# "ENHANCED OIL RECOVERY WITH DOWNHOLE VIBRATION STIMULATION IN OSAGE COUNTY OKLAHOMA"

## FINAL REPORT

## JULY 13, 2000 – JUNE 30, 2003

BY
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ISSUED NOVEMBER 2003

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| DOE Contract Number: | DE-FG26-00BC15191 |
| Contractor: | Oil & Gas Consultants International, Inc.<br>2930 South Yale Avenue<br>Tulsa, Oklahoma 74114 |
| Contract Date: | July 13, 2000 |
| Completion Date: | June 30, 2003 |
| Principal Investigators: | J. Ford Brett<br>Robert V. Westermark |
| Project Manager: | Virginia Weyland<br>National Petroleum Technology Office |

## *Disclaimer*

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## *Abstract*

This Final Report covers the entire project from July 13, 2000 to June 30, 2003. The report summarizes the details of the work done on the project entitled “Enhanced Oil Recovery with Downhole Vibration Stimulation in Osage County Oklahoma” under DOE Contract Number DE-FG26-00BC15191.

The project was divided into nine separate tasks. This report is written in an effort to document the lessons learned during the completion of each task. Therefore each task will be discussed as the work evolved for that task throughout the duration of the project. Most of the tasks are being worked on simultaneously, but certain tasks were dependent on earlier tasks being completed.

During the three years of project activities, twelve quarterly technical reports were submitted for the project. Many individual topic and task specific reports were included as appendices in the quarterly reports. Ten of these reports have been included as appendices to this final report. Two technical papers, which were written and accepted by the Society of Petroleum Engineers, have also been included as appendices.

The three primary goals of the project were to build a downhole vibration tool (DHVT) to be installed in seven inch casing, conduct a field test of vibration stimulation in a mature waterflooded field and evaluate the effects of the vibration on both the produced fluid characteristics and injection well performance. The field test results are as follows:

In Phase I of the field test the DHVT performed exceeding well, generating strong clean signals on command and as designed. During this phase Lawrence Berkeley National Laboratory had installed downhole geophones and hydrophones to monitor the signal generated by the downhole vibrator. The signals recorded were strong and clear.

Phase II was planned to be ninety-day reservoir stimulation field test. This portion of the field tests was abruptly ended after one week of operations, when the DHVT became stuck in the well during a routine removal activity. The tool cannot operate in this condition and remains in the well. There was no response measured during or afterwards to either the produced fluids from the five production wells or in the injection characteristics of the two injection wells in the pilot test area. Monitoring the pilot area injection and production wells ceased when the field test was terminated March 14, 2003.

Thus, a key goal of this project, which was to determine the effects of vibration stimulation on improving oil recovery from a mature waterflood, was not obtained. While there was no improved oil recovery effect measured, there was insufficient vibration stimulation time to expect a change to occur. No conclusion can be drawn about the effectiveness of vibration stimulation in this test.

The project was closed June 30, 2003.

## *Executive Summary*

### Contract Synopsis:

The DOE Grant Contract DE-FG26-00BC15191 was signed July 13, 2000. The project team at that time was composed of Grand Resources, Inc., Phillips Petroleum Company and Oil & Gas Consultants International and the field test was to be conducted on the Osage Reservation in a mature waterflooded field.

Under DOE advisement, the project activities began June 14, 2000, although the contract was signed on July 13, 2000.

Five contract amendments have been proposed and consummated.

1. Amendment M001 changed contract officers from Rhonda Lindsey to Virginia Weyland, replaced Grand Resources, Inc. with Calumet Oil Company as the operating company and moved the test pilot area from the Blazer field operated by Grand, to the North Burbank Unit field, operated by Calumet.
2. Amendment M002 added additional tasks for Lawrence Berkeley National Laboratory (LBNL) and Las Alamos National Laboratory (LANL), increase the grant amount to $670,750 and extending the completion date to Nov 12, 2001.
3. Amendment M003 reduced some project reporting requirements, dropped the LBNL and LANL tasks supported by the project and extended the project closing date to May 13, 2002.
4. Amendment M004 was the first "no cost" extension changing the project closing date to December 31, 2002
5. Amendment M005 was the second "no cost" extension received moving the project closing date to June 30, 2003.

### Financial status:

The following is an estimate of the contributions of each of the project participants:

| | |
|---|---|
| DOE | $ 675,750 |
| Seismic Recovery LLC | $ 451,075 |
| Phillips Petroleum | $ 162,375 |
| Calumet Oil Company | $ 336,475 |
| Grand Resources | $ 9,250 |
| Total Contributions | $ 959,175 |
| Total Project Cost | $ 1,634,925 |

## Project Key Dates and Activities

In Table 1 below is a synopsis of key dates and activities during the three-year project.

**U.S. Department of Energy Project DE-PS26-99BC 15191**
**"Enhanced Oil Recovery with Downhole Vibration Stimulation"**

| Project Phases | Date | | KEY Project Activities |
|---|---|---|---|
| **Pre-Project Phase** | Aug | 1999 | Submitted proposal |
| | Dec | 1999 | Proposal Selected |
| | Jan | 2000 | Began to Negotiate DOE Contract |
| **Start Date Blazer Phase** | Jul | 2000 | **Project Start Date July 15, 2000, Select Location** |
| | Aug | 2000 | Build Location, wait on drilling rig |
| | Sep | 2000 | Offset Cores to Phillips |
| | Nov | 2000 | Designing full size DHVT V 1.0 |
| | Dec | 2000 | Switch from Blazer to North Burbank Unit (NBU) |
| | Jan | 2001 | Began discussions with Calumet for NBU test |
| **North Burbank Unit Phase** | Feb | 2001 | Begin building DHVT V 1.0 |
| | Aug | 2001 | **Drilled cored, logged and cased Well 111 W 27** |
| | Sep | 2001 | Phillips starts NBU core studies |
| | Oct | 2001 | First Performance test of DHVT V 1.0 at Wynona, |
| | Nov | 2001 | Repair DHVT V 1.0 |
| | Dec | 2001 | Second Performance test of DHVT V 1.0 at Wynona, |
| | Jan | 2002 | Build Knights Pecan Farm (KPF) test facility |
| | Mar | 2002 | Testing DHVT versions 1.4 to 1.6 |
| | Apr | 2002 | Redesign DVHT with gears and self lubrication system |
| | Jul | 2002 | Built DHVT V 3.2 prototype with self lubrication |
| | Aug | 2002 | Testing DHVT V 3.2. |
| | Sep | 2002 | Start building DHVT V 3.2 |
| | Jan | 2003 | KPF Performance testing DHVT 3.2 |
| Start Field Test | Feb | 2003 | **Start NBU Field Test Feb 14, 2003** |
| End Field Test | Mar | 2003 | **End NBU Field Test March 14, 2003 DHVT V 3.2 Stuck in Well 111W 27** |
| | Apr | 2003 | Process and analyze field test data |
| | June | 2003 | **Close out project** |
| | Nov | 2003 | Final Report issued |

**Table 1 Project Key Dates and Activities**

## Technical Conclusions:

The three primary goals of the project were:

1. to build and test a downhole vibration tool (DHVT) to be installed in seven inch casing
2. conduct a 90-day field test of vibration stimulation in a mature waterflooded field
3. evaluate the effects of the vibration on both the produced fluid characteristics and injection well performance.

*Build and test a downhole vibration tool (DHVT) to be installed in seven inch casing*
The project accomplished this goal, although it required a major tool redesign. The initial project estimates for building and testing a vibrator to run in seven inch casing were quickly eclipsed when the first vibrator version proved to be unable to operate at high force levels. To expedite the testing of the original and subsequent designs, a test site was built which could test prototype and full size tools. The test site was cost effective and facilitated in proving the final version of the vibrator was ready for the field stimulation test.

*Conduct a 90-day field test of vibration stimulation in a mature waterflooded field*
The value of the project centered on conducting a vibration stimulation field test and a comparison with laboratory results from sonic core tests. To possibly provide technical understanding of the process of, the field test was conducted in conjunction with Phillips' unique laboratory sonic core tests.

To be able to make a controlled comparison from lab data with field data, an extensive data collection system was operated prior to and during the field stimulation test. Due to delays in tool construction, baseline production and injection information was collected for nearly two years prior to commencing the field test. Real-time injection and production data was being collected during the field test. Unfortunately, the test did not run the proposed 90-day period due to mechanical difficulties in retrieving the vibrator for routine maintenance. The field test was abruptly terminated after running the tool approximately 40 hours during a five-day period of initial operations.

*Evaluate the effects of the vibration on both the produced fluid characteristics and injection well performance.*
Although the field test was much shorter than originally planned, the data collected prior to and during the actual vibration stimulation was as used to determine if any changes in either injection or production characteristics occurred. Produced fluid samples, oil water ratios and well tests remained constant during the time just prior to starting the field test and when the test was terminated. Water injection rates and pressures in the two pilot injection wells remained constant, allowing for recognized daily fluctuations due to the operations of the injection system.

Thus a primary goal of this project, which was to determine the effects of vibration stimulation on improving oil recovery from a mature waterflood, was not obtained. While there was no improved oil recovery effect measured, unfortunately there was insufficient vibration stimulation time to expect a change to occur. No conclusion can be drawn about the effectiveness of vibration stimulation in this test.

## ACKNOWLEDGEMENTS

The field-testing of downhole vibration stimulation described in this report was supported by the U.S. Department of Energy, National Energy Technology Laboratory under contract DE-FG26-00BC15191. For their guidance, timely and helpful suggestions, and unwavering support, we would like to thank Rhonda Lindsay and Virginia Weyland, of the NETL Tulsa office as the initial and present representatives of the contracting officer for the project. In addition, a special thanks goes to Jolene Garrett for her assistance in tracking the project reporting requirements and to Susan Jackson for organizing the field trip to the project site.

The Osage Tribal Council and former Principal Chief, Charles Tillman, are recognized for their strong endorsement and support of the project and to Joe Hughlett, petroleum Engineer for the Osage Tribe, for frequent conversations regarding progress of the project.

Special recognition needs to be given to Calumet Oil Company and their subsidiaries Green Country Submersible Pump Company and Green Country Supply Company. Specifically, the cooperation and support given by Jack Graves and his organizations is truly appreciated. The following personnel are but a few of those who significantly supported the field operations during the project: David Spencer, Richard Langston, Wayne Porter, Jim Adair, Roy Franklin, Anna Lawless, Bob Allen, Bill Morrison, and Hoot Gibson.

Genuine appreciation is given to David Zornes, Dan Maloney, Terry Siemers, Johnny Jack and others at Phillips Petroleum Company for their interest in advancing this tantalizing technological concept. Specific kudos are given to Phillips for sharing with the project their sonic core test technology.

Recognition is given Marvin Robinowitz, president of Grand Resources, Inc. for his enthusiasm in the initial efforts to evaluate this technology in the Blazer Field, Osage County, Oklahoma.

The following organizations and individuals were very important to the project and to each person is extended a sincere and heart felt “Thank You” in recognition of their part in this project:

Ernie Majers, Tom Daley, Dale Cox and Cecil Hoffpauir from Lawrence Berkeley National Laboratory for conducting the downhole seismic monitoring efforts during Phase I of the field test.

Peter Roberts from Las Alamos National Laboratory for his support in advancing awareness of this emerging technology both with laboratory experiments and monitoring field tests.

John and Janie Carter at Machine Engineering, who built the evolving versions of the DHVT and made it a pleasure working in their shop for the past three years.

Bob Knight, owner and proprietor of Knights Pecan Farm, for his support of the DHVT reliability and performance testing conducted on his property.

Jack Cole and Will Myers for their engineering work, design efforts and insight in orbital vibrators.

Scott Lovin, president of Samuel Technical Services, for his ideas on tool design and his untiring efforts in keeping the ever growing data acquisition system running.

We would like to thank the following OGCI-Seismic Recovery LLC personnel for their work in supporting the project: Dennis Wing, Terri Cotton, Donna Forslund, and field operations specialist, Joey Turner.

Sincerely,

Bob Westermark

Ford Brett

## *Background*

### LOS ALAMOS NATIONAL LABORATORY (LANL) PROJECT

In 1997, OGCI became aware of LANL's Natural Gas and Oil Technology Partnership (NGOTP) sponsored Seismic Stimulation Project. OGCI joined the project in 1998 and agreed to contribute the use of OGCI's vibration technology for possible application in reservoir stimulation.

Two of the LANL Seismic Stimulation Project meetings were attended in which the principal investigator, Peter Roberts shared his on going laboratory work and a storehouse of literature on Russian work on this technology.

The cornerstone of technical papers on vibration stimulation published in the United States is the Beresnev and Johnson[1] paper published in 1984. This was a joint effort between a LANL researcher and a visiting Russian scientist. This paper reviewed efforts from around the world where various types of vibrations were being applied to increase oil production. The value of the Beresnev and Johnson paper is the review of the impact of the full spectrum of vibration frequencies from earthquakes to ultrasonic of over 50,000 hertz. Of the many papers discussed, a large number were originally written in Russia. In their bibliography are numerous English translations of Russian papers dealing with vibration stimulation both from laboratory and field data. A paper entitled "Residual Oil Reservoir Recovery With Seismic Vibrations," by Nikolaevskiy, V.N. [2] et al, focused on the concept of a dominant or natural frequency of the reservoir.

### PHILLIPS PETROLEUM SONIC CORE TEST CELL PROJECT

While working on other projects with the Phillips research group, in 1997, OGCI was informed about the investigation Phillips was conducting with regard to vibration stimulation laboratory studies. Phillips was designing a modified core test cell to be able to measure the effects of vibration while conducting core waterflood tests. It was through Phillips that OGCI learned of the LANL project.

### DOE SOLICITATION DE-PS26-99BC15184 "APPLICATIONS OF PETROLEUM TECHNOLOGIES ON NON-ALLOTTED NATIVE AMERICAN AND ALASKAN NATIVE CORPORATION LANDS"

OGCI had developed, tested and patented a compact, but very strong downhole seismic vibrator. Encouraged by the LANL research and the interest expressed by Phillips in supporting a field test demonstration project with their proprietary sonic stimulation capabilities, OGCI submitted a proposal to the above solicitation. The field test was to take place in a mature waterflooded oil field on the Osage Mineral Reservation, Osage County, Oklahoma.

In late December 1999, OGCI was informed that their proposal was one of the selected projects. Contract negotiations ensued with DOE and the grant contract, DE-PS26-99BC15191, was finalized in June 2000. The project start date was July 13, 2000.

## *INTRODUCTION*

The objective of this project was to demonstrate the impact of downhole vibration stimulation on production rates in a mature waterflood field. To achieve the project objectives, the work was divided into the following nine tasks; some were concurrent, while other tasks relied on completion of preceding steps.

Task 1 Determine appropriate pilot test area and location of vibration stimulation well.
Task 2 Drill, core, log and cement 7" production casing in a dedicated vibration stimulation well.
Task 3 Conduct sonic core tests to determine fluid flow response to a range of vibration frequencies.
Task 4 Design, build, and test a new version of the downhole vibration tool.
Task 5 Instrument the vibration test well, monitor seismic signal characteristics in an offset well(s) and monitor and record production and injection well operating parameters.
Task 6 Conduct a ninety-day vibration stimulation field test.
Task 7 Report and analyze the results of the vibration stimulation field test.
Task 8 Perform technology transfer using workshops, technical papers and other appropriate venues.
Task 9 Close out the project.

## Lessons Learned

The following is a brief discussion of each of the project tasks and with hindsight, how each decision was based on newly developed data and the affects of those decisions on both parallel and sequential tasks.

Task 1 Determine appropriate pilot test area and location of vibration stimulation well.

This task was perhaps the most critical for understanding the possible influence vibration stimulation might have in enhancing oil recovery. The underlying concept for this task answers the question: "Why not use an existing well rather than drill a new well?"

There were three primary reasons to drill a new well:

1. The idea of generating and then relating laboratory sonic vibration core test results with field test vibration stimulation results was the basic reason Phillips was interested in participating in this project. To accomplish this concept, new cores from the field test pilot area would be required to allow this direct comparison.

2. The necessity of a properly cemented casing string to transmit vibrations into the formation was paramount in placing the vibrational energy into the reservoir rather than just shaking an un-cemented casing string. Also to reduce potential problems of damaging the integrity of the production casing, confidence in the mechanical condition of the casing and the quality of the cement job were necessary. New properly cemented casing would satisfy these requirements

3. The ability to differentiate between near wellbore effects and the impact on fluid flow in the reservoir from the vibration stimulation was considered critical. To accomplish this, a new well would be drilled in the pilot area and not be perforated. Thus the only change to the reservoir dynamics in the pilot area would be the introduction of the vibration energy. Therefore, if a change in either the production or injection characteristics were measured during the field test, it would be reasonable to conclude the change occurred in the reservoir due to the vibration stimulation operations and not due to changes in near well bore flow characteristics.

The reason Task 1 was performed twice during the project, first for the Blazer field and then for the North Burbank Unit field, is explained below.

The initial active participants in the project were Phillips Petroleum Company, Grand Resources and OGCI. After a review of Grand Resources operated fields in Osage County, the Blazer field was selected to be the original pilot test site and a test well location selected. There were excessive delays while waiting for the availability of a drilling rig to drill the test well. During which time, Grand Resources located a core from an offset well to the Blazer field. It was decided to conduct a preliminary sonic test on this offset core, while waiting for an available drilling rig.

While conducting a sonic core test from an offset well was not in the original project plan, it provided Phillips and the project an opportunity to compare the Blazer offset sonic test results with other sonic core test results that Phillips had performed on cores from another Osage County mature waterflood field. The results on the Blazer offset sonic core tests were discouraging; to the point of rejecting the Blazer test site and relocating to another test site.

Prior to joining the project, Phillips had conducted sonic core tests with positive results on cores from the North Burbank Unit (NBU) field in Osage County, OK, a field Phillips had operated for more than sixty years. Phillips had sold the NBU field to Calumet Oil Company in November 1995. When faced with re-locating the pilot areas test site, the NBU was first on the list of test site candidates. Consequently, Calumet was contacted and the details of the DOE project to date were presented. Calumet was interested in testing the technology at the NBU and agreed to join and support the project. Calumet Oil Company replaced Grand Resources as the independent operating company in the project. The field test would be conducted in the NBU field.

In concert with the Calumet staff, a review of the NBU field was conducted and a new pilot test area was selected. Details on the selection process for both pilot areas can be found in the Results and Discussion, Task 1 section of this report.

By the time the new pilot area was selected and the test well location determined the project was eight months behind schedule. However, Calumet injected a new enthusiasm into the project and was able to provide substantial technical and field support through their subsidiary Green Country Submersible Pump Company.

Task 2 Drill, core, log and cement 7" production casing.

While this task is straightforward, when considering the above discussion, it can be seen that external events controlled when the pilot test well was drilled and sonic core test results from the offset core influenced where the well would be drilled. It was serendipitous that while waiting for a drilling rig, Phillips had time to perform the sonic tests on an offset core, which allowed the quality of the Blazer field as a test site to be determined. Certainly changing operating companies introduced a delay in the project schedule, but there was a strong consensus that by doing so, the probability of a successful field test was greatly improved.

In August 2001, the test well, NBU 111 W-27, was drilled, cored, logged and the casing cemented as planned. Three cores were cut resulting in 87' of recovered core. In the second core, approximately 16' of fractured core was recovered. The details of the drilling operations and a geologic report for well 111 W-27 was provided by Calumet and can be found in Appendix A of this report.

The initial location for the test well was built at Blazer (but not used) in August 2000, the NBU test well was drilled one year later; this was significant delay in a project that was originally scheduled to last 16 months. The need to amend the original contract was addressed by extending the project completion date from November 12, 2001 to May 12, 2002.

Task 3 Conduct sonic core tests to determine fluid flow response to a range of vibration frequencies.

Phillips had been researching the effects of vibration as a possible means for improving oil recovery for several years prior to joining this project. The opportunity to investigate the scaling effect from laboratory results to field test results provided the impetus for Phillips to share with the project members the confidential results of their work. Based on available literature on this technology and with knowledge gained from their lab work, it was hypothesized that there should exist a relationship between vibrational frequencies and intensities with changes in fluid flow in a reservoir.

Several Russian researchers have published reports on their identification of resonant frequencies for stimulating a particular reservoir. It has been theorized that the resonant frequency would be a function of the rock type and rock properties, reservoir thickness and fluid saturations. Phillips was pursuing the identification of a resonant frequency in the lab tests. If a resonant frequency could be identified in the lab, the final assembly of the DHVT could be altered to allow the maximum out put energy to occur at the desired frequency range. Furthermore, it was hypothesized that a reservoir resonant frequency might also be identified during field-testing and this became one of the goals for Task 5.

Phillips, under the guidance of David Zornes, reservoir section manager, did extraordinarily fine work in analyzing and performing tests the cores from well NBU 111 W-27. Dan Maloney, the principal researcher on the sonic core test cell contributed two technical reports to the project, the first covering the preliminary sonic core study on the Blazer offset well. This report is found in Appendix B. It was a pivotal report for the project because, based on the results from that work, the location of the project was change from the Blazer field to the NBU field.

Maloney's second report encompassed the routine core analysis work done by Phillips core lab and the special sonic core tests. The full report can be perused in Appendix E. This report reviews in detail the results of the sonic core tests performed on the NBU core samples. Dan co-authored SPE paper 67303, the first technical paper on the project, which has been included as Appendix I. He also gave one of the presentations at the SPE/DOE IOR Symposium Sonic Stimulation Workshop, held in April 2002.

Geologist, Terry Siemers, wrote the other major report contributed by Phillips. In his report, Terry examined the NBU core and reported on the lithology, stratigraphy and sedimentology observed in the core samples. This "Core Petrology Report for well NBU 111 W-27" was distributed in the Quarterly Technical Progress Report for the period ending March 31, 2002 as Appendix B, which was the seventh of the twelve quarterly project reports.

Task 4 Design, build, and test a new version of the downhole vibration tool.

The pre-project version of the OGCI vibration tool was called Downhole Seismic Mass (DSM). It was built in 1992 to go into 8 5/8 inch casing, was run a hundred and twenty feet down in an dry (empty) Amoco test well and powered by a hydraulic motor with hoses connected to the surface. It successfully performed seismic signal generation tests at the former Amoco geophysical test facility nears Mounds, OK, ten miles south of Tulsa.

The tool specifications for the DOE project required that the tool would need to run in 7 inch casing, approximately 3000 feet deep, submerged in wellbore fluid, and run continuously for weeks at a time with no maintenance. The DSM was re-designed to meet these criteria. The new tool was called a Downhole Vibration Tool (DHVT).

The full size 7-inch tool was built and shop tested satisfactorily at low RPMs. The initial fully operational tests for this version were called the power source field tests. These tests required a workover rig to run the tool into the well. Calumet provided a workover rig and offered the use of an idle well with 7-inch casing, in the fall of 2001. The two power source field tests were conducted at Calumet's Wynona field in Osage County in October and again in December 2001. When this version was run at full RPM, several design problems became evident. The total combined run time for the two tests was only 30 hours, which was unsatisfactory. Details of this testing program can be found in Appendix C DHVT Power Source Field test Report. It was clear that there needed to be a more economical method of operationally testing the full-size DHVT.

To facilitate a more efficient means of testing the full size tool at high load level, a test facility was built in January 2002, at Knight's Pecan Farm (KPF), south of Tulsa seventeen miles. Numerous changes in material, finishes and tool hardness in DHVT V 1.0 were tested between January and March of 2002. The basic design problems could not be resolved. In April 2002, it was decided that the tool needed to be re-designed and a new tool built for the field test at NBU.

Jack Cole, a professor at the University of Arkansas, was contracted to assist in redesigning the tool. Dr. Cole has numerous patents on downhole vibrators from his time at Conoco's geophysical research facility in Ponca City, OK. Jack and his associate, Will

Myers, developed several potential designs; the one selected was designated DHVT Version 3.2.

A full diameter prototype of DHVT V 3.2 was built and tested satisfactorily during the summer of 2002 at KPF. Substantial testing was performed on this version of the tool. During the reliability test, the prototype ran forty 24-hour days with no noticeably wear. This design performed exceedingly well. Appendix D is the "DHVT Reliability Test Report".

Building the full-size field test version was started in September 2002. It was assembled in January 2003 and tested satisfactorily at KPF. The "DHVT V 3.2 Performance Test Report" can be found in Appendix F.

The field test began February 12, 2003. Originally the field test had been scheduled to start in January 2000. This represents a delay of two years based on the original project schedule. The need to re-design, build and function test a new version of the tool had a very significant impact in extending the duration of the project, as well as, the total cost.

Task 5 Instrument the vibration test well and an offset well to monitor seismic signal characteristics.

This task was accomplished by completing three separate operations by three different groups.

The first sub-task was to modify the tank battery at the pilot test area. Calumet quickly performed this operation by setting equipment that was dedicated to handling only the produced fluids from the five producing wells in the pilot test area. This allowed Calumet to began gathering baseline pilot area production information in April 2001, four months before the well was drilled. They continued to gather on a daily basis, both production and injection information, until the field test was terminated.

The second sub-task was to build a data acquisition system to record the DHVT performance during all testing operations. This spanned the requirements for the tests conducted in the machine shop, at the KPF test site, during the Wynona field test and the NBU field test. During the NBU field test, 26 different parameters were being recorded or controlled by the data acquisition system. Scott Lovin built this system, he has also built data acquisitions systems for Amoco and Baker Hughes. He did a remarkable job in building the necessary flexibility to adapt the system to such varied test operating conditions.

The third group was the team from Lawrence Berkeley National Laboratory (LBNL). Ernie Majer, the group leader, possesses the patience of Job. His team needed to be mobilized from Berkeley, CA to conduct a short-term monitoring operation of the DHVT. There were at least four aborted mobilization efforts during the last two years of the project, due to delays in the getting the final DHVT version ready for the NBU field test.

The LBNL team had two goals while conducting their activities during Phase I of the NBU field test; one goal was to record the seismic signal generated from the DHVT using downhole geophones and hydrophones run in adjacent idle wells, the second goal was to identify a resonant reservoir frequency if possible. The first task was accomplished with stellar results. The LBNL tools recorded strong and clear seismic signals downhole in two different wells that were more than 1200 feet from the well with the DHVT. However, with the second goal, the preliminary field evaluation of the recorded signals concluded there was no discernable resonant frequency effect. LBNL has not issued a report covering their involvement in the NBU field test. Appendix G contains a copy of Dale Cox's field notes during the LBNL activities at NBU.

During the field test, the desirability of a two-computer data acquisition system became apparent. The amount of data generated (hundreds of gigabits) lead to using an external hard drive for adequate back up of information. However having all systems running on one computer was risky. Using two computers would have allowed for redundancy and recording data at different collection rates.

Task 6 Conduct a ninety-day vibration stimulation field test.

The field test was designed to be conducted in two phases. Phase I was underway on February 12, 2003. The tool performed as designed while the LBNL team was on location, recording the downhole seismic signals.

This also provided time to understand the performance of the DHVT. After four days of adjusting operating parameters the tool was ready to be run around the clock to begin the vibration stimulation experiment. Suddenly, the on-board sensors indicated a substantial internal temperature rise and subsequent erratic data recordings, indicating possibly damage to the electronics.

It was decided to pull the DHVT inspect and repair it, if necessary. On March 7$^{th}$ Calumet moved their rig on location to retrieve and inspect the tool. The tool had been pulled up approximately 400 feet from the well when it became stuck approximately 2500 feet from the surface. The tool remains stuck in the well.

The estimated cost to remove the tool from the well ranges from a minimum of $65,000 to a possible $250,000. There is a very high probability that the tool will be totally destroyed in attempting to remove it from the well. Calumet and OGCI are continuing to discuss all options concerning tool retrieval possibilities including plugging the well with the tool in place. The removal operation will be carried out after the DOE project is closed out.

Task 7 Report and analyze the results of the vibration stimulation field test.

The results of the vibration stimulation field test are that no conclusion can be made on the effectiveness of this vibration stimulation technology for improving oil recovery in mature waterfloods. The operating time was insufficient to reasonably expect changes in the operating parameters of the offset producing and injection wells.

Thus, a primary goal of the project cannot be satisfied, which was to determine the effectiveness of vibration stimulation. This is very disappointing for all concerned. But with the project delays, carrying the project cost for the two six month extensions, and the loss of the tool has forced Calumet and OGCI to agree to stop the project. The results of the field test are fully documented in Appendix H.

Task 8 Perform technology transfer using workshops, technical papers and other appropriate venues.

Over the course of the project, numerous efforts at technology transfer were undertaken. The upside potential of vibration stimulation in recovering by-passed oil in old waterfloods certainly captured the imagination of some die-hard independents, who only wanted to be shown that it worked if only just a little. But that did not happen. If the project had experienced even a glimmer of enhanced oil recovery with vibration stimulation, this technology transfer list would be considerably longer.

In the technology transfer section in the body of the report is a list of all the efforts made to spread the word about vibration stimulation as a possible IOR technique.

Two SPE papers were written and presented, a one-day workshop was held at the SPE/DOE IOR Symposium in Tulsa in April 2002 and attended by a international group of interested professionals.

A paper was presented at the DOE/Oklahoma Geologic Survey Symposium in Oklahoma City in May 2001 and an article was published in OGS Circular 107, the proceedings from that meeting.

A presentation was given at the final LANL Seismic Stimulation Project Meeting April 25, 2001, at Berkeley; co-sponsored by Las Alamos National Lab and Lawrence Berkeley National Lab.

The material was also presented, by invitation, at the Petroleum Technology Transfer Council / Marcus Evans conference on Maximizing Recovery 2001 June 25-26, 2001 in Houston. This was one of four presentations given on seismic stimulation efforts by different organizations given to managers of technology development for operating companies.

The Osage Tribe hosted on September 23-25, 2001 the Osage Oil and Gas Summit in Tulsa Oklahoma. Seismic Recovery, LLC was invited to set up booth and display information concerning the vibration stimulation project; Seismic Recovery LLC was pleased to attend the conference as a vendor. The strong attendance to the conference was encouraging, as were the questions from attendees concerning this novel technology. The model of the downhole vibration tool was the high interest point for our display. The working model, even though it is only 2 inches in diameter, grabbed everyone's attention when the floor around the booth began shake as the vibrator was being revved up.

A project summary was presented by invitation to the Society of Exploration Geophysists Development and Production Forum, July 21-23, 2003, in Big Sky MT.

Task 9 Close out the project.

Twelve quarterly technical reports with numerous appendices have been prepared and distributed, documenting all tasks of the project. This final task began in March 2003 after the tool became stuck in the test well and the field test was terminated. Ten appendices have been included in the final report, with the intention of providing a concise document covering the critical aspects of the project.

A project summary meeting was held at DOE's Tulsa NETL office with both the initial and second contract officer representatives present to review the field test results and provide guidance in preparing the final report. In addition, Jolene Garrett of the Tulsa office of NETL has been very helpful through the project in keeping track of the reporting requirements and has continued to provide guidance as the project is being closed out.

## *Task Results and Discussion*

*TASK 1: DEFINE MOST APPROPRIATE TEST AREA*

- *MEET AS TEAM TO REVIEW FIELD PRODUCTION HISTORY AND SCOPE POSSIBLE LOCATIONS.*
- *REVIEW WELL LOGS, PRODUCTION RECORDS ETC. AND DETERMINE A PROPOSED TEST WELL LOCATION*
- *MEET TO DEFINE DRILLING LOCATION*
- *REPORT TO OSAGE TRIBAL REPRESENTATIVES OF PROJECT PLANS*

As discussed in the introduction section, Task 1 was actually performed twice, once for the Blazer field at the beginning of the project and again after changing the operating companies and the re-locating the pilot area for the field test to the North Burbank Unit field.

To provide insight into the process a short explanation of the process used for the Blazer field will be given, then a more complete discussion will cover the NBU process.

### BLAZER PILOT FIELD TEST AREA

The first pilot site was planned to be in the Blazer Field, Osage County, OK, Figure 1, and operated by Grand Resources, Inc. The field was discovered and developed began

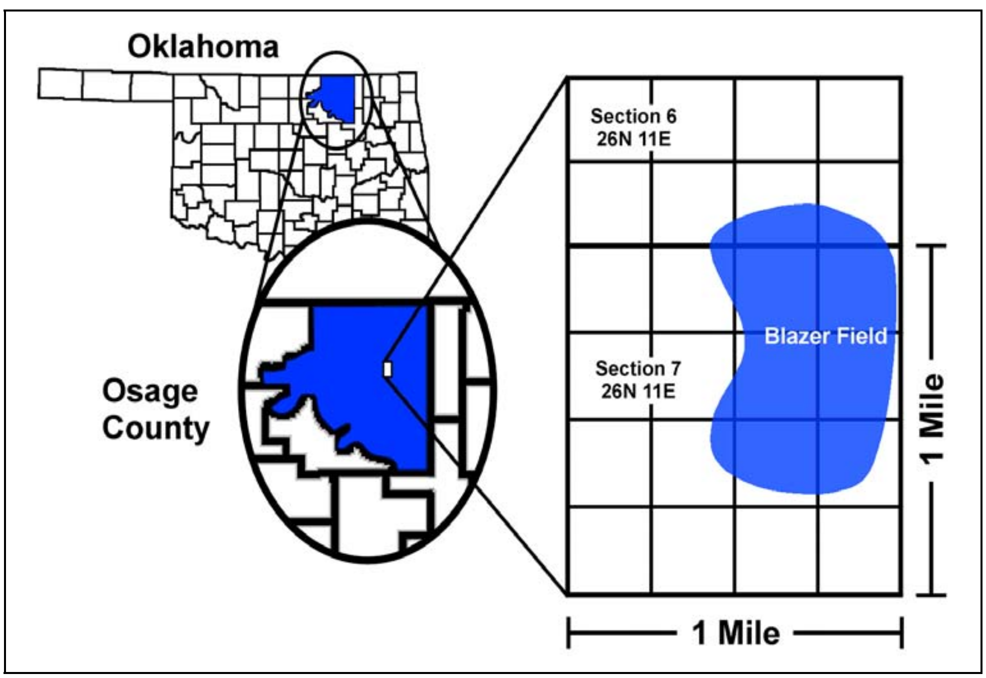


**Figure 1 Blazer Field Location, Osage County Oklahoma**

in 1984, with the waterflood starting in 1989. In 2000, the field was producing 10 bopd and 200 bwpd. It seemed to be a typical Bartlesville reservoir with projected secondary recovery cumulative production approximately equal to primary cumulative production.

Using the Blazer individual well production and injection records, well completion histories and cross-sections based on logs, the location of the vibration stimulation well was selected. Three criteria were used to assist in determine the location for the test well:

1. Select an area that has good net pay for this field, in this case about 12 ft.

2. Select an area that has good residual oil saturation. This was determined with a geo-microbial survey, which indicated higher levels of hydrocarbon remaining in south end of the field.

3. Locate the vibration well close to a producing well to maximize strength of vibration.

   The well was planned to be drilled approximately 200' from two producing wells and approximately 300 ' from the nearest injection well. A rough surface terrain impacted in the actual location, due to construction and run-off considerations.

The well location was built and a rig contracted to drill the well in September of 2000. Unfortunately, the drilling rig was damaged in a road accident while moving to the Blazer location. The damage to the rig required months to repair. During that autumn, a mini-drilling boom for coal bed methane wells was occurring in northeast Oklahoma. After the rig accident the well went back on several contractors' waiting lists. Ultimately, the Blazer pilot test area was found to be undesirable based on Phillips sonic core test results on an offset core (details of this sonic core test are found under Task 4). The Blazer well was not drilled and the field test was moved to the North Burbank Unit, (NBU) operated by Calumet Oil Company.

**NORTH BURBANK UNIT PILOT FIELD TEST AREA**

The North Burbank Unit is called the crown jewel of Osage County, and it is the largest oilfield in the county, see Figure 2 for the location of the NBU.

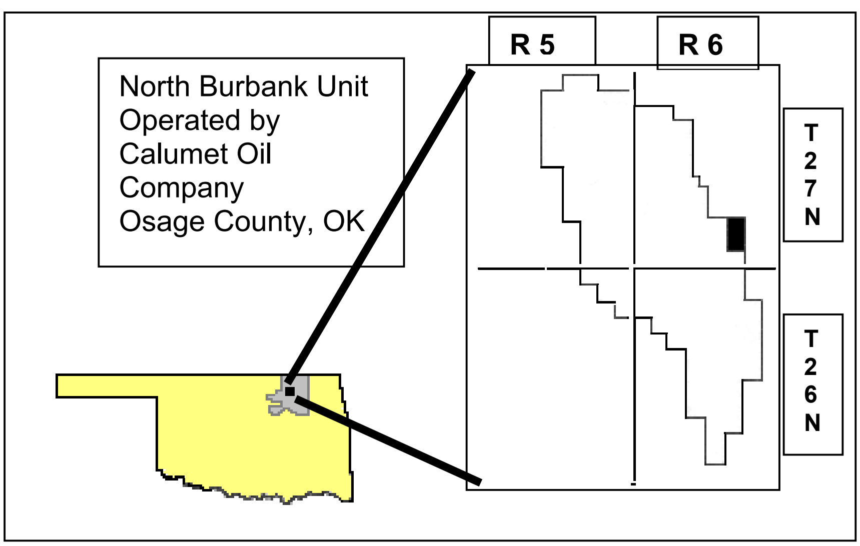


**Figure 2 Location of the North Burbank Unit Field, Osage County, OK.**

NBU underwent waterflooding in the 1950s. It was sold to Calumet Oil Company in 1995. The present production is 1200 bopd and 180,000 bwpd yielding an average field wide oil cut of less than 1%. The location of the vibration stimulation pilot area with respect to the entire field is seen in Figure 3.

The screening criteria for selecting the test location in the NBU were slightly different from the Blazer criteria, mainly due to the improve quality of the reservoir. The selection criteria were as follows:

- The area should have good pay thickness (greater than 40') but low initial production tests (less than 500 bopd IP). The area should have wells which may not have been flooded as thoroughly as wells with better thickness and higher initial production tests.
- A single tank battery should service the area, this will reduce complications when testing the wells and determining changes in oil production.
- The area should have been under flood with the same pattern for at least one year, this will aid in establishing a solid baseline for production profiles prior to initiating the vibration simulation.

Two meetings were held to discuss the test well location in the NBU. The first was a general review of the entire field operations. Four areas met the first criteria listed above, having good pay thickness but low initial production rates. The next meeting reviewed the production equipment facilities, active and inactive wells available, and the time frame of the current injection and production well configuration. This short-listed the potential areas to two sites. Then consideration of electric power accessibility, surface topography and land use allowed for the final selection of Section 8 T26N, R6E, also known as NBU Tracts 111, 112, 117 and 118. Please refer to Figures 3.

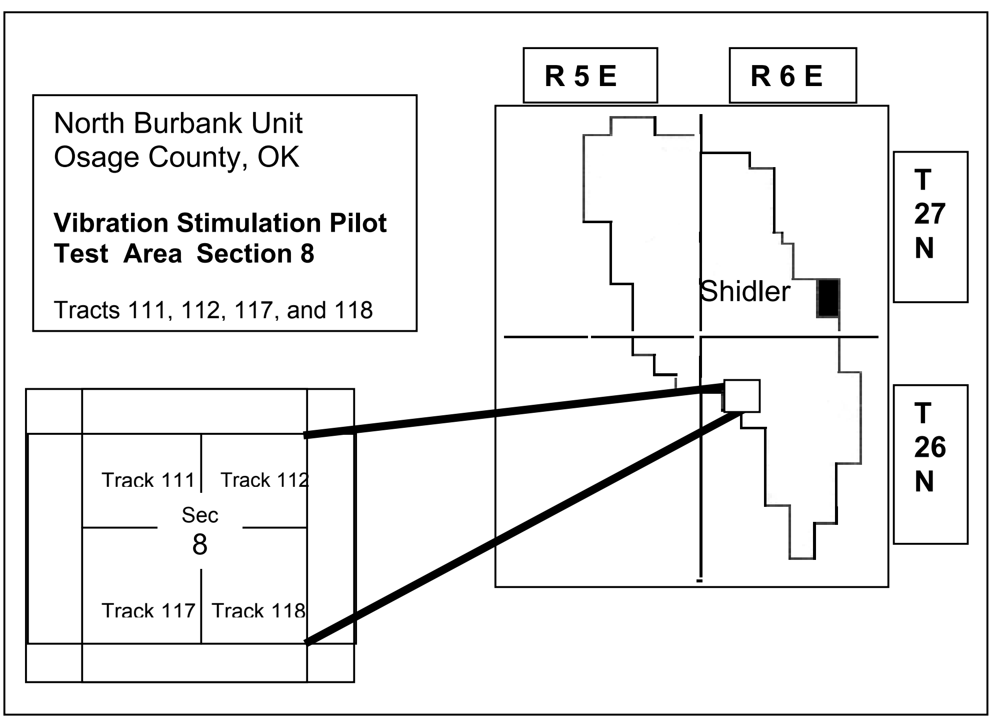


**Figure 3 Vibration Stimulation Pilot Test Area Section 8 T26N R6E, NBU, Osage County, OK**

There have been numerous articles, papers and bulletins published on the Burbank Sandstone, a major producing formation in western Osage County. Many of the reports were generated as deliverables from earlier DOE sponsored projects. Detail of the various DOE sponsored projects can be found in the Third Quarterly Technical Report for the period January 1, 2001 to March 31, 2001.

Below in Table 2 are the reservoir parameters of the NBU.

| Parameter | Value | Units |
|---|---|---|
| | | |
| Area | 36.5 | sq. miles |
| Avg. Thickness | 53.3 | feet |
| Acre Ft | 128,000 | Acre feet |
| Depth | 2850 | feet |
| Stock Tank Oil Gravity | 39 | API Gravity |
| Reservoir Volume Factor | 1.2 | reservoir bbls/stock |
| Original reservoir Pressure | 1,200 | psia |
| Original GOR | 380 | cubic feet/barrel |
| Temperature | 120 | degrees Fahrenheit |
| Viscosity | 3.3 | centipoise |
| Produced Water Salinity | 85,000 | Parts per million |
| Average Porosity | 16.8 | percentage |
| Connate Water Saturation | 26 | percentage |
| Average Permeability | 50-100 | millidarcy |

**Table 2 NBU Reservoir Characteristics**

A presentation of the project status was made at the April 18, 2001 meeting of the Osage Tribal Council. The presentation used much of the material used for the Society of Petroleum Engineers (SPE) Oklahoma City, Production Operations Symposium presentation of SPE Paper 67303.

We announced the switch for the project pilot test area from the Blazer field to the North Burbank Unit. Mr. Jack Graves, Chairman of Calumet Oil Company, was present to answer questions regarding Calumet's participation in the project. Principal Chief Charles O. Tillman was pleased with the effort to find a potentially successful pilot test area and acknowledged the importance of the test.

### *Task 2 Drill and Core Test Well*

- *Prepare the well plan and permit the well*
- *Bid the drilling rig and services*
- *Award the drilling and service contracts*
- *Prepare Location*
- *Drill, Core, and Case Well*
- *Report to Osage Tribal Representatives of project progress*

Vibration Stimulation Test Well Drilled and Cored

The vibration stimulation test well location is 2560 ft FWL and 510 ft FSL of NW/4 of Section 8, this quarter section is known as Tract 111. The well number is Well 111 W-27. The distance from the offset wells (producers, injectors and shut-in wells) to the vibration stimulation well can been seen in Figure 4.

The well was spud July 28, 2001 at 11:00AM. 9 5/8" surface casing was run and cemented at 200 ft. 8 ¾" hole was drilled to core point at 2850 ft. Core # 1 was cut from 2850 to 2880 ft. Core #2 was cut from 2880 to 2910 ft. Core # 3 was cut from 2910 to 2934 ft. Core recovery was 98%. As the cores were being laid down from the core barrel onto the catwalk, several sections were bleeding oil. Also, in the second core barrel, approximately 12 feet of a vertical fracture was recovered with whole rock samples from both sides of the fracture. The cores were taken to Phillips core laboratory, in Bartlesville for standard tests and sonic testing.

The well was drilled to total depth of 3090 ft, which put TD into the Mississippi Lime formation. Schlumberger logged the well. 7-inch, 23-lb/ft casing was run to TD and cemented with 190 sacks of Premium Plus cement. A drilling and completion report was filed with the Osage Agency.

Please refer to Appendix A, which contains the morning drilling reports as provided by David Spencer, Calumet Operations Manager and the Geologic report for the well which was prepared by Calumet's consulting Geologist, Richard Langston.

When the Burbank field was developed, 160-acre leases were auctioned at the Osage Tribal headquarters in Pawhuska, OK. Because there were many operating companies competing for the early flush production, each of these leases originally had 16 wells, so there were 64 wells per 640 acres or ten-acre spacing. When the field was unitized for waterflooding, each 160-acre lease was assigned a Track number. The numbering scheme began on the northern most leases and increased to the south. Most of the wells have been plugged over the years. Today, there are only 16 accessible wells left in section 8 and only seven of these are active.

The production from the wells in this portion of the field is piped via flowlines to a central tank battery located in Track 118. The water injection pump for this area of NBU is also located at the tank battery.

Well 111 W-27 is nearly in the center of Section 8, which is why Section 8 is considered the pilot test area; this includes Tracks 111,112.117 and 118. The five producing wells in the pilot area are shown in Figure 4 as green circles. The two injection wells are blue circles with diagonal arrows through the circles. Inactive producers are light gray circles and the inactive injectors are light blue circles.

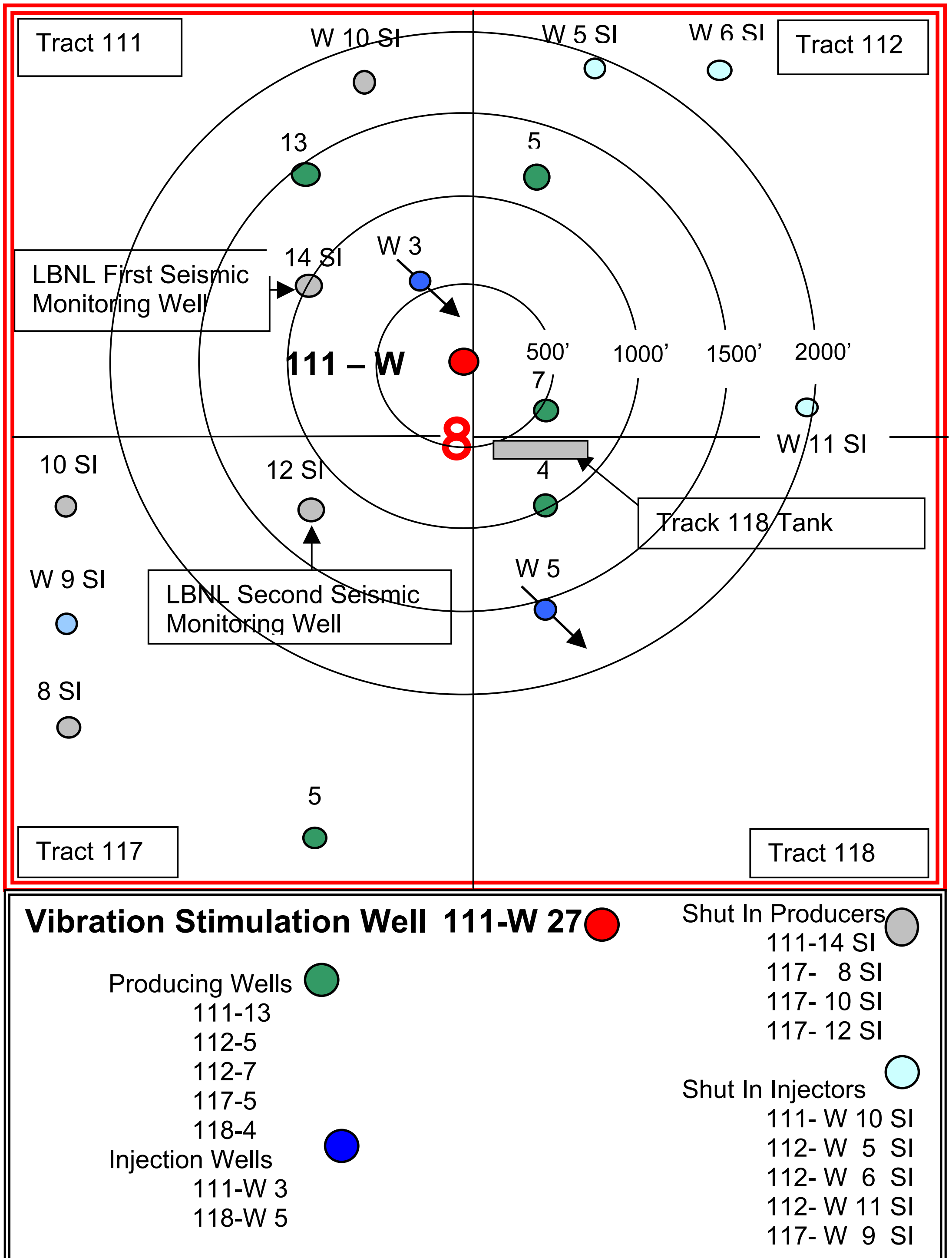


**Figure 4 NBU Vibration Stimulation Pilot Test Area**

### *TASK 3: DEFINE, CONDUCT AND EVALUATE LAB TESTS*

- *DEFINE SUITE OF LAB TESTS*
- *REVIEW BARTLESVILLE SANDSTONE FIELD CHARACTERISTICS*
- *REVIEW OF LITERATURE*
- *ANALYZE THE OFFSET CORE*
- *CONDUCT LAB TESTS*
- *EVALUATE LAB TEST RESULTS FOR FREQUENCY AND AMPLITUDE*
- *MEET TO REVIEW LAB TEST RESULTS & BRACKET FIELD TEST FREQUENCIES/AMPLITUDES*
- *REPORT TO OSAGE TRIBAL REPRESENTATIVES ON PROJECT PROGRESS*

Phillips had been researching the effects of vibration as a possible means for improving oil recovery for several years prior to joining this project. Phillips had designed and built a sonic core test cell. This apparatus allowed the introduction of controlled vibration frequency and intensity in conjunction with the study of fluid flow through convention core samples. Encouraged by their initial research Phillips was interested in comparing their laboratory results with field test results.

The opportunity to investigate the scaling effect from laboratory results to field test results provided the impetus for Phillips to share with the project members the confidential results of their work. Based on available literature on this technology and with knowledge gained from their lab work, it was hypothesized that there should exist a relationship between vibrational frequencies and intensities with changes in fluid flow in a reservoir.

Several Russian researchers discuss the importance of finding a resonant stimulation frequency for a particular reservoir, since it was theorized that the resonant frequency would be a function of the rock type, thickness and fluid saturations. The paper entitled "Residual Oil Reservoir Recovery With Seismic Vibrations," by Nikolaevskiy, V.N. et al[2], seems to tie in well with the observations of Phillips sonic core tests, regarding the concept of a dominant or natural frequency of the reservoir. Thus, the idea of possibly finding a resonant reservoir frequency in the lab tests became part of the quest of the project.

If a resonant frequency could be identified in the lab, the final assembly of the DHVT could be altered to allow the maximum out put energy to occur at the desired frequency range. The vibration tool's output frequency is directly related to its rotating speed. The desired output frequency can be adjusted with controlling the tool's RPM; doubling the RPM doubles the output frequency. However, the intensity of the vibrational energy is a function of the square of the rotating speed, so by doubling the tool RPM the output force is increased by a factor of four. To generate a given amount of energy at a particular frequency is possible if the frequency range is known before the tool is finally assembled since the tool can be engineered to produce maximum output force over a narrow range of frequencies.

The concept of fine-tuning the OGCI vibrators output to match laboratory findings of a resonant reservoir frequency became a goal shared by Phillips and OGCI. If such a dominant frequency had been identified, the DHVT would be designed to deliver maximum intensity in that frequency range.

Phillips, under the guidance of David Zornes, reservoir section manager, did extraordinary work on analyzing and performing tests the cores from the project, primarily, well NBU 111 W-27. Dan Maloney, the principal researcher on the sonic core test cell prepared two project reports, the first covering the preliminary sonic core study on the Blazer offset well. This report is found in Appendix B. It was a pivotal report for the project because based on the results from that work, the location of the project was change from the Blazer field to the NBU field. One of the conclusions from this report:

> *The permeability of the core to brine was measured while imposing longitudinal vibration (cycles of compression and relaxation) with frequencies from 8 to 2,000 Hz and intensities from 0.0001 to 1 w/m$^2$. No particular frequency or intensity was found that caused a significant change in permeability.*

The project team compared the results of the Blazer offset core to previous sonic core test results from Osage County cores. Prior to joining the project, Phillips had conducted sonic core tests with positive results on 'old' cores (cores obtained in the 1970s) from the North Burbank Unit (NBU) field in Osage County, OK, a field Phillip had operated since unitization until November 1995, when Phillips had sold the NBU field to Calumet Oil Company.

Consequently, Calumet was contacted and the details of the DOE project to date were presented. Calumet was interested in testing the technology at the NBU and agreed to join and support the project. Calumet Oil Company replaced Grand Resources as the independent operating company in the project. The field test would be conducted in the NBU field.

Changing the operating company delayed obtaining cores from the test site for one year. Phillips continued to conduct sonic stimulation research for their field operations world wide and waited patiently until the NBU core was available.

In August 2001, with the fresh NBU cores at the Phillips core lab in Bartlesville, Phillips' core lab jumped into high gear. Routine core tests were performed; porosity, permeability, saturations were determined. After the cores were slabbed, Phillips geologist, Terry Siemers, prepared a "Core Petrology Report" for well NBU 111 W-27. This report was distributed in seventh Quarterly Technical Progress Report for the period ending March 31, 2002 as Appendix B.

Meanwhile, Maloney's team performed sonic test on the new NBU cores. Preliminary results were interesting but quite different from the results Phillips had obtained from the 'old' NBU cores. One obvious difference was the lack of an apparent resonant frequency effect. The conclusions from the sonic core tests on the NBU cores:

> *Special core analyses consisted of tests to measure waterflood oil recovery without and with sonic stimulation (low frequency p-wave or vibration stimulation). Limited results from waterfloods without and with sonic stimulation provide evidence that oil recovery was accelerated as a result of vibration stimulation compared to waterflood results without vibration stimulation although results do not provide enough insight to provide guidance on vibration frequencies and intensities that will*

> *optimize NBU oil production and recovery. Results suggest that it may be advantageous to stimulate with vibration in a dynamic mode; periodically turning off and on vibration and changing frequency and intensity of vibration.*

The full report on the NBU sonic core tests is excellent documentation of Phillips’ major contribution to this project; it is found Appendix E.

While there was no resonant frequency found in fresh NBU sonic core tests, Maloney proposed potential technique by which to conduct the field test, that being alternating periods of vibration stimulation with periods of no stimulation. This was adopted as the basis for the field test program discussed under Task 6.

Dan Maloney’s efforts throughout this project were very positive, professional and conservative, being a scientist he desired a thorough understanding og the reported phenomenon of enhanced oil recovery with vibration stimulation. Dan co-authored SPE paper 67303, which has been included as Appendix I. He also gave one of the presentations at the SPE/DOE IOR Symposium Sonic Stimulation Workshop, held in April 2002.

Unfortunately, with the delays in conducting the field test and obtaining results, interest and funding in this technology by the Phillips business units waned and the sonic core lab budget went to zero in 2002.

## *Task 4: Design and Construct Down Hole Vibration Tool and Surface Power Source*

- *Front End Source Engineering - Select most appropriate power source*
- *Engineer Sources to specifications*
- *Construct Tool(s) & Sources*
- *Surface Test Tools*
- *Conduct power source life test*
- *Report to Osage Tribal Representatives on project progress*

The pre-project version of the tool was called Downhole Seismic Mass (DSM). It was built in 1992 to go into 8 5/8 inch casing and was run hundred feet deep in a test well using hoses connected to a hydraulic motor in the tool. It had successfully performed seismic signal generation tests at the former Amoco geophysical test facility nears Mounds OK, south of Tulsa about ten miles.

The tool requirements for the DOE project were that the tool would need to run in 7 inch casing, approximately 3000 feet deep, submerged in wellbore fluid, and run continuously for weeks at a time with no maintenance. The DSM was re-designed to meet these criteria and was called DHVT V 1.0.

The full size 7-inch tool would be run in the test well on 2 7/8" tubing and secured to the casing with a dual set of anchoring slips. The slips would be set by specific tubing movements from the surface and released with a similar but reversed sequence. The two sets of slips would evenly distribute the vibration forces over the length of the tool, transmitting all the vibration energy into the casing. The tool would be sealed to keep wellbore fluids from entering the tool when set in the well at 2900 ft. Downhole instrumentation would be included in the tool to transmit to the surface the tool temperature and vibration measurements of the tool. When the tool is properly anchored to the casing, there is not much actual movement of the tool as the vibrations are transmitted into the earth.

The new design was based on the use of pre-compressed flex shafts rotating the vibrating mass inside the tool housing. At low energy levels this design worked fine. But when this version was put into a well and run at full RPM, several design problems became evident.

Initial field performance testing of the DHVT occurred in the fall of 2001. These tests were called the power source field tests because, this was the first time the tool was rotated with power from the surface with the sucker rods. The tests were conducted at Calumet's Wynona field in an inactive well with 7-inch casing. The two field tests were performed in October and again in December and produced a total run time of about 30 hours, which was unsatisfactory. Details of this testing program can be found in Appendix C DHVT Power Source Field test Report. The results of these tests led to a re-evaluation of the material hardness and finish specifications of the internal rotating mechanisms. The anchoring slip system, the onboard instrumentation, and the surface data acquisition system performed adequately but various functions were identified which required improvements and further testing.

To facilitate a more efficient means of testing the full size tool at high load level, a test facility was built at Knight's Pecan Farm (KPF), south of Tulsa seventeen miles. In hindsight, this facility should have been in the original proposal, as it was very efficient in testing both the data acquisition system and tool performance. With no need for a workover rig, numerous changes in material, finishes and tool hardness were quickly tested between January and March of 2002. Below in Figure 5 is a photo of DHVT V 1.0 being tested at KPF. It soon became apparent that the basic design problems could not be resolved. In April 2002, it was decided that the tool needed to be re-designed and a new tool built for the field test at NBU. A detail of DHVT V 1.0 reliability testing is provided in Appendix D.

**Figure 5 Testing DHVT V 1.0 at Knight's Pecan Farm January 2002**

## Re-Designing the DHVT

During the DHVT V 1 design process, while reviewing other patents on downhole vibrators, the name of Jack Cole kept reappearing as Dr. Cole has numerous patents on downhole vibrators. Jack had worked at Conoco's geophysical research facility in Ponca City, OK and was now a professor at the University of Arkansas. With the decision to re-design the DHVT, Jack was contracted to assist in developing new tool designs. Jack and his associate, Will Myers developed several potential designs, the one selected was designated DHVT Version 3.2.

The new design had two new internal systems, an innovative and unique gearing/bearing combination and internal self-lubricating system. The anchoring slip system remained the same. The on-board instrumentation was modified to fit into the new design, but basically remained the same, using accelerometers to measure tool motion and temperature probes to monitor internal tool temperature.

A prototype of DHVT V 3.2 was built and tested satisfactorily during the summer of 2002 at KPF. Substantial testing was performed on this version of the tool. During the reliability test, the prototype ran forty 24-hour days. This prototype performed exceedingly well. Building the full-size field test version was started in September 2002. It was assembled in January 2003 and tested satisfactorily at KPF. The “DHVT V 3.2 Performance Test Report” can be found in Appendix F. A key lesson gained from to this testing was the amount of tool temperature increase with continuous operation. Figure 6 below, is an example of the tool temperature rise during KPF test operations.

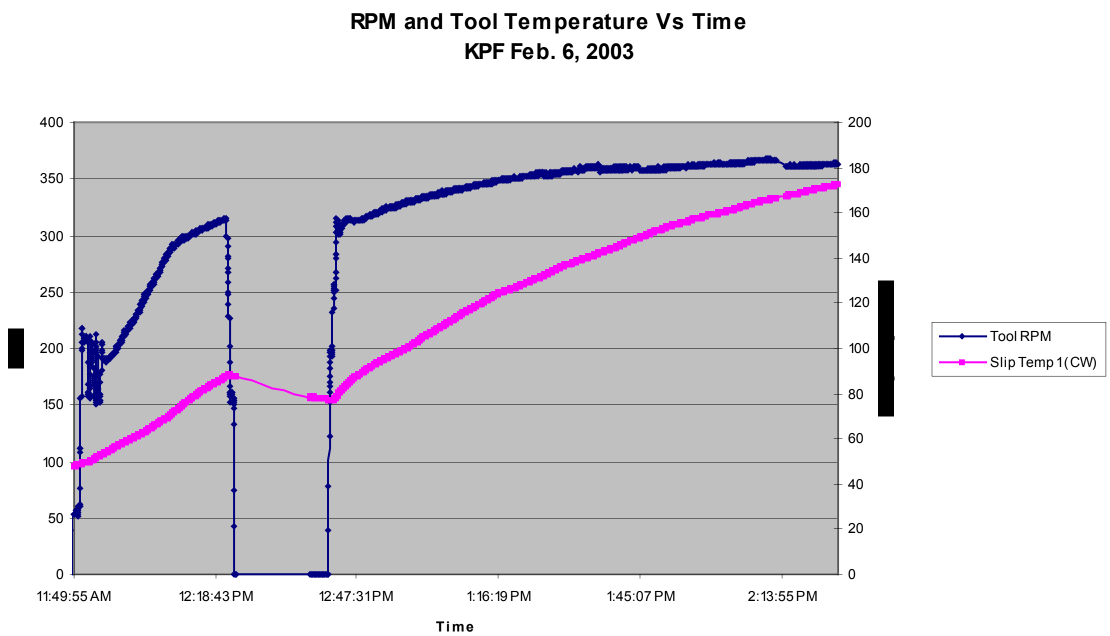


**Figure 6 DHVT V 3.2 Performance Test at KPF RPM and Tool Temperature vs. Time**

The field test began February 12, 2003. Originally the field test had been scheduled to start in January 2001. This represents a delay of two years based on the original project schedule. The impact of re-designing the DVHT was very significant in extending the duration of the project as well as the total cost.

### *TASK 5: INSTRUMENT TEST WELLS*

- *ENGINEER SEISMIC MEASUREMENT SYSTEM*
- *SPECIFY SEISMIC MEASUREMENT SYSTEM*
- *INSTALL SEISMIC MEASUREMENT SYSTEM*
- *REPORT TO OSAGE TRIBAL REPRESENTATIVES ON PROJECT PROGRESS*

This task was accomplished by completing three separate operations by three different groups supporting the project. The timing for each sub-task was independently driven by other project activities.

The first sub-task was to modify the tank battery at the pilot test site. Calumet quickly performed this operation by setting equipment that was used solely to handle the produced fluid from the five producing wells in the pilot test area. This allowed Calumet to began gathering baseline production information in April 2001, four months before the well was drilled. Calumet continued to gather on a daily basis both production and injection information until the field test was terminated.

The second sub-task was to build a data acquisition system to record the DHVT performance during all testing operations. This spanned the requirements for the tests conducted in the machine shop, at the KPF test site, at the Wynona field test and the NBU field test. All data reporting for the project was collected and stored by the data acquisition system (DAS).

Much of the data is considered high speed since each data channel is collected at a rate of 2000 bytes per second. The immensity of generated data for the project runs in the hundreds of gigabytes stored data. During the NBU field test, 26 different parameters were being recorded or controlled by the data acquisition system, which amounted to 500 megabytes created every twenty minutes. Data management and storage were critical issues to resolve. Scott Lovin, who has built data acquisitions systems for Amoco and Baker Hughes, built this system. He did a remarkable job in building the necessary flexibility to adapt the system to such varied test operating conditions.

The third sub task was to install and record down hole seismic signals in offset well. This was accomplished by a team from Lawrence Berkeley National Laboratory, coordinated by Ernie Majer, the group manager. His team needed to be mobilized from Berkeley, CA to conduct a short-term monitoring operation of the DHVT. Two sub-tasks were set for this team, one to record the seismic signal generated from the DHVT using downhole geophones and hydrophones run in adjacent idle wells, the second was to identify a resonant reservoir frequency if possible. The first task was accomplished with stellar results. The LBNL tools recorded strong and clear seismic signals downhole in two different well more than 1200 feet from the well with the DHVT. But in the preliminary field evaluation of the recorded signals, there was no discernable resonant frequency effect. Appendix G contains a copy of Dale Cox’s field notes during the LBNL activities at NBU.

Having the vibration stimulation test data continuously recorded was considered a necessity for a proper evaluation of the field test data. There needed to be a time related series of data files providing the ability to compare DHVT stimulations operation with delayed production/injection well responses.

*TASK 6: CONDUCT A 90 DAY FIELD VIBRATION STIMULATION TEST*

The goals of the field test are to determine the operating characteristics of DHVT V 3.2 and to run DHVT V 3.2 a sufficient period of time to be able to evaluate it's potential impact on reservoir fluid flow characteristics in this mature waterflood. Ninety days was considered to be more than adequate to observe any changes in flow characteristics and sufficient time to establish the reliability of the DHVT operations. To accomplish these goals, the vibration stimulation field test was conducted in two phases:

**Phase 1** Determine if there is an identifiable resonant frequency associated with the Burbank reservoir and establish the operating parameters for the long term vibration stimulation test. In conjunction with LBNL, a combination of surface geophones and downhole sensors were run in inactive offset wells to detect and evaluate the seismic signals generated.

**Phase 2** Conduct a 90 day test of reservoir vibration stimulation, which should provide adequate time to observe any changes in the production or injection wells within the pilot area. The combined oil and water production for the pilot area was being monitored daily. The two injection wells in the pilot area were equipped to measure and record continuous real-time injection pressure and rate information.

The evaluation of the results of the field test are discussed later under: *TASK 7 REPORT FIELD TEST RESULTS*.

**Phase I Characterize DHVT V 3.2 Performance**

The following four tasks were conducted during Phase I:

1. Deployment of LBNL equipment
2. Deployment of data acquisition system
3. Installation of DHVT V 3.2 into well 111-W 27
4. Operation of DHVT V 3.2 to characterize performance

Deployment of LBNL equipment

LBNL personnel laid out on the ground, a string of 24 surface 3-axis geophones in a line between wells 111 W-27 and 111-14. Please refer to Figure 4. The purpose of the surface geophones are to record seismic signals as they traveled to the surface from the DHVT down in the 111 W-27 wellbore at approximately 2900'. However, this required the line of surface geophones to pass underneath a 14,400-voltage electric transmission line. When attempting to collect data from the LBNL surface geophones, it was determined that the electrical noise was excessive. Attempts were made to isolate the noisy signals with various electronic filters and alternative power sources, but with no success. The data from the LBNL surface geophones was considered unusable. Therefore, the attempt to collect the surface geophone information was abandoned.

The two nearest inactive wells were chosen for running the downhole seismic logging tools. The location of the two wells 111-14 and 117-12 also provided an opportunity to monitor the generated seismic signal both parallel and transverse to the known fracture orientation of the Burbank sandstone.

The 3-axis LBNL downhole geophone-logging tool was run on wireline and set at approximately 2800' in well 111-14. The seismic signals were recorded at five different depths; coming up the well bore in 50' increments. A similar operation was conducted with LBNL's downhole hydrophone logging tool.

Deployment of Seismic Recovery LLC data acquisition system

The four sources of data being recorded during the vibration stimulation field tests are:

1. Continuous, real-time injection well pressure and rate information;
2. Responses to surface motion detectors;
3. Tool performance indicators from the on-board sensors;
4. Rod rotating drive unit operations.

*Injection well data*
The DAS was designed to continuously collect real time injection well performance, measuring and recording both injection pressure and injection rates. There were two injection wells in the pilot area. Well 111-W 3, about 500' northwest of 111-W 27 and 117 W-5, about 1500' south-southeast of the vibration well. Each well was equipped with calibrated pressure sensors and flow meters. The data was transmitted back to the DAS computer via a seven conductor steel wireline cable run across the pasture and lease roads. The grazing cattle did not bother the steel jacketed wireline cable nor did the traffic on the lease roads.

*Surface motion detectors*
Two types of surface motion detectors were deployed. Accelerometers were placed on well 111-W 27 to record any motion at the wellhead. This primarily measured the motion of the rod rotating unit, which was attached to the wellhead, rather than the DHVT, which was down the well nearly 2900'.

A single 3-axis geophone was placed in the soil 12 inches below the surface, approximately 1000' northeast of well 111-W 27. This geophone had an insulated and shielded cable and was equipped with special electronic filters to minimize electrical noise caused by the high voltage electrical distribution system. The minute earth movement caused by the seismic signals emanating from the DHVT was consistently recorded on the up/down (vertical) axis. This provided an accessible and accurate indication of the tool operations.

*Tool performance indicators from the on-board sensors*
One temperature sensor and three accelerometers were located inside the tool. The maximum operating temperature limit for the downhole electronics was 250 $^{o}$F. This equipment was subjected to the hostile environment produced by operating the downhole vibrator. The on-board electronics' longevity was subject to excessive tool motion and high temperatures. These devices were sensing and sending tool-operating data to the surface. All downhole data was sent to the surface via a seven-conductor steel wireline strapped to the outside of the tubing.

*Rod rotating drive unit operation*
Numerous operating parameters were recorded while the rod-rotating unit was driving the DHVT. Tool RPM, motor RPM, horsepower, torque, rotating time were recorded and sent to the DAS via an insulated, shielded cable.

Installation of DHVT V 3.2 into well 111-W 27

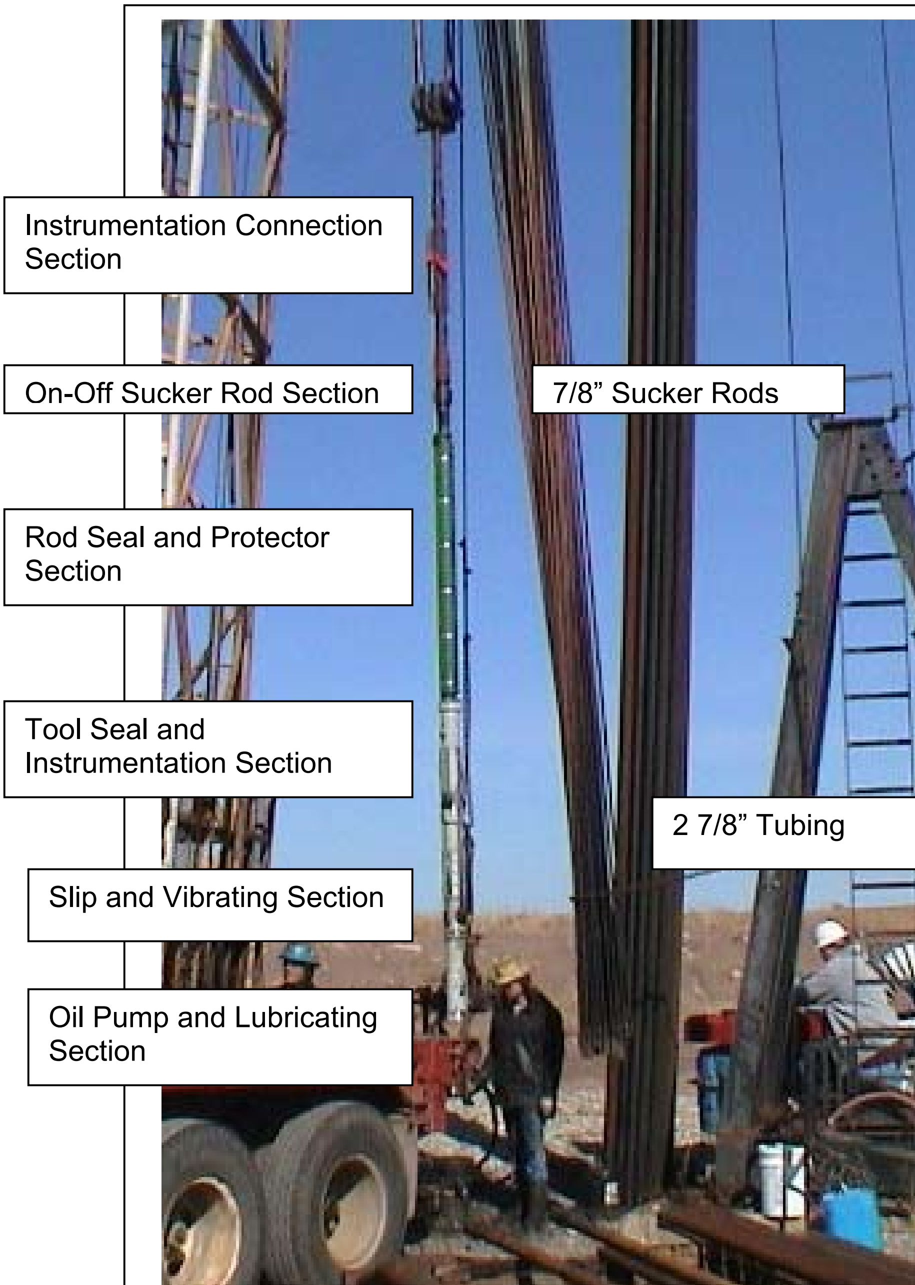


**Figure 7 Picking up the Complete DHVT V. 3.2 NBU Field Test**

The DHVT was picked up and screwed onto tubing and lowered into the well as seen in Figure 7 above. The data wireline cable exiting from the DHVT on-board electronics package was secured to the outside of the tubing with stainless steel bands placed on every joint of tubing. The DHVT was run to 2878' and set by activating the anchoring slips. The tubing was then hung onto the wellhead which supported the weight of the tubing plus 30,000 lbs of tension.

The DHVT was powered by rotating sucker rods from the surface. To engage the DHVT drive shaft with the sucker rods an on-off tool was utilized. The on-off tool was screwed onto the bottom sucker rod and the rods were run into the tubing. The DHVT drive shaft was engaged with the on-off tool on the sucker rods. The rod-rotating unit was put onto the wellhead and the rods were clamped to the rod-rotating unit. The DHVT was ready for operation. The rod-rotating unit could be controlled either manually or by computer, during the initial NBU field test operations, the rotating speed of the DVHT was controlled by computer.

Operation of DHVT V 3.2 to characterize performance

This version of the DHVT has a gearing system using special gears named gerotors. The gerotors insure that the whirling motion of the tool is reliable and consistent. The particular gerotors used for this test result in ten vibrations for each revolution of the tool. This makes it simple to determine output frequency when tool RPM is known. To calculate the output frequencies of the tool in Hertz ( Hz, cycles per second), divide the RPM by 6. If the tool is turning at 300 RPM the output frequency will be 50 Hz.

The DHVT was first operated at discrete frequency output levels. This procedure was called a step test. It involved increasing the generated signals approximately 1.5 Hz per step and allowing the DHVT to stabilize at that frequency output for two to three minutes. Slowly the frequency was raised from 25 Hz to about 75 Hz. This process was repeated five times as the down hole geophone was repositioned coming up the well in 50’ increments.

The next DHVT operation was increasing the output frequency of the tool from 25 Hz to 60 Hz and then reducing the frequency back to 25 Hz in sixty seconds. With the computer controlled electric motor system, the generation of the seismic signals was very precise, uniform, and repeatable.

These frequency sweeps were conducted at five stations 50’ apart, pulling the logging tool up the offset well bore. The geophone-logging tool was then pulled from the well and the hydrophone-logging tool installed and run to 2800’. The step tests and the frequency sweeps were repeated again at each of the five depths coming up the hole with the hydrophone.

The predicted frequencies generated from the DHVT were precisely what LBNL was recording. Once the DHVT reached the 25 Hz frequency output, there was no doubt about the source of the signals being recorded, it was very distinct from all background noise. Dale Cox, LBNL representative, stated that the strength of the DHVT signal was the strongest seismic signal that LBNL has recorded in conjunction with other seismic stimulation type field tests. While on site, Dale Cox performed a limited preliminary field evaluation of the DHVT performance by comparing the characteristics of predicted signal to the signals recorded. All the field data was sent via the Internet to LBNL for further processing.

However, there was no identification of a resonant frequency of the reservoir. The strength of the seismic signal arriving at the listening devices seemed to be tied directly to the output signal amplitude rather than to any resonant frequency affects.

In all, over 200 data files were created during the LBNL seismic monitoring tests. The following conclusions are from a presentation made by Ernie Majer:

- *The Seismic Recovery DHVT generates 25-75 Hz energy, at constant frequency or swept frequency, measurable over 1200 ft away within reservoir*
- *Signal is observable with both geophone and hydrophone*
- *Maximum signal at ~1000 ft offset for 72 Hz source:*
  - o *Velocity (peak-to-Peak) = 4 x 10 - 6 m/s*
  - o *Strain = 3 x 10 -9 (assuming velocity = 2500 m/s)*
  - o *Maximum noise strain 1 x 10 -10 (after applying 20 – 100 Hz bandpass and 60 Hz notch filter)*

In conversations with LBNL personnel concerning the seismic monitoring field activities in the NBU pilot area, three items were clear:

1. The DHVT V 3.2 generated the predicted signals reliably and repeatedly;
2. DHVT V 3.2 generated seismic signals were recorded at depth with downhole geophones and hydrophones in both the two offset wells 111-14 and 117-12, approximately 1000' and 1200' respectively from the source well;
3. The strong DHVT V 3.2 seismic signals were readily being detected as very clean and sharp signals substantially above the background noise recorded.

Operations during the Phase I of the field test, two key operating parameters were observed characterizing DHVT V 3.2 operations.

1. The DHVT operated as designed; output frequency followed exactly the predicted frequency. Temperature build up at the tool was directly related to the vibration forces being generated at higher frequencies. Of the downhole on-board sensors, the data from temperature probes became the primary monitoring device for conducting tool operations. Controlling tool temperature build-up was considered critical in an effort not to exceed the temperature limits of the downhole electronics.

2. The surface, three-axis geophone used to record the operations of the DHVT was laid out 1000' to the northeast and responded precisely with the tool's on board accelerometers. This surface vibration detector proved to be a very reliable tool performance indicator. This was very beneficial as there was concern for the long-term reliability of the downhole electronics. The downhole instruments were being subjected to a hostile environment created by operating the DHVT. The surface geophone readings became the primary monitoring system of the tool's operation, after the downhole electronics had registered the temperature spike, which is discussed later.

## Phase II Vibration Stimulation Field Test

Vibration Stimulation Test Design

Based on the sonic core test results from Phillips Petroleum Company (PPCo), the concept of intermittent vibration pulsing was selected as the appropriate technique to begin the vibration stimulation testing. During sonic core testing of the NBU cores, PPCo had observed the maximum effect of sonic vibrations in the laboratory occurred by subjecting the core to intermittent pulse of vibrations, stopping the vibrations, then repeating the vibration pulse. This resulted in a 10% decrease in injection pressure at a constant injection rate, which was interpreted as a 10% increase in apparent permeability. This improvement in fluid flow occurred when the produced fluid was primarily water (98% water cut). This is fully detailed in Phillip's sonic core test report found in Appendix E.

## Pilot Test Area Production and Injection Well Monitoring

All produced fluids are gathered into the Tract 118 tank battery. It was necessary to be able to measure accurately the produced fluid from just the pilot test area wells. To isolate the production to just the producing wells within the pilot area, a separate water knockout, separator and storage tank was installed in April 2001. The baseline for production/injection data collection began after the modifications to the tank battery. After the pilot test area oil is separated from the produced fluids, the produced water is recombined with the remaining produced water at the tank battery to be re-injected. All the produced water is sent to a holding tank on the inlet side of the centrifugal injection pump.

The injection pump runs constantly and operates near its maximum capacity. The water injection volume of the pump is controlled by a set of water level sensors in the holding tank. If the pump output is slightly in excess of the produced water volume entering the tank, the tank level will drop. The sensors will respond to the low liquid level and cause the pump to be slowed down until the tank level begins to rise again. As the tank rises to the high liquid level sensor, the pump is sped up and the level in the tanks will drop again. This results in a subtle cycling of injection rate and pressure about every fifteen minutes when everything is running smoothly.

In addition to the fifteen-minute injection pump cycle, once a day the lease operator (the pumper) "skims" oil off the water in the holding tank. This is done by reducing the injection rate approximately 100 bwpd which is accomplished by slowing down the injection pump. The water holding tank is skimmed of any accumulated oil. When this is finished, the injection pump is sped up to catch up with daily water production and the injection system is put back on automatic mode. This process takes about three hours and produces a distinctive injection rate drop and subsequent peak of approximately 10% once each 24-hour period.

## Data Acquisition System Requirements and Design

The objective of the DAS was to record all surface and downhole data with a common time reference to allow correlation of all recorded parameters for potential responses. While this may sound trivial, to do all data collection and control the electric motor with one computer was a challenge. Two data collection modes, fast and slow, were built. During Phase I, the fast mode recorded all DHVT sensor output at 2000 bits per second, which also required all other sensors were being recorded at that high data density. The fast mode would generate a 500-megabit file every 20 minutes, requiring the constant attention of personnel to manage the data. During Phase II, once confidence was gained in operating the DHVT, the need for detailed fast data acquisition could be relaxed. By reducing the data rate recorded from the downhole electronics, the slow mode of data collection was about 2 bits per second. This allowed the data to be collected over night with no supervision required.

Computer Controlled DHVT Operations

The DHVT speed can be controlled either manually or with a computer. The test plan was to cycle the tool on and off in a manner similar to the technique PPCo employed in the laboratory, but increasing the duration between the pulses. Pulsing the vibrations was accomplished by using a speed control program on the computer for operating the electric motor. The computer was used to bring the DHVT up to a desired speed, hold that condition for several hours, and then bring the tool speed back to zero in a controlled manner. The computer could automatically repeat the cycle for days.

## Phase II Operations

Phase II began February 17, 2003, after the LBNL equipment was mobilized back to Berkeley, CA. Each 24-hour period was broken into two venues of data collection, fast and slow modes. While operating the DHVT, to assess its temperature profile, the fast data collection mode was used to be able to evaluate the tools motion and internal temperature. For example, at the 400 to 500 RPM range, considerable heat was generated and the internal temperature could have quickly exceed the 250 $^{o}$F temperature rating of the on-board electronic sensors. In an effort to prolong the life of the downhole electronics, the tool was run at elevated RPMs for only short periods of time, the tool was then allowed to cool back near the ambient wellbore temperature of 120 $^{o}$F before running it at high RPM again.

As the testing progressed, the on-board accelerometers registered increasing tool motion, which indicated that the anchoring slips were losing their grip on the casing. If this situation continued, the tool would shake violently instead of transmitting vibrations into the casing, subjecting the downhole sensors to very hostile conditions.

With concern for the long-term reliability of the downhole electronics, a concerted effort was made to develop a correlation of the tool operations with the responses recorded by the surface geophone. This 3-axis geophone had been placed approximately 1000' northeast of well 111- W 27and buried 12 inches into the soil. In previous field operations with DHVT Version I, electrical noise prevented the surface geophone from "recognizing" the seismic signals. But by adding a shielded cable and special electronic filters, the geophone was precisely responding to the operation of the DHVT.

A tentative over-night pulsing schedule was ready to be implemented February 21, 2003. Before this could be initiated, the tool temperature instantly jumped from around 200$^{o}$F to over 550$^{o}$F. Figure 8 is a graph of the tool operation when the temperature spiked at 550 $^{o}$F. The DHVT was immediately shut down, fearing a major failure of the tool. With the tool shut down, the temperature data was still being collected. The temperature fell off in a peculiar manner, indicating that perhaps the temperature spike was faulty data from the electronics, rather than a catastrophic tool failure.

The over-night pulsing operation was postponed, letting the tool sit quietly overnight instead. The tool was checked again in the morning, it started fine, it had normal operating temperature, but the tool motion had increased raising concern that the slips had lost their grip on the casing. A snowstorm blew in that weekend and prevented additional field-testing operations for almost a week. The tool was checked several more times, as road conditions allowed. On each occasion, it was starting fine, the static temperature stabilized at 120 $^{o}$F, which is the reservoir temperature, but the motion of the tool was becoming more violent even at low rotating speeds.

On March 7, 2003, Calumet moved a workover rig onto well 111-W 27 to pull the DHVT from the well to determine the reason for the excessive tool motion. When the tubing was picked up to release the slips in the wellhead, the rig's weight indicator showed a loss of 10,000 lbs of tension in the 2 7/8" tubing, indicating the anchoring slips had partially lost their grip on the casing and that the tool had moved up the hole about 6 inches.

The DHVT anchoring slips were then fully released and the tool began to be pulled from the well. After 7 stands of doubles (two-joints of tubing), or about 400 ft of tubing had been pulled, the rig operator noticed a slight increase in apparent tool weight (known as drag) while pulling the tubing upwards. That stand of tubing was slowly worked back into the well. Normally the weight of the tubing would pull the tubing back down the well. However the tubing was not easily going down the well. It became necessary to push the tubing back down. Pushing the tubing back down became progressively more difficult and eventually the tubing would not come up either. The tubing was hung back in the wellhead. The six stands of tubing that had been pulled out were laid down on the pipe rack as were the sucker rods and the rig moved off the well. The DHVT was stuck in the well, approximately 2500' below the surface.

Having a tool stuck off bottom is undesirable. It prevents the operator from having access to the Burbank sandstone, the reservoir at NBU. The design of the DHVT is such that when it is stuck in the well it most likely will be damaged beyond repair when attempting to fish (retrieve) it from the well. Discussions with Calumet resulted in a decision to postpone fishing operations. It is anticipated that the tool will either be pushed to the bottom of the well and left there, or it will have to be burned over to retrieve it. If either fishing option is successful this would allow access to the producing formation. However, if the fishing operation is unsuccessful, the well will be plugged and abandoned with the DHVT still stuck in the well.

Terminating the NBU vibration stimulation test operations

With the DHVT stuck in the well and having only approximately 48 hours of vibration time between February 12 and March 7, 2003, the field test was terminated on March 14, 2003. Daily monitoring of the pilot area production and injection wells stopped and the data collection system was removed.

Details of the vibration stimulation field test operations can be found in Appendix H *NBU Vibration Stimulation Field Test Report.*

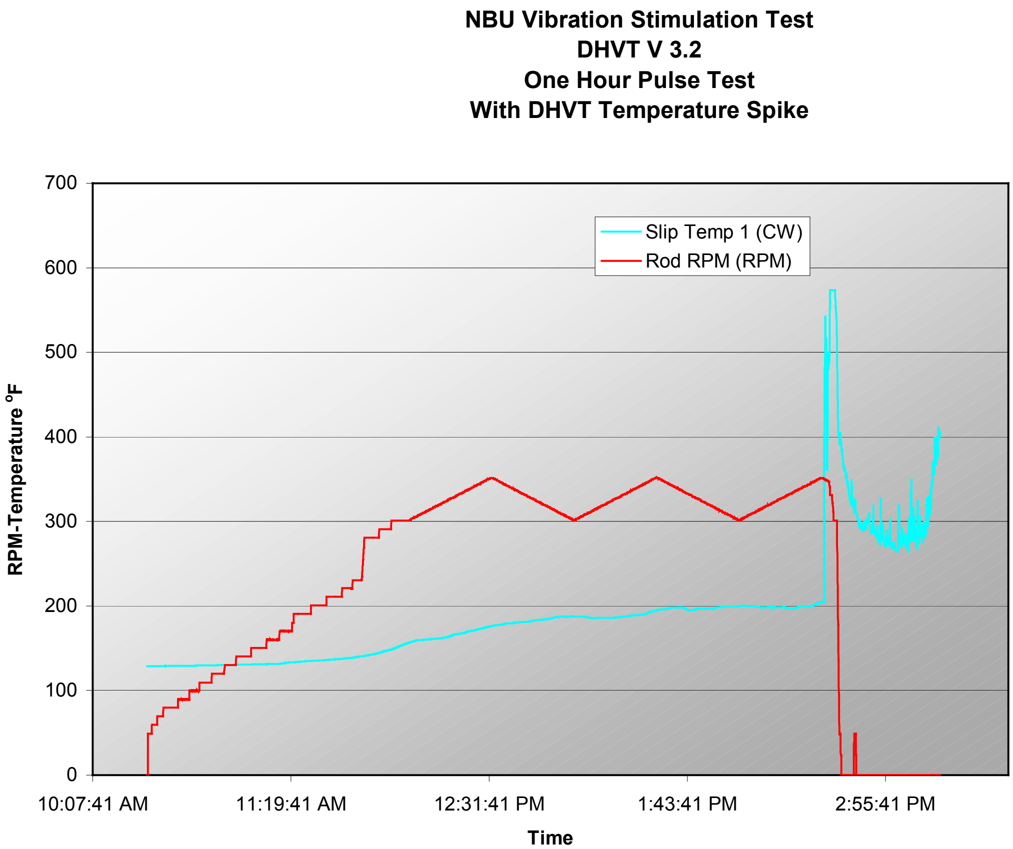


**Figure 8 One Hour Pulse Test and Temperature Spike NBU Field Test**

*TASK 7: REPORT FIELD TEST RESULTS*

The following is a synopsis of the results of both Phase I and II of the vibration stimulation field test, further details are reported in Appendix H, *NBU Vibration Stimulation Field Test Report*.

## Phase I Results

The DHVT operated during Phase I exceedingly well. The LBNL downhole 3-axis geophone and the hydrophone logging runs were successful in both offset wells, with more than 200 data files created as the DHVT went through it's operational paces.

After the first day of seismic signal monitoring, Dale Cox, LBNL representative, performed a limited amount of preliminarily processing of a portion of the data recorded. There was no resonant frequency identified in the data processed on site. Details from Dale Cox's field notes and preliminary processing can be found in Appendix H *NBU Vibration Stimulation Field Test Results*.

The first signal monitoring was done using step tests. Below in Figure 9 is a graph of data from the on-board sensors during one of the step tests conducted. The tool speed was slowly increased and held constant for two to three minute intervals. Time in minutes is on the X-axis. On the left hand Y-axis, tool RPM and temperature are recorded, while on the right-hand Y-axis, the predicted and measured output frequency in are plotted. Please note the hump in the tool temperature curve when the DHVT was operating in excess of 400 RPM. This is an example of the rapid temperature rise at higher rotating speeds.

Using LBNL proprietary software, Dale Cox prepared plots of both the step tests and the frequency sweep tests. Figure 10 is a chart produced from the LBNL data recorded. This is the same step test as seen in Figure 9, but plotted with LBNL software. In the LBNL graph, the predicted frequency is plotted against with the measured frequency. Both axes have frequency in hertz as units. The amplitude of the recorded signal provides a dark shaded spot on each vertical seismic trace lines, which indicates that the recorded frequency was the same as the predicted output frequency. This is confirmation of the reliability of the DHVT as an engineered seismic source.

Examples of the data recorded during sweep tests are shown in Figures 11 and 12 below. Figure 12 is a plot of the signal generated as measured by on-board sensors on the DVHT. Time is on the X-axis and represents a single up-down cycle just slightly more than one minute (sixty-three seconds). Tool RPM is on the left-hand vertical axis, while frequency, both measured and predicted are plotted against the right-hand vertical axis.

Whereas, in the graph of the LBNL processed data in Figure 12, the data is from a 3-axis geophone logging tool 1000' away. The format of this chart is different from Figure 11.

In Figure 12, the X-axis is the frequency recorded, increasing in value to the right of the chart. This chart has time on the Y-axis in μ-seconds (1/1000 of a second), ranging from 0 at the top of the chart increasing to 60,000 μ–seconds at the bottom of the chart. The total time from top to bottom of the graph represents 60 seconds of recording time. This graph also provides a third scale by using various colors representing the strength of the signal recorded. Blue represents background noise levels with the maximum signal strength displayed in red, which is about 80 decibels above background noise. The trace of the signal from the DHVT is discernable beginning at about 25Hz at the top of the graph as a yellow diagonal stripe increasing in strength and frequency to about 60 Hz and back to the 25 Hz signal. The vertical stripe at 60 Hz is a result of the overhead high-voltage lines in between the wells.

By comparing Figures 11 and 12, the similarities between the DHVT on-board sensors measurements with LBNL recordings of the seismic signal over a 1000’ away are remarkable.

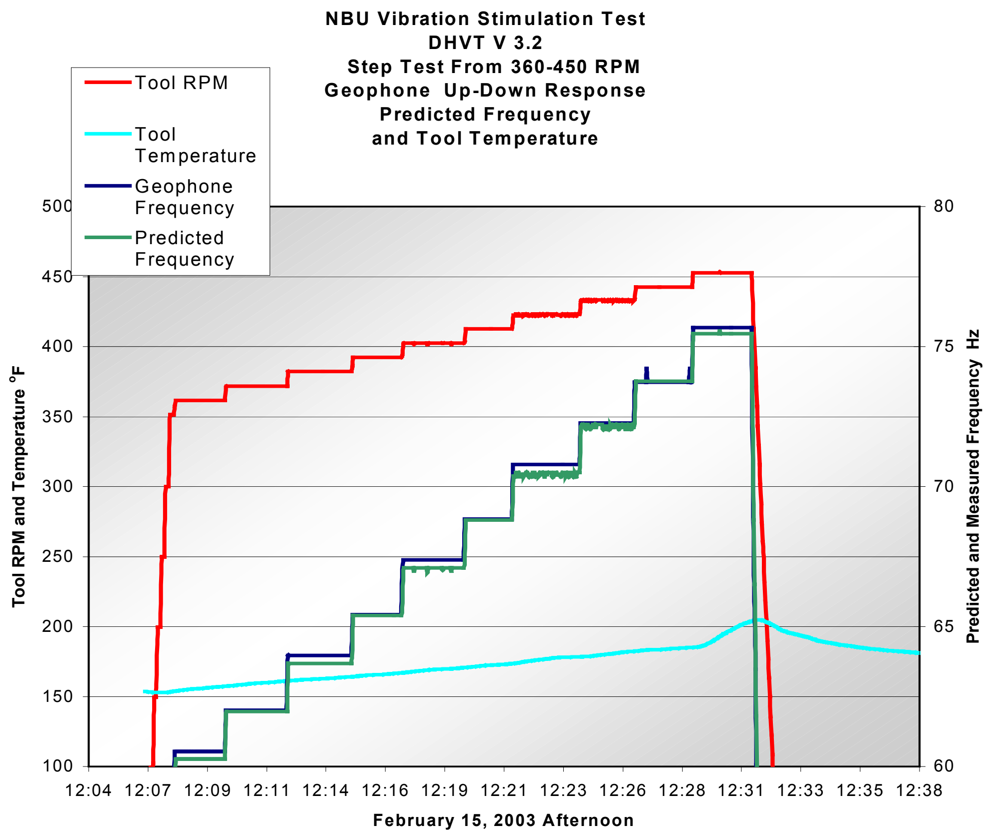


**Figure 9 DHVT Step Test Phase I NBU Field Test 2-15-03**

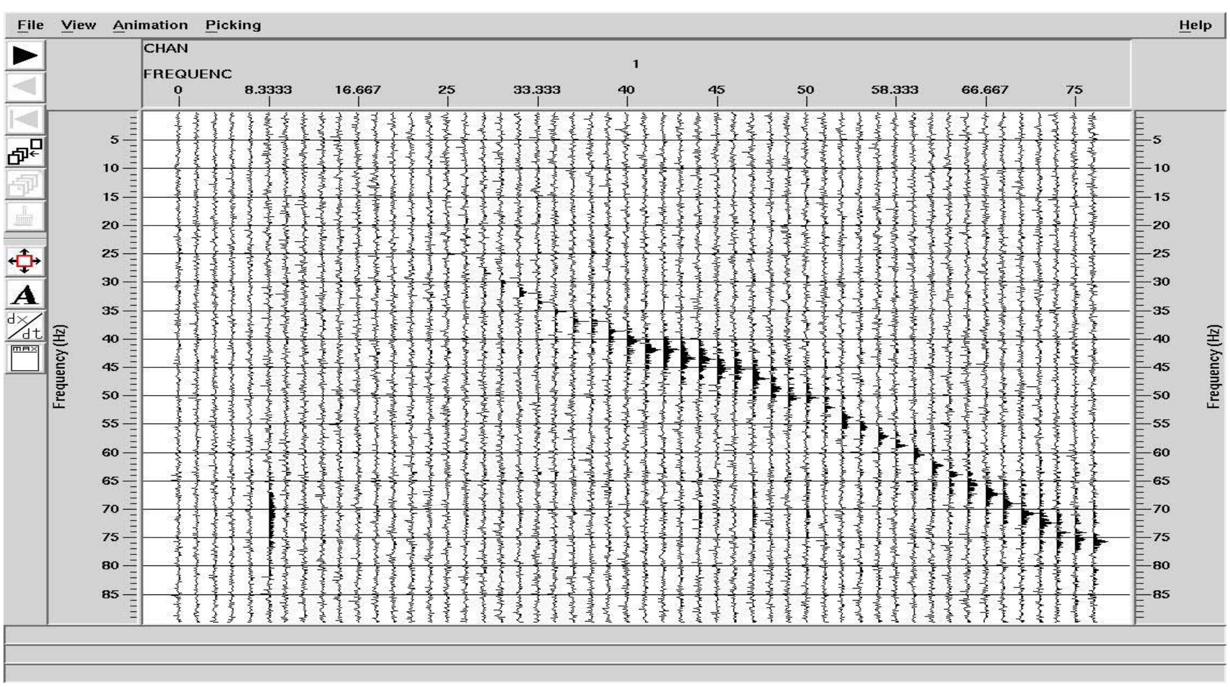


**Figure 10 LBNL Recorded and Processed Step Test Phase I NBU Field Test 2-15-03**

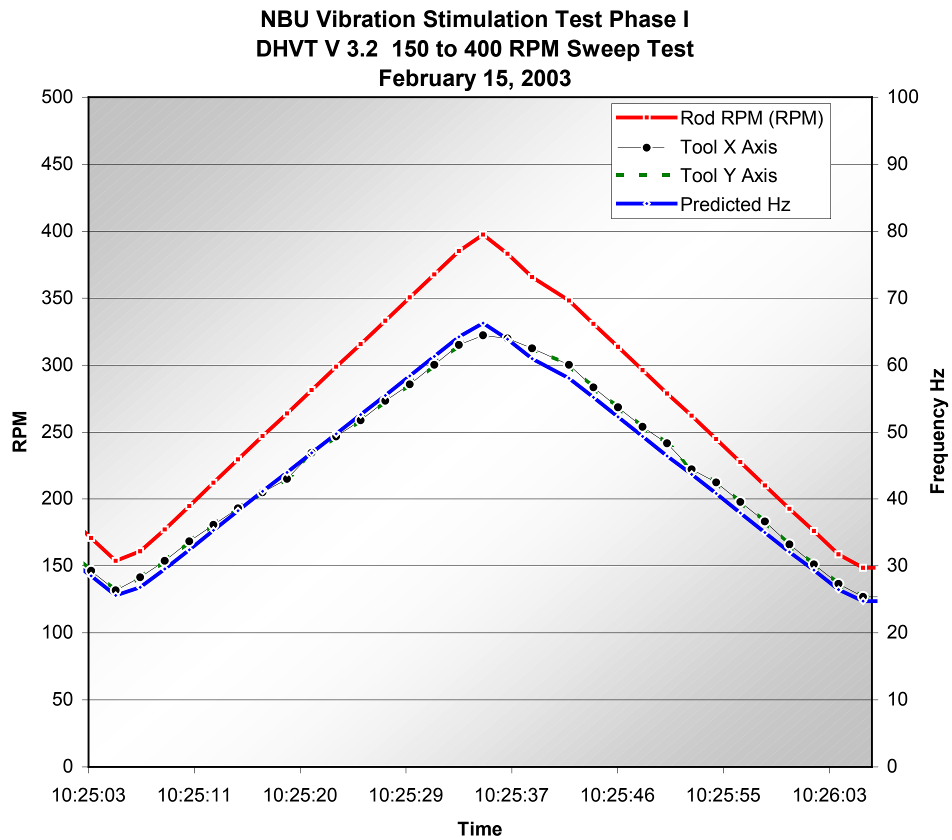


**Figure 11 DHVT Sweep Test Phase I NBU Field Test 2-15-03**

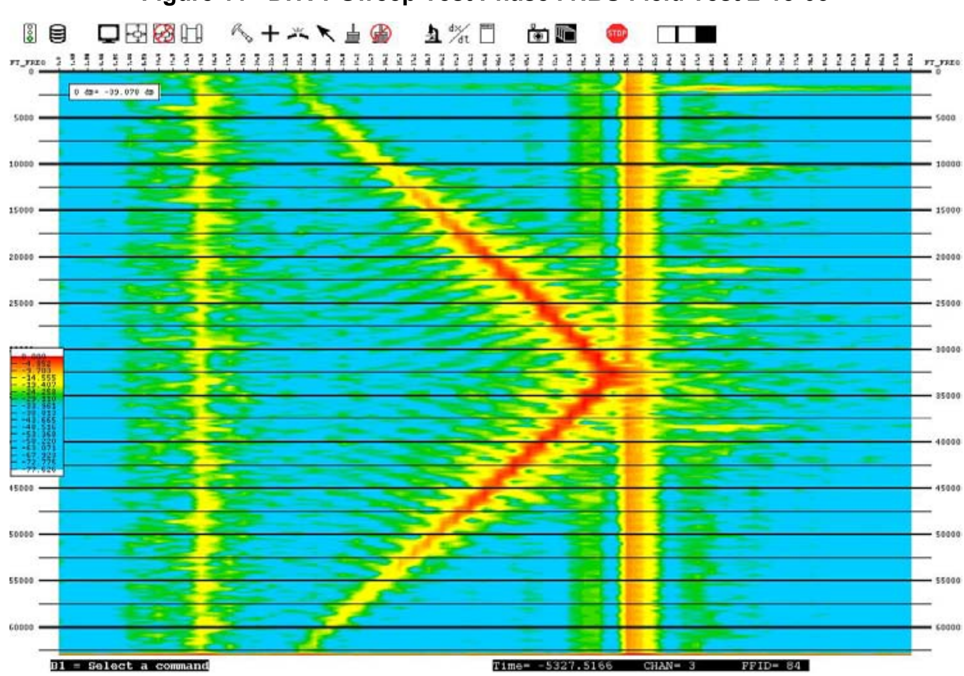

**Figure 12 LBNL Processed Sweep Test Phase I NBU Field Test 2-15-03**

## **Phase II Results**

DHVT Operational Problems

During Phase I, the tool was run approximately twenty hours over a three-day period. The tool was generally run for periods of less than one hour and most of the time it was run in a frequency sweep mode ramping up and down every sixty seconds. During Phase I it is doubtful that sufficient vibration energy was input into the reservoir to affect fluid flow characteristics.

Phase II started on a high note from the success of Phase I. The vibration stimulation phase of the field test was scheduled to last 90 days. Four days were spent determining the temperature profile for different operating sequences. It was deemed necessary to determine how to keep the tool temperature below the 250 $^{o}$F limit of the downhole electronics by using the heat absorption capacity of the formations surrounding the DHVT outside the casing. However, on February 21, 2003, the DHVT V 3.2 onboard sensors indicated ever-increasing tool movement and an extreme tool temperature spike in excess of 550 $^{o}$F. Please refer to Figure 8 in the previous section above.

It was decided to remove the tool from the well to check out the anchoring mechanism. On March 7, 2003 a rig was moved in, the tool's slip mechanism released with no difficulty. The tool began to be removed from the well. The tool had been moved up about 400 feet when it became stuck. It is presently at approximately 2500 feet from the surface.

Effects on the Pilot Area Production and Injection Wells

There was no change in produced fluids from the pilot area wells during or in the two weeks following the operation of the DHVT. Figure 13 below is the daily record of produced for the plot test area February 1 to March 14, 2003. The minor fluctuations in the daily production curve were due to the snowstorm, which struck on February 22, 2003 and field electrical problems on March 7, 2003. The pilot production wells were individually tested and fluid levels shot prior to the start of the vibration stimulation test and again one week later, there was no change in individual well test fluid volumes nor in the fluid levels recorded. Wellhead production samples were also collected prior to start of stimulation and again one week later, no changes were found in water-cuts of the wellhead samples or in produced water salinity.

The vibration stimulation had no discernable effects on the injectivity of the two pilot area injection wells. The injection wells' pressure and rates were continuously recorded real-time throughout the field test. In Figure 14 the individual daily injection well volumes and the combined pilot area injection volumes are plotted for the time period from February 12 to February 28, 2003. The average injection rates remained the same throughout the test. The erratic nature of the graph depicts an operation called "skimming" the holding tank and is solely a function of the lease operator's daily activities.

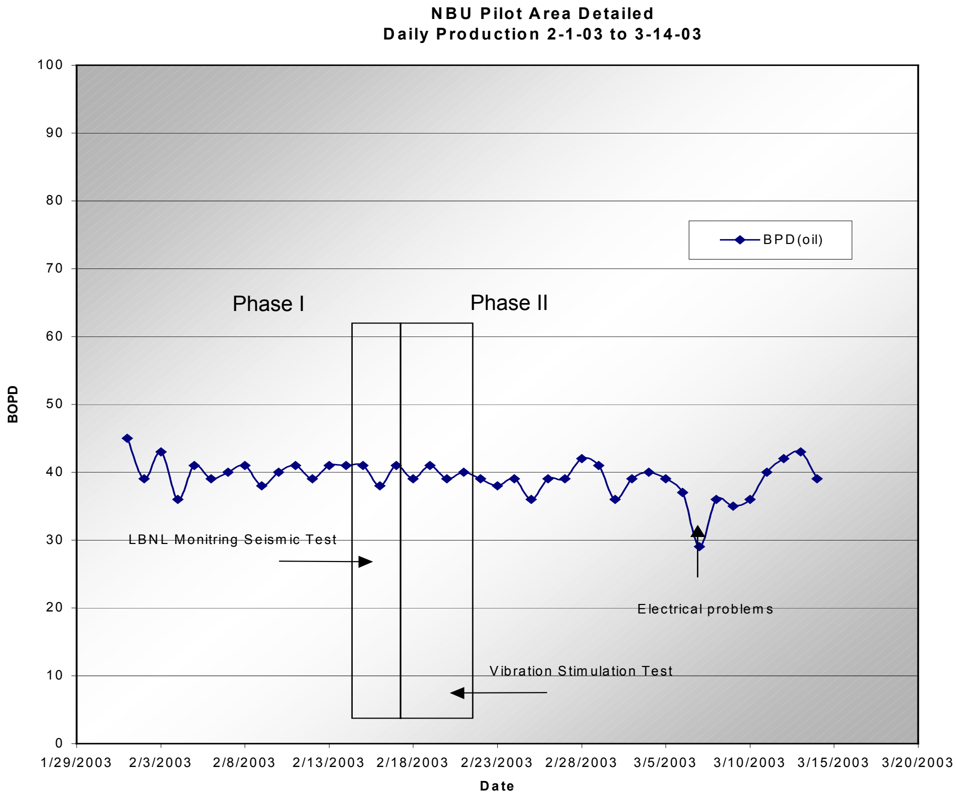


**Figure 13 NBU Pilot Area Daily Production**

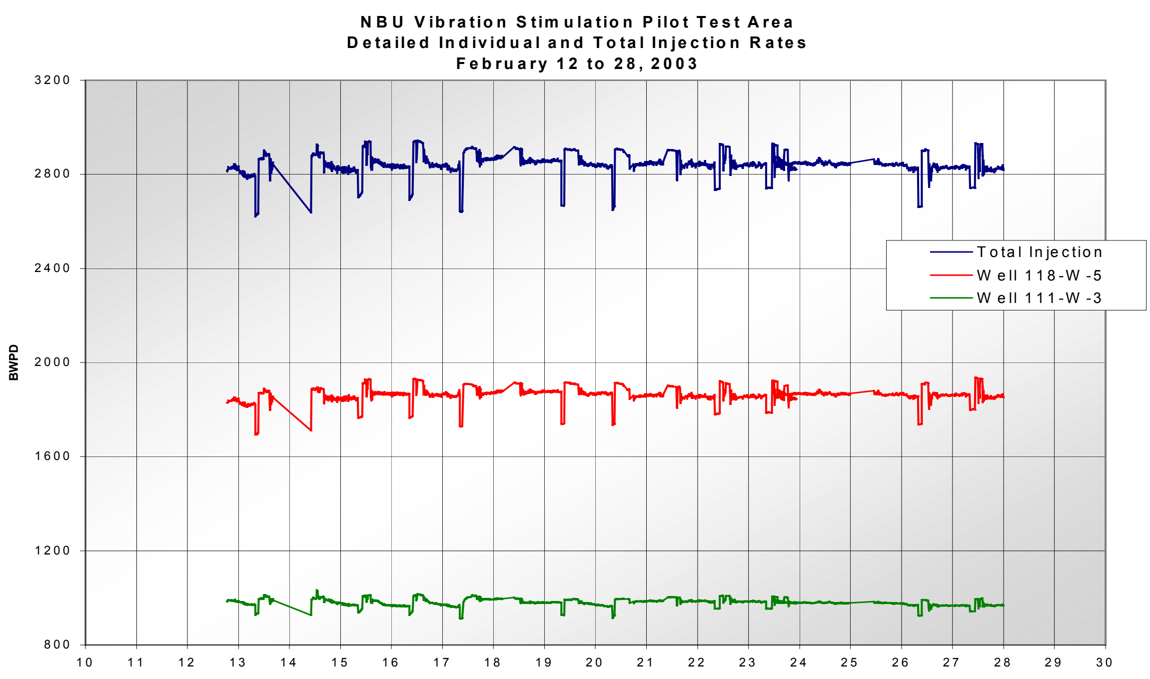


**Figure 14 NBU Pilot Area Daily Water Injection Rates February 2003**

Unfortunately, a primary objective of this project, which was to determine the effects of vibration stimulation on improving oil recovery from a mature waterflood, was not obtained. While there was no improved oil recovery effect measured, there was insufficient vibration stimulation time to expect a change to occur. Therefore no conclusion can be drawn about the effectiveness of vibration stimulation from this test.

DHVT V 3.2 remains in the well. No further efforts will be made during the DOE project to remove the tool from the well. At some point in the future, the tool will either be pushed to the bottom of the well and abandoned or it will be destroyed in attempts to remove it from the well.

The results of the field test are fully documented in Appendix H.

## *TASK 8: TECHNOLOGY TRANSFER, PUBLICIZE TEST RESULTS*

- *WRITE & SUBMIT SPE PAPER ABSTRACT*
- *AUTHOR SPE PAPER*
- *PREPARE VIBRATION ENHANCED PRODUCTION WORKSHOP*
- *CONDUCT DOE/IOR/SPE VIBRATION ENHANCED PRODUCTION WORKSHOP*
- *CONDUCT PTTC OK CITY VIBRATION STIMULATION WORKSHOP (CANCELLED)*
- *CONDUCT PTTC /U OF K VIBRATION ENHANCED PRODUCTION WORKSHOP (CANCELLED)*
- *AUTHOR DOE CONFERENCE PRESENTATION (CANCELLED)*
- *PRESENT DOE CONFERENCE PAPER (CANCELLED)*
- *PRESENT DOE/BIA CONFERENCE PAPER (CANCELLED)*

Over the course of the project, numerous efforts at technology transfer were performed. The upside potential of vibration stimulation in recovering by-passed oil in old waterfloods captured the imagination of some independent operators, who only wanted to be shown that it worked. But that did not happen. Consequently the proposed workshops planned to explain this intriguing technology will not be conducted. If the project had experienced enhanced oil recovery with vibration stimulation, the technology transfer list would be considerably longer.

Below is a list of the activities conducted during the project to begin to introduce the concept of vibration stimulation for mature waterfloods.

- SPE Paper 67303 "Enhanced Oil Recovery with Downhole Vibration Stimulation" was given at the Production and Operations Symposium (POS) in Oklahoma City, OK on March 27, 2001.

- Presentation of the material from SPE Paper 67303[3] (delivered at the OK City Production Operations Symposium, March 29, 2001) was given at the NPTO Office of the DOE April 19, 2001, at the invitation of Ginny Weyland, contract officer.

- A presentation of SPE paper 67303[3] updated has been presented to the Mid Continent Section of the SPE (Tulsa) in December, 2001.

- A version of the SPE Paper 67303[3] was published by World Oil, a Gulf Publishing Company trade magazine, in their October 2001 issue.

- Updated project material was presented to the Oklahoma Geologic Survey / DOE Annual Workshop in Oklahoma City May 8-9, 2001.

- A presentation was given at the final LANL Seismic Stimulation Project Meeting April 25, 2001, at Berkeley; co-sponsored by Las Alamos National Lab and Lawrence Berkeley National Lab.

- The material was also presented, by invitation, at the Petroleum Technology Transfer Council / Marcus Evans conference on Maximizing Recovery 2001 June 25-26, 2001 in Houston. This was one of four presentations given on seismic stimulation efforts by different organizations given to managers of technology development for operating companies.

- A one-day SPE sponsored short course which covered seismic stimulation efforts around the world, was offered at the SPE/DOE Thirteenth Symposium on Improved Oil Recovery in Tulsa, OK, April 13-17, 2002.

- SPE paper 75452[4] was given April 16, 2002 at the SPE/DOE 13$^{th}$ Improved Oil Recovery Symposium, Tulsa, OK.

- Osage Oil and Gas Summit

  The Osage Tribe hosted on September 23-25, 2001 the Osage Oil and Gas Summit in Tulsa Oklahoma. Seismic Recovery, LLC was invited to set up a booth and display information concerning the vibration stimulation project, Seismic Recovery LLC was pleased to attend the conference as a vendor. The strong attendance to the conference was encouraging, as were the questions from attendees concerning this novel technology. The model of the downhole vibration tool was the high interest point for our display. The working model, even though it is only 2 inches in diameter, grabbed everyone's attention when the floor around the booth began shake as the vibrator was being revved up.

- Idaho National Environmental and Engineering Laboratory (INEEL)

  As a result of technology transfer efforts for this project, Dave Weinberg of the INEEL, Boise, Idaho, contacted us concerning the fractured core recovered during the drilling operations. INEEL are testing orbital vibrators as a possible method of detecting and orientating natural fractures through the steel casing of wells. They asked if they could run several of their orbital vibrators in Well 111 W-27 to determine if their tools could identify and orient fractures through the casing. Calumet Oil Company was consulted and granted permission for INEEL to use the well for the INEEL test program. INEEL conducted their field tests June 13-20, 2002.

- Oklahoma Geological Survey

  Oklahoma Geological Survey (OGS) published Circular 107 in November 2002. This publication contains the proceeding of the "Revisiting old and assessing new petroleum plays in the southern Midcontinent, 2001 symposium" [5] held in Oklahoma City, OK in May 2001. The symposium was co-sponsored by the Oklahoma Geological Survey and the National Petroleum Technology Office, U.S. Department of Energy. Seismic Recovery, LLC presented "Enhanced Oil Recovery with Downhole-Vibration Stimulation, Osage County, Oklahoma" which was a project update report. The article can be found on pages 173-177 of OGS Circular 107.

- The DOE had two field trips to the NBU test site and several presentations during the project were give at the Tulsa office for interested parties.

- Two presentations were made to Osage Tribal Council advising this group of the project status. Monthly conversations were held with Joe Hughlett, the petroleum engineer for the Osage tribe.

- A project summary was presented to the Society of Exploration Geophysists Development and Production Forum, July 21-23, 2003 in Big Sky MT.

### *TASK 9: FINISH AND CLOSE OUT PROJECT*

Twelve quarterly technical reports with numerous appendices have been prepared and distributed, documenting all tasks of the project. This final task began in March 2003 after the tool became stuck in the test well and the field test was terminated. Ten appendices have been included in the final report, with the intention of providing a concise document covering the critical aspects of the project.

A project summary meeting was held at DOE’s Tulsa NETL office with both the initial and second contract officer representatives present to review the field test results and provide guidance in preparing the final report. In addition, Jolene Garrett of the Tulsa office of NETL has been very helpful through the project in keeping track of the reporting requirements and has continued to provide guidance as the project is being closed out.

### *Conclusions*

The three primary goals of the project were:

4. build and test a downhole vibration tool (DHVT) to be installed in seven inch casing
5. conduct a 90-day field test of vibration stimulation in a mature waterflooded field
6. evaluate the effects of the vibration on both the produced fluid characteristics and injection well performance.

*Build and test a downhole vibration tool (DHVT) to be installed in seven inch casing*
The project accomplished this goal, although it required a major tool redesign. The initial project estimates for building and testing a vibrator to run in seven inch casing were quickly eclipsed when the first vibrator version proved to be unable to operate at high force levels. To expedite the testing of the original and subsequent designs, a test site was built which could test prototype and full size tools. The test site was cost effective and facilitated in proving the final version of the vibrator was ready for the field stimulation test.

*Conduct a 90-day field test of vibration stimulation in a mature waterflooded field*
The value of the project centered on conducting a vibration stimulation field test and a comparison with laboratory results from sonic core tests. To possibly provide technical understanding of the process of, the field test was conducted in conjunction with Phillips' unique laboratory sonic core tests.

To be able to make a controlled comparison from lab data with field data, an extensive data collection system was operated prior to and during the field stimulation test. Due to delays in tool construction, baseline production and injection information was collected for nearly two years prior to commencing the field test. Real-time injection and production data was being collected during the field test. Unfortunately, the test did not run the proposed 90-day period due to mechanical difficulties in retrieving the vibrator for routine maintenance. The field test was abruptly terminated after running the tool approximately 40 hours during a five-day period of initial operations.

*Evaluate the effects of the vibration on both the produced fluid characteristics and injection well performance.*
Although the field test was much shorter than originally planned, the data collected prior to and during the actual vibration stimulation was as used to determine if any changes in either injection or production characteristics occurred. Produced fluid samples, oil water ratios and well tests remained constant during the time just prior to starting the field test and when the test was terminated. Water injection rates and pressures in the two pilot injection wells remained constant, allowing for recognized daily fluctuations due to the operations of the injection system.

Thus a primary goal of this project, which was to determine the effects of vibration stimulation on improving oil recovery from a mature waterflood, was not obtained. While there was no improved oil recovery effect measured, unfortunately there was insufficient vibration stimulation time to expect a change to occur. No conclusion can be drawn about the effectiveness of vibration stimulation in this test.

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3. Westermark, R.V. et al.: “Enhanced Oil Recovery with Downhole Vibration Stimulation” SPE 67303 presented in Oklahoma City, OK, March 24-27, 2001.

4. Westermark, R.V. et al.: “Enhanced Oil Recovery with Downhole Vibration Stimulation in Osage County Oklahoma” SPE 75542 presented in Tulsa, OK, April 13-17, 2002.

5. Westermark, R.V. et al.: “Enhanced Oil Recovery with Downhole-Vibration Stimulation, Osage County, Oklahoma” p 173-177 of Oklahoma Geologic Survey Circular 107, Nov 2002.

## *Appendices*

| | |
|---|---|
| Appendix A | Drilling and Geologic Report NBU Well 111 W-27<br>Calumet Oil Company |
| Appendix B | Blazer Offset Sonic Core Tests<br>Phillips Petroleum Company |
| Appendix C | DHVT Power Source Field Test Report |
| Appendix D | DHVT Reliability Test Report |
| Appendix E | NBU Routine and Sonic Core Test Report<br>Phillips Petroleum Company |
| Appendix F | DHVT Version 3.2 Performance Test Report |
| Appendix G | LBNL Field Notes of NBU Field Test |
| Appendix H | NBU Vibration Stimulation Field Test Report |
| Appendix I | SPE Paper 67303, "Enhanced Oil Recovery with Downhole Vibration Stimulation" |
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*Appendix A*

# Drilling and Geologic Report

## North Burbank Unit

## Well 111 W-27


**By**

**David Spencer**

**And**

**Richard Langston**

**Calumet Oil Company**

# DRILLING REPORT

## CALUMET OIL COMPANY

NBU #111-W27
NW/4 Sec 8-T26N-R06E
Osage County, Oklahoma

7/29/01
Current Depth: 210 ft. Current Activity: Running 9 5/8" Casing. Summary: MIRU Goober Drilling Company Rig #3. Spud at 11:00 A.M. drilling 7 ¼" pilot hole to 210'. TOOH w/ 7 ¼" bit and begin drilling 12 1/4" hole to 210 ft. Reached current depth at 6:00 A.M.

7/30/01
Current Depth: 1200 ft. Current Activity: Drilling 8 ¾" hole in lime and shale. Summary: RIH w/9 5/8" csg to 200 ft and cmtd to surface. Cmting completed by 11:00 A.M. WOC 8 hrs. Pick up Bit #1 8 ¾" and start drilling at 7:00 P.M. Slope test $1/2^o$ @ 900'.

7/31/01
Current Depth: 2020 ft. Current Activity: Drilling in Lime and Shale. Summary: Drilled to 1593 ft w/Bit #1. Slope test $3/4^o$ @ 1593'. POOH w/ Bit #1 and RIH w/Bit #2 8 ¾" Lime bit.

8/01/01
Current Depth: 2640 ft. Current Activity: Drilling in Pink Lime. Summary: Drilled and service rig. SD 4 hours to service mud pump. Slope test $3/4^o$ @ 2320'.

8/02/01
Current Depth: 2850 ft. Current Activity: TIH to circ for core. Summary: Drilled 8 ¾" hole to 2850' w/Bit #2. Started circ for core and lost circ. Build mud and add LCM. TOOH w/ Bit & DP. Start in hole w/30 ft core barrel & DP. Slope test $3/4^o$ @ 2850'.

8/03/01
Current Depth: 2910 ft. Current Activity: TOOH w/Core #2. Summary: Finish GIH w/core barrel & DP. Core #1 2850' to 2880'. TOOH w/Core #1. TIH w/ core barrel & DP cut core #2 from 2880' to 2910'. Start OOH w/Core #2.

8/04/01
Current Depth: 2984 ft. Current Activity: Drilling in Miss Lime. Summary: Finish OOH w/Core #2. GIH w/core barrel & DP. Core #3 2910' to 2934'. TOOH w/Core #3. GIH w/bit #2 and ream core section from 2850 to 2924'. Begin Drilling.

8/05/01

Current Depth: TD @ 3090 ft. Current Activity: TIH to LDDP. Summary: Drilled to TD of 3090' in Miss Lime. Circ for Logs. TOOH w/DP & bit #2. WO Loggers. TIH w/DP circ 30 min. TOOH w/DP. MIRU Schlumberger Logging and log. RDMO Schlumberger. TIH w/DP. Slope test 3/4$^o$ @ 3090'.

8/06/01

Current Activity: RDMO Goober Drilling Rig 3. Summary: Finish in hole w/DP. TOOH and LDDP. Remove circ head from under rig to run 7" csg. RIH w/7" 23 #/ft LTC csg to 3088'. Circ for 45 min. MIRU Halliburton. Cemented 7" in place with 190 sks Premium Plus cement w/5% Calseal & 3 #/sk Gilsonite. Plug down @ 5:45 PM. Nipple up head to set csg in neutral weight on slips. RDMO Goober Drilling.

# Geological Report

## CALUMET OIL COMPANY

## NORTH BURBANK UNIT #111-W27

## SECTION 8-26N-6E
## OSAGE COUNTY, OKLAHOMA

Richard S. Langston
CPG #3981
Tulsa, Oklahoma

# RICHARD S. LANGSTON

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# GEOLOGICAL REPORT

**NORTH BURBANK UNIT NO. 111-W27**

**E/2-E/2-SE-NW 510' FSL 2560' FWL**
**SECTION 8-26N-6E**
**OSAGE COUNTY, OKLAHOMA**

| | |
|---|---|
| **OPERATOR:** | Calumet Oil Corporation |
| **SPUD:** | July 28, 2001 |
| **LOGGED:** | August 5, 2001 |
| **TOTAL DEPTH:** | 3090' Driller<br>3095' Logger |
| **CONTRACTOR:** | Goobers Drilling Company<br>Stillwater, Oklahoma |
| **HOLE SIZE:** | 9.625" Casing Set to 248'<br>8.75" From 248' to TD (3095') |
| **HOLE DEVIATION:** | 860………1/2<br>1764……..1 1/4<br>2534……..1<br>2850…….1<br>3095…….3/4 |
| **ELECTRIC LOGGING:** | Schlumberger<br>Duncan, Oklahoma |
| **SURVEYS:** | Array Induction SFL/GR (Platform Express)<br>Compensated Neutron Log / Litho-Density w/ Gamma ray<br>Micro Log |
| **ELEVATIONS:** | Ground Level: 1054.6<br>Drill Floor: 1062.6<br>Kelly Bushing: 1064.6<br>All measurements relative to Kelly Bushing. |

**FORMATION TOPS:**

| | |
|---|---|
| Checkerboard | 2410 (-1345) |
| Big Lime | 2522 (-1457) |
| Oswego | 2638 (-1573) |
| Pink Lime | 2805 (-1740) |
| Burbank | 2840 (-1775) |
| Base Burbank | 2914 (-1849) |
| Mississippian | 2938 (-1873) |
| TD | 3095 |

**Classification of Shows:**

| | |
|---|---|
| Fluorescence: | Faint, Dull, Bright, Very Bright |
| Odors: | Slight, Fair, Good, Strong |
| Cuts: | Poor, Fair, Good, Excellent |
| Porosity: | Tight, Fair, Good, Very Good |

**DETAILED DESCRIPTION OF MAJOR ZONES:**

**BURBANK** **2840' TO 2914'**

The Burbank Sandstone was cored, using a 30' core barrel at the following intervals. The core was measured then double wrapped in plastic wrap and foil, boxed and taken to Phillips Petroleum core facilities in Bartlesville. The core was not washed at the wellsite. Phillips personnel did boxing of the core.

Core #1 2850 to 2880; recovered 29.4 feet
Core #2 2880 to 2910; recovered 29.6 feet
Core #3 2910 to 2933; cored 23 feet, recovered approximately 20 feet

**CONCLUSIONS:**

The North Burbank Unit #111-W27 was drilled in conjunction with OGCI and the Department of Energy as an "enhanced recovery" well in the historical Burbank Field in Osage County, Oklahoma. The Burbank Sandstone was cored and taken to the core facilities at Phillips Petroleum in Bartlesville, Oklahoma.

The Burbank deposit starts at 2840’ and the base is 2914’, for 74’ of deposit. Most of the 74’ is a “shaly“ sandstone and sometimes a “sandy” shale. The best development of sand is two lobes at the base, separated by 6’ of shale.

The log calculations take into account this “shaliness” by using cut-offs from the gamma ray log. Although these calculations are interesting it should be noted that this reservoir was found and has produced since the 1920’s. Saltwater saturations and BVW calculations indicate productive zones, however, in all probability, water will be produced along with hydrocarbons.

The well was subsequently deepen to the Mississippi Lime and TD’d at a total depth of 3095’.

Richard S. Langston
CPG #3981
Tulsa, Oklahoma

*Appendix B*

# Blazer Offset Sonic Core Tests

**By**

**Dan Maloney**

**Phillips Petroleum Company**

These are the reports form Phillips concerning the "old" Bartlesville and "Old" Burbank core responses to their sonic tests. The first report provides the results of the sonic core test on the Blazer Field offset cores the second report details the X-ray images Phillips took of the same core.

***Date:*** ***5-25-01***

***To:*** ***Bob Westermark***

From: Dan Maloney

Subject: Update on Bartlesville Sandstone Sonic Measurements

Sonic measurements were performed earlier this year on Bartlesville Sandstone cores as practice runs in advance of receiving fresh Blazer Field cores. The Bartlesville Sandstone cores were cut from sections of whole core from an adjacent lease that had been saved (for a good many years). Core plug locations were shown on a previous document. (Appendix B) The plugs were cleaned by alternating cycles of hot toluene and methanol extraction followed by flow cleaning with toluene and methanol.

The coreholder used for sonic tests required core plugs of 5.08-cm diameter and 10-cm length. Plug stacks of 10-cm length were assembled using plug pairs whose appearance on x-ray radiographs suggested similar porosity and mineralogy.

Original intent was to use samples of Blazer oil and brine as test fluids. Samples of these produced fluids were available. These fluids were filtered through 0.45-micron filters to remove sediments.

Plugs 1B and 2B were tested first (2214-1 CSO #17w Domes Unit TR#4 1820-1826). The cores were saturated with filtered formation brine. The porosity of the composite core stack was 17%. The permeability of the core to brine was initially measured as 6.9 mD, but decreased by 50% after an overnight period of inactivity. The permeability continued to drop as additional brine was injected. The bottom of the beaker containing brine that had been produced from the core during the previous day was covered with white silt. Although the brine and silt were not analyzed, we suspected that the brine was incompatible with the rock. No further tests were conducted on these plugs.

Plugs 1E and 2E (2214- 4 CSO #17w Domes Unit TR#4 1834.5 – 1836) were tested next. The cores were saturated with filtered formation brine. The porosity of the composite core was 12%. The Elastic Modulus of the brine-saturated core stack was measured as $6.48 \times 10^5$ psi. The permeability of the core to brine was 0.2 mD. The permeability of the core to brine was measured while imposing longitudinal vibration (cycles of compression and relaxation) with frequencies from 8 to 2,000 Hz and intensities from 0.0001 to 1 $w/m^2$. No particular frequency or intensity was found that caused a significant change in permeability. An attempt was made to flood the core to a residual brine saturation condition using filtered Blazer oil (16.1 cP at $76^o$ F). With 200 psi injection pressure and no back-pressure, scarcely any oil entered the core during a day of injection. Rather than continuing to test these plugs with abnormal pressure gradients, tests on plugs E1 and E2 were discontinued.

As a possible remedy for problems encountered while testing previous plug sets, the test brine was changed to synthetic brine (2% by weight KCl in de-ionized water).

Plugs 2C and 6C (2214-2 CSO #17w Domes Unit TR#4 1826-1831) were saturated with synthetic brine. The porosity of the composite core stack was 18.7%. The Elastic Modulus of the brine-saturated core was measured as 5.98 x $10^5$ psi. The permeability of the core to brine was 18.6 mD. Permeability was continuously measured as the core was subjected to longitudinal vibration with frequencies from 10 to 600 Hz and intensities from 1x$10^{-4}$ to 200 w/m$^2$. Figure 1 shows permeability versus vibration frequency from these measurements. Figure 2 presents permeability versus intensity results. Note that at each frequency, permeabilities were recorded under conditions of different vibration intensity. Figure 3 was constructed to evaluate the combined effects of frequency and intensity on permeability. For frequency and intensity combinations that were not measured, the base permeability of 18.6 mD was used when constructing figure 3. As shown by these figures, although it appears that some permeability enhancement occurred as a result of vibration, permeability enhancement at best was less than 7%.

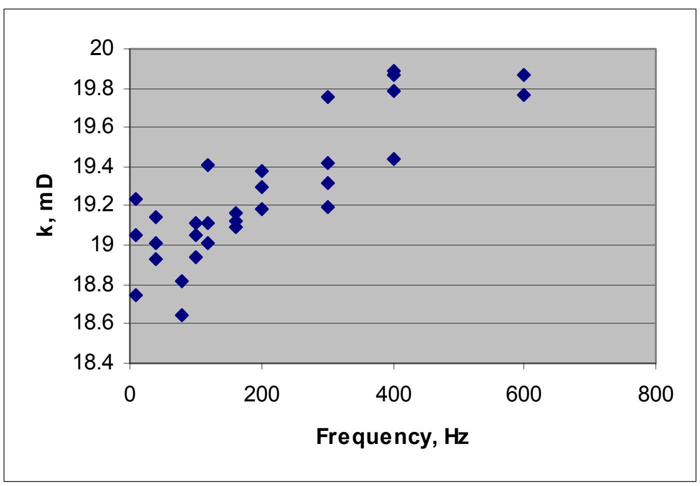



Figure 1. Permeability versus vibration frequency, C cores.

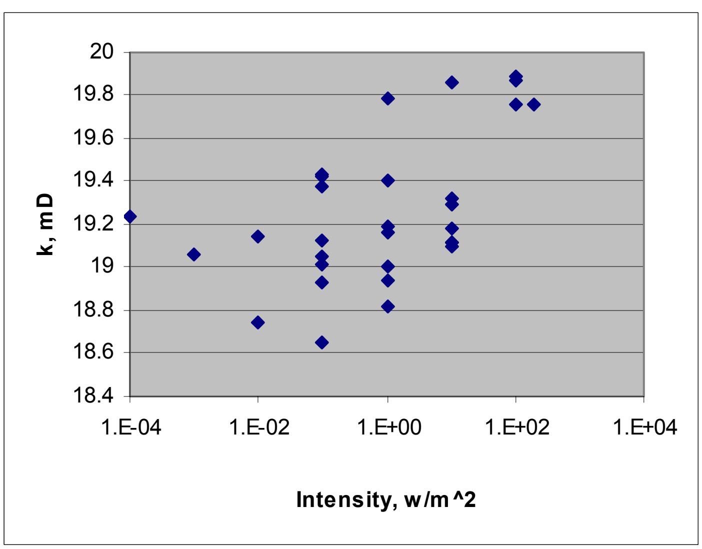



Figure 2. Permeability versus vibration intensity, C cores.

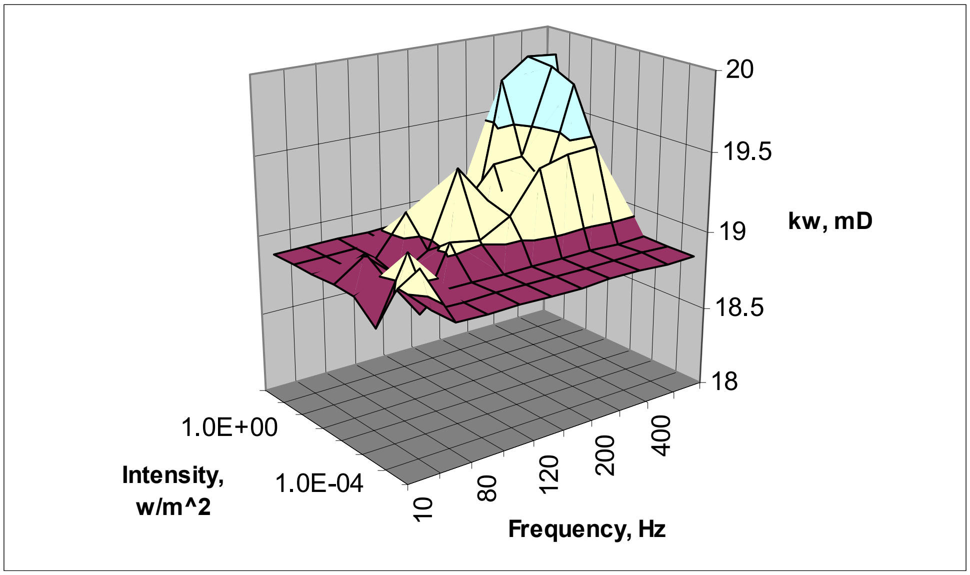



Figure 3. Variation in permeability with vibration frequency and intensity, C cores.

The core was flooded with filtered Blazer oil (16.1 cP at 76$^o$ F) to a residual brine saturation condition ($S_{wr}$ = 24%). The oil permeability at this brine saturation condition was 2.2 mD. Next, the core was waterflooded with a brine injection rate of 0.15 mL/minute. After 1 PV (pore volume) of brine was injected, the water saturation was 53%. No additional oil was produced as an additional 2.8 PV of brine was injected at the same 0.15 mL/minute rate. Thereafter, as brine injection continued, 300 Hz, 10 w/m$^2$ longitudinal vibration was imposed. No additional oil was produced while an additional 1.3 PV of brine were injected through the core. The final permeabilty of the core to brine was 0.2 mD with $S_w$ = 53%.

These shakedown tests were considered sufficient to prepare for testing fresh Field cores. A new sonic coreholder was purchased for testing 3.81 cm diameter cores of variable length. The coreholder was designed to facilitate loading and unloading test cores without having to dissassemble the entire coreholder. Slightly higher vibration intensities can be achieved with the same vibration actuator when using 3.81 cm diameter cores compared to 5 cm diameter cores owing to the smaller surface area over which force is applied.

***Date:*** ***6-12-01***

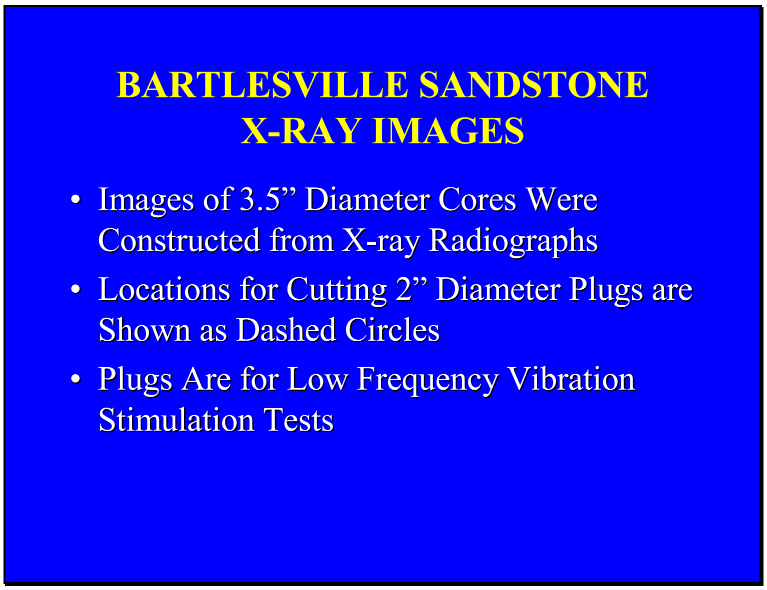
***To:*** ***Bob Westermark***

From: Dan Maloney

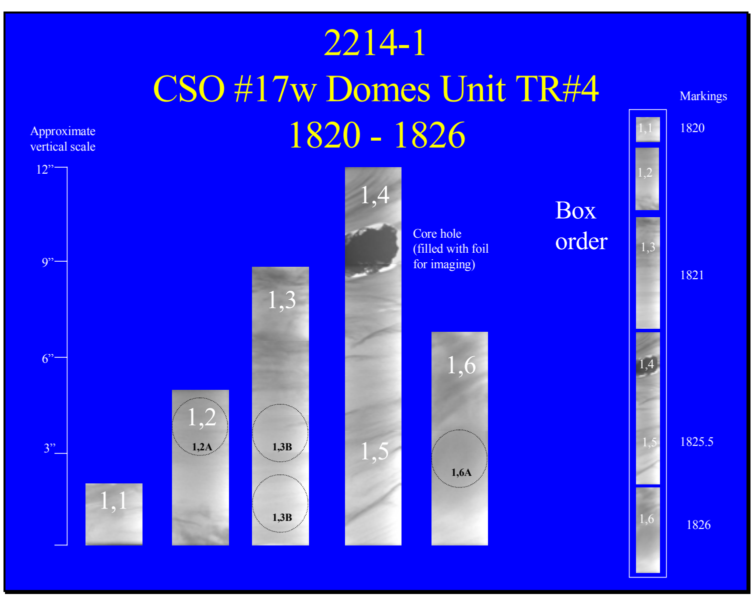
Subject: Location of Core Plugs from CSO # 17 W Domes Unit Track #4

These are the X-ray images of the subject core, which was provided by Grand Resources as an offset core to their Blazer Field.

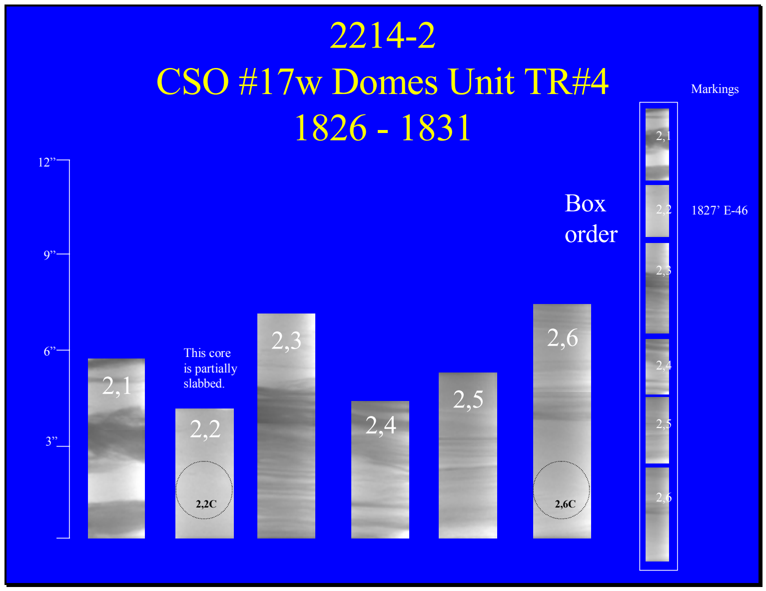
Slide 1



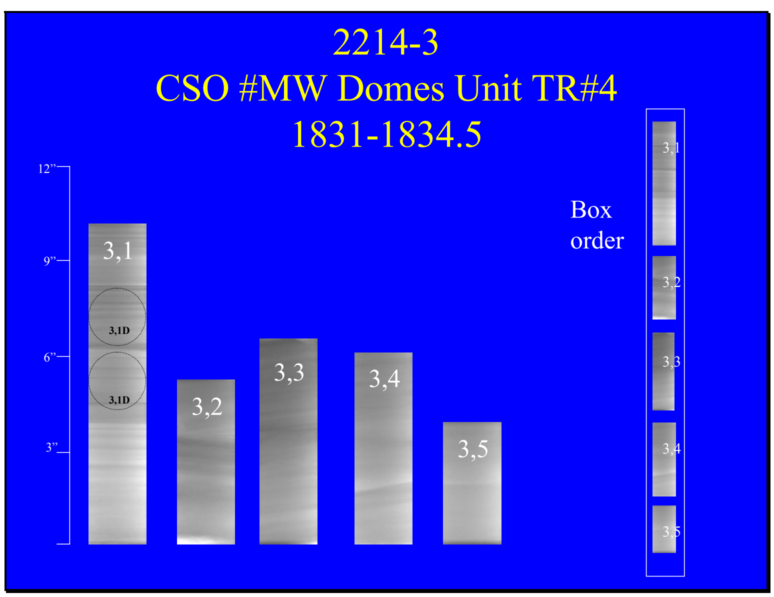

Slide 2



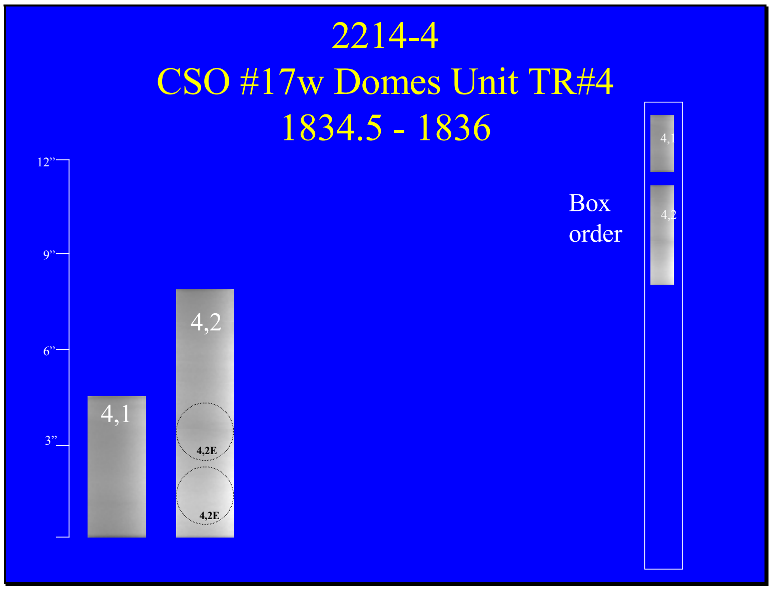
Slide 3



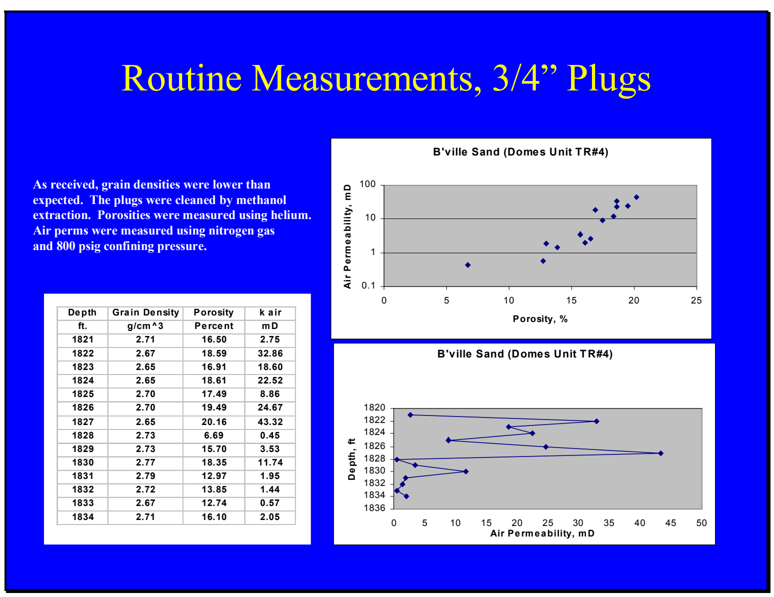

Slide 4



Slide 5




Slide 6




| Depth | Grain Density | Porosity | k air |
|---|---|---|---|
| ft. | g/cm^3 | Percent | mD |
| 1821 | 2.71 | 16.50 | 2.75 |
| 1822 | 2.67 | 18.59 | 32.86 |
| 1823 | 2.65 | 16.91 | 18.60 |
| 1824 | 2.65 | 18.61 | 22.52 |
| 1825 | 2.70 | 17.49 | 8.86 |
| 1826 | 2.70 | 19.49 | 24.67 |
| 1827 | 2.65 | 20.16 | 43.32 |
| 1828 | 2.73 | 6.69 | 0.45 |
| 1829 | 2.73 | 15.70 | 3.53 |
| 1830 | 2.77 | 18.35 | 11.74 |
| 1831 | 2.79 | 12.97 | 1.95 |
| 1832 | 2.72 | 13.85 | 1.44 |
| 1833 | 2.67 | 12.74 | 0.57 |
| 1834 | 2.71 | 16.10 | 2.05 |

*Appendix C*

# DHVT Power Source

# Field Test Report

*By*

**Bob Westermark**

**Seismic Recovery LLC**

# DHVT Power Source Field Test

***Purposes of test:*** **To obtain operating information and determine the durability of the DHVT, in an inactive well with the tool set at a shallow depth, +/- 500'.**

## Tasks to be performed and evaluated

1. Assemble, run, set, operate and retrieve the 7" DHVT with a downhole instrumentation package and data electric line back to the surface to test its functionality and durability.
2. Assemble the rod-rotating unit, operate the 50 Hp motor using the computer to operate the variable speed motor controller, and collect data from the motor controller data acquisition system.
3. Assemble and deploy the data acquisition system for the downhole instruments, variable speed motor controller, surface accelerometers, and a single, three-axis surface geophone.
4. Collect and analyze the data generated as the DHVT is operated from data acquisition system mentioned in 3 above.

### Evaluation of the Power Source Field Tests

1. Functionality: Satisfactory
   The DHVT ran and set in the well as designed, (four times at +/- 500') the retrieving mechanism has also has functioned correctly. The sucker rod on-off tool worked correctly, but initially sheared at a low over pull value, this was corrected by using a larger, stronger shear pin. The downhole instruments and electric line to the surface have operated satisfactorily. However, in the December 18th test, the soldered electrical components were shaken off the printed circuit board, indicative of excessive vibrations. These have since been repaired and, as this report is been written, are functioning properly.

   Durability: Unsatisfactory
   The durability of the DHVT have been a disappointment. At the end of the October 29th test, the tool had failed due to sever galling resulting in a broken flexshaft. The severe galling problem appears to have been over come by heat-treating the material to a much harder finish, (56 Rockwell C). Excessive torque loads have occurred causing the failures in the top flexshafts. The flexshafts have been redesigned and are currently being tested.

2. The rod-rotating unit has functioned well. The ability to control the speed of the motor with the computer has proven to be trouble free. However, the variable speed motor controller has been determined to be a major source of the electrical noise, which plagued data collection during the first days of the downhole testing, preventing complete data collection. To minimize the motor controller's impact on the data collection system, it is being moved out of the doghouse and closer to the well for the NBU test.

3. The computer and software used for the data collection system has functioned well, considering the electrical noise problems. The flexibility of the software to adapt to changing instrumentation configurations has proven most beneficial. The data collection requirements have grown considerably since the initial plans and this computer/software combination have been able to expand to fill the needs collecting data at up to 5000 bits per second per channel. The motor controller data collection has also worked as designed.

   The surface accelerometers were added as acquisition sources when we unable to pick up signals from the geophones. These were placed on the wellhead and they verified that indeed the desired vibrations were being generated downhole and could be measured at the wellhead 500' above the DHVT.

However, the data collected from the geophones has been problematic. With earlier field testing in 1994, we knew that the earlier version of the DHVT generated a very strong seismic signal, easily picked by geophones over 1000' away from the vibration well. Lack of seismic signals indicated either the tool was not running properly or the casing was not well cemented at the depth the DHVT was being run. Well records indicated a remedial cement job had been performed satisfactorily over the depth interval in question. The ability of the DHVT to shake the earth is predicated on good cement bonding between the casing and the formation. It became a priority at the end of the year to be able to determine if the tool operation or cement bonding was the problem. As this report is being prepared, a test site was built south Tulsa and is now being used to finish the power source testing operation.

4. Collecting the data from the downhole instruments, motor controller, surface accelerometers, and a single, three-axis surface geophone has had it's complications as described above. However the real challenge has been to develop a timely, analytical process for this newly acquired information, streaming in at very high data rates. At the surface test site south of Tulsa, we have been gathering enough data every forty minutes to fill a 650 megabit CD ROM. The preferred method of analyzing the data is to replay the data and observe the relative changes in the amplitude of the signals relative to time. This works fine sitting at a computer but producing "snapshots or stills" onto paper of moving data loses it's impact.

## Planned Approach Forward

The power source field tests provided necessary operating information of the DHVT to monitor and record its performance. At the time of this report preparation, DHVT modifications have been made and are currently under test at a surface test site south of Tulsa. The preliminary results are encouraging and we plan to begin the vibration stimulation testing in February 2002 in the NBU Well 111-W-27.

## Summary of Power Source Field Tests

1. The DHVT was run in the well October 19 and pulled October 29. The tool quit working after about 24 hours of operating time. Data was being recorded as the DHVT went from a normal running condition to failure in a few seconds. The mass and adjacent housing surface was severely galled. Subsequently the top flex shaft was severely bent. Please refer to figure 1 below (the top flexshaft).
2. After a failure analysis was conducted, numerous improvements were made to the DHVT, notably a hardened mass and hardened internal sleeve were added to prevent galling. Other improvements included tighter tolerances on the two bearing assemblies, added sealing attachments and tighter tolerances on the spring housing.
3. Shop tests were conducted Nov. 30 through Dec. 5, 2001 to check out the performance of the above modifications. The DHVT was running correctly. It was then readied for further power source field-testing in the Wynona well.
4. The DHVT was run Dec. 18, operated for 4 hours and pulled to check for any internal wear problems. The DHVT was good condition, but the downhole electronics package was damaged. The DHVT was re-run, without the downhole instrumentation package Dec. 20, 2001. The tool operated only thirty-seven minutes and quit working. It was pulled and inspected. There was no galling on the internal parts. The top flex shaft was slightly bent and the threads broken. Please refer to figure 1 below (the second from bottom).
5. Stronger shafts have been made and the DHVT is being re-tested on the surface as this report is being written. The preliminary results are encouraging.

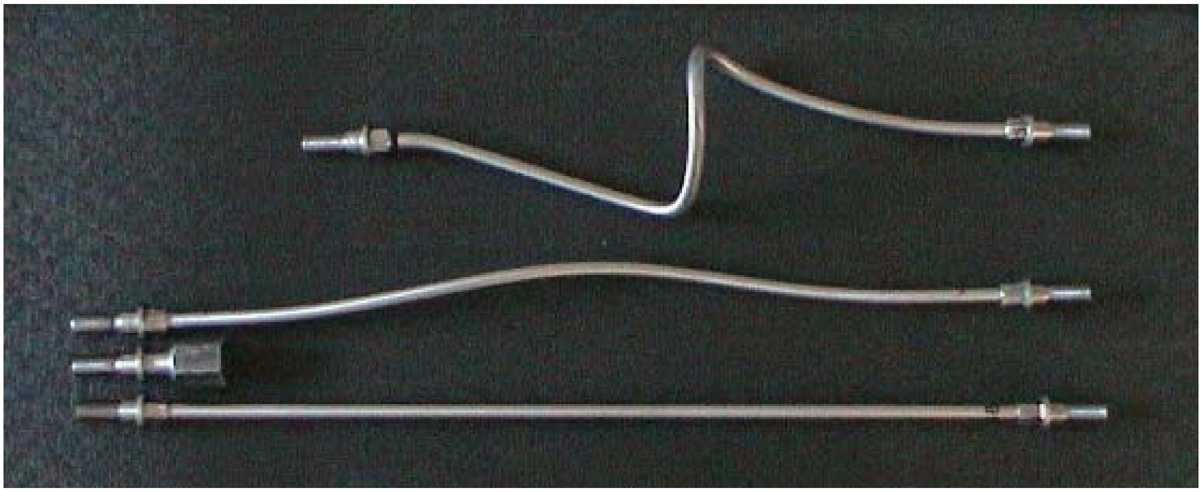


Figure 1 Bottom to top: Straight flex shaft, flex shaft thread test sample, slightly bent flex shaft, severely bent flex shaft. Length of straight shaft is approximately 26 inches end to end.

## Location of Well for Power Source Field Test

The power source field test was conducted in Wynona Waterflood Unit, Well 12-20. This well has been inactive since being shut-in in 1986.

## Detail of Worked Performed on WWU 12-20

Aug. 10, 2001 The data acquisition doghouse and the rod-rotating unit were set at the well.

Oct. 17, 2001 A well service rig moved on the well to run a bit and scaper prior to running a packer to test the pressure integrity of the casing. The casing pressure test was okay.

Oct. 18, 2001 The 7" DHVT was run to about 500' set with 10,000 lbs. of tension on the slips. The 7/8" sucker rod on-off tool was run inside the tubing and latched onto the DHVT drive shaft.

The on-off tool was sheared off the DHVT drive shaft with only 3000 lbs. over pull. The DHVT slips were released and the tool pulled from the well. The shear pin was strengthened to provide approximately 5000 lbs. overpull before shearing.

Oct. 19, 2001 Ran the 7" DHVT and set at 507'. Rigged up the rod-rotating unit. Begin rotating the sucker rods. Unable to decipher any instrumentation data due to electrical noise. Worked to reduce the electrical noise.

Oct. 22, 2001 Worked on reducing electrical noise, partially successful.

Oct. 23, 2001 Installed portable generator, electrical noise down to an acceptable level but not eliminated.

Oct. 24, 2001 Ran DHVT for approximately 4 hours and were able to obtain acceptable data from downhole instrumentation. The vibration generated were measured in the 30 to 50 Hz range.

Oct. 25, 2001 Ran DHVT for approximately 6 hours, and were able to obtain acceptable data from downhole instrumentation. Unable to detect any vibrations with the three-axis geophone at a distance of 500' northwest of the well. The vibrations generated were measured in the 30 to 50 Hz range.

Oct. 29, 2001 Ran DHVT for approximately 4 hours, and were able to obtain acceptable data from downhole instrumentation. The test today was run to duplicate the data obtain on Friday and to add hours to the run time. The downhole instrument package indicated the tool failed while running at 50 Hz. The rig moved in and the DHVT was partially retrieved from the well when work was shut down for night.

Oct. 30, 2001 Finished pulling the DHVT from the well. Took it to the machine shop to began disassembling the tool. The rotating mass and the adjacent inside of the housing was severely galled and the upper flex shaft was severely bent and broken.

Nov 1 to Dec 15, 2001

The tool was repaired, shop tested, and readied for additional power source field-testing.

Dec. 18, 2001 Moved-in the well service rig, ran the DHVT and data cable, operated for 4 hours, and pulled the DHVT. The tool operated as anticipated, however the downhole electronics quit working after about 37 minutes of run time today. Unable to obtain a signal with the three-axis geophone, this time placed about 600' east of the well.

Dec. 19, 2001 The DHVT was disassembled and was in good condition. However the downhole electronics package was damaged beyond repair. The tool was re-assembled without the electronics package.

Dec. 20, 2001 Ran the DHVT and tried to operate the tool for about 1 hour, but it was not operating correctly. Pulled the DHVT. The upper flexshaft was slightly bent and the threads broken. There was no galling inside the tool.

## DHVT Surface Power Source Test Run Time

| Date | Duration (hrs) | Cumulative Time | RPM |
|---|---|---|---|
| October 19, 2001 | 2.0 | 2 | 0 to 60 |
| October 23, 2001 | 2.0 | 4 | 0 to 250 |
| October 24, 2001 | 7.5 | 11.5 | 0 to 250 |
| October 25, 2001 | 8.5 | 20 | 0 to 350 |
| October 29, 2001 | 4.0 | 24 | 0 to 350 |
| December 18, 2001 | 4.0 | 28 | 0 to 400 |
| December 20, 2001 | 0.6 | 28.6 | 0 to 400 |

*Appendix D*

# DHVT Reliability

# Test Report


**By**

**Bob Westermark**

**Seismic Recovery LLC**

## DHVT RELIABILITY TESTING

OGCI's Test Facility at Knight's Pecan Farm
January 18 through March 27, 2002

# *Summary*

**Purpose:**

The purpose of constructing the Knights Pecan Farm Test Facility (KPF) was to be able to quickly test the DHVT with different configurations and to determine the performance of the specific configuration.

**Technique:**

Operate the tool with full instrumentation at load levels approaching those planned for the NBU vibration stimulation field test. The testing will focus on the two problem areas identified of critical components during the October and December 2001 Wynona field tests. Critical components of the DHVT are the flexshafts and the rotating mass inside the housing. Two problems were identified, galling of the mass and the adjacent contact area inside the housing and the failure of the flexshafts.

**Conclusions:**

The conclusions from the results of the KPF tests are as follows:

1. The galling continued between the mass and the inner housing with various finishes and metallurgical combinations used in the tests. The recommended solution to the galling problem is to have lubrication between the mass and the surface, which it contacts.
2. The basis of generating whirl with flexshafts is to establish sufficient friction with side loading to initiate the whirl movement. Adding lubrication to the system will prevent the use of flexshafts. Therefore another method of initiating whirl will need to be designed. To be able to generate a whirling lubricated mass, positive positioning of the mass to the housing will be required.
3. A new tool designed to operate with lubrication is necessary to have adequate reliability for conducting the field test in the North Burbank Unit.

**Details**

Knights Pecan Farm Test (KPF) Facility Site

Construction of the KPF began Jan. 7, 2002 with digging a 12' deep hole to install three pieces of casing (4 ½", 5 ½" and 7"). With 80,000 lbs of concrete being poured Jan 10 and 11th a 16' tall A-frame was built to allow for hoisting the equipment in and out of the casing.

The first test commenced Jan 18, 2002. Twelve separate tests have been conducted from Jan. 18 through Mar. 27, 2002.

Synopsis of the tests to date:

Jan 18 –Feb 4

- Purpose: to gather operating data, specifically if the DHVT runs properly or not and measure the energy output with the tool configuration identical to the Wynona field tests. Two types of flexshaft connection designs were tested, running a nitrided mass inside the nitrided sleeve.
- Result: The DHVT ran most of the time in a normal mode. The signals from the geophone were readily apparent and fluctuated with changing output frequencies. The order of magnitude of the energy produced matched the predicted forces. When higher loads were applied, galling occurred between the mass and the sleeve, then the flexshaft twisted and failed.

Mar. 5 – Mar 27

- Purpose: Test the gall resistance of the new Carburized mass and sleeve and test the new flexshaft designs and material. Titanium shafts were tested as well as 4140 alloy steel and the more flexible 1018 alloy.

- Results: The Carburized mass and sleeve ran satisfactorily, however a red powder of iron oxide was generated at even the lowest of operating loads. This fine powder is a precursor to galling. The titanium and 4140 alloy shafts both failed. The 1018 flexshafts worked satisfactorily.

Below is a break down of each test run at KPF. Each test generated data, which was analyzed using graphical plots of key parameters. The figures 1 through 6 are representative of analysis performed. Figures 1 and 2 are plots relating real time to RPM and the operating loads for that test in terms of horsepower and torque. This is a result of measuring tool rotation and the hydraulic pressure needed to turn the tool at those speeds. This measures how much work in being done by the tool.

Figures 3 and 4 are a measure of the tool generating vibration frequency at the tool and in the adjacent 5 ½" casing versus the predicted frequency for a range rotating speeds. This information indicates how smoothly the tool is running.

Figures 5 and 6 are plots of the vibration forces measured both at the tool and in the adjacent 5 ½" casing. This is an indication how well the tools is able to transmit the vibration energy into the 70, 000 lbs. of concrete in the test cell. This information indicates how efficiently the tool is coupled to the concrete through the slips and the measure of movement of the concrete block within the soil surrounding it.

| Test No. | Test Date | Tool Configuration | Results |
|---|---|---|---|
| 1 | Jan. 18-21 | Old 1018 .400 shaft, Nitrided mass and sleeve. Sleeve ID 3.500 - Mass OD 3.2 | Good results. No wear. Wanted to run the .450 shafts. |
| 2 | Jan. 22-23 | Old 1018 .450 shaft, Nitrided mass and sleeve. | Everything looked good. Some violent splashing at 400 rpm. Pulled tool to run new .400 shaft. |
| 3 | Jan. 24-28 | New 4140 .400 shaft, Nitrided mass and sleeve. | Running good with bottle jacks instead of pallet jack. Shaft twisted @ 575 rpm. |
| 4 | Feb. 04 | New 4140 .400 shaft, Nitrided mass and sleeve. Sleeve has been loc-tited in place. | Sleeve still moved up even with loc-tite. Run tool up to 600 rpm and had a galling failure. |
| 5 | March 5-6 | Titanium shaft, Carburized mass and sleeve. | The tool did not run well at all with the titanium shafts. It appeared to be canted all the time. |
| 6 | March 7-11 | New 4140 .450 shaft, Carburized mass and sleeve. | Once we got the spring setting it seemed to run ok. A lot of FeO dust when we took apart for inspection. |
| 7 | March 12 | New 4140 .450 shaft, Carburized mass and sleeve. Sleeve has been honed to 100% clean-up. | Pulled the tool for inspection and noticed a fatigue crack on the upper shaft. |
| 8 | March 13 | Titanium shaft, Carburized mass and sleeve. Sleeve ID 3.508 - Mass OD 3.160 | Tool was running ok until the titanium shaft twisted. |
| 9 | March 14-18 | New 1018 .450 shaft, Carburized sleeve and mass. | The tool seemed to be running well. When we pulled the tool it looked like it was starting to gall. |
| 10 | March 22 | New 1018 .450 shaft, Carburized sleeve and mass. Sleeve ID 3.515 - Mass OD 3.156 | Ran the tool for a short time. When we pulled it for inspection there was a lot of FeO dust. |
| 11 | March 25 | New 1018 .450 shaft, Carburized sleeve and mass. Grease added to the OD of the mass. | Added grease to see if we could whirl with lubrication with out gears. It did not work. |
| 12 | March 26-27 | New 1018 .450 shaft, Carburized sleeve and nitrided mass. Sleeve ID 3.508 - Mass OD 3.102. | Run the tool at 320 rpm for several hours. Pulled the tool for inspection and there was lots of FeO dust. |

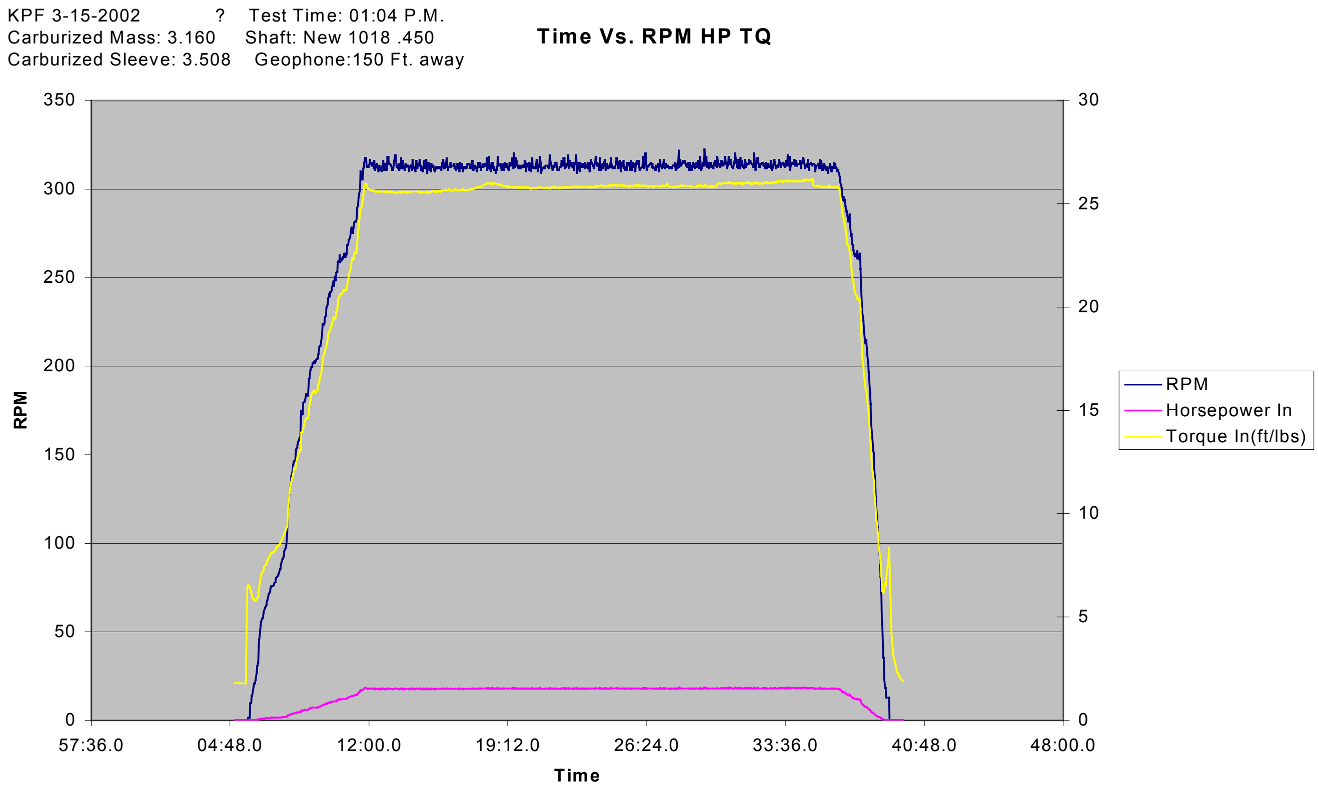



**Figure 1 Time vs. RPM, Horsepower and Torque**

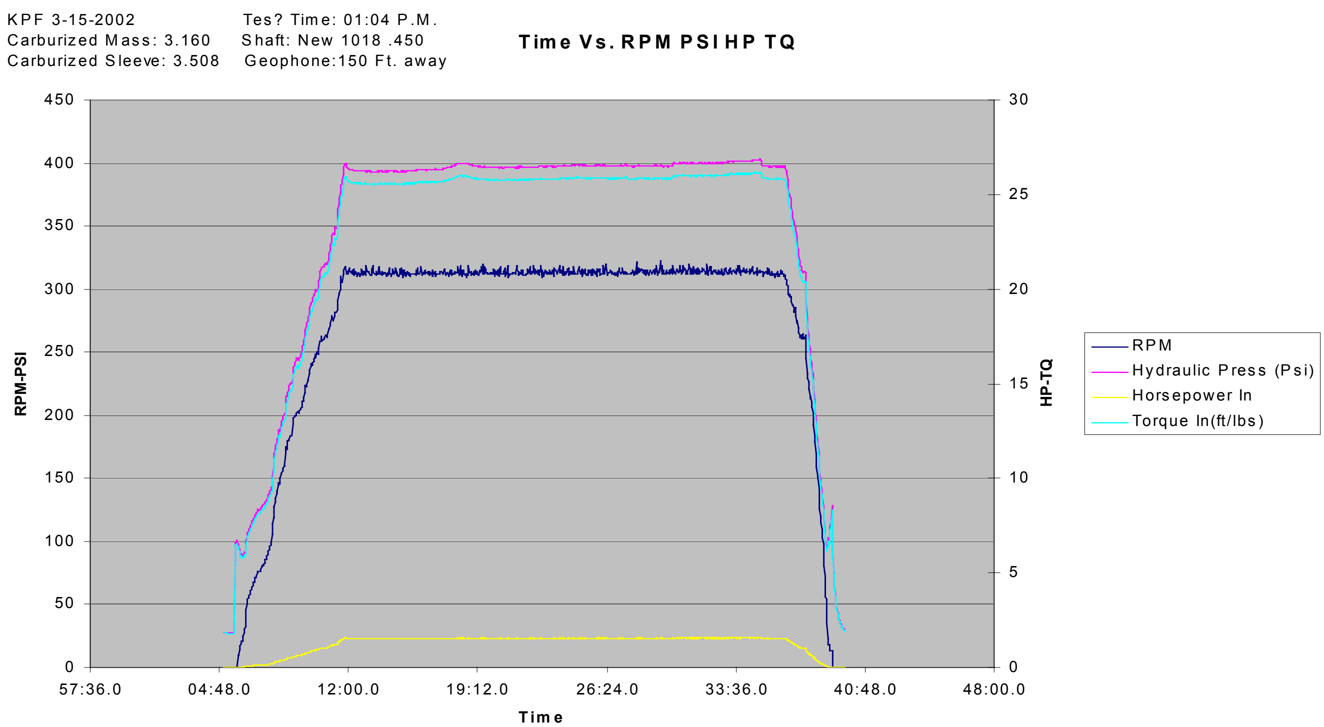



**Figure 2 Time vs. RPM, Hydraulic Pressure and Torque**

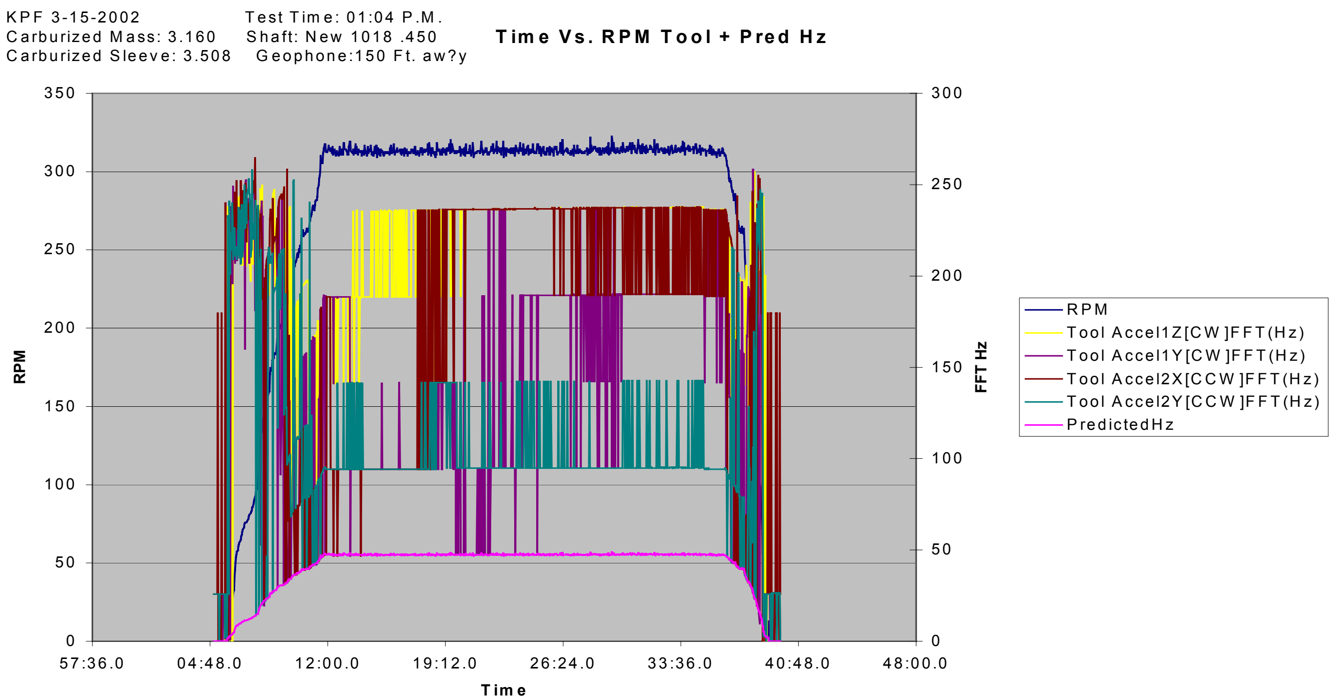



**Figure 3 Time vs. RPM, Tool and Predicted Frequency**

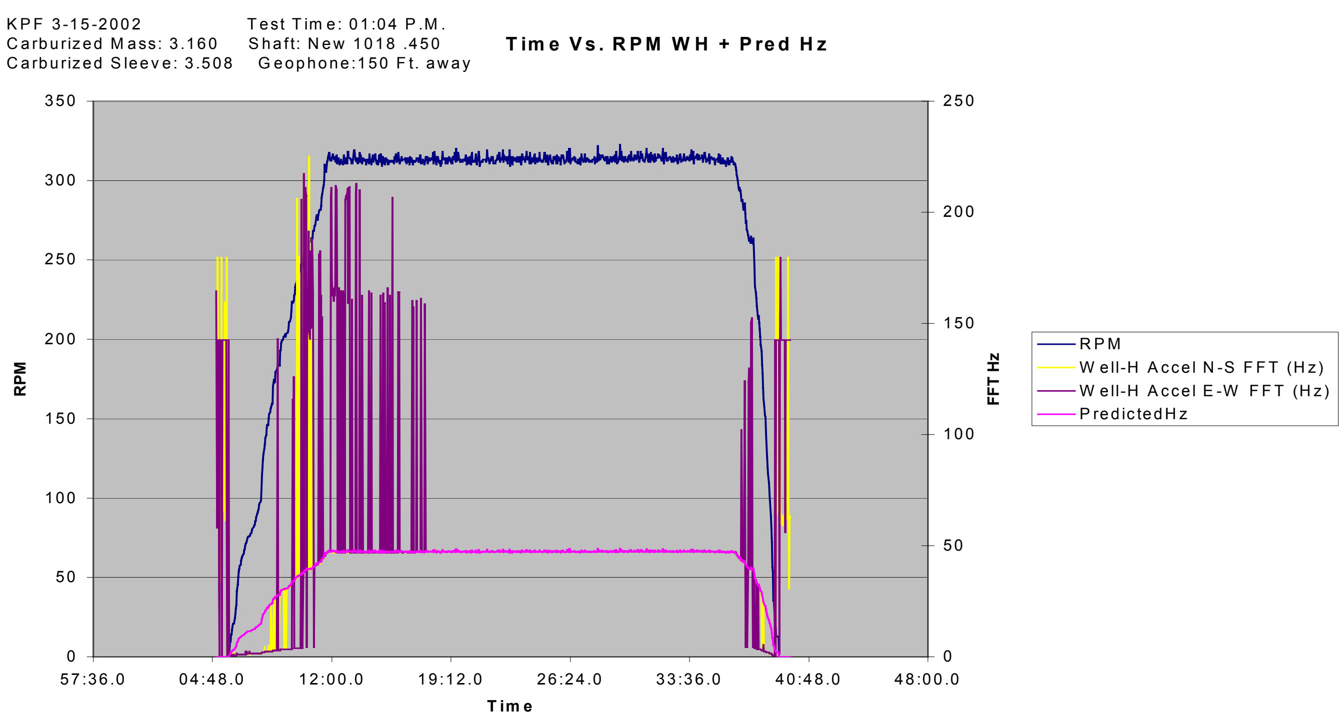



**Figure 4 Time vs. RPM, Wellhead and Predicted Frequency**

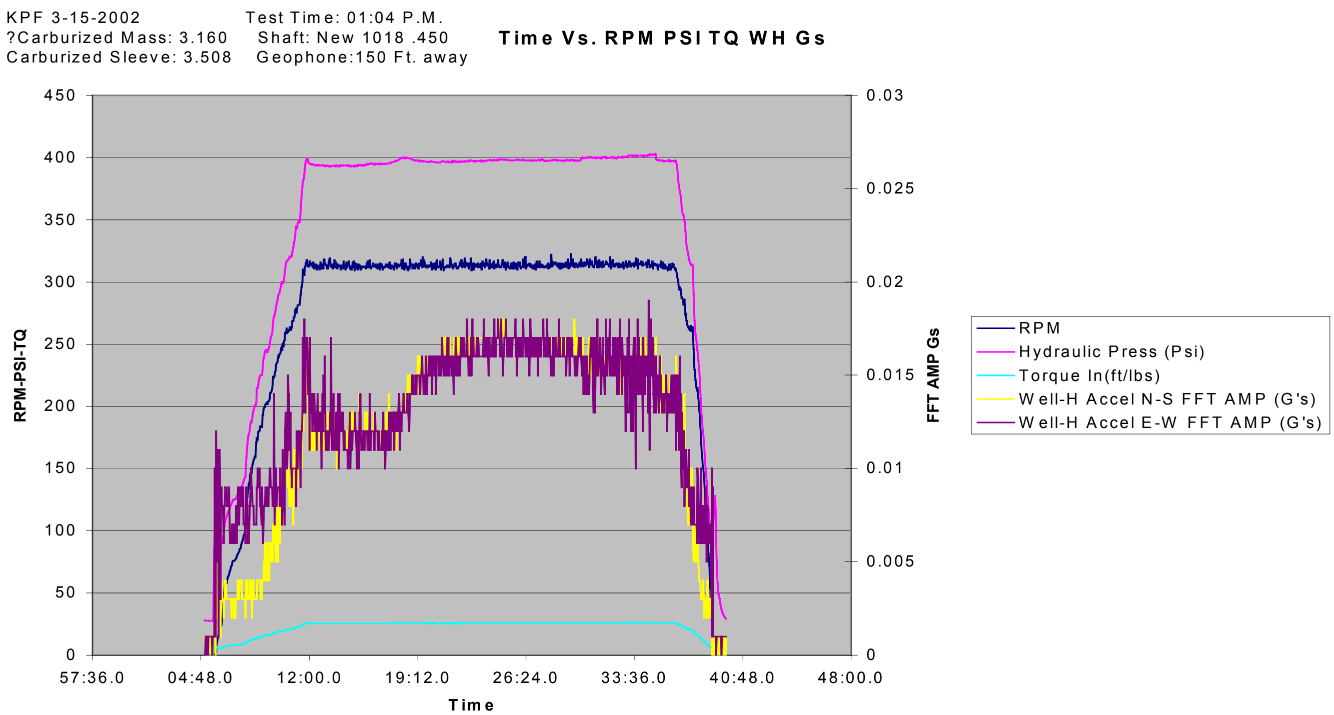



**Figure 5 Time vs. RPM, Hydraulic Pressure, Torque and Wellhead G's**

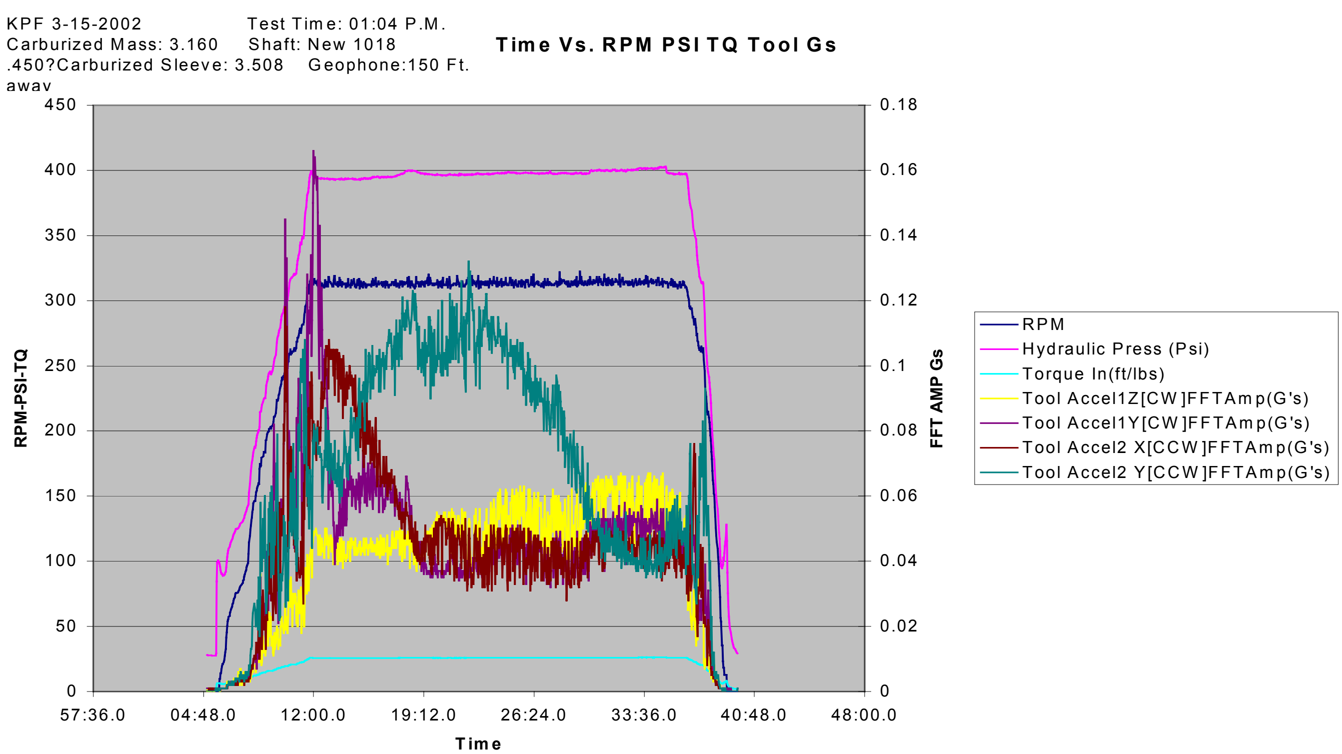



**Figure 6 Time vs. RPM, Hydraulic Pressure, Torque, and Tool G's** **Figure 6 Time vs. RPM, Hydraulic Pressure, Torque, and Tool G's**

*Appendix E*

# NBU ROUTINE CORE ANALYSES AND SONIC CORE TESTS
# IN SUPPORT OF SEISMIC RECOVERY, LLC's
# FIELD DEMONSTRATION PROJECT
# (DOE GRANT NO. DE-FG26-00BC15191


***By***

**Dan Maloney**

**Phillips Petroleum Company**

# NBU ROUTINE CORE ANALYSES AND SONIC CORE TESTS IN SUPPORT OF SEISMIC RECOVERY, LLC's FIELD DEMONSTRATION PROJECT (DOE GRANT NO. DE-FG26-00BC15191)

By Dan Maloney, Phillips Petroleum Company

## SUMMARY

This report describes results of routine and special core analyses conducted on Burbank core plugs as an in-kind contribution supporting Seismic Recovery, LLC's field demonstration project (DOE Grant No. DE-FG26-00BC15191). Data from routine property measurements are described and presented. Special core analyses consisted of tests to measure waterflood oil recovery without and with sonic stimulation (low frequency p-wave or vibration stimulation). Limited results from waterfloods without and with sonic stimulation provide evidence that oil recovery was accelerated as a result of vibration stimulation compared to waterflood results without vibration stimulation although results do not provide enough insight to provide guidance on vibration frequencies and intensities that will optimize NBU oil production and recovery. Results suggest that it may be advantageous to stimulate with vibration in a dynamic mode; periodically turning off and on vibration and changing frequency and intensity of vibration.

## ROUTINE CORE ANALYSES

Routine core analyses were conducted on core from Well 111-W-27 from section 8 T26N R6E of Osage County Oklahoma. The well was cored in early August 2001. Phillips technicians brought whole cores to Bartlesville for temporary storage, slabbing, and core sampling. Core plugs were drilled from whole core samples at the Phillips Research Center (PRC) in Bartlesville Oklahoma. PRC staff performed the core analyses described in this report.

Extraction columns were prepared prior to extracting fluids from core plugs. Toluene was boiled in Dean Stark extraction units for 1 day to remove trace amounts of water. Desiccant-filled tubes were placed on top of each extraction column. The purpose of the desiccant was to keep humid air out of extraction columns.

The weight of each core plug was initially recorded. Core plugs were extracted with toluene using the Dean Stark method. After Dean Stark extraction, alternating cycles of toluene and methanol extraction further cleaned the plugs. One of the reasons for extracting with methanol is to remove salt from the core plugs. Cleaned plugs were dried in a vacuum oven. Weights of the cleaned plugs were recorded. Pore volume for each core plug was determined by a gas expansion technique. Porosity was determined by dividing pore volume by bulk volume.

For each plug, initial brine volume was calculated by applying a salt correction to the volume of water recovered by Dean Stark extraction. The salt correction assumes that, as cores are extracted, water captured in the side arm water trap of the extraction column is salt-free. Salt constituents of the brine that are left in the core are later removed by methanol extraction. The volume of water recovered from a core therefore underestimates brine volume. The intent of the salt correction is to account for this volume difference. Because the whole cores were originally slabbed using tap water and cores were cut using tap water, it is possible that some of the brine that was originally in the core plugs had been diluted or replaced by tap water. If this occurred, then the salt correction may overestimate brine contents of core plugs. Brine saturation was calculated by dividing brine volume by the pore volume.

The volume of oil initially contained in each plug was calculated by dividing the weight loss from cleaning less the calculated weight of brine extracted, by the density of the oil. Oil saturation was calculated by dividing oil volume by the pore volume.

Gas volume was calculated by subtracting oil and brine volume from the pore volume. Gas (air) saturation was calculated as air volume divided by pore volume.

Figure 1 is a plot of plug depth versus initial brine, oil, and gas (air) saturation from measurements described in previous paragraphs. Although lines are drawn between data points, where data points are not shown, one should not infer that the lines represent measured saturations. The data will not ideally reconcile with saturations that existed in the rock before the rock was cored for a number of reasons. First, as whole cores were drilled from the reservoir, cutting fluid may have flushed some of the pore fluids from the rock. Next, as the cores were lifted from the reservoir environment to the surface, any gas that evolved from the oil may have displaced oil or brine from the core. Finally, while the whole cores were slabbed and plugs were drilled, some of the pore fluids may have been replaced by the core cutting fluid (water). The data shown on Figure 1 can be found elsewhere.[1]

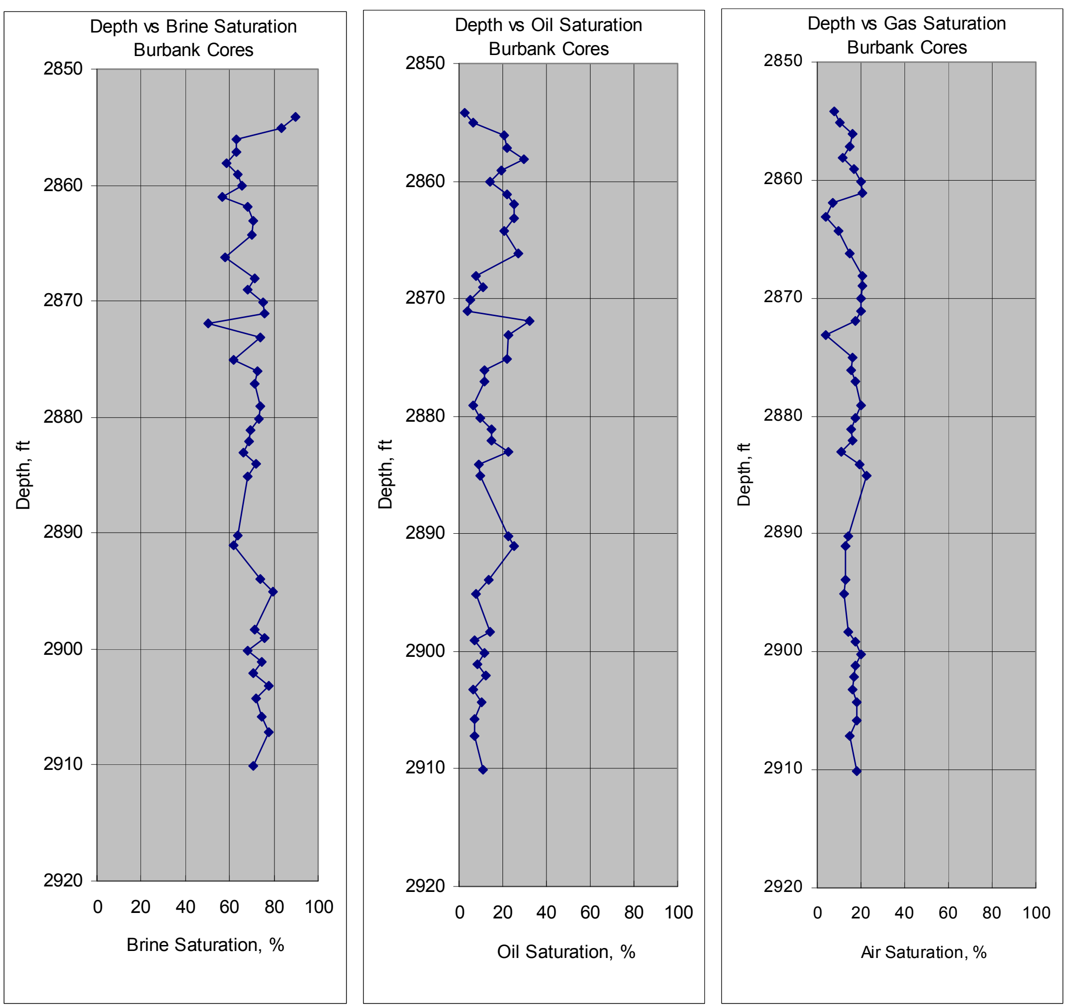



**Figure 1.** Routine core properties and saturations calculated from weight change and extracted water volumes.

Routine properties measured for each clean and dry core plug included bulk volume, pore volume, grain volume, grain density, permeability to nitrogen gas, and porosity. The technician who measured permeability had calibrated his measurement system for plugs of 0.1 mD or greater permeability. When he encountered plugs of permeability below the range of accuracy for his equipment configuration, he recorded “<0.01 mD.” This is not to say that those samples were impermeable, but rather that they were of lower permeability than he was prepared to measure.

Permeability and porosity results from routine measurements are shown in Figure 2. Note that permeability is on a log scale. At first glance, it appears from the data that there are 3 moderately permeable zones within the depth column that are separated by zones of lower permeability and porosity. These are 2861.9’ to 2873.1’, 2876.1’ to 2885.1’, and 2893.9’ to 2910.1’.

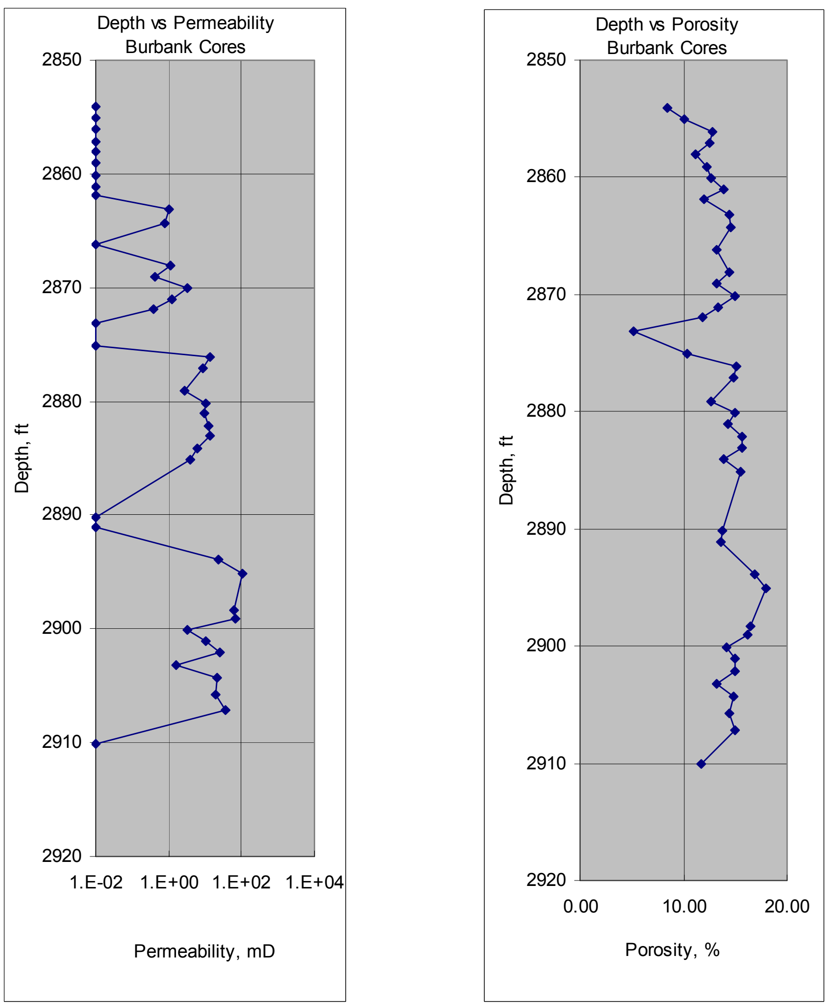



**Figure 2.** Permeability and porosity results from routine measurements.

## SONIC CORE TESTS

### Cores and Fluids for Coreflood Tests with Vibration

After considering results of figure 2, several core plugs were selected for coreflood tests from each of the following depth ranges: 2861.9’ to 2873.1’, 2876.1’ to 2885.1’, and 2893.9’ to 2910.1’.

Samples of formation brine were collected from the field. Days after filtering the field brine through a 0.45 μm filter and sealing the filtered-brine in a flask, the brine took on a brown tint. The tint is probably related to oxidization of iron in the water. Rather than risking damage to the core plugs by using this field brine, synthetic brine was used in core tests rather than formation brine. Synthetic brine was prepared using a recipe derived from a water analysis report from the field (analysis for sample Cal 68, 10/13/00). Table 1 provides the recipe that was followed in preparing each kilogram of brine:

**Table 1.** Synthetic Brine Recipe

| Consituent | Weight, grams |
|---|---|
| NaCl | 66.960 |
| $CaCl_2*2H_2O$ | 32.912 |
| MgCl2*6H2O | 11.445 |
| $BaCl_2*2H_2O$ | 1.247 |
| $H_2O$ | 887.436 |

The synthetic brine was filtered through a 0.45 μm filter. The density and viscosity of the brine at ambient temperature and pressure were 1.0721 g/cm$^3$ and 1.56 cP respectively. Synthetic brine remained clear (no brown tint) throughout the testing period.

Crude oil samples were delivered from the field in the fall of 2001 from several producing wells surrounding the stimulation well. Tests were performed to “fingerprint” the oil samples, with intent of later being able to determine whether vibration stimulation caused oil to preferentially move toward a producer from different areas surrounding the stimulation well. “Fingerprints” for the oil samples from different nearby producing wells were virtually the same. Our analyst told us that they were the most consistent set of samples he has tested.

Approximately 1 liter of oil was selected for sonic waterflood tests. The oil was filtered through a 0.45 μm filter. The density and viscosity of the filtered oil at ambient temperature and pressure were 0.8403 g/cm$^3$ and 8.61 cP respectively.

### Sonic Coreholder

Cores were tested in a “sonic” coreholder. Figure 3 is a photo of the coreholder. The photo shows the coreholder with horizontal orientation. The coreholder was later rearranged with vertical orientation. The silver-colored vessel on the right side of the photo is the coreholder. It was custom-manufactured by Phoenix Precision specifically for Phillips’ sonic lab. The end-cap on the right-hand side of the coreholder, as shown in the photo, attaches to the pressure vessel via a cam lock arrangement, and also contains the flow distribution end-piece that butts against one end of the core plug. The cam lock feature and other aspects of the coreholder provide for easy core plug insertion and removal without having to disassemble the coreholder. Longitudinal and radial stress applied to the core plug can be varied independently, as shown in Figure 4, a sketch of the coreholder. The left end of the coreholder, as shown toward the center of the photo (Fig. 3), contains a hydraulic ram. When hydraulic pressure is applied behind the ram, the ram exerts longitudinal stress to the core plug. Radial stress, or confining pressure, is applied by pressurizing fluid between the Viton rubber sleeve that surrounds the core plug and the inside of the coreholder.

Referring to Figure 3, a rod extends from the center of the left end of the coreholder. This rod links the flow distribution end-piece within the coreholder to a dynamic force sensor (device connected to the rod that has a thin white power/signal cable), which in turn is linked to the vibration actuator (Etrema Terfenol-D actuator, underneath the while plastic cylinder). The vibration actuator is pre-loaded with 100 lbf by a thrust plate. Along the rod between the vibration actuator and left-end of the coreholder, one can see a metal disk that is fixed to the rod. This disk holds an LVDT (displacement measurement device) that measures the movement of the disk with respect to the coreholder body. Because the rod extends to the inlet fluid distribution face that butts up against the core plug, movement of the disk with respect to the coreholder reflects the change in length of the core plug that is within the coreholder.

Note that the end of the vibration actuator opposite from the coreholder butts against a thrust plate. The thrust plate can be pushed against the vibration actuator by applying torque to the screw shown to the left of the thrust plate on Figure 3. Initially, while applying longitudinal stress to a sample, the screw is backed-off from the thrust plate so that the vibration actuator is not subject to load. After adjusting longitudinal stress, the screw is adjusted to push the thrust plate against the actuator, preloading the actuator with 100 lbf. This preload protects the actuator from going into tension, which might break the Terfenol material. After vibration measurements are finished, the screw is backed-off before changing or relieving longitudinal stress on the sample. In essence, the vibration actuator superimposes cycles of compression and relaxation onto the static longitudinal stress magnitude.

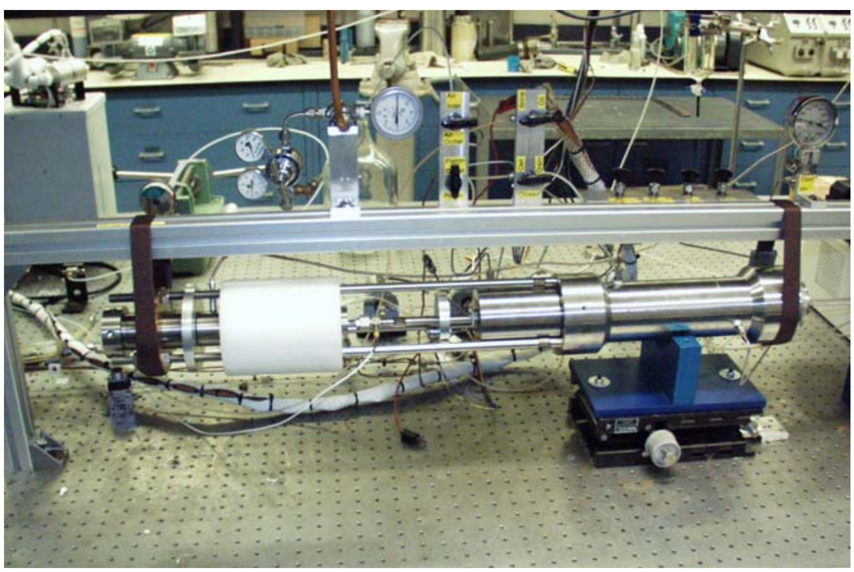


**Figure 3.** Sonic Coreholder

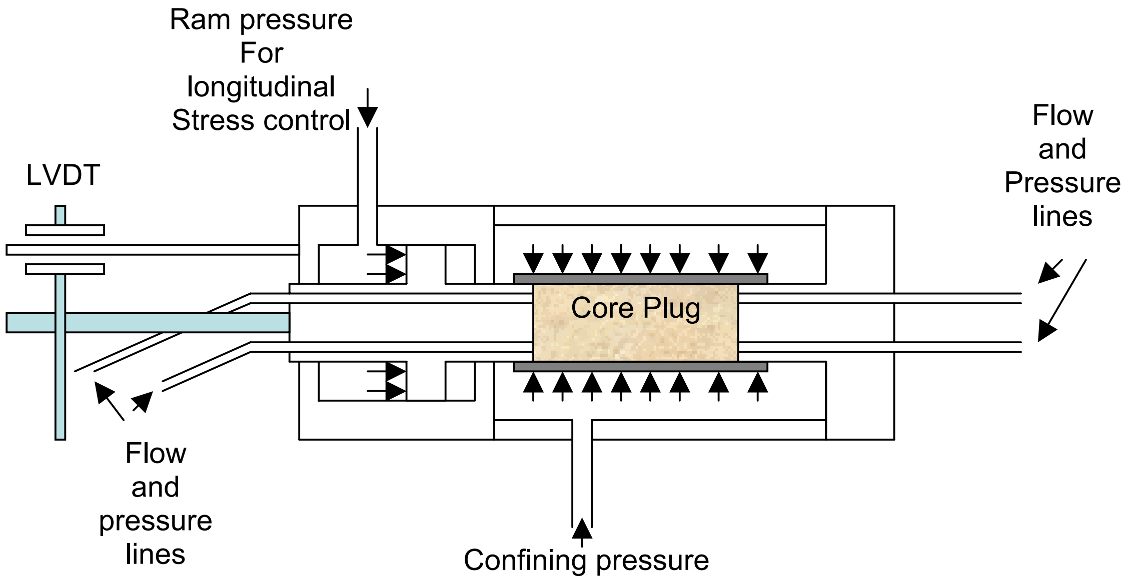



**Figure 4.** Schematic of the coreholder.

## Preliminary Test Procedures

Each clean and dry core plug was weighed. Next, each plug was saturated with brine. The weight of the brine-saturated plug was measured. Pore volume was calculated by dividing the weight change (from dry to brine saturated condition) by the density of the brine. Porosity was determined by dividing pore volume by bulk volume.

After a 1.5 inch diameter brine-saturated core is installed in the coreholder, longitudinal and radial stress are increased such that the radial stress is approximately 1,000 psig and the longitudinal stress is 400 psig. The LVDT output is "zeroed" for this stress condition. The change in core length with increasing longitudinal pressure is measured in steps as the longitudinal stress is increased to 1,000 psig. Elastic or Young's Modulus is calculated based on the change in sample length in response to changes in longitudinal loading according to:

$$\Delta L/L = F/AE \tag{1}$$

where $\Delta L$ is the change in core length, L is the original length of the core, F is the force applied in the longitudinal direction, A is the cross-sectional area of the core ($A=\pi R^2$), and E is the Elastic Modulus. Table 2 provides example data from measurements on core plug 245 (from 2895.08 ft depth). The length of the plug was 2.862 inches. Figure 5 is a plot of the data. Note that the slope of the best-fit line through the data, which is also shown on the graph, is equal to the Elastic Modulus.

| **Table 2.** Example Data for Elastic Modulus Computation | | | |
|---|---|---|---|
| F/A, psi | ΔL, inch | F/A * L | |
| 435.3 | 0 | 1245.8286 | |
| 492.27 | 0.000419 | 1408.87674 | |
| 549.72 | 0.000659 | 1573.29864 | |
| 597.49 | 0.000886 | 1710.01638 | |
| 652.49 | 0.001198 | 1867.42638 | |
| 700.87 | 0.001463 | 2005.88994 | |
| 749.53 | 0.001705 | 2145.15486 | |
| 798.2 | 0.001939 | 2284.4484 | |
| 845.14 | 0.00218 | 2418.79068 | |
| 890.22 | 0.002402 | 2547.80964 | |
| 927.16 | 0.002615 | 2653.53192 | |
| 959.45 | 0.002727 | 2745.9459 | |
| 999.89 | 0.002923 | 2861.68518 | |
| slope | E (english) = | 5.589E+05 | psi |
| | E (metric)= | **3.85E+09** | kg/(m*s$^2$) |
| correlation coefficient | | | |
| | $R^2$ | 0.999 | |

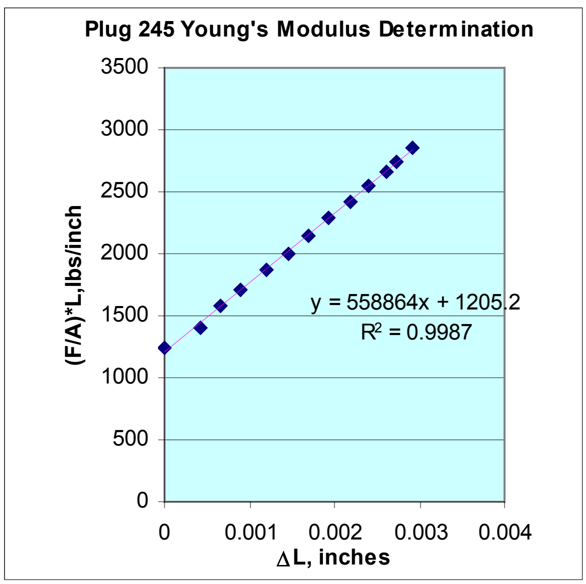



**Figure 5.** Young's Modulus data, plug 245.

## Vibration Intensity Calculations Based on Frequency and Dynamic Force

After measuring Elastic Modulus, calculations are performed to determine relationships among core properties and dynamic force to provide guidance toward achieving particular vibration intensities for a range of vibration frequencies. Vibration intensity is related to the change in sample length under the action of cycles of compression and relaxation. Depending upon the elastic properties of the rock, displacement for a particular frequency and intensity condition can be very small. Rather than relying on direct measurements of dynamic displacement from the LVDT to calculate intensity, dynamic force and frequency are used to calculate intensity, as described in the following paragraphs.

Rewriting Equation 1 to solve for ΔL yields,

$$\Delta L = FL/AE \qquad (2)$$

An equation listed in a paper by Aschepkov[2] relating intensity of vibration for a core to other parameters was rewritten as:

$$I = 0.5\rho(\Delta L^{2})(4\pi^{2})(f^{2})*c \qquad (3)$$

where $I$ = Field action intensity, w/m$^2$
$\rho$ = rock density (presumed to be grain density), kg/m$^3$
$\Delta L$ = amplitude of displacement, (also known as A in Ashchepkov paper), m
$\pi$ = 3.14159
$f$ = frequency, cycles/s (Hz)
$c$ = elastic field phase velocity of the specimen material (Vp in Ashchepkov paper), m/s

In the absence of measurements of c, the following approximation was used to estimate c:

$$c = [E/\rho]^{0.5} \qquad (4)$$

Combining equations 2, 3, and 4 yields

$$I = 0.5\rho(FL/AE)^{2}(4\pi^{2})(f^{2})*[E/\rho]^{0.5} \qquad (5)$$

During vibration tests, Equation 5 is used to approximate vibration intensity using inputs of dynamic force (measured by the dynamic force sensor), frequency, and the other pre-measured characteristics of the rock. Displacement is calculated from Equation 2.

Figure 6 is a plot of calculated displacement versus vibration frequency and intensity for core plug 245. Figure 7 shows dynamic force as a function of frequency and intensity. The vibration actuator is rated for maximum dynamic force of 200 lbf. Dynamic forces in our tests are typically kept below 200 lbf to prevent damage to the force sensor and vibration actuator. The output from the dynamic force sensor is voltage. Figure 8 shows voltage output from the dynamic force sensor versus vibration frequency and intensity. Results such as those shown on Figure 8 are used to determine the target force sensor output to achieve a particular intensity for a given vibration frequency. While viewing the force sensor voltage on the oscilloscope, the waveform generator voltage that controls the vibration actuator is increased until the peak-to-peak force sensor output voltage equals the target voltage necessary to achieve the intensity of interest.

As described above, dynamic forces that can be applied while subjecting a core to vibration stimulation are limited by equipment constraints. This, along with the elastic properties of the rock and relationship between force, frequency, and elasticity places a limit on maximum vibration intensity that can be imposed during a test. Dynamic force output from the vibration actuator is in the form of a sine wave. The maximum operating frequency of the vibration actuator is 2,000 Hz. Dynamic force output from the vibration actuator is in the form of a well-defined sine wave with frequencies from about 40 Hz to 2,000 Hz, but with our current power supply and waveform generator, the waveform becomes ill-defined when operating with frequencies less than about 7 Hz.

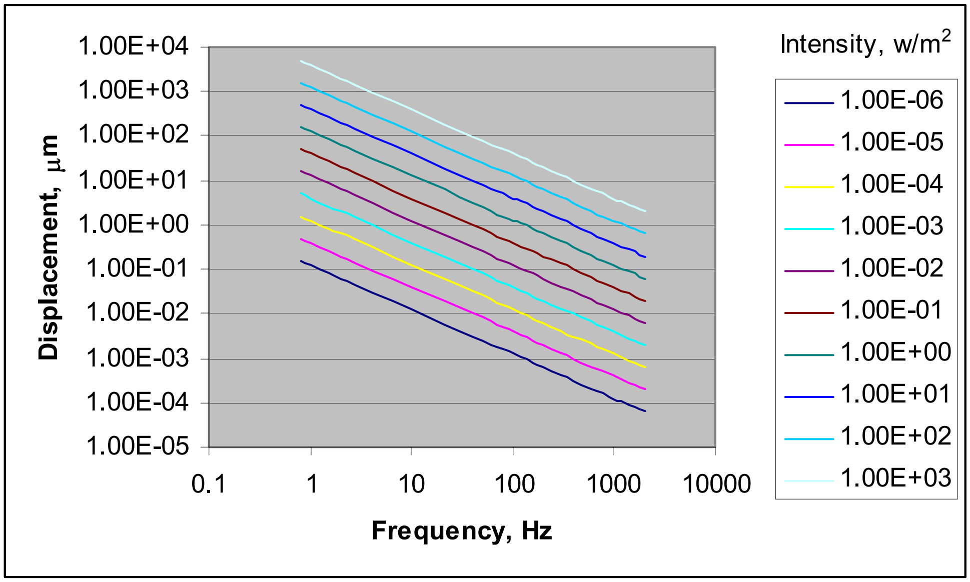



**Figure 6.** Displacement versus frequency and intensity, core plug 245.

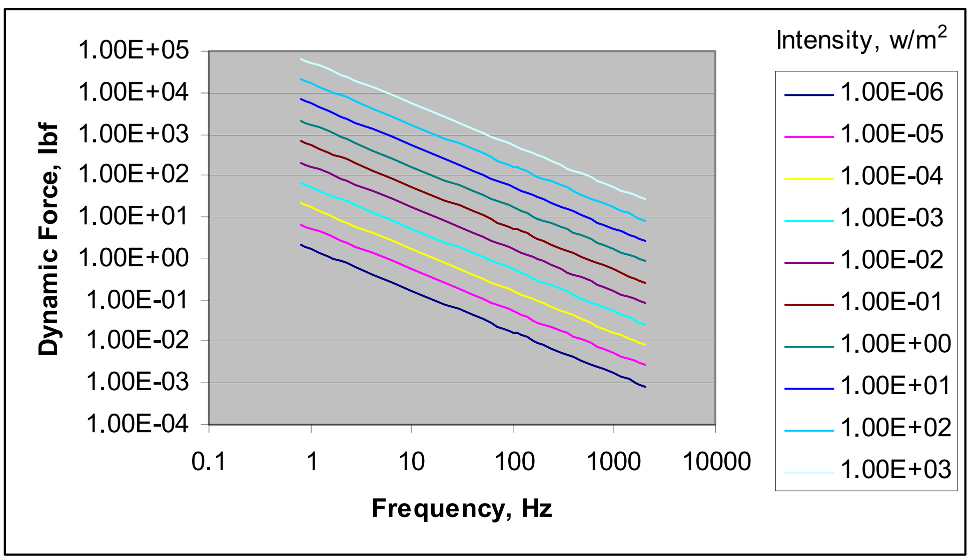



**Figure 7.** Dynamic force versus frequency and intensity, core plug 245. Vibration actuator is limited to a maximum dynamic force of 200 lbf.

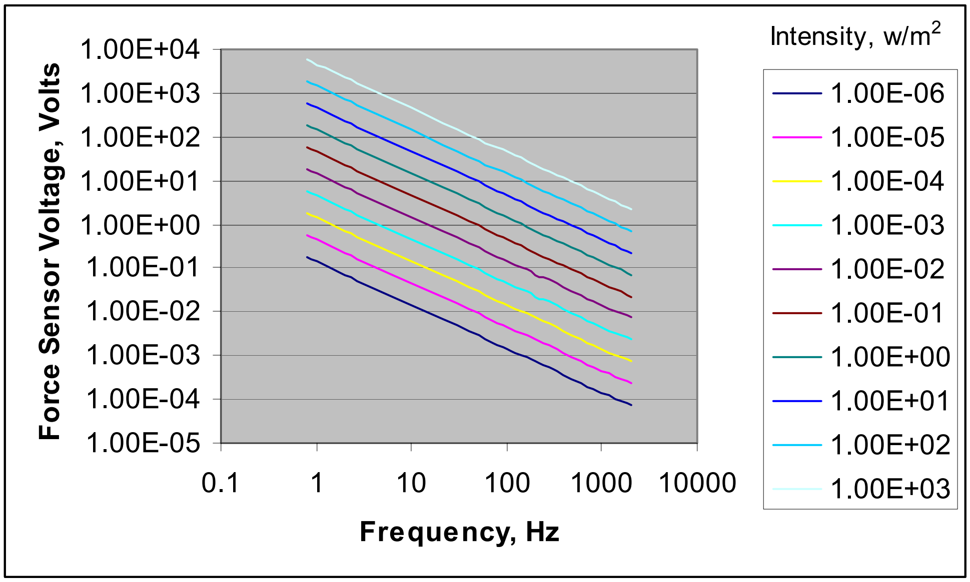



**Figure 8.** Dynamic force sensor output versus frequency and intensity, core plug 245. Range of measurement for this sensor is between .050 and 10 volts.

## Brine Permeability Measurement

After Elastic Modulus has been determined and the previously described vibration relationships have been calculated, flow tests begin. The first step is to measure the permeability of the core plug to brine.

During single-phase flow measurements, brine is injected through a core using a Quizix QL700 high precision metering pump. Pressure drop (denoted dP or $\Delta P$ in this report) across the length of the core plug (pressure at the inlet face of the core plug minus pressure at the downstream face) is measured using a Honeywell differential pressure transmitter. Downstream pressure for these tests was atmospheric pressure. Effluent from the core was captured in a graduated cylinder on a digital balance. The purpose of the digital balance is to enable measurement of produced fluid volume on a nearly continuous basis. Data from the balance as well as pressure, temperature, time, and manually-entered comments are logged by a computer. Produced fluid volumes are also visually monitored and manually recorded at various test times. Equations used to gain information from weight changes on the balance included the following:

$$\Delta V_i\text{, cm}^3 = (Q_i\text{, cm}^3\text{/minute})\ (\Delta T\text{, minutes}) \tag{6}$$

$$\Delta V_p\text{, cm}^3 = (\Delta W\text{, grams})/\ (\rho\text{, g/cm}^3) \tag{7}$$

$$Q_p\text{, cm}^3\text{/minute} = (\Delta W\text{, grams})/\ [(\Delta T\text{, minutes})(\rho\text{, g/cm}^3)] \tag{8}$$

where $Q_i$ is the pump injection rate, $Q_p$ is the fluid production rate as determined from weight change, $\Delta V_i$ is the change in fluid volume injected, $\Delta V_p$ is the change in fluid volume produced as calculated from weight change, $\Delta T$ is change in time, and $\rho$ is the density of the produced fluid. When the time step is small, as between two successive weight measurements, $Q_p$ represents an "instantaneous" production rate. With relatively short time steps, constant injection rate, and steady-state flow, $Q_i$ and $Q_p$ should be equal. They can differ immediately after flow test start up as upstream pressure builds, after changes in pump injection rate, or at other times when pressure within the flow system is non-stable. With such conditions and long time steps, equation 8 does not provide an accurate reflection of flow rate.

Pressure drop across the length of the core plug (pressure at the inlet face of the core plug minus pressure at the downstream face) is measured for at least 4 different flow rates. Figure 9 shows pressure drop versus time as brine was injected through core plug 245 at various rates. Figure 10 was constructed using steady-state pressure drop versus rate data from Figure 9.

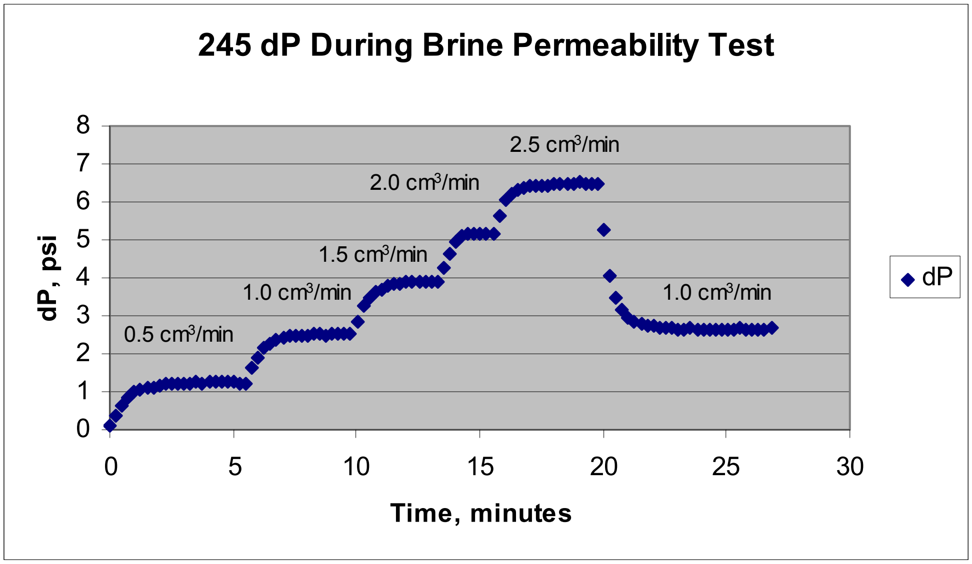



**Figure 9.** Pressure drop versus time during brine permeability measurements on core plug 245.

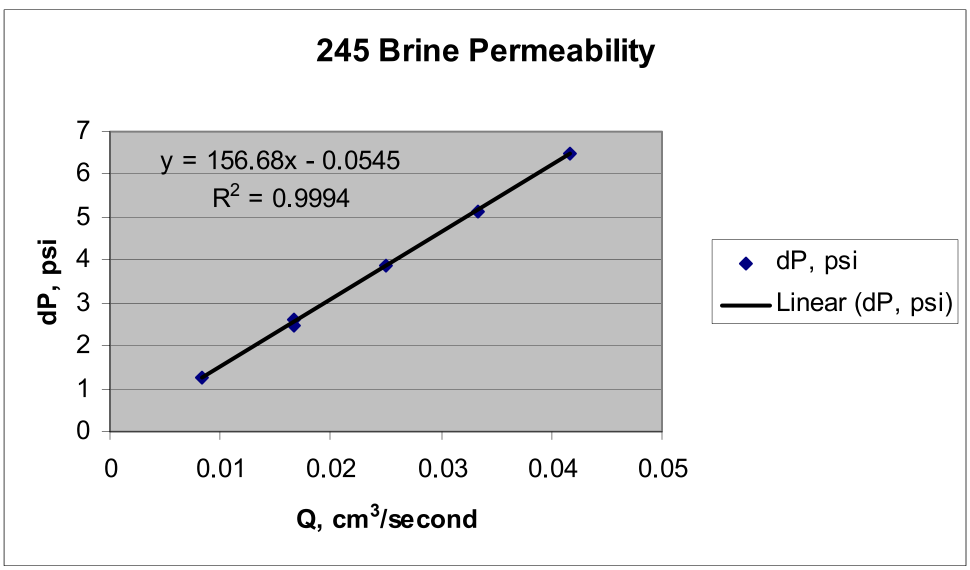



**Figure 10.** Pressure drop versus flow rate from brine permeability tests on plug 245.

From figure 10, dP versus Q is linear (as it should be according to Darcy's Law) with a correlation coefficient that is very close to 1. The y-intercept value suggests that the pressure transmitter would likely read -0.0545 psi without flow. One can either correct each pressure for this offset in using the data to calculate permeability, or use the inverse of the slope of the best-fit line to calculate permeability. The inverse of the slope is the ratio Q/dP. This value can be substituted directly into the Darcy equation for linear flow:

$$k = (Q/dP)\mu L*14696/A \tag{9}$$

where k is permeability, Q is flow rate, μ is viscosity, L is core length, A is cross-sectional area of the core, and dP is pressure drop across the length of the core. The 14696 constant is for unit conversions (psi instead of atmospheres and k in mD rather than D).

If the core plug is the first in a series of plugs that are of similar permeability, vibration tests are conducted to determine whether the permeability of the plug to brine changes or responds to a particular vibration frequency and intensity. Various vibration frequencies and intensities are imposed while injecting brine through the core at constant flow rate. From some of our earlier brine permeability tests with vibration, we learned that after imposing a particular vibration frequency and intensity that caused permeability to change, after "turning off" the vibration source but continuing to inject brine at constant rate, the change in permeability generally decayed back to the original permeability after a time period ranging from minutes to days. From this observation, one might gain the sense that after imposing a vibration frequency and intensity that causes a change in pressure drop through the core, vibration should be turned off so that the permeability can return to the baseline permeability before testing with other frequencies and intensities. However, tests take considerable time using such an approach. As a compromise, we test by changing vibration characteristics every 5-10 minutes and acknowledge that after a change in permeability as a result of a particular frequency and intensity combination, some subsequent frequencies and intensities that might also affect permeability to an equal or lesser degree may be masked by the recovery time described previously, while perhaps only vibration settings that have an even more pronounced effect on permeability might be observed with subsequent settings.

## Oil Flood to $S_{wr}$ and Oil Permeability Measurement

After completing measurements with the core saturated only with brine, the core is flooded with oil to a residual brine saturation ($S_{wr}$) condition. As with brine permeability measurements, effluent from the core is captured in a graduated cylinder on a digital balance. Data from the balance as well as pressure, temperature, time, and manually-entered comments are logged by a computer. Produced fluid volumes are also visually monitored and manually recorded at various test times.

Equations used to gain information from weight changes on the balance include equations 6, 7, and 8 for brine production before brine break-through and for late-time oil production when only oil is produced, and the following for times when both oil and brine are produced:

$$\Delta W = (\Delta V_o)(\rho_o) + (\Delta V_w)(\rho_w) \quad (10)$$

If injection rate is constant,

$$\Delta V_o = (Q\Delta T) - \Delta Vw \quad (11)$$

$$\Delta W = (Q\Delta T - \Delta Vw)(\rho_o) + (\Delta V_w)(\rho_w) \quad (12)$$

$$\Delta V_w = (\Delta W - Q\Delta T\rho_o)/(\rho_w - \rho_o) \quad (13)$$

Upon completing the oil flood, the permeability of the core plug to oil at $S_{wr}$ is measured with at least 4 sets of rate and pressure drop data pairs. Post-test data analysis includes dead-volume corrections and time-synchronization of pressure drop and production data. Dead-volume corrections are necessary to account for brine that is produced from the upstream and downstream tubing rather than from the core plug. Time synchronization is necessary because pressure response versus time reflects pressure changes in real-time during the test as does the combined produced fluid flow rate, whereas there is a time lag between when a droplet of fluid produced from the outlet end of the core plug reaches the end of the downstream tubing and is accounted for by produced fluid volume measurements.

## Waterflood with Vibration

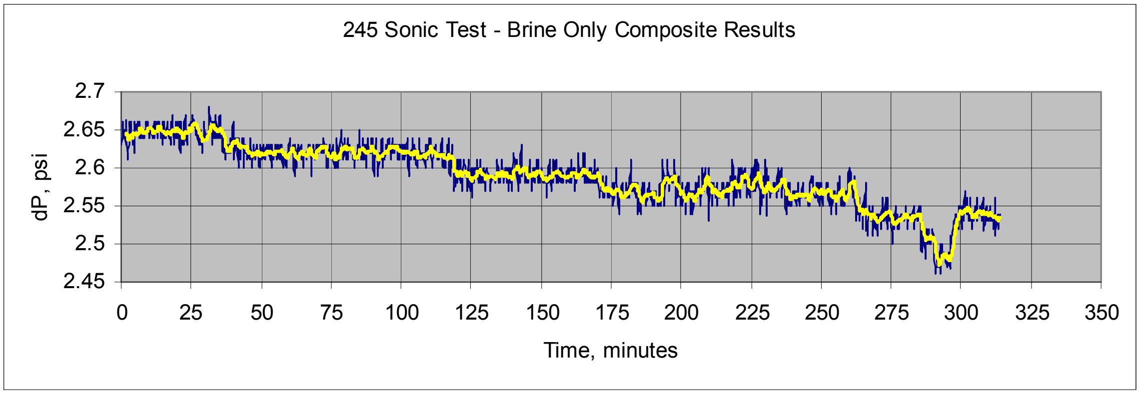
Finally, the core is waterflooded. Data measurements and equations previously described are also used for waterflood production calculations, as are post-test data analyses. After water breakthrough when oil production declines significantly, vibration is turned on with particular intensity. Production is monitored for a time period with vibration to determine whether pressure drop across the length of the core appears to change in a manner that is inconsistent with the trend prior to imposing vibration and whether additional oil recovery is observed. If no effect is noted, other vibration frequencies and intensities are imposed to determine whether pressure drop or production change as a result of vibration.

## SONIC TESTS ON CORE 245

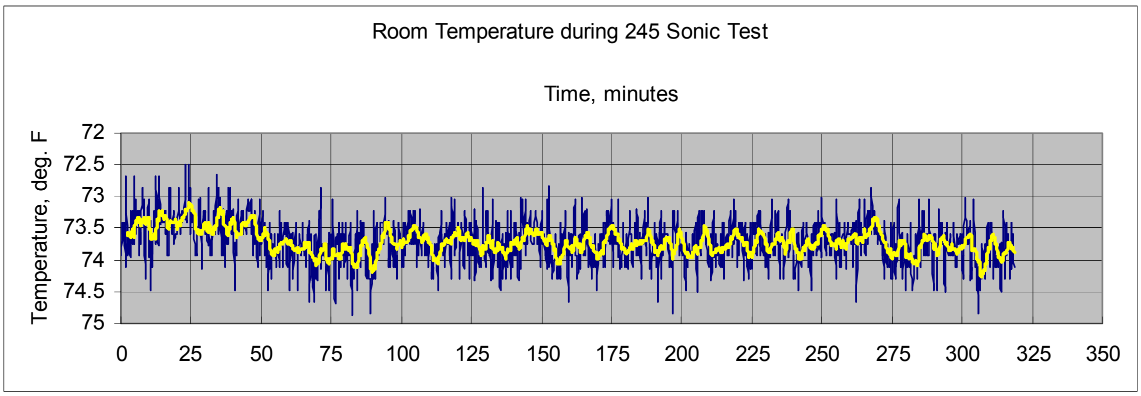
Plug 245 from 2895.08 ft depth was tested first. Air permeability and porosity for the plug from routine property tests were 107 mD and 17.92% respectively. The plug was saturated with synthetic brine. The pore volume, as determined by dividing the weight change (brine-saturated weight – dry weight) by the density of the brine, was 14.91 $cm^3$. The porosity calculated using this pore volume was 17.99%.

Young's Modulus was measured. The Young's Modulus as calculated from test measurements was $5.6 \times 10^5$ psi. Figure 5 is a graph of the test data.

After measuring Young's Modulus, confining pressure and longitudinal pressure were set to 1,000 psig and 400 psig respectively. Permeability to brine was measured as 91 mD, although when re-measured the next day, permeability had dropped to 89 mD. With brine flow rate set at 1 $cm^3$/minute, pressure drop was monitored as various combinations of vibration frequency and intensity were applied to the sample along its long axis. Figure 11a shows pressure response at various times during this brine flow test with vibration. From figure 11a, one can see that pressure response changed during the brine flow test with vibration although pressure changes were subtle. One might question whether pressure responded to changes in temperature within the laboratory. Figure 11b shows temperature in the laboratory versus the time line of Figure 11a. Note that the scale on the temperature plot is reversed compared to common convention. If temperature increases, the viscosity of the brine decreases. A reduction in viscosity of the injected brine would cause a reduction in pressure drop if permeability remains constant. From Figure 11b, one may identify that temperature change in the lab was slight overall, with the least change for times greater than 100 minutes. Temperature changes in the laboratory were not responsible for the pressure gradient changes observed during the test.




(a) Pressure response history during brine permeability test with vibration.




(b) Variation in the laboratory temperature during the test.

**Figure 11.** Pressure response and laboratory temperature during brine permeability measurements with vibration, core plug 245.

Figures 12, 13, and 14 provide detail of pressure drop changes that coincided with changes in vibration frequency and intensity at various times during the brine permeability test. Note that some of the data is repeated on these figures to provide a visual reference for identifying pressure changes.

From figure 12, 160 Hz, low intensity (0.03 $w/m^2$) vibration caused a small but noticeable change in pressure drop. With constant injection rate, a reduction in pressure drop is indicative of an increase in permeability. From figure 13, after applying 400 Hz, 200 $w/m^2$ vibration, the frequency was randomly adjusted up and down. This appears to have influenced permeability. Figure 14 shows that frequency and intensity combinations of 450 Hz – 30 $w/m^2$, 10 Hz – 0.1 $w/m^2$, and 5 Hz – 0.02 $w/m^2$ had notable effects on pressure drop and thereby permeability with the most pronounced effect following 5 Hz vibration.

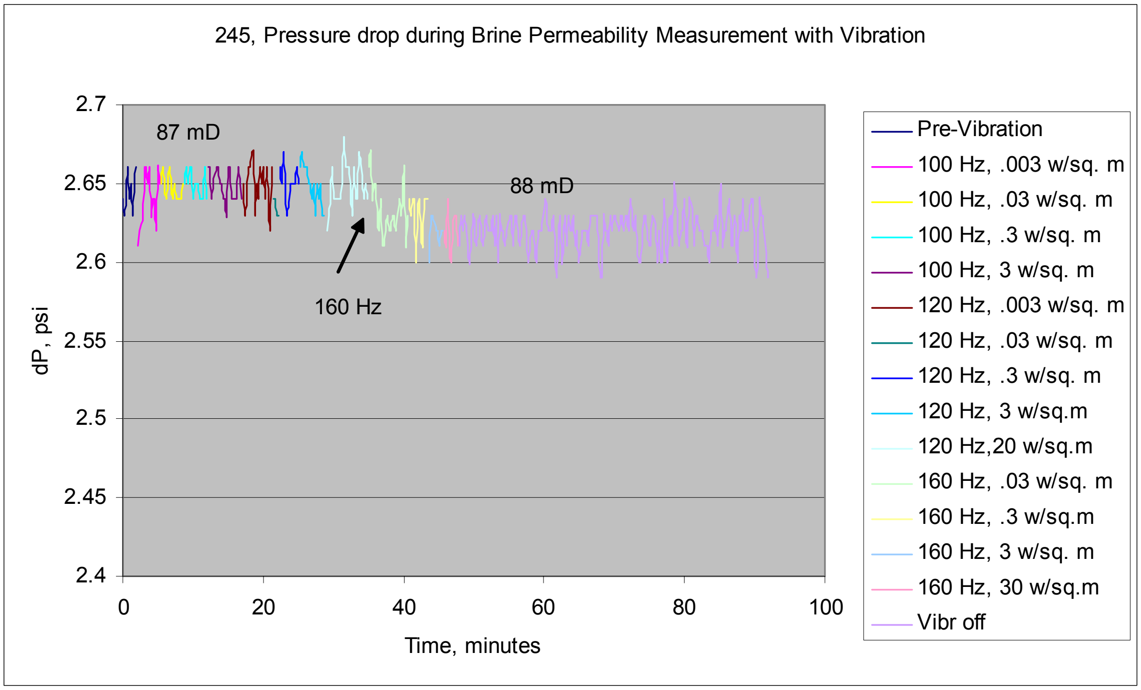



**Figure 12**. Pressure drop history, 0 to 100 minutes, core 245 brine permeability test with vibration.

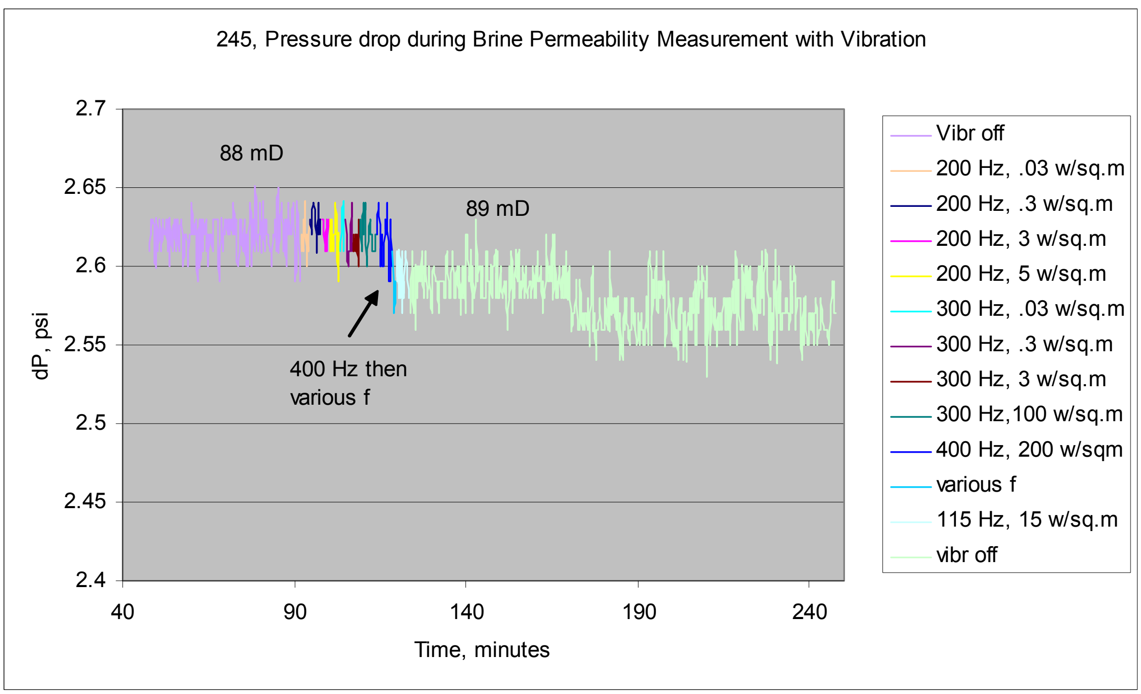



**Figure 13.** Pressure drop history, 40 to 240 minutes, core 245 brine permeability test with vibration.

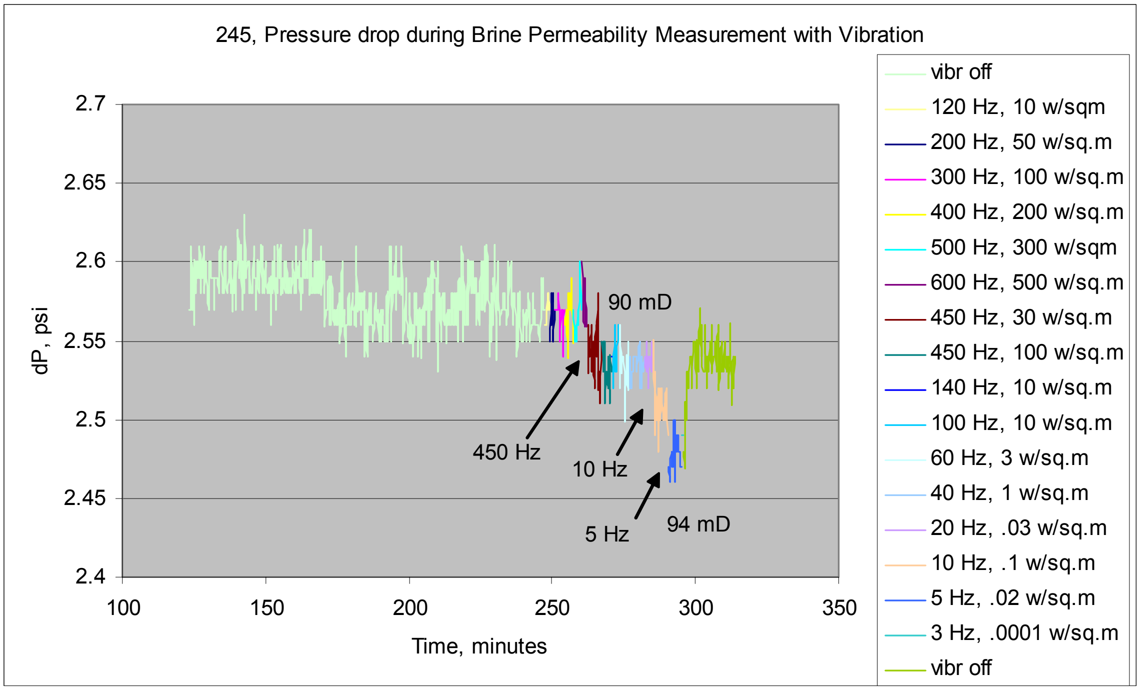



**Figure 14.** Pressure drop history, 100 to 320 minutes, core 245 brine permeability test with vibration.

Plug 245 was flooded with filtered Burbank oil to a residual brine saturation condition. At the end of the oil flood, the permeability of the core to oil was 23.5 mD. Normalizing this result with respect to the brine permeability yields $k_{ro}$ = 0.258. Brine saturation for this condition was 42.2%, or expressed as a fraction, $S_w$ = 0.422.

The core plug was waterflooded at 0.5 $cm^3$/minute brine injection rate. In other units, this equates to an injection rate of 1 pore volume of brine/half-hour or a front advance velocity of 11.5 ft/day. Produced fluids were captured in a graduated cylinder on the electronic balance. Vibration was imposed after the water-cut became high. Frequency and intensity of vibration were varied in an effort to determine vibration parameters that affect oil recovery.

In addition to recording data throughout the waterflood test, visual observations were also made to determine whether particular vibration parameters yielded changes in oil production. Tubing downstream from the coreholder was semi-transparent plastic. As effluent from the core plug changed from 100% oil to fractions of oil and brine, droplets of oil were easily identified in the downstream tubing, although the tubing appeared to have been darkened or stained as a result of contact with the oil. After changing the frequency or intensity of vibration, if additional droplets of oil were not seen in the plastic portion of the downstream tubing, we initially assumed that the particular vibration was ineffective. Later, we learned that assuming that changes in oil production could be observed by watching for oil droplets in the downstream tubing was a flawed assumption. Post-test data analyses indicated that what had appeared to be a brown stain on the plastic tubing was oil flowing in a thin film through the tubing.

Initial inspection of test results displayed some unusual anomalies. Figure 15 shows oil production from first-pass calculations (before dead-volume and time corrections) using equations 10-13, assuming that flow rate was 0.5 $cm^3$/minute at all times throughout the test. The results of figure 15 are obviously in error. Oil that has been produced can't suddenly disappear!

Figure 16 shows pressure history during the flood. Note pressure anomalies on Figure 16 correspond to production anomalies of figure 15. Also of interest is the period of flat pressure response following the abrupt change in pressure drop (between 100-130 minutes). To further analyze these vexing occurrences, "instantaneous" production rate versus test time was calculated from changes in produced fluid weight over short time intervals. These results (Figure 17) show that production, in coincidence with the 3 specific pressure drop anomalies, briefly spiked above 1 $cm^3$/minute whereas at all other times production rate averaged 0.5 $cm^3$/minute. These three flow rate spikes and pressure anomalies correspond to the following vibration events:

a) First spike occurred when intensity of vibration with 200 Hz frequency was increased from 3 $w/m^2$ to 50 $w/m^2$
b) Second spike occurred when intensity of vibration with 300 Hz frequency was changed from 3 $w/m^2$ to 100 $w/m^2$
c) Third spike occurred when intensity of vibration with 400 Hz frequency was increased from 3 $w/m^2$ to 200 $w/m^2$

Production results were recalculated by substituting the 3 anomalous flow rates of figure 17 into the calculations for the times when they occurred while continuing to use 0.5 $cm^3$/minute as the average production rate for all other test times. Oil production and $\Delta P$ results after this correction, dead-volume correction, and time synchronization are shown in Figure 18.

Final results in terms of change in brine saturation within the core plug versus time are presented in Figure 19. Oil recovery equals $1 - S_w$. Table 3 lists starting and ending times of periods of vibration that were imposed during the waterflood test on core plug 245.

The permeability of the core to brine at the end of the flood was 9.54 mD, yielding a brine relative permeability ($k_{rw}$) of 0.105. Final brine saturation fraction was $S_w = 0.862$.

Upon completing this test, the core was cleaned. Similar procedures were used to waterflood the core again, except this time, without vibration. Results from the waterflood without vibration are also shown on figures 18 and 19. Note that the test without vibration was carried out for a longer time period than is shown on the graphs. Final brine saturation stabilized at 0.78 during this test after 240 minutes and did not change from that time until the test was terminated after 360 minutes. Final brine permeability was 7.69 mD, yielding a brine relative permeability ($k_{rw}$) of 0.084.

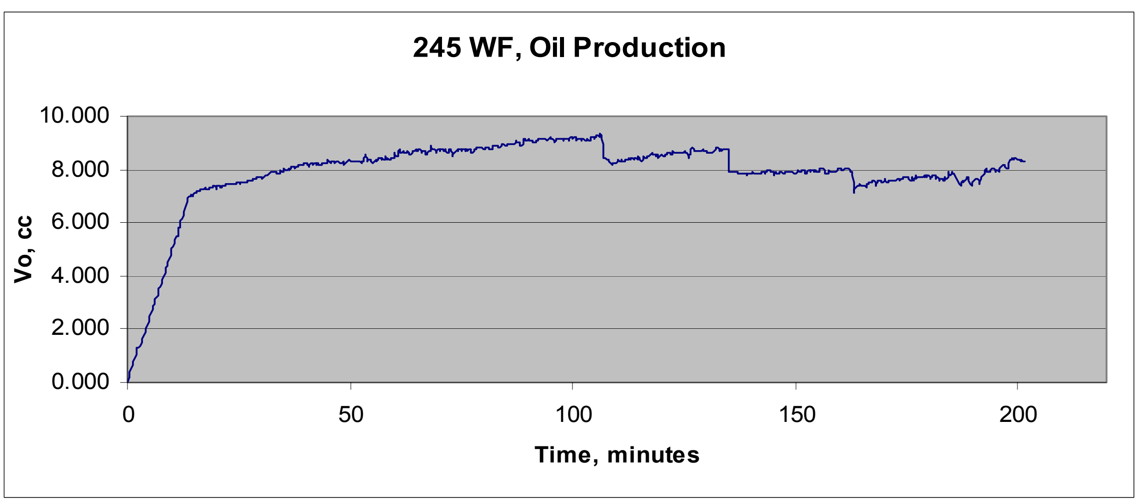



**Figure 15.** Oil production during waterflood of core 245 before dead-volume corrections.

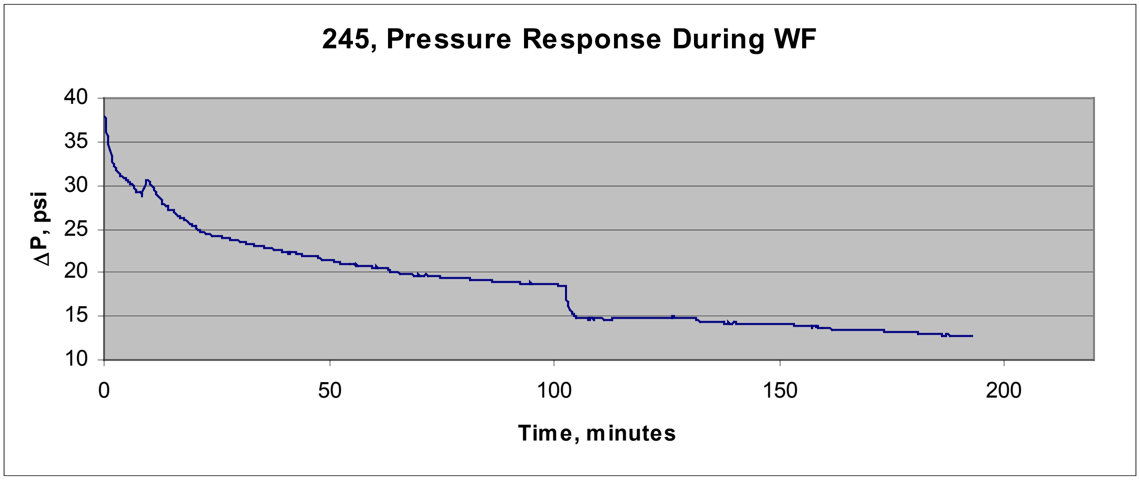



**Figure 16.** Pressure response during waterflood of core 245.

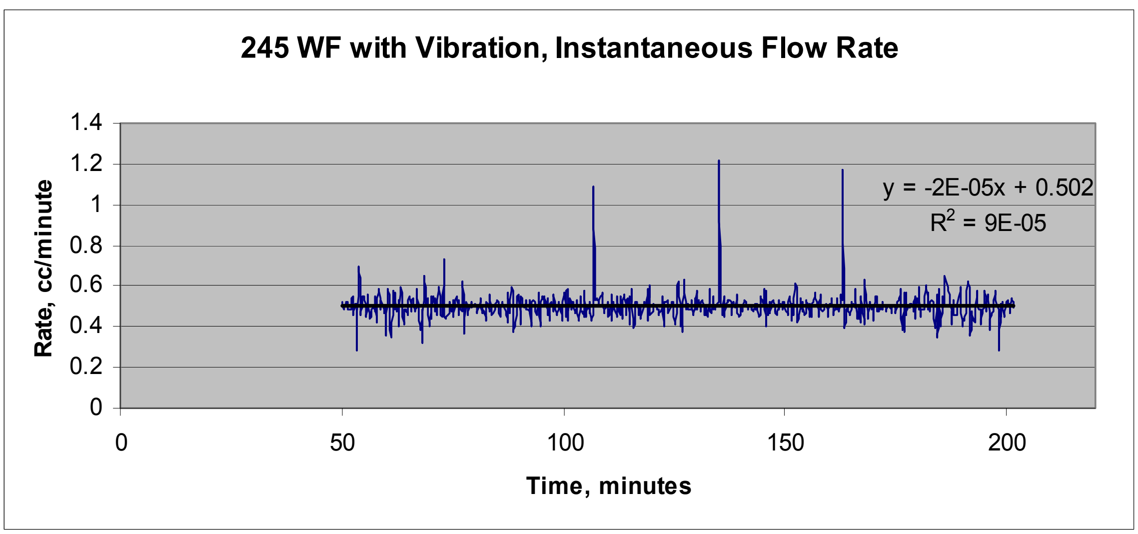



**Figure 17.** "Instantaneous" production rate during waterflood of core 245.

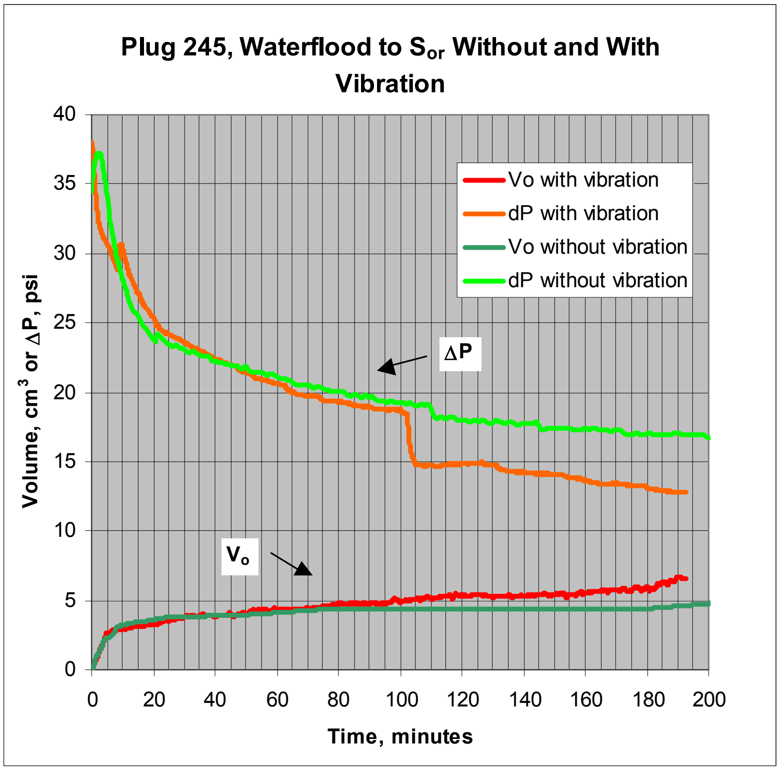



**Figure 18.** Oil production and pressure response during waterflood of core 245.

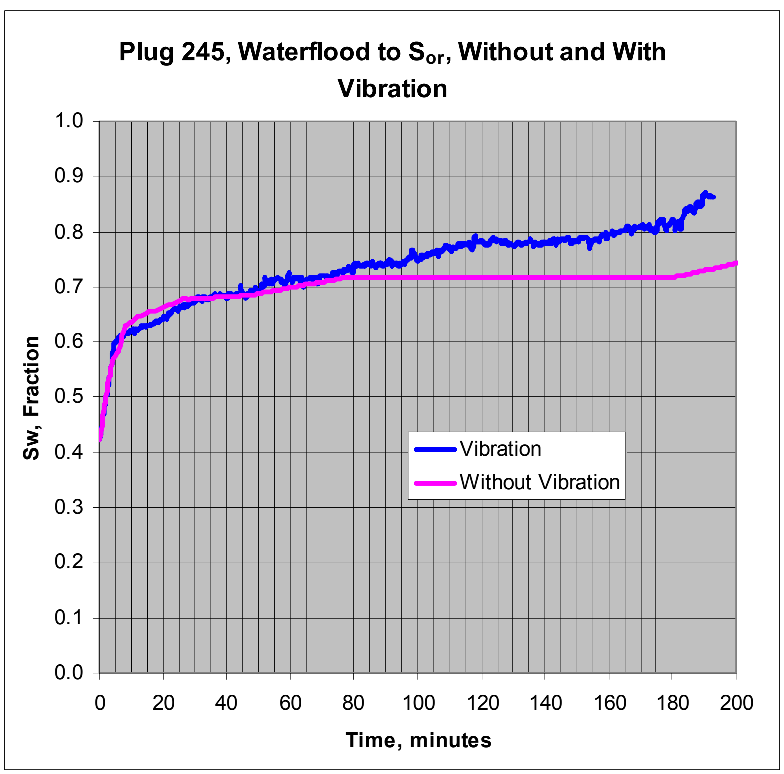



**Figure 19.** Change in brine saturation with time during waterflood of core 245. Injection rate corresponds to 1 pore volume of brine injected for each 30 minutes of test time.

| Table 3. Vibration History During Waterflood of Core 245 | | | |
|---|---|---|---|
| Start time, minutes | End time, minutes | Frequency, Hz | Intensity, w/$m^2$ |
| 0 | 46.10 | 0 | 0 |
| 46.10 | 58.6 | 100 | 3 |
| 58.6 | 65.53 | 100 | 10 |
| 65.53 | 80.68 | 0 | 0 |
| 80.68 | 86.60 | 120 | 3 |
| 86.60 | 88.63 | 120 | 20 |
| 88.63 | 93.25 | 0 | 0 |
| 93.25 | 97.88 | 200 | 3 |
| 97.88 | 106.90 | 200 | 50 |
| 106.90 | 117.07 | 0 | 0 |
| 117.07 | 126.28 | 300 | 3 |
| 126.28 | 137.50 | 300 | 100 |
| 137.50 | 142.90 | 0 | 0 |
| 142.90 | 154.20 | 400 | 3 |
| 154.20 | 159.87 | 400 | 200 |
| 159.87 | 167.57 | 0 | 0 |
| 167.57 | 173.17 | 10 | 0.1 |
| 173.17 | 175.95 | various | various |
| 175.95 | 177.23 | 135 | 20 |
| 177.23 | 179.80 | various | various |
| 180.07 | 181.58 | 451 | 100 |
| 181.58 | 184.35 | 517 | 100 |
| 184.35 | 185.63 | 151 | 20 |
| 185.63 | 187.42 | 35 | 1 |
| 187.42 | 188.42 | 5 | 0.0005 |
| 188.42 | 192.75 | 0 | 0 |

Comparing waterflood results for this core with and without vibration, it appears that trends were similar for test times less than about 70 minutes. Thereafter, waterflooding with vibration appears to have accelerated recovery. Table 4 lists vibration parameters that apparently affected flow through the core. Negative indicates that oil production appeared to stop during vibration.

| Table 4. Core 245 Summary, Effect of Vibration on Fluid Production | | | |
|---|---|---|---|
| Brine Permeability | Waterflood | | |
| $k_w$ with $S_w$=1.000 Frequency, intensity | Sort term rate/dP effect Frequency, Intensity | Accelerate Oil Recovery Frequency, Intensity | |
| 5, 0.02 | 200, 50.0 | 10, 0.1 | negative effect |
| 10, 0.10 | 300, 100.0 | 120, 3-20 | negative effect |
| 160, 0.03 | 400, 200.0 | 200, 3-50 | positive effect |
| various | | 300, 3-100 | negative effect |
| 450, 30.0 | | 400, 3-200 | positive effect |

## SONIC TESTS ON CORE 249

Plug 249 from 2899.08 ft depth was also tested. Air permeability and porosity for the plug from routine property tests was 65.4 mD and 16.14% respectively. The plug was saturated with synthetic brine. The pore volume, as determined by dividing the weight change (brine-saturated weight – dry weight) by the density of the brine, was 13.74 $cm^3$. The porosity calculated using this pore volume was 15.9%.

Young's Modulus was measured. Young's Modulus as calculated from test measurements was 6.5 x $10^5$ psi. Permeability to brine was measured as 70.1 mD. Vibration tests were not conducted on the brine-saturated core plug. Plug 249 was flooded with filtered Burbank oil to a residual brine saturation condition. At the end of the oil flood, the permeability of the core to oil was 21.5 mD. Normalizing this result with respect to the brine permeability yields $k_{ro}$ = 0.307. Brine saturation for this condition was 42.9%, or expressed as a fraction, $S_w$ = 0.429.

The core plug was waterflooded with 0.5 $cm^3$/minute brine injection rate. This equates to an injection rate of 1 pore volume of brine per 27.4 minutes or a front advance velocity of 13 ft/day. Produced fluids were captured in a graduated cylinder on the electronic balance. Vibration of different frequency and intensity was imposed at various times after the water-cut became high.

Waterflood test results for core plug 249 are shown on Figures 20-22. Figure 20 shows pressure gradient measurements during the waterflood. No pressure anomalies were encountered. Figure 21 shows pressure gradient and oil production response versus time. Final results in terms of change in brine saturation within the core plug versus time are presented in Figure 22. Oil recovery equals 1 – $S_w$. Table 5 lists starting and ending times of periods of vibration that were imposed during the waterflood test on core plug 249. Comparing results of Figure 22 with data of Table 5 allows one to speculate about which frequencies and intensities seemed to influence oil recovery. Results of such a comparision are provided in Table 6. The 140 Hz frequency appeared to be a resonating frequency in that the waveforms from the LVDT (core displacement) and dynamic force sensor were in synch at this frequency, whereas at other frequencies, they are somewhat out of phase. The 140 Hz frequency did not appear to have a positive influence on oil recovery, but rather seemed to suppress oil recovery.

The permeability of the core to brine at the end of the flood was 8.89 mD, yielding a brine relative permeability ($k_{rw}$) of 0.127. Final brine saturation fraction was $S_w$ = 0.671.

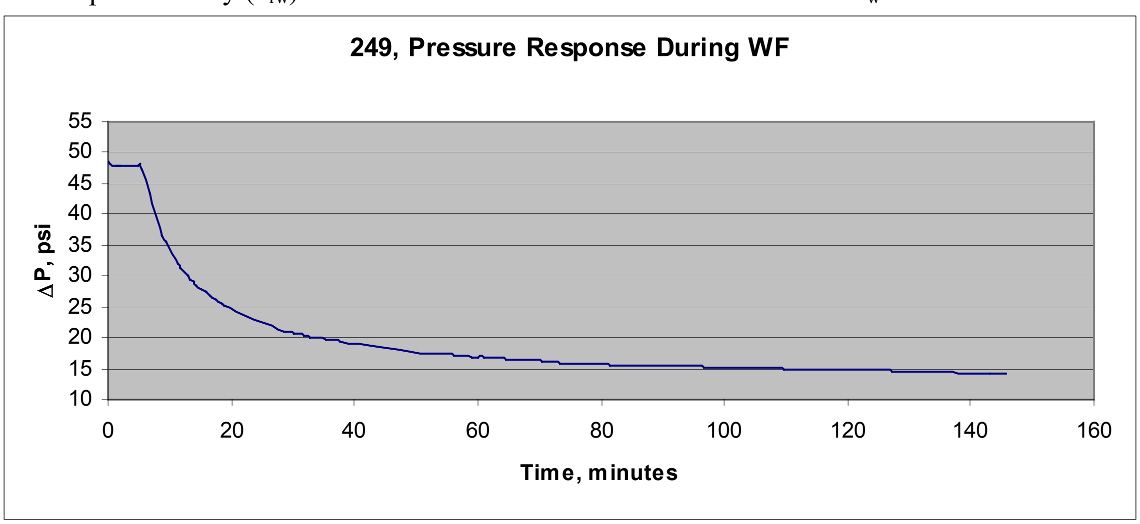



**Figure 20.** Pressure response during waterflood of core 249.

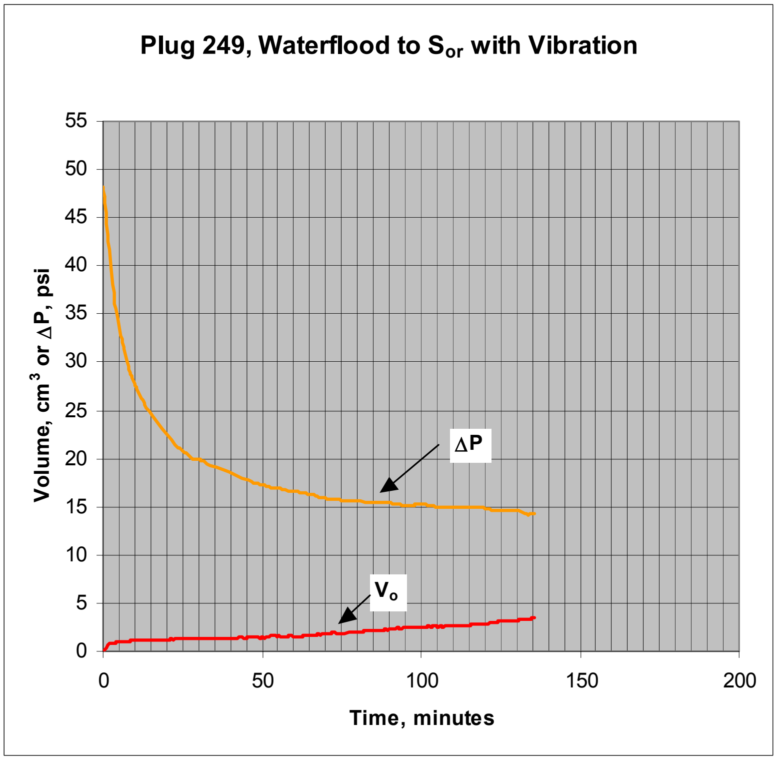



**Figure 21.** Oil production and pressure response during waterflood of core 249.

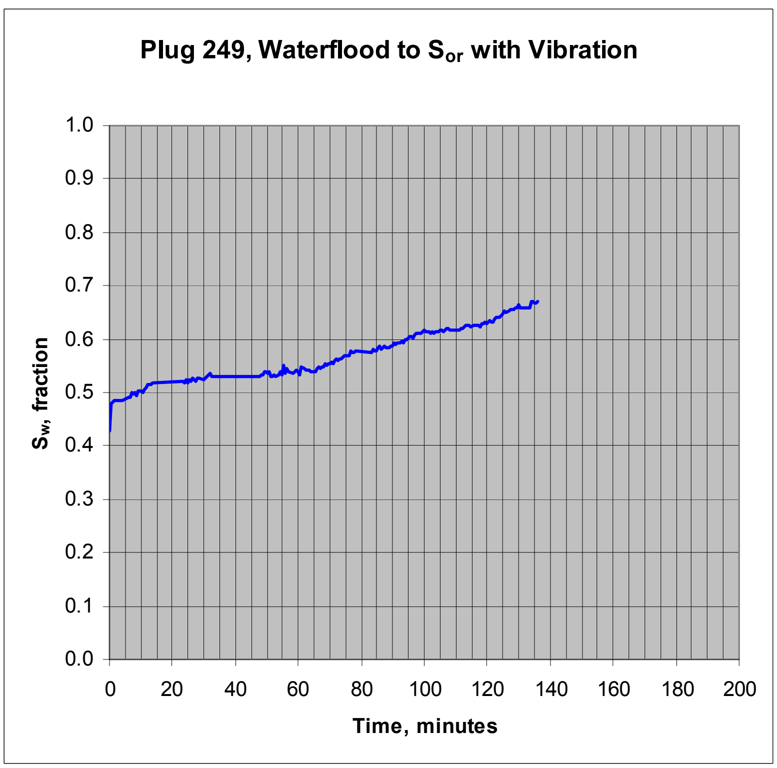



**Figure 22.** Change in brine saturation with time during waterflood of core 249. Injection rate corresponds to 1 pore volume of brine injected for each 27.4 minutes of test time.

| **Table 5.** Vibration History During Waterflood of Core 249 | | | |
|---|---|---|---|
| Start time, minutes | End time, minutes | Frequency, Hz | Intensity, $w/m^2$ |
| 0 | 19.22 | 0 | 0 |
| 19.22 | 20.75 | 80 | 0.05 |
| 20.75 | 21.78 | 160 | 10 |
| 21.78 | 25.83 | 140 | 10 |
| 25.83 | 27.35 | 140 | 100 |
| 27.35 | 43.65 | 200 | 10 |
| 43.65 | 44.67 | 300 | 1 |
| 44.67 | 50.73 | various | various |
| 50.73 | 51.23 | 123 | 10 |
| 51.23 | 59.33 | 47 | 10 |
| 59.33 | 61.35 | 100 | 10 |
| 61.35 | 80.58 | 440 | 100 |
| 80.58 | 83.12 | 140 | 10 |
| 83.12 | 101.30 | 0 | 0 |
| 101.30 | 109.88 | 140 | 10 |
| 109.88 | 124.03 | 0 | 0 |
| 124.03 | 130.17 | 1 | 0.001 |
| 130.17 | 130.67 | 5 | 0.01 |
| 130.67 | 133.73 | 300 | 100 |
| 133.73 | 135.77 | 0 | 0 |

| **Table 6.** Core 249 Summary, Effect of Vibration on Fluid Production | | |
|---|---|---|
| Time, minutes | Frequency (Hz) , intensity ($W/m^2$) | Effect |
| 27.35 to 43.65 | 200, 10 | Positive |
| 61.3 to 80.6 | 440, 100 | Positive |
| 80.6 to 83.1 | 140, 10 | Negative |
| 83.1 to 101.3 | 0, 0 | Positive |
| 101.3 to 109.9 | 140, 10 | Negative |
| 109.9 to 124.0 | 0, 0 | Positive |
| 124.0 to 130.2 | 1, 0.001 | Positive |

## TESTS ON OTHER CORE PLUGS

While data from tests on plugs 245 and 249 were being analyzed, tests were performed on plugs 114 (2864.29 ft), 126 (2876.08 ft), and 248 (2898.33 ft). Several changes were made to the coreflood system in between tests on these plugs in an attempt to improve data quality and minimize test complexity. However, changes made between experiments made the task of analyzing subsequent test data more complex and time consuming at a time when resources allocated for this project had been exhausted. In conclusion, although the 3 additional plugs were tested, results were not analyzed to the extent that they could be included in this report.

## DISCUSSION

Although vibration stimulation results for only two core plugs are provided in this report, results indicate that vibration stimulation influenced oil recovery. Results, however, do not provide clear-cut guidance on how to operate a tool in the field for maximum benefit. The following situations were encountered in these tests:

- Net effect of vibration with various frequencies/intensities stimulated oil recovery, although

    - Periods of vibration with particular frequency/intensity accelerated oil recovery
    - Periods of vibration with particular frequency/intensity retarded oil recovery
- Oil recovery increased sometimes during periods without vibration following a vibration event
- 200 and 400 Hz frequency and high intensity seemed to stimulate oil recovery for both plugs although it is not known whether these are "optimum" frequencies
- Frequencies and intensities that caused the permeability of a brine-saturated core to increase were not reliable indicators of frequencies and intensities that could subsequently stimulate oil recovery during a waterflood
- Vibration stimulation didn't seem to offer benefit until late in a waterflood when water cut was high. Might this indicate a transition from oil droplet to oil film flow?
- Changing from low to high intensity at particular vibration frequencies appeared to "instantaneously" increase flow rate during tests on plug 245 although effects were only momentary
- Dynamic vibration (turning vibration on and off and varying frequency and intensity) might provide better results than continuous vibration stimulation with one frequency/intensity, although more testing would be needed to support this hypothesis

Results of Figures 19 and 22 indicate that more oil might have been produced had the tests been run longer. While considering the results from these "sonic stimulation" tests, keep in mind that tests of the nature described in this report are rare. Little if any guidance on how to make these measurements can be gained from the petroleum literature. These tests were purposefully conducted with relatively high injection rates in an effort to lessen the influence of capillary end-effects (fluid retention at the discharge end of the core because of capillary effects – a laboratory phenomena related to the use of short core plugs). The tests can likely be improved through the use of a different means of providing vibration (perhaps testing with shear waves in addition to or in lieu of p-waves or using another type of vibration actuator) and through direct measurements of in-situ saturations. In-situ saturation measurements would certainly simplify complexity of evaluating test results and allow one to gain useful information while testing with reservoir-like flow rates. We considered measuring in-situ saturation changes in our x-ray imaging lab, but did not pursue this approach owing to magnetic field considerations. Our x-ray scanner uses an image intensifier. Image intensifiers are known to be susceptible to distortion from magnetic fields. The vibration actuator that we use (Terfenol-D) puts out a fairly strong and relatively wide magnetic field. In tests performed before those of this project, before we learned the necessity of putting distance between the actuator and other objects, the magnetic field from the vibration actuator magnetized tools on the testing table, and rendered several electronic devices useless (computer, computer monitor, pressure transducers).

## CONCLUSIONS

The following are conclusions from this work.

1. Data from routine property measurements are described and presented. Brine saturations were relatively high in core plugs cut from whole core obtained from the NBU seismic stimulation well. Core fluids may have changed compared to reservoir conditions by drilling and coring processes.
2. Special core analyses consisted of tests to measure waterflood oil recovery without and with sonic stimulation (low frequency p-wave or vibration stimulation). Limited results from waterfloods without and with sonic stimulation provide evidence that oil recovery was accelerated as a result of vibration stimulation compared to waterflood results

without vibration stimulation, although results do not provide enough insight to provide guidance on vibration frequencies and intensities that will optimize NBU oil production and recovery.

3. Sonic stimulation test results suggest that it may be advantageous to stimulate with vibration in a dynamic mode, periodically turning off and on vibration and changing frequency and intensity of vibration.

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2. Ashchepkov, Y., Filtration Characteristics of Inhomogeneous Porous Media in a Seismic Field. Translated and published by Plenum Publishing Corporation (1990). Translated from Fiziko-Tekhnicheskie Problemy Razrabotki Poleznykh Iskopaemykh, No. 5, (Sept. – Oct. 1989), pp. 104-109.

*Appendix F*

# DHVT Version 3.2

# Performance Test Report

*By*

**Bob Westermark**

**Seismic Recovery LLC**

# Knight’s Pecan Farm (KPF)
# Performance Testing DHVT V 3.2

## Conclusions

The DHVT V 3.2 gear drive, self-lubricating, and slip set and release systems have been satisfactorily shop tested and performance tested at KPF test site. It was noted during the KPF tests, that the internal temperature can approach the working temperature limits of the downhole electronics. Field-testing operations will need to closely monitor tool temperature and adjust operating procedures to allow for correct heat dispersion during tool cycling operations.

## Details

### Shop testing

DHVT V 3.2 was finished being assembled January 14, 2003. Shop testing closed loop lubricating system started January 15, 2003. The assembled tool was run at low RPM to check lubricating system and 8-9 gerotors contact wear patterns. The 8-9 gerotors were replaced with 10-11 gerotor sets. The lubricating system was re-checked. The lubricating oil pump discharge volume is correct and gerotor wear patterns are satisfactory. The shop tests were repeated on January 20, 2003. DHVT V 3.2 was ready for performance testing at KPF.

### Knight’s Pecan Farm Performance Testing

Tuesday, January 21, 2003, the DHVT V 3.2 was taken to KPF. The hydraulic drive unit and electronics for the data acquisition system were hooked up.

The short term testing started Wednesday, January 22, 2003. All sensors and tool were working okay. Ran the DHVT V 3.2 for two hours, then remove tool and checked for wear patterns. Everything looked fine; the tool was reassembled for testing on Thursday. January 23, 2003. The tool ran for 4 hours before pulling the tool to again check for wear. The tool was running satisfactorily. The oil, oil pump gerotors and track rollers all appear working fine. The tool was reassembled to conduct long term performance tests.

The long term testing began Friday, January 24, 2003. The tool ran overnight at about 300 RPM. Tool temperature stabilized at around $120^0$F. While running over night, there was a random fluctuation in RPM. On Saturday, January 25, 2003 the tool continued to run at about 300 RPM. The temperature stabilized at $120^0$F. The tool had sped up to over 450 RPM for a short period Saturday night, but was running at about 350 RPM Sunday morning. The tool was slowed down to about 180 RPM. It ran smoother at that speed. The tool was again run overnight. Cumulative performance test run time 96 hours.

On Monday morning, January 27, 2003 the tool had slowed down to 155 rpm over the course of the night. The tool was sped back up to 330 rpm. It began producing high and strange acceleration values. The first long term performance test was terminated. Cumulative performance test run time 108 hours.

When the tool was pulled out of the hole, it was noted that the bottom slip straps had vibrated loose the top two bolts holding the slip straps on all three slips. The bolts did not back off. They were wired together with safety wire. The threads on the bolts were worn off such that they just pulled out of the female threads in the J-sleeve. When the oil drain plug was removed, there was a large amount of water in the oil reservoir. This indicated that there had been a breach across one of the internal/external seals on the tool. We took the tool back to the machine shop for further analysis.

## Failure Analysis and Mitigation

On Tuesday January 28, 2003, we disassembled the tool. The upper slip straps were too stiff in comparison to the lower slip straps. This caused the lower slips to set and prevented the upper slips from properly setting. We determined a means to re-machine the upper J-sleeve to allow for slip straps of equal length, allowing the slips to be set with the correct synchronization.

We tested the seals on the tool with low-pressure air, approximately 25 psig. The leaking seal was between the lower housing and the middle housing flange. Due to dimensional considerations, we tried a larger o-ring in flange, re-tested the tool and it held pressure. It took five days to re-configure the J-sleeves and slip straps.

## Second Performance Test KPF

### *Slip synchronization tests*

Tuesday, February 4, 2003, we put the tool together and went k out to KPF facility for pre-Burbank test. On Wednesday, February 5, 2003, we ran a series of slip synchronization tests. We put duct tape on all of the slips and put it in casing and set slips. We un-set slips and pulled out of hole to check to see if the tape is evenly cut. It was cut on all six slips. We conducted a repeat of this test with the same results. The slips were setting correctly.

### *Seal Integrity Lubricating System Tests*

February 6, 2003, we re-ran the tool back in the casing, hooked up electronics and set slips. Ran the tool for four hours; the tool ran well, but we did not run it overnight. Please refer to Figure 1 DHVT V 3.2 KPF RPM and Temperature vs. Time.

The tool was started again in the morning and ran for three hours. The tool was pulled out of the hole for inspection. There were no problems with the slips and there was no water in the oil this time. The gerotors looked good and the tool was put back together. To confirm proper re-assembly, the tool was run one hour Friday, February 7, 2003. Everything on DHVT V 3.2 was working as expected. The tool was loaded to go to Shidler Oklahoma for North Burbank Unit to began the field tests.

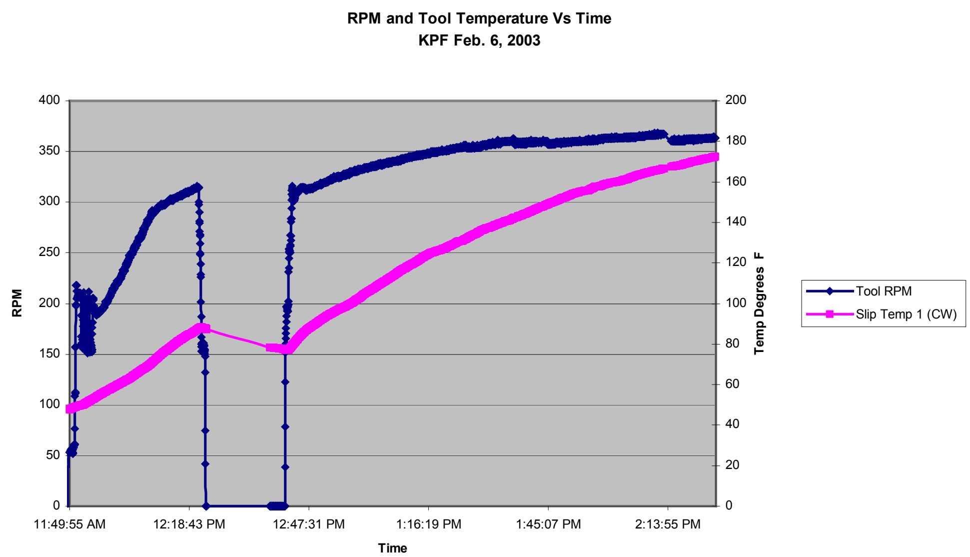


Figure 1 DHVT V 3.2 KPF RPM and Temperature Vs Time

*Appendix G*

# LBNL Field Notes

# of

# NBU Vibration Stimulation Field Tests


***By***

**Dale Cox**

**Consultant for**

**Lawrence Berkeley National Laboratory**

***NBU Field Test Report***

***LBNL Data Collection***

***North Burbank Unit Field Test***

***Downhole Vibration Tool Version 3.2***

***DOE Grant No. DE-FG26-00BC15191***


***Field Notes of Dale Cox***

***LBNL Representative***

***Edited by Bob Westermark***

***Seismic Recovery LLC***

## List of Figures

## *LBNL Data Collection*

## *North Burbank Unit Field Test*

## *Downhole Vibration Tool Version 3.2*

## *DOE Grant No. DE-FG26-00BC15191*

### Field Data Acquisition Notes from Dale Cox LBNL Representative

My hand written notes from the field have been scanned and transcribed.

The following is a summary of the notes.

The source was in the W-27 well at a depth of 2878 ft. The receivers were in two different wells. The first part of the experiment was in well 14 S1. The second part of the experiment was in well 12 S1.

| Well | approximate distance from source well | approximate azimuth | approximate elevation re source well | receiver depth |
|---|---|---|---|---|
| 14 S1 | 1000 ft | 315 degrees | 15 ft | 2800 ft |
| 12 S1 | 1250 ft | 225 degrees | -15 ft | 2550 ft |

Two surface lines were laid out. One started at well 14 S1 and was laid along a line towards the source well. The first three channel of this line was connected to the downhole tool. Channels 4 was approximately at the well head of 14 S1, channel 4 was at the end of the line towards the source well. The second line started approximately 300 ft from the source well and was laid along a line towards 14 S1. Channel 25 was nearest to well 14 s1 and channel 48 was nearest to the source well.

The lines were laid out on Tuesday Feb. 11th. Some test data were acquired on Tuesday and Wednesday Feb. 12th. Tom took notes on this data and I do not have those notes. This data is in /m/geo/dandecox/burbank/2_12_03

All the rest of the data covered by these notes are in:
/m/geo/dandecox/burbank/data

On Thursday Feb 13th, they had source problems and Cecil and I worked on rebuilding the shipping case for the downhole receiver.

On Friday 14tn everything was ready. We had had rain. We started taking data and there was a lot of 60 Hz noise. We had the recorder in the source shack. We also had 60 Hz on the pilot, which did not go away when we used the optical isolator. We used battery power in the shack to see if that would eliminate the power line noise. Then we moved the recorder to the road and used battery power, but nothing would work. We then move to the logging truck and used battery power. We finally were able to acquire data there, using only the downhole tool. We recorded data all this time and finally verified that we were in fact seeing the source. At this point we reconnected the surface line nearest the receiver well. The sun had come out and dried the ground enough that we could use the data.

Definitions:
Two different frequencies are involved in the notes. The source is driven by an electric motor at the surface. That motors turns at a certain RPM. The source has a natural frequency multiplier (a factor of 10) built in.

Thus a 150-350 sweep means the motor rpm is 150-350. This has a frequency of 150 rpm * (1min/60 second) = 2.5 Hz. But the actual frequency of the source is 2.5 Hz * 10 = 25 Hz. **In other words to get from motor rpm to source frequency in hz, divide by 6.**

Status: ffid 1-66 various noise tests.
Ffid 64-66 test of the sweep 150-350 with downhole geophone only
Ffid 70-71 noise test with surface line connected (OK)

TEST FINALLY STARTED.

The first test consisted of a series of sweep tests at 5 downhole geophone levels. We then removed the geophone from the well and conducted the same test using the hydrophone. End of day.

Saturday, February 15th.

We put the geophone tool back in 14 -S1 and did a series of tests where the source was driven at a constant frequency started at 50 rpm through 450 rpm in steps of 10 rpm. We recorded one-63 second record at each frequency. In the observers notes we noted the amplitude of the fft for the corresponding tool frequency for each of the 3 channels.

At the end of the day, I transferred the data to the SCSI disk and went to town to transfer the acquired data to the lab and did some plotting of the data. Cecil, with Bob and Joey's help, moved to the equipment to the second well.

Sunday, February 16th.

The tool was in the second well and we did the same sweep and constant frequency test in the second well. End of LBNL Data Collection

In summary, we recorded the following tests.

All of the tests were recorded for 63 seconds (their sweep had a length of 60 sec. The sample rate was 2 ms.

Well 14 S1

Sweep tests of 150-350 rpm at geophone depths of 2800, 2750, 2700, 2650, and 2600 ft.

| FFID | depth |
|---|---|
| 72-74 | 2800 |
| 78-80 | 2750 |
| 78-80 | 2700 |
| 81-83 | 2650 |
| 84-86 | 2600 |

I calculated ft of this data in flows w14_02 sweep test and w14_03 sweep ft single frequency test:

All of this was collected at 2800 ft.

FFID 106-157: The noise test here was conducted with the logging truck motor off.

See flows
w14_00 10-hertz test
w14_01 10-hertz fft
w14_01a 10 hz noise avg.
w14_01b 10 hz sub noise

well 12 S1
Sweep test 150-350 rmp

| FFID | depth |
|---|---|
| 161-164 | 2550 |
| 207-209 | 2500 |
| 210-212 | 2450 |
| 213-215 | 2400 |
| 216-218 | 2350 |

I did not process this data.

Single frequency test:

All collected at 2550

FFID 166-206
see flows
w12_00 10 hertz test
w12_01 10 hertz fft
w12_01a 10 hz noise avg.
w12_01b 10 hz sub noise

See my notes about data processing under “processing.notes” in this directory for more information.

Dale Cox

## Data Processing Notes from Dale Cox LBNL Representative

processing in
area cox
line burbank

**Processing for Source in W-27 Receiver in Well 14**

Source depth is 2878 ft.
Receiver well head for well 14 is 15 ft higher than the source well head.
Receiver depth measured from receiver well head.
Channel 1-3 are downhole geophone (x,y,z) at 2800 ft and 4-24 are surface.

---------------------

flow w14_00 10 hertz test
This flow reads in the seg2 data, sets certain header words and outputs the data in promax format. Mapped ffid to correspond to notes. Set rec_dep to 2800 for downhole and 0 for surface. Defined promax header rpm to be the source motor rpm
Defined promax header frequency to the frequency of signal.
Saved in W14_00 10 hertz test.
A noise test were taken with no rotation of the tool and designed at 0 rpm and frequency.

--------------------------

flow w14_01 10 hertz fft
This flow calculates the fft amplitude and outputs it. Sorted out channels 1-3 and in order of increasing frequency. Did header dump of ffid,chan,rpm,frequency.
Did fft and eliminated the phase keeping, only amplitude. Calculated dB down from 1. Displayed.
Screen dumps are in:
w14_10_hertz_ch*.jpg
saved in w14_01 10 hertz fft

------------------------------

flow w14_01a 10 hz noise avg.
This flows reads in the noise fft amplitudes and outputs the average with the Aim of subtracting the noise average from the fft amplitudes.
Reads in the noise test for the 10 hertz test, the data is then stacked, the output stack is duplicated the same number of times as the number, of total 10 hz trials.
The trace headers are modified to duplicate the headers of the 10 hz trials.
Saved in w14_10a noise avg.

--------------------------

flow w14_01b 10 hz sub noise
This reads in the fft amplitude data and sets the promax repeat header word. It then writes the data in a temporary file. The temp file is then read in by channel and repeats number and merged with the fft noise average data.
The average is then subtracted from the data and displayed.
Screen dumps are in:
w14_10_adjust_ch*.jpg (color); w14_10_adjust_ch*_w.jpg (wiggle trace);
w14_10_adjust_ch1_g.jpg (gray scale);w14_10_adjust_clup.jpg (a close-up of one of the wiggle traces)
The data is then written out to a segy file called w14_01_adjust.sgy.

------------------------------------

flow w14_02 sweep test
This flow reads in all the data from the sweep test. Corrected ffid to match field note numbers. Set rec_dep to the correct values.
saved in w14_02 sweep test.

----------------------------------
flow w14_03 sweep ft.
This flow displays selected ft's using the old F-T Analysis. Screen dumps are in format:
sweep_xxxx_yy.jpg
where xxxx is either 2600 or 2800 for the receiver depth and y is 1,2,3,h2,h3 for geophone channel 1,2, and 3 and hydrophone on channel 2 or 3.

---------------------------------------------
---------------------------------------------

**Processing for Source in W-27 Receiver in Well 12**

Source depth is 2878 ft.
Receiver wellhead for well 12 is 15 ft lower than the source wellhead.
Receiver depth measured from receiver well head.
Channel 1-3 are downhole geophone (x,y,z) at 2550 ft.

---------------------------

flow w12_00 10 hertz test
This flow reads in the seg2 data, sets certain header words and outputs the data in promax format.
Mapped ffid to correspond to notes. Set rec_dep to 2800 for downhole and 0 for surface. Defined promax header rpm to be the source motor rpm. Defined promax header frequency to the frequency of signal.
Saved in W12_00 10 hertz test.
Noise test were taken with no rotation of the tool and designed at 0
Rpm and frequency.

-------------------------

flow w12_01 10 hertz fft

This flow calculates the fft amplitude and outputs it. Sorted out channels 1-3 and in order of increasing frequency, did header dump of ffid,chan,rpm,frequency

Did fft and eliminated the phase keeping, only amplitude. Calculated dB down from 1. Displayed.

Screen dumps are in :

w12_10_hertz_ch*.jpg. Saved in w12_01 10 hertz fft

------------------------------

flow w12_01a 10 hz noise avg.

This flows reads in the noise fft amplitudes and outputs the average with the aim of subtracting the noise average from the fft amplitudes.

Reads in the noise test for the 10 hertz test, the data is then stacked, the output stack is duplicated the same number of times as the number, of total 10 hz trials.

The trace headers are modified to duplicate the headers of the 10 hz trials.

Saved in w12_10a noise avg.

--------------------------

flow w12_01b 10 hz sub noise

This reads in the fft amplitude data and sets the promax repeat header word. It then writes the data in a temporary file. The temp file is then read in by channel and repeats number and merged with the fft noise average data. The average is then subtracted from the data and displayed.

Screen dumps are in:

w12_10_adjust_ch*.jpg (color. The data is then written out to a segy file called w12_01_adjust.sgy

Dale Cox

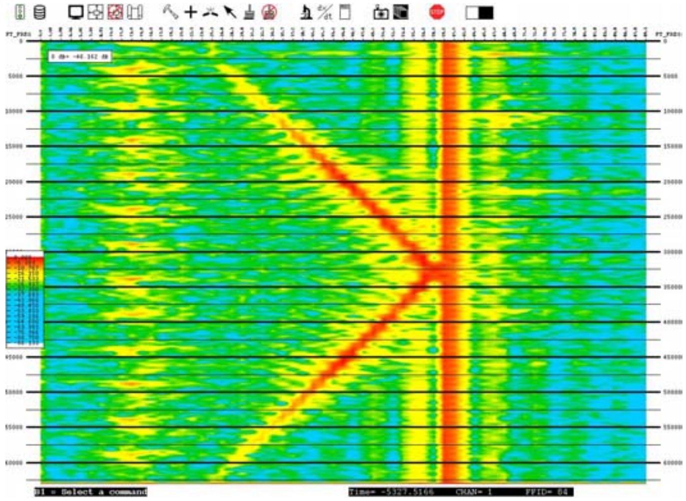

**Figure 1 Well 117 - 12 Frequency Sweep at 2600 ft Channel 1**

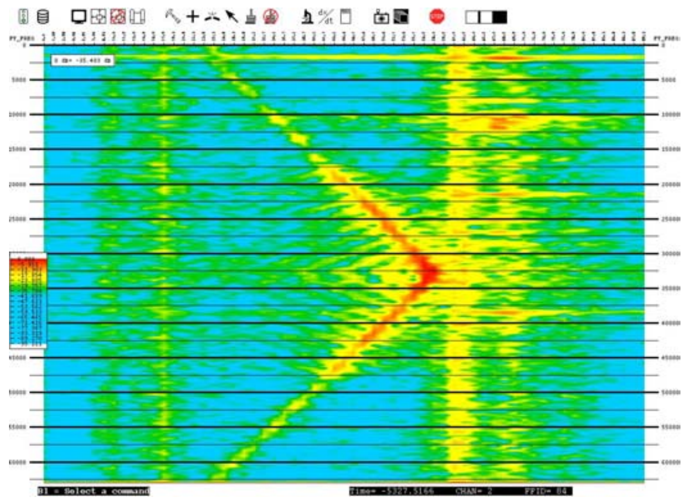

**Figure 2 Well 117 - 12 Frequency Sweep at 2600 ft Channel 2**

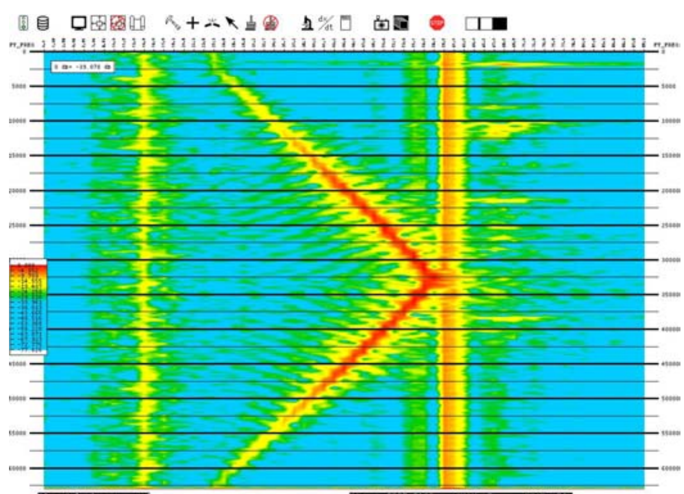

**Figure 3 Well 117 - 12 Frequency Sweep at 2600 ft Channel 3**

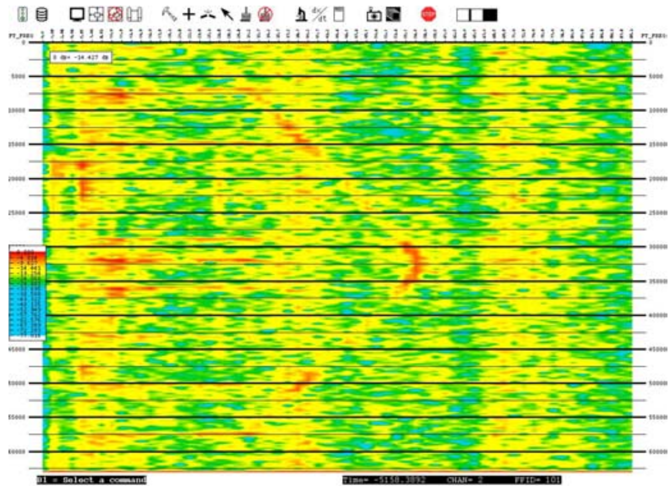

**Figure 4 Well 117 - 12 Frequency Sweep at 2600 ft Hydrophone 2**

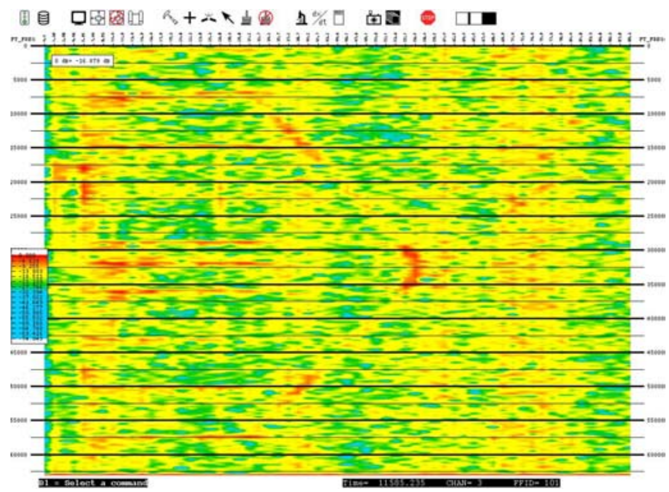

**Figure 5 Well 117 - 12 Frequency Sweep at 2600 ft Hydrophone 3**

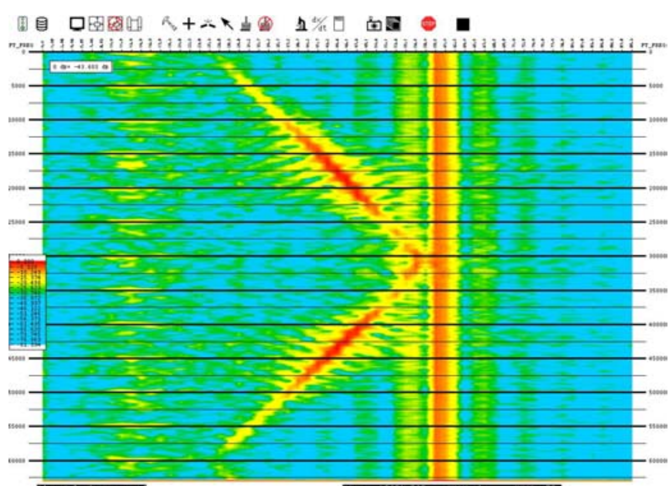

**Figure 6 Well 111 - 14 Frequency Sweep at 2800 ft Channel 1**

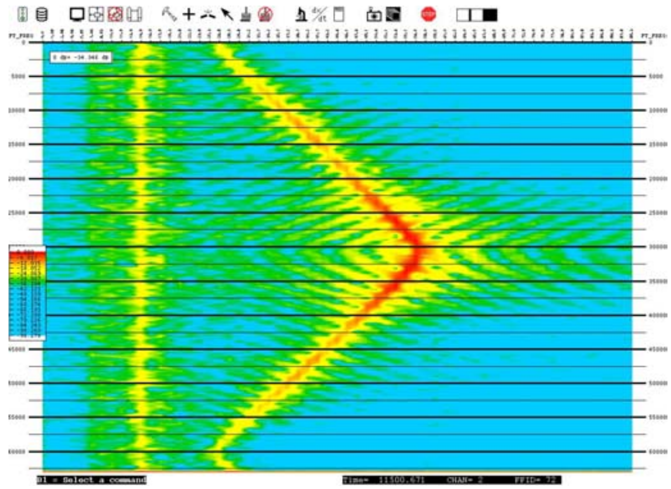

**Figure 7 Well 111 - 14 Frequency Sweep at 2800 ft Channel 2**

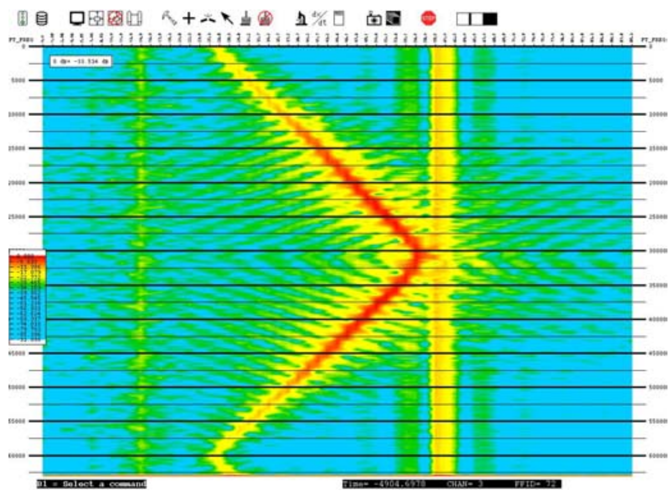

**Figure 8 Well 111 - 14 Frequency Sweep at 2800 ft Channel 3**

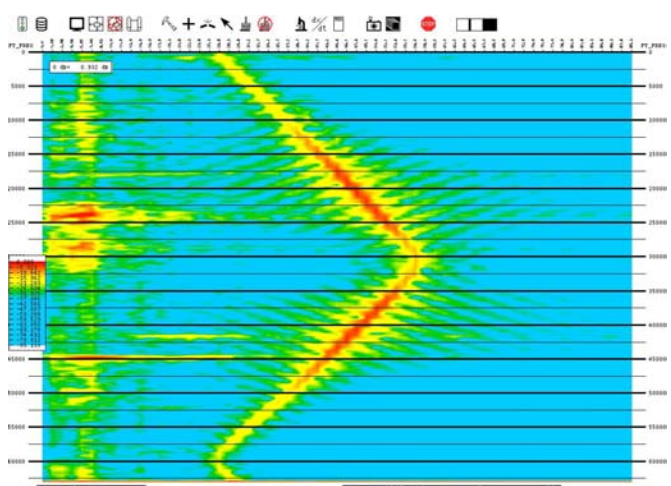

**Figure 9 Well 111 - 14 Frequency Sweep at 2800 ft Hydrophone 2**

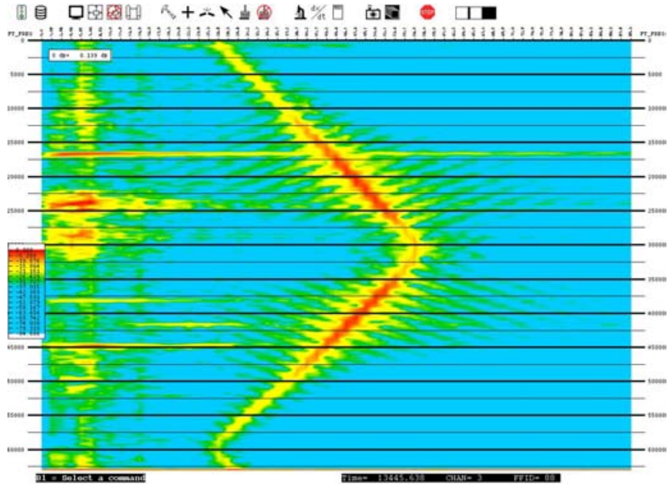

**Figure 10 Well 111 - 14 Frequency Sweep at 2800 ft Hydrophone 3**

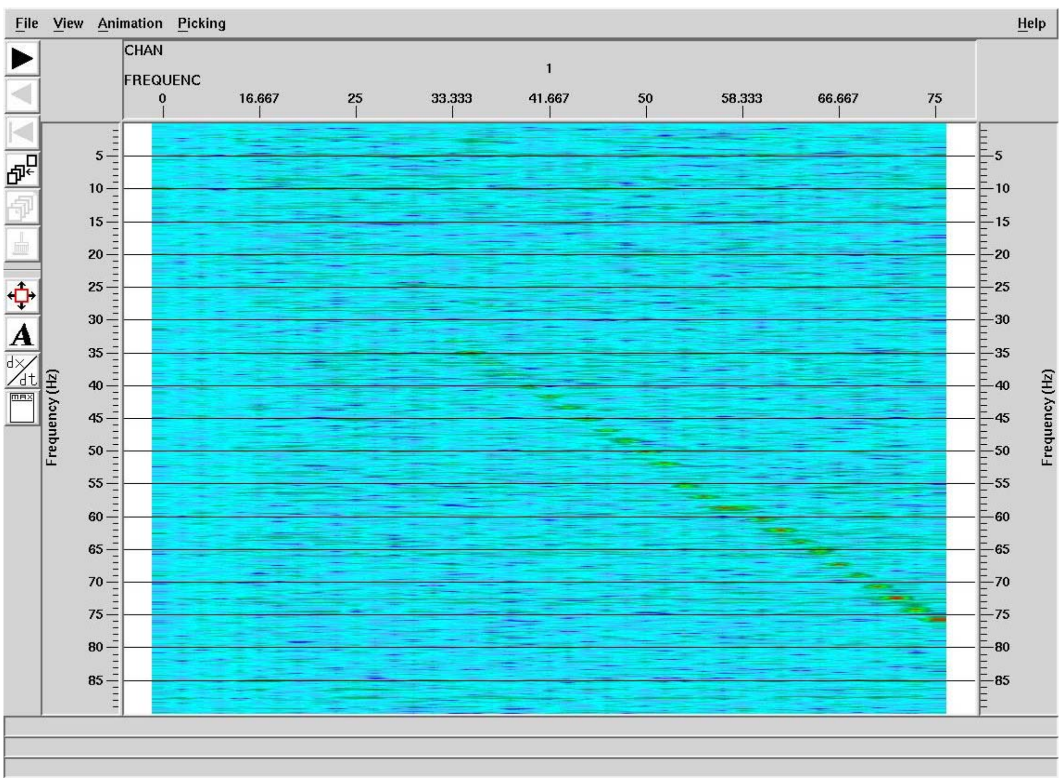


**Figure 11 Well 117-12 Step Test Adjusted Channel 1**

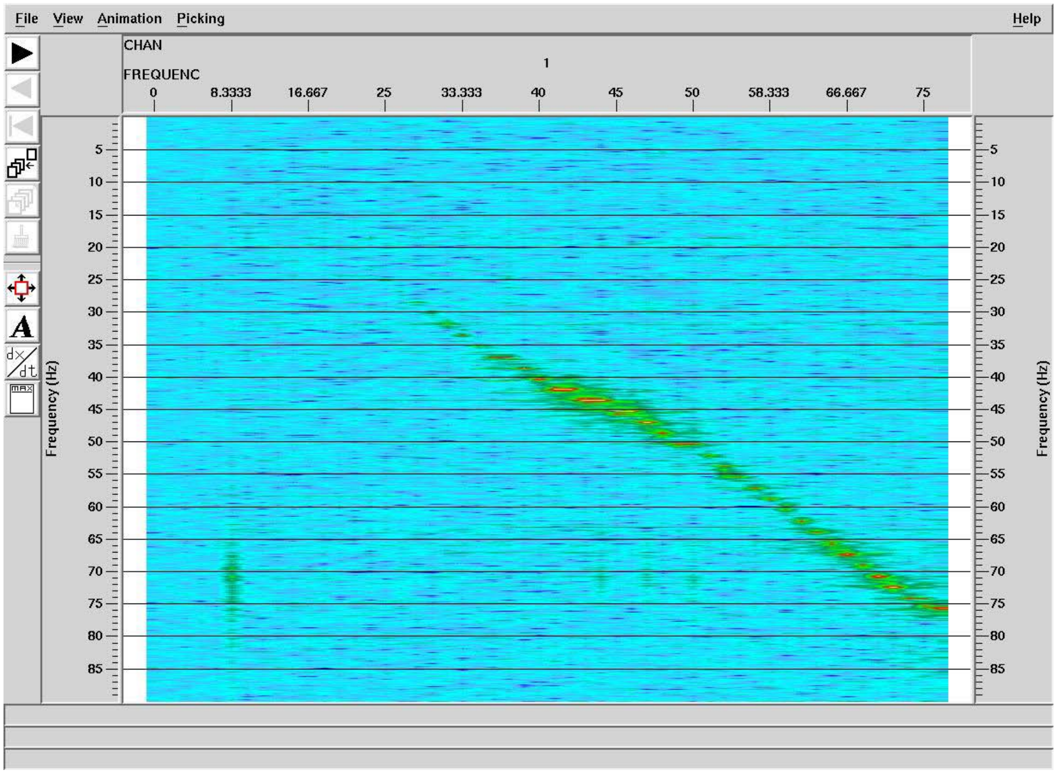


**Figure 12 Well 111-14 10 Adjusted Channel 1**

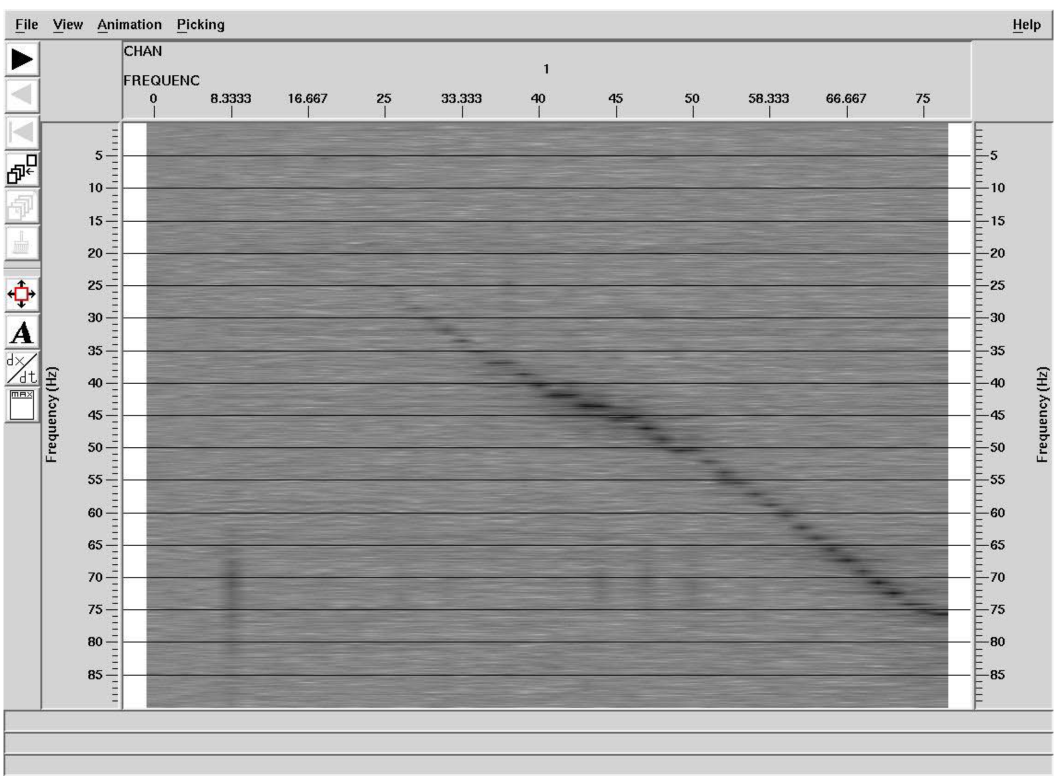


**Figure 12 Well 111-14 10 Adjusted Channel 1 Gray Scale**

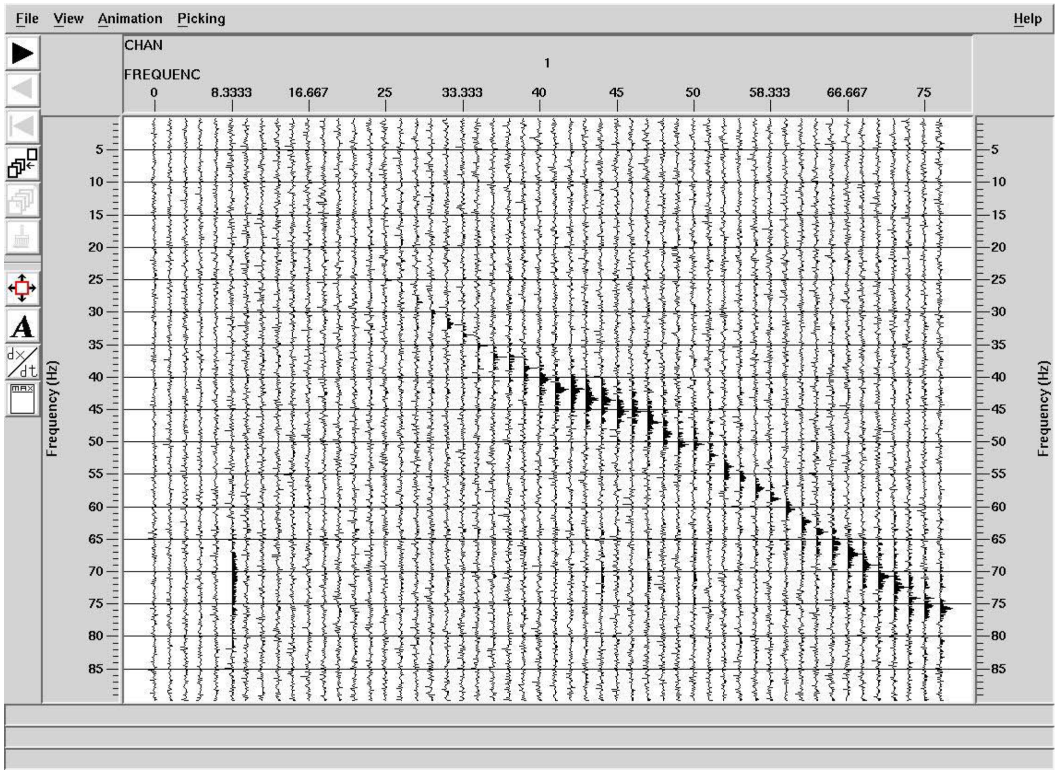


Figure 14 Well 111-14 10 Adjusted Channel 1 Black and White

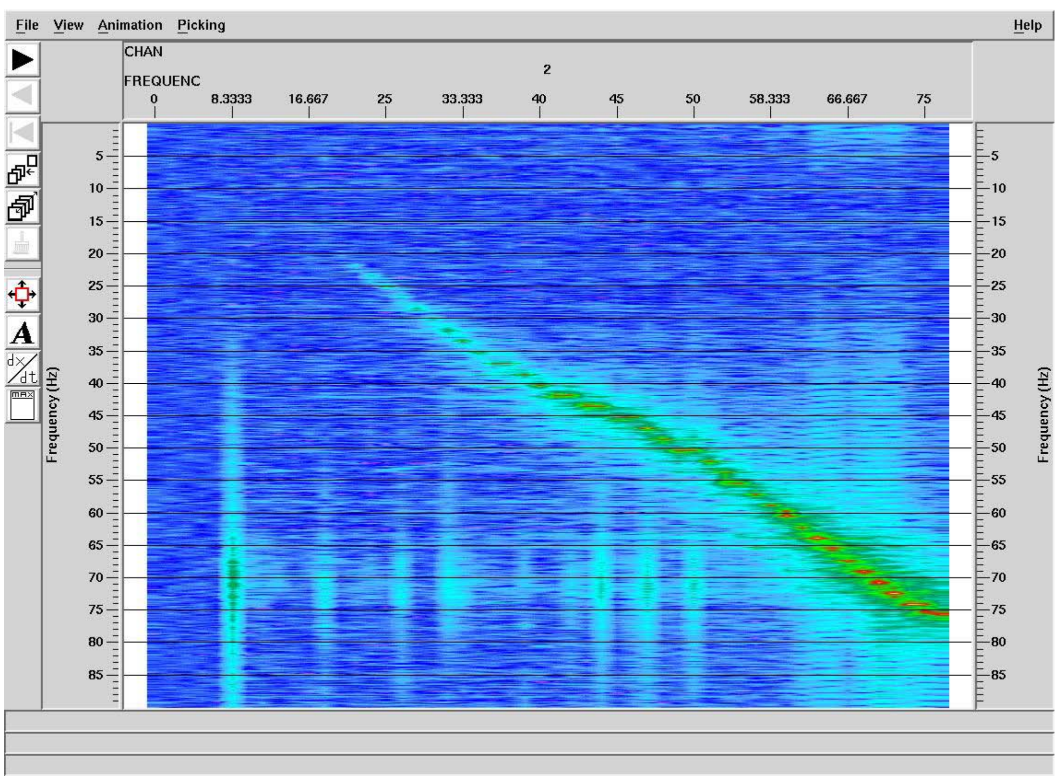


Figure 15 Well 111-14 10 Adjusted Channel 2

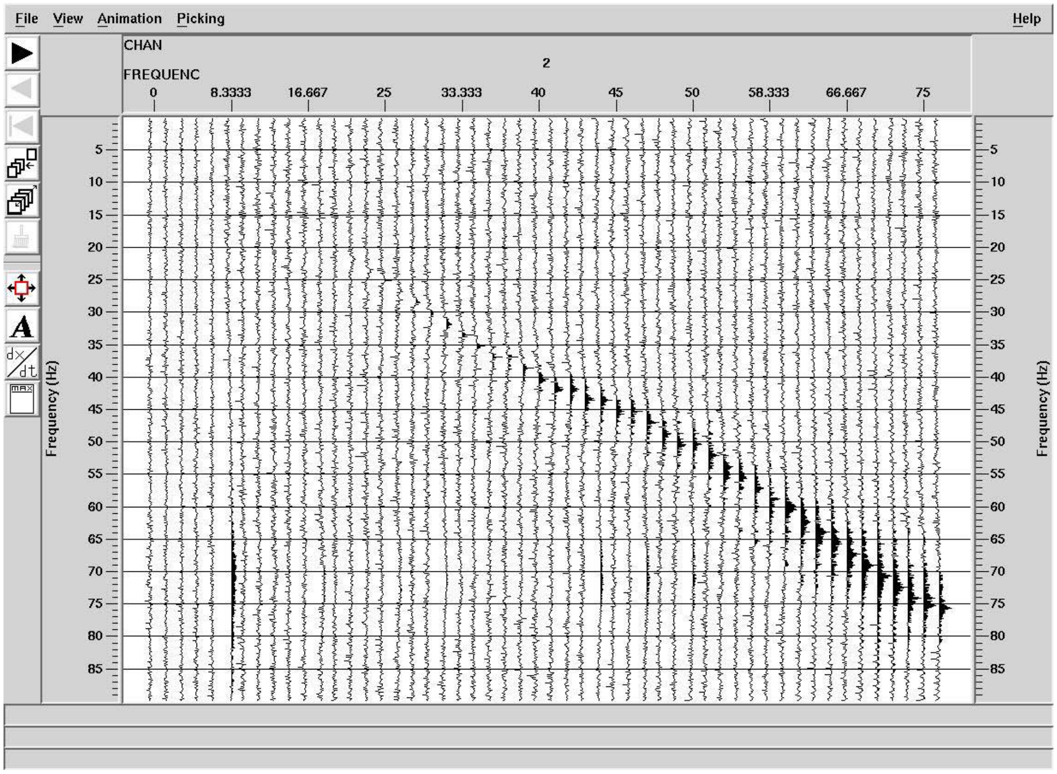


**Figure 16 Well 111-14 10 Adjusted Channel 2 Black and White**

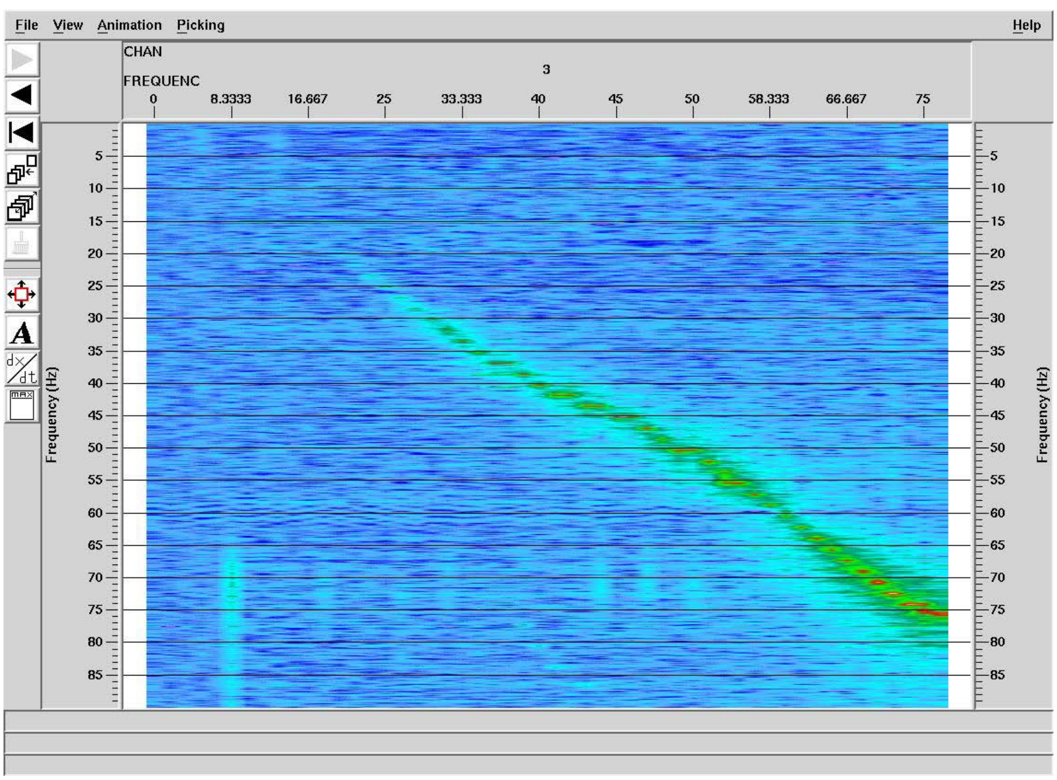


**Figure 17 Well 111-14 10 Adjusted Channel 3**

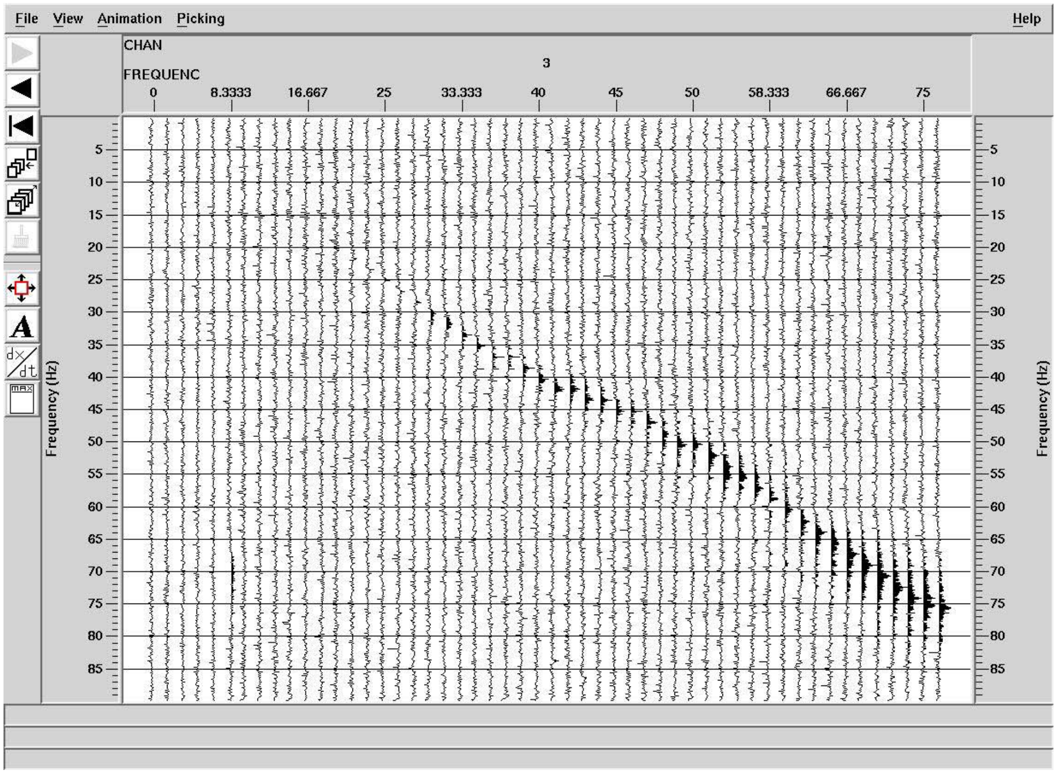


**Figure 18 Well 111-14  Step Test Adjusted Channel 3  Black and White**

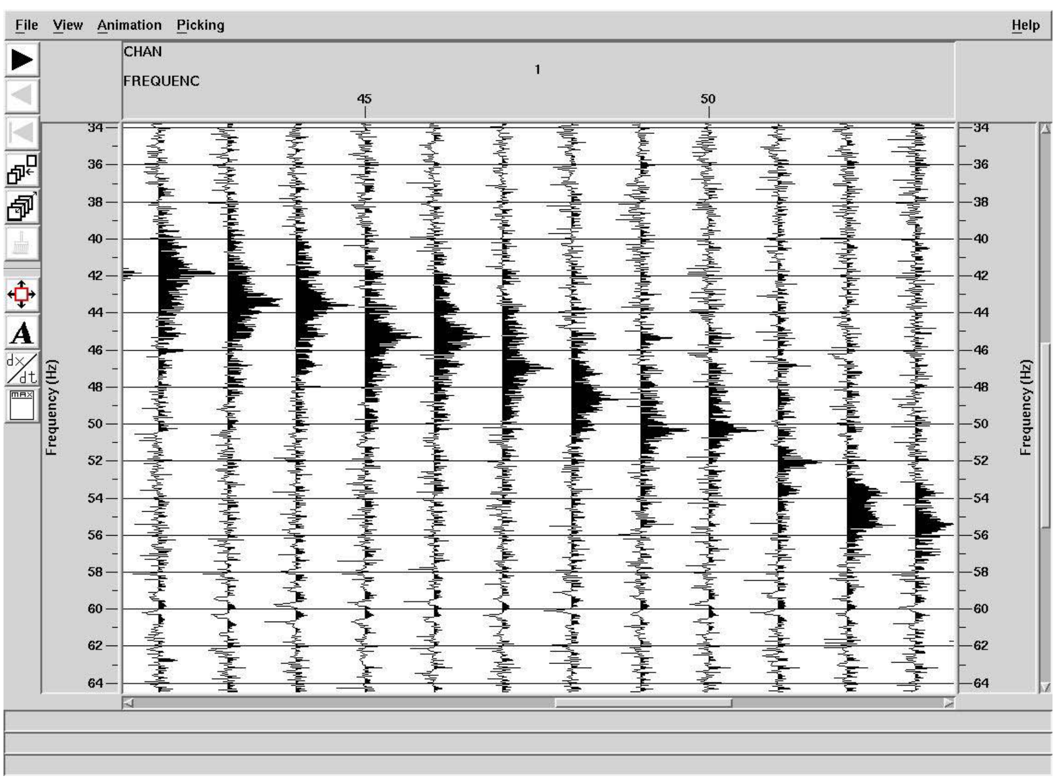


**Figure 19 Well 111-14  Step Test Adjusted Channel 3, Close Up, Black and White**

Figure I-13 Well 111-14  10 Hertz Step Test Channel 1

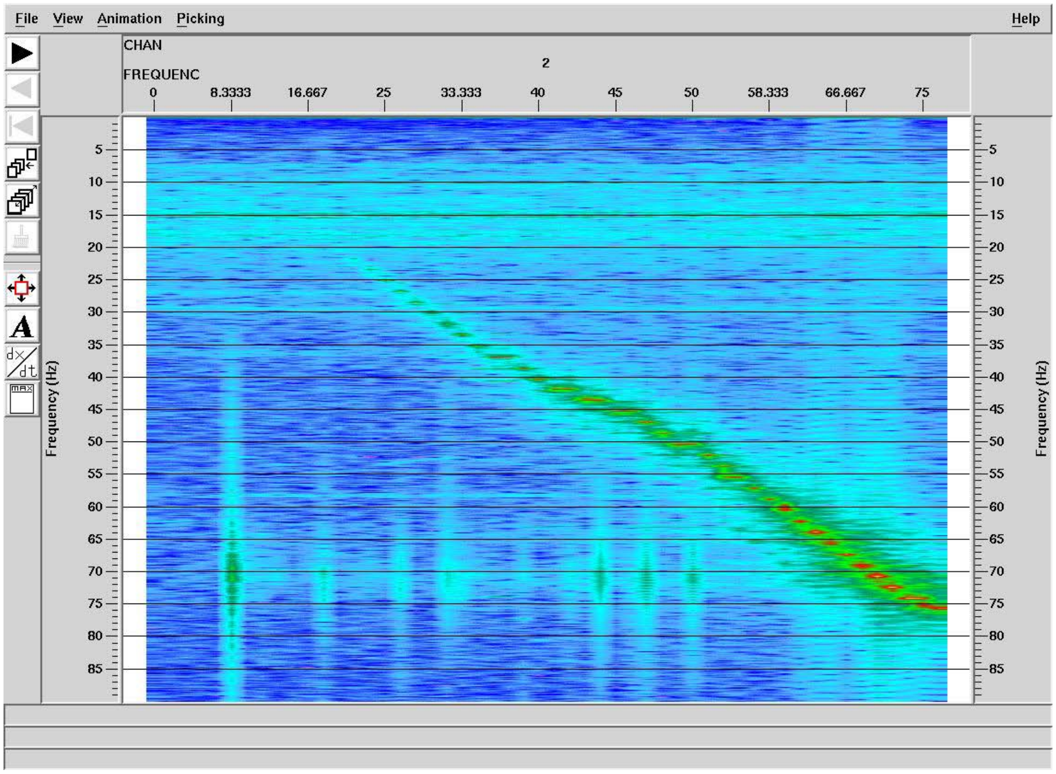


Figure 20 Well 111-14  10 Hertz Step Test Channel 2

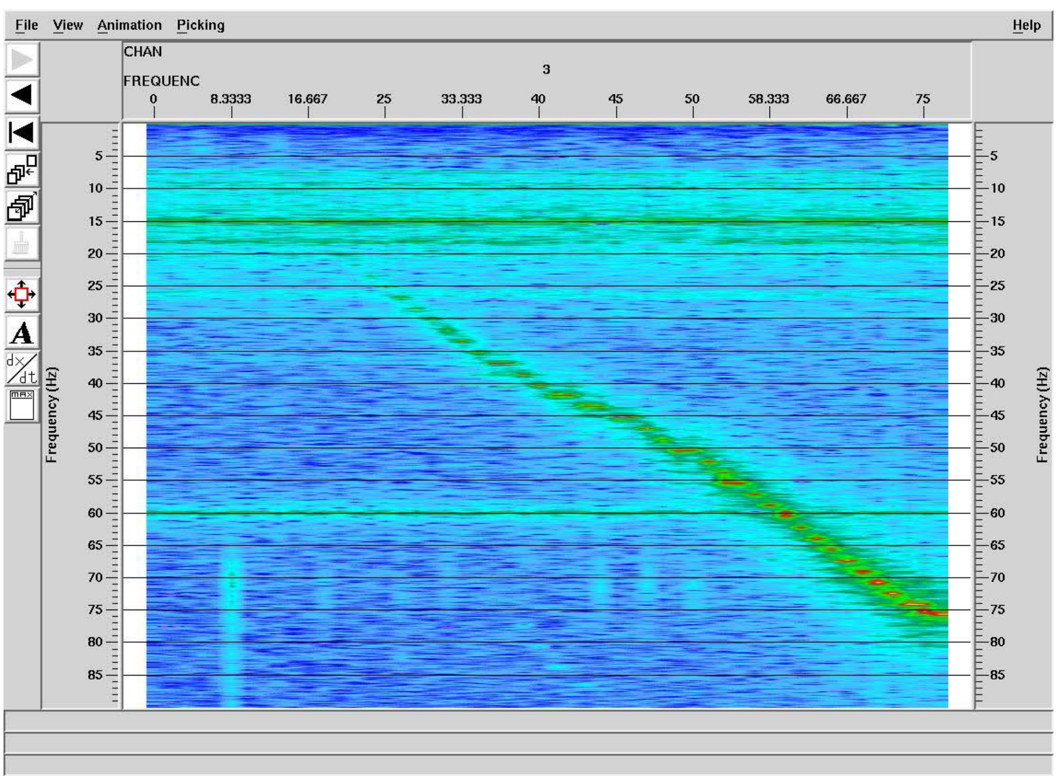


Figure 21 Well 111-14  10 Hertz Step Test Channel 3

*Appendix H*

# NBU Vibration Stimulation

# Field Test Report


***By***

**Bob Westermark**

***Seismic Recovery LLC***

# North Burbank Unit

# Vibration Stimulation

# Field Test Report

**By**
**Bob Westermark**
**Seismic Recovery LLC**

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# North Burbank Unit
# Vibration Stimulation Field Test Report

## Conclusions

The Field test was conducted in two phases. The following are the conclusions by phase:

Phase I

- DHVT V 3.2 generated the predicted signals reliably and repeatedly.
- DHVT V 3.2 generated seismic signals were recorded with downhole geophones and hydrophones in both the two offset wells 111-14 and 117-12, approximately 1000' and 1200' respectively from the source well.
- The seismic signals can easily be seen as very clean and strong signals above the background noise recorded.
- There were no resonant frequencies identified during this portion of the field test.

Phase II

- There was no response or change in either injection or production parameters during or after the vibration stimulation test.
- The primary objective of this project, which was to determine the effects of vibration stimulation on improving oil recovery from a mature waterflood, was not obtained.
- While there was no improved oil recovery effect measured, there was insufficient vibration stimulation time to expect a change to occur. No conclusion can be drawn about the effectiveness of vibration stimulation in this test.

## Details

This report describes in detail the background in designing the field vibration stimulation test, the procedures prepared, the field operations, and results of each of the two phases of the field test. In addition two appendices are attached to this report. Appendix I is a report entitled "LBNL Data Collection North Burbank Unit Field Test Downhole Vibration Tool Version 3.2 DOE Grant No. DE-FG26- 00BC15191," which is a compilation of LBNL representative Dale Cox's field notes. Appendix II is the NBU Field Test Daily Reports for February – March 2003.

### GOALS FOR THE FIELD VIBRATION STIMULATION TEST

The goals of the field test are to measure and record the operating characteristics of DHVT V 3.2 and to run DHVT V 3.2 for a sufficient period of time to be able to evaluate it's potential impact on reservoir fluid flow characteristics in this mature waterflood. To determine potential effects on both production and injection wells, a combination of historical production and injection data was compared with corresponding production and injection information obtained during the vibration stimulation test. To accomplish these goals, the vibration stimulation field test was conducted in two phases.

**Phase I**

The operating characteristics of the DVHT V 3.2 were to be evaluated with respect to the Burbank sandstone, the formation being stimulated. In 1996, Nikolaevskiy theorized that "the resonant frequency" of the liquids and matrix within the producing formation was responsible for the success of seismic vibration for improving oil recovery in mature waterfloods. To monitor the seismic signals produced and to possibly identify a resonant frequency, LBNL was invited to collaborate during Phase I of the field test. Ernie Majer, LBNL, is managing a DOE sponsored NGOTP project entitled "An Integrated Approach to Assessing Seismic Stimulation". A sub-task of this project is to record seismic signals generated by the various seismic stimulation type systems offered by different vendors. With the assistance of LBNL, the seismic signals would be recorded with downhole logging tools in offset wells and an attempt would be made to identify the resonant frequency. LBNL has performed similar operations in conjunction with other vendors of seismic stimulation type equipment during their respective field tests.

**Phase II**

A 90-day test of reservoir vibration stimulation was planned, which should have provided adequate time to observe any changes in the production or injection wells within the pilot area. Two years of baseline data have been gathered on production and injection operations. During the field test the production for the pilot area will be recorded daily. Individual well tests and producing fluid levels will be monitored weekly, or more frequently if a production response is detected. The two injection wells in the pilot area have been equipped to provide continuous real-time injection pressure and rate information.

## BACKGROUND OF FIELD VIBRATION STIMULATION TEST

### Location of Vibration Stimulation Pilot Test Area

This huge field is located in northwestern corner of Osage County OK. The field was discovered and developed in the 1920s. After unitization, each production quarter section (160 acres) was designated with a tract number. It is currently operated by Calumet Oil Company. The vibration stimulation Well 111-W27 is located in the southern portion of the North Burbank Unit. The well is near the center of section 8 Township 26 North, Range 6 East. The four tracts in this section are 111, 112, 117, and 118. All the produced fluids in this section are processed at the Tract 118 tank battery, shown in Figure 1 below.

**North Burbank Unit Vibration Stimulation Pilot Test area**
**Section 8, T26N, R6E, Osage County OK**

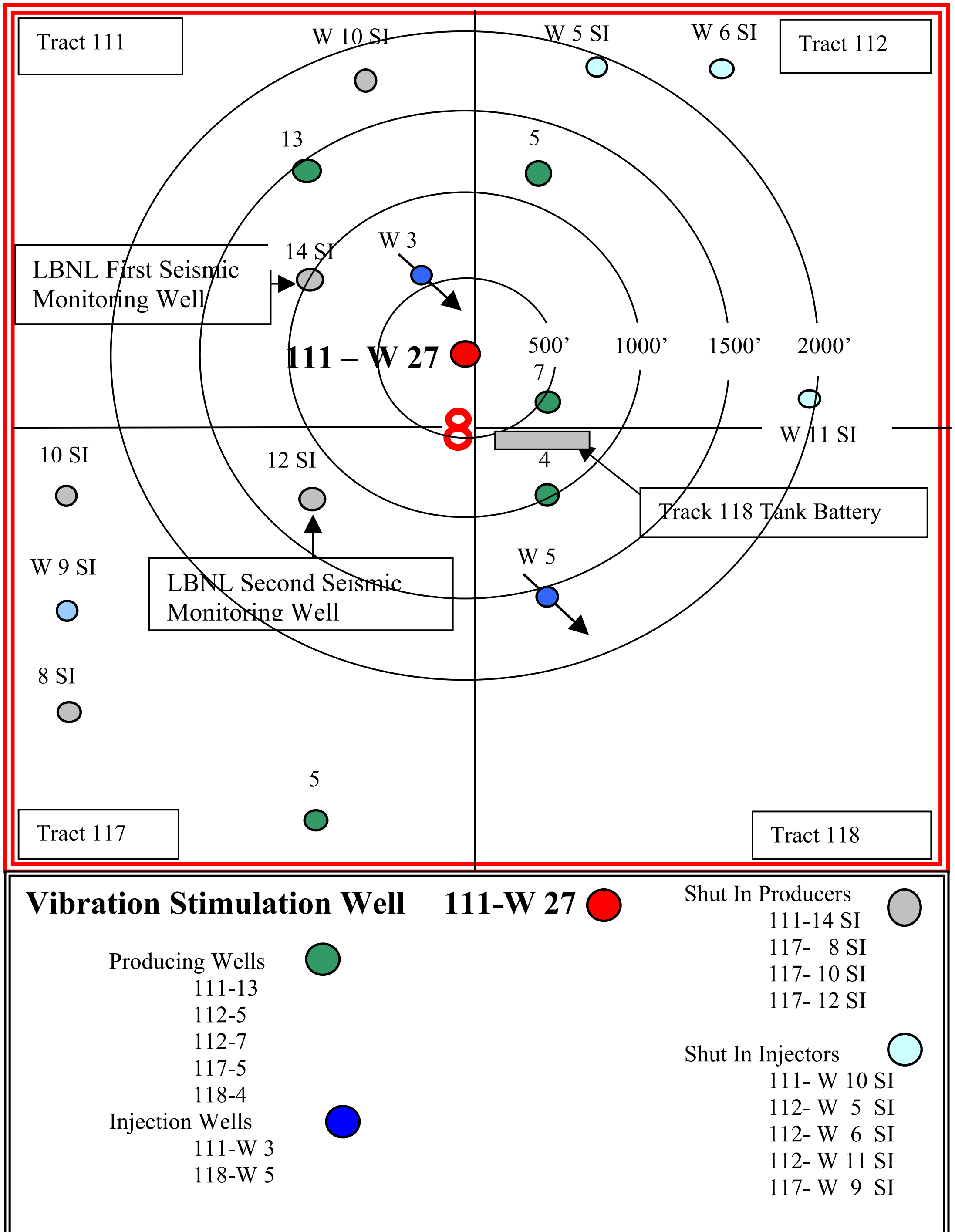


**Figure 2 North Burbank Unit Vibration Stimulation Pilot Test Area**

Phillips' Sonic Core Test as guideline

Based on the sonic core test results from PPCo, the concept of intermittent vibration pulsing was selected as the appropriate technique to begin the vibration stimulation testing. During sonic core testing of the NBU cores, PPCo had observed the maximum effect of sonic vibrations in the laboratory occurred by subjecting the core to intermittent pulse of vibrations, stopping the vibrations, then repeating the vibration pulse. This resulted in a 10% decrease in injection pressure at a constant injection rate, which was interpreted as a 10% increase in apparent permeability. This improvement in fluid flow occurred when the produced fluid was primarily water (98% water cut).

There are two injection wells in the pilot area. Well 111-W 3, about 500' northwest of 111-W 27 and 117 W 5, about 1500' south-southeast of the vibration well. It was reasoned that if the vibrations were to improve the apparent permeability of the reservoir, the injection parameters may be effected sooner than changes in the nearest producing well, which is 112-7. It was anticipated that the change, if it occurred, would be a subtle, but gradual improvement in injectivity. It was hypothesized that the nearest injection well 111-W 3 would most likely be the first well affected by vibration stimulation. Therefore, the requirement to obtain continuous real-time injection well pressure and rate data became a key element in designing the field test data acquisition system.

Facility Description

All produced fluids are gathered into the Tract 118 tank battery. It was necessary to be able to measure accurately the produced fluid from only the pilot test area wells. To isolate the production to just the producing wells within the pilot area, a separate water knockout, oil and water separator and storage tank was installed in April 2001. The baseline for production/injection data collection began after the modifications to the tank battery. After the pilot test area oil is separated from the produced water, the produced water is then recombined with the remaining produced water at the tank battery to be re-injected. All the produced water is sent a holding tank on the inlet side of the centrifugal injection pump.

The injection pump runs constantly and operates near its maximum capacity. The injection volume of the pump is controlled by a set of water level sensors in the holding tank. If the pump output is in excess of the produced water volume entering the tank, the tank level will drop. The sensors will respond to the low liquid level and cause the pump to be slowed down until the tank level begins to rise again. As the tank rises to the high liquid level sensor, the pump is sped up and the level in the tanks will drop again. This results in a subtle cycling of injection rate and pressure about every fifteen minutes when everything is running smoothly.

Data Acquisition System

The objective of the data acquisition system (DAS) was to record all surface and downhole data with a common time reference to allow for a correlation of all operations and potential responses. This may sound trivial, however it was a challenge to do all data collection with one computer. The DAS built for the NBU field test has four separate data sources, these are: individual injection well pressure and rate data; downhole on-board sensor accelerometers and temperature sensor data; electric motor operational data; surface vibration detection data from accelerometers and a 3-axis geophone.

Two data collection modes, fast and slow, were built which basically coincided with the two phases of the field test.

In Phase I, a fast data collection mode was required. The fast mode recorded all DHVT sensor output at 2000 bits per second, which also required that all other sensors were recorded at that high data density. The fast mode would generate a 500-megabit file every 20 minutes. This required the constant attention of personnel to manage the data. Once confidence was gained in operating the DHVT, the need for detailed data would be able to be relaxed.

In Phase II, the rate of data recorded from the downhole electronics was reduced. This slow mode of data collection was only approximately 20 bits per second. This allowed the data to be collected over night with no supervision required.

In Table 1 below is a list of the data sources, which the DAS was designed and built to collect, display, and store, including the production data being gathered daily or weekly.

Computer Controlled DHVT Operations

The DHVT speed can be controlled either manually or with a computer. The test plan was to cycle the tool on and off in a manner similar to the technique PPCo employed in the laboratory, but increasing the duration between the pulses. This was to be done by applying the speed control function of the computer for operating the electric motor. The computer would bring the tool up to a desired speed, hence, a predetermined output frequency, hold the tool at that condition for several hours, bring the tool speed back to zero in a controlled manner. The computer would automatically repeat the cycle for days. After that, a new stimulation frequency range would be selected, the computer reprogrammed to control the motor accordingly, and the test continued.

DHVT V 3.2 RPM and Frequency Relationship

This version of the DHVT has a gearing system using special gears named gerotors. The gerotors insure that the whirling motion of the tool is reliable and consistent. The particular gerotors used for this test result in ten vibrations for each revolution of the tool. To convert tool RPM into revolutions per second simply divide by 60. This makes it simple to determine output frequency when tool RPM is known. To calculate the output frequencies of the tool in hertz (cycles per second), divide the RPM by 6. If the tool is turning at 300 RPM, the output frequency will be 50 Hz.

| Parameter | Data Link | Data Speed | Critical | Units |
|---|---|---|---|---|
| Injection Wells (2) | | | | |
| Rate | Steel wireline | Slow | Yes | BWPD |
| Pressure | Steel wireline | Slow | Yes | psig |
| Production Wells | | | | |
| Production | Manual | Daily | Yes | BOPD |
| Weekly well Tests | Manual | Weekly | Yes | BOPD |
| Pumping Fluid Levels | Manual | Weekly | Yes | Feet above pump |
| Surface DHVT Drive Operations | | | | |
| Speed Controller | Insulated wire | Slow | Yes | RPM |
| Rotating Speed | Insulated wire | Slow | Yes | RPM |
| Horsepower | Insulated wire | Slow | No | Hp |
| Torque | Insulated wire | Slow | No | Ft-lbs |
| Power Consumption | Insulated wire | Slow | Yes | Kilowatts |
| Sub-surface DHVT Sensors | | | | |
| X1 axis Accelerometer | Steel wireline | Fast | No | Frequency (Hz) and amplitude (ft/sec$^2$) |
| Y1 axis Accelerometer | Steel wireline | Fast | No | Frequency (Hz) and amplitude (ft/sec$^2$) |
| Z2 axis accelerometer | Steel wireline | Fast | Yes | Frequency (Hz) and amplitude (ft/sec$^2$) |
| Y2 axis accelerometer | Steel wireline | Fast | No | Frequency (Hz) and amplitude (ft/sec$^2$) |
| Tool Temperature | Steel wireline | Slow | Yes | $^o$F |
| Surface DHVT Sensors | | | | |
| X axis Wellhead accelerometer | Insulated wire | Fast | No | Frequency (Hz) and amplitude (ft/sec$^2$) |
| Y axis Wellhead accelerometer | Insulated wire | Fast | No | Frequency (Hz) and amplitude (ft/sec$^2$) |
| Three axis Geophone | | | | |
| Up/Down movement | Insulated wire | Fast | Yes | Frequency (Hz) and amplitude (ft/sec$^2$) |
| North/South movement | Insulated wire | Fast | No | Frequency (Hz) and amplitude (ft/sec$^2$) |
| East/West movement | Insulated wire | Fast | No | Frequency (Hz) and amplitude (ft/sec$^2$) |

**Table 1 Data Acquisition System Design Criteria for NBU Field Test**

**Phase I Procedure**

1. Prepare two wells in the pilot area to be able to have downhole geophones run on wireline. The two nearest inactive, offset wells are 111-14 and 117-12. Earlier in the project, Calumet had pulled the tubing from these wells in preparation for running the seismic signal logging tools. The location of the two wells also provided an opportunity to monitor the generated seismic signal both parallel and transverse to the known fracture orientation of the Burbank sandstone, the reservoir at NBU.

2. Lay a string of twenty-four 3-axis geophones on the surface in a line between the seismic source well 111-W 27 and the first monitoring well 111-14. The surface geophones are used to pick up seismic signals as they traveled to the surface from the DHVT well 111- W 27 at approximately 2900' below the surface.

3. Run LBNL's 3-axis downhole geophone logging tool on a seven-conductor wireline to approximately 2800' in well 111-14. Record seismic signals at five different depths, going up the well bore in 50' increments. A similar operation would be conducted with LBNL's downhole hydrophone logging tool. The downhole data recorded with these two different logging devices, represents the seismic signals, which essentially travels horizontally through the subsurface formations between the DHVT source and sensing devices.

4. Operate the DHVT either at discrete frequency steps or in controlled frequency sweeps of specific duration. Obtain a record of DHVT operations and the predicted frequencies generated.

5. Record the data from the string of surface geophones, in conjunction with monitoring downhole logging tools' response. Input the necessary DHVT operational data into the LBNL data acquisition system. While on site, perform a field evaluation of the DHVT performance by comparing the characteristics of predicted signal to the signals recorded and attempt to identify the resonant frequency of the reservoir. Send the field data back to LBNL for further processing.

**Phase I Field Operations**

1. LBNL rigged the wireline truck on Well 111-14 and ran a gauge ring to confirm that there were no restrictions in well. The 3-axis geophone-logging tool was made up and surface tested, then ran into the well and set at 2800'.

2. LBNL personnel laid out surface geophones in a line between wells 111-W 27 and 111-14. This required passing underneath a 14,400-voltage electric transmission line. The electrical noise level sensed by the geophones was excessive. Attempts were made to minimize the electrical noise with various electronic filters and alternative power sources with no success. Therefore, the data from the surface geophones was considered unusable. The attempt to collect the surface geophone information was abandoned because of the aforementioned problems.

3. The rotating speed of the DHVT was slowly increased, which increased the output frequency and intensity of the generated signal. The LBNL geophone was able to distinguish the seismic signal from the DHVT from the background noise when the generated signals exceeded 25 Hz, which corresponds to 150 RPM.

The step tests were the initial monitoring operations. This involved increasing the generated signals approximately 1.5 Hz per step and letting the DHVT stabilize at that frequency output for two to three minutes. Slowly the frequency was raised from 25 Hz to about 75 Hz. This process was repeated five times as the tool was repositioned up the well in 50' increments.

The second round of monitoring was accomplished while sweeping the DHVT output frequency up and down in a precisely controlled manor. For this function a computer is used to control the DHVT rotating speed. The tests started from a low frequency of about 25 Hz, quickly increasing to an upper range of 60 Hz and back to the beginning 25 Hz. This sweep was done in sixty seconds. With computer control, the generation of the seismic signals was very precise, uniform, and repeatable.

Frequency sweeps were conducted at five stations 50' apart, going up the wellbore. The geophone-logging tool was then pulled from the well and the hydrophone-logging tool installed and run to 2800'. The step tests and the frequency sweeps were repeated again at each of the five depths coming up the hole. This completed the monitoring done at well 111-14.

4. The LBNL equipment was moved to well 117-12. Due to restrictions in the well, the maximum logging depth was limited 2550'. Step tests and frequency sweeps were conducted using both the geophone and hydrophone logging tools. This concluded the LBNL downhole monitoring work.

5. The predicted frequencies generated from the DHVT were precisely what LBNL was recording. Once the DHVT reached the 25 Hz frequency output, there was no doubt about the source of the signals being recorded, it was very distinct from all background noise. Dale Cox stated that the strength of the DHVT signal was the strongest seismic signal that LBNL has recorded in conjunction with other seismic stimulation type field tests.

   Some preliminary data processing from the step and sweep tests were done to prepare graphs of the data from the two types of tests conducted. LBNL has developed software to prepare plots of both the step tests and the frequency sweep tests. Details from Dale Cox's field notes and preliminary processing can be found in Appendix I "LBNL Data Collection North Burbank Unit Field Test Downhole Vibration Tool Version 3.2 DOE Grant No. DE-FG26- 00BC15191."

**Phase I Results**

The DHVT operated during Phase I as designed. The deployment of the LBNL monitoring system went as planned, other than not being able to use the LBNL surface geophones between the vibration source well and the monitoring wells because of the overhead high voltage power lines.

The downhole 3-axis geophone and the hydrophone logging runs were successful in both offset wells; more than 200 data files were created as the DHVT went through it's operational paces. Only a small portion of the data has been preliminarily processed. The data has not been completely processed by LBNL, nor has a final report yet been issued.

Below in Figure 2 is a graph of data from the on-board sensors during one of the step tests conducted, where the tool speed is slowly increase and held constant for two to three minutes. Figure 3 is a chart produced from the LBNL data recorded. This is the same step test as seen in Figure 2, but plotted with LBNL software. In the LBNL graph, the predicted frequency is plotted against with the measured frequency. Both axes have hertz as units. It indicates the predictability of the DHVT as an engineered seismic source.

Graphs of the frequency sweep tests are also provided. In Figure 4, the graph provides an example of the DHVT signal characteristic as measured by the on-board sensors and processed by the projects data acquisition system. Time is on the X-axis and represents a single up-down cycle just slightly more than one minute (sixty-three seconds). Tool RPM is on the left-hand vertical axis, while frequency, both measured and predicted are plotted against the right-hand vertical axis.

Whereas, in the graph in Figure 5, the image is a product of LBNL's processing of the signals the downhole logging tools recorded. In the graph of the LBNL processed data in Figure 5, the data plotted is from the 3-axis geophone set at 2800' during a one-minute frequency sweep test. The format of this chart is different from Figure 4. In Figure 5, the X-axis is the frequency recorded, increasing in value to the right of the chart. This chart has time on the Y-axis in μ-seconds (1 /1000 of a second), ranging from 0 at the top of the chart increasing to 60,000 μ–seconds at the bottom of the chart. The total time from top to bottom of the graph represents 60 seconds of recording time. This graph also provides a scale of various colors representing the strength of the signal recorded. Blue represents background noise levels with the maximum signal strength displayed in red, which is about 80 decibels above background noise. The trace of the signal from the DHVT is discernable beginning at about 25Hz at the top of the graph as a yellow diagonal stripe increasing in strength and frequency to about 60 Hz and back to the 25 Hz signal. The vertical stripe at 60 Hz is a result of the overhead high-voltage lines in between the wells. By comparing Figures 4 and 5, the similarities between the DHVT on-board sensors measurements with LBNL recordings of the seismic signal over a 1000' away are remarkable.

However, based on the preliminary seismic signal processing, there no identification of a resonant frequency within the reservoir.

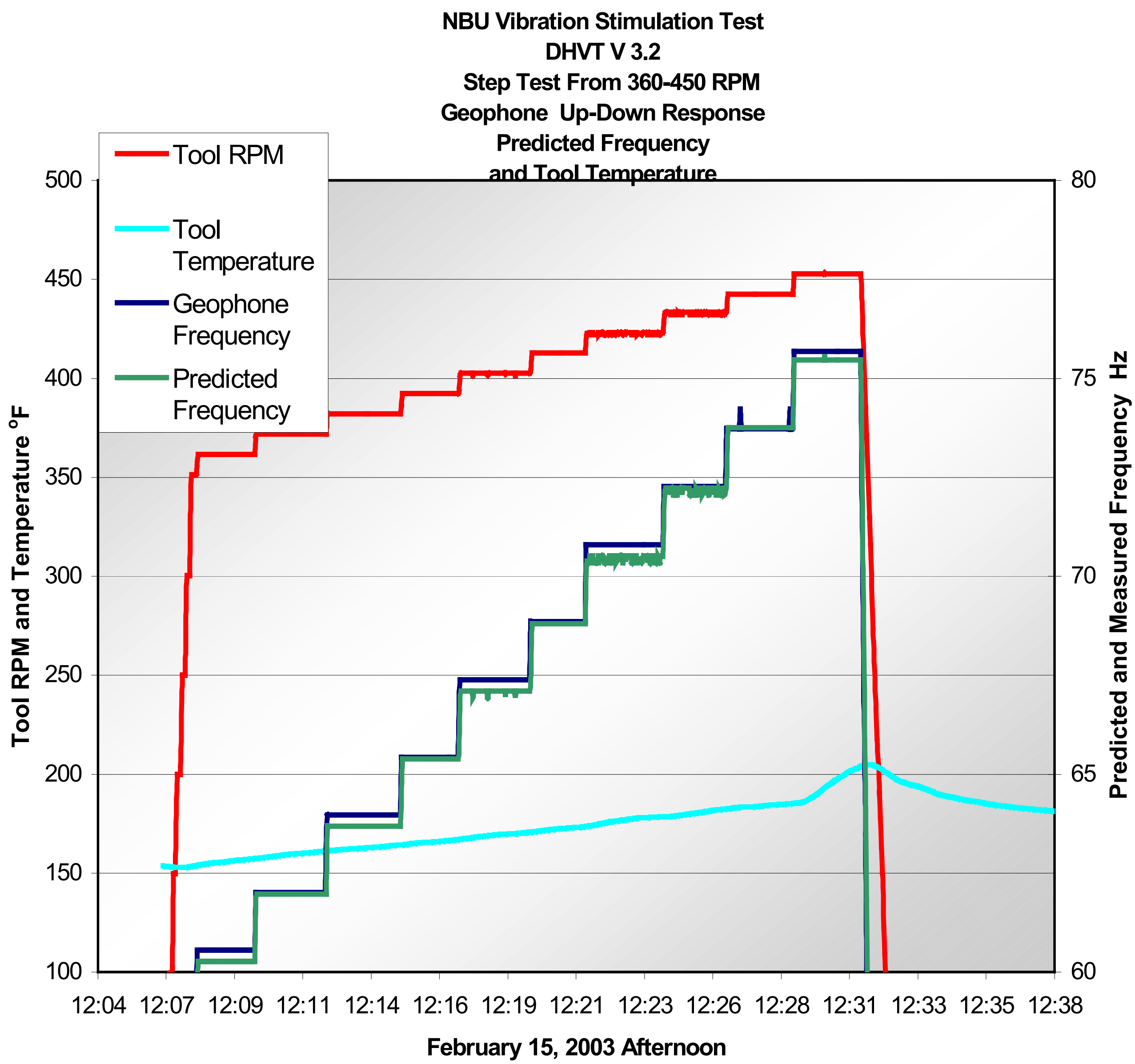


**Figure 3 NBU Field Test Phase I DHVT V 3.2 Step Test**

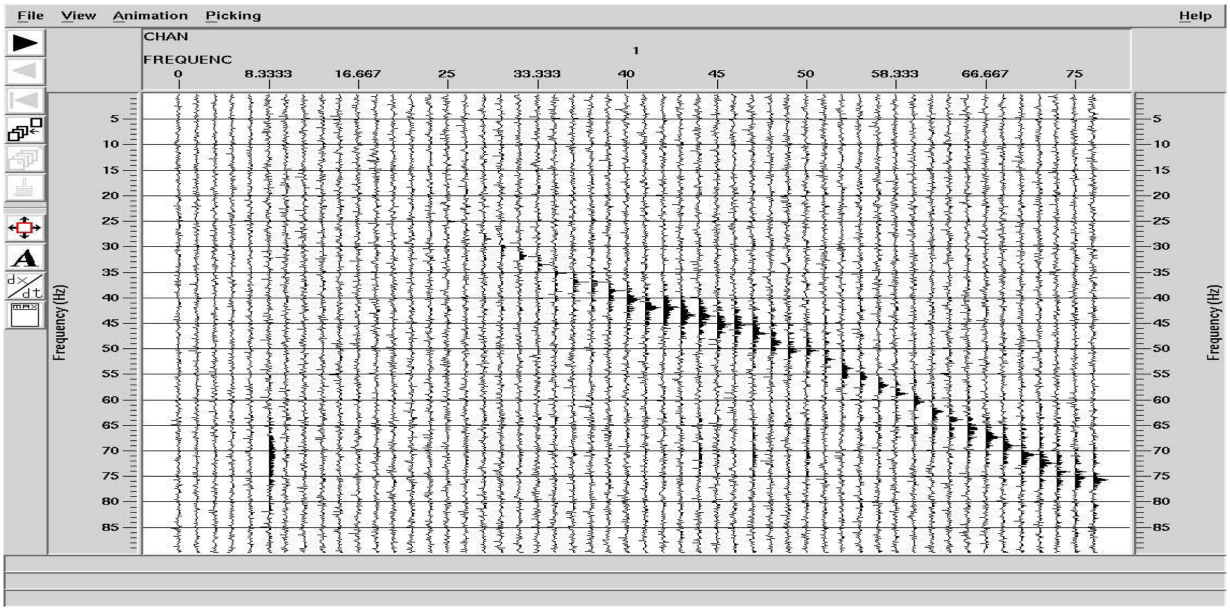


**Figure 3  LBNL Recorded and Processed Step Test February 15, 2003**

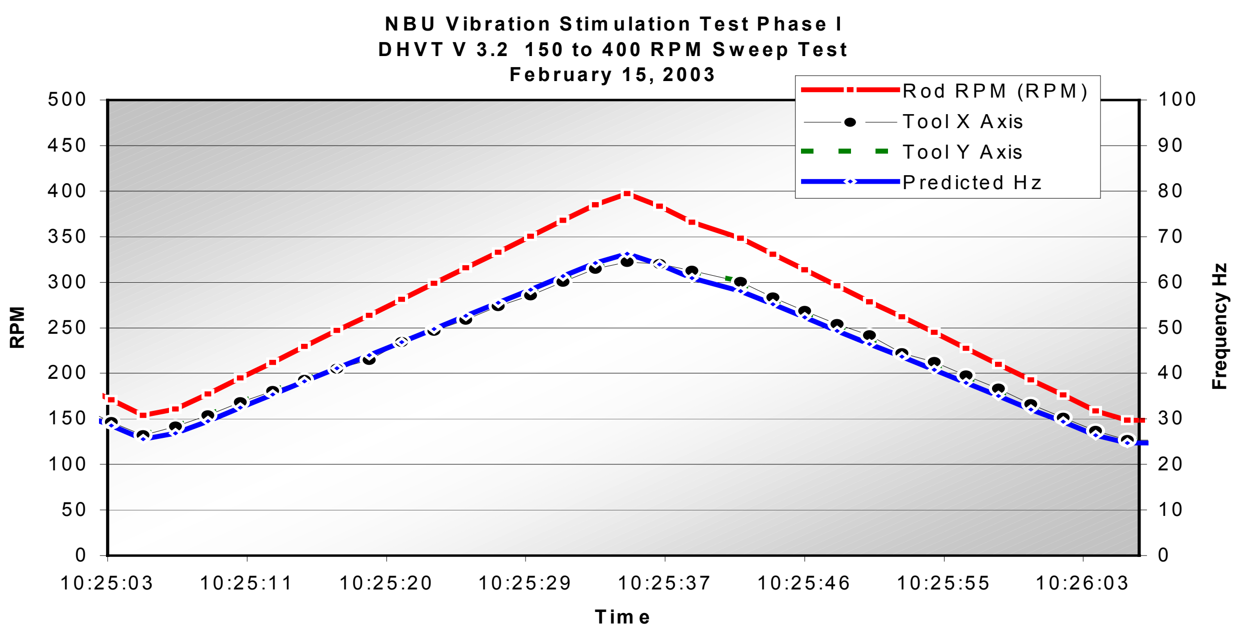


**Figure 4  DHVT Generated One Minute Frequency Sweep Test**

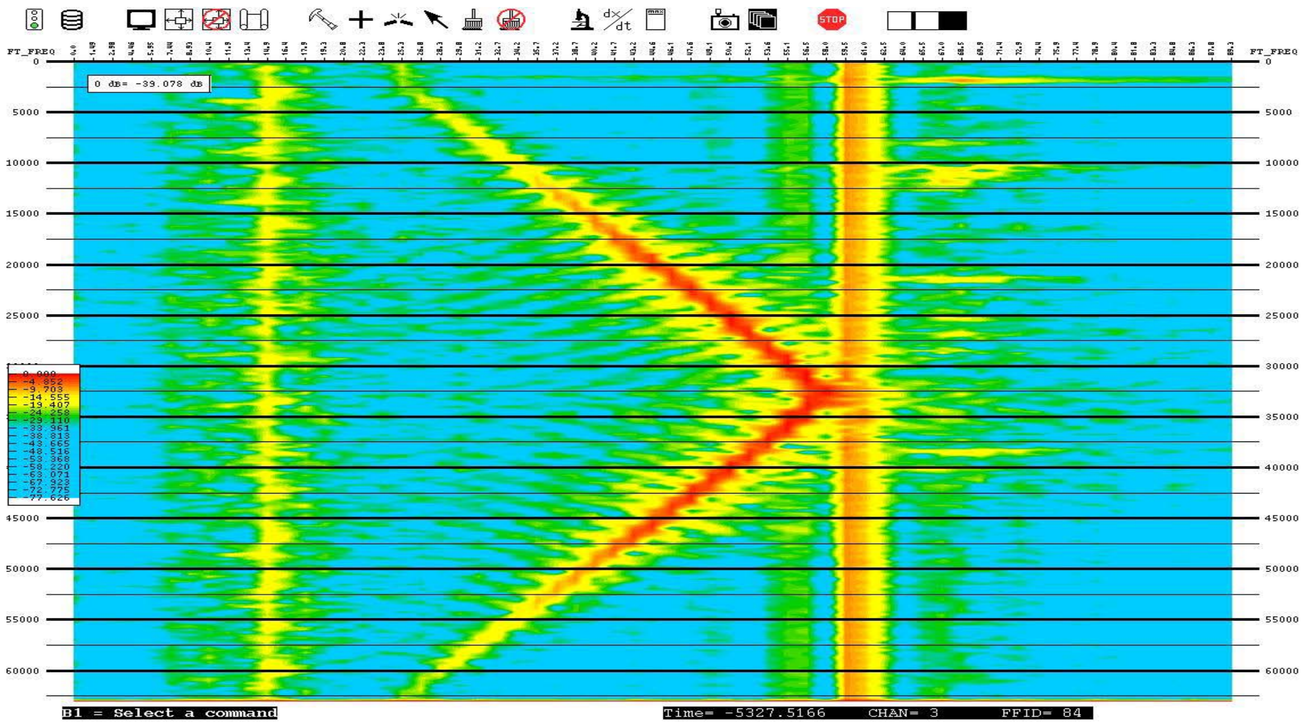

**Figure 5 LBNL Recorded and Processed One minute Frequency Sweep Test**

In conversations with Tom Daily and Dale Cox regarding the LBNL field activity in the NBU pilot area, three items are emphasized:

- The DHVT generated the predicted signals reliably and repeatedly;
- The seismic signals were recorded at depth with downhole geophones and hydrophones in both the two offset wells 111-14 and 117-12, approximately 1000' and 1200' respectively from the source well;
- The seismic signals can easily be seen as very clean and strong signals above the background noise recorded.

Performance testing at KPF and the Phase I operations of the field test provided several key lessons learned for operating the DHVT.

- Of the downhole on-board sensors, the data from temperature probes became the key tool operational factor. The tool temperature build-up was a critical parameter to monitor in an effort not to exceed the temperature limits of the downhole electronics.

- The surface, three-axis geophone was used to record the operations and proved to be a very reliable tool performance indicator. This was very beneficial, as there was concern for the long-term reliability of the downhole electronics, being located in a hostile environment. The surface geophone became the back up system for the downhole on-board electronic sensors.

**<u>Phase II Procedures</u>**

The procedure followed in Phase II would be determined if a reservoir resonant frequency could be identified. If such a stimulation frequency was found, the DHVT V 3.2 would be operated in a narrow frequency range centered on the resonant frequency. Should no resonant frequency be identified, a matrix of frequencies would be tested over the proposed 90-day test period.

Operating the DHVT over a narrow, but increasing band of frequencies during four-hour pulsing periods would create the frequency test matrix. The tool would then be shut down for a four-hour quiet period, the next pulse would be a repeat of the first pulse. This would continue for five days Then the computer would be re-programmed to go to the next range of frequencies to be pulsed using four hour cycles for five days. In table 2 below, is one of the test matrix that had been considered.

| Tool Speed | | Frequency (Hz) | | |
|---|---|---|---|---|
| Low RPM | High RPM | Minimum | Maximum | Band width |
| 420 | 450 | 70 | 75 | 5 |
| 408 | 468 | 68 | 78 | 10 |
| 378 | 498 | 63 | 83 | 20 |
| 348 | 528 | 58 | 88 | 30 |
| 318 | 558 | 53 | 93 | 40 |
| 288 | 588 | 48 | 98 | 50 |

**Table 2 NBU Potential Vibration Stimulation Test Matrix**

**<u>Phase II Operations</u>**

Phase II of the vibration stimulation test began February 17, 2003, after the LBNL equipment was mobilized back to Berkeley, CA. Each 24-hour period was broken into two venues of data collection, fast and slow modes. While establishing the DHVT temperature profile, the fast data collection mode was used to relate the tools operation and internal temperature build up. When operating the tool in the 400 to 450 RPM range, considerable heat was generated. If the tool were held at a constant high RPM the internal temperature would quickly exceed the 250 $^{o}$F temperature rating of the on-board electronic packages.

In an effort to prolong the life of the downhole electronics, the tool was allowed to run at elevated RPMs for controlled periods of time. The tool was then given time to cool back near the ambient wellbore temperature of 120 $^{o}$F before running it at high RPMs again.

With knowledge gained from previous tests, it was known that if the tool began to have excessive vertical motion, it indicated that the slips were losing their grip with the casing. If tool operation continued in this situation, the tool would be shaking violently instead of transmitting vibrations into the casing, subjecting the downhole sensors to a very hostile condition.

With concern about the long-term reliability of the downhole electronics, a concerted effort was made to develop a correlation of tool operations with the responses recorded by the surface geophone. This surface 3-axis geophone was place approximately 1000’ northeast of well 111-W 27. In previous field operations with DHVT Version I, electrical noise had prevented the surface geophone from "hearing" the seismic signals. Now, the geophone was responding to the operation of the DHVT because a new shielded cable and additional electronic filters were included for this test.

On February 21, 2003 a tentative over-night pulsing schedule was ready to be initiated when excessive tool motion was indicated from the on-board accelerometers. Suddenly, the tool temperature instantly jumped from around 200°F to over 550°F. Figure 6 is a graph of the tool operations when the temperature spiked at 550 °F. The DHVT was shut the down, fearing a major failure of the tool. The tool temperature continued to be collected, but without the tool operating, the temperature rose again and fell off in a peculiar manner. This indicated that perhaps the temperature spike was faulty data rather than a catastrophic tool failure.

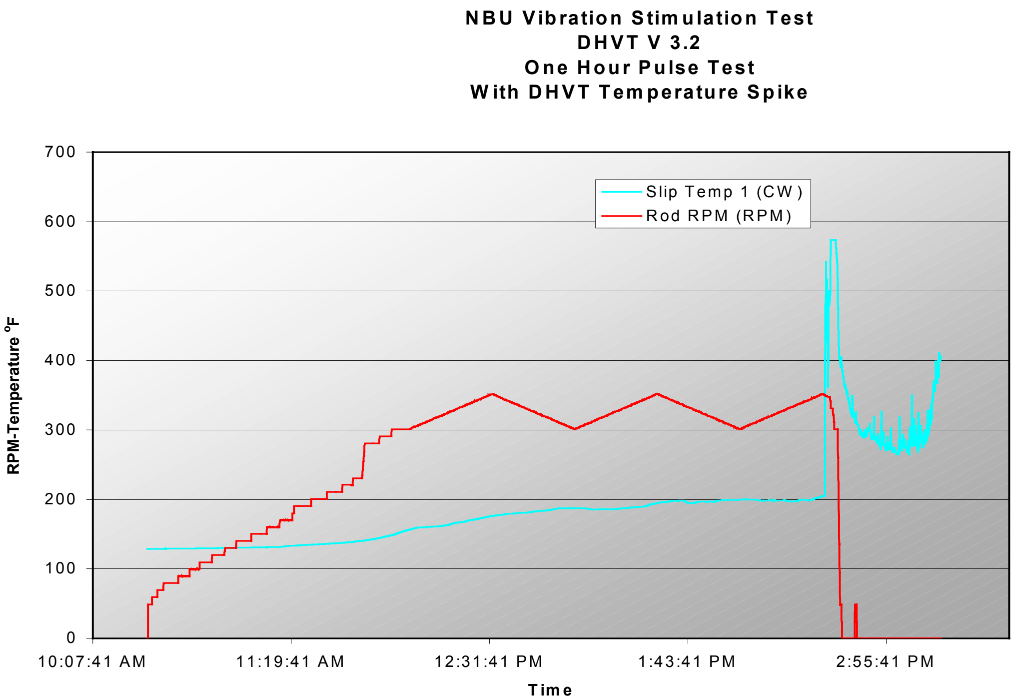


**Figure 6 One Hour Pulse Test and Temperature Spike**

The over-night pulsing operation was postponed, letting the tool sit overnight instead. The tool was started in the morning, and worked fine, no temperature problem, but the tool motion had increased giving concern that the slips had lost their grip on the casing. A snowstorm blew in that weekend and prevented additional field test operations for about a week. The tool was checked as road conditions permitted. On each occasion, it started as expected, but the motion of the tool was becoming more severe.

On March 7, 2003, Calumet moved a workover rig onto well 111-W 27 to pull the DHVT from the well to determine the reason for the excessive tool motion and check the electronics. When the tubing was picked up to release the slips in the wellhead, the hook load had lost about 10,000 lbs of tension. This indicated the tool's anchoring slips had at least partially lost their grip on the casing and the tool had moved up the hole about 6 inches.

The DHVT anchoring slips were released and the tool began to be pulled from the well. After 7 stands of doubles (two-joints of tubing) had been pulled, the rig operator noticed a slight increase in drag while coming up with the tubing. That stand was worked back into the well. It became progressively more difficult to go down and would not come up either. It was decided to hang the tubing back in the wellhead and move the rig off the well. The DHVT was stuck in the well, approximately 400' off bottom. The DHVT is unable to operate in this situation.

This situation is undesirable because it prevents Calumet from having access to the Burbank sandstone, the reservoir at NBU. The design of the DHVT is such that when it is stuck in the well it will be damaged beyond repair when attempting to fish (retrieve) it from the well. Discussions with Calumet resulted in a decision to postpone the fishing operation until summer time when the rig can work longer hours. It is anticipated that the tool will either be pushed to the bottom of the well and left there, or it will have to be milled over to retrieve it. If either option is successful this would allow access to the producing formation. If the fishing operation is unsuccessful, the well will be plugged and abandoned.

Terminating the NBU vibration stimulation test operations.

With the DHVT stuck in the well and having only delivered 48 hours of vibration time since the test began February 12, 2003, the field test was terminated March 14, 2003. Daily data collection in the pilot area production and injection wells ceased and the data collection system was removed.

## Phase II Results

### *DHVT V 3.2 Operational Problems*

Phase II of the field test was scheduled to last 90 days. Four days were spent determining the temperature profile for different operating sequences. It was deemed necessary to determine how to keep the tool temperature below the 250 $^{o}$F limit of the downhole electronics by using the heat sink capacity of the formations surrounding the DHVT outside the casing. However, on February 21, 2003, the DHVT V 3.2 onboard sensors indicated ever-increasing tool movement and an extreme tool temperature spike. Please refer to Figure 6 above.

It was decided to remove the tool from the well to check out the anchoring mechanism. March 7, 2003 a rig was moved in, the tool's slip mechanism was released with no difficulty. The tool began to be removed from the well. The tool had been moved up about 400 feet when it became stuck. It is presently at approximately 2500 feet from the surface.

### *Effects on the Pilot Area Production Wells*

During Phase I, the tool was run approximately twenty hours over a three-day period. The tool was generally run for periods less than one hour and much of the time it was run in a frequency sweep mode ramping up and down every sixty seconds. In Phase I it is doubtful that sufficient vibration energy was input into the reservoir to affect fluid flow characteristics.

In Phase II the tool operated a total of approximately 28 hours before the test was terminated. The tool was tested in periods of three to five hours during the day for four days and was shut down each night. These tests were being conducted to determine the operating temperature profile of the tool in preparation for continuous vibration stimulation.

There was no change in produced fluids from the pilot area wells during, or in the three weeks following, the operation of the DHVT. The pilot production wells were individually tested and fluid levels shot prior to the start of the vibration stimulation test and again one week later, there was no change in individual well test fluid volumes nor in the fluid levels recorded. Wellhead production samples were also collected prior to start of stimulation and again one week later, no changes were found in water-cuts of the wellhead samples or in produced water salinity.

The data for the production baseline has been collected since April 2001 and is plotted in Figure 7. The production is recorded daily, but reported to governmental agencies on a bi-monthly basis. Figure 7 uses the bimonthly production values. The oil cut percentage is plotted on the left-hand vertical axis with an expanded scale. It appears to fluctuate directly with the reported oil production. In considering the variation of only 0.20% in oil cut over a two year period, the pilot test area was operated in a very stable manner throughout the project.

In Figure 8, the daily production for February 1 through March 15, 2003 is plotted. This corresponds to the oil production rate just prior to beginning the test, during the test and three weeks following the test. The fluctuations in production after the test ceased were caused by the snowstorm and a field electrical problem. When compared to Figure 7 with the baseline average daily oil production at 39.7 BOPD, the daily oil production seen in Figure 8 hovers around the 40 BOPD value. It can be concluded that there was no change in the oil production during or after the vibration stimulation field test.

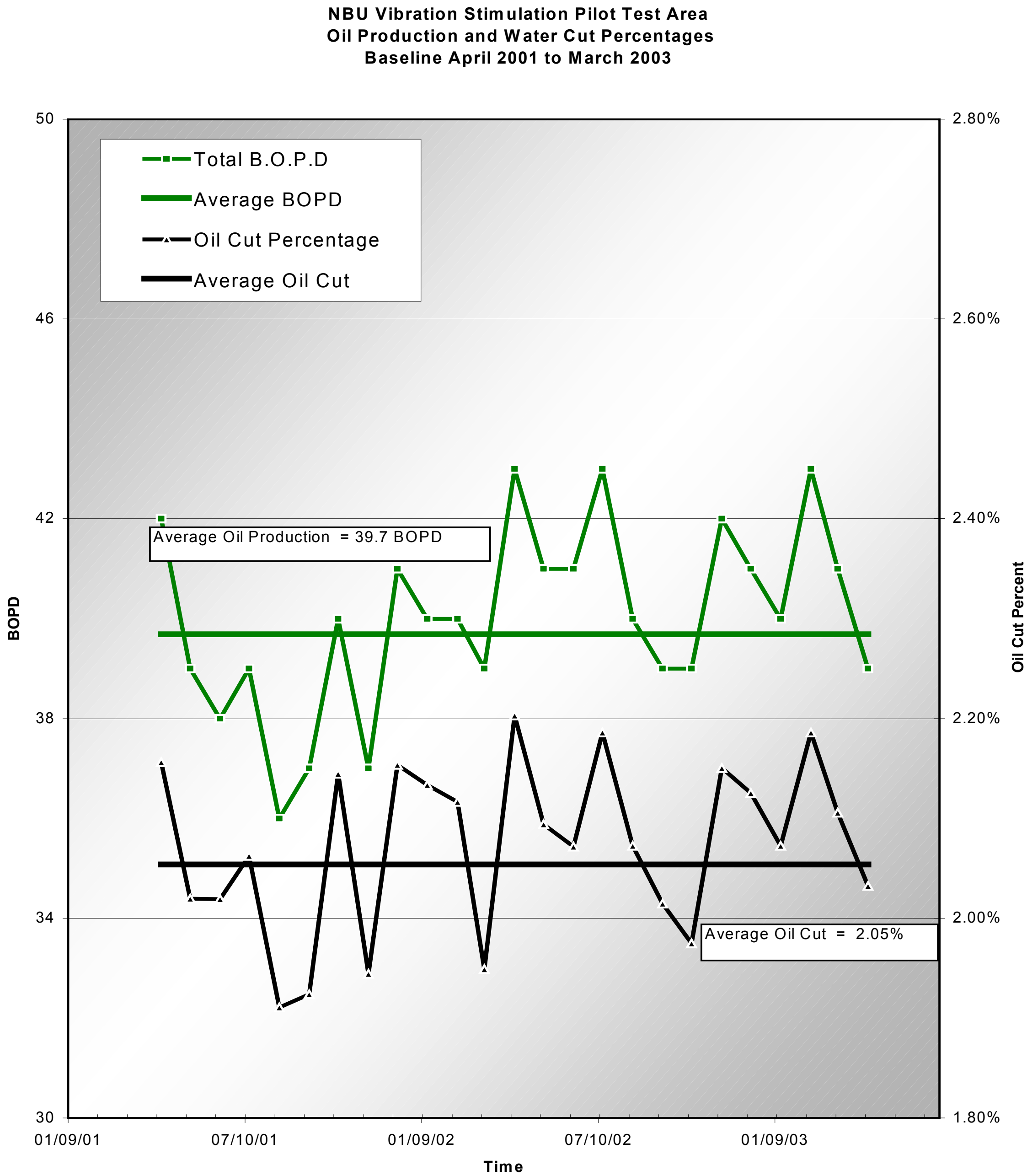


**Figure 7 NBU Baseline Production April 2001 to March 2003**

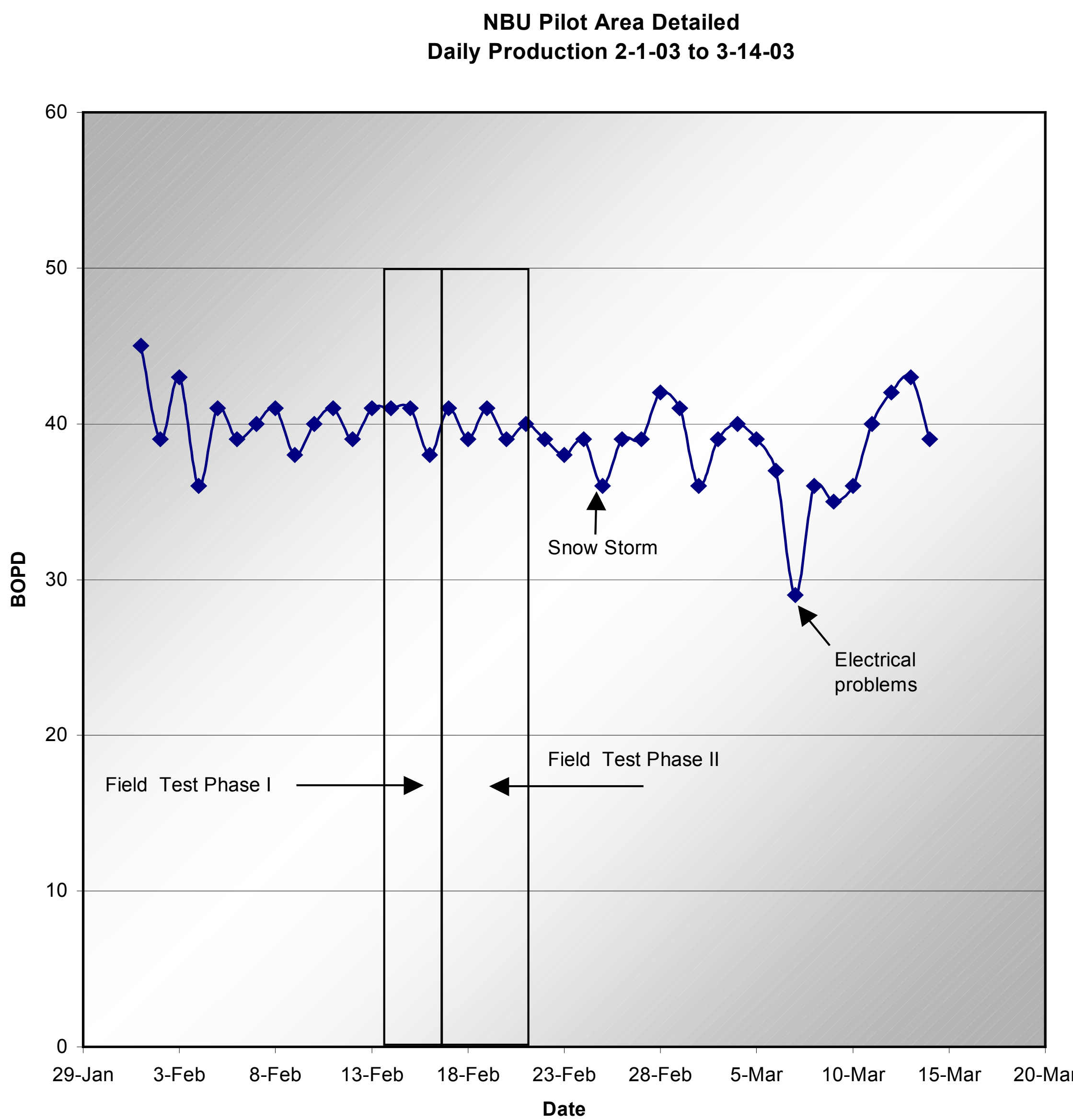


**Figure 8 NBU Pilot Area Daily Production February 1 to March 14, 2003**

*Effects on the Pilot Area Injection Wells*

Figure 9 displays the baseline injection data for the two injection wells in the pilot test area. As with the production information, injection data is recorded daily and reported twice a month to governmental agencies. The data used for in Figure 9 is the bi-monthly injection rates for each well and the combined injection rate for the pilot area. There has been a reasonable amount of injection rate changes during the past two years of the project. The critical period of stability occurred during the first part of 2003.

However, there is a substantial change in the characteristic of the injection operation when recorded continuously. Figure 10 is a plot of the continuous real-time data recorded beginning February 12 through Feb 28, 2003. The erratic nature of the graph depicts an operation called “skimming” the holding tank and are solely a function of the lease operator’s daily activities. By plotting just a 24-hour period, the skimming operation can be seen in detail. Figure 11 is a detail of the water injection operations for February 15, 2003, during Phase I of the field test. The process is carried out almost everyday and results in a 10% fluctuation of injection rates during a four to six hour period. With these injection parameter variations on a daily basis, effects of the vibration stimulation would be recognized on a the long term basis if they occurred. Figure 10 has the average injection rates plotted for each well and the total injection volume. There are no discernable effects on the injectivity of the injection wells from the vibration stimulation.

*Conclusions from Phase II Operations*

Thus the primary objective of this project, which was to determine the effects of vibration stimulation on improving oil recovery from a mature waterflood, was not obtained. While there was no improved oil recovery effect measured, it is the opinion of the authors that there was insufficient vibration stimulation time to expect a change to occur. Therefore no conclusion can be drawn about the effectiveness of vibration stimulation in this field test.

DHVT V 3.2 remains in the well. No further efforts will be made during the DOE project to remove the tool from the well. At some point in the future, the tool will either be pushed to the bottom of the well and abandoned or be destroyed in the process of fishing it from the well.

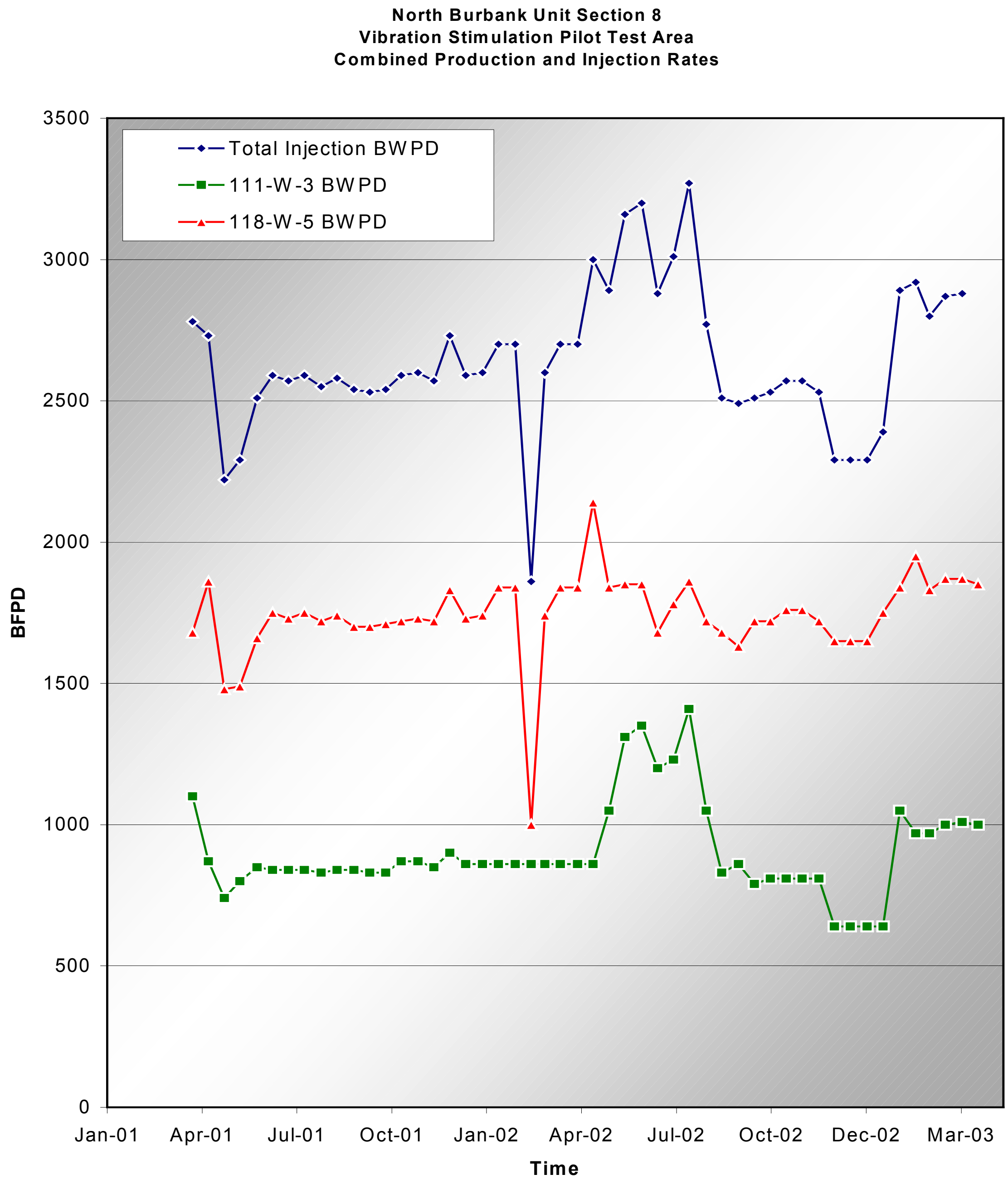


**Figure 9 NBU Pilot Test Area Baseline Injection Well Data**

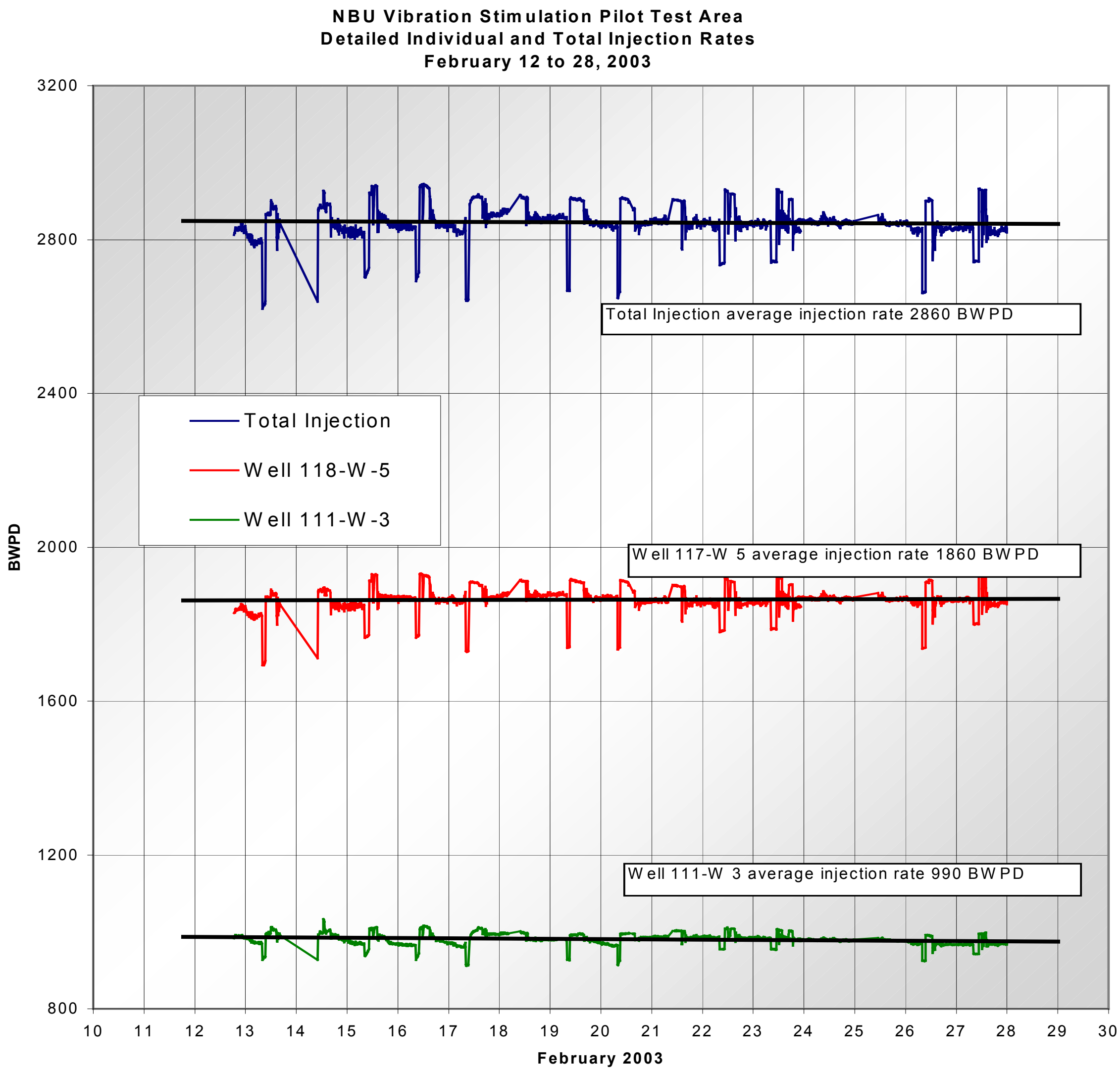


**Figure 10   NBU Pilot Area Water Injection Rates February 12 to 28, 2003**

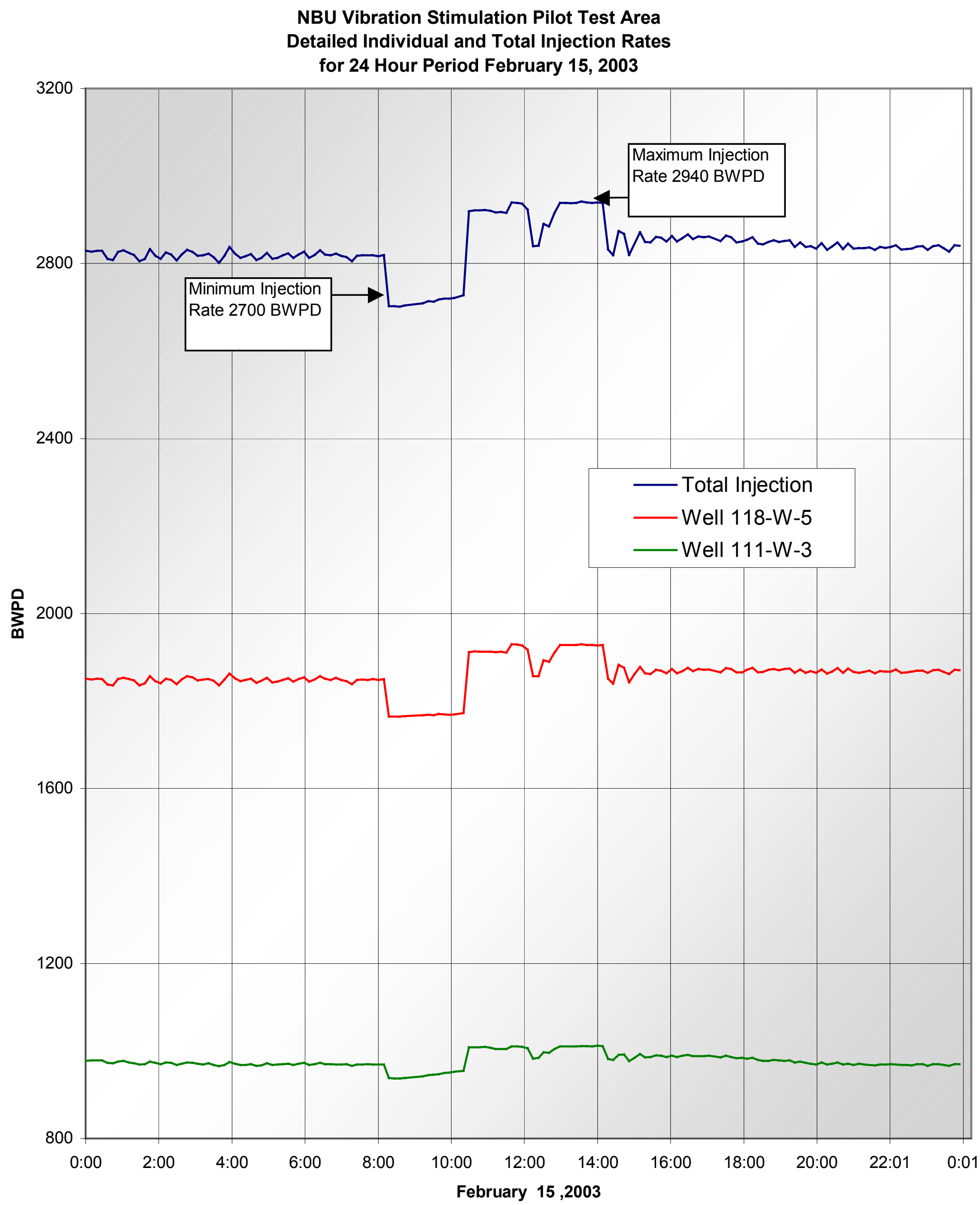


**Figure 11 NBU Pilot Area Injection Operations February 15, 2003**

# NBU Field Test Daily Reports

## February – March, 2003

## Phase I Run DHVT V 3.2 Collect Data for LBNL

### Monday, February 10, 2003:

The DHVT V 3.2 was taken to Calumet's shop in Webb City outside Shidler, OK. The data acquisition computer was taken to and set up at the doghouse on location. Wire was strung to the injection wells using the old downhole wireline as the data line. We began to hook up the electronic sensors.

### Tuesday, February 11, 2003:

Met with Tom Daily (LBNL), Dale Cox and Cecil Hoffpauir (consultants for LBNL, both ex-Conoco) at Ponca City. Stopped at Calumet's office for introductions. Went to stimulation Well 111 W -27 and began to rig up the LBNL equipment. Ran a gauge ring and collar locator in well #111-14 (designated in LBNL notes as SI-14), which is shut in. We finished running our surface geophone, wellhead instruments, RPM pickup lines and connected them to the electronics junction box.

Started to test the DHVT V 3.2 downhole electronic sensors and the connecting plugs would not fit properly because epoxy had filled some of the prong ports in the female connector, which is housed in a stainless steel cap. We tried to clean the epoxy out of the plug which resulted in breaking a piece of a small drill bit off in the hole for the serial plug, damaging the female end of the plug. We could not re-use the stainless steel cap without cleaning it up on a lathe and re-running the wires. We were able to pull enough slack to allow use of a spare cap and female connector we had available. We decided to use the aluminum cap to hold the plug. This was the same cap we had used at the KPF test set-up. There was a problem with aluminum housing run in the DHVT V 1.0 test in August 2002, but this seemed like the most timely and reasonable solution for repairing the data line connecting plugs.

### Wednesday, February 12, 2003:

Meet at Shidler shop to assemble the DHVT to run in the hole. Finish assembly and take to the well site. Finish re-wiring the downhole electronics plug and plug in to the tool. The electronics are working great. PU DHVT and R.I.H. with 2 7/8" tubing. Put a perforated nipple on top of the eighth joint of tubing. Check the electronics on the way in the hole working well. R.I.H. to bottom ~ 2890'. Set slips and pull 40-45 thousand pounds over string weight. Electronics are working well. Shut down due to darkness.

### Thursday, February 13, 2003:

Go to well site and start running in the hole with the rods to make a dummy run for space out on the polish rod. Come out of the hole with the rods and attach on-off tool and run back in the hole with the rods and on-off tool. Latched on to the on-off tool and picked up to check weight. When we picked up on the rods the brass pin sheared prematurely. Tried to get back on the splined collar with the shaft, but was unable to. Decided to come out of the hole with the rods to make sure that we sheared the pin. The pin was sheared. Bob decided to go to Machine Engineering to get a stronger pin, a ¼" low yield steel pin instead of the brass pin. While Bob was in Tulsa the rig pulled the tool out of the hole and we were ready to replace the pin when Bob arrived at the well with the new pin. Put the new steel pin in and tripped back in the hole with the tubing. Set the slips and hung them off at the wellhead. Shut down because of darkness.

### Friday, February 14, 2003:

Run in the hole with the on-off tool and latch on. Strip the rotating unit over the polish rod and pull 5,000 pounds over the string weight of the rods and set the rod clamp. Turned on all electronic equipment and was receiving good signals from everything. Turned the tool a little while very slowly just to make sure it was working. It was, and we released the rig. LBNL finished laying lines and getting their baseline noise data while the rig was rigging down. Started NBU/LBNL test at 10:05 A.M. We started running the tool at 50 rpm up to 150 rpm. Start 50-150 rpm ramp test at 11:15 A.M. End 50-150 rpm ramp test at 1:40 P.M. Ran a 50-200 rpm ramp test from 1:40 P.M. to 2:15 P.M. Ran a 50-300 rpm ramp test from 2:15 P.M. to 2:40 P.M. Ran a 50-400 rpm ramp test from 2:40 P.M. to 2:50 P.M. Ran a 150-350 rpm ramp test from 3:06 P.M. to 6:20 P.M. Shut down for the night. Collecting injection data overnight. LBNL is seeing the DHVT seismic signals loud and clear.

DHVT V 3.2 cumulative running hours = 8

### Saturday, February 15, 2003:

Started testing at 9:05 A.M. The guys from LBNL were getting a lot of noise in the doghouse so the decided to take their equipment to the wire line truck. Start constant rpm increment testing at 9:23 A.M. From 9:23 A.M. to 10:19 A.M. we were running at 50 rpm. From 10:19 A.M. to 10:31 A.M. we went up from 50 to 200 rpm in 25-rpm increments and back down to 100 rpm in 10-rpm increments. From 10:31 A.M. to 12:47 P.M. we went up from 50 rpm to 450 rpm in 10-rpm increments. We skipped from 280 to 300 because of excessive Z-g's. From 12:47 P.M. to 1:03 P.M. we went back and got the data from 280-300 rpm in 10-rpm increments. From 1:03 P.M. to 5:17 P.M. we collected ASCII data for the temperature curve. Shut down tool for the night and started overnight injection data at 5:17 P.M. Moved the wireline truck to Well 117-12 (designated by LBNL as SI-12). Rigged up LBNL to run in the hole.
DHVT V 3.2 cumulative running hours = 12

### Sunday, February 16, 2003:

Started testing at 9:28 A.M. Ran the tool at 50 rpm to warm it up. Started a 50-450 rpm ramp test at 10:10 A.M. We were seeing really high g readings as the tool peaked at 450 rpm. We decided to start going from 150 to 350 rpm ramps until 10:45 A.M. From 10:45 A.M. until 1:18 P.M. we did a 100-450 rpm increment test in 10-rpm increments. From 1:18 P.M. until 2:20 P.M. we did the 150-350 rpm ramp test. Let the ASCII data run until 3:58 P.M. Start overnight injection data at 3:58 P.M. Pack up LBNL and get them on their way home. The tool seemed to be getting loose because we are getting higher "g" readings than when we started.
DHVT V 3.2 cumulative running hours = 17 during 3 days of tool operations

## End of Field Test Phase I

## Phase II Operate the DHVT V 3.2 and Monitor Injection and Production Wells Performance

### Monday, February 17, 2003:

Collected ASCII data for the entire day and did not run the tool.

### Tuesday, February 18, 2003:

Started tool warm-up at 9:33 A.M. Ran at 50-150 rpm. From 10:14 A.M. to 4:58 P.M. Ran tool up to 380 rpm slowly and held it constant. The temperature got up to about 218 $^{o}$F and held constant as well. We are calling this the Tool Temperature Profile Test. Started overnight injection data collection at 4:58 P.M.
DHVT V 3.2 cumulative running hours = 24.5 during 4 days of tool operations.

### Wednesday, February 19, 2003:

Started testing at 8:40 A.M. with a 300-320 rpm tool warm-up. Temperature got up to 190 degrees. From 12:08 P.M. to 1:44 P.M. we did a 300-400 rpm ramp test over 12 minute cycles. From 1:44 P.M. to 4:48 P.M. we did the 300-400 rpm ramp test over 10 minute cycles. The temperature got up to 215 degrees. Started overnight injection data collection at 4:48 P.M.
DHVT V 3.2 cumulative running hours = 32.5 during 5 days of tool operations.

### Thursday, February 20, 2003:

Started testing at 8:45 A.M. From 8:45 A.M. to 3:09 P.M. Ran a 300-400 rpm ramp test over a 100-minute cycle. From 3:09 P.M. to 5:39 P.M. we were doing test runs to see how the data would look at a slower sampling rate. We were running at about 350 rpm during this time. Started overnight injection data collection at 5:39 P.M.
DHVT V 3.2 cumulative running hours = 41.5 during 6 days of tool operations.

### Friday, February 21, 2003:

Started testing at 10:27 A.M. Warm-up tool for a few minutes then start with 300-350 ramps. We had planned to run the tool overnight using a slow ramp up, then hold at 350 RPM and use a slow ramp back down. At about 2:33 P.M. the downhole data indicated an instantaneous spike in the tool temperature of 550 $^{o}$F. Other data values were erratic. Shut the tool down and continued to collect data to see if the data would return to normal. The temperature started to come back down from 550 $^{o}$F but it was not smooth and it kept spiking. We decided not to run over night, but to start collecting overnight injection data at 3:17 P.M.
DHVT V 3.2 cumulative running hours = 45.5 during 7 days of tool operations.

### Saturday, February 22, 2003:

Checked the electronic sensor reading in the morning. They seem to be back to normal. Started the tool at 9:00 A.M. Ran the tool up to 150 rpm slowly to check electronics. The surface geophone was picking up the signal immediately. The tool also seemed to be responding as it should, however, the g's seemed to be slightly higher than before. Decided not to run tool, but collected the ASCII data. Started the ASCII data at 9:20 A.M. on 2-22-03.
DHVT V 3.2 cumulative running hours = 47 during 7 days of tool operations.

## Sunday to Wednesday, February 23 to 26, 2002:

Unable to get to the well because of a snowstorm

## Thursday to Sunday, February 27 to March 2, 2003:

Collected ASCII data.

## Monday, March 3, 2003:

Reset ASCII data collection. Ran the tool for half hour, slowly from 50-150 rpm to check electronics. They seemed to be back to normal ranges, although the g's were still high. Shut down tool.
DHVT V 3.2 cumulative running hours = 47.5 during 7 days of tool operations.

## Tuesday, March 4, 2003:

Collected ASCII data.

## Wednesday March 5, 2003:

We decided to pull the tool out of the hole to see if we could see why it appeared to be loose. We sheared off of the on-off tool. It sheared fine. Pulled out of the hole with the rods. The rods do not look like they have any significant wear on them. Pull up on tubing to get wellhead slips out and notice we have more stretch than we should. It appeared as though the tool had slipped up the hole about six inches or so. We pulled the wellhead slips out and un-jayed the tool. The tool un-jayed without any problems. We started out of the hole and everything was going normal.

We had six stands out of the hole and as he almost had the seventh stand out he pulled tight into something. We tried slacking off and turning the pipe to the left and coming back up, but every time we pulled up on the pipe it would pull tight like the slips were setting immediately. We had a meeting with Wayne Porter and decided that the best thing to do was try and get the stand down and continue to try turning the pipe to the left and picking up on it to see if the jay was stuck. The further we got in the hole with the stand the harder it was to turn the pipe and it started to take weight to push it down. When we got to the tool joint to set the slips I could not turn the pipe at all and it sounded and felt like the pipe was stacking out on something. We decided to set the wellhead slips and meet with Ford and Jack Graves to discuss our options.

## Thursday, March 6, 2003:

Collected ASCII data. Met with Calumet and discussed fishing options.

## Friday, March 7, 2003:

Went to Green Country Sub Pump in Hominy to assemble a replica of the tool assembly of what we have downhole. Met with Wayne Porter and Jim Adair about fishing procedures. Ford and Bob discussed additional aspects of the fishing operation and who would be in charge of fishing the tool out of hole, Calumet or Seismic Recovery LLC.

## Monday, March 10, 2003:

We decided that we would not pursue fishing operations until later this summer when we can work longer hours.

### Tuesday, March 11, 2003:

Went to well and reset data ASCII collection.
Checked the downhole electronics by plugging them in and they were displaying valid readings. The temperature was showing a negative number. This may mean something fell on top of us or it may not.

### Wednesday, March 12, 2003:

Collected ASCII data.
Took a load of DHVT V 1.0 parts and tools to storage in Bixby.

### Thursday, March 13, 2003:

Met at Elite Wire line in Skiatook to talk with Terry Sparks about fishing the tubing and tubing cut-off options. We need a precision cut to avoid leaving any of the data wireline, which is strapped to the tubing in the well, when cutting the tubing. Showed Terry what we had in the hole and decided to use a chemical cutter to be able to space off of the top of our splined collar, to give a precision cut. Terry ordered a couple of pieces that go on the bottom of the chemical-cutter for us to modify, as needed.

### Friday, March 14, 2003:

Went to well site in Shidler and stopped data computer. Tore it down and brought it to the machine shop. Started pulling some wires and the geophones.
***DHVT V 3.2 cumulative running hours = 47.5 during 7 days of tool operations.***

## End of NBU Field Test Phase II

SPE 67303

# Enhanced Oil Recovery with Downhole Vibration Stimulation

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## Abstract

The use of vibration to improve oil recovery has long been investigated. The background for this novel technology is reviewed along with the project rationalizations, designs considerations, and measurements performed in advance of a downhole vibration stimulation field test. This field demonstration will pilot test the potential of downhole vibration to enhance oil recovery from a shallow oilfield in Osage County, Oklahoma. The project is supported by the Department of Energy (DOE), Seismic Recovery LLC, Phillips Petroleum Co., and Grand Resources, Inc. Recent literature has reported successful vibration stimulation in shallow reservoirs with high water oil ratios (WOR). Osage County has, like many areas of the United States, numerous old fields under waterflood, with many wells producing marginal oil with substantial water production.

## Introduction

When wells in waterflooded fields are abandoned due to high water-cut, often there are still significant amounts of oil trapped in the formation, although production is not economical. Vibration stimulation is a possible method for improving oil production and increasing ultimate economic recovery in these situations. The vibration force introduced in the reservoir is thought to facilitate the movement of oil in one or more ways: by diminishing capillary forces; reducing adhesion between the rock and fluids; or causing oil droplets to cluster into "streams" that flow with the waterflood.

**Significance of Vibration Stimulation.** The ability to generate sufficient downhole vibration energy to improve flow characteristics is a very intriguing concept. The economic potential for vibration stimulation for enhanced oil recovery is truly staggering. The Interstate Oil and Gas Compact Commission reported in 1995, "immobile oil is held in reservoirs by viscous and capillary forces…. Only a small amount of immobile oil can be recovered by conventional primary and secondary techniques. Instead, the 238 billion – bbls immobile oil reserve (U.S.) is the target for enhanced oil recovery techniques."[1] Vibration stimulation has the capability to shift the relative permeability curve and, as an enhanced oil recovery technology, increase recovery of "immobile oil reserves."

### Vibration Stimulation Historical Background

***Russian Investigations.*** The interest in elastic-wave vibration stimulation (as opposed to non-elastic vibration, such as explosions) goes back to the 1950s. This interest is well documented in the paper by Beresnev and Johnson, in which the authors reported on the full spectrum of investigative work in both the USSR and USA.[2] They review the efforts of over a hundred researchers probing the effects of man-made vibrations from the ultra sound range of 5 MHz to barely audible, low end of 1 Hz including traffic induced seismic stimulation. The effects of earthquakes on oil production were also reviewed, however the results of conventional and nuclear explosions were not.

The majority of the reported work came from four Soviet institutions, each one producing numerous technical papers on laboratory and field studies. Each group of Soviet researchers presented general descriptions of the mechanism and the effect of vibration on fluid saturated media. In an effort to explain the observed changes on the fluid flow characteristics, theories abounded, covering the effects of gravitational and capillary forces, such as: changes in wetting phase and thickness of wetting phase; altered relative permeability; coalescence and/or dispersion of the oil drops; effects of connate water salinity; reduction in viscosity; increase in temperature; frequency and/or intensity dependency; constant or intermediate application of wave energy; elastic and/or non-elastic effects; resonant and/or dominant frequencies; surface seismic stimulation and/or downhole stimulation effectiveness. There is no consensus on theoretical explanations for the effects of elastic vibration stimulation on fluid flow in porous media.

V.N. Nikolaevsky, et al.[3] proposes that the ultrasonic oscillations are generated by seismic waves. While using surface vibro-stimulation, in-situ measurements were made indicating that the energy of seismic waves was converted to a dominant frequency, independent of the source frequency. He explains "theoretical and field investigations of the phenomena suggest that vibrations may influence substantially the water or oil relative permeability that appears to be partially reconstituted at saturations that ordinarily would prohibit the flow of a particular phase."

Results of laboratory and pilot field testing of the vibro-seismic technology show both an increase in oil recovery and a reduction of the WOR.[4] Recent publication of the success from utilizing the Soviet developed seismic stimulation comes from the application of vibro-seismic impact technology (VSIT), which is a surface stimulation method. V. N. Belonenko reports that elastic waves cause an acceleration of the filtration process effects, the intensification of the accumulation of dispersed oil/gas bubbles, and an acceleration of gravitational segregation of gas, oil, and water.[5,6] In field tests in Indonesia, Caltex Pacific Indonesia (CPI) reported that the total cumulative incremental oil production reached 20.2% above the agreed production baseline.[7] CPI is considering additional field studies of this stimulation technique, which appears to be a novel and successful enhanced oil recovery technology.

***Chinese Studies.*** A number of papers, from several institutes, have been published recently from laboratory research performed on sound vibration stimulation in China. The testing has revolved around investigating the effects of vibration while performing core-flooding tests.[8,9,10] Mingyuan reports that the wettability of a core saturated with oil can be changed into a more water wettable condition with sound vibration, resulting in increased oil recovery rate by waterflooding in conjunction with sound vibration.[11]

A theoretical attempt to produce a coupling wave propagation model in porous media with artificial vibration is presented by Wenfei, et al.[12] This is a topic, which needs corroboration, to improve the understanding of compression and shear wave propagation in both the solid (rock), and liquid (multi-phase) portion of the porous media.

***Canadian Heavy Oil Applications.*** While work in other areas of the world were progressing on vibration stimulation, a Canadian group was making strides in another EOR technique, that of pressure pulsing. It is mentioned here because of the work performed by Spanos and Dusseault, et al. in explaining the theory of flow enhancements through pressure pulsing.[13,14,15] The concept of porosity diffusion, caused by a low frequency, high amplitude pressure wave is introduced. They discuss the Biot-Gaussman porous media model and their derivation of the de la Cruz-Spanos porous media models by considering porosity as a dynamic variable.

Initially, their application was for producing cold, heavy, high viscosity oil in poorly consolidated young sandstones, where actual sand production is considered desirable. This technique was termed Cold Heavy Oil Production (CHOP) and has been used successfully in heavy oil sands of Alberta and Saskatchewan, Canada. Several case studies report success in fields having higher gravity oils, improved production due to diffusion of acid during stimulations, and positive responses in carbonate formations.

***Reported United States Research***

*Los Alamos National Laboratory Research.* Motivated by the review work of Bersenev and Johnson (Ref. 2), a joint industry project, funded by DOE's Office of Basic Energy Science, Division of Advanced Energy Projects, to study the fundamentals of vibration stimulation was initiated by Peter M. Roberts at Los Alamos in 1995. This startup project evolved into the current "Seismic Stimulation for Enhanced Production of Oil Reservoirs."[16,17] This has been a three-year Natural Gas and Oil Technology Partnership, DOE sponsored effort to study this emerging technology. Los Alamos has teamed with Lawrence Berkeley National Laboratory and the University of California at Berkeley to perform laboratory core-scale stimulation flow tests, to monitor field tests conducted by the project's industry partners, and to develop theoretical frameworks for describing the stimulated flow phenomenon.

The laboratory experimental portion of this project has utilized a core test cell with a magnetostrictive actuator applying mechanical stress excitation to sandstone core samples during single-phase and two-phase fluid flow. A number of encouraging core tests has been run.[18] Results indicate that mechanical stress excitation at 100 Hz and lower can strongly influence two-phase fluid flow behavior in Berea sandstone under both steady state and simulated flood conditions. Preliminary interpretation of these results is that altered wettablity may be a dominant mechanism controlling the enhanced production of oil. It was also observed that in-situ clay fines can be mobilized so that the absolute permeability of the rock will increase.

The project is currently involved with monitoring industry-supported field stimulation tests in California's Central Valley. Initial tests have shown an increase in oil-cut that is directly correlated with the stimulation treatment. Downhole seismic and pressure signals are being recorded so that additional correlations can be made between the wavefield parameters and the degree of enhanced production observed.

*Stanford University.* In the work done for her doctoral thesis, Yan Pan investigated the concept of using intermediate frequency excitation to perform reservoir analysis.[19] She developed five flow models, which incorporates both Darcy's law and Biot's theory as special cases (her model II, and III respectively). While not researching vibration stimulation specifically, she concluded "that elastic solid vibration has positive effects on fluid flow in porous media if the perturbation signal is within the intermediate range. It is possible to stimulate oil production by applying harmonic perturbation of optimal frequencies to reservoirs under compatible conditions."

*Other Efforts.* Numerous vibration stimulation field tests have been or are being conducted throughout the United

States, but very little information is available in the public domain.

## DOE Project

The United States Department of Energy, National Energy Technology Laboratory (NETL), through the National Petroleum Technology Office (NPTO), issued a program solicitation for "Applications of Petroleum Technologies on Non-allotted Native American and Alaskan Native Corporation Lands." The primary mission of this program is to conduct oil related research and development activities.[20] This will be accomplished by expanding the knowledge base through which industry can bring additional oil resources and new technology options into the marketplace in a cost effective and environmentally acceptable manner. The program is directed toward technologies applied to the recovery of the estimated 890 million-bbls of oil and natural gas liquids on Native American and Alaskan Native Corporation lands.

This field test project is focused at satisfying the first of three technical topics listed in this solicitation, which is utilizing innovative technologies to improve the reserves development of a known oil field.

**Osage Tribe Mineral Estate.** Osage County, Oklahoma (**Fig. 1**) serves as a unique testimony to Chief James Bigheart and supporting tribal leaders, who were able to negotiate the communal ownership of all mineral rights under their reservation.[21] In the Osage Allotment Act of 1906, Congress established the Osage Mineral Estate, and divided the mineral rights based on the "headrights" of the 2,229 Osage people. With the rapid development of the oil rich region in the early 1900s, the Osage were destined to become known as the richest tribe in the United States. Many Oklahoma oil barons had their start in Osage County.

Initial production began a century ago, in 1901 and rapidly peaked, in 1923, at over 40 million bbls for the year. In the heady oil boomtown days, the wells were flowed at the maximum rate the oil could be sold, using horse drawn wagons hauling to railroad terminals and primitive pipelines. As the pressures depleted, the drillers moved on looking for new gushers to bring in. Waterflooding and fracture stimulation was introduced in the 1950s, which gave new life to the depleted fields. Then with the rise in oil prices in 1973, due to the Arab embargo, Osage County experienced yet another oil boom.

The county's major producing formation is the Bartlesville Sandstone. Many studies of this prolific zone have been written over the years. The United States Geologic Survey (USGS) performed a classic study. Since the county was under federal jurisdiction, the Department of the Interior, commissioned the USGS to study and produce, in 1942, Bulletin 900 "Subsurface Geology and Oil and Gas Resources of Osage County, Oklahoma." [22] Written by N.W. Bass and others, it reviewed the entire county by township and range. Bulletin 900 collected the existing production records and even suggested promising geologic structures and potential well locations (down to the quarter-quarter section) which had not been fully explored by the early developer's drill bit.

Today, the major fields are under waterflood, which are barely economical at 98% water-cut. But of the estimated 2.2 billion bbls produced to date, there remains an equal amount in the old reservoirs, due in part to the poor reservoir management techniques of the early boom days. Consequently, the Osage Tribe is very interested in new forms of technology, which may be able to recover additional oil economically prior to well abandonment.

**Interdisciplinary Project Team.** Oil and Gas Consultants International and Phillips Petroleum Company had been following the research of reservoir vibration stimulation by Las Alamos National Laboratory. With the DOE solicitation, the opportunity presented itself to collaborate in an effort to apply this novel technology to the nearby, nearly watered out Osage County oil fields. When the Osage tribe was approached, a warm endorsement of the proposal was issued in Resolution 30-490 of the Osage Tribal Council, August 1999. Several Osage County operators were approached and Grand Resources, Inc. was selected to participate. They were anxious, since they had become interested in vibration stimulation when contacted in the early 1990s by a group promoting Russian vibro-seismic technology.

**Backwards Whirl Vibrator:**
**A Unique Orbital Vibrator Design.**

Backwards whirl has been known for sometime to be harmful to PDC bit life. Efforts to construct bits to eliminate or reduce this harmful effect have had reasonable success.[23,24] While the motion is certainly harmful for bits, the patented tool to be used on this project attempts to exploit the phenomena.[25] Backwards whirl is very much like a pinion and gear system, where the rotating source, which is a cylindrical mass, acts like the pinion and the inner surface of the housing acts like the gear (a simple way of investigating this occurrence is to observe the patterns generated from a child's spirograph toy with different wheel and ring sizes). Backwards whirl can occur when a smaller cylinder rotates in a larger cylinder seen in **Fig. 2,** such that the center of instantaneous rotation of the smaller cylinder is the point of contact.

The patent has a full description of the phenomena. However, backwards whirling motion has three interesting characteristics for possible use as a downhole seismic vibration source. First, the motion multiplies the frequency generated from a rotating source by the diameter of the source divided by the difference between the two diameters. For example, a 4" diameter mass backwards whirling in a 4.5" housing would, when rotated at 1200 rpm (20 Hz), produces a vibration of 160 Hz. The reason this is beneficial is that in order to achieve an equivalent frequency without the multiplying factor (as a conventional orbital vibrator operates) would require rotating the mass at 9600 rpm. While equipment running at 1200 rpm can be installed in a well (existing small mud motors and downhole electric motors currently operate in that rpm range), tools rotating at 9600 rpm would need to be developed.

Second, a backwards whirling mass can easily be subject to hundreds of times *g*, the acceleration of gravity. This means that a reasonably sized mass (50 lbs) can produce many tens of thousands of pounds of force on the wellbore. The patent describes how this seemingly unlikely outcome is not only possible, but can be engineered with precision.

Finally, a backwards whirling mass creates the same type of force on a wellbore as an orbital vibrator, which is a rotating eccentric mass. The mass creates both compression and shear waves. There are two reasons this may be important when trying to improve recovery with seismic energy. Under some theories (Ref. 2) it is suggested that the reduction in surface tension caused by the differential velocity between the rock matrix and the pore fluid is the fundamental source of the increased permeability. Since fluid can transmit compressional waves, the differential velocity induced in the pore space by compressional waves will be less than what would be induced by shear waves of the same magnitude. Also, since shear and compressional waves travel at different velocities, when both waves are present, there will be times during the propagation when they will vectorially reinforce each other. That may result in greater permeability increases than either wave can produce alone.

In 1994, a prototype backwards whirl based downhole seismic tool was tested to determine its signal characteristics. **Fig. 3** is a photo of that early generation tool. The tool's housing was made from a mechanically set, liner hanger body, to place the tool in mechanical contact with the casing at about 120' below ground level. This prototype tool was powered by a 25 hp hydraulic motor that was driven by a power source on the surface. The backwards whirling mass weighed approximately 70 lbs. and the hydraulic motor could rotate the mass up to 1200 rpm (20Hz). With the tool's configuration, the backwards whirl kinematics amplified the rotational speed to produce a resultant frequency of about 120 Hz being transmitted into the formation.

**Fig. 4** shows the results of this early test of the seismic source tool at the (then) Amoco seismic test facility at Mounds, Oklahoma, 10 miles south of Tulsa. The figure depicts the changing frequency plotted against time, using color to indicate the magnitude of the signal measured by a downhole geophone 500' deep at a distance of 1100 ft. from the vibrating tool. The figure shows the frequency sweeping up from 30 Hz to about 120 Hz and back to 30 Hz in a total of about 12 seconds, producing a signal, at that distance, of approximately 80 dB over background noise.

## Field Test in Mature Waterflood

**Field selection.** The test is to be performed in Osage County, in a mature waterflooded field. The operator in the project had four fields, producing from the Bartlesville sandstone formation, the most prolific producing formation in Osage County, which were under various stages of waterflooding. The Bartlesville formation is a Middle Pennsylvanian sandstone found in northeastern Oklahoma and is interpreted to be a fluvial-dominated, incised-valley fill, deposited mainly during rising stages of relative sea level.[26] Fields in the Bartlesville sandstone have been produced for over ninety years, producing an estimated 1.5 billion barrels through 1997. However, with an estimated of recovery of original oil in place (OOIP) as low as 20% in some production tracts, the potential for additional oil recovery is very encouraging.

The four fields were reviewed as possible pilot test areas based on stability of the injection/production profile, well bore conditions, and estimated recovery of OOIP. The Blazer field shown in Fig. 1, is located in Section 7 T6N, R11E. This field was chosen primarily due to its consistent waterflooding history, cased hole completions, with fracture stimulations and estimated remaining 70% of OOIP. An estimated 15% of OOIP was extracted during primary production and an additional 15% OOIP recovered with waterflooding.

**Select Test Area.** The criteria for selecting the location for the test well were: 1.) An area that has good net pay; 2.) An area that has good residual oil saturation; 3.) A location close to at least one producing well to maximize strength of vibration.

Openhole logs were used to determine the areas in the field having the best net pay with minimum shale laminations. The fifteen years of production records were used to assess the sweet spots of the field and when combined with the injection history a pattern of the best reservoir flow capabilities emerged. The sweet spots were interpreted as areas of natural fractures, which run in the NE to SW direction. The possibility for encountering either natural fractures or those created during completion stimulation, determined that the center of the field was a high-risk area for the pilot vibration test. Therefore, the southern end of the field was chosen for the pilot test area.

However, with essentially no individual well test histories, little confidence could be placed in estimating residual oil saturations throughout the field. Therefore, a hydrocarbon micro-seepage survey was conducted across the field to help assess the areas of higher residual oil.[27,28] The survey indicated the higher microbial count to be in the both the center and south end of the field, adding confidence of the location selected. The test well location was placed in the south end of the field near the 2W injection well and the two producers, wells 10A and 7A.

**Drill and core vibration stimulation well.** The vibration test well will be air drilled and cored through the Bartlesville sandstone. After logging, seven-inch casing will be set and cemented. The well will be completed with a small fracture stimulation and put on pump until its production has leveled off matching the field decline curve.

**Fig. 5** has three schematics indicating the various configurations the test well will experience during the field demonstration. Initially the well will be completed and beam pumped as shown in **Fig. 5a**. To begin the vibration stimulation test, the pump will be pulled and downhole vibration tool will be installed. It will be powered by a surface rod rotating system as seen in **Fig. 5b**. Finally, the vibration tool will be run as the deeper string of a dual completion found in **Fig 5c**. The vibration tool will be set across the perforations and powered with a surface rod rotating system. The production tubing will be run with a conventional ball and seat, reciprocating pump and operated separately from the rod rotating system.

**Fig. 6** shows a detail of the downhole vibration tool, utilizing two sets of mechanical slips to transmit the vibration energy from the backwards whirling mass into the producing formation.

**Core Testing.** Currently there are no firm 'rule of thumb' guidelines to determine optimum wave frequencies and intensities for reservoir stimulation; both parameters are important. High frequency waves become less intense at shorter distances from a source compared to low frequency waves. Assuming that wave stimulation loses effectiveness below a threshold intensity level, the range of influence of a vibration stimulation source is then both related to the vibration frequency and intensity.

Various authors propose different stimulation frequencies as optimal (Refs. 2,3,4,6,16, and 19). Some suggest that best results occur when the reservoir is stimulated at its natural or resonance frequency, while others suggest that optimum frequency for particular rock strata is related to pore and grain sizes. Interpretation of the work of Fairbanks and Chen suggests that natural frequencies of rocks with small pores (lower permeability) are higher than natural frequencies of rocks with large pores (higher permeability).[27] This is also implied by results from Ref. 10. The goal of laboratory vibration tests is to identify *a priori* (cause and effect), do particular frequencies and intensities influence hydrocarbon recovery for specific reservoir rocks.

Phillips Petroleum Company's coreflood apparatus was used in this project to assess effects of vibration on fluid flow. **Fig. 7** is a partial schematic of the apparatus. The system consists of a biaxial coreholder with hydraulic rams on both ends of the sample, fluid reservoirs, pumps, pressure transducers, mass balance and volumetric balance fluid production measurement devices, and vibration measurement and control devices. Linear variable displacement transducers (LVDTs) on the coreholder are used to measure changes in the length of a core sample during compression and vibration tests. Vibration is applied to a core in the same direction as fluid-flow using a magnetostrictive actuator that supplies cyclical compressive stress. This stress, which is super-imposed on the static longitudinal stress, is in the form of a sine wave. Frequency of operation is from about 8 Hz to 2000 Hz. A dynamic force transducer is mounted along the load path between the core and vibration actuator. Output from the dynamic force transducer is read from an oscilloscope. Dynamic force supplied during vibration is adjusted to achieve target vibration intensities at test vibration frequencies.

***Typical Vibration Test Sequence.*** After inserting a brine-saturated core in the coreholder and applying longitudinal and radial stress, Young's modulus of the rock is measured. One of the hydraulic rams of the biaxial coreholder is used for this purpose, while the other ram is maintained in fixed position. Young's modulus is calculated from measurements of core length changes with changes in longitudinal stress. From rock dimensions and Young's modulus, dynamic loads are calculated for conditions of various vibration frequencies and intensities. The permeability of the core plug to brine is measured to establish baseline permeability without vibration. Subsequently, permeability is measured while applying a range of vibration frequencies and intensities to determine whether permeability enhancement occurs under particular vibration conditions. The core is oil flooded to a residual water saturation condition. After an aging period, the core is waterflooded without vibration to document oil production versus pore volumes of water injected. Another waterflood test is conducted with vibration on the same or similar core. Options include vibrating continuously throughout the waterflood, vibrating continuously after water breakthrough occurs and water cuts are high, or intermittently vibrating by turning vibration on and off several times during a test.

In-house lab tests have shown that, for many rock cores, the permeability of a brine-saturated core can be increased by 10% or more by imposing particular vibration frequencies and intensities. For example, **Fig. 8** shows absolute permeability enhancement as a function of vibration intensity and frequency for a Berea sandstone core plug. Highly water wet samples tested thus far show about the same waterflood production response with and without vibration. Subtle enhanced waterflood performance has been seen when testing rocks that are not highly water wet. One such example is shown in **Fig. 9** from a test on an intermediate-wet to oil-wet core from a Mid-Continent field. Two types of vibration tests were conducted; one with continuous vibration (also referred to as CW or continuous wave in the literature) and a second test in which the vibration was intermittently turned on and off (intermittent vibration). Waterfloods with vibration provided slightly higher oil recoveries than without vibration, while recovery versus time with intermittent vibration somewhat outperformed the continuous vibration test.

***Bartlesville Sandstone Tests.*** Since, the vibration test well in the Blazer Field has not yet been cored, a search was conducted in the Oklahoma Geological Society Core and Sample library in Norman, Oklahoma which found nearby cores cut nearly forty years earlier. To gain early insight into how the rock might behave under vibration, core plugs were cut from these old, existing whole cores. The core was x-ray scanned to select representative samples. Due to the age of the core, it was extensively flow-cleaned with alternating cycles of hot toluene and methanol. Initial flow tests were conducted using separator oil from the Blazer field and synthetic brine. Results from these tests were unavailable at the time of this writing.

**Design, build, and test Downhole Vibration Tool.** Versions of the downhole vibration tool have been tested as seismic sources operated near the surface, approximately 120' below ground level. For this field test, the downhole vibration tool will be run at approximately 1800', placing it across the perforations in the Bartlesville sand. Because of the mechanical nature of this backwards whirl orbital vibrator, it was desirable to employ commercially available rotating systems. The feasibility of using existing downhole electric motors, positive displacement motors, or surface rod rotating systems to power a downhole vibration source were investigated. The rod rotating system was chosen for its simple, field proven operation and for the ease of adapting from a progressive cavity pump installation to the downhole vibrator application.

The final design for the desired frequencies and intensities to be generated by this tool, will be based on the above lab tests and an ongoing effort to understand which parameters will most likely increase the oil production in this mature waterflood. The conventional orbital vibrator output frequency is a one-to-one function of its rotating speed. With the whirling orbital vibrator, the output frequency is a function of the rotating speed times a multiplying ratio of the difference in housing and mass diameter. This mechanical aspect allows for optimizing vibration intensity over a select range of frequencies for the available horsepower. This will allow it to maximize the energy generated within the constraint imposed by casing size. It will be mechanically attached to the casing (much like a production packer) and placed opposite the reservoir to maximize the energy transmitted to the formation **(Fig. 6)**.

The vibration tool will be operated with computer controlled, variable speed, 40 hp electric motor. It will be able to slowly increase frequencies and intensities, hold the system at that level of output and step it back down in a predetermined manner. It has safety devices at the surface to shut-down the automated stimulation cycle should the motor draw current levels outside tightly controlled limits. The history of the vibration tool operation will be recorded and time stamped to allow for cross-referencing both fluid response data and all geophone recordings (both downhole and surface listening devices).

***Install downhole and surface monitoring equipment.*** The vibration detection tools (geophones) will be installed in a selected well at approximately 500' from the vibration stimulation well (Fig. 10). To allow the sensitive geophones to detect and identify the generated vibrations, the selected well will remain inactive while monitoring is being conducted. Equipment and personnel from Lawrence Livermore National Laboratory in conjunction with Las Alamos National Laboratory will be used to measure and record strength of vibrations within the reservoir. This data will be recorded and time stamped to allow for cross-referencing with the tools operations.

Surface monitoring of produced and injected fluids within the pilot area will continue as normal production operations for the selected pilot wells. Pilot production wells will be placed on a continuously rotating production testing schedule to determine water and oil rates on individual wells. A continuous record of pilot injection well information will be kept. This will produce a high quality base line for production and injection data in advance of initiating the vibration stimulation field test.

***Perform three-month vibration stimulation test.*** The flexibility of being able to either produce and/or vibrate the stimulation well will afford the capability to establish a matrix of vibration response tests. Initially, the vibration test well will be stimulated and the offset wells closely monitored for changes in fluid characteristics and produced volumes. Simultaneously, the listening devices will be recording any discrete seismic signals, which are identified occurring above ambient noise. The acoustic response will be rapid (measured in seconds), due to close distances between the 5 acre spaced wells (330'). It is anticipated that fluid flow changes will take longer, perhaps as much as 48 hours to be manifested in either production volumes, injection pressures, or annulus fluid level changes.

Initially the well will be vibrated continuously at discrete frequencies in the 50 to 200 Hz range. The results of the first matrix of tests will determine the second testing logic. This may take on a re-configuration of the tool to produce higher amplitude vibrations at a narrower frequency range. Since the output amplitude is a squared function of the frequency, adjustments may be necessary. Also, should the geophones detect a dominant or resonant frequency occurring, modification to operations or the tool itself will be made to generate that frequency if possible.

***Assess the vibration effects on oil production.*** A technical assessment of the field test will be the focus of the project's final report. Project success will obviously be tied to economical increases in oil production from the field test. But the project will have a scorecard for each of the major tasks to allow review of the intermediate steps.

The question of the economics for this particular test will be straightforward. The reliability of this version of the tool, its maintenance requirements both surface and downhole, and power consumption, will determine the operating expense incurred. This will be compared to the changes in the WOR and oil sold during the field test.

It is premature, at this point, to speculate how this particular downhole vibration stimulation tool might work in different reservoir situations such as higher permeability sandstones, unconsolidated sand, or carbonate reservoirs.

***Transfer vibration stimulation technology.*** Reports covering the project will be submitted to the DOE contract officer and to the Osage Tribal Council. Technical papers and presentations, such as this one, will be prepared and delivered. Preliminary conversations with the Petroleum Technology Transfer Council (PTTC) have explored offering workshops through the South Mid-Continent Region to introduce this technology to the Osage County operators. These sessions will be prepared, advertised, and delivered based on participant response and may be expanded. Exploratory talks have considered establishing a technical session dedicated to reviewing world wide applications of vibration stimulation at the 2002 SPE/DOE/IOR Symposium in Tulsa. It is envisioned that researchers and practitioners of vibration stimulation worldwide would be invited to present their current efforts to allow the industry a concise and intense review of the state of the art in vibration stimulation activities, successes, challenges and areas of opportunity.

## Conclusions

1. Vibration stimulation of hydrocarbon reservoirs is being conducted today on a limited scale. Some of the stimulation is with downhole tools, while most of the reported success comes from surface vibro-seismic stimulation.
2. Orbital vibrators are capable of producing both shear and compression wave energy at frequencies and intensities which can be engineered to provide enhanced fluid flow through porous media.
3. Laboratory investigations have demonstrated various effects of vibration on the flow of multi-phase fluids through porous media. However, it is not clear which basic fluid and rock parameters are effected by elastic vibration.
4. Additional basic research is needed to better understand the effects vibration stimulations on specific parameters of multiphase fluids in porous media.
5. With reported increases of 20% of baseline production rates, there is a huge impetus to conduct further field testing with a keen interest in vibration stimulation effects on ultimate recovery.

## Acknowledgements

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## Nomenclature

| | | |
|---|---|---|
| *bbls* | = | *5.61 cubic feet* |
| *cp* | = | *centipoise* |
| *dB* | = | *decibels* |
| *Hz* | = | *cycle /second* |
| *hp* | = | *horsepower* |
| *g* | = | *acceleration of gravity* |
| *k* | = | *permeability* |
| $k_w$ | = | *Permeability to water* |
| *md* | = | *millidarcy* |
| *MHz* | = | *million cycles /second* |
| *OOIP* | = | *Original oil in place* |
| *PV* | = | *Pore volume* |
| *rpm* | = | *revolutions per minute* |
| *Swi* | = | *Irreducible water saturation* |
| *WOR* | = | *water oil ratio* |

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## SI Metric Conversion Factors

| | | | | |
|---|---|---|---|---|
| bbl | x | 1.589 873 | E – 01 | = $m^3$ |
| cp | x | 10* | E – 03 | = Pa · s |
| cycles/sec. | x | 1.0* | E + 00 | = Hz |
| ft | x | 3.048* | E – 01 | = m |
| inch | x | 2.54* | E + 00 | = cm |
| lbf | x | 4.448 222 | E + 00 | = N |
| md | x | 9.869 233 | E – 04 | = $m^2$ |
| psi | x | 6.894 757 | E + 00 | = kPa |

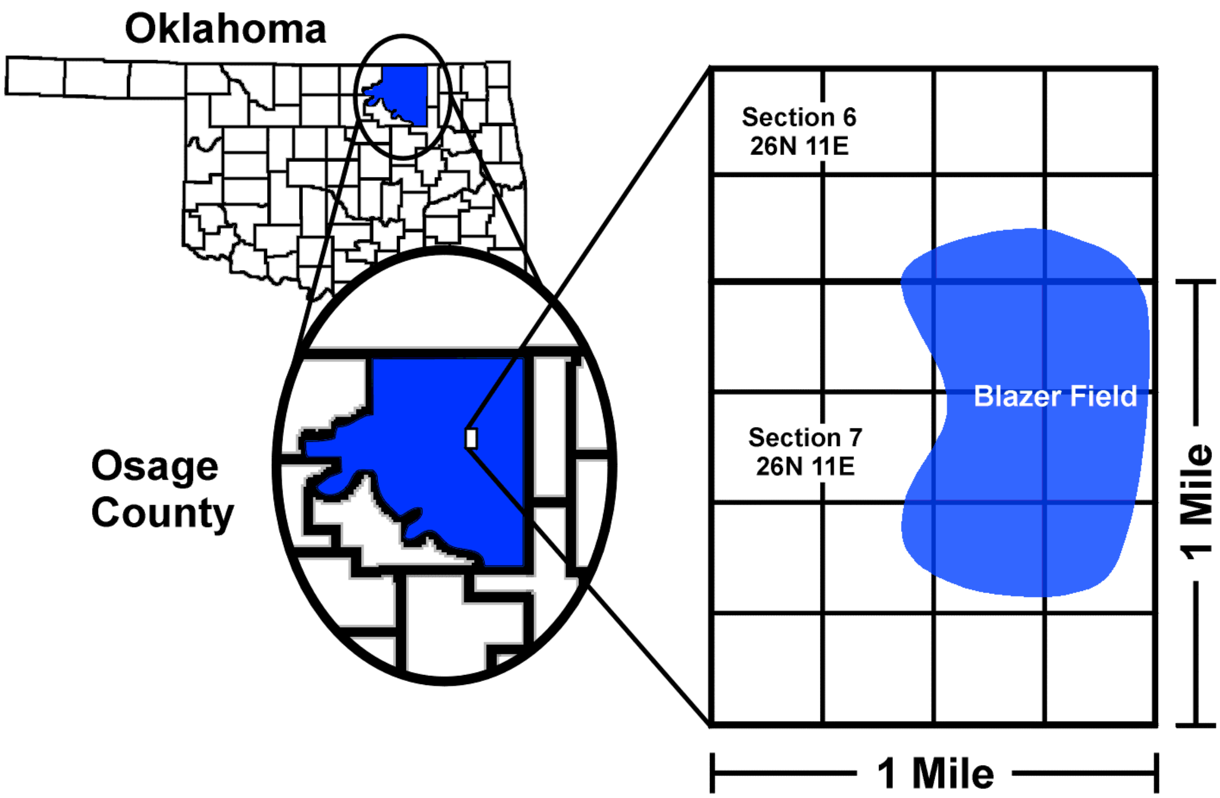


*Fig. 1-Location of Blazer Field, Osage County, Oklahoma.*

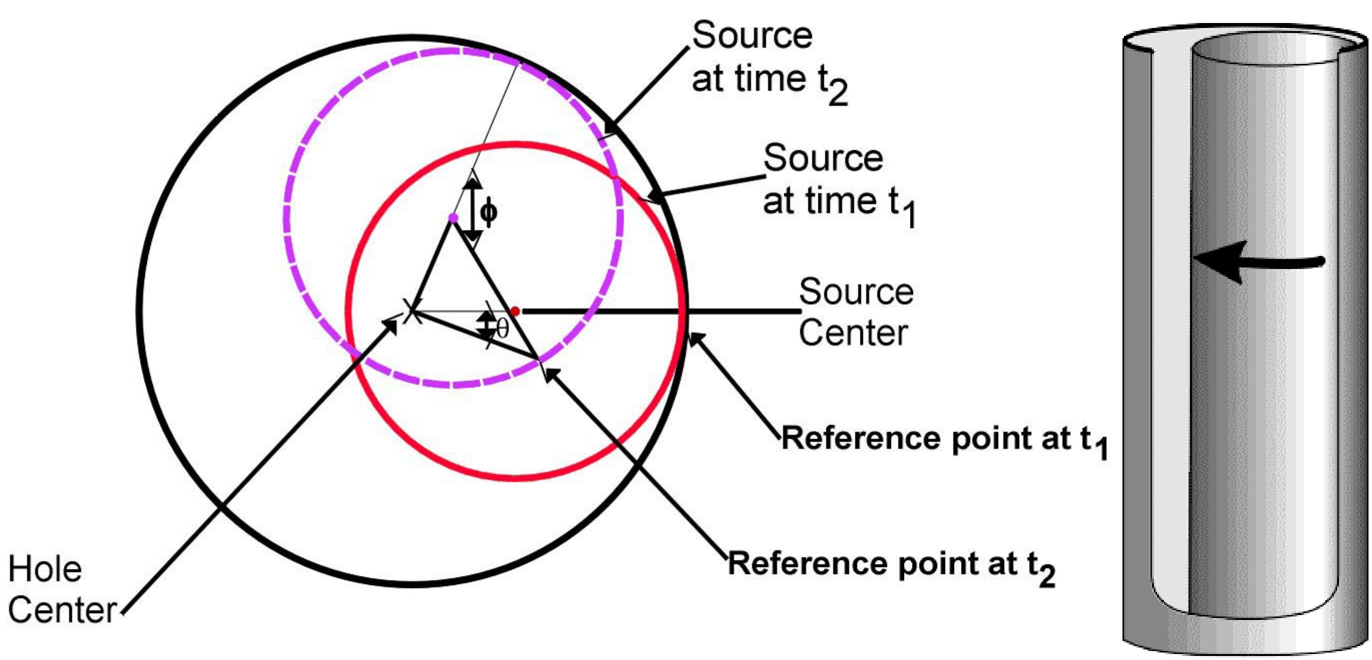


*Fig. 2-Whirl kinematics, showing clockwise rotation, with mass rolling counter-clockwise within housing.*


*Fig. 3-Downhole vibration tool in earlier version as a geophysical seismic source inside 8 5/8" casing.*

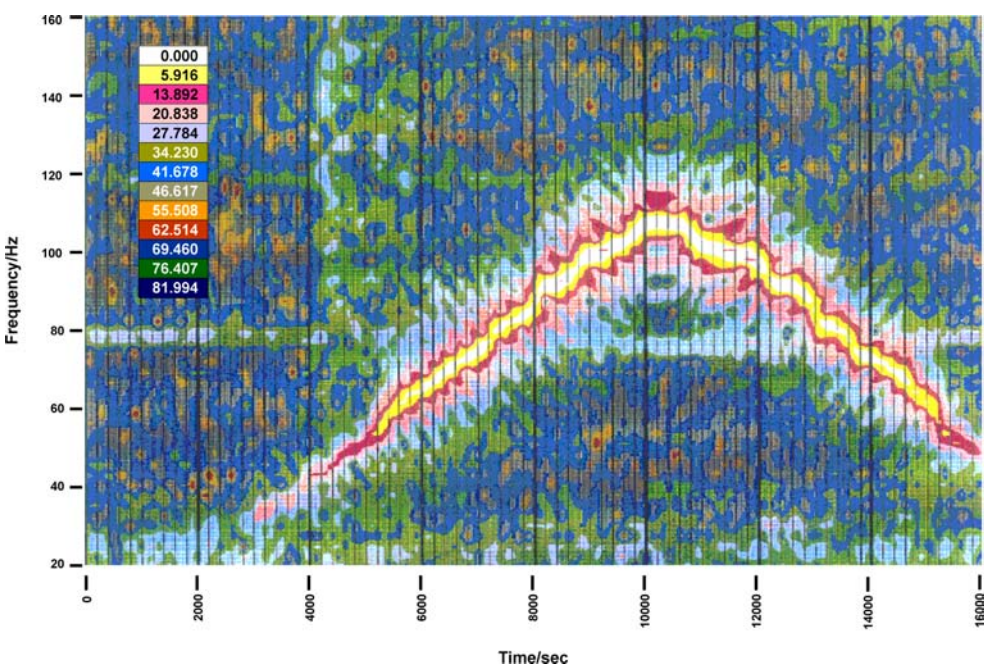


*Fig. 4-Geophysical signal, measured 1100" from source, was generated by ramping the downhole tool from 30 to 120 Hz and back to 30 in 12 seconds*

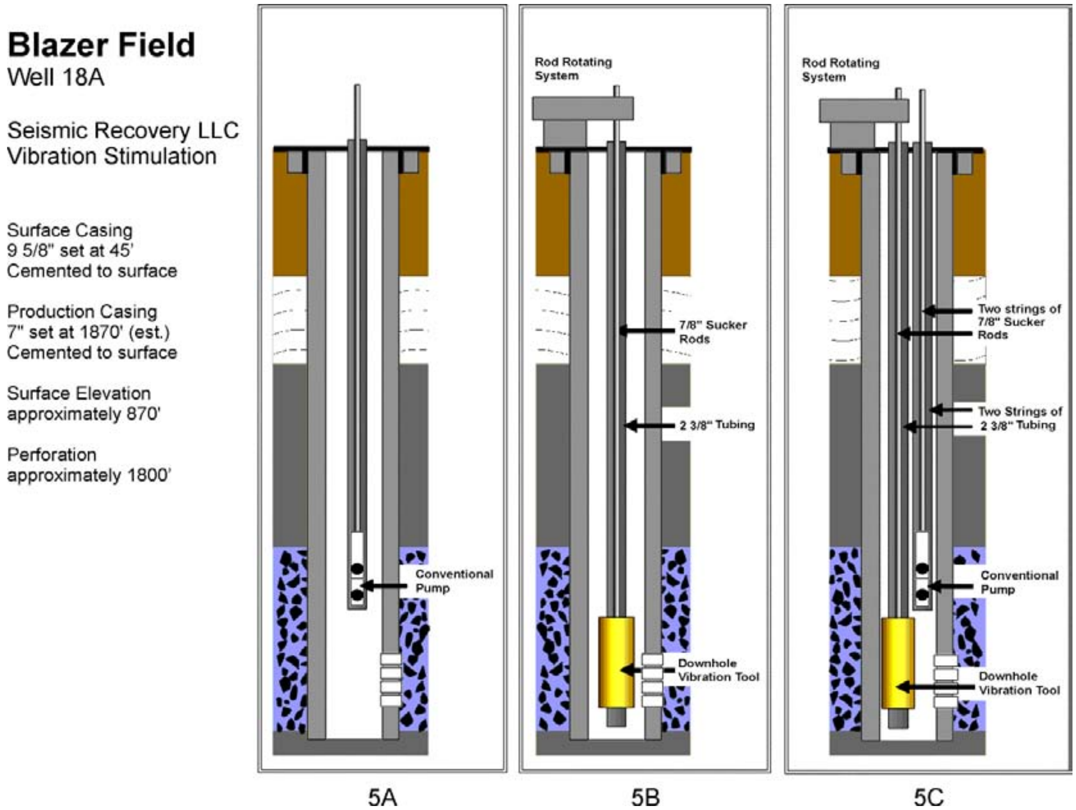


*Fig. 5- Schematic of vibration test well: 5A-Initial completion tubing string; 5B-Initial vibration configuration and 5C-dual completion with downhole vibration tool and reciprocating pump configuration.*

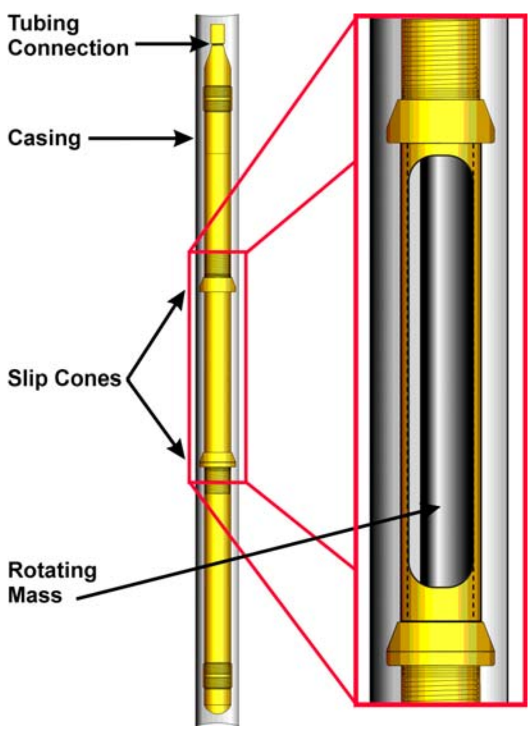


*Fig. 6-Schematic of 7-inch downhole vibration tool anchored with dual set of mechanical slips.*

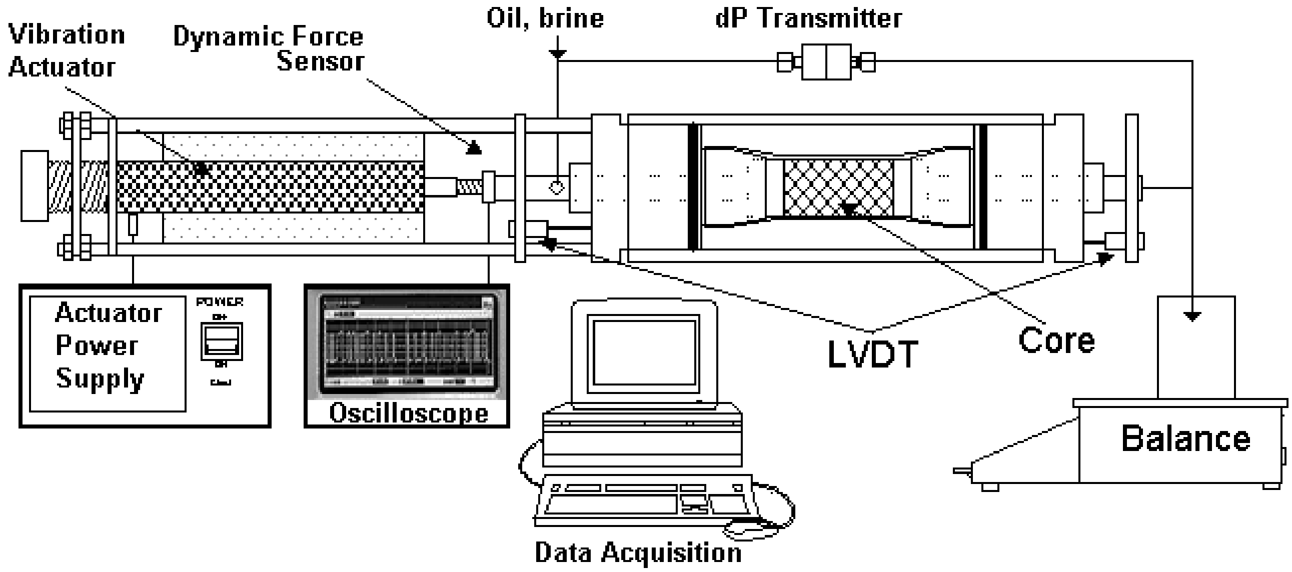


*Fig. 7- Sonic core test cell, with axial magnetostrictive vibration source.*

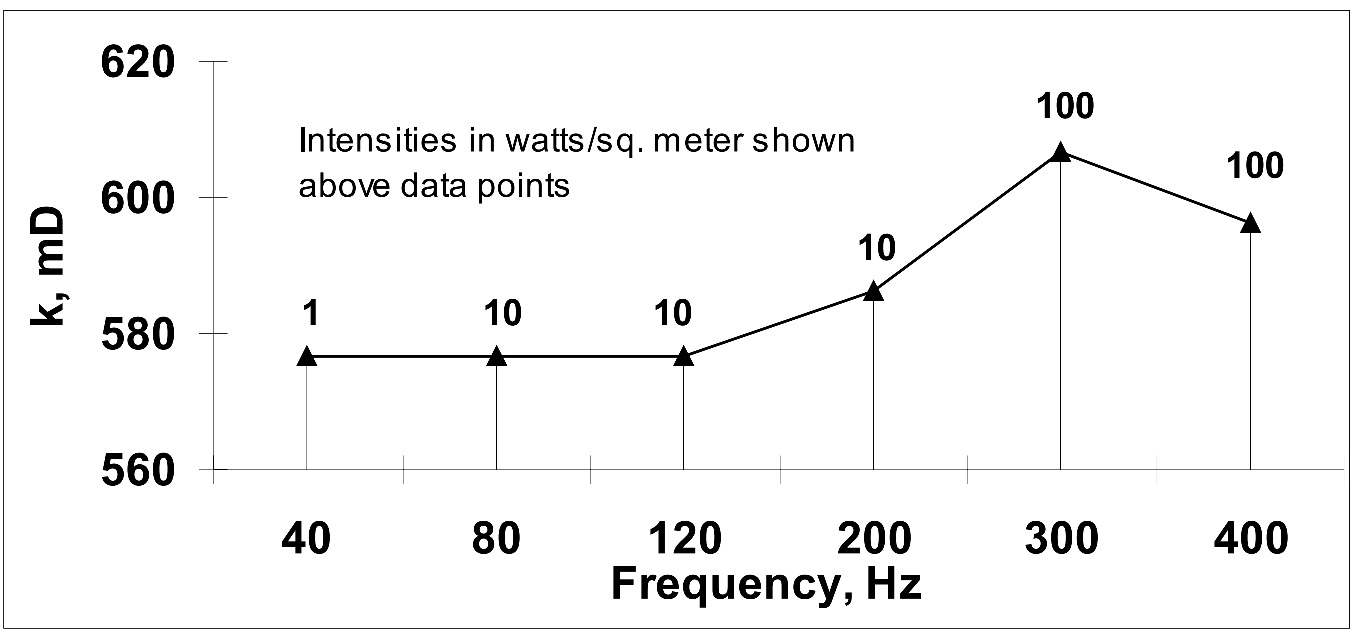


*Fig. 8- Brine permeability enhancement with vibration, Berea sandstone core.*

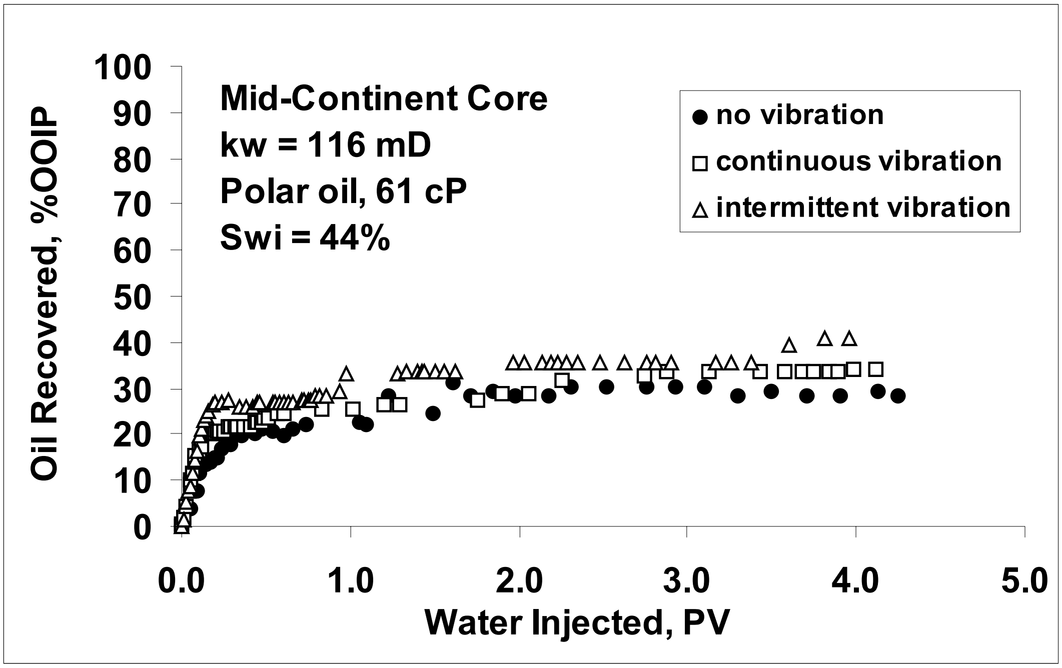


*Fig. 9- Waterflood results for a Mid-Continent reservoir core without and with vibration stimulation.*

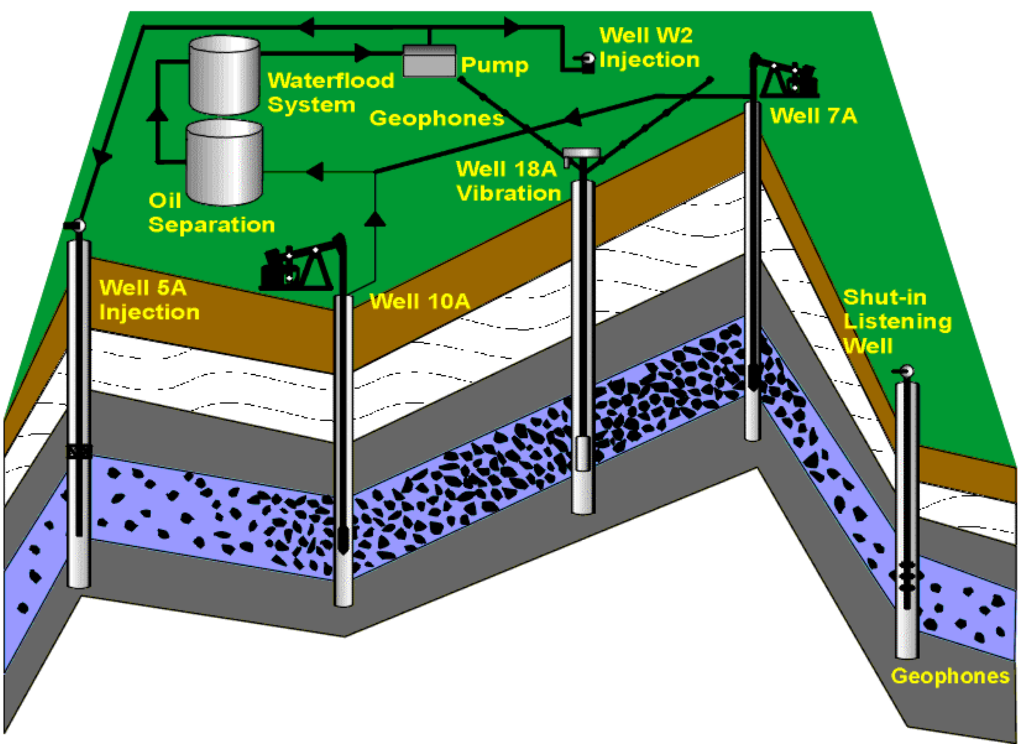


*Fig. 10-Schematic of production test and water injection facilities with temporary surface and downhole geophones for monitoring vibration strength.*

SPE Paper Number 75254

# Enhanced Oil Recovery with Downhole Vibration Stimulation, Osage County, Oklahoma

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This paper was prepared for presentation at the SPE/DOE Thirteenth Symposium on Improved Oil Recovery held in Tulsa, Oklahoma, 13–17 April 2002.



## Abstract

This paper provides status of the project to test downhole vibration as a means of oil production stimulation in Osage County, OK. Supported by a grant from the Department of Energy (DOE) and an in-kind contribution from Phillips Petroleum Company, along with field support by Calumet Oil Company, Seismic Recovery LLC will test this intriguing technology for enhanced oil recovery in the Burbank formation, which is a Pennsylvanian age sandstone.

A new well has been drilled and cored within the designated pilot area, in the central portion of the North Burbank Unit. The field is a mature waterflood that is currently producing at approximately 1% oil cut. The recovered core has been subjected to sonic core-testing by Phillips Petroleum personnel to measure the effect of vibration on the flow of oil and water in cores.

Offset inactive wells are being instrumented to monitor the vibrations emitted. Pilot area injection wells are being equipped to monitor changes in injection pressure and rate. Production wells are checked for total produced fluid, pumping fluid levels and oil cut. Due to project delays, at the time of this paper preparation, the field test for vibration stimulation has not yet begun. Therefore, we are unable to present conclusions from this vibration stimulation field test.

## Introduction

It is well established in the oil industry that often significant amounts of oil still remain in the producing formations at the time of field abandonment. Wells in waterflooded fields are abandoned because production is uneconomical due to high water-cut. Many techniques have been developed in an attempt to economically recover this immobile oil. Vibration stimulation may be a method for improving oil production and increasing ultimate economic recovery in these situations. The vibration force introduced in the reservoir is thought to facilitate the movement of oil in one or more ways such as: causing change in phase permeabilities; changes in acceleration fields; reduction in surface forces, surface films, and/or capillary pressure; coalescence of oil droplets and remobilization; breaking up of oil droplets into sizes that are smaller than the pore throats; release of gas; long to short seismic wave energy conversion; disruption of clays; and porosity diffusion.

**Historical Background of Vibration Stimulation.** The interest in elastic-wave vibration stimulation (as opposed to non-elastic vibration, such as explosions) goes back to the 1950s. Interest in this technology is well documented by Beresnev and Johnson,[1] who reported on the full spectrum of investigative work in both the USSR and USA. They reviewed the efforts of over a hundred researchers who had probed the effects of man-made vibrations from the low end of 1 Hz to the high end of ultra sonic with frequencies up to 5 MHz.

The effects of earthquakes on oil production were also included in this paper. Russian literature reported success in shallow reservoirs with high water content using surface equipment to generate vibro-seismic stimulation. Westermark et al.[2] included a comprehensive update of current vibration related stimulation technologies from around the world, when they presented the initial Osage County project plans.

**Recent Research Reported in the United States.**

***Los Alamos National Laboratory Research**.* A joint industry project, funded by DOE's Office of Basic Energy Science, a Division of Advanced Energy Projects, to study "Seismic Stimulation for Enhanced Production of Oil Reservoirs" was conducted from 1995 to 2001 and has been completed[3].

The laboratory experimental portion of this project utilized a core test cell with a magnetostrictive actuator applying mechanical stress excitation to sandstone core samples during single-phase and two-phase fluid flow. Results indicate that mechanical stress excitation at 100 Hz and lower can strongly influence two-phase fluid flow behavior in Berea sandstone under both steady state and simulated flood conditions. The updated details of the Los Alamos core studies can be found at the project's homepage provide in reference 3.

In addition, Lawrence Berkeley National Laboratory (LBNL) has provided geophone monitoring equipment and interpretation services for number of vibration stimulation field tests. By analyzing the vibrations generated during a test, LBNL can estimate the energy levels being transmitted to the oil bearing formation. Applied Seismic Research [4] has reported several successful field tests using their pressure pulsing system.

## Downhole Vibration Stimulation Project

**Project Team.** Seismic Recovery LLC, a subsidiary of Oil and Gas Consultants International, and Phillips Petroleum Company recognized an opportunity to collaborate in testing this novel technology in the nearby, essentially watered out Osage County oil fields. When the Osage tribe was approached with this concept, they issued Resolution 30-490 of the Osage Tribal Council, August 1999 in support of this effort.

Calumet Oil Company is participating in the project and is the operator for the North Burbank Unit (NBU). Additional technical synergy was gained through Green Country Submersible Pump Company, a subsidiary of Calumet Oil Company. Their experience in manufacturing downhole production equipment was freely shared in support for developing the systems necessary to conduct this project.

Refer to Fig. 1 for a map showing the location of the NBU field in Osage County, Oklahoma. Fig. 2 is a detail of Section 8, the pilot test area, with injection, production and inactive wells shown.

**Downhole Vibration Tool.** Backwards whirl has been studied for the past twenty years in the oil well drilling industry. Whirl generates intense vibrations, which are known to be harmful to manmade diamond drill bits. A key property of backswards whirl is that there are multiple vibrations generated per revolution, compared to one vibration per revolution for an eccentric style vibrator. This means the desired vibrational frequencies can be generated at much lower rotational speeds than conventional eccentric systems.

The patented tool for this project exploits the backswards whirling phenomena. To control the frequency and intensity of the vibrations, the rotating mass is placed within a housing. Rotation speed determines both the frequency and vibrational force generated for a particular tool configuration. Fig. 3 is a picture of the 7-inch Downhole Vibration Tool (DHVT), which has been specifically built for this project. Adjacent to the photograph is a schematic depicting the rotating mass inside the housing of the tool. When run in the well to the depth of the producing formation, the DHVT is securely attached to the casing using conventional packer slips, which can be set and released.

**Pilot Field Test in Mature Waterflood.**

***Select the Field.*** Two mature waterflooded fields have been considered for this field test. The initial field considered for the pilot test was changed after sonic core stimulation tests conducted by Phillips Petroleum Company indicated little improvement in reservoir flow characteristics could be expected from vibration stimulation. These sonic core tests were performed on an old core from an offset well. This was done before the vibration stimulation well had been drilled.

Previously, as part of an effort to identify rock and fluid characteristics contributing to successful vibration stimulation, Phillips had tested cores from the NBU that had been recovered 30 years earlier when Phillips operated the field. Results from vibration stimulation tests using the NBU core and oils from different sources were encouraging. The NBU operator was approached by Seismic Recovery LLC, and agreed to conduct the pilot test. The Burbank formation is a Middle Pennsylvanian sandstone often found in the western half of Osage County, in northeastern Oklahoma. Discovered in 1922, it is the largest field in Osage County, and has been under waterflood for nearly 60 years. It is now a very mature waterflood, which produces approximately 1200 barrels of oil per day and over 160,000 barrels of water per day with the average oil cut of less than 1%.

An immediate advantage of moving the pilot test to the NBU was the voluminous amount of technical material describing this world-class reservoir. When Phillips Petroleum Company operated the field; it was the site of numerous tertiary oil recovery pilot tests. In 1976, a three-year project micellar/polymer flood pilot test was initiated with the support of the DOE.[5, 6] At that time, since NBU was an aging waterflood in an oil-wet, naturally fractured reservoir, special attention was placed on residual oil determination and problems with injection pressures exceeding parting pressure. Refer to Table 1, which provides the average original values of the field's characteristics and those of the pilot test area.

***Determine the Pilot Test Area.*** The criteria for selecting the location for the pilot test area in the NBU and placement for vibration stimulation well were: 1) an area that has had a consistent waterflood pattern for at least two years and produces into one tank battery; 2) an area having a minimum total pay thickness of at least 40 feet; 3) an area having had low initial production rates (less than 500 barrels of oil per day) after being shot. All original production wells were cable tool drilled in the early 1920s as open-hole completions and shot with nitroglycerin.

To be able to operate at an average field wide oil cut of about 1%, the operator had consolidated many tank batteries throughout the field. Calumet also became very selective in maintaining active injection wells, utilizing a modified line drive pattern to take advantage of the pattern of the natural fractures in the reservoir and keep the injection pressures below the low parting pressures in this 2850 ft. deep reservoir. Furthermore, they implemented widespread use of electric submersible pumps to maximize fluid withdrawal as well as for water injection purposes.

***Drill and Core Vibration Stimulation Well.*** The purpose of drilling a new well was threefold: 1) obtain fresh cores to be tested utilizing Phillips sonic core test apparatus; 2) provide a well bore with 7-inch casing cemented through the producing interval; 3) provide a well bore to install the DHVT without changing the established fluid movement patterns within the reservoir encompassed by pilot test area.

The well was drilled in July 2001. Three cores were cut through the Burbank formation: core # 1 from 2850' to 2880'; core #2 from 2880' to 2910', core # 3 from 2910' to 2934'. Core recovery was 98% even though twenty feet of core #2 encountered a natural fracture. Fig 4 is a photograph of a portion of the natural fracture, which appeared to be open 1/8 of an inch. The cores were transferred to Phillips core laboratory for standard tests and special sonic testing. The well was drilled to total depth of 3090' and logged. Seven inch casing was run and cemented.

***Core Testing***. The purpose of obtaining fresh core samples from the NBU was to allow for a comparison of laboratory sonic vibration tests conducted on the 30 year old cores and the new cores. The sonic test procedure utilized was the same procedure as reported in SPE Paper 67303, which reported an increase in oil cut (up to 20%) and additional total oil recovery up 10% to 15%.

First, standard core analysis were performed to determine porosity, permeability, water and oil saturations. In Fig. 5 are four charts displaying the results from the standard core analysis. The first chart shows core test results for formation brine saturation as a function of depth. The next chart is the oil saturation values by depth. Since there is no gas remaining in the reservoir, the discrepancy in the fluid saturations not adding to 100% needs an explanation. It is assumed to be oil lost downhole during coring and loss at the surface. The core was bleeding oil as it was laid down from the core barrel.

The initial sonic core tests results on the fresh cores were unlike the previous results. There was a reasonable increase (10 to 15%) in fluid flow through the core at frequencies in the 10 to 100 Hz range, but there was no shift in the oil cut recovered from the additional flow.

***Design, build, and test Downhole Vibration Tool (DHVT).*** Simultaneous with drilling the stimulation well and conducting sonic core tests, a new 7-inch DHVT was designed, built and function tested. Earlier versions of this tool had been run with hydraulic motors shallow depths. For this field test, the DHVT would be run at a depth of approximately 2800 ft. placing it across the Burbank formation.

To minimize development time and cost, it was desirable to employ commercially available rotating systems to power the DHVT for this application. A rod rotating system was chosen for its simple, field proven operation, its low RPM operating range, and for the ease in adapting from a progressive cavity pump installation to the downhole vibrator application. Also, by using certain standard electrical submersible pump components, the adaptation for running the instrumented DHVT was expedited, enhanced by the use of rugged field proven equipment.

With this type of vibrator, the output frequency is a function of the rotating speed. This aspect allows for optimizing vibration intensity over a select range of frequencies for the desired horsepower. The DHVT is mechanically attached to the casing, similar to a tension set production packer, and placed opposite the reservoir. This maximizes the vibrational energy transmitted to the formation.

Prior to attempting the production stimulation field test, the DHVT, the surface rotating equipment and data acquisition system were function tested in an idle well operated by Calumet Oil Company. Refer to Fig. 6 for the equipment layout during this function test. The purpose of conducting this function test was to debug the data acquisition system and the rod rotating system and primarily to ascertain the durability of the DHVT. Again the Calumet personnel provided very helpful field operations support in both planning and execution of the function testing.

The DHVT is powered with a 50 Hp electric motor computer controlled, variable speed drive system. Downhole instrumentation provides real time data, measuring vibration frequency, intensity and tool operating temperature. However, the durability of the original DHVT design has been less than desirable. This has resulted in numerous reconfigurations of the tool components and further function testing. This alone has delayed the field vibration stimulation test at least six months.

***Install Downhole and Surface Monitoring Equipment.*** Downhole monitoring of the vibration stimulation test will take place in adjacent inactive wells and be synchronized with the downhole instrumentation on the DHVT. Equipment and personnel from LBNL will be on location to measure and record the strength of vibrations within the reservoir. Their three-axis downhole geophone will be installed initially in Well 111-14 approximately 1000 ft. from the vibration stimulation well. Also a surface array of geophones will be laid out orthogonally, with the center of the two lines being at vibration well. This data will be recorded and time stamped with the data from the DHVT to allow for initial on-site processing of the signals.

The output of the DHVT will be ramped up and down over a pre-selected frequency range. The computer controlled variable speed drive will increase rotational speed, hold the system at a constant output and then step it back down in a predetermined manner. This cycling action of the tool's rotational speed is designed to sweep through a discrete frequency range sending a unique seismic pulse through the formation.

Surface monitoring of produced and injected fluids within the pilot area has been ongoing for nearly 12 months and will continue as normal production operations for the selected pilot wells. Pilot production wells have been placed on a continuous production-testing schedule to determine water and oil rates on individual wells. Tank battery modifications have assured the isolation and accurate measure of pilot area production. This has resulted in a high quality base line of both production and injection data prior to initiating the vibration stimulation field test. In addition, a real time record of the two pilot injection well's injection pressure and rate performance will be recorded when the field test commences.

***Perform the Vibration Stimulation Test.*** To eliminate any changes in the pilot area reservoir flow patterns by fluids leaving or entering the vibration stimulation well, it has not been perforated. Fig. 7 is a schematic of NBU Well 111-W-27 with the DHVT installed. The first response to vibration stimulation may occur in the offset injection wells. The real-time recording of injected fluid volumes and pressures is expected to provide the first indication if the seismic vibrations have altered the fluid flow in the pilot area. All pilot area production wells will be closely monitored for changes in produced water-oil ratios, water salinity and pumping fluid levels.

Initially, the DHVT will be vibrated intermittently at discrete frequencies in the 40 to 60 Hz range. Should the production or injections wells seem to respond at a dominant or resonant frequency, modification to tool operations will be made to generate those frequencies. This may require a re-configuration of the tool to produce higher amplitude vibrations at a narrower frequency range.

The DHVT rotating system has safety devices at the surface to shutdown the automated stimulation cycle should it abnormal electric current levels occur outside tightly set limits. Power consumption will be metered and used to determine operating cost projections.

***Assess the Vibration Effects on Oil Production.*** A technical assessment of the field test will be the focus of the project's final report. Obviously, project success will be tied to economical increases in oil production from the field test.

The question of the economics for this particular test will be straightforward. Using an estimate for manufacturing costs, the reliability of this version of the tool, its maintenance requirements (both on the surface and downhole), and its power consumption, will determine the capital investment required and operating expense incurred. These costs will be compared to the changes in the water-oil ratio, the oil sold during the field test, and a possible reduction in injection energy requirements.

***Transfer Vibration Stimulation Technology.*** Quarterly technical reports covering the project have been submitted to the DOE and the Osage Tribal Council. Technical papers and presentations have been prepared and delivered. Preliminary conversations with the Petroleum Technology Transfer Council (PTTC) have explored offering workshops through the South Mid-Continent Region to introduce this technology to the Osage County operators.

A one-day short course "Sonic Production Techniques" was given at the Thirteenth SPE/DOE Improved Oil Recovery Symposium in April 2002 in Tulsa, OK. Researchers and practitioners of vibration stimulation technology presented their current efforts to provide the industry an intense but concise review of the state of the art in vibration stimulation activities, successes, challenges, and areas of opportunity.

## Conclusions

1. Interest worldwide is still growing concerning the use of vibrations stimulation for improving oil recovery in mature waterfloods. However, only a small number of suppliers have published results.
2. Experimental laboratory results alone are inconclusive, and therefore still need to be conducted in concert with field-testing.
3. Project delays of nearly one year have caused the North Burbank Unit vibration stimulation to be postponed, consequently at the time of preparing this paper, there are no field test results to report.

## Acknowledgements

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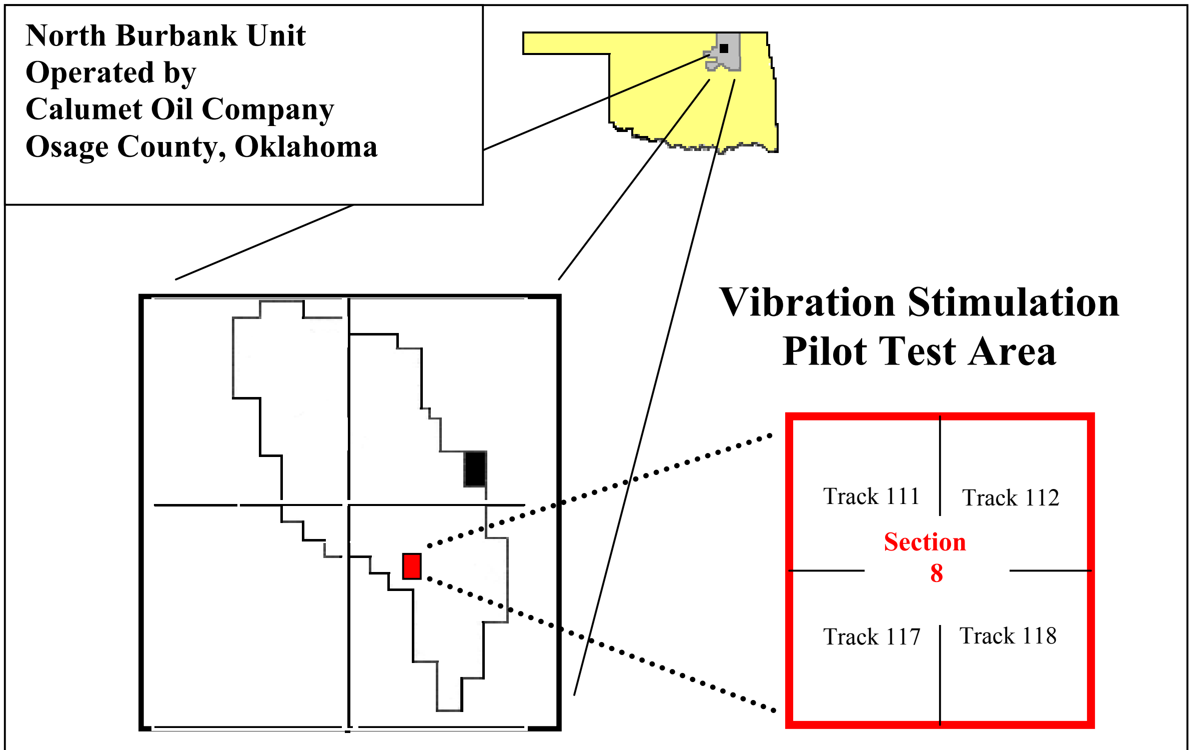


**Figure 1. Location of North Burbank Unit Field, Osage County, Oklahoma.**

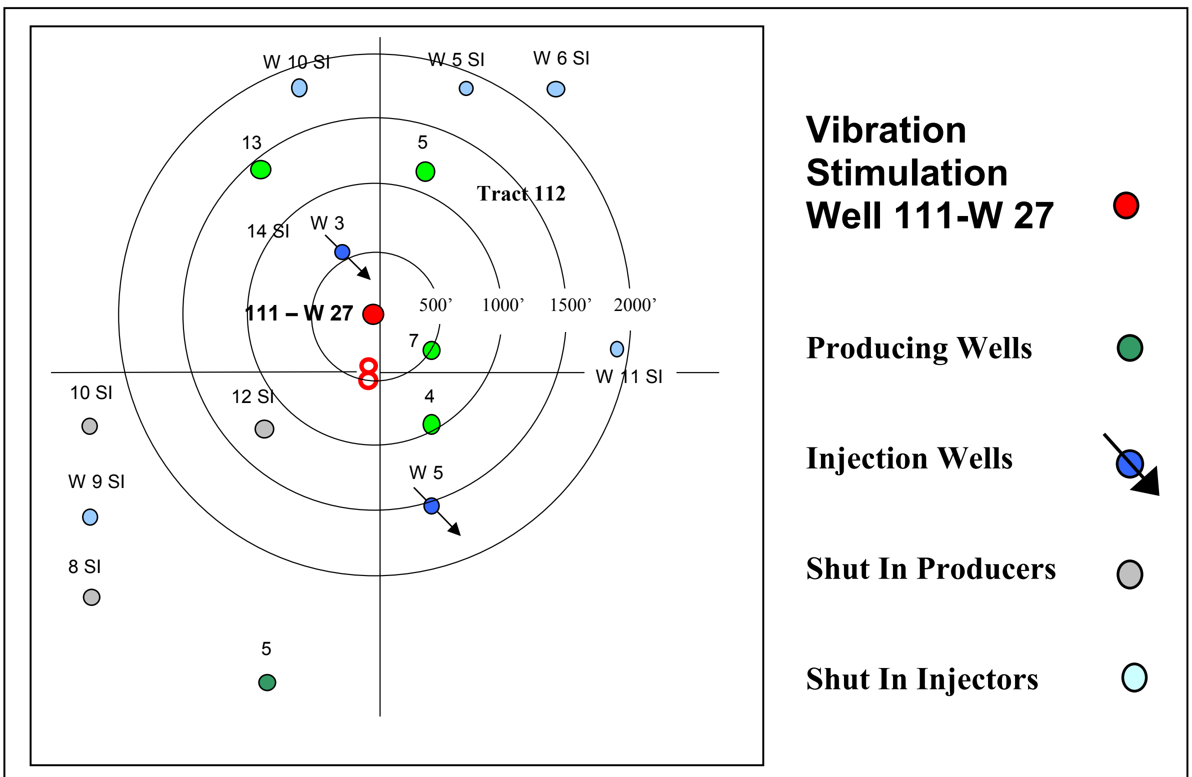


**Figure 2. North Burbank Unit, R6E T26N Section 8 Vibration Stimulation Pilot Test Area.**

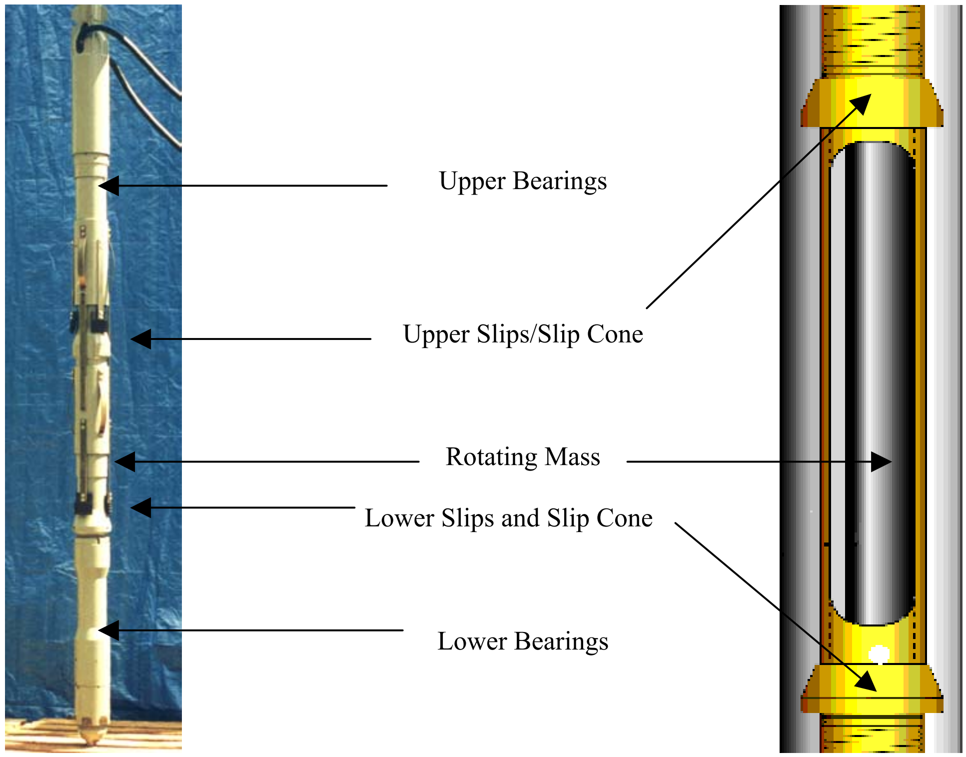


**Figure 3. Photograph of 7-inch Downhole Vibration Tool (DHVT) and drawing of rotating mass inside housing.**

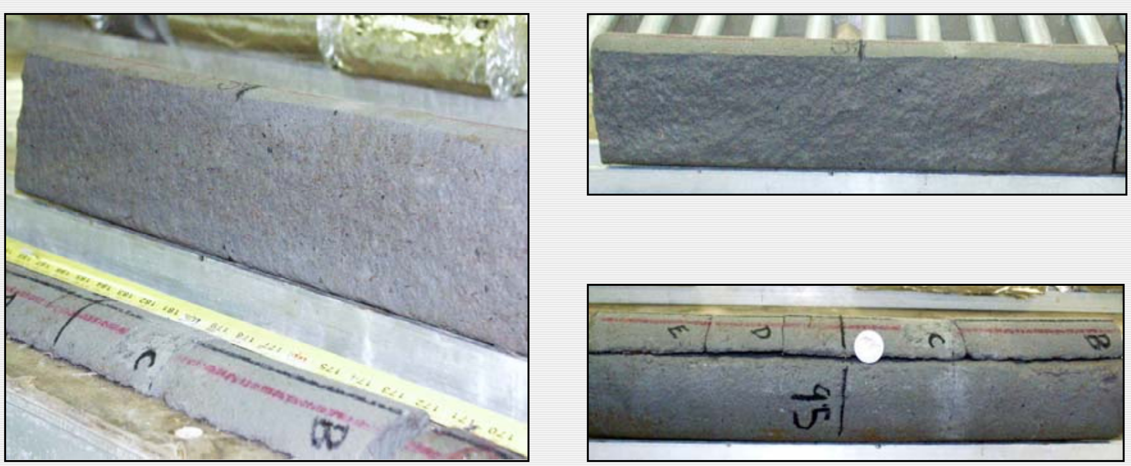

**Figure 4. Photographs of North Burbank Unit Well 111-W-27 Naturally Fractured Core.**

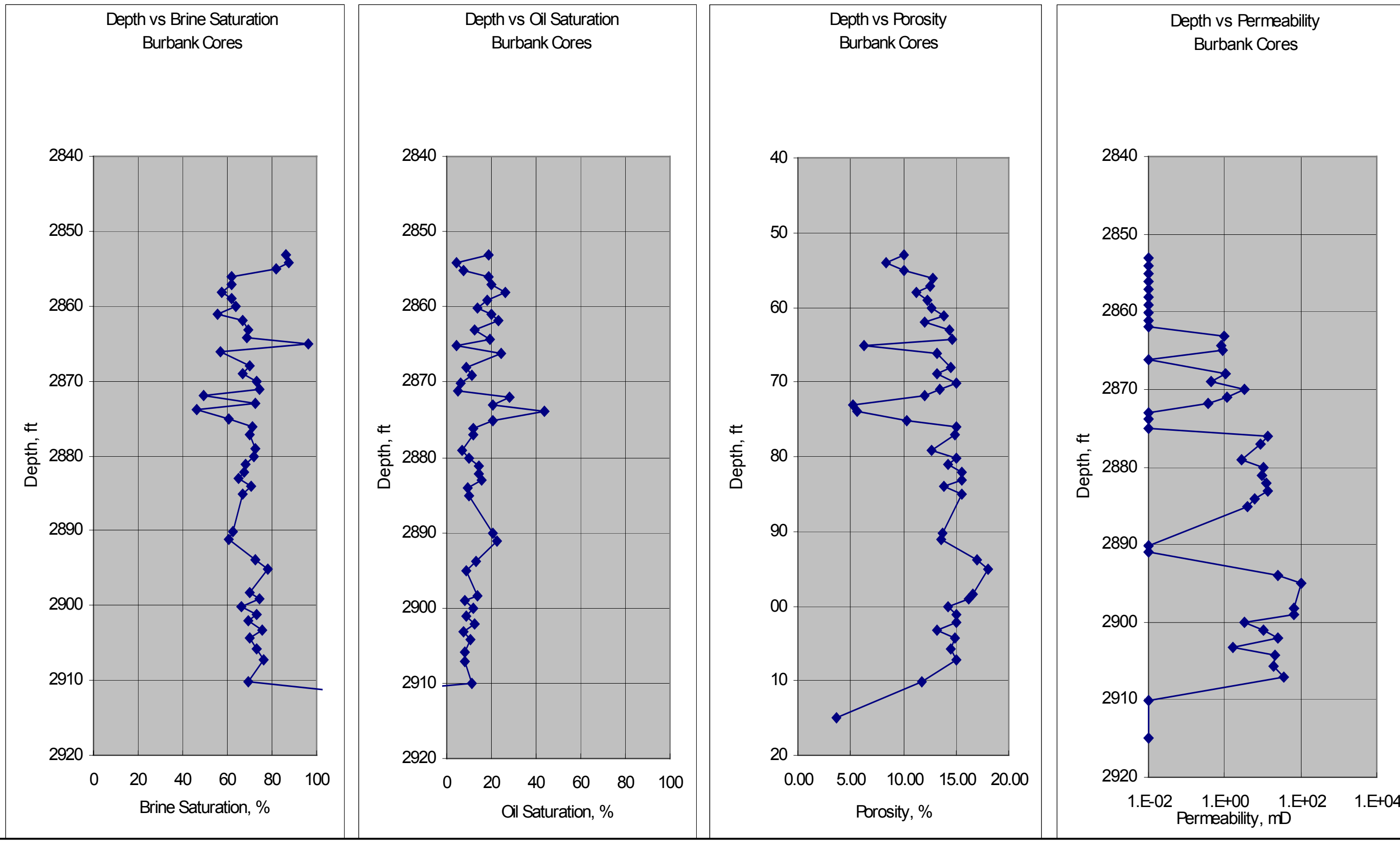


**Figure 5. Standard Core Test Results from NBU Well 111-W-27.**

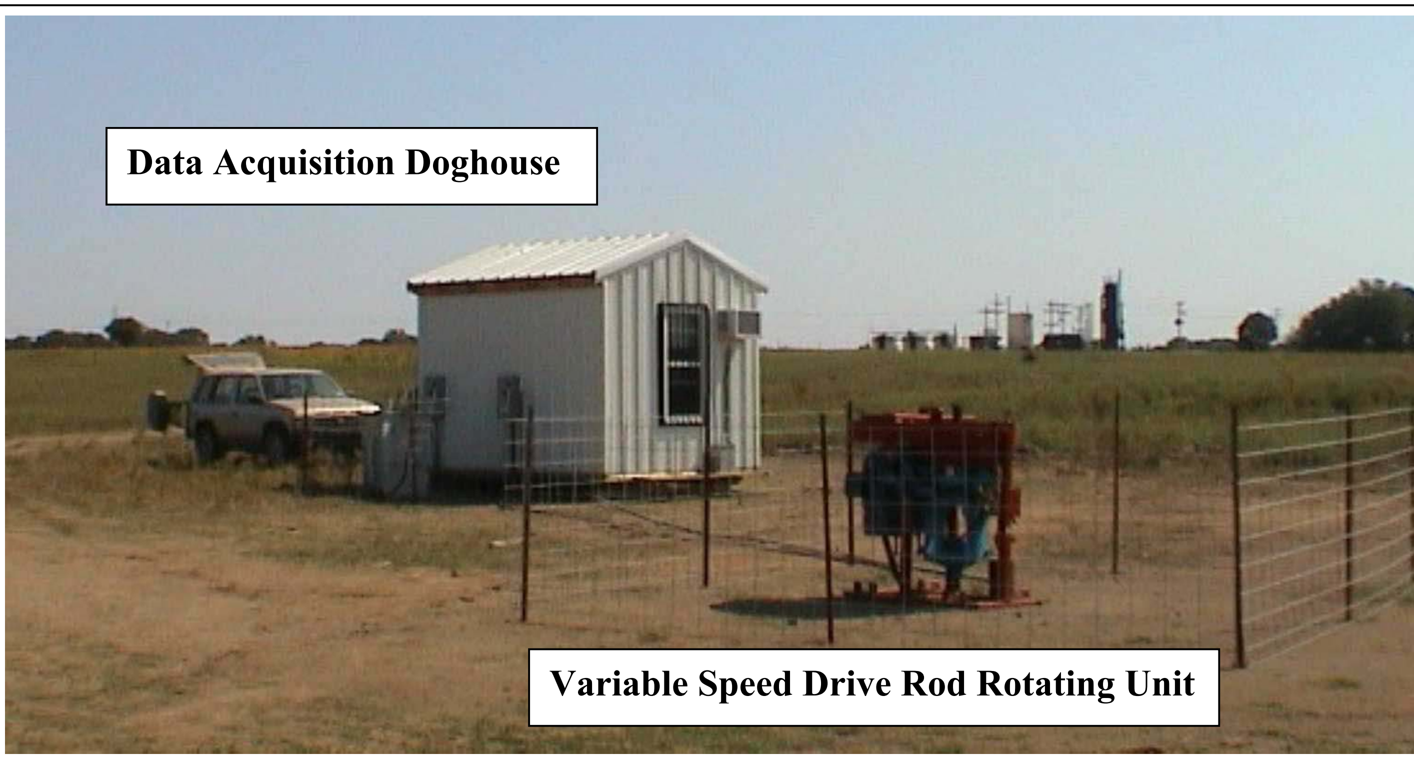


**Figure 6. Photograph of surface equipment used to run DHVT and acquire operating information.**

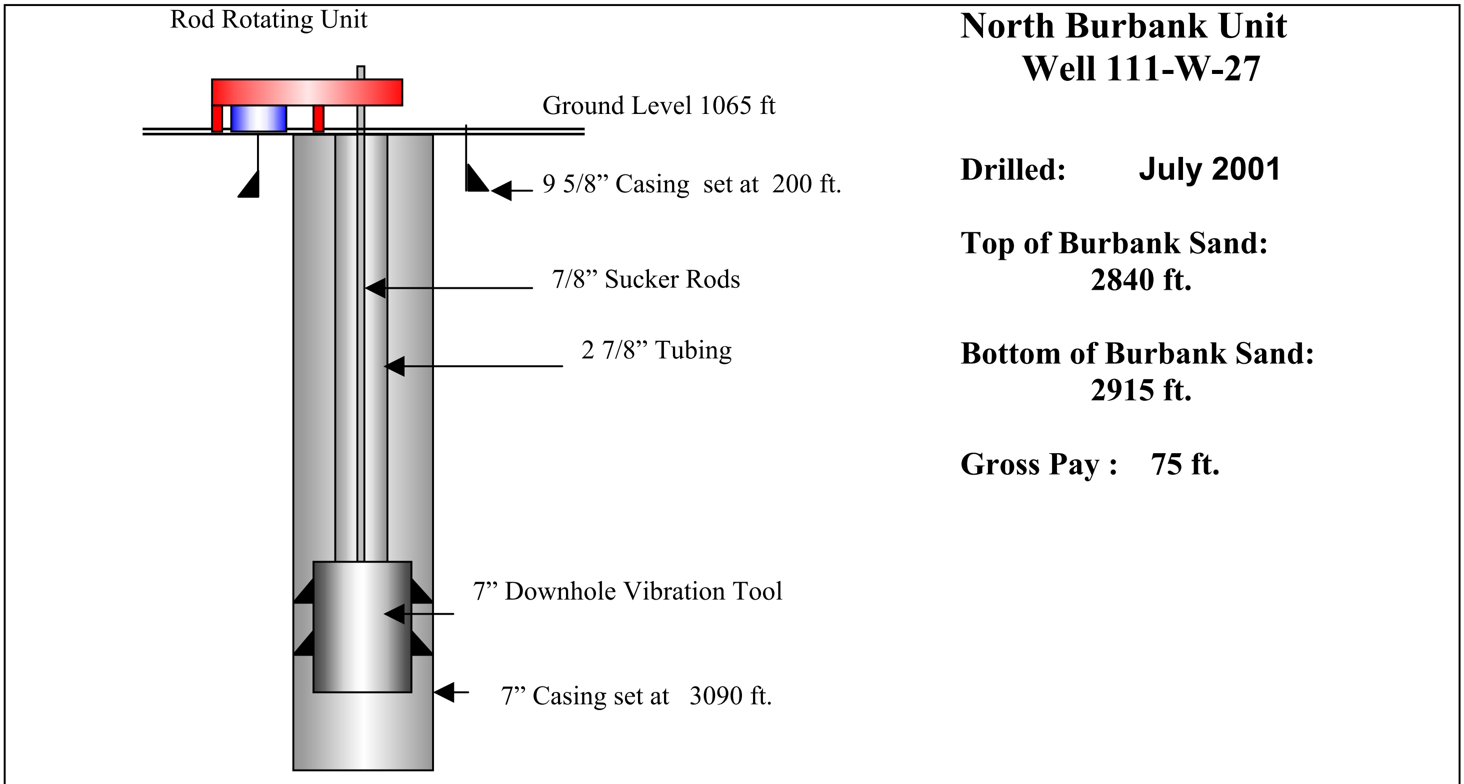


**Figure 7. Schematic of North Burbank Unit 111-W-27 with Downhole Vibration Tool Installed.**

| Parameter | Original Average Field Values | Current Pilot Test Area Values | |
|---|---|---|---|
| Area | 36.5 | 1 | Square miles |
| Avg. Gross Thickness | 53.3 | 75 | feet |
| Depth | 2850 | 2840 | feet |
| Stock Tank Oil Gravity | 39 | 39 | API Gravity |
| Reservoir Volume Factor | 1.2 | 1 | reservoir bbls/stock tank bbls |
| Original reservoir Pressure | 1,200 | 1050 | psia |
| Original GOR | 380 | 0 | cubic feet/barrel |
| Temperature | 120 | 105 | degrees Fahrenheit |
| Viscosity | 3.3 | 3.3 | centipoise |
| Produced Water Salinity | 85,000 | 45,000 | parts per million |
| Average Porosity | 16.8 | 15 | percentage |
| Water Saturation | 26 | 70 | percentage |
| Permeability | 50-100 | 50-100 | millidarcy |

**Table 1. Reservoir Characteristics of North Burbank Unit and the Vibration Stimulation Well 111-W-27.**