TITLE: ECONOMIC RECOVERY OF OIL TRAPPED AT FAN MARGINS USING HIGH-ANGLE WELLS AND MULTIPLE HYDRAULIC FRACTURES

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Objective

This project attempts to demonstrate the effectiveness of exploiting thin, layered, low-energy, deposits at the distal margin of a prograding turbidite complex through use of fractured horizontal or high-angle wells. The combination of hydraulic fracturing and horizontal drilling will allow greater pay exposure than conventional vertical wells while maintaining vertical communication between thin interbedded layers and the wellbore.

A high-angle well will be drilled in the fan margin portion of a slope-basin clastic reservoir and will be completed with multiple hydraulic fracture treatments. Geologic modeling, reservoir characterization, and fine-grid reservoir simulation will be used to select the well location and orientation. Design parameters for hydraulic fracture treatments will be determined by fracturing an existing test well. Fracture azimuth will be predicted, in part, by passive seismic monitoring from an offset well during fracture stimulation of the test wellbore.

Summary of Technical Progress

An existing vertical well in the Yowlumne Field, Kern Co., California was hydraulically fractured. Microseismic and pressure data collected from this work are being used to predict fracture geometry and azimuth for future treatments in the proposed high-angle well.

A detailed reservoir characterization of the field demonstration site is complete. This work includes interpretation of a 3-D seismic survey, analysis of all available well logs, description of three whole cores, petrographic analysis of thin sections and incorporation of pressure and production data.

A partial-field fine-grid model based on the reservoir characterization has been constructed and initialized. Efforts to history match the model to actual production and pressure data are underway.

Fracture Characterization

Field operations associated with characterizing and designing hydraulic fracture treatments for the high-angle well are complete. This work includes fracturing a producing well, YUB 84-32, and monitoring the resulting microseismic events in a neighboring wellbore, YUB 86-32.

Both an unpropped mini-frac and a propped fracture treatment were pumped in YUB 84-32 to estimate fracture azimuth, fracture geometry and other relevant design parameters. During these treatments, microseismic events were passively

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monitored in YUB 86-32 using a clamped three-component geophone. Distance and direction of microseismic events generated by propagating the fracture were estimated from the difference in arrival times of P and S waves and by polarization of the P wave. This work represents one of the deepest (13000') and most widely spaced (1300' from wellbore to wellbore) tests of microseismic logging. Despite less than ideal subsurface conditions (Fig. 1), numerous events were detected during both treatments and are currently being analyzed to determine fracture azimuth.

Fluid pumped during the mini-frac treatment was tagged with a radioactive isotope. Temperature and gamma ray logs run immediately following the treatment indicated nearly all fluid exited the wellbore within a 40 ft section of the 200 ft reservoir interval. Therefore, only a small portion of the gross vertical section appears to have been stimulated. However it should be noted that an interpretation based only on log data potentially underestimates the vertical extent of the fracture, since the fracture possibly grew in a different vertical plane than the north-south plane containing the deviated wellbore and therefore the fracture may not have intersected the well over its entire height. Nonetheless, pressure data tended to agree with log results and indicated the fracture was confined to a 35 to 40 ft interval.

Pressure data were also used to infer other common treatment design parameters such as fracture gradient and leakoff coefficient. Interpretation of pressure decline data from the mini-frac suggested a very high fracture gradient, 1.05 psi/ft, as well as a very high leakoff coefficient, 0.014 ft/min^{1/2}. The high frac gradient was assumed to be due to local compressional forces, while the elevated leakoff coefficient was thought to be due to possible microfractures. Despite these adverse reservoir conditions, field operations continued forward and the propped frac was successfully pumped to completion. Results from the propped frac generally corroborated the mini-frac interpretation (Fig. 2).

Reservoir Characterization

Characterization of the fan margin area surrounding the expected well site is complete. This work includes description of three cores, petrographic analysis of 47 thin sections, modification of an existing petrophysical model, reinterpretation and refinement of hydraulic flow units, calculation of zonal averages, mapping of reservoir properties and volumetric analysis of the project area.

Descriptions of over 280 ft of core taken from YUB 22X-3, 14X-3RD and 46X-34 were completed by faculty and graduate students from the University of California-Santa Barbara (UCSB). The descriptions include observations of sedimentological characteristics, correlations to the Bouma¹ vertical sequence, and identification of Mutti and Ricci Lucchi² turbidite facies. The descriptions also include comparison of lithofacies to log response to aid in identifying rock types from logs.

Petrographic analyses of thin sections were also completed by UCSB. This work helped to qualitatively describe the reservoir's effective porosity, detrital mineralogy and secondary mineralogy. Findings indicate that the effective porosity results primarily from the compaction of original depositional porosity with only subtle diagenetic alteration. Additionally no significant stratigraphic or lateral variation in mineralogy could be identified except for an isolated chert cemented zone located near the top of the reservoir interval.

Review and modification of an existing petrophysical model have also been completed. Data from three cores were used to evaluate the accuracy of the log model in estimating shale volume, porosity, water saturation and permeability for the fan margin. In general, the model adequately represents most rock properties. However several modifications were needed to improve correlation between core and log permeabilities.

Following modification of the log model, hydraulic flow unit correlations were reinterpreted for the project area. Flow units were identified primarily from log response, production and injection profiles, and RFT pressure measurements. Ten flow units were correlated within the project area (Fig. 3).

Reservoir property averages were then determined for each flow unit for 32 wells in the project area. Only intervals meeting net sand criteria ($V_{sh} < 0.30$, $\phi_{eff} > 0.08$) were included in the averages. Zonal averages were then mapped over the entire project area. Sand edges, as interpreted from a 3-D seismic survey, were used to constrain mapping algorithms.

Volumetric analysis of the mapped project area was also completed. Based on this work, original fluids in place are estimated to be:

- OOIP 74.3 MMBO
- OGIP 44.7 MMCF (solution gas)
- OWIP 63.0 MMBO.

The OOIP determined for the project area represents approximately 31% of the total field original oil in place.

Reservoir Modeling

A fine-grid 3-D model was constructed and initialized using the fan margin reservoir description. Efforts to match model performance to historical primary and waterflood pressure and production data are underway.

A fine-grid 34 X 34 X 10 model lattice has been constructed for the project area (Fig. 4). Within the lattice, each flow unit is represented by an individual layer, and areal boundaries are defined to correspond with the eastern sand edge and three approximate no-flow boundaries, as determined from streamline models. Areal cell sizes are designed to provide at least six cell interfaces between adjacent injectors and producers.

Model saturation and fluid properties are based on experimental data from the project area. These data include black oil fluid studies, unsteady state water-oil and gas-oil relative permeability tests and air-brine porous plate capillary pressure measurements.

Model rock properties, except for initial fluid saturations, are drawn directly from the reservoir description. In order to prevent equilibration problems, initial fluid saturations are estimated in the model using fluid contacts and a J-function based on experimental capillary pressure data.

Following construction of the model lattice and compilation of basic reservoir data, the model was initialized and fluid volumes compared to integrated map volumes. No model adjustments were needed to match the mapped volumes.

Having completed model initialization, work was begun to history match the model to actual field performance. Within the model, oil production rates and water injection rates are explicitly specified. The model will be adjusted to match water and gas production rates, average reservoir pressures and producing bottomhole pressures.

Early history match efforts indicate that despite the model's fine grid, numerical dispersion still impacts performance, as model water-oil-ratios are significantly higher than actual WOR's. Water-oil relative permeability curves will be altered to offset dispersion effects³. Additional history match adjustments will potentially include:

- boundary flux curves which will be estimated from a history matched full field model
- adjustment of well completion skins to match producing BHP's.

After completing an approximate history match, ARCO intends to apply local grid refinement to the immediate area surrounding the proposed high-angle well. Once a nested grid is included in the model, the solution method will be switched from IMPES to fully implicit. The history match will then be updated for the altered grid and solution technique. The model will then be used to predict performance of the high-angle well.

Technology Transfer

Project objectives and preliminary results were presented at a well stimulation forum held in Girdwood, Alaska during the week of March 11-15. The forum was hosted by ARCO Alaska Inc. and was attended by representatives from over 20 companies and universities.

Work is currently underway to establish an "open file" with the California Division of Oil, Gas and Geothermal Resources. The file will be available to the general public through the DOGGR.

References

1. Bouma, A. H., *Sedimentology of Some Flysch Deposits: A Graphic Approach to Facies Identification*, Elsevier, Amsterdam, 1962.
2. Mutti, E. and Ricci Lucchi, F., *Turbidite Facies and Facies Associations, Examples of Turbidite Facies and Facies Associations from Selected Formations - Northern Apennines: 9th International Congress of Sedimentology, Nice, 21-36, 1975.*
3. Mattax, C. C. and Dalton, R. L., *Reservoir Simulation*, Monograph Series, SPE, Richardson, TX, (1990)-13, 51-53.

Fig. 1 N-S cross-section through test and monitor wells

Fig. 2 G function plot of YUB 84-32 pressure decline

Fig. 3 Yowlumne flow units with 27X-34 Vsh curve

Fig. 4 34 X 34 model grid covering the project area

Fig. 1 N-S cross-section through test and monitor wells

YUB 84-32 Pressure Decline G Function Plot

Fig. 2 G function plot for YUB 84-32 pressure decline

YUB 27X-34

Fig. 3 Yowlumne sand flow units with 27X-34 Vsh curve

Model "YOWLUNNE"
 Grid "NXX" Layer "STRUCTUR"
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