U.S. Department of
ENERGY

Domestic Unconventional Fossil Energy Resource Opportunities and Technology Applications Report to Congress

September 2011

United States Department of Energy
Washington, DC 20585

Message from the Secretary

I am pleased to submit the enclosed report, *Domestic Unconventional Fossil Energy Resource Opportunities and Technology Applications.* This report outlines the domestic unconventional resource opportunities and technology applications of a comprehensive research, development, and deployment strategy for unconventional oil, gas, and coal resources. [1] The resource opportunities and challenges of developing these important domestic resources are summarized in the material that follows.

This report was prepared by the Department of Energy's Office of Fossil Energy. Funds were provided by the Energy and Water Development and Related Agencies Appropriations Act, 2010.

According to statutory requirements, this report is being provided to the following Members of Congress:

- **The Honorable Joseph R. Biden, Jr.**
  President of The Senate
- **The Honorable John Boehner**
  Speaker of the House of Representatives
- **The Honorable Harold Rodgers**
  Chairman, Committee on Appropriations
- **The Honorable Daniel K. Inouye**
  Chairman, Committee on Appropriations

If you need additional information, please contact me or Mr. Jeff Lane, Assistant Secretary, Office of Congressional and Intergovernmental Affairs, at (202) 586-5450.

Sincerely,

Steven Chu

Steven Chu

Enclosure

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[1] The direction to prepare this report is contained in the Conference Report (House Report 111-278) for the Energy and Water Development and Related Agencies Appropriations Act, 2010.

Executive Summary

The Energy and Water Development and Related Agencies Appropriations Act, 2010, which was included in the final legislation (H.R. 3183, Public Law 111-85), directed the U.S. Department of Energy (DOE) to develop this report outlining domestic unconventional fossil energy resource opportunities and associated technology applications, in support of an overall research, development, and deployment (RD&D) strategy for the further development of these resources. While the strategy report is prepared by DOE, the scope of the RD&D opportunities and associated technology application is nationwide.

Based on the current state of ongoing private and public research efforts, the report summarizes:

- The potential magnitude of the resource base for each of the unconventional fossil energy sources;
- The technical, safety, and environmental challenges that have been identified in connection with each of the unconventional resources; and
- The current status of research activity, both public and private, focused on these resources.

From this review of past research activity, the report identifies the following principal remaining technological and environmental challenges:

- Production of residual oil that remains in large domestic oil reservoirs while simultaneously storing carbon dioxide (CO_2) in those same reservoirs;
- Potential development of the nation's unmineable coal resource via underground coal gasification;
- The producibility of natural gas from methane hydrate and the potential for simultaneously sequestering CO_2;
- Development of gas shale and tight gas sands;
- Application of advanced computational methods for evaluating cumulative environmental and socioeconomic impacts of simultaneous development of conventional and unconventional resources on a regional basis;
- Collection and archiving of historical baseline data related to unconventional fossil fuel resources that may facilitate collaborative efforts among researchers; and
- Quantifying the environmental and safety impacts of unconventional resource development and identifying ways to reduce and/or mitigate these impacts, thereby improving environmentally sustainable production of the resources.

This document is divided into six main parts. Sections I and II provide background and context. Section III characterizes and quantifies each of the categories of unconventional fossil energy resources. Section IV describes the technical and environmental challenges to developing these resources. Section V summarizes those challenges that are currently the subject of research and identifies many of the performers involved. Section VI combines the information developed in the previous sections.

In preparing this document, the DOE drew from a large number of public reports, studies, white papers, workshop/conference summaries, reports by expert advisory committees, and other publications. DOE, in the normal course of implementing its mission, works closely with academia and industry to carry out cost-shared R&D focused on most of the resources and technologies identified in this document. Information gleaned from these past activities was also considered in the report's preparation.

The technical challenges associated with unconventional natural gas development have been delineated as part of the planning process for the Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research and Development Program established pursuant to Title IX, Subtitle J (Section 999A-999H (Subtitle J) of the Energy Policy Act of 2005 (EPAct). As required by Subtitle J, DOE contracted with a consortium
(Research Partnership to Secure Energy for America or RPSEA) to administer three program elements identified in EPAct 2005, one of which is focused on unconventional natural gas.

The consortium has conducted extensive planning utilizing a network of volunteer member experts representing academic, industry and environmental groups and has conducted forums to help frame the technology requirements for unconventional gas. The new Annual Plan outlines technical challenges related to the development of tight gas sands, gas shale and coalbed methane and reflects an important shift in priorities. The information developed as part of this process was captured as part of this document.

In addition, stakeholders from industry and academia were encouraged to comment on a draft of this report posted on the NETL website and publicized via the NETL listserv with a request for responses. Appendix A characterizes the 27 responses received. These comments were reviewed and changes were made to the report where appropriate.

Domestic Unconventional Fossil Energy Resource Opportunities and Technology Applications

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I. Legislative Language

This report responds to legislative language set forth in The Conference Report (House Report 111-278) for the Energy and Water Development and Related Agencies Appropriations Act, 2010, (H.R. 3183, Public Law 111-85), which states:

... Unconventional Fossil Energy Technologies. The conference agreement provides $20,000,000 to establish a comprehensive research, development and deployment (R&D) strategy for the development of unconventional oil, gas and coal resources as proposed by the Senate. In developing its R&D strategy, the conferees direct the Department to develop a report outlining the domestic resource opportunities as well as technology applications that will be the focus of this effort. Further, the Department shall include input from academia and industry in the report.

This document has been prepared to fulfill this request. While DOE has drawn on a number of academic and industry sources in preparing this document, a draft version was posted on a DOE website for review and comment by all interested stakeholders, including experts from industry and academia. Comments received during this review were incorporated into this document, and key comments are summarized in Appendix A.

II. The U.S. Energy Situation: Current Status and Projected Outlook

The Energy Information Administration's (EIA) Annual Energy Outlook 2011[2] (AEO2011 Early Release) provides a context for this document. Three issues are particularly relevant to the topic of energy supply from domestic unconventional fossil energy resources: current and future sources of energy supply by fuel type, energy security as represented by imports of liquid fuels, and current and future greenhouse gas emissions.

2.1 Sources of Energy Supply

While taking steps to move towards a clean energy economy, coal, petroleum liquids, and natural gas will still be relied on for a significant portion (78 percent in 2035) of U.S. energy consumption in foreseeable future (Figure 2-1).

[2] Annual Energy Outlook 2011 Early Release Overview, available online at http://www.eia.doe.gov/forecasts/aeo/index.cfm?featureclicked=1&

Biofuel consumption is projected to account for most of the growth in consumption of renewable fuels, mainly from the implementation of the Federal Renewable Fuels Standard for transportation fuels and State renewable portfolio standard (RPS) programs for electricity generation.

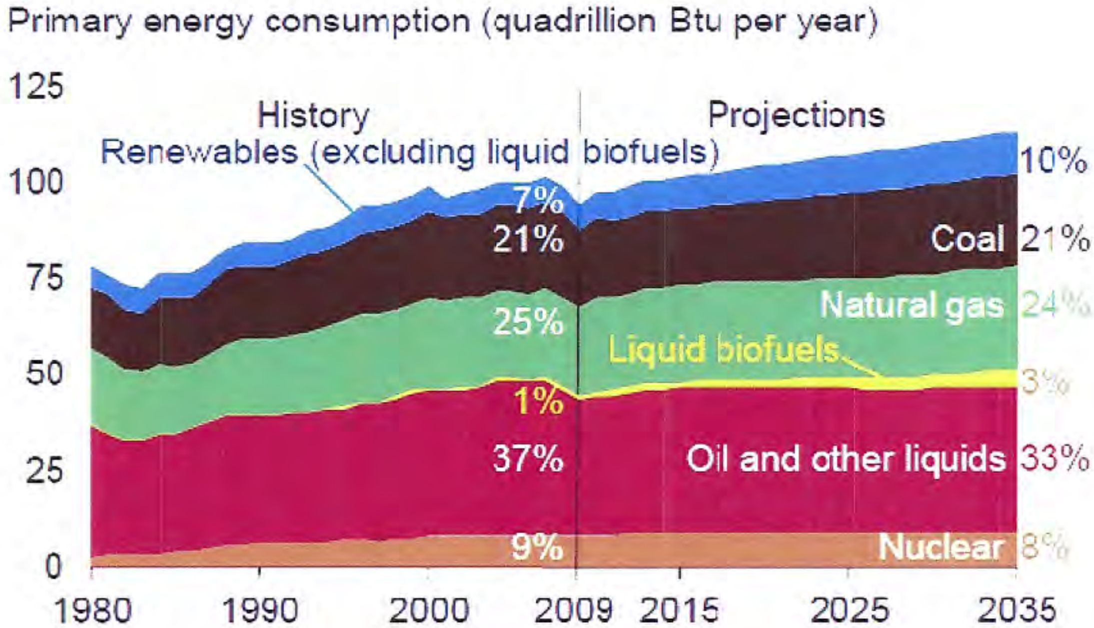
Total primary energy consumption in the Energy Information Administration's Annual Energy Outlook 2011 (Early Release) reference case grows 20.6 percent between 2009 and 2035. This is slightly more than was predicted in the 2010 projection (19.8 percent). Total U.S. consumption of liquid fuels, including both fossil liquids and biofuels, grows from 18.8 million barrels per day in 2009 to 22 million barrels per day in 2035. Biofuel (primarily ethanol) consumption accounts for much of the growth, as consumption of petroleum-based liquids is expected to remain essentially flat, except for diesel fuel. The transportation sector currently dominates demand for liquid fuels, and this is not expected to change over the next 25 years.

In the AEO2011 reference case, natural gas consumption is projected to fall slightly in the near term and then increase gradually to 26.45 trillion cubic feet (Tcf) per year in 2035. Coal consumption, mostly for electric power generation, is projected to grow about 1 percent per year throughout the projection period, with more intensive utilization of existing plants and the start up of new plants already under construction. This increase in coal consumption is expected in spite of higher levels of natural gas use for electric power generation due to relatively lower natural gas prices resulting from the expected growth in natural gas supply.

Even though total consumption of renewable fuels is expected to grow 2.9 percent per year in the AEO2011 reference case, overall growth in energy demand will mean that the contribution of fossil energy to the Nation's energy mix will remain very significant. Renewable fuels include wood, municipal waste, and biomass in the end-use sectors; hydroelectricity, geothermal, municipal waste, biomass, solar, and wind for generation in the electric power sector; and ethanol for gasoline blending and biomass-based diesel in the transportation sector.

While growth in renewable energy supplies are expected to be robust, the expectation is that fossil energy resources will continue to be critical components of our Nation's energy portfolio.

Figure 2-1: Energy Consumption by Fuel (1980-2035)[3]



2.2 Energy Security

Growth in energy imports is expected to be moderated by increased use of biofuels (much of which are produced domestically), demand reductions resulting from new efficiency standards, rapid improvement in the efficiency of appliances, and higher energy prices. However, while U.S. dependence on imported liquids (measured as a share of total U.S. liquid fuels use) is expected to decline somewhat from the 60 percent share attained in 2005-06, it will still be a 45 percent share in 2035 (Figure 2-2).

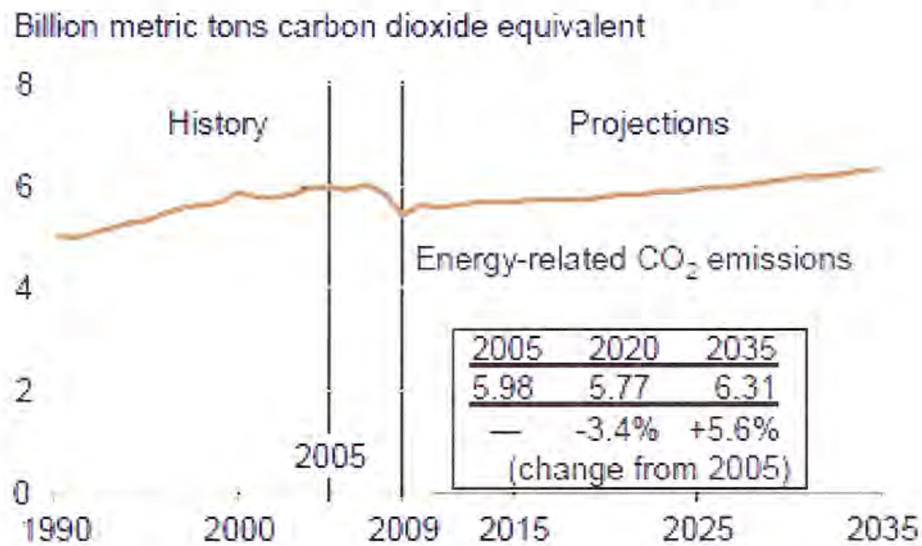
In the AEO2010 reference case, domestic crude oil production increases from 5 million barrels per day in 2008 to 6.3 million barrels per day in 2027 and remains at just over 6 million barrels per day through 2035. Production increases are relied on from the deepwater areas of the Gulf of Mexico (GOM) and from onshore Enhanced Oil Recovery (EOR) projects.

[3] Ibid.

2.3 Greenhouse Gas Emissions

After falling by 3 percent in 2008 and nearly 7 percent in 2009, largely driven by the economic downturn, total U.S. energy-related CO2 emissions do not return to 2005 levels (5,980 million metric tons) until 2027, and then rise by an additional 5 percent from 2027 to 2035, reaching 6,315 million metric tons in 2035 (Figure 2-2).[4] Emissions per capita fall by an average of 0.8 percent per year from 2005 to 2035, as growth in demand for electricity and transportation fuels is moderated by higher energy prices, efficiency standards, State RPS Requirements, and Federal CAFE standards.

Figure 2-2: Energy-related Carbon Dioxide Emissions, 1990-2035[5]



It is important to note that EIA's projection assumes current policy remains unchanged and no technology advancement with regard to carbon emissions. Legislative efforts to slow the increase in greenhouse gas emissions may be implemented. Any consideration of increasing domestic production of unconventional fossil energy should recognize that increasing production of lower carbon forms of fossil energy (e.g., natural gas), or increasing production in ways that reduce net carbon emissions (e.g., carbon sequestration), will serve this objective as well. Efforts to increase domestic production of oil, particularly heavy oil, oil from Green River oil shale, or bitumen from oil sands, will have a negative impact on carbon dioxide emissions, even as they have a positive impact on energy security (reduced imports).

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[4] Ibid.
[5] Ibid.

III. Domestic Resource Opportunities

This section briefly defines and quantifies the "unconventional oil, gas and coal resources" that exist within the United States. A number of studies and reports have focused on these resources during the last decade, and these are referenced in the text and also listed at the end of this document under "Key References."

3.1 Definitions

Hydrocarbons can be found in a wide variety of deposits within the Earth's crust. In the 1970s, when concerns about energy supplies began to rise, it became common to refer to certain types of deposits of natural gas and petroleum or petroleum-like hydrocarbons as "conventional" and certain other types as "unconventional." These designations were more or less determined by the type of reservoir rock (in the case of natural gas) or the hydrocarbon properties (in the case of petroleum). Oil and natural gas that could be produced at relatively high rates from (typically) sandstone or limestone reservoirs having relatively high permeability were considered "conventional."

Unconventional "oil" was generally considered to be in any one of three categories: 1) a petroleum-like material that could be produced by heating the kerogen found in oil shale deposits, 2) bitumen that could be extracted from oil sand deposits, or 3) very low gravity (heavy) crude oil found in more conventional reservoirs, but which required thermal energy inputs (heat) to be produced.

Unconventional gas was generally considered to be gas produced from one of three types of reservoirs: 1) "tight" (low permeability) sandstones, 2) coal seams (also referred to as "coalbed methane" or CBM), or 3) gas-bearing shale. Methane from methane hydrate deposits was also considered unconventional, as was methane dissolved in the brine found in geopressured aquifers.

In general, conventional oil and gas deposits were much less expensive to find and produce at commercial rates than those trapped in non-conventional formations. Oil and gas companies naturally looked to develop the less expensive deposits first. However, beginning in the mid 1970s and on into the 1980s and 1990s, new exploration and production technologies coupled with higher oil and gas prices began to change the notion of what was considered "unconventional." Resources that were previously considered to be technically and/or economically un-producible became producible. The unconventional became conventional.

Today, roughly 50 percent of the domestically produced natural gas supply comes from gas shale, tight gas sands, and coal seams, and this share is expected to rise over the next 25 years to 74%.[6] Finding and development costs for new gas shale plays have dropped and estimates of technically recoverable natural gas resources have jumped dramatically to 827 trillion cubic feet as of January 1, 2011.[7] In Canada, investment in oil sands development has grown and the production rate of various grades of oil from Canadian oil sands is expected to rise from just over 1.2 million barrels (bbl) per day in 2008 to approximately 2.2 million bbl per day in 2015 and to about 3.3 million bbl per day in 2025, assuming projects are developed at a pace similar to historical trends.[8] At the same time, the cost of producing "conventional" oil from hard-to-reach places like the deepwater areas of the GOM and the Arctic has risen dramatically with the increase in cost of capital and operating investments in these challenging environments.

While they were never precisely defined, it is clear that the designations of conventional and unconventional have less meaning than 30 years ago. The legislative language (see Section 1.0, page 7) is not specific. Accordingly, we are defining unconventional for the purposes of this report, to include those hydrocarbons historically termed unconventional, as well as others that are currently close to the edge or outside the range of combinations of oil/gas price, available technology, and industry risk tolerance that would enable them to be widely produced today. These are listed in Table 3-1.

One category that deserves special attention is residual oil. The rationale for including it as an "unconventional" oil resource stems from the fact that like the other categories of oil, its location is known, the volumes can be estimated, economic recovery will require continued technological advancements, and many of the producing companies with access to the deposits are unfamiliar with the technologies under development and are reluctant to invest due to a perception that the risks are too great.

While the text of the legislation speaks of "unconventional ... coal resources," there are no subcategories of domestic coal deposits that are commonly considered to be "unconventional" in the same manner of speaking as the oil or natural gas deposits listed above. Accordingly, this text is interpreted to mean currently *un-mineable* coal and lignite that could potentially be developed as a fossil energy source employing *unconventional* technologies.

[6] Annual Energy Outlook 2011 Early Release Overview, available online at http://www.eia.doe.gov/forecasts/aeo/index.cfm?featureclicked=1&
[7] Ibid.
[8] CAPP, 2009, "Crude Oil Forecast, Markets and Pipeline Extensions," (http://www.capp.ca/library/publications)

Also, with reference to the term "resources," we are following the definition for the term accepted by the Society of Petroleum Engineers (SPE).[9] The major recoverable resources classes defined by the SPE are production, reserves, contingent resources, and prospective resources. *Production* is oil or gas already produced for use by consumers. *Reserves* represent that part of resources which are technically and economically recoverable and have been justified for development. *Contingent resources* are resources that are potentially recoverable but not yet considered mature enough for commercial development due to technological or economic hurdles. Contingent resources may be considered *technically* recoverable but yet not *economically* recoverable at current prices. *Prospective resources* are estimated volumes associated with undiscovered accumulations.

Table 3-1: Unconventional Oil and Gas

Oil	**Description**
Oil from Oil Shale	Hydrocarbon liquids produced by heating the kerogen found in organic shale deposits, suitable for refining as crude
Oil from Oil Sands	Bitumen extracted from sandstone deposits and upgraded into syncrude suitable for refining as crude
Heavy Oil	Very low gravity, high viscosity crude oil requiring enhanced production methods
Oil from Fractured Shale	Conventional crude oil producible from fractured organic shale (e.g., Bakken Shale)
Residual Oil	Conventional crude oil that exists as a residual oil saturation in waterflooded reservoirs or in zones below the original oil-water contact (in the "residual oil zone" or ROZ), that is producible using enhanced production methods beyond those currently in use
Gas	**Description**
Tight Gas	Natural gas produced from reservoirs that have very low porosities and permeabilities (generally matrix porosity of much less than 10% and permeability of 0.1 millidarcy or less, exclusive of fracture permeability)
Gas from Coal Seams	Natural gas produced from wells completed in coal seams (also termed "coalbed methane")
Gas Shale	Natural gas produced from naturally fractured and/or hydraulically fractured shale formations
Methane Hydrate	Methane contained in clathrate hydrate deposits found in arctic and deepwater marine sediments

[9] SPE Website: http://www.spe.org/industry/reserves/

3.2 Oil Resources

3.2.1 Oil Shale

There are a number of oil shale deposits in the United States. The two most important from the standpoint of development potential are to be found in the Eocene Age Green River Formation (Fm.) in Colorado, Wyoming, and Utah, and in the Devonian–Mississippian Age black shale in the eastern United States.[10] Other deposits in Nevada, Montana, Alaska, and Kansas are relatively small and/or low grade. Dyni (2005) reported on estimates of oil shale in-place resources (Table 3-2). This shows the Green River Fm. to be the largest deposit.

Table 3-2: Oil Shale In-Place Resources (after Dyni, 2005)

Formation	Location	In-Place Resource (MM bbl oil equiv.)	Source
Eastern Devonian Shale	KY (TN, OH, IN)	189,000	Matthews & others (1980)[11]
Green River Fm.	CO, UT, WY	1,466,000	Dyni (2005)[12]
Phosphoria Fm.	MT	250,000	Smith (1980)[13]
Heath Fm.	MT	180,000	Smith (1980)
Elko Fm.	NV	228	Moore & others (1983)[14]

The potential for retorting–heating to about 500 degree Celsius in absence of air - mined oil shale from the Green River Fm. to produce "shale oil" has been recognized since the early 1900s. In 1967, the U.S. Department of Interior first investigated commercialization of the Green River Fm. oil shale deposits. In 1974 parcels of public oil shale lands were leased in Colorado and Utah to oil companies, and development was also initiated on private leases. Underground mining facilities, retorts, and upgrading plants were built and operated. Unocal and Exxon, in particular, invested hundreds of millions of dollars in shale oil production operations.[15] Unocal produced about 4.4 million bbl. of shale oil under a program partly subsidized by the U.S. Government. At its peak, production was about 5,900 bbl per day. The facility, the last to commercially produce shale oil, was closed in 1991 due to low oil prices.

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[10] Dyni, J. R., 2005, Geology and Resources of Some World Oil-Shale Deposits, Scientific Investigations Report 2005–5294, USGS

[11] Matthews, R.D., Janka, J.C., and Dennison, J.M., 1980, Devonian oil shale of the eastern United States, a major American energy resource [preprint]: Evansville, Ind., American Association of Petroleum Geologists Meeting, Oct. 1–3, 1980, 43 p.

[12] Dyni, op cit.

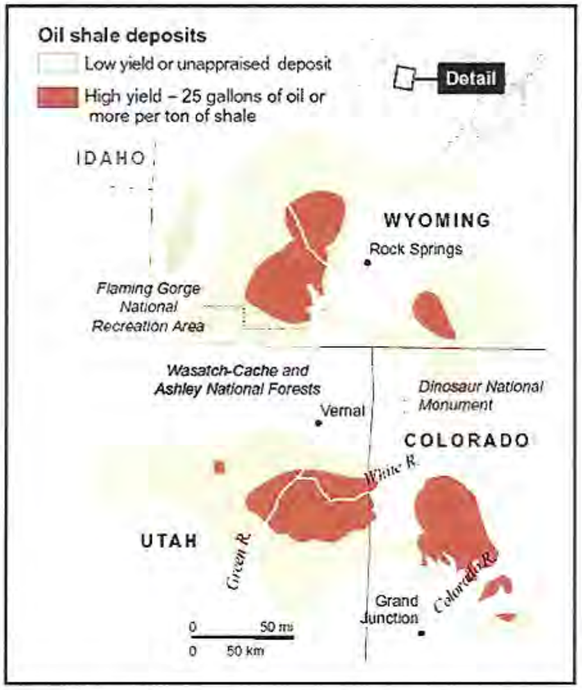
[13] Smith, J.W., 1980, Oil shale resources of the United States: Golden, Colorado School of Mines, Mineral and Energy Resources, v. 23, no. 6, 30 p.

[14] Moore, S.W., Madrid, H.B., and Server, G.T., Jr., 1983, Results of oil-shale investigations on northeastern Nevada: U.S. Geological Survey Open-File Report 83-586, 56 p., 3 app.

[15] Ibid.

The Green River Fm. oil shale deposits in Colorado's Piceance Basin are the most well characterized, and Dyni reported an estimate of oil equivalent-in-place for that deposit totaling 1.0 trillion bbl (Figure 3-1).[16] Green River oil-shale deposits in Utah's eastern Uinta Basin are estimated at 214 billion bbl and in southwest Wyoming's Green River Basin at 244 billion bbl of oil-in-place. Additional Green River Fm. shale oil resources are also to be found in the Washakie Basin east of the Green River Basin in southwest Wyoming.[17] Together, these estimates total about 1.5 trillion bbl of in-place oil.

Figure 3-1: Western U.S. Oil Shale Deposits[18]



Estimates of the in-place resource depend in part on the richness or grade (gallons of oil that can be produced by retorting a ton of kerogen-containing shale) of the shale. Oil shale that yields 25 to 50+ gallons per ton is the most economically attractive to develop. Deposits with grades below 10 gallons per ton are generally not counted in resource estimates as it is assumed they would not produce enough oil to justify the costs and energy expended in mining and processing.[19] Some estimates of the total oil equivalent-in-place for the Green River oil shale in all basins have ranged as high as 1.8 trillion bbl, due in part to uncertainties in the volume and richness of the deposits in Utah and Wyoming.[20]

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[16] Dyni, op cit.
[17] Ibid.
[18] From http://newenergyandfuel.com/http:/newenergyandfuel/com/2009/12/16/lots-of-oil-right-here-in-the-us/ (information from Office of Naval Petroleum and Oil Shale Reserves)
[19] Bartis, J.T., et al., 2005, Shale Development in the United States, prepared by RAND for the National Energy Technology Laboratory
[20] Ibid.

In March of 2009, the U.S. Geological Survey (USGS) published a reassessment of in-place oil shale resources in the Green River Fm. in the Piceance Basin of Colorado. The total volume of oil-in-place was estimated at 1.525 trillion bbl, compared to the 1.0 trillion reported by Dyni.[21] The new assessment incorporated about twice as many oil-yield data points as were used previously and several additional oil shale intervals were included that were not assessed previously, for lack of data.

Only a portion of the in-place resource is recoverable. Because oil shale is not being commercially developed in the United States, it is difficult to estimate exactly what the technical and economic recovery factors might be. Estimates of the contingent oil shale resource have generally been based on rough estimates of the fraction of the resources in place that can be accessed and recovered, which in turn are based on assumptions about mining and retorting methods. Currently, a number of companies are developing and testing new technologies for producing oil from oil shale, but the precise efficiency of these methods is not yet publically known.

Bartis, in a 2005 RAND report, assumed an upper bound for the physically accessible portion of the Green River Fm. resource base at 80 percent, assuming low environmental impact extraction methods can be developed.[22] Of this, it was assumed that at most 75 percent of the accessible resource could be extracted, yielding an upper bound of 60 percent for a net recovery factor. Applying this net recovery factor to an estimated in-place resource in place of 1.5 to 1.8 trillion bbl yields an upper bound between 900 billion and 1.1 trillion bbl of oil. Assuming an accessibility factor of 60 percent and an extraction factor of 50 percent yields a lower bound of about 30 percent net recovery or roughly 500 billion bbl. Based on these assumptions, the range of potentially recoverable oil from the Green River Fm. oil shale could be estimated at between 500 billion and 1.1 trillion barrels. If we apply the same range of recovery factors to the Montana deposits, the total range could increase to 630 billion to 1.36 trillion barrels. However, the actual technically and economically recoverable resource could be lower.

The western and eastern oil shale originate from very different sources and were deposited at different geologic times.[23] The sediments of the Green River Fm. are lacustrine (lake sediments) and the organic matter is thought to have come from blue-green algae. As the lakes containing the sediments became closed off and thus increasingly arid, the waters became more saline and alkaline. Besides hydrocarbons, the western deposits include the commercially useful sodium carbonate minerals nahcolite, dawsonite, and trona.

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[21] Johnson, R.C., Mercier, T.J., Brownfield, M.E., Pantea, M.P., and Self, J.G., 2009, Assessment of in-place oil shale resources of the Green River Formation, Piceance Basin, western Colorado: U.S. Geological Survey Fact Sheet 2009–3012, 6 p.

[22] Bartis, op cit.

[23] Dyni, op cit.

The black organic marine shale underlying the eastern United States were deposited in a relatively shallow sea with little wave and current disturbance.[24] The eastern shale deposits underlie the states of New York, Pennsylvania, West Virginia, Maryland, Ohio, Michigan, Illinois, Indiana, Virginia, North Carolina, Kentucky, Tennessee, and Alabama; however, 98 percent of the organic-rich and relatively shallow resource is located in Kentucky, Ohio, Indiana, and Tennessee. The eastern shale contain only a minor amount of carbonate minerals.

Eastern oil shale is low-grade compared with the Green River deposits.[25] The eastern black shale yield half the amount of organic matter as the Green River oil-shale due to differing kerogen types. In the Interior Platform (Kentucky, Ohio, Indiana, and Tennessee), where the black shale is nearest to the surface and richest, the eastern oil shale is potentially a commercial resource. A study conducted in 1980 on the eastern shale oil deposits concluded that just the richest portion of the resource—at least 25 gal per ton— in the Kentucky Knobs region, is estimated to hold 16 billion bbl.[26] However, the feasibility of large open pit mining and retorting of shale in populated woodland areas is problematic. Figure 3-2 displays the mineable eastern oil shale deposits along with population densities. The average population density of Kentucky, for example, is about 100 people per square mile, compared to an average of less than 10 people per square mile for the area of Colorado where Green River Fm. oil shale is found. <u>For the purposes of this report, no estimate of recoverable resource is assigned for the Eastern oil shale deposits.</u>

Recovery of oil from the Green River Fm. oil shale will require one of two types of production processes. Surface processes involve mining and crushing the shale and retorting it at the surface using one of a number of methods. *In situ* retorting involves heating the shale in the ground and producing the hydrocarbons that result via wells.

For a first-of-a-kind oil shale mining and surface retorting plant operation to be profitable, Bartis (2005) states that the price of low-sulfur, light crude oil will need to be at least \$70-\$95 per barrel.[27] Capital expenditures were estimated to range from \$5 billion to \$7 billion and higher for an operation producing 50,000 bbl per day. Operating and maintenance costs were assumed to be \$17-\$23 per barrel for a first-of-a-kind plant. The report recognized that future costs for environmental control technologies could raise operational expenses, but also that technical advances may counterbalance increases in cost. With experience, the RAND report suggests that the economic oil price could decrease to \$35-\$48 per barrel.

[24] Ibid.

[25] Ibid.

[26] Johnson, H.R., et al., 2004, Strategic Significance of America's Oil Shale Resource, Volume II Oil Shale Resources, Technology and Economics, March, Final Report.

[27] Bartis, op cit.

Others have estimated that the use of the Alberta-Taciuk Processor (ATP), a surface retort that was demonstrated in Australia during 1999-2004, would enable a full-sized plant to produce 157,000 bbl per day of synthetic crude oil at a capital cost of \$3.5 to \$4.0 billion and with operating costs of \$7.50 to \$8.00 per barrel.[28] The ATP technology is to be used in two plants totaling 15,000 bbl per day that are being planned for Jordan.[29]

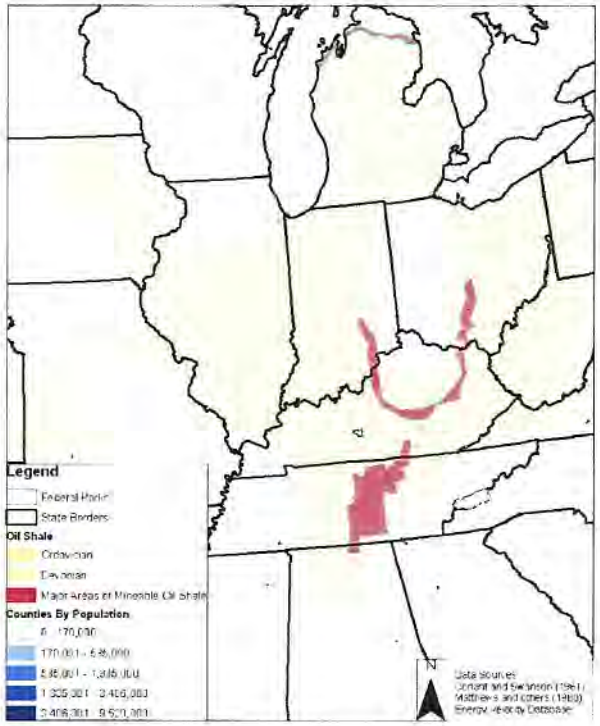
In situ retorting, as has been proposed by Shell and Exxon and is being tested by both of these companies in Colorado, as well as others, (see Section 4.1.1.2 of this report), could enable oil to be produced from oil shale without mining and surface retorting and thus at a lower cost. Shell stated in 2005 that its technology could conceivably become competitive at world oil prices "above \$30 per barrel." However, the company has since stated that it will not know the commercial potential of its process until its research program is completed. At the same time, over the past five years oil field capital construction costs and energy costs have escalated significantly.

A report by the Task Force on Strategic Unconventional Fuels published in 2007 estimated that first-of-a-kind mining and surface retorting plants would be economic (i.e., produce a 15 percent rate of return) at sustained average world oil prices between \$44 and \$54 per barrel, and *in situ* processes may be economic at prices above \$30 per barrel.[30]

None of these estimates take into consideration the cost of capturing and storing any CO2 produced as a result of the processes envisioned, or of any cost penalties for the emissions, should emissions regulations be put in place in the future.

[28] Johnson, op cit.
[29] http://www.jeml.co.uk/
[30] *America's Strategic Unconventional Fuels: Oil Shale, Oil sands, Coal Derived Liquids, Heavy Oil, CO2 Enhanced Recovery and Storage*, Volume III – Resource and Technology Profiles, prepared by the Task Force on Strategic Unconventional Fuels, September 2007

Figure 3-2: Eastern U.S. Mineable Oil Shale Deposits



3.2.2 Oil Sands

Oil sand is a consolidated or unconsolidated rock comprised of naturally occurring crude bitumen, sand, water, and clay. Bitumen is a hydrocarbon that has a viscosity above 10,000 centipoise (cP) at 60°F (15.6°C), and as such it will not flow without either being heated or diluted with a lighter hydrocarbon. The most well known oil sands deposits are located in Canada, which has almost 1.7 trillion bbl of original oil in place (OOIP) in the form of bitumen in western Canada.[31] The U.S. oil sands resource is considerably smaller.

The U.S. oil sands resource is estimated at about 70 billion bbl of oil-in-place in the form of bitumen, of which about 19 billion bbl are considered to be a "measured" resource (i.e., contingent) and 51 billion bbl considered "probable," "possible," or "speculative" (prospective).[32] The largest oil sands deposits in the United States are in Utah (Table 3.3).[33] Additional resource characterization will be necessary to resolve the range of resource estimates. Of course, while these numbers are quite large, the portion that might be physically accessible and technically recoverable will be considerably lower.

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[31] Energy Resources Conservation Board of Alberta, 2009, Alberta's Reserves 2008 and Supply Demand Outlook 2009-2018: Statistical Series, ST98-2009: Calgary, Energy Resources Conservation Board of Alberta.
[32] UHOP, 2007, *A Technical Economic and Legal Assessment of North American Heavy Oil, Oil Sands, and Oil Shale Resources,* prepared in Response to Energy Policy Act of 2005 Section 369(p) for the U.S. Department of Energy by the Utah Heavy Oil Program, Institute for Clean and Secure Energy, The University of Utah, September, 2007.
[33] Ibid.

More than 40 percent of the contingent reserves are associated with the Uinta and Paradox basins of Utah. In the early 1980s, seven Special Tar Sand Areas in the Uinta Basin were designated by the (USGS) pursuant to the Combined Hydrocarbon Leasing Act of 1981.[34] In 1995, the Bureau of Land Management (BLM) issued leases at two of these deposits, but no significant development took place. Other significant oil sands deposits in Alaska, California, Texas, and Alabama are not well defined. Oil sand deposits are also present in southeastern Kansas, southeastern Missouri, and Oklahoma, and occur most frequently in rocks of Middle Pennsylvanian Age.[35]

The bitumen in oil sands has been extracted both by mining and *in situ* recovery methods. Canadian oil sands are different than U.S. oil sands in that Canadian oil sands are water wetted, while U.S oil sands are hydrocarbon wetted.[36] As a result of this difference, extraction techniques for the oil sands in Utah would need to be different than for those in Alberta, Canada. If we assume that 60 percent of U.S. tar sand deposits are accessible, and that 75 percent of the bitumen is recoverable from mined oil sands, an estimate of the technically recoverable resource could be calculated at roughly between 10 and 30 billion bbl of bitumen. However, the actual technically and economically recoverable resource could be lower. As with the hydrocarbon material produced from retorted oil shale, this bitumen would need to be upgraded to a material suitable for input into a refinery. However, the specific upgrading requirements would be different for oil shale and oil sands.

Table 3-3: Oil Sands In-Place Resources (UHOP, 2007, after Reid, et al., 1993; Oblad et al., 1987; and Ritzma, 1979)

Location	**Oil-in-Place (million barrels)**			
	Proven (Measured)	**Probable**	**Possible**	**Total**
Utah (Uinta Basin)				
Asphalt Ridge	435	438	175	1048
Asphalt Ridge, NW	2	3	95-120	100-125
Hill Creek	350	480	330	1160
PR Spring	2500	1200	550-1100	4250-4800
Sunnyside	1800	2200	1200-1850	5200-5850
Whiterocks	50	40	35-50	125-140
Utah (Circle Cliffs)	707	430	170	1307
Utah (San Rafael Swell)	35	55	355-455	445-545
Utah (Paradox Basin)				
Tar Sand Triangle	2500	3600	3400-7900	9500-14,000
30 other deposits	60	66	119-212	245-338
Utah Total	8439	8512	6429-12,363	23,380-29,313
Texas	4420		1021	5441
California	2541		2799	5340
Alabama	1760		4600	6360
Alaska	0		19,000	19,000
KS, KY, NM, MO, OK, WY	2221		5502	7723
U.S. Total	**19,381**	**8512**	**45,284-67,249**	**67,244-73,177**

[34] UHOP, op cit.

[35] Ibid.

[36] Oil and Oil sands Programmatic EIS (http://ostseis.anl.gov/guide/tarsands/index.cfm)

3.2.3 Heavy Oil

Heavy oil is categorized as crude oil having an API gravity of less than 22.3° and a viscosity of 100-10,000 cP at 60°F (15.6°C). The largest deposits in the U.S. are in California and in the Schrader Bluff/West Sak/Ugnu area on the North Slope of Alaska.

The U.S. Heavy Oil Database lists 154 deposits of over 50 million bbl (excluding Alaska), of which 121 are located in California.[37] Thermal EOR methods (steam and hot water injection) are used to produce these fields. Production of heavy oil is spread among more than 200 reservoirs, most of which are less than 4,000 feet deep, have high permeabilities (>1,000 milliDarcies, mD), and have overall sand thicknesses that exceed 50 feet.[38] In addition to the major deposits in southern California's San Joaquin, Los Angeles, Santa Barbara, Ventura, Santa Maria, Cuyana and Salinas basins, additional Lower 48 deposits are found along the Gulf Coast, in the Bighorn Basin of Wyoming, and in the Ardmore Basin and Anadarko Basin in Oklahoma.

Table 3-4: Heavy Oil In-Place Resources (UHOP, 2007, after U.S. Heavy Oil Database, 2004; Alaska from BP[39])

	Original Oil in Place (million barrels)	Cumulative Production through 2003 (million barrels)	Remaining Oil in Place (million barrels)
California	75,851	8,751	67,100
Alaska	20,000	50	19,950
Texas	2,977	349	2,628
14 other states	5,404	1,738	3,666
Total	**104,232**	**10,888**	**93,344**

[37] National Energy Technology Laboratory. U.S. Heavy Oil Database: 2004. http://www.netl.doe.gov/technologies/oil-gas/Software/datbase.html
[38] UHOP, op cit.
[39] Ibid.

In Alaska, the Schrader Bluff, West Sak, and Ugnu heavy oil reservoirs overlie the major oil reservoirs on the North Slope, in the Kuparuk River (Tabasco and West Sak), Milne Point (Schrader Bluff), and Prudhoe Bay (Orion, Polaris) fields.[40, 41] With up to 30 billion bbl OOIP, these deposits are larger than the North Slope's Prudhoe Bay. These deposits are at depths between 2,000-4,700 feet. The deeper Schrader Bluff Fm. and West Sak Sands have 17° to 21° API gravities and viscosities of 20 to 3,000 cP, while the shallower Ugnu Sands are heavier with 7° to 12° API gravities and viscosities of 2000 to over 10,000 cP.[42] Currently, all of the production is from the Schrader Bluff Fm.; no heavy oil is being produced from the Ugnu Sands. DOE is currently funding research into ways to produce the Ugnu heavy oil. The Alaskan heavy oil is being produced via waterflood, using horizontal wells.

Current estimates of recoverable oil from the Alaskan heavy oil resource are on the order of 5 to 10 percent, or about 1 to 2 billion bbl.[43] Roughly 11 percent of the California resource has been recovered but production is declining. <u>If new technologies were to be developed that would enable just 20 percent recovery of the combined Alaskan and Californian resource, the total remaining recoverable resource would be roughly 10 billion bbl.</u>

3.2.4 Oil from Fractured Shale (OFS)

Oil from fractured shale (OFS) is included here as part of the "unconventional" domestic oil resource due to the need for significant improvements in knowledge and technology to ensure its economically efficient recovery. The characterization of this resource as "oil from fractured shale" is done with some stretching of geological terminology. The Bakken shale play of the Williston Basin in North Dakota and Montana is the most well known example of this type of production, although the production in the Bakken play is not from the shale directly but from an adjacent sandstone and siltstone formation.

Successful exploitation of the Bakken has resulted in a doubling of production from 150,000 bbl oil per day (BOPD) in 2005 to almost 300,000 BOPD in 2009.[44] The potential for source rocks other than the Bakken to become oil productive exists, assuming development and application of appropriate technologies.

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[40] Werner, M.R., 1987, *Tertiary and Upper Cretaceous Heavy-Oil Sands, Kuparuk River Unit Area, Alaskan North Slope,* in Exploration for Heavy Crude Oil and Natural Bitumen, Studies in Geology, Vol. 25; AAPG.
[41] State of Alaska DOR, 2006 Fall Revenue Resources Book (http://www.revenue.state.ak.us/ACESDocuments/Bulletins/11-1-07%20Heavey%20Oil%20Bulletin.pdf)
[42] UHOP, op cit.
[43] BP Alaska (http://www.heavyoilinfo.com/feature_items/bp-pilot-tests-chops-in-alaska)
[44] EIA, 2009.

OFS is recovered from self-sourced, rich, mature source rocks that are oil-wet. A critical technical problem for commercial success with OFS plays is that of obtaining sufficient permeability to obtain flow at economic rates for what is essentially immobile oil. This must be achieved through one or a number of geologic mechanisms—faulting, tectonic fracturing, micro-fracturing from fluid expansion, or the employment of interbeds or immediately adjacent reservoir quality rocks to sustain flow. Advanced technology, principally horizontal wells, and advanced fracture stimulation, are also required.

3.2.4.1 Bakken Shale Example

The Bakken Shale has technically recoverable resources (TRR) estimated at 3,645 million bbl of oil.[45] In-place estimates are on the order of 300 billion bbl of oil.[46] Upper Devonian-Lower Mississippian in age, the Bakken Fm. has upper and lower marine shale containing organic matter, sandwiching a middle member composed mainly of sandstone and siltstone. The middle member, maximum thickness of 85 ft, contains the oil from the shale and is currently the drilled objective.[47] At the depocenter the upper shale has a maximum thickness of 25 ft and the lower shale 45 ft.[48] The system has 7 to 12 percent porosity, low permeabilities of 0.01 to 0.02 mD, and 70 to 80 percent oil saturation.

The combination of the shallow depth, high average total organic carbon (TOC) of about 12 percent for the play, and significant paleo-heat flow makes the Bakken Shale ideal for exploitation as a productive oil reservoir.[49] A high geothermal gradient transforms the Type II kerogen in the source rocks into oil at depths starting at 8,500 ft.[50] The process of oil generation causes an increase in volume, and the surrounding lithofacies trap the oil, which constrains the pressure generated in the source rock and results in horizontal microfractures. This pressure also creates natural fracturing of the brittle middle member.

The Bakken Shale is productive at depths of 8,600 to 10,800 feet, and the degree API oil gravity from production averages 41.[51] While its presence has been known for decades, Bakken oil has been technically unrecoverable until relatively recently. Capability of vertical drilling to depths of 10,000 ft was the first technical difficulty that was overcome. The implementation of directional drilling, which now reaches horizontal distances of up to 10,000 feet, has significantly increased the amount of resource one well can access.[52] A second difficulty was

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[45] Anna, L.O., Pollastro, K., Gaswirth, B., et. al. 2008. *Assessment of Undiscovered Oil and Gas Resources of the Williston Basin Province of North Dakota, Montana, and South Dakota*. National Assessment of Oil and Gas Fact Sheet. USGS.
[46] Eppink, J., Kuuskraa, V., Ferguson, R., & Moodhe, K. 2005. *Nonconventional Oil from Shale – Potential Recovery Methods and Economics of Recovery of Oil from Rich, Mature Sources Rocks*. Advanced Resources International.
[47] EIA, Office of Oil and Gas, Reserves and Production Division, 2006, "Technology-Based Oil and Natural Gas Plays: Shale Shock! Could There be Billions in the Bakken?"
[48] Peterson, J. A., 1995, *Williston Basin Province (031): 1995 National Oil and Gas Assessment*, USGS.
[49] Ibid.
[50] EIA, op cit.
[51] EIA, op cit.

the limited capacity for natural fractures to deliver oil to the wellbore. This has been solved by the use of hydraulic fracturing to complement horizontal drilling. The combination of horizontal drilling and fracturing increases the oil production from the Bakken Shale significantly.[53]

Per well reserves of 850,000 bbl, with initial production rates of 770 to 1,150 BOPD have been reported.[54] Development costs of $4.4 million for about 300,000 bbl of reserves (slightly less than $15 per barrel), using 5000 foot horizontal laterals with 15 stages of fracturing have also been reported.[55] Data show that the costs for development in the Bakken Shale have dropped dramatically, from about $34.45 per Bbl in 2006 to $11.16 in mid-2009.[56] Interestingly, due to the success of the Bakken play, the Williston Basin is pipeline-constrained, and oil will be tanked out of the basin via rail, starting in 2010.[57] NETL is currently undertaking a North Dakota Refining Capacity study to assess the feasibility of increasing oil refinery capacity in North Dakota and the slate of refined products that would produce the most economic benefit.

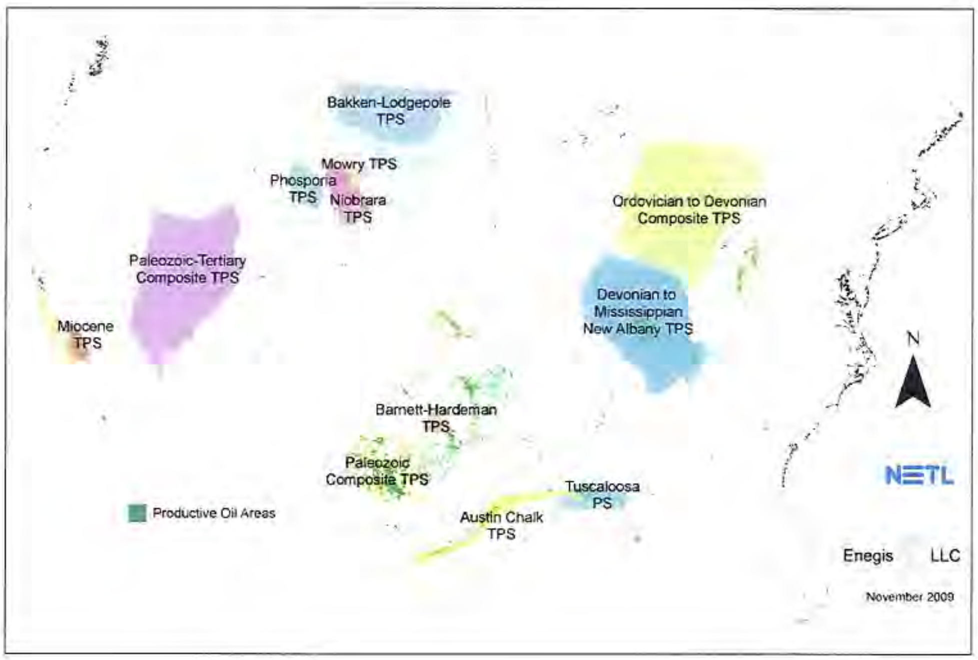
3.2.4.2 Resource Estimate

In the case of conventional oil deposits, generated oil migrates from source beds into reservoir beds with traps where it can be exploited. However, this process of secondary migration and entrapment is not efficient. In its study of the Mowry Shale of Wyoming, the USGS determined that related conventional oil deposits represent only 6 to 8 percent of the generated oil.[58] The calculated amounts of petroleum generated from the drainage areas are invariably several orders of magnitude higher than what has already been found or can be reasonably expected in associated traps, indicating that the resource potential for OFS is very large. On the other hand, conventional oil developments have a recovery efficiency of about one-third of the oil-in-place. The recovery efficiency for OFS plays would be expected to be much smaller, on the order of 3 to 5 percent, at least with current technology.

[52] Murphey, E., 2008, *The Department of Mineral Resources Assessment of the Bakken Formation*. Department of Mineral Resources Newsletter, Vol. 6, No. 1., pp. 19-20.
[53] Wiley, C., Eberhard, M., Barree, B., & Lantz, T. 2004. *Improved horizontal well stimulations in the Bakken Formation, Williston Basin Montana*. Society of Petroleum Engineers.
[54] Leiker, L. 2009. *EOG Senior Executive Vice President, Exploration, Investor Presentation, Bank of America Merrill Lynch Energy Conference,* November 18, 2009, Retrieved November 25, 2009 from http://www.eogresources.com/investors/investor_pres.html
[55] Bakken Shale (Blog), 2009. *EOG Resources Bakken Shale Update*, Retrieved November 25, 2009 from http://shale.typepad.com/bakkenshale/2009/11/eog-resources-bakken-shale-update.html
[56] Brigham Exploration Company. 2009. *Third Quarter 2009 Conference Call presentation,* Retrieved November 26, 2009 from http://www.bexp3d.com/IR_pres.pdf
[57] Leiker, op cit.
[58] Anna, et al., op cit.

To illustrate the potential for OFS, Figure 3-3 depicts oil producing areas and petroleum systems based on USGS data.[59] An examination of petroleum assessments of undiscovered TRRs can provide a starting point for assessing potential OFS resources. The USGS in its National Oil and Gas Assessment (USGS 1995, 2001 and later) has examined both conventional and unconventional (*continuous* in USGS terminology) plays.[60, 61] Table 3-5 shows a listing of the largest petroleum systems (also depicted on Figure 3-3). The TRRs in the column marked "conventional" are estimated to have migrated to reservoir rocks within the systems. The volumes in the column marked "continuous" are estimated to be located in the source rock. It is important to note that the TRR volumes shown in Table 3-5 are an under-representation of source rock potential for conventionally sourced total petroleum systems (TPSs) due to migration inefficiencies. The total amount of oil generated in these systems may be much larger. In addition, shale source rocks may be sealed and thus not manifested in conventional production. Further, few of these systems have been studied as closely as the Bakken Shale has been in recent years. Significant work needs to be done to better understand the full potential of the OFS resource. A rough estimate of the volume of technically recoverable OFS resource would be between 5 and 10 billion bbl, perhaps much more.

Figure 3-3: Map Depicting Productive Areas in the Lower-48 States, Oil Provinces (lighter hues) and Petroleum Systems with Significant Undiscovered Technically Recoverable Resources



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[59] Biewick, L. R. H. 2008. *Areas of historical oil and gas exploration and production in the United States: U.S. Geological Survey Digital Data Series DDS-69-Q.* USGS.

[60] USGS Central Energy Team. 1995. *National Oil and Gas Assessment.* USGS. Retrieved November 15, 2009 from http://energy.cr.usgs.gov/oilgas/noga/1995.html

[61] USGS Central Energy Team. 2001 and later years. *National Oil and Gas Assessment.* USGS. Retrieved November, 15 2009 from http://energy.cr.usgs.gov/oilgas/noga/index.html

Table 3-5: Technically Recoverable Oil from Fractured Shale Source Rocks, Volumes > 100 Million Bbl of Oil (USGS, 1995, 2001 and later years)

Geologic Province or State	Total Petroleum System	Conventional (million barrels oil)	Continuous (million barrels oil)	Total (million barrels oil)
Williston	Bakken-Lodgepole	12	3645	3657
Eastern Great Basin	Paleozoic-Tertiary Composite	1598		1598
Permian Basin	Paleozoic-Composite	747	510	1257
Michigan Basin	Ordovician to Devonian Composite	779		779
Powder River, Denver, SW WY, Hanna	Niobrara	25	368	393
Wyoming	Mowry	157	198	354
San Joaquin Basin, Offshore CA	Miocene	328		328
Illinois Basin	Devonian to Mississippi New Albany	142		142
Big Horn Basin, UT, ND	Phosphoria	119		119
Total		**3907**	**4721**	**8627**

Production of OFS outside of the Bakken Fm. is nascent, although historic and increasing development has occurred in the Barnett Shale (Texas), Tuscaloosa Shale (Louisiana) and the Miocene Monterey Fm. (California), Denver Basin (Colorado), and Anadarko Basin (Oklahoma and Texas).[62] Selected source rocks that are considered as likely targets for development, in addition to the Bakken, are listed in the following subsections.

Permian Basin (after Ball, 1995)[63]

The Permian Basin petroleum system has multiple source rocks, the major ones being the Simpson Group, Woodford Shale, Spraberry-Dean, and organic-rich Pennsylvanian and Permian basinal shale facies.

[62] Oil and Gas Investor, 2007. *Stealth Shale*.

[63] Ball, M. M. 1995. "Permian Basin Province (044): 1995 National Oil and Gas Assessment." USGS.

Michigan Basin (after Dolton, 1995)[64]

While the Michigan Basin is known for gas production from the Antrim Shale of Late Devonian age, it also produces oil. The "black facies" of the organic-rich Antrim Shale has an organic content ranging from less than 1 percent to 25 percent, averaging about 8 percent. The shale are well within the oil generative window at depths greater than about 2,500 feet. Oil in the play is sweet, and its API gravity ranges from 44 to 46 degrees API.

An additional source rock in the basin is the Utica Shale, which is organic rich and is of good source-rock quality to the south in Ohio, although geochemical analyses in Michigan suggest that quality diminishes rapidly to the north and, in central and northern parts of the basin, may not be sufficient for generation.

Powder River, Denver, Southwestern Wyoming and Hanna basins - Niobrara TPS, (after Anna 2009)

The Niobrara TPS is present in a number of basins ranging from northwestern Colorado across eastern Wyoming to Montana. The Niobrara Fm., part of an extensive and thick upper Cretaceous marine system, consists of shale and carbonate with thin, low-permeability, shallow marine sandstones. Fractures appear localized or enhanced in association with structural flexures and faults.

The Niobrara Fm. averages more than 3 percent TOC. It contains Type II kerogen and produces high gravity oil. Niobrara oil production has also taken place in the Denver Basin. EOG Resources drilled a horizontal well in the basin in 2008 to produce oil from the Niobrara Shale. The well was completed with multi-stage fracture stimulation and averaged 320 BOPD in its first month.

Wyoming - Mowry TPS, (Anna, 2008)[65]

The source rock for the Mowry TPS is the Mowry Fm., extensive marine shale deposited during the early Cretaceous period in the Western Interior seaway. The Mowry shale can be found in a number of basins including the Big Horn Basin, Central Montana Uplift, Denver Basin, Green River Basin, Powder River Basin (PRB), Sweetgrass Arch, Uinta Uplift, Williston Basin, Wind River Basin and others. Exploration activity is advancing for the Mowry Shale.
The Oil & Gas Journal reports that Brigham Exploration Company has been accumulating significant acreage that includes the Cretaceous Mowry shale in the southeastern PRB.[66]

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[64] Dolton, G. 1995. *Michigan Basin Province (063): 1995 National Oil and Gas Assessment*, USGS.
[65] Anna, L.O., & Cook, T.A. 2008. *Assessment of the Mowry Shale and Niobrara Formation as continuous hydrocarbon systems, Powder River Basin, Montana and Wyoming, American Association of Petroleum Geologists Section Conference, July 9, 2008, Denver, Colo.: U.S. Geological Survey Open-File Report 2008-1367.*
[66] OGJ. 2007. *Powder River wells to target oil in Mowry shale*

Miocene TPS, San Joaquin Basin, offshore California (after Hosford Scheirer, S., Ed., 2007)

The Monterey Fm. is the source rock of interest in the Miocene TPS of California and is found in the San Joaquin Basin (SJB) and offshore California. The Monterey is thick, rich in organic material, and is oil-prone. Its principal source rock for petroleum is the Antelope Shale member, which generally ranges between 500 and 4000 feet thick. Burial depths of 13,000 to 15,000 feet are required for oil generation from the Antelope Shale source rock. The shale is naturally fractured.

The Monterey source rock contains lighter oil than is typically found elsewhere in California.[67] Royale Energy has drilled horizontally into the Monterey, and Venoco has drilled both onshore and offshore. Venoco is hoping to fracture the Monterey offshore at its Sockeye Field with purpose-built fracturing equipment in 2010. Other players such as EOG Resources and Chevron have produced over 7 million bbl of light, sweet oil from the Monterey Shale in the North Shafter field.

Other Examples of OFS

Although known as the pioneer gas shale play, the Barnett Shale produces light oils in its northwestern extents. The oil has low sulfur content (less than 0.10 to 0.40 percent) and API gravities range from 34° to 62°. In 2008, EOG Resources, Inc., announced an oil discovery in the Barnett Shale where EOG has drilled for natural gas since 2004.[68] EOG is delineating its oil discovery, and estimates possible crude oil reserve potential at 225 to 460 million Bbls on its 250,000 net acres in Montague, Clay, and Archer counties (900 to 1600 Bbls per acre). EOG reports that its northwestern Barnett acreage wells average IP is 300 to 1000 BOPD plus 130 Bbls of natural gas liquids (NGLs). Their acreage will be developed using horizontal and vertical wells, dependent upon the shale thickness. Recoverable reserves are estimated to be 70 MMBO plus 175 Bcf per section.

The Tuscaloosa marine shale (TMS), a naturally fractured, Cretaceous-aged shale found in southwestern Mississippi and southern Louisiana, ranges in thickness from 500 to 800 feet. Part of the Tuscaloosa Group, it is situated between the upper and lower Tuscaloosa sands. Production of oil from the TMS is in a nascent stage. Two wells are known to have produced from the marine shale in southeastern Louisiana, the shallowest depth of approximately 10,000 feet, with one having produced over 20,000 Bbls of oil in the last 20 years.

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[67] OGJ. 2009. *Venoco to press Monterey shale work in 2010.* Sept. 1, 2009 Infinity, Inc., 2005, Investor presentation, Retrieved November 25, 2009 from http://www.infinityres.com/presentations/June%202005%20Corporate%20Presentation.pdf

[68] OGJ. 2008, *EOG makes Barnett shale oil discovery*, OGJ Newsletter.

The Eagle Ford Shale, currently a target for development in southern Texas, is Cretaceous calcareous over-pressured organic shale at 10,000 to 14,000 feet with 120 to 350 feet of thickness. The productive acreage includes dry gas, lean condensate, and rich condensate areas. A typical well producing 7 millions of cubic feet per day (MMcfd) of gas, 790 barrels per day (BPD) of NGLs and 500 BPD of condensate, yields nearly twice the revenue as a well in the dry gas area producing twice as much gas and no liquids.[69]

3.2.5 Residual Oil (Post-Water flood and Transition Zone)

Primary and secondary (water flood) production of conventional light crude oil will recover only about one third of the oil in place, or roughly 200 billion bbl of the roughly 600 billion bbl of conventional oil originally in place in discovered U.S. reservoirs. Roughly seven eighths of that oil, or about 175 billion barrels, has been produced while roughly 19 billion barrels of reserves remain. The 400 billion barrel volume of residual oil left in the ground is a target for EOR. In the case of conventional light oil, the EOR options are chemical flooding (surfactants) and miscible flooding. The most commonly used miscible flooding agent is CO2. In fact, CO2 flooding is the most common EOR technique for light oil. Incremental production from all United States CO2 EOR projects totaled 281,000 bbl per day in 2010, according to the Oil & Gas Journal's biennial survey.[70] There are 114 CO2 EOR projects operated by more than 20 companies. The large majority of these are in the Permian Basin of western Texas and eastern New Mexico, but additional projects have been started in WY, CO, MS, and other states.

CO2 EOR has been successful because the cost of the miscible agent is relatively low. In the case of surfactants and solvents, many of which are refined or produced from petrochemicals, the injectant cost is high and rises with the price of crude oil. If large, reliable volumes of readily available CO2 result from carbon capture and sequestration efforts, CO2 EOR could be applied much more widely in areas of the country where it currently is not being employed. For this reason, CO2 EOR is seen as the most likely mechanism for turning the residual oil resource into reserves.

[69] Sheffield, T., 2010, presentation on Pioneer Natural Resources presented at RPSEA Unconventional Gas Conference, April 6th, Denver, CO.
[70] OGJ, 2010, EOR Survey, April 19.

A reservoir-by-reservoir assessment of 1,655 large oil reservoirs amenable to CO2-EOR (extrapolated to national totals) shows that 83 billion bbl of domestic additional oil may be recoverable with the application of current "best practices" CO2-EOR technologies.[71] An additional 38 billion bbl (in addition to the 83 billion bbl for a total of 121 billion bbl) is potentially recoverable with widespread application of "next generation" CO2-EOR technology (Table 3-6, Figure 3-4). For perspective, the total volume of current domestic proved crude oil reserves is 19 billion bbl, as of the end of 2008.[72]

Geologically complex oil reservoirs with large volumes of residual oil (due to low primary and secondary recovery sweep efficiencies) will benefit the most from next generation technology. The Permian Basin of West Texas and New Mexico, with its world class size carbonate reservoirs, offers the largest volume of technically recoverable oil resource from application of next generation CO2-EOR technology. In addition, significant potential exists in East and Central Texas, the Mid-Continent, the Gulf Coast and California. The more homogeneous sandstone reservoirs, such as those in the offshore GOM, which achieve high oil recovery efficiencies using current best practices CO2-EOR technologies, may be less favorable settings for next generation technology.

Because best practices CO2-EOR technology is in use by only a handful of operators in a few recently started CO2-EOR floods, earlier availability and aggressive implementation of next generation CO2-EOR technologies could enable other operators to select these higher efficiency technologies, thus increasing oil recovery.

Table 3-6: Technically Recoverable Resources from Applying "Next Generation" CO2-EOR: Totals from Extrapolating Advanced Resources' Database to National Level

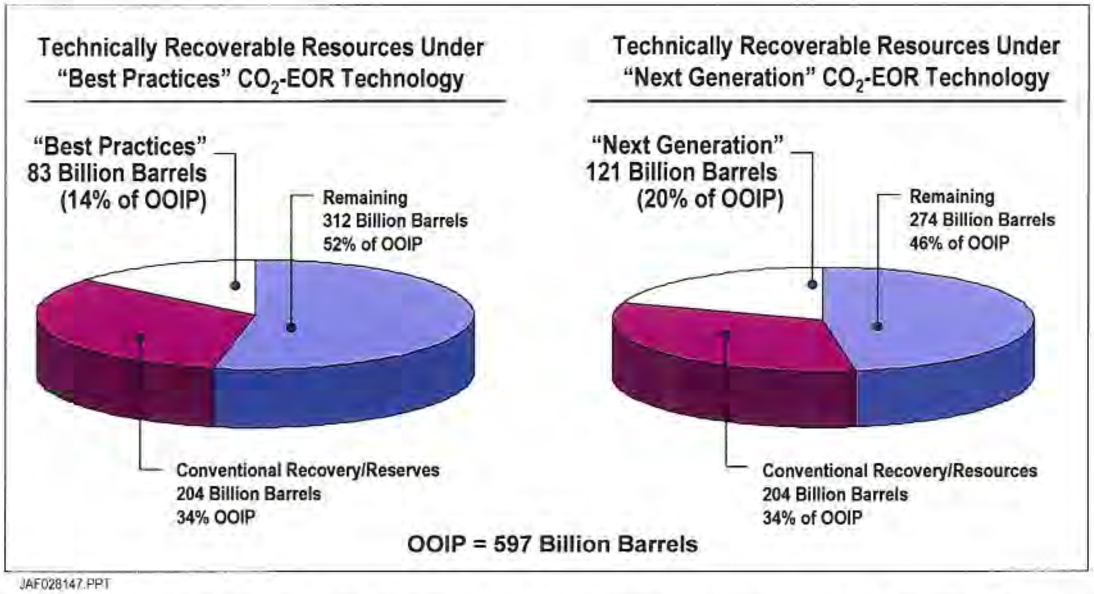
Basin/Area	OOIP (Billion Bbl)	OOIP Favorable for CO2-EOR (Billion Bbl)	Technically Recoverable (Billion Bbl)	
			"Best Practices" Technology	"Next Generation" Technology*
Lower-48 Onshore	500.3	232.5	68.9	102.8
Offshore GOM	46.1	29.6	5.8	5.8
Alaska	50.7	42.5	8.6	12.7
Total	**597.1**	**304.6**	**83.3**	**121.3**

** "Next Generation" technically recoverable total includes increment from "Best Practices"*

[71] *Storing More CO_2 and Producing More Domestic Crude Oil with Next Generation CO_2-EOR Technology*, report by Advanced Resources International for U.S. Department of Energy, National Energy Technology Laboratory, October 30, 2009.

[72] EIA web site, (http://tonto.eia.doe.gov/dnav/pet/pet_crd_pres_dcu_NUS_a.htm)

Figure 3-4: Recoverable Domestic Oil from "Best Practices" and "Next Generation" CO2-EOR Technologies



In addition to the post-water flood residual oil left behind in producing oil reservoirs, there are significant amounts of residual oil in "residual oil zones" (ROZ), the portion of an oil reservoir *below* its estimated original oil-water contact. This zone, also called the transition zone, can extend for hundreds of feet and could hold large volumes of previously undocumented and undeveloped oil. Because of the low to moderate oil saturation, ROZ oil is not considered economic for primary or secondary oil recovery, and wells are completed above the oil-water contact (the first observance of water), even though oil saturations exist lower in the reservoir.

A small number of ROZ pilots using CO2 injection are underway in West Texas, in oil fields such as Seminole, Wasson and East Vacuum, looking to establish the viability of recovering oil from the ROZ. One of these pilot projects, the Phase 2 ROZ CO2 Flood at Seminole, was selected for further evaluation as part of a model calibration effort by NETL.[73] History matching established that significant volumes of oil are recoverable from the ROZ of the Seminole field.

Based on the initial pilots only, NETL initially estimated that in the Permian Basin the Deep Saline/ROZ oil could total 12 billion bbl of recoverable oil.[74] However, this initial estimate of the size of the ROZ oil volume was established for areas beneath only the discrete boundaries of a handful of the very large oil fields in this basin.

[73] Melzer, L.S., Koperna, G.J., and Kuuskraa, V.A., *The Origin and Resource Potential of Residual Oil Zones* SPE 102964-PP, presented at the 2006 SPE Annual Technical Conference and Exhibition, San Antonio, TX, 24-27 September 2006.

[74] *Technical Oil Recovery Potential from Residual Oil Zones: Permian Basin*, prepared by Advanced Resources International, Inc. for the U.S. Department of Energy, Office of Fossil Energy, Office of Oil and Natural Gas, October 2005.

Current evidence indicates that this oil saturation extends laterally beyond the boundaries of existing oil fields and, most likely, consists of a series of "fairways." Applying the "fairway" concept, the incremental oil recovery potential from using CO2-EOR is now estimated at 54 billion bbl of recoverable domestic oil in three key basins (Table 3-7).

Further, the Deep Saline/ROZ oil is estimated to be able to provide on the order of 100 billion bbl of additional technically recoverable domestic oil, including the 54 billion bbl in the basins studied and an additional 56 billion bbl from extrapolation of the "fairways" concept to all domestic oil basins with ROZs.[75,76] This incremental oil is in addition to the 121 billion barrels of technically recoverable oil from application of next generation CO2 EOR, for a total of 230 billion barrels.

Table 3-7: Estimates of ROZ Technical Recovery from Three Basins Under "Fairways" Concept

Basins	Estimated ROZ OOIP (billion bbl)	Calculated ROZ OIP* (billion bbl)	Technically Recoverable w/CO2-EOR (billion bbl)
Permian	300	100	40
Williston	70	23	10
Big Horn	50	15	4
TOTAL	**420**	**138**	**54**

*After hydrodynamic flushing of the OOIP in the ROZ interval.

3.3 Natural Gas Resources

The United States has an enormous complement of natural gas within its borders, by virtue of the many deep sedimentary basins that are found there. During the last three decades (primarily during the last one) as conventional gas reservoirs discovered during the early and middle periods of the 1900s have been depleting, unconventional (i.e. less easily produced) reservoirs have been tapped. This resource is typically categorized by the three most common and currently most productive reservoir rock types: tight gas sands, gas from coal seams (CBM), and shale gas. Methane hydrate is another enormous resource that may be developed in the future.

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[75] *Validation of ARI's Stream Tube CO_2-EOR Model (PROPHET2),* Unpublished draft prepared and presented by Advanced Resources International, Inc., for the U.S. Department of Energy, National Energy Technology Laboratory, October 19, 2009, Morgantown, WV.

[76] *White Paper: Establishing the Viability of Storing CO2 in Deep Saline Formations Containing Residual Oil,* prepared by Advanced Resources International, Inc. and Melzer Consulting for the U.S. Department of Energy, National Energy Technology Laboratory, September 8, 2009.

In 2009 the Potential Gas Committee (PGC) released the results of its latest biennial assessment of the nation's natural gas resources, which indicated that the United States possesses a total resource base of 1,836 Tcf.[77] The significant increase from the previous assessment arose from a reevaluation of shale-gas plays in the Appalachian basin and in the Mid-Continent, Gulf Coast and Rocky Mountain areas. The PGC estimates are "base-line estimates" that provide a reasonable appraisal of what is considered to be the "technically recoverable" gas resource potential of the United States. The break out of this number by resource type is shown in Table 3-8.

The total future supply of natural gas can be estimated by adding this total to the current proved reserves, which according to EIA was 238 Tcf at the end of 2008, to obtain a total supply of 2,074 Tcf. If cumulative production to date (1,132 Tcf) is added, we can obtain a current estimate of the ultimately recoverable natural gas resource in the United States, 3,206 Tcf. Only a little more than one third of the nation's natural gas recoverable resource have been produced over the past 190 years.

Table 3-8: PGC Gas Resource Estimates (Tcf) as of December 31, 2008

Resource	**Probable**	**Possible**	**Speculative**	**Total**
Traditional Resources (includes conventional gas plus tight gas and gas shale)	441	737	501	1,673
Coalbed Methane				163
TOTAL	**441**	**737**	**501**	**1,836**

Current proved reserves estimates for unconventional gas are included in the EIA reserve value and the potential volumes of tight gas and gas shale are included in the 1,673 Tcf figure. Based on independent resource assessments by Advanced Resources International (ARI), the undeveloped unconventional gas resource base is 917 Tcf (~50 percent of the total), and proved unconventional gas reserves are 140 Tcf (59 percent of the total).[78]

[77] PGC, 2009, *Advance Summary of Potential Supply of Natural Gas in the United States*, June 2009, available at http://geology.mines.edu/pgc/index.html

[78] Kuuskraa, V., 2009, "Paradigm Shift in the Natural Gas Resource Base," ARI presentation May 5, 2009 at Clean Technology Conference, Houston, TX.

3.3.1 Tight Gas

ARI estimates the total volume of undeveloped tight gas sand resource is 357 Tcf, of which half (179 Tcf) is to be found in the "Big Five" plays [Pinedale/Jonah Fields (Lance Fm., Green River Basin), Mesaverde/Williams Fork formations (Piceance and Uinta Basins), and Bossier/Cotton Valley (East Texas Basin]. ARI also estimates that roughly half of the undeveloped resource (184 Tcf) is of lower quality and will require advances in geological knowledge and extraction technologies beyond that already in use to be economically produced. For the purposes of this report, we are assuming ARI's estimate of the tight gas resource requiring additional technology development to be reflective of the truly "unconventional" gas target of R&D. Based on an assumed 5800 cubic feet of natural gas per barrel of oil equivalent, <u>184 Tcf is equivalent to ~30 billion barrels.</u>

3.3.2 Gas from Coal Seams

ARI estimates the total volume of undeveloped CBM resource is 90 Tcf, of which half (54 Tcf) is to be found in the "Big Two" plays (PRB and San Juan Basin). This estimate is more conservative than the PGC estimate of 163 Tcf, which includes speculative resources. ARI estimates that roughly half of this undeveloped resource (41 Tcf) is of lower quality and will require advances in geological knowledge and extraction technologies beyond that already in use to be economically produced. For the purposes of this report, we are assuming ARI's estimate of the CBM resource requiring additional technology development to be reflective of the truly "unconventional" gas target of R&D. Based on an assumed 5800 cubic feet of natural gas per barrel of oil equivalent, <u>41 Tcf is equivalent to 7 billion barrels.</u>

3.3.3 Shale Gas

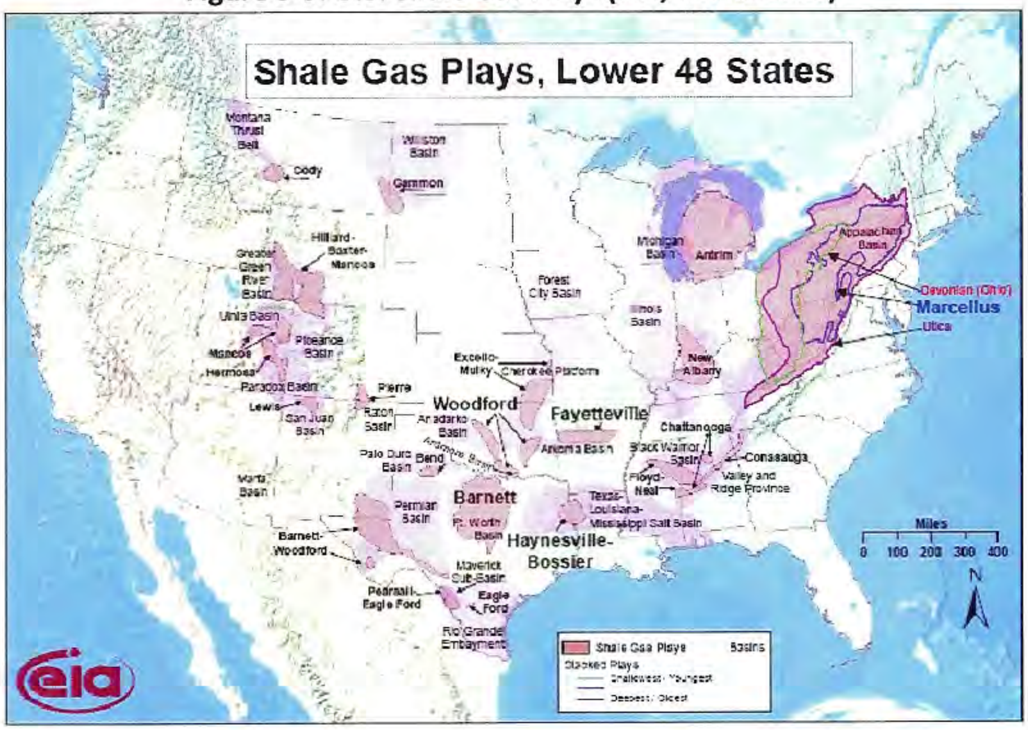
There are dozens of gas bearing shale formations in multiple sedimentary basins across the U.S. The EIA has created a map (Figure 3-5) that identifies the location of the shale plays that are currently being explored or developed. Some of these, like the Ohio (Devonian) Shale of the Appalachian Basin, the Antrim Shale of the Michigan Basin, and the New Albany Shale of the Illinois Basin have a long history of gas production. Plays like the Barnett, Marcellus, Haynesville, Woodford and Fayetteville are the scene of very active development operations using horizontal laterals completed with multiple, high volume fracture stimulation stages. Yet other plays (Eagle Ford, Pearsall) are a bit further back along the development path. A large number of plays, including some not shown on the EIA map, have yet to be fully evaluated for their potential.

Estimates of recoverable shale gas resource have been increasing, based on surveys of operators or selected opinions of experts. In general, the increase has followed an increase in available information as multiple shale gas plays are developed, in particular, the Barnett, Haynesville, Fayetteville, Woodford, and Marcellus plays (the "Big Five").

Table 3-9 outlines the most recent public estimates of recoverable shale gas. The estimates are from Navigant Consulting,[79] the EIA,[80] ICF (for INGAA[81] and MIT[82]), ARI,[83] PGC[84] and others.

The most recent estimate, an interim report by ICF International for Massachusetts Institute of Technology, projects shale gas resources at 631 Tcf, all of which would be recoverable at prices below $18 per Mcf, and ~500 Tcf of which would be recoverable at prices below $8 per Mcf. Dr. Terry Engelder's latest published estimate, based on an analysis of well performance data, for the technically recoverable gas in the Marcellus shale, falls within a range of 168 Tcf (90 percent probability) to 516 Tcf (10 percent probability) with a 50 percent probability of 489 Tcf.[85]

Figure 3-5: U.S. Shale Gas Plays (EIA, March2010)



[79] Navigant Consulting Inc., *North American Natural Gas Supply Assessment,* prepared for American Clean Skies Foundation, July
http://www.navigantconsulting.com/downloads/knowledge_center/North_American_Natural_Gas_Supply_Assessment.pdf

[80] Annual Energy Outlook 2010. EIA, http://www.eia.doe.gov/oiaf/aeo/index.html

[81] *Availability, Economics, and Production Potential of North American Unconventional Natural Gas Supplies*, INGAA Foundation, November 2008. http://www.ingaa.org/cms/31/7306/7628/7833.aspx

[82] *The Future of Natural Gas*, Interdisciplinary MIT Study, interim report, June 2010.
http://web.mit.edu/mitei/research/studies/naturalgas.html

[83] Kuuskraa, V., 2009, *Paradigm Shift in the Natural Gas Resource Base,* ARI presentation May 5, 2009 at Clean Technology Conference, Houston, TX.

[84] PGC, 2009, *Advance Summary of Potential Supply of Natural Gas in the United States,* June 2009, available at http://geology.mines.edu/pgc/index.html

[85] Terry Engelder, 2009, *Marcellus 2008, Fort Worth Basin Oil and Gas Magazine*, August
http://www.geosc.psu.edu/~engelder/references/link155.pdf/

ARI estimates the total volume of undeveloped gas shale resource is 470 Tcf, of which 439 Tcf is to be found in the "Big Five" plays. ARI estimates that a little more than half of this undeveloped resource (261 Tcf) is of lower quality and will require advances in geological knowledge and extraction technologies beyond that already in use to be economically produced.

These two estimates give some indication of the wide range of opinions on exactly how much gas will be recoverable from shale over the next decades. An accurate understanding of how much gas will be recoverable from the nation's gas shale will require the collection and analysis of additional production performance data. For the purposes of this report, we are assuming ARI's estimate of the shale gas resource requiring additional technology development to be reflective of the truly "unconventional" gas target of R&D. Based on an assumed 5800 cubic feet of natural gas per barrel of oil equivalent, 261 Tcf is equivalent to 45 billion barrels.

Table 3-9: Shale Gas Recoverable Resource Estimates (Tcf)

Source	Play	Gas-in-Place	Technically Recoverable
NCI Survey (July 2008)	All shale	3,765	274 mean
	Marcellus only	1,500*	34.2 mean
	Barnett only	168*	26.2 mean
EIA (Jan. 2008)	All shale	na	347
ICF for INGAA (Nov. 2008)	All shale	na	385
ARI (Jan. 2009)	Five main plays	3,760	475
	Marcellus	2,100*	200
Engelder (Aug. 2009)	Marcellus	na	489 mean
PGC (Jan. 2009)	All shale	na	616 mean
ICF for MIT (2009)	All shale	na	631
EIA AEO 2001 (2011)	All shale	na	827

** included in "all shale" total*

3.3.4 Methane Hydrate

The worldwide volume of methane held as methane hydrate is immense; a frequently quoted "consensus" estimate for the global methane gas hydrate resource is 20,000 trillion cubic meters (about 700 thousand Tcf).[86] Studies of the methane hydrate resource in the United States are being conducted for the GOM, the Alaskan North Slope, and an area off the Atlantic coast.

In 2008, the U.S. Minerals Management Service (MMS) released a preliminary assessment of the in-place gas hydrate resource in the GOM.[87] The MMS assessment, which does not consider whether the resource is technically or economically recoverable, concluded that there is a 95 percent probability of 314 trillion cubic meters and a 5 percent probability of 974 trillion cubic meters of methane held within methane hydrate in the sediments of the GOM. The mean value is 607 trillion cubic meters (about 21,400 Tcf) of methane in-place in hydrate form. The assessment also determined that about 190 trillion cubic meters (about 6,700 Tcf) of this resource occurs in relatively high-concentration accumulations within sandy sediments, the sort of reservoir that would be more likely to permit the gas flow.

Also in 2008, the USGS estimated that there is approximately 85 Tcf of undiscovered, technically recoverable natural gas resource within gas hydrates on the North Slope of Alaska. A previous assessment by the USGS in 1995 had estimated that there could be as much as 590 Tcf of natural gas in-place within methane hydrate trapped beneath the permafrost on the North Slope.

As research provides more information about the location and concentration of methane hydrates, these in-place resource estimates will be refined, and as data is gathered from testing and modeling, these in-place estimates can be factored to arrive at estimates of the technically and economically recoverable natural gas. At this point, while these estimates cannot be precisely predicted, we can form a general picture of the categories of methane hydrate resources (see Figure 3-6).

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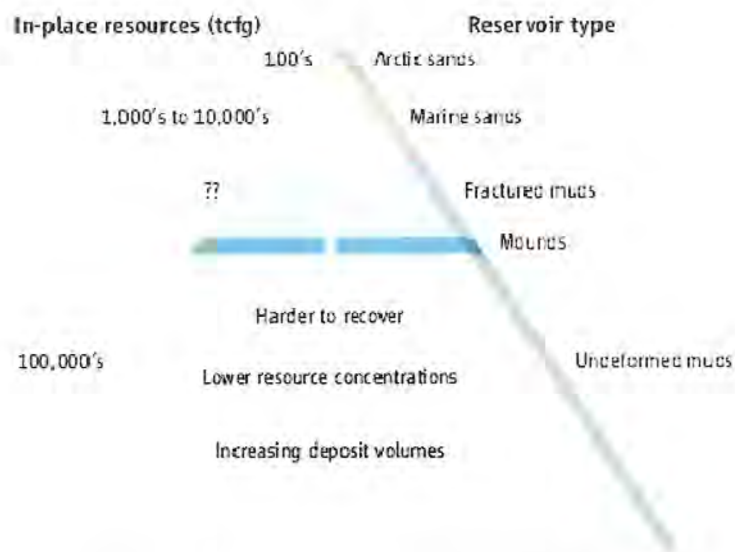
[86] Boswell, R., 2009, *Is Gas Hydrate Energy Within Reach?*, Science, Vol. 325, August 21, downloaded from www.sciencemag.org on August 21, 2009

[87] M. Frye, Minerals Management Service Report 2008-004; www.mms.gov/revaldiv/GasHydrateFiles/MMS2008-004.pdf

Figure 3-6: The gas hydrate resource pyramid (Boswell, 2009)[88]



The gas hydrate resource pyramid[89] depicts resources according to reservoir type; those that are currently considered to be the most easily recoverable are found at the peak, while those that are the most technically challenging to extract lie at the base. The relative amounts of gas held in these categories are also indicated. For example, Arctic sandstone reservoirs hold the most promise for near-term recovery of natural gas from methane hydrate; these sands contain in-place resources estimated to be in the 100's of Tcf. Of this resource, the most likely to be tested and produced is that located within range of existing oil and gas production infrastructure, thought to be in the 10's of Tcf.[90]

Arctic and marine sands have relatively high permeability and porosity; characteristics which make their methane hydrate potentially producible using technologies already in use today.[91] Marine sands, however, are considered less easy to develop than Arctic deposits due to the higher costs and technical challenges associated with deep water exploration and production. Methane hydrate deposits in the marine sands of the GOM are particularly attractive when compared to those in less developed waters as they are near existing platform and pipeline infrastructure. These sands contain in-place resource estimated to be in the 1000's of Tcf.

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[88] From Boswell, R., 2009, *Is Gas Hydrate Energy Within Reach?,* Science, Vol 325, August 21, 2009. This figure is reprinted with permission from AAAS.

[89] Original concept by T. Collett and R. Boswell described in the Fall 2006 issue of Fire in the Ice, the NETL methane hydrate newsletter (available at http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/Newsletter/).

[90] T. S. Collett et al., U. S. Geol. Survey Fact Sheet 2008-3073.

[91] G. J. Moridis et al., www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/reports/G308_SPE114163_Feb08.pdf

Methane hydrate resource categories farther down the pyramid include hydrate filled fractures in marine muds, nodules and lenses dispersed in undeformed, fine-grained marine sediments, and mounds of hydrate located on the seafloor where natural gas has seeped from faults or fractures. Each of these deposits presents very significant technical challenges for anyone seeking to extract the methane resource.

While the volumes of resource increase by orders of magnitude as we head down the pyramid, the concentration decreases, and the difficulty of development increases significantly. Higher concentration methane hydrate deposits found in rock formations that are similar to conventional gas reservoirs and located in areas with existing infrastructure, will most likely be produced first.

<u>For the purposes of this report, if we assume the USGS estimate of 85 Tcf of undiscovered, technically recoverable natural gas resource within gas hydrates on the North Slope of Alaska as a minimum, and a relatively conservative recovery of 30 percent of gas-in-place for methane hydrate deposited in sandstone sediments in either the Arctic or GOM, the estimate of recoverable gas would range from a minimum of 85 Tcf for Arctic sands alone, to roughly 2035 Tcf for GOM and Arctic sands. On a barrel of oil equivalent (BOE) basis, this range would be between 17 and 350 billion barrels.</u>

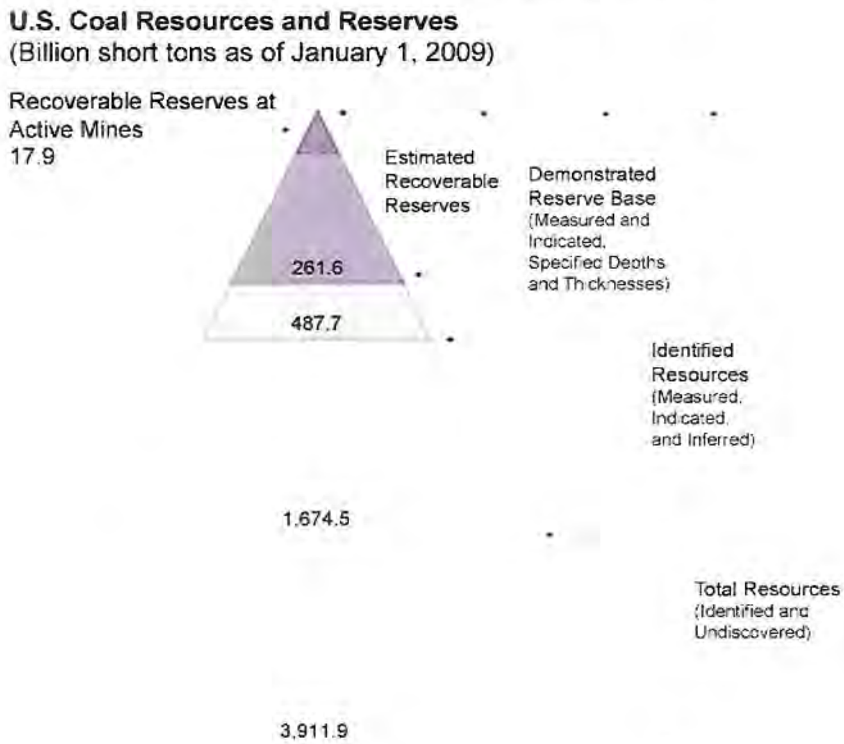
3.4 Coal Resources

The U.S. possesses abundant coal resources. The EIA uses the classification system illustrated in Figure 3.7 as a reserve/resource pyramid.[92] The coal quantities in the pyramid are in billions of short tons (bst) —one short ton is 2,000 pounds—and based on a number of analyses.

For example, the recoverable reserves at producing mines were reported to be 17.9 bst, as of January 1, 2009. The total coal resource in the U.S., including undiscovered, is estimated to be about 3912 bst. This estimate is based on an assessment published by the USGS in 1975. While more recent regional assessments of U.S. coal resources have been conducted, a new national level assessment has not been completed. The difference between the "identified resources" and "total resources," about 2240 bst, is the amount of coal that is estimated to be undiscovered within the U.S. Identified coal resources have been measured or inferred from surface and subsurface data.

[92] EIA, 2009, (http://tonto.eia.doe.gov/energyexplained/index.cfm?page=coal_reserves)

Figure 3-7: U.S. Coal Resources and Reserves



Source: U.S. Energy Information Administration, Form EIA-7A, *Coal Production Report* (February 2009)

However, not all coal is feasible to mine. The Demonstrated Reserve Base is the in-place coal that could be mined commercially. EIA estimates the Demonstrated Reserve Base to measure about 488 bst.

Finally, the "Estimated Recoverable Reserves" include only the coal that can be mined with today's mining technology, after accessibility constraints and recovery factors are considered. EIA estimates that there are 262 bst of U.S. recoverable coal reserves, about 54 percent of the Demonstrated Reserve Base.

Accordingly, the target for Underground Coal Gasification (UCG) – a gasification process carried on in non-mined coal seams using injection and production well drilled from the surface - is at least as large as the difference between the Estimated Recoverable Reserves and the Demonstrated Reserve Base (about 226 bst), and could be as large as the difference between the Estimated Recoverable Reserves and the Total Resources (3640 bst). In fact, the upper limit may be greater, depending on the degree to which more precise regional estimates of the Total Resources figure may cause the total number to increase. To put these numbers into context, the annual amount of coal mined in the U.S. in 2008 was 1.17 bst.[93]

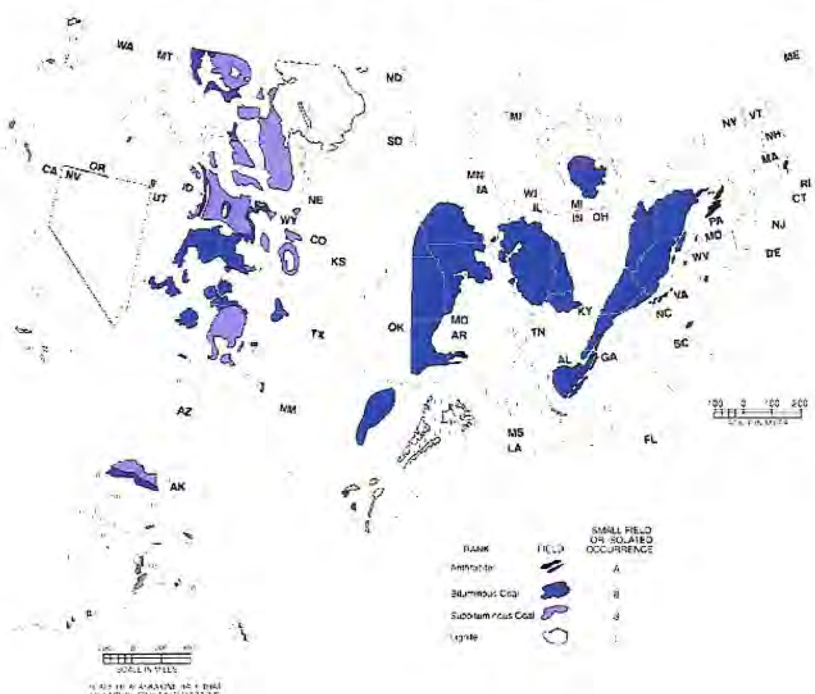
[93] EIA, http://www.eia.doe.gov/cneaf/coal/page/acr/table1.html

Of course, only a portion of the target will be both accessible and suitable for UCG. The suitability depends on coal type, thickness, and depth. Of the major coal deposits in the U.S., the western coal fields of Wyoming, Montana, North Dakota, Colorado, Utah, and New Mexico (Figure 3.8) have large resources suitable for UCG. Lignite coal fields in Texas and Louisiana may also have suitable coal resources for UCG development.

The PRB in northeast Wyoming and southern Montana is the most prolific U.S. coal producing region. In 1999, the USGS estimated a total coal resource of 510 bst for the basin.[94] PRB coal seam thicknesses can exceed 200 feet. The coal is sub bituminous with very low sulfur content.

In 2007, GasTech Inc. conducted an extensive evaluation of the PRB for UCG potential.[95] The assessment considered only coal seams 30 feet or more in thickness at depths of 500 feet or greater, and identified 307 bst of coal that met these criteria, of which 71 bst was in coal seams greater than 100 feet thick.

Figure 3-8: U.S. Coal Resources



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[94] USGS, 1999, *Resource Assessment of Selected Tertiary Coal Beds and Zones in the Northern Rocky Mountains and Great Plains Region*, Professional Paper 1625A (http://pubs.usgs.gov/pp/p1625a/Chapters/ES.pdf).
[95] GasTech, 2007, *Viability of Underground Coal Gasification in the Deep Coals of the Powder River Basin*, Cheyenne, WY, Wyoming Business Council, State Energy Office (http://www.wyomingbusiness.org/pdf/energy/WBC_Report_061507_SPM.pdf).

Two areas of the U.S. have significant amounts of lignite with some potential for UCG development: North Dakota and the Gulf Coast. In 2006, the North Dakota Geological Survey determined the total amount of lignite in North Dakota to be 1270 billion tons.[96] Of this amount, only 2 percent (25 billion tons) was determined to be economically recoverable by surface mining. The Gulf Coast lignite resources include deposits in Louisiana and Texas which are found at relatively shallow depths in thin to moderate thicknesses (10 feet thick or less) that may be too thin for UCG.[97]

Alaska's extensive coal resources are largely unexplored. Estimated at as much as 5,500 bst, of which only a small percentage has been identified (ranging from 129-140 bst), Alaskan coal resources are mostly sub-bituminous and lignite deposits.[98] This estimate is considerably more than the total resources number identified in Figure 3-6, an indication of the uncertainty in U.S. in-place coal resource estimates.

However, the remote location, climate, and environmental sensitivity may limit the potential for both mining and UCG in Alaska. The largest resource is located in the Northern Province near the Brooks Range, where infrastructure (other than oil and gas production facilities) is limited.

Estimating the volume of natural gas equivalent that could result from the conversion of coal through UCG requires that we estimate the volume of the resource that would be accessible for UCG and also the percentage of the energy in the coal that could be converted to synthetic natural gas. Assumed ranges for the first and second factors could be estimated at 50 to 75 percent, and 50 to 70 percent, respectively. Assuming an average energy content range for sub-bituminous/bituminous coal of 20 million British thermal units (BTUs) per ton, and assuming average energy content for natural gas of 1 million BTU per Mcf, the range for conversion of coal to natural gas via UCG could be roughly estimated at between 5 Mcf/ton and 10 Mcf/ton of coal.

Assuming that only the PRB coal resource identified by GasTech in 2007 was to be targeted for UCG, (307 bst) the total volume of natural gas equivalent would be between 1,500 and 3,000 Tcf, roughly the same as the current PGC estimate of recoverable domestic natural gas resource (potential and reserves) in both conventional and "unconventional" reservoirs (2,074 Tcf).[99]

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[96] Murphy, E.C., *et al.*, 2006, *The lignite resources of North Dakota: North Dakota Geological Survey*, Report of Investigation No. 105.

[97] Luppens, J.A., *et al.*, 2009, "Coal Research Availability, Recoverability, and Economic Evaluations in the United States-A Summary, U.S. Geologic Survey, Professional Paper 1625-F.

[98] Flores, R.M., et al., 2003, *Alaska Coal Resources and Coalbed Methane Potential,* U.S. Geological Survey Bulletin 2198 (http://pubs.usgs.gov/bul/b2198/).

[99] Potential Gas Committee, 2009, "Potential Supply of Natural Gas in the United States (December 31, 2008)"

Assuming that the target for UCG is as large as the difference between the Estimated Recoverable Reserves and the Total Resources mentioned above (2750 bst), and applying the same accessibility and recovery factors, yields a total volume of natural gas equivalent of between 18,200 and 36,400 Tcf. These are enormous numbers, 9 to 18 times the current PGC estimate. This range, from 1,500 Tcf to 36,400 Tcf would be equivalent to between 250 billion barrels and 6,275 billion barrels.

In comparison, the World Energy Council's 2007 Survey of energy sources estimates that 152 bst of coal in the U.S. is suitable for UCG and that it could produce 1462 Tcf of gas if gasified.[100] This would be roughly the same as the lower end of the estimated range.

Given the uncertainty of the resource estimates, for the purposes of this report a minimum estimate of 1500 Tcf or 250 billion barrels oil equivalent will be assumed for UCG recoverable resource.

IV. Challenges to Resource Development and R&D Needs

This section outlines the challenges to development of the resources identified in the previous section, and where possible, lists the R&D needs for addressing these challenges. The challenges are categorized as technology related or environmental related. Each of the resource categories is treated separately within these categories, unless indicated otherwise. While this report is prepared by DOE, the scope of the challenges and the R&D needs for addressing them is nationwide.

4.1 Technology

4.1.1 Oil Shale

The more difficult issues related to the commercialization of domestic oil shale via mining and surface retorting appear to be related to high capital costs, uncertainties regarding oil shale development regulations, and environmental considerations, rather than process-related technical challenges. Surface retorting technology has been in development for many years, and commercial operations are active in a few countries. Some companies are working to develop paths for extracting oil from oil shale that avoid or reduce some of the environmental impacts (e.g., *in situ* retorting methods that reduce the surface, air, and water impacts of mining and surface processing of shale). These *in situ* methods are in a substantially less mature state for deployment than the surface retort techniques.

[100] http://www.worldenergy.org/documents/ser2007_final_online_version_1.pdf

4.1.1.1 Surface Retorting Processes

There are three types of surface retorting processes: indirect, direct, and a combination of the two. With indirect retorting, pyrolysis of the shale is carried out using heat supplied by a heat carrier.[101] Heat carriers are heated separately from the oil shale, circulated through the bed of mined oil shale, and then recycled back through the heater. In direct retorting, natural gas is injected into the bottom of the process vessel where it moves upward, countercurrent to the crushed shale. Combustion of the gas heats the shale. When the plant is in normal operation, the process gas generated by pyrolysis may be used for this heating.

A third type of retorting combines both indirect and direct retorting processes. There are a number of patented systems that employ these approaches. The better known include the following:

- The ATP is one example of a combination process. Testing of this process to date has included: small-scale and batch test work on Green River Fm. oil shale samples from the White River area in Utah, similar shale from Colorado from Wyoming. All the test results were positive and indications were that the ATP Technology could work efficiently on even the high-grade mahogany shale.[102]
- The Paraho Process can be either direct or indirect. The Paraho Indirect Process has been selected over ATP for QER's Stuart Oil Shale Project in Queensland, Australia, although this project has seen some delays.[103]
- Petrobras operates a commercial oil shale operation in the Brazilian state of Paraná employing its Petrosix process, an indirect process using hot gas as a heat carrier. This facility, which has been operating since 1991, has two units that produce a total of 4600 bbl of oil per day.[104] [105]
- The Kiviter process used by VKG Oil in Estonia, a subsidiary of Viru Keemia Grupp
- The Galoter process is employed by Eesti Energia at its Narva Oil Plant in Estonia to produce about 2700 bbl per day of oil.[106] In addition, VKG Oil started up a Galoter process plant in December 2009, also in Estonia.[107]

- The Fushun Mining Group of China operates the largest (by capacity) oil shale processing plant in the world, producing about 3600 bbl per day using the Fushun Process. The oil shale ore is a byproduct of coal mining.

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[101] *A Technical Economic and Legal Assessment of North American Heavy Oil, Oil Sands, and Oil Shale Resources*, Utah Heavy Oil Program, Institute for Clean and Secure Energy, The University of Utah, September, 2007.
[102] e-mail from Bill Taciuk, developer of the system, by way of Jeremy Boak, CSM
[103] http://www.qer.com.au/
[104] Epifanio, D., 2009, *Petrosix Technology*, presentation at the International Oil Shale Conference in Amman, Jordan, April.
[105] http://www.oilshaleexplorationcompany.com/news.asp
[106] Qian, J., 2006, *Oil Shale Activity in China*, 26th Oil Shale Symposium, Colorado School of Mines, October.
[107] VKG company website press release (http://www.vkg.ee/?id=4923)

Several of these established processes for surface retorting of mined oil shale have a significant amount of commercial operating history. However, international oil shale production peaked in 1980 and then went into a sharp decline through the late 1990s. Global production has subsequently increased slightly since 2006. Most of the oil extracted from oil shale is produced in Estonia, China, and Brazil.[108]

In 2007 the BLM leased government land in Colorado and Utah to private companies to permit them to conduct six RD&D projects, with the possibility that the projects could be followed by a commercial leasing program. The primary term of the 160-acre leases offered in the first round of RD&D leasing is ten years, ending Dec 31, 2016. Of the six leases, the Oil Shale Exploration Company (OSEC) project at the White River Mine Co. is the only Utah lease and also the only surface retorting research project. Work on permitting the first phase of the project to open the White River Mine as a source of shale is ongoing. Petrobras is now a partner with OSEC and has initiated a commercial feasibility study.

An alternative approach to conventional surface retorting is being developed by Red Leaf Resources on a private lease in Utah.[109] Red Leaf's EcoShale process has been pilot tested.[110] In this process, oil shale mined from near the surface is placed in a pit equipped with heating and production piping, covered with dirt, and retorted by circulating a heated fluid through the piping. The oil is recovered through horizontal collection piping located above the heating pipes. Based on pilot plant results, Red Leaf estimates the operating cost to produce a barrel of crude oil at less than $25 dollars for an 8,000 barrel per day operation.[111] The pilot plant ran for only 90 days, but reportedly produced 15,000 barrels of oil. A commercial operation could produce between 80 and 90 thousand barrels of oil per acre.

4.1.1.2 In Situ Processes

Five of the BLM first round R&D leases entail projects that involve *in situ* technologies. Shell Oil was awarded three of these R&D leases to test three different aspects of their technology to prove technical, environmental, and commercial viability. Shell's *In-situ* Conversion Process (ICP) slowly heats isolated shale strata over an extended period of time using tightly spaced electric heaters.[112] The heaters uniformly heat the oil shale by thermal conduction to a conversion temperature of about 650°F. This technology utilizes extensive drilling of numerous heating, production, and isolation holes.

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[108] Johnson, R.C., et al., 2009, *An Assessment of In-Place Oil Shale Resource in the Green River Formation*, Piceance Basin, CO, a presentation at the 29th Oil Shale Symposium, CSM, Golden, CO, October. (http://energy.usgs.gov/flash/OilShale2009_slideshow.swf)

[109] Red Leaf Resources, http://www.redleafinc.com

[110] http://www.redleafinc.com/index.php

[111] Laura Nelson of Red Leaf quoted in an article published June 25, 2009 in the Carbon Co. Utah Sun Advocate, accessed online at http://www.sunad.com/index.php?tier=1&article_id=16029

[112] Fowler, T. D., H. J. Vinegar, 2009, "Oil Shale ICP – Colorado Field Pilots," SPE 121164, presented at the 2009 SPE Western Regional Meeting, San Jose, CA, March

The process protects local ground water by constructing a freeze wall around the *in situ* retort. The thermal conduction of heat generates slower heat up rates and results in lower process temperatures, reducing oil losses from thermal cracking and coking reactions, as well as decomposition of carbonate rock. Pressure from the production of gases and vapors creates permeability and allows transport of oil vapors to the production wells.

Shell has been testing various elements of its process on private acreage near their R&D leases since 1996.[113] A large scale test of the freeze wall remains under way. Planning for additional research using the R&D field tests is in progress, according to Shell.[114] In 2008, Shell indicated that "the earliest a commercial decision would be made is in the middle of this decade and possibly later depending on the outcome of research activities." [115]

Chevron Oil was also awarded an R&D lease to further develop an *in situ* process which will use conventional drilling technologies and modified fracturing techniques designed to control and contain the process underground. It entails drilling wells into the oil shale and applying a series of controlled horizontal fractures within the target interval to prepare the production zone for heating and *in situ* pyrolysis.[116] In this approach, additional fracturing of the shale is facilitated by subjecting the formation to thermal cycles. Hot CO2 gas is introduced into the fractured formation and flows between connected fracture test wells to further rubblize the process interval. If necessary, propellants and/or explosives may be used to facilitate further rubblization in the production zone. The heating and *in situ* pyrolysis phases of the process include the generation of hot CO2 gas that would be circulated in the target zone to create the heat needed to decompose the kerogen into producible hydrocarbons. Chevron has been gathering data to assess the grade of oil shale and to more fully characterize the subsurface while planning for an initial test of its process.

American Shale Oil LLC (AMSO), previously EGL Resources, Inc., also is an RD&D lease holder developing an *in situ* technology. The AMSO approach involves drilling a line of cased well pairs to a depth of about 2000 ft and with horizontal laterals of about 2000 ft.[117] The heating wellbore is located underneath the producing wellbore in each well pair. The heat for converting kerogen to oil and gas is supplied by downhole burners fired using gas co-produced with the shale oil. The process will take advantage of thermomechanical fracturing to create permeability for distributing heat and extracting the oil for production through each producing well horizontal lateral. Phase I of the research program was started in 2007 and will be completed in 2010. It includes site characterization and the establishment of baseline

[113] Ibid.
[114] Ibid.
[115] http://www-static.shell.com/static/usa/downloads/about_shell/upstream/icp_factsheet.pdf
[116] *Oil Shale Research, Development & Demonstration Project. Plan of Operation*; Chevron USA Inc.; 2006. (http://www.blm.gov/pgdata/etc/medialib/blm/co/field_offices/white_river_field/oil_shale.Par.37256.File.dat/OILSHALEPLANOFOPERATIONS.pdf)
[117] http://www.amso.net/Our-Concept/Our-Process.aspx

geo-hydrologic conditions through a series of drilling tests and studies. Phase II will include construction and operation of a pilot heating test, with an inclined well that will be used to introduce heat into the subsurface and produce generated oil and gas.

The BLM offered an additional round of R&D leases in 2009 and received three applications. ExxonMobil Corp. and Colorado-based Natural Soda Inc. applied for one lease each in northwest Colorado, and AuraSource Inc. of Scottsdale, Arizona, applied for a lease in northeast Utah. The limited response was attributed to the fact that in this offering, the 160-acre R&D leases could only be converted to 640-acre commercial leases, versus the 5120-acre conversion possible with the earlier R&D leases awarded in 2007.[118] The new 10-year research leases will likely be awarded in the fall of 2010.

Should Exxon be awarded an RD&D lease, it will likely use it to develop its Electrofrac process. Exxon has conducted some small scale testing of the process at their Colony project site on Parachute Creek, Colorado. The original Colony project was designed to be a surface retort fed by an underground room and pillar mine. The Electrofrac process is designed to heat oil shale *in situ* by creating a hydraulic fracture in the shale, filling the fracture with an electrically conductive material, and using electricity to heat the oil shale *in situ*.[119] Heat flows from the planer fracture into the shale, gradually converting the kerogen in the rock to oil and gas.

The planar heat source is considered to be more effective than radial conduction from wellbores. Lab experiments have shown that calcined petroleum coke is a suitable Electrofrac conductant. Electricity is conducted from one end of the fracture to the other, making it a resistive heating element, and multiple layers of heating wells may be stacked for increased heating efficiency. The resulting oil and gas hydrocarbons are produced by conventional methods. Assuming the process works on a large scale, Exxon estimates that up to 162,000 bbl of oil per surface acre may be recoverable at a 50 percent recovery rate. The results suggest a 3-to-1 ratio of energy recovered over energy expended. It appears ExxonMobil can make its process work using about 1.5 bbl of water for each barrel of oil produced. Even under the most optimistic of scenarios, ExxonMobil sees no production from oil shale for 10 to 24 years.

[118] http://www.billingsgazette.com/news/state-and-regional/wyoming/article_26d7b9d6-0b9e-11df-9529-001cc4c002e0.html

[119] Harmon, G., 2009, *Exxon tests successful tech in quest to tap oil shale,* Daily Sentinel, Denver, CO. (http://www.gjsentinel.com/news/articles/exxon_tests_successful_tech_in)

While the technologies described above highlight the most well publicized efforts, a publication by the U.S. DOE Office of Naval Petroleum and Oil Shale Reserves in September 2009 listed an additional 27 companies that are currently engaged in domestic oil shale resource and technology development.[120] In addition, a chapter in a book on oil shale planned for publication by the American Chemical Society will provide additional details on these processes, as well as a number of others.[121]

While the technologies associated with mining oil shale (either underground or open pit) are generally considered to be commercially proven, there remains some uncertainty about the commercial-scale viability of the various surface retorting technologies for converting the organic material (kerogen) of oil shale into "oil" suitable for refining. The major technical challenges (not environmental) to commercial development include relatively low process energy efficiency (net energy balance) and relatively high net water requirements as compared to conventional oil production.

The technologies being developed for *in situ* recovery of oil from oil shale (either underground or open pit) are technically and commercially unproven, and face the same energy efficiency challenges. In addition, *in situ* technologies face very process-specific challenges. For example, Shell has been working to perfect a reliable downhole heater for its ICP process.[122] In addition, Shell has been working to prove its freeze wall system for isolating the *in situ* retort to prevent groundwater contamination.

The report from the Task Force on Strategic Unconventional Fuels published in 2007 concluded that government support is necessary to achieve commercial oil shale production in a reasonable time period.[123] The Task Force report recommended government support for cost-shared demonstrations of existing, promising oil shale technologies at commercially-representative scale (up to four demonstration projects, including at least one surface and one *in situ*). The report also recommended that National laboratories should be funded to help industry resolve technical challenges on a cost-shared basis.

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[120] *Secure Fuels from Domestic Resources: The Continuing Evolution of America's Oil Shale and Oil sands Industries*, prepared for the U.S. Department of Energy Office of Petroleum Reserves, Office of Naval Petroleum and Oil Shale Reserves, September 2009. (http://www.unconventionalfuels.org/publications/reports/SecureFuelsReport2009FINAL.pdf)
[121] Crawford, P., J. Killen, 2010 (planned), "New Challenges and Directions in Oil Shale Development Technologies," a chapter in a book to be published by the American Chemical Society.
[122] Fowler, op cit.
[123] *America's Strategic Unconventional Fuels: Oil Shale, Oil sands, Coal Derived Liquids, Heavy Oil, CO2 Enhanced Recovery and Storage*, prepared by the Task Force on Strategic Unconventional Fuels, September 2007, Volume II – Resource-Specific and Cross-cut Plans.

Private industry is also funding universities to help support their research, particularly in areas related to characterization of oil shale deposits. TOTAL (a 50 percent owner of AMSO), Shell, and Exxon have funded the Colorado School of Mines' Center for Oil Shale Technology and Research to do research on the geomechanical behavior of oil shale, geologic controls on oil shale properties, geomechanical and geochemical properties, and digitization of oil shale data.[124]

General technical challenges and associated R&D needs include:

- How to quantify the environmental/safety risks inherent with oil shale development.
- How to increase process energy efficiency (net energy balance) for both surface and *in situ* extraction processes.
- How to reduce high net water requirements.
- How to improve the reliability of downhole heating sources for *in situ* processes.
- Improved understanding of the fundamental character of oil shale (rock properties and analytical methods).
- Improved understanding of pyrolysis under *in situ* conditions.
- Enhanced characterization of the oil shale resource quantity and quality.

4.1.2 Oil sands

Canadian oil sands deposits, where the only large scale commercial oil sands development is underway, are produced by open pit mining with surface processing or by *in situ* processes (either thermal or non-thermal), depending on the deposit's depth. Common *in situ* thermal extraction techniques include steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). Currently, surface extraction/processing accounts for 50 percent, and *in situ* processes account for ~50 percent of total production; this distribution is expected to remain roughly the same as overall production is projected to roughly double through 2025.[125] Surface extraction processes are solvent-based, with water being the most common solvent; other (mainly hydrocarbon) solvents are not yet commercial.[126]

Mining Utah oil sands will be more challenging than mining Canadian oil sands because the Utah deposits, while relatively shallow, are not deposited in sediments with uniform thickness but in lenticular formations. The Utah deposits are also located in more rugged and mountainous terrain, and are geologically consolidated deposits (i.e., they will require milling-type mining equipment in contrast to the shovel type equipment used in Canada).[127] On the plus side, Utah oil sands have a lower percentage of clay minerals and sulfur.

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[124] *Oil Shale Research in the United States – Profiles of oil Shale Research and Development Activities in Universities, National Laboratories, and Public Agencies,* 2009, prepared by the U.S. DOE, Office of petroleum Reserves, Office of Naval Petroleum and Oil Shale Reserves, June (http://www.eccos.us/images/pdfs/research_project_profile_book.pdf)

[125] CAPP, 2009, *Crude Oil Forecast, Markets and Pipeline Extensions,* (http://www.capp.ca/library/publications)

[126] UHOP, op cit.

[127] Ibid.

Pilot-scale and small commercial scale mining and solvent extraction operations are being planned and conducted by Temple Mountain Energy and Earth Energy Resources Inc. in some Utah deposits.[128, 129, 130] According to a published statement, these processes could be economical at current oil prices, and commercial development of Utah oil sands is possible using solvent extraction processes.[131] As significant portions of the Utah deposits are deep and not easily accessible, *in situ* processes would need to be adapted to fit the nature of the Utah oil sands deposits (i.e., leaner and more stratified).[132]

General technical challenges and associated R&D needs include:

- How to quantify the environmental/safety risks inherent with oil sands development.
- How to adapt new developments in tar sand extraction technology to U.S. deposits
- How to deal with the hydrocarbon-wet character of U.S. oil sands.
- Understanding the best approach for upgrading bitumen to a form suitable for a refinery.
- How to minimize energy, water, and solvent inputs.

4.1.3 Heavy Oil

The technology for producing heavy oil is relatively well understood. Nonetheless, California heavy oil production has dropped from just over 650,000 BOPD in 1992 to about 300,000 BOPD in 2008.[133] This decline is due to a variety of factors, including the maturity of existing thermal recovery projects, the high cost of implementing new projects, the increased environmental restrictions on steam generation and field development, and the price differential for heavy oil. The price for domestic heavy crude is less than that for conventional benchmark crude oils. The first purchase price of California Midway-Sunset (13° API) heavy crude has averaged about 89 percent of that for West Texas Intermediate (39-40° API) over the past three years.[134]

While the price for heavy oil is consistently lower than that for the lighter crude, the production costs are higher, primarily due to the cost of natural gas for steam generation. Thermal recovery operations tend to be troubled by sand production, casing or tubing failure in older wells and increased corrosion rates in both downhole and surface equipment. Steam injection also requires higher capital costs. California operators can improve their costs by using cogeneration facilities to produce both steam and electricity that can be sold to the grid.

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[128] UHOP, op cit.
[129] http://www.templemountainenergy.com/
[130] http://www.earthenergyresources.com/index.php

[131] UHOP, op cit.
[132] Ibid.
[133] State of California, 2008 Annual report of the Oil and Gas Supervisor, Pub. PR06 (http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx)
[134] EIA price database (http://tonto.eia.doe.gov/dnav/pet/pet_pri_dfp2_k_m.htm)

While the technology for producing heavy oil is mature, there are some challenges that still require research. A primary issue is how to produce heavy oil in environments where it is not easy to maintain steam quality as it is pumped downhole due to temperatures, for example, on the North Slope and offshore. One promising concept is the application of downhole heaters to create steam downhole.[135] This approach solves not only the problem of heat loss, but also the issue of lack of space for equipment (offshore), and the issue of surface generation of greenhouse gases. There are currently several industrial heating companies, previously involved with pipeline heating and combustion projects, working on the concept of downhole heaters.

Sand production can be a problem and work continues to be done to develop downhole tools that reduce sand production. Water breakthrough can lead to high water cuts in producing wells, and work to reduce water production is on-going as well.[136]

In Alaska, BP has to date produced about 50 million bbl of heavy oil, mostly from multilateral wells; up to five laterals per well. Most existing production is of oil with a sufficiently low viscosity that the reservoirs can be produced with the assistance of water flood.[137]

BP is currently performing a pilot project to evaluate the applicability in Alaska of cold heavy oil production with sand (CHOPS) and other cold recovery operations that are used in Canada.[138] This is part of a 5-year program to evaluate heavy oil production options in the area. The pilot is targeting the Ugnu Fm. CHOPS was selected for the 3,700 ft well because steam is difficult to apply at such depths. In CHOPS wells, high pressure drawdown brings in sand. BP plans to employ time series 3D multicomponent seismic surveys to map changes in density to determine the progress of the CHOPS approach.[139] The produced sand and solids are processed and then injected into a highly porous non-hydrocarbon bearing semi-brackish aquifer. The recovery factor is expected to be in the range of 8–10 percent, perhaps greater if follow-up EOR processes such as solvents and/or thermal are applicable.[140]

General technical challenges and associated R&D needs include:

- How to reduce sand production How to quantify the environmental/safety risks inherent with heavy oil production.
- How to reduce sand production from thermally stimulated wells.
- How to improve the efficiency of steam generation and injection.
- Technologies for downhole steam generation.
- Advanced technologies for improving steam or hot water sweep efficiency.

[135] Schlumberger Heavy Oil Info (http://www.heavyoilinfo.com/feature_items/expert-viewpoint-with-gordon-graves)
[136] Ibid.
[137] Ibid.
[138] BP Alaska (http://www.heavyoilinfo.com/feature_items/bp-pilot-tests-chops-in-alaska)
[139] Ibid.
[140] Ibid.

- Advanced technologies for producing heavy oil in cold climates, from deep wells, or at offshore locations.

4.1.4 Oil from Fractured Shale

In considering the technology challenges to successfully developing potential OFS plays, it is useful to examine their cousins, gas shale plays. Successful gas production from shale requires a process for driving down overall costs. Advances in drilling and completion technologies have allowed for economic production from gas shale. The major technology advances that have improved recovery from gas shale are related to coiled tubing, perforation, hydraulic fracturing, horizontal drilling, 3D seismic imaging, and advanced reservoir visualization and modeling software.

In addition, reservoir knowledge guides the choices that can make or break shale wells. A good understanding of rock properties, fracture geometry, and fluid interactions is critical. Mineralogy must be identified and wireline log data and laboratory core analysis must be integrated to help define shale characteristics. This information aids fracture treatment design by enabling the identification of targets, which is critical to well performance in shale reservoirs. Simulations of shale reservoirs indicate that formation brittleness is also a valuable guide to identifying fracture initiation points.

Future development of the OFS resource will depend on: comprehensive geologic assessments (regional and play levels), including oil-source rock correlations and source rock potential characterization and assessment; development of improved geological tools/methods, including depositional and paleogeographic models and kerogen reaction kinetics models; and continued development of enhanced technologies in horizontal drilling optimization and hydraulic fracturing optimization.

General technical challenges and associated R&D needs include:

- Quantifying the environmental/safety risks inherent in producing oil from fractured shale
- Understanding the potential resources associated with new or underdeveloped fractured shale plays and identifying technical and economic barriers to their development.
- Understanding the geological, geochemical, and geophysical framework of fractured shale plays with oil potential.
- Developing surface-based and borehole-based technologies that identify natural fracture "sweet spots".
- Developing technologies for characterizing fracture attributes (orientation, intensity, openness, fluid saturation).
- Developing methods to optimize the position and orientation of horizontal wellbores.

- Developing methods to improve the design and implementation of hydraulic fracturing.
- Understanding the geological, geochemical, geophysical, and operational parameters that differentiate high-performing wells, areas and/or fields.
- Developing and demonstrating techniques to analyze large volumes of data in real-time for application during fractured shale development.
- Development of improved drilling methods that lower cost, reduce time on location, use less materials, or otherwise increase the efficiency and effectiveness of well construction.
- Development of improved stimulation and completion methods (including multi-zone techniques, steerable hydraulic fractures, non-damaging fluids, high strength/low density proppants, and lower treatment volume processes).
- Development of methods and technologies to maintain the permeability generated through stimulation operations and minimize formation damage over time.
- Development of improved models for optimizing oil production from fractured shale reservoirs.
- Development of approaches for improved treatment, handling, reuse, and disposal of fluids produced and/or used in field operations.
- Development of comprehensive approaches for the conservation and management of water resources used and produced during all aspects of fractured shale play development.
- Development of advanced drilling, completion and/or stimulation methods that minimize surface impact and environmental disturbances, including noise and particulates.

4.1.5 Residual Oil (Including ROZ)

The "next generation" technologies that must be developed to target post-water flood residual oil include a number of specific items. One is optimized well design and placement methodologies to ensure that both previously highly water flood-swept (with low residual oil) portions of the oil reservoir and poorly water flood-swept (with higher residual oil) portions of the reservoir are optimally contacted by injected CO2. Examples of innovative well design and placement options include: (1) isolating the previously poorly-swept reservoir intervals (with higher residual oil) for targeted CO2 injection; (2) drilling horizontal injection (and/or production) wells to target bypassed or poorly produced reservoir areas or intervals; (3) modifying the injection and production well pattern alignment as well as using optimum well spacings; and (4) developing and demonstrating the technologies of gravity stable CO2-EOR.

A second next generation technology involves developing ways to increase the viscosity of injected water (as part of a CO2-Water Alternating Gas (WAG) process) using polymers or other agents. Although increasing the viscosity of the CO2 itself with CO2-philic agents could further improve recovery, this was not considered as one of the next generation technologies in the assessment described in Section 2. Another option for achieving this result involves developing ways to improve process control using physical or chemical driven materials to direct CO2 into previously poorly-contacted portions of the reservoir. Various chemicals or other materials can be selectively placed into the reservoir to effectively "block" CO2 flow into previously well-swept zones, and thus direct CO2 into more poorly-contacted zones. Selective, targeted well completions would potentially achieve the same objective.

A third next generation technology involves developing "miscibility extenders" that can be added to the CO2-EOR process to reduce minimum miscibility pressure requirements by 500 psi (pounds per square inch). Examples of miscibility enhancing agents could include the addition of liquefied petroleum gasses (LPG) to the CO2, addition of hydrogen sulfide (H2S) or other sulfur compounds, or the use of other (yet to be developed) miscibility pressure or interfacial tension reduction agents. Successful development and application of this technology could allow fields where the pressure/oil character combination currently does not permit miscible flooding, to be miscibly flooded.

A fourth next generation technology option involves increasing CO2 injection volumes to 1.5 times the hydrocarbon pore volume (HCPV). Higher HCPVs of injected CO2 enable more of the reservoir's residual oil to be contacted by the injected CO2. In the past, the combination of high CO2 costs and low oil prices led operators to use small-volume injections of CO2 (traditionally 0.4 HCPV) to maximize profitability. This low volume CO2 injection strategy was also selected because field operators had very limited capability to observe and then control the sub-surface movement of the injected CO2 in the reservoir. With adequate volumes of lower cost CO2 and higher oil prices, CO2-EOR economics today favor using higher volumes of CO2. However, these increased CO2 volumes would need to be monitored and managed via advanced seismic and other sensing technologies, to assure that they contact, displace, and recover additional residual oil, rather than merely circulate through a high permeability interval of the reservoir.

General technical challenges and associated R&D needs include:

- How to quantify the environmental/safety risks inherent in producing oil from residual oil zone.
- Development and demonstration of optimized well design and placement methodologies.
- Development and demonstration of technologies for increasing the viscosity of injected CO2 relative to reservoir fluids.
- Development and demonstration of technologies for improving sweep efficiency of injected CO2, including the use of nanoparticles.
- Development and demonstration of miscibility extension technologies.
- Demonstration of novel approaches for increasing CO2 injection volumes.
- Development of enhanced reservoir visualization and modeling technologies.

4.1.6 Tight Gas

The technical challenges associated with tight gas development have been delineated as part of the planning process for NETL's management of the Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research and Development Program established pursuant to Title IX, Subtitle J of EPAct. As required by Subtitle J, DOE contracted with a consortium to administer three program elements identified in EPAct 2005, one of which is focused on unconventional natural gas. The 2010 Annual Plan outlines a number of technical challenges related to the development of tight gas sands, gas shale and CBM. This plan has been evaluated by a panel of experts representing academic, industry, and environmental groups.

The technical challenges related to tight gas sands include:

- Quantifying the environmental/safety risks inherent in producing natural gas from tight sands.
- Understanding the potential resources associated with new or underdeveloped tight gas plays and identifying technical and economic barriers to their development
- Understanding the geological, geochemical, and geophysical framework of tight gas plays
- Developing surface-based and borehole-based technologies that identify natural fracture "sweet spots"
- Developing technologies for characterizing fracture attributes (orientation, intensity, openness, fluid saturation)
- Developing methods to optimize the position and orientation of vertical and horizontal wellbores
- Developing methods to improve the design and implementation of hydraulic fracturing
- Understanding the geological, geochemical, geophysical, and operational parameters that differentiate high-performing wells, areas, and/or fields
- Developing and demonstrating techniques to analyze large volumes of data in real-time for application during tight gas sand development
- Development of improved drilling methods that lower cost, reduce time on location, use less materials, or otherwise increase the efficiency and effectiveness of well construction
- Development of improved stimulation and completion methods (including multi-zone techniques, steerable hydraulic fractures, non-damaging fluids, high strength/low density proppants, and lower treatment volume processes)
- Development of methods and technologies to maintain the permeability generated through stimulation operations and minimize formation damage over time
- Development of improved models for optimizing gas production
- Development of approaches for improved treatment, handling, reuse and, disposal of fluids produced and/or used in field operations

- Development of comprehensive approaches for the conservation and management of water resources used and produced during all aspects of tight gas development
- Development of advanced drilling, completion, and/or stimulation methods that minimize surface impact

4.1.7 Gas from Coal Seams

The technical challenges related to CBM include the following, some of which are common to tight gas and gas shale:

- Quantifying the environmental/safety risks inherent in producing natural gas from coal seams.
- Understanding the potential resources associated with new or underdeveloped CBM plays and identifying technical and economic barriers to their development
- Developing methods to optimize the position and orientation of vertical and horizontal wellbores
- Development of methods for multiseam completions for sub-bituminous, soft, caving coals
- Developing methods to improve the design and implementation of hydraulic fracturing
- Development of extra-extended single and multi-lateral drilling techniques
- Development of improved drilling methods that lower cost, reduce time on location, use less materials, or otherwise increase the efficiency and effectiveness of well construction
- Development of approaches for improved treatment, handling, reuse and, disposal of produced water
- Development of comprehensive approaches for the conservation and management of water resources used and produced during CBM development
- Development of water management approaches that minimize the impact of drilling, completion, stimulation, and production operations on natural water resources
- Development of advanced drilling, completion and/or stimulation methods that minimize surface impact

4.1.8 Shale Gas

The technical challenges related to gas shale include the following, some of which are common to tight gas and CBM:

- Quantifying the environmental/safety risks inherent in detecting and producing shale gas and developing technologies to mitigate them.
- Understanding the potential resources associated with new or underdeveloped unconventional gas plays and identifying technical and economic barriers to their development
- Understanding the geological, geochemical, and geophysical framework of unconventional resource plays

- Developing surface-based and borehole-based technologies that identify natural fracture "sweet spots"
- Developing technologies for characterizing fracture attributes (orientation, intensity, openness, fluid saturation)
- Developing methods to optimize the position and orientation of vertical and horizontal wellbores
- Developing methods to improve the design and implementation of hydraulic fracturing
- Understanding the geological, geochemical, geophysical, and operational parameters that differentiate high-performing wells, areas and/or fields
- Developing and demonstrating techniques to analyze large volumes of data in real-time for application during unconventional resource development
- Development of extra-extended single and multi-lateral drilling techniques
- Development of improved drilling methods that lower cost, reduce time on location, use less materials, or otherwise increase the efficiency and effectiveness of well construction
- Development of improved stimulation and completion methods (including multi-zone techniques, steerable hydraulic fractures, non-damaging fluids, high strength/low density proppants, and lower treatment volume processes)
- Development of methods to accurately assess the potential for shale gas production based on reservoir and production data
- Development of methods and technologies to maintain the permeability generated through stimulation operations and minimize formation damage over time
- Development of improved models for optimizing gas production from gas shale
- Development of approaches for improved treatment, handling, reuse and, disposal of fluids produced and/or used in field operations
- Development of comprehensive approaches for the conservation and management of water resources used during all aspects of gas shale development
- Development of water management approaches that minimize the impact of drilling, completion, stimulation, and production operations on natural water resources
- Development of methods for the treatment of produced water and fracturing fluids
- Development of advanced drilling, completion and/or stimulation methods that minimize surface impact and environmental disturbances, including noise and particulates.

4.1.9 Methane Hydrate

Overcoming the challenges to safe, economic development of this resource will require continued research to understand what combinations of exploration and production technologies work best for a given category of hydrate deposit. In addition, development of methane hydrate will face the same economic tests as any other natural gas resource: are the costs and risks justified by the value of the volume of gas that can be produced and the rate at which it can be extracted? Some fundamental scientific questions also need to be addressed: How do they form? What is their role in the global carbon cycle? What is their role in seafloor ecological systems? How extensive are they? How stable are they? The ongoing research program is helping to shed light on these questions.

There are two major near-term challenges that will likely determine whether the sand-enclosed gas hydrates near the top of the hydrate resource pyramid are an exploitable resource. The first challenge is to more accurately determine the extent of gas hydrates in sand reservoirs in the marine environment. Estimates of the hydrate resource need to be confirmed by drilling, logging, and coring operations.

The second challenge is to determine whether such deposits can yield methane gas at the rates necessary to make production commercially viable. The most promising production method involves reducing pressure in the well bore. Water in the formation then moves toward the well, causing a region of reduced pressure which causes the hydrate to dissociate and release methane. The affect of applying thermal or chemical stimulation methods to enhance methane production from hydrates will need to be evaluated.

The viability of this approach has been confirmed during a 6-day production test completed in April 2008 by the governments of Japan and Canada at the Mallik site in the Canadian Northwest Territories. Numerical simulations show that production based primarily on reducing pressure by pumping could release methane at rates that make commercial production feasible in certain settings.

Another possibility is the injection of CO2, which has the potential to displace methane from at least half of the hydrate structure and also leave the CO2 sequestered within the hydrate. Initial studies of these two approaches have been encouraging, but extended production tests of both methods are needed. Such testing, currently in the planning stages for sites in Alaska, will be needed to help prepare for marine production tests, which are still several years away.

General technical challenges and associated R&D needs include:

- Quantifying the environmental/safety risks inherent in detecting and producing natural gas from gas hydrate formation and developing technologies to mitigate them.
- To confirm the producibility of methane from hydrate in the Arctic with a long term test, while building a better understanding of the process of hydrate dissociation in a reservoir under producing conditions.
- To determine the extent of gas hydrate in sand reservoirs in the marine environment by

drilling, logging, and coring operations.

- To determine whether such marine deposits can yield methane gas at the rates necessary to make production commercially viable.
- Enhance our understanding of the process of using CO2 to replace methane in hydrate.
- To characterize more fully the geohazard issues, capability to assess risks and predict environmental impacts, and any constraining conditions to be avoided during production.

4.1.10 Unmineable Coal

UCG is coal gasification conducted *in situ* where oxygen reacts with coal to generate heat, thereby initiating multiple reactions that generate products of the gasification process. Oxygen injection as air or as a steam/oxygen mixture, or as a water/oxygen mixture sustains the process.

Vertical injection and production wells are drilled into a coal seam (40 to 500 feet apart). The coal is then ignited, and air or oxygen is pumped into the injection well to maintain combustion. Through partial combustion and a series of other subsequent reactions, the coal is converted to syngas (carbon monoxide and hydrogen) as well as other gases. The syngas flows from the gasification chamber through the coal seam to a production well. The injection and production wells may be linked together horizontally by pre-combustion drilling or fracturing, or become connected along natural fractures as a result of the combustion process. The produced syngas can be used to fuel power generation, converted to hydrocarbon liquids via a Fischer-Tropsch (gas-to-liquids) process, or used as a feedstock for other petrochemical processes.

There are a number of variations on this basic approach. For example, the Controlled Retracting Injection Point (CRIP) process utilizes a retractable injection wellbore directionally drilled parallel to the bottom of the coal seam. The injection point is retracted as the gasification zone grows back toward the injection well.

The reaction products of the coal gasification process include gases (CO, CO2, CH2, and CH4), tar, oil, ash, water (steam), and heat. The relative percentages of the gaseous products will vary depending on whether air or oxygen is injected (Table 4-1).

There are two general configurations for UCG depending on the orientation of the coal seam orientation. The majority of U.S. coal seams are relatively horizontal with dips ranging between 0 and 45 degrees. The basic horizontal UCG process involves two wells drilled to the bottom of the coal seam.

Table 4-1: Underground Coal Gasification Produced Gas Composition

Component	Oxygen Blown Composition (%)	Air Blown Composition (%)
H_2	30	18
CH_4	10	5
CO	20	10
CO_2	36	18
N_2	< 0.5	48
H_2S	1	0.5
C_2 + Hydrocarbons	2	1
Approximate Gas Heating Value (Btu/Scf)	280	145

There were four UCG tests conducted in the U.S. from 1972 through 1995. These were the Hanna series, which included the Rocky Mountain 1 tests, the Hoe Creek tests, the Rawlins series including the Carbon County UCG Test, and the Centralia (Tono) series. There were other tests that were conducted in Texas lignites (Easterwood during 1977 and Tennessee Colony during 1978 and 1979) and a West Virginia bituminous coal (Pricetown during 1997).[141, 142] Lawrence Livermore National Laboratory (LLNL) developed two of the test sites; the ones in Centralia, Washington, and Hoe Creek, Wyoming. Livermore researchers also patented a UCG process called Controlled Retraction Ignition Point, which was used in pilot tests performed in Europe during the 1990s.

Hanna and Rocky Mountain 1 UCG Tests – The Laramie Energy Technology Center/DOE conducted five field tests in the Hanna #1 coal seam in the Hanna Basin in south central Wyoming at depths ranging from 350 feet to 400 feet (Hanna I, II, III, IV, and Rocky Mountain 1) from 1973 to 1979. The Hanna test series was largely successful and produced some of the highest heating value products. These tests were air blown. The Rocky Mountain 1 test was carried out by Gas Research Institute and Morgantown Energy Technology Center (U.S. DOE) in 1987-1988.

[141] GasTech, 2007, "Viability of Underground Coal Gasification in the Deep Coals of the Powder River Basin," Cheyenne, WY, Wyoming Business Council, State Energy Office (http://www.wyomingbusiness.org/pdf/energy/WBC_Report_061507_SPM.pdf).

[142] Burton, E, J. Friedmann, and R. Upadhye, 2005, "Best Practices in Underground Coal Gasification," Lawrence Livermore National Laboratory and U.S. Department of Energy, Contract No. W-7405-Eng-48.

Hoe Creek Test Series – LLNL and DOE conducted the Hoe Creek test series south of Gillette, WY in the PRB, approximately 10 miles south of Gillette, WY. The target coal resource was the 25 foot thick Felix 2 coal seam, a shallow coal at depths of 80 to 145 feet. Another coal seam, the Felix 1, exists at a distance ranging from 15-25 feet above the Felix 2 coal seam. The Felix 1 coal thickness ranges from 10 to 15 feet thick. Three tests conducted from 1976 through 1979 resulted in significant groundwater contamination and surface subsidence.

Rawlins Steeply-Dipping-Bed (SDB) Tests – Two SDB tests and one pre-commercial attempt were conducted at a site west of Rawlins, in south central Wyoming. Gulf Oil conducted the first two tests (T-1 in 1979 and T-2 in 1981) with support from DOE. Williams Companies attempted a pre-commercial UCG operation in 1995. The coal resource was a 23-foot thick coal seam that dipped at a 60-degree angle. The T-1 test used initial air injection at a depth of 400 feet, while the T-2 test used steam/oxygen injection at a depth of approximately 600 feet. Both tests were considered to be successful. The Williams Companies expanded on T-2 at a depth of approximately 1,700 feet with multiple injection wells and a multi-lateral production well. The test encountered many problems, and the use of high pressure in an attempt to force gasification caused groundwater contamination. The operation gasified little coal and was deemed unsuccessful.

Centralia (Tono) Tests – Two tests were conducted by LLNL/DOE at an active coal mine near Centralia, Washington in 1981-1982. The tests evaluated novel processes using various oxygen/steam ratios. Because this test was in an active mine, a controlled excavation of the UCG cavity provided valuable information on UCG cavity growth mechanisms and reaction conditions during gasification.[143]

When gas and oil prices dropped in the 1980s and 1990s, efforts to commercialize UCG came to a halt. However, interest in UCG has increased outside of the U.S. over the past decade. The Chinchilla project, operating from 1997 to 2003 in Queensland, Australia, demonstrated UCG in a long-term pilot. The developers of that project are now at the point of raising capital for a gas-to-liquids pilot. In South Africa, the electricity supply company Eskom is developing UCG at the Majuba Coal Field and achieved ignition in January 2007. The Majuba UCG Project has operated over the last 40 months with continuous gas as of May 2010.[144] In the United Kingdom, a new UCG partnership has been hosting international conferences. In India, at least three pilot projects are now in the planning stages. Organizations currently active in UCG technology development include: Lawrence Berkeley National Laboratory (LBNL), Ergo Exergy, Linc Energy, and BP.

[143] Oliver, R., 1987, "Results from the Controlled Excavation of the Tono I UCG Cavity, Centralia, Washington. Proceedings of the 13th Underground Coal Gasification Symposium (pp. 371-381). Laramie, WY: U.S. Department of Energy, DOE/METC-88/6095 (Conf-8708106) (DE88010255).

[144] e-mail correspondence, Larry Nemec, UCG Technology Manager, Laurus Energy Inc.

In 2006, DOE commissioned LLNL to evaluate the current state of UCG technology. *Best Practices in Underground Coal Gasification* was completed at the end of 2006 and is awaiting official release by DOE.[145] In March 2006, LLNL signed a memorandum of understanding with Ergo Exergy, which has licensed its proprietary Exergy UCG technology, or εUCG, to clients around the world. The two organizations have agreed to cooperate in conducting research in the areas of UCG process simulation and carbon sequestration, with an emphasis on evaluating the environmental performance of a large-scale operation.[146] In June 2007, Ergo Exergy also teamed up with BP to work together on UCG technology development. εUCG is being applied in South Africa, Canada, India, and for Linc Energy in Chinchilla, Australia. The company also provides technical expertise on UCG at the Angren UCG facility in Uzbekistan.[147]

Ergo Exergy is also providing εUCG technology in Alberta and Nova Scotia, where Laurus Energy is establishing several εUCG power plants. In India, where Gail Ltd.'s εUCG-IGCC power plant will eventually provide approximately 750 MWe.

Linc Energy, an Australian based company, acquired coal lease holdings totaling 173,327 acres from GasTech Inc. (an affiliate of World Oil Properties) in 2009 across the states of Wyoming, Montana, and North Dakota. These coal holdings, which may be amenable to UCG, are found in the Powder River and Williston basins. Linc Energy opened an office in 2009 in Casper, Wyoming and plans to complete a UCG pilot program in the PRB in mid-to-late 2011. Gas Tech Inc., based in Casper, and Linc Energy are partners in this project. GasTech completed a feasibility study for the Wyoming Business Council showing UCG to be a better option with respect to cost, emissions, and environmental effects, when compared with conventional coal-fired stations and integrated gasification combined-cycle plants in the PRB.[148] Linc Energy also plans to begin a commercial UCG project in Vietnam once its trial UCG project has proven successful. In Australia, the company operated the Chinchilla Demonstration Facility. Additionally, the company is planning to establish its first commercial operation in South Australia. This project is currently in a conceptual phase.

There are two proposed UCG projects proposed for Alaska. The first is being promoted by one of the larger Alaskan companies, Cook Inlet Regional Corporation (CIRI), which has very large coal reserves west of Anchorage at a depth (>1500 feet) which makes mining of the coal uneconomical. The company projects that gasification of 3 to 5 acres per year of the sub-bituminous coal deposit would produce enough synthetic gas to power a 100 megawatt power generation facility, and that the deposit would last for 100 years at this rate. CIRI is working with Laurus Energy and Lawrence Livermore National Laboratory to further develop the technology.[149] Preliminary plans include capture of the CO2 for reinjection or sale if possible.

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[145] Burton, E., J. Friedmann and R. Upadhye, DRAFT 2006, "Best Practices in Underground Coal Gasification," LLNL, (http://www.purdue.edu/discoverypark/energy/pdfs/cctr/BestPracticesinUCG-draft.pdf)
[146] LLNL website https://www.llnl.gov/str/April07/Friedmann.html
[147] Ergo Exergy website http://www.ergoexergy.com/
[148] Wyoming Business Council (http://www.wyomingbusiness.org/pdf/energy/WBC_Report_061507_SPM.pdf)
[149] Underground Coal Gasification (UCG) Progresses, http://www.yachtchartersmagazine.com/node/1406279

A second potential UCG project has recently been proposed by another Alaska native corporation in western Alaska. This project involves bituminous coal in the area of Kotzebue, Alaska. Although this project has not been officially announced, feasibility studies are being conducted.

General technical challenges and associated R&D needs include:

- Quantifying the environmental/safety risks inherent in producing natural gas from unmineable underground coal seams.
- Enhanced capabilities related to UCG process simulation and modeling.
- Develop a better understanding of the combustion process and of how this process can be controlled to produce the highest quality gas, with a minimum of associated pollutants.
- Develop and demonstrate technologies for combining UGC with carbon sequestration.
- Develop and demonstrate technologies for optimizing existing UCG processes for application to specific coal deposits.

4.2 Environmental

4.2.1 Oil Shale

There are significant environmental challenges to development of U.S. oil shale. Researching technologies that can overcome these problems remains a priority for development of this resource. The challenges include:

- <u>Surface impacts</u> affecting land use, animal habitat, and vegetation, that would result from open pit mining or facilities related to subsurface mining, *in situ* processing, and/or upgrading operations for hydrocarbons produced from either surface or subsurface processing.
- Potential for surface and/or subsurface <u>water contamination</u> from open pit or subsurface mining operations, or subsurface aquifer contamination resulting from products of *in situ* retorting.
- <u>Emissions</u> of criteria air pollutants from mining and retorting (both surface and subsurface) operations, spent shale tailings, and incremental power generation necessary to supply power for oil shale mining, retorting (both surface and subsurface), and upgrading.
- Generation of <u>particulates</u> (dust) from surface mining and/or retorting operations.
- Impact of process <u>water demand</u> on surface and subsurface (aquifer) water resources and subsequent impacts on competing users, animal habitat, and vegetation.
- Potential for <u>negative socio-economic impacts</u> related to sudden industrial growth in rural areas.
- Increased <u>CO2 emissions</u> from power generation and shale retorting operations.

During an October 2007 Oil Shale Environmental Issues and Needs Workshop held at the Colorado School of Mines (in conjunction with the 26th Annual Oil Shale Symposium), the attendees identified R&D needs.[150] The results are listed below, categorized by Air, Water, and Land issues:

Air Quality

- Develop a protocol for basin/regional emissions monitoring to address the need for long-term, basin/regional air quality monitoring and measurement.
- Develop accurate, predictive regional models for release, fate, and transport of emissions.
- Conduct process-/resource- specific emissions research and evaluation of best available cleanup technology (BACT).
- Identify gaps, and conduct R&D to develop innovative technologies for reducing (high efficiency) or controlling (capture/separation) emissions at any point; pre-process through post-process.
- Assess life-cycle emissions under various development scenarios, including full suite of infrastructure requirements.

Water Quality/Availability

- Develop integrated basin/regional baseline surface and groundwater data and Geographical Information System (GIS)-based analytical tools to help assess the cumulative impacts on surface and groundwater quality and availability.
- Conduct process-specific research to evaluate generated contaminants and water consumption; evaluate BACT.
- Conduct R&D to develop new, low water consumption processes, cost-effective water treatment, and improved recycle/reuse options.
- Conduct R&D to characterize and assess alternative by-product uses for spent shale.
- Assess water requirements and potential effluents for multi-site oil shale development in conjunction with other regional water use planning efforts.

Land

- Spent shale characterization and R&D for alternative by-products.
- Conduct research and analysis to reduce process/development foot print.
- Conduct research on subsidence and potential mitigation strategies.

[150] *Report - 2007 Oil Shale Environmental Issues and Needs Workshop*, NETL Strategic Center for Natural Gas and Oil (http://www.netl.doe.gov/technologies/oil-gas/publications/EP/2007-OilShaleEnvWorkshop.pdf)

The DOE has funded an effort with the University of Utah's Institute for Clean and Secure Energy (ICSE) to improve industry's ability to develop oil shale (and oil sands) resources in a manner that minimizes environmental impact and effectively capture the combustion CO2 from production, upgrading, and refining of the produced liquid fuel.

DOE, through the office of Naval Petroleum and Oil Shale Reserves (NPOSR), has funded Los Alamos National Laboratory (LANL) to develop integrated assessment models to investigate basin-wide requirements and impacts associated with regional, rather than individual operator, development of a potential oil shale production industry. LANL's focus is on energy requirements, carbon management, and water resources demands and impacts recognizing the interdependencies of industrial growth, power requirements, population increase, land change, and economic requirements. The study, scheduled for publication in 2010, used systems models to look at integrated impacts and process models to look at regional flow in the Colorado River for scenarios of industrial growth and climate change.

4.2.2 Oil sands

There are significant environmental challenges to development of the U.S. tar sand resource, and many of these challenges mirror those facing potential developers of oil shale. Researching technologies that can overcome these problems remains a priority for stakeholders interested in developing oil sands. The challenges include:

- Surface impacts affecting land use, animal habitat, and vegetation, that would result from open pit mining or facilities related to subsurface mining, disposal of processed sand, and surface facilities associated with upgrading operations.
- Potential for surface and/or subsurface water contamination from open pit or subsurface mining operations, and from materials leaching from processed sand.
- Emissions of criteria air pollutants from mined sand deoiling and processing, processed sand disposal, and incremental power generation necessary to supply power for tar sand mining, processing, and upgrading.
- Impact of process water demand on surface and subsurface (aquifer) water resources and subsequent impacts on competing users, animal habitat, and vegetation.
- Increased CO2 emissions from power generation and sand processing operations.

The R&D needs are similar to those for oil shale, particularly with respect to water and land:

- Develop integrated basin/regional baseline surface and groundwater data (quality and quantity) and GIS-based analytical tool.
- Conduct process-specific research to evaluate generated contaminants and water consumption; evaluate BACT.
- Conduct R&D to develop new, low water consumption processes, cost-effective water treatment, and improved recycle/reuse options.

- Assess water requirements and potential effluents for multi-site tar sand development in conjunction with other regional water use planning efforts for the development of a Water Resource Management Plan.

- Lack of process-specific data on solid and liquid wastes (waste constituents and volumes).
- Cumulative impacts (tar sand development plus other uses) on land, habitats, and ecosystems unknown.
- Information on land requirements (spatial/temporal) for tar sand development and associated infrastructure needed.
- Need for of integrated multi-resource land use planning.
- Processed sand characterization and R&D for alternative by-products or disposal.
- Conduct research and analysis to reduce process/development foot print.

4.2.3 Heavy Oil

For the most part, heavy oil resources are located in areas with existing oil production infrastructure and their development does not entail activities that result in environmental impacts beyond those of conventional oil production activity. Heavy oil production relies on thermal processes that require the generation of heat through combustion and consequently produce CO_2 and other emissions. Research to reduce the need for surface steam generation through the use of downhole steam generators, is one area where an entirely new approach could lead to a reduction in emissions.

Sand production can be an environmental problem as well as an operational problem, as deoiling the sand to allow for its safe disposal can be a costly effort.

General environmental challenges and associated R&D needs include:

- Development and demonstration of technologies to reduce emissions associated with steam generation or heavy oil processing and upgrading.
- Develop and demonstration of cost-effective technologies for dealing with produced sand in an environmentally safe manner.
- Develop and demonstrate cost-effective technologies for producing heavy oil in environmentally sensitive environments (e.g., offshore, arctic).

4.2.4 Oil from Fractured Shale

Exploration and production operations for producing OFS is carried out in the same manner as conventional oil and gas exploration and production operations, with the exception that a growing number of the wells drilled are horizontal and completion includes multiple fracture treatments, much like gas shale development. Because most of the current and potential future development locations for this resource are congruent with established oil and gas producing areas, further development would not likely result in the need to build new infrastructure in populated areas unfamiliar with drilling and producing operations (as has been the case with some unconventional gas resources). Environmental challenges are expected to be largely limited to the need to reduce water consumption, operational footprint (e.g., development of low impact drilling operations), and emissions from drilling and production activities.

General environmental challenges and associated R&D needs include:

- Developing ways to reduce the volume of water required and to encourage water recycling and re-use for large volume water fracturing treatments.
- Developing and demonstrating advanced, efficient, and cost-effective treatment technologies for produced and fracturing flowback water.
- Developing technologies to reduce the likelihood of contamination of surface water supplies during collection, transport, and disposal of flowback water volumes.
- Developing technologies to reduce the footprint of drilling and production activities.
- Developing technologies to mitigate sound and particulate dispersion associated with operations.

4.2.5 Residual Oil

Production operations for producing residual oil from conventional reservoirs would be carried out in the same manner as conventional oil and gas E&P operations and would, by definition, take place in existing fields. Environmental challenges are expected to be limited to the need to reduce operational footprint (e.g., development of low impact drilling operations) and emissions from drilling and producing activities; however, these challenges are no greater than those facing conventional oil and gas operations. There may be some additional environmental impact from the need to build CO2 pipeline infrastructure, but this would not be considered to be a special challenge unique to this resource, nor would it entail the need for any R&D to overcome specific environmental impact challenges.

4.2.6 Tight Gas

The primary environmental challenge related to tight gas sand production is in developing ways to reduce the footprint of drilling and production activities in arid ecosystems and to mitigate particulate dispersion associated with operations. Water usage and disposal is a similarly critical issue in tight gas plays. One challenge is to develop regional assessment methods to consider water resource requirements and impacts and to investigate technologies to reduce fresh water demand in the production of tight gas.

4.2.7 Gas from Coal Seams

Environmental challenges related to CBM production and the R&D needs that result from those challenges fall into two categories: water disposal and surface disturbance.

General environmental challenges and associated R&D needs include:

- Developing ways to reduce the volume of produced water (during the coal seam dewatering phase) and to reduce the amount of ionic constituents in saline waters before disposal.
- Development of alternative methods for disposal of both saline and fresh produced water that will mitigate any environmental impacts.
- Developing ways to reduce the footprint of drilling and production activities, and to mitigate sound and particulate pollution associated with operations.
- Development of an improved understanding of the potential for exacerbating methane seepage from natural outcrops as a result of dewatering coal seams for CBM production.

4.2.8 Shale Gas

There are three primary environmental challenges related to shale gas exploration and production: water supply, water impacts, and surface disturbance. Impact on air quality may be a concern.

General environmental challenges and associated R&D needs include:

- Developing ways to reduce the volume of water required and to encourage water recycling and re-use for large volume water fracturing treatments.
- Developing and demonstrating advanced, efficient, and cost-effective treatment technologies for produced and fracturing flowback water.
- Developing technologies to reduce the likelihood of contamination of surface water supplies during collection, transport, and disposal of flowback water volumes (which can be high in salinity).
- Developing technologies to reduce the footprint of drilling and production activities.
- Developing technologies to mitigate sound and particulate dispersion associated with operations.
- Conducting scientific analyses to assess the potential risks to drinking water posed by hydraulic fracturing of shale formations.
- Conducting analyses to assess potential air emission concerns associated with shale gas operations.

4.2.9 Methane Hydrate

The National Research Council (NRC) conducted a review of DOE's Methane Hydrates Research Program in 2009, as mandated in the Energy Policy Act of 2005.[151] This review determined that with respect to considering eventual commercial production of methane from methane hydrate, understanding the potential environmental impacts of methane hydrate degassing and the seafloor hazards ("geohazards") resulting from methane hydrate dissociation as a result of oil and gas drilling and production are of specific importance. In particular, the NRC report determined that designing production tests, appraising and mitigating environmental and geohazard issues related to production, and quantification of the methane hydrate resource, were critical to achieving the Program goals on the Alaska North Slope in the near term and in marine methane hydrate–bearing sand reservoirs over the longer term.

Specifically, appraisal and mitigation of environmental and geohazard issues related to production should include:

- Compilation of industry experience associated with conventional oil and gas production in areas where methane hydrate occurs.
- Organized workshops to solicit input and identify research goals needed to evaluate and mitigate geohazards and environmental issues specific to the production of methane from methane hydrate and to perturbations of methane hydrate associated with other oil and gas development activities.
- Studies specifically addressing potential geohazards associated with methane production from methane hydrate (e.g., laboratory measurements, modeling, and natural perturbation experiments) to provide more confidence in risk assessments and effective mitigation strategies.

The NRC report concluded that although understanding the role of methane hydrate as a source of global greenhouse gas is of general interest, this research is not uniquely related to realizing methane hydrate as an energy resource. However, quantifying ongoing, natural methane fluxes from methane hydrate on a local scale was determined to be necessary to provide a baseline to evaluate the effects of any future production and development of the methane hydrate resource. Thus, studies are required to address the processes involved (a) in the transmission of methane from the subsurface through the methane hydrate stability zone to the surface and (b) in the subsequent fate of the released methane. It was recommended that these studies focus on degassing processes and potentially enhanced environmental impacts from commercial production of methane from methane hydrate and from methane hydrate associated with other oil and gas developments. Areas for research focus related specifically to environmental impacts included the following.

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[151] National Academies of Sciences, 2010, *Realizing the Energy Potential of Methane Hydrate for the United States*, Committee on Assessment of the Department of Energy's Methane Hydrate Research and Development Program: Evaluating Methane Hydrate as a Future Energy Resource (available at http://www.nap.edu/catalog/12831.html)

Geomechanical response – There are substantial changes expected in sediment strength and permeability when methane production occurs from a hydrate bearing zone. Over the life of producing methane hydrate reservoirs the dissociated zone may initially affect the near well-bore area, but with time, the affected area could move some distance away from the producing well. Strength and consolidation changes in the near well-bore area and production-induced regional subsidence could induce significant forces on the well casing resulting in casing failure. Because most methane hydrate–bearing sediments are unconsolidated, potential also exists for sediment migration into the producing well, resulting in operational problems. Specific challenges may exist if production schemes such as the use of horizontal wells are considered.

Water production issues – Another largely understudied topic is the amount and chemistry of the produced water that may be released when methane hydrate deposits dissociate. Some reservoir simulation models suggest that the pore water liberated when methane hydrate dissociates will be highly mobile and will flow to the producing well. The volume of produced water associated with methane hydrate production will directly impact the design of the well completion (i.e. downhole pump selection) but also will be a consideration in terms of ancillary environmental issues related to water disposal.

Seal integrity and control of gas migration – An important environmental consideration in any gas field is the risk of gas migration away from the production well infrastructure interacting with other geologic strata at depth or reaching the surface. In both cases a critical consideration is the seal integrity of the permeability barrier overlying the production interval in the near well bore area and also away from the well bore. For most methane hydrate deposits, the nature of the seals may differ significantly from traditional hydrocarbon reservoirs. In some settings, methane hydrate itself or a permafrost layer may act as a seal and trap free gas below.[152] The relatively shallow depths of methane hydrate occurrences also may mean that secondary sealing by the overlying sediment may only be weakly developed. At present the mobility of the gas and water released from methane hydrate decomposition is unknown, including their potential to migrate to the surface.[153,154] Migrating methane can also reform into methane hydrate within the cold ocean bottom waters and could potentially compromise subsea system operations. Likewise, erosion of the seafloor around wellheads could compromise these structures.

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[152] Grauls, D. 2001. Gas hydrates: Importance and applications in petroleum exploration. Marine and Petroleum Geology 18:519-523.

[153] Xu, W., and C. Ruppel. 1999. Predicting the occurrence, distribution, and evolution of methane gas hydrate in porous marine sediments. Journal of Geophysical Research 104:5081-5096.

[154] Judd, A., and M. Hovland. 2007. Seabed fluid flow: The impact on geology, biology and the marine environment. Cambridge, UK: Cambridge University Press. 492 pp.

Potential impact on unique marine biological communities – Although the target for commercial development would be methane hydrate deposits within sand sediments in the subsurface and not the seafloor hydrate deposits that are home to biological communities dependent on hydrocarbons, there is some potential for impacts to these communities that needs to be addressed with targeted research.

4.2.10 Unmineable Coal

Environmental challenges related to UCG include ground subsidence and leakage of combustion gases and contaminants from the combustion cavity into adjacent strata, including groundwater aquifers. Groundwater must be protected by operating the gasification process at pressures below those of the nearby aquifers (i.e., below hydrostatic pressure). Process variables, including oxygen and steam injection pressure, rate, concentration, and well placement are used to achieve this.

General environmental challenges and associated R&D needs include:

- Developing ways to reduce the potential for or mitigate ground subsidence.
- Developing and demonstrating advanced, efficient, and cost-effective technologies for preventing contamination of underground water aquifers during or after UCG.
- Developing technologies to reduce the footprint of drilling and production activities associated with UCG in sensitive ecosystems.
- Developing technologies to mitigate sound and particulate dispersion associated with operations.
- Developing and demonstrating technologies for reducing CO2 emissions from UCG, including those processes required for conversion of syngas into other product streams.

V. Resource/R&D Matrix

This section attempts to align identified R&D needs for each resource with current R&D activities, both public and private. Federal R&D activities are highlighted in green, university research activities in blue, and private industry activities in red. Where public funding is supporting academic or industry efforts, a notation is made.

These tables are as comprehensive as currently possible, given the proprietary nature of some industry efforts and some academic efforts funded by industry. The purpose of this summary is to provide a general sense of where current R&D activity is focused. It does not, however, provide any indication of appropriate relative levels of funding. Neither do the entries in this table reflect any indication of the magnitude of progress towards meeting any of the challenges. It only reflects that some research is under way.

It is important to recognize that Federal oil and gas R&D activities span a spectrum of initiatives that are implemented through a number of paths:

- Research funded by congressionally appropriated funds and that is managed by DOE Office of Fossil Energy and implemented through NETL (the legislative language in Section 1 of this document is an example)
- Research funded by Title IX, Subtitle J of EPAct that is focused on specific topics (ultra-deepwater architecture, unconventional natural gas and other petroleum resources, and challenges of small producers) that is also managed by the DOE Office of Fossil Energy and implemented through NETL (through an agreement with RPSEA, the Research Partnership to Secure Energy for America)
- Research funded by Title IX, Subtitle J of EPAct that is focused on research that is complementary to the work being done under the consortium and is carried out by NETL's Office of Research and Development.

The current public research efforts outlined in the following tables are being implemented through one of these three paths. A significant number of projects related to unconventional natural gas are being carried out by contracts awarded under the 2007 and 2008 R&D portfolios administered by RPSEA.

5.1 Oil Shale

Challenge Category	Challenges/R&D Needs	Current R&D Activity Performer*
Process/Production Technology	How to increase process energy efficiency (net energy balance) for both surface and *in situ* processes	Various private industry enterprises
	How to reduce high net water requirements	Various private industry enterprises
	How to improve the reliability of downhole heating sources	Various private industry enterprises
	Need to understand fundamental characteristics of oil shale (rock properties and analytical methods)	Colorado School of Mines' Center for Oil Shale Technology and Research (supported by industry) University of Utah (supported by NETL)
	Fundamental understanding of pyrolysis under surface and *in situ* conditions	Idaho National Laboratory University of Utah (supported by NETL)
	Enhanced characterization of resource quantity and quality	USGS University of Utah (supported by NETL) Utah Geological Survey (supported by BLM and USGS)
Environmental	Need to acquire basin/regional baseline air emissions data and develop models for evaluating impacts of oil shale development	LANL (supported by DOE Office of Naval Petroleum and oil Shale Reserves) USGS (various state and local governments) NETL (Office of Research and Development)
	Need to develop and evaluate technologies for reducing or controlling air emissions (including CO2)	Idaho National Laboratory University of Utah (supported by NETL)
	Need to acquire and integrate basin/regional baseline surface and groundwater data (quality and quantity) and develop tools for modeling changes	Colorado School of Mines' Center for Oil Shale Technology and Research (supported by industry and NETL) Idaho National Laboratory Utah Geologic Survey
	Need for assessment of water requirements and potential effluents related to oil shale development (both surface and *in situ*) in conjunction with other regional water uses	Idaho National Laboratory University of Utah (supported by NETL)
	Need to develop and evaluate technologies for reducing or controlling water contamination, either surface or subsurface	University of Utah (supported by NETL)
	Need to develop technologies for reducing water consumption	Various private industry enterprises
	Need to assess alternative by-product uses for spent shale	
	Need to coordinate infrastructure evaluation using GIS-based analysis tools to assess oil shale and alternative land use development scenarios	Idaho National Laboratory
	Find ways to reduce process/development foot print	Various private industry enterprises
	Conduct research on subsidence and potential mitigation strategies	
Regulatory	Analysis of regulatory issues to enhance efficiency and reduce regulatory burden	University of Utah (supported by NETL) USGS
	Data repository and decision-making tools	Idaho National Laboratory

** from "Oil Shale Research in the United States – Profiles of oil Shale Research and Development Activities in Universities, National Laboratories, and Public Agencies," 2009 and other sources identified in previous sections of this report*

5.2 Oil sands

Challenge Category	Challenges/R&D Needs	Current R&D Activity Performer*
Process/Production Technology	How to increase process energy efficiency (net energy balance) for both surface and *in situ* processes	Various private industry enterprises
	How to reduce high net water requirements	Various private industry enterprises
	Enhanced characterization of resource quantity and quality	University of Utah (supported by NETL)
Environmental	Need to develop and evaluate technologies for reducing or controlling air emissions (including CO2)	Idaho National Laboratory University of Utah (supported by NETL)
	Need to acquire and integrate basin/regional baseline surface and groundwater data (quality and quantity) and develop tools for modeling changes	Colorado School of Mines (supported by industry and NETL) Idaho National Laboratory Utah Geologic Survey
	Need to develop technologies for reducing water consumption	Various private industry enterprises

5.3 Heavy Oil

Challenge Category	Challenges/R&D Needs	Current R&D Activity Performer
Process/Production Technology	How to improve recovery of heavy oil in Arctic reservoirs where thermal methods are more difficult to apply	University of Texas, New Mexico Tech, Colorado School of Mines (supported by NETL) BP Alaska
	Development and testing of downhole steam generators	Various private industry enterprises
	How to reduce sand production and water production	Various private industry enterprises

5.4 Oil from Fractured Shale

Challenge Category	Challenges/R&D Needs	Current R&D Activity Performer
Process/Production Technology	How to accurately assess the hydrocarbon potential for the Bakken stratigraphic interval on a sub-regional basis and develop modeling capabilities for this unconventional reservoir	Colorado School of Mines (supported by Idaho National Laboratory and NETL, USGS) Various independent producers
	Characterize the *in situ* stress and geomechanical properties of the Bakken Fm., and use these results to increase the success rate of horizontal drilling and hydraulic fracturing to improve the ultimate recovery	University of North Dakota (supported by NETL)
	Characterize the factors that impact well productivity and oil recovery in the Bakken	University of North Dakota Energy & Environmental Research Center, West Virginia University (supported by NETL) NETL (ORD) Various private industry enterprises
	Understand how to model fracture flow in the Bakken Shale	NETL (ORD)
	Understand if CO2 can be used to enhance production from the Bakken Shale	NETL (ORD)
Environment al	Development of approaches for improved treatment, handling, reuse and, disposal of fluids produced and/or used in field operations	GE Global Research, Altela, Eltron, Farraday Tech., Giner (supported by NETL) ANL (supported by NETL) U. WV, Texas A&M U. (supported by NETL)

5.5 Residual Oil

Challenge Category	Challenges/R&D Needs	Current R&D Activity Performer*
Process/Production Technology	Development and demonstration of methods for implementing CO2 EOR in areas where it has not historically been applied.	U. Alabama, Alabama Geological Survey, Denbury Resources (supported by NETL) U. Kansas (supported by NETL)
	Development of CO2 thickeners	U. Pittsburgh (supported by NETL- ORD)
	Development of new technologies for improving CO2 sweep efficiency (including the use of nanoparticles)	Mississippi State U. LSU (supported by NETL)
CO2 Supply	Develop improved understanding of the physical correlation between CO2 sources and candidate reservoirs for EOR and an up-to-date understanding of the costs of CO2 capture and delivery	NETL
	Develop low-cost options for on-site production of CO2 for small scale flooding	Various private industry enterprises

5.6 Tight Gas

Challenge Category	Challenges/R&D Needs	Current R&D Activity Performer*
Process/Production Technology	Understanding the potential resources associated with new or underdeveloped tight gas plays and identifying technical and economic barriers to their development	Gas Technology Institute (supported by NETL)
	Understanding the geological, geochemical, and geophysical framework of tight gas plays	C.S. Mines (supported by NETL) LBNL (supported by NETL)
	Developing technologies for characterizing fracture attributes (orientation, intensity, openness, fluid saturation)	U. Texas (supported by NETL)
	Developing methods to improve the design and implementation of hydraulic fracturing	Texas A&M U., U. Tulsa (supported by NETL) C.S. Mines (FAST industry consortium)
	Understanding the geological, geochemical, geophysical, and operational parameters that differentiate high-performing wells, areas, and/or fields	Various private industry enterprises
	Development of improved drilling methods that lower cost, reduce time on location, use less materials, or otherwise increase the efficiency and effectiveness of well construction	Various private industry enterprises
	Development of methods and technologies to maintain the permeability generated through stimulation operations and minimize formation damage over time	Stanford, Texas A&M U. (supported by NETL)
	Development of improved models for optimizing gas production	Texas A&M U., U. Texas, U. Tulsa, U. Utah (supported by NETL) C.S. Mines (FAST industry consortium)
Environmental	Development of approaches for improved treatment, handling, reuse, and disposal of fluids produced and/or used in field operations	GE Global Research (supported by NETL)
	Development of comprehensive approaches for the conservation and management of water resources used and produced during all aspects of tight gas development	C.S. Mines (supported by NETL)
	Development of advanced drilling, completion, and/or stimulation methods that minimize surface impact	HARC (supported by NETL)

5.7 Gas from Coal Seams

Challenge Category	Challenges/R&D Needs	Current R&D Activity Performer*
Process/Production Technology	Developing methods to improve the design and implementation of hydraulic fracturing	Penn State U. (supported by NETL)
	Development of approaches for improved treatment, handling, reuse and, disposal of fluids produced and/or used in field operations	GE Global Research (supported by NETL)
Environmental	Development of comprehensive approaches for the conservation and management of water resources used and produced during all aspects of tight gas development	C.S. Mines (supported by NETL) Geological Survey of Alabama (supported by NETL)
	Development of advanced drilling, completion, and/or stimulation methods that minimize surface impact	HARC (supported by NETL)
	Development of an improved understanding of the potential for exacerbating methane seepage from natural outcrops as a result of dewatering of coal seams for CBM production.	

5.8 Shale Gas

Challenge Category	Challenges/R&D Needs	Current R&D Activity Performer*
Process/Production Technology	Understanding the potential resources associated with new or underdeveloped shale plays and identifying technical and economic barriers to their development	Geo.Survey of Alabama (supported by NETL) Utah Geological Survey (supported by NETL)
	Understanding the geological, geochemical, and geophysical framework of shale plays	LBNL (supported by NETL)
	Developing technologies for characterizing fracture attributes (orientation, intensity, openness, fluid saturation)	U. Texas (supported by NETL)
	Developing methods to improve the design and implementation of hydraulic fracturing	LBNL (supported by NETL) U. Houston (supported by NETL) C.S. Mines (FAST industry consortium)
	Understanding the geological, geochemical, geophysical, and operational parameters that differentiate high-performing wells, areas, and/or fields	LBNL (supported by NETL)
	Development of improved drilling methods that lower cost, reduce time on location, use less materials, or otherwise increase the efficiency and effectiveness of well construction	Various private industry enterprises
	Development of improved stimulation and completion methods (including multi-zone techniques, steerable hydraulic fractures, non-damaging fluids, high strength/low density proppants, and lower treatment volume processes)	Various private industry enterprises
	Development of methods to accurately assess the potential for shale gas production based on reservoir and production data	Various private industry enterprises
	Development of improved models for optimizing gas production	LBNL (supported by NETL) Texas A&M U., U. Texas, CIT (supported by NETL) C.S. Mines (FAST industry consortium)
Environmental	Development of approaches for improved treatment, handling, reuse and, disposal of fluids produced and/or used in field operations	GE Global Research, Altela, Eltron, Farraday Tech., Giner (supported by NETL) ANL (supported by NETL) U. WV, Texas A&M U. (supported by NETL)
	Development of comprehensive approaches for the conservation and management of water resources used and produced during all aspects of shale gas development	U. Arkansas, U. WV (supported by NETL)
	Development of advanced drilling, completion, and/or stimulation methods that minimize surface impact	HARC (supported by NETL)
	Development of water management approaches that minimize the impact of drilling, completion, stimulation, and production operations on natural water resources	C.S. Mines, U. WV, U. Pittsburgh (supported by NETL) Gas Technology Institute, ALL Consulting (supported by NETL)
Regulatory	Reducing impacts using broad stakeholder approach	IOGCC (supported by NETL)

5.9 Methane Hydrate

Challenge Category	Challenges/R&D Needs	Current R&D Activity Performer*
Process/Production Technology	Characterize in-place methane hydrate resource on the Alaska North Slope (ANS) via field and lab studies	BP, UAF, USGS, LBNL, NETL, other academic and industry partners (with NETL)
	Characterize methane hydrates in the deep water GOM	JIP (Chevron-led Joint Industry Project) (with NETL) U.Texas, MIT (supported by NETL), USGS U. Miss. Center for Marine Resources and Environ. Technology (CMRET) (supported by NETL)
	Understand geomechanical and geohazards issues	BPXA, ConocoPhillips, USGS, LBNL, NETL
	Understand effect of CO2 injection on methane hydrate producibility	ConocoPhillips (with NETL), PNNL, NETL
	Understand relationship of residual heat flow anomalies to fluid flow and gas hydrate distribution in the subsurface	Oregon State (supported by NETL)
	Need to develop new tools for the characterization and quantification of the occurrence of hydrate in the seafloor section	UC San Diego (Scripps), LLNL, USGS, Baylor U. (supported by NETL)
Environmental	Understand the fundamental nature of gas hydrate systems and how that affects development as an energy resource and influence on climate, including the physical characteristics of methane hydrate and the sediments in which it is found, under static and dynamic pressure/temperature conditions	Georgia Tech, MIT, Rice U., U.Texas, ORNL, LBNL (supported by NETL), USGS, PNNL, NETL
	Understand role of methane hydrates in the global carbon cycle, including methane flux in marine and arctic environments	U.CA-Santa Barbara, U Delaware, U. Alaska – Fairbanks, Tex. A&M, U. Chicago (supported by NETL), NETL, NRL, USGS

5.10 Unmineable Coal

Challenge Category	Challenges/R&D Needs	Current R&D Activity Performer
Process/Production Technology	How to increase process efficiency though better site selection well placement and injection/production controls	Various private industry enterprises LLNL, ANL
	Enhanced capabilities related to UCG process simulation and modeling	Various private industry enterprises
	Develop and demonstrate technologies for optimizing existing UCG processes for application to specific coal deposits.	Various private industry enterprises LLNL, ANL
Environmental	Develop technologies for avoiding and mitigating environmental impacts of UCG on subsurface water and surface ecosystems	
	Develop and demonstrate technologies for combining UGC with carbon sequestration.	
	Develop a better understanding of the combustion process and of how this process can be controlled to produce the highest quality gas, with a minimum of associated pollutants	

5.11 Crosscutting Technology Transfer

Challenge Category	Challenges/R&D Needs	Current R&D Activity Performer
Archiving of Past R&D Information	Need to develop and maintain processes for capturing historical data and information related to unconventional fossil energy and centralized locations for archiving this information in a way that maximizes its availability to the research and producer communities	CSM, University of Utah (supported by NETL and industry partners) NETL
Outreach and Facilitation of Industry/Academic R&D Collaboration	Meetings, conferences, symposia, and workshops related to unconventional resources (e.g., Annual Oil Shale Conference at CSM)	CSM (supported by NETL and industry partners) Industry Publishing Companies and Professional Associations Research consortia (supported by NETL)
	Publications related to unconventional resources	Industry Publishing Companies and Professional Associations Research consortia supported by NETL NETL

VI. Conclusion

As set forth in section I above, past and continuing research focused on unconventional fossil energy resources is driven by several factors, including:

- An understanding of the potential magnitude of each resource and the associated benefit of developing it as a long term source of domestic energy supply,
- An understanding of the technical and environmental challenges, and the research needs facing developers of each resource,
- A general understanding of the current status of research activity for each resource category, and
- Recognition and quantification of the cumulative environmental, safety, and resource impacts of simultaneous development of multiple conventional and unconventional resources on a regional/ national basis.

Through an examination of past and continuing research into unconventional fossil energy resources, Section II confirms the following:

- In the near-term, energy consumption will continue to grow and in particular, liquid fossil fuels will remain a significant part of our national energy mix.
- Demand for liquid fossil fuels will require the U.S. to continue to import crude oil for the foreseeable future, despite strong growth in renewable biofuels supply.
- Despite expected dramatic improvements in energy efficiency and conservation, emissions of CO2 from fossil fuel consumption will continue to be a challenge.

Section III of this document outlines the relative magnitude and character of each of the unconventional fossil fuel resources, given certain assumptions and with recognition of the lack of precision in some resource estimates. Table 6-1 lists the unconventional resource categories in order of magnitude (using a bbl of oil equivalent (BOE) conversion of 5,800 cubic feet of gas per BOE) along with a brief summary statement related to the current R&D activity level (synthesized from Sections IV and V of this document) among public and private performers.

Table 6-1: Resource Magnitude and Relative R&D Activity Aligned with Carbon Management Goals

Resource	Est. Recoverable (billion BOE)	Alignment with National Carbon Management Goals	Current R&D Activity Level	
			Private	**Public**
Oil Shale	630 - 1360	**Negative** or **neutral** (assuming increased CO2 emissions can be captured and stored).	Significant investment *in situ* methods by small subset of industry. Some investment in surface methods also.	Low to moderate support from public funding currently. Significant past funding to establish knowledge base.
Methane Hydrate	17 to 350+ (85 to 2000+ Tcf)	**Positive** due to replacement of higher carbon fuel sources with natural gas **and possible** sequestration of anthropogenic CO2 in hydrate.	Moderate investment by a small subset of major producers partnering with DOE. Major funding by other nations.	Moderate support from public funding currently. Moderate past funding to establish knowledge base.
Unmineable Coal	250+ (1500+ Tcf)	**Neutral** (assuming carbon emissions can be captured and stored) or **possibly positive** if syngas replaces coal in power generation.	Minor investment in U.S. Higher level of activity internationally.	Minor investment through national lab.
Residual Oil	230	**Positive** due to sequestration of anthropogenic CO2 in oil reservoirs.	Minor investment by small subset of independent producers that are focused on this resource.	Low public funding currently. Significant past funding to establish knowledge base.
Gas Shale	45 (261 Tcf)	**Positive** due to replacement of higher carbon fuel sources with natural gas.	Moderate investment by independent producers that are focused on this resource.	Significant public funding currently. Significant past funding to establish knowledge base.
Tight Sands	32 (184 Tcf)	**Positive** due to replacement of higher carbon fuel sources with natural gas.	Moderate investment by producers focused on this resource.	Significant public funding currently. Significant past funding to establish knowledge base.
Oil Sands	10-30	**Negative** or **neutral** (assuming increased CO2 emissions can be captured and stored).	Minor investment.	Low public funding currently.
Heavy Oil	10	**Negative** or **neutral** (assuming increased CO2 emissions can be captured and stored).	Minor investment by producers that are focused on this resource.	Low public funding currently. Significant past funding to establish knowledge base.
CBM	7 (41 Tcf)	**Positive** due to replacement of higher carbon fuel sources with natural gas.	Low to moderate investment by subset of producers focused on this resource.	Low to moderate public funding currently. Significant past funding to establish knowledge base.
Oil from Fractured Shale	5-10+	**Neutral** (assuming increased CO2 emissions can be captured and stored) or **possibly positive** if CO2 can be stored via EOR.	Minor investment by small subset of independent producers that are focused on this resource.	Moderate public funding currently.

VII. Appendix A: Responses to Request for Comments on Draft Report

A total of 27 responses containing more than 200 individual comments were received during a 30-day comment period beginning April 25, 2010. The organizations represented by the responders are shown in the table below.

Organization	Number of Responses
Private Individual	7
Industry (incl. industry groups)	6
Universities	5 (from 2 univ.)
Nonprofit/public interest groups	3
Research consortia	2
Lobbying groups	1
Professional associations	1
State Geological Surveys	1
National Labs (not NETL)	1

The comments can be categorized in five categories: (1) identification of errors or typos, (2) suggested improvements in structure, wording, or emphasis, (3) comments related to the rationale or conclusions, (4) comments related to the premise of the report, and (5) other comments. These are summarized below in reduced form, with specific responses indicated, in bold.

1. **All of the comments in Category One were addressed.**

2. **All of the comments in Category Two were addressed where appropriate.** For example:

- There should be a crosscutting focus area (in addition to the various resource topic areas) related to technology transfer; specifically, information archiving and outreach efforts. **This was added to Sections 5 and 6, and a recommendation was made in the Summary.**
- Clarify the fact that a significant portion of current federally funded research related to unconventional natural gas is being administered by a consortium under the EPAct 2005 legislation. **This was added in the Summary and again in Section 5.**
- The primary factor hindering CO2 EOR is not technology, but reasonably priced CO2 supply. Need to include as an R&D need, an assessment of all potential by-product CO2 supply sources in the United States and a state-of-the-art assessment of the costs for extracting and delivering CO2 from flue gas streams to candidate reservoirs. "Feasibility and Economics of By-Product CO2 Supply for Enhanced Oil Recovery, DOE/MC/08333-3, 1982 should be updated and expanded. **A research need was added in Section 5.**
- Research is needed to develop low cost options for on-site generation of CO2. **A research need was added in Section 5**.
- The sections on methane hydrate are incomplete, and the discussion of R&D challenges does not reference activities of the methane hydrate program documented in the NRC report, "Recognizing the Energy Potential of Methane Hydrate for the United States." **This was corrected.**

- Two areas that are not specifically mentioned in Section 4 but where research is needed related to CBM environmental impacts are not included. These are: improved understanding of the potential for exacerbating natural methane seepage at outcrops due to dewatering of deeper coal seams and improved understanding of the potential for outcrop coal seam fires due to dewatering. **Additions were made to Sections 4 & 5.**
- The potential for CO2 EOR combined with sequestration is significant, but the single greatest challenge to realizing that potential is the poor volumetric sweep efficiency of the process. The key goal in CO2 EOR and EOR/sequestration must be to control the pathways of CO2 in the reservoir. The design and development of smart stabilizers incorporating nanoparticles is of importance in this effort. **Additions were made to Sections 4 and 5.**
- The research roadmap for UCG published by the Clean Air Task Force with input from LLNL in 2009 should be considered in this report. Specifically, consideration should be given to the need to improve fundamental understanding of UCG processes and interactions with the subsurface environment, including simulation, monitoring and CO2 capture/sequestration technologies, development of a UCG field program and dedicated R&D/training facility, and support for international field activities. **Additions were made to Section 5.**
- Miscible flooding using CO2 is very important to residual oil recovery, but it cannot be applied to certain classes of reservoirs. Chemical flooding is an effective process to recover residual oil from these reservoirs. These processes are economic at the current prices and many oil companies are developing their capability in chemical flooding right now. NETL should include it in its priority list along with CO2 flooding. **While it is true that chemical flooding holds promise in specific reservoirs and federal R&D has been (and is currently) focused on this area, the volume of recoverable oil via this method is believed to be considerably less than that potentially recoverable via miscible flooding at this time.**
- Regional geologic knowledge is the framework that allows for assessments of resource potential and the foundation for developing and refining resource estimates. Enhancing geologic knowledge will improve estimates of unconventional fossil energy resources, and this should be an increased focus of federal R&D investment. This is an area of chronic underinvestment across federal agencies. **The document supports this, although not explicitly.**
- Federal R&D investment should focus both on technologies to produce the resource and ways to minimize the environmental impact of such development. There is scope for additional partnering between the public and private sector to make technological gains and move these technologies from the laboratory to the field through demonstration projects. **The document supports this.**
- Broad dissemination of the research results, new technologies, and the underlying geological data and samples is important to encourage adoption of new techniques and best practices throughout the industry and to spur additional improvements. **Additions to Sections 5 and 6, and a recommendation made in the Summary were added to strengthen this point.**
- The nomenclature is inconsistent with respect to oil production from shale. **This was**

corrected in Section 3.2.4.

- Environmental challenges for producing oil from fractured shale are consistent with those faced by shale gas developers and they should be listed in Section 4.2 and 5. **This was added.**
- Proper terminology should be "oil sands," not "tar sands" (American usage). Both are used, and this is confusing. **This was corrected.**
- The environmental challenges section for tight gas (Section 4.2.6) mentions that the primary environmental challenges are to reduce the surface footprint and mitigate particulate dispersion associated with operations. Water usage/disposal is a similarly critical issue in tight gas plays. One challenge is to develop regional assessment methods to consider water resource requirements and impacts and to investigate technologies to reduce fresh water demand in the production of tight gas. **This was added.**
- Clarify in Section 4.1.1 that in the case of oil shale, *in situ* methods are in a substantially less mature state for deployment than the surface retort techniques. **This was added.**
- Move references to the DOE funding of the University of Utah's Institute for Clean and Secure Energy (ICSE) to Section 4.2.1, and add there also reference DOE funding of LANL research to develop integrated assessment models to investigate basin-wide requirements and impacts associated with regional development of a potential oil shale production industry. **This was done.**

3. The questions raised by the comments in Category Three (rationale/conclusions) can be sub-categorized into two groups: Oil Shale and Other. All of these comments were considered in finalizing the report.

Comments related to the conclusions regarding the relative need for additional research related to oil shale, both pro and con (summarized):

- The research strategy section (Section 6) is vague and the relative importance of various criteria is ambiguous. Oil shale appears to have been unfairly penalized. Water use should be important in the discussion, and should reflect the best available state of knowledge. This will make clear the tradeoffs in evaluating energy options, and hopefully guard against sub-optimization by too heavy focus on one criterion. The substantially higher water use for EOR relative to oil shale should be discussed.
- The challenges and associated R&D needs related to oil shale appear to be those worthy of public support, but based on the reviewers experience in both the public and private sectors, there is concern that public research in all these areas will not be productive. Specifically:
    - The government should not get involved in oil shale process design. Companies will pursue their own proprietary processes. The general principles for process design are now pretty well established.

- New processes being pursued today take less water, and further process optimization will not be significantly aided by government assistance. What may be needed and helpful is financial support for better water desalinization processes (of broad importance), understanding tributary hydrology associated with water usage, and government support for rational water policies.
- Heater technology is closely related to process design, and researching one type of heater will necessarily benefit one company over another. Only basic material science research would be worthwhile.
- There are lots of data on oil shale thermomechanical properties, but there is room for extending these studies to a wider range of lithologies and to develop some fundamental mathematical models that address the variability of the rock properties as a function of grade and lithology and how they change with temperature and kerogen conversion. There may be a role for government-industry collaboration in validating these models at the footscale level, but integration into process models should be left to industry.
- In-situ pyrolysis is understood pretty well based on oil shale work from the 1980s and proprietary work by those companies currently pursuing in-situ recovery. Recent public sector (university and national lab) work behind the state of the art. Experimental work experiment tends to be process specific and consequently companies prefer to pursue their own methods.
- The size and quality of the oil shale resource is known fairly well. What is lacking is demonstration of a cost effective process.
- Cooperative research work by government and industry is best focused on: (1) reducing the costs of desalinization, (2) understanding deep hydrology as it affects tributary water regulations (rather than the hydrology of the upper Green River Fm.), (3) reducing the costs of capturing CO_2 emissions (e.g. by mineralization in spent in-situ retorts versus deep sequestration).
- It is difficult to arrange industry-funded contracts with universities and national labs due to problems with publication and intellectual property rights.

- The report should: (1) assign a high priority to development of domestic oil shale, sands and heavy oil resources; (2) emphasize research on emerging technologies in these segments; and (3) recommend enhanced implementation of the federal oil shale leasing program and research partnerships with key resource holders.
- Higher research priority should be given to technologies for extraction of oil shale, oil sands and heavy oil. With respect to CO_2 EOR, the report states that "any reason to reduce the amount of crude oil or liquid fuels that must be imported from foreign suppliers will enhance energy security." If that is a primary criterion then oil shale, oil sands and heavy oil should rank high as well. Arguably, these resources along with heavy oil are the low hanging fruit in the area of domestic unconventional resources.

- Research priorities should be informed by the high priority that Congress has assigned to development of domestic shale, sands and heavy oil resources (e.g., The Oil Shale, Tar Sands, and Other Strategic Unconventional Fuels Act of 2005 states that the US oil shale and tar sands are strategically important domestic resources that should be developed). Congress enacted Section 369(i), which directs DOE to establish a program for development of domestic oil shale, sands and heavy oil resources.
- The Federal Task Force Report titled Secure Fuels from Domestic Resources: The Continuing Evolution of America's Oil Shale and Tar Sands Industries (June 2007) concludes that more than 30 companies are sponsoring new technologies in various stages of development. These include Shell, Phoenix Wyoming, IEP, Petro Probe, Chevron, EGL, Exxon/Mobil, Schlumberger, Red Leaf, Mountain West. These promising new technologies are at various stages of development, but all have the potential for significant reductions in environmental and water consumption impacts.
- Implementation of the Department of Interior commercial oil shale leasing program has been suspended by the current Administration. While the Administration has proceeded with the Department's program for research, development and demonstration (RD&D) leases, the leasing terms have been sufficiently severe to discourage most applicants. In total, the federal oil shale program is now nearly three years behind the schedule mandated in the Energy Policy Act of 2005. The report should establish a high research priority for oil shale, sands and heavy oil resources by noting the importance of timely implementation of the current Interior Department programs.
- The Strategic Unconventional Fuels Task Force wrote a strategic plan for the commercialization of Unconventional Fuels, which was submitted to Congress in 2007. This document should serve as the starting point for the current strategy. Oil shale must play a prominent role in the nation's unconventional fuels strategy and be adequately considered in this publication based upon the size of the resource and its potential to meet U.S. petroleum demands for several centuries.
- The document should Include shale oil as a priority resource, specify U.S. energy and economic development as a strategic priority, define the time-line of unconventional fuel development as a long term strategy and weight the value of projects accordingly, include a consideration of the geographic distribution of resources, weight the value of resources in relation to market needs and product uses, include processing, including on-site upgrading as a technology priority, and give field laboratory research demonstrations that will help expedite technology development and reduce commercial and environmental risks higher priority than small-scale laboratory and modeling studies.
- In light of the technical immaturity of shale oil development and the wide availability of other, cheaper and environmentally preferable options, devoting Federal research resources in this area is not recommended.
- More emphasis should be placed on in-situ electromagnetic heating of heavy oil and oil shale.

Other comments related to the rationale and conclusions:

- Natural gas R&D will not contribute much to decreasing our dependence on foreign energy supplies, especially from nations unfriendly to the U.S. or threatened by political instability. A balanced strategy would tie RD&D elements proportionally to resources where increased production will reduce imports.
- It would be beneficial to tie development challenges of unconventional fossil energy resources to a time scale. Alongside the development time line the projected demand by fuel type and energy sources for the U.S. should be plotted. Using the development timeline and the projected demand, a more realistic assessment could be made of the timing of when these domestic unconventional resources should "come on line" and the timing for needed R&D investments, to meet the Nation's energy requirements. **This type of analysis, while potentially useful, is beyond the scope of this report.**
- If the cost of capturing CO2 and the life cycle CO2 footprint for oil shale is considered, natural gas might emerge as a much higher priority due to the lower CO2 emissions impact – less energy to extract and cleaner burning.
- The technical staffs of operating companies do not need any academic research help with gas shale.
- There is very limited space to store CO2 in the pore space of oil reservoirs and it is not going to be significant.
- Only a tiny, tiny portion of gas hydrates (those found in thick porous reservoirs) have much chance of being commercially produced.
- The research ranking choices are presumably influenced by perceptions of future supply. The report states that oil production is expected to increase (during the forecast period) from 5 million bbl/day to more than 6 million bbl/day. There is no justification for this assumption and the past three decades of production history for the US does not support it. **Current EIA projections were accepted.**
- No significant mention is made of timing - when might some of the projected volumes become available? The end of the report speaks to short-term and long-term impacts on supply, but no effort is made to consider scale-up timing and requirements. **Calculating the timing of production for each resource is beyond the scope of this report.**
- The estimates of resource, accessibility, and recoverability are optimistic and do not reflect a sufficient level of uncertainty. The probability of all these unconventional resources delivering on their high-end estimates should be considered to be quite small. **The charge was to characterize the relative sizes of the various unconventional fossil energy resources and the research needs associated with them based on currently available information. Calculating the probability of production for each is beyond the scope of this report.**
- Hydrates may have little potential for near-term impact simply because there is no pipeline from Alaska to the lower 48. This appears to be a chicken-and-egg problem. If indeed the hydrates were understood and technically and economically available, a pipeline might be justified. **This point is recognized in the report.**

- No mention is made of the LNG potential which is still growing around the globe and which can land product on US shores cheaper than most of these resources can be produced. What impact would that have on funding decisions and funding levels? **While the price of LNG imports is an import factor in projections of supply and demand balances, it was not considered to be a major factor in determining the relative volume of unconventional fossil energy resources and the research needs related to their development.**
- The report understates that the environmental challenges from unconventional gas production. The issues related to air pollution, water management and noise pollution should be considered for all unconventional gas resources. Additional research is needed related to well construction, fracturing, monitoring and well plugging, with regard to safeguarding groundwater. **Additions were made.**
- Regarding potential environmental impacts, the draft report notes that CO2-EOR operations pose similar risks as conventional oil production operations. The report, however, does not adequately present or quantify those risks. **It is not within the scope of the report to discuss risks related to conventional oil and gas production.**
- UCG deserves research attention because it is possible that carefully-implemented versions of the technology could deliver important environmental benefits over conventional coal extraction and use, in terms of land disturbance, air pollution, water use and impacts, and greenhouse gas mitigation. However, if not performed safely and regulated effectively, UCG could also pose a number of threats to public health and the environment that must be addressed. Research on UCG should address persistent technical questions through improvements in basic science research, simulation techniques, monitoring and verification methods, module design, pursue pathways to CCS and improve control of environmental risks associated with UCG.
- In light of the potential environmental and oil production benefits of CO2-EOR, there should be further research into the environmental integrity, management and lifecycle emissions of the process, as well as further study of the CO2 storage and oil production potential in the ROZ. Such research should also include a more rigorous evaluation of and comparison to conventional oil production practices and alternates for enhanced oil recovery, as well as to imports.
- The report highlights significant potential to produce residual oil from existing oil fields using methods to improve oil flow and boost production with injection of CO2, which can be compatible with the Administration's goals for carbon sequestration and GHG reductions provided effective regulations are in place to ensure permanent sequestration in CO2-enhanced oil recovery projects (CO2-EOR). Furthermore, increasing oil production from fields that have already been developed avoids the considerable additional impacts and risks associated with exploration and development in new fields, onshore or offshore. CO2-EOR can also bring on new supplies of oil much faster than exploration and development of new oil fields.

- Overall it's an excellent piece of work and hits the mark. The research strategy focuses, in order of importance, on residual oil, unmineable coal, methane hydrates, shale gas, tight sands, oil shale, tar sands, heavy oil, and shale oil. This seems about right, given that producers are targeting the latter six of these, and not expending much effort on the first three. In my view, this is not to say that the first three are the most important target for achieving energy security, creating jobs, and reducing CO2 emissions, it's just where the most "bang for the government research buck" is likely to be found. Natural gas (from shale, tight sands, and coals) provides the best opportunity to achieve all three goals.

4. **The comments under Category Four (premise) included:**

- Why aren't we just going all out to produce existing conventional resources?
- Several kinds of resources are present in essentially unlimited supply. Most of them (oil shale, most methane hydrates, coal-to-liquids) are not economic. A few (coal bed and shale methane, Canadian oil sands) are economic. The issues are costs, not technology. They are best determined by private investment and experience. The only role of the government is to do basic R&D if relevant.
- The report fails to acknowledge that exploitation of any of the unconventional fossil resources assessed in the report would be incompatible with the Administration's carbon budget objectives unless deployed with carbon control technology (likely carbon capture and sequestration, or CCS). The report should clearly quantify the GHG emission potential from each of the stated resource estimates of unconventional fossil energy sources, considering scenarios that range from a complete absence of carbon controls to high control rates using CCS or other control technologies associated with the production and use of these resources. The report should also examine whether the exploitation of those resources individually and cumulatively would be compatible with the Administration's stated GHG reduction goals. In addition, the report should examine the technical and economic feasibility of implementing carbon controls through CCS or other technologies with each of the unconventional sources mentioned, comparing and contrasting between those technologies and with non-fossil alternatives, and considering the full life cycle. **This assessment is not within the scope of the report.**
- The final report should consider the energy security, job and wealth creation balance of benefits and impacts of each unconventional resource, while comparing them with those of other fossil and clean alternatives. A complete assessment of the cost, public health, and environmental impacts of unconventional fossil fuels in comparison to other sources should be carried out as a central element of DOE's design of its research, development, and deployment strategy. **This assessment is not within the scope of the report.**
- Given that commercial tar sands development in the U.S. has not taken place and given the additional technical challenges associated with exploiting the U.S. reserves outlined in the draft report, devoting Federal research resources in this area is not recommended unless there are clear potential environmental benefits to be gained.

5. The comments under Category Five (other comments) included:

- Existing USGS resource estimates of the Gulf shelf and US Atlantic appear to be incorrect the potential for deep gas is technically easier to realize than that of gas hydrate consider funding deep gas drilling research rather than unconventional fossil energy.
- More emphasis should be placed on directly helping small producers economically.
- More emphasis should be placed on geothermal energy.
- In subsea areas where both hydrates and minable sulphides are present, the extraction of each would go toward offsetting the costs of extracting the other, along with the sequestration of CO2.
- The $20 million funding for unconventional fossil energy technology is just too little for this huge area of technology. DOE budget for other forms of energy (coal, renewables etc.) is 10 to 100 times larger. About 60 percent of the energy consumption comes from oil and gas where as 25 percent from coal and 7 percent from renewables. As the report shows correctly, the share of the fossil fuel primary energy source is not going to decrease drastically in the next 25 years. We need competent people to enter this area and develop new and safe technology and keep the US leadership alive. This can only be achieved by having strong research programs in petroleum engineering and geosciences at universities and by attracting bright young people to these disciplines. That is only possible if federal funding in this area is substantially more than $20 million per year.
- An often overlooked factor in federal R&D is its role in supporting the nation's research infrastructure through the involvement of universities and colleges, which have proven to be a rich source of technological innovation. Federal R&D investments are essential to the training and development of the next generation of scientists and engineers needed to boost U.S. competitiveness.

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