Minimizing Formation Damage to Maximize Well Productivity
Final Report- Abstract

Information supplied by the Oklahoma Geological Survey and Dwights Energy Data indicates the Mocane-Laverne gas area has produced a cumulative 2.347 TCFG to date from the Morrow formation. A total of 890 wells are currently producing from the Morrow formation in the Mocane-Laverne gas area. In 1994, 95 BCFG was produced from the area with a large portion of the production coming from Morrow reservoirs.

In 1995 approximately 50 Morrow wells were completed, and it is believed that most of the Morrow completions will need to be stimulated. Production reports indicate that some of the better Morrow wells reach an average of 150 MMCFG per year over 10 to 30 years of production, while other wells may only produce an average of 30 MMCFG per year during the first 2 to 3 years of the well's life. A majority of these wells have undergone hydraulic fracturing, and many have been acidized to stimulate lagging production.

Current typical fracturing treatments for the Morrow formation in the Mocane-Laverne gas area place between 50,000 and 60,000 lb of 20/40 Ottawa sand in 40,000 gal of fluid (typically foams) at concentrations up to 11 lb/gal down tubing and up to 6 lb/gal down casing. This study will evaluate the commonly recommended fracturing and stimulation treatments for the Morrow formation in the Mocane-Laverne gas area. Analysis of historical data and laboratory testing will be used to predict the impact of various treatments upon productivity, thus allowing the selection of fluids, proppants and designs that will optimize production in future completion and stimulation programs.

The conclusions of the study, however, have shown that the stimulation treatment details have only a secondary effect on the ultimate recovery from the well. The average well penetrates and drains a reservoir of 100 to 200 acres. The effectiveness of the stimulation treatment is seen in the first 3 years of the well's productive life. A longer period (20-30 years) of low pressure, low rate gas production is required to maximize recovery. Because these wells also produce condensate, production practices and management of wellbore fluids are the dominant features controlling long term production rate.

Minimizing Formation Damage to Maximize Well Productivity
Final Report- Executive Summary

The Mocane-Laverne Gas Area is located in northwest Oklahoma and the Oklahoma Panhandle in Beaver, Harper and Ellis counties. Additional analysis was performed on core samples and cuttings from the Morrow Formation in wells located in Blaine County. Regionally, the Mocane-Laverne area is located along the northern shelf of the Anadarko basin where fluvial-deltaic and shallow marine deposits accumulated during the Lower Pennsylvanian. Morrow production in this area is primarily from fluvial-deltaic, estuarine and shallow marine deposits. The depth of the Morrow sands in the study area ranges from 6,000 to 9,000 feet.

Visual, petrographic and SEM examination of cores from wells in the study area resulted in the definition of four major sandstone reservoir lithologies. Samples are grouped into either a marine or fluvial-deltaic origin and then subdivided into two reservoir types each. Reservoir quality is directly related to depositional environment in the Morrow wells examined. The fluvial-deltaic deposits are much more permeable than those deposited in the marine environment. Well-developed natural fractures were a common occurrence in the marine intervals.

The analysis of the historic completion and production characteristics of the Morrow producers in the Mocane-Laverne field was conducted to determine if there is a statistical difference in the performance of wells treated with different stimulation procedures. Surprisingly, over 50% of the wells completed only in the Morrow have less than 0.5 bcf of gas production and the large majority of the wells produce less than 20,000 BO. Wells producing more than 5 bcf gas are extremely rare. There are a large number of wells that are approximately 10 years old as well as a number of wells originally completed in the 60's that are still producing at low rates. In field drilling continues today.

The typical production profile is a first month average gas rate over 1 mmcfd and rapidly declining to 100-300 mcfd after 3 years. Many wells then produce at that rate for up to 30 years. Liquid loading is often a significant problem during this period and the wells are difficult to keep producing.

No conclusions could be drawn about the optimum stimulation fluid from the statistical analysis of the production data. Furthermore, natural producers and hydraulically fractured wells have similar decline curves. This suggests that there are reservoir characteristics that are the primary factor controlling production, not the completion practices.

Because of the difficulty in drawing general conclusions, two areas were selected for detailed study, the South Logan Field in Beaver county, which is low permeability, hydraulically fractured as well as high permeability, fluvial gas producers in Blaine county were studied.

The South Logan Field is located on the Beaver County border in the Oklahoma Panhandle. A number of successful completions have been completed in the field. A wide variety of treatment types were utilized from 1958 to the present. All of the wells were fracture stimulated and a number of wells were re-fractured.

The wells had similar production characteristics as those seen in the database of Mocane-Laverne completions. There were a number of anomalous production examples and many of the wells have severe decline curves, which was one of the key problems we wished to address in this study.

The M2 sand interval in South Logan field is composed of a series of three to six multistory sand lobes. The individual lobes are typically ten to fifteen feet thick, but may get up to 20 feet in thickness. Individual lobes may fine upwards, while others in the same well may coarsen upwards. Some sand lobes pinch out laterally between adjacent wells. Characteristic of the M2 interval is resistivity values ranging between 10 and 20 ohms, with the exception of the uppermost sand lobe which usually has a resistivity value of around 40 ohms.

Although core was not available for examination, several cores were taken in the field and a brief description of lithology was located. The sands were described as fine to very fine grained with abundant glauconite, clays and clay streaks, calcite cement and fossil grains. One core was described as very highly fractured. The description of mineralogy for the Lower Morrow M2 interval suggests the sands were deposited in a marine environment. Log characteristics and mineralogical constituents are consistent with the Type 2 reservoir described in section 1 of this report.

The M2 structure in South Logan field is relatively uncomplicated. Regional dip is less than 1 degree to the south-southeast. Structural closure is only observed along an east-northeast striking fault located in the west half of the field. The M2 sands are multistory, composed of three to six stacked lobes that are not necessarily continuous from well to well. Thickness of the M2 sand ranges from 40 to 110 feet.

The Logan Field completions analysis shows that the drainage area associated with the compartments penetrated by the wellbore is the primary factor that will ultimately dictate cumulative recovery from any wellbore. This appears to be the reason that no individual wellbore has produced more that 2 bcf in this area.

The production records indicate there are significant problems in maintaining production rates. All the wells produce variable amounts of condensate. Since the reservoir pressure is rapidly reduced, the condensate dropout reduces gas permeability, and liquids loading makes consistent production difficult.

The re-fracs conducted in the area suggest that fracture length is not a primary factor in controlling production. After a well has been partially depleted, the fracture treatment is confined primarily to the pressure depleted zones, and therefore fracture length will be significantly longer from the re-frac. Even short fractures eventually drain the compartment and after 3-5 years, there appears to be little benefit from longer fracture length. The data shows that in field drilling on 160 acre spacing will counter depletion in a significant number of wells while at least 50% of the wells will still exhibit close to native reservoir pressure. The better the stimulation, the faster the initial recovery. However, there will still be a significant period of production at low rates to maximize recovery.

The Rambler Oil Company Cravens Estate in Blaine Co. was cored and log correlations suggest that it is in the same general channel development as two more wells 3 miles to the south/southwest where we had detailed completion and production information that could help characterize the factors responsible for the production characteristics seen in natural completions in the Morrow. The measured permeability is exceptionally good in the upper lobe averaging well over 200 md. Even the lower quality rock in the second lobe has 50 md permeability.

This study was the major factor confirming that compartment size is the dominant feature controlling production in Morrow completions. These wells were produced at a drawdown of 100-300 psi under the reservoir pressure as confirmed by periodic shut-ins. As the reservoir pressure dropped, the condensate yield decreased and the permeability to gas was reduced. Surprisingly, the loss in gas permeability had a limited impact on production rate in these limited reservoirs because depletion is so dominant in determining the gas rate. If the production rate had not been limited to a low drawdown, the permeability loss due to excess condensate dropout could have become a dominant factor controlling production.

The initial examination of the production data for the Mocane-Laverne Field showed that a major amount of the reserves in successful completions were recovered over a long period of time at low production rates. Anomalous changes in production often occurred. We had hypothesized that the reservoir might have very adverse relative permeability and capillary pressure properties, which accentuated the production problems that are caused by condensate dropout that occurs in condensate reservoirs.

The samples that were above the threshold permeability of about 0.1 md showed a low capillary pressure threshold and desaturated to very low water saturations indicating that the pore throats do not contain high levels of clay that will retain water. The other case where water is not mobile was observed in micro-darcy permeability samples. The question thus remains whether this type of porosity contributes to production. In the South Logan field study, frac treatments with reduced reservoir pressure did not appear to show adverse saturation effects and therefore this type of rock does not appear to be a major contribution to production. In addition, oil based stimulation treatments captured in the database do not show superior performance, also suggesting that rock with these characteristics does not appear to be a major source of gas production at least in the areas we have studied in detail. It is possible that there are areas that have traditionally been poor producers where this type of rock predominates and a change of stimulation practices to non-aqueous fluids would improve production. An independent study elsewhere in the Morrow has concluded that the low resistivity porosity does not contribute to production with current completion practices.

The imbibition relative permeability studies were conducted to study what might happen during resaturation. The data shows that a high trapped gas saturation will exist in the flooded rock, thus limiting resaturation, and at the same time should have gas permeability for drainage once the well is back on production. This does look like a case where one would expect severe water or oil blocks to limit production. Therefore, we have concluded from these data that there are no special properties associated with these core which will promote a fluid sensitivity problem.

A literature review was conducted before embarking on a detailed simulation of production characteristics in gas condensate reservoirs. Two recent SPE papers were found which describe the simulation method in detail and addresses the key issue that we hoped to answer with the simulator. That is, there are operational controls on production rate that can optimize the net recovery of hydrocarbon.

One of the key factors appears to be the interfacial tension between the gas and condensate. The Morrow production is even more complex because some wells also have oil saturation at discovery. When the gas flow rate is too low, condensate is not effectively lifted in the wellbore and remains in the reservoir. As the reservoir pressure drops below the dew point, condensate begins to drop out in the pressure-depleted zone. A high GOR is the natural consequence in both cases.

Monitoring GOR is a key way to optimize production. Any production practice that causes GOR to increase should be avoided. Optimum long-term production will occur from treating these wells as oil wells. Production histories in the Morrow show that a sharp increase in GOR is quickly followed by a precipitous drop in gas rate.

A series of tests were conducted to examine the effect of selection of stimulation fluid on the returned permeability of both the proppant pack and reservoir. The data showed similar returned permeability for high pH, crosslinked borate nitrogen foam and zirconate crosslinked CO_2 foams. This information confirmed the production data analysis that showed no clear preference for any particular type of treating fluid. Surprising, the core was very stable to different brine. In fact, all lithologies showed no damage to fresh water. All factors, relative permeability, brine insensitivity, and good return permeability of reservoir samples exposed to fracturing fluids suggest that type of fluid selected will have a minimum impact on ultimate recovery.

It is a general consensus that a standing level of water or oil in the wellbore reduces gas production due to the backpressure created on the sand face. This is not considered to be important early in the life of the well when the reservoir pressure is high. Later in the life of the well, the fluid level provides enough backpressure to reduce the gas flow rate to a value that does not efficiently remove liquids and then the well logs off.

Standard practice in gas well completions is to set the tubing some distance above the upper most perforations. This makes it highly likely that there are liquids in contact with some if not all perforations and thus raises the question about the saturation effects on the proppant pack and formation face.

A series of laboratory tests were conducted with a large Plexiglas model with approximately 3 lb sand/ft^2 proppant. Both gas and water were flowed into the model and the standing level of water in the simulated wellbore was controlled by the tubing height. The data showed that the permeability to gas could be reduced by up to 50% in this 4 ft high model due to having the water level over the perforations.

These studies confirm the hypothesis that a standing level of fluid in the wellbore can have a more adverse impact on gas production than would be predicted by the additional backpressure. Operationally this suggests that the standard operational practice of placing the tubing above the perforations needs to be abandoned in favor of placing the tubing below the perforations.