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:	QUARTERLY	Reporting Period Start Date:	04/01/2001 End Date: 06/30/2001
Principal Author(s):	Scott Hara _____ _____ _____ _____		
Report Issue Date:	07/31/2001	DOE Award No.:	DE- FC22 - 95BC14939
Submitting Organization(s)	Tidelands Oil Production Company	(1)	
Name & Address	P O Box 1330		
	Long Beach, CA 90801		
	City of Long Beach	(2)	
	Department of Oil Properties		
	211 E. Ocean Blvd. - Ste. 500		
	Long Beach ,CA 90802		
	University of Southern California	(3)	
	Petroleum Engineering Program		
	Hedco 316		
	Los Angeles, CA 90089-1211		
	GeoSystems	(4)	
	formerly David K. Davies and Associates, Inc.		
	1410 Stonehollow Drive		
	Kingwood, TX 77339		
	_____	(5)	

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

Cooperative Agreement No.: DE-FC22-95BC14939

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

Date of Report: July 31, 2001

Award Date: March 30, 1995

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

DOE Award: \$6,177,952 (Cum Actual through June 2001)
\$400,000 (2001 Projected)
\$88,350 (June 2001 YTD Actual)

Principal Investigator: Scott Hara - Tidelands

Program Manager: Gary Walker - National Petroleum Technology Laboratory

Reporting Period: April 1, 2001 to June 30, 2001

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

Objectives

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

Summary of Technical Progress

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

The project team spent the Second Quarter 2001 performing well work and reservoir surveillance on the Tar II-A post-steamflood project. The Tar II-A steamflood reservoirs have been operated over fifteen months at relatively stable pressures, due in large part to the bimonthly pressure monitoring program enacted at the start of the post-steamflood phase in January 1999. Starting in the Fourth Quarter 2000, the project team has ramped up activity to increase production and injection. This work will continue through 2001 as described in the Operational Management section.

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

Much of the second quarter was spent writing DOE annual and quarterly reports to stay current with contract requirements.

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 was the basis for a technical paper presented at the AAPG / SPE Western Regional Meeting in June 2000¹.

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 performed its primary function of setting injection and production rates and predicting when steam chest fill-up would occur. 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 injection to production ratio to use following steam chest fill-up. These model weaknesses will probably require a stochastic 3-D model to correct.

The plan is to adapt the 3-D deterministic model for use on the Tar V horizontal well steamflood pilot project to determine the current status of reservoir heating from steam injection. The Tar V project, unlike the Tar II-A project, has only a few temperature observation wells that provide an indication of reservoir heating, but not a comprehensive three-dimensional estimate over the entire project area. Optimizing steamflood operations and oil recovery will require a 3-D deterministic model.

The plan will also update the Tar II-A post-steamflood model to provide a comparison of model projections to actual reservoir temperatures and pressures for the past two years. The actual temperature data are from gross fluid production from individual wells and temperature profile surveys. The pressure data are from the bimonthly fluid level surveys and periodic Amerada bomb pressure recordings on idle wells. Once the model is adapted for actual temperature and pressure conditions, it can be used to optimize the post-steamflood operations regarding how to maximize production while minimizing injection volumes, heat loss and surface subsidence.

Reservoir Management

The Tar II-A steamflood project was terminated in January 1999 when the project lost its inexpensive steam source from the Harbor Cogeneration Plant as a result of electric power deregulation in California. An operational post-steamflood plan was developed and implemented to mitigate the effects of the lost steam injection and possible thermal-related formation compaction by injecting cold water into the flanks of the steamflood. The purpose of flank injection has been to increase and subsequently maintain reservoir pressures at a level that would fill-up the steam chests in the "T" and "D" sands before they could collapse and cause formation compaction and to prevent the steam chests from

reoccurring. A new 3-D deterministic thermal reservoir simulation model provided operations with water injection rates and allowable production rates by well to minimize future surface subsidence and it accurately projected reservoir steam chest fill-up by October 1999. Figure 1 shows the post-steamflood wells active in 2001 compared to the original steamflood patterns. A geomechanics study and a separate reservoir simulation study have been performed to determine the possible causes of formation compaction, the temperatures at which specific compaction indicators may be affected and the projected temperature profiles in the over and underburden shales over a ten year period following steam injection. See the Operational Management section for more details.

Steam chest fill-up of the "D" sands occurred in September 1999 when the pressure throughout most of the reservoir exceeded 90% hydrostatic or about 960-1000 psi. The reservoir then acted more like a waterflood that could be operated at lower injection to production ratios (I/P) and net injection rates. However, maintaining reservoir pressure is important to prevent steam chest reoccurrence. In mid-September 1999, net water injection was reduced substantially in the "D" sands and reservoir pressure plummeted about 100 psi within six weeks. Starting in late-October 1999, net "D" sand water injection was increased and reservoir pressure rose back to the desired steam chest fill-up pressure of 90% hydrostatic pressure by March 2000. Reservoir pressure has been maintained. The pressure averaged 90% hydrostatic in December 2000 and 91% hydrostatic in March and June 2001. After reaching fill-up in October 1999, net "T" sand injection remained at a high rate through April 2000 and reservoir pressures stabilized at 98% hydrostatic pressure. The objective is to lower "T" sand pressure slowly to 90% hydrostatic. Net injection was reduced and "T" sand reservoir pressure averaged 96% hydrostatic in December 2000, 95% in March 2001 and 92% in June 2001. Table 1 lists the "T" and "D" sand average reservoir pressures during steam

injection and after January 1999 when the post-steamflood phase began.

TABLE 1					
TAR II-A STEAMFLOOD PROJECT - RESERVOIR PRESSURE					
"T" Sands - Phase 1-1C Wells			"D" Sands - Phase 1-1C Wells		
	<u>Reservoir Pressure</u>			<u>Reservoir Pressure</u>	
	psi	hydrostatic %		psi	hydrostatic %
Jun-97	818	79	May-96	594	54
			Aug-98	748	68
Mar-99	888	85	Mar-99	881	79
Jun-99	925	89	Jun-99	1026	92
Sep-99	976	94	Sep-99	1056	95
Dec-99	1002	96	Dec-99	954	86
Mar-00	1008	97	Mar-00	1009	91
Jun-00	1011	97	Jun-00	991	90
Sep-00	1000	96	Sep-00	995	90
Dec-00	1003	96	Dec-00	999	90
Mar-01	992	95	Mar-01	1005	91
Jun-01	955	92	Jun-01	1009	91

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

Operational Management

The Tar II-A project averaged 1,012 BOPD and 20,877 BPD gross fluid (19.63 water-oil ratio [WOR]) with 31.455 BPD water injection during the Second Quarter 2001. These rates compare with 1,075 BOPD and 19,035 BPD gross fluid (16.71 WOR) with 27,064 BPD water injection during the First Quarter 2001 and 1,026 BOPD and 19,366 BPD gross fluid (17.88 WOR) with 28,354 BPD water injection in the Fourth Quarter 2000. Second quarter production experienced several involuntary electrical power shutdowns, higher water-oil ratios and downhole pumps going short. During the next quarter, pumps will be changed where necessary and high WOR wells will be idled. The majority of the well work this quarter was to clean up and stimulate the water injection wells, which is apparent by the increased injectivity.

Expanding the DOE project in March 1999 to include the Tar V steamflood has allowed the project team to continue research related to the Tar II-A horizontal well pilot steamflood operations. The Tar V pilot steamflood began in June 1996 and initially included two new horizontal steam injectors (wells FJ-202 and FJ-204), two existing vertical water injectors (wells FR-111 and FRA-83), three new horizontal producers (wells J-201, J-203 and J-205), and three existing vertical well producers (wells A-186, A-195 and A-320). The steamflood project wells are completed in the Wilmington Field Fault Block V Tar Zone "S" sands as shown in the "S4" Sand structure map in Figure 2. Well FRA-29 was converted to a water injector in November 2000. A new horizontal producer, J-206, is being proposed to drill in 2002 along with converting a south flank well to water injection for additional pressure support (both shown in red).

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

Figure 2

Pilot steamflood performance was excellent for the first two years as shown in Figure 3 with oil production peaking at 743 BOPD in January 1998 at a cumulative steam-oil ratio (SOR) of 4.4. All five horizontal wells were given initial cyclic steam jobs to consolidate the formation sands and to stimulate heavy oil production. For the five horizontal wells, Table 2 lists the initial production date, the

peak monthly oil production rate, the date of peak oil production, and the cumulative oil production through June 2001. The three infill vertical wells, A-186, A-195 and A-320, all responded favorably to steam injection in the horizontal wells. Wells A-186 and A-320 still contributed a combined 81 BOPD during the Second Quarter 2001, although this is a decline of 27 BOPD since December 2000. Well A-195 was idled in August 1998 because of steam breakthrough and is used as a temperature observation well.

Table 2
Tar V Steamflood Pilot - Horizontal Wells

Well	Init Prod Date	Peak Prod, BOPD	Peak Prod Date	Cum Oil Prod Thru June 2001, 1000 BO
FJ-202	Nov 96	280	Dec 96	40.8
FJ-204	Feb 97	223	Apr 97	27.0
J-205	Apr 97	328	May 97	91.6
J-203	Jun 97	267	Mar 98	157.9
J-201	Oct 97	283	Jan 98	94.4

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

After reaching peak production of 743 BOPD in January 1998, the pilot project oil production declined significantly to a low of 148 BOPD in October 1999 for various reasons including lower steam injection rates than planned, well downtime from sand control problems, and gross production restrictions to meet new injection to production ratio (I/P) requirements for surface subsidence control. Restricting gross production rates became a problem because the horizontal producers began responding to steam and water injection that resulted in higher producing fluid levels and water cuts. Steam injection to the pilot project was increased in October 1999 and well work was performed to repair two of the horizontal producers for sand control and to convert one vertical well to water injection. This work resulted in oil production rising to 304 BOPD in December 2000 with a cumulative SOR of 6.4. During the First Quarter 2001, oil production declined gradually to 231 BOPD without any appreciable change in gross production, probably due to steamflood and waterflood response. During the Second Quarter 2001, production increased in June to 261 BOPD as a result of speeding up the pumping units on the three horizontal well producers. The wells still have high producing fluid levels that need to be pumped down further.

The projected oil reserves for the pilot project is 1.7 million barrels assuming the use of 8.5 million barrels of cold water equivalent steam at 80% quality and 16.7 million barrels of total steam and water injection over 14 years. As of June 2001, the pilot has produced 629,000 barrels of oil and 5,602,000 barrels of gross fluid (89% average water cut) and injected 4,325,000 barrels of steam and 6,078,000 barrels of total steam and water for an overall I/P ratio of 1.08. The steamflood performance curves in cumulative barrels vs time for oil production, gross fluid production, steam injection and total steam and water injection are shown in Figure 4.

The pilot project through the Fourth Quarter 2000 was meeting the original reservoir

engineering projections based on oil recovery vs cumulative gross fluid production and cumulative steam injection. The original pilot projections showed that to recover 586,000 barrels of oil would require producing 4,990,000 barrels of gross fluid (actual is 2.5% lower) and injecting 3,643,000 barrels of steam (actual is 2.3% higher). However, the project is behind schedule because production and injection rates throughout the project have been too low.

Based on the original projected volumes, the project should have recovered 586,000 barrels of oil by the second quarter of 1998 or 1.5 years earlier. An important issue not considered in comparing projected to actual steamflood performance is that the injected steam quality was rarely at 80% and probably was closer to 40%. This will need to be evaluated further.

The Tar V pilot project has been operated differently than originally planned because of thermal-related surface subsidence concerns regarding the Tar II-A steamflood project. Steam and water injection were increased to raise the average I/P ratio to 1.05, compared to the originally planned I/P ratio of 0.75 during the first four years of the project. The planned I/P ratio was lower because the Tar II-A project averaged a 0.75 I/P ratio from 1990 to 1994 without any apparent adverse surface subsidence effects. The lower I/P ratio in a steamflood was considered safe because injected high temperature steam displaces much more volume than its cold water equivalent volume, up to 35 times more at 800 psi reservoir pressure. The change in plan accelerated steamflood and waterflood response, hence the high producing fluid levels in the wells. Because the horizontal producers are completed at the bottom of the S4 sands, high oil production rates are dependent upon pumping the wells down. The pilot is now operating significantly below projections as the instantaneous steam-oil ratios since November 2000 have averaged over 10.

The pilot project has excellent potential for increasing oil production without further increasing steam injection. All three horizontal producers have had high producing fluid levels over 1300 feet over the pump (FOP) for several months. Speeding up the pumping units on wells J-201, J-203 and J-205 to draw down the fluid levels should increase production to about 2200 BPD gross and 125 BOPD per well (incremental of 900 BPD gross and 75 BOPD, 8.8% oil cut) based on leaving a safe producing fluid level to prevent sand inflow. The pumping unit speed-ups performed in June 2001 have increased oil production about 50 BOPD and reduced the pumping fluid levels to about 1150 FOP. Well FRA-29 was converted to injection in November 2000 to provide the necessary water injection support for production increases in wells J-201 and J-203. This well will also provide more reservoir pressure support from outside the pilot area to improve well productivity similar to the flank water injection in the Tar II-A project. Additional water

injection on the south flank of the project is needed to support increasing production in well J-205 as shown in Figure 2.

Pilot production in June 2001 was 261 BOPD. The proposed work could increase oil production by 345 BOPD. Assuming an average steam injection rate of 3300 BCWESPD, the projected pilot oil rate of 604 BOPD would give a steam-oil ratio of 5.46, which appears achievable.

Shale Compaction Study:

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.

GeoSystems, formerly David K. Davies and Associates, Inc (DKD), 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 and its overall subsidence effect is minor. 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 and its overall subsidence effect can be severe.

Using the seven compaction indicators given in the report, 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 OB2-5 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). Two similar shale core samples were heated to 275°F and 550°F, respectively. The core sample that was heated to 550°F experienced late stage shale compaction. Early stage compaction was observed in most of the shales that experienced reservoir heating and in the 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 shale 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 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 "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 shale test at 275°F, compaction was based on early stage compaction symptoms or mostly through dehydration of the clays. The shale test at 550°F underwent late stage compaction symptoms such as microfracturing, color changes, and mica realignment. Further shale tests 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.

Technology Transfer

Scott Hara nominated and helped prepare the 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 given the award at the 2001 PSAAPG Annual Meeting in Universal City, CA on April 10, 2001.

The sand consolidation well completion technology introduced in this DOE project has attracted further research from Texaco and Texas A&M University. F. E. Moreno and D. D. Mamora of Texas A&M University presented two papers, the first one entitled "Sand Consolidation Using High-Temperature Alkaline Solution" and the second one similarly entitled "Sand Consolidation Using High-Temperature Alkaline Solution – Analysis of Reaction Parameters". The first paper was presented at the 2000 SPE Annual Technical

Conference and Exhibition in Dallas, TX from October 1-3³ and the second one was presented at the 2001 SPE Western Regional Meeting held in Bakersfield, CA from March 26-30.⁴ This paper is based on lab work performed on Wilmington Field cores in an effort to duplicate in the laboratory the sand consolidation well completion process developed in this project. This DOE project is referred to in both papers.

Scott Hara is scheduled to make an oral presentation about successful operating practices from this DOE project to the California Conservation Committee of Oil and Gas Producers on September 19, 2001 in Long Beach. The actual subject matter and title of the presentation are to be determined.

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. 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, Long Beach, CA, June 19-22.
2. 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, 2001.
3. 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.
4. 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.