Originally appeared in:
January 2008 issue, pgs 95-97.
Posted with permission.
World Oil

RMOTC tests Vortex Flow surface tools

Positive results were seen when units were put through tests dealing with pressure reduction and ice and paraffin blockage.

Mark Milliken, RMOTC

Several Vortex Flow surface tools of different sizes were installed in single phase liquid gathering systems of two Tensleep Formation wells at the Rocky Mountain Oil Field Testing Center (RMOTC) at Tea Pot Dome near Casper, Wyoming. Data measurements included upstream and downstream pressure and flowrates. Flowline ice mitigation testing in gas gathering lines demonstrated reduced constrictions due to ice buildup. Additional testing of the units in high paraffin-prone wells resulted in decreased paraffin buildup in gathering lines.

INTRODUCTION

Vortex Flow contacted RMOTC to inquire about testing their units in high rate single phase gathering systems at NPR-3. RMOTC suggested adapting the units to flowlines from Tensleep wells, which have fluid flowrates in excess of 1,000 bpd. At first, Vortex requested a 2-in. line for their smaller units. RMOTC provided well 44-1-TPX-10 with flowrates in the range of 4,000–5,000 bpd. Later, the testing partner requested a 3-in. flowline with lower rates to test larger units. RMOTC provided well 43-2-TPX-10, with flowrates in the range of 1,000–2,000 bpd.

The project expanded to include two phase gas/water and paraffin testing. Gas gathering line tests were conducted at wells 25-STX-23 and 76-TX-3. Paraffin mitigation testing was conducted at wells 47-A-34 and 85-AX-20.

The tested units are designed with a tangential inlet to fit a 90° bend in a pipeline, flowline or gathering line. The proprietary device combines very specific geometry, precise machining and the laws of applied fluid dynamics to optimize the flow of materials within a pipe. The unit converts turbulent flow into laminar flow with a slow moving boundary layer, closest to the pipe wall.

In the case of a typical gas pipeline with a two-phase flow (gas and liquid), the device creates two distinct flows within the overall laminar flow. First, an annular or "spiral" flow is established and travels along the outer wall of the pipe. This spiral flow carries most or all of the liquid phase of the pipe flow. In the center of the spiral, a strong laminar flow is created where the gas phase of the flow is conveyed. The fluids remain entrained in the laminar flow, reducing drop-out. Prior testing has shown the flow regime can be maintained over long distances and dramatic elevation and directional changes. This boundary layer provides a cushioning effect that reduces pressure drop over the length of the line, as compared to turbulent flow.

TEST HISTORY AND RESULTS

Units of various sizes were installed on operating gathering systems at various positions in the lines. Flowrate and pressure data were recorded over time to determine optimal installation design and prove/disprove efficacy of technology application. In paraffin conditions, lines were cut, visually examined and hot water treated and pump pressures were recorded. Pressure recorders were installed on gas gathering lines to monitor pressure changes due to liquid buildup.

Well 44-1-TPX-10 (2-in. flowline). This well was selected to test 2-in. inlet/outlet units. The flowline was modified to allow installation of a flowmeter and Barton Meter pressure chart recorders. A production bypass was installed to maintain flow while each unit was installed. Baseline testing data was gathered using a 90° elbow. Water and oil rates were measured at the treater, and total flow was measured at the wellhead.

During baseline testing, high-side and low-side pressures were 155 and 145 psi. Total flow ranged between 4,100 and 4,300 bpd. After nine days of baseline testing, a 2-in. unit was installed. High-side pressure increased to 165 psi, and the low side remained 145 psi; while flowrates remained stable to slightly lower. These data suggest the unit was acting like a choke to inhibit flow. After 12 days of testing, a 3-in. unit was installed. After an initial surge, the pressures stabilized at much lower levels, suggesting much greater flow efficiencies with increasing unit volume. The pressure difference between high side and low side with the larger 3-in. unit dropped to a low of 5 psi, compared to 20 psi with the smaller 2-in. unit.

Well 43-2-TPX-10 (3-in. flowline). In May 2002, construction began on modifications to well 43-2-TPX-10 to accept three inch and larger units. As before, a bypass manifold was installed to keep the well in service during unit changeovers. Baseline testing began with a 90° elbow installed. For reasons unknown, upstream pressures were indicated to be lower than downstream (35 psi vs. 45 psi). Flowrate and pressure data were gathered for 11 days, then a 3-in. unit was installed.

The Barton recorders used the high pressure 500 psi calibration due to expected high pressures at well 44-1-TPX-10. Well 43-2-TPX-10 had less flowing pressure, so the meter calibration was changed to 200 psi for better chart resolution. Subsequent pressure readings were in the range of 55–62 psi for both high and low side meters. The high-side pressures were still slightly lower than the low side pressures, but within meter error.

Because of the pressure meter recalibration, a baseline test using a 90° elbow was reinstated on June 19. A large 4-in. unit was installed and monitored for 11 days. Line pressures dropped by 10 psi, to around 50 psi, and flowrates increased slightly over the baseline and 3-in. unit tests. The pressure drop associated with the 4-in. unit demonstrates the increased efficiency of larger volume units in single phase liquid systems.

Paraffin mitigation at well 47-A-34. Well 47-A-34 was treated with hot water. Pump pressures were 1,000 psi initial and 200 psi final, suggesting severe paraffin blockage. A standard 2-in. unit was installed. The line was treated after 45 days of operation. The pump pressures were 125 psi initial and 125 psi final. According to field personnel, these pressures suggested a relatively clean flowline. Field personnel said the line should have required more pump pressure given the operating time. At the request of the testing partner, the flowline at 47-A-34 was cut and re-welded, paraffin buildup was observed to be ±1⁄16 in. The production line was cut again, after 40 days of production, with again ±1⁄16 in. of paraffin buildup observed. The line was cut and observed again on April 9, with no paraffin buildup. The next day, a test section in the flowline was installed at 47-A-34 to decrease the time required for observing paraffin buildup. The section consisted of a spool and two full bore 2-in. valves. The line was hot water treated. Pump pressures were very low, at 125/125 psi before/after pumping.

After 40 days, the line was observed to be 25%–30% constricted with paraffin. The unit was removed and found to be choked with paraffin and ineffective. The 2-in. unit was removed and taken by the testing partner for analysis. Once the unit becomes even slightly contaminated with paraffin, its performance is compromised, and the gathering line becomes constricted. RMOTC recommended periodic cleaning of the unit to prevent flowline constriction. To minimize servicing time, RMOTC recommended that the testing partner design a unit that can be easily disassembled and serviced on location.

On June 2, the testing partner delivered a special flanged unit fabricated by them at the request of RMOTC. This design greatly reduces the time required to service the unit, and the interior of the unit has a special ceramic coating to reduce wax buildup. The flowline for 47-A-34 was hot water treated on June 11, with pump pressures at 150/150 psi, and the well was returned to production. After 30 days of operation, paraffin buildup was similar to that observed on May 20. Once again, the unit lost its efficiency after becoming coated itself. A RMOTC field technician said the well had been recently treated for downhole paraffin, resulting in premature contamination of the unit. RMOTC pumped 40 barrels of hot water down the flowline. On August 28, the testing partner requested a progress report on paraffin mitigation at 47-AX-34 from RMOTC. Pumping wellhead pressure was 75 psi. A RMOTC field technician disassembled the unit and found only a small amount of paraffin.

On November 25, well 47-A-34 was treated for downhole paraffin buildup and the line flushed. The unit was disassembled and had only a light coating of wax (+/-1⁄16 in.) after 49 days.

Paraffin mitigation at well 85-AX-20. The testing partner requested that a second paraffin test be conducted on a trouble-prone well in a different part of the field. A standard 2-in. unit was installed on well 85-AX-20 on April 2, 2003. The gathering line was flushed with hot water, and a test section similar to well 47-A-34 was installed.

An inspection revealed the spool to be completely free of paraffin after 62 days of operation. The spool was again inspected after 103 days of operation, and only a light film of paraffin was observed.

Well 85-AX-20 received a downhole paraffin treatment on December 11. Thirty-three days later, the unit was found to be completely plugged, possibly as a result of the downhole treatment. A similar occurrence happened at the previously tested well.

Gas gathering testing under low temperature conditions at 25-STX-23. The testing partner requested that RMOTC conduct a test of a unit in a two phase gas/water long distance gathering line subject to frequent freezing. Well 25-STX-23 was chosen for testing, and a standard 2-in. unit was installed on December 12, 2002. The gathering line for this well runs along the surface for 5,400 ft to the B-1-14 test treater.

The southern segment of the gathering line is constructed of 2-in. fiberglass, with the northern segment being 4-in. black poly, gathering lines from wells 32-SX-23 and 27-SHH-14 tee into the main line. All lines are on the surface and subject to frequent freezing, particularly at a deep creek crossing. An elevation change of about 25 ft occurs as the line crosses the creek, resulting in water hold-up. Testing of the unit would demonstrate its capability of entraining water in an organized flow over a long distance. Water would remain mobilized through low spots, reducing freeze-up problems.

Casing head gas is collected from the three wells on vacuum, with a compressor at the B-1-14 facility. Initially, vacuum gauges were installed at the compressor and well 25-STX- 23 to measure pressure differential. Vacuum readings at B-1-14 were found to be inconsistent due to fluid level fluctuations in wells 32-SX-23 and 27-SHH-14. The readings were stopped because of unreliable data.

Production continued through what is traditionally the coldest part of the winter with no line freeze-ups. On February 24, 2003, the line did freeze after the ambient temperature reached an unusually low –45°F. The line was treated with methanol, and no further freeze-ups were reported. On June 3, the entire line was inspected and no evidence of water hold-up was found.

Gas/water demonstration at well 76-MX-3. The testing partner requested RMOTC provide a two phase well with an uphill gathering line several hundred feet long. Well 76-MX-10 was selected to meet these criteria. The gathering line is 545 ft long with a volume of 4.76 bbl. The objective was to demonstrate the separation of water into an organized flow that would keep the gathering line unloaded. Several different unit designs were tested. A standard 3-in. 90° unit was delivered to the well. A portable separator was installed at the manifold ten days later, and production resumed.

Prior to operation, the line was drained, with three gallons of water collected. Seven days after the separator was installed, a special domed unit was installed. The domed unit was intended to meet Canadian specifications for pressurized vessels.

During several occasions, water was introduced into the gathering line because no measurable water was being produced from the well. Generally, there was no production observed through the separator. After 30 days of operation, the standard unit was reinstalled. Frequent power upsets in the field caused gas production to cease periodically. When power resumed, increased well pressure resulted in slugs of water passing through to the tank. Full stabilization sometimes took several days to achieve.

The well was shut in on August 27, 2003. Pressure was bled off of the gas gathering line, and the separator was drained. Ten gallons of water were introduced to the gas gathering line at the wellhead and the well reopened. In ten minutes, 3.5 gallons of water were drained from the separator. This test suggested the relative inefficiency of the Canadian pressure vessel design. Chart readings were: wellhead 7.1 psi, manifold 7.0 psi.

On September 22, 2003, two newly designed in-line units were installed along with a 10-ft section of clear Plexiglas to place in the flowline downstream from the units. The Plexiglas tube test section was installed with the standard 90° unit at the wellhead. When flow resumed, an initial slug of liquid passed through the test section in a spiral pattern. Upon stabilization, liquid assumed a stream-flow along the bottom of the tube. The testing partner requested the clear tube be moved to the wellhead, and that all three units be tested. The 90° unit was tested first, and yielded a two-foot long spiral flow pattern. Unit 2 yielded a five foot long spiral, and unit 1, a spiral in excess of 10 ft.

CONCLUSIONS

Single phase high rate liquid. Testing of units on high flowrate Tensleep wells demonstrated the need for much greater unit volumes, or different designs. Improved flow efficiencies were observed and recorded when upsized units were installed. Units up to 4-in. inlet/outlet size were tested. Based on the data trends, greater internal volume resulted in increased unit efficiencies.

Paraffin mitigation. The units were effective in mitigating paraffin in gathering lines at wells 47-A-34 and 85-AX-20. In both wells, little or no paraffin was observed in removable flowline spools after production periods exceeding 60 days. Significant wax buildup would normally have been expected during that time.

Unit efficiency decreases substantially when wax buildup occurs internally. Field-serviceable units are helpful, as is the internal ceramic coating. Of course, the units cannot control downhole paraffin buildup, which will eventually contaminate the unit. When downhole treatments are done, the units quickly become coated with paraffin and lose their effectiveness. This problem can be mitigated by combining downhole treatments with flowline treatments.

Two-phase liquid mobilization and ice mitigation. A special clear Plexiglas viewing line proved the relative effectiveness of different unit designs in mobilizing water. The most successful design was the longest in-line unit. The least efficient design proved to be a 90° domed unit designed for high pressure applications. An empirical test demonstrated the apparent ability of the unit to sweep water and minimize freezing in a 5,400 ft long gas gathering line.

FURTHER TESTING

Based on the previous successful testing from 2002–2004 at RMOTC, Vortex Flow LLC is interested in having its surface tool more thoroughly tested in 2008. The next set of testing will be done at RMOTC's unique flow assurance 6-in. line. This looped line was originally built to test subsea conditions and consequently will be ideal to test the tool in a variety of its key applications; including pressure reduction, ice blockage, paraffin and hydrate mitigation. The 6-in. flow assurance line will need to initially simulate conditions for flowrates less than 5 MMcfd. The pressure conditions should be studied in two categories, first to simulate the CBM environment and/or typical low pressure fields, focusing on pressures less than 100 psig. The second set of testing would concentrate on pressures up to 1,500 psig.

The scope of work would include testing the lines with and without the tool in a number of predetermined flow rates and pressure settings. This effort is being considered for the winter of 2008. Ice block and hydrate movement will be tested that winter, and when temperatures warm the following spring, testing will focus on deposition of paraffin in crude oil operations. **WO**

THE AUTHOR

Mark Milliken has more than 25 years of experience as a professional geologist in the engineering and petroleum fields. At the Naval Petroleum Reserve No.1, Elk Hills Field, he participated in exploration, development, and production projects extending the economic life of the 60,000 bopd field. Mark has an MS in Geology from Eastern Washington University.