the United States was drilled adjacent to an oil seep in Pennsylvania. Perhaps the most significant technological advance was the development of two-dimensional (2D) reflection seismology in the 1920s. The emergence of 2D seismic lines with improved processing led to the discovery of many of the world's largest oil and natural gas fields in the following decades. In the 1990s, three-dimensional (3D) seismic technologies became the industry standard, with improved resolution and characterization of the subsurface geology. Today, new ways of looking at seismic data focus on specific attributes and derivative properties that enhance identification of hydrocarbon prospects (e.g., direct hydrocarbon indicators) as well as computer tools that aid in quantitative interpretation of rock and fluid properties.

Improvements in exploration technology have had a significant impact on discovering resources, reducing finding costs, and improving exploration success rates both in the United States and globally.[14] Thanks to technological improvements, costs for 3D seismic acquisition and processing fell by almost a factor of 5 from 1990 to 2001 (Figure 3-9).[15, 16] Despite the substantial improvements in exploration technology and reduction in deployment costs since the 1970s, oil and gas explorers have not maintained the high discovery volumes of that earlier period. This decrease came despite the increased amount of 3D seismic surveys being shot over the period. Several authors

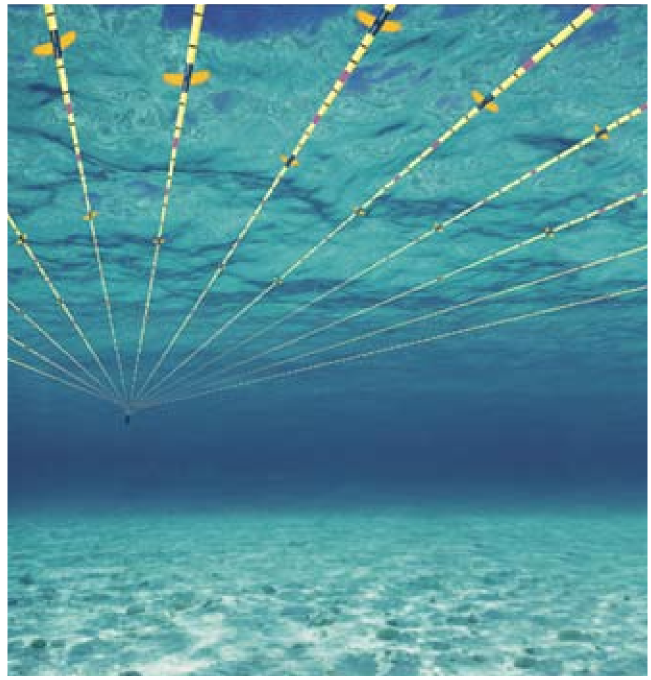


FIGURE 3-9. *Graphic of Towed Seismic Streamers*

concluded that improved exploration and exploitation technology has prevented a more drastic decline in discovery volumes.[17]

Some authors have suggested that improved methods of exploring for unconventional resources might reverse the trend; however, it should be noted that many unconventional resources have already been discovered and await new exploitation technologies.

The future of exploration technologies is bright, but it is still likely that the volumes of hydrocarbons discovered with time will continue to decrease, as shown historically in Figure 3-10, although the exploration success rate may continue to improve.[18] The Exploration Technology Topic Report identified five core exploration-technology areas in which future developments have the potential to significantly improve exploration results over the next 25 years:

- Seismic technology—High- and ultrahigh-density acquisition technologies have great potential for

14 Boutte, D, "The Role of Technology in Shaping the Future of the E&P Industry," *The Leading Edge* 23, no. 2 (2004): 156-158.

15 Voola, J, "Technological Change and Industry Structure: A Case Study of the Petroleum Industry," *Economics of Innovation and New Technology* 15, no. 3 (2006): 271–288.

16 Voola, JJR, Osaghae, O, and Khan, JA, "Risk Reducing Technology and Quantity Competition: The Seismic Story," paper SPE 88583 presented at the SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Australia (October 18–20, 2004).

17 Cuddington, JT and Moss, DL, "Technological Change, Depletion and the U.S. Petroleum Industry: A New Approach to Measurement and Estimation," Georgetown University Working Paper #96-10R (1998).

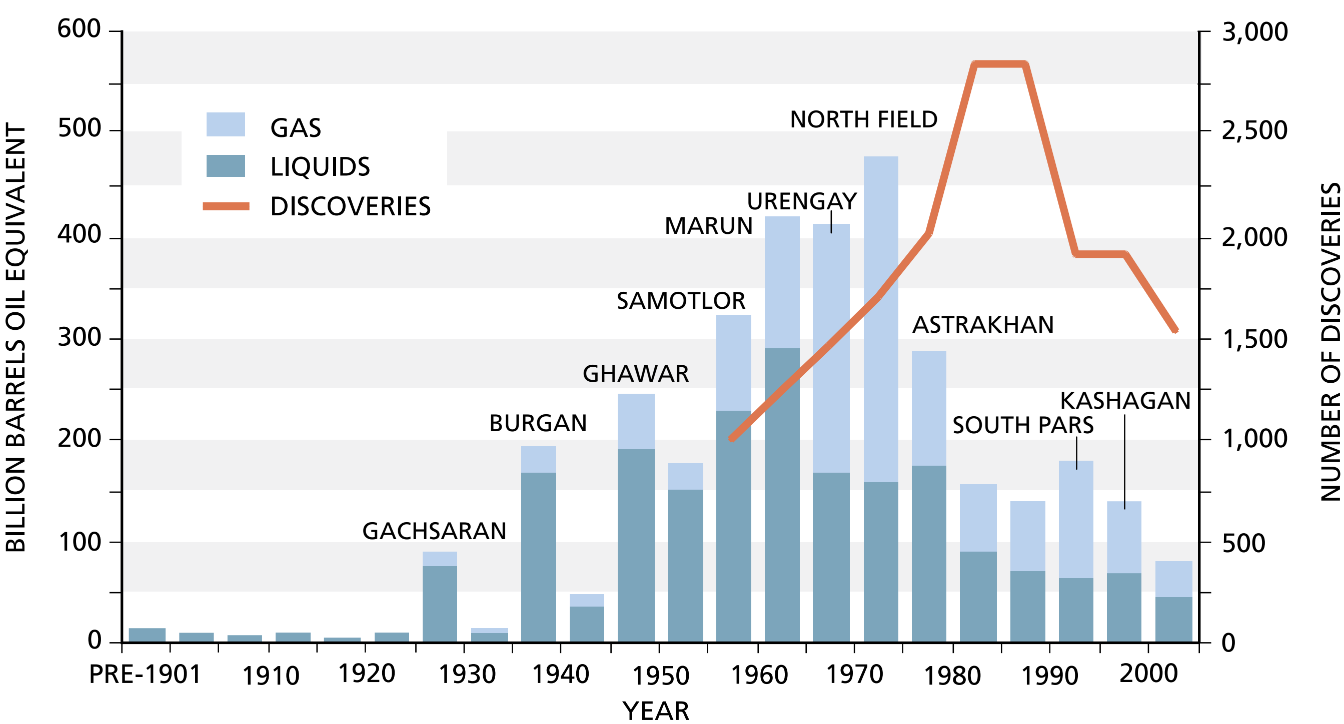
18 Bahorich, M, "End of Oil? No, It's a New Day Dawning," *Oil & Gas Journal* (August 21, 2006): 30–34.

advances. Rapid data processing could significantly improve seismic resolution of complex subsalt, deep, or subtle geologic features.

- Controlled source electromagnetism (CSEM)—CSEM identifies subsurface hydrocarbon accumulations through a contrast in resistivity between hydrocarbon-saturated and water-saturated reservoirs. Two key potential improvements are:
  - Development of fast 3D modeling and inversion to reduce the number of erroneously identified "anomalies" (false positives)[19]
  - Extension of the technology to shallow-water and onshore settings.
- Interpretation technology—Interpreters struggle with the sheer volume and complexity of data and the need for increasingly quantitative interpretations. Two advances that could have significant results are:
  - Better integration of geophysical and geologic data to develop quantitative interpretations
  - Development of seismic search engines to interrogate increasing data volumes.[20]
- Earth-systems modeling—Modeling natural systems of basin formation, fill, and fluid migration is becoming increasingly common. Advances in modeling more-integrated earth systems along with capturing uncertainties in potential scenarios and parameters could significantly help explorationists to identify new plays (areas for exploration) and "sweet spots" (localized exploration targets).
- Subsurface measurements—Measurement of subsurface properties (fluid type, porosity, permeability, temperature, etc.) is crucial to exploration success. Advances in sensor types, durability, sensitivity, and deployment could improve exploration programs significantly by identifying both penetrated and bypassed "pay," that is, economically producible hydrocarbons that may or may not have been intercepted by a wellbore.

19 Inversion is a mathematical process by which data are used to generate a model that is consistent with the data. See www.glossary.oilfield.slb.com/Display.cfm?Term=inversion.

20 Barnes, A, "Seismic Attributes in Your Facies," *CSEG Recorder* (September 2001): 41-47.



Source: IHS Energy (Bahorich, 2006).

FIGURE 3-10. *Evolution of Oil Discovery Volumes with Time (Total Discovered Resources to End-2004, excluding United States and Canada)*

This Exploration Technology Subgroup highlighted unconventional resources as a special category in the early stages of understanding (both exploration and exploitation) to which many of the core exploration technologies could potentially be applied. Two key advances could improve the effectiveness of exploration for unconventional resources:

- Improved measurement capabilities and predictive modeling of the geologic factors controlling hydrocarbon distribution and deliverability.
- Significant improvements in exploration or exploitation technologies that could help define exploration targets ("sweet spots") and the technologies needed to identify them.

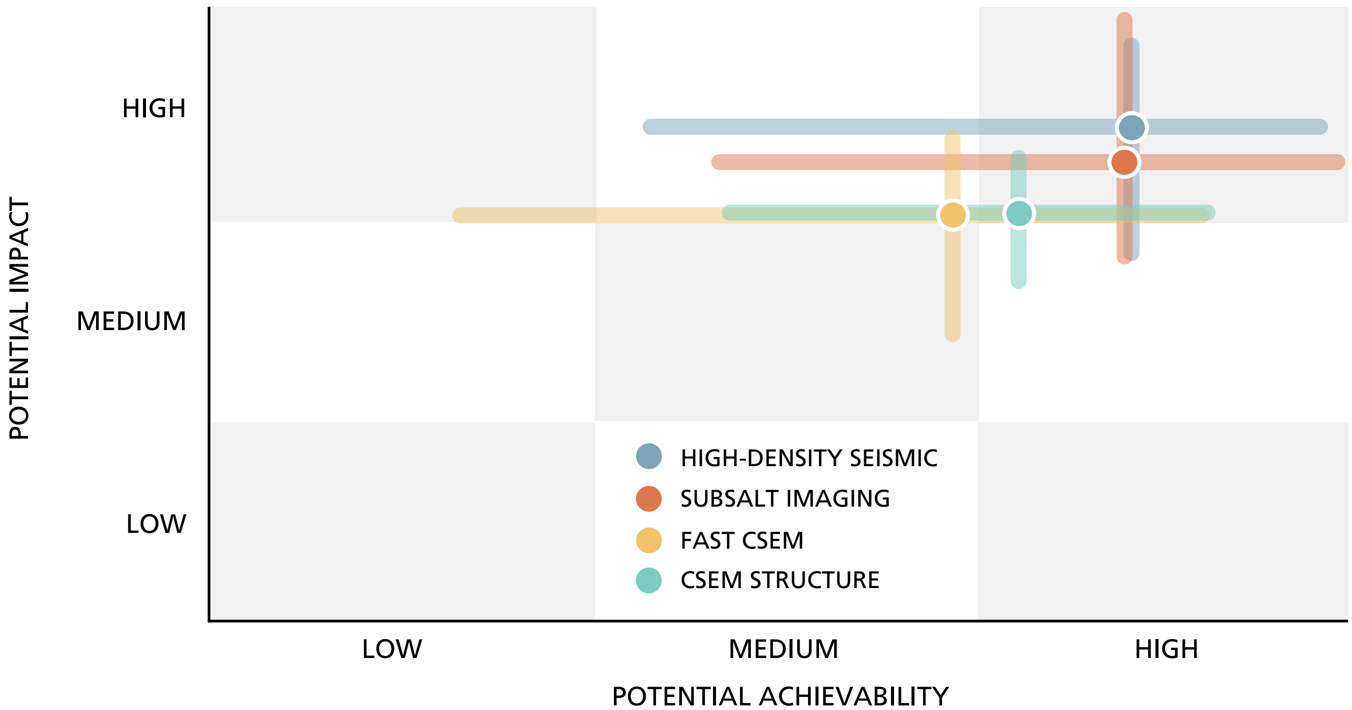
The Exploration Technology Topic Report also identified auxiliary technologies in which future developments or applications have the potential to significantly improve exploration results by 2030:

- Drilling technology—Projected technical advances could improve the ability to tap new environments and encourage more exploration drilling of higher risk, new play types via reduced drilling costs.
- Nanotechnology—The most likely opportunities for applications are in increased sensor sensitivity, improved drilling materials, and faster and more powerful computing.
- Computational technology—Improvements in speed, memory, and cost will impact data acquisition, processing, and interpretation industry-wide.

Research into technologies that could mitigate potential environmental impacts will continue to

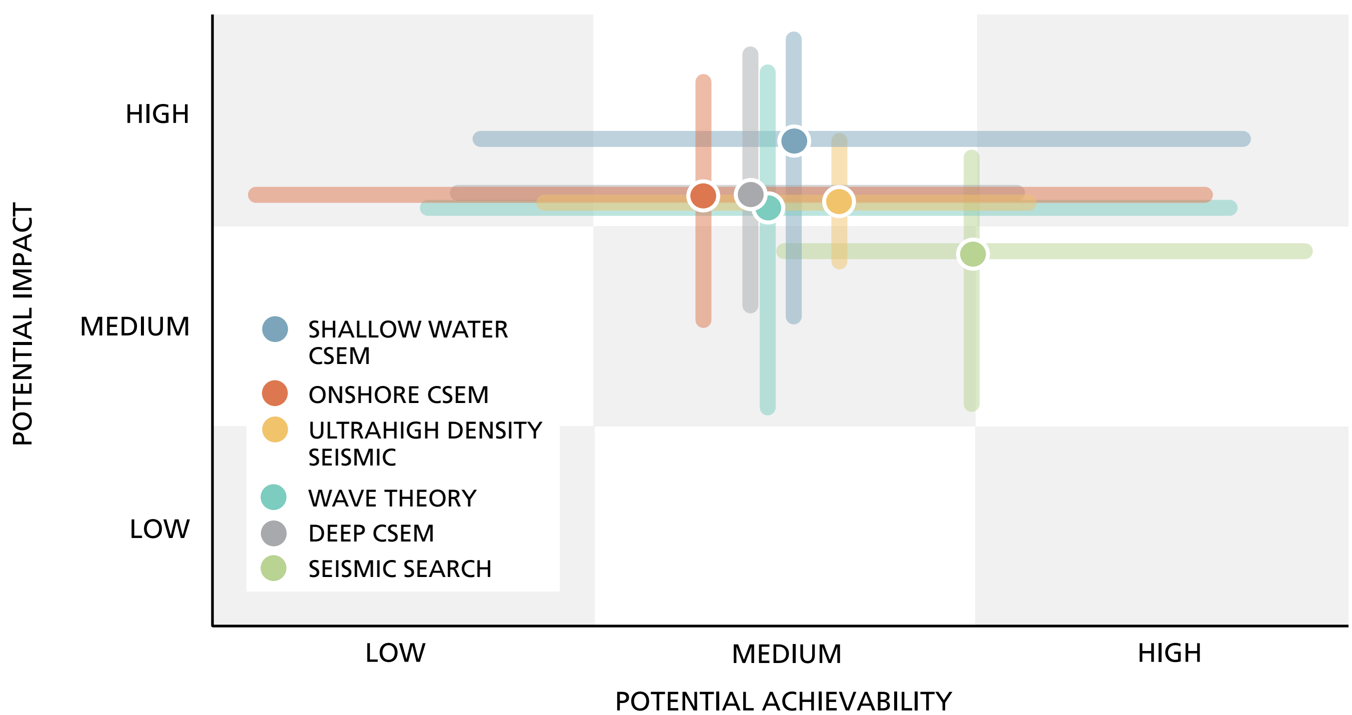
Technology	Significance	Brief Discussion
High-density seismic data and rapid data processing	High	Higher-density seismic-data acquisition with greater signal-to-noise ratios result in greater resolution, which allows for more robust interpretations of reservoir character and hydrocarbon potential to be made. However, for higher-density data to have commercial impact, substantial improvements in processing methods must be made.
Subsalt imaging (seismic)	High	Salt is a highly distorting acoustic lens that creates "blind spots" beneath it. Considerable efforts have been made to produce high-quality subsalt images resulting in drilling success in the Gulf of Mexico. Enhanced subsalt imaging will undoubtedly result in new discoveries and improved economics.
Fast controlled source electromagnetism (CSEM) 3D modeling and inversion	High	CSEM can discriminate between scenarios that are indistinguishable via seismic amplitudes; e.g., commercial oil versus residual (non-commercial) natural gas. However, false positives are common; e.g., hydrates, salts, and volcanics can yield a response similar to a commercial petroleum response. Fast 3D modeling and inversion capability can help discriminate against such false positives.
Integration of CSEM with structural information from seismic surveys	High	An important approach to increase the resolution of information obtained via CSEM methods.

TABLE 3-6. *Summary of Highly Significant Nearer-Term (by 2010) Exploration Technologies*



Note: CSEM = controlled source electromagnetism.

FIGURE 3-11. *Potential Impact versus Achievability for Nearer-Term Exploration Technology Advances*



Note: CSEM = controlled source electromagnetism.

FIGURE 3-12. *Potential Impact versus Achievability for Longer-Term Exploration Technology Advances*

Technology	Significance	Brief Discussion
Shallow water controlled source electromagnetism (CSEM)	High	The shallow-water environment is much noisier than the deepwater environment for CSEM techniques. Substantial advances are needed to enable robust signal acquisition and analysis in such an environment. But, if successful, it can open up the application domain for CSEM beyond deepwater basins.
Onshore CSEM	High	The onshore environment is much noisier than the deepwater environment for electromagnetic techniques. Substantial advances are needed to enable robust signal acquisition and analysis in such an environment. But, if successful, it can open up the application domain for CSEM beyond deepwater basins.
Ultra high-density data and processing	High to medium	Data density and processing continue to improve at incremental steps. However, if extremely high-density data could be acquired and processed rapidly at low costs, game-changing breakthroughs could occur. These include new hydrocarbon discoveries as well as exploitation efficiencies.
Wave theory research (seismic)	Potential high impact but with attendant high risk	Basic research into wave theory is a continuing effort in both industry and academia. Synergistic collaborations between the two have led to gradual improvements in processing and could result in large leaps forward. For example, it should enable more accurate quantitative modeling of key seismic data.
Deep CSEM	High to medium	Even in deep water, current application is limited to relatively shallow reservoirs (6,500 to 10,000 feet below sea floor). Advances in penetration depth could open up applications in several new basins.
Development of an automated "seismic search engine" to find new opportunities	Medium to high	This type of technology would take advantage of advances in computational power, pattern-recognition technology, geophysical data, and geological concepts in a highly automated fashion.

TABLE 3-7. *Summary of Highly Significant Longer-Term Exploration Technologies*

be important. Examples of active areas of research include:

- Mud recovery without a riser from seabed to surface, which reduces discharge
- Ultra-extended-reach drilling, which can help avoid sensitive surface environments
- Research into seismic sources that are alternatives to the conventional seismic airgun arrays.

Complementary research efforts on marine biology and other topics could provide better data to improve informed-risk assessment, public debate, and informed decision-making by regulatory agencies.

Significant nearer-term technologies are outlined in Table 3-6 and Figure 3-11, with longer-term technologies described in Table 3-7 and Figure 3-12.

DEEPWATER TECHNOLOGY

Deepwater oil and natural gas resources are conventional reserves in an unconventional setting. They constitute a resource class of their own, largely because they face a common set of technological challenges as they are identified, developed, and produced (Figure 3-13).

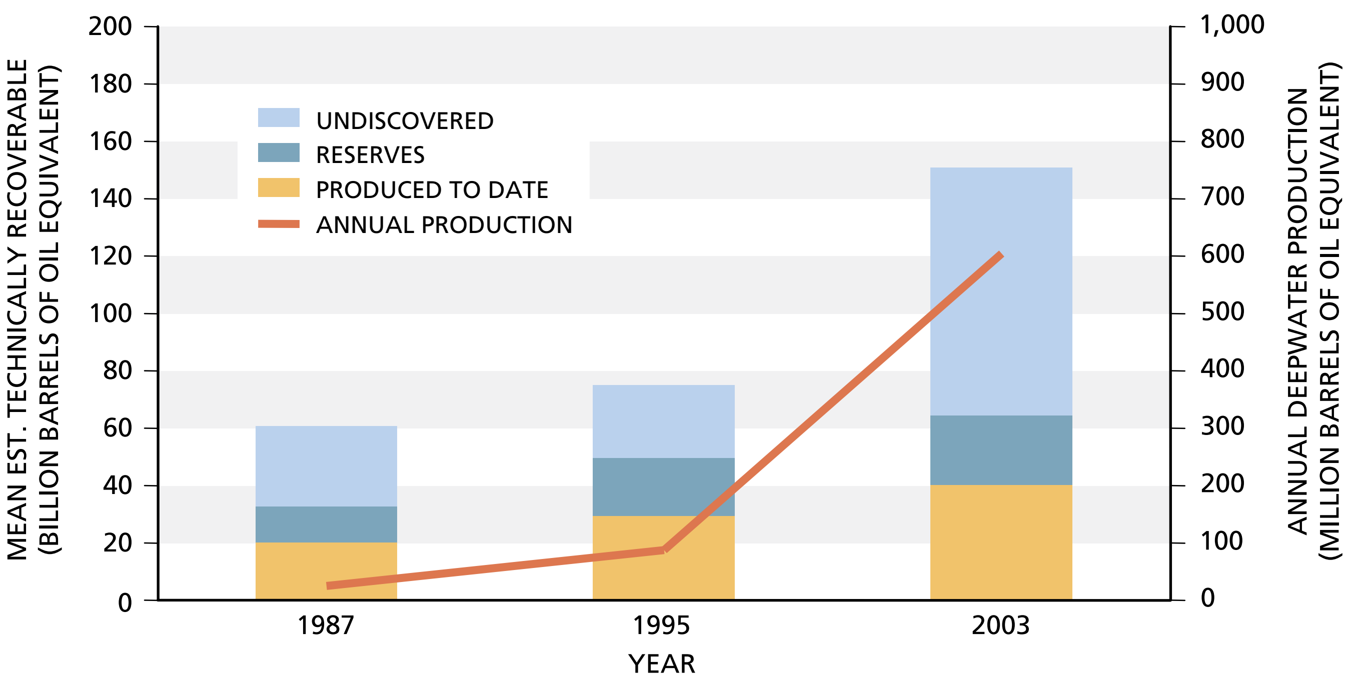
The U.S. Gulf of Mexico represents a clear case where the more we know, the more attractive the opportunities for oil exploration and discovery become. Figure 3-14 illustrates that our appreciation for the scope of the potential total Gulf of Mexico resource has grown dramatically as deepwater production has come online.[21]

Deepwater exploration is a success for both technology and policy that is still in the making. The data continue to support significant scope for economic oil and natural gas resource development in both U.S. and global deep oceans. Ahead lie four top-priority, deepwater-specific technological challenges:

21 Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources, Energy Policy Act of 2005 – Section 357. Available at www.mms.gov/revaldiv/PDFs/FinalInvRptToCongress050106.pdf .

FIGURE 3-13. *Offshore Platforms*

1. Reservoir characterization: predicting and monitoring the production behavior of increasingly complex reservoirs with fewer—but more costly—direct well penetrations.



Source: Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources, Energy Policy Act of 2005 – Section 357.

FIGURE 3-14. *U.S. Gulf of Mexico Oil and Natural Gas Resource Endowment*

2. Extended system architecture: subsea systems for flow assurance (the ability to produce and move fluids to surface), well control, power distribution and data communications that improve recovery and extend the reach of production hubs to remote resources.

3. High-pressure and high-temperature (HPHT) completion systems: materials and equipment to reliably produce the growing number of deepwater resources in corrosive environments with extraordinary pressures and temperatures.

4. Metocean (combined meteorological and oceanic) forecasting and systems analysis: integrated models to predict both atmospheric and below surface "weather" and engineering system response.

Within these four priority areas, HPHT completion systems and metocean forecasting and systems analysis represent opportunities for practical government and industry cooperation. Accelerating progress in HPHT service is likely to cost hundreds of millions of dollars over many years. Excellent potential exists to transfer or co-develop fundamental materials science and engineering technologies across industry boundaries—most notably aerospace and military (especially naval). Thus, although these are domains of intentional industry pursuit, there is compelling scope for collaborative research in academia and government labs. Theoretical developments for both the weather and engineering systems could be accelerated with a few millions of dollars. Development and operation of regional data-acquisition technologies and associated predictive capabilities will likely cost tens to hundreds of millions of dollars.

Additionally, it is important to understand that deepwater technology is tightly related to topics covered by other NPC Technology Topic Papers (Table 3-8). We have also identified two issues that we conclude are critical to the continued successful development of oil and natural gas resources in ever-harsher ocean environments (Table 3-9).

Marine sciences and engineering is a specialty field in which many disciplines (e.g., mechanical and civil engineering) can be taught to apply known techniques. However, the few small centers of excellence that have historically trained the leading marine thinkers, conceptualizers, and innovators are disappearing due to university competition for research in information-, nano-, and bio-technologies—MIT, Michigan, and Berkeley, for example. The U.S. Navy has also recognized this nationally important concern. Improving the current situation is likely to cost tens of millions of dollars for top-tier universities in ocean sciences and marine engineering.

A second key issue, policies about access to acreage for the purposes of oil and natural gas exploration and development, raises complex matters. However, access to acreage with potential for economic oil and natural gas resources is itself a major—perhaps primary—driver encouraging technology development. For example, the onset of area-wide leasing for the U.S. Gulf of Mexico in the early 1980s led to significant acceleration of interest in deepwater regions.

Technology	Significance	Brief Discussion
Subsalt imaging (Exploration technology topic)	Finding large new resources	Novel seismic processing methods that enable one to accurately image below complex salt layers
Gas liquefaction (Supply topic)	Bringing remote natural gas to market	Technology to convert natural gas into more easily transportable forms becomes more valuable with both distance from shore and water depth
Arctic (Conventional well technology topic)	Large untapped offshore regions	Economic development of oil and natural gas in the offshore arctic will likely build on traditional deepwater technologies

TABLE 3-8. *Summary of Technologies Related to Deepwater Technology, in Priority Order*

Technology	Significance	Brief Discussion
Future marine technology leadership	Innovation capability	Reduced centers of excellence in specialized field of marine science and engineering will limit inflow of technical experts required to keep industry moving forward after the "big crew change"
Valuing technology to enable access	Innovation motivation	Access to acreage with potential for economic oil and natural gas resources is in and of itself a primary, if not the largest, driver that encourages technology development

***TABLE 3-9.** Summary of Key Deepwater Issues, in Priority Order*

The coming decade will be pivotal for determining our ability to safely and economically develop the energy resource endowment in U.S. and global oceans. At the very time the drive to ultra-deep waters is increasing both the magnitude and complexity of the challenge, the technological capacity of the workforce faces untimely impairment by "the big crew change." The future of deepwater exploration and production depends on industry and governments successfully co-navigating this linked technology and policy transition.

UNCONVENTIONAL NATURAL GAS RESERVOIRS—TIGHT GAS, COAL SEAMS, AND SHALES

Unconventional natural gas resources—including tight sands, coalbed methane, and gas shales—constitute some of the largest components of remaining natural gas resources in the United States. Unconventional natural gas is the term commonly used to refer to low-permeability reservoirs that produce mainly natural gas with little or no associated hydrocarbon liquids. Many of the low-permeability reservoirs that have been developed in the past are sandstone, but significant quantities of gas are also produced from low-permeability carbonates, shales, and coal seams. One way to define unconventional natural gas is that "the reservoir cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment, a horizontal wellbore, or by using multilateral wellbores."[22]

22 Holditch, SA, "Tight Gas Sands," SPE Paper 103356, Distinguished Author Series (2006).

Research and development on the geologic controls and production technologies required to evaluate and produce these unconventional natural gas resources have provided many new technologies during the past several decades. New technologies have enabled operators in the United States to unlock the vast potential of these challenging resources, boosting production levels to about 30 percent of current U.S. natural gas production (Figure 3-15).

Around the world, unconventional natural gas resources are widespread but, with several exceptions,

***FIGURE 3-15.** Land Drilling Rig*

they have not received close attention from natural gas operators. This is due, in part, because geologic and engineering information on unconventional resources is scarce, and natural gas policies and market conditions have been unfavorable for development in many countries. In addition, there is a chronic shortage of expertise in the specific technologies needed to successfully develop these resources. As a result, only limited development has taken place to date outside North America. Interest is growing, however, and during the last decade development of unconventional natural gas reservoirs has occurred in Canada, Australia, Mexico, Venezuela, Argentina, Indonesia, China, Russia, Egypt, and Saudi Arabia.

Many of those who have estimated the volumes of natural gas in place within unconventional gas reservoirs agree that it is a large resource (Table 3-10). Using the United States as an analogy, there is good reason to expect that unconventional gas reservoir production will increase significantly around the world in the coming decades.

Tight Gas Sands

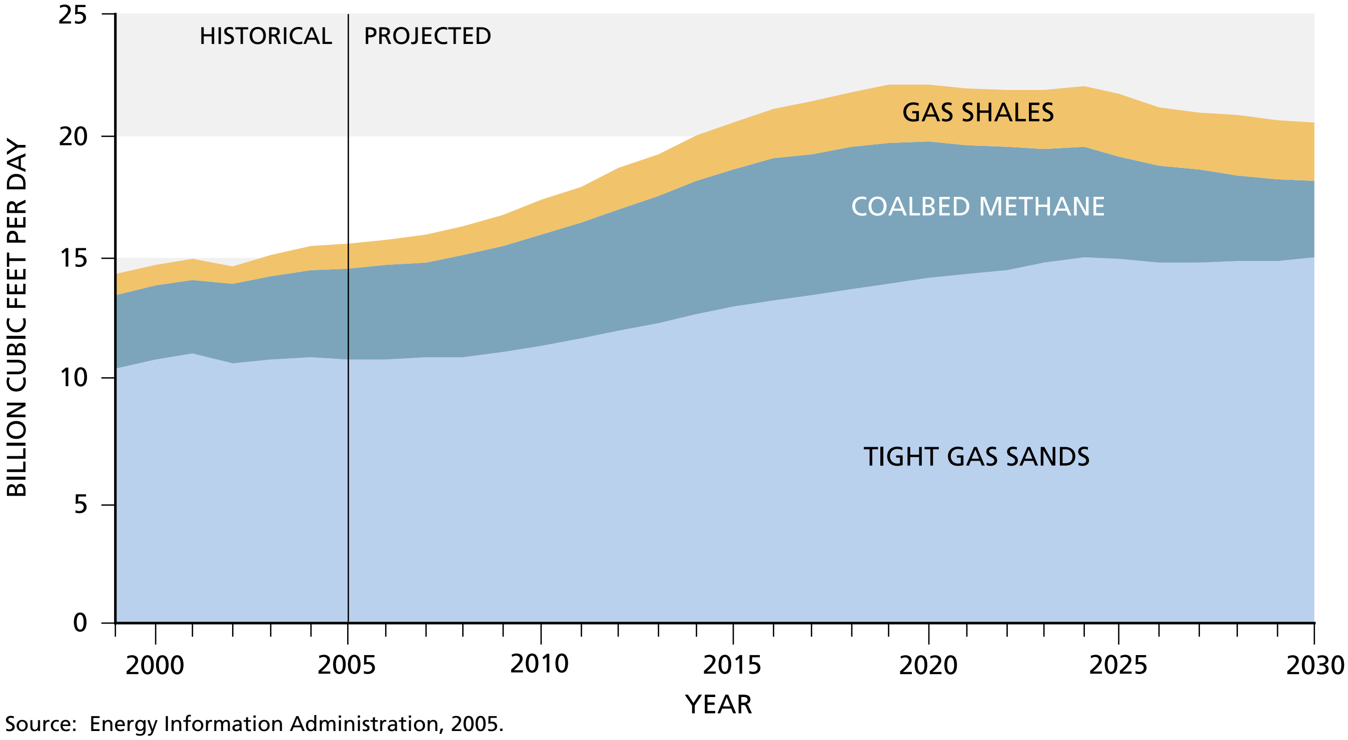
From a global perspective, tight gas resources can be considered vast, but undefined. No systematic evaluation has been carried out on global emerging resources. The magnitude and distribution of worldwide resources of natural gas in tight sands, as well as gas shales and coalbed methane formations, have yet to be understood.

From almost no production in the early 1970s, today unconventional resources, particularly tight sands, provide almost 30 percent of domestic natural gas supply in the United States. The volumes of natural gas produced from U.S. unconventional resources are projected to increase in importance over the next 25 years, reaching production levels as high as 22 billion cubic feet per day (Figure 3-16).

Region	Coalbed Methane	Shale Gas	Gas in Tight Sands	Total
North America	3,017	3,840	1,371	8,228
Latin America	39	2,116	1,293	3,448
Western Europe	157	509	353	1,019
Central and Eastern Europe	118	39	78	235
Former Soviet Union	3,957	627	901	5,485
Middle East and North Africa	0	2,547	823	3,370
Sub-Saharan Africa	39	274	784	1,097
Centrally Planned Asia and China	1,215	3,526	353	5,094
Pacific	470	2,312	705	3,487
Other Asia Pacific	0	313	549	862
South Asia	39	0	196	235
World	9,051	16,103	7,406	32,560

Source: Kawata and Fujita, "Some Predictions of Possible Unconventional Hydrocarbons Availability Until 2100," Society of Petroleum Engineers, SPE Paper 68755, 2001.

TABLE 3-10. *Distribution of Worldwide Unconventional Natural Gas Resources (Trillion Cubic Feet)*



Source: Energy Information Administration, 2005.

FIGURE 3-16. *U.S. Unconventional Natural Gas Production and Future Projection*

Coal Seams

Coalbed methane (CBM) perhaps best exemplifies how technology can influence the understanding and eventual development of a natural gas resource. While natural gas has been known to exist in coal seams since the beginning of the coal-mining industry, only since 1989 has significant production been realized (Figure 3-17).

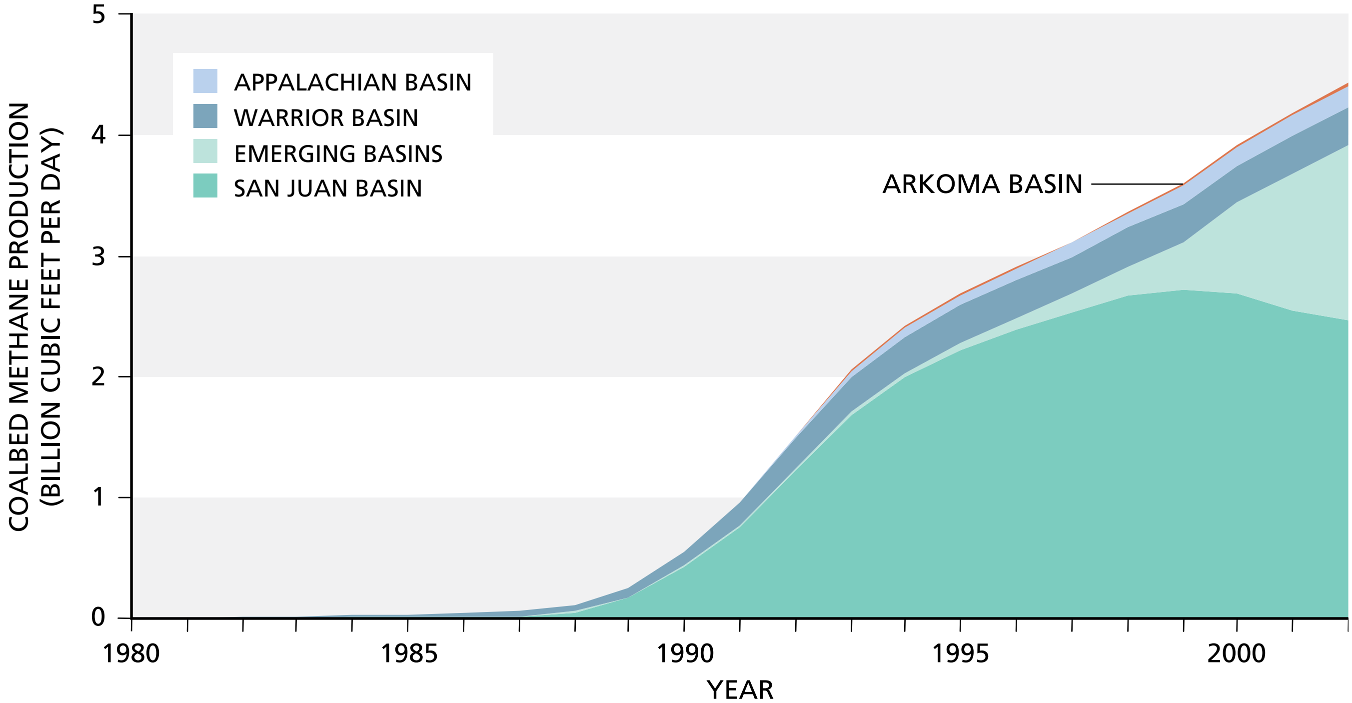
CBM is a resource that was drilled through and observed for many years, yet never produced. New technology and focused CBM research ultimately unlocked the production potential. CBM now provides more than 4.4 billion cubic feet of natural gas production a day in the United States, and is under development worldwide, including the countries of Canada, Australia, India, and China.

In many respects, the factors controlling CBM production behavior are similar to those for conventional natural gas resources, yet they differ considerably in other important ways. One prominent difference is the understanding of the resource, especially the values of gas in place. Natural gas in coal seams adsorbs to the coal surface, allowing for significantly more to be stored than in conventional rocks amid shallow, low-pressure formations. To release the adsorbed gas for production, operators must substantially reduce the pressure in the reservoir. Adsorbed gas volumes are not important for conventional gas resources, but are critical for CBM reservoirs. Significant research was required in the 1990s to fully understand how to produce the adsorbed gas in coal seams, and to develop the technology required to explore for—and produce—CBM reservoirs.

A major difference between CBM reservoirs and sandstone gas reservoirs is that many of the coal seams are initially saturated with water. Thus, large volumes of water must be pumped out of the coal seams before realizing any significant gas production. This water production reduces the pressure so desorption will occur. The technology developed in the 1990s for understanding and dewatering coal seams allowed significant CBM development in several U.S. geologic basins.

Shale Gas

Shale rocks act as both the source of the natural gas and the reservoir that contains it. Natural gas is stored



Source: IHS Energy.

FIGURE 3-17. *Natural Gas Production from Coal Seams in the United States*

in the shale in three forms: free gas in rock pores, free gas in natural fractures, and adsorbed gas on organic matter and mineral surfaces. These different storage mechanisms affect the speed and efficiency of gas production.

Shale gas production in the United States has shown that stimulation techniques, especially hydraulic fracturing, are almost always necessary for shale gas production. Other important technology advances include applying horizontal and directional drilling, and characterizing reservoirs. For wells in the Barnett Shale (near Fort Worth, Texas), using technology currently available, the per-well recovery factor averages 7 percent of the gas in place. This is far below a potentially achievable 20 percent recovery factor.

In areas with limited surface access and landowner restrictions, horizontal drilling has been applied. Horizontal wells provide greater wellbore contact within the reservoir rocks than do vertical wells. Microseismic fracture mapping has also been successfully used to improve the evaluation of hydraulic fracturing in the horizontal wells.

Tables of Advances

Tables 3-11, 3-12, and 3-13 describe current technology under development and that which needs to be developed and used in future years. These tables indicate only the high-impact technologies; others are described in the Unconventional Gas Topic Paper. The priority was determined by estimating the difference in impact between a business-as-usual case and an accelerated-technology case. High impact includes those technologies having greatest possibilities for producing more gas or reducing cost, while for moderate impact effectiveness is lesser or is more difficult to measure.

The amount of research and development needed to fully develop a given technology is described in these tables as follows:

- Incremental—research and development as usual
- Accelerated—research and development as usual, but with a major increase in funding (factors of 3 to 5)
- Breakthrough—substantial increase in funding (factors of 10 to 100) and more use of consortiums.

Unconventional Gas Technology Under Development or Anticipated by 2010	Research and Development Required for Success	Discussion
Fracture modeling and analysis, full 3D models for new types of treatments	Accelerated	Incorporating new physics for fracture propagation, in naturally fractured reservoirs, fracture-proppant transport, and better models for horizontal and multilateral wells.
New fracturing fluids and proppants	Incremental	Strong, light-weight proppants are needed. Better fluids that do not damage the reservoir and fracture must be developed.
Hydraulic fracturing methods used in horizontal wells	Incremental	Fort Worth basin (Barnett Shale): increased production rate by 2 to 3 times rate of vertical well.
Stimulation methods used in naturally fractured formations	Incremental	Gas shales and coal seam reservoirs are normally naturally fractured. We need a better understanding and better technologies for such reservoirs to include better models to determine gas storage and gas production using multiple gas systems, such as CO_2, wet gas, and N_2.
Micro-seismic fracture mapping and post-fracture diagnostics	Accelerated	Fort Worth basin (Barnett Shale): improved understanding of hydraulic fracturing in horizontal wells so that designs can be improved.
Data collection and availability during drilling, completions, stimulations, and production	Incremental	Significant data are being generated by increased drilling and new tools and techniques. The ability to handle and use data is being challenged. The data need to be evaluated in detail to learn more about formation evaluation, fracture treatments and production.
Integrated reservoir characterization of geologic, seismic, petrophysical, and engineering data	Accelerated	More complex reservoirs, lower permeability, greater depth and more cost require a more in-depth understanding of reservoir petrophysics. Better models will be required to properly integrate all the data and optimize the drilling and completion methods.
Horizontal drilling and multilateral wellbore capability	Accelerated	Enables development of stacked, thin-bed coal seams and reduces environmental impact. Also need to develop multiple wells from a single pad. This technology is very important in shale-gas reservoirs, and sometimes important in tight-gas reservoirs.
Reservoir characterization through laboratory measurements	Accelerated	We need better core-analysis measurements for basic parameters such as permeability, porosity, and water saturation. In coal seams and shales, we need better methods for estimating sorbed gas volumes and gas-in-place values in the reservoir.
Reservoir imaging tools	Incremental	Understanding the reservoir characteristics is an ongoing challenge and priority for all unconventional reservoirs.
Overall environmental technology	Accelerated	We need to reduce the impact of operations on the environment by reducing waste, reducing noise, using smaller drilling pads and adequate handling of waste water.
Produced water handling, processing and disposal	Accelerated	Coal seams and shale gas continue to produce significant volumes of water. Efficient handling and environmentally safe and low impact disposal are needed.

TABLE 3-11. *Summary of Currently Developing Technologies for Unconventional Natural Gas from Now to 2010 (Those with High Significance Only)*

2020 Technology for Unconventional Gas Reservoirs	Research and Development Required for Success	Discussion
Real-time sweet-spot detection while drilling	Breakthrough	Will allow the steering of the drill bit to the most productive areas of the reservoir.
Coiled tubing drilling for wells less than 5,000 ft.	Accelerated	Will allow the advantages of continuous tubing drilling to be realized (fast drilling, small footprint, and rapid rig moves) for currently difficult drilling areas.
3D seismic applications for imaging layers and natural fractures in shale reservoirs	Accelerated	We could improve recovery efficiency from existing wells if we used well testing methods to better understand the reservoirs.
Produced-water processing	Accelerated	Produced water is processed and utilized such that it no longer is viewed as a waste stream but as a valuable product for agriculture, industrial use, and for all well drilling and completion needs.
Deep drilling	Incremental	We need to determine how deep we can develop coalbed methane, shale gas and other naturally fractured unconventional reservoirs.
Enhanced coalbed methane production via CO_2 injection/ sequestration	Accelerated	We need to determine the technological solutions and screening of suitable pairing of deposits and CO_2 sources.
Data handling and databases	Incremental	Databases are available and user-friendly allowing access to geologic and engineering data for most North American basins, and are being developed for geologic basins worldwide.

TABLE 3-12. *Summary of Technologies Anticipated for 2020 (Those with High Significance Only)*

2030 Technology for Unconventional Gas Reservoirs	Research and Development Required for Success	Discussion
Resource characterization and gas-in-place potential	Accelerated	All of the basins worldwide need to be assessed for unconventional gas potential. The results should be recorded in databases and made available to the producing community around the world.
Well drilling and completion	Accelerated	Well drilling technology must be advanced through improvement in downhole drilling systems, better metallurgy and real-time downhole sensors allowing drilling to sweet spots, use of underbalanced drilling where needed, advantages of continuous tubing drilling, and efficient utilization of multilaterals.

TABLE 3-13. *Summary of Technologies Anticipated for 2030 (Those with High Significance Only)*

UNCONVENTIONAL HYDROCARBONS: HEAVY OIL, EXTRA-HEAVY OIL, AND BITUMEN

Heavy oil, extra-heavy oil, and bitumen are unconventional oil resources that are characterized by high viscosity (resistance to flow) and high density compared to conventional oil. Most heavy oil and bitumen deposits originated as conventional oil that formed in deep formations, but migrated almost to the surface where they were degraded by bacteria and by weathering, and where the lightest hydrocarbons escaped (Figure 3-18). Heavy oil and bitumen are deficient in hydrogen and have high carbon, sulfur, and heavy metal content. Hence, they require additional processing (upgrading) to become a suitable feedstock for a normal refinery.

The IEA estimates that there are 6 trillion barrels of heavy oil worldwide, with 2 trillion barrels ultimately recoverable.[23] Western Canada is estimated to hold 2.5 trillion barrels, with current reserves of 175 billion barrels. Venezuela is estimated to hold 1.5 trillion barrels, with current reserves of 270 billion barrels. Russia may also have more than 1 trillion barrels of heavy oil. Heavy-oil resources in the United States amount to 100 to 180 billion barrels of oil, with large resources in Alaska (44 billion barrels), California (47 billion barrels), Utah (19 to 32 billion barrels), Alabama (6 billion barrels), and Texas (5 billion barrels). Heavy oil has been produced in California for 100 years, and currently amounts to 500,000 barrels per day of oil. Heavy oil resources in Alaska are being developed on a small scale with less than 23,000 barrels per day of oil in 2003.[24] Heavy oil and bitumen resources in Western Canada and the United States could provide long-term, stable, and secure sources of oil for the United States. Most of these resources are currently untapped.

Heavy oil is also located—and being produced—in Indonesia, China, Mexico, Brazil, Trinidad, Argentina, Ecuador, Colombia, Oman, Kuwait, Egypt, Saudi Arabia, Turkey, Australia, India, Nigeria, Angola, Eastern Europe, the North Sea, Iran, and Italy.

23 Christian Besson, *Resources to Reserves, Oil & Gas Technologies for the Future*, International Energy Agency (2005), p. 75.

24 *Undeveloped Domestic Oil Resources: The Foundation for Increasing Oil Production and a Viable Domestic Oil Industry,* Advanced Resources International, Feb. 2006, p. 12, 18.

FIGURE 3-18. *High-Viscosity Heavy Oil Acquired by Wireline Sampling*

Exploration technology has minor significance since large resources have already been discovered, but optimizing production technology is important. Because heavy oil, extra-heavy oil, and bitumen do not flow readily in most reservoirs, they require specialized production methods. Very shallow oil sands can be mined. Slightly deeper deposits can be produced by increasing reservoir contact with horizontal wells and multilaterals (multiply branched wellbores), producing the oil with large amounts of sand, or by injecting steam, which lowers the viscosity and reduces the residual oil saturation, thus improving recovery efficiency (Figure 3-19). In situ combustion has also been used to heat the reservoir, but several technical and economic challenges limit application of this technique. A few reservoirs are sufficiently hot that heavy oil can be produced using essentially conventional methods.

The production of heavy oil, extra-heavy oil, and bitumen is economic at current oil prices with existing production technologies. However, heavy oil and bitumen sell at a lower price than conventional oil because it is more difficult to process the heavier crude to create refined products, and because fewer refineries have the capability to process it. In addition, production is more costly than for conventional oil, so the profit margin is less. If an oil company has equal access to conventional oil and to heavy oil,

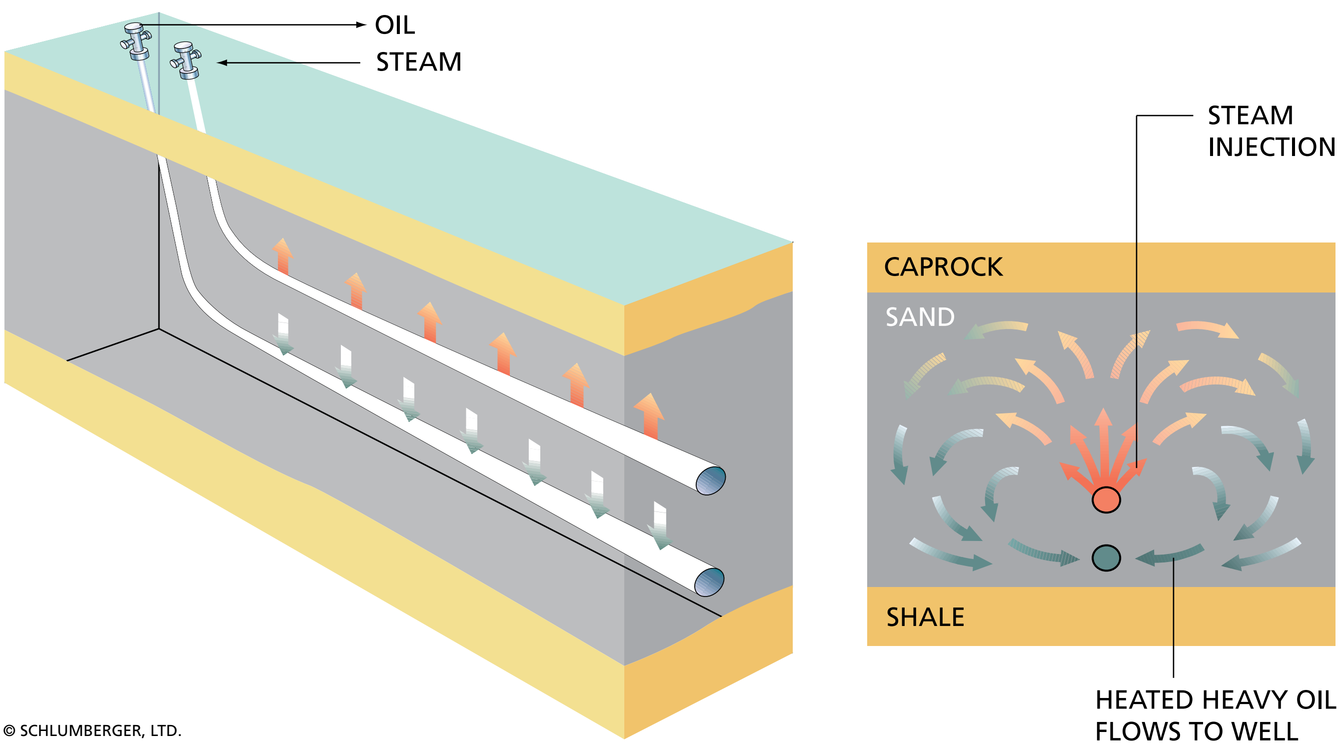


FIGURE 3-19. *Steam-Assisted Gravity Drainage Process for Producing Heavy Oil*

economics would favor conventional oil. However, gaining access to conventional oil resources is becoming more difficult in many countries.

There are several barriers to the rapid growth of heavy oil, extra-heavy oil, and bitumen production. Open-pit mining has a large environmental

Method	Locations used	Factors
Open pit mining	Canada, for shallow oil sands	High recovery factor, but high environmental impact
Cold production using horizontal wells and multilateral wells	Venezuela and some use in North Sea	Low recovery factor, may use water drive (North Sea)
Cold heavy oil production with sand (CHOPS)	Western Canada, to exploit thin layers	Low recovery factor, needs good gas/oil ratio, unconsolidated sands
Cyclic steam stimulation (CSS)	United States, Canada, Indonesia, many others	Reduce viscosity of heavy oil, needs good caprock, fair to good recovery factor
Steam flood	United States, Canada, Indonesia, many others	Follow-up to CSS for inter-well oil, good to high recovery factor
Steam-assisted gravity drainage (SAGD)	Canada	Allows production from shallower sands with weaker caprock

TABLE 3-14. *Major Commercial Production Methods for Heavy Oils*

Method	Time Frame	Description	Advantage
Vapex	2010	Use solvent rather than steam in SAGD-type wells	Lower energy consumption, low production rates
Hybrid	2010	Solvent plus steam in SAGD, CSS, and steam-flood wells	Lower energy consumption, increased production
In situ combustion with vertical and horizontal wells	2010	Uses heavy oil in reservoir and injected air	Eliminate need for natural gas for steam generation
Downhole heating with electricity	2010	Resistance, induction, or radio-frequency	Offshore, deep and arctic regions
Alternative fuels with gasification and carbon capture and sequestration	2020/ 2030	Uses coal, coke, or heavy ends for energy and hydrogen	CO_2 reduction in a CO_2 limited world
Nuclear power plant fit-for-purpose	2020/ 2030	Small scale for energy and hydrogen production	CO_2 reduction in a CO_2 limited world, safety, proliferation, fuel disposal, societal concerns
In situ upgrading	2020/ 2030	Application of in-situ thermal energy with or without catalysts to upgrade oil in place	Critical energy balance
Downhole steam generation	2020/ 2030	Possible options include generating heat downhole from either electricity or combustion of fuel.	Arctic, offshore, deep formations
Combination subsurface mining and well production techniques	2020/ 2030		Arctic and extremely restricted surface footprint environments

TABLE 3-15. *Major Heavy-Oil Production Methods, with Time Frame for Commercialization*

impact and can only exploit resources near the surface; further, it is a mature technology and only evolutionary improvements in efficiency are likely. By contrast, there are several commercial in situ production technologies, and several more are in research or the pilot phase. Many of the in situ production methods require an external energy source to heat the heavy oil to reduce its viscosity. Natural gas is currently the predominant fuel used to generate steam, but it is becoming more expensive due to tight supplies in North America. Alternative fuels such as coal, heavy oil, or byproducts of heavy-oil upgrading could be used, but simply burning them will release large quantities of CO_2. One option is gasification with carbon capture and sequestration. Nuclear power has also been proposed as a heat source, but faces societal opposition. Another fuel option is using the unconventional oil itself by injecting air into the reservoir for in situ combustion.

Other in situ methods are undergoing pilot testing. Vapex uses a solvent to reduce heavy-oil viscosity by itself or in combination with steam. These could reduce energy requirements and possibly open resources that are too deep, in arctic regions, or offshore where steam injection is difficult. Other options are generating steam downhole, or directly heating the formation by electricity—such as resistance, induction, or radio-frequency heating. Research indicates that some in situ upgrading may also be possible with heat, combustion, solvents, or catalysts.

Heavy oil, extra-heavy oil, and bitumen projects are large, capital-intensive undertakings. This capital spending includes the production infrastructure and additional upgrading, refining, and transportation facilities, plus pipelines for heavy oil and possibly for CO_2 sequestration. Another issue is obtaining a sufficient supply of diluent for moving heavy oil by pipeline. These projects also have long operating and payback periods, so unstable oil prices can deter long-term investments. Skilled people are also required to staff these projects.

Technologies that upgrade value, drive down costs, and reduce environmental effects will have the greatest influence on increasing the production of heavy oil, extra-heavy oil, and bitumen. There are a large number of technologies that can achieve these goals, but there is no single, simple solution owing to the tremendous variety of heavy oil, extra-heavy oil, and bitumen resources.

A list of commercial production methods is shown in Table 3-14, and a list of pre-commercial production methods is in Table 3-15.

UNCONVENTIONAL HYDROCARBONS: OIL SHALE

Oil shale comprises a host rock and kerogen. Kerogen is organic matter that has not gone through the "oil window" of elevated temperature and pressure necessary to generate conventional light crude oil. Kerogen has a high hydrogen/carbon ratio, giving it the potential to be superior to heavy oil or coal as a source of liquid fuel (Figure 3-20). Globally, it is estimated that there are roughly 3 trillion barrels of shale oil in place, which is comparable to the original world endowment of conventional oil. About half of this immense total is to be found near the common borders of Wyoming, Utah, and Colorado, where much of

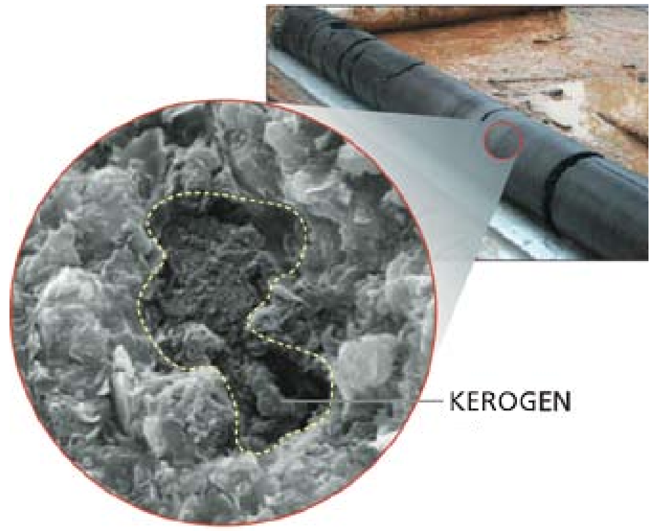


FIGURE 3-20. *Shale Core, with Scanning Electron Micrograph indicating Kerogen Content*

the resource occurs at a saturation of more than 25 gallons of product per ton of ore (about 10 percent by weight) in beds that are 100 to 1,000 feet thick. Like heavy oil reservoirs, oil shale is found near the surface, ranging from outcrops down to about 3,300 feet.

In the past, the most common production technology has been surface mining in conjunction with processing in above-ground retorts. With process temperatures at about 930°F, these techniques convert kerogen to oil in about an hour. This approach has the virtue of simplicity, but requires expensive surface facilities and the disposal of vast quantities of spent rock. Both pose significant economic and environmental problems. Moreover, raw product quality is poor compared to conventional crude oil; however, upgrading using conventional hydroprocessing techniques yields high-quality finished products.

The mining and retort method is an old approach that could benefit from new technology. Improved methods for spent shale remediation would clearly make this approach more acceptable. Improved retorting methods are also a priority. Innovations that allow oil shale to be processed at lower temperature without an increase in reaction time would result in improved economics and improved product quality.

An alternative process still in development, in situ conversion, has captured the industry's attention. Wells are drilled, and the oil shale reservoir is slowly heated to about 660°F, at which point kerogen is converted to oil and gas over months. Using an in situ conversion process at pilot scale, Shell has extracted a good quality middle distillate refinery feedstock, requiring no further upgrading. In order to contain nascent fluids, and to prevent groundwater from seeping into the reaction zone, Shell generates a "freeze wall" around the production area. Chevron has proposed a simpler technique that takes advantage of the low hydraulic permeability of oil shale formations to isolate heated process volumes from surrounding aquifers.

Because in situ conversion technology is just emerging, it is not yet clear which specific techniques can advance the state of the art over the coming decades. However, the efficient use of heat is almost certain to be an important issue. The ability to map the temperature and the saturation of generated oil and natural gas throughout the reservoir would enable advanced control strategies. It will also be useful to monitor the freeze wall or low permeability barrier, to ensure that there is no fluid mixing between the reaction zone and surrounding formations.

As a domestic source of transportation fuel, oil shale could compete with heavy oil and coal-derived liquids. Oil shale, heavy oil, and coal are all abundant in North America. Canadian tar-sand production is already commercial. Coal can be treated with coal-derived solvents and gaseous hydrogen at high temperature to produce high-grade synthetic crude oil. An advantage of oil shale is that it has the potential to produce a superior liquid fuel product. However, the direct and indirect costs for fuel production from oil shale have yet to be fully evaluated.

The estimated time frames in which the commercial application of potential advances in oil shale technologies occur are listed below.

- 2010—None.
- 2020—Improved methods of shale remediation; innovative surface retort architecture and chemistry; and pilot scale in situ conversion methods.
- 2030—Large-scale oil shale production.

UNCONVENTIONAL HYDROCARBONS: GAS HYDRATES

Gas hydrates constitute a class of crystalline compounds in which individual gas molecules reside within cages of water molecules. Gas hydrates are solids and have physical properties similar to those of ordinary ice. They form when a hydrocarbon gas, such as methane or a natural gas mixture, comes in contact with liquid water at high pressure and low temperature.

Gas hydrates are found within and under permafrost in arctic regions. They are also found within a few hundred meters of the seafloor on continental slopes and in deep seas and lakes. The reservoir architecture, technology needs, and eventual economic importance of hydrates in arctic and marine environments may be very different. Therefore they are considered separately in this report.

Arctic Hydrates

Gas hydrates are found within and beneath permafrost on the North Slope of Alaska, in the Canadian arctic, and in northern Siberia. Some of these accumulations are in areas where there has been significant conventional hydrocarbon development, with associated modern seismic and well-data surveys. In those areas, resources have been quantitatively evaluated. The results suggest that arctic hydrates have the potential to become economically viable sources of natural gas.

The best-documented Alaskan accumulations are in the Prudhoe Bay-Kuparuk River area. These contain about 30 trillion cubic feet of natural gas, which is about twice the volume of conventional gas found in the Prudhoe Bay field.[25] The proximity to highly developed oilfield infrastructure makes the Prudhoe-Kuparuk accumulation particularly attractive. The absence of a natural gas pipeline to market means that currently the gas is stranded. However, even without a pipeline, this resource may possibly enable the development of the nearby Schrader Bluff and Ugnu heavy oil reservoirs, which together amount to about 25 billion barrels of original oil in place.

The main technology barrier is the lack of validated methods for economically viable natural-gas production from hydrates. An arctic site capable of supporting multi-year field experiments would provide an opportunity for significant progress beyond the present state of knowledge.

25 Collett, TS, "Energy Resource Potential of Natural Gas Hydrates," *AAPG Bulletin* 86 (2002): 1971–1992.

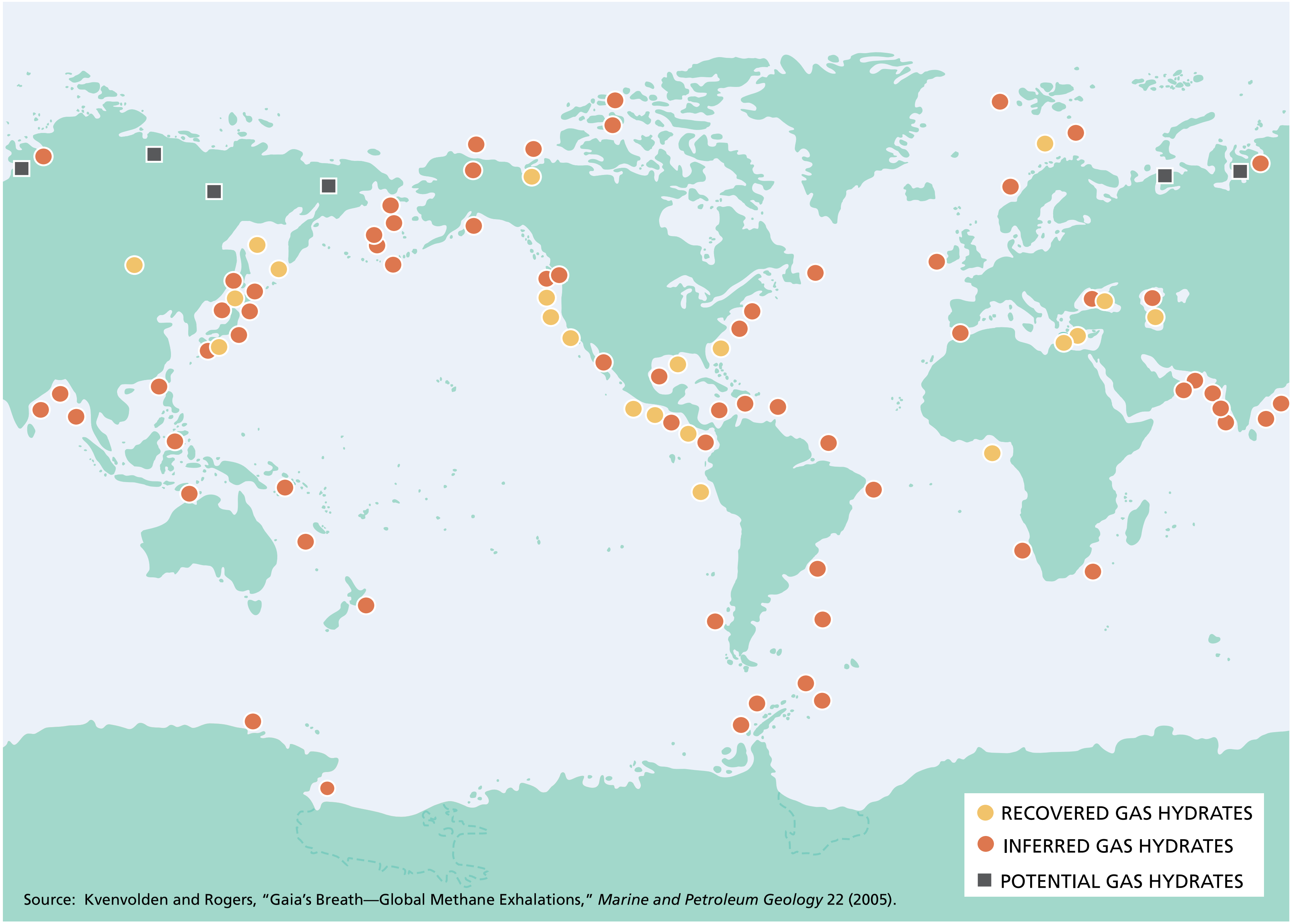


FIGURE 3-21. *Sites where Natural Gas Hydrates have been Recovered or are Inferred*

Marine Hydrates

A widely quoted USGS estimate predicts that there is twice as much organic carbon in gas hydrates as in all recoverable and unrecoverable conventional fossil fuel resources, including natural gas, coal, and oil.[26] Much of this endowment has been thought to be located on continental slopes in close proximity to major energy-consuming nations (Figure 3-21).[27] Estimates of hydrate-bound gas abundance have been repeatedly scaled back over the years, although large uncertainties remain.[28, 29]

Worldwide, only a few dozen boreholes have been drilled to assess marine hydrate resources. Most of these boreholes were drilled offshore around Japan in 2004,[30] and offshore from India in 2006. Comprehensive reports of these campaigns are not yet in the public domain, so there is a scant record available on which to assess the efficacy of exploration paradigms. Thus, the main technology barrier is the lack of validated means of reliably finding significant marine gas hydrate resources. A multi-site geological and geophysical exploration program, followed up with a multi-site drilling campaign, would accelerate the assessment of marine gas hydrates as an energy resource.

The estimated time frames in which the commercial application of potential advances in gas hydrate technologies occur are listed below.

- 2010—None.
- 2020—Production methods for arctic reservoirs developed through field tests and reservoir simulation; and broad-based exploration and delineation of gas hydrate resources in U.S. waters.
- 2030—Production methods for marine gas hydrates.

26 Kvenvolden, KA, "Gas Hydrates—Geological Perspective and Global Change," *Reviews of Geophysics* 31 (1993): 173–187.

27 Kvenvolden, KA and Rogers, BW, "Gaia's Breath—Global Methane Exhalations," *Marine and Petroleum Geology* 22 (2005): 579–590.

28 Milkov, AV, "Global Estimates of Hydrate-Bound Gas in Marine Sediments: How Much Is Really Out There?" *Earth-Science Reviews* 66 (2004): 183–197.

29 Klauda, JB and Sandler, SI, "Global Distribution of Methane Hydrate in Ocean Sediment," *Energy & Fuels* 19 (2005): 459–470.

30 Fujii, T et al., "Modes of Occurrence and Accumulation Mechanism of Methane Hydrate – Result of METI Exploratory Test Wells Tokai-oki to Kumano-nada'," *Proceedings of the Fifth International Conference on Gas Hydrates*, Trondheim, Norway (2005).

COAL TO LIQUIDS

In addition to direct combustion to produce heat and power, coal can be used as a feedstock for producing liquid and gaseous fuels. The Coal-to-Liquids Topic Report presents the issues associated with—and the potential for—coal-to-liquids (CTL) and coal-to-gas (CTG) technologies. CTL and CTG offer an opportunity for the United States to reduce its petroleum imports by producing petroleum products, such as diesel fuel and gasoline, from domestic coal resources. The primary technology reviewed is CTL; most reports have focused on CTL due to the cost and transportation issues associated with CTG. The other important objective included in the Topic Report is viewing and understanding the inputs and assumptions from various publications and the range of production estimates from CTG and CTL technology. A large uncertainty exists for CTL due to various assumptions including petroleum price and technological abilities. The quality of coal and the technological ability of converting the coal varied among the studies. Key assumptions were left unexamined, such as product transportation, labor, equipment availability, and environmental risk.

Overall, the published CTL production estimates are small in the total global petroleum market perspective. Even in the most optimistic scenario from the Southern States Energy Board (SSEB), the volume from CTL amounts to only 20 percent of the U.S. petroleum market.[31] The National Coal Council (NCC) indicated a 10 percent market share,[32] whereas various EIA scenarios had 0 to 6 percent of the U.S. market share.[33] The NCC and SSEB both mentioned the added benefit of using the CO_2 for enhanced oil recovery (EOR), however the increased oil volumes directly associated with using CO_2 from CTL are left unmentioned in those reports. The Topic Report discusses each of these reports in depth.

Even though the production estimates are small relative to the overall petroleum market, the incremental

31 "American Energy Security: Building a Bridge to Energy Independence and to a Sustainable Energy Future," The Southern States Energy Board, Norcorss, Georgia (July 2006). Accessible at www.americanenergysecurity.org/studyrelease.html.

32 "Coal: America's Energy Future," The National Coal Council, Washington, DC (March 2006). Accessible at nationalcoal council.org/report/NCCReportVol1.pdf .

33 "Annual Energy Outlook 2006 with Projections to 2030," Energy Information Administration (February 2006). Accessible at www.eia.doe.gov/oiaf/archive/aeo06/index.html.

gains from this technology added to gains from other technology areas, such as oil shale, could have a significant effect on U.S. energy cost and import dependency. The use of coal provides the added benefit of relying on a resource that is more plentiful domestically than petroleum. However, this reliance must be carefully balanced with the economics of developing the resource, since CTL facilities can cost more than $1 billion for each 10,000 barrels per day of production. This has implications for the competitiveness of the U.S. economy within the global economy.

The primary routes for converting coal to liquid products are called *direct* and *indirect liquefaction*. Both technologies were used by Germany to produce fuels before and during World War II (direct liquefaction more extensively).

From the 1970s through the early 1990s, the U.S. Department of Energy conducted research and development related to direct liquefaction. Plans to construct large demonstration plants based on direct coal liquefaction were cancelled during the 1980s, in response to concerns about technical risks, increasing estimates of investment costs, and decreasing world oil prices. Additionally, fuels generated by direct liquefaction are rich in high-octane aromatics, but current clean-fuel specifications in the United States limit the benzene and aromatics content, and the toxicity of gasoline.

In the early 1980s, South Africa's Sasol Company expanded its 1950s production base by building two large indirect coal-liquefaction facilities. Currently, these two Sasol facilities produce a combined total of about 150,000 barrels per day of fuels and chemicals using coal as the primary feedstock.

Dakota Gasification Company's Beulah plant produces about 170 million cubic feet per day of substitute natural gas from lignite. In 2000, the plant began exporting CO_2 for use in EOR. Currently, about 95 million cubic feet per day of CO_2 produced at the plant are transported via a 205-mile-long pipeline to EnCana Corporation's Weyburn oil field in southern Saskatchewan. The CO_2 is used for enhanced oil recovery, resulting in 5,000 barrels per day of incremental oil production, or an additional 130 to 140 million barrels of oil over the life of the project. The Weyburn field is the subject of a long-term monitoring program to assess the final disposition of the CO_2 being injected in this project.

Engineering analyses indicate that co-production or *polygeneration* plants may offer superior economic and environmental performance, as compared to separate dedicated fuels-only plants. The co-products most often considered in previous projects and studies have been electric power and liquid fuels, usually diesel, produced through a process developed by Fischer and Tropsch.

No commercial scale CTL plant has been sited or permitted in the United States. Given that these plants will have aspects of both a refinery and a power generation facility, it is not clear how quickly this untested permitting process can be expedited, particularly if opponents intervene aggressively. These potential delays have associated financial risks to the first plants.

Unfortunately, at the time of this writing, many large construction projects, including GTL, are experiencing dramatic capital-cost increases from rising material costs, skilled-labor shortages, and contractor backlogs. It is unclear how long this current trend will continue. If these escalations are cyclical, their effect on future CTL growth may be marginal. Otherwise, they may have a pronounced effect on the construction of CTL, especially in the developed world.

The various reports used to predict the production outlook for coal-to-petroleum products differed in production range, and all seemed to be missing discussions on many significant fundamental variables required to develop a sound economic decision. The reports discussed variables such as labor, equipment, product transportation, environmental risk, and feedstock only briefly, if that. Though the reports had significant analyses showing the large untapped resources of coal, practicalities for actually making the coal available—such as labor issues and the price impact of greater demand—should be investigated further before launching a significant coal-to-liquids program.

BIOMASS ENERGY SUPPLY

Some forecasters have expectations that renewable resources will be able to play a significant role in satisfying future energy demand. Others have a more pessimistic view and forecast that they will not make up even 2 percent of the total energy mix by 2030.[34] At issue is whether agriculture and forestry sources

34 McNulty, S, "An Unsustainable Outlook," *Financial Times*, Oct 20 2006: 1.

can supply food and fiber as well as significant energy needs for a growing population.

In 2001, global primary energy consumption was 396 quadrillion Btu per year (Quad).[35] Of this total, biomass supplied 43 Quad. This is significantly more than the 2 percent predicted to be used by 2030, but is probably overlooked because about 37 Quad of this was from traditional heating and cooking. Global biomass production on the Earth's land surface is equal to 4,320 Quad, of which half is lost by autotrophic respiration and decomposition, leaving 2,160 Quad.[36] This still would indicate that there is considerable potential for biomass to play a role of some type in global energy production beyond heating and cooking.

Numerous studies have been carried out to determine the global biomass production that could be used to meet some of the world's energy needs.[37] All of the studies have had to deal with the variety of paths that biomass takes in the modern world, and have had to deal with estimates of global population, changing diets, and changes in crop yields. A recent report by the Food and Agriculture Organization of the United Nations (FAO) has estimated population, food needs, and agricultural development for the time between 2015 and 2030.[38] The report covers many of the pertinent factors that will determine whether sufficient agricultural output will be available for providing food, fiber, and fuel in the future.

According to the FAO, agricultural production of food and feed will continue to grow at a pace to meet the needs of the world population through 2030. Population growth will continue to decrease during this time period and on into the next century. Over the last 40 years, food production has been controlled by demand rather than supply, leading to a decline of almost 50 percent in the value of commodity crops—in constant dollars—over this time period. This has had a dramatic effect on crop productivity globally: crop yields and production have reached the highest levels only in countries with farm support programs, while third-world production has lagged.

35 Biomass energy is often measured in exaJoules (EJ), where 1.055 EJ is about a Quad.

36 Smeets, EMW, Faaij, APC, Lewandowski, IM and Turkenburg, WC, "A Quickscan of Global Bio-energy Potentials to 2050," *Progress in Energy and Combustion Science* 33 (2007): 56–106.

37 See Biofuels Topic Report for the full list of reports examined.

38 Bruinsma, J (editor): *World Agriculture: Towards 2015/2030, An FAO Perspective*. Earthscan Publications Ltd., London (2003).

Over the last 20 years, many studies have been carried out looking at the potential of agriculture to produce both energy and food for the world, if such production were optimized. While these studies have had varying conclusions, most estimate between 237 and 474 Quad of biomass energy could be produced while still feeding a growing world population. The most optimistic studies have as a criterion that the global agricultural food production per hectare, under equivalent environmental conditions, reaches optimal levels. This condition would allow large areas of land to become available for energy-crop production. If only waste biomass and dung were used from our current agricultural production, an energy supply of ~95 Quad could be expected.

Biotechnology is predicted to increase crop production in the next few decades at a faster-than-historical rate. This increase is being brought about by marker-assisted breeding, which can increase trait development by a ten-fold rate over conventional breeding. Along with this increased breeding rate, the ability to engineer specific new traits into crops will bring about remarkable changes in crop production. This increase could be expected to double the average yield of crops such as corn by 2030.

Such an increase in the U.S. corn crop would allow U.S. corn production to reach 25 billion bushels, compared with 11 billion bushels produced in 2005. A corn crop of that size would make it possible to produce 54 billion gallons of ethanol by conventional means, 6 billion gallons of biodiesel from the corn oil, and 21 billion gallons of ethanol from the excess stover (e.g., stalks). On top of all of this, 154 million metric tons of distiller's dried grain would swamp the animal feed market that is currently being met by corn and soybean production.

Many of these predictions require that some pressure be brought upon agriculture to spur production globally. The energy market could provide this new opportunity for agriculture by speeding investment in production. The development of new energy crops has the potential to produce even more bioenergy per hectare with fewer inputs and more environmentally friendly production means. This will not happen without the development of local conversion methods and logistics for efficiently handling the low energy density of most biomass feedstocks.

In the past, first-generation biomass conversion to fuels has been based on crops like corn, sugarcane, and soybeans, which are also food sources. Developing second-generation biomass conversion technologies in the future, such as cellulosic ethanol that uses trees and plant waste as a feedstock, would—if technically and economically successful—allow non-food vegetation to become fuels and improve the energy balance. Energy balance is the ratio of the energy output obtained from a given energy input.

As with any newly developed energy sources, certain technical, logistical, and market requirements must be met for biofuels to achieve any significant scale. Challenges include: expanding rail, waterway, and pipeline transportation; scaling-up ethanol production plants and distribution systems; developing successful cellulosic conversion technology; and dealing with water and land-use issues. Collecting and utilizing the largest amount of potential biomass for conversion into fuels will need new technology development. This includes converting the biomass into a storable, stable form near its production site. That material would be shipped to a facility that can convert it into its final fuel form. This technology should optimally be able to take a variety of feedstocks in wet or dry form. The logistics of collection will demand such a complementary conversion technology.

While agriculture and forestry look like environmentally sound future-energy sources, this will only be true if it is done sustainably. This requires a systems approach to ensure that the natural resources at our disposal are not depleted. Closed-loop systems with energy production linked to meat production from the process wastes and methane production from the animal wastes generated are attempts at such systems. Much research must be done to truly understand what the consequences will be of these different options.

NUCLEAR OUTLOOK AND ITS IMPACT ON OIL AND NATURAL GAS

Nuclear power is a significant contributor to the world's energy supply, representing about 6 percent of all energy utilized, and about 16 percent of the world's electricity. Nuclear power is projected to grow in the future, but this growth could be hampered by adverse public perceptions, policies, and economics.

In power generation, nuclear power is an asset that provides base-load electric power, meaning that nuclear power plants are operating at or near capacity all the time. This type of power generation does not typically compete with generation from traditional oil and natural gas power, which are typically load-following: that is, they are able to quickly increase or lower the amount of power supplied based on fluctuations in electricity demand. It is because of these different types of power systems that nuclear power displaces a much greater amount of coal-power generation growth and a smaller amount of oil and natural gas generation.

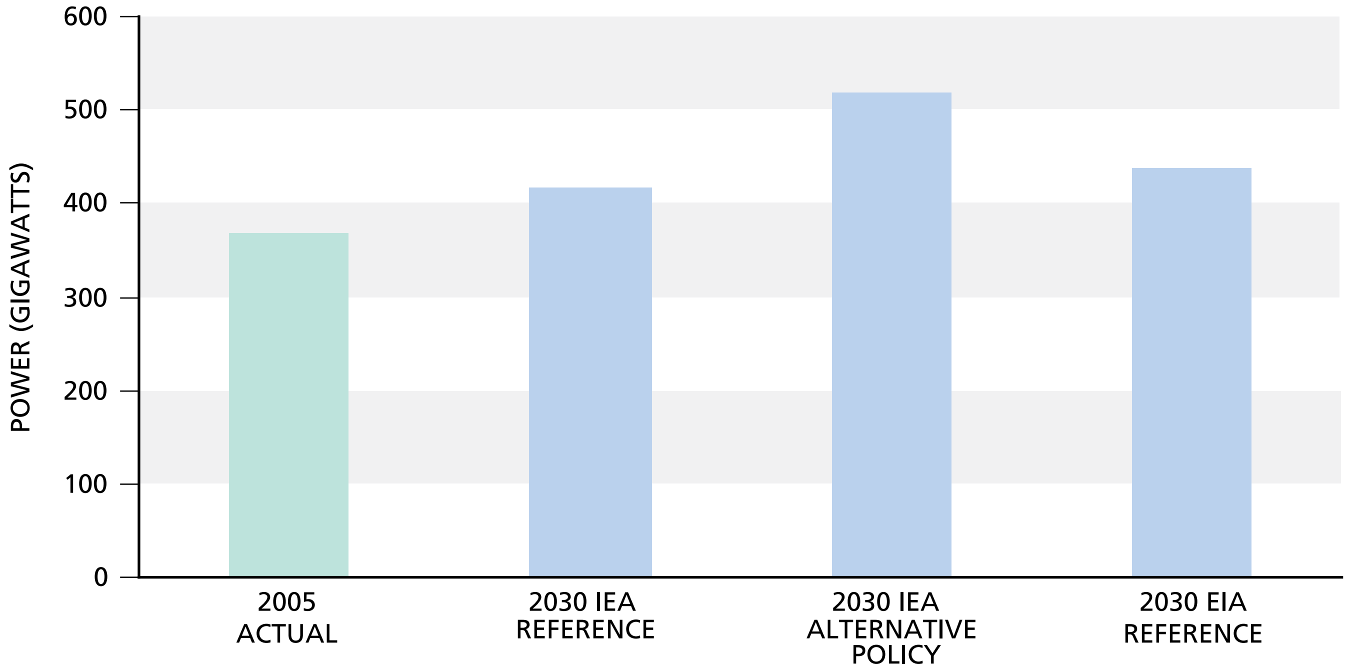
Over the past 40 years, nuclear power has emerged as a significant source of electricity. The majority of today's operating nuclear power plants were constructed during the 1970s and 1980s. However, because of high capital costs and a lack of public acceptance due to safety concerns, new nuclear power plant construction has significantly declined from its peak of 200 gigawatts during the decade of the 1980s.

Many forecasts show nuclear power increasing in amount of power generation, but declining as a percentage of total electricity generated. The majority of nuclear power plant construction is projected to be in non-OECD countries, with the majority of growth forecast in Asia. The period before 2030 forecasts that nuclear power will use existing technology fissile reactors, with more advanced technologies coming online after 2030.

The 2006 IEA World Energy Outlook has a "business as usual" reference case and an alternative policy forecast (Figure 3-22). The alternative policy case assumes that there is an effort to curtail global warming that includes measures to boost the role of nuclear power. The reference case forecasts for 2030 that nuclear power growth will trail alternative methods of power generation by about 3 to 1. The percentage of total electricity produced declines from 16 percent to 10 percent. In the IEA alternative policy forecast, nuclear power grows at a more rapid rate, but it is still outpaced by alternative power generation technologies, declining from 16 percent to 14 percent of total electricity generated.

The 2006 EIA International Energy Forecast is a "business as usual" scenario, with growth in non-OECD countries offset by decommissioning of nuclear power plants elsewhere.

With the current forecasts for nuclear power growth, it is believed that there is sufficient uranium as fuel and that the infrastructure could be constructed to



Sources: Energy Information Administration (EIA), *International Energy Outlook 2006;* and International Energy Agency (IEA), *World Energy Outlook 2006.*

FIGURE 3-22. *Projected Nuclear Power Growth, 2005 to 2030*

support the level of growth indicated in the forecasts. If growth is significantly higher than forecast, there is a possibility that the supply chain for critical nuclear components will need additional time to increase their manufacture.

Four issues can delay new nuclear construction. First is cost: the high capital costs for nuclear power plant construction, the financing required to construct these plants, and the resulting cost of energy often make new nuclear construction a difficult investment decision for a utility. There are government measures both domestically and abroad to encourage new construction of nuclear plants. One significant measure that would increase the competitiveness of nuclear power would be a pricing mechanism on CO_2; a CO_2 mechanism could result in a faster rate of adoption of nuclear energy than forecast.

The second issue facing nuclear energy is the storage and processing of spent fuel; waste management must be a strategic part of any nuclear development plan. The third issue is public perceptions around nuclear power safety. Fourth, there are global concerns about the proliferation of nuclear materials. If these four issues are not addressed, it is likely that nuclear power will grow at a global rate that is slower than the forecasts.

TRANSPORTATION EFFICIENCY

Advanced technologies have the potential to reduce petroleum fuel demand for the five subsectors of transportation (light duty vehicles, heavy duty vehicles, air transport, marine shipping, and rail transport) between now and 2030. Over time, new technologies will enter the marketplace if one or more of the following occur:

- The technologies mature and costs decrease
- Fuel costs increase and remain high
- The technologies are valued by the consumer
- Policies encourage adoption of improved technologies.

Government and industry play important roles in filling and maintaining the technology pipeline for transportation efficiency, can encourage academic research in high-profile transportation-technology areas such as advanced batteries and bio-based fuels, and can encourage students to enter engineering, science, and mathematics professions to work on these challenging issues. In addition, increased funding of R&D increases the number of breakthrough concepts that can be pursued, making the odds more favorable for some to be successfully commercialized.

The various modes of freight shipment have different energy requirements on a ton-mile basis, as do the various modes of passenger travel (automobiles, buses, trains, and aircraft). Policies that encourage efficient use across transportation subsectors were not addressed in the Transportation Efficiency Topic Report, and the costs, benefits, and hurdles of mode-shifting should be studied further.

Finally, alternative fuels have a generic impact across all of the subsectors by displacing some petroleum-based fuel, but have little effect on reducing the energy demand (e.g., Btu per mile) for a subsector. Hydrogen—when used as an energy carrier in fuel cells—and electricity, in plug-in hybrids or battery-electric vehicles, result in higher efficiency than existing technologies. Infrastructure requirements and the energy required to produce the fuels should be considered for these alternatives (e.g., well-to-tank assessment).

U.S. fuel demand for the five transportation subsectors, shown in Table 3-16, is based on EIA projections and is defined as the Reference Case in the Topic Report. Subsectors are discussed here in their order of the percentage of transportation demand. In all of the transportation subsectors, fuel consumption was considered at the end-use point (e.g., tank-to-wheels for the light duty vehicle sector). Energy is required to produce the fuels associated with the various transportation modes. These well-to-tank energy requirements can be substantial for some alternatives to petroleum (i.e., hydrogen, biofuels, and electricity, depending on the source). The Topic Report contains detailed tables of potential advances and their impacts for each subsector.

General Conclusions

The study team concluded that technology can make a significant difference in improving transportation efficiency. The light duty vehicle sector offers the greatest opportunities, but also has a number of challenges. Technology hurdles, costs, and potential infrastructure investments are some of these. In addition, the ways that consumer preferences affect the deployment of various technologies are complex. For the other sectors, a sound business case affects the deployment of technology, including fuel cost savings and operational factors.

It is important that all of the technologies are analyzed from a wells-to-wheels efficiency and cost basis. This was not done in the Topic Report, because the focus was on transportation efficiency at the point of end use (excluding fuel availability, production, and distribution issues).

It should be noted that, although the technologies discussed below are analyzed from a U.S. perspective, they are generic and can be applied in all parts of the world, when the appropriate attributes and constraints are considered for the specific countries of interest.

Sector	Quadrillion Btu Per Year		Percent of Transportation	
	2005	2030	2005	2030
Light Duty Vehicles	16.28	22.98	61.6	60.5
Heavy Duty Vehicles	5.65	8.73	21.3	23.0
Air	2.81	4.15	10.6	10.9
Marine	1.06	1.12	4.0	3.0
Rail	0.67	0.97	2.5	2.6
Total	26.47	37.95		

TABLE 3-16. *EIA Reference Case—U.S. Transportation Fuel Demand*

Light Duty Vehicles

The EIA reference case projects that, in 2030, technology improvements will result in ~13 percent improvement in new vehicle fuel consumption from 2005 levels. It is estimated that this includes technological improvements of ~30 percent at constant vehicle performance, and vehicle attribute changes that reduce this improvement by about half. Based on this study's analysis, technologies (drive train and body improvements, and hybridization) exist, or are expected to be developed, that have the potential to reduce fuel consumption of new light duty vehicles by 50 percent relative to 2005 vehicles. This assumes constant vehicle performance and entails higher vehicle cost. The extent to which these technologies translate into reduction in fuel consumption depends on factors not evaluated in this study, including customer preferences, vehicle and fuel costs, and vehicle attributes (acceleration, weight, size). Improvements beyond 50 percent will require breakthroughs in batteries or fuel cells, potentially resulting in significantly higher vehicle costs and significant infrastructure investments.

Technologies such as hybrids and fuel cells will take longer to deploy in the fleet than more conventional changes (such as improved fuel injection or turbocharging). Hydrogen for fuel cells would displace petroleum-based fuels. However, the source of the hydrogen, costs, technical hurdles, and infrastructure requirements are major unknowns and it is difficult to estimate the impact of fuel cells in 2030.

Heavy Duty Vehicles

Technologies exist to reduce new heavy-duty-truck fuel consumption by 15 to 20 percent in the United States by 2030, which is about equal to the EIA reference case. These technologies (e.g., engine efficiency, rolling resistance, and aerodynamic improvements) will involve higher cost and require an associated financial business case. Operational improvements such as reduced idling and improved logistics can provide a benefit of 5 to 10 percent across the fleet during this period. Advanced technology solutions, such as hybridization and fuel cells, offer fuel consumption reductions of an additional 25 percent, and applications would likely be initiated in local-delivery, short-haul, medium-duty delivery trucks and buses. In the near term, U.S. heavy-duty emission standards will limit the potential to reduce fuel consumption.

Air

Fuel consumption improvements on the order of 25 percent are the basis for the EIA reference case. This is an aggressive projection and all of the known technologies appear to be included in the EIA estimates. New technologies will need to be discovered to achieve additional improvements in efficiency. These new technologies will require a reinvigoration of U.S. research, development, and demonstration initiatives, similar to programs currently being carried out in Europe.

Marine Shipping

The EIA reference case is based on a 5 percent improvement in marine shipping fuel consumption by 2030. This level of improvement is achievable with operational solutions and existing technologies. Improvements greater than 5 percent will require new hull designs and new propeller designs. Given the long life of ships (greater than 20 years), migration of these solutions into the fleet will not have a large impact until later in the study period. Operational changes, affecting the entire fleet, may be more significant than technological improvements.

Rail Transport

The EIA reference case assumes that fuel consumption will improve by 2.5 percent between 2005 and 2030. Incremental improvements in engine design, aerodynamics, and use of hybrids have the potential to reduce new locomotive fuel consumption by up to 30 percent over 2005 technology. Rollout of new technology into the fleet is slow due to low turnover and will be difficult to achieve during the years considered in this study. Emissions standards will tend to increase fuel consumption.