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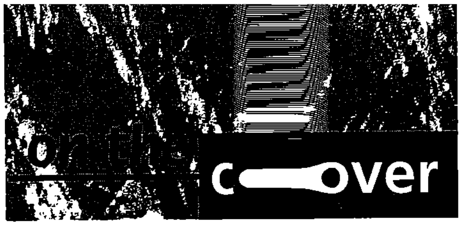
Featuring:
- *Alabaster Cavern entrance roof collapse*
- *Looking for gas-bearing layers in the Anadarko Basin*



Alabaster Cavern Entrance Roof Collapse, Woodward County, Oklahoma

During the weekend of December 25, 2004, a portion of the rock ledge above the entrance to Alabaster Cavern collapsed into the sink that formed part of the cave entrance (cover photo). Figure 1 shows the entrance as it appeared before the roof of the cave entrance collapsed.

Photo courtesy Oklahoma Tourism and Recreation Department

Figure 1. Alabaster Cavern entrance as it appeared before the roof collapsed.

The entrance to Alabaster Cavern is about 60 ft wide and about 11.5 ft high towards the center of the entrance (Fig. 1). The roof collapse occurred across the entire width of the entrance, and the resulting debris pile filled it to just over half its height (Fig. 2). The debris contained particles ranging in size to about 13 ft in length and about 5 ft wide. The largest amount of material appeared to have fallen from the center of the ledge.

Damage to the entrance includes: (1) the rock ledge or overhang directly above the paved concrete entrance collapsed and impaired entry into the cavern; (2) the cast-iron railing at the cavern entrance was crushed; (3) loose blocks of gypsum rock in the remaining rock ledge of the Nescatunga Gypsum at the cave entrance appeared unstable; and (4) loose rock and soil debris draped the sides of the sink at the cave entrance.

In the cover photo and Figure 2, soil material is observed on top of the debris pile. The reasons for this are (1) the block of gypsum rock and soil directly above the entrance collapsed as one unit; (2) the block of collapse debris did not move far, preventing the soil and rock from mixing; or (3) most soil movement occurred after the rock ledge collapsed.

Figure 3 shows portions of the fracture surface at the rock ledge after the collapse. Mud, soil, and organic material are present along the fracture surfaces. Observation of the newly formed rock ledge provided little evidence of freshly broken rock surfaces, indicating failure most likely occurred along preexisting fractures.

According to Alabaster Caverns State Park officials, the area had recently received a high amount of precipitation beforehand. Rain water or snow and ice melt percolated into vertical and near-vertical fractures in the Nescatunga. Mud, soil, and organic material absorbed and retained a good deal of the moisture. Northern Oklahoma experienced sub-freezing temperatures at the time the collapse occurred. When water in the fractures froze, it expanded causing frost wedging of the gypsum blocks above the cave entrance. This frost wedging probably was responsible for the rock ledge collapse. Figure 4 shows that icicles had formed below some of the rock ledge fractures where water had percolated through them.

Figure 4. Icicles formed after melt waters from snow and/or ice or rain water percolated through Nescatunga Gypsum fractures in the rock ledge above the entrance to Alabaster Cavern.

Figure 2. Rock ledge of Nescatunga Gypsum collapsed at the entrance to Alabaster Cavern.

Figure 3. Fracture surfaces in the rock ledge above the entrance to Alabaster Cavern after the collapse had occurred.

The Nescatunga Gypsum at the cavern entrance also has bedding plane fractures, and one small-scale normal fault with an almost imperceptible amount of movement; but neither of these apparently contributed to the collapse of the rock ledge.

On December 26, 2004, the magnitude 9.0 Sumatra-Andaman Islands Earthquake occurred at 00:58:53 UTC (Coordinated Universal Time). There is no evidence to link the cavern entrance collapse with the earthquake. The quake was too distant and shock waves too diminished in Oklahoma to have any effect. The rock ledge failure and earthquake occurrence are only coincidental. Local circumstances associated with freeze-thaw phenomena were the major cause for the rock ledge collapse.

Stanley T. Krukowski

Cover photo taken by Mike Caywood Manager, Alabaster Caverns State Park

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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* managing editor at the address above.

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Looking for Gas-Bearing Layers in the Anadarko Basin, Oklahoma

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INTRODUCTION

The Anadarko basin is the deepest sedimentary basin on the North American craton. Total sediment thickness in the deepest section exceeds 40,000 ft (12 km) and consists of sandstones, limestones, and shales of Cambrian to Permian age (Johnson and others, 1988). The basin covers almost the entire western part of Oklahoma and extends into the northeastern part of the Texas panhandle (Fig. 1).

The Anadarko basin is one of the most prolific natural gas producers in the North American continent. The majority of the basin's gas reserves occur in the basin-scale compartments termed the megacompartment complex (MCC) (Al-Shaieb and others, 1992, 1994a,b) and in the deep basin below the MCC. The upper part of the basin also contains substantial amounts of oil and natural gas. In 1980, the ultimate recovery of natural gas from the Anadarko basin was estimated at more than 110 trillion cubic feet (TCF) (Hill and Clark, 1980), an amount approximately equivalent to four times the production of natural gas from all of North America in the year 2000. Several large (>1 TCF production through January 2001) gas fields are in the Oklahoma part of the Anadarko basin. According to Lay (2001), Elk City, Putnam, Carpenter, and Watonga-Chickasha fields, as well as parts of the Sooner Trend and Golden Trend fields, have produced about 9 TCF of natural gas since their discovery. The Anadarko basin also is believed to be the source of gas found nearby in the Panhandle-Hugoton field, the largest gas field in North America. Clearly, the Anadarko basin still holds large reserves of natural gas yet to be discovered and extracted.

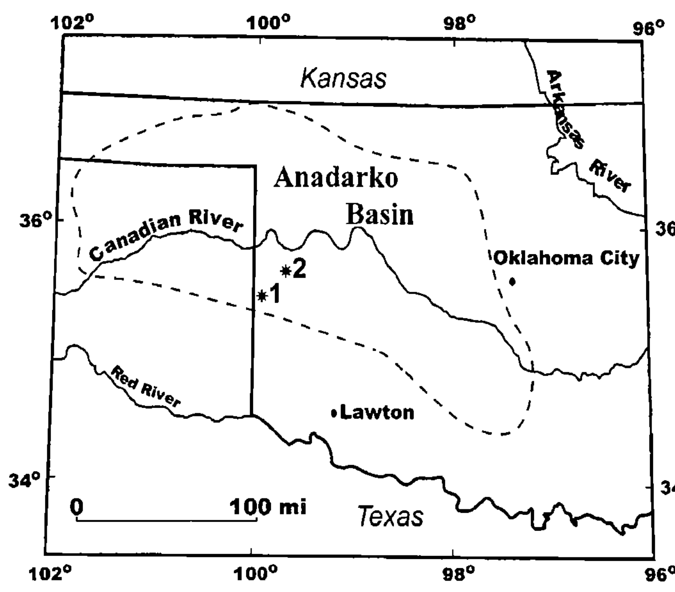

Figure 1. The Anadarko basin in Oklahoma and Texas and the two sites of case history discussed in text (1—Wesner 2-1 well; 2—Cobb 2-27 well).

The goal here is to present a synergistic interpretation of various well logs for detecting gas-bearing layers in the Anadarko basin. Although the examples chosen for interpretation are from a particular area of the basin (Roger Mills County), there is no impediment in extending it to other areas, and to other sedimentary basins holding gas-bearing layers.

THEORETICAL BACKGROUND

Identifying gas-bearing layers in a sedimentary basin requires a thorough and complex interpretation of information contained in well logs. Detection of gas with open-hole logs is tied primarily to the use of porosity type logs, which are the only logs generally run in open hole that really are influenced by the occurrence of natural gas rather than by the occurrence of oil or water. The gas detected is in the invaded zone close to the borehole wall, or sometimes in the virgin formation if there is little to no invasion. The response(s) of such porosity devices must be understood to fully appreciate the procedures assumed in setting up gas detection systems.

Neutron Porosity Log

The key to definitive open-hole gas detection is the neutron-porosity log, which responds to hydrogen contained in rock pores. Replacement of liquid by gas in the pore space of rock lowers the hydrogen density of the pore fluid. (Lower gas density predominates over increased hydrogen fraction by weight.) As a result the neutron porosity curve, calibrated for liquid-filled porosity, indicates abnormally low porosity. The effect may be large. As an example, consider the zone from 14,035 ft to 14,080 ft in Figure 2: it is a gas-bearing interval with density porosity close to 16%, but the neutron log shows an average of about 5%. It is implied, as a first approximation, that about two-thirds the pore space in the invaded zone is filled with gas, and one-third is filled with liquid.

The situation is complicated further because the *excavation effect* (Dewan, 1983) must be taken into account. The excavation effect may be defined as the difference in the neutron log values in porosity units or percent between a gas-bearing formation and a completely liquid-saturated formation in which water and oil have the same hydrogen content. The former shows lower porosity because it will contain less rock matrix, which allows neutrons to travel a little farther. For example, a 30%-porosity formation with 50% water and 50% air in its pores would read a porosity of

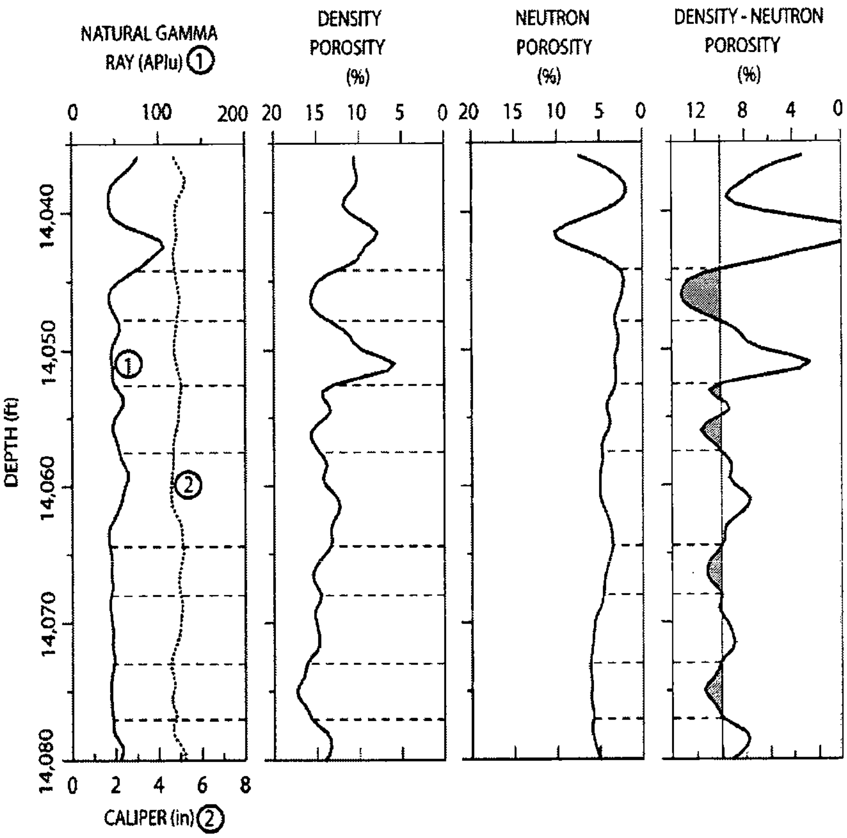

Figure 2. Well logs from Wesner 2-1 well, sec. 1, T. 12 N., R. 22 W., Roger Mills County, Oklahoma.

9%, not 15% as expected. The excavation effect would be 6%, which is not negligible. The reason for the difference is because the air space has not been replaced by rock matrix.

Neutron porosity logs record shale as having relatively high porosity. So in most cases, the shale response looks like an increase in porosity (Fig. 2, depth interval around 14,042 ft, or Fig. 3, depth interval around 11,335 ft). In other words, a shale response on a neutron porosity log exhibits the opposite effect of a gas response.

Density Porosity Log

The density porosity log is recorded by a tool comprised of a medium-energy gamma ray source and two gamma ray detectors. When emitted gamma rays collide with electrons in the geologic formation, the collisions result in a loss of energy from the gamma ray particle. Scattered gamma rays that return to the detectors in the tool are measured in two energy ranges. The number of returning gamma rays in the higher energy range is proportional to the electron density of the formation. For most geologic formations of interest in hydrocarbon exploration, electron density is related to formation bulk density (ρ_b) through a constant (Tittman and Wahl, 1965), and the bulk density is related to porosity.

The relationship that involves formation bulk density (ρ_b), formation matrix density (ρ_{ma}), formation density-derived porosity (Φ_D), and the density of the fluid (saltwater mud, freshwater mud, or hydrocarbons) in the pores (ρ_f) is expressed as:

$$\Phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \qquad (1)$$

Using Equation 1, a computer in the logging unit calculates density porosity from the measured bulk density of the formation. The matrix and fluid densities must be defined prior to density porosity calculation.

On a density-derived porosity log, gas shows as an apparent increase in porosity (decrease in bulk density) (Fig. 2, depth interval 14,035–14,080 ft, or Fig. 3, depth interval 11,253–11,368 ft). The effects of changes in fluid saturation are quantitatively predictable on the density-derived porosity log (which is calibrated from the bulk density log) due to the predictable relationship among porosity, formation density, and fluid densities (Equation 1).

Shales generally are considered to have a density close to "clean" (shale-free) sandstones. But in some cases, sandstones with interstitial clays or interbedded shales (so-called "dirty" rocks) are less dense than sandstone grains. Consequently, clays or shales in "dirty" rocks appear to produce an increase in porosity.

If the actual matrix density (ρ_{ma}) of the formation is less than the matrix density used in calculating the porosity (for example, calculating porosity of a sandstone [ρ_{ma} = 2.644 g/cm^3] using a limestone matrix density [ρ_{ma} = 2.710 g/cm^3]), then the log shows a calculated porosity higher than the actual porosity of the formation. If the formation's actual fluid density (ρ_f) is less than the fluid density used in calculating the porosity (for example, calculating the porosity of a saltwater-filled formation [ρ_f = 1.1 g/cm^3] using a freshwater value [ρ_f = 1.0 g/cm^3]), then the log shows a calculated porosity lower than the actual porosity of the formation. Because matrix-density values occupy a wider range than fluid-density values, errors in estimating matrix density have a bigger impact on the calculated porosity (Asquith and Krygowski, 2004).

It is also important to know better the matrix density (ρ_{ma}) at low porosity (~high ρ_b) than at high porosity (~low ρ_b). For example, at ρ_b = 2.6 g/cm^3, derived porosities would be ~3% for sandstone and ~6% for limestone. The porosities differ by a factor of 2 and could mean the difference in expecting commercial or noncommercial production as the threshold often is set around 5%. On the other hand, at ρ_b = 2.2 g/cm^3, derived porosities would be ~27% and ~30%, a difference of only 3%.

Combined Neutron Porosity and Density-Derived Porosity Logs

When plotted together (at the same scale and with the same porosity units), neutron porosity and density porosity logs could be used to identify gas-bearing layers. As previously stated, replacement of liquid by gas in the pore space of rocks reduces both bulk density and hydrogen content. Consequently, in a zone containing a gas-bearing layer, the density porosity log will show higher porosity, while the neutron porosity log will show a lower porosity. In that zone, the two porosity curves will intersect and cross over each other. The phenomenon is the well-known *crossover effect* that occurs on neutron-density porosity logs when they are plotted together, or when they occur as positive values on a density-neutron porosity curve (see shaded areas in Fig. 2, from 14,035 to 14,080 ft, and in Fig. 3, from 11,253 to 11,368 ft). The magnitude of the crossover (the amount of separation between the curves) is related to the gas saturation more qualitatively than quantitatively.

The true porosity Φ may be estimated by taking an average of the two log readings, or by applying the following equation (Dresser Industries, 1975; Dewan, 1983; Brock, 1986; Labo, 1986; Schlumberger, 1987):

$$\Phi = \sqrt{\frac{\Phi_N^2 + \Phi_D^2}{2}} \qquad (2)$$

where Φ_N and Φ_D are neutron and density porosities, respectively. The square-root equation may be preferred for suppressing the effects of any residual gas in the flushed zone. In the case discussed above (Fig. 2, $\Phi_D = 16\%$ and $\Phi_N = 5\%$) the formula yields $\Phi = 12\%$. Therefore, in gas-bearing zones porosity is not midway between neutron and density logs, but it is about two-thirds the way from the neutron reading to the density reading.

The crossover effect in detecting gas-bearing layers may lead to false predictions in the following situations:

a) Porosity curves are recorded based on limestone matrix (ρ_{ma} = 2.710 g/cm^3), but strata are actually sandstone (ρ_{ma} = 2.644 g/cm^3). The clue to a false gas indication during log examination is a 6–7% consistent difference between neutron and density logs. When the difference is observed, a matrix effect (i.e., different matrices recorded on the same log) should be suspected.

b) A log is recorded on sandstone matrix (ρ_{ma} = 2.644 g/cm^3) and a low-porosity, gas-bearing limestone is penetrated. The crossover effect (due to the occurrence of gas) might occur; but if it is less than 6–7%, it would not cause the neutron log to cross over the density log. (A log recorded on sandstone matrix, however, is rarely, or never, performed in the Anadarko basin.)

c) Gas is found in a dolomite matrix (ρ_{ma} = 2.877 g/cm^3). In contrast to limestone or sandstone recordings, dolomite causes the neutron log to indicate a much higher porosity than a density log, primarily because of higher dolomite density compared to limestone or sandstone densities. It is therefore possible to suppress crossover effect in gas-bearing zones. In such cases (b and c), it is important to have independent determination of lithology, such as a litho-density log.

d) A borehole wall has caverns or washed-out zones, making use of neutron porosity and density porosity logs invalid. Here, the density-porosity tool measures drilling fluid density instead of bulk density, and consequently, the displayed porosity values, as well as crossover effect, are anomalously high. False gas indications may be ruled out by looking at caliper log indications (caverns and washed-out zones are indicated by anomalously high caliper indications).

e) Mud cakes on the borehole wall, especially in boreholes drilled with barite-loaded mud, such as wells with overpressures, may appear denser than adjacent formations. In such cases the density tool will show the density too high and the porosity too low, and so the crossover effect may be drastically attenuated. A solution is to check the caliper readings (which will show a reduction of measured borehole diameter) and density corrections on the density log (which may be negative for barite-loaded mud). Such corrections are adequate up to about 0.15 g/cm^3, but not beyond that point.

f) The neutron tool tends to record high porosities in shales (the *shale effect*). The shale effect occurs when bound water and hydrogen within the clay structure are detected along with hydrogen in the pore space. The shale effect will offset the effects of gas, which tends to lower the apparent porosity. A shaly gas zone could be interpreted as a clean water zone. Also, drilling fluid invading the formation may displace gas away from the borehole beyond the range of the neutron tool. So even if the zone contains gas, the neutron tool

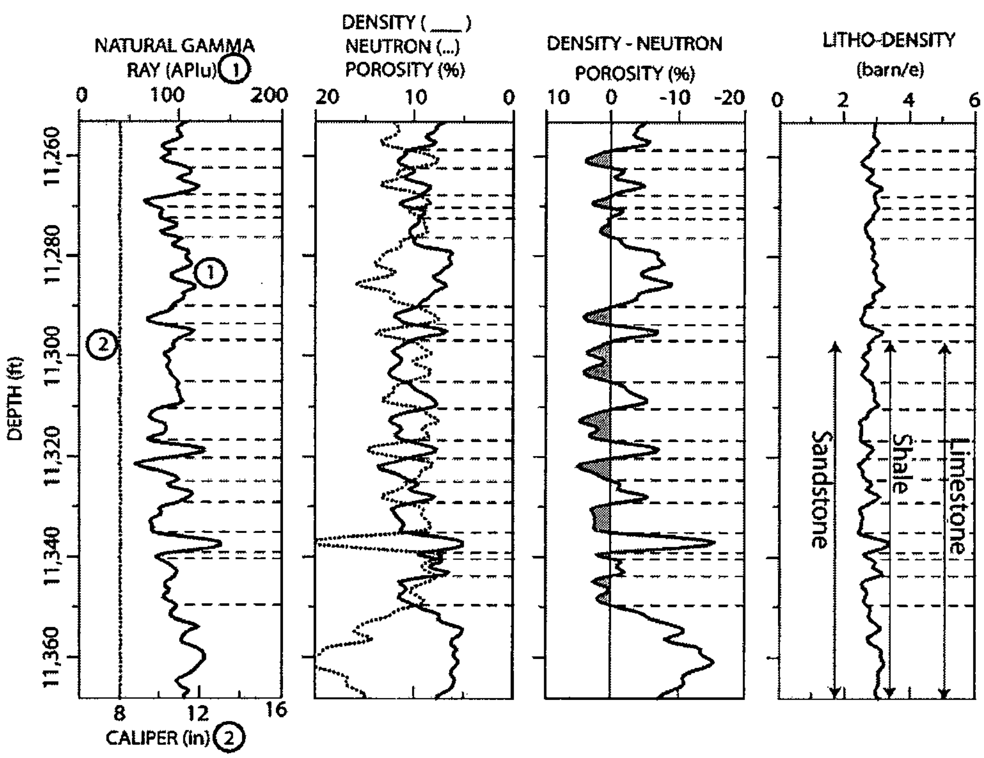

Figure 3. Well logs in Cobb 2-27 well, sec. 27, T. 15 N., R. 23 W., Roger Mills County, Oklahoma (modified from Deming and others, 2002).

may respond mostly to the filtrate. When such a situation (shaly gas zone or drilling fluid invasion) occurs, it requires a thorough analysis of the gamma ray (GR) and litho-density logs to evaluate the shale content of the formation, as well as an analysis of electric logs to determine the extent of drilling fluid invasion.

Litho-Density (PE) Log

The litho-density (PE) tool records the photo-electric factor or photo-electric absorption curve, PE (barn/electron, or barn/e) (Fig. 3). The PE curve reflects the average atomic number of the mineral or rock, and therefore is a good indicator of the type of rock matrix. PE values (in barn/e) for most common rocks and minerals are as follows (Schlumberger, 1987; Hearst and others, 2000): clean sandstone, 1.74; shaly ("dirty") sandstone, 2.70; limestone, 5.08; average shale, 3.42; dolomite, 3.14; quartz, 1.81; and barite (a drilling mud additive), 267. PE values are influenced by porosity and fluid (water or gas) content (Brock, 1986).

A major impediment occurs when using the photo-electric absorption factor (PE) to determine lithology and the presence of gas in wells drilled with barite mud. Barite has an extremely high PE (267). Barite-loaded mud inevitably will intrude between the formation and the PE tool arm (which presses against the borehole wall) so that the very high PE values of barite will swamp the formation value, rendering the PE curve useless. In areas of high formation pressure, where drillers counteract the high pressure with the heavy weight of barite mud, the limitation of using the litho-density log is severe.

Gamma Ray Log (GR)

The gamma ray (GR) logging tool consists mainly of a Geiger counter or scintillator that estimates the distribution of gamma ray emitters in rock. Two kinds of tools are used: a total gamma ray tool that counts all gamma rays without discrimination (Natural Gamma Ray log, Fig. 2 and Fig. 3) and a spectral gamma ray tool that counts the gamma rays whose energy lies in ranges corresponding to the windows of uranium, potassium, and thorium. In any case, the effect of attenuation in the rock and in the drilling fluid must be considered.

Shale-free sandstones ("clean") and carbonates have low concentrations of radioactive material so they give low gamma ray values. As shale content increases, the gamma ray log response increases, because the concentration of radioactive material (mostly potassium) in shale increases; however, "clean" sandstones also might produce a high gamma ray response if the sandstone contains potassium feldspars, micas, glauconite, or uranium-rich waters.

Limestones and anhydrite have the lowest values, 15–20 APIu; dolomites and "clean" sandstones have slightly higher values, about 20–30 APIu. Shales average about 100 APIu, but can vary from 75 to 150 APIu. Few very radioactive shales, for example the Woodford Shale (Upper Devonian to Lower Mississippian), may record 200–300 APIu (Dewan, 1983); therefore, the GR log normally separates "clean" sandstones and carbonates from shale quite nicely.

Caliper Log

The caliper log is the instrument used to determine the true size and shape of the borehole after it is drilled. The caliper log monitors changes in borehole diameter caused by environmental effects such as mud cakes on the borehole wall, cavities in the borehole wall, washed-out zones, and fractures. Information provided by the caliper log is used to validate other wireline logs by checking and evaluating suspect log values.

Definition of Terms

APIu (American Petroleum Institute unit)—The unit of radioactivity used for natural gamma ray logs. The unit is based on an artificially radioactive concrete block at the University of Houston, Texas, USA, that is defined to have a radioactivity of 200 American Petroleum Institute (API) units. The 200 APIu value was chosen because it was considered to be twice the radioactivity of typical shale. The formation is the primary standard for calibrating gamma ray logs; however, even when properly calibrated, different gamma ray tools will not necessarily have identical readings downhole because their detectors may have different spectral sensitivities. The gamma ray tools will record identical values only if the downhole formation contains the same proportions of thorium, potassium and uranium as the Houston standard.

barn—1 barn = 10^{-24} cm^2. The probability of interaction of any particle (neutron, gamma, etc.) with a single atom or nucleus is called the *cross section* for that interaction and is normally expressed in barns.

borehole breakouts—Borehole enlargements due to borehole stress concentrations.

caliper log—A well log that measures hole diameter (in inches). It is used in an open hole.

effective stress—The difference between the lithostatic stress and the fluid pressure.

filtrate—The drilling fluid that has passed through the mud cake into formation.

gamma ray (GR)—A log that records natural (gamma) radioactivity. In sediments, the log mainly reflects shale content because minerals containing radioactive isotopes (the most common of which is potassium) tend to concentrate in clays and shales. For examples, see first panel in Figure 2 and Figure 3.

litho-density log—A log that can distinguish among many minerals and rocks by recording their photo-electric factor (PEF or PE or P_e).

lithostatic stress—The stress caused by the weight of overlying rock.

overpressure—The amount by which the formation or pore fluid pressure exceeds hydrostatic or *normal pressure*.

Borehole Environment and Its Effects on Well Logging

The purpose of logging is to measure the properties of rocks and the fluids they contain. Yet drilling a borehole causes changes of *in situ* conditions, and introduces new material(s) into the borehole environment. For example, drilling fluids, having various compositions, fill the borehole and often invade, at variable lateral distances, the pore space of the rock.

All the logs described above are influenced by many factors related to the borehole environment and the drilling process: borehole size variation, washed-out zones, borehole salinity, formation salinity, mud weight, borehole temperature, mud cake thickness on the borehole wall, temperature, lithostatic stress, rock pore fluid pressure, effective stress, borehole breakouts, and borehole wall rugosity. Correction factors need to be applied to log readings before proceeding with interpretation.

The drilling company completion card recorded a gas production zone in the 14,035- to 14,081-ft interval (Desmoinesian granite wash, Middle Pennsylvanian). The presence of gas is shown by DENSITY–NEUTRON POROSITY positive values (above +10%) and does not indicate a matrix effect, which is, in general, 6–7%. Moreover, the natural gamma ray curve, with values ranging from 40 to 60 APIu, indicates that the zone is probably sandstone with some shale content (a "dirty" sandstone). The granite wash, so called by drillers, consists mainly of conglomerates eroded from the Wichita Mountains (Johnson and others, 1988). Unfortunately, the PE curve cannot be used because the Wesner 2-1 well was drilled with barite-loaded mud (see "Litho-Density (PE) Log" above). It is also true for several other wells, where P_n is higher than 0.5. P_n, normalized pressure, is a dimensionless parameter defined as a function of fluid pressure, hydrostatic pressure, and lithostatic pressure. P_n ranges from 0 for hydrostatic pressure, to 1 for lithostatic pressure (Lee and Deming, 2002). Four or five gas-bearing layers, with thickness ranging from 1.3 to 4.3 ft, have been identified (shaded layers in Fig. 2). The reader is referred to previous comments about the Wesner 2-1 well under the discussion "THEORETICAL BACKGROUND."

CASE HISTORY: COBB 2-27 WELL, SEC. 27, T. 15 N., R. 23 W., $P_n = 0.11$, FIGURE 3

The drilling company recorded the gas production zone extending from 11,257 to 11,348 ft in Prue sandstone, which is part of the Desmoinesian Cabaniss (Cherokee) Group (Middle Pennsylvanian). The difference curve DENSITY–NEUTRON POROSITY (density porosity minus neutron porosity) indicates 10 gas-bearing layers (shaded layers in Fig. 3), with thickness varying from 2 to 6 ft. The average difference between density porosity and neutron porosity is about 4%, which excludes a matrix effect as a possible interpretation for the difference. Using Equation 2, the average porosity for the 10 gas-bearing layers is 10%. The natural gamma ray curve displays values from 70 to 90 APIu for the 10 gas-bearing layers, suggesting shaly sandstone. The caliper curve (CALIPER) does not show any anomalous variation of borehole diameter, indicating a very competent rock. The density curve (not shown) indicates quite homogeneous rock with a ρ_b varying from 2.50 to 2.52 g/cm^3. The P_n value for the Cobb 2-27 well is 0.11, indicating a low barite load, and consequently the litho-density log (PE) can be used. The PE log indicates the same value, 2.50 barn/e, for nine out of 10 gas-bearing layers. The P_n value ranges from 1.74 barn/e for "clean" (shale-free) sandstone to 2.70 barn/e for "dirty" (shaly) sandstone (Schlumberger, 1987). The interpretation from all the above information is that the gas-bearing layers are found in quite homogeneous shaly sandstone with shale intercalations. The Cobb 2-27 well was used as an example by Deming and others (2002) to demonstrate the possibility of the existence of gas capillary seals in the Anadarko basin.

CONCLUSIONS

A thorough, synergistic analysis of available borehole well logs may offer a valuable approach to identify gas-bearing layers. The suite of well logs should include density porosity and neutron porosity logs to help detect the occurrence of gas through crossover effects. The logs are proxy indicators, and side effects, and side effects (described above in "Borehole Environment and Its Effects on Well Logging") may create crossover effects; therefore, one must be careful to rule out alternative interpretations. For example, in borehole sections where the diameter increases indicating washed-out zones, crossovers are created by drilling fluid in wall cavities. In this case, the caliper log reveals cavernous zones. Other logs, such as natural gamma ray, density, and photo-electric logs, can help to filter out side effects and yield more reliable information about lithology, which then enables the interpreter to predict with greater confidence the occurrence of gas-bearing layers. Finally, an extra way of checking the interpretation is to compare the gas-production intervals, as indicated by drilling company completion cards, and gas intervals, as revealed by the present interpretation using well log analysis.

The procedure described herein may be applied in other sedimentary basins where gas-bearing layers are thought to exist, and if the proper well log suite is available.

Drilling a well does not automatically ensure that one will find the oil or gas sought. In most cases, one needs to perforate the borehole wall to open gas-bearing layers, putting them in communication with extraction equipment. But how does one know in advance where to perforate? This paper offers a possible answer.

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

The Booch Gas Play in Southeastern Oklahoma: Regional and Field-Specific Petroleum Geological Analysis

Although the sandstones of the Booch Formation have produced oil and natural gas in Oklahoma since before Statehood, they continue to make a significant contribution to State production, especially gas production. The Booch produces gas across parts of eastern Oklahoma in the structural provinces of the Arkoma Basin and Cherokee Platform. Cumulative production amounts to nearly 80 million barrels of oil and 470 billion cubic feet of gas from about 2,700 wells. Dominantly a gas producer today, the 710 active Booch gas wells produce about 23 million cubic feet of gas per day.

This study of the Booch gas play is a companion to earlier work done on the Booch oil play, which was published by the OGS in 1995. The new publication includes regional discussions of the Booch stratigraphy, geologic history and petroleum system, as well as field studies for Brooken (Texanna SW) Field, Reams Southeast Field, and Pine Hollow South Field.

For the first time a compact disk is included with the publication that, in addition to a series of general oil and gas reference files, contains digital versions of virtually all of the data and interpretations that went into the compilation of this study. Digital files are included to help speed the evaluation process so that maps and datasheets can be edited or expanded for any area that an operator might consider prospective. General reference files include: (1) a listing of oil- and gas-related OGS publications, (2) an inventory of core and core analyses maintained by the OGS, (3) a document identifying public sources of Oklahoma oil and gas data, and (4) digital versions of State oil and gas production maps organized by field boundary (distinguishing coalbed-methane production) and reservoir interval. Included with the regional production maps is a complete listing of field names, locations, production types, and discovery dates.

OGS Conference

COALBED METHANE AND GAS SHALES IN THE SOUTHERN MIDCONTINENT

March 21, 2006 ❖ Oklahoma City

Coalbed methane (CBM) has been an important unconventional gas play in Oklahoma since 1988 with as many as 600 completions a year. The most successful CBM wells are where specialized completion techniques were applied with a knowledge of coal as a reservoir. The success of the Barnett Shale as a gas shale in the Fort Worth Basin in Texas has generated an interest in other potential gas shales (e.g., Woodford Shale, Caney Shale, and Fayetteville Shale) in the southern Midcontinent.

Potential topics include geology, source-rock characterization, reservoir architecture, exploration concepts appropriate to the region, methodologies and techniques for improved recovery, case studies, and current activity related to coalbed methane and gas shales. Area studies will be confined to the southern Midcontinent (Oklahoma and parts of surrounding states).

This conference will consist of 12 papers presented orally, 5 informal poster presentations, and 8 commercial exhibits. Approximately 150–200 people are expected to attend.

REGISTRATION INFORMATION

The fee for advance registration (*by March 7*) is $65 and includes lunch; late and on-site registration is $75. Students rates are available.

For more information, contact Brian Cardott (email: bcardott@ou.edu), Oklahoma Geological Survey, 100 E. Boyd, Room N-131, Norman, OK 73019; phone (405) 325-3031 *or* (800) 330-3996; fax 405-325-7069. For registration forms, contact Tammie Creel (tcreel@ou.edu) at the same address and phone numbers. The program can be accessed on the OGS Web site: **http://ogs.ou.edu.**

upcoming meetings

FEBRUARY

Oklahoma Aggregates Association, Annual Meeting, February 13–14, 2006, Oklahoma City, Oklahoma. Information: Oklahoma Aggregate Association, 3500 N. Lincoln Blvd., Oklahoma City, OK 73105; (405) 524-7680; fax 405-524-7677. Web site: http://www.okaa.org/.

MAY

Interstate Oil and Gas Compact Commission, Midyear Issues Summit, May 21–23, 2006, Billings, Montana. Information: IOGCC, P.O. Box 53127, Oklahoma City, OK 73152; (405) 525-3556; fax 405-525-3592; e-mail: iogcc@iogcc.state.ok.us. Web site: http://www.iogcc.state.ok.us.

JUNE

Annual Forum of Coal Geologists, Western Interior Coal Basin, June 5–7, 2006, Poteau, 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.

National Minerals Education Conference, June 25–28, 2006, Oklahoma City, Oklahoma. Information: Stan Krukowski, 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: skrukowski@ou.edu. Web site: http://www.ogs.ou.edu.

Candidate Selection for Horizontal Drilling with Case Studies in Osage and Tulsa Counties, Oklahoma

More than 95 attendees participated in a one-day workshop held July 27 in Norman, Oklahoma, which evolved from a DOE-sponsored horizontal waterflood project in Osage County. Grand Resources, Inc. in Tulsa manages the U.S. Department of Energy project. The horizontal drilling operations for this DOE project have been conducted by Grand Directions, LLC, a wholly owned subsidiary of Grand Resources, Inc. Bob Westermark, president of Grand Directions, shared their experiences in conducting this project to date, emphasizing the need for a team approach in planning a horizontal well project.

Planning is a critical phase for drilling oil and gas wells, but this has become routine for most active operators. However, planning an economically successful horizontal well requires a strong technical team reviewing detailed aspects of geology and engineering that are not generally considered in drilling vertical wells. The workshop material reviewed the candidate selection process for drilling horizontal wells for improved primary and secondary recovery. Current available horizontal drilling options were discussed with the focus on medium- and short-radius techniques. In wrapping up the workshop, four other field case studies of horizontal wells in Tulsa and Osage Counties, Oklahoma, were summarized.

The workshop addressed the following questions:

How do I determine which of my reservoirs are valid horizontal well candidates?

Collect sufficient reservoir and production data to be able to build a computer model of the reservoir. Perform history matching to gain confidence on the simulation results. Predict the production effects of various horizontal completions options to determine the most reasonable approach to applying horizontal wells to accelerate reserve recovery.

How do I choose which horizontal drilling system is appropriate for my reservoir?

An engineering assessment of the completion techniques necessary to economically recover the reserves will largely determine if the horizontal well can be an open-hole completion or will require tubulars placed in the curve and/or in the horizontal sections. The critical issue is wellbore stability and the need for zonal isolation to construct a low-maintenance, long-life completion.

What are the costs associated with drilling horizontal wells using various drilling systems?

Based on studies of more than 25,000 horizontal wells worldwide, an expert has recognized key relationships between horizontal and vertical well costs.

- One third of horizontal wells are not economic successes.
- When the cost ratio for a proposed horizontal well approaches or exceeds 2.5 to 3.0 times the cost of a vertical well in the same field, the chances for an economic success are greatly reduced.

This means when evaluating the cost benefit of the horizontal candidate, if the proposed drilling and completion design costs are approaching 2.5 to 3.0 times the cost of a typically completed vertical well in the field, there is very little room for error and proceeding with assumptions rather than data can become very costly.

Do you need to drill a new well or can you use an existing well?

No, many techniques are available to use existing vertical wells and exit through the casing. Depending on the completion techniques required, the costs for using existing wells compared to new wells will generally favor existing well utilization. However, geologic considerations and current reservoir data collection opportunities must be weighed carefully with any potential cost savings.

Will an open hole provide a satisfactory completion technique?

This is determined by understanding the long-term borehole stability issue associated with the candidate reservoir. This issue is critical in determining the answer to open-hole completions versus installing casing or liners in the curve or lateral sections.

How can your drilling and completion operation minimize formation damage?

Overbalanced or poorly designed/maintained drilling fluids will cause excessive formation damage. The lower the bottomhole pressure (BHP) of the target reservoir, the more difficult it is to mediate any damage caused from the drilling and completion process.

Underbalanced drilling, when properly conducted, will help to minimize formation damage reducing or eliminating remedial action required to restore wellbore productivity. The drilling fluids needed for underbalanced operations are determined by reservoir BHP. For low BHP situations, air or air mist/foam drilling may be required.

If you choose to drill underbalanced, can you safely drill with air?

Air drilling oil and gas wells has been an accepted industry practice for more than 60 years. Grand Directions has been drilling with an air mist/foam system for the last 3 years with no safety problems. However, many organizations/individuals are concerned with downhole and or surface fires, and therefore require additional procedures to mitigate this safety concern.

What kind of rig is necessary to drill horizontal wells?

When new wells are planned to be drilled horizontally, the drilling rig usually is employed to drill both the vertical and horizontal portions of the wells. However, depending on the equipment requirements for the curve and lateral sections, a smaller (less costly) workover rig may be moved in after the drilling rig has completed the vertical section.

When existing wells are to be used for horizontal completions, often a workover rig can be outfitted to handle the physical requirements of the operations less expensively than employing a drilling rig to do the work.

How do you determine and control the actual direction and location of the wellbore?

This is a two-pronged question:

1. How to determine the best direction to drill is determined by a thorough study of the geologic deposition, structural history, and the reservoir fluid flow patterns resulting from withdrawal and injection activities. The size of the target and any spatial constraints associated with the target must be determined and specified in the well-path plan.

2. How to control well-path direction is the realm of the drilling operations. Many improvements in the directional surveying and tool-steering services have occurred in the past 15 years. Generally, the tighter the need for wellbore placement control, the more expensive the process.

Can you run open- and cased-hole logs in horizontal wells?

The idea of drilling horizontal into a known reservoir should produce open-hole logs of consistent petrophysical measurements. This has not been the experience most people have had with regards to open-hole logs from horizontal wells. When fracture identification and orientation with respect to the well bore are critical to the productivity of the horizontal well, open-hole logs become keystone to the horizontal well project.

For example, understanding the injection profile of a horizontal injection well proved invaluable in reconfiguring the DOE pilot horizontal waterflood.

If necessary, how do you stimulate horizontal wells?

Many horizontal wells drilled today in the various "oil shale" plays in the USA require massive hydraulic fracture stimulation treatments, often costing as much as the horizontal section of the well. The wells must be drilled and completed with this in mind, as this is the technique that has evolved in a particular basin, providing the most economical cost-benefit ratios. Designing horizontal well fracture stimulation was beyond the scope of this workshop; therefore, it was not discussed.

—*Bob Westermark*
Grand Directions, LLC

Log Interpretation Workshop a Popular Choice

Eighty-nine individuals participated in the Log Interpretation Workshop held September 21 in Norman, Oklahoma. This event was cosponsored by the Oklahoma Geological Survey and the South Midcontinent Petroleum Technology Transfer Council (PTTC). The course presenter was John Doveton from the Kansas Geological Survey. The course began with an overview of the alternative sources of wireline log data, either as hard-copy paper records or in digital form as either scans (raster) or as numerical data (vector) on LAS files. The course presentation alternated between a PowerPoint sequence of slides keyed to the course manual interspersed with interactive demonstrations of spreadsheet functions for log analysis using Excel. Excel can be applied as a log-analysis method to both curve numbers transcribed by hand from paper copies or from LAS files read directly by Excel. A course manual was supplied to participants together with a CD-ROM containing the spreadsheet workbook *The Log Analysis Yellow Pages*, and three example LAS log data files. The *Yellow Pages* workbook is intended both to aid participants in their understanding of log analysis and also as simple freeware templates to apply to their own logs. The example LAS files contained logging data from reservoir sections of the Oil Creek Sandstone, Viola Limestone, and a Pennsylvanian oomoldic limestone.

The manual and its presentation provided participants with training in basic petrophysical concepts and a review of resistivity, SP, photoelectric index, neutron, density, and sonic porosity logs. Methods to estimate true volumetric porosity were described that accommodate changes in lithology as well as the effect on gas. The Archie equation was demonstrated with a variety of reservoir lithologies in the determination of water saturation. Extensive discussion was made of interpretation methods keyed to estimating water-cut of potential productive zones based on log indications of pore size from bulk volume water values. The course differed from a traditional log analysis course because of its emphasis on the use of spreadsheet software instead of chart book procedures and calculators. Almost all students and recent graduates of universities are already proficient in spreadsheet usage and so are well advanced on the learning curve to their application to log interpretation. Professionals with many years of experience in industry may have had limited exposure to spreadsheet methods, but these skills can be acquired easily in courses at local colleges in continuing education programs. In summary, the course provided participants both a basic understanding of log analysis and the software methods appropriate to a PTTC target audience of small independents and individuals working within the energy industry.

—*John Doveton*
Kansas Geological Survey

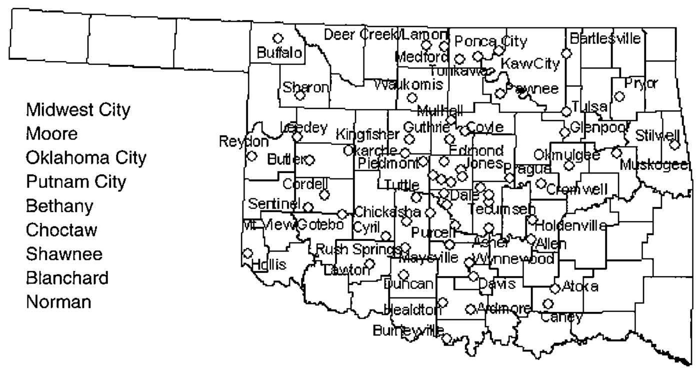
OGS Participates in Earth Week Activities, April 18–24, 2005

The Oklahoma Geological Survey (OGS) participated in Earth Week activities at the Oklahoma City Zoo (OCZ) in Oklahoma City, and Reeves Park in Norman on April 21 and April 24, respectively. OGS was Station No. 13 at the Oklahoma City Zoo where Oklahoma school children learned about the recovery and restoration of earth resources through a hands-on exercise called Birdseed Mining. Geologists Stan Krukowski and Galen Miller conducted the exercise with the assistance of Sue Crites, OGS public relations coordinator. Also in assistance were several students in Sigma Gamma Epsilon (the Earth Science Honor Society), Gamma Chapter, from the School of Geology and Geophysics at the University of Oklahoma.

ScienceFest is an annual Earth Week event at OCZ and is a day of interactive science and environmental activities focusing on the conservation of natural resources and the use of alternative energies. Nearly 4,600 4th- and 5th-grade students were in attendance at ScienceFest 2005, representing 171 classes from across the State of Oklahoma. Students participated in 27 different activity stations that explored many topics in science including such diverse subjects as geology, biodiversity, the environment, soil science, water chemistry, and physics.

Sponsors of ScienceFest 2005 were OGE Energy Corp., Oklahoma Department of Environmental Quality, Oklahoma Department of Commerce, and Oklahoma Office of the Secretary of the Environment. Activity stations were manned by scientists, engineers, and technicians from 20 agencies and organizations. They hosted groups of students at their respective booths and presented instruction and information on specific scientific topics. Students were able to view alternative fuel vehicles, increase their knowledge of the sciences, and stimulate their interest in science, which may lead them to pursue science and engineering careers.

OGS conducted Birdseed Mining at its activity station, teaching students the importance of using Earth resources



Schools registered to attend ScienceFest 2005. Figure courtesy of ScienceFest 2005 (http://www.sciencefestok.com/schools.htm).

in a responsible manner. OGS estimated that up to 600 students participated in the Birdseed Mining exercise. The principles of sustainable development in resource development and mining operations were emphasized, demonstrating the roles of all stakeholders, including miners, nearest neighbors, the environment, government regulators, non-government organizations, and consumers. The OGS station included poster displays of mining and reclamation activities, and consumer demands for Earth resources. Many hundreds more students, teachers, and chaperones visited the poster display and exhibit. Students visiting the OGS activity station and exhibit also collected samples of crushed fossiliferous limestone (approximately 700 lbs) that was donated by the Dolese Bros Co of Oklahoma City.

Teachers received packets of teaching aids and classroom exercise materials from the various sponsors, agencies, and organizations. OGS distributed information on industrial minerals and energy resources of Oklahoma, including several OGS classroom activities and exercises, as well as the video *Common Ground* and the CD *Adventures in Earth Science Education*, both from Caterpillar Inc. The latter provide a series of classroom activities in minerals education for grades K–12 that focuses on mining, minerals, and coal.

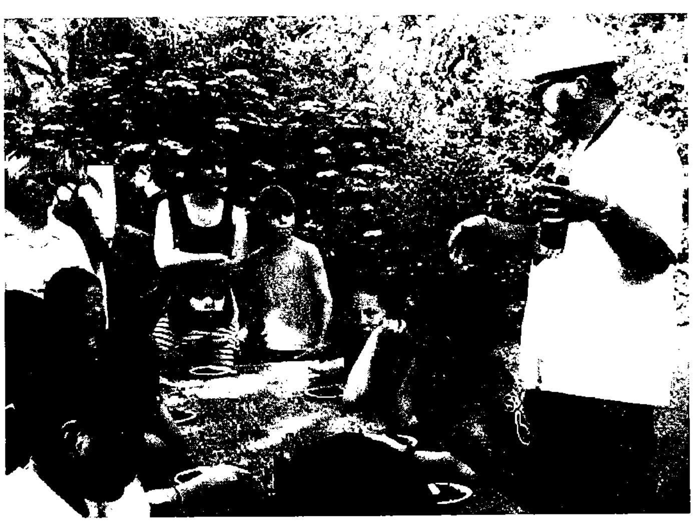
On April 24, OGS also had an activity station at Reeves Park in Norman, where it participated in

(Above) Oklahoma Geological Survey Birdseed Mining activity station prior to the student horde.

(Right) Middle school students dig into the fossiliferous limestone cache to retrieve ancient Oklahoma fossil treasure.

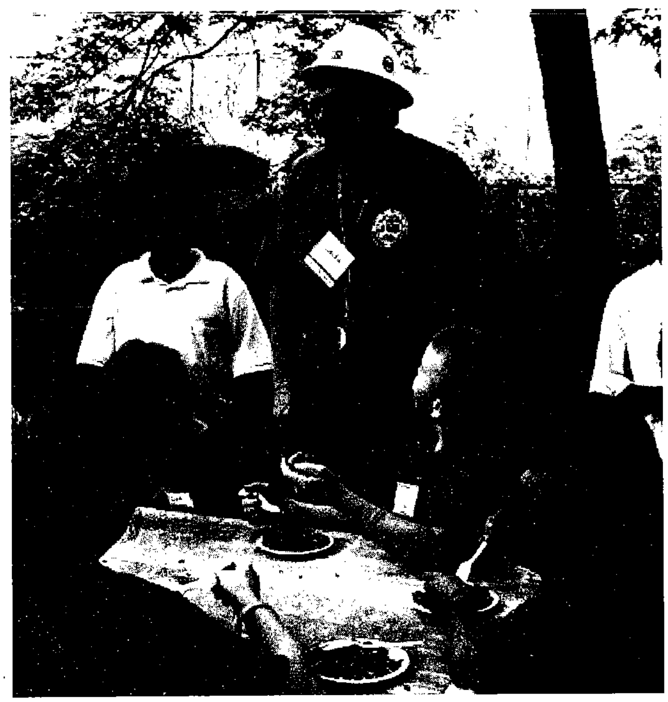
OU graduate student Tamieka Searcy demonstrates the finer points of birdseed mining to ScienceFest 2005 participants.

the Little River Zoo's Kids for Kindness Earth Day Festival. The event was celebrated in conjunction with Earth Week and Arbor Day activities. The same cast from ScienceFest 2005 manned the OGS booth with the addition of Michelle Summers, OGS technical project coordinator. Kids for Kindness is a program designed to encourage children to actively protect and care for animals and the environment. More than 30 community booths taught children the principles of humane education with the purpose of connecting children with the natural world. Activities included worm composting, creating backyard habitat, recycling, and many others. The day was planned for children from pre-school to middle school, so OGS activities were adjusted appropriately. Both parents and children participated in birdseed mining at the OGS booth during Kids for Kindness day.



OGS geologist Stan Krukowski making a point about sustainable development and use of natural resources to teachers, parents, and students.

Birdseed Mining is an activity that was modified from the *Adventures in Earth Science Education* CD, and used at the OGS booth for the Earth Week activities. Appropriate mineral wealth, in this case costume jewels, was placed in a small pile of birdseed along with candy treats (M&Ms® or Skittles® work well) and a "googly" eye. Students were given the task of mining for jewels and candy (mineral resources) without spilling birdseed from a 4-inch plate. Spilling birdseed meant that they went outside the mine permit area and so they consequently were shut down by the mine inspector; finding a "googly" eye (a mine accident) had the same result. Students in either of the latter categories were given candy consolation prizes. At the end of the mining period (30 seconds) students could eat their excavated candy (consume the mineral resource) before reclamation, which consisted of restoring the birdseed to its original stockpile cone on the 4-inch plate. A question-and-answer period followed stressing the principle of sustainable development and the environment.



OGS geologist Galen Miller reacts to the enthusiasm of birdseed miners during ScienceFest 2005.

The Oklahoma Geological Survey also participated in Earth Week activities at the Lakeview Elementary School, a Norman, Oklahoma, public school. The OGS prepared student and teacher packets with educational materials such as teachers' aids, lesson plans, and classroom activity worksheets that emphasized earth science, environment, and mineral resources.

The Oklahoma Geological Survey activities were sponsored in part by the Petroleum Technology Transfer Council, Dolese Bros Co, and the Oklahoma Conservation Commission.

—*Stanley T. Krukowski*

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.

Capillary Sealing as an Overpressure Mechanism in the Anadarko Basin

CONSTANTIN CRANGANU and *MARIA A. VILLA*, Dept. of Geology, Brooklyn College, 2900 Bedford Ave., Brooklyn, NY 11210

The Anadarko Basin in southwestern Oklahoma is known to contain today areas of extensive overpressures (pressures higher than hydrostatic pressure). Explaining the origin and maintenance of overpressured pore-fluids in the basin over long periods of time cannot be achieved by invoking classical, common causes, such as compaction disequilibrium or gas generation. We propose a capillary sealing mechanism that is responsible for both generating and maintaining almost all overpressure observed today in the Anadarko Basin. Capillary sealing occurs in a sedimentary basin when capillary forces act at gas-water interfaces between coarse- and fine-grained clastic rocks. Detecting capillary seals and estimating the magnitude of their pressure sealing implies two main aspects: (1) measuring the pore throat radius of coarse- and fined-grained clastic rocks, and (2) detecting the presence of gas-bearing layers using geophysical logs and other data. Measurements by injecting mercury into rock pores allow estimation of the pore throat radii controlling the capillary sealing. 21 fine-grained rock samples from the Anadarko Basin were thus measured and the average pore throat radius was found to be 2.5×10^{-8} m. The proposed model also requires the presence of gas-bearing layers interbedded into shale layers. Using a suite of geophysical logs from more than 100 wells, we were able to identify such gas-saturated layers in more than 50 wells. Further calculation indicates that a capillary sealing mechanism in the overpressured area of the Anadarko Basin may produce ~40 MPa of pressure, or ~80% of the maximum observed overpressure in the basin.

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Controls on Hydrocarbon Entrapment and Reservoir Distribution: The Pennsylvanian Oswego Limestone and Big Lime Limestone in the Putnam Field Area, Anadarko Basin, Oklahoma

JAMES R. GEARY, Anadarko Petroleum, P.O. Box 1330, Houston, TX 77251; and *STACY ATCHLEY*, Dept. of Geology, Baylor University, P.O. Box 97354, Waco, TX 76798

Putnam Field, located along the northern margin of the Anadarko Basin and extending through Custer and Dewey counties in western Oklahoma, USA, has produced over 400 BCF and 13 MMBO from the Pennsylvanian (Desmoinesian) Oswego Limestone and Big Lime. Hydrocarbons are stratigraphically trapped within phylloid algal mound complexes that are isolated within shallowing-upward parasequence sets; mound complexes generally trend west-east across the study area parallel to the northern structural margin of the Anadarko Basin. Reservoir quality within phylloid algal mounds is controlled by variations in the abundance of moldic, vugular, and fracture pore types (average porosity = 2%, median permeability = 0.2 md). Eleven parasequence sets occur within the study interval and from the section base to top stack progradationally within the Oswego Limestone, and aggradationally to retrogradationally within the overlying Big Lime. The change from progradational to retrogradational stacking of parasequence sets most likely reflects an accelerating rate of subsidence during deposition that was induced by thrust-loading along the Ouachita foldbelt. Furthermore, retrogradational stacking within the Big Lime suggests that undiscovered hydrocarbon reserves may exist updip (northward) of the Putnam Trend in slightly younger deposits. Detailed maps of structure, facies, gross pay, and pore volume were generated for each parasequence set, and compared with the spatial distribution of producing wells and their associated drainage radii. From these attributes, a geologic risk assessment was completed across the Putnam Trend to determine the most prospective areas for future step-out development.

Reprinted as published in the American Association of Petroleum Geologists *2005 Annual Convention Abstracts Volume*, v. 14, p. A50.

Improving Recovery from Heterogeneous Clastic Reservoirs Using Borehole Image Sedimentology: Morrow Formation (Lower Pennsylvanian), Anadarko Basin, Oklahoma, U.S.A.

P. ZARIAN, *R. D. BLUMSTEIN*, and *S. A. LOMAS*, Baker Atlas, 17015 Aldine Westfield, Houston, TX 77073; and *T. A. VANDEVEN*, United Oil Corporation, 1801 Broadway, Denver, CO 80202

The Morrow Formation gas reservoirs on the northwestern shelf of the Anadarko Basin are an instructive example of fluvial to shallow marine clastic systems (incised valley fills, estuarine, deltaic to open marine) characterized by a very high degree of lateral and vertical variability. A major challenge to exploration and production of the Morrow sandstones is the subsurface mapping of the reservoir sand-bodies, whose apparent discontinuity and facies heterogeneity make them generally unamenable to conventional log-based well-to-well correlations.

Our multi-well integrated analysis demonstrates borehole image sedimentology as an approach to create geological models based on specific observational criteria from resistivity borehole images. The wireline log responses of the Morrow sands lack distinctive characteristics for confident discrimination between different sand-body types. However, the high-resolution detail afforded by borehole imaging technology allows recognition of sedimentary features (e.g. bioturbation, scours, cross bedding, style of sand-on-sand contacts) and vertical stacking which can be used as criteria for facies-based differentiation of distinct depositional sub-systems (e.g. fluvial

channel-fill, splay, marine bar, shoreface). In this way, the significance and potential continuity of sandstones encountered can be assessed deterministically, enabling prediction of fairways of productive sand facies.

The case-studies reservoirs discussed here were investigated in great detail using borehole image analysis to predict systematic down-dip facies distributions, paleotransport directions and sediment body geometries, which ultimately reduces geological uncertainty and thus facilitates decision-making for drilling and completion of future wells.

Presented at the 2005 AAPG International Conference and Exhibition, Paris, France, September 11–14, 2005. Abstract can be accessed online at http://aapg.confex.com/aapg/paris2005/techprogram/A99521.htm.

Influence of Accommodation Space on Distribution of the Upper and Lower Skinner Sandstone Reservoirs in Oklahoma

JIM PUCKETTE, School of Geology, Oklahoma State University, 105 Noble Research Center, Stillwater, OK 74078; and *LARRY GERKEN*, GeoPLUS Corporation, 8801 S. Yale, Suite 380, Tulsa, OK 74137

The Skinner sandstones, Pennsylvanian (Desmoinesian) Cabaniss Group, produce large volumes of oil and gas in central and western Oklahoma. To develop a better understanding of the processes controlling sand deposition, the Skinner interval was reinterpreted within a sequence stratigraphic framework instead of the traditional lithostratigraphic one. The new stratigraphic framework is based on the premise that dark "hot" (radioactive) shales represent maximum flodding surfaces (MFS) and that the basal contacts of deeply incised channels represent sequence boundaries.

Based on these caveats, the Skinner interval contains two primary sequences, the lower and upper, respectively. Within the sequence stratigraphic framework, the traditional Lower Skinner interval appears to be part of the Upper Pink sequence. The Lower Skinner sequence boundary is represented by the erosional contact between fluvial-dominated incised valley fills and the underlying Pink limestone or "Skinner" shale. The upper boundary for the Lower Skinner sequence is the base of the Upper Skinner sandstone. Valleys that form the sequence boundaries formed during drops in sea level. Sand accumulation in these valleys occurred during the lowstand systems tract (LST) and the transgressive system tract (TST).

Coal-forming peats with widespread distribution apparently were deposited during the TST. With continued transgression and deepening water, disaerobic conditions dominated and dark-colored mud accumulated that ultimately became the "hot" shale markers, which are identified as the MFS. Faunal and mineralogical evidence in these shales supports their interpretation as deeper-water deposits. During the highstand systems tract (HST) delta progradation dominated deposition. Large volumes of sediments were carried into the Anadarko and Arkoma basins. Subsidence, which was approximately equal in both basins early in Skinner time, slowed in the Arkoma Basin prior to Upper Skinner deposition. In contrast, rapid subsidence created new accommodation space in the Anadarko Basin. As a result, Upper Skinner fluid systems flowed westerly around the southern end of the Nemaha positive area and into the Anadarko Basin.

Channel-fill complexes in both the Upper and Lower Skinner sequences contain reservoirs that produce large volumes of oil and gas. On the Northeastern Oklahoma Platform, incised valley fill reservoirs in the Lower Skinner sequence can produce in excess of 400 thousand barrels of oil (MBO) per well. In the Morewood trend of western Oklahoma, individual wells in the Upper Skinner channel trend have produced in excess of 6 BCF and 100 MBO.

Reprinted as published in *The Meeting Program for the 2005 AAPG Mid-Continent Section Meeting*, p. 35–36.

Pre-Pennsylvanian Paleocanyon in a Portion of McClain County, Oklahoma: Implications for Deese Oil and Gas Production

STEVE HADAWAY and *SURINDER SUHAI*, School of Geology, Oklahoma State University, 105 Noble Research Center, Stillwater, OK 74078

The Golden Trend oil field is located on the north flank of the Arbuckle mountains, the east flank of the Anadarko basin, south of the Nemaha Ridge and just to the west of the Pauls Valley Uplift. This field has produced 84 million bbls of oil and 1 TCF of gas since 1979. The Deese interval has produced 34 million bbls of oil and 119 bcf of gas. The study area is in Township 5N Range 3W in McClain County, Oklahoma, and has produced more than 1.3 million bbls of oil and 14 bcf of gas from the Deese interval.

The study consisted of examination of well logs, mud logs, completion reports, Lasser production data, available seismic and previously published work in the area. The Deese interval contains limestones and sandstones. But most of the production comes from sandstones, many with fining upward sequences. Log signatures indicate deltaic deposition of the Deese strata. The dominant feature in the study area is a paleocanyon trending approximately north-south. The canyon was identified by the lack of Tulip Creek to Caney strata in well logs. The imprint of this pre-Deese canyon can be seen in Deese structure maps. The best production in the area is located south and southwest of the canyon. In the deeper portions of the canyon there are only two wells that have significant production. However, there is significant production on the southeast and northwest flanks of the canyon. The best production can be found in the deltas emptying into the canyon.

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A Dynamic Model for the Permian Panhandle and Hugoton Fields, Western Anadarko Basin

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Panhandle-Hugoton, the largest North American gas field, has long been controversial because of extreme subnormal pressures, variable gas composition, and "tilted" fluid contacts, commonly attributed to hydrodynamic flow despite the absence of an effective up-dip aquifer. These anomalies are addressed in terms of a basin-scale petroleum system history, largely independent of the geographically underlying pre-Permian system.

Hydrocarbons were already being generated in the deep Anadarko basin duringthe Early Permian, with efficient southward migration from all potential source rocks via bounding faults and Pennsylvanian–Permian alluvial fans. Giant Amarillo uplift drape structures trapped hydrocarbons immediately following Permian evaporite deposition. The pre-Laramide Panhandle field, at maximum pressures of 1500–2500 psi, contained most of the oil and gas now found in Mid-continent Permian reservoirs.

The Early Tertiary Laramide orogeny redistributed Panhandle field fluid columns, possibly spilling gas into the Hugoton embayment. Subsequent erosion of Permian reservoir facies in eastern Kansas allowed water discharge to outcrops at elevations below the regional hydraulic head. As regional pressure dropped in response, the Panhandle field gas cap expanded rapidly, forcing a Late Tertiary–Quaternary mass movement of gas northward to fill Hugoton and associated fields.

Panhandle-Hugoton pressures, upon discovery, were subnormal relative to drilling depth but normal relative to reservoir outcrop elevations in eastern Kansas, indicating that pressures are controlled by aquifer communication with the surface rather than burial depth. Variations in fluid contacts, pressure, and gas composition suggest that reservoir fluids are still moving, driven by decompression and the rapid volumetric expansion of a supergiant gas accumulation.

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CO_2 Sequestration, Petroleum Accumulation, and Groundwater Flow in Kansas: A Regional Assessment

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There is a growing experience with CO_2 disposal in deep saline aquifers. These aquifers hold promise in terms of storage capacity and proximity to emission sources to sequester geologically large quantities of carbon. Large, regional-scale open aquifers with good top seals (very low permeability layers) and extremely low rates of fluid migration can provide effective sequestration through hydrodynamic trapping. The Lower Paleozoic (Cambrian to Mississippian) aquifer systems in Kansas, Missouri, and Oklahoma comprise the Western Interior Plains aquifer system, one of the largest regional-scale saline aquifer systems in North America. Understanding hydrologic conditions and processes of this aquifer system provides insight to evolution of the various sedimentary basins across Kansas, migration of hydrocarbons out of the Anadarko and Arkoma basins, distribution of Arbuckle petroleum reservoirs across Kansas, and a basis to evaluate CO_2 sequestration potential.

The Cambrian and Ordovician stratigraphic units form a saline aquifer that is in hydrologic continuity with the freshwater aquifer of the Ozark Plateau, providing an explanation for the under pressure within the Arbuckle Group. However, large-scale fluid movements provided hydrodynamic traps for hydrocarbons, and the opportunity to sequester large quantities of CO_2. Using relational databases and geographic information systems estimated sequestration potential is generated for each square mile of the lower aquifer (Arbuckle Group) for the entire state of Kansas. Under any reasonable set of assumptions, the amount that could be stored in the Arbuckle Group by either displacement or dissolution is large and amounts to many years of United States CO_2 emissions.

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Depositional Model and Distribution of Marginal Marine Sands in the Chase Group, Hugoton Gas Field, Southwest Kansas and Oklahoma Panhandle

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Since the 1930's, the Hugoton Gas Field of southwest Kansas and the Oklahoma panhandle has produced approximately 29 TCF from the Wolfcampian (Lower Permian) Chase Group. The rocks of the Lower Permian Chase Group were deposited on the broad shallow shelf of the Hugoton Embayment of the Anadarko Basin. Important reservoir lithofacies are dolomitized grainstone, carbonate packstone and grainstone, and marginal marine sandstone. In the Hugoton Field, marginal marine sandstone lithofacies comprise a significant portion of the reservoir volume, but are not well characterized. In many of these very fine grained sandstones, porosities range from 15–25% and have permeability in the 10–100 millidarcies range, making them excellent storage and flow units. The sandstones of the Herrington, Winfield, and Towanda Limestones and the Holmesville Shale are at the top and base of the marine portion of glacio-eustatic driven, marine-nonmarine cycles. Based on sedimentary structures, stratigraphic context (position within the marine-nonmarine cycles) and depositional geometry (broad, relatively thin sheets), these sandstones are interpreted as deposits of tidal flats to shallow subtidal environments of the upper shelf.

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Overview of the Hugoton Asset Management Project, Southwest Kansas and Oklahoma Panhandle

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The Hugoton Asset Management Project (HAMP) is a two-year industry–Kansas Geological Survey study of the reservoir systems in the Hugoton Embayment of the Anadarko Basin with modeling the Permian gas reservoir systems and developing a digital field catalog for the pre-Permian reservoirs as primary objectives. The project is a collaboration between the Kansas Geological Survey and nine industry partners designed to provide the knowledge and technical base required for intelligent stewardship, identification of new opportunities, and continued improvement in recovery strategies.

The Hugoton and Panoma Fields, North America's largest, produce from the Wolfcampian Chase and Council Grove groups, respectively, and have yielded 34 TCF gas in Kansas and Oklahoma since the 1930's, an estimated 67% of original gas in place. Remaining gas in this giant stratigraphic trap is mostly in lower permeability pay zones of the 550-foot thick, layered reservoir system consisting of thirteen fourth-order marine-nonmarine sequences.

Direct estimates of water saturation by electric logs are not possible due to deep filtrate invasion. Lithofacies-controlled petrophysical properties dictate gas saturation and accurate discrimination of lithofacies reduces error in predicted permeability and gas volume. The use of neural networks to predict lithofacies at wells, automation and stochastic modeling make it possible to develop robust geologic models for the giant reservoir. Integration of core and log petrophysics with the geologic model provides an accurate static engineering model. Numerical reservoir simulations validate the static model and help identify higher pressure, under produced intervals in the layered reservoir system and forecast future production rates.

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Accommodation Model for Wolfcamp (Permian) Redbeds at the Updip Margin of North America's Largest Onshore Gas Field

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Red siltstones and paleosols are the lateral seal of the mid-continent U.S. Hugoton and Panoma Fields. They dominate the western updip margin of stacked, gas-productive, marine-nonmarine sedimentary cycles (Lower Wolfcamp). Principal flow units are shoaling-upward carbonates deposited during high sea level on a low-relief shelf (Hugoton Embayment of Anadarko Basin). Carbonate units thin to the northwest (factor of four) and are interbedded with reciprocally thicker continental red siltstones that thin oppositely across the shelf (also by a factor of four). Climate changes (arid-humid and prevailing wind direction) and sea-level fluctuation associated with glacial-interglacial cycles, shelf geometry, and proximity to silt source (Ancestral Rockies) are intricately related in an accommodation model for siliciclastic-carbonate cyclic sedimentation on the low-relief shelf.

Large-scale patterns in a 3D subsurface model and sedimentary structures in core support two accommodation mechanisms for thick siltstones. Dominant siltstone facies are mottled and massively bedded (to 3 meters). Layering, either absent or very faint, vertical root traces (to 20 cm long) and well developed Bk paleosol horizons (caliche) suggest an eolian origin for these siltstones (loessites) where silt was trapped and stabilized by vegetation well above a water table during low sea level. Less widespread, but still important, is silt that was trapped at the top of the capillary fringe of a rising water table tied to rising sea level. This mechanism is indicated by adhesion structures in close association with sabkha sedimentary structures. Positive relief on loessites may have reduced accommodation for marine carbonates at the updip field margin.

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Geologic Model for the Giant Hugoton and Panoma Fields

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The Hugoton and Panoma Fields, North America's largest, produce from thirteen fourth-order marine-nonmarine sequences of the Wolfcampian Chase and Council Grove groups, respectively. The degree of heterogeneity, large volume to be modeled, and an immense data set made developing a geologic model by conventional methods impractical. Geostatistical methods (artificial intelligence and modern modeling software) and automation facilitated building a finely detailed 3D cellular geomodel using a four step workflow: (1) define lithofacies in cores and correlate lithofacies to electric log curves (training set), (2) train a neural network to predict lithofacies, (3) predict lithofacies at non-cored wells with trained neural network, and (4) predict lithofacies between wells using stochastic methods to populate a three dimensional cellular model. A fifth step is to populate the cellular model with lithofacies associated petrophysical properties and fluid saturations for volumetric analysis and numerical simulation.

The lithofacies spectrum was split into eight marine and two nonmarine lithofacies primarily based on texture and grain or pore size. Marine carbonates and sandstones are the principal reservoir facies in both the Chase (Hugoton) and Council Grove (Panoma). Two lithofacies unique to the Chase, dolomitized coarse-grained grainstones and fine-grained marginal marine sandstones, are the dominant storage and flow lithofacies in the Chase. Grainstones, packstones, wackestones and fine-crystalline dolomites are the dominant reservoir lithofacies in the Council Grove and contribute significantly in the Chase as well. Other marine lithofacies, siltstones and mudstones, and nonmarine lithofacies, coarse siltstones and shaly siltstones, provide some storage especially when high in the gas column.

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Reservoir Pressures Suggest Communication Between Hugoton and Panoma Fields and Provide Insights on the Nature of the Connections

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Analysis of Hugoton and Panoma pressure through time and pressure versus cumulative production at well to field scales suggests the vertically stacked Hugoton and Panoma Fields are in communication and are one giant reservoir system. Insights on the nature of the communication are gained by comparing temporal and spatial relationships of reservoir pressure with spatial geologic variables. However, pressures by zone data support the concept that the Hugoton and Panoma are layered reservoirs with relatively low cross flow between differentially depleted zones, thus presenting a quandary.

Hugoton and Panoma Fields in Kansas have undergone three phases of development: pre-1950 Hugoton "parent" wells, Panoma wells in the 1960's and Hugoton "infill" wells in the late 1980's. Hugoton and Panoma biannual 72-hour wellhead shut-in pressure (WHSIP) through time are nearly equal and paralleling and the correlation of change in slope of pressure versus cumulative production with development phases, all suggesting communication. Dynamic visualization of the WHSIP data volume through time and space provides a novel, multi-dimensional view of subtle anomalies in reservoir pressure. Linear to sub-linear anomalous pressure regions in 3D space coincide with lineaments in the first derivative of reservoir structure that are likely related to basement fractures and faults. Mile to tens of miles scale pressure anomalies may be a result of vertical communication enhancement by swarms of small-scale vertical fractures associated with these lineaments. Though avenues for large-scale communication between Hugoton and Panoma Fields the lineament spacing may be too distant to provide complete pressure equalization between zones.

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Reservoir Engineering Studies in Hugoton-Panoma Systems

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Reservoir engineering studies, in the Hugoton Asset Management Project (HAMP), included analyses of available pressure and production data, material balance studies, and simulation of single and multiple well systems in select areas. The intent of these studies is to validate the underlying reservoir geomodel, developed by integrating inputs from geology, log analysis, petrophysics, and neural-logic based lithofacies prediction, by matching the production/pressure histories at both regional- and well-levels given the volumetrically estimated original-gas-in-place (OGIP).

Surface shut-in (SI) pressure data from Chase (parent and infill) and Council Grove wells in 2 different regions indicate that reservoir pressures declined along a common trend. However, questions remain about how representative 48–72 hr surface shut-in recordings are of average reservoir pressures. Available data also indicate that new wells at completion record 20–30 psi higher SI pressures than older neighbors but pressures soon fall inline with the regional decline trend. Material balance (MB) calculations indicate that the later Council Grove well added reserve volume beyond that drained by earlier Chase (parent) well in the same Section. Possible overlapping of drainage areas of newer wells with those of older ones limits the applicability of MB-calculated OGIP in charging the geomodel. DST permeability matches corresponding plug and whole core permeability values when corrected for sub-surface conditions. Reservoir simulation studies at Flower 1 area indicate that an upscaled geo-model of 25-layer can match differential pressure depletion, evident from layer-specific shut-in pressure data available from the Flower 1 well, while producing under historic production constraints.

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Automated Processing of Large Data Volumes for Development of the Hugoton-Panoma Geomodel

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The Hugoton Asset Management Project has focused on the development of a geomodel for the Hugoton and Panoma fields. This process has required automated processing of large data volumes at several steps, including prediction of lithofacies from geophysical well logs in numerous wells based on a neural network trained on log-facies associations observed in cored wells, generation of geologic controlling variables (depositional environment indicator and relative position in cycle) from a tops dataset, and computation of porosities corrected for mineralogical variations between facies and for washouts. In addition, we have developed code for batch processing the predicted facies and corrected porosities at the wells to estimate water saturations and original gas in place using petrophysical transforms and height above free water level, providing a quickly computed measure of the plausibility of the geomodel. The neural network code, including batch facies prediction based on logs from a large number of LAS files, has been added to an earlier Excel add-in for nonparametric regression and classification. However, the computationally intensive task of determining the optimal neural network parameters through cross-validation has been accomplished using scripts in the R statistical language. The remaining tasks have been implemented in Excel, with the controlling parameters from each process specified in a simple spreadsheet layout. Due to the data volume involved, automation of these procedures has been crucial to the development of the Hugoton-Panoma geomodel.

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Assessment of In-Situ Gas Saturation and Permeability from Logs in the Hugoton Field Based on the Physics of Mud-Filtrate Invasion

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Large discrepancies between the salinity of connate water and drilling mud are responsible for the presence of a prominent low-resistivity annulus in many of the wells drilled in the Hugoton field. This resistivity annulus suppresses the sensitivity of electromagnetic induction tools to quantify in-situ gas saturation. We give a quantitative explanation for the presence of the low-resistivity annulus based on the physics of mud-filtrate invasion.

Simulation of the process of mud-filtrate invasion in the Hugoton field is based on seven basic parameters that define the physical properties of the mud plus knowledge of the overbalance pressure. In addition, the simulation requires basic petrophysical properties such as porosity, permeability, relative permeability, and capillary pressure.

We introduce the inverse problem of mud-filtrate invasion, in which the array induction, bulk density, and neutron logs are provided and one aims at determining the underlying permeability and radial variations of gas saturation away from the borehole wall. A least-squares constrained optimization method is employed to solve the inverse problem. Array induction measurements are simulated in coupled mode with the process of mud-filtrate invasion. Automatic adjustments to permeability and fluid saturation are made until the array induction measurements are matched within the assumed noise level. An extensive analysis is performed of the accuracy and reliability of the inversion when a priori knowledge of mud properties is uncertain. Inversion exercises performed on two key wells that penetrate the Krider and Fort Riley formations, Youngren-J1H and Youngren-J2H, yield accurate and petrophysically-consistent estimates of permeability and in-situ gas saturation.

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When Seismic Is Not Enough: Improving Success by Integrating High-Resolution Surface Geochemical Data with Seismic Data

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Seismic data are unsurpassed for imaging trap and reservoir geometry, however, in many geological settings seismic data yield little or no information about whether a trap is charged with hydrocarbons. In other settings, the acquisition of seismic data is difficult and extremely costly, and quality of such seismic data is poor due to unfavorable geology or surface conditions. Detailed surface geochemical surveys document that hydrocarbon microseepage from petroleum accumulations is common and widespread, is predominantly vertical, and is dynamic (responds quickly to changes in reservoir conditions).

For this presentation we will review the results of integrated seismic and geochemical surveys (1) over East Texas Cotton Valley pinnacle reefs, (2) in the Ft. Worth basin of North Texas, and (3) from Pennsylvanian channel sandstones in Oklahoma and Texas. Geochemical data acquired over the pinnacle reefs clearly discriminated between hydrocarbon-charged reefs and reefs subsequently shown to be dry or non-commercial. In the Fort Worth Basin example, geochemical evaluation of a seismically defined Ordovician Ellenburger structural trap identified a minor microseepage anomaly associated with the Ordovician high and an areally extensive hydrocarbon microseepage anomaly over a nearby structural low. Subsequent drilling found non-commercial oil on the «high» and, more significantly, discovered a new Park Springs Conglomerate (Pennsylvanian) field in the area of the seismic «low.» The channel sandstone surveys in Texas and Oklahoma demonstrate the use of gridded microbial surveys to discriminate between charged and uncharged sandstone reservoirs.

Applications such as these require close sample spacing and are most effective when results are integrated with subsurface data, especially 3-D seismic data. The need for such integration cannot be overemphasized. Seismic data will remain unsurpassed for imaging trap and reservoir geometry, but only detailed geochemical surveys can reliably image hydrocarbon microseepage from those same reservoirs. High-resolution microseepage surveys offer a flexible, environmentally friendly, low-risk and low-cost technology that naturally complements more traditional geologic and seismic methods. Properly integrated with 2-D and 3-D seismic, their use has led to the discovery of new reserves, drilling of fewer dry or marginal wells, and optimization of the number and placement of delineation, development, or secondary wells.

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Petroleum and Mineral Resources: The Rosetta Stones of Basin Fluid Flow

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Integrating observations using increasingly sophisticated quantitative models of large spatial scale has proven effective in the quest to find and understand economic resources. Sedimentation at >2 km/Myr in the Gulf of Mexico basin drives salt and mud diapirs, and petroleum generation, migration, and venting. Because this and most other basins are giant flow-through reactors that vent almost all the petroleum that escapes their thin source strata, future petroleum supplies will be either those retained in the source (oil shales) or frozen in the process of venting (hydrates and tar sands). In general, central portions of basins can be filled entirely with gas. In active basins of low intrinsic permeability, permeability adjusts dynamically to allow the escape of fluids driven by compaction, thermal expansion, and petroleum generation. If petroleum can migrate, by buoyancy and super-hydrostatic pressure gradients faster than it is generated, the petroleum fingers through the brine, as in the Gulf of Mexico. If not, brine displacement occurs, and this is promoted by richer, thicker organic source strata, and by rapid sedimentation under hydrostatic conditions. Both fingering and displacement can be expected, and both can occur in basins that are over-pressured or hydrostatic. The Appalachian, Arkoma, and Western Canada basins are under-pressured gas-filled basins, and are also genetically associated with the extensive North American Mississippi Valley-type (MVT) Pb-Zn mineralization. The gas in these basins complicates the two currently favored hypotheses for MVT mineralization. Cross-basin gravity-driven flow is blocked by the gas, and the overpressures that could rapidly expel brine could not have existed during or after the basin filled with gas because erosion leads to overpressuring. Slow brine expulsion could produce the deposits, but their thermally anomalous nature at mineralization time and their low thermal maturity require short pulses of rapid brine expulsion. We do not understand how such pulses can be produced. The intertwining of organic and inorganic materials and fluids in forming resources means that resources reflect changes that impact living organisms. Economic geology will continue to be a scientific window to the most interesting and important aspects of the Earth's past and future.

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Turbidite Facies Analysis Through Integration of Electrical Images with Openhole Logs, Mudlogs and Map Data, Red Oak Field, Oklahoma, U.S.A.

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Integration of electrical borehole images with openhole logs, mudlogs, and map data has been carried out over the Red Oak and Fanshawe Formation intervals (Middle Atoka) in the study area. This analysis records a clastic intra-slope transition from a well-amalgamated channel facies (Red Oak) upwards through an overlying canyon cut-and-fill facies (Fanshawe). Ten wells with image and/or dip data were analyzed and integrated into the study. The resultant re-interpretation of the area has led to an updated geologic model and a better understanding of current and potential reservoir intervals.

The Red Oak Sands are dominated by well-amalgamated channel facies. The relative lack of lobe and levee facies is probably due to sandy channel amalgamation in a restricted fairway.

Borehole images reveal well-defined internal inclined-bedding bounded by erosional amalgamation surfaces in the sand units. In contrast to the current cross beds in fluvial channels, the azimuth statistics of these inclined-bedding in turbidite channels are widely scattered.

Fanshawe sands are dominated by finer grained and less amalgamated sheet turbidites. The thick section of thin parallel-laminated sandy silts seen in borehole images are either a levee-lobe component of a large single channel system, or sheet turbidites of continuous hyperpycnal flows. The best reservoir sands in the Fanshawe are associated with debris flows on the top of the sequence. The methodology developed in this project to extract and interpret turbidite elemental information from different wireline logs may provide valuable insights for more expensive deepwater exploration projects.

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Exploration Discipline Matrix: A Key to Reestablishing a Vibrant Exploration Industry in the Mid-Continent and Other "Mature" Provinces

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A recent *Oil and Gas Journal* article reported that the number-one issue holding back the Domestic U.S. Industry is lack of high-quality prospects in the Lower 48. This tells us that the state of our domestic industry and its future as an employment source is tenuous at best.

Our plan is to promulgate a set of twelve exploration disciplines to provide a tool for generating exploration project ideas. The Exploration discipline Matrix reflects the level of experience of the explorationist, codifies the actual exploration idea-generating process and its various approaches into a new and powerful tool for reinvigorating our industry. This matrix is a guide for both experienced and novice explorationists to access and organize the combined knowledge and experience of those who have gone before, together with our modern knowledge and technology, in order to develop a more continuous flow of exploration ideas and eventually leading to quality prospects.

"TRANSLATION" is one of twelve approaches, which can be used for developing exploration targets in the "mature" basins of North America. The TRANSLATION case history applies an idea related to vertical hydrocarbon migration in Nevada, found in Chamberlain, 2003, to the southeastern extension of the Ardmore basin where an under-explored volume of rock plunges beneath the Ouachita Overthrust Belt. The vertical migration idea is used to explain the enigmatic Isom Springs oil field in Marshall County, Oklahoma and could help define an exploration fairway for oil and gas within the allochthonous thrust sheets as well as within the underlying autochthon.

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Fate and Transport of Oil-Field Brine at the OSPER Sites, Oklahoma

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The USGS has been investigating environmental impacts of oil production activities at the Osage-Skiatook Petroleum Environmental Research (OSPER) Sites "A" and "B," which are located near Skiatook Lake, Osage County, Oklahoma. The "B" site is an active oil production area, whereas the "A" site is an oil field that was largely abandoned 68 years ago. Contamination of soil, ground water, and surface water from crude oil and brine production is extensive at both sites. We drilled about 50 wells up to 36 meters deep at each site for ground-water sampling and hydraulic testing. Water samples indicate there are extensive subsurface plumes of salt water (2,000–30,000 mg/L TDS) at both sites. Borehole cores identified many thin and poorly permeable sandstone layers (<1 m thick) separated by thicker shale and mudstone confining units. Well tests indicate the hydraulic conductivity of the permeable sandstone units is about 1 cm/day. Continuous monitoring of water levels in wells indicates the ground-water recharge rate is low. During the oil-production era at the "A" site, brine from oil wells (TDS up to 150,000 mg/L) was evidently discharged directly into pits and an ephemeral creek bed. Although the rate of recharge was low, enough brine seeped from the pits and into the creek bottom over the 25-year life of the field to form a substantial subsurface plume in the sandstone. Since the "A" site was abandoned, natural dilution of the plume has been very slow because the natural ground-water flow rate is low. Also, the down-slope migration of the plume likely slowed when Skiatook Lake reservoir was filled in 1987, raising the water table elevation at the toe of the plume. Mixing of fresh rain water with the deeper salt water may have been limited by density stratification. At the "B" site, brine holding pits have leaked and created salt scars at the surface. We believe that over the 40-year life of the "B" site, brine has flowed from the pits through a 7-meter thick shale layer near the surface into the deeper sandstone units. Results indicate the brine plumes at both sites will exist for many years to come with continued deleterious environmental impact at ground-water discharge points.

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Impacts of Petroleum Production on Ground and Surface Waters: Results from the Osage–Skiatook Petroleum Environmental Research A Site, Osage County, Oklahoma

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As part of a multidisciplinary group of about 20 scientists, we are investigating the transport, fate, natural attenuation, and ecosystem impacts of inorganic salts and organic compounds present in releases of produced water and associated hydrocarbons at the Osage–Skiatook Petroleum Environmental Research (OSPER) sites, located in Osage County, Oklahoma. Geochemical data collected from nearby oil wells show that the produced water source is a Na-Ca-Cl brine (~150,000 mg/L total dissolved solids [TDS]), with relatively high concentrations of Mg, Sr, and NH_4, but low SO_4 and H_2S. Results from the depleted OSPER A site show that the salts continue to be removed from the soil and surficial rocks, but degraded oil persists on the contaminated surface. Eventually, the bulk of inorganic salts and dissolved organics in the brine will reach the adjacent Skiatook Lake, a 4250-ha (10,501-ac) potable water reservoir.

Repeated sampling of 44 wells show a plume of high-salinity water (2000–30,000 mg/L TDS) at intermediate depths that intersects Skiatook Lake and extends beyond the visibly impacted areas. No liquid petroleum was observed in this plume, but organic acid anions, benzene, toluene, ethylbenzene, and xylene (BTEX), and other volatile organic carbon (VOC) are present. The chemical composition of released brine is modified by sorption, mineral precipitation and dissolution, evapotranspiration, volatilization, and bacterially mediated oxidation-reduction reactions, in addition to mixing with percolating precipitation water, lake water, and pristine groundwater. Results show that only minor amounts of salt are removed by runoff, supporting the conclusion that significant amounts of salts from produced water and petroleum releases still remain in the soils and rocks of the impacted area after more that 65 yr of natural attenuation.

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Pore Waters Contaminated with Oil Field Brine, Osage County, Oklahoma: Implications for Water Quality and Ecosystem Health

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Shallow ground water is contaminated with brine from past and present operations at an oil field production site in northeastern Oklahoma. The contaminated ground water provides a source of salts, metals, and hydrocarbons to sediment and water of adjacent Skiatook Lake. An additional source of contamination at the site is a former brine storage pit of 10 m diameter that is now submerged beneath the lake. Cores of the upper 30–40 cm of lake sediment were taken at an offshore saline seep, at the submerged pit, and at a location containing relatively uncontaminated lake sediment. Pore waters from each 2-cm interval were separated by centrifugation and analyzed for dissolved anions, cations, and trace elements. High concentrations of dissolved chloride in pore waters (200–5000 ppm) provide the most direct evidence of oil field brine contamination and compare to an average value of ~35 ppm in Skiatook Lake. Cl/Br mass ratios of 220–250 in contaminated pore waters are comparable to values from produced water and saline soil extracts collected onshore. Dissolved concentrations of Se, Pb, and Cu in Cl-rich pore waters exceed current USEPA criteria for toxicity to freshwater aquatic life. The offshore seep sustains high concentrations of dissolved Cl at the sediment/water interface. In the pit the dissolved Cl concentrations are highly anomalous only at depths below 10 cm, indicating a combination of recent burial, mixing, and exchange with lake water, and bioturbation in this near-shore setting. Annual contribution of Cl to the lake is estimated to be ~20 kg for the entire area of the submerged pit (diffusive flux dominant), and ~5 kg for an assumed circular seepage area of 1 m diameter (advective flow dominant). Such contributions have minimal impact on water quality in the 323,000 acre-ft lake.

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Environmental Impacts of Oil and Gas Exploration and Production: Ground Water Impacts at OSPER Sites, Osage County, Oklahoma

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Starting in the 1950s, oil and natural gas became the main sources of primary energy for the increasing World population. The clear benefits of petroleum consumption, however, carry major environmental impacts that range from local to global in scale, including air pollution, global climate change and water contamination. Exploration and production of petroleum have caused detrimental impacts to soils, surface and ground waters, and ecosystems in the 36 producing states in the USA. These impacts arose primarily from the improper disposal of some of the large volumes (~20 billion bbl/yr total) of saline water, with toxic organic and inorganic components, produced with oil and gas; from accidental hydrocarbon and produced water releases; and from the large number (>2.5 million) of abandoned petroleum wells, some of which were "orphaned" or not correctly plugged. Impacts to ground-surface can arise from related activities, such as site clearance, construction of roads, tank batteries, brine pits and pipelines, and other necessary land modifications. For the last five years, we have been investigating the transport, fate, natural attenuation and ecosystem impacts of inorganic and organic compounds in releases of produced water and associated hydrocarbons at the Osage-Skiatook Petroleum Environmental Research (OSPER) sites, located in NE Oklahoma. Approximately 1.0 ha of land at both OSPER "A" (inactive lease) and "B" (active lease) sites, are visibly affected by salt scarring, tree kills, soil salinization, and brine and petroleum contamination. Geochemical data from nearby oil wells show that the produced water source is a Na-Ca-Cl brine (~150,000 mg/L TDS), with high Mg, but low SO_4 and dissolved organic concentrations. Groundwater impacts are being investigated using a variety of methodologies, including detailed chemical analyses of water from repeated sampling of 85 boreholes, 1–71 m deep. The most important results are: (1) A plume of high-salinity water (2,000–30,000 mg/L TDS) extends beyond the visibly impacted areas at OSPER "A", indicating a large amount of salt remains in the rocks after more than 65 years of natural attenuation; and, (2) produced-water brine and minor dissolved organics have penetrated the thick (3.5–6 m) shale units at OSPER "B", resulting in three saline ground water plumes.

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Organic Compounds Related to Produced-Water Releases: Results from the OSPER "A" Site, Osage County, Oklahoma

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We are investigating the fate and transport of produced water and associated hydrocarbon releases at the Osage-Skiatook Petroleum Environmental Research (OSPER) site "A", an inactive oilfield within the larger Lester lease. The site is located ad-

jacent to Skiatook Lake, a 4250-hectare potable water reservoir in Osage County, OK. Produced water and associated hydrocarbon releases occurred primarily from 1912 to 1937, when most of the total ~100,000 barrel (bbl) of oil were produced. Oil production was from the Bartlesville sandstone (Pennsylvanian age). Stripper wells in nearby areas currently average ~2.8 bbl/d oil and >30 bbl/d brine. Data from nearby oil wells show that source of the produced water is a Na-Ca-Cl brine, with relatively high concentrations of Mg, NH_4, but low HCO_3 and very low SO_4 and H_2S; the DOC concentrations range from 2 to 7 mg/L, and carboxylic acid anions, BTEX, phenols and PAHs are relatively low. The source oil is paraffinic-naphthenic light crude (API gravity ~35°), containing n-alkanes as the dominant components. Biodegradation of the oil is likely limited by the high salinity of the associated produced water. The asphaltic and weathered oil persisting on the site are from the same source, but have been subjected to various biodegradation stages. Extensive and repeated sampling of 58 wells (1 to 36 m deep) from this site show a plume of high salinity water (2,000–30,000 mg/L TDS), generally at intermediate depths, that extends beyond the visibly impacted areas and intersects Skiatook Lake. Minor amounts of oil were observed only in water samples from a well drilled 0.6 km northwest of the visibly impacted area, but high DOC (up to 500 mg/L), organic acid anions (mainly acetate and propionate, and to a lesser extent oxalate), hydrocarbon gases, and relatively low concentrations of BTEX and other VOCs, were measured in the water samples from the main plume. Reducing conditions in parts of the plume are indicated by relatively higher Fe, Mn and DOC, and lower D.O. concentrations. Results from this site show that in addition to inorganic salts, oil degradation products, including small amounts of BTEX and organic acid anions from produced water and petroleum releases remain in the rocks and water of the impacted area after more than 65 years of natural attenuation.

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Natural Attenuation and Removal of Contaminant Salt from Produced Water Releases by Runoff: OSPER Site A, Osage County, Oklahoma

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The Osage-Skiatook Petroleum Environmental Research (OSPER) site A is part of a depleted oil field, where 15–30 million kg of salt was discharged to the surface during 1912–1937 in high salinity (180,000 mg/L TDS) produced water associated with ~100,000 bbl of oil production. Salt contamination from the Na-Ca-Cl type brine has visibly impacted a ~1.2 hectare area that is characterized by a salt scar, excessive soil and rock erosion, and dead vegetation, downslope from two pits that were the primary source for produced water releases. Extensive geologic, hydrologic, and geophysical characterization of the site, including repeated geochemical sampling of groundwaters from 44 monitoring wells, show that: (1) contaminant salts have been mostly leached from soil and surficial rocks, except on the salt scar, where salt efflorescence is common during the hot/dry seasons; and (2) a plume of high salinity groundwater (2,000–30,000 mg/L TDS), up to 10 m in vertical thickness and at least 2.5 hectare in lateral extent, extends predominantly to the north, downslope and downdip from the brine pits and salt scar, terminating at Skiatook Lake, a 4250-hectare reservoir that provides drinking water to the local communities. The plume is estimated to contain 0.1–0.3 million kg of salt. Site A is ideally suited to study the natural overland transport of salt, because the salt impacted area lies within a small 1.7 hectare watershed, which drains into a narrow ephemeral stream at the base of the salt scar and just above the conservation water level for Skiatook Lake. A weir, installed at the site in March 2003, has enabled the periodic monitoring of discharge and chemical composition of surface runoff during precipitation events. Results to date show that the initial runoff that leaches the previously precipitated surficial salt can have a relatively high salinity (up to 3,000 mg/L TDS), but that relatively small amount of total salt (~500 kg/yr) is removed by runoff from normal precipitation rates (90–100 cm/yr) in the area. This result suggests that it will require hundreds of years to remove the salt from the impacted area under current conditions, supporting the conclusion that significant salt from produced water releases still remains in the rocks of the impacted area after more than 65 years of natural attenuation.

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Microbial Ecology and Geochemistry of Produced Water from the Osage-Skiatook Petroleum Environmental Research Sites, Osage County, Oklahoma

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During a multidisciplinary study at two oil production sites of differing ages near Lake Skiatook, Osage County, Oklahoma, a series of oil, water, brine, and soil samples were characterized and analyzed for microbial populations and geochemical parameters that are indicative of microbial activity. Petroleum wells and production tank batteries at site "A" have been inactive for some time and the bulk of the hydrocarbon (now degraded and weathered oil) and produced water releases occurred more than 65 years ago. One pit at this site, however, contains relatively fresh asphaltic oil and high salinity brine. In contrast to site "A", site "B" (located approximately 6 km away) includes an active production tank battery and adjacent brine and oil pit, an inactive tank battery and an injection well with a small brine pit. The area source oils are light, paraffinic-naphthenic crude oils, containing n-alkanes as the dominant components and are unimpacted by biodegradation, even though petroleum production is from shallow sandstones (300–600 m depth). The oils at the inactive site "A" are similar to each other in their chemical fingerprints, although in varying stages of biodegradation. The n-alkanes in oil samples taken from surface pits at the active site "B" do not appear to have undergone significant biodegradation yet. Microbial populations at both sites are degrading the water-soluble, low-molecular-weight, aromatic, n-alkane, and the more refractory n-alkylcyclohexane compounds from the crude oil. The high dissolved Fe(II), low nitrate and other geochemical evidence, as well as the composition of the microbial populations at both sites indicate that the systems are poised at the level of iron reduction. However, the progression of n-alkylcyclohexane loss (higher molecular weight homologs are lost first) within some deeper, more degraded samples suggest that some methanogenesis has occurred. Populations of aerobic, fermentative and iron-reducing microorganisms are on the order of 100 times greater at site "A" compared to site "B", reaching concentrations of 100,000 organisms per gram of sediment. Contamination has been present for a longer time at site "A" than site "B", allowing for a longer growth period.

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Environmental Impacts of Oil Production on Soil, Bedrock, and Vegetation at the U.S. Geological Survey Osage–Skiatook Petroleum Environmental Research Site A, Osage County, Oklahoma

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The U.S. Geological Survey is investigating the impacts of oil and gas production on soils, groundwater, surface water, and ecosystems in the United States. Two sites in northeastern Oklahoma (sites A and B) are presently being investigated under the Osage–Skiatook Petroleum Environmental Research project. Oil wells on the lease surrounding site A in Osage County, Oklahoma, produced about 100,000 bbl of oil between 1913 and 1981. Prominent production features on the 1.5-ha (3.7-ac) site A include a tank battery, an oil-filled trench, pipelines, storage pits for both produced water and oil, and an old power unit. Site activities and historic releases have left open areas in the local oak forest adjacent to these features and a deeply eroded salt scar downslope from the pits that extends to nearby Skiatook Lake. The site is underlain by surficial sediments comprised of very fine-grained eolian sand and colluvium as much as 1.4 m (4.6 ft) thick, which, in turn, overlie flat-lying, fractured bedrock comprised of sandstone, clayey sandstone, mudstone, and shale. A geophysical survey of ground conductance and concentration measurements of aqueous extracts (1:1 by weight) of core samples taken in the salt scar and adjacent areas indicate that unusual concentrations of NaCl-rich salt are present at depths to at least 8 m (26 ft) in the bedrock; however, little salt occurs in the eolian sand. Historic aerial photographs, anecdotal reports from oil-lease operators, and tree-ring records indicate that the surrounding oak forest was largely established after 1935 and thus postdates the majority of surface damage at the site. Blackjack oaks adjacent to the salt scar have anomalously elevated chloride (>400 ppm) in their leaves and record the presence of NaCl-rich salt or salty water in the shallow subsurface. The geophysical measurements also indicate moderately elevated conductance beneath the oak forest adjoining the salt scar.

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Geologic Controls on Movement of Surface and Subsurface Brine at the OSPER "A" Site, Skiatook Lake, Osage County, Oklahoma

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USGS research on the soil, ground water, surface water, and ecosystem impacts of past oil production at its Osage-Skiatook Petroleum Environmental Research site "A" began in 2001. Commercial oil production at this site began in 1913 and continued through at least 1973. Produced fluids were separated into wooden tanks in the upper part of the site, then the brine and crude oil were moved by trench to two downslope pits, one of which temporarily held the brine and the other of which held the crude until it could be pumped into a tank truck. Under accepted oilfield practices at the time, brines in the one pit were allowed to evaporate, seep through the pit bottom, or overflow the pit through a notch on the north berm of the pit. These brine releases moved downslope following topography into a small stream and downdip in the subsurface following (1) channels at the contact between surficial sediments and underlying bedrock, and (2) permeable sandstone layers and fractures in the gently northwest-dipping bedrock. Like the sandstones, interbedded shales in the upper part of the section became salt saturated with time. Downward movement of brine through bedrock was locally limited by layers of heavily dolomite-cemented sandstone. The salt moved deeper stratigraphically, probably along fractures, as it migrated laterally through bedrock downdip. A large salt scar formed downslope to the north of the pits. The upper part of this salt scar starts where a less permeable shale layer forces brine, moving through permeable weathered sandstone immediately underlying the pits, to the near surface. This salt scar can be observed about 80 percent developed in the earliest aerial photos available for the site (1936). The impacts of production thus include a highly saline creek (as seen in older aerial photos and reported anecdotally, the creek was later flooded by the creation of Skiatook Lake), salt scars, and a subsurface volume of saline bedrock that extends at least 120 m north, northwest, and west of the pit source and to depths of at least 12 m. The limits of the volume of saline bedrock derived from this source are not delineated to the north and northwest of existing drillholes and saline bedrock likely extends out under Skiatook Lake.

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Use of Dissolved Chloride Concentrations in Tributary Streams to Support Geospatial Estimates of Cl Contamination Potential Near Skiatook Lake, Northeastern Oklahoma

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Current and historic saline water produced from oil and gas wells potentially impacts surface-water bodies. The goal of this study is to assess impacts of saline releases to Skiatook Lake in Osage County, Oklahoma. About 6,715 oil and gas wells are located in the 350 mi^2 drainage basin that contains the lake and the 10,500 acres of land flooded by the lake (flooding began 1984) has approximately 215 plugged wells. The effect of the produced saline water (total dissolved solids >100,000 mg/L) on the lake was evaluated using a mass balance of concentrations of chloride in the inflowing waters draining into Skiatook Lake and correlating that with well densities in the various contributing drainages.

To provide a snapshot of current surface water inputs of Cl to Skiatook Lake, discharge measurements were made at the mouths of 18 streams draining into the lake, as well as the lake outfall. Chloride concentrations were measured at these sites, at 6 sites within the lake, and along the reaches of 2 of the streams that were observed to have high concentrations of Cl in a previous survey. Water in the lake has an average Cl value of 36 mg/L, with an estimated residence time of 18 months. Inflow from Hominy Creek, the major stream dammed by the lake, was 63 percent of the water entering the lake, draining an area representing 37 percent of the total drainage area of the basin that contains 44 percent of the oil and gas wells. Calculations indicate that almost 80 percent of the Cl load entering Skiatook Lake is from Hominy Creek. A mass balance calculation using the weighted average Cl concentration for all the other tributaries (17.8 mg/L), combined with the concentration of 44 mg/L Cl in Hominy Creek provided a reasonable match for the concentration of Cl (36 mg/L) in the lake. Geospatial analysis of well densities in subdrainages, also used to assess contamination potential, are compared to measured Cl values from the main streams in those areas.

Results indicate that a mass balance approach utilizing Cl concentrations coupled with geospatial analysis of well densities may be useful for assessing impacts of saline water releases to surface-water bodies.

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Borehole Induction Conductivity and Natural Gamma Logging at the Osage Skiatook Research Site, Northeastern Oklahoma: Lessons Learned

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Induction conductivity and natural gamma-ray logs collected from wells at the Osage Skiatook Research Site support ongoing geological, geophysical, geochemical, and hydrologic studies of the environmental impacts of oil production. Logged wells range in depth from 15 to greater than 100 feet and were completed with 2-inch PVC casing, bentonite grout, sand pack around the screened interval and steel well-head protectors. These logs can be obtained from cased wells and provide data both above and below the water table. The site lithologies include shales with high gamma activity and moderate conductivity, and sandstones with low gamma activity and low conductivity. Higher conductivity in the wells above the water table indicated the presence of conductive salts in the unsaturated zone. This was confirmed by high sodium chloride content in 1:1 aqueous extracts of selected samples from crushed core samples from the intervals.

The induction conductivity logs show the vertical distribution of soluble salts in the unsaturated zone and of saline ground water in the saturated zone. Induction conductivity logs augment chemical analyses of soil/rock extracts and ground-water samples, and improve estimates of the total volume of rock affected by salts. For example, higher conductivity values found in some shales indicated the extent of penetration of sodium chloride contamination into these low permeability rocks.

Gamma-ray logs were used to identify distinctive radioactive layers and these were used for lithologic correlations. When used in combination with conductivity logs, the gamma-ray logs provided additional lithologic information to supplement, or substitute for, core sample descriptions.

Vertical profiles of estimated electrical conductivity were used in calibration and interpretation of surface electrical conductivity surveys. The borehole logs have provided critical data to assist in other aspects of the study including geologic, geochemical, and hydrologic interpretations.

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Environmental Effects of Oil Production on Soil, Vegetation, and Surface and Ground Waters at the U.S. Geological Survey, Osage-Skiatook Petroleum Environmental Research Site, Osage County, Oklahoma

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The U.S. Geological Survey is conducting multidisciplinary research into the transport, fate, and natural attenuation of inorganic salts, organic compounds, trace metals, and radionuclides present in produced water at the Osage-Skiatook Petroleum Environmental Research site, located on Skiatook Lake in Osage County, Oklahoma. Investigations have included geologic mapping; soil, bedrock, and ground-water geochemistry; water-level monitoring; borehole and surface geophysics; oak leaf biogeochemistry and tree ring dating; plant surveys; microbial population studies; and an aerial hyperspectral survey.

Petroleum production at the site began in 1913 and continued to about 1973. A salt scar and production-operation pits, seen on a 1936 aerial photograph, remained after oilfield operations ceased. Surface geophysics and soil and bedrock core extracts indicate higher concentrations of sodium chloride salt are present to depths as deep as 11.5 meters in the bedrock.

The bedrock is composed of shale and sandstone. Oak trees adjacent to salt sources have greater chloride concentrations in the leaves than to trees located away from the salt sources. Repeated sampling of observation wells indicates a plume of high-salinity water (2000–30,000 milligrams per liter total dissolved solids) is present at depths below the mean level of Skiatook Lake. The plume extends laterally beyond the visibly effected surface areas. Results indicate only minor amounts of salt are removed by runoff. Salts still remain in the soil and bedrock of the effected area after more than 75 years of natural attenuation.

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Electrical Geophysical Surveys of Oil Field Saline Water Contamination, Osage Skiatook Petroleum Environmental Research Site, Northeastern Oklahoma

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The first extensive field studies at the Osage Skiatook Petroleum Environmental Research Site (OSPERS), carried out in the fall of 2001, consisted of dc resistivity depth soundings and single frequency electromagnetic (EM) conductivity profiling. The dc resistivity surveys showed that subsurface plumes of contaminated water have resistivities lower than 5 ohm meters (electrical conductivity of 200 millisiemens per meter, ms/m). In contrast, background resistivities were found to be on the order of 50 ohm meters (20 ms/m). Resistivity soundings near the Skiatook Lake shoreline show there is a high conductivity layer overlain by a resistive layer. The high conductivity is likely due to the high TDS ground water in the region whereas the resistive layer is due to fresher waters of the lake and dryer sediments. The ground profiling EM measurements defined a geometrically complex, near surface (within 5 m) conductivity anomaly produced by highly-soluble salts that do not always correspond to surface salt scars. Both resistivity soundings and EM measurements suggest that salts contamination has penetrated shale units normally considered aquitards. Drilling was carried out in 2002, based in part on these geophysical results and confirms the basic subsurface electrical interpretation. In August of 2003, depth imaging (multi-frequency) EM profiling and borehole logging was done. The subsurface interpretation of shallow high conductivity correlates well with geophysical induction conductivity logs and mapped the lateral extent of the shallow plumes. By chance repeat EM profiling measurements were made of part of the site before and after a rainstorm when runoff salinity was being monitored. At this time a marked increase in conductivity occurred within a narrow delta at the shore of Skiatook Lake. During May of 2005, EM profiles were completed on land and in the lake along shallows near the shore. Areas of high subsurface conductivity were mapped beneath the lake where an old, submerged, brine disposal pit is located and where previously noted high conductivities from runoff occur.

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Remediation of a Spill of Crude Oil and Brine Without Gypsum

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The empowerment of small independent oil and gas producers to solve their own remediation problems will result in greater environmental compliance and more effective protection of the environment, as well as making small producers more self-reliant. Here, we report on the effectiveness of a low-cost method of remediation of a combined spill of crude oil and brine in the Tallgrass Prairie Preserve in Osage County, Oklahoma. Specifically, we have used hay and fertilizer as amendments for remediation of both the oil and the brine. No gypsum was used. Three spills of crude oil plus produced water brine were treated with combinations of ripping, fertilizers and hay, and a downslope interception trench in an effort to demonstrate an inexpensive, easily implemented, and effective remediation plan. No statistically significant effect of treatment on the biodegradation of crude oil was, however, observed. Total petroleum hydrocarbon (TPH) reduction clearly proceeded in the presence of brine contamination. The average TPH half-life considering all impacted sites was 267 days. The combination of hay addition, ripping, and a downslope interception trench was superior to hay addition with ripping or ripping plus an interception trench in terms of rates of sodium and chloride leaching from the impacted sites. Reductions in salt inventories (36 months) were 73% in the site with hay addition, ripping, and an interception trench, 40% in the site with hay addition and ripping only, and less than 3% in the site with ripping and an interception trench.

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Environmental Releases from Exploration and Production Operations in Oklahoma: Type, Volume, Causes, and Prevention

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A total of 16,906 recent fluid releases were reported to the Oklahoma Corporation Commission (OCC) during the 10-yr period from 1993 to 2003. Of these, 12,863 were identified as exploration- and production-related releases of oil or saltwater from identified geographic areas. The primary reported origins of oil and saltwater releases were leaks from lines, tanks, wellheads, surface equipment, and pits. Important reported causes of fluid releases range from common overflows (tank, pit, and dike), intentional dumping or other illegal activity, storms, fires or explosions, accidents (including the actions of livestock), and to occasional corrosion. Approximately 34% of all recent oil or saltwater releases resulted in reported injury to environmental receptors (surface water, crops or livestock, soil, fish, or wildlife). For the 10-yr period of record, 41% of all exploration and production complaints to OCC involved the release of oil or saltwater. On an annual basis, complaints involving the release of fluids decreased from 65.8% in 1993 to 46.1% in 2002. Releases specifically identified as involving oil or saltwater comprised 76.1% of all fluid releases. Quantified releases of oil had a median volume of 10 bbl, whereas quantified releases of saltwater had a median volume of 40 bbl. For those releases in which the volume of both oil and saltwater were quantified, the volume of saltwater spilled was approximately 76% of the total volume.

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Environmental Contaminant Releases from E&P Operations in Oklahoma: Type, Volume, Causes and Prevention

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Rationale management and decision making regarding environmental management requires information. Although most oil and gas regulatory bodies have rules that specifically prohibit pollution, little is known about the specific origins, causes and magnitudes of pollution incidents that result from onshore exploration and production activities. This paper presents an analysis of over 18,000 fluid release incidents documented by the Oklahoma Corporation Commission (OCC) for the ten-year period from 1993 to 2003. Of these, nearly 17,000 were recent releases, and nearly 13,000 of these releases could be traced to exploration and production (E&P) operations within a specific section-township-range locations within Oklahoma. Fluid releases from E&P operations resulted from both preventable and non-preventable causes. The primary origins of oil and saltwater releases were from flowlines lines, tanks, wellheads, surface equipment and pits. Important causes of fluid releases, in order of decreasing number, were: overflows (tank, pit and dike), leaks (lines), intentional dumping or other illegal activity, storms, fires or explosions, accidents (including the actions of livestock) and corrosion. On average, over 58,000 bbls of oil and over 146,000 bbls of saltwater were released annually in Oklahoma between 1993 and 2003. Approximately 34% of all recent oil or saltwater releases resulted in reported injury to environmental receptors (surface water, crops or livestock, soil, fish or wildlife). For this period, 41% of all E&P complaints to the OCC involved the release of oil or saltwater and 54% of all E&P complaints to the OCC involved the release of some type of fluid. On an annual basis, complaints involving the release of fluids decreased from a high of 65.8% in 1993 to 46.1% in 2002. Releases specifically identified as involving oil or saltwater comprised 76.1% of all fluid releases. Quantified releases of oil had a median volume of 10 BBLs while quantified releases of saltwater had a median volume of 40 BBLs. For those releases in which the volume of both oil and saltwater were quantified, the volume of saltwater spilled was approximately 76% of the total volume of oil and saltwater released.

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Remediation of Oil-Field Brine-Impacted Soil Using a Subsurface Drainage System and Hay

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This study involved a demonstration of a novel remediation technology for brine-impacted soil at a site in Osage County, Oklahoma, which was recently contaminated with produced-water brine from a leak in a steel line leading to a saltwater disposal well. At this site, topsoil was underlain by clay-rich subsoil, which had resulted in leaching and transport of brine components from the site to an environmental receptor (farm pond) downgradient. Encouraging further movement of brine components using natural drainage patterns would have only further contaminated the pond. A subsurface drainage system was installed to intercept brine components, enhance the lateral subsurface transport process, and prevent further contamination of the pond. Chloride and sodium concentrations in the soil were reduced by an average of 93 and 78%, respectively, in the 4 yr after the subsurface drainage system was installed. More importantly, approximately 95% of the site revegetated during this period. This is in stark contrast to the complete lack of vegetation before the current work was initiated.

A thick layer of prairie hay was applied across the surface of this site after the subsurface drainage system was installed. In addition to limiting the rate of evaporation from the site, this organic material appears to have also been a significant factor in desalination and revegetation of the site. The fibrous hay enhanced leaching after mechanical disruption of the soil and provided soil organic matter that helped to build soil structure and sustain the soil ecosystem.

Based on the results from this study, a two-step remediation strategy for brine-impacted topsoil is proposed. The first step involves the tilling of hay and fertilizer into the soil, whereas the second step involves a subsurface drainage system, if necessary.

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