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	(5)

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	Budget Period 1
	September 30, 2006	Budget Period 2
DOE Award:	$6,347,766 (Cum Actual through March 2003)	
	$29,485 (March 2003 YTD Actual)	
	$337,692 (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:	June 4, 2003
Reporting Period:	**January 1, 2003 to March 31, 2003**

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; and
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.

Table of Contents

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 First Quarter 2003, the project team continued to activate and repair wells to accelerate oil recovery and reservoir cooling in the Tar II-A post-steamflood project and to perform major well work on the Tar V post-steamflood pilot project. Research work on the geochemistry and process regarding the sand consolidation well completion technique took a positive leap with the signing of a research contract with Stanford University in January. The project team made good progress in updating the Tar II-A three-dimensional (3-D) thermal reservoir simulation model to optimize well operations by increasing oil production rates, minimizing operating costs and addressing the remaining high reservoir temperature areas that have contributed to thermal-related formation compaction.

The Tar II-A post-steamflood operation started in February 1999 with flank cold water injection and steam chest fillup occurred in 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 oil production increased from 1009 BOPD in the first quarter to a peak of 1199 BOPD in June 2002. By January 2003, Tar II-A gross fluid production increased almost 60% or 12,000 BGFPD since March 2002 whereas associated injection rates increased only about 26% or 9,000 BWIPD and oil production declined to 1059 BOPD with higher water cuts averaging 96.8%. The higher gross fluid production and water injection rates caused more frequent well failures from stressing the system and operating costs increased significantly. Reservoir pressures declined to 89% hydrostatic in the "T" sands and increased to 93% hydrostatic in the "D" sands. Well work during the quarter is described in the Reservoir Management section.

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. Plans have been approved to drill and complete well A-605 as a Tar V horizontal producer and recomplete well A-194 as a Tar V interior vertical steamflood pattern producer in the second quarter 2003. See Operational Management for more details.

The project team completed developing laboratory research procedures to analyze the sand consolidation well completion technique and a contract was approved with the Stanford University Petroleum Engineering Department to initiate work effective January 6, 2003. By the end of the quarter, Stanford was preparing the laboratory equipment and cores for the experiments.

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 January 1, 2003 to March 31, 2003. Most of the work was concentrated on the post-steamflood operation in Tar II-A and on the Tar V horizontal well steamflood pilot. 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 project team completed developing laboratory research procedures to analyze the sand consolidation well completion technique and a contract was approved with the Stanford University Petroleum Engineering Department to initiate work effective January 6, 2003. Stanford was preparing laboratory equipment and cores for the experiments at the end of the quarter.

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 is comparing the differences between the CMG STARS 98 Unix and current STARS 2002 PC thermal reservoir simulator versions to confirm that they give the same answers and don't introduce reservoir performance changes. The comparison cases use the latest Tar II-A model run developed in July 1999.

The last modeling work performed on the Tar II-A was in July 1999. To date, the project team has updated the data input decks with production and injection volumes through March

2003, revised the reservoir model 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, and began history matching the new data from July 1999 through March 2003. The updated model results will be compared with the actual pressure and temperature survey data collected since January 1999. The temperature data include the gross fluid production from individual wells, periodic Amerada bomb temperature recordings and 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 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].

The updated reservoir simulation model will address two main technical challenges that cannot be determined intuitively or manually. The first is the model’s ability to predict formation temperatures over time throughout the vertical and areal extent of the steamflood project for each operating plan scenario. Reservoir pressures and temperatures in the project area are affected by the following occurrences: mixing of the hot and cold fluids at the water injection sites; continuous heat loss in the mature steamflood area to the overburden and underburden formations; steam chest collapse and expansion in the structurally updip areas; and the movement and production of hot fluids throughout the steamflood project area. Taken together, these parameters make the prediction of reservoir temperatures and pressures too difficult without a viable reservoir model. The second challenge the model can address is determining the effective water injection rates into the northerly and southerly flank injection wells to minimize water loss into the aquifer and the associated expense.

Reservoir Management

Tar II-A Steamflood Project

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.

Steam chest fill-up of the “D” sands occurred in September 1999 when the pressure throughout most of the reservoir exceeded 90% hydrostatic or about 960-1000 psi. Maintaining reservoir pressure is important to prevent steam chest reoccurrence. In mid-September 1999, net water injection was reduced substantially in the “D” sands and reservoir pressure plummeted about 100 psi within six weeks, even though injection to production ratios (I/P) ratios were still above 2.0. Starting in late-October 1999, net “D” sand water injection was increased and reservoir pressure rose back to the desired steam chest fill-up pressure of 90% hydrostatic by March 2000. Since then, reservoir pressure has been maintained at 92±2% hydrostatic through March 2003. The reservoir has begun acting more like a waterflood that can be operated at lower net injection rates and lower I/P ratios of about 1.4, still high compared to the 1.05 in most of the other Wilmington waterflood projects. 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				"D" Sands - Phase 1-1C Wells		
	Reservoir Pressure				Reservoir Pressure	
	psi	hydrostatic %			psi	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	920	89		Mar-03	1027	93

After reaching steam chest fill-up in October 1999, net “T” sand injection remained at a high rate through April 2000 and reservoir pressures stabilized at 98% hydrostatic pressure. Net injection was reduced and "T" sand reservoir pressure averaged 95% hydrostatic by March 2001. A flurry of “T” sand injector failures occurred from January to September 2001, the most serious ones in the third quarter. Although the wells were repaired promptly, the reduced injection caused reservoir pressure to drop rapidly to 92% hydrostatic in June 2001 and 89% hydrostatic in September 2001. Reservoir pressures continued to decline slowly through March 2002 to 88% hydrostatic even though “T” water injection rates were increased back to normal in October 2001. Since then, reservoir pressures increased to 90% hydrostatic by September 2002 and have been maintained at 90±1% hydrostatic since then.

The project team developed a well work plan in March 2002 to accelerate cooling of the Tar II-A steamflood reservoirs by increasing flank cold water injection and high temperature gross fluid production. The plan proposed activating eleven producers and five injectors. All of the proposed work has been completed except for one injector that has mechanical problems. Through March 2003, an additional nine producers and one injector were activated. Of the seventeen producers active before March 2002 and the twenty producers activated afterwards, eleven have been idled as uneconomic. Major well work was completed on three producers. Horizontal well 955 was activated after installing a gravel-packed inner liner for sand control (in original plan). Recent well tests show UP-955

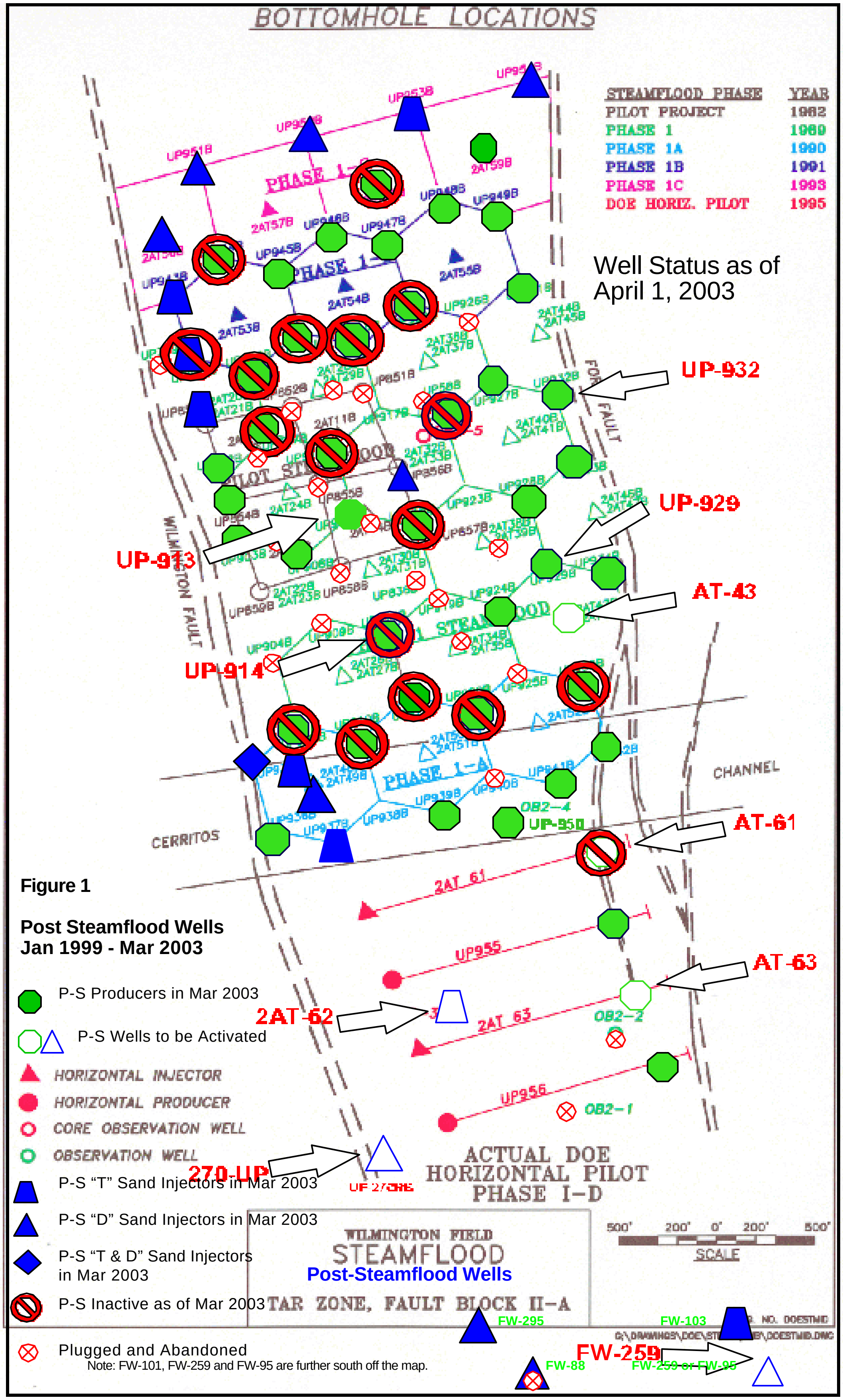


Figure 1

Post Steamflood Wells Jan 1999 - Mar 2003

successfully producing 1754 BGFPD and 70 BOPD with 1864 feet of fluid over the pump. Well AT-59 was recompleted to the upper “D1” sands after watering out in the lower “D1” and “D3" sands. AT-59 initially produced at a disappointing rate of 1775 BGFPD and 29 BOPD with 1552 feet of fluid over the pump. Production decreased to 863 BGFPD and 10 BOPD and fluid was at the pump, which indicates a scale problem and premature water coning. Well UP-927 (in original plan) was activated and sanded up. The well required installation of an inner liner and the well currently produces 1322 BGFPD and 41 BOPD. Figure 1 shows the 26 producers and 14 injectors that were active in the Tar II-A post-steamflood area as of April 1, 2003 compared to the original steamflood pattern wells. Eighteen wells have been activated during the post-steamflood period and later idled.

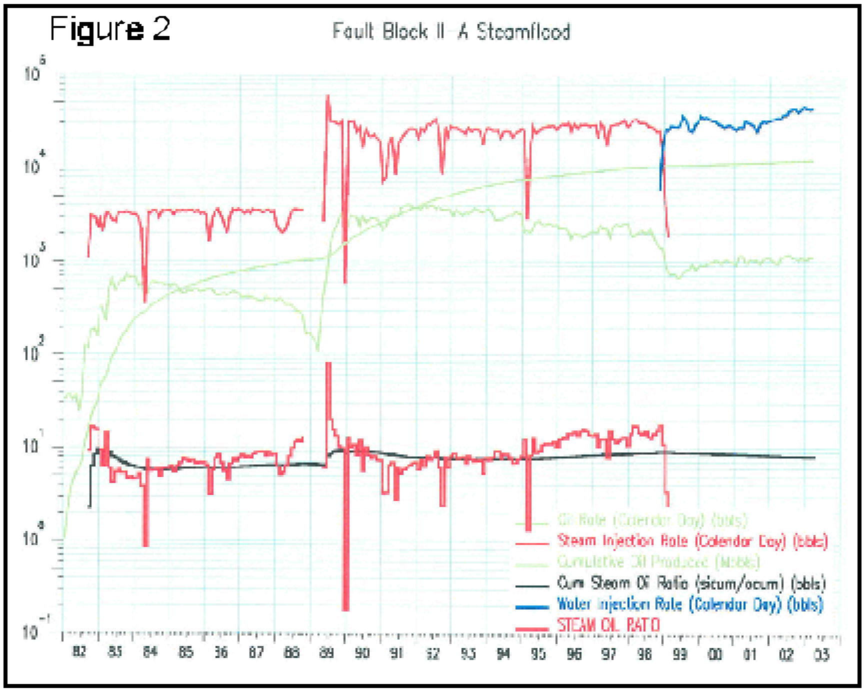
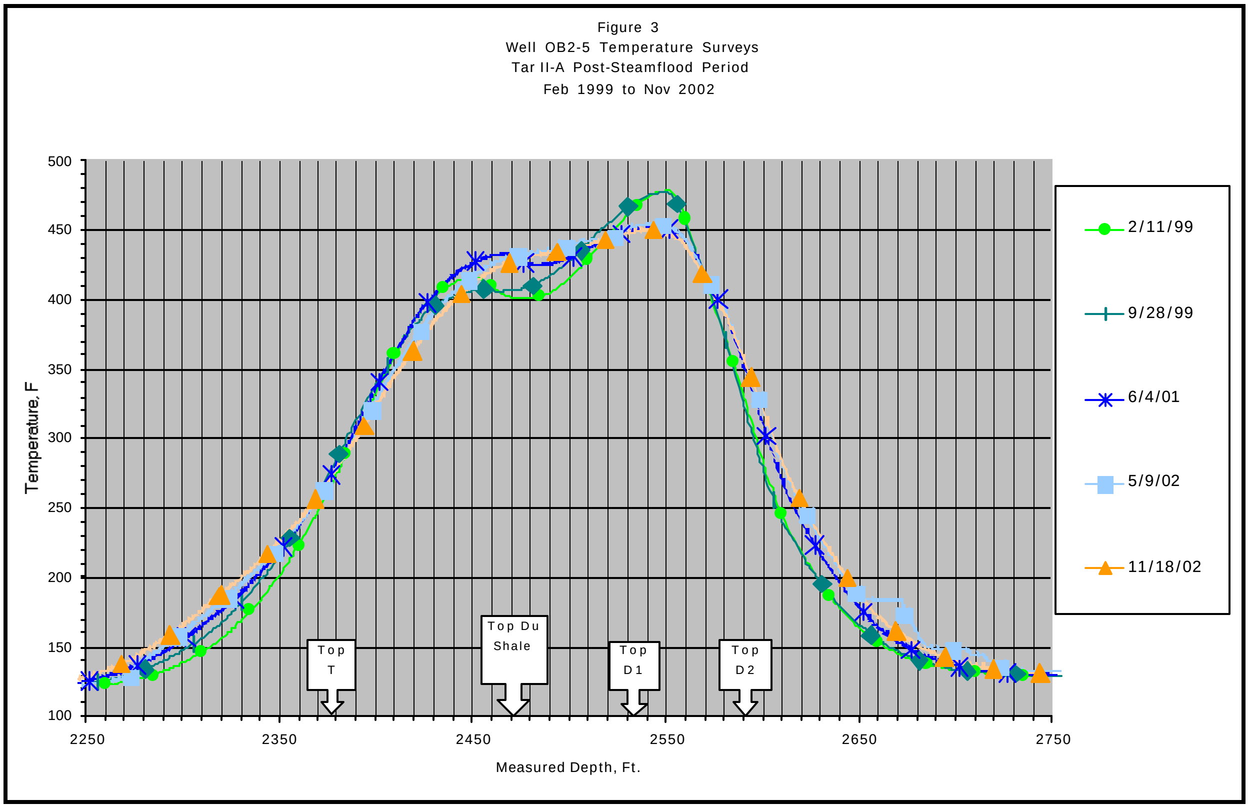


Figure 2

The Tar II-A project averaged 1,102 BOPD and 31,914 BPD gross fluid (27.4 water-oil ratio [WOR]) with 43,836 BPD water injection during the First Quarter 2003. The production acceleration plan called for increasing total gross fluid production by 9,600 BPD, oil production by 427 BOPD, and water injection by 12,500 BWIPD. From February 2002 through March 2003, gross fluid production increased 11,200 BPD, oil production increased 154 BOPD, and water injection increased 11,600 BWIPD. The incremental oil production is actually much higher as most of the Tar II-A producers have experienced higher water cuts and lower oil rates since February 2002. Many of the “additional” wells activated produced at greater than 99% water cut and were subsequently idled. Also, many of the downdip producers appear to be watering out from the higher cold water injection rates. The post-steamflood project WOR has risen from 21.9 during the second quarter 2002, to 28.0 in the first quarter 2003. Figure 2 is a production graph of the Tar II-A steamflood project from inception in 1982 through March 2003.

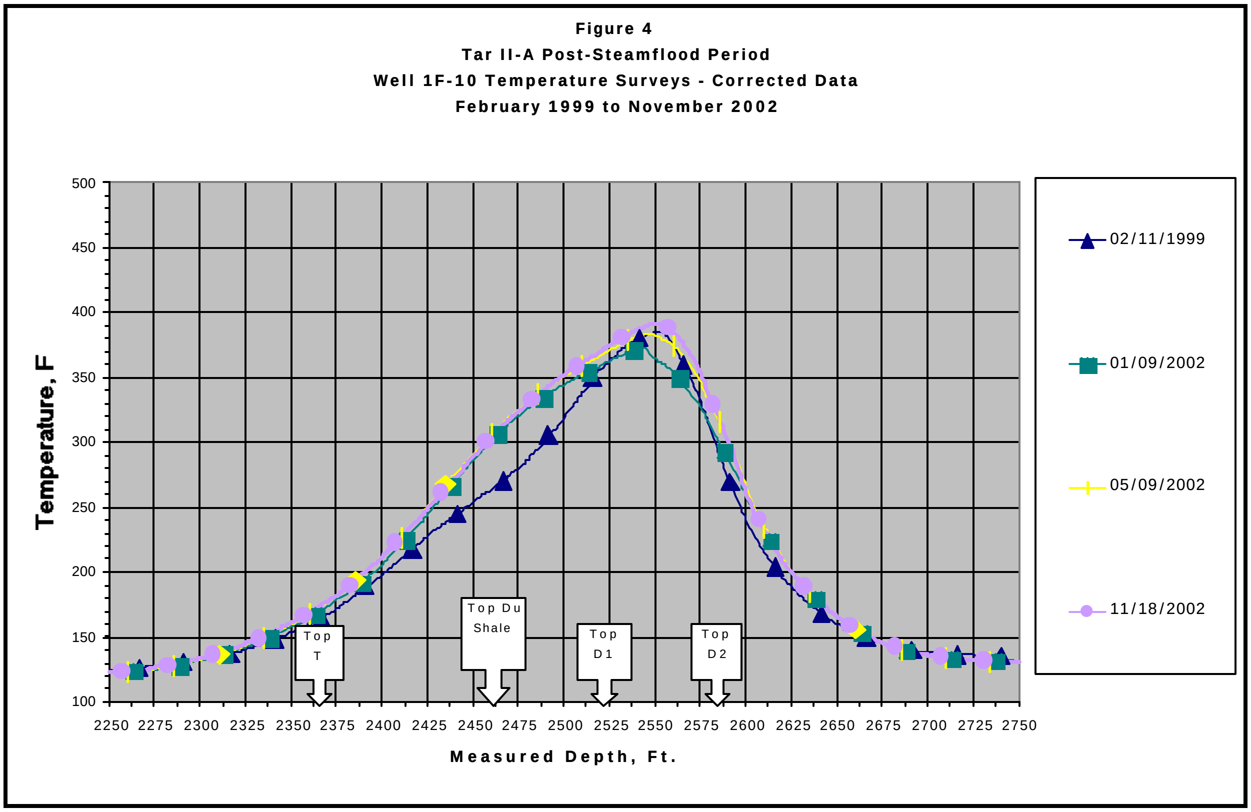
The accelerated cooling plan included testing cold-water injection into one interior “D” sand pattern injector (2AT-33) starting on April 27, 2002 to observe whether the formation would react like a normal waterflood or experience adverse formation compaction effects. The ten feet of “DU” shale above 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.

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 June 2001 survey showed a peak temperature of 452°F and the latest temperature survey on November 18, 2002 shows a peak temperature of 450°F. The "T" sand temperatures hardly changed, with peak temperatures of 415°F at the start of the post-steamflood and also most recently in November 2002, with temperatures ranging from 407°F to 429°F from 1999 to 2002. 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 to November 2002 have risen from 401°F to 430°F because of overburden and underburden heat transfer through conduction. The post-steamflood temperature surveys for well OB2-5 are shown in Figure 3. Conductive heat transfer could cause more shale compaction to occur, especially in areas surrounding former steamflood injectors or in direct injector-producer pathways where the shale temperatures were originally below the shale failure temperature and increase above that temperature, which is believed to be about 350 - 400°F. Conductive heat transfer is slow and therefore should cause only nominal lateral heating of the formation.

The temperature survey data from well 1F-10 show an interesting heating trend in the upper "D1" sands in three surveys from January 9, 2002 to November 18, 2002 where peak temperatures have risen from 374°F to 391°F (Figure 4). Prior to injection into 2AT-33, the temperature in the upper "D1" sands declined from 385°F at the start of the post-steamflood (February 1999 survey) to 374°F in January 2002, at a cooling rate typically observed in other wells. The heating trend usually occurs within a well when conductive heat from hotter sands are transferred vertically to cooler sands. This is not the case here since the peak temperature is rising. Lateral conductive heat transfer is expected to happen too, 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



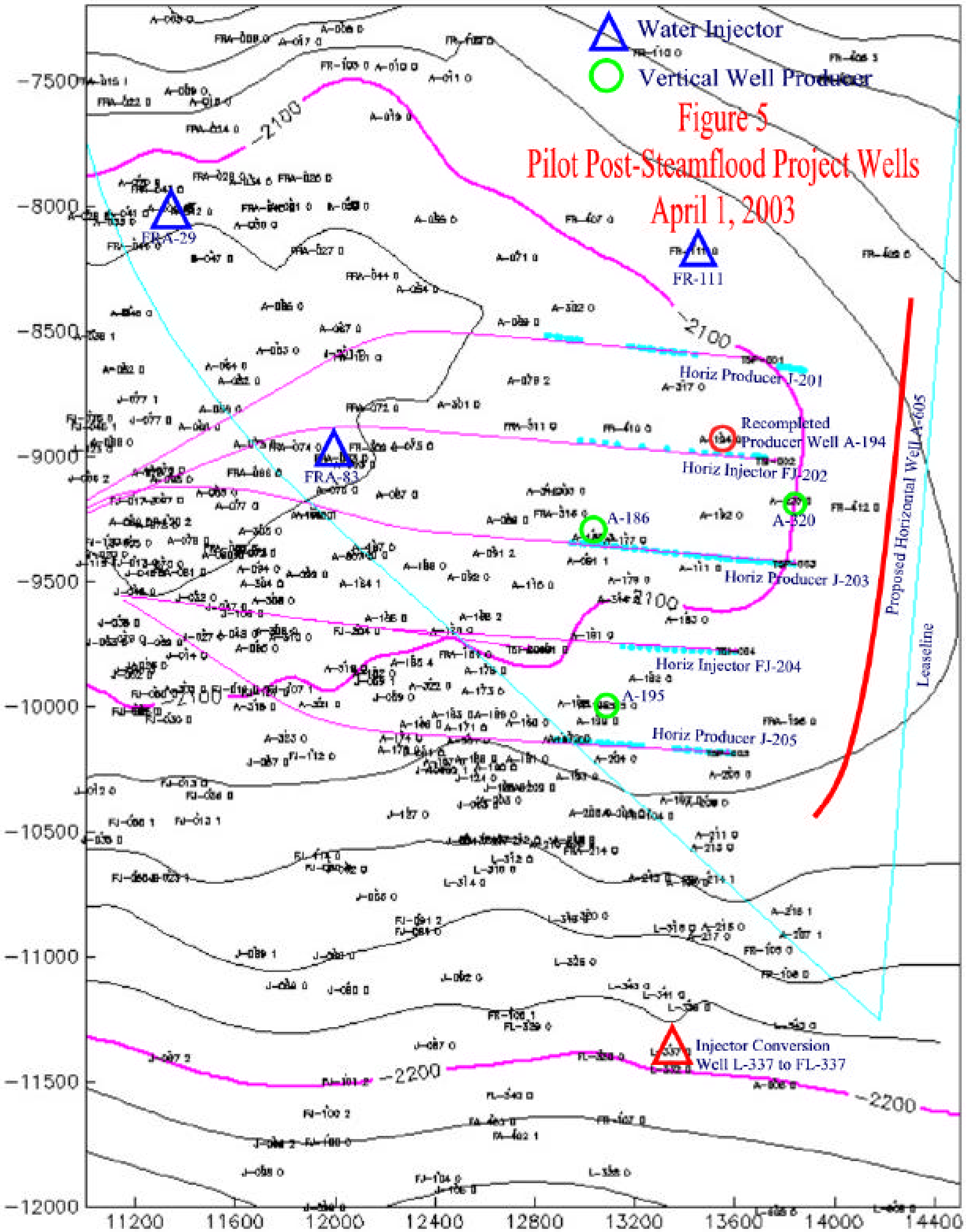
was heated over a short distance to above 400°F which then convectively heated the "cooler" sands surrounding well 1F-10. If true, this would require more evaluation of temperature changes in the reservoir due to operational changes, like adding more interior water injectors. The updated reservoir simulation model should help tremendously.

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.

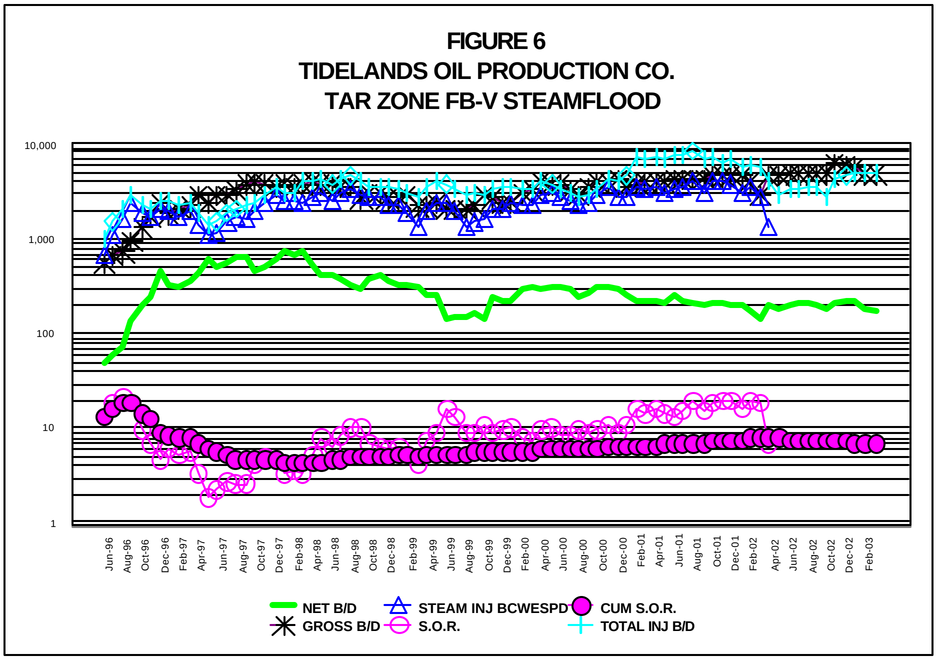
Tar V Pilot Steamflood Project

The project team expanded the DOE project in March 1999 to include the Tar V pilot steamflood to continue research related to the Tar II-A horizontal well pilot steamflood operations. 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 5. Well FRA-29 was converted to a water

Tar V S4 Structure Map. Scale: 1'' = 500'



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 35 BGFPD and 6 BOPD with no fluid at the pump. During the second quarter 2003, the plan is to drill a new horizontal producer, A-605, to capture oil reserves along the leaseline . Wells FL-337 and A-194 and proposed well A-605 are shown in red in Figure 5.

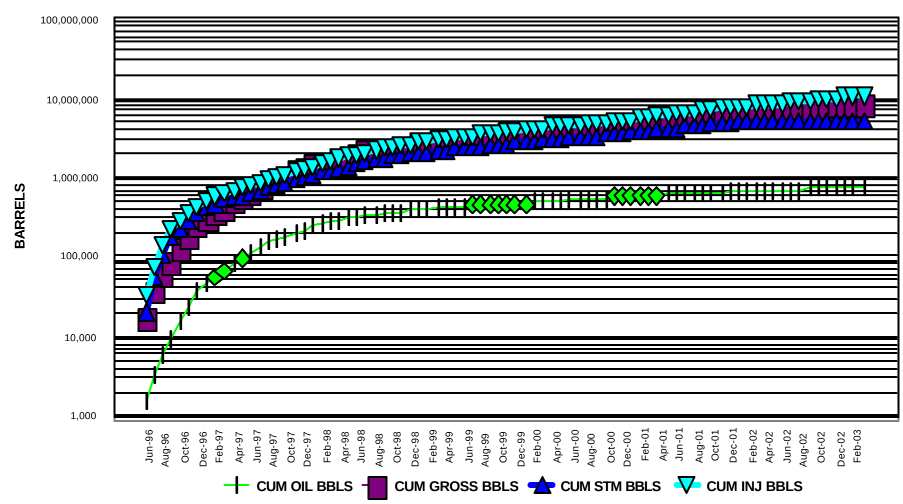


Pilot steamflood performance was excellent for the first two years as shown in Figure 6 with oil production peaking at 743 BOPD in January 1998 at a cumulative steam-oil ratio (SOR) of 4.5. All five horizontal wells were given initial cyclic steam jobs to consolidate the formation sands and to stimulate heavy oil production. The three infill vertical wells, A-186, A-195 and A-320, all responded favorably to steam injection in the horizontal wells. Well A-195 was idled in August 1998 because of steam breakthrough and was used as a temperature observation well, but was repaired in May 2002. The three infill wells contributed a combined 83 BOPD in March 2003 of the 180 BOPD from the pilot.

After reaching peak production of 743 BOPD in January 1998, the pilot project 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. Steam injection to the pilot project was increased in October 1999 and well work was performed to repair two of the horizontal producers for sand control and to convert one vertical well to water injection. This work 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 failing pumps in two horizontal wells (that were replaced in March). Hot water injection was terminated in April 2002 and replaced with 100% cold water injection. In May, horizontal well J-205 sanded up. Even still, oil production in the third quarter 2002 averaged 204 BOPD from activating A-195 and continually pumping down well J-203. Well J-205 was repaired with a gravel-packed inner liner to restore sand control, however, the completion was damaged and the well produces only 1111 BGFPD and 33 BOPD, compared to its pre-sanded potential of over 3000 BGFPD and 150 BOPD. Well L-337 was converted to water injection well FL-337 in the Tar V zone and injects 1600 BWIPD. Well A-194 was recompleted into the Tar V zone with selected perforations and a gravel-packed inner liner and produces only 35 BGFPD and 6 BOPD..

The projected oil reserves for the pilot project is 1.7 million barrels assuming the use of 8.5 million barrels of cold water equivalent steam at 80% quality and 16.7 million barrels of total steam and water injection over 14 years. Through March 2003, the pilot has produced 757,000 barrels of oil and 8,714,000 barrels of gross fluid (91.3% average water cut) and injected 5,357,000 barrels of steam/hot water and 11,050,000 barrels of total steam and water for an overall I/P ratio of 1.27. The steamflood performance curves in cumulative barrels vs time for oil production, gross fluid production, steam injection and total steam and water injection are shown in Figure 7.

FIGURE 7
TIDELANDS OIL PRODUCTION CO.
TAR ZONE FB-V STEAMFLOOD



The Tar V pilot project has been operated differently than originally planned because of thermal-related surface subsidence concerns affecting the Tar II-A steamflood project. Steam and water injection were increased to raise the cumulative I/P ratio to 1.16 through the steam injection phase, compared to the originally planned I/P ratio of 0.75 during the first four years of the project. The planned I/P ratio was lower because the Tar II-A project averaged a 0.75 I/P ratio from 1990 to 1994 without any apparent adverse surface subsidence effects. The lower I/P ratio in a steamflood was considered safe because injected high temperature steam displaces much more volume than its cold water equivalent volume, up to 35 times more at 800 psi reservoir pressure. The change in plan accelerated steamflood and waterflood response, hence the high producing fluid levels in the wells. Because the horizontal producers are completed at the bottom of the S4 sands, high oil production rates are dependent upon pumping the wells down. When the producing fluid temperatures reached 350°F in the interior horizontal producer well J-203 in May 2001, the City of Long Beach defined the project as mature and required the steam generator to output only hot water at a temperature not to exceed 350°F to prevent thermal-related formation compaction. This significantly affected steamflood performance as the overall reservoir was not heated to adequate temperatures and cumulative steam injection was reduced by over 3.5 million cold water equivalent barrels from planned volumes. During the first quarter 2002, the pilot produced at an instantaneous “steam-oil” ratio of over 18. Through the end of hot water injection in April 2002, the cumulative SOR of the pilot was 7.6, marginal assuming steam costs based on market-priced fuel. Since only cold water is currently injected, the cumulative

SOR will decline with time and is 7.1 through March 2003.

The pilot project through the Fourth Quarter 2000 met the original reservoir engineering projections based on oil recovery vs cumulative gross fluid production and cumulative steam injection. The original pilot projections showed that to recover 586,000 barrels of oil would require producing 4,990,000 barrels of gross fluid (actual is 2.5% lower) and injecting 3,643,000 barrels of steam (actual is 2.3% higher). However, the project was behind schedule because production and injection rates throughout the project have been too low. Based on the original projected volumes, the project should have recovered 586,000 barrels of oil by the second quarter of 1998 or 1.5 years earlier.

An important issue to consider when comparing projected to actual steamflood performance is to normalize actual steam usage to a BTU equivalent volume of 80% quality steam. For the Tar V project, the injected steam quality was rarely at 80% and probably was closer to 60% for the 4,223,000 barrels injected during the steam injection phase of the project (June 1996 - May 2001). The steam quality difference amounts to injecting about 89% of the BTU heat into the formation than planned per pound of water. The cumulative SOR through June 2001 was 6.9. If steam volumes are normalized based on heat transfer using 80% quality steam, the corrected SOR would be a much more reasonable 6.1 or about 11% lower. Hot waterflooding occurred from July 2001 through April 2002, with the hot water rate averaging 3188 BCWEPD. The hot water averaged about 330° F at no steam quality, which has about 21% of the heat transfer of 80% quality steam. Therefore, the first quarter 2002 SOR of 18.2 using hot water injection would have a normalized SOR of 3.8 based on the equivalent heat transfer of 80% quality steam. As steam fuel cost and the steam-oil ratio are the main parameters determining the profitability of a steamflood, a more thorough economic evaluation needs to be made of the Tar V pilot steamflood performance.

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. A new horizontal producer, well A-605, is planned to be drilled in a south to north direction along the Tidelands leaseline to capture the remaining thermally-heated oil in the pilot area. A vertical well within the horizontal well drive patterns, A-194, was recompleted into the upper "S" sands. Water injection on the south flank of the project was added by converting well L-337 to support increasing production from the horizontal wells. The proposed wells are shown in Figure 5.

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 and L-233 (Tidelands' DOE Class 3 near-term waterflood project). Tidelands' plan is to develop and improve both completion methods because each has advantages depending upon the type formation sands to complete, reservoir recovery method, existence of interbedded wet sands, and availability of steam or heated fluid source. 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.

The project team completed developing laboratory research procedures to analyze the sand consolidation well completion technique and a contract was approved with the Stanford University Petroleum Engineering Department. Project work was initiated in January 2003. The project team will perform research to better understand the geochemistry that occurs within the Wilmington Tar zone sands at reservoir pressure when contacted by hot alkaline fluids at varying temperatures and alkalinity. 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. If successful, 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. The sand consolidation well completion has many advantages over the conventional gravel-packed, slotted –liner completions related to 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 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.

Objectives of Laboratory Research:

1. Confirm sand consolidation process in the lab using typical Wilmington Tar zone cores using different injection fluids with varying alkalinity and temperatures. Confirm whether process is reproducible. The lab research entails performing hot waterflood potential-type tests through selected Tar II-A cores. The water would be at the same temperatures and pressures injected in the field and alkaline will be added to raise the pH to levels equivalent to the steam condensate. These tests will confirm whether our theories of hot alkaline steam condensate causing sand grain dissolution to form "worm holes" and sand consolidation are valid and may possibly show whether the steam vapor phase (or rather the lack of it) is beneficial to the process. Multiple sensitivity cases will be run to get a range of results. The objectives are to confirm the process and how to control it. Positive results may indicate reasons for our successes and failures in wells recently completed with this method and show how we can improve on the process.

2. Define geochemical bonding products and the origin of the products, whether they are from the formation rocks, formation water and/or injected water. The objective is to duplicate the empirical process in the lab.

Conceptual Stanford Lab Procedures
Stage 1: Define the Soups

Objective: Define the geochemical soups created from flowing high temperature alkaline fluids similar to typical steam generator condensate through unconsolidated sand cores from the Wilmington Tar zone. Tests are to be taken at 100°F intervals starting at 400°F to at least

700°F. Additional tests can be taken at 50°F intervals if deemed necessary. Figure 8 shows the conceptual design of the apparatus, with hot alkaline water going into the stew pot and the soup with the dissolved minerals exiting the stew pot and entering a series of sand packs to observe what precipitates out at different temperatures. A back-pressure regulator controls the pressure drops throughout the system.

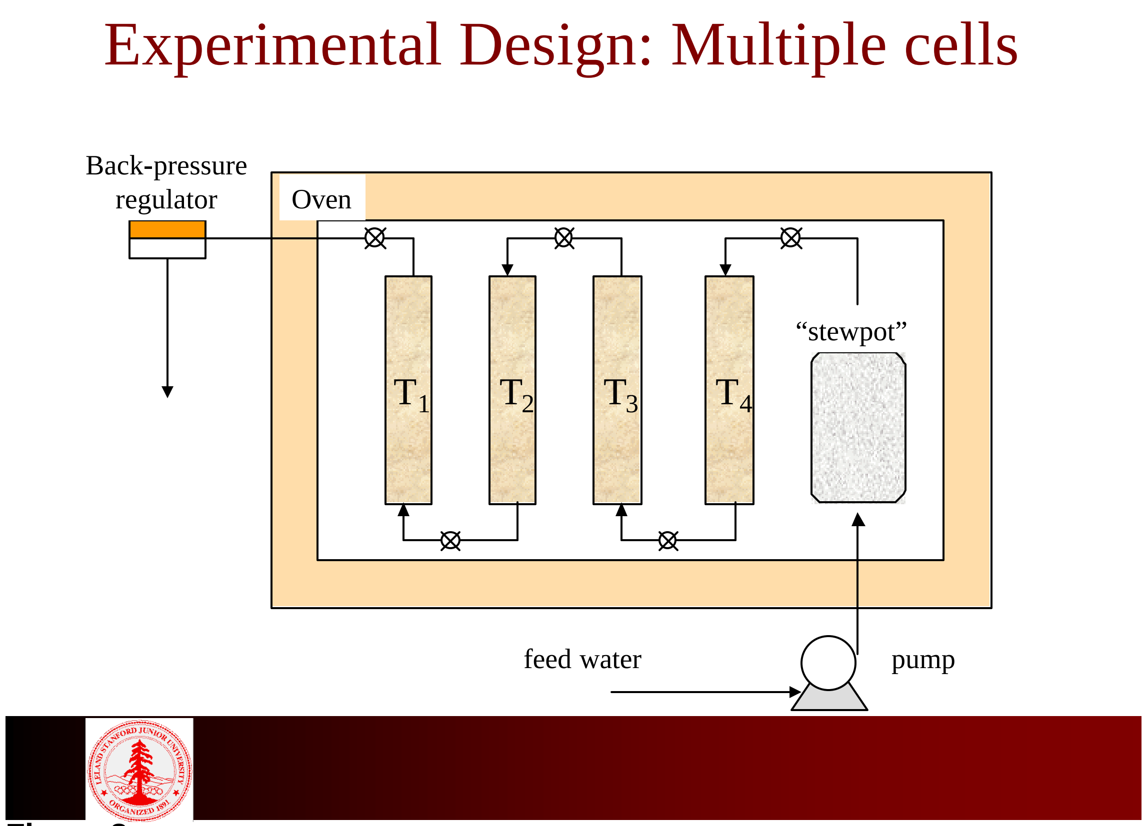


Figure 8

Stage 2: Define the Sand Consolidation Precipitates

Objective: Define the mineral content of the cements that are precipitated at different temperatures onto Ottawa sand. The soup created will be continuously flowed through several ovens at different and declining temperatures, each containing a pressure vessel with Ottawa sands to mimic the precipitation that occurs with distance from the wellbore and as concentrations of various key minerals decline.

Stage 3: Determine the Strength of the Cements

Objective: Determine the strength of the cements binding the Ottawa sand grains in terms of differential pressures and flow velocities they can withstand. Empirically, the sand consolidated completion wells appeared to withstand high flow rates, but not high differential pressure conditions. This stage may also utilize mechanical stress-strain apparatus to measure the amount of compaction the test cores can withstand.

A separate study will calculate the productivity and injectivity indexes and formation well-face skin factors of wells completed with the sand consolidation process. This is an academic exercise utilizing actual well test and fluid level data to calculate the relative productivity and injectivity of the sand consolidation technique compared to other unconsolidated sand well completions.

Technology Transfer

Don Clarke of the City of Long Beach and Chris Phillips of Tidelands wrote a white paper entitled "Three-dimensional Geologic Modeling and Horizontal Drilling Bring More Oil Out of the Wilmington Oil Field of Southern California" which was published in a new 2003 AAPG book entitled "*Horizontal Wells: Focus on the Reservoir*"[2].

A project homepage can be viewed on the Internet at http://www.usc.edu/dept/peteng/topko.html. A CD-ROM of the project on IBM PC format will be distributed free upon request to Scott Hara, Tidelands Oil Production Company, phone - (562) 436-9918, email - scott.hara@tidelandsoil.com.

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2. Clarke, Don, City of Long Beach, Phillips, Chris, Tidelands Oil Production Co., "Three-dimensional Geologic Modeling and Horizontal Drilling Bring More Oil Out of the Wilmington Oil Field of Southern California", published by AAPG in the book, "*Horizontal Wells: Focus on the Reservoir", 2003, pages 27-47, Tulsa, OK.*