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.

Date of Report: November 1, 2001

Award Date: March 30, 1995

Anticipated Completion Date: March 29, 2001* Budget Period 1
March 29, 2004* Budget Period 2

DOE Award: \$6,199,652 (Cum Actual through September 2001)
\$400,000 (2001 Projected)
\$110,050 (September 2001 YTD Actual)

Principal Investigator: Scott Hara - Tidelands

Program Manager: Gary Walker - National Petroleum Technology Laboratory

Reporting Period: July 1, 2001 to September 30, 2001

*Request for two-year, no cost extension of Budget Periods 1 and 2 submitted to Keith Miles on March 29, 2001. Project team is still awaiting DOE approval.

Objectives

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.

Summary of Technical Progress

Through June 2001, project work has been completed on the following activities: data preparation; basic reservoir engineering; developing a deterministic three dimensional (3-D) geologic model, a 3-D deterministic reservoir simulation model and a rock-log model; well drilling and completions; and surface facilities on the Fault Block II-A Tar Zone (Tar II-A). Work is continuing on research to understand the geochemistry and process regarding the sand consolidation well completion technique, final reservoir tracer work, operational work and research studies to prevent thermal-related formation compaction in the Tar II-A steamflood area, and operational work on the Tar V steamflood pilot and Tar II-A post-steamflood projects.

The project team spent the Third Quarter 2001 performing well work and reservoir surveillance on the Tar II-A post-steamflood project. The Tar II-A post-steamflood operation started in February 1999 and steam chest fillup occurred in September - October 1999. The targeted reservoir pressures in the "T" and "D" sands are maintained at $90\pm 5\%$ hydrostatic levels by controlling water injection and gross fluid production and through the bimonthly pressure monitoring program enacted at the start of the post-steamflood phase. The project team ramped up well work activity from October 2000 to September 2001 to increase production and injection. This work will continue through 2001 as described in the Operational Management section.

Expanding thermal recovery operations to other sections of the Wilmington Oil Field, including the Tar V horizontal well pilot steamflood project, is a critical part of the City of Long Beach and Tideland's Oil Production Company's development strategy for the field. The current steamflood operations in the Tar V pilot are economical, but recent performance is below projections because of wellbore mechanical limitations that are being addressed in 2001. See Operational Management for more details.

Reservoir Management

The Tar II-A steamflood project was terminated in January 1999 when the project lost its inexpensive steam source from the Harbor Cogeneration Plant as a result of electric power deregulation in California. An operational post-steamflood plan was developed and 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. Figure 1 shows the post-steamflood wells active on September 30, 2001 compared to the original steamflood patterns. Four of the post-steamflood wells have been idled (crossed out) and work is proposed for the Fourth Quarter 2001 on four wells (arrows). A geomechanics study and a separate reservoir simulation study have been 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. The reservoir then acted more like a waterflood that could be operated at lower injection to production ratios (I/P) and net injection rates. 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. 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 pressure by March 2000. Since then, reservoir pressure has been maintained at 90 - 91% hydrostatic through September 2001. 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. The objective has been to lower "T" sand pressure slowly to 90% hydrostatic. Net injection was reduced and "T" sand reservoir pressure averaged 96% hydrostatic in December 2000, 95% in March 2001 and 92% in June 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, one well

required four rig jobs and two others required two rig jobs each. The reduced injection caused reservoir pressure to drop to 89% hydrostatic in September 2001. Table 1 lists the "T" and "D" sand average reservoir pressures before the post-steamflood phase began and thereafter in quarterly periods.

TAR II-A STEAMFLOOD PROJECT - RESERVOIR PRESSURE					
"T" Sands - Phase 1-1C Wells			"D" Sands - Phase 1-1C Wells		
	<u>Reservoir Pressure</u>			<u>Reservoir Pressure</u>	
	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

A reservoir pressure monitoring program was developed as part of the post-steamflood reservoir management plan. This bi-monthly sonic fluid level program measures the static fluid levels in all idle wells an average of once a month. 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. This data allows engineering to respond quickly to rises or declines in reservoir pressure by either increasing injection or production or idling production.

Operational Management

The Tar II-A project averaged 1,022 BOPD and 19,946 BPD gross fluid (19.52 water-oil ratio [WOR]) with 27,733 BPD water injection during the Third Quarter 2001. These rates compare with 1,012 BOPD and 20,877 BPD gross fluid (20.63 WOR) with 31,455 BPD water injection during the Second Quarter 2001 and 1,075 BOPD and 19,035 BPD gross fluid (16.71 WOR) with 27,064 BPD water injection in the First Quarter 2001. Third quarter production experienced several injection well problems, many of them

discussed above. Rig work was performed on many producers to repair bad pumps and an observation well, OB2-4, was converted to producer well UP-950 and completed into the "T" and "D" sands with perforations and a gravel-packed wired wrapped screen. During the next quarter, well work is proposed on four wells in the north flank of the steamflood area as shown with arrows in Figure 1. The proposed work includes converting two former steamflood injectors (952-UP and 954-UP) to water injection into the "D" sands, plugging back "D" sand injector 953-UP and recompleting it into the "T" sands, and plugging back watered out producer AT-59 out of the lower "D" sands and recompleting it into the upper "D" sands with perforations and a gravel-packed inner liner.

Expanding the DOE project in March 1999 to include the Tar V steamflood has allowed the project team 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 2. Well FRA-29 was converted to a water injector in November 2000. A new horizontal producer, J-206, is being proposed to drill in 2002 along with converting a south flank well to water injection for additional pressure support (both shown in red).

Pilot steamflood performance was excellent for the first two years as shown in Figure 3 with oil production peaking at 743 BOPD in January 1998 at a cumulative steam-oil ratio (SOR) of 4.4. All five horizontal wells were given initial cyclic steam jobs to consolidate the formation sands and to stimulate heavy oil production. For the five horizontal wells, Table 2 lists the initial production date, the peak monthly oil production rate, the date of peak oil production, and the cumulative oil production through September 2001. The three infill vertical wells, A-186, A-195 and A-320, all responded favorably to steam injection in the horizontal wells.

Figure 2

Wells A-186 and A-320 still contributed a combined 76 BOPD during the Third Quarter 2001, although this is a decline of 32 BOPD since December 2000. Well A-195 was idled in August 1998 because of steam breakthrough and is used as a temperature observation well.

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 304 BOPD in December 2000 with a cumulative SOR of 6.4. During the First Quarter 2001, oil production declined gradually to 231 BOPD without any appreciable change in gross production, probably due to steamflood and waterflood response. During the Second Quarter 2001, production increased in June to 261 BOPD as a result of speeding up the pumping units on the three horizontal well producers. Production declined to 196 BOPD in September 2001 but should increase during the fourth quarter after changing and speeding up pumps. The wells still have high producing fluid levels that need to be pumped down further.

Table 2
Tar V Steamflood Pilot - Horizontal Wells

Well	Init Prod Date	Peak Prod, BOPD	Peak Prod Date	Cum Oil Prod Thru Sept 2001, 1000 BO
FJ-202	Nov 96	280	Dec 96	40.8
FJ-204	Feb 97	223	Apr 97	27.0
J-205	Apr 97	328	May 97	96.1
J-203	Jun 97	267	Mar 98	161.2
J-201	Oct 97	283	Jan 98	99.4

Note: Wells FJ-202 and FJ-204 converted to injection Jun 97 and Oct 97, respectively.

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. As of September 2001, the pilot has produced 648,000 barrels of oil and 6,004,000 barrels of gross fluid (89% average water cut) and injected 4,660,000 barrels of steam and 6,559,000 barrels of total steam and water for an overall I/P ratio of 1.09. 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 4.

The pilot project through the Fourth Quarter 2000 was meeting 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 is 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 not considered when comparing projected to actual steamflood performance is that the injected steam quality was rarely at 80% and probably was closer to 40%. Because steam fuel cost is the main concern when correlating steamflood performance to steam-oil ratio, an evaluation needs to be made to normalize actual steam usage to a BTU equivalent volume of 80% quality steam.

The Tar V pilot project has been operated differently than originally planned because of thermal-related surface subsidence concerns regarding the Tar II-A steamflood project. Steam and water injection were increased to raise the average I/P ratio to a minimum of 1.05, 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. The pilot is now operating significantly below projections as the instantaneous steam-oil ratios since November 2000 have averaged over 10. In addition, when producing fluid temperatures reached 350/F in the interior horizontal producer well J-203 in May 2001, the City of Long Beach required the steam generator to output only hot water at a temperature not to exceed 350/F to prevent thermal-related formation compaction. This could significantly affect steamflood performance as the overall reservoir has not been heated to adequate temperatures.

The pilot project has potential for increasing oil production without further increasing hot water injection. All three horizontal producers have had high producing fluid levels over 1150 feet over the pump (FOP) for several months. Speeding up the pumping units on wells J-201, J-203 and J-205 during the second quarter increased oil production by 50 BOPD and reduced fluid levels about 150 feet. Theoretically, drawing down the fluid levels should increase production to about 2200 BPD gross and 125 BOPD per well (incremental of 900 BPD gross and 85 BOPD, 10.7% oil cut) based on leaving a safe producing fluid level to prevent sand inflow. Well FRA-29 was converted to injection in November 2000 to provide the necessary water injection support for production increases in wells J-201 and J-203. This well will also provide more reservoir pressure support from outside the pilot area to improve well productivity similar to the flank water injection in the Tar II-A project. Additional water injection on the south flank of the project is needed to support increasing production in well J-205 as shown in Figure 2.

Technology Transfer

Scott Hara made an oral presentation entitled "Applying New Technology to an Old Field" to the California Conservation Committee of Oil and Gas Producers on September 19, 2001 in Long Beach. The presentation focused on the Tar II-A post-steamflood modeling and operations and on the successful drilling of horizontal well L-232 to thin oil sand beds in the Tar V zone, both DOE Class III-related projects.

Scott plans to reprise the presentation on November 2, 2001 to the Petroleum Engineering Department at Stanford University.

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.

References and Notes

1. Hara, Scott, Tidelands Oil Production, "Applying New Technology to an Old Field", California Conservation Committee of Oil and Gas Producers, Long Beach, CA, 19 September 2001.
2. Hara, Scott, Tidelands Oil Production, "Applying New Technology to an Old Field", Stanford University Petroleum Engineering Dept., Stanford University, CA, 2 November 2001.