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

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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 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.

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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 Results

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 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 relationship 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.

For more information on Class Program projects, contact Herb Tiedemann at DOE's National Petroleum Technology Office:

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

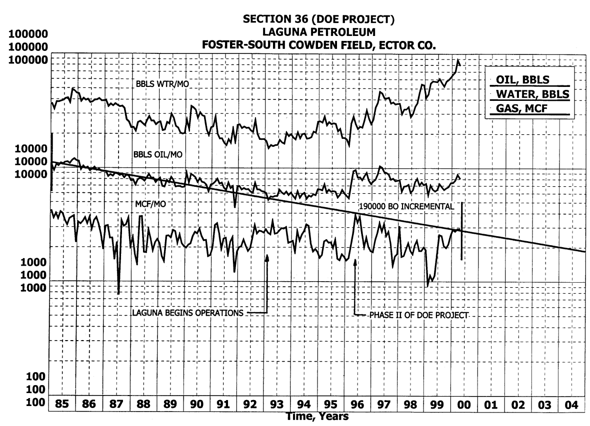

Figure 2. Production plot showing the original decline curve and the extended life of the reservoir.