

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

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Contractor Names: City of Long Beach Department of Oil Properties (City) and Tidelands Oil Production Company (Tidelands), Long Beach, CA.

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Objectives

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

Summary of Technical Progress

Through December 1999, project work has been completed on the following activities: data preparation; basic reservoir engineering; developing a deterministic three dimensional (3-D) geologic model, a 3-D deterministic reservoir simulation model and a rock-log model; well drilling and completions; and surface facilities on the Fault Block II-A Tar (Tar II-A) Zone. Work is continuing on improving core analysis techniques, final reservoir tracer work, operational work and research studies to prevent thermal-related formation compaction in the Tar II-A steamflood area, and operational work on the Tar V steamflood pilot and Tar II-A post steamflood project. Work was discontinued on the stochastic geologic model and developing a 3-D stochastic thermal reservoir simulation model of the Tar II-A Zone in order to focus the remaining time on using the 3-D deterministic reservoir simulation model to provide alternatives for the Tar II-A post steamflood operations and shale compaction studies.

Thermal-related formation compaction is a concern of the project team due to observed surface subsidence in the local area above the Tar II-A steamflood project. On January 12, 1999, the steamflood project lost its inexpensive steam source from the Harbor Cogeneration Plant as a result of the recent deregulation of electrical power rates in California. An operational plan was developed and implemented to mitigate the effects of the two situations by injecting cold water into the flanks of the steamflood. The purpose of flank injection has been to increase and subsequently maintain reservoir pressures at a level that would fill-up the steam chests in the "T" and "D" sands before they can collapse and cause formation compaction and to prevent the steam chests from reoccurring. A new 3-D deterministic thermal reservoir simulation model was used to provide operations with the necessary water injection rates and allowable production rates by well to minimize future surface subsidence and to accurately project reservoir steam chest fill-up by October 1999. A geomechanics study and a separate reservoir simulation study have been performed to determine the possible indicators of formation compaction, the temperatures at which specific indicators are affected and the projected temperature profiles in the over and underburden shales over a ten year period following steam injection.

It was believed that once steam chest fill-up occurred, the reservoir would act more like a waterflood and production and cold water injection could be operated at lower Injection to production ratios (I/P) and net injection rates. In mid-September 1999, net water injection was reduced substantially in the "D" sands following steam chest fill-up. This caused reservoir pressures to plummet about 100 psi within six weeks. Starting in late-October 1999, net "D" sand injection was increased and reservoir pressures have slowly increased back to steam chest fill-up pressures as of the end of March 2000. When the "T" sands reached fill-up, net "T" sand injection was lowered only slightly and reservoir pressures stabilized. A more detailed discussion of the operational changes is in the Reservoir Management section of this report.

A reservoir pressure monitoring program was developed as part of the post-steamflood reservoir management plan. This bi-monthly sonic fluid level program measures the static fluid levels in all idle wells an average of once a month. The fluid levels have been calibrated for liquid and gas density gradients by comparing a number of them with Amerada bomb pressures taken within a few days. This data allows engineering to respond quickly to rises or declines in reservoir pressure by either increasing injection or production or idling production.

Expanding thermal recovery operations to other sections of the Wilmington Oil Field, including the Tar V horizontal well pilot steamflood project, is a critical part of the City of Long Beach and Tidelands Oil Production Company's development strategy for the field. The current thermal operations in the Wilmington Field are economical with low oil prices due to the availability of inexpensive steam from an existing 50 MMBTU/hr steam generator that can utilize non-commercial low Btu produced gas. Such favorable terms for obtaining steam are not expected to be available in the future. Future expansion of thermal recovery to other parts of the Wilmington Field and other SBC reservoirs will depend on improving the efficiency and economics of heavy oil recovery, as is the intent of the project.

Advanced Reservoir Characterization

With the shutdown of the steam injection process into the Tar II-A zone, further work on the 3-D stochastic reservoir modeling work has been limited to completing the core analysis and reservoir tracer work and finalizing the neural network log analyzer report. A preliminary report on the characterization of discontinuous shale bodies has been prepared that utilizes the available core analysis data and shows initial log-core correlation work and stochastic renderings of geologic models.

Past core analysis data had indicated inflated values for porosity and permeability when measuring unconsolidated sand formations. The project team evaluated several alternative procedures for analyzing conventional core data compared to the "routine porosity, permeability, and saturation techniques used by commercial core analysis companies. The most important and cost-effective procedural change is to measure reservoir characteristics with the core samples under original overburden-type stresses. The study also provides correlations to correct data measured using the previous "routine" core analysis method.

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 Gamma Ray logs. Sample stochastic grid block models were test run on the 3-D Earth-Vision™ 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 changes in the character of lithology logs in sand-shale sequences makes the visual correlation often a very difficult task. With over 600 penetrating well logs through an average of 280 ft of gross Tar II-A sands, the need for developing a neural network analyzer to expedite the stochastic geologic modeling was evident.

Tracer studies were conducted on characterizing the anisotropic nature of the formation. A study measuring naturally existing cations and anions in the produced water as affected by dilution of formation water by the condensed fresh water in the steam was completed and

presented at the 1999 SPE Thermal Recovery Meeting in Bakersfield. The report has been upgraded and will be included in the 1997 - 2000 Annual Report.

The reservoir tracers, ammonium thiocyanate (AT) and lithium chloride (LC), were bulk injected on February 14 1997 into two hot water-alternating-steam pilot injectors. Sampling of produced fluids from first and second rows of producers were collected for analysis of the ammonium and lithium tracers. Very few tracer hits above background levels were recorded. The mixed signals were partly because the tracers break down in the very high temperature environment and in part because of operational changes dictated by the rapid conversion of steam injectors to hot water injectors. The tracer work included the issues related to tracer selection, concentrations and volumes and to field sampling, laboratory analyses and interpretation of the produced water results for tracer hits. In spite of its mixed results, the technology transfer value of the findings is substantial for other similar thermal operations.

Reservoir Simulation

The original intent of the 3-D advanced reservoir 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 rebuild the 3-D deterministic geologic model and examine various stochastic realizations of reservoir conceptual models for simulation purposes. The STARS™ thermal reservoir simulation program by the Computer Modelling Group (CMG) of Calgary and the R10,000 Onyx RE2 work station by Silicon Graphics Incorporated (SGI) were selected for the reservoir simulation modeling which began in October 1996. History matches covering the primary depletion, waterflood, and steamflood periods were completed for the 3-D deterministic thermal reservoir simulation model in June 1998.

The City of Long Beach modified the project priorities in the third quarter 1998 to address their concerns about steamflood-related surface subsidence and how to safely operate the Tar II-A wells during the post-steamflood phase. The 3-D deterministic reservoir simulation model was immediately used to optimize oil production while accelerating steam chest fill-up with flank water injection by measuring the mass fluid and heat balance effects as they pertained to reservoir pressure. Reservoir pressures in the target area are affected by the following occurrences: mixing of the hot and cold fluids at the flank 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 post-steamflood reservoir simulation modeling study is the basis for a technical paper scheduled for presentation at the AAPG / SPE Western Regional Meeting in June 2000².

Recap of Operational Use of 3-D Deterministic Model

Using the 3-D deterministic reservoir simulation model for day to day operations has been a learning process. A recap of the highlights of using the model operationally by reporting quarter is described below.

In the third quarter 1998, reservoir simulation studies determined that cold water

flank injection was better than cold water injection into the pattern steam injectors because it maintained higher reservoir temperatures and had less risk of causing sudden formation compaction. The City accepted flank water injection as its base case strategy. The City wanted the steam chests filled as quickly as possible. The model showed that net injection rates of 40,000 BWPD could fill the steam chest within 2-3 months, however, it would also cause reservoir pressures around the injectors to rise above fracture pressures, making that scenario undesirable.

In the fourth quarter 1998, the model assumed no production and a constant 20,000 BPD of flank water injection with an increasing number of flank injection wells over time to distribute the pressure. This rate, which was based on current surface facility capabilities, was predicted to fill-up the steam chests in September 1999 and was adopted by the City. No further interior injection scenarios were considered due to undesirable reservoir cooling.

In the first quarter 1999, when the flank water injection operation was installed and activated, model runs were made to study the effects of limited production while maintaining a net injection of 20,000 BWPD. The production and injection database was updated with actual volumes from July 1998 to February 13, 1999 and the data was history-matched by the model. The model predicted that steam chest fill-up would be achieved in mid-October 1999 with 7,700 B/D of gross (oil and water) production and 28,000 B/D of cold water injection. The model showed that steam chest fill-up was very dependent on specific injection well locations and rates relative to the locations of the active production wells and their completion intervals. Indiscriminately injecting 20,000 BPD of water more than gross fluid production did not necessarily achieve steam chest fill-up in a timely fashion, with some scenarios showing fill-up occurring over six months later than October 1999. The City approved limited production but required an extensive reservoir pressure monitoring program be implemented, which is described in the Operations Management section.

In the second quarter 1999, the reservoir simulation model was updated with production and injection actuals from February 13, 1999 through April 1999. The model predicted that reservoir steam chest fill-up in the "T" and "D" sands would occur in early October 1999 and that reservoir pressures could be maintained to prevent the steam chests from reoccurring by varying injection rates into individual wells to offset the production wells being idled or returned to production. Actual reservoir pressures increased at or above the model plan.

In the third quarter 1999, the reservoir simulation model was updated with production and injection actuals from May 1999 through July 1999. Multiple scenarios were run to determine the changes in reservoir pressure and the steam chest from wide variations in production and injection rates. The model predicted steam chest fill-up in October at about 800 psi which did occur. The model showed that following steam chest fill-up, an I/P ratio of 1.22 and net injection of about 3000 BWPD would be enough to keep the steam chest from reestablishing itself. Actual reservoir pressures needed to increase to about 950-1000 psi before the steam chests were effectively removed. When actual production was increased to 11,500 BPD at an I/P ratio of 2.4 and net injection of 15,700 BWPD, reservoir pressure declined about 100 psi and the steam chest in the "D" sands started to reoccur. Water injection had to be increased substantially. Operational data show that net injection should be reduced slowly (over a nine month period) following steam chest fill-up to about 9000 BWPD to maintain reservoir pressures.

The real time response capability of the reservoir simulation model has made it an

indispensable tool for day to day reservoir management purposes. The model can effectively predict overall mass and heat balance of the injected and produced fluids, provided it is updated with actual data. The model cannot predict net oil production and did not provide the correct steam chest fill-up pressure or the short term I/P ratio following steam chest fill-up, but it did perform its primary function of setting injection and production rates and predicting when steam chest fill-up would occur. This model should be adapted for use on the Tar V steamflood pilot project.

Simulating Thermal Heating of Overburden and Underburden Shales

In the fourth quarter 1999, reservoir simulation modeling efforts were directed towards determining the amount of reservoir heat that is thermally conducted from the Fault Block II-A Tar Zone steamflood sands to the overburden and underburden shales. The model was based on a 1/12 of a seven-spot 5 x 5 x 81 grid (2025 grid blocks) using the CMG STARS™ thermal reservoir simulation software. The grid dimensions were 48 feet by 83 feet with the thickness of the vertical layers varying from 3 feet to 35 feet depending on whether the layer was part of a sand or shale. The model had 60 feet of non-steamflooded sands and shales below the steam zone and 200 feet of non-steamflooded sands and shales above the steam zone. The steam zone consisted of 50 feet of the "T" sands with three 3 foot interbedded shales and 50 feet of the "D" sands. There were 51 feet of non-steamflooded sands and shales between the "T" and the "D" sands. The model mimicked two injection wells (one for the "T" sand and one for the "D" sand) and one production well in a specific seven-spot pattern in the middle of the Tar Zone steamflood. The distance between the injection wells, 2AT-032 ("T" sand) and 2AT-033 ("D" sand), and the production well, UP-922 ("T" & "D" sands), was 384 feet. This is equivalent to an 8.8 acre pattern, although the average pattern size was 7.5 acres. The three wells were selected as the model pattern because observation well OB2-5 is located halfway between the injectors and the producer so reservoir temperatures in the model could be compared to actual data.

The first scenario was to inject 1,000 BPD of cold water equivalent steam (CWES) at 580°F and 80% quality into wells 2AT-032 and 2AT-033 and produce well UP-922 at 1200 B/D of gross production from June 1989 to January 1, 1999. The model's predicted temperature profile of the steamflood zones and the adjacent non-steamflood layers in the observation well for January 1, 1999 was compared to an actual temperature profile in observation well OB2-5 for the same time period and had a very good match. The producer was shut-in on January 1, 1999. The injectors stopped injecting steam and started injecting only enough 500°F hot water to maintain reservoir pressures at 90% of the hydrostatic pressures, 930 psi in the "T" sand and 980 psi in the "D" sand. Without some form of injection, reservoir pressures would decline due to steam chest collapse from over and underburden heat losses and fluid losses to the lower pressured aquifers. In actuality, the reservoir pressures in the steamflood area are being maintained by flank cold water injection. Hydrostatic pressure is the pressure at a specific depth equivalent to the weight of a column of water from that specific depth to the surface. The model continued to run an additional ten years to determine the heating and cooling effects after steam injection. The heating and cooling data of the layers above and below the steam zone were recorded and analyzed. The normal reservoir temperature before steamflooding was 123°F. The model predicted that the average temperature of the steam zone cooled off from 523°F in January 1999 to 470°F by January 2009 at the injection wells, 520°F to 448°F at the observation well, and 515°F to 448°F at UP-922. The model showed that after steam

injection the steam zone and shale immediately adjacent to the sands cooled off by 60-70 degrees while the remaining shale layers above and below continued to heat up slightly.

The second scenario was to restart the model on January 1, 1999 and inject only enough 135°F water into the injectors to maintain 90% hydrostatic reservoir pressures in the "T" and "D" sands. The producer was shut-in on January 1, 1999 and returned to production on October 1, 1999 following the model's projected reservoir steam chest fill-up. This simplified 1/12 of a seven-spot model predicted the same reservoir steam chest fill-up time as the full reservoir 3-D deterministic thermal model. The model continued to run an additional ten years and the heating and cooling data of the layers above and below the steamflood zone were recorded and analyzed. The model predicted that the steamflood zone cooled off from 523°F in January 1999 to 135°F by January 2009 at the injectors, 520°F to 160°F at the observation well, and 515°F to 214°F at the producer. Ten years after the steamflood was shut-in, the layers above and below the steamflood zone continued to heat up proportionally to how the steamflood zones were cooling off.

Reservoir Management

A post-steamflood operating plan was developed during the third quarter 1998 and implemented in the fourth quarter 1998 to mitigate problems associated with the January 1999 shutdown of steam injection and the probability of thermal-related surface subsidence from cooling and subsequent collapse of the steam chests in the "T" and "D" sands. A total of twelve water injection wells have been in service on the northern and southern flanks of the steamflood area, including two existing injectors (wells FW-101 and FW-103), seven wells that were added in the fourth quarter 1998 (wells FW-88, 901-UP, 935-UP, 937-UP, 943-UP, 951-UP, and 2AT-56), two wells added in the second quarter 1999 (2AT-48 and 953-UP) and one well (2AT-20) added in the fourth quarter 1999. Their purpose is to increase and subsequently maintain reservoir pressures in the "T" and "D" sands at a high enough level to eliminate and prevent the reoccurrence of any steam chest. Increasing reservoir pressure causes the steam vapor phase to go back into solution before it can cool through overburden heat loss and cause possible formation compaction. The flank water injection strategy increases reservoir pressure by "squeezing" the steamflood area along its structural downdip flank without introducing cold water into the interior of the mature steamflood area.

The new 3-D deterministic thermal reservoir simulation model was used to provide sensitivity cases to optimize production, steam injection, flank cold water injection and reservoir temperature and pressure. According to the model, reservoir fill up of the steam chests would occur in October 1999 at a constant injection rate of 28,000 BPD and gross fluid production rate of 7,700 BPD (I/P ratio of 3.6, net injection of 20,300 BPD). Actual operations followed the model's recommendations during the first six months of 1999, as water injection averaged 28,600 BPD and gross fluid production averaged 7,800 BPD.

Further model runs found that varying individual well injection rates was better for addressing localized sub-zone pressure problems caused by added production and could reduce steam chest fill-up by up to one month. Based on this information, Tidelands increased water injection in July and August 1999 to an average of 36,000 BPD while only increasing gross fluid production to 9,500 BPD (I/P ratio of 3.8, net injection of 26,500 BPD). This operational change accelerated overall reservoir steam chest fill-up in the "D" sands to August 1999 because most of the increased net injection went to those sands.

Reservoir pressures in the "D" sands at fill-up ranged from 960-1180 psi with a rough average of 1080 psi (89-106% hydrostatic pressure, 98% avg). Steam chest fill-up in the "D" sands was accompanied by steeply rising reservoir pressures, as would be expected in a fully liquid, relatively incompressible fluid situation.

It was believed that once steam chest fill-up occurred, the reservoir would act more like a waterflood and production and cold water injection could be operated at lower I/P ratios and net injection rates. The City and Tidelands decided to maintain reservoir pressures at about 90%±5% hydrostatic as ideal in the short term and to possibly lower reservoir pressures to 80% hydrostatic over time provided no steam chest development reoccurred. The model predicted steam chest fill-up at about 78% hydrostatic pressure. The City and Tidelands felt that production rates could be increased as long as water injection rates were kept at relatively high injection to production ratios (I/P).

In September 1999, "D" sand gross fluid production was increased from 6200 BPD to 7800 BPD and water injection was reduced substantially from 24,200 BPD to 14,500 BPD (net injection from 18,000 BPD to 6700 BPD). Injection was increased slightly in the "T" sands from 10,700 BPD to 12,700 BPD (net injection from 7100 BPD to 9000 BPD). The "T" sands reached steam chest fill-up on schedule in mid-October 1999 with reservoir pressures ranging from 930-1070 psi with an average of 980 psi (91-103% hydrostatic pressure, 95% avg).

The significant decrease in "D" sand net injection rates caused reservoir pressures to plummet about 100 psi to an average of 980 psi and 90% hydrostatic pressure (range 930-1050 psi) within six weeks. This happened even though the I/P was 1.85. Starting in late-October, gross fluid production in the "D" sands was further increased to 8800 BPD, but net injection was increased to 10,200 BPD to an I/P of 2.20. "D" sand reservoir pressures stabilized by the end of December to an average of 960 psi and 88% hydrostatic pressure (890-1030 psi range). Following "T" sand fill-up in October, gross fluid production was increased from 3700 BPD to 5600 BPD and net injection was lowered only slightly to 7400 BPD (I/P of 2.33). "T" sand reservoir pressures stabilized by December 1999 to an average of 1010 psi and 98% hydrostatic pressure (950-1060 psi range).

In the first quarter 2000, the plan was to reach 90% hydrostatic pressure in both the "T" and "D" sands by increasing net injection rates in the "D" sands and by carefully lowering net injection rates in the "T" sands. The "D" sand gross fluid production rates were decreased to 8200 BPD and net injection was increased to 12,300 BPD for an I/P of 2.5. By the end of the quarter, the average "D" sand reservoir pressure increased to 1020 psi and 91% hydrostatic pressure (940-1090 psi range). The "T" sand gross fluid production rates were increased to 8400 BPD and net injection was lowered slightly to 6700 BPD for an I/P of 1.80. By the end of the quarter, the "T" sand reservoir pressures essentially stayed constant at 1020 psi and 98% hydrostatic pressure (980-1070 psi range). Injection well profile logs run during the quarter showed that two "D" sand injectors were partially injecting into the "T" sands at an average rate of 3000 BPD, of which about 2000 BPD was entering the DU3 thief sand. By adjusting the "D" and "T" sand injection totals to reflect net effective injection, the "D" sands had a net injection of 9,300 BPD and I/P of 2.1, slightly lower than fourth quarter rates, and the "T" sands net injection actually increased to 7700 BPD and I/P of 1.92. The high net injection rate into the "D" sands was still adequate to increase reservoir pressure to the desired level. The higher net injection into the "T" sands explains why the reservoir pressures slightly increased.

In summary, reservoir pressures in the mature Phase 1 area have increased during

the last three years. The average "T" sand pressure has risen from 818 psi in June 1997, to 889 psi in March 1999, to 979 psi in September 1999, and to 1020 psi or 98% hydrostatic pressure in March 2000. Reservoir pressures will be decreased to an average of about 930 psi \pm 50 psi or 90% \pm 5% hydrostatic pressure in the "T" sands in any specific area. The average "D" sand pressure has gone from 594 psi in May 1996, to 748 psi in August 1998, to 874 psi in March 1999, to 1080 psi in September 1999, to 960 psi in December 1999 and to 1020 psi or 91% hydrostatic pressure in March 2000. The objective is to maintain the "D" sand pressures at about 1010 psi \pm 50 psi or 90% \pm 5% hydrostatic pressure in any specific area for the remainder of 2000.

At first, it was postulated that reservoir pressures only needed to reach an estimated 800 psi to fill the steam chests based on the saturated steam pressure - temperature relationship. Field experience shows that higher reservoir pressures above 900 psi are needed to achieve steam chest fill-up throughout the reservoir, which means that certain areas in the steamflood had maximum reservoir temperatures exceeding 530/F.

As reservoir pressures increased in the "T" and "D" sands, gross fluid production correspondingly increased due to higher differential pressures in the wellbore from 6145 barrels of gross fluid per day (BGFPD) and 725 barrels of oil per day (BOPD) in March 1999 to 7200 BGFPD and 673 BOPD in June 1999. Water injection rates in July and August averaged 36,000 BPD compared to the June rate of 29,400 BPD to compensate for the increased production levels and to accelerate steam chest fill-up. After achieving steam chest fill-up in the "D" sands in August, water injection was reduced into the "D" sands and increased into the "T" sands. Overall total water injection declined from 36,000 BPD in July and August to 26,100 BPD in October. Following steam chest fill-up of the "T" sands in October 1999, gross fluid production was increased from 10,500 BPD in September to 14,500 BPD in November by activating seven production wells, of which six were dual "T" and "D" completions and one was a "D" completion to replace an offset "D" well that sanded up. When the "D" sand reservoir pressures declined, total injection was increased to 30,900 BPD in November and 31,600 BPD in December, with most of the increase going to the "D" sands. Five high water cut wells were idled in November and December and two of the best oil producing wells were idled in November to accommodate the surface owner for a possible 12 - 18 months. In December 1999, one "T" sand injection well and six production wells were activated, including four "T" only completions and two "T" and "D" completions. No major well changes occurred in the first quarter 2000.

Reservoir pressure data were continued to be retrieved approximately once a month from each idle well using sonic fluid levels and Amerada bombs as explained in previous quarterly reports.

Operational Management

Operational management is focused on the apparent steamflood-related surface subsidence for the Tar II-A project due to shale compaction above the "D" sands. A study has been performed to confirm steamflood-related shale compaction, to determine where this phenomenon is occurring, to measure the extent of shale failure and identify the critical temperatures and reactions that occur during shale failure.

Expanding the project to the Tar V steamflood has allowed the project team to continue ongoing thermal operations in a pilot horizontal well steamflood that was based on the Tar II-A horizontal well pilot. Two of the three Tar V horizontal producers (wells J-205 and J-201) had

experienced sand inflow problems and required the well completions to be re-treated with steam to reconsolidate the formation sands. Both jobs were recently completed and the wells have been on production with no further sand problems. Well J-205 began producing in September 1999 at low rates and was sped up in November to a stabilized rate of 90 BOPD and 800 BWPD. Well J-201 began producing in March 2000 at low rates. As of this report, flank well A-29 is proposed to be converted to water injection. This well will supplement the injection to production ratio for surface subsidence control and allow increased production from the horizontal wells which currently all have high pumping fluid levels. This well will also provide more reservoir pressure support from outside the pilot area to improve well productivity similar to the flank water injection in the Tar II-A project.

Shale Compaction Study:

While steam injection can improve the recovery of heavy oil from a reservoir, it can also potentially affect the composition and physical properties of the reservoir rock and surrounding shales. Of particular interest in this regard is the effect of steam injection on the compactional properties of shales occurring within and surrounding the Tar II-A reservoir. Changes in shale volume in response to steaming could impact surface subsidence.

David K. Davies and Associates, Inc analyzed both the pre-steam cores from well OB2-3 and the pre- and post-steam cores from wells OB2-5 and UP-908. DKD concluded that the most serious shale compaction is occurring in a six foot interval above the D1 sands as was conjectured. Lesser forms of shale compaction are occurring above and throughout the T2 sand, the thickest of the T sands, and in the interbedded shales within the upper D1 sands above the apparent steam / oil interface as delineated by the density - neutron log crossovers in the post-steam wells.

The study suggests that the shale compaction process occurs in two stages, an early compaction stage and a late compaction stage. The early compaction stage is a result of a relatively gradual expulsion of fluids from the shales through the matrix pore system into the surrounding sand laminations. The late compaction stage is a result of fluid expansion causing pore pressures to build up high enough to cause hydraulic microfracturing throughout the shale matrix. The shales exposed to high temperatures are going through a general sequence of seven events that includes the following:

Early Compaction Stage

1) Clay dehydration occurs resulting in the expulsion of interlayer clay water from the clays to the adjacent shale pores. This is believed to start at 60/C or 140/F. Earlier studies indicated that the virgin shales can have high porosities above 35% of the bulk volume and that dehydrated shales from clay dewatering can have porosities as low as 15%. Dehydrated clays can rehydrate back to original conditions upon cooling if water is present, even if heated to 288/C or 550/F during steamflooding;

2) Kerogens within the shales are partially converting to liquid hydrocarbons, pressuring up and exuding into adjacent pores. The kerogens in the shales are organic rich and can yield gas and oil when heated. Well OB2-5 had minimal kerogen thermal effects 11 ft above the D1 sand and the shales bordering the sands had the most "live" oil in them. Apparently, an expert can deduce the temperature range a kerogen has experienced by looking at their "reflectance" or shininess factor and estimated that the kerogens above the D1 sands underwent 439/C or 822/F in the lab, which is too high. The lab procedure

consistently raised core temperatures rapidly compared to actual reservoir conditions. It is possible that the hydrocarbon distillates which form in the steam chest from the D1 sand oil could be affecting this evaluation or maybe some of the geochemical reactions that occur at higher temperatures are exothermic and increasing local temperatures above reservoir temperatures;

3) Thermal expansion of all formation fluids increases the pore pressure within the shale, including the original connate water, the new oil generated from the kerogens and the interlayer clay water;

4) Some of the pore fluids gradually and continuously escape through the matrix pore system without significant textural changes in the rock. Lab work indicates that the clays in the Tar II-A shales can be dewatered at temperatures below 275/F without microfracturing the shale matrix or causing textural changes in the rock. The actual temperature necessary to dewater the shales is dependent on the proximity of sand layers, the pore pressure, and horizontal and vertical permeability of the shale matrix. Color changes in the shales are subjective and qualitative, but are definitely different for virgin and heated shales. The virgin shales have a dominant green color with patches of very light brown. Shales that undergo some heat are light brown without the green hue. The highly heated shales are dark brown to black. The first color change is attributed to generating oil from the kerogens and the second color change is attributed to coking the oil. Some color changes could be due to mineral transformations;

Late Compaction Stage

5) Coking of the liquid hydrocarbons darkens the shale color and possibly reduces the shale matrix permeability. According to tests performed from 1990-92 by Alberta Sulphur Research LTD. of the University of Calgary for Union Pacific Resources Corp, Tar II-A crude oil begins cracking at 250/C or 482/F and coking reactions require temperatures exceeding 285/C or 545/F;

6) As temperature and pressure increase, mineral transformations occur due to the geochemistry between the shale pore fluids and the surrounding rocks. Specific diagenetic minerals can precipitate or dissolve at certain temperatures, making them possible paleothermometers for defining the temperature ranges experienced by the formation rocks. A few diagenetic transformations in the Tar II-A sands include the creation of chlorites, epidote, the zeolite, Analcime, and pyrites; and

7) Microfracturing of the shales occurs when the pore pressure exceeds the lithostatic pressure which results in the rapid release of pore fluids and shale compaction. It appears that the micas immediately above the D1 sands in the pre-steam cores are more randomly packed and oriented whereas in the post-steam cores the micas are oriented more parallel with the bedding plane, indicating late stage shale compaction. Virgin and early stage compacted shales generally have less than 35% of the micas oriented within 0-10/ of horizontal bedding and less than 70% micas within 0-20/. In comparison, late stage compacted shales generally had over 45% micas oriented within 0-10/ of horizontal bedding and more than 75% micas oriented within 0-20/. The compaction also causes mica grains to fold or break when in contact with sand grains. These microfractures cannot generally be seen in thin sections unless specifically looking for them since they are hidden where the kerogens and smaller than 2 micron size grains are located and because they do not break individual grains of quartz and feldspar.

Using these indicators, late stage shale compaction occurred in well OB2-5 from

2412.5 - 2440.15 ft (above and throughout T2 sand), from 2531.5 - 2534.8 ft (above D1 sand) and in the interbedded shales within the D1 sands to a depth of 2542 ft which is above the steam / oil contact. The most impacted samples were above the D1 sands. According to the density-neutron log, the steam chest (log separation) in the T2 sand extended throughout the sand from 2417-2446 ft and the D1 sand steam chest also extended throughout the sand from 2535-2587 ft with a major log separation from 2535-2550 ft. In UP-908, the shales exhibited late stage compaction from 2558.25 - 2561.75 ft (above D1 sand). The ReSpec core sample that was heated to 550/F also experienced late stage shale compaction. Early stage compaction was observed in most of the shales that experienced reservoir heating and in the ReSpec core sample that was heated to 275/F. Recent Thermal-Decay-Time logs run in wells UP-800 and 1F-10 only show noticeable compaction in the twelve foot interval above the D1 sands and none in the "T" sands or interbedded shales in the "D1" sands, even when comparing total gross sub-zone thicknesses with the original logs.

The temperature ranges for the early and late compaction stages have not been clearly defined, but evidence uncovered to date can place some temperature limits on the processes. For early stage compaction, clay dewatering is known to start at 60/C or 140/F. The ReSpec core sample that was heated to 135/C or 275/F experienced clay dewatering but not late stage compaction symptoms. Based on paleo-thermometry, a sample of post-steamflooded core in well OB2-5 experienced mineral transformations (chlorites and vitrinite reflectance values) indicative of late stage compaction. The core underwent minimum temperatures of 192 -202/C (398-416/F) to create chlorites and could not have experienced temperatures above 280/C or 536/F or else the chlorites would have dissolved. Vitrinite is a kerogen-based hydrocarbon that provides reflectance values of the highest temperatures it encounters. The vitrinite reflectance values further reduced the upper range to 250/C or 482/F. Yet as mentioned above, the crude oil tends to coke at approximately 285/C or 545/F and epidotes commonly form at 260-270/C or 500-518/F, so discrepancies still exist. Therefore, it is safe to conclude that early stage compaction starts at 60/C or 140/F and late stage compaction starts between 135-192/C or 275-398/F. The upper temperature limits cannot be determined, other than to conclude it is below the steam injection temperature of 316/C or 600/F or to assume the maximum thermal reservoir simulation model temperature of 273/C or 523/F in the shales at the end of steamflood injection. These findings indicate that more ReSpec-type "open" shale compaction tests should be performed, perhaps at 177/C and 218/C (350/F and 425/F, respectively), to determine the critical microfracture temperature and measure the physical expansion and contraction of the samples.

With respect to the ReSpec "open-system" high temperature compaction tests on sands and shales, where fluids were allowed to bleed off to maintain constant pressures, the tests on the shales were probably closer to a "semi-closed" system because of the lack of vertical permeability in the samples. During the shale tests at 275/F and 550/F, both samples were allowed to bleed fluids out of the system to maintain constant pressure in the test vessel. However, the rate of fluid expulsion was not recorded and therefore it cannot be determined when, if at all, the pore pressures exceeded critical lithostatic pressures and a resultant sudden release of pore fluids occurred. The sample heated to 550/F appears to have microfractures whereas the sample heated to 275/F did not. The test procedure also ramped up whole core temperatures within an hour, which may not have allowed the "whole core-size" shale samples to heat up uniformly and to "gradually" bleed off pressure to adjacent interbedded sands as would happen in the field. In the ReSpec shale test at 275/F, compaction was based on early stage compaction symptoms or mostly through dehydration of the clays. The ReSpec shale test at 550/F underwent

late stage compaction symptoms such as microfracturing, color changes, and mica realignment. Further shale tests at ReSpec should measure the rate of fluid expulsion from the core samples and ramp up temperatures more gradually to allow the large shale samples to heat up more uniformly

Technical Transfer

Most of the quarter was spent writing delinquent quarterly reports for the project.

Don Clarke of the City will reprise his oral presentation entitled "At 68, Wilmington Still Has Life: New Technology Revitalizes the Old Field" at the 2000 AAPG / SPE Western Regional Meeting to be held in Long Beach, CA, June 17-24¹.

Julius Mondragon, Iraj Ershaghi, and Zhengming Yang of USC will present an SPE paper entitled "Post Steamflood Reservoir Management Using a Full-Scale Three-Dimensional Deterministic Thermal Reservoir Simulation Model, Wilmington Field, California" at the 2000 AAPG / SPE Western Regional Meeting to be held in Long Beach, CA, June 17-24².

David Davies of David K. Davies and Associates will teach a class on Formation Damage and Well Stimulation - Identification & Prevention of Formation Damage Through Detailed Rock Analysis", to be given at 2000 AAPG / SPE Western Regional Meeting to be held in Long Beach, CA, June 17. Much of the material for this class is based on research from this DOE project³.

Don Clarke of the City will lead a Field Trip for Teachers on "Geology and Exploitation of Los Angeles Oil Fields", to be given at 2000 AAPG / SPE Western Regional Meeting to be held in Long Beach, CA, June 24⁴.

Don Clarke of the City and Scott Hara of Tidelands will be the Co-General Chairperson and Co-Technical Program Chairperson, respectively, for the AAPG/SPE Western Regional Meeting to be held in Long Beach, CA, June 17-24⁵.

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

References and Notes

1. Clarke, D.O., City of Long Beach, "At 68, Wilmington Still Has Life: New Technology Revitalizes the Old Field", SPE Paper #63306, 2000 AAPG / SPE Western Regional Meeting to be held in Long Beach, CA, June 19-22.
2. Mondragon, J.J. III, Ershaghi, I., and Yang, Z., USC, "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 to be held in Long Beach, CA, June 19-22.

3. Davies, D.K., Teach Class on “Formation Damage and Well Stimulation - Identification & Prevention of Formation Damage Through Detailed Rock Analysis”, to be given at 2000 AAPG / SPE Western Regional Meeting to be held in Long Beach, CA, June 17.
4. Clarke, D.O., Tour Guide for Field Trip for Teachers on “Geology and Exploitation of Los Angeles Oil Fields”, to be given at 2000 AAPG / SPE Western Regional Meeting to be held in Long Beach, CA, June 24.
5. Clarke, D.O., Hara, P.S., Co-General Chairperson and Co-Technical Program Chair person, respectively, for 2000 AAPG / SPE Western Regional Meeting to be held in Long Beach, CA, June 19-22.