Analysis of Petroleum Technology Advances Through Applied Research by Independent Oil Producers

November 1999

Prepared by
The Brashear Group LLC and RMC Incorporated
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Petroleum Technology Advances Through Applied Research by Independent Oil Producers

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This report was based on the information made available from public files and personal contacts with the operators who conducted the tests reported herein. The Brashear Group LLC makes no warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately awarded rights. References herein to any specific commercial product, process, or service by trade name, trade mark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by The Brashear Group LLC or any employee or subcontractor thereof. The views and opinions expressed are those of the authors.

Ms. Rhonda Lindsey (Technology Manager for Drilling and Demonstrations) assisted by Mr. James Barnes (Project Manager), both of the National Petroleum Technology Office of the U.S. Department of Energy, oversaw this project reported in this report and the latter portions of the program it analyses. The project is an independent analysis of twenty-two cost-shared projects carried out by small independents. It was supported under Subcontract No. DE-AC75-98SW43123-1 between The Brashear Group and RMC Incorporated, under its contract with DOE/Southwestern Power Administration.

For the Brashear Group, Walter B. North was the primary analyst, personally performing the bulk of the data compilation, analysis and reporting. He was assisted by Charles P. Thomas, Alan B. Becker (Modern Energy Concepts, Inc.), David D. Faulder and Jerry Paul Brashear. Connie M. Clarke formatted and produced the final report.
Summary

"Petroleum Technology Advances Through Applied Research by Independent Oil Producers" is a program of the National Oil Research Program, U.S. Department of Energy. Between 1995 and 1998, the program competitively selected and costshared twenty-two projects with small producers. The purpose was to involve small independent producers in testing technologies of interest to them that would advance (directly or indirectly) one or more of four national program objectives:

- Extend the productive life of reservoirs;
- Increase production and/or reserves;
- Improve environmental performance; and
- Broaden the exchange of technology information.

The twenty-two projects addressed nine diverse technology areas in twelve states. The total cost of the projects was $3.5 million, with $1.0 million (29%) in Federal funds and $2.5 million (71%) from the operators. This report analyses the performance and results of these projects relative to their technological and economic success (Figure 1) and the benefit-cost of the program as a whole.

Figure 1. The Majority of 22 Projects by Independents Were Successful*

Technologically Successful 64%

- Promising
  1. Cleary
  2. EDCO
  3. Brothers
  4. Double Eagle
  5. Keener

- Too Early To Tell But Promising 23%
  - Limited Application
    3. Diamond
  - Not Technologically Successful 14%
    - Not Economically Successful
      19. Poud

- Technologically Successful, Economically Not Estimated
  11. X-TRAC
  12. K-Stewart

- Technically & Economically Successful
  6. Cole
  10. Edinboro
  12. James
  14. IFM
  15. Sipple
  21. Spier
  22. Tenison

*Totals do not add due to rounding.
Overall, the program’s twenty-two projects met with remarkable success:

- Fourteen projects (64%) met their technology objectives:
  - Seven of these (32%) were profitable as stand-alone projects or demonstrated the viability of cost-saving new technologies.
  - One (4%) was so successful in a laboratory demonstration that full scale-up is being planned.
  - Three (14%) technologically successful projects had insufficient data to estimate economic results.
  - Three (14%) technologically successful projects were not economically successful under then prevailing oil prices, but one of them would be profitable at present prices.

- Five projects (23%) were technologically promising but require additional monitoring or further testing to confirm technological success; all of these were in the very advanced but high-potential areas of horizontal drilling and very advanced reservoir characterization (3-D seismic and telluric surveys).

- Only three projects (14%) failed to meet their technological objectives and two of them generated scientifically useful information.

Of the twenty-two projects, seven were judged as ready for technology transfer to other operators, twelve were sufficiently promising to justify additional monitoring or testing, and three had little or only limited future potential in oil reservoirs.

Incremental recovery was reported on a project-specific basis for eight projects and was extrapolated for two more. Incremental production from the eight specific projects was 269 thousand barrels of oil equivalent (BOE). Almost 95% of this was from projects that were marginally profitable or better. The two extrapolated projects would add another 8 million BOE for a total of 8.3 million BOE. Ultimately, of course, additional incremental reserves and production would result from step-outs of these projects, from the projects that did not report specific incremental recovery, and -- most importantly -- from the potentially hundreds or even thousands of fields that could adopt these solutions due to technology transfer.

Economic benefits of a research/demonstration program like this are difficult to assess because they depend on the extent to which operators of fields in addition to those directly participating in the program adopt and adapt the tested technologies over an extended period of time. A lower bound on the benefits, however, can be estimated directly from the projects yielding detailed project economic data. Of the eight projects for which detailed economic evaluations could be performed at the project level, four were clearly profitable, one was marginal, and three were not profitable at the then prevailing economic conditions (one of which would be economic at present oil prices).

In the absence of universally accepted benefits criteria for programs like this, one simple way to examine costs and benefits is to assume that the Federal outlays represent the costs to the economy and the incremental economic gains net of all costs (excepts transfer payments) represent the benefits to the economy. The left side of Figure 2 shows the Federal outlays at
three levels: in total ($1,014M); for the eight projects that could be evaluated economically ($376M); and for the subset of five projects that were profitable ($234M). The right side of the figure represents the incremental economic gains from only the five economic projects.

The total estimated incremental gain to the economy from the five projects is $1,919M, made up of $895M in after-tax cash flow to the independent operators, $586M in taxes (state, $299M; Federal, $287M), and $483M in royalties. This severe lower bound estimate, then, shows that returns to the public (taxes and royalties) from only the five evaluated, economic projects (excluding even step-outs of those) exceeded the Federal outlays for all twenty-two projects. Inclusion of net cash flows to operators would raise this to almost double. Considering only the benefits of the five economic projects but the full cost of the program, the benefit-cost ratio is 1.9 to 1. (The benefit-cost ratio for the five economic projects, relative to their Federal outlay, but still excluding any benefits from expanded use of the demonstrated technologies, is 8.2 to 1).

Economic analysis was also conducted for two other projects on the basis of hypothetically reaching the project forecasted results or of scaling-up laboratory demonstrations to full commercial scale. The economic benefits of either of these projects would exceed the Federal cost of the full program--one by more than 100-fold. Expansion of the economic projects within the test fields, technology transfer to other fields, and benefits from projects that did not report detailed economics will all add to these benefits but not to the costs of the program. Clearly, it is safe to conclude that the program overall was both technically and economically successful.

NPTO plans to continue the program by selecting and cost sharing with independents in field tests of other technologies with promise. Further, outreach and technology transfer efforts are continuing to ensure that all operators are aware of the results of these projects and how the tested technologies might be applied in their own fields.
Background

As the United States continues to mature as an oil-producing province, exploration, development, and production become ever more demanding, even as independent producers assume ever larger roles. Many small independents lack the technical resources or ability to bear the risk of testing unfamiliar technologies or novel approaches that might offer solutions to their most pressing problems.

The U.S. Department of Energy (DOE), through its National Petroleum Technology Office (NPTO), initiated a program entitled, "Petroleum Technology Advances through Applied Research by Independent Oil Producers" (informally called "Support to Independents") to address this problem. The goal of the program was to encourage small independents to experiment with higher-risk, unfamiliar technologies and/or novel, unproven solutions to specific problems. The approach was for the Federal Government to share up to half the costs of competitively selected field projects, provided that the Federal outlay was no greater than $50,000 per project. To be eligible, the operators had to produce oil onshore in the U.S., have no affiliation with major oil companies, and employ 50 or fewer people. Operators of the projects were to communicate the results of these tests so that other operators in their regions and elsewhere could make use of the findings. The program was administered by BDM-Oklahoma, Inc., as management and operations contractor for NPTO’s predecessor organization.

Between 1995 and 1998, twenty-two projects were competitively selected from more than 100 proposals. They were designed to advance one or more of the following objectives:

- Extend the economic production of domestic fields, thus slowing the rate of well abandonments and preserving the industry infrastructure (including facilities, wells, data, and expertise).

- Increase ultimate recovery in known fields using advanced technologies by demonstrating:
  - Improved methods of formation evaluation.
  - Developmental oil recovery and production technologies.
  - Well control and remedial work for environmental compliance.

- Develop new technologies or expand or improve the application of available technologies to solve production problems and/or reduce costs.

- Use field demonstrations to broaden information exchange and technology application.

The selection process also assured a distribution across technology areas and geographic regions. Appendix B provides additional description of the program’s approach.
The present analysis was initiated in 1999 by DOE/NPTO to review and analyze these twenty-two projects. Three criteria were to be addressed:

- **Technological success** of each project: the extent to which project and program technical objectives were met, specifically resulting in increased production or reserves, improved environmental performance, or reduced costs.
- **Economic success** of each project: positive net present value to the project’s operator at then prevailing or likely future economic conditions.
- **Benefit-cost performance** of the program as a whole: the extent to which incremental gains to the economy exceeded Federal outlays.

The purpose was to capture and articulate the “lessons learned” in the respective projects, to develop materials to complement the technology transfer by the operators, and to make suggestions that might benefit of the program in the future.

All contractual documents and progress reports were examined in detail and the operators were contacted to answer questions and supplement the available documentation. All projects were reviewed and analyzed relative to whether they met the objectives stated in the original proposal and contributed to the overall program goals. For those projects that provided sufficient data, an independent economic analysis was conducted to assess the viability of the technology tested and to provide a rough indication of the benefits of the program.

**Overview of Project Results**

Table 1 presents basic information about the twenty-two projects that were selected, including the sub-contract number*, project location, technology area, field and formation, and Federal and operator shares of the total costs.

As displayed on the map in Figure 3, twelve states were represented. The projects addressed nine technology areas and both carbonate and clastic formations. A total of nearly $3.5 million was expended on the projects, of which $1.0 million (29%) was Federal and almost $2.5 million (71%) was invested by the operators.

Table 2 summarizes the results of the program’s projects relative to technical and economic success and advances a recommendation for each.

Fourteen of the twenty-two projects met or exceeded their technological objectives—increasing production or reserves, and/or demonstrating the technical efficacy of new or adapted exploration, production or environmental technology. Two of these (*Cobra* and *ITM*) demonstrated cost-saving new technologies, but provided only general economic information.

*All were subcontracts under prime contract number DE-AC22-94PC91008 between DOE and BDM-Oklahoma, Inc., management and operations contractor of the National Institute for Petroleum and Energy Research.
Sufficient data were available to conduct independent, detailed economic assessments at the project level for eight of the technologically successful projects. Five of those projects (Edmiston, James, Sipple, Spier, and Tenison) were at least marginally profitable at prevailing conditions, while the other three (Grace, Park, and Rock Island) were not profitable despite their technical success. Beyond the five profitable projects, independent economic calculations on another (X-TRAC) showed it to be highly economic based on scale-up of the project’s large scale laboratory demonstration results. Data were insufficient on the remaining three technically successful projects (Sandia, Dakota, and K-Stewart) to independently assess their economic performance, but each successfully developed or demonstrated technology for use in future solutions by independents. Results of these fourteen projects could be applied in a variety of reservoir settings by a broad range of operators.

In addition to the fourteen projects that met their technological objectives, five more were considered “too early to tell” but initial results indicated future promise of technological success. The two horizontal drilling projects (Cleary and EDCO) encountered mechanical difficulties that could be overcome in later attempts. Cleary provided economic data suggesting a high degree of profitability (based on a short production test) had the mechanical problems not been encountered. The two 3-D seismic projects (Brothers and Double-Eagle) had promising results that can only be confirmed by drilling additional successful wells based on the data generated in their initial testing. The telluric survey test (Keener) was unsuccessful, but added to the experience base of this immature but promising technology.

Only three projects were found to be clearly unsuccessful in meeting their technological objectives, and two of those (Diamond, and Spring) generated useful technical information.

By these criteria, nineteen of twenty-two, or 86%, of the projects were successful or advanced promising technologies, with two more (9%) generating useful technical information.
<table>
<thead>
<tr>
<th>Project No. &amp; Operator</th>
<th>Subcontract No.</th>
<th>Project Location</th>
<th>Technical Area</th>
<th>Field/Formation</th>
<th>Operator</th>
<th>Cost Share</th>
<th>DOE/NPTO</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Cleary Exploration L.L.C.</td>
<td>G4P70039</td>
<td>Oklahoma</td>
<td>Horizontal Drilling</td>
<td>Hunton Formation Dolomitic Limestone</td>
<td>$115,000</td>
<td>70%</td>
<td>$50,000</td>
<td>30%</td>
</tr>
<tr>
<td>2. EDCO Producing, Inc.</td>
<td>G4P60386</td>
<td>Ohio</td>
<td>Horizontal Drilling</td>
<td>Trempealeau Formation</td>
<td>$39,000</td>
<td>50%</td>
<td>$39,000</td>
<td>50%</td>
</tr>
<tr>
<td>3. Brothers Production</td>
<td>G4P60306</td>
<td>Texas</td>
<td>3-D Seismic</td>
<td>Ellenburger/Strawn Dolomite</td>
<td>$450,000</td>
<td>90%</td>
<td>$50,000</td>
<td>10%</td>
</tr>
<tr>
<td>4. Double Eagle Enterprises</td>
<td>G4P60320</td>
<td>Oklahoma</td>
<td>3-D Seismic</td>
<td>Wilcox Formation</td>
<td>$240,000</td>
<td>83%</td>
<td>$50,000</td>
<td>17%</td>
</tr>
<tr>
<td>5. Keener Oil &amp;Gas Company</td>
<td>G4P51722</td>
<td>Oklahoma</td>
<td>Telluride Survey</td>
<td>Wilcox Sand</td>
<td>$100,000</td>
<td>67%</td>
<td>$50,000</td>
<td>33%</td>
</tr>
<tr>
<td>6. Univ. of Alabama/Cobra O&amp;G</td>
<td>G4P50139</td>
<td>Alabama</td>
<td>FMI Log</td>
<td>Frisco City Sandstone</td>
<td>$25,000</td>
<td>50%</td>
<td>$25,000</td>
<td>50%</td>
</tr>
<tr>
<td>7. Sandia Operating Corporation</td>
<td>G4P51726</td>
<td>Texas</td>
<td>Coring System</td>
<td>First Cole Sandstone</td>
<td>$70,800</td>
<td>59%</td>
<td>$50,000</td>
<td>41%</td>
</tr>
<tr>
<td>8. Dakota Oil Producers, Inc.</td>
<td>G4P50140</td>
<td>Wyoming</td>
<td>Inert Gas Injection</td>
<td>Lakota Sand</td>
<td>$50,000</td>
<td>51%</td>
<td>$47,202</td>
<td>49%</td>
</tr>
<tr>
<td>9. Diamond Exploration, Inc.</td>
<td>G4P51723</td>
<td>Kansas</td>
<td>Thermal Stimulation</td>
<td>Cottage Grove Sand</td>
<td>$49,500</td>
<td>50%</td>
<td>$49,500</td>
<td>50%</td>
</tr>
<tr>
<td>10. Edmiston Oil Company, Inc.</td>
<td>G4P60387</td>
<td>Kansas</td>
<td>Microbial IOR</td>
<td>McLouth Sand</td>
<td>$117,900</td>
<td>70%</td>
<td>$50,000</td>
<td>30%</td>
</tr>
<tr>
<td>11. X-TRAC Energy, Inc.</td>
<td>G4P70040</td>
<td>Utah</td>
<td>Extraction</td>
<td>PR Springs and Asphalt Ridge Sandstones</td>
<td>$97,359</td>
<td>66%</td>
<td>$50,000</td>
<td>34%</td>
</tr>
<tr>
<td>12. James Engineering, Inc.</td>
<td>G4P60318</td>
<td>Ohio</td>
<td>Computer Software</td>
<td>Clinton/Rose Run Fields</td>
<td>$47,500</td>
<td>50%</td>
<td>$47,500</td>
<td>50%</td>
</tr>
<tr>
<td>13. K-Stewart Petroleum Corporation</td>
<td>G4P60397</td>
<td>Oklahoma</td>
<td>Well Stimulation</td>
<td>Morrow Formation</td>
<td>$623,400</td>
<td>93%</td>
<td>$50,000</td>
<td>7%</td>
</tr>
<tr>
<td>15. Sipple Oil Company</td>
<td>G4P60307</td>
<td>Kentucky</td>
<td>Fracture Treatment</td>
<td>Cretaceous Dolomite Formation</td>
<td>$60,818</td>
<td>55%</td>
<td>$49,753</td>
<td>45%</td>
</tr>
<tr>
<td>16. Grace Petroleum</td>
<td>G4P51721</td>
<td>Oklahoma</td>
<td>Polymer Flood</td>
<td>Bartlesville Sand</td>
<td>$56,000</td>
<td>53%</td>
<td>$50,000</td>
<td>47%</td>
</tr>
<tr>
<td>17. Harry A. Spring</td>
<td>G4P60383</td>
<td>Oklahoma</td>
<td>Water Disposal</td>
<td>Carmichael Sand</td>
<td>$27,500</td>
<td>50%</td>
<td>$27,500</td>
<td>50%</td>
</tr>
<tr>
<td>18. Kenneth Y. Park</td>
<td>G4P51725</td>
<td>Oklahoma</td>
<td>Polymer Treatment</td>
<td>Bartlesville Sand</td>
<td>$50,458</td>
<td>52%</td>
<td>$45,775</td>
<td>48%</td>
</tr>
<tr>
<td>20. Rock Island Service Company, Inc.</td>
<td>G4P70041</td>
<td>West Virginia</td>
<td>Microbial Cleanup</td>
<td>Salt Sand</td>
<td>$46,430</td>
<td>50%</td>
<td>$46,430</td>
<td>50%</td>
</tr>
<tr>
<td>21. Speir Operating Company</td>
<td>G4P50724</td>
<td>Indiana</td>
<td>Microbial Cleanup</td>
<td>Cypress Limestone</td>
<td>$48,775</td>
<td>50%</td>
<td>$48,775</td>
<td>50%</td>
</tr>
<tr>
<td>22. Tenison Oil Company</td>
<td>G4P60385</td>
<td>Louisiana</td>
<td>CaCO3 Prevention</td>
<td>Hosston Sandstone</td>
<td>$41,690</td>
<td>53%</td>
<td>$37,400</td>
<td>47%</td>
</tr>
</tbody>
</table>

**Totals** | **2,480,030** | **71%** | **1,013,335** | **29%** | **3,493,365**
<table>
<thead>
<tr>
<th>Technology Area</th>
<th>Project Number &amp; Title</th>
<th>Operator</th>
<th>Outcomes</th>
<th>Recommendation</th>
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</thead>
<tbody>
<tr>
<td>Drilling</td>
<td>Horizontal Drilling to Increase Production</td>
<td>Cleary Exploration L.L.C.</td>
<td>TETT</td>
<td>Yes-Q</td>
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<tr>
<td>Drilling</td>
<td>Horizontal Drilling for Improved Wellbore Drainage</td>
<td>EDCO Producing, Inc.</td>
<td>TETT</td>
<td>Yes-Q</td>
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<td>Exploration</td>
<td>Improved 3-D Seismic Processing Techniques</td>
<td>Brothers Production</td>
<td>TETT</td>
<td>Yes-Q</td>
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<td>Exploration</td>
<td>Integrated Exploration Using 3-D Seismic</td>
<td>Double-Eagle Enterprises</td>
<td>TETT</td>
<td>Yes-Q</td>
</tr>
<tr>
<td>Exploration</td>
<td>Telluric Surveys</td>
<td>Keener Oil &amp; Gas Company</td>
<td>TETT</td>
<td>Yes-Q</td>
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<td>Formation Evaluation</td>
<td>Formation Micro-Imaging (FMI) Log</td>
<td>University of Alabama/Cobra O&amp;G</td>
<td>Yes</td>
<td>Yes-Q</td>
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<td>Formation Evaluation</td>
<td>Low-Invasion Unconsolidated Coring System &amp; Core Analysis</td>
<td>Sandia Operating Corporation</td>
<td>Yes</td>
<td>Yes-Q</td>
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<td>Improved Oil Recovery</td>
<td>Inert Gas Injection</td>
<td>Dakota Oil Producers, Inc.</td>
<td>Yes</td>
<td>N/Est.</td>
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<td>Improved Oil Recovery</td>
<td>Stimulating Formations Thermally</td>
<td>Diamond Exploration, Inc.</td>
<td>No</td>
<td>N/Est.</td>
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<td>Improved Oil Recovery</td>
<td>Microbial Improved Oil Recovery</td>
<td>Edmiston Oil Company, Inc.</td>
<td>Yes</td>
<td>Yes-Q</td>
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<td>Improved Oil Recovery</td>
<td>Closed-Loop Extraction of Hydrocarbons and Bitumen from Oil-Bearing Soils</td>
<td>X-TRAC Energy, Inc.</td>
<td>Yes</td>
<td>Yes-Q</td>
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<tr>
<td>Operations</td>
<td>Computerized Well Monitoring System</td>
<td>James Engineering, Inc.</td>
<td>Yes</td>
<td>Yes-Q</td>
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<td>Production Problems</td>
<td>Improved Stimulation</td>
<td>K-Stewart Petroleum Corporation</td>
<td>Yes</td>
<td>N/Est.</td>
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<td>Production Problems</td>
<td>Resin-Coated Prepacked Gravel</td>
<td>Industrial Technology Management, Inc.</td>
<td>Yes</td>
<td>Yes-Q</td>
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<tr>
<td>Stimulation</td>
<td>Foam Frac and Foam Acid Treatment</td>
<td>Sipple Oil Company</td>
<td>Yes</td>
<td>Yes-Q</td>
</tr>
<tr>
<td>Water Production</td>
<td>Gel Polymer Treatment</td>
<td>Grace Petroleum</td>
<td>Yes</td>
<td>No-Q</td>
</tr>
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<td>Harry A. Spring</td>
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<td>Gel Polymer</td>
<td>Kenneth Y. Park</td>
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<td>Oxygen Activation Log</td>
<td>J. R. Pounds, Inc.</td>
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<td>No</td>
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<td>Calcium Carbonate Prevention</td>
<td>Tenison Oil Company</td>
<td>Yes</td>
<td>Yes-Q</td>
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</tbody>
</table>

1. **TETT**: Too early to tell; **"Yes"**: met project and/or program objectives; **"No"**: did not meet objectives
2. **"Yes"**: appears economically viable; **"No"**: does not appear economically viable; **"N/Est"**: Not estimated; **"Q"**: quantified in this report, **"N/Q"**: Not quantified in this report
3. Economics based on operator assumptions rather than directly from field test results.
Project-by-Project Summary of Results

A brief description and summary of the results of the technical review of each of the twenty-two projects is presented in this section. The tabbed sections that follow the summary report present additional data in a standard format, and more detailed discussion of each project is presented in Appendix A.

Project 1. **Horizontal Drilling to Increase Production**, operated by Cleary Exploration LLC

Cleary Exploration LLC drilled a horizontal wellbore into a Hunton Formation low-permeability dolomitic limestone reservoir in Pottawatomie County, Oklahoma in an attempt to intersect additional fracture and/or paleokarst systems to increase oil production. The horizontal section was drilled and completed open-hole as proposed with approximately 1,400 feet of horizontal section, although serious hole stability difficulties were encountered during drilling. Initial results indicated significantly improved total fluid production from the horizontal wellbore, but the beam pumping unit being used to produce the well was incapable of moving the amount of fluid produced by the horizontal hole. It was estimated that the produced volumes could exceed 200 BOPD, possibly stabilizing around 100 BOPD, if the well were equipped with high-lift production equipment. However, the first 200 feet of the horizontal hole collapsed before a submersible pump could be installed to fully test the production capacity of the horizontal wellbore. It appears that the horizontal hole collapsed where the hole had drifted up into the overlying "troublesome Woodford shale" during drilling. Attempts to clean out the horizontal section were unsuccessful and the hole was lost before the well could be produced to capacity. While the project did not result in increasing production, the promising initial results of the demonstration suggest technical feasibility. Economic analysis based on the hypothesis that the well would perform as projected showed the well to be highly profitable. A sustained production test would be necessary to determine whether or not production could be improved by the proposed technology.

Project 2. **Horizontal Drilling for Improved Wellbore Drainage**, operated by EDCO Producing, Inc.

EDCO Producing, Inc., attempted to drill a horizontal wellbore in energy depleted compartmentalized reservoir to try to intersect possible accumulations of trapped oil in the Trempealeau Formation in Morrow County, Ohio. Drilling of the horizontal hole was suspended approximately 30 feet into the curve section because of severe hole problems and the extreme difficulty in keeping the hole direction stabilized. The fractured dolomite formation being drilled began to crumble and slough into the borehole. The drilling assembly became stuck and had to be fished out. Based on the inability of the wellbore to stay on course and the corkscrew of the borehole, in conjunction with the formation hole problems, the horizontal drilling attempt was suspended far short of the 300-600 feet of vertical section originally planned. The proposed technology was not successfully applied and oil production rates were not improved. Although the operator expressed an interest in conducting additional drilling efforts, there are no current plans to do so because of low oil prices, which existed at the time of the project. The feasibility of horizontal drilling in this formation remains to be adequately demonstrated and certainly the concept of increasing production rates by intersecting compartmentalized, trapped oil with a vertical borehole remains undemonstrated.
Project 3. **Improved 3-D Seismic Processing Techniques**, operated by Brothers Production Co.

Brothers Production Company used a new analytical 3-D seismic interpretation algorithm, developed to improve time-to-depth conversion, to map the Ellenburger dolomite in the Fluvara, SW Field of Borden County in West Texas. Reprocessing and reinterpretation of the existing 3-D seismic data using the new analytical function resulted in confidently mapping Ellenburger dolomite reflections. The reinterpretation has identified several Ellenburger structural anomalies, which were uneconomic to drill due to low oil prices at the time. The reinterpreted 3-D seismic data indicated that the Ellenburger top in two pre-project dry hole wells was lower than had been predicted from the original 3-D seismic data due to interpretation inaccuracies and processing artifacts of the time-to-depth conversions. The two dry holes would not have been drilled had the reinterpreted 3-D seismic been available at that time. One well was drilled to test a Wolfcamp structural anomaly, identified from the reinterpreted 3-D seismic data. The Wolfcamp structure was present as indicated, but the formation was water saturated. No Ellenburger wells have yet been drilled to verify the reinterpreted 3-D seismic maps. Further drilling activity in the area was suspended because of low oil prices which existed at the time of the project and the uncertainty in current oil prices. The operator does plan to integrate the mapping results into future exploitation drilling plans when economics improve sufficiently. Several wells would need to be drilled in order to determine the accuracy of the Ellenburger maps developed from the use of this technology (i.e., a statistical issue) and the final outcome of this project is yet to be established.


Double-Eagle Enterprises, Inc., used 3-D seismic survey data to supplement existing 2-D seismic data to better identify drilling prospects in the Wilcox sandstone formation in Kay County, Oklahoma. Available 2-D seismic data did not provide sufficient information to identify the more likely productive features of the Wilcox structure, resulting in a low exploration success rate for the area. Two structures were examined. The 3-D seismic data interpretation on a first prospect did not support the existence of a structural anomaly that had been indicated by the 2-D seismic data, so the well to test the structure was cancelled and not drilled, thereby possibly preventing the drilling of a dry hole. Another well was drilled on a second prospect to test a structural anomaly identified from the 3-D seismic data interpretation, but due to an unanticipated thickening of the overlying formation, the Wilcox top was structurally flat (low) and the formation was water saturated. Review of the seismic data suggested that although the top of the overlying formation was structurally high, as confirmed by drilling data, the 3-D seismic data did not suggest that the overlying formation was thickening and that a possible seismic velocity pull-up had been misinterpreted as a favorable underlying Wilcox structural high. Further drilling activity in the area was suspended because of low oil prices, which existed at the time of the project. Although the project results were disappointing, the experience gained from this project and the data from 3-D seismic program may provide useful information, which can be integrated into future drilling plans. Several more wells would need to be drilled in order to determine if the success rate has been statistically improved by this technology. The final outcome of this project (i.e., the success or failure) is yet to be established.
Project 5. **Telluric Surveys**, operated by Keener Oil & Gas Co.

Keener Oil & Gas Company used an electrotelluric (telluric) survey as a tool to try to define subsurface oil and gas bearing structural traps in the Wilcox Sand of Creek County, Oklahoma. An electrotelluric survey is a measurement of the resonance signal created when electromagnetic pulses penetrate the earth’s surface, creating a secondary electrical field, which propagates downward and ultimately resonates from subsurface beds of contrasting resistivities. A well was drilled to test a subsurface structural anomaly identified through the telluric survey data interpretation, but the target formation was not on structure and was dry. The target formation was 22 feet lower than indicated by the telluric interpretation. Review indicated that formation tops and target zones predicted by the telluric data were either undefinable or shallower than the actual depth encountered by the drilled well. The survey interpretation results were not accurate enough to give reliable results. This technology concept appears feasible, but is still in an early developmental phase. Further testing of this technology by the operator has been temporarily suspended because of the unfavorable economics of development drilling at the low oil prices, which existed at the time of the project. The proposed technology has significant application potential if it can be adequately developed. Telluric survey costs are considerably less than for a seismic survey, leaving little if any environmental impact, and thus certainly warrants further research and development by the industry.

Project 6. **Formation Micro-Imaging (FMI) Log**, operated by the University of Alabama (with partners Cobra Oil & Gas and Schlumberger)

Schlumberger’s Formation Micro-imaging (FMI™) log was used to determine facies and reservoir characteristics in Alabama’s Frisco City sandstone as an alternative to coring in order to reduce drilling costs and coring risks. The log was run in a Frisco City Sandstone well for which whole core was readily available. The core description was compared to the FMI log interpretation to determine if the FMI log can be used as a less expensive and less risky means to obtain information necessary for the development of fluid flow models used for drilling, production, and reservoir management purposes. The core was described to determine the facies distribution, geological characteristics, and reservoir properties. The FMI log environment of deposition interpretation did not differ significantly for the whole core interpretation, demonstrating its reliability for deciphering reservoir quality. The porous and permeable intervals as determined from the FMI log interpretation were consistent with the pay zones defined from the whole core analysis. The FMI log provided paleocurrent direction and sandstone orientation data that is not available from core description, yet this information is critical to establishing a regional reservoir stratigraphic model. The FMI log proved beneficial in identifying anisotropic features that could be barriers to fluid flow. Core analysis did, however, indicate which porous and permeable intervals had potential for oil production (the presence of hydrocarbons in the core samples) which could not be interpreted from the FMI log. Comparison between the FMI log interpretation and the whole core analysis from the same well confirmed that the FMI log can be used successfully to provide information on geological description, facies distribution, and reservoir properties as a valid alternative to whole core and whole core analysis.
Project 7. **Low-Invasion Unconsolidated Coring System & Core Analysis**, operated by Sandia Operating Corporation

Sandia Operating Company successfully used a low-invasion, hydrolift coring system to recover a full-diameter unconsolidated Cole sand core for core analysis in Orlee Field area of Duval County, Texas. The hydro-lift system permits more complete and less damaging core recovery by allowing the newly cut core to enter into an aluminum inner barrel. After coring is completed, the core is frozen and retained in the inner barrel for better fluid preservation and protection from damage during shipment. The Cole Sand formation water is fresh, rendering reliable log interpretation and water saturation calculation nearly impossible. Unreliable log analysis creates difficulty in identifying higher oil saturation zones for development drilling. Because of the unconsolidated nature of the sand, there were previously no cores available for log calibration or core description. Core recovery from the well was 100% and only one foot of the core visually appeared to be invaded and flushed by mud filtrate. A suite of core analyses was performed, including 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. The core analysis provided information on reservoir facies, porosity, and oil saturations, and provided data with which to successfully calculate $S_o$ from the logs. Core analysis provided valuable information on porosity and permeability distributions not available from logs, and allowed revision of oil & water saturations within the cored interval.

Project 8. **Inert Gas Injection**, operated by Dakota Oil Producers, Inc.

Dakota Oil Producers applied two different foam-inert gas procedures to the low-pressure North Wind Creek field reservoir in Crook County, Wyoming, in an attempt to increase reservoir pressure and mobilize oil. A high-foam, anoxic surfactant mixture and an inert gas were injected into a single producing well in a "huff and puff" test program to reduce water mobility and water coning. The second procedure involved injecting water-surfactant foam and inert gas into three downdip injection wells in a line-drive pattern for an enhanced waterflood with foam procedure in an attempt to repressurize the oil reservoir to mobilize oil and improve oil production rates. Eight wells were involved in the project out of 20 wells on the 320-acre lease. The inert gas, generated on-site by equipment designed by Dakota, was injected up-dip. The foam mixture, composed of 0.5% surfactant in 55 barrels of water, was injected into the reservoir down-dip each day. The "huff and puff" test did not appear successful and was discontinued. Although two wells experienced cement failure and produced only water, oil production rates from other parts of the project area doubled from the pre-project rates. Oil production stabilized at 10.5 BOPD, double the pre-project rate of 5.7 BOPD. Four hundred fifty barrels of emulsified oil were produced, which had to be treated before it could be sold.

Project 9. **Stimulating Formations Thermally**, operated by Diamond Exploration, Inc.

Diamond Exploration, Inc. used high-voltage electrical current to generate heat in the small, heterogeneous, shallow, Cottage Grove sand of the Paola-Rantou-Shoestring Field in Miami County, Kansas, in an attempt to improve heavy (low-gravity) oil recovery. Copper probes were placed at the formation in each of three probe wells in a triangular pattern approximately 100 feet apart with a producing well in the center. The probes were energized by an electrical current
over a period of six days. The reservoir temperature at the probe wells was elevated from 58°F to 101°F and a small, non-commercial quantity of 21°API gravity viscous oil was recovered from one of the probe wells. Inert gas was injected into each of the probe wells after the formation was heated and communication was immediately established with the producing well. However, the formation temperature at the producing well did not increased and no oil was recovered from the producing well. The technology applied did not result in any oil production. Although the operator remains optimistic about the potential of this technology, it is still in an early experimental stage and the feasibility of the technology remains to be demonstrated.

Project 10. **Microbial Improved Oil Recovery**, operated by Edmiston Oil Company, Inc.

Edmiston injected MEOR (microbial enhanced oil recovery) components into a low-gravity McLouth Sand oil reservoir of the Easton NE Field in Leavenworth County, Kansas, to clean scale, paraffins, and asphaltine deposition from the near wellbore formation in order to improve oil mobility, effective permeability, and hence improve oil recovery. Twenty-four producing wells on eight different leases were treated periodically with conventional matrix squeeze type treatments where MEOR materials were blended and injected down the wellbore into the reservoir. MEOR materials were continuously injected into the reservoir on the Kroll lease by weekly adding MEOR material to the water injection tank of an injection well. Only the Kroll Lease (with continuous MEOR injection from the start) resulted in any appreciable production increase while the response from the squeeze treatments on the other leases was minimal to negative. The probable reasons for production decline for some of the leases has not been determined. Kroll lease production increased from 3 BOPD before the project to 21 BOPD over an eight-month period. However, three months after MEOR injection was started, water injection rates on the Kroll lease were increased from 30 BWPD to 90 BWPD. From the data available, it is difficult to determine whether the Kroll lease response was due to MEOR treatment or to the increased water injection rates or a combination of the two. Additional assessment would be required to determine the probable results of the MEOR treatment alone. Produced oil had greatly improved flow ability for the first year following the treatment, resulting in an operating cost savings during the first two years of the project.

Project 11. **Closed-Loop Extraction of Hydrocarbons and Bitumen from Oil-Bearing Soils**, operated by X-TRAC Energy, Inc.

Oil-bearing soil was mined from the P.R. Springs and the Asphalt Ridge tar sand deposits in Uintah County, Utah, and delivered to X-TRAC Energy's demonstration test facility site at the Sherard Dome Field in Washakie County, Wyoming, for processing. A closed-loop extraction system employing recyclable hydrocarbon solvents was used to extract hydrocarbons and bitumen from oil-bearing tar sands efficiently and in an environmentally safe manner. The test facility contained an entirely closed-loop system for the recovery of the extraction solvents and extracted hydrocarbons which allowed the separation, recapture and recycling of the solvents during the process. The field test was conducted using the large-scale extraction equipment and the tar sand material was processed without difficulty. Twenty thousand pounds of P.R. Spring tar sand material was crushed and processed through the extraction unit, recovering approximately 125 gallons of bitumen. Eighteen thousand pounds of Asphalt Ridge tar sand material was also crushed and processed through the extraction unit, also recovering
approximately 125 gallons of bitumen. Laboratory analysis of the processed material indicated that 60% of the residual oil in place was recovered at operating temperatures and that, at elevated temperatures, recovery could be increased to as much as 80%. 50-60% of the extracted hydrocarbon was 50-60% asphaltenes, 20-25% diesel, and 20-25% light gas oil. Oil analysis indicates that the recovered asphalt is of high grade, which will not require high-cost processing to make the asphalt into premium grade road asphalt. The asphalt and diesel markets are very strong in the area of Utah where the deposits are located. X-TRAC Energy (now UTAR Energy, Inc.) is proceeding to install a commercial-scale facility at the Utah site that will output 2,160 barrels of oil output per day.


James Engineering developed production monitoring system computer software to download production forecasts from major commercial reserve analysis software and upload well production information for a large number of marginal wells. The software compares actual production to forecast values in order to identify wells producing less than forecasted. Loss of production due to individual well production problems in a large number of marginal wells is difficult to identify timely and efficiently, resulting in delays in taking remedial action. A monitoring and prediction software package was developed for 250 wells operated by James Engineering in the Clinton/Rose Run Fields of East central Ohio which could identify production problems quickly and allow prompt remedial action. During a five-month trial period, total production for the 250 wells increased approximately 5½% above the same period for the previous year even though the nominal production decline for that period of time was approximately 6% per year. Based on the results of the demonstration project, James Engineering has successfully developed highly applicable technology. The operator has continued to utilize the technology developed and is well satisfied with the results.

Project 13. **Improved Stimulation**, operated by K-Stewart Petroleum Corporation

K-Stewart Petroleum contracted STIM-LAB to conduct a study identifying minimum formation damage completion and production techniques to maximize production following hydraulic fracturing of Northwest Oklahoma Morrow formation gas wells. Morrow wells in this area historically have not responded consistently to acidizing and hydraulic fracturing. Although Morrow well productivity typically improves with hydraulic fracturing, response to stimulation treatment tends to vary considerably from one well to another and any initially high production rates quickly drop off. The effects of various fluids on matrix permeability and fracture conductivity were compared in laboratory tests; production was correlated to completion methods and production practices by compiling and standardizing records in a relational database; and laboratory testing was related to the field by use of database correlations and characterization of the rocks tested. The study resulted in recommendations that frac fluid and breaker be selected to minimize pressure drop, proppant be selected to provide maximum conductivity in the presence of multiphase flow, and backpressure be held on the well during production to avoid dropping out condensate in the surrounding formation which would otherwise lower the effective conductivity. Low energy prices near the end of and following the project demonstration period have suspended work-over and drilling activities and thus far have prevented utilization of the recommendations developed.

Industrial Technology Management, Inc. (ITM) developed and manufactured a resin-coated prepacked gravel (sand) pack that fits inside a perforated liner for sand control as an alternative to the traditional external wire-mesh wrapped prepacked gravel pack which often becomes damaged while setting. The product consists of a gravel (sand) pack that is bonded to a perforated base pipe and formed into a cylindrical shape to conform to the internal dimensions of a wellbore. The gravel (sand) that makes up the pack medium is a commercial-grade resin-coated sand that has been shaped through the application of heat. The liner has no external wire wrapping or other mechanism for pack containment. Sample prepacked resin-coated liners were laboratory tested for permeability, bond strength, and chemical exposure. These tests indicate that the liner would be durable enough to withstand the typical down-hole environment. A prototype liner mold was developed and a resin-coated prepacked gravel (sand) pack was manufactured. The product has not yet been field tested in a producing well but a suitable well test candidate is actively being sought. The product is being introduced into the Bakersfield and Los Angeles markets. A resin-coated prepacked gravel (sand) pack is a somewhat less expensive product and the installation costs are about half the cost to install a conventional gravel pack system.

Project 15. **Foam Frac and Foam Acid Treatment**, operated by Sipple Petroleum Company

Sipple Oil Company has wells completed in the first, second, and third Corniferous Dolomite Formation in the Big Sinking Field of Lee County, Kentucky. These wells produce water or water with only trace amounts of oil. Typically, when wells in the field are stimulated, water breakthrough occurs soon after stimulation, resulting in low oil and high water production. Sipple conducted and compared three different stimulation treatments in three separate wells to determine the most successful treatment method for increasing oil production while reducing water production. A foam frac treatment in one well using resin-coated sand as a proppant was slightly successful in increasing oil production (0.5 BOPD and 4 BWPD) but was not economical at such a low production rate. A foam frac treatment in a second well using sand as a proppant was successful in increasing oil production (5.4 BOPD and 5 BWPD) and appears to be the most economically and technically successful procedure. A foam acid treatment in the third well was unsuccessful in increasing oil production (0 BOPD and 51 BWPD). Following the project demonstration period, Sipple drilled another well and stimulated using the foam frac with sand treatment. The well is producing 2 BOPD and about one gallon of water per day. Wells that are successfully stimulated in this area typically produce at low oil rates with little if any water. Indications are that foam frac with sand proppant is the most economically and technically successful stimulation procedure to use in this type of reservoir.
Project 16. **Gel Polymer Treatment**, operated by Grace Petroleum

Grace Petroleum used a gel polymer treatment in an attempt to reduce water production from Bartlesville sandstone wells in Nowata County, Oklahoma. The wells were producing large volumes of water due to channeling. The producing wells were treated by injecting a volume of partially hydrolyzed polyacrylamide using a chromium cross-linking agent and ammonium salt to prevent clay swelling into the water zone of each well. The wells were treated with gel polymer then fractured in an attempt to achieve a more horizontal rather than vertical fracture. Injection wells were not treated with polymer. The project consisted of an 80-acre area with two adjacent 5-spot patterns. PAR Services treated the producing wells with approximately 100 barrels of gel polymer. Before treatment, the lease was producing 10 BOPD and 333 BWPD. During the first 562 days, oil production increased from 12 BOPD to 19 BOPD and water production increased from 300 BWPD to 640 BWPD for an increase in WOR from 25 to 34. Oil production increased 58% and water production increased 113%.

Project 17. **Cost Effective Water Disposal**, operated by Harry A. Spring

Harry A. Spring installed a commercially available down hole simultaneous gas production/disposal tool (DHI tool) in a watered-out shut-in Carmichael sand gas well in Logan County, Oklahoma, in an attempt to economically dispose of the produced formation water in order to return the well to gas production. The DHI tool is a device which allows produced formation water to be injected into a lower formation without first being lifted to the surface while allowing simultaneous gas production to occur. Additionally, it was thought that dewatering of the formation near the well bore would allow higher flowing gas rates. The tool was installed in the well, but after several months of production the disposal zone pressured-up and would not accept water with the existing pumping equipment due to the limited injection capacity of the disposal zone and a larger volume of produced water than was originally anticipated. The DHI tool appears to have functioned properly as proposed, but the injection capacity of the disposal formation was inadequate for the volume of formation water being produced. The well was then abandoned because of the high cost of conventional water disposal (hauling). The project was unsuccessful in re-establishing gas production, although the feasibility of the technology was adequately demonstrated. Although disappointed in the results of the project, the operator is satisfied that the technology has additional application potential.

Project 18. **Gel Polymer**, operated by Kenneth Y. Park

Kenneth Y. Park used a gel polymer treatment to reduce water production from Bartlesville sandstone wells in the Bird Creek field of Cleveland, Oklahoma. The water zone in both the producing wells and the injection wells were treated with partially hydrolyzed polyacrylamide with a chromium cross-link agent and ammonium salt to prevent clay swelling. The two producing wells on the lease were producing 5 BOPD and 470 BWPD before the treatment and four wells were shut-in due to high water cut. Following treatment, oil production tripled to 17.5 BOPD and water production doubled to 860 BWPD. Additional oil production may have been possible, but rates were limited by water injection capacity. Oil production decreased to 11 BOPD (6 BOPD incremental) shortly after treatment. All of the wells except one have since been shut-in. The remaining well is producing 5 BOPD and 400 BWPD.

J. R. Pounds proposed to use an Oxygen Activation Log to locate holes in casing for repair as a way of reducing costs in the Rodessa Sand of the Bolton Field in Hinds County, Mississippi. During initial investigation by the operator, a logging service company advised that the Oxygen Activation Log was not designed for casing hole detection in the particular situation that existed in the target well. The target well was on rod pump, shut-in, and not flowing. The logging tool requires the flow of water past the tool in order to function. Conventional bridge-plug and packer pressure testing methods were then employed to locate the casing holes and conventional casing leak repair methods were used to successfully repair the leaks. The production problem was solved and the well was put back on production using conventionally available (non-R&D type) technology to solve and correct the problem. The project failed to meet the requirements of the program because the proposed technology was not applicable to the situation and was thus not applied.

Project 20. **Microbial Cleanup of Paraffin**, operated by Rock Island Service Company, Inc.

Rock Island Service Company, Inc., injected paraffin-mobilizing microbes, surfactant, and nutrients into each of 5 Salt Sand wells scattered over several leases in the Camden Lewis Field in Lewis County, West Virginia, to remove paraffin precipitation in the producing formation in an attempt to improve oil production. The wells last produced in 1984 at a combined rate of 1079 BOPY (3 BOPD). Each well was re-equipped to produce with rods, tubing, rod pump, pump jack, and prime mover prior to treatment. The wells received periodic treatments of 1 to 2 gallons of microbes, 2.5 to 5 gallons of surfactant, 5 to 10 pounds of nutrients, and 400 gallons of water per well. The five wells were treated, shut-in for a week, and then placed on production. Early indications were that for four of the five wells, production increased by 50% over pre-treatment production and that the fifth well's production decreased by 50%. Total 1998 production from the five wells was projected to be 1,535 BOPY (4.2 BOPD) for an incremental increase of 1.2 BOPD.

Project 21. **Microbial Wellbore Cleanup**, operated by Speir Operating Company

Speir Operating Company treated nine producing wells and two injection wells with microbial solution to remove paraffin and sulfide scale in perforations, tubing, and the near-wellbore region in an attempt to improve oil production. The wells, located near Evansville in Posey County, Indiana, produce from the Cypress limestone at 2,200 feet. Paraffin and sulfide scale precipitation was reducing productivity and injectivity. All wells were treated with acid, then operated for about one month prior to receiving the microbial treatments. The wells were treated monthly by injecting 5 barrels of warm water, followed by 10 gallons of microbes and nutrients followed by a 20 barrel warm water flush. Following treatment, oil production and water injection capacity increased initially then returned to pre-treatment levels, indicating that repeated treatments would be required on a continuing 2-3 month interval to treat reoccurring buildup. Oil production, which initially increased from 4 BOPD prior to treatment to 21
BOPD, stabilized at 13-15 BOPD. Injection improved from 20 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.

Project 22. Calcium Carbonate Prevention, operated by Tenison Oil Company.

Tenison Oil Company was experiencing excessive operating costs and downtime of their Hosston Formation wells in Claiborne Parish, Louisiana, because of wellbore problems, i.e., pump sticking, rods parting, and worn parts due to calcium carbonate (CaCO₃) scale deposition in the rod pumps. Prior to the project, one well had been shut-in and the second well was scheduled to be shut-in because of high operating costs, excessive downtime, and loss of production. Chemical analysis of the produced water showed ordinary levels of bicarbonates, indicating a downhole problem causing abnormal CaCO₃ deposition. Tenison redesigned the rod pumps without seating nipples and tubing anchors to reduce heat created by friction in order to reduce calcium carbonate precipitation during production. The rod pump was redesigned to exceed the capacity of the well, which allowed the well equipment to be adjusted to provide sufficient pump capacity even with the tubing anchor removed. Following the remedial action, production from the two wells, which were modified, was doubled from 10 BOPD to 23 BOPD. Workover and operating costs were reduced from $10,000 per month for the one producing well before the project to $1,200 per well per month after the project, well down time was reduced to practically zero.

Project Economic Assessments

Independent economic analyses were conducted for all the projects with sufficient available data. The purpose was to gauge the extent to which the projects themselves had been profitable and whether the technologies being tested were likely to be commercially viable. The criterion was whether the projects had positive net present values under conditions prevailing during the study period or reasonably likely in the future.

The participating operators were not obliged to provide economic information other than that requested in their initial proposals, so the evaluation was conducted on a “best available data” basis. Some of the data were taken from the proposals, some from operators’ progress or final reports, and some from direct contacts with the operators. The analysis was conducted on an incremental basis, segregating incremental revenues and costs from on-going field operations. Historical actual oil and gas prices were used. Future oil prices of $17.50/barrel and gas prices of $2.15/mcf were assumed. The criterion of economic success was a positive net present value when discounted at 15%. Appendix C expands on the method used.

Eight projects provided sufficient data to permit detailed analysis of the net present value economics of the project. It was possible to develop detailed economics for two other projects on an extrapolated or scaled-up basis. An eleventh project, Cobra, succeeded in demonstrating a cost-reduction of $10 thousand to $20 thousand per well by using FMI logs rather than coring, and a twelfth, Industrial Technology Management (ITM), developed and demonstrated a resin-
coated, prepackaged gravel pack that was significantly less costly than conventional gravel packs. No detailed economic data were available for these two projects but, because they demonstrated technologies that performed as well or better and at lower cost than their conventional counterparts, they were assumed to meet the incremental net present value criterion.

Table 3 shows the results of the eight detailed project economic analyses with the projects arranged in descending order of net present values. For James, Tenison, Speir, and Edmiston, the projects met the economic criterion on the basis of the prevailing prices during their tests. Sipple was seen as marginally economic, with a positive and significant net cash flow but negative net present value discounted at 15%. At a slightly higher price or lower but still reasonable discount rate, it would have a positive net percent value, so was classified as marginally economic. These results suggest that these five operators made money on their projects and these technologies are commercially viable. Park, Rock Island, and Grace were not economic under these conditions.

Additional sensitivity analyses were conducted on the projects that were marginal or uneconomic. These analyses found that:

- At an oil price of $20/barrel, which has recently been exceeded, Sipple and Park become clearly economic, although Rock Island and Grace do not.

- If the DOE investment is excluded from the costs in the economic assessment, Sipple and Park again are economic. This demonstrates how DOE’s cost sharing can buffer the risk of an independent’s testing unfamiliar or advanced technology.

- If the projects’ actual performance had been as favorable as forecasted, Sipple, Park, and Grace would all have been strongly economic. This underscores the high quality of the projects proposed. Only Rock Island would not have been economic even if it had performed as forecast under the economic conditions of the times.

These results support to the conclusions that additional testing and/or technology transfer are the appropriate next steps for the technologies tested in at least the leading seven of these eight projects.

Table 4 summarizes the results for the two projects for which extrapolated or scaled-up economic analyses were feasible. Because these two projects could only be analyzed in this form, it was inappropriate to combine them with the project-specific economics of the preceding table.
Table 3. Summary of Economic Performance – Project Level*

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<td>22</td>
<td>21</td>
<td>10</td>
<td>15</td>
<td>18</td>
<td>20</td>
</tr>
<tr>
<td>Incremental. Prod, MBOE</td>
<td>98.2</td>
<td>64.7</td>
<td>26.2</td>
<td>30.8</td>
<td>18.2</td>
<td>238.2</td>
<td>15.7</td>
</tr>
<tr>
<td>Net Revenue Income, $M</td>
<td>1,086.2</td>
<td>957.4</td>
<td>374.8</td>
<td>377.4</td>
<td>267.2</td>
<td>3,063.0</td>
<td>231.7</td>
</tr>
<tr>
<td>Royalty, $M</td>
<td>155.2</td>
<td>136.8</td>
<td>53.5</td>
<td>53.9</td>
<td>38.2</td>
<td>437.6</td>
<td>33.1</td>
</tr>
<tr>
<td>State Revenue, $M</td>
<td>114.7</td>
<td>134.7</td>
<td>4.9</td>
<td>30.5</td>
<td>14.2</td>
<td>299.0</td>
<td>19.6</td>
</tr>
<tr>
<td>Federal Revenue, $M</td>
<td>212.0</td>
<td>60.5</td>
<td>8.9</td>
<td>2.7</td>
<td>2.9</td>
<td>286.9</td>
<td>0</td>
</tr>
<tr>
<td>Net Cash Flow, $M</td>
<td>566.6</td>
<td>228.7</td>
<td>56.1</td>
<td>16.3</td>
<td>37.6</td>
<td>895.2</td>
<td>0.7</td>
</tr>
<tr>
<td>Net Present Value (15%), $M</td>
<td>261.1</td>
<td>105.9</td>
<td>19.9</td>
<td>15.6</td>
<td>-15.2</td>
<td>387.4</td>
<td>-25.9</td>
</tr>
<tr>
<td>DOE Share, $M</td>
<td>47.5</td>
<td>37.4</td>
<td>48.8</td>
<td>50.0</td>
<td>49.8</td>
<td>233.4</td>
<td>45.8</td>
</tr>
<tr>
<td>Operator Share, $M</td>
<td>47.5</td>
<td>41.7</td>
<td>48.8</td>
<td>117.9</td>
<td>60.8</td>
<td>316.7</td>
<td>50.4</td>
</tr>
<tr>
<td>Total, $M</td>
<td>95.0</td>
<td>79.1</td>
<td>97.6</td>
<td>167.9</td>
<td>110.6</td>
<td>550.1</td>
<td>96.2</td>
</tr>
<tr>
<td>Econ. Life, years</td>
<td>10</td>
<td>14</td>
<td>12</td>
<td>6</td>
<td>17</td>
<td>12</td>
<td>5</td>
</tr>
<tr>
<td>Inv. P.O., months</td>
<td>NA</td>
<td>17</td>
<td>NA</td>
<td>NA</td>
<td>77</td>
<td>122</td>
<td>No P.O.</td>
</tr>
<tr>
<td>NCF/BOE, $/BOE</td>
<td>0.94</td>
<td>3.53</td>
<td>2.14</td>
<td>0.53</td>
<td>2.06</td>
<td>0.05</td>
<td>-8.33</td>
</tr>
<tr>
<td>NPV/BOE, $/BOE</td>
<td>0.44</td>
<td>1.64</td>
<td>0.76</td>
<td>0.51</td>
<td>-0.83</td>
<td>-1.65</td>
<td>-7.74</td>
</tr>
</tbody>
</table>

*State and Federal Income does not include any of the tax revenues associated with the Royalty Owner's allocation of incremental production; numbers may not add due to rounding.
Table 4. Summary of Economic Performance—Extrapolated and Scaled-up Projects

<table>
<thead>
<tr>
<th>Operator</th>
<th>Cleary</th>
<th>X-TRAC</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Number</td>
<td>1</td>
<td>11</td>
<td></td>
</tr>
<tr>
<td>Incremental Production, MBOE</td>
<td>179.2</td>
<td>7,884.0</td>
<td>8,063.2</td>
</tr>
<tr>
<td>Net Revenue Income, $M</td>
<td>2,566.7</td>
<td>200,884.0</td>
<td>203,450.7</td>
</tr>
<tr>
<td>Royalty, $M</td>
<td>366.7</td>
<td>28,698.0</td>
<td>29,064.7</td>
</tr>
<tr>
<td>State Revenue, $M</td>
<td>286.2</td>
<td>14,184.0</td>
<td>14,470.2</td>
</tr>
<tr>
<td>Federal Revenue, $M</td>
<td>456.1</td>
<td>20,047.0</td>
<td>20,503.1</td>
</tr>
<tr>
<td>Net Cash Flow, $M</td>
<td>1,227.5</td>
<td>67,364.0</td>
<td>68,591.5</td>
</tr>
<tr>
<td>Net Present Value (15%), $M</td>
<td>693.1</td>
<td>32,658.0</td>
<td>33,351.1</td>
</tr>
<tr>
<td>DOE Share, $M</td>
<td>50.0</td>
<td>50.0</td>
<td>100.0</td>
</tr>
<tr>
<td>Operator Share, $M</td>
<td>115.0</td>
<td>97.4</td>
<td>212.4</td>
</tr>
<tr>
<td>Total, $M</td>
<td>165.0</td>
<td>147.4</td>
<td>312.4</td>
</tr>
<tr>
<td>Econ. Life, yr.</td>
<td>18</td>
<td>10</td>
<td></td>
</tr>
<tr>
<td>Inv. P.O., no.</td>
<td>10</td>
<td>16</td>
<td></td>
</tr>
<tr>
<td>NCF/BOE, $/BOE</td>
<td>6.85</td>
<td>8.54</td>
<td></td>
</tr>
<tr>
<td>NPV/BOE, $/BOE</td>
<td>3.87</td>
<td>4.14</td>
<td></td>
</tr>
</tbody>
</table>

The *Cleary* project was a horizontal well in a fractured, low-permeability limestone that performed very well until the open hole collapsed and could not be remedied cost-effectively. The hypothetical case assumed that improved directional control would help avoid the overlying shale, which caused the collapse. In this case, the well would have been highly profitable. It could have repaid the Federal investment in it nine-fold in taxes alone, disregarding other benefits.

*X-TRAC* was the second project for which scaled-up economics were compiled. On the strength of a highly successful, large-scale laboratory test of a solvent extraction process for Utah tar sands, the operator is proceeding to obtain partners and/or financing to construct a $9 million, 2,160 b/d plant to implement the technology at full commercial scale. The summary economics of this scaled-up plant show this project to be the most profitable of all of the projects on per-barrel basis. The projected Federal tax revenue of this project alone is 20 times the Federal outlay for the *entire* twenty-two projects in the program through 1998.

Program-Level Benefit-Cost Analysis

Benefits to society or to the economy of a research/demonstration program such as this are difficult to assess in definitive terms. The program was designed to test and demonstrate on small-scale novel solutions to widespread problems. Ultimate benefits will depend on the
expansion from the small-scale tests to full field application and from the test fields to others with the same or similar problems. Estimation of these full benefits was beyond the scope of the present analysis. A lower bound of the benefits can, however, be estimated from the economic results of the projects themselves. As noted above, because the operators were not obliged to provide economic data, detailed, independent economic analyses could be conducted for only ten projects eight for actual project-specific results and two for hypothetical or scaled-up results.

Several methods and indicators of benefits and costs could be used. One simple, straightforward way is to assume that the Federal outlays represent the costs to the economy and the incremental economic gains after payment of all direct costs (except transfer payments) represent the incremental benefits to the economy. These gains would include those to the independent operators and their stockholders (after-tax net cash flow), to royalty holders, and to the citizens of the respective states and the U.S. as a whole through taxes. Alternative definitions of costs and benefits are certainly possible. For example, one might compare only Federal outlays and Federal returns. While this would not reflect the full economic benefits, it would give a very simple input-output comparison. Table 5 presents the elements that are available for consideration. (Note that no positive benefits were assigned for the uneconomic projects because they would not have been implemented under market conditions at the time, so the benefits in the first two columns are the same.)

### Table 5. Rough Estimate of Benefits and Costs of the Program
(In thousands of dollars, undiscounted)

<table>
<thead>
<tr>
<th></th>
<th>Five Economic Projects</th>
<th>Eight Projects with Project Specific Analyses</th>
<th>Cleary (Hypothetical)</th>
<th>X-TRAC (Scaled-up)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>After tax net cash flow to operators</td>
<td>895</td>
<td>1,228</td>
<td>67,364</td>
<td>69,487</td>
<td></td>
</tr>
<tr>
<td>Royalty Payments</td>
<td>438</td>
<td>367</td>
<td>24,968</td>
<td>25,503</td>
<td></td>
</tr>
<tr>
<td>State Taxes</td>
<td>299</td>
<td>299</td>
<td>14,184</td>
<td>14,769</td>
<td></td>
</tr>
<tr>
<td>Federal Taxes</td>
<td>287</td>
<td>287</td>
<td>20,047</td>
<td>20,790</td>
<td></td>
</tr>
<tr>
<td>Subtotal Taxes</td>
<td>586</td>
<td>586</td>
<td>34,231</td>
<td>35,559</td>
<td></td>
</tr>
<tr>
<td>Subtotal Royalties and taxes</td>
<td>1,024</td>
<td>1,024</td>
<td>58,929</td>
<td>61,062</td>
<td></td>
</tr>
<tr>
<td>Total incremental economic gain</td>
<td>1,919</td>
<td>1,919</td>
<td>12,6293</td>
<td>130,549</td>
<td></td>
</tr>
<tr>
<td>Less: Federal Outlay</td>
<td>234</td>
<td>376</td>
<td>50</td>
<td>50</td>
<td>1,013</td>
</tr>
<tr>
<td>Net Benefits</td>
<td>1,685</td>
<td>1,543</td>
<td>12,6243</td>
<td>129,536</td>
<td></td>
</tr>
<tr>
<td>Gross Benefit: Cost Ratio</td>
<td>8.2</td>
<td>5.1</td>
<td>46.7</td>
<td>2,525.9</td>
<td>128.9</td>
</tr>
</tbody>
</table>
Examination of Table 5 shows that by essentially any indicators, the program yielded significant benefits relative to its costs. Considering the most stringent level of benefits, i.e., that the only economic benefits were those that actually accrued from the five projects found to be economic or marginal at the project-specific level compared to the total Federal outlay, the total benefits are nearly double the costs. This completely ignores all benefits from the other seventeen projects, the step-out expansion of even these five projects within the fields in which they were tested, or adoption of these solutions in other fields with similar problems. The hypothetical economic benefits of the Cleary well alone would have been more than double the full Federal outlay. The scale-up of the X-TRAC test as planned by the company would itself return more than 100 times the Federal outlays in overall economic benefits — twenty-fold on Federal taxes alone.

Conclusions and Recommendations

“Petroleum Technology Advances through Applies Research by Independent Producers” is a highly successful program on several levels:

- **Technological success**, increased production or reserves, improved environmental performance, or reduced costs: Nineteen of twenty-two projects (86%) either clearly met their technical objectives or hold sufficient initial promise to justify follow-up or additional testing.

- **Economic successes**, positive net present value: For the twelve projects for which economic analysis was possible, nine (75%) were profitable under then-prevailing or expected future conditions.

- **Benefit-cost ratio**, incremental gains to the economy in excess of Federal outlays: Even disregarding the projects for which economic analysis was not possible, the step-outs in fields where economic projects were conducted, and the adoption of tested solutions in other fields with similar problems, and admitting to a variety of definitions of benefit, the program’s calculated benefits exceed the outlays by at least a factor of two and perhaps by more than two orders of magnitude.

By any standard, the program is successful. Table 2, above, advanced recommendations as to the next step for each individual project (expanded in the tabbed sections that follow). Many of the individual projects’ technologies were sufficiently successful enough to warrant aggressive technology transfer. Some of these technologies and certainly those classified as “too early to tell” justify additional monitoring, R&D, and/or demonstration and testing. Low and falling oil prices may have deterred from some of the operators’ ability to continue testing or to expand. The recent price recovery may help expedite the expansions or other tests of these solutions.

Two of the projects that did not meet their technological objectives were seen as having limited application outside the immediate area of their testing and one project proposed a technology that was inappropriate to the problem it was supposed to address. Only these three projects do not justify follow-up in some form.
The ultimate benefit of the program’s initial successes depends on how far and how fast its results are transferred and its technologies are adopted by operators beyond those participating directly in the program. Technology transfer to other independents is critical to ultimate success of the program. Under the 1995-1998 version of the program, the funded operators were expected to be the primary technology transfer agents. Two factors inhibited the effectiveness of this approach. First, the desire to minimize the paperwork burden on busy operators limited the amount of information sought and acquired by the program. Second, independent operators may have lacked the resources and/or willingness to prepare and present their results effectively. While the operators made a commitment to transfer their findings, none is in the business of technology transfer. NPTO should to utilize a number of additional channels to make this effort optionally effective. NPTO’s Internet home page and perhaps other sites, regional offices of the Petroleum Technology Transfer Council, regional and national professional meetings, the trade and professional press, and perhaps other mechanisms are all channels for NPTO to use to highlight the completed program and similar efforts in the future.

Some projects that did not fully meet their technological and economic objectives could have benefited from additional technical review and input during the test period. The program did not provide direct technical assistance during the contract period. In some cases, operational difficulties encountered could have been overcome, if direct access to engineering, geology, and laboratory assets were available. A multi-disciplinary team of advisors with limited access to labs and service companies could have helped the operators solve their problems as they arose. Further, uniform technical assistance across all projects would have enhanced the consistency of research methods and reporting and increased the impact of individual projects and the entire program.

Additional documentation the of projects would aid in the analyses of results, technology transfer, and research and development follow-up critical to achieving the full benefits of the program. Even several successful projects lacked the clear documentation needed to analyze project and program benefits. Closer monitoring of progress during the project and a more comprehensive, consistent, and required reporting would have enhanced the impact of research results. Standardized documentation, including the development of a final report format, could increase the consistency of reporting without being overly burdensome while providing the data needed to achieve the program’s full potential.

Low oil prices dramatically constrained the research activities in the initial phase. Given the historical volatility of oil prices, NPTO should consider the impact that changes in oil price, up or down, could have on future research projects. Given that most of the projects undertaken had marginal project economics, changing oil prices can cause operators to revise their projects in ways that may reduce their technical value. The program must be sensitive to the changes in project economics attendant to changes in oil prices and the risks they impose on operators. However, the program needs also to attain a minimum return of performance and data from each project. Perhaps it would be useful to agree upon a minimal project execution (perhaps well less than the full design) that would be completed even if oil prices were to fall dramatically. Such an agreement could be included in the final stages of contract negotiations.
DOE/NPTO has successfully planned, implemented, and completed critical research and demonstrations through the "Applied Research by Independent Producers" program. By sponsoring twenty-two projects in thirteen states covering essentially all major product areas served by NPTO, valuable knowledge was gained through which independent producers can lower costs and increase future production. All of the technologies found successful or promising in the program so far hold future significant potential for solving key problems facing independent operators. Significant benefits have been stimulated and more can be realized through systematic technology transfer and follow-up R&D and testing. With additional, improved documentation, selective technical assistance, and aggressive technology transfer, continuation of this program will be extremely valuable, aiding domestic operators, and hence the nation as a whole.
horizontal drilling to increase production

TECHNOLOGY AREA
Drilling

PROBLEM
Production Rates and Ultimate Recovery Vary Widely and Unpredictably from One Well to Another

SITUATION
Low Oil Production and Recovery

RESULTS
Project Completed as Proposed
Initially Production Increased

Horizontal Section of Hole Collapsed, Stopping Production

Cleary Exploration L.L.C.
Oklahoma City, Oklahoma

Hunton Formation
Dolomitic Limestone
@ 5,734 ft

Background
Production rates and ultimate recovery vary widely and unpredictably from one well to another in this area of the fractured Hunton Dolomitic Limestone Formation in Pottawatomie County, Oklahoma, and production from new wells is often marginal to non-commercial. The inconsistent and unpredictable results are believed to be due to the presence or absence of specific reservoir fracture and/or paleokarst (karst) system intersecting the vertical wellbore.

Project Description
Cleary Exploration re-entered an existing vertical wellbore and drilled a medium radius horizontal section through the reservoir in an attempt to intersect additional fracture and/or karst systems to increase oil production.

Results
The horizontal wellbore was drilled and completed open-hole, as proposed, with approximately 1,400 foot of horizontal section. Serious hole stability difficulties were encountered during drilling. Initial results indicated significantly improved total fluid production from the horizontal wellbore, but the beam pumping unit being used to produce the well was incapable of moving the amount of fluid produced by the horizontal hole. It was estimated that the produced volumes could exceed 200 BOPD, possibly stabilizing around 100 BOPD, if the well was equipped with high lift production equipment. However, the first 200' of the horizontal hole collapsed before a submersible pump could be installed. It appears that the horizontal hole collapsed where the hole had drifted up into the overlying "troublesome Woodford shale" during drilling. Attempts to clean out the horizontal section were unsuccessful and the hole was lost. The project was unsuccessful in increasing and sustaining production, however, the inconclusive results of the demonstration do suggest the technical feasibility and do indicate significant production potential. A sustained production test would be necessary to determine whether or not production could be improved by the proposed technology.

Economics
Economic analysis based on the indicated production rate of 100 BOPD and a project cost of $381,000 ($256,015 to drill and complete plus $124,985 to equip to produce) indicates that an estimated 179,212 BO could be recovered over an 18 year economic life with an NPV (discounted at 15%) of $693,055.

Project Funding
DOE made an award of $165,000 (30% DOE, 70% Cleary) to Cleary Exploration, LLC for the horizontal drilling portion of this project.
## Project 1. **Horizontal Drilling to Increase Production**, Cleary Exploration LLC

<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 8-01-96</th>
<th>Ended: 7-30-97</th>
<th>Duration: 12 months</th>
</tr>
</thead>
</table>

### Problem:
Production rates and ultimate recovery vary widely from one well to another and production from new wells is often marginal to non-commercial.

### Proposed Solution & Technical Description:
Re-enter an existing vertical well and drill a 1,500 foot horizontal section through the formation to intersect the maximum number of potentially productive fractures. The horizontal wellbore will expose more formation face to the wellbore and extend the effective drainage area of the well.

### Reservoir Setting & Information:
The Hunton Formation in Pottawatomie and Oklahoma Counties, Oklahoma, is a dolomitic fractured limestone section occurring at about 5,100 ft. The zone is known to be very prolific in areas of adequate porosity and permeability development, explained by the possible presence of localized areas identified as karst zones.

### Objective/Intent:
Program Objective: Increase production and reserves.
Project Objective: Test the feasibility and economics of drilling a horizontal well through the oil zone of the fractured limestone reservoir to encounter additional fracture or karst systems to increase production.

### Working Hypothesis:
Drill a horizontal well to accelerate the production of reserves compared to continued marginal production from the vertical wellbore to the economic limit and then shut-in and abandon the well.

### Baseline & Forecast:
The vertical well, drilled and completed in 1996, originally tested 10 BOPD and 70 BWPD. No production forecast was presented.

### Compare Actual vs baseline:
Initial fluid production from the horizontal section increased approximately 6 fold with fluid level at around 2,000 foot and the well was not pumped-off with the existing rod pump. Indicated production potential was around 100 BOPD, if the well were equipped with high-lift equipment. The horizontal hole collapsed shutting off production before a submersible pump could be run to produce the well to capacity. After the hole collapsed, production rates quickly dropped and the working fluid level fell to the rod pump intake.

### Economic?
Economic analysis based on the indicated rate of 100 BOPD with a project cost of $381,000 (had production been sustained) would be expected to have a positive NPV of $693,055, producing 179,212 BO during an economic life of 18 years.

### Economic Detail
- **Production (BO):** 179,212
- **NCF (Undisc.) ($):** 1,227,505
- **Econ. Life (years):** 18
- **NRI Income ($):** 2,566,745
- **NPV (15% Disc.) ($):** 693,055
- **Inv. PO (months):** 10
- **Royalty Income ($):** 366,678
- **Investment ($):** 381,000
- **NTER: 4.22**
- **State Revenue ($):** 286,164
- **Expense ($):** 0
- **Undisc Profit ($/BO):** 6.85
- **Federal Revenue ($):** 456,075
- **Operating Cost ($) :** 216,000
- **Disc Profit ($/BO):** 3.87

### Project Objective Met?
The project objective was not met. The well was drilled and completed open hole as proposed with approximately 1,400 foot of horizontal section. Initial production was interrupted approximately 3 days after production start-up when the horizontal hole collapsed where the hole had drifted up into the overlying Woodford shale during drilling. Attempts to clean out the obstruction were unsuccessful and the borehole was lost.

### Program Objective Met?
The program objective was not met. No additional oil was produced and no additional reserves were added. However, the inconclusive results of the demonstration do suggest the technical feasibility and do indicate significant production potential.

### Lessons Learned
Inability to maintain hole stability during drilling of the horizontal section probably created the conditions, which resulted in the hole collapsing. Setting a liner in the horizontal section might have protected the hole.

### Application (area/region)
The potentially productive fractured Hunton Limestone formation underlies an estimated 200 square miles of several counties in central Oklahoma. If successfully demonstrated, the technology would have wide aerial application with significant production potential.

### Limitations
There are few limitations to the technology other than the incremental production volumes, which must be high enough to justify the additional cost and risk of horizontal drilling. Horizontal drilling technology is well developed and has been applied successfully in other similar applications.

### Recommendations
Additional horizontal drilling should be encouraged in this area, using improved horizontal drilling and completion technology in conjunction with the experience gained in this attempt, to fully determine the feasibility of this technology application. A sustained production test is necessary to determine whether or not production can be improved in this field by the proposed technology.

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28
horizontal drilling for improved wellbore drainage

TECHNOLOGY AREA
Drilling

PROBLEM
Heterogeneous Formation with Low Reservoir Energy

SITUATION
Low Oil Production

RESULTS
Unable to Complete Horizontal Section Due to Drilling Difficulties

EDCO Producing, Inc.
Mt. Gilead, Ohio

Trempealeau Formation @ 3,088 ft

Background
Low reservoir energy and possible compartmentalization result in limited oil recovery from the Cambrian dolomite Trempealeau Formation in Morrow County, Ohio. Numerous wells were drilled during early development of the field because there were no spacing rules, thus the reservoir pressure was prematurely depleted.

Project Description
EDCO attempted to drill a horizontal wellbore into the reservoir to try to intersect possible accumulations of trapped oil. Because of the low reservoir pressure, it was necessary to drill the short-radius turn and horizontal section with air. The short-radius turn was necessary to place the downhole rod pump intake as low as possible in the curved section in order to reach the fluid level.

Results
Drilling of the horizontal hole was suspended approximately 30 ft. into the curve section because of severe hole problems and extreme difficulty in keeping the hole direction stabilized. The fractured dolomite formation being drilled began to crumble and slough into the borehole, sticking the drilling assembly, which then had to be fished out. Based on the inability of the wellbore to stay on course and the corkscrew of the borehole, in conjunction with the formation hole problems, the horizontal drilling attempt was suspended far short of the 300-600 ft. of vertical section originally planned. A coiled tubing anchor with a check-valve was run into the curved section below the rod pump in order to reach the fluid level. Well production stabilized at the pre-project rate of 5 BOPD and 15 BWPD.

Economics
The cost of the project was $93,423.37 with no incremental increase in production. A successful horizontal well completion and a sustained production test would be necessary to determine whether or not production can be improved in this field by the proposed technology. It is yet to be determined if horizontal drilling in this formation can be successfully applied and whether or not the production can be improved by a horizontal wellbore.

Project Funding
A project award of $78,000 (50% DOE, 50% EDCO) was made to EDCO for this horizontal drilling project.
<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 5-03-96</th>
<th>Ended: 8-01-96</th>
<th>Duration: 2 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>Limited oil recovery due to low reservoir pressure in a heterogeneous, and possibly compartmentalized, fractured dolomite reservoir.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Drill a short radius 300-600 ft horizontal well section from an existing vertical wellbore to intersect isolated, undepleted oil accumulations and provide a conduit for the low energy oil to migrate to the vertical wellbore.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reservoir Setting &amp; Information</td>
<td>Limited oil recovery from the Cambrian dolomite Trempealeau Formation @ 3,088 ft. in Morrow County, Ohio, due to low reservoir pressure and possible formation compartmentalization. Numerous wells were drilled during early development and the reservoir pressure was prematurely depleted possibly leaving significant recoverable oil in place.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Increase production and reserves. Project Objective: Drill a short radius 300-600 ft horizontal well section from an existing vertical wellbore in a mature, pressure depleted, possibly compartmentalized reservoir to increase oil recovery.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Working Hypothesis</td>
<td>Drill a horizontal wellbore to encounter compartmentalized oil and increase oil production rates compared with continued low oil production to the economic limit then shut well in and abandon prematurely, leaving significant recoverable oil in place.</td>
<td></td>
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<tr>
<td>Baseline &amp; Forecast</td>
<td>Prior to the project, the well was producing 6 BOPD and 12 BWPD. Estimated incremental production increase was 16.6 BOPD and 33.3 BWPD. No incremental forecast was presented. No increased operating costs were anticipated.</td>
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<tr>
<td>Compare: Actual vs baseline</td>
<td>Results were inconclusive because the horizontal section was not completed due to drilling problems, thus there was no production data generated for the proposed horizontal wellbore. Seven weeks after the project, the well was pumped-off, producing 2 BOPD and 7 BSWPD. The operator then ran a coiled tubing anchor with check-valve below the rod pump into the curved section. Well production stabilized at pre-project rate of 5 BOPD and 15 BSWPD. The well was then shut-in due to economics.</td>
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<tr>
<td>Economic?</td>
<td>Economics could not be run because no production data was generated for the proposed horizontal wellbore. The original project AFE for the horizontal recompletion was for $78,000 (without contingency) for approximately a 16.6 BOPD incremental increase, with no increase in op. costs. The actual cost of $93,423.37 included $39,000 for a drilling rig vs. $7,000 for a service rig to drill the horizontal section.</td>
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<tr>
<td>Project Objective Met?</td>
<td>The project objective was not met. Approximately 32 ft. into the curved section, the fractured dolomite formation began to crumble, sticking the drilling assembly, which had to be fished out. Based on the inability of the wellbore to stay on course and the corkscrew of the wellbore, the horizontal drilling attempt was suspended. The objective of increasing production with a horizontal wellbore was not investigated.</td>
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<tr>
<td>Program Objective Met?</td>
<td>The program objective was not met. No incremental oil was produced and there was no increase in reserves. Due to drilling problems encountered during the early stages of drilling, the horizontal section was not completed.</td>
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<tr>
<td>Lessons Learned</td>
<td>Horizontal drilling in this formation appears to be exceedingly difficult and several drilling problems would need to be addressed before another attempt could be reasonably made.</td>
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</tr>
<tr>
<td>Application (area/region)</td>
<td>Horizontal drilling, when successfully demonstrated, has extensive application in fractured or compartmentalized formations. A successful horizontal well completion and a sustained production test would be necessary to determine whether or not production can be improved in this field by the proposed technology. It is yet to be determined if (1) horizontal drilling in this formation can be successfully applied even with modifications to the drilling program and (2) production can be improved at all by a horizontal wellbore.</td>
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<tr>
<td>Limitations</td>
<td>Even if horizontal drilling was successful and production was improved, the technology application would be limited by the low incremental production potential due to the low reservoir pressures. Also, the problem of production from the horizontal section with low fluid levels would need to be solved. The low production potential makes the use of downhole submersible pumps cost prohibitive.</td>
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<tr>
<td>Recommendations</td>
<td>Due to the low production potential and marginal economics of horizontal drilling in this field, horizontal drilling activities do not appear to be economically practical based on this project's results. Additional testing and redesigned are required before this technology in this formation can be considered viable.</td>
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</tbody>
</table>
improved 3-D seismic processing techniques

Brothers Production Company, Inc.
Midland, Texas

Ellenburger/Strawn Dolomite @ 8,300 ft

Background
The Ellenburger dolomite formation top on the Permian Basin Eastern Shelf is often difficult to accurately map from seismic data interpretation. The inability to map the Ellenburger due to incorrect time-to-depth conversion increased the risk for infill drilling prospects in the Fluvanna, SW Field in Borden County, West Texas.

Project Description
Use an integrated interpretation of existing log and 3-D seismic data to conduct a velocity analysis then use new analytical functions to more accurately predict the time-to-depth relationship. Reinterpret the existing 3-D seismic data to generate structural maps to identify structural anomalies for exploitation prospects and drill a well to test the accuracy of the integrated re-interpretation technique.

Results
Reinterpretation of the 3-D seismic data using the new analytical procedure has resulted in identifying Ellenburger reflections with which to confidently map the structure top. Several Ellenburger structural anomalies have been identified for exploitation prospects but no Ellenburger wells have been drilled to verify the reinterpreted 3-D seismic maps. The reinterpreted 3-D seismic data indicated that the Ellenburger top in two pre-project dry hole wells was lower than had been predicted from the original 3-D seismic data and the wells would not have been drilled if the reinterpreted data had been available. One well was drilled to test a Wolfcamp structural anomaly, identified from the reinterpreted 3-D seismic data. The Wolfcamp structure was present as indicated, but the formation was wet. Further development drilling activities were suspended due to the low oil prices, which existed at the time.

Economics
The project AFE was for $55,700 for 3-D seismic reinterpretation plus $450,000 to drill and complete an Ellenburger well. No incremental increase in Ellenburger production resulted from the project, although there is a high level of confidence in the structural maps, which were generated. Several wells would need to be drilled in order to actually determine the accuracy of the technology developed during this project.

Project Funding
A project award of $500,000 (10% DOE, 90% Brothers) was made to Brothers Production Co. for this 3-D seismic processing technology development project.
<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 4-15-96</th>
<th>Ended: 9-15-96</th>
<th>Duration: 5 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>Ellenburger dolomite infill drilling prospects are difficult to identify because the formation top cannot be accurately mapped by conventional 3-D seismic interpretation due to incorrect time-to-depth conversion of seismic horizons.</td>
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<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Use an integrated interpretation of existing log and 3-D seismic data to conduct a velocity analysis using new analytical equations to predict time-to-depth conversions. Generate structural maps to identify structural anomalies for exploitation prospects and drill a well to test the accuracy of the integrated re-interpretation technique.</td>
<td></td>
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<tr>
<td>Reservoir Setting &amp; Information</td>
<td>Conventional 3-D seismic survey data was acquired and utilized in an attempt to identify Ellenburger dolomite structural highs between existing development wells for infill drilling prospects in the Fluvanna, SW Field in Borden County, Texas. Using conventional 3-D seismic interpretation, two dry holes were drilled into the Ellenburger dolomite @ 8,400 ft. The error in the existing time to depth conversion technique was severe enough that additional wells would not be drilled unless the technology could be developed to improve the conversion process significantly.</td>
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</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Increase reserves. Project Objective: Reinterpret the existing 3-D seismic data using analytical functions to improve the time-to-depth conversions, generate structural maps of objective exploitation prospects, then drill a well to test the accuracy of the technology.</td>
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<tr>
<td>Working Hypothesis</td>
<td>Reinterpret 3-D seismic data using new analytical functions to improve the velocity conversion to an accuracy which will reduce the risk in drilling exploitation prospects compared to suspending all infill drilling activities in the prospect area due to low success rate.</td>
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<tr>
<td>Baseline &amp; Forecast</td>
<td>Based on conventional 3-D seismic interpretation, two pre-project dry holes were drilled in the prospect area and future drilling activities were suspended. Successful wells were predicted to produce 41.4 BOPD &amp; 21 MCFD. 5 successful exploitation prospects could add an estimated 1.5 MMBO reserves to the project area.</td>
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<tr>
<td>Compare: Actual vs baseline</td>
<td>No Ellenburger wells were drilled based on the reinterpreted 3-D seismic data (due to low oil prices at that time). One Wolfcamp dry hole was drilled based on the 3-D seismic reinterpretation. Based on drilling information, the well was successfully completed in the shallower Spraberry formation and 150,000-200,000 barrels of new oil reserves were developed.</td>
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<tr>
<td>Economic?</td>
<td>There is no data with which to run economics on the project. The well drilled did not result in production from the Ellenburger formation. The AFE for drilling and completing the proposed Ellenburger well was for $264,000 dry hole and $450,000 completed.</td>
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<tr>
<td>Project Objective Met?</td>
<td>The project objective was not met. The reinterpreted 3-D seismic data has identified several Ellenburger structural anomalies, but none of those have yet been drilled. The operator is of the opinion that the quality of the Ellenburger structural mapping was improved significantly by the reinterpreted 3-D seismic data and that the overall drilling success rate will be increased. The operator plans to integrate the mapping results into their future Ellenburger exploitation plans.</td>
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</tr>
<tr>
<td>Program Objective Met?</td>
<td>The program objective was not met. As of yet, no additional Ellenburger reserves have been developed by the project.</td>
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</tr>
<tr>
<td>Lessons Learned</td>
<td>Final results have not yet been determined. Development drilling activities have been suspended until the economics conditions improve. The quality of the Ellenburger structural map may have been improved by the re-interpreted data, but several wells will need to be drilled in order to determine if the drilling success rate can be improved by this technology. An improvement in the overall drilling success rate requires the drilling of at least as many wells as were utilized in determining the baseline success rate.</td>
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<tr>
<td>Application (area/region)</td>
<td>The technology developed, if successfully demonstrated, has wide application to the Ellenburger formation throughout the Easter Shelf of the Permian Basin area. With the improved confidence from the reinterpreted 3-D seismic data and the experience gained, the operator plans to utilize the technology in future in-fill drilling activities in the Fluvanna SW Field, when drilling activities resume.</td>
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</tr>
<tr>
<td>Limitations</td>
<td>The technology has yet to be successfully demonstrated. Additional drilling will be required to determine if the re-interpretation improves the overall success rate.</td>
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</tr>
<tr>
<td>Recommendations</td>
<td>This project should be reviewed periodically to evaluate the final results of any future drilling activities to determine whether or not the technology can be successful applied.</td>
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</tr>
</tbody>
</table>
integrated exploration using 3-D seismic
(formerly integrated exploration using 3-D seismic and surface microbial technique)

TECHNOLOGY AREA
Exploration

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

SITUATION
Low Exploration Success Rate

RESULTS
3-D Seismic Interpretation Completed
Drilled One Dry Hole Well
Additional Prospects Not Yet Drilled

Double-Eagle Enterprises, Inc.
Tulsa, Oklahoma

Wilcox Formation @ 5,734 ft

Background
Existing subsurface and 2-D seismic data did not provide sufficient information to identify the more likely productive features of the Wilcox Sand structure of Northern Kay County, Oklahoma, resulting in a low exploration success rate for the area.

Project Description
Double-Eagle Enterprises proposed to conduct a 3-D seismic survey to supplement existing 2-D seismic data and conduct surface microbial analysis to better identify drilling prospects in the Wilcox sandstone formation. The proposal was later modified to eliminate the surface microbial survey due to budget constraints.

Results
3-D seismic data was acquired and processed and two prospects were identified. The 3-D seismic data interpretation on the first prospect did not support the existence of a structural anomaly that had been indicated by the 2-D seismic data. Therefore the well to test the structure was cancelled and the prospect was not drilled, thereby probably preventing the drilling of a dry hole. Another well was drilled on the second prospect to test a structural anomaly identified from the 3-D seismic data interpretation, but due to an unanticipated thickening of the overlying formation, the Wilcox top was structurally flat (low) and the formation was wet. Review of the seismic data suggested that although the top of the overlying formation was structurally high, as confirmed by drilling data. The 3-D seismic data did not suggest that the overlying formation was thickening and that a possible seismic velocity pull-up had been misinterpreted as a favorable underlying Wilcox structural high. Further drilling activities were suspended due to the low oil prices that existed at the time.

Economics
The project AFE was for $290,000 for 3-D seismic data acquisition and interpretation and drilling costs. Although the project results were disappointing, the experience gained from this project and the data from the 3-D seismic program has provided useful information, which can be integrated into future drilling plans when oil prices recover. Several more wells should be drilled in order to determine if the success rate has been improved by this technology.

Project Funding
A project award of $290,000 (17% DOE, 83% Double-Eagle) was made to Double-Eagle Enterprises for this 3-D seismic project.
# Project 4. Integrated Exploration Using 3-D Seismic, Double-Eagle Enterprises

<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 5-30-96</th>
<th>Ended: 12-31-97</th>
<th>Duration: 19 months</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Problem</strong></td>
<td>The success rate for Wilcox Sand discoveries in Northern Kay County, Oklahoma, using existing exploration technology is well below 10%. Currently, only subsurface and either single fold or 2-D seismic data are available.</td>
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</tr>
<tr>
<td><strong>Proposed Solution &amp; Technical Description</strong></td>
<td>Acquire and integrate 3-D seismic data and surface geo-microbial recon techniques (the microbial survey was later dropped from the revised project plan due to budget constraints) into existing exploration program to improve the discovery success rate. Drill 2-3 of the potential prospects to determine the accuracy of the technology.</td>
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</tr>
<tr>
<td><strong>Reservoir Setting &amp; Information</strong></td>
<td>Only subsurface and either single fold or 2-D seismic data have been used for exploration in the shallow, 4,000 ft. Wilcox sands of Northern Kay County, Oklahoma. The shallow Wilcox structures are small in areal extent, usually less than 100 acres, and not economically attractive for large regional 3-D seismic surveys.</td>
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<tr>
<td><strong>Objective/Intent</strong></td>
<td>Program Objective: Increase reserves. Project Objective: Incorporate 3-D seismic techniques into existing exploration program to improve the discovery success rate; test by drilling 2 to 3 Wilcox sand wells in the prospect area.</td>
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</tr>
<tr>
<td><strong>Working Hypothesis</strong></td>
<td>Use 3-D seismic data to improve the exploration success rate compared to continuing use of 2-D seismic data, which has an exploration success rate of less than 10%.</td>
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<tr>
<td><strong>Baseline &amp; Forecast</strong></td>
<td>Previous exploration drilling success rate was less than 10%. Forecast was that the success rate could be improved to 25% or more utilizing 3-D seismic data. Successful Wilcox sand wells can produce over 100,000 barrels of reserves.</td>
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<tr>
<td><strong>Compare: Actual vs baseline</strong></td>
<td>A Wilcox sand was drilled to test a structural high indicated by the 3-D seismic data, but the structure was lower than indicated and the well was a dry hole. The Wilcox sand drilling success rate was not improved using the reinterpreted 3-D seismic data for the well drilled. Further drilling activity was suspended (due to low oil prices at that time). Based on the 3-D seismic data, the second prospect was not drilled.</td>
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<tr>
<td><strong>Economic?</strong></td>
<td>No data was generated with which to run economics. The Wilcox well drilled was dry, thus there was no production. All cost of the project, including the drilling of the well, was lost. The AFE for drilling and completing the well was $65,250 dry hole cost and $113,250 for a completed producer.</td>
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<tr>
<td><strong>Project Objective Met?</strong></td>
<td>The project objective was not met. One dry hole was drilled based on the 3-D seismic interpretation. A second prospect, identified from 2-D seismic data, was not confirmed by the 3-D seismic data and thus was not drilled. The operator identified several conditions that may have led to a misinterpretation of the data. The operator is of the opinion that the 3-D seismic data will improve the drilling success rate overall when drilling activity resumes.</td>
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<tr>
<td><strong>Program Objective Met?</strong></td>
<td>The program objective was not met. As of yet, no increased production has resulted from the project and no additional reserves have been developed.</td>
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<tr>
<td><strong>Lessons Learned</strong></td>
<td>The final results have not yet been determined. Drilling activities have been suspended until the economics improve sufficiently. Several wells will need to be drilled in order to determine if the drilling success rate can be improved. An improvement in the overall drilling success rate requires the drilling of at least as many wells as were utilized in determining the baseline success rate.</td>
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<tr>
<td><strong>Application (area/region)</strong></td>
<td>The technology, if successfully demonstrated, has wide application throughout the area. With the improved confidence from the 3-D seismic data and the experience gained, the operator plans to utilize the technology in future exploration drilling activities in the Wilcox sand, when drilling activities resume.</td>
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<tr>
<td><strong>Limitations</strong></td>
<td>The technology has yet to be successfully demonstrated. Additional drilling will be required to determine if the 3-D seismic interpretation improves the overall success rate.</td>
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<tr>
<td><strong>Recommendations</strong></td>
<td>This project should be reviewed periodically to evaluate the final results of any future drilling activities in order to determine whether or not the technology proves to be successful.</td>
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</table>
TECHNOLOGY SOLUTIONS FOR INDEPENDENT PETROLEUM OPERATORS

telluric surveys

Keener Oil & Gas Company
Tulsa, Oklahoma

Wilcox Sand
@ 3,869 ft

Background
A Wilcox Sand structural anomaly was identified from an electrotelluric (telluric) survey run in Creek County, Oklahoma, which could not be verified by any other subsurface information available for the area. A telluric survey is a measurement of the resonance signal created when atmospheric generated electromagnetic pulses penetrate the earth's surface, creating a secondary electrical field that propagates downward and ultimately resonates from subsurface beds of contrasting resistivities.

Project Description
Keener Oil & Gas proposed to drill a well to test the subsurface structural anomaly identified through the telluric survey data interpretation.

Results
A well was drilled to test the prospect, but the target formation was not on structure and was dry. The target formation was 22 feet lower than indicated by the telluric interpretation. Review indicated that formation tops and target zones predicted by the telluric data were either not definable or shallower than the actual depths encountered by the drilled well. The exact cause(s) for the inaccurate interpretation are not understood at this time. This project proposed the use of a technology that is still in a very early development stage. The technology concept appears feasible, but will require considerably more research and field development to improve the interpretation accuracy.

Economics
The project AFE to drill the well was $87,675 dry hole cost. There was no incremental production as a result of the project. However, the technology has significant application potential if it can be adequately developed. The expense of a telluric survey is a small fraction of the cost of a comparable seismic program. Additionally, the technique is completely noninvasive and leaves little, if any, environmental impact.

Project Funding
A cost-share award of $150,000 (33% DOE, 67% Keener) was made to Keener Oil & Gas for this technology development project.
**Project 5. Telluric Surveys, Keener Oil & Gas Company.**

<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 10-15-95</th>
<th>Ended: 12-31-95</th>
<th>Duration: 3 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>A telluric survey indicated a Wilcox sandstone structural anomaly not previously indicated by any other data available. An electrotelluric (telluric) survey is a measurement of the resonance signal created when atmospheric generated electromagnetic pulses penetrate the earth's surface, creating a secondary electrical field, which propagates downward and ultimately resonates from subsurface beds of contrasting resistivities.</td>
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<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Drill a well to test the capability of tellurics as an additional tool to define subsurface features for exploratory and development drilling by comparing structural tops in the drilled well with structural tops interpreted from a telluric survey.</td>
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<tr>
<td>Reservoir Setting &amp; Information</td>
<td>A Wilcox Sandstone subsurface structural anomaly was identified in Creek County, Oklahoma, from a telluric geophysical survey. There was no other subsurface data from the immediate area to confirm the telluric interpretation.</td>
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</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Develop new technology. Project Objective: Drill a well to test the capability of tellurics as an additional tool to define subsurface features for exploratory and development drilling by comparing structural tops in the drilled well with structural tops interpreted from a telluric survey.</td>
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<tr>
<td>Working Hypothesis</td>
<td>Use Telluric survey data to reduce cost, risk and better define structural control where seismic data cannot be acquired for exploration and development drilling compared to acquiring sometimes cost-prohibitive seismic data or utilize other high-risk techniques.</td>
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<tr>
<td>Baseline &amp; Forecast</td>
<td>A previously undetected Wilcox sandstone formation structural anomaly was interpreted from a telluric survey. 50-100 BOPD expected from a successful Wilcox well completion.</td>
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<tr>
<td>Compare: Actual vs baseline</td>
<td>Wilcox sand drilling success rate was not improved using the telluric data for the well drilled. The operators are of the opinion that telluric data can be used to improve the drilling success rate overall, but will not eliminate the risk completely, and certainly requires additional technical development.</td>
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<tr>
<td>Economic?</td>
<td>There was no production generated by this project therefore no economic analysis could be conducted. The Wilcox sandstone well drilled was dry, thus all cost of the project, including the drilling of the well, was lost. The AFE for the well was $87,675 dry hole and $191,213 completed as a producer.</td>
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<tr>
<td>Project Objective Met?</td>
<td>The project objective was not met. A dry hole was drilled based on telluric survey interpretation. The telluric data interpretation accuracy was not sufficient or definitive enough to provide reliable data.</td>
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<tr>
<td>Program Objective Met?</td>
<td>The program objective was not met because no oil was produced and reserves were not increased. There was some experience gained and information added to the knowledge base, but the state of technology development was not improved appreciably.</td>
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<tr>
<td>Lessons Learned</td>
<td>The technology used in this project is in a very early stage of research and development.</td>
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<tr>
<td>Application (area/region)</td>
<td>This technology, if successfully developed, has wide application throughout the world. Telluric surveys are a fraction of the cost of seismic surveys and are completely non-invasive (i.e., environmentally friendly).</td>
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<tr>
<td>Limitations</td>
<td>If adequately developed and demonstrated, telluric data interpretation could have world-wide application. Telluric data interpretation would not eliminate the risk involved in drilling activities, however, successful development of the technology could reduce the risk and the cost significantly.</td>
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<tr>
<td>Recommendations</td>
<td>Considerably more R&amp;D development is needed before this technology can be utilized, however, the potential for cost and risk reduction is significant and further technology development should be encouraged.</td>
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</tbody>
</table>

36
TECHNOLOGY AREA
Formation Evaluation

PROBLEM
High Cost and
High Risk of
Coring

SITUATION
Develop Alternative
to Coring

RESULTS
FMI Log
Interpretation
Compared
Successfully
to Whole Core
Description

FMI Log
Interpretation
is a Valid
Alternative to
Coring

Background
Whole core Frisco City Sandstone sample analysis are required for the identification of reservoir quality sandstone and for the development of fluid flow models used for drilling, production, and reservoir management purposes in the East Frisco City Field of Monroe County, Alabama. Coring operations are expensive and of great risk to wellbore integrity.

Project Description
Schlumberger's Formation Micro-imaging (FMI™) log was run in a Frisco City Sandstone well for which whole core was readily available. The core was described to determine the facies distribution, geological characteristics, and reservoir properties. The core description was compared to the FMI log interpretation to determine if the FMI log can be used as a less expensive and less risky means to determine the necessary facies and reservoir characteristics.

Results
The FMI log environment of deposition interpretation did not differ significantly for the whole core interpretation, demonstrating its reliability for deciphering reservoir quality. The porous and permeable intervals as determined from the FMI log interpretation were consistent with the pay zones defined from the whole core analysis. The FMI log provided paleocurrent direction and sandstone orientation data that is not available from core description, yet this information is critical to establishing a regional reservoir stratigraphic model. The FMI log proved beneficial in identifying anisotropic features that could be barriers to fluid flow. Core analysis did, however, indicate which porous and permeable intervals had potential for oil production (the presence of hydrocarbons in the core samples) which could not be interpreted from the FMI log.

Economics
Comparison between whole core analysis and the FMI log interpretation from the same well confirmed that the FMI log can be used successfully as a valid alternative to coring, with a cost savings of approximately $10,000 to $25,000 per well in this area.

Project Funding
A project award of $50,000 (50% DOE, 50% Cobra and partners) was made to Cobra and partners for this core-log comparison technology development project.
<table>
<thead>
<tr>
<th><strong>Project Timing</strong></th>
<th><strong>Problem</strong></th>
<th><strong>Proposal Solution &amp; Technical Description</strong></th>
<th><strong>Reservoir Setting &amp; Information</strong></th>
<th><strong>Objective/intent</strong></th>
<th><strong>Working Hypothesis</strong></th>
<th><strong>Baseline &amp; Forecast</strong></th>
<th><strong>Compare: Actual vs baseline</strong></th>
<th><strong>Economic?</strong></th>
<th><strong>Project Objective Met?</strong></th>
<th><strong>Program Objective Met?</strong></th>
<th><strong>Application (area/region)</strong></th>
<th><strong>Limitations</strong></th>
<th><strong>Recommendations</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Started: 10-15-95 Ended: 10-14-96 Duration: 12 months</td>
<td>Whole core sample analysis is required for Frisco City sandstone reservoir characterization, production purposes, and reservoir management. Coring operations are expensive and of risk to wellbore integrity.</td>
<td>FMI log electrical image analysis provides structural information for fault identification, discrimination from sedimentary dip, determination of structural dip, visualization of complex structures, and detailed formation features associated with local changes in porosity and permeability. FMI log data, if properly integrated with whole core analysis, has the potential to identify reservoir grade sandstone and productive intervals, thus replacing the need for riskier and more expensive whole core coring operations.</td>
<td>The Frisco City sandstone sequence consists of fine-grained sandstones stacked with conglomerates and interbedded with mudstones and siltstones. Whole core samples are essential to identify reservoir grade sandstone intervals with adequate local porosity and permeability for producibility.</td>
<td><strong>Program Objective</strong>: Develop new technology. &lt;br&gt;<strong>Project Objective</strong>: Develop scientifically valid methodologies for integrating whole core information and Formation Micro-Imaging (FMI) log data to provide a more economical solution for sandstone reservoir characterization and production applications.</td>
<td>Conduct the study to reduce cost and risk compared with continuing to obtain high risk and sometimes cost prohibitive cores for analysis.</td>
<td>Coring costs typically run $20,000 per well. FMI logs were forecasted to run $5,000 per well.</td>
<td>The cost to run logs to 12,000', Schlumberger log interpretation (which was considerably more expensive than anticipated), cut core, core description, etc., reduced the indicated cost savings to 25% instead of the expected 75% for the project. The original project AFE was for $100,000 to core and log a well, analyze the core, interpret the log, and make the comparisons. An available core was obtained and the AFE amount was reduced to $50,000.</td>
<td>Indicated savings range between $10,000 to $25,000 per well (depending on well depth and conditions) if the FMI log is used instead of cutting and analyzing whole core. The project was intended to develop technology for utilization in reservoir evaluation.</td>
<td>The project objective was met. Whole core analysis was successfully integrated with FMI log data and the FMI log interpretations did not differ significantly from the whole core analysis. The porous and permeable intervals in the Frisco City Sandstone identified from the FMI log were consistent with the pay zones identified by whole core analysis.</td>
<td>The program objective was met. Indications are that use of the FMI log can save 50% or more of the estimated $20,000 coring costs and eliminates the risk involved with cutting a whole core.</td>
<td>World wide technology application in reservoirs requiring whole core analysis for sandstone characterization. There is no drilling activity in the Frisco City Sand at this time due to unfavorable economic conditions.</td>
<td>Few limitations. The FMI log can be run as a substitute for coring in many cases where whole core analysis is currently required for sandstone reservoir characterization.</td>
<td>Implement into Technology Transfer Program and encourage application.</td>
</tr>
</tbody>
</table>
low-invasion, unconsolidated coring system & core analysis

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
Successful Unconsolidated Whole Core Recovery and Analysis

Sandia Operating Corporation
San Antonio, Texas
First Cole Sandstone @ 1,700 ft

Background
Development wells producing from the Cole sand of the Orlee Field area in Duval County, Texas, have irregular oil saturation and irregular oil-cuts from wells throughout the field because of reservoir heterogeneity. Some down dip wells produce higher oil cuts than up-dip wells. The formation water is fresh, rendering reliable log interpretation and water saturation calculation nearly impossible. Unreliable log analysis creates difficulty in identifying higher oil saturation zones for development drilling. Because of the unconsolidated nature of the sand, there are no cores available for log calibration or core description.

Project Description
Sandia Operating Company proposed using a low-invasion, hydrolift coring system to recover a full-diameter unconsolidated Cole sand core for core analysis. The hydrolift system permits more complete and less damaging core recovery by allowing the newly cut core to enter into an aluminum inner barrel. After coring is completed, the core is frozen and retained in the inner barrel for better fluid preservation and protection from damage during shipment.

Results
Core recovery from the well was 100% and only one foot of the core visually appeared to be invaded and flushed by mud filtrate. A suite of core analyses was performed, including 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. The core analysis provided information on reservoir facies, porosity, and oil saturations, and provided data with which to successfully calculate $S_w$ from the logs. Core analysis provided valuable information on porosity and permeability distributions not available from logs, and allowed revision of oil and water saturations within the cored interval.

Economics
No data was produced with which to perform project economic analysis. This was a technology development project intended to produce for future development drilling activities, including well placement and identification of potential completion intervals. The project AFE was for $51,500 to drill the well and an additional $59,300 for coring and core analysis.

Project Funding
A project award of $120,800 (41% DOE, 59% Sandia) was made to Sandia Operating Co. for this core retrieval and core analysis project.
## Project 7: Low-Invasion Unconsolidated Coring System & Core Analysis, Sandia Operating Co.

<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 10-15-95</th>
<th>Ended: 10-14-96</th>
<th>Duration: 12 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>Development wells within the field have irregular oil saturation and some downdip wells produce with higher oil cuts than some updip wells. No cores or core descriptions are available to determine reservoir characteristics or with which to calibrate logs in the unconsolidated sand oil reservoir containing fresh formation water.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Cut full diameter core using new hydro-lift, low invasion coring system. Analyze for porosity, permeability, oil saturation, relative permeability, wettability, mineralogy and depositional environment to better understand oil distribution within the reservoir.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reservoir Setting &amp; Information</td>
<td>Unconsolidated Cole sand oil reservoir at 1,700 feet, containing fresh formation water. Typically, conventional core recovery of the softer, unconsolidated reservoir rock would be very low.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Develop new technology. Project Objective: Recover and analyze a whole core in a Cole sand reservoir in South Texas.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Working Hypothesis</td>
<td>Obtain and analyze whole core for reservoir characterization and log calibration to compare with current operations with unreliable analysis and inadequate reservoir understanding.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Baseline &amp; Forecast</td>
<td>11 wells on the lease making an average of 6.6 BOPD per well. The whole core analysis was designed to provide a more representative understanding of the reservoir properties to aid in development and infill well placement and zone completions.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Compare: Actual vs baseline</td>
<td>No actual data produced. It is expected that the core analysis will allow a better and more representative log interpretation, a better understanding of the oil distribution within the reservoir, and a better prediction of reservoir geometry.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Economic?</td>
<td>No data was produced with which to run project economics. This was a technology development project intended to produce results which could be utilized in future development drilling activities. The AFE was for $61,500 to drill the well and an additional $59,300 for coring and core analysis.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Project Objective Met?</td>
<td>The project objective was met. 28 feet (100%) of whole core was successfully recovered using the hydrolift, low-invasion coring system and analyzed as per project proposal.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program Objective Met?</td>
<td>The program objective was met. The core analysis was used to improve water saturation calculations from the electric log data and calculation of height above free water level. A high porosity zone, not distinguishable on logs, was identified from the core analysis. Depositional environment, mineralogy, and reservoir facies distribution were identified from the core analysis. Drilling activities in the area were suspended due to low oil prices following the project demonstration period.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Application (area/region)</td>
<td>Technology has local specific application to other Jackson Series traps in the area, and general application to all unconsolidated formations.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Limitations</td>
<td>Technology can be applied to any unconsolidated formation where core and core analysis is essential.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Recommendations</td>
<td>Implement into Technology Transfer Program and encourage application.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
inert gas injection

Dakota Oil Producers, Inc.
Pierre, South Dakota

Lakota Sand
@ 1,100 ft

TECHNOLOGY AREA
Improved Oil Recovery

PROBLEM
Low Oil Recovery
Due to Low Reservoir Pressure

SITUATION
No Reservoir Energy to Mobilize Oil

RESULTS
Emulsified Oil was Produced
Several Wells Experienced Cement Failure

Background
Low-pressure in the Lakota Sand reservoir of the North Wind Creek field in Crook County, Wyoming, results in low oil production rates. In 1995 before the start of the project, daily production from the leases was 5.7 Barrels of oil per day. Dakota previously tried water-flooding the reservoir, but without success.

Project Description
Dakota Oil Producers applied two different foam-inert gas procedures in an attempt to increase pressure and mobilize oil. 7-8 wells were involved in the project out of 20 wells on the 320 acre lease. A high foam, anoxic surfactant mixture and an inert gas was injected into a single producing well in a "huff-and-puff" procedure to reduce water mobility and water coning. Water-surfactant foam and inert gas was injected into three downdip injection wells in a line-drive pattern for an enhanced waterflood with foam procedure to repressurize the oil reservoir in an attempt to mobilize oil and improve oil production rates.

Results
Initially, oil production had stabilized at 10.54 barrels per day, double the 1995 production rate, on parts of the injection area. On the other part of the project site, two wells experienced cement failure and produced only water. 450 barrels of emulsified oil was produced during the project, which must be treated before it can be sold. The "huff-and-puff" test was not successful and was discontinued. The lease was shut-in due to surface usage disagreements and low oil prices at the time.

Economics
There is not enough data available to run an economics analysis on the project. Some emulsified oil was produced as a result of the treatments, but it's value after treating is difficult to determine.

Project Funding
A project award of $97,202 (49% DOE, 51% Dakota) was made to Dakota Oil Producers, Inc. for this project.
## Project 8: Inert Gas Injection, Dakota Oil Producers

<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 10-15-95</th>
<th>Ended: 10-14-96</th>
<th>Duration: 12 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>Oil production from low gravity oil reservoir with bottom water has been decreasing because of serious water coning and many wells have been shut-in due to excessive water production.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Add surfactant to injection water along with inert gas (87% nitrogen and 12% CO₂) to generate foam of high viscosity in (1) a line-drive waterflood pattern and (2) inject inert gas into individual production wells in &quot;huff-and-puff&quot; injection-production cycles to diminish water coning and early water breakthrough.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reservoir Setting &amp; Information</td>
<td>Shallow 750 ft. Lower Lakota sand stringer with low gravity, &quot;asphalt-type&quot; oil producing at low oil rates and high WOR.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Increase production. Project Objective: Inject water-surfactant foam and inert gas into downdip injection wells in a line-drive pattern in a low-pressure formation to repressurize the oil reservoir, mobilize oil and improve oil production rates. Inject inert gas into the producing wells in a &quot;huff-and-puff&quot; test program to reduce water mobility and prevent water coning.</td>
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<td></td>
</tr>
<tr>
<td>Working Hypothesis</td>
<td>Use a surfactant, inert gas, &amp; water foam treatment to increase oil production and reduce water coning to compare with continued operations with low oil production, high water cut, and several wells shut-in as uneconomic.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Baseline &amp; Forecast</td>
<td>Pre-project production was 5.27 BOPD with high water cut from 22 producing wells.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Compare: Actual vs baseline</td>
<td>Post-project production was over 12 BOPD with about 80% water cut. 450 barrels of emulsified oil were produced between the summer of 1996 and the spring of 1997 (approximately 9 months). The project has been shut-in due to low oil prices.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Economic?</td>
<td>There is not enough definitive data available to run an economics analysis. The project AFE was for $47,202.50. Indications are that there was a production response to the treatments, but specific data was not provided.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Project Objective Met?</td>
<td>The project objective was met. Both the line-drive injection pattern and the &quot;huff-and-puff&quot; treatments provided varying degrees of success. Emulsified oil was produced from several wells on the lease and an improved oil-water ratio was observed in several wells.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program Objective Met?</td>
<td>The program objective was met. Oil production from the lease was increased from 5.27 BOPD to over 12 BOPD.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Application (area/region)</td>
<td>Could have fairly wide application potential, especially if the process was more fully researched to define specific applications.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Limitations</td>
<td>Process not well documented, but appears to have been successful. Future attempted application of this technology will require case-by-case assessment.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Recommendations</td>
<td>Conduct detailed technical study of implementation to better define the application and results. Document the process and incorporate into the Technology Transfer Program.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Diamond Exploration Company, Inc.
Paola, Kansas

Cottage Grove Sand
@ 200 ft

Background
Low oil recovery due to low oil gravity and low reservoir energy in the small, heterogeneous, shallow, Cottage Grove sand of the Paola-Rantou-Shoestring Field in Miami County, Kansas.

Project Description
Diamond Exploration, Inc. designed a high-voltage electrical generator and used the electrical current to generate heat in the reservoir in an attempt to improve heavy (low gravity) oil recovery. Copper probes were placed at the formation in each of three wells in a triangular pattern approximately 100 feet apart with a producing well in the center. An electrical current was used to energize the probes over a period of six days. Inert gas was injected into each of the probe wells after the formation was heated and communication was immediately established with the producing well.

Results
The reservoir temperature at the probe wells was elevated from 58°F to 101°F and a small, non-commercial quantity of 21°API gravity viscous oil was recovered on a wire line from one of the probe wells. The formation temperature at the producing well did not increase and no oil was recovered from the producing well.

Economics
The technology applied in this project did not result in any incremental oil production. Although the operator remains optimistic about the potential of this technology, it is still in an early experimental stage and the feasibility of the technology remains to be demonstrated.

Project Funding
A project award of $99,000 (50% DOE, 50% Diamond) was made to Diamond Exploration for this project.
<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 10-15-95  Ended: 4-15-96  Duration: 6 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>A shallow, 200 feet deep, 6 feet thick, low gravity oil sandstone formation is non-producible.</td>
</tr>
<tr>
<td>Proposed Solution</td>
<td>Drill 3 electrode wells in a triangular pattern 100' apart with a producing well in the middle. Insert copper electrodes, connected to a 400-cycle generator, into the formation. Pass an electrical current through the shallow, low pressure, heavy oil reservoir to generate heat to activate dormant gas and lower the oil viscosity, mobilizing the oil. Inject inert gas if necessary to increase reservoir pressure.</td>
</tr>
<tr>
<td>&amp; Technical Description</td>
<td>A shallow, 200 feet deep, 6 feet thick, low gravity oil sandstone formation is non-producible. Earlier attempts to waterflood this zone were unsuccessful. The oil zone is approximately 6 ft. thick and the underlying water zone is approximately 2-3 ft. thick.</td>
</tr>
<tr>
<td>Reservoir Setting &amp; Information</td>
<td>The Cottage Grove sand at 200-300 ft. depth is a shallow, low gravity oil sandstone in Miami County, Kansas, and is non-producible. Earlier attempts to waterflood this zone were unsuccessful. The oil zone is approximately 6 ft. thick and the underlying water zone is approximately 2-3 ft. thick.</td>
</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Increase reserves. Project Objective: Heat the reservoir by passing an electrical current through the reservoir to activate dormant gas and lower the oil viscosity, mobilizing the oil. Inject inert gas if necessary to increase reservoir pressure.</td>
</tr>
<tr>
<td>Working Hypothesis</td>
<td>Heat formation and attempt to recover non-producible heavy oil compared with no development with zero recovery.</td>
</tr>
<tr>
<td>Baseline &amp; Forecast</td>
<td>Zero pre-project oil production. No forecast was provided. Small diameter, rotary core sample oil saturations were 25-35%.</td>
</tr>
<tr>
<td>Compare: Actual vs baseline</td>
<td>There are no results to compare. A 50 ml downhole oil sample was recovered from one of the electrode wells. The oil sample had an API gravity of 21° and viscosity of 1,730 centipoises. The oil saturation was probably too low to be producible.</td>
</tr>
<tr>
<td>Economic?</td>
<td>There are no results for economics. All costs were lost. Estimated total project proposal cost was $99,000. Due to high cost of fuel to run the electric generator and the low quality of the oil, it is unlikely that such a project would be economic even if technically successful.</td>
</tr>
<tr>
<td>Project Objective Met?</td>
<td>The project objective was not met. The formation at the electrode wells was heated from 58 °F to 101 °F, but no oil was produced. The formation at the center producing well was not heated. Injection of inert gas at the electrode wells had no effect on oil production, although gas communicated to the center producing well.</td>
</tr>
<tr>
<td>Program Objective Met?</td>
<td>The program objective was not met because no oil was produced and no reserves were added.</td>
</tr>
<tr>
<td>Lessons Learned</td>
<td>Either insufficient heat was generated beyond the immediate vicinity of the electrode wells and/or the reservoir oil saturation was at irreducible.</td>
</tr>
<tr>
<td>Application (area/region)</td>
<td>If the technology could be developed, and demonstrated to be practical, feasible, and economic the large oil resource in shallow, heavy oil reservoirs could be exploited.</td>
</tr>
<tr>
<td>Limitations</td>
<td>Application would be limited to recovery of heavy oils that could become mobile at moderate temperature increases.</td>
</tr>
<tr>
<td>Recommendations</td>
<td>Additional research would be required to determine the extent of the formation affected by the temperature increase and to determine if the technology is practical, feasible, and/or economic.</td>
</tr>
</tbody>
</table>
microbial improved oil recovery

TECHNOLOGY AREA
Improved Oil Recovery

PROBLEM
Wellbore Damage

SITUATION
Low Oil Production

RESULTS
MEOR Squeeze Treatments Gave Mixed Results

Continuous MEOR Treatment with Water Injection Improved Production

Edmiston Oil Company, Inc.
Wichita, Kansas

McLouth Sand @ 1,350 ft

Background
Wells producing low-gravity oil from the McLouth Sand, Easton NE Field, Leavenworth County, Kansas, experience low production volumes due to a low mobility ratio. Wellbore damage due to paraffin and asphaltene scaling requires conventional chemical remediation treatments resulting in very high operating costs and premature shut-in of wells.

Project Description
Edmiston injected MEOR components into the oil reservoir to clean scale, paraffins, and asphaltene deposition from the near wellbore formation and to improve oil mobility and effective permeability in order to improve oil recovery. Twenty-four producing wells on eight different leases were treated periodically with conventional matrix squeeze type treatments where MEOR materials were blended and displaced down the wellbore into the reservoir. MEOR materials were continuously injected into the reservoir by weekly adding MEOR material to the water injection tank of an injection well on the Kroll lease.

Results
Only the Kroll lease (with continuous MEOR injection from the start) resulted in any appreciable production increase while the response from the squeeze treatments on the other leases was minimal to negative. The probable reasons for production decline for some of the leases has not been determined. Kroll lease production increased from 3 BOPD before the project to 21 BOPD over an eight-month period following the initial treatments. However, three months after MEOR injection was started, water injection rates on the Kroll lease were increased from 30 BWPD to 90 BWPD. It is difficult to determine what portion of the production increase was directly attributable to the MEOR treatments.

Economics
Economic analysis of the Kroll lease portion of the project indicates that an estimated 30,784 barrels of incremental oil can be recovered, (assuming production continues to an economic life of 6 years), with an NPV (discounted at 15%) of $15,632. The Kroll lease portion of the total project cost, including well preparation, MEOR treatments, and incremental lease operating costs was $124,850 during the first two years. Kroll lease incremental operating costs for the remaining four years of the economic life would be $203,100.

Project Funding
A project award of $167,900 (30% DOE, 70% Edmiston) was made to Edmiston Oil Company for this microbial treatment project.
## Project 10: Microbial Improved Oil Recovery, Edmiston Oil Co.

<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 6-30-96 Ended: 7-01-97 Duration: 12 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>Wells in the field produce at low oil volumes. These wells are uneconomic to produce using conventional chemical treatment to reduce paraffin buildup and control asphaltenes and will have to be shut-in and abandoned.</td>
</tr>
<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Apply Microbial Enhanced Oil Recovery (MEOR) technology to utilize microbes as a cost effective method to clean up wellbores and improve oil recovery by (1) treating producing wells through the wellbore in a procedure similar to a conventional matrix squeeze approach using 3 different MEOR systems and (2) treating an injection well in a waterflood pattern with a single MEOR system.</td>
</tr>
<tr>
<td>Reservoir Setting &amp; Information</td>
<td>The near wellbore formation is believed to have been damaged due to precipitation of paraffins and asphaltenes, which restrict oil flow below commercial quantities in a low gravity, low mobility oil reservoir with low production volumes.</td>
</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Increase production. Project Objective: Implement a MEOR project to determine if it is economically feasible to treat wells with microbes for paraffin and sulfide scale problems and to increase oil recovery.</td>
</tr>
<tr>
<td>Working Hypothesis</td>
<td>Use MEOR technology to economically treat wells and continue production compare with continued periodic conventional chemical treatment (uneconomic) to the economic limit, then abandon.</td>
</tr>
<tr>
<td>Baseline &amp; Forecast</td>
<td>Production from the leases involved in the project was 34 BOPD. Kroll lease (4 producing wells and 1 WI well) pre-treatment production was 3 BOPD.</td>
</tr>
<tr>
<td>Compare: Actual vs baseline</td>
<td>Kroll lease production increased from 3 BOPD to 21 BOPD following MEOR treatment. None of the other leases treated showed any appreciable response (25 wells on 8 leases were eventually treated). Low oil prices caused MEOR treatments to become uneconomic and MEOR treatments were discontinued in January 1999.</td>
</tr>
<tr>
<td>Economic?</td>
<td>The total project cost was $167,900 including microbial treatments. The Kroll lease portion of the project cost was $124,850. Based on historic oil prices and continuation of the project to the economic limit, economic analysis indicates that the Kroll lease portion of the project would give a positive NPV of $15,632, producing 30,784 barrels of oil, with a short economic life of 6 years, due to the high cost of continuing the periodic MEOR treatments and the relatively low oil production rates.</td>
</tr>
<tr>
<td>Project Objective Met?</td>
<td>The project objective was met. Following MEOR treatment of the injection well on the Kroll lease, production increased significantly after water injection rate was doubled. Response to the matrix squeeze treatment was mixed with some leases/wells showing slight increase and some showing slight decrease in production. The reasons for the observed responses are not known.</td>
</tr>
<tr>
<td>Program Objective Met?</td>
<td>The program objective was met. Overall, production was increased due almost entirely to the Kroll lease response.</td>
</tr>
<tr>
<td>Application (area/region)</td>
<td>Technology would have wide application to oil reservoirs with paraffin and/or asphaltine scaling problems.</td>
</tr>
<tr>
<td>Limitations</td>
<td>The project needs considerable review to determine the reasons for the mixed success/failure, and to refine treatments for future application. The project would need considerable evaluation to determine the specific treatments to apply under various reservoir/well conditions.</td>
</tr>
<tr>
<td>Recommendations</td>
<td>Conduct further review and/or research to determine to what extent the MEOR treatment contributed to the Kroll Lease increased production. Conduct further review to determine why some leases/wells responded favorably and others did not.</td>
</tr>
</tbody>
</table>
closed-loop extraction of hydrocarbons and bitumen from oil-bearing soils

TECHNOLOGY AREA
Improved Oil Recovery

PROBLEM
Recovery of Tar Sand Hydrocarbons are Uneconomic

SITUATION
No Commercial Technology Available for Extraction Process

RESULTS
Extraction Process Was Successfully Demonstrated

X-TRAC Energy, Inc.
Englewood, Colorado

PR Springs and Asphalt Ridge Sandstones @ 0-100 ft

Background
The P.R. Springs and Asphalt Ridge tar sand deposits in Uintah County, Utah, contain an estimated 15 billion barrels of bitumen and heavy oil with estimated potential reserves of 4.7 to 7.3 billion barrels. No technology or process had been demonstrated to be efficient and environmentally benign for the commercial extraction of marketable hydrocarbons from the shallow tar sand reserves within the United States.

Project Description
X-TRAC Energy has licensed proprietary technology which employs an entirely closed-loop extraction system using recyclable hydrocarbon solvents to extract hydrocarbons and bitumen from oil-bearing soil. The process requires mining and crushing of the oil-bearing sand and then mixing the crushed material with a hydrocarbon solvent in a pressurized vessel where the hydrocarbon components are extracted from the crushed material. The solvent is separated from the hydrocarbons by heating and the recovered solvent is then recycled through the system.

Results
Twenty thousand pounds of P.R. Springs tar sand and eighteen thousand pounds of Asphalt Ridge tar sand material were processed through the large-scale extraction demonstration test facility without difficulty, recovering approximately 125 gallons of bitumen from each of the two samples. 50-60% of the residual oil in place was recovered. 50-60% of the extracted hydrocarbon was high grade asphaltnes, 20-25% was diesel, and 20-25% was light gas oil.

Economics
The operator used results of the demonstration project to develop production/cost numbers critical to justifying a full-scale commercial facility. Capital cost for construction of a 2,160 barrels of oil output per day facility is estimated at $15,000,000. Economic analysis indicates that 9,500,000 barrels of incremental oil could be recovered (valued at $29.12 per barrel) during an operating life of 12 years, with a NPV (discounted at 15%) of $32,658,000.

Project Funding
A project award of $147,359 (34% DOE, 66% X-TRAC) was made to E-TRAC Energy, Inc. for this technology demonstration project.
**Project 11: Closed-Loop Extraction of Hydrocarbons and Bitumen from Oil-Bearing Soils,**
**X-TRAC Energy, Inc.**

<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 4-01-97</th>
<th>Ended: 11-30-97</th>
<th>Duration: 8 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>The extensive tar sand reserves within the State of Utah, estimated between 20 and 30 billion barrels, are currently uneconomic because no efficient and environmentally benign commercial extraction process is available.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Apply proprietary technology, which employs hydrocarbon solvents in a closed-loop system to extract hydrocarbons and bitumen from the oil bearing soils. Mine and crush the oil bearing tar sands and process the material through the proposed extraction process to recover the hydrocarbon components.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reservoir Setting &amp; Information</td>
<td>The P.R. Springs and the Asphalt Ridge tar sand deposits in Uintah County, Utah, range in thickness from 30 to 300 feet at depths from surface down to 600 feet, with hydrocarbon saturation around 50% (0.6538 barrels of residual oil in place per ton of oil-bearing soil).</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| Objective/intent | Program Objective: Develop new technology.  
Project Objective: Demonstrate that the proposed technology can efficiently extract and produce quality oil from shallow tar sand reserves obtained from a mining lease in Utah. |
| Working Hypothesis | Test and develop new technology to extract the resource that could not be produced otherwise. |
| Baseline & Forecast | Zero production prior to the project. Estimated 30,000 to 200,000 BOPM for a full-scale operation at an estimated operating cost of $9.00 per barrel of oil extracted. |
| Compare: Actual vs baseline | The demonstration unit recovered approximately 50-60% of the oil in place. |
| Economic? | Based on the results of the demonstration project, operating costs for a commercial scale operation are estimated at $8.50 to $13.00 per barrel of oil extracted. Operating costs will increase as the overburden to oil sand strip ratio increases. The total capital investment for a 2,100 BOPD output facility is estimated to be $15 million. 50-60% of the extractant was asphaltines, 20-25% was diesel, and 20-25% was light gas oil. The asphalt market and the diesel markets are very strong in the area of Utah where the deposits are located. SHRP specific asphalt (a processed product) sells for $200/ton, roofing quality asphalt sells for $150/ton, diesel sells for $0.55/gal, and light gas oil sells at WTI prices. |
| Economic Detail | Production (BO): 7,884,000  
NRI Income ($) : 200,884,000  
Royalty Income ($) : 28,698,000  
State Revenue ($) : 14,184,000  
Federal Revenue ($) : 20,047,000  
NCF (Undisc.) ($) : 67,364,000  
NPV (15% Disc.) ($) : 32,658,000  
Investment ($) : 15,000,000  
Operating Cost ($) : 84,289,000  
Expenses ($) : 0  
Profit ($/BO): 8.54  
NPV (15% Disc.) ($) : 32,658,000  
Investment ($) : 15,000,000  
OPEX (months): 16  
Econ. Life (years): 10  
NTER: 5.49  
Disc Profit ($/BO): 4.14 |
| Project Objective Met? | The project objective was met. 19 tons of crushed tar sand were processed smoothly through the large scale demonstration extraction unit, recovering eight 55-gallon drums of bitumen (approximately 50% of the 6.5 weight percent of pre-test rock oil in place) leaving levels of 1,000 PPM residual hydrocarbons in the processed soil. The recovered oils had a sulfur content of approximately 0.3% and an API gravity in the range of 17-20 with compositions of 50% kerosene, diesel, and light gas oils and 50% asphalt. |
| Program Objective Met? | The program objective was met. The project successfully demonstrated that the process is economic and environmentally safe. |
| Application (area/region) | The technology has world-wide application to all mineable tar sand deposits with market availability. UTR Energy (previously X-TRAC Energy) is proceeding to obtain partners and/or financing to begin commercial operations at the Utah tar sand deposit site with a 700-800 Tons/year processing plant. The western United States annual 1994 road asphalt market usage was 5.6 million tons and the roofing asphalt market usage was 671 thousand tons. The road asphalt market has been projected to increase at +10% per year, as the repair of the nation's highway system becomes a high priority. |
| Limitations | Requires mineable heavy oil/tar and deposits and market demand for the hydrocarbon product(s) produced. |
| Recommendations | Encourage commercial development of this technology and incorporate into the Technology Transfer Program. |

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computerized well monitoring system

Background
Loss of production due to individual well production problems in a large number of marginal wells is difficult to identify timely and efficiently, resulting in delays in taking corrective action.

Project Description
James Engineering developed a production monitoring and prediction computer software package for 250 wells in the Clinton/Rose Run Fields of East central Ohio. The system could identify production problems quickly and allow prompt remedial action to be taken. The software package was developed to download production forecasts from major commercial reserve analysis software and upload well production information for a large number of marginal wells to compare actual production to forecast values in order to identify wells producing less than forecasted.

Results
During a five-month trial period, total production for the 250 wells increased approximately 5.5% above the same period for the previous year even though the nominal production decline for that period of time was approximately 6% per year. The operator has continued to utilize this highly applicable technology and is well satisfied with the results.

Economics
Economic analysis conducted on the project using historic gas prices indicates that this was a very successful project, which both increased production and resulted in positive economics. The total project cost was $95,000 to develop the software package with incremental operating costs of $108,000. The project economics were run for 10 years of production, resulting in an incremental recovery of 589,267 mcf of gas. The project would be expected to have an excellent return on expenditures, with a relatively modest volume of incremental gas recovered due to the marginal rates of production. NPV would be about $261,123 (discounted at 15%).

Project Funding
A project award of $95,000 (50% DOE, 50% James) was made to James Engineering, Inc. to develop and implement the computerized production monitoring system.
### Project 12: **Computerized Well Monitoring System**, James Engineering

<table>
<thead>
<tr>
<th><strong>Project Timing</strong></th>
<th>Started: 4-30-96</th>
<th>Ended: 12-31-97</th>
<th>Duration: 20 months</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Problem</strong></th>
<th>Inability to monitor quickly and cost efficiently a large number of marginal wells to identify and remediate production problems in individual wells in order to maintain maximum production.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Proposed Solution &amp; Technical Description</strong></th>
<th>Develop a simplistic computerized production monitoring program that utilizes commercial production forecasting software and compares forecasted rates to actual weekly and/or monthly production, to quickly identify decreases in production from individual wells in order to take remedial action.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Reservoir Setting &amp; Information</strong></th>
<th>Loss of production due to individual well production problems from a large number of marginal wells is difficult to identify cost-efficiently, resulting in delays in taking corrective action. Small operators with limited staffing often only become aware of production decreases in individual wells after it has persisted for some period of time and has become large enough to affect lease-level cash flow.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Objective/intent</strong></th>
<th>Program Objective: Develop new technology. Project Objective: Develop a simple computerized production monitoring program that will quickly and cost effectively identify production losses in individual production wells.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Working Hypothesis</strong></th>
<th>Develop and utilize computerized model compared to continued operation at higher overall cost and lower production.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Baseline &amp; Forecast</strong></th>
<th>Pre-project production was 27 BOPD and 2,000 MCFD from 200 marginal wells. Forecasted incremental improvement was 4 BOPD and 300 MCFD from the same 200 wells.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Compare: Actual vs baseline</strong></th>
<th>During a 5 month production period following implementation of the software system, total production from the 250 wells monitored by the system increased approximately 5.5% over the same period of a year earlier even though the nominal decline for the same group of wells was 6% per year.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Economic?</strong></th>
<th>Economic analysis indicates that the $95,000 technology development and implementation cost can be expected to produce 589,267 mcf of gas and return an NPV of $261,123 over a ten year period of operation.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Economic Detail</strong></th>
<th>Production (mcf): 589,267</th>
<th>NCF (Undisc.) ($) : 556,586</th>
<th>Econ. Life (years): 10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royalty Income ($) : 1,086,244</td>
<td>NPV (15% Disc.) ($) : 261,123</td>
<td>Inv. PO (months): NA</td>
<td></td>
</tr>
<tr>
<td>State Revenue ($) : 114,693</td>
<td>Expense ($) : 95,000</td>
<td>Undisc Profit ($/BO) : 0.94</td>
<td></td>
</tr>
<tr>
<td>Federal Revenue ($) : 211,965</td>
<td>Operating Cost ($) : 108,000</td>
<td>Disc Profit ($/BO) : 0.44</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Project Objective Met?</strong></th>
<th>The project objective was met. Software was developed and the technology was implemented as proposed by the operator.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Program Objective Met?</strong></th>
<th>The program objective was met. The technology developed is being used effectively by the operator to monitor, identify, and correct production problems and has increased production significantly.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Application (area/region)</strong></th>
<th>The technology has application to oil and gas production world-wide, and especially in the operation of a large number of marginal wells by independents with limited resources. Application of the software requires a minimal amount of additional effort/cost in order to monitor quickly and cost efficiently a large number of marginal wells to maximize production.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Limitations</strong></th>
<th>Applicable to all but the extremely small operations with only a few wells which can be monitored with limited manpower and resources.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Recommendations</strong></th>
<th>Integrate into the Technology Transfer Program and encourage application.</th>
</tr>
</thead>
</table>
improved stimulation

K-Stewart Petroleum Corp.
Oklahoma City, Oklahoma

Morrow Formation
@ 8,300 ft

TECHNOLOGY AREA
Production Problems

PROBLEM
Formation Damage

SITUATION
Inconsistent Stimulation Results

RESULTS
Study Resulted in Recommendations For Improved Stimulation Procedures

Background
Many Morrow gas wells in the Carlton and Watonga fields of Blaine County, Oklahoma, do not respond consistently to acidizing and hydraulic fracturing. Although gas productivity typically improves with hydraulic fracturing, response to stimulation treatment tends to vary considerably from one well to another and any initial high production rates quickly drop off.

Project Description
K-Stewart contracted STIM-LAB to conduct a study to identify minimum formation damage completion and production techniques to maximize production following hydraulic fracturing. The project design was to compare the effects of various fluids on matrix permeability and fracture conductivity via laboratory tests, correlate production to completion and production practices through a relational database, and to relate laboratory testing to the field operations by correlating and characterizing the rocks tested in the database.

Results
The study resulted in recommendations that frac fluid and breaker be selected to minimize pressure drop, proppant be selected to provide maximum conductivity in the presence of multiphase flow, and maximize condensate yield to slow the steep decline in production. Maximizing condensate yield can be accomplished by holding a backpressure on the well during production to minimize pressure drawdown in the reservoir to avoid dropping out condensate in the surrounding formation, which would otherwise lower the effective conductivity.

Economics
No incremental production resulted from this project as it was a technology development project intended to produce results which could be utilize in future production activities. The project AFE was for $623,400 to drill a well to test the study recommendation (the well was not drilled) and an additional $50,000 for the stimulation study.

Project Funding
A project award of $673,400 (7.4% DOE, 92.6% K-Stewart) was made to K-Stewart for this project.

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**Project 13: Improved Stimulation, K-Stewart Petroleum**

<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 9-16-96</th>
<th>Ended: 7-28-97</th>
<th>Duration: 11 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>Many Morrow formation gas wells do not respond consistently to acidizing and hydraulic fracturing treatments due to suspected formation damage. Fracture and acid stimulation results are generally not predictable, and it is difficult to predict whether a well will be a poor, average or good producer.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Analyze the historic completion and production characteristics of producing wells in the area to determine if there is a statistical difference in the performance of wells treated with different stimulation procedures. Characterize reservoir and fluid properties and correlate to treatment types and production responses and develop minimum formation damage technology. Conduct systematic analysis of geographic and lithologic variables in a regional database to identify correlating parameters with which to predict well response.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reservoir Setting &amp; Information</td>
<td>The gas productivity of Morrow reservoir wells in the Mocane-Laverne Gas area of northwest Oklahoma and the Oklahoma Panhandle is typically improved with hydraulic fracturing, but this increase is often short lived and the response to treatments is not consistent from one well to another.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Develop new technology. Project Objective: Conduct study to identify minimum formation damage completion and production techniques to maximize gas production following hydraulic fracturing, then drill and complete a Morrow sand gas well utilizing the results of the study.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Working Hypothesis</td>
<td>Conduct the study, make recommendations, and drill the well compared with continued completion and operations with unpredictable results.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Baseline &amp; Forecast</td>
<td>Average well pre-treatment production is 66 BOPD &amp; 658 MCFD. A good producer's pre-treatment production is 299 BOPD &amp; 3935 MCFD. Production after stimulation of average wells normally exceed pre-treatment rates 4 to 5 fold.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Compare: Actual vs baseline</td>
<td>Although the study was conducted and recommendations were made, low oil prices at the time of the project caused suspension of work-over and drilling activities.</td>
<td></td>
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</tr>
<tr>
<td>Economic?</td>
<td>There is no data available with which to run economics. This project was intended to develop technical results, which could be utilized in stimulation treatments.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Project Objective Met?</td>
<td>The project objective was not met. The study was conducted as proposed, but there is no indication in the project documentation that the proposed well was ever drilled.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program Objective Met?</td>
<td>The program objective was met. The study identified several factors that contributed to the inconsistency between treatments and to the nature of the production response characteristics. Several recommendations were made regarding treatment design and production practices, and the operators are in agreement with the recommendations made.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Application (area/region)</td>
<td>Study results have wide application to Morrow formation gas wells throughout the area.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Limitations</td>
<td>Limited to Morrow formation gas wells.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Recommendations</td>
<td>The project generated guidelines about the treatments to be used in this formation. These guidelines should be validated in application and, if profitable, moved to technology transfer.</td>
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</tbody>
</table>
resin-coated prepacked gravel Pack

TECHNOLOGY AREA
Production Problems

PROBLEM
Cost Efficient Sand Control

SITUATION
Conventional Sand Control Techniques are Expensive

RESULTS
Developed a Resin-Coated Prepacked Gravel Pack For Commercial Marketing

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 during operations to set the traditional prepacked gravel pack. 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.

Project Description
ITM proposed to develop, construct, and test a resin-coated prepacked gravel pack that fits inside a perforated liner for sand control as an alternative to the traditional external wire-mesh wrapped prepacked gravel pack. The resin-coated prepacked gravel pack would be inserted into the wellbore for sand control.

Results
A prototype resin-coated prepacked gravel (sand) pack was manufactured and tested for permeability, bond strength, and chemical exposure. The tests indicate that the liner would be durable enough to withstand the typical down-hole environment and is resistant to most of the commonly found oil field chemicals. The gravel pack fits inside a perforated liner and has no wire wrapping or other mechanism for pack containment. The gravel pack consists of a commercial-grade resin-coated sand that has been shaped into a solid cylindrical form through the application of heat and formed in a cylindrical shape to conform to the internal dimensions of a wellbore. Liner joints are screwed together to the desired length, inserted into the wellbore, and set in place using conventional liner hanging equipment.

Economics
The product has not yet been field-tested in a well, although a field test candidate is being actively sought. The product is being introduced into the market in Bakersfield and Los Angeles, California. A resin-coated prepacked gravel (sand) pack is a less expensive product and the installation costs are about half the cost to install a conventional gravel pack system. The project has good application potential and offers considerable cost savings over conventional procedures, but does need a field demonstration to determine degree of technical success.

Project Funding
A project award of $99,500 (49.7% DOE, 50.3% ITM) was made to Industrial Technology Management for this technology development project.
<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 6-17-97</th>
<th>Ended: 4-30-98</th>
<th>Duration: 11 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>Conventional sand control liners are expensive to install or replace, often resulting in wells being shut-in due to unfavorable remedial economics.</td>
<td></td>
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</tr>
<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Develop an economical pre-packed resin coated gravel (sand) pack that fits inside a perforated liner which can be installed into the wellbore for sand control.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reservoir Setting &amp; Information</td>
<td>Conventional wire wrapped sand control liners (used for sand control in wells which tend to produce sand along with oil) are often damaged during installation or during use, resulting in a failure to control sand production, requiring expensive replacement.</td>
<td></td>
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</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Develop new technology. Project Objective: Develop, construct, and field test an economical Pre-packed Resin Coated Liner prototype as a low cost sand control alternative to traditional wire wrapped sand control liners.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Working Hypothesis</td>
<td>Develop and utilize new technology compared to continued use of existing, often cost prohibitive completion and production methods.</td>
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<td></td>
</tr>
<tr>
<td>Baseline &amp; Forecast</td>
<td>Design a product for fast, economic, and versatile sand control completion, for well repair applications to restore sand control where economics require minimal repair cost.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Compare: Actual vs baseline</td>
<td>A prototype was designed and constructed, but due to low oil prices at the time of the project the product has not been tested in a producing well.</td>
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<td></td>
</tr>
<tr>
<td>Economic?</td>
<td>This project was intended to develop technology to be utilized in production operations. The project final report indicates that the Prepacked Resin Coated Liner provides a cost effective alternative to existing gravel packing technology.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Project Objective Met?</td>
<td>The project objective was met. A prototype was constructed and tested as per the project proposal.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program Objective Met?</td>
<td>The program objective was met. A product was developed which consists of a commercial-grade resin coated sand that has been shaped into a solid cylindrical shape (through heat application) to conform to the internal dimensions of a wellbore, and bonded to a perforated base pipe. The product has no wire wrapping or other mechanism for pack containment. Laboratory testing indicated that the product was suitable for downhole wellbore conditions.</td>
<td></td>
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</tr>
<tr>
<td>Application (area/region)</td>
<td>The technology, if demonstrated successfully in actual oil producing wells, has world-wide application.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Limitations</td>
<td>No limitations unless determined by field testing under producing conditions.</td>
<td></td>
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</tr>
<tr>
<td>Recommendations</td>
<td>Encourage field testing in an oil producing well, then if successful, incorporate into the Technology Transfer Program.</td>
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</tr>
</tbody>
</table>
TECHNOLOGY SOLUTIONS FOR INDEPENDENT PETROLEUM OPERATORS

foam frac and foam acid treatment

TECHNOLOGY AREA
Stimulation

PROBLEM
Frac Treatments Are Often Unsuccessful

SITUATION
Low Oil Production and High Water Production

RESULTS
Foam Fracturing With Low-Cost Sand Increased Production

Sipple Oil Company
Beatyville, Kentucky

Corniferous Dolomite Formation @ 1,100 ft

Background
Historically, cased hole hydraulic fracture treatments of wells in the Corniferous formation in the Big Sinking Field of Lee County, Kentucky, have had a high failure rate, high retreatment failure rate, and have bypassed an oil bearing zone which is incompatible with existing completion procedures. Typically, when wells in the field are stimulated, water breakthrough occurs soon after stimulation resulting in low oil and high water production.

Project Description
Sipple Oil Company conducted and compared three different frac stimulation treatments in three separate wells to determine the most successful treatment method for increasing oil production while reducing water production rates.

Results
A foam frac treatment in one well using resin-coated sand as a proppant was slightly successful in increasing incremental oil production (0.5 BOPD and 4 BWPD) but was not economical given the low production rates. A foam frac treatment in a second well using sand as a proppant was successful in increasing incremental oil production (5.4 BOPD and 5 BWPD) and appears to be the most economically and technically successful procedure. Acid treatment in the third well was unsuccessful in increasing incremental oil production (0 BOPD and 51 BWPD). Indications are that foam frac with untreated sand proppant is the most economically and technically successful frac treatment in this reservoir.

Economics
Economic analysis conducted on the total project indicates that the project was uneconomic due to the high cost of treating all three wells and the low oil production rates realized. The total project cost to treat and monitor all three wells was $110,570 and incremental operating costs of $102,000 over a project life of 17 years, resulting in an incremental recovery of 18,248 BO and a NPV of -$16,257 (discounted at 15%).

However, economic analysis of the one successfully treated well (foam frac using sand as a proppant) indicates technical and economic. The treatment cost for the one successful well was $36,857 with incremental operating costs of $75,600 over a project life of 21 years, resulting in an incremental recovery of 17,553 BO and an NPV of $37,382 (discounted at 15%).

Project Funding
A project award of $110,571 (45% DOE, 55% Sipple) was made to Sipple Oil Company to conduct the stimulation project.
### Project 15: Foam Frac and Foam Acid Treatment, Sipple Oil Co.

<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 4-01-96 Ended: 3-31-97 Duration: 12 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>Historically, cased hole hydraulic fracture treatments in the Coniferous formation have had a high failure rate, high retreatment failure rate, and have bypassed an oil bearing zone, which is incompatible with existing completion procedures.</td>
</tr>
<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Use three separate hydraulic fracture treatment methods in three separate wells to: (1) test foam frac with adjusted foam quality to increase sand concentration to prevent formation closure, (2) test foam frac with adjusted foam quality and resin activated sand to prevent sand rejection, and (3) test a foamed acid completion to prevent breakthrough to the underlying water zone and to eliminate emulsion problems.</td>
</tr>
<tr>
<td>Reservoir Setting &amp; Information</td>
<td>Typically, wells are drilled and cased through the three pay zones of the Coniferous formation, perforated in the second and third pay zones, and fracture stimulated with 20/40 mesh sand as a proppant. Thirty percent of the fraced wells failed to respond to treatment, and none of the wells that failed have responded successfully to retreatment. The first pay zone is considered incompatible with present completion practices due to its vugular nature and high solubility to the acid used in the completion fluid.</td>
</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Increase production and reserves. Project Objective: Frac the second and third pay zones in two separate wells with two variations of a foam frac treatment for comparison of results. Frac the first pay zone with a foamed acid treatment to improve the bypassed oil zone treatment.</td>
</tr>
<tr>
<td>Working Hypothesis</td>
<td>Test and determine the best foam acid treatment compared with continued current costly hit-and-miss treatments.</td>
</tr>
<tr>
<td>Baseline &amp; Forecast</td>
<td>Pre-project average per well production was 0.5 BOPD and 1.0 BWPD. Forecasted after-treatment average per well production was 1.0 BOPD and 2.2 BWPD.</td>
</tr>
<tr>
<td>Compare: Actual vs baseline</td>
<td>After treatment, Well #35 (foam frac w/sand) was producing 5.4 BOPD and 5 BWPD, Well #41 (foam frac w/resin coated sand) was producing 0.5 BOPD and 5 BWPD, and Well #32 (foamed acid) was producing 0 BOPD and 51 BWPD.</td>
</tr>
<tr>
<td>Economic?</td>
<td>The total project AFE to treat all three wells was for $110,571, producing 18,248 BO over an economic life of 17 years, with a negative NPV of $15,156. Only the well (#35) treated with foam frac w/sand proppant was successful and economic. That one well's portion of the project cost was $36,857. Economic analysis indicates that the results of the successful well would have a positive NPV of $37,382, producing 17,553 BO during an economic life of 21 years. The project would also have been economic at higher oil prices or a lower discount rate.</td>
</tr>
<tr>
<td>Project Objective Met?</td>
<td>The project objective was met. The first treatment was successful, the second treatment was uneconomic although technically successful, and the third treatment failed.</td>
</tr>
<tr>
<td>Program Objective Met?</td>
<td>The program objective was met. The first treatment resulted in an increase in oil production rate.</td>
</tr>
<tr>
<td>Application (area/region)</td>
<td>The successful treatment technology has field-wide application if it can be demonstrated to produce consistent results.</td>
</tr>
<tr>
<td>Limitations</td>
<td>Due to the low production rates of these wells (typically 1-2 BOPD), application of the technology is limited only by oil prices.</td>
</tr>
<tr>
<td>Recommendations</td>
<td>The technology needs additional demonstration and/or evaluation to verify the successful results and determine whether or not the results will be consistent. If successfully demonstrated, incorporate into the Technology Transfer Program. Document the process and encourage expanded application.</td>
</tr>
</tbody>
</table>
TECHNOLOGY SOLUTIONS FOR INDEPENDENT PETROLEUM OPERATORS


Grace Petroleum
Dewey, Oklahoma

Bartlesville Sand
@ 1,200 ft

Background
Wells producing from the Bartlesville sand in Nowata County, Oklahoma, produce a large volume of water because of channeling resulting in low oil production. Before treatment, the lease was producing 12 BOPD and 333 BWPD.

Project Description
Grace Petroleum Company injected gel polymer into the water zone to try to reduce water production. The project consisted of an 80-acre area with two adjacent 5-spot patterns. The producing wells were treated with approximately 100 barrels of a partially hydrolyzed polyacrylamide with chromium cross-linking agent. The oil zone was treated with the gel polymer then fracture stimulated in an attempt to get a more horizontal rather than vertical fracture. Injection wells on this project were not treated with polymer.

Results
Oil production increased from 12 BOPD to an average of 17 BOPD and water production increased from 300 BWPD to 640 BWPD for an increase in WOR from 25 to 38. Although oil production increased 42%, water production increased 113%.

Economics
The incremental production response of 7 BOPD was considerably less than the forecasted 50 BOPD and the final project cost was reported as $125,423. Economic analysis based on actual response indicates that 8,341 incremental barrels of oil would be produced with a negative NPV of -$61,127 and that the project investment will not pay out.

With the DOE cost share portion, the operator's share of the project cost was reduced to $61,814 which would pay out in 86 months (a little over 7 years) with an NPV of -$13,548.

Although the project did result in incremental production, the project was uneconomic at the low oil production rate, high water-cut, and high capital investment.

Project Funding
This gel polymer project was performed by Grace Petroleum Company with a budget of $106,000 (47% DOE, 53% Grace).
# Project 16: Gel Polymer Treatment, Grace Petroleum Co.

<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 10-01-95</th>
<th>Ended: 5-30-97</th>
<th>Duration: 8 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>Waterflooding a pressure depleted reservoir to improve oil recovery results in producing a large volume of water due to injected water channeling down through a thick, wet, lower section of the reservoir.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Inject a crosslinked polymer gel treatment into the lower, wet zone of both the injection wells and the production wells in an attempt to create a relatively impermeable barrier to 1) inhibit the growth of fractures from the upper oil bearing zone down into the lower wet zone during fracture treatment of the producing well and 2) inhibit water channeling through the wet zone during waterflooding.</td>
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</tr>
<tr>
<td>Reservoir Setting &amp; Information</td>
<td>Waterflooding to repressurize a pressure depleted Bartlesville Sandstone reservoir to improve oil recovery results in excessive injected water channeling down and through a lower, wet zone. Water channeling is increased by fracture treatment of producing wells, which is necessary to obtain acceptable production rates.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Increase production. Project Objective: Treat the wet zone of an inverted five-spot waterflood pattern with a crosslinked polymer gel and compare the waterflood performance to an adjacent conventional, untreated inverted five-spot waterflood pattern.</td>
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<tr>
<td>Working Hypothesis</td>
<td>Use proposed technology compared to continued operations that will result in low oil recovery.</td>
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</tr>
<tr>
<td>Baseline &amp; Forecast</td>
<td>Pre-project production from 10 wells was 12 BOPD &amp; 333 BWPD. Forecasted production increase was 50 BOPD and 167 BWPD from the lease. Estimated waterflood recovery is 600,000 to 1,000,000 BO.</td>
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</tr>
<tr>
<td>Compare: Actual vs baseline</td>
<td>At the end of the project demonstration period, the 6 producing wells were producing 17 BOPD (5 BOPD increase).</td>
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</tr>
<tr>
<td>Economic?</td>
<td>The project response was considerably less than the 50 BOPD forecasted. The final project cost was reported as $125,423. Economic analysis based on actual response indicates a negative NPV of -$61,127.</td>
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<td></td>
</tr>
<tr>
<td>Economic Detail</td>
<td>Production (BO): 8,341 NCF (Undisc.) ($) : -48,997 Econ. Life (years): 11 NRI Income ($) : 122,159 NPV (15% Disc.) ($) : -61,127 Inv. PO (months): NA Royalty Income ($) : 17,451 Investment ($) : 111,814 NTER: 0.61 State Revenue ($) : 12,733 Expense ($) : 13,609 Undisc Profit ($/BO): -5.87 Federal Revenue ($) : 0 Operating Cost ($) : 33,000 Disc Profit ($/BO): -7.33</td>
<td></td>
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</tr>
<tr>
<td>Project Objective Met?</td>
<td>The project objective was met. The project was implemented as proposed.</td>
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</tr>
<tr>
<td>Program Objective Met?</td>
<td>The program objective was met. Production from the lease was increased. The project was in an early stage of operation at the end of the project demonstration period. It is possible that waterflood response in the polymer treated pattern had not yet fully occurred.</td>
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<tr>
<td>Application (area/region)</td>
<td>Applicable to all similar types of bottom-water reservoirs experiencing water channeling.</td>
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<tr>
<td>Limitations</td>
<td>The technology is limited to reservoir-fluid systems that are compatible with the polymer system used.</td>
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<tr>
<td>Recommendations</td>
<td>Re-evaluate this project periodically to determine the final response. If demonstration eventually proves successful and is economic, incorporate into the Technology Transfer Program and encourage application.</td>
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</tr>
</tbody>
</table>
Harry A. Spring  
Ardmore, Oklahoma

Carmichael Sand  
@ 3,192 ft

**TECHNOLOGY AREA**  
Water Production

**PROBLEM**  
High Water Production

**SITUATION**  
High Cost of Water Disposal

**RESULTS**  
Downhole Injection  
Tool Functioned as Designed  
Injection Formation Pressured Up and Stopped Taking Water

**Background**  
A watered-out shut-in Carmichael sand gas well in Logan County, Oklahoma, was making so much water that water disposal (hauling) became cost prohibitive and the well was shut-in.

**Project Description**  
Harry A. Spring installed a commercially available down hole simultaneous gas production/disposal tool (DHI tool) in the well an attempt to economically dispose of the produced formation water into a lower disposal zone. The DHI tool is a device which allows produced formation water to be separated downhole and injected into a lower formation without first being lifted to the surface while allowing simultaneous gas production to occur. Additionally, dewatering of the formation near the well bore could allow higher flowing gas rates.

**Results**  
The tool was installed in the well, but after several months of production the disposal zone pressured-up and would not take water with the existing pumping equipment due to the limited injection capacity of the disposal zone and a larger volume of produced water than was originally anticipated. The DHI tool appears to have functioned properly as proposed, but the injection capacity of the disposal formation was inadequate for the volume of formation water being produced. The well was then abandoned due to the high cost of conventional water disposal (hauling). The project was unsuccessful in re-establishing gas production, although the feasibility of the technology was adequately demonstrated. Although disappointed in the results of the project, the operator is satisfied that the technology has additional application potential.

**Economies**  
No incremental production resulted from this project. The project AFE was $55,000 including $14,500 for the DHI tool. The technology allows the disposal of produced water without first being brought to the surface, thus reducing disposal costs and reducing the risk of contamination of the surface environment or shallower fresh-water zones.

**Project Funding**  
A project award of $55,000 (50% DOE, 50% Spring) was made to Spring for this project.
### Project 17. Cost Effective Water Disposal, Harry A. Spring

<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 5-30-96</th>
<th>Ended: 5-29-97</th>
<th>Duration: 12 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>Gas well making so much water that conventional water disposal became cost prohibitive and the well was shut-in.</td>
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</tr>
<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Install a down hole simultaneous gas production/disposal tool (DHI tool) to produce gas and economically dispose of produced formation water into a deeper formation without first being brought to the surface. Dewatering of the formation near the well bore will allow higher flowing gas rates.</td>
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<tr>
<td>Reservoir Setting &amp; Information</td>
<td>Gas well producing from the Carmichael Sand @ 3,123 ft., in Logan County, Oklahoma, making too much water to economically dispose of conventionally (by hauling). Initial gas production was 1,017 mcfd but after 18 months of production, the well was producing 448 mcfd and 120 BWPD. Water hauling became cost prohibitive and the well was shut-in. The high cost of water disposal will result in premature abandonment of the well leaving significant gas reserves in the ground.</td>
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</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Increase production and reserves. Project Objective: Install a down hole simultaneous gas production/disposal tool (DHI tool) to produce gas and economically dispose of produced formation water into a deeper formation.</td>
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</tr>
<tr>
<td>Working Hypothesis</td>
<td>Use new technology compared with no production due to high cost of water disposal at the surface.</td>
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</tr>
<tr>
<td>Baseline &amp; Forecast</td>
<td>Prior to the project, production before the well was shut-in was 448 mcfd gas and 120 BWPD. Forecast returning well to production at 600 MCFPD gas and zero surface water produced.</td>
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</tr>
<tr>
<td>Compare: Actual vs baseline</td>
<td>Unable to maintain injection after applying technology. Initially, the well produced 30-40 mcfd and the DHI tool was disposing of approximately 300 BWPD with the fluid level at 1,500 ft. The well was producing more water than had been anticipated. After 18 months, the injection interval pressured up to 2,091 psi and quit taking water. The well was abandoned at that time.</td>
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<tr>
<td>Economic?</td>
<td>No data to run economics. The project AFE was $55,000 including $14,500 for the DHI tool. Economics included in the project proposal indicated a 13-month pay out for the installation costs.</td>
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</tr>
<tr>
<td>Project Objective Met?</td>
<td>The project objective was not met. Although the DHI Tool appears to have performed as designed, the disposal formation was incapable of taking the volume of water produced by the well and the producing formation did not dewater as intended.</td>
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<tr>
<td>Program Objective Met?</td>
<td>The program objective was not met. The pre-project gas production rate was not re-established. The well was abandoned without increasing production or adding reserves.</td>
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<tr>
<td>Lessons Learned</td>
<td>Adequate disposal zone injection capacity must be available to dispose the volume of water produced.</td>
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<tr>
<td>Application (area/region)</td>
<td>The technology has world-wide application for use in gas wells producing only gas and water. The technology allows the disposal of produced water without first being brought to the surface, thus reducing disposal costs and reducing the risk of contamination of the surface environment.</td>
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<tr>
<td>Limitations</td>
<td>The technology applied is limited to use in gas wells producing only gas and water, and which have a deeper disposal zone with sufficient injection capacity. The DHI tool requires a beam pumping unit with a rod string and sinker bars.</td>
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<tr>
<td>Recommendations</td>
<td>Continue to monitor additional tests and applications. If successful disseminate results through Technology Transfer to other operators.</td>
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</tbody>
</table>
TECHNOLOGY SOLUTIONS FOR INDEPENDENT PETROLEUM OPERATORS


Kenneth Y. Park
Skiatook, Oklahoma

Bartlesville Sand
@ 1,250 ft

Background
Wells on the Batie in the Bird Creek Field near Skiatook, Oklahoma are completed in a Bartlesville sandstone reservoir. The two producing wells on the lease were producing 5 BOPD and 470 BWPD, and four wells were shut-in. The low oil production and high water production resulted in low recovery efficiency.

Project Description
Kenneth Y. Park proposed to treat the water zone in the producing and injection wells with a partially hydrolyzed polyacrylamide with a chromium cross-link agent to reduce water production.

Results
After treatment, the project lease was initially producing 17.5 BOPD (12.5 BOPD incremental) and 860 BWPD. Oil production tripled whereas water production doubled after treatment. Additional oil production may have been possible, but rates were limited by injection capacity. The water-oil-ratio was lower (WOR of 49) after treatment than before treatment (WOR of 94). Water production was effectively decreased, but oil production decreased to 11 BOPD (6 BOPD incremental) shortly after treatment.

Economics
The project response was considerably less than the 20 BOPD incremental production forecasted. Economic analysis indicates that the project will produce 15,715 barrels of incremental oil during a 12 year economic life. The project AFE was for $96,234 with indicated incremental operating costs of $115,200, resulting in an NPV (discounted at 15%) of -$25,936.

With the DOE cost share portion, the operator's share of the project cost was reduced to $36,626, which would pay out in 39 months with an NPV of $13,670.

Although the project did result in incremental production, the total project was uneconomic at the low incremental oil production rate and high capital investment required. DOE's cost share contribution resulted in reducing the operator's financial exposure even at the low oil production rates, as the program was intended to do.

Project Funding
A project award of $96,233 (47.6% DOE, 52.4% Park) was made to Park for this project.

61
<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 10-15-95</th>
<th>Ended: 10-14-96</th>
<th>Duration: 12 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>Wells producing from the Bartlesville sand formation are either shut-in due to uneconomic high water production or are producing at near uneconomic high water-oil-ratios (WOR).</td>
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</tr>
<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Inject cross-linked gel polymer treatments into the water bearing portions of the formation to reduce water production to lower lifting costs and increase oil production.</td>
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</tr>
<tr>
<td>Reservoir Setting &amp; Information</td>
<td>Prior to the project, only two of the six production wells on the lease were producing. The other wells were shut-in as uneconomical due to high water production and low oil cut. Produced water was being injected back into the reservoir. High water production rates are common throughout most Bartlesville sand wells in Northeastern Oklahoma.</td>
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</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Increase production. Project Objective: Evaluate the effectiveness of injecting crosslinked polymer gel into the water zone of a sandstone reservoir to reduce the WOR in production wells.</td>
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</tr>
<tr>
<td>Working Hypothesis</td>
<td>Use proposed technology compared with continued production at high WOR and high lifting costs until wells are uneconomic, then shut-in the wells and abandon the lease.</td>
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</tr>
<tr>
<td>Baseline &amp; Forecast</td>
<td>Pre-treatment, the lease was producing 5 BOPD &amp; 470 BWPD (94 WOR) with 2 wells producing and 4 wells shut-in due to low economics. Forecasted incremental production was 22 BOPD.</td>
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<tr>
<td>Compare: Actual vs baseline</td>
<td>After treatment, the lease produced 11 BOPD &amp; 860 BWPD (78 WOR) with 7 wells producing (one well was added by recompletion).</td>
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<tr>
<td>Economic?</td>
<td>The project AFE was $91,550. Final project cost was $96,233.52 due to the drilling of a SWD well, which was not in the original proposal. The project response was less than had been forecasted. Economic analysis indicates that the project would have a negative NPV of -$25,936.</td>
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<tr>
<td>Economic Detail</td>
<td>Production (BO): 15,715 NCF (Undisc.) ($) 731 Econ. Life (years): 12 Non-Reserve Income ($): 231,749 NPV (15% Disc.) ($) 25,936 Inv. PO (months): 122 Royalty Income ($): 33,107 Investment ($): 82,401 NTER: 1.01 State Revenue ($) 19,584 Expense ($): 13,832 Undisc Profit ($/BO): 0.05 Federal Revenue ($) 0 Operating Cost ($) 115,200 Disc Profit ($/BO): -1.65</td>
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</tr>
<tr>
<td>Project Objective Met?</td>
<td>The project objective was met. The technology was applied as proposed and production response was achieved.</td>
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<tr>
<td>Program Objective Met?</td>
<td>The program objective was met. The technology was successfully applied and oil production was increased at a lower WOR.</td>
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</tr>
<tr>
<td>Application (area/region)</td>
<td>The technology has good application potential in the area. Applicable to all similar types of bottom-water reservoirs experiencing high water cut.</td>
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<tr>
<td>Limitations</td>
<td>The technology is limited to reservoir-fluid system which are compatible with the polymer system used.</td>
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<tr>
<td>Recommendations</td>
<td>The technology should be further tested in an attempt to improve the production response. If the technology application, and thus the project economics, can be improved then the technology should be incorporate into the Technology Transfer Program and encourage application.</td>
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</tbody>
</table>
TECHNOLOGY SOLUTIONS FOR INDEPENDENT PETROLEUM OPERATORS


Oxygen Activation Log

J. R. Pounds, Inc.
Laurel, Mississippi

Rodessa Sand
@ 11,120 ft

TECHNOLOGY AREA
Wellbore Problems

PROBLEM
Holes in Casing

SITUATION
Casing Leaks,
Well Shut-In

RESULTS
Proposed Technology
Not Applicable

Casing Leaks Repaired by
Convention Techniques

Background
The operator had shut-in a well in the Bolton Field of Hinds County, Mississippi, with holes 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. The operator believed the hole had reopened and wanted to return this well to production.

Project Description
The operator, J. R. Pounds, Inc., proposed to locate the hole(s) in the casing using an Oxygen Activation Log, then to repair the leaks by conventional casing repair techniques.

Results
During initial investigation, logging companies advised that the Oxygen Activation Log was not designed for casing hole detection in the proposed application. The tool uses a neutron generator to temporarily activate the oxygen molecules in the water, then uses a set of detectors to detect the slug of activated water as it flows past the detectors. The oxygen activation log can sometimes be used to detect casing leaks in water-injection wells, but in all cases needs moving water to work, i.e., a flowing well. The casing leaks were then located conventional bridge-plug and packer techniques. Conventional casing leak repair methods were then employed to successfully repair the leaks.

Economics
The proposed oxygen activation log was not applicable for locating casing leaks in this shut-in well, and thus no new technology was used in this project.

Project Funding
A project award of $122,400 (41% DOE, 59% Pounds) was made to J. R. Pounds, Inc. for this casing leak detection and repair project.
### Project 19. Oxygen Activation Log, J. R. Pounds

<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 4-15-96</th>
<th>Ended: 4-14-97</th>
<th>Duration: 12 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>Well was shut down due to various down-hole mechanical problems which were caused from casing leaks.</td>
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</tr>
<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Run an Oxygen Activation Log in the well to locate casing leaks, then repair with casing patch and/or cement squeeze. Using the Oxygen Activation Log instead of conventional bridge-plug and packer will save time and costs.</td>
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</tr>
<tr>
<td>Reservoir Setting &amp; Information</td>
<td>The Gaddis Farms A-1 oil well producing from the Rhodessa formation @ 11,120 ft., in the Bolton Field, Hinds County, Mississippi, is off production because of remedial problems due primarily to ruptured and/or leaking casing.</td>
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</tr>
</tbody>
</table>
| Objective/intent    | Program Objective: Increase production.  
Project Objective: Run an Oxygen Activation Log in the well to locate casing leaks, then repair with casing patch and/or cement squeeze. |
| Working Hypothesis  | Use Oxygen Activation Log to locate casing leaks as compared to the current method using more costly and time consuming usual bridge-plug and packer method. Locate and repair casing leaks vs. leaving well shut-in. |
| Baseline & Forecast | Well was shut-in prior to the project. Forecasted production 60 BOPD & 100 BWPD after remediation. |
| Compare: Actual vs baseline | No incremental production due to new technology application. The proposed new technology was not used in this project. |
| Economic?            | There are no economics to run. |
| Project Objective Met? | The project objective was not met. The proposed Oxygen Activation log was not applicable for locating casing leaks in this producing well, and thus was not used. Casing leaks were located and repaired using conventional techniques. |
| Program Objective Met? | The program objective was not met because no new technology was used in the project. |
| Lessons Learned      | Use of the proposed technology was not sufficiently investigated prior to the project proposal. |
| Application (area/region) | The Oxygen Activation Log is used to detect water movement past the tool in a flowing well and is some-times be used to detect casing leaks in active injection wells. The log requires water flowing past the tool in order to function properly. |
| Limitations          | Technology cannot be applied in a non-flowing well and requires water in the production stream. |
| Recommendations      | This project was approved based on an indication that the proposed technology is generally applicable to the types of production problems cited, but the specifics of the production problem in this project precluded the technology from being applicable. In this case, preliminary contact with a logging service company would have identified that the tool could not be used for the proposed application. |
microbial cleanup of paraffin

Rock Island Service Company, Inc.
Catlett, Virginia

Virginia Salt Sand
@ 1,700-1,800 ft

TECHNOLOGY AREA
Wellbore Problems

PROBLEM
Paraffin Precipitation

SITUATION
Reduced Productivity

RESULTS
Microbial Treatment Successful

Production Increased

Background
Wells in the Camden Lewis Field of Lewis County, West Virginia, were being prematurely abandoned because paraffin precipitation in the producing formation has caused formation damage in the reservoir, restricting production resulting in uneconomic operations.

Project Description
Rock Island Service Company, Inc., proposed to inject paraffin-mobilizing microbes, surfactant, and nutrients into each of 5 Salt Sand wells, scattered over several leases, to remove paraffin precipitation in the producing formation to improve oil production. These wells were shut-in during 1984. 1984 production from the five wells was 1,079 BOPY (3 BOPD) total.

Results
All five of the wells were re-worked and equipped to produce; including tubing, rods, rod pumps, pumping units, and prime movers. The five wells were treated, shut-in for a week, and then placed on production. The produced water was retained and used as injection water to periodically re-treat the wells as needed. Early indications were that for four of the five wells, production increased by 50% over pre-treatment production and that the fifth well's production decreased by 50%. 1998 production was projected to be 1535 BOPY (4.2 BOPD) for a 42% increase of 456 BOPY (1.25 BOPD). Treatment was successful, but requires periodic re-treatment.

Economics
Economic analysis indicates, given the high capital investment required to equip the wells for production ($56,130) and the low incremental increase in production (1.25 BOPD), the project is uneconomic. Indicated incremental recovery is 6,945 BO over a 5-year project life, with an NPV (discounted at 15%) of -$53,755 and the capital investment does not pay out.

Project Funding
A project award of $92,860 (50% DOE, 50% Rock Island) was made to Rock Island for this project.
### Project 20: Microbial Cleanup of Paraffin, Rock Island Service Company, Inc.

<table>
<thead>
<tr>
<th><strong>Project Timing</strong></th>
<th>Started: 4-01-97</th>
<th>Ended: 3-31-98</th>
<th>Duration: 12 months</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Problem</strong></td>
<td>Paraffin precipitation seals off the formation at the bore hole and/or plugs the tubing resulting in marginally economic wells being shut-in and/or abandoned prematurely.</td>
<td></td>
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</tr>
<tr>
<td><strong>Proposed Solution &amp; Technical Description</strong></td>
<td>Treat shut-in producing wells with a solution of microbial bacteria, surfactant, nutrients, and water down the casing to remove paraffin precipitation from the near-wellbore formation to improve oil production. Leave wells shut-in for one week and then returned to production.</td>
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<tr>
<td><strong>Reservoir Setting &amp; Information</strong></td>
<td>Thousands of oil wells in West Virginia and elsewhere have been prematurely abandoned because paraffin precipitation in the producing formation has caused formation damage, restricting production to uneconomic levels. Paraffin precipitation has clogged production tubing and lead lines, resulting in high operating costs for remedial action. The 5 wells in the Camden Lewis Field were completed in the Salt Sand at 1700-1800 feet in Lewis County, West Virginia. These wells have been shut-in since 1984.</td>
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</tr>
<tr>
<td><strong>Objective/intent</strong></td>
<td>Program Objective: Increase production and reserves. Project Objective: Treat shut-in producing wells with a solution of microbial bacteria, surfactant, nutrients, and water down the casing to remove paraffin precipitation from the near-wellbore formation.</td>
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<tr>
<td><strong>Working Hypothesis</strong></td>
<td>Use new technology compared with leaving wells shut-in due to low economics.</td>
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<tr>
<td><strong>Baseline &amp; Forecast</strong></td>
<td>Pre-treatment production for the lease was 1,079 BO (3 BOPD annual average) in 1984 (the last year the wells were produced). A 25-35% increase in production was expected. No forecasted production was given.</td>
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<tr>
<td><strong>Compare: Actual vs baseline</strong></td>
<td>After the project, the 5 wells were placed on production at 1,535 BO projected for 1998 (4 BOPD annual average). Initial production increased by 50% the first week, 33.3% second week, then about 25% for an extended period.</td>
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<tr>
<td><strong>Economic?</strong></td>
<td>The project AFE was for $92,859.62 including re-working the wells for production start-up and 24 months of MEOR treatment. Due to the high capital investment costs and extremely low incremental production rates, the project was uneconomic with an indicated NPV of -$53,755.</td>
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</tr>
<tr>
<td><strong>Project Objective Met?</strong></td>
<td>The project objective was met. The 5 wells were treated as proposed and placed on production.</td>
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<td></td>
</tr>
<tr>
<td><strong>Program Objective Met?</strong></td>
<td>The program objective was met. Treatment was successful and oil production increased, but required periodic re-treatment. The operator planned to expand the treatment to additional wells but could not continue re-treatments after the project demonstration period due to low oil prices.</td>
<td></td>
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</tr>
<tr>
<td><strong>Application (area/region)</strong></td>
<td>The technology has worldwide application for paraffin precipitation treatment.</td>
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</tr>
<tr>
<td><strong>Limitations</strong></td>
<td>The technology can be applied to all wells with similar problems.</td>
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</tr>
<tr>
<td><strong>Recommendations</strong></td>
<td>Additional testing is indicated before this technology is ready for technology transfer.</td>
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</tr>
</tbody>
</table>

66
microbial wellbore cleanup

TECHNOLOGY AREA
Wellbore Problems

PROBLEM
Paraffin and Sulfide Scale

SITUATION
Reduced Productivity and Injectivity

RESULTS
Microbial Treatment Successful
Production Increased
Injectivity Increased

Speir Operating Company
Albion, Illinois

Cypress Limestone
@ 2,200 ft

Background
Wells producing from the Cypress limestone in the St. Wendell field near Evansville in Posey County, Indiana, were experiencing reduced productivity and water injection wells were experiencing a loss of injectivity. Paraffin and sulfide scale precipitation in the perforations, tubing, and the near-wellbore region were reducing oil production and increasing injection pressures, requiring hot oil and acid treatments.

Project Description
Speir Operating Company injected a solution of microbes and nutrients, followed by a warm water flush, into nine producing wells and two injection wells to evaluate the effectiveness of microbial well treatments for cleaning up the wells. All wells were treated with acid, then operated for about one month prior to receiving the microbial treatments. Initial treatments were performed in December, 1995. Treatments were repeated monthly through May, 1996.

Results
Following the initial treatments, producing wells began unloading sulfide scale, paraffin, and oil-water emulsion. Oil production and water injection capacity increased initially. Oil production initially increased from 4 BOPD prior to treatment to 21 BOPD, then stabilized at 14 BOPD. Injection improved from 20 BWPD at 1650-1700 psig to 25 BWPD at 400 psig. 5 months after final treatment, production had declined to 6 BOPD plus 25 BWPD, indicating that repeated treatments would be required on a continuous 2-3 month interval to ensure improved oil production rates. Water injection pressures remained at 400 psig. The monthly electric bill was reduced by 32% as a result of lowering injection pressure.

Economics
The total project AFE was for $97,550 including one initial MEOR treatment and six additional MEOR treatments. Economic analysis indicates that the project will have a positive NPV of $19,862, producing 26,191 BO over an economic life of 12 years.

Project Funding
A project award of $97,550 (50% DOE, 50% Speir) was made to Speir Operating Co. to conduct the microbial wellbore cleanup project.
### Project 21: Microbial Wellbore Cleanup, Speir Operating Co.

<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 10-15-95</th>
<th>Ended: 10-14-96</th>
<th>Duration: 12 months</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Problem</strong></td>
<td>Sulfide and paraffin scale precipitation in the near-wellbore formation, perforations, and tubing are causing severe corrosion problems, high operating costs and low oil production.</td>
<td></td>
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</tr>
<tr>
<td><strong>Proposed Solution &amp; Technical Description</strong></td>
<td>Treat producing wells and water injection wells with microbes (anaerobic bacteria) to remediate sulfide scale and paraffin precipitation in the wellbore and near-wellbore formation.</td>
<td></td>
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</tr>
<tr>
<td><strong>Reservoir setting &amp; Information</strong></td>
<td>Sulfide scale formation and paraffin precipitation, severe surface and downhole corrosion problems, and high water injection pressures are resulting in low oil production, excessive remedial workovers, and high operating costs.</td>
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</tr>
<tr>
<td><strong>Objective/intent</strong></td>
<td>Program Objective: Increase production and reserves. Project Objective: Evaluate the effectiveness of microbial well treatments for cleaning up production and injection wells to reduce operating costs and increase production.</td>
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</tr>
<tr>
<td><strong>Working Hypothesis</strong></td>
<td>Use new technology compared with continued operations involving frequent and expensive workover operations.</td>
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</tr>
<tr>
<td><strong>Baseline &amp; Forecast</strong></td>
<td>Lease was producing 4 BOPD &amp; 20 BWPD from 9 producing wells before the treatment. Forecasted production after treatment was 10 BOPD &amp; 23 BWPD from the lease. Injection pressures before treatment was 1700 psi.</td>
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</tr>
<tr>
<td><strong>Compare: Actual vs baseline</strong></td>
<td>Initial lease production after treatments was 21 BOPD for the first 3 months, then stabilized at 14 BOPD. Injection pressure was 400 psi after treatment and electricity consumption decreased 25-30%.</td>
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<td></td>
</tr>
<tr>
<td><strong>Economic?</strong></td>
<td>The total project AFE was for $97,550 including 1 initial MEOR treatment and 6 additional MEOR treatments. Economic analysis indicates that the project will have a positive NPV of $19,862, producing 26,191 BO over an economic life of 12 years.</td>
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<tr>
<td><strong>Economic Detail</strong></td>
<td>Production (BO): 26,191 NCF (Undisc.) ($) 56,143 Econ. Life (years): 12 NRI Income ($) 374,789 NPV (15% Disc.) ($) 19,862 Inv. PO (months): NA Royalty Income ($) 53,541 Investment ($) 0 NTER: 1.58 State Revenue ($) 4,940 Expense ($) 97,550 Undisc Profit ($/BO): 2.14 Federal Revenue ($) 8,856 Operating Cost ($) 207,300 Disc Profit ($/BO): 0.76</td>
<td></td>
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</tr>
<tr>
<td><strong>Project Objective Met?</strong></td>
<td>The project objective was met. The treatments were carried out as proposed. The number of required well workovers was reduced, operating costs were lowered, and injection pressures were lowered.</td>
<td></td>
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<tr>
<td><strong>Program Objective Met?</strong></td>
<td>The program objective was met. Lease production was increased and operating costs were lowered. Frequent re-treatment is required to sustain the improvements.</td>
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<tr>
<td><strong>Application (area/region)</strong></td>
<td>Technology has world-wide application.</td>
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<tr>
<td><strong>Limitations</strong></td>
<td>The technology can be applied to all wells with similar problems.</td>
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</tr>
<tr>
<td><strong>Recommendations</strong></td>
<td>Incorporate into the Technology Transfer Program and encourage application.</td>
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</tbody>
</table>
calcium carbonate prevention

Tenison Oil Company
Abilene, Texas

Hosston Formation
@ 5,000 ft

Background
Calcium carbonate (CaCO₃) scale build-up was causing failure of down-hole equipment resulting in excessive down-time, high operating costs, and premature shut-in of producing wells in the Lisbon Unit of the Hosston Formation in Claiborne Parish, Louisiana.

Project Description
Prior to the project, one well had been shut-in and the second well was scheduled to be shut-in because of high operating costs, excessive downtime, and loss of production due to CaCO₃ scale deposition. Chemical analysis of the produced water showed ordinary levels of bicarbonates, indicating a downhole problem causing abnormal CaCO₃ deposition on the rod pumps. Tenison redesigned the rod pumps without seating nipples and tubing anchors to reduce heat created by friction in order to reduce calcium carbonate precipitation during production. The rod pump was redesigned to exceed the capacity of the well, which allowed the well equipment to be adjusted to provide sufficient pump capacity even with the tubing anchor removed.

Results
Following the remedial action, production from the two wells that were modified more than doubled from 10 BOPD to 23 BOPD. Workover and operating costs were reduced from $10,000 per month for the one producing well before the project to $1,200 per well per month after the project, well down time was reduced to practically zero.

Economics
The total project cost was $130,317. Economic analysis indicates that the project would result in an incremental recovery of 67,745 BO and a NPV of $105,941 (discounted at 15%) with incremental operating costs of $403,200 over a project life of 14 years.

Project Funding
A project award of $79,090 (47% DOE, 53% Tenison) was made to Tenison Oil Company to conduct the stimulation project.
<table>
<thead>
<tr>
<th>Project Timing</th>
<th>Started: 6-30-96</th>
<th>Ended: 5-13-97</th>
<th>Duration: 11 months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Problem</td>
<td>Calcium carbonate (CaCO₃) scale build-up is causing failure of down-hole equipment resulting in excessive downtime, high operating costs, and premature shut-in of producing wells.</td>
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</tr>
<tr>
<td>Proposed Solution &amp; Technical Description</td>
<td>Prevent down-hole CaCO₃ scale deposition in producing wells rather than treating for it after deposition. Make mechanical changes to downhole equipment to determine if the scaling problem can be reduced or eliminated. If mechanical changes are unsuccessful, threat the well with a chemical inhibitor solution as an alternative.</td>
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</tr>
<tr>
<td>Reservoir Setting &amp; Information</td>
<td>From the time the wells in the area are put on pump, there are problems with CaCO₃ scaling which is causing excessive pump wear, pumps to stick, rods to part, gas anchors to clog up, etc. Frequent acid treatment workovers are required to remove the CaCO₃ scale build-up. Chemical analysis of the produced water shows normal levels of bicarbonate, indicating that a downhole problem is causing the abnormal CaCO₃ deposition.</td>
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</tr>
<tr>
<td>Objective/intent</td>
<td>Program Objective: Increase production and reserves. Project Objective: Prevent down-hole calcium carbonate scale deposition in producing wells by mechanical and/or chemical solutions.</td>
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<td></td>
</tr>
<tr>
<td>Working Hypothesis</td>
<td>Apply proposed technology to solve problem compared with continue frequent and expensive work-over operations.</td>
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</tr>
<tr>
<td>Baseline &amp; Forecast</td>
<td>Prior to the project, one well was producing and one well was shut-in. Lease production was 8.5 BOPD and 82 BWPD with 200,000 BO estimated remaining recoverable reserves. Forecasted after treatment incremental production increase was 21 BOPD &amp; 214 BWPD with both wells producing.</td>
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</tr>
<tr>
<td>Compare: Actual vs baseline</td>
<td>After treatment, both wells were producing a total of 23 BOPD and monthly operating costs were reduced from an average of $10,000 per well to $1,200 per well with very little down-time.</td>
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<tr>
<td>Economic?</td>
<td>The total project AFE was for $79,090 including re-working the wells and equipping for production. Economic analysis of the project indicates a positive NPV of $105,941, producing 64,745 BO over an economic life of 14 years.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Economic Detail</td>
<td>Production (BO): 64,745 NCF (Undisc.) ($) : 228,663 Econ. Life (years): 14 NRI Income ($) : 957,351 NPV (15% Disc.) ($) : 105,941 Inv. PO (months): 17 Royalty Income ($) : 136,764 Investment ($) : 130,317 NTER: 2.75 State Revenue ($) : 134,694 Expense ($) : 0 Undisc Profit ($/BO): 3.53 Federal Revenue ($) : 60,476 Operating Cost ($) : 403,200 Disc Profit ($/BO): 1.64</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Project Objective Met?</td>
<td>The project objective was met. Scaling problems were solved and the wells have not experienced any production interruption due to work-overs.</td>
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</tr>
<tr>
<td>Program Objective Met?</td>
<td>The program objective was met. Lease production increased from 8.5 BOPD with $10,000 per month operating costs and excessive down-time to 23 BOPD with normal $1,200 per well per month operating costs and very little down-time.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Application (area/region)</td>
<td>The technology has field-wide application and possible application to similar operating conditions in other fields/areas.</td>
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<tr>
<td>Limitations</td>
<td>Limited to the type of pumping equipment configuration can be used.</td>
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</tr>
<tr>
<td>Recommendations</td>
<td>Incorporate into the Technology Transfer Program and encourage application.</td>
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</tbody>
</table>
APPENDIX A

PROJECT DESCRIPTION

This section consists of a discussion describing the details of each of the projects.

Project 1. **Horizontal Drilling to Increase Production**, Cleary Exploration LLC

Project 2. **Horizontal Drilling for Improved Well-bore Drainage**, EDCO Producing

Project 3. **Improved 3-D Seismic Processing Techniques**, Brothers Production Co.

Project 4. **Integrated Exploration Using 3-D Seismic**, Double-Eagle Enterprises

Project 5. **Telluric Surveys**, Keener Oil & Gas Company

Project 6. **Formation Micro-Imaging (FMI) Log**, University of Alabama/Cobra Oil&Gas

Project 7. **Low-Invasion Unconsolidated Coring System & Core Analysis**, Sandia Operating Co.

Project 8. **Inert Gas Injection**, Dakota Oil Producers

Project 9. **Stimulating Formations Thermally**, Diamond Exploration

Project 10. **Microbial Improved Oil Recovery**, Edmiston Oil Co.

Project 11. **Closed-Loop Extraction of Hydrocarbons and Bitumen from Oil-Bearing Soils**, X-TRAC Energy, Inc.

Project 12. **Computerized Well Monitoring System**, James Engineering

Project 13. **Improved Stimulation**, K-Stewart Petroleum

Project 14. **Pre-Packed Resin Coated Liner**, Industrial Technology Management (ITM)

Project 15. **Foam Frac and Foam Acid Treatment**, Sipple Oil Co.

Project 16. **Gel Polymer Treatment**, Grace Petroleum Co.

Project 17. **Cost Effective Water Disposal**, Harry A. Spring

Project 18. **Gel Polymer**, Kenneth Y. Park


Project 20. **Microbial Cleanup of Paraffin**, Rock Island Service Company, Inc.


Project 22. **Calcium Carbonate Prevention**, Tenison Oil Co.
Project 1. **Horizontal Drilling to Increase Production**  
Hunton Formation Dolomitic Limestone, Pottawatomie County, Oklahoma  
Cleary Exploration LLC, operator  
Oklahoma City, Oklahoma

Technology Area: Drilling  
Project Date: 8-1-96 to 7-30-97  
Subcontract No. G4P70039

Cost Share:  
Operator $115,500 (70%)  
DOE/NPTO $ 49,500 (30%)  
Total $165,000

Problem:  
Production rates and ultimate recovery vary widely and unpredictably from one well to another in this area of the fractured Hunton Limestone formation and production from new wells is often marginal to non-commercial. The inconsistent and unpredictable results appears to be due to the specific reservoir fracture and/or paleokarst (karst) system intersected (or not intersected) by the vertical wellbore.

Objective:  
Test the feasibility and economics of drilling a horizontal well, extended for a minimum of 1500 feet through the oil zone in the top 10 feet of the fractured Hunton limestone reservoir, to encounter additional fracture systems, or karst systems, thus increasing reserves and accelerating production.

Summary:  
A horizontal wellbore was drilled into a low-permeability dolomitic limestone reservoir in an attempt to intersect additional fracture and/or karst systems to increase oil production. Initial results indicated significantly improved total fluid production from the horizontal wellbore, but the beam pumping unit being used to produce the well was incapable of moving the amount of fluid produced by the horizontal hole. It was estimated that the produced volumes could exceed 200 BOPD, possibly stabilizing around 100 BOPD, if the well was equipped with high lift production equipment. However, the first 200' of the horizontal hole collapsed before a submersible pump could be installed to fully test the production capacity of the horizontal wellbore. Attempts to clean out the horizontal section were unsuccessful and the hole was lost.

Background:  
The Hunton Formation in Oklahoma and Pottawatomie Counties, Oklahoma, is a dolomitic fractured limestone occurring at about 5,100 ft. The Hunton formation in this area is a thick carbonate section, generally fractured, normally pressured, and productive of both oil and water with minimal gas production. The zone is known to be very prolific in areas of adequate porosity and permeability development, explained by the possible presence of localized areas of extensive fracturing, erosion, and re-working resulting from tectonic folding, and identified as karst zones.
Project Description:
Cleary Exploration, LLC, of Oklahoma City, Oklahoma, proposed to re-enter an existing vertical well and drill a 1,500 foot horizontal section through the reservoir to intersect the maximum number of potentially productive fractures. The horizontal wellbore would expose more formation face to the wellbore and extend the effective drainage area of the well. Cleary attempted to reenter and recomplete an abandoned well in Section 18, Township 11N, Range 2E, in Pottawatomie County, Oklahoma, near the line separating Pottawatomie and Oklahoma counties. The original vertical well was drilled in January, 1996 and completed in the top 10 feet of the Hunton Limestone from 5725-5735. The original well was cored, but not logged. Routine core analysis indicated permeabilities from 10 Md to 250 Md and medium perm around 10 Md. Porosity was below 5%, typical of most Hunton limestone. After acid treatment, the original well started producing 21 BOPD plus 130 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.

Cleary proposed to drill a medium radius horizontal re-entry of the oil producer in June 1997. The proposal was to re-enter the existing productive well, cut and remove the existing 5-1/2" casing, side-track around the resulting casing stub and drill a 300 foot medium turning radius build section and set 5-1/2" casing to the end of the build section. After casing was set through the curve, a 4-3/4" lateral section would be drilled in a slight overbalanced condition. Once drilled, the lateral would be produced via rod pump as an open hole completion. The horizontal section was planned to extend to the northwest because the primary fracture direction is northeast-southwest and a well drilled to the northwest was projected to intersect more fractures, increasing production and recovery of the oil. A 1,500 foot horizontal section was to be drilled through the reservoir to intersect the maximum number of potentially productive fractures. The horizontal wellbore should expose more formation face to the wellbore and extend the effective drainage area of the well. A successful horizontal well was expected to stimulate horizontal drilling in four adjoining counties, where completions in fractured Hunton dolomitic limestone reservoirs have been marginal to noncommercial.

Results:
The horizontal section was drilled and completed as proposed although hole stability difficulties were encountered during drilling. 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 the 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. The horizontal hole collapsed and the hole was lost before the well could be produced to capacity. The horizontal portion of the hole was lost because the first 200 feet collapsed before a submersible pump could be run to test the full production potential of the well.
It appears that the horizontal hole collapsed due to exposure of the overlying Woodford shale to the open horizontal borehole. The horizontal hole had drifted up into the overlying Woodford shale while drilling the horizontal section. Inability to maintain hole stability during drilling may have set up the conditions which led to the hole collapsing. Comments in the Final Report indicate some concern for drilling the "troublesome Woodford shale".
Project 2. **Horizontal Drilling for Improved Well-bore Drainage**

**Trempealeau Formation, Shaver-Neff Unit, Morrow County, Ohio**

EDCO Producing, operator
Mt. Gilead, Ohio

**Technology Area:** Drilling

**Project date:** 05-30-1996 to 08-01-1996

**Subcontract No.:** G4P60386

**Cost Share:**
- Operator $39,000 (50%)
- Operator $39,000 (50%)
- **Total** $78,000

**Problem:**
Low oil production due to heterogeneous formation and low reservoir energy.

**Objective:**
Drill a short radius 300-600 ft horizontal well section from an existing vertical wellbore in a mature, pressure depleted, possibly compartmentalized reservoir to increase oil recovery.

**Summary:**
Attempted to drill a horizontal well bore in the energy-depleted compartmentalized reservoir to intersect accumulations of trapped oil. Experienced horizontal drilling problems, including difficulty maintaining hole angle and direction, which resulted in abandoning horizontal drilling efforts at approximately 32 feet of horizontal section instead of the 300-600 feet targeted. Set rod pump at top of curved section and placed on production. After seven weeks of production from the horizontal well bore the fluid level decreased to the pump level and production rates declined to 2 barrels of oil and 7 barrels of saltwater per day, lower than the rates from the original vertical well bore. The reason for the disappointing result was the inability of the pump to remain submerged (low fluid level). The operator then ran a coiled tubing anchor with check-valve below the rod pump into the curved section. Well production stabilized at pre-project rate of 5 BOPD and 15 BWPD. The well was eventually shut-in due to low economics.

**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 pool of trapped oil thought to exist but not produced due to compartmentalization and low reservoir energy. The well selected for this project was the Shaver-Neff No. 1, which 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 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:
EDCO Producing, Inc. attempted to drill a horizontal wellbore into the reservoir to try to intersect possible accumulations of trapped oil. Drilling of the horizontal hole was suspended approximately 30 ft. into the curve section because of severe hole problems and extreme difficulty in keeping the hole direction stabilized. The fractured dolomite formation being drilled began to crumble and slough into the borehole, and the drilling assembly became stuck and had to be fished out. Based on the inability of the wellbore to stay on course and the corkscrew of the borehole, in conjunction with the formation hole problems, the horizontal drilling attempt was suspended far short of the 300-600 ft. of vertical section originally planned.

Approximately 30 feet into the curved section (approximately 45° inclination), the fractured dolomite formation began to crumble and slough into the borehole. The drilling assembly became stuck and had to be fished out. Based on the inability of the wellbore to stay on course and the corkscrew of the borehole, in conjunction with the formation hole problems, the horizontal drilling attempt was suspended.

A rod pump was set at top of curved section and the well was placed on production. After seven weeks of pumping the production decreased to 2 barrels of oil and 7 barrels of salt water per day. The producing 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). The operator then ran a coiled tubing anchor with check-valve below the rod pump into curved section. Well production stabilized at pre-project rate of 5 BOPD and 15 BSWPD.

Drilling the tight radius build section with air in the fractured dolomite may have created the hole problems and/or may have created equipment problems in addition to the formation problems. Numerous equipment problems were reported during drilling, indicating that the drilling assembly may not have been adequately designed for the unanticipated drilling conditions encountered.
It is difficult to determine whether or not production might be improved with a horizontal borehole in this formation because the horizontal section was not completed and thus there was no production test. It does appear, based on the results of the project, that horizontal drilling in this formation is difficult and that several drilling problems would need to be addressed before another attempt can be reasonably made. The feasibility of horizontal drilling in this formation remains to be adequately demonstrated and certainly the concept of increasing production rates by intersecting compartmentalized, trapped oil with a vertical borehole remains undemonstrated.
Project 3. **Improved 3-D Seismic Processing Techniques**  
Ellenburger/Strawn Dolomite, Fluvanna SW Field, Borden County, Texas

Brothers Production Company, operator  
Midland, Texas

Technology Area: Exploration  
Project Date: 04-15-1996 to 09-15-1996  
Sub Contract No. G4P60306

Cost Share:  
Operator $450,000 (90%)  
DOE/NPTO $50,000 (10%)  
Total $500,000

Problem:  
Unable to map Ellenburger reflections in 3-D seismic survey for identification of bypassed oil for selecting in-fill drilling locations due to incorrect time-to-depth conversion of seismic horizons.

Objective:  
Reinterpret the existing 3-D seismic data using analytical functions to improve the time-to-depth conversions, generate structural maps of objective exploitation prospects, then drill a well to test the accuracy of the technology.

Summary:  
A new analytical seismic interpretation algorithm was developed to map the Ellenburger dolomite in West Texas. Reprocessing and reinterpretation of the existing 3-D seismic data resulted in confidently mapping of reliable Ellenburger dolomite reflections, showing probable faulting which has identified locations of possibly bypassed oil. Reinterpretation using the analytical function has identified several Ellenburger structural anomalies, which will be drilled if and when oil prices recover and stabilize. The reinterpretation did not support the two pre-project dry hole wells and the wells would not have been drilled if the reinterpreted data had been available. Drilled one well to test a Wolfcamp structural anomaly identified from the reinterpreted 3-D seismic data (which was on structure, but wet). The well resulted in a commercial oil discovery in the shallower Spraberry (not Ellenburger), identified from drilling data. No Ellenburger wells have yet been drilled to verify the reinterpreted 3-D seismic maps.

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.

Project Description:
The seismic reprocessing involved the following sequential steps:

1. Tying all seismic data to existing sonic logs by inverting the seismic data.
2. Correcting the seismic data and tying in all other wells to the corrected seismic data.
3. Conducting a velocity analysis using new equations developed by ERC Tigress.
4. 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.

Reinterpretation of the 3-D seismic identified several Ellenburger prospects that have not yet been drilled. One Wolfcamp formation dry hole was drilled based on a structural anomaly identified from the reinterpreted 3-D seismic data. Brothers Production Company staff estimates that approximately 150,000 barrels of new potential oil reserves have been identified by reprocessing and interpreting 3-D seismic data. The Wolfcamp structure was present as indicated, but the structure was wet. However, a commercial producer was completed in the shallower Spraberry based on shows when drilled, but was not identified from the reinterpreted 3-D seismic. The well was subsequently completed in the shallower Spraberry (identified from the well data) and was completed as a commercial producer with an estimated 150,000 to 200,000 BO reserves. The well was not drilled to the Ellenburger and did not result in production from the Ellenburger formation. The reinterpreted 3-D seismic indicated that the Ellenburger top in both of the pre-project dry hole wells was lower than predicted from the original 3-D seismic data due to inherent interpretation inaccuracies and processing artifacts of the time-to-depth conversions. The two dry holes would not have been drilled had the reinterpreted 3-D seismic been available. Highly leveraged DOE funding contributed to a significant advancement in 3-D seismic processing technology.

The quality of the structural map appears to have been improved by the reinterpreted data, as indicated by the Wolfcamp prospect. Several more wells would need to be drilled in order to determine if the success rate can be improved by the reinterpretation.
Project 4. **Integrated Exploration Using 3-D Seismic**
Wilcox Formation, Kay County, Oklahoma

Double-Eagle Enterprises, operator
Tulsa, Oklahoma

Technology Area: Exploration
Project Date: 05-30-1996 to 12-31-1997
Subcontract No. G4P60320 (workshop presentation)

Cost Share:
Operator $240,000 (83%)
DOE/NPTO $50,000 (17%)
Total $290,000

Problem:
Unable to locate reliable drilling prospects using subsurface and 2-D seismic data resulting in a low exploration success rate.

Objective:
Incorporate 3-D seismic techniques into existing exploration program to improve the discovery success rate in the drilling of 2 to 3 Wilcox sand wells in the prospect area.

Summary:
The original proposal was to conduct a 3-D seismic survey to supplement existing 2-D seismic data and conduct surface microbial analysis to better target drilling prospects in the Wilcox sandstone formation. Existing 2-D seismic data did not provide sufficient information to identify the more likely productive areas of the Wilcox structure. The proposal was modified to eliminate the surface microbial survey due to the operators' budget constraints. 3-D seismic data was acquired and processed for two prospects. The 3-D seismic data interpretation on the first prospect did not support the existence of a structural anomaly that had been indicated by the 2-D seismic data, thus a well to test the structure was not drilled on that prospect, thereby possibly preventing the drilling of a probable dry hole. Based on the 3-D seismic data interpretation on the second prospect, a well was drilled to test the structure, but due to an unanticipated thickening of the overlying formation, the Wilcox was structurally flat (low) and subsequently wet. Review of the seismic data suggested that although the top of the overlying formation was structurally high, as confirmed by drilling data, the 3-D seismic data did not suggest that the overlying formation was thickening and that a possible seismic velocity pull-up had been interpreted as a favorable underlying Wilcox structural high.

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 Descriptions:
Double-Eagle Enterprises proposed to conduct 3-D seismic surveys on areas identified by its subsurface studies. An area 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. The data was sent to Star Geophysical in Oklahoma City for processing where interpretation of the Hinton Prospect data was completed. Nemaha Resources shot seismic data over the Sewell Prospect in Section 18, Township 29N, Range 2E and that data was also interpreted by Star Geophysical. Drillsite selections were made on both prospects.

The 3-D seismic data interpretation on the Hinton Prospect did not support the existence of a structural anomaly that had been indicated by the 2-D seismic data. Thus a well to test the structure was not drilled on that prospect, thereby preventing the drilling of a probable dry hole.

Parsons Engineering Corp., the operator, drilled a 4,000-ft. Wilcox test well, the No. 1-17 Blanche well, in S/2 NW NW SW Sec. 17- T29N- R2E on the Sewell Prospect in March, 1998. An additional 100 ft. of Mississippian limestone section was encountered on top of the Wilcox sand. Although the well was drilled on the structurally highest top of the Mississippian, the unanticipated thickening of the Mississippian structure caused the underlying Wilcox sand to be structurally flat (low) and the Wilcox tested wet. The well was then plugged and abandoned.

After the drilling and log evaluation had been completed, the seismic data was reviewed and found to suggest the Mississippian section was thickening at the drill site, and the Wilcox structural anomaly may be only a seismic velocity pull-up. Several geophysicists had reviewed the Sewell Prospect database and had missed this interpretation.

Although the results were disappointing, the 3-D seismic program was successful in providing useful information that can be integrated into future drilling plans in the Kay County area. Further drilling activity was suspended at the time due to the low oil prices. Significant potential remains if and when oil prices recover. Information and experience gained from this project can be utilized in future development activities. Although the results were disappointing, the 3-D seismic program may be successful in providing useful information that can be integrated into future drilling plans in the area. Several more wells would need to be drilled in order to determine if the success rate has been improved, (i.e., a statistical issue).
Project 5. **Telluric Surveys**
Wilcox Sand, Bates-Springer Lease, Creek County, Oklahoma

Keener Oil & Gas Company, operator
Tulsa, Oklahoma

Technology Area: Exploration
Project Date: 10-15-1995 to 12-31-1995
Subcontract No. G4P51722

Cost Share:
Operator $100,000 (67%)
DOE/NPTO $50,000 (33%)
Total $150,000

Problem:
Locate structure with alternative geophysical technology to reduce finding costs for drillable structures.

Objective:
Drill a well to test the capability of tellurics as an additional tool to define subsurface features for exploratory and development drilling by comparing structural tops in the drilled well with structural tops interpreted from a telluric survey.

Summary:
A telluric survey was used as a tool to define subsurface oil and gas bearing structural traps. An electrotelluric (telluric) survey is a measurement of the resonance signal created when atmospheric generated electromagnetic pulses penetrate the earth's surface, creating a secondary electrical field, which propagates downward and ultimately resonates from subsurface beds of contrasting resistivities. A well was drilled to test a subsurface structural anomaly identified from telluric survey data interpretation, but the target formation was not on structure and was dry. Review indicated that formation tops and target zones predicted by the telluric data were either not definable or shallower than the actual depth encountered by the drilled well.

Background:
It has long been known that electromagnetic pulses are generated in the upper atmosphere when the planetary magnetic field interacts with proton emissions from the sun. These incident electromagnetic pulses are known to penetrate the surface of the earth and create a secondary electrical field, which in turn also propagates downward and ultimately resonates from the subsurface beds of contrasting resistivity. This process has been used for years to study subsurface features. More recent developments of a direct depth/frequency relationship in the electrical component make it possible to circumvent the clumsy depth/resistivity modeling previously employed. This technique is somewhat involved and is described elsewhere. The technology requires only a single operator, and a half dozen data stations (including several calibration surveys) can be processed in a single day, depending, of course, on the amount of detail required, and a consistency of good weather. The importance of this system of subsurface data acquisition, aside from its inherent simplicity, is twofold. First, the expense of an
electrotelluric survey is but a fraction of the cost of a comparable seismic program. Second, the technique is completely noninvasive, requiring at the very least, the passive digital recording of the natural and continuous electrotelluric signal on a clear day. A team can conduct a survey through a downtown intersection, or through a wetland covered with nests of endangered migratory birds and never be noticed.

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 of 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.

Project Description:
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:

1. Perform a telluric survey in an oil and gas producing region to try to identify a previously unknown structure.

2. Integrate the telluric data with current well control.

3. Drill a well to prove/disprove the accuracy or reliability of the tellurics.

Results:
A subsurface anomaly was identified in Section 2, Township 14N, Range 8E, Creek County, Oklahoma. An Ordovician Wilcox sandstone well was drilled to test the accuracy of the telluric signals used to locate and define the subsurface structure. The well was drilled, but the Wilcox sandstone was dry and not on structure. 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 not definable or shallower than the actual depth encountered by the drilled well. The telluric survey as used here is unable to predict tops, although the method has reportedly been used successfully in other fields.

Telluric surveys are being used in the industry for oil & gas development. The well they drilled to test the telluric interpretation was low on structure, and dry. The target formation was 22 feet lower than indicated by the telluric interpretation. The structural anomaly was misidentified from the telluric survey data. The telluric survey interpretation was not precise enough to give completely reliable results. A second well was drilled based on the telluric survey and it was also dry, although it was then completed up-hole as a producer. The telluric data requires good, tight well control but is considered a viable, cost-effective alternative to seismic. Telluric data
gives some structural definition, but not as good as good seismic. A telluric survey can be used to obtain additional information on a prospect where seismic acquisition is cost prohibitive. Drilling activity was shut down due to low oil prices, which existed at the time.

The project proposed the use of a technology that is still in an early developmental phase. The concept is feasible, though of low/or limited probability of success at the current stage of development. A telluric survey costs considerably less than a seismic survey and leaves little, if any, environmental impact, and thus certainly warrants further consideration and development by the industry.
Project 6. Formation Micro-imaging (FMI) Log
Frisco City Sandstone, East Frisco City Field, Monroe County, Alabama

Department of Geology at the University of Alabama, operator (with partners Cobra Oil & Gas Corporation, Geological Survey of Alabama, and Schlumberger Well Services)
Tuscaloosa, Alabama

Technology Area: Formation Evaluation
Project Date: 10-15-1995 to 10-14-1996
Subcontract No. G4P50139 (workshop presentation)

Cost Share:
Operator $25,000 (50%)
DOE/NPTO $25,000 (50%)
Total $50,000

Problem:
Whole core sample analyses are required for Frisco City sandstone reservoir characterization, production purposes, and reservoir management. Coring operations are expensive and of risk to wellbore integrity.

Objective:
Develop scientifically valid methodologies for integrating whole core information and Formation Micro-Imaging (FMI) log data to provide a more economical solution for sandstone reservoir characterization and production applications.

Summary:
Schlumberger's Formation Micro-imaging (FMI™) log was used to determine facies and reservoir characteristics in Alabama's Frisco City sandstone as an alternative to coring in order to reduce drilling costs and coring risks. Comparison between whole core analysis and an FMI log interpretation from the same well confirmed that the FMI log can be used successfully to provide information on geological description, facies distribution, and reservoir properties as a valid alternative to whole core and whole core analysis.

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 risk for a blowout or losing the well. Success with the FMI or similar logs would represent 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 Alabama Geological Survey and University of Alabama Geology Department analyzed and described the
core 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 the FMI logs to replace coring will result in savings of approximately $25,000 per well in this area.

The FMI log environment of deposition interpretation did not differ significantly for the whole core interpretation. The FMI log provided paleocurrent direction and sandstone orientation data that is not available from core description, yet this information is critical to establishing a regional reservoir stratigraphic model of the Frisco City Sandstone. The FMI log demonstrated its reliability for deciphering reservoir quality. The porous and permeable intervals as determined from the FMI log interpretation were consistent with the pay zones defined from the whole core analysis. The FMI log proved beneficial in identifying anisotropic features that could be barriers to fluid flow. Core analysis did, however, indicate which porous and permeable intervals had potential for oil production (the presence of hydrocarbons in the core samples) which could not be interpreted from the FMI log.
Project 7. **Low-invasion Unconsolidated Coring System & Core Analysis**
Cole Sand @ 1,799 ft., Orlee Field, Duval County, Texas

Sandia Operating Company, operator
San Antonio, Texas

Technology Area: Formation Evaluation
Project Date: 10-15-1995 to 10-14-1996
Subcontract No. G4P51726

Cost Share:
Operator $ 70,800 (59%)
DOE/NPTO $ 50,000 (41%)
Total $120,800

Problem:
Development wells within the field have irregular oil saturation and some downdip wells produce with higher oil cuts than some updip wells. No cores or core descriptions are available to determine reservoir characteristics or with which to calibrate logs in the unconsolidated sand oil reservoir containing fresh formation water. Unreliable log analysis creates difficulty in identifying higher oil saturation zones for development drilling.

Objective:
Recover and analyze a whole core in a Cole sand reservoir in South Texas.

Summary:
Use a low-invasion, hydrolift coring system to recover unconsolidated Cole sand core and perform core analysis to calibrate logs and to calculate water saturation in the fresh formation water environment. Core recovery from the well was 100% and only one foot of the core visually appeared to be invaded and flushed by mud filtrate. Core analysis provided information on reservoir facies, porosity, and oil saturations, and provided data with which to successfully calculate \( S_w \) from the logs.

Background:
The problem in the Orlee Field area in Duval County, Texas is irregular oil-cuts from wells throughout the field because of reservoir heterogeneity. Some down dip wells produce higher oil cuts than up-dip 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 the Orlee Field.
A low-invasion hydro-lift system was used to recover the unconsolidated Cole sand. Coring was performed by Baker-Inteq. The hydro-lift part of the system permits more complete and less damaging core recovery by allowing the newly cut core to enter and 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 hydro-lift 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 (1,000 to 5,000 millidarcies), the very high porosity zone is not distinguishable on logs, and was not know 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 calculation upward and decreases $S_w$ calculated from logs.
Project 8. **Inert Gas Injection**  
Lakota Sand, N. Wind Creek Field, Crook County, Wyoming @1,100 ft.

Dakota Oil Producers, Inc., operator  
Pierre, South Dakota

Technology Area: Improved Oil Recovery  
Project Date: 10-15-1995 to 10-14-1996  
Subcontract No. G4P51723 (workshop presentation)

Cost Share:  
Operator $50,000 (51%)  
DOE/NPTO $47,202 (49%)  
Total $97,202

Problem:  
Need to increase pressure in reservoir. No reservoir energy to drive oil.

Objective:  
Inject water-surfactant foam and inert gas into downdip injection wells in a line-drive pattern in a low-pressure formation to repressurize the oil reservoir, mobilize oil and improve oil production rates. Inject inert gas into the producing wells in a "huff and puff" test program to reduce water mobility and prevent water coning.

Summary:  
The project consisted of applying two different foam-inert gas procedures to a low-pressure North Wind Creek field reservoir in Crook County, Wyoming, in order to increase pressure and mobilize oil.

Test 1: Inject a high foam, anoxic surfactant mixture and an inert gas into a single producing well in a "huff and puff" test program to reduce water mobility and water coning. This test did not appear successful and was discontinued.

Test 2: Inject water-surfactant foam and inert gas into three downdip injection wells in a line-drive pattern for an enhanced waterflood with foam procedure in a low-pressure formation to repressurize the oil reservoir to mobilize oil and improve oil production rates. Although two wells experienced cement failure and produced only water, oil production rates from other parts of the project area doubled from the pre-project rates. The operator plans to expand this test project.

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 the reservoir without success.
Project Description:
7-8 wells were involved in the project out of 20 wells on the 320 acre lease. The wells are producing at this time. Water-surfactant mixture of 0.5% surfactant with 55 barrels of water was injected down-dip, and inert gas was injected up-dip to re-pressurize the oil reservoir. The wells were then shut-in. The huff 'n' puff process is repeated when oil production begins to decline.

Results:
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.
The huff 'n' puff project will be expanded to two wells on an 80-acre tract to the south that had been previously non-productive because of the economics. Generated the gas on site. Used small quantities of inert gas and keep pressures low. Increased production twofold. 400 barrels of emulsion to be treated before it can be sold. Building a centrifuge to break the emulsions.
Project 9. **Stimulating Formations Thermally**
Cottage Grove sand @ 250-300 ft., Paola-Rantou-Shoestring Field, Miami County, Kansas

Diamond Exploration, operator
Paola, Kansas

Technology Area: Improved Oil Recovery
Project Date: 10-15-1995 to 04-15-1996
Subcontract No. G4P51723

Cost Share:
Operator $49,500 (50%)
DOE/NPTO $49,500 (50%)
Total $99,000

Problem:
Low oil recovery due to low oil gravity and low reservoir energy.

Objective:
Heat the reservoir by passing an electrical current through the reservoir to activate dormant gas and lower the oil viscosity, mobilizing the oil. Inject inert gas if necessary to increase reservoir pressure.

Summary:
High-voltage electrical current was used to generate heat in a small, heterogeneous, shallow, heavy oil (low gravity) reservoir in an attempt to improve oil recovery. Copper probes were placed at the formation in each of three wells in a triangular pattern approximately 100 feet apart with a producing well in the center. The probes were energized by an electrical current over a period of six days. The reservoir temperature at the probe wells was elevated from 58°F to 101°F and a small, non-commercial quantity of 21°API gravity viscous oil was recovered from one of the probe wells. Inert gas was injected into each of the probe wells after the formation was heated and communication was immediately established with the producing well. However, the formation temperature at the producing well did not increase and no oil was recovered from the producing well.

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:
Thermally stimulation was tested in the 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 target formation was the Cottage Grove sand at 250-300 ft. depth. The oil zone was approximately 6 ft. thick and the underlying waster zone was approximately 2-3 ft. thick. Four wells were drilled for the project. Three electrical input (probe) wells in a triangle 100 ft. apart and one production well in the middle of the triangle. The services of an electrical engineer was used in designing the project. A 3-phase, very high cycle (80 cycles or so) industrial electrical generator (use to start jet engines) using propane fuel was used (a lot of fuel was consumed) to produce the electrical power. One phase of the output was supplied to each of the three electrical probe wells. The aquifer below the oil 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 milliliters 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 101°F. The formation at the center producing well located 57 ft. away from the probe wells was not heated. Injection of inert gas at the electrode wells had no effect on oil production, although gas communicated to the center producing well. The process heated the formation, but no oil was produced.

A small amount of oil was recovered on a wire line from one of the electrode wells during the demonstration project. The oil gravity was 20°API with a viscosity of 1,730 centipoise at 74°F.

Core samples were obtained from a well on the lease and analyzed in 1982. The reservoir had good permeability and porosity, ranging from 110 md to 169 md and from 26.9% to 28.1% respectively. Analysis of the core samples indicated oil saturations in the range of 21% to 38 %.

There are several possible explanations (or combinations of explanations) as to why there was no oil produced, even at the electrode wells:

- The oil saturation was at, or close to, irreducible and too low to be producible (difficult to determine).
- The oil was too viscous to flow, even at 100°F.
- There was not enough heat generated beyond the immediate vicinity of each individual electrode well to heat the formation enough to mobilize the oil.

The technology is not at all well developed and very little effort has been conducted in this technical area. There are too many unknowns for the current stage of development of this novel and new experimental technology.
Problem:
Wellbore damage due to paraffin and asphaltine scaling resulting in low oil production.

Objective:
Inject hydrocarbon-utilizing microorganisms, inorganic nutrients, and a biocatalyst in a MEOR process into a low-gravity oil reservoir to clean scale, paraffins, and asphaltine deposition from the well bores and to improve oil mobility and effective permeability in order to improve oil recovery.

Summary:
Three different microbial systems (supplied by three different MEOR companies) were applied to three different groups of wells. The first group of wells consisted of only producing wells, the second group consisted of producing wells and one injection well, and the third group initially consisted of producing wells with one producing well later converted to a water injection well following the initial producing well MEOR treatments. The producing wells in each group received initial conventional matrix squeeze type MEOR treatments for wellbore clean-up and near-wellbore effective permeability improvement, followed over a period of time by periodic squeeze type MEOR treatments. The injection well in the second group received continuous MEOR injection. The converted injection well in the third group received no MEOR injection treatment, although it was planned to inject MEOR treatment on a continuous basis into one of the converted injection wells at a later date.

Initial indications are that the second set of wells (with continuous MEOR injection from the start) responded favorably while the response from the first (squeeze treatment only) and third group (Squeeze treatment then conversion to water injection) of wells was minimal to negative, although 3 wells on one of the leases in the first group indicated some slight increase in production.

Only the Kroll Lease resulted in any appreciable production increase:

Four producing wells on the Kroll lease were initially (squeeze method) MEOR treated 7-17-96. Production decreased 50 % to 1.67 BOPD within the first 30 days.
The Kroll #5 producing well was acidized in August.

- The Kroll #6 producing well was re-treated with MEOR in September.
- There was no change in production as a result of either treatment.
- Began weekly injection water MEOR treatments of Kroll #WI-3 well on 7-17-96 at 30 BWPD continuous water injection.
- In September, 1996, WI rates were increased to 90 BWPD.
- Within 30 days, the Kroll lease production increased from 3 BOPD to 8 BOPD.
- Within 60 days, the Kroll lease production had increased to approximately 15 BOPD.
- In mid-March, 1997, Kroll lease production increased to 21 BOPD for over a year.
- It is difficult to determine whether the production response was due to MEOR treatments or to the increased water injection rates.
- MEOR treatments were suspended in early 1999 due to low oil prices.

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:
Three different Microbial methods were applied in the field. Each MEOR process used for this test included hydrocarbon-utilizing microorganisms, inorganic nutrients, and a biocatalyst. The MEOR materials were blended and injected down the wellbore into the reservoir. The project had two parts. Phase I was a pilot treatment Initiated on the Heintzelman and Kroll leases. The Heintzelman lease had five producing wells. The Heintzelman No. 3 had been cored and analyzed. The Kroll lease had four producing wells and one injection well. The Kroll No. 6 had been cored and analyzed. Phase II was to be 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 of all producing wells on both the Heintzelman Lease and the Kroll Lease 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 MEOR materials into the reservoir by weekly adding the MEOR material to the water injection tank while continuously injecting water down the injection well.

Results:
The five wells on the Heintzelman Lease were treated by the squeeze method on July 17, 1996. Production dropped 50% to 3.34 BOPD within the first 30 days. Production did not recover to the pretreatment production level. The Heintzelman #2 well was converted to water-injection on July 20, 1997, with plans to treat the well with MEOR similar to the Kroll Lease injection well. Conversion of the well to WI contributed to the Heintzelman Lease production decrease.
The four producing wells on the Kroll Lease were treated with a mixture of hydrocarbon-utilizing microorganisms, inorganic nutrients, and a biocatalyst from Biodynamics Corporation by the squeeze method on July 17, 1996. This treatment generates surfactant in order to reduce interfacial tension of the oil-water interface to clean up the wellbore and to improve oil relative permeability. Production dropped by 50% within the first 30 days. Weekly, a small nutrient/microbe mixture was added directly to the water tank at the injection well and the mixture was injected continuously at 30 BWPD. In September, 1996, two months after MEOR treatment began, water injection rates were increased on the Kroll Lease to 90 BWPD. Within 30 days, production on the Kroll Lease increased from 3 BOPD to 8 BOPD. Within 60 days, the lease production had increased to approximately 15 BOPD. From the data available, it is difficult to determine whether the Kroll lease response was due to MEOR treatment or increased water injection rates or a combination of the two. Additional engineering assessment would be required to determine the probable results of the MEOR treatment alone.

Two wells on the Crook Lease and one well on the Wilson Lease well 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, 1996. Crook Lease production decreased 4% from pretreatment baseline. Wilson Lease production decreased 37% from baseline, partly due to gunbarrel dumping oil into stock tanks during the previous quarter reporting period.

Three wells on the Eberhart Lease, five wells on the Hoge Lease, two wells on the Haigwood Lease, and two wells on the Hick-Olmstead Lease 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 pretreatment baseline. Hoge Lease production decreased 14% from pretreatment baseline, partly due to converting one well to water injection. Haigwood Lease decreased 19% from pretreatment baseline. Hick-Olmstead Lease production increased 31% from pretreatment baseline, mostly due to mechanical repairs during the previous reporting period.

MEOR treatments were stopped in January 1999 due to unfavorable economics at that time.

Summary Reported changes in oil production from pre-treatment:

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<td>-29%</td>
<td>-13%</td>
<td>-37% (gun-barrel dumping)</td>
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<tr>
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<td>+418%</td>
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<td>Hick-Olmstead</td>
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Project 11. Closed-Loop Extraction of Hydrocarbons and Bitumen from Oil-bearing Soils
PR Springs and Asphalt Ridge Sandstone deposits, Uintah County, Utah

X-TRAC Energy, Inc. (now UTAR Energy, Inc.)
Englewood, Colorado

Technology Area: Improved Oil Recovery
Project Date: 4-1-1997 to 11-30-1997
Subcontract No. G4P70040

Cost Share:
Operator $97,359 (66%)
DOE/NPTO $50,000 (34%)
Total $147,359

Problem:
No technology or process has been demonstrated to be efficient and environmentally benign for the commercial extraction of marketable hydrocarbons from shallow tar sand reserves within the United States.

Objective:
Demonstrate that the proposed technology can efficiently extract and produce quality oil from shallow tar sand reserves obtained from a mining lease in Utah.

Summary:
A closed-loop extraction system employing recyclable hydrocarbon solvents was used to extract hydrocarbons and bitumen from oil-bearing tar sands efficiently and in an environmentally safe manner. Oil-bearing soil was mined from the P.R. Springs and the Asphalt Ridge tar sand deposits in Uintah County, Utah, and delivered to X-TRAC Energy's demonstration test facility site at the Sherard Dome Field in Washakie County, Wyoming, for processing. The test facility contained an entirely closed-loop system for the recovery of the extraction solvents and extracted hydrocarbons which allows the separation, recapture and recycling of the solvents during the process. The field test was conducted using the large-scale extraction equipment and the tar sand material was processed without difficulty. Laboratory analysis of the processed material indicated that 60% of the residual oil in place was recovered at operating temperatures and that at elevated temperatures recovery could be increased to as much as 80%. 50-60% of the extracted hydrocarbon was asphaltines, 20-25% was diesel, and 20-25% was light gas oil. The oil analysis indicates that the recovered asphalt is of high grade, which will not require large costs to process the asphalt into premium grade road asphalt.

Background:
The P.R. Springs and Asphalt Ridge tar sand deposits in Uintah County, Utah, contain an estimated 15 billion barrels of bitumen/heavy oil in the Utah deposits. The estimated tar sand bitumen/heavy oil reserves of the P.R. Springs deposit ranges from 3.7 to 5.9 billion barrels and the estimated reserves of the Asphalt Ridge deposit ranges from 0.8 to 1.4 billion barrels (4.5 to 7.3 billion barrels combined). The tar sand deposits range in depth from the surface down to 600 feet, and the tar sands range in thickness from 30 to 300 feet. The P.R. Springs tar sand oil
saturation averages 52 percent (ranging from 780 to 1,100 barrels per acre-foot, depending on net pay) and the Asphalt Ridge tar sand oil saturation averages 48 percent (ranging from 400 to 880 barrels per acre-foot, depending on net pay). No technology or process has been demonstrated to be efficient and environmentally benign for the commercial extraction of marketable hydrocarbons from shallow tar sand reserves within the United States.

Project Description:
X-TRAC Energy, Inc. has licensed a closed-loop solvent extraction system that employs recyclable hydrocarbon solvents to extract heavy oil and bitumen from oil-bearing soils. The solvent extraction process used requires mining and crushing of the oil sand and then processing of the crushed oil sand through a pressurized closed-loop system. The crushed oil sand is mixed with a hydrocarbon solvent in a pressurized vessel where the heavy oil and bitumen components are extracted from the crushed oil-bearing material. The extraction solvent is separated from the extracted hydrocarbon components by heating and the recovered solvent is then recycled through the system. Laboratory testing using the solvent extraction process indicates that the recovery efficiency is 56.3% from the PR Springs sand and 45.8% from the Asphalt Ridge sand using butane as the extraction solvent at an extraction temperature of 65°. Using Butane as the solvent, lab analysis showed that they were getting 60% of the residual oil out of the tar sand at operating temperature and at elevated temperatures lab tests showed 80% recovery. The recovery efficiency can be improved by heating the solvent, and recoveries from the Asphalt Ridge tar sand improved to 80.3% using pentane as the extraction solvent. Laboratory testing further indicates that using other solvents, extraction efficiencies can approach 98% or greater.

Results:
Tar sand samples were collected from mine sites at each of the Utah tar sand locations and transported to X-TRAC Energy's large-scale equipment site, located at the Sherard Dome Field in Washakie County, Wyoming. The tar sands processed at the Wyoming facility had no difficulty in running through the extraction equipment during the field test. Twenty thousand pounds (approximately 6 barrels of material) of P.R. Springs tar sand material was crushed and processed through the extraction unit, recovering approximately 125 gallons (three barrels) of bitumen, representing approximately 50% recovery at 0.6538 barrels of residual oil in place per ton of oil-bearing sand. Eighteen thousand pounds (approximately 6 barrels of material) of Asphalt Ridge tar sand material was crushed and processed, also recovering approximately 120 gallons (three barrels) of bitumen, representing approximately 50% recovery at 0.6538 barrels of residual oil in place per ton of oil-bearing sand. Crude sample analysis of the P.R. Springs recovered hydrocarbon indicated an ASTM distillation API Gravity of 16.9 degrees with 0.32% sulfur content and of the Asphalt Ridge recovered hydrocarbon indicated an ASTM distillation API Gravity of 20.2 degrees with 0.29% sulfur content.

Based on the results of the demonstration project, one barrel of extracted hydrocarbon output will consist of 50% by volume asphaltnes, 25% diesel, and 25% light gas oil. The asphalt and diesel markets are very strong in the area of Utah where the deposits are located. SHRP specific (Strategic Highway Research Program specifications), a processed asphalt product, sells for $200/Ton, roofing quality asphalt sells for $150/Ton, diesel sells for $0.65 per gallon, and light gas oil sells at WTI prices for a composite value of approximately $29.12 per BO recovered. Of the recovered asphalt, approximately 85% is of sufficient quality SHRP specific and the remaining 15% can be utilized in the roofing market.
The western United States annual 1994 road asphalt market usage was 5.6 million tons and the roofing market usage was 671 thousand tons. The road asphalt market has been projected to increase at +10% per year, as the repair of the nation's highway system has become a high priority.

Based on the results of the demonstration project, the estimated capital cost for a facility to process 150 tons/hr of bulk material (2,160 barrels of oil per day output) is $15 million, which includes the refining facilities, the asphalt upgrading facilities, tankage for storage and the oil extraction facilities. Estimated operating costs range from $8.50 per barrel to $13.00 per barrel of oil recovered. This includes mining costs, crushing costs, and rehabilitation (overburden, topsoil, and oil sand) costs of $5.79 and extraction and refining costs of $2.75.
Project 12. Computerized Well Monitoring System
Clinton/Rose Run Fields, East central Ohio

James Engineering, Inc., operator
Marietta, Ohio

Technology Area: Operations.
Project Date: 4-30-1996 to 12-31-1997
Subcontract No. G4P60318 (workshop presentation)

Cost Share:
Operator $47,500 (50%)
DOE/NPTO $47,500 (50%)
Total $95,000

Problem:
Inability to monitor quickly and cost efficiently a large number of marginal wells to identify and remediate production problems in individual wells in order to maintain maximum production. Loss of production due to individual well production problems in a large number of marginal wells is difficult to identify timely and efficiently, resulting in delays in taking corrective action. Small operators with limited staffing often become aware of production decreases only after the decrease has persisted for some period of time and becomes large enough to affect cash flow.

Objective:
Develop a simplistic computerized production monitoring program that utilizes commercial production forecasting software and compares forecasted rates to actual weekly and/or monthly production, to quickly identify decreases in production from individual wells in order to take remedial action.

Summary:
Use a computerized production monitoring system to download production forecasts from major commercial reserve analysis software (Aries) and upload well production information to compare actual production with forecast values to identify problem wells. A computer monitoring and prediction software package was developed for 250 wells, which could identify production problems quickly and allow prompt remedial action to be taken. During a five-month trial period, total production for the 250 wells increased approximately 5½% above the same period for the previous year even though the nominal production decline for that period of time was approximately 6% per year.

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 250 wells. Additional changes have been made to facilitate data entry from sources other than Aries. This helps the smaller operators who do not have the more sophisticated software packages. Preliminary results were favorable. During a five-month production period at the end of 1996 and the start of 1997, total production for 250 wells increased by approximately 5¼% over the same period in 1995 and 1996. It should be noted that the nominal decline for these wells is approximately 6% per year.
Project 13. **Improved Stimulation**
Morrow Formation, Carlton and Watonga Fields, Blaine County, Oklahoma.

K-Stewart Petroleum Corp., operator
Oklahoma City, Oklahoma

Technology Area: Production Problems
Project Date: 9-16-1996 to 7-28-1997
Subcontract No. G4P60397

Cost Share:
- Operator $623,400 (92.6%)
- DOE/NPTO $ 50,000 (7.4%)
- Total $673,400

Problem:
Formation damage and inconsistent stimulation results.

Objective:
Conduct study to identify minimum formation damage completion and production techniques to maximize production following hydraulic fracturing of Northwest Oklahoma Morrow formation wells which historically have not responded consistently to acidizing and hydraulic fracturing.

Summary:
Although Morrow well gas productivity typically improves with hydraulic fracturing, response to stimulation treatment tends to vary considerably from one well to another and any initially high production rates quickly drop off. The effects of various fluids on matrix permeability and fracture conductivity were compared via laboratory tests, production was correlated to completion methods and production practices by compiling and standardizing records in a relational database, and laboratory testing was related to the field by use of database correlations and characterization of the rocks tested. The study resulted in recommendations that frac fluid and breaker be selected to minimize pressure drop, proppant be selected to provide maximum conductivity in the presence of multiphase flow, and backpressure be held on the well during production to avoid dropping out condensate in the surrounding formation which would otherwise lower the effective conductivity.

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 wells will react positively to stimulation.

Project Description:
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:
Researchers concluded that producing Morrow wells under conditions that 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. History shows that how these wells were produced may have a greater influence on ultimate recovery than how the wells were fracture stimulated. Fracture treatment should consider the following:

1. Select the fluid breaker to minimize pressure drop.
2. Select the proppant to provide maximum conductivity in the presence of multiphase flow.
3. Maintain the backpressure needs on the well during production to avoid dropping out condensate in the surrounding formation.

K-Stewart plans to utilize the stimulation recommendations, but at that time had no plans for work-overs due to low oil prices. They did not utilize the production recommendations because low economics requires higher production rates for the time being.
Project 14. **Resin-coated Prepacked Gravel**  
Kern County, California

**Industrial Technology Management (ITM), operator**  
Torrance, California

**Technology Area:** Production Problems  
**Project Date:** 6-17-1997 to 4-30-1998  
**Subcontract No.** G4P70090

**Cost Share:**  
Operator $50,000 (49.7%)  
DOE/NPTO $49,500 (50.3%)  
Total $99,500

**Problem:**  
Traditional sand control prepacked gravel packs have high failure rates and are expensive to repair or replace.

**Objective:**  
Develop, construct, and field test an economical Pre-packed Resin Coated Liner prototype as a low cost sand control alternative to traditional wire wrapped sand control liners.

**Summary:**  
Construct and test a resin-coated prepacked gravel pack that fits inside a perforated liner for sand control as an alternative to the traditional external wire-mesh wrapped prepacked gravel pack which often becomes damaged while setting. Sample prepacked resin-coated liners were tested for permeability, bond strength, and chemical exposure. These tests indicate that the liner would be durable enough to withstand the typical down-hole environment.

**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 grave pack. 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.

**Project description:**  
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 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 connection, gravel (sand) mesh sizes, resin coatings and proppant materials, depending on the customers 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.

Project results:
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 then determined from a fractured section by placing the section in a hydraulic press and applying a force 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. Bond strength for Sample No. 1 was 2,000 pounds and for Sample No. 2 was 1,860 pounds.

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 of the entire bonded liner system, including the base pipe, to measure the permeability of the liner in an as-built liner configuration. The calculated average permeability of four flow tests for each sample were 32.3 darcies for the 16-20 mesh sample, 26.0 darcies for the 20-40 mesh sample, and 24.7 darcies for the 40-60 mesh sample.

Chemical resistance testing indicates that the ITM sand and resin mixture is resistant to most of the commonly found oil field chemicals. Review of the test data shows that the resin coating is stable in nearly all oil field chemicals with the exception of EDTA (iron sequestering agent), high pH exceeding a pH of 12, isopropyl alcohol, and barium sulfate scale converters, all of which result in resin loss and loss of compressive strength in varying degrees.

A prototype liner mold has been developed and a manufactured resin-coated prepacked gravel pack for a well test is available. The product has not yet been field-tested in a well due to current economic conditions, but is now being marketed in California and a field test candidate is being actively sought. The product is being introduced into the market in Bakersfield and Los Angeles. This project has good application potential, but needs a field demonstration to determine technical success.
Project 15. **Foam Frac and Foam Acid Treatment**
Corniferous Dolomite Formation, Big Sinking Field, Lee County, Kentucky.

Sipple Petroleum Company, operator
Beattyville, Kentucky

Technology Area: Stimulation
Project Date: 4-1-1996 to 3-31-1997
Subcontract No. G4P60307

Cost Share:
Operator $ 60,814 (55%)
DOE/NPTO $ 49,757 (45%)
Total $110,571

Problem:
Water breakthrough comes too soon after well stimulation resulting in low oil and high water production.

Objective:
Frac the second and third pay zones in two separate wells with two variations of a foam frac treatment for comparison of results. Frac the first pay zone with a foamed acid treatment to improve the bypassed oil zone treatment.

Summary:
Compare three stimulation treatments to determine the most successful treatment method for increasing oil production while reducing water production from wells producing only water or water with only trace amounts of oil. The results of three different stimulation treatment methods, all from different wells, were compared to determine the most successful treatment method for use in other wells across the reservoir. A foam frac treatment using resin-coated sand as a proppant was slightly successful in achieving oil production but probably is not economical. A foam frac treatment using sand as a proppant was relatively successful in achieving oil production and appears to be the most economically and technically successful procedure. A foam acid treatment was unsuccessful in achieving oil production.

Background:
Sipple Oil Company (Beattyville, Kentucky) has wells completed in the first, second, and third Corniferous 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.

Project Description:
Well No. 41 completed in the second and third Corniferous reservoirs received a foam fracturing treatment with resin-coated sand. Well No. 35 completed in the second and third Corniferous reservoirs received a foam fracturing treatment without resin-coated sand. Well No. 32
completed in the first Corniferous 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 Corniferous reservoirs. On July 31, 1996, production was 0.5 BOPD and 4 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 Corniferous reservoir. On July 32, 1996, it was producing 0 BOPD and 51 BWPD. Treatment was unsuccessful.

This project demonstrated that foam frac with sand proppant is the most economically and technically successful procedure in this type of reservoir. Drilled 2nd well and foam fractured w/sand producing 2 BOPD and about 1 gallon of water per day. Wells typically produce low rates of oil and little if any water for many years.
Project 16. Gel Polymer Treatment
Gordineer Lease, Bartlesville Sand, Nowata County, Oklahoma

Grace Petroleum, operator
Dewey, Oklahoma

Technology Area: Water Production
Project Date: 10-1-1195 to 5-30-1997
Subcontract No. G4P51721

Cost Share:
Operator $ 56,000 (53%)
DOE/NPTO $ 50,000 (47%)
Total $106,000

Problem:
Water channeling causing low oil production and high water production.

Objective:
Treat the wet zone of an inverted five-spot waterflood pattern with a crosslinked polymer gel and compare the waterflood performance to an adjacent conventional, untreated inverted five-spot waterflood pattern.

Summary:
Use a gel polymer treatment to reduce water production from Bartlesville sandstone wells producing large volumes of water due to channeling. The producing wells were treated by injecting a volume of partially hydrolyzed polyacrylamide using a chromium cross-linking agent and ammonium salt to prevent clay swelling into the water zone of each well. Injection wells were not treated (possibly were treated as per presentation) with polymer. During the first 562 days, oil production increased from 12 BOPD to 19 BOPD, resulting in 2,907 incremental BO. Water production increased from 300 BWPD to 640 BWPD for an increase in WOR from 25 to 34. Although oil production increased 58%, water production increased 113%. Considering that the total cost of the project was $106,000 and that water disposal costs would have gone up significantly due to the increased volume, this project probably did not pay out. Even if production rates have been sustained, it would probably not be economic to expand the project, especially at current economic conditions. There is no information to indicate the current status of this project.

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 BOPD and 333 BWPD.
Project Description:
The project consisted of an 80-acre area with two adjacent 5-spot patterns. PAR Services treated the producing wells with approximately 100 barrels of gel polymer. The gel polymer used to threat the wells was HS-WSP partially hydrolyzed polyacrylamide 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:
Treated the oil zone with gel polymer then frack'd in an attempt to get a more horizontal rather than vertical fracture and got a little increase in production. Oil production increased from 10 BOPD in October 1996 to an average of 19 BOPD in April 1997.
Project 17. **Cost-effective Water Disposal**
Carmichael Sand, W. Lawrie Field, Logan County, Oklahoma

Harry A. Spring, operator
Ardmore, Oklahoma

Technology Area: Water Production
Project date: 05-30-1996 to 05-29-1997
Subcontract No. G4P60383

Cost Share:
Operator $27,500 (50%)
DOE/NPTO $27,500 (50%)
Total $55,000

Problem:
High water production causing high water disposal costs. Gas well making so much water that water disposal (hauling) became cost prohibitive and the well was shut-in.

Objective:
Install a down hole simultaneous gas production/disposal tool (DHI tool) to produce gas and economically dispose of produced formation water into a deeper formation.

Summary:
A commercially available down hole simultaneous gas production/disposal tool was installed in a watered-out gas well to produce gas and economically dispose of the produced formation water. The device allows gas production to occur while simultaneously allowing produced formation water to be injected into a lower formation without first being lifted to the surface. Additionally, dewatering of the producing formation near the well bore should allow higher flowing gas rates. The tool was installed in the well, but after several months of production the disposal zone pressured-up and would not take water with the existing pumping equipment due to the limited injection capacity of the disposal zone and a larger volume of produced water than was originally anticipated. The well was then abandoned due to the high cost of water disposal (hauling).

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. has developed a concurrent production-disposal tool to simultaneously produce gas and at the same time dispose of saltwater downhole. The tool is commercially designated as the Down Hole Injection (DHI) down hole simultaneous disposal and gas production tool. 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.
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 the surface, concerns about contaminating freshwater resources, surface solid, and other environmental problems are eliminated.

The Klick No. 1 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 4½ inch production casing was set at 3,398 ft. with 150 sacks of cement. The Carmichael sand was perforated at 3,192-3 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.

Project Description:
The Down Hole Injection (DHI) down hole simultaneous disposal and gas production tool, capable of displacing salt water downhole while simultaneously producing gas uphole from the same wellbore, was installed and tested in the watered out gas well. The device allows produced formation water to be injected into a lower formation without first being lifted to the surface while allowing simultaneous gas production to occur.

Results:
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 ¾ bpm at 400 psi, 1 bpm at 435 psi, and 1 ¼ bpm at 450 psi. Bleed off was the same for each pump rate at 375 psi in 290 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 production portion of the formation was reperforated at 3,286-90 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 of 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 test showed the fluid level 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 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 ¾ spm was acceptable. The gas production gradually increased from 10
mcf/d to a maximum of 75 mcf/d. A fluid level check showed fluid at 1,494 ft. The DHI tool was
disposing a calculated 314 bwpd at 9 /12 strokes.

Production leveled out at 30-40 mcf/d 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 pressured
was up to 2,091 psi. At this time, the Klick No. 1-13 well has been abandoned due to high water
production disposal costs. The well produced 9,086 mcf of gas during this time period.

Although the specific well conditions prevented continued use of this method, the test did
demonstrate the technical capability and economic feasibility of using the DHI simultaneous
disposal and production tool. 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 18. Gel Polymer
Bartlesville Sand, Bird Creek Field, Cleveland County, Oklahoma

Kenneth Y. Park, operator
Skiatook, Oklahoma

Technology Area: Water Production
Project Date: 10-15-1995 to 10-14-1996
Subcontract No. G4P51725

Cost Share:
Operator $ 50,426 (52.4%)
DOE/NPTO $ 45,807 (47.6%)
Total $ 96,233

Problem:
Low oil and high water production resulting in low recovery efficiency.

Objective:
Evaluate the effectiveness of injecting crosslinked polymer gel into the water zone of a sandstone reservoir to reduce the WOR in production wells.

Summary:
A gel polymer treatment was used to reduce water production from Bartlesville sand wells producing large volumes of water. The water zone in the producing and injection wells was treated with HS-WSP partially hydrolyzed polyacrylamide with a chromium cross-link agent and ammonium salt to prevent clay swelling. After treatment the oil production tripled and the water production doubled, indicating that the project produced favorable results.

Background:
Wells in this project are completed in a Bartlesville sandstone reservoir in the Bird Creek Field near Skiatook, in Cleveland County, Oklahoma. The two producing wells on the lease were producing 5 BOPD and 470 BWPD before polymer treatment and four wells were shut-in.

Project Description:
Kenneth Y. Park conducted a cost-shared gel polymer treatment program. The purpose of this project was to reduce water production. Cross-linked polymer was injected into the water zone of the reservoir in producing and injection wells. PAR Services treated the 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 polyacrylamide with chromium cross-linking agent. Ammonium salt was used to prevent swelling of the clay.

Results:
After treatment, lease production was initially 17.5 BOPD and 860 BWPD. Oil production tripled whereas water production doubled after treatment. Additional oil production may have been possible, but rates were limited by injection capacity. The water-to-oil ratio was lower than it was at the beginning of the project. The water-to-oil ratio was lower (WOR of 49) after
treatment than before treatment (WOR of 94). Water production was effectively decreased, but oil production decreased to 11 BOPD (6 BOPD incremental) shortly after treatment. Well productivity increased twofold and water production was effectively decreased, but oil production eventually essentially returned to pre-project rates shortly after treatment. All wells have since been shut-in except one. The one remaining well is producing 5 BOPD and 400 BWPD.
Project 19. **Oxygen Activation Log**  
Rodessa Sand, Bolton Field, Hinds County, Mississippi

J. R. Pounds, operator  
Laurel, Mississippi

Technology Area: Wellbore Problems  
Project Date: 04-15-1996 to 04-14-1997  
Subcontract No. G4P60305

Cost Share:  
Operator $72,400 (59%)  
DOE/NPTO $50,000 (41%)  
Total $122,400

Problem:  
Well shut-in due to holes in the casing.

Objective:  
Run an Oxygen Activation Log in the well to locate casing leaks, then repair with casing patch and/or cement squeeze.

Summary:  
It was proposed to use an Oxygen Activation Log to locate holes in casing for repair as a way of reducing costs. The oxygen activation log is sometimes used in water-injection wells. During initial investigation by the operator, the logging service company advised that the Oxygen Activation Log was not designed for casing hole detection in the particular situation that existed in the target well. The target well was on rod pump, shut-in, and not flowing. The logging tool requires the flow of water past the tool in order to be applicable. Conventional pressure testing methods were then employed to locate the casing holes and conventional casing leak repair methods were employed to successfully repair the leaks.

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. Pound’s personnel believed the hole had reopened and wanted to return this well to production.

Project Description:  
The operator proposed to locate the hole(s) in the casing using an Oxygen Activation Log.

Results:  
Initial investigation indicated that an Oxygen Activation Log is unsuitable for the proposed application. When the operator was ready to locate the holes in the casing, logging companies advised that the oxygen activation log was not designed for this problem. Therefore, conventional pressure testing was used to locate holes in the casing between 3307-3338 feet,
between 8403-8462 feet, at 8587 feet, and at 8618 feet. The holes were successfully repaired by conventional cement squeeze, the well was stimulated with acid, and oil production resumed. Maximum oil production after acid treatment was 40 BOPD on pump. As of August 29, 1996, the well was pumping intermittently and producing 30 BOPD with no saltwater.

The Oxygen Activation Log is used to detect water movement past the tool in a flowing well. The tool uses a neutron generator to temporarily activate the oxygen molecules in the water, then uses a set of detectors to detect the slug of activated water as it flows past the detectors. The volume, flow rate, etc. can then be calculated. The tool can be used through pipe or through perfs or in the flowing stream itself, but in all cases needs moving water to work, i.e., a flowing well.

This project failed to meet the requirements of the program because the proposed technology was not applicable to the situation and was not applied. The production problem was solved and the well was put back on production using conventionally available (non-R&D type) technology to solve and correct the problem.
Project 20. Microbial Cleanup of Paraffin
Camden Lewis Field, Lewis County, West Virginia

Rock Island Service Company, Inc., operator
Catlett, Virginia

Technology Area: Wellbore Problems
Project Date: 4-01-1997 to 3-31-1998
Subcontract No. G4P70041

Cost Share:
Operator $46,430 (50%)
DOE/NPTO $46,430 (50%)
Total $92,860

Problem:
Paraffin precipitation reduced productivity.

Objective:
Treat shut-in producing wells with a solution of microbial bacteria, surfactant, nutrients, and water down the casing to remove paraffin precipitation from the near-wellbore formation.

Summary:
Inject paraffin-mobilizing microbes, surfactant, and nutrients into each of 5 Salt Sand wells in the Camden Lewis Field in Lewis County, West Virginia, to remove paraffin precipitation in the producing formation to improve oil production. The five wells were treated, shut-in for a week, and then placed on production.

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 well 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 1700-1800 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:
Early indications were that for four of the five wells, production increased by 50% over pretreatment production and that the fifth well's production decreased by 50%. There was no decrease in production except for Well No. 5. The subject wells were last produced in 1984.
Total 1984 production was 1079 BOPY (3 BOPD), total 1998 production was projected to be 1535 BOPY (4.2 BOPD) for an increase of 42% to 456 BOPY (1.2 BOPD).

Well No. 1 1984 production was 302 BO, 1998 production is projected to be 512 BO.  
Well No. 2 1984 production was 241 BO, 1998 production is projected to be 342 BO.  
Well No. 3 1984 production was 223 BO, 1998 production is projected to be 298 BO.  
Well No. 4 1984 production was 200 BO, 1998 production is projected to be 341 BO.  
Well No. 5 1984 production was 113 BO, 1998 production is projected to be 43 BO.

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 the project on gas driven wells that make no water, the water will come back out.

The cost of reworking the wells in order to have all the wells on an equal basis, i.e., tubing free of paraffin and with new pumps in good working order, was underestimated when preparing the wells for the project. The operating costs 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. Treatment was successful, but required periodic re-treatment. Initial production increased by 50% the first week, 33.3% second week, then about 25% for quite a long time. Didn't produce back much sludge. Treatment wells were scattered over several leases. Rock Island planned to continue the wells on the program and to expand the treatment to additional wells. Could not continue re-treatments after project expired because of low oil prices.
Project 21. Microbial Wellbore Cleanup
Cypress Limestone, Posey County, Indiana @ 2,200 ft.

Speir Operating Company, operator
Albion, Illinois

Technology Area: Wellbore Problems.
Contract Date: 10-15-1995 to 10-14-1996
Subcontract No. G4P51724

Cost Share:
Operator $ 48,775 (50%)
DOE/NPTO $ 48,775 (50%)
Total $ 97,550

Problem:
Wellbore problems due to paraffin and sulfide scale which reduce productivity and injectivity.

Objective:
Evaluate the effectiveness of microbial well treatments for cleaning up production and injection wells to reduce operating costs and increase production.

Summary:
Treat nine producing wells and two injection wells with microbial solution to remove paraffin and sulfide scale in perforations, tubing, and the near-wellbore region to improve oil production. Following treatment, oil production and water injection capacity increased initially then returned to pre-treatment levels, indicating that repeated treatments would be required on a continuous 2-3 month interval to treat reoccurring buildup.

Background:
The project, which is located near Evansville in Posey County, Indiana, produces from the Cypress limestone at 2,200 feet. Paraffin and sulfide scale precipitation in perforations, tubing, and the near-wellbore region were reducing oil production, requiring hot oil and acid treatments. Nine producers and two injection wells were involved in the microbial test.

Project Description:
Speir Operating Company conducted a cost-shared project with DOE to evaluate the effectiveness of microbial well treatments for cleaning up production and injection wells. 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 emulsion. Treatments were repeated monthly through May, 1996.
Results:
Oil production, which initially increased from 7 BOPD prior to treatment to BOPD, stabilized at 13-15 BOPD. Injection improved from 20 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 22. Calcium Carbonate Prevention
Hosston Formation, Claiborne Parish, Louisiana

Tenison Oil Company, operator
Abilene, Texas

Technology Area: Wellbore Problems.
Project Date: 6-30-1996 to 5-31-1997
Subcontract No. G4P60385

Cost Share:
Operator $ 41,918 (53%)
DOE/NPTO $ 37,172 (47%)
Total $ 79,090

Problem:
Wellbore problems, i.e., pump sticking, rods parting, and worn parts due to calcium carbonate
(CaCO₃) scale deposition in the rod pumps.

Objective:
Prevent down-hole calcium carbonate scale deposition in producing wells by mechanical and/or
chemical solutions.

Summary:
Redesign the rod pump without a seating nipple and tubing anchor to reduce heat created by
friction and thus reduce calcium carbonate precipitation during production of Hosston Formation
wells in Northern Louisiana. The rod pump was redesigned to exceed the capacity of the well,
which allowed the well equipment to be adjusted to provide sufficient pump capacity even with
the tubing anchor removed. Following the remedial action, production from the two wells which
were modified has doubled.

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
CaCO₃ 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 wells have been on production. Before Tenison redesigned the pump, removed the tubing anchor, and kept the mud anchor, production was 10 BOPD. After remedial action, production has been 23 BOPD.
APPENDIX B

Program Description

This section consists of a discussion describing the goals, objectives, and requirements of the program, "Petroleum Technology Advances Through Applied Research by Independent Oil Producers."

The United States Department of Energy (DOE), through the Office of Fossil Energy National Petroleum Technology Office (NPTO), initiated a program, referred to as "Petroleum Technology Advances through Applied Research by Independents", to provide cost-sharing to small independent operators to help find solutions for their local production problems. The program intent was to encourage producers to apply higher-risk, unfamiliar technologies and/or novel, unproven approaches to solve their particular operational problems through field research demonstration projects. The program was intended to help the small independent oil producing industry maintain current production levels and to help curtail the premature loss of domestic production due to low economic conditions.

Many small independent operators lack the resources to test unfamiliar technologies or novel, unproven approaches without cost-sharing assistance to reduce financial risk. By providing cost-sharing, DOE has encouraged producers to experiment with higher-risk technologies to help solve their particular production problems. The program was primarily aimed at the use of innovative field application of technologies to increase production and to demonstrate the benefits of the applications to other operators.

The program was initially overseen through BDM-Oklahoma, Inc., (BDM), Management and Operating Contractor for the DOE/NPTO. Work for the program was completed under prime contract DE-AC22-94PC91008 at the National Institute for Petroleum and Energy Research (NIPER), Bartlesville, Oklahoma. BDM's role was that of administrator of the program; i.e., to select the projects for the program, monitor the individual project progress, insure that the program requirements were adhered to, and to distribute the cost-sharing funds to the project operators.

The support was to be provided by means of cost-sharing agreement subcontracts and was not to be considered as a grant to the operators. The prospective subcontractors were required to provide a minimum 50% cost-share, including in-kind contributions. DOE’s matching cost-share portion of each individual subcontract was not to exceed $50,000.

The program was intended to encourage smaller independent operators to utilize unfamiliar and innovative approaches to increase production, reduce operational costs, reduce environmental concerns, or develop new technology as a way of maintaining domestic production and recovery levels. The objectives of the program were expressed as follows:
1. Extend the economic production of domestic fields, thus slowing the rate of well abandonment's and preserving industry infrastructure (including facilities, wells, data, and expertise).

2. Increase ultimate recovery in known fields using advanced technologies by demonstrating:
   - Better methods of formation evaluation.
   - More efficient oil recovery and production technologies.
   - Well control and remedial work for environmental compliance.

3. Develop new technologies or expanded or improve the application of available technologies to solve production problems and/or reduce costs.

4. Use field demonstrations to broaden information exchange and technology application.

BDM issued a Research Opportunity Announcement (ROA), Number OKL-5027-01, soliciting proposals to a program generally entitled "Research and Development by Small, Independent Petroleum Operators to Provide Solutions towards Production Problems". A one-year response period between February 1, 1995, through January 31, 1996, was allowed for the contract process. Small independent petroleum operators were defined as: (1) operating onshore in the lower-48 states, (2) having no affiliation with a major oil or gas producer (domestic or foreign), and (3) employing no more than 50 full time company staff or contractors. The period of performance of a proposed project was ideally 24 months or less. Firm fixed-price cost-sharing subcontracts were solicited.

The types of technologies to be considered were not limited to, but could include reservoir characterization; well drilling, completion or stimulation; environmental compliance; artificial lift; well remediation; secondary and tertiary oil recovery; and production management.

The selection for subcontract awards was based on a scientific and engineering evaluation of the responses (technical and price/cost) to determine the relative merit of the approach. New and innovative concepts, ideas, and approaches were of primary interest and were ranked highest in the evaluation process. Proposals aimed at applying proven concepts received relatively low rankings. Price/cost was ranked as the second order of priority in the selection process. The technical and price/cost responses were evaluated concurrently.

A proposal was to consist of a fully completed and executed "Proposal Submission Form". The 6-page form, provided by BDM upon request was a "fill in the blank" format. Upon request, the contractor was to provide BDM with any or all data pertinent to the proposed project. With the assistance of BDM, the contractor was required to submit monthly, quarterly, and annual progress reports. BDM was to provide assistance to the contractor in the preparation of the progress reports, and BDM was responsible for preparation of a final report for each project. To assist in preparing the final report, the contractor was required to provide BDM with copies of daily production reports, maps of the lease, and site at which the work was to be done, available
well logs, cores and core data, well treatment history, and project pre-treatment and post-treatment production data. An environmental investigation of the offer could be made by BDM in support of a National Environmental Policy Act (NEPA) determination. As an integral part of the proposal, the contractor was required to demonstrate and implement an aggressive technology transfer plan primarily targeted for small independent petroleum operators.

The initial program was announced in February 1995 and initiated in September 1995. Over one-hundred proposals were received and evaluated, and twenty-two projects were awarded (about one in five proposals were approved) in nine specific technical areas; drilling, exploration, formation evaluation, improved oil recovery, operations, production problems, stimulation, water production, and wellbore problems. The first project was started in October 1995 and the last project was completed in April 1998. The typical project duration was about 12 months. Out of a total program expenditure of $3.5 million, the operators contributed a total of $2.5 million (71%) and DOE/NPTO provided $1.0 million (29%).

This Study

The “Petroleum Technology Advances Through Applied Research by Independent Oil Producers” program was initiated by DOE/NPTO to provide small independent operators with the means to help find solutions for their local production problems. The program, in the form of cost-sharing assistance, was aimed at encouraging producers to apply new technologies and new and innovative concepts, ideas, and approaches to solve their particular operational problems.

The goals and objectives of the program were to:

- Extend economic production of domestic fields.
- Increase ultimate recovery in known fields.
- Broaden information exchange and technology application.

Twenty-two individual projects were awarded and carried out under the terms of the initial 1995-1998 phase of the Support to Independents program. The initial phase of the program was entitled "Petroleum Technology Advances Through Applied Research by Independent Oil Producers".

In January 1999, a study was initiated by DOE/NPTO to review the twenty-two projects conducted through the initial 1995-1998 phase. The evaluation of the individual projects and the collective program was designed to determine the direct benefits of the program to the producers and to the nation and to improve the effectiveness of the DOE/NPTO technology transfer efforts.

The objective of the study was to evaluate the initial phase of the Support to Independents program to determine the benefits produced as a result of the program in terms of accomplishing the intended program objectives of increasing production, increasing reserves, or developing new technology.

The report presented herein describes the work performed during that formal study which sought to assess the extent the projects met their respective objectives and contributed to the program’s overall goals.
In February 1999, the Support to Independents program was extended to cover a second phase of field demonstration projects (entitled "Technology Development with Independents"). A cost-share arrangement, similar to the initial phase, was implemented for the new work. As a part of the present study the available material, data, and information pertaining to the initial phase of the program has been reviewed and analyzed to determine the effectiveness of the program as well as the benefits resulting from the program. It is intended that the results of this study will be useful in designing, managing, and administering that second phase of the program.
APPENDIX C

ECONOMIC PARAMETERS

This section contains definitions of the parameters and methods used in the economic analyses presented in the report.
Definitions

Incremental Production is the total volume of incremental production in barrels of oil equivalent (BOE) recovered due to the application of the project. Natural gas was converted to BOE by dividing the incremental mcf by 6.

Net Revenue Interest Income is the operators, or producers, share of the total incremental production, i.e., after deduction of the Royalty Owners allocated share of incremental production, times the sales price of the produced product.

Royalty is the volume of incremental production allocated to the Royalty Owner times the sales price of the produced product.

State Revenue is the total of Severance Tax (the Severance Tax on the Revenue Interest portion of the incremental production only), Ad Valorem Tax, and State Income Tax. NOTE: The State Revenue does not include any of the taxes associated with the Royalty Owner's allocation of incremental production.

Federal Revenue is the Federal Income Tax on the operator, portion of taxable income.

Net Cash Flow is the cumulative annual after-tax cash flow obtained from the operators’ share of revenue from incremental production less any capital investments, operating costs, severance taxes, ad valorem taxes, state income taxes, and federal income taxes.

Net Present Value (NPV) is the cumulative discounted net cash flow.

Economic Life is the number of years that the project results in sustained positive annual before-tax cash flow, also referred to as the economic producing life or the economic limit.

Investment Pay Out is the number of months required to recover the Capital Investment from the annual After-Tax Net Cash Flow.

Net Cash Flow per Incremental Barrel of Oil Recovered (NCF/BBL) is the cumulative after-tax net cash flow per unit of total incremental production, expressed in $/BOE.

Net Present Value per Incremental Barrel of Oil (or mcf of Gas) Recovered (NPV/BBL) is the cumulative after-tax net present value per unit of total incremental production, expressed in $/BOE.

Discussion

The projects which produced positive technical results were reviewed to determine the economic parameters (Capital Investment, Production Forecast, Operating Costs, etc.) necessary to conduct an economic evaluation of the project with which to quantify the economic benefits of the results. A review of the available data and information was conducted to obtain production and
cost data for the project economic analysis. Because of a general lack of detailed data (data requirements were not established when the program was initiated to specifically capture all of the data that would be necessary for a detailed economic analysis) some generalized, and reasonable assumptions were made regarding missing data. Often, results were only implied and/or imbedded within the information available.

The economic evaluation consisted of a set of standard economic calculations to determine the producing life (economic limit) and the net present value (NPV) and all of the economic factors (net revenue interest income, state and Federal taxes, cash flow, etc.) necessary to calculate these factors.

The results of the economic analysis should be viewed with due caution regarding the numerical results and should be considered as an indication of the likely outcome of the project based on the assumptions and premises which went into the analysis.

- Some of the project cost data was taken from the project proposal AFE and not actual incurred costs as some projects were modified during the demonstration period and final costs were seldom reported.

- Declining and continuing low oil prices during and following the project demonstration period continually changed and modified the project operations. In all cases, the cost data was examined to determine its reasonableness.

- The incremental costs incurred during the economic life of the producing property were separated into three cost components:
  - The incremental capital investment associated with the project (i.e., drilling and completion, equipping to produce, etc).
  - The incremental expense portion of the operating expenses associated specifically with the project (i.e., well work-overs, frac and stimulation treatments, existing pumping equipment replacement, polymer or MEOR treatments, monitoring and engineering, technology or software development, etc.) during the economic producing life of the project.
  - The incremental direct lease operating cost associated with operating the producing property (other than the incremental expense above) to the economic limit.

- Historic oil prices from EIA data through 1998, then O&GJ data for 1999 (an average of $17.50 WTI, adjusted for crude quality, $2.15 per mcf of gas was assumed for 1999 and beyond) were used for the base case.

- A base case was run for each project. This case analyzed the total project, i.e., total project costs (as best could be determined) and total project results (as best could be determined), and using the historical/gas price.
• It was assumed that the project would continue to produce to the economic limit (as determined from the economic analysis). Even though extremely low oil prices during late 1998 and into early 1999 caused some of the projects to become uneconomic and thus shut-in (and perhaps in some cases even abandoned, as far as the project technology application was concerned), it was assumed that the project would continue (or be restarted and continued) to the economic limit. Each operator (those operators who could be located) was contacted in early 1999 (Feb, Mar, Apr) in an attempt to determine the then current status of their projects.

• Generalized assumptions were made regarding royalties (1/8 royalty was used in all cases); actual state severance taxes, ad valorem taxes, state income taxes; and federal income taxes (35% was used as generalized average for each case as each individual operators particular tax situation would vary). Note: State and federal taxes do not include severance or income taxes on the Royalty Interest Income share of production.

• If the base case was indicated as uneconomic, additional economic cases were run using modifications to determine if there were conditions under which the project might become economic or break-even. Such as:

  – Higher oil prices of $20/BOE were assumed.

  – Subtracting out DOE's cost-share contribution so that operator's capital investment portion of the project cost reflected only his out-of-pocket cost to see if DOE's cost-share contribution would intended by the cost-share program).

  – Assuming the projects performed as predicted in the proposal or early project documents. This approach was and is scaling up the results for the projects operated by Cleary and X-TRAC.