OKLAHOMA: THE ULTIMATE OIL OPPORTUNITY

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Abstract

The petroleum industry in Oklahoma continues to be focused on natural gas, which today accounts for about 80% of both drilling activity and BOE production. Although there was a modest uptick in 2006, the first since 1984, record prices for the last several years have had little impact on oil's long-term decline. Today the industry and the State are precariously dependent on natural gas; the price of which tends to reset each year based on the severity of winter weather.

This study shows that an under-exploited opportunity exists in Oklahoma that is centered on improving oil recovery in existing fields. The State's original oil in-place (OOIP) volume is over 84 BBO, and long-term decline projections show an estimated ultimate recovery (EUR) volume of about 16 BBO. This 19% aggregate recovery factor, which is the result of complex reservoir geometries and poor reservoir management, equates to 68 BBO being left in the ground at abandonment. If the studies that were analyzed here are representative of the State as a whole, there are many opportunities, using simple techniques, to economically recover additional oil in fields throughout the State.

The major technical obstacle to a systematic search for these opportunities is scattered, inaccessible, and incomplete well and production data. This issue is now being addressed through an initiative, called Energy Libraries Online, of the Oklahoma City Geological Society and The Oklahoma Well Log Library, but this will require financial support to see it through. If operators are provided the tools necessary to identify this huge, untapped potential, a resurgence in oil activity and production is assured, with all of the financial benefits that these will bring to the industry and the State.

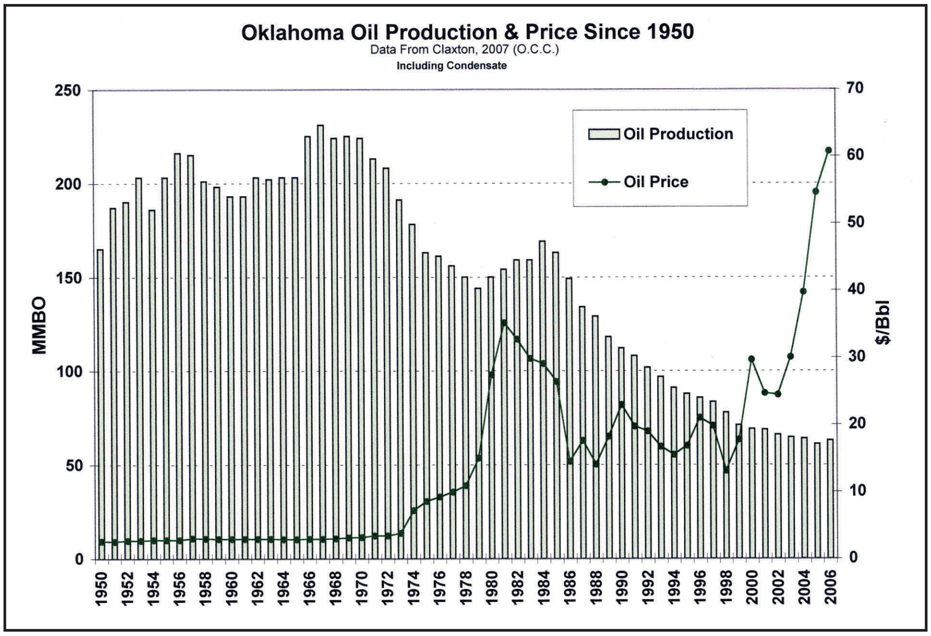

Figure 1: *Oil production and average crude-oil price (unadjusted) in Oklahoma from 1950 through 2006. From Claxton (2007).*

Oklahoma Oil Trends

Current Status

Oklahoma oil exploration began over 100 years ago, with early successes propelling the territory to statehood in 1907. Rapid development of many of the largest oil reservoirs led to State production peaking in 1927. There have been intermediate highs and lows in oil production since that time, with the last peak occurring during the price-driven 'oil boom' in the late 1970s and early 1980s. Excepting a slight increase in the last year reported, oil production has declined steadily, regardless of oil price since 1984. The disconnect between price and production is demonstrated by the intermediate price peaks in 1990, 1996, and 2000 that did little to slow the long-term drop in production, and the fact that it took four years of record prices to achieve a modest bump in 2006 (Fig. 1).

The price of oil in Oklahoma, and the rest of the world, has been on an upward trend since 2002, with the 2006 average price setting a record at $60.75/Bbl, and the 2007 price sure to set an all-time record. Despite this, average daily oil production in 2005 dropped 8,165 BOPD; the largest decrease seen since 1998. The production figures shown in Figure 1 include condensate, but this represents less than 3% of the total liquid hydrocarbons produced (Claxton, 2007).

The easiest way to boost a region's oil production is to find large, long-lived fields. Unfortunately, in Oklahoma those days are long past, as our last 100 MMB field (Postle) was discovered in 1958, and the last 10 MMB field (Wheatland) in 1981 (Boyd, 2002a). Over 500,000 wells have been drilled in the last 100+ years, with tens of thousands of separate oil accumulations and over 3,000 named oil fields discovered. As a result, although deeper potential may exist in some older fields, the prospective oil-producing regions of the State have been extensively explored.

Because discoveries are no longer a significant component of new oil production, future reserve additions must largely come from improvements to the recovery in existing fields. Most Oklahoma oil production comes from fields that have been producing for decades, and in which the average well makes about 2 BOPD. Although small, undrained accumulations continue to be found, usually in or adjacent to existing fields, the possibility of finding one or more new oil fields large enough to significantly affect the State's long-term production decline has become vanishingly small.

In 2006 over 4600 wells were completed in Oklahoma, with 22% of these (1043) as oil completions. Most of these were in existing fields, with more than one quarter of the total being workovers (IHS Energy, 2008). Oil-targeted drilling has grown since the price run-up that began in 2002, but the increase in oil completions is less than a third that of gas. In fact, oil drilling activity is still insufficient to maintain well numbers (Fig. 2). In the last five years pluggings have outstripped new oil completions by two to one, reducing the number of active wells by 1,600 to a total of about 80,000 (Claxton, 2007).

There are plausible explanations for why oil drilling and production continues to fall in a high price environment: 1) Operators are concerned that current prices will not hold long enough to recoup large initial investments, 2) The economics for natural gas are better, giving gas-targeted drilling an advantage, or 3) There is not enough producible oil left to justify a large-scale evaluation of improved recovery projects.

1) Long-term price forecasts can be driven by many factors that are impossible to predict, and operators in Oklahoma have been affected by all of them. Although it is easy to understand a hesitancy to invest in oil, it is believed that over the long term demand will continue to rise and oil prices will remain strong (Boyd, 2005). Regardless of one's view of when or if 'peak oil' will occur, in today's world there are certainly many more factors that could bring about price increases than those that could push prices lower.

2) Because of the concurrent rise in natural gas prices there is no question that the average gas well in Oklahoma, which produces about 135 MCFPD, can now generate more cash flow than the average oil well. Using the standard energy conversion of 6 MCF per barrel this equates to 22.5 BOEPD, or about 10 times what the average oil well produces (2.1 BOPD). Using average 2006 prices this means that, in terms of gross revenue, the average gas well can make about $848 per day, while an oil well only about $128 per day. Although gas wells are more expensive to produce and maintain, the income discrepancy is huge, making industry's preoccupation with gas easy to explain.

3) Is there enough producible oil left for it to make a comeback? This cannot be easily answered, because each area, field and reservoir must be evaluated on its own merits. This review will show that there are many fields that have seriously underperformed when compared to closely analogous fields. However, the objective here is not to evaluate the economics of individual oil projects, but simply to prove that sufficient potential exists to justify evaluating the possibilities.

History (How We Got Here)

Oil exploration in Oklahoma began before there was any real understanding of why and where it might occur. It had been known to exist in the subsurface long before Statehood through the drilling of water wells that became contaminated by crude oil. Early wells intentionally looking for oil were usually drilled near seeps, with the first commercial success coming adjacent to a seep near Bartlesville in 1897. The Nellie Johnstone ushered in the oil age to Oklahoma and began a meteoric rise in territorial and then State fortunes in which annual crude production went from 1,000 barrels in 1897 to 43.5 million barrels in 1907 - the year of Statehood (Franks, 1980) (Fig. 3).

The oil produced in 1907 was only the beginning, as the oil-rush continued with a steady stream of enormous discoveries. These included Cushing (1912), Burbank (1920), Seminole District (1923), and Oklahoma City (1928), each of which would produce more than 500 MMBO (Fig. 4). Oil production peaked in 1927, and rose and fell many times thereafter. Increases in production came through discoveries, increased allowables, large secondary recovery projects, or price-driven surges in drilling activity. Falls in production were caused by forced curtailment (due to low price), reduced drilling activity, or, as is the case now, a natural, long-term decline in field production.

All geologic provinces eventually

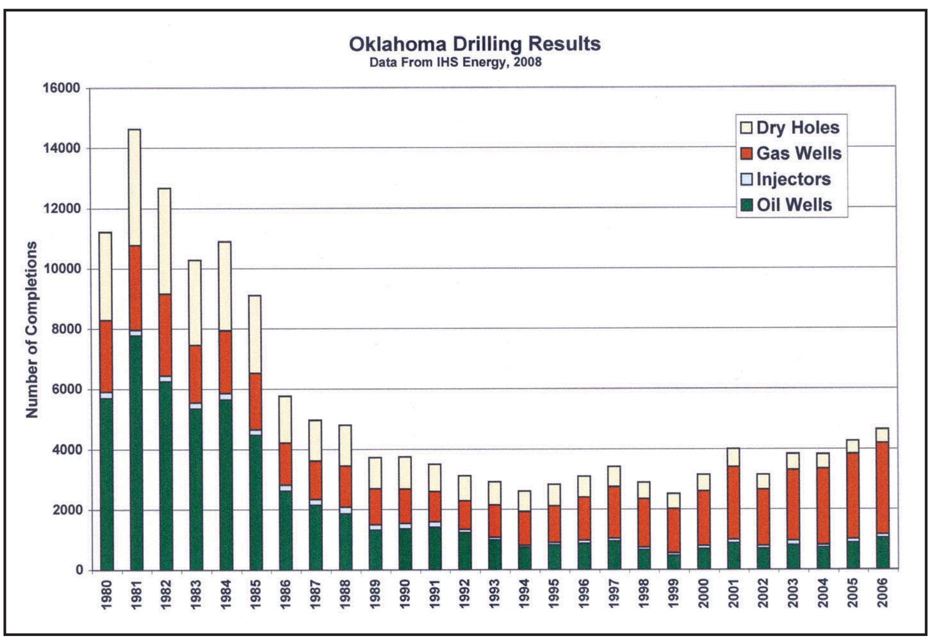

Figure 2: *Oklahoma well-completions from 1980 through 2006, showing the trend away from exploration, based on dry hole percentage, and towards gas development. From IHS Energy, 2008.*

reach a point at which the potential reward no longer justifies the risk and expense of large-scale exploration. When that occurs activity moves elsewhere, and for Oklahoma this happened in the late 1960s. The price of crude oil had remained nearly flat for decades, and discovery sizes no longer justified widespread exploration. In 1967 oil production began a long downhill slide that was only briefly interrupted by the drilling boom in the late 1970s and early 1980s (Fig. 1).

Most of the oil discovered in Oklahoma was found during a time when natural gas, especially that seen in association with oil, was viewed mainly as a drilling hazard. Early wells were drilled with cable tool rigs that, unlike modern rotary rigs, operate without drilling mud and therefore any mechanism to control fluid flows. A discovery meant a blowout, with gas in the air and oil on the ground. The gas was vented or flared and earthen dams were used to collect the oil. If a well encountered a large gas flow, it would be vented, sometimes for days, to determine if there was an oil rim beneath. If oil did eventually cone into the well, the oil was produced and the gas flared. If not, the well would be plugged. An example is the discovery well for Wewoka Field, the R. H. Smith - #1 Betty Foster, which was drilled in March 1923. After penetrating a few inches into sandstone, this well blew out flowing 20 MMCFPD and 'spraying oil'. The 'oil', which clearly was initially gas condensate, increased to 200 BOPD in a few days as underlying oil coned into the well, caus-

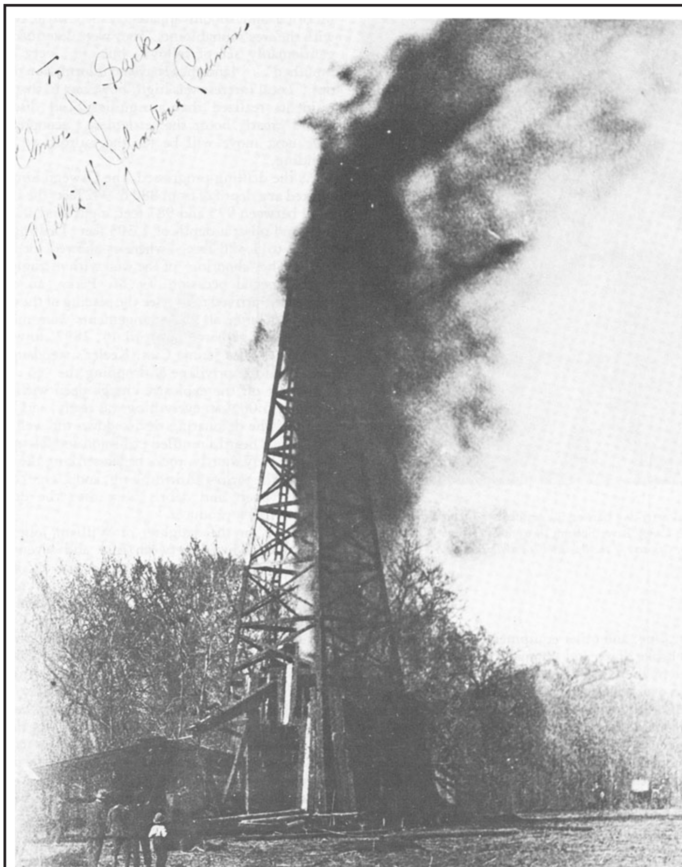

Figure 3: *The Nellie Johnstone #1, drilled in 1897 just south of Bartlesville, established the first economic production in Oklahoma. Photograph taken from Franks, 1980.*

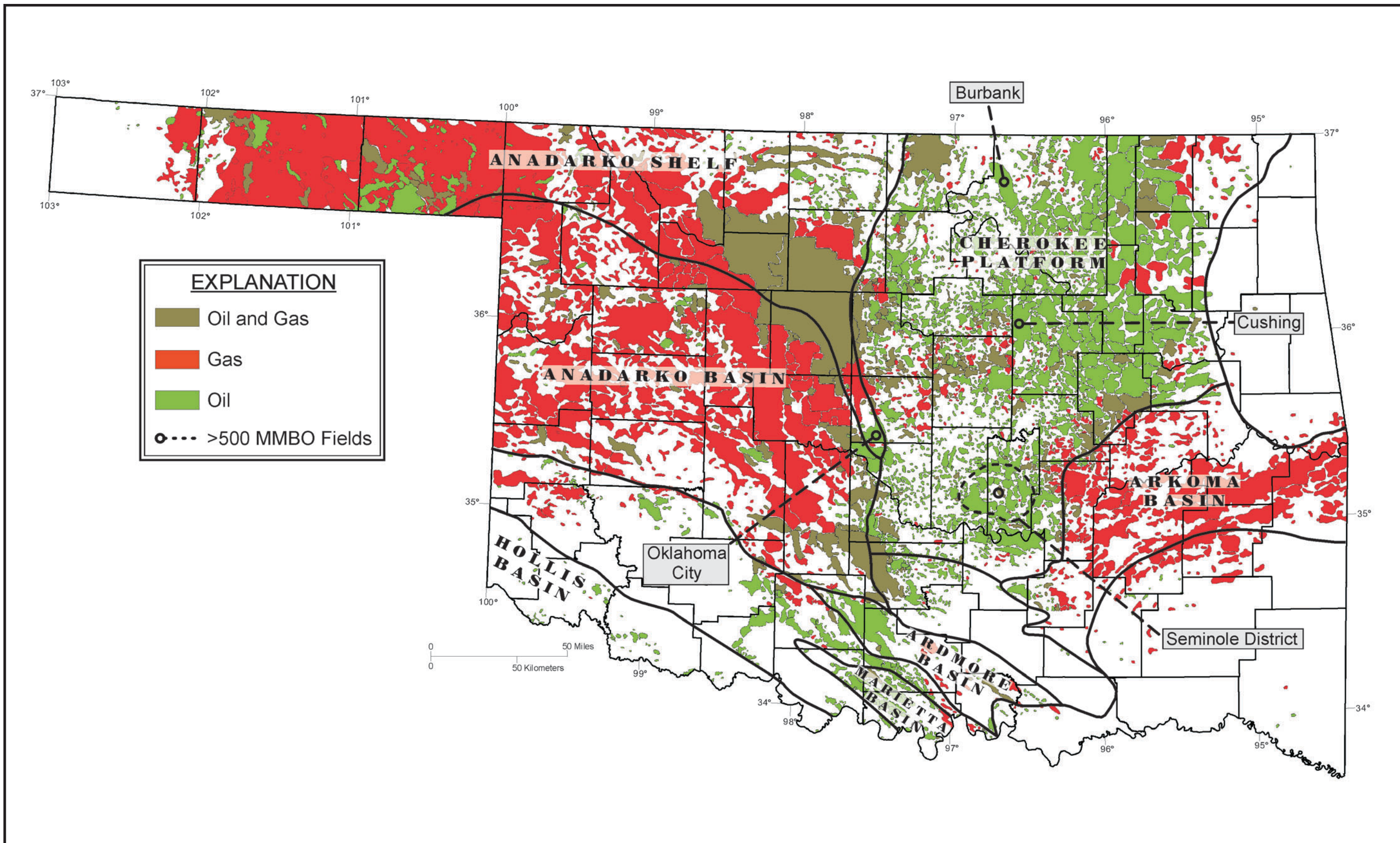

Figure 4: *Map of major geologic provinces of Oklahoma showing oil and gas fields distinguished by GOR and oil fields with more than 500 MMB recovery. Modified from Boyd (2002b).*

ing the gas flow to decrease. This permitted a deepening of the well, making it capable of a rate of 3,500 BOPD (Franks, 1980).

The frontier mentality in the State's early history made it reluctant to intervene in what were viewed as 'private business practices'. Although the Oklahoma Corporation Commission was formed in 1907 to regulate the oil industry, the organization was chronically understaffed. The lack of inspectors forced it to rely on an honor system in which the industry became largely self-regulating. As a result, independent oil producers themselves were the first to address what were termed 'intolerable conditions in the oil fields'. In addition to numerous large oil spills and fires, these conditions included a waste of natural gas that by 1913 had assumed 'scandalous proportions'. In this year the federal government estimated that $20,000 of gas was wasted each day at Cushing Field alone, and that the daily waste of gas Statewide was equal to 10,000 tons of coal. (Using the standard of 14 cf per pound of bituminous coal, this equates to 280 MMCFGPD or 102 BCF in that year.) This attention was viewed by many as a pretext for the federal government to extend its authority over Oklahoma. This never happened, but it did prompt preventative action to be taken. In 1914 the OIPA advocated regulation of the industry, with the focus on prorationing. (Franks, 1980).

The practice of flaring huge quantities of gas in Oklahoma's early oil fields, with the resulting loss of reservoir energy, had a devastating impact on recoveries and caused rates to plummet after peak production was reached. Healdton Field, which was discovered in 1913, peaked in 1916 at 95,000 BOPD. (It was noted in Franks, 1980 that individual wells in this field were flaring up to 13.5 MMCFGPD.) By 1918 the field was capable of only 40,000 BOPD, and by 1924 only 16,000 BOPD. Another example is Burbank Field, where July 1923 peak production of 122,000 BOPD fell to an average in 1924 of 60,000 BOPD, which further fell to 37,000 BOPD by 1926. Although the presence of abundant gas in the oil had the benefit of making pumping equipment unnecessary, flaring was recognized, even at this time, as reducing oil recovery. However, the atmosphere was such that large-scale gas flaring remained the accepted practice (Franks, 1980).

The volume of gas flared in the early days in Oklahoma is impossible to quantify directly because flow rates were guesstimates and there was no requirement to report gas production that was not sold. In the studies reviewed for this report it was found that most oil accumulations were found at or just below gas saturation. This is confirmed by the number of fields that were discovered with small gas caps or formed secondary gas caps immediately after production began. The average (weighted by field size) initial gas to oil ratio (iGOR) for the fields studied was 665 standard cubic feet per stock tank barrel (scf/STB). This is in substantial agreement with the average (unweighted) iGOR from the government compiled in the TORIS database, which is 724 scf/STB (U. S. Dept. of Energy, 1984).

If the average produced GOR through abandonment pressure is roughly three times the initial value (Knapp, 2006), the Statewide associated gas volume should be about 1995 scf/STB. By linking gas with oil production in this way it becomes possible to estimate how much associated gas was liberated as oil was produced. By subtracting from the associated gas volume the gas that was actually sold, it is possible to estimate how much was vented or flared. This estimate ignores non-associated gas that may have been flared from gas caps. It also assumes that all gas sold was associated gas which, given high GORs and huge oil sales, seems a safe assumption (Fig. 5).

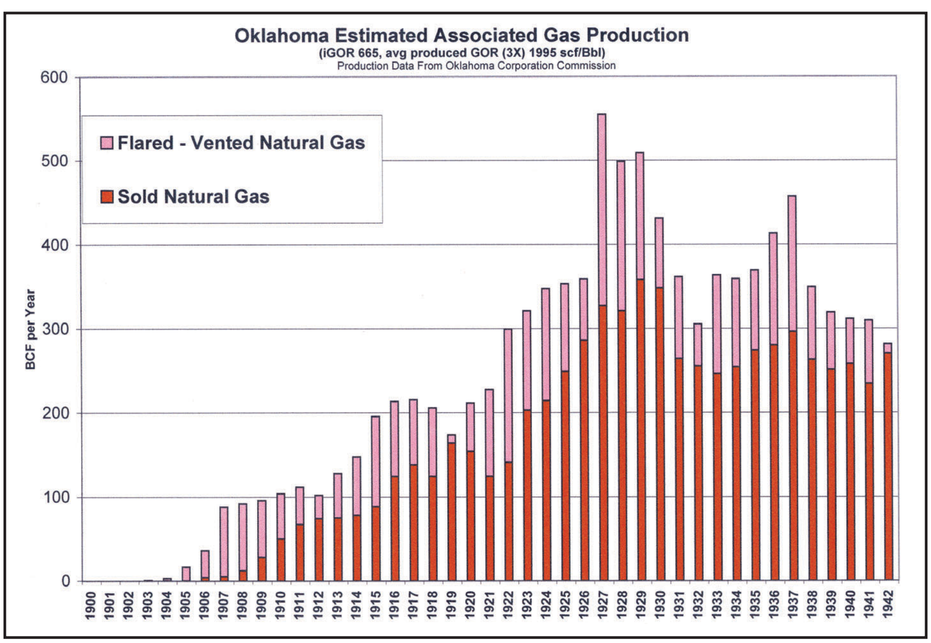

Figure 5: *Estimate of associated gas production in Oklahoma from 1900 through 1942. Production based on an average produced GOR of 1995 scf/Bbl. Flared/vented gas is the difference between the total calculated and that sold.*

The first year in which more than 1 BCF of gas was officially sold in Oklahoma was 1906. From this time, peaking in 1927 and continuing through 1942, the calculated volume of associated gas is much greater than that on which taxes were paid. From 1900 through 1942, 6.9 trillion cubic feet (TCF) of gas and 5.13 BBO were sold. The oil produced should have generated 10.2 TCF of associated gas, so if the produced GOR estimate is accurate, the volume of gas vented and flared in Oklahoma during this time was about 3.3 TCF. This formula generates a 1913 flared volume of only 53 BCF, which is roughly half the previously quoted federal estimate of 102 BCF for that year. Although 3 to 6 TCF is a relatively small amount in a

State that has already sold more than 97 TCF, its real impact was in the reduction of oil recoveries.

There were other early practices that reduced oil recovery, including 1) the coning of water into oil reservoirs through over-production, 2) uncoordinated, patchwork waterfloods in which a poorly understood reservoir geometry left large areas unswept, and 3) subsurface cross-flow in which commingled zones exchanged fluids or where uncased wells allowed oil reservoirs to charge permeable water-bearing zones. However, the practice that had the most profound impact on oil recovery in the State was that of gas flaring. This reduced recovery by rapidly reducing reservoir pressure and gas saturation in the oil, and by leaving behind unproducible oil saturations through the smearing of oil into gas caps. Ultimately however, this is water under the bridge. What is important is that a great deal of oil remains in the ground.

The Future (Where We're Going)

One of the objectives in this analysis was determining how much oil will be left in the ground, given a continuation of the current production decline. The first step in this process is a determination of ultimate recovery. This task is never easy, but it is made simpler by the fact that most of the State's production comes from wells that have produced for decades, and because discoveries large enough to affect State production will no longer occur.

In the latest reserve estimate in 2005, which is based on a poll of the State's operators, the Energy Information Administration of the U.S. Department of Energy projected Oklahoma's proved oil reserves at 588 MMBO (E.I.A., 2005). The same poll taken in 2000 placed reserves at 621 MMBO, meaning that proved reserves dropped only 33 MMBO in a five-year period in which 332 MMBO were produced. Obviously, the near doubling of crude oil prices in that period did much to improve the average operator's outlook, but through it all the decline in production since 1995 has averaged about 3.5% per year.

If State production remains in long-term decline, notwithstanding the uptick in 2006, it is possible to calculate a range of remaining oil reserves. Although this estimate carries many assumptions, it does show the effect that changes in the long-term decline have on EUR volumes. Using the 3.5% decline experienced since 1995, and carrying it through the year 2050, remaining reserves as of January 2007 were 1,371 MMB. If the decline is increased to 4.5%, or about the 2005 decline, remaining reserves through the year 2050 are 1,158 MMB (Figure 6). If the average net loss of about 300 oil wells per year holds (Claxton, 2007), in 2050 there will be about 66,000 producing wells, making the per-well ending rate in these cases about 1/2 BOPD and 1/3 BOPD. The cutoff in 2050 and the resulting per well production rates were arbitrary, as the actual economic threshold is impossible to predict.

Given these assumptions, the range of remaining oil reserves is surprisingly narrow. In both the 3.5% and 4.5% decline cases, remaining reserves are significantly greater than the 588 MMB reported by the E.I.A. So, given a continuation of current trends in drilling and plugging, and an average abandonment rate for an oil well in Oklahoma of less than ½ barrel per day, there is good reason to believe that more than a billion barrels are left to produce. This means that in a status quo situation, ultimate recovery for the State will be slightly more than 16 BBO. The good news is that, short of a price collapse, the chances are excellent Oklahoma will produce at least twice the oil now carried as reserves. The bad news is, if correct, we are about 92% produced and the end is in sight.

Defining Oklahoma's Oil Resource

Procedure

This is clearly a daunting task, but a determination of the remaining oil in-place first requires an estimate of the volume that was originally in-place. The State contains tens of thousands of separate oil accumulations, at depths from a few hundred to more than 11,000 feet, located in thousands of fields scattered across almost every county. This oil resides in hundreds of named reservoir-intervals of every description, trapped in every conceivable trap type (structural, stratigraphic and combination), and has been produced through a variety of natural and artificial drive mechanisms. Given such complexity, the key is simplifica-

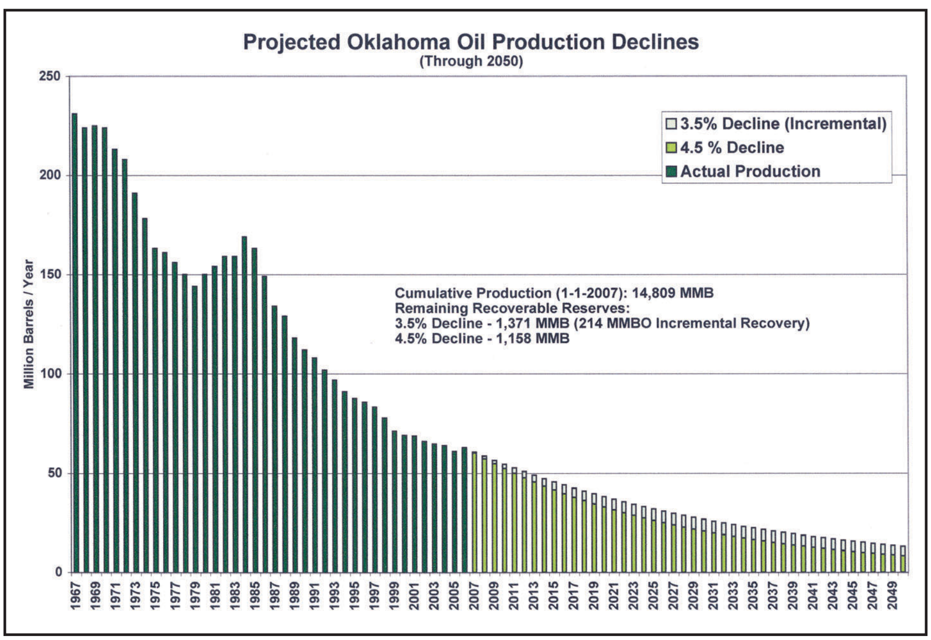

Figure 6: *Projected Oklahoma oil production using 3.5 and 4.5% annual declines through 2050. Both cases end with the average well producing less than ½ BOPD. This suggests the ultimate oil recovery for the State will be slightly more than 16 BBO.*

tion. This begins with the placement of all oil reservoirs into three major classes: Blanket Sandstones (BS), Carbonate Shelves (CS), and Fluvial-Dominated Deltaic Sandstones (FDD). These correspond to what the Department of Energy calls Strandplain\Barrier, Shallow Shelf\Open, and Delta\Fluvial Dominated reservoirs (U. S. D.O.E., 1993).

To draw statistically meaningful conclusions, reservoir, fluid, and related data were gathered on as many oil accumulations as possible. Because of the time necessary to produce these data from scratch, and because so much excellent work has already been done, information was acquired primarily through studies available in the literature. Although those with volumetrics were the most useful, valuable data were gleaned from work from even in the earliest days of the industry, where oil/gas analyses, initial rate and GOR, cumulative production by reservoir, and production techniques were noted. The best reservoir descriptions, including core-derived porosity/permeability, begin in studies from the late 1940s, with volumetric analyses becoming routine by the mid-1950s. The quality of the work in these studies was generally quite good, and even those with missing data or ambiguous results contributed valuable information.

The data recorded include general location information, reservoir property and trap information, fluid properties, production and volumetric calculations, and information concerning the study type and issues affecting its applicability. The studies originated from a variety of sources, including 1) the Oklahoma Geological Survey, 2) publications from the AAPG, the Journal of Petroleum Technology, and the Oil and Gas Journal, 3) professional groups, including the Oklahoma City, Tulsa, Ardmore, and Panhandle Geological Societies, 4) governmental studies from the US Bureau of Mines, the USGS, the Department of Energy, and the Oklahoma Academy of Science, and finally 5) theses and dissertations from OU. Where possible, these data were compared to that published in the TORIS database (U. S. Dept. of Energy, 1984).

Each of the 225 studies examined had useful information, but the volumetrics and recovery factors in many were unusable. For these the most common disqualifier was the inability to confirm production, either because of missing data, or because the productive area had increased to the point that the study's volumetrics had become meaningless. Many excellent field studies had to be excluded from recovery factor statistics because cumulative production quoted from original operator records, often from the 1950s or 60s, was much more than that shown in the latest IHS data. For fields in which production was shown as commingled, production was only assigned to leases in which the reservoir under study was listed first. Of the studies with volumetrics that were reviewed, roughly half (123) had verifiable production (BS-24, CS-25, FDD-74) (Fig. 7). (Appendix). Recovery factors are based on these studies.

The three reservoir types, although very broad, are useful in defining some of the most fundamental factors affecting oil recovery. These include subsurface geometry, reservoir heterogeneity, pore volume, porosity type(s) and permeability. The impact these factors have on fluid movement through the reservoir helps determine drive mechanism, and ultimately recovery factor. By comparing oil fields with similar trap types and reservoirs it becomes

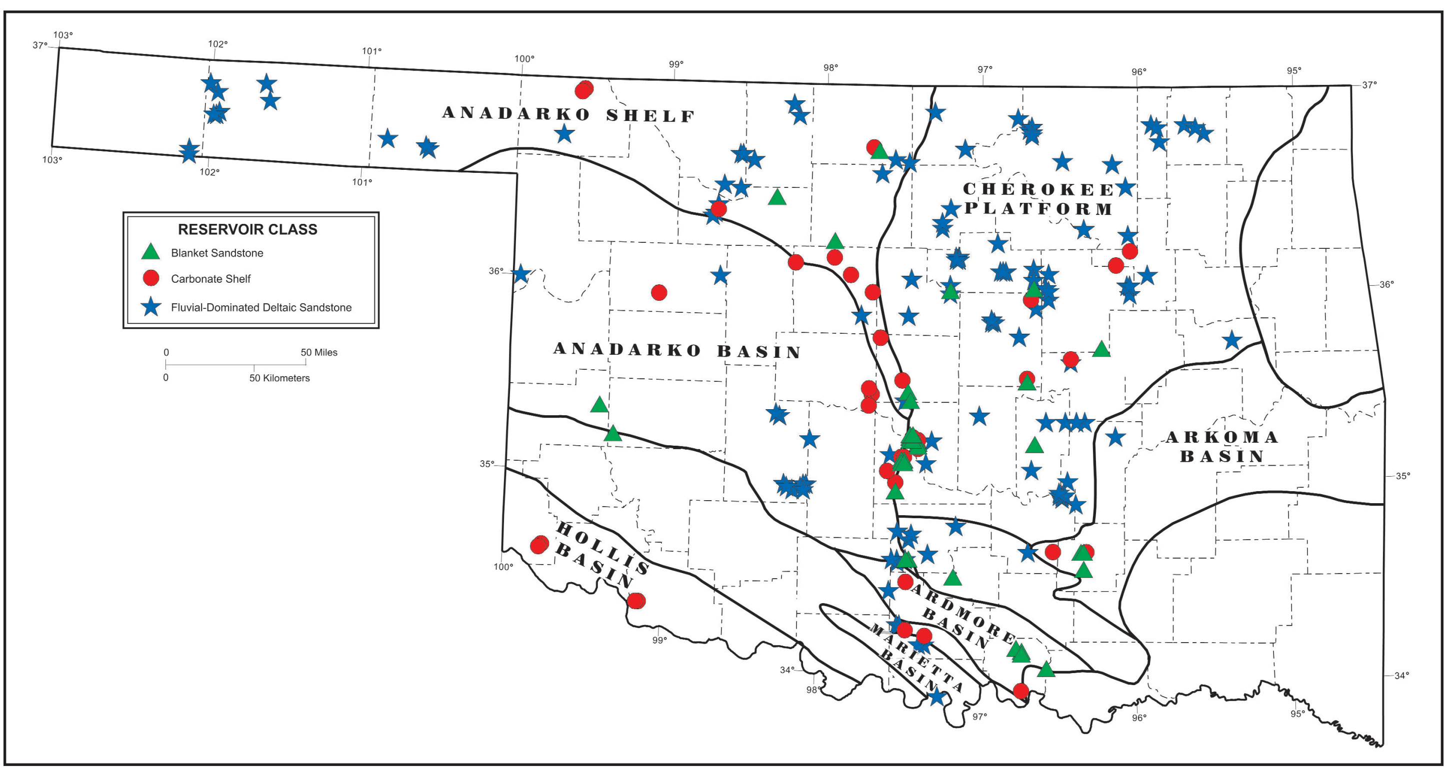

Figure 7: *Map showing major geologic provinces and the location and reservoir class of the reservoir studies that were analyzed in this report.*

possible to assign an 'ideal' recovery factor to similar fields based on the results of those that performed the best. In a review of this nature, it is impossible take into account all of the variables that can affect recovery factor. However, general rules of thumb can be drawn for common reservoir/trap types that can help identify under-performing fields throughout the State.

Blanket Sandstones (BS) refer primarily to the Ordovician-age Simpson reservoirs, which are clean, well-sorted, high quality sandstones. These include the Bromide, McLish, Oil Creek, Tulip Creek and Wilcox Sandstones (Fig. 8). A single Misener study was included in this group because, although aerially restricted, it is composed of eroded Simpson-age sandstones, with similar porosity and permeability (Appendix). Blanket sandstone reservoirs generally have high porosity and excellent permeability. They are laterally continuous, and as a result, trap only on structural highs. Their drive mechanism is dominantly solution gas drive, with varying degrees of water support. Water movement is dependent on how much reservoir below the oil/water contact is in communication with the oil trap, which in these laterally continuous reservoirs is usually controlled by faulting off-structure.

Carbonate Shelf (CS) reservoirs studied are limestones and dolomites ranging in age from the Cambro-Ordovician Arbuckle dolomite to the Mid-Pennsylvanian Oswego Limestone. The most important producers in this category are the Arbuckle, Hunton and various Mississippian limestones. Carbonate reservoirs are often stratigraphically trapped along the regional truncation of a porous facies, but where porosity is pervasive they can also be found structurally trapped. Carbonates are often dual-porosity reservoirs in which a low porosity/permeability matrix is enhanced by dissolution features (molds, vugs, and caverns) and fractures. The dissolution features and fractures greatly increase wellbore access to the lower permeability matrix that would otherwise not be of reservoir quality. A single Arkansas Novaculite study was included in this group because of its similar dual-porosity system and production characteristics (Appendix).

Fluvial-Dominated Deltaic (FDD) reservoirs are by far the most important group in Oklahoma. They are Pennsylvanian and Permian in age, with the most productive being the Bartlesville, Deese, Morrow, and Red Fork. They are a diverse group of sandstones, which although mostly deposited as channel-fills (distributary channels and incised valley-fills) also include overbank splays and various types of marine-reworked deltaic sandstones, including distributary mouth bars and tidal channels. Reservoir quality is highly variable, with the various channel-fill sandstones being by far the best. The defining characteristic of FDD reservoirs is their limited aerial extent and a complex subsurface plumbing system. For this reason, although structure can sometimes influence the trap, even FDD reservoirs occurring on structural highs have a strong stratigraphic component. Like the BS reservoirs, the drive mechanism tends to be solution gas drive, but with little or no water support (Fig. 8).

The published findings were generally taken at face value, under the assumption that in a large sample there should be an equal tendency to overestimate as underestimate any particular parameter affecting volumetric calculations. There were several cases in which all of the key variables necessary to estimate OOIP were provided, but the calculated recovery factor turned out inordinately high. For some the calculated recovery factor was multiples of the reservoir class average, such as an FDD reservoir with more than a 70% recovery factor. Anomalies could usually be traced to the addition of zones within the reservoir interval, or an expansion of the productive area since the study date. Reservoir and other data from these studies were still valid, but these fields were omitted from

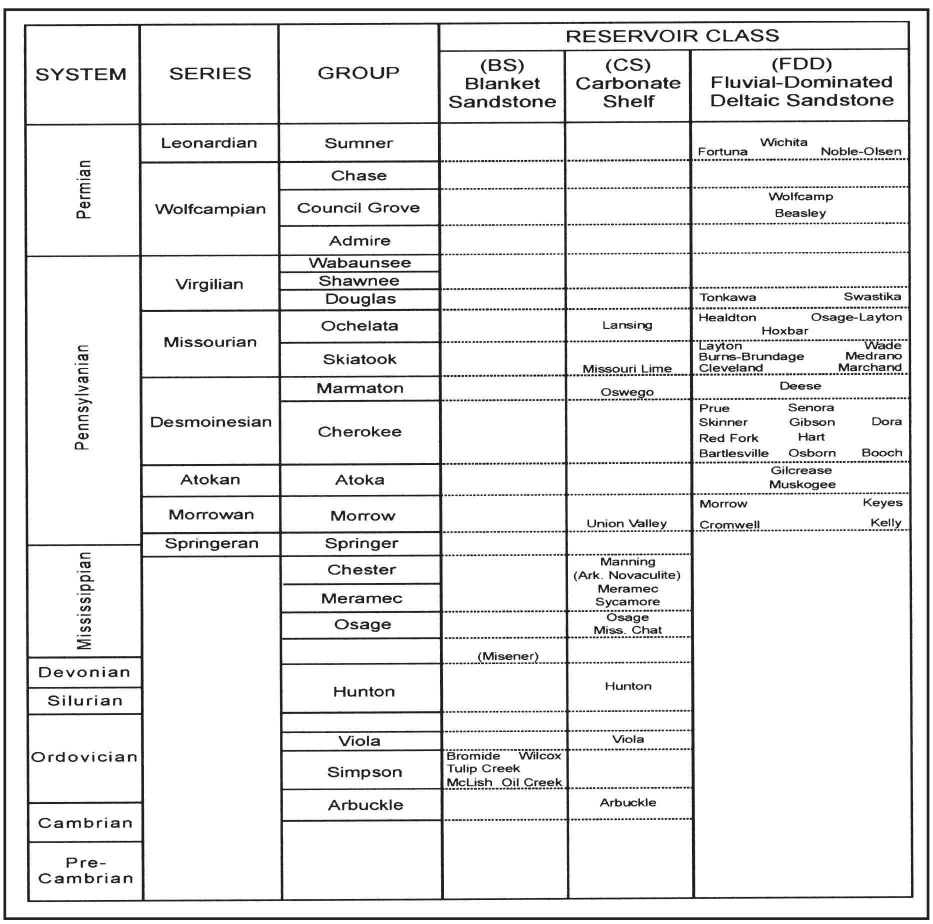

Figure 8: *Generalized Oklahoma stratigraphic column highlighting the oil reservoir classes and the names of those reviewed in this report.*

recovery factor statistics. Although disqualifying studies in which the recovery factor was deemed too high may introduce a systematic error that would tend to underestimate recovery factors, smaller scale commingling in those studies that were used should tend to cancel this potential bias.

This analysis is predicated on a number of key assumptions. The first is that the fields and reservoir studies that were reviewed represent a statistically representative cross-section of those that exist throughout the State. Also, because the work of dozens of geologists has been used, one must assume that the studies are of equal quality and that there is no systematic bias that would tend to over- or underestimate recovery factors. As will now be discussed, the largest source of uncertainty in this analysis is not in the pore volumes calculated, but in the oil produced.

Challenges

There were many challenges associated with a project of this scope, but by far the most serious involves data availability, especially early production data. The best publicly available database in Oklahoma is that compiled and maintained by IHS Energy. Their monthly oil production data begins in 1970 and their well database has records for about 485,000 wells. The State database (NRIS), which is offered online by Oil Law Records, begins monthly oil production in 1979 and has records for about 450,000 wells. The total number of wells drilled in Oklahoma is believed to be well over 500,000. Because of its earlier start date for monthly production and larger number of well records, the IHS Energy database was used to confirm and update production for the studies that were reviewed.

Unfortunately, even the IHS Energy database has some serious shortcomings, most of these due to circumstances beyond their control. Because the State has not consistently distinguished condensate from oil, all volumes quoted as oil refer to total hydrocarbon liquids. If the average condensate yield for all Oklahoma gas reservoirs is 5 barrels per MMCF, this would amount to roughly 500 MMBC lumped into the gross oil production volumes. While this is a large volume, it still represents only about 3% of the total liquid hydrocarbon production for the State.

There are other, more serious production data issues. Using Tax Commission data, the Oklahoma Corporation Commission has compiled annual, statewide 'oil' production volumes since 1900 and annual volumes by county since 1975. These official numbers show a cumulative recovery of 14.809 billion barrels (Claxton, 2007). Total production in the IHS Energy database, including the 'beginning cums' which refer to production prior to 1970, is 12.873 BBO (IHS Energy, 2008). The missing 1,936 MMBO, representing 13% of State production, is not accounted for in any digital database. Fortunately, a random comparison of IHS to Vance Rowe (hard copy) production in fields that appeared to be underreported confirms that much of the 'missing' oil is carried by Vance Rowe.

An additional 2,995 MMBO, or 20% of State production, was produced from wells in which the cell for productive reservoir is either blank or marked 'Unknown'. IHS Energy records multiple reservoirs for wells in which more than one reservoir was listed by the operator, which has helped identify the source for some commingled production. However, for 383 MMB of production, or 3% of State production, the official reservoir name is 'Commingled'.

Another production data problem relates to oil produced from secondary/enhanced recovery units, usually waterflood units. Here the State has no requirements regarding water injection or production, only requiring operators to report the total monthly (oil-gas) volume for the entire unit, regardless of its size. With operator records now largely lost, it has made it all but impossible to identify areas in larger waterflood units where producible volumes of unswept oil may still reside. This policy has resulted in a single quarter-quarter section in Cushing Field assigned a cumulative production of 425 MMBO, and one at Burbank with 315 MMBO (IHS Energy, 2008).

Thus, in the most complete production database in the State, a total of 5,314 MMB, or 36% of total production, is either missing or has no reservoir identified. This has made it nearly impossible to determine cumulative recoveries or calculate recovery factors for fields that were the subject of excellent studies. Often cumulative production shown through the date of the study, usually in the 1950s or 1960s, and provided by the operator, is many times that shown by IHS as the cumulative production through 2008. Such studies could not be used in recovery factor statistics.

Results

With a 16 BBO estimate of ultimate oil recovery, the next step is to determine the OOIP volume from which this production has or will come. Because recovery factors vary with reservoir type, this involves apportioning cumulative production into one of the three reservoir classes described previously. This fixes the relative contribution of each class, which combined with an average recovery factor based on field study statistics, makes it possible to calculate an overall OOIP.

Classifying each Oklahoma oil reservoir into one of three reservoir classes at first seems daunting. The N.R.I.S. listing of productive reservoirs includes about 7,500 names, exactly as reported (and spelled) by operators. Even IHS Energy, which has streamlined this list, still has over 3,000 named reservoirs. Luckily, the vast majority of oil reservoirs have less than a handful of completions, and with this in mind, only those reservoirs with at least 10 tions, a great deal of other information was also gathered. In this way, studies that had incomplete or unverifiable information concerning volumetrics could make valuable contributions in other areas. The following is a brief summary of some of the geological/engineering findings that were gathered from the 225 oil field studies that contributed in some way to this report.

In the studies reviewed reservoir depths ranged from 720' to 11,400', with the vast majority between 3,000 and 9,000'. For those giving an initial reservoir pressure, it was found that two thirds began at or near hydrostatic (0.43 psi/ft.), or 'normal' pressure. The remaining third were mostly underpressured, with most of these located on the Anadarko Shelf. The few that began overpressured were mostly in the Anadarko Basin. It was rarely indicated whether the initial reservoir pressure was measured directly or calculated from the shut-in tubing pressure. Those that were calculated will tend to underestimate the true bottom-hole pressure, and this may account for some reservoirs that appear to have started underpressured.

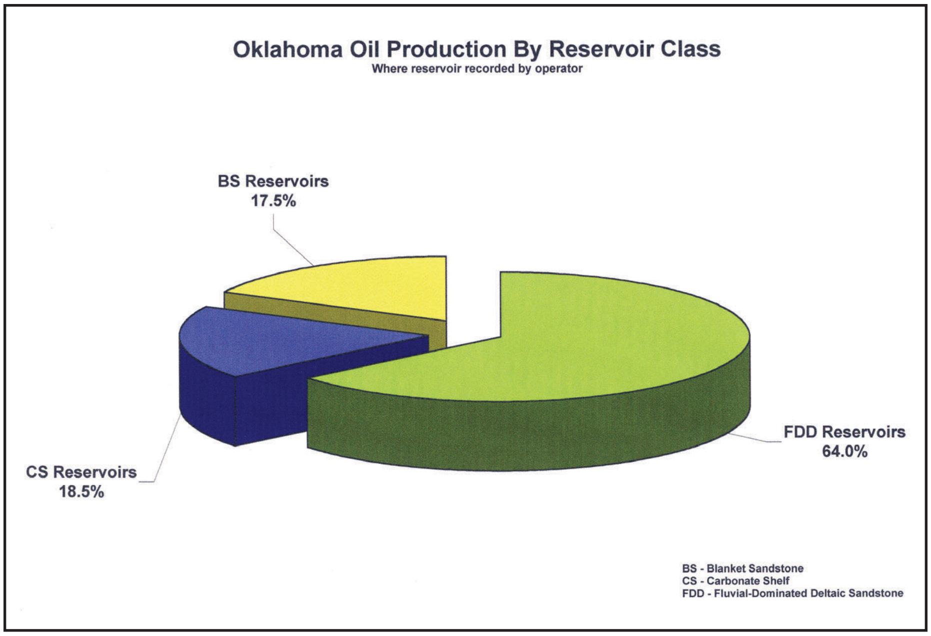

Figure 9: *Oklahoma oil production by reservoir class.*

completions were counted. Commingled completions, where the individual reservoirs were identified, had their production assigned to the first reservoir listed.

There are only 167 reservoirs with at least 10 oil completions, and although they represent a small percentage of the total named, they account for over 98% of the 9,280 MMBO assigned to specific reservoirs (IHS Energy, 2008). There are 6 BS, 36 CS, and 125 FDD reservoirs with at least 10 oil completions. By summing their production it was found that BS reservoirs accounted for 17.5%, CS reservoirs 18.5%, and FDD sandstones 64.0% of the State's cumulative production that is assigned to a specific reservoir (Figure 9).

If it is assumed that unassigned and missing production is of a roughly equal proportion, the actual cumulative production for the three reservoir classes to date is: 2,592 MMBO for BS reservoirs, 2,740 MMBO for CS reservoirs, and 9,478 MMBO for FDD reservoirs. If the wells producing from these reservoirs decline at roughly the same rate, they should also make up the same proportion of the ultimate oil recovery. Thus, given current trends, roughly one sixth of Oklahoma's ultimate oil recovery will come from BS reservoirs, one sixth from CS reservoirs, and two thirds from FDD reservoirs. This may actually understate the relative importance of FDD reservoirs to Oklahoma, as much of the unassigned production, which was produced mostly in the early years, was from the shallower FDD reservoirs.

In addition to collecting data on all of the variables affecting volumetric calcula-

In fluid properties, as stated earlier, the weighted average for the IGOR was 665 scf/Bbl. The distribution of oil gravity ranges from a low of 20° API to a high of 50° API, with most values between 37° and 42° API (Fig. 10). Taking the published numbers at face value, the average gravity for the oil in the studies reviewed was 39.6° API. However, any values in the mid-40s and higher are likely in part condensate, which if discounted, would reduce the

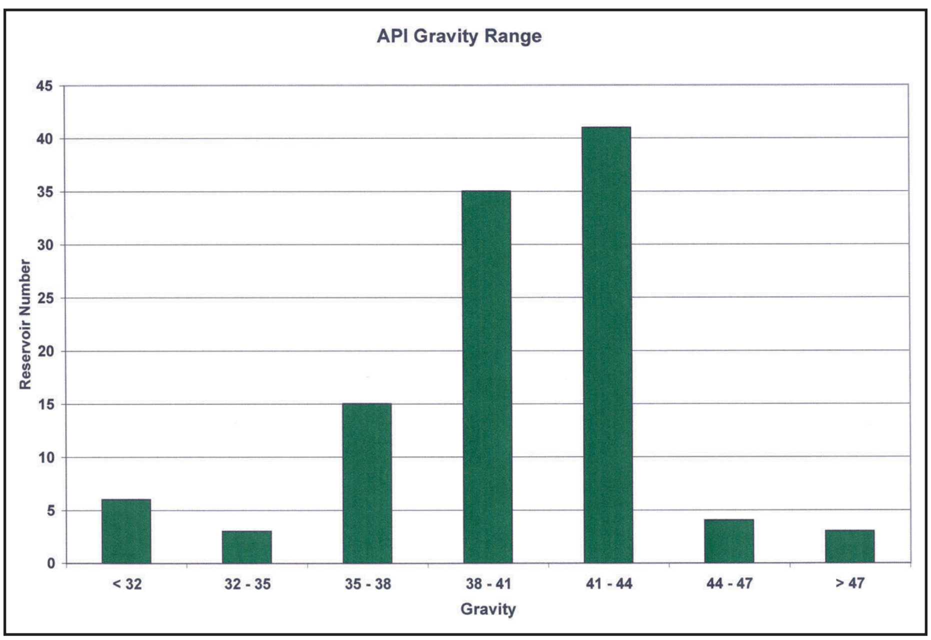

Figure 10: *API gravity range for the studies analyzed in this report. The higher values probably have a component of gas condensate.*

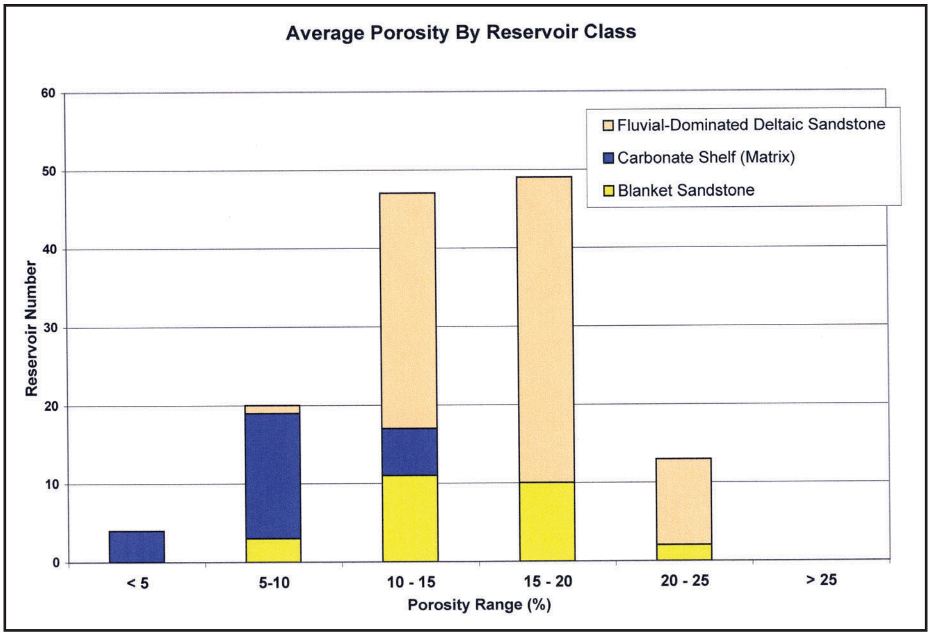

Figure 11: *Average porosity by reservoir class. Values are averages of the productive part of the reservoir for the studies analyzed in this report.*

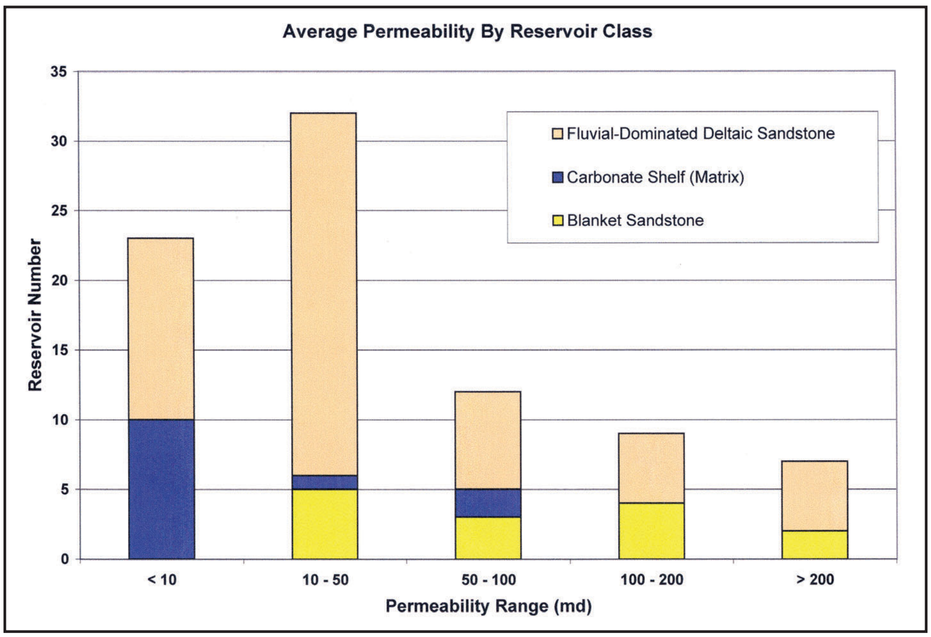

Figure 12: *Average permeability by reservoir class. Values are averages of the productive part of the reservoir for the studies analyzed in this report.*

overall average. Regardless of any possible inconsistencies, the bulk of the crude oil found in Oklahoma is high-quality, very light, and began with ample dissolved gas.

Reservoir statistics, which were only core-derived, quantitatively highlight some of the differences between the three reservoir classes. Although they were deposited in different environments, BS sandstones and FDD sandstones have similar porosity distributions. The FDD reservoirs are more numerous, but the average porosity in their oil pay, at 16.2%, is very close to the blanket sandstone's 15.2%. The porosity distribution (matrix) for CS reservoirs, as well as their average porosity of 7.9%, is much lower than that of the other two reservoir classes. In fact, without the dissolution/fracture component, many of these would not be of reservoir quality (Fig. 11).

Core permeability values were recorded in many of the studies that were reviewed, and here the two sandstone reservoir classes differ. The FDD reservoirs were deposited mostly as channel-fills and therefore contain more fine-grained material than the well-winnowed blanket sandstones. Although the FDD sandstones can be as permeable as the BS, their average permeability is 68 md, compared to the BS sandstone's 121 md. The CS reservoir's distribution is somewhat bimodal, with all but three reservoirs having very low permeability. The 21 md average is misleading because it applies to only what can be effectively measured from core i.e.: matrix permeability. In the subsurface this lower matrix permeability can be greatly improved by dissolution features and especially fractures; both natural and artificial (Fig. 12).

Oil in the Ground

Recovery factor ranges were calculated for each of the three reservoir classes. These are based on the studies in which the OOIP was given or where enough critical information was given to calculate the OOIP. In those cases where the initial oil saturation or formation volume factor was not given, these values were estimated based on comparisons to analog fields. (OOIP = *Area* in acres x *Thickness* in feet x *Average Porosity* % x *Average Initial Oil Saturation* % x 7,758 Barrels per Acre-Foot / *Formation Volume Factor* in Reservoir Barrels per Stock Tank Barrel).

For each of the studies reviewed the Estimated Ultimate Recovery (EUR) was calculated by maintaining the last month's production flat for 8 years and adding this to cumulative production (Fig. 13). This simplistic approach, because of almost universally low production rates, seldom left more than a few percent of the EUR left to produce. However, if oil prices can keep wells economic and producing significantly below 1/2 BOPD, this estimate will be somewhat conservative. Because EUR is a fraction of OOIP, an error of a few percent in the EUR will have a minimal impact on the overall recovery factor.

The recovery factors that were calculated for fields in each of the three reservoir classes varied considerably, in some cases due to the nature of the reservoir, in others because of how it was produced. Carbonate shelf reservoirs tend to concentrate on the lower end of the recovery scale, while the blanket sandstones stand out in the higher ranges. Average recovery factor values for each reservoir class were weighted by dividing the summed EURs by the summed OOIPs. This gives larger fields, which account for the bulk of production, more weight than the more numerous small fields. This weighting should give a more representative picture of the average recovery factor for the three reservoir classes. The higher level of attention focused on larger fields could also give them better recovery factors than similar reservoirs in smaller fields. The following are the average ultimate recovery factors calculated for Oklahoma's major reservoir classes: Blanket Sandstone - 44.1%, Carbonate Shelf - 10.0%, and Fluvial-Dominated Deltaic Sandstone - 21.2% (Fig. 14).

Assuming that recovery factors from the oil reservoirs in this study are representative of those throughout the State, it becomes possible to calculate an OOIP for all of Oklahoma. Based on the proportionate share of total production of the three reservoir classes stated above, the aggregate recovery factor for all oil reservoirs in the State is about 19.0%. This yields an OOIP for the State of 84.2 BBO, with 68.2 BBO projected to still be in the ground at abandonment. This assumes a continuation of the current production decline until an ultimate recovery of 16.0 BBO (an additional 1.2 BBO) is reached. Clearly, any program that can yield even a small percentage of the oil left behind has the potential to dramatically increase the State's EUR (Fig. 15).

Because every oil accumulation is different, even in the same reservoir class, a wide range of recovery factors are possible. In BS reservoirs with high permeability, if the structure is unbroken and water support strong, recovery factors well over 50% are possible. Despite this, about half of the studies reviewed calculated recovery factors of less than 30%, often substantially less. In some cases this reflected poorer reservoir quality, but more often occurred in structurally complex fields. Unlike unbroken structures that are essentially self-flooding, these tended to have

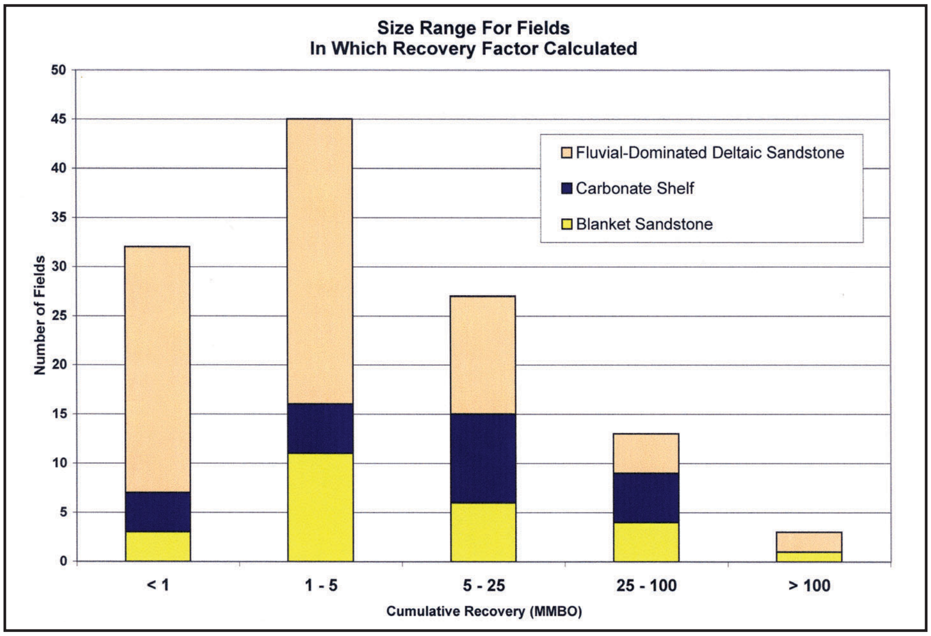

Figure 13: *Size range, in MMBO of cumulative recovery, for fields in which recovery factor was calculated.*

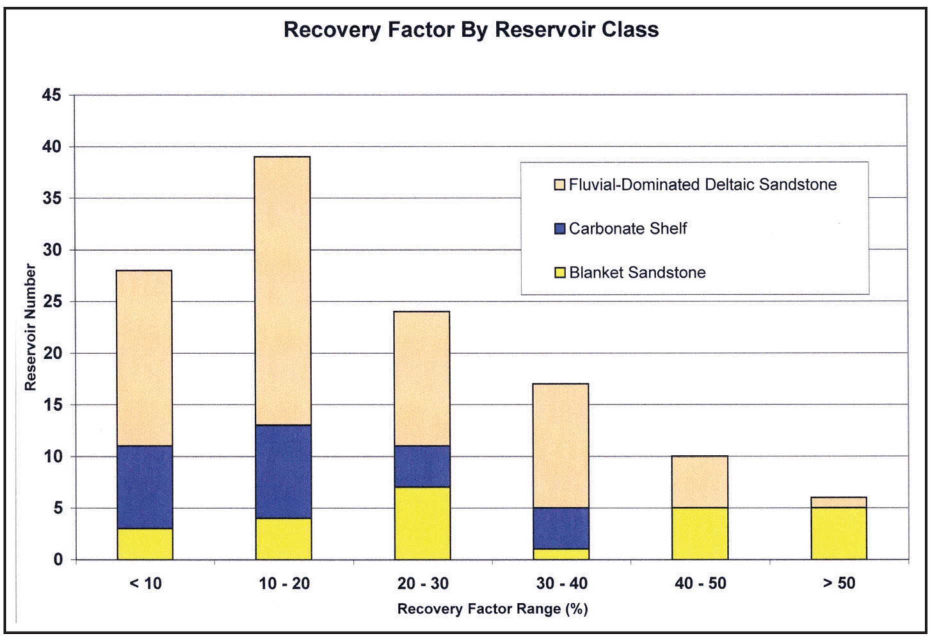

Figure 14: *Recovery factor by reservoir class for fields in which recovery factor was calculated.*

Oklahoma Original and Remaining Oil In-Place Volumes (MMBO) By Reservoir Class

Reservoir Class	% of Cum Prod	E.U.R. (Max)	Average Recovery Factor	1/RF%	OOIP	Rem OIP
BS	17.54%	2,806	44.1%	2.27	6,370	3,564
CS	18.43%	2,949	10.0%	10.00	29,490	26,541
FDD	64.03%	10,245	21.2%	4.72	48,356	38,111
Total	100.00%	16,000 (1-1-2007 Cum = 14,809)	<<<< Aggregate 19.0% >>>>		84,216	68,216

Figure 15: *Table showing Oklahoma original and remaining oil in-place volumes (MMBO) by reservoir class. Share of cumulative production based on proportions of IHS Energy production assigned to specific reservoirs. OOIP volumes assume same recovery factor for all production from that reservoir class and are based on an EUR of 16 BBO.*

weaker water support and a higher probability of undrained fault-blocks or missed attic oil.

In the CS reservoirs, where matrix porosity and permeability are relatively high and secondary porosity in the form of vugs and fractures are abundant, recovery factors of over 35% were recorded after waterflooding. However, about half of the studies reviewed had recovery factors of less than 15%. For many of these the oil produced appeared to have come mostly from the secondary porosity system, with little input from the poorer quality matrix. For those fractured carbonate shelf reservoirs with poor quality matrix, production usually started very strong, but declined dramatically within a few months. A de-watering program designed to reduce reservoir pressure and force matrix oil into the fracture system may be able to substantially improve recovery in some of these.

The largest reservoir class in Oklahoma is the FDD sandstones. They account for about two thirds of the OOIP, and have recovery factors that range from 52% to less than 5%. Stratigraphically they are by far the most diverse class of reservoirs, ranging from multi-story channel-fills more than 200' thick with 25% porosity and darcies of permeability, to overbank splay or mouth bar sandstones a few feet thick that can barely flow oil. The majority of those studied in the literature were the better quality FDD reservoirs, i.e.: channel-fill sandstones, where the better recoveries after waterflooding range from 32% to 44%. For most of the FDD channel-fill oil reservoirs a typical scenario involves primary production of 10 to 15% of the OOIP, followed by secondary (waterflood) recovery of an additional 10 to 15%. In cases where flow barriers are minimal and sweep efficiency is good, even higher recoveries are possible. For the roughly half of FDD channel-fill reservoirs in which the estimated recovery factor is less than 20%, a more detailed review is certainly warranted.

In spite of the rather arbitrary cutoffs quoted, a review of oil reservoirs for improved recovery should not be restricted to those below a particular recovery factor. Rather, on a first pass screening, BS reservoirs with less than 30%, CS reservoirs with less than 15%, and FDD reservoirs with less than 20% are obvious candidates for a closer look. Few of the studies reviewed quoted irreducible oil saturations or movable oil volumes. However, with the three reservoir classes leaving behind 56% to 90% of the OOIP, in most cases the critical issue should not be the volume of movable oil.

There are many ways in which the results cited here could be somewhat inaccurate. However, because of the overall quality of the studies on which the statistics in this report is based, there is little doubt that if trends continue, a very large volume of producible oil will be left in the ground at abandonment. A number of these studies were able to accurately predict ultimate recovery (primary + secondary) only a few years after the discovery of a field. Some, often with the help of a reservoir simulation, made recommendations concerning how to improve recovery, including changes in the injection pattern, re-completions, or new wells that, despite large incremental recovery estimates, were never implemented. Some fields were waterflooded, while others that appeared analogous, were not. In others the flood response was weak or delayed, indicating poor sweep. For many, the field that was studied significantly under-performed relative to analogous reservoirs under similar conditions.

If the studies evaluated here are even remotely representative of the State as a whole, the possibilities for improving oil recovery seem nearly endless. Although economics were not considered, a large percentage of the fields reviewed, in all three reservoir classes, appeared to have significant improvement potential. High quality seismic is an important component in evaluating most BS or structurally trapped CS reservoirs. Overall, the best possibilities are in the FDD reservoirs, which represent the largest volume of remaining oil, and where complex stratigraphy has created a subsurface plumbing system that can be difficult to unravel.

What can ultimately be produced is impossible to predict, but if the average recovery factor for each reservoir class can be improved, it is possible to calculate a range of possibilities. For the case in which average recovery factors in each reservoir class are increased to an 'ideal' level, based on results in the better fields, the incremental increase over current projections are BS-5.9%, CS-10%, and FDD-8.8%. This yields an incremental recovery of over 7.5 BBO, or about half the current State EUR. Although technically possible, this is shown only for comparison and is not considered realistic. Though, when starting with a remaining OIP of 68 BBO, even very modest improvements to average recovery factors generate large volumes of incremental oil. This is illustrated in the minimum case scenario in which the average net improvements in recovery factor over current projections are: BS-

Incremental Oil Possibilities For Three Arbitrary Average Recovery Factors*

Reservoir Class	Avg RF (Actual)	Avg RF (Max) RF	Avg RF (Max) Incr Oil	Avg RF (Intermediate) RF	Avg RF (Intermediate) Incr Oil	Avg RF (Min) RF	Avg RF (Min) Incr Oil
BS	44.1%	50.0%	376	47.5%	217	45.0%	57
CS	10.0%	20.0%	2,949	15.0%	1,475	12.5%	737
FDD	21.2%	30.0%	4,255	25.0%	1,838	22.5%	629
Total			7,580		3,530		1,423

* - In MMBO

Figure 16: *Table showing incremental oil recoveries given three possible increases in average recovery factor for three reservoir classes.*

0.9%, CS-2.5%, and FDD-1.3%. In this example, where all recovery factors are significantly below levels that are routinely achieved in the better managed fields, the incremental volume of producible oil is still a staggering 1.4 BBO (Fig. 16).

Recommendations

It is fitting, as the State begins its second century, that a concerted effort be initiated to revitalize production of the resource that led to Statehood. To accomplish this, steps must be taken to enable operators to identify where it is possible to economically recover oil that will otherwise be left in the ground.

Data

Oklahoma's historically hands-off attitude towards oil and gas data has created a situation in which service companies and geologic societies have become the main repositories for these data. A program called Energy Libraries Online Inc. (ELO), founded by the Oklahoma City Geological Society and The Oklahoma Well Log Library, is now underway. This online reference library will eventually contain scanned images of virtually all of the hard-copy data now housed in these two libraries. Ultimately the online library will also include the State oil and gas data that is maintained by the Oklahoma Geological Survey at the Oklahoma Petroleum Information Center.

Even the best organized and maintained hard-copy collections cannot compare to digital databases. In addition to their ability to archive irreplaceable documents, they bring together the many, disparate data elements that earth scientists need to evaluate oil and gas in the subsurface. The ELO database will put in one place scout cards, completion data, well logs (including geological sample logs, strip or driller's logs, electrical logs, and mud logs), and production data. It is important to organize and archive all subsurface data in one place, but one of the most important benefits the ELO system will bring to operators seeking to identify underperforming oil reservoirs will be access to early production data, scout cards and strip logs, which today is difficult to impossible.

With such persuasive evidence that recovery factors in a significant percentage of the State's oil fields are substandard, little more needs to be done than to give the industry the tools it needs to find it. If these data increase oil-targeted drilling and production activity, every facet of the State economy will receive a boost. However, the benefits of a fully functioning online library extend well beyond the oil and gas industry. The ELO effort will also assist Oklahoma scientists in other areas of vital research, such as the study of groundwater resources and environmental quality.

Production

The lack of early production data is a major roadblock to operators seeking to revive old fields. IHS Energy data are severely handicapped by the nearly two billion barrels of missing production mentioned previously, and monthly data that begins in 1970. The inability to obtain monthly production data from inception, and thereby reliably assign cumulative production on a lease basis, is one of the largest impediments to finding substandard recoveries and thereby producing additional oil. Drilling and secondary/enhanced recovery activity is easy to identify with complete monthly production data. However, because 70% of Oklahoma's oil was produced before 1970, in most of the fields that were examined the 'beginning cum' number dwarfs the volume on which monthly production is shown. Thus, the production curve usually shows little more than the tail of a decline that began long before 1970.

Complete production data do exist on microfilm and microfiche at the Oklahoma Tax Commission, but these records also include confidential tax data, and therefore are unavailable for large-scale, public use. (Limited lease production requests can be filled on a case by case basis by OTC personnel.) Hard-copy monthly lease production data from 1935 have been available at the Oklahoma City and Tulsa Geological Society libraries in their collections of Vance Rowe production books. These monthly production values will be hand-entered into a digital database and be available online through the ELO system.

Because Vance Rowe production begins nearly 40 years after production began in Oklahoma, these data will not completely solve the State's oil production issues, but they will vastly improve the situation. They will help put 75% of the State's total oil production into a monthly framework, and hopefully find a home for much of the missing 2 BBO of production. This will make it possible to review detailed production histories and verify cumulative production for many more fields than is possible now. It will also make it possible to calculate reliable recovery factors and more easily identify and high-grade improved oil recovery candidates. Without reliable production data an operator runs the risk, especially in an older field, that the incremental oil being sought has already been produced.

Strip or Driller's Logs

The Oklahoma Geological Survey is the final stop for most of the hard-copy data used by the State's oil and gas industry. In addition to the hard-copy 1002A forms, it is also the repository for the electric logs submitted by operators to the State. It is estimated the Survey has paper electric logs for about 365,000 wells. Most of these are available through service companies in digital format. However, a key dataset that has been unavailable to the industry is the State's collection of approximately 125,000 hand-plotted driller's strip logs. If all goes well, these will also be available online in the near future.

In the days before rotary drilling and the requirement for drilling mud, wells were drilled using cable tool rigs. Cable tool wells have only air in the hole, creating an essentially continuous DST in which anything less than oil-to-surface was considered a dry hole. Most of these wells were drilled before the advent of electrical logs, so cable tool drillers recorded the subsurface formations penetrated on what is called a driller's log. These logs, with comments, were later plotted by students or geologists on blank strip logs. These logs vary in what they contain and the detail in which it is recorded, but most record depth, lithology, fluid type, shows and initial potential. For some of these, there is no API number or well spot, making a single, narrow strip of yellowing paper virtually the only record of that particular well.

Rotary drilling was developed in the late 1920s and became the dominant drilling technique by the mid-1930s. Although the evolution to rotary drilling was gradual, if one assumes that every well drilled prior to January 1, 1935 was drilled with a cable tool rig, then about 104,000 Oklahoma wells, of which 62,000 were oil wells, were drilled using cable tool rigs (IHS Energy, 2008). Based on this, strip logs represent the only subsurface data for over one quarter of the State's oil wells and one fifth of all of the wells ever drilled. While these do not have the utility or resolution of electrical logs, when used with more modern logs they can dramatically improve subsurface control. This is especially true in areas where early drilling predominates, which includes every major area where oil is produced. It is not known how many of the early cable tool wells are represented in the combined strip log collections of the OCGS, TGS and the OGS. This is because duplicates were created when more than one geologist looked at the cuttings. However, between the Survey's roughly 125,000 and the Tulsa and Oklahoma City library's 100,000, the majority should be represented.

Operators

The recommendation to operators is simply: "Don't give up on oil." Poor field management in the early days, complex reservoirs, diverse ownership, and a lack of basic well and production data have combined to leave, even at this late stage in the industry, large quantities of moveable oil in many reservoirs. If the studies evaluated in this article are indicative of those throughout the State, the economically remaining producible oil volume is very large. The primary hurdle, and it will remain a large one, is in identifying it. After that, the techniques recommended here for its production tend to be decidedly low-tech: new wells, water in the ground in new or modified waterfloods, or water out of the ground in dewatering operations.

A great deal of the secondary recovery work done thus far has been piecemeal. Except in the largest fields, there has been little coordination between operators and undoubtedly little detailed, field-wide reservoir simulation work. A map of the waterflood unit boundaries in the NRIS database (those active since 1979) shows an irregular patchwork of secondary recovery projects that overlay less than half of currently producing oil leases in Oklahoma. Based on the field studies carried out by the OGS, many of these waterflood units have been subdivided into smaller areas that are operated in isolation and at cross-purposes with the management of adjacent units. In the survey of field studies in this review it was found that many had muted and/or delayed responses to injection, clearly showing that sweep efficiency was poor.

A technique that has shown promise in some clastic, and especially carbonate dual-porosity reservoirs is called 'de-watering'. It works best in fractured rocks with low matrix permeability where there is significant down-dip water, but it can also be effective in clastic reservoirs with thick transition zones or where high and low permeability zones are juxtaposed. Such reservoirs often have very low recovery factors because only the oil stored in the high permeability part of the dual porosity system (usually secondary porosity) is drained. After this the oil rate drops dramatically, with little loss in reservoir pressure, as water rises through the reservoir. Although the lower permeability (matrix) component of the reservoir is still largely undrained, most operators will give up at this point. However, with sufficient water pumping and disposal capability one can reduce the reservoir pressure until the associated gas in the unproduced oil expands. This oil can then be pushed into the fracture system and ultimately the wellbore. In West Carney Field the dewatering technique took a Hunton (CS) reservoir with cumulative production of just 38 MBO and 0.5 BCF to one with reserves of 2.2 MMBO and 16 BCF (Chernicky, 2002a). A number of the low recovery CS reservoir field studies showed production curves strongly suggestive of a dual porosity system that might lend them to this recovery technique.

New Dominion L. L. C., a leader in the de-watering technique, has also had success in a Red Fork (FDD) reservoir in Mount Vernon Field. Here aggressive water production and the resulting drop in reservoir pressure has allowed associated gas in intervals of low permeability and high water saturation to push oil into larger pore systems and fractures. In this field incremental recovery was increased 1.26 MMBO + 18.5 BCF + 1.77 MMBC (Chernicky, 2002b).

There are a variety of more exotic improved recovery options that may be viable in selected areas. The injection of gas, microbes, detergents, surfactants, as well as in-situ combustion techniques have all been applied with varying degrees of success. CO_2 injection has received much press recently, often in the dual role of both oil enhancement and sequestration. However, while there are a handful of fields in which CO_2 is being used successfully to enhance oil recovery, its widespread use should be viewed with caution. Because of the many old and undocumented wells in most of the oil producing areas of the State, issues of cross-flow into other reservoirs, including aquifers, as well as surface leakage will likely be persistent problems.

Any systematic effort to identify underachieving oil reservoirs in Oklahoma will be manpower intensive and require collaboration between engineers, geologists, and landmen. Areas where original operator records are available (especially those showing pressures and water production) are ideal, but certainly in most areas an incomplete data set will add an element of risk to any improved recovery project. Drilling, log, completion, and production data for Oklahoma are scattered, with some existing only in hard-copy. Access to these data will be greatly facilitated with the completion of the ELO system, which will bring the OCGS and TGS library's hard-copy data to one place, in a digital format. Even more important will be the addition of two major datasets that are not yet accessible, but critical to the effort described in this report. These are the Vance Rowe production data, that will push monthly production records back to 1935, and the State's major strip log collections. ELO will help to fill critical gaps in our knowledge and greatly facilitate the search for underachieving oil reservoirs.

Conclusions

Oil production in Oklahoma has fallen almost continuously since 1984, with record prices in the last several years having a minimal affect on the long-term decline. Although large oil discoveries are no longer possible, huge volumes of producible oil are waiting in thousands of existing fields. Early production practices (which allowed for the flaring of 3-6 TCF of associated gas), fragmented ownership, and a variety of complex reservoirs will combine to leave 81% (68 BBO) of the State's OOIP in the ground at abandonment. A review of the geologic literature shows examples of low recovery that can be addressed relatively simply, through waterfloods, modified waterfloods, de-watering, new wells and/or re-completions.

Historically haphazard production reporting and data dissemination has greatly complicated efforts to systematically evaluate oil possibilities in Oklahoma. However, while this has discouraged operators from evaluating oil possibilities in the past, it has also helped to create the current opportunity. As data issues are addressed and the long-term price of oil rises, as it surely must, a large-scale re-evaluation of Oklahoma's oil reservoirs is inevitable. The results of such an effort have the potential to extend the life of meaningful oil production for decades beyond current estimates, and directly and indirectly benefit every area of the State.

There is no shortage of challenges associated with such an undertaking, but if the studies reviewed here are in any way representative of the State as a whole, the oil volumes and potential rewards for the State and the industry are enormous. The volume that may be recoverable through a wide-scale effort is impossible to predict, but every 1% of the remaining oil in-place represents a staggering 680 MMBO of incremental recovery. At $75 per barrel (excluding associated gas production) every 100 MMBO produced represents $7.5 billion in total income and $525 MM net to the State in gross production tax revenues. What are we waiting for?

Acknowledgements

The author would like to thank the IHS Energy Group, who provides the Oklahoma Geological Survey the free use of their database, which greatly facilitated the completion of this study. A debt of gratitude is also owed Roy Knapp, professor of petroleum and geological engineering at the University of Oklahoma College of Earth and Energy, and Tim Brown, executive director of Energy Libraries Online, who had useful ideas that were incorporated into this study.

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Dan Boyd is a petroleum geologist with the Oklahoma Geological Survey, where he has been employed since 2001. Dan received his Master of Science degree in geology from the University of Arizona in 1978. He spent the first 22 years of his career as an exploration and development geologist in the petroleum industry. From 1978 through 1991 he worked on a variety of areas in the United States from Houston, Dallas, and Oklahoma City for Mobil Oil and Union Texas Petroleum. In 1991 he moved overseas, working in Karachi Pakistan for four years and Jakarta Indonesia for the following four. He returned with his family to the U.S. in 1999 with Arco (the successor to Union Texas) where, until Arco's sale to BP, he worked on the offshore Philippines from Plano, Texas. He now enjoys a more settled life in Norman, Oklahoma with his wife and two children. Dan is a history buff, amateur astronomer, and violinist in the OU Civic Symphony.

Since joining the Staff of the Oklahoma Geological Survey in 2001, Dan has been involved in updating the Oil and Gas Map of Oklahoma in 2002 and preparing and presenting several published reports on the history, status, and future outlook of the oil and gas industry in Oklahoma. He chaired the 2002 Symposium on Cherokee Reservoirs in the Southern Midcontinent and edited the attendant publication, OGS Circular 108. Dan also prepared and presented his report on the Morrow-Springer gas in Oklahoma for the 2005 Springer Gas Play Symposium. Dan recently prepared and presented, with others, the study on the Booch gas play in southeastern Oklahoma and the subsequent OGS Special Publication 2005-1.

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Appendix : Listing of Volumetric Studies

Original Field Name	Reservoir Name	Date	Author
Blanket Sandstone			
Aylesworth Dist SE	Oil Creek	1994	Roger Spring
Centrahoma	McLish	1975	W. P. Anderson
Centrahoma	Oil Creek	1994	Roger Spring
Coyle SE	Wilcox	1994	Robert Tehan
Criner -Payne	Bromide	1963	Lloyd Gatewood
Davis SW	Oil Creek	1981	Thomas Current
Eola-Robberson	McLish	1981	Bill Harrison compiler
Eola-Robberson	Oil Creek	1981	Bill Harrison compiler
Eola-Robberson	Bromide	1981	Bill Harrison compiler
Hunter S	Misener	1979	Mike Kernan
Madill N	Bromide	1965	Joseph Kornfeld
Madill N	McLish	1994	W. E. Jackson
Noble NW	Tulip Creek	1994	Harry Buck
Noble NW	Oil Creek	1994	Harry Buck
Noble NW	McLish	1994	Harry Buck
Noble Townsite	Tulip Creek	1994	Paul Smith
Noble Townsite	Bromide	1994	Paul Smith
Oconee E	Oil Creek	1973	Don Morris
Oklahoma City	Wilcox	1968	Lloyd Gatewood
Oklahoma City	Oil Creek	1968	Lloyd Gatewood
Prague W	Wilcox	1994	Lee Lamar
Rich Valley	Wilcox	1963	D. W. Bell
Washington N	Bromide	1994	Paul Smith
Washington N	Tulip Creek	1994	Paul Smith
Carbonate Shelf			
Buffalo N	Lansing	1963	B.D. Price
Buffalo N	Arbuckle	1963	B.D. Price
Centrahoma	Viola	1975	W. P. Anderson
Cheyenne Valley	Hunton (Henryhouse)	1994	Kathy Lippert
Cottonwood Creek	Arbuckle (Brown Zone)	1994	David Read
Criner -Payne	Hunton	1963	Lloyd Gatewood
Dibble SE	Hunton	1963	Harold Meuller
Dover-Hennessey	Manning	1963	John Ware
Dover-Hennessey	Meramec	1963	John Ware
Edmond W	Hunton	1981	Bill Harrison compiler
Fitts	Viola	1981	Bill Harrison compiler
Isom Springs	Arkansas Novaculite	1981	L.S. Morrisson

Original Field Name	Reservoir Name	Date	Author
Lincoln	Oswego	1962	Charles Durham
Mustang (partial)	Hunton (Bois d'Arc)	1973	William London
Mustang (all)	Hunton (Bois d'Arc)	1995	Robert Ho
Noble NW	Viola	1994	Harry Buck
Noble Townsite	Viola	1994	Paul Smith
Oklahoma City	Arbuckle	1968	Lloyd Gatewood
Prague W	Hunton	1994	Lee Lamar
Putnam	Oswego	1963	Donald Brown
Rich Valley	Miss Chat	1963	D. W. Bell
Rosenwald	Union Valley	1957	M. R. Smith
Shalom Alechem	Sycamore	1974	Lee R. Riley
Sooner Trend	Meremec-Osage	1975	S. A. Harris
Washington N	Viola	1994	Paul Smith
FDD			
Alamo SW	Osborn	1994	Marion Hutchinson
Allen	Gilcrease	1981	Bill Harrison compiler
Allen (partial)	Booch	1981	Bill Harrison compiler
Allen (partial)	Booch	1981	Bill Harrison compiler
Antioch SW-Elmore City N	Gibson	1948	Marshall Dayton
Balko S	Morrow (A)	1995	Rick Andrews
Binger E	Marchand	1980	Louis Ford
Blackwell	Tonkawa	1997	Kurt Rottman
Blackwell Lake E	Osage-Layton A	1996	X. Yang
Blackwell Lake E	Osage-Layton B	1996	X. Yang
Blackwell Lake E	Osage-Layton C	1996	X. Yang
Blackwell Lake E	Osage-Layton D	1996	X. Yang
Boyd	Morrow (Upper)	1961	Panhandle Strat committee
Burbank S	Burbank	1963	T. A. Matthews
Butner NW	Senora	1958	James Duck
Canton	Lw Morrow B & C	1995	Rick Andrews
Carmen N	Red Fork	1997	Rick Andrews
Cement	Noble Olsen	1981	Bill Harrison compiler
Cement	Fortuna	1981	Bill Harrison compiler
Cement	Wade	1981	Bill Harrison compiler
Cement	Medrano	1981	Bill Harrison compiler
Cherokee NE	Red Fork	1963	Eugene F. Culp
Coyle SE	Skinner	1994	Robert Tehan
Cushing	Prue	1981	Bill Harrison compiler

Original Field Name	Reservoir Name	Date	Author
Dibble N	Osborn	1974	Gene Jeary
Dora	Dora Sd	1941	W. I. Ingham
Elmwood W	Morrow	1963	John Dowds
Eola-Robberson	Skaggs Sand	1981	Bill Harrison compiler
Eva NW	Kelly Sand	1961	W. W. Williams
Fitts W	Cromwell	1981	Bill Harrison compiler
Flat Rock	Bartlesville	1954	C. H. Riggs
Glencoe SE	Red Fork	1994	Chris Fowler
Glenn Pool	Glenn Sand	1994	Kuykendall, Matson
Golden Trend	Hart	1981	Bill Harrison compiler
Greasy Creek	Booch	1995	Bob Northcutt
Griggs S	Wichita Sand	1961	Lloyd Pippin - Leland Poling
Griggs S	Wolfcamp (Winfield Sd)	1961	Lloyd Pippin - Leland Poling
Guthrie SW	Skinner	1996	Kurt Rottman
Healdton (partial)	Healdton Sand	1981	Bill Harrison compiler
Healdton (all)	Healdton Sands	1953	C. H. Riggs et al
Higgins S	Morrow	1994	Robert Tehan
Katie	Gibson	1949	Chandler, William A
Lake Blackwell E	Osage-Layton	1996	Jock Campbell
Layton Sand Unit	Layton	1972	James Pate
Long Branch	Prue	1996	Rick Andrews
Long Branch	Red Fork (ch-fill)	1997	Rick Andrews
Long Branch	Red Fork (other)	1997	Rick Andrews
McQueen SW	Swastika	1994	W. E. Jackson
Mount Vernon (B)	Red Fork	2002	David Chernicky

Original Field Name	Reservoir Name	Date	Author
Mount Vernon (comb)	Red Fork	2002	David Chernicky
Muskogee	Muskogee	1959	C. H. Riggs
Norge NW-Verden	Marchand	1974	T. B. Curlee
Oakdale	Red Fork	1968	Gustavo Gonzalez-P.
Ohio-Osage	Bartlesville	1997	Andrews-Northcutt
Oklahoma City	Prue	1981	Bill Harrison compiler
Otoe City S	Red Fork	1997	Kurt Rottman
Paradise	Bartlesville	1997	Rick Andrews
Pauls Velley E	Burns-Brundidge	1949	Frank Folger
Perry SE	Skinner	1996	Kurt Rottman
Perry Townsite	Skinner	1993	S. B. Cline
Pleasant Mound	Cleveland	1997	Kurt Rottman
Quapaw	Bartlesville	1952	James West
Reck	Deese Basal	1994	J. T. Boyce
Rice NE	Purdy "C"	1995	Rick Andrews
Rice NE	Purdy "B"	1995	Rick Andrews
Rosenwald	Cromwell	1957	M. R. Smith
Russell NW	Bartlesville	1997	Rick Andrews
Salt Fork N	Skinner	1996	Rick Andrews
Salt Fork SE	Skinner	1963	W.R. Sumter
Sivells Bend	Beasley	1958	Bracken, Barth W.
Sturgis E	Purdy Sd	1961	W. W. Williams
Tecumseh NW	Red Fork	1994	Fletcher Lewis
Unity N	Keyes Sd	1961	W. P. Buckthal
Wewoka NW	Booch	1995	Kurt Rottman