

# Unconventional Energy Resources: 2011 Review

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This report contains nine unconventional energy resource commodity summaries prepared by committees of the Energy Minerals Division (EMD) of the American Association of Petroleum Geologists. Unconventional energy resources, as used in this report, are those energy resources that do not occur in discrete oil or gas reservoirs held in structural or stratigraphic traps in sedimentary basins. These resources include coal, coalbed methane, gas hydrates, tight gas sands, gas shale and shale oil, geothermal resources, oil sands, oil shale, and uranium resources. Current U.S. and global research and development activities are summarized for each unconventional energy commodity in the topical sections of this report. Coal and uranium are expected to supply a significant portion of the world's energy mix in coming years. Coalbed methane continues to supply about 9% of the U.S. gas production and exploration is expanding in other countries. Recently, natural gas produced from shale and low-permeability (tight) sandstone has made a significant contribution to the energy supply of the United States and is an increasing target for exploration around the world. In addition, oil from shale and heavy oil from sandstone are a new exploration focus in many areas (including the Green River area of Wyoming and northern Alberta). In recent years, research in the areas of geothermal energy sources and gas hydrates has continued to advance. Reviews of the current research and the stages of development of these unconventional energy resources are described in the various sections of this report.

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**KEY WORDS:** Coal, Coalbed methane, Gas hydrates, Tight gas sands, Gas shale and shale oil, Geothermal, Oil sands, Oil shale, Uranium, Unconventional energy resources.

## INTRODUCTION

Peter D. Warwick<sup>3</sup>

The Energy Minerals Division (EMD) of the American Association of Petroleum Geologists (AAPG) is a membership-based, technical interest group having the primary goal of advancing the science of geology, especially as it relates to exploration, discovery, and production of unconventional energy resources. Current research on unconventional energy resources is rapidly changing and

exploration and development efforts for these resources are constantly expanding. Nine summaries derived from 2011 committee reports presented at the EMD Annual Meeting in Houston, Texas in April, 2011, are contained in this review. The complete set of committee reports is available to AAPG members at [http://emd.aapg.org/members\\_only/annual2011/index.cfm](http://emd.aapg.org/members_only/annual2011/index.cfm). This report updates the 2006 and 2009 EMD unconventional energy review published in this journal (American Association of Petroleum Geologists, Energy Minerals Division 2007, 2009).

Included in this report are reviews of current United States and global research activities related to coal, coalbed methane, gas hydrates, tight gas sands, gas shale and shale oil, geothermal resources, oil sands, oil shale, and uranium resources. The field of gas hydrates research is rapidly expanding and is

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currently focused on identifying areas with resource potential and investigating production technology. Research and development of gas shales, geothermal resources, oil sands, and uranium resources are continuing and new interest in these resources has driven exploration efforts into frontier basins. New production technologies such as horizontal drilling and hydro-fracturing have significantly contributed to the advanced development of these unconventional resources and have allowed them to become important contributors to the current energy mix. Please contact the individual authors for additional information about the topics covered in this report. The following website provides more information about all unconventional resources and the Energy Minerals Division: <http://emd.aapg.org>.

## COAL

**W. A. Ambrose<sup>4</sup>**

### *World Production and Consumption*

Coal is a significant component of the world's energy production and consumption, accounting for 27% of total energy use (Energy Information Administration 2010b). Recent developments in clean coal, underground gasification, and coal-to-liquids technology promise to expand coal's role in power generation and fuel consumption.

Coal production in 2010 is estimated to have exceeded 7 billion short tons, or 130.4 quadrillion BTU. Non-OECD (Organisation for Economic Co-operation and Development) Asia led the world in coal production (72.8 quadrillion BTU) in 2007, of which China produced 55.3 quadrillion BTU. In contrast, 2007 coal production in OECD North America represented only 25.3 quadrillion BTU, of which coal production in the United States was 23.5 quadrillion BTU. World coal production is estimated to rise to ~207 quadrillion BTU by 2035 to meet expected increasing demand (Energy Information Administration 2010b). Approximately 64% of international coal consumption in 2008–2009 was

used for generation of electricity, whereas 33% was sold for industrial use (primarily steel manufacture). The remainder was primarily for consumers in residential and commercial sectors. Although most steel-producing countries reduced their steel production more than 10% from 2008 to 2009, China, India, and Iran saw increase.

### *U.S. Production and Consumption*

Coal has traditionally provided ~50% of U.S. electricity generation, although this has recently declined to 47%, owing to a variety of factors that include increased use of cheaper natural gas for power generation, decrease in demand owing to the recent recession, as well as delays in commissioning new proposed coal-fired power plants. Approximately 300 gigawatts (GW) or 281,557 billion BTU of electrical capacity in the U.S. was provided by coal from ~1,500 generating facilities in 2009 (Energy Information Administration 2011b). The National Coal Council estimates that 375 million short tons (mst; 340 million tonnes, Mt) year<sup>-1</sup> for 100 GW of new electric power from coal must be installed by 2025 to meet projected demands in the U.S. (Beck 2006) although few new coal-fired power plants are currently being commissioned for reasons given above.

Coal production in the U.S. fell from 1,171.8 to 1,074.9 mst (1,063–975.1 Mt) between 2008 and 2009, the largest 1-year decline since 1949 (Energy Information Administration 2009a). Likewise, coal consumption in the electric sector declined by 10.3%, whereas coking coal consumption decreased by 30.6%. These declines resulted in record high coal stocks of 233.0 mst (211.3 Mt) at the end of 2009 (Energy Information Administration 2009a).

The western coal region, which includes Alaska, Arizona, Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming, continues to lead the U.S. in coal production, accounting for ~585 mst (530 Mt) in 2009 (Table 1). Wyoming was the largest coal-producing state, although coal production in Wyoming decreased for the first time in 17 years. West Virginia in the Appalachian Basin experienced the greatest tonnage decline in the region in 2009, dropping by 20.7–137.1 mst (18.8–124.4 Mt) (Table 1). Most states experienced declines, with the exception of Ohio, Illinois, Western Kentucky, Alaska, and North Dakota.

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**Table 1.** U.S. Coal Production by Region and State, 2008–2009

Coal-producing Region and State	2008 Production (mst)	2009 Production (mst)
Appalachian total	390.2	341.4
Alabama	20.6	18.8
Kentucky, Eastern	90.3	74.7
Maryland	2.9	2.3
Ohio	26.3	27.5
Pennsylvania	65.4	58.0
Tennessee	2.3	2.0
Virginia	24.7	21.0
West Virginia	157.8	137.1
Interior total	146.6	145.8
Arkansas	0.1	0.0
Illinois	32.9	33.7
Indiana	35.9	35.7
Kansas	0.2	0.2
Kentucky, Western	30.1	32.6
Louisiana	3.8	3.7
Mississippi	2.8	3.4
Missouri	0.2	0.5
Oklahoma	1.5	1.0
Texas	39.0	35.1
Western total	633.6	585.0
Alaska	1.5	1.9
Arizona	8.0	7.5
Colorado	32.0	28.3
Montana	44.8	39.5
New Mexico	25.6	25.1
North Dakota	29.6	29.9
Utah	24.4	21.7
Wyoming	467.6	431.1
Refuse recovery	1.4	2.7
U.S. total	1,171.8	1,075.0

Modified from Energy Information Administration 2009a.  
*mst* = Million short tons or 0.9 million tonnes.

### Clean Coal

The U.S. government has recently been favoring initiatives to develop clean-coal technology for power plants that involve carbon capture and storage (CCS). In June, 2008 the U.S. Department of Energy (DOE) issued a Funding Opportunity Announcement (FOA) to invest in Integrated Gasification Combined Cycle (IGCC) or other clean-coal power plants with CCS technology. IGCC plants currently have an average 45% thermal efficiency, and advanced technologies with pressurized fluid combustion will increase thermal efficiencies up to 50% (U.S. Department of Energy 2009). Existing coal-based IGCC plants in North America include the 260-megawatt-equivalent (MWe) Polk power station southeast of Tampa, Florida and the 262-MWe Wabash River Coal Gasification

Repowering Project in west-central Indiana (National Energy Technology Laboratory 2000). Non-U.S. IGCC plants are represented by the 253-MWe Buggenum plant in the Netherlands, which gasifies 2,000 metric tonnes (2,204 short tons) of coal per day, and the 335-MWe Puertollano in Spain (ELCOGAS 2010).

Clean coal is coal that is gasified and burned in high-oxygen mixtures, resulting in removal of hazardous substances such as arsenic, lead, cadmium, mercury, and nitrogen and sulfur dioxides, as well as capture of CO<sub>2</sub> and hydrogen. Factors that impact costs and the selection of optimal areas for new clean-coal sites include (1) proximity of sites to mine mouths, (2) distance of CO<sub>2</sub> transport via pipelines to carbon sinks, and (3) transmission losses between new power-generating facilities and user load (Mohan et al. 2008; Cohen et al. 2009; Dooley et al. 2009; Hamilton et al. 2009). Newcomer and Apt (2008) conclude that optimal sites for new clean-coal facilities should be near user electric load, owing to transmission losses exceeding costs of installing new CO<sub>2</sub> pipelines and fuel transport. However, economic incentives that support new clean-coal facilities should also be considered, including enhanced oil recovery (EOR) with generated CO<sub>2</sub> (Holtz et al. 2005; Advanced Resources International 2006a, b; Ambrose et al. 2010). Other incentives include enhanced coalbed methane recovery (ECBM) (Reeves 2003; McVay et al. 2009), and underground coal gasification with CCS (Roddy and Younger 2010).

Clean-coal activity in North America is led by the Dakota Gasification Company, where ~95 million cubic feet per day (2.69 million cubic meters) of CO<sub>2</sub>, generated by gasification of North Dakota lignite, is transported via a 205-mile (328 km) pipeline to the Weyburn oil field in Saskatchewan for EOR (Chandel and Williams 2009). Weyburn field has become the largest land-based CO<sub>2</sub> storage project in the world, having sequestered >12 Mt (13.2 mst) (Preston et al. 2009).

In March 2010, DOE announced that it reached a cooperative agreement with Summit Texas Clean Energy LLC to design, build and demonstrate a coal-gasification plant near Odessa, Texas (Fairley 2010). The plant is designed to provide electricity for >165,000 homes. Approximately 90% of the CO<sub>2</sub> (3 Mt year<sup>-1</sup>, 3.3 mst year<sup>-1</sup>) produced from the plant will be captured and transported with existing CO<sub>2</sub> pipelines for EOR in nearby oil reservoirs. CO<sub>2</sub> sales to oil and gas operators are projected to increase plant revenues by 50%. Revenues from EOR could cover the price premium for carbon

capture at the Odessa clean-coal facility, assuming an oil price of \$75 per barrel (Al-Juaied and Whitmore 2009). Funding will be provided by DOE and the National Energy Technology Laboratory (NETL). The estimated total cost for the project is \$1.73 billion and DOE's share will be \$350 million.

### *Underground Coal Gasification*

Underground Coal Gasification (UCG) is conversion of unmined subsurface coal into a gas that can be used for power generation, manufacture of hydrogen for fuel cells, synthetic natural gas, liquid fuels, and fertilizers. UCG involves drilling wells into coal seams, with injection wells containing oxidants to enhance coal combustion, followed by coal gasification and subsequent production of syngas. An advantage of UCG technology is low plant costs, owing to no surface gasifiers and coal-transport expenditures. UCG is also associated with fewer surface emissions and could be employed in conjunction with CO<sub>2</sub> storage after gasification.

UCG activity is worldwide, with projects planned or beginning operation in China, India, Australia, South Africa, Europe, and North America. China is currently operating ~30 projects in various stages of development, whereas India plans to develop UCG in ~350 billion tonnes (Gt; 385.8 billion short tons) of coal resources (World Coal Association 2011). South Africa has identified 160 Gt (176.4 billion short tons) of coal resources with UCG potential (ESI-Africa 2010).

Current UCG proposed projects in the U.S. include an underground coal gasification plant in Alaska and sites in Colorado. In Alaska, Cook Inlet Region Inc. (CIRI) is pursuing permits with Laurus Energy to construct an underground coal gasification facility to support a 100-MW power plant. The operation will convert coal into a synthetic gas at a depth of  $\geq 1,800$  feet (ft;  $\geq 550$  m). An estimated  $\leq 3$  acres (1.2 ha) year<sup>-1</sup> of underground coal will be required to support the power facility, with ~90 acres (36.4 ha) to supply the plant for its expected lifetime. Commercial power production is projected to begin in 2014 (Greentechmedia 2010). The Colorado Geological Survey estimates that total coal resources in Colorado exceed 434 billion short tons (394 Gt) to a depth of 6,000 ft (1,830 m). It is estimated that almost 12 billion short tons (10.9 Gt) of bituminous and sub-bituminous coal resources in Colorado have UGC potential (Carroll 2010).

### *Coal-to-Liquids*

CTL technology consists of breaking coal down into a solvent at high temperatures and pressures, followed by treatment with hydrogen gas and a catalyst. It also involves indirect liquefaction, with an initial stage of gasifying coal into an artificial syngas, and then manufacturing zero-sulfur synthetic fuels from the syngas. Several economic, technical, and environmental obstacles, including high refinery and potential CO<sub>2</sub>-sequestration costs, must be overcome for future CTL production to contribute significantly to world's energy base.

China is currently active in CTL development, where new coal-liquefaction plants could provide an annual production capacity of 440 million barrels of liquid fuel. The U.S. coal industry should be able to process a modest CTL industry, using 60–70 mst (54–64 Mt) of coal year<sup>-1</sup>, without premature depletion of the country's coal reserves (Milici 2009). Plans for CTL production in the U.S. are underway at various sites. Accelerergy Corporation, a company in Houston, Texas, has developed a process for converting coal into jet fuel. The company plans to sell jet fuel to the U.S. Air Force and has already received inquiries from commercial aircraft and engine manufacturers (Sourcewatch 2010). A proposed CTL plant in Belwood, Mississippi, would produce synthetic diesel and other fuels from coal and petroleum coke. The project is funded by \$2.75 billion state-issued bonds. Several large airline companies have signed a memorandum of understanding to purchase 500,000 barrels (79,500 m<sup>3</sup>) per month of jet fuel from the proposed plant.

## **COALBED METHANE**

### **J. C. Pashin<sup>5</sup>**

The U.S. remains the world leader in coalbed gas exploration, booked reserves, and production. Currently, there is commercial coalbed gas production or exploration in approximately 12 U.S. basins and several basins in Canada, although activity has slowed in response to low gas prices. The major producing areas are the San Juan, Powder River, Black Warrior, Raton, Central Appalachian, and Uinta (Ferron and Book Cliffs) Basins. Other U.S.

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areas with significant exploration or production are the Cherokee, Arkoma, Illinois, Hanna, Gulf Coast, and Greater Green River Basins. Exploration continues in all major U.S. basins, and the principal environmental issue confronting development is water disposal. Production operations are maturing in U.S. coalbed methane basins, and the U.S. Department of Energy (DOE) has sponsored a series of pilot tests for CO<sub>2</sub> storage and CO<sub>2</sub>-enhanced coalbed methane recovery in coal. Injection has been completed in the Illinois, San Juan, Appalachian, Williston, and Black Warrior Basins. A major pilot being conducted by CONSOL Energy, Inc. is in progress, and DOE is evaluating the possibility of new pilot programs in coal.

Annual coalbed methane (CBM) production in 2009 was 1,914 billion cubic feet (Bcf; 54.2 million m<sup>3</sup>) and was nearly level with 2008 coalbed methane production (1,966 Bcf, 155.7 million m<sup>3</sup>) (Fig. 1; Table 2). Coalbed methane reserves decreased from 20,798 Bcf (588.9 million m<sup>3</sup>) in 2008 to 18,578 Bcf (526 million m<sup>3</sup>) in 2009 representing a decrease of 2,220 Bcf (62.9 million m<sup>3</sup>) or (10.7%) (Fig. 2; Table 3). Coalbed methane currently represents 9.3% of 2009 dry-gas production and 6.8% of proved dry-gas reserves in the United States. Interestingly, coalbed methane production is holding steady as a proportion of U.S. gas production but is declining significantly in terms of proved dry gas reserves. This decline appears to be related to the booking of major shale gas reserves during 2009, which is significantly changing U.S. gas markets (Fig. 3).

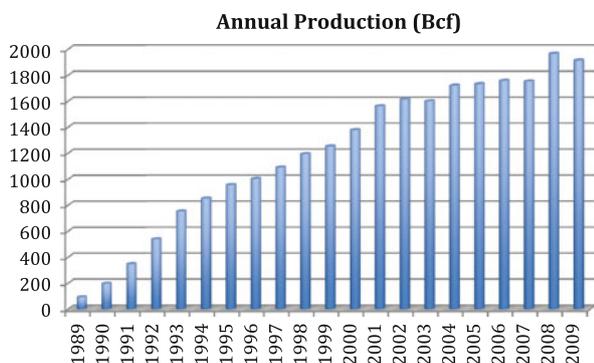
Most of the coalbed methane activity in the eastern U.S. is focused on the Appalachian Basin of Southwestern Virginia and the Black Warrior Basin

of Alabama, with several companies actively developing joint CBM and coal-mine methane (CMM) projects. At least 2,267 coalbed methane wells have been drilled to date in southwestern Virginia and production has increased from 105 Bcf (3 million m<sup>3</sup>) in 2008 to 111 Bcf (3.1 million m<sup>3</sup>) in 2009 (Table 2). West Virginia had more 290 coalbed methane wells and coalbed methane production of

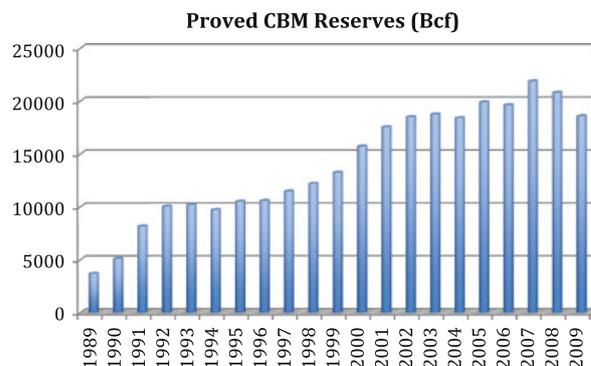
**Table 2.** Historic U.S. Coalbed Methane Production by Year (1989–2009; billion cubic ft, Bcf)

Year	US	AL	CO	NM	OK	UT	VA	WV	WY	Others
1989	91	23	12	56						0
1990	196	36	26	133						1
1991	348	68	48	229						3
1992	539	89	82	358						10
1993	752	103	125	486						38
1994	851	108	179	530						34
1995	956	109	226	574						47
1996	1003	98	274	575						56
1997	1090	111	312	597						70
1998	1194	123	401	571						99
1999	1252	108	432	582						130
2000	1379	109	451	550		74			133	62
2001	1562	111	490	517		83			278	83
2002	1614	117	520	471		103			302	101
2003	1600	98	488	451		97			344	122
2004	1720	121	520	528		82			320	149
2005	1732	113	515	514	58	75	56	30	336	35
2006	1758	114	477	510	68	66	81	18	378	46
2007	1753	114	519	394	82	73	85	25	401	60
2008	1966	107	497	443	69	71	101	28	573	77
2009	1914	105	498	432	55	71	111	31	535	76

Data from the Energy Information Administration (2010a, b, c, d, e, f, g, h, i); [http://www.eia.gov/dnav/ng/hist/rngr52nus\\_1a.htm](http://www.eia.gov/dnav/ng/hist/rngr52nus_1a.htm). Accessed June 22, 2011).  
1 billion cubic ft = 28.3 million m<sup>3</sup>.



**Figure 1.** Historic U.S. coalbed methane production 1989–2009. Data from the Energy Information Administration (2010a, b, c, d, e, f, g, h, i); [http://www.eia.gov/dnav/ng/hist/rngr52nus\\_1a.htm](http://www.eia.gov/dnav/ng/hist/rngr52nus_1a.htm), accessed June 22, 2011). 1 billion cubic ft (Bcf) = 28.3 million m<sup>3</sup>.



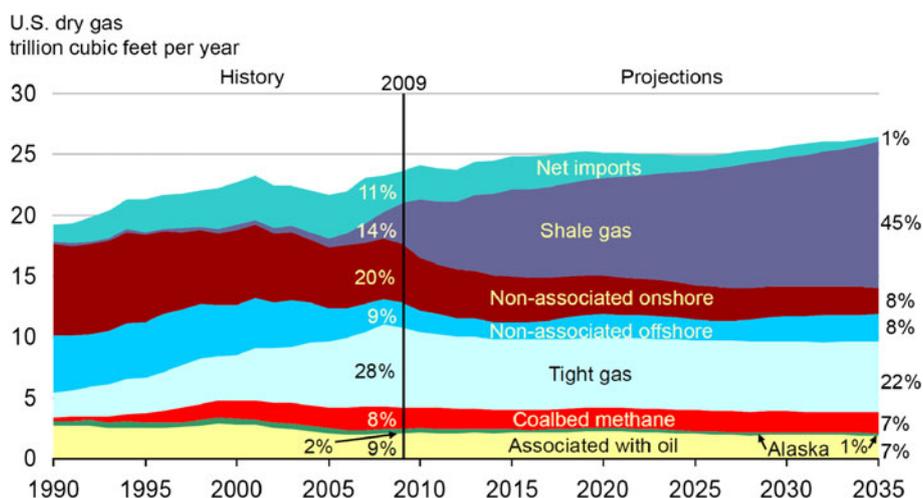
**Figure 2.** Historic U.S. coalbed methane reserve trends 1989–2009. Data from the Energy Information Administration (2010a, b, c, d, e, f, g, h, i); [http://www.eia.gov/dnav/ng/hist/rngr51nus\\_1a.htm](http://www.eia.gov/dnav/ng/hist/rngr51nus_1a.htm), accessed June 22, 2011). 1 billion cubic ft (Bcf) = 28.3 million m<sup>3</sup>.

**Table 3.** Historic U.S. Coalbed Methane Proven Reserves by Year (1989–2009; billion cubic ft, Bcf)

Year	US	AL	CO	NM	OK	UT	VA	WV	WY	Others
1989	3676	537	1117	2022						0
1990	5087	1224	1320	2510						33
1991	8163	1714	2076	4206						167
1992	10034	1968	2716	4724						626
1993	10184	1237	3107	4775						1065
1994	9712	976	2913	4137						1686
1995	10499	972	3461	4299						1767
1996	10566	823	3711	4180						1852
1997	11462	1077	3890	4351						2144
1998	12179	1029	4211	4232						2707
1999	13229	1060	4826	4080						3263
2000	15708	1241	5617	4278		1592			1540	1440
2001	17531	1162	6252	4324		1685			2297	1811
2002	18491	1283	6691	4380		1725			2371	2041
2003	18743	1665	6473	4396		1224			2759	2226
2004	18390	1900	5787	5166		934			2085	2518
2005	19892	1773	6772	5249	568	902	1572	186	2446	424
2006	19620	2068	6344	4894	684	750	1813	194	2448	425
2007	21874	2126	7869	4169	1265	922	1948	255	2738	582
2008	20798	1727	8238	3991	511	893	1851	246	2781	560
2009	18578	1342	7348	3646	338	725	2261	220	2328	370

Data from the Energy Information Administration (2010a, b, c, d, e, f, g, h, i; [http://www.eia.gov/dnav/ng/hist/rngr51nus\\_1a.htm](http://www.eia.gov/dnav/ng/hist/rngr51nus_1a.htm). Accessed June 22, 2011).

1 billion cubic ft = 28.3 million m<sup>3</sup>.



**Figure 3.** Sources of U.S. Natural gas production showing projected steady coalbed methane supply concurrent with major increase of shale gas supply (Source: Energy Information Administration, [http://www.eia.gov/neic/speeches/newell\\_12162010.pdf](http://www.eia.gov/neic/speeches/newell_12162010.pdf), accessed June 22, 2011). 1 trillion cubic ft (Bcf) = 28.3 billion m<sup>3</sup>.

31 Bcf (0.9 million m<sup>3</sup>) as of the end of 2009. The number of wells in Pennsylvania is undetermined, but production increased from 11 Bcf (0.3 million m<sup>3</sup>) in 2008 to 16 Bcf (0.45 million m<sup>3</sup>) in 2009. The advent of pinnate horizontal drilling has resulted in a significant expansion of the coalbed methane

industry in the Appalachian Basin by providing access to large volumes of gas in low-permeability coal seams. There are over 4,800 coalbed methane wells currently operating in Alabama with cumulative production of 2.2 Tcf (63.3 billion m<sup>3</sup>) and annual production of 105 Bcf (3 million m<sup>3</sup>) in 2009.

The mid-continent region, consisting of the Cherokee, Forest City, Arkoma, and Illinois Basins has recently been one of the more active regions in the United States, but production and reserves appear to be declining. Exploration in the Cherokee Basin in Oklahoma and Kansas has spread northward to include the southern part of the Forest City Basin. The Arkoma Basin continues to produce CBM and there are multiple prospects being developed in this basin. As in the Appalachian Basin, horizontal drilling is proving to be an effective development strategy, although major increases of production in recent years are now being offset by decline. Production for Kansas decreased from 47 Bcf (1.3 million m<sup>3</sup>) in 2008 to 43 Bcf (1.2 million m<sup>3</sup>) in 2009, whereas production decreased in Oklahoma from 69 Bcf (1.9 million m<sup>3</sup>) in 2008 to 55 Bcf (11.6 million m<sup>3</sup>) in 2008 (a 20.3% decrease).

Infill drilling of Fruitland CBM wells in the San Juan Basin (Colorado and New Mexico) decreased markedly in 2009 due to the recession. To minimize the environmental impact of infill drilling, operators are drilling deviated wells into Fruitland coal from the existing well pads. Environmental groups continue to express concern about gas seeps along the margins of the San Juan Basin in the Fruitland outcrop belt. Colorado and New Mexico continue to dominate CBM production and reserves (Tables 2, 3). Cumulative production for Colorado and New Mexico represents over 67% of total U.S. CBM production. In 2009, CBM production in Colorado held steady at 498 Bcf (14.1 million m<sup>3</sup>) [(vs. 497 Bcf or 14.7 million m<sup>3</sup>) in 2008], and production in New Mexico declined slightly from 443 to 432 Bcf (12.5–12.2 million m<sup>3</sup>).

There were 3,500 fewer producing wells in the Powder River Basin in 2009 compared to 2008. The production high in 2008 was attributed to: (a) “Big George” production that has been on for many years but is finally lowered the hydrostatic pressure enough to yield major gas production, and (b) the likelihood that many of the wells shut in 2009 were not big producers. Another positive statistic for the basin is the lowest water to gas ratio since the play became commercial, 1.02 barrels (0.16 m<sup>3</sup>) of water per Mcf (28.3 thousand m<sup>3</sup>). In December 2009, the U.S. Environmental Protection Agency (EPA) raised concerns about the discharge of CBM-produced water in the Powder River Basin, claiming that Wyoming’s surface discharge program does not meet Clean Water Act or Wyoming’s own agricultural protection standards. As a result a number of water discharge permit applications

with the Wyoming Department of Environmental Quality were put on hold. The Wyoming Department of Environmental Quality (DEQ) and State Engineer’s offices have had to refine their oversight of coalbed methane water management. In Wyoming, 2009 CBM production totaled 535 Bcf (15.1 million m<sup>3</sup>), whereas only 12 Bcf (0.3 million m<sup>3</sup>) was produced in Montana.

International activity has been on the rise, and operations in the Qinshui Basin of China remain active, thus proving the CBM potential of intensely fractured semi-anthracite and anthracite. Exploration and development activity continues in western Canada, where the Horseshoe Canyon coals host a major coalbed methane play. Horizontal drilling is playing an increasingly important role in the development of low-permeability coal seams in western Canada. Exploration and development efforts are intensifying in the Bowen, Surat, and Sydney Basins of Australia, as well as the Karoo Basin of South Africa. Coalbed methane in eastern Australia is being produced from high-permeability coal seams that can contain large quantities of oil-prone organic matter, and produced gas is being considered for export into Asian liquefied natural gas (LNG) markets. A number of LNG plants (up to 5 or 6) are being considered in Australia so many of these companies are striving to book CBM reserves to justify the expenditure for LNG plant development as quickly as possible. The most likely outcome is that only 2 or 3 LNG plants will be developed.

Major potential exists in the Gondwanan coal basins of India, and development of fields and pipeline infrastructure is underway. The absence of regional pipelines to market has hindered CBM development in India. However, in April 2009, India launched its fourth licensing round of the CBM Licensing Policy. The government received bids for eight out of ten blocks, and contracts were awarded to two Indian energy companies (Essar Oil and Deep Industries) and an Australian Company (Arrow Energy). Exploration activities continued throughout the country in 2009 (Oil and Natural Gas Corporation, BP, Arrow), while three CBM projects have already reached the production phase.

Significant potential also exists in the coal basins of Europe and the Russian platform, and development in these areas is focusing mainly on coal-mine methane. Russia is continuing to promote CBM exploration and development but defining a market for the gas and predicting gas prices are problematic for future development. However, the

coal basins in Russia may contain the largest CBM resources in the world so once a market for this gas, internally or internationally, is identified, then CBM exploration in Russia should increase significantly. Some significant exploration programs have been initiated within the past year to explore for coalbed methane in the structurally complex European coal basins of western Europe, including Germany.

## GAS HYDRATE

### A. H. Johnson<sup>6</sup>

A field test to assess sustainable production rates for hydrate reservoirs on the North Slope of Alaska has been in the planning stages for several years, with substantial funding from the U.S. Department of Energy (DOE). This test has been planned as an industry-scale, long-term operation that would extend for as long as 2 years. The operator, BP Exploration Alaska, had been working to obtain partner approval for over a year and a location for the test had been selected in Prudhoe Bay Field. Unfortunately, the BP test is currently on hold for reasons that a spokesperson for BP said would be announced at a later date. A statement on the DOE Methane Hydrate website says that "BP identified serious potential impediments to performing activity under this project in the Prudhoe Bay Unit (PBU). Further consideration of these issues and evaluation of the likely impact to planned project activities are in progress." <http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates/maincontent.htm>, accessed June 24, 2011).

Another hydrate test on the North Slope has been proposed by ConocoPhillips Company and would test the concept of CO<sub>2</sub> injection into a methane hydrate reservoir to determine the potential for methane production while permanently sequestering CO<sub>2</sub>. That test is currently waiting on partner approval, and with the delay in the BP project, the timing of the CO<sub>2</sub> project is uncertain.

Results of the 2009 Gulf of Mexico hydrate drilling and logging program, undertaken by a consortium led by Chevron Corporation, are being prepared for publication. Among the most significant results from the 2009 program were the discovery of highly saturated gas hydrate accumulations in

reservoir-quality sands in two of the three locations drilled, and the validation of the pre-drill predictive model. A follow-up program of coring and logging has been planned for 2011, but has been pushed back to 2012 due to issues surrounding the Deepwater Horizon oil spill. These issues include the current drilling moratorium, questions regarding the future process for the issuance of deepwater drilling permits, and concerns about the availability and cost of deepwater ships and equipment. Some level of geophysical site characterization may be undertaken in 2011.

A gas hydrate drilling program was conducted by South Korea during the summer of 2010 that targeted hydrate-bearing sands. Results of the program have not yet been released. This program is a follow-up to the successful hydrate drilling program conducted offshore South Korea in 2007.

Two deepwater hydrate production tests are planned for offshore Japan in fiscal 2012 (calendar 2013). The test durations are currently planned for 4 weeks and 3 months, respectively, and will provide important information for MH21, the Japanese gas hydrate program, but may not be designed to yield high production rates. Site selection, test details, and other considerations are currently under review.

In late 2009, China released an initial report of the gas hydrate being recovered from the Tibetan Plateau. Given the large area with pressures and temperatures within which gas hydrate would be stable, this suggests a very large potential onshore gas resource base.

Due to the nature of natural gas markets, commercial hydrate development will likely occur fastest in regions where demand is strong and supplies are limited; in particular, Japan, India, China, and South Korea. This interest and activity represent an opportunity for stronger interconnection with members of the American Association of Petroleum Geologist outside of the United States.

## TIGHT GAS SANDS

### C. D. Jenkins<sup>7</sup>

#### *Introduction*

Natural gas production from tight sandstones (those with permeabilities of less than 0.1 millidarcy,

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md) is currently about 6 trillion cubic feet (Tcf; 170 billion  $m^3$ ) per year in the United States, representing nearly 25% of annual gas production. The U.S. Energy Information Administration (EIA) estimates that approximately 310 Tcf (8.8 trillion  $m^3$ ) of technically recoverable tight gas exists within the United States, and worldwide it is estimated that there is more than 7,400 Tcf (210 trillion  $m^3$ ) of gas in tight sands, with some estimates exceeding 30,000 Tcf (850 trillion  $m^3$ ). The fraction of this that can actually be produced will depend on the applicability of key technologies (3-D seismic, horizontal drilling, hydraulic fracture stimulation), well costs, and gas prices. Tight gas sand plays are being tested and developed in many countries including Canada (Western Canadian Sedimentary Basin), Australia (Perth, Gippsland, and Cooper Basins), China (Ordos Basin), and Ukraine (Donetsk-Dnepr Basin). In the United States multiple tight gas sand projects are underway with long production histories that provide insights and analogs for the appraisal and development of new areas. Four of these projects are summarized below.

#### *Dew-Mimms Creek Field*

The Bossier Formation sands in the Dew-Mimms Creek Field are part of the Upper Jurassic Cotton Valley Group in the East Texas Basin. The field produces from a series of stacked sand-shale packages containing 75–100 ft (23–30 m) of net sand with average porosities ranging from 6 to 10%, absolute permeabilities ranging from 1 microdarcy to 1 md, and water saturations ranging from 5 to 50%. The play seeks to exploit an overpressured cell by drilling for gas close to the overpressure ceiling which is at depths of 12,400–13,200 ft (3,780–4,023 m). The Dew-Mimms Creek Field is being developed on a 80–160 acre (32.4–64.8 ha) well spacing. Wells are fracture stimulated with small to large slickwater fracs by pumping 100,000–350,000 pounds (45,360–158,757 kg) of proppant. Initial well rates range from 2 to 5 million cubic feet per day (MMcfd; 56.6–141.5 thousand  $m^3$ /day) and declines are hyperbolic with flows stabilizing after 2–3 years at 500–900 thousand cubic feet per day (Mcfd; 14.2–25.5 thousand  $m^3$ /day). Estimated ultimate recoveries (EURs) per well range from 1 to 4 Bcf (28.3–113.2 million  $m^3$ ). Geological factors controlling well success include the ability to locate main

channel sand trends where sands are thicker and of better quality, and to establish sustained economic production rates from inferior reservoirs through improved completion practices.

#### *Jonah Field*

Jonah Field, located in the northwestern Green River Basin of Wyoming, produces from over-pressured sandstones of the Cretaceous Lance Formation at depths of 11,000–13,000 ft (3,353–3,962 m). The field is fault-bounded and contains a stacked sequence of 20–50 fluvial channel sands in an interval that is 2,800–3,600-ft (853–1,097 m) thick. Sandstone bodies occur as individual 10–25-foot (3.0–7.6 m) thick channels that are stacked into channel sequences up to 200-ft (61 m) thick. Porosities range from 5 to 14%, with permeabilities of 1–30 md and water saturations of 30–60%. Pressure gradients are 0.55–0.60 psi/foot (37.9–41.3 millibars/0.3 m). Wells are completed by pumping multiple fracture treatments (8–20) into wells that are near-vertical through the Lance. The frac design includes 100,000–400,000 pounds (45,360–181,440 kg) of sand in a cross-linked borate gel and a 25–50% nitrogen assist in each stage which is typically less than 200-ft (61 m) long. Current development is on a 20–40 acre (8.1–16.2 ha) well spacing with 10-acre (4 ha) and 5-acre (2 ha) pilot areas. It is estimated that 67% of the original gas in place (OGIP) can be recovered at a 10-acre (4-ha) spacing and 77% at a 5-acre (2-ha) spacing. Initial well rates range from 5 to 15 MMcfd (142–425 thousand  $m^3$ /day) with EURs ranging from 5 to 10+ Bcf (141.5–283 thousand  $m^3$ ) per well.

#### *Mamm Creek Field*

The Mamm Creek Field is responsible for about 75% of the current gas production from the Piceance Basin of northwestern Colorado. The main producing interval is the 2,000-foot thick overpressured Williams Fork Formation which consists of lenticular fluvial to marine sands at depths of 4,500–8,500 ft (1,372–2,591 m). Packages of “stacked sands” can be correlated over areas of 30–70 acres (12–28 ha) but individual sands are only correlative over areas ranging from about 5 to 17 acres (2–7 ha).

Results from 200 well tests showed permeabilities ranging from 1 to 100 md with half the tests indicating the presence of open fractures. Each development pad contains 12–16 wells that are vertical through the reservoir and completed with 4–10 slickwater fracture stimulation stages using 50,000–500,000 lbs (22,680–226,800 kg) of sand and 2,000–13,000 barrels (318–2,067 m<sup>3</sup>) of water per stage. Larger treatments lead to longer half-lengths, which in turn result in higher production and EURs. Each well costs about 1.2 million dollars (MM\$) which is equally divided between the drilling and completion costs. Wells have been downspaced to 20 acres (8.1 ha) and recent evidence indicates that it may be optimal to downspace to 10 acres (4 ha) in order to recover about 75% of the OGIP.

### *Wamsutter Field*

Wamsutter Field covers a 50 square mile (129 km<sup>2</sup>) area in the Greater Green River Basin of Wyoming and contains an estimated 50 Tcf (1.42 trillion m<sup>3</sup>) of OGIP. The field currently produces 450 MMcfd (12.7 million m<sup>3</sup>/day) of gas from more than 2,000 wells. The reservoir consists of stacked marine and fluvial sands of the Mesaverde Group Almond Formation and numerous turbidite flows within the Lewis Shale. The Almond Formation is generally encountered between depths of 8,500 and 10,500 ft (2,590 and 3,200 m) with reservoir pressures varying from initial conditions (0.54–0.58 psi/ft; 37.2–40 milibar/0.3 m) in the Lower Almond to varying stages of pressure depletion in the Upper Almond. Sands typically have 8–12% porosity and 2–30 md of permeability. The average net pay footage ranges from 50 to 80 ft (15–24 m) per well. Completion depths range from 7,000 ft (2,133 m) for shallow Lewis wells to 12,200 ft (3,718 m) for deep Mesaverde wells. The Mesaverde is completed in 2–3 stages, and the Lewis is completed in 1–2 stages. Fracture stimulations total 40,000 gallons (151 m<sup>3</sup>) of borate-crosslinked guar fluid and 175,000 pounds (79,380 kg) of 20/40 mesh sand or lightweight ceramic proppant. A typical initial gas rate for a fracture stimulated well is 1 MMcfd (28 thousand m<sup>3</sup>/day) with an average recovery of 2 Bcf (56.6 million m<sup>3</sup>) per well. Since 2004, BP, one of the big operators in Wamsutter, has drilled over 300 eighty acre (32.4 ha) infill wells and recently has been evaluating the possibility of infilling with wells at a 40 acre (16.2 ha) spacing.

## GAS SHALE/SHALE OIL

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### *Introduction*

The production of natural gas from shales continues to increase in North America, and shale gas exploration is on the rise in other parts of the world since the previous report by this committee was published by American Association of Petroleum Geologists, Energy Minerals Division (2009). For the United States, the volume of proved reserves of natural gas increased 11% from 2008 to 2009, the increase driven largely by shale gas development (Energy Information Administration 2010c). Furthermore, shales have increasingly become targets of exploration for oil and condensate as well as gas, which has served to greatly expand their significance as “unconventional” petroleum reservoirs.

This report provides information about specific shales across North America and Europe from

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**Figure 4.** Map showing the location of basins in the United States discussed in this article in which shale gas and/or shale oil exploration and/or production is occurring.

which gas (biogenic or thermogenic), oil, or natural gas liquids are produced or is actively being explored. The intent is to reflect the recently expanded mission of the Energy Minerals Division (EMD) Gas Shales Committee to serve as a single point of access to technical information on shales regardless of the type of hydrocarbon produced from them. The contents of this report were drawn largely from contributions by numerous members of the EMD Gas Shales Advisory Committee, with much of the data being available from public websites such as state or provincial geological surveys or other public institutions. Shales from which gas or oil is being produced in the United States are listed in alphabetical order by shale name. Information for Canada is presented by province, whereas for Europe, it is presented by country.

*Antrim Shale.* The Upper Devonian Antrim Shale has produced biogenic gas for at least 24 years from wells in the Michigan Basin (Fig. 4). As of November 2010, the number of producing wells totaled approximately 11,375, with about 9,800 still actively

producing gas (<http://www.dleg.state.mi.us/mpsc/gas/production/sumnov10.pdf>, accessed March 14, 2011). There are 33 operators actively producing in the basin, with the top 10 operators responsible for almost 80% of Antrim production in 2009. Although most wells are completed within a depth range of 1,000–2,500 ft (305–762 m), some are as shallow as 350 ft (107 m) with the deepest being just over 3,000 ft (914 m). Total cumulative production reached 2.917 trillion cubic feet of gas (Tcft; 82.6 billion m<sup>3</sup>) from 788 separate projects by the end of April 2010. (Note: Antrim production is reported by project—a project is a group of wells owned by the same operator and the production from them is comingled—rather than by individual well or lease, and projects may be only a few wells or more than 70 wells.) Cumulative production for the first 4 months of 2010 was 39,912,880 thousand cubic feet of gas (Mcfg; 1.1 million m<sup>3</sup> gas, g), which was a 2.9% decline from the first 4 months of 2009. New drilling decreased with only three new wells drilled during the first 4 months of 2010.

Although some Antrim wells can initially produce as much as 500 Mcfg/day (14,158 m<sup>3</sup> g/day, d), wells typically settle at rates less than 100 Mcfg/day (2,831 m<sup>3</sup> g/day), with average production being 33 Mcfg/day (934 m<sup>3</sup> g/day) per well as of April, 2010. Many wells begin with high water production, but gas production typically increases as the water is pumped off; however, water production generally continues at lower rates throughout the life of a project. A gas-to-water production ratio for the Antrim reached almost 3 Mcfg/barrel (85 m<sup>3</sup> g/159 l) in 1998, but steadily decreased to 2.21 Mcfg/barrel (59 m<sup>3</sup> g/159 l) in 2004 and 1.52 Mcfg/barrel (43 m<sup>3</sup> g/159 l) at the end of April 2010. This overall decrease in the gas/water ratio through time probably reflects a decline in total gas production (due to aging wells) and an increase in water production as new wells, with high water cuts, come online. A fairly recent study estimated that the Antrim in the Michigan Basin contains an estimated mean undiscovered volume of about 7 Tcf (198 billion m<sup>3</sup>) of technically recoverable gas (Swezey et al. 2005).

**Bakken Formation.** The Upper Devonian–Lower Mississippian Bakken Formation in the Williston Basin (Fig. 4) has produced oil for almost 60 years. Oil was first produced from the Bakken in 1953 in North Dakota, and production continued through the 1980s with a focus on production from the upper shale member (informal nomenclature) of the formation as well as some from the underlying Three Forks Limestone. Development of the Elm Coulee Field in Montana in 1996 resulted in the first significant oil production from the middle sandstone member of the Bakken Formation, and this member remains the production focus to the present in the U.S. portion of the Williston Basin. In North Dakota, production from the middle sandstone member began in 2005 when it was demonstrated that horizontal drilling coupled with large-scale hydraulic fracture stimulation could successfully tap significant oil reserves along the east flank of the Williston Basin.

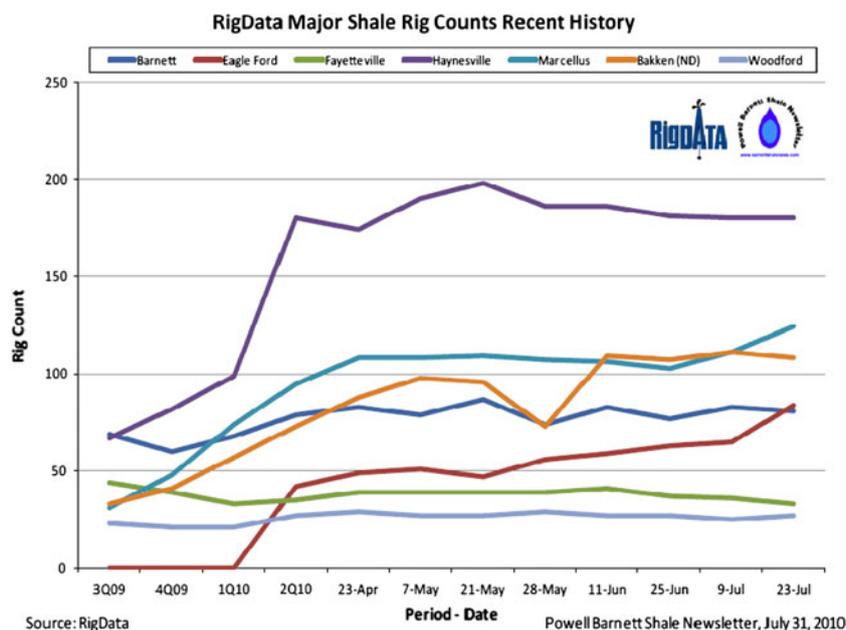
More than 600 horizontal wells have been drilled in the Elm Coulee field since its discovery, and more than 94 million barrels of oil (MMBO; 15 million m<sup>3</sup> oil) have been produced. Initial production (IP) from these wells is between 200 and 1,900 barrels of oil/day (BOPD; 31.8 and 302 m<sup>3</sup>/day) (Sonnenberg and Pramudito 2009). The productive portions of the reservoir contain between 3 and 9% porosity, with an average permeability of 0.04

millidarcy (md). A pressure gradient in the Bakken of 0.53 pounds per square inch per foot (psi/ft; 36.5 millibars/0.3 m) indicates that the reservoir is overpressured. Initial production rates of the North Dakota wells were in excess of 500 BOPD (79.5 m<sup>3</sup> oil/day), whereas staged fracture stimulation has resulted in several wells with IPs in excess of 2,000 BOPD. More than 300 wells in the eastern part of the Williston Basin currently produce in excess of 2 MMBO (31.8 thousand m<sup>3</sup> oil) per month. Cumulative production since 2005 has been more than 105 MMBO (16.7 million m<sup>3</sup> oil) from the 1,137 wells in the 81 fields producing from the middle member.

The North Dakota portion of the Williston Basin is extremely active, with 173 rigs running as of March 14, 2011 (<https://www.dmr.nd.gov/oilgas/riglist.asp>, accessed March 14, 2011). Recent studies estimate the U.S. portion of the Williston Basin to contain an estimated mean volume of undiscovered, technically recoverable oil in the Bakken Formation of 3.65 billion barrels (BBLs; 580 million m<sup>3</sup>) (Pollastro et al. 2008).

**Barnett Shale.** The Mississippian Barnett Shale in the Fort Worth Basin (Fig. 4) has been the focus of thermogenic gas and natural gas liquids production from both vertical and horizontal wells since drilling began in the early 1980s. Indeed, the successful production of gas from the Barnett Shale, which increased significantly in the late 1990s, has been commonly used to mark the onset of what is now a world-wide interest in shales as “unconventional” petroleum reservoirs. Given the current interest in shales as petroleum reservoirs, it is commonly overlooked that shale exploration and production have a relatively short history. Nevertheless, much interest in shale reservoirs stems from the geological, engineering, and business successes that went into development of the Barnett Shale play, an historical accounting of which is outlined by Steward (2007).

As of late in 2010, there were more than 14,000 Barnett gas wells within the core production area alone, with an additional 3,000 permitted locations within the same area (Texas Railroad Commission, <http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf>, accessed January 2011). Production between January 2004 and September 2010 alone was more than 7.4 Tcfg (209 billion m<sup>3</sup> gas) from the formation, just in the core area of production (Texas Railroad Commission, <http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf>, accessed January



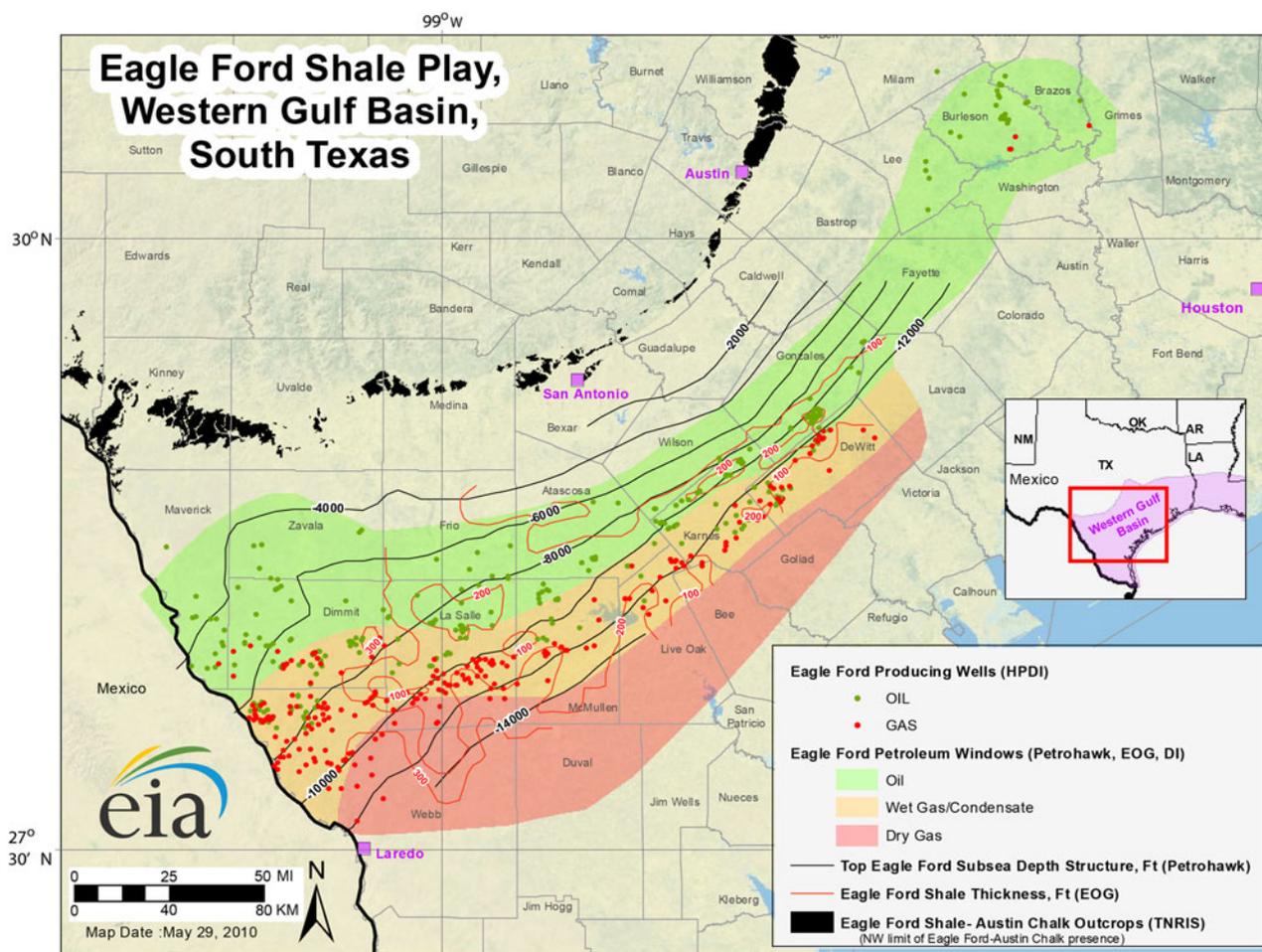
**Figure 5.** Graph showing the recent history of the number of rigs drilling for shale gas or shale oil for select shales in the United States. (<http://www.barnettshalenews.com/>, accessed March 15, 2011).

2011). Nevertheless, it was overtaken as the most active shale play in the United States in the third quarter of 2009 in terms of rig count; it now follows the Haynesville, Marcellus, Bakken, and Eagle Ford plays (Fig. 5). Of the approximately 90 rigs actively drilling for Barnett gas, fully one-third are in Tarrant County, Texas. Operators continue to drill in the outlying areas of the play where the Barnett is less thermally mature (e.g., Palo Pinto and Montague) but at a much lower rate than 2 years ago. By contrast, operators continue to be active in counties with the best overall production and to keep leases active. Drilling depths average about 7,500 ft (2,286 m) in the Fort Worth Basin (Bowker 2007). The Barnett Shale in the basin contains a mean volume of undiscovered, technically recoverable gas estimated at 26.2 Tcf (741.4 billion m<sup>3</sup>) (Pollastro et al. 2006).

**Chattanooga Shale.** The Devonian-Mississippian Chattanooga Shale in the Black Warrior and Appalachian Basins (Fig. 4) has been an exploration target for thermogenic gas for several years. Although there has been minimal production since 2008 in the Black Warrior Basin, no new wells were drilled there in 2009 or in the first half of 2010. A total of four wells were producing in the basin, and since 2008 they produced 82 million cubic feet of gas (MMcfcg; 2,321 m<sup>3</sup> gas); at present, all are shut in.

Initially, production from the Chattanooga in the Appalachian Basin seemed promising, but plans for drilling new wells in 2010 were abandoned. One company with a 244,000-acre (98,743 ha) position in the play reported year-end 2009 reserves of proved-developed 12 billion cubic feet of gas (Bcfg; 340 million m<sup>3</sup> gas), proved-undeveloped of 29 Bcfg (821 million m<sup>3</sup> gas), probable of 120 Bcfg (3.4 billion m<sup>3</sup> gas), and possible of 640 Bcfg (18.1 billion m<sup>3</sup> gas). The future for Chattanooga production is uncertain.

**Eagle Ford Shale.** The Cretaceous (Cenomanian-Turonian) Eagle Ford Shale of the Rio Grande Embayment of the Gulf of Mexico Basin (Fig. 4) has recent production of oil, thermogenic gas, and condensate. The Eagle Ford play trends across south Texas from the Mexican border and into Louisiana, an area roughly 50-miles (81 km) wide and 400-miles (644 km) long (Fig. 6). The play is variably a target for oil, dry gas, and(or) wet gas/condensate; currently, oil production is the most important component of the produced hydrocarbons. The first Eagle Ford gas well, drilled in 2008, flowed at a rate of 7.6 Mcfcg (215 m<sup>3</sup> gas) per day from a 3,200-foot (975 m) lateral (first perforation at 11,141 (3,396 m) feet total vertical depth) with 10 frac stages. Wells completed since then have an initial potential similar to that of the discovery well, followed by a rapid



**Figure 6.** Map showing the extent of the Eagle Ford Shale play in the Western Gulf of Mexico Basin, the approximate limits of petroleum generation windows, and the location of producing wells by petroleum type. Map is modified from the Energy Information Administration ([http://www.eia.gov/oil\\_gas/rpd/shaleusa9.pdf](http://www.eia.gov/oil_gas/rpd/shaleusa9.pdf), accessed January 31, 2011).

decline in production similar to those in other shale plays. Recently, drilled shale oil wells have IPs of several hundreds of BOPD, and between January 2009 and October 2010 more than 1.6 MMBO (254,379 m<sup>3</sup> oil) were produced from the Eagle Ford (Railroad Commission of Texas, <http://www.rrc.state.tx.us/eagleford/eagleford-oilproduction.pdf>, accessed January 2011). As of December 2010, there were 944 permitted and 281 completed wells (Railroad Commission of Texas, <http://www.rrc.state.tx.us/eagleford/eagleford-oilproduction.pdf>, accessed January 2011) in the Eagle Ford. In February 2011, the number of permitted wells increased to 1,132 (Railroad Commission of Texas, <http://www.rrc.state.tx.us/eagleford/images/EagleFordShalePlay201>

[102-large.jpg](#), accessed January 2011). The trend has an average depth of 11,000 ft (3,353 m), and the reservoirs are overpressured.

As with the Barnett and Haynesville Shales, the Eagle Ford is a viable target for hydrocarbon exploitation because of advances in the application of horizontal drilling and fracturing procedures. Mineralogy of the Eagle Ford is somewhat different than other gas shales, in that, where it is being explored, it contains significant marl beds, with as much as 70% calcite and lesser amounts of quartz; clay content is relatively low (Durham 2010). Most operators are drilling horizontal-well laterals of 3,500–5,000 ft (1,067–1,524 m) and are fracing the wells with slick water or acid in at least 10 different stages. The

average well cost is between 5 and 6 million dollars (Railroad Commission of Texas, <http://www.rrc.state.tx.us/eagleford/index.php>, accessed July 2010). The current area of primary interest, due to market return on liquid commodities, is where the Eagle Ford is in the oil or wet gas window. In the future, extensive development in the gas window will be dependent on increased gas market prices. For more information on Eagle Ford production, refer to the Texas Railroad Commission web link at <http://www.rrc.state.tx.us/eagleford/> (accessed March 14, 2011).

*Fayetteville Shale.* The Upper Mississippian Fayetteville Shale play within the central and eastern Arkoma Basin of Arkansas (Fig. 4) is the current focus of a regional shale-gas exploration and development program. Production of thermogenic gas from the formation began in 2004 and continues to the present. According to the Arkansas Oil and Gas Commission, there has been a general annual increase in wells drilled, with 24 wells drilled in 2004, 33 in 2005, 129 in 2006, 428 in 2007, 587 in 2008, and 891 in 2009. As of August 2010, there were a total of 2,620 producing gas wells in the Fayetteville Shale play. Most wells are horizontal wells that have been fracture stimulated using slickwater or cross-linked gel fluids. Gas production generally ranges between depths of 1,500 and 6,500 ft (457–1,981 m). Horizontal wells drilled from 2009 to 2010 averaged 4,720 ft (1,439 m) in lateral length with some wells as much as 7,000 ft (2,134 m).

Early estimates have indicated that there are more than 40 Tcfg (1,132 billion m<sup>3</sup> gas) reserves in the Fayetteville Shale, although recent studies indicate that the formation contains a mean volume of undiscovered, technically recoverable gas of 13.2 Tcf (373.6 billion m<sup>3</sup>) (Houseknecht et al. 2010). Also, smaller proved reserves of 9.07 Tcf (256.7 billion m<sup>3</sup>) were reported for the Fayetteville Shale (Energy Information Administration 2010c), based on data provided by operators. Estimated ultimate recovery (EUR) for a horizontal well is 2.9 Bcfg/well (82 million m<sup>3</sup>/well). As of June 2010, cumulative production of Fayetteville Shale totaled about 1.2 Tcf (34 billion m<sup>3</sup>); production for the first 6 months of 2010 was about 353 Bcfg (9,990 million m<sup>3</sup>). Initial production rates of horizontal wells have recently averaged about 2,800 MCFG/day (79,287 m<sup>3</sup>/day). Additional information is available on the Arkansas Oil and Gas Commission web site at <http://www.aogc.state.ar.us/Fayprodinfo.htm> (accessed March 14, 2011).

*Gothic Shale.* The Middle and Upper Pennsylvanian Hermosa Formation contains several shales of economic interest, but the focus herein will be on the informally named Gothic shale, which is currently being evaluated in the Paradox Basin (Fig. 4) for thermogenic gas. Five vertical “science” wells, followed by nine horizontal wells were drilled and completed in the Gothic in southwestern Colorado between 2007 and 2010 to test the shale. After 90 days of production, the well with the best sustained production (IP of approximately 3 MMcfg/day; 8,4950 m<sup>3</sup>/day) was producing only 600 MCFG/day (16,990 m<sup>3</sup>/day). Several other horizontal wells had IPs exceeding 5 MMCFG/day (141,584 m<sup>3</sup>/day), but after approximately 6 months production dropped to 500–800 MCFG/day (1,4158–2,2653 m<sup>3</sup>/day). Based on measurements of Poisson’s Ratio and Young’s Modulus, the Gothic in these exploration wells is brittle (Bereskin and McLennan 2008). Efforts are now underway to create greater stimulated reservoir volumes in subsequent wells by adjusting the number of frac stages, increasing the volumes of slickwater and sand concentrations pumped, raising the injection rates, and modifying flowback processes (Moreland 2010). Future drilling may occur and such efforts might benefit from lower drilling costs and more effective completions.

In all wells, frac water dissolved salt to form brines with fluid weights of as much as 10.5 pounds per gallon (4.76 kg/3.79 l). As the hot brines cooled during flowback, salt precipitated in the wellbore at about 3,000 ft (914 m). The future for significant production of gas from the Gothic remains uncertain.

*Haynesville and Bossier Shales.* The Haynesville Shale and overlying Bossier Shale (both Jurassic) have thermogenic gas production from wells throughout the Texas–Louisiana–Mississippi Salt Basin in western Louisiana and eastern Texas (Fig. 4). Interest in the Haynesville/Bossier has been significant over the last few years, and as of November 2010, 809 wells were producing gas, 132 were being drilled, and 288 wells were permitted but drilling had not begun. The producing horizons are overpressured (0.7–0.9 psi/ft; 48.3–62 millibars/0.3 m).

The Haynesville Shale covers an area of approximately 9,000 square miles (23,310 km<sup>2</sup>) with an average thickness of 200–300 ft (61–91 m). The thickness and areal extent of the formation has allowed operators to evaluate a wide variety of well

spacings. Companies now are drilling six to eight wells per square mile with each well being drilled with a 5,000-foot-long (1,524 m) horizontal component. Original gas-in-place is estimated to be 717 Tcf (20.3 billion m<sup>3</sup>) and technically recoverable gas resources are estimated at 251 Tcf (7.1 billion m<sup>3</sup>).

Initial production rates range from <3 to >24 MMcfd/day (<85 to >680 thousand m<sup>3</sup>/day) per well. Declines are very steep, exceeding 80% in the first year with EURs ranging from 3 to >10 Bcfd (85 to >283 thousand m<sup>3</sup>/day) per well. Drilling and completion costs range from 6 to 9 million dollars per well, which includes 12–15 fracture stages stimulated with slickwater and either ceramic or resin-coated proppant. Several companies are choking back new wells in an attempt to preserve fracture conductivity and reservoir permeability. This results in lower initial gas rates, but could translate into significantly higher ultimate recoveries per well if the technique proves successful over the long term. Additional information on the Haynesville can be found at the Louisiana Oil and Gas Association (<http://loga.la/haynesville-shale-news/>, accessed March 14, 2011).

*Mancos Shale.* The Upper Cretaceous Mancos Shale is an emerging shale-gas play in the Uinta Basin (Fig. 4), although Mancos completions are typically commingled with gas production from overlying and underlying sandstone reservoirs. All Mancos completions are in vertical drill holes; horizontal drilling has not been attempted because specific horizontal targets within the thick shale units have not yet been identified. Background information on the Mancos and its past production was presented by Schamel (2006) and well information is given at the Utah Oil and Gas website ([http://oilgas.ogm.utah.gov/Data\\_Center/LiveData\\_Search/well\\_information.htm](http://oilgas.ogm.utah.gov/Data_Center/LiveData_Search/well_information.htm), accessed March 14, 2011).

Current production from the Mancos Shale in the Uinta Basin is modest, but is increasing as a result of recent drilling activity. For example, in the northeastern part of the basin, some 50 deep wells were drilled in the Mancos during 2007–2008, which significantly increased total Mancos production. In the northwestern part of the basin, more than 20 deep Mancos wells have been drilled according to public records at <http://oilgas.ogm.utah.gov/Publications/Publications.htm> (accessed March 15, 2011). Given the relatively small number of wells drilled thus far and the short history of horizontal drilling of the Mancos, the future for significant gas production from it in the Uinta Basin is uncertain

(Robert Resselar, Utah Geological Survey, written communication, March 15, 2011).

*Marcellus Shale.* The Middle Devonian Marcellus Shale of the Appalachian Basin (Fig. 4) is one of the most active thermogenic gas plays in North America. Between 2008 and 2009, Pennsylvania nearly doubled state reserves with a net increase of 3.4 Tcf (96.3 billion m<sup>3</sup>) because of discoveries in the Marcellus (Energy Information Administration 2010c). Based on proved reserves and production reported by operators, reserves in the formation in the Appalachian Basin increased from 102 Bcf to 4.478 Tcf (2.9–126.8 billion m<sup>3</sup>) between 2008 and 2009 (Energy Information Administration 2010d). The Marcellus Shale continues to grow in importance to the national energy supply due to improvements in the effectiveness of horizontal drilling with hydraulic fracturing (Fig. 7).

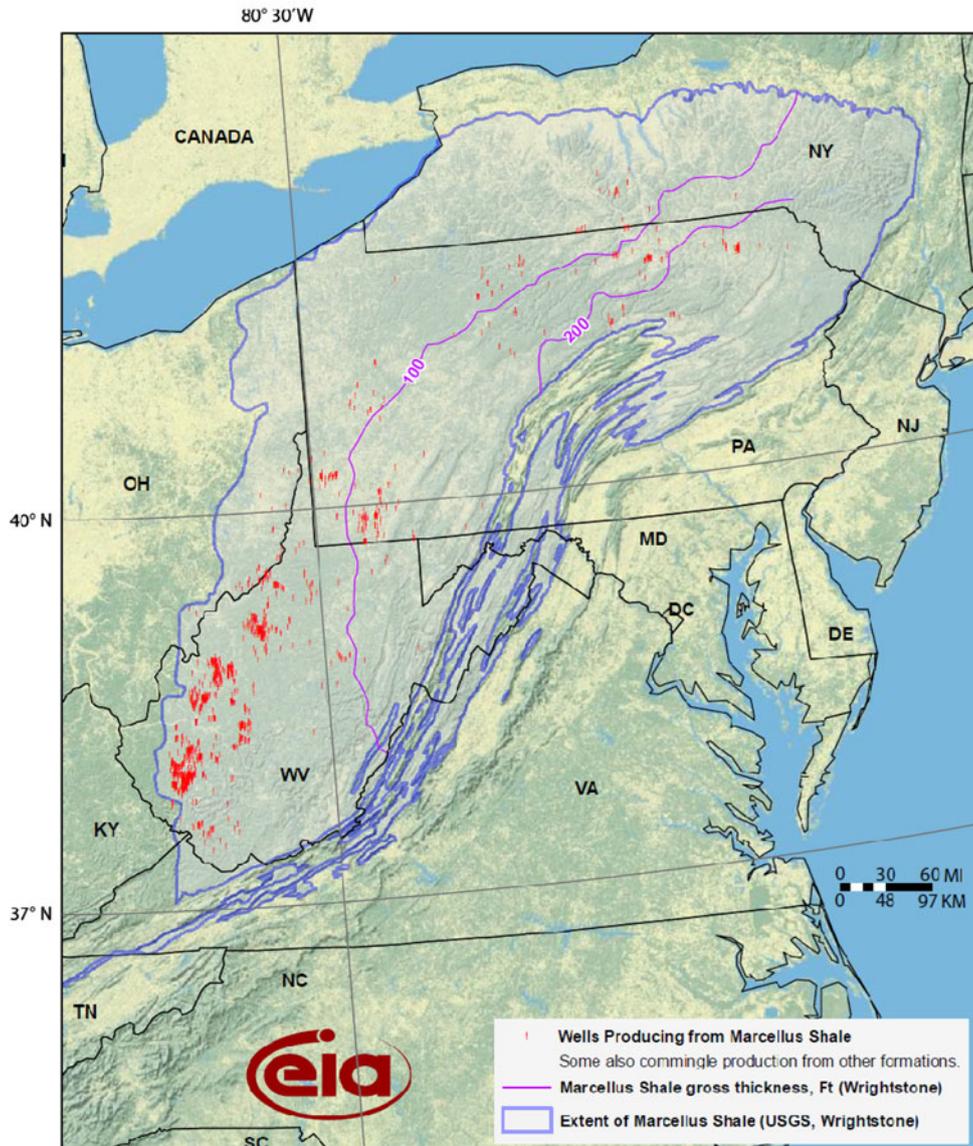
The organic-rich zone of the Marcellus has a net thickness ranging from 50 (15 m) to more than 250 ft (76 m) and lies at drilling depths of 2,000–9,000 ft (610–2,743 m) (American Association of Petroleum Geologists, Energy Minerals Division 2009). In most of the currently productive area, the Marcellus has a vitrinite reflectance greater than 1.0%  $R_o$  (Milici and Swezey 2006; Ryder et al. 2010) and produces mostly natural gas. Published data indicate the total organic content (TOC) is as much as 11 wt% (Repetski et al. 2008).

In 2002, the U.S. Geological Survey estimated the mean undiscovered technically recoverable resource potential of the Marcellus Shale at 11 million barrels of natural gas liquids (MMBNGL; 1.7 million m<sup>3</sup>) and 1.9 Tcfd (53.8 billion m<sup>3</sup>) (Milici et al. 2003); in a revised assessment, the estimated mean undiscovered technically recoverable resource potential of the Marcellus is 84 Tcfd (2.4 billion m<sup>3</sup> gas) and 3,379 MMBNGL (537.2 million m<sup>3</sup>) (Coleman et al. 2011).

Given that the Marcellus play covers several states (Fig. 7), discussion about recent activity is organized by state.

*New York:* In 2009, there were 27 wells with Marcellus listed as the producing formation in New York (Fig. 7). From 2003 to 2009, production increased from almost 3.3 MMcfd (934,456 m<sup>3</sup>) to more than 56 MMcfd (1.6 million m<sup>3</sup> gas), with the maximum production in 2008 at 64 MMcfd (1.8 million m<sup>3</sup> gas); no liquid hydrocarbon production has been reported. The New York Department of Environmental Conservation (DEC) is preparing new requirements for well permits for gas well

Marcellus Shale Gas Play, Appalachian Basin



Source: Energy Information Administration based on data from WVGES, PA DCNR, OH DGS, NY DEC, VA DMME, USGS, Wrightstone (2009). Only wells completed after 1-1-2003 are shown. Updated March 17, 2010

**Figure 7.** Map showing the extent of the Marcellus Shale gas play in the Appalachian Basin. Map is modified from the Energy Information Administration ([http://www.eia.gov/oil\\_gas/rpd/shaleusa5.pdf](http://www.eia.gov/oil_gas/rpd/shaleusa5.pdf), accessed January 31, 2011).

development using high-volume hydraulic fracturing. A temporary moratorium (until May 15, 2011) on the issuance of new drilling permits for wells targeting the Marcellus in New York was enacted by legislation that passed the New York State Assembly in August 2010 (<http://www.bloomberg.com/news/2010-08-04/new-york-s-senate-approves-drilling-moratorium-on-natural-gas-from-shale.html>, accessed

March 14, 2011). According to the DEC, only one new well was completed in 2009 and none were completed in 2010.

*Pennsylvania:* During the first 8 months of 2010, 2,046 Marcellus wells were permitted, and 822 were drilled in Pennsylvania (see Fig. 7 for well locations in Pennsylvania). Of the total number of permitted wells, 1,771 were planned as horizontal wells. From

2004 to 2008, over 6.8 Bcfg (192.5 million m<sup>3</sup>) and 19,500 barrels (3,100 m<sup>3</sup>) of liquid hydrocarbons were produced from the Marcellus in Pennsylvania. Additional information about the Marcellus in Pennsylvania can be obtained at the Pennsylvania Department of Conservation and Natural Resources website (<http://www.dcnr.state.pa.us/topogeo/oilandgas/marcellus.aspx>, accessed March 14, 2011).

*West Virginia:* The West Virginia Geological and Economic Survey (<http://www.wvgs.wvnet.edu/>, accessed March 14, 2011) identified more than 2,800 wells permitted through 2009, with some wells specifically listing the Marcellus as the target and others designating only “Devonian shale”. Preliminary production of about 3.5 Bcfg (99.1 million m<sup>3</sup>) for 2006, 7.7 Bcfg (218 million m<sup>3</sup>) for 2007, and 13.6 Bcfg (385.1 million m<sup>3</sup>) for 2008 can be attributed to wells with Marcellus reported as the pay. Total production for 2005–2008 exceeded 24.8 Bcfg (702.3 million m<sup>3</sup> gas) from nearly 900 wells (Fig. 4). The Marcellus was completed in many wells along with shallower shales and sandstones.

*Ohio:* In 2009, 68 drilling permits were issued for wells targeting Devonian shale, including 13 issued for Marcellus Shale. The Ohio Department of Natural Resources (website <http://www.dnr.state.oh.us/geosurvey/tabid/23014/Default.aspx>, accessed March 14, 2011) reported that as much as 200 MMcfg (5.7 million m<sup>3</sup> gas), 2,784 barrels (442.6 m<sup>3</sup>) of oil, and 40,425 barrels (6,427 m<sup>3</sup>) of water were produced from the formation between 2006 and 2009 (see Fig. 7 for well locations in Ohio).

*Virginia and Maryland:* Although applications have been submitted to drill for Marcellus targets in both states, no permits have been issued to date (see <http://www.dmme.virginia.gov/DGOinquiry/frmMain.aspx?ctl=60>, accessed March 16, 2011; <http://www.mde.state.md.us/programs/Land/mining/Non%20Coal%20Mining/Pages/Programs/LandPrograms/Mining/mog/naturalgas.aspx>, accessed March 16, 2011). There is gas production from the Marcellus Shale in southwestern Virginia, but because it is commingled with gas from other formations, the quantities attributed to the Marcellus are indeterminate.

*New Albany Shale.* Production from the Upper Devonian and Lower Mississippian New Albany Shale in the Illinois Basin (Fig. 4) is in two separate plays: (1) a shallow [( $<1,500$  ft;  $<457$  m) true vertical depth] vertical play, primarily concentrated along the eastern basin rim, from which biogenic gas is

produced; and (2) a deeper [(1,500–3,000 ft; 457–914 m) true vertical depth] horizontal play concentrated in southwestern Indiana and western Kentucky from which a mixture of biogenic and thermogenic gas is produced. The shallow vertical play has largely been concentrated in Harrison County, Indiana, and Meade County, Kentucky, both areas where the shale has been producing for more than 100 years (Hassenmueller and Comer 1994). Producing wells in this vertical play typically average 75–150 Mcfg/day (2,124–4,247 m<sup>3</sup>/day) but individual wells have been brought on at more than 1 MMcfg/day (2,8317 m<sup>3</sup>/day). Likewise, the results of early New Albany Shale drilling in the deeper horizontal play have been mixed, with some individual well testing at 7 MMcfg/day (198,218 m<sup>3</sup>/day) or more, but with wells placed on production yielding 150–300 Mcfg/day (4,247.5–8,495 m<sup>3</sup>/day) on average (Richard Sumner, written communication, March 15, 2011).

New Albany Shale drilling activity in the Illinois Basin has continued to decline from its peak in 2005–2007. Nevertheless, the State of Indiana has issued 62 New Albany permits through October 2010, whereas Kentucky has issued less than a dozen permits in the Illinois Basin portion of that state thus far in 2010. Illinois has not issued any permits in 2010. The New Albany Shale contains an estimated mean undiscovered volume of 3.79 Tcf (107.3 billion m<sup>3</sup>) of technically recoverable gas from the formation (Swezey et al. 2007).

*Utica Shale.* The Ordovician Utica Shale of the Appalachian Basin (Fig. 4) has been a recent drilling target for thermogenic gas, particularly in New York. In June 2010, two permits were authorized to drill Utica wells in New York, although no spud dates have been reported. These permits were phase one of a four-phase program to be initiated to test and develop production in the formation. A well drilled in October 2009 and subsequently fraced in November 2009, remains the most recent activity in New York. The modest vertical frac in a part of the Utica produced a sustained rate of more than 70 Mcfg/day (1,982 m<sup>3</sup>) over a test period of 24 days; however, there has been no production to date (Hill and Lombardi 2010).

No additional permits have been issued for horizontal drilling and the high-volume hydraulic fracturing needed to develop the Utica Shale in New York. A temporary moratorium (until May 15, 2011) on the issuance of new drilling permits for wells

targeting the formation was enacted by legislation passed by the New York State Assembly in August 2010 (<http://www.bloomberg.com/news/2010-08-04/new-york-s-senate-approves-drilling-moratorium-on-natural-gas-from-shale.html>, accessed March 14, 2011). The future for significant gas production from the Utica in New York remains uncertain, but recent drilling of Utica wells in the Michigan Basin suggests that the formation may also be a target outside of the Appalachian Basin ([http://www.ogj.com/index/article-display.articles.oil-gas-journal.exploration-development-2.2010.03.michigan-basin\\_utica.QP129867.dcmp=rss.page=1.html](http://www.ogj.com/index/article-display.articles.oil-gas-journal.exploration-development-2.2010.03.michigan-basin_utica.QP129867.dcmp=rss.page=1.html), accessed March 14, 2011).

*Woodford Shale.* The Upper Devonian–Lower Mississippian Woodford Shale produces gas (largely thermogenic with some biogenic gas) and/or condensate from wells drilled in the Anadarko Basin Province and Arkoma Basin (Fig. 4); oil is produced from the formation in the Ardmore Basin (Fig. 4). As of September 2010, there were 1,525 Woodford Shale well completions (excludes wells commingled with Caney or Sylvan Shales) in Oklahoma since 2004 (first application of advanced completion technology). The play in Oklahoma has expanded from mainly a thermogenic methane play to a more complex, multiphase hydrocarbon play as follows: (1) western Arkoma Basin in eastern Oklahoma, with thermogenic methane production at thermal maturities from <1 to >3% vitrinite reflectance ( $R_o$ ) and condensate production up to 1.67%  $R_o$ ; (2) Anadarko Basin Province shelf (“Cana” play) in western Oklahoma, with thermogenic methane at thermal maturities from 1.1 to 1.6%  $R_o$  and condensate production up to 1.4%  $R_o$ ; (3) Ardmore Basin in southern Oklahoma, with oil and thermogenic methane production from thermal maturities in the oil window (<1.2%  $VR_o$ ); and (4) Wagoner County (northeast Oklahoma), with biogenic methane production from thermal maturities <1.2%  $VR_o$  (Cardott 2010).

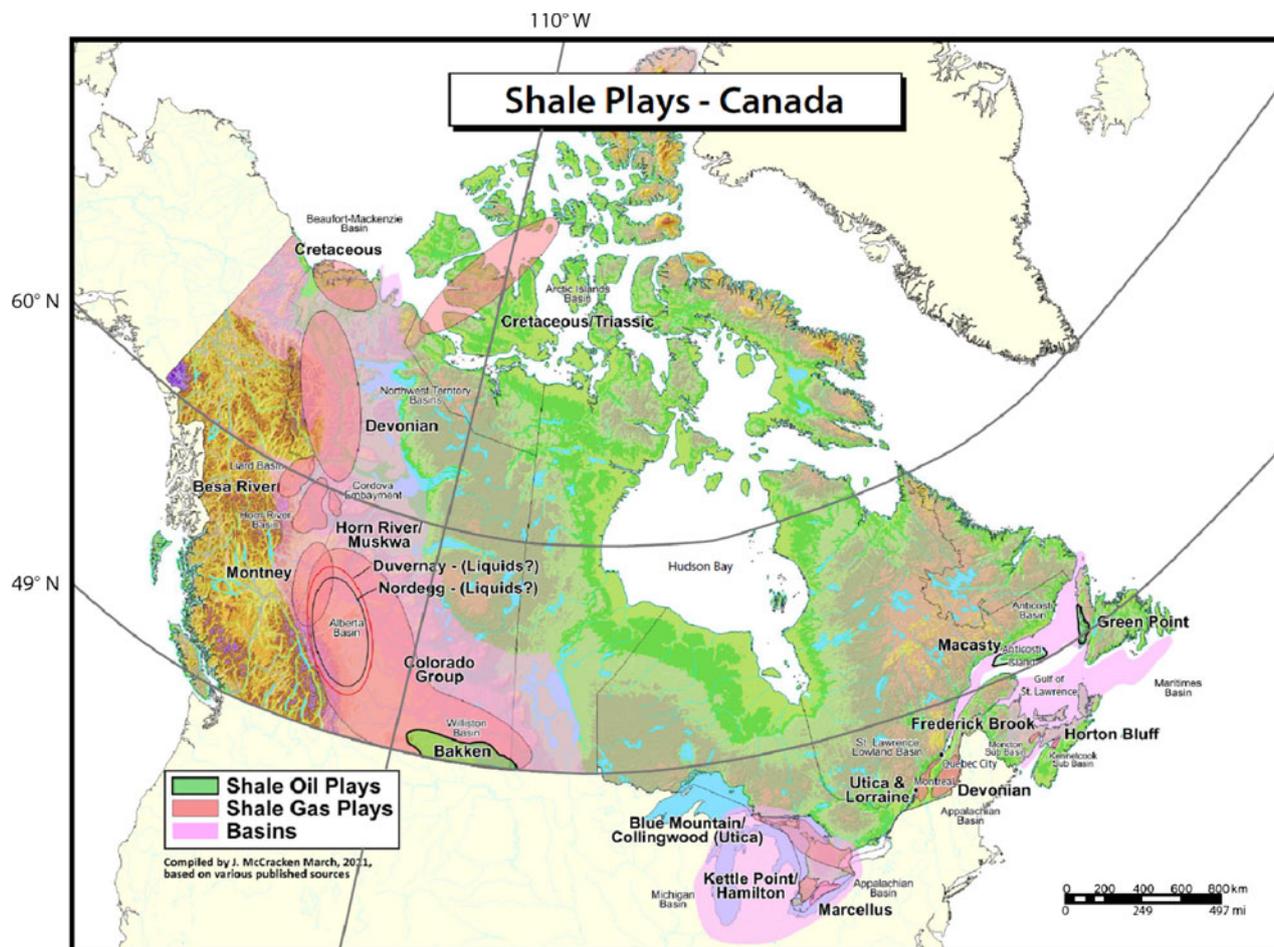
Of a total of 1,186 horizontal Woodford Shale gas wells from 2005 to 2010, initial potential gas rates ranged from 3 to 12,097 Mcfg/day (342,549 m<sup>3</sup>) (average of 2,777 Mcfg/day or 78,636 m<sup>3</sup>/day from 1,159 wells) and lateral lengths of 10–10,195 ft (3–3107 m) (average of 3,403 ft (1037 m) from 1,178 wells). Cumulative production from 1,285 Woodford Shale-only wells drilled from 2004 to 2010 is 683 Bcfg (19.3 billion m<sup>3</sup>) and 2,303,403 barrels (366,212 m<sup>3</sup>) of oil/condensate. A gas shale-completions database,

lists of references, maps, and several presentations are available on the Oklahoma Geological Survey web site (<http://www.ogs.ou.edu/level3-oilgas.php>, accessed March 14, 2011). Recent assessments are that the Woodford contains mean volumes of undiscovered technically recoverable resources estimated at 15.9 Tcfg (450.2 billion m<sup>3</sup>) and 393 million barrels (62.4 million m<sup>3</sup>) of natural gas liquids in the Anadarko Basin Province (Higley et al. 2011).

*Canadian Shales.* Shale gas exploration and production in Canada is now more than 4 years old, following new discoveries at the beginning of 2007. To date, there is shale exploration activity in 9 of the 10 Canadian provinces, with the province of Prince Edward Island being the only exception. A brief summary of shale gas and/or oil exploration/production activity by province follows below. Much of the information is available through the websites of provincial governments or links from them, as well as from news releases and the websites of companies actively exploring for gas.

*British Columbia:* Two giant thermogenic gas plays, one in the Devonian Muskwa/Horn River Shales and the other in the Triassic Montney Formation, are the focus of shale gas development in northeastern British Columbia (Adams et al. 2007). Muskwa/Horn River exploration and production is currently the most extensive in the Horn River Basin (Fig. 8). Exploration is underway in areas adjacent to the Horn River Basin, including the Cordova Embayment to the east, and the Laird Basin to the west (Fig. 8), although no production information is currently available. The Montney is a complex tight gas/shale gas play. Additional information about shale gas plays in British Columbia can be obtained from the following sources: Adams (2010), British Columbia Ministry of Energy, Mines and Petroleum Resources (2011), and Horn River News (2011).

*Alberta:* Target formations in this province include shales of the Upper Cretaceous Colorado Group, the Lower Jurassic Nordegg Member of the Fernie Group, and the Devonian Duvernay Formation of the Woodbend Group (Energy Resources Conservation Board [ERCB] 2009b). In eastern Alberta (Fig. 8), Colorado Group shales are being targeted for biogenic gas (Pawlowicz et al. 2008; Fishman et al., in press). The Nordegg in central Alberta is a recognized source rock in the Alberta Basin and has recently been a subject of some investigation for its potential as a shale oil play



**Figure 8.** Map showing the location of sedimentary basins in Canada discussed in this article in which there is active shale gas and/or shale oil exploration and/or production.

(Alberta Geological Survey 2011). So far this play has produced only limited liquids. The Duvernay, a shale unit stratigraphically equivalent to the Muskwa of British Columbia, is an exploration target in western Alberta as a thermogenic gas play with some oil/liquids potential. Despite being about 4,000-m (13,123 ft) deep, there has been a recent sharp increase in land sales associated with this play.

*Saskatchewan:* Exploration focus in this province has been primarily on two locations of biogenic gas accumulations within Upper Cretaceous rocks, as well as oil in the Upper Devonian–Lower Mississippian Bakken Formation (Government of Saskatchewan 2011b), one of the hottest plays in Western Canada. The biogenic shale gas plays are along the Saskatchewan–Alberta border and in the eastern half of the province (Fig. 8), where thin laminae of sandstone and siltstone that lie within the

shales of the Upper Cretaceous Colorado Group are the targets for production (Fishman et al., in press). Oil production from the Bakken Formation continues to be of significant interest in the province, with production increasing from about 1 to 2,000 barrels of oil per day (BO/day; 318 m<sup>3</sup>/day) in 2005 to about 50,000–60,000 BO/day (7,949 m<sup>3</sup> to 9,539 m<sup>3</sup>/day) at the beginning of 2010 (Government of Saskatchewan 2011a). Bakken production comes from the siltstone and sandstone within the shales (Kreis and Costa 2005). Bakken wells tend to be highly productive (200 barrels, or 31.7 m<sup>3</sup>, per day or more), producing sweet, light crude oil with 41° API gravity (Jock McCracken, written communication, March 14, 2011).

*Manitoba:* As in Saskatchewan, the Upper Cretaceous Colorado Group and the Upper Devonian–Lower Mississippian Bakken Formation (Fig. 8)

are the focus of interest in hydrocarbons from shales in the province. There is currently no production of gas from shales in the Colorado Group, but interest remains in their potential (Nicolas and Bamburak 2009). The production of oil from the Bakken, which began in the mid-1980s, continues, with about 14,700 BO/day (2,337 m<sup>3</sup>/day) from the formation, a tenfold increase since 2005 (Manitoba Energy and Mines Petroleum Branch 2011).

*Ontario:* The shales in Ontario are mostly considered secondary targets with only one well announced as a shale gas well (Ontario Oil, Gas and Salt Resources Library 2011b). The biogenic gas potential in these shales is in the Upper Ordovician Blue Mountain and Collingwood Shale (Utica Shale equivalent), Upper Devonian Kettle Point Shale (Antrim Shale equivalent), and in the Middle Devonian Marcellus Shale (Fig. 8) (Ontario Oil, Gas and Salt Resources Library 2011a).

*Quebec:* In Quebec, there is active shale exploration in the Upper Ordovician Utica-Lorraine shale (Questerre Energy Corporation 2010) within a 300-km (186 mi) by 100-km (62 mi) fairway between Montreal and Quebec City (Fig. 8). Six vertical wells, with tested rates at from 300 to 900 Mcfg/day (8,495–25,485 m<sup>3</sup>/day), were drilled initially in 2008 and then horizontal wells were drilled in 2009 and 2010 with more than 20 wells drilled to date (Eaton 2010). There have been reports of test rates up to 6 MMcfg/day (169,901 m<sup>3</sup>/day) but little information has been released. Recently, there have been delays and hearings because of public opposition for potential environmental concerns. In addition, the Upper Ordovician Macasty Shale (Utica equivalent) on Anticosti Island in the Gulf of St. Lawrence (Fig. 8) has seen some interest, largely as a secondary target, with results from recent coring identifying shale oil potential (Martel 2011).

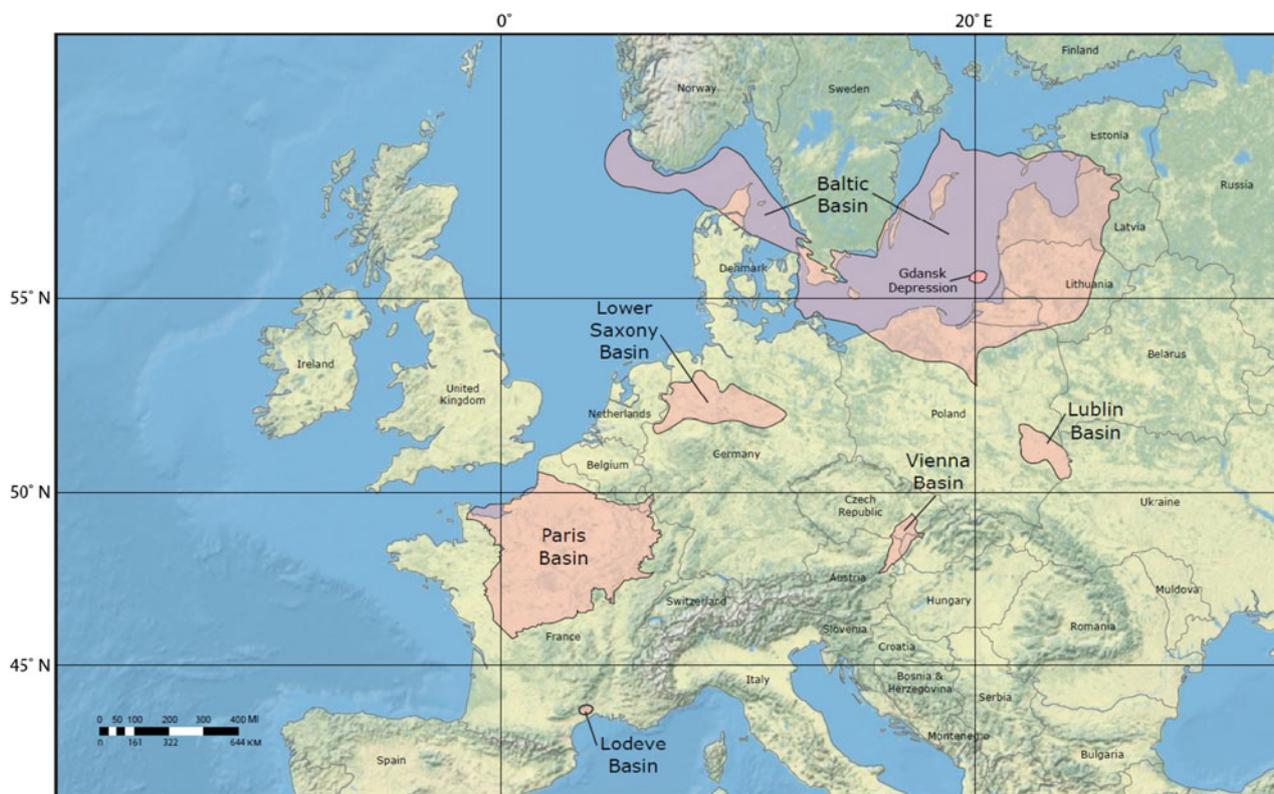
*New Brunswick:* The Lower Mississippian Fredrick Brook Shale in the Moncton Sub Basin (Fig. 8) has been the focus of thermogenic gas exploration in New Brunswick. A well drilled in November 2009 was tested in two zones after fracturing with propane (Apache Corporation 2011a). The lower black shale interval of the formation flowed at a rate of 0.43 MMcfg/day (12,176 m<sup>3</sup>), whereas the upper silty/sandy shale zone tested at initial peak rates of 11.7 MMcfg/day (331,307 m<sup>3</sup>/day) and a final rate of 3.0 MMcfg/day (84,950 m<sup>3</sup>/day). Evaluation of the Fredrick Brook play is still in progress (Apache Corporation 2011b).

*Nova Scotia:* The Upper Devonian–Lower Mississippian Horton Bluff Shale in the Kennetcook Sub Basin (Fig. 8) has been the primary exploration target for thermogenic shale gas in the province. A total of five vertical exploration wells were drilled since May 2007, but despite fracture treatments none has successfully produced gas (Jock McCracken, written communication, March 16, 2011). Additional exploration elsewhere in the province is underway on the Horton Bluff, although no additional information is currently available. Information about shale gas exploration in Nova Scotia can be obtained from <http://www.gov.ns.ca/energy/oil-gas/> (accessed March 16, 2011).

*Newfoundland:* The Cambrian-Ordovician Green Point Formation (Fig. 8) is the focus of exploration activity for thermogenic shale gas and oil in the western parts of the province. This Green Point interval has been studied in outcrop by the Geological Survey of Canada and is summarized by Hamblin (2006). A well drilled in 2008 encountered about 500 m of shale with siltstone stringers with high gas and oil shows throughout the formation but no testing was attempted (Jock McCracken, written communication, March 16, 2011). Geochemical analysis indicates that this zone is in the oil window. Further evaluation of the shale oil potential of this formation is currently underway as of January 2011.

*European Shales.* Activity in Europe has increased dramatically with extensive acreage positions being staked by a number of international companies, although drilling restrictions are currently in place in some countries due to environmental concerns regarding hydrofracing. Although most of the activities related to European shales have been for shale gas resources, some minor shale oil exploration is also underway. Although this report presents information as drawn from governmental sources and news releases, a comprehensive review of European shale resource potential can also be found by Chew (2010). Only countries with current shale gas or oil exploration or production are included below, with information listed by country (countries presented in alphabetical order).

*Austria:* There is active exploration for gas from the organic-bearing (a marl) Upper Jurassic Mikulov Formation (Vesterbye 2010) in the deep part of the Vienna Basin (Fig. 9). In addition, the Lower Jurassic Posidonia Shale may also be a target in the basin (Chew 2010).



**Figure 9.** Map showing the location of basins in Europe discussed in this article in which shale gas and/or shale oil exploration and/or production is occurring.

*Denmark:* A borehole targeting the Cambrian-Ordovician Alum Shale (Natural Gas for Europe 2011) was planned in association with the GASH Project (gas shales consortium in Europe) project (Fig. 9). This effort will include considerable investment in analytical studies as well as exploratory activities. Drilling commenced in May 2010, but the results have not yet been announced.

*France:* Jurassic rocks in the Paris Basin (Fig. 9) are the target of a possible Bakken-like oil system (Schaefer 2010). The Upper Jurassic Schistes Carton, Banc de Roc, and the Amaltheus Shale occur in a similar stratigraphic configuration as the upper shale member, middle sandstone member, and lower shale member of the Bakken Formation, respectively. Oil has been reported from two vertical wells tested in the Schistes Carton in 2010 with 32°–38° API gravity oil, although no flow rates have been reported. The Banc de Roc is a drilling target by several companies in 2011. In the Lodeve Basin of eastern France (Fig. 9), the Lower Permian Autunian Shale, a lacustrine source rock is being evaluated for gas (Chew 2010).

*Germany:* The Lower Saxony Basin (Fig. 9) has recently had four shale gas wells drilled in it (Chew 2010), with the Upper Cretaceous Wealden Shale and the Upper Jurassic Posidonia Shale as the likely targets (World Oil 2011). Other possible targets in Germany include the Upper Devonian Kellwasser Shale, the Visean Shale, and Namurian Shale (Chew 2010).

*Poland:* Poland remains an important country with respect to its shale-gas potential (Chew 2010). Two vertical wells have been completed in the offshore Baltic Basin (Fig. 9), one of which, in the Gdansk Depression, targeted Silurian and Ordovician shales to evaluate their potential. Exploration in the onshore Baltic Basin (Fig. 9) is also underway with two wells having been drilled recently. In the Lublin Basin of southeastern Poland, the first hydraulic stimulation was performed on shale, although results appear to be negative, or at least less promising than expected. Another well is planned in western Poland in 2011 (Chew 2010).

The Polish Geological Institute and the U.S. Geological Survey will conduct a resource

assessment of shale gas potential in Poland with their first report scheduled to be presented in April 2011 (Chew 2010); the results of the cooperative effort have not yet been released. In addition, a consortium—including the Polish Geological Institute, the Polish national oil company, and some companies—has recently been established to advance the understanding and evaluation of shale gas resource systems.

*Sweden:* The first of three proposed wells has been drilled to evaluate the thermogenic gas resource potential in the Cambrian-Ordovician Alum Shales (Chew 2010). The results of this test are unknown at this time.

*Other European Activities:* There is continuing interest in Paleozoic and/or Mesozoic shale exploration targets in The Netherlands, Switzerland, Ukraine, and the United Kingdom, but exploration is not being as actively pursued in these countries as elsewhere in Europe (Chew 2010).

## GEOTHERMAL

**R. J. Erdlac, Jr.<sup>24</sup>**

### *Introduction*

While geothermal production continues to move forward in the United States and around the world (see Geothermal Energy Associates (GEA) newsletters at <http://www.geo-energy.org/>, accessed March 16, 2011) a new direction for geothermal electrical power production has finally taken root and is sprouting from the substratum. The U.S. Department of Energy (DOE) and several oil and gas companies are recognizing that geothermal can be produced in areas around the world where traditionally only oil and gas was produced.

In the mid-1970s through the 1980s the DOE conducted extensive work in the Texas and Louisiana Gulf Coast area toward testing geopressured geothermal formation water for both heat extraction for electricity and the dissolved natural gas within these subsurface brines. Demonstration wells and projects documented the capability of generating electrical power from this untapped resource. By the beginning of the 1990s with the low price of oil and gas, work to further develop this untapped resource

ceased. For nearly 20 years work in the United States toward geothermal development in sedimentary basins and other nontraditional areas was sporadic at best. In the last few years this movement in geothermal development has been drastically altered, ranging in variable DOE funding availability and renewed interest in sedimentary basin geothermal energy.

### *DOE Funding*

In 2009, the Department of Energy issued \$338 million in awards through the American Recovery and Reinvestment Act toward the expansion and acceleration of geothermal development in all facets throughout the United States. This money was matched in a more than one-for-one basis with an additional \$353 million in private and non-Federal cost-share funds. This money went toward the support of 123 projects in 39 states, with recipients including private industry, academic institutions, tribal entities, local governments, and DOE's National Laboratories.

These grants were directed toward identifying and developing new geothermal fields and reducing the upfront risk often encountered with geothermal development through innovative exploration and drilling projects and data development and collections. The grants would also support the deployment and creative financing approaches for ground source heat pump demonstration projects across the country.

The projects that were selected for negotiation of awards fell into six categories:

1. Innovative Exploration and Drilling Projects (up to \$98.1 million): Twenty-four projects have been selected focusing on the development of new geothermal fields using innovative sensing, exploration, and well-drilling technologies.
2. Co-produced, Geopressured, and Low-Temperature Projects (up to \$20.7 million): Eleven projects have been selected for the development of new low-temperature geothermal fields, a vast but currently untapped set of geothermal resources. This includes geothermal heat found in the hundreds of thousands of oil and gas wells around the United States, where up to ten barrels of hot water are produced for every barrel of oil.

<sup>24</sup>Access Energy (A Calnetix Company), Midland, TX 79703, USA; Chair, EMD Geothermal Energy Committee.

3. Enhanced Geothermal Systems Demonstrations (up to \$51.4 million): Three projects have been selected for the exploration, drilling, and development of enhanced geothermal systems (EGS) to validate power production from deep hot rock resources using innovative technologies and approaches.
4. Enhanced Geothermal Systems Components Research and Development/Analysis (up to \$81.5 million): Forty-five projects have been selected to focus on research and development of new technologies to find and drill into deep hot rock formations, stimulate enhanced geothermal reservoirs, and convert the heat to power.
5. Geothermal Data Development, Collection and Maintenance (up to \$24.6 million): Three projects have been selected for the population of a comprehensive nationwide geothermal resource database to help identify and assess new fields.
6. Ground Source Heat Pump Demonstrations (up to \$61.9 million): Thirty-seven projects have been selected to demonstrate the deployment of ground source heat pumps for heating and cooling of a variety of buildings for a variety of customer types, including academic institutions, local governments, and commercial buildings.

This funding was separate from the primary budget requests for the Geothermal Technology Program (GTP). In 2010, the GTP was apportioned \$43,120,000 that was focused on enhanced geothermal systems. A congressional request had been made for a major increase in FY 2012 for \$101,535,000. This budget request named enhanced geothermal systems (EGS) (\$61.5 million), low-temperature coproduced resources (\$14 million), systems analysis (\$5 million), innovative exploration technologies (\$15 million), and permeable sedimentary resources (\$6 million) as target areas for geothermal activity.

However in May 2011, the GEA newsletter announced that the final 2011 full year funding level for the GTP would be only \$38 million, down to 86% of the 2010 level. In June, the House Appropriations Committee confirmed the FY 2012 GTP budget at \$38 million. Of interest was that the Committee directed that the Geothermal Department continues to advance technologies that can exploit the vast resource that lies virtually untapped

from low-temperature geothermal and co-produced geothermal resources.

Also in June, U.S. Energy Secretary Steven Chu announced that eight projects in five states (California, Connecticut, Louisiana, Texas, and Utah) had been selected to receive up to \$11.3 million to support research and development of pioneering geothermal technologies. Among these projects are a new generation of gravity-driven downhole pump, heat extraction from a single well system, the use of CO<sub>2</sub> in equipment and subsurface heat capture, and horizontal well recirculation systems for geothermal energy recovery. All these and other geothermal projects can be found at <http://www1.eere.energy.gov/GEOTHERMAL/>.

#### *Geothermal and the Oil and Gas Industry*

When geothermal is mentioned, the first location that many people think of is volcanoes, hot springs, fumaroles, etc., which are valid considering the nature of a volcano and the associated hot water with their formation at depth. However, most people in the oil and gas industry know of stories where a drilled well encountered such high temperatures that “the tool melted in the hole.” These anecdotes have made for interesting stories but they also represent the realization that the industry quite often reaches temperatures in excess of 200°F (93.3°C) in its drilling for oil and gas.

Heat is energy, and the oil and gas industry is finally beginning to realize that this heat, once only a nuisance and a problem, is an untapped energy resource to be developed. Toward this end several companies have begun to recognize this “stranded” heat energy resource and are beginning to harness this energy for electrical power generation for their own use or to sell to utility companies.

Several companies are looking at generating geothermal electricity from co-produced hot water in conjunction with oil or gas production. For example, Continental Resources, the University of North Dakota, Access Energy, and the DOE have partnered to generate electricity from six water supply wells that produce 40,000–50,000 BBLs (6,359–7949 m<sup>3</sup>) of 190–200°F (88–93°C) water per day. As the water must be cooled prior to its use, Continental saw this as an opportunity to extract energy for electrical power generation and use within the Cedar Creek field. The University also demonstrated that some \$2.5 million in savings could

be had by Continental over a 25-year period by electric generation from waste heat.

Denbury Resources, Inc. is working with Gulf Coast Green Energy, Southern Methodist University, and a grant from the Research Partnership to Secure Energy for America (RPSEA) to establish a co-production project at the Summerland Field in Mississippi. Produced water of nearly 200°F (93°C) at 4,000 BBLs/day (636 m<sup>3</sup>/day) will be used to offset electrical operating expense at this field, with the production of about 50 kW of electricity. This is a test project to determine how effective co-production may be for offsetting these electrical expenses. However, if successful this may open the door for additional co-produced opportunities in geothermal energy development.

Hilcorp Energy Company, working with a turbine company and Cleco Corporation, is working to produce power from a south Louisiana well from 240°F (116°C) water at a rate of 4,000–5,000 BBLs/day (636–795 m<sup>3</sup>/day). Produced power would be in the range of 50–100 kW output.

While these companies are looking at co-produced power opportunities, other companies are anticipating a different approach to power generation. Universal GeoPower, composed of oil and gas professionals, won a DOE grant to develop geothermal energy from abandoned oil and gas wells in Texas. They have been pursuing possible sites in the Liberty County area. They have created a flow model for reservoir analysis and have been developing the software by iteration, making predictions on past wells and comparing those with their actual production records and then making forward model predictions on new wells regarding fluid flow. Universal is looking at Eocene-age sands where porosity can be 28–32% and permeability in the Darcy range.

Louisiana Geothermal (the sister company of Louisiana Tank Inc.), Jordan Oil Company, and Central Crude of Lake Charles, received funds from the DOE to conduct a geopressured geothermal project just east of the Sweet Lake area of Cameron Parish, Louisiana, keying off past work of the DOE in the Gulf Coast of Louisiana and Texas. This past work included the Pleasant Bayou #2 well which existed as a geopressured geothermal power plant for several months at a 1.2 MW capacity in Brazoria County, Texas. The company anticipates this project to produce enough power in the next 2 years to provide much of the power needs of Cameron Parish. The well would be drilled specifically for geopressured-geothermal power production to a

depth on the order of 16,000 ft (4,877 m), with a calculated net potential of around 5.6 MW of power. Flow was anticipated at 30,000 BBLs/day (4,770 m<sup>3</sup>) with a capacity factor of +90%. Unforeseen difficulties with additional funding resulted in a cancellation of this project and a return of the DOE funds. However, company representatives believe this is a viable project and remain interested in geothermal energy development within the Gulf Coast region.

Finally, Pioneer Natural Resources Company is investigating the potential for developing geothermal power in the Raton Basin of Colorado. This project is in the early exploratory phase and is seen by Pioneer as an attractive alternative, or even a supplement, to existing fossil-fuel production due to geothermal energy's potential as a long-term, clean, and 24/7 base-load energy resource. This makes geothermal more attractive than other alternatives like solar and wind that have neither the 24/7 capability nor the issues surrounding operation and maintenance. Pioneer has been working with the Colorado Geological Survey as this area is being investigated for its geothermal opportunity by other companies as well.

### *The Future*

Requests to the U.S. Congress for continued support of geothermal development from DOE have continued. In FY2010, the Geothermal Technologies Program received direct funding in the amount of \$43 million. For FY2011 a request of \$55 million had been made, with a near doubling of this request to \$102 million for FY2012. The FY2012 request was confirmed at only \$38 million and the future of continued funding at a consistent level is uncertain. A June 2011 GTP Blue Ribbon Panel submitted recommendations that included a statement that the Program should no longer invest in research, development, and demonstration of low-temperature, co-produced, geopressured, or sedimentary resources due to the absence of any major technological challenges to those areas, with efforts being concentrated on EGS and other geothermal activities. But, with politics aside, energy drives all aspects of our economy and technology and with the importance that energy is taking on more and more pushing the development of this baseload energy resource is long overdue.

As to the future for oil, gas, and geothermal combined, interest is expected to continue. The

Rocky Mountain Oilfield Testing Center has had an Organic Rankin Cycle (ORC) binary turbine From Ormat operating on a well at the Teapot Dome, or the Naval Petroleum Reserve No. 3. Electrical power generation has been produced from a 250-kW unit from 190°F (88°C) water and about 45,000 BBLs (7,154 m<sup>3</sup>) per day from the Tensleep Formation. A total of 1,918 Mwh have been produced to date, making it the first test unit to use co-produced hot water to generate electricity in an operating oil field. Additional testing of other company geothermal recovery technology is expected for future activities.

Recently, an oil and gas company (name withheld by request) in the Gulf Coast area, working with Access Energy, has placed an ORC unit at one of its wells and is producing over 50-kW gross, with part of this power operating the system and the remainder being sold to the electric grid. Finally, Continental Energy Corporation has advertised in the Geothermal Energy Association newsletter its interest in seeking local operators or parties with access to properties with hot oil or gas wells (shut-in or production) in Mississippi for the purpose of co-produced geothermal energy development.

Several turbine and generator companies have developed units to convert heat to electric power at lower temperatures and power outputs. Companies such as Access Energy, Electra Therm, Ormat, Pratt and Whitney (UTC Power), and Turbine Air Systems (TAS) are among those producing units that have the potential for producing power from waste heat (including geothermal) sources within the oil and gas industry.

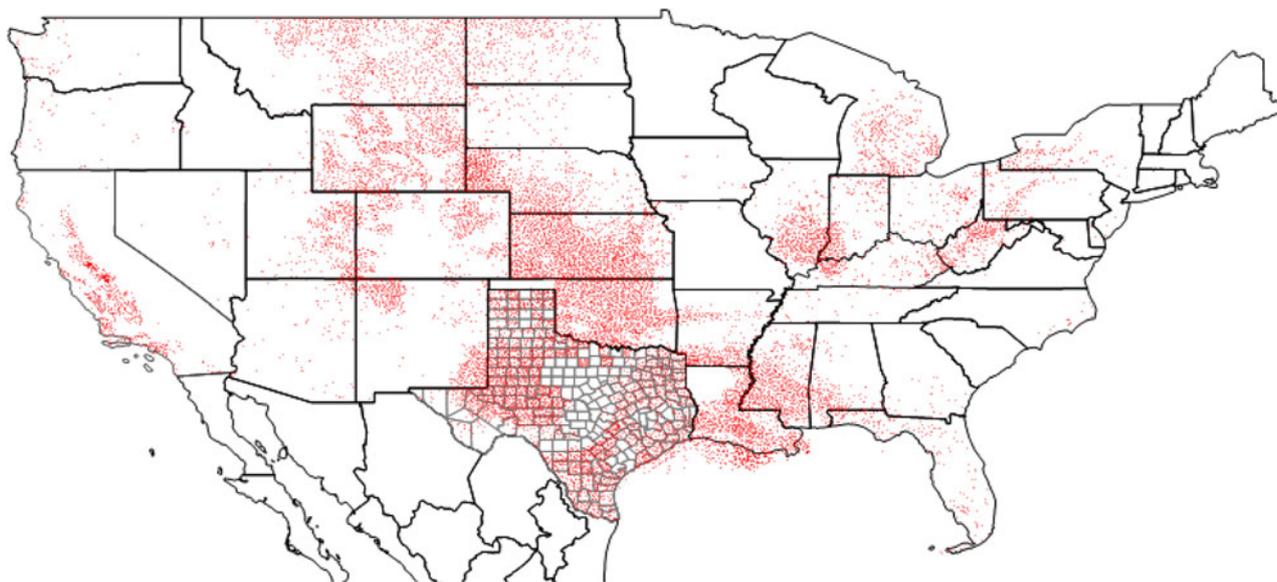
What makes geothermal energy in sedimentary basins such a huge potential benefit for energy development is the availability of an incredible amount of subsurface data courtesy of the oil and gas industry. A quick well count using IHS Enerdeq under production allocated data type shows a count of 1,782,367 wells drilled in the U.S. within that particular database. Many more wells may exist that have not yet been placed in that or other state database files. Seismic reflection data also provides a huge benefit in understanding the expanse and subsurface architecture of target formations for hot water production.

The point to recognize is that each well drilled for oil or gas provides important information at that locality regarding the subsurface rock type, porosity and permeability, fluid type, temperature, and other formation characteristics. Such information is not as readily available in other states where oil or gas has

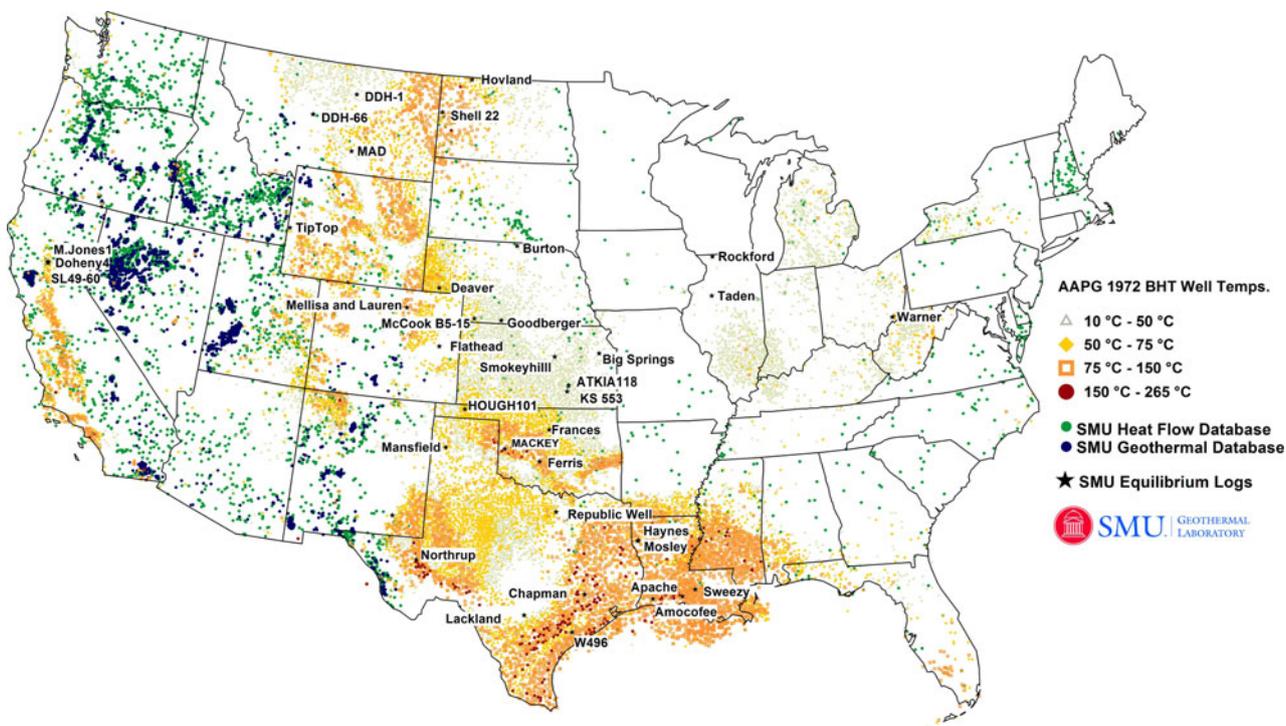
not been actively explored or produced. In the 1970s and 1980s when the DOE managed a major Gulf Coast geopressured geothermal project, the American Association of Petroleum Geologists (AAPG) and U.S. Geological Survey (USGS) developed subsurface temperature and thermal gradient maps of North America using temperature data provided mostly by the oil and gas industry. Over 18,000 wells were available in the U.S. alone for the construction of these maps (Fig. 10). As of 1998, these data were still available for purchase through the AAPG in DOS format but which could be converted into modern spreadsheet format. The Southern Methodist University (SMU) Geothermal Laboratory has made use of these well data along with other shallow heat flow measurements in various western states (Fig. 11) for numerous maps generated for the DOE and other geothermal studies and presentations. Figure 11 shows many of the bottom hole temperature (BHT) readings from these oil and gas wells that indicate subsurface temperatures in the 167–302°F (75–150°C) range. Wells with BHT readings above 302°F (150°C) are found in the Gulf Coast and the deep part of the Delaware Basin in West Texas.

Many more wells have been drilled since the time that these data were collected. However, other than through this AAPG database, no easy way has existed to acquire addition BHT data for enhancing existing geothermal maps, generally developed at a constant depth, other than choosing a location of interest and looking at log headers or drill stem test (DST) information, a time-consuming activity. About one-and-one-half years ago the DOE initiated funding of a major project that includes all State geological surveys to develop a Geothermal Data Catalog that will be publically available through internet connections allowing download pertinent geothermal information. The interested reader can visit this site to see what presently exists by going to <http://catalog.usgin.org/geoport/catalog/content/about.page>.

The SMU Geothermal Laboratory has also maintained a separate site of geothermal data for a number of years. In addition, downloadable information on SMU's yearly geothermal symposiums is available specifically for support of geothermal in the oil and gas industry (<http://smu.edu/geothermal/>). Additional maps generated by the SMU staff have been made available for viewing through Google using Google Earth as a visual platform (<http://www1.eere.energy.gov/geothermal/maps.html>). Other



**Figure 10.** Map showing the location (red dots) of the U.S. wells originally provided by industry to the American Association of Petroleum Geologists/U.S. Geological Survey (AAPG/USGS) geothermal study of North America. Additional wells covered parts of Canada and Mexico.



**Figure 11.** Bottom hole temperature (BHT) sites from oil and gas wells in the conterminous U.S. in the American Association of Petroleum Geologists (AAPG) database combined with the location of regional heat flow and geothermal database sites. The named wells have been used for calibration of subsurface temperature. The BHT symbols are based on depth and temperature (Blackwell et al. 2007). 1°C = 33.8°F.

information regarding geothermal energy in sedimentary basins can be found through the DOE in their Legacy Data and at the Texas State Energy Conservation Office (SECO).

Thus, the interest in geothermal energy in the more “unconventional” geographic areas of the world has begun, unconventional for geothermal but conventional for the oil and gas industries. The future may be brighter for all, with a new energy future in oil, gas, and geothermal combined.

## OIL SANDS

**D. K. Higley<sup>25</sup>, F. J. Hein<sup>26</sup>**

Heavy and extra-heavy oil deposits occur in more than 70 countries across the world, with the largest deposits located in Canada and Venezuela (Meyer et al. 2007; Dusseault et al. 2008; Hein and Marsh 2008; Hernandez et al. 2008; Marsh and Hein 2008; Villarroel 2008). Extra-heavy oil that does not naturally flow to a well is known as bitumen. The largest bitumen deposits are hosted in unlithified sand reservoirs and, therefore, the bitumen is commonly called oil sands or tar sands. However, reservoirs can also include porous sandstone or carbonates. Bitumen API gravity is less than 10° and viscosity is generally greater than 10,000 centipoises (cP) at reservoir pressure; heavy oil API gravity is between 10° and 25° with viscosity greater than 100 cP (Danyluk et al. 1984; Schenk et al. 2006).

Almost all the bitumen being commercially produced in North America is from Alberta, Canada. Canada is an important strategic source of bitumen and synthetic crude oil (SCO) that is obtained by upgrading bitumen. Bitumen and heavy oil are also characterized by high concentrations of nitrogen, oxygen, sulfur, and heavy metals, which results in higher costs for extraction, transportation, and refining than for conventional oil (Meyer and Attanasi 2010). Research is being conducted on transportation alternatives for heavy crude and bitumen using new and existing infrastructure of pipelines and railways. Such integration has been called a virtual “pipeline on rails” to get the raw and

upgraded bitumen to the U.S. markets (Perry and Meyer 2009).

A U.S. goal for energy independence could include production from existing U.S. oil sands deposits using surface mining or in situ extraction. Current U.S. bitumen production is mainly for local use on roads and similar surfaces. Schenk et al. (2006) listed total measured plus speculative in-place estimates of bitumen at about 54 BBLs (8.6 billion m<sup>3</sup>) for 29 major oil sand accumulations in Alabama, Alaska, California, Kentucky, New Mexico, Oklahoma, Texas, Utah, and Wyoming. Estimated in-place Alberta oil sands resources are 1804 BB (286.6 billion m<sup>3</sup>), and estimated ultimate recovery is 315 BB (50.0 billion m<sup>3</sup>) (ERCB 2010, p. 3). Alberta’s 2007 crude bitumen production totaled 482.5 million barrels (76.7 million m<sup>3</sup>), which was equivalent to 1.32 million BBLs per day (210 thousand m<sup>3</sup> per day); of this total bitumen production, 59% (284.7 million BBLs; or 45.3 million m<sup>3</sup>) was from surface mining and 41% (197.8 million BBLs; or 31.4 million m<sup>3</sup>) from in situ production (ERCB 2008). The bitumen that was produced by surface mining was upgraded to SCO; in situ bitumen production was marketed as non-upgraded crude bitumen (ERCB 2008, 2009a). Cumulative bitumen production for Alberta in 2009 was 302 million BBLs mined and 245 million BBLs in situ recovery (48 million m<sup>3</sup> mined and 39 million m<sup>3</sup>, respectively) (ERCB 2010).

Alberta bitumen production has more than doubled in the last decade, and is expected to increase to greater than 3 million BBLs per day (>0.48 million m<sup>3</sup>) over the next decade. Over the last 10 years, the contribution of bitumen to Alberta’s total crude oil, raw bitumen, and SCO production has increased steadily. Alberta bitumen and SCO contribution was 62% in 2006, 69% in 2009, and is estimated to reach 86% of cumulative petroleum by 2016, and 89% by 2019 (ERCB 2008, 2010). Figure 12 shows the increasing contribution of bitumen and SCO to Alberta’s petroleum supply. This production through time is associated in Figure 13 with SCO price.

As of December 2008, Alberta bitumen reserves under active development (mainly by surface mining) accounted for only 15% of the remaining established reserves of 21 BBLs (3.3 billion m<sup>3</sup>). Unlocking the huge potential of the remaining bitumen resources will require enhancing other in situ technologies. The most commonly used in situ technologies are Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation

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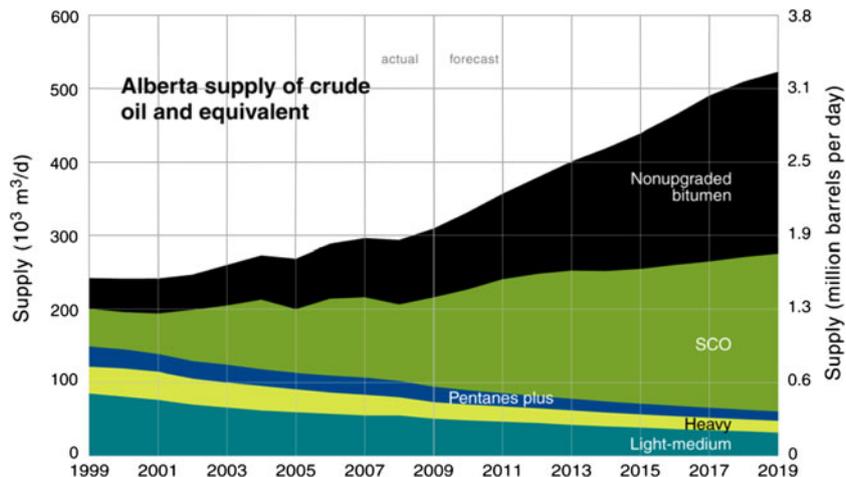


Figure 12. Alberta supply of crude oil and equivalents (ERCB, 2010, Figure 3). SCO refers to synthetic crude oil produced from bitumen.

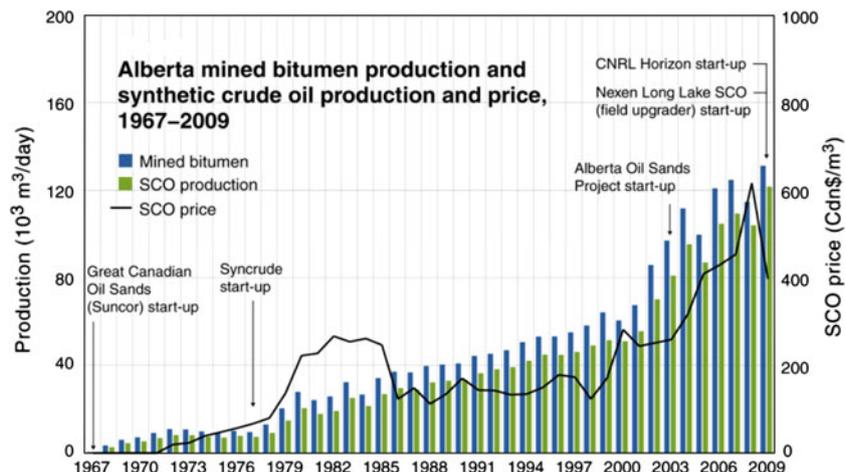


Figure 13. Alberta mined bitumen production and derived SCO production and price (ERCB 2010, Fig. 9). Start-up times refer to onset of production from various companies and processes.

(CSS). Steam Assisted Gravity Drainage and CSS utilize considerable energy and water to produce steam. Also required are good permeability (both vertical and horizontal), relatively thick pay zones (>32.8 ft or 10 m), and an absence of barriers (cemented zones, thick laterally continuous shales), and the lack of significant top/gas or bottom-water thief zones. A comprehensive, two-volume edition book entitled: “Handbook on theory and practice of bitumen recovery from Athabasca oil sands” (Masliyah et al. 2011) focuses on the extraction of bitumen from oil sands mainly using surface mining methods, and also includes a chapter on in situ processes. Volume I covers the basic scientific

principles of bitumen recovery, froth treatment, diluents recovery, and tailings disposal; Volume II is devoted to industrial practices. Some of the focus of recent in situ technology and advances includes:

- Integration of future oil sands technology with that of emerging oil shale co-production in the western United States.
- New developments concerning in situ recovery and underground refining technologies for oil sands in western Canada include underground combustion and refining.
- Use of Cold Heavy Oil Production with Sand (CHOPS) as a specialized primary type of

production where progressive cavity pumps assist in lifting bitumen and sand to the surface, and utilize this sand production to create wormholes for increased permeability in the reservoir.

- Search for alternative sources of energy for steam production, including the use of nuclear energy in conjunction with in situ oil sands production plants (Peace River, Alberta).
- Further development and use of technologies, including Vapor Extraction (VAPEX), Toe-to-Heel-Air-Injection (THAI), Supercritical Partial Oxidation (SUPOX), and various hybrid developments, including CO<sub>2</sub> flooding.

Critical technology needs include enhancing current methods and developing new more-environmentally friendly methods of extraction, production, and upgrading of oil sands. Emphasis of surface mining operations is on reclamation of tailings and consolidated tailings, and on re-vegetation of open-pit mine sites. In early February 2009, the Energy Resources Conservation Board (ERCB) issued Directive 074 that outlines new cleanup rules and harsh penalties for non-compliance regarding tailings ponds regulations for the oil sands areas. This directive resulted from the ERCB acknowledgment that, although operators invested heavily in improved tailings reduction strategies, targets set out in the original development applications have not been met. Firm performance criteria are defined for reclaiming the tailings ponds, with performance inspections, and subsequent penalties due to neglect, omission, or commission.

Most of the bitumen resources are extracted by in situ technologies (mainly thermal, such as Steam Assisted Gravity Drainage and Cyclic Steam Stimulation). Because there is significant co-production of greenhouse gases with bitumen production and upgrading, critical technology needs involve research into: (1) alternative sources of heat for generation of steam (e.g., geothermal, nuclear, burning of slag); (2) methods to reduce the viscosity of the bitumen so it will flow to the well bore or through pipelines more easily (such as use of diluents, catalysts, microbial, and nanotechnology); (3) underground in situ extraction, refining, and upgrading; and (4) co-sequestration of greenhouse gases by injection into abandoned reservoirs or other deep geologic sites. At present, there is an excess supply of sulfur above what is used in agricultural and other markets. Excess sulfur

associated with bitumen production and upgrading is stockpiled.

The primary environmental issues relate to the balance among greenhouse gas emissions and water/energy usage and the recovery, production, and upgrading of bitumen. Specifically, the critical environmental focus is how to cleanly, efficiently, and safely extract, produce, and upgrade the bitumen. Goals include reducing (1) energy required to heat the water to steam; (2) CO<sub>2</sub> emissions. Current greenhouse gas emissions are decreasing and remaining emissions are compensated for by carbon trading and (or) CO<sub>2</sub> sequestration; and (3) improving the economics and processes of extraction, production, and upgrading of the bitumen. Some of the areas of focus for the latter include:

- Land reclamation in surface mining.
- Tailings and consolidated tailings disposal and reclamation.
- Bitumen upgrading and co-production of other products from tailings (such as vanadium, nickel, and sulfur).
- In situ recovery.
- Underground refining.

Oil sand developers in Canada are working to reduce CO<sub>2</sub> emissions by 45% per barrel by 2010, compared to 1990 levels. Canadian developers are legislated to restore oil sand mining sites to at least the equivalent of their previous biological productivity. For example, at the Syncrude mine site near Fort McMurray, Alberta, the Fort MacKay Indian Band has reclaimed much of the previous tailings pond areas into grasslands that are now supporting a modest bison herd (~500–700 head).

An American Association of Petroleum Geologists (AAPG) memoir with the proposed title “Heavy Oil/Bitumen Petroleum Systems in Alberta & Beyond” is in preparation; it includes research papers on oil sands that include presentations from the 2007 Hedberg Conference “Heavy Oil and Bitumen in Foreland Basins—From Processes to Products.” At the 2009 AAPG Annual Meeting, the Energy Minerals Division (EMD) poster session on oil (tar) sands was part of the unconventional resources sessions. A similar EMD session was included in the 2010 AAPG Annual Meeting in New Orleans. Fran Hein, previous Chair of the EMD Oil (Tar) Sands Committee, was the AAPG EMD co-chair for the AAPG International Conference &

Exhibition (ICE), held in Calgary in September, 2010. EMD-sponsored sessions included a full day on unconventional resources, which included morning and afternoon sessions on Heavy Oil/Bitumen and the Bakken, and a plenary talk by Dr. Dale Leckie on Nexen's Long Lake SAGD project in northern Alberta.

## OIL SHALE DEVELOPMENTS

### J. Boak<sup>27</sup>

Global production of shale oil is currently ~20,000 barrels of oil per day (BOPD; 3,180 m<sup>3</sup>), all from mining and retorting operations in Brazil, China, and Estonia. Current projections show that oil shale will not be a significant part of global production (>500,000 BOPD; 79, 494 m<sup>3</sup>), for at least another decade. Projects over the next 4–5 years could, however, increase production by 2–5 times. Data contained in this review is primarily from publically available government and industry websites.

Dyni (2006) estimated world resources of shale oil to be >3.0 trillion barrels (477 billion m<sup>3</sup>), with ~2 trillion barrels (318 billion m<sup>3</sup>) located in U.S.A. The latest U.S. Geological Survey assessments for Colorado and Utah are 1.5 and 1.32 trillion barrels (238 and 210 billion m<sup>3</sup>), a significant increase over the previous estimates. A Wyoming assessment in review indicates a resource that exceeds that in Utah. Yuval Bartov of Israel Energy Initiatives Limited suggested Israeli resources are as high as 250 billion barrels of oil (BBO; 39.7 billion m<sup>3</sup>), and Jordan Energy Minerals Limited (JEML) reports an estimated resource of 102 BBO (16.2 billion m<sup>3</sup>) for Jordan.

Critical environmental issues for oil shale development are how to extract, produce, and upgrade shale oil in an environmentally friendly and economically sound way such that:

1. Use of energy to pyrolyze kerogen is minimized.
2. Greenhouse gas emissions are reduced or compensated for by CO<sub>2</sub> capture and sequestration.

3. Water use is minimized and does not deplete water resources in arid regions.
4. Extraction, production, and upgrading of shale oil do not unduly affect the quality of air, native biological communities, or surface and ground water.

### U. S. Activity

The U.S. Bureau of Land Management (BLM) is reviewing three lease nominations from ExxonMobil Corporation, Natural Soda, Inc., and AuraSource, Inc. for a second round of Research, Development, and Deployment (RD&D) leases. BLM completed a technical review in the Spring of 2010, and announced in September 2010, that it would advance all three to the next stage of environmental analysis, which will take 4–18 months to complete. The leases offer the same 160-acre (64.7 ha) RD&D area as the previous round. However, the lease preference area, which becomes available at fair market price after a company has shown commercial feasibility for its technology, has been reduced to 480 acres (194.2 ha), for a total of 640 acres (259 ha).

On February 15, 2011, U.S. Department of Interior Secretary Ken Salazar announced that the U.S. BLM would take a fresh look at commercial oil shale rules and plans that the Bush administration issued in 2008 to determine if they need to be updated to reflect the latest research and technologies, to account for expected water demands in the arid U.S. west, and to ensure they provide a fair return to the taxpayer.

Red Leaf Resources, Inc. of Cottonwood Heights, Utah, anticipates moving forward with production of 9,500 BOPD (1,510 m<sup>3</sup>) within 24 months, and plans to expand that to a 30,000 BOPD (4,770 m<sup>3</sup>) facility that will start construction in 2013, using In-Capsule Extraction, a method they developed. It involves mining of oil shale, encapsulation in a surface cell akin to a landfill, heating and extraction of the products, and sealing of the exhausted retort. Red Leaf currently estimates an energy return on investment of 11.5–1, based on recent trial (described in more detail at Red Leaf's website: <http://www.redleafinc.com/>, accessed June 22, 2011). This would be a globally significant development for oil shale.

American Shale Oil LLC (AMSO), partnered with Total, S.A., plans to conduct a pilot test of their in situ process (Conduction, Convection &

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Reflux-CCRTM) in 2011. The test will be conducted in the illitic oil shale of the Garden Gulch Member of the Green River Formation in Colorado. Microseismic and other methods will be used to image growth of the retort zone. Experimental results suggest the process yields 35–40 API gravity oil with a net energy return of ~4:1.

Shell Oil Company continues to experiment with its In situ Conversion Process (ICP), which involves electric heating of a block of rock contained by a freeze wall to protect ground water and minimize heat loss. Shell has demonstrated elements of this system on a small scale, and completed a larger scale freeze wall in Colorado. They have circulated water through the test block to re-move hydrocarbons not extracted through the production wells. Shell has submitted a permit application for a test on its multi-mineral RD&D lease.

ExxonMobil Corporation continues work at its Colony site in Colorado to investigate the Electro-Frac™ technology, which also involves electric heating, but through large plate electrodes created by hydrofracturing from horizontal wells and injecting an electrically conductive proppant. They have demonstrated that the process can create an effective connected heating element. Chevron has completed geologic and hydrologic characterization (and monitoring) wells at its RD&D lease in Colorado. It has been relatively quiet about development of its own technology for in situ extraction.

In the U.S., concern exists especially about greenhouse gas emissions and water consumption of an oil shale industry. The primary source of CO<sub>2</sub> emissions for in situ production comes from power plants, and power plant water consumption is the second largest use for a Shell-type in situ operation (Boak 2008; Boak and Mattson 2010). Minimizing energy use is essential. ExxonMobil suggested air-cooled power plants to reduce water use, but these may increase CO<sub>2</sub> emissions (Thomas et al. 2010). AMSO has emphasized the potential for sequestration of CO<sub>2</sub> in exhausted in situ retorts (Burnham and Collins 2009). Socioeconomic impacts are also issues of concern. The recent offering of RD&D leases required that each of these concerns be addressed explicitly in the lease application. Shell has determined that developers must interact with 47 separate regulatory bodies before production can begin. These interactions include at least two separate environmental impact assessment stages.

Understanding and mitigating the environmental affects of oil shale production across entire

regions is clearly not the responsibility of individual leaseholders, but rather of the majority steward of the land, the Federal government. In the past, the U.S. Department of Energy managed an Oil Shale Task Force charged with defining and integrating baseline characterization and monitoring needs for environmental impacts within the western U.S. basins containing the Green River Formation. The Task Force included representatives of government and industry, including environmental firms retained by major potential producers. This need is not being addressed.

### *International Activity*

Estonia is significantly expanding its capability to produce oil from shale, while de-emphasizing the use of oil shale for combustion in power plants. Eesti Energia, A.S., has recently signed agreements with Morocco and Jordan to evaluate oil shale deposits and potential production systems. Petrobras and Total have been working with Morocco to develop well-characterized oil shale deposits near Timadhit. San Leon Energy of Dublin, Ireland, plans to begin testing of its in situ technology at Tarfaya in 2011.

China appears to be rapidly increasing its capacity to produce shale oil through surface retorting. Currently, it appears there are over 500 retorts of various sizes (mostly 100 tonne (t) or 110 short tons/day shale, Fushun-type retorts) installed with more than 200 under construction. Although total production was only about 10,000 barrels (1,590 m<sup>3</sup>) per day, the numbers do not make clear whether the current limitation is the capacity or the efficiency of the retorts. A significant number of the retorts are new in the last year, and may not yet be on line.

Jordan is actively pursuing partnerships to develop its significant resources of oil shale, partnering with Petrobras, Shell, Eesti Energia, Jordan Energy Minerals, Limited, and others to define a path toward energy independence. Jordan Energy Minerals Limited (JEML) has nearly completed a Memorandum of Understanding with the Jordanian government for a project to process oil shale, with startup planned for 2014 at 15,000 BOPD (2,385 m<sup>3</sup>), estimated breakeven price of \$38/barrel.

Internationally, there is a lack of consistently structured resource assessments. The energy security of the world would benefit from enabling developing countries that do not have the large resource

database available in the U.S. to assess their oil shale resources. Developing criteria and methods for such assessments would be a contribution to global development of this resource, and would potentially create good will between the U.S., the European Union, and the developing countries. Critical to such assessments will be careful estimation of the uncertainty regarding resource estimates where data are sparse.

### *Information Resources*

The Colorado School of Mines, Golden, Colorado, hosts the Oil Shale Symposium, the premier international meeting on oil shale in October. The 31st Oil Shale Symposium is scheduled for October 17–21, 2011 in Golden, with a field trip to Colorado and Utah. Proceedings abstracts, presentations, and papers of the Oil Shale Symposium are available at: <http://www.ceri-mines.org/oilshaleresearch.htm>, accessed June 22, 2011. Research in oil shale processes and impacts is published in the journal *Oil Shale*, published in Estonia (<http://www.kirj.ee/oilshale> accessed June 22, 2011). Another good reference on oil shale is a recently published book entitled *Oil Shale—Petroleum Alternative* (Qian and Yin 2010).

## URANIUM AND NUCLEAR MINERALS—AN UPDATE

M. D. Campbell,<sup>28</sup> M. A. Wiley<sup>29</sup>

### *Introduction*

By far the biggest use for uranium is to produce electricity—the U.S. produces almost 20% of its electricity via nuclear power. One pound (0.45 kg) of yellowcake ( $U_3O_8$ —the final product of the uranium milling process) has the energy equivalence of 35 barrels ( $5.6 \text{ m}^3$ ) of oil. One 7 g (0.25 oz) uranium fuel pellet has an energy-to-electricity equivalent of 17,000 cubic feet ( $481.4 \text{ m}^3$ ) of natural gas, 564 l (3.5 barrels) of oil, or 1,780 pounds (807.4 kg) of coal.

Today, there are some 441 nuclear power reactors operating in 30 countries and nuclear energy provides approximately 15% of the world's

electricity. These 441 reactors, with combined capacity of over 376 GW (one GWe equals one billion watts or one thousand megawatts), require approximately 152 million pounds  $U_3O_8$  (69,000 tonnes of uranium oxide, tU).

According to the World Nuclear Association (2010d), about 58 power reactors are currently being constructed in 14 countries. In all, there are over 148 power reactors planned and 331 more proposed. Each GWe of increased capacity will require about 507,000 pounds  $U_3O_8$  (195 tU) per year of extra uranium production. A \$4- to \$6-billion dollar investment in a new reactor requires that a fuel supply of more than 1 year is available.

In 2008, U.S. uranium mining operations supplied 114 million pounds  $U_3O_8$  (51,600 tU concentrate containing 43,853 tU), roughly 75% of nuclear utility power requirements. The remaining supply deficit has been offset by stockpiled uranium held by nuclear power utilities, but their stockpiles are nearing depletion. Production is now primarily supplemented by ex-military material—the “Megatons to Megawatts” program which ends in 2013. Russia has stated that the agreement will not be renewed.

The approximately 104 nuclear power plants operating in the U.S. today consume about 50 million pounds of uranium ( $U_3O_8$ ) per year ( $19,000 \text{ tU year}^{-1}$ ), but the U.S.'s current annual production is only about 4 million pounds per year ( $1,540 \text{ tU year}^{-1}$ ). As is the current situation with oil, the U.S. is highly reliant on foreign sources for its uranium. Although Canada and Australia are politically stable, market forces may restrict supplies. Numerous alternative sources will likely be developed throughout the world wherever such resources are made available to the world market at acceptable prices.

There is also a new development in the size of nuclear reactors in the 25-MW range to 100-MW. A number of groups are designing small, modular reactors that can be trucked into supply electricity for a population 25,000–50,000 in emergency circumstances or for use in remote areas, on the Earth and even off-world locations. The current status of the development of these small reactors is summarized by the World Nuclear Association (2011c).

According to the latest available data from U.S. Department of Energy, Energy Information Administration (DOE, EIA) (Energy Information Administration 2010e), between 2004 and 2008, total domestic energy use decreased 0.09%. In 2008, total nuclear-generated electricity accounted for 8.47% of

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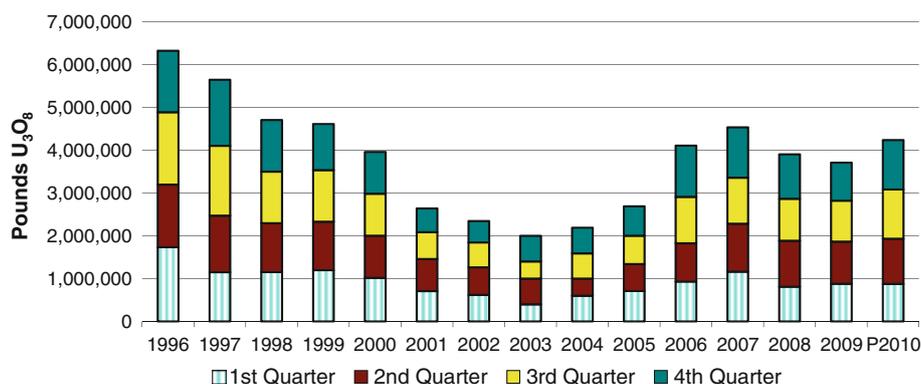
<sup>29</sup>The Consulting Operation, Canyon Lake, TX 78133, USA; EMD Councilor – Gulf Coast Region (Deceased).

**Table 4.** Yellowcake Production (in Pounds of U<sub>3</sub>O<sub>8</sub>) (Adapted From Energy Information Administration, 2011a)

Calendar Year Quarter	2003 See Note	2004 See Note	2005	2006	2007	2008	2009	2010
1st	400,000	600,000	709,600	931,065	1,162,737	810,189	880,036	876,064
2nd	600,000	400,000	630,053	894,268	1,119,536	1,073,315	982,760	1,055,102
3rd	400,000	588,738	663,068	1,083,808	1,075,460	980,933	956,657	1,150,725
4th	600,000	600,000	686,456	1,196,485	1,175,845	1,037,946	888,905	1,153,104
Year total	2,000,000	2,282,406	2,689,178	4,105,626	4,533,576	3,902,383	3,708,358	4,235,015
Change %	-14.6	14.1	17.8	52.6	10.4	-13.47	-4.97	14.0

Note. All of 2003 and all but third quarter 2004 production was rounded to the nearest 100,000 pounds to avoid disclosure of individual company data.

1 pound = 0.45 kg.



**Figure 14.** Uranium concentrate production in the United States, 1996 to 4th Quarter 2010 (adapted from Energy Information Administration 2011a). 1 pound = 0.45 kg.

the total domestic electric energy use, an increase of 2.49% from 2004.

### U.S. Uranium Production

Based on a current Energy Information Administration (2011a) report, U.S. production of uranium (see Table 4) increased from 2003 to 2007 and decreased until mid-2010 when production again began to rise. During the 4th quarter of 2010, U.S. uranium concentrate was produced at five U.S. uranium concentrate processing facilities:

- U.S. uranium mill in production:
  - White Mesa Mill, Utah
- U.S. uranium in situ-recovery (ISR) plants in production:
  - Alta Mesa Project, Texas
  - Crow Butte Operation, Nebraska
  - Smith Ranch-Highland Operation, Wyoming
  - La Palangana, Texas.

Starting in the fourth quarter 2010, La Palangana produced uranium that was supplied to the Hobson ISR Plant, which had not been processed into uranium concentrate. Hobson and La Palangana are part of the same project (Energy Information Administration 2011a).

U.S. uranium production totaled 4,235,015 pounds U<sub>3</sub>O<sub>8</sub> (1,629 tU) in 2010 (Fig. 14). This amount is 14% higher than the 3,708,358 pounds (1,426 tU) produced in 2009 (Energy Information Administration 2011c).

The EIA has expanded its coverage of uranium and nuclear power reporting to the general public (Energy Information Administration 2009b).

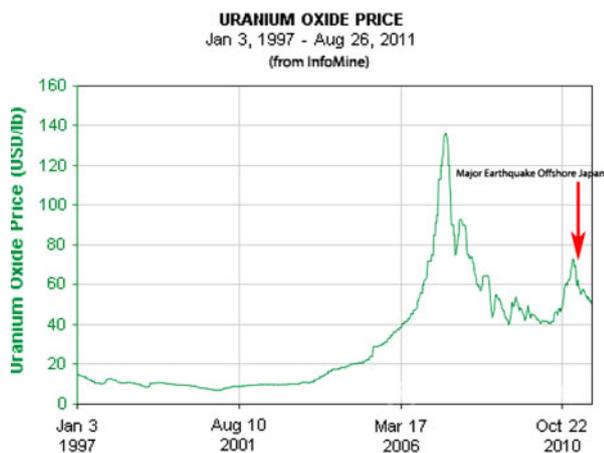
### Uranium Prices

Table 5 shows U<sub>3</sub>O<sub>8</sub> production and the price per pound (0.45 kg) realized for the period 2002–2009 (Energy Information Administration 2010i; Ux Consulting Company 2011). Spot prices are summarized in Figure 15 from 1997 to August, 2011. For total delivery, prices had remained fairly steady with

**Table 5.** Uranium Purchased by Owners and Operators of U.S. Civilian Nuclear Power Reactors (Adapted from Energy Information Administration 2010i)

Delivery Year	2002	2003	2004	2005	2006	2007	2008	2009
U.S. Origin U <sub>3</sub> O <sub>8</sub> (million pounds)	6.2	10.2	12.3	11.0	10.8	4.0	7.7	7.1
Weighted average price	\$10.89	\$10.81	\$11.87	\$15.11	\$17.85	\$28.89	\$59.55	\$48.92
Foreign Origin U <sub>3</sub> O <sub>8</sub> (million pounds)	45.5	46.4	51.8	54.7	55.7	47.0	45.6	42.8
Weighted average price	\$10.29	\$10.81	\$12.76	\$14.21	\$18.75	\$33.05	\$43.47	\$45.35
Spot contracts U <sub>3</sub> O <sub>8</sub> (million pounds)	8.6	8.2	9.2	6.9	6.3	6.6	8.7	8.1
Weighted average price	\$9.29	\$10.10	\$14.77	\$20.04	\$39.48	\$88.25	\$66.95	\$46.45

1 pound = 0.45 kg.



**Figure 15.** U<sub>3</sub>O<sub>8</sub> spot prices (Ux Consulting Company 2011, March 22, 2011). 1 pound = 0.45 kg.

only a slight gain though 2005. The spot price surged 35.7% between 2004 and 2005. From 2005 to 2006, spot prices nearly doubled (97%). Between 2006 and 2007, spot prices more than doubled and some prices now exceed \$100 per pound (0.45 kg) U<sub>3</sub>O<sub>8</sub>. This sparked a large reinvestment of uranium mining in Texas and elsewhere. However, although spot prices declined in 2008 and 2009, since July, 2010, the spot prices are showed a sharp rise (see Fig. 15), which spurred new production (Energy Information Administration 2010i; Ux Consulting Company 2011). However, as evident in Figure 15, the March, 2011, earthquake and subsequent nuclear plant incidents have sent shock waves throughout the nuclear power industry and sent the spot price for yellowcake on a sharp decrease until rebounding somewhat and then fading below the \$50.00 range by August, 2011. The low price will likely begin to rise as world demand continues to drive yellowcake prices. A new round of mergers and acquisitions has recently become apparent indicating a renewed

confidence in demand for yellowcake in the near term.

### U.S. Nuclear Power Plant Plans

According to the Nuclear Energy Institute (2011), 19 companies had at least 23 reactors in some stage of planning or license application. These would cost \$6 to \$8 billion each. As many as eight plants are planned to come on line by 2016 or thereafter allowing for certain delays.

Owners and operators of U.S. civilian nuclear power reactors purchased uranium of several material types for 2009 deliveries from 29 sellers, down from the 33 sellers in 2008. Uranium concentrate was 69% and natural UF<sub>6</sub> and enriched uranium were 31% of the deliveries in 2009. During 2009, 17% of the uranium was purchased under spot contracts at a weighted-average price of \$46.45 per pound (0.45 kg). The remaining 83% was purchased under long-term contracts at a weighted-average price of \$45.74 per pound (0.45 kg). Spot contracts are a one-time delivery (usually) of the entire contract to occur within 1 year of contract execution (signed date). Long-term contracts include those with one or more deliveries to occur after a year following the contract execution (signed date) and as such may reflect some agreements of short and medium terms as well as longer term (Energy Information Administration 2010h).

Owners and operators of U.S. civilian nuclear power reactors purchased a total of 50 million pounds (22,680 t) U<sub>3</sub>O<sub>8e</sub> (U<sub>3</sub>O<sub>8</sub> equivalent) of deliveries from U.S. suppliers and foreign suppliers during 2009, at a weighted-average price of \$45.86 per pound (0.45 kg) U<sub>3</sub>O<sub>8e</sub>. The 2009 total of 50 million pounds (22,680 t) U<sub>3</sub>O<sub>8e</sub> decreased 7% compared with the 2008 total of 53 million pounds (24,040 t) U<sub>3</sub>O<sub>8e</sub>. Fourteen percent of the U<sub>3</sub>O<sub>8e</sub>

delivered in 2009 was U.S.-origin uranium at a weighted-average price of \$48.92 per pound (0.45 kg).

Foreign-origin uranium accounted for the remaining 86% of deliveries at a weighted-average price of \$45.35 per pound (0.45 kg). Australian- and Canadian-origin uranium together accounted for 40% of the 50 million pounds (22,680 t). Uranium originating in Kazakhstan, Russia, and Uzbekistan accounted for 29% and the remaining 17% originated from Brazil, Czech Republic, Namibia, Niger, and South Africa.

#### *U.S. Uranium Reserves/Resources*

The Energy Information Administration has updated its estimates of domestic uranium reserves for year-end 2008, representing the first revision of the estimates since 2004. The update is based on analysis of company annual reports, any additional information reported by companies at conferences and in news releases, personal contacts, and expert judgment.

The Energy Information Administration indicated that at the end of 2008, U.S. uranium reserves totaled 1,227 million pounds of  $U_3O_8$  (471,962 tU) at a maximum forward cost of up to \$100 per pound (0.45 kg)  $U_3O_8$ . At up to \$50 per pound (0.45 kg)  $U_3O_8$ , estimated reserves were 539 million pounds of  $U_3O_8$  (207,325 tU). Based on average 1999–2008 consumption levels (uranium in fuel assemblies loaded into nuclear reactors), uranium reserves available at up to \$100 per pound (0.45 kg) of  $U_3O_8$  represented approximately 23 years' worth of demand, while uranium reserves at up to \$50 per pound (0.45 kg) of  $U_3O_8$  represented about 10 years' worth of demand. Domestic U.S. uranium production, however, supplies only about 10%, on average, of U.S. requirements for nuclear fuel, so the effective years' supply of domestic uranium reserves is actually much higher, under current market conditions.

In 2008, Wyoming led the U.S. in total uranium reserves, in both the \$50 and the \$100 per pound (0.45 kg)  $U_3O_8$  categories, with New Mexico second, and Texas a close third. Taken together, the first two states constituted about two-thirds of the estimated reserves in the U.S. available at up to \$100 per pound (0.45 kg)  $U_3O_8$ , and 75% of the reserves available at less than \$50 per pound (0.45 kg)  $U_3O_8$ . By mining method, uranium reserves in underground

mines constituted just under half of the available product at up to \$100 per pound (0.45 kg)  $U_3O_8$ . At up to \$50 per pound (0.45 kg)  $U_3O_8$ , however, uranium available through in situ recovery (ISR) was about 40% of total reserves, somewhat higher than uranium in underground mines in that cost category. In situ recovery is the dominant mining method for U.S. production today and is likely to increase in the future. For additional current information see Energy Information Administration (2010a).

#### *Uranium: Emphasis on Supply*

*Availability of U.S. Uranium Resources.* A Massachusetts Institute of Technology (2003) report was updated in 2009 (Massachusetts Institute of Technology 2009) to include a consideration on how long the uranium resource base would be sufficient to support large-scale deployment of nuclear power without reprocessing and/or breeding. Present data suggest that the required resource base will be available at an affordable cost for a long time. Estimates of both known and undiscovered uranium resources at various recovery costs are given in the NEA/IAEA "Red Book" (International Atomic Energy Agency 2011). For example, according to the latest edition of the Red Book, known resources recoverable at costs at less than \$31/pound  $U_3O_8$  (\$80/kg U) and less than \$50/pound  $U_3O_8$  (\$130/kg U) are approximately 7.8 billion and 10.4 billion pounds  $U_3O_8$  (3 and 4 Mt of uranium, respectively). However, the amount of known resources depends on the intensity of the exploration effort, mining costs, and the price of uranium. Thus, any predictions of the future availability of uranium that are based on current mining costs, prices, and geological knowledge are likely to be extremely conservative.

For example, the MIT (2009) update indicated that a doubling of the uranium price from its current value of about \$50/pound  $U_3O_8$  (\$130/kg U) could be expected to create about a 10× increase in known resources recoverable at costs less than \$31/pound  $U_3O_8$  (\$80/kg U), i.e., from about from 7.8 billion to 78 billion pounds  $U_3O_8$  (3–30 Mt). By comparison, a fleet of fifteen hundred 1,000 MWe reactors operating for 50 years requires about 39 billion pounds  $U_3O_8$  (15 Mt of uranium), which amounts to 800 million pounds  $U_3O_8$  year<sup>-1</sup> (300,000 tU year<sup>-1</sup>) using conventional assumptions about burn-up and enrichment.

Moreover, there are good reasons to conclude that even as demand increases, the price of uranium (yellowcake) will remain relatively low: the history of all extractive metal industries, e.g., copper, indicates that increasing demand stimulates the development of new mining technology that greatly decreases the cost of recovering additional ore. Finally, since the cost of uranium represents only a small fraction of the busbar cost of nuclear electricity, even large increases in the former—as may be required to recover the very large quantities of uranium contained at low concentrations in both terrestrial deposits (3.5 ppm U) and seawater (3 ppb U)—may not substantially increase the latter as reported by Japanese research (Nobukawa 1994). He concluded that resource utilization is not a pressing reason for proceeding to reprocessing and breeding; although reprocessing remains to be considered seriously to insure that resources are available for at least the next 50 years.

*Wyoming Uranium Roll-Fronts.* Wyoming is particularly important to U.S. uranium production because it has a large number roll-front uranium deposits in its sandstones and has the largest known uranium reserves of any U.S. state. There is no doubt expressed by many recognized authorities that the state will be a key player in supplying the fuel to the nuclear power plants in the U.S. to become independent of foreign supplies.

Marion Loomis, Executive Director of the Wyoming Mining Association, has indicated that because Wyoming is a pro-mining state, it has prolific numbers of roll-front uranium deposits, and because of the rising spot uranium price in a resurgent uranium market, Wyoming is a major center for in situ recovery mining (ISR). To this must be added New Mexico, Arizona, Texas, and in frontier areas elsewhere in the U.S. because some professionals have concluded that the latter states also have significant potential for additional roll-front deposits, albeit deeper than those found to date.

Wyoming ISR uranium mines were the only ones that were able to continue operating economically in the U.S. during the 1980s and 1990s when the downturn in uranium prices occurred. Whether that was a management decision or a comment on the economic advantage of the particular operations is debatable. The debate may well swing to the latter since there may have been no lingering capital costs involved, leaving only direct operational costs.

*Solution Mining.* In situ recovery (ISR), also known as in situ leaching (ISL), involves recovering uranium in solution from the subsurface by dissolving the ore and pumping the uranium-bearing solution to the surface where uranium and other products can be recovered. There is little surface disturbance and no tailings or waste rock are generated. In situ recovery comprised 36% of global uranium production in 2009 (World Nuclear Association 2010a).

In the U.S., legislation requires that the water quality in the affected aquifer be restored after ISR mining. This means the ground water must be usable for the same purposes as it was before mining began. However, considering the ground water within the zones of mineralization never has been usable because it has been naturally contaminated for millions of years, only the environment within the zones are returned to their original unoxidized condition by removing excess oxygen. This process forces the uranium (and other metals) that were in solution for production purposes, to become essentially insoluble once again. Nevertheless, the ground water within the aquifer hosting the uranium mineralization will always remain naturally contaminated and, therefore, unusable (Campbell and Wise 2010).

*Permitting.* In Wyoming, there are two major permits/licenses, plus others, required for the commencement of In Situ Recovery (ISR) uranium recovery operations:

- The federal Nuclear Regulatory Commission (NRC) (U.S. Nuclear Regulatory Commission 2011) Source Material License.
- The Wyoming Department of Environmental Quality (WDEQ; Wyoming Department of Environmental Quality 2011) Permit to Mine.

These two items allow for the construction of an ISR uranium operation and ultimately the commencement of uranium production. For the NRC, the Source Material License is composed of two parts: (1) A technical review that results in a Safety Evaluation Report (SER) and (2) An environmental review which produces an Environmental Impact Statement (EIS). The EIS is in two parts: the Generic EIS and the Supplemental EIS.

A technical review of the project must be approved and an Aquifer Exemption must be granted (to remove the areas of the aquifers containing the mineralization from potential use because of their natural contamination). The generalized flow-sheet

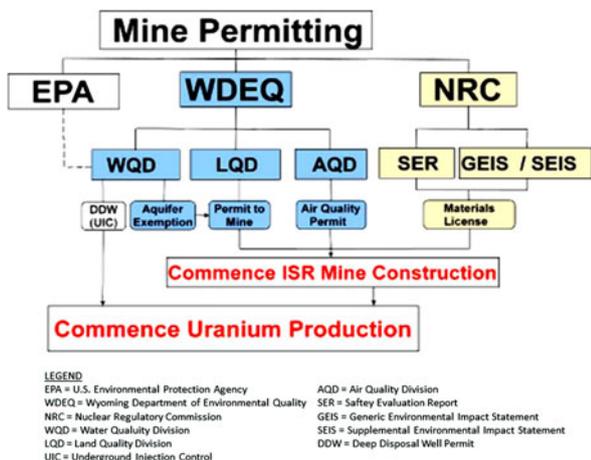


Figure 16. Wyoming uranium mine permitting flow chart (Uranerz Energy Corporation 2011).

in Figure 16 (the left) illustrates the permitting steps.

In addition to the two major permit/licenses there are two important permits that are required from the WDEQ:

- Deep Disposal Well Permit.
- An Air Quality Permit.

For the Deep Disposal Well permit and the Aquifer Exemption permit, the U.S. Environmental Protection Agency (EPA) is also involved. The EPA reviews the applications for the Deep Disposal Wells and Aquifer Exemption and gives their approval of the permits, but the issuing authority is the WDEQ since they have primacy with the EPA for Wyoming.

The Air Quality permit is required along with the Permit to Mine to begin construction of the ISR uranium facility. The Deep Disposal Well permit is not needed for construction, but is necessary for the commencement of operations for the ISR uranium facility to dispose of liquid wastes.

**Current Production in Wyoming.** The Powder River Basin has some of the highest grade uranium deposits in the State that are amenable to ISR operations methods. Commercial ISR operations in the Powder River Basin have been ongoing since 1987. Cameco Resources Inc.'s Smith Ranch-Highland in situ mine in Converse County is currently the only active uranium production facility in the state. It is the largest in situ uranium facility in the country, producing approximately 1.8 million pounds of

$U_3O_8$  (5,770 tU) in 2009. Cameco plans to increase its Smith Ranch-Highland operations and undertake new operations in the Gas Hills (central Wyoming) and near Pumpkin Butte in Campbell County.

Uranium One's Christensen Ranch ISR facility in the Powder River Basin is expected to resume operations in 2011. It is expected to yield about 1 million pounds (385 tU) of yellowcake over a period of 3 years.

Recently, the NRC issued an operating license for the Uranium One, Inc., Moore Ranch uranium mine. It is the first new uranium mine license issued in the U.S. since 1998. Production of uranium-bearing resins from Moore Ranch is expected to begin in 2012.

**Permitting Activities.** There has never been a uranium ISR operation application rejected in Wyoming. Uranerz Energy Corporation has submitted federal and state mining applications to build and operate the Nichols Ranch ISR Uranium Project—a central processing facility at the Nichols Ranch property and a satellite facility at the Hank property.

The central processing facility is being licensed for a capacity of 2 million pounds per year of  $U_3O_8$  (770 tU). This facility will process uranium-bearing solutions from well fields of the Nichols Ranch property, as well as uranium-loaded resin transported from the Hank satellite facility, plus uranium-loaded resin from any additional satellite deposits that may be developed on the company's other Powder River Basin properties. This centralized design enhances the economics of Uranerz's potential additional satellite projects by maximizing production capacity while minimizing further capital expenditures on processing facilities.

Given the proximity of Uranerz's Nichols Ranch Project/Hank properties to Moore Ranch and similar timing of both company's applications, the final Supplemental Environmental Impact Statement (SEIS) for Uranerz's Nichols Ranch Project is expected to be completed very soon. A finalized SEIS for Uranerz's Moore Ranch Project from the NRC would lead to an issuance of a source materials license that would allow Uranerz to receive, possess, use, transfer, and deliver radioactive materials.

**Properties and Resources.** Uranerz has over 30 wholly owned and joint-ventured projects in the Powder River Basin of Wyoming. Uranerz also has an undivided 81% interest in the North American Mining and Minerals Corporation (NAMMCO)

properties, which cover approximately 67,000 acres in the central Powder River Basin. The Arkose Property is located in proximity to the Company's 100%-owned properties in the Powder River Basin.

*World Uranium Resources*

As nuclear power has re-emerged over the past few years in the U.S. and elsewhere, concerns have been raised that the known uranium resources might be insufficient when judged in terms of current production and current rate of use (World Nuclear Association 2010d). Our knowledge of geology is such that we can be confident that identified resources of metal minerals are a small fraction of what is available, at various level of cost (see World Nuclear Association 2010c). Much of what follows is taken from recent summaries of conditions as considered by the "uranium press" (Brown 2010; Pinkasovitch 2010; Uranium Investing News 2011).

Uranium is ubiquitous on the Earth. It is a metal approximately as common as tin or zinc, and it is a constituent of most rocks and even of the sea. Economic concentrations of it are not uncommon, but significant tonnages sufficient to make a mine are not. Typical averages in concentrations are given below:

Very high-grade ore (e.g., Canada): 24% U <sub>3</sub> O <sub>8</sub> (20% U)	200,000 ppm U
High-grade ore (e.g., N. Australia): 2.4% U <sub>3</sub> O <sub>8</sub> (2% U)	20,000 ppm U
Low-grade ore (Roll Fronts): 0.118% U <sub>3</sub> O <sub>8</sub> (0.1% U)	1,000 ppm U
Very low-grade ore (Roll Fronts): 0.012% U <sub>3</sub> O <sub>8</sub> (0.01% U)	100 ppm U
Granite	4-5 ppm U
Sedimentary rock	2 ppm U
Earth's continental crust	2.8 ppm U
Seawater	3 ppb U

An economically viable uranium deposit depends on the concentration of uranium, the volume and geographical location of available ore, the cost of extraction and on the market price at the time of production. At present, neither the oceans nor the granites are considered economic resources, but they conceivably could become so if prices were sufficient and the costs of production were favorable. At ten times the current uranium price (i.e., \$500/lb U<sub>3</sub>O<sub>8</sub>) or even less, seawater might become

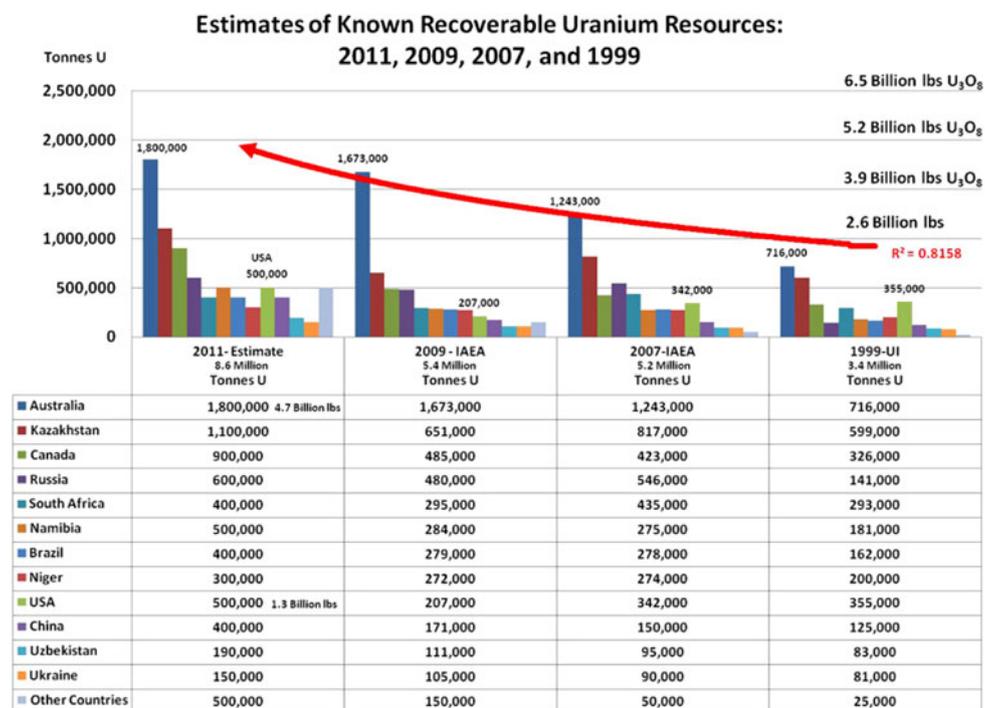
a potential source of vast amounts of uranium (Nobukawa 1994). Uranium resources are also dependent on the intensity and effectiveness of past exploration efforts, which are basically statements about what is known rather than what may be present, and on the political climate of the host country.

Changes in costs or prices, or further exploration, may alter measured resource figures markedly. Thus, any predictions of the future availability of any mineral, including uranium, which are based on current cost to produce, market price, and current geological knowledge, are likely to be extremely conservative. To date, this has been proven to be the case with uranium.

*Uranium Availability.* With the above qualifications, uranium resource estimates were made by the International Atomic Energy Agency (IAEA) in 2009, 2007, and by the World Nuclear Institute (WNI) in 1999 (World Nuclear Association 2011d). Figure 17 shows the countries with the known major uranium resources in order of total resources, plus an estimate for 2011 by the authors. It should be noted that from 1999 to 2009, the estimate of the world uranium resources increased by 84%. Of course, the actual resources did not increase; just that which has become available based on our knowledge of what has been discovered over the past 10 years. In an attempt to keep track of the rapid expansion in world exploration for uranium and other nuclear minerals, the IAEA also estimates U.S. and world uranium resources (International Atomic Energy Agency 2011), in metric units, which can be converted to pounds (0.45 kg) U<sub>3</sub>O<sub>8</sub> in the following conversion application (WISE Uranium Project 2010).

Fifteen countries show increasing estimates of uranium resources over the past 10 years. The common producers (i.e., Australia, Kazakhstan, Canada, Russia, South Africa, and Namibia) showing increasing resources but many other countries are also beginning to report significant uranium resources. Various countries in Africa, South America (including Brazil, Guyana, Uruguay, etc.), and central Asia and China will also likely show major increases over the next 10 years. Figure 17 illustrates the changing resource estimates and suggests that with increasing exploration, more discoveries will result.

Current world uranium consumption (in conversion to yellowcake) is about 177 million pounds



**Figure 17.** Estimates of known recoverable uranium resources (International Atomic Energy Agency 2009; Nuclear Energy Agency 2010). Note: Reasonably Assured Resources plus Inferred Resources, to US\$130/kg U, 1/1/09.

$\text{U}_3\text{O}_8$  year<sup>-1</sup> (68,000 tU year<sup>-1</sup>). Thus, the world's present measured resources of uranium of 14 billion pounds  $\text{U}_3\text{O}_8$  (5.4 MtU—see Fig. 17, 2009 Estimate) in the cost category slightly above present spot prices and used only in conventional reactors, are enough to last for about 80 years. This represents a higher level of assured resources than is normally estimated for most strategic commodities. Further, exploration and higher prices will, on the basis of present geological knowledge, certainly yield additional resources as current resources are consumed.

As indicated above, exploration targets are now known in many parts the world. International Atomic Energy Agency (2009) data on the location and type of uranium mineralization are summarized in Figure 18. This illustrates that the most common types of mineralization are found in sandstone and in veins, and which produce the largest ore bodies. These have been the most predominant types explored over the past 75 years, but other types, with potential for producing substantial reserves, are beginning to be explored in other areas gone unexplored in past uranium exploration cycles.

The geographical locations of the ore bodies are of major importance. Now that new discoveries are

being explored in Africa and South America, new production may come from these regions sooner than previously expected. No longer will Canada and Australia be the sole source of uranium at a low price, but continuity of delivery comes into play which may complicate the supply to the new and old nuclear power plants of the world.

The geographical distribution of current and past exploration in the world has been summarized in Figure 19 according to regions and countries. The number of known deposits is indicated for each country and associated regions. These data are further documented in a table based on International Atomic Energy Agency (2009) research that includes the deposit names and locations where uranium has been discovered to date (Campbell 2010a, b).

*Characteristics of Uranium Exploration Cycles.* The initial uranium exploration cycle was military-driven, from 1945 to 1958. The second cycle, from about 1974 to 1983, was driven by civil nuclear power and in the context of a perception that uranium might be scarce. There was relatively little uranium exploration between 1985 and 2003, so the significant increase in exploration effort since then could

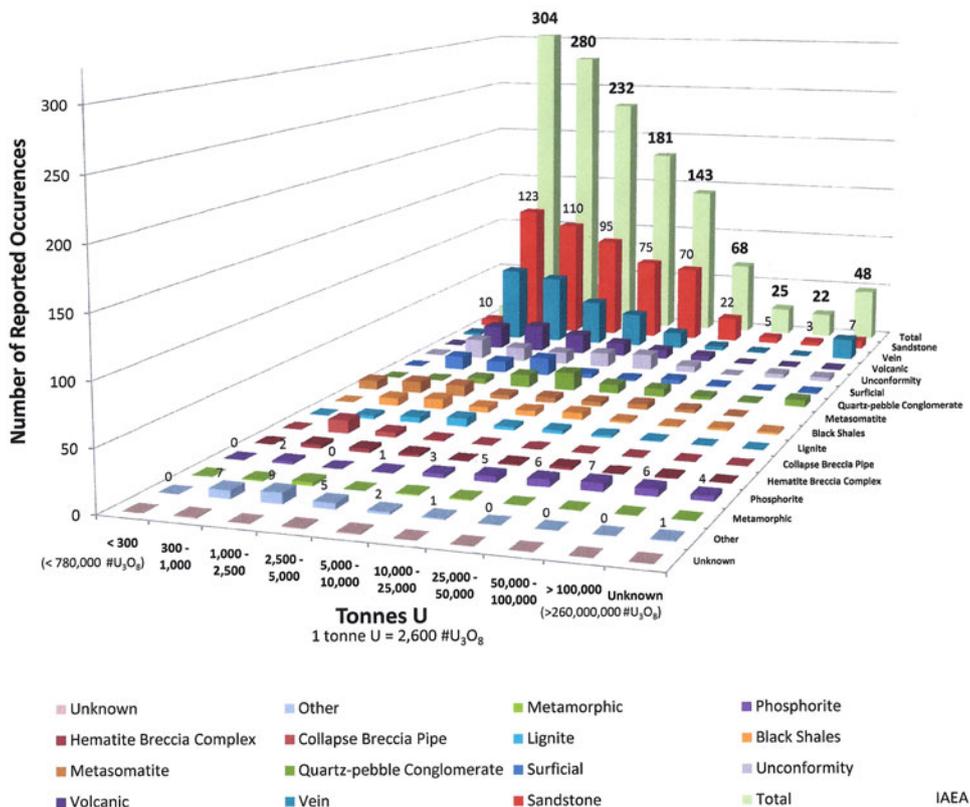


Figure 18. Reported uranium occurrences according to deposit reserves and type of mineralization (International Atomic Energy Agency 2009). 1 tonne = 1.1 short tons.

conceivably double the known economic resources despite adjustments due to increasing costs. In the 2 years 2007–2009, the world’s known uranium resources tabulated above increased by 17%.

World uranium exploration expenditure in 2006 was US\$705 million, in 2007 \$1,328 million, and in 2008 \$1,641 million, an increase of almost 25%. In the third uranium exploration cycle from 2003 to the end of 2009, about \$5.75 billion was spent on uranium exploration and deposit delineation on over 600 projects. In this period, over 400 new junior companies were formed or changed their orientation to raise over \$2 billion for uranium exploration. About 60% of this was spent on previously known deposits. All this was in response to the anticipated increase in the uranium price in the market, which has turned markedly upwards but more recently below \$50/pound (0.45 kg) U<sub>3</sub>O<sub>8</sub> (\$130/kg U). As discussed previously, the earthquake in Japan had a dramatic impact on the spot yellowcake price (see Fig. 15).

The price of uranium, and almost any other mineral commodity, also directly determines the amount of known resources that are economically recoverable. On the basis of analogies with other metal minerals, a doubling of price from present levels could be expected to create about a tenfold increase in measured economic resources, over time, due both to increased exploration and the reclassification of resources regarding what is economically recoverable. The World Nuclear Association (WNA) monitors these activities. Figure 19 illustrates the resource base currently known for the two market-price levels.

By adding a price increase of \$50/pound (0.45 kg) U<sub>3</sub>O<sub>8</sub> (\$130/kg U) to all conventional resources considered in Figure 20, another 13 billion pounds U<sub>3</sub>O<sub>8</sub> (5.5 Mt—beyond the 5.4 Mt of known economic resources), would provide 160 years of yellowcake supply (and its equivalent fuel) at today’s rate of consumption (and same number of plants). This omits unconventional resources such as phosphate/



**Figure 19.** Plot of World uranium known deposits by country and region (2009). The data for the above figures were substantially derived from MacDonald (2003) and including a model "Economic adjustments in the supply of a 'non-renewable' resource" from Ian Hore-Lacy (IAEA-UDEPO Data 2009).

phosphorite deposits of some 57 billion pounds  $U_3O_8$  (22 Mt U) recoverable as by-product) and seawater of some 10 trillion pounds  $U_3O_8$  (up to 4,000 Mt), but which would, as indicated earlier, likely be uneconomic in the foreseeable future under current prices.

In the mid-1990s, about 20% of the U.S. uranium production came from central Florida's

phosphate deposits, as a by-product, but it then became uneconomic as the price fell. With higher uranium prices today the resource is being examined again, as is another lower-grade deposit in Morocco. Plans for Florida extend only to about 1 million pounds  $U_3O_8$  year<sup>-1</sup> (400 tU year<sup>-1</sup>) at this stage (World Nuclear Association 2010f).

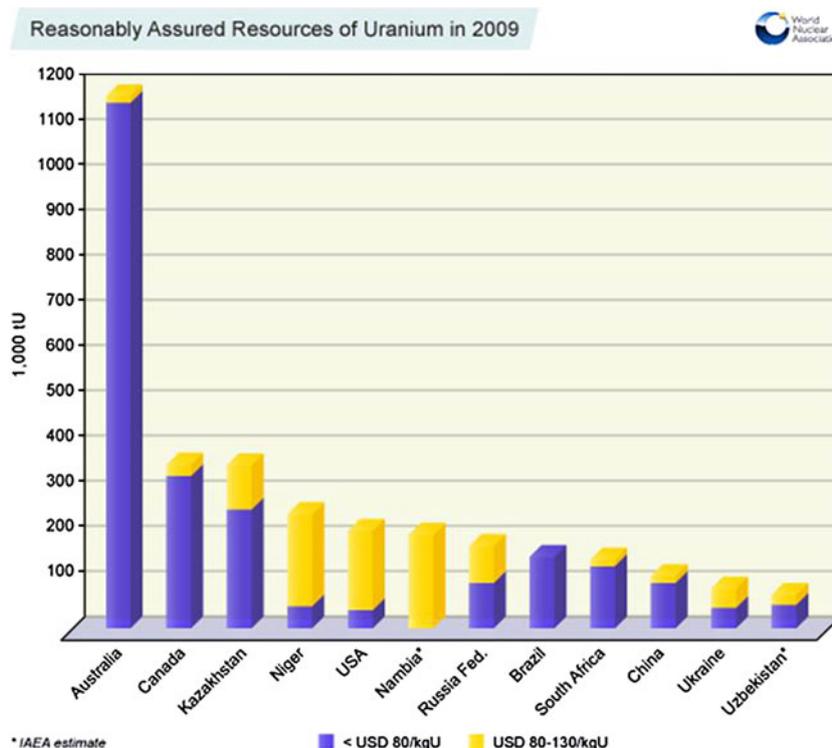


Figure 20. Reasonably assured resources of uranium by country (World Nuclear Association 2011d). 1 tonne = 1.1 short tons; 1 kg = 2.2 pounds.

Coal ash is another easily accessible though minor uranium resource in many parts of the world. In central Yunnan Province in China, the coal uranium content varies up to 315 ppm and averages about 65 ppm. The ash averages about 210 ppm U (0.021% U)—which is above the cut-off level for some uranium mines. The Xiaolongtang power station ash heap contains over 2.6 million pounds  $U_3O_8$  (1000 tU), with annual contributions of approximately 500,000 pounds  $U_3O_8$  year<sup>-1</sup> (190 tU year<sup>-1</sup>). Recovery of this product by acid leaching is about 70%.

*Indirect Utilization of Fuel Supply.* Widespread use of beryllium and thorium in with the uranium has been found to significantly increase fuel burn life and reduce reactor-load requirements. The primary interest in developing the breeder reaction is because the “fast breeder” reactor design could increase the utilization of uranium 50× or more. This type of reactor can be started up on plutonium derived from conventional reactors and operated in closed circuit with its reprocessing plant. Such a reactor, supplied with natural or depleted uranium for its “fertile

blanket,” can be operated so that each tonne of ore yields 60 times more energy than in a conventional reactor (World Nuclear Association 2010e).

*Reactor Fuel Requirements.* The world’s power reactors, with combined capacity of some 375 GWe, require about 150 million pounds  $U_3O_8$  year<sup>-1</sup> (68,000 tU year<sup>-1</sup>) from mines or elsewhere each year. While this capacity is being increased each year, with higher capacity factors and reactor power levels (larger plant designs), the uranium-fuel requirement is also increasing, but not necessarily at the same rate. Therefore, the factors of increasing fuel demand are offset by a trend for higher rate of burn-up of fuel and related matters, so demand is steady. Over the years 1980–2008, the electricity generated by nuclear power increased by 3.6 times, while uranium used increased by a factor of only 2.5. Reducing the tails assay in enrichment reduces the amount of natural uranium required for a given amount of fuel. Reprocessing of used fuel from conventional light water reactors also utilizes present resources more efficiently, by a factor of about 1.3 overall.

Today's reactor fuel requirements are met from primary supply (direct mine output—78% in 2009) and secondary sources: commercial stockpiles, nuclear weapons stockpiles, recycled plutonium and uranium from reprocessing used fuel, and some from re-enrichment of depleted uranium tails (left over from original enrichment). These various secondary sources make uranium unique among the other energy minerals.

*Nuclear Weapons as a Source of Fuel.* An important source of nuclear fuel is the world's nuclear weapons stockpiles. Since 1987 the United States and countries of the former USSR have signed a series of disarmament treaties to reduce the nuclear arsenals of the signatory countries by approximately 80%.

The weapons contained a great deal of uranium enriched to over 90%  $U^{235}$  (i.e., up to 25 times the proportion in reactor fuel). Some weapons have  $Pu^{239}$ , which can be used in mixed-oxide (MOX) fuel for civil reactors. From 2000, the dilution of 78,000 pounds  $U_3O_8$  (30 t) of military high-enriched uranium has been displacing about 23 million pounds  $U_3O_8$  year<sup>-1</sup> (10,600 t $U_3O_8$  year<sup>-1</sup>) from mines, which represents about 15% of the world's reactor requirements. Details of the utilization of military stockpiles are described in some detail in the coverage by the World Nuclear Association (2011a).

*Other Secondary Sources of Uranium.* The most obvious source is civil stockpiles held by utilities and governments. The amount held is difficult to quantify, due to commercial confidentiality. As of January 2009, some 335 million pounds  $U_3O_8$  (129,000 tU) of total inventory was estimated for utilities, 26 million pounds  $U_3O_8$  (10,000 tU) for producers and 39 million pounds  $U_3O_8$  (15,000 tU) for fuel-cycle participants, making a total of approximately 400 million pounds  $U_3O_8$  (154,000 tU) (see World Nuclear Association 2011a). These reserves are expected not to be drawn down, but to increase steadily to provide a stockpile for energy security and continuity for utilities and governments.

Recycled uranium and plutonium is another source, and currently saves from 3.9 to 5.2 million pounds  $U_3O_8$  year<sup>-1</sup> (1500–2000 tU) of primary supply, depending on whether just the plutonium or also the uranium is considered. In fact, plutonium is quickly recycled as MOX fuel, which is nuclear fuel that contains more than one oxide of fissile material. MOX fuel contains plutonium blended with natural uranium, reprocessed uranium, or depleted uranium.

Reprocessed uranium (RepU) is mostly stockpiled. For additional information on the processing of used nuclear fuel for recycle paper, see the WNA (World Nuclear Association 2011b).

Re-enrichment of depleted uranium (DU, enrichment tails) is another secondary source. There is about 3.9 billion pounds  $U_3O_8$  (1.5 Mt) of depleted uranium available, from both military and civil enrichment activity since the 1940s, most at tails assay of 0.25–0.35%  $U^{235}$ . Non-nuclear uses of DU are very minor relative to annual increase of over 91 million pounds  $U_3O_8$  year<sup>-1</sup> (35,000 tU year<sup>-1</sup>). This leaves most DU available for mixing with recycled plutonium on MOX fuel or as a future fuel resource for fast neutron reactors. However, some resource that has a relatively high assay that can be fed through under-utilized enrichment plants to produce a natural uranium equivalent, or even enriched uranium ready for fuel fabrication. Russian enrichment plants have treated 26–39 million pounds  $U_3O_8$  year<sup>-1</sup> (10–15,000 t year<sup>-1</sup>) of DU assaying over 0.3%  $U^{235}$ , stripping it down to 0.1% and producing a few thousand tonnes per year of natural uranium equivalent. This Russian program treating Western tails has now finished, but a new U.S. program is expected to start when surplus capacity is available, treating about 364 million pounds  $U_3O_8$  (140,000 t) of old DU assaying 0.4%  $U^{235}$ .

*Thorium as a Nuclear Fuel.* Today, uranium is the only fuel supplied for nuclear reactors. However, thorium can also be utilized as a fuel for the Canadian CANDU reactors or in reactors specially designed for this purpose. Neutron efficient reactors, such as CANDU, are capable of operating on a thorium fuel cycle, once they are started using a fissile material such as  $U^{235}$  or  $Pu^{239}$ . Then the thorium ( $Th^{232}$ ) atom captures a neutron in the reactor to become fissile uranium ( $U^{233}$ ), which continues the reaction. Some advanced reactor designs are likely to be able to make use of thorium on a substantial scale.

The thorium fuel cycle has some attractive features, though it is not yet in commercial use. IAEA reports that thorium is about three times as abundant in the earth's crust as uranium. International Atomic Energy Agency (2011) "Red Book" lists 9.4 billion pounds  $U_3O_8$  (3.6 MtU) of known and estimated resources as reported, but points out that this excludes data from much of the world, and estimates about 15.6 billion pounds  $U_3O_8$  (6 MtU) overall (World Nuclear Association 2010e).

*Environmental Considerations.* Nuclear power's life-cycle emissions range from 2 to 59 grams of carbon dioxide-equivalents per kilowatt-hour. Only hydropower's range ranked lower at 2–48 grams of carbon dioxide-equivalents per kilowatt-hour. Wind comes in at 7–124 g and solar at 13–731 g. Emissions from natural gas fired plants ranged from 389 to 511 g. Coal produces 790–1,182 grams of carbon dioxide-equivalents per kilowatt-hour. The IAEA (Hagen et al. 2001) produced a report on this subject.

Groups opposing uranium exploration and development (and nuclear power in general) focus on the potential impact to local ground water supplies. Campbell and Wise (2010) and Campbell et al. (2010a, b) have addressed these issues.

Other societal issues include nuclear waste storage, the solution of which is political in nature, not technical. Experience over five decades has shown the fear of a nuclear catastrophe to be exaggerated, and the local impact of a severe accident or terrorist attack is likely to be small—the Three Mile Island incident in 1979 being a good example of a minor industrial mishap, although the media played a major role in setting the U.S. nuclear industry back by decades by creating undue fear about nuclear facilities. The Chernobyl disaster a few years later in the 1980s occurred as a result of conditions that were never present in the U.S. The area has recovered sooner than expected (International Atomic Energy Agency 2005). Nevertheless, as new plant construction resumes in the U.S., one of the reasons that construction costs are high is that current regulations and liability requirements have increased over the past 15 years (see World Nuclear Association, November 2010b). The increased liability is largely the result of media and political backlashes from Three Mile Island, Chernobyl, and now from the Fukushima Daiichi Nuclear Power Plant, the latter of which was damaged by an earthquake and tsunami with no loss of life due to radiation to date.

*Future Off-World Sources of Nuclear and Strategic Minerals.* In 2009, anomalous uranium, thorium, and samarium were reported by the SELENE spacecraft in certain areas of the Moon (Campbell and Ambrose 2010). Also in 2009, the Uranium (Nuclear Minerals) Committee of the American Association of Petroleum Geologists Energy Minerals Division published its report on the role of

nuclear power in space, which encouraged industry to begin the planning for serious exploration and development of energy and strategic minerals within the next 20 years (Campbell et al. 2009). The AAPG is publishing a comprehensive review of this subject as a Special Paper or Memoir with a working title of: *The History and Path Forward of the Human Species into the Future*, including updates to the above papers (Campbell et al. 2009; Campbell and Ambrose 2010) and some 10 additional papers on related topics. The works should be published by the end of 2011 or early 2012.

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## WEB LINKS FOR OIL SANDS/HEAVY OIL ORGANIZATIONS AND PUBLICATIONS

Alberta Energy Resources Conservation Board (ERCB): [www.ercb.ca](http://www.ercb.ca).

Alberta Chamber of Resources: [www.abchamber.ca](http://www.abchamber.ca).

Alberta Department of Energy: [www.energy.gov.ab.ca](http://www.energy.gov.ab.ca).

Alberta Department of Sustainable Resource Development: [www.srd.alberta.ca](http://www.srd.alberta.ca).

Alberta Energy Research Institute: [www.aeri.ab.ca](http://www.aeri.ab.ca).

Alberta Environment Information Centre: [www.environment.gov.ab.ca](http://www.environment.gov.ab.ca).

Alberta Geological Survey: [www.ags.gov.ab.ca](http://www.ags.gov.ab.ca).

Alberta Government: [www.alberta.ca](http://www.alberta.ca).

Alberta's Industrial Heartland Association: [www.industrialheartland.com](http://www.industrialheartland.com).

Alberta Ingenuity Centre for In Situ Energy: [www.aicise.ca](http://www.aicise.ca).

Alberta Innovation & Science: [www.aet.alberta.ca](http://www.aet.alberta.ca).

Alberta Research Council: [www.arc.ab.ca](http://www.arc.ab.ca).

Alberta Sulphur Research Ltd.: [www.chem.ucalgary.ca/asr](http://www.chem.ucalgary.ca/asr).

Athabasca Regional Issues Working Group: [www.oilsands.ca](http://www.oilsands.ca).

Canadian Association of Petroleum Producers: [www.capp.ca](http://www.capp.ca).

Canadian Energy Research Institute: [www.ceri.ca](http://www.ceri.ca).

Canadian Geoscience Council: [www.geoscience.ca](http://www.geoscience.ca).

Canadian Heavy Oil Association: [www.choa.ab.ca](http://www.choa.ab.ca).

Canadian Institute of Mining, Metallurgy & Petroleum: [www.cim.org](http://www.cim.org).

Canadian Petroleum Institute: [www.cppi.ca](http://www.cppi.ca).

Canadian Society of Petroleum Geologists: [www.cspg.org](http://www.cspg.org).

Canadian Well Logging Society: [www.cwls.org](http://www.cwls.org).

CanMet Mining and Mineral Sciences Laboratories: [www.nrcan.gc.ca](http://www.nrcan.gc.ca).

Careers: The Next Generation: [www.nextgen.org](http://www.nextgen.org).

Climate Change Central: [www.climatechangecentral.com](http://www.climatechangecentral.com).

EnergyInet: [www.energyinet.com](http://www.energyinet.com).

Environment Canada: [www.ec.gc.ca](http://www.ec.gc.ca).

Fort McMurray Chamber of Commerce: [www.fortmcmurraychamber.ca](http://www.fortmcmurraychamber.ca).

Freehold Owners Association: [www.fhoa.ca](http://www.fhoa.ca).

Geological Survey of Canada: <http://gsc.nrcan.gc.ca/>.

Institute for Sustainable Energy, Environment and Economy: [www.iseee.ca](http://www.iseee.ca).

International Energy Foundation: [www.ief-energy.org](http://www.ief-energy.org).

National Energy Board: [www.neb-one.gc.ca](http://www.neb-one.gc.ca).

National Research Council's Industrial Research Assistance Program: [www.irap-pari.nrc-cnrc.gc.ca](http://www.irap-pari.nrc-cnrc.gc.ca).

Natural Resources Canada: [www.nrcan-rncan.gc.ca](http://www.nrcan-rncan.gc.ca).

Oil Sands Discovery Centre: [www.oilsandsdiscovery.com](http://www.oilsandsdiscovery.com).

Petroleum Society of Canada: [www.petsoc.org](http://www.petsoc.org), [www.spe.org/canada](http://www.spe.org/canada).

Petroleum Technology Alliance Canada: [www.ptac.org](http://www.ptac.org).

Petroleum Technology Research Centre: [www.ptrc.ca](http://www.ptrc.ca).

Saskatchewan Industry and Resources: [www.ir.gov.sk.ca](http://www.ir.gov.sk.ca).

Saskatchewan Government: [www.ir.gov.sk.ca](http://www.ir.gov.sk.ca).

Saskatchewan Research Council: [www.src.sk.ca](http://www.src.sk.ca).

Seeds Foundation: [www.seedsfoundation.ca](http://www.seedsfoundation.ca).

Small Explorers and Producers Association of Canada: [www.sepac.ca](http://www.sepac.ca).

Society of Petroleum Engineers: [www.speca.ca](http://www.speca.ca).

The Canadian Society of Exploration Geophysicists: [www.cseg.ca](http://www.cseg.ca).

The Environmental Association of Alberta: [www.esaa.org](http://www.esaa.org).

U.S. Energy Information Administration: [www.eia.doe.gov](http://www.eia.doe.gov), <http://search.usa.gov/search?affiliate=eia.doe.gov&v%3Aproject=firstgov&query=oil+sands>.

U.S. Geological Survey: <http://pubs.usgs.gov/of/2007/1084/OF2007-1084v1.pdf>.

U.S. Bureau of Land Management: [www.blm.gov](http://www.blm.gov).

Utah Heavy Oil: <http://www.heavyoil.utah.edu/outreach.html>; <http://map.heavyoil.utah.edu/>.