OPERATIONAL CHANGES AT BLOCK 31 DEVONIAN UNIT CRANE COUNTY, TEXAS

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ABSTRACT

Several operational changes have taken place at Block 31 to reduce operating costs and increase revenue. The most significant change has been the utilization of waste heat for treating oil emulsions. This has resulted in increased gas sales by reducing fuel gas requirements, a reduction in operating costs, and the elimination of a potential safety hazard. Computerized test equipment has been installed to provide more accurate testing, which in turn has provided improved data to assist in the management of the reservoir. A plunger gas lift system is being used to improve lift efficiency and to reduce operating costs.

INTRODUCTION

Block 31 Devonian Field was discovered in 1945 in Crane County, Texas. The Block 31 Devonian Unit is a pressure maintenance miscible oil recovery operation which began in 1949. Both residual hydrocarbon gas and flue gas are utilized for the injection gas. The Unit covers 7840 acres with 360 MMBO originally in place. Today the Unit is producing at a rate of 12,500 BOPD and we have recovered over 185 MMBO. The ultimate recovery is expected to be 260 MMBO, or 60% of the original oil in place. The field rules allow for 40-acre spacing and this is used across most of the Unit. There are approximately 172 producing wells and 64 injection wells in the Unit and the number of wells continues to rise due to our continuing drilling program. There are six additional producing zones in the Unit other than the Devonian; however, this paper will cover only the Devonian operations.

In 1980 the squeeze on operating profits caused by rising costs and falling production necessitated a concentrated study to lower field operating costs. Our main expenses, other than compression for the reinjected gas, were fuel for oil treating, maintenance of fired vessels, and paraffin-cutting costs.

SURFACE FACILITIES

Prior to the operational changes which are the subject of this paper, the oil was treated at eleven test stations located around the field before going to a central tank battery. Each test station had four pressure systems, ranging from a high of 1200 psig to a low of 30 psig as shown in Figure 1. Oil was produced into all of the pressure systems with each system incrementally staging down to the low pressure system. Line heaters were utilized upstream of many of the heater treaters to help heat the oil for treating. One MMSCFPD in residue gas was used to heat the oil for treating. Since one MMSCFPD in fuel savings was a good economic incentive ($75,000/month), a study was made of all the test stations for ways to reduce fuel consumption.

Test Stations

Many of these test stations are on the edge of the field and they required a higher pressure (up to 65 psig in some areas) to move the oil to the central tank battery. This caused a potential safety hazard when the working pressure approached the design pressure of these fired vessels. In addition, many of the heater treaters were overloaded due to the high production rates, resulting in poor water/oil separation. As a result, water had to be drained from the sales tank each day before the oil would meet pipeline specifications. Because of the poor oil quality and the excessive fuel consumption, the feasibility of a new treating system was investigated with the hope that the BS&W content in the oil would be reduced enough to meet pipeline specifications without manually draining the water each day and at the same time reduce the fuel requirements.

Central Treating System

A central treating system was decided upon after considering the additional capital equipment costs of upgrading each individual test station. Thus the new treating system has all of the oil piped into one location for treating. This scheme eliminated our potential safety hazard by replacing the heater treaters with 125 psig working pressure separators at the test stations. The next problem was the determination of the type of treater to use and its location. It was decided to locate the central treating facility close enough to the plant to utilize the waste heat that was available from the gas plant. At the time of this study, the gas plant was having trouble with cooling capacity on the jacket water system for two compressor buildings. Those two compressor buildings contained 27 compressors with a common jacket water system and a combined horsepower rating of 28,850 HP. The new system utilized the jacket water from the compressors to provide the waste heat source for treating the oil, while also cooling the water for the compressors. By utilizing the jacket water as the heat source to treat the oil, it was possible to save the one MMSCFPD in residue gas that was used at the test stations. The economic incentives for saving gas volumes of this size were excellent.

The central treating facility has two parallel systems, either of which will handle the entire production stream for the field. The parallel system was decided upon to prevent the possibility of shutting down the field to repair equipment in the treating system. Figure 2 shows a flow diagram of the central treating system. The jacket water enters the exchangers at 155° F. and returns to the compressors at a minimum temperature of 150° F. The exchangers are sized for 11 MM BTU per hour. The oil goes through the tube side in the exchangers and then to a separator to remove the flashed gas from the oil before going to the horizontally heated free-water knockout vessels. These vessels are equipped with fire tubes in case the jacket water for the heat exchangers is not available. Under normal operation the fire tubes are not used. The jacket water going through the shell side of the heat exchangers is maintained at 30 psig higher pressure than the oil in the tubes to prevent oil getting into the jacket water system in the event of leak. The jacket water system is not set up for the removal of oil, while the produced oil is set up for water removal. The oil stream was put through the tubes of the heat exchanger instead of the shell side because of the ease of cleaning the tubes in the event of scale or paraffin deposition. Scale or paraffin deposits will increase the pressure drop across the exchanger and decrease the heat transfer efficiency as well as increasing the rate of corrosion. The pressure drop across clean tubes is approximately 3 psig for the present producing rate. When the pressure drop increases to 5 psig the tubes will be cleaned; however, this system has been in operation over one year without an increase in pressure drop across the heat exchangers.

Vapor Recovery System

With the central treating facility in operation, gas vapor loads on the vapor recovery units at the oil storage tanks were greatly reduced. The vapor recovery units at the storage tanks recovered 1.7 MMSCFPD in tank vapors with gas still venting before the central treating facility was installed. The central treating system now recovers the major portion of that gas and gas is no longer being vented from the tanks. The vapor recovery unit is now recovering 700 MSCFPD, which is 59% less than required before. This has allowed shutdown of one of the compressors in the vapor recovery unit, which has further reduced the operating and maintenance costs.

Low Pressure Separators

After the central treating facility became operational,all of the vertical heater treaters in the Devonian unit were taken out of service and replaced with low-pressure separators. This served a dual purpose. It eliminated the potential safety hazard of overpressured fired vessels, and since separators require less maintenance than heater treaters it reduced maintenance costs as well.

All the water lines from the heater treaters to the central salt water disposal system were taken out of service and the water now flows with the oil to the central treating facility. This reduced the active water lines going to the salt water disposal system from 6.5 miles to 0.5 miles and reduced maintenance accordingly.

WELL TESTING

While modifying the test stations to accommodate the oil being treated at the central treating facility, the accuracy of the well tests was evaluated and was found to be only 80% accurate when compared to actual production. Unfortunately, this test accuracy was only on the oil rate, as the test accuracy of the water production was much less. The poor test accuracy of the water production was due primarily to the method being used to test the wells. Tests were made using a one-barrel dump pot counter to determine the total fluid production, and a wellhead sample was taken to determine the water cut of the well being tested. The wellhead samples were unreliable because the fluid was flowing by slugs rather than continuously, which by this method yields non-represented samples and the resulting erratic water cuts.

Because of this slugging effect, a new test system was installed to continuously monitor the water and oil production. The continuous monitoring system installed is the Barton net oil computer. The net oil computer operates using a differential pressure principle based on the specific gravities of the water and oil. The complete system is designed to handle the full range of water-oil ratios with less than 2% error. With better test data available, the reservoir engineers have more confidence in the reserves and rates used to justify new drilling and the management of the reservoir has improved.

ARTIFICIAL LIFT

Gas Lift

In 1980 drilling of wells on the edge of the reservoir was initiated. The new wells were step-out wells that did not have full injection support. Although these wells produced with high GOR's, they would not flow as strongly as the interior wells, making some type of artificial lift a requirement. Because gas lift is well suited for lifting high GOR wells, in part due to economic considerations of requiring less capital outlay, a gas lift system was selected. The installation of gas lift was approximately one-third the cost of pumping unit installations. One problem encountered with the gas lift system has been the control of paraffin. The normal method of paraffin control is to mechanically cut the paraffin with a wireline at an average cost of $100 per well per day. In the absence of a regular paraffin removal progrem, costs have escalated when excessive paraffin buildup necessitated hot oiling or even pulling of some wells when production had stopped completely.

Plunger Lift

To reduce paraffin cutting costs, well pulling costs, and to increase run time, plunger lifts were installed in conjunction with the gas lift system. To use a plunger with gas lift, the well must be gas lifted intermittently rather than continuously. All the Devonian wells that are gas lifted are low-volume producers with production ranging from 15 to 100 barrels of fluid per day. Due to these low producing rates, intermittent lift is preferred over continuous lift. Two benefits have resulted from the plunger lift installations: elimination of paraffin cutting costs and more efficient operation due to the seal achieved by the plunger. This seal reduced the fallback of each liquid slug lifted. Reducing the fallback decreases the number of slugs that must be lifted each day to achieve the same production rate. Reducing the number of slugs to be lifted and the fallback of each slug means less gas is required for gas lift operations.

Economics for the plunger lift installations resulted in a payout, based on the savings of paraffin cutting alone, of less than two months. Added to the paraffin cutting savings are the savings on compression and the increase in run time by the elimination of paraffin plugging the tubing, making the economic incentives excellent.

SUMMARY

In 1980, with the production rate declining and operating costs rising, studies were initiated to establish ways to cut the operating costs without any loss of production. With the cost of gas rising, the use of waste heat as the heat source for oil treating became very attractive. Centralizing the treating system and using waste heat reduced fuel and maintenance costs greatly. Utilizing plunger lift in conjunction with the gas lift system reduced paraffin cutting costs for the unit. Upgrading of the test systems has improved our reservoir management of this field.

CONCLUSIONS

1. Waste heat can be used to reduce or eliminate fuel requirements for oil treating.

2. A centralized treating system can reduce maintenance costs by reducing the amount of equipment in the field and therefore possible down time.

3. Plunger lift, when used in conjunction with an intermittent gas lift system on low production wells, increases efficiency and reduces paraffin cutting costs.

4. For accurate well tests on flowing wells, a continuous oil/water ratio monitoring test system should be used.

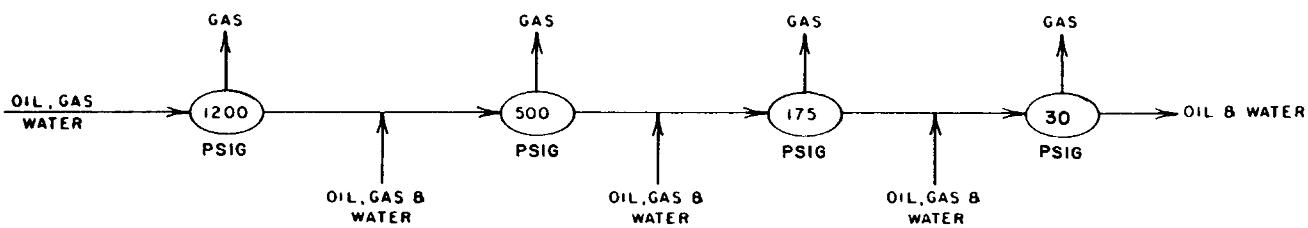

Figure 1 - Block 31 Unit. Typical test station operation.

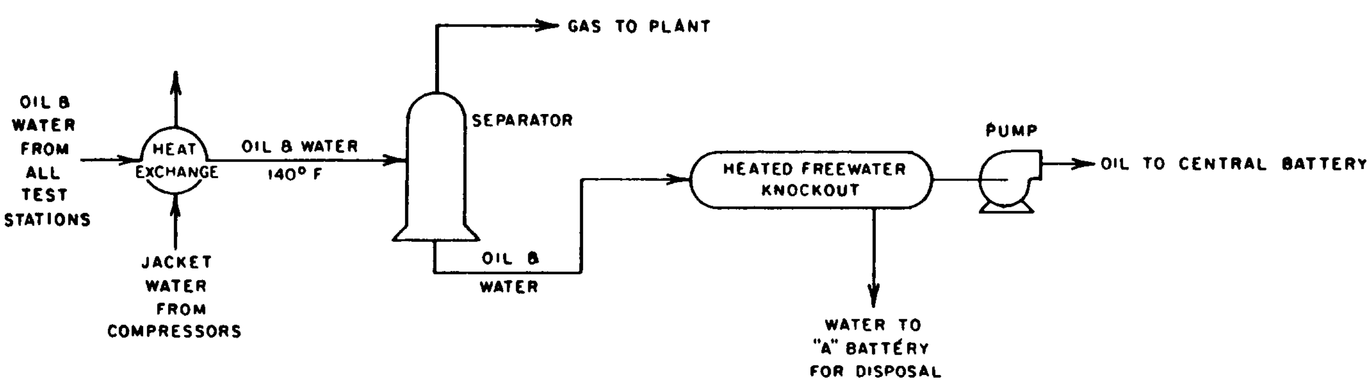

Figure 2 - Block 31 Unit. Flow diagram, central treating facility, Crane Co., Texas.