The Class Act

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Significant New Learnings From an Integrated Study of an Old Field, Foster/South Cowden Field (Grayburg/San Andres), Ector County, TX

By Robert Trentham, Laguna Petroleum
Midland, TX

This DOE-supported study by **Laguna Petroleum** of the Grayburg and San Andres reservoirs in a portion of the Foster Field, Ector County, Texas, was designed to test whether an integrated engineering, geological, and geophysical study could significantly add reserves, preserve access to existing wellbores and extend the life of this 66-year-old field. The study has been successful in adding 190,000 BO incremental reserves to date, resulted in the re-entry of 3 plugged or temporarily abandoned wells, the drilling of 4 wells (**Figure 1**), and the restimulation of over a dozen wells, while extending the economic life of the field from 9 to 16 years (**Figure 2**).

Learnings

It was anticipated that the successful integration of seismically derived, log-guided porosity maps into a reservoir simulation would be the major contribution of this study. There are, however, a number of other engineering, geological and geophysical "learnings" that have come out of this study.

Water Chemistry

Water chemistry analyses can describe differences and changes in the reservoir in this 40-year-old

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Figure 1 Foster #11, one of the successful wells.

What's Inside

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waterflood. In addition to the 320 water samples analyzed prior to the inception of the project, over 350 new water samples have been collected and analyzed. These analyses and recent tests have allowed the determination of original "virgin" water chemistries of the different producing zones and of the various injection make-up waters. Realizing the potential uses of this data set, Laguna Petroleum initiated periodic sampling of each well. In addition, water samples were taken prior to and following any change in a wells status (setting bridge plugs—CIBP's, refracturing, etc.). The produced water analyses are now being used as a real time indicator of the success or failure of day-to-day field operations. Some of the questions that are being addressed are:

- What is the source of produced water? Virgin formation, flood water or a mix?
- Was the setting of a CIBP successful in isolating a zone or zones?
- Was fracture stimulation successful in producing from a single zone (Pipeline Frac) or multiple zones (conventional frac)?
- What is the cause of a sudden change in production?
- Is water being coned up from a deeper reservoir?
- Is there a casing leak?

Bottom Hole Pressures

Bottom hole pressure tests indicate that different areas in a single zone and different zones within the same formation can be at significantly different pressures. A series of bottom-hole pressure tests run before and after the setting of bridge plugs demonstrated that the upper Grayburg was typically at much higher pressure than the lower Grayburg and San Andres. There is also a low pressure area within the upper Grayburg in one of the leases with offset wells varying in pressure by as much as 1500#. This supports the conclusion that the waterflood has not efficiently flooded the entire reservoir.

A corollary conclusion was that bottom-hole pressure tests need to be of longer duration to identify the presence of multiple reservoirs. Tests of from 3 to 7 days are adequate to characterize single-zone reservoirs with uniformly high porosity and permeability. However, in a reservoir like the Grayburg with 4-12% porosity, 0.1 to 10 millidarcies of permeability and pressures ranging from 300 to 2200 pounds, tests of from 21 to 30 days are necessary to define the variations in the multi-zone reservoir. Longer duration tests are, therefore, an essential part of a successful reservoir characterization.

Fracture Simulations

From the bottom-hole pressure testing data, it was determined that fracture stimulations completed from 1955 – 1982 have either closed or healed. The fracture treatments performed on older wells consisted of 40,000 gallons of fluid and 20,000 lbs. of sand. Although the treatments achieved initial producing rates considered successful, the relatively small treatments created short frac wing lengths that closed with time, resulting in rapid production declines. It was decided much larger treatments had to be utilized in order to achieve greater frac lengths. Both conventional and non-conventional frac designs have been utilized in the field with good results. The conventional fracs are three times as large as had been utilized in the field prior to the project and have resulted in contacting larger volumes of reservoir. A "pipeline" fracturing technique, designed to increase the induced fracture length yet control frac height, was used to improve fluid production in some wells by more effectively contacting the reservoir. Fracture lengths over 200 ft have been achieved utilizing this method.

Stimulation

To date nine wells have been restimulated. Prior to the workovers, total production from the nine wells was 37 BO, 181 BW and 9 MCF. Production from the wells after the re-fracs peaked at 286 BO, 2109 BW and 86 MCF and has since stabilized at 183 BO, 1723 BW and 42 MCF. This represents a 5-fold increase in total sustained production from the nine wells.

A review of the results of all fracture stimulation completed during the study determined that the success of a workover is proportional to the bottom-hole pressure and the oil/water ratio prior to the restimulation of wells with higher bottom-hole pressures (greater than 1500 #), and low oil/water ratios (typically less than 1:4), were more successful. In wells where both variables did not fall within the acceptable range, the stimulation produced poorer economic outcome. By production and bottom-hole pressure testing wells prior to restimulations, only high-pressure, low-water-cut wells will be chosen as workover candidates high-risk wells (those with low pressure and/or high water cuts) can be eliminated as workover candidates.

Flowing water or 100% water swab recoveries following restimulation does not condemn a zone. Many of the restimulated wells produced little if any oil until the water level was dropped to below 1000 ft from surface. This is believed to be the result of different pressures in zones with different oil/water productivity. It is believed that the zones with higher pressure are water productive (swept by the water flood) and

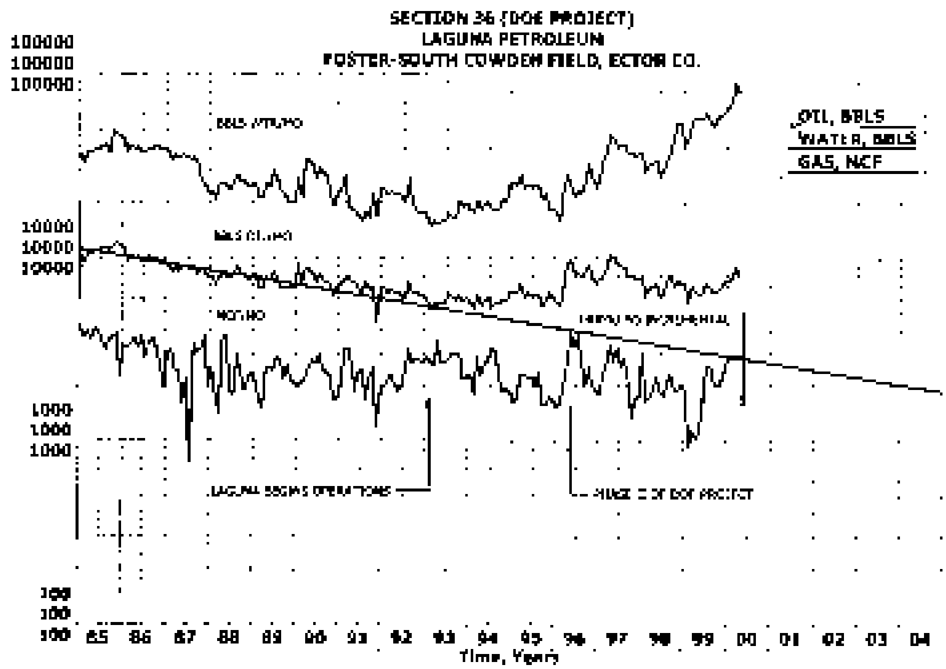

Figure 2 Production plot showing the original decline curve and the extended life of the reservoir.

the zones with lower pressures have higher oil/water ratios. Imagine how many potentially productive waterflood wells have been plugged as a result of producing 100% water during the days immediately following the completion!

Conclusion

The San Andres, the reservoir with the apparently highest quality has, economically, the lowest potential. The coring and production testing of the San Andres has confirmed that the low permeability and compartmentalization of the reservoir has resulted from karstification and anhydrite cementation. Although thick intervals with porosities reaching 15 to 20% are common, production typically declines rapidly and completions are marginally economic. In this project it was initially assumed that the San Andres was responsible for 40% of the total production. In fact, the San Andres contributed less than $^1/_4$ of that amount, or less than 10% of the total!

The expected correlation between seismic velocity and sonic porosity did not materialize.

Instead, there is a good, direct, correlation between the inversion-modeled seismic velocity and the cross plot of gross average neutron density porosity for each zone, with an acceptable error bar. A two-line slope-curve (non-linear) relationship was used to calculate the final values of porosity from the seismic inversion data. Each line rela-

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Improved Recovery from Smackover Carbonates at Womack Field

By Ernest A. Mancini, Center for Sedimentary Basin Studies,
University of Alabama, Tuscaloosa, Alabama

Introduction

Pruet Production Co. and the Center for Sedimentary Basin Studies at the University of Alabama, in cooperation with Texas A&M University, Mississippi State University, University of Mississippi, and Wayne Stafford and Associates have begun a focused, comprehensive, integrated and multidisciplinary study of Upper Jurassic Smackover carbonates, involving reservoir characterization, 3-D modeling, and an integrated field demonstration project at Womack Hill Oil Field Unit, Choctaw and Clarke Counties, Alabama, Eastern Gulf Coastal Plain (**Figure 3**).

Estimated reserves for Womack Hill Field are 119 million barrels of oil (MMBO). During the production history of the field, which began in 1970, 30 million barrels of oil have been produced. Conservatively another 12 to 24MMBO (an additional 10-20%), remain to be recovered through the application of advanced technologies in optimizing field management and production. Womack Hill Field is one of 57 Smackover fields in the regional, peripheral fault trend play of the eastern Gulf Coastal Plain. To date, 674 million barrels of oil have been produced from these fields. The fields in this play have a common petroleum trapping mechanism (faulted salt anticlines), petroleum reservoir (ooid grainstone and dolograinstone shoal deposits), petroleum seal (anhydrite), petroleum source (microbial carbonate mudstones), overburden section, and timing of trap formation and oil migration. Therefore, the work at Womack Hill Field is directly applicable to these 57 fields and can be transferred to Smackover fields located along this fault trend from Florida to Texas.

Scope of Project

Phase I (3 years) of the research involves characterization of the ooid shoal reservoir at Womack Hill Field to determine reservoir architecture, heterogeneity and producibility in order to increase field productivity and profitability. This work includes core and well log analysis; sequence stratigraphic, depositional history and structure study; petrographic and diagenetic study; and pore system analysis. This information will be integrated with 2-D seismic data and probably 3-D seismic data to produce an integrated 3-D stratigraphic and structural model of the reservoir at Womack Hill Field. The results of the reservoir characterization and modeling will be integrated with petrophysical and engineering data and pressure communication analysis to perform a 3-D reservoir simulation of the field reservoir. The results from the reservoir characterization and modeling will also be used in determining whether undrained oil remains at the crest of the Womack Hill structure (attic oil), in assessing whether it would be economical to conduct strategic infill drilling in the field, and in determining whether the acquisition of 3-D seismic data for the field area would improve recovery from the field and is justified by the financial investment. Parallel to this work, engineers will be characterizing the petrophysical and engineering properties of the reservoir, analyzing the drive mechanism and pressure communication (through well performance data), and developing a 3-D reservoir simulation model. Further, the engineering team members will determine what, if any, modifications should be made to the current pressure maintenance program, as well as assess what, if any, other potential advanced oil recovery technologies are applicable to this reservoir to extend the life of the field by increasing and maintaining productivity and profitability. Also, in this phase, researchers will be studying the ability of in-situ microorganisms to produce a single by-product (acid) in the laboratory to determine the feasibility of initiating an immobilized enzyme technology project at Womack Hill Field Unit.

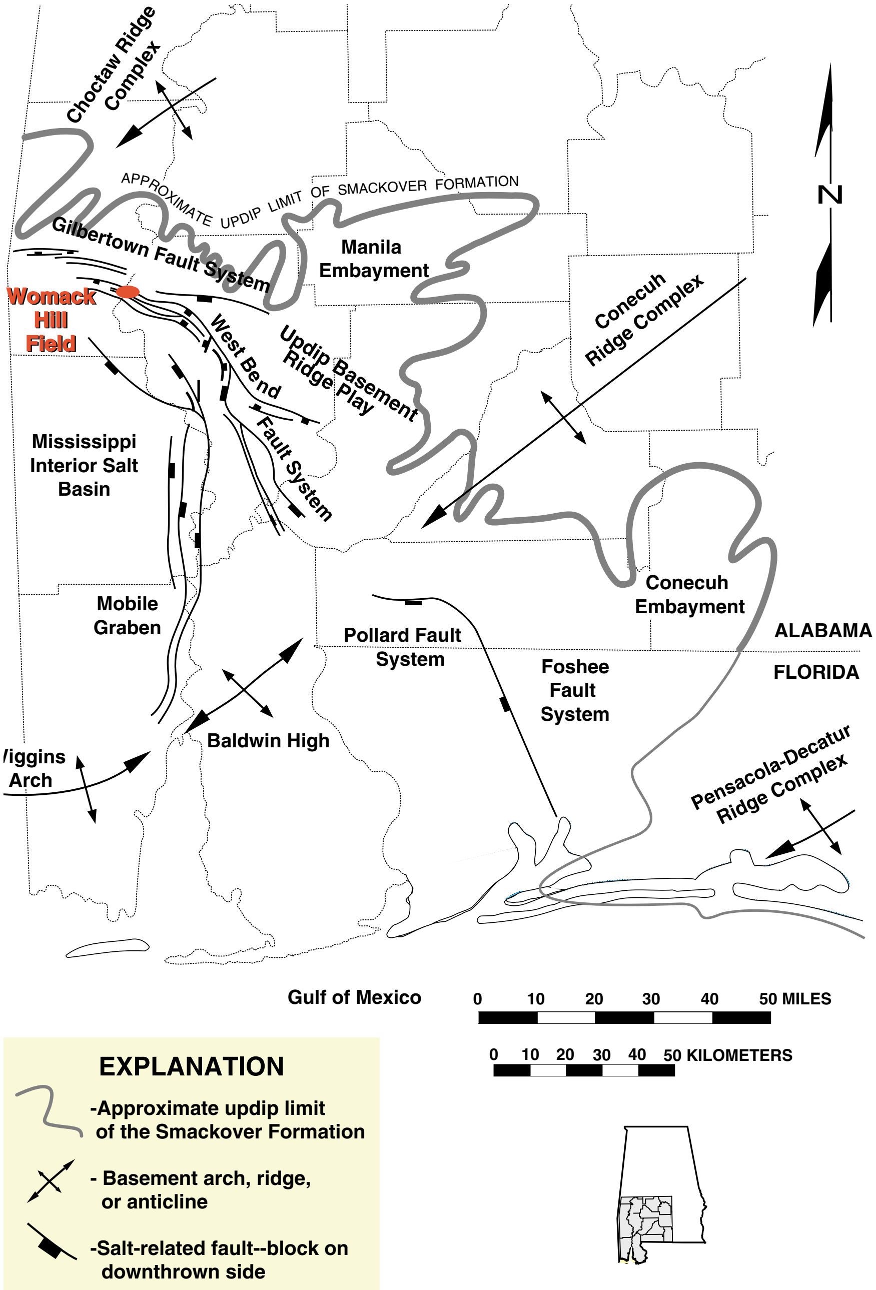

Figure 3 Map of the Smackover formation showing structural features and the Womack Hill project area.

Phase II (2.5 years) of the research will proceed along three lines if the results from Phase I justify the continuance of this work. Line 1 involves the integration of the 3-D seismic imaging into the 3-D geologic model. The model will be used to assess the merits of strategic infill drilling, including drilling in the interwell area and or drilling a crestal well. If new well(s) are drilled, fracture identification log technology will be used to assess whether a lateral/multilateral completion for these wells would be successful. Line 2 involves integrating the data obtained from the 3-D seismic imaging, petrophysical and engineering data acquired from drilling new wells using lateral/multilateral well completions, and the results of the analysis of the well performance data (field/well pressure and rate histories). These integrated data will be used to refine the 3-D reservoir simulation model, implement modifications to the pressure maintenance program, and initiate any additional activities, such as further infill drilling and/or advanced oil technology applications to improve recovery. Line 3 involves confirming the ability of in-situ microorganisms to produce a single by-product (acid) and injecting nutrients into the field reservoir to sustain the cells rather than to support cell proliferation for initiation of the immobilized enzyme technology project.

Phase III (0.5 year) of the project involves monitoring the enhanced pressure maintenance program and advanced technology application project, and evaluating the viability of entering existing field wells for lateral/multilateral well completions to improve field productivity and profitability. Also, the immobilized enzyme technology project will be monitored to evaluate the impact of this technique on overall oil recovery from the field.

Producibility Problems

The principal problem at Womack Hill Field is productivity and profitability. With time, there has been a decrease in oil production from the field, while operating costs in the field continue to

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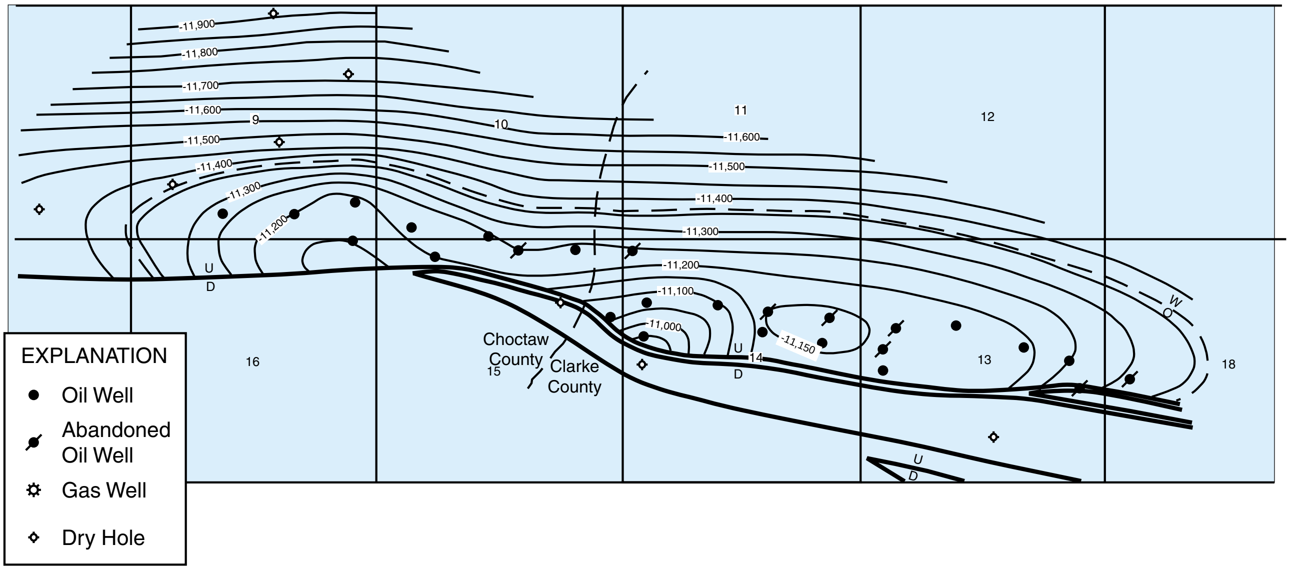

Figure 4 Top of the Smackover Formation, Womack Hill field, Choctaw and Clark Counties, Alabama.

increase. In order to maintain pressure in the reservoir, increasing amounts of water must be injected annually. These problems are related to cost-effective, field-scale reservoir management, to reservoir connectivity due to carbonate rock architecture and heterogeneity, to pressure communication due to carbonate petrophysical and engineering properties, and to cost-effective operations associated with the oil recovery process.

Improved reservoir producibility will lead to an increase in productivity and profitability. To increase reservoir producibility, a field-scale reservoir management strategy based on a better understanding of reservoir architecture and heterogeneity, of reservoir drive and communication and of the geological, geophysical, petrophysical and engineering properties of the reservoir is required. Also, an increased understanding of these reservoir properties should provide insight into operational problems, such as why the reservoir is requiring increasing amounts of freshwater to maintain the desired reservoir pressure, why the reservoir drive and oil-water contact vary across the field, how the multiple pay zones in the field are vertically and laterally connected and the nature of the communication within a pay zone.

Several potential opportunities have been identified, which could lead to increased reservoir productivity. First, the drilling of the Dungan Estate Unit 14-5 well in Sec. 14, T.10N., R.2W. suggests that undrained oil (attic) may be present on the crest of the Womack Hill Field structure (**Figure 4**). The 14-5 well encountered oil in the Norphlet and Smackover at a horizon that previously was not productive in the field. These productive zones were structurally higher in this well, than in any of the wells prior to the drilling of the 14-5 well. Second, field-scale heterogeneity affects the producibility of the reservoir. A major barrier to flow separates the field reservoir into a western portion and an eastern portion and results in structural compartmentalization in Womack Hill Field. This flow barrier dramatically impacts production strategy in the field. Only the western portion of the field has been unitized and only this part of the reservoir is experiencing pressure maintenance. The reservoir drive mechanism in the eastern portion of the field is a strong bottom-up water drive, while the drive mechanism in the western portion of the field is primarily solution gas. This flow barrier has been interpreted to be a major fault (megascopic heterogeneity) or change in permeability. If the barrier to flow is a result of lower permeability, the reduction in permeability could be due to a change in mesoscopic heterogeneity (depositional facies change), a change in microscopic heterogeneity (diagenetic change), or a combination of the two processes. Also, there are multiple shoal lithofacies in the

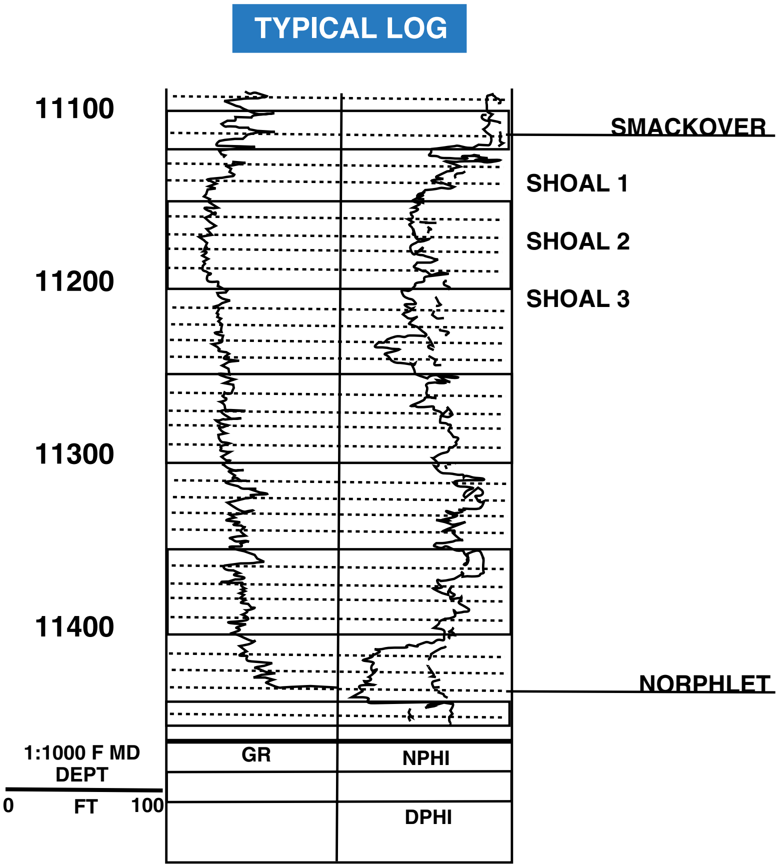

Figure 5 The shoal lithofacies on a log from the Smackover Formation.

field (**Figure 5**). The nature of the communication among and within these multiple pay zones is unclear at this time. Susceptibility of carbonates to alteration by early to late diagenetic processes dramatically impacts reservoir heterogeneity. Diagenesis is the fundamental influence in determining which carbonate deposits will become seals, which will become reservoirs, and what the nature of the reservoir quality and producibility will be. Reservoir characterization and the study of heterogeneity, therefore, becomes a major task because of the physiochemical and biological origins of carbonates and because of the masking of the depositional rock fabric and reservoir architecture principally due to dolomitization. Thus, greater lithofacies and/or diagenetic variability (greater reservoir heterogeneity) translates into more difficulty in predicting between wells (interwell areas) at any spacing, but particularly at Womack Hill Field where the well spacing is as great as 120 acres. Third, prior investigations have suggested that Smackover carbonate reservoirs should be naturally fractured at depths of 11,000 ft. Therefore, well completions, such as lateral/multilateral completions, that utilize the fractured nature of these carbonates should lead to increased producibility of the field. Fourth, understanding and accurately predicting the flow units and barriers to flow in this heterogeneous reservoir is vital to improving producibility. An enhanced pressure maintenance program, advanced oil recovery application, and/or immobilized enzyme technology project that accounts for inherent properties of this heterogeneous reservoir, multiple pay zones, and the nature of the variable drive mechanisms and oil-water contacts in the field should result in increased producibility of Womack Hill Field. The improved connectivity in this compartmentalized reservoir should result in the production of more incremental oil.

Technology Transfer

The project results will be vigorously transferred to producers through five technology workshops. The first workshop will focus on the results of carbonate reservoir characterization, data integration, carbonate reservoir modeling, and 3-D reservoir simulation. The second workshop will focus on aspects of the integrated field demonstration project, results of the 3-D seismic imaging, and drilling program. Later workshops will focus on the results of using lateral/multilateral well completions in the field, results of the enhanced pressure maintenance program and advanced oil recovery application project, and the results of the immobilized enzyme technology project. These workshops will be conducted in cooperation with the Eastern Gulf Region of the Petroleum Technology Transfer Council (PTTC).

Multi-lateral Well Pays Off in Vernon Field, MI

By J.R. Wood and T.J. Bornhorst, Michigan Technological University, Houghton, MI;
W.B. Harrison, D.A. Barnes, Western Michigan University, Kalamazoo, MI;
W. Quinlan and E. Taylor, Cronus Energy, LLD, Traverse City, MI

Introduction

As part of the Class Revisit Program a university-industry-DOE consortium drilled a successful multi-lateral well in Vernon Field, Isabella County, Michigan. The State Vernon & Smock #13-23 was spudded October 16, 2000 in the Vernon Field and drilled to a total depth of 4630 feet, bottoming in the (M. Devonian) Dundee Formation. The first lateral encountered shale in the expected pay zone and was abandoned after drilling 750+ feet. The second lateral was drilled 9 feet deeper to the NE and located 125 (lateral) feet of pay in the Dundee Formation on November 4. Drilling was preceded by a surface geochemistry survey that confirmed an anomaly in the area.

The purpose of this project was to develop and demonstrate new techniques for locating and producing bypassed oil in the Shallow Shelf Carbonates. A previous demonstration well, the TOW 1-3 HD, drilled in Crystal Field (DOE Class program) had shown that horizontal wells could be used to locate and produce bypassed oil. The TOW 1-3 HD, has produced 100,000 bbls of oil since 1993 and is projected to produce an additional 50,000 – 100,000 bbls before the end of its productive life. A post mortem study concluded that this well was successful because it skimmed the top of the reservoir just below the (Bell Shale, U. Devonian) seal in a structural high. However, subsequent horizontal wells both at Crystal Field and elsewhere produced mixed results, and operators are not as enthusiastic with the prospects as they were initially. This project sought to rekindle interest in the use of horizontal drain wells by: (**1**) using a multi-lateral well to probe for hydrocarbons, and (**2**) using surface geochemistry to pinpoint favorable areas prior to drilling.

History of Vernon Field

Vernon Field is located in T16N-R4W in Vernon Township, Isabella County MI (**Figure 6**). The field was developed in the 1930s and redeveloped once in the 1950s. It was generally developed on 10-acre spacing (**Figure 6**) with several secondary disposal wells. The field produced 5 million barrels of oil from the original 78 wells with an average recovery of 5,700 bbls/acre. The main producing zone is the upper Dundee (“Rogers City”) which is a shallow-shelf carbonate, locally altered to porous, vugular dolomite by hydrothermal fluids. The field is situated on a plunging anticline, but the oil pool is primarily the result of an updip permeability barrier-type stratigraphic trap, sealed to the south by impervious limestone. The top seal is the Bell Shale. Reservoir pressure is maintained by a strong bottom-water drive and the original oil-water contact is projected at a subsea depth of –2950 feet. The maximum gross pay thickness was 55 feet.

The Geochemical Survey

Prior to drilling, a surface geochemical survey was run over the area (**Figure 7**) using several different geochemical techniques. A good anomaly was detected using microbial indicators. The surveys were conducted in several stages in May and August of 2000 and later in November as the well was being drilled. The survey locations are shown in **Figure 7**. The May survey was a line profile across Vernon Field parallel to Mission Road and was designed to test several geochemical methods. These included: surface iodine, enzyme leach on samples from the “B” soil horizon, head space gases from sample depths of about 36 inches, and microbial survey. Full descriptions and results from these surveys will be reported elsewhere. The results indicated that the microbial survey produced the best results, and was adopted for all subsequent surveys.

The May survey detected a positive microbial anomaly over

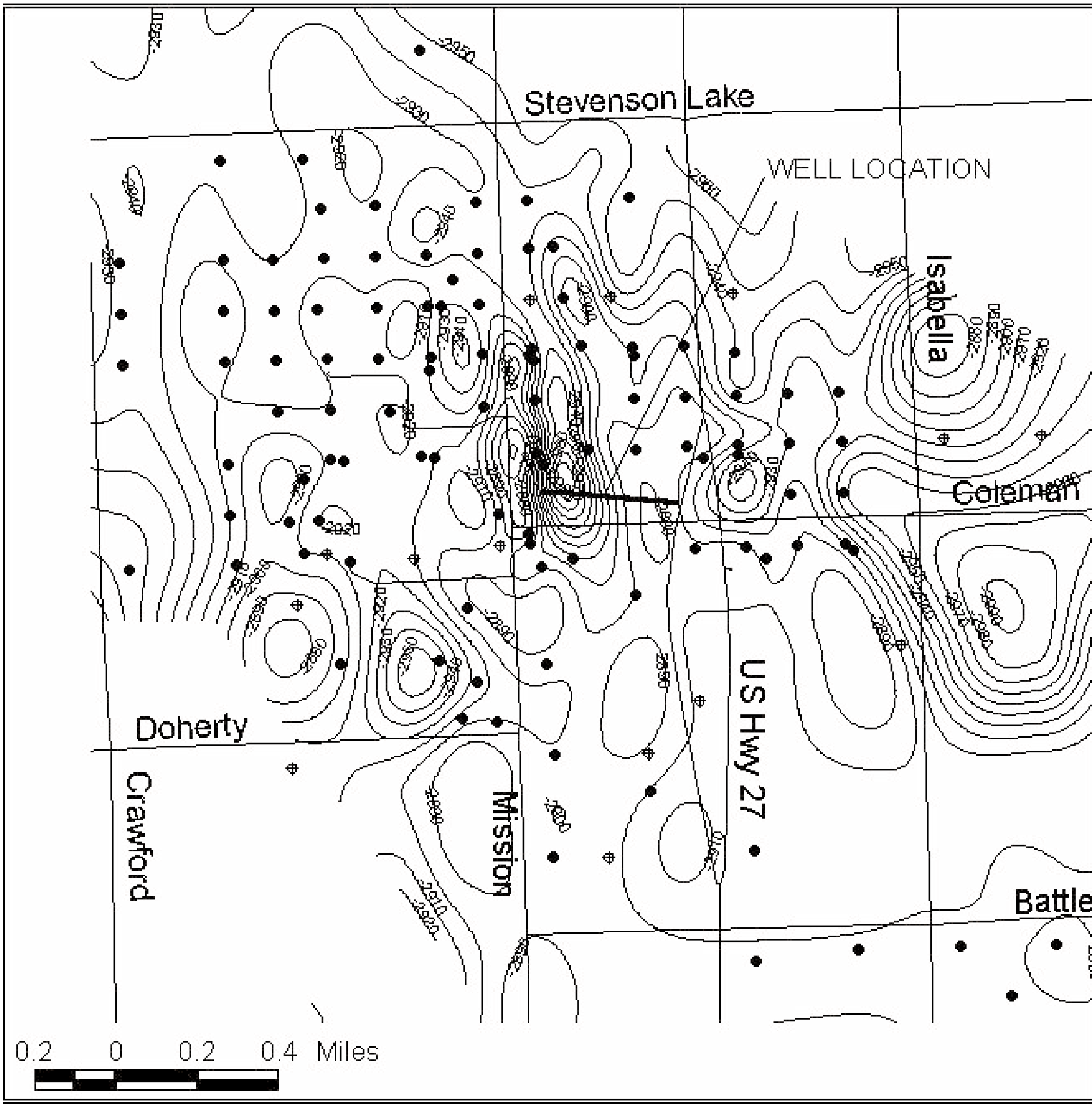

Figure 6 Location map showing existing oil wells at Vernon Field and location of project demonstation well. Contours on top of Dundee. Contour Interval=10 feet

the site of the proposed well, which was confirmed by both subsequent surveys.

The Demonstration Well: State Vernon & Smock #13-23

The demonstration well was sited to pass on a East-West line between a gap in the 10-acre pattern (**Figure 6**) based on subsurface geology and historical production from previous wells. The first lateral drilled as expected until the bit exited the curve and failed to penetrate either limestone or dolomite. Drilling continued for 751 feet until it was determined that the shale was too extensive and the bit was pulled back, repositioned to penetrate 9 feet deeper and to the SE of the first lateral. The second lateral penetrated carbonates as expected, including approximately 110 feet of good dolomitic reservoir.

Work is currently on going at the well to successfully isolate

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and produce the reservoir section of the second lateral. During initial testing, it has become evident that natural fracturing within the reservoir is contributing water production while bypassing recoverable oil reserves. In addition, it has been learned that extensive formation damage while drilling has resulted in a plugging of the pay section within the lateral. As such, plans to run 4.5" casing through the second lateral are now being contemplated, to effectively isolate the pay sections and effectively treat and produce them.

Summary-Lessons Learned

The State#1-Smock well has provided us with several lessons, the most important being that in drilling old fields like Vernon it pays to begin with a drilling program that includes a horizontal well with multi-laterals. In this case, the first lateral drilled encountered a shale plug that was avoided with the second lateral. A vertical well or a single-lateral horizontal well would not have been successful.

It has also been learned that natural fractures may have a key

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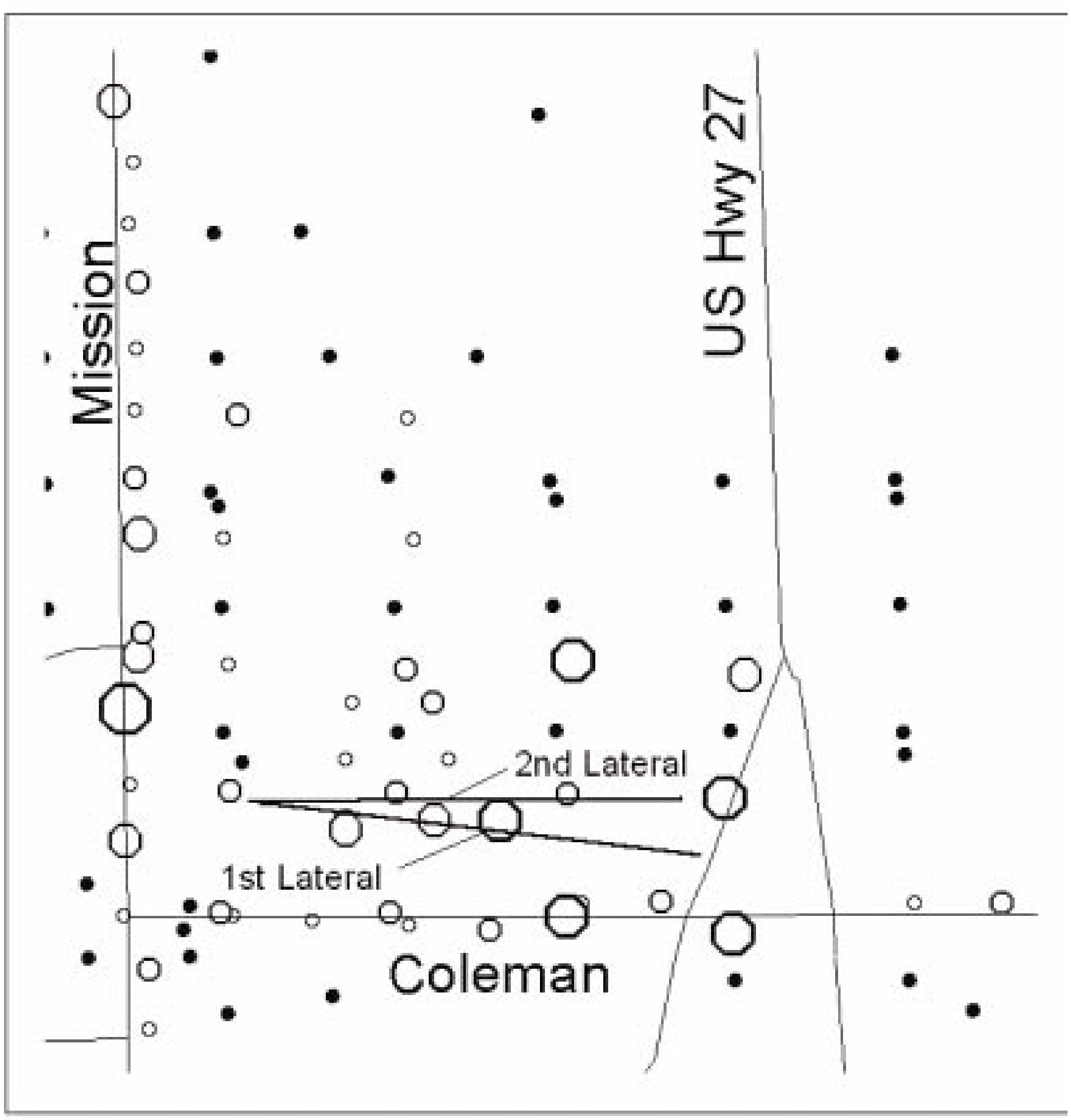

Figure 7 Locations of laterals for State #1 - Smock 23 HD wells at Vernon Field. Filled black circle are oil wells, open circles are microbial sample points. Size of open circles are proportional to geochemical signal.

Technology Developments with Independents

By Walt North, RMC-Consultants, Inc.

A second phase of the United States Department of Energy's Support to Independents Program announced by Energy Secretary Bill Richardson in February 1999 is showing positive and encouraging results. Although still early in the demonstration phase, several individual projects implemented through the program have provided sufficient results to indicate significant production enhancement-improvement benefits.

American Warrior, Inc. Garden City, KS

Reducing lease-operating costs will extend the economic producing life of the Schaben field by several thousands of barrels of oil. Once demonstrated, the technology will have potential application to numerous leases throughout the area.

Well operations at the Williams Unit in the Schaben field of Ness County, Kansas, were becoming uneconomic due to high electrical utility costs. The high lease production costs had already necessitated the shutting in of 3 wells on the lease and the 11 remaining wells were close to the breakeven point, with several pumping below normal efficiency because of the lack of funds available for repairs. Oil production is from the Mississippian Osage Formation at 4,400 feet, and the 11 producing wells in the Unit produce at high water-cut and marginal oil production, averaging 8.5 BOPD and 350 BWPD.

Figure 8 American Warrior — GEM Inc. designed high-slip and high-efficiency rewound electric motors which will buffer most of the cyclic loading of the motors.

A shallower gas zone in the Schaben field, the Chase Formation, is known to contain significant quantities of low BTU, low commercial value natural gas. The gas is unusable for commercial pipeline sales, because of a high N_2 content (50%).

Equipment manufacturers, CAT and Waukesha, have reviewed an analysis of the gas, and confirmed that it would be a satisfactory fuel source for a gas engine driven electrical generator. An existing temporarily abandoned oil well has been converted to a gas supply well to provide fuel for a gas powered electrical generator.

The operator will significantly reduce lease production costs by using the available onsite natural gas to power an electrical generator that will provide electricity to run the 12 beam pumping units and 2 electrical submersible pumps on the lease. The operator estimates a 65% reduction in electricity costs which will result in an operating cost savings of $9,675 per month. The reduced operating costs will allow resumed production on the 3 shut-in wells, and increased production on several of the other 11 wells.

Beam pumping units have a high cyclic power usage on electric motor prime movers, which is very hard on an electrical generator, usually requiring an oversized generator to compensate for the current peaks. High-slip, high-efficiency rewound electric motors were designed to buffer the cyclic loading (**Figure 8**). These electric motors will be installed as prime movers for the 12 conventional beam pumping units to minimize cyclic loading on the electrical generator. The use of the high-slip, high-efficiency rewound electric motors will allow electrical capacity for additional wells, increase the time between generator overhaul, and decrease sucker rod and gear box loading. The use of the rewound electric motors will result in cost savings of nearly $50,000 on purchase of a smaller electrical generator, and reduce fuel requirements from 200 mcf per day to 150 mcf per day.

St. James Oil Corporation, Laguna Hills, CA

Producing wells in the Los Angeles Downtown field in Los Angeles County, California, have strong scale forming tendencies. In the past, hydrochloric acid stimulation has been successfully applied to several of the wells in the field. The best results have been obtained using minimum volumes of low-strength hydrochloric acid for scale removal and perforation clean out. However, decline rates after stimulation have been relatively high and generally within six months to a year, production rates decline to pre-treatment rates.

Oil production from the 250-acre Los Angeles Downtown field is from the Upper Miocene Puente formation, turbidite sandstone. The Broadway zone of the Puente, composed of thinly interbedded sands and shales at 2,900-3,500 feet, was targeted for a new hydrochloric acid stimulation treatment used in conjunction with phosphonic acid for more effective, longer lasting cleaning of scale and small particles. The new acid treatment is designed to sustain the improved production response, which typically results from conventional hydrochloric acid treatments.

Four wells were selected for acid stimulation treatment using 10% hydrochloric acid in the first stage, followed by a second stage of lease water containing phosphonic acid and other protective additives (corrosion inhibitors, emulsion controllers, and anti-sludge agents). The phosphonic acid reacts with the aluminum in the clays and feldspars to form a temporary protective film, allowing deeper treatment penetration and more effective reaction from the hydrochloric acid which reacts with and eliminates migrating fine particles that interfere with oil movement into the wellbore. The phosphonic acid also inhibits the formation of calcium carbonate scale in the wellbore that otherwise decreases production efficiency.

Production from the first well treated went from 10 BOPD prior to treatment up gradually to a peak of 63 BOPD eight months after the stimulation treatment, then settling to 42 BOPD. The 2nd well's production went from 5 BOPD prior to treatment up initially to a peak of 28 BOPD, then settled to a rate of 21 BOPD two weeks after treatment. The 3rd well went from 32 BOPD to 55 BOPD following treatment, then settled to 44 BOPD one month after treatment. Production data is not yet available for the fourth well treated.

Preliminary review of the well production data indicates initial response to the treatments was very good and that early production remains considerably higher than pre-treatment rates. Time will show whether these modified acid stimulation chemicals will result in flatter decline rates by more effectively removing formation damage and scale accumulation.

Patriot Resources, LLC, Bakersfield, CA

The Mission-Visco Lease in the Cascade Oil field of Los Angeles County, California is 50 acres with an estimated OOIP of 14 million STBO. Cumulative oil production from the Cascade zone as of January 1999 was 2 million BO (65 BOPD from 7 wells), with 12 million STBO trapped in the faulted anticline.

The 2,300-3,000 ft deep Cascade zone, waterflooded since 1970, was evaluated for increased water injection to improve oil recovery. A secondary gas cap has formed in the up-dip portion of the reservoir with very low gas cap pressures of 15-25 psig; causing concern that oil could be displaced into the gas cap. Resaturating the gas cap with oil could result in the loss of recoverable oil. Therefore, injecting gas into the gas cap to keep the gas cap pressurized and restrict the influx of oil was an option. The reservoir geology in the gas cap area is very complex with folding and faulting and potential pressure barriers.

Because of concerns about the pattern of gas flow from well to well, the possibilities of cycling gas without the desired increased pressure, and the possible loss of oil displaced into the gas cap, reservoir simulation and modeling efforts were initiated using DOE's BOAST98, 3-D, black oil reservoir simulation package. Results from the reservoir characterization and simulation indicate considerably more faulting within the reservoir than originally thought. The additional faulting probably interferes with inter-well continuity and connectivity, resulting in large portions of the reservoir being poorly drained by the existing production-water injection well patterns.

Since the reservoir is a thick sand, the additional faulting is probably “sand-on-sand” and not detectable by conventional geological methods of analysis. Also, the downdip aquifer support appears to play a larger role in pressure maintenance than originally thought. Migration of water vertically from deeper, wet sections is probably minimal, and the original oil/water contact may be deeper than originally believed.

As a result of the modeling effort, there has been a significant change in the depletion planning strategy from a process improvement involving increased water injection down-dip with simultaneous gas injection up-dip to a program of infill drilling for further field development while relying on natural water influx from the aquifer for optimum oil recovery. Performance predictions from the simulation model indicate that by implementing infill drilling, reserves can be increased by the rate of 125,000 BO per well, and up to 10 infill wells could be drilled in the field. Field production rates could be increased two to three times over the current 65 BOPD.

MNA Enterprises LTD, Co., Hobbs, NM

Production from the 520-acre Shugart Queen Sand, Penasco Unit in Eddy County, New Mexico, is approaching the economic limit. Considerable reserves may be lost under the current reservoir management scenario, because of low oil production rates due to poor waterflood pattern development and low water injection rates.

The Penasco Unit has been waterflooded since 1974. Production from the 5 remaining producing wells on the lease is 100 BOPM (3.3 BOPD) and 300 BWPM (9.9 BWPD), and is approaching the economic limit. The Penasco Unit waterflood production has not responded as well as other Queen Sand units in the same area. The operator felt that the property had remaining waterflood oil potential, because the water injection program had been abruptly and seemingly prematurely discontinued by the previous operator.

A waterflood simulation study was initiated to help solve the declining production problem. The study consisted of a data acquisition and reservoir characterization phase, production history match using DOE's BOAST III reservoir simulation model, and performance predictions for different operating scenarios.

Artificial neural network technology was applied to correlate the older well logs, and mapping software was used to interpolate and map reservoir properties across the Unit. The maps were used to define the input parameters required for the reservoir simulation model used to history match the primary and secondary production history. The model results indicate that re-initiating water injection at 300 BWPD with the existing flood pattern could result in additional secondary oil recovery at a projected rate that would be economically attractive.

Model results indicate that realignment of the production-injection pattern by converting one existing producer to an injection well and converting one injector to a producing well would increase the waterflood sweep efficiency. At a water injection rate of 300 BWPD over a ten-year period, 36,000 incremental barrels of oil could be recovered. Adding a second producing well to the realigned flood pattern could result in the recovery of an additional 15,000 incremental barrels of oil. If water injection rates could be increased to 600 BWPD, the projected oil production rates could be doubled. A deeper, undeveloped interval, the Penrose zone, identified during the Queen sand log evaluation, also has primary and secondary recovery potential.

The study has provided valuable insight regarding restoring water injection, and remaining oil recovery possibilities, operational changes to realize the full secondary oil recovery potential. The study has resulted in considerable expansion of the Queen waterflood area, and has also identified the Penrose zone as an additional potential production source.

Multi-lateral

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role in the production of these carbonate reservoirs. Isolating productive regions from water-conductive fractures may be an important issue in recovering significant reserves. In addition, formation damage due to pulverized cuttings and drill pipe abrasion appears to be a prevalent issue within porous zones, even after relatively short periods of lateral drilling exposure.

An additional lesson is that geochemical surveys, particularly microbial, are worthwhile in these fields. They are relatively inexpensive and in this case appeared to provide reliable guides to the presence or absence of hydrocarbons.

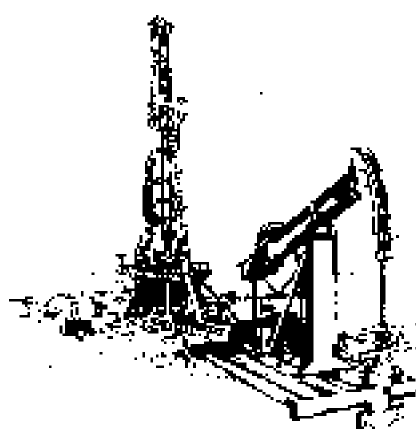
Finally, our knowledge of the state of the upper Dundee Formation greatly increased as a result of this exercise. We now feel that the top of the Dundee in the vicinity of the Vernon Field represents an exposed karst surface spotted with deep sinkholes filled with shale, perhaps similar to modern day topography around Tampa Florida.

Learnings

cont'd from page 3

tionship was used to calculate a porosity map. Values of porosity above 4% from one map were combined with porosity values below 4% from the second, to create a single map. This results in a porosity map that is on the same scale as a reservoir simulation. Each seismic porosity value represents a 110 x 110' bin. Each grid cell in the simulation is 120 x 120'.

The “Learnings” developed here are already being implemented in other properties and fields in the area. The Grayburg and San Andres reservoirs are major reservoirs in the Permian Basin and these learnings are applicable to most of the older waterfloods in the basin. There is significant potential for recovering incremental reserves and extending the lives of older fields by utilizing the learnings developed as a result of this DOE supported project.



The Class Act

The Class **Act** is a biannual newsletter devoted to providing information about DOE's Reservoir Class Program.

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If you have a project that you would like to preview in an issue of The Class Act please contact Viola Rawn-Schatzinger.

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C A L E N D A R

Meetings and Announcements

AAPG Southwest Section, Dallas, TX, March 10-13, 2001.

TORP 14th Oil Recovery Conference, Wichita, KS, March 14-15, 2001.

AAPG Pacific Section, Universal City, CA, April 9-11, 2001.

Offshore Technology Conference, Houston, TX, April 30-May 3, 2001.

AAPG Annual Meeting, Denver, CO, June 3-6, 2001.

Professional Well Log Analysts (SPWLA), June 17-20, 2001.

National Petroleum Technology Office joins the National Energy Technology Laboratory

On November 1, 2000, the U.S. Department of Energy's primary field office for petroleum technology in Tulsa, Oklahoma, became part of the agency's national laboratory complex as an arm of the recently created National Energy Technology Laboratory. Energy Secretary, Bill Richardson made the announcement on November 1st. Richardson said he was taking the action to "elevate the status of department's petroleum research program."

> *"The future of our domestic petroleum industry will be determined largely by technology, and it is important that we streamline the coordination throughout our research complex in developing advances that can benefit our domestic producers,"* Richardson said.

Previously, the Tulsa office, the **National Petroleum Technology Office (NPTO)** operated as a separate part of the Energy Department's Fossil Energy organization. With the new change in reporting relationships, the office will report to the **National Energy Technology Laboratory (NETL)** located in Morgantown, WV, and Pittsburgh, PA. NETL was designated last December by Richardson as the nation's 15th national laboratory and is the Energy Department's primary fossil fuel research center. Part of its organization includes a new Strategic Center for Natural Gas, which will oversee a wide range of natural gas related activities.

The 26 employees at NPTO will remain in Tulsa and will continue to be the lead site for coordinating the Energy Department's oil technology program. Integrating the petroleum office into the National Energy Technology Laboratory also will give petroleum specialists in Tulsa more immediate access to the Laboratory's onsite research facilities and its research support capabilities.

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