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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: April 30, 2002

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Anticipated Completion Date: September 30, 2003 Budget Period 1
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\$18,532 (March 2002 YTD Actual)
\$450,061 (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

Reporting Period: January 1, 2002 to March 31, 2002

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 December 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.

During the First Quarter 2002, the project team developed an accelerated oil recovery and reservoir cooling plan for the Tar II-A post-steamflood project and began implementing the associated well work in March. The Tar V pilot steamflood project will be converted to post-steamflood cold water injection in April 2002.

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. Most of the 2001 well work resulted in maintaining oil and gross fluid production and water injection rates. Reservoir pressures in the "T" and "D" sands are at 88% and 91% hydrostatic levels, respectively. Well work during the first quarter and plans for 2002 are described in the Reservoir Management section.

The steamflood operation in the Tar V pilot project is mature and profitable. Recent production performance has been below projections because of wellbore mechanical limitations that have been addressed during this quarter. As the fluid production temperatures were beginning to exceed 350/F, our self-imposed temperature limit, the pilot steamflood was converted to a hot waterflood project in June 2001 and will be converted to cold water injection next quarter. 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. 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.

Figure 1 shows the post-steamflood wells active in the First Quarter 2002 compared to the original steamflood patterns. Five of the post-steamflood wells were idled (crossed out). The most southerly "D" sand water injector, FW-88, was abandoned in December 2001 and replaced by a new well, FW-295, located just to the north of FW-88.

Shown in outlined well symbols in Figure 1 are four injectors and thirteen producers that are to be activated in the first half of 2002. The proposed well work is to accelerate cooling of the Tar II-A steamflood reservoirs by increasing cold water injection and high temperature gross fluid production. Of the thirteen

producers to activate, two are idled post-steamflood wells and four are located on the western downdip flanks and could become water injection conversion candidates when they are water out.

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 pressure by March 2000. Since then, reservoir pressure has been maintained at 90 - 91% hydrostatic through March 2002 and the reservoir has acted more like a waterflood that could be operated at lower net injection rates and lower I/P ratios of about 1.4-1.5, still high compared to the 1.05 in most of the other Wilmington waterflood projects.

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

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 95% hydrostatic in 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 even though "T" water injection was increased back to normal in October 2001. An injection well meter is suspected of being partially plugged and providing erroneously high injection rates by about 3,000 BWIPD from September 2001 to March 4, 2002. Since then, injection rates were confirmed and reservoir pressure has started to increase. Fortunately, reservoir pressures only need to rise about 20-25 psi to 930-935 psi to meet the objective 90% hydrostatic level. 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.

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 1,009 BOPD and 20,393 BPD gross fluid (19.21 water-oil ratio [WOR]) with 33,951 BPD water injection during the First Quarter 2002. The oil and gross fluid production rates are lower than the previous quarter because of gradual pump failures that were repaired by the end of the quarter. First quarter water injection rates were increased to accommodate the activation and testing of additional producers. The first four wells activated resulted in two profitable wells totaling 73 BOPD, one downdip watered-out well, and one well with a bad pump. Pump repair work on well UP-946 increased oil production from 35 BOPD pre-job to 105 BOPD.

Starting in March, well work has proceeded to convert three wells to "D" sand water injection and one well to "T" sand water injection. Three of the wells are in the north flank of the steamflood area as shown in Figure 1. The proposed work includes converting two former steamflood injectors (952-UP and 954-UP) to water injection into the "D" sands and plugging back "D" sand injector 953-UP and recompleting it into the "T" sands. The fourth well, 2AT-33, will be converted to a "D" sand water injector in an interior steamflood pattern that has experienced the most surface subsidence and includes observation wells OB2-5 and 1F-10. A recent temperature survey in OB2-5 showed the "T" and "D" sands to have peak temperatures of 450/F. The objective is to initiate water injection by April to get several weeks of injection before the May subsidence surveys are taken. The project team will evaluate formation compaction and cooling and surface subsidence in the pattern over the next six month period through the use of bimonthly GPS surveys, temperature surveys in OB2-5 and 1F-10, and possibly another cased-hole neutron log in 1F-10 to compare shale compaction with previous logs.

Figure 2 is a production graph of the Tar II-A steamflood project from inception in 1982 through March 2002.

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 3. Well FRA-29 was converted to a water injector in November 2000. A new horizontal producer, A-605, 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 4 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. Wells A-186 and A-320 still contributed a combined 60 BOPD during the First Quarter 2002. Well A-195 was idled in August 1998 because of steam breakthrough and is used as a temperature observation well. Table 2 lists the initial production date, the peak oil production rate, the date of peak oil production, and the cumulative oil production for the five horizontal and three vertical producing wells through March 2002.

After reaching peak production of 743 BOPD in January 1998, the pilot project oil production

FIGURE 4
TIDELANDS OIL PRODUCTION CO.
TAR ZONE FB-V STEAMFLOOD

Table 2
Tar V Steamflood Pilot - Horizontal & Infill Wells

Well	Init Prod Date	Peak Prod, BOPD	Peak Prod Date	Cum Oil Prod Thru Mar 2002, 1000 BO
FJ-202 HW	Nov 96	280	Dec 96	40.8
FJ-204 HW	Feb 97	223	Apr 97	27.0
J-205 HW	Apr 97	328	May 97	101.8
J-203 HW	Jun 97	267	Mar 98	166.6
J-201 HW	Oct 97	283	Jan 98	111.7
A-186	Prior Jun 96	83	Mar 00	86.4
A-195	Prior Jun 96	86	Nov 96	19.5
A-320	Prior Jun 96	145	Nov 97	129.5
Pilot Total	Jun 96	743	Jan 98	683.3

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

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 an average of 176 BOPD in the First Quarter 2002 despite continuing to speed up pumping units and increasing gross fluid production rates. 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. Second quarter 2002 production is expected to average 250 BOPD. The high producing fluid levels are being addressed and should substantially lower next quarter.

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 March 2002, the pilot has produced 683,300 barrels of oil and 6,780,000 barrels of gross fluid (90% average water cut) and injected 5,318,000 barrels of steam/hot water and 8,328,000 barrels of total steam and water for an overall I/P ratio of 1.23. 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 5.

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 has significantly affected steamflood performance as the overall reservoir was not heated to adequate temperatures. During the first quarter 2002, the pilot produced at the instantaneous "steam-oil" ratio over 18.

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 40% 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 78% of the BTU heat into the formation than planned. The 1,095,000 barrels of 350/F hot water injected is only 24% of the heat injected compared to an equivalent weight of water as 1600 psi 80% quality steam. Because steam fuel cost is the main concern when correlating steamflood performance to steam-oil ratio, an evaluation needs to be made to. Using the

ballpark heat input estimates of 40% quality steam and 350/F hot water compared to 80% quality steam, the adjusted "pseudo-80% quality steam volume injected through March 2002 is 3,557,000 barrels instead of the 5,318,000 barrels of water actually injected or 67%. This results in a normalized cumulative steam-oil ratio of 5.2 instead of the 7.8 shown for the project using unadjusted barrels. The original project projections showed an SOR of 6.2 for the cumulative oil recovered to date.

The pilot project has potential for increasing thermal oil recovery. In addition to repairing pumps in two of the horizontal wells, the plan is to install inner liners in two horizontal producers 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 THUMS / Tidelands lease line to capture the remaining thermally-heated oil in the pilot area. Additional water injection on the south flank of the project is needed to support increasing production from the horizontal wells. The proposed producer and water injection conversion well are shown in Figure 3.

Technology Transfer

Scott Hara made an oral presentation entitled "World Oil and Gas Reserves and Recovery Methods" to the geology classes at Long Beach Polytechnic High School in Long Beach, CA on March 13, 2002. The presentation provided a general overview of thermal oil recovery in the Wilmington and included displaying pre- and post-steamed cores from the Tar II-A project. The presentation also covered world oil pricing.

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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