Project Summary Page

INCREASING HEAVY OIL RESERVES IN THE WILMINGTON OIL FIELD THROUGH ADVANCED RESERVOIR CHARACTERIZATION AND THERMAL PRODUCTION TECHNOLOGIES

Cooperative Agreement No.:	DE-FC22-95BC14939	
Contractor Names:	City of Long Beach Department of Oil Properties (City) and Tidelands Oil Production Company (Tidelands), Long Beach, CA.	
Award Date:	March 30, 1995	
Anticipated Completion Date:	September 30, 2003 September 30, 2006	Budget Period 1 Budget Period 2

DOE Award: $6,685,495 (Cum Actual through June 2003)
$273,511 (Sept 2003 YTD Actual)
$0 (Remaining funds in BP 1)
$1,206,355 (Remaining funds in BP 2)

Principal Investigator: Scott Hara - Tidelands

Program Manager: Gary Walker - National Petroleum Technology Laboratory

Type of Report: **Quarterly Technical Progress Report**

Date of Report: March 5, 2004

Reporting Period: **July 1, 2003 to September 30, 2003**

Disclaimer

Abstract

The overall objective of this project is to increase heavy oil reserves in slope and basin clastic (SBC) reservoirs through the application of advanced reservoir characterization and thermal production technologies. The project involves improving thermal recovery techniques in the Tar Zone of Fault Blocks II-A and V (Tar II-A and Tar V) of the Wilmington Field in Los Angeles County, near Long Beach, California. A primary objective is to transfer technology which can be applied in other heavy oil formations of the Wilmington Field and other SBC reservoirs, including those under waterflood.

The thermal recovery operations in the Tar II-A and Tar V have been relatively inefficient because of several producibility problems which are common in SBC reservoirs. Inadequate characterization of the heterogeneous turbidite sands, high permeability thief zones, low gravity oil, and nonuniform distribution of remaining oil have all contributed to poor sweep efficiency, high steam-oil ratios, and early steam breakthrough. Operational problems related to steam breakthrough, high reservoir pressure, and unconsolidated formation sands have caused premature well and downhole equipment failures. In aggregate, these reservoir and operational constraints have resulted in increased operating costs and decreased recoverable reserves. The advanced technologies to be applied include:

(1) Develop three-dimensional (3-D) deterministic and stochastic geologic models.
(2) Develop 3-D deterministic and stochastic thermal reservoir simulation models to aid in reservoir management and subsequent development work.
(3) Develop computerized 3-D visualizations of the geologic and reservoir simulation models to aid in analysis.
(4) Perform detailed study on the geochemical interactions between the steam and the formation rock and fluids.
(5) Pilot steam injection and production via four new horizontal wells (2 producers and 2 injectors).
(6) Hot water alternating steam (WAS) drive pilot in the existing steam drive area to improve thermal efficiency.
(7) Installing an 2400 foot insulated, subsurface harbor channel crossing to supply steam to an island location.
(8) Test a novel alkaline steam completion technique to control well sanding problems and fluid entry profiles.
(9) Advanced reservoir management through computer-aided access to production and geologic data to integrate reservoir characterization, engineering, monitoring, and evaluation.

The Project Team Partners include the following organizations:

1. The City of Long Beach - the operator of the field as a trustee of the State of California-granted tidelands;
2. Tidelands Oil Production Company - the contract operator of the field for the City of Long Beach, and the party in charge of implementing the project;
3. The University of Southern California, Petroleum Engineering Program - consultants to the project, playing a key role in reservoir characterization and simulation;
4. GeoSystems, formerly David K. Davies and Associates - consultants to the project regarding petrography, rock- based log modeling, and geochemistry of rock and fluid

interactions; and

5. Stanford University, Petroleum Engineering Department – consultants to the project, performing laboratory research on sand consolidation well completion process effective January 2003.

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Executive Summary

The project involves using advanced reservoir characterization and thermal production technologies to improve thermal recovery techniques and lower operating and capital costs in a slope and basin clastic (SBC) reservoir in the Wilmington field, Los Angeles Co., Calif.

During the Third Quarter 2003, the project team concentrated its efforts on developing well work and drilling plans for Budget Period 2. The Tar II-A post-steamflood project experienced higher water cuts and a rash of producing well problems that reduced oil production, both probably a direct result of the reservoir cooling and oil recovery acceleration strategy. The Tar V post-steamflood pilot project experienced an increase in oil production from new well A-605 that was neutralized by problems in other pilot wells. Stanford has made good progress in their laboratory work injecting hot alkaline fluid into formation cores in an effort to duplicate the sand consolidation well completion process. Their initial findings of what causes sand consolidation are much different that what was previously thought. The project team has completed updating the Tar II-A three-dimensional (3-D) thermal reservoir simulation model and the results show that the model continued to do a good job of predicting reservoir temperature and pressure compared to actual results from January 1999 to July 2003.

The Tar II-A post-steamflood operation started in February 1999 with flank cold water injection and steam chest fillup occurring from September - October 1999. The targeted reservoir pressures in the “T” and “D” sands are maintained at 90±5% hydrostatic levels by controlling water injection and gross fluid production and through the monthly pressure monitoring program enacted at the start of the post-steamflood phase.

The Tar II-A accelerated oil recovery and reservoir cooling plan began in March 2002 and the overall result has been to accelerate the watering out of the producers. Water production rates have increased by 8,799 BGFPD compared to the incremental water injection of 7,852 BWIPD. The 88 BOPD of additional oil production has an incremental water cut of 99.0%. The higher gross fluid production and water injection rates have caused more frequent well failures from stressing the well facilities and operating costs have increased significantly. Well work during the quarter is described in the Reservoir Management section.

The project team completed comparing the latest 2002 STARS thermal reservoir simulation software for PCs with the older 1998 STARS version for Unix-based workstations using the 1999 Tar II-A steamflood base case run. Both software versions provided very similar formation temperature results, the key parameter being analyzed, which gave the project team confidence to proceed using the newer 2002 STARS PC software with no modifications to the basic model. The model was updated with production and injection data through May 2003 to create a new 2003 post-steamflood base case. This case shows that the post-steamflood operation has been effective in cooling reservoir temperatures. The May 2003 base case will be used to determine how to proceed with the post-steamflood. See the Reservoir Simulation section for more details.

The Tar V pilot steamflood project terminated hot water injection and converted to post-steamflood cold water injection on April 19, 2002. The post-steamflood production performance in the Tar V pilot project has been below projections because of wellbore mechanical limitations. Major well work during the fourth quarter 2002 included repairing one of the sand-consolidated horizontal wells that sanded up, well J-205, with a gravel-packed inner liner job and converting well L-337 to a Tar V water injector that was renamed FL-337. During the first quarter 2003, well A-194 was unsuccessfully recompleted as a Tar V interior vertical steamflood pattern producer. During the second quarter 2003, well A-605 was successfully drilled and completed as a Tar V horizontal producer running north-south along the Thums leaseline and perpendicular to the existing five Tar V horizontal steamflood wells. See the Reservoir Management section for more details.

The project team is conducting laboratory research on cores for the sand consolidation well completion process experiments. Injection of high temperature, high pressure alkaline water into the formation core samples began last quarter and initial results do not generate the expected calcium silicate cements. The initial assumptions that the experimental design was based upon are being reexamined. Experimental design and parameters will be adjusted according to our findings. See the Operations Management section for more details.

Introduction

The objective of this project is to increase the recoverable heavy oil reserves within sections of the Wilmington Oil Field, near Long Beach, California. This is realized through the testing and application of advanced reservoir characterization and thermal production technologies. It is hoped that the successful application of these technologies will result in their implementation throughout the Wilmington Field and, through technology transfer, will be extended to increase the recoverable oil reserves in other slope and basin clastic (SBC) reservoirs.

The project involves the implementation of thermal recovery in the Tar zone of Fault Blocks II-A (Tar II-A) and V (Tar V). The more mature Tar II-A steamflood has been relatively inefficient due to several producibility problems commonly associated with SBC reservoirs. Inadequate characterization of the heterogeneous turbidite sands, high permeability thief zones, low gravity oil, and non-uniform distribution of the remaining oil have all contributed to poor sweep efficiency, high steam-oil ratios and early steam breakthrough. Operational problems related to steam breakthrough, high reservoir pressure, and unconsolidated formation sands have caused premature well and downhole equipment failures. In aggregate, these reservoir and operational constraints have resulted in increased operating costs and decreased recoverable reserves.

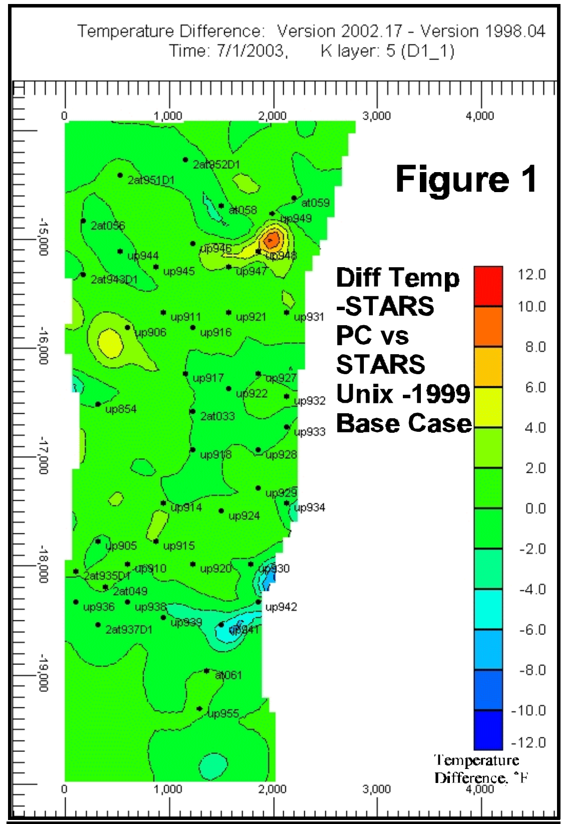
This report covers the period from July 1, 2003 to September 30, 2003. Most of the work was concentrated on the post-steamflood operations in Tar II-A and Tar V projects. The project team is updating the Tar II-A 3-D deterministic reservoir simulation model to analyze post-steamflood operations to date and to evaluate alternatives for reducing peak reservoir temperatures to safe levels below 350°F throughout the project area. The Stanford University Petroleum Engineering Department started laboratory research to analyze the sand consolidation well completion technique during the first quarter 2003. This quarter saw the start of laboratory work to process hot alkaline fluids through the prepared core samples. Initial results from the lab work will be discussed.

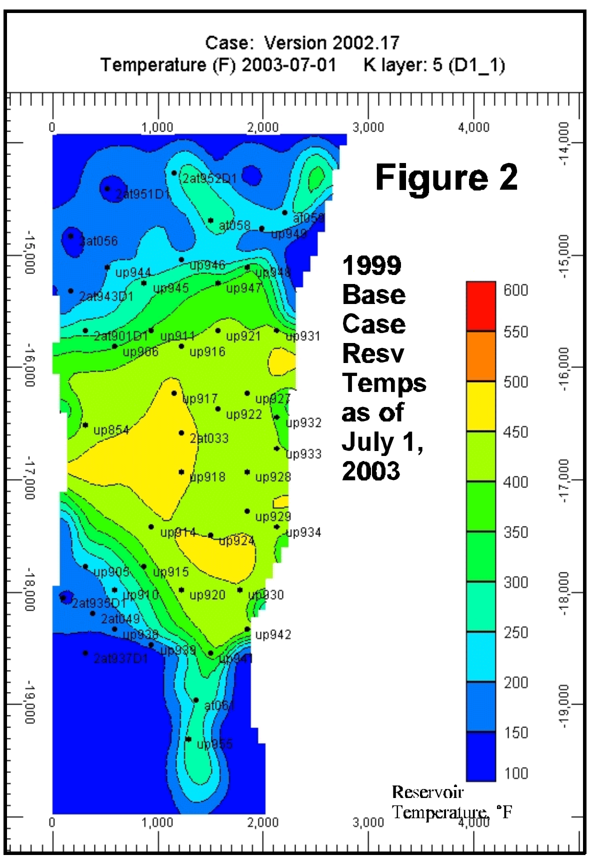
Reservoir Simulation

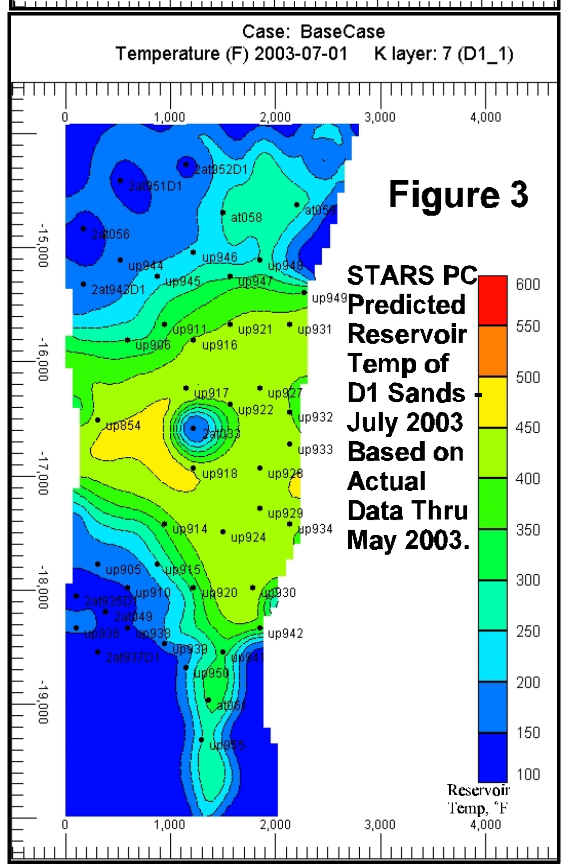
The project team is updating the Tar II-A 3-D deterministic thermal reservoir simulation model to analyze post-steamflood operations to date and to evaluate alternatives for reducing peak reservoir temperatures to safe levels below 350°F throughout the project area. The objective of updating the model is to minimize the risk of further thermal-related shale compaction and associated surface subsidence. Multiple sensitivity cases will be run to evaluate where and how much water to inject to reduce reservoir temperatures to safe levels as quickly as possible while maximizing oil production and ultimate oil recovery at the lowest cost.

The project team completed comparing the Computer Modelling Group's (CMG) STARS 98 Unix and current STARS 2002 PC thermal reservoir simulator versions and determined that they give essentially the same answers and do not introduce any significant reservoir performance changes. The comparison cases used the latest Tar II-A model run developed in July 1999, which was the basis for the Tar II-A post-steamflood flank water injection program. The main parameter compared was predicted reservoir temperature, which generally matched to within 4/F with a maximum difference in isolated spots of 10/F. Figure 1 shows the temperature difference between the STARS PC and Unix versions at the top of the D1 sands as of July 1, 2003. This temperature difference was considered minor relative to the reservoir temperatures observed in the models and field of over 500/F. Figure 2 shows the predicted absolute reservoir temperatures for the D1 sand as of July 1, 2003 from the STARS PC version of the 1999 base case.

The last modeling work performed on the Tar II-A was in July 1999. Upon confirmation that the STARS PC software version provided acceptable results, the project team updated the 1999 model with production and injection volumes through May 2003. The original 1999 reservoir model was revised to include three vertical grid layers to represent the compacting shales between the "T" and "D" sands rather than the one grid layer used previously. The new May 2003 model was history matched with the new data from July 1999 through May 2003. Figure 3 shows the predicted absolute reservoir

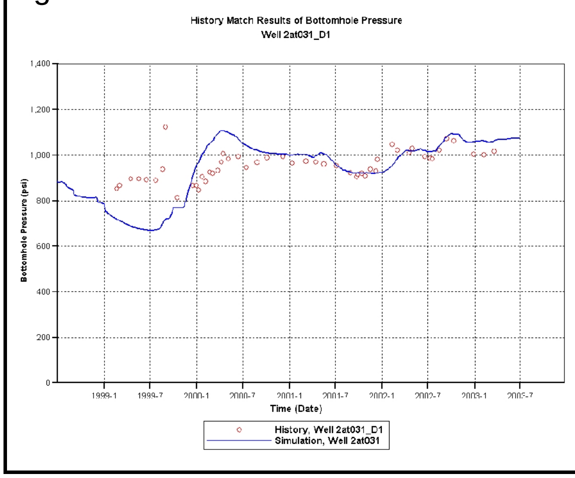






temperatures for the D1 sands as of July 1, 2003 from the STARS PC version of the new May 2003 base case. In comparing figures 2 and 3, note that the new and updated 2003 base case shows lower reservoir temperatures for the D1 sands as of July 1, 2003 than the 1999 base case. This is because of the accelerated production and water injection program that began in March 2002. The cool (blue) area in the middle of the Phase 1 steamflood is caused by water injection into D sand pattern well 2AT-33, which was not considered in the 1999 base case.

Figure 4



The updated May 2003 base case model had a reasonable correlation with the actual reservoir pressure readings as shown in Figure 4 for idle "D" sand injection well 2AT-31. Compared with the pressure data taken from most of the idle "T" and "D" sand injection wells, the model tended to predict lower pressures during 1999, a slightly higher and delayed peak pressure, and slightly lower pressures in 2001. Actual reservoir temperature readings appeared about 50-100/F lower in the "T" sands and were very reasonable in the "D" sands compared to the model. The temperature data is measured from the gross fluid production from individual wells, periodic Amerada bomb temperature recordings in idle injectors and selected idle producers, and contact temperature profile surveys. The pressure data are from the monthly fluid level surveys and periodic Amerada bomb pressure recordings on idle wells.

The reservoir simulation model was used as a reservoir management tool in late 1998 to convert the high pressure - high temperature Tar II-A steamflood to a cold waterflood in a stress-sensitive formation to minimize surface subsidence. The model provided several operating strategies and justified the flank cold water injection plan ultimately selected. Whereas the initial management plan was to idle all producing wells until steam chest fillup occurred, the simulation model successfully provided for limited oil production. The model provided the water injection and gross fluid production rates to use and correctly predicted steam chest fillup by October 1999. Oil production in August 1998 averaged 2253 BOPD. Following termination of steamflooding in January 1999, oil production in February was reduced to 781 BOPD, bad but much better than no oil production. The reservoir simulation work and post-steamflood plan and initial operation are reported in SPE Paper #62571 entitled "Post Steamflood Reservoir Management Using a Full-Scale Three-Dimensional Deterministic Thermal Reservoir Simulation Model, Wilmington Field, California"[1].

Reservoir Management

<u>Tar II-A Steamflood Project</u>

The Tar II-A steamflood project was terminated in January 1999 when the project lost its inexpensive steam source. An operational post-steamflood plan was implemented to mitigate the effects of the lost steam injection and possible thermal-related formation compaction by injecting cold water into the flanks of the steamflood. The purpose of flank injection has been to increase and subsequently maintain reservoir pressures at a level that would fill-up the steam chests in the "T" and "D" sands before they could collapse and cause formation compaction and to prevent the steam chests from reoccurring. A new 3-D deterministic thermal reservoir simulation model provided operations with water injection rates and allowable production rates by well to minimize future surface subsidence and it accurately projected reservoir steam chest fill-up by October 1999. A geomechanics study and a separate reservoir simulation study were performed to determine the possible causes of formation compaction, the temperatures at which specific compaction indicators may be affected and the projected temperature profiles in the over and underburden shales over a ten year period following steam injection.

Maintaining reservoir pressure is important to prevent steam chest reoccurrence. Since March 2000, reservoir pressure in the “D” sands have been maintained at 92±2% hydrostatic through September 2003. The “T” sands have been maintained within the allowable 90%±5% hydrostatic after pressures were allowed to decline to 95% hydrostatic in March 2001. The reservoirs have begun acting more like a waterflood that can be operated at lower net injection rates and lower injection / production (I/P) ratios of about 1.4, still high compared to the 1.05 in most of the other Wilmington waterflood projects. The higher than normal I/P ratios were derived empirically and are needed because of two reasons: the hot produced fluids are less dense than the injection water and therefore take up more reservoir volume per unit weight; and flank water injection losses to the aquifer. Table 1 lists the “T” and “D” sand average reservoir pressures before the post-steamflood phase began in February 1999 and thereafter in quarterly periods.

TABLE 1
TAR II-A STEAMFLOOD PROJECT - RESERVOIR PRESSURE

"T" Sands - Phase 1-1C Wells	Reservoir Pressure psi	Reservoir Pressure hydrostatic %	"D" Sands - Phase 1-1C Wells	Reservoir Pressure psi	Reservoir Pressure hydrostatic %
Jun-97	818	79	May-96	594	54
			Aug-98	748	68
Mar-99	888	85	Mar-99	881	79
Jun-99	925	89	Jun-99	1026	92
Sep-99	976	94	Sep-99	1056	95
Dec-99	1002	96	Dec-99	954	86
Mar-00	1008	97	Mar-00	1009	91
Jun-00	1011	97	Jun-00	991	90
Sep-00	1000	96	Sep-00	995	90
Dec-00	1003	96	Dec-00	999	90
Mar-01	992	95	Mar-01	1005	91
Jun-01	955	92	Jun-01	1009	91
Sep-01	926	89	Sep-01	1008	91
Dec-01	920	89	Dec-01	1005	90
Mar-02	910	88	Mar-02	1009	91
Jun-02	909	88	Jun-02	1001	91
Sep-02	940	91	Sep-02	1040	94
Dec-02	930	90	Dec-02	1007	91
Mar-03	917	88	Mar-03	1027	93
Jun-03	893	86	Jun-03	1026	93
Sep-03	917	89	Sep-03	1022	93

The Tar II-A accelerated oil recovery and reservoir cooling plan began in March 2002 and production initially increased from 1009 BOPD and 20,393 BGFPD (4.95% oil cut) in the first quarter 2002 to an oil peak rate of 1199 BOPD in July 2002 and a gross

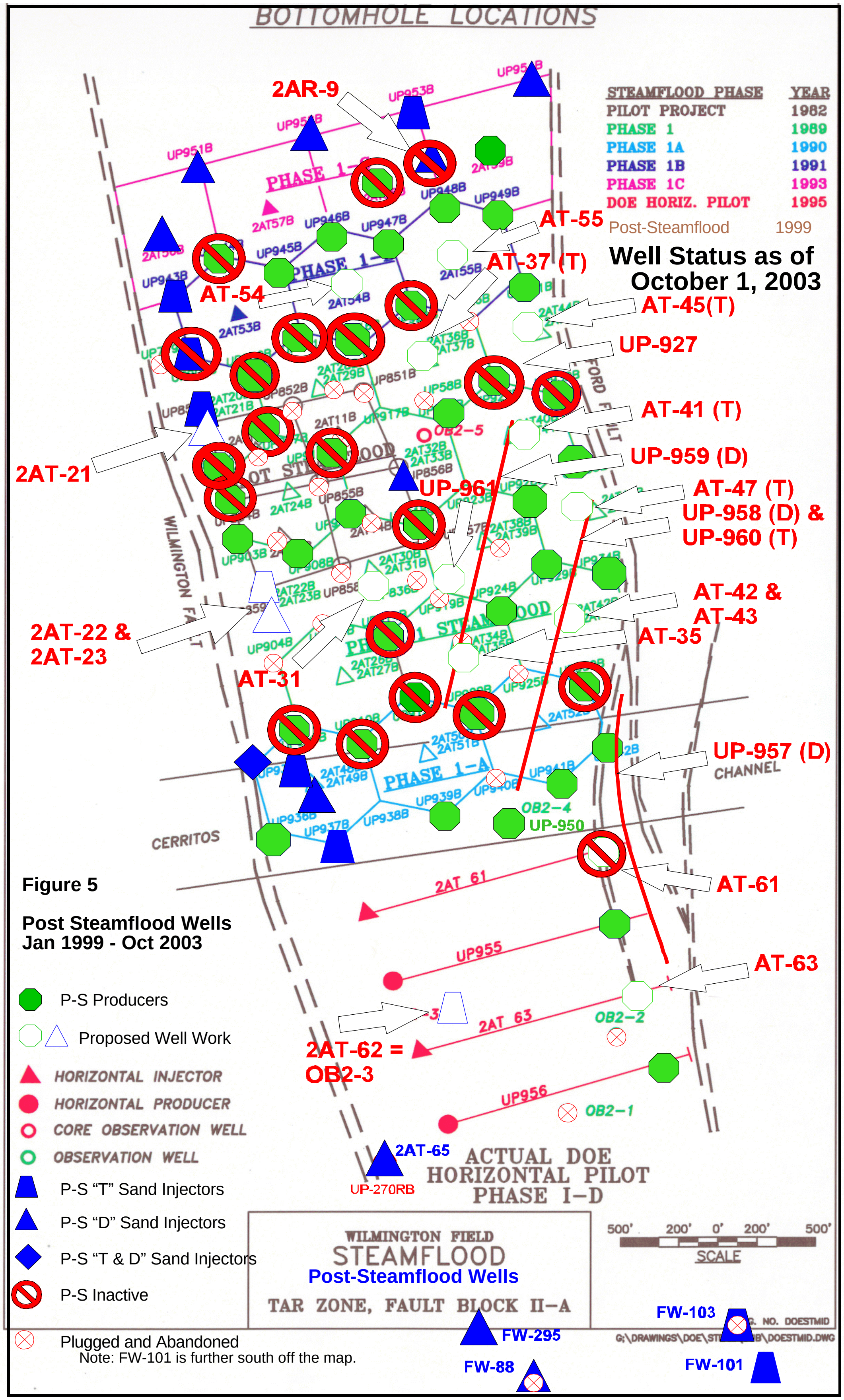
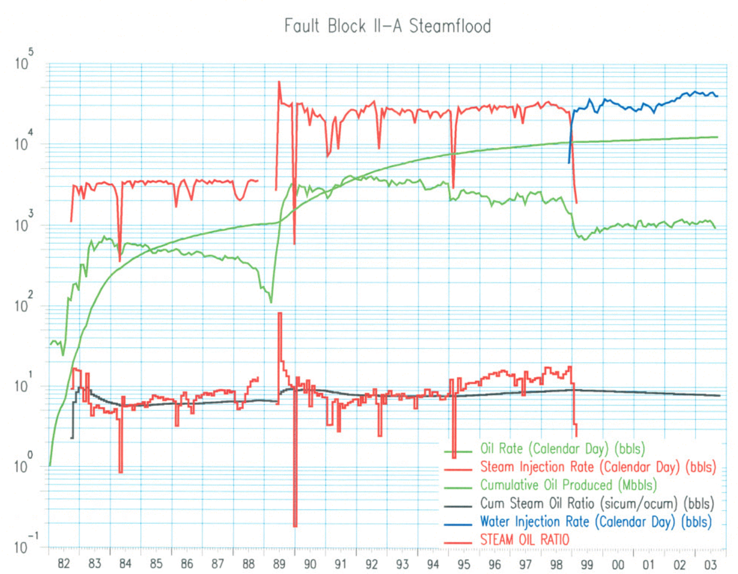


Figure 5

Post Steamflood Wells Jan 1999 - Oct 2003

fluid peak rate of 31,555 BGFPD in November 2002. However, the overall result of the plan has been to accelerate the watering out of the producers. Of the seventeen producers active in March 2002 and the twenty-four producers activated afterwards through September 2003, eighteen have been idled as uneconomic. Water production rates have increased by more than the amount of incremental water injection with little change in oil production. From March 2002 to the third quarter 2003, Tar II-A gross fluid production increased 8,799 BGFPD to an average of 29,192 BGFPD whereas the associated injection rate increased 7,852 BWIPD to an average of 41,803 BWIPD. Oil production during the same period increased only 88 BOPD to an average of 1097 BOPD for at an incremental water cut of 99.0%. The production acceleration plan called for increasing total oil production by 427 BOPD, but most of the production from activated wells was offset by the higher water cuts, especially in the downdip wells. The higher gross fluid production and water injection rates have caused more frequent well failures from stressing the well facilities and operating costs have increased significantly. These problems have resulted in oil production at the end of September 2003 declining to 923 BOPD, but this rate should rise back to about 1,100 BOPD when the economically profitable wells are repaired. Reservoir pressures declined to 86% hydrostatic in the “T” sands early in the third quarter 2003 due to temporarily reduced water injection rates and rose back to 89% by the end of September. Reservoir pressures were reduced to 91% hydrostatic in the “D” sands. Figure 5 shows the 23 producers and 15 injectors that were active in the Tar II-A post-steamflood area as of October 1, 2003 compared to the original steamflood pattern wells. Figure 6 is a production graph of the Tar II-A steamflood project from inception in 1982 through September 2003.

Figure 6



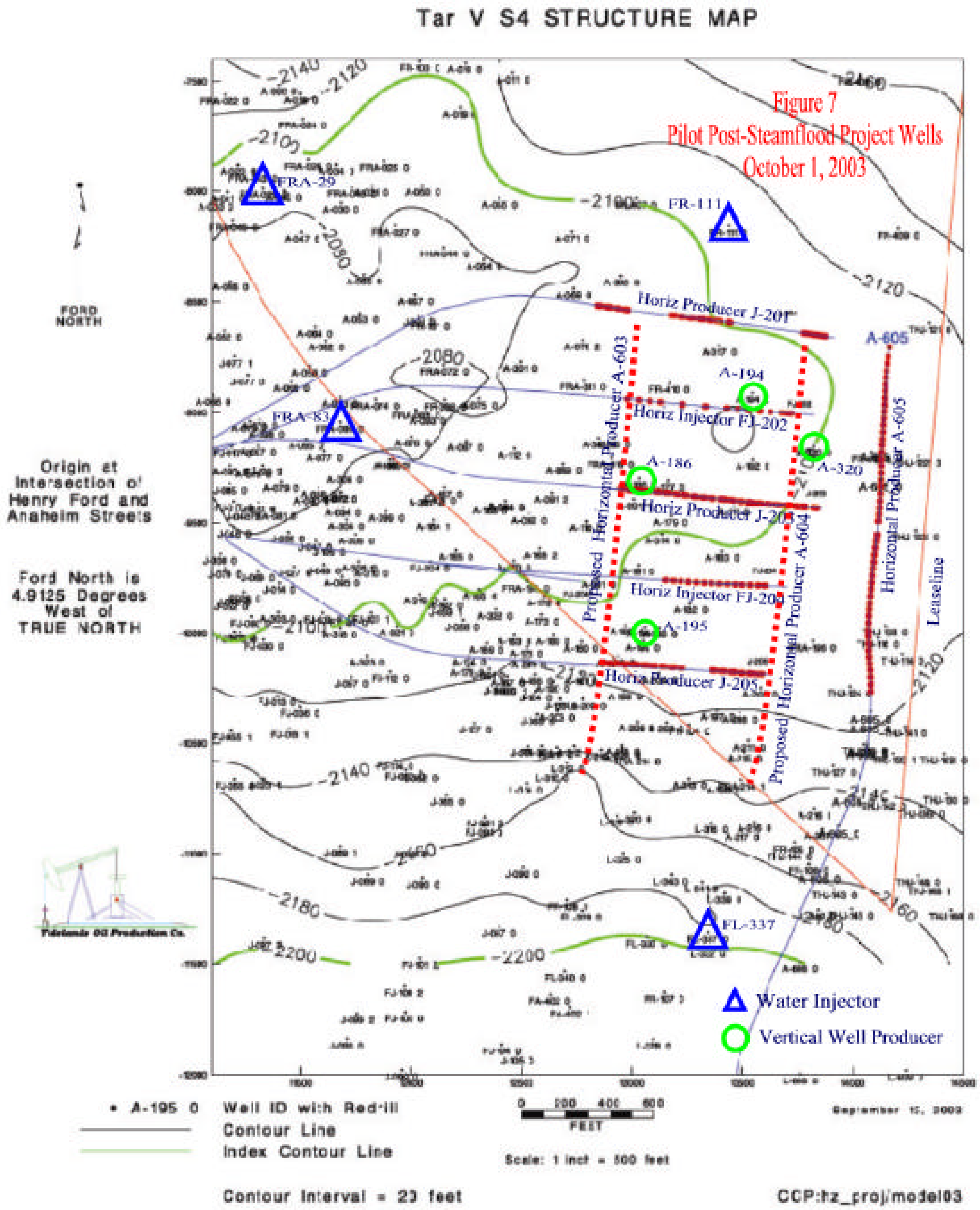
The accelerated cooling plan included testing cold-water injection into one interior “D” sand pattern injector (2AT-33) starting on April 27, 2002 to observe whether the formation would react like a normal waterflood or experience adverse formation compaction effects. The ten feet of “DU” shale above the “D” sands in this pattern have experienced formation compaction of about 6"-9" based on comparing the gross shale thickness in the original induction log (circa 1981 pre-steamflood) of interior pattern well 1F-10 with a follow-up Thermal Neutron Decay Time (TDT) log in December 2001. A new TDT log for well 1F-10 is planned for 2004.

Temperature survey data within the 2AT-33 pattern show that the high temperatures at the top of the “D1” sands are cooling very slowly, even with cold water injection into 2AT-33. At the start of the post steamflood injection in January 1999, pattern observation well OB2-5 had a peak temperature of 479°F at the top of the “D1” sands. The baseline May 9, 2002 survey showed a peak temperature of 452°F or about an 8°F drop per year. The first temperature survey following injection into well 2AT-33 occurred on November 18, 2002 and shows a peak temperature of 450°F. The latest temperature survey was on August 9, 2003, which shows a peak temperature of 443°F, therefore, the interior injection well is not cooling the reservoir where it is needed. The "T" sand temperatures have hardly changed, with peak temperatures of 415°F at the start of the post-steamflood and most recently in August 2003. The most interesting observation occurs in the "Du" shale interval between the "T" and "D" sands, where peak temperatures from the start of the post-steamflood through August 2003 have risen from 401°F to a peak of 430°F because of overburden and underburden heat transfer through convection and conduction. Lateral conductive heat transfer is expected to happen, but it is slow moving and not been observed in temperature surveys during the post-steamflood period. One possible explanation for the heating is that some of the injected cold water from 2AT-33 was heated over a short distance to above 400°F which then convectively heated the "cooler" sands surrounding well OB2-5. As the shale failure temperature is believed to be about 350 - 400°F, convective heat transfer could cause more shale compaction to occur, especially in areas not within the direct injector-producer pathways that are at temperatures below 350°F. If convective heat transfer is occurring, this would require more evaluation of possible temperature effects in the reservoir due to operational changes, like adding more interior water injectors. The water from well 2AT-33 appears to be gravity segregating to the bottom of the "D1" sands as the latest survey shows that the lowest thirty feet are about 30-40°F cooler than previous surveys.

A comprehensive reservoir surveillance program was developed for the post-steamflood reservoir management plan. A sonic fluid level program measures the static fluid levels in all idle wells monthly to monitor reservoir pressures. The fluid levels have been calibrated for liquid and gas density gradients by comparing them with a number of wireline downhole Amerada bomb pressures taken within a few days. Formation compaction and surface subsidence are monitored through the use of biannual GPS surveys and comparing new TDT neutron logs with pre-steamflood induction logs in key wells. Both Amerada bomb temperature surveys and contact temperature surveys are run as needed in key observation wells.

Tar V Pilot Steamflood Project

The project team expanded the DOE project in March 1999 to include the Tar V pilot steamflood to continue research related to the discontinued Tar II-A horizontal well pilot steamflood project. The Tar V pilot steamflood began in June 1996 and initially included two new horizontal steam injectors (wells FJ-202 and FJ-204), two existing vertical water injectors (wells FR-111 and FRA-83), three new horizontal producers (wells J-201, J-203 and J-205), and three existing vertical well producers (wells A-186, A-195 and A-320). The steamflood project wells are completed in the Wilmington Field Fault Block V Tar Zone "S" sands as shown in the "S4" Sand structure map in Figure 7. Well FRA-29 was converted to a water injector in November 2000. During the fourth quarter 2002, south flank well L-337 was converted to water injection well FL-337 for additional pressure support. In February 2003, well A-194 was recompleted to the upper Tar "S" sands to recover post-steamflood oil reserves as an interior pattern well. Unfortunately, the well experienced extreme formation damage and production has stabilized at 38 BGFPD and 5 BOPD with no fluid at the pump. Last quarter a new horizontal producer, well A-605, was drilled and completed from south to north and perpendicular to the toes of the existing pilot horizontal wells to capture oil reserves along the Thums leaseline. The well initially produced 614 BGFPD and 115 BOPD with 543 ft of fluid over the pump on April 30. By the end of the second quarter, production declined to 418 BGFPD, 86 BOPD and by the


Tar V S4 STRUCTURE MAP
Figure 7
Pilot Post-Steamflood Project Wells
October 1, 2003
FRA-29
FR-111
FRA-83
FL-337
A-194
A-186
A-320
A-195
A-605
Horiz Producer J-201
Horiz Injector FJ-202
Horiz Producer J-203
Horiz Injector FJ-204
Horiz Producer J-205
Proposed Horizontal Producer A-603
Proposed Horizontal Producer A-604
Horizontal Producer A-605
Leaseline
Water Injector
Vertical Well Producer
FORD NORTH
Origin at Intersection of Henry Ford and Anaheim Streets
Ford North is 4.9125 Degrees West of TRUE NORTH
Contour Line
Index Contour Line
FEET
Scale: 1 inch = 500 feet
CCP:hz_proj/model03

end of this quarter, production appeared to stabilize at 411 BGFPD and 62 BOPD. The produced fluids are at normal reservoir temperatures of 120/F and the well is producing similarly to the other recently drilled Tar V non-thermal horizontal wells in the "T" sands. The well was projected to produce 120 BOPD and 1500 BGFPD assuming thermal enhanced recovery response, which could still happen with time.

Pilot steamflood performance was excellent for the first two years as shown in Figure 8 with oil production peaking at 743 BOPD in January 1998 at a cumulative steam-oil ratio (SOR) of 4.5. After reaching peak production, the oil production declined significantly to a low of 148 BOPD in October 1999 for various reasons including lower steam injection rates than planned, well downtime from sand control problems, and gross production restrictions to meet new injection to production ratio (I/P) requirements for surface subsidence control. Restricting gross production rates became a problem because the horizontal producers began responding to steam and water injection that resulted in higher producing fluid levels and water cuts. Subsequent well work and higher steam rates resulted in oil production rising to 326 BOPD in November 2000 with a cumulative SOR of 6.3. In June 2001, steam injection was terminated and converted to 350˚F hot water injection to prevent overheating the overburden shales and causing formation compaction. Oil production declined to a new low of 147 BOPD in March 2002 due to well problems. Hot water injection was terminated in April 2002 and replaced with 100% cold water injection. The cold water injection is watering out the horizontal producers because they are completed at the bottom of the "S4" sands. Even still, oil production has been maintained at about 200 BOPD from repairing wells and continually trying to pump down the horizontal wells. Second quarter 2003 saw a jump in production to 285 BOPD from activating new horizontal well A-605. Unfortunately, production declines and other pilot well failures have reduced oil production to about 210 BOPD.

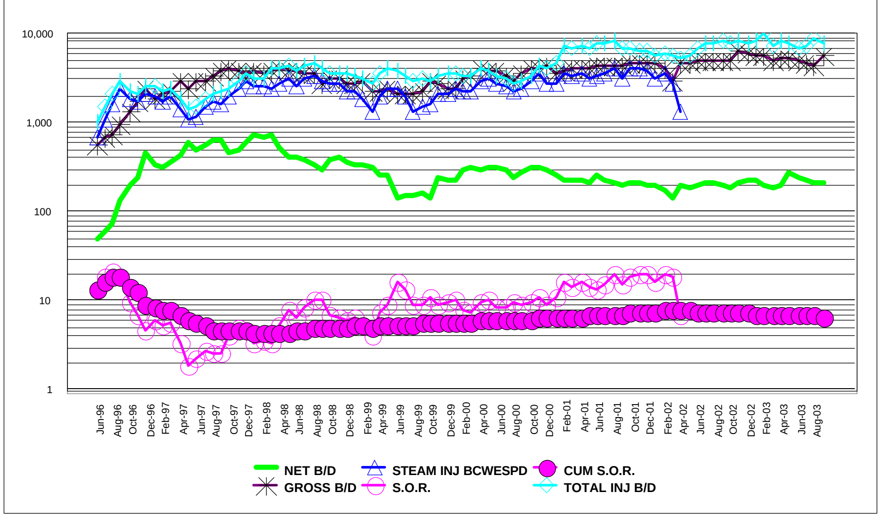


FIGURE 8
TIDELANDS OIL PRODUCTION CO.
TAR ZONE FB-V STEAMFLOOD

Although steam and hot water injection has been terminated, the pilot project still has potential for increasing thermal oil recovery. Inner liners may be installed in two horizontal producers, J-201 and J-203, so they can be pumped off without sanding up. Horizontal producer well A-605 has increased pilot oil production and could further increase it if it connects to the thermally heated oil bank nearby. Wells A-194 and J-205 have formation damage and may be acidized to stimulate production. Additional drilling of horizontal wells may be profitable in the top of "S4" sands in the heated zone above the existing pilot horizontal wells.

Operational Management

Sand Consolidation Well Completion Method

Tidelands has been applying two well completion technologies for horizontal wells including the sand consolidation process and a new gravel-packed, slotted-liner completion procedure that has been successful to date in Tar V wells L-232, L-233 (Tidelands' DOE Class 3 near-term waterflood project) and A-605. Tidelands' plan is to develop and improve both completion methods because each has advantages depending upon the type of formation sands to complete, reservoir recovery method, existence of interbedded wet sands, and availability of steam or heated fluid sources. Having viable and continuously improved completion options will be a key factor in successfully producing more complex customized wells that are drilled and completed to tap specifically targeted oil sands.

A series of experiments were designed and performed by SUPRI-A (Stanford University Petroleum Research Institute) to determine how hot alkaline steam condensate artificially cements reservoir sands while preserving producibility as experienced in steam completed wells in Wilmington Field. The goal is to improve the sand consolidation well completion process by strengthening the cement bonds between sand grains to withstand more differential pressure without effectively reducing formation permeability around the wellbore. This research work will duplicate most of the aspects of the sand consolidation well completion process in the laboratory and confirm the mineralogy of the cementing materials being created at different fluid temperatures and alkalinity and their sources of origin. The sand consolidation well completion has many advantages over the conventional gravel-packed, slotted–liner completions, including lower capital costs, higher fluid productivity, more reservoir and mechanical control, relative ease and lower cost of repair, and more operational flexibility.

All research to date on the sand consolidation well completion process has been empirical, as in trial and error in the field. Tests to date have been extremely encouraging, but not foolproof. The completion appears to have very high fluid productivity and can endure high flow rates at high water cuts. The biggest weakness observed is that it cannot withstand high differential pressures; therefore the wells cannot be pumped down to maximize fluid production. Even still, typical sand consolidated wells can produce over 1500 barrels of fluid per day at high water cuts with fluid levels over 1000 ft above the pump. The geochemical theory behind the technology is based on wellbore sand fill samples and not on actual cores of sands surrounding the perforation tunnels or lab tests. Lab research will attempt to recreate the process in Wilmington Tar sand cores.

The experimental design is based upon field practices, interpretation of artificially cemented sands recovered from the tubing tail pipe of well UP-955 as described by Davies and others[2] (1997), the use of conventional cores from the Tar zone "T" and "D" sands in the Wilmington Field and temperature profile modeling. Davies and others (1997) identified three steam treatment-induced cements in the 5 mm thick tubing tail sample, namely silica, pseudohexagonal calcium silicate, and a bladed complex magnesium- and iron-bearing calcium silicate. In addition to the artificial cements, they observed oversized pores caused by dissolution of framework grains or dissolution "wormholes". These "wormholes" are thought to preserve productivity by serving as high permeability pathways through the cemented zones.

The first three experiments were performed using a stewpot filled with cleaned T sands from the Wilmington Tar II-A zone and heated to 550°F (Fig. 9). The stewpot was connected to a core holder filled with quartz sand at different temperatures for each run (Run 1 at 400°F, Run 2 at 300°F, and Run 3 at 150°F). Hot alkaline fluid based upon the composition of steam feed water used in Wilmington Field was pumped into the bottom of the stewpot and through the sand pack. Pressure was maintained for single-phase flow using an Isco injection pump and a back pressure regulator. A pressure transducer measured pressure differentials in four locations along the length of the core. The pressure measurements were then used to calculate permeability, both before and after each experiment. Porosity of each sand pack was determined using X-ray computed tomography (CT) before and after each experiment. The holders for the sand packs were made of aluminum. The interiors of the core holders were coated with gold to help prevent the interaction of the hot alkaline fluids with the aluminum. Effluent samples were collected throughout each experiment. The pH was measured and the samples saved for subsequent silica and elemental analyses. Samples of the cemented sand pack material were examined using scanning electron microscopy (SEM) and energy dispersive X-ray spectroscopy system (EDS) to determine the composition and structure of resulting cements. In addition, the stewpot material was compared with unused T sands to observe changes attributed to the high temperature alkaline fluids.

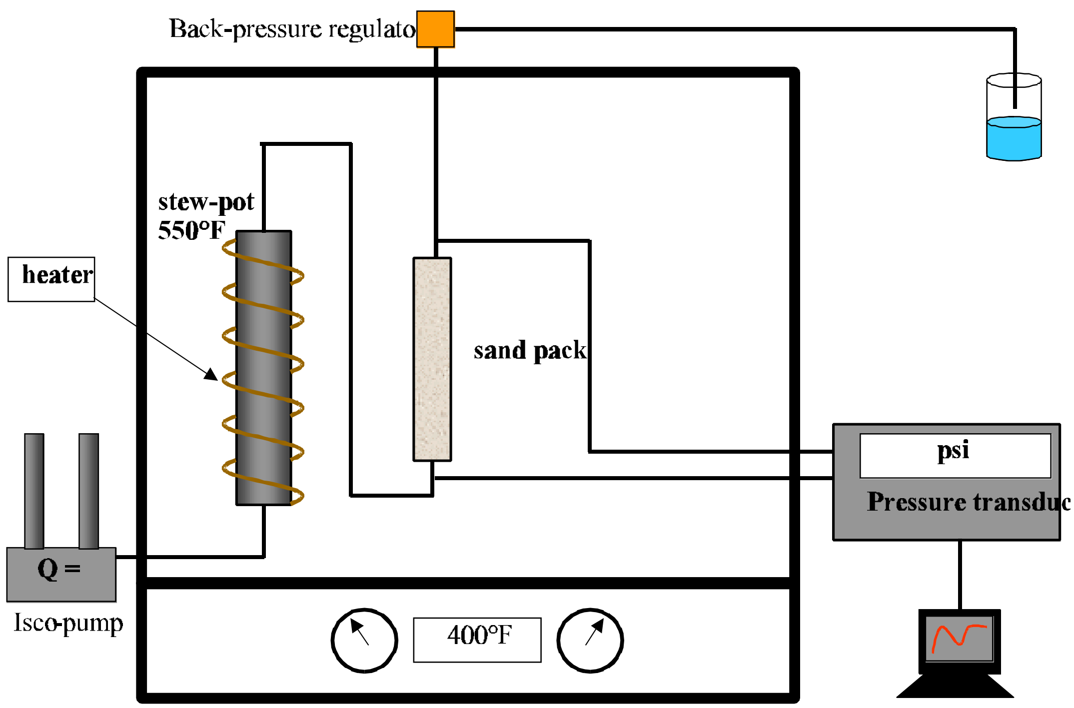


Figure 9: Experimental design for the first experiment, Run 1.

Each of the three experiments resulted in the precipitation of cements and a reduction in permeability (Table 2). Run 1 with the highest temperature, lowest flow rate, and longest injection duration had the largest volume of cement precipitated and yet had a slight increase in porosity (Fig. 10). Most of the cement was an aluminum oxide or hydroxide deposited at the cylinder wall and inlet. The cylinder wall was extremely pitted and the cement formed under the gold plating. This cement was generated by the high temperature alkaline solution reacting with the aluminum core holder where the gold plating had been scratched while tamping the sand into the cylinder. Silica cements with traces of carbon (likely from trace hydrocarbons that remained despite cleaning) were observed near the inlet while salt was found throughout the sand pack. The next sand

Table 2: Summary table of Runs 1, 2, and 3. The stewpot was at 550°F for each experiment. Porosity and permeability values are listed with the initial, pre-experiment values first and the final, post-experiment value last.

	Run 1	Run 2	Run 3
Stewpot material	Fresh cleaned T-sand	Fresh cleaned T-sand	Reused cleaned T-sand
Sand Pack Properties			
Temperature	400°F	300°F	150°F
Packing	Packed quartz sand	Packed quartz sand	Loose quartz sand
Sorting	D-sand sorting	D-sand sorting	Well sorted (#120)
Porosity	27.4 to 28.2%	28.4 to 27.4%	53.7 to 35.2%
Permeability	8.6 to 6.8 D	8-9 to 7.1 D	4.9 to 0.5-2 D
Cements	Silica, aluminum oxide or hydroxide, NaCl	Silica, aluminum oxide or hydroxide, carbonate	NaCl, KCl, silica
Experiment Parameters			
Initial Fluid	Synthetic formation water	Synthetic formation water	Synthetic formation water
Flushing Fluid	Synthetic formation water	Synthetic formation water followed by de-ionized water	Synthetic formation water followed by de-ionized water
pH injection	10.5-11	10.5-11	10.5-11
pH effluent	7-4	7-6	7
Effluent	dark to clear	dark to clear	clear
Flow rate	0.5 cc/min	20 cc/min	20 cc/min
Flow range	0.5-55 cc/min	20-40 cc/min	20-40 cc/min
Duration	98 hrs	3 hrs	3 hrs
Volume injected	9431 cc	3709 cc	4183 cc

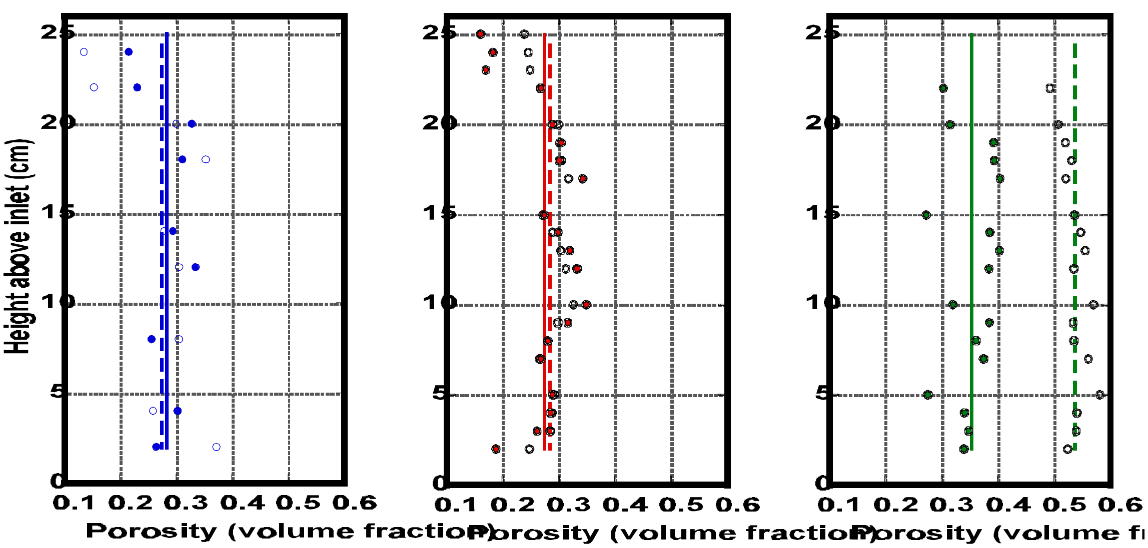


Figure 10: CT porosity values measured on sand packs before (circle) and after (dot) each experiment, Run 1 (blue), Run 2 (red), and Run 3 (green). The initial average porosity values (dashed) and final average porosity values (solid line) are shown.

pack was more gently tamped to avoid scratching the cylinder's gold plating and subsequent experiments were flushed with de-ionized water to remove salts precipitated by the injection fluid and synthetic formation water.

Run 2 resulted in some cements forming at the inlet and near the cylinder walls. The inlet cements were silica and calcium carbonate. As in the first run, the silica cements contained traces of carbon. Again, the cylinder walls were pitted, albeit not as extensively as in the first experiment. In both the first and second experiment, fresh stewpot material was used. Although the reservoir sand used in the stewpots had been cleaned prior to use, the effluent was initially dark and gradually lightening until it was clear at the end of the experiments (Fig. 11). The effluent typically is neutral (generally pH = 7) with exceptions occurring when experimental conditions cause the flow to convert to two-phase (i.e., steam production). This typically happens when a leak develops over the course of an experiment as occurred in Run 1 with associated pH values of 4 (Table 2).

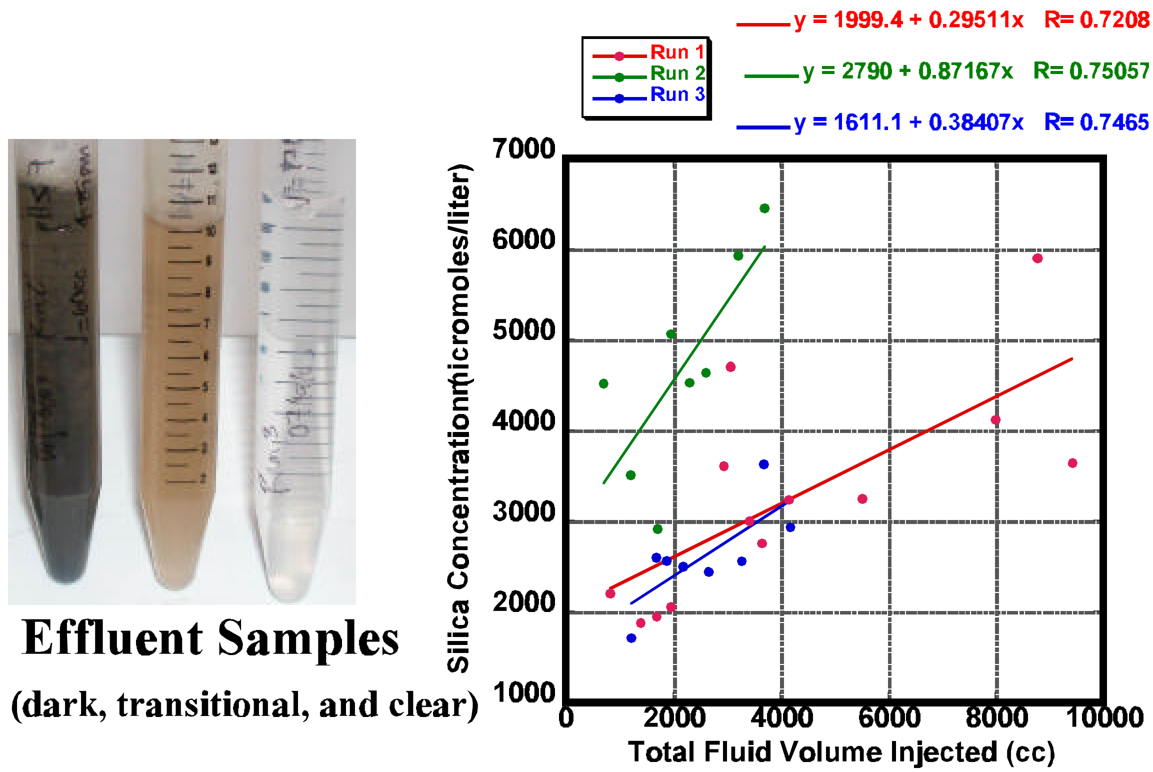


Figure 11: Photograph of dark, transitional, and clear effluent samples collected for silica analyses. Plot of silica concentration versus total volume of high alkalinity fluid injected for Runs 1, 2, and 3 using the stewpot and single sand pack design. The silica content was determined using a modified silicomoybdate spectrophotographic procedure based on Strickland and Parsons[3] (1972).

For Run 3, the sand was poured into the core holder rather than packed as with the earlier experiments in order to avoid scratching the gold plating. Also, a well sorted quartz sand was used instead of poorly sorted quartz sand whose grain size distribution was selected to mimic that of the D sands. The poor sorting of the previous grain packs complicated the subsequent SEM analyses, so a well sorted quartz sand was selected to simplify inspection of the cements and identify overgrowths. Another difference between Run 3 and the other experiments is that the stewpot sand was reused in order to determine if the carbon observed in the silica cement arises from the initial dark effluent. Cursory inspection of the stewpot material used in Run 1 did not reveal obvious dissolution and the sand remained disaggregated.

Of the three experiments, Run 3 at 150°F resulted in the greatest reduction in permeability and porosity (Table 2). Salts (NaCl and KCl) predominantly cemented this sand pack and were most prevalent in the outlet half of the sand pack. The salt cements in the inlet half of the core holder were partially dissolved when the holder was flushed with de-ionized water at the end of the experiment. Preliminary SEM observations found some potential indications of silica cements along with the salts. Further investigation is needed to determine whether the silica coatings on the grains are either derived from the stewpot effluent or are found on the sand grains prior to the experiment.

Comparison of the silica content of the effluent samples reveals a surprising trend in that the silica content is expected to be greater in the higher temperature experiments (Fig. 11). In this study, the highest temperature (450°F) experiment, Run 1, has a silica concentration trend similar to that of the lowest temperature (150°F) experiment, Run 3. The intermediate temperature (300°F) experiment, Run 2, has the highest silica concentration. Initially, it was thought that the light transmission-based spectrophotometer might have anomalously high readings for the dark effluent samples. This is not the case in that the initial dark effluent samples for Run 1 have comparatively low silica concentrations whereas the initial dark effluent samples for Run 2 have higher silica concentrations as shown in Figure 11. In addition, the concentration relationship for each run remains linear although the effluent in Runs 1 and 2 are initially dark and clear by the end of the experiment. The other alternative is colloidal silica and polymer chains might have formed as the effluent samples cooled. Silica in this form would not be detected using the modified silicomoybdate spectrophotographic procedure. Further analyses will determine whether or not this is the cause of the unexpectedly low silica concentrations for the Run 1 effluent samples.

Although cements were produced in all three of the experiments, the cements that were anticipated, namely calcium silicates, were not precipitated. The initial assumptions that the experimental design was based upon are being reexamined. Experimental design and parameters will be adjusted according to our findings. Also, salt will be left out of the synthetic steam condensate in future experiments in order to avoid deposition of salt cements.

Technology Transfer

Project team members from Stanford University plan to submit an abstract for a paper entitled “A Laboratory Investigation of Temperature Induced Sand Consolidation” to the Society of Petroleum Engineers’ 2004 Annual Technical Conference and Exhibition scheduled September 26-29 in Houston, Texas.

All questions regarding the project should be referred to Scott Hara, Tidelands Oil Production Company, phone - (562) 436-9918, email - scott.hara@tidelandsoil.com.

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