Pilot Capillary Surfactant-Injection System in the San Juan Basin

Depletion of San Juan basin reservoirs is causing production rates to drop below the rate required for the minimum critical velocity (MCV) in a large number of wells. Traditional methods used to remedy this situation include plunger lift, pumping units, foam lift, and recirculation. With declining reservoir pressures, plunger lift and recirculation become less effective, and often the expense of purchasing and operating a pumping unit cannot be justified. In some cases, surfactant injection may offer the most cost-effective fluid-removal method.

Introduction

As gas reservoir pressures are depleted and production rates decline, liquid loading becomes a problem. When flow rates fall below the MCV, liquid accumulates in the wellbore, causing additional backpressure on the formation that reduces production rates. A downhole capillary surfactant-injection system (DCSIS) has been shown to aid in removing these fluids. The DCSIS delivers surfactant directly to the bottom of the wellbore where it is needed to be effective. A stainless-steel capillary-tubing string is run in the wellbore and is attached to a fluid pump and a chemical-storage tank. Once installed, a metered amount of surfactant is injected downhole to help unload the well.

Promising results were seen from installation of a DCSIS on a slimhole well in the San Juan basin. A 10-well pilot was proposed to test the system. Initial criteria for the pilot required that a well be experiencing liquid loading and that all other artificial-lift methods had been ineffective or were uneconomic. The primary objective of the pilot was to determine the best applications for the system in the San Juan basin.

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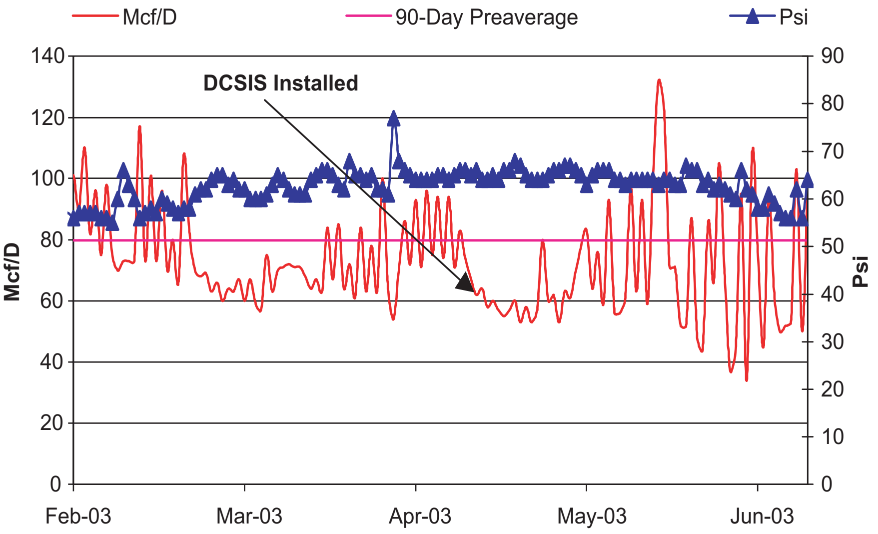

Fig. 1—Gas production for a well with more condensate than water in the produced fluids.

Foam Flow

Surfactant injection reduces density, gas slippage, and surface tension of the liquid/surfactant mixture. Most attempts to model the MCV required to lift foam to the surface are based on the Turner model, which is based on drop-entrainment mechanics. The Turner model calculates the velocity required to lift the largest liquid droplet to the surface. This velocity is a function of the liquid-drop density and diameter, gas-phase density, drag coefficient, and acceleration resulting from gravity.

Typical values for surface tension and liquid density are 60 dynes/cm and 67 lbm/ft^3, respectively. However, proper surfactant treatment can lower the surface tension to less than 40 dynes/cm and also reduce the density significantly. Because the Turner model is based on the physical properties of a water droplet, some assumptions made by Turner probably are not valid for foam flow.

Preliminary and published data indicate that wells can lift foam at a much lower velocity than that required for water. One question is whether this decrease in MCV is a function of gas slippage or of greater agitation in the liquid/foam mixture. Gas slippage is reduced with foam flow, thus helping to generate a homogeneous single-phase fluid throughout the wellbore. Greater velocities may help generate more foam, and the force generated by the pressure differential between the bottomhole pressure and surface pressure lifts this foam to surface.

Equipment

The DCSIS combines standard surfactant-injection components with a capillary-tubing string. The required components

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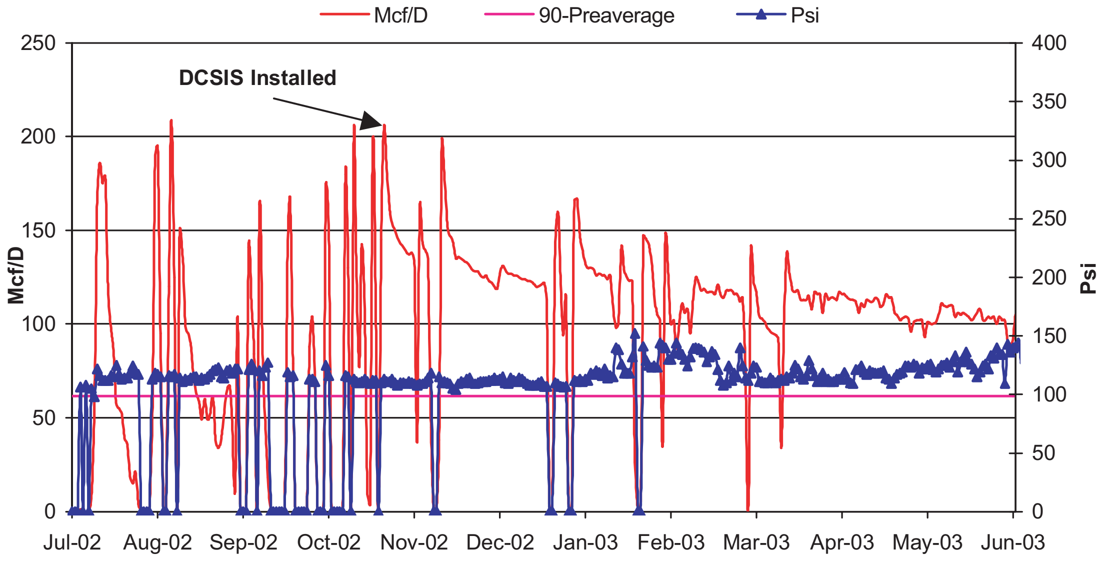

Fig. 2—Gas production for a well with a high PI and well potential.

are a surface tank, stand, fluid pump, and a capillary string with an atomizer bottomhole assembly for injection purposes. The capillary-tubing string is run in the wellbore and is attached to the fluid pump and the chemical-storage tank. The capillary string can be run inside or outside the tubing.

Criteria Identification

Factor Identification. The primary objective of the pilot was to establish better criteria for future installations. To accomplish this, it was necessary to analyze the positive and negative responses of the installation and identify the factors that led to each response. Multivariable regression analysis was used to determine the most important factors affecting the percent increase in production. The results from the model can be used to aid in candidate selection for future installations. Percent increase in production was determined using the 90-day preinstallation production average compared with the 90-day post-installation production average.

The factors that appeared to affect the response variable in the pilot wells were water/condensate ratio, productivity index (PI) and well potential, compression limitations, and tubing position in the perforated interval. These factors were identified by analyzing the positive and negative responses to the DCSIS and determining the characteristics that led to each response.

Water/Condensate Ratio. The first factor affecting the percent increase in production was the water/condensate ratio. The wells that produced more condensate than water did not experience positive results from installation of the system. **Fig. 1** shows production data for a well that did not respond in a positive manner because the liquid hydrocarbons prevented proper foaming action. The produced fluid was approximately 60% liquid hydrocarbons. A blender test performed on the produced liquid to determine surfactant concentration required for foaming found that even at high surfactant concentrations, minimal foaming occurred.

PI and Well Potential. The next factors influencing the percent production increase are PI and well potential. The wells that showed significant lift potential when unloaded with surfactant and were in an area of high deliverability experienced better results from installation of the system than the wells that did not meet these criteria. **Fig. 2** shows a production plot for a slimhole well that met these criteria. Large production spikes can be seen in the plot before the system installation, indicating periods when the well was unloaded. The well also appears to be underperforming. The combination of these factors suggested that the well had significant potential when unloaded. The well began receiving batch treatments of surfactant, and a positive response was observed. After the DCSIS was installed, production increased to approximately 99% more than in the 3-month presurfactant testing period shown in Fig. 2.

Compressor Limitations. In the cases where wells were producing with compression, any compression limitations appeared to affect the percent increase in production. Two types of compression limitations were encountered. First, adequate compressor horsepower must be available for an increase in production. Second, the compressor and other surface equipment must be free from any problems that would limit production. The compressor began overheating during the summer months, causing regular compressor downtime. A better cooling system was installed, which decreased compressor downtime and increased available horsepower. Near the end of the 90-day post-installation evaluation period, the well was producing approximately 55 Mcf/D more than its preinstallation 90-day average.

Tubing Position. It appears that wells responded better when the tubing was landed above the bottom perforation. The capillary string and $^{3}/_{4}$-in.-diameter atomizer were landed in the $1^{1}/_{4}$-in. tubing. The capillary string was landed inside the tubing because the tubing was landed below the bottom perforation. The belief was that if the capillary string was landed outside of the tubing below the perforations, there would not be sufficient agitation to cause proper foaming action.

Initially, the overall volumes from the well decreased after DCSIS installation. However, the well did not log up. Then, the well was produced up the annular space between the $1^{1}/_{4}$-in. tubing and the $2^{7}/_{8}$-in. casing. Before installation of the injection system, the well logged up on a regular basis. Since installation of the injection system, the well has not logged up completely even though the surface flowing pressure (pipeline pressure) has increased. Production has increased approximately 28% since injection-system installation.

Factor Effects/Advanced Criteria

Of the four factors that affected percent production increase, compression limitations were the most significant, the water/condensate ratio has the next most significant effect, PI and well potential were the third most significant, and tubing position within the perforated interval had the least effect. It should be noted that the model is valid only for the range of operating conditions initially considered, and caution must be taken when extrapolating beyond the region containing the original observations.

Backpressure on the formation, whether from liquids or a surface restriction, limits well production. The significant effect of the compression-limitations factor demonstrates the importance of performing a total system review before installation of any artificial-lift system. Often, more than one factor limits well production. Each individual factor should be identified and resolved before installing a DCSIS.

The effect of the water/condensate ratio factor shows the importance of properly analyzing the fluid before DCSIS installation. It is recommended that a blender test be performed on the produced fluids to determine fluid/surfactant compatibility before installing a DCSIS. If a compatible surfactant cannot be found, a different artificial-lift system should be considered to remove wellbore fluids.

Wells should show significant lift potential when unloaded with surfactant by exhibiting large production spikes (40 Mcf/D above average) and be in an area of high deliverability before installing the DCSIS. A simplistic form of Darcy's law for gas wells demonstrates that the greater the well permeability, the greater the response in production that will be seen from reducing the flowing pressure. Removing fluids from the wellbore reduces the flowing pressure. This relationship indicates that wells with greater productivity, a function of permeability, are better candidates for installation of any artificial-lift system, including the DCSIS.

It is believed that if the capillary string is installed in a well where the tubing is landed below the perforated interval, there will not be sufficient agitation to cause proper foaming action. It is recommended that the DCSIS not be installed in wellbores where the tubing is landed below the bottom perforation.

Conclusions

1. The positive results from the initial DCSIS installations suggest that the system has significant potential for removing fluids from certain wells in the San Juan basin.
2. The significantly better results from the wells meeting the advanced criteria suggest that the advanced criteria should be used for future installations.
3. An order-of-magnitude reduction in MCV was observed when proper foaming action occurred.
4. The modified Turner equation seems to provide a reasonable estimate of MCV for foam flow.
5. Each well should be batch treated with surfactant before installing the DCSIS to determine if the proper conditions are present to generate foam flow.
6. Future installations in the San Juan basin should be in wells producing more water than liquid hydrocarbons. JPT