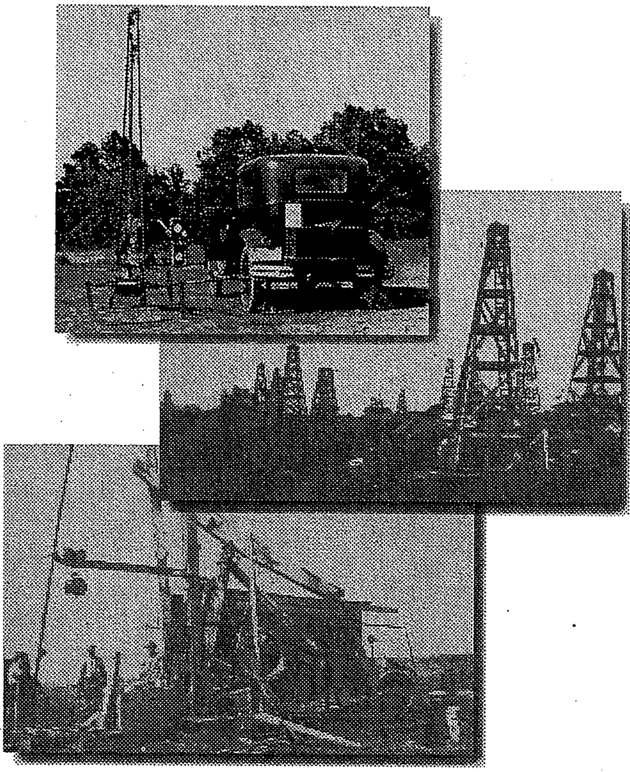

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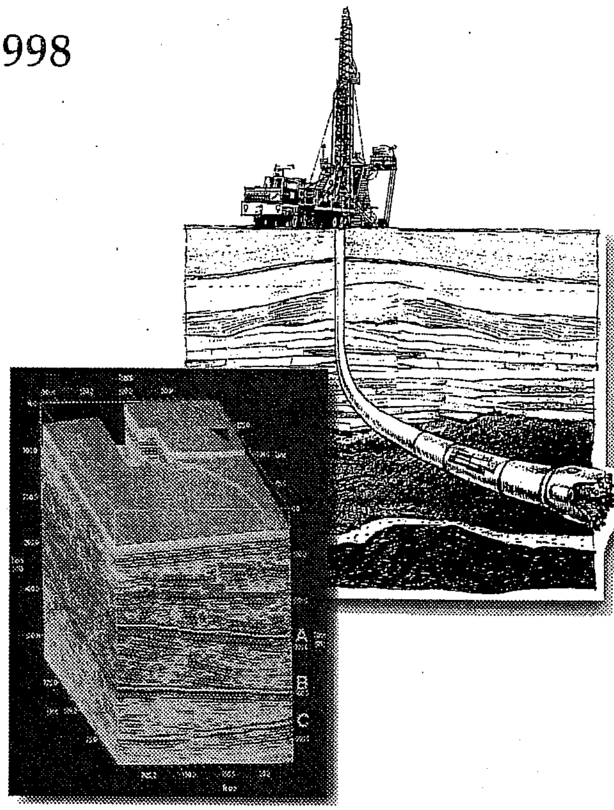
U. S. Department of Energy
National Petroleum Technology Office
Tulsa, Oklahoma

Petroleum Technology Advances Through Applied Research by *Independent Oil Producers*

September 1998



Implemented by
BDM-Oklahoma, Inc.
National Institute for Petroleum and Energy Research
Bartlesville, Oklahoma

PETROLEUM TECHNOLOGY ADVANCES THROUGH APPLIED RESEARCH BY INDEPENDENT OIL PRODUCERS

Work Performed Under Contract No.
DE-AC22-94PC91008

Prepared for
U.S. Department of Energy

DISCLAIMER

BDM-Oklahoma, Inc.
P.O. Box 2565
Bartlesville, Oklahoma 74005

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Tables & Figures

Support to Independents

Petroleum Technology Advances Through Applied Research by Independent Oil Producers

Introduction

The United States Department of Energy, through the National Petroleum Technology Office (DOE/NPTO), is targeting technical assistance through "Research and Development by Small Independent Petroleum Operators" (Support to Independents) to provide solutions for local production problems. Small independents are defined as those having less than 50 employees. Many small independents lack resources to test unfamiliar technologies or novel, unproven approaches without cost-sharing to reduce financial risk. By providing cost-sharing ($50,000 or less per project), DOE/NPTO is encouraging producers to experiment with higher risk approaches that could mean the difference between maintaining production or shutting down an oil field.

The goals and objectives for this program are as follows:

1. Extend the economic production of domestic fields by slowing the rate of well abandonments and preserving industry infrastructure (including facilities, wells, data, and expertise).
2. Increase ultimate recovery in known fields using advanced technologies by demonstrating:
   - Better methods for formation evaluation
   - Developmental oil recovery and production technologies
   - Well control and remedial work for environmental compliance
3. Use field demonstrations to broaden information exchange and technology application among stakeholders by:
   - Expanding participation in DOE projects to include both traditional and non-traditional participants
   - Increasing third-party participation and interaction throughout the life of DOE-sponsored projects
   - Making technology transfer products user-friendly

Since the initial program announcement in February 1995, 22 projects have been awarded. About one in five proposals has received an award. Table 1 summarizes the name of the company, project location, technology area, and specific technical activity employed for each project. Individual fact sheets in the tabbed sections contain specific project information and the results reported to date.

Table 1 Technology Development Contracts

Company	State	Technology	Technical Activity
Brothers Production	TX	Exploration	3-D Seismic Processing
Cleary Exploration	OK	Drilling	Horizontal Drilling
Cobra Oil & Gas	AL	Formation Evaluation	Schlumberger FMI
Dakota Oil Producers	WY	Improved Oil Recovery	Inert Gas Injection
Diamond Exploration	KS	Improved Oil Recovery	Stimulating Formations Thermally
Double Eagle Enterprises	OK	Exploration	3-D Seismic and Surface Microbial
EDCO Oil Company	OH	Drilling	Horizontal Drilling
Edmiston Oil Company	KS	Improved Oil Recovery	Microbial Improved Oil Recovery
Grace Petroleum	OK	Water Production	Gel Polymer Treatment
Harry A. Spring	OK	Water Production	Cost-Effective Water Disposal
Industrial Technology Management	CA	Production Problems	Resin-Coated Prepacked Gravel
J.R. Pounds	MS	Wellbore Problems	Oxygen Activation Log
James Engineering, Inc.	OH	Operations	Computerized Well Monitoring
K-Stewart Petroleum	OK	Production Problems	Improved Well Stimulation
Keener Oil & Gas	OK	Exploration	Telluric Surveys
Kenneth Y. Park	OK	Water Production	Gel Polymer
Rock Island Services Co.	WV	Wellbore Problems	Microbial Clean-Up of Paraffin
Sandia Operating Corp.	TX	Formation Evaluation	Low-Invasion Coring System
Sipple Petroleum Company	KY	Stimulation	Foam Fracturing
Speir Operating	IN	Wellbore Problems	Microbial Wellbore Clean-Up
Tenison Oil Company	LA	Wellbore Problems	$CaCO_3$ Prevention
X-TRAC Energy, Inc.	CO	Improved Oil Recovery	Solvent Extraction

All 22 projects have final results. Of the 22 projects, 18 are a technical success. More time is needed to evaluate whether technical success translates into economic success. One project experienced field or operational problems which prevented evaluating the targeted technology. Although three projects appear unsuccessful, insight concerning limitations of the technologies employed is valuable. The following tables give information on these results.

Table 2 Final Indications of Technical Success (Completed Projects)

Company	State	Technology	Technical Activity
Brothers Production	TX	Exploration	3-D Seismic Processing
Cobra Oil & Gas	AL	Formation Evaluation	Schlumberger FMI
Dakota Oil Producers	WY	Improved Oil Recovery	Inert Gas Injection
Double-Eagle Enterprises	OK	Exploration	2 & 3-D Seismic Processing
Edmiston Oil Co.	KS	Improved Oil Recovery	Microbial Improved Oil Recovery
Grace Petroleum	OK	Water Production	Gel Polymer Treatment
Harry A. Spring	OK	Water Production	Cost Effective Water Disposal
Industrial Technology Management	CA	Production Problems	Resin-Coated Prepacked Gravel
J.R. Pounds	MS	Wellbore Problems	Oxygen Activation Log–Located Holes in Casing w/Pressure Testing
K-Stewart Petroleum	OK	Production Problems	Improved Well Stimulation
Kenneth Y. Park	OK	Water Production	Gel Polymer
Rock Island Services Co.	WV	Wellbore Problems	Microbial Clean-Up of Paraffin
Sandia Operating Corp.	TX	Formation Evaluation	High-Resolution Logging
Sipple Oil Company	KY	Stimulation	Foam Fracturing
Speir Operating	IN	Wellbore Problems	Microbial Wellbore Clean-Up
Tenison Oil Company	LA	Wellbore Problems	Calcium Carbonate Prevention
X-TRAC Energy, Inc.	CO	Improved Oil Recovery	Solvent Extraction

Table 3 Lessons learned—Technical Failures (Completed Projects)

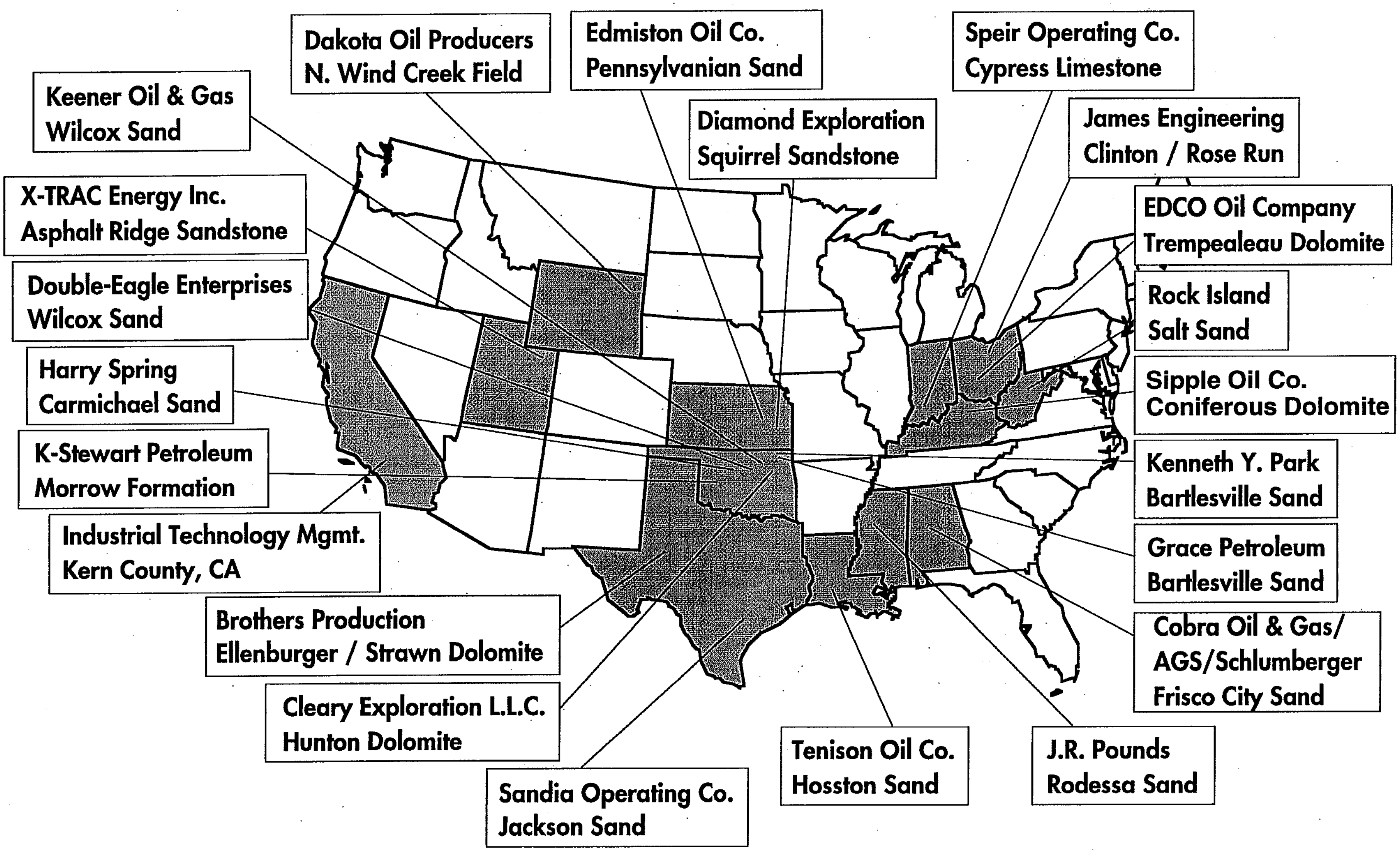
Company	State	Technology	Technical Activity
Cleary Exploration	OK	Drilling	Horizontal Drilling
Diamond Exploration	KS	Improved Oil Recovery	Stimulating Formations Thermally
EDCO Oil Company	OH	Drilling	Horizontal Drilling
Keener Oil & Gas	OK	Exploration	Telluric Surveys

DOE/NPTO also administers three other programs that are aimed at larger reservoirs and involve full-scale field tests: Reservoir Management, Class and Field Demonstrations, and Advanced Demonstrations. The field tests, in most cases, demonstrate multiple techniques for maintaining production. Additional information about the Reservoir Class Field Demonstration Program is available from Herb Tiedemann (phone, 918-699-2017; e-mail, htiedema@ npto.doe.gov) at DOE/NPTO.

The Support to Independents effort discussed in this publication pinpoints specific production problems and attempts to demonstrate lower cost remedies, often focusing on an individual well or group of wells. The project location map (see Figure 1) and technology development contracts table (see Table 1) illustrate the diversity of project locations and technologies.

Current projects and other projects added to the program in the future will be the focus of an extensive technology transfer effort by DOE/NPTO and BDM-Oklahoma. Through workshops, technical reports, and the use of expanding DOE and industry electronic networks, techniques and results from the trial projects will be made available to other producers. For additional information, please contact Rhonda Lindsey (phone, 918-699-2037; e-mail, rlindsey@npto.doe.gov) at DOE/NPTO.

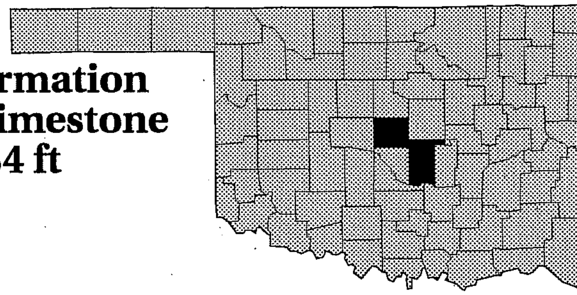
Support to Independents Project Map



horizontal drilling to increase production

CLEARY EXPLORATION L.L.C.
OKLAHOMA CITY, OK

Hunton Formation
Dolomitic Limestone
@ 5,734 ft



TECHNOLOGY AREA
Drilling

PROBLEM
Water Production by Encroachment up Natural Fracture System Increases after Acid Stimulation

SITUATION
Low Oil Production and Recovery

RESULTS
Project Completed

Initially Production Increased

Horizontal Section of Hole Collapsed, Stopping Production

Background

Cleary attempted to reenter and complete an abandoned well in a low-permeability, fractured dolomitic limestone reservoir in Section 18, Township 11N, Range 2E, near the line separating Oklahoma and Pottawatomie counties, Oklahoma. After acid treatment, the well started producing 21 barrels of oil per day (BOPD) plus 130 barrels of water per day (BWPD). Approximately 60 days later, however, production had declined to 9.4 BOPD plus 14 BWPD. In this producing trend, Hunton wells tend to produce less oil and more water after acid treatment because, it is believed, acid widens fractures, thus allowing water to move upward into the wellbore.

Project Description

Cleary proposed using an existing vertical well as the basis for drilling a new horizontal well. Cleary planned to first pull the well casing, then plug it back and drill a horizontal well with a 300-foot turning radius and extending approximately 1500 feet to the northwest. Because the primary fracture direction is northeast-southwest, a well drilled to the northwest is projected to intersect more fractures, increasing production and recovery of the oil. A successful horizontal well in this project is expected to stimulate horizontal drilling in four adjoining counties, where completions in fractured Hunton dolomitic limestone reservoirs have been marginal to noncommercial.

Results

The final report on this project to reenter and complete an abandoned well has been received. All phases were completed including preparing the well and pulling casing, conditioning the hole and sidetrack, drilling the build section and lateral, completing the well, and putting on production.

Initially swabbing the well yielded a total fluid production of approximately 600 barrels per day with a 30–40% oil cut encouraging completion to proceed. The service company tripped in hole with tubing, mud anchor, and seating nipple. Pump and rods were set in the well, and the beam pumping unit installed.

The well had about a 1500-foot fluid level, and the total fluid production was significantly increased in the horizontal hole over that of the vertical well. Initial performance from operations showed the beam pump incapable of moving the amount of fluid produced by the horizontal hole. Therefore, a submersible pump was considered to replace the beam pump.

Correspondence included with the final report, stated the horizontal portion of the hole was lost because the first 200 feet collapsed. The company stated they hope to re-drill the horizontal section.

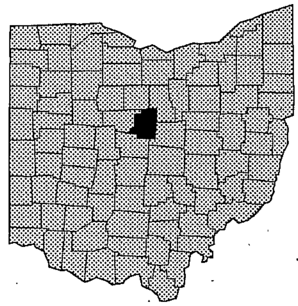
Project Funding

DOE made an award for a cost-shared project of $165,000 (30% DOE, 70% CLeary Exploration L.L.C.) to Cleary Exploration L.L.C. for this horizontal well.

horizontal drilling for improved wellbore drainage

EDCO OIL COMPANY
MT. GILEAD, OH

Trempealeau Formation @ 3,088 ft



TECHNOLOGY AREA
Drilling

PROBLEM
Heterogeneous Formation Low Reservoir Energy

SITUATION
Low Oil Production

RESULTS
Project Completed Horizontal Well Failed to Improve Production

Background

Oil was discovered in Morrow County, Ohio, in 1961 and started a drilling boom. Numerous wells were drilled because there was no spacing regulation. Consequently, the reservoir energy was prematurely depleted, leaving a significant quantity of oil in this heterogeneous reservoir. The operator proposed to drill a horizontal well to tap into the pools of trapped oil thought to exist but not produced due to compartmentalization and low reservoir energy. The well selected for this project is the Shaver-Neff No. 1 located in Section 15 of Peru Township, Morrow County. Shaver-Neff No. 1 was producing 6 barrels of oil and 12 barrels of salt water per day. The oil zone is thick enough to allow a margin of error in the drilling process.

Project Description

The horizontal drilling method was chosen based on the following criteria:

1. Drilling with air is essential because of the pressure-depleted reservoir.
2. For the same reason, the horizontal wellbore should be close to the vertical wellbore to ensure that the downhole pump can reach the fluid level in the well.
3. A short-radius horizontal well is needed to fulfill criterion 2.

Horizontal Ventures, Inc. was contracted to drill the horizontal well because of its expertise in drilling short-radius horizontal wells. Drilling started in August 7, 1996. A window was milled in 4-1/2 inch casing, and a short radius curve was successfully drilled. The drill pipe stuck and twisted off after approximately 30 feet of the horizontal wellbore was drilled. Attempts to retrieve the drill pipe were unsuccessful. The well was recompleted and put back on production in September 1996.

Results

After seven weeks of pumping the Shaver-Neff No. 1 well, the production decreased to 2 barrels of oil and 7 barrels of salt water per day. The production rate is less than before drilling the horizontal well. The reason for this disappointing result is the inability of the pump to remain submerged (low fluid level).

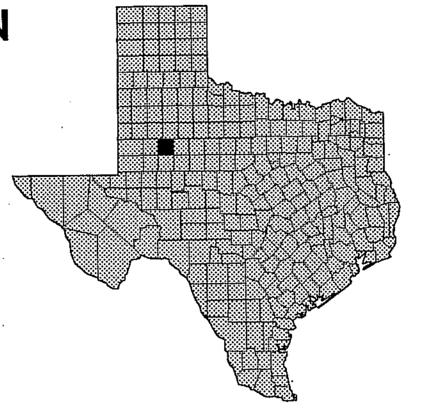
Project Funding

A project award of $78,000 (50% DOE, 50% EDCO Producing Inc.) was made to EDCO Producing Inc. for this horizontal well project.

improved 3-D seismic processing techniques

BROTHERS PRODUCTION MIDLAND, TX

Ellenburger/Strawn Dolomite @ 8,300 ft



TECHNOLOGY AREA
Exploration

PROBLEM
Could Not Map Ellenburger Reflections in 3-D Seismic Survey

SITUATION
Identification of Bypassed Oil for Selecting Drilling Locations

RESULTS
Project Completed

Ellenburger Reflections Successfully Mapped

Background

Brothers Production Company (Midland, Texas) and Pathfinder Oil & Gas, Inc. (Houston, Texas) own and operate Ellenburger (Cambro-Ordovician age) and Strawn (Pennsylvanian age) oil-producing properties in Fluvanna, SW Field in Borden County, Texas. Brothers and Pathfinder had acquired a 17.5-square-mile 3-D seismic survey in and adjoining the Fluvanna, SW Field. As often happens on the Permian Basin Eastern Shelf, the seismic contractor had been unable to map the Ellenburger dolomite. The operators contracted with ERC Tigress in Houston to use its new algorithm to reprocess and interpret the 3-D seismic data.

Seismic Processing

The seismic reprocessing involved the following sequential steps:

- Tying all seismic data to existing sonic logs by inverting the seismic data
- Correcting the seismic data and tying in all other wells to the corrected seismic data
- Conducting a velocity analysis using new equations developed by ERC Tigress
- Interpreting the reprocessed data

ERC Tigress has completed the processing and velocity analysis and is currently interpreting the reprocessed data.

Results

Geophysicists with ERC Tigress were able to map an Ellenburger dolomite reflection on the records. This reflection showed probable faulting extending to the top of the Ellenburger and, in some cases, into the overlying Mississippian and Strawn carbonates. Locations in the Ellenburger and Strawn reservoirs containing possible bypassed oil have been identified. Results remain to be confirmed by drilling. Achieving reliable Ellenburger reflections on the Eastern Shelf represents a significant advancement in 3-D seismic processing technology. Brothers Production Company staff estimates that approximately 150,000 barrels of new oil reserves have been identigfied by reprocessing and interpreting 3-D seismic data.

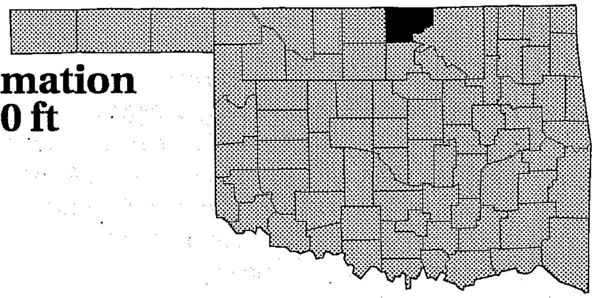
Project Funding

Total project cost was $500,000, Brothers Production Company contributed 90% or $450,000. Acquiring 3-D seismic data cost $450,000, and reprocessing 3-D seismic data cost $50,000. Highly leveraged DOE funding contributed to a significant advancement in 3-D seismic processing technology.

integrated exploration using 3-D seismic

(formerly integrated exploration using 3-D seismic and surface microbial techniques)

DOUBLE-EAGLE ENTERPRISES TULSA, OK



Wilcox Formation @ 4,000 ft

TECHNOLOGY AREA
Exploration

PROBLEM
Subsurface and 2-D Seismic Data Unable to Locate Prospect

SITUATION
Low Exploration Success Rate

RESULTS
Project completed 3-D Seismic Interpretation Successful

Background

Double-Eagle Enterprises has conducted subsurface and 2-D seismic mapping studies to identify candidate areas in Kay County, Oklahoma. The subsurface studies target the Ordovician-age Wilcox sandstone as the objective formation for prospecting. Usually, these studies do not provide enough information to locate the most productive area and to confirm the highest point on a Wilcox structure.

Project Description

Double-Eagle Enterprises proposed to conduct 3-D seismic surveys on areas identified by its subsurface studies. An area of 40 to 100 acres was to be surveyed. The company planned to use a dynamite energy source for collecting one set of data and a vibroseis energy source for the other set of data to compare data quality for each methodology.

Results

Double-Eagle Enterprises, Inc. completed the 3-D Seismic Survey over the Hinton Prospect in Section 23, Township 29N, Range 1E, Kay County, Oklahoma. As outlined in the July 31, 1997, update letter covering the revised project, Double-Eagle Enterprises has sent the data to Star Geophysical in Oklahoma City for processing. Interpretation of the Hinton data was completed in September. Permitting of the surface owners at the Sewell Prospect, Section 18, Township 29N, Range 2E was completed on August 18. Because of wet conditions over the Sewell Prospect, Nemaha Resources delayed shooting seismic until the first week of September. Data interpretation and drillsite selection on both prospects were completed by mid-October.

Also Double-Eagle completed the 3-D seismic survey and spudded a 4,200-ft. Arbuckle test well at a S/2 NW NW SW Sec. 17,T29N,R2E location. Parsons Engineering Corp., the operator, has signed a drilling contract with Mendenhall Drilling. Drilling on the Sewell Prospect began in March 1998. Double-Eagle provided BDM with daily drilling reports and a technical summary of the well results.

Parsons Engineering did spud and drill a 4,000-ft. Wilcox test at S/2 NW NW SW Sec. 17, T29N, R2E in Kay County, Oklahoma. The Wilcox was wet, and the No. 1-17 Blanche well encountered an additional 100 ft. of Mississippian limestone section. Parsons Engineering, the operator, has subsequently plugged and abandoned the well.

Although the No. 1-17 Blanche well was structurally the highest well on top of the Mississippian, an unanticipated thickening of the Mississippian section caused the Wilcox sand (primary target) to be structurally flat and unfortunately wet. Because the Wilcox was low, drilling was discontinued at the base of the Wilcox sand. The Arbuckle, which needs to be structurally high to be productive, was not tested.

Although these results were disappointing for the investors, the 3-D seismic was very successful. Through the DOE cost-sharing contract, several small investor groups and independents were introduced to the power of 3-D seismic. After the drilling and log evaluation had been completed, the seismic data were revisited and found to suggest that the Mississippian section was thickening at the drill site, and the structure all thought they had been drilling may be only a seismic velocity pull-up. Several geophysicists had reviewed the Sewell database and missed this intepretation. This information can now be integrated into future drilling plans in Kay County.

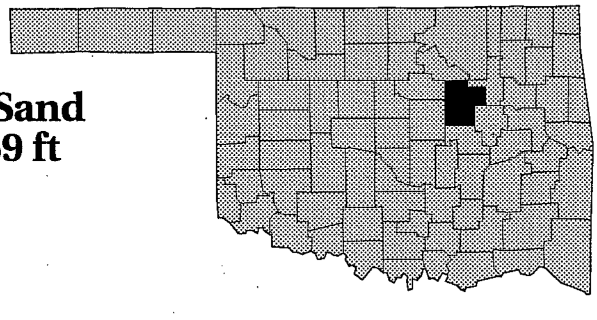
Project Funding

A project award of $290,000 (17% DOE, 83% Double-Eagle Enterprises, Inc.) was made to Double-Eagle Enterprises, Inc. for this integrated 3-D seismic.

telluric surveys

KEENER OIL & GAS TULSA, OK

Wilcox Sand @ 3,869 ft



TECHNOLOGY AREA
Exploration

PROBLEM
Locate Structure with Alternative Geophysical Technology

SITUATION
Use Geophysical Technology to Reduce Finding Costs for Drillable Structures

RESULTS
Project Completed
New Well Failed to Produce Desired Results

Background

The objective of this project was to test tellurics as a tool to define subsurface features, thus reducing risk and enhancing the potential of exploratory and/or development wells.

Electromagnetic pulses generated in the atmosphere are known to penetrate the surface of the earth and create a secondary electrical field. This secondary electrical field in turn propagates downward and ultimately resonates from the subsurface beds of contrasting resistivity. Tellurics is the measurement or reading of the changes in subsurface conductivity from one bed or horizon to another and can, in some cases, be used for facies identification. Tellurics has been used for mining.

A subsurface structural anomaly was located in Section 2, Township 14N, Range 8E, Creek County, Oklahoma, by a telluric geophysical survey. An Ordovician Wilcox sandstone well was drilled to test the accuracy of telluric signals to locate and define a subsurface structure.

Telluric Survey

The objective was to test the theory that an oil- or gas-bearing structural trap can be identified using tellurics exclusively. The purpose was to find a less expensive exploration alternative to 2-D or 3-D seismic.

The work was performed in three stages:

- Perform a telluric survey in an oil- and gas-producing region to try to identify a previously unknown structure.
- Integrate the telluric data with current well control.
- Drill a well to prove/disprove the accuracy or reliability of the tellurics.

When the data were compared, the results showed a margin of error too great to warrant using this method of exploration. Specifically, the formation tops and therefore the target zones predicted by the tellurics were either undefinable or shallower than the actual depth encountered by the drilled well. Also, the structure was nonproductive.

Results

A well was drilled, and the Wilcox sandstone was dry and not on structure. The telluric survey as used here is unable to predict formation tops, although this method has reportedly been used successfully in other fields.

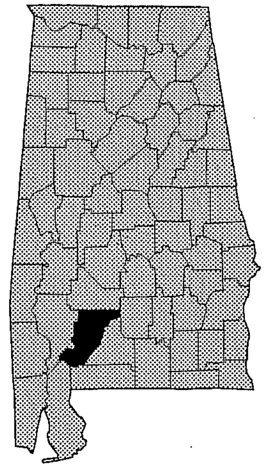
Project Funding

DOE made an award for a cost-shared project of $150,000 (33% DOE, 67% Keener) to Keener Oil and Gas Company for this survey.

formation micro-imaging (FMI) log

COBRA OIL & GAS
UNIVERSITY OF ALABAMA
TUSCALOOSA, AL

Frisco City Sandstone @ 11,500 to 12,000 ft



TECHNOLOGY AREA
Formation Evaluation

PROBLEM
High Cost and Risk of Coring

SITUATION
Looking for Alternative to Coring

RESULTS
Project Completed
FMI Log Successfully Reduced Need for Coring

Background

Through a cost-shared project with DOE, Cobra Oil & Gas and partners (Alabama Geological Survey, University of Alabama Geology Department, and Schlumberger) conducted work to determine whether Schlumberger's Formation Micro-Imaging (FMI™) log could be used to determine facies and reservoir characteristics in Alabama's Frisco City sand reservoir. Regional experience indicated that core data was required to adequately characterize the reservoir. In addition to the high associated costs coring at 12,000-foot depths presented significant risks for a blowout or losing the well. Success with the FMI or similar logs would represent a major cost savings and reduce drilling risks significantly.

Project Description

Schlumberger ran an FMI log on a well for which whole core was available. The core was described by the Alabama Geological Survey and University of Alabama Geology Department to determine the facies distribution, geological characteristics, and reservoir properties. The FMI and core description results were compared to determine if the FMI log can successfully determine facies, core description, and reservoir characteristics.

Results

The study indicates that the FMI log can be used to provide information on geological description, facies distribution, and reservoir properties determination without the need for a whole core or a whole-core analysis. The work has confirmed that the FMI log is a valid alternative to coring in the Frisco City sand. Using FMI logs to replace coring will result in savings of approximately $25,000 per well in this area.

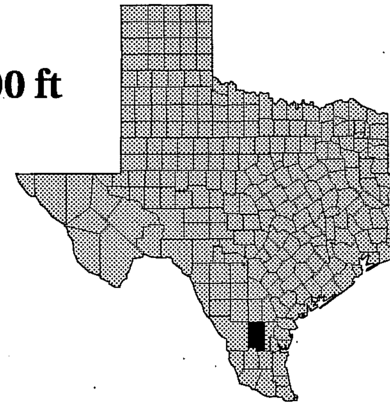
Project Funding

This core-log comparison project was performed at a cost of $50,000 (50% DOE, 50% Cobra Oil & Gas and partners).

low-invasion, unconsolidated coring system & core analysis

SANDIA OPERATING COMPANY SAN ANTONIO, TX

Cole Sand @ 1,700 ft



TECHNOLOGY AREA
Formation Evaluation

PROBLEM
Unreliable Log Analysis Because Fresh Formation Water and Cores Are Not Available for Calibration Because of Unconsolidated Formation

SITUATION
Difficulty in Identifying High Oil-Saturation Zones for Drilling

RESULTS
Project Completed

Successful Unconsolidated-Core Retrieval and Analysis

Background

The problem in the Orlee Field area (Duval County, Texas) is irregular oil-cuts from wells throughout the field because of reservoir heterogeneity. Some downdip wells produce higher oil cuts than updip wells. The formation water in this Eocene age, unconsolidated Cole sand is fresh, rendering reliable log interpretation and water saturation calculation nearly impossible. Because of the unconsolidated nature of the sand, there are no cores available for calibrating the induction logs.

Project Description

Sandia Operating Company proposed to recover a full-diameter core and to perform core description, and standard and routine core analyses to calculate the water saturation and to calibrate well logs. The well chosen for coring was the Gonzalez Mineral Trust A-24 Lopez in Orlee Field.

A low-invasion hydrolift coring system was used to recover the unconsolidated Cole sand. Coring was performed by Baker-Inteq. The hydrolift part of the system permits more complete and less damaging core recovery by allowing the newly cut core to enter an aluminum inner barrel. After coring was completed, the core was frozen and retained in the inner barrel for better fluid preservation and protection from damage during shipment.

A suite of core analyses was performed. These include gamma radioactivity readings, Dean-Stark extraction, grain density, porosity, permeability, sand sizes, petrology, capillary pressure, formation factor, resistivity index, cation exchange capacity, and relative permeability.

Results

The core recovery process using the low-invasion hydrolift system was successfully applied. Core recovery was 100%. Only one foot of the core visually appeared to be invaded and flushed by mud filtrate. The reservoir contains facies with very high porosity (30–35%) and permeability (1000 to 5000 millidarcys), the very high porosity zone is not distinguishable on logs, and was not known to exist prior to core analysis. Oil saturation in the cores was as high as 35%, residual oil saturation was determined to be 25%. The very high porosity revises reserve calculations upward and decreases S_W calculated from logs.

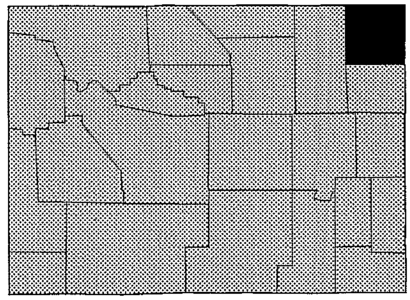
Project Funding

DOE made an award for a cost-shared project of $120,800 (41% DOE, 59% Sandia Operating Company) to Sandia Operating Company for this core retrieval and analysis project.

inert gas injection

DAKOTA OIL PRODUCERS PIERRE, SD

**N. Wind Creek Field
Crook County,
Wyoming @ 1,100 ft**



TECHNOLOGY AREA
Improved Oil Recovery

PROBLEM
Need to Increase Pressure in Reservoir

SITUATION
No Reservoir Energy to Drive Oil

RESULTS
Project Completed

Successful

Some Wells Experienced Cement Failure

Background

Huff 'n' puff technology was used in the Dakota Oil Producers (Pierre, South Dakota) and DOE cost-shared project. The low-pressure in the reservoir would not move oil toward the producing wells. Inert gas produced by a generator and fluid injection composed of 0.5% surfactant in 55 barrels of water per day was used to pressurize the reservoir and mobilize oil. In 1995 before the start of this project, daily production on Dakota Oil Producers' leases was 5.7 barrels of oil per day.

Dakota previously tried waterflooding on this reservoir without success.

Foam and Gas Injection

Water-surfactant mixture of 0.5% surfactant with 55 barrels of water was injected downdip, and inert gas was injected updip to repressurize the oil reservoir. The wells were then shut in. The wells are producing at this time. The huff 'n' puff project will be expanded to two wells on an 80-acre tract to the south that had been previously nonproductive because of the economics. The huff 'n' puff process is repeated when oil production begins to decline.

Results

After experiencing numerous startup problems during the first two months of the project, the project became both a success and a failure. Current oil production has stabilized at 10.54 barrels per day, double the 1995 production rate, on part of the lease. On the other part of the project site, several wells experienced cement failure. Dakota produced 450 barrels of oil that were produced during the project that must be treated for emulsions before being sold.

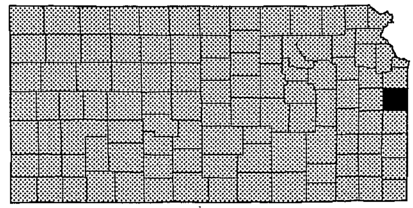
Project Funding

This huff 'n' puff demonstration project was conducted by Dakota Oil Producers at a budget of $97,202 (49% DOE, 51% Dakota).

stimulating formations thermally

DIAMOND EXPLORATION
PAOLA, KS

Squirrel Sandstone @ 750 ft



TECHNOLOGY AREA
Improved Oil Recovery

PROBLEM
Low Reservoir Energy

SITUATION
Low Oil Production

RESULTS
Project Completed
Failure Technically

Background

Heavy oil in the Mid-Continent area occurs in tight, heterogeneous, and small reservoirs which cannot be economically produced using steam injection methods that are being applied successfully in California reservoirs. Waterflooding also is not economical. Diamond Exploration, Inc. designed a high-voltage electric generator to provide electricity to thermally stimulate production from a shallow, heavy oil reservoir. The objective of this project was to demonstrate the economic feasibility of this thermal method for improving oil recovery.

Project Description

Thermal stimulation was tested in Paola–Rantou–Shoestring Field, Miami County, Kansas. Copper probes were placed approximately 100 feet apart in the reservoir. These probes were energized by an electrical generator to heat reservoir oil and water to reduce the viscosity of the heavy oil. The oil was drained by gravitational forces into the producing wells.

Results

The aquifer below the oil cycle zone was energized with 220–225 volt, 400–410 cycle current maintaining 60 amps for 24 hours. The probes were elevated 2 feet into the oil zone where amperage dropped to 43 amps and then 41 amps. After 28 hours the probes were lowered to their original position. After 6 days of energizing, 50 milliliter of oil that was 21°API gravity and viscosity of 1,730 centipoise at 74°F was recovered. Temperature of the reservoir was elevated from 58°F to 91° to 101°F. The reservoir was heated, but commercial oil was not recovered.

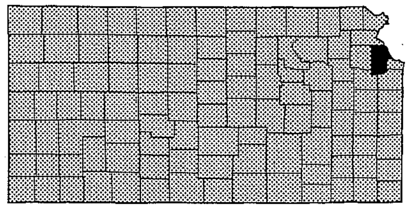
Project Funding

A project award of $99,000 (50% DOE, 50% Diamond Exploration, Inc.) was made to Diamond Exploration, Inc. for this electrical stimulation project.

microbial improved oil recovery

EDMISTON OIL CO. WICHITA, KS

McLouth Sand @ 1,350 ft



TECHNOLOGY AREA
Improved Oil Recovery

PROBLEM
Wellbore Damage

SITUATION
Low Oil Production

RESULTS
Project Completed
Treatment with INJECT-CHECK
Improved Production

Background

Low-gravity oil was found in Easton NE Field, Leavenworth County, Kansas, in significant quantities. However, primary recovery efficiency was low (estimated at less than 2%), and waterflooding would be uneconomical because of an unfavorable mobility ratio. Plus, many of the wells in the field were damaged by scale, paraffins, and asphaltene deposition. This project investigated the feasibility of applying microbes to clean up wellbores and improve oil recovery. Successful use of this technology will benefit many operators in this region, as low-gravity oil is common in eastern Kansas.

Project Description

The MEOR process used for this test included hydrocarbon-utilizing microorganisms, inorganic nutrients, and a biocatalyst. The MEOR materials were blended and injected into the reservoir. The microbes sought crude oil accumulations trapped in pore spaces, and use a small portion of the oil as a source of energy to reproduce, generating byproducts such as solvents, surfactants, acids, and gases. Only the surfactant byproducts were necessary to the MEOR process. Surfactants improve the oil mobility by reducing the oil surface tension to rock and water surfaces. Also, the MEOR process will likely improve effective permeability in the near-wellbore reservoir area by removing organic debris that restricts fluid movement.

The project had two parts. Phase I was a pilot treatment initiated on the Heintzelman and Kroll leases. The Heintzelman lease has five producing wells. The Heintzelman No. 3 was cored and analyzed. The Kroll lease has four producing wells. The Kroll No. 6 was cored and analyzed. Phase II was the expansion of the MEOR process to the remaining wells in the field managed by the operator.

The treatment strategy included an initial treatment, followed by treatments every six months. The MEOR materials were displaced into the target reservoir through the wellbore on all five producing wells in a procedure similar to a conventional matrix squeeze approach. After initial displacement, the wells were shut in for a period specified by a subcontractor. The subcontractor supervised the blending and pumping operations. The injection well on the Kroll Lease was used to transport the materials into the reservoir. The injection well was treated weekly.

Once the MEOR process had begun, actual production could be compared to the production volumes projected by the extrapolated decline trend curves for that period. Incremental production increases in excess of baseline production would indicate the success or failure of the MEOR process. Incremental production resulting from the result of a workover, recompletion, or any process other than MEOR was monitored closely to ensure the accuracy of the success or failure of the MEOR process.

Results

Three microbial methods were applied in the field. Responses were calculated by comparing the pretreatment average barrels of oil produced by well starting on January 1, 1996, to the

beginning date of the respective leases' first treatment. The fourth quarter began on April 18, 1997, and ended on July 17, 1997. All calculations took into consideration mechanical and weather downtimes.

4th Quarter Treatment Response

Two wells (Crook Nos. 1 and 3) were treated with INJECT-CHECK by Geo-Microbial Technologies, Inc. (GMT). INJECT-CHECK is a nontoxic formulation of inorganic water-soluble salts that inhibit sulfate-reducing bacteria. It also removes scale and paraffins. Treatments were performed in March and May.

Crook lease:	Production decreased 4% from baseline.
Wilson lease:	Production decreased 37% from baseline. Higher production decrease is because of gunbarrel dumping water into stock in previous quarter.

Five wells from the Heintzelman lease (Nos. 2, 3, 4, 5, and 6), and five wells from the Kroll lease (Nos. 1, 3, 4, 5, and 6) were treated with a mixture of hydrocarbon-utilizing microorganisms, inorganic nutrients, and a biocatalyst from Biodynamic Corporation. This treatment generates surfactant in order to reduce interfacial tension at the oil/water interface to clean up the wellbore and to improve oil relative permeability. The first treatment was performed in July.

Heintzelman lease:	Production decreased 25% from baseline. Decrease is because No. 2 was converted to an injection well.
Kroll lease:	Production increased 549% from baseline.

Three wells from the Eberhart lease (Nos. 1, 2, and 3), five wells from the Hoge lease (Nos. 1, 2, 3, 4, and 5), Wilson No.1, Haigwood lease (Nos. 2 and 3), and Hick-Olmstead lease (Nos. 2 and 3) were treated with a bacterial blend BIO-E-SWT by Bio-Engineering International, Inc. The BIO-E-SWT microbes are designed to clean up scales, paraffins, and asphaltene by reducing water-oil interfacial tension, modifying wettability, and inhibiting sulfate-reducing bacteria.

Eberhart lease:	Production increased 29% from baseline.
Hoge lease:	Production decreased 14% from baseline. Decrease is partly because No. 2 well was converted to an injection well.
Wilson lease:	Production decreased 37% (treated by GMT since March 27th, 1996). Decrease is partly because of gunbarrel dumping oil into stock tanks during the third quarter reporting period.
Haigwood lease:	Production decreased 19% from baseline.
Hick-Olmstead lease:	Production increased 31% from baseline. Increase is because of mechanical repairs during fourth quarter.

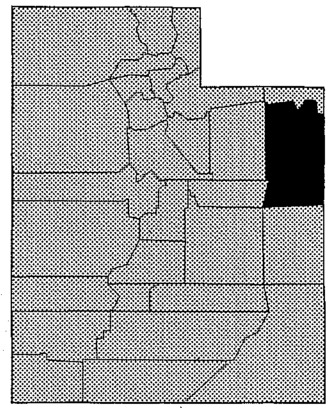
Project Funding

A project award of $167,900 (30% DOE, 70% Edmiston) was made to Edmiston Oil Company for this microbial treatments project.

closed-loop extraction of hydrocarbons and bitumen from oil-bearing soils

X-TRAC ENERGY, INC.
ENGLEWOOD, CO

Uintah County Asphalt Mine Asphalt Ridge Sandstone @ 0–100 ft



TECHNOLOGY AREA
Improved Oil Recovery

PROBLEM
Development of a Commercial Extraction Process

SITUATION
No Commercial Technology for Extraction of Hydrocarbons from Bitumen-Saturated Soils

RESULTS
Project Completed

Extraction Successful and Expansion Costs Projected for Full Scale Expansion

Background

The Asphalt Ridge sandstone is more than 100 feet thick in Uintah County, Utah. In the project area, it contains an estimated 20 to 30 billion barrels of heavy oil and bitumen from the surface down to more than 100 feet. No technology or process has been demonstrated to be efficient and environmentally benign for the commercial extraction of marketable crude oil from shallow tar sand reserves within the United States.

Project Description

X-TRAC has licensed a closed-loop system that employs recyclable hydrocarbon solvents to extract hydrocarbons and bitumen from oil-bearing soils. Projected oil production after project implementation is 60,000 to 200,000 barrels per month.

Results

The tar sand reserves of the Asphalt Ridge deposits and the PR Spring deposits range from 4.5 to 7.3 billion barrels of bitumen/heavy oil deposits. The depth of the deposits range from surface to 600 feet. The strip ratio (overburden thickness to pay sand thickness) over most of the area is equal to one or less. The solvent extraction process used requires the mining of the oil sand, crushing of the oil sand, and processing of the oil sand through a pressurized vessel.

Laboratory testing using the solvent extraction process was done to examine the recovery efficiencies on the two tar sand samples under laboratory conditions. The butane used as the extraction solvent was recovered: PR Springs 56.3%; Asphalt Ridge 45.8%. The Asphalt Ridge recovery was improved to 80.3% using pentane.

The tar sands tested had no difficulty in running through the extraction equipment when tested in the field. The test was done using X-TRAC's large-scale equipment, located at the Sherard Dome field in Washakie County, Wyoming.

Oil samples were recovered from the PR Spring tar sands and the Asphalt Ridge tar sands. These samples were analyzed at a refinery and were fingerprinted. The recovered oil for PR Springs has a sulfur content of 0.32% and an API gravity of 16.9°. The recovered oil for the Asphalt Ridge test has a sulfur content of 0.29% and an API gravity of 20.2°.

The field extraction process recovered all of the solvent from the cleaned sand. A small amount of solvent was intentionally left in the oil samples to prevent the samples from setting up. In actual practice, all of the solvent can be recovered from the extracted oil.

Two types of distillation were run on the recovered oil from PR Spring samples: flash distillation and vacuum distillation. The recovery using flash distillation was 23% kerosene and diesel oil, the remaining 77% was asphalt. The recovery on the PR Spring samples using vacuum distillation was 42.8% kerosene, diesel, and light gas oils, the remaining 51.2% was asphalt.

The same two types of distillation were run on the recovered oil from the Asphalt Ridge samples. The recovery using flash distillation was 23% kerosene, diesel oil, and light gas oils, and 77% asphalt. Recovery using vacuum distillation was 48% kerosene, diesel, and light gas oils and 52% of asphalt.

Costs were examined for a full-scale tar sand project and included mining costs, rehabilitation costs, extraction costs, and capital costs for the equipment. The estimated total operating cost including the mining and extraction costs is $7.49 per barrel (mining and rehabilitation costs at $4.17 per barrel plus the extraction costs at $3.32 per barrel). The estimated total capital investment for a facility to process 9,000 barrels per day is $7.5 million ($2.5 million for the first portion to process 1,800 barrels per day, and the remaining $5.0 million for the installation of four more plants to produce 7,200 barrels per day).

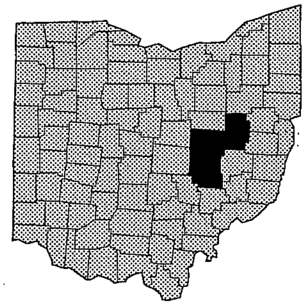
Project Funding

DOE made an award for a cost-shared project of $147,359 (34% DOE, 66% X-TRAC Energy, Inc.) to X-TRAC Energy, Inc. for this project.

computerized well monitoring system

JAMES ENGINEERING MARIETTA, OH

Clinton/Rose Run @ 5,000–7,000 ft



TECHNOLOGY AREA
Operations

PROBLEM
Inability to Monitor Quickly and Cost-Effectively Manage a Large Number of Marginal Wells

SITUATION
Not Maximizing the Recovery from Marginal Production

RESULTS
Project Completed
Production Efficiency was Increased by 5 1/2 %

Background

Most small operators have lean staffing. Therefore, they have difficulties monitoring production regularly. This creates the possibility of lost opportunities to correct well problems promptly and maximize recovery from marginal wells. James Engineering, Inc. proposed to use a computerized monitoring system to compare forecast production with well production rates to identify problem wells. Remedial actions could be applied promptly. Successful completion of this project could result in a system that can be economically applied by every operator regardless of size.

Project Description

The goal was to develop simple software to download production forecasts from major commercial reserve analysis software and upload production information from a field or group of wells. This software would also compare actual production with forecast values to identify production declines. Such information would be made available to field personnel so they can identify problems quickly and correct deficiencies as soon as possible.

Results

The project was initiated on May 31, 1996. A computer monitoring and prediction remedial work forecast software package was developed for 240 wells. Preliminary results were favorable.

A paper describing the software developed was presentated at the October 1997 SPE Eastern Regional Meeting in Lexington, Kentucky. The paper included wells successfully identified and corrected by the program. The program also has identified and evaluated many additional wells to determine if production is being optimized.

Modifications to the program, renamed *Priority*, have included an action column to aid in the follow-through of wells identified for remedial work. Additional changes have been made to facilitate data entry from sources other than Aries. This helps smaller operators who do not have the more sophisticated software packages. *Priority* was placed on the DOE Web site and is available to small operators at www.npto.doe.gov.

The overall results of the program are as follows. During a five-month production period at the end of 1996 and the start of 1997, total production for 240 wells increased by approximately 5 1/2% over the same period in 1995 and 1996. It should be noted that the nominal decline for these wells is approximately 6% per year. Although all production increases may not be directly attributable to *Priority*, they are indirectly attributable. The indirect increase was because of consistent production monitoring, which caused a change in the attitudes and actions of all participants. Monthly accountability swiftly corrected many problems that previously had gone unaddressed.

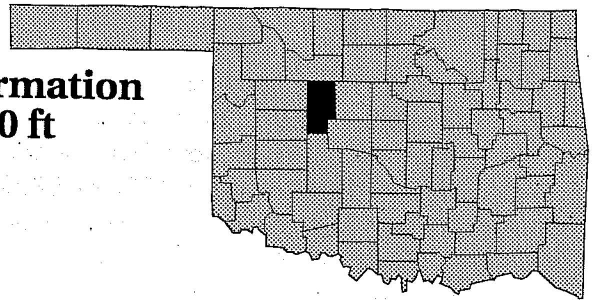
Project Funding

DOE made an award for a cost-shared project of $94,000 (50% DOE, 50% James Engineering, Inc.) to James Engineering, Inc. to develop and test this computerized production monitoring system.

improved stimulation

K-STEWART PETROLEUM OKLAHOMA CITY, OK

Morrow Formation @ 8,300 ft



TECHNOLOGY AREA
Production Problems

PROBLEM
Formation Damage

SITUATION
Inconsistent Stimulation Results

RESULTS
Project Completed Successfully Scale-up of Lab Data to Field Successful

Background

Because of formation damage, many Morrow wells in Carlton and Watonga fields, Blaine County, Oklahoma, do not respond consistently to acidizing and hydraulic fracturing. Nor is there any *a priori* method to predict which well will react positively to stimulation.

Improved Stimulation Method

Morrow reservoirs in Beaver, Harper, Ellis, and Blaine counties of northwest Oklahoma and the Oklahoma Panhandle were studied to identify minimum formation damage completion and production techniques to maximize production following hydraulic fracturing. To attain this goal, K-Stewart contracted STIM-LAB to:

1. Compare the effects of various fluids on matrix permeability and fracture conductivity via laboratory tests.
2. Correlate production to completion and production practices through a relational database.
3. Relate laboratory testing to the field by correlating and characterizing the rocks tested in the database.

Results

Four sandstones in the cores studied were identified as potential reservoirs. Two may have been deposited in estuarine, tidal, or shallow marine environments, and two others in fluvial or distributary channels.

Researchers concluded that producing these Morrow wells under conditions which maximize the condensate yield as long as possible would slow the steep decline in production. The easiest way to achieve these conditions was to hold back pressure and minimize the drawdown in the reservoir. This is not normal practice, as such actions significantly reduce the gas rate, but the long-term recovery of all hydrocarbons should be much higher. Management of wellbore fluids also plays an important role in production practices. History shows that how these wells were produced may have a greater influence on ultimate recovery than how the wells were fracture stimulated. Therefore, before fracture treating a Morrow well, consider the following:

1. Select the fluid and breaker to minimize pressure drop. This initiates flow to clean the fracture from wellbore to tip. Failure to initiate cleanup results in short, effective frac lengths and proportionally lower initial production. Evidence of poor fluid and/or quality control appears in the database several times. On site, such wells have unbroken frac fluid returning to the surface. The preliminary report shows the results of fluid selection on effective frac length and production. Effective frac lengths can be as low as 50 feet and as high as 300 feet because of frac fluids. The shorter frac length will produce one-sixth as much as the full-length frac.

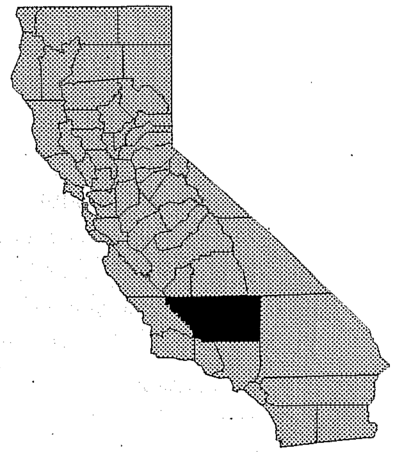
2. Select the proppant to provide maximum conductivity in the presence of multiphase flow. Multiphase flow of oil in the gas lowers the effective conductivity by an order of magnitude at levels seen in the Morrow. From the production simulations of hydraulic fracturing treatments of the Morrow formation using PREDK and SLFRAC, multiphase conductivity can range from 200 to 500 millidarcy-feet depending upon proppant selection. The result can be an improvement of 20% to 30% in production. This improvement is likely masked in the database due to reservoir property changes.
3. Maintain the backpressure needs on the well during production to avoid dropping out condensate in the surrounding formation. Once the condensate is dropped out and retained in the formation, the relative permeability to gas is low. One way to model this is to lower the net height available for gas flow and/or lower the effective gas permeability. In the simulation with PREDK and SLFRAC, condensate retention has decreased the net height to 10 feet. Under these circumstances, production drops from 2 million cubic feet per day to 100–300 thousand cubic feet per day very quickly. These simulations closely match reported observations in wells in this study. From this standpoint, the maintenance of backpressure becomes the foremost factor, overshadowing fluid and proppant selection. Differences in fluid and proppant selection can only be seen if the backpressure is properly maintained.

Project Funding

DOE made an award for a cost-shared project of $673,400 (7.4% DOE, 92.6% K-Stewart Petroleum) to K-Stewart Petroleum Corporation for this improved stimulation project.

resin-coated prepacked gravel

INDUSTRIAL TECHNOLOGY MANAGEMENT (ITM) TORRANCE, CA



Kern County, CA

TECHNOLOGY AREA
Production Problems

PROBLEM
Sand Control

SITUATION
Testing an Alternative Method of Sand Control

RESULTS
Project Completed
ITM Marketing Prepacked Resin Coated Liner in Bakersfield and Los Angles. Further Markets Expected in Water Well Applications

Background

Traditional prepacked gravel (sand) packs with external mesh wire wrapping are used for sand control in wells that produce sand along with oil. The wire mesh wrapping often becomes damaged while setting the traditional prepacked gravel (sand) pack for sand control. With the wire mesh damaged, sand control is less effective and leads to expensive remediation and/or failure to control sand production, causing more costly environmental remediation of oil-coated produced sand.

Results

Improve Prepacked Gravel (Sand) Pack

ITM has developed a resin-coated prepacked gravel (sand) pack that fits inside a perforated liner for sand control as an alternative to the traditional prepacked gravel (sand) pack. This product consists of a gravel (sand) pack that is bonded to a perforated base pipe, formed in a cylindrical shape to conform to the internal dimensions of a wellbore. The liner is inserted into the wellbore for sand control. The gravel (sand) that makes up the pack medium is commercial-grade resin-coated sand that has been shaped into a solid cylindrical form through the application of heat. The liner has no wire wrapping or other mechanism for pack containment. The liner product is offered in standard joint lengths, as well as custom joint lengths. The liner is available in a variety of outer and inner diameters, base pipe grades, thread connections, gravel (sand) mesh sizes, resin coatings, and proppant materials, depending on the customer's need for the wellbore. Liner joints are screwed together to the desired length, inserted into the wellbore, and set in place using conventional liner hanging equipment.

Two sample prepacked resin-coated liners were produced for use in compressive testing. The bond strength of the prepacked resin coated liner was determined through a load applied perpendicular to the perforated pipe. The load was applied at approximately 100 pounds per minute. Bond strength was reported at the stress level where failure occurred when the resin-coated gravel separated from the pipe and broke down into smaller pieces. The compressive strength of the resin-coated proppant was determined from a fractured section. The section was placed on a hydraulic press, and a force was applied on the sample at a rate of 100 pounds per minute. The compressive strength was reported at the load where catastrophic failure of the resin-coated proppant occurred. Results are as follows:

Bond strength Sample No. 1 = 2000 pounds
Bond strength Sample No. 2 = 1860 pounds

Permeability Testing

Permeability measurements for the resin-coated liner were conducted for three different grain sized samples of the liner (16-20, 20-40, and 40-60 mesh). The permeability testing objective was to determine the permeability (fluid flow capacity) of the entire bonded liner system, including the base pipe. This test would measure the permeability of the liner in an as-built liner configuration, not solely the permeability of the bonded sand itself.

The permeability testing consisting of sectioning the full diameter liner into 3-inch lengths resulting in a core of 6 inches diameter by 3 inches in length with an inner base metal pipe diameter. Three core samples were tested, each with a different sand grain size (*16-20, 20-40, and 40-60 mesh). Each core sample was installed in an apparatus designed to be filled with water for the permeability testing. The core sample to be tested was sealed on both ends, exposing only the outer area to water flow.

Permeability Testing Data and Results

Core Sample	1	2	3
Sample Grain Size (mesh)	16-20	20-40	40-60
Sample Outside Diameter (inches)	6.0	6.0	6.0
Sample Inside Diameter (inches)	3.0	3.0	3.0
Test Hydrostatic Pressure (psi)	1.732	1.732	1.732
Water Flow Volume (cc)*	18760	18760	18760
Water Flow Time (seconds)*	60	60	60
Calculated Permeability (Darcys)	32.3	26.0	24.7

*Average measurement of four flow tests for each sample.

Chemical Resistance

Project data indicate that the ITM sand and resin mixture is resistant to most of the commonly found oil field chemicals. Tests of immersed samples measured the following properties: (1) Loss of resin %, and (2) loss of compressive strength (psi). A review of these data shows that resin coating is stable in nearly all oil field chemicals with the exception of the following chemicals:

1. EDTA (iron sequestering agent)—Lab test measured a 55% loss of resin in 100% EDTA solution, and a 10.5% loss is a 50% EDTA solution.
2. High pH—The test data indicate that in very high pH solutions the resin will strip and also reduce the cured pack's compressive strength; significant loss occurs in pH exceeding 12.
3. Isopropyl alcohol(IPA)—Isopropyl alcohol causes higher levels of resin degradation at increasing concentrations. A 25% solution causes a 3% loss, a 50% solution results in a 14% loss, and a 100% IPA solution causes a 19% loss in resin.
4. Scale converters—It has been determined that barium sulfate scale converters at high pHs will strip the resin.

The product is being introduced into the market in Bakersfield and Los Angeles California.

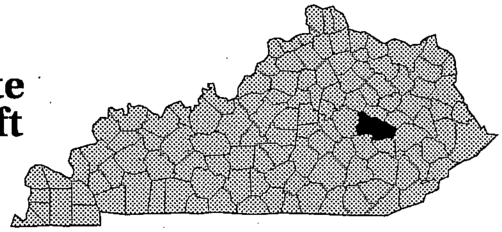
Project Funding

DOE made an award for a cost-shared project of $99,500 (49.7% DOE, 50.3% ITM) to Industrial Technology Management for construction and field testing of its prepacked resin-coated gravel (sand) pack liner.

foam frac and foam acid treatment

SIPPLE OIL
BEATTYVILLE, KY

Coniferous Dolomite Formation @ 1,100 ft



TECHNOLOGY AREA
Stimulation

PROBLEM
Water Breakthrough Comes Too Soon After Well Stimulation

SITUATION
Low Oil and High Water Production

RESULTS
Project Completed

Foam Fracturing with Low-Cost Sand Was Successful

Background

Sipple Oil Company (Beattyville, Kentucky) has wells completed in the first, second, and third Coniferous zones (Silurian age) of Big Sinking Field. These wells were producing water or water with only trace amounts of oil. This project compares three stimulation procedures for increasing oil production while reducing water production.

Foam Stimulation

Well No. 41 completed in the second and third Coniferous reservoirs received a foam fracturing treatment with resin-coated sand. Well No. 35 completed in the second and third Coniferous reservoirs received a foam fracturing treatment without resin-coated sand. Well No. 32 completed in the first Coniferous reservoir received a foam acid treatment.

Results of these three stimulation methods were compared. The most successful treatment method will be used in other wells in these reservoirs.

Results

Well No. 41 was stimulated with a foam frac using resin-coated sand in the second and third Coniferous reservoirs. On July 31, 1996, production was 0.5 barrels of oil per day (BOPD) and 4 barrels of water per day (BWPD). Treatment was successful in achieving oil production in this well, but probably was not economical.

Well No. 35 was stimulated with a foam frac using sand as proppant. On July 31, 1996, production was 5.4 BOPD and 5 BWPD. Treatment was successful.

Well No. 32 was stimulated with foam acid treatment in the first Coniferous reservoir. On July 31, 1996, it was producing 0 BOPD and 51 BWPD. Treatment was unsuccessful.

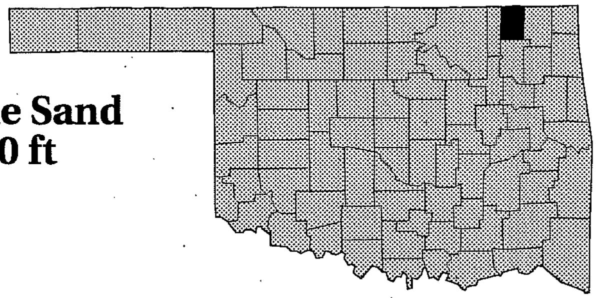
This project demonstrated that foam fracturing with sand proppant is the most economically and technically successful procedure in this type of reservoir.

Project Funding

Sipple Oil Company conducted the stimulation project with a budget of $110,571 (45% DOE, 55% Sipple).

gel polymer treatment

GRACE PETROLEUM DEWEY, OK



Bartlesville Sand @ 1,200 ft

TECHNOLOGY AREA
Water Production

PROBLEM
Channeling

SITUATION
Low Oil and High Water Production

RESULTS
Project Completed
Successful
Oil Production Increased

Background

Grace Petroleum Company (Dewey, Oklahoma) conducted a cost-shared gel polymer treatment project in a Bartlesville sandstone reservoir. Wells in the Bartlesville sand are producing a large volume of water because of channeling. Gel polymer was injected into the water zone to try to reduce water production. Before treatment, the lease was producing 10 barrels of oil per day (BOPD) and 333 barrels of water per day (BWPD).

Gel Polymer Treatment

PAR Services treated the producing wells with approximately 100 barrels of gel polymer. The gel polymer used to treat the wells was HS-WSP partially hydrolyzed polyacrylomide with chromium cross-linking agent. Ammonium salt was used to prevent swelling of the clay. Injection wells on this project were not treated with polymer.

Results

Oil production increased from 10 BOPD in October 1996 to an average of 19 BOPD in April 1997.

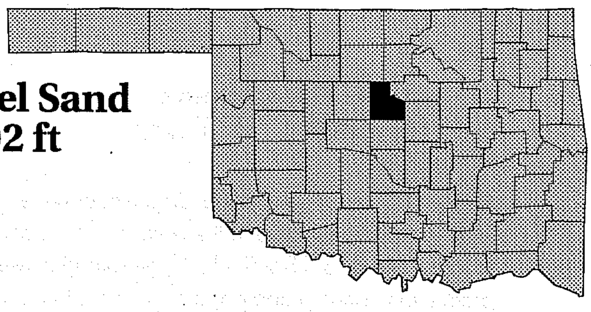
Project Funding

This gel polymer project was performed by Grace Petroleum Company with a budget of $106,000 (47% DOE, 53% Grace).

cost-effective water disposal

HARRY A. SPRING
ARDMORE, OK

Carmichael Sand
@ 3,192 ft



TECHNOLOGY AREA
Water Production

PROBLEM
High Water Production

SITUATION
High Cost of Water Disposal

RESULTS
Project Completed
Downhole Injection Tool Successful
Gas Production Increased

Background

The cost of disposing salt water coproduced from oil and gas wells can render potentially viable wells marginal or even uneconomical. In most cases, drilling and equipping a separate disposal well is cost-prohibitive. To overcome this high cost of salt-water disposal, Enviro-Tech Tools, Inc. is developing a concurrent production-disposal process to simultaneously produce gas and dispose of salt water. In this process, a conventional downhole mechanical lift pump is modified to displace salt water downhole. This technology allows operators to produce gas and dispose of water in the same wellbore, reducing water disposal cost significantly. The purpose of this project is to test the technical feasibility of this process in the Klick No. 1-13 well in Logan County, Oklahoma.

Concurrent Production-Disposal Process

The Enviro-Tech tool uses a modified conventional downhole mechanical lift pump to inject a large quantity of unwanted saltwater downhole, simultaneously producing gas. A prospective well requires a porous water-bearing formation below the production interval and production casing set at a sufficient depth to cover the intended injection zone. Therefore, underground injection control permits are required. Because wastewater is never brought to surface, concerns about contaminating freshwater resources, surface soils, and other environmental problems are eliminated.

Results

The Klick No. 1–13 located in SW SW NW Sec. 13, 17N, 3W in Logan County, Oklahoma was drilled to a total depth of 3,946 ft. Logs were run and 4 1/2 inch production casing was set at 3,398 ft with 150 sacks of cement. The Carmichael sand was perforated at 3,192–3, 195 ft. Initial gas production was 1,017 mcfd at 850 psi flowing pressure on 16/64 inch choke. Initial shut in pressure was 1,000 psi. After producing 263,419 mcf in 18 months, the production was 400 mcfd with 200 bbl of salt water per day at 190 psi. Shut-in pressure was 600 psi. Water hauling became cost prohibitive and the well was shut-in.

The operator chose to use the Down Hole Injection (DHI), formerly Enviro-Tech, down hole simultaneous gas production/disposal tool method of economically disposing of the lease salt-water. This tool allows the formation water to be injected in a lower formation without being first lifted to the surface. This also allows dewatering in the formation near the wellbore and allows for higher gas flowing rates.

After obtaining Oklahoma Corporation Commission approval, the Klick wellbore was prepared by drilling out the shoe joint and cleaning out the open hole with aerated saltwater. The drilling fluid, saltwater, was aerated to reduce hydrostatic pressure to decrease potential damage to the Carmichael formation. The open hole was cleaned out to 3,884 ft.

An injection test was performed on the disposal zone. The disposal formation injection test was 3/4 bpm at 400 psi, 1 bpm at 435 psi and 1 1/4 bpm at 450 psi. Bleed off was the same for each pump rate at 375 psi in 10 minutes.

Additional perforations in the Carmichael were recommended to aid in dewatering the formation. The additional perforations were in the bottom of the zone at 3,202–06 ft. The productive portion of the formation was reperforated at 3,186–90 ft. All perforations were treated with acid and cleaned up. With the disposal and production zones prepared, the DHI simultaneous disposal and production tool was installed. Sinker bars and polished rods were added to the rod string to increase the weight on the plunger. (This increases the amount of injection pressure exerted on the formation.) Once the tool had been put in place, along with the rods and tubing, the recommended surface equipment was set.

The initial fluid level showed fluid at 950 ft. The pumping unit was started at a rate of 9 strokes per minute (spm) with a 54 inch stroke. After pumping 16 hours, the fluid level was lowered to 2,360 ft with a slight show of gas. The dynamometer card showed that the addition of sinker bars was needed because actual injection pressure was higher than anticipated. The unit was slowed to 8 spm. The fluid level rose to 2,150 ft. Additional sinker bars were added and the dynamometer showed 9 3/4 spm was acceptable. The gas production gradually increased from 10 mcfd to a maximum of 75 mcfd. A fluid level check showed fluid at 1,494 ft. The DHI tool was disposing a calculated 314 bwpd at 9 1/2 spm.

Production leveled out at 30–40 mcfd with the fluid level at about 1,500 ft. The DHI tool was disposing of approximately 300 bbl of salt water per day. The producing formation was making more water than the existing equipment could handle, thus the high fluid level. After approximately 8 months, the well stacked out and would not pump. The disposal zone pressure was up to 2,091 psi. At this time, the well was abandoned. The well produced 9,086 mcf of gas during this time period.

The DHI simultaneous disposal and production tool is an effective and economical way of producing a well that otherwise would have been abandoned. There are, however, several things to be considered before using the tool. The most important consideration is the injection pressure and capacity of the disposal zone. In order to pump down your producing formation to increase production, you must dispose of your water faster than it is coming into your wellbore. Disposal capacity is limited by the formations' ability to take the water and the surface equipment used to pump the water (i.e., longer stroke and heavier rod string will increase injection capacity because of higher injection pressure). The Klick No. 1–13 failed primarily due to the limited capacity of the disposal zone, and secondly the producing formation made more water than anticipated.

In order to successfully and effectively use the DHI simultaneous disposal and production tool, one must know the injection capacity of the disposal formation and have sufficient surface equipment and rod string design to handle the injection pressures and volumes of the produced water. The DHI tool would have pumped and worked more effectively on the Klick No. 1–13 if the disposal zone had only had better injection capabilities.

The DHI simultaneous disposal and production tool will be beneficial to the oil and gas industry by extending the life of marginal wells, reducing the cost of handling water, potentially increasing gas production, and protecting the environment by not bringing salt water to the surface.

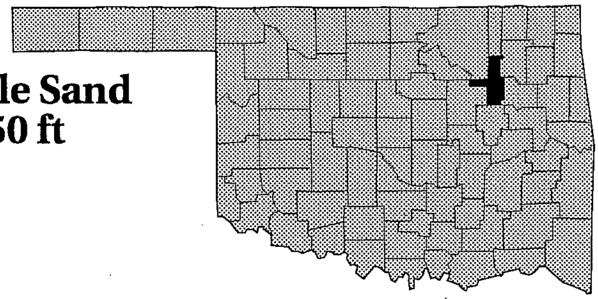
Project Funding

A project award of $55,000 (50% DOE, 50% Harry Spring) was made to Harry A. Spring for this water disposal project. The project start date was August 1, 1996.

gel polymer

KENNETH Y. PARK
SKIATOOK, OK

**Bartlesville Sand
@ 1,250 ft**



TECHNOLOGY AREA
Water Production

PROBLEM
Low Oil and High Water Production

SITUATION
Low Recovery Efficiency

RESULTS
Project Completed
Increased Well Productivity & Decreased Water-Oil Ratio

Background

Kenneth Y. Park (Skiatook, Oklahoma) conducted a cost-shared gel polymer treatment project. The purpose of this project was to reduce water production. Wells in this project are completed in a Bartlesville sandstone reservoir in Bird Creek Field near Skiatook, Oklahoma. These wells were producing 5 barrels of oil per day (BOPD) and 470 barrels of water per day (BWPD) before polymer treatment. Crosslinked polymer was injected into the water zone of the reservoir in producing and injection wells.

Gel Polymer System

PAR Services treated producing wells and injection wells with approximately 100 barrels of gel polymer. The gel polymer used to treat the wells was HS-WSP partially hydrolyzed polyacrylomide with chromium cross-linking agent. Ammonium salt was used to prevent swelling of the clay.

Results

After treatment, the project lease is producing 17.5 BOPD and 860 BWPD. Oil production tripled whereas water production doubled after treatment. Additional oil production is possible, but rates are limited by injection capacity.

Indications are that this project is successful. Well productivity increased twofold. The water-to-oil ratio is now lower than it was at the beginning of the project. Projected payout for this project is 44 months.

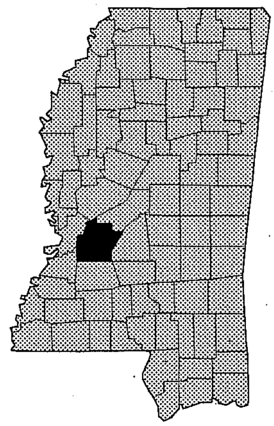
Project Funding

This gel polymer project was conducted by Kenneth Park with a budget of $96,233.52 (47.6% DOE, 52.4% Kenneth Park).

oxygen activation log

J. R. POUNDS
LAUREL, MS

Rodessa Sand
@ 11,120 to 11,130 ft



TECHNOLOGY AREA
Wellbore Problems

PROBLEM
Holes in Casing

SITUATION
Holes in Casing, Well Shut-in

RESULTS
Project Completed
Holes Repaired, Well Producing

Background

J. R. Pounds, Inc. shut in a well (Bolton Field, Hinds County, Mississippi) in the belief that there was a hole in the casing. Before the company acquired the producing lease, the previous operator had repaired a casing leak at approximately 3,000 feet by squeezing cement into the hole. J. R. Pounds personnel believed that the hole had reopened and wanted to return this well to production.

The operator proposed to locate the hole(s) in the casing with an Oxygen Activation Log.

Project Description

Initial investigation indicated that an Oxygen Activation Log is unsuitable for the proposed application. To locate the hole, pressure testing was performed.

Results

When the company was ready to locate the holes in the casing, logging companies advised that the oxygen activation log was not designed for this problem. Therefore, pressure testing was used to locate holes in casing and was successful.

The casing was pressure tested. Holes were found between 3,307 and 3,338 feet, 8,403 and 8,462 feet, and 8,587 and 8,618 feet.

After cement was squeezed into the holes in the casing and the well was stimulated with acid, oil production resumed. Maximum oil production after acid treatment was 40 barrels of oil per day (BOPD) on pump. As of August 29, 1996, the well was pumping intermittently and producing 30 BOPD with no saltwater.

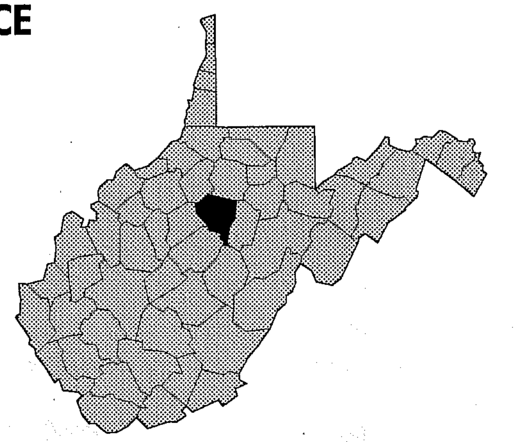
Project Funding

J. R. Pounds, Inc. performed this demonstration project with a budget of $122,400 (41% DOE, 59% J. R. Pounds).

microbial cleanup of paraffin

ROCK ISLAND SERVICE COMPANY, INC. CATLETT, VA

Camden Lewis Field Lewis County, West Virginia Salt Sand @ 1700–1800 ft



TECHNOLOGY AREA
Wellbore Problems

PROBLEM
Paraffin Precipitation

SITUATION
Reduced Productivity

RESULTS
Project Completed Paraffin-Mobilizing Microbes Appeared to Cause Production Increase

Background

Thousands of oil wells in West Virginia and elsewhere have been prematurely abandoned because paraffin precipitation in the producing formation has caused formation damage, and paraffin precipitation has narrowed production tubing and lead lines. Paraffin precipitation in the reservoir restricts production to uneconomic levels, causing premature abandonment of wells and leaving 90% or more of the recoverable resource in the reservoir unrecovered.

Project Description

Rock Island proposed to inject 1 to 2 gallons of paraffin-mobilizing microbes, 2.5 to 5 gallons of surfactant, 5 to 10 pounds of nutrients, and 400 gallons of water into each of 5 wells in the project. The 5 wells in the Camden Lewis Field were completed in the Salt Sand at 1700 feet–1800 feet in Lewis County, West Virginia. These wells were shut-in during 1984.

Each well resumed production after being shut in for a week after treatment. Additional microbial treatment would then be applied as needed.

Results

The cost of reworking the wells was underestimated when preparing the wells for the project, but this was not really germane to the purpose of the project, except to have all wells on an equal basis, i.e., tubing free of paraffin and with new pumps that would be in good working order.

Each of the five wells received the materials shown in the following tables.

Table 1 - Cost to Reestablish Each Well

Tubing, 1,500 feet at $1.50/foot	$2,250.00
Rods, 1,500 feet at $1.00/foot	$1,500.00
Pump	$606.00
Pump unit (used)	$2,000.00
Gasoline engine	$550.00
Service rig, 24 hours at $105.00/hour	$2,520.00
Roustabout, 16 man-hours at $25.00/hour	$400.00
100 Barrel tank (used)	$1,000.00
Miscellaneous pipe fittings	$200.00
Dozer work, 4 hours/well at $50/hour (prepare site and pull equipment in)	$200.00
Total	$11,226.00

Material Cost for Treatment

Bacteria per gallon	$65.00
Surfactant per gallon	$20.00
Nutrients per pound	$4.50

Table 2 - Well Treatment

Initial	**Well #1**	**Well #2**	**Well #3**	**Well #4**	**Well #5**
Bacteria	2.5 gal.	2.5 gal.	2.5 gal.	2.5 gal.	2.5 gal.
Surfactant	2.5 gal.	2.5 gal.	2.5 gal.	2.5 gal.	2.5 gal.
Nutrients	5 lbs.	5 lbs.	5 lbs.	5 lbs.	5 lbs.
Water	400 gal.	400 gal.	400 gal.	400 gal.	400 gal.
Monthly	**Well #1**	**Well #2**	**Well #3**	**Well #4**	**Well #5**
Bacteria	1 gal.	2 gal.	2. gal.	-0-	1 gal.
Surfactant	1 gal.	2 gal.	-0-	2 gal.	-0-
Nutrients	5 lbs.	5 lbs.	10 1bs.	10 lbs.	5 lbs.
Water	400 gal.	25 gal.	25 gal.	25 gal.	25 gal.

Table 3 - Cost of Well Treatment

Initial	**Well #1**	**Well #2**	**Well #3**	**Well #4**	**Well #5**
Bacteria	$162.50	$162.50	$162.50	$162.50	$162.50
Surfactant	$50.00	$50.00	$50.00	$50.00	$50.00
Nutrients	$22.50	$22.50	$22.50	$22.50	$22.50
Water Trans. & Injection	$100.00	$100.00	$100.00	$100.00	$100.00
Initial Treatment Costs	$335.00	$335.00	$335.00	$335.00	$335.00
Bimonthly	**Well #1**	**Well #2**	**Well #3**	**Well #4**	**Well #5**
Bacteria	$65.00	$130.00	$130.00	0.00	$65.00
Surfactant	$40.00	$80.00	0.00	$80.00	0.00
Nutrients	$22.50	$22.50	$45.00	$45.00	$22.50
Water Trans. & Injection	$50.00	$50.00	$50.00	$50.00	$50.00
Monthly Treatment Cost	$177.50	$282.50	$225.00	$175.00	$137.50

The produced water was retained and used as injection water. This provided the opportunity to reuse the bacteria that had accumulated along the oil/water interface in the tanks, as well as any surfactant that was still attached to the water. Rock Island's experience has been that when more than 150 gallons of water is used, the well goes on vacuum, and the water is rapidly sucked in. In this case, the treatment moves back into the formation and very little if any of that water comes back. From experience outside of this project on gas driven wells that make no water, the water will come back out.

The operating cost increased by the amount of the treatment without time required to make the treatment, the 5 wells on gas engines are pumped in 3 hours. The treatment adds 5 hours.

There was no decrease in production except for Well No. 5. The subject wells were last produced in 1984.

Table 4 - Well Production

Well		1984	1998 (projected)
Well #1	McDonald	302	512
Well #2	Jarvis	241	341
Well #3	L. White #1	223	298
Well #4	L. White #2	200 (estimated)	341
Well #5	Camden	113	43

Rock Island plans to continue the wells on the program and add more wells to this program.

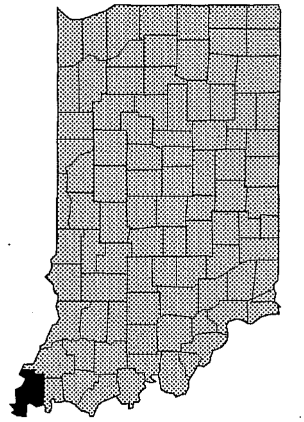
Project Funding

DOE made an award for a cost-shared project of $92,859.62 (50% DOE, 50% Rock Island Service Company, Inc.) to Rock Island Service Company, Inc. for this microbial project.

microbial wellbore cleanup

SPEIR OPERATING ALBION, IL

Posey County, IN
Cypress Limestone
@ 2,200 ft



TECHNOLOGY AREA
Wellbore Problems

PROBLEM
Paraffin/Sulfide Scale

SITUATION
Reduced Productivity/ Injectivity

RESULTS
Project Completed
Successful Wellbore Cleanup

Background

Speir Operating Company (Albion, Illinois) conducted a cost-shared project with DOE to evaluate the effectiveness of microbial well treatments for cleaning up production and injection wells. The project, which is located near Evansville in Posey County, Indiana, produces from the Cypress limestone at 2,220 feet. Paraffin and sulfide scale precipitation in perforations, tubing, and the near-wellbore region were reducing oil production, requiring frequent hot oil and acid treatments. Nine producers and two injection wells were involved in the microbial test.

Treatment Procedure

All wells were treated with acid, then operated for about one month prior to receiving the microbial treatments. Wells were treated by injecting 5 barrels of warm water, followed by 10 gallons of microbes and nutrients, followed by a 20-barrel warm water flush. Initial treatments were performed in December 1995. Following the initial treatments, producing wells began unloading sulfide scale, paraffin, and oil-water-paraffin emulsion. Treatments were repeated monthly through May 1996.

Results

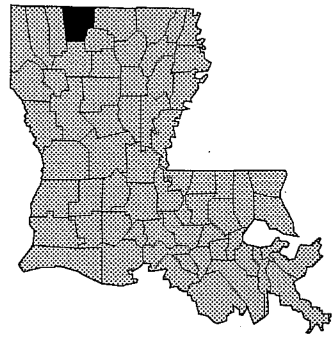
Oil production, which initially increased from 7 barrels of oil per day (BOPD) prior to treatment to 21 BOPD, stabilized at 13–15 BOPD. Injection improved from 20 barrels of water per day (BWPD) at 1650–1700 psig to 25 BWPD at 500 psig. After 5 months, production declined to 6 BOPD plus 25 BWPD, indicating that repeated treatments with less than 6 months frequency are needed to ensure improved oil production rates. The monthly electric bill was reduced by 32% as a result of lowering injection pressure, although electricity rates increased by 25%.

Project Funding

Speir Operating Company conducted this microbial treatment demonstration project with a budget of $97,550 (50% DOE, 50% Speir).

calcium carbonate prevention

TENISON OIL COMPANY
CLAIBORNE PARISH, LA



**Hosston Formation
@ 5,000 ft**

TECHNOLOGY AREA
Wellbore Problems

PROBLEM
Pump Sticking, Rod Parting, and Worn Parts

SITUATION
Calcium Carbonate Scale Deposition

RESULTS
Project Completed
Treatment Successful

Background

From the time the wells in the area were put on pump, there have been problems keeping the wells operating because of calcium carbonate scaling. The chemical analysis of the produced water shows ordinary levels of bicarbonates, indicating a downhole problem causing abnormal $CaCO_3$ deposition.

Project Description

Other operators in the area work around the problem by treating the wells with acid to dissolve the scale. Tenison proposed using mechanical changes to avoid scale deposition.

A seating nipple was positioned at the base of the tubing with a rod pump in the tubing. The friction causes water heating resulting in calcium carbonate precipitation. Tenison proposed removing the seating nipple and reworking the pump.

Results

Tenison redesigned the pump to exceed the flow capacity of the well. The well equipment could be adjusted to provide sufficient pump capacity even with the tubing anchor removed. Both wells were put back on production, with only a mud anchor. Both the Thomas No. 1 and the Tanner No. 1 have been on production. Before Tenison redesigned the pump, removed the tubing anchor, and kept the mud anchor, production was 10 barrels of oil per day (BOPD). After remedial action, production has been 23 BOPD.

Project Funding

DOE made an award for a cost shared project of $79,090 (47% DOE, 53% Tenison Oil Co.) to Tenison Oil Company.