The Class Act

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# Improved Oil Recovery in Fluvial-Dominated Deltaic Reservoirs of Kansas

By Rodney R. Reynolds, Don W. Green, G. Paul Willhite, Michael J. Michnick, and Dwayne McCune, Tertiary Oil Recovery Project (TORP), University of Kansas

## Introduction

Common oil field problems exist in fluvial-dominated deltaic reservoirs in Kansas. The problems are poor waterflood sweep efficiency and lack of reservoir management. The poor waterflood sweep efficiency is due to (**1**) reservoir heterogeneity, (**2**) channeling of injected water through high permeability zones or fractures, and (**3**) clogging of injection wells due to solids in the injection water. In many instances, the lack of reservoir management results from (**1**) poor data collection and organization, (**2**) little or no integrated analysis of existing data by geological and engineering personnel, (**3**) the presence of multiple operators within the field, and (**4**) not identifying optimum recovery techniques.

This project involves two demonstration projects, one in a Morrow reservoir located in the southwestern part of the state and the second in the Cherokee Group in eastern Kansas. Morrow reservoirs of western Kansas are still actively being explored and constitute an important resource in Kansas. Cumulative oil production from the Morrow in Kansas is over 200,000,000 bbl. Much of the production from the Morrow is still in the primary stage and has not reached the mature declining stage as Cherokee production has. The Cherokee Group has produced about 1 billion bbl of oil since the first commercial production began over a century ago. Many of the reservoirs are operated close to the economic limit, although the small units and low production per well are offset by low costs associated with the shallow nature of the reservoirs (less than 1000 ft deep).

The project is being conducted in a cooperative manner involving University of Kansas scientists, engineers, and geologists and independent oil operators. Different independent oil operators operate the two demonstration sites. The Stewart Field Morrow reservoir is located in Finney County, Kansas and is operated by

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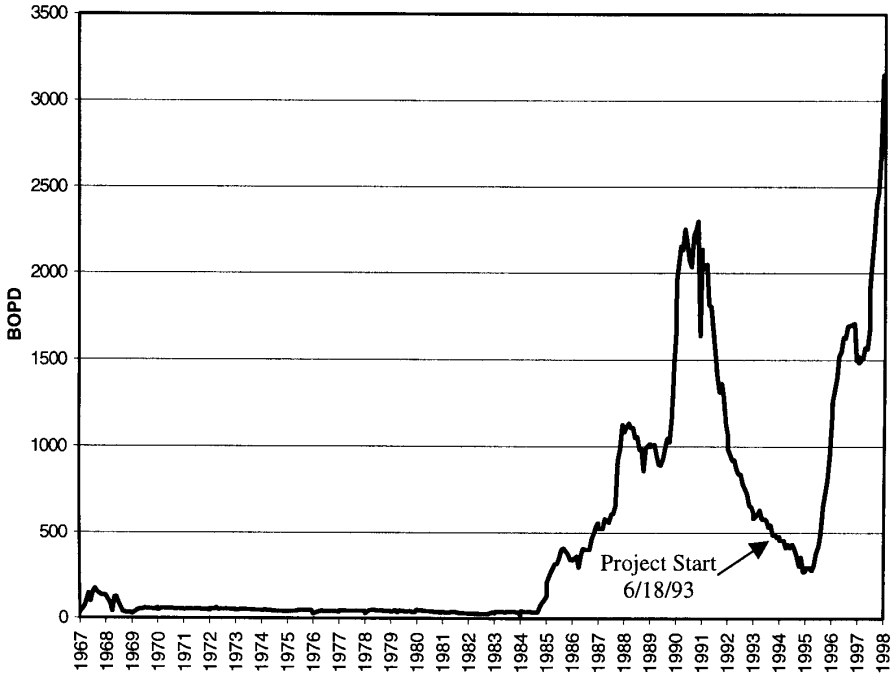


**Figure 1** Stewart Field oil production

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**PetroSantander, Inc.** This field was in the latter stage of primary production at the beginning of this project and is currently being waterflooded as a result of the project. The other demonstration site, the Nelson Lease (an existing waterflood) is located in Allen County, Kansas, in the N.E. Savonburg Field and is operated by **James E. Russell Petroleum, Inc.**

The objective of the project is to increase recovery efficiency and economics in these types of reservoirs. The technologies being applied to increase waterflood sweep efficiency are (**1**) in-situ permeability modification treatments, (**2**) infill drilling, (**3**) pattern changes, and (**4**) air flotation to improve water quality. The technologies being applied to improve reservoir management are (**1**) database development, (**2**) reservoir simulation, (**3**) transient testing, (**4**) database management, and (**5**) integrated geological and engineering analysis.

## Stewart Field Background

The Stewart Field ranges from 0.25 to 0.5 miles wide, is 4.5 miles long, and covers approximately 2400 acres. The field was discovered in 1967 with the first well completed in a basal Pennsylvanian Morrow sand from 4755 to 4767 ft for 99 BOPD. Only four additional wells were drilled until 1985. Active development of the field took place from 1985 to 1994. Wells produced with minor stimulation until, in 1990 and 1991, a field-wide hydraulic fracture program was conducted.

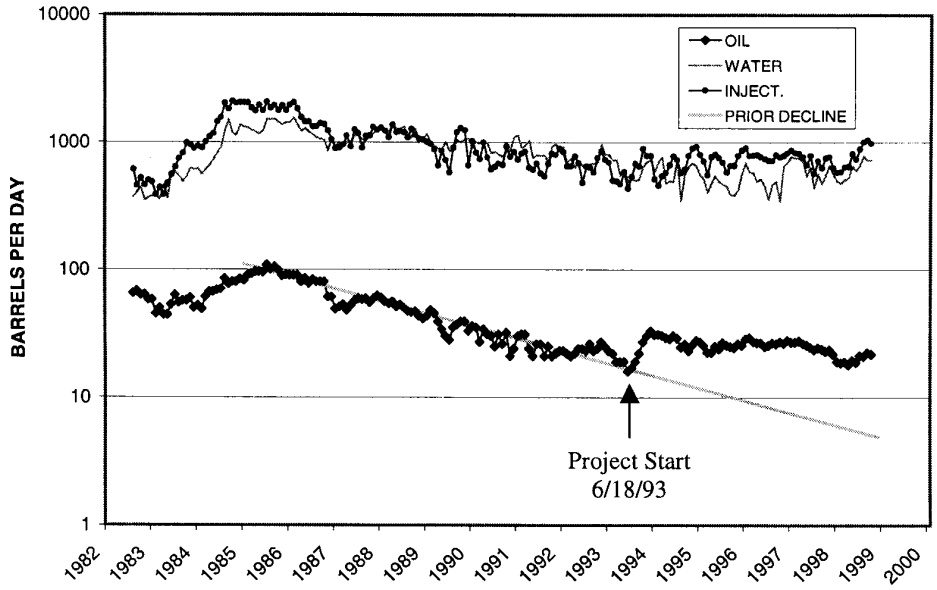


**Figure 2** **Savonburg Field waterflood production and injection**

The Stewart Field contains 28°API oil with a small amount of solution gas (37 SCF/bbl). The initial reservoir pressure was estimated to be 1102 psig with a bubble point of approximately 180 psi. The reservoir oil was highly undersaturated, and the expected primary production behavior was a rapid decline of reservoir pressure as the reservoir energy in the form of fluid and rock expansion was depleted.

Two field-wide shut-in tests were conducted in 1989 and 1991 to determine reservoir pressure distribution. Pressure tests indicated continuity of the reservoir over the 4.5-mile length of the field. Material balance calculations were performed from the initial reservoir pressure to the average reservoir pressures observed in the 1989 and 1991 field-wide tests. Assuming no water influx, the fluid produced should be due to fluid and rock expansion over the given pressure drop. These calculations gave an estimate of more than 100 million bbl of oil in place. Volumetric mapping of the net sand indicated only 22 million bbl in place.

It was determined that uncertainties in fluid and rock properties would not resolve the difference in determining the original oil in place, between volumetric mapping of the net sand and material balance calculations. Either a large volume of the reservoir was yet to be defined or a limited water influx (pressure support) existed within the field. This uncertainty provided motivation for the extensive database development and reservoir study associated with this project.

## Stewart Field Results

The Stewart Field project results include design, initiation, and operation of a waterflood using improved reservoir management techniques that resulted in an increase in oil production rate from 270 to over 2700 BPD (December 1, 1998).

**North American Resources Company** (NARCO) was the operator that implemented the waterflood. The waterflood design was based on a reservoir simulation

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study conducted as part of this project. The original waterflood pattern was a modified six-line drive, resulting from six producing wells being converted to injection. Water injection began on October 9, 1995. In March 1996, oil production in the field began to respond to the water injection. Oil production increased to 1700 BOPD by October 1997, and NARCO sold the Stewart Field waterflood to PetroSantander, Inc., which subsequently converted six additional producing wells to injection. Oil production has continued to increase and, as of October 1, 1998, total incremental waterflood response is over 2400 BOPD.

Oil production over the life of the field is shown in **Figure 1**. The increase in production rates during the period 1985–1989 was due to rapid development of the field. Peak primary production rates were observed following the hydraulic fracturing program carried out in 1990 and 1991, followed by a rapid decline in production. Current total field production is over 2700 BOPD. Total incremental waterflood production through September 1998 is 1,363,146 BO.

## Savonburg Field Background

This project is comprised of three 160-acre leases totaling 480 acres in Sections 21, 28, and 29, Township 26 South, Range 21 East, Allen County, Kansas. The first well drilled in the location of this project was in 1962. Fifty-nine production wells and 49 injection wells have been drilled and completed since 1970. A pilot waterflood was initiated in March 1981 and expanded in 1983. Full development occurred in 1985. In 1986, eleven gel polymer treatments were implemented successfully on the Nelson Lease. Overall incremental oil recovery was 3.5 barrels per pound of polymer placed for a total of 12,500 BO. The production increase was not sustained because of wellbore plugging that resulted from poor water quality.

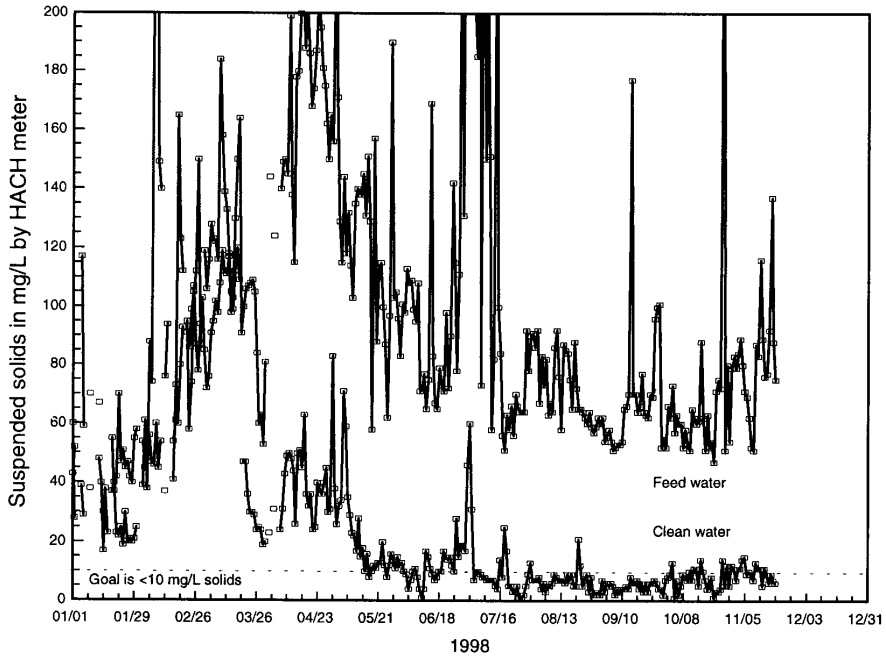


**Figure 3** **Savonburg Field comparison of suspended solids content for water entering and exiting the air floatation unit**

## Savonburg Field Results

This project started in June 1993. Although uncontacted regions of the reservoir were identified, the response to changes in water injection patterns stabilized the decline, as shown in **Figure 2**. The principal results from this project is the improvement in the quality of the injection water and corresponding reduction in treating and wellbore cleanup costs.

The injection water at the Savonburg project is a mixture of supply water (containing 40 mg/L sulfate and 50 mg/L sulfide) and produced water (containing 140 mg/L barium and 12 mg/L iron). Barium sulfate and black iron sulfide formed when the two waters were mixed. Before the project started, less than 1000 BPD of water could be processed through the water plant through 75-micron filter bags. Frequent well workovers were required to clean injection wells in order to restore injectivity.

An air flotation unit (AFU) was developed to remove oil and suspended solids from the injection water. The AFU consists of a 4-ft diameter by 4-ft tall tank. Two venturi tubes are mounted 2 ft below the surface of the water at a 45° angle to the center of the tank. Clean water from the bottom of the AFU is pumped through the venturi tubes to produce a stream of small air bubbles, which rise to the water surface, sweeping solids and oil from

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the water. A high-molecular-weight cationic polymer flocculation agent is used to enhance the separation. Now 1000 BPD of clean water is routinely processed by a pair of 1-micron filters that last as long as 4 days before replacement. The goal for water quality at the Nelson Lease was less than 10 mg/L of suspended solids in the water sent to the field. **Figure 3** illustrates the turbidity measurements made by field personnel in 1998. Note that the goal of less than 10 mg/L was achieved in early May when the 1 SCFM air per 10 gpm feed water was achieved and the waste weir was relocated to the center of the tank. From July 2 through November 15, the solids in the feed water ranged from 47 to 370 mg/L, with an average of 80 mg/L by turbidity (18 mg/L by weight). The solids in the clean water exiting the water plant ranged from 1 to 25 mg/L, with an average of 7 mg/L (1.6 mg/L by weight). This corresponds to a decrease in solid content of 90%, which is equivalent to a decrease from 2300 to 200 pounds solids per year sent to the field. Preliminary cost estimates are $1.25, $2.40, $4.35, and $9.40 per day for cationic polymer, hypochlorite, scale inhibitor, and filters, respectively, for 1000 BPD of clean water, or $0.02 per barrel of water. The clean water allowed the replacement of the 75-micron filter with 5- or 2-micron cartridge filters at each injection well. Cleaner water and better filtration at each injection well reduced the frequency of well cleaning by 50-75% for additional savings in the waterflood operation at the Nelson Lease. ♦

# A Tale of Two Simulations or How 3D Seismic Was Used To Improve Production in an Old Field

by Robert C. Trentham, Muskoka Consultants, and William Robinson, Seismic Decisions

The Laguna Petroleum Class II project is a tale of two simulations. First a "typical" history match and simulation was based on geologically derived reservoir porosity and porosity thickness maps. Second, a revised simulation based on geological AND geophysical input. The typical history match and simulation resulted in the generation of a number of successful workovers and new drills. When 3D seismic was used with the geological data to create porosity and phiH maps on the same scale as the engineering simulation, many additional workovers and new drills were identified, and a better understanding of the waterflood was gained. This was all done cost-effectively on PCs and low-end workstations with state-of-the-art software packages available to smaller independents.

The "typical" history match and reservoir simulation for a 59-year old field such as Texas' Foster/South Cowden, would typically use porosity, porosity thickness, and saturation distribution generated by the geologist, using the "standard" log suites run over the last 40 years. The addition of core analyses porosity and permeability from cores that have long since disappeared provide additional data. This data set generates maps with hard data points for 10-to-20 acre spacing. The simulation resulted in a number of workovers and new drill candidates. Production from the lower Grayburg increased by 285 BO and 75 MCFGPD as a result of three new drills and one deepening. Production increased by 97 BO and 24 MCFGPD from one upper Grayburg recompletion and one reentry. The simulation also indicated a "retooling" of the upper Grayburg waterflood was necessary. The results left everyone satisfied, but wondering if they could have done better.

Grayburg and South Cowden production was established in Laguna Petroleum's portion of the Foster/South Cowden Field in Ector County, Texas, in 1939. Water-free production from 400 to 1500 BOPD per well on 40-acre spacing was established from 3750 to 4200 ft in open holes completed with nitro. In the mid-1950s, the wells were hydro fraced, resulting in a three-fold increase in production. In 1961, 4 of the 16 wells in Section 36 were converted to injection. In the late 1970s, 20-acre infill wells were drilled. A total of 6.2 million have been produced from the three reservoirs (upper and lower Grayburg, and San Andres).

The original history match indicated that 85% of the floodwater has gone into the "A" zone of the upper Grayburg. The logs and multizone completion results indicated that the San Andres was a major contributor to the total oil production. As a result of the "geology only" history match and

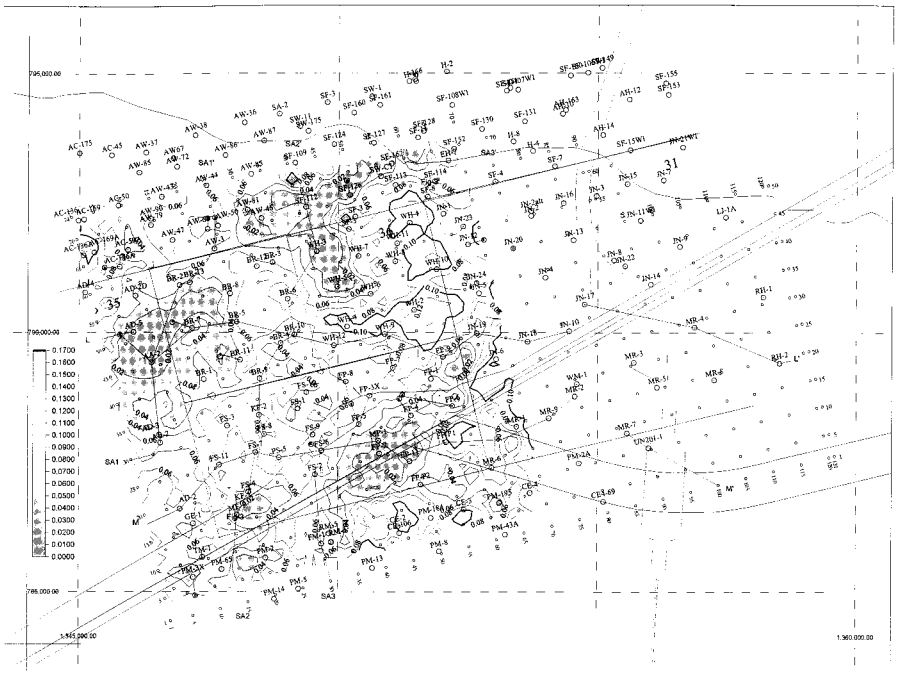

**Figure 4 Seismic-derived porosity for the Grayburg "A" zone**

**Higher porosity is shown in the northwest part of section 36. A low porosity area across the southeast part of section 36 is coincident with the structural shelf break, and forms a barrier to fluid flow.**

simulation, three wells were drilled and one deepened to the San Andres to tap the high-porosity, relatively undeveloped reservoir. Cores and a full suite of logs were taken in the three new drills. The core analyses and log evaluation indicated that although the San Andres has a large amount of original oil in place, the subaerial exposure at the end of San Andres time resulted in a heavily karsted, compartmentalized, low-permeability reservoir. This was confirmed by selected completions of the San Andres zone, which resulted in the discovery that the San Andres is a limited reservoir, and not a candidate for waterflood. Cores taken in the lower Grayburg along with selective completions indicate this reservoir has good potential in limited areas. However, injection tests in this zone indicate poor permeability. This result left the upper Grayburg as the main target in the study area.

The use of 3D seismic in reservoir evaluation has been tried in a number of reservoirs in the Permian Basin, with only limited success reported. This project, supported by the DOE and Laguna Petroleum, has demonstrated that when an inversion model of the 3D seismic (**Figure 4**) was coupled with the geological data to create porosity (**Figure 5**) and porosity thickness maps on the same scale as the engineering simulation, many additional workovers and new drills could be identified. Initially, attribute analyses were attempted with the wiggle trace data set in this study. Only a poor correlation between amplitude, frequency, and phase with porosity, and porosity thickness was observed. For the 3D seismic to be usable in the simulation, a high correlation coefficient is necessary. Inversion modeling was considered because it removes the wavelet from the data. Seismic inversion modeling is a computer applied process by which normal seismic traces (wiggle amplitude) are converted to log-like traces. Constraints of rock velocity and known seismic wavelet characteristics are used to calculate the inverted traces. Essentially, the process converts the conventional seismic response to a quantitative set of data directly relatable to engineering concerns.

Seismic velocity, derived from the inversion model, was plotted against the porosity derived from all available porosity logs. A crossplot of seismic velocity vs. log porosity was made for the upper Grayburg "A" zone. The crossplot had a low correlation coefficient. It was noted, however, that if only the wells with modern neutron-density crossplotted porosities were used, a high correlation coefficient was achieved.

A linear relationship between the seismic velocity and log porosity was established with an error bar of 1.5%. A porosity map generated from the inversion model-derived velocity was now input into the simulation. Striking features of the seismic derived porosity map are the low-porosity (less than 1%) trend, paralleling a break in slope on both the seismic and geological structure maps, and the high-porosity areas in the northeast quarter of Section 36. The low-porosity zone was also seen in the geologically derived porosity map, but the continuity and exact trend could only be guessed at because of

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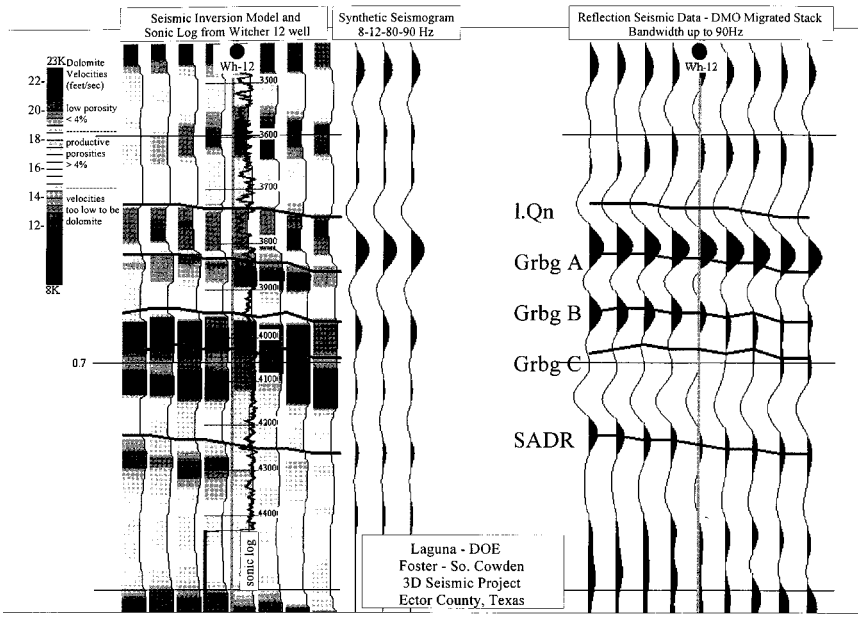


**Figure 5**

A comparison of Seismic Inversion Model traces to the reflection seismic data input traces. Inverted traces compare to the sonic log curve in velocity values and shape. Resolution of about 50 ft is achieved from the inversion model traces, compared to the 1 ft resolution of the sonic log. The synthetic seismogram trace, a product of the sonic log, compares well to the reflection seismic traces for major reflectors. Amplitudes are strong in the lower Grayburg and San Andres; the inversion model shows more velocity contrast there than the sonic log.

the low data density (one well per 14 acres). When the engineer looked at the porosity map, he observed that the low-porosity zone was actually a permeability barrier and proposed reorienting the simulation grid from parallel to the section lines to parallel and perpendicular to the "no flow" boundary. With this completed, a new simulation was run, significant differences in the present-day oil-in-place were seen. A number of additional workovers were identified, and a lease line injector and new producer proposed. To date, three additional re-fracs have been completed, with a sustained ten-fold increase in total production. Well tests and pressure buildup tests have recently been completed on 13 additional wells, identifying additional candidates for re-fracs.

In summary, inversion modeling has been demonstrated to improve the sensitivity of the reservoir simulation. The seismic-derived porosity maps are at the same scale as the simulation (110 by 110 ft bins for the seismic and 132 by 132 ft grid blocks for the simulation), whereas, the geologic derived porosity maps are based on well control at 990 by 990 ft, a much coarser grid. The cost-effective use of 3D seismic, state-of-the-art technology, and PCs by smaller independents can enhance production from older reservoirs.

We acknowledge James J. Reeves and Hoxie W. Smith for conceiving and managing the DOE study and for being responsible for the geophysical study. Since April 1996, William C. Robinson has been responsible for the reprocessing and reinterpreting the seismic data and for the geophysical study, and Robert C. Trentham has been responsible for project management.

# The *Class* Act

**The *Class* Act** is a biannual newsletter devoted to providing information about **DOE's Reservoir Class Program**.

For more information on Class Program projects, contact **Herb Tiedemann** at **DOE's National Petroleum Technology Office**:

Ph. 918-699-2017
Fax 918-699-2005

You may also contact **Viola Rawn-Schatzinger**:

Ph. 918-699-2018
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**Editor:** *Viola Rawn-Schatzinger, RMC, Inc.*
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# Optimization of Heavy-oil Production By Steamflood From a Shallow Sandstone Reservoir, Midway-Sunset Field, Southern San Joaquin Basin, California

by Steven Schamel, Energy & Geoscience Institute at the University of Utah

A previously idle portion of California's Midway-Sunset field, Aera Energy's Pru Fee property, has been brought back into commercial production through tight integration of geologic characterization, geostatistical modeling, reservoir simulation, and petroleum engineering. This property, shut-in over a decade ago as economically marginal using conventional cyclic steaming methods, has a 200-300 ft thick oil column in the Monarch sand. However, the sand lacks effective steam barriers and has a thick water-saturation zone above the oil-water contact. These factors require an innovative approach to steamflood production design that will balance optimal total oil production against economically viable steam-oil ratios and production rates. The methods used in this DOE Class III oil technology demonstration are accessible to most operators in the Midway-Sunset field and could be used to revitalize properties with declining production of heavy oils throughout the region.

The 40-acre Pru Fee property is located in the super-giant Midway-Sunset field and produces from the late Miocene Monarch sand, part of the Belridge Diatomite Member of the Monterey Formation. The Midway-Sunset field was discovered before 1890. The original 13 wells drilled on the Pru lease in the early 1900s were operated on primary production by Bankline Oil Company before 1959, then Signal Oil Company until 1969, when infill drilling and cyclic steaming was initiated by Tenneco. During the half century of primary production nearly 1.8 million BO was produced from the Pru property, 114,000-151,000 bbl per well, but production declined steadily reaching insignificant quantities by the late 1960s. Cyclic steaming was partially successful in extracting the remaining viscous 13° API oil until the Pru property was shut down in 1986 as uneconomic. Total secondary recovery from the 40-acre site peaked at about 300 BOPD in 1972, but by the time the property was shut-in it had dropped to less than 10 BOPD. ARCO Western Energy (AWE) acquired the lease in 1988 along with various producing properties in the Midway-Sunset field. On October 31, 1998, all of the AWE properties in the southern San Joaquin basin, including Pru Fee, were transferred to **Mobil and Aera Energy**, a Mobil-Shell joint-venture company.

In June 1995, the shut-in Pru Fee property was selected for a DOE Class III oil technology demonstration which initially resulted in the renovation of old wells and cyclic production facilities at the site and the drilling of two new wells, Pru 101 and TO-1. Pru 101 was cored, steam stimulated, then put into production. In January 1997, the

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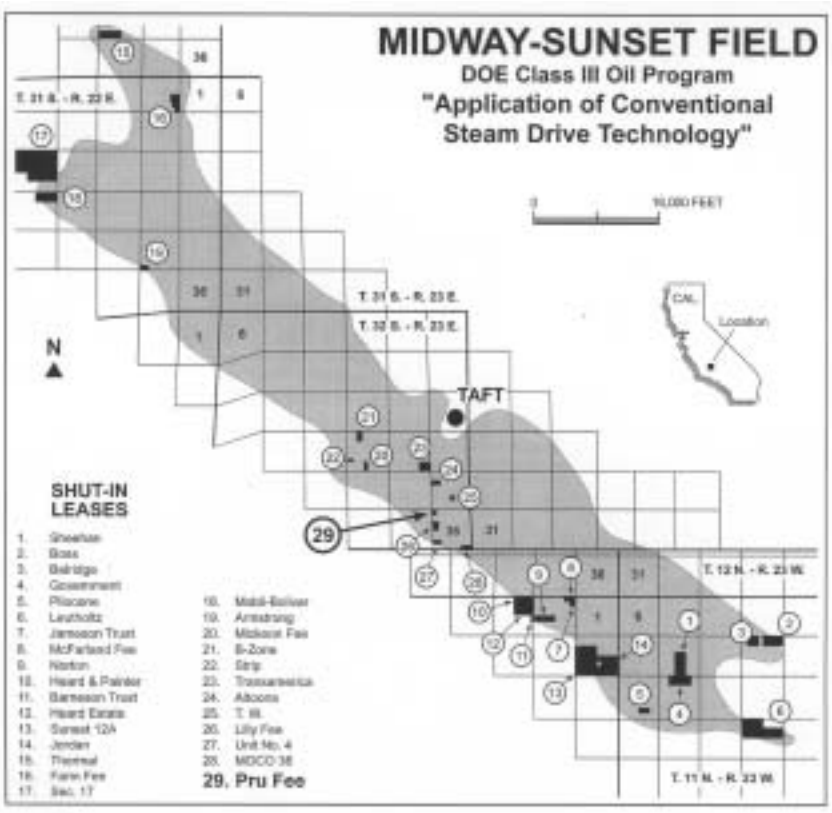


**Figure 6**

Map of the Midway-Sunset field showing the location of the Pru Fee property (#29) and other leases that were shut-in before the start of this DOE Class III oil technology demonstration.

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demonstration project entered its second and main phase with the purpose of demonstrating on an 8-acre pilot whether steamflood can be a more effective mode of production of the heavy, viscous oils from the Monarch sand reservoir than the more conventional cyclic steaming. The objective is not just to produce the pilot site within the Pru Fee property south of Taft (**Figure 6**), but to test which production parameters optimize total oil recovery at economically acceptable rates of production and production costs.

The Monarch sand is present at depths of 1100-1400 ft at the Pru Fee property. Like other sand bodies within the Monterey Formation, it is a deep submarine channel or proximal fan deposit encased in diatomaceous mudstone. The sand is derived from an elevated portion of the Salinas block, which during the late Miocene lay immediately to the west of the San Andreas fault, just 15 miles to the west of the site. The top of the Monarch sand, actually a Pliocene/Miocene unconformity, dips at less than 10° to the southeast. The unconformity bevels downward at a very low angle to the northwest across the upper portion of the Monarch sand body. The net pay zone, which averages 220 ft at Pru, thins to the southeast as a top of the sand dips through the nearly horizontal oil-water contact. The only other oil-bearing unit at the Pru Fee property is the Tulare Formation, interbedded fluvial sands and shales at a depth of about 500 ft which contain an estimated 2.5 million bbl

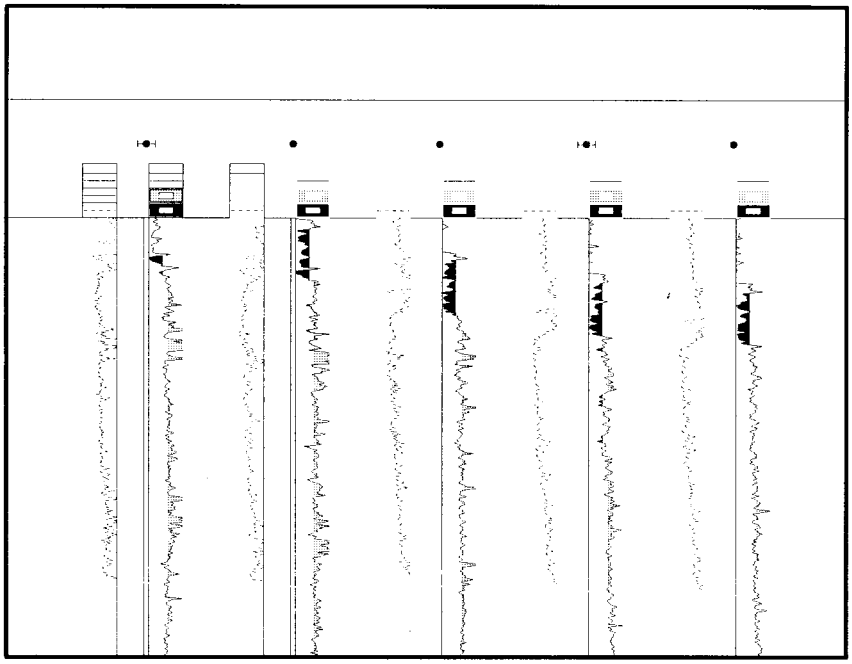

**Figure 7**

Representative wells through the Monarch sand reservoir at the Pru Fee property showing thick transition zone of downward decreasing oil saturation in the pair of curves to the far left. From left to right the curves are (1) project SW based on Pru 101 core calibration, (2) standard Archie SE, (3) gamma ray, and (4) density. The project SW equation yields oil saturations about 5% greater than those determined from the standard Archie calculation. The wells shown (from left to right) are TO-2, 202, 206, TO-3, and 209. The locations of the wells in the pilot array are shown in Figure 6.

potential reserves. These additional reserves were discovered as a consequence of drilling and logging the wells for the DOE Class III demonstration pilot.

Average Monarch sand reservoir characteristics derived from core and the log model developed for this project are 31% porosity and 2250 md permeability. The initial (1995) average oil saturation is estimated to be 59%. However, all wells have a relatively thick transition zone of downward decreasing oil saturations in the bottom half of the pay interval (**Figure 7**). The oil is both heavy and viscous, 13° API and 2200 cp at the reservoir temperature of 100° F.

During the initial phase of the project, a multifaceted feasibility study was carried out to examine whether the pilot project could be justified technically and economically at this site. This study included:

**1.** Recompletion of nine shut-in wells and drilling of an additional producer and a new temperature observation well. A core was taken from the reservoir interval in the new producer, Pru-101. The wells were produced by conventional cyclic steaming over a period of 15 months to establish a production baseline for the site.

**2.** Characterization of the stratigraphy and petrophysical properties of the Monarch sand reservoir using existing well logs and analyses on samples in the core taken from Pru-101. The resulting data were used to develop a geostatistical model of

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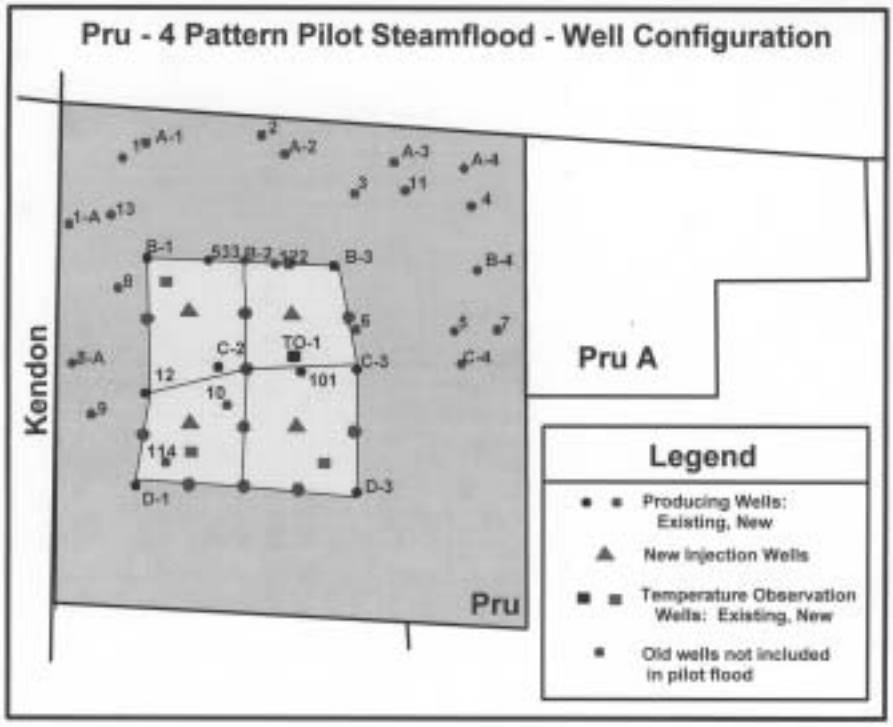


**Figure 8**

Map of the Pru Fee property showing the well configuration in the four-pattern pilot steam flood. The Pru property is 40 acres in size and 1250 feet in E-W direction.

the reservoir at the Pru Fee property and a specific reservoir simulator for the pilot test site on the property.

**3.** Use of the reservoir simulator to test various steamflood and cyclic-steaming production options leading to design of a production strategy for the pilot steamflood based on a four-pattern, 9-spot array covering 8 acres near the center of the 40 acre Pru Fee property. The array chosen required drilling additional producers and injectors to supplement the existing wells recompleted in the initial phase of the project.

Reservoir simulations with geostatistically generated data sets revealed that the initial fluid distribution in the reservoir had the most significant impact on the economics of the cyclic-flooding process. The initial fluid distribution was determined by the placement of the oil-water contact and the resulting transition zone in the reservoir. The current approach involves initial steam injection within the upper third of the oil column, where the oil saturation (SO) is greater than 60%, so as to avoid undue loss of heat to water. Simulations predict recovery of 23% of original oil in place (OOIP) over a 10-year project cycle following a conventional steamflood strategy alone. However, simulations show that as production proceeds and unrecovered oil drains downward, the injection string can be shifted downward to keep pace with the observed steam chest and the simulated high SO interval. After approximately 5 years of production by conventional steamflood through vertical wells, during which time an estimated 16% OOIP will be recovered from the 8-acre pilot, an additional 15% OOIP can be recovered by a pair of appropriately placed horizontal wells.

Activities on the pilot site during the actual steamflood demonstration included drilling 18 new wells: 11 producers (Pru-201 through Pru-211), 4 injectors (Pru 12-1 through Pru 12-4), and three temperature observation wells (TO-2 through TO-4). The drilling was started on January 14, 1997 and completed on March 16, 1997. All wells were logged. The four-pattern, 9-spot array (**Figure 8**) uses 10 pre-existing wells that were recompleted and cyclic steamed in the initial phase of the project. All new wells were drilled into the oil-water contact to establish the depth of that horizon. The producers were completed through the entire pay zone, however, the injectors were completed so as to maintain the critical standoff from the oil-water contact deemed optimal in earlier simulations. Based on the new wells, the stratigraphic model for the pilot was reevaluated using GeoGraphix (GES and Prizm) workstation software, and the geostatistical distribution of porosity and permeability was rerun using GeoMath's Heresim package. This analysis preceded revision of the thermal simulator for the pilot. History matching of steam injection rates and monthly production to fine tune the simulator will provide the basis for optimizing production practices and parameters for the next several years of the demonstration.

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During the initial cyclic baseline test period in 1996, production for the total group of 9 wells averaged about 65 BOPD, ranging from 3 to 10 BOPD per well for the old wells and about 15 BOPD for the new Pru 101 well. Total production during the cyclic baseline testing was 28,700 BO. As soon as the group of new producers had been primed by steaming and in turn put into production in the early summer 1997, rates for the pilot climbed to nearly 400 BOPD. The sharp increase in production can be attributed in part to the increase in the number of producers from 9 to 20 and the fact that the performance of the new wells is consistently better than the old renovated wells. However, the well average jumped from about 8 BOPD to nearly 20 BOPD with the onset of the pilot steam flood. As of late 1998, the rate at the Pru pilot was averaging 330 BOPD. To date, the cumulative production of the Pru pilot (phase 2) is 192,500 BO, which exceeds projections based on the current thermal simulator by about 20%. Temperature monitoring at the site is suggesting that full steamflood production had begun late in 1997.

The early production success of the pilot and the discovery of significant quantities of oil in the Tulare Formation during the preparation of the pilot led AWE early in 1998 to expand operations elsewhere in the Pru Fee property. Twelve cyclic producers in the Monarch sand marginal to the pilot put into production in the first half of 1998 have already yielded an additional 35,500 BO. It is anticipated that a substantial increase in production soon will be coming from the group of 23 additional wells in the Monarch sand and 19 new wells in the Tulare Formation. These wells were put into cyclic production late in 1998.

It is highly likely that without the incentives to AWE to partner with the DOE Class Program in carrying out this pilot project, the Pru Fee property never would have been brought back into production. Based on historic performance and the existing geologic evaluation, it was *known* to be a highly marginal property. Yet in the three years since the initiation of the DOE Class III demonstration the total production from this 40-acre shut-in tract has gone from zero to nearly 400 BOPD, and AWE has invested in a total of 54 new producers external to the pilot. Total production since the end of 1995 is 254,900 BO.

Members of the project team, past and present, are Steven Schamel (project manager), Milind Deo, and Craig Forster, **University of Utah**; Bob Swain, Kevin Olson, and Michael Simmons, **ARCO Western Energy**; Creties Jenkins and Ray Wydrinski, **ARCO Exploration and Production Technology**; and Douglas Sprinkel and Roger Bon, **Utah Geological Survey**. It is anticipated that Thomas Zeiner, Jaime Roig, and Lucy Bultmann will join the project team when **Aera Energy** begins operating the Pru Fee property in January 1999. The DOE program manager responsible for the project is Gary D. Walker, assisted by Viola Rawn-Schatzinger of **RMC, Inc.**.

## Class Projects In Review

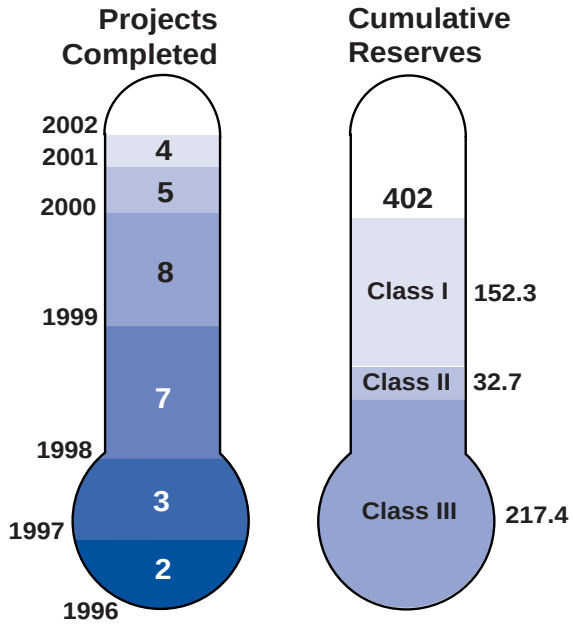


**Figure 9**
The number of completed Class projects and the total reserves generated by the 29 class projects. The thermometer on the left indicates the number of projects completed or scheduled to be completed each year. On the right, a scale shows the 402 million bbl of new oil reserves resulting from the combined Class I, II, and III projects.

# C A L E N D A R

## Workshops/Conferences

**February 1999, PTTC Workshop,** *"Wireline Logging Applications in the Michigan Basin".* Call W. B. Harrison, 616-387-5488 for details.

**March 10-12, 1999 SIPES Annual Convention, Wichita, KS,**

*"Stewart Field Waterflood Project"* by Rodney Reynolds, University of Kansas, Class I.

**March 17-18, 1999 TORP, Wichita, KS,**

*"Stewart Field Waterflood"* by Jason Sizemore, Class I, *"Savonburg Field Project"* by Rodney Reynolds, University of Kansas, Class I.

**Spring, 1999 Roswell Geological Society, Roswell, NM,**

*"Seismic Attribute Analysis"* by Bruce Stubbs, Strata Production, Class III.

**April 11-14, 1999 AAPG Annual Convention, San Antonio, TX,**

*"Controls on Reservoir Quality Distribution in the Ramsey Sandstone Deep-Marine Clastic Reservoirs, Bell Canyon Formation, Delaware Basin, Texas"* by S. P. Dutton, M. D. Barton, J. I. Guzman, G. B. Asquith and A. G. Cole, Univ. of Texas BEG, Class III (Poster Session, April 13).

*"Diagenetic Characterization of Shallow-Shelf Carbonate Reservoirs, Pennsylvanian Paradox Formation, Southern Paradox Basin, Utah"* by T. C. Chidsey, Jr. and D. E. Eby, Utah Geological Survey Class II (Poster Session, April 12).

*"Using Detailed Gamma-Ray Log Correlations to Understand Depositional Patterns of a Fluvial-Deltaic Lacustrine Reservoir"* by C. D. Morgan, Utah Geological Survey Class I (Poster Session, April 13).

*"Fractured Reservoirs in Michigan Basin"* by J. R. Wood, and W. B. Harrison, Michigan Technical University, Class II.

*"The Use of Seismic Data and Attributes for Reservoir Characterization in Crystal Field, Michigan"* by Terra Lutch and W. D. Pennington, presented in SEPM Session (April 12), Seismic Imaging and Modeling of Depositional Systems and Facies, Michigan Technical University, Class II.

**May, 1999 PTTC Waterflood Workshop, Kansas**

*"Stewart and Savonburg Fields Case Studies".* Contact Rodney Reynolds, 785-864-7398 for date and information.

**May 14, 1999 Permian Basin Geophysicis Society Spring Exploration,**

*"Tomography (Acquisition, Analysis and Interpretation) West Welch Field"* by Jim Justice, Advanced Reservoir Technologies, OXY Project, Class II.

**June 28-30, 1999, Oil and Gas Conference—Technology Options for Producers Survival, Dallas, TX,**

*"A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam to Bond the Sand Grains"* by Scott Walker, Tidelands Oil Co.

*"Increased Oil Production and Reserves Utilizing Secondary/Tertiary Recovery Techniques on Small Reservoirs in the Paradox Basin, Utah"* by T. C. Chidsey, Jr., Utah Geological Survey

*"New Techniques for Using Old Geophysical Logs in Reservoir Characterization: Examples from Bell Canyon Sandstones, Ford Geraldine and East Ford Units, Delaware Basin"* by S. P. Dutton, G. B. Asquith, J. I. Guzman, and W. A. Flanders, University of Texas BEG.

*"Air Injection in a Gulf Coast Light Oil Field"* by Travis Gillham, Amoco.

*"Improvement in Performance of a Mature Oil Field Through Horizontal Well Drilling"* by Mohan Kelkar, University of Tulsa.

*"Exploration Methods & Basin Analysis"* by James Wood, Michigan Technological University.

*"$CO_2$ Flood Utilizing Horizontal Injection Wells"* by Rex Owen, Phillips Petroleum.

*"Cost-Effective Techniques for Improved Oil Recovery in Mississippian Carbonate Reservoirs of Kansas"* by Tim Carr, Kansas Geological Survey.

*"Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic Reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, New Mexico"* by Mark Murphy, Strata Production Co.

*"Major Pennsylvanian Fluvial-Deltaic Light Oil Reservoir Systems in Oklahoma"* by Jock Campbell, Oklahoma Geological Survey.

*"A Low-Cost Solution for Enhanced Waterflood Performance"* by James Stephens, Hughes Eastern Corporation.

*"Incorporating Seismic Attribute Porosity into a Flow Model of the Grayburg Reservoir in the Foster-South Cowden Field"* by Bob Trentham, Laguna Petroleum.

*"Improved Oil Recovery in Fluvial Dominated Deltaic Reservoirs of Kansas"* by Don Green, Kansas Geological Survey.

*"Bed-Isolation Treatments of a Mature Well in the Bluebell Field on the Uinta Basin, Utah, That Has Undergone Numerous High Volume Shot-Gun Completions"* by Craig Morgan, Utah Geological Survey.

# Class Revisit

The Class Revisit was announced in January. Proposals must be submitted within 90 days of the announcement. Projects from Class I, II, and III reservoirs are eligible for DOE funding under this announcement. Projects from all states, including Alaska, will be considered, as will both heavy or light oil reservoirs. For information, see the DOE Home Page at **http://www.npto.doe.gov**

# Final Reports Available

Final reports for completed projects are available from DOE. Contact Herb Tiedemann at **htiedema@npto.doe.gov** or 918-699-2017.

Reports available include:

- Diversified Operating, BC14954-14
- Oklahoma Geological Survey, BC14956-16
- Lomax Exploration (Inland Resources), BC14958-15
- University of Texas BEG, BC14959-21
- Michigan Technical University, BC14983-14
- Luff Exploration, BC14984-16
- Field Demonstrations of Logging Technologies for Reservoir Characterization NIPER/BDM-0379

Advanced Class Projects

- James E. Russell Petroleum 91008-10
- Diversified Operating Corp. 91008-11
- Kansas Geological Survey 91008-12

**Herb Tiedemann**
**Department of Energy**
**National Petroleum Technology Office**
**P. O. Box 3628**
**Tulsa, OK 74101-3628**