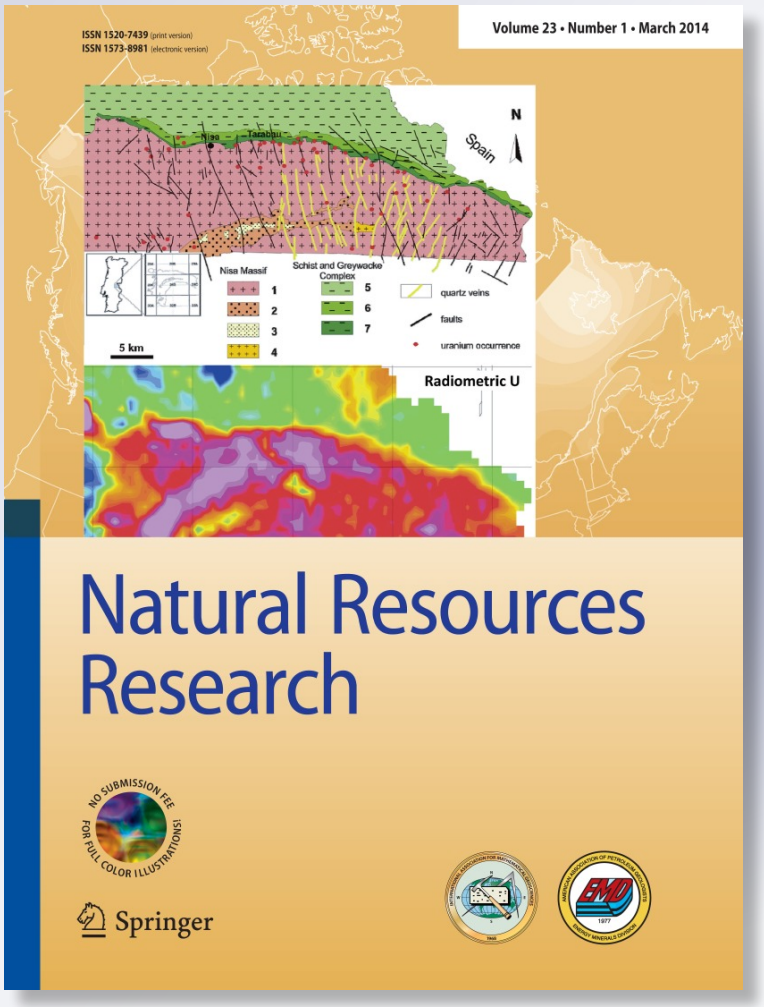
Unconventional Energy Resources: 2013 Review

American Association of Petroleum Geologists, Energy Minerals Division

Natural Resources Research
formerly `Nonrenewable Resources'

ISSN 1520-7439
Volume 23
Number 1

Nat Resour Res (2014) 23:19-98
DOI 10.1007/s11053-013-9224-6



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Natural Resources Research, Vol. 23, No. 1, March 2014 (© 2013)
DOI: 10.1007/s11053-013-9224-6

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American Association of Petroleum Geologists, Energy Minerals Division[1,2]

Received 23 July 2013; accepted 17 September 2013
Published online: 30 November 2013

This report contains nine unconventional energy resource commodity summaries and an analysis of energy economics prepared by committees of the Energy Minerals Division 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 U and Th resources and associated rare earth elements of industrial interest. Current U.S. and global research and development activities are summarized for each unconventional energy commodity in the topical sections of this report.

KEY WORDS: Coal, coalbed methane, gas hydrates, tight-gas sands, gas shale and shale oil, geothermal, oil sands, oil shale, U, Th, REEs, unconventional energy resources, energy economics.

INTRODUCTION

Peter D. Warwick,[3] **Paul C. Hackley**

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 2013 committee reports presented at the EMD Annual Meeting in Pittsburgh, Pennsylvania in April, 2013, 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. This report updates the 2006, 2009, and 2011 EMD unconventional energy review published in this journal (American Association of Petroleum Geologists, Energy Minerals Division 2007, 2009, 2011).

Reviews of research activities in the U.S., Canada, and other regions of the world, that are related to coal, coalbed methane, gas hydrates, tight-gas sands, gas shale and shale oil, geothermal resources, oil sands, oil shale, and U and Th resources and associated rare earth elements (REEs) of industrial interest, are included in this report. An analysis of energy economics is also included. Exploration and development of all unconventional resources has expanded in recent years and is summarized in this report. Please contact the individual authors for additional information about the topics covered in this report for each section. The following website provides more information about all unconventional resources and the EMD: http://emd.aapg.org.

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COAL

William A. Ambrose[4]

World Coal Production and Consumption

Coal continues to be a significant component of the world's energy production and consumption, with total world coal production slightly exceeding 8 billion short tons (bst), or ~7.2 billion metric tonnes in 2010 (U.S. Energy Information Administration 2011a). Coal has represented the world's largest source for electricity generation over the past century, and is second only to oil as the world's top energy source. More than 1,400,000 megawatts (MW), or >1,400 gigawatts (GW) of electricity could be supplied from the ~1,200 newly proposed coal-fired power plants worldwide (MIT Technology Review 2011).

China produced 45% of the world's coal in 2010, more than three times than the U.S., and more than the U.S., India, Australia, and Indonesia combined (Fig. 1). Relative ranking among the top coal-producing countries has been nearly consistent since 2000, with Indonesia having its coal production increasing by 368% from 2000 to 2010, thereby displacing Russia as the fifth largest producer. China's coal production has grown by 188%, whereas U.S. coal production has increased by only 1% from 2000 to 2010 (Fig. 2).

China also consumed 3.8 bst (3.45 billion metric tonnes) of coal in 2011, nearly half the world's total consumption (Sweet 2013). This increased consumption is partly driven by more than a threefold increase in electricity generation in China since 2000. Global demand for coal has grown by about 2.9 bst (2.6 billion metric tonnes) since 2000, with 82% of the total demand in China.

U.S. Coal Production and Consumption

U.S. coal production in 2011, spurred by a rise in exports, increased to ~1.1 bst (1.0 billion metric tonnes), up from 2010 levels (U.S. Energy Information Administration 2012a). Capacity utilization increased ~2.8 to ~79% at underground mines, whereas utilization at surface mines was unchanged at 83.3%. Although U.S. coal production for exports

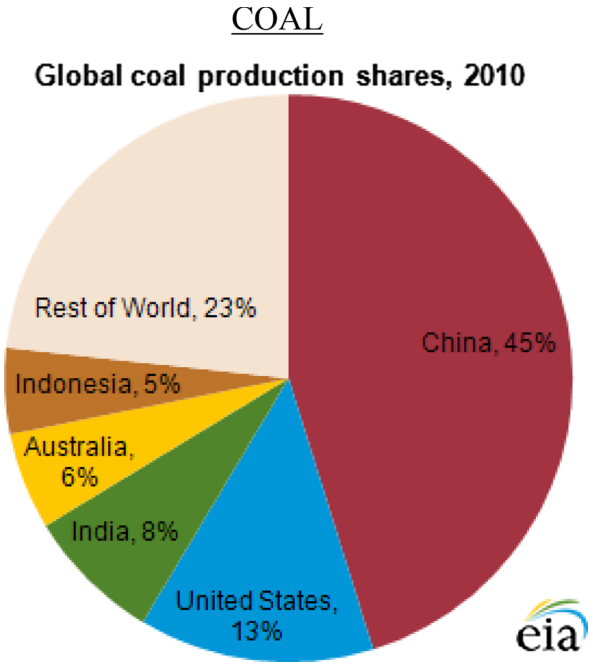

Figure 1. Relative world coal production in 2010 from China, the United States, India, Australia, Indonesia, and the rest of the world. From U.S. Energy Information Administration (2011a).

continues to be strong, the share of coal to the country's overall energy production is declining, mainly owing to expanded natural gas production (Humphries and Sherlock 2013). Lower demand for coal in U.S. markets is projected from a combination of factors that include increasingly strict federal regulations, lower natural gas prices, and coal plant retirements. Celebi et al. (2012) and Reuters (2012), based on data from NERC (2011), estimated that market conditions and environmental regulations will contribute to 59–77 GW of coal plant retirements by 2016 (Fig. 3). The greatest loss of coal-fired electricity generation is projected to be in the southeastern U.S., with 27–30 GW of plant retirements, followed by the northeastern U.S. (18–26 GW).

Coal production in the western U.S., dominated by Wyoming, was 587.6 million short tons (mst) (~529,000 metric tonnes) in 2011, representing a decrease of 0.7% from the previous year (U.S. Energy Information Administration 2012a). Factors causing this decrease in western U.S. coal production included limited access to foreign markets and flooding in Montana. Coal production in the Appalachian region, driven by exports of bituminous coal, increased by 0.2% to 336.0 mst (~302,000 metric tonnes). Texas, Illinois, and Indiana saw production increases of 12.0, 13.6, and 7.1%, respectively.

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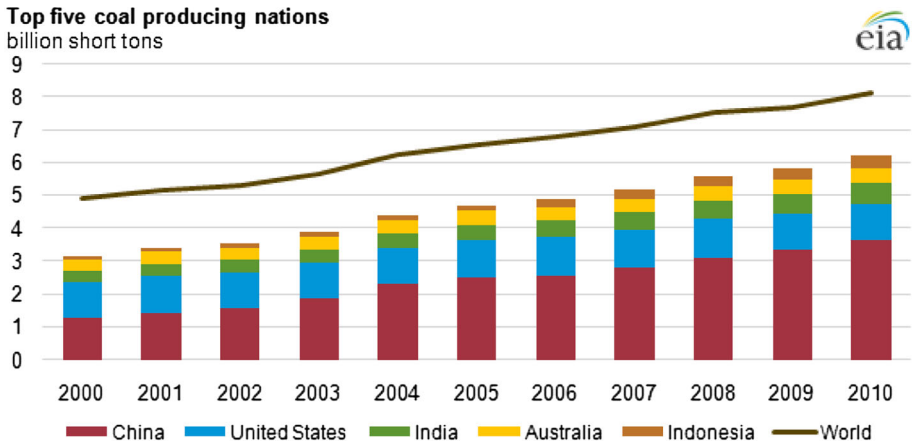

Figure 2. Chart displaying world coal production from the leading coal-producing countries and the rest of the world from 2000 to 2010. From U.S. Energy Information Administration (2011a). Billion short tons or 0.9 billion metric tonnes.

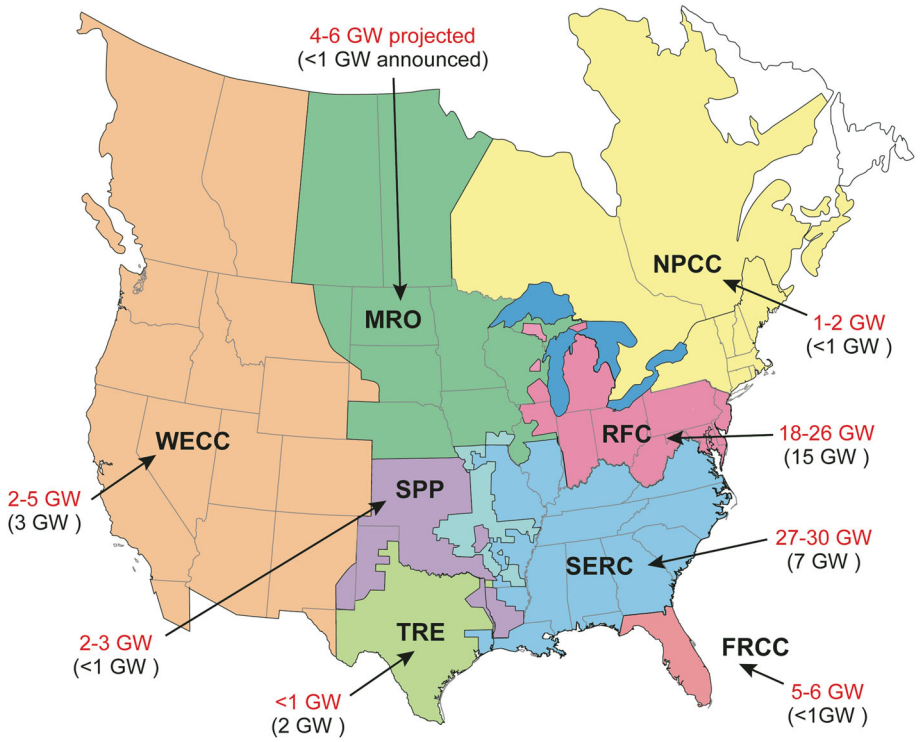

Figure 3. Announced and projected coal coal-fired power plant capacity retirements in the U.S. by North American Electric Reliability Corporation (NERC). From Celebi et al. (2012) and from data in NERC (2011). Abbreviations used are for Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool, RE (SPP), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC).

Export demands were responsible for increases in coal production in Illinois and Indiana, whereas increased production in Texas was also the result of demand from new domestic power plants.

U.S. Coal Regulatory Issues and Clean Coal

The U.S. Environmental Protection Agency (EPA) has issued greenhouse gas regulations that

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have impaired the construction of new coal-fired power plants in the U.S. that do not employ clean coal technology that involves carbon capture and storage (CCS). EPA is expected to also apply these regulations to existing power plants. However, coal will still account for up to 35% of U.S. electricity generation for another 30 years (U.S. Energy Information Administration 2011b). Currently, the U.S. maintains 316,000 MW of coal-fired generation, representing ~30% of the nation's total electricity generation fleet.

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_2 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_2 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) concluded that optimal sites for new clean coal facilities should be near the user electric load, owing to transmission losses exceeding costs of installing new CO_2 pipelines and fuel transport. However, economic incentives that support new clean coal facilities should also be considered, such as EOR (enhanced oil recovery) with generated CO_2 (Holtz et al. 2005; Advanced Resources International 2006; Ambrose et al. 2011, 2012).

Clean coal activity in North America is led by the Dakota Gasification Company where ~95 million cubic feet per day of CO_2, generated by gasification of North Dakota lignite, is transported via a 205-mile (328-km) pipeline to Weyburn oil field in Saskatchewan for EOR (Chandel and Williams 2009). Weyburn field has become the largest land-based CO_2 storage project in the world, having sequestered >12 million metric tonnes (Preston et al. 2009).

Texas has several examples of new and planned clean coal projects that illustrate how clean coal technology can be applied to EOR. Texas, which produced 45.9 mst (~41,300 metric tonnes) of coal and lignite in 2011 (U.S. Energy Information Administration 2012a), contains a wide variety of areas suitable for clean coal technologies. These areas are delineated by mapping spatial linkages between coal- and lignite-bearing formations, groundwater and surface water resources, and CO_2 sinks in brine formations for long-term CO_2 storage or in mature oil fields with EOR potential. Primary regions in Texas where favorably co-located CO_2 source–sink factors related to coal and lignite trends include the Gulf Coast, the Eastern Shelf of the Permian Basin, and the Fort Worth Basin. However, areas outside coal and lignite basins also have clean coal potential because of existing CO_2 pipelines and proximity to EOR fields that can economically sustain new clean coal facilities.

The Texas, Louisiana, Mississippi, and Alabama part of the Gulf Coast contains an additional 4.5 billion barrels (BBls; 715 million m^3) of oil that could be technically produced by using miscible CO_2 flooding (Holtz et al. 2005). For example, the Texas part of the Permian Basin has the potential for technical recovery of 5.6 BBls (890 million m^3) and economic recovery of ~0.7 BBls (111 million m^3) of oil from 127 reservoirs (Advanced Resources International 2006). Although the CO_2 pipeline infrastructure is well developed in the Permian Basin, the Texas Gulf Coast also has great potential for clean coal development, owing to co-located CO_2 sources and sinks such as mine-mouth electric power plants and abundant lignite resources, as well as CO_2 storage potential in EOR fields, deep, unmined low-rank coal seams (McVay et al. 2009), and thick brine formations.

Three clean coal projects and facilities are being developed in Texas, including (1) the NRG Parish Plant near Houston (NRG 2013), (2) the Tenaska Plant near Sweetwater (Tenaska 2013), and (3) the TCEP Summit Plant near Odessa (TCEP 2013). The NRG Parish Plant contains four main units, with up to 2,650 MW of coal-fired and 1,200 MW of gas-fired generation capacity. Its advanced burners can achieve 50–60% reductions in NO_x and it has a flue-gas slipstream that can capture 90% of the CO_2. Up to 1.65 metric tonnes (1.8 mst) of CO_2 will be sequestered annually. EOR opportunities exist in the Frio Formation (Oligocene) in nearby oil fields, including West Ranch field in Jackson County (Galloway and Cheng 1985; Galloway 1986).

The Tenaska Plant near Sweetwater, Texas is to be a 2,400-acre (970 ha) facility to be completed in 2014. The plant is designed for supercritical steam generation, using dry-cooling technology. It will have a 600 MW net capacity and coal will be supplied from the Powder River Basin. The plant will capture 85–90% CO_2 for EOR and additional production of 10 million BBls/year in the Permian Basin. Prominent nearby oil fields include the SACROC Unit (Scurry Area Canyon Reef Operators Committee), from which oil has been produced from miscible-CO_2 floods since 1971 (Brummett et al. 1976).

Operations for construction of the Summit Plant near Odessa, Texas are to begin in 2014–2015.

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The total project cost is projected to be ~$2.4 billion USD, with a $450 million contribution from the U.S. Department of Energy (DOE). The Summit Plant is designed as a 400 MW IGCC (integrated gasification combined cycle) plant with feedstock from the Powder River Basin. The plant will capture up to 90% of the CO_2, representing 3 metric tonnes (3.3 mst) per year for Permian Basin EOR.

Other uses of coal and associated carbon materials are discussed by Campbell in this Review, in context with the nuclear power industry and the emerging carbon industry.

COALBED METHANE

Jack C. Pashin[5]

EMD Activities

The 2012 AAPG Annual Convention and Exposition in Long Beach featured presentations on environmental impacts, coal seam CO_2 storage, and seismic characterization of coalbed methane (CBM) reservoirs. The 2013 program in Pittsburgh featured an oral presentation on produced water and poster presentations covering topics from resource evaluation to stable isotopes in CBM reservoirs.

One goal of the EMD Coalbed Methane Committee is to monitor international CBM activities more closely. Sources of international production and reserves data are being examined and are important for characterizing expansion of the CBM industry in Australia and Asia. The chairmanship of the Coalbed Methane Committee remains open, and the search for a new chair continues.

Industry Activity, Production, and Reserves

The U.S. remains the world leader in CBM 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. However, activity has slowed substantially in response to low gas prices. The major producing areas are the Powder River, San Juan, Black Warrior, Central Appalachian, Raton, 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. Development continues in all major U.S. basins, and the principal environmental issue confronting the industry is water disposal. Production operations are maturing, and the U.S. DOE has sponsored a series of studies on produced water management and CO_2-enhanced coalbed methane recovery. Of major interest is a new pilot program that is being led by Virginia Tech in the Appalachian Basin of Virginia, which is scheduled to begin injection of up to 20,000 short tons (18,144 metric tonnes) of CO_2 into multiple coal seams to determine the viability of enhanced recovery and geologic storage.

The U.S. Energy Information Administration (EIA) has released CBM production and reserve numbers through the end of 2010. CBM production in 2010 was 1,886 billion cubic feet (Bcf) (53.4 billion m^3), decreasing by 1.5% from 2009 (Fig. 4; Table 1) (U.S. Energy Information Administration 2012c). Booked reserves decreased from 18,578 Bcf (526 billion m^3) in 2009 to 17,508 Bcf (496 billion m^3) in 2010 representing a decrease of 1,070 Bcf (30 billion m^3) (5.7%) (Fig. 5; Table 2). CBM represented 8.5% of 2010 dry gas production and 5.7% of proved dry gas reserves in the U.S. Interestingly, CBM production is declining only slightly as a proportion of U.S. gas production but is declining significantly in terms of proved dry gas reserves. This decline is related to the booking of major shale gas reserves, which is significantly changing U.S. gas markets (Fig. 6).

Most CBM 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 coalmine methane (CMM) projects. In southwestern Virginia, production has decreased substantially from 111 Bcf (3.1 billion m^3) in 2009 to 97 Bcf (2.7 billion m^3) in 2010 (Table 1). West Virginia production declined from 31 to 17 Bcf (0.9 to 0.5 billion m^3) over the same time period. Pennsylvania production decreased from 16 to 3 Bcf. In Alabama, production decline was less pronounced, with 105 Bcf (2.97 billion m^3) being produced in 2009 and 102 Bcf (2.89 billion m^3) being produced in 2010.

The Midcontinent region consists of the Cherokee, Forest City, Arkoma, and Illinois Basins. Horizontal drilling has been an effective development strategy, although major increases of production in recent years are now being offset by slowed development. Kansas production decreased modestly from 43 Bcf (1.21 billion m^3) in 2009 to 41 Bcf (1.16 billion m^3) in 2010,

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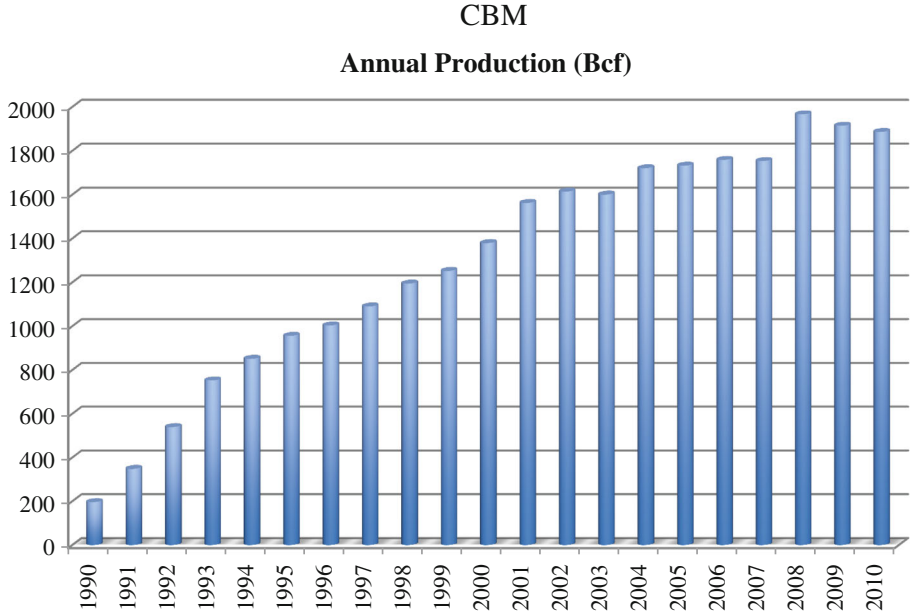

Figure 4. Historic U.S. CBM production 1990–2010. Data from the U.S. Energy Information Administration (2012c). 1 Billion cubic feet (Bcf) = 28.3 million m^3.

Table 1. Historic U.S. CBM Production by Year (1989–2010; Billion cubic feet, Bcf)

Year	US	AL	CO	NM	OK	UT	VA	WV	WY	Others
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
2010	1886	102	533	402	45	66	97	17	566	58

Data from the U.S. Energy Information Administration (2012c). 1 Billion cubic feet = 28.3 million m^3.

whereas Oklahoma decreased from 55 Bcf (1.56 billion m^3) in 2009 to 45 Bcf (1.27 billion m^3) in 2010, continuing a steep decline trend that began in 2007. The principal issue affecting CBM development in the eastern and midcontinental U.S. is competition with shale gas, which has introduced significant price pressure. Although production operations persist, few wells are being drilled, and reserves are not being replaced.

Infill drilling of Fruitland CBM wells in the San Juan Basin (Colorado and New Mexico) decreased markedly in 2009 due to recession, but activity is starting to accelerate. Colorado and New Mexico continue to

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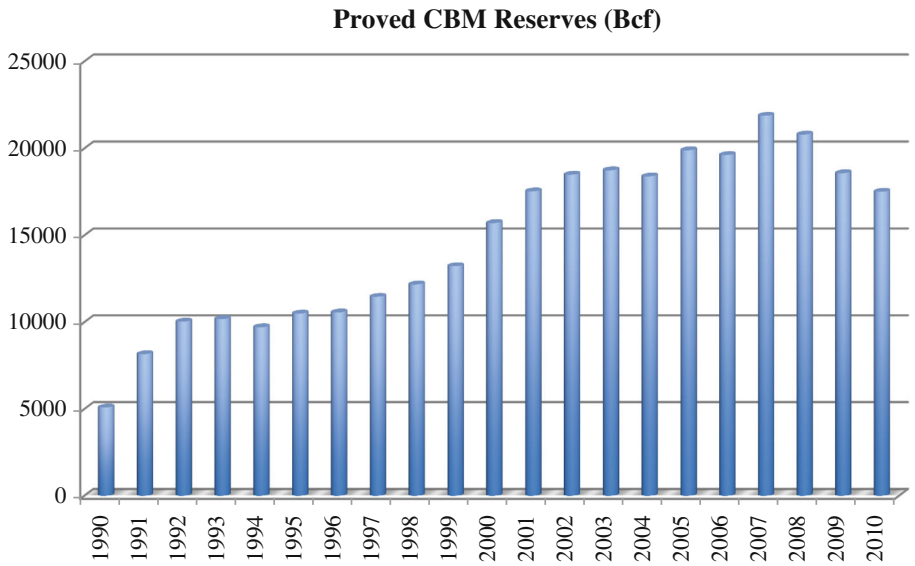

Figure 5. Historic U.S. CBM reserve trends from 1990 to 2010. Data from U.S. Energy Information Administration (2012c). 1 Billion cubic feet (Bcf) = 28.3 million m^3.

Table 2. Historic U.S. CBM Proven Reserves by Year (1989–2010; Billion cubic feet, Bcf)

Year	US	AL	CO	NM	OK	UT	VA	WV	WY	Others
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
2010	17508	1298	6485	3532	325	718	1752	220	2683	495

Data from the U.S. Energy Information Administration (2012c). 1 Billion cubic feet = 28.3 million m^3.

dominate CBM production and reserves (Tables 1, 2). Cumulative production for Colorado and New Mexico represents 50% of total U.S. CBM production. In 2010, CBM production in Colorado increased from 498 to 533 Bcf (14.1 to 15.1 billion m^3), and production in New Mexico declined slightly from 432 to 402 Bcf (12.2 to 11.4 billion m^3). Also, activity is rebounding in the Powder River Basin of Wyoming, and production increased in 2010 from 535 to 566 Bcf (15.1 to 16 billion m^3), accounting for 30% of U.S. CBM production.

International activity has been on the rise, and operations in the Qinshui Basin of China remain

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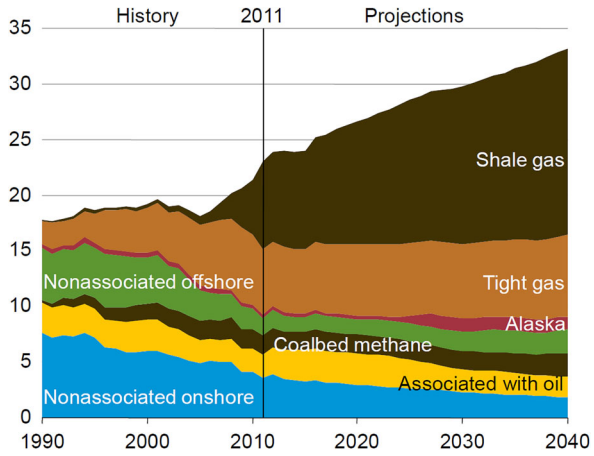

Figure 6. Sources of U.S. Natural gas production (trillion cubic feet) showing projected steady coalbed methane supply concurrent with major increase of shale gas supply. Note that shale gas production becomes significant by 2010, and is projected to dominate by 2040 (Source: U.S. Energy Information Administration, 2012b). 1 Trillion cubic feet (Tcf) = 28.3 billion m^3.

active, thus proving the CBM potential of intensely fractured semi-anthracite and anthracite. As in the U.S., depressed natural gas prices are slowing Canadian development. Development is intensifying in the Bowen, Surat, and Sydney Basins of Australia, as well as the Karoo Basin of South Africa. CBM in eastern Australia is being produced from high-permeability coal seams that can contain large quantities of oil-prone organic matter, and the 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. Hence, companies are striving to book reserves to support the expenditure for LNG plant development as quickly as possible. Significant potential exists in the Gondwanan coal basins of India, and some fields have been developed.

Potential also exists in the coal basins of Europe and the Russian platform, and development in these areas is focusing mainly on CMM. Exploration programs have been initiated in recent years to explore for CBM in the structurally complex European coal basins of western Europe, including Germany. Russia continues 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. Once a market for this gas is identified, then CBM exploration in Russia should increase significantly.

GAS HYDRATE

Art H. Johnson[6]

Japanese Gas Hydrate Production Test

On March 12, 2013 the Japanese Ministry of Economy, Trade and Industry announced the commencement of the first offshore gas hydrate production test. The test was conducted in the Nankai Area off the coasts of Atsumi and Shima peninsulas in water depths of approximately 1,000 m (3280.8 ft).

Production was initiated through depressurization of hydrate-bearing turbidite sands located 300 m (984.3 ft) beneath the seafloor. Sustained natural gas production was established with a drillstem test at a rate of 0.7 million cubic feet per day (MMcfd; 19.8 thousand m^3/day). The test continued until March 18, 2013, at which point there was both a malfunction of the pump used for depressurization and a simultaneous increase in sand production. A total of 4 million cubic feet (113 thousand m^3) of gas was recovered in total, an amount higher than had been predicted. Initial analysis of the test indicates that the dissociation front reached the monitoring wells located 20 m (65.6 ft) from the test well.

Abandonment of the site will be completed by August 31, 2013. The brief test was not designed to yield commercial production rates; however, the results will be used to implement the next phase of the MH21 program, which will include commercial development. That phase is scheduled for fiscal years 2016–2018.

The Nankai test was conducted with the deep sea drillship ''Chikyu.'' The produced gas was either vented or flared, depending on flow rates and weather conditions. In preparation for the production test, a part of the production well (AT1-P) and two temperature-monitoring boreholes (AT1-MC/MT1) were drilled in February and March, 2012. During drilling operations, intensive geophysical logging was conducted. In addition, a dedicated borehole in the same area was drilled to recover pressure cores. This was undertaken to obtain detailed data regarding the geology, geomechanics, geochemistry, microbiology, and petrophysics of the hydrate-bearing sediments.

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United States Gas Hydrate Program

The U.S. DOE's Methane Hydrate Program continues to pursue several important areas of gas hydrate research and characterization despite severe budget constraints. The selected projects are designed to increase the understanding of gas hydrates in the context of future energy supply and changing climates. U.S. Geological Survey (USGS) personnel continue their involvement in resource evaluation, including consultation with assessment programs being conducted outside of the U.S.

Ignik Sikumi Gas Hydrate Exchange Trial

The results of the Ignik Sikumi Gas Hydrate Exchange Trial were released in late 2012, including a presentation at the Arctic Technology Conference. The test was carried out from February 15 to April 10, 2012 in Prudhoe Bay Field, Alaska. The project team injected a mixture of carbon dioxide (CO_2) and nitrogen into hydrate-bearing sand, and demonstrated that this mixture could promote the production of natural gas. This test was the first ever field trial of a methane hydrate production methodology whereby CO_2 was exchanged in situ with the methane molecules resulting in methane gas and CO_2 hydrate.

After measurement and compositional analysis, gas from the Ignik Sikumi test was flared. During the test, 210 thousand cubic feet (5.9 thousand m^3) of a N_2/CO_2 gas mixture was pumped into the methane hydrate-bearing formation. The injected gas was 23% N_2 and 77% CO_2. The recovered gas was 2% CO_2, 16% N_2, and 82% CH_4, demonstrating that significant exchange had taken place within the reservoir of carbon dioxide for methane. Although not a technology for near-term production of methane from hydrate deposits, the test provides a path for carbon sequestration in the future. All data developed in the test were released in March, 2013. The Prudhoe Bay production test, delayed by a number of issues, remains under review by the partners. The Gulf of Mexico Joint Industry Project (JIP) has concluded. The pressure core system and laboratory equipment developed for the JIP was used for the Japanese program.

Gas Hydrate in India

A planned LWD (logging-while-drilling) drilling program is under review for offshore India in 2014, with site selection finalized in April, 2013. This program is focused on reservoir delineation and resource assessment, and is targeting hydrate-bearing sands. Two legs are planned, with the first dedicated to LWD logging. The previous gas hydrate field program (2006) targeted seismic BSRs (bottom simulating reflectors) and recovered significant amounts of gas hydrate, but in fine-grained sediments having low permeability.

Gas Hydrate in China

China commenced exploratory gas hydrate drilling and coring in Spring, 2013. Results and other details of the program have not yet been released.

Gas Hydrate in South Korea

After two successful drilling programs (2006 and 2010), South Korea is planning a gas hydrate production test for 2014.

TIGHT-GAS SANDS

Fran Hein[7] and Dean Rokosh[8]

Tight gas is in low-permeability (mD to μD)/low-porosity reservoirs, and gas cannot be extracted economically without expending much technological effort (i.e., fracturing and/or acidizing) (King 2012). Most tight-gas sand production/exploration activities take place in North America, China, Australia, Poland, and the Ukraine (Jenkins 2010, 2011; Hein and Jenkins 2011; and Hart's Unconventional Gas Center, www.ugcenter.com). The following play descriptions show the variability of tight-gas sands.

The United States

1. The Dew–Mimms Creek Field, East Texas Basin (Fig. 7), hosted by the Bossier Formation, yields ~1% of East Texas gas

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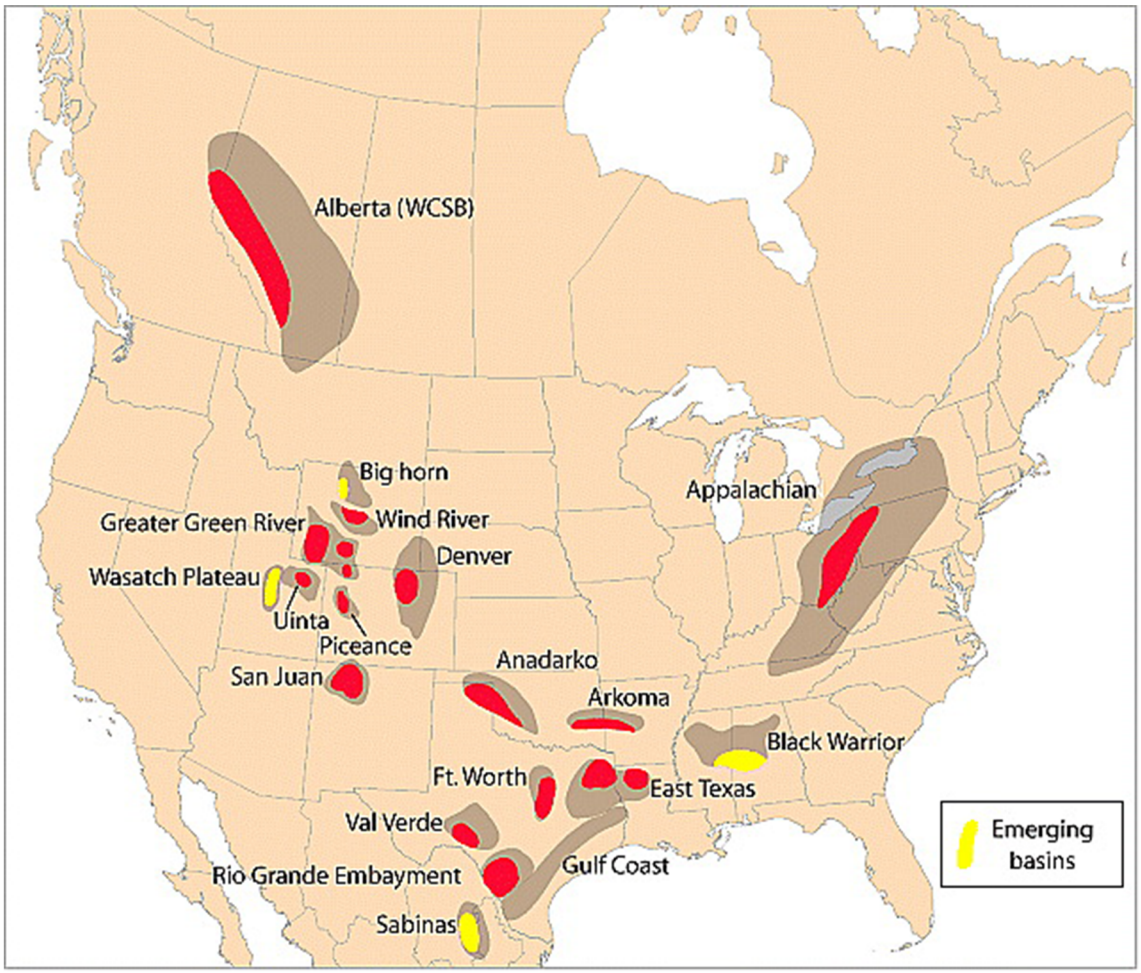

Figure 7. Basins in North America with long-term tight-gas sandstone production (red) and more prospective areas (yellow). Tight-gas sandstone plays discussed are in the East Texas, Green River, Piceance basins of the U.S.A. and the Western Canada Sedimentary Basin (WCSB) of Alberta, Canada. Modified from Meckel and Thomasson (2008).

production. During early Bossier time, small alluvial fan-deltas developed along NW ancestral Gulf of Mexico, resulting in highly lenticular reservoirs, with little connectivity. Commingled production from multiple sandstones in each wellbore facilitates recovery from marginal sandstones that would otherwise not be produced. This has resulted in field consolidations, with commingling of the Cotton Valley Sand, the Bossier Sand, and the deeper Cotton Valley limestone. Estimated ultimate recoveries (EURs) per well range from 28.3 to 113.2 million m^3 (1,000–3,998 million cubic feet, MMcf).

2. The Jonah Field, Green River Basin (Fig. 7), has large net-pay thickness of low-permeability sandstones over a very large area, with conventional trapping mechanisms. Primary production is from basin-centered accumulations (Fig. 8) of the fluvial Lance Formation. The field has converging faults along flanks of a major anticline, with updip trapping against boundary faults. Tight-gas production is from a zone where permeability is enhanced due to faulting. In the Jonah

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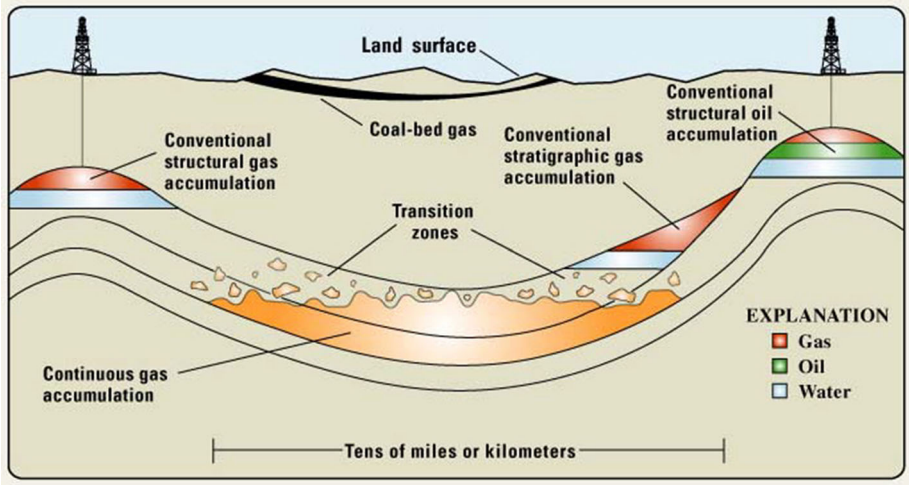

Figure 8. Schematic diagram of the different types of onshore natural gas plays. Conventional resources are buoyancy-driven hydrocarbon accumulations, with secondary migration and structural and/or stratigraphic closures. Unconventional, continuous gas accumulations, in basin centers and transition zones, are controlled by expulsion-driven secondary migration and capillary seal (from U.S. Departments of the Interior, Agriculture, and Energy 2008, p. 46).

field there are currently 1,876 gas wells, 73 dry holes (or suspended), and 112 permitted locations or actively/completing wells. Cumulative production reported to date for 1,818 wells are: 3,860 billion cubic feet (Bcf; 109 billion m^3) gas, 36.4 million barrels (MMBBLs; 5.8 million m^3) oil, 39.6 MMBBLs (5.8 million m^3) water, and water to gas ratio (WGR) 10.3 BBLs/MMcf.

3. The Mamm Creek Field, Piceance Basin (Fig. 7), ~20% of gas production in the Piceance Basin (Fig. 7), has most of its production from tight basin-centered accumulations (Fig. 8) of the fluvial Williams Fork Formation. The complexity of this fluvial-marginal marine system resulted in very heterogeneous connectivity between reservoirs. In the Mamm Creek field there are currently 2,649 gas wells, 42 dry or suspended, and 463 permitted locations or actively/completing wells. Cumulative production reported to date for 3,780 wells are: 1,222 Bcf (34.6 billion m^3) gas, 10.5 MMBBLs (1.7 million m^3) oil, 69.9 MMBBLs (11.1 million m^3) water, and WGR 57.2 BBLs/MMcf.
4. Wamsutter Development Area, greater Green River Basin (Fig. 7) has ~1.42 trillion m^3 (50.1 trillion cf) of original gas in place (OGIP). Unconventional reservoirs are in the Almond Formation. The main producer is the Upper Almond—an amalgamated shoreface deposit, with tidal channels. The greater Wamsutter area consists of >15 federal units and companies define the area differently. Taking the deep basin gas as "Wamsutter," there are currently >4,000 wells in the area, consisting of >3,600 gas wells, ~100 dry or suspended, and 365 permitted locations or actively/completing wells. Cumulative production reported to date for 3,730 wells are: 3,385 Bcf (95.8 billion m^3) gas, 52.7 MMBBLs (8.4 million m^3) oil, 53.6 MMBBLs (8.5 million m^3) water, and WGR 15.8 BBLs/MMcf.

Canada

In Alberta (Fig. 7) recent advances in drilling/completion technologies have opened up unconventional, low-permeability zones for economic production. At present, most of the wells being drilled in Alberta are horizontal (Fig. 9), focused on the Cardium and Montney formations, with <10% on other tight-gas plays (i.e., Nikanassin, Fig. 10).

5. The Cardium Formation, Alberta, Canada (Fig. 7), with >10 billion barrels (1.6

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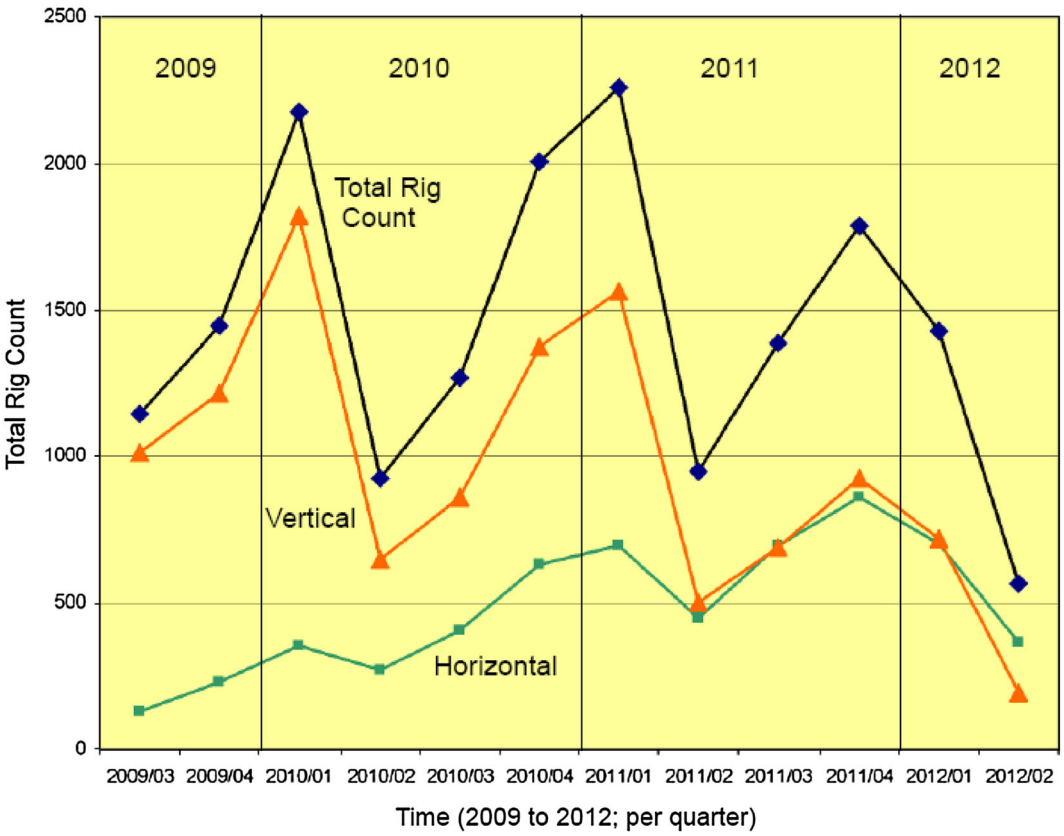

Figure 9. Drilling statistics related to total rig count, number of vertical and horizontal wells completed on a quarterly basis from 2009 to 2012 in the Alberta portion of the Western Canada Sedimentary Basin (Alberta Energy Regulator 2013, http://www.aer.ca/).

billion m^3) of oil-in-place, has had only ~17% of its hydrocarbons recovered using conventional technologies. Cardium conventional reservoirs are incised estuarine valley-fills, progradational shorefaces, or transgressive sheets. Surrounding these conventional reservoirs are "halos" of the largely tight (permeabilities < 0.5 mD), thin-bedded, mixed lithologies of very fine sandstone to shale. This example is one in which there is a clear continuum of fluids, reservoir, and development strategies between the older (but now renewed) conventional fields, and the emerging fringe tight-gas and liquids-rich gas accumulations in the distal edges of the conventional fields.

6. The Nikanassin Formation, British Columbia and Alberta, Canada (Fig. 7) has thinner (5–15 m) fluvial channel and thicker (>50–500 m; >164–1,640 ft) incised-valley-fill reservoir sandstones, with porosities of 6–10%, and permeabilities of 0.01–1 μD. Reservoir sandstones are quartz-rich, highly cemented, brittle, and, where productive, extensively fractured. The Nikanassin is a structural play where thrust-belt tectonics has fractured the brittle sandstones to enhance porosity/permeability. Gas was generated in the associated coals with regional conventional trapping. Nikanassin development fairways are along the leading edges of the NW–SE—trending thrust faults. Early returns show production up to 3.2 Bcf (90,000,000 m^3) per well (Oil and Gas Inquirer 2012).
7. The Montney Formation, British Columbia and Alberta, Canada (Fig. 7), commonly called a "shale gas," is a thin-bedded succession of mixed-bed lithologies, including siltstone and very fine sandstone that overlies organic-rich shale. Since 2003, the upper and lower Montney tight-gas sandstones/siltstones have been developed using

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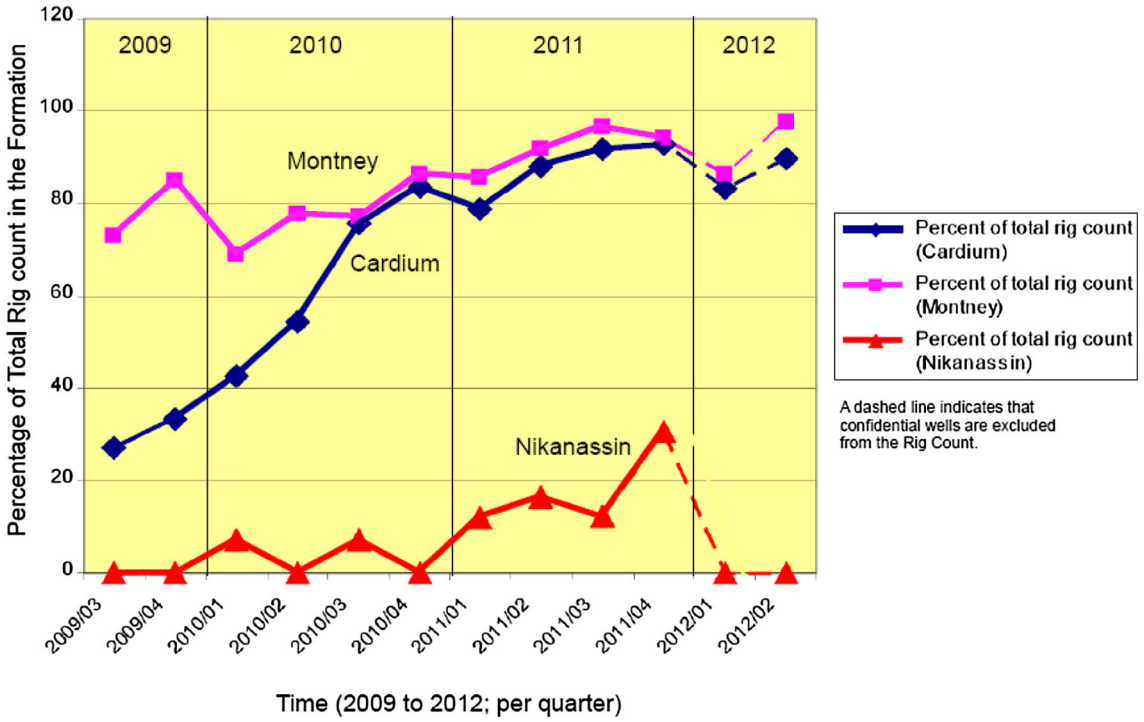

Figure 10. Drilling statistics for non-confidential wells related to total rig count, for the Montney, Cardium, and Nikanassin, completed on a quarterly basis from 2009 to 2012 in the Alberta portion of the Western Canada Sedimentary Basin (Alberta Energy Regulator 2013, http://www.aer.ca/).

multi-stage hydraulically fractured horizontal wells. The upper and lower Montney is stacked distal shoreface/delta fringe, shelf sandstone/siltstone, and turbidites with gross thicknesses to 156 m (512 ft) in the lower Montney of British Columbia and about 250 m thick in the upper Montney of Alberta; porosities typically <3–10%, with <mD permeabilities. Most recent drilling in the Montney has focused on liquid-rich gas or oil-prone areas.

China

8. The Shuixigou Group, Hami Basin, China (Fig. 11) consists of three stacked successions of tight-gas sandstones from lacustrine-braided delta-front settings, with thick associated coals (Feng et al. 2011). Reservoirs have porosity of 4–8.4% and permeability of 0.077–3.61 mD; individual reservoirs range from 18 to 55 m (59 to 180 ft) net thickness, with a gross thickness of 105–280 m (344–919 ft). Gas traps are combined stratigraphic-structural traps. The most favorable production is from faulted anticlines with high densities of fractures and thick (20–30 m; 65–98 ft) top coal measures. In China, other tight-gas sandstones, with proved reserves >3,000 billion m^3 (105.9 trillion cf), are widely distributed and are undergoing extensive exploration and development (Fig. 11; Table 3).

There is a ''blending'' of the conventional versus unconventional resources in these technology-driven plays. The more ''distal'' unconventional tight-gas sands (''hybrid shales'') have high sandy silt/siltstone content, relatively low clay content, but with self-sourced organics. These include halos around conventional fields and basin-centered accumulations. As technology continues to evolve there will be a continuum from fringe conventional plays to tight-gas sandstones/siltstones, and the present distinctions between these commodities will become less clear.

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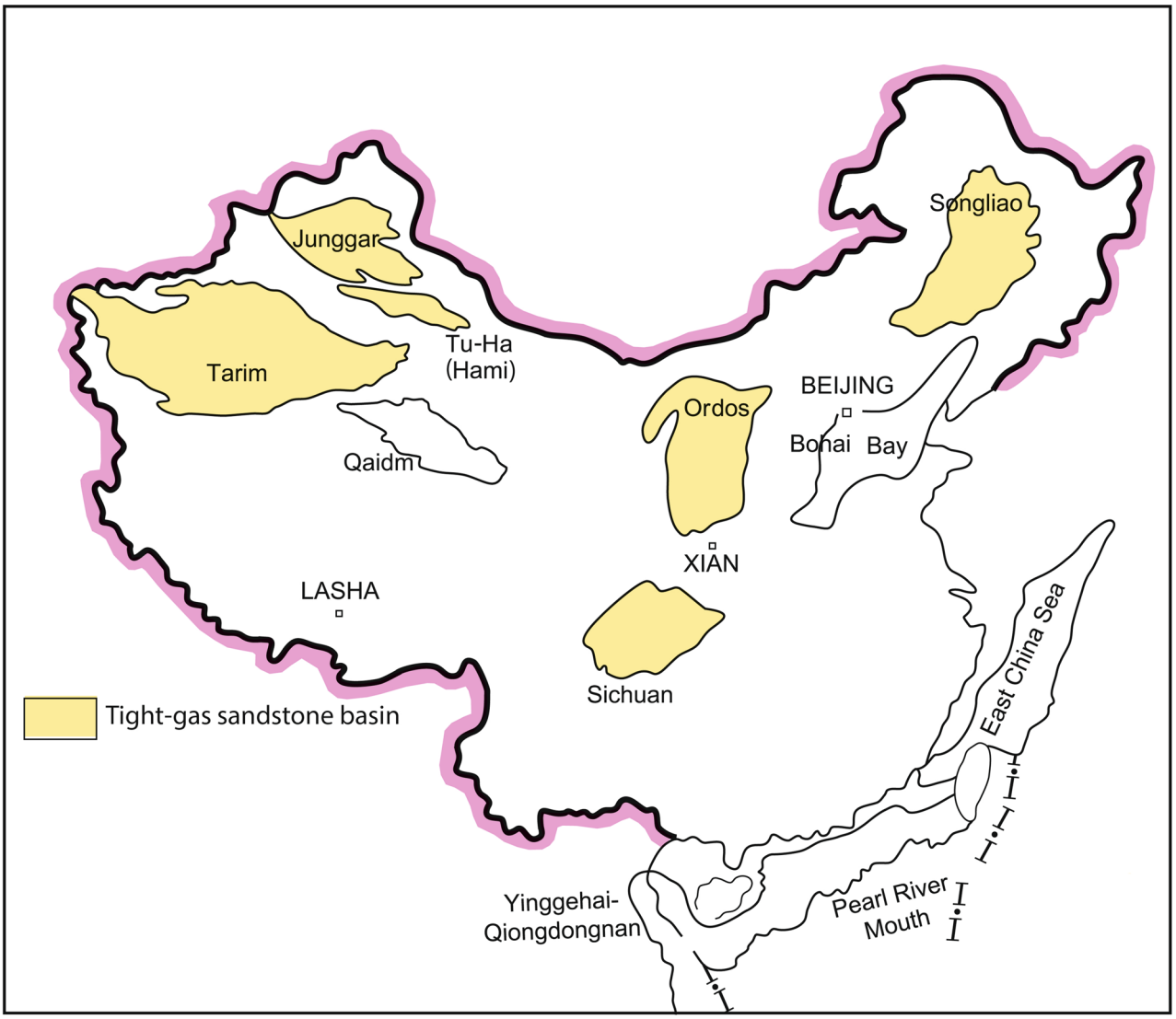

Figure 11. Location of China's major tight-gas sandstone deposits (Guang-Ming 1986; Ma 2009; Carroll et al. 2010). Modified from Zhao et al. (2008).

GAS SHALE AND LIQUIDS

Gas Shale and Liquids Committee of the Energy Mineral Division

Worldwide, organic-rich "shales,"[9] whether siliciclastic- or carbonate-dominated, are increasingly targets for exploration and production of oil, condensate, and natural gas. These organic-rich rocks were always considered an important component of petroleum systems insofar as they were the organic-rich source rocks from which petroleum was generated. However, in addition to being the source rocks for conventional reservoirs, sufficient hydrocarbons remained locked in the organic-rich mudrocks such that they are now the focus of exploration and production as "unconventional" reservoirs. Although there is an international interest in exploiting hydrocarbons from these unconventional reservoirs, with active exploration projects on most continents (U.S. Energy Information Administration 2013d), much of the successful exploitations from mudrocks continue to be in North America, particularly in the U.S. but increasingly so in Canada (Fig. 12). Hydrocarbons are

[9]The term "shale" is herein also referred to as a mudrock. Mudrock is defined as a rock in which a majority of detrital grains in it are less than 62.5 micrometers in diameter.

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Table 3. Characteristics of main tight-gas sandstone reservoirs in China (Yukai et al. 2011)

Basin	Depth (m)	Amount of Resources (trillion m^3)
Ordos basin	2500–4500	8.4
Sichuan basin	1500–4500	3.5
Faulted depression beneath the Songlaio basin	1500–6000	Not estimated
Southern deep layer in the Junggar basin	4000–7000	Not estimated

1 m = 3.28 ft; 1 Trillion m^3 = 35.31 Trillion cubic feet.

produced from unconventional shale reservoirs that range in age from Ordovician to Tertiary.

Interestingly, natural gas has been produced from shales in the U.S. for more than 200 years. The first documented production of natural gas from shales was that from Devonian rocks in New York in 1821 (Hill et al. 2008), and the gas was used to light street lamps in at least one town (Roen 1993). Although this early production proved that gas could be successfully exploited from shales, shale gas production remained low and even in 1990, gas from shales accounted for less than 1% of all the natural gas produced in the U.S. (based on production figures from U.S. Energy Information Administration 2013a). Nevertheless, by 2010, approximately 23% of gas produced in the U.S. was from shales (U.S. Energy Information Administration 2013a) and current projections are that by 2040, about 50% of domestic gas production will be from shales (Fig. 6).

Examples of how shales have contributed to overall increases in production in some states can be seen in Figure 13. For example, in Texas, exploitation from the Mississippian Barnett Shale resulted in the statewide increase in gas production starting in 2004, although Barnett production started more than 10 years earlier. In addition, the statewide increase observed in 2011 for Texas is due to exploitation from the Cretaceous Eagle Ford Formation as well as the Jurassic Haynesville Shale (U.S. Energy Information Administration 2012d). The Haynesville is also responsible for the statewide increase in gas production in Louisiana, whereas production from the Mississippian Fayetteville Shale (Fig. 13) resulted in the statewide increase for Arkansas. The Devonian Marcellus Shale is responsible for increase in gas production in Pennsylvania and West Virginia. Shale gas development, although in its infancy, is also underway from the Devonian Horn River Formation and the Triassic Montney Formation in western Canada (*Jock McCracken, Egret Consulting, written communication, 2013*).

Production of oil from mudrocks—commonly referred to as *"tight oil"*—is also occurring in the U.S. and the increase in domestic exploitation has contributed to the observed reversal in oil production after a general decline over the last 20 years (U.S. Energy Information Administration 2012d). The increase in production of tight oil is most apparent in North Dakota, due to exploitation of the Late Devonian-Early Mississippian Bakken Formation; oil and condensate production from the Eagle Ford Formation in Texas (Fig. 14) also has contributed significantly to an overall increase in domestic production in the U.S. The Bakken Formation in Manitoba and Saskatchewan is also producing oil (*Jock McCracken, Egret Consulting, written communication, 2013*). Oil produced from the Late Devonian-Early Mississippian Woodford Shale has helped to keep production level from Oklahoma over the past decade (Fig. 14).

Although there is active exploration elsewhere in the world for unconventional gas and oil, successful exploitation is limited. Overall, Europe remains relatively unexplored as compared to North America, with Paleozoic and Mesozoic organic-rich rocks as potential exploration targets. Nevertheless, recent decisions to scale back exploration efforts have made it difficult to evaluate what the future holds for European shale gas and oil exploitation (*Ken Chew, Independent Analyst, written communication, 2013*). As with Europe, many parts of Asia remain relatively unexplored for unconventional shale gas and oil, but interest in these plays is certainly high. Australia, China, New Zealand, India, and Japan have all experienced interest in exploration for shale gas and oil (*Shu Jiang, University of Utah, Energy Geosciences Institute, and Jeff Aldridge, Dart Energy, Ltd., Singapore, written communication, 2013*). Mesozoic organic-rich rocks in South America also have potential as unconventional shale gas and oil reservoirs, but exploration and exploitation of these reservoirs is not as mature as that in North America.

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GAS SHALE AND LIQUIDS

Figure 12. Locations of shale plays in North America. (U.S. Energy Information Administration, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm#shaleplay, accessed July 17, 2013).

The Shale Gas and Liquids Committee of the EMD of the AAPG continues to monitor exploration activities related to shale gas and oil that are occurring throughout the World. Two reports a year are produced by members of the committee, with emphasis on individual shales in North America, but sections of these reports are also devoted to exploration activities in Europe, China, and elsewhere in Asia. The complete set of committee reports is available to AAPG members at http://emd.aapg.org/members_only/annual2011/index.cfm. As interest in unconventional shale resources continues to increase, it is expected that the committee reports will expand to incorporate information to keep AAPG members abreast of the ever-changing environment of unconventional shale gas and oil.

GEOTHERMAL

Richard J. Erdlac, Jr.[10]

Introduction

The focus of this review presents highlights of two significant geothermal scientific conferences that were held in 2012 and 2013. The two conferences are the Geothermal Resources Council Annual Meeting, held in Reno, Nevada, September 30 to October 3, 2012, and the Southern Methodist University (SMU) Geothermal Conference, held March 13–14,

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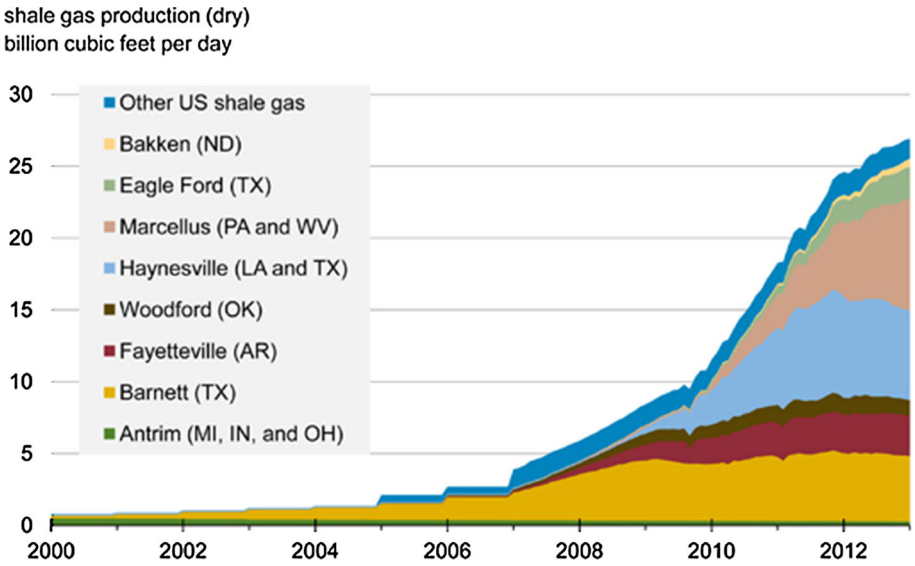

Figure 13. Shale gas production for various shales in the U.S. from 2000 to the present. *ND* North Dakota, *TX* Texas, *PA* Pennsylvania, *WV* West Virginia, *LA* Louisiana, *OK* Oklahoma, *AR* Arkansas, *MI* Michigan, *IN* Indiana, *OH* Ohio. (U.S. Energy Information Administration, http://www.eia.gov/energy_in_brief/article/about_shale_gas.cfm, accessed 7/17/2013.) 1 billion cubic feet = 28.3 million m^3.

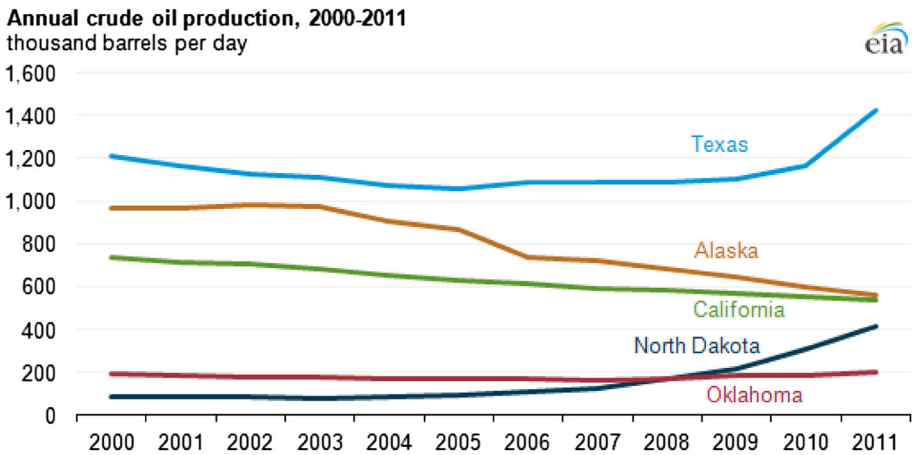

Figure 14. Shale oil production for various states in the United States for the time period 2000–2011. The increase in production in Texas in 2011 is due to exploitation of the Eagle Ford Formation. The increase in oil production in North Dakota since 2005 is largely due to exploitation of the Bakken Formation. (U.S. Energy Information Administration, http://www.eia.gov/todayinenergy/detail.cfm?id=5390#, accessed July 17, 2013.) 1 Barrel (oil) = 0.159 m^3.

2013, in Dallas, Texas. However, prior to this review, a brief discussion of U.S. geothermal is appropriate.

Geothermal power production is the only renewable energy resource that shares many of the same geoscience, reservoir analysis, drilling, completion, and other qualities found in the production of oil and gas. In the case of geothermal, the goal is to produce hot water…the hotter the better…for the conversion of heat to electrical power. The Geothermal Energy Association (http://www.geo-energy.org/)

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reports that most of the geothermal energy produced in the United States (3,187 MW capacity) has been in the western states, with California and Nevada leading the nation with 2,615 and 469 MW, respectively. Other states such as Hawaii (43 MW), Utah (42 MW), Idaho (16 MW), Alaska (0.73 MW), Oregon (0.28 MW), and Wyoming (0.25 MW) produce the remaining amount of geothermal electric power.

Historically, most early geothermal power generation in the U.S. came from dry steam produced from wells drilled in areas of high heat flow and at relatively shallow depths (Fig. 15). Dry steam power plants account for around 1585 MW (nearly 50%) of installed geothermal capacity, all of which are located in California. This type of production is from high-temperature resources where live steam is found in the subsurface. But it is also limited in aerial distribution, requiring specific geologic criteria to be met for this type of resource. Hence, dry steam production became flat by 1985. Fortunately, new technology was developed to capture additional heat through flash-steam processes, allowing somewhat lower temperature water under pressure to ''flash'' to steam during a pressure reduction process. The flash-steam process generated an additional 900 MW of power, mostly from California, between 1985 and 1990, after which further production through 2012 occurred at a much slower rate. The development of binary turbine technology has opened the industry even more, allowing much lower temperature fluids to be used for power generation along with a move of the geographic footprint beyond California, especially in the last decade. It is the binary technology that has allowed various demonstration projects for heat capture from produced hot water in conjunction with oil and gas production that has the potential to drastically expand geothermal power production into sedimentary basins in the U.S. and worldwide.

Numerous projects are underway regarding geothermal production in areas generally perceived as oil and gas regimes, and are part of this discussion below. Additionally, a major project at data gathering throughout the country is underway through the various State geologic surveys (discussed below) that will make larger amounts of data…especially from oil and gas well temperature data…available for subsurface map generation. Some of these data have been used to generate an interactive map hosted by Google Earth that allows for a very regional picture of potential temperatures existing at various depths in the subsurface (Fig. 16). The data can be queried for different depth ranges of temperature, surface heat flow, along with other parameters. For Figure 16 a depth of 5.5 km was chosen due to this depth being in the range of deeper gas fields in many parts of the country. The yellow dots located in each state represent the potential for geothermal energy production within each state. Clicking on any state initiates a drop-down window that shows the production potential within that state. Figure 17 is an example from Texas. The depth range for energy recovery is 3–7 km. Temperatures are listed for the various depths, along with the estimates of the amount of recovery in megawatts of power. Low, median, and high potential recovery factors are listed and are calculated over a 30-year project life.

The importance of these data, along with the following discussion, is to demonstrate that geothermal energy is no longer confined to areas worldwide where active or recently active volcanic activity is dominant. Geologically quiescent areas such as sedimentary basins appear to hold a vast heat energy source that has yet to be fully explored. Because of the drilling and data available through the oil and gas industry, this industry is sitting on a huge untapped potential for energy production that is renewable, has good upsider public relations potential, and can provide jobs for geoscientists, petroleum engineers, drillers, and many other support services for decades to centuries to come.

Geothermal Resources Council Annual Meeting—September 30–October 3, 2012

A total of 214 presentations were made at the Geothermal Resources Council annual meeting in Reno, Nevada. At least 20 articles related to geothermal energy in sedimentary environments were identified through the table of contents by title and recognition of various authors involved with this type of geothermal energy production. When presented, the papers are arranged within session topics. Although there may be additional presentations that fall within low-temperature geothermal production or geothermal energy from sedimentary rock, these were the presentations that stood out from the others. A brief description of these presentations is presented here.

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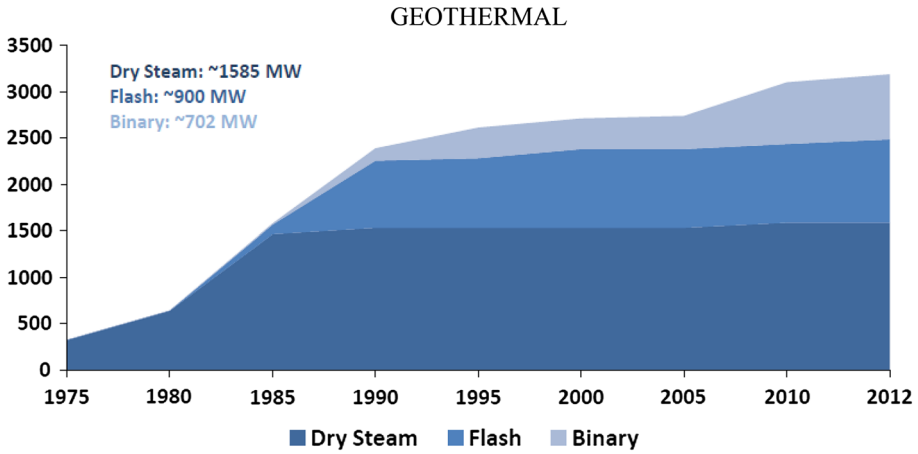

Figure 15. Total U.S. geothermal installed capacity by technology type from 1975 to 2012. Output is in megawatts (MW) of power. Source from Geothermal Energy Association Annual Geothermal Power Production and Development Report: April 2012 (http://www.geo-energy.org/).

Case Studies. While previous geothermal studies involving Mississippi have focused in the southern part of the state and the Mississippi River flood plain, a study presented by Lindsey (2012) has looked at the eastern, north-central Mississippi area in Oktibbeha County. Using well data from the Mississippi Oil and Gas Board website, wells with online log images were downloaded with the bottom-hole temperature (BHT) data recorded for the county. During the data analysis stage, temperature correction values were applied to the data that improved the expected temperature found at depth, thereby improving upon past mapping of the region and increasing the likelihood that geothermal energy could be produced over a larger area than previously thought. By contrast, the Denbury Resources well that demonstrated coproduced geothermal power production using the ElectraTherm Green Machine was farther south in the Summerland Field of Covington and Jones Counties.

Jumping to Germany, Lentsch et al. (2012) presented a discussion on overcoming drilling challenges with rotary steerable systems in deep geothermal wells in the Molasse Basin of southern Germany. These wells have been drilled to between 8,200 and 14,700 ft (2499 and 4,480 m), with horizontal displacement of up to 9,800 ft (2,987 m). The wells are drilled into karstified dolomites and limestones of the upper Jurassic that form the most productive thermal aquifer of the basin. Depending on temperature and production rates, the thermal energy is used for power generation coupled with heating, or for heating alone in the case of lower temperatures. Temperatures between 176 and 284°F (80 and 140°C) and water production rates over 44,000 BBLs per day (6,995 m^3) are common.

Another presentation by Borozdina et al. (2012) focused on thermochemical modeling of cooled brine injection into low-enthalpy sedimentary reservoirs for district heating projects. The concept discussed is that of a doublet well system—an injector—producer combination—and the chemistry consequences that can result and which must be managed. Two case studies were modeled for this study, the Dogger limestones of the Paris Basin and the Rijswijk sandstones in the southern Netherlands. The practical outcomes of the studies were that although porosity changes caused by temperature-induced precipitation or dissolution of mineral species (carbonate, anhydrite, and silicates) do occur, their magnitude neither alter porosity, permeability, nor subsequent reservoir performance significantly.

Coproduction. Not to be outdone by coproduced geothermal demonstration projects in the U.S., the LB reservoir in the Huabei oil field has been studied and used in China for geothermal power production. Xin et al. (2012) reported that pilot tests were conducted in oil wells with produced water temperatures in the 230–250°F (110–121°C) range. The field is 93 miles (150 km) south of Beijing with an oil reservoir area of around 11,000 acres (4,452 ha), with the oil layer located in Mesoproterozoic Jixian System Dolomite at a depth of over 10,500 ft (3,200 m). Rock porosity was reported at 6.0% with

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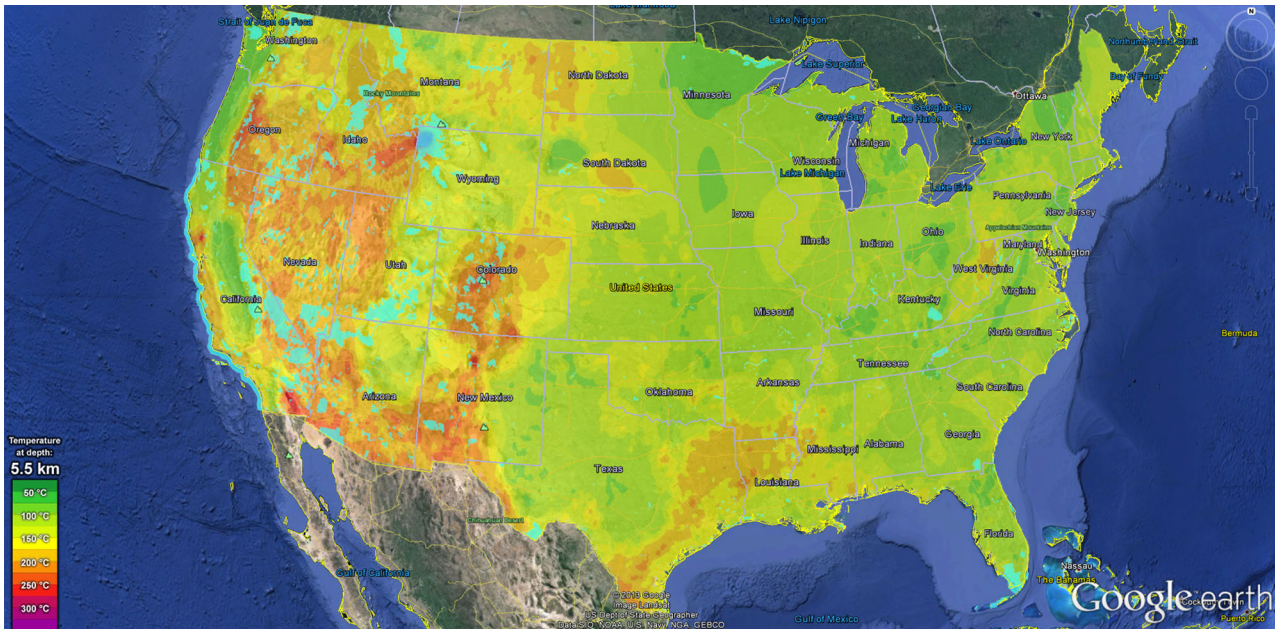

Figure 16. Subsurface temperature map produced through Google Earth for a depth of 5.5 km (18,000 ft). Temperatures range from 50°C (122°F) in dark green to 300°C (570°F) in purple, at increments of 50°C. Areas in light blue are excluded from production potential due to being national parks or preserves.

permeability around 158 mD. There is a dense micro-fracture network at 1–2 fractures/cm^2. The rock is dominated by small vugs and the fractures are the main channel for fluid flow. Prior to this project, there were 6 producing wells out of a field total of 27, with a 97.8% water cut. The project appeared to be an attempt to not only increase the amount of oil being produced but also, with the increase in hot water production, capture the heat and generate electrical power. To test this concept, a 400-kW screw expander manufactured by Jiujiang Power was used with a water flow of over 18,000 BBls (2,862 m^2) per day from 8 producing wells. Gross output was 360 kW with net at 310 kW, for a total energy generated of 310,000 kWh of electricity over a several months period. When fully operational, the power plant can generate 2,700,000 kWh of electricity per year, with an increase in oil production.

Returning to the U.S., Augustine and Falkenstern (2012) of the National Renewable Energy Laboratory (NREL) provided an estimate of the near-term electricity generation potential from co-produced water from active oil and gas wells. Previous studies have estimated that 15–25 billion barrels (2.4–4 billion m^3) of water are coproduced annually. These studies suggested that total electricity generation potential could be in the tens of gigawatts. Augustine and Falkenstern (2012) focused on the near-term market potential of the co-produced resource by developing a 2.5 million well database from information derived from 24 state oil and gas commissions, of which 500,000 were identified as active wells. Cut-off temperature for electricity production was chosen to be 176°F (80°C). As an electronic database for well temperatures was not readily available, the authors assumed a BHT from comparing the location and depth of the wells to previous U.S.-wide geothermal and temperature maps derived from the SMU Geothermal Laboratory and the older AAPG BHT database. With these assumptions in place, the authors concluded that a near-term electricity production potential of 300 MW existed. Various practical operational factors such as minimum power plant size, available cooling water or transmission, project economics,

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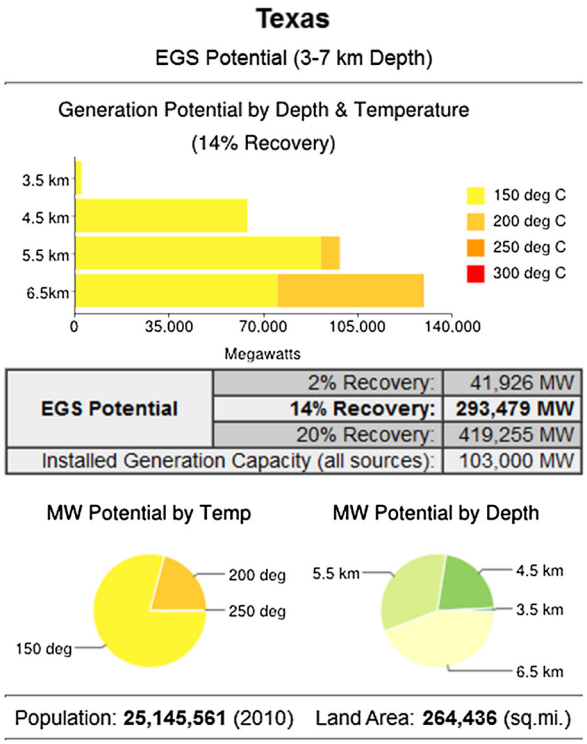

Figure 17. Example of geothermal potential within Texas for a 3–7-km-depth range. Source: www.google.org/egs.

etc., could further limit the number of sites that could be developed. Interestingly, roughly two-thirds of the near-term potential was found to exist in Texas.

Focusing into specific basin level geothermal, Crowell et al. (2012) investigated various BHT correction methods within the Denver Basin of Colorado and Nebraska. When oil and gas wells are drilled the act of drilling alters the temperature profile of a well to some generally unknown distance into the surrounding rock. Since most wells are not allowed to sit to allow for a return to temperature equilibrium between the well bore and the formation, correction factors are the attempt to calculate what the actual BHT in the well would be if equilibrium was reached. Crowell et al. (2012) investigated three existing schemes: the Forster, the Harrison, and the Kehle corrections. Each of these correction equations were generated with a specific region or dataset in mind, making the application of these corrections to other basins inappropriate, since different lithologies and thermal histories will be present in different areas. Several wells that were in the Nebraska part of the basin were in temperature equilibrium, and these wells were used to generate a correction factor specific to the Denver Basin.

Moving into Wyoming, Nordquist and Johnson (2012) presented a discussion of data collected on a 3.5-year operation of an Ormat 250 kW power generation plant operating on the RMOTC facility at the Teapot Dome oil field north of Casper. During this time the power plant has produced over 2,120,000 kWh (enough for 120 homes each year) and utilized over 11,140,000 barrels (1,771,118 m^3) of water, at a temperature between 195 and 210°F (91 and 99°C). Production is from the Tensleep Battery that has up to 60,000 BBLs (9,539 m^3) water per day available from multiple wells. This project was started as a demonstration to determine the feasibility of coproduced geothermal energy and has been successful in showing the potential for future development. Further information can be found at www.rmotc.doe.gov.

Knowing and determining the reliability of data is important when using that data to make decisions regarding energy production, be it geothermal or oil and gas operations. Various standards of quality codes have been used since the 1970s for conventional geothermal analysis that include equilibrium temperature logs, thermal conductivity measurements, and appropriate data corrections. However, the increased use of BHT data from oil and gas wells has required a re-evaluation, and new standards that cover this preponderance of new data are being made available through the National Geothermal Data System. Richards et al. (2012) from SMU have proposed a revised reliability code that incorporated the past systems with increased parameter definition to cover both the traditional and BHT sites. A method encompassing weighted values for each primary parameter used to determine heat flow is linked in a series to rank the site reliability. Thus, heat flows from different data types and calculation methods can be compared to determine data reliability.

Enhanced Geothermal Systems (EGS). EGS represents an approach whereby a geothermal potential exists at a location but that the deliverable water/heat from that formation will occur only if the formation or rock units are enhanced through some induced process—i.e., fracking. In the first of these two papers, Bruno et al. (2012) from Terralog, USA, stated that the recent advance in drilling, completion, and production technology within the oil and gas industry has the potential to be applied in the

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geothermal industry to unlock geothermal resources in areas where geothermal has not been produced. Working in conjunction with the University of California, Irvine, this group is investigating advanced design concepts for paired horizontal well recirculation systems that would be optimally configured for geothermal energy recovery in permeable sedimentary and crystalline formations. In this example, horizontal well pairs would exist as an injector and producer to establish a relatively closed-loop recirculation system, thus allowing more efficient and controlled flow and heat transfer, and reduced wastewater management requirements.

Another paper of this session by Allis et al. (2012) looked at stratigraphic reservoirs in the Great Basin of the western U.S. They indicated that deep basins in this high heat flow region of the western U.S. may have stratigraphic reservoirs deeper than 9,800 ft (2987 m) with temperatures over 300°F (149°C). These reservoirs are sub-horizontal and may be larger in area and geothermal power potential than the traditional fault-hosted hydrothermal reservoirs that have been previously developed. They looked in some detail at two such basins, the Black Rock Desert in Utah and the north Steptoe Valley in Nevada, identifying high temperatures and sufficient signs of stratigraphic permeability to warrant more intensive investigation of their geothermal power potential.

Exploration. Exploration is the first step in any subsurface energy (or mineral) production; the resource needs to be located. Allison et al. (2012), at the Arizona Geological Survey, have been the portal of data collection for the National Geothermal Data System (GDS) which was begun with financial support from the U.S. DOE for the purpose of fostering geothermal energy exploration and development. The data are being provided by all 50 states (www.stategeothermaldata.org), federal agencies, national labs, and academic centers. An increasing set of over 30 geoscience data content models is in use or under development to define standardized interchange formats for aqueous chemistry, borehole temperature data, drill stem tests (DSTs), seismic event hypocenter, geologic unit features, well header features, heat flow/temperature gradients, and permeability to name just a few of the data assets being made available. As of May 2012 there were nearly 37,000 records registered in the system catalog, and 550,075 data resources online, along with hundreds of Web services to deliver integrated data to the desktop from free downloading or online use. The GDS is under simultaneous design, population, and deployment with completion of the initial phases due mid-to-late 2013.

Other groups actively involved in establishing this database are the DOE-Energy Efficiency and Renewable Energy (EERE) Geothermal Technologies Program, Boise State University, and the National Renewable Energy Laboratory (NREL). Anderson et al. (2012) presented information on the basic structure of the National Geothermal Data System (NGDS) as envisioned by the DOE. They discussed the planned functionality of the site for data retrieval, usage, and submission of information. DOE foresees a NGDS that will allow users to search, analyze, and download high-quality geothermal datasets and relevant geothermal information. Once the system is fully operational, the future of the NGDS lies in basic activities of data capture, data curation, and data analysis. An example of data analytical integration would be the use of an ESRI ArcGIS application to pull in Google temperature and depth maps as well as SMU 2004 heatflow maps. The success of the program depends upon geothermal scientists and data scientists working to answer key questions pertinent to putting clean, base-load geothermal energy online.

While the U.S. is actively placing geothermal-related data in a format for anyone to use, Canada is also moving forward in ways for developing its geothermal resources. Richter et al. (2012) provided an update on development within Canada involving resource potential, geothermal projects currently being developed, and a description of the current geothermal energy market and its players, along with the activities of the Canadian Geothermal Energy Association (CanGEA) that works to foster geothermal development in Canada. Various studies have indicated that a significant resource potential exists, but that the market for geothermal power and direct use of heat has remained stagnant. CanGEA has been working to create a favorable legal framework and support scheme on both the federal and provincial/territorial level. Additionally, CanGEA is developing a National Geothermal Database, provincial/territorial geothermal favorability maps, commencing work on a Geothermal Power and Direct Use of Heat Technology Roadmap and Implementation Framework, and continuing its efforts to bring geothermal to the oil and gas sector of Canada.

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Returning to the U.S., Gosnold et al. (2012) have been investigating the thermostratigraphy of the Williston Basin, important not only for geothermal energy but also for better understanding the history of oil and gas generation. They developed an approach for determining temperatures of strata in a sedimentary basin using heat flow, formation lithology, thickness, and thermal conductivity of rock. They calibrated the method on five sites in the basin where temperature versus depth profiles allowed an iterative analysis of temperature gradient, thermal conductivity, and heat flow. Comparison of the temperature projections to BHT provided insight on determining a reliable correction for BHT data. Large-scale application of the method using stacked structure contours can provide a complete and accurate assessment of geothermal resources in a basin.

Geophysics. Reflection seismic data have generally not been used extensively in the geothermal industry while magnetic surveys have been more important in industry development. Ardakani and Schmitt (2012) presented a discussion on the integration of both survey types for geothermal exploration in northeast Alberta, Canada. The ''Athabasca region'' holds a significant amount of Alberta's bitumen resources contained in both oil sands and carbonates. The area has not been developed due to its relative isolation from existing infrastructure and uncertainties associated with in situ production from the carbonates. More recent interest in the region has opened possibilities for either EGS or conventional geothermal system development. Over 50 2D seismic lines and high-resolution aeromagnetic data, along with well log data from 511 wells, were obtained for integration and interpretation in construction of a regional geological/geophysical model for this area of relatively thin layers of sediments overlying the Precambrian metamorphic rocks of the Canadian Shield. Motivation for the study is the need to find sustainable and lower greenhouse gas emission solution for production of bitumen from these oil sands, using geothermal heat as part of the production process.

Regulatory Environmental Issues. Energy and environmental analyses have been important in working to develop a robust set of geothermal technologies that meet future demand. Previous work summarized what is currently known about the life cycle freshwater requirements of hydrothermal and EGS-generating systems. Clark and Harto (2012) of Argonne National Laboratory presented an assessment of the use of freshwater in low-temperature geopressured geothermal power (GPP) generation systems as part of a larger effort to compare the life cycle impacts of geothermal electricity generation with other power generation technologies. Argonne carried out this life cycle analysis (LCA) to quantify energy, water, and environmental impacts of GPP plants to understand the potential environmental impacts of future geothermal industry growth. The LCA boundaries include all on-site activities for the construction and operation of a geothermal facility over a 30-year operational lifetime. The LCA focused on a GPP scenario that produced 3.6 MW of electric power from the geothermal contribution and 17.3 MW of thermal power from the natural gas contribution. Parameters used were based on industry experts and well field characteristics at Pleasant Bayou (Texas) and other geopressured geothermal test wells. Clark and Harto (2012) found that on a per-well basis and a per-kWh lifetime energy output basis, geopressured geothermal systems appear to consume less water than other geothermal technologies. Overall water requirements across the lifetime are low because maintaining reservoir pressure is not a long-term goal of geopressured systems. The spent geofluid is typically sent to a disposal well, also the opportunities for reuse of the geofluid could be explored.

Turning from freshwater usage in geothermal production, Morgan (2012) presented information on geothermal regulations in Colorado, with land ownership being a key issue. Colorado geothermal resources are separately classified as water on private land and as mineral on state and federally administered lands. Additionally, where classified as mineral, only the heat is classified as mineral, regardless of the land administration. Any water used to extract the heat is administered by the Colorado State Engineer through the Division of Water Resources. Rules and regulation for permitting geothermal exploration and development are better understood if considered separately for private, state-administered, and federally administered lands. Many geothermal resources cover more than one of these types of land, but the permitting processes are not synchronized. Sovereign Native American lands were not included in his discussion as they represent a special category of land. As a result, multiple agencies may be involved at any given time with geothermal activities, with each

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agency or group operating on different time schedules.

Reservoir Management. Every geologist knows that geothermal energy is a vast resource, based solely on the makeup of our planet. The difficulty is in retrieving it for use and support of our technical infrastructure. Much of the geothermal production has historically occurred in the western states, with EGS technology opening areas where low-temperature geothermal reservoirs can be used for various purposes. Bedre and Anderson (2012) from West Virginia University presented a paper discussing sensitivity analysis of low-T reservoirs and the direct use of geothermal energy. While they indicated that the eastern U.S. has lower temperature gradients than many of the western states, West Virginia has a higher gradient compared to other eastern states. Of course, knowledge of this fact has been the direct result of much greater drilling in places such as the Appalachian Basin for oil and reservoirs. For example, these data have resulted in identifying a hot spot in the eastern part of West Virginia where temperatures reach 300°F (149°C) at a depth of around 14,700–16,400 ft (4,481–4,999 m). Bedre and Anderson (2012) performed a sensitivity analysis of a reservoir at this temperature at a depth of 16,400 ft (4,999 m), using seven natural and human controlled parameters within a geothermal reservoir: reservoir temperature, injection fluid temperature, injection flow rate, porosity, rock thermal conductivity, water loss (%), and well spacing. A 30-year timeframe of operation was used to run the reservoir simulation. Their results indicated that reservoir temperature was the most important parameter affecting production. Variations in porosity and rock thermal conductivity did not affect the reservoir performance significantly. Other factors had varying levels of impact, with reservoir temperature or injection flow rate having the greatest impact.

Resource Assessment. There has been a renewed interest in recovering the geothermal energy stored in sedimentary basins for electricity production. With exploration for oil and gas resources and well logs, temperatures at depth, and reservoir properties such as depth to basement and formation thickness are better known than in many conventional geothermal areas. The availability of these data reduces exploration risk and allows development of exploration models for each basin. Porro et al. (2012) of NREL presented estimates in the magnitude of recoverable geothermal energy from 15 major U.S. sedimentary basins and ranked these basins relative to their potential. Total available thermal resource per basin was estimated using the volumetric heat-in-place method, and a qualitative recovery factor was determined for each basin based on data on flow volume, hydrothermal recharge, and vertical and horizontal permeability. A more in-depth study is necessary to better determine recovery factors for each basin. [*Of interest is that onshore Gulf of Mexico was not included in this study, where past efforts produced viable geothermal energy.*]

Turning from the regional U.S. basin study to a specific basin, Bohlen (2012) presented a preliminary geothermal resource assessment for the Raton Basin in Colorado. While Colorado has substantial thermal resources, slow geothermal progress has generally been due to geological complexities, rugged terrains, and ''not in my back yard'' attitudes that have prevented serious development. A number of rock samples have been taken from the outcrop of Raton Basin rocks to determine thermal conductivity in the laboratory. Surface and BHT data were available from 1,172 active gas wells in the Raton Basin from an operating producer. Total depths ranged from just over 650 to over 7,200 ft (198–2,195 m). The majority (999 wells) are less than 3,200 ft (975 m) and go no deeper than the Pierre Shale. Using the well data and conductivity values, thermal gradients and heat flow were calculated for 3,200; 6,500; and 9,800 ft (975; 1,981; and 2,987 m) depths, indicating higher temperatures at depth than previously thought. All of the analyses resulted in a picture of the Raton Basin being a far better candidate for geothermal power production than previously thought.

SMU Geothermal Conference—March 13–14, 2013

No geothermal conference was held at SMU in 2012 as there was conflict with other geothermal meetings around the country and the fact that the SMU personnel were busy in participation in these conferences, such as at the AAPG Annual meeting. However, an SMU Geothermal Laboratory Conference on Geothermal Energy and Waste Heat to Power: Utilizing Oil and Gas Plays was held in March, 2013 with 171 attendees, 24 oral presentations, and 10 poster presentations. The AAPG-EMD geothermal committee was represented by David Blackwell and Paul Morgan. Notes recorded

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about the conference taken by Denise Gatlin and Maria Richards, along with student Stefano Benato, assisted in the writing of this article.

For the past 7 years there has been a new focus for the geothermal industry to use the data from oil and gas fields to develop coproduction of all fluids and in turn extract the heat to generate power. Since the first SMU Geothermal Energy Utilization Conference in 2006, numerous improvements in technology, resource evaluation, and associated economics have occurred. The paradigm shift from high temperature, hydrothermal system geothermal development in the western U.S., to today's focus including low temperature, coproduction from sedimentary basins, represents the broader interest in pushing the envelope for producing electricity. The expectation of early adoption by the oil and gas community has fallen short, yet interest and expectation that someday it will happen is generally accepted. For the first time, this event combined the surface waste heat to power (WHP) equipment with geothermal energy projects, realizing the need for the oil and gas industry to be able to ''kick the tires'' on equipment and in the process immediately be able to take advantage of the heat and pressure currently created by their surface equipment. This is of special interest as indicated by Texas Railroad Commissioner David Porter hosting a workshop on using excess natural gas for power on drilling leases, along with discussion of other options for on-site power generation such as waste heat energy capture in December of 2012.

Oral Presentations. Opening remarks by the Maguire Energy Institute's Bud Weinstein stating ''Heat is a terrible thing to waste!'' grabbed the attention of attendees and set the ground work for covering all aspects of electrical production from heat sources in oil and gas fields. The source could be from surface equipment, referred to as ''waste-heat,'' or geothermal heat brought to the surface with oil/gas/water from the reservoir.

Federal Energy Regulatory Commission (FERC) Chairman Jon Wellinghoff (2013) impressed the attendees during his keynote address with his in-depth knowledge of the geothermal and waste heat resources and applicable technologies. Wellinghoff emphasized FERC's focus to open the generation market to small, independent producers as a method to improve U.S. electrical security, consistency, and ability to deal with natural hazards. Use of geothermal resources, in all forms from home loop systems to direct use to electrical production along with the vast applications for waste heat power are seen by Wellinghoff as part of the necessary energy mix for the U.S. to meet the projected electricity generation needs for the future.

The conference structure took attendees through all aspects of oil and gas field development, representing the vast applications for both geothermal and waste heat to apply to improved field operations. The Environmentally Friendly Drilling Systems Program (EFD) presenter, David Burnett (2013) explained how society's acceptance of environmental issues either slows or speeds up changes from innovative technology improvements. Texas A&M University has been the coordinator of the EFD program working with the U.S. DOE, Houston Advanced Research Center, Research Partnership to Secure Energy for America, oil/gas companies, universities, national labs, and environmental organizations to develop and implement improved hydraulic fracturing use of water, and air emissions from drilling. An EFD scorecard was developed to see how any site ranks within the defined criteria. Although geothermal is a smaller industry, as developers move into sedimentary basins for co-produced geothermal or larger scale projects using enhanced geothermal systems, Burnett emphasized the need to engage all stakeholders, public and private, for successful project completion. [*Just as hydraulic fracturing has resulted in public and private push-back in the oil and gas industry, the geothermal sector is not immune to similar events, such as push-back occurring in Hawaii regarding geothermal development – Erdlac comment from Geothermal Energy Association news announcement.*]

Lukawski (2013), a PhD candidate at Cornell University, compared geothermal drilling to oil and gas drilling costs. Flow rates in geothermal wells can only be dreamt about in most oil and gas environments as they start for geothermal typically in the 10,000 BBLs (1,590 m^3) per day range. Well drilling and completion contribute 20–75% of the capital investment in geothermal power plants, with enhanced geothermal systems requiring the most costly upfront expenditures because of the deeper depths. One difference from oil and gas completions is the cementing of the full annulus because of the pressure and flow rates. Yet the study showed that while the cost of drilling has increased for oil and gas wells, geothermal well costs have leveled off because of improvements in drilling techniques for deeper depths, and at shallow depths (<6,000 ft; 1,829 m)

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geothermal is similar to slightly less in cost. Lukawski (2013) concluded that the geothermal community should not use the oil and gas cost indices to normalize the cost of geothermal wells.

Once the reservoir is drilled, testing is needed; Randy Normann (2013) of Perma Works discussed how the Hydro-Fracturing Monitoring Tool is able to ''run barefoot'' (no heat shield) up to 570°F (299°C) under high pressure and stay in the reservoir for weeks to years without removing the logging tool. This allows for long-term monitoring of changes in the well and reservoir such as testing changes in injection or production, well connectivity, shut-in testing, reservoir pull down test, and power plant maintenance. This capability will change our understanding of the life of a reservoir system, pressure fluxes, and how to improve stimulation. Tools capable of these harsh conditions make high-temperature EGS projects more viable.

A key factor driving the rapid improvement in equipment is the ability of manufacturers to meet the needs of both the geothermal and waste heat to power communities with the same technology. Highlighting the small-scale (<100 kW) environments, Fox (2013) of ElectraTherm discussed improvements in their Green Machine after a demo at an oil well in Mississippi and how the same technology is being deployed rapidly into the European market to meet the demand for waste heat applications. With fluid temperatures in the 190–240°F (88–116°C) temperature range, a number of oil and gas operations become viable for waste heat energy capture including coproduced hot fluids, compressor stations, natural gas well head flaring, and amine sweetening plants.

Ronzello (2013) of Pratt and Whitney Power Systems discussed the expected outcome from the acquisition by Mitsubishi Heavy Industries of the PWPS/Turboden ORC equipment line, which ranges from small to medium sized (1–10 MW). Ronzello's graphic on efficiency as a function of resource and surface temperature clearly explained the benefit of utilizing the highest heat sources. In his example, similar equipment efficiency can range between 7.5% and 25%, depending upon the source temperature variations, i.e., 195°F and 590°F (91 and 310°C), respectively. This emphasized the importance of the temperature rather than industry or source of the temperature: such as biomass, geothermal, waste heat, CHP, etc.

Trying to contain excitement, Dickey (2013) of TAS Energy (Turbine Air Systems) showed pictures of their first project on ''un-separated mixed hydrocarbons'' in California at a mid-stream oil production facility. This project had fluid temperature of 300°F (149°C) from the ground at 38,000 lbs (17,236 kg)/h and is from a steam flood. The expander was designed for a 1.2 MW output with actual gross output of 750 kW and a net of 500 kW. It was expected that this site has a potential of 1 MW gross output. The second part of Halley's talk was on a ''geopressured integrated hybrid system'' that TAS is working on in the Gulf Coast region. Geopressured hybrid systems were proven at Pleasant Bayou in Brazoria County, Texas in the late 1980s with a nominal 1.0 + MW output from heat in the produced water and natural gas burned on site. This project would expand the previous work by incorporating a binary system with the un-separated mixed hydrocarbon approach along with waste heat recovery from engine exhaust and jacket water, and other efficiency improvements, for an integrated hybrid system producing 3.5 MW from some 25,000 BBLs (3,975 m^3) per day of produced fluid. Filters would be used for particulate capture should this be necessary.

For the first time, two newly developed pressure-related power systems were publicly viewable on the SMU Campus for the Geothermal Conference. Kerlin (2013) displayed their Helidyne planetary expander, named after the similarities to the sun/planets relationship for the machine's extremely high-precision rotating system with no belts or gears. This state-of-the-art expander is designed to work with natural gas applications such as J–T valves, wellhead chokes, gas processing plants, let-down stations, and, where possible, geothermal geopressured wells.

The second system, the Langson Helical Screw Energy Converter, developed by Richard Langson (DiPippo and Langson 2013), was installed in the SMU Campus boiler room to run the pressure equipment and is capable of installation/removal in just hours. The machine greened-up campus electricity for a few hours during the day of its installation. Being capable of using either water or steam, it allows for fluctuating flow rates or pressure changes, making it applicable in numerous industry applications, such as geothermal geopressure, petrochemical, power plants, biogas, and on equipment in the oil and gas field. The system is scalable with sizing variations between 1 and 50 MW. Langson indicated that installation costs could be ≤ $1,500/kW with return on investment in 1.85 years.

Instead of line shaft and submersible pumps for a high water cut well, the Gravity Head Pump is designed for installation without shafts, rods, or

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electrical cables. Pierce (2013) of Geotek Energy explained how with one additional string in a well the expander pump is capable of lifting fluids from deeper depths and generates power from high-temperature sites. The technology patent is pending and locations to demonstrate the technology are under consideration.

The Canadian Gas Pipeline industry is setting the example in the gas compressor station business. Straquadine (2013) of NRGreen Power gave examples of what the U.S. could be accomplishing based on the already successful power generation in Canada. Using Organic Rankine Cycle (ORC) technology the waste heat to power facilities in Saskatchewan are producing over 20 MW currently, and in Alberta additional sites will bring the total generation to approximately 40 MW. Straquadine conveyed the frustration of the WHP industry not being included as a renewable energy equivalent since it is not defined in the Public Utilities Regulatory Policy Act (PURPA) or the Energy Independence and Security Act of 2007. This sentiment was highlighted by Southerland (2013) representing the WHP industry trade association, Heat is Power. This energy source is application-based for generation capability; therefore, the individual states have determined if it will be considered part of the renewable portfolio or considered separately. Being considered a part of the renewable package option opens the door to improved financing, electrical purchase price, and tax credits. For the oil and gas industry, through inclusion of surface waste heat in their operations, they have an opportunity improve their energy efficiency and in addition generate income through renewable energy credits and/or carbon offsets in those states with WHP incentives.

Presenter Trevor Demayo (Demayo and Schrimpf 2013), Energy Management Coordinator for Chevron's San Joaquin Valley Operations, detailed the competing uses for waste heat in a field before it can be used to generate electricity. The challenges are to find the locations where incremental power is needed, such as where high power costs, safety, and security are improved with additional on-site electrical generation. Often the changes in the oil and gas industry are driven from regulations in other countries raising the bar to efficiency. Although the conference had generating electricity as a focus, multiple presenters noted the need to offset heating/cooling of buildings; how the use of wells for district heating or green commercial building sites is another substantial resource currently being under-utilized. Demayo included offsetting building loads for field operators as a first step to reducing known expenses, with little permitting/regulation concerns. District heating is underway in West Chester University in Pennsylvania and even Maine has geothermal potential with economically designed systems for buildings.

Through the increased ability to use bottom-hole temperature data from oil and gas wells, the geothermal industry has studied how to correct the temperatures for drilling impact and then determined the geothermal resource. The reserves for Maine, New York, Pennsylvania, North Dakota, Oklahoma, Texas, Colorado, and Montana were discussed at this meeting. The outcome of these studies shows that within sedimentary basins there are areas with temperature differentials between surface and current drilling depths which are capable of generating electricity. In states with high winter heat loads, there is also the ability to use the under 200°F (93°C) fluids to heat buildings and thus reduce our nation's need for fossil fuel-generated electricity. Texas Christian University has received a National Science Foundation grant to fund further research on stored energy within sedimentary basins. Holbrook (2013), lead of the SEDHEAT program, emphasized the importance of removing hurdles for the geothermal and oil and gas industries to work together on defining and developing the next generation of combined plays. Fluid flow pathways must be defined at a broader scale as well as more refined for the greatest heat extraction. Inclusion in the SEDHEAT program is open to all researchers and companies.

The expectation by the geothermal industry is for low-temperature coproduction projects within sedimentary basins to expand into large-scale enhanced/engineered geothermal systems (EGS). The U.S. DOE is funding projects to move the "future of geothermal" forward. As a result of experiments in EGS during the past few months, that future is now today. Uddenburg (2013) of AltaRock Energy highlighted how the project at Newberry Volcano in Oregon has successfully hydrosheared (created shear failure along existing fractures) the reservoir, thereby increasing the reservoir capacity from approximately 10 L/s to 20 L/s over a 1-month cycling injection procedure.

High water volumes are rarely the talk of the oil and gas industry, but as Will Gosnold (Gosnold and Barse 2013) (University of North Dakota) showed, in the Williston Basin there is no way to avoid it; high water volumes are exactly what is needed for oil and gas wells to be economically viable for the

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geothermal energy production. By switching the focus and producing even higher water volumes, make possible geothermal sites using the Bakken, Red River, Madison and Cedar Hills formations. Finding companies to work with on demonstration of equipment is difficult. Denbury Resources is one company which has done so multiple times, allowing for comparison of various companies' equipment for the same field conditions both in the Williston Basin and central Mississippi. Gosnold's 2011/2013 presentations compared output efficiency and cost for the power production equipment available. In the U.S. with the 30% ITC and 10 cent power the payback is typically less than 5 years. As the MWs produced increases, the price/kilowatt hour needed drops to as low as 5 cents.

High water cut is also found to the west in Montana, where Gary Carlson (Carlson and Birkby 2013) reported on work underway on the Fort Peck Reservation. The area has a significant number of wells where coproduced geothermal energy has potential. Some 760 BHTs have been analyzed to date with the highest temperature recorded at 278°F (137°C); nearly 90 BHTs are equal or greater than 200°F (93°C). In addition to working with existing wells, the project seeks to identify the geothermal potential in undrilled areas on the Reservation. Economic analysis toward power generation and greenhouse heating options are part of the project.

To the north yet into central Alaska, Karl (2013) of Chena Hot Springs gave a rousing presentation involving several new geothermal applications currently in use at the resort in Alaska. Beside approximately 400 kW power generation from two PWPS PureCycle units, Chena uses hot water for heating buildings, greenhouse support, and a 15 short ton (15.2 metric tonnes) absorption chiller for temperature control inside their Ice Museum. A new 300 kW screw expander designed by Kerry and produced by Kaishan Compressor Company is being installed to increase on-site production of additional electricity. Chena Power is also completing two mobile ORC demonstrations in Utah that can be used in oil and gas fields.

Heading south to a warmer climate, Cutright (2013) of the BEG spoke on the state-wide database of well temperature being compiled and that will be available in September, 2013. He discussed data analysis results, site identification, economics of geothermal and its competitiveness, and alternative heat extraction fluids such as CO_2. The largest area of higher geothermal gradients was shown to be along the Balcones fault system and to the east and south. Other local areas of interest included the Crockett and Val Verde County area, the Trans-Pecos region along the border with Mexico, the deepest part of the Delaware Basin, a portion of the Texas Panhandle, and in the Fort Worth Basin.

The use of CO_2 for heat transport was continued by Dunn (2013) (Enhanced Energy Group) as he spoke on its use in enhanced oil recovery and its potential use in engineered geothermal systems. He contrasted the use of CO_2 and water for heat transport. CO_2 has advantages over water in fields with reduced natural fluids. A current problem is that the quantities of CO_2 required makes cost a major factor. New technology is reducing the cost to produce the CO_2 and designed for large-scale production of 2–12 MW of electricity generated while consuming the CO_2 in the geothermal reservoir. It can also be used for enhanced oil recovery and is beneficial for a combined geothermal/oil operation.

On the water side of things, Erdahl (2013) presented information on re-using produced oilfield water, not only in geothermal development, but also in the impact on hydraulic fracturing. He reviewed aspects of macro market trends, economic analysis, and the growth of water usage in the oil and gas industry. He contrasted some of the differences such as cost of water usage between the geothermal and oil and gas industry.

Turning to other topics, energy financing for geothermal power was presented by Daniel East (2013) of The Carlyle Group. He spoke on the various types of energy-related projects that the Group supports, with their focus on mezzanine financing. He discussed the typical geothermal project life cycle as it presently exists.

Electrical connectivity and various legal issues helped to round out the broad arena of topics. Schue (2013) focused on Texas regulation of geothermal and the various agencies involved. This included past laws enacted by state legislation that defined geothermal as a mineral. He also listed the tax codes that allow certain amounts of oil and gas to be ''incidentally produced'' from a geothermal well exempt from production taxes. He spoke on various legal issues of mineral ownership along with unknowns involving rule of capture with regards to heat. Schue also presented information on various legislative actions underway along with Electric Reliability Council of Texas (ERCOT) and their concern on having reliable power generation, a plus for geothermal as a baseload energy resource.

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Rounding out the federal involvement of oral speakers was Hollett (2013), the Director of the Geothermal Technologies Office. He openly contributed to the discussion and answered related questions on the DOE program throughout the 2 days. Hollett gave the reception presentation, which was taped for a YouTube video, clearly informing the attendees on various short- and long-term goals and project activities related to all aspects of geothermal from identifying new geothermal plays to an ''underground field observatory'' for EGS R&D. Coproduction development, blind hydrothermal systems, and EGS are all in the DOE's plan through 2030. The ability to add additional value with the inclusion of geothermal energy for projects using waste heat or storage technologies was a connector between the industries. Coming from the oil and gas industry, Hollett showed how current use of the word ''Play'' in the oil and gas industry is now being expanded to include geothermal energy as new drilling and hydroshearing techniques are changing the reservoir evolution.

Poster Presentations. A total of nine poster presentations were available for review during the first day of the 2-day session. As with the oral presentations the posters covered the range from the potential for geothermal production in various areas of the country to equipment discussion. It was during the time of the poster session and the reception that the Helidyne planetary expander was available for first public viewing.

Areas in the northeast part of the U.S. were discussed with potential for geothermal development and usage. Hootsmans (2013) of Colby College presented information on the geothermal potential of Maine. A couple of states to the south and west, Aguirre et al. (2013) displayed information on BHT data from over 8,000 new wells drilled for unconventional natural gas in Pennsylvania and New York. Temperatures reaching 300°F (149°C) at 18,000 ft (5,486 m) can be utilized for district heating in an economical manner. Another poster by Gatlin (2013) of West Chester University in Pennsylvania discussed the performance of a 350-well district geoexchange system at WCU.

Moving westward, Will Gosnold (Gosnold and Barse 2013) also presented a poster on the status of the North Dakota oil field geothermal projects. Two posters were shown involving Colorado. The Lower Cretaceous formations in the Denver Basin were evaluated by Crowell (2013) for recoverable thermal energy. Using a volumetric approach for assessing recoverable energy, Crowell indicated that these formations, including the ''D'' and ''J'' oil-producing sandstones, have high capacity for heat production with target temperature being around 280°F (138°C). Morgan (2013) of the Colorado Geological Survey also presented on Colorado geothermal gradients and opportunities within the Piceance Basin using BHT data from over 10,000 hydrocarbon wells. Morgan speculated on how geothermal energy could be used to preheat in-place oil shale prior to hydrocarbon extraction. South of Colorado in Oklahoma, Randy Keller (2013) of the Oklahoma Geological Survey presented studies of thermal regimes and geothermal potential within Oklahoma. Discussion of the Meers fault, near the Wichita Mountains, brought to light the fact that even in the mid-continent, earthquakes naturally occur.

Falling into the more conventional arena for geothermal energy was a presentation of an EGS project at Desert Peak, Nevada. The poster offered a new, plausible explanation for the location of observed deep micro-earthquakes and for the potential mechanisms that controlled permeability changes during the main stimulation operations. The study defined key geological structures involved in the experiment and original permeability in the rock volume around the well. The continuum mechanics model ($FLAC^{3D}$) used in the study showed that fluid pressure diffusion generated during the low-flow rate injection phase is consistent with the activation of hydraulically induced shear failure along the identified structures. The project was discussed by PhD Candidate, Benato (2013) of the Desert Research Institute (University of Nevada, Reno). This project is part of the U.S. DOE funding for EGS and the Itasca Education Partnership program.

DOE Coproduction Technology Manager, Reinhardt (2013), presented a poster on low-temperature and coproduced resources below 300°F (149°C) and the various projects completed, ongoing, and being proposed for future activities. Proposed activities included an innovative rotating heat exchanger prototype and potential funding opportunities for fiscal year 2014. Of interest to many was the new technique to extract strategic minerals from the geothermal brines. Lithium extraction is possible for incorporation into projects, where applicable. For the low-temperature community, significant research is being completed by the Pacific Northwest National Lab to develop microporous metal–organic solids for heat carrier and transfer mediums, expected to increase power generation by 15%.

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The conference concluded with attendees re-energized to find ways to work with the oil and gas industry to develop geothermal and waste heat in existing fields. Waste heat applications already exist in almost every field across the nation. In the Geothermal Industry it was shown that financing larger projects may be easier, and if that is the case, producing the high fluid volumes shown to exist in the resource assessments can get projects to market with much needed clean energy for the local community. As Bud Weinstein stated, ''Heat is a terrible thing to Waste''!

OIL SANDS

Steven Schamel[11] Fran Hein[12]

This commodity commonly consists of bitumen and heavy oil in unlithified sand; however, heavy oil reservoirs can also include porous sandstone and carbonates. Oil sands petroleum is named bitumen, tar, and extra-heavy oil, although these accumulations can also contain some lighter hydrocarbons and even gas. Bitumen API gravity is less than 10° and viscosity is generally greater than 10,000 centipoises (cP) at reservoir temperature and pressure; heavy oil API gravity is between 10° and 25° with viscosity greater than 100 cP (Danyluk et al. 1984; Schenk et al. 2006). Heterogeneity in reservoirs occurs at microscopic through reservoir scales, and includes sediments of variable depositional energy and hydrocarbon composition. Viscosity gradients of hydrocarbons in the Athabasca oil sands of Alberta primarily reflect differing levels of biodegradation (Adams 2008; Gates et al. 2008; Larter et al. 2008; Fustic et al. 2013). Heavy and extra-heavy oil deposits occur in more than 70 countries across the world, with the largest accumulations 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).

Resources and Production

Almost all of the bitumen being commercially produced in North America is from Alberta, Canada. Canada is an important strategic source of bitumen and of the synthetic crude oil (SCO) obtained by upgrading bitumen. Bitumen and heavy oil are also characterized by high concentrations of nitrogen, oxygen, sulfur, and heavy metals, which results in increased costs for extraction, transportation, refining, and marketing compared to conventional oil (Meyer and Attanasi 2010). Research and planning are ongoing for transportation alternatives for heavy crude, bitumen, and upgraded 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 U.S. markets (Perry and Meyer 2009). SCO from bitumen and (or) partially upgraded bitumen is being evaluated for potential long-distance transport to refineries in the Midwest and Gulf states of the USA and to existing or proposed terminals on the west coast of North America. Associated concerns include effects on the price of crude oil, and the environmental impacts that are associated with land disturbance, surface reclamation, habitat disturbance, and oil spills or leaks with associated potential pollution of surface and ground waters.

Excellent sources of information on Alberta oil sands and carbonate-hosted bitumen deposits are the resource assessments and regulatory information by the Alberta Energy Regulator (former Energy Resources Conservation Board, ERCB) (http://www.ercb.ca/data-and-publications/statistical-reports/st98). Estimated in-place resources for the Alberta oil sands are 1844 billion barrels (BBLs) (293.1 billion m^3) (ERCB 2012, p. 2). Estimated remaining established reserves of in situ and mineable crude bitumen is 169 billion BBLs (26.8 billion m^3); only 4.6% of the initial established crude bitumen has been produced since commercial production began in 1967 (Table 4) (ERCB 2012, p. 8). Cumulative bitumen production for Alberta in 2011 was 8.1 billion BBLs (1,294 million m^3). The bitumen that was produced by surface mining was upgraded; in situ bitumen production was marketed as non-upgraded crude bitumen (ERCB 2012). 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^3) over the next decade. Over the last 10 years, the contribution of bitumen to Alberta's total primary energy production has increased steadily. A breakdown of production of energy in Alberta from all sources, including renewable sources, is given in Figure 18.

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Table 4. Summary of Alberta's Energy Reserves, Resources, and Production at the End of 2011 (from ERCB 2012)

	Crude Bitumen		Crude Oil		Natural Gas[a]		Raw Coal	
	Million m^3	Billion Barrels	Million m^3	Billion Barrels	Billion m^3	Trillion cubic feet	Billion tonnes	Billion tons
Initial in-place resources	293,125	1,844	11,357	71.5	9,504	337	94	103
Initial established reserves	28,092	177	2,863	18.0	5,384	191	35	38
Cumulative production	1,294	8.1	2,617	16.5	4,377	155	1.49	1.64
Remaining established reserves	26,798	169	246	1.5	1,007[b]	35.7[b]	33	37
Annual production	101	0.637	28.4	0.179	111	3.9	0.030[d]	0.033[d]
Ultimate potential (recoverable)	50,000	315	3,130	19.7	6,276[c]	223[c]	620	683

[a]Expressed as "as is" gas, except for annual production, which is at 37.4 megajoules per m^3; includes coalbed methane natural gas.
[b]Measured at field gate (or 34.7 trillion cubic feet downstream of straddle plant).
[c]Does not include unconventional natural gas.
[d]Annual production is marketable.

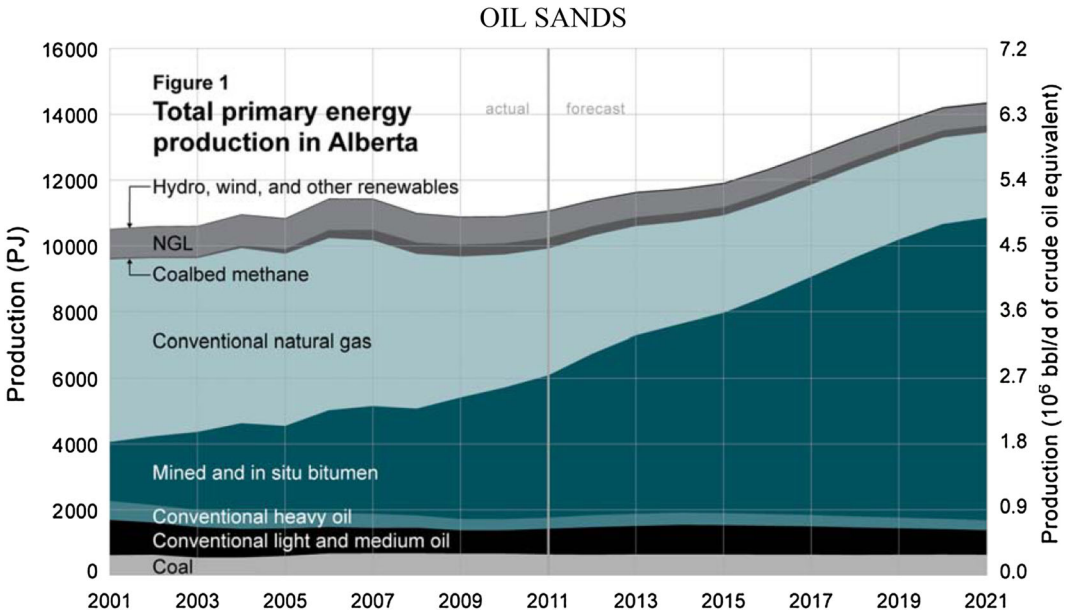

Figure 18. Total primary energy production in Alberta (ERCB 2012). *NGL* natural gas liquids.

Crude bitumen is heavy and extra-heavy oil that at reservoir conditions has a very high viscosity such that it will not naturally flow to a well bore. Administratively, in Alberta, the geologic formations (whether clastic or carbonate) and the geographic areas containing the bitumen are designated as the Athabasca, Cold Lake or Peace River oil sands areas (Fig. 19). Most of the in-place bitumen is hosted within unlithified sands of the Lower Cretaceous Wabiskaw–McMurray deposit in the in situ development area (Table 5), followed by the Grosmont carbonate bitumen deposit, and the Wabiskaw–McMurray deposit in the surface mineable area (Table 5).

Reassessments for the Athabasca-Grosmont carbonate bitumen (done in 2009) and the Athabasca-Grand Rapids oil sands and Athabasca-Nisku carbonate bitumen deposits (done in 2011) are included in the initial in-place volumes of crude bitumen (Table 5). The Nisku reassessment resulted in a 57% increase in initial bitumen volume in place. The Nisku Formation, like the Athabasca-Grosmont carbonate bitumen deposit, is a shelf carbonate that has undergone significant leaching and karstification, with the creation of an extensive vug and cavern network. Conventional oil migrated and infilled the paleocave deposits and then degraded in place to form the bitumen. Other prospective carbonate bitumen reservoirs are being explored west of the town site of Fort McMurray, with initial industry estimates indicating that bitumen pay zones may exceed 100 m (328 ft) in

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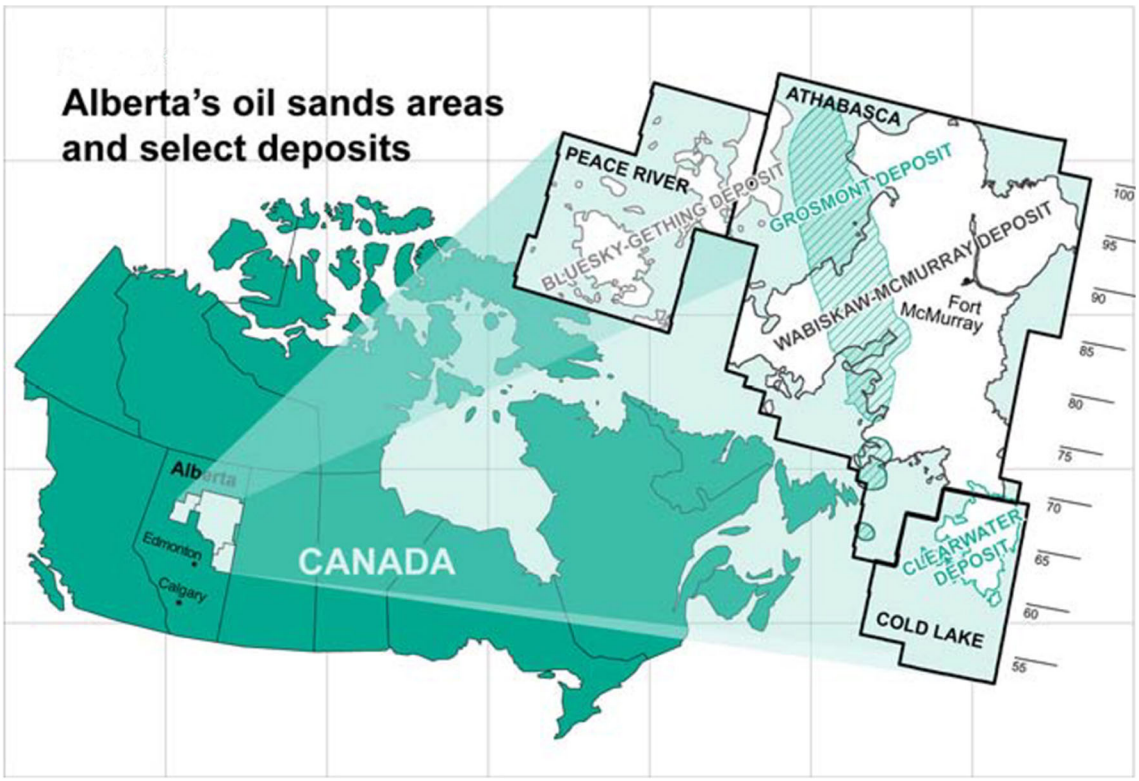

Figure 19. Alberta's Peace River, Athabasca and Cold Lake oil sands areas, highlighting the main deposits (ERCB 2012).

Table 5. Initial In-Place Volumes of Crude Bitumen as of December 31, 2011 (from ERCB 2012)

				Average Reservoir Parameters			
Oil Sands Area	Oil Sands Deposit	Initial Volume In Place (10^6 m^3)	Area (10^3 ha*)	Average Pay Thickness (m)	Mass (%)	Pore Volume Oil (%)	Average Porosity (%)
Athabasca	Upper Grand Rapids	5,817	359	8.5	9.2	58	33
	Middle Grand Rapids	2,171	183	6.8	8.4	55	32
	Lower Grand Rapids	1,286	134	5.6	8.3	52	33
	Wabiskaw–McMurray (mineable)	20,823	375	25.9	10.1	76	28
	Wabiskaw–McMurray (in situ)	131,609	4,694	13.1	10.2	73	29
	Nisku	16,232	819	14.4	5.7	68	20
	Grosmont	64,537	1,766	23.8	6.6	79	20
	Subtotal	242,475					
Cold Lake	Upper Grand Rapids	5,377	612	4.8	9.0	65	28
	Lower Grand Rapids	10,004	658	7.8	9.2	65	30
	Clearwater	9,422	433	11.8	8.9	59	31
	Wabiskaw–McMurray	4,287	485	5.1	8.1	62	28
	Subtotal	29,090					
Peace River	Bluesky–Gething	10,968	1,016	6.1	8.1	68	26
	Belloy	282	26	8.0	7.8	64	27
	Debolt	7,800	258	25.3	5.1	66	18
	Shunda	2,510	143	14.0	5.3	52	23
	Subtotal	21,560					
Total		293,125					

1 m = 3.28 ft; 1 ha = 2.47 acres; 1 m^3 = 35.31 cubic feet.
*ha = hectare.

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thickness, hosted primarily within the Leduc Formation carbonates (ERCB 2012).

A number of factors (including economic, environmental, and technological criteria) are applied to the initial in-place volumes of crude bitumen to attain the established reserves. In Alberta there are two types of reserves for crude bitumen—those that are anticipated to be recovered by surface mining techniques (generally in areas with <65 m (<213 ft) of overburden in the Athabasca area), and those to be recovered by underground in situ technologies (in areas with >65 m or >213 ft overburden) (largely thermal, for Athabasca, mainly steam-assisted gravity drainage (SAGD); for Cold Lake, cyclic steam stimulation (CSS); and for Peace River, thermal and primary recovery) (Tables 6, 7).

Alberta is Canada's largest producer of marketable gas (71% in 2011) and of crude oil and

Table 6. Mineable Crude Bitumen Reserves in Alberta for Areas Under Active Development as of December 31, 2011 (from ERCB 2012)

Development	Project Area[a] (ha)	Initial Mineable Volume In Place (10^6 m^3)	Initial Established Reserves (10^6 m^3)	Cumulative Production (10^6 m^3)	Remaining Established Reserves (10^6 m^3)
CNRL Horizon	28,482	834	537	13	524
Fort Hills	18,976	699	364	0	364
Imperial/Exxon Kearl	19,674	1,324	872	0	872
Shell Muskeg River	13,581	672	419	70	349
Shell Jackpine	7,958	361	222	7	215
Suncor	19,155	990	687	300	387
Syncrude	44,037	2,071	1,306	430	876
Total	151,863	6,951	4,407	820	3,587

1 ha = 2.47 acres; 1 m^3 = 35.31 cubic feet.
[a]The project areas correspond to the areas defined in the project approval.

Table 7. In Situ Crude Bitumen Reserves[a] in Alberta for Areas Under Active Development as of December 31, 2011 (from ERCB 2012)

Development	Initial Volume In Place (10^6 m^3)	Recovery Factor (%)	Initial Established Reserves (10^6 m^3)	Cumulative Production[b] (10^6 m^3)	Remaining Established Reserves (10^6 m^3)
Peace river oil sands area					
Thermal commercial projects	63.7	40	25.5	11.1	14.4
Primary recovery schemes	160.8	10	16.1	12.3	3.8
Subtotal[c]	224.5		41.6	23.4	18.2
Athabasca oil sands area					
Thermal commercial projects	391.8	50	195.9	89.1	106.8
Primary recovery schemes	1,026.2	5	51.3	23.1	28.2
Enhanced recovery schemes[d]	(289.0)[e]	10	28.9	18.9	10.0
Subtotal[c]	1,418.0		276.1	131.1	145.0
Cold lake oil sands area					
Thermal commercial (CSS)[f]	1,212.8	25	303.2	226.6	76.6
Thermal commercial (SAGD)[g]	33.8	50	16.9	2.6	14.3
Primary recovery schemes	6,257.5	5	312.9	90.6	222.3
Subtotal[c]	7,504.1		633.0	319.8	313.2
Total[c]	9,146.6		950.7	474.3	476.4

1 m^3 = 35.31 cubic feet.
[a]Thermal reserves reported in this table are assigned only for lands on which thermal recovery is approved and drilling development has occurred.
[b]Includes amendments to production reports.
[c]Any discrepancies are due to rounding.
[d]Schemes currently on polymer or waterflood in the Brintnell–Pelican area. Previous primary production is included under primary schemes.
[e]The in-place number is that part of the initial volume in place for primary recovery schemes that will see incremental production due to polymer or waterflooding.
[f]Cyclic steam simulation projects.
[g]Steam-assisted gravity drainage projects.

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equivalent production, and the only producer of upgraded bitumen (also called ''SCO'') and non-upgraded bitumen. Heavy oil is produced in both Alberta and Saskatchewan. Although there are oil sands resources in northwestern Saskatchewan, as yet these have not been brought to commercial production. In Alberta, of the 2011 primary energy production, bitumen accounted for 78% of the total crude oil and raw bitumen production, with production increasing by 4% in surface mining areas, and by 13% from in situ areas from the previous year. During this same time crude oil production increased by 7%, total marketable natural gas declined by ~5%, total natural gas liquids production remained flat, and coal production declined by 5%. By comparison, only about 0.2% of energy is produced from renewable energy sources, such as hydro and wind power.

Starting in 2010, the downward trend of total crude oil production in Alberta was reversed, with light–medium crude oil production increasing due to technological advances, such as horizontal, multi-stage drilling with hydraulic fracturing and/or acidization. This resulted in an increase of total crude oil production by 7% in 2011 (ERCB 2012). Along with this technologically driven increase in crude oil production, the ERCB (Rokosh et al. 2012; Beaton et al. 2013) conducted a regional resource assessment of crude oil in six of Alberta's shale and siltstone-dominated formations, that pointed to a vast potential (best in-place estimates of 423.6 billion BBLs or 67.3 billion m^3 of crude oil; 3,424 trillion cubic feet or 97 trillion m^3 of natural gas; and 58.6 billion BBLs or 9.3 billion m^3 of natural gas liquids) in tight formations, which until now were considered uneconomic due to challenges related to production from these low-permeability reservoirs. To date, these hydrocarbon resource estimates identify other (non-bitumen) unconventional resources in the province; but, how these relate to the total energy resource endowment of the province is not known until it is addressed if they are technologically or economically feasible to produce at large scales with existing or near-future resource technologies. In the future, it is expected that the in situ thermal production of bitumen will overtake the mined production of bitumen in the province; with perhaps a modest rise in both conventional and tight-formation development—largely a result of improvements in multi-stage hydraulic fracturing from horizontal wells that are targeting these previously uneconomic (but potentially large) resources.

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. This is due mainly to the different characters and scales of the bitumen reservoirs, but partly, perhaps, it is because the states do not have the infrastructure of the Alberta oil sands area. Schenk et al. (2006) compiled total measured plus speculative in-place estimates of bitumen of about 54 billion BBLs (8.6 billion m^3) for 29 major oil sand accumulations in Alabama, Alaska, California, Kentucky, New Mexico, Oklahoma, Texas, Utah, and Wyoming (Table 8). However, these older estimates of total oil sand resources provide only limited guidance for commercial, environmentally responsible development of the oil sand deposits. Additionally, the estimates do not factor in commercially viable heavy oil resources. The resources in each of the states have distinct characteristics that influence current and future exploitation.

California has the second largest heavy oil reserves in the world, second only to Venezuela (Hein 2013). California's oil fields, of which 52 have reserves greater than 100 million BBLs (15.9 million m^3), are located in the central and southern parts of the state (Fig. 20). As of 2010, the proved reserves were 2,938 million BBLs (467.1 million m^3), nearly 70% of which were in the southern San Joaquin basin (U.S. Energy Information Administration 2013f). Most of the fields were discovered and put into primary production in the period 1890–1930. However, with the introduction of waterflooding, thermal recovery, and other EOR technologies starting in the 1950s and 1960s, oil recoveries improved dramatically and the proved reserves increased several fold (Tennyson 2005).

Nearly all of the oil is sourced from organic-rich intervals within the thick Miocene-age Monterey diatomite, diatomaceous mudstone and carbonate. Due to a combination of Type IIS kerogen, modest burial and thermal heating, and generally shallow depths of oil pools, the oil tends to be heavy and relatively viscous. These are thermally immature, partially biodegraded oils. Approximately 40% of the oil is produced by steam flooding, cyclic steam stimulation, or other thermal recovery methods. Thermally produced oil comes mainly from fields in the San Joaquin basin (Table 9, Fig. 20). In general, the reservoirs are poorly consolidated or un-consolidated sandstones intercalated within or overlying

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Table 8. Previous Estimates (in Million Barrels, MMB) of Bitumen-Heavy Oil Resource-In-Place in the United States

State	No. Deposits	°API Range	Measured, MMB	Total, MMB
Utah	10	−2.9 to 10.4	11,350	18,680
Alaska	1	7.1 to 11.5	15,000	15,000
Alabama	2	na	1,760	6,360
Texas	3	−2.0 to 7.0	3,870	4,880
California	6	0.0 to 17.0	1,910	4,470
Kentucky	4	10	1,720	3,410
New Mexico	1	12	130	350
Wyoming	2	na	120	145

1 Barrel (oil) = 0.159 m^3. Data from Schenk et al. (2006).

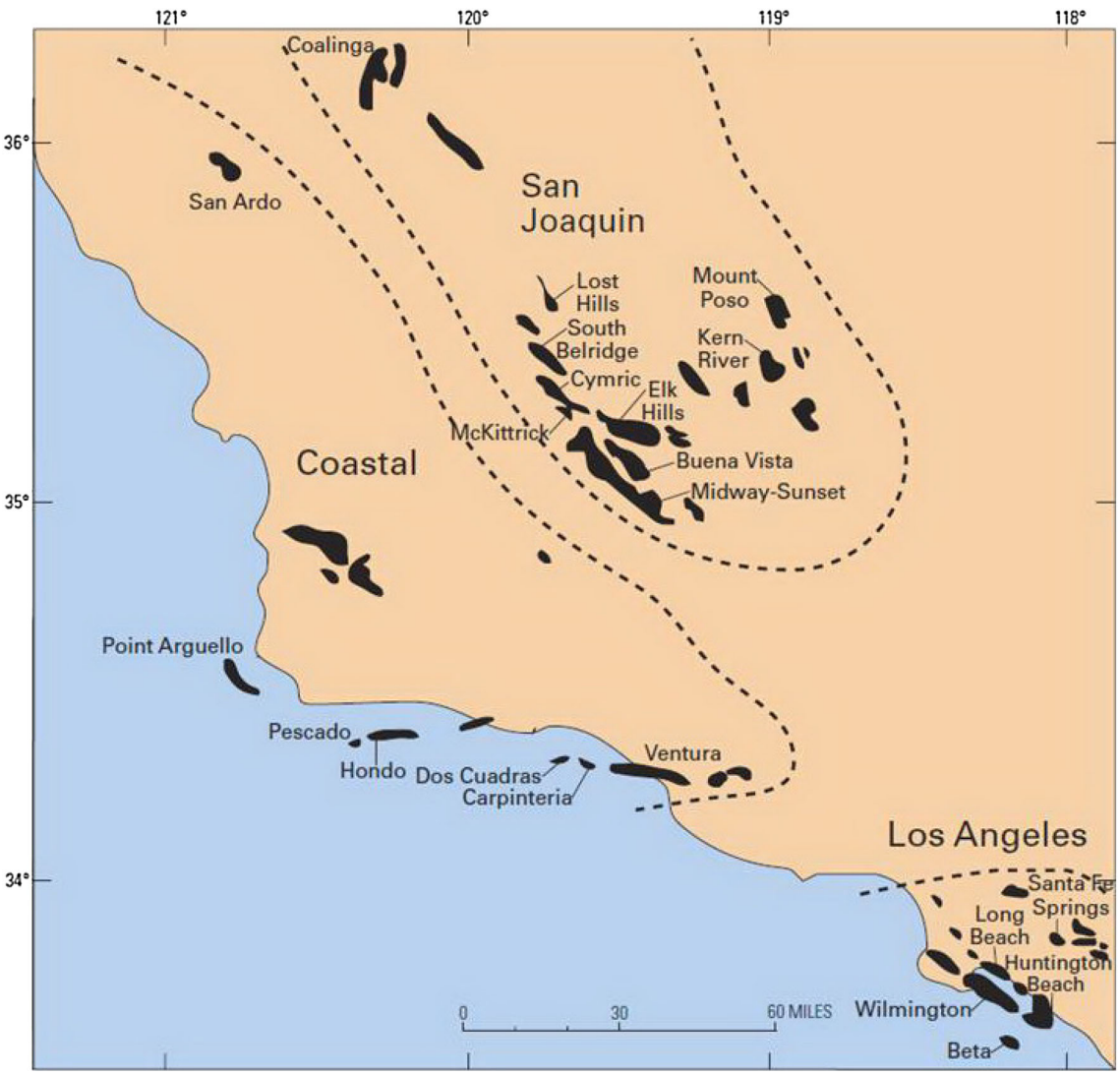

Figure 20. Principal oil fields of California (Tennyson 2005).

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Table 9. California Oil Fields Produced by Thermal Recovery Methods

Field	2011 Oil, MMB	2011 GOR	°API	Oil Viscosity, cp	Oil Temp., °F
Midway-Sunset	30.564	165	11–14	1000–10000	85–130
Kern River	26.804	0	13	4000	90
South Belridge	25.165	414	13–14	1500–4000	95
Cymric	13.089	374	11–14	1000–2000	95–105
Lost Hills	11.232	710	12.7–13.9	1500–4000	75–82
San Ardo	6.835	193	11–12	1000–3000	125–130
Coalinga	5.603	38	9–13	2000–28000	84–105
Kern Front	2.829	0	13–14.8	1500	80–95
Poso Creek	2.781	4	13	2800	110
McKittrick	1.832	1,202	10–12	13000–51000	83
Edison	0.840	5	14	2000	90
Placerita	0.710	0	13	10000	90
North Antelope Hills	0.380	0	14	1400	80

The fields are arranged by 2011 total oil yield (in million barrels, MMB); the volume of associated gas is indicated by the gas–oil ratio (GOR) in units of SCF gas/barrels oil. The characteristic oil gravity, oil viscosity, and reservoir or in situ oil temperature of the fields are also shown. 1 Barrel (oil) = 0.159 m^3; °F = °C×9/5 + 32. Data from California Division of Oil, Gas, and Geothermal Resources and Koottungal (2012).

the Monterey Formation. However, the South Belridge field produces from diagenetically altered, highly fractured diatomite. The Coalinga field produces from sandstones in the Temblor Formation underlying the Monterey Formation; the source rock is the Middle Eocene Kreyenhagen Formation unconformably overlain by the Temblor Formation.

The larger thermal oil fields (Table 9) have experienced oil production declines in the 5-year period 2007–2011 on the order of 11.3% (Kern River) to 28.8% (Cymric). Smaller fields have had little or no declines. The young (1952) San Ardo field immediately west of the San Joaquin basin (Fig. 20) has actually doubled production in this period. A small portion of the supergiant Wilmington field in the Los Angeles basin was produced by steam flood using two pairs of parallel horizontal injector and producer wells. The project was stopped because of surface subsidence problems. With the exception of this successful pilot, air quality issues associated with steam generation have limited the expansion of thermal recovery methods in the Los Angeles basin.

In addition to the heavy oil accumulations that are being produced, California has numerous shallow bitumen deposits and seeps that are not currently exploited. The total resource is estimated to be as large as 4.7 billion BBLs (0.74 billion m^3) (Kuuskraa et al. 1987).

Five of the six largest tar sand deposits are in the onshore Santa Maria basin (central Coastal zone in Fig. 20), covering a total area of over 60 square miles (155 km^2). In general, the deposits are in the Sisquoc Formation, which overlies and is a seal to the oil-generating Monterey Formation. An additional major deposit is in the onshore Ventura basin (extreme southeast of the Coastal zone). Minor tar sand deposits and surface seeps are scattered throughout the oil-producing areas of California normally overlying or updip from known oil fields.

During the past decade, oil production in California has steadily declined (U.S. Energy Information Administration 2012e). The rate of decline is being slowed, and may be reversed, through the application of fully integrated reservoir characterization and improved recovery technologies that are resulting in higher recovery factors (Dusseault 2013), up to 70–80% in some fields.

Alaska's heavy oil and bitumen deposits on the North Slope are very large (24–33 billion BBLs, or 3.8–5.2 billion m^3) and they hold promise for commercially successful development. Since early 1980s (Werner 1987), two very large, shallow heavy oil-impregnated sands have been known to overlie the Kuparuk River field and underlie a 1,800 ft (549 m) thick permafrost (Fig. 21). These are the Ugnu Sands (8–12 °API) at depths of 2,000–5,000 ft (610–1,524) and the West Sak Formation (16–22 °API) at 2,300–5,500 ft (701–1,676 m). The size of the deposits is well defined with the numerous wells tapping the underlying conventional oil fields. For the Lower Ugnu Sands and West Sak Formation the resources are 12–18 billion BBLs (1.9–2.9 billion m^3) and 12 billion BBLs (1.9 billion m^3), respectively. The reservoirs are fluvial-deltaic sands deposited during the Late Cretaceous–earliest Paleocene in the north and

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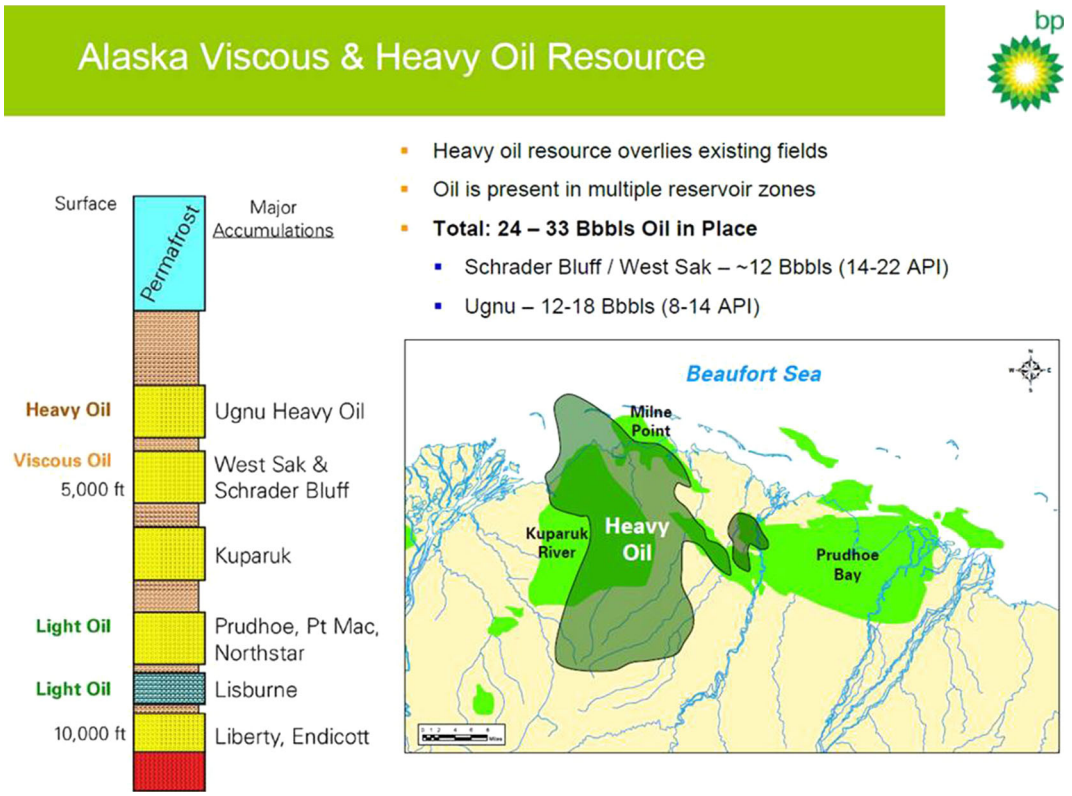

Figure 21. Location of shallow, heavy oil accumulations on the North Slope of Alaska. Heavy oil deposits overlie the Kuparuk field and parts of the Prudhoe and Milne Point fields and occur in sands within the Ugnu, West Sak and Schrader Bluff formations. Source: Gordon Pospisil, BP Exploration (Alaska) Inc., January 6, 2011.

northeast prograding Brooks Range coastal plain (Hulm et al. 2013).

Production of viscous (50–5000 cp) oil from the West Sak pools began in the early 1990s, reaching the current level of 4,000–5,000 BBLs (636–795 m^3) of oil per day in 2004. To date, over 100 million BBLs (15.9 million m^3) have been recovered from the formation using a combination of vertical wells and water flood. The heavy oil in the Ugnu Sands presents a much greater technical challenge due to its higher viscosity (5,000 to over 20,000 cp) and the friability of the reservoir sand. At its Milne Point S-Pad Pilot, BP Alaska is testing two different recovery strategies in the Ugnu Sands. One pilot is pumping from the heel of a cased and perforated horizontal well, which early in 2013 successfully produced heavy oil at a rate of 350 BBLs (55.6 m^3) of oil per day (Fairbanks Daily News-miner, January 16, 2013; http://www.newsminer.com). The other is a test of the CHOPS (cold heavy oil production with sand) recovery process (Young et al. 2010) with results not yet announced.

Utah's bitumen and heavy oil deposits are found throughout the eastern half of the state (Schamel 2009, 2013a, b). In northeast Utah, the largest accumulations are located along the southern margin of the Uinta Basin underlying vast portions of the gently north-dipping East and West Tavaputs Plateaus. This highland surface above the Book and Roan Cliffs on either side of the Green River (Desolation) Canyon is supported by sandstone and limestones of the Green River Formation (Lower Eocene). Here the resource-in-place is at least 10 billion BBLs (1.6 billion m^3), nearly all of it reservoired in fluvial-deltaic sandstone bodies within the lower member of the Green River Formation. On the northern margin of the Uinta Basin, heavy oil occurs in a variety of Mesozoic and Tertiary reservoirs on the hanging wall of the Uinta Basin Boundary Fault. The proven resource is less than 2.0 billion BBLs (0.32 billion m^3), but the potential for additional undiscovered heavy oil and bitumen is great. In both areas, the source of the heavy oil is organic-rich lacustrine calcareous mudstone in the

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Table 10. Estimated Resource Size (in Million Barrels, MMB) and Richness of the Principal Heavy Oil-Bitumen Deposits in Utah

Bitumen-Heavy Oil Deposit	Resource Estimate MMB	Areal Extent Square Miles	Richness, Average MB/Acre	°API Gravity	Reservoir Unit
P. R. Spring–Hill Creek	7,790	470	25.9	5.9 to 13.8	Lower Green River ss
Sunnyside	3,500–4,000	122	45–51	7.1 to 10.1	Lower Green River ss
Sunnyside ''core''	1,160	2.7	638.3		Lower Green River ss
Asphalt Ridge	1,360	16	132.9	10.0 to 14.4	Mesaverde ss (U Cret.)
Whiterocks	98	0.45	338	11.4 to 13.5	Navajo Ss (Tr.-Jr.)
Tar Sand Triangle	4,250–5,150	198	33.3–40.6	−3.6 to 9.6	White Rim Ss. (L Perm)
TST ''core''	1,300–2,460	30–52	67.7–73.9		White Rim Ss. (L. Perm)

1 Barrel (oil) = 0.159 m^3; 1 mi^2 = 2.59 km^2; 1 acre = 0.4 ha; 1; *MB* million barrels. Data from Schamel (2013a, b).

Green River Formation. These naphthenic oils have API gravities in the 5.5–17.3° range, are only weakly biodegraded in the subsurface, and are sulfur-poor (0.19–0.76 wt%). The known oil sand reservoirs are lithified and oil-wet.

New resource-in-place estimates for the major deposits are determined from the average volume of bitumen/heavy oil measured in cores distributed across the deposit, as delineated by wells and surface exposures (Table 10). The deposits on the south flank of the basin are extensive and large, but the actual concentrations (richness) of resource are small. For the vast P. R. Spring–Hill Creek deposit, the average richness is just 25.9 thousand BBLs (4.1 thousand m^3) per acre; it is only slightly higher for the entire Sunnyside accumulation west of the Green River. However, a small portion of the Sunnyside deposit having unusually thick reservoir sands within an anticlinal trap has a measured average richness of 638.3 thousand BBLs (101.2 thousand m^3) per acre. The two principal deposits on the north flank of the basin, Asphalt Ridge and Whiterocks, are relatively small, but they contain high concentrations of heavy oil (Table 10).

In the southeast quadrant of Utah, there are numerous shallow bitumen accumulations on the northwest and west margins of the Pennsylvanian–Permian Paradox Basin. The deposits are hosted in rocks of late Paleozoic and early Mesozoic age. With the exception of the Tar Sand Triangle and Circle Cliffs deposits, most accumulations are small and/or very lean. Normally, the oils are heavier than 10° API and highly biodegraded. In contrast to the Uinta Basin deposits, this bitumen is derived from a marine source rock and is aromatic with high sulfur content (1.6–6.3 wt%), but low nitrogen (0.3–0.9 wt%).

Bitumen in the Tar Sand Triangle deposit, located south of the junction of the Green River with the Colorado River, is reservoired in a several-hundred-foot-thick eolian sandstone of Lower Permian age. Across an area of 84 square miles (217 km^2), the thickness of bitumen-impregnated sandstone exceeds 100 ft (30 m). The API gravity of the bitumen is less than 8° at the surface and just over 10° in the subsurface. Schamel (2013b) estimated that the total in-place bitumen resource is between 4.25 and 5.15 billion BBLs (0.67 and 0.82 billion m^3) in a deposit just less than 200 square miles (518 km^2) in size. However, at a resource threshold equal to or greater than 60 thousand BBLs (9.5 thousand m^3) per acre, the resource ranges between 1.30 and 2.46 billion BBLs (0.21–0.39 billion m^3) in an area of 30–52 square miles (78–135 km^2), respectively. Approximately half of the deposit is in the Glen Canyon National Recreation Area, where exploitation could be severely limited. The Circle Cliffs deposit, with an estimated 1.73 billion BBLs (0.27 billion m^3), lies completely in the Capitol Reef National Park and Grand Staircase-Escalante National Monument, areas off limits to development.

The Uinta Basin heavy oils and bitumens are highly viscous; the Tar Sand Triangle bitumen is only slightly less viscous. Both groups of oils have viscosity that is orders of magnitude greater than that of the 13°API heavy oil produced by steam flood in the southern San Joaquin Basin, California. So far, the Utah ''tar sands'' have resisted attempts at commercial development. However, two pilot projects announced to start in 2014 will produce liquids from surface-mined oil sand using a closed-loop solvent extraction process. One of the pilots is in the P. R. Spring deposit and the other is at the south end of Asphalt Ridge.

On March 22, 2013, BLM Principal Deputy Director Neil Kornze signed the Record of Decision (ROD) for the Oil Shale and Tar Sands Programmatic EIS, finalizing the Proposed Land Use Plan Amendments for Allocation of Oil Shale and Tar

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Sands Resources on Lands Administered by the BLM in Colorado, Utah, and Wyoming and Final Programmatic Environmental Impact Statement (OSTS PEIS) that was released in November 2012. The ROD opens 130,000 Federal acres (52,609 ha) of designated tar sands in Utah for leasing and development. Federal lands in adjacent Wyoming and Colorado, also covered by this ROD for oil shale leasing, hold no oil (tar) sand deposits. Further information is available at: http://ostseis.anl.gov/documents/.

The Southwest Texas Heavy Oil Province (Ewing 2009) is located on the northeastern margin of the Maverick Basin, northeast of Eagle Pass. Bitumen is hosted in early to middle Campanian carbonate grainstone shoals (Anacacho Formation) and in late Campanian–Maastrichtian sandstone (San Miguel, Olmos, and Escondido Formations). The largest accumulation is in the San Miguel "D" Sandstone with a reported 3.2 billion BBLs (0.51 billion m^3) in an area of 256 square miles (663 km^2) (Kuuskraa et al. 1987). The bitumen is highly viscous and sulfur-rich (10%) with an API gravity of −2°API to 10°API. The average resource grade of the deposit is less than 20 thousand BBLs (3.2 thousand m^3) per acre. Only a very small part of the deposit has a grade in excess of 40 thousand BBLs (6.4 thousand m^3) per acre. In the late 1970s and early 1980s, Exxon and Conoco produced 417,673 BBLs (66,405 m^2) of bitumen from pilot plants at this deposit, but since then there has been no successful exploitation of the deposit. The shallow Anacacho deposit contains an estimated 550 million BBLs (87.4 million m^3) resource in an area of 36.6 square miles (94.8 km^2). The average resource grade is 23.5 thousand BBLs (3.7 thousand m^3) per acre. The deposit has been mined since 1888 for asphaltic road paving.

In northwest Alabama, the bitumen-impregnated Hartselle Sandstone (Mississippian) occurs sporadically along a 70-mile (113 km)-long belt extending east-southeast across the Cumberland Plateau from near the Alabama–Mississippi border to the front of the Appalachian thrust belt. To the south of this outcrop belt, bitumen is observed in wells penetrating the Hartselle Sandstone. The Alabama Geological Survey (Wilson 1987) speculated that there could be 7.5 billion BBLs (1.2 billion m^2) of bitumen in an area of 2,800 square miles (7,252 km^2), of which 350 million BBLs (55.6 million m^3) is at depths shallower than 50 ft (15 m). Despite the large potential resource, the deposit is lean, with an average bitumen-impregnated interval of 14 ft (4.3) and an average richness of only 4.3 thousand BBLs (0.68 thousand m^3) per acre.

The heavy oil deposits of western Kentucky form an arcuate belt along the southeast margin of the Illinois Basin. The heavy oil is hosted in fluvial sandstones, some filling paleovalleys, of Late Mississippian-Early Pennsylvanian age (May 2013). The area is crossed by the east–west trending Rough Creek and Pennyrile fault systems that aid in trapping the heavy oil pools and may have been the conduits for eastward oil migration from hydrocarbon kitchens at the juncture of Illinois, Indiana, and Kentucky. The largest deposit (2.1 billion BBLs; or 3.3 billion m^3) extends in a zone 5–10 miles (8–16 km) wide and 50 miles (80 km) long situated north of Bowling Green. This deposit, hosted in the Clifty Sandstone, generally is lean with thickness of the oil-impregnated sands from a few to just over 50 ft (Noger 1999). The API gravity of the heavy oil is 10°. Other deposits are considerably smaller and have API gravities of 10° to 17°. Kentucky's oil sand total oil-in-place is estimated to be 3.42 billion BBLS (0.54 billion m^3) (Noger 1999). At present, there is no commercial exploitation of the deposits for liquid hydrocarbons, although at least one operator has announced plans to do so.

Oil sand accumulations in east-central New Mexico have total in-place measured and speculative resources of 130 million BBLs (20.6 million m^3) and 190–220 million BBLs (30.2–35 million m^3), respectively (IOCC 1983; Schenk et al. 2006). The oil accumulations are within Triassic Santa Rosa Sandstone at depths of less than 2,000 ft (3,219 m) (Broadhead, 1984). Speculative in-place oil sand resources total 800 million BBLs (127.2 million m^3) for Oklahoma (IOCC 1983; Schenk et al. 2006). Oil sands are located mostly within Ordovician Oil Creek Formation sandstones and Viola Group limestones, with lesser accumulations in Mississippian through Permian sandstones (IOCC 1983). A bibliography of Oklahoma asphalt references through 2006 (B. J. Cardott, compiler) can be downloaded from http://www.ogs.ou.edu/fossilfuels/pdf/bibOkAsphalt7_10.pdf. In-place resources for two oil sand accumulations in Wyoming total 120 million BBLs (19 million m^3) measured and 70 million BBLs (11.1 million m^3) speculative (IOCC 1983; Schenk et al. 2006). The larger accumulation is within Pennsylvanian–Permian sandstones of the Minnelusa Formation in northeastern Wyoming, and the smaller is within Cretaceous sandstones in the Wind River Basin, central Wyoming (IOCC 1983).

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Resource Technology

As of December, 2012, Alberta bitumen reserves under active development (mainly by surface mining, compare cumulative production in Tables 3 and 4) accounted for only 4.8% of the remaining established reserves of 169 billion BBLs (2.68 billion m^3) since commercial production began in 1967 (Table 4) (ERCB 2012). In 2011, in situ production from all three oil sand areas in Alberta grew by 12.7%, compared with a 4.1% increase in production for mined bitumen. If this present rate of production growth is maintained, it is expected that in situ production will overtake mined production by 2015 (ERCB 2012).

Unlocking the huge potential of the remaining bitumen resources in Alberta will require enhancing other in situ technologies. The most commonly used in situ technologies are SAGD and CSS. SAGD and CSS utilize considerable energy and water to produce steam; good permeability (both vertical and horizontal), relatively thick pay zones (>10 m; 32.8 ft), and an absence of barriers (cemented zones, thick laterally continuous shales) and the lack of significant top/gas, top/lean, or bottom water thief zones are also required. Generally, the cross-bedded sands of lower point bar depositional environments are characterized by vertical permeability ranging from 2 to 6 D. Associated inclined heterolithic stratification from upper point bar deposits exhibits a 2–3 order of magnitude decrease in permeability, and siltstone in abandoned channel and point bar strata also exhibits a 2–3 order-of-magnitude decrease in permeability (Strobl 2007, 2013; Strobl et al. 2011). Depositional heterogeneities at vertical and lateral scales influence bitumen recovery from in situ processes.

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 (editor, Jan Czarnecki, at jc7@ualberta.ca). Some of the focus of recent in situ technology and advances includes:

- Integration of future oil sands technology with that of emerging oil shale coproduction in the western U.S.
- New developments concerning in situ recovery and underground refining technologies for oil sands in western Canada include underground combustion and refining.
- Use of 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 in the strata to increase permeability in the reservoir. Liberatore et al. (1912) examined alternative seismic methods for in situ monitoring of CHOPS heavy oil recovery. Seismic modeling indicates that signature of wormholes developed during CHOPS production can be detected.
- 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 integration of technologies that include solvent co-injection, electromagnetic heating, wedge (in-fill) wells, in situ combustion, hot solvent gravity drainage, Supercritical partial oxidation, and various hybrid developments, including CO_2 flooding (*Rudy Strobl, Nov. 14, written communication*).

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 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 SAGD and CSS). Since there is significant coproduction of greenhouse gases with bitumen production and upgrading, critical technology needs to involve research into: (1) alternative sources of heat for generation of steam (e.g.,

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geothermal, nuclear, and 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. There was in the past an excess supply of produced sulfur, above what was used in agricultural and other markets. Excess sulfur is stockpiled from bitumen and sour gas production and refining. Produced and stored sulfur is sold to various markets, the largest being China, mainly converted to sulfuric acid for use in manufacturing phosphate fertilizer (ERCB 2012).

In California, where the principal thermal recovery methods currently are steam flood and CSS, an emphasis is being placed on increasing in situ recovery factors through fully integrated reservoirs characterization and improvements in thermal recovery technologies to make them effective, as well as more energy-efficient and less polluting (Dusseault 2013). New sources of heat for steam generation are being tested. For instance, in the San Joaquin Basin two solar steam heavy oil recovery demonstration projects have been operating since 2011. One is a Chevron-Bright Source Energy partnership in the Coalinga field (Fig. 20). The other is a Berry Petroleum Co.–GlassPoint Solar partnership in a portion of the McKittrick field.

Environmental Issues

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 and (2) CO_2 emissions. Current greenhouse gas emissions are decreasing and remaining emissions are compensated for by carbon trading and (or) CO_2 sequestration; and (3) improving the economics and processes of extraction, production, and upgrading of the bitumen. Some of the areas of focus include

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

Oil sand developers in Canada are focused on reducing CO_2 emissions by 45% per barrel by 2010, as compared to 1990 levels. Also in Canada, developers are legislated to restore oil sand mining sites to at least the equivalent of their previous biological productivity. For example, at development sites near Fort McMurray, Alberta, the First Nation aboriginal community, as part of the Athabasca Tribal Council, and industry have worked together to reclaim disturbed land (Boucher 2012) and industry has reclaimed much of the previous tailings pond areas into grasslands that are now supporting a modest bison herd (~500–700 head).

New Publication

AAPG Studies in Geology 64 entitled ''Heavy-oil and Oil-Sand Petroleum Systems in Alberta and Beyond'' has been released in April 2013 (bookstore@aapg.org). It is a combination hard-copy and CD publication, with 160 pages printed (3 chapters), and all 28 chapters in electronic form on the CD-ROM. This oil sands and heavy oils research includes presentations from the 2007 Hedberg conference in Banff, Canada titled ''Heavy oil and bitumen in foreland basins—From processes to products.'' Publication editors are Frances Hein, Dale Leckie, Steve Larter, and John Suter. The volume contains 28 chapters that encompass depositional settings of oil sands and heavy oil accumulations, reservoir characterizations, geochemical characteristics of bitumen and of oil biodegradation, geologic and petroleum system modeling, petroleum reserves and resources, surface mining and in situ production processes, such as SAGD, for accumulations in Canada, Russia, the U.S., and Venezuela, and oil sands tailings and water use management.

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OIL SHALE DEVELOPMENTS

Jeremy Boak[13]

Global production of shale oil is currently ~30,000 BBLs (3,180 m^3) of oil per day, all from mining and retorting operations in Australia, Brazil, China, and Estonia, with an increase to 35,000 BBLs (5,564 m^3) of oil per day anticipated over the next 6 months. If all currently planned surface retorting projects achieved their stated goals, oil shale production could reach 400,000 BBLs (64,000 m^3) of oil per day by 2030 (Boak 2013a, b). Data contained in this review are primarily from publically available government and industry websites.

The World Energy Council (2010) estimated world resources of shale oil to be 4.79 trillion barrels (761 billion m^3), with 3.7 trillion barrels (589 billion m^3) located in U.S.A. The latest USGS assessment for the Green River Formation in Colorado, Utah, and Wyoming is 4.29 trillion barrels (682 billion m^3), a significant increase over previous estimates (Mercier et al. 2010, 2011). A recent fact sheet (Birdwell et al. 2013) presented data for the resource indicating the amount available at a given oil yield. The oil recoverable from rocks considered at least marginally recoverable (> 63 L/tonne = 15 gallons/ton) is around 183×109 m^3 (1.1×1012 barrels), and the richest, most readily recoverable resource (>104 L/tonne = 25 gallons/ton) is about 56×109 m^3 (353×109 barrels). These figures indicate the substantial variability in richness in many oil shale deposits. Similar comparative figures are not available for any other oil shale deposit.

Yuval Bartov of Israel Energy Initiatives Limited suggested Israeli resources are as high as 250 billion BBLs of oil (39.7 billion m^3), and Jordan Energy Minerals Limited reported an estimated resource of 102 BBLs of oil (16.2 billion m^3) for Jordan. Overall, global totals are likely to exceed 5 trillion barrels (800 billion m^3).

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_2 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. BLM awarded Research, Development, and Deployment (RD&D) leases to Exxon-Mobil Corporation and Natural Soda, Inc. The leases offer 160-acre (64.7 ha) RD&D areas, with lease preference areas, which becomes available at fair market price after a company has shown commercial feasibility for its technology, of 480 acres (194.2 ha), a total of 640 acres (259 ha).

Former U.S. Department of Interior Secretary Ken Salazar finalized plans for oil shale and tar sand development on BLM lands. The ROD and plan amendments make nearly 700,000 acres (283,280 ha) in Colorado, Utah, and Wyoming available for potential leasing, but only through RD&D leases. In addition, the new plans remove more than 90% of the richest resource in Colorado from potential leasing without a clear rationale. Large portions of the land offered are highly likely to be uneconomic for shale oil production. BLM has also issued new rules for commercial oil shale that impose duplicative restrictions and leave little clarity for companies on the actual royalty structure.

Red Leaf Resources, Inc. of Cottonwood Heights, Utah, anticipates moving forward with a production test within 12 months, and plans to expand that to a 9,500 BBLs oil per day (1,510 m^3) production facility that will start construction after completion of the production test, and then to 30,000 BBLs oil per day (4,770 m^3), 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 a 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.

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American Shale Oil LLC (AMSO), a partnership of Genie Oil and Total, S.A., is conducting a pilot test of their in situ process (Conduction, Convection & 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 that the process yields 35–40 API gravity oil with a net energy return of 4:1.

Shell Oil Company is preparing a multi-mineral test on one of its RD&D leases in Colorado. The test will produce nahcolite by solution mining and then shale oil by its In Situ ConversionTM technology. 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.

In the U.S., concern exists especially about greenhouse gas emissions and water consumption of the oil shale industry. The primary source of CO_2 emissions for in situ production comes from power plants, and power plant water consumption is the largest use for a Shell-type in situ operation (Boak 2008, 2013a, b; Boak and Mattson 2010). Minimizing energy use is essential. ExxonMobil suggested air-cooled power plants to reduce water use, but these may increase CO_2 emissions (Thomas et al. 2010). AMSO has emphasized the potential for sequestration of CO_2 in exhausted in situ retorts (Burnham and Collins 2009). Current industry estimates of 1–3 BBLs (0.16–0.48 m^3) of water use for one barrel of oil result in a one million BBL (159,000 m^3) per day industry using ~1% of Colorado's annual water consumption. Socioeconomic impacts are also issues of concern.

Understanding and mitigating the environmental effects 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. DOE 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 by the Federal government at this time.

International Activity

The Queensland government has lifted a 20-year moratorium on oil shale mining imposed in 2008 by the former Labor government. Queensland Energy Resources (QER) has operated a technology demonstration plant in Gladstone, and is considering the Stuart site of the Yarwum resource to be an important source of oil for the future. China produces shale oil from the Fushun, Huadian, Huangxian, Junggar, Maoming, and Luozigou Basins, and from the Dalianhu and Haishiwan areas. Operating oil shale retorting plants are located in Beipiao, Chaoyang, Dongning, Fushun, Huadian, Jimsar, Longkou, Luozigou, Wangqing, and Yaojie. Evaluation is continuing in four other basins and a number of other areas. New retorts are being built rapidly in China.

In Estonia, Viru Keemia Grupp has opened the first new oil shale mine at Ojamaa, with reserves estimated at 58 million tons, and an expected 15–17 year lifetime. Eesti Energia is in the process of bringing its Enefit 280 retort on line. New technology has enabled Eesti Energia to increase electricity production by 30% over the last decade while decreasing sulfur emission by 66%.

In Brazil, Petrobras continues mining and retorting operation in the Irati oil shale. However, startup Irati Energy Limited plans to launch a feasibility study of an 8,000 BBL (1,272 m^3) per day shale oil plant, and expand its South Block oil shale resource through drilling. Irati, based in Southern Brazil, controls >3,100 km^2 (1,197 mi^2), with over 2 billion BBLs (0.3 billion m^3) of potential oil shale resources. In Australia, QER continues to operate its demonstration plant near Gladstone, selling the 40 BBLs (6.3 m^3) per day of product into the commercial market. Now that the moratorium on oil shale development has been lifted, QER is moving ahead toward the next stage.

Jordan has attracted international interest in its oil shale resources. It signed agreements to explore oil shale development in 2009 (JOSCo [Shell] and Aqaba Petroleum for Oil Shale), in 2010 (Eesti Energia), in 2011, (Karak International Oil), in 2012 (Global Oil Shale Holdings and Whitehorn Resources), and in 2013 (Saudi Arabian Oil Co). In addition, the Attarat Power Company, a wholly owned subsidiary of Enefit Jordan BV, announced it

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has received six bids for Jordan's first oil shale-fired power plant from engineering and construction companies. JOSCo continues to investigate ICP technical and commercial feasibility in the Jordanian oil shale. Over 270 assessment wells have been drilled to date providing thousands of resource samples for lab characterization. Key risks are being reviewed and field pilots options are being considered.

In Morocco, San Leon Energy has said that results from samples from two reservoir zones confirmed that a commercial operation is possible. San Leon commissioned Enefit Outotec Technology to conduct an initial study of the Tarfaya Oil Shale, based on surface retorting utilizing the Enefit 280 process. Genie Oil Shale Mongolia, LLC, and the Petroleum Authority of Mongolia have entered into an exclusive 5-year development agreement to explore and evaluate commercial potential of oil shale resources on 34,470 km^2 (13,309 mi^2) in Central Mongolia, the first such oil shale agreement in Mongolia.

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 33rd Oil Shale Symposium is scheduled for October 14–16, 2013 in Golden, with a field trip to Colorado and Utah. Proceedings abstracts, presentations, and papers of the Oil Shale Symposia are available at: http://www.costar-mines.org/oil_shale_symposia.html, accessed July 2, 2013. Research in oil shale processes and impacts can be found in the journal Oil Shale, published in Estonia (http://www.kirj.ee/oilshale accessed July 2, 2013). Another good reference on oil shale is a recently published book entitled Oil Shale–Petroleum Alternative (Qian and Yin 2010).

U, Th, AND ASSOCIATED REEs OF INDUSTRIAL INTEREST

Michael D. Campbell[14]

Introduction

Immediately after the Fukushima tsunami disaster in 2011, nuclear power seemed doomed, again. Japan shut down all 54 of its reactors. Germany, Switzerland, and other countries announced grand plans to phase out nuclear completely and the price of U plummeted by more than 40%. But today, a shift back toward nuclear energy is underway. New reactors are in planning and more are beginning construction in the U.S. and around the world. Major export economies in Europe and Asia have energy-intensive industries that cannot eliminate nuclear power plants on a whim. Research shows that nuclear power is gaining popularity in both governments and the general public around the world. Although the U spot price has been languishing in the low $40 range for some time, it is apparent to many that U is on the critical tipping point toward higher prices.

Ernest Moniz of Massachusetts Institute of Technology (MIT) is President Obama's choice for Energy Secretary. Dr. Moniz stated in Foreign Affairs, that ''…the government and industry need to advance new designs that lower the financial risk of constructing nuclear power plants…'' Moniz (2011). He supports development of small, modular reactors for economy of manufacturing. He also described the growth in domestic shale gas production over the past few years as paradigm-shifting from coal to natural gas and nuclear power (Wald 2013).

It is apparent that coal and associated carbon-rich natural resources can be converted to form high-grade carbon through heat and pressure, producing material similar to the naturally occurring anthracite coal and graphite (Conca 2013e). Both of these are composed of (at the submicroscopic level) stacked sheets of ''graphene,'' so named for the one-atom thick, honeycomb carbon lattices present. It appears at the atomic-scale like chicken wire made of carbon atoms and their covalent bonds (Fig. 22). Graphene is the strongest material in nature (ScienceDaily 2013) and is an important material for the construction of both historical and modern nu-

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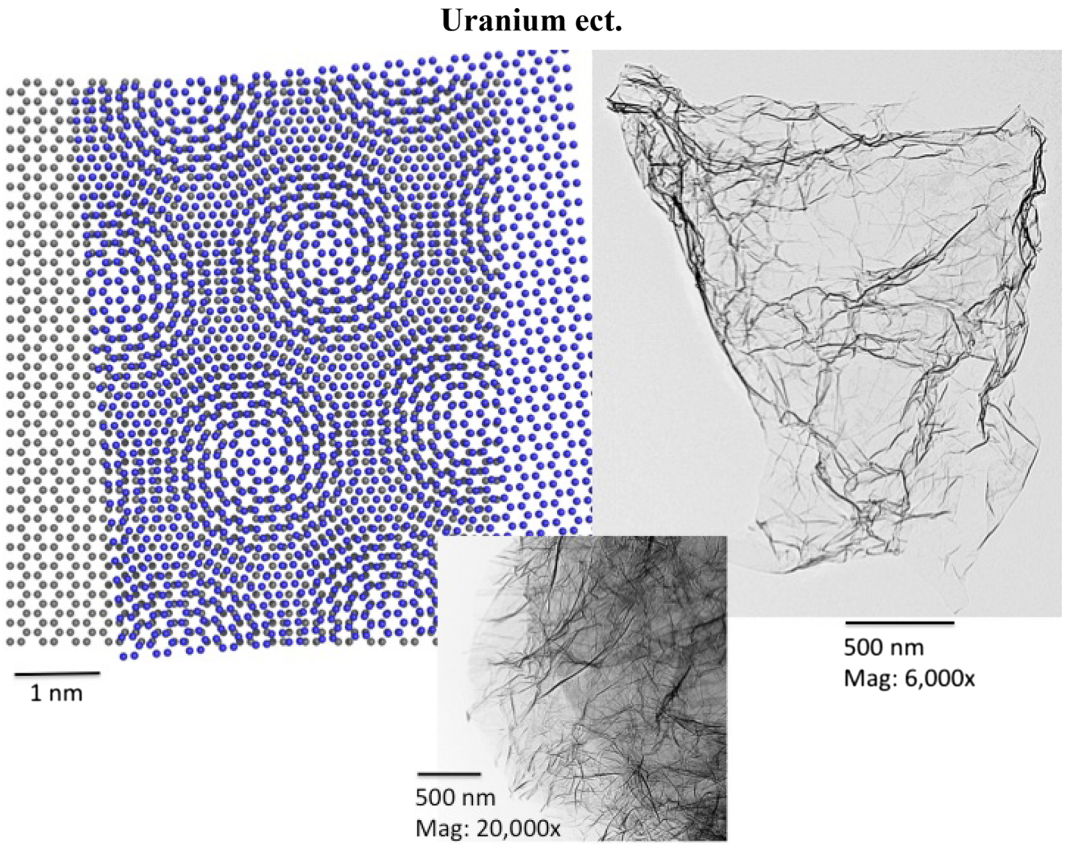

Figure 22. The regular framework structure of graphene sheets overlain upon each other show Moiré patterns, new larger periodic patterns. Image credits—National Institute of Standards and Technology (NIST) and Cabot Corporation (TEM images; http://www.cabot-corp.com/New-Product-Development/Graphenes).

clear reactors because it is one of the purest materials manufactured at industrial scale and it retains its physical and electrical properties (including strength) at high temperatures. It is used for components needed for heating nuclear fuel and in the cool-down process and can absorb heat up to 3,000°C without any consequences (NewsScience 2010). It is clear that carbon materials are increasingly important and useful resources being used to drive the expansion of a new carbon-based technology not only in the nuclear industry but also in many other applications.

In the foreseeable future, graphene use will replace the need to harvest trees and to produce petroleum used currently to manufacture wood-based and plastic-based products such as furniture, utility poles, building construction materials, and a host of other products. Coal and the other carbon-rich natural resources no longer need not be burned for the purpose of generating electricity but would be used as a feedstock to formulate carbon fiber and carbon (graphene) nanotubes that are presently used in reinforced plastics, heat-resistant composites, cell phone components, fishing rods, golf club shafts, bicycle frames, sports car bodies, and many other products, including graphite rods used in nuclear reactors to control the rate of fission. The production of these products would maintain or increase employment in the current coal industry and associated new carbon-based industries. Even as we move off-world in the coming decades, carbon products of high density and strength will also be used in exploration to protect human habitation and electronics from radiation and various types of inherent stresses in orbit or on the surface of the Moon, asteroids, and even Mars.

Natural gas and nuclear power will continue to compete for the electricity generation market for decades to come, replacing coal on the basis of its environmental unsuitability and of the likely high cost of ‘‘clean-coal’’ technology. The need for nuclear fuel in the form of yellowcake produced by

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mines will rise for decades to come. Uranium exploration will continue on Earth in regions where new discoveries have been made on every continent, except Antarctica, and off-world until fusion becomes the principal source of power perhaps at least by the end of the twenty-first century (Campbell and Wiley 2011; Campbell et al. 2013).

Introducing a major MIT report (MIT 2013) on the future of natural gas, Moniz called this transition ''a bridge to a low-carbon future'' of not burning fuels to produce electricity. ''In the long term, natural gas would also likely be phased out in favor of zero-carbon options such as nuclear power,'' he said. But ''for the next several decades, however, natural gas will continue to play a crucial role in enabling very substantial reductions in carbon emissions.''

Nuclear power is considered a low-carbon source of energy that mitigates fossil fuel emissions and the resulting health damage and deaths caused by air pollution from burning hydrocarbons and especially from coal. Jogalekar (2013) reported that Kharecha and Hansen (2013), (the latter of whom is a well-known proponent of climate change) estimated that as many as 1.8 million human lives would be saved by replacing fossil fuel sources with nuclear power.

Kharecha and Hansen (2013) also estimated the saving of up to seven million lives in the next four decades, along with substantial reductions in carbon emissions, if nuclear power were to replace fossil fuel usage on a large scale. This includes coal and hydrocarbons. In addition, their study found that the proposed expansion of natural gas would not be as effective in saving lives and preventing carbon emissions. In general, they provided optimistic reasons for the responsible and increased use of nuclear technologies in the near future.

They also emphasized the point that nuclear energy has prevented many more deaths than accidents related to production from other energy sources (coal, oil and gas, geothermal energy, wind, and solar), with the exception of hydropower. For an assessment of risks also see Campbell (2005) for a review of human risks and attitudes toward nuclear power used to supply the U.S. electrical power grid.

U.S. Nuclear Power Industry

The designed age for nuclear reactors in the U.S. is 40 years. The average age of the 104 working plants is 32 years, according to the EIA (U.S. Energy Information Administration 2013b), a part of the U.S. DOE. With age is sure to come more maintenance and more outages. Other operators are likely to take the path chosen by the Kewaunee plant in Wisconsin and by the Crystal River Plant in Florida and begin the lengthy, complex, and expensive process of shutting down, cleaning up, and decommissioning (USNRC 2013a).

Primarily a result of the Fukushima tsunami disaster in 2011, new nuclear plant safety requirements have been added to include emergency backup power and instrumentation to ensure that spent fuel pools operate adequately. All these reactors must also now have hardened vents for reactor containment structures to relieve pressure and discharge built-up hydrogen during a reactor vessel accident. The Nuclear Regulatory Commission (NRC) is also contemplating requiring filters to capture vented radioactive material.

As retirements near for many of the U.S. nuclear reactors, NRC's oversight of the trust funds used to pay for decommissioning becomes paramount. Last year, a review by the Government Accountability Office (GAO), the investigative arm of Congress, challenged NRC's formula for determining the size of these funds (USGAO 2012). The GAO report charges that the formula lacks detail and transparency, and in a sample of power plant savings programs, the report found NRC's formula may underestimate cleanup costs (USNRC 2013b). GAO investigated 12 reactors' trust funds, comparing company-prepared site-specific decommissioning cost estimates to NRC's formula. For nine reactors, NRC's formula resulted in funds below the companies' estimates. In one case, a company believed it needed $836 million, which was $362 million more than NRC's formula figure. GAO also noted NRC's funding formula was more than 30 years old (Johnson 2013).

The Vogtie Nuclear Plant in South Carolina has commenced construction of a new reactor, the second AP 1000 in America to start construction early 2013. World Nuclear News (WNN) also reported pouring of special basement concrete in South Carolina at the VC Summer Nuclear Plant. The site is the first reactor construction in 30 years. In addition, a second round of funding by the U.S. Government to encourage the development of Small Modular Reactors has begun (WNN 2013a).

Status of U.S. Uranium Industry

1st Quarter 2013 Statistics U.S. Energy Information Administration (2013c) reported that U.S. production of U in the first quarter 2013 was

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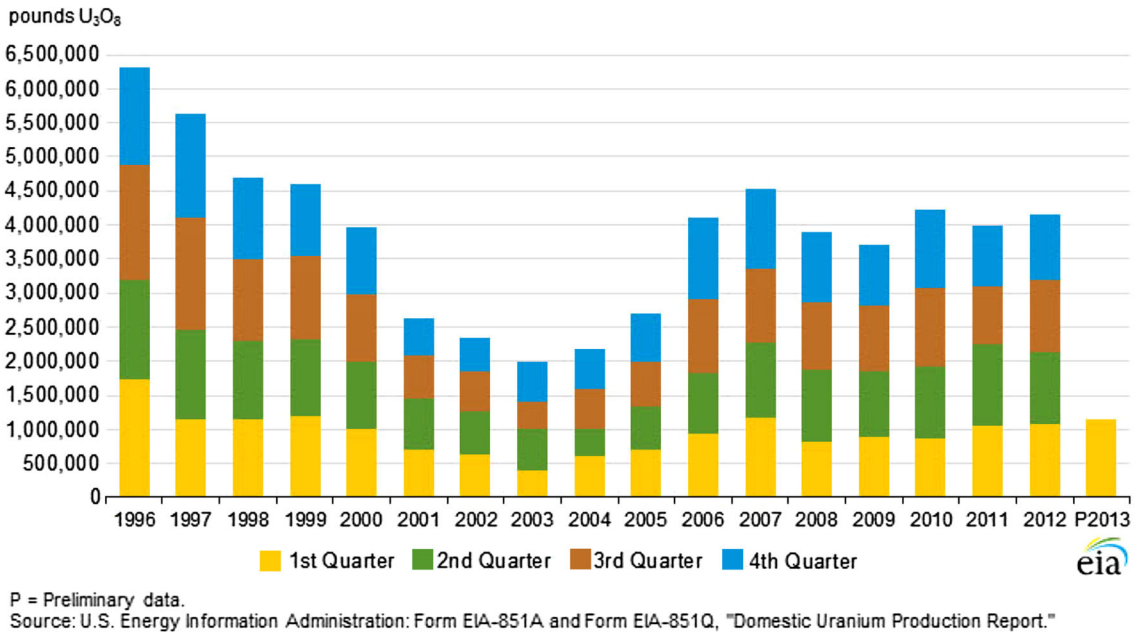

Figure 23. Uranium concentrate production in the U.S.—1996 through 1st Quarter, 2013 (from U.S. Energy Information Administration 2013c). 1 Pound = 0.45 kg.

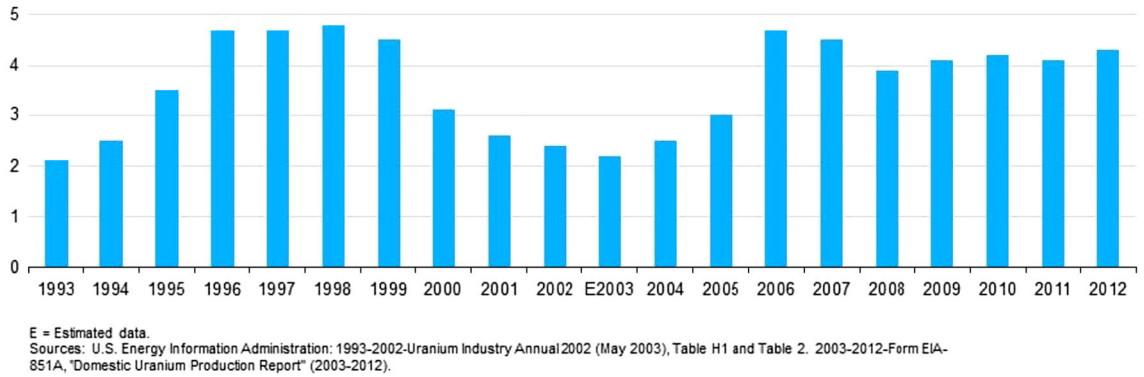

Figure 24. U.S. mine production of uranium (million pounds U_3O_8), 1993–2012. From U.S. Energy Information Administration (2013c). 1 Pound = 0.45 kg.

1,147,031 pounds (520,284 kg) U_3O_8, up 20% from the previous quarter and up 6% from the first quarter 2012. During the first quarter 2013, U.S. U was produced at six U.S. U facilities.

U.S. Uranium Mill in Production (State)

1. White Mesa Mill (Utah)

U.S. Uranium In Situ-Leach Plants in Production (State)

1. Alta Mesa Project (Texas)
2. Crow Butte Operation (Nebraska)
3. Hobson ISR Plant/La Palangana (Texas)
4. Smith Ranch-Highland Operation (Wyoming)
5. Willow Creek Project (Wyoming)

Total U.S. U concentrate production in 2012 totaled 4,145,647 pounds (1,880,434 kg). This amount is 4% higher than the 3,990,767 pounds (1,810,181 kg) produced in 2011 (Fig. 23). Figure 24 illustrates the historical total production of U from 1993 through 2012. In 2012, 4.3 million pounds (1.9 million kg) U_3O_8 were produced, 4% more

Table 11. Uranium In Situ Recovery Plants (By Owner, Location, Capacity, and Operating Status) (from U.S. Energy Information Administration 2013b)

In Situ Leach Plant Owner	In Situ Leach Plant Name	County, State (Existing and *Planned* Locations)	Production Capacity (Pounds U_3O_8 per Year)	Operating Status at End of	
				2012	1st Quarter 2013
Cameco	Crow Butte Operation	Dawes, Nebraska	1,000,000	Operating	Operating
Hydro Resources, Inc.	Church Rock	*McKinley, New Mexico*	1,000,000	Partially permitted and licensed	Partially permitted and licensed
Hydro Resources, Inc.	Crownpoint	*McKinley, New Mexico*	1,000,000	Partially permitted and licensed	Partially permitted and licensed
Lost Creek ISR, LLC	Lost Creek Project	Sweetwater, Wyoming	2,000,000	Under construction	Under construction
Mestena Uranium LLC	Alta Mesa Project	Brooks, Texas	1,500,000	Producing	Producing
Power Resources, Inc. dba Cameco Resources	Smith Ranch-Highland Operation	Converse, Wyoming	5,500,000	Operating	Operating
Powertech Uranium Corp	Dewey-Burdock Project	*Fall River and Custer, South Dakota*	1,000,000	Developing	Developing
South Texas Mining Venture	Hobson ISR Plant	Karnes, Texas	1,000,000	Operating	Operating
South Texas Mining Venture	La Palangana	Duval, Texas	1,000,000	Operating	Operating
Strata Energy Inc	Ross	*Crook, Wyoming*	3,000,000	Partially permitted and licensed	Partially permitted and licensed
URI, Inc.	Kingsville Dome	Kleberg, Texas	1,000,000	Standby	Standby
URI, inc.	Rosita	Duval, Texas	1,000,000	Standby	Standby
URI, Inc.	Vasquez	Duval, Texas	800,000	Restoration	Restoration
Uranerz Energy Corporation	Nichols Ranch ISR Project	Johnson and Campbell, Wyoming	2,000,000	Under construction	Under construction
Uranium Energy Corp.	Goliad ISR Uranium Project	*Goliad, Texas*	1,000,000	Permitted and licensed	Permitted and licensed
Uranium One Americas, Inc.	Jab and Antelope	*Sweetwater, Wyoming*	2,000,000	Developing	Developing
Uranium One Americas, Inc.	Moore Ranch	*Campbell, Wyoming*	500,000	Permitted and licensed	Permitted and licensed
Uranium One USA, Inc.	Willow Creek Project (Christensen Ranch and Irigaray)	Campbell and Johnson, Wyoming	1,300,000	Producing	Producing
Total production capacity			27,600,000		

1 Pound = 0.45 kg.

Notes: Production capacity for 1st Quarter 2013. An operating status of "Operating" indicates that the in situ leach plant usually was producing uranium concentrate at the end of the period. Hobson ISR Plant processed uranium concentrate that came from La Palangana. Hobson and La Palangana are part of the same project. ISR stands for in situ recovery. Christensen Ranch and Irigaray are part of the Willow Creek Project.

Source: U.S. Energy Information Administration; Form EIA-851A and Form EIA-851Q, "Domestic Uranium Production Report."

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Table 12. U.S. Uranium Mills (By Owner, Location, Capacity, and Operating Status) from U.S. Energy Information Administration (2013b)

Owner	Mill and Heap Leach[a] Facility Name	County, State (Existing and *Planned* Locations)	Capacity (Short Tons of Ore per day)	Operating Status at End of	
				2012	1st Quarter 2013
EFR White Mesa LLC	White Mesa Mill	San Juan, Utah	2,000	Operating	Operating
Energy Fuels Resources Corporation	Piñon Ridge Mill	*Montrose, Colorado*	500	Partially permitted and licensed	Partially permitted and licensed
Energy Fuels Wyoming Inc	*Sheep Mountain*	*Fremont, Wyoming*	725	–	Undeveloped
Kennecott Uranium Company/Wyoming Coal Resource Company	Sweetwater Uranium Project	Sweetwater, Wyoming	3,000	Standby	Standby
Strathmore Resources (US) Ltd.	*Gas Hills*	*Fremont, Wyoming*	2,200	–	Developing
Strathmore Resources (US) Ltd.	Pena Ranch	*McKinley, New Mexico*	2,000	–	Developing
Uranium One Americas, Inc.	Shootaring Canyon Uranium Mill	Garfield, Utah	750	Standby	Standby
Total capacity			11,175		

1 Short ton = 0.907 metric tonnes.
– No data reported.
[a]Heap leach solutions: The separation, or dissolving out from mined rock, of the soluble uranium constituents by the natural action of percolating a prepared chemical solution through mounded (heaped) rock material. The mounded material usually contains low-grade mineralized material and/or waste rock produced from open-pit or underground mines. The solutions are collected after percolation is completed and processed to recover the valued components. Notes: Capacity for 1st Quarter 2013. An operating status of ''Operating'' indicates the mill was producing uranium concentrate at the end of the period. Source: U.S. Energy Information Administration: Form EIA-851A and Form EIA-851G, ''Domestic Uranium Production Report.''

than in 2011, from six facilities: one mill in Utah (White Mesa Mill) and five ISL plants (Alta Mesa Project, Crow Butte Operation, Hobson ISR Plant/La Palangana, Smith Ranch-Highland Operation, and Willow Creek Project). Nebraska, Texas, and Wyoming produced U concentrate at the five ISL plants in 2012.

The U.S. EIA has added new information (Tables 11, 12) that now includes County and State location of existing and planned mills and in situ leach (ISL) plants. U.S. U mines produced 4.3 million pounds (1.9 million kg) U_3O_8 in 2012, 5% more than in 2011. Six underground mines produced U ore during 2012, one more than during 2011. Uranium ore from underground mines is stockpiled and shipped to a mill, to be processed into U concentrate (a yellow or brown powder, otherwise known as yellowcake). Additionally, five ISL mining operations produced solutions containing U in 2012 that was processed into U concentrate at ISL plants. Overall, there were 11 mines that operated during part or all of 2012. Total shipments of U concentrate from U.S. mills and ISL plants were 3.9 million pounds (1.8 million kg) U_3O_8 in 2012, 2% less than in 2011. U.S. producers sold 3.6 million pounds (1.6 million kg) U_3O_8 of U concentrate in 2012 at a weighted-average price of $49.63 per pound U_3O_8.

At the end of 2012, the White Mesa mill in Utah was operating with a capacity of 2,000 short tons (1,814 metric tonnes) of ore per day. Shootaring Canyon Uranium Mill in Utah and Sweetwater Uranium Project in Wyoming were on standby with a total capacity of 3,750 short tons (3,402 metric tonnes) of ore per day. There is one mill (Piñon Ridge Mill) planned for Colorado. Five U.S. U ISL plants were operating at the end of 2012, with a combined capacity of 10.8 million pounds (4.9 million kg) U_3O_8 per year (Crow Butte Operation in Nebraska; Alta Mesa Project, Hobson ISR Plant/La Palangana in Texas; Smith Ranch-Highland Operation and Willow Creek Project in Wyoming). Kingsville Dome and Rosita ISL plants in Texas were on standby with a total capacity of 2.0 million pounds (0.9 million kg) U_3O_8 per year. Lost Creek Project and Nichols Ranch ISR Project were under construction in Wyoming. There are seven ISL plants planned in New Mexico, South Dakota, Texas, and Wyoming (U.S. Energy Information Administration 2013c).

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Table 13. Texas Uranium Exploration Permits (By Permit Number, Company Name, and County)

Permit No.	Permittee	Texas County
118	URI, Inc.	Duval
121A	URI, Inc.	Kleberg
122 A	URI, Inc.	Duval
123 A	UEC	Goliad
124B-1	S.TX Mining Venture	Duval
125A-1	Mestena	Brooks & Jim Hogg
126 A	UEC	Karnes
127	UEC	Goliad
128	UEC	Zavala
129	UEC	Goliad
131	URI, Inc.	Jim Wells & Duval
132	URI, Inc.	Duval & McMullen
133	URI, Inc.	Jim Wells & Neuces
134	Signal Equities LLC	Atascosa
135-1	Signal Equities LLC	Live Oak
136	UEC	Briscoe
Pending	Signal Equities LLC	Bee
Pending	S. TX Mining Venture	Brooks, Starr & Hidalgo
Pending	Manti Operating Co	Karnes
Pending	URI, Inc.	Duval

Drilling Statistics in Uranium Exploration. U.S. Energy Information Administration (2013b) reports that U.S. U exploration drilling was 5,112 holes covering 3.4 million feet (1 million m) in 2012. Development drilling was 5,970 holes and 3.7 million feet (1.12 million m). Combined, total U drilling was 11,082 holes covering 7.2 million feet (2.19 million m), 5% more holes than in 2011.

Exploration has been brisk in the U.S. until recently when some exploration companies began to cut expenditures because of the uncertain future of yellowcake prices. Texas has remained active with exploration permits increasing over the past few years (see Table 13). Campbell et al. (2007, 2009) and Campbell and Wise (2010) discussed the fundamentals of U exploration, assessment, and yellowcake production.

The International Atomic Energy Agency (IAEA) has published a new report providing a description of geophysical methods in U exploration. It presents several relevant advances in geophysics and provides some evidence of advances in airborne and ground geophysics for U exploration through selected examples from industry and government entities (IAEA 2013).

Employment in the Uranium Industry. The historical total employment in the U.S. U production industry for the period 1993 through 2012 is illustrated in Figure 25. For 2012 employment, U.S. Energy Information Administration (2013b) reported 1,196 person-years, an increase of less than 1% from the 2011 total. Exploration employment was 161 person-years, a 23% decrease compared with 2011. Milling and processing employment was 394 person-years in 2012, a 6% decrease from 2011. Uranium mining employment was 462 person-years in 2012, the same as in 2011, while reclamation employment increased 75% to 179 person-years from 2011 to 2012. Uranium production industry employment for 2012 was in 11 States: Arizona, Colorado, Nebraska, New Mexico, Oklahoma, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming.

Expenditures in the Uranium Industry. Total expenditures for land, exploration, drilling, production, and reclamation were $353 million USD in 2012, 11% more than in 2011. Expenditures for U.S. U production, including facility expenses, were the largest category of expenditures at $187 million in 2012 and were up by 11% from the 2011 level. Uranium exploration expenditures were $33 million and decreased 23% from 2011 to 2012. Expenditures for land were $17 million in 2012, a 14% decrease compared with 2011. Reclamation expenditures were $49 million, a 46% increase compared with 2011. U.S. Department of interior's Budget Appropriations Bill of November, 2012, recommended reforming Hardrock Mining on Federal Lands to a leasing program, including Au, Ag, Pb, Zn, Cu, U, and Mo. Annual claim rental fees and a royalty not

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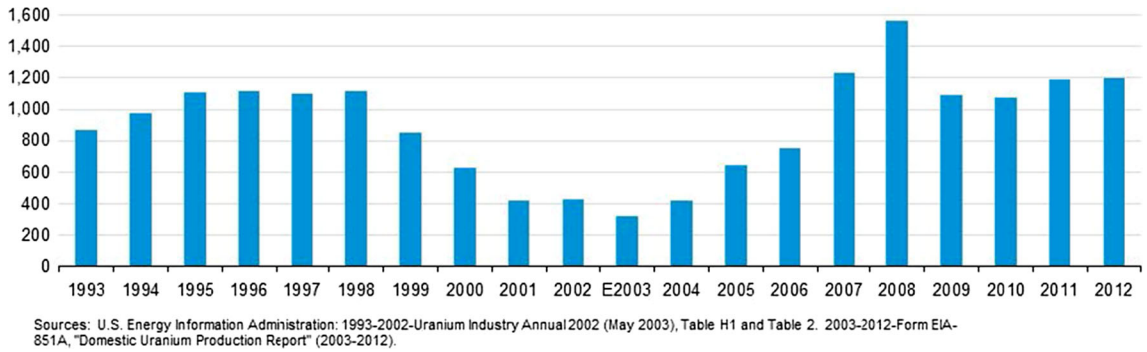

Figure 25. Employment in the U.S. uranium production industry in person-years, 1993–2012 (U.S. Energy Information Administration 2013c).

less than 5% of gross proceeds were recommended to generate Treasury fees of $80 million over 10 years (U.S. Energy Information Administration 2013c).

Uranium Reserves

The U.S. EIA in 2010 began collecting annual reserve estimates on the survey Form EIA-851A, ''Domestic Uranium Production Report.'' To date, these annual reserve estimates span data years 2009 through 2012. There are no plans to publish data prior to 2012 due to reporting inconsistencies and data accuracy concerns. The U.S. EIA indicated that the 2012 U reserves are estimated quantities of U in known mineral deposits of such size, grade, and configuration that the U could be recovered at or below a specified production cost (forward cost) with currently proven mining and processing technology and under current laws and regulations (U.S. Energy Information Administration 2013c). This information is collected from the entities that otherwise report on the Form EIA-851A; i.e., companies that conduct U drilling, exploration, mining, and reclamation.

Beginning with this report, and for the data year 2012, a new table includes U reserve estimates for mines and properties by status, mining method, and State (U.S. Energy Information Administration 2013c). Sixteen respondents reported reserve estimates on 71 mines and properties. Estimated U reserves were 52 million pounds (23.6 million kg) U_3O_8 at a maximum forward cost of up to $30 per pound. At up to $100 per pound, estimated reserves were 304 million pounds (137.9 million kg) U_3O_8. At the end of 2012, estimated U reserves for mines in production were 21 million pounds (9.5 million kg) U_3O_8 at a maximum forward cost of up to $50 per pound (U.S. Energy Information Administration 2013c).

The U reserve estimates (U.S. Energy Information Administration 2013a) presented cannot be easily compared with the much larger historical dataset of U reserves published in the EIA's July 2010 report U.S. Uranium Reserves Estimates. Those reserve estimates were made by EIA based on data it has collected and data developed by the National Uranium Resource Evaluation (NURE) program, operated out of Grand Junction, Colorado, by the U.S. DOE and predecessor organizations. The EIA data covered approximately 200 U properties with reserve estimates, collected from 1984 through 2002. The NURE data covered approximately 800 U properties with reserve estimates, developed from 1974 through 1983. Although the 2012 data collected by the Form EIA-851A survey cover a much smaller set of properties than the earlier EIA data and NURE data, EIA believes that within their scope the EIA-851A data provide more reliable estimates of the U recoverable at the specified forward cost than estimates derived from 1974 through 2003. In particular, this is because the NURE data have not been comprehensively updated in many years and are no longer a current information source. However, because much of the data gathered are proprietary and cannot be released by EIA, this makes these new reports of limited value.

In any event, potential U resources are likely to increase substantially over this decade as discoveries are made in frontier areas of the U.S. (Campbell and Biddle 1977) and in trend areas (Dickinson and

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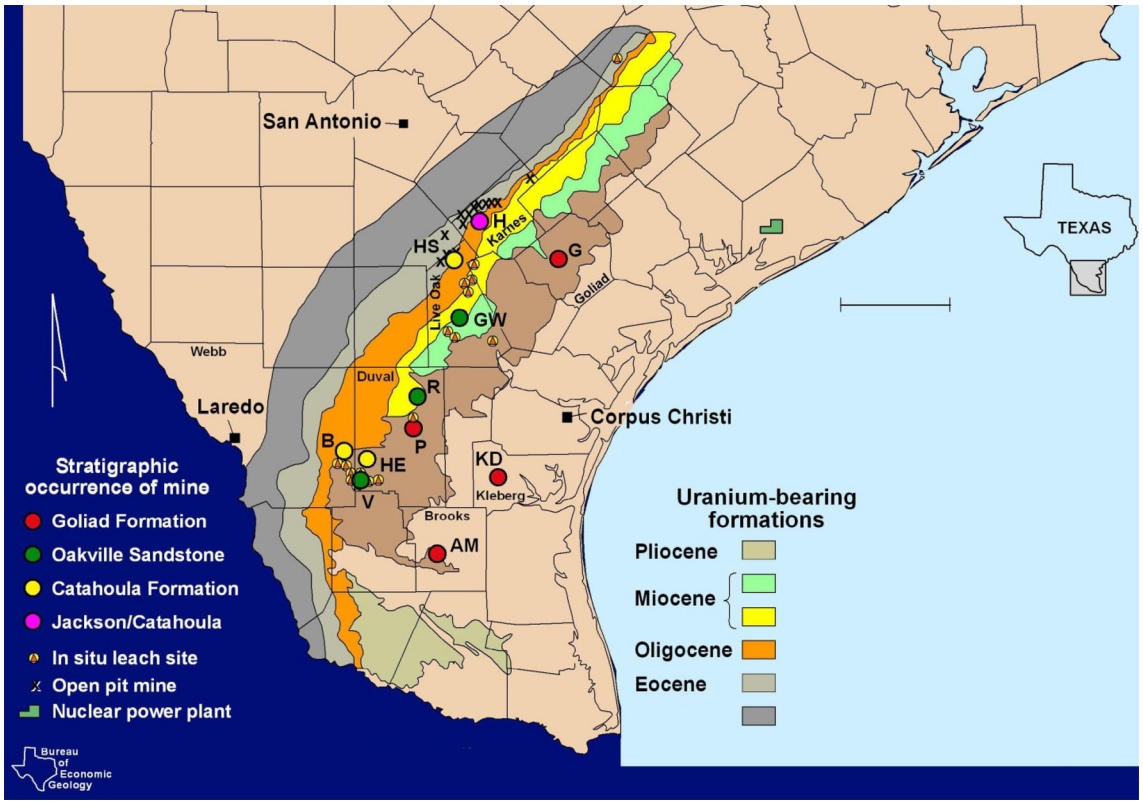

Figure 26. Uranium trends in South Texas (Ambrose 2007).

Duval 1977). The known areas in Texas that are favorable for U occurrence are suggested in Figure 26. Extensions to these areas of mineralization are likely, both along trend and at greater depths. Discoveries outside the U.S. have been made in South America, Africa, and in Australia and Canada. Greenland has confirmed a substantial, new REE and U discovery along the northern area of the Ilímaussaq Complex, which offers the potential to produce both LREE and HREE products, U, and other products (Campbell et al. 2013, p. 206). Overseas U resources were reviewed in the 2011 review in this journal (Campbell and Wiley 2011), and will be reassessed during late 2015.

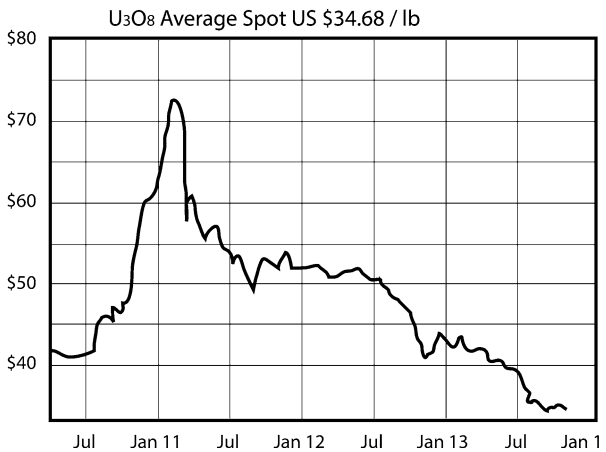

Figure 27. Yellowcake spot price (TradeTech; http://www.uranium.info/).

Uranium Prices

Industry consultant TradeTech's Weekly U_3O_8 Spot Price Indicator dropped to U.S. $34.68/lb by late 2013. U.S. $40 has been tested time and time again, but now the price level has finally been penetrated (see Fig. 27). TradeTech (2013) reported that current spot demand remains small and the only way to conclude sales at the moment is to drop prices. One non-U.S. utility has recently considered offers for over 500 thousand pounds (2,266 kg) of U_3O_8, with a supplier to be named, and the price from this transaction will likely remain around the

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U.S. $40 mark and lower. However, these prices are expected to rise over the next few months. According to global industry resource experts at Money Morning (2013), four factors could come into play to cause a major increase in the current price of U in the next few months. They are summarized and expanded in the following:

Factor 1: Increasing Demand in Developing Markets. The growth in nuclear power is centered on the emerging markets, especially China. Last summer, the Chinese cabinet reconfirmed the country's commitment to its nuclear program, saying it would begin issuing new reactor licenses again after temporarily suspending them post-Fukushima. China's renewed pledge to nuclear power means they could be adding as many as 100 nuclear reactors over the next two decades, considering that China currently operates only 15 reactors. Its capacity is likely to climb to 40 million kW from nuclear by 2015, compared to 12.54 million kW at the close of 2011. Clearly, China will need to acquire substantial U fuel, which they have apparently been doing in the spot market recently.

For instance, earlier this month Russia's state owned Atomredmetzoloto and its Effective Energy N.V. affiliate, otherwise known together as ARMZ, announced they would buy at a premium the remaining 48.6% of Uranium One, which they did not already own. This effectively solidifies them as the world's fourth largest U producer, concentrating U production even further into Russian control.

It is not just China and Russia that are recommitting to nuclear power. Other nations such as the United Kingdom, India, South Korea, and the United Arab Emirates are contemplating new nuclear power plants as well, adding to the 435 nuclear reactors already providing base-load power worldwide. Today, 65 nuclear power plants are under construction in the world, another 160 new reactors are currently in the planning stages and 340 more have been proposed. Given this activity, the demand for U will increase but there is currently a U-supply (yellowcake) deficit and this alone should result in increasing prices for yellowcake and hence increased activity in exploration and plant start-ups.

Factor 2: Growing Supply Deficit. Because of the post-Fukushima fallout, and the severely depressed yellowcake prices that followed, many U explorers and producers were forced to shelve development and expansion projects. This has led to a sizeable supply deficit. According to the World Nuclear Association (WNA 2012a), total consumption of U was 176.7 million pounds (80 million kg) in 2011 and growing, while the 2012 total U output was 135 million pounds (61 million kg). That is an annual deficit of roughly 40 million pounds (18 million kg). Altogether, by 2020, the world demand would be short by 400 million pounds. Of course, as discussed in a previous paper (Campbell and Wiley 2011, pp. 317–323), resource estimates typically rise as frontier exploration discovers new ore bodies. Such activities require time to unfold and production from a new ore body may require up to 10 years before the first yellowcake can be produced for further processing into nuclear fuel pellets and rods. However, in situ development projects often require less time to go online than open-pit operations. In the interim, yellowcake prices are likely to rise and fuel alternatives, such as Th, will emerge.

Factor 3: Japan Reverses Course. As a result of considerably higher energy costs, Japan is now shifting its stance on nuclear power. Japan's current power grid, without nuclear power, has been experiencing rolling blackouts. Natural gas imports have risen 17%, and even coal imports are up 21%. According to Japan Today, newly elected Prime Minister Shinzo Abe indicates that he is willing to build new nuclear reactors, which is a dramatic shift from the previous government's pledge to phase out all of the country's 50 working reactors by 2040. This reality is likely to spread to Germany and other countries that panicked after the tsunami in Japan a few years ago. But when Japan announced that it was shutting down its 54 nuclear power plants, they erased 20 million pounds of U_3O_8 demand, and exacerbated the pricing situation by simultaneously selling 15 million pounds U_3O_8 into the market, primarily to China.

Factor 4: Megatons to Megawatts. With the end of a program called Megatons to Megawatts this year, the fuel supply deficit will increase. The program was created in the wake of the cold war; the Megatons to Megawatts program is an agreement between the U.S. and Russia to convert highly enriched U taken from dismantled Russian nuclear weapons into low-enriched U (LEU) for nuclear fuel. The existence of this program alone covers a large portion of the worldwide annual deficit, with 24 million pounds (10.9 million kg) of U going to American utilities. In years past, up to 10% of the electricity produced in the U.S. has been generated by fuel fabricated using

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LEU from the Megatons to Megawatts program. The program will expire toward the end of 2013, if the Russians decide not to renew the agreement—and that is the general expectation worldwide—the impact would be substantial but can be offset.

A Look into the Future

In 2012, world consumption of U was 165 million pounds (74.8 million kg) versus 152 million pounds (70 million kg) of mined U production. Globally there are 434 nuclear reactors operable, 67 reactors are under construction, 159 are on order or planned, and 318 are proposed. However, just counting the reactors currently under construction, it is expected that U demand will increase by 13%, pushing up annual consumption to 200 million pounds (90.7 million kg), and that is not accounting for any reactors in the planning stages. The problem is that some experts think we may only see as much as 180 million pounds (81.6 million kg) of annual U output by 2020; and it is estimated that spot prices need to reach and remain around $70–$80/pound U_3O_8 before mining companies will be prepared to bring on new projects to reach that 180 million pound (81.6 million kg) level.

Campbell and Wise (2010) made some preliminary calculations on the likely development of production within the U.S. over the next 15 years and considered the impact of fuel additives, such as BeO and Th to improve fuel-burn efficiency on yellowcake production levels and the arrival of fast-breeder reactors by 2030. These projections may be pushed into the future some 15–20 years, although volatility in the spot and long-term price may return, which will push prices up over an extended period of time stimulating the start-up of those mines currently poised to initiate production in the U.S. and overseas including Canada, Australia, and Kazakhstan. There are plans for 13 new reactors in the U.S., three reactor units are under construction, and as many as six may come online in the next decade so U exploration and development of mines in the U.S. will need to be increased to supply these new reactors over this decade and beyond.

U.S. Uranium Activities

Exploration and mine development in the U.S., although slow at the moment, are posed to ramp up as soon as the yellowcake price begins to rise. Although Canada, Australia, and Kazakhstan can produce during low prices, the U.S. mines must have higher prices to meet stockholders expectations. The following are brief summaries of the more active companies in the U.S. by State:

Arizona. Energy Fuels Inc. has shifted focus to mining low-cost, high-grade breccia pipes. At White Mesa, milling of U and V ores continues from stockpiles.

Colorado. Energy Fuels Inc. reported that the Pinion Ridge U mill has won the approval of the Colorado Department of Health and Environment. Cotter Corporation at the Schwartzwalder Mine area will attempt a molasses and alcohol mix in Ralston Creek above the mine in a bioremediation exercise to treat a 24,000 ppb heavy metal contamination level. ASARCO Inc. is also conducting similar tests at its smelter in Denver, according to an Associated Press release to the Casper Star Tribune, March 4, 2013.

Nebraska. CAMECO Corporation continued exploration drilling at Crow Butte with two drills.

New Mexico. Strathmore Minerals Corporation announced in March (2013) that the 3-year Roca Honda Mine area study by Mangi Environmental Group's Draft Environmental Statement managed by the U.S. Forestry Service has been published. Uranium Resources Inc.'s feasibility studies at its Section 8 property in the Grants Mineral Belt reported 6.5 million pounds (2.9 million kg) of 0.11% U_3O_8 with a 67% recovery of the deposit. Direct production costs have been estimated at U.S. $20 to $23 per pound U_3O_8.

South Dakota. Powertech Uranium Corporation has its final Safety Evaluation Report for the Dewey-Burdock project, signaling the end of NRC's technical reviews and requiring only the Supplemental Environmental Impact Statement and NRC review. The 6.7 million pound (3 million kg) indicated that U_3O_8 deposit covers 17,800 acres (7,203 ha) located on the southwest flank of the Black Hills, SD. Another 4.5 million pounds (2 million kg) U_3O_8 are inferred in two additional deposits.

Texas. Uranium Energy Corporation announced on February 28, 2013 receipt of a NI 43-101 resource estimate for 2.9 million pounds (1.3 million kg)

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grading 0.047% U_3O_8 at its Burke Hollow project exploration site. Drilling has located two lower Goliad sub-roll fronts at a depth of between 700 and 860 ft (213 and 243 m).

Virginia. Virginia Energy Resources Inc. (VE) shares will be acquired by Energy Fuels to help develop the Coles Hill deposit in south-central Virginia. That deposit, the largest in the U.S., totals some 133 million pounds (60 million kg) grading 0.056% U_3O_8. VE indicates that progress is being made by the Virginia Legislature in considering lifting the State's ban on U mining.

Wyoming. Bayswater Uranium Corporation announced that it will receive investment funding of $2.5 million from Pacific Road Resources Funds, the first of a $7.5 million investment in the AUC LLC Project, where commercial production is planned for 2016. CAMECO reported that 16 production drills are active in 2013 at the Christensen Ranch project in Powder River Basin. Energy Fuels this year continues baseline environmental monitoring of properties acquired from Titan in the Great Divide Basin Sheep Mountain area. The Lost Creek Project is having some legal issues regarding permitting. In the meantime, 10 development drills were active mid-March, 2013.

Peninsula Energy Ltd. has upgraded its east Wyoming Lance resource estimates to 17.2 million pounds (7.8 million kg), measured and indicated U resources. Total resources are now at 53.7 million pounds (24.3 million kg) U_3O_8. Peninsula completed an Optimization Study showing gross revenue of $187 million with a long-term contract price of U.S. $62.33 per pound U_3O_8. Metallurgical recoveries of 64% were calculated for the associated Ross, Kendrick, and Barber production units.

Strathmore Minerals Corporation late in 2012 indicated that Crosshair Energy had returned all claims to the Juniper Ridge U property in south-central Wyoming, which is within shipping distance of Strathmore's Gas Hills proposed U mill, citing ''continued deterioration of existing market conditions.'' Crosshair drilled 549 drill holes and identified a new U trend and an NI 43-101 resource estimate of 5.2 million pounds (2.3 millon kg) U_3O_8.

Stakeholder Energy LLC and Uranium One Inc. continue U reserves development in Wyoming. Reserves are estimated to be 4.14 million pounds (1.9 million kg) with an average grade of 0.063% U_3O_8.

Canadian Uranium Activities

Canada was the world's largest U producer for many years, accounting for about 22% of world output, but in 2009 was overtaken by Kazakhstan. Production in Canada comes mainly from the McArthur River mine in northern Saskatchewan Province, which is the largest in the world (Canadian Nuclear Safety Commission 2013). A more detailed summary of activities in Canada is provided in Campbell (2013b). Production is expected to increase significantly in 2013 as the renovated Cigar Lake mine returns to operation. With known U resources of 572,000 tons (518,910 metric tonnes) of U_3O_8 (or 485,000 tons U; 439,985 metric tonnes U), as well as continuing exploration, Canada will have a significant role in meeting future world demand. The country has a very vigorous research program underway at the federal, provincial, and university levels, with considerable funding provided by industry. Exploration and mine development in Canada are also posed to ramp up as soon as the yellowcake price begins to rise. Canada can produce at some mines during low prices. The following provide a brief summary of the more active companies in Canada:

Ashburton Ventures has acquired two U properties in Saskatchewan's Patterson Lake South (Alpha Minerals/Fission Energy discovery area).

CAMECO reduced long-term U plans due to the weak global economy. CAMECO will concentrate on projects presently in an advanced stage and anticipates production of 36 million pounds (16.3 million kg) U_3O_8 annually by 2018. Cigar Lake production will commence in 2013, with expansion of the Key Lake Mill and extension of Rabbit Lake and ISL facilities.

Denison Mines Corporation reported Wheeler River drilling involves two drill rigs on a 24-hole program, with 18 holes already completed in the Athabasca Basin. At the Phoenix A deposit, four infill drill holes returned one occurrence of 3.5 m (11.5 ft) grading 36.3% U_3O_8 and three lesser occurrences grading from 13.5 to 24.1% U_3O_8, 2.6 to 3.0 m thick. Moore Lake exploration continues to encourage further drilling.

Skyharbor Resources has picked up six U exploration properties in the Athabasca Basin totaling 209,000 acres (84,579 ha) in the Patterson Lake area. Uranium mineralization is associated with granitic plutons, stocks, and felsic gneiss.

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Innuit government sources in Nunavut were indicated in www.wise-uranium.org to be changing earlier mining policy to encourage mining by reducing the current 12% royalties on all minerals, including Au and U.

British Columbia has banned U and Th exploration, for now.

Ontario's Ministry of Northern Development has modernized their Mining Act (April, 2013), allowing no staking on private lands and requiring private companies to consult with aboriginal groups.

Saskatchewan will cut royalty rates, as of March 22, 2013. No details or rates were mentioned by WISE via www.wise-uranium.org. AREVA Resources Canada was reported to have won a royalty-calculating methodology law suit against the provisional government, which must repay AREVA millions of dollars in overage charges.

Australian Uranium Activities

Australia has the world's largest Reasonably Assured Resources of U and currently is the world's third largest producer of U after Kazakhstan and Canada. There are three operating U mines, at Olympic Dam and Beverley in South Australia and Ranger in the Northern Territory, plus three additional operations are scheduled to begin production in the near future. Australia's U production is forecast to more than double by 2030. Australia is a dominant supplier to the world and has been so for the past 30 years (WNA 2012a, b). The country has a vigorous research program underway at the federal, state, and university levels. A more detailed summary of activities in Australia is provided in Campbell (2013b).

The Queensland Government has recently lifted the 10-year ban on U mining and as a result U exploration has resumed in earnest. Western Australia will also initiate U mining in the near future after many years of opposition.

Overseas Activities of Particular Note

Greenland Minerals and Energy will evaluate potential for an ''offsite refinery'' for its Kvanefjeld U/REEs project projected to offer a potential production rate of three million tons per year. The firm claims inferred U reserves of 512 million pounds (232 million kg) U_3O_8. The reserves of REEs and other metals have not been announced but are considered to be substantial.

Environmental Issues

Uranium and other nuclear minerals are critical energy resources that are necessary for generating electricity, and the nuclear industry has an outstanding safety record when all the information is considered. The Three-Mile Island incident and the Japanese earthquake that caused severe damage to the Fukushima Daiichi Power Plant have served to make the nuclear industry even stronger than before. No lives were lost at either power plant. The Chernobyl disaster does not count against the U.S. nuclear industry's safety record because the Soviet Union's nuclear industry made seriously flawed design decisions that led to the meltdown and explosion at the facility; and Chernobyl was a dual-use weapons reactor, designed to produce Pu for weapons as well as energy, so the Chernobyl disaster does not fit in the same discussion with power-reactor accidents.

According to the IAEA (2005), the Chernobyl catastrophe resulted in the deaths of a number of managers and firemen, and approximately 4,000 children and adolescents contracted thyroid cancer some years later but almost all of these recovered with a treatment success rate of about 99%. Few realize that these design decisions had been severely criticized by the West as the reactors were being built many years ago. They ignored the West's comments because of the competitive pressures of the ''Cold War.''

Community Cooperation. Campbell (2013a) has developed a program of commenting on selected media articles, which focus on inhibition of nuclear power expansion, to provide alternative opinions regarding nuclear power and U exploration and recovery.

Effects of Radiation. The World Health Organization (WHO 2013) reports that ''Clear cases of health damage from radiation generally occur only following exposure of greater than 1,000 mSv''—which is far more radiation than the reported Fukushima doses of 10–50 mSv. Radiation is also discussed in Campbell et al. (2013), which focuses on both off-world and on-Earth exposure issues. Campbell et al. (2013) indicated that: ''A fairly strong relationship

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exists between dose and cancer occurrence at high doses, but the relationship disappears below 10 rem. These observations, taken together with the fact that there has not been a single death in more than 20 years in the civilian nuclear industry in the U.S., suggest that the risk associated with chronic low doses of radiation less than 10 rem/year (0.1 Sv/year) appears to be small with respect to any other risk associated with normal living and working activities…''

Further, Conca (2013b) indicated that radiation doses less than about 10 rem (0.1 Sv) are not significant. The linear no-threshold dose hypothesis does not apply to doses less than 10 rem (0.1 Sv), which is the range encompassing background levels around the world, and is the region of most importance to nuclear energy, most medical procedures, and most areas affected by accidents like Fukushima.

The United Nations Scientific Committee on the Effects of Atomic Radiation (UNSCEAR) (United Nations 2012) reports that among other things, uncertainties at low doses are such that UNSCEAR ''does not recommend multiplying low doses by large numbers of individuals to estimate numbers of radiation-induced health effects within a population exposed to incremental doses at levels equivalent to or below natural background levels.'' (United Nations 2012; WNN 2013b).

Nuclear Wastes in the U.S.. There are four general categories of nuclear waste in the U.S. (see Fig. 28): commercial spent nuclear fuel (SNF), high-level waste (HLW) from making weapons, transuranic waste (TRU) also from making weapons, and low-level radioactive waste (LLW) from many things like the mining, medical, and energy industries. Minor amounts of other radioactive wastes are distributed among these categories. This nuclear and radioactive waste comes in four different types that are treated and disposed off in different ways and at different costs. However, most of the HLW is no longer waste with high levels of radiation (Conca 2013c).

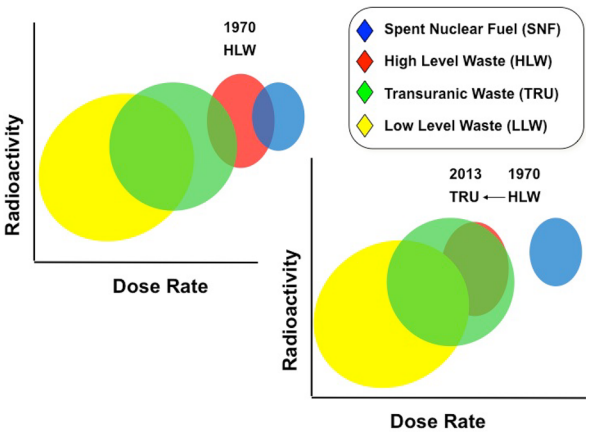

Figure 28. Types of nuclear waste (Conca 2013c).

Conca (2013c) also suggests that changing laws, regulations, and agreements are very difficult in today's political climate, but it is still a better strategy and cheaper than treating HLW that no longer exhibits high-level radiation. The cost of physically and chemically treating transuranic waste as though it is HLW is very expensive and unnecessary. He concludes that the difference is about $200 billion, suggesting that this is a significant amount to spend on a legal technicality.

Conca (2013c) indicated that the SNF is the waste with the highest radiation, consisting of two isotopes, Cs-137 and Sr-90, both with approximately 30-year half-lives, making the waste exhibit high-level radiation for less than 200 years. Similarly for HLW, it is the Cs-137 and Sr-90 that contribute the high radiation, although not as much as SNF. LLW is considered by many to exhibit low-level. TRU spans the gamut from low-level to high-level radiation, and is primarily determined by the amount of Pu, while the level of radiation is again determined by the amount of Cs-137 and Sr-90.

There is a myriad of laws and regulatory controls on all of the wastes, but this may have changed recently. The U.S. Congress took the first step in adopting a rational and achievable nuclear waste disposal plan that would reverse the catatonic state of our existing nuclear program (Conca 2013d). The Nuclear Waste Administration would be formed as a new and independent agency to manage nuclear waste, construct an interim storage facility(s) and site a permanent waste repository through a consent-based process. All of this is to be funded by ongoing fees collected from nuclear power ratepayers which have been accumulating in the Nuclear Waste Fund for decades (Conca 2013d).

University Uranium Research in U.S., Canada, and Australia

The Uranium (Nuclear and Rare Earth Minerals) Committee of the EMD is pleased to remind

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readers of the Jay M. McMurray Memorial Grant, which is awarded annually to a deserving student whose research involves U or nuclear fuel energy. This grant is made available through the AAPG Grants-In-Aid Program, and is endowed by the AAPG Foundation with contributions from his wife, Katherine McMurray, and several colleagues and friends. For further information, see American Association of Petroleum Geologists Foundation (2013).

Research in the U.S.. Uranium-related research activities at the major American universities were limited in scope in 2012. Funding was primarily from private sources, usually U mining companies. The Society of Economic Geologists (SEG) provided two student grants related to U ore deposits. One of the U-related grants was for study of U/REEs in mid-crustal systems and their links to iron oxide–copper–gold deposits while the other grant was for a study of a deposit in British Guyana. In contrast, a total of four SEG grants were for the study of REE.

In the U.S., U-related research at government agencies in 2012 was mostly limited to the USGS and the Wyoming State Geological Survey in cooperation with the University of Wyoming Department of Geology and Geophysics. The USGS continues its research into the U ore-forming processes and the geology and geochemical changes that take place during extraction and processing and into the occurrence of REEs in the U.S., especially as reported in Wyoming. For additional information on these programs, see Campbell (2013b).

Research in Canada. In Canada, U-related research is driven by a prosperous U industry and robust funding by the Canadian Government and by the Provinces involved in U exploration and mining. This funding supports numerous programs at the Geological Survey of Canada, the Saskatchewan Geological Survey, the Canadian Mining Innovation Council, and at numerous universities, i.e., Nancy Université, Queen's University, University of Regina, University of Saskatchewan, and University of Windsor. Funding is principally provided by AREVA, CAMECO, CanAlaska Uranium, JNR Resources, and Uravan Minerals among others. A more detailed summary of activities in Canada is provided in Campbell (2013b).

Research in Australia. In Australia, U-related research is also driven by an active U industry and by funding from the Australian Government via the Commonwealth Scientific and Industrial Research Organization, and the Australian National University, and by the States involved in U exploration and mining, such as Macquarie University of Sydney, University of Queensland, James Cook University, University of Adelaide, and University of New South Wales. A more detailed summary of activities in Australia is provided in Campbell (2013b).

Status of the Thorium Industry

Most of the world's nuclear power reactors currently run on U fuel. However, other designs exist that may offer more desirable characteristics. Some such designs utilize Th as the fuel, which is considered to be a more sustainable energy source. These designs are drawing increasing interest. Research is being conducted in the United Kingdom to study the viability of these designs (Sorensen 2012). Oslo-based Thor Energy is pairing up with the Norwegian government and U.S.-based (but Toshiba owned) Westinghouse to begin a 4-year test that they hope will dispel doubts and make Th a viable fuel for nuclear power (Thor Energy 2013). China is also using Canadian and American research to pursue a safe reactor based on Th (Xuqi 2011).

Moreover, pilot Th-based reactors have been built and are being evaluated. The Molten Salt Reactor, built in the Oak Ridge National Laboratory in Tennessee, ran for 4 years and helped to prove the basic concepts of a Liquid Fluoride Thorium Reactor (Sorensen 2012). The CANDU reactor in Canada also has had a long history of outstanding operation.

Thorium Resources. Geochemically, Th is four times more abundant than U in the Earth's crust and economic concentrations of Th are found in a number of countries. Geologically, Th deposits are found in various geological environments, such as alkaline complexes, pegmatites, carbonatites, and heavy-mineral sands with wide geographic distribution. For vein-related Th occurrences in the U.S., see Armbrustmacher et al. (1995).

Worldwide, current Th resources are estimated to total about six million tons. Major resources of Th are present in Australia, Brazil, Canada, India, Norway, South Africa, and the U.S. Thorium exploration is presently ongoing in some countries, such as India and the U.S. The present production of Th is mainly a by-product of processing of heavy-mineral sand

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deposits for Ti, Zr, Sn, and REEs. Thorium is widely available in Australia from sands containing monazite in heavy-mineral beach sand deposits (Memagh 2008). Thorium (and REEs) have also been tentatively identified on the Moon (Campbell and Ambrose 2010).

Status of the REE Industry

The EMD Mid-Year Report for 2011 offers the uninitiated reader an introduction to the REE commodities. That report covers the list of 17 REEs, their geological origins and distribution, production, prices, and explores some of the geopolitical issues involved, with a brief description of the REEs on the Moon. That report also contains extensive introductory discussions and references on REEs and associated deposits (Campbell 2011).

Light REEs. Binnemans et al. (2013) reported that the balance between the demand by the economic markets and the natural abundance of the REEs in ores is a major problem for the marketing of these elements. At present, the light REEs (LREEs) market is driven by the demand for Nd for use in the manufacture of neodymium–iron–boron (NdFeB) magnets. For example, only about 25,000 short tons (22,680 metric tonnes) of Nd were required for the production of magnets in 2011. This means that significant quantities of REE ores had to be mined to produce 25,000 short tons (22,680 metric tonnes) of Nd metal. Since the natural abundance of Nd is relatively low in LREE ores (say 0.10% Nd for example), then only about 300 thousand short tons (2,721 metric tonnes) of ore would needed to be mined and processed to produce 25,000 tons (22,680 metric tonnes) of Nd metal (making certain assumptions about metal recovery during mining, processing, and separating the concentrates into Nd metal), with Ce, Pr, and Sm often produced from the same ore but processed separately to produce marketable concentrates or metals.

At present the demand is not large, and although this is expected to rise as magnet demand rises, especially for Sm, the LREEs are available in various parts of the world but China is currently controlling the prices to a significant extent. For additional information on REEs occurring off-world (especially Sm) see Campbell et al. (2013, pp. 194–195).

The La market is in balance, i.e., production = sales, for use in Ni metal hydride batteries and optical glasses. Praseodymium can be used as an admixture in NdFeB magnets but not Sm. More Sm-Co magnets could be produced, but the high price of Co is an issue. To bring the LREE market into balance, new high-volume applications using Sm, Pr, and especially Ce are required.

Heavy REEs. Binnemans et al. (2013) reported that the heavy REEs (HREEs) are produced in much smaller quantities than the LREEs. Currently, the HREE market is driven by the demand for Dy, which is used to increase the temperature resistance of NdFeB magnets. About 1,600 short tons (1,451 metric tonnes) of Dy were consumed in 2011. The supply equals the demand for Eu, Y, and Er. However, there is a shortage of Tb, but this problem can still be relieved by the use of stockpiles. Gadolinium, Ho, Tm, Yb, and Lu are produced in excess and are stockpiled at most production sites around the world. New large volume applications are needed that use the heaviest REEs (Ho through Lu on the element periodic chart). Apparently, no large-scale separation of these elements is being performed by industry.

Although production levels of the REEs are relatively small, Tanton (2012) estimated that the U.S. must import 96% of the REEs consumed (and 92% of U consumed), while $40 billion in increased economic development are lost and nearly 9,000 jobs are not filled due to bureaucratic and political demands impacting mine permitting in the U.S. He recommended trade missions to Australia and Canada where mine permitting is often completed in one quarter of the time while meeting all appropriate environmental and mine-safety concerns, which minimizes mining project opponents from delaying or denying mining projects through litigation.

Status of Selected REE Projects. Although the first quarter of 2013 was challenging for the REE sector as a whole because of depressed markets for development funding, there have been some notable developments, especially with a few junior REE mining companies. China continues to acquire properties and companies in various parts of the world. Currie (2013) provided a summary of current REE activities. The following are selected highlights:

Greenland Minerals and Energy Ltd. conducted studies that show that the costs and risks associated with its Kvanefjeld project can be lowered and its financial returns increased if it establishes the

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refinery for the project outside of Greenland. The company had originally considered establishing the refinery for U and HREEs and LREEs in southern Greenland, in proximity to the mine and concentrator.

Search Minerals Inc. announced a revised preliminary economic assessment (PEA) for its Foxtrot REE project, which is located in Labrador, Canada. Highlights include a reduction in capital costs from $469 million to $221 million, with a 3.8-year payback period. Further, net revenue for the project has increased by $110 per metric tonne milled and operating expenditures have increased by $38 per metric tonne. The revised project will now focus on higher grade REE material of ''0.89% total REE … on average, which compares to the 0.58% TREE on average for the original bulk open pit concept,'' according to a press release.

Peak Resources Ltd. announced further improvements to beneficiation process for its Ngualla REE project in Tanzania. It confirmed that the ability to concentrate mineralization at an early stage prior to acid leach recovery is likely to have a ''significant impact'' on costs. One improvement is that the optimization of the beneficiation process reduces by 43% the mass of feed to be treated by the acid leach recovery process. The latest test work also indicated that conventional magnetic separation and flotation techniques will reduce the mass of the feed mineralization by 78% through the rejection of relatively mineralized barite and iron oxides. The cost reductions will be quantified in a revision of the scoping study, and an economic assessment is scheduled for completion in the second quarter of 2013.

Lynas Corporation, the major Australian REE miner, plans to implement a price schedule for its REE concentrates on July 1, 2013. The company said recent spot prices for REEs of $16 to $20 per kilogram are 25% below the price that producers need for sustainable operations. Prices had been $100 per kilogram less than 3 years ago.

Rare Element Resources Ltd. announced a 65% increase to its total measured and indicated REE resource estimate for the Bear Lodge project. The increase saw a rise from 571 to 944 million pounds (259 to 428 million kg) of rare earth oxides (REO). The updated NI 43-101 compliant resource estimate includes the first indicated resource at the HREE-enriched Whitetail Ridge deposit and high grades of critical REOs (CREOs) in all deposits. CREOs are REOs that have the highest values and the strongest projected future growth.

Great Western Minerals Group Ltd. released a PEA for its Steenkampskraal REE project that indicates strong potential for its integrated business model. Project highlights include a $555-million after-tax net present value when applying a 10% discount rate, a 28% South African corporate tax rate, and a 66% after-tax internal rate of return. On an after-tax basis, the project has a 4.3-year estimated payback period from the start of underground mining production. It also has an 11-year potential mine life.

Tasman Metals Ltd. announced the first NI 43-101 compliant independent resource estimate for its 100%-owned Olserum HREE project in Sweden. Its press release notes that highlights include a 0.4% total REO (TREO) cut-off, an indicated resource of 4.5 million metric tonnes (4.9 short tons) at 0.60% TREO and an inferred resource of 3.3 million metric tonnes (3.6 million short tons) at 0.63% TREO. It adds that ''higher value'' HREEs comprise 34% of the total REE content at Olserum, with the five critical REEs (Dy, Tb, Eu, Nd, and Y) comprising approximately 40% of the REE content.

Ucore Rare Metals Inc. confirmed that U.S. senators Lisa Murkowski and Mark Begich jointly introduced a bill in Washington, D.C. to authorize construction of a road to the Niblack and Bokan Mountain projects on Prince of Wales Island. Ucore also highlighted the introduction of Senate Joint Resolution No. 8 in the Legislature of the State of Alaska by senators Lesil McGuire, Berta Gardner, and Johnny Ellis. The resolution supports the continued and increased exploration, extraction, processing, and production of REEs in the state. It is positive news for the project as it supports a number of initiatives and urges state agencies that administer the permits required for the development of REE projects in Alaska to expedite the consideration and issuance of permits for the development of REE deposits.

Quest Rare Minerals Ltd. provided an update on the preparation of a Preliminary Feasibility Study (PFS) for the B-Zone deposit at its Strange Lake HREE deposit, located in Quebec. It confirmed that significant development work demonstrates that Strange Lake is a ''very large rare earth project'' with high concentrations of HREEs, as well as by-products such as Zr and Nb.

Further Research on Availability of REEs. On other developments, the USGS has built a website offering information on mineral deposits containing REE

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and Y in the U.S. and from around the world with geographical locations, grade, tonnage, and mineralogy, where available (U.S. Geological Survey 2013). Many publications on the various aspects of REEs, U exploration and mining, Th development, and nuclear power development are included as URLs or PDFs in the interactive I2M Web Portal. At present, the database contains almost 3,000 URLs of technical papers and news items related to the subjects covered in this review and many other subjects of interest to the geoscientist and general public (I2M Associates, LLC 2013).

EMD Uranium Committee Publications Released

The AAPG-EMD Memoir 101: *The History and Path Forward of the Human Species into the Future: Energy Minerals in the Solar System* has just been released in book form (Ambrose et al. 2013). The EMD's Uranium (Nuclear and REE Minerals) Committee and members of I2M Associates, LLC, contributed the final Chapter 9, entitled: *Nuclear Power and Associated Environmental Issues in the Transition of Exploration and Mining on Earth to the Development of Off-World Natural Resources in the 21st Century*. Since the 2012 updates to Chapter 9 were omitted during final editing, these updates have been included in a PDF version of the chapter. Chapter 9 is included as a PDF in the References list below, followed by author biographies, the Memoir 101's Press Release, Table of Contents, ordering information, book preface, and a copy of the front book cover (Campbell et al. 2013) below. Forbes.com has highlighted Memoir 101 in a recent article emphasizing the coverage of Chapters 8 and 9 (Conca 2013a).

The 2013 Mid-Year Report of the EMD Committee on Uranium (Nuclear and RRE Minerals) was released on November 15, 2013, well after this article went to press. We include a reference to the report as an update to this article (Campbell 2013c) because of the rapidly changing conditions within the nuclear industry both in the increased pace of uranium exploration in the U.S. and overseas based on the anticipation of rising yellowcake prices in 2014, the advances in thorium research, and in the changing conditions within the rare earth industry in new exploration, mining development and production facilities that are moving forward in direct competition with China.

THE SHALE JUGGERNAUT—GAINS AND CASUALTIES

Jeremy B. Platt[15]

Leading energy supply and demand developments are summarized in this overview, with an emphasis on natural gas. The time envelope is principally 2012 to mid-2013, with some historical information included along with comments and projections to 2020. The upside, or gains, from now-abundant natural gas include the flow of benefits from lower cost gas to industry (e.g., petrochemical, steel, and fertilizer) and consumers of natural gas and electricity. The downside, or casualties, include producers and processors affected by continued low prices and the sudden collapse of natural gas liquid (NGL) prices, particularly ethane and propane, and coal producers who have lost market share to natural gas-fired generation, not to mention their exposure to softening global thermal and metallurgical markets and the beginnings of a wave of U.S. coal plant retirements.

The selection of topics is far from exhaustive. Insights from analysts in industry and energy consultants, offered expressly to support the AAPG's Energy Economics and Technology Committee, are included with appreciation. Contributors are identified at the appropriate places. Additional information is derived from the U.S. EIA, the trade press, energy producers, and other public sources. This review is brief, contrasting with more lengthy material developed for the Committee a year earlier and available online to members of AAPG's EMD at http://emd.aapg.org/members_only/annual2011/index.cfm. The sequence addresses supply, resources, and market impacts. It shifts to demand, and closes with limited remarks about the coal industry.

Appreciating the Scale of the Shale Gas Phenomenon

Shale gas now accounts for about 40% of U.S. gas supply—more particularly the Lower 48 States' (L48) wellhead supply. The speed and scale of shale gas growth is remarkable and all the more astonishing in light of depressed natural gas prices and sharp curtailments of drilling. An easy way to keep

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Table 14. Shale Gas Share of L48 Wellhead Natural Gas Production

Billion cubic feet/day	U.S. Wellhead Prod.	All Shales	% of U.S.
Dec 2011	71.3	26.8	37.6%
Jun 2012	70.8	28.7	40.5%
Dec 2012	72.6	30.2	41.6%

Source: LCI Energy Insight, *G. Lippman, personal communication 11 May 2013*

track of shale gas' production growth is to consult the EIA's Natural Gas Weekly (NGW) report issued each Thursday along with the latest data on natural gas storage. While this information is widely accessible, I have rarely encountered individuals inside or outside the industry conversant with the share achieved by shale gas production. Figure 13 is taken from the latest NGW at the time of writing. The data are provided to the EIA by Lippman Consulting, Inc. George Lippman, its president, also provided the data in Table 14, which calculate the shales' share of L48 supply. The figures will not agree precisely with alternative methods of calculation, such as relying solely on EIA production statistics, but they have the advantage of assuring that production figures are derived on the same basis.

Just How Much Gas is This?

On a gross basis, 30.2 Bcf/per day (0.85 billion m^3/day) is about 11 trillion cubic feet per year (Tcf/year) (312 billion m^3/year) per day or 10 Tcf/year on a dry basis (281 billion m^3/year). Looking at EIA 2012 statistics, this amount is 1.42 times the natural gas consumed in Texas, California, and Louisiana; 2.4 times the amount of natural gas consumed in the entire residential sector; or 9.4% greater than all the natural gas consumed in electric power generation in 2012. Measured internationally, the dry gas total from U.S. shales is equivalent to 67% of all gas consumed in Russia, 2.4 times Japan's consumption (even after accounting for the 10.3% increase in Japan's natural gas consumption after the Fukushima Daiichi tsunami and nuclear disaster of March 2011); or 93% of all natural gas consumed in the five largest gas consuming countries in Europe (the United Kingdom, Germany, Italy, France, and the Netherlands). By any measure, the numbers are stunning. At this level of production, every dollar per thousand cubic feet saved by consumers from abundant natural gas adds up to direct savings of $10 billion/year.

Second Great Jump in Resource

The Potential Gas Committee (PGC) conducts biennial assessments of potential gas resources—probable, possible, and speculative resources, not reserves. Shale gas was not broken out in its 2006 assessment (Potential Gas Committee 2007), but it was estimated to be about 200 Tcf (5.7 trillion m^3) at the time. In 2008, shale gas came onto the scene in the U.S. in a dramatic way, and the Potential Gas Committee (2009) reported shale gas resources of 615.9 Tcf (17.4 trillion m^3) (all shale gas has been in the probable and possible categories), an increase of 416 Tcf (11.8 trillion m^3). The estimate increased by only 71 Tcf (2 trillion m^3) in 2010 (Potential Gas Committee 2011), reaching 686.6 Tcf (203 trillion m^3). The latest (Potential Gas Committee 2013) assessment released April 9, 2013 recorded another spectacular jump of 386 Tcf (10.9 trillion m^3), bringing the total resource attributed to shale gas to 1,073 Tcf (30.4 trillion m^3). This is 53% of the Lower 48 States resource, excluding coalbed gas. The growth in the shale resource accounted for 85% of the growth in the overall national estimate. The biggest growth occurred in the PGC's Atlantic region, which comprises the Marcellus shale, the Utica shale, other shales, and conventional resources. The Atlantic region resource more than doubled from 353.6 to 741.3 Tcf (10 to 21 trillion m^3). As this progression clearly indicates, 2012 was a very important year in both confirming and extending the resource attributed to shales. Figure 29 charts these changes. The resource doubled in 8 years. The markets are responding—both immediately and in prospect for the coming decade.

Commodity Price Collapse—Company Downgrading Risks

One effect of burgeoning production is the oversupply of 2012, which drove prices (e.g., Henry Hub) below $3.00/million Btu (the lowest prices of below

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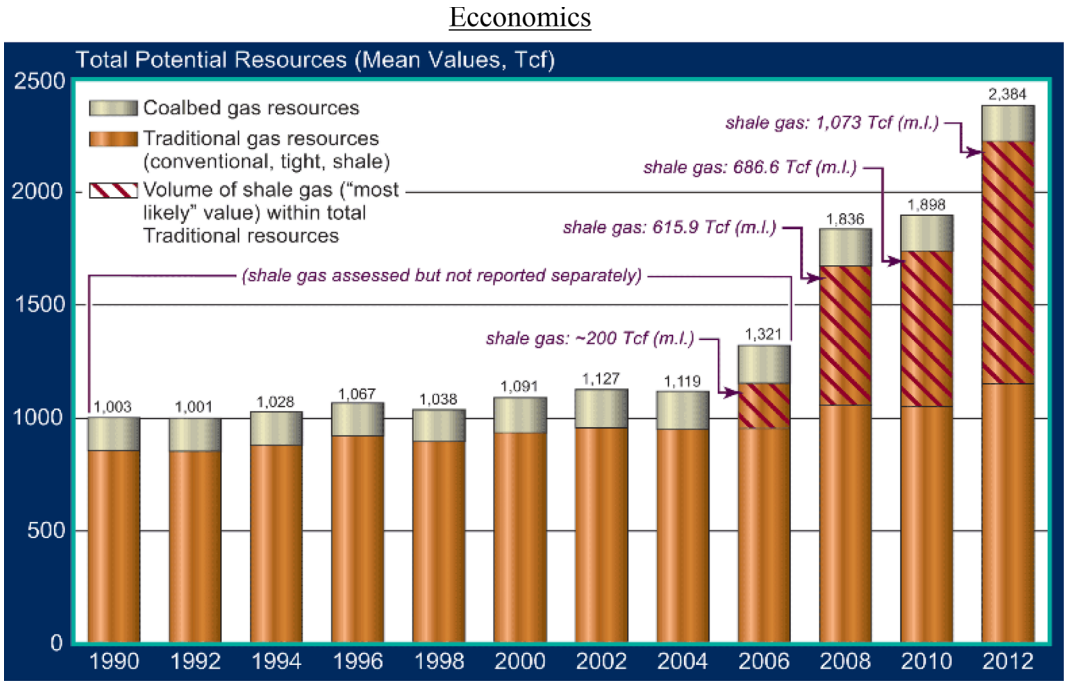

Figure 29. PGC Resource Assessments, 1990–2012. Source: Potential Gas Committee, April 2013 slideset. Used by permission of PGC, July 24, 2013.

$2.00 the first 2 weeks of April) and promoted record displacement of coal-fired generation by natural gas. This is potentially great for end-use consumers of natural gas and electricity and disastrous for natural gas producers. Its impact on power companies is mixed. Perhaps the most notable casualty of generally depressed natural gas prices, and thus power prices, is Energy Futures Holding Company, the firm created after the 2007 $45 billion buyout of TXU Corp., the largest generator in Texas. Its Achilles Heel was expectation of continuing high or rising natural gas prices—the same driver behind LNG import terminal developments at the time. Restructuring arrangements remain in limbo in mid-2013.[16]

Dr. Michelle Foss of the University of Texas pointed out the problem of company downgrading, as follows:

> ''It [natural gas] is not cheap - with a gas well you get 1/6 the Btu content for the same cost of a good black oil well and still less than one that is (hopefully) NGLs rich. The best shale wells produce less than thousand barrels of oil equivalent per day, and that is mostly dry Haynesville converted to make the books look good. We went through a list of companies that we expect to downgrade - there just aren't enough good liquids positions to be had and the ones that are out there are very expensive.'' (*Personal communication, January 24, 2013*)

Supply Momentum

To make things worse on the upstream side, an added price-weakening consideration is the many billions of dollars in yet-expended ''drill carries'' in the U.S. and Canada that will prop up exploration and production beyond the normal economics of drilling for some years to come. Drill carries are financial arrangements by which investors taking a stake in a shale producer's properties agree to shoulder some or all exploration expenses for a period of time, in effect

[16]This deal was characterized as ''the largest leveraged buyout in history.'' A natural gas price of $6.15/million Btu was cited as the break even threshold. (*New York Times*, Feb. 28, 2012. Peter Latman: ''A Record Buyout Turns Sour for Investors''). Composed of Luminant, Oncor and TXU Energy, in February, 2012 the company reported a 2011 loss of $1.9 billion. Losses since 2007 have climbed to $18 billion (Wall Street Journal, April 13, 2013. Mike Spector: ''Former TXU Seeks to Erase Debt''). Its bankruptcy ''would rank among the 10 largest in the U.S.''. (*Wall Street Journal*, July 13, 2013. Tom Fowler and Cassandra Sweet: ''At Texas Electric Firm, Users May Hold Key''). The outstanding debt of $32 billion is comparable to the value of all U.S. gas shale production over a year (10 Tcf (0.28 trillion m^3), $3.50/thousand cf, $35 billion).

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decoupling drilling from normal market signals. The period from mid-2008 through 2010 saw many such arrangements, along with outright acquisitions. These were recorded in the EMD Energy Economics and Technology Committee report of March 2011, where the total of drill carries alone had climbed to $13.2 billion. This influence has shrunken but not yet faded away. To this effect, the inventory of drilled but uncompleted wells adds to the ability to add supply at low incremental cost (*Personal communication, Steve Thumb, Energy Ventures Analysis, Inc.*).

Ethane and Propane Price Aberration

The collapse of NGL and propane prices is adding to upstream cash flow pressure even for wet gas plays. This was pointed out to me by Kyle Sawyer of Boardwalk Pipeline Partners, LP:

> ''…ethane prices dropped below rejection levels last year, starting in Appalachia and the Rockies, moving to the Mid-Continent and finally to Mt. Belvieu over the last 2 months. Propane has moved downward significantly as well due to high inventories from last year's 'non-winter' and burgeoning production.''
>
> ''The lower NGL prices are pressuring returns from the shift to the wet gas shale plays and could impact the amount of capital available for new wells, particularly since a large number of exploration and production companies are running negative cash flows.'' (*Personal communication, January 30, 2013*).

The 2011–2012 split in price trajectories is captured in the Federal Energy Regulatory Commission (FERC) Market Oversight's summary of NGL prices (Fig. 30). Rejection occurs when it is more costly to fractionate and transport ethane than to leave it in the gas stream. Both the ethane and propane oversupplies are transitory, with the timing depending on construction schedules of ethane crackers, NGL pipeline capacity, and on the market response to bargain propane and ethane prices. An implication of Sawyer's comments is that upstream market participants attempting to understand current and future revenue streams will have to be knowledgeable about much more than ''gas'' and ''oil,'' to include ethane, propane, and butanes and the fundamentals leading to their anomalous price depression. An informative web-based resource on natural gas processing economics is RBN Energy LLC (http://www.rbnenergy.com/). They have tallied an increase of over 40% in fractionation capacity over the next few years—two-thirds of which will be in the Mont Belvieu, Texas, NGL hub region (as an example, see Postel 2013).

Access to low-cost feedstock coming from expanding shale gas/liquids production is known in the chemical industry as the U.S. ''ethane advantage'' compared to facilities that use naphtha as a feedstock (e.g., Western Europe). Industry participants foresee this advantage persisting for as little as 5 years, for 10 years, for as long as shale gas remains prominent, or for as long as oil prices remain above $70/barrel. Despite the uncertainty, major investments to exploit US' globally competitive natural gas and NGL prices are proceeding apace in the industrial sector.

Shift in Fundamentals of Industrial Gas Use

The American Chemical Council (ACC 2013) issued a report in May which identified 97 projects announced by the chemical industry, amounting to a capital investment of $71.7 billion through 2020. Prior ACC studies examined impacts of more abundant natural gas on, not only chemicals, but also paper, plastics, and metals (e.g., iron and steel). A theoretical boost in ethane supply, which has subsequently begun, was also examined.

The ACC's report is a strong indicator of directional trends, but it takes a sharp pencil and intimate familiarity with each project to vet the most likely candidates and their progress to key milestones. Energy Ventures Analysis, Inc. (EVA 2013) has examined announced projects in the power and industrial sectors. Rather than focus on jobs, capital spending, and industrial policies—the principal thrust of chemical industry's voice—EVA's objective is to gauge energy use. The company's calculations are based on its vetting of announced projects and translating these into total gas requirements per year. Their results are shown in Figure 31. Among industrial demands, the chief components are petrochemicals (various substances plus methanol), fertilizer, and at the end of the decade, at least two (and possibly four) gigantic gas-to-liquids ''trains'' rated at 0.42 billion cf (11.9 million m^3) per day each. A smaller segment is represented by expansion in the steel industry. (*Steve Thumb and Jeffrey Quigley, personal communication, May 15, 2013*).

Underlying the chart shown on Figure 31, the tidal wave of growth in the industrial sector has been calculated to be about 3.6 billion cf (102 million m^3) per day or 1.3 trillion cf (36.8 billion m^3) per year, and possibly more. This is a topic that is dynamic

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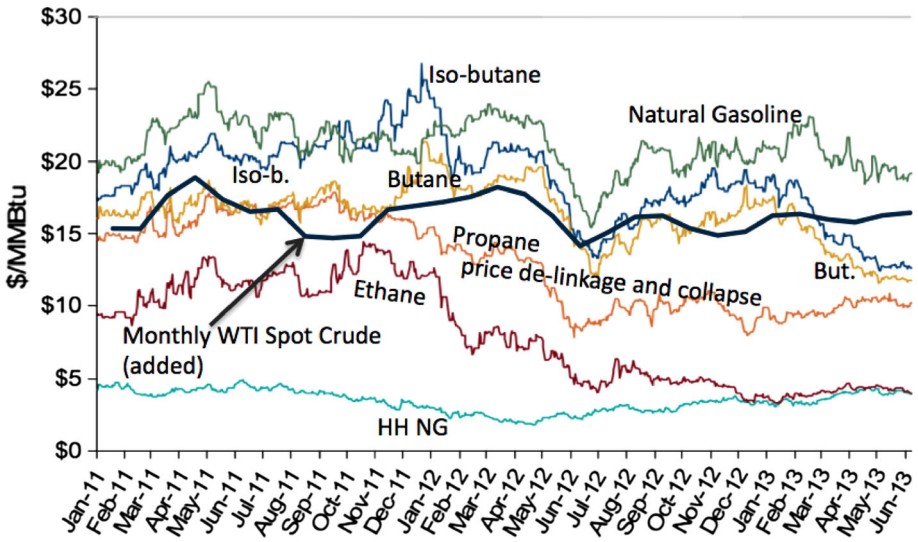

Figure 30. Ethane and propane price aberration in dollars per million British thermal units ($/MMBtu). Source: Federal Energy Regulatory Commission (FERC) Market Oversight, April 23, 2013 (Derived from Bloomberg; http://www.ferc.gov/market-oversight/mkt-gas/overview/2013/04-2013-ngas-ovr-archive.pdf). West Texas Intermediate spot crude price added by author from Energy Information Administration data (http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=M). *Iso-b.* iso-butane, *but.* butane, *HH NG* Henry Hub natural gas, *WTI* West Texas intermediate.

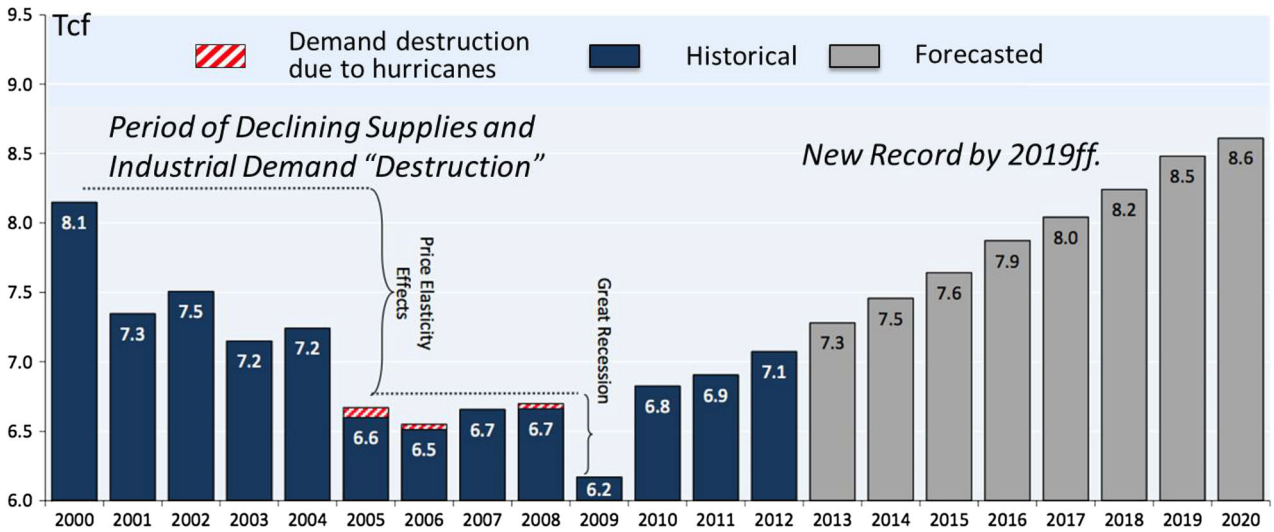

Figure 31. Industrial sector gas demand. Source: Energy Ventures Analysis, Inc. (http://eea.epri.com/pdf/epri-energy-and-climate-change-research-seminar/2013/2013_11.pdf).

and warrants continued monitoring. The broad sector is one component of increasing demand. The other major components are the power sector—experiencing swings of gas use in existing units as well as retirements and replacement of generating units over time—and LNG exports. The transportation sector remains a question mark.

Power Sector Natural Gas Demand in the Short and Intermediate Term

Short Term. Displacement of coal-fired generation by natural gas has been unprecedented and newsworthy ever since it commenced during the last 5 months of 2008, continuing essentially una-

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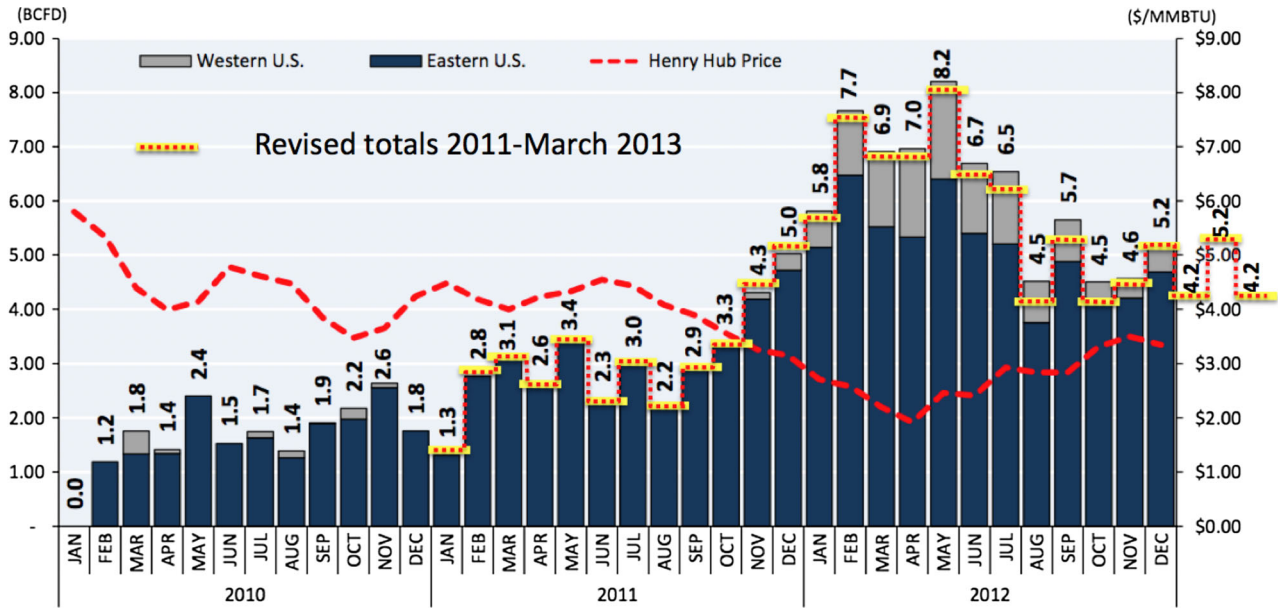

Figure 32. Monthly coal generation displaced by natural gas. Source: Energy Ventures Analysis, Inc. (http://evainc.com/publications/coal-to-gas-fuel-switching-report/).

bated and reaching peaks in 2012. Principally spurred by low gas prices, especially in 2012, it has also been spurred by the global boom in coal prices (climbing coal prices 2010 through mid-2011) and other factors. It occurs via substitution ''on the grid'' of power from gas-fired combined cycle units, not by substituting fuel into coal steam generators.

Peak monthly levels of this kind of fuel switching increased natural gas demand by as much as 8 billion cf (226 million m^3) per day in May 2012, as calculated by Energy Ventures Analysis, Inc. which prepared the analysis of monthly coal displacement/enhanced gas-fired generation shown in Figure 32. While natural gas prices recovered in 2013 and coal generation indeed increased, it is notable that very significant levels of switching continued throughout the first quarter of 2013. (*Steve Thumb and Jeffrey Quigley, personal communication, May 15, 2013*). On an annualized basis, high-efficiency gas-fired generation from 4 billion cf (113 million m^3) per day is roughly equivalent to that derived from over 70 million tons (63.5 million tonnes) of high-quality coal—one of the primary reasons for the record decline in coal generation and U.S. CO_2 emissions experienced in 2012 even as global emissions reached a new high (International Energy Agency 2013).[17]

Intermediate Term. Changes in the generation capacity mix (retirements, replacements, and new capacity additions) govern how much gas will be required for power generation in the long run. The principal impetus through mid-decade is the retirement of coal-fired capacity in response to continued competition from natural gas and investment hurdles to meet mercury and air toxics standards.

Metin Celebi of The Brattle Group emphasizes the vulnerability of coal plants to the remarkable levels of coal switching, pointing out ''Low natural gas prices (spot and forward), result not only in coal-to-gas dispatch switching and but also worse projections for coal units' future energy margins.'' (*Personal communication, January 29, 2013*). Brattle's assessment of possible coal plant retirements are summarized in Figure 3. The study (Celebi et al. 2012) indicates retirements of 59–77 GW of coal capacity by 2016, the range depending on the stringency of air

[17]This translation assumes gas-fired generation is 30% more efficient that coal-fired generation (Btu/kWh) and that the representative coal heat content is 12,500 Btu/lb.

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toxics standards. To replace the generation from 59 GW, based in these units' 2011 output, would require about 6 billion cf (170 million m^3) per day. This allows one to get a sense of the possible boost in gas use in the power sector from pending coal retirements. Some of this replacement generation has already occurred, contributing to the 2012 peaks of coal switching. Celebi et al. (2012) found that additional coal retirements from assuming $1.00/mmBtu cheaper natural gas are comparable to those which would be caused by imposing a $30/ton carbon tax. It is possible to conclude, then, that abundant gas is already impacting coal power plants like a controversial carbon tax and without incurring the political expenditure of enacting such measures.[18] Coal plant retirements are addressed again in a later section.

The U.S. government's climate policy plays into the longer term outlook. This too was highlighted by Celebi et al. (2012): "EPA's greenhouse gas limits on new generation units to be less than 1000 lbs (454 kg) CO_2 per MWh essentially block new coal units without carbon capture and storage (CCS). There are rumors that EPA will try to introduce limits for existing units as well…" (*Personal communication, January 2013*). This emission rate would make new coal plants' emission profile similar to gas units, provided one overlooks the considerable parasitic energy loss associated with CCS and the implications of lessening diversity of dispatchable generation—for neither issue is there a clear methodological path on how to take it into account.

The principal policy change announced June 25, 2013 in the President's Remarks on Climate Change (http://www.whitehouse.gov/the-press-office/2013/06/25/remarks-president-climate-change) and Presidential Memorandum—Power Sector Carbon Pollution Standards (http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards) concern development of standards during 2014–2015 to be applied to existing power plants in accord with states' implementation in 2016. This confirms the direction of the rumors noted by Celebi et al. (2012), although it is too early to see the details.

The policy direction is toward natural gas and renewables. The FERC has begun to address increasing gas dependency and deliverability risks at a regional level. This is being accomplished through a series of technical conferences under FERC auspices, according to Celebi et al. (2012). Early responses of industry organizations to the announced climate policies include concerns that natural gas, so important in its downstream applications, not be unnecessarily hindered in its upstream capabilities.

LNG Exports as a Source of Natural Gas Demand

LNG exports are experiencing a period of exuberance with ultimate outcomes still uncertain. While a large number of export applications are before the FERC and U.S. Department of Transportation Maritime Administration (MARAD) (Fig. 33), only a fraction is considered likely to move forward as a result of high capital investment costs and financing challenges, competition between sources, international competition, and U.S. policies and policy responses to market developments over time. As of June 3, 2013, FERC counts 26 export terminals. Sixteen are proposed projects (13 U.S. proposed to FERC—18.29 billion cf (518 million m^3) per day; three Canada—1.95 billion cf (55 million m^3) per day), nine are potential projects (six U.S.—6.42 billion cf (182 million m^3) per day, three Canada—3.445 billion cf (97 million m^3) per day), and one project is before MARAD/Coast Guard (3.33 billion cf (94 million m^3) per day). The total of proposed and potential capacity is 33.32 billion cf (94 million m^3) per day (U.S.—27.93 billion cf (791 million m^3) per day; Canada—5.39 billion cf (152 million m^3) per day). New projects are still being announced. A single project to date is approved and under construction, Cheniere/Sabine Pass LNG's 2.6 billion cf (73 million m^3) per day facility in Sabine, Louisiana. This brings FERC's grand total to 35.92 billion cf (1.02 billion m^3) per day.

Financial knowledge, experience, and trained skepticism are required to winnow the herd and set realistic expectations. Kyle Sawyer, Boardwalk Pipeline Partners, LP, made a cautious observation: "The LNG export projects are one of the major potential drivers for demand growth in the next 5–8 years. Although compliance with MATS (Mercury and Air Toxics Standards, discussed above) will certainly drive electric generation demand for natural gas higher, it may not be enough to balance the supply surplus without a contribution from another consumption segment such as LNG. Current

[18]The Brattle natural gas price trajectory reaches ~ $4.00/mmbtu in 2015, increasing to ~ $5.25 in 2020.

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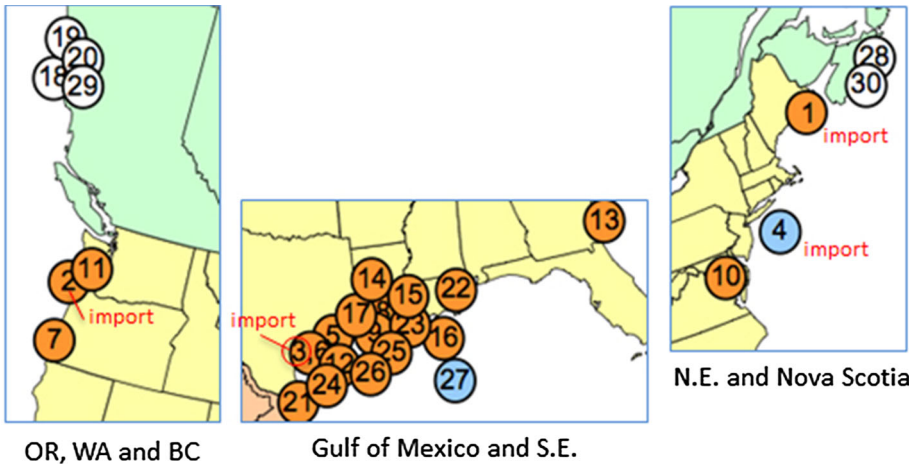

Figure 33. Proposed and potential import and export LNG facilities. Source: Federal Energy Regulatory Commission (FERC; http://www.ferc.gov/industries/gas/indus-act/lng/lng-proposed-potential.pdf); sections of original map extracted by author.

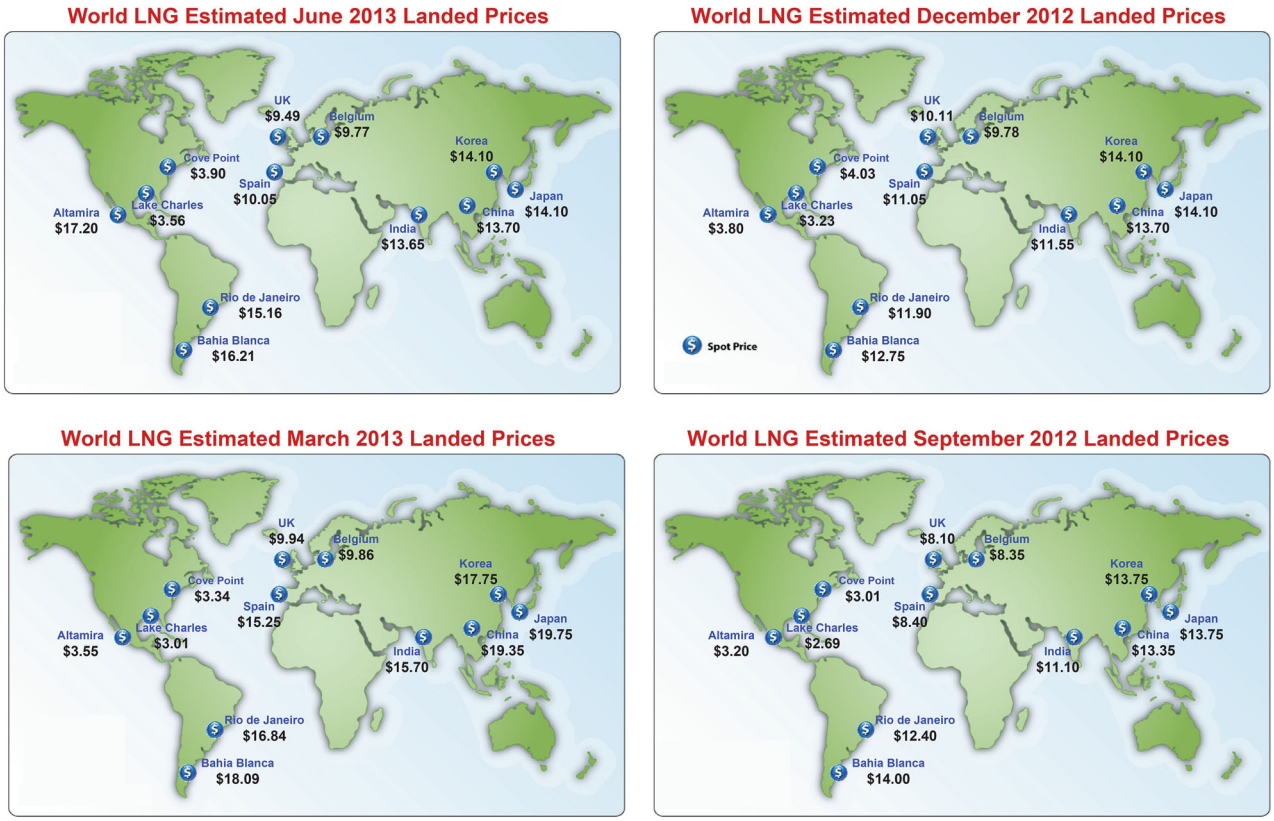

Figure 34. Spot LNG prices. Source: Federal Energy Regulatory Commission (FERC) Market Oversight (https://www.ferc.gov/market-oversight/othr-mkts/lng.asp). LNG prices provided to FERC by Waterborne Energy. The author cannot confirm whether the anomalous Altamira price for June 2013 is a reporting error.

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expectations are for LNG exports to reach ~6 billion cf (170 million m^3) per day by 2020 and it could go quite a bit higher if the DOE does not crimp investment plans." (*Personal communication, January 30, 2013*).

The lure of selling LNG overseas and particularly to the Asian markets is the historical practice of linking LNG prices to oil. Whether this linkage can hold at its current levels is a matter of debate. LNG delivered into the United Kingdom and Western Europe commands much lower prices, reflecting historical pricing linked to a basket of fuels rather than to oil alone, to more competitively priced pipeline gas, and even to coal. Even incoming oil-linked gas from Russia has been under price pressure. Transactions compiled by FERC Market Oversight in Figure 34 illustrate price changes geographically over a year. Price fluctuation is a considerable investment risk for developers. South American Atlantic coast prices appear to be tracking oil linkage.

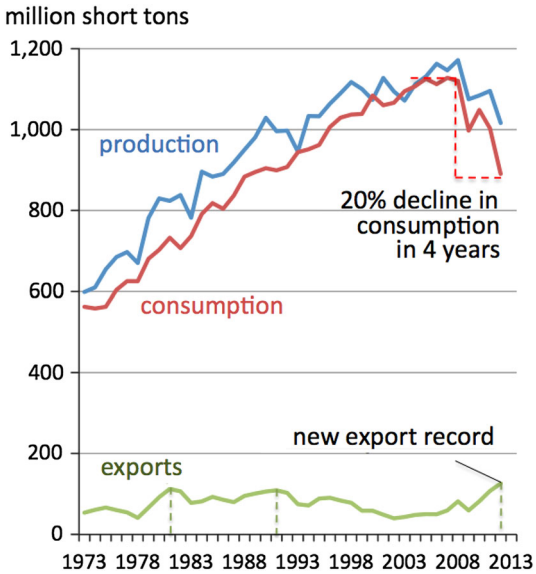

Figure 35. U.S. Coal production, consumption, and exports 1973–2012. Data source: U.S. Energy Information Administration Monthly Energy Review (http://www.eia.gov/totalenergy/data/monthly/index.cfm). Accessed April 25, 2013. 1 Million short tons = 0.907 metric tonnes).

Natural Gas and Regulations Hammer Coal in the U.S.

The turndown of U.S. coal consumption is the most immediate impact of natural gas competition. On its heels are effects of MATS-driven coal plant retirements occurring 2015–2016 and into 2017. The turndown is of historic proportions (Fig. 35). Production in 2012 (1,016 million short tons; 921.7 metric tonnes) dropped to levels not seen since before 1994 (1,034 million short tons; 938 metric tonnes); consumption (890 million short tons; 807 metric tonnes) to levels not seen since 1989 (895 million short tons; 812 metric tonnes).

Much has been said of booming U.S. coal exports (126 million short tons (114 metric tonnes) in 2012) (Fig. 35). Prior peaks in coal exports (marked with dashed lines on Fig. 35) have rivaled those of today, namely 1981 and 1991 (113 and 109 million tons; 102 and 99 million metric tonnes). In June 2013, the U.S. Energy Information Administration (2013e) reported that March 2013 exports set an all-time monthly record of 13.6 million short tons (12.3 million metric tonnes). Prior peaks were recorded April–June 2013 of 12.5, 12.3, and 12.7 million short tons (11.3, 11.1, and 11.5 million metric tonnes). Metallurgical tonnages have slightly exceeded thermal, averaging 56% of exports in 2012, 57% during the first quarter of 2013. These have offered a bright spot to various coal producers; but financially, exports have neither fully offset the domestic tonnage turndown nor the global thermal and metallurgical coal price-depressive effects from weak European economies and weakening Chinese growth.

The sector's performance and that of several U.S., U.S.-based, and international companies are shown in Figure 36. U.S. coal has been highly competitive in Europe due to far higher priced natural gas from Russia, other sources of pipeline gas (e.g., Norway, Netherlands, and N. Africa) and LNG. But the coal sector's financial performance continued to suffer. Both Peabody, with Australian production, and BHP Billiton, with Australian and other global production, are exposed to China's slowdown. As a multi-commodity energy, iron ore, metals and potash producer, BHP Billiton's slippage has been mitigated by the portfolio effect of this mix.

How does the coal industry itself view these events? Recent investor presentations, while aimed at Wall Street to respond to events without undermining confidence, gauge effects from the wave of retirements, shifts among producing regions and longer term international prospects. Alpha Natural Resources (2013) confirmed that 212 coal units, mostly in the eastern U.S., will be retiring or discontinuing to run on coal due a number of different environmental regulations. These changes amount

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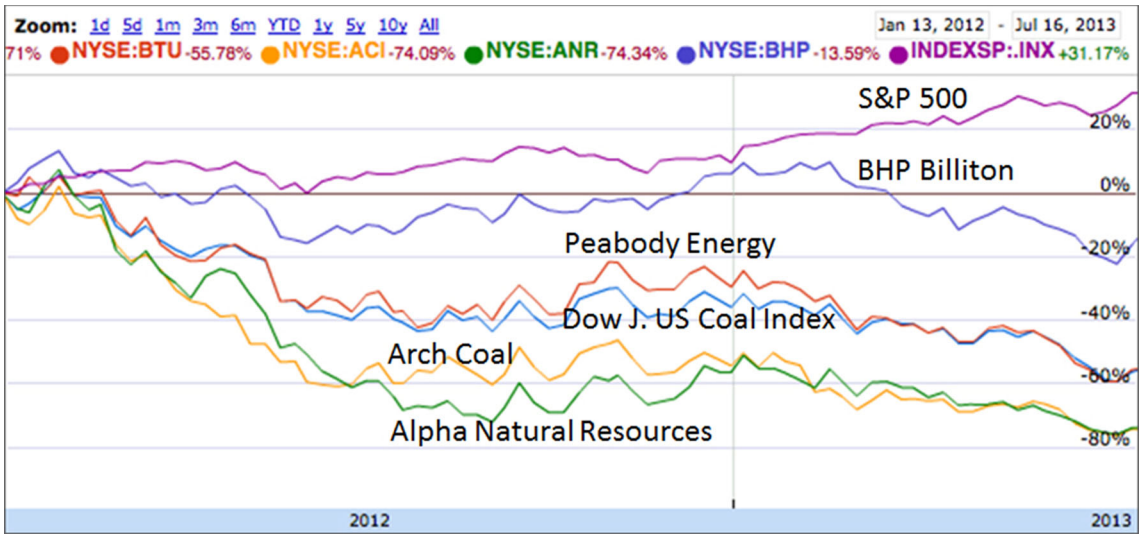

Figure 36. Selected U.S. and international coal producer performance showing weekly changes from January 13, 2012 to July 16, 2013. Source: Google Finance, (http://www.google.com/finance). Accessed July 17, 2013. *S&P* Standard and Poors, *Dow j.* Dow Jones.

to 32.8 GW.[19] John Eaves (2013), President and Chief Executive Officer of Arch Coal, Inc., described the extent of retirements as 29% of units by 2018, 13% of capacity and only 7% of coal consumption. Boyce (2013), Chairman and Chief Executive Officer of Peabody Energy, underscored the winning production regions, the Powder River Basin (PRB) and the Illinois Basin, projected to serve a 20% growth by 2017 from plants using these coals in a combination of new generation, expanded use from existing plants, and plants switching sources to these coals. They see retirements as primarily centered in the southeast U.S. and they drew attention to the prospects of greater overseas sales of these coals from both the Gulf region and from such proposed terminals as the Gateway Pacific Terminal slated to handle as much as 48 million short tons per year of Powder River Basin coal.

[19]Regulatory drivers listed are: Mercury and Air Toxics Standards, Maximum Available Control Technology standards, the Cross-State Air Pollution Rule (a reference to pollution ''transport'' regulations—due to court ruling EPA's Clean Air Interstate rule, CSAPR's predecessor, remains in effect), Coal Ash regulations and New Source Performance Standards.

Replace a Coal Plant with New Natural Gas Units? The Knife's Many Edges of this Decision

Many decisions will be made over just the next few years about keeping older coal generating units after adding high capital cost environmental controls or replacing these with new, relatively flexible high-efficiency natural gas combined cycle units. Many studies, including those cited here, have indicated how many retirements are likely and what the implications are for a surge in natural gas use (e.g., on the order of 6 billion cf (170 million m^3) per day—greater than industrial use and on par with some judgments about LNG exports). John Dean of JD Energy offers observations about the factors at play. His work pits one unknowable, the price of natural gas, against another unknowable, the timing and stringency of carbon regulations/legislation—shedding light on how solid are the computer analyses we rely on to gauge even near-term changes in the natural gas market (*Personal communication July 19, 2013*).

> ''The extraordinary fickleness of such decisions is exemplified by First Energy's Hatfield's Ferry coal units in southwest Pennsylvania, which received an injection in excess of $500 million dollars to retrofit flue-gas desulfurization (FGD) scrubbers on the plant's three 576 MW units in 2009–2010. On July 9,

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> 2013, the company announced it will deactivate the plant at the end of 2013 because it is too expensive to operate.'' (*John Dean, JD Energy*).

What happened? There are lessons in this extraordinarily compressed turn of events and scores of similar decisions which JD Energy explored by examining local economic factors at some 70 GW of coal capacity. A large fraction of this capacity is slated for retirement according to company announcements. Dean points out that the consensus view of $4–6/mmBtu gas prices over the next decade ''is not very helpful. Scores of coal plants will be competitive after retrofitting controls at $6, but will have no hope of recapturing this hefty investment if the price is $4.'' He finds that the magnitude of the capital investment in a coal retrofit (FGD, selective catalytic reduction, activated carbon injection for mercury control, and a baghouse/fabric filters) is often equal to the cost of an entirely new natural gas unit.

When coupled with risk of even a ''moderate'' carbon price of $7–15 per ton in the 2020–2025 period, he found that a plant's dispatch (i.e., capacity utilization) would fall from 65–75 to 45–60%. This destroys the economics, raising the specter that a unit will not ''outlive its investment'' and forcing companies to adopt ever more stringent criteria, such as 10-year paybacks rather than the 15–25-year norm. These considerations would tend to tilt toward plant retirement/natural gas options, but many executives remember the late 1990s gas-fired capacity building frenzy predicated on low gas price expectations, which ''led to construction of 270 MW of combined cycle (CC) and peaking units. The CCs were intended to operate at 65–70% but rarely exceeded 30% when higher prices emerged in the 2000–2007 period. This has created a 'once burned, twice shy mentality'.''

Dean concludes that a power company's perceptions of what lies ahead plays a much larger role in this kind of decision making than can be supported by any ''hard data.''

Asian Markets Define Coal's Growth Prospects

Just as Asia provides the ''lure'' for LNG export projects, it is where the action is in the global coal trade. Typical of many international energy assessments, Peabody Energy captures this phenomenon in Figure 37. The 2013–2017 period is anticipated to see a 1.1 billion metric tonne (1.2 billion short tons) expansion in coal use driven principally by China's 760 million metric tonne increase (838 million short tons), by which time China's use will have increased from about 5.2 to 6.2 times U.S. levels.

The Matter of Pacific Northwest Coal Exports. It is too early to speculate on any hard timelines or the scale or routing of coal exports out of existing (three terminals in British Columbia) or new terminals/expansions. Coal's losses in domestic markets to regulations and to cheap natural gas heighten interest in ways to expand business overseas. Gateway Pacific Terminal is located on Puget Sound between Bellingham and the Canadian border and could handle large, Capesize-class bulk vessels. It is owned by SSA Marine Terminals, with a commitment from Peabody Energy for a major share of its capacity. A second, similarly sized proposed terminal, also in the permitting stage, is Millenium Bulk Terminals-Longview (MBTL) on the Columbia River in Longview, Washington.[20] It is being advanced by Ambre Energy (62%) and Arch Coal (38%). These terminals are important to monitor due to their size and, therefore, their market impacts. Each faces strong environmental opposition. Their effects potentially reach far beyond the direct stakeholders via mechanisms of ''netback pricing.'' At some threshold of large tonnages, the value of Powder River Basin coal could become linked to the value of coal in Asian markets, even after accounting for costs of rail transportation, transloading, and ocean shipment.

An October 2012 economic analysis (McCalister 2012) calculated a $55/short ton cost advantage for PRB coal compared to major mines in Australian serving Chinese markets. Should such differentials persist, the question is how much of this advantage, after taking into account different heating values, can be captured by the final consumer as savings and by other entities in the chain (e.g., railroads and PRB producers) as enhanced profits. There are no hard and fast analytical guidelines to such calculations. A doubling of the value of PRB coal can be envisioned, theoretically, which would have tremendous impacts in energy markets and in economies. Historical price swings in international coal and shipping markets have shown that netbacks are not stable. Further instability would come from

[20]The state of Washington's Department of Ecology is a useful resource for tracking the permitting process. MBTL is entering a scoping process in 2013 to determine what to include in the coming Environmental Impact Statement. PGT has completed this phase and started to draft a preliminary EIS.

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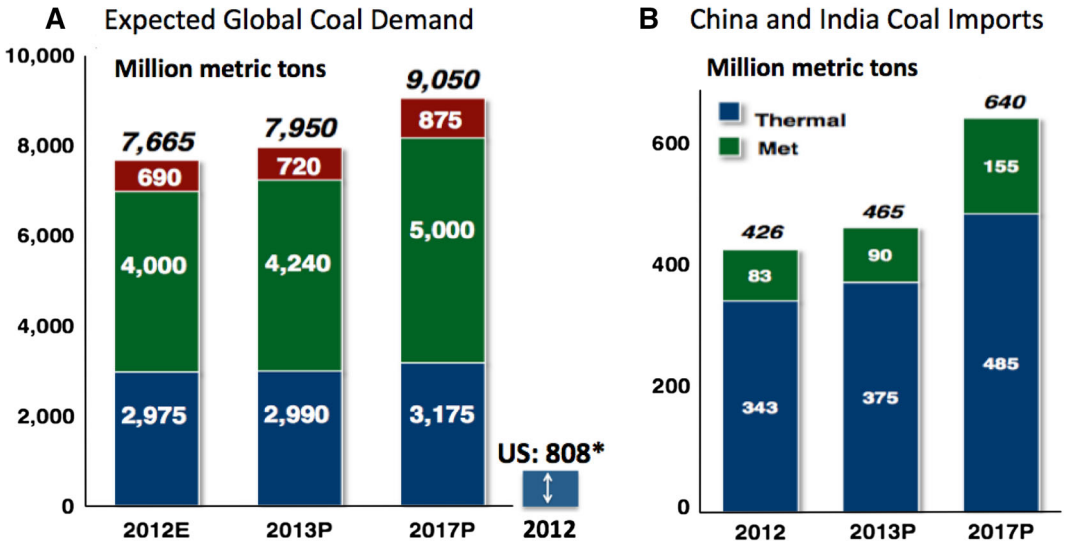

Figure 37. (A) Expected global coal demand. (B) China and India coal imports. Source: Boyce, (2013, Peabody global analytics (A, B) and India market watch (B). *U.S. 2012 consumption added for reference to (A) by Jeremy B. Platt, based on U.S. Energy Information Administration Monthly Energy Review (http://www.eia.gov/totalenergy/data/monthly/index.cfm).

supplier on supplier competition and the introduction or expansion of alternative transportation corridors—Capesize Gulf-based shipment through the enlarged Panama Canal is an example.

The Guar Gum Story: Nothing Cures High Prices Like High Prices

For economic historians, mineral economists, and managers of some of the largest oil/gas well service companies and others, the recent, dramatic boom/bust of guar gum prices is a case study of the linkage of engineering to volatile agricultural markets. Also, it is a reminder that derivative instruments so widely used to manage risk in energy markets owe their origin to risk management in agriculture.[21] 2012 is the year in which this saga came to a head. The line between gain and casualty depends on a combination of outright luck, risk management practices, and point of view.

Guar gum is a thickener used in hydraulic fracturing fluids. Its primary source is India, source

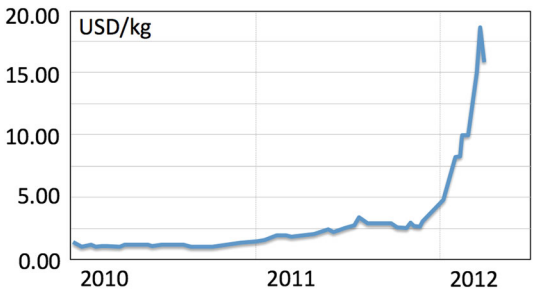

Figure 38. Guar gum price boom 2010–2012. Source: NCDEX data in Pensa (2012).

of 70–80% of the world's supply and perhaps 96% of world trade. The hydraulic fracturing boom led to escalating demand, rising prices, and then intense speculation in guar seed and gum trading in India. Exports are only permitted for the gum, not the seeds. Prices did not reach $1.00 per pound until early 2011 (Fig. 38). Facing escalating oil industry demands and poor weather, prices peaked on March 27, 2012 at 95,920 rupees per 100 kg or $8.62/pound at then current exchange rates. This triggered India's Forward Markets Commission to suspend trading for over a year, to May 14, 2013. During the shortages and with up to 20,000 pounds required per well, guar gel alone was reported to comprise as much as 30% of a hydraulic fracturing job. Plantings increased enormously. Guar seed crops have become

[21]Early trading occurred in rice (Japan). The Chicago Board of Trade (CBOT) was established in 1848 and introduced "forward" contracts in 1851. The first non-agricultural product, silver futures, did not trade on the CBOT until 1969 (CME Group timeline, http://www.cmegroup.com/company/history/timeline-of-achievements.html).

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India's most valuable export crop. With resumption of trading, spot prices had dropped to $2.45 per pound and continued to slide to $1.43 (as of June 19, 2013). The next season's crop (October) is trading even lower, $1.13. Current prices are available from India's National Commodity and Derivatives Exchange Ltd., or NCDEX, and the Multi Commodity Exchange of India Ltd. Guar gum's colorful history can be followed through news reports; these include Pensa (2012), Sharma and Gebrekidan (2012), Gupta and Sidhartha (2013), and Mishra (2013).

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