Oil & Natural Gas Technology

DOE Award No.: DE-FC22-95BC14939

Final Report

Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies"

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Prepared for:
United States Department of Energy
National Energy Technology Laboratory

Office of Fossil Energy

U.S. Department of Energy Title Page Form Maker v1.0

Report Title:	Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies
Report Type:	FINAL
Reporting Period Start Date:	03/30/1995
End Date:	03/31/2007
Principal Author(s):	Scott Hara
Report Issue Date:	08/01/2007
DOE Award No.:	DE-FC22-95BC14939
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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 Dates: September 30, 2003 Budget Period 1
March 31, 2007 **Budget Period 2**

DOE Award: $6,685,458 (Cum Actual Budget Period 1 from 3/30/95 to 9/30/03)
$0 (Remaining funds in BP 1)
$703,296 (Cum Actual BP2 Funds expended 10/1/03-3/31/07)
$70,089 (Remaining funds in BP 2)

Principal Investigator: Scott Hara – Tidelands Oil Production Company

Program Manager: James Barnes - National Energy Technology Laboratory

Type of Report: **Final Technical Report**

Date of Report: August 1, 2007

Reporting Period: **March 30, 1995 to March 31, 2007**

Disclaimer

Abstract

The overall objective of this project was 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 involved 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 has been to transfer technology that can be applied in other heavy oil formations of the Wilmington Field and other SBC reservoirs, including those under waterflood.

The first budget period addressed several producibility problems in the Tar II-A and Tar V thermal recovery operations that are common in SBC reservoirs. A few of the advanced technologies developed include a three-dimensional (3-D) deterministic geologic model, a 3-D deterministic thermal reservoir simulation model to aid in reservoir management and subsequent post-steamflood development work, and a detailed study on the geochemical interactions between the steam and the formation rocks and fluids. State of the art operational work included drilling and performing a pilot steam injection and production project via four new horizontal wells (2 producers and 2 injectors), implementing a hot water alternating steam (WAS) drive pilot in the existing steamflood area to improve thermal efficiency, installing a 2400-foot insulated, subsurface harbor channel crossing to supply steam to an island location, testing a novel alkaline steam completion technique to control well sanding problems, and starting on an advanced reservoir management system through computer-aided access to production and geologic data to integrate reservoir characterization, engineering, monitoring, and evaluation.

The second budget period phase (BP2) continued to implement state-of-the-art operational work to optimize thermal recovery processes, improve well drilling and completion practices, and evaluate the geomechanical characteristics of the producing formations. The objectives were to further improve reservoir characterization of the heterogeneous turbidite sands, test the proficiency of the three-dimensional geologic and thermal reservoir simulation models, identify the high permeability thief zones to reduce water breakthrough and cycling, and analyze the nonuniform distribution of the remaining oil in place. This work resulted in the redevelopment of the Tar II-A and Tar V post-steamflood projects by drilling several new wells and converting idle wells to improve injection sweep efficiency and more effectively drain the remaining oil reserves. Reservoir management work included reducing water cuts, maintaining or increasing oil production, and evaluating and minimizing further thermal-related formation compaction. The BP2 project utilized all the tools and knowledge gained throughout the DOE project to maximize recovery of the oil in place.

<u>The Project Team Partners include the following organizations:</u>

1. The City of Long Beach - the operator of the field as 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 processes.

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Executive Summary

The project involved 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., California. The contract was awarded on March 30, 1995 and Pre-Award Approval was given on January 26, 1995, however, initial project work began on October 1, 1994. Budget Period 1 (BP1) effective dates were from March 30, 1995 to September 30, 2003. The project team received DOE BP2 contract approval on May 18, 2004 with the BP2 effective dates from October 1, 2003 to March 31, 2007.

The first budget period phase addressed several producibility problems in the Tar IIA and Tar V thermal recovery operations that are common in SBC reservoirs. A few of the advanced technologies developed include a three-dimensional (3-D) deterministic geologic model, a 3-D deterministic thermal reservoir simulation model to aid in reservoir management and subsequent post-steamflood development work, and a detailed study on the geochemical interactions between the steam and the formation rocks and fluids. State-of-the-art operational work included drilling and performing a pilot steam injection and production project via four new horizontal wells (2 producers and 2 injectors); implementing a hot water-alternating-steam (WAS) drive pilot in the existing steamflood area to improve thermal efficiency; installing a 2,400-foot insulated, subsurface harbor channel crossing to supply steam to an island location; testing a novel alkaline steam completion technique to control well sanding problems; and starting work on an advanced reservoir management system through computer-aided access to production and geologic data to integrate reservoir characterization, engineering, monitoring, and evaluation.

The second budget period phase (BP2) implemented state-of-the-art operational work to optimize thermal recovery processes, improve well drilling and completion practices, evaluate and mitigate adverse geomechanical characteristics of the producing formations, update the 3-D geologic and reservoir simulation models, and utilize the models to identify and drill new well locations. The reservoir evaluation work included improving the characterization of the heterogeneous turbidite sands, identifying high-permeability thief zones to reduce water breakthrough and cycling, and analyzing the nonuniform distribution of the remaining oil-in-place. The evaluation work resulted in the redevelopment of the Tar II-A and Tar V post-steamflood projects by drilling a few new wells and converting idle wells to more effectively drain the remaining oil reserves by improving injection sweep efficiency and reducing water cuts while minimizing further thermal-related formation compaction. With no steam currently available to inject, efforts are being made to test cold heavy oil production techniques. The BP2 work utilized all the tools and knowledge gained throughout the DOE project to maximize recovery of the oil-in-place.

Benefits

Tidelands attributes many successful outcomes in the field and for the industry to the technologies learned from Tidelands' two Class III DOE projects (DE-FC22-95BC14939 and DE-FC22-95BC14934).

Tidelands is experiencing the most successful drilling in 25 years at the Wilmington onshore oil field area owned by the City of Long Beach. Tidelands' operated Wilmington field oil production dropped to a low of 6100 BOPD in March 2002. A drilling program was started in 2003 and Tidelands drilled 49 producers, 11 water injectors, and one slurry waste disposal injection well through May 2007 and has plans in early 2008 to drill 8 producers and 5 water injectors. The 49 producers have been active from one month to four years and current production well test rates total 3,025 BOPD and 63,140 BGFPD (95.4% water cut), which represent 36% of Tidelands' 8,422 BOPD operated production in May 2007. Eight wells have been drilled to the Fault Block 3 Upper Terminal zone since 2003 in an area the City of Long Beach had almost given up on as depleted. Initial well rates have ranged from 159 – 1048 BOPD and the wells produced 403 BOPD in May 2007.

The drilling results are particularly encouraging since the portion of the Wilmington Field that Tidelands operates has been on production since the 1930's, was completely developed by the 1950's and has been waterflooded since 1953. The average water cut is 96.7% and the natural decline is about 8% per year. Tidelands has recently been drilling three types of production wells: selective completions, horizontal wells and fracture stimulated wells. Our success with the first two types of production wells, selective completions and horizontal wells, are a direct result of the work that Tidelands completed under the DOE Class III projects.

Tidelands developed a novel sand-consolidation well completion method that prevents sand entry into the producing wellbore through the injection of typical oilfield-generated steam into wells. This new technology offers lower capital costs, provides more operating flexibility, and appears to have higher productivity indexes than other sand-control completions. The technology was patented (U.S. Patent No. 6,554,067 Davies, Mondragon, Hara) in April 2003 and further researched by Stanford University.

Tidelands and DOE funding supported new technologies that spurred the growth of two startup companies: Dynamic Graphics, Inc. (DGI), Alameda, CA, and Geomechanics International, Inc. (GMI), Houston. DGI significantly expanded after other independent operators learned from the DOE project the effectiveness of 3-D modeling in describing a complex reservoir and oilfield such as Wilmington. Since then, they have become a 3-D modeling provider of choice to small- and mid-size California independent operators who have seen the value of this technology for complex reservoirs. Stanford geophysics researchers teamed with Tidelands and Magnetic Pulse, Incorporated of Fremont, California to interpret novel well logs calibrated to accurately measure porosity and oil saturation through sound-wave technology. GMI was created afterwards by these and several other Stanford geophysics researchers who collectively developed new ways to apply their expertise to improve drilling techniques and reservoir characterization.

The deeper and higher-pressure attributes of the Wilmington steamflood caused unanticipated operational problems that do not occur in most other steamfloods. Significant deeper and higher-pressure heavy oil deposits exist in the world that can be recovered applying thermal enhanced recovery techniques. The technologies and practical solutions developed in this project will reduce the operating problems, expenses, and risks of similar projects. Tidelands personnel have discussed their findings with operators in California, Alaska, Wyoming, Texas, Canada, Trinidad and Tobago, China, Oman, and Venezuela.

Budget Period 2 (BP2) Annual Project Summary – April 1, 2006 to March 31, 2007

The project has experienced several drilling and operational highlights during BP2 for the annual period ending March 31, 2007 based on utilizing technologies learned during BP1.

Tidelands utilized the 3-D thermal reservoir simulation model to drill and complete Tar II-A horizontal well UP-961 at the top of the highly oil-saturated D1 sands in the downdip, cold oil area southwest of the steamflood where vertical waterflood producers had very high water cuts. UP-961 was placed on production in November 2005 and has been an excellent well, initially producing 185 BOPD and 635 barrels of gross fluid per day (BGFPD) and in May 2007 producing 66 BOPD and 1404 BGFPD. Tar II-A vertical infill well UP-960 was drilled within a mature pattern that had been steamflooded and hot waterflooded to confirm oil sweep efficiency and the heterogeneity of sands. The well logs showed that a steam chest had formed in the D1 sands, which was oil depleted, but the T sands had high, pre-steamflood oil saturations. The well was completed in January 2006 into the T sands and the top of the depleted D1 sands to try to accelerate gravity segregation of oil in the lower D1 sands to the top of the sands. Well UP-960 initially produced 1 BOPD and 1001 BGFPD, but within two months hit a peak oil rate of 70 BOPD and 1328 BGFPD. Production in February 2007 was still at 72 BOPD and 1645 BGFPD, but recently declined in May 2007 to 39 BOPD and 938 BGFPD, probably due to a failing pump.

Tidelands activated 11 idle wells in the Tar II-A post-steamflood area from 2004-06, five as producing wells and six as water injection wells, to improve reservoir performance. The average oil production and gross fluid rates and water-oil ratio (WOR) in the fourth quarter 2003 were 944 BOPD, 28,215 BGFPD, and 29 BW/BO, respectively. Tar II-A performance improved from April 2004 to March 2005, with average 12-month oil production and gross fluid rates and WOR of 1169 BOPD, 29,185 BGFPD, and WOR of 24, respectively, a significant 225 BOPD increase in oil production while increasing water production less than 1000 BPD. A Tar II-A comprehensive reservoir monitoring plan was implemented to evaluate remaining high temperature areas and to determine the extent and magnitude of thermal-related formation compaction.

Tar II-A oil production improved from 902 BOPD at a 3.3% oil cut (28.9 WOR) in November 2003 to a peak of 1422 BOPD at a 3.7% oil cut (26.1 WOR) in November 2005. Production declined to an average of 1082 BOPD at a 2.8% oil cut (35.1 WOR) in 2007 through May as many wells are watering out. A new reservoir management plan needs to be implemented to reduce the high water cuts.

Tidelands drilled three new horizontal wells in the Tar V zone adjacent to successful well A-603 to further test the ability of horizontal wells completed at the top of the S4 sands in previously waterflooded areas to recover cold tarry oil. Well A-115 was drilled in October 2005 and wells J-131 and Z1-64 were drilled in November 2006. Well A-115 was successful like A-603, initially producing at a peak rate of 224 BOPD and 1497 BGFPD in November 2005. Production in February 2007 was still high at 145 BOPD and 1507 BGFPD, but net oil decreased in May to 64 BOPD and 1446 BFPD for reasons to be determined, which could range from the well watering out to well tester problems. Wells J-131 and Z1-64 do not appear to be as good as their predecessors. Well J-131 initially peaked at 64 BOPD and 2074 BGFPD in January 2007 and in May was producing 50 BOPD and 2119 BGFPD. Well Z1-64 had an encouraging initial peak rate of 216 BOPD and 1382 BGFPD. Production in March 2007 was 115 BOPD and 1877 BGFPD and oil rates continued to decline to 75 BOPD and 1795 BGFPD in May. Both wells appear to be pumped at excessive rates compared to A-603 and A-115, which could be watering them out prematurely. Wells A-603 and A-115 are slightly updip of J-131 and Z1-64 and their high oil rates could be affecting downdip water movement.

Stanford researchers completed their contract work injecting hot alkaline fluid into formation cores and quart sand vessels to determine if they could duplicate the sand-consolidation empirical process from the field in the laboratory. Initial results did not generate the expected calcium silicate cements. The experimental design assumptions were reexamined, and further testing indicated the calcium silicate cements probably originated from dissolution of wellbore cements used in completing the well. Their results show that it may be possible to add calcium silicate to injected hot alkaline water to consolidate formation sands in a perforated well completion. A second phase of laboratory research to formulate hot alkaline, geochemical solutions to consolidate formation sands was not performed and may occur after the contract termination date, to be covered by Tidelands and the City of Long Beach.

Tidelands initiated contact with service companies to evaluate improved oil recovery processes. Tidelands worked with Coriba Oil Company, LLC from 2004-06 to test their Coriba™ line of chemicals that water-wet formation sands and release the resident oil. A pilot test to improve water injection well injectivity did not perform as expected and work has been suspended.

Tidelands is evaluating the potential of BJ Services' chemical named AquaCon™ that is a relative permeability modifier for reducing water productivity into wells. Tidelands and BJ Services are at the technical discussion phase to run core flow tests.

Technology Transfer

Tidelands was acquired by Occidental Petroleum Corporation (Oxy) in February 2006. Oxy is in the process of developing one of the largest steamflood projects in the world in the Mukhaizna Oil Field in Oman to startup in 2008. Tidelands is working with Oxy engineers in Oman to transfer technologies and operating expertise gained from the Wilmington steamflood project.

Stanford delivered SPE paper no. 92398 about the results of their laboratory research on the sand consolidation well completion process in March 2005. This paper, entitled "A Laboratory Investigation of Temperature Induced Sand Consolidation," by C. M. Ross, E. R. Rangel-German*, L. M. Castanier, A. R. Kovscek, Stanford University, and P. S. Hara, Tidelands Oil Production Company, was peer-reviewed and published in the June 2006 issue of the *SPE Journal.*

The American Oil and Gas Reporter published an article in July 2006 entitled "3-D Modeling Leads to Horizontal Well Success", based on SPE paper no. 94021 entitled "Applying a Reservoir Simulation Model to Drill a Horizontal Well in a Post-Steamflood Reservoir, Wilmington Field, California" by Philip Scott Hara, Tidelands Oil Production Company, Julius J. Mondragon III, H. Henry Sun, City of Long Beach, Zhengming Yang, EXGEO (CGG Venezuela), and Iraj Ershaghi, University of Southern California

Hart E&P Magazine will be publishing an article on "Brownsfield Development" in August 2007 based on the 2006 DOE annual technical progress report for this project.

The DOE Office of Fossil Energy of the National Energy Technology Laboratory published a CD on this project entitled "Giving an Aging Heavy Oil Giant a New Lease on Life" in 2006, which contains selected papers generated by the project team.

Introduction

Report Overview

The final technical report covers the period March 30, 1995 to March 31, 2007. The project involved 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., California. The contract was awarded on March 30, 1995 and Pre-Award Approval was given on January 26, 1995, however, initial project work began on October 1, 1994. Budget Period 1 (BP1) effective dates were from March 30, 1995 to September 30, 2003. The project team received DOE BP2 contract approval on May 18, 2004 with the BP2 effective dates from October 1, 2003 to March 31, 2007.

This chapter begins with an overview of the field development and production history of the Wilmington Oil Field. Many of the project benefits are included in the history. Subsequent chapters conform to the manner consistent with the Activities, Tasks, and Sub-tasks of the project as originally provided in Exhibit C1 in the Project Management Plan dated May 5, 1995. These chapters summarize the objectives, status and conclusions of the major project activities performed during the project. The report concludes by describing technology transfer activities stemming from the project and providing a reference list of all publications of original research work generated by the project team or by others regarding this project.

Project Overview

The overall objective of this project was 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 involved 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 has been to transfer technology that can be applied in other heavy oil formations of the Wilmington Field and other SBC reservoirs, including those under waterflood

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The project was implemented by a team including:

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.

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

Acknowledgments

This research was performed under the Class III Oil Program of the U.S. Department of Energy (DOE), National Energy Technology Laboratory, Office of Fossil Energy, and contract number DE-FC22-95BC14939. The Contracting Officer's Representative is James Barnes, with the DOE National Energy Technology Laboratory in Tulsa, OK.

The following individuals and companies provided valuable assistance to this project through participation on the project team or as consultants to the team:

The City of Long Beach **562-570-3900**	Bailey, Scott Barth, Jack Clarke, Don Colazas, Xenophon Costa, Alex Henderson, Curtis Henry, Mike Hernandez, Laura Koerner, Roy Lujan-Saad, Sylvia Mondragon, Julius* Schoij, Suzanne Sullivan, Dennis Sun, Henry Tougas, Kevin
Tidelands Oil Production Company **562-436-9918**	Cassinis, Rick Farabaugh, Kenneth Fickes, Robert Hara, Scott Jongbloed, Peter Kapelke, Mark Parmelee, Chris Payan, Rudy Phillips, Chris Quay, Jim Shatwell, Danny Shemaria, Mark Siegwein, Steve Walker, Scott Whitaker, Walt Wills, Jim
University of Southern California **213-740-0321**	Akkutlu, Yucel Al-Qahtani, M. Amili, Pouya An, Linji Arias, Jose Bronson, Jon Brown, Al Du, Changan Ershaghi, Iraj Gallant, Geoff

	Ghaffari, Bayesteh Handy, Lyman. Hassibi, Mahnaz Hosn, Nadim Schaller, Herman Smith, Linda Tagliari, Anthony Yang, Zhengming Yew, Kelvin
GeoSystems, formerly David K. Davies & Associates 281-358-2662	Aumon, John Davies, David K. Vessel, Richard K.
Stanford University 650-723-1218	Louis Castanier Anthony Kovscek Edgar Rangel-German Cynthia Ross

Wilmington Field Development and Production History, including Work Performed During Budget Periods 1 and 2

The Wilmington Oil Field is the fourth largest oil field in the United States, based on the total oil recovered. Almost 2.6 billion barrels of oil have been produced to date, from an original oil in place of 8.8 billion barrels.

The field is located in and around the City of Long Beach, in Southern California. Location maps of the field are in Figures 1 and 2. Figure 3 shows an aerial view of Tidelands Oil Production Company's operations in Fault Blocks I-VI. The Wilmington Field is divided into ten fault blocks (Figure 4), and has seven major producing zones (Figure 5). Heavy oil occurs in the Tar, Ranger and Upper Terminal zones. This project is being conducted in the Tar zone within Fault Blocks II-A and V as shown in Figures 3, 4, 5 and 6.

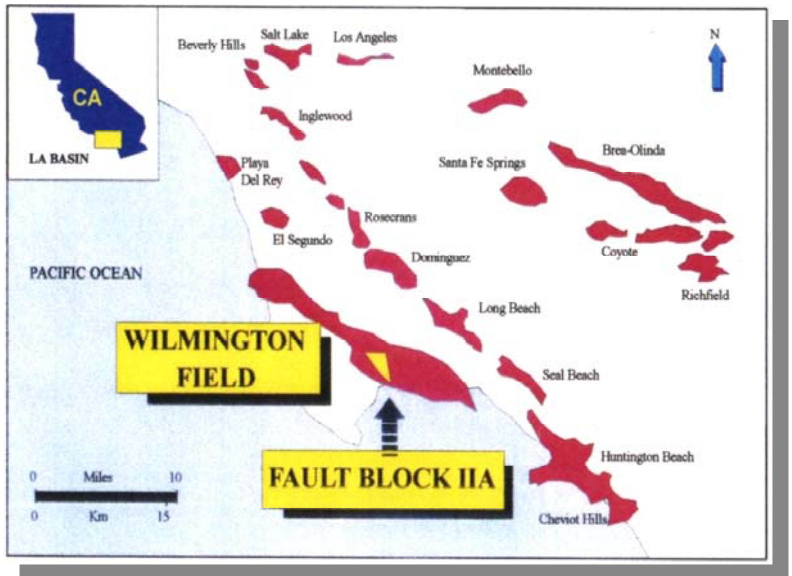


Figure 1: Map showing the geographical location of the Wilmington Field in Southern California.

Primary production from the field began in 1936. Large-scale waterflooding was introduced during the 1950-60s to increase oil recovery and control surface subsidence. Various tertiary recovery projects have been tried, but with only limited success. For most of the producing zones, the dominant form of economic oil recovery remains waterflooding. The current water cut is approximately 97.0%. Recoveries in the waterflood and tertiary recovery projects have been hindered by poor sweep efficiency, as is typical of heterogeneous reservoirs with turbidite geology.

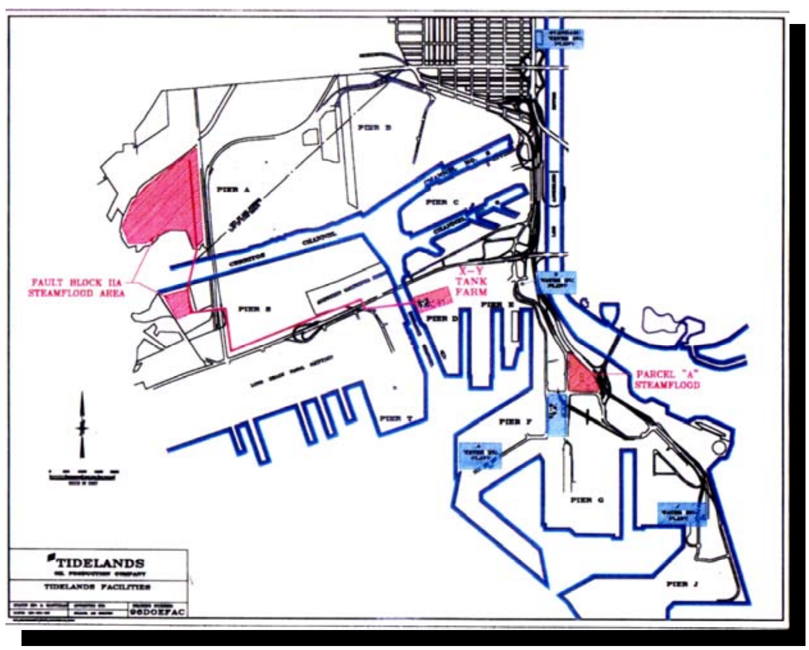


Figure 2: Plan view of Tidelands facilities showing the steamflood zone of Fault Block II-A Wilmington Field.

Tar II-A Production

The Union Pacific Railroad Company first produced the Tar II-A in 1937. The Fault Block II oil operations were unitized for secondary recovery operations (waterflooding) in 1960 to maintain reservoir pressures. Water injection began later that year. The Tar II-A cumulative oil production through 1979, after 19 years of waterflooding, was 20 million barrels; equivalent to a recovery factor of only 20% of the original oil in place (OOIP). These low recovery factors are due to adverse mobility ratio and sand heterogeneity, which have resulted in low areal and vertical sweep efficiencies. Because of the poor waterflood performance, applying steam injection was evaluated to improve heavy oil recovery (13° API). [A1, D3]

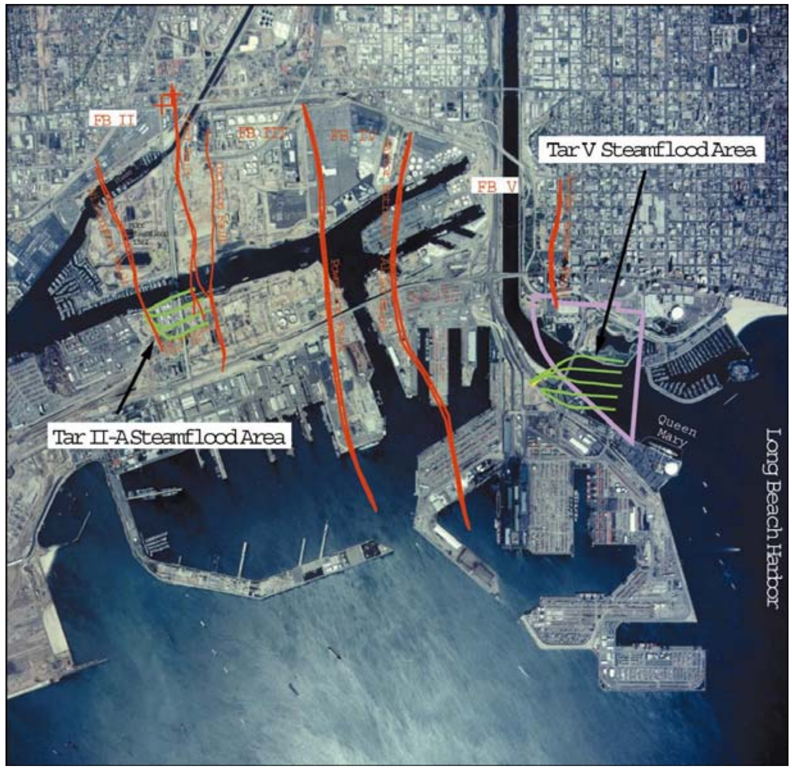


Figure 3: Aerial view of the Wilmington Field showing locations of FB II-A and V steamflood projects.

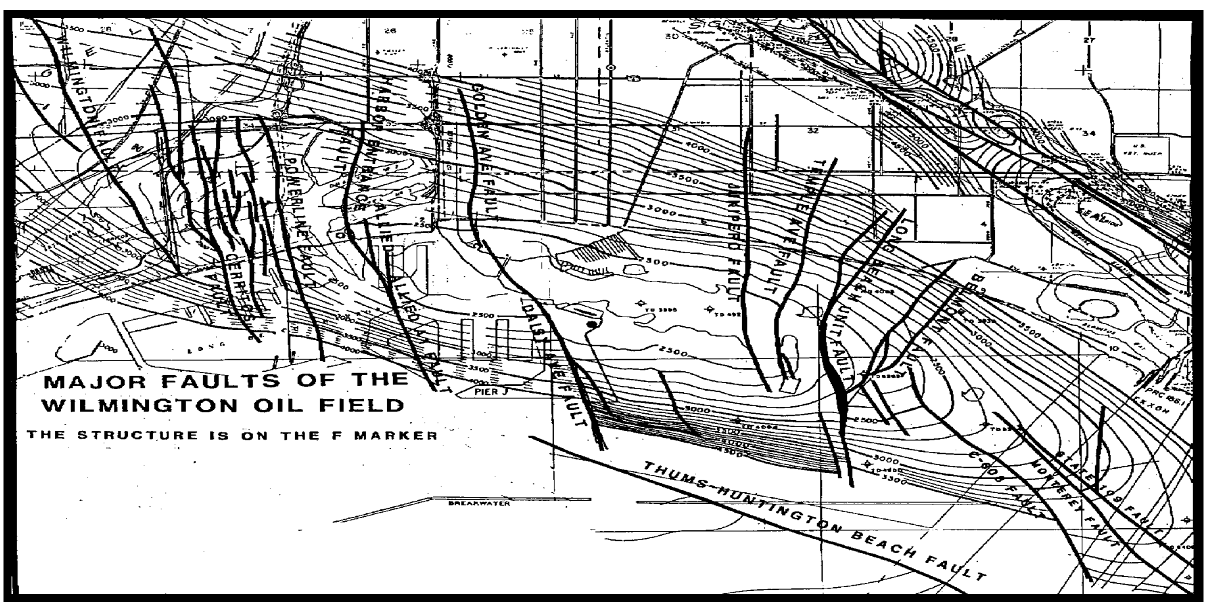
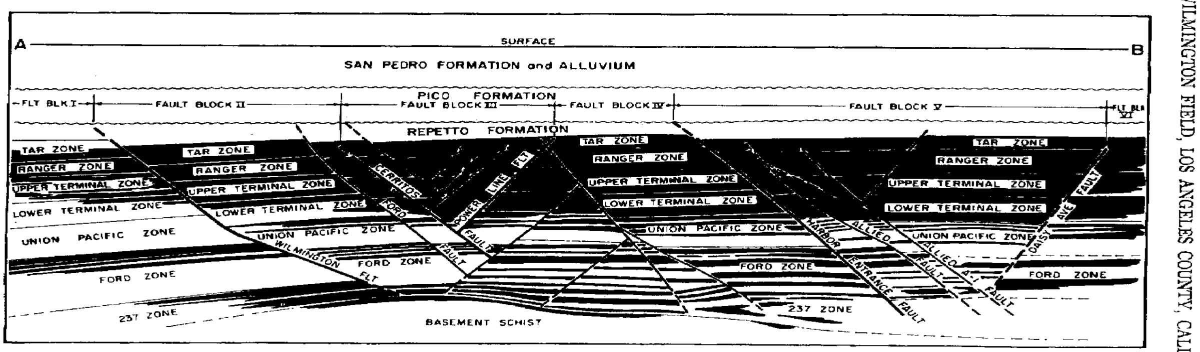


Figure 4: Geologic representation of the Wilmington Oil Field detailing fault line layout.



Northwest-southeast cross section, Wilmington field, showing producing zones. Trace of section is *A-B* on Fig. 1. Source—*California Oil and Gas Fields*, Pt. 2; courtesy California Division of Oil and Gas.

Figure 5: Cross-section of a representative sector of the Wilmington field detailing producing zones.

Figure 6: Fault Blocks II-A (red) and V (green), Wilmington Field. Structural contours on Ranger Zone.

Champlin Petroleum, later called Union Pacific Resources Company, performed a successful steam injection pilot test in the Tar zone of Fault Block II-A from 1982-1989.[D3] The pilot project was comprised of four inverted 5-acre five-spot patterns and recovered 1.1 million barrels of oil for a recovery factor of 75% OOIP or an incremental recovery of 55% OOIP over waterflooding. The pilot had a reasonable cumulative steam/oil ratio (SOR) of 6.4 barrels of cold water equivalent steam (BCWES) per barrel of oil recovered, with the lowest annual SOR of 5.5 occurring in 1984. Steamflood expansion potential was considered to be better than the pilot because most of the production wells would be backed up with steam injection from all directions.

The Tar II-A pilot was expanded to 98 acres using an inverted 7-spot pattern in the northern half of the fault block in 1989 (Figure 7). Subsequent phases were added from 1990 through 1995 for a total area under steamflood of 194 acres. The expanded steamflood project did not meet with the same degree of success as the pilot. Although the steamflood achieved peak oil rates exceeding 3,000 BOPD in 1991, the best instantaneous SOR for a month only went as low as 5.5. From 1991 to the end of steam injection in January 1999, steam injection rates maintained an average of 25-32,000 BCWESPD while oil production rates gradually declined to 2,000 BOPD. This resulted in a very high instantaneous SOR in 1998 averaging about 15 and a high cumulative SOR of 9 for the project (Figure 8a). The project experienced several downhole and surface operational problems. Well problems included scaling of the slotted liners and downhole pumps and premature equipment failure due to the high produced fluid temperatures accompanying steam breakthrough. Costly and inflexible completion practices were utilized to control

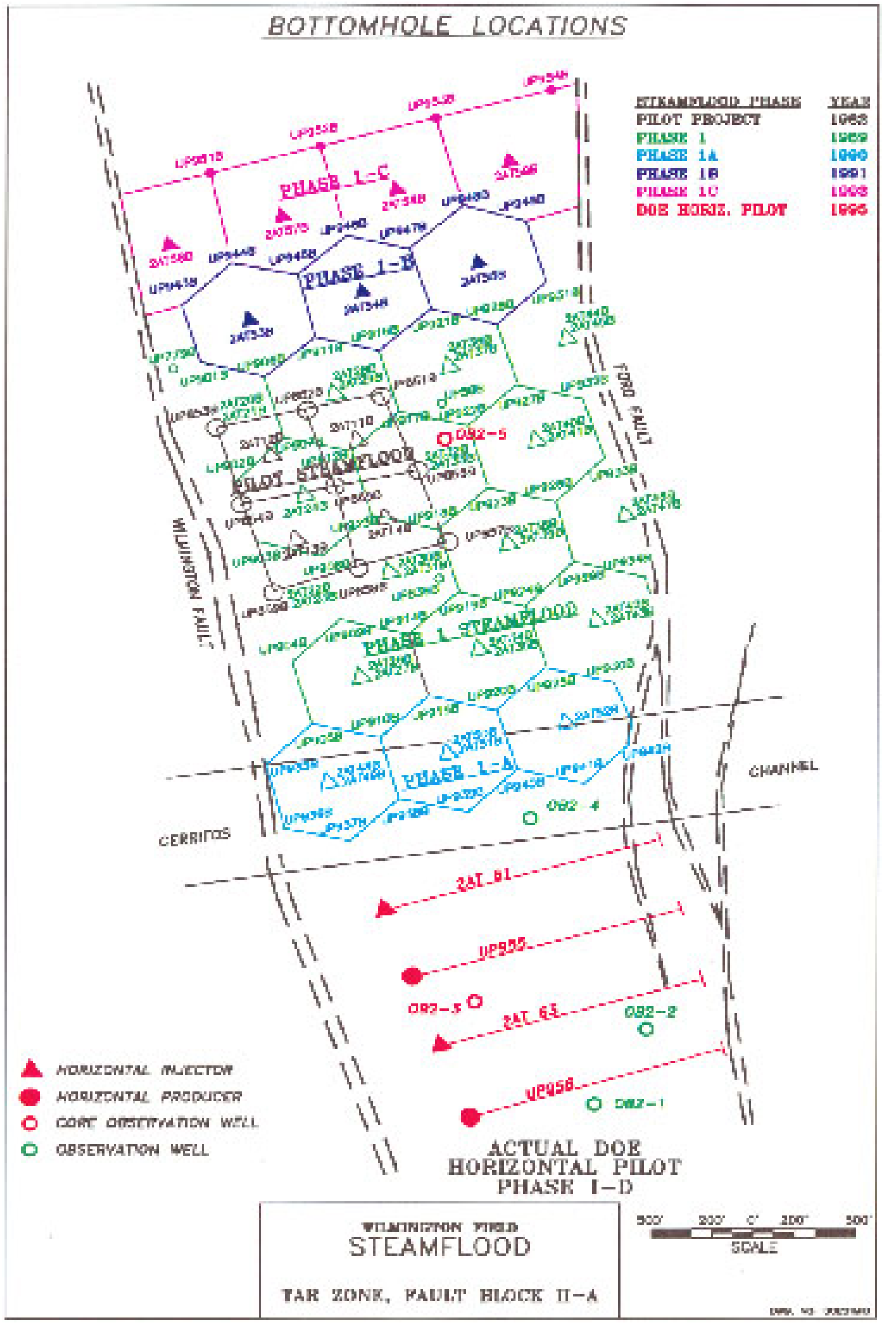


Figure 7: Tar II-A pilot and expansion steamflood projects. The steamflood expansion phases, start dates and well patterns are shown.

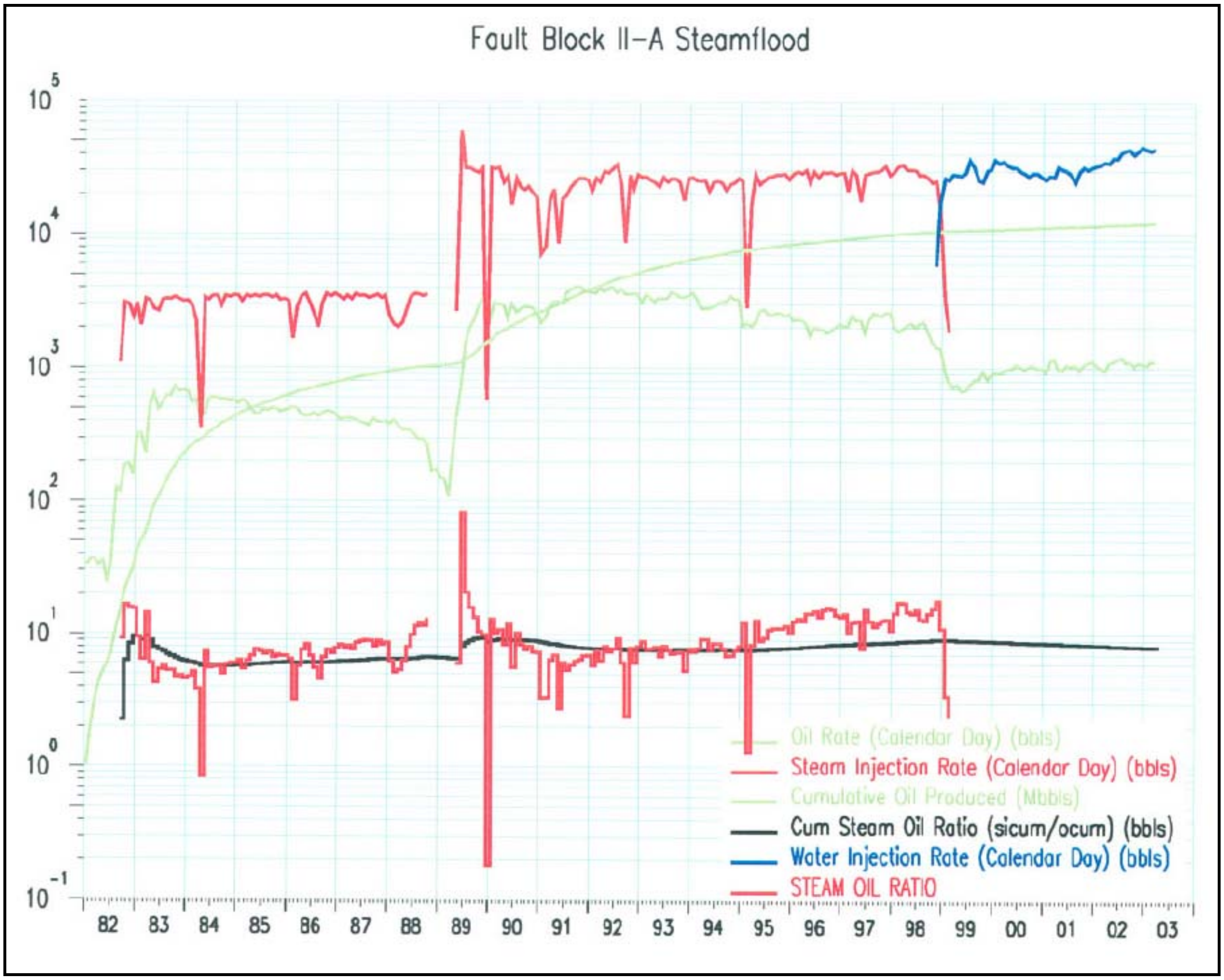
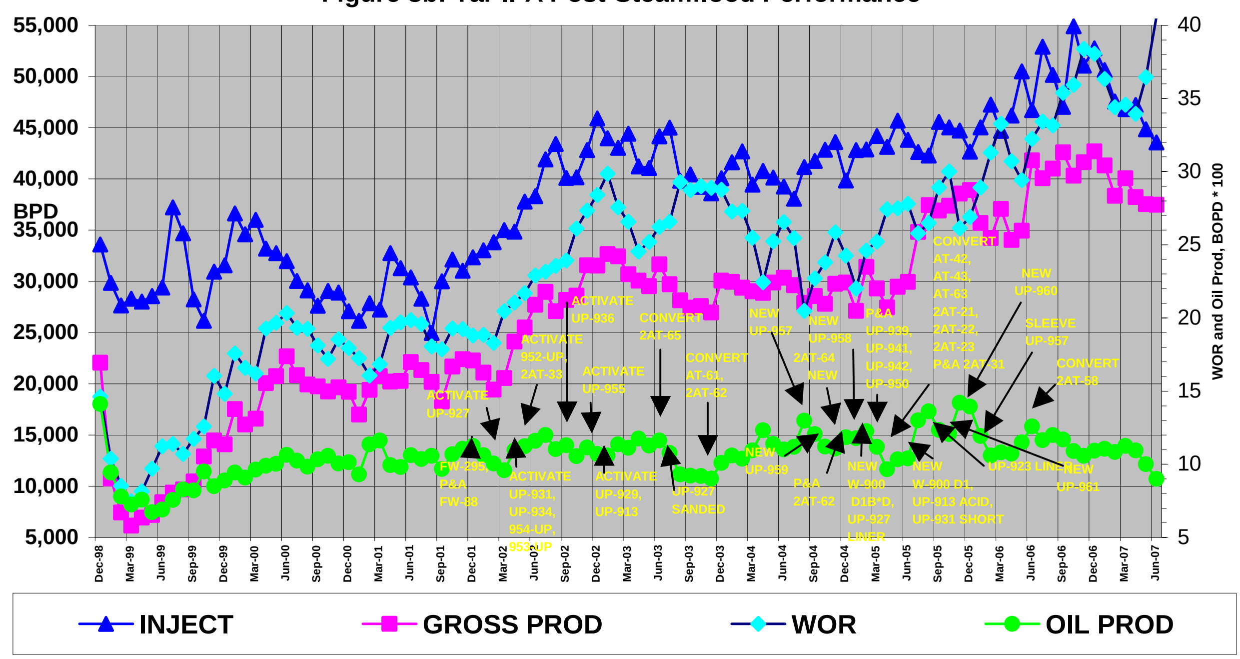


Figure 8a: Tar II-A steamflood production and injection from 1/82 to 3/03.

sanding problems that have occurred elsewhere in the field. Surface facility problems included handling the hydrogen sulphide, mercaptans, and carbon dioxide gases created in the reservoir by the steam heat, controlling steam breakout in the production gathering lines, and monitoring tank farm fluid temperatures and pressures for safety and to prevent damage to vessels and pipelines. Many of these types of problems could have been anticipated with a better understanding of the mineralogy of the formation sands and water and the complex turbidite geology of SBC reservoirs in the Tar zone. The steamflood was primarily profitable because of a favorable steam purchase contract with the Harbor Electric Cogeneration plant. Harbor Cogen discontinued supplying steam in January 1999 after Southern California Edison Company purchased its favorable electric power contract through an electric deregulation incentive program.

The Tar II-A project area began experiencing severe surface subsidence just prior to the cessation of steam injection. There were several possible causes, including grading work by the Port of Long Beach that added several tens of millions of tons of compacted fill to the area to expand port facilities, the wholesale abandonment of adjacent waterflood wells for port expansion that terminated water injection, and heat-related formation compaction in the steamflood sands. The last possibility jumpstarted the development of a post-steamflood operating plan in 1998 to mitigate the problem. Based on the results of sensitivity studies utilizing the deterministic 3-D thermal reservoir simulation model developed by USC, water injection wells were strategically placed along the structural flanks of the reservoir and replaced pattern steam injection. Gross production was curtailed by 75% to increase reservoir pressure. Production declined from 2253 BOPD and 33,241 barrels of gross fluid per day (BGFPD; 6.8% oil cut) with steam and water injection at 30,118 cold water equivalent barrels per day (CWEBPD) in August 1998 to 725 BOPD and 6145 BGFPD (11.8% oil cut) with water injection at 28,322 CWEBPD in March 1999. The post-steamflood plan was successful in slowing the surface subsidence rate and oil and gross fluid production were increased to an average of 1036 BOPD and 20,836 BGFPD (5.0% oil cut) with water injection at 31,230 CWEBPD during the annual reporting period ending in March 2002. 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. Production during the reporting year ending March 2003 averaged 1113 BOPD and 29,077 BGFPD (3.8%) with injection averaging 41,730 CWEBPD. The gross fluid production increased 8241 BPD whereas oil production increased only 77 BOPD, for an incremental oil cut of 0.9% and incremental water-oil ratio (WOR) of 106 BW/BO. Figure 8b is a production graph of the Tar II-A post-steamflood performance from December 1998 through June 2007.

Figure 8b: Tar II-A Post-Steamflood Performance



In early 2003, it was imperative to improve management of the high gross fluid production and water injection rates. Of the seventeen producers active before March

2002 and the twenty producers activated afterwards, eleven were idled as uneconomic, mostly from high water cuts. Oil production suffered initially, but recovered by early 2004. The proposed BP2 well workovers and drilling candidates were completed starting in mid-2004 and oil production increased as gross production stabilized. Production during the reporting year ending March 2005 averaged 1169 BOPD and 29,185 BGFPD (4.0%) with injection averaging 41,431 CWEBPD. Oil production continued to increase to a peak of 1340 BOPD in the fourth quarter 2005. With higher oil prices, marginal producers became profitable to operate at high water-oil ratios and were activated. This necessitated correspondingly higher water injection rates to maintain reservoir pressures and prevent surface subsidence. The accelerated production strategy was unsuccessful as oil rates declined and water breakthrough and more frequent mechanical failures occurred in many wells. A new reservoir management plan needs to be implemented to reduce the high water cuts.

The Tar II-A cumulative oil production through May 2007 is about 41 million barrels for a recovery factor of 41% OOIP, which doubles the 20 million barrels recovered just prior to steamflooding in 1979.

Tar V Production

The Long Beach Oil Development Company (LBOD), as contract operator for the City of Long Beach, began Tar V production in 1951. Similar to Tar II-A, LBOD and the City of Long Beach implemented a non-unitized waterflood project in the Tar V in 1960 to increase and maintain reservoir pressure at about 80% of hydrostatic pressure or 800 psi to prevent further surface subsidence. The Tar V cumulative oil production through 1960 was 9.8 million barrels or about 5% OOIP. Reservoir pressure in 1960 averaged about 460 psig. After 36 years of waterflooding and just prior to the steamflood pilot, cumulative oil production through 1996 was 50 million barrels for a waterflood recovery factor of 25% OOIP.

Tidelands drilled five Tar V horizontal steamflood pilot wells in late 1995 to early 1996 and production began in late 1996. Figure 9 shows the locations of the wells. The Tar V pilot project was developed based on the Tar II-A horizontal well steamflood pilot, with wells drilled along the bottom of the S4 sands to drain the heated oil. Each horizontal well received a cyclic steam-stimulation job to provide a sand consolidation well completion and to accelerate oil production. All five wells had early peak oil rates ranging from 223 - 328 BOPD. Two of the horizontal wells, FJ-202 and FJ-204, were converted to permanent steam injection following cyclic steam production. Steam drive response for each of the three horizontal producers (wells J-201, J-203 and J-205) peaked at 91 - 151 BOPD. The three producers had continuously high producing fluid levels and were capable of producing at higher peak rates, but were not because of concerns with sand production and the effectiveness of the sand consolidation completion methods in these wells. The wells were steam cycled with a new 50MMBTU/hr steam generator that could utilize low and variable BTU fuel gas. The generator needed to be operated at a lower steam quality of 60-70% to prevent scale buildup, which was permissible for the steamflood but not the sand consolidation completion process.

Peripheral water injection was increased in March 1998 to boost the project injection to production (I/P) ratio from 0.92 to above 1.05 to reduce the risk of surface subsidence. The higher water injection rates adversely affected oil production and water cuts because the pilot horizontal producers were completed at the bottom of the sands and experienced higher water rates and fluid levels. The instantaneous steam-oil ratio (SOR) of the project increased from an average of 4.3 from June 1996 through March 1998, to 6.9 from April 1998 - March 1999, to 9.5 from April 1999 - March 2000, and to 11.5 from April 2000 - June 2001, when steam injection was prematurely ended and the steam injection wells converted to hot water injection. Significant oil production was recovered from three pre-steamflood vertical producers (wells A-186, A-195 and A-320) located within the steamflood area that recovered 331,912 barrels of oil from June 1996 through April 2007 or 26% of the cumulative steamflood oil recovery of 1,287,420 barrels. A fourth vertical producer, well A-194, was recompleted to the Tar V pilot area in February 2003 and experienced immediate mechanical problems and was idled. Peripheral water injection in March 2003 was from four wells: FRA-29, FRA-83, FL-337 and FR-111 (Figure 9a).

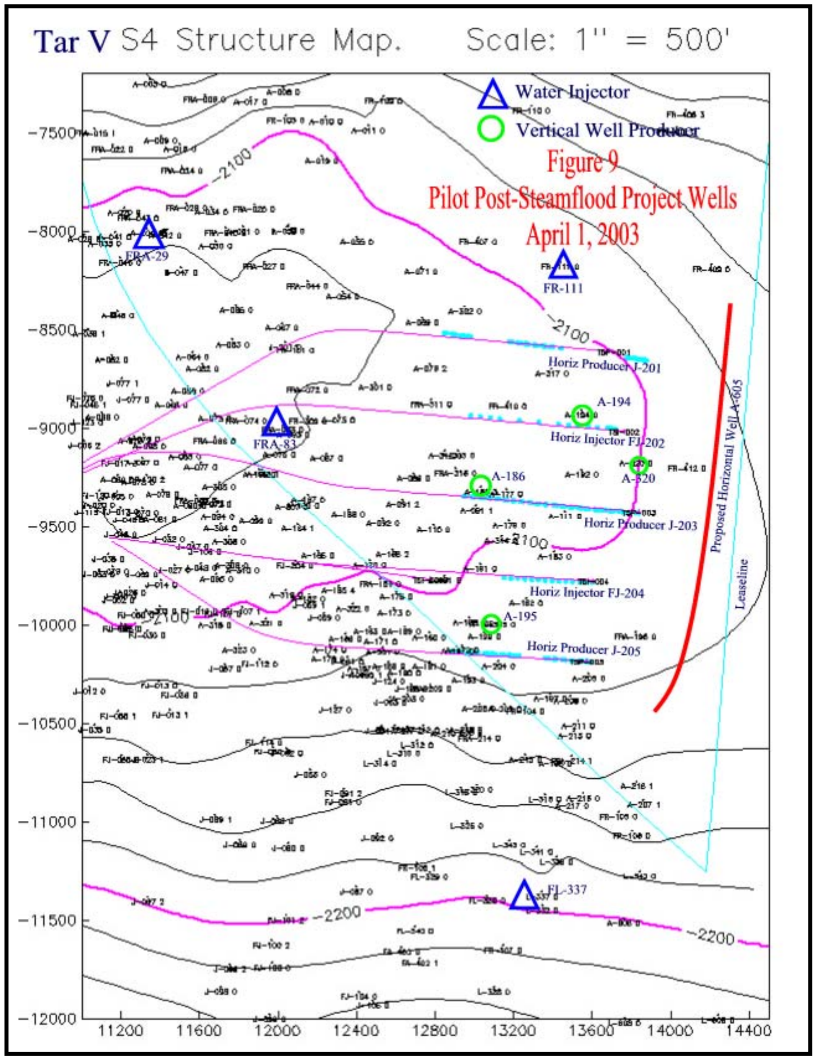
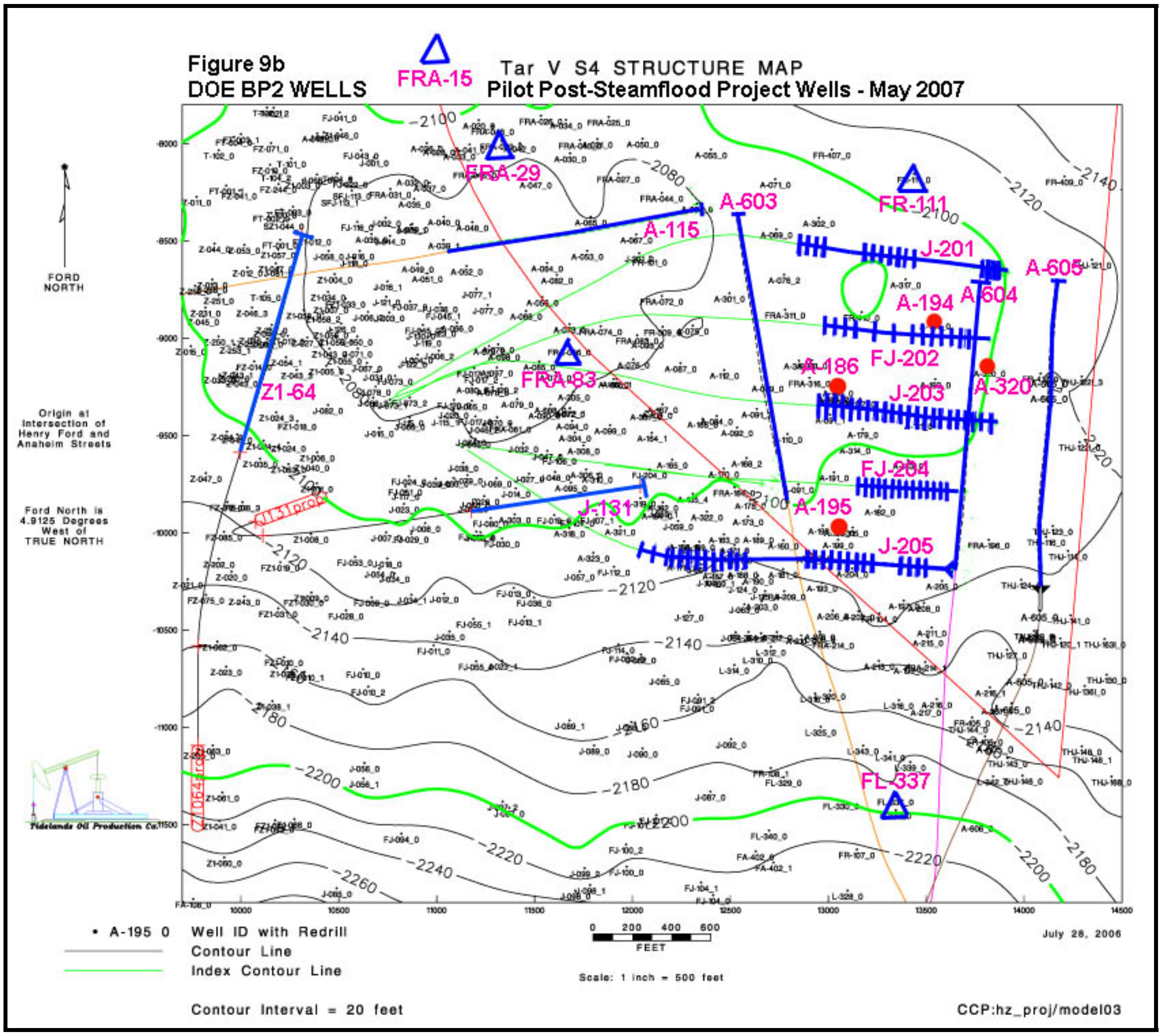


Figure 9a: Tar V steamflood project wells as of March 31, 2003, including three horizontal producers (light blue "J" wells), two horizontal steam injectors (light blue "FJ" wells), four vertical infill producers (green circles) and four flank water injectors. (blue triangles)

Tar V horizontal well A-604 was drilled and placed on production in March 2004 at an initial peak rate of 229 BOPD and 528 BGFPD. The well was strategically located at the top of the S4 sands going south to north along the toes of the other pilot steamflood horizontal wells to capture pilot steamflood oil that would gravity segregate to the top after increasing water and hot water injection in the pilot area (Figure 9b).

The well quickly declined to 42 BOPD and 841 BGFPD by July 2004 and gradually declined to 25 BOPD over the next two years. The well was expected to produce much more oil and is probably being watered out by the two horizontal water injectors below it.



Cold Tar Zone Horizontal Wells

In the DOE project areas, Tidelands Oil Production Company (Tidelands) drilled four horizontal wells from 2003-2005 to test the ability of horizontal wells completed at the top of the highly oil-saturated sands in previously waterflooded areas to recover cold tarry oil. Tar II-A well UP-961 in "D1" sands and Tar V wells A-115, A-603 and A-605 in "S4" sands were all completed at the top of the oil sands (Figure 9b) and all have been very successful and paid out their capital costs within a year. UP-961 was placed on production in November 2005 and has been an excellent well, initially producing 185 BOPD and 635 barrels of gross fluid per day (BGFPD) and in May 2007 producing 66 BOPD and 1404 BGFPD. Well A-605 was activated in April 2003 and reached a peak rate of 176 BOPD and 560 BGFPD within a week. Production declined during the next four months to 70 BOPD and 461 BGFPD, which was unexpectedly fast, but fortunately the rate stabilized at that level for several months and slowly declined to 40 BOPD and

501 BGFPD in May 2007. Cumulative production through April 2007 for well A-605 was 74,000 BO. Well A-603 has been the best Tar zone well, cold or hot. The well was activated in March 2005 and peaked at 408 BOPD and 759 BGFPD. One year later, A-603 was still producing 208 BOPD and 1311 BGFPD and in May 2007, production was 116 BOPD and 1332 BGFPD with cumulative oil production of 147,000 BO. Well A-115 was drilled in 2005 and was also successful, initially producing at a peak rate of 224 BOPD and 1497 BGFPD in November 2005 and 145 BOPD and 1507 BGFPD in February 2007. Net oil decreased in May 2007 to 64 BOPD and 1446 BFPD for reasons to be determined, which could range from the well watering out to well tester problems. Existing north flank water injection well FRA-15 supports the production from wells A-603, A-115 and Z1-64.

Tidelands drilled two new Tar V horizontal producing wells, J-131 and Z1-64 (Figure 9b), in November 2006 as downdip stepouts to the recent cold Tar V "S4" sand horizontal wells A-115 and A-603. Well Z1-64 was activated on December 22, 2006 and within a week reached a promising initial peak rate of 216 BOPD and 1382 BGFPD. The well production declined quickly to 75 BOPD and 1795 BGFPD by May 2007. Well J-131 was activated on January 2, 2007 and tested 54 BOPD and 1952 BPD gross fluid at a 97.2% water cut on January 18 after initially producing only 23 BOPD and 927 BPD gross fluid. This is below the expected initial projected rate of 105 BOPD, but the well has appeared to stabilize at 50 BOPD and 2190 BGFPD in May 2007. Both Z1-64 and J-131 appear to be pumped at excessive rates compared to A-603 and A-115, which could be watering them out prematurely. Wells A-603 and A-115 are slightly updip of J-131 and Z1-64 and their high oil rates could be affecting downdip water movement.

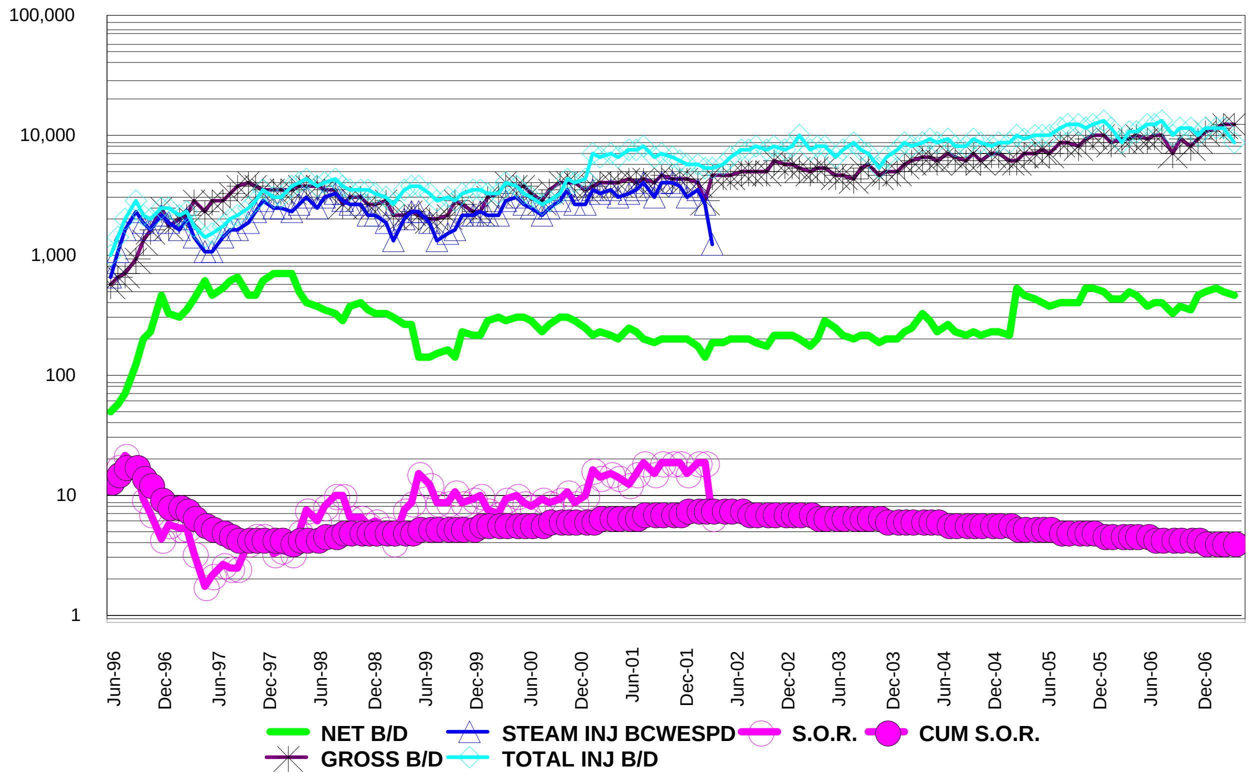
With the overall success of the cold Tar horizontal producers, Tidelands still has several more Tar zone well candidates to drill throughout Fault Blocks I through V.

Warren Resources, an offset operator, has been drilling cold, heavy oil Tar zone D1 sand horizontal wells in Fault Block I since 2006. Thums Long Beach Company, an offset operator, intended to drill similar cold, heavy oil Tar S sand horizontal wells in Fault Block V in 2007.

Cumulative steamflood oil and cold heavy oil horizontal well production from June 1996 through April 2007 was 1,287,420 barrels (1,053,948 bbls steamflood only) and oil production in the first four months of 2007 averaged 513 BOPD, of which 120 BOPD was from the pilot steamflood wells and 393 BOPD from cold tar wells A-603, A-115, J-131 and Z1-64. The pilot steamflood project was originally estimated to ultimately recover 1.7 million incremental barrels, whereas the four cold heavy oil horizontal wells was projected to recover 00.7 million barrels of oil. Total steam injection rates into Tar V averaged 2637 BCWESPD from June 1996 through June 2001, the end of steamflood injection. Hot waterflooding occurred from July 2001 through April 2002, when all thermal injection was discontinued. The hot water rate averaged 3188 BCWEPD. At that time, cumulative pilot oil production was 683,278 bbls with a cumulative steam/oil ratio (SOR) of 7.8, very marginal assuming steam costs based on market-priced fuel.

The high cumulative SOR for the project does not necessarily mean the project is uneconomic because the heated reservoir continued to contribute oil production without steam injection, which reduced the cumulative SOR to 5.1. Also, the steam quality for the project probably averaged closer to 60% than the design quality of 80%, an incremental difference of 107 BTU / lb of steam injected or 11% less heat transfer. In addition, the hot water averaged about 330° F at no steam quality, which has about 21% of the heat transfer of 80% quality steam. Therefore, if steam volumes are normalized based on heat transfer using equivalent 80% quality steam, the effective heat transfer rate was 75.7% of the design rate and the corrected cumulative SOR in April 2002 would have been a much more reasonable 5.9 or about 24% lower. The cumulative SOR for the pilot steamflood through April 2007 is 3.85, which is significantly lower than the 7.8 shown in April 2002. Figure 10 is a production and injection graph for the combined Tar V pilot steamflood project and four cold heavy oil horizontal wells from June 1996 through April 2007. Note the jump in oil production starting in March 2005, when the horizontal wells started contributing.

FIGURE 10
TIDELANDS OIL PRODUCTION CO.
TAR ZONE FB-V STEAMFLOOD



Waterflood operations in April 2007 represent the vast majority of the oil production from the Tar V sands. Tar V oil production in April 2007 averaged 1017 BOPD, of which pilot steamflood production was 120 BOPD or 12%.

Geologic Setting

The Wilmington Oil Field is an asymmetrical, highly faulted, doubly plunging anticline, eleven miles long and three miles wide (Figures 4 and 6). The productive area consists of approximately 13,500 acres. Fault Block II-A is located near the western edge of the field and is bounded on the east by the Cerritos Fault and on the west by the Wilmington Fault. Fault Block V is located just west of the center of the field and is bounded on the west by the Harbor Entrance and Allied faults and on the east by the Daisy Avenue and Golden Avenue faults. Neither the Daisy Avenue nor the Golden Avenue faults penetrate the Tar zone. The Tar sands stratigraphically thin and pinch out to the east before reaching the Junipero Fault. From the surface, Fault Block V lies within the eastern-most portion of the Port of Long Beach shipping operations. The north and south production limits of both fault blocks are governed by water-oil contacts within the individual sand members of the various zones (Figures 4 and 6). The seven zones within each fault block listed in order of increasing depth are: Tar, Ranger, Upper Terminal, Lower Terminal, Union Pacific, Ford and "237" (Figure 5).

Oil from the Wilmington Field and from throughout the Los Angeles Basin is produced mainly from Lower Pliocene (8 –11 million years ago [mya]) and Upper Miocene (11 – 16 mya) age deposits. The Tar zone has the shallowest oil producing sands in the Wilmington Field. These sands are lower Pliocene, middle Repetto formation lobe deposits. The Pliocene age deposits go as deep as the "X" sands in the Ranger zone. The upper Miocene age Puente formations begin with the "G" sands in the Ranger zone and continue through the other five zones mentioned above. The "237" zone overlays a basement schist occasionally capped with a basal conglomerate. The schist is considered Jurassic age (130 – 180 mya), although it has similarities with local Cretaceous (65 – 130 mya) age formations. Wells have been completed into the Schist zone and are oil productive along the anticlinal axis at localized structural highs where the schist is fractured.

During the late Miocene, the Los Angeles Basin experienced a phase of accelerated subsidence during which the Puente Formation and Pliocene age sands were deposited. Structurally, the late Miocene Puente Formation deposits in the Wilmington Field appear to be drape-folded over a relative basement high, with generally thinner beds at the crest of the structure and thicker beds on the flanks. Starting in the middle Pliocene age to the current time, the Los Angeles Basin has experienced significant tectonic activity that has resulted in a major syncline within the central portion of the basin and uplift along the margins, as in the Wilmington – Palos Verdes area. For example, the basement schist top is found at 10,000 ft subsea depth in the Thums area and at 600 ft above sea level in Palos Verdes, a two-mile vertical change within a ten-mile distance! During the late Miocene to Pliocene ages is when the Wilmington Field developed its anticlinal structure. The Pliocene age sands were divided into two units, the Repetto Formation for the early Pliocene sands and the Pico Formation which unconformably overlies the Repetto formation. Both the Repetto and Pico formations contain prolific oil deposits within the Los Angeles Basin. In the Wilmington Field, the top of the Repetto Formation was eroded away, probably by the Pico Formation, which is relatively thin and probably also eroded away. The Pleistocene (<1 mya) and Holocene (recent) age sediments cover the flat erosional surface of the upper Repetto - Pico sands. They buried the Wilmington anticline under 1,800 – 2,000 ft of horizontal younger beds. The Pleistocene and Holocene sands originally contained fresh water, but now contain filtered, low oxygen-filled seawater because of rapid fresh water removal for domestic and agricultural use in the early-mid 20th century. The Pleistocene Gaspur zone was the prime injection source water for the waterflood projects.[A36, D8, D9]

The upper Miocene Puente and lower Pliocene Repetto formations within the Wilmington Field consist of interbedded sand/shale sequences belonging to submarine fan facies. These are considered to be bathayal, slope and base-of-slope deposits. The upper Miocene sands are intercalated with shales and siltstones in the form of widespread thin turbidites. Large lobate fans dominate the Pliocene section.

Tar Zone Geology

The Tar zone consists of four major producing intervals, the "S", "T", "D" and occasionally "F_1/F_0" sands. The Tar II-A waterflood and steamflood wells produce from the "T" and "D" sands. The "S" sand has a relatively small oil productive area in Tar II-A that is completely underlain by water, therefore, only a few wells have been completed. The Tar V waterflood produces from the "S", "T", and "F_1/F_0" sands and the steamflood pilot is in the "S4" sands. The "F_1/F_0" sands are defined as being in the Tar zone in most of Fault Block V, however, they are defined as in the Ranger zone throughout the rest of the field. Each subzone exhibits typical California-type alternation of sand and shale layers as illustrated by the type logs in Figure 11 for Tar II-A and Figure 12 for Tar V.

The Tar zone sands tend to be unconsolidated, friable, fine to medium-grained and contain varying amounts of silt. The thickness of the sand layers varies

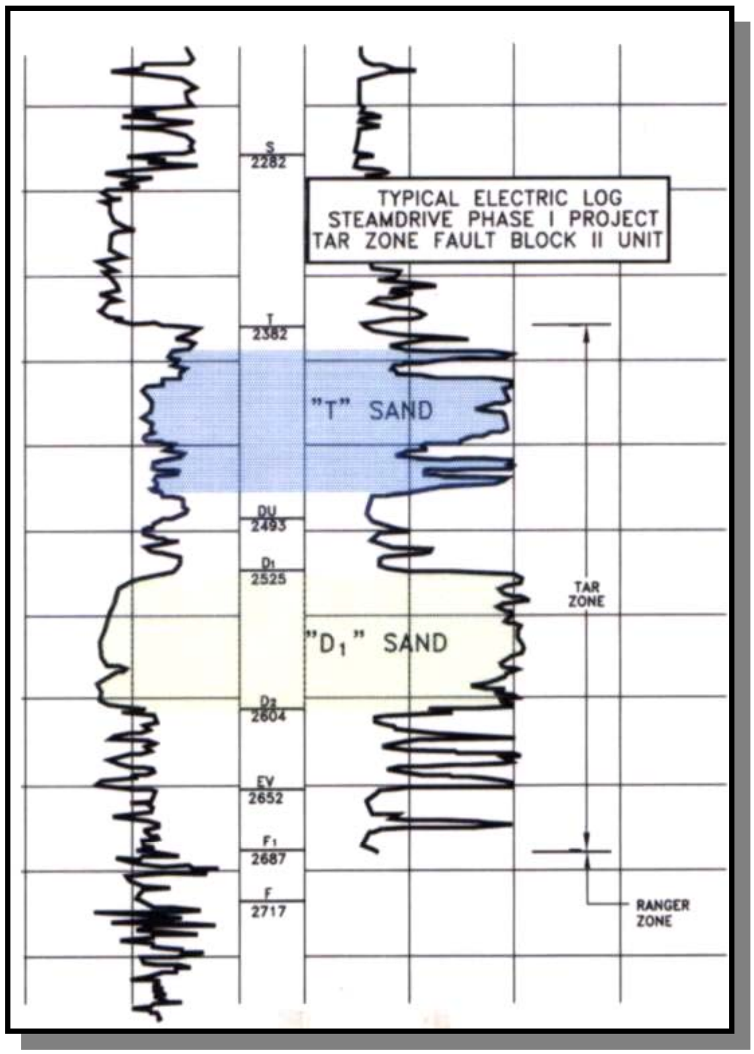


Figure 11: Type Log, Fault Block II-A Tar Zone, illustrating "T" and "D1" sands.

from a few inches to several tens of feet. Shales and siltstones are generally massive, with abundant foraminifera, mica, and some carbonaceous material. The shales are generally soft and poorly indurated, although there are thin beds of fairly firm to hard shale. The oil is of low gravity, ranging from 12-15^{o} API with a viscosity of 360 cp and an initial formation volume factor of 1.057 RB/STB. Based on available information, the Tar zone sands have an average porosity ranging from 30-35% and permeabilities ranging from 500-8,000 millidarcies with a weighted average of 1,000 millidarcies. Approximate zone thickness ranges from 250-300 ft. The top of the structure appears at a depth of 2,330 ft below sea level in Fault Block II and at 2,000 ft below sea level in Fault Block V.

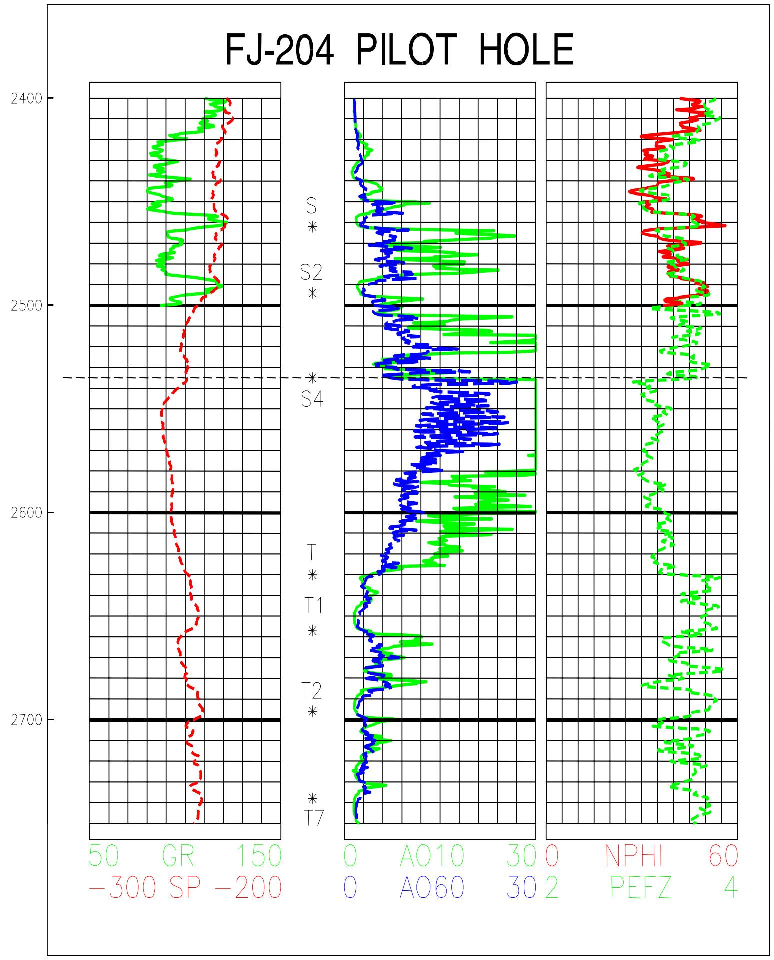


Figure 12: Type Log, Fault Block V Tar Zone, illustrating "S" and "T" sands.

Sedimentological analyses of the textures, sedimentary structures and fossils preserved in the Tar II-A conventional cores reveal that the Tar zone sediments were deposited in several related environments of a deep sea submarine fan system (Figure 13A). The sediments that compose the fan were supplied by gravity-induced flows that transported sands from the northeast (sediment source) towards the southwest (basin of deposition). Sand deposition occurred basinward of a slope break that lay to the east of the present field location. Shales were deposited by differential pelagic settling of fine particles from the overlying water column. The Tar II-A "T" and "D" sand reservoirs represent two unrelated submarine fan systems, as evidenced by the thick, basinal shale that separates them (Figure 11). The "S" sands in Tar II-A and Tar V represent another separate, unrelated submarine fan system that appears similar in description to the "D" sands (Figures 11 and 12). [A32]

Growth of a submarine fan system involves the repeated supply of coarse-grained detritus (sand) by individual gravity flows. The architecture of the reservoir is the result of this growth. Fan growth is accomplished in three ways:

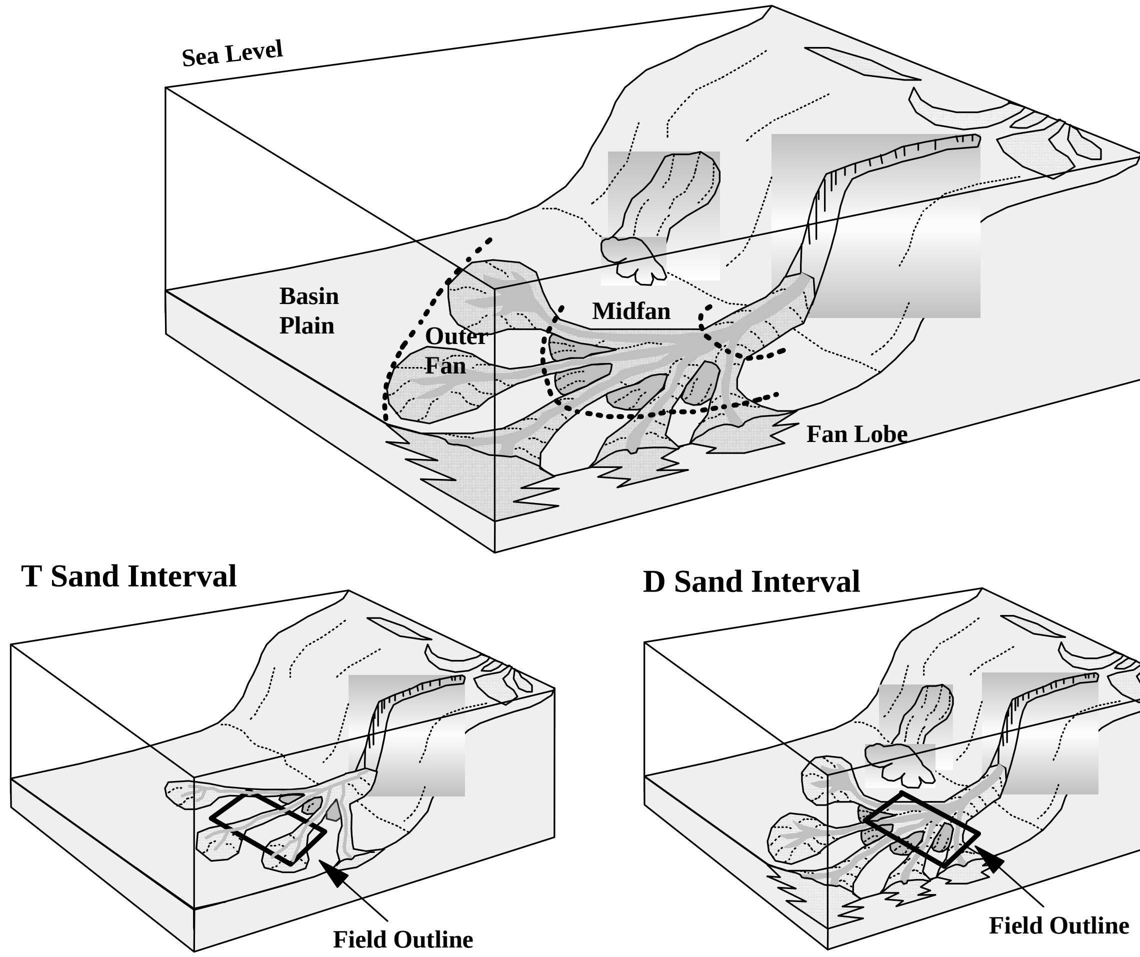


Figure 13: Diagrammatic reconstruction of submarine fan system.

1. **Progradation: Sands are deposited basinward of the break-in-slope due to a decrease in flow velocity. Continued supply of sands to the basin floor results in the gradual basinward growth (progradation) of the sand-rich fan system out over previously deposited basin shales.**

2. Avulsion and Lobe Switching: As the fan system progrades into the basin, individual feeder channels are avulsed (abandoned) and the feeder channels are re-directed into the topographically low areas adjacent to the existing lobes. As a result, new sand lobes are developed in these inter-lobe areas and the old lobes are abandoned.

3. Agradation: Continued supply of sands over time results in the overall vertical growth (agradation) of the reservoir sand bodies.

The model presented in Fig. 13 represents a submarine fan at one instant of time. The simultaneous operation of progradation, avulsion and agradation over a period of time results in the random, vertical stacking of the various fan elements. This produces reservoirs that are internally complex and heterogeneous, such as those in the Wilmington Tar zones.

T Sands

The T Sand interval is approximately 85 ft thick (Figure 11). It was deposited in the outer fan environment, specifically in feeder channels and fan lobes (Figure 13B). The reservoir interval has a high degree of internal complexity, much higher than is indicated by a cursory evaluation of the wireline logs. In all conventional cores, the T Sand consists of numerous, thin (2 ft), porous and permeable sand beds each of which is capped by an impermeable shale (see the geological core description, Figure 14).

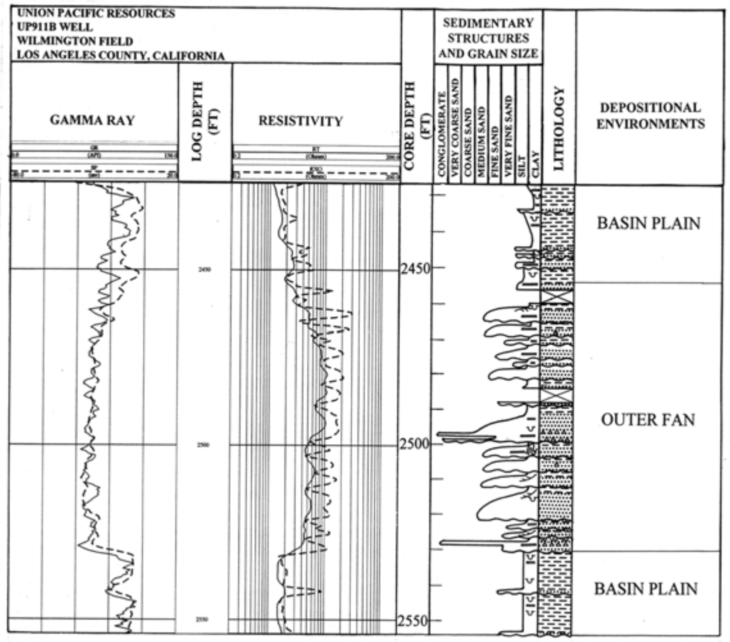


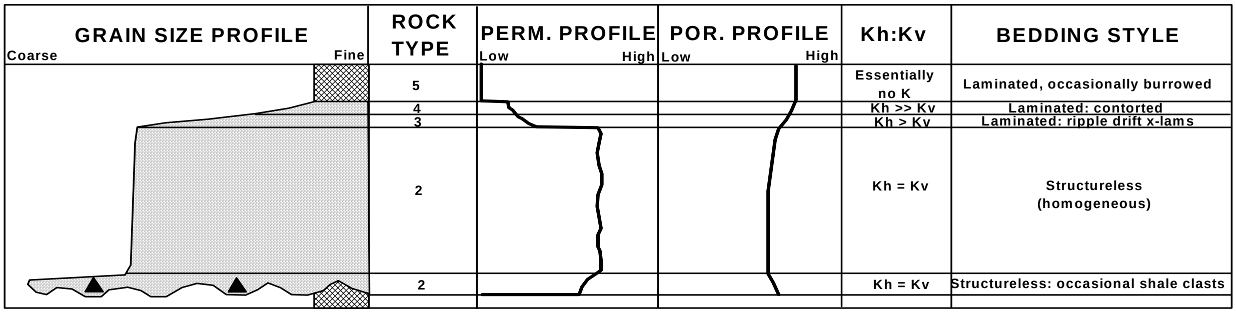
Figure 14: Log response and geological core description, outer fan environment, T Sand interval

Each sand bed was deposited from a single, gravity- driven turbidity current that carried coarse detritus (sand) from the nearby slope out onto the basin plain. Geological and petrophysical characteristics of these sand beds are presented in Figure 15A. The basal contact of individual sand beds with underlying shale is erosive, indicating high energy during sand transportation and deposition. Within each sand bed, grain size fines upwards – a characteristic of many turbidites. This internal, upwards fining of grain size reflects a reduction of current energy (flow velocity and turbulence) with time. The sands that make up most of the thickness (>90%) of any bed (central portion in Figure 15A) are homogeneous; they show little or no vertical change in grain size and contain <1% shale, based on thin section and X-ray diffraction analysis.

Shale beds cap virtually all of the numerous sand beds that comprise the T Sand reservoir. The shale beds are thin (0.5ft) but are known to be laterally very extensive in outer fan environments. The shales form effective barriers to vertical flow and therefore impact significantly the vertical sweep efficiency. In this field, this is demonstrated by the fact that post-steam cores (cores taken in areas of the field that have been swept by steam) show no change of oil saturation in thin (<1inch thick) sand layers that occasionally occur within the shale beds.

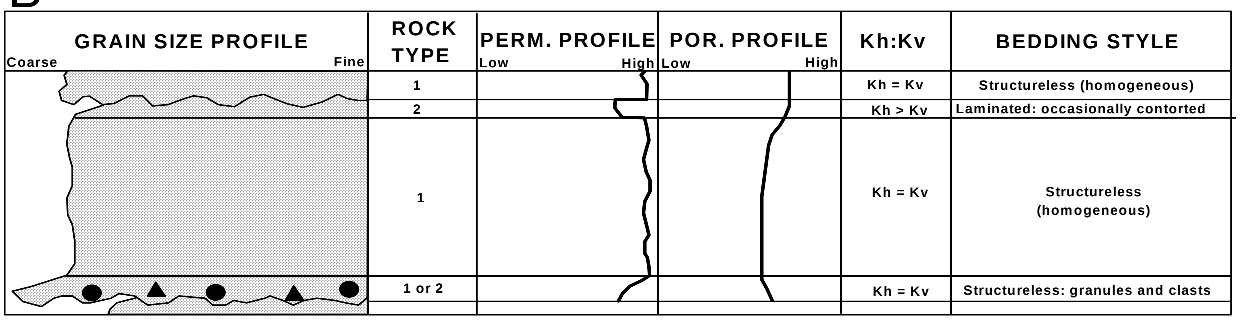
The presence of numerous interbeds of pelagic shale causes the T Sand reservoir to be strongly laminated (bedded). The Spontaneous Potential (SP), Gamma

A



LATERAL EXTENT OF INDIVIDUAL SAND BEDS: >3,000ftparallel to depositional dip, <1,000ft perpendicular to dip

B



INDIVIDUAL SAND BEDS LATERALLY EXTENSIVE IN ALL DIRECTIONS DUE TO ABSENCE OF SHALES

Figure 15: Geological and petrophysical characteristics of individual sand beds: A: T Sand interval; B: D Sand interval. (Not to scale).

Ray (GR) and true Resistivity (R_T) responses do not effectively reveal the highly laminated nature of this reservoir. On the other hand, the flushed zone resistivity (R_{XO}) response gives an improved indication of the high degree of reservoir lamination (Figure 14). High GR response in the T (and D) Sand is the result of the presence of abundant radioactive sand grains (orthoclase feldspar and micas).

A map of the gross thickness of the T Sand interval (Figure 16) reveals a characteristic NE-SW trending pattern of alternately thick and thin deposits. Long, narrow "thicks" (such as in the northern area of the field) are characterized by increased sand content (relative to shale), and they represent the locations of the outer fan submarine feeders that were the main avenue of transport of the sands to the distal lobes. In a general sense, these can be regarded as channels, but it is important to stress that they are not characterized by significant down cutting (basal incision). The system was strongly agradational: deposition dominated over erosion. While erosion surfaces are common at the base of most sand beds, the amount of vertical downcutting at the base of any sand bed is less than one or two inches. The sands do not completely erode the underlying shale beds. This fact is important because it means that the laminated nature of the reservoir is preserved even in areas where feeder channels are dominant. Sands were transported along the feeder channels (axes of the "thicks") into the basin. Overbank flow resulted in deposition of sands along the sides of the principal avenues of sand transport.

The map of the distribution of T interval thickness (Figure 16) displays the result of the growth and abandonment of several individual outer fan feeder channels and lobes during the sedimentation of the entire interval. This map shows the presence of a major feeder channel in the NW portion of the field, and the proximal portions of several lobes in the rest of the field. Not all of these channels and lobes were active at the same time. As a result, reservoir continuity is anisotropic. Individual sand beds are continuous in a NE-SW direction (>3,000ft) and discontinuous in a NW-SE direction (<1,000ft) based on a consideration of log responses and maps of sand distribution.

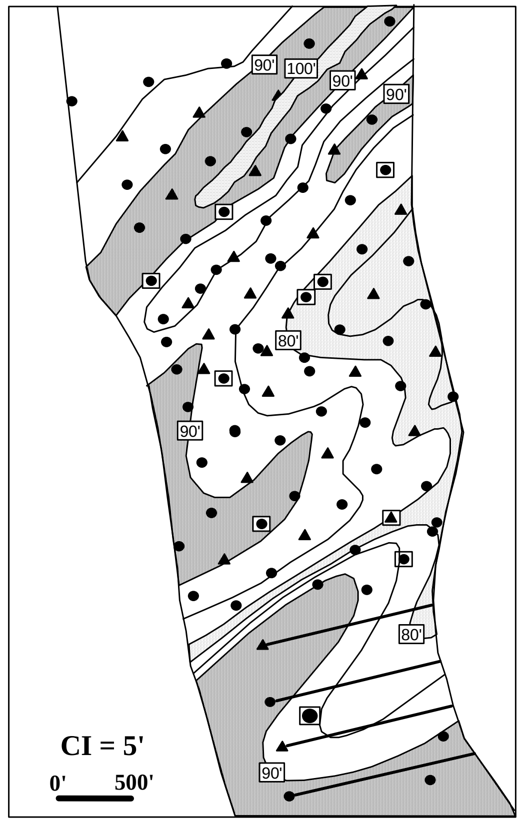


Figure 16: Isopach map of gross thickness, T Sand interval

D Sands

The D Sand interval is approximately 60ft thick. It was deposited in the Middle Fan (midfan) environment (Figure 13C) as indicated by the characteristics of the sand beds and the general absence of shale interbeds. Sand bed thickness is a function of relative position on the fan surface (Figures 17 and 18). Sand beds are thick in the proximal (inner) portion of the midfan and they thin gradually towards the distal portion of the midfan (outer midfan). Shale beds occur only in cores from the outer midfan sub-environment, where they are very thin (<0.2ft) and discontinuous due to minimal deposition and subsequent erosion of the thin shale beds during transportation and deposition of the overlying sand beds.

The D Sand interval is characterized by a vertical stacking of numerous porous and permeable sand beds. In the outer portions of the midfan sub-environment, grain size fines upwards within individual

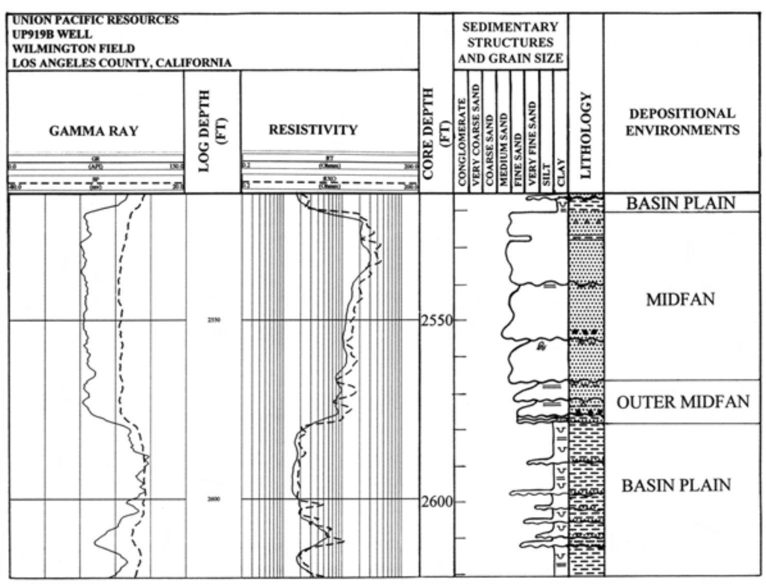


Figure 17: Log response and geological core description, central mid-fan environment, D Sand interval

sand beds (Figure 18). Sand beds deposited in this environment have similar geological and petrophysical characteristics to those of the outer fan environment.

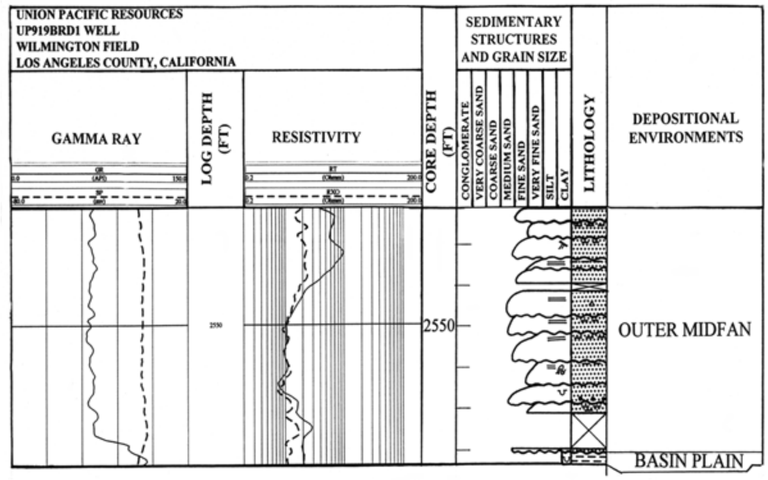


Figure 18: Log response and geological core description, outer mid-fan environment, D Sand interval.

Sand beds deposited in the central portion of the midfan environment exhibit no consistent vertical change in grain size (Figures 15B and 17) because here 1) deposition occurs from debris flows as well as from turbidity currents, and 2) bed contacts are erosive, sand-on-sand (shale interbeds are absent), making it difficult to separate deposits of individual gravity flows. The SP, GR and R_T responses do not effectively respond to the internal bedding characteristics of the D Sand interval. This is to be expected given the presence of sand-on-sand contacts between adjacent beds in this reservoir.

A map of the gross interval thickness of the D Sand interval (Figure 19) reveals that NE-SW trending areas that are alternately thick and thin dominate sediment distribution patterns. However, the rate of change of thickness is less pronounced than in the T Sand interval (compare Figures 16 and 19). These differences reflect the differences in detailed depositional environments between the two intervals. The D Sand interval was deposited in the center of a submarine fan system where rapid changes in sediment thickness are not common. The T Sand interval was deposited towards the outer edges of a submarine fan system where lateral changes in thickness and lithology (sand to shale) are common (Figures 13B and 13C).

In this field, the D Sand was deposited in a submarine fan system that received sediment along several, NE-SW oriented feeders (the apexes of the sand thicks, Figure 19. Sand quality in the D interval increases towards the northeast (towards the sediment source) along the directions of the feeders.

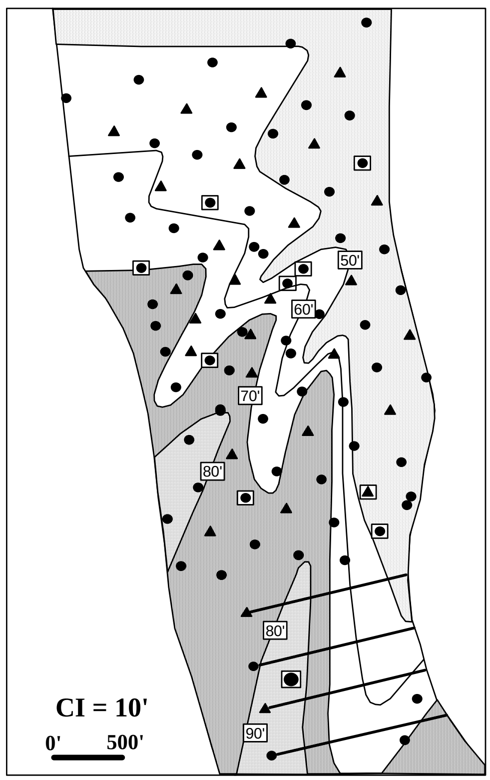


Figure 19: Isopach map of gross thickness, D Sand interval

Vertical permeability, vertical sweep efficiency and sand continuity are very high, as indicated by efficient oil displacement during steamflood operations. Finer grained portions of sand beds act only as permeability baffles, not as permeability barriers. The D Sand is the most homogeneous and most productive interval of the Tar Zone in Fault Block II.

Despite the overall homogeneity of this interval, production history reveals that the most productive wells occur along a northeast-southwest trend that parallels the depositional trend. Analyses of water salinity variations over time likewise reveal that the reservoir sweep has a preferred anisotropy in a NE-SW direction.

Geologic Modeling of Tar V

In 1995, five horizontal wells were drilled into the Fault Block V Tar zone as part of a steamflood pilot operation. The wells were drilled on average 1500 feet horizontally within the S_4 sand. Three-dimensional (3-D) geologic modeling and visualization were used from planning through completion of the wells. The modeling work was the subject of a paper by Clarke and Phillips entitled "3-D Geological Modeling and Horizontal Drilling Bring More Oil Out of the 68-Year Old Wilmington Oil Field of Southern California." [A36]

Horizontal wells require precision placement to be effective. The studied areas required significant geological evaluation and characterization. The area was modeled with Dynamic Graphic's EarthVision™ software that provided 3-D visual displays of stratigraphic and structural relationships and also enabled excellent error checking of data and grids in 3-D space. The 3-D model provided a visual reference for well planning and communicating the spatial relationships contained within the reservoir.

The technologies developed in the Tar II-A steamflood project were applied to the Tar V steamflood project where five horizontal wells were drilled. The excellent accuracy of the 3-D geological model generated, and the usefulness of the computerized tools used to extract information from the model, greatly enhanced the success of the project.

As with the Tar II-A project, the 60+ year-old electric logs were reviewed and recorrelated dividing the Tar V zone into 14 sub-subzones. The log in Figure 12 shows a portion of the stratigraphic section from the probe hole drilled prior to the horizontal section in well FJ-204. The "S_4" sand has the highest resistivity (oil saturation) and is the most thick, continuous, and clean Tar V sand across the fault block. The FJ-204 probe hole verified the oil saturations and reservoir pressures in the individual Tar sands and confirmed the subsidence-corrected vertical depths used in generating the maps for horizontal well placement.

A deterministic geological model was created from which the maps and cross-sections were extracted and used to geosteer the horizontal wells. The modeling was much more straightforward than in the earlier Tar II-A project, as the lateral sections of the horizontal wells are in unfaulted areas with relatively little structural relief (Figure 9). Customized 2-D and 3-D visualizations were used during drilling for interpreting the Logging-While-Drilling (LWD) resistivity, gamma ray and well survey data and for monitoring well progress. Map and section plots brought to the rig site allowed the drilling team to correlate real-time drilling to the geologic maps, thus providing a strong confidence factor that drilling operations were on target. Accurate and rapid post-drilling analysis for completion interval selection and LWD analysis completed the process.

The experience gained in the Tar II-A project and improvements to the EarthVision™ software made modeling even easier. Adding interpretive "ghost" points through the EarthVision 3-D viewer and then reconstructing the model controlled the mapped areas with "no data". This interpretative technique cut modeling time significantly.

During drilling, the LWD data provided near real-time data as the recorder was 60 ft behind the bit. This current data stream allowed the drilling team to adapt quickly when the penetrated formations did not correlate to the geologic maps. For example, one area of the geologic model indicated an anomalous structural low. The survey and log picks appeared to be correct for a well located in this "low" area. The datum point was honored and horizontal well J-201 was drilled into the area. It was apparent from the LWD curve separation and bed boundary intersections that the "T" shale below the "S_4" sand was shallower than the model indicated. The well course was changed during drilling of the horizontal section to point the bit up. Unfortunately, the new drilling course overcorrected for the problem and the well exited the top of the "S_4" sands for 200 ft before the reentering the sand. Still, the well course was placed into the "S_4" and "S_2" sands rather than in the "T" shale or below. Afterwards, the offending well datum was removed and the model was revised based on the multiple horizon picks from well J-201. Because this remodeling can now be done in almost real-time, the geologist can revise the model as drilling proceeds or after each new well is drilled.

The 3-D model in Figure 20 is "bench cut" and shows the five horizontal wells and their perforations. The goal was to keep the wells parallel to and within five feet above the top of the "T" shale to maximize recoverable reserves from the superjacent "S_4" sand. The maps, cross-sections and geological model were all used to place the horizontal wells accurately. Figure 21 shows the

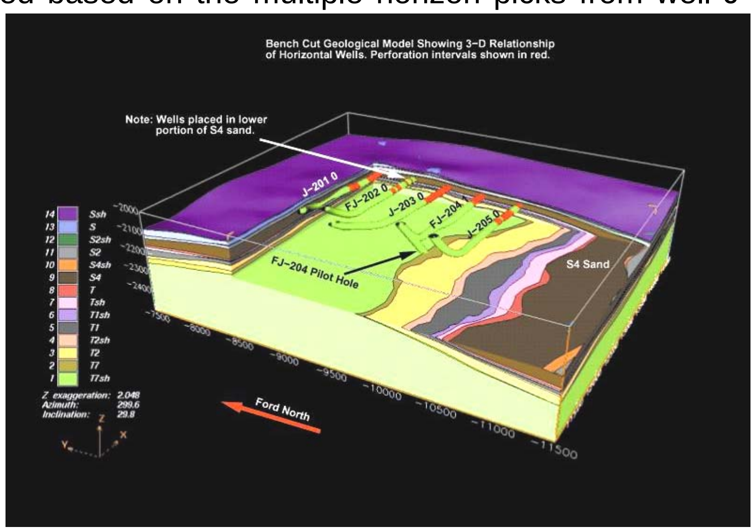


Figure 20: Three-dimensional bench cut of FB V Tar Zone showing steamflood project in S4 sand. "J" wells are producers and "FJ" wells are injectors. Well completions shown in red. This structurally flat area has 2X vertical exaggeration.

cross-section for well J-203, which was drilled near perfect along the bottom of the "S_4" sands.

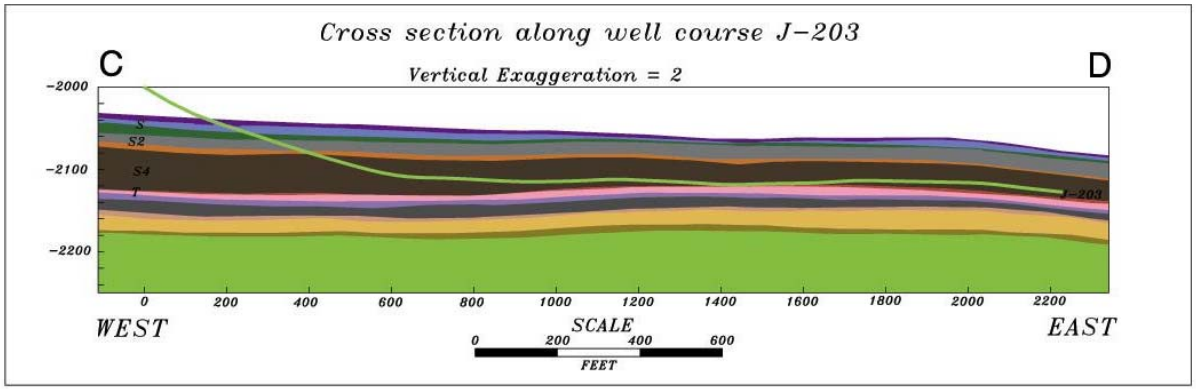


Figure 21: Cross-section along well course of J-203. Placing the well as close to the bottom of the S4 sand as possible to increase oil recovery.

Overall, the Tar V drilling project was a major technical and economic success. Based on what was learned in the Tar II-A project and the accuracy of the 3-D model, the drilling team was able to plan and drill with confidence. No wells were plugged back for geological reasons and drilling time was reduced by spreading out survey lengths, using less time for correctional sets, and rotating the tool string while drilling a large percentage of the horizontal section. Roller reaming prior to running casing was eliminated as shales were avoided, allowing reaming with the bit already in the hole. In addition, only one pilot hole in FJ-204 was necessary. As a result, time and money were saved. Well J-203 took only six days from rig up to rig down to drill and case the 4,661 ft measured depth hole.

For the drilling team, having 2-D and 3-D visuals at the rig site stimulated better feedback and established a clearer understanding of how the geology affected drilling performance. Drilling efficiency was improved because 2-D and 3-D visuals provided the ability to see quickly what a particular directional tool set accomplished. Previously, the drillers only had numbers to look at which were much less intuitive and informative.

The Tar V horizontal well drilling budget was based on the Tar II-A horizontal wells. The average savings per well was US$12,400 on directional costs and US$18,000 due to fewer drilling days. In total, US$152,000 was saved on the five horizontal wells drilled. The monetary savings and management's confidence in the 3-D model allowed all five laterals to be extended an extra 12%, on average, effectively increasing the producible area and adding 382, 000 stock tank barrels (STB) or 60,734 stock tank m^3 (STCM) of oil.

Geologic Model Conclusions

The geologist who can carefully characterize rock data and apply 3-D modeling and visualization techniques adds greatly to the horizontal well drilling team. The highly accurate 3-D visualizations of the reservoir greatly increase the confidence factor of the team by reducing drilling risks and costs, thus enabling Wilmington Field oil reserves to be maximized.

To be effective, horizontal wells require precision placement. Three-dimensional models help isolate data inconsistencies, while 3-D viewers are good for adding data to correct the geological model. Once the final geological model is created, the drilling team can use the resulting 3-D visuals with confidence to improve drilling techniques and directional control. Post-well analysis of the LWD data also is facilitated using 3-D geological models.

The 3-D techniques contributed significantly to the economic success of the Tar Zone horizontal project. Assuming a 50% oil recovery factor, every foot the well is drilled above the target is equivalent to 15,876 STB (2,524 STCM) in lost reserves. [A37] At US$50/ bbl oil, being off as much as five feet vertically would equate to U.S.$4 million in lost revenue.

Activity 1
Compilation and Analysis of Existing Data

A computer database of production and injection data, historical reservoir engineering data, detailed core studies, and digitized and normalized log data was completed to start work on the basic reservoir engineering study and 3-D deterministic and stochastic geologic models. Logs from 171 wells were digitized and normalized for use in the rock-log and geologic models. The digitized logs included the electric or induction and the spontaneous potential (SP) and/or gamma ray (GR) for all of the wells and the formation density and compensated neutron logs for the nine cored wells used for the rock-log model. The 171 wells (of over 600 wells penetrating the Tar zone in the area) are distributed throughout the fault block. Measurement While Drilling (MWD) and Logging While Drilling (LWD) data was acquired from the installation of eight new Tar II-A horizontal wells and eleven new Tar V horizontal wells. Open hole logs and conventional core data was acquired from five new Tar II-A observation wells and four new Tar II-A vertical producer and injection wells.

Tidelands is in the process of downloading production and injection volumes for each well in the Wilmington Field into a Dynamic Surveillance System™ (DSS) database by Landmark. Data includes well and fluid and injection volumes from field inception in 1938 to 2007. All data still requires confirmation before using. Tar II-A database is complete and confirmed through June 2007.

ACTIVITY 2
ADVANCED RESERVOIR CHARACTERIZATION

Task 1: Basic Reservoir Engineering

A basic reservoir engineering study was conducted and a report generated that evaluated the role of aquifer water influx, determined the original oil in place from gas production data to support the material balance work, and calculated the cumulative oil, gas and water recovery from the Fault Block II-A Tar zone (Tar II-A). Allocating oil, gas, and water production to each well and to each zone completed in the wells was a problem because multiple sands were commingled in most of the wells. This problem was evident from using the production and injection well data in the analysis of primary and waterflood recoveries and material balance. For this reason, multiple approaches were used to calculate original oil in place (OOIP) and cumulative oil, gas and water recoveries from the Tar sands. The study included permeability estimates from performance data, compared water injection profile surveys to the allocated injection volumes for each sub-zone, determined vertical communication between sands, evaluated the aquifer for water influx and determined original oil in place from gas saturations to support the material balance work. The quality of the new and old well logs was evaluated for determining log-derived OOIP, oil saturations over time, and the validity of geologic marker picks. The calculated OOIP using the different methods ranged from 98-100 million stock tank barrels of oil, a surprisingly tight range that provided more confidence of the methodologies used and OOIP estimates.

A study was also completed on the projected steam drive recoveries from vertical and horizontal wells and the diagnostic methods for evaluation of steam displacement between horizontal injectors and producers. The study utilized the TETRAD™ thermal reservoir simulator program, a product of Dyad 88 Software Inc. The aim of the study was to compare recovery from vertical and horizontal well completions as a function of reservoir properties, crude oil characteristics, and injection strategies.

Task 2: Obtaining New Characterization Data

A field pilot study demonstrated a low cost and operationally simple reservoir tracer alternative to obtain information about reservoir rock anisotropy from produced water chemistry data. Normally, reservoir tracer work is expensive and generally performed in one batch treatment that can lead to inconclusive results. This study periodically acquired inexpensive water chemistry data from producers to measure naturally existing cations and anions (salinity) in the produced formation water as affected by dilution from the condensed fresh water in the steam in the Tar II-a steamflood project. The project was conducted over a three-month period on two 7.5-acre inverted seven-spot well patterns with two steamflood injectors per pattern and ten producers. The correlation study showed that the reservoir sand connectivity or preferential permeability path of the steam condensate front trended in a northeast to southwest direction, which is consistent with the geological description of interpreted sand deposition. Water salinity data continues to be collected in the Tar II-A post-steamflood project wells to indicate water breakthrough of the injected cold-water to the producers.

Two reservoir tracers, ammonium thiocyanate (AT) and lithium chloride (LC), were injected into two, Tar II-A hot water-alternating-steam pilot injectors on February 14, 1997. The tracer work included issues related to tracer selection, concentrations and volumes and to field sampling, laboratory analyses and interpretation of the produced water results for tracer hits. Samples of produced fluids collected from the first and second rows of producers were analyzed for the ammonium and lithium tracers. The tracer analysis work recorded very few tracer hits above background levels. Upon further review of the tracer selection criteria and steamflood pattern wells used, the project team believes that the disappointing results occurred because the tracers possibly broke down in the very high temperature reservoir environment and because of operational changes related to the rapid conversion of steam injectors to hot water injectors.

Three observation wells and two core hole/observation wells were drilled in 1995 to monitor steam drive operations and to obtain critical log, core and reservoir pressure data for the stochastic geologic and reservoir simulation models. Observation well OB 2-4 was converted to well UP-950 in July 2001 and producing from the “T” and “D” sands. Core-hole/observation well OB 2-3 was converted to water injection well 2AT-64 and completed into the “T” sub-zone sands in the second half 2002. Core-hole/observation well OB 2-5 is still a critical temperature observation well in the Tar II-A Phase I steamflood area. Two observation wells, OB 2-1 and OB 2-2, were plugged and abandoned in 1999 at the request of the surface landowner.

Task 3: Deterministic 3-D Geologic Model

A three-dimensional (3-D) deterministic geologic model was completed using the EarthVision™ 3-D imaging software by Dynamic Graphics, Inc. The geologic model was initially completed in June 1995 with ten defined sand tops in the Tar II-A. The geologic model was used to drill four horizontal steamflood wells and five observation wells, two of which were conventionally cored throughout the two-steamflooded Tar sub-zone formations in the “T” and “D” sands. The geologic model was also used to develop the framework of the 3-D deterministic reservoir simulation model to optimize reservoir management and thermal recovery methods. Since then, the fault picks were re-evaluated and the defined sand tops were increased from ten to eighteen. The model and newly acquired data have identified the existence of a northeast-southwest gradient of higher sand quality, the presence of a major channel sand cutting through the upper “T” sands, and the existence of previously unmapped faults.

A petrophysical rock-log model was completed that identified five rock types to describe the sands and shales within the “T” and “D” formations. Building the model required the development of empirical relationships between the core and log data and the porosity and permeability data. The study was performed on the seven wells drilled from 1988-89 that had modern log suites (gamma ray [GR], resistivity, formation density and compensated neutron) and conventional cores through the Tar sands. Defining the five rock types with similar log and reservoir characteristics is critical for the stochastic geologic modeling as it provides an objective means of predicting petrophysical rock types and permeability profiles for “T” and “D” sands in locations where only minimum log data and no core data are available. The model has been applied to uncored wells within the area to aid in reservoir description and permeability modeling for the stochastic and reservoir simulation models. Another important outcome of this study is that traditional log analysis techniques can significantly overestimate shale content in thin-bedded sands and consequently underestimate oil saturation and net oil sand picks. This modeling technique corrects for that problem.

In 1995, five horizontal wells were drilled into the Fault Block V Tar zone as part of a steamflood pilot operation. The wells were drilled on average 1500 feet horizontally within the S_4 sand. Three-dimensional (3-D) geologic modeling and visualization were used from planning through completion of the wells.

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Task 4: Stochastic 3-D Geologic Modeling

For the stochastic geologic model, a neural network analyzer was developed to analyze the similarities of various zones and sub-zones in terms of sequence stratigraphy using GR logs. Sample stochastic grid block models were test run on the 3-D EarthVision™ visualization software to ensure compatibility. A neural network analyzer can identify the unique well log characteristics of geologic markers in turbidite sequences and quickly correlate hundreds of digitized well logs. The required changes in the character of lithology logs / sand-shale, makes the visual correlation often a very difficult task. With over 600 penetrating well logs through the Tar II-A sands, the need for developing a neural network analyzer to expedite the stochastic geologic modeling was evident.

Following development of the 3-D deterministic geologic model, work began on a 3-D stochastic geologic model to describe the heterogeneous turbidite geology of the Fault Block II-A Tar zone. The reservoir characterization work was first partitioned into sand modeling and shale description projects. Determining sand continuity is of particular importance for turbidite sands, because sand sequences in adjacent wells may look similar but in fact may not be connected because of the lobated nature of the sand sequences. The detailed core analyses work on eleven cored wells located throughout the Tar II-A zone provided the backbone of the stochastic model. The core analysis work on the two wells cored in 1995, OB2-3 and OB2-5, were performed under both in situ overburden pressure of 1800 psi and "routine" minimum pressure of about 300 psi. Most core analysis work performed on unconsolidated sands, including the nine Tar II-A wells cored from 1981-88, use the routine minimum pressure to hold the core sample together. Performing core analysis at higher in situ overburden pressure is cost-effective because the results give lower porosity measurements that more closely match log porosity data. To further refine permeability measurements, core tests were performed under overburden stress to calculate liquid permeabilities compared to the typical air permeabilities measured in the lab. Relatively clean Tar sands that would normally be measured at 700 – 2000 md of unstressed air permeability would have adjusted overburden liquid permeabilities of 300 – 600 md. By analyzing the differences in formation characteristics between the core samples measured under the two pressures, the older core data could be normalized for the stochastic geologic model. Shaliness indicators were identified from density and neutron logs and correlated with the corrected core permeability. The vertical and horizontal geostatistical spatial correlation studies applied the core data work to develop variogram models for the stochastic geologic model.

A sequential gaussian simulator was used to help create the 3-D stochastic geologic model. For input, the simulator used the variogram models of the porosity and permeability fields, density log porosity data, permeability cloud transforms, and permeability-normalized neutron log porosity data. Stochastic simulations were conducted on porosity and shaliness indicators. Permeability fields were generated from shaliness indicator results through cloud-transforms. Detailed shale mapping was partially created based on resistivity and density log responses to define the shale streaks accurately. The shale streaks control the effective vertical permeability. A method for upscaling the model is discussed for porosity, sand permeability and the combination of the shale spatial continuity information and the sand permeability.

The original intent of the 3-D stochastic geologic modeling work was to address the lateral variations in rock geology using geostatistical correlation methods. Upon completion of the geostatistical work, the plan was to convert the 3-D deterministic geologic model and examine various stochastic realizations of reservoir conceptual models for simulation purposes. With the extended time to complete the core analysis work and the unexpected shutdown in January 1999 of the steam injection process in the Tar II-A zone, the project priorities were modified by the City of Long Beach to address their concerns about steamflood-related surface subsidence and how to safely operate the Tar II-A wells during the post-steamflood phase. In mid-1998, stochastic geologic modeling work was discontinued so the project team could concentrate on developing a post-steamflood operating plan using the 3-D deterministic thermal reservoir simulation model.

ACTIVITY 3
RESERVOIR SIMULATION

Task 1: Deterministic 3-D Reservoir Simulation Modeling

For reservoir simulation work, benchmark tests were conducted on several advanced thermal reservoir simulation packages and computer workstations. The project team selected the STARS™ thermal reservoir simulation software by the Computer Modelling Group (CMG) of Calgary. The software was installed on a R10,000 Onyx RE2 work station by Silicon Graphics Incorporated (SGI) for modeling purposes.

The 3-D deterministic reservoir simulation model incorporated the 3-D deterministic geologic model for the Fault Block II-A Tar Zone created for this project. The reservoir simulation study started in January 1997. The model consisted of 26,660 grid blocks (43 X 155 X 4 grids), with aquifers on the north and south flanks. The model successfully history-matched primary production in the Tar II-A sands starting in 1938, waterflood operations starting in 1960, and the steamflood pilot and expansion operations starting in 1981. Development work included how the model was built, the key reservoir and modeling assumptions used, the testing of the model to predict waterflood and steamflood performance versus actual rates, and the development of a rock compaction subroutine that was incorporated into the CMG STARS™ thermal reservoir simulation software. During the preliminary runs, the single component oil (dead oil) feature of STARS was applied in simulations to speed up the modeling work. The project team identified two dynamic reservoir processes that significantly affected the history matches: compaction-related deformation of the rock and gas liberation. The formation compaction / rebound irreversibility was quantitatively determined and the contribution of the Tar Zone to the total surface subsidence was also estimated. The model's four layers were expanded to 13 layers to account for steam gravity override to simulate the 20-acre steamflood pilot and 150 acres of steamflood expansions. This increased the number of grid blocks to 86,645. The model was validated when a seven-year projection of oil and water production for the 20-acre steamflood pilot compared favorably with actual total project production data. The model subsequently was able to closely match ten years of production from the 150 acres of steamflood expansions.

The USC and Tidelands project members used the 3-D deterministic thermal reservoir simulation model to develop the post-steamflood plan. The objective was to use the model as a reservoir management tool to convert the high pressure - high temperature Tar II-A steamflood to a cold waterflood in a stress-sensitive formation without any surface subsidence. The model was used to create multiple sensitivity cases to optimize oil production while accelerating steam chest fill-up within the reservoir by measuring the mass fluid and heat balance effects as they pertained to reservoir pressure. Reservoir pressures in the target area were 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 pressures too difficult without a viable reservoir model. The model results demonstrated the importance of carefully monitoring and managing the reservoir pressure.

Model sensitivity cases were developed assuming the conversion of various wells to water injection at various rates. The model confirmed the project team's plan to convert structurally downdip wells to create a flank water injection strategy. Whereas the City's initial plan was to idle all producing wells until steam chest fillup occurred from flank water injection, the simulation model successfully provided for limited oil production while filling the steam chest before it could collapse from heat loss to the overburden formation. 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 model accurately predicted steam chest fillup in October 1999 due in part to operations successfully meeting the model's gross production and water injection rate projections.

Vertical Heating Reservoir Simulation Model

A study was performed to quantify the heating of over and underburden shales and sands in a typical Tar II steamflood pattern over a ten year period subsequent to steamflooding. The purpose was to determine the potential for thermal-related shale compaction over time. The CMG STARS thermal reservoir simulator was used to develop a 1/12 of a seven-spot, 2025 grid block (5 x 5 x 81 grids) model to determine how much, how far vertically, and for what length of time the reservoir heat is thermally conducted from the Fault Block II-A Tar Zone steamflood to the overburden and underburden sands and shales. The model mimicked an area in the middle of the steamflood project and had two injectors (one for the T Sand & one for the D Sand), one producer, and an observation well halfway between the injectors and the producer. Two basic scenarios were run, one with continual 500°F hot water injection and one with 135°F cold water injection. Injecting 500°F water for ten years after steam injection only cooled off the steam zone by 53 – 67°F while the shale layers above and below continued to heat up. Injecting 135°F cold water to maintain a 90% hydrostatic reservoir pressure in the T and D sands would cool the reservoirs to 135°F within five years after the steam was shut-in.

2003 Reservoir Simulation Model Update

The project team updated the Tar II-A 3-D deterministic thermal reservoir simulation model on Computer Modelling Group's (CMG) STARS 2002 PC version with production and injection data through May 2003. The objective of updating the model was to minimize the risk of further thermal-related shale compaction and associated surface subsidence. The original 1998-99 reservoir simulation model was used as a reservoir management tool 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 reservoir simulation work, post-steamflood plan and initial operation are reported in SPE Paper #62571 entitled "Post Steamflood Reservoir Management

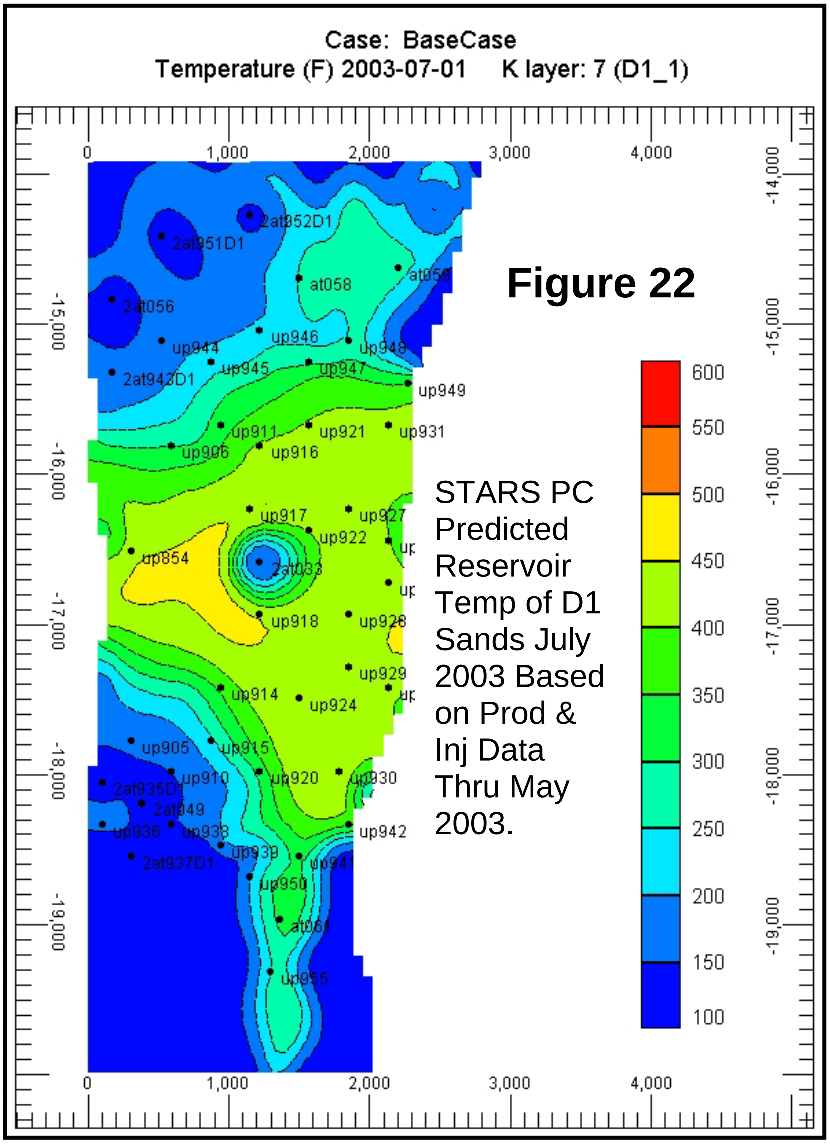


Figure 22

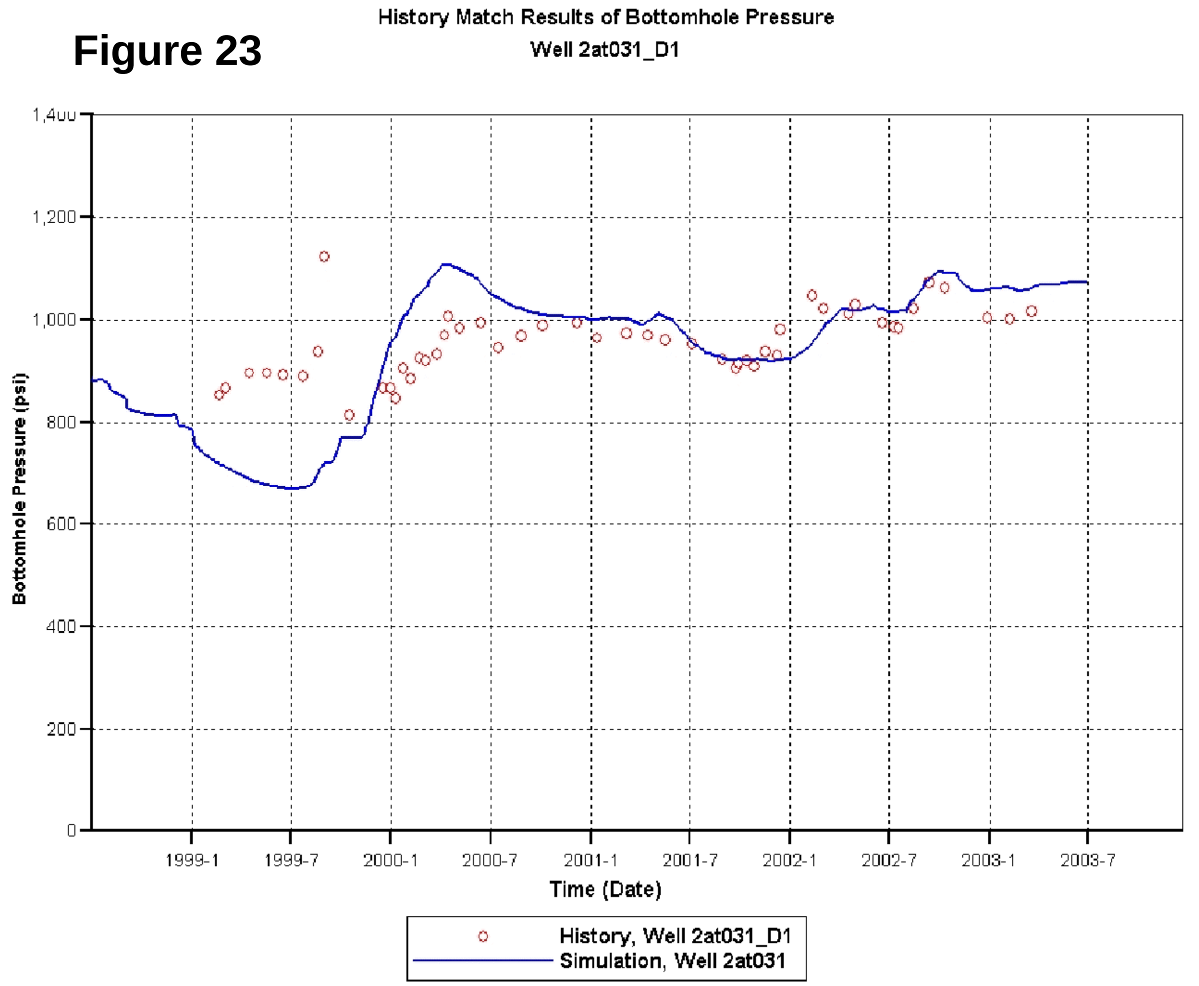
STARS PC Predicted Reservoir Temp of D1 Sands July 2003 Based on Prod & Inj Data Thru May 2003.

Using a Full-Scale Three-Dimensional Deterministic Thermal Reservoir Simulation Model, Wilmington Field, California"[3].

The Project Team confirmed that the 2002 STARS PC software version provided model results consistent with the 1998-99 Unix-based version using historical production and injection volumes through May 2003. The original 1998-99 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. Figure 22 shows the predicted reservoir temperatures for the top of the D1 sands as of July 1, 2003 based on the STARS PC version using the new base case model. The updated 2003 base case shows lower reservoir temperatures for the D1 sands than the 1999 base case 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.

The updated May 2003 base case model had a reasonable correlation with actual reservoir pressure readings as shown in Figure 23 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 consistent in the "D" sands compared to the model. The temperature data is based on gross fluid production temperature measurements from individual wells,

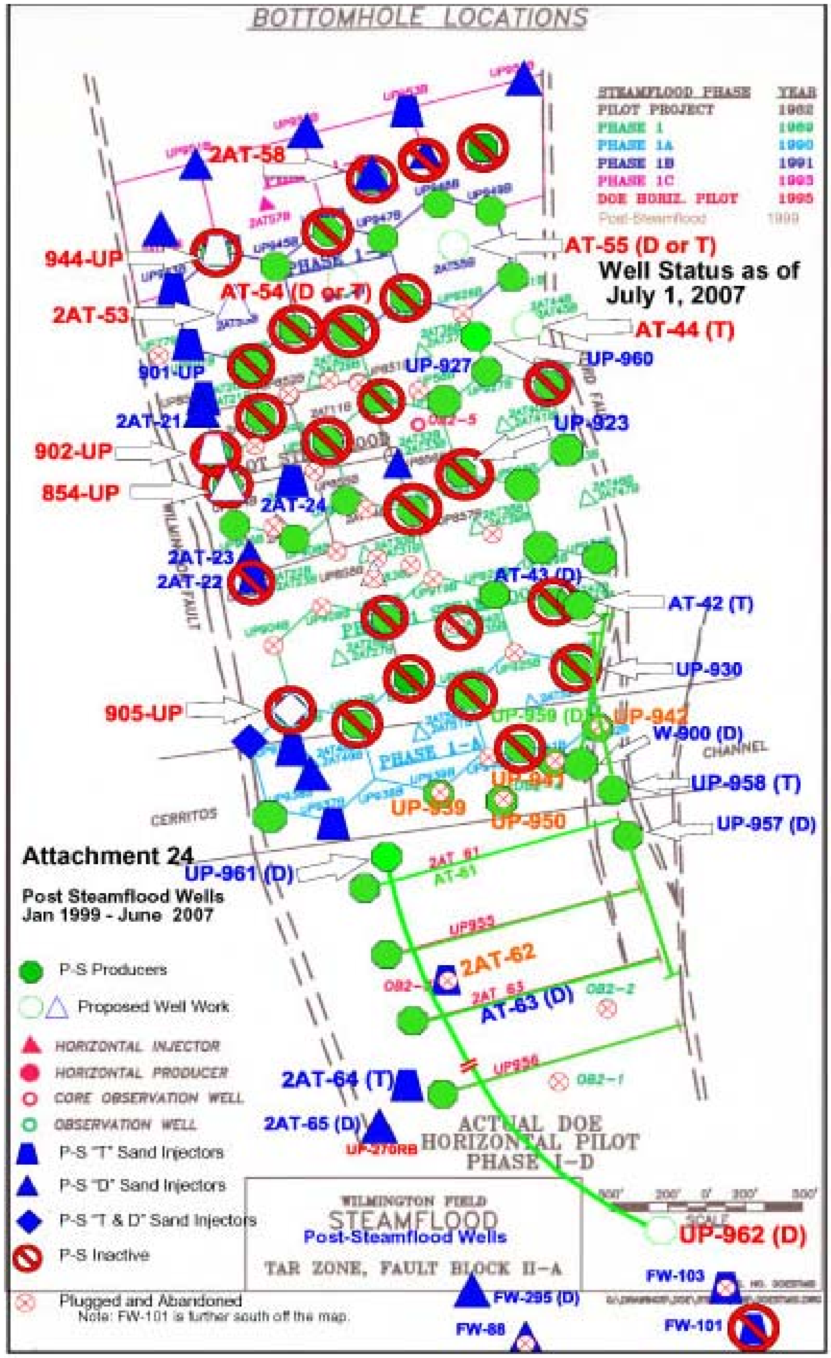
Figure 23



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.

Tar II-A Post-Steamflood Reservoir Cooling Acceleration Project

The Tar II-A post-steamflood project underwent a reservoir cooling and oil recovery acceleration strategy starting in mid-2002 that continued through the remainder of the project. Several long-term idle wells were activated or converted as producers or water injectors, the Port of Long Beach replaced six wells, and three new producers were drilled. The net result of the program was that oil production increased less than 10% or less than 100 BOPD while gross production increased by about 16,000 BPD or over 75%. Water injection increased about 14,000 BPD in the same time frame. The program caused premature water breakthrough in many producing wells and resulted in more well work and downtime. Oil production fluctuated from well drilling and idle well activations and once increased to over 1400 BOPD in November 2005, but would repeatedly decline and stabilize at about 1100 BOPD. Reservoir cooling did accelerate, but at the cost of pumping significantly higher water production and injection volumes while experiencing higher operating costs and little increase in oil production. Figure 24 is a Tar II-A steamflood pattern map showing the locations of the post-steamflood wells as of July 1, 2007, including new wells UP-957, UP-958, UP-959, UP-960, UP-961, W-900, and 2AT-64, abandoned wells UP-942, UP-941, UP-950, UP-939 and 2AT-62, and converted wells AT-42, AT-43, AT-61, AT-63, 2AT-21, 2AT-22 and 2AT-23. Figure 8b is a production graph for the Tar II-A post-steamflood project from December 1998 to June 2007 showing oil and gross fluid production, water injection, and produced water – oil ratio. The oil production stream is annotated with the recent well work, new wells and well abandonments.

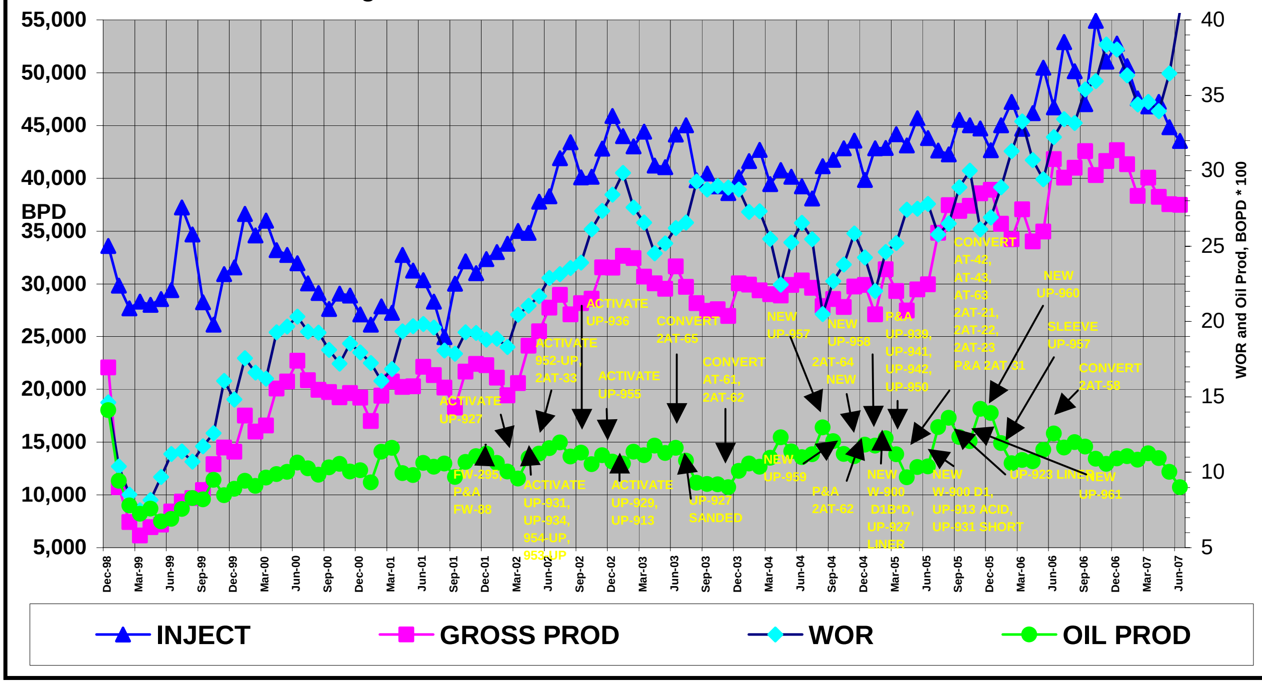


The Tar II-A production performance for the past three years is described below in annual segments. Also included is an analysis of horizontal producing well UP-957, which was drilled in 2004 based on the results of the most recent reservoir simulation model update performed in 2003 and affected the wells drilled afterwards.

April 2004 to March 2005 General Work

The Tar II-A post-steamflood project underwent major operational changes to accommodate the Port of Long Beach (POLB) container terminal expansion. The project had to plug and abandon four of the best producing wells totaling 345 BOPD and one T sand injection well. The POLB paid for three replacement producing wells (UP-958, UP-959 and W-900) and an injection well (2AT-64), which were drilled and activated from October 2004 to February 2005. The three replacement producers were initially proposed as the first three DOE BP2 wells to be drilled.

Figure 8b: Tar II-A Post-Steamflood Performance



Tar II-A oil production from April 2004 to March 2005 averaged 1169 BOPD at a 4.01% oil cut (24.0 WOR), substantially better than in November 2003 when it averaged 902 BOPD at a 3.3% oil cut (28.9 WOR). The production increase was primarily due to adding well UP-957 and replacement wells UP-958, UP-959 and W-900 and repairing producer well UP-927.

Reservoir Simulation Used for Development Drilling
Tar II-A Horizontal D1 Sand Production Well UP-957

The 3-D thermal reservoir simulation model was used to drill Tar II-A horizontal producing well UP957 in March 2004 to the best remaining oil-saturated sands in the D1 sands. The well reached peak oil production in April 2004 at 259 BOPD, over 100% better than projected. The well is currently producing 40 BOPD and has cumulatively produced 76,006 BO through May 2007.

The project team drilled new horizontal producing well UP-957 to recover stranded steamflood oil reserves at the top of the D1 sands within a fault splinter that the reservoir simulation model showed had the highest remaining Tar II-A oil saturations. The Ford Fault is not sealing where UP-957 crossed it, but it could be sealing further south where the displacement is greater and newer well log data revealed oil saturation differences on opposite sides. Figure 25 is a Tar II-A color-coded oil saturation map of the upper D1 sands as of July 2003 that includes geologic structure contour lines, the faults, and the well path for UP-957. Figure 26 is a cross-section of the actual well path through the D1 sands. The cross- section includes the resistivity and gamma ray logs, and highlights the oil-saturated D1 sands in green and the relatively oil-depleted D1 sands in blue based on log resistivity data.

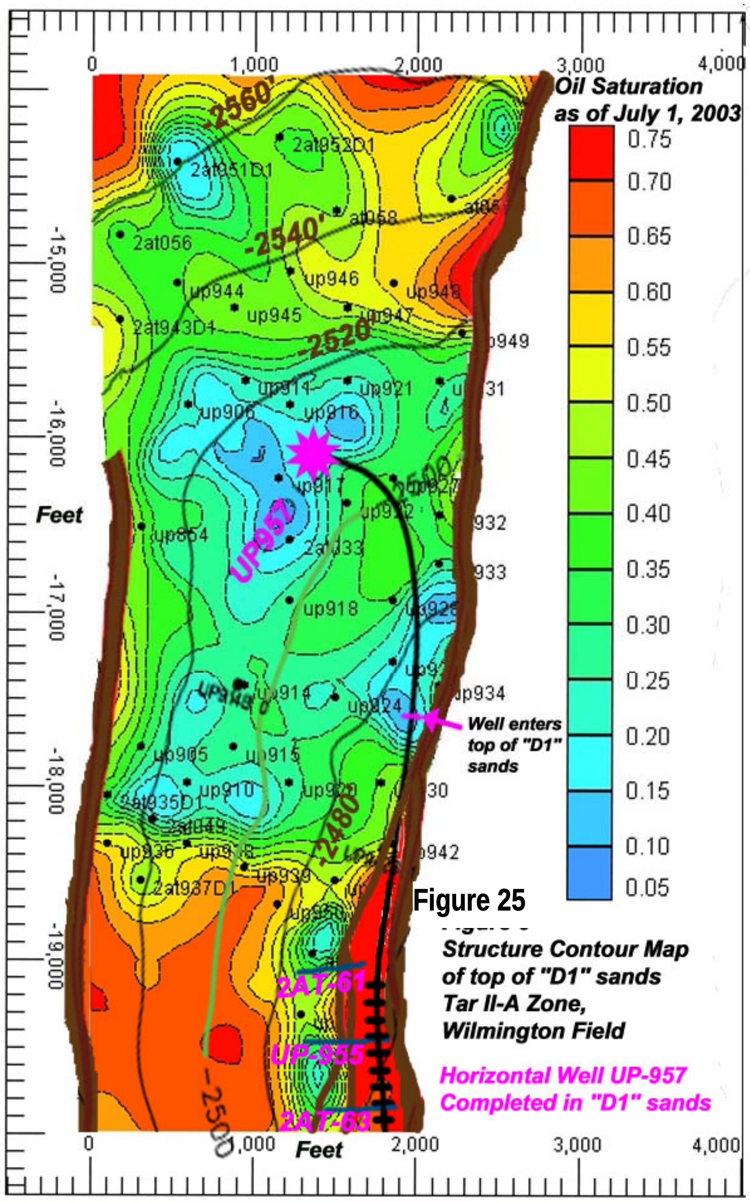
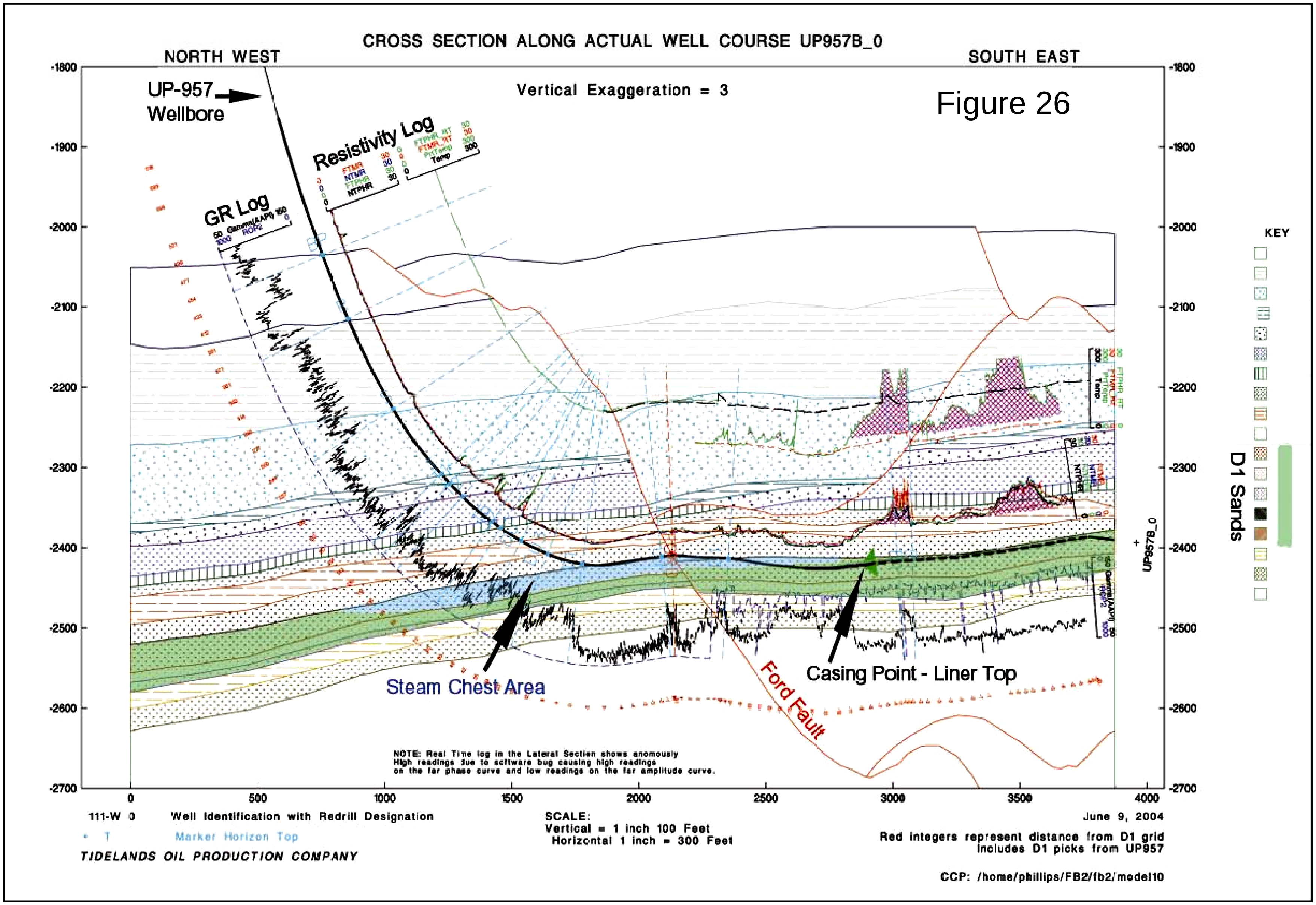


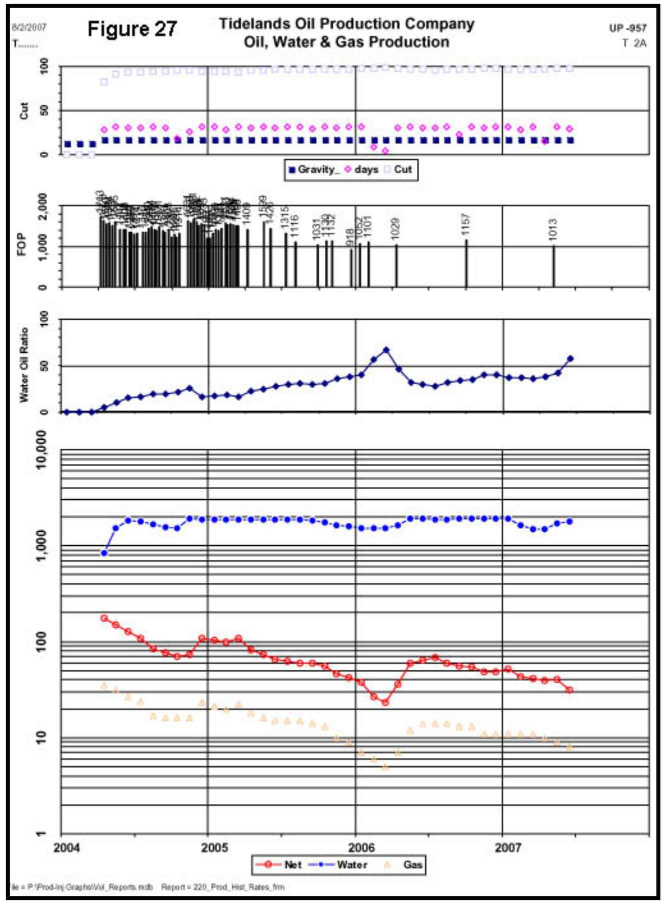
Figure 25
Structure Contour Map of top of "D1" sands Tar II-A Zone, Wilmington Field

The well was completed with 845 ft of open-hole, gravel-packed, wire-wrapped screen on April 2, 2004 and reached peak oil production on April 6 of 249 BOPD (over 100% better than projected 100 BOPD) and 723 BPD gross fluid at 197°F at the wellhead and with a producing fluid level of 2,122 feet over the mid-perforation depth of 2,403 feet VSS. Gross fluid production was increased three times within the first two months to a maximum rate of 2,000 BPD. Following each gross fluid rate increase, oil production rose temporarily and then declined more rapidly than expected to 110 BOPD by December 2004, resulting in higher water cuts up to 94.5 percent (a maximum WOR of 17.2)–a nine-fold increase in eight months. Producing fluid levels decreased slightly during the first eight months, ranging from 1,800-2000 ft over the mid-perforation depth and the well experienced higher fluid temperatures at the wellhead (up to 256 degrees). The rising fluid temperatures and water cuts were attributed to the well drawing in hot water and oil from the steam chest area through the heel of the completion rather than the warm oil and water from the highly oil saturated sands. The gross fluid production during 2005 was maintained at 2,000 BPD and oil production declined to a stabilized rate of 60 BOPD by August 2005.

In November 2005, the well began to water out and oil production plummeted to 25 BOPD and 1560 BPD gross fluid by February 2006 for a 98.4% water cut and WOR of 61.5. A workover was performed in March 2006 to install a 705 ft tubing sleeve with


CROSS SECTION ALONG ACTUAL WELL COURSE UP957B_0
NORTH WEST
SOUTH EAST
Vertical Exaggeration = 3
Figure 26
UP-957
Wellbore
Resistivity Log
GR Log
KEY
D1 Sands
Steam Chest Area
Casing Point - Liner Top
Ford Fault
NOTE: Real Time log in the Lateral Section shows anomously High readings due to software bug causing high readings on the far phase curve and low readings on the far amplitude curve.
111-W 0 Well Identification with Redrill Designation
T Marker Horizon Top
TIDELANDS OIL PRODUCTION COMPANY
SCALE:
Vertical = 1 inch 100 Feet
Horizontal 1 inch = 300 Feet
June 9, 2004
Red integers represent distance from D1 grid
includes D1 picks from UP957
CCP: /home/phillips/FB2/fb2/model10

dual packers to seal off the first 507 ft of open-hole completed section of wire-wrapped screen and 198 ft of casing-liner lap section. The objective was to isolate the heel section and produce from the cooler and higher oil saturated sands. Well production in March 2006 was set at 2000 BPD gross fluid and oil production stabilized at 60 BOPD. Oil production began declining in 2007 and water-oil ratios indicate the problem is reoccurring. Figure 27 shows a well test production graph of No. UP-957 through June 2007 with oil and gross fluid rates, water cuts, fluid temperatures and pumping fluid levels over the pump. If well UP-957 is connected to the steam chest, this flow path undoubtedly will dominate future productivity from the well, as it is hotter and has much higher mobility than the cooler and more viscous tar sands across the completion interval, especially if producing fluid levels remain high.



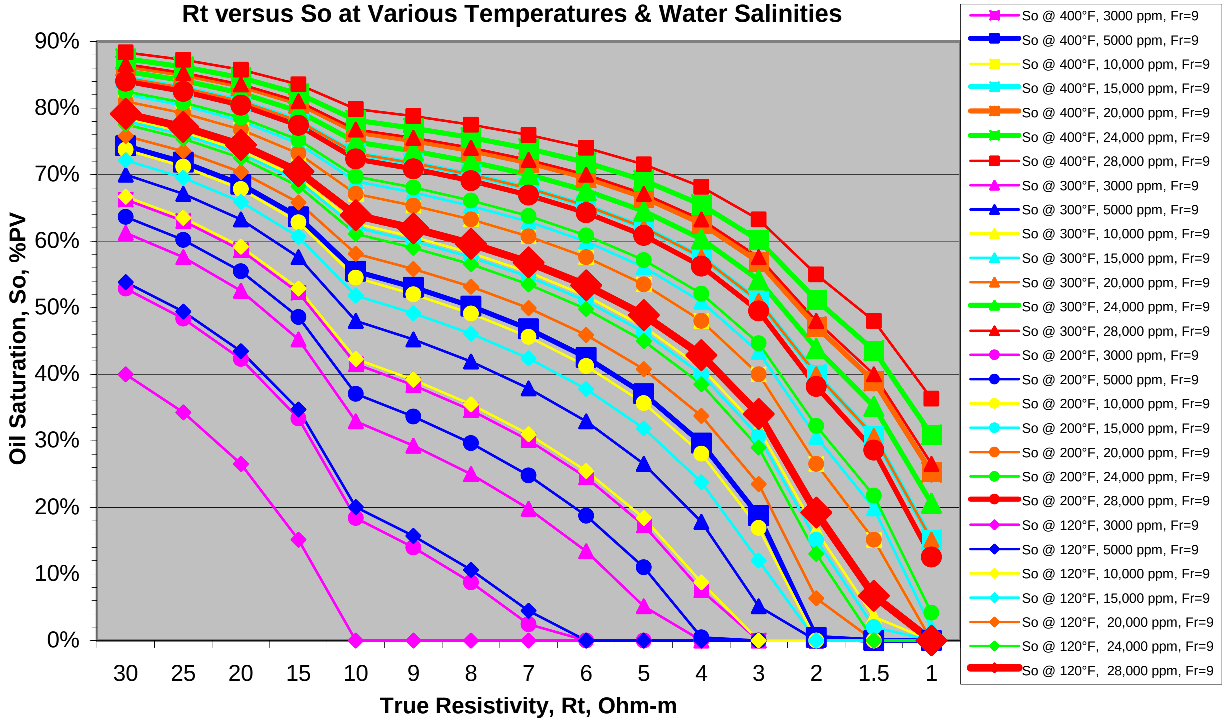
The study area provided a unique opportunity to examine the effect of sustained heating on the formation petrophysical properties. For conventional material balance studies, resistivity logs are used at Wilmington to assess remaining oil saturations. For the majority of the tar zone oil sands, a minimum of 6.0 Ohms of true resistivity is used as the completion cutoff point for economically recoverable steamflood oil. A true resistivity of 6.0 Ohms in the tar zone sands at the pre-steamflood temperature of 120 degrees and formation water salinity of 28,000 ppm yields an estimated oil saturation of 53 percent pore volume.

The logging-while-drilling resistivity log for well UP-957 showed extremely low true resistivity values in the steam chest area, ranging from below 1.0 Ohm where the well first entered the D1 sands in the main steamflood area, to 2.0 Ohms from the Ford Fault to 60 feet before the casing point. These low resistivities resulted in oil saturations of 0-19 percent using pre-steamflood formation temperatures and water salinities. The resistivity readings were so low in the steam chest area that some were below the typical tar zone readings for 100 percent formation water saturation.

The low-resistivity readings were believed to be a tool problem, so a second conventional open-hole resistivity logging tool was run on the end of drill pipe, which confirmed the low readings. Resistivity-based oil saturations were reevaluated for in-situ formation temperatures and water salinities. A map of the average formation temperatures in the top third of the D1 sands in the steamflood area showed formation temperatures in the neighborhood of 400 degrees along the well path based on the reservoir simulation model in July 2003. Monthly analyses of produced fluids from multiple Tar II-A wells have shown increasing salinities during the post-steamflood phase from 3,000 to 28,000 ppm. Salinities in the well path area currently range between 20,000 and 24,000 ppm.

Figure 28 is a chart of oil saturations versus true resistivities assuming reservoir temperatures of 120-400 degrees and formation water salinities of 3,000-28,000 ppm. As shown, resistivities of 1.0-2.0 Ohms at 400 degrees and formation water salinity of 24,000 ppm signify oil saturations of 31-51 percent. This oil saturation range closely aligns with the remaining oil saturations estimated by the model in the steam chest area shown in Figure 25.

Figure 28 - Wilmington Field - Tar Zone
Rt versus So at Various Temperatures & Water Salinities



Tar II-A Infill Delineation Production Well UP-959

Well UP-959 was drilled as a directional delineation well. The well was drilled in an structurally updip position that provided a current vertical oil saturation profile showing significant oil depletion in the former steam chest area ranging from 20-75% recovery of the original oil in place, averaging about 50% oil recovery. Most of the remaining oil was in the T2, the D1b&d, and top of the D1 sands. UP-959 was selectively perforated into the top of the D1 sands and completed with an inner wire-wrapped screen and gravel-packed. The well was placed on production in October 2004 at 42 BOPD and 737 BPD gross fluid and peaked at 84 BOPD and 2108 BPD gross fluid in June 2005. Production declined to 55 BOPD and 1840 BPD gross fluid by February 2006 and the well watered out in March 2006. Most likely, the high gross fluid rates coned water into the well. The plan has been to leave the well idle for several months and then activate it at a much lower gross fluid rate. Figure 29 is a production graph for UP-959 through June 2007.

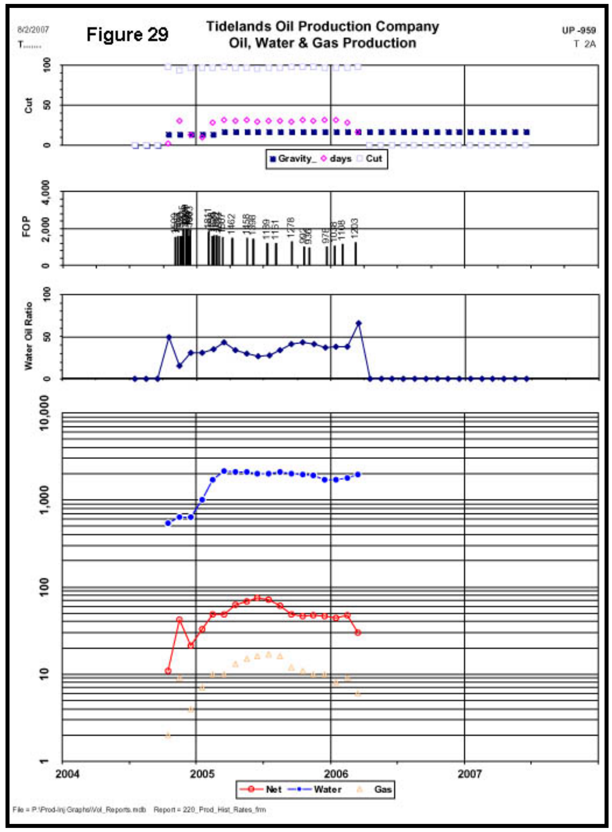


Figure 29

The reservoir model and logs from UP957 and UP959 showed oil-depleted steam chests (~20% oil saturation, down from 80% original) in the structurally updip sands of all the steamflooded sands. The model showed that oil would resaturate the steam chests as post-steamflood water injection continued along the downdip flanks of the project. Two new horizontal wells, UP958 and W900, were completed in the updip oil-depleted steam chest areas of the T2 and D sands, respectively, to accelerate the upward migration of hot oil. Well UP-958 was completed into the T2 sands and reached a peak rate of 226 BOPD/1749 BPD gross (87% water cut) in November 2005. Well W-900 was completed into the D1, D1b and D1d sands and averaged 155 BOPD at 93% water cut in November 2005. The two wells are currently producing 109 BOPD and 38 BOPD and have cumulatively produced 109,793 BO and 55,840 BO through May 2007, respectively. These two successful wells show the value of reservoir modeling and the confidence placed on the model results, because it was not intuitive to drill horizontal wells into the oil-depleted steam chests.

Tar II-A Horizontal T2 Sand Production Well UP-958

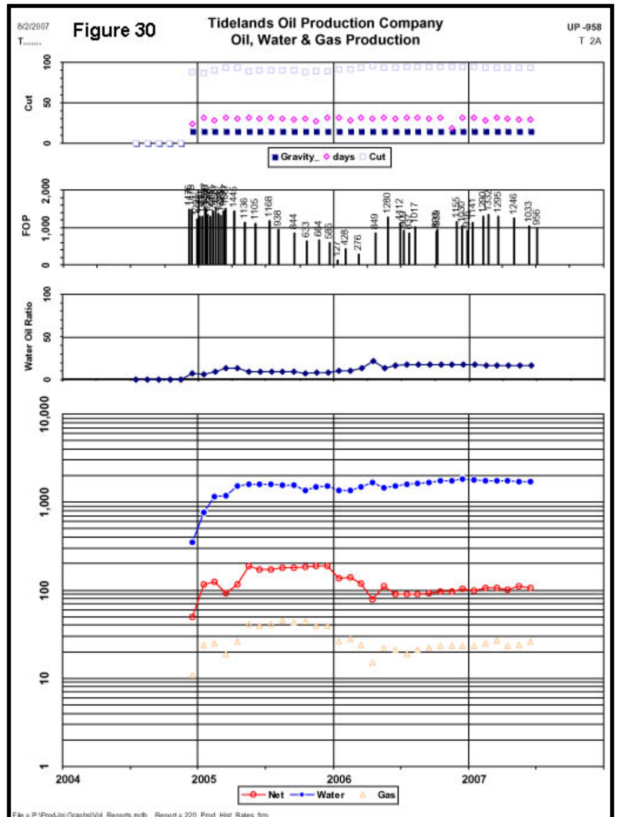
Well UP-958 was drilled and completed along the top of the T2 sands in the updip steamflood area, and like wells UP-957 and UP-959, showed low apparent oil saturations in the open-hole logs. The well was drilled based on the Tar II-A 3D thermal reservoir simulation model to capture oil that gravitated updip, despite the expected instantaneous low oil saturation data shown on well logs. The well was completed with 1067 ft of open-hole, 4.5” wire-wrapped, gravel-packed completion. The well was placed on production in December 2004 and has been excellent, peaking at 219 BOPD and 1828 BPD gross fluid five months after initial start-up compared to the projected initial oil rate of 140 BOPD. Figure 30 is a production graph of UP-958 through June 2007 showing how stable the oil rate has been over the past year at 100 BOPD.

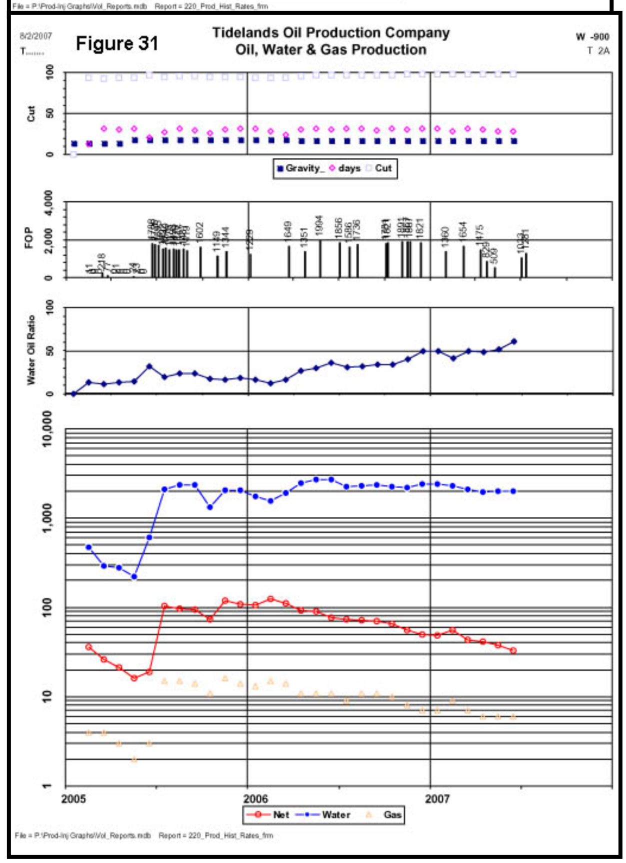
Tar II-A Horizontal D1 Sand Production Well W-900

This well was drilled to penetrate and complete all of the D1 sands over a long measured depth interval exceeding 1500 ft. The well was initially completed in February 2005 in the lower D1 sands (D1b and D1d) with selected perforations and an inner wire-wrapped screen and gravel-pack to test oil productivity. The well produced at low oil and gross fluid rates of 48 BOPD and 532 BPD gross that were relatively cool, about 140-180°F. Production declined to 26 BOPD and 205 BPD gross by June 2005, when the well was recompleted and commingled with perforations at the top of D1 sands. The well production peaked at 177 BOPD and 2461 BPD gross fluid in July 2005 and declined to 78 BOPD and 2794 BPD gross fluid by May 2006 and 30 BOPD by June 2007, as shown in Figure 31.

Tar IIA T Sand Injection Well 2AT-64

This well was drilled in a structurally downdip location to replace T sand injection well 2AT-62, which was abandoned for the POLB. The well logs showed high remaining oil saturations in the D1 sands in a downdip structural position in the reservoir that was bypassed during the waterflood development phase of Tar II-A during the 1960s and 70s. The well was activated in November 2004 and initially injected 1242 BWIPD, which quickly declined to a stabilized rate of 500 BWIPD at 1040 psi maximum wellhead pressure. In October 2005, the well had an inner wire-wrapped screen and gravel-pack installed to control sand inflow and was given a HCl-HF acid stimulation job. The well injection rate rose to 2054 BWIPD but by January 2006 had declined back down to 800 BWIPD. Well injectivity was



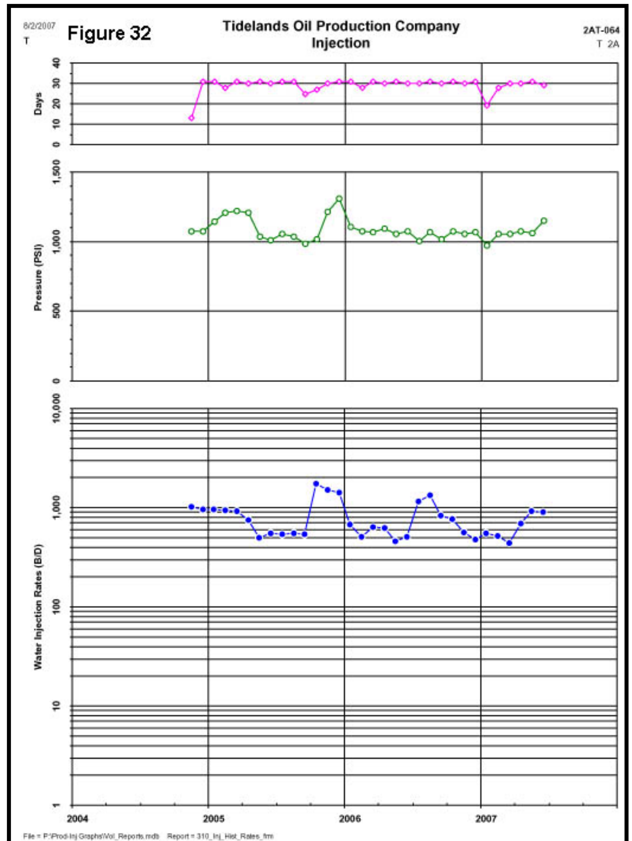


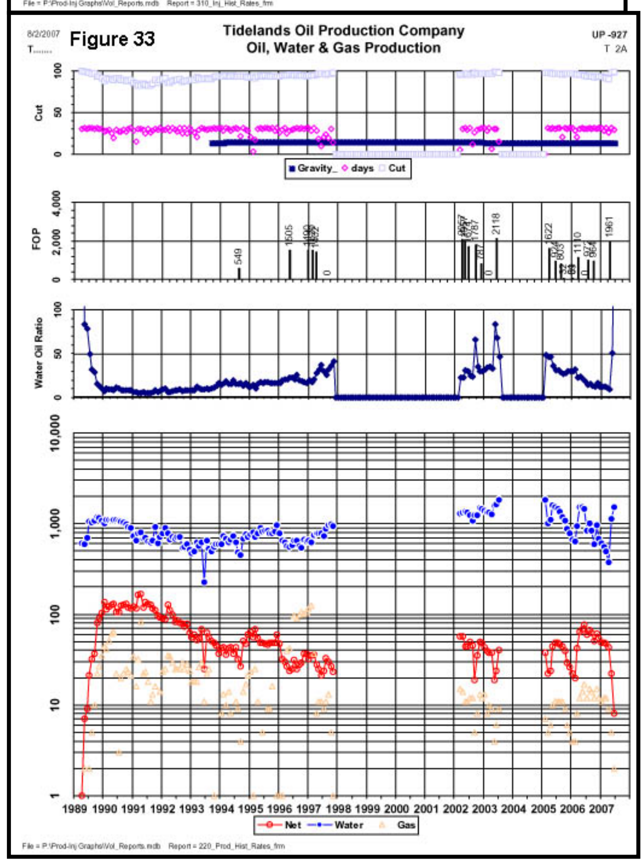
significantly lower than the 2500 BPD anticipated rate, probably due to highly saturated cold oil surrounding the wellbore, which reduces the water relative permeability. The project team tested a new patent pending chemical by Coriba Oil Company, LLC, Coriba700, with an HCl job in June 2006 to improve injectivity. The well did not perform any better than the HCL-HF job in 2005. Figure 32 is an injection graph of well 2AT-64 through June 2007.

Replacement wells UP-959 UP-958, and W-900 peaked at 84 BOPD, 219 BOPD and 177 BOPD, respectively, for a total of 480 BOPD compared to the 345 BOPD produced by the wells that were abandoned. Wells W-900 and UP-958 confirm that oil resaturation can be accelerated into the steam chest area as indicated by the model. However, UP-959 watered out and the two horizontal wells produced only 175 BOPD in June 2006 and 130 BOPD in June 2007 so losing the original wells due to the POLB construction work hurt the project.

April 2004 to March 2005 Well Work

Well UP-927 was repaired in February 2005 by installing an inner wire-wrapped screen and gravel pack to restore sand control. This was the only major well workover in Tar II-A from April 2004 to March 2005. The job was successful, resulting in near-term peak production of 58 BOPD and 1496 BPD gross fluid in July 2005. Production following a pump change and HCl acid stimulation job in March 2006 increased to a peak of 85 BOPD and 1566 BPD gross fluid in June 2006. Net oil production decreased to 45 BOPD in early 2007 before sanding up in March 2007. Figure 33 is a production graph of





UP-927 through June 2007.

Five Tar IIA wells, UP-939, UP-941, UP-942, UP-950, and 2AT-62 were plugged and abandoned from January to March 2005 for the POLB.

April 2005 to March 2007 General Work

During the period from April 2005 to March 2007, oil production declined in March 2005 from the abandonment of producing wells UP-939, UP-941, UP-942 and UP-950 and dropped to as low as 967 BOPD in April 2005. Oil production rose to a high of 1422 BOPD in November 2005 from converting or repairing existing wells and drilling new wells. Several idle wells were activated in May 2005 to increase production and water injection. Wells AT-42, AT-43 and AT-63 were converted from steam injection to production and wells 2AT-21, 2AT-22 and 2AT-23 were converted from steam to water injection. New horizontal well W-900 was recompleted in June 2005 to the top of the D1 sands in the “depleted steam chest section” and peaked at 177 BOPD in July 2005. Existing producers UP-923 and UP-930 were given workovers from June to July 2005 to improve oil production. Oil production from T sand horizontal well UP-958 steadily improved from an initial rate of 35 BOPD and 245 BPD gross fluid in December 2004 to a peak rate of 219 BOPD in September 2005. New well UP-961 was activated in November 2005 with an initial peak rate of 185 BOPD and new well UP-960 was activated in January 2006 and reached a peak oil rate of 70 BOPD in March 2006. New well UP-957 was watering out and had a tubing sleeve installed in March 2006 that resulted in 65 BOPD. Wells 901-UP and 2AT-24 were successfully activated for water injection in 2006.

Tar II-A production from April 2005 to March 2006 averaged 1192 BOPD, 34,846 BPD gross fluid, water-oil ratio (WOR) of 23.97 and 44,346 BPD water injection compared to production and injection rates the previous year of 1169 BOPD, 29,185 BPD gross fluid, WOR of 28.22 and 41,431 BPD water injection. Production from April 2006 to March 2007 was significantly worse, with production averaging 1131 BOPD and 39,904 BGFPD, WOR of 34.28, and 49,812 BPD water injection. Production in the second quarter 2007 was declining rapidly to 999 BOPD and 37,738 BGFPD and WOR of 37.78. Activation and/or conversion of idle wells to production and injection has continued to result in more incremental water production and associated water injection with only a short-term increase in oil rates. Existing producers, especially those closest to the water injectors, are experiencing higher water cuts or watering out from the increased injection water. The accelerated cooling strategy must be adapted to minimize water cycling and lower water cuts and injection rates to more manageable and profitable levels.

Development Drilling during the Last Half 2005

Three new wells, UP-959, UP-958 and W-900, that were proposed in the DOE BP2 plan for the Tar II-A project, were drilled at the cost of the POLB as compensation for abandoning other wells. Two of the budgeted wells were replaced by new Tar II-A wells UP-960 and UP-961, which were drilled during the second half 2005.

Tar II-A Infill Delineation Production Well UP-960

Well UP-960 was drilled in November 2005 for the DOE project as a vertical infill delineation well in place of well UP-959. The objectives were to determine remaining oil saturations in a mid-structural pattern location within the main steamflood area that had experienced both steamflooding and hot waterflooding and to find out why adjacent wells have abnormally high water cuts. The well logs showed good oil saturations in the T sands at pre-waterflood levels, even though waterflood and steamflood injectors surround the well, whereas the D1 sands appear oil depleted by steamflooding. The T sands do not appear resaturated because a recent temperature survey run in the well shows the sands as relatively cold from 140-180°F, as if they were never steamed. These patterns were steamflooded for 6-7 years and then hot waterflooded for three years; therefore, it is difficult to understand why the sands are not hot just from conductive heat transfer. The resistivity log looks just like an offset 1953 well that was completed in a deeper zone. The D1 and D3 sands were very hot and exhibited the same characteristics as in well UP-959, only the resistivities were even lower. Based on the So versus Rt chart[1] developed for UP-957 (Figure 28) and assuming reservoir temperature of 300°F and 20,000 ppm salinity, the D1 sands (0.7 - 2.0 ohms) had less than 15% So at the top and 40% So at the middle to bottom of the sands.

The well was cased to total depth and completed in the T sands and the top of the D1 sands, assuming that the remaining D1 oil would migrate and resaturate the top of the sands. An inner wire-wrapped screen was gravel-packed inside the casing for sand control. Completing the depleted former steam chest sands followed the same philosophy used to complete successful horizontal wells UP-957, UP-958 and W-900. Well UP-960 was activated on January 23, 2006 with an initial rate of 1 BOPD and 1001 BPD gross fluid. The well was sped up and by February 14 it was producing 18 BOPD and 1462 BPD gross fluid (98.8%water cut). The well peaked in February 2006 at 70 BOPD and 1328 BPD gross fluid (94.7% water cut) . The fluid level was pumped down to the pump and the pumping unit was slowed, which resulted in the well producing 52 BOPD and 783 BPD gross fluid (93.4% water cut) in April 2006, which is a good rate for an infill well location. The well was given an HCl/HF

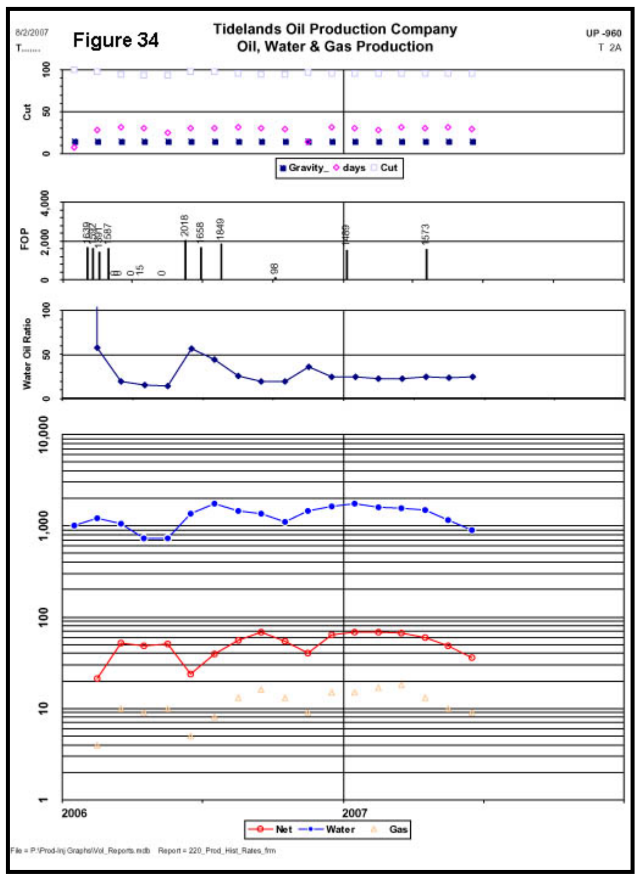


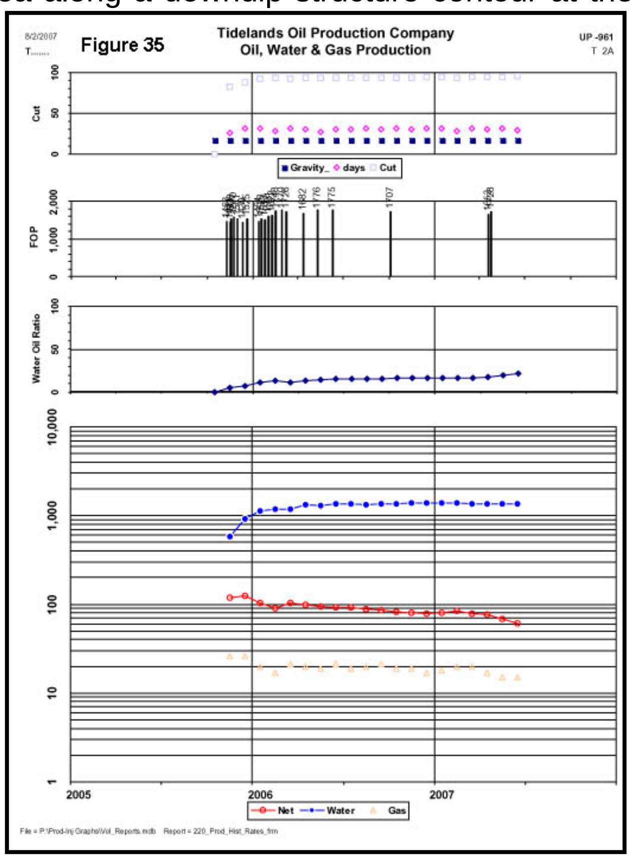
Figure 34

acid stimulation job in May and production restarted in June 2006 at 1 BOPD and 1285 BPD gross fluid. The well was sped up and the well improved to 70 BOPD and was stable for a year, but oil and gross fluid rates have fallen off during the second quarter 2007, as shown in the production graph in Figure 34.

Tar IIA Horizontal D1 Sand Production Well UP-961

The 3-D reservoir simulation model showed that continued operations through the year 2013 would not recover oil from the highly oil saturated D1 sands in the cold, structurally downdip areas south of the steamflood patterns. Recent drilling of replacement Tar II-A downdip water injection well 2AT-64 and new Upper and Lower Terminal zone injection well 2AU-512 in this area confirmed the very high oil saturations greater than 70% PV at the top of the D1 sands. When Union Pacific Resources (UPR) developed their Tar II-A waterflood in 1959, this area was avoided because initial vertical waterflood wells had 98-99% water cuts. Instead, UPR concentrated their efforts on the up-structure sands.

Well UP-961 was drilled for the DOE project in place of well W-900 as a horizontal D1 sand well, only instead of drilling into the updip depleted steam chest, the well was completed in the downdip, highly oil saturated area to test production in the cold tar sands where vertical wells produced at 98+% water cuts. This was again a very counterintuitive decision based on past vertical well performance. The well was drilled in November 2005 outside the steamflood area along a downdip structure contour at the top of the cold D1 sands, a very counter-intuitive decision based on past well performance in the area. The well had 7-5/8" casing and was completed in the open hole with 993 ft of 4-1/2" wire-wrapped screen and a gravel-pack for sand control.



The logs for well UP-961 confirmed the high oil saturations and the well was placed on production on November 4, 2005 with an initial peak rate of 185 BOPD and 635 BPD gross fluid (70.9% water cut). The well had high fluid levels ranging from 1400-1700 feet over the pump and was sped up. Oil production declined but still tested 115 BOPD and 1285 BPD gross fluid (91.1% water cut) in January 2006. Through March 2007, oil production declined to 80 BOPD and has further declined to 60 BOPD by June 2007, as shown in the production graph in Figure 35. The well has cumulative production of 51,519 BO through May 2007.

Well Work April 2005 to March 2006

Eleven idle wells were worked on to activate and/or convert for use as Tar II-A producers (wells AT-43, AT-42, AT-63, UP-923, UP-930) or water injectors (2AT-21, 2AT-22, 2AT-23, 2AT-35, 2AT-24, 901-UP) from April 2005 to March 2006. All of the wells except UP-930 are completed in a single sub-zone, T or D1 sands, to provide better reservoir management control in an effort to increase oil production rates and reduce water cuts.

Six of the jobs were listed in the DOE BP2 proposal and the work on well UP-923 replaced a similar job slated for Tar V well A-194 that was completed prior to BP2 approval. The work on wells UP-930, 2AT-35, 2AT-24, and 901-UP were not included in the BP2 budget. The five producers peaked at 242 BOPD and 6009 BGFPD (96.0% water cut), with three wells being good and two wells producing almost all water. Two of the three other wells subsequently watered out and require further review. Five of six wells were converted successfully to water injection, while one well had casing damage.

<u>1. Tar II-A D1 sand well 2AT-21 (DOE BP2):</u> Successfully converted steam injection well to water injection in May 2005 at 1000 BPD. Injection was quickly increased to 3000-5000 BPD and the well has injected up to 7000 BPD on occasion.

<u>2. Tar II-A T sand well 2AT-22 (DOE BP2):</u> Successfully converted steam injection well to water injection at 2000-3000 BPD from May to July 2005. The well experienced a packer leak and upon investigation, a severe shallow casing restriction was found at 1600 ft. A packer fish and tubing kill string were left in hole and the well was idled.

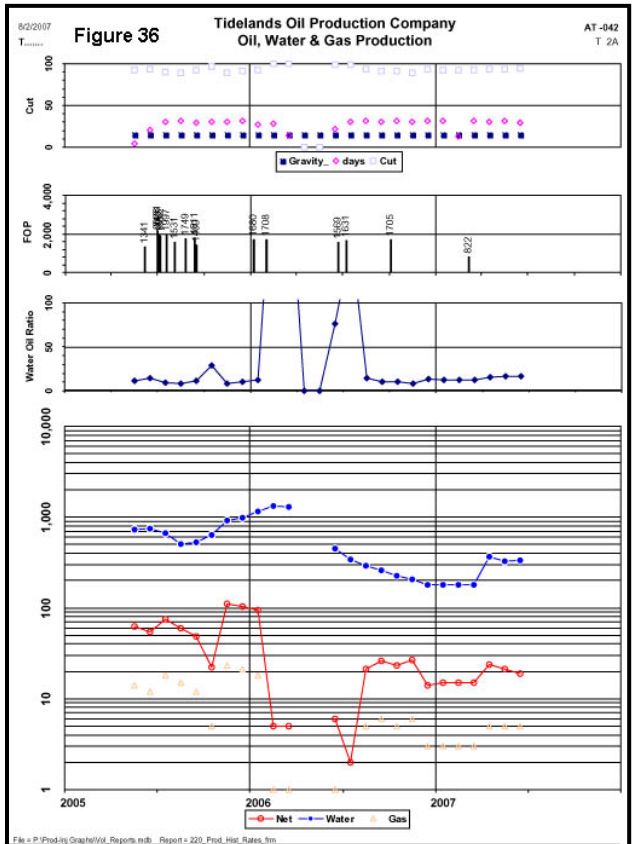
<u>3. Tar II-A D1 sand well 2AT-23 (DOE BP2):</u> Successfully converted steam injection well to water injection in May 2005 at 1000 BPD. Injection was quickly increased to 2500-5000 BPD and on occasion the well has injected up to 7000 BPD.

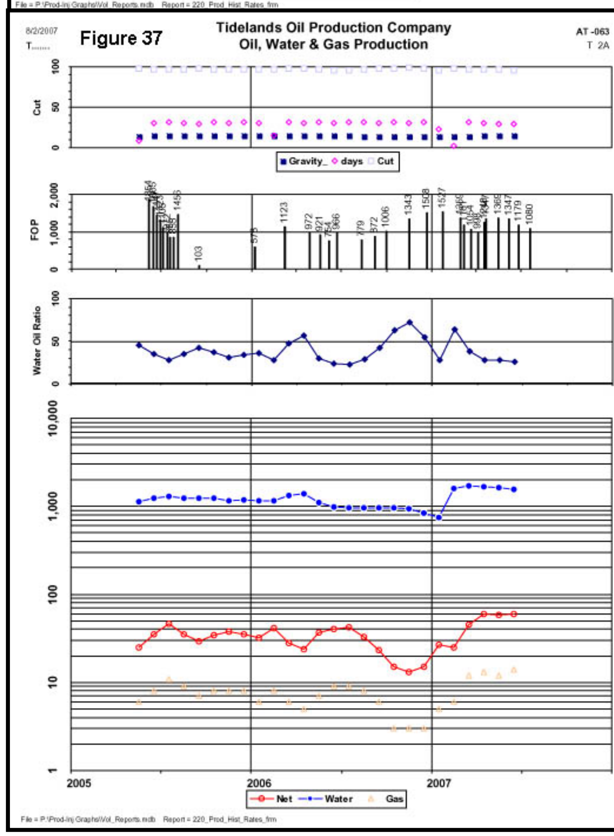
<u>4. Tar II-A T sand well 2AT-42 (DOE BP2):</u> Successfully converted steam injection well AT-42 to production in May 2005 at 75 BOPD and 792 BPD gross fluid. Production fluctuated from 60-130 BOPD and 900-1200 BPD gross fluid from June to December 2005. In January 2006, the well watered out and the produced fluids were very hot and the pump would gas lock. The well was temporarily plugged back to the top of the T2 sands in June 2006 and activated at a much lover rate of 2-4 BOPD and 334-430 BPD gross fluid. From August 2006 to June 2007, oil production increased to over 20 BOPD and gross fluid decreased to an average rate of 300 BGFPD, which was the desired outcome. Well AT-42 is located in the updip, oil-depleted, steam chest area and injected steam into the same "T" sands for seven years, so this is another example of accelerating the gravity segregation of oil back into the steam chest in a well that would normally not be expected to produce any oil. Figure 36 is a production graph of AT-42 through June 2007.

5. <u>Tar II-A D1 sand well 2AT-43 (DOE BP2):</u> Converted to production as well AT-43 in May 2005 with very high water cuts to date. Production peaked at 20 BOPD and 2334 BPD gross fluid in December 2005. The well was plugged back with sand to the upper D1 sands and production in 2006 has ranged between 8-20 BOPD and 1400-2500 BPD gross fluid, the higher rates coming after a pump speed up in June 2006. The well watered out in January2007 and was idled.

6. <u>Tar II-A horizontal D1 sand well 2AT-63 (DOE BP2):</u> Successfully converted pilot horizontal steam injection well to production as well AT-63 in May 2005. Initial production in June 2005 was 54 BOPD and 1375 BPD gross fluid with a pumping fluid level of 1447 ft over the pump. Oil rates varied between 15-40 BOPD during 2006 whereas gross fluid rates were stable at 1000 BGFPD. Pump rates were increased to 1800 BGFPD in early 2007 and oil rates rose to a peak rate of 60 BOPD during the second quarter 2007, as shown in the production graph in Figure 37.

7. <u>Tar II-A T sand well UP-923 (DOE BP2 in place of A-194):</u> Repaired well by installing inner wire-wrapped screen and gravel pack to restore sand control in July 2005. The well initially produced 57 BOPD and 440 BPD gross fluid and then experienced three well failures within six months that required pulling jobs. After the first pulling job in October 2005, the well only produced 13 BOPD and 398 BPD gross fluid. After the second pulling job in November 2005, the well resumed good rates of 58 BOPD and 338 BPD gross fluid. After the third pulling job in February 2006, the well only produced 1 BOPD and 379 BPD gross fluid. After





confirming the bad production, the well was idled in April 2006.

8. Tar II-A T and D sand well UP-930: Successfully repaired well by installing 228 ft. of 5-1/2" blank liner above the 5-1/2" liner top to seal off a casing leak in June 2005. The well is located structurally updip and was expected to produce like new updip vertical well UP-959, which was producing 50-80 BOPD at the time. The well initially peaked at 22 BOPD and 1095 BPD gross fluid, which was very hot at 326°F at the wellhead or about 375°F in the formation. The well had pumping problems related to gas, most likely steam breakout around the downhole pump and from non-condensable gases like CO_2, H_2S and mercaptans that migrate into the updip wells. The well experienced lost circulation problems in the lower D1 and D3 sands that could mean the lower sands were either steam depleted or steam bypassed and low pressure. The latter situation is probably the case. A gas anchor was installed in August 2005. The well was idled in September 2005 due to the high water cuts. The well may be plugged back to the top of the D1 sands like UP-959 to help eliminate watered out sands and pumped at much lower gross fluid rates.

9. Tar II-A D1 sand well 2AT-35: Attempt to convert steam injection well to water injection failed in December 2005 as well had shallow casing damage at 1618 ft.

10. Tar II-A T sand well 2AT-24: Successfully converted steam injection well to water injection at 2000 BPD from February to June 2006. Upon surveying the well in June 2006 for water injection profile, a casing hole was discovered at the top of the liner in the S sands and the well was idled. The well was repaired in May 2007 and water injection was resumed at over 2000 BPD.

11. Tar II-A T sand well 901-UP: Successfully converted steam injection well to water injection at 2000-3000 BPD in April 2006.

12. Tar IIA D1 sand production well AT-58: Successfully converted to D sand water injection as well 2AT-58 in August 2006 at over 2000 BPD to improve water injection sweep efficiency of post-steamflood project. This well replaced "well 2AT-54" in the BP2 budget.

13. Tar II-A T sand water injection well FW-101: Efforts to install an inner slotted liner to control sand inflow were unsuccessful in September 2006 and the well was plugged and abandoned in April 2007.

Tar IIA D1 sand injection well 2AT-31 was plugged and abandoned in May 2005 due to irreparable mechanical damage.

Tar II-A New and Idle Well Conversion and Activation Plan

The Tar II-A post-steamflood project has excellent remaining oil reserve potential that can be recovered by both new and existing idle wells. The 2002 Tar II-A waterflood acceleration plan, as explained previously, resulted in premature watering out of the producing wells and increased mechanical breakdowns and well costs. The 2002 plan required the flank injection wells to inject water at extremely high individual well rates, which encouraged early water breakthrough, exacerbated poor vertical injection profiles, and created severe injection/production ratio problems when an injection well was idled because of mechanical problems.

Several idle wells can alleviate the production and injection well problems mentioned above at relatively low costs. The objective of this well conversion and activation plan is three-fold: 1) To increase the number of flank injection wells to enable the project to maintain water injection rates while allowing each well to inject water at lower and more maintainable rates. This would also provide spare injection capacity to apply when individual injection wells are idled for well work or other reasons; 2) To improve reservoir control of production and increase oil rates by increasing the number of wells producing from only the T or D sands; and 3) To improve oil production rates by repairing idle producing wells located structurally updip that had previous economic production prior to experiencing mechanical problems. In the near term, the injection wells are also needed to supplement water injection to maintain injection/production (I/P) ratios as idle wells are converted to production. The loss of three injection wells and the unanticipated high gross fluid production rates in late 2005 and 2006 have left the project short of water injection. Although reservoir pressures in the T and D sands appeared stable through September 2005, they began to fluctuate dramatically as new and idle production wells were activated in late 2005 and early 2006.

The next set of proposed well work includes converting idle producers UP-944 and UP-902 and idle steam injection well 2AT-53 to T sand injection and idle producer UP-854 and steamflood injector 2AT-58 (currently idle producer AT-58) to D sand injection. Also, idle producer UP-905 will be converted to a T and D sand water injector. These wells will allow average water injection rates per well to decline to 2000 BPD rather than the current 3500-4000 BPD rates.

Several idle steam injection wells can be selectively recompleted or activated nd new wells can be drilled strategically to optimize oil rates at lower water cuts, especially horizontal wells and vertical reservoir delineation wells. New horizontal well UP-961 confirmed the oil production potential in the highly oil saturated downdip D1 sands near the heels of the pilot horizontal steamflood wells. Proposed reservoir delineation well UP-960 showed high remaining oil saturations in the T sands despite being located between two patterns that had been steamflooded and hot waterflooded. The production performance of these wells and recently drilled updip wells UP-957, UP-958, UP-959 and W-900 provide the necessary justification for future Tar II-A drilling. Idle steam injection wells 2AT-54, 2AT-55, and 2AT-44 can be activated and/or selectively recompleted as new Tar II-A producers. Figure 24 is a Tar II-A steamflood pattern map showing the location of the active post-steamflood wells and the proposed wells to be drilled and reactivated.

The Tar II-A post-steamflood project will experience a short-term jump in gross fluid and oil production that will also require increased water injection. The long-term objective is to allow gross fluid rates to decline from its current 40,000 BPD rate to about 27,000 BPD and reduce water injection accordingly to meet the 10,000 BPD of net injection. The new and activated producers are capable of producing at much lower water cuts than the existing T and D commingled producers. The goal is to improve overall Tar II-A project oil rates and oil cuts by producing at lower gross fluid rates and injecting significantly less water. A 1.0% oil cut improvement can increase Tar II-A oil rates by 25-30%. This will also reduce the mechanical wear and tear on well equipment and lower the operating and maintenance costs per well.

Future Well Work and Drilling for the Tar II-A Post Steamflood Project

Tar II-A oil production improved from 902 BOPD at a 3.3% oil cut (28.9 WOR) in November 2003 to a peak of 1422 BOPD at a 3.7% oil cut (26.1 WOR) in November 2005. Production has declined to an average of 1082 BOPD at a 2.8% oil cut (35.1 WOR) in 2007 through May as many wells are watering out. A new reservoir management plan needs to be implemented to reduce the high water cuts.

The first objective is to continue realigning the Tar II-A post-steamflood project to increase the wells producing from single subzones and selective completions to improve oil production and reduce water cuts. The second objective is to increase the downdip water injectors to improve the areal sweep efficiency of the waterflood.

<u>1. Tar II-A proposed D sand horizontal well UP-962:</u> Drill and complete structurally downdip horizontal well along the top of the Tar II-A D1 sands parallel to the structure contours, similar to well UP-961.

<u>2. Tar IIA sand production well UP-905:</u> Convert to T and D sand injection well 905-UP to improve water injection sweep efficiency of post-steamflood project.

<u>3. Tar IIA D sand steam injection well 2AT-53:</u> Plug back, recomplete and convert to T sand water injection.

<u>4. Tar IIA D sand production well UP-854:</u> Convert to D sand water injection.

<u>5. Tar IIA production well UP-944:</u> Plug back, recomplete and convert to T sand water injection.

<u>6. Tar IIA T sand production well UP-902:</u> Convert to T sand water injection.

<u>7. Tar IIA D1 sand injection well 2AT-55 (DOE BP2):</u> Plug back and recomplete as either a D1 or T sand production well AT-55.

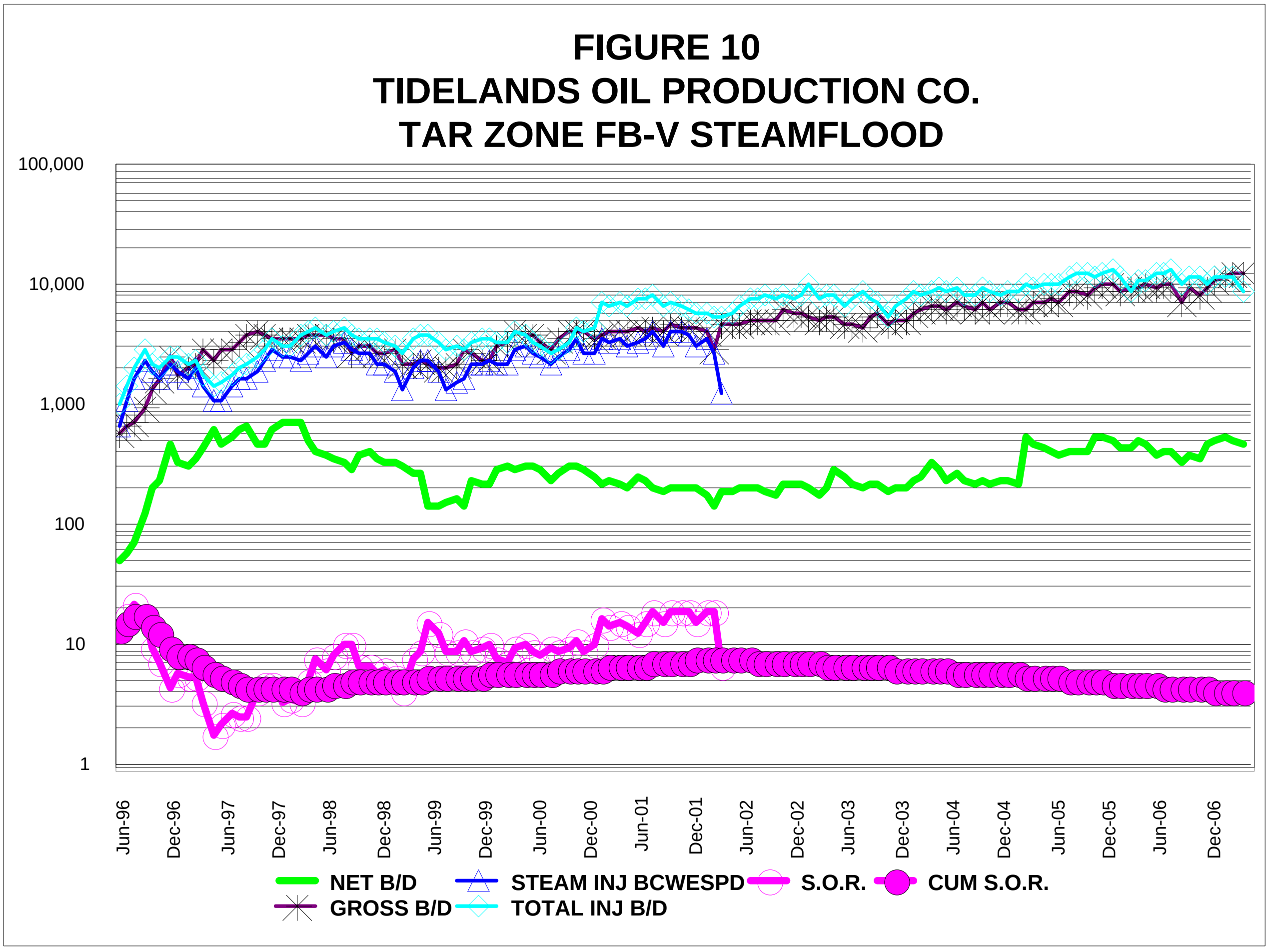
<u>8. Tar IIA T sand injection well 2AT-44:</u> Convert to T sand production well AT-44

<u>9. Tar IIA D1 sand injection well 2AT-54 (DOE BP2):</u> Plug back and recomplete as either a D1 or T sand production well AT-54.

Wells UP-854 and UP-944 were activated in late August and September 2006. Both wells still had high water cuts exceeding 99% and were idled.

Tar V Pilot Post-Steamflood Project
April 2005 – March 2006 General Work

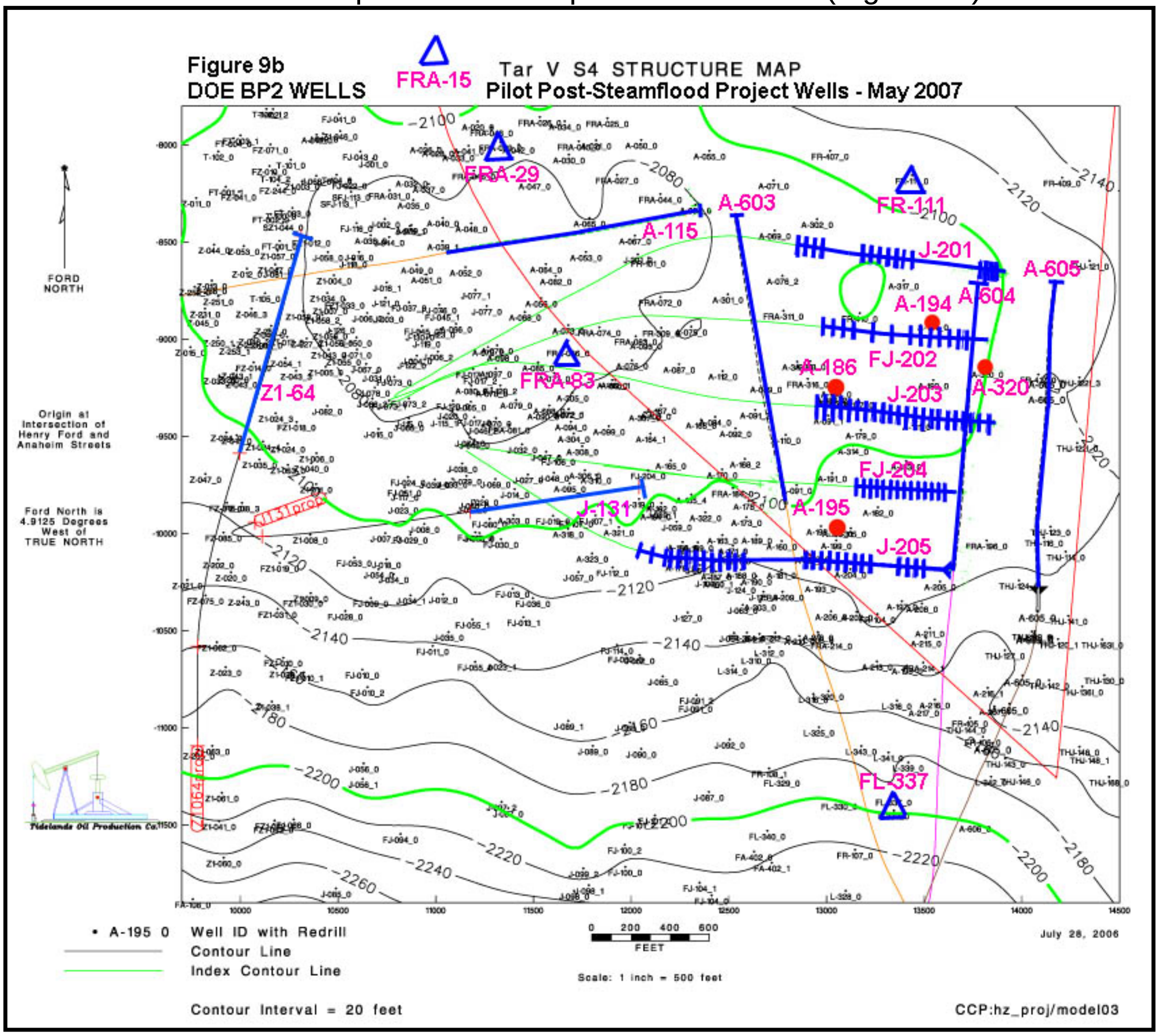
The Tar V post-steamflood pilot project continued to benefit from the successful development drilling of horizontal production wells along the top of the S_4 oil sands. Recently drilled S_4 horizontal wells include A-605 in April 2003, A-604 in May 2004, A-603 and A-115 in 2005 and Z1-64 and J-131 in November 2006. Also, pilot steamflood horizontal producer well J-205 was recompleted to the top of the S4 sands in July 2005.



Pilot project oil production has increased significantly since the reporting year ending March 2003 at 203 BOPD. The average oil production for the year ending March 2004 was 225 BOPD, for the year ending March 2005 was 275 BOPD, for the year ending March 2006 was 464 BOPD, and for the latest year ending March 2007 was 448 BOPD. Figure 10 is a production graph of the Tar V pilot steamflood and post-steamflood projects. Figure 9b is a structure contour map of the top of the Tar V S4 sands that shows the location of the post-steamflood pilot wells and the new cold heavy oil horizontal production wells. The following is a discussion of the new Tar V horizontal S4 sand producer wells drilled since 2003.

Cold Heavy Oil Tar Zone Horizontal Wells

In the DOE project areas, Tidelands Oil Production Company (Tidelands) drilled four horizontal wells from 2003-2005 to test the ability of horizontal wells completed at the top of the highly oil-saturated sands in previously waterflooded areas to recover cold tarry oil. Tar II-A well UP-961 in "D1" sands and Tar V wells A-115, A-603 and A-605 in "S4" sands were all completed at the top of the oil sands (Figure 9b) and all have been



very successful and paid out their capital costs within a year. UP-961 was placed on production in November 2005 and has been an excellent well, initially producing 185 BOPD and 635 barrels of gross fluid per day (BGFPD) and in May 2007 producing 66 BOPD and 1404 BGFPD. Well A-605 was activated in April 2003 and reached a peak rate of 176 BOPD and 560 BGFPD within a week. Production declined during the next four months to 70 BOPD and 461 BGFPD, which was unexpectedly fast, but fortunately the rate stabilized at that level for several months and slowly declined to 40 BOPD and 501 BGFPD in May 2007. Cumulative production through April 2007 for well A-605 was

74,000 BO. Well A-603 has been the best Tar zone well, cold or hot. The well was activated in March 2005 and peaked at 408 BOPD and 759 BGFPD. One year later, A-603 was still producing 208 BOPD and 1311 BGFPD and in May 2007, production was 116 BOPD and 1332 BGFPD with cumulative oil production of 147,000 BO. Well A-115 was drilled in 2005 and was also successful, initially producing at a peak rate of 224 BOPD and 1497 BGFPD in November 2005 and 145 BOPD and 1507 BGFPD in February 2007. Net oil decreased in May 2007 to 64 BOPD and 1446 BFPD for reasons to be determined, which could range from the well watering out to well tester problems. Existing north flank water injection well FRA-15 supports the production from wells A-603, A-115 and Z1-64.

Tidelands drilled two new Tar V horizontal producing wells, J-131 and Z1-64 (Figure 9b), in November 2006 as downdip stepouts to the recent cold Tar V "S4" sand horizontal wells A-115 and A-603. Well Z1-64 was activated on December 22, 2006 and within a week reached a promising initial peak rate of 216 BOPD and 1382 BGFPD. The well production declined quickly to 75 BOPD and 1795 BGFPD by May 2007. Well J-131 was activated on January 2, 2007 and tested 54 BOPD and 1952 BPD gross fluid at a 97.2% water cut on January 18 after initially producing only 23 BOPD and 927 BPD gross fluid. This is below the expected initial projected rate of 105 BOPD, but the well has appeared to stabilize at 50 BOPD and 2190 BGFPD in May 2007. Both Z1-64 and J-131 appear to be pumped at excessive rates compared to A-603 and A-115, which could be watering them out prematurely. Wells A-603 and A-115 are slightly updip of J-131 and Z1-64 and their high oil rates could be affecting downdip water movement.

Gross fluid temperatures from the cold heavy oil horizontal wells are normal for the Tar Zone at 120°F. The five Tar V wells have very promising oil rates and water cuts that may result in better net energy ultimate recoveries than the steamflood wells if they don't water out and their open-hole, gravel-packed, wire-wrapped screen completions survive for several years. Net energy ultimate recovery is defined as the barrels of oil recovered less the thermal btu-equivalent energy used in the EOR method to recover the oil. These wells may represent an effective alternative waterflood oil recovery mechanism that can outperform steamflooding. With the overall success of the cold Tar horizontal producers, Tidelands still has several more Tar zone well candidates to drill throughout Fault Blocks I through V.

Warren Resources, an offset operator, has been drilling cold, heavy oil Tar zone D1 sand horizontal wells in Fault Block I since 2006. Thums Long Beach Company, an offset operator, intended to drill similar cold, heavy oil Tar S sand horizontal wells in Fault Block V in 2007.

Cumulative steamflood oil and cold heavy oil horizontal well production from June 1996 through April 2007 was 1,287,420 barrels (1,053,948 bbls steamflood only) and oil production in the first four months of 2007 averaged 513 BOPD, of which 120 BOPD was from the pilot steamflood wells and 393 BOPD from cold tar wells A-603, A-115, J-131 and Z1-64. The pilot steamflood project was originally estimated to ultimately recover 1.7 million incremental barrels, whereas the four cold heavy oil horizontal wells was projected to recover 00.7 million barrels of oil. Total steam injection rates into Tar V averaged 2637 BCWESPD from June 1996 through June 2001, the end of steamflood injection. Hot waterflooding occurred from July 2001 through April 2002, when all thermal injection was discontinued. The hot water rate averaged 3188 BCWEPD. At that time, cumulative pilot oil production was 683,278 bbls with a cumulative steam/oil ratio (SOR) of 7.8, very marginal assuming steam costs based on market-priced fuel.

The high cumulative SOR for the project does not necessarily mean the project is uneconomic because the heated reservoir continued to contribute oil production without steam injection, which reduced the cumulative SOR to 5.1. Also, the steam quality for the project probably averaged closer to 60% than the design quality of 80%, an incremental difference of 107 BTU / lb of steam injected or 11% less heat transfer. In addition, the hot water averaged about 330° F at no steam quality, which has about 21% of the heat transfer of 80% quality steam. Therefore, if steam volumes are normalized based on heat transfer using equivalent 80% quality steam, the effective heat transfer rate was 75.7% of the design rate and the corrected cumulative SOR in April 2002 would have been a much more reasonable 5.9 or about 24% lower. The cumulative SOR for the pilot steamflood through April 2007 is 3.85, which is significantly lower than the 7.8 shown in April 2002. Figure 10 is a production and injection graph for the combined Tar V pilot steamflood project and four cold heavy oil horizontal wells from June 1996 through April 2007. Note the jump in oil production starting in March 2005, when the horizontal wells started contributing.

Waterflood operations in April 2007 represent the vast majority of the oil production from the Tar V sands. Tar V oil production in April 2007 averaged 1017 BOPD, of which pilot steamflood production was 120 BOPD or 12%.

April 2005 – May 2007 Well Work

The post-steamflood cold-water injection has essentially watered out the original horizontal steamflood producer wells J-201, J-203 and J-205 because they were completed at the bottom of the S4 sands. Only wells J-201 and J-203 remain with totals of 30 BOPD and 2944 BPD gross fluid (99.0% water cut). The total of all pilot steamflood wells is 120 BOPD. Oil production was maintained for a few years at about 200 BOPD by repairing and continually trying to pump down the horizontal wells.

Although steam and hot water injection were terminated, the pilot project still has potential for increasing heavy oil recovery as evidenced by the performance of wells A-603 and A-115. Horizontal well J-205 was plugged out of the horizontal section at the bottom of the S4 sands and recompleted to the top of the S4 sands in July 2005. The objective was to avoid the high water cuts from post-steamflood water injection. The well peaked in August at 35 BOPD and 706 BPD gross fluid (95.0% water cut). Production declined to 13 BOPD and 642 BPD gross fluid in December 2005 and has fluctuated between 10-25 BOPD and 600-800 BPD gross fluid during 2006 and 2007 through June. Inner liners may be installed in two horizontal producers, J-201 and J-203, so they can be pumped off without sanding up or else they can be plugged back and recompleted to the top of the S4 sands like J-205. Oil rates could increase in horizontal well A-605 if it connects to the thermally heated oil bank nearby, although that scenario gets less likely with time. Wells A-194 and A-604 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.

ACTIVITY 4
RESERVOIR MANAGEMENT

Tar II-A Reservoir Pressure Monitoring

Maintaining reservoir pressure is important to prevent steam chest reoccurrence and surface subsidence. Since March 2000, reservoir pressures in the "D" sands were maintained at 92±3% hydrostatic through September 2004. The "T" sand pressures were allowed to slowly decline to 87% hydrostatic after reaching a peak pressure of 97% hydrostatic in March 2000. The average reservoir pressures of the T and D sands were slowly reduced from September 2003 to September 2004 as planned by 14 psi and 12 psi, respectively, to 905 psi (87% hydrostatic) and 1010 psi (91% hydrostatic). T and D sand reservoir pressures decreased at a faster rate than planned from September 2004 to March 2005 to 873 psi (84% hydrostatic) and 968 psi (87% hydrostatic), respectively, despite increasing water injection and injection/production ratios to improve reservoir pressure control. Pressures probably declined temporarily because the new updip replacement wells and the original updip wells to be abandoned for the POLB were all produced for a couple of months before the original wells were abandoned in March 2005. Also, well UP-927 had an inner liner installed and was returned to production in February 2005. Other possible reasons for the unusual pressure drops could be the well testers were measuring gross fluid production too low or the water injection metering system was measuring too high.

Reservoir pressures in the T and D sands fluctuated widely from April 2005 to March 2006. The T sands went from 84% hydrostatic pressure in March 2005 to 87% in September 2005, to 73% in December 2005, and up to 81% in March 2006. Reservoir pressure should be about 4% hydrostatic or 40 psi higher. The D sands went from 87% hydrostatic in March 2005 to 89% in September 2005, to 79% in December 2005, and back up to a reasonable level of 90% in March 2006. Higher injection rates from April 2006

TABLE 1
TAR II-A STEAMFLOOD PROJECT - RESERVOIR PRESSURE

"T" Sands - Phase 1-1C Wells	Reservoir Pressure		"D" Sands - Phase 1-1C Wells	Reservoir Pressure	
	psi	hydrostatic %		psi	hydrostatic %
Jun-97	818	79	May-96	594	54
			Aug-98	748	68
Mar-99	887	85	Mar-99	881	79
Jun-99	929	89	Jun-99	1026	92
Sep-99	977	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	956	92	Jun-01	1009	91
Sep-01	928	89	Sep-01	1008	91
Dec-01	922	89	Dec-01	1005	90
Mar-02	915	88	Mar-02	1009	91
Jun-02	910	88	Jun-02	1001	91
Sep-02	941	91	Sep-02	1040	94
Dec-02	929	90	Dec-02	1007	91
Mar-03	918	89	Mar-03	1027	93
Jun-03	895	86	Jun-03	1026	93
Sep-03	920	89	Sep-03	1022	93
Dec-03	915	88	Dec-03	1017	92
Mar-04	915	88	Mar-04	1053	95
Jun-04	917	89	Jun-04	1046	95
Sep-04	906	87	Sep-04	1010	91
Dec-04	886	85	Dec-04	982	89
Mar-05	873	84	Mar-05	968	87
Jun-05	901	87	Jun-05	980	88
Sep-05	902	87	Sep-05	984	89
Dec-05	759	73	Dec-05	880	79
Mar-06	841	81	Mar-06	984	90
Jun-06	912	88	Jun-06	1036	94
Sep-06	913	88	Sep-06	1030	94
Dec-06	954	92	Dec-06	1108	100
Mar-07	956	92	Mar-07	1039	94
Jun-07	928	89	Jun-07	1006	91

to March 2007 raised average pressures in both the T and D sands to 92% and 94% hydrostatic, respectively, which are higher than desirable. Table 1 lists the quarterly ending reservoir pressures for the T and D sands from March 1999 to June 2007. The high number of well activations was destabilizing reservoir pressures in specific locations. Fluid level pressure data confirmations occur a month after the fact, making it difficult in the short term to react to specific pressure changes in the reservoir. In February 2006, the City of Long Beach Gas and Oil Department changed the Tar II-A water injection requirements from maintaining reservoir pressures to injecting a net 10,000 BPD of water over gross production. This rate is close to our recent historical net injection average and was done in an effort to better align production and injection on an objective basis. The net injection requirement will be adjusted as necessary to maintain overall control of reservoir pressures. From April 2005 to March 2006, the average net injection was 9500 BPD and from April 2006 to March 2007, the average net injection was 9900 BPD.

The T and D sand reservoirs have been acting more like waterfloods where small changes in voidage can result in large pressure drops compared to the gaseous steamflood steam chests that can compress and expand as reservoir voidage or fillup occurs to cushion pressure changes. Now that the steam chests have been collapsed and the reservoirs have been cooled enough to prevent steam chest reoccurrence, the reservoirs can be operated at lower net injection rates and lower injection / production (I/P) ratios of about 1.3 - 1.4, still high compared to the approximately 1.05-1.10 I/P ratios used 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: 1) the hot produced fluids are less dense than the injection water and therefore take up more reservoir volume per unit weight; and 2) flank water injection losses to the aquifers in the north and south. As the reservoirs cool, the necessity of maintaining high reservoir pressures dwindles. The plan is to slowly reduce pressures in the T and D sand reservoirs to about 85-87% hydrostatic over the next two years and eventually reduce pressures to 70-80% hydrostatic.

Tar II-A Reservoir Temperatures and Formation Compaction Monitoring

The City of Long Beach (City) and Tidelands Oil Production Company (Tidelands) implemented an intensive formation temperature profile and formation compaction study throughout the Tar II-A post-steamflood project from October 2005 to February 2006. The surface lands above the Tar II-A steamflood area started to subside in 1993 after steamflood peak production and formation of the updip steam chests. The surface lands have continued to subside during the remaining years of the steamflood project from 1993-1998 and over the seven-year life of the post-steamflood project through March 2006, with specific survey markers subsiding a maximum of about two feet. The surface subsidence is occurring where the land is at sea level; therefore it can adversely affect the current structures in the area. Also, the Port of Long Beach (POLB) is planning to use the subject surface lands for future port operations.

There were several possible causes for the subsidence, including grading work by the Port of Long Beach that added several tens of millions of tons of compacted fill to the area to expand port facilities, the wholesale abandonment of adjacent waterflood wells for port expansion that terminated water injection, and heat-related formation compaction in the steamflood sands. Most likely, all three reasons contributed to the problem. The City decided in 1998 to discontinue steam injection and develop a post-steamflood reservoir management plan, without knowing for sure whether thermal-related formation compaction was occurring. The study was to determine reservoir temperature changes and heat movement through the T and D1 steamflood sands from the start of the post-steamflood phase in January 1999 through February 2006 and to confirm the extent of formation compaction, if any.

The formation compaction study utilized Schlumberger's Reservoir Saturation Tool (RST) and gamma ray (GR) cased-hole logs to compare with the original induction – spontaneous potential – GR logs for determining the affected depth intervals and extent of thermal-related formation compaction. Previous RST logs run in two wells since 1998 indicate significant formation compaction in the Du sand and shale interval between the T and D sands in the former steam chest areas. This study involved running RST logs in thirteen wells located throughout the areal extent of the Tar II-A steamflood. The temperature surveys were run to determine reservoir temperature changes and heat movement through the T and D1 steamflood sands from the start of the post-steamflood phase in January 1999 through February 2006. The temperature surveys also would show the current formation temperatures of the sands above and below the steamflooded sands.

Preliminary analysis by Tidelands indicates Tar zone compaction ranging from zero to 6.0 feet from the top of the S subzone to the top of the Ranger F subzone. Generally, the worst compaction occurred in nine wells between the top of the Du subzone to the top of the D1 sands in the Phase 1, 1-A, and 1-B areas where the D1 sands are the hottest. Four wells (UP-506, UP175, UP-3 and UP-800) had four feet or more of compaction and five wells (1F-10, UP-413, 2AT-54, 2AT-55, and 1F-6) had two to four feet of compaction.

The cooler areas on the structural downdip flanks have the least formation compaction, as expected. Three wells along the structural downdip flank, UP-809, UP-833, and 2AT-53, showed minor to no thermal-related compaction from the S to F sands. Two downdip wells showed formation compaction in between the T5-T7 steamflood sands in the 2005 logs, which should be evaluated further. Two wells showed formation compaction between the D2-D3 sands. Any changes between the D3-F sands are probably more due to previous waterflooding than thermal effects. Only one well showed significant compaction of 2.0 ft in the D1 steamflood sands, and only one well showed minor compaction between the D1d and D2 sands. The comprehensive surveys showed less compaction within the T and D steamflood sands than expected, given the high reservoir temperatures achieved and high volumes of fluids injected and produced

The steamflooded T and D sands continue to cool slowly at the top of the sands but have experienced accelerated cooling at the bottom of the sands due to water injection and gravity segregation. Temperatures in the Du shales between the T and D sands have risen after 1998 when steam injection terminated because of heat transfer from the much hotter rocks above and below, which could make the shales susceptible to future formation compaction. At this point, it is probably premature to believe that hot areas over 350°F have completed compacting. Fortunately, the reservoirs are cooling over time so the risks of further compaction diminish too.

The post-steamflood water injection rates into the downdip flank injectors are set at 10,000 bpd above the gross production rates to maintain reservoir pressures in the T and D sands. Surface subsidence above the Tar II-A project have continually been reduced since 2003 and preliminary indications in June 2007 are that subsidence has been stopped.

Coriba Chemical Injection Well Stimulation Test

Tidelands began working with Coriba Oil Company, LLC in 2004 to evaluate and test a patent-pending chemical product named "Coriba 700" as a possible enhanced oil recovery (EOR) process. Our previous DOE Project Manager, Gary Walker, facilitated this collaboration because he observed tests of Coriba 700 used on heavy oil cores and was impressed with its ability to release significant quantities of residual oil. The key to the laboratory core work and field testing was whether the product could work at reasonably low concentrations to make an EOR project feasible. Initial core flood tests at low concentrations of Coriba 700 did not show favorable incremental oil recovery results, however, it was noticed that relative water permeabilities increased up to 300% from about 9 to 27% of absolute permeability. Tidelands has had problems injecting water at high rates into newly completed water injection wells in cold tar areas.

A water injection stimulation test was performed in July 19, 2006 on new Tar II-A "T" sand injection well 2AT-64, which was drilled and placed in service in November 2004. The stimulation test was a two-stage HCl acid / Coriba 700 job and performance was compared with a single stage HCl acid job performed in October 2005 that only provided about 90-100 days of incremental injectivity. Tidelands initially concluded in October 2006 that the Coriba 700 job performed on Tar II-A water injection well 2AT-64 in July 2006 was unsuccessful and did not provide any appreciable incremental water injectivity compared to the HCl / HF acid job performed previously on the well. Since that appraisal, water injection from well 2AT-64 stabilized at a higher rate than the HCl / HF acid job from October to December 1 before declining down to the base injection rate and officially ending the job in December 2006. Although the Coriba job was still economically unsuccessful, the later stage injection rates indicated that the Coriba 700 may have removed cold tar from the near wellbore region and improved the relative permeability to water before wellbore plugging by iron sulfide bioslime and scales overcame those benefits.

Coriba believes that the formulation and concentrations of Coriba 700 used in the test were optimal based on core flooding tests and that the job could have been improved had more volume of Coriba 700 been injected. Tidelands and Coriba believe that Coriba 700 could still work profitably using different volumes, different chemical additives, different order of injection, and perhaps not combining it with HCl acid in order to improve the test economics. Tidelands and Coriba have decided to suspend further tests at this time and Coriba will pursue testing the product in other reservoirs where the incremental enhanced recovery and well stimulation benefits are more obvious.

ACTIVITY 5
OPERATIONAL MANAGEMENT

Tidelands has been applying three well completion technologies for horizontal wells, including the sand consolidation process, a gravel-packed, slotted-liner completion procedure in open-hole, and a cased-through selectively perforated well with a gravel-packed, slotted-inner liner completion. Tidelands' plan is to develop and improve all three 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.

Stanford researchers completed their contract work injecting hot alkaline fluid into formation cores and quart sand vessels to determine if they could duplicate the sand-consolidation empirical process from the field in the laboratory. Initial results did not generate the expected calcium silicate cements. The experimental design assumptions were reexamined, and further testing indicated the calcium silicate cements probably originated from dissolution of wellbore cements used in completing the well. Their results show that it may be possible to add calcium silicate to injected hot alkaline water to consolidate formation sands in a perforated well completion. A second phase of laboratory research to formulate hot alkaline, geochemical solutions to consolidate formation sands was not performed and may occur after the contract termination date, to be covered by Tidelands and the City of Long Beach. Future laboratory work will lay the underpinnings to lower the costs of the sand consolidation method, enable the application of the sand consolidation method to deeper and higher-pressure reservoir intervals at Wilmington, and increase the rate of success of sand consolidation completions as well as the longevity of treatment.

Task 1: Sand Consolidation Well Completion Method

The sand consolidation well completion empirically developed by Tidelands 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. The problems above are compounded in horizontal wells and specialized directionally drilled wells. As an example, specialized directional wells may require more extreme doglegs in the completion interval and, consequently, it is more difficult to install and center the slotted liner and to gravel pack. Such wells are found where drill sites are limited as in oilfields in urban areas, offshore platforms, and Arctic wilderness situations.

The ultimate 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.

Results of Phase 1 Sand Consolidation Lab Experiments

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 objective of the research work was to 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 experimental design was 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[5] (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.

Stanford's first three experiments were performed using a stewpot filled with cleaned T sands from the Tar II-A zone and heated to 550°F. 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. 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 were reexamined.

Stanford investigated the chemistry of the rocks and reservoir fluids to determine the possible sources of the calcium silicate cements found in the tubing tail samples in well UP-955. Initial results did not generate the expected calcium silicate cements. Although the formation waters and certain sand grains (plagioclase and hornblende) contain calcium, the high survival rate of the calcium-rich grains led Stanford to believe that the calcium silicate cements were from non-reservoir sources.

Stanford reexamined the experimental design assumptions and further testing indicated the calcium silicate cements might have originated from dissolution of wellbore cements used in completing the well. They experimented by flowing hot alkaline fluids through cores consisting of various concentrations of Portland cement mixed with well-sorted quartz material at different temperatures. Stanford found they could duplicate the sand consolidation empirical process from the field in the laboratory. Their results show that it may be possible to add calcium silicate to injected hot alkaline water to consolidate formation sands in a perforated well completion.

Proposed Phase 2 Sand Consolidation Lab Experiments

The next phase of the laboratory research is to formulate and conduct experiments to optimize the geomechanical performance of the hot-alkaline-water sand consolidation process. Further laboratory work lays the underpinnings to

- lower the costs of the sand consolidation method by switching the injectant from high-quality steam to either hot water or low-quality steam thereby providing more flexibility in the operating conditions of the steam generator and the ability to burn noncommercial fuel gas instead of utility-grade natural gas;
- enable the application of the sand consolidation method to deeper and higher-pressure reservoir intervals at Wilmington, such as the Upper and Terminal zones, by using hot water injection rather than steam injection; If the gas phase is determined to be important, a non-reactive gas can be injected along with the hot alkaline fluid.
- increase the rate of success of sand consolidation as well as the longevity of treatment by developing geochemical stews for injection that improve the geomechanical strength of the grain cements and promote consolidation for the specific conditions found at Wilmington, including formation mineralogy and fluids, formation overburden and pore pressures, and regional tectonic stresses;
- a logical progression to move from the laboratory to field tests of in-situ sand consolidation.

The primary approach to reduce the cost of sand consolidation completions is to minimize energy costs. Changing from 600°F, 80% quality steam to 600°F, 0% quality hot water reduces energy costs by about 50%. Further energy savings are achieved by first reducing the volume of hot alkaline water needed to treat a 0.25” perforation below the 750 BCWESPD steam per perforation derived by the empirical field method and second reducing the temperature of the hot alkaline water to the minimum required to form the geochemical stew.

For practical purposes, we will conduct lab tests with cores that mimic field conditions in order to create consolidated sand samples similar to the formation sand grains surrounding the perforation tunnels. The sand samples will be analyzed to confirm the mineralogy of the cements created, the formation of secondary porosity from sand grain dissolution, the creation of worm-holes from gas-induced, high-velocity fluid injection rates, and the geo-mechanical strength of the grain cementing bonds. Most downhole tools for measuring the above parameters in actual wells require destructive testing of sand-consolidated perforations or provide uncertain, conditional or insufficient results, all at relatively high acquisition costs. Thus, laboratory tests are vital to further development of this completion method.

The project is designed to help field engineers delineate criteria that indicate successful treatment in the field. The Phase 1 laboratory results suggest that a more effective means to achieve consolidation is to inject a high-temperature geochemical solution already containing the key ingredients for consolidation. Thus, the first task will be the development of “geochemical stews” at different temperatures and calcium silicate concentrations that are low cost and field applicable. Significant solubility is needed over a range of temperatures.

The effectiveness of various formulations will be verified in the laboratory for (i) permeability retention, (ii) compressive strength, and (iii) permanence. A test variant is to co-inject geochemical stews with inert nitrogen gas to increase fluid velocity and sand grain contact to assist reservoir permeability retention. Permeability retention will be measured by pressure drop across the core sand pack. Permanence to flow and chemical treatments is gauged after consolidation. At the end of a given consolidation experiment, injection is switched to a cool, brine solution at the outlet and permeability measured again as a function of time. This reversed injection continues for several hundred pore volumes thereby simulating the production of fluid moving through the pore space close to perforations. Injection rates can be ramped up to test permanence at high rates. Chemical permanence is tested by exposing consolidated sand to typical acids (15% hydrochloric) used for well and formation cleanup. The suite of chemicals tested can be expanded, if needed. Compressive strength is best measured in a triaxial cell. Samples will be tested for various moduli of interest as a function of stress/strain.

Image analysis at a variety of length scales is also planned to gauge the effectiveness of consolidation. It is also employed as a means to interpret the morphology of consolidated grains. Specific imaging and image analysis items include:

- The use of X-ray CT (computed tomography) to visualize and measure the distribution of porosity along the sand packs before and after each experiment. Again, these measurements confirm that the process has few negative effects on a formation.
- Samples of the sand-pack grains are taken after porosity is measured and examined under a scanning electron microscope (SEM). These images yield the mode of consolidation and the type of cements/precipitates as a function of temperature. Other compositional methods will be employed as needed including petrographic, XRD, XRF, and microprobe analyses.
- Samples of the effluent are collected and their elemental concentrations are measured using ICP spectroscopy.

One advantage of the hot water process, as opposed to steam injection, is that feedwater to the boiler does not need to be fresh and soft to prevent scaling. An extension of the laboratory task is to test the injection of alkaline solutions made from produced water as opposed to fresh water piped from utility water mains. Time and funding permitting, this aspect will be pursued as it lays one of the foundations to move from pilot-scale to field-wide implementation. If time does not permit this work, it should be pursued at some future date.

This project is a coordinated laboratory investigation leading to an improved process for consolidating unconsolidated and weakly consolidated oil-reservoir sands. One or two wells would be recompleted and given sand consolidation jobs based on the results of the laboratory work. The second phase of laboratory research should start in

2006 and may extend past the contract date. Costs incurred after the contract date would be covered by Tidelands and the City of Long Beach.

Tasks 2 and 3: Horizontal Well Completion Techniques for Producers and Injectors and Profile Control

Traditional means of establishing a quality completion for sand control in a vertical well cannot always be technically or economically applied to horizontal wells. Cementing and gravel packing operations are problematic, tending to leave gaps and voids on the top of the hole and liner. The relatively long length of the completion interval in a horizontal well requires a completion technique which is effective yet inexpensive on a dollar per foot basis. Productive capacity should be increased by a factor of five to ten. Finding the proper balance between effective technique and cost is essential. Cemented casing which is perforated in the low-side and treated with hot alkaline water/steam injection appears to be the best hope of attaining this objective. Two existing horizontal wells in Fault Block I Tar Zone have experienced sand problems after applying the sand consolidation the first time. A second application of steam was applied in stages, 200-ft sections at a time. This treatment helped one well, but the other is shut-in with a sand problem. The problem is attributed to too many and too large perforations which would have required much higher steam rates and volumes to consolidate the sand. The horizontal injectors were given eleven 0.29-in. perforations per well compared to seventy 0.50-in. perforations in the Fault Block I horizontal wells. The new horizontal producers were given thirty-five to forty-five 0.29-in. perforations per well and the sand consolidation was done in stages.

Discussions of new horizontal producing well completions using slotted liners and gravels in both the open hole and inside of selectively perforated casing are discussed in the reservoir management section.

Profile control in horizontal injectors was achieved through the use of the limited entry perforating technique. The mechanical use of packers and steam diverters is expensive and highly problematic because of the high steam temperatures which can vulcanize the packer seals and breakdown the chemical diverters. Perforating horizontal injectors without using the limited entry technique has been tried in horizontal steam injectors. In order to achieve any kind of profile control the well had to be steamed in stages, steaming only several hundred feet at a time in order to achieve a sand consolidation completion. This method was only fifty percent effective, was labor intensive and wasted steam energy. Limited entry perforating has been very successful in vertical injection wells, where profile control is obtained by the number and size of the perforations and the injection and reservoir pressure.

Task 4: Minimize Scale Problems

A geochemical study of the scale minerals created in the steamflood producing wells was completed that determines the mineralogy and source of the scales and how to minimize their occurrence. Wellbore fill samples (sand, scale, gravel pack) from the existing steamflood wells were analyzed and found to contain several types of scale, including calcites, dolomites, barites, anhydrites, and magnesium-silicates. Although only the carbonate scales are soluble in hydrochloric acid (HCl), performing HCl jobs appear to eliminate most of the wellbore scale damage and increase production to typical Tar zone rates. The problem occurs mostly in wells that produce very hot fluids. To minimize the problem, most of the hot wells are produced with more backpressure on the formation. This initial geochemical study points to the importance of performing more thorough high temperature lab work on the cores and formation fluids before initiating a steamflood.

ACTIVITY 7
TECHNOLOGY TRANSFER

Introduction

The project team actively published new papers and articles of interest to industry and made dozens of presentations and field tours to both industry professionals and to the public. The specific technology transfer activities conducted during the past two years are presented in the following sections under the appropriate BP2 activity number.

A Reference section is included in the back of the report that includes a list of all of the original publications written by the project team since project inception in 1995. Tidelands and its project team members are proud to have written and published 89 original technical reports (see Reference sections A and E) related to this project. Many of the reports generated wide interest within industry and were used as the primary material for two dozen articles in such prestigious technical and news publications including the SPE Journal, SPE Journal of Petroleum Technology, SPE Reservoir Evaluation and Engineering, SPE Production and Facility Engineering, Los Angeles Times, Hart E&P Magazine, American Oil and Gas Reporter, AAPG Bulletin, Petroleum Engineer, Offshore Magazine, and the Canadian Journal of Petroleum Technology.

Tidelands attributes many successful outcomes in the field and for the industry to the technologies learned from Tidelands' two Class III DOE projects (DE-FC22-95BC14939 and DE-FC22-95BC14934).

Tidelands and DOE funding supported new technologies that spurred the growth of two startup companies: Dynamic Graphics, Inc. (DGI), Alameda, CA, and Geomechanics International, Inc. (GMI), Houston. DGI significantly expanded after other independent operators learned from the DOE project the effectiveness of 3-D modeling in describing a complex reservoir and oilfield such as Wilmington. Since then, they have become a 3-D modeling provider of choice to small- and mid-size California independent operators who have seen the value of this technology for complex reservoirs. Stanford geophysics researchers teamed with Tidelands and Magnetic Pulse, Incorporated of Fremont, California to interpret novel well logs calibrated to accurately measure porosity and oil saturation through sound-wave technology. GMI was created afterwards by these and several other Stanford geophysics researchers who collectively developed new ways to apply their expertise to improve drilling techniques and reservoir characterization.

The proof of the viability of new technology is when offset operators begin applying the new methods. Warren Resources, an offset operator to Tidelands to the north in Fault Blocks I and II, has been drilling cold, heavy oil Tar zone D1 sand horizontal wells in Fault Block I since 2006.

Tidelands developed a novel sand-consolidation well completion method that prevents sand entry into the producing wellbore through the injection of typical oilfield-generated steam into wells. This new technology offers lower capital costs, provides more operating flexibility, and appears to have higher productivity indexes than other sand-control completions. The technology was patented (U.S. Patent No. 6,554,067 Davies, Mondragon, Hara) in April 2003 and further researched by Stanford University.

The deeper and higher-pressure attributes of the Wilmington steamflood caused unanticipated operational problems that do not occur in most other steamfloods. Significant deeper and higher-pressure heavy oil deposits exist in the world that can be recovered applying thermal enhanced recovery techniques. The technologies and practical solutions developed in this project will reduce the operating problems, expenses, and risks of similar projects. Tidelands personnel have discussed their findings with operators in California, Alaska, Wyoming, Texas, Canada, Trinidad and Tobago, China, Oman, and Venezuela.

Direct Technology Transfer Benefits to Tidelands and Occidental Petroleum Corporation

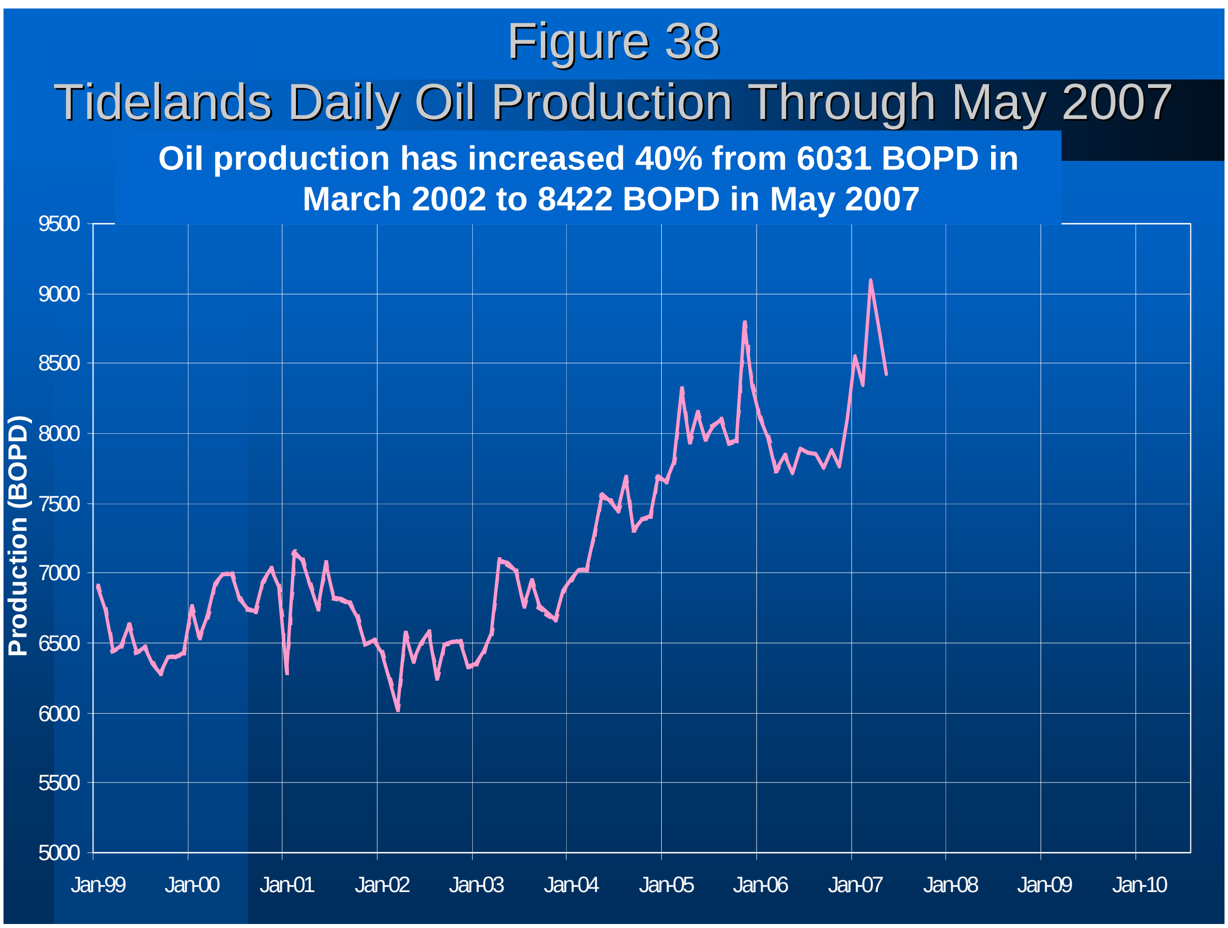
Tidelands was acquired by Occidental Petroleum Corporation (Oxy) in February 2006. Oxy is in the process of developing one of the largest steamflood projects in the world in the Mukhaizna Oil Field in Oman. The Mukhaizna oil field was discovered in 1975 in south central Oman and produces 14-18° API crude oil from the Lower Permian age Upper Gharif-2 sands. The Upper Gharif-2 sands are at a true vertical depth of 2200-2500 ft, have net sands up to 100 ft, porosities ranging from 20-35%, permeabilities ranging from 100-5000 md, and oil saturations ranging from 40-60% PV. The field has an estimated original oil in place of 2 billion barrels and cumulative recovery through 2006 of about 24 million barrels. Oxy is installing a steamflood project that is projected to produce 150,000 BOPD by 2012 and maintain that rate for 10 years at a steam-oil ratio of 3.5.

Tidelands is working with Oxy engineers in Oman to transfer technologies and operating expertise gained from the Wilmington steamflood project. The two projects have several similarities that may affect operating performance at Mukhaizna, including deeper reservoir depths, higher heavy oil quality, and relatively high reservoir pressures from 150-1400 psi. These operating parameters made the Wilmington steamflood perform much differently than typical California-based steamflood projects in the Kern River, Midway Sunset and Belridge oil fields. Scott Hara received Occidental Petroleum’s 2007 Chuck Schwab Award for the best technology transfer within the company during the past year based on initiating contact with Oxy Oman personnel working on the Mukhaizna Field steamflood project and continually sending them technical papers from this DOE project and offering advice on technical issues and Tidelands operating experiences at Wilmington.

Thums Long Beach Company, also a wholly-owned subsidiary of Occidental Petroleum Corporation, is Tidelands offset operator. Thums intends to drill similar cold, heavy oil Tar S sand horizontal wells in Fault Block V in 2007 or 2008.

Tidelands is experiencing the most successful drilling in 25 years at the Wilmington onshore oil field area owned by the City of Long Beach. Tidelands' operated Wilmington field oil production dropped to a low of 6100 BOPD in March 2002. A drilling program was started in 2003 and Tidelands drilled 49 producers, 11 water injectors, and one slurry waste disposal injection well through May 2007 and has plans in early 2008 to drill 8 producers and 5 water injectors. The 49 producers have been active from one month to four years and current production well test rates total 3,025 BOPD and 63,140 BGFPD (95.4% water cut), which represent 36% of Tidelands' 8,422 BOPD operated production in May 2007. Eight wells have been drilled to the Fault Block 3 Upper Terminal zone since 2003 in an area the City of Long Beach had almost given up on as depleted. Initial well rates have ranged from 159 – 1048 BOPD and the wells produced 403 BOPD in May 2007.

The drilling results are particularly encouraging since the portion of the Wilmington Field that Tidelands operates has been on production since the 1930's, was completely developed by the 1950's and has been waterflooded since 1953. The average water cut is 96.7% and the natural decline is about 8% per year. Tidelands has recently been drilling three types of production wells: selective completions, horizontal wells and fracture stimulated wells. Our success with the first two types of production wells, selective completions and horizontal wells, are a direct result of the work that Tidelands completed under the DOE Class III projects.



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

Task 1: DOE Reports

The project team is current on quarterly and annual technical progress reports from project inception on March 30, 1995 through March 31, 2006, which total 32 quarterly reports, two semi-annual reports and eight annual reports[E1-42]. The eight prior "annual" reports cover the periods 1995-96, 1996-97, 1997-2000, 2000-01, 2001-02, 2002-03, 2004-05 and 2005-06 (no reports due for 2003-04 and 2006-07). This "final technical report" covers the entire project life from March 30, 1995 to March 31, 2007.

Task 2: Publications

Project team publications or publications by others that are related to project team work and were written during the reporting period have been categorized by professional society, DOE, or other organizations.

Professional Societies

Stanford made their first technical presentation on their sand consolidation laboratory research at a Sand Control and Management US Conference sponsored by the International Quality and Productivity Center on July 21-22, 2004 at the Doubletree Post Oak Hotel in Houston, Texas. They subsequently wrote SPE Paper #92398 entitled "A Laboratory Investigation of Temperature Induced Sand Consolidation", and presented it at the 2005 SPE Western Regional Meeting from March 30-April 1 in Irvine, CA[A-43].

Tidelands, the City and USC presented SPE Paper #94021 about the new Tar II-A horizontal well UP-957 entitled "Applying a Reservoir Simulation Model to Drill a Horizontal Well in a Post-Steamflood Reservoir, Wilmington Field, California" at the Society of Petroleum Engineers' 2005 Western Regional Meeting from March 30 - April 1 in Irvine, CA[A-44].

Geologic consultant, Vivian Bust, and Tidelands presented SPE Paper #94259 entitled "Analytical Technique for Allocating Production to Subzones to Evaluate Prospect Candidates in the Terminal Zone of Fault Blocks III/IV, Wilmington Field, CA.," at the Society of Petroleum Engineers' 2005 Western Regional Meeting from March 30 - April 1 in Irvine, CA[A-45]. This paper presented a geologic and reservoir engineering model created for the Wilmington Field Fault Block IV Terminal zones that visualizes reservoir drainage by formation subzones, which provides a quick screening technique for identifying new development well prospects.

Tidelands and Spec Services, Inc. presented SPE Paper #93993 entitled "Achieving Low Emissions in an Internal Combustion Engine Using Off-Spec Produced Fuel Gas," at the Society of Petroleum Engineers' 2005 Western Regional Meeting from March 30 - April 1 in Irvine, CA[A-46]. This paper presented the development of internal combustion engines used in Wilmington oilfield operations that can burn variable low-quality BTU gas resulting in low air pollutant emissions.

Industry Trade Journals and Newspapers

The project team had three publications become the bases of three recent articles in trade journals.

Stanford's SPE paper #92398 entitled "A Laboratory Investigation of Temperature Induced Sand Consolidation" was peer-reviewed and published in the June 2006 issue of the *SPE Journal*, one of the most prestigious technical publications by the Society of Petroleum Engineers[B19].

Tidelands' SPE paper #94021 about the new Tar II-A horizontal well UP-957 entitled "Applying a Reservoir Simulation Model to Drill a Horizontal Well in a Post-Steamflood Reservoir, Wilmington Field, California" was summarized and rewritten as a magazine article in the July 2006 issue of the American Oil and Gas Reporter, an independent industrial trade publication that serves as the Official Publication for 28 oil and gas associations, including the California Independent Petroleum Association, of which Tidelands and the City are members[B20].

DOE Symposium Proceedings

The project team did not participate in any DOE Symposiums during the past two years.

Professional Society Newsletters / Mailing List

The U. S. DOE and Tidelands wrote a *Fossil Energy Techline* article entitled "DOE-Funded Project Revives Aging California Oilfield" on March 10, 2006[B18]. The article discussed how the DOE Wilmington Field project operated by Tidelands has created new technologies and companies to benefit both oil and gas recovery in the Wilmington Field as well as domestic and worldwide supplies. The *Fossil Energy Techline* is published by the U. S. DOE and provides updates of specific interest to the fossil fuel community.

Database Files

Tidelands is in the process of downloading production and injection volumes for each well in the Wilmington Field into a Dynamic Surveillance System™ (DSS) database by Landmark. Data includes well and fluid and injection volumes from field inception in 1938 to 2007. All data still requires confirmation before using. Tar II-A database is complete and confirmed through June 2007.

Task 3: Presentations

Presentations on project-related technical work given during the current reporting period are categorized by PTTC, professional society, DOE, or other organizations.

Professional Societies

SPE/AAPG-organized Oral Presentations

See publications – professional societies under activity 3.2.1.

Industry Organizations

In cooperation with the West Coast Petroleum Technology Transfer Council (PTTC), Richard Finken of the City of Long Beach coordinated the 2005 and 2006 COMET programs held from June 27-31, 2005 and June 25-30, 2006 to introduce the brightest high school 11th graders to the energy industry, with emphasis on the oil and gas industry. COMET is held at the University of Southern California and selected students live on campus for a week of classes and field trips presented by professors and industry professionals. The California-based oil and gas companies sponsor the student fees for the program. Scott Hara of Tidelands Oil Production Company helped to coordinate the programs.

Non-oil Industry Organizations

Scott Hara of Tidelands Oil Production Company made numerous presentations to the public about the petroleum industry, most specifically addressing world and domestic energy supplies to middle school, high school, university classes, engineering societies and to teachers. Presentations during the previous two years were made at Long Beach Polytechnic High School on February 23, 2005, February 24, 2006 and February 23, 2007, at Brightwood Elementary School on April 15, 2005 and May 19, 2006, to the Tau Epsilon Pi society members at USC on March 31, 2006, and at Alhambra High School on April 17, 2007. He made hands-on presentations about the earth sciences and read a book to first graders at the International Elementary School in Long Beach on May 17, 2006 and on May 23, 2007 and at Garfield Elementary School in Alhambra, CA on June 9, 2006.

Tidelands hosted several onsite tours and classes to teachers and students. A special class was held for the science teachers attending the National Science Teachers Association convention in Long Beach on April 6, 2006. A class was held on July 7, 2006 for the John Hopkins University pilot summer engineering program being held at the California State University at Long Beach Engineering School for bright high school students. The geology students from Long Beach Polytechnic High School took a Thums Island tour and joined Tidelands personnel in a field office to discuss the oilfield over lunch on June 1, 2007.

Scott Hara coordinated the technical projects for Science Festivals held at Brightwood Elementary School for 5th through 7th graders on March 24, 2006 and March 23, 2007.

Scott Hara of Tidelands Oil Production Company is currently a State-wide Board of Director of the California Math, Engineering and Science Achievement (MESA) program. MESA is a University of California-based academic preparation program whose primary mission is to increase the number of educationally disadvantaged students into technology-based professions that require four-year degrees in engineering and other math-based scientific fields. Tidelands sponsors his expenses related to participating in MESA activities.

Task 4: Technology Awards

Scott Hara of Tidelands Oil Production Company received a 2006 Diploma of Honor from the University of Southern California, Pi Epsilon Tau National Petroleum Engineering Honor Society on March 31, 2006 “For Outstanding Service to the Petroleum Industry”.

Scott Hara received Occidental Petroleum’s 2007 Chuck Schwab Award for the best technology transfer within the company during the past year based on initiating contact with Oxy Oman personnel working on the Mukhaizna Field steamflood project and continually sending them technical papers from this DOE project and offering advice on technical issues and Tidelands operating experience at Wilmington.

Task 5: Web Site and CD-ROM Projects

The DOE Office of Fossil Energy of the National Energy Technology Laboratory published a CD on this project entitled “Giving an Aging Heavy Oil Giant a New Lease on Life” in 2006, which contains selected papers generated by the project team. The purpose of the CD is to distribute them to the public and government agencies to showcase some of the technologies developed in the DOE Class III reservoir program.

Task 6: Field Tours

See non-oil industry organizations in Activity 3.3.3.

ACTIVITY 8
PROJECT MANAGEMENT

Tasks 1 and 2: Executive Committee and Steering Committees

The Executive and Steering Committees actively supported the operation of the Tar II-A and Tar V thermal projects and committed to the technology transfer aspects of this DOE project. In fact, as of the end of the project, the Project Team partners have published more original papers and given more presentations to industry and non-industry groups than any other DOE Class Project.

REFERENCES

The following references were either developed or used in this project and are grouped in categories from “A” to “E”. The list is comprehensive as it includes the key references starting from project inception in March 1995. References in “A”, “B”, and “E” below provide all of the original papers, commercial publications, and DOE-related reports, respectively, of original technical work completed throughout the project or in progress. References in “C” below are poster and oral presentations that were given and from which no published references were developed. References in “D” below were key references cited in this or previous DOE reports that were developed outside of this project.

A. Papers, Articles, Reports, CD-ROMs, Web Sites, and Other Original Technical Work Generated by DOE Project Team

[A1] Sameer Joshi, L.M. Castanier and W.E. Brigham (Stanford University), Mike C. Wood (Union Pacific Resources Co.), ”Steamflooding a Waterflooded Reservoir - Performance Evaluation Prediction”, SPE Paper 29669 presented at the 1995 Western Regional Meeting of the Society of Petroleum Engineers in Bakersfield, CA, 8-10 March 1995.

[A2] Mike C. Wood, Bruce Laughlin, Doug Fuller and Robert Fickes (Tidelands Oil Production), “The Use of Downhole Submersible Pumps in a High Temperature Steamflood”, SPE paper 29507, presented at the 1995 Society of Petroleum Engineers Production Operations Symposium in Tulsa, OK, April 1995.

[A3] David Crane, William R. Barry II (Digital Petrophysics Inc.), ”Database preparation for Wilmington Field, Fault Block II-A - Tar Zone” dated 15 June 1995.

[A4] Herman E. Schaller, ”Study of Water Injection Surveys, Tar Zone, Fault Block II, Wilmington Field” dated 8 November 1995.

[A5] David Crane (Digital Petrophysics Inc.), report dated 12 March 1996 detailing list of well data that had undergone checking and processing.

[A6] David K. Davies, Richard K. Vessel (David K. Davies and Associates), ”Nature, Origin, Treatment and Control of Well-Bore Scales in an Active Steamflood, Wilmington Field, California”, SPE Paper No. 35418, 1996 Society of Petroleum Engineers/Department of Energy Tenth Symposium on Improved Oil Recovery in Tulsa, OK, 21-14 April.

[A7] Linji An, University of Southern California, “Sealing Property of Extensional Faults in Wilmington Field, CA” dated May 1996, submitted to AAPG Bulletin, Oct. 1997.

[A8] Smith, L., ``Stratigraphic Equivalents of the Wilmington Field "Tar Zone`` in the Subsurface Los Angeles Basin, California", Report, Petroleum Engineering Program, University of Southern California, 1996.

[A9] Donald Clarke (City of Long Beach), Chris Phillips (Tidelands Oil production), "Old Oil Fields and New Life: A Visit to the Giants of the Los Angeles Basin", field trip and guidebook of 14 papers, given at the 1996 Annual Meeting of the American Association of Petroleum Geologists (AAPG) in San Diego, California, May 1996. The guidebook was revised for a tour given at the 1997 Western Regional Meeting of the Society of Petroleum Engineers and subsequently reprised each year for industry professionals and public school teachers.

[A10] Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), and Linji An (University of Southern California), "3-D Modeling, Horizontal Drilling... Give New Life to Aging Fields", *American Oil & Gas Reporter*, September 1996 issue, pages 106-115.

[A11] Iraj Ershaghi, M. Hassibi (University of Southern California), "A Neural Network Approach for Correlation Studies in a Complex Turbidite Sequence", SPE Paper No. 36720, 1996 Society of Petroleum Engineers Annual Technical Conference and Exhibition in Denver, CO, 6-9th October.

[A12] Rick Cassinis (Tidelands Oil Production), "2100-foot, 14-inch Steam Line Under a hip Channel", SPE Paper No. 37530, 1997 SPE International Thermal Operations and Heavy Oil Symposium in Bakersfield, CA, 10-12 February 1997.

[A13] Al-Qahtani, M., Ershaghi, I., University of Southern California: "Characterization and Estimation of Permeability Correlation Structure from Performance Data", Paper presented at Fourth International Reservoir Characterization Technical Conference sponsored by DOE, BDM, and AAPG, 2-4 March 1997.

[A14] Iraj Ershaghi, Lyman L. Handy, Yucel I. Akkutlu (University of Southern California), Julius J. Mondragon III (Tidelands Oil Production), "Conceptual Model of Fault Block II-A, Wilmington Field, from Field Performance Data", SPE Paper No. 38309, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A15] Iraj Ershaghi, Pouya Amili (University of Southern California), "Correlations for Prediction of Steamflood Oil Recovery in Steam-Assisted Gravity Drainage (SAGD) Process Using Horizontal Injectors and Producers", SPE Paper No. 38297, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A16] Walt Whitaker II (Tidelands Oil Production), "7-ppm No. 50 MM BTU/hr Oilfield Steam Generator Operating on Low-Btu Produced Gas", SPE Paper No. 38277, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A17] F. Scott Walker (Tidelands Oil Production), ”Locating and Producing Bypassed Oil: A DOE Project Update”, SPE Paper No. 38283, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June. This DOE waterflood project for Wilmington describes new application of well completion technology using steam to consolidate sand developed in this project.

[A18] Richard Cassinis (Tidelands Oil Production), William A. Farone (Applied Power Concepts, Inc.), ”Improved H_2S Caustic Scrubber”, SPE Paper No. 38273, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A19] David K. Davies, Richard K. Vessel (David K. Davies and Associates), ”Improved Prediction of Permeability and Reservoir Quality through Integrated Analysis of Pore Geometry and Open-hole Logs: Tar Zone, Wilmington Field, California”, SPE Paper No. 38262, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A20] Donald Clarke, (City of Long Beach), Chris Phillips, (Tidelands Oil Production Company), "Horizontal Drilling for Thermal Recovery in the Wilmington Field, California", Article for Summer 1997 edition of U. S. DOE *The Class Act*.

[A21] David K. Davies (David K. Davies and Associates), Julius J. Mondragon III, P. Scott Hara (Tidelands Oil Production), ”A Novel Low-Cost Well Completion Technique Using Steam for Formations with Unconsolidated Sands, Wilmington Field, California”, SPE Paper No. 38793, 1997 Society of Petroleum Engineers Annual Technical Conference and Exhibition in San Antonio, TX, 6-8 October.

[A22] David K. Davies, John Aumon, Richard K. Vessel (David K. Davies and Associates), ”Improved Prediction of Reservoir Behavior through Integration of Quantitative Geological and Petrophysical Data”, SPE Paper No. 38914, 1997 Society of Petroleum Engineers Annual Technical Conference and Exhibition in San Antonio, TX, 6-8 October.

[A23] Iraj Ershaghi, Chang-An Du, Linji An (University of Southern California), ”A Three Stage Conditioning Process for Scrutinizing Stochastic Representation of a Turbidite Sequence in a Densely Drilled Formation”, SPE Paper No. 38681, not done in 1997 as planned.

[A24] Zhengming Yang, Linji An (University of Southern California): Developed COMPACT software program was incorporated as module into Computer Modeling Group’s STARS 97.2 thermal simulator program. COMPACT is an algorithm that can mimic local and dynamic features of rock compaction and rebound as a function of reservoir pressure.

[A25] Montgomery, Scott (Consultant Technical Writer), "Increasing Reserves in a Mature Giant: Wilmington Field, Los Angeles Basin, Part I: Reservoir Characterization to Identify By-passed Oil", *AAPG Bulletin*, March 1998, pages 367-385.

[A26] Montgomery, Scott (Consultant Technical Writer), "Increasing Reserves in a Mature Giant: Wilmington Field, Los Angeles Basin, Part II: Improving Heavy Oil Production Through Advanced Reservoir Characterization and Innovative Thermal Technologies", *AAPG Bulletin*, April 1998, pages 531-544.

[A27] Du, C., Y. Akkutlu, I. Ershaghi, J. Mondragon, "A Review of Preliminary Customized Core Analysis and Recommendations for Future Tests", Report to Petroleum Engineering Program USC and Tidelands Oil Production Company, July 1998.

[A28] Yang, Zhengming and Ershaghi, Iraj, (University of Southern California), Mondragon, Julius III and Hara, Scott, (Tidelands Oil Production Co.), "Method for Handling the Complexities Associated with History Matching the Performance of a Highly Stress-Sensitive Formation", SPE Paper #49314, 1998 SPE Annual Technical Conference, New Orleans, LA, Sept. 27-30.

[A29] Phillips, Christopher C., Tidelands Oil Production Co, Clarke, Donald D., City of Long Beach, "3-D Modelling / Visualization Guides Horizontal Well Program in Wilmington Field", *CIM Journal of Canadian Petroleum Technology*, October 1998, pages 7-15.

[A30] Yang, Zhengming and Ershaghi, Iraj, (USC), Mondragon, Julius J. III, (Tidelands), "A Simulation Study of Steamflooding in a Highly Stress-Sensitive Heavy Oil Formation", 1998 UNITAR International Conference on Heavy Crude and Tar Sands, Beijing, China, Oct. 27-31.

[A31] Bronson, Jonathan, and Ershaghi, Iraj, (USC), Mondragon, Julius J. III and Hara, P. Scott, (Tidelands), "Reservoir Characterization in a Steamflood Using Produced Water Chemistry Data", SPE Paper #54118, 1999 SPE International Thermal Operations and Heavy Oil Symposium, Bakersfield, CA, March 17-19.

[A32] Hassibi, Mahnaz, (USC), "A Method For Automating Delineation of Reservoir Compartments and Lateral Connectivity From Subsurface Geophysical Logs", Doctoral Thesis, USC Department of Chemical Engineering - Petroleum Engineering Program, May 1999.

[A33] Hara, P. Scott and Mondragon, Julius J. III, (Tidelands), Davies, David K., (DKD), "A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam", 1999 DOE Oil and Gas Conference, Dallas, TX, June 28-30.

[A34] Davies, David K., (DKD), Davies, John P., (Chevron), "Stress-Dependent Permeability: Characterization and Modeling", SPE Paper #56813, 1999 SPE Annual Technical Conference and Exhibition (ATCE), Houston, TX, October 3-6.

[A35] Davies, David K., (DKD), Hara, P. Scott and Mondragon, Julius J. III, (Tidelands), "Geometry, Internal Heterogeneity and Permeability Distribution in Turbidite

Reservoirs, Pliocene California", SPE Paper #56819, 1999 SPE Annual Technical Conference and Exhibition (ATCE), Houston, TX, October 3-6.

A36 Ershaghi, Iraj and Hassibi, Mahnaz, (USC), "Reservoir Heterogeneity Mapping Using an Artificial Intelligence Approach", SPE Paper #56818, 1999 SPE Annual Technical Conference and Exhibition (ATCE), Houston, TX, October 3-6.

A37 Mondragon, Julius J. III, Yang, Zhengming, Ershaghi, Iraj, U. of Southern California, Hara, P. Scott, Tidelands Oil Production Co., Bailey, Scott, Koerner, Roy, City of Long Beach, "Post Steamflood Reservoir Management Using a Full-Scale Three-Dimensional Deterministic Thermal Reservoir Simulation Model, Wilmington Field, California", SPE Paper #62571, 2000 AAPG/SPE Western Regional Meeting, Long Beach, CA, June 19-22.

A38. Changan Du, Iraj Ershaghi, (USC), "Reservoir Characterization and Stochastic Modeling of Fault Block II-A Turbidite Sand Formation of Wilmington Oil Field, Long Beach, California", technical report, USC Department of Chemical Engineering – Petroleum Engineering Program, December 1998. Revised by Julius Mondragon III, (City of Long Beach), May 2001.

A39. Donald D. Clarke, City of Long Beach, Christopher C. Phillips, Tidelands, "3-D Geological Modeling and Horizontal Drilling Bring More Oil Out of the 68-Year Old Wilmington Oil Field of Southern California," GCSSEPM Foundation 20th Annual Research Conference – Deep-Water Reservoirs of the World, Houston, TX, December 3-6, 2000

A40. Christopher C. Phillips, Tidelands, "Enhanced Thermal Recovery and Reservoir Characterization", in Field Guide prepared by Don D. Clarke, City of Long Beach George E. Otott, Jr., THUMS, and Christopher C. Phillips, "Old Oil Fields and New Life: A Visit to the Giants of the Los Angeles Basin: Pacific Section AAPG, 1996 AAPG Annual Meeting, May 18-22, p. 65-82.

A41. 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.*

A42. Steve Siegwein, Tidelands Oil Production Company, "Gravel Packing Through the Shoe Saves Horizontal Openhole Job", *World Oil* magazine (pages 74-76), November 2003.

A43. C.M. Ross, E.R. Rangel_German, L.M. Castanier and A.R. Kovscek, Stanford University, P.S. Hara, Tidelands Oil Production Company, "A Laboratory Investigation of Temperature Induced Sand Consolidation", SPE Paper #92398, 2005 SPE Western Regional Meeting, Irvine, CA, March 30 - April 1.

[A44.] P. Scott Hara, Tidelands Oil Production Company, Julius J. Mondragon, H. Henry Sun, City of Long Beach, Zhengming Yang, EXGEO (CGG Venezuela), and Iraj Ershaghi, University of Southern California, “Applying a Reservoir Simulation Model to Drill a Horizontal Well in a Post-Steamflood Reservoir, Wilmington Field, California”, SPE Paper #94021, 2005 SPE Western Regional Meeting, Irvine, CA, March 30-April 1.

[A45.] Bust, V.K., VKB Consulting, Phillips, C.C., Hara, P.S, Tidelands Oil Production Company, “Analytical Technique for Allocating Production to Subzones to Evaluate Prospect Candidates in the Terminal Zone of Fault Blocks III/IV, Wilmington Field, CA.,” SPE #94259, presented at 2005 SPE Western Regional Meeting, March 30 - April 1, Irvine, CA.

[A46.] Cassinis, R., Tidelands Oil Production Company, Larson, W.A., Spec Services Inc., “Achieving Low Emissions in an Internal Combustion Engine Using Off-Spec Produced Fuel Gas,” SPE #93993, presented at 2005 SPE Western Regional Meeting, March 30 - April 1, Irvine, CA.

B. Publications Related to Original DOE Project Technical Work and Articles of Interest

[B1] Steve Bell, “Extraction Technologies May Increase Recoverable Reserves by Billions”, Hart’s *Petroleum Engineer*, Tech Trends, page 9, March 1995.

[B2] Donald D. Clarke, Xen Colazas (City of Long Beach), Janet Wiscombe (Los Angeles Times), ”Drilling in Disguise”, *Los Angeles Times*, Metro Section, page B2, 15 November 1996.

[B3] Chris C. Phillips (Tidelands Oil Production), Pat Prince Rose (Los Angeles Times), “In Geological Time, He’s Ancient”, *Los Angeles Times*, Business Section, Trends, page D5, 9 December 1996.

[B4] Iraj Ershaghi (University of Southern California), Frank Clifford (Los Angeles Times), ”A New Oil Boom”, *Los Angeles Times*, Metro Section, Next L.A., page B2, 24 December 1996.

[B5] Richard Cassinis, Sean Massey (Tidelands Oil Production), Stuart M. Heisler (TJ Cross Engineers Inc.), for the Sulfatreat Company ”The Story Behind Lo~CoST[SM]”, *Oil, Gas and Petrochem Equipment* Magazine, back cover page, March 1997. Advertisement by the Sulfatreat Company on product developed through the DOE project work related to “Improved H_2S Caustic Scrubber” technology. Also refer to, http://www.ingersoll-rand.com/compair.

[B6] Iraj Ershaghi (University of Southern California), Herb Tiderman (DOE), Gail Dutton (Compressed Air Magazine), ”Coaxing Crude From The Ground”, *Compressed* Air Magazine, pages 22-26, March 1997.

[B7] Jeff Schwalm (Dynamic Graphics Inc.), Chris C. Phillips (Tidelands Oil Production), ”Earth Vision Software Solutions for Structurally Consistent 3-D Geologic Modeling, 3-D Well Placement Planning”, Advertisement Mailer sent to the 1997 American Association of Petroleum Geologists (AAPG) Annual Meeting attendees, conducted 7-9 April 1997. Mailer contains copy of “3-D Modeling, Horizontal Drilling... Gives New Life to Aging Fields”, Wilmington DOE projects featured in Dynamic Graphics’ exhibit booth at convention and in Internet homepages: (info@dgi.com and http://www.dgi.com/topko.html)

[B8] University of Southern California, West Coast DOE projects comprehensively summarized and can be accessed at: http://www.usc.edu/dept/peteng/doe.html. Summarized content of the previous year’s annual report is located at: http://www.usc.edu/dept/peteng/topko.html

[B9] University of Southern California, A collection of interviews and presentations saved as brief movie clips detailing the scope of operations at Tidelands Oil production related to the Class III DOE project on CD-ROM.

[B10] Davies, David K., David K. Davies and Assoc. Inc., Mondragon, Julius J. III and Hara, P. Scott, Tidelands Oil Production Co., SPE Paper #38793 "Well-Completion Technique Using Steam For Formations With Unconsolidated Sands", *SPE Journal of Petroleum Technology* (pages 46-52, an abridged version of the paper), September 1998.

[B11] Clark, Donald D., City of Long Beach, Phillips, Christopher C., Tidelands Oil Production Company, “Successful Horizontal Well Program In Wilmington Field”, *DGInsider, the EarthVision Newsletter*, First Quarter 1999.

[B12] Davies, David K., Vessel, Richard K., Aumon, John P., DKD, “An Improved Prediction of Reservoir Behavior Through Integration of Quantitative Geological and Petrophysical Data”, SPE Paper #38914 peer-reviewed and assigned SPE Paper #55881, *SPE Reservoir Evaluation and Engineering* Magazine, April 1999.

[B13] Davies, David K., DKD, Davies, John P., Chevron wrote an article entitled “Stress-dependent Permeability in Unconsolidated Sand Reservoirs”, *Offshore Magazine*, February 2000, pp 82-84, a summary of SPE Paper 56813, “Stress-Dependent Permeability: Characterization and Modeling” in ref. A31 above.

[B14] Ron Bowman (Case Engineering and Laboratory, Inc.), L. C. Gramms (Separ Systems and Research Ltd.), R. R. Craycraft (Union Pacific Resources Inc.), “High-Silica Waters in Steamflood Operations”, SPE Paper #37528 peer-reviewed and assigned SPE #63015, *SPE Production and Facility Engineering Magazine* (pages 123-125), May 2000.

[B15] D. D. Mamora, F. E. Moreno, Guillemette R. (Texas A&M University), "Sand Consolidation Using High-Temperature Alkaline Solution", SPE Paper #62943, 2000 SPE Annual Technical Conference and Exhibition, Dallas, TX, October 1-3.

[B16] F. E. Moreno, D. D. Mamora, (Texas A&M University), "Sand Consolidation Using High-Temperature Alkaline Solution – Analysis of Reaction Parameters", SPE Paper #68847, 2001 SPE Western Regional Meeting, Bakersfield, CA, March 26-30.

[B17] D. D. Mamora, F. E. Moreno, R. Guillemette, K. A. Nilsen (Texas A&M University), "Sand Consolidation by Use of a High-Temperature Alkaline Solution", SPE Paper #62943 published in *SPE Journal of Petroleum Technology* (pages 55-56 abridged version of paper), May 2001.

[B18] James Barnes, U. S. DOE, Scott Hara, Tidelands, "DOE-Funded Project Revives Aging California Oilfield", *Fossil Energy Techline*, U. S. DOE, March 10, 2006.

[B19] C.M. Ross, E.R. Rangel_German, L.M. Castanier and A.R. Kovscek, Stanford University, P.S. Hara, Tidelands Oil Production Company, "A Laboratory Investigation of Temperature Induced Sand Consolidation", SPE Paper #92398 peer-reviewed and published in *SPE Journal* (pages 206-215), June 2006

[B20] P. Scott Hara, Tidelands Oil Production Company, Julius J. Mondragon, H. Henry Sun, City of Long Beach, Zhengming Yang, EXGEO (CGG Venezuela), and Iraj Ershaghi, University of Southern California wrote an article entitled, "3-D Modeling Leads to Horizontal Well", based on SPE Paper #94021 entitled "Applying a Reservoir Simulation Model to Drill a Horizontal Well in a Post-Steamflood Reservoir, Wilmington Field, California", *American Oil & Gas Reporter* (pages 68-79), July 2006.

[B21] P. Scott Hara, Tidelands Oil Production Company and Don Francis, Hart Energy Publishing, LP wrote an article on "Brownsfield Development" for August 2007 issue of Hart's *E&P Magazine* based on the 2006 DOE Annual Technical Progress report for this project.

[B22] DOE Office of Fossil Energy, National Energy Technology Laboratory published a CD on this project entitled "Giving an Aging Heavy Oil Giant a New Lease on Life", 2006.

C. Presentations, Poster Sessions, Tours, and Other Activities from which No New Published Materials were Generated

[C1] Davies, D. K., Core photo description work for Tidelands Oil Production Company, 1995.

[C2] Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), Linji An (University of Southern California), "Horizontal Wells in a Clastic Oil Field with Intraformational Compaction", poster session presentation at the 1997 American Association of Petroleum Geologists (AAPG) Annual Meeting in Dallas, TX, 7-9 April.

[C3] Iraj Ershaghi, Linji An (University of Southern California), Donald D. Clarke (City of Long Beach), Chris Phillips (Tidelands Oil Production), "Sealing Behavior of Normal Faults in Fault Block II, Wilmington Oil Field, California", poster session presentation at the 1997 American Association of Petroleum Geologists (AAPG) Annual Meeting in Dallas, TX, 7-9 April.

[C4] Jeff Schwalm, John Perry (Dynamic Graphics Inc.), "3-D Geologic Modeling: Theory and Application", a half day workshop sponsored by the PTTC at USC Campus, Los Angeles, CA on 2 May 1997. Presentation utilizes 3-D Deterministic Geologic Model from this project to explain fundamentals of 3-D Geologic Modeling.

[C5] Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), Linji An (University of Southern California), "Tertiary Development of Heavy Oil Sands through Thermal Recovery in the Wilmington Oil Field, California: An Update and Some New Challenges", Oral presentation at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, on 14-16 May.

[C6] Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), Linji An (University of Southern California), "Reservoir Characterization Using Advanced 3-D Computer Modeling Technology: A Case Study of the Fault Block II in Wilmington Field, California", Electronic poster session at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, 14-16 May.

[C7] M. Hassibi, Iraj Ershaghi (University of Southern California), “Characterization of Lithological Log Responses in Turbidite Series using Neural Networks”, oral presentation at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, 14-16 May 1997.

[C8] David K. Davies, Richard K. Vessel (David K. Davies and Associates), "Geological Controls on Permeability Distribution and Sand Distribution: Tar Zone, Fault Block II-A, Wilmington Field", oral presentation at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, 14-16 May.

[C9] Donald D. Clarke (City of Long Beach): Project status presentation for DOE/BDM conference regarding status of all DOE contracted projects, Houston, TX, 16-20 June 1997.

[C10] Julius Mondragon III, Scott Hara (Tidelands Oil Production), "Novel Sand Consolidation Completion Technique Using Alkaline-Steam Injection in the Tar Zone, Wilmington Field", SPE GEM Presentation WR GEM 29, 1997 Western Regional Meeting in Long Beach, CA 23-27 June.

[C11] Chris Phillips, Scott Hara (Tidelands Oil Production), "Three-Dimensional Geological Modeling as a Cost-Effective Tool for Horizontal Drilling", SPE GEM Presentation WR GEM 6, 1997 Western Regional Meeting in Long Beach, CA 23-27 June.

[C12] Mark Kapelke (Tidelands Oil Production), "How to Work With the DOE" and "Multimedia and Technical Transfer", National Petroleum Technology Resource Center sponsored by the DOE, 1997 Western Regional Meeting in Long Beach, CA 23-27 June.

[C13] Phillips, C. C. and L. An, supporting all faults and surfaces files for USC, 1997, Cheng, A., *GOCAD Manual*, GOCAD Consortium, Nancy Geological School, August, 1997.

[C14] Du, C., University of Southern California, West Coast PTTC staff, organized short course entitled "GOCAD^{++} Training" and made a presentation during the course, November 14, 1997 at USC campus.

[C15] Hara, S., Tidelands Oil Production Company, reprised sand consolidation well completion presentation - SPE paper 38793, SPE Los Angeles Basin Section New Technology and Environmental Forum meeting, November 19, 1997, Long Beach Petroleum Club.

[C16] Ershaghi, I., University of Southern California, Clarke, D., City of Long Beach, West Coast PTTC staff: Organized geologic short course and field trip on "Turbidite Reservoirs in California", November 24, 1997, Ventura, CA.

[C17] Tidelands Oil Production Company gave a short presentation of the two Wilmington Class III projects to Guido DeHoratiis of the DOE on December 4, 1997 in Tidelands' office.

[C18] Clark, D., City of Long Beach, Phillips, C., Tidelands Oil Production Company, "Subsidence and Old Data Present Unique Challenges in Aging Turbidite Oil Fields. Examples of Successful Technologies Solutions from the Wilmington Oil Field, California, USA", 3rd AAPG / EAGE Joint Research Conference on Developing and Managing Turbidite Reservoirs: Case Histories and Experiences, Almeria, Spain, 4-9 October 1998.

[C19] Du and Nadim, Shale mapping of D1 interval, FBIIA, Petroleum Engineering Program, Dec. 1998.

[C20] Scott Hara gave an oral presentation entitled “Steamflooding Recovery of a Class 3 Reservoir – DOE’s Cooperative Efforts with Independent Producers to Enhance Production While Maintaining Safe and Environmentally Compatible Operations” at the Technology Assessment & Research Program’s Technology Seminar held on May 19, 1999 at the office of the U. S. Minerals Management Service in Camarillo, CA.

[C21] Same as (C18), but given at 1999 EAGE Conference and Technical Exhibition, Helsinki, Finland, June 7-11.

[C22] Same as (C18), but given at 1999 AAPG/SPWLA Hedberg Research Symposium, The Woodlands, TX, October 10-13.

[C23] Clarke, Donald D., City of Long Beach, “At 68, Wilmington Still Has Life: New Technology Revitalizes the Old Field”, 1999 AAPG/SPWLA Hedberg Research Symposium, The Woodlands, TX, October 10-13.

[C24] Scott Hara reprised his presentation entitled “A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam” at two West Coast Petroleum Technology Transfer Council (PTTC) workshops on “Sand Control for California Oilfield Operations” given in Long Beach, CA on November 18, 1999 and in Bakersfield, CA on November 19, 1999.

[C25] Scott Hara made an oral presentation summarizing this DOE project’s achievements related to reservoir and operational management and technical transfer of steamflood experience to the Wilmington Fault Block V Tar zone. The presentation was given at the West Coast PTTC Annual Forum held on the USC campus on December 10, 1999.

[C26] Scott Hara, Tidelands, reprised presentation “A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam”, 2000 IPAA Mid-year Meeting, San Francisco, CA, May 18-20.

[C27] Don Clarke, City of Long Beach, reprised oral presentation “At 68, Wilmington Still Has Life: New Technology Revitalizes the Old Field”, 2000 Pacific Section AAPG/SPE Western Regional Meeting, Long Beach, CA, June 19-22.

[C28] Scott Hara nominated and helped prepare application for the 2001 Pacific Section AAPG Teacher of the Year Award Winner, Mr. John Jackson, of Monterey Highlands Elementary School, Monterey Park, CA. Mr. Jackson was presented the award at the 2001 PSAAPG Annual Meeting, Universal City, CA, April 10.

[C29] Hara, Scott, Tidelands Oil Production Company, "Applying New Technology to an Old Field", California Conservation Committee of Oil and Gas Producers, Long Beach, CA, 19 September 2001.

[C30] Hara, Scott, Tidelands Oil Production Company, "Applying New Technology to an Old Field", Stanford University Petroleum Engineering Dept., Stanford University, CA, 2 November 2001.

[C31] Hara, Scott, Tidelands Oil Production Company, "World Oil and Gas Reserves and Recovery Methods", Geology classes, Long Beach Polytechnic High School, Long Beach, CA, 13 March 2002.

[C32.] Don Clarke, City of Long Beach, "2003 Mayor's Environmental Forum", Will Rogers Middle School, Long Beach, CA, March 2

[C33.] C.M. Ross, E.R. Rangel_German, L.M. Castanier and A.R. Kovscek, Stanford University, P.S. Hara, Tidelands Oil Production Company, "A Laboratory Investigation of Temperature Induced Sand Consolidation", Sand Control and Management US Conference sponsored by the International Quality and Productivity Center, Doubletree Post Oak Hotel, Houston, TX, July 21-22, 2004.

[C34] Scott Hara, Tidelands Oil Production Company, "Historical Look at Petroleum Industry in LA", 2005 COMET program at University of Southern California, June 27.

D. Key Outside References Related to Project and Cited in Current or Previous DOE Reports Listed in Section E

[D1] Small, G.P., Shell California Production Inc. "Steam-Injection Profile Control Using Limited-Entry Perforations", SPE Paper 13607, presented at the 1985 California Regional Meeting in Bakersfield, CA, March 27-29 1985.

[D2] R.M. Butler, "Gravity Drainage to Horizontal Wells", *Journal of Canadian Petroleum Technology*, Volume 31, No. 4, pages 31-37, April 1992.

[D3] F.H. Lim, W.B. Saner and W.H. Stillwell (Union Pacific Resources Co.) and J.T. Patton (New Mexico State University), "Steamflood Pilot Test in Waterflooded, 2500 ft. Tar Zone Reservoir, Fault Block II Unit, Wilmington Field, California", presented at the 1993 Society of Petroleum Engineers Annual Technical Conference and Exhibition in Houston, TX, 3-6 October 1993.

[D4] R.M. Butler, *"Horizontal Wells for the Recovery of Oil, Gas and Bitumen; Monograph 2"*, Petroleum Society of CIM, Calgary 1994.

[D5] M. Polikar, D.A. Redford, “Evolution of Steam-Based Technology for the Recovery of Canadian Heavy Oil Reservoirs”, *Journal of Petroleum Technology*, Volume 34, No. 5, pages 33-40, May 1995.

[D6] Ershaghi, I., Omoregie, O., University of Southern California, “A Method for Extrapolation of Cut Vs. Recovery Curves,” *Journal of Petroleum Technology*, pages 203-04, February 1978.

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E. Required Reports Generated for the Department of Energy

[E1] P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, “Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies”, DE-FC22-95BC14939, (30 March 1995 - 30 June 1995).

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