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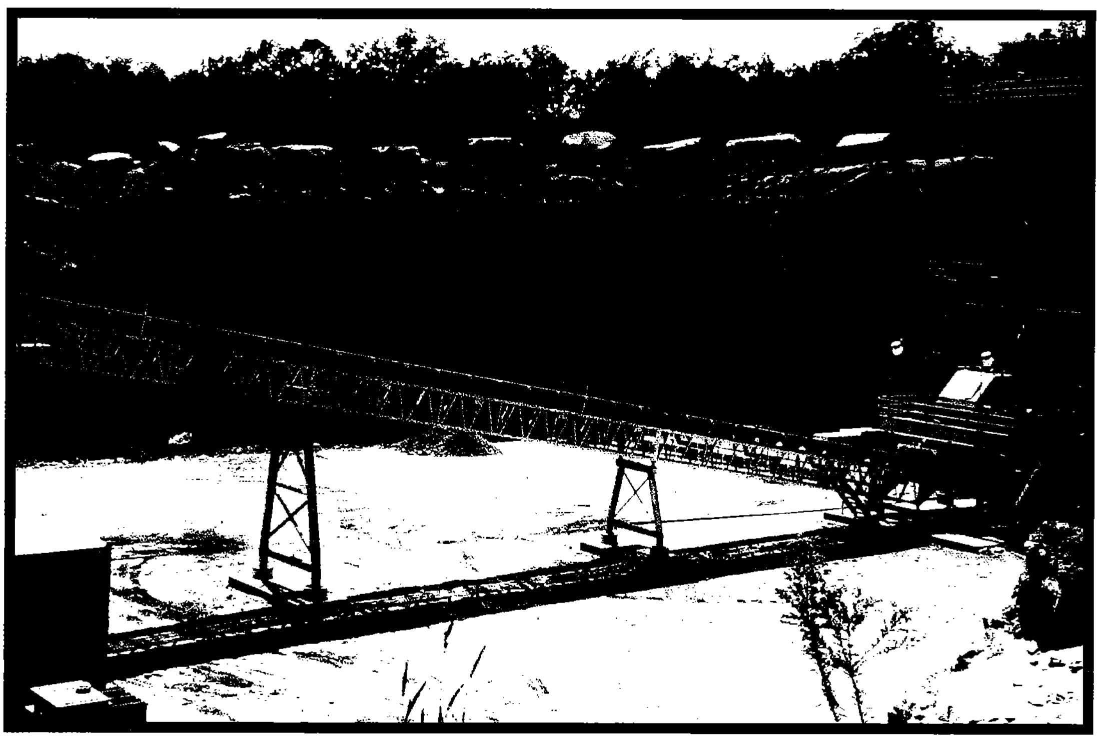

Featuring:

- *Oklahoma oil and natural gas: our place in the big picture*
- *New crushed-stone operation at Mill Creek*

on the cover

New crushed-stone operation at Mill Creek, Johnston County, southern Oklahoma

The cover photograph shows the primary crusher of Texas Industries, Inc., at Mill Creek, Johnston County, Oklahoma, which began operation in July 2002. The first shipment of its crushed-stone product was sent out by rail in August. The plant capacity is 5 million short tons per year, with scheduled production for the first year of a little over 2 million tons.

This view of the primary crusher shows dipping beds of the Reagan Sandstone of Cambrian age. The overlying Butterly Dolomite of Ordovician age is mined or quarried just west of here and hauled to the primary crusher at right, where the crushing and screening process begins. A conveyor belt carries the crushed rock from the primary crusher to additional crushing and screening stations.

The Butterly Dolomite here consists mostly of gray, medium to coarsely crystalline sandy dolomite with some finely crystalline limestone. Some thin, clay-rich shale units interbedded with the dolomite are eliminated as fines during crushing and screening.

Rail shipments to the Dallas–Fort Worth market account for most of the production, and the remainder is hauled by truck to local markets.

Exploration at this site began 4 years ago and included geologic mapping and extensive core drilling. The results indicated sufficient reserves of dolomitic rock to maintain maximum production levels for 100 years.

For more details on the Texas Industries operation at Mill Creek, see the article beginning on page 31.

—Stanley T. Krukowski

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EDITORIAL MATTER: Short articles on aspects of Oklahoma geology are welcome from contributors; please direct questions or requests for general guidelines to the *NOTES* editor at the address above.

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OKLAHOMA GEOLOGY

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Oklahoma Oil and Natural Gas: Our Place in the Big Picture

Dan T. Boyd
Oklahoma Geological Survey

INTRODUCTION

The Oklahoma energy landscape cannot be fully appreciated without an understanding of the larger, global issues that ultimately control it; hence the need to review the big picture. The conclusions in this article are predicated on a reversal of a geological axiom, "the present is the key to the past." Here, knowledge of our energy past and how we arrived at our present situation is crucial to understanding what promises to be an unsettled energy future.

This is the last of three articles examining the oil and gas industry in Oklahoma, written for non-technical readers interested in the petroleum industry. The first two, "Oklahoma Oil: Past, Present and Future" and "Oklahoma Natural Gas: Past, Present and Future," were published in the Fall and Winter 2002 issues of *Oklahoma Geology Notes*. Although each paper was written to stand alone, readers are encouraged to review the first two articles, as the principles that have shaped Oklahoma's energy history apply equally to the world at large. The articles can be purchased in hard copy from the Oklahoma Geological Survey Publications Office (405-360-2886), or accessed on the Oil and Gas page in the Fossil Fuels section of the Survey's Web site: **http://www.ogs.ou.edu/**.

The issue of energy is more critical today than ever before. Because the United States (like most of the developed world) is no longer energy-independent, issues involving domestic production, consumption, regulation, and prices must be examined against a backdrop of worldwide economic cycles and regional political stability. Security in our energy future is now inextricably linked to foreign policy and the ability to constructively interact with the governments of the producing nations on which we depend. For a nation that historically has prided itself on independence, the situation is sometimes uncomfortable. However, until consumption of fossil fuels diminishes, our long-term economic security will depend on the stability, good will, and economic interests of other nations.

Inexpensive energy in abundance is one of the greatest factors responsible for the unprecedented prosperity now enjoyed by the U.S. and the rest of the developed world. Though as history shows, dependence on oil and natural gas makes us sensitive to interruptions of supply. Whether these interruptions are short term or long, they inevitably result in higher prices that reduce economic growth; and any government that finds its economy at risk may be forced to neglect other national interests in an effort to maintain its energy supply. The precarious nature of this linchpin of the world economy, and the unforeseen consequences that securing its supply entail, will continue to rivet the attention of the world.

Much has been published about the world energy situation by the many organizations dedicated to its research. Critical variables, including size of the resource base, increases in future energy demand, and world productive capacity always will be in dispute. As a result, forecasts are often as much a function of the bias of authors as the data on which their predictions are based. Reasonable people can always disagree about the world's energy future. Even if the resource base were known precisely, and the infrastructure for moving oil and gas to the market always in place, we still would face economic, environmental, and political imponderables whose effect no one can predict. The only indisputable facts are that the world runs largely on oil and natural gas and the resource base for those commodities is finite.

As no viable alternative appears on the horizon, fossil fuels—especially oil and natural gas—will account for the vast bulk of world energy use for the foreseeable future. Although the oil and gas industry will remain an integral part of the Oklahoma economy, its health depends on price, and price is controlled by nations in the developing world where reserves and productive capacity are high but consumption is low. Thus the volume of Oklahoma oil and gas remaining in the ground is less important than how much will be economic to produce in a global market. In spite of Oklahoma's standing as a major producing state, we will experience at least as much price volatility in the future as in the past. A predicted rise in long-term energy prices will aid the State's energy industry, but the negative impact on other areas of the economy leaves the net effect uncertain.

Meanwhile, the world is producing (and consuming) more oil than is being discovered, and projections show that productive capacity will be overtaken by demand before the end of the decade. After that, prices will rise, demand will fall, and, where possible, consumers will switch to other fuels. Natural gas is the fastest growing component of world energy supply and has far more remaining reserves than oil, but major sources for both fuels tend to be concentrated in unstable areas of the world. In the U.S., demand for natural gas is met by domestic production and imports from Canada. However, North American resources can now barely meet demand, and rising consumption will depend increasingly on imports.

Despite pronouncements by ambitious politicians, U.S. energy independence in a world dominated by oil and natural gas is not possible. We can extend the life of domestic reserves by opening new areas to exploration and development, and conservation can reduce our vulnerability to shortages. However, neither the U.S. nor Oklahoma can ever reach old production highs, nor is a significant reduction in demand likely through voluntary conservation. With demand expected to increase substantially even as our domestic production declines, we will become increasingly dependent on external resources.

Even so, the future holds much promise. As our primary energy source has evolved from wood to coal, then oil, and eventually to natural gas, we have become increasingly efficient and less polluting in our energy consumption. Because energy resources are still vast, we have been able to rely mainly on the reserves that are most easily produced. The market forces of supply and demand ensure that we will never run out of energy from any source; it will simply become more expensive as the accumulations that are more difficult to produce are forced to satisfy a progressively larger share of demand.

WORLD OIL: PAST AND PRESENT

During most of human history, wood was the principal energy source. Initially abundant, cheap, and easily obtainable, it carried many societies through their pre-industrial age. Unfortunately, the legacy of large-scale wood burning is a landscape marred by clear-cut forests. In the 1800s, as wood became increasingly scarce, the United States and world energy economies gradually converted to coal (Fig. 1). An unintended benefit of this conversion was that, as dirty as coal burning was, it allowed forests to re-establish themselves in areas not committed to agriculture (Fisher, 2002). Coal assumed the bulk of the energy load from the late 1800s through the early 1900s, and, although its use remains high, throughout the developed world it was overtaken by petroleum in the mid-1900s.

For thousands of years, oil seeps and associated tar sands and asphalt deposits have been used by mankind. They occur around the globe and in many of today's major petroleum-producing areas, including the Persian Gulf, the La Brea Tar Pits of Los Angeles, and seeps in Oklahoma. Oil, in the form of asphalt, has been used throughout human history, but mainly as an adhesive or sealant. This changed in the early 1800s when, as a result of spreading prosperity, large numbers of people had the money to substitute expensive whale oil for the vegetable oil or animal grease previously used in lamps. Increased demand decimated local whale populations, forcing whalers to hunt farther afield and pushing the price for premium sperm whale oil to over $2.50 per gallon (Yergin, 1992). High prices precipitated a search for alternatives, and in the late 1840s and early 1850s it was discovered that "rock oil," now better known as crude oil, made an excellent substitute for whale oil in lamps. Rock oil had the additional advantage that it made a high-quality lubricant for machines powering the industrial revolution.

It was against this backdrop that "Colonel" Edwin Drake drilled the first producing oil well in 1859 near Titusville, Pennsylvania. He showed that high-quality crude oil could be obtained from the Earth's subsurface and that wells could produce the oil in commercial quantities. As refining techniques improved and the variety of products made from crude oil grew, uses multiplied and demand increased substantially. A major increase in demand came with the advent of the internal-combustion engine and its need for gasoline. Technological advances and improvements in refining techniques added more products and uses for crude oil. In addition to a variety of transportation uses, heating and the generation of electricity also became major uses of crude oil.

A similar sequence of events occurred throughout the Western world, spawning a global market for petroleum. Prices rose and fell, often sharply, as supply and demand sought balance. The production side included many notable discoveries: 1873, Russia (Baku); 1885, Indonesia (Sumatra); 1897, Oklahoma (Bartlesville-Dewey); 1901, Texas (Spindletop); 1905, Oklahoma (Glenn Pool); 1908, Iran; 1910, Mexico (Golden Lane); 1912, Oklahoma (Cushing); 1920, Oklahoma (Burbank); 1922, Venezuela; 1930, Texas (East Texas); 1932, Bahrain; 1938, Kuwait and Saudi Arabia; 1956, Algeria and Nigeria; 1968, Alaska (Prudhoe Bay); 1969, North Sea. Because of the petroleum industry's success in finding oil, prices remained low and oil was able to fill a progressively larger share of the world's demand for energy. Between 1949 and 1972, world energy consumption tripled, but petroleum demand rose 5.5 times (Yergin, 1992).

Petroleum in the U.S. became prominent in the early 1900s, due largely to early discoveries in Oklahoma (Boyd, 2002a), and since then both demand and production have grown rapidly if somewhat irregularly (Fig. 1). To prevent catastrophic drops in crude-oil price that could result from over-production, a group of organizations in the U.S.—then the world's largest producer and consumer—curtailed production to help balance supply and demand. The cartel, sanctioned by the government, was the precursor of the Organization of Petroleum Exporting Countries (OPEC) and was led by the Texas Railroad Commission, the Oklahoma Corporation Commission, and the Louisiana Conservation Commission. Although not sounding as threatening to Americans as OPEC, which includes two charter members of the current "Axis of Evil," this cartel performed the same function. It maintained the price of crude oil at a level high enough to sustain the petroleum industry, yet low enough to keep demand robust.

Throughout most of the 20th century the productive capacity of the United States sufficed to make up for any sud-

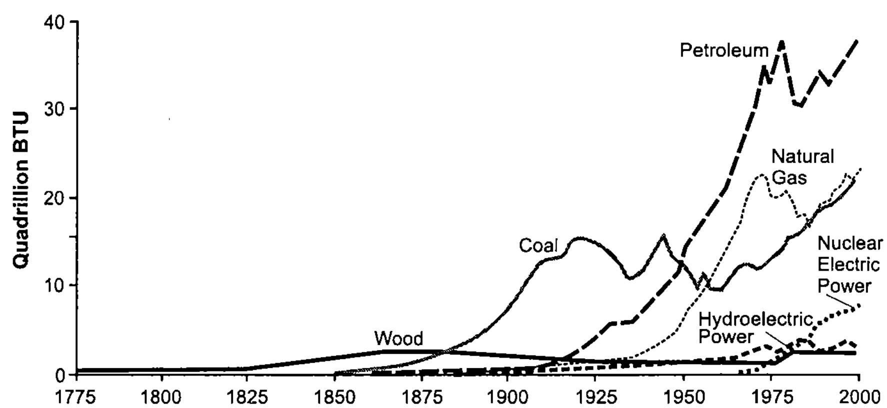

Figure 1. United States energy consumption by source, 1775–2000. From Energy Information Administration (2003).

den loss of imports. This permitted a balance of petroleum supply and demand that lasted through the early 1970s. The loss of some imports resulting from the 1967 war in the Middle East was the last major supply interruption to be overcome without a large increase in price. The shortage was made up largely by increased production in Ward and Winkler Counties in the Delaware Basin, authorized by the Texas Railroad Commission (Deffeyes, 2001). Similarly, in 2003, Saudi Arabia increased production to overcome U.S. shortages caused by strife in Venezuela. Because refineries are designed to process specific types of crude oil, this entailed the production of a crude (Arab Heavy) that matched the missing Venezuelan oil.

To reduce the negative effects from interrupted imports, the U.S. has stored about 550 million barrels of oil (MMBO) in the Strategic Petroleum Reserve. Storage is mostly in hollowed salt domes along the coast of the Gulf of Mexico. The reserve is meant to be a stopgap in the event of a major shortage; however, transporting large crude volumes from storage facilities to refineries has posed problems. In addition, the entire reserve represents only 52 days of petroleum imports, further reducing its effectiveness as a temporary source of supply.

The vulnerability of the U.S. to supply interruptions dramatically increased between the late 1950s, when excess capacity was about 4 million barrels per day (MMBOPD), and 1970, when this shrunk to 1 MMBOPD. The turning point came in March 1971 when, for the first time, Texas went to 100% allowable, placing all oil production in the country at 100% of capacity. Between 1967 and 1973, U.S. imports increased from 2.2 MMBOPD, or 19% of consumption, to 6.2 MMBOPD, or 36% of consumption (Fig. 2). That is why the 1967 embargo had no effect on supply, price, or consumption, but the embargo of 1973 (in the Yom Kippur War) led to drastically reduced supply and increased prices, and forced Americans for the first time to wait in line for gasoline. The Middle East war of 1973 disrupted the entire world economy by raising the price of a barrel of oil from $5.40 in October to $16 a month later (Yergin, 1992). This incremental price increase was followed by yet another in early 1979, when the Shah of Iran fell (Fig. 3).

For many decades the U.S. was by far the world's leading producer of oil, reaching its peak in 1970 (Fig. 4). Note: natural gas liquids are liquid hydrocarbons that condense from gas as it is produced and brought to atmospheric pressure; they are not added to the crude-oil volumes in Figure 4. Although Oklahoma's peak oil production came in the 1920s, it reached a lesser peak in the late 1960s, after which its production curve closely matches that of the United States as a whole (Boyd, 2002a). Both show a production drop in the early 1970s, a rise and secondary peak in the mid-1980s, and since then a nearly continuous decline.

In the international realm, Russian production has fallen from historic highs reached in the Soviet era, and Saudi Arabia—as the swing producer in OPEC—is believed to produce about 2.5 million barrels per day less than its capacity. As a result, in 2001 the U.S. was the world's leading producer of oil and natural gas liquids (Fig. 5; World Oil Magazine, 2002). However, the relative maturity of the U.S. oil industry is highlighted by the fact that its production in 2001 required more than 560,000 wells, while Saudi Arabia's production and much greater capacity required only 1,560 (Deffeyes, 2001).

WORLD NATURAL GAS: PAST AND PRESENT

Throughout much of history, natural gas was an enigma. Where it seeped from the subsurface it was sometimes ignited by lightning and became a burning spring—a phenomenon perceived as evidence of supernatural forces. Often springs became religious centers, a famous example being the spring associated with the Oracle of Delphi in ancient Greece.

Humans were slow to make practical use of natural gas, but about 500 B.C. the Chinese harnessed the potential of burning springs. Where gas seeped to the surface, they constructed crude pipelines of bamboo and transported the gas to locations where it could be burned to boil sea water. This

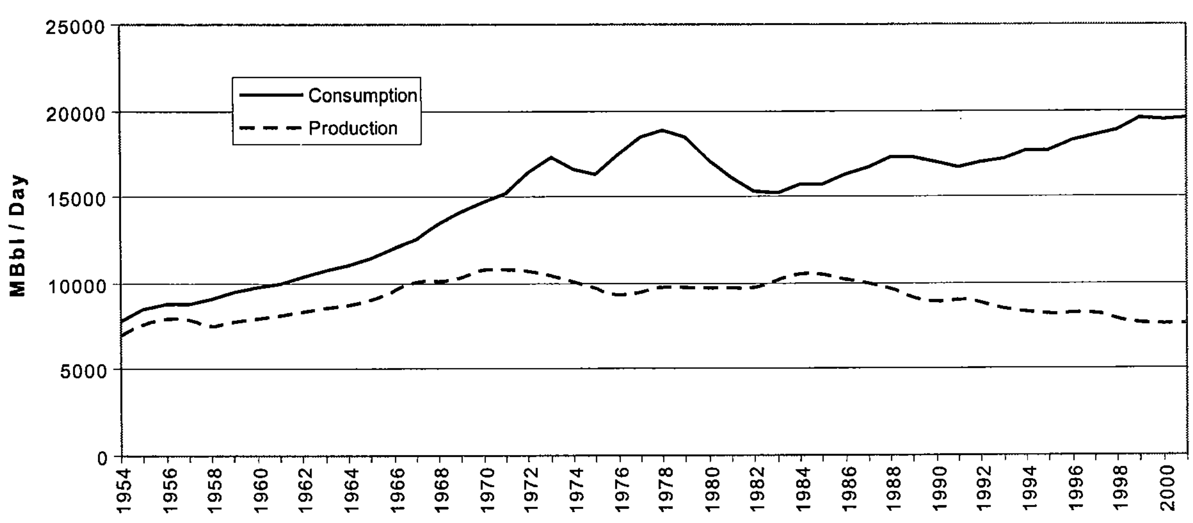

Figure 2. United States petroleum production vs. consumption, 1954–2001. From Energy Information Administration (2003).

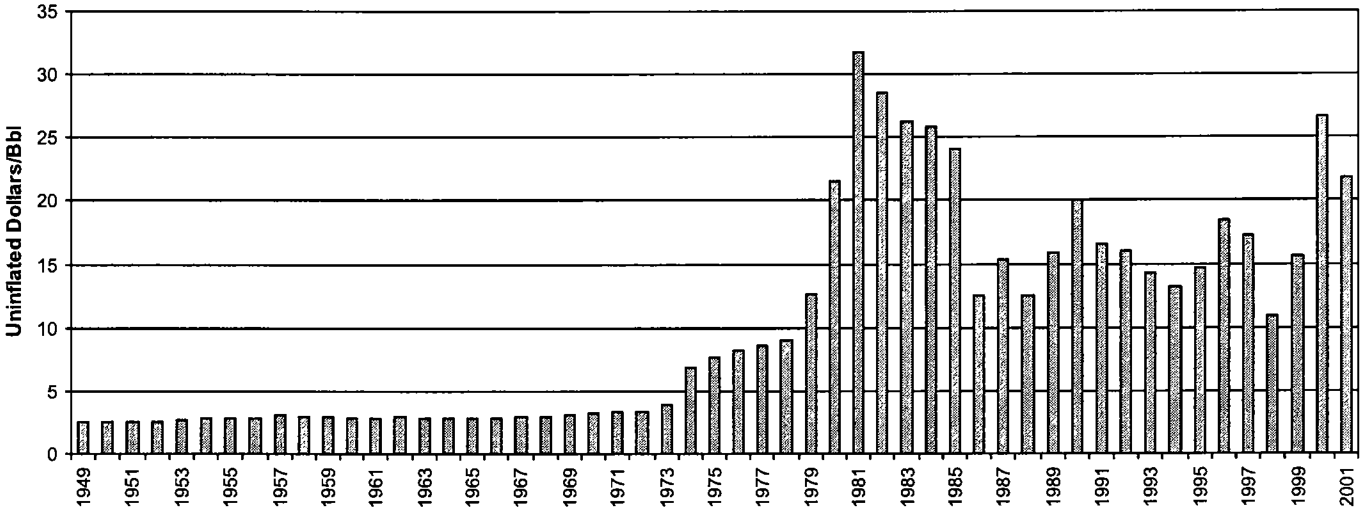

Figure 3. United States crude oil prices, 1949–2001. From Energy Information Administration (2003).

early distillation process removed salt from sea water, making it drinkable (NaturalGas.org, 2002).

Great Britain was the first country to commercialize use of natural gas, producing gas from coal in 1785 and using it for lighting. In North America, French explorers were the first to identify natural gas, observing natives in 1626 igniting seeps near Lake Erie. It was not until 1821 that the first well was dug with natural gas as the objective. In that year, William Hart (regarded by many as the father of natural gas in America) noticed gas bubbling to the surface of a creek at Fredonia, New York, and dug a 27-ft well to increase the flow (NaturalGas.org, 2002).

During most of the 19th century, natural gas was used almost exclusively for illumination in cities and businesses close to a source of supply. Demand remained low because, lacking pipelines, it was impossible to make gas widely available. Construction of large pipeline systems in the early 1900s led to a dramatic increase in demand. This led to the widespread home use of natural gas in heating and appliances, and its industrial use in manufacturing and processing plants (NaturalGas.org, 2002). Because gas is less expensive than oil as measured by equivalent heating capacity (or energy equivalence), it gradually replaced oil as a boiler fuel, and is now second only to coal in the generation of electricity.

Natural gas is found in conjunction with oil, and in the early days was usually considered a nuisance or a drilling hazard. Because gas had little value, when encountered it was commonly vented or flared until drillers determined whether oil was present in the reservoir below the gas (Boyd, 2002b). Difficulty of transport and the lack of local markets kept most early drilling focused on oil, and it was not until the late 1970s—with oil embargos, price deregulation, and the resulting increases in demand and price—that natural gas became a major exploration objective in many parts of the world.

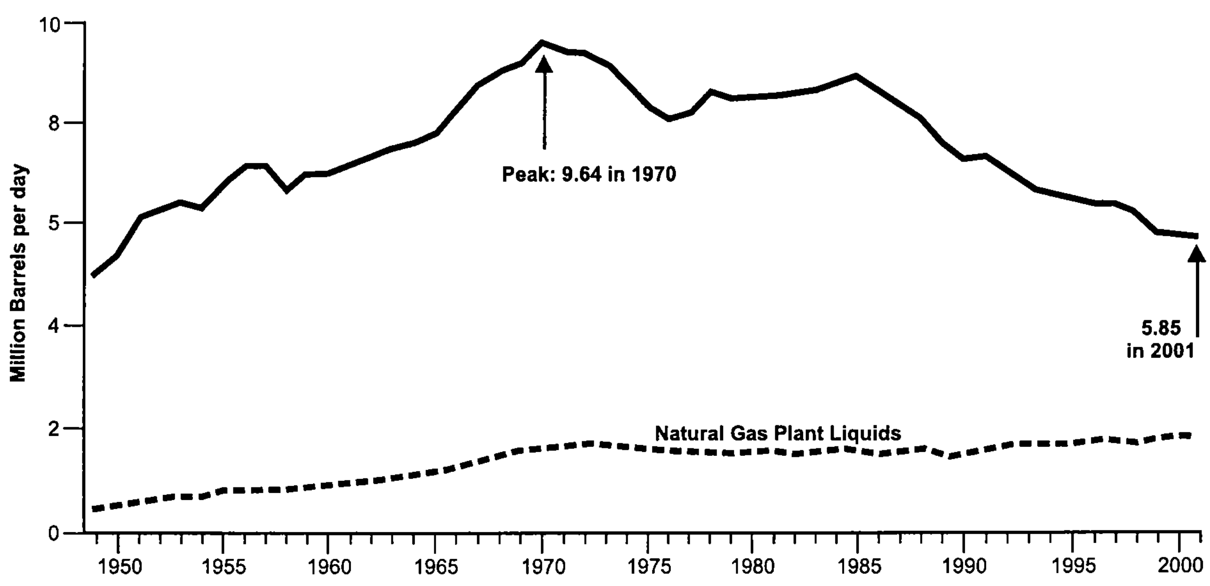

Figure 4. United States crude oil and natural gas liquids production, 1949–2001. From Energy Information Administration (2003).

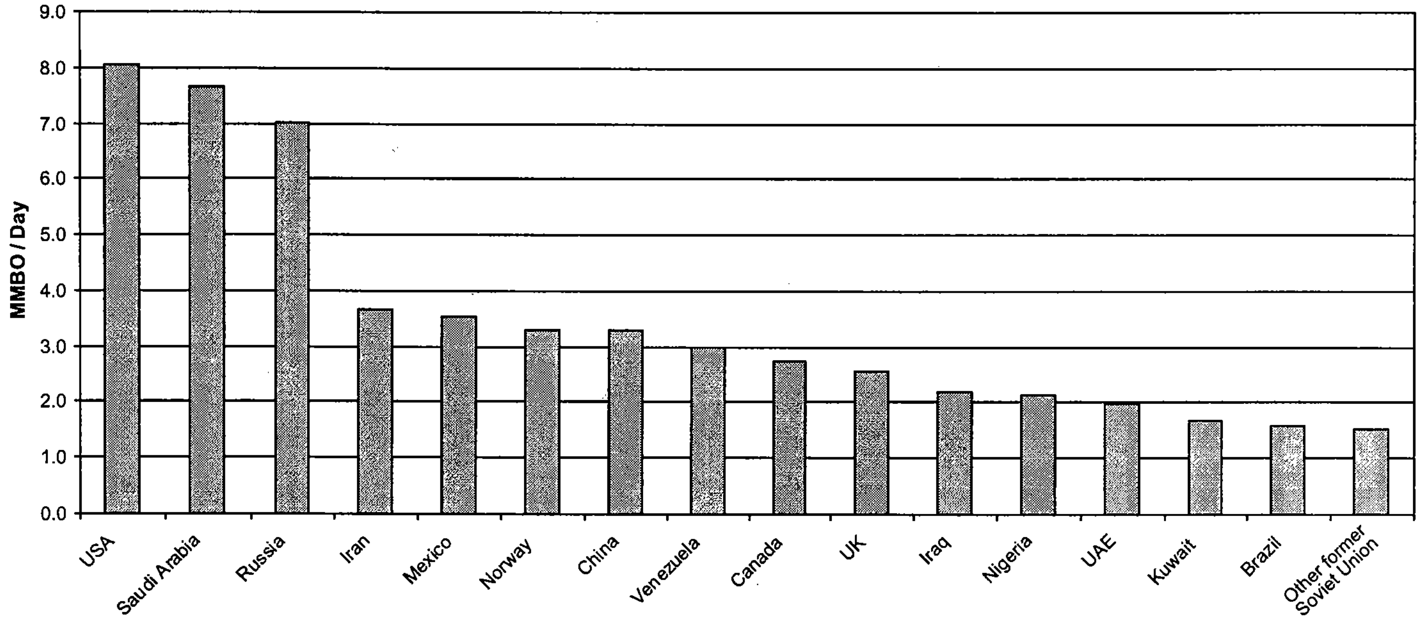

Figure 5. Daily national petroleum production (crude and natural gas liquids) for the top world producers. 2001 data from *World Oil*, from Energy Information Administration (2003).

In the same way that oil gradually supplanted coal in overall energy consumption, so natural gas began its rise to prominence 25–30 years later than oil. Although the uses of oil and gas differ, graphs of national consumption reveal parallel courses (Fig. 1), and with gas-price deregulation in the 1970s, the pattern is likely to continue. Deregulation has allowed the price to move with market demand; thus the correlation of oil and natural gas prices shown in Figures 3 and 6 (Boyd, 2002b). A similar parallel appears in graphs of U.S. production and consumption. Where the curves separate, imports begin rising rapidly. For oil the rise begins about 1967 (Fig. 2) and for gas 1986 (Fig. 7). Although it is not apparent in the figures, prior to 1958 the U.S. was a net gas exporter. The decline in production and consumption from 1972 through 1983 was due to rapid increases in gas price and the perception of a shortage, leading to government policies discouraging its use (U.S. Geological Survey, 2002).

The production of gas worldwide is—unlike oil—a function of access to a major market. Because the infrastructure for producing and transporting gas is expensive, long-term markets must be secured before development begins. If the market is overland, a pipeline system can be used to move the gas to market (for example, Russian gas exports to Europe via the Trans-Siberia Pipeline). If the market is overseas, the solution is usually shipment of liquefied natural gas (LNG) in the way that Indonesia supplies gas to Japan, South Korea, and Taiwan—from large LNG facilities in Sumatra and Kalimantan (Borneo). LNG is made by cooling natural gas until it liquifies. The supercooled liquid is then shipped in tankers that maintain the gas in a liquid state. Upon arrival at an offloading facility, the LNG is allowed to warm and revert to a gaseous state, whereupon it is sent via pipeline to consumers.

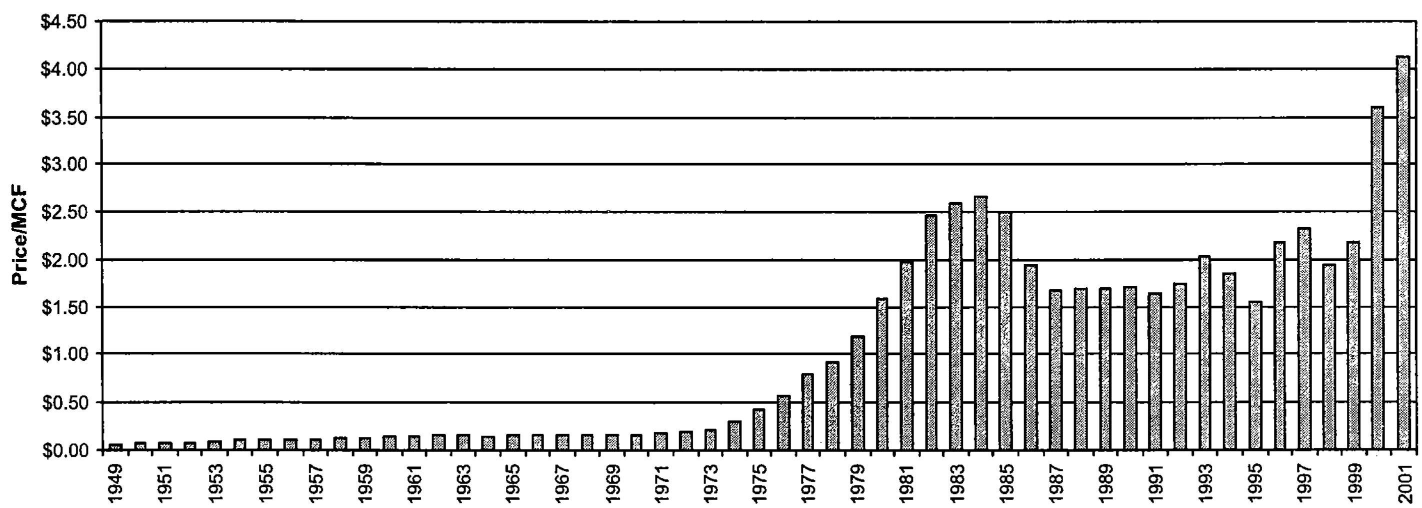

Figure 6. United States average wellhead natural gas price, 1949–2001. From Energy Information Administration (2003).

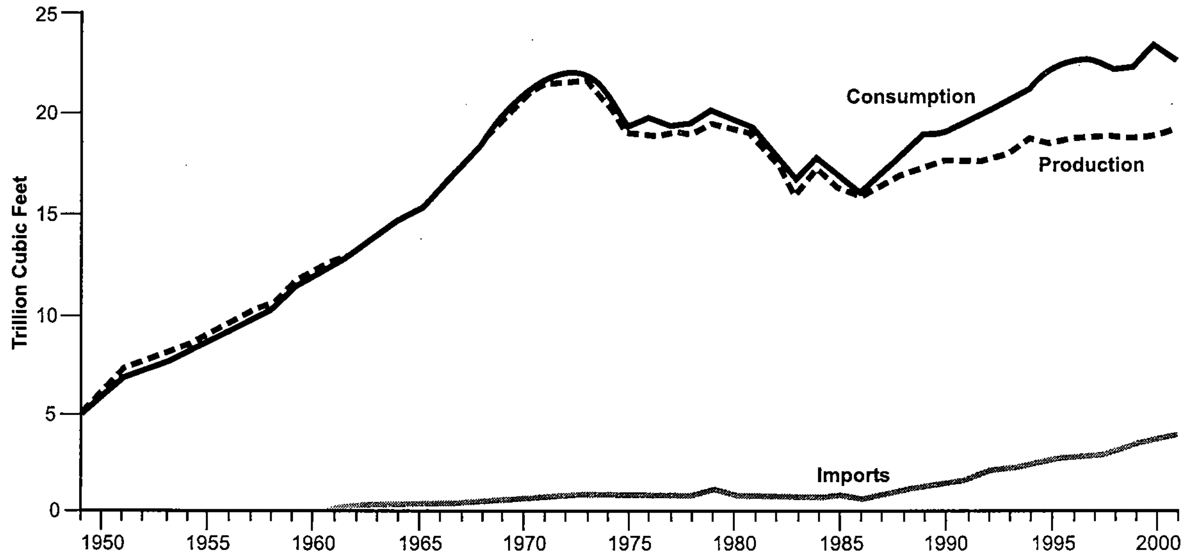

Figure 7. United States natural gas overview, 1949–2001. From Energy Information Administration (2003).

Because the up-front costs for both pipeline systems and LNG infrastructure are often measured in billions of dollars, the desire to insure that these investments are recouped is strong. To do so, a long-term gas market must be secured through contracts that are designed to protect both the buyer and seller. Under these the importer is committed to buy gas from the same facility for the life of the contract, but the price of the gas delivered is allowed to fluctuate with the market. (In most cases the gas price is based on a formula tied to the average world price of oil.) Because contracts are renewable and may span many years, large segments of the gas market are made unavailable to fields discovered in other areas. In addition, contracts are usually renewed until the seller no longer can meet demand, so the length of time that markets are dedicated is often measured in decades. Thus any gas inaccessible to existing gathering systems is stranded until additional demand justifies building another transportation system.

Countries that produced more than 2 trillion cubic feet (TCF) of gas in 1999 are shown in Figure 8 (Hinton, 2002). Russia and the U.S. continue to be the world's largest producers of natural gas. In Russia, gas development has paralleled both economic growth and the development of a large export market in Europe. In the U.S., where gas resources are smaller than in Russia, historically high demand has brought the development and production of gas much earlier than anywhere else. Gas production peaked in the U.S. in 1972 at 21.4 TCF (Fig. 7). Cumulative U.S. production is about 839 TCF (U.S. Geological Survey, 2002), of which Oklahoma has contributed 90 TCF, or 11% (Boyd, 2002b). Of the U.S. production total, about 64% was conventional, non-associated gas, 30% was gas associated with oil production, and about 6% was from non-conventional sources such as coalbed methane, shale gas, fractured reservoirs, and tight (low-permeability) reservoirs.

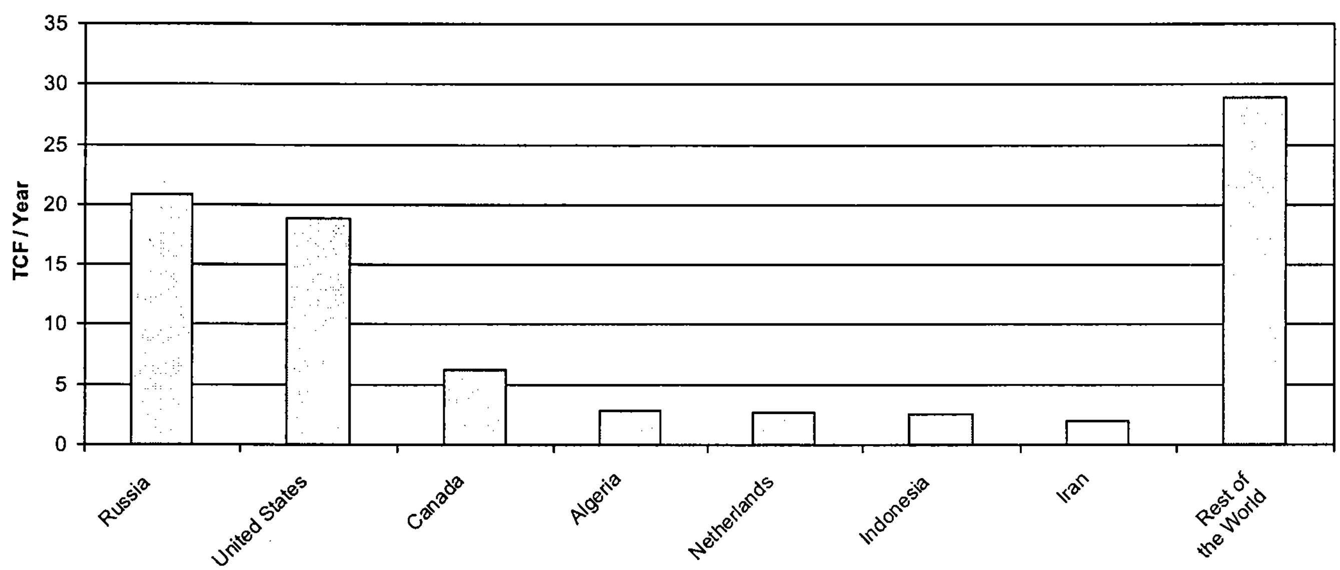

Figure 8. Countries producing >2 TCF of natural gas in 1999. From Energy Information Administration (2003).

THE OUTLOOK FOR OIL

Reserves

The most important variable in the analysis of any natural resource is proved reserves. For oil and gas, proved reserves are defined as the volume that geological and engineering data demonstrate, with reasonable certainty, to be recoverable from known reservoirs under existing economic and operating conditions. Their low technical and economic risk allows them to be assigned a monetary value. If reserves are divided by the annual rate of consumption (also known as the reserves to production or R/P ratio), one can estimate reserve life, which is the length of time that a given reserve volume can sustain the current rate of consumption (Boyd, 2002b). Reserve life is used as a yardstick in long-term planning, although it ignores future increases in demand resulting from economic growth.

It is convenient to categorize reserves by the world region in which they are found (Fig. 9). To clarify regional boundaries: (1) North America includes only Canada, the United States, and Mexico. (2) Asia/Oceania includes all countries east of Iran that are not former members of the U.S.S.R. (3) Greenland and Antarctica are assigned no reserves. The terms "developed country" and "developing country" refer to industrial development. In the broadest terms, developing countries are concentrated in the regions with the largest proved reserves of crude oil—the Middle East, Central and South America, and Africa. The industrialized countries are concentrated in North America, Western Europe, and Eastern Europe and the former U.S.S.R. Asia/Oceania comprises the developing economies of China, the Indian subcontinent, and Indonesia, as well as the industrial societies of Japan, South Korea, Australia, Taiwan, and Singapore.

Estimates of world oil reserves are relatively consistent. The value used here is the 2001 value of 1,028 billion barrels of oil (BBO), based on work by the *Oil and Gas Journal* (Fig. 10). As published by the Energy Information Association (EIA) of the U.S. Department of Energy (Hinton, 2001), it is very close to the value independently calculated by *World Oil Magazine* of 1,004 BBO for the same date, and is not far from a USGS estimate (based on 1996 data) of 891 BBO (U.S. Geological Survey, 2000). The similarity of these estimates reveals both a scarcity of the raw input data necessary to calculate reserves and a limited number of independent assessments for many of the countries involved. Note: oil's importance in the world economy has created conditions—in both developing and developed countries—in which political considerations commonly influence the size of reserve volumes reported.

As time passes, approximations of world oil reserves should converge. That does not mean that in a given economic environment there ever will be a precise and final estimate; rather, in a scheme in which 100 BBO has only a marginal effect, the range may be narrowing. The industry has matured, and the inventory of geologic basins that have been studied and explored has grown. In areas where exploration is allowed, the vast majority of promising basins have been evaluated. This is not to imply that they have been appraised to the level of many U.S. basins, but certainly large amounts of subsurface data have been acquired and the most promising areas have been drilled. Technology has advanced in the disciplines of well completion and evaluation, seismic acquisition and interpretation, and directional, horizontal, and deep-water drilling causing few prospective areas (in which drilling is permitted) to remain untested.

Because few frontier areas remain in the world, large future additions to reserves will be driven by technologies made economic through higher prices. One example is enhanced recovery operations in fields made after secondary (waterflood) recovery operations are completed. Another is in deep-water drilling (in more than 500 meters of water), where technological advances have made accessible large areas offshore. Deep-water discoveries account for an ever-increasing proportion of worldwide reserves, and have added roughly 21 BBO to the world total (Shirley, 2002b). In another realm, technological developments in producing oil from tar sands may greatly enhance proved reserves—as long as the long-term price of oil exceeds the cost of processing the tar. The tar sands in Canada (Athabasca) and Venezuela (Orinoco) will be the most important.

Except for the Middle East, the bulk of every region's reserves lie in one or two countries, each with at least 9 BBO of proved oil reserves. In North America, the U.S. and Mexico represent 91% of the region's total reserves; Venezuela contains 81% of the reserves in Central and South America; Norway, 54% of Western Europe; Russia, 83% of Eastern Europe and the former U.S.S.R.; Libya and Nigeria, 69% of Africa; and China, 55% of Asia/Oceania. In the Middle East, Saudi Arabia, Iraq, the United Arab Emirates (U.A.E.), Kuwait, and Iran each have at least 90 BBO reserves, and together account for 96% of the region's total. To complete the list of countries with more than 9 BBO of reserves, and to underscore the concentration of oil in the Middle East, the tiny nation of Qatar has reserves of 13.2 BBO. Qatar, whose land area is roughly the size of Connecticut, has reserves equal to 60% of the volume for the entire U.S.

One indication of disparity in the distribution of oil reserves around the globe is the two-tier system used by the American Association of Petroleum Geologists to classify fields as giants. In the Middle East, North Africa, and Asian Russia, a field must have an ultimate recovery of at least 500 MMB of oil or 3 TCF of gas to be considered a giant. For the rest of the world this hurdle drops to 100 MMB of oil or 1 TCF of gas (Fitzgerald, 1980). By the latter measure, Oklahoma has 26 oil fields (Boyd, 2002a) and 11 gas fields (Boyd, 2002b) classified as giants.

As one might expect, most of the world's future reserve additions probably will come from the areas with the bulk of today's proved reserves. Although analysts agree that OPEC countries still are the most promising areas for new reserves, some official estimates may be overstated, as member state's production quotas are determined in part by proved reserves. OPEC reserve estimates have risen dramatically in recent years, based largely on the expectation of higher recovery rates in existing fields. However, to be produced, much of these reserves will require huge capital investment (Sandrea, 2002).

Reserves are the part of a resource base (the total known supply) that is economically recoverable. As exploration around the world continues, the proportion of the resource

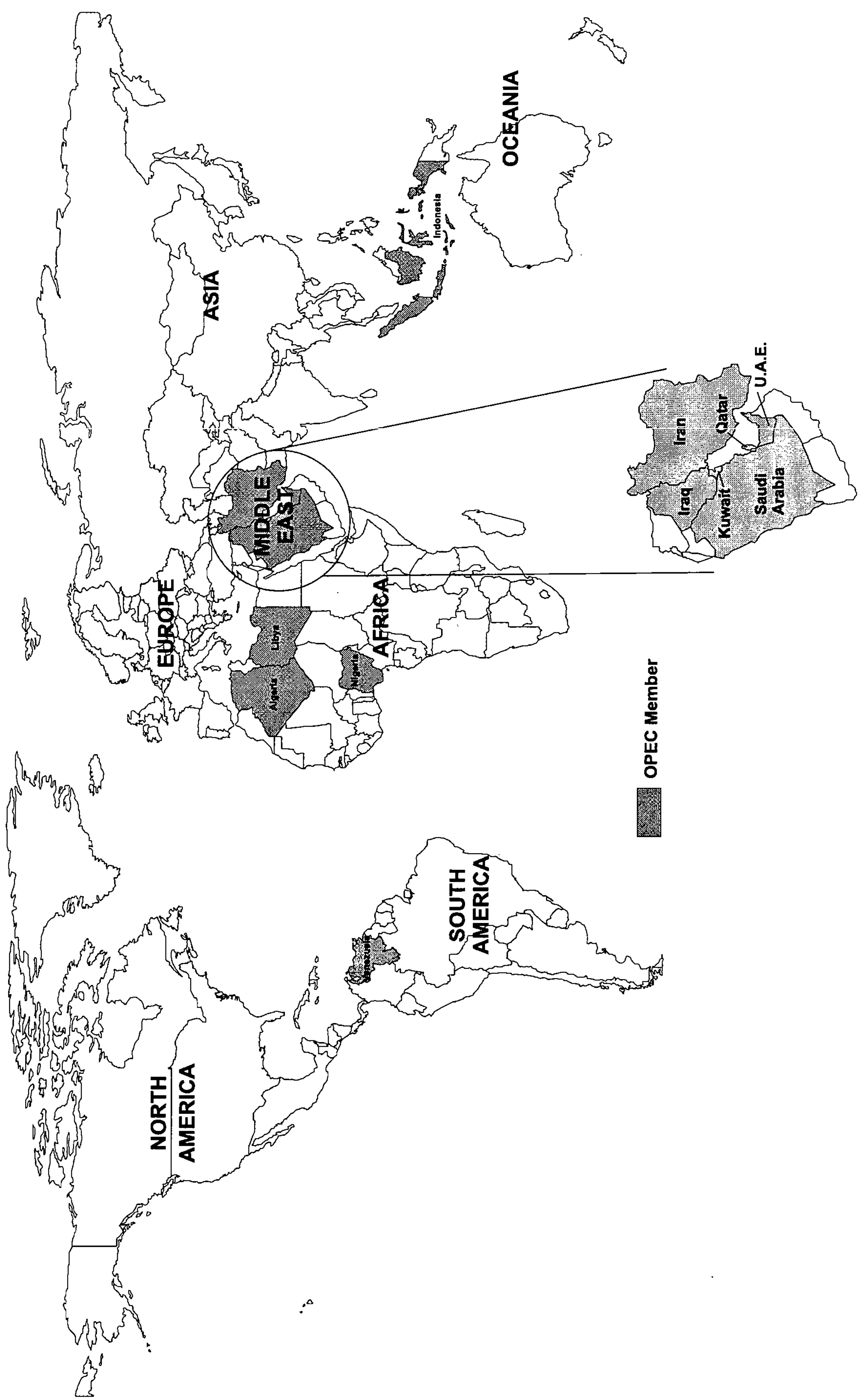

Figure 9. Map of world regions showing OPEC member states.

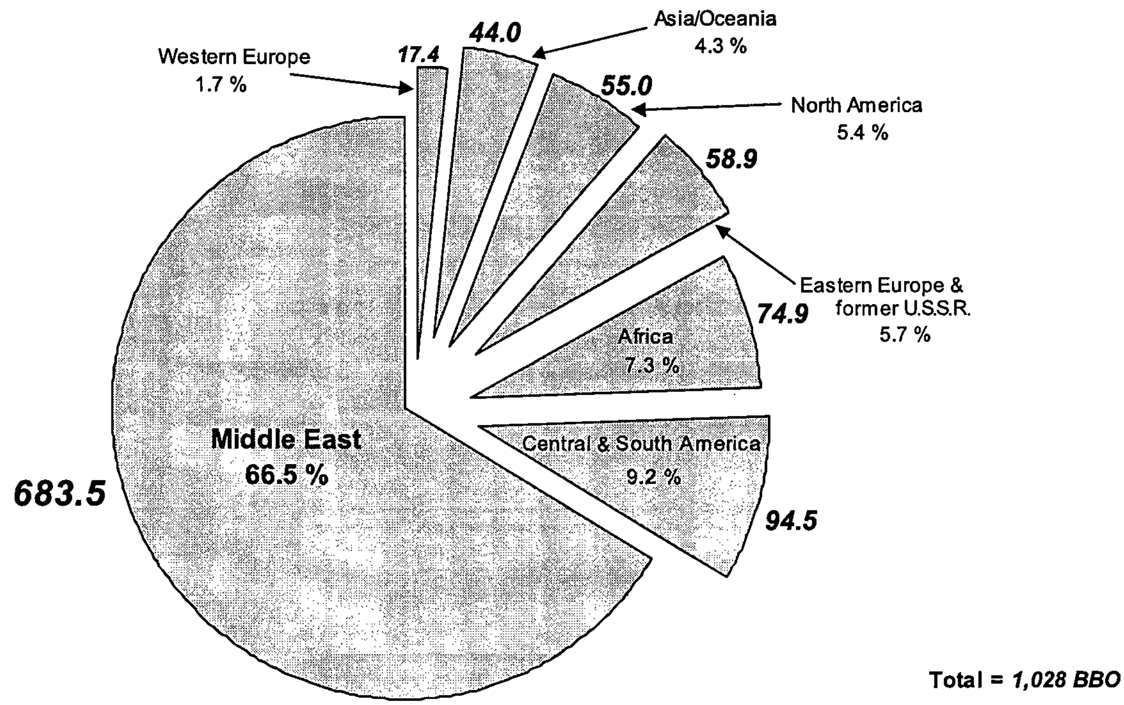

Figure 10. Proved oil reserves by world region (January 2001). Data from *Oil and Gas Journal*, from Energy Information Administration (2003).

base expected to be ultimately producible has grown. Historical reserve trends, advances in technology, and an ever-increasing volume of geological data have all been used to predict the size of additions to world reserves. Because these projected volumes are far less constrained than proved reserves, estimates can vary markedly. In order to avoid the problem of reserve volumes shifting categories through time (future reserves becoming proved reserves, and proved reserves being produced and becoming cumulative production), it is common to speak in terms of petroleum endowments. An endowment is the sum of all three categories (cumulative production, proved reserves, and future reserves) and is meant to represent the ultimate volume that will ever be produced.

Estimates of the world petroleum endowment range from about 1.8 trillion barrels of oil (Campbell, 1997) to 3.0 TBO (U.S. Geological Survey, 2000), with values clustering around 2.1 TBO (Deffeyes, 2001). Such calculations are not academic. The production curve for any large area tends to follow a bell-like shape, the peak of which can be determined, given enough historical data, based on ultimate recovery. Because much of the world's endowment has been produced, a realistic estimate of ultimate recovery should enable us to estimate a plausible date at which peak production will be reached. Because the world economy is based largely on petroleum, this prediction is very useful, as it marks the transition from a buyer's market to a seller's market.

Consumption

Consider the world's approximately one trillion barrels of remaining proved oil reserves in light of annual consumption, which an EIA assessment for the year 2000 places at about 28 BBO (Fig. 11). Most consumption is by industrialized countries that, as a result of early and rapid domestic production of oil, now find themselves at the bottom of the list in terms of reserves (Fig. 10). The world's top consumers of crude oil are the U.S., Japan, China, Germany, and Russia (Fig. 12; data begin in 1992 because no earlier statistics for Russia are available.)

U.S. consumption, at nearly 20 MMBO per day, is greater than that of the next six countries. The price shocks that began in 1979 reduced U.S. petroleum consumption below the peak reached in 1978 (Fig. 2). However, higher energy costs were absorbed by the economy, and demand began recovering in 1983. Except for minor, short-term declines, demand for oil in the U.S. has increased continuously. Nor does oil stand alone at the peak; nearly every other major energy source (natural gas, coal, nuclear energy, and hydropower) including wood is now used at record levels in the U.S. and the rest of the world (Fig. 1).

If one divides a proved reserve volume of 1,028 BBO by annual consumption of 28 BBO, one finds that reserves can sustain consumption at the current rate for about 37 years. This statistic is useful, but potentially misleading because it rests on many assumptions. It assumes no change in world demand (either up or down), although in the U.S., despite an ailing economy, demand has risen about 14% in the last 10 years. It presupposes that the petroleum industry will produce the remaining reserves as rapidly as those already produced. It also takes for granted that the proved reserve volume will remain static, though long-term revisions of worldwide reserves have always risen (but usually not enough to replace consumption). Finally, it assumes that all reserves (and the equipment necessary to produce them) will be continuously available to support demand—but think of recent news from Nigeria, Venezuela, and Iraq.

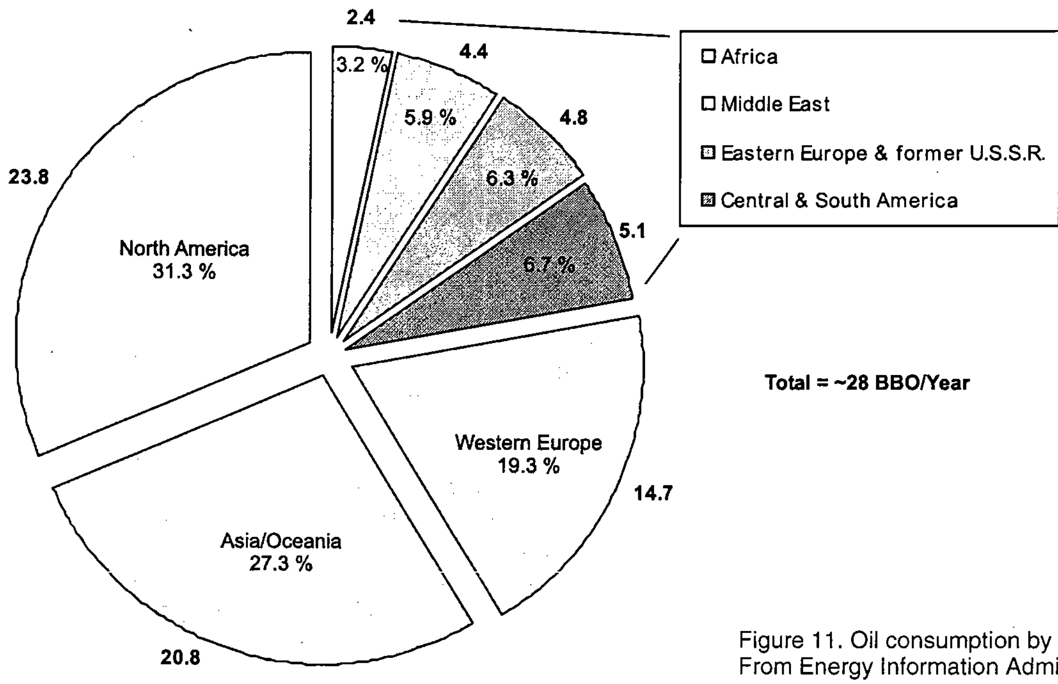

Figure 11. Oil consumption by world region (2000). From Energy Information Administration (2003).

Around the globe, as in the U.S., demand for energy is increasing continuously. Until recently this growth was confined almost exclusively to more developed and less populated regions. Now, industrialization has enlarged the proportion of world oil consumed in developing countries. Take China and India: their combined consumption in 2000 was a third that of the U.S.—but they had eight times the population. The point is not that our per capita use of energy is 24 times that of China and India; it is that in the last 10 years, while U.S. consumption was rising 14%, consumption in China and India rose 84% (Energy Information Administration, 2003). Their 2.2 billion people make up more than one third of the population of the planet. Although the developing world will never match per capita U.S. consumption, progressive industrialization will continue to push their energy demand higher.

The only factor that affects long-term oil consumption is price. Interruptions in supply are responsible for most major price increases, and, as a result, also the major drops in consumption. (These major supply interruptions are distinguished from those that are designed solely to keep oil within a price window that producers see as desirable.) Because the developed world has (by definition) an industrialized economy and the corresponding history of energy de-

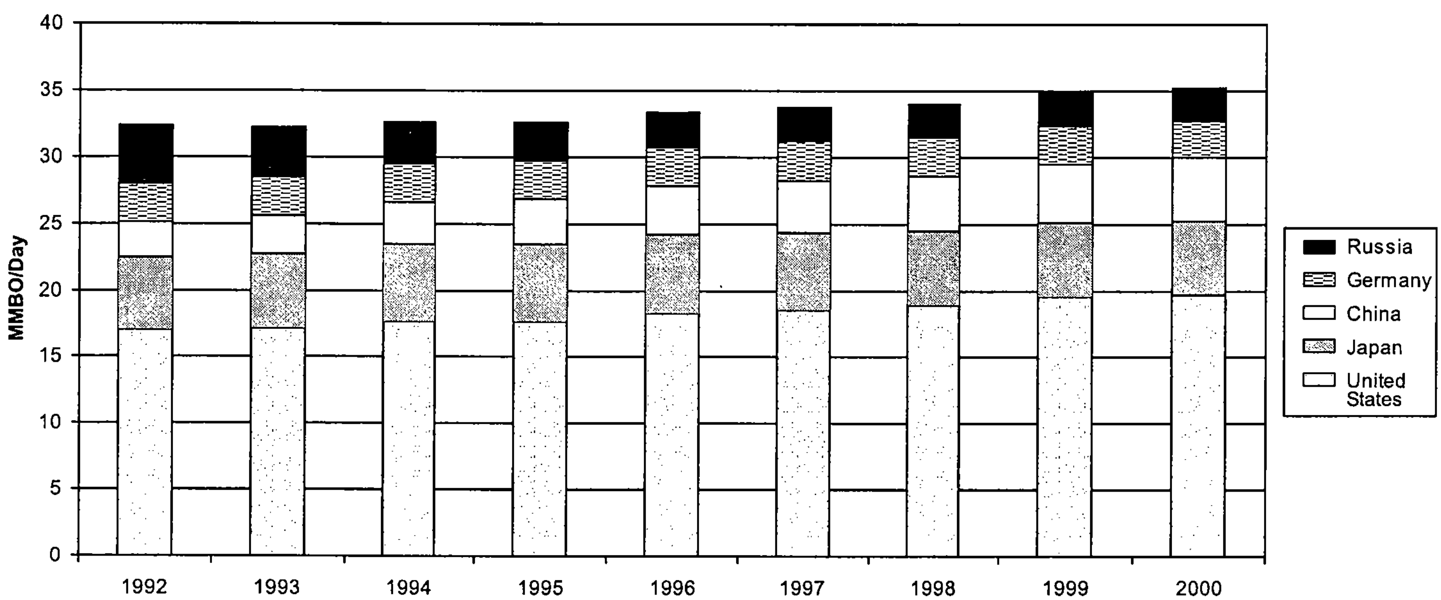

Figure 12. Countries consuming >2.5 MMBOPD (2000). From Energy Information Administration (2003).

mand, it has already produced the bulk of its oil reserves. As a result, an increasingly higher proportion of the remaining reserves reside in countries that have been slower to develop modern economies and the commodities that fuel them. Many developing countries are subject to all manner of internal and external disturbances that can disrupt their ability to produce oil. The world's excess production capacity is smaller than ever, so meeting today's demand requires sustained production from all major producers. In a precariously balanced market, a real or threatened interruption of supply anywhere inevitably leads to higher prices for everyone.

Production

World oil production, except in the Middle East, is about equally divided among the seven world regions (Fig. 13). Their shares vary from about 9 to 16%, with the Middle East accounting for roughly a third of the world total. However, this analysis understates the leverage that Middle Eastern oil production exerts on the world market. North America, Asia/Oceania, and Western Europe use all of their own oil and import large volumes of crude. Eastern Europe and the former U.S.S.R., and Central and South America, produce significant amounts of oil, but they use most of it themselves. Thus Africa and the Middle East, with their tiny share of the consumption pie, remain the largest exporters of crude oil. The Middle East produces three times as much oil as Africa, and also contains most of the world's remaining excess productive capacity. This explains the enormous influence that news from this region has on world energy markets. The situation is unlikely to change, because in addition to proved reserves, projected future oil reserves are also concentrated in the Middle East.

In almost every petroleum province the distribution of field size is asymmetrical, with the larger and easier-to-find fields making up a disproportionate share of total production and reserves. Oklahoma follows the worldwide trend with 5% of the fields responsible for about 83% of the State's oil production and reserves (Boyd, 2002a). Because most of the largest fields are found early in the life of a petroleum province, initial production in a given region tends to increase rapidly. This increase continues until the first of the large fields peak and begin to decline. Early discovery of most of Oklahoma's largest fields led to the State's production peak in 1927 (Boyd, 2002a). If the decline in big fields cannot be overcome by production from later discoveries (which must be large to have much impact), the overall production curve begins to decline. Because even small percentage declines in large fields are large volumes, as more fields mature the overall effect snowballs. As average discovery sizes become progressively smaller, even concerted drilling programs usually can only reduce the rate of decline. Secondary and enhanced recovery operations combined with many smaller discoveries can extend the length of time that high production rates are maintained, which often leads to lesser, intermediate peaks. However, by this stage only the rate of the long-term decline can be affected.

The sequence just described creates a production curve conforming to a general bell-shape. Such a curve is seldom symmetrical, for peaks vary in duration, and intermediate highs are sometimes quite large. Lesser peaks may be caused by price fluctuations resulting from wars, embargoes, economic booms and busts, or anything that affects supply or demand. The opening of new areas to exploration late in the productive life of a given region also can generate bumps in the overall production curve. Such events can magnify intermediate highs, and if the timing is right they can extend the period of maximum production.

An example of both effects may be found in the U.S. oil production curve. It peaked in 1970, but production from the Prudhoe Bay Field and a nationwide drilling boom enabled it to stay near its maximum through the mid-1980s. (Note that Figure 14 shows only crude oil and not liquids derived from natural gas production, which do appear in Figure 5.) If production from Alaska is omitted, the 1970 peak is far more pronounced and the curve becomes far more bell-shaped.

Prudhoe Bay Field, the last supergiant (>10 BBO) found in North America, is the largest field in the U.S. Before the field's 1968 discovery the North Slope of Alaska had been drilled only sparsely. Its recognition was greatly facilitated by the use of early reflection seismology (Jamison, 1980).

Although the effect is not as dramatic, in recent years the decline in national production has been noticeably slowed by the addition of oil from deep-water fields in the Gulf of Mexico. Much of the oil in the Gulf had been out of industry's reach until new drilling technology enabled drilling in water depths of several thousand feet. This development has brought essentially all prospective offshore areas within reach of the drill bit.

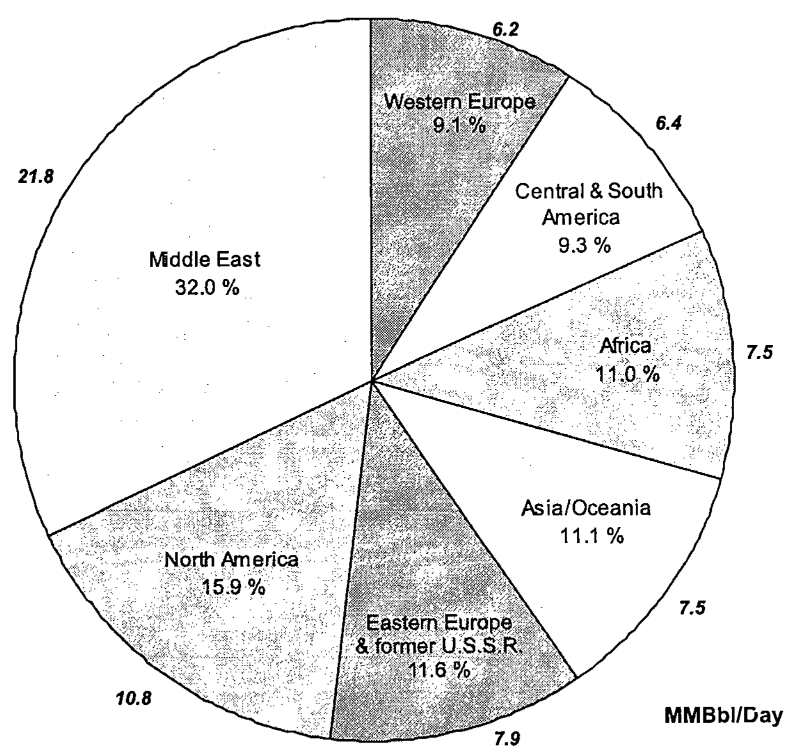

Figure 13. Oil production by world region (2000). From Energy Information Administration (2003).

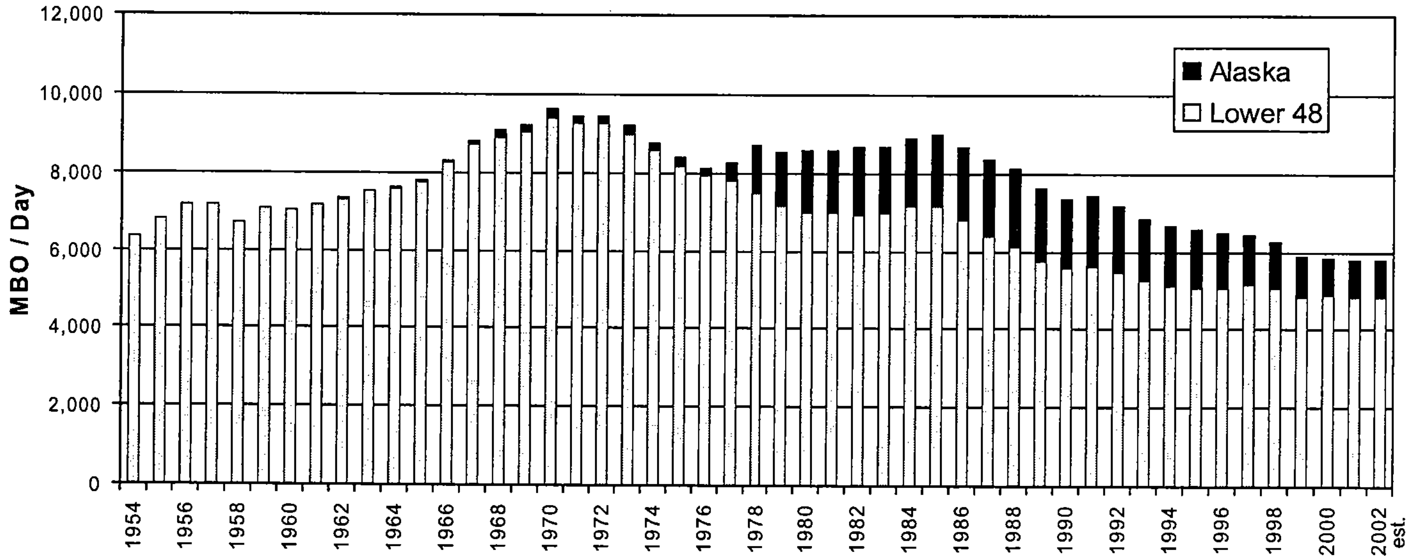

Figure 14. United States crude oil production, 1954–2002. From Energy Information Administration (2003).

Giant fields like Prudhoe Bay hold not only reserves, but also most of the world's capacity for oil production. The world has 583 giants (defined as having at least 500 MMBO of reserves plus production). The giants constitute 0.1% of all fields, but account for roughly 85% of global reserves (Fitzgerald, 1980). Not surprisingly, most of the largest oil giants were found early and have been producing for decades. Their increasing age is demonstrated by production rates: in 1986, 15 of the giants could produce more than 1 MMBO per day, but now only four can make this rate. The survivors are Ghawar in Saudi Arabia, Kirkuk in Iraq, Burgan in Kuwait, and Cantarell in Mexico (Petzet, 2001). Many other major producing fields are declining or soon will be, even in the Middle East. Two of Iran's four largest fields are in secondary recovery, and the U.A.E.'s two largest fields are about to begin secondary recovery operations. OPEC's overall peak production capacity of 40 MMBO per day was reached in the mid-1970s, when the largest fields were still young. Although massive spending on infrastructure could increase OPEC production, old highs are unlikely to be matched (Bakhtiari, 2002).

For Oklahoma and the U.S. as a whole, nothing can return production to historic highs. Oklahoma is 75% (573 MBO per day) below its peak rate, and the U.S. is down by 40% (4 MMBO per day). Although the declines in both have flattened in recent years, as a result of higher prices, their long-term slides continue (Boyd, 2002a). The U.S., unlike Oklahoma, has many promising areas off limits to exploration. They include the Arctic National Wildlife Refuge on the North Slope, the eastern Gulf of Mexico, offshore areas along the entire East Coast and most of the West Coast, and areas in the Rocky Mountains. However, even if all of these were opened today production still could not approach previous highs.

North Slope production remains by far the most important to be found in the U.S. in decades. At their peak, Prudhoe Bay and its satellite fields represented 25% of the national output and even now about 17% (Fig. 14). Without the North Slope, U.S. imports today would account for about 75% of consumption. Although Prudhoe Bay production peaked at about 2 MMBO per day, that was 20 years after the discovery well was drilled. The decline for Prudhoe Bay and its satellites alone in the next 20 years is estimated at 400 to 700 MBO per day (Energy Information Administration, 2001). Adding the concurrent loss in production that is expected in the rest of the country during the same period (2.0–3.5 MMB per day) makes apparent the difficulty in just maintaining today's production level. Even in the most optimistic outlook, the American "snowball" has gathered far too much momentum to ever be pushed back to the top of the hill.

Over a century of world oil production, and the realization that production graphs (in statistically large samples) tend to yield a bell curve, makes possible certain predictions. These include broad estimates of the peak production rate and when this peak will occur. Critical variables include ultimate recovery and the precise shape of the curve. In a given area production inclines and declines are often irregular and may be steep or gradual on either side of the peak. Economic factors and the addition of new sources of supply can affect the duration of production peaks (Fig. 14).

If the curve used to predict the peak of world oil production is roughly symmetrical and encompasses an ultimate recovery of about 1.8 TBO, the world could reach the peak this year, in 2003. Clearly we have not yet reached the peak, for although OPEC production capacity is kept secret most analysts believe that excess production capacity for the world is still 4 to 5 MMB per day (Toal, 2002). However, with current daily consumption at 76 MMBO and this increasing to more than 118 MMBO per day by 2020 (Energy Information Administration, 2003), it is clear that we are working with little cushion. The low level of excess capacity explains why even a small, brief interruption of supply can have a major impact on price.

If the ultimate recovery volume is increased by 300 BBO (or about half the cumulative production to date) to 2.1 TBO, world production should peak between 2005 and 2009 at an annual consumption rate of about 31 BBO (Fig. 15; Deffeyes, 2001). This is believed to be more realistic, and would show about 34% of the world's petroleum endowment as cumulative production, 42% as proved reserves, and 24% as future reserve growth. Different scenarios for reserve growth, discovery, infrastructure, and pricing could end with different dates and durations for peak production. However, even moderate economic growth leads to increases in world oil demand of 1–2 MMBO per day per year. So if the world's excess capacity is truly 4–5 MMBO per day, the supply-demand curves could easily cross in this decade.

An estimate by the U.S. Geological Survey (2000), of more than 3.0 TBO of ultimate recovery, has been used as evidence that peak oil production will not be seen for decades. However, this estimate is roughly 1 TBO higher than most others and requires a doubling of the current proved world oil reserves (Fig. 10). Some of this oil could come through improved recoveries in existing fields. However, most of it must come as a result of new discoveries. The discovery of so much economically producible oil so late in the life of worldwide oil exploration contradicts experience. Huge, prospective, and hitherto unexplored regions would have to be opened. Some areas of the world do remain sparsely explored, but unrealistic success rates also must be invoked in order to find the equivalent of 100 Prudhoe Bay fields. The worldwide field-size distribution (where $1/1000^{th}$ of the fields represent 85% of reserves) and the trend in oil discovery size make it unlikely that ultimate recovery can be increased by a trillion barrels.

For reserves to significantly affect the date at which world oil production peaks, they must be found in large fields in reservoirs where high production rates can be established in the next few years. If they occur, for instance, in comparatively small pools in deep water, beneath Antarctic ice, or in low-permeability reservoirs that require intensive drilling to attain high production rates, they will not affect the point when demand exceeds supply. To delay the world's production peak much beyond the 2 to 6 years estimated requires bringing into production, every year, the equivalent of at least one field delivering 1–2 MMBO per day. Although nonconventional resources like tar sands and oil shale occur in very large volumes, they cannot approach such yields, and certainly not any time soon.

When demand is forced to match supply, the extreme price lows that prove ruinous to low-rate oil production (a situation dominant in Oklahoma) should become a thing of the past. Although volatility in price will undoubtedly persist, the lows will be higher than those of the recent past. Higher average prices will permit the use of new, more expensive recovery techniques in producing fields and will open to the world market some smaller accumulations now stranded by transportation costs. Exploration could become economic in less-hospitable environments, perhaps even in Greenland and the Antarctic. Many enhanced recovery projects with large up-front costs, which have been on hold for fear of prolonged periods of low prices, could become economically viable.

Higher oil prices also could make possible large-scale investment in extraction of oil from tar sands, in which potential reserves are huge but production and environmental costs are high. Processing tar sands requires great amounts of water as well as the disposal of up to 10 tons of solid waste per ton of oil produced (Energy Information Administration, 2002). Tar sands such as the Athabasca (in Alberta) and Orinoco (in Venezuela), although huge resources, will probably have little effect on when maximum world oil production will be reached. Their main value, like other sources that become economic in a high-cost environment, will be in providing a large (if expensive) source of petroleum for long-term demand.

The key point is that (transportation costs aside) similar types of oil sell for essentially the same price anywhere in the world, regardless of the political compatibility of buyer and seller. In this age of instant communication, the global market ensures that oil will be sold only to those who pay the going rate. When supply can no longer meet demand, prices will rise sharply until demand falls to a level that can be sup-

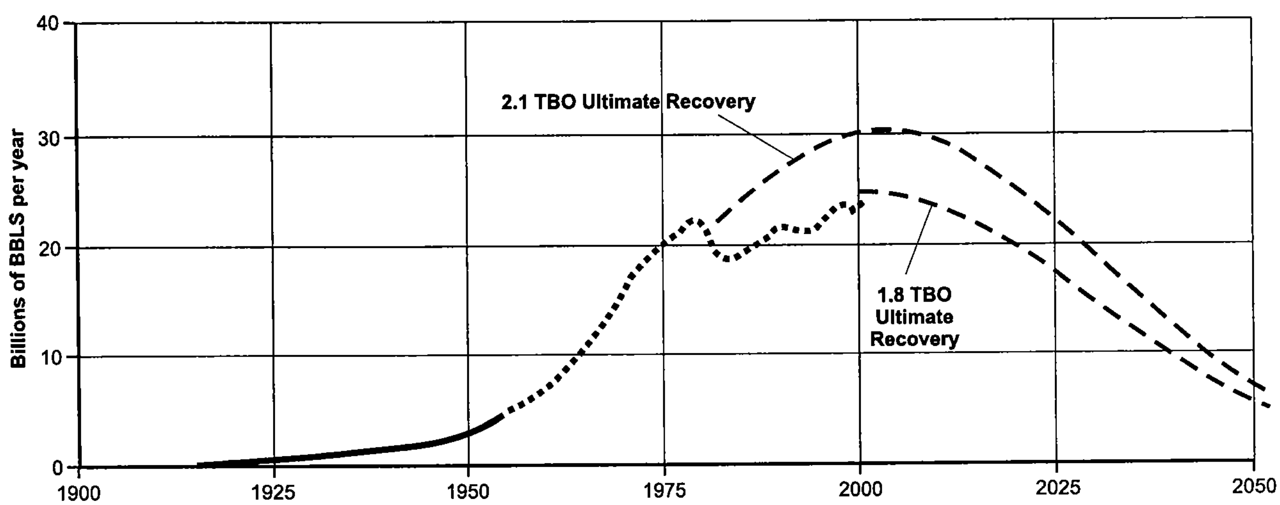

Figure 15. World oil production through 2000 (heavy dots) showing projected production through 2050 (dashed lines) for two possible ultimate recoveries. From Deffeyes (2001).

ported, usually through conservation and fuel switching. This relationship between supply and demand ensures that the world will never "run out" of oil.

THE OUTLOOK FOR NATURAL GAS

Reserves

There are many reasons to be optimistic about the long-term outlook for natural gas. Among them: (1) Gas remains a secondary target in many parts of the world, so it is comparatively under-explored. (2) When discovered in an area with no gas market, delineation wells (follow-up wells, to determine the size of the field) usually are not drilled, making reserve estimates cursory, and typically conservative. (3) If lacking a near-term market, an entire basin that is viewed as gas-prone may receive little attention from industry. (4) Gas can exist in deeper reservoirs than oil, and be produced from strata with much lower permeability than oil (Boyd, 2002b). (5) Many areas intensively drilled for oil have not been completely evaluated for deeper gas potential. (6) Non-conventional sources of natural gas, like gas hydrates, coalbed methane, and various types of low-permeability reservoirs, have huge resource potential; for them, even small changes in recovery estimates have a large impact on reserves. (7) In many areas of the world with large conventional gas reserves, little effort has been made to evaluate non-conventional resources.

Like oil, the world's proved reserves of natural gas are distributed unevenly (Fig. 16); Eastern Europe and the former U.S.S.R. and the Middle East contain nearly three-quarters of the world's proved reserves. On a national reserve basis, Russia has a large lead, but four of the top seven countries are in the Middle East (Fig. 17). A single huge accumulation in Qatar (the North Field) gives that tiny nation roughly three times the proved reserves of the U.S.

In the period from January 2000 to September 2002, according to IHS Energy (2002), 28 giant discoveries were made worldwide, with estimated reserves of more than 500 million barrels of oil equivalent (MMBOE). For gas, this is a reserve volume of at least 3 TCF (Fitzgerald, 1980). Two-thirds of these discoveries were gas, with all but one of the giant oil discoveries having a significant gas component. During the same period in North America, mirroring Oklahoma in recent years (Boyd, 2002b), 1,180 new fields were discovered. Most were small, but fully three-quarters were gas or coalbed methane (IHS Energy, 2002), indicating that industry's focus in North America has shifted strongly to natural gas. In the rest of the world, although oil may still be the primary objective, it is gas that is being found in the largest quantities.

Future additions to global reserves also are strongly skewed towards Eastern Europe and the former U.S.S.R. and the Middle East. Although the Northwest Shelf of Australia and offshore Norway hold promise, most new reserves are expected to come from Russia (Siberia, Barents, and Kara Sea) and the Middle East around the Persian Gulf (Ahlbrandt, 2002). These area's large conventional gas reserves have reduced the incentive to assess non-conventional resources, which are harder to produce and will not be needed for 60–100 years.

In North America, most easily produced gas already has been found, and large volumes of harder to produce gas are necessary to meet demand. Except for the many areas off limits to exploration, all possible sources of natural gas are being evaluated. Non-conventional sources such as coalbed methane and low-permeability reservoirs constitute a substantial part of both the resource base and daily production. For North America the resource volume of technically recoverable gas (proved reserves plus conventional and non-conventional resources) has been estimated at 2,500 TCF (Energy Information Administration, 2003).

Studies made in 1995–2001 of gas remaining in the U.S. (by private and federal organizations) project an average recoverable resource of 1,549 TCF—about nine times current

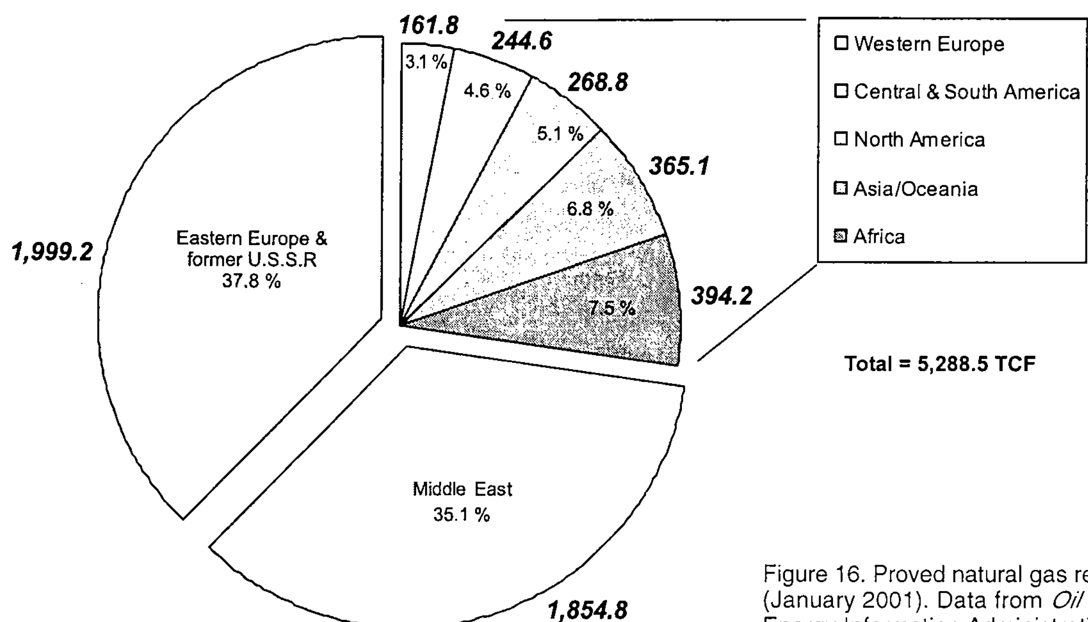

Figure 16. Proved natural gas reserves by world region (January 2001). Data from *Oil and Gas Journal*, from Energy Information Administration (2003).

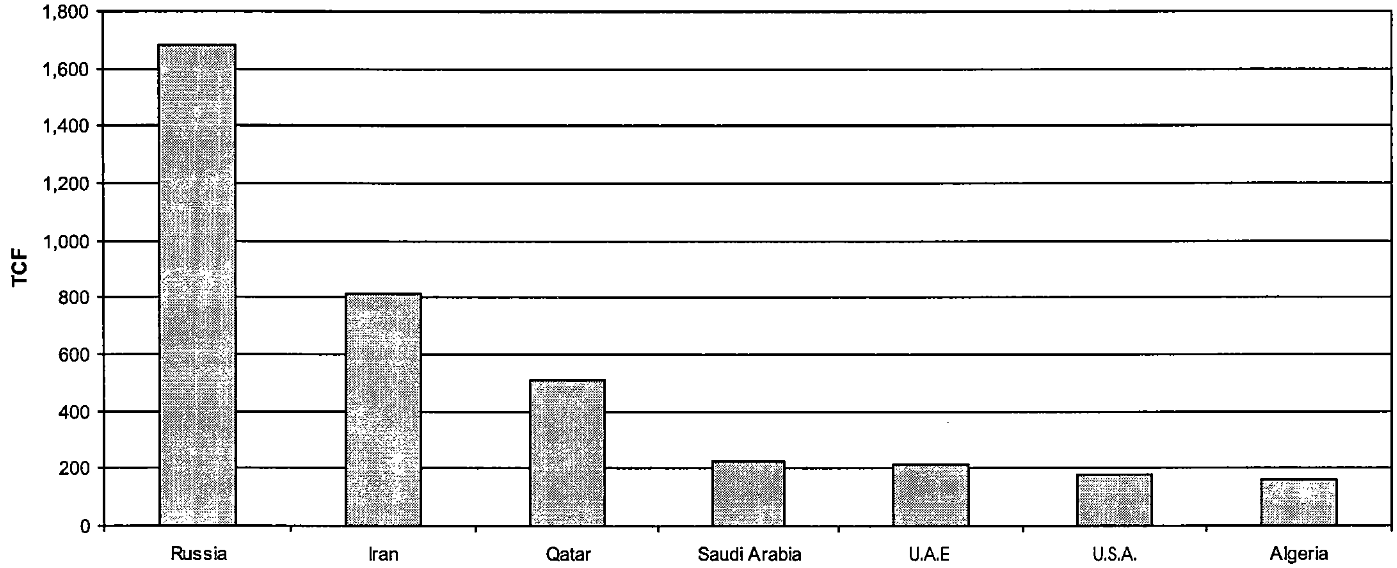

Figure 17. Proved natural gas reserves by nation (January 2002). Data from *Oil and Gas Journal*, from Energy Information Administration (2003).

proved reserves. This suggests that our reserve base can be greatly increased. The projected volume (assuming these resources all become reserves) amounts to a 67-year supply at the current rate of consumption. Non-conventional gas is a substantial component of the nation's resource base, so incremental improvements here could lead to large increases in reserves. For example, estimates of technically recoverable coalbed methane average 70 TCF, and for tight gas sands, 275 TCF. Although the non-conventional resource types are defined and assessed in different ways, and estimates vary considerably, the volume of potentially recoverable gas is clearly large (Curtis, 2002).

Proved gas reserves in the U.S. have remained fairly steady, averaging about 183 TCF over the last 25 years (Energy Information Administration, 2003), a volume equivalent to 8 years of current consumption. Year-end 2001 U.S. reserves were 183.5 TCF, but our ability to keep pace with production has not resulted from the discovery of large gas fields; in 2001, discoveries accounted for only 16% of additions to U.S. gas reserves. Most additions come from the expansion of old fields and upward revisions in recovery factors. Increasingly, additions are coming from non-conventional sources such as coalbed methane, tight gas, deep gas (>15,000 feet depth), shale gas, and offshore gas from deep water. These account for about 20% of U.S. reserves now, and this share is expected to grow to 50% by 2020. The coalbed methane component of gas reserves has grown since 1989 from less than 4 TCF to 18 TCF, or roughly 10% of total reserves (Energy Information Administration, 2003). In the Midcontinent (including Oklahoma) reserves are 16.9 TCF of recoverable tight gas, 5.8 TCF of coalbed methane, and 17.7 TCF of deep gas, mostly in the Anadarko Basin (Shirley, 2002a).

For gas, as for oil, endowments are the sum of cumulative production, proved reserves, and future reserves. They are meant to represent the ultimate volume of gas that will ever be produced and do not distinguish between associated and non-associated or conventional and non-conventional (Boyd, 2002b).

The USGS estimate of the world's natural gas endowment for the year 2000 is 15.4 quadrillion cubic feet (QCF), or 15,400 TCF. Of that endowment, 11% (~1,700 TCF) has been produced; 31% (~5,000 TCF) is proved reserves, and 58% (8,900 TCF) are reserves yet to be found. The volumes are huge, but in most parts of the world they include only conventional gas resources. Because this estimate could not include analyses for all prospective sedimentary basins, most consider the assessment conservative, despite its size (Ahlbrandt, 2002). In the last 20 years, as average prices have remained steady in real terms, consensus estimates of the world's remaining natural gas reserves have increased tenfold (Fisher, 2002), and discoveries and development show that this trend is likely to continue.

Any discussion of natural gas resources must include gas hydrates (also called methane hydrates). Hydrates are an enormous—but still uneconomic—non-conventional source of natural gas. They are solid, crystalline, ice-like substances composed of water, methane, and small amounts of other gases trapped in a water-ice lattice. Hydrates, which form at moderately high pressure at temperatures near the freezing point of water, are found in permafrost regions onshore and in ocean-bottom sediments in water depths below 450 meters (~1,500 feet). Some offshore hydrate deposits are exposed on the ocean bottom, but most are found in sediment beneath the seafloor. A growing body of evidence suggests that natural releases of methane from hydrates in the geological past have had major effects on the Earth's climate. How hydrate releases occur is not understood, but their production as an energy source could mitigate a long-term environmental hazard (Morehouse, 2001).

The volume of methane locked in natural gas hydrates around the world is staggering. Estimates vary widely, reflecting the early stage of research, but range from 35 QCF to >61,000 QCF. Compare these numbers to a resource estimate of 15.4 QCF for gas worldwide, and reserves of about 5.3 QCF. In terms of oil equivalence, Lubick (2002) estimates that worldwide methane hydrate resources total 137.5 TBOE (825 QCF), a volume that dwarfs a 2.1 TBO petroleum endowment. Although gas hydrate volumes are colossal, the percentage that may be economically recoverable is unknown and could be very small. No technology is available for making hydrates a practical fuel. However, in the U.S. alone, the gas hydrate resource has been estimated at 250 times the conventional gas volume and almost 2,000 times current reserves (Morehouse, 2001).

If only a small percentage of the world's gas hydrates can be produced commercially, they would still represent a huge source of energy. This gas could be used in conventional applications, such as a boiler fuel or in heating. However, looking much farther ahead, methane from hydrates could become a source of hydrogen for fuel cells, which many view as the energy of the future. Technology and economics will ultimately determine whether the world's hydrate resource can be widely exploited. Meanwhile, extensive research is under way in Japan, Russia, India, Norway, Germany, Canada, and the U.S.

Consumption

In the year 2000, natural gas consumption worldwide was 87.4 TCF. As with other energy sources, gas consumption is at record levels and has increased 65% over the last 20 years (Fig. 18). However, in energy equivalence natural gas is still far behind that of oil (Fig. 1), mostly because its large-scale use started much later. The long-term share that gas takes of the world's energy budget will increase with time, and many variables will affect the rate of increase. However, fuel switching will be one of the most important, as global oil production peaks and prices rise accordingly.

Regional gas consumption resembles that of oil. The largest consuming region, North America, accounts for precisely the same share of the gas market as the oil—31.3% (Fig. 19). Natural gas reserves and infrastructure in Russia push Eastern Europe and the former U.S.S.R. into second place. Western Europe, with several moderate-size economies, is third. In gas, as with oil, the Middle East has the world's most favorable ratio of reserves to consumption, with 35.1% of gas reserves (Fig. 16), but only 7.7% of consumption.

Russia and the U.S. continue to be by far the world's largest consumers of natural gas (Fig. 20), together accounting for 42% of the world's consumption in 2000. Russia is self-sufficient in natural gas and a major exporter. The U.S. uses about 22 trillion cubic feet (TCF) of gas per year, produces about 18 TCF, and imports 4 TCF—nearly all from Canada. Production declines and the current level of imports (~18%) suggest that the U.S. gas market is roughly 25–30 years behind oil. Demand growth for gas parallels that of oil, forcing the U.S. to rely on ever-increasing gas imports. Although the import percentage for gas is still small relative to oil, the gap between production and consumption is headed in the same direction. Using these trends, Beims (2002) predicts that in 30 years the U.S. will import 50–60% of the gas it consumes.

The total North American gas endowment of 2,500 TCF (Energy Information Administration, 2003) can support current demand for more than 100 years, although it must use a great deal of non-conventional gas to do so. The challenge is that for these resources to be produced, they must be competitive with gas imports—ultimately meaning LNG. Hence, in North America what matters is not the size of the endowment but the economics of producing much of that endowment. Natural gas that does not eventually become economic to produce has no impact.

Analysts believe that prices approaching $4.00 per MCF will make economic the building of the infrastructure necessary to move large volumes of LNG into the U.S. market. Based on energy equivalency, this is also the same price at which the burning of coal can economically meet current environmental standards (Fisher, 2002). Natural gas prices will always be volatile, but when $4.00 per MCF is perceived to be the lower limit (or price floor), domestic gas production will face the same constraint as oil. This is a production cost competition in which hundreds or even thousands of U.S. wells are necessary to equal the production from a single well in an exporting country. Although the price of gas from

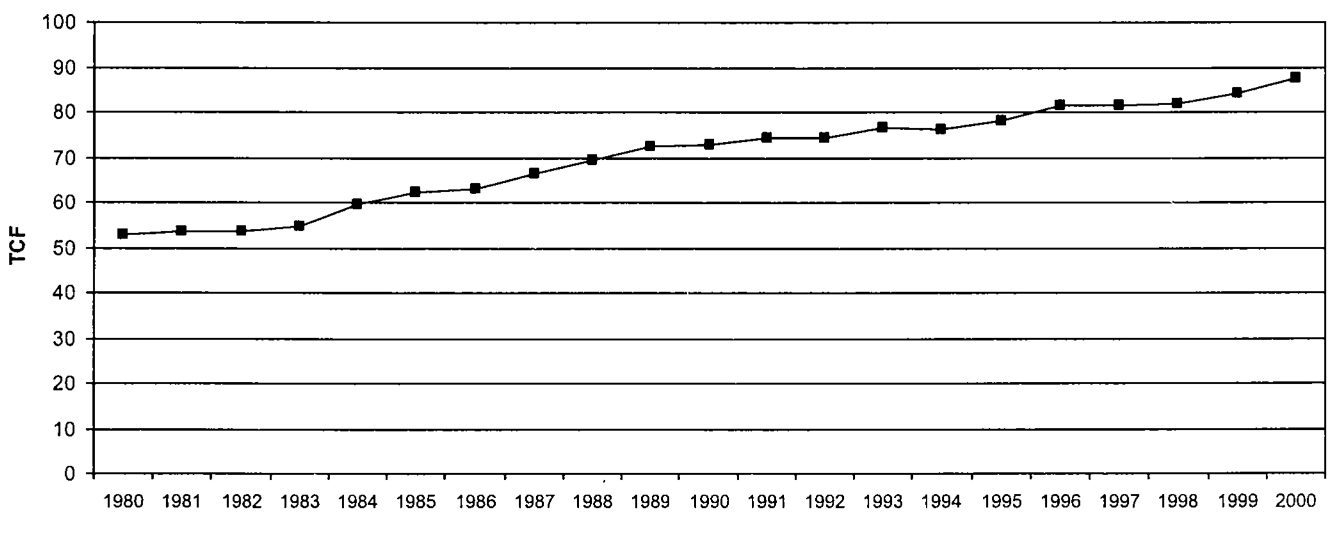

Figure 18. World natural gas consumption, 1980–2000. From Energy Information Administration (2003).

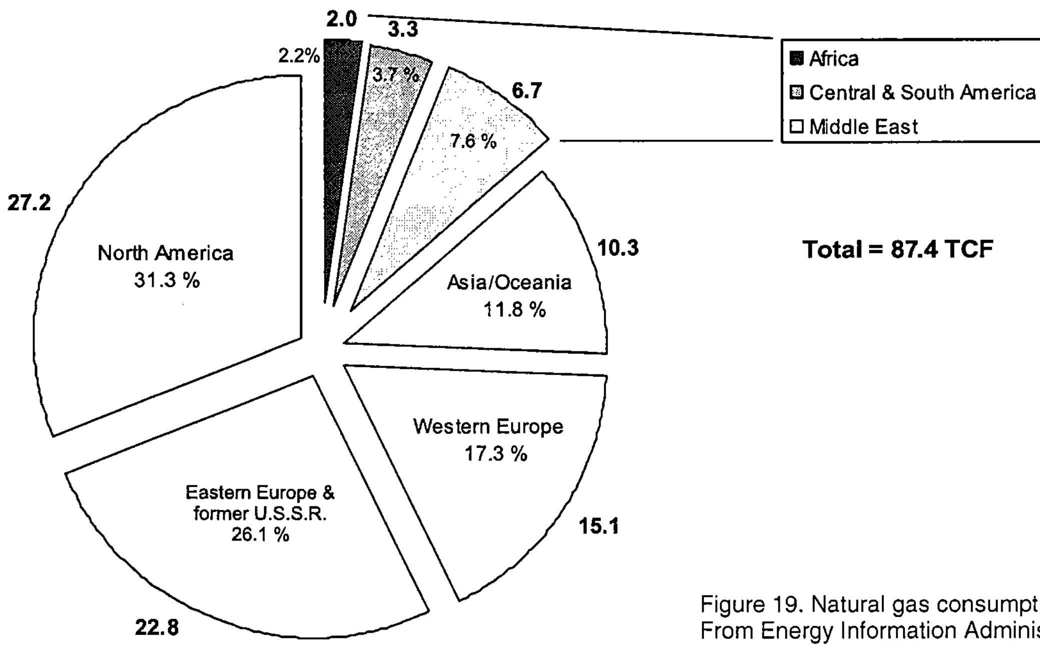

Figure 19. Natural gas consumption by world region (2000). From Energy Information Administration (2003).

an exporting country must include the cost of its conversion to LNG and transportation to our shores, this can be overcome by the disparity in production costs. Thus, when the infrastructure is in place to bring large volumes of LNG to the U.S. market, price will be beyond our control. Depending on where the global price settles, we could find a large part of our gas resource base inaccessible for the same reason that so much of our oil remains in the ground—namely, economics. Although various techniques can be used to produce more U.S. gas, it may cost more to produce than to buy from overseas. This could leave much of the North American gas endowment in the ground.

Gas prices have risen above $4.00 per MCF in the past, but only temporarily and usually during cold winters. To date, it is only the certainty that price lows would bring the average annual price well below winter highs that has kept international gas at bay. In fact, in the last 20 years the average price in the U.S. has been only $2.20 per MCF. Although the two most recent years of complete data (2000 and 2001) show record prices, averaging $3.60 and $4.12 per MCF, prices in the previous two years were only $1.94 and $2.17 (Fig. 6). The market for natural gas is delicately balanced, and a 2.5% change in supply or demand can lead to a 100%-plus rise in price. With a flat to declining production trend, price volatility is bound to remain high, but—barring a dramatic drop in demand (say in an economic depression) or an unexpected technological breakthrough—long-term prices seem sure to rise (Beims, 2002).

Natural gas has advantages over its major competitors, petroleum and coal. Gas is the most environmentally friendly of the three, and is so abundant that even conservative estimates show its reserves meeting increasing demand

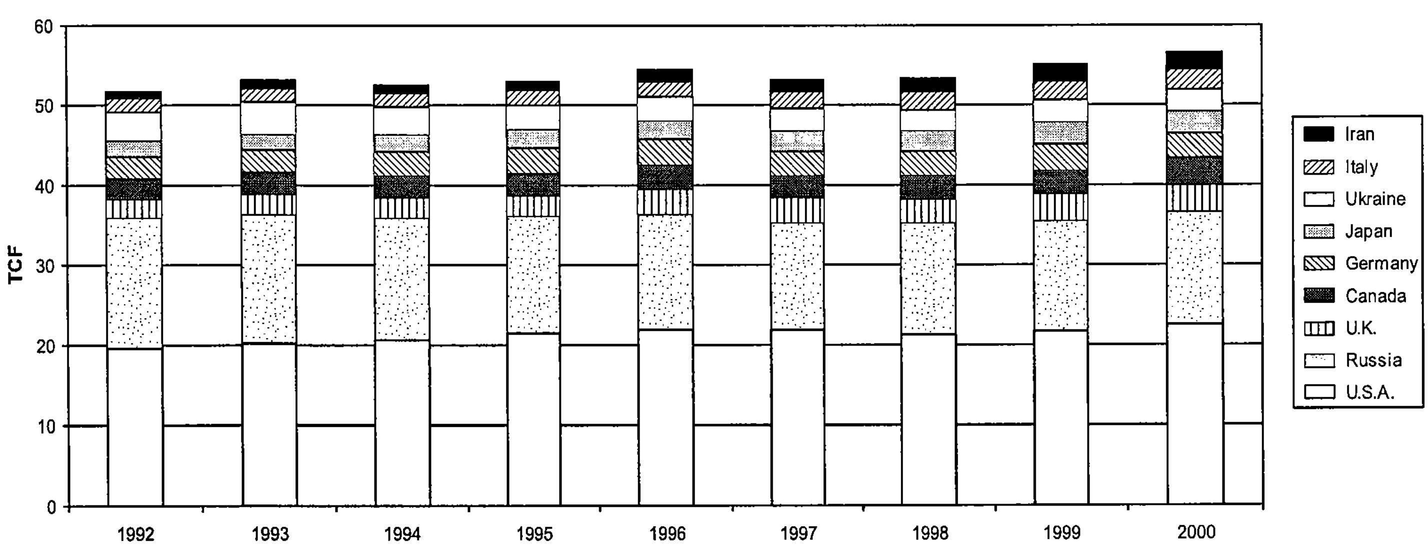

Figure 20. Countries consuming >2 TCF (2000). From Energy Information Administration (2003).

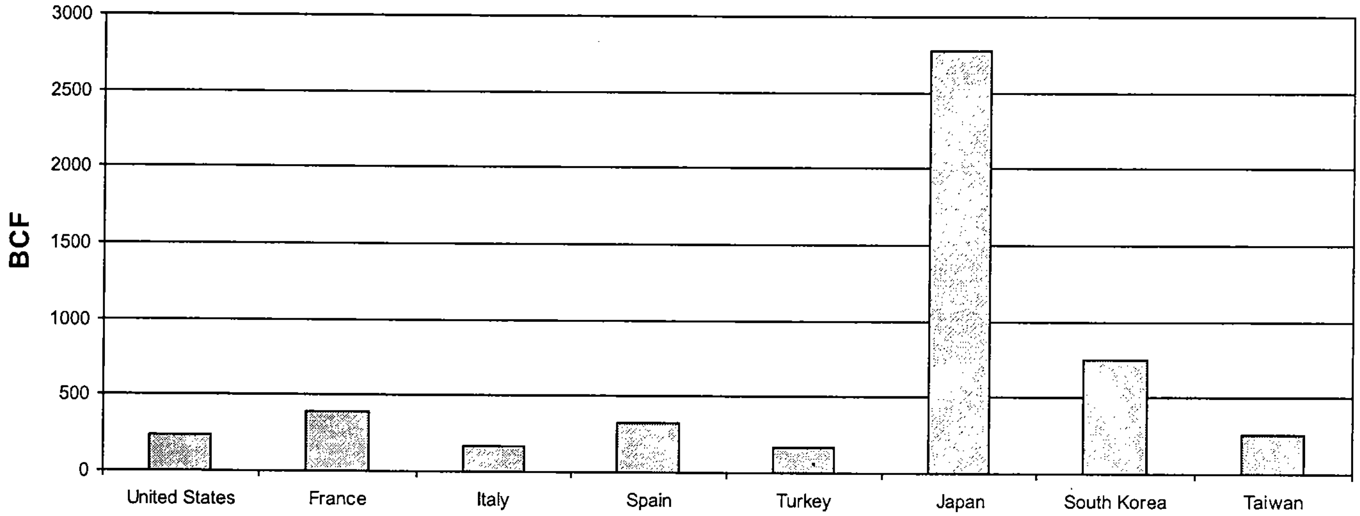

Figure 21. LNG importers of >100 BCF (2001). From Energy Information Administration (2003).

for several decades. The problem is that most of the reserves will be coming from the same regions as our imported oil. In addition, large imports will require a major investment in infrastructure and years of construction. This infrastructure will include a large number of LNG tankers, high-volume LNG off-loading and processing facilities, and pipelines for moving the gas inland. Today the largest LNG importers in the world are the hydrocarbon-poor nations of Japan and South Korea (Fig. 21). Only relatively minor volumes of LNG are consumed in other countries, including the U.S., but consumption is likely to increase substantially in the next few years.

The predicament for the U.S. is that much fuel-switching capability in the face of high oil prices involves increased use of natural gas. However, North America as a whole can barely keep pace with demand, and only when winters are mild. The point is illustrated by the abnormally cold winter of 2002–2003, when U.S. gas storage dropped to record lows, and prices increased four- to fivefold. If a problem with oil supply markedly increases gas demand, or if another cold winter comes, it is doubtful that enough gas will be available in the short term. Although this situation could starve some industries of energy so that homes could be heated, the problem is only temporary. A lasting solution will come when large-scale LNG imports are possible. Currently imported LNG meets only 1% of U.S. natural gas demand, and although this is a tenfold increase over 1995 LNG imports, maximum U.S. capacity for handling LNG is only about 4% of demand (Ziff Energy Group, 2001). If demand for natural gas grows faster than our capacity to import LNG, average prices should stay well above $4.00 per MCF until imported LNG can reach the market.

Despite North America's supply problems and high global consumption rates, the outlook for natural gas is good. Proved reserves and estimates of future additions are very large. Current proved reserves alone could support world demand for more than 60 years at current rates of use. If one adds the 8.9 QCF of future reserve additions predicted in 2000 by the USGS, consumption could be supported for a century more. A reserve life of 160 years, and the belief by most that even this estimate is conservative, explains why natural gas is seen as the bridge to sustainable energy sources.

Production

World gas consumption is balanced by gas production (Fig. 22). Even for non-exporting regions that are self-sufficient (e.g., North America), these volumes rarely match (Fig. 19), with small differences between production and consumption reflecting additions or withdrawals from storage. The U.S. and Russia dominate production as they do con-

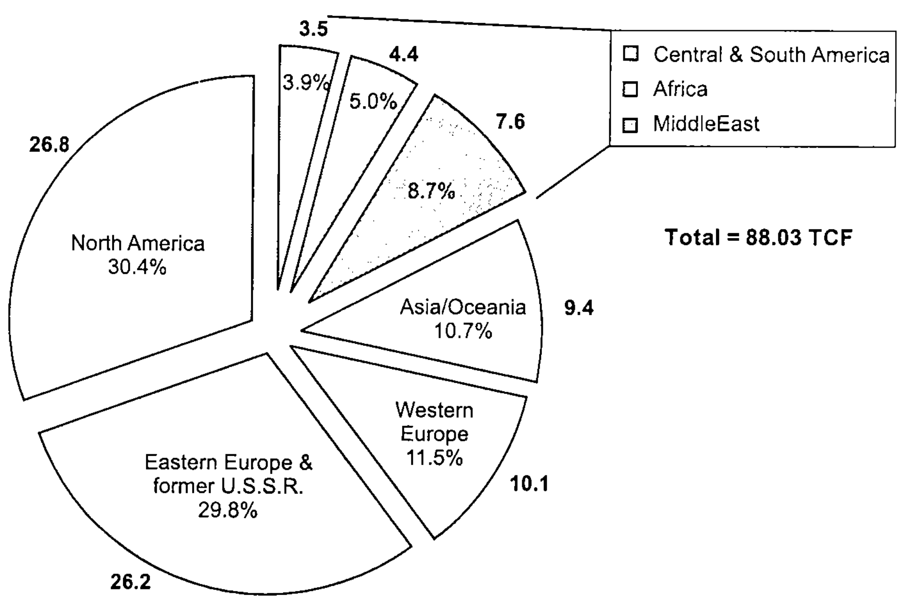

Figure 22. Natural gas production by world region (2000). From Energy Information Administration (2003).

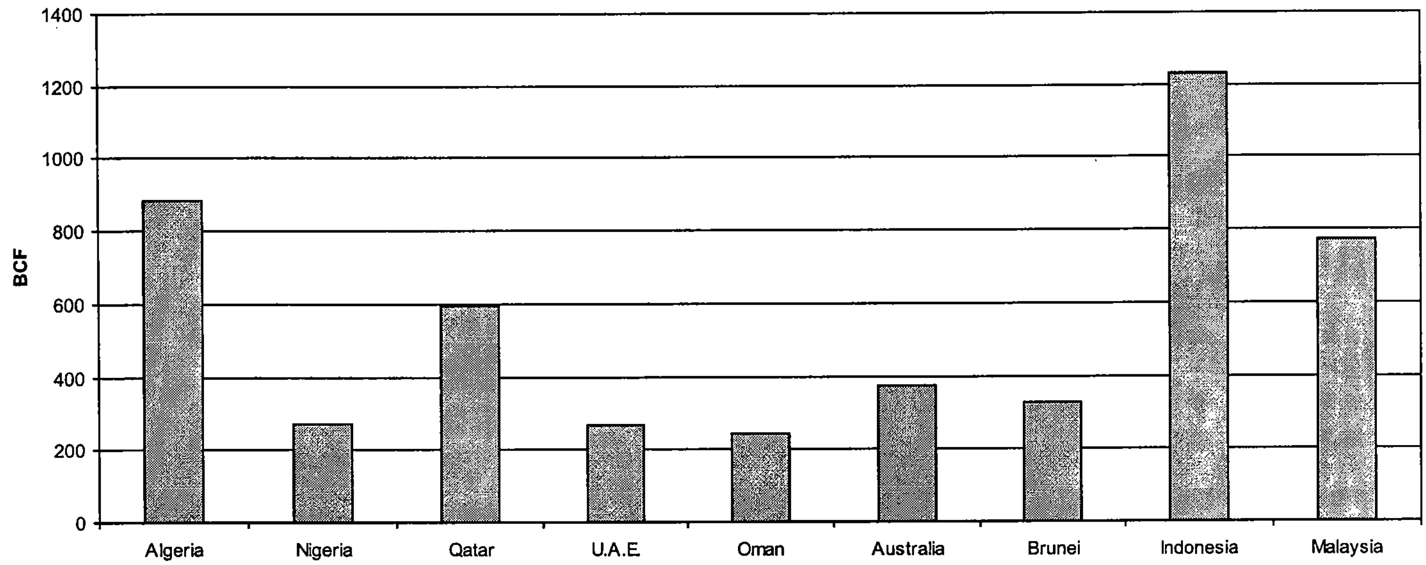

Figure 23. LNG exporters of >200 BCF (2001). From Energy Information Administration (2003).

sumption. However, production of gas (unlike oil) is not a direct indicator of the location of global reserves. It shows instead where reserves are connected to a market, which can be overland via pipeline or by seaborne LNG transport. Today only about 6% of the world's demand for natural gas is fed through LNG imports, but as reserves in the developed world are produced and consumption increases this percentage will grow markedly.

The largest LNG exporters are not the countries with the largest reserves but those that first met emerging demand from developed countries (Fig. 23). Many countries have larger gas reserves than Indonesia and Malaysia, but early drilling and reserve certification enabled them to obtain contracts with major Asian consumers—Japan, South Korea, and Taiwan (Fig. 21). Long-term contracts enabled them to build the infrastructure for shipping LNG to their markets, and later discoveries and additions to reserves have enabled the expansion of facilities to handle growing demand. Algeria's proximity to Western Europe has given it a decided advantage over other sources of LNG.

In the U.S., non-conventional resources such as tight gas and coalbed methane are taking a progressively larger share of production (Fig. 24), and conventional gas from deep water in the Gulf of Mexico and the U.S. and Canadian Arctic also will increase their contributions. However, the last three years in the U.S. have shown that even concerted gas drilling has not greatly increased our productive capacity. In fact, although demand continues to grow, we can barely maintain existing production levels. New volumes of conventional and non-conventional gas in North America are not large

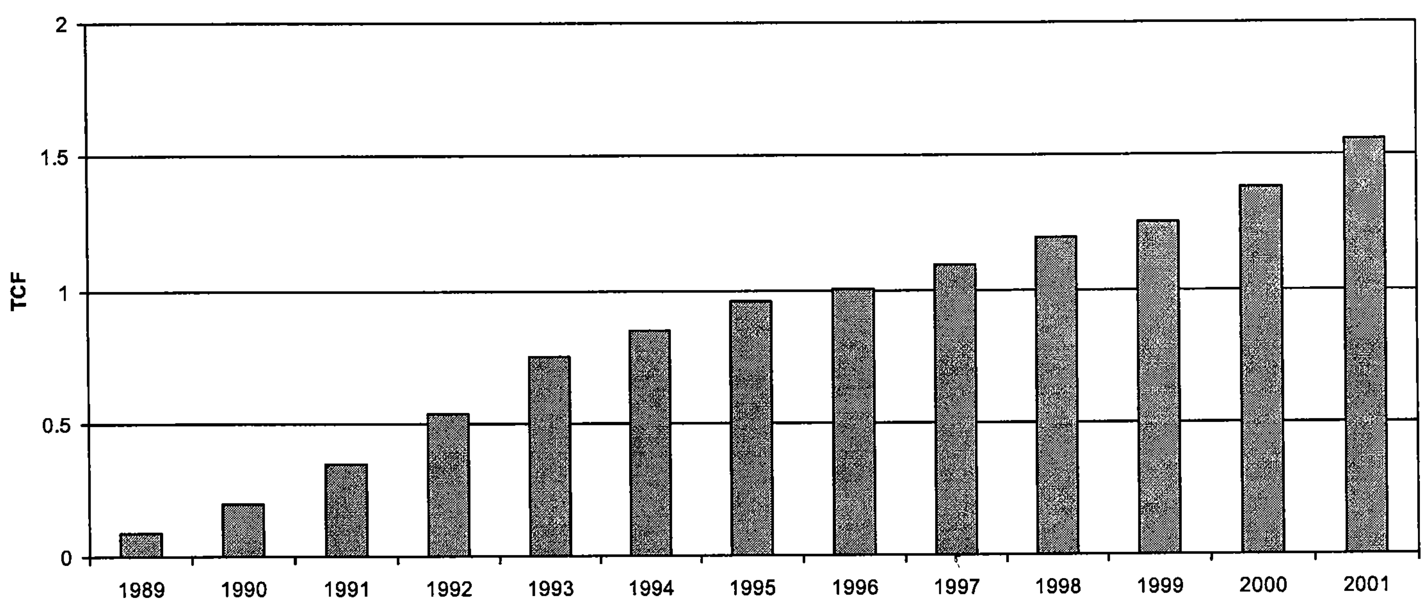

Figure 24. United States coalbed methane production, 1989–2001. From Energy Information Administration (2003).

enough, nor can they be produced fast enough, to prevent the need for large quantities of LNG in coming years. Although the U.S. is certain to be the largest emerging LNG market, of concern is the time needed to build the ships and facilities necessary to import it. With the delicate balance of supply and demand, it could take several years of progressively higher, roller-coaster prices before large volumes of LNG become available.

Ironically, many LNG facilities, which must be sited offshore and as close as possible to centers of demand, will be built over gas-prone basins that for political and environmental reasons are off limits to the petroleum industry. Examples include basins off the East Coast, adjacent to some of the nation's largest population centers.

The world's preoccupation with oil has often relegated natural gas to second-class status, especially in countries where oil is abundant. However, for both Oklahoma and the U.S. as a whole, it is gas that will largely be called upon to fill gaps left by reduced oil capacity. (A case in point is the conversion process of natural gas to liquid fuel, which will allow it to satisfy considerable oil demand.) The need for natural gas can only rise in the long run. Demand may temporarily fall as a result of conservation and fuel switching, but core demand—demand that remains whatever the price—will continue to increase. Core demand is being further augmented by gas-fired power plants built to meet increased electrical demand, most of which have no fuel-switching capability (Wright, 2002).

THE GLOBAL ENERGY FUTURE

As the world economy becomes more integrated, analysis of any one region in isolation becomes impossible. Thus, to understand Oklahoma's oil, gas, and larger energy picture one must first take into account the principal global and national issues. The overriding reality is that fossil fuels (oil, natural gas, and coal) will continue to fill the great bulk of the world's energy needs for a long time to come. As a result, the primary matter in the short to medium term is the degree to which supply (production) can meet the demand (consumption) for these critical commodities.

From 1975 though 2000, the volume of oil discovered every 5 years has been decreasing, and in the period from 1995 to 2000 an annual average of 3 BBO was discovered—while 27 BBO was consumed (Magoon, 2000). Estimates of discovered oil vary, but all agree that the world is living in the red. Only the vast reserves and productive capacity of the Middle East have allowed this situation to continue, but as time passes dwindling reserves must eventually result in reductions in supply and corresponding reductions in demand.

The dominant economies of North America, Asia, and Western Europe consume the bulk (78%) of the world's oil production, but they control only 11% of the reserves. In fact, the disparity between their proved oil reserves and their consumption is growing. For example, North America and Western Europe account for about 50% of world consumption and 25% of production, but a paltry 7% of world reserves. Thus, in addition to having smaller proved reserve volumes, these regions are producing their reserves proportionately faster. Compare this to the Middle East, which accounts for 6% of world consumption, 32% of world production, and 67% of world reserves. The inequity between the "haves" and "have-nots" will continue to accelerate because predictions of where future discoveries will be made also are skewed strongly towards developing regions. In order of importance, these are the Middle East, the Siberian and Caspian Sea areas of the former U.S.S.R., and the Niger and Congo River deltas in western Africa (Ahlbrandt, 2002).

A similar disparity exists for natural gas. Nations in Eastern Europe and the former U.S.S.R. and in the Middle East contain almost three-quarters of world reserves, yet account for only about one-third of consumption. These regions are also projected to contain the greatest volume of future reserves. In contrast, North America and Western Europe possess only 8% of the world's gas reserves, but consume about half the world's production.

The key producing regions of Central and South America, Africa, and especially the Middle East, are mostly the remnants of dismembered colonial empires, and not surprisingly some have been politically unpredictable. The concentration of oil reserves in countries that have only recently gained independence or are perhaps fledgling democracies means that instability in oil supplies will remain the norm, not the exception. These regions account for 83% of world reserves, with a fraction of the Middle East alone possessing two-thirds of the planet's proved oil volume. The resulting reserve geography makes the Middle East's stability especially important to the world economy, so news-making events in even the smallest of its nations often have international implications.

Many of the political, economic, and military issues confronting us today can be traced directly to the distribution of the world's oil reserves (Fig. 10). This linkage has made possible what would have been unthinkable until recently: U.S. reliance on Russia and previous members of the U.S.S.R. (the former "Evil Empire") to provide a stable source of supply to reduce dependence on oil from the Middle East (the center of the current "Axis of Evil"). Politics changes, as do our perceptions of the world, but trying to determine the level of U.S. oil security by calculating (often to 2 decimal places) the percentage of imported oil coming from sources considered "unreliable" misses the point (Fig. 25). Whether oil is imported from a close ally or a potential enemy, the market for oil is *global*: so aside from transportation charges, a barrel of oil from Iraq costs a U.S. refinery the same as a barrel of oil from Oklahoma. Any production added to the world market, regardless of origin, will push prices lower. Conversely, if a producing area goes down for any reason, its customers will seek oil from another source, whether that oil is spoken for or not. This drives prices higher.

The U.S. government has predicted that nuclear and hydroelectric energy will remain flat, and that the use of other renewable sources will increase only slightly through 2025 (Fig. 26). Coal, natural gas, and especially petroleum demand (fossil fuels) are expected to increase dramatically. Even as a percentage of total energy consumption, the U.S. dependence on fossil fuels is expected to grow from its current 85% to 88% by 2025.

Of the nation's top energy resources, only coal can meet demand from exclusively domestic sources. Both coal and

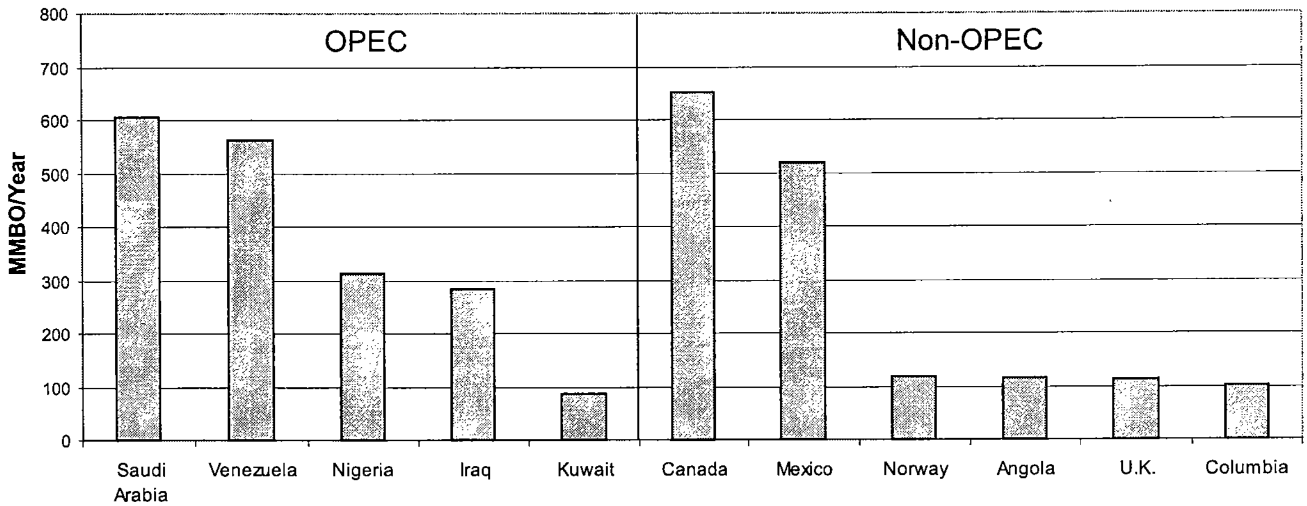

Figure 25. Major sources of United States crude oil imports (2001). From Energy Information Administration (2003).

nuclear energy, whose reserve lives (at current consumption rates) are 300 years and 100 years (Deffeyes, 2001), bear important environmental and political liabilities. As a result, it is unlikely that there will be a major shift in energy demand from oil into either of these. The fuel with the reserves and environmental qualities necessary to make up for any shortfalls in future oil supply is natural gas.

The peaking of world oil production, whenever it occurs, will lead to a considerable rise in price, and users that can shift to cheaper fuels will begin doing so. Coal, in which the U.S. is self-sufficient, is the least expensive, but on a Btu basis natural gas also has been cheaper historically than oil (Boyd, 2001). As fuel switching occurs, oil demand and prices will decline somewhat, but benefits from fuel switching are limited. Some petroleum products have no satisfactory substitutes. For example, about half of U.S. oil demand is in the form of gasoline and jet fuel, so for industries involved with transportation conversion may be too expensive or impossible.

Oil is America's number-one energy source, but a 50% increase in the current level of production and imports will be required to meet expected demand in 2025 (Energy Information Administration, 2003). As discussed previously, such an increase does not seem likely. In fact, under most scenarios, demand will exceed petroleum supply within years—not decades—and probably by 2009. When this occurs oil demand will be forced to match supply, with other energy sources taking up the slack. Whether demand exceeds production by one barrel or one million, the point where production and consumption curves cross will mark the beginning of the end of the age of oil.

Although market forces ensure that demand quickly balances supply, the range in which long-term oil prices will settle is impossible to predict. Price volatility probably will remain high, but the perception of scarcity should keep both price lows and average prices higher (in real terms) than they are today. The key to reducing turmoil is a gradual transition from an energy economy dominated by oil, to one in which a variety of long-lived resources can help shoulder the burden. To that end governments would be wise to plan for the long term, where possible using the most abundant domestic energy sources. Where economics dictate the use of less-expensive imported fuel, prudence demands formulating contingency plans involving fuel switching in favor of domestic resources. The goal is a smooth transition, with a minimum of price spikes. Reducing the speed at which prices rise is important, as it affords time to retool infrastructure and adapt to new economic constraints—an important task for developed and developing countries alike.

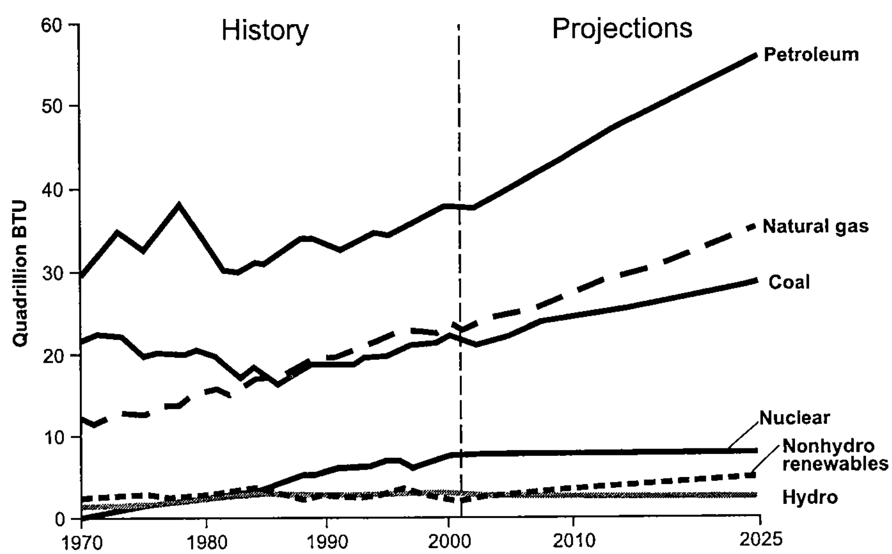

Figure 26. United States 2003 annual energy outlook—early release, 1970–2025. From Energy Information Administration (2003).

Apart from a decline between 1977 and 1982, resulting from sharply higher oil prices, U.S. consumption and dependence on imports have risen steadily. This trend will continue, as fully half of the 1.3 MMBO per day projected increase in worldwide demand in 2003 is expected to come from the U.S. (Wright, 2003a). A high level of national consumption is not surprising, as the American economy produces far more goods and services than any other country; however, we also have become more efficient in our energy usage. Between 1959 and 2001 the U.S. economy grew more than fourfold, but in 2001 we used half as much energy per dollar of gross domestic product as we did in 1959 (Radler, 2002).

The U.S. and the rest of the world depend on the free flow of oil and LNG from exporting countries. For their part, OPEC countries, excepting two embargoes intended to influence American policy in the Middle East, have provided oil in abundance. However, unforeseen events will continue to affect the flow of oil, forcing government planners to take precautions to ensure there are no interruptions. For instance, a primary mission of the U.S. Navy is to keep sea-lanes open to commerce, as our economic health, as well as that of the rest of the global community, depends on free access to energy supplies. The U.S. has fought one war over insuring access to oil and has recently completed another that, among other things, also will improve our long-term access to petroleum.

World events can lead to uncertainty in energy markets and create anxiety in the public mind. Our insecurity in energy matters is usually brought about by jumps in gasoline and natural gas prices. Complaints then become common, and conspiracies are alleged. However, with a myriad of uncontrollable factors that can affect prices, and an increasingly delicate balance between supply and demand, the wonder is that the average annual oil price has remained so steady in the $10–$20 per barrel range. Prices for oil (and gasoline) have, except for a jump in the early 1980s, remained nearly constant in real terms for 30 years (Fig. 27). Headlines may declare that the price of gasoline is the highest in history, but in constant dollars everything is more expensive. It is OPEC and the world's overcapacity in oil production that has largely kept energy prices independent of inflation. The price of natural gas in the U.S. has been proportionately more volatile than oil, but this is mostly because demand is more seasonal and we do not yet have large-scale access to overseas reserves. As a result, with the help of Canada, in natural gas we have been largely on our own.

What can America do to improve its lot? We are limited in our ability to maintain the uninterrupted flow of oil from producing countries, and for the same reason we have little control over price. Our options are to either reduce demand through some form of conservation, or enhance the supply of domestic oil and gas. Unfortunately, encouraging voluntary conservation of any kind is politically difficult, so only the supply side of the equation remains open. However, because of the maturity of our industry the only way to markedly increase long-term domestic oil and gas production is to open to leasing many areas that are now off limits. Popular sentiment also makes this course unlikely. For instance, gas-prone offshore areas (hence, with a minimal risk of oil spills) that are beyond sight of land have been placed off limits. (Bans have even been decreed retroactively through the denial of development permits after discoveries have been made.)

Although valid arguments exist both for drilling and for not drilling, it is important to understand that decisions to exclude areas from oil and gas exploration are as much philosophical as environmental. The industry's environmental track record is excellent, even in sensitive areas like the North Slope of Alaska where oil production has been under a microscope for more than 30 years. An environmental awareness that focuses on drilling restrictions tends to ignore the one element that would bring the greatest number of undeniable environmental benefits—reduced consumption. For example, 85% of the oil that enters North America's offshore environment (natural seepage excepted) results

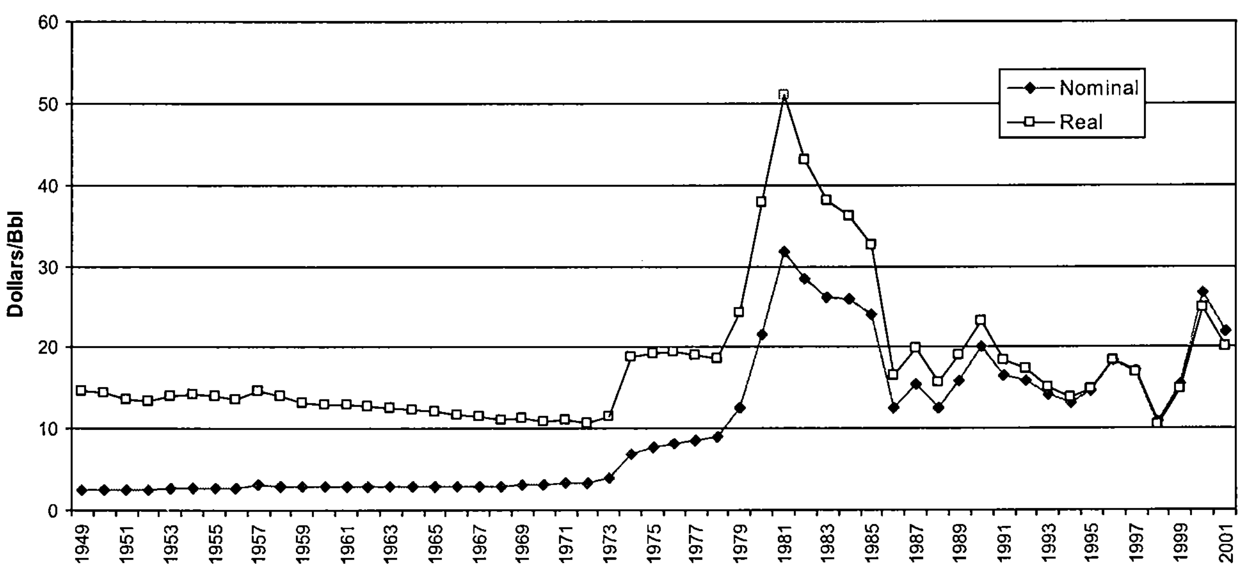

Figure 27. United States crude oil prices in 1996 dollars, 1949–2001. From Energy Information Administration (2003).

from consumption (runoff from urban areas and non-tanker shipping and boats). Transportation and refining account for an additional 11%, with only 4% entering the water through exploration and production activity (Wright, 2003b).

The irony is that increased domestic production would have not only economic benefits, but would also reduce the environmental hazards inherent in transport. Unfortunately, the environmental consciousness that finds it easy to reduce activity in areas that are tightly regulated has no problem in allowing the developing world, with far less stringent environmental regulations, to suffer greater risks satisfying our energy demand. The bulk of the negative environmental impact resulting from use of any fossil fuel comes not from activity devoted to its discovery, production, refinement, or transport, but from its consumption. Minimal conservation, combined with increased industrial efficiency and domestic production would generate many benefits. These include a reduced reliance on external energy sources and the level of insecurity that we feel with every unsettling event that occurs worldwide. National economics would benefit from an improved balance of payments. Environmental risks of all kinds could be mitigated, an important one being a reduction in the number of tankers plying the nation's and the world's waterways.

The world will never "run out" of energy supplies. They will only become more expensive. However, inexpensive energy encourages waste and speeds the day when supply will no longer meet demand. Fuel economy in the average U.S. motor vehicle today is lower than it was in 1980, and for 20 years American energy consumption per capita has been more than 40 times the world average (Cloud, 2003). Although many Americans can afford higher energy prices, many others many cannot. Look beyond our borders: for many countries, especially those in the developing world that are resource poor, increasing energy prices will retard many aspects of development. More than affecting the size or horsepower of the vehicles driven, or whether homes and shopping malls can be air-conditioned to 65°F, in a poor country expensive energy has a major effect on industrial growth, jobs, food production and distribution, and ultimately social and regional stability.

When world oil production peaks it will signal not that we are running out of energy, only energy in a very convenient form. Natural gas can be brought to the U.S. in vast quantities in the form of LNG. It and our own gas reserves can be converted to liquid fuels, but this comes at a price. Even our abundant coal reserves can be converted to liquid fuels, but again at a price. All agree that the next major shift in energy usage will increase demand for natural gas at the expense of oil, coal, and nuclear energy. However, this shift is simply one in a long line of gradual changes in the history of energy consumption. The progression is characterized by increased energy efficiency as hydrogen-to-carbon ratios have increased (Fisher, 2002). The transition from wood to coal to oil to natural gas has not only increased overall energy efficiency, but each step has reduced the number and intensity of harmful side effects, such as clear-cut forests, acid rain, and greenhouse gases. Unfortunately, we cannot take credit for directing this evolution, because market forces (supply and demand) drove the development of the technology that made such improvements possible.

As we become more proficient technologically, the use of pure hydrogen may become the next logical step. Hydrogen has many potential applications and, although not yet viable, it may play an important role in developing sustainable transportation in the U.S. It does not pollute and can be produced in virtually unlimited quantities using renewable or abundant resources. Pure hydrogen and hydrogen mixed with natural gas have been used effectively to power automobiles. However, hydrogen's real value rests in its potential in fuel-cell vehicles. Fuel cells are essentially batteries that, constantly being replenished with fuel, never lose their charge (Alternative Fuels Data Center, 2003).

Hydrogen is produced by two methods: (1) electrolysis and (2) synthesis gas production by steam reforming (partial oxidation). Both methods need large amounts of energy to produce pure hydrogen, which is a major technical hurdle that must be overcome. Electrolysis uses electrical energy to split water molecules into hydrogen and oxygen. It is not efficient in producing hydrogen, and the U.S. Department of Energy has concluded that it is unlikely to become the dominant method for generating hydrogen in large quantities. Steam reforming, which separates carbon from the hydrogen in natural gas, is the dominant method used to create hydrogen fuel. If this method becomes economically viable, a large share of future demand for natural gas could come from the creation of hydrogen fuel (Alternative Fuels Data Center, 2003).

It is possible that a technological breakthrough will fundamentally change the world's energy budget by providing abundant, environmentally friendly, inexpensive energy that could substitute for oil and gas. Although the economic, environmental, and political benefits would be enormous, the likelihood of such an event occurring in the near-term is remote. Research continues in many areas, but nothing on the horizon promises to end our dependence on fossil fuels for decades to come.

OKLAHOMA'S OIL AND NATURAL GAS FUTURE

The energy future of Oklahoma, for both producers and consumers, is inextricably tied to the global marketplace. In that respect, our State is no different from any other. Its production of oil and especially natural gas is typified by large numbers of low-rate producers whose rates and long-term declines are tightly linked to drilling. Our reserves and production, although important nationally (Oklahoma ranks fifth in oil reserves and fourth in natural gas) are insufficient to affect, even in the slightest, the key variable influencing economics—world energy prices.

Price is especially important to Oklahoma's industry because our finding and development costs are higher, and production rates lower, than much of the rest of the world. This means when oil and gas prices slump, so do drilling and investment in infrastructure. In addition, during periods of low prices some wells become uneconomic to operate and, if low prices persist, many may be permanently abandoned (Boyd, 2002a).

The good news from a consumer's standpoint is that OPEC, like the state commissions before it, works hard to keep prices in a range that balances producers' income requirements with the world's economic interests. Unfortunately, this price range is barely enough to maintain Oklahoma's oil industry at a low level, and even this requires government programs designed to keep low-rate producers active (Boyd, 2002a). The relatively high cost of producing a barrel of Oklahoma oil is no one's fault, and there is no conspiracy to suppress U.S. drilling and production. The truth is that the oil price necessary to attract large investment (another drilling boom) in the State would also bring a global economic recession or depression. High prices would themselves soon reduce demand and bring on yet another round of falling prices. OPEC's balancing act is difficult, but must be judged as largely successful, for even as demand for oil has increased its price has remained reasonably stable. This factor, more than any other, has allowed the U.S. and other world economies to experience record growth.

World events make it all but impossible to entirely control energy prices, and short-term volatility will remain high. As long as the world's oil supply exceeds demand, the potential exists for prices to sink to levels ruinously low for Oklahoma's petroleum industry, although such drops should not last long. As demand continues to increase and oil production peaks—as is likely in the next few years—prices will rise. Then the balancing factor will cease to be the productive capacity of exporting countries, but the ability of consumers to reduce consumption. Volatility will continue, but both the peaks and valleys of price cycles should be higher than of those of the past. It is impossible to predict in what range oil prices will then move, but we can hope that the average will be high enough to encourage long-term investment in Oklahoma's oil industry. If so, it will be possible to concentrate on something that we can influence—how much oil is produced.

Any major increase in Oklahoma's oil reserves and production rate requires investment in concerted secondary and enhanced recovery work, especially in fields where recovery is substandard. The up-front costs are substantial for such projects, which require sustained higher prices in order to become economically attractive, but such prices could come in this decade. Regardless of how it is measured, the oil still residing in Oklahoma reservoirs is a staggering volume (44 to 82 BBO), all of which has already been mapped (Boyd, 2002a). Even a modest increase in the overall recovery factor for only the largest fields could yield huge rewards. A prudent strategy (in anticipation of the sustained oil price increase that seems inevitable) is to gather data and to rank candidate fields now, while interest in such projects is still relatively low.

Help could come as a result of studies (being sponsored by the U.S. Department of Energy) evaluating the feasibility of collecting carbon dioxide generated by industrial processes. The objective is to reduce greenhouse gases in the atmosphere, and this could be accomplished by pumping CO_2 into underground reservoirs from which it will never escape. The impact in this discussion is that CO_2 is very useful in enhancing oil recovery, and if the federal government decides that large-scale CO_2 sequestration is feasible, huge volumes of low-cost CO_2 could become available for enhancing oil recovery. If implemented, such a plan could dramatically increase ultimate oil recoveries in the eastern and southern parts of the State.

Higher oil prices will push natural gas demand and prices higher. However, unlike oil, the U.S. cannot yet import from overseas more than a tiny fraction (1–4%) of its gas requirements. Because our balance of supply and demand for gas is so tight, LNG capacity may be insufficient to satisfy all of the extra demand that may result from higher oil prices. Expensive oil, combined with a tight gas supply, could diminish our ability to reduce demand by switching fuels, and this may take prices for both to all-time highs. Higher prices would spur drilling, but there would certainly be negative repercussions for the overall State economy.

Drilling in Oklahoma is dominated by wells seeking gas. Nevertheless, major additions to gas reserves and production will require sustained drilling in areas that are still underdeveloped or underexplored. These include deep and low-permeability reservoirs that may be in areas of shallow, long-standing oil production. The continued development of coalbed methane resources also will remain critical to the State's gas industry. Oklahoma's location, geology, resource estimates, pipeline system, and the industry's strong history ensure that natural gas will be a key component of the State's economic future well into the 21st century. However, these strengths will avail us nothing without a steady stream of investment.

Petroleum products represent about a third (34%) of the State's energy consumption, nearly half of this as gasoline. Natural gas represents another 37% and coal 24%, bringing the total share for fossil fuels to 95%. The prices for all three tend to rise and fall together, but coal (as measured in Btu) is the cheapest and oil the most expensive. Unfortunately, coal use involves environmental issues that offset many of its advantages, and because most of Oklahoma's coal has high sulfur content, more than 90% of the coal burned here comes from Wyoming (Boyd, 2001).

Oklahoma's status as a major energy producer at the national level does not mean that the State's consumers are less affected by shortages or high prices. Even if we produced as much energy (oil, natural gas, and coal) as we use, prices in the global economy would remain beyond our control. (Local producers are obliged to maximize profits, and so cannot offer discounts to local consumers.) Ignoring taxes, transportation, and government subsidies, energy prices are the same everywhere on Earth. Oklahoma's production and nearby refineries reduce some transportation costs, but this price advantage is small and becomes less important as prices rise.

When prices for oil and gas swing widely, their value to the State depends far more on average price than on how much is produced (Boyd, 2002b). This is especially true for natural gas, which is the State's most abundant resource and its most important export. Two-thirds of Oklahoma's production of natural gas (roughly 1 TCF per year) is sold outside the State, and every dollar per MCF in gas price means \$1.5 billion in gross revenue (1.5 TCF × \$1.00/MCF). Building more gas-fired power plants will permit the conversion of some of these exports from gas to electricity, and the higher

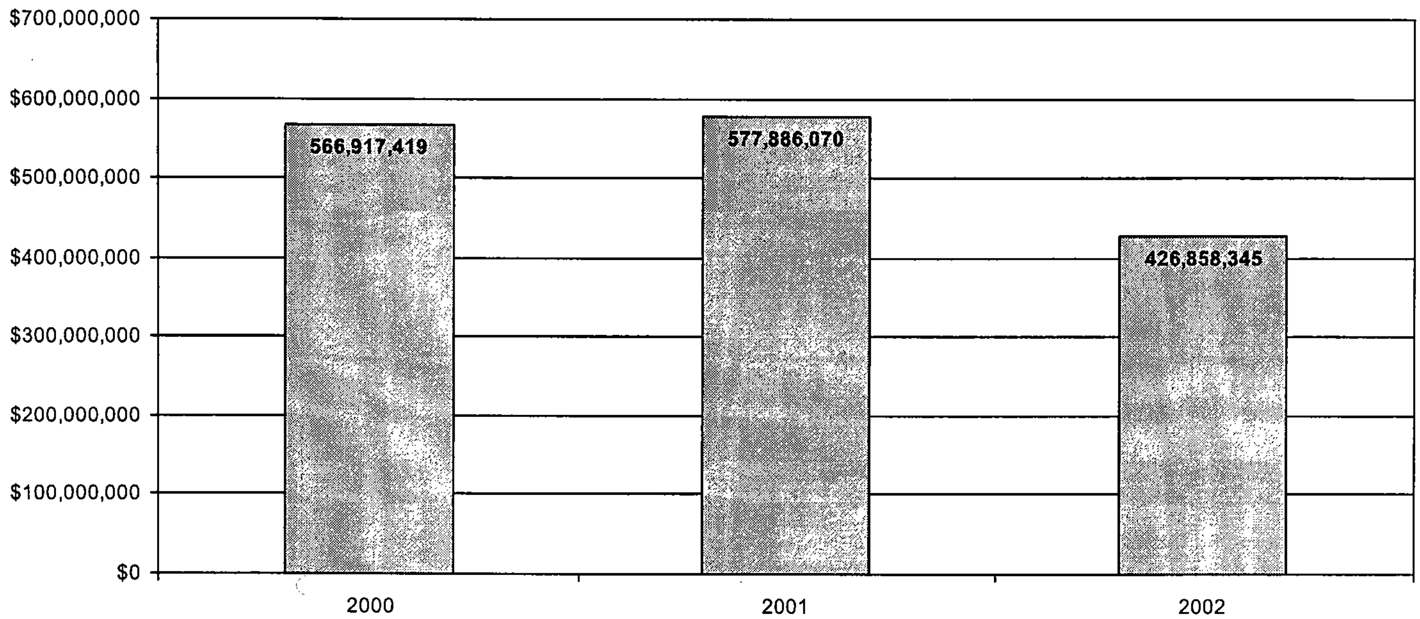

Figure 28. Oklahoma oil and gas tax revenues, 2000–2002. From Oklahoma Tax Commission.

price of electrical energy over raw natural gas should increase revenues to the State.

The annual decline in oil and gas production in Oklahoma has usually been less than 5%, but price can easily fluctuate 50–300% in a single year. This is why gross income and the resulting tax revenue to the State is so much more sensitive to price than the amount produced. Much of the shortfall in State revenue for 2002 can be directly attributed to lower prices for oil and gas—especially gas (Fig. 28). About three-quarters of the State's oil and gas tax revenue comes from gas production.

Oklahoma's Gross Production Tax has a sliding scale based on the average monthly price of oil and gas paid by the top three purchasers in the State. For oil the rate is 7% if the price is $17 per barrel or above, 4% from $14 to $16.99, and 1% if below $14. For gas the tax is 7% if the price is $2.10 per MCF or above, 4% from $1.75 to $2.09, and 1% if below $1.75 (Oklahoma Tax Commission, 2003). Such a variable tax is common among other States, but Oklahoma's scale is well below most others. For example, Kansas receives 8% of the revenue for oil and 15–17% for gas (Interstate Oil and Gas Compact Commission, 2003).

In light of recent tax shortfalls in Oklahoma, and the likelihood of substantially higher oil and gas prices in the future, an increase in our variable tax for prices well above $17 per barrel and $2.10 per MCF seems prudent. The negligible tax rate at low prices has done much to protect marginal producers, but State help given to producers in hard times should be balanced by higher rates when prices—and profits—are high. This is not a new idea, but it warrants consideration, especially as much of Oklahoma's royalty ownership is held by out-of-State residents (Dauffenbach, 2001).

Particularly important in the long term is the proportion of State resources that ultimately will become economic in an environment in which we cannot control price. How much of our oil and gas will be economically competitive with imports? Can we compete with LNG imported at $3.50 or $4.00 per MCF? Will long periods of low oil prices force abandonment of wells? Will new secondary and enhanced recovery projects become economic as world production plateaus and oil prices rise? In the more distant future, what proportion of reduced demand for oil will be met by natural gas? By coal? Hydrogen?

Our energy industry is important to the financial health of the State, and it certainly will benefit from higher energy prices. Higher prices will foster growth in energy-related businesses and increase State revenue, directly as production taxes and indirectly as a result of growth in the overall tax base through increased employment. However, because energy is an integral part of almost every business, the higher prices that help the oil and gas industry may not offset negative effects on other areas of the economy. No one can say whether the overall effect on Oklahoma will be positive or negative, but higher energy costs certainly will adversely affect much of the rest of the State's economy, and industries especially sensitive to energy prices will suffer disproportionately.

CONCLUSIONS

Oklahomans have no reason to be apprehensive about the energy future. The world will never run out of any source of energy. The question is how smoothly an energy market dominated by oil can change to one in which no single source dominates. Scenarios range widely. One is a gradual, seamless shift in energy consumption in the different parts of the world in which changes in demand and production balance and the required infrastructure is always at hand. This utopian vision is as unlikely as the other extreme, a sudden collapse of the global economy resulting in numerous political and military confrontations.

Our future is far more likely to resemble the past, with supply disruptions continuing to cause volatile prices. A narrower gap between supply and demand will cause this volatility to increase in the long term and prices to spike more severely than in the past. It may take several years for this to happen, but as the world's excess productive capacity continues to shrink, flexibility of supply will be lost. The world will remain an unsettling place. The difference is that when there is no longer a Saudi Arabia that can quickly ratchet up production to cover supply shortages in Venezuela, West Africa, Kuwait, or Iraq, our sensitivity to supply interruptions will be magnified.

Society has progressed from a primary energy dependency on wood to one that is evolving to a combination of oil, natural gas, coal, and lesser resources. Although nothing on the horizon is capable of replacing fossil fuels, we still have plenty of time to prepare. The transition certainly will be bumpy, but the reserves remaining for each fuel are still large.

An individual can prepare for the coming transition and its uncertainties by factoring energy considerations into long-term decisions. A vehicle purchased today should last several years. However, if a 50% increase in gasoline prices in this timeframe is likely to be a financial burden, a reevaluation may be in order. In the same vein, a house 30 miles from the office may be appealing, but only if 300 miles of commuting per week with higher gasoline prices is not an economic strain. The same house also should be evaluated for its energy efficiency, because both the natural gas used to heat it in winter and the electricity used to cool it in summer are bound to become more expensive.

The American mindset tends to see any inducement designed to encourage conservation as restricting a basic freedom in our consumer society. As a result, we have arrived at this juncture sooner than was necessary. Only higher prices have ever led to appreciable conservation in the U.S., and as energy prices rise they will again curtail demand. It is impossible to predict exactly when prices will rise, or by how much, but energy inevitably will take an increasing share of everyone's budget. There are no guarantees concerning our energy future, but understanding the forces involved and taking simple precautions certainly will render us less vulnerable.

We have ample cause to be optimistic. The world economy and our average level of prosperity have grown dramatically, even as energy usage has become more efficient and less polluting. Although mankind will depend on fossil fuels for a very long time to come, history shows that we are adaptable. In spite of the many uncertainties that lie before us, the challenges ahead are no greater than those we already have overcome.

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Texas Industries, Inc., opens a new crushed-stone operation at Mill Creek, Johnston County, southern Oklahoma

Stanley T. Krukowski
Oklahoma Geological Survey

Texas Industries, Inc. (TXI), began operating its Mill Creek, Oklahoma, crushed-stone plant in July 2002. The first shipment was sent out by rail in August. The plant capacity is 5 million tpy (short tons per year), with scheduled production a little over 2 million tpy for the first year. Plans for future expansion will depend on market demand. Company officials say that the Mill Creek operation can achieve an additional 2–3-million-tpy capacity through increased run time.

TXI built a 6,000-ft-long rail loop into the plant site to facilitate loading and shipping stone products. Capable of loading crushed stone at 3,200 tph (short tons per hour), unit trains of up to 120 hopper cars are loaded in less than 4 hours. Each hopper car has a capacity of 112 t (short tons). Rail shipments to the Dallas–Fort Worth market in Texas account for 80–85% of production; the remainder is hauled by truck and is intended for local markets (Carter, 2002).

Exploration for this greenfield operation began 4 years ago with the intention of supplying the Dallas–Fort Worth market. (The term *greenfield* refers to a site or area with no previous history of development: the entire operation must be built from the ground up.) The Mill Creek area has several advantages in this regard. First, transportation is close at hand, with the Burlington Northern Santa Fe Railroad parallel to State Highway 1, just east of the plant. The TXI mine and plant site are close to several properties that already are being mined. Second, People's Electric Cooperative has a substation on the TXI property that provides the Mill Creek operation with electrical power. Third, water for washing aggregate also is available, and TXI permitted and constructed settling ponds at the site.

Reconnaissance geologic mapping and sampling began in 1999. Initial diamond-core drilling of the deposit on 1,600-ft centers followed. Additional drilling with tighter centers at the eastern end of the property provided the information necessary to define the dimensions of the deposit and also provided data for mine planning.

The TXI Mill Creek operation currently mines the Ordovician Butterly Dolomite (Fig. 1). The Butterly consists mostly of gray, medium to coarsely crystalline sandy dolomite with some finely crystalline limestone. Some thin, clay-rich shale units are interbedded with the dolomite, but these are eliminated as fines during crushing and screening. Some milky

Figure 1. The Butterly Dolomite is blasted, and then loaded and hauled to the primary crusher at the Texas Industries, Inc., Mill Creek quarry. The rock is mined in an orthogonal manner across its strike and dip directions. The quarry wall at left is nearly parallel to strike, and the quarry wall at right is nearly perpendicular to strike (parallel to dip).

quartz is observed on weathered surfaces or as float. Sandstone and granite also occur on the property, and TXI is permitted to mine all three rock types.

The cover photograph shows the primary crusher, which was built on the Cambrian Reagan Sandstone. The Precambrian Troy Granite is mined down the road by a competitor neighbor, and TXI might mine granite in the future; but with reserves of dolomitic rock sufficient to maintain production levels at 5 million tpy for 100 years, TXI has put off development of its granite resources.

The mining is done by openpit methods (Fig. 1) in one shift per day. A single blasting event loosens up to 50,000 t of dolomitic rock, which is loaded into 85-t haul trucks and taken to the primary crushing station for crushing and screening (cover photograph). Oversize (plus-4-in.) material is sent to the primary cone crusher, whereas minus-4-in. material is stored in a 125,000-t surge pile with 30,000 t of live storage, or the amount of storage that is variable (Fig. 2). The 1½-in. and ¾-in. stone are stockpiled separately and are reclaimed for road-base material. Material from the surge pile is conveyed 2,800 ft to the secondary crusher, a 1,000-hp (horse power) vertical-shaft impactor, and then conveyed to stockpiles. The secondary crusher produces concrete rock (1 in. and 1½ in.), with each product stored in a separate stockpile with 14,000 t of live storage. These products then are sent to the rail loadout along an 800-ft-long reclaim tunnel. (The term *reclaim tunnel* refers to the conveyor tunnel that returns previously rejected materials for reprocessing; see Fig. 2.)

Figure 2. Four-in. crushed stone is conveyed through the reclaim tunnel from beneath the primary-crusher surge pile at the new Texas Industries, Inc., Mill Creek operation. (Photograph courtesy Prime Media, Inc.)

A 400-hp vertical-shaft impactor serves as the tertiary crushing plant, where smaller size fractions are crushed and screened into a variety of asphalt aggregate products (⅜ in. and ⅝ in.). The Mill Creek operation sand plant produces concrete sand and minus-⅜-in. × 30-mesh sand. Sand products are washed at the sand plant, and some concrete and asphalt rock pass through rinse screens before reaching the rail loadout. Figure 3 shows a part of the elaborate crushing and screening operation at the TXI plant.

The plant is set up to be run from the main control room by one operator. This is made possible because all PLC (programmable logic controller) stations are linked by a fiber-optic network from the main crusher to the rail and truck loadout. Another operator controls the loading of the rail cars. There are about 20 personnel employed at the plant site, and additional personnel mine and haul rock in the quarry. The remainder of the staff maintains the office, manages the plant itself, and directs sales. TXI contracts the drilling and blasting in the quarry.

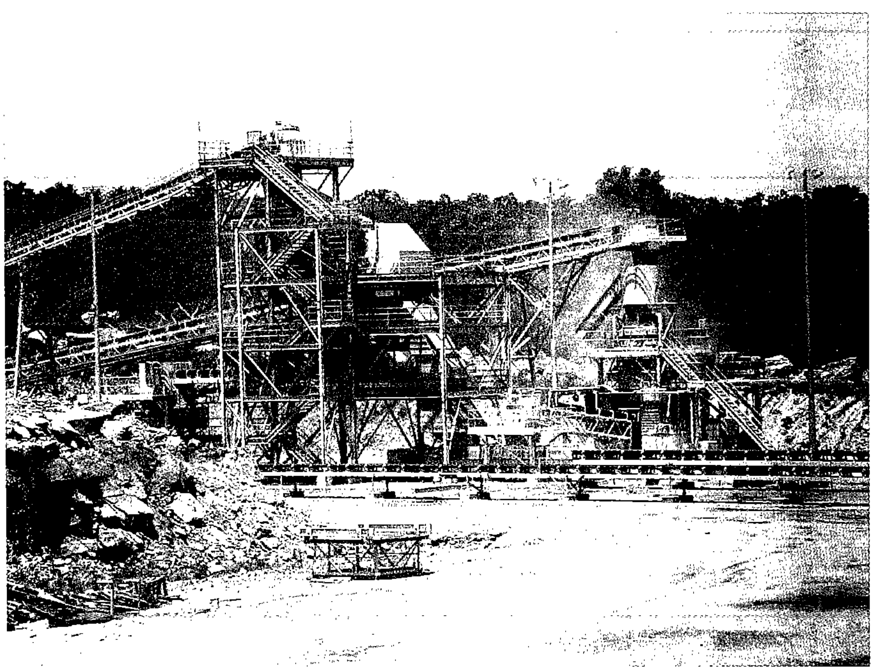

Figure 3. The Texas Industries, Inc., Mill Creek crushed-stone operation began shipping product in July 2002. This photograph shows a part of the elaborate crushing and screening operation. (Photograph courtesy Prime Media, Inc.)

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new OGS publications

EDUCATIONAL PUBLICATION 8

- **James R. Chaplin**
- **104 pages**
- **Three-ring binder**
- **$15**

Oklahoma Geology for Earth Science Teachers/Students Grades 6–12

This new book of earth science information and activities for teachers seeks to expose more teachers and students to earth science and the geology of Oklahoma through a series of activities that educate and entertain. The book contains crossword puzzles, word searches, word unscrambles, geodetective clues, and other projects that introduce geologic concepts in a fun format. The activities vary in difficulty and complexity to provide for different skill levels. Some information is repeated in separate formats to emphasize learning from repetition.

Some of the topics addressed include minerals and rocks of Oklahoma, general geology of Oklahoma, earthquakes in the State, water resources, nonfuel minerals, energy facts about Oklahoma oil and gas, a look at the State parks, fossils, dinosaurs that lived in this area, and information about the Arbuckle, Ouachita, and Wichita Mountains.

GEOLOGIC MAPS

- **Dan T. Boyd**
- **Scale 1:500,000**
- **Folded in envelope**
- **GMs 36 and 37 — $8**
- **GM 38 — $4**

GM 36: Oklahoma Oil and Gas Fields (Distinguished by GOR and Conventional Gas vs. Coalbed Methane)

GM 37: Oklahoma Oil and Gas Fields (Distinguished by Coalbed Methane and Field Boundaries)

GM 38: Oklahoma Oil and Gas Production (by Reservoir Age)

Oil and gas production in Oklahoma, including coalbed methane, is presented in three new geologic maps. The data for this project were compiled and interpreted by OGS petroleum geologist Dan T. Boyd using coalbed methane data supplied by Brian J. Cardott, also a Survey geologist. The primary data for these maps are taken from production figures collected by the Oklahoma Corporation Commission and compiled in the Natural Resources Information System (NRIS).

GM-36, *Oklahoma Oil and Gas Fields (Distinguished by Gas-to-Oil Ratio (GOR) and Conventional Gas vs. Coalbed Methane)*, shows producing, non-producing, active, and abandoned fields as well as provisional boundaries for productive areas that are not yet included within field outlines. Field colors are based on GOR (oil, gas, or a combination), and coalbed methane fields are distinguished by color from conventional gas fields. Included with the map is a 128-page booklet that contains three tables. The first alphabetically lists all of the recognized, unnamed oil and gas fields and provisional coalbed methane fields (active and abandoned) in the State by a single, centrally located township. This table corresponds to the outlines on the map and includes the DOE field code and discovery date. The other two tables list unrecognized field names, with the first sorted by the original (obsolete) name and the second sorted by the recognized name. These tables make it easy to find the names and locations of older fields that were merged into the larger fields that are known today.

GM-37, *Oklahoma Oil and Gas Fields (Distinguished by Coalbed Methane and Field Boundaries)*, has the same outlines are those seen in GM-36. In this map the provisional coalbed methane fields are the same, but conventional fields are randomly colored to more easily distinguish field boundaries. The accompanying booklet contains the same tables as the one included with GM-36.

GM-38, *Oklahoma Oil and Gas Production (by Reservoir Age)*, shows the underlying geology by grouping productive areas based on geologic age rather than field boundaries. The productive stratigraphic section in the State was divided into eight intervals, each containing all producing formations that have at least 10 completions listed in the NRIS database. These are listed alphabetically on the map along with their completion numbers.

Educational Publication 8 and **GMs 36, 37, and 38** can be purchased by mail from the Survey at 100 E. Boyd, Room N-131, Norman, OK 73019; fax 405-325-7069. To mail order, add 20% to the cost for postage, with a minimum of $2 per order.

All OGS publications can be purchased over the counter at the OGS Publication Sales Office, 2020 Industrial Blvd., Norman; phone (405) 360-2886, fax 405-366-2882, e-mail ogssales@ou.edu.

Request the OGS *List of Available Publications* for current listings and prices.

AAPG Spring Student Expo hosted by OU

The American Association of Petroleum Geologists held its third Spring Student Expo at the University of Oklahoma on March 14–15, 2003. Co-sponsored by the OU School of Geology and Geophysics, Oklahoma Geological Survey, and Sarkeys Energy Center, the Spring Expo was attended by 152 students. Abstracts for six poster presentations pertaining to Oklahoma geology are reproduced here.

Structural Geometry and Evaluation of Thrust Faulting in the Damon and Wilburton Quadrangles in Latimer County, Southeastern Oklahoma

MARLINE COLLINS, Oklahoma State University, Stillwater

The Arkoma Basin and the Ouachita Mountains of southeastern Oklahoma and western Arkansas were formed during the late Paleozoic Ouachita orogeny. In Oklahoma, the Choctaw fault forms the structural boundary between the frontal Ouachitas and the Arkoma Basin. This study is aimed at determining the structural geometry of the Late Paleozoic thrust faults in the Damon and Wilburton Quadrangles in Latimer County, in southeastern Oklahoma. Six balanced structural cross-sections are under construction to delineate the structural geometry in the study area. Data from the surface geological maps by the Oklahoma Geological Survey, wireline well logs, scout tickets, and seismic profiles, donated by Exxon and Amoco corporations, were used to construct the cross-sections.

The two main structural features of the study area are the south-dipping Choctaw and the north-dipping Carbon faults. Our preliminary interpretations of the available data suggest that the two faults form a triangle zone and a duplex structure present in the footwall of the Choctaw fault. The Springer detachment is the floor thrust and the Lower Atokan detachment is the roof thrust of the duplex. The Carbon fault loses its surface trace north of the Wilburton gas field. Seismic data indicate that the Carbon fault becomes a blind thrust as it continues to define the northern flank of the triangle zone within the eastern part of the study area, probably through a lateral ramp along its fault surface. Our cross-sections should provide a better understanding of subsurface geometry of this lateral ramp along the Carbon fault.

Structural Geometry of Thrust Faulting in the Hartshorne Area of Frontal Ouachitas, Arkoma Basin, Oklahoma

STEVE HADAWAY, Oklahoma State University, Stillwater

The Ouachita Mountains and Arkoma basin are two related tectonic provinces formed during the Late Paleozoic Ouachita Orogeny. The Arkoma basin consists of gentle synclines and thrust-cored anticlines. The frontal Ouachitas are characterized by imbricate thrusts and complex fold geometries.

This study is concerned with the structural geometry of thrusting within the Hartshorne SW quadrangle in southeastern Oklahoma. The study area includes the Hartshorne gas field where gas production ranges from five bcf in 17 months (middle Atoka from Agnes #1 well) to numerous dry holes.

Five balanced structural cross-sections are being constructed to determine the geometry of the Late Paleozoic thrust system. Data from the surface geological maps by the Oklahoma Geological Survey, wire-line well logs, scout tickets, and seismic profiles, from BPAmoco and ExxonMobil Corporations are used to construct the cross-sections. Upon their completion, the cross-sections will be restored to determine the amount of shortening induced by thrusting in the area.

The Hartshorne, Red Oak, Panola, Brazil, and Spiro sandstones are identified as marker beds to construct the cross-sections. We considered the Spiro to include the Wapanucka and Cromwell formations. Our preliminary interpretation of the available data suggest that a triangle zone exists between the Carbon Fault to the northwest and the Choctaw Fault to the southeast. A duplex structure and associated horses appear to exist above the Woodford and Springer detachments with the Lower Atokan Detachment as the roof thrust.

Reservoir Potential of the Upper Jackfork Sandstone (Lower Pennsylvanian), Western Ouachita Region, Arkansas

CLAIBORNE B.B. MORTON, University of Arkansas, Fayetteville

The upper Jackfork Sandstone (Lower Pennsylvanian) in the frontal Ouachita Mountains of west-central Arkansas is a sand-dominated distal flysch deposit reflecting axial delivery along the compressing Ouachita trough. Exposures in Scott County, Arkansas, were measured, and sampled for permeability, porosity, and standard petrographic analysis. In addition, synthetic gamma ray logs were constructed from the same exposures to provide a basis for regional correlation. The lithologic data demonstrate that the upper Jackfork sandstones are mostly quartz arenites (grain densities typically 2.65) possessing consistently low porosites, typically less than 4%, and average permeabilities below 0.005 millidarcies (Klinkenberg). In contrast, the sandstones are highly fractured as a result of their near vertical uplift in response to the Ouachita orogeny. This relationship suggests potential for horizontal drilling should the presence of hydrocarbons be detected. The Potato Hills, Latimer County, Oklahoma, includes hydrocarbon production from both the Arkansas Novaculite and the upper Jackfork Sandstone providing an analogue and some encouragement for further exploration of adjacent western Arkansas.

Reservoir Characterization Analysis of the Frisco Formation, Hunton Group, Seminole County, Oklahoma

KENNETH J. RECHLIN, Oklahoma State University, Stillwater

An integrated reservoir study was completed on the Frisco Formation, of the Hunton Group in northern Seminole County, Oklahoma. These reservoirs consist of complex bioherm mound system with specific facies associated with it. The mounds were then compared and correlated with the Frisco Formation carbonate mound outcrop along Bois d'Arc Creek in Pontotoc County. This subsurface to surface correlation was completed using conodont biostratigraphic data, as well as wire-line log characteristics, and is important for characterizing reservoir geometry in the Seminole County area.

Stratigraphically, the Frisco reservoirs are lower Devonian in age, (Emsian, Pragian) the youngest and uppermost formation in the Hunton Group. The Frisco Formation is separated from the underlying Hunton carbonate by an unconformity and represents a distinctly different style of deposition. The carbonate mounds present accumulate at or below the normal wave base and near the boundaries of the photic zone (Wilson, 1975) whereas lower Hunton rocks were deposited in a mostly subtidal, lower energy environment. In the Seminole County area, it is these Frisco mounds that are seemingly linked to the renewed production of hydrocarbons from the Hunton Group reservoirs.

The major data sources used for characterization of the reservoir rock was Petrophysical data, core-analysis, thin-section petrography, and biostratigraphy. Wire-line logs were used to correlate and map the reservoir in the Seminole area as well as to correlate south to the outcrop in Pontotoc County. Wire-line log data was also compared to core-analysis data, and was found to be quite consistent. Therefore the core-analysis data were used where available to characterize the quality of the reservoir. Thin-section petrographic analyses were completed in order to characterize reservoir constituents, as well as confirm fauna present in mound building. Conodont biostratigraphic data available on five cored wells, as well as outcrop samples were utilized to correlate and confirm a framework of wire-line log electro-facies, used to distinguish facies and stratigraphy.

Identification of Architectural Elements of Turbidite Deposits, Jackfork Group, Potato Hills, Eastern Oklahoma

GLORIA A. ROMERO, University of Oklahoma, Norman

This poster presents findings relating to a study that develops criteria to recognize architectural elements of turbidite deposits in subsurface data, in order to identify the main production mechanisms and reservoir quality of the Jackfork sequence.

The Jackfork gas play is a turbidite sequence located in the Lynn Mountain Syncline/Potato Hills area of eastern Oklahoma which was deposited during the Early Pennsylvanian time (Morrowan). The Jackfork Group has been widely studied at outcrop scale, but there are no significant studies of the subsurface reservoir behavior in the area. Due to the highly lateral variability of the depositional environment and the structural complexity of the Potato Hills area, the well-to-well correlation and the stratigraphical model is a difficult task with subsurface data. The key characteristics of the turbidite deposits are usually below the vertical resolution of conventional well logs, making necessary the use of additional information. Integration of well logs, borehole images, dipmeter patterns and cutting analysis provide a better understanding of the reservoir in the subsurface. Data from two gas-producing wells was available for this study. The cutting analyses and thin section description were essential to identify differences within the sand bodies and how these differences are linked to the log response. Identification of textural and compositional differences between the sandstone bodies in addition to the sedimentary structures recognized from the borehole image allows us to assign architectural elements to the Jackfork sequence.

Reservoir Properties and Distribution of Lower Skinner Valley-Fill Sandstones: Payne County, Oklahoma

WILLIAM A. SIEMERS, Oklahoma State University, Stillwater

Lower Skinner sandstones, in parts of Payne County, Oklahoma, Central Oklahoma Platform, represent incised valley-fill deposits. The Desmoinesian Lower Skinner is an important oil and gas producing sandstone in the Cherokee Group. Evidence from cores and cross-sections indicates that the Lower Skinner sandstone commonly fills valleys incised into underlying strata. In places, incision completely eroded the Pink Limestone, resulting in thick Lower Skinner valley-fill deposits that are juxtaposed on the older Red Fork sandstone. Additional evidence from core indicating that the sandstones are fluvial deposits include clay/mudstone rip-up clasts, and inclined and planar bedding in fining-upward sequences. There is also an absence of marine fossils. Isopach maps and cross-sections, which were constructed using wire-line logs in the computer program PETRA®, were utilized to establish the distribution and geometry of Lower Skinner sandstones as narrow, elongate channel filling deposits, with fining-upward characteristics.

Cores from three wells in the study area were examined, described and sampled. Rock properties were established using thin-section petrography, quantitative x-ray powder diffraction, and scanning electron microscopy. Porosity in the Skinner Sandstone is primary and secondary. Primary porosity is minimal, averaging less than 2%, whereas secondary porosity is more abundant. Secondary porosity can be as high as 16%, averaging approximately 8% across the entire Skinner interval. Secondary porosity formed from the partial to complete dissolution of detrital plagioclase and metamorphic rock fragments. Corrosion of quartz grains and porosity occlusion by carbonate cement are also evident. Some Skinner sandstones contain relatively high amounts of clay, approximately 12%, which occurs as grain coating, pore filling, and detrital matrix. Clays are primarily kaolinite, illite, and chlorite.

OGS Employees Honored

Brian J. Cardott

Cardott elected to AAPG EMD Executive Committee

Brian J. Cardott, geologist with the Oklahoma Geological Survey, has been voted president-elect of the Energy Minerals Division (EMD) of the American Association of Petroleum Geologists (AAPG). Cardott will serve as president-elect for one year beginning July 1, 2003, followed by one year as president.

Cardott served the EMD as Mid-Continent Section Councillor in 1994–1998, as Secretary in 1998–2000, and as Vice President in 2000–2001. He also was chairman of the EMD Alternative Energy Technology Committee in 1999–2003.

EMD members have an interest and expertise in one or more of the unconventional energy technical areas and geospatial information under the EMD banner. Technical areas include coal, coalbed methane, oil shale, oil (tar) sands, uranium, gas hydrates, geothermal, and energy economics and technology. Cardott has worked with coal, coalbed methane, oil shale, and oil sands in Oklahoma.

OGS Educational Publication receives award

An Oklahoma Geological Survey publication that teaches map-reading skills was selected as a Notable Document of 2001 by the *Journal of Government Information*. The award for OGS Educational Publication 7, *Reading Topographic Maps—Activities for Earth Science Teachers and Students,* will be announced in the soon-to-be-released December issue of the journal. The book's author, OGS geologist **James R. Chaplin**, wrote the book to help teachers, students, scout groups, and others learn to use topographic maps in a meaningful way for everyday life.

OU Staff Senate recognizes OGS staff

Six Oklahoma Geological Survey staff members were honored on Friday, May 2, at the University of Oklahoma Staff Senate Awards Ceremony.

Christie Cooper, OGS managing editor, received the Informational Staff Association Distinguished Performance Award from the association's president-elect Annette Schwiebert and OU President David L. Boren.

The ceremony's program brochure described some of Christie's accomplishments at the Survey: "Christie is responsible for the publications of the Oklahoma Geological Survey. This endeavor requires a diverse array of talents, ranging from publication organization, editing, layout skills, literature research, and word-processing skills. Christie goes out of her way to ensure accuracy, professionalism, and productivity for this division of the Survey. From acquiring manuscripts to editing to design and layout and finally to printing, Christie is involved with every process. She frequently works with authors who have little experience publishing papers, which in some cases requires extraordinary patience."

Christie Cooper accepts the Distinguished Performance Award from OU President David L. Boren and Annette Schwiebert.

Also recognized at the awards ceremony were a number of other Survey staff members for their University service:

25 Years

Mitzi G. Blackmon, *Clerk-Typist I*
David O. Pennington, *Operations Assistant II*

20 Years

Walter C. Esry, *Manager of OGS Core and Sample Library*
Michelle J. Summers, *Technical Project Coordinator*

15 Years

James H. Anderson, *Manager of Cartography*

upcoming meetings

2003

NOVEMBER

Geological Society of America, Annual Meeting, November 2–5, 2003, Seattle, Washington. Information: GSA Meetings, Box 9140, Boulder, CO 80301; (303) 447-2020 *or* (888) 443-4472; fax 303-447-1133; e-mail: meetings@geosociety.org. Web site: http://www.geosociety.org/meetings/.

Oklahoma Geological Survey and
Petroleum Technology Transfer Council

CROMWELL PLAY

FIELD TRIP

November 12–13, 2003
Ada, Oklahoma

OGS geologists Neil Suneson and Rick Andrews will lead a two-day field trip to examine outcrops of the Cromwell Sandstone near Ada and equivalent lower Morrowan strata in the Ouachita Mountains and Ozark Uplift. The key for interpreting the origin of the Cromwell Sandstone is understanding the lower Morrowan paleogeography of eastern Oklahoma. Participants will examine and discuss the origin of the Cromwell as shallow-marine bars and will visit equivalent shale-rich, deeper-marine strata (Springer Group) and coarsely bioclastic limestones (Sausbee Formation) that were deposited in a carbonate ramp environment. The field trip will leave from Ada and end near Muskogee.

HALF-DAY WORKSHOPS

November 17, 2003
Oklahoma City, Oklahoma

December 3, 2003
Tulsa, Oklahoma

OGS geologist Rick Andrews will conduct half-day workshops that address both detailed and regional aspects of the Cromwell play. Regional topics include sandstone distribution trends, structure, allocation of oil and gas production, stratigraphic concepts, depositional environments, and facies relationships. Surface-to-subsurface correlations also will be shown for strata encompassing the Atoka to the Mississippian unconformity. These data are presented on regional cross sections and used to clarify regional correlations, identify unconformities, and document facies changes.

Registration fees: Field trip, $75; workshops, $40 each.

Information: Michelle Summers, Oklahoma Geological Survey, 100 E. Boyd, Room N-131, Norman, OK 73019; (405) 325-3031 *or* (800) 330-3996; fax 405-325-7069; e-mail: ogs@ou.edu. Web site: http://www.ogs.ou.edu/.

2004

FEBRUARY

Second International Symposium on the Dynamics of Fluids in Fractured Rock, February 10–12, 2004, Berkeley, California. Information: Boris Faybishenko, Earth Sciences Division, Lawrence Berkeley National Laboratory, 1 Cyclotron Road, Mail Stop 90-1116, Berkeley, CA 94720; (510) 486-4852; fax 510-486-5686; e-mail: bfayb@lbl.gov. Web site: http://www-esd.lbl.gov/fluidsinrock.

MARCH

American Association of Petroleum Geologists, Southwest Section Meeting, March 6–9, 2004, El Paso, Texas. Information: David J. Sivils, Fasken Oil and Ranch, Ltd., 303 W. Wall Street, Midland, TX 79701; (432) 687-1777; e-mail: davids@forl.com. Web site: http://www.aapg.org/meetings. *(Abstract deadline is December 15, 2003.)*

OGS Workshop: "Unconventional Energy Resources in the Southern Midcontinent," March 9–10, 2004, Oklahoma City, Oklahoma. Information: Brian Cardott, Oklahoma Geological Survey, 100 E. Boyd, Room N-131, Norman, OK 73019; (405) 325-3031 *or* (800) 330-3996; fax 405-325-7069; e-mail: bcardott@ou.edu. Web site: http://www.ogs.ou.edu/. *(Abstract deadline is November 30, 2003.)*

Geological Society of America, South-Central Section Meeting, March 15–16, 2004, College Station, Texas. Information: Christopher Mathewson, Dept. of Geology and Geophysics, Texas A&M University, 3115 TAMU, College Station, TX 77843; (979) 845-2488; e-mail: mathewson@geo.tamu.edu. Web site: http://www.geosociety.org/meetings/.

American Wind Energy Association, Global Windpower Conference and Exhibition, March 28–31, 2004, Chicago, Illinois. Information: AWEA, 122 "C" Street, N.W., Suite 380, Washington, DC 20001; (202) 383-2500; fax 202-383-2505; e-mail: windmail@awea.org. Web site: http://www.awea.org/conference/.

APRIL

National Earth Science Teachers Association, Annual Meeting, April 1–4, 2004, Atlanta, Georgia. Information: NESTA, 2000 Florida Ave., N.W., Washington, DC 20009; (202) 462-6910; fax 202-328-0566; e-mail: fireton@kosmos.agu.org.

American Association of Petroleum Geologists, Annual Convention, April 18–21, 2004, Dallas, Texas. Information: AAPG, P.O. Box 979, Tulsa, OK 74101; (918) 560-2679 *or* (800) 364-2274; fax 918-560-2684 *or* 800-281-2283. Web site: http://www.aapg.org/meetings/.

OCTOBER

OGS Field Symposium: "Stratigraphic and Structural Evolution of the Ouachita Mountains and Arkoma Basin: Applications to Petroleum Exploration," October 26–28, 2004, Poteau, Oklahoma. Information: Neil Suneson, Oklahoma Geological Survey, 100 E. Boyd, Room N-131, Norman, OK 73019; (405) 325-3031 *or* (800) 330-3996; fax 405-325-7069; e-mail: nsuneson@ou.edu. Web site: http://www.ogs.ou.edu/.

Surface-Water Characteristics and Quality on the Osage Reservation, Osage County, Oklahoma, 1999

USGS Water-Resources Investigations Report 02-4060

Concern about the effects of early oil-industry practices of surface disposal of produced-brine water prompted an investigation of the surface-water quality on the Osage Reservation. About 38,000 oil wells have been drilled on the Osage Reservation since drilling began in 1896.

Prepared in cooperation with the Osage Tribal Council, U.S. Department of Energy, and Bureau of Indian Affairs, this 68-page report describes the occurrence and ranges in concentrations of water properties, major ions, nutrients, and selected trace metals at 140 sites sampled at low flow conditions from February to August 1999. Authors Marvin M. Abbott and Robert L. Tortorelli report that, despite more than a century of intensive petroleum development, surface-water quality on the Osage Reservation of northeastern Oklahoma has not been substantially affected by brines typically associated with that development. Surface water on the reservation had lesser concentrations of dissolved solids, nitrate-nitrogen, and sulfate than ground water sampled from nearby wells, but it had similar concentrations of chloride, a common constituent of oil-field brines.

Order WRI 02-4060 from: U.S. Geological Survey, Water Resources Division, 202 N.W. 66th St., Bldg. 7, Oklahoma City, OK 73116; phone (405) 843-7570; fax 405-843-7712. A limited number of copies are available free of charge.

Overview of Water Resources In and Near Wichita and Affiliated Tribes Treaty Lands in Western Oklahoma

USGS Water-Resources Investigations Report 03-4024

The Wichita and Affiliated Tribes of Oklahoma, in cooperation with the U.S. Geological Survey, conducted a reconnaissance study of the availability and quality of water resources in and near tribal treaty lands in western Oklahoma. Written by M. M. Abbott, R. L. Tortorelli, M. F. Becker, and T. J. Trombley, this 52-page report describes surface- and ground-water availability, water quality, and water use in the study area, which includes most of Caddo County, part of western Grady County, southwestern Blaine and Canadian Counties, and parts of eastern Custer and Washita Counties.

Order WRI 03-4024 from: U.S. Geological Survey, Water Resources Division, 202 N.W. 66th St., Bldg. 7, Oklahoma City, OK 73116; phone (405) 843-7570; fax 405-843-7712. A limited number of copies are available free of charge.

Possible Sources of Nitrate in Ground Water at Swine Licensed-Managed Feeding Operations in Oklahoma, 2001

USGS Water-Resources Investigations Report 02-4257

In this 76-page report, authors Mark F. Becker, Kathy D. Peter, and Jason Masoner describe the results of the study to determine possible sources of nitrate in ground water from 79 monitoring wells at 35 swine licensed-managed feeding operations (LMFO) in Oklahoma. Wastewater lagoons and monitoring wells were sampled from May to August 2001. Prepared in cooperation with the Oklahoma Department of Agriculture, Food and Forestry, the report states that LMFO waste was designated as a possible source of nitrate in water from 10 wells.

Order WRI 02-4257 from: U.S. Geological Survey, Water Resources Division, 202 N.W. 66th St., Bldg. 7, Oklahoma City, OK 73116; phone (405) 843-7570; fax 405-843-7712. A limited number of copies are available free of charge.

Environmental Characteristics and Geographic Information System Applications for the Development of Nutrient Thresholds in Oklahoma Streams

USGS Water-Resources Investigations Report 02-4191

The U.S. Environmental Protection Agency has developed nutrient criteria using ecoregions to manage and protect rivers and streams in the United States. Environmental characteristics thought to affect impairment from nutrient concentrations in Oklahoma streams and rivers were determined for 798 water-quality sites in Oklahoma. This 43-page report describes the methods, procedures, and data sets used to determine the environmental characteristics. Prepared in cooperation with the Oklahoma Water Resources Board, this report was written by Jason R. Masoner, Brian E. Haggard, and Alan Rea.

Order WRI 02-4191 from: U.S. Geological Survey, Water Resources Division, 202 N.W. 66th St., Bldg. 7, Oklahoma City, OK 73116; phone (405) 843-7570; fax 405-843-7712. A limited number of copies are available free of charge.

Statistical Analysis of Stream Water-Quality Data and Sampling Network Design Near Oklahoma City, Central Oklahoma, 1977–1999

USGS Water-Resources Investigations Report 02-4111

This 125-page report summarizes water-quality data collected in cooperation with the City of Oklahoma City by the U.S. Geological Survey from 1993–99 at five sites on Bluff, Deer, and Chisholm Creeks and from 1988–99 at five sites in the North Canadian River and evaluates the sampling program. The data indicated that there were significant differences in constituent values among sites for water properties, major ions, trace elements, nutrients, turbidity, pesticides, and bacteria. Concentrations of dissolved solids and sulfate generally decreased as streams flowed through the Oklahoma City urban areas. Concentrations of organic carbon, nitrogen and phosphorus compounds, lindane, and 2,4-D, and frequencies of detection of pesticides increased in the North Canadian River as it flowed through the urban area. Concentrations of dissolved oxygen, sulfate, chloride, ammonia, manganese, diazinon, dieldrin, and fecal coliform bacteria periodically exceeded federal or state water-quality standards at some sites.

The report was written by Mark E. Brigham, Gregory A. Payne, William J. Andrews, and Marvin M. Abbott.

Order WRI 02-4111 from: U.S. Geological Survey, Information Services, Box 25286, Federal Center, Denver, CO 80225; phone 1-888-275-8747. The cost is $4, plus $5 per order for handling.

Statistical Summaries of Streamflow in Oklahoma through 1999

USGS Water-Resources Investigations Report 02-4025

Streamflow statistics are used by individuals and organizations involved in the planning of projects with surface-water resources. The U.S. Geological Survey, in cooperation with the Oklahoma Department of Environmental Quality, conducted an investigation to update streamflow statistics in Oklahoma.

Statistical summaries of streamflow records through 1999 for gaging stations in Oklahoma and parts of adjacent states are presented for 188 stations with at least 10 years of streamflow record. Streamflow at 113 of the stations is regulated for specific periods. A brief description of the location, drainage area, and period of record is given for each gaging station. A brief regulaton history also is given for stations with a regulated streamflow record. This 510-page report was written by Robert L. Tortorelli.

Order WRI 02-4025 from: U.S. Geological Survey, Information Services, Box 25286, Federal Center, Denver, CO 80225; phone 1-888-275-8747. The cost is $4, plus $5 per order for handling. This report also is available on the Web at **http://pubs.water.usgs.gov/wri024025**.

Percentile Distributions of Median Nitrite Plus Nitrate as Nitrogen, Total Nitrogen, and Total Phosphorus Concentrations in Oklahoma Streams, 1973–2001

USGS Water-Resources Investigations Report 03-4084

Nutrients are one of the primary causes of water-quality impairments in streams, lakes, reservoirs, and estuaries in the United States. The U.S. Environmental Protection Agency has developed regional-based nutrient criteria using ecoregions to protect streams in the United States from impairment.

Prepared in cooperation with the Oklahoma Water Resources Board, authors Brian E. Haggard, Jason R. Masoner, and Carol J. Becker calculated median percentile distribution from available nutrient data collected at 563 sites in Oklahoma and 4 sites in Arkansas near the Oklahoma and Arkansas border. The percentile distributions presented in this 23-page report can be used in the Use Support Assessment Protocols (USAP) to facilitate the development of nutrient criteria for Oklahoma streams. The USAP is a classification process that groups streams using environmental characteristics such as stream order, stream slope, turbidity, and percent canopy shading to identify streams in Oklahoma affected by nutrients.

Order WRI 03-4084 from: U.S. Geological Survey, Water Resources Division, 202 N.W. 66th St., Bldg. 7, Oklahoma City, OK 73116; phone (405) 843-7570; fax 405-843-7712. A limited number of copies are available free of charge.

Water Science for Schools

USGS Water-Resources Investigations Report 98-4086

Available both online and on CD-ROM, "Water Science for Schools" offers information on many aspects of water, along with pictures, data, maps, and an interactive center where students can give opinions and test their water knowledge. Topics include water basics, Earth's water, and water use. The CD-ROM has been produced in accordance with the ISO 9660 Standard and is capable of being read on any computing platform that has appropriate CD-ROM driver software installed.

Order WRI 98-4086 from: U.S. Geological Survey, Information Services, Box 25286, Federal Center, Denver, CO 80225; phone 1-888-275-8747. The cost is $32, plus $5 per order for handling. This report also is available on the Web at **http://ga.water.usgs.gov/edu/**.

Oklahoma abstracts

The Oklahoma Geological Survey thanks the American Association of Petroleum Geologists and the Geological Society of America for permission to reprint the following abstracts of interest to Oklahoma geologists.

Oklahoma's Digital Geologic Mapping Program

RUSSELL STANDRIDGE, THOMAS M. STANLEY, NEIL H. SUNESON, and *GALEN W. MILLER*, Oklahoma Geological Survey, 100 E. Boyd St., Room N-131, Norman, OK 73019

Since the mid-1990's the Oklahoma Geological Survey (OGS), as part of the STATEMAP component of the USGS's National Cooperative Geologic Mapping Program has been developing a GIS-based digital geologic mapping program for Oklahoma. OGS digital mapping consists of two programs: (1) a series of 1:100,000-scale reconnaissance geologic maps of the entire State that will become the foundation for a new 1:500,000-scale geologic map of Oklahoma; and (2) detailed 1:24,000-scale geologic maps of metropolitan areas, which help identify potential engineering and environmental hazards in rapidly growing urban areas.

Although both projects entail differing geological mapping procedures, cartographic methodology for the 1:100,000- and 1:24,000-scale maps are virtually identical. Procedures in converting the geologists' field maps into digital format that can be viewed as both GIS data files or as hard-copy color maps are as follows: (1) the original USGS topographic base is subdivided into three component film positives consisting of culture, hypsography and hydrography, and each is scanned at 400 dpi producing a TIFF image; (2) the hydrography and hypsography layers are vectorized using ASC R2V software, which allows for better line work and color manipulation of these components; (3) all three layers are then incorporated and georeferenced as shapefiles in ESRI ArcInfo 8.1, forming the final, digital base; (4) the geologists' field sheets are carefully georeferenced with ESRI ArcView 3.2 and digitized into individual layers representing each geologic formation; and (5) this compilation is then incorporated into ESRI ArcInfo 8.1 and placed underneath the base layers for final layout. For hard-copy reproduction of finalized geologic maps, the coloration of units, unit labels, map explanation, and any other information are manipulated and standardized using CorelDraw 8.

Once the geology has been adequately georeferenced, the shapefiles can be incorporated onto any number of specialized USGS bases (DOQ's or DEM's) with little additional manipulation.

Reprinted as published in the Geological Society of America *2003 Abstracts with Programs*, v. 35, no. 1, p. 58–59.

Estimating Topographic Heights in the Permian Wichita Mountains, Oklahoma

M. CHARLES GILBERT, School of Geology and Geophysics, University of Oklahoma, Norman, OK 73019

The Wichita Mountains of southwestern Oklahoma expose a preserved Early Permian tor topography that is now being exhumed. Combining information derived from the local facies, the Post Oak Conglomerate, of the surrounding Leonardian Hennessey Shale with regional stratigraphic data, and with an understanding of how the tor topography was generated, allows us to constrain sizes, shapes, and heights of the Permian topographic elements.

The rocks of the Wichitas are Early Cambrian granites, rhyolites, and gabbros, and overlying Cambro–Ordovician limestones. The igneous rocks are the floor of the Cambrian Southern Oklahoma Aulacogen. These rocks were once buried 3–5 km beneath the ancestral Anadarko Basin (Early to Mid Paleozoic "Oklahoma" Basin of Johnson). During Pennsylvanian uplift (i.e., Ancestral Rockies), structural relief of ~12 km developed between the Wichita Uplift and the Anadarko Basin to the north. Substantial relief could have existed during this interval, but is entirely conjectural.

However, the Permian development of the tor topography on the granitic substrate requires a pre-existent, low-relief subhorizontal surface, giving us a reference base. Uplift in the Early Permian and renewed erosion formed a new topography which was subsequently buried in Permian sediments. Relief of topographic highs on this topography reach 300–400 m. Surrounding stratigraphy indicates these are probably also elevations.

Reprinted as published in the Geological Society of America *2002 Abstracts with Programs*, v. 34, no. 6, p. 472.

Estimates of Permian Tectonism in the Wichita Mountains Area

M. CHARLES GILBERT, School of Geology and Geophysics, University of Oklahoma, 810 Sarkeys Energy Center, 100 E. Boyd St., Norman, OK 73019

The last stages of localized, Late Paleozoic uplift in the Wichita Mountains of southwestern Oklahoma, related to Ancestral Rockies Deformation/Ouachita Collision Event, can reasonably be inferred. Utilization of distribution of paleotopography, of unconformity characteristics, and of offset of lithologies leads to the following estimates of uplift and deformation in the Early Permian: vertical uplift of ~700 m (described in this presentation), and horizontal offset along the Meers Fault of approximately several kms (from studies of Donovan). This contrasts with the main deformation in the Pennsylvanian where the Wichita Mountains block was uplifted ~7 km (described here) and horizontally offset by ~10–15 km (documented by McConnell). Thus there is about an order of magnitude difference between the main phase of deformation and that which occurred at the end of the deformation sequence in the Late Paleozoic.

The interesting aspect of this deformation sequence is that the final phase can be documented as occurring as a descrete phase because of the nature of some of the Permian stratigraphic units surrounding the Wichitas. This story hinges on understanding the Post Oak Conglomerate and its origin. The other interesting aspect of this last part of the deformation sequence is that the offsets cannot be due to passive effects, such

as "settling" or compaction in the deep Anadarko Basin, because there is a distinct vertical component of uplift that simple subsidence to the north in the basin cannot explain. Far-field stresses would seem to be necessary.

Reprinted as published in the Geological Society of America *2003 Abstracts with Programs*, v. 35, no. 1, p. 71.

Geologic Mapping of the Quanah Granite, Wichita Mountains, Southwestern Oklahoma

NICOLE D. BAYLOR, KEVIN J. SMART, and *M. CHARLES GILBERT,* School of Geology and Geophysics, University of Oklahoma, 810 Sarkeys Energy Center, 100 E. Boyd St., Norman, OK 73019

The Wichita Mountains in southwestern Oklahoma are a geologic window into the Cambrian Southern Oklahoma Aulacogen that forms the basement of a large portion of Southern Oklahoma. A U.S. Geological Survey EDMAP grant is supporting the detailed mapping of the main outcrops of one of the youngest and most different of the eleven members of the Wichita Granite suite. Of particular interest are the contacts between the Quanah Granite and its surroundings: the earlier Glen Mountains Layered Complex, the earlier Mount Scott Granite, and the Permian Post Oak Conglomerate.

The Quanah Granite is identified by its blocky cm-scale salmon-pink feldspars and distinctive riebeckitic amphibole and/or annitic biotite. Its intrusive contact with the Mount Scott Granite can be mapped because of its characteristic gray ovoid feldspar phenocrysts, although the contact shows much detailed interdigitation in places. The intrusive contact with the Glen Mountains Layered Complex is distinctive and can easily be followed. The Post Oak Conglomerate contains well-rounded, variably-sized clasts of granite lying unconformably on and against the Quanah.

The goal of this project is to produce a detailed (1:24,000 scale) digital geologic map on a modern topographic base for the Quanah Granite. Reconnaissance work shows that the Quanah Granite consists of several different textural and mineralogical facies but these have never been completely mapped out. The contact relations with the abutting finer Mount Scott Granite have also not been mapped sufficiently to show the degree of complexity of the intrusive relations of the Quanah into the Mount Scott. Results from this mapping project will be used in several ways: (1) in the preparation of the Oklahoma Geological Survey's 1:100,000 areal geologic map of the Lawton sheet; (2) in providing geological materials for public use on the hiking and nature trails and entire public sections of the Wichita Mountains Wildlife Refuge; (3) the map will provide a base for models detailing the hydraulic recharge to the local aquifer systems and for more detailed studies of intrusive processes and later imposed deformation.

Reprinted as published in the Geological Society of America *2003 Abstracts with Programs*, v. 35, no. 1, p. 59.

The Brevard Zone in Atlanta, Georgia, and the Meers Fault of Southern Oklahoma: Conjugate Wrench Faults Formed Under Contrasting Temperature Conditions

JOHN H. RAYMER, Jordan Jones & Goulding, 6801 Governors Lake Parkway, Norcross, GA 30071

Geologic investigations for recent deep tunnel projects in Cobb County and Atlanta, Georgia, suggest that the Brevard Zone is a late Paleozoic, right-lateral wrench fault that is related more to the late Paleozoic wrench faults of southern Oklahoma than to the compressional tectonics that dominate the rest of the southern Appalachians. The principal difference is that the Brevard Zone formed in an already hot pile of amphibolite facies metamorphic rocks, whereas the southern Oklahoma system formed in a sedimentary basin. The Brevard Zone extends southwestward from Virginia, through Atlanta, and on into Alabama where it becomes buried under the Cretaceous onlap. The Brevard Zone cross cuts, albeit at a low angle, the structural, stratigraphic, and topographic grain of the Appalachians. The Brevard Zone in Atlanta contains both ductile and brittle deformational features. The ductile features are concentrated in a 2-km-wide belt of mylonite and ultramylonite. The brittle features consist of several persistent fracture sets that occupy a belt about 10 km wide that surrounds and includes the ductile belt. The fracture patterns mapped in the tunnels are consistent with a right-lateral wrench system. Together, the mylonite and the fractures show a continuous retrograde sequence ranging from amphibolite facies, through greenschist and zeolite facies, to post-metamorphic calcite pyrite, and gypsum. The mylonite and retrograde mineral assemblage are interpreted as being caused by the ambient temperature conditions in which the faulting happened to occur. The dropping temperature is reflected first in the change from ductile to brittle deformation, then by the various mineral assemblages occuring in the brittle fractures. The Brevard Zone appears to be the mirror image of the left-lateral wrench faults of Oklahoma. Both are of equivalent length and both have equivalent but opposite lateral offsets of around 35 to 45 km. The vertical offset of the Meers Fault is around 14 km (down to the northeast); the vertical offset of the Brevard Zone is not known. If both faults are projected beneath the Cretaceous onlap, they would meet near New Orleans at the intersection of the Mississippi embayment rift and the edge of the Paleozoic continental margin.

Reprinted as published in the Geological Society of America *2003 Abstracts with Programs*, v. 35, no. 1, p. 58.

Sulfur Geochemistry in an Alluvial Aquifer Affected by Landfill Leachate—A Case Study from Norman, OK, USA

MICHELE L. W. TUTTLE, GEORGE N. BREIT, ISABELLE COZZARELLI, and *SCOTT CHRISTENSON,* U.S. Geological Survey, MS 973, Box 25046, Denver Federal Center, Denver, CO 80225

Sulfate is an important electron acceptor for bacterial degradation of organic matter in landfill leachate, therefore, processes controlling its distribution and availability are important in studying leachate attenuation. These processes are similar in contaminated and uncontaminated ground water, pore water, and alluvium along a transect from the closed Norman, Oklahoma, landfill to the nearby Canadian River. Sulfur isotope systematics differentiated complex processes of natural sulfur cycling and the impact of landfill leachate.

Regional ground water and river water contain 100 to 500 mg/L sulfate with $\delta^{34}SO_4$ of approximately 10 to 12‰. Contaminated ground water contains less sulfate. A Rayleigh fractionation model describes the $\delta^{34}SO_4$ as ground-water sulfate concentrations decrease. In some contaminated wells, sulfate is <5 mg/L, suggesting extensive sulfate reduction, yet isotopic compositions are near 12‰. We hypothesize that this sulfate is from dissolution of barite (identified by SEM analysis) or sulfate released from organosulfur compounds in within the leachate (sulfur concentration in dissolved organic matter is about 2%).

Natural sulfur cycling in alluvium produces variable isotopic compositions. When porewater sulfate is >20 mg/L, $\delta^{34}S$ pyrite values are negative (–24 to –9‰); when porewater sulfate is <2 mg/L, $\delta^{34}S$ pyrite values fall within a greater range (–24 to +12‰). Acid-volatile sulfides (FeS) are always 0 to 15‰ more positive than coexisting pyrite. Isotopically heavier FeS is likely a recent phase, whereas pyrite accumulates throughout burial history.

The amount of pyrite or FeS does not differentiate contaminated from uncontaminated alluvium. However, the isotopic composition of sulfides in uncontaminated alluvium (pyrite median –15‰; FeS median –10‰) is significantly more negative than in contaminated alluvium (pyrite median –5‰; FeS median 0‰). These differences are attributed to availability of organic matter in the leachate, which allows for more complete reduction of sulfate.

Reprinted as published in the Geological Society of America *2003 Abstracts with Programs*, v. 35, no. 1, p. 73.

Trace Metal and Sulfur Geochemical Records of Late Paleozoic Paleoenvironmental Variability in North American Black Shales

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Our work over the past several years has focused on spatial geochemical variability within the laterally continuous cyclic Pennsylvanian shales of the Midcontinent and Appalachian Basin. Although light and uniform sulfur isotope ratios suggest pervasive euxinic deposition of our Midcontinent (Missourian) shales, regional gradients can be inferred for the efficiency of Mo scavenging and for rates of siliciclastic sedimentation expressed in spatially varying Fe/Al ratios. Black shales in Iowa show Mo enrichment roughly five times greater than that observed in coeval shales in Oklahoma. Trends for Fe are opposite those observed for Mo. In Oklahoma, Fe/Al ratios in black shales are up to five times larger than the continental ratio of 0.5 observed in the over- and underlying oxic shales and in the coeval black shales in Iowa. Enrichments in Fe often result from scavenging in a euxinic water column during syngenetic pyrite formation. Despite complications linked to possible hydrothermal contributions and epigenetic mineralization, observed Fe and Mo trends are reasonably interpreted in terms of early mineralization controlled by independently predicted regional patterns in (1) the organic reservoir, including relative inputs of terrestrial versus marine organic matter, and (2) rates of siliciclastic input. We have also explored possible variations in the intensity and persistence of water-column euxinicity.

To the east, Pennsylvanian black shales in the Appalachian Basin show strong correspondence between faunal records of low-salinity deposition and predicted high ratios of organic carbon to pyrite sulfur. While encouraging, exceptions exist. Our current model favors diffusive overprints by marine sulfate following a depositional transition from nonmarine to marine conditions. Such overprints have diagnostic sulfur isotope character, which can be distinguished readily from pyrite formed under primary marine conditions, including secondary overprints associated with transitions from oxic marine to euxinic marine conditions, as we observe in midcontinent transgressive gray shales. These two models for sulfur overprinting are directly analogous to the contrasting S isotope patterns recorded across the most recent glacial-interglacial transition in the Black Sea and Cariaco Basin.

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The Replacement Character of Copper-Silver Mineralization in the Permian Flowerpot Shale and Wellington Sandstone Formations of Oklahoma

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Disseminated copper-silver mineralization occurs within Permian dark gray shales and sandstones at many localities in Kansas, Oklahoma, and Texas. Ore microscopic studies of two localities, Creta and Paoli, Oklahoma, provide clear evidence that the mineralization has formed by selective replacement of favorable minerals and that those minerals differed significantly between the two deposits.

Shale-hosted, stratiform, copper mineralization was mined at Creta, Oklahoma, for about 10 years beginning in 1965. Mining was largely confined to a dark greenish gray shale that is about 8 inches thick. The copper-bearing dark greenish gray shale lies beneath a thin gypsum bed within a sequence of red shales and gypsum beds. The copper grade averaged about 2% and ranged up to 4.5%.

Sandstone-hosted copper mineralization has been drilled extensively but not mined at Paoli, Oklahoma. Intervals of copper mineralization 8–13 feet thick are localized along the reduced side of roll fronts within sandstone channels. Copper grades measured about 1–4% and the silver content is about 0.5–10 oz/ton, but locally ranges up to more than 200 oz/ton.

Ore microscopy shows that three types of copper sulfide grains were deposited at Creta by replacement of: (1) spores, (2) pyrite, and (3) pyrrhotite. Replacement of megaspores began in their interiors and gradually progressed to their spore cases forming obate grains about 120 μm across and with smooth outer margins. The spore replacements diminished downward beneath the ore zone. Colloform pyrite grains, about 40 μm in diameter and with lobate outer margins, are thoroughly replaced within the ore zone, and the extent of their replacement diminishes upward. The smallest copper sulfide grains are 10 μm long, prismatic in shape, and they replaced pyrite pseudomorphs after pyrrhotite. The copper sulfide minerals are chalcocite, digenite, anilite, and djurleite. Silver occurs as stromeyerite.

In contrast, hematite grains were selectively replaced at Paoli, although some cubes and pyritohedrons of pyrite as well as pyrite cement around quartz sand grains also were replaced. The paragenetic sequence of replacement was: native silver, chalcopyrite (early), bornite, digenite, and chalcocite.

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The Character of the Tri-State (Missouri, Oklahoma, Kansas) Zinc-Lead Ore Deposits and a Comparison with the Lead-Zinc-Copper-Cobalt Deposits of the Viburnum Trend, Southeast Missouri

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The two world-class Mississippi Valley–type ore districts, located partly or entirely in Missouri, the Tri-State Zn-Pb District and the Southeast Missouri Pb-Zn District (including the Viburnum Trend) are similar in many respects and are significantly different in other respects.

The ores of the Tri-State District (Missouri, Oklahoma, Kansas) are contained within Mississippian rocks. The hostrocks originally were cherty limestones that have been intensively dolomitized, silicified to jasperoid, and thinned in the vicinity of the orebodies. The orebodies were horizontal linear runs and flat sheetlike deposits consisting of chert breccia fragments cemented by jasperoid and ore minerals. The ore runs were about 500 feet wide and tended to form circular map patterns. In both districts, sphalerite and galena were the dominant ore minerals, smaller amounts of chalcopyrite, marcasite, and pyrite were present, and the principal gangue minerals introduced with the ore fluids were dolomite and quartz. Sphalerite dominated over galena in Tri-State, and galena dominates over sphalerite in the Viburnum Trend. Cadmium, germanium, and gallium were recovered from sphalerite.

The ores of the Viburnum Trend are contained within Cambrian rocks. The hostrocks originally were limestones that have been intensively dolomitized and partly thinned in the vicinity of the orebodies. Ore runs trend predominantly north–south, but diverge around buried Precambrian knobs. Mineralized solution collapse dolomite breccias are common at most of the mines, but locally thin flat orebodies occur above reefs extending eastward from the main trend. In addition to the main ore minerals, smaller amounts of other ore minerals, present in the Viburnum Trend but absent from the Tri-State District, include siegenite, millerite, polydymite, tennantite, enargite, gersdorffite, vaesite, nickeliferous pyrite, nickeliferous carrollite, bornite, chalcocite, digenite, djurleite, covellite, blaubleibender covellite, and castaingite. Cadmium is recovered from Viburnum sphalerite, and silver is recovered from both sphalerite and galena.

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Carbon Stable Isotope Patterns in the Pawnee Cyclothem, Middle Pennsylvanian of Midcontenent North America

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The Pawnee cyclothem includes the transgressive Childers School Limestone overlain by the offshore dark phosphatic Anna Shale, in turn overlain by regressive Myrick Station Limestone, and clastic Mine Creek Shale. The regressive sequence is interrupted by a lesser transgression producing the Frog Cemetery Limestone, offshore Joe Shale and regressive Laberdie/Coal City Limestone. The major Lower Pawnee and intermediate Coal City cyclothems merge basinward into Oklahoma as the Joe Shale joins the top of the Anna where the Frog Cemetery Limestone disappears. We analyzed carbonate-mud matrix of the limestone members from outcrop and core samples, in a shelf to basin (north–south) transect from Iowa to Oklahoma.

All units are most depleted in the north and most enriched basinward in the south. The transgressive Childers School is depleted in ^{13}C at ~ –1 to 0.8‰ on the shelf and enriched to ~3 to 4‰ in the south. The early regressive Myrick Station ^{13}C values range from ~ –2 to 0‰ shoreward, and from ~ –1.5 to 1.2‰ basinward. The Frog Cemetery increases from ~ –1 to 0‰ at its north end southward to ~0 to 1‰. The regressive Coal City/Laberdie, like the other units, has its most enriched compositions basinward. However, it is characterized by a distinct upward depletion, both in the north where it ranges from ~ –1 at the base to ~ –3‰ at the top, and in the south where it ranges from ~4.5 at the base to ~1‰ at the top.

The general ^{13}C enrichment trend basinward indicates that the overall relative contribution of ^{13}C-enriched marine dissolved inorganic carbon (DIC) was greater basinward than the contributions of ^{13}C-depleted DIC derived from oxidation of terrestrial and/or marine organic matter. The vertical depletion in the regressive units suggests that as the shoreline migrated basinward, the relative nearshore contribution of terrestrial DIC progressively increased. Importantly, minor isotopic excursions appear to be preserved and might provide a means of evaluating potential causal mechanisms for minor changes in the various DIC fluxes into the basin, such as minor sea-level oscillations or changes in riverine fluxes.

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Tracking the Mysterious Mississippian Chert Belt: Western, Central, and Southern United States

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Tremendous volumes of bedded chert are found within Mississippian carbonate strata throughout the western, central and southeastern portions of the United States. Within the Osagean series, a continuous belt of carbonate-hosted bedded chert stretches from Tennessee and Illinois in the east to Arizona and Nevada in the southwest, and into the western states of Utah, Wyoming and Colorado. The origin of these persistent chert beds has remained unclear, and the source of silica problematic. Studies by several workers have shown that these cherts formed primarily in shallow-water nearshore and shelf environments through replacement of carbonate host rock early in the diagenetic process, often within a few meters of the sediment-water interface. Although silica in some Osagean bedded chert deposits has been attributed to a biologic source, primarily sponge spicules, most workers have rejected a principally biogenic origin based on either petrographic or geochemical evidence. Other possible sources of dissolved silica for bedded chert genesis during the Mississippian include (1) chemical weathering of silicates generated during orogenesis, (2) hydrothermal alteration of basalts along mid-ocean spreading ridges, (3) increased weathering of silicates due to development of land plant features such as expanded root systems and broad leaves, (4) vigorous ocean circulation during glaciation, and (5) input of volcanic ash. Evidence suggests that geochemical analysis of

Osagean bedded cherts (particularly REE and trace elements) hold the best promise for determining the relative contributions of possible silica sources.

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Thermoregulatory Adaptations of *Acrocanthosaurus atokensis*: Evidence from Oxygen Isotopes

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Recent advances in mass spectrometry techniques have resulted in new applications to the field of dinosaur paleontology. Specifically, oxygen isotope signatures from the bone phosphate can be used as proxies for metabolic functioning. Oxygen isotopes fractionate according to the temperature at which the bones mineralize. Skeletal isotopic variations are utilized to distinguish temperature differences within an animal's body. This study consists of an isotopic examination of *Acrocanthosaurus atokensis*, a large theropod dinosaur from the Aptian–Albian of south-central North America. This dinosaur's large size and potentially active lifestyle during a hot house climate leads to the hypothesis that supplementary thermoregulatory mechanisms were necessary to prevent overheating. Temperature differences within the *Acrocanthosaurus* body, as suggested by $\delta^{18}O$ values, are compared with those of modern animals representing a range from ectothermic heterothermy to endothermic homeothermy. The possibilities of heat loss through panting or oral gaping and dissipation from a sail-like structure on the back are tested through examination of the palatal bones and neural spine oxygen isotopic signatures in relation to core body temperature. These comparisons are suspected to support the hypothesis that *Acrocanthosaurus* maintained a moderate to high level of homeothermy supplemented by the aforementioned heat regulatory mechanisms.

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Regional Carbon Isotope ($\delta^{13}C$) Stratigraphy of Chatfieldian (Upper Middle Ordovician) Carbonates in Central and Eastern North America

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Carbon isotope ($\delta^{13}C$) analyses of Chatfieldian marine carbonates are compared from two well-studied sections from Central and Eastern North America. The Guttenberg $\delta^{13}C$ excursion (GICE), which was first recognized in Iowa, and later found in Pennsylvania, Illinois, Kentucky, New York, Tennessee, and Baltoscandia we now recognize the GICE in two sections in Oklahoma and Virginia in the Viola Springs Fm. in Oklahoma, and in the Trenton Ls. in Virginia. The excursion begins in the Midcontinent *P. undatus* Conodont Zone and reaches its peak values in the *P. tenuis* Conodont Zone, and in the North American *C. americanus* Graptolite Zone. An ~3‰ positive shift in $\delta^{13}C$ is recorded from these two sections: the shift in Oklahoma begins with values of −1.6‰ and reaches its peak values as heavy as +1.5‰, and in Virginia the shift begins with values of ~−0.1‰ and reaches its peak values as heavy as +2.8‰.

It has been shown that in Mohawkian seas there was a wide variance in $\delta^{13}C$ values (4‰ difference) indicating the presence of different temperature-salinity-defined water masses (aquafacies) (Holmden and others, 1998). Based on lithologies and marine faunas present the Viola Springs Fm. (Oklahoma) is interpreted to have been deposited in a deeper water/basinal-type setting and the Trenton Ls. (Virginia) in a shelf-type setting. The beginning of the GICE in North America was previously reported occurring a few meters above the Millbrig K-bentonite bed in Kentucky, however, in Virginia it occurs ~35 m above the Millbrig. The occurrence of the GICE higher in this section is consistent with previous ideas of relatively high subsidence and depositional rates for this area of the Taconic Foreland Basin. The differences in the $\delta^{13}C$ values, marine faunas, and lithologies shows that the Oklahoma and Virginia sections were deposited in two different aquafacies. The (Chatfieldian) Guttenberg $\delta^{13}C$ excursion, apart from the larger end Ordovician excursion, is in terms of magnitude, the most prominent $\delta^{13}C$ excursion currently identified in the Ordovician and it is of major significance for local and regional correlation.

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Astogeny and Phylogeny of Some Late Ordovician Graptolites from Oklahoma: New Evidence from Three-Dimensionally Preserved Specimens

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The Late Ordovician Viola Group of the Arbuckle Mountains in Oklahoma is well known for containing three-dimensionally preserved specimens of graptolites. Viola Group graptolites have greatly improved our understanding of the astogeny and phylogeny of several graptolite groups. We isolated well-preserved specimens of *Climacograptus caudatus, Neurograptus margaritatus, Corynoides americanus*, and *Dicranograptus hians* from the Mountain Lake section (Alberstadt section I), and *Climacograptus cruciformis, Dicranograptus spinifer, Corynoides calicularis*, and *Rectograptus* n. sp. from the U.S. Highway 99 section near Fittstown (Alberstadt section D). The Mountain Lake fauna indicates a *Coryoides americanus* Zone age, and the U.S. 99 specimens are probably *Climacograptus bicornis* Zone in age. Several of these taxa have not previously been described from three-dimensional material and need revised descriptions of their astogeny and phylogenetic relationships. *Climacograptus caudatus* Lapworth is a globally distributed taxon, usually recognized by its long virgella and parasicula. Our 3-D material reveals that the long spine is actually a theca 1^1 spine and that the parasicula hides a small, deflected virgella. *C. caudatus* has a Pattern E proximal development, is closely related to *Diplacanthograptus spiniferus*, and should be referred to *Diplacanthograptus*. Climacograptinids from the basal Viola Springs Formation at section D that have previously been referred to *Climacograptus bicornis* are actually *C. cruciformis* Vandenberg. These specimens have a Pattern D proximal development, a long virgella, and horizontal theca 1^1 and 1^2 spines. *Neurograptus margaritatus* has a Pattern G proximal development and very short sub-apertural walls from which branched ventral spines and lacinia develop. Its periderm is greatly reduced, particularly in the sub-apertural region of the first two thecae where thinning results in a characteristic "birds-head" opening. Similar structures occur in *Brevigraptus*, *Orthoretiolites*, and *Pipiograptus*. Our specimens of *Neurograptus margaritatus* confirm its close relationship to other Lasiograptinae. A new species of *Rectograptus* retains the primitive character of thecal lappets, which reinforces its close phylogenetic relationship to *Amplexograptus*.

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Rare Earth Element Fractionation During Phosphate Nodule Diagenesis

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Major element and some trace element compositions including the REE compositions of marine and non-marine phosphate nodules from the Mississippian age of central Arkansas and Oklahoma regions have been analyzed.

Differences in the major and trace element chemistry between the rims and the cores of these nodules reflect competing influences such as diagenesis, weathering, and aqueous geochemistry of certain elements. These nodules contain, in their cores, exceptionally well preserved fossils, which can be attributed to the REE chemistry and the patterns of these phosphate nodules itself.

There is a difference in the cores and the rims of the phosphate nodules collected from the possibly non-marine to the marginally marine shales in Arkansas and that of the deeper marine facies in Arkansas and Oklahoma. The cores are enriched in the MREE in the deeper facies whereas the opposite trend is observed in the coastal nodules with the rims enriched in the middle rare earth elements. The relative loss of the MREE is generally not accompanied by a commensurate loss in the light or heavy REE.

The non-marine phosphate nodules can indeed be justified as non-marine nodules rather than marine ones due to the evidence such as in-situ plant fossils in root casts that are closely associated with the phosphate concretions. Delicate plant material such as fern foliage that are preserved in the phosphate concretions would certainly not survive transport from a terrestrial to a marine environment.

Several factors may explain the trend observed in the ICP-MS based data. Mineralogical differences between the cores and the rims of both the marine and non-marine concretions may control the fractionation of the MREE. Rims in the near-shore nodules are generally enriched in silicate material than their marine counterparts. The higher electronegativity of the clays may encourage the movement of MREE away from the cores in the non-marine nodules. However, in the marine nodules, the movement of MREE may be towards the core. High phosphate content may characterize clay-poor nodules, which probably favors the higher overall REE abundance. Although many of these hypothesized factors may favor enhanced fossil preservation, further exploration of the chemical and mineralogical differences both within and among these phosphate nodules is required.

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The Importance of Diffusion, Advection, and Host-Rock Lithology on Vein Formation: A Stable Isotope Study from the Paleozoic Ouachita Orogenic Belt, Arkansas and Oklahoma

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More than 600 stable isotope analyses from veins and their metasedimentary host rocks from the Ouachita orogenic belt of Arkansas and Oklahoma provide an opportunity to study fluid-rock interaction processes associated with vein formation during deformation and low-grade regional metamorphism. The $\delta^{18}O$ values of vein quartz vary from 16.0 to 26.4‰, whereas co-existing host rocks have a greater range from 12.9 to 27.4‰. The oxygen isotopic compositions of quartz vein versus those of the coexisting host rocks follow an array described by $\delta^{18}O_{\text{vein quartz}} \approx \delta^{18}O_{\text{whole rock}} + \varepsilon$, where $\varepsilon \approx 8-0.3(\delta^{18}O_{\text{whole rock}})$. This relationship emphasizes the dependence of $\delta^{18}O$ values of vein quartz on host-rock oxygen isotopic composition. The ε term empirically monitors the difference between the quartz-water fractionation factor and the compositional dependence of the bulk-rock–water fractionation factor. Vein-quartz–host-rock $\Delta^{18}O$ fractionations are ~0‰ in chert, novaculite, quartzite, and siliceous shale and typically between 1 and 4‰ in sandstones and shales. In quartzite and sandstone units that are bounded by shales and associated with significant quartz-crystal deposits, vein-quartz–host-rock fractionations are often unusually large, near 7‰. Quartz-calcite oxygen isotope geothermometry indicates that veins from the Ouachita Mountains formed over a temperature interval of 100°C, consistent with fluid-inclusion temperatures previously obtained from quartz crystals. Individual quartz veins are homogeneous, with <0.4‰ variation, for all vein orientations at all scales, even though vein formation occurred over a temperature interval in which quartz-water fractionation varies by 5‰. This homogeneity highlights the insensitivity of vein-quartz $\delta^{18}O$ values to temperature when veins form under rock-buffered conditions. The similarity between vein and host-rock $\delta^{18}O$ values in quartz-rich lithologies, and between vein and host rock $\delta^{13}C$ values in calcite-bearing rocks, indicates that diffusion was an important mass-transport mechanism. The variability in $\delta^{18}O$ values between calcite-bearing veins and host rocks and large vein-quartz–whole-rock fractionations in some sandstones and quartzites indicates that advection also played a major role in mass transport associated with vein formation. This inference leads to the interpretation that veins from the Ouachita Mountains formed by a combined diffusion-advection process, whereby ^{18}O and ^{13}C from the host rock was transported into the veins with the assistance of a rock-buffered fluid on outcrop scales of 10–100 m.

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Appalachian–Ouachita Thrust Belt: Along-Strike Changes in Stratigraphic Composition and Structural Style

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The late Paleozoic Appalachian–Ouachita thrust belt bends abruptly around the Alabama promontory of southeastern Laurentia (North America), reflecting the shape of the older rifted continental margin. The northeast-striking Appalachian thrust front truncates the northwest-striking Ouachita thrust belt, consistent with diachroneity of foreland subsidence and synorogenic clastic deposition. Abrupt along-strike changes in detachment level, stratigraphic composition, and structural style coincide with the thrust-belt junction. Appalachian thrust sheets are detached near the base of the Paleozoic cover succession; a massive stiff layer of lower Paleozoic passive-margin carbonates controls structural style of imbricate thrusts. In contrast, the Ouachita allochthon consists of off-shelf deep-water sedimentary facies in internally disharmonic thrust sheets. The Ouachita allochthon rests on an upper-level detachment above authochthonous, lower Paleozoic passive-margin carbonates equivalent to those within Appalachian thrust sheets.

Although broken by rift-stage faults, basement beneath the Appalachian thrust belt dips gradually southeastward at shallow depths, indicating low-amplitude, long-wavelength subsidence of the foreland. In contrast, deeper basement beneath the Ouachita thrust belt reflects relatively high-amplitude, short-wavelength subsidence. In the Black Warrior foreland basin, in the foreland corner between the intersecting thrust belts, a late Paleozoic synorogenic clastic wedge thickens southwestward toward the Ouachita thrust front, and the top of the underlying passive-margin carbonate succession dips southwestward beneath the Ouachita thrust front. Southwestward foreland deepening toward the Ouachita thrust front results in along-strike deepening along the younger Appalachian thrust front. The younger, structurally shallower, stratigraphically lower Appalachian detachment truncates the older, structurally deeper, stratigraphically higher Ouachita allochthon and the southwestward-deepening Ouachita foreland basin.

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Episodic Orogenesis in the Ouachita Fold and Thrust Belt

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Polyphase deformation has long been recognized within the Broken Bow uplift of the Ouachita Mountains. One of these deformational phases preceded northerly directed thrusting. Timing of this event has been uncertain as the youngest involved units are the Mississippian age Stanley Group. Recent study north of the uplift has documented 20–30% shortening in the Stanley Group not observed in the overlying 10–15 km Carboniferous flysch sequence. To the west, late Mississippian foreland deformation is documented within the Criner Hills near the Arbuckle Mountains. A multistage tectonic model is proposed incorporating Mississippian age shortening followed by 20–30 my of flysch deposition. Initial shortening involved the lower Paleozoic sequence which was deposited outboard of the continental margin on an extended continental crust. Southerly directed subduction and reactivation of basement blocks led to areas of southerly verging structures commonly observed in the uplifts. This shortening was oriented in a north–south direction and suggests a "soft collision" along the southern margin of North America. During the remaining Carboniferous, a thick submarine fan developed from east to west, filling the trough. Northerly directed thrusting developed during the middle to late Pennsylvanian with shortening nearly coaxial with the earlier stage. The Ouachtia sequence was detached and translated inboard 100–200 km. Early folds were deformed and younger northerly verging folds were developed in the overlying flysch sequence. The final stages of deformation involved counter clockwise rotation of the shortening direction towards the northwest and the transition to local thick skin deformation. These stages reflect the collision events along the southern margin of North America. We interpret the initial stage as the collision of a small continental block or possibly island arc with southern margin of North America. Large scale northerly directed thrusting was driven by the collision of South America incorporating the intervening smaller blocks. The SE–NW shortening observed in the basement uplifts is believed to be related to final adjustments along the southeastern margin of North America.

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Nanichito Thrust: Deformed Unconformity in the Central Zone of the Ouachita Mountains?

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Integration of remote sensing data, detailed mapping (1:12,000), and GIS analysis has led to a refined interpretation of the east central section of the Ouachita Mountains. Dominant northerly verging structures of the thrust belt are apparent in the younger Carboniferous flysch. Less apparent are the complex, tighter folds documented in the older Mississippian sequence. Down plunge views reveal a contrast in folding above and below a very narrow discontinuity. Along the Eagle Fork River, OK, this discontinuity is a sub horizontal (~5 m wide) fault zone (Nanichito thrust) with several imbrications and a complex kinematic history. In the hanging wall, folds are very open (interlimb angle, ia., ~120–160°) and plunge 10–15° to the west. Northerly vergence is apparent in the synclines while the younger Nanichito anticline folds both the Boktukola and Nanichito thrusts. Four structural domains are identified in the footwall. Folds in the northern domain are open (ia. 71–102°), upright, and westerly plunging (8–19°). The central domain folds are tight (ia. 35–60°), upright, and sub horizontal. In the southern domain, folds are open (63–106°), southerly verging, and gently plunging (1–17°) with variable plunge directions. Folds within the sub thrust imbrication are tight (ia. 10–54°), northerly verging, and moderately plunging (9–40°). The footwall folds were restored, assuming constant volume and

flexural folding in the hanging wall. 20–30% shortening is apparent below the Buffalo thrust. In addition, three of the domains contain either upright or southerly verging folds; while the imbrication and hanging wall reveal primarily northerly vergence. These data argue for deformation during the Mississippian followed by a deformational hiatus. 700–1000 m of the Upper Stanley Group were involved with this early deformation which ended just before deposition of the Moyers Formation (Late Meramecian). No erosional surface has been documented. It is inferred that subsequent deformation within this shale sequence obliterated the primary structures. Approximately 20–30 My later northerly directed thrusting translated the entire sequences over the continental margin successions.

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Reservoir Potential of the Upper Jackfork Sandstone (Lower Pennsylvanian), Western Ouachita Region, Arkansas

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The upper Jackfork Sandstone (Lower Pennsylvanian) in the frontal Ouachita Mountains of west-central Arkansas represents sand-dominated distal flysch deposition reflecting axial delivery along the compressing Ouachita trough. Exposures in Scott County, Arkansas, were measured, and sampled for permeability, porosity, and standard petrographic analysis. In addition, synthetic gamma ray logs were constructed from the same exposures to provide a basis for regional correlation. The lithologic data demonstrate that the upper Jackfork sandstones are mostly quartz arenites (grain densities typically 2.65) possessing consistently low porosites, typically less than 4%, and average permeabilities below .005 milledarcies (Klinkenberg). In contrast, the sandstones are highly fractured as a result of their near vertical uplift in response to the Ouachita orogeny. This relationship suggests potential for horizontial drilling should the presence of hydrocarbons be detected. The Potato Hills, Latimer County, Oklahoma, includes hydrocarbon production from both the Arkansas Novaculite and the upper Jackfork Sandstone providing an analogue and some encouragement for further exploration of adjacent western Arkansas.

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Facies and Porosity Control in a Deepwater Reservoir Outcrop Analog, Jackfork Group, Oklahoma

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The importance of understanding depositional and post-depositional geologic controls on porosity and permeability is very critical for predicting and understanding the production performance of reservoirs. Thus, characterizing outcrops of deepwater sandstones in the Pennsylvanian Jackfork Group in Southeast Oklahoma may be useful to understanding production performance in deepwater reservoirs

The Pennsylvanian Jackfork Group provides classic outcrop exposures of deepwater turbidites deposited in an elongate east–west-trending Pennsylvanian basin. The sandstones in the study area are predominantly well-cemented, fractured, tabular-bedded, quartz arenites. However, extremely friable sandstones occur stratigraphically between well-cemented sandstone beds in certain outcrops.

Three stratigraphic sections have been measured with corresponding outcrop gamma-ray logs. The stratigraphy consists of multiple Depositional Sequences and Systems Tract deposits, which aid in characterizing the distribution of facies in the sections. The different sandstones are representative of differing porosity and facies types. In a reservoir, porosity in similar cemented sandstones is due to fracture, while in similar friable sandstones, porosity is matrix controlled.

Petrographic studies of the sandstones show differing diagenetic features of quartz overgrowth, pressure solution and clay content between the two sandstone types. Though distinguishable in outcrop, results from the outcrop gamma ray log show that it is difficult to impossible to distinguish the zones containing matrix porosity from those containing fracture porosity. This could be the case in other deepwater reservoirs and may have direct implications for on-going and future exploration in the Ouachita Mountains of Southeast Oklahoma.

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Subsurface Sequence Architecture of the Cromwell Sandstone (Morrowan), Oklahoma

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The Cromwell Sandstone is a prolific gas-producing reservoir in the Kinta field, of the Arkoma basin. The predictability, however, of Cromwell reservoirs has been elusive based on the published literature. The study area encompasses four townships in Haskell County, Oklahoma and includes two cores, which in turn were used to calibrate well-log responses to stratigraphic elements. High-resolution sequence stratigraphy was applied to delineate the geometry and distribution of Cromwell reservoirs and offer insight to production strategy.

The Cromwell Sandstone is the lower member of the Morrowan-age Union Valley Formation. The Union Valley Limestone overlies the Cromwell Sandstone and is the upper member of the Union Valley Formation. The Union Valley Formation rests on the sub-Pennsylvanian disconformity and is succeeded conformably by shale and limestone of the Wapanucka Formation.

The investigation revealed that the Cromwell is marine in origin and formed under the dominant influence of sea-level transgression. Five Parasequence sets are identified within the Cromwell Sandstone, two to seven parasequences are associated with each parasequence set. Cromwell reservoirs are regarded as having been deposited as shore-oblique to shore-parallel offshore ridges. An important finding of this study is the recognition of two intra-Cromwell 4th-order sequence boundaries. From parasequence-based correlation, Cromwell reservoirs develop into retrogradational parasequence sets. Correlation within the Cromwell using sequence architecture provides a better understanding of the distribution of gas production; however, diagenesis is a contributing factor to porosity formation.

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Bending Stresses, Faulting, and Deep Migration of Fluids in the Arkoma Basin

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Reconstructed thickness of Late Paleozoic sediments in the Arkoma Basin are consistent with flexure of the lithosphere with an effective elastic thickness of 70 km. This result is consistent with a previous estimate of lithospheric flexure from gravity data and the expected flexural rigidity based on the thermal age of the lithosphere at the time of the Ouachita orogeny.

Tensional bending stresses in the crust beneath the foreland are large (>100 MPa) immediately following the orogeny, which could fracture and/or reactivate faults in the basement to depths of >10 km. Tensional bending stresses in the crust beneath the foreland diminish with uplift/erosion and/or viscoelastic relaxation. Rebound of the lithosphere following erosion of the thrust belt at the end of the Ouachita orogeny generates approximately 1 km of differential topography. Accumulated bending stresses are largest when the lithosphere is cold/strong and/or loading/unloading is rapid.

At the end of the orogeny, fluids will infiltrate into the fractured/faulted crust beneath the foreland where they are heated and chemically interact with basement rocks. With time, tensional bending stresses are reduced by uplift and erosion and/or viscoelastic relaxation. Thus, as fractures and faults in the basement close, heat and fluid are transported upward and away from the thrust belt into distal basin sediments. These basement-derived fluids would then interact with basinal fluids transported by the newly generated topography in the foreland basin.

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Selected Coal Bed Methane Produced Water Management Strategies and Associated Technical and Economic Issues

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Coal bed methane (CBM) production is becoming a greater portion of the natural gas supply in the United States and this trend is expected to increase in the foreseeable future. However, significant amounts of water are also produced along with CBM. The ability to economically manage produced water is often the key issue in development of a CBM resource. Research sponsored by the Gas Technology Institute has been conducted since 1997 to understand produced water management practices and localized disposal costs in the Rocky Mountain States of Wyoming, Colorado, New Mexico and Utah. A database of oil, gas and water production data at selected basins in these states was developed. Operators producing high volumes of water in the targeted oil and gas basins were interviewed by telephone in 1998 to identify their produced water management strategies and the associated costs. The effort was later expanded to include an examination of produced water management practices and disposal costs in the states of Montana, Illinois, Oklahoma, Kansas, Louisiana and Michigan. The database was updated with current production data for all states considered and operators were again interviewed by telephone to provide 2001 water management data.

This paper focuses on the produced water management practices and disposal costs at a selection of CBM fields in the U.S. It specifically examines localized management practices and disposal costs identified by producers in the selected fields. Gas and water production data from a variety of CBM fields in the United States are presented and water management techniques used in each field are examined with respect to cost and successful application criteria.

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Coal-Bed Methane Potential and Activity of the Western Interior Basin

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The Western Interior Basin is a Pennsylvanian-age series of deltaic and minor sediments that was deposited in Iowa, Eastern Kansas, Western Missouri and Eastern Oklahoma. The basin is divided into three sub areas: the Forest City Basin, the Cherokee Basin and the Northeast Oklahoma Shelf. Since 1920 there has been sporadic but recently increasing activity to exploit the coals of Desmoinesian and Atoka age. The coals are thin, have large lateral extent, are high volatile B to medium bituminous rank, sulfur content varies from 2% to 11%, ash 5% to 50% and moisture contents tend to be less than 6%. Gas contents vary from 50 to 375 scf per ton. The basin has a history of unconventional gas production from as early as the 1920s in and around Kansas City stretching southward to Northeast Oklahoma. As with all basins, these coals have their own unique characteristics, basin thermal and structural history and completion practices. Existing permeability, desorption and adsorption data sets indicate good permeability and gas contents extend throughout much of the basin. Completion practices have gone from historical single seam to present-day multiple seam completions with initial indications of success. The basin is undergoing heavy leasing and intense drilling as the unique position of the basin to strong gas markets and good reservoir characteristics cause its exploitation.

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