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Unconventional Energy Resources and Geospatial Information: 2006 Review

American Association of Petroleum Geologists, Energy Minerals Division[1]

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This article contains a brief summary of some of the 2006 annual committee reports presented to the Energy Minerals Division (EMD) of the American Association of Petroleum Geologists. The purpose of the reports is to advise EMD leadership and members of the current status of research and developments of energy resources (other than conventional oil and natural gas that typically occur in sandstone and carbonate rocks), energy economics, and geospatial information. This summary presented here by the EMD is a service to the general geologic community. Included in this summary are reviews of the current research and activities related to coal, coalbed methane, gas hydrates, gas shales, geospatial information technology related to energy resources, geothermal resources, oil sands, and uranium resources.

KEY WORDS: Coal, coalbed methane, gas hydrates, geospatial information technology, geothermal, oil sands, uranium.

INTRODUCTION

P.D. Warwick[2,3]

The inevitable increase in demand and continuing depletion of accessible oil and gas resources during the 21st century will cause greater dependence on energy minerals such as coal, uranium, and unconventional sources of oil and natural gas to satisfy our increasing energy needs. The Energy Minerals Division (EMD) of the American Association of Petroleum Geologists (AAPG) is a membership-based technical interest group with goals to: (1) advance the science of geology, especially as it relates to exploration, discovery, and production of mineral resources and subsurface gas and liquids (other than conventional oil and gas) for energy-related purposes; (2) foster the spirit of scientific research; (3) disseminate information related to the geology of energy minerals and the associated technology of energy mineral resources extraction; and (4) advance the professional well-being of its members. This article contains a brief summary of some of the 2006 annual committee reports presented to the EMD Leadership. These reports are available to the EMD Membership at http://emd.aapg.org/members_only. This collection of short reports is presented here by the EMD as a service to the general geologic community and to simulate interest in the focus technical areas of EMD.

Included in this article are reviews of the current research and activities related to coal, coalbed methane, gas hydrates, geospatial information technology, geothermal resources, oil sands, and uranium resources. Please contact the various EMD

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authors for additional information about the topics covered in this report. To learn more about the Energy Mineral Division visit the following website: http://emd.aapg.org.

COAL

R.C. Milici[4]

Introduction

This short article is based almost entirely on estimated coal reserve data published by the Energy Information Agency (EIA), primarily the data from Table 1. Estimated Recoverable Reserves of Coal by Btu/Sulfur Range, State, and Type of Mining at: http://www.eia.doe.gov/cneaf/coal/reserves/appendixa_taba2.html. Data from this table were used to provide information both on the sulfur and calorific value (British thermal units/lb, Btu) of the Nation's coal deposits, by state, as of 1997. Although the estimates of coal reserves have been updated since then (EIA, 1999), the revisions do not characterize the coal by both sulfur content and calorific value. Other EIA publications used in the compilation are the Annual Energy Outlook (EIA, 2006), Coal Industry Annual (EIA, 1994–2000), the Annual Coal Report (EIA, 2001–2005), and Coal Production (EIA, 1979–1980; 1981–1993). Historical coal production data was obtained from reports of the U.S. Bureau of Mines (1927–1933; 1933–1976) and the U.S. Geological Survey (1907–1926).

Coal reserve estimates in tons were converted to reserve estimates in Btu by using an average calorific value for the Btu ranges provided in EIA (1997) (Tables 1–4). As used by EIA, the term "coal reserves" may be better described as "potential coal reserves," inasmuch as they are generally not proven by detailed drilling. In EIA reports, the tonnages reported as "Coal Reserves at Producing Mines" are those most likely to be proven reserves that may be mined economically over the next several decades.

Coal Production and Coal Quality by Region

The major coal-producing regions of the U.S. are shown in Figure 1. The Appalachian (Eastern) Region includes Alabama, Georgia, Eastern Kentucky, Maryland, Ohio, Pennsylvania, Tennessee, and West Virginia. Because the region includes all of Alabama, lignite tonnages of the Eastern Gulf of Mexico Coastal Plain are included with the bituminous coal reserve estimates of the Appalachian Basin. These lignite data are excluded from the totals in Table 1, but are included in Table 4. The Interior Region includes Arkansas, Illinois, Indiana, Iowa, Kansas, Western Kentucky, Louisiana, Mississippi, Missouri, Oklahoma, and Texas. The Western Region includes Alaska, Arizona, California, Colorado, Montana, New Mexico, North Dakota, Utah, Washington, and Wyoming.

U.S. coal (Fig. 2) shows a remarkable increase in production from the Western Region, especially from Wyoming and Montana (Powder River basin), since the inception of Clean Air Act revisions in 1970, thus demonstrating the increased importance of this low-sulfur coal to the U.S. economy. It is expected that near-term growth in U.S. coal production will continue to come from the Western Region. The relationship of potential coal reserves, both in tons and Btu's, to coal quality for the three major coal-producing regions of the U.S. is shown in Figs. 3–5. From these plots, it is clear that the Appalachian Region has substantial reserves of low- and medium-sulfur coal, the Interior Region is dominated by high-sulfur coal, and the Western Region contains mostly low- and medium-sulfur coal. In general, the Appalachian region contains about 1,438 quadrillion Btu's (Quads) of energy in potential coal reserves, from about 54.5 billion tons of potential coal reserves (Table 1). The Interior Region contains about 1,452 Quads of energy in potential coal reserves, from about 68.8 billion tons of potential coal reserves (Table 2). The Western Region contains about 2,542 Quads of energy, from about 151.1 billion tons of potential coal reserves (Table 3). About 40% of the potential coal reserve in the Appalachian Region is high-sulfur coal, whereas about 88% of potential coal reserve in the Interior Region is high sulfur. In contrast, only 5% of the western coals are classified as high sulfur. Interestingly, the ratio of potential energy reserves in quads to potential coal reserves in tons decreases across the country, from 28.5 Quads per billion tons for the Appalachian Region (excluding Alabama lignite), to 21.1 Quads per billion tons for the Interior Region, to 16.8 Quads per billion tons for the Western Region. As a result, from 1.3 to 1.7 times as much coal must be mined from the Western coals to

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Table 1. Eastern Region Coal Reserves in Millions of Short Tons Remaining (MSTR) and Btu's Remaining as of 1 January 1997 (Table A2. Estimated Recoverable Reserves of Coal by Btu/Sulfur Range, State, and Type of Mining, http://www.eia.doe.gov/cneaf/coal/reserves/chapter3p5.html#2)

Recoverable	Low Sulfur Coal				Medium Sulfur Coal				High Sulfur Coal					
Sulfur content (Pounds of sulfur per million Btu)	<0.41		0.41–0.60		0.61–0.83		0.84–1.67		1.68–2.50		>2.50		Total[a]	
Average heat content (Million Btu per short ton)	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining
12							771.4	9,256.8						
17.2	0.0	0.0	13.5	232.2	33.9	583.1	108.3	1,862.8	27.1	466.1	94.8	1,630.6	277.6	4,774.7
21.5	7.5	161.3	345.3	7,424.0	385.6	8,290.4	982.7	21,128.1	1,062.2	22,837.3	1,394.9	29,990.4	4,178.0	89,831.3
24.5	274.8	6,732.6	1,895.3	46,434.9	1,836.3	44,989.4	4,589.1	112,433.0	4,255.8	104,267.1	8,448.5	206,988.3	21,299.8	521,845.1
28.0	972.6	27,232.8	8,568.7	239,923.6	4,274.3	119,680.4	8,959.0	250,852.0	5,391.4	150,959.2	2,795.5	78,274.0	30,961.5	866,922.0
Total short tons (millions)	1,254.9		10,017.6		5,796.6		12,161.5		10,356.4		12,733.7		52,320.1	
Total Btu's (trillions)		34,126.7		294,014.6		173,543.2		395,532.6		278,529.7		316,883.2		1,492,629.9
Quadrillion Btu		34		294.0		173.5		395.5		278.5		316.9		1,493
Ouadrillion Btu		328				569				595			1,493	

[a]Total does not include Alabama lignite.

Table 2. Interior Region Coal Reserves in Millions of Short Tons Remaining (MSTR) and Btu's Remaining as of 1 January 1997 (U.S. Coal Reserves: 1997 Update: http://www.eia.doe.gov/cneaf/coal/reserves/front-1.html)

Region total	Low sulfur coal				Medium sulfur coal				High sulfur coal					
Sulfur content (Pounds of sulfur per million Btu)	<0.41		0.41–0.60		0.61–0.83		0.84–1.67		1.68–2.50		>2.50		Total	
Average heat content (Million Btu per short ton)	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining
12.0	0.0	0.0	0.0	0.0	584.3	7,011.6	5,983.2	71,798.4	3,374.5	40,494.0	372.5	4,470.0	10,314.5	123,774.0
17.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6	96.3	71.2	1,224.6	76.8	1,321.0
21.5	45.6	980.4	357.8	7,692.7	460.2	9,894.3	1,441.1	30,983.7	3,282.6	70,575.9	30,031.7	645,681.6	35,619.0	765,808.5
24.5	0.5	12.3	186.0	4,557.0	180.6	4,424.7	983.4	24,093.3	2,753.5	67,460.8	17,585.7	430,849.7	21,689.7	531,397.7
28.0	0.0		179.0	5,012.0	242.9	6,801.2	165.6	4,636.8	305.0	8,540.0	183.5	5,138.0	1,076.0	30,128.0
Total short tones (millions)	46.1		722.8		1,468.0		8,573.3		9,721.2		48,244.6		68,776.0	1,452,429.1
Total Btu's (trillions)		992.7		17,261.7		28,131.8		131,512.2		187,167.0		1,087,363.8		1,452,429.1
Quadrillion Btu		1.0		17.3		28.1		131.5		187.2		1,087.4		1,452.4
Quadrillion Btu		18.3				159.6				1,274.5			1,452.4	

Table 3. Western Region Coal Reserves in Millions of Short Tons Remaining (MSTR) and Btu's Remaining as of 1 January 1997 (U.S. Coal Reserves: 1997 Update: http://www.eia.doe.gov/cneaf/coals/reserves/front-1.html)

Region total	Low sulfur coal				Medium sulfur coal				High sulfur coal				Total	
Sulfur content (Pounds of sulfur per million Btu)	<0.41		0.41–0.60		0.61–0.83		0.84–1.67		1.68–2.50		>2.50			
Average heat content (Million Btu per short ton)	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining	MSTR	Btu's remaining
12.0	1,901.5	22,818.0	3,660.4	43,924.8	9,349.7	112,196.4	5,532.9	66,394.8	2,650.7	31,808.4	2,488.6	29,863.2	25,583.8	307,005.6
17.2	42,050.9	723,275.5	32,305.6	555,656.3	22,402.5	385,323.0	12,118.5	208,438.2	1,464.6	25,191.1	1,334.4	22,951.7	111,676.5	1,920,835.8
21.5	1,392.7	29,943.1	2,673.9	57,488.9	1,722.5	37,033.8	2,223.6	47,807.4	307.9	6,619.9	426.8	9,176.2	8,747.4	188,069.1
24.5	1,632.7	40,001.2	1,538.2	37,685.9	706.4	17,306.8	395.6	9,692.2	95.2	2,332.4	0.0	0.0	4,368.1	107,018.5
28.0	233.0	6,524.0	386.6	10,824.8	34.6	968.8	42.8	1,198.4	0.0	0.0	0.0	0.0	697.0	19,516.0
Total short tons (millions)	47,210.8		40,564.7		34,215.7		20,313.4		4,518.4		4,249.8		151,072.8	2,542,445.0
Total Btu's (trillions)		822,561.7		705,580.7		552,828.8		333,531.0		65,951.8		61,991.1		2,542,445.0
Quadrillion Btu		823		706		553		334		66		62		2,542
Quadrillion Btu	1,528				886				128				2,542	

Table 4. Summary of U.S. Coal Reserve Tonnages and Btu Values as of 1 January 1997

Average heat content	Western region			Interior region			Eastern region			Total all regions			
(Million Btu per short ton)	Total Btu (Trillions)	Total Btu (Quads)	Total short tons (Millions)	Total Btu (Trillions)	Total Btu (Quads)	Total short tons (Millions)	Total Btu (Trillions)	Total Btu (Quads)	Total short tons (Millions)	Btu (Trillions)	Btu (Quads)	Short tons (Millions)	Coal type
12.00	307,005.6	307	25,583.80	123,774.0	124	10,314.50	9,257	9	771	477,146	477	36,670	Lignite
17.20	1,920,835.8	1,921	111,676.30	1,321.0	1	76.80	4,775	5	278	2,040,889	2,041	112,031	Lignite to subbituminous C
21.50	188,069.1	188	8,747.60	765,808.5	766	35,618.90	63,791	64	2,967	1,066,019	1,066	47,334	Subbituminous B and A
24.50	107,018.5	107	4,367.80	531,397.7	531	21,689.30	527,323	527	21,523	1,214,486	1,214	47,581	Bituminous C and B
28.00	19,516.0	20	697.00	30,128.0	30	1,076.00	833,014	833	29,751	915,064	915	31,524	Bituminous A to Anthracite
			151,073			68,776			55,290			275,138	
Trillion Btu	2,542,445			1,452,429			1,438,159			5,713,604			
Quadrillion Btu		2,542			1,452			1,429			5.714		

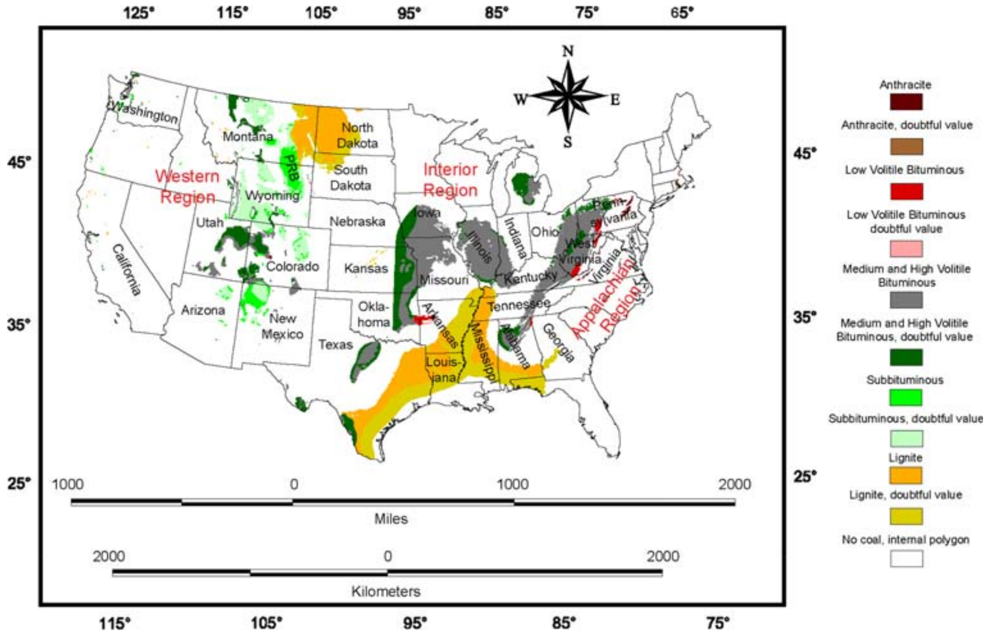

Figure 1. Coal fields of conterminous U.S. (after Tully, 1996). Texas is included in the Interior Region. PRB is Powder River Basin.

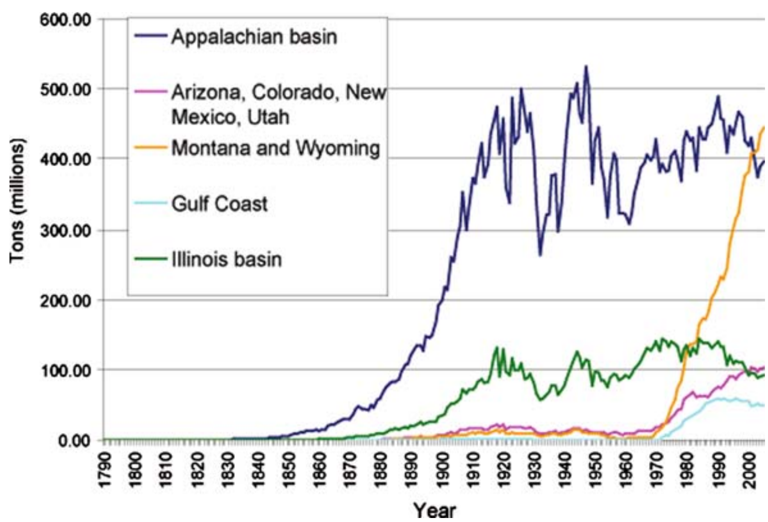

Figure 2. U.S. Coal production from 1790 until 2005. Since 1970, almost all growth has been from western coals. Data from EIA (1977 to present); U.S. Bureau of Mines (1927–1976); and U.S. Geological Survey, 1907–1926).

provide the energy obtained from the Appalachian and Interior coals, respectively.

Recoverable Reserves at Producing Mines

The recoverable reserves at producing mines from 1985 to 2005, perhaps the only truly proven coal reserve numbers (proved by drilling) published by EIA, show a generally declining trend for the last two decades (Table 5, Fig. 6). EIA changed its reporting methods for these data in 2001, from the Coal Industry Annual (EIA, 1994–2000) to the Annual coal Report (EIA, 2001–2005), so that withheld (W) data are not included in the totals from 2001 to 2005, which results in slightly lower values for the

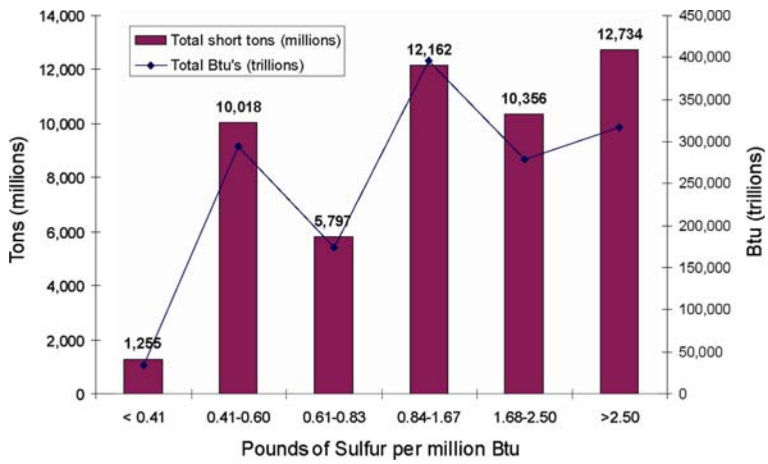

Figure 3. Appalachian Region bituminous coal reserves in millions of short tons and trillions of Btu's remaining as of 1 January 1997 (EIA, 1997; data labels in millions of tons).

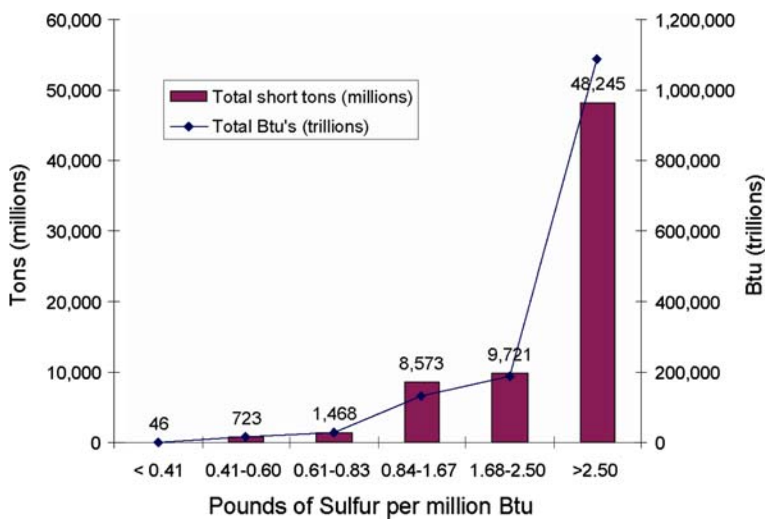

Figure 4. Interior Region coal reserves in millions of short tons remaining as of 1 January 1997 (EIA, 1997; data labels in millions of tons).

Interior and Western Regions for these years. Nevertheless, there is an almost continuous decline in the reserves at producing mines during this period, so that at present, only about 15 years of "proved coal reserves" remain at current production rates. The percentage decline of reported reserves at producing mines ranges from about 45% in the Appalachian and Interior Regions to about 25% in the Western Region from 1985 to 2005. During this same period, coal production has remained relatively constant in the Appalachian and Interior Regions and has increased significantly in the Western Region (compare Fig. 7 with Fig. 6).

The Future

EIA (2006) projects future coal production to rise from about 1.1 billion tons annually to about 1.7 billion tons annually in 2030, with almost all of the growth expected to come from the Western Region (Fig. 7). EIA predicts prices will increase during the near term, but then will rise only slightly over the long term (Fig. 8). Where is this additional coal going to come from? Within the next several decades, much of the shallow Powder River Basin and the low-sulfur coals of the Appalachian Basin may be significantly depleted. Mining and

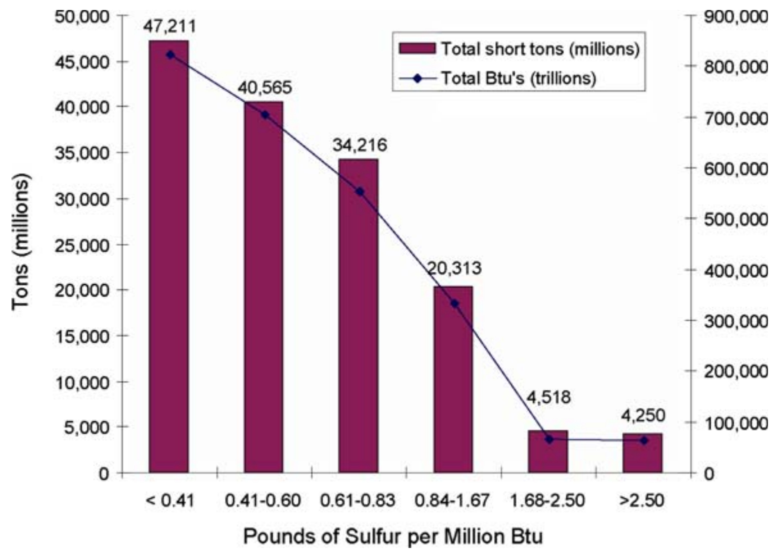

Figure 5. Western Region coal reserves in millions of short tons and trillions of Btu's remaining as of 1 January 1977 (EIA, 1997; data labels in millions of tons).

combustion costs may escalate as thinner, deeper, and higher sulfur subbituminous and bituminous coal resources are accessed and as carbon dioxide sequestration strategies are implemented. Indeed, much of the additional tonnages mined during the latter part of this century may be from lower grade coals, especially if coal becomes a more important feed stock for the production of synthetic liquids and gases in addition to its prime use for the generation of electric power.

COALBED METHANE

A.R. Scott[5] and J.C. Pashin[6]

Coalbed Methane Activity

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 more than 12 U.S. basins. The major producing areas are the San Juan, Powder River, Black Warrior, Raton, Central Appalachian, and Uinta basins. Other U.S. areas with significant exploration or production are the Cherokee, Arkoma, Illinois, Hanna, Gulf Coast, and Greater Green River basins.

Most of the coalbed methane activity in the eastern U.S. is focused on the Appalachian Basin of

Table 5. Recoverable Coal Reserves at Producing Mines (millions). *Sources*: Coal Industry Annual, 1994—2000 (DOE/EIA-0584(94-2000); Annual Coal Report DOE/EIA 0585 (2001–2005)[a]

Year	Appalachian	Interior[a]	Western[a]	U.S.
1985	7,566	4,313	13,267	25,146
1986	7,343	4,321	13,384	25,048
1987	7,009	4,206	13,027	24,241
1988	6,707	3,979	12,895	23,581
1989	6,331	3,907	12,442	22,680
1990	5,989	3,682	13,091	22,761
1991	5,807	3,715	12,477	21,999
1992	5,446	3,559	12,622	21,627
1993	5,596	3,300	12,639	21,535
1994	4,855	3,069	13,093	21,017
1995	4,538	2,835	12,732	20,105
1996	4,530	2,757	12,141	19,428
1997	4,632	2,591	11,941	19,164
1998	4,456	2,428	12,438	19,322
1999	3,968	2,620	12,331	18,920
2000	3,801	2,490	12,048	18,339
2001[a]	4,027	2,217	10,696	17,801
2002[a]	3,776	2,279	11,369	18,216
2003[a]	3,625	2,340	11,224	17,954
2004[a]	3,907	2,063	11,420	18,122
2005[a]	4,215	2,301	11,612	18,944

[a]Regional data does not include withheld tonnages from mines in several states.

[5]Altuda Energy Corporation, San Antonio, TX 78209.
[6]Geological Survey of Alabama, Tuscaloosa, AL 35486.

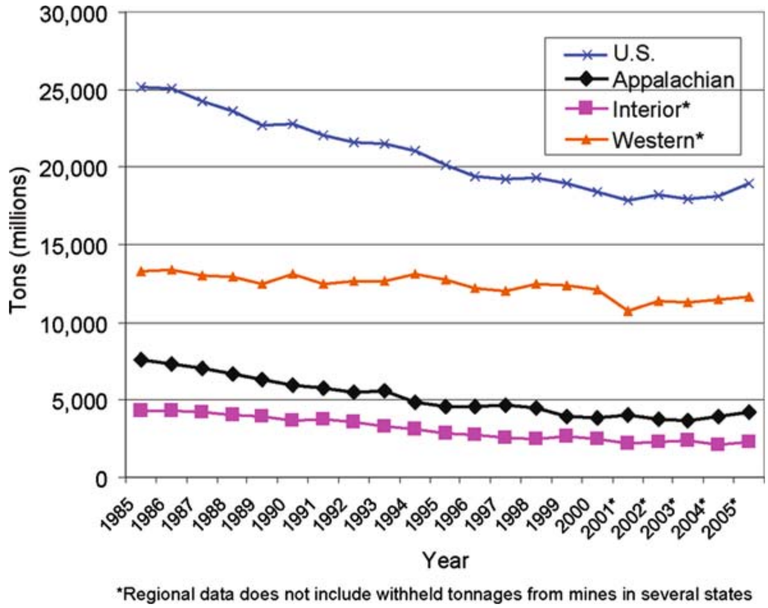

Figure 6. Recoverable reserves at producing U.S. coal mines (EIA, 1994–2000, 2001–2005).

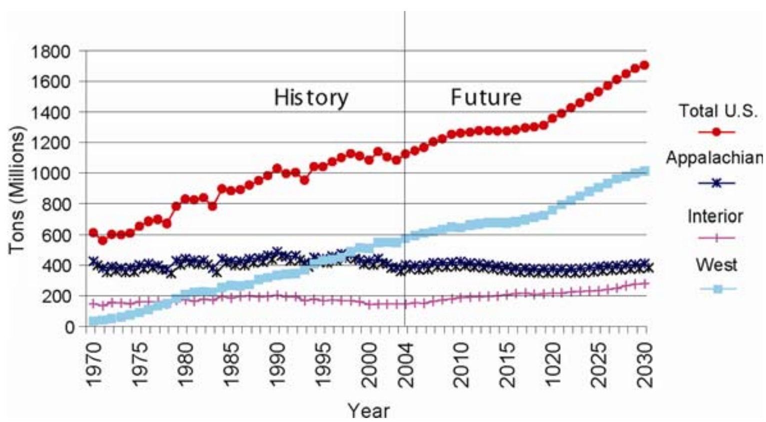

Figure 7. Historical and projected coal production (EIA, 2006).

southwestern Virginia and the Black Warrior Basin of Alabama, with several companies actively developing joint coalbed methane (CBM) and coalmine methane (CMM) projects. At least 2,753 coalbed methane wells have been drilled in south-western Virginia (2005), and 69 billion cubic ft (Bcf) of gas was produced in 2005. The advent of pinnate horizontal drilling has resulted in a significant expansion of the coalbed methane industry in Virginia by providing access to large volumes of gas in low-permeability coal seams. West Virginia had 290 coalbed methane wells and a cumulative coalbed methane production of 33.2 Bcf as of the end of 2003. The number of wells in Pennsylvania is 285 as of 2005, but cumulative production is 9.5 Bcf; annual production in 2003 was 1.6 Bcf. There are 4,625 coalbed methane wells currently operating in Alabama with a cumulative production through May 2006 of 1.82 trillion cubic feet (Tcf).

The Midcontinent region, consisting of the Cherokee, Forest City, Arkoma, and Illinois basins is one of the more active regions in the U.S. 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 in

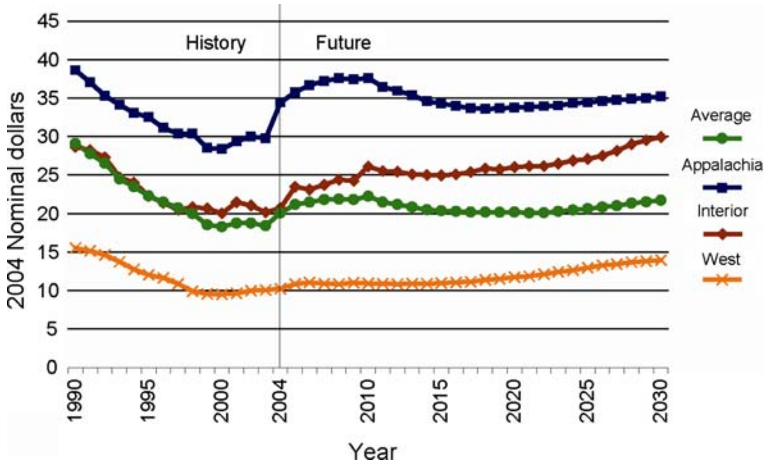

Figure 8. Average minemouth price of coal by Region, 1990–2030 (EIA, 2006).

low-permeability coal is proving to be a productive development strategy.

Infill drilling of Fruitland CBM wells in the San Juan Basin (Colorado and New Mexico) continues at a high rate. A major portion of the infill drilling is being accomplished through boreholes that are drilled directionally from existing well pads. Environmental groups have continued to express concern about gas seeps along the margins of the San Juan Basin in the Fruitland outcrop belt.

International activity has been on the rise, and operations in the Qinshui Basin of China are the first to prove the producibility of coalbed gas from anthracite. Intense exploration and development activity continues in western Canada, where the Horseshoe Canyon coals host a major coalbed methane play. Exploration and development efforts are intensifying in the Bowen and Sydney basins of Australia, as well as the Karoo Basin of South Africa. Major potential exists in the Gondwanan coal basins of India, and development of fields and pipeline infrastructure is underway. Significant potential also exists in the coal basins of Europe and the Russian platform, and development in these areas is focusing mainly on coalmine methane. However, immense potential exists for development independent of coalmines in the large coal basins of the Russian platform.

2004 Coalbed Methane Reserves

The Energy Information Agency released their ''Advance Summary of U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves – 2004 Annual Report'' in September 2005 (DOE/EIA-0216(2004)Advance Summary). In 2004, U.S. CBM reserves were approximately 18.39 Tcf, or 9.6% of the total U.S. dry natural gas reserves of 192.0 Tcf (Fig. 9, Table 6). This represents a 1.9% decrease over 2003 CBM reserves, but represents a 5-fold increase over 1989 coalbed gas reserves (3.7 Tcf). The greatest CBM reserves gains were in New Mexico, the Eastern States, and the Western states. Note that Wyoming, Utah, Eastern States, and Western States, are included in the ''Other'' category prior to 1999. These areas now have 33% of the proved CBM reserves (6.2 Tcf), whereas in 1990 they represented only about 0.6% of Proved Reserves.

The largest gain in CBM reserves came from the Western States (Arkansas, Kansas, Oklahoma, and Montana), where reserves increased from 698 Bcf to 898 Bcf or 200 Bcf, representing a 28.7% increase in reserves. New Mexico increased reserves from 4,396 to 5,166 Bcf or 17.5% primarily because of extensive infill drilling activity in the San Juan Basin. Wyoming reserves declined by 24.4% to 2,085 Bcf, and reserves in Utah decreased by 23.7% from 1,224 Bcf to 934 Bcf. Reserves in the Eastern States (Indiana, Ohio, Pennsylvania, Virginia, and West Virginia) increased by 6.0% to 1,620 Bcf.

2004 U.S. Coalbed Methane Production

The annual U.S. coalbed gas production has increased steadily since 1985, but CBM production declined slightly (0.9%) in 2004 to 1,720 Bcf (Fig. 10, Table 7). Coalbed methane production represents

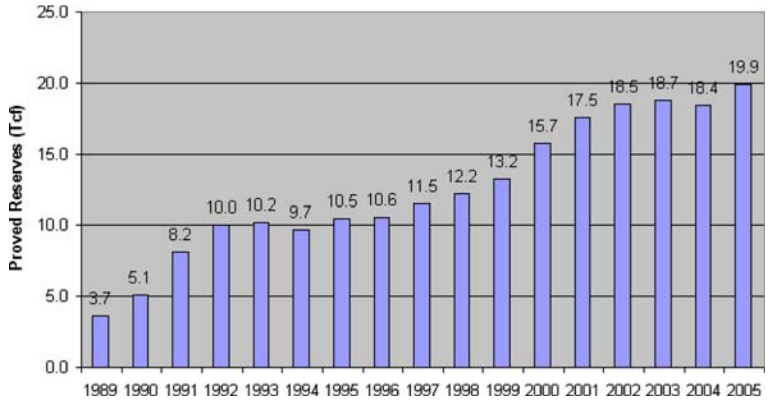

Figure 9. Proved coalbed methane reserves trends. Data from the Energy Information Administration (2005). http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/current/pdf/table12.pdf.

Table 6. Proved Coalbed Methane Reserves. Data from the Energy Information Administration (2005). http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/current/pdf/table12.pdf

Year	Alabama	Colorado	New Mexico	Utah	Wyoming	E. States	W. States	Others[a]	Total
1989	537	1,117	2,022	NA	NA	NA	NA		3,676
1990	1224	1,320	2,510	NA	NA	NA	NA	33	5,087
1991	1714	2,076	4,206	NA	NA	NA	NA	167	8,163
1992	1968	2,716	4,724	NA	NA	NA	NA	626	10,034
1993	1237	3,107	4,775	NA	NA	NA	NA	1,065	10,184
1994	976	2,913	4,137	NA	NA	NA	NA	1,686	9,712
1995	972	3,461	4,299	NA	NA	NA	NA	1,767	10,499
1996	823	3,711	4,180	NA	NA	NA	NA	1,852	10,566
1997	1,077	3,890	4,351	NA	NA	NA	NA	2,144	11,462
1998	1,029	4,211	4,232	NA	NA	NA	NA	2,707	12,179
1999	1,060	4,826	4,080	NA	NA	NA	NA	3,263	13,229
2000	1,241	5,617	4,278	1,592	1,540	1,399	41	4,572	15,708
2001	1,162	6,252	4,324	1,685	2,297	1,453	358	5,793	17,531
2002	1,283	6,691	4,380	1,725	2,371	1,488	553	6,137	18,491
2003	1,665	6,473	4,396	1,224	2,759	1,528	698	6,209	18,743
2004	1,900	5,787	5,166	934	2,085	1,620	898		18,390
2005	1,773	6,772	5,249	902	2,446	1,822	928		19,892

[a]After 1999, E. States include Ohio, Pennsylvania, West Virginia, and Virginia, and W. States include Arkansas, Kansas, Montana, and Oklahoma. Prior to 2000, includes Oklahoma, Pennsylvania, West Virginia, Virginia, Utah, Wyoming; after 1999, this column is the sum of all but the first three columns.

9% of dry natural gas production in the U.S. Production in Colorado and New Mexico increased from 939 Bcf in 2003 to 1,048 Bcf in 2004, which is an increase of 11.6%.

Production in the Black Warrior Basin increased in 2004 to 121 Bcf because of accelerated drilling and completion activity in the basin. Coalbed methane production in Utah declined for a second straight year from 97 Bcf to 82 Bcf or a 15.5% decline in 2004. Peak coalbed methane production in Utah was of 103 Bcf in 2002. Therefore, production has declined by 20% during the past 2 years, and reserves also have declined significantly. This seems to reflect the increasing maturity of existing fields and may indicate that decline will continue unless additional acreage is developed.

The Western States consisting of the Midcontinent region of Arkansas, Kansas, Oklahoma, and the State of Montana had the largest increase in coalbed methane production as drilling activity continued to increase (Table 7). Total production increased from 51 to 77 Bcf or a 51% increase, the

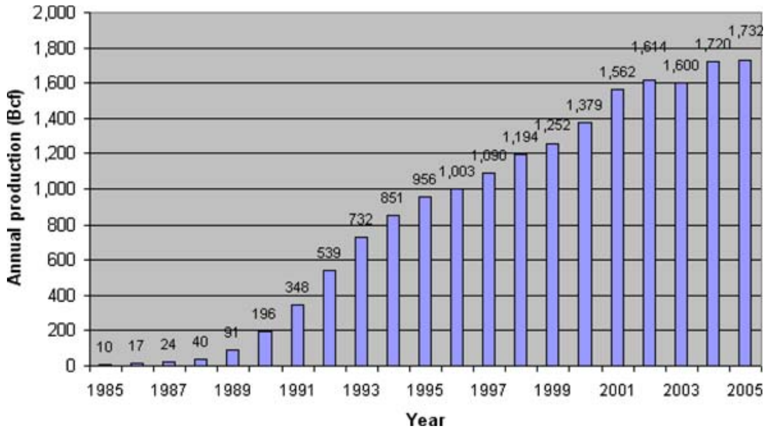

Figure 10. Coalbed methane production trends. Data from the Energy Information Administration (2005). http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/current/pdf/table12.pdf.

Table 7. Coalbed Methane Production by Region. Data from the Energy Information Administration. http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_ publications/crude_oil_natural_gas_reserves/current/pdf/table12.pdf

Year	Alabama	Colorado	New Mexico	Utah	Wyoming	E. States	W. States	Others[a]	Total
1989	23	12	56	NA	NA	NA	NA		91
1990	36	26	133	NA	NA	NA	NA	1	196
1991	68	48	229	NA	NA	NA	NA	3	348
1992	89	82	358	NA	NA	NA	NA	10	539
1993	103	125	486	NA	NA	NA	NA	18	732
1994	108	179	530	NA	NA	NA	NA	34	851
1995	109	226	574	NA	NA	NA	NA	47	956
1996	98	274	575	NA	NA	NA	NA	56	1,003
1997	111	312	597	NA	NA	NA	NA	70	1,090
1998	123	401	571	NA	NA	NA	NA	99	1,194
1999	108	432	582	NA	NA	NA	NA	130	1,252
2000	109	451	550	74	133	58	4	269	1,379
2001	111	490	517	83	278	69	14	444	1,562
2002	117	520	471	103	302	68	33	506	1,614
2003	98	488	451	97	344	71	51	563	1,600
2004	121	520	528	82	320	72	77		1,720
2005	113	515	514	75	336	90	89		1,732
Total	1,645	5,101	7,722	514	1,713	428	268	2,250	17,859

After 1999, E. States include Ohio, Pennsylvania, West Virginia and Virginia, and W. States include Arkansas, Kansas, Montana, and Oklahoma.

[a]Prior to 2000, includes Oklahoma, Pennsylvania, West Virginia, Virginia, Utah, Wyoming; after 1999, this column is the sum of all but the first three columns.

second such increase in the past two years. The Powder River Basin in Wyoming experienced a decrease in coalbed methane production from 344 to 320 Bcf (42 Bcf) which represents a 7.0% decrease in production. The decline in coalbed methane production may be attributed to the abandonment of mature wells. Coalbed methane production in the Eastern States increased slightly from 71 to 72 Bcf, or by 1.4%.

GAS HYDRATES

Arthur H. Johnson[7]

Gas hydrate is a solid, crystalline material that forms when gases (such as methane) combine with water under conditions of relatively high pressure

[7]Hydrate Energy International, Kenner, LA 70065.

and low temperature. A single cubic foot of gas hydrate yields approximately 164 cubic feet of gas at atmospheric pressure, along with about 0.8 cubic feet of water. The resource potential of natural gas from gas hydrate is enormous, yet critical issues of technology and economics remain.

With growing concerns in many parts of the world regarding future natural gas supply, research activities and field investigations aimed at commercializing gas hydrates are increasing. In the United States, several oil companies have taken initial steps toward evaluating hydrate resource potential on their acreage. In addition, the U.S. Minerals Management Service is completing a comprehensive assessment of gas hydrate potential in the Federal offshore.

Significant challenges remain before gas hydrate that can be considered a viable resource. Foremost among them are the need for improved exploration approaches that will allow the identification and quantification of producible accumulations, and development technology that will yield commercial production rates while maintaining safety and low operating expense. Understanding the relationship of hydrate to its host sediment is of critical importance for both issues and significant progress is being made. Recent drilling programs have made use of improved coring tools and core handling techniques whereas computer modeling has provided new insights into production scenarios.

Significant concentrations of gas hydrate occur within the pore space of sands, as mounds on the sea floor near vents, and filling fractures. Initial production is most commercially feasible from hydrate-bearing sands, and this is the primary focus of most investigators addressing hydrate resource potential.

Several new drilling efforts are planned for the next 18 months that will determine further the commercial viability of gas hydrate as a gas resource. An international consortium of companies and government agencies led by Chevron drilled several wells the Gulf of Mexico in 2005 with a primary focus on geohazards. Potential sites are currently being evaluated for the next phase of the consortium's program that will have resource assessment as a primary focus. Drilling operations will begin as early as mid-2007. In early 2007, BP Alaska will drill, log, and core a hydrate-evaluation well in the Milne Point field on the North Slope as part of an ongoing assessment effort. If this phase of the program is successful, a production test is likely within a few years. Canada and Japan will be conducting a production test of a hydrate-bearing formation in the Canadian Arctic during the winter of 2006–2007, and a longer duration (75–80 days) production test during the winter of 2007–2008.

The People's Republic of China will conduct offshore drilling operations to assess hydrate resource potential in Spring 2007. South Korea will drill for hydrates off its coast later in the year. India conducted an extensive drilling, logging, and coring program off its coast during 2006. Following the initial results of the program, India has announced its plans for a gas hydrate production test in 2008.

Although not yet a proven commercial resource, gas hydrate is the focus of significant research efforts worldwide by universities, government agencies and industry. These efforts are rapidly moving gas hydrate toward commercial viability.

GEOSPATIAL INFORMATION TECHNOLOGY

S.H. Limerick[8]

The availability of live, interactive maps on the Internet continues to grow by leaps and bounds. Google Earth (http://earth.google.com/) has open code, enabling ''mashups'' where users modify code to display their data on the web. Comment from *Directions Magazine*: ''Let's face it, everything that came before and after, from professional GIS to consumer websites to APIs, is now compared to Google's offerings. Bottom line: Google obliterated the once difficult task of integrating remotely sensed with terrain data in a flashy, easily searchable portal. Leave it to a non-GIS company to make geography sexy.''

Examples of Google Earth mashups are crime data and locations in Chicago (http://www.chicagocrime.org/) and real estate (http://www.housingmaps.com/). In order to learn more about how to use Google Earth, tutorials are available at: http://www.gearthblog.com/blog/archives/2006/03/tutorials_for_g.html.

Microsoft's answer to Google Earth is Microsoft Virtual Earth, which undergoes a name change to ''Windows Live Local powered by Virtual Earth'' (http://local.live.com/). Live Local contains the ''birds eye'' oblique imagery provided by Pictometry, now complete for about 25% of the

[8]Z, Inc./U.S. Department of Energy, Dallas, TX 75201.

US population. This oblique-view of data is preferred by many users to the rooftop view of conventional aerial photos. In late 2006, Microsoft released 3D models of 25 cities (must have Windows XP operating system to install the 3D viewer).

The use of Global Positioning Systems (GPS) in commercial applications is also expanding quickly. In the USA, nearly 1.9 million GPS/wireless devices are used to monitor fleet vehicles, trailers, construction equipment, and mobile workers. The largest market segment is the local and long haul fleet Automatic Vehicle Location market, which use installed GPS/wireless devices to track the location of fleet vehicles. One of the fastest growing market segments is the emerging market for managing mobile workers through the use of GPS-equipped cellular phones and other portable devices.

GIS software vendor ESRI release the new version of their ArcGIS mapping software (9.2) in late 2006. Enhancements include:

- Ability to grid with faults (just like Z-Map).
- Animations are easier with toolbar in ArcMap. ESRI has a demo on Lost Soldier Field (WY), where red and green pie charts over each well on a map display the well's oil & gas mix over time (1-year increments) as a time versus production (oil/gas/water) is drawn.
- ArcGIS Server product makes it easy to serve out maps on the internet. This will be replacing the more cumbersome ArcIMS software.

GEOTHERMAL

J.L. Renner[9]

Geothermal resources generate electricity and provide direct use of the thermal energy for heating in the United States. Lund and others (2005) estimate that the capacity for electrical generation is 2,534 megawatts-electric (MWe) and that about 17,840 gigawatt hours (GWh) of electricity are produced per year. The direct uses include heating of pools and spas, greenhouse and aquaculture facilities, space heating and industrial uses. The installed capacity is 7,817 megawatts-thermal and the annual energy usage is about 31,200 terajoules.

There has been a slight change in the capacity of geothermal power plants producing electricity during the past year. A small (200 KWe net), but interesting, power plant has been placed on line at Chena Hot Springs, Alaska and a new 27 MWe plant began operations at Steamboat, Nevada. A number of projects are in various stages of development. Construction of a new plant began at Raft River, near Malta, Idaho and a new binary plant at Desert Peak, Nevada should come on line by the end of 2006.

Several web sites offer periodic information related to the geothermal industry and legislation and regulation affecting geothermal development. The Geothermal Energy Association (GEA) publishes the *GEA Update* periodically. It is available at http://www.geo-energy.org or http://www.geo-energy.org/publications/updates.asp. GEA also provides a page providing summaries of geothermal development projects in the United States (http://www.geo-energy.org/information/developing.asp) The Nevada Division of Minerals also periodically publishes the *Nevada Geothermal Update* at http://minerals.state.nv.us/ or http://minerals.state.nv.us/formspubs.htm.

U.S. Geothermal Activity

The U.S. Geological Survey (USGS) has initiated a new assessment of the geothermal resources of the United States (Williams and Reed, 2005) to replace the last assessment, results of which were published in 1979 (Muffler, 1979).

The Energy Policy Act of 2005 modified leasing provisions and royalty rates for both geothermal electrical production and direct use. Notable changes include a legislative mandate that all geothermal leases to be awarded competitively and changes in royalty rates. The new law parallels existing oil and gas leasing provisions.

A ''Geothermal Energy Generation in Oil and Gas Settings Conference'' was hosted by Southern Methodist University during March 2006. The conference goal was to stimulate the development of geothermal energy into new areas utilizing existing oil and gas infrastructure. Conference abstracts, presentations and DVDs of the presentation are available from the SMU Geothermal Lab (http://www.smu.edu/geothermal/Oil&Gas_SMUmeeting.htm).

[9]Idaho National Laboratory, Idaho Falls, ID 83415.

State Reports

Information for the following state activity summaries is primarily from the GEA web site. Only significant activity is reported here. For more detailed information see the GEA and Nevada Division of Minerals web sites.

Alaska. A 200 KWe binary powerplant was commissioned at Chena Hot Springs (http://www.yourownpower.com/Power/) during the fall of 2006 and a second unit was being installed at the end of the year. The project is notable because it has provided the entrance into the geothermal industry of United Technologies Company owner of Carrier. The plants are based on UTC's air conditioning equipment. They hope that installations utilizing their off-the-shelf equipment will allow production from otherwise low to moderate temperature geothermal resources that have been uneconomic.

California. California Energy Company has placed on hold a 185 MWe plant in the Salton Sea pending extension of a geothermal production tax credit. At The Geysers geothermal field, about 90 miles north of San Francisco, two companies have announced plans to develop new power plants. U.S. Renewable Group intends to repower the mothballed Bottlerock plant. Western GeoPower announced that they intend to drill wells and build a new geothermal plant near the site of the decommissioned PG & E Unit 15 geothermal plant.

Idaho. U.S. Geothermal currently is constructing a 10 MWe geothermal plant at the Raft River geothermal field near Malta, Idaho. They plan to bring power on line in 2007. Idatherm has announced several geothermal exploration projects in southeastern Idaho. Both are within the southeastern Idaho phosphate belt and the Idaho portion of the overthrust belt.

New Mexico. Lightning Dock Geothermal has announced plans to build a 20 MWe plant in the Lightning Dock geothermal field in southwestern New Mexico. Details of this project are given at: http://www.geo-energy.org/information/developing/LightningDock.asp.

Nevada. Nevada remains the most active state for geothermal development with power plant expansions or modifications at three sites and exploration and development drilling on at least 12 sites. A total of 13 projects are under development in Nevada. These would supply up to 365 MW of electricity.

Exploration activity is most advanced at the Blue Mountain geothermal site in Humboldt County where Nevada Geothermal Power Company has completed one development well and has reported that the well was hotter than expected and flowed in commercial quantities.

Ormat Nevada brought on-line a 27 MWe binary plant at Steamboat Springs, Nevada. After completion of an additional plant, the Steamboat Springs geothermal complex will provide about 90 MWe of power to the Reno area.

Ormat also has completed construction of a new plant at the Desert peak field about 50 miles northeast of Reno. The 11 MWe binary plant will replace the existing flash steam plant.

Oregon. Nevada Geothermal has announced plans for further exploration and possible development of the Crump Geyser geothermal prospect in Warner Valley, Oregon. Northwest Geothermal Company has entered into a power sales agreement with Pacific Gas & Electric Company for power from the Newberry geothermal project about 25 miles south of Bend, Oregon. Newberry was the site of extensive geothermal activity during the 1980s.

Utah. Amp Resources is continuing development of the Cove Fort geothermal field somewhat to the southeast of the intersection of interstate highways 15 and 70 in central Utah. Cove Fort was the site of a small geothermal plant which was been decommissioned by Amp Resources but was undergoing exploration by Amp at the end of 2006. Amp was purchased by Enel North America in early 2007.

Rocky Mountain Power is considering expansion of the Roosevelt geothermal field through the addition of a binary bottoming cycle plant to its existing 26 MWe plant.

OIL SANDS

F.J. Hein[10]

Recent world events are placing a greater reliance of North American interests on unconventional energy resources, including the vast oil sands and heavy oil deposits. Unconventional energy resources are those deposits previously considered

[10]Alberta Energy and Utilities Board, Calgary, AB, Canada T2P 3G4.

uneconomic, the result of either poor energy market conditions and/or inefficient or costly technologies. Today such economic or technological barriers have been generally overcome for many of the oil sands and heavy oil deposits. Oil sands consist of bitumen (soluble organic matter) and host sediment, excluding any associated natural gas accumulations. Oil sands usually are unconsolidated, held together by the pore-filling bitumen, a thick, tar-like, naturally degraded oil. In its natural state, bitumen will not flow to a well bore (density range of 8–12° API; at room temperature viscosity $>50,000$ centipoises). In Alberta other heavy oil in sand is also considered as 'oil sands' if located within the oil-sand application areas. However, because the heavy oil is not as viscous as bitumen, and it will flow to a well bore under natural conditions, these deposits are considered as 'primary *in situ* bitumen.' Heavy oil deposits outside the oil sand application areas, such as much of the heavy oil in Saskatchewan and east-central Alberta, are considered separate from the bitumen in reserves calculations.

Oil sands and heavy oil have been reported from more than 70 countries, with the largest deposits located in Canada and Venezuela. In the USA, oil sands or heavy oil occur in California, Alaska, Utah, New Mexico, Texas, Oklahoma, Kentucky, Alabama, and on the border between Kansas and Missouri.

Alberta has the largest oil sands deposit in the world, with current estimates by the Alberta Energy and Utilities Board (EUB) indicating that about 174 billion barrels (bbl) (or about 28 billion cubic meters) (m^3) are recoverable using present day technologies (EUB, 2006). In Alberta, the oil sands occur in Cretaceous fluvial-estuarine deposits of northeastern Alberta, where they cover an area exceeding 140,000 square-kilometers (km^2). Alberta also has bitumen hosted in Devonian carbonate rocks but at present these deposits have not been commercially produced. Most recently, current exploration in 2005–2006 has provided encouraging results for a possible eastward extension of the Athabasca oil sands deposit into northwestern Saskatchewan, although delineation programs are ongoing. In west-central Saskatchewan, thermal operations have been operating in the Lloydminster heavy oil field for more than 20 years, where current heavy-oil production exceeds 20,000 barrels per day. Here oil recovery from thermal projects ranges from 30 to 70%, compared with 5 to 10% for primary production from the same area.

In the past decade, bitumen production in Canada has more than doubled. In 2001, Alberta's production of raw bitumen and synthetic crude oil (derived by refining and upgrading of bitumen and byproducts) exceeded Alberta's production for conventional crude oil, accounting for 53% of the province's oil production. In 2005, bitumen production was approximately 169,000 m^3/d (169 thousand cubic meters/day). It was originally estimated that about 20% of the vast oil sands reserves in Alberta will be recoverable by surface mining; *in situ* technologies are needed for the remaining 80% of the oil sands that are buried at depths with greater than 75 meters of overburden. Currently in Alberta, of the 2005 bitumen production, 59% was recoverable by surface mining and 41% was recovered by thermal-assisted *in situ* techniques, mostly by Steam-Assisted Gravity Drainage (SAGD). Oil sand or heated bitumen is transported to processing plants, where hot or warm water separates the bitumen from the sand, followed by the addition of dilutants (mainly lighter hydrocarbons) and upgrading to synthetic crude oil. In 2005, Alberta's surface mineable bitumen was upgraded to produce about 87,000 m^3 of synthetic crude oil. By 2013, it is expected that about 80% of Alberta's oil production will be from bitumen and synthetic crude oil.

The main challenge of recovering bitumen from depth is to overcome its high viscosity to allow it to flow to a well bore. In order to overcome the high viscosity, various thermal (or other nonprimary) in situ techniques are used—usually SAGD or Cyclic Steam Stimulation (CSS). The largest *in situ* bitumen recovery project is located at Cold Lake, Alberta, which uses CSS. At Cold Lake about 3,200 wells are currently producing bitumen from multiple pads, with two above ground pipelines—one to deliver steam and one to transport the heated fluids back to the processing plant. In CSS steam is injected down the well bore into the reservoir to heat the bitumen. This steam injection is followed by a soak period and then the same well bore is used to pump up the heated fluids. In the Athabasca deposit of northeastern Alberta SAGD technology may be used. Here horizontal well pairs (approximately 700 meters long) are drilled along inclines from surface to intersect the bitumen zone. Steam is used to mobilize the bitumen and is injected into the reservoir from the upper injector well. As the steam expands it reduces the viscosity of the bitumen, which then flows by gravity down to the producer well. In areas of depleted overlying gas caps,

Table 8. Total Production of Uranium Concentrate in the United States, 1996 – 3rd Quarter 2006 (Pounds U_3O_8)

Calendar-Year Quarter	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006[P]
1st Quarter	1,734,427	1,149,050	1,151,587	1,196,225	1,018,683	709,177	620,952	400,000E	600,000E	709,600	921,999
2nd Quarter	1,460,058	1,321,079	1,143,942	1,132,566	983,330	748,298	643,432	600,000E	400,000E	630,053	894,268
3rd Quarter	1,691,796	1,631,384	1,203,042	1,204,984	981,948	628,720	579,723	400,000E	588,738	663,068	1,083,808
4th Quarter	1,434,425	1,541,052	1,206,003	1,076,897	973,585	553,060	500,000E	600,000E	600,000E	686,456	NA
Calendar-Year Total	6,320,706	5,642,565	4,704,574	4,610,672	3,957,545	2,639,256	2,344,107E	2,000,000E	2,282,406	2,689,178	NA

P = Preliminary data.
E = Estimate – The 4th quarter 2002 production amount was estimated by rounding to the nearest 100,000 pounds to avoid disclosure of individual company data. This also affects the 2002 annual production. The 2003 and 1st, 2nd, and 4th quarter 2004 production amounts were estimated by rounding to the nearest 200,000 pounds to avoid disclosure of individual company data.
NA = Not available.
Notes: Totals may not equal sum of components because of independent rounding. Next update is approximately 45 days after the end of the fourth quarter 2006.
Sources: Energy Information Administration: Form EIA-851A and Form EIA-851Q, "Domestic Uranium Production Report."

low-pressure SAGD is done with assistance of electrical submersible pumps. One of the largest challenges for SAGD is the source of energy and water for steam production. Generally it takes 28 m^3 (or 1,000 ft^3) of natural gas and from 2.5 to 4.0 barrels of water to produce one barrel of bitumen. There is ongoing research on emerging technologies for bitumen recovery, including use of nuclear energy for steam generation, and other alternative fuels such as palletized coke or bitumen, or other processes such as *in situ* combustion, which would overcome the need to pump the heated bitumen to surface. At present, most of these technologies are only in the development stage and planning has begun for some pilot plant tests.

In the U.S.A. ongoing work is addressing enhanced oil recovery from heavy oil fields, some using fracing, solvent injection, and CO_2 injection. Elsewhere, particularly in the Utah oil sands, technologies compatible to both oil sand and oil shale recoveries are being developed. These emerging technologies may make oil sand operations prospective in areas where their recovery could be combined with other infrastructure being developed for nearby oil shale resources. As is the situation for almost all of the unconventional resources, successful development of the oil sand and heavy oil industries face continuing challenges for economic *in situ* recovery, mainly involving the water and energy requirements for steam generation, the reduction of greenhouse gas emissions, and reclamation and mitigation efforts. In Alberta, the reclamation of surface mining areas for bitumen is done to a standard to at least the equivalent of their previous biological productivity.

In 2006, three quarters of Alberta's crude oil, crude bitumen, synthetic crude oil, condensate, and pentanes plus was exported to other provinces, the U.S.A. and offshore. Beginning in the mid-1970s, the North American energy crises have made the Canadian oil sands a more strategic resource for North American interests, with accelerated industrial interest and development of these vast resources. With increasing price of crude oil and advances in technological developments, it is expected that the oil sands/heavy oil expansion trend will continue for years to come.

PRESSURE ON THE ELECTRICAL GRID AND 3RD QUARTER, 2006 URANIUM CONCENTRATE PRODUCTION

M.D. Campbell[11]

First quarter 2007 production of uranium concentrate in the United States was 1,162,737 pounds uranium oxide (U_3O_8). This quarterly production was 3% lower than the previous quarter, but increased 25% compared with the 1st quarter 2006 production. For 2006, the U.S. uranium concentrate production totaled 4.1 million pounds, 53% higher than the previous year, and is the highest production level since 1999 (Table 8). There was one producing U.S. mill and five U.S. in situ-leach plants at the end of March 2007, the same as at the end of 2006 (Tables 9–11 and Fig. 11).

[11]M.D. Campbell & Associates, L.P., Houston, TX 77019.

Table 9. Number of Uranium Mills and Plants Producing Uranium Concentrate

Uranium concentrate processing facilities	End of 1996	End of 1997	End of 1998	End of 1999	End of 2000	End of 2001	End of 2002	End of 2003	End of 2004	End of 2005	End of September 2006
Mills—conventional milling[a]	0	0	0	1	1	0	0	0	0	0	0
Mills—other operations[b]	2	3	2	2	2	1	1	0	0	1	1
In situ Leach Plants[c]	5	6	6	4	3	3	2	2	3	3	5
Byproduct recovery plants[d]	2	2	1	0	0	0	0	0	0	0	0
Total	9	11	9	7	6	4	3	2	3	4	6

[a]Milling uranium-bearing ore.
[b]Not milling ore, but producing uranium concentrate from other (non-ore) materials.
[c]Not including in situ leach plants that only produced uranium concentrate from restoration.
[d]Uranium concentrate as a byproduct from phosphate production.
Sources: Energy Information Administration: Form EIA-851A and Form EIA-851Q, "Domestic Uranium Production Report."

Table 10. U.S. Uranium Mills by Owner, Capacity, and Operating Status

			Operating status at end of			
Mill owner(s)	Mill name	Milling capacity[a] (short tons of ore per day)	2005	1st Quarter 2006	2nd Quarter 2006	3rd Quarter 2006
Cotter Corporation	Canon City	400	Operating		Standby	
Kennecott Uranium Co./ Wyoming Coal Resource Company	Sweetwater	3,000	Standby			
Plateau Resources Limited	Shootaring Canyon	1,000	Reclamation		Changing license to operational	Amend license to full operations
Rio Algom Mining LLC	Ambrosia Lake	–	Demolished			
White Mesa LLC	White Mesa	2,000	Operating–processing alternate feed			
Total Milling Capacity		6,400				

[a]Milling capacity based on most recent report.
– denotes not applicable.
Note: Operating status based on most recent report.
Sources: Energy Information Administration: Form EIA-851A and Form EIA-851Q, "Domestic Uranium Production Report."

Table 11. U.S. Uranium in situ Leach Plants by Owner, Capacity, and Operating Status

In situ Leach Plant Owner	In situ Leach Plant Name	Production Capacity[a] (pounds U_3O_8 per year)	Operating Status at End of			
			2005	1st Quarter 2006	2nd Quarter 2006	3rd Quarter 2006
COGEMA Mining, Inc.	Christensen Ranch	–	Reclamation			
COGEMA Mining, Inc.	Irigaray	–	Reclamation			
Crow Butte Resources, Inc.	Crow Butte	1,000,000	Operating			
Everest Exploration, Inc.	Hobson	1,000,000	Standby			
HRI, Inc.	Churchrock	1,000,000	Permitted and licensed			
HRI, Inc.	Crownpoint	1,000,000	Partially permitted and licensed			
Mestena Uranium LLC	Alta Mesa	1,000,000	Operational			
Power Resources, Inc.	Smith Ranch-Highland	5,500,000	Operating			
URI, Inc.	Kingsville Dome	800,000	Standby		Producing	
URI, Inc.	Rosita	1,000,000	Standby			
URI, Inc.	Vasquez	800,000	Producing			
Total Production Capacity:		13,100,000				

[a]Capacity based on most recent report.
– denotes not applicable.
Note: Operating status based on most recent report.
Sources: Energy Information Administration: Form EIA-851A and Form EIA-851Q, "Domestic Uranium Production Report."

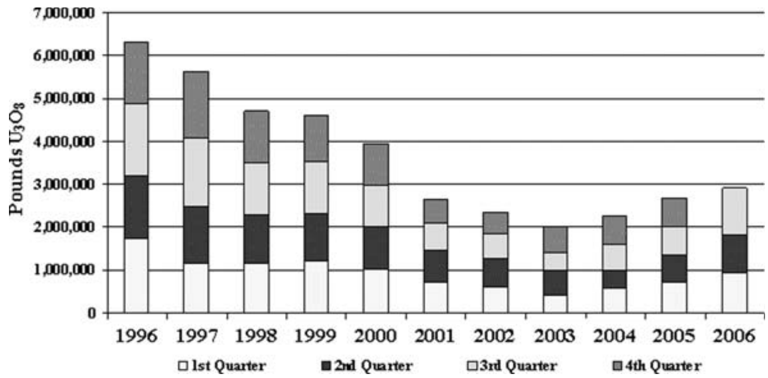

Figure 11. Uranium concentrate production in United States, 1996-3rd Quarter 2006. *Notes*: The 4th quarter 2002 production amount was estimated by rounding to the nearest 100,000 pounds to avoid disclosure of individual company data. This also affects the 2002 annual production. The 2003 and 1st, 2nd, and 4th quarter 2004 production amounts were estimated by rounding to the nearest 200,000 pounds to avoid disclosure of individual company data. *Sources*: Energy Information Administration: Form EIA-851A and Form EIA-851Q, ''Domestic Uranium Production Report.''

Although bullish through 2010, a few speculate that spot-market prices will begin to fall as uranium production exceeds consumption, to below $50 per pound U_3O_8 by 2013. However, these claims ignore a number of factors that would clearly support higher prices for a number of years well beyond 2020, such as:

- Many have concluded that based on apparent long-term market conditions, prices paid via short-term contracts with utilities will stabilize for as long as the Australian and Canadian high-grade, high-tonnage deposits can be produced at prices below those of American and Kazakhstan producers using in situ recovery (ISR) methods of yellowcake production.
- Based on the resurgence of nuclear power in the U.S. and around the world, especially in China and the expansion in the U.S., Japan, and elsewhere, the need for nuclear fuel will continue to rise well past 2020. This will drive exploration to meet production needs and the prices will reflect the free-market conditions existing between nuclear power utilities and the uranium producers well past 2020.
- Because many of the uranium exploration companies are funded by Canadian, American, and European public companies, their reported reserves may be inflated estimates of recoverable U_3O_8, which, if is a widespread condition, would combine to affect production figures and thereby keep demand and spot-prices high, i.e., above $90/pound U_3O_8 well past 2020.

Based on the three factors here, many conclude that any precipitous fall below $50/pound would seem to be without foundation. This is supported by *TradeTech* 6/2/07 increases of the long-term price to $95/pound and Cameco Corporations' 5/23/07 estimate of a long-term price of $85/pound. It should be recognized that the spot-market price is that price speculators use to evaluate stock-market conditions over short and long-term periods. This price usually is well above the prices paid by utilities to producers; the two price structures tend to converge when commodities become ''relatively scarce.'' Spot-market and utility-contract uranium prices are likely to converge in the range of between $80 and $100/pound well past 2020.

Uranium spot prices typically increase when:

- New nuclear plant construction projects are announced and when news spread that the plants have not arranged for fuel for their first 5 years of operation;
- News of global warming continues to grow more serious and convinces more to support accelerated construction of nuclear power plants worldwide;
- The accuracy of uranium reserve estimates by one or more public companies come under serious challenge; or

- New uranium deposits are not discovered or put into production at the rate anticipated to meet demand from utility companies.

Uranium spot prices typically fall when:

- A number of large uranium discoveries are announced in the world;
- A series of large-capacity mines come into production;
- Permitting or construction plans for new nuclear plants are slowed, because public support wanes;
- A major nuclear plant has a serious accident in the world somewhere; or
- After 2020, international fuel recycling comes on line, if then.

In summary, many see the need for nuclear power expansion is so strong that public concerns for climate change will trump all serious challenges to new nuclear power plant construction. Public concerns regarding nuclear-waste handling also will diminish as confidence returns regarding safety issues. Many now realize that minor industrial accidents are bound to occur in nuclear plants, as in oil & gas refineries, from time to time somewhere in the world but the public, this time, will place these incidents into the proper perspective of risk. Fluctuations are to be expected in the uranium market price (spot-market prices leading utility-contract prices), but at or above the $90/pound level for the foreseeable future past 2020.

Commodity price considerations have a dramatic impact on industry growth and associated employment opportunities. The uranium industry is likely to grow significantly over the next 20 years. There is a great need to fill in for the lost generation of uranium professionals who disappeared during the uranium industry slumber of the past 25 years. Only a few of those professionals remain.

For additional information on uranium and nuclear power and the environment, see: http://emd.aapg.org/members_only/uranium/index.cfm available to members of AAPG's Energy Minerals Division (EMD), and http://emd.aapg.org/technical_areas/uranium.cfm available to the general public.

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