DOERMOTC - 020166

VORTEX FLOW:

FIELD TESTING VORTEX OIL & GAS UNITS IN NPR-3 GATHERING SYSTEMS

Final Report for the Period April 02, 2002 – December 1, 2004

Date Completed: December 16, 2004

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Office of Fossil Energy

Work Performed Under Rocky Mountain Oilfield Testing Center (RMOTC)
CRADA No. 2002-008

DISCLAIMER

ABSTRACT

The program is designed to complete a commercial evaluation of Vortex Oil and Gas Unit technology to improve throughput of stripper oil well single phase gathering systems. Testing provided for monitoring actual units in controlled conditions to prove efficacy of the unit in increasing throughput in operating gathering systems. After unit size was optimized, line pressures stabilized at much lower levels, suggesting the units provide much greater flow efficiencies, especially with increasing internal volumes.

Flow line ice mitigation testing in gas gathering lines demonstrated reduced constrictions due to ice buildup. Additional testing of the Vortex Flow units in high paraffin-prone wells resulted in decreased paraffin buildup in gathering lines. Paraffin buildup in the downhole and wellhead environments tends to reduce the effectiveness of the units. For this reason, a serviceable unit was manufactured and successfully tested.

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Executive Summary

Several Vortex Flow units of different sizes were installed in single phase liquid gathering systems of two Tensleep wells at NPR-3. Data measurements included upstream and downstream pressure and flow rates. Initial results suggested the units were too small, and actually served as line restrictions. As the units were scaled up in size, flow rates improved. Once optimized, the units provided a noticeable drop in pressure at the wellhead while maintaining the flow rates.

Flow line ice mitigation testing in gas gathering lines demonstrated reduced constrictions due to ice buildup. Additional testing of the Vortex Flow units in high paraffin-prone wells resulted in decreased paraffin buildup in gathering lines. Paraffin buildup in the downhole and wellhead environments tends to reduce the effectiveness of the units. For this reason, a serviceable unit was manufactured and successfully tested.

Introduction and Background

In 2000, U.S. Patent 6,155,751 – *Flow Development Chamber for Creating a Vortex Flow and a Laminar Flow* was issued to Walter Prince and Darrin Lane. The patent assignee is Ecotech Systems International. The technology was originally developed to convey solids (such as coal) over long distances by creating very specific flow characteristics within a pipe carrying the material. In 2001, Vortex Flow LLC signed an exclusive licensing agreement with Ecotech to further develop and commercialize the technology.

Initial versions of the Vortex Oil and Gas Unit (VF Unit) were fabricated and field-tested in flow line applications on a very limited basis with favorable results. The unit improved flow characteristics in two phase stripper well flow lines, thereby increasing well production of both gas and oil.

Figure 1 is a timeline of testing with various devices at NPR-3 wells. Vortex Flow contacted RMOTC in February 2002 to inquire about testing their units in high rate single phase gathering systems at NPR-3. RMOTC suggested adapting the units to flow lines from Tensleep wells, which have fluid flow rates in excess of 1,000 BPD. At first, Vortex requested a two-inch line for their smaller units. RMOTC provided well 44-1-TPX-10 with flow rates in the range of 4,000 – 5,000 BPD. Later, Vortex requested a three-inch flow line with lower rates to test larger units. RMOTC provided well 43-2-TPX-10, with flow rates in the range of 1,000 – 2,000 BPD.

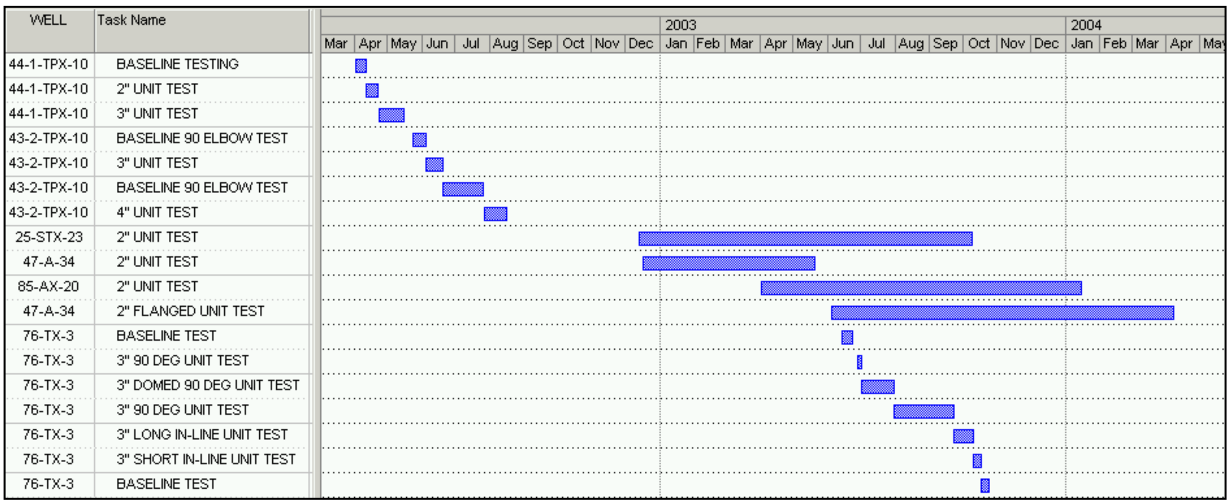

Figure 1. Test history of various VF units on NPR-3 wells

In late 2002 and 2003, 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. VF units of various sizes and designs were tested at these wells.

Vortex Flow's Technology

The Vortex Unit is designed with a tangential inlet to fit a 90-degree bend in a pipeline, flow line or gathering line (Figure 2). 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 Vortex 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 flow looks much like a stretched "Slinky"®. 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.

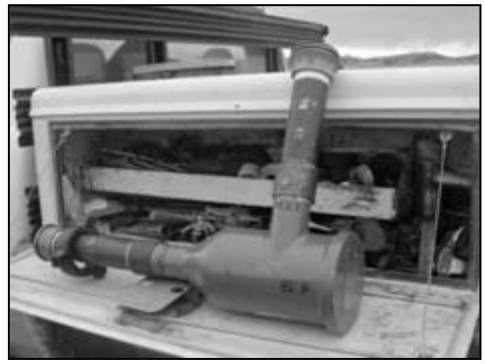

Figure 2 . Two-inch inlet/outlet Vortex unit being readied for installation

Objectives

There are four key objectives of the project:

1) Field testing the efficacy of Vortex Oil and Gas Units when installed in high flow rate single phase liquid gathering systems (Tensleep).
2) Determining optimal operating conditions in gathering systems for the Vortex Oil and Gas Unit through analysis of field test data.
3) Determining unit effectiveness in paraffin in oil gathering flow lines.
4) Determining unit effectiveness in liquid mitigation in low pressure gas gathering lines.

Methodology

Vortex Oil and Gas Units of various sizes were installed on operating gathering systems at various positions in the lines. Flow rate 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.

Several wells were used for the various testing goals:

- **Single phase high rate liquids:** 44-1-TPX-10 (two-inch flow line) and 43-2-TPX-10 (three-inch flow line). See appendices 1-3 for raw pressure and production data, and additional photographs.
- **Paraffin mitigation:** 47-AX-34, 85-AX-20.
- **Gas gathering liquid mitigation:** 25-STX-23, 76-TX-3

Test History and Results

Well 44-1-TPX-10 (Two-inch Flow Line).

This well was selected to test two-inch inlet/outlet Vortex Units. The flow line was modified to allow installation of a flow meter and Barton Meter pressure chart recorders (Figure 3). A production bypass was installed to maintain flow while each VF unit was installed. Manifolding was completed and baseline testing began on April 2, 2002. Pressure data are plotted on Figure 4.

Appendix 1 contains a table of raw data gathered during testing. Baseline testing data was gathered using a 90° elbow instead of the VF unit. 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 two-inch unit was installed. High side pressure increased to 165 psi, and the low side remained 145 psi; while flow rates remained stable to slightly lower. These data suggest the unit was acting like a choke to inhibit flow. After 12 days of testing, a three-inch 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 upside and low side with the larger three-inch unit dropped to a low of 5 psi, compared to 20 psi with the smaller two-inch unit (Appendix 1).

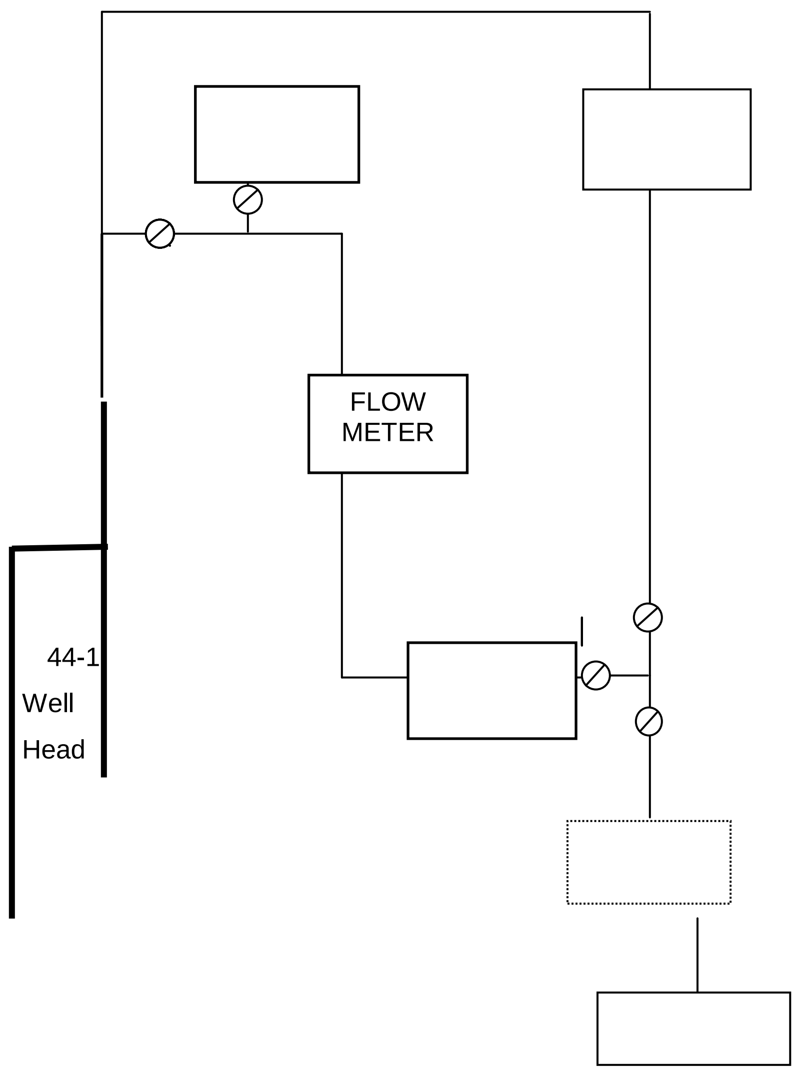

Figure 3. Schematic of manifolding at well 44-1-TPX-10

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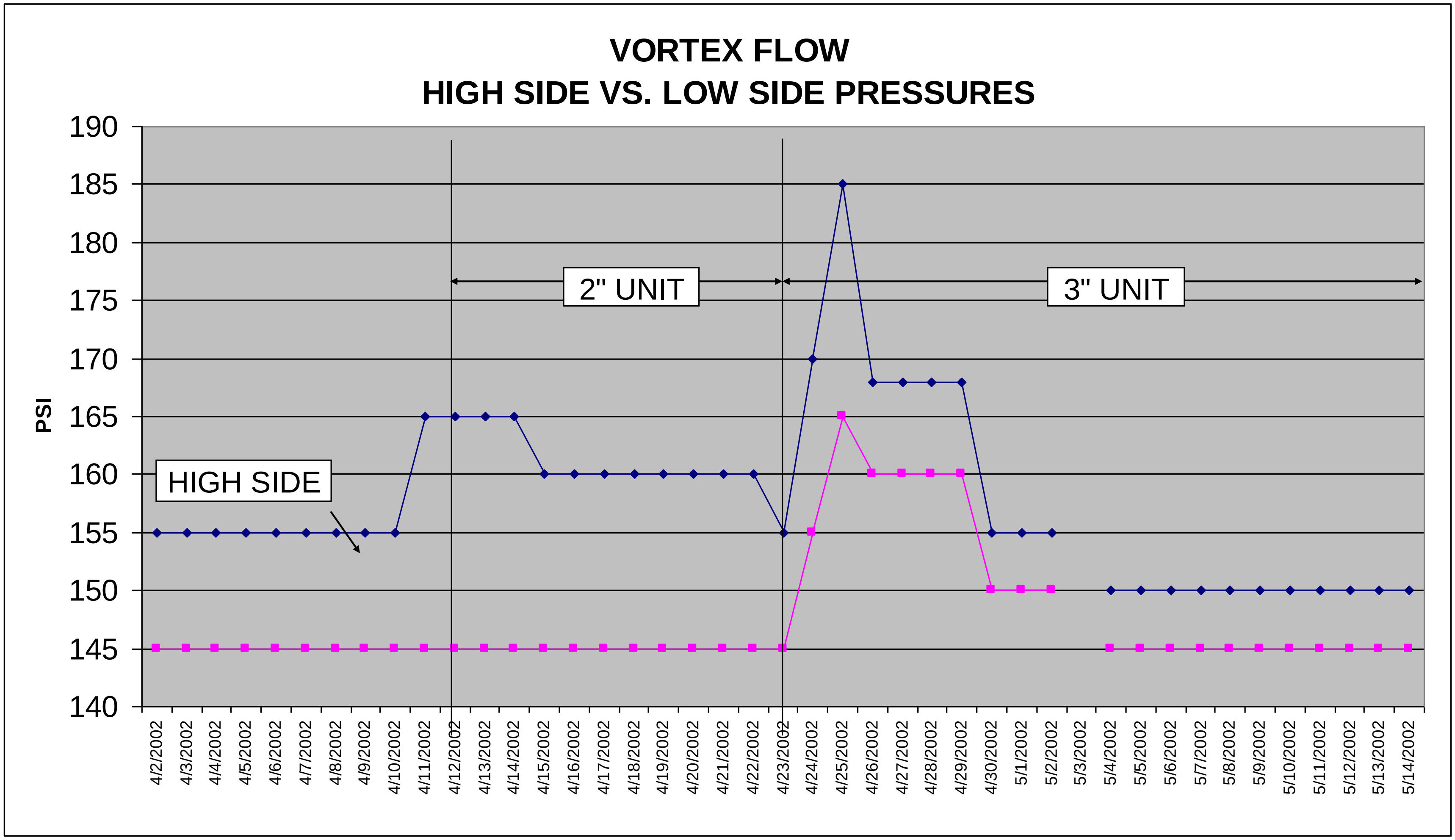

Figure 4. 44-1-TPX-10 pressure responses from different Vortex Flow arrangements

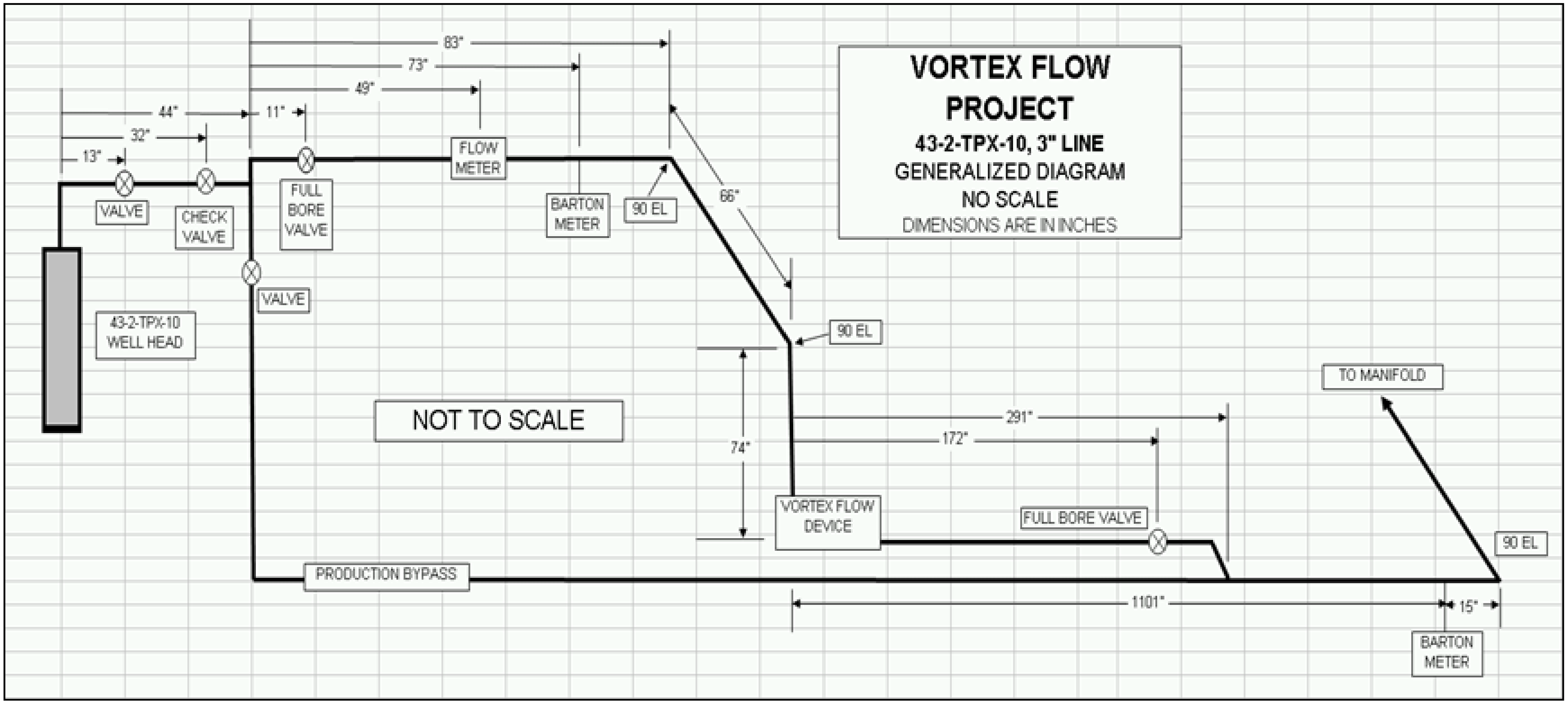

Figure 5. Schematic of manifolding at well 43-2-TPX-10

Well 43-2-TPX-10 (Three-inch Flow Line)

In May 2002, construction began on modifications to well 43-2-TPX-10 to accept three-inch and larger VF units. Vortex Flow requested the low side pressure tap be placed further downstream. As before, a bypass manifold was installed to keep the well in service during unit changeovers (Figure 4).

Baseline testing began on May 23, 2002, with a 90° elbow installed (Figure 5). For reasons unknown, upstream pressures were indicated to be lower than downstream (35 psi vs. 45 psi). Flow rate and pressure data were gathered until June 3, 2002, when a three-inch Vortex Flow unit was installed (Appendix 2).

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. The changeover was made on June 9. 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, but within meter error.

Because of the pressure meter recalibration, a baseline test using a 90° elbow was reinstated on June 19. A large four-inch unit was installed July 25 and monitored until August 5. Line pressures dropped by 10 psi, to around 50 psi, and flow rates increased slightly over the baseline and three-inch unit tests. The pressure drop associated with the four-inch unit demonstrates the increased efficiency of larger volume units in single phase liquid systems. Photos of the manifolding and Vortex Flow installations are presented in Appendix 3.

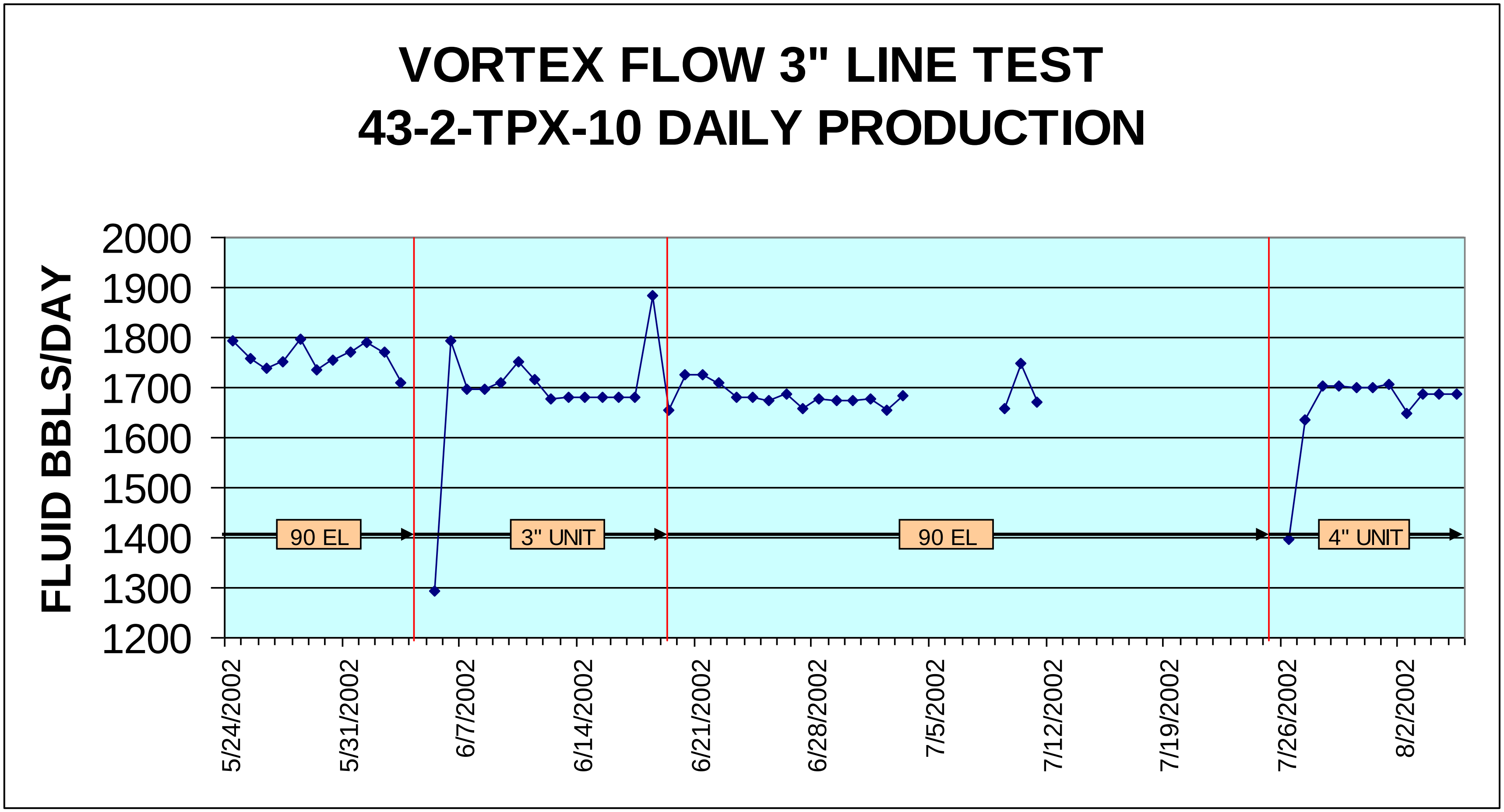

Figure 6. Flow rates for well 43-2-TPX-10 during testing of Vortex Flow units

Figure 7. Original two-inch unit installed at well 47-A-34 on December 16, 2002.

Paraffin Mitigation at Well 47-A-34

On December 16, 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 two-inch VF unit was installed (Figure 7).

On January 30, 2003, 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 flow line. Field personnel said the line should have required more pump pressure given the operating time. At the request of the testing partner, the flow line at 47-A-34 was cut and rewelded. Paraffin buildup was observed to be ± 1/16 inch. The production line was cut again on March 11, after 40 days of production, with again ± 1/16 inch of paraffin buildup observed.

The line was cut and observed again on April 9, with no paraffin buildup. On April 10, a test section in the flow line was installed at 47-A-34 to decrease the time required for observing paraffin buildup (Figure 8). The section consisted of a spool and two full bore two-inch valves. The line was hot water treated. Pump pressures were very low, at 125/125 psi before/after pumping.

Figure 8. Test section installed at well 47-A-34 on April 10, 2003. Hat for scale**.**

On May 20 after 40 days, the line was observed to be 25% - 30% constricted with paraffin. The VF unit was removed and found to be choked with paraffin and ineffective. The two-inch Vortex Flow unit was removed and taken by Vortex Flow for analysis. Once the VF 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 flow line constriction. To minimize servicing time, RMOTC recommended that Vortex Flow design a unit that can be easily disassembled and serviced on location.

Figure 9. The special flanged unit.

On June 2, Vortex Flow delivered a special flanged unit fabricated by them at the request of RMOTC. This design greatly reduces the time required to service the unit. The interior of the unit has a special ceramic coating to reduce wax buildup. (Figure 9).

The flow line for 47-A-34 was hot water treated on June 11. Pump pressures were 150/150 psi. A total of 40 bbls of hot water were pumped at 2 bpm. The well was returned to production.

On June 26, Vortex Flow reported Anadarko's purchase of three VF units based on RMOTC testing results. Anadarko engineering requested that RMOTC release test data on paraffin applications.

On July 10, after 30 days of operation, paraffin buildup was similar to that observed on May 20, 2003. Once again, the unit lost its efficiency after becoming coated itself. Note the clockwise spiral orientation of the paraffin buildup in Figure 10. RMOTC field technician Dan Kelly said the well had been recently treated for downhole paraffin, resulting in premature contamination of the VF unit. RMOTC pumped 40 barrels of hot water down the flow line. Pump truck clean-out pressures were 125/100 psi.

Pump pressures required to clean out the gathering line are a good indication of the degree of paraffin blockage. Figure 11 is a chart showing how these pressures dropped during the course of Vortex Flow testing at well 47-A-34.

On August 28, Brad Fehn of Vortex Flow requested a progress report on paraffin mitigation at 47-AX-34. Pumping wellhead pressure was 75 psi. RMOTC field technician Dan Kelly disassembled the unit and found only a small amount of paraffin. Brad said that as a result of testing at RMOTC, Vortex Flow installed ten paraffin units in Texas.

Figure 10. Dissasembled flanged VF unit after 30 days of operation

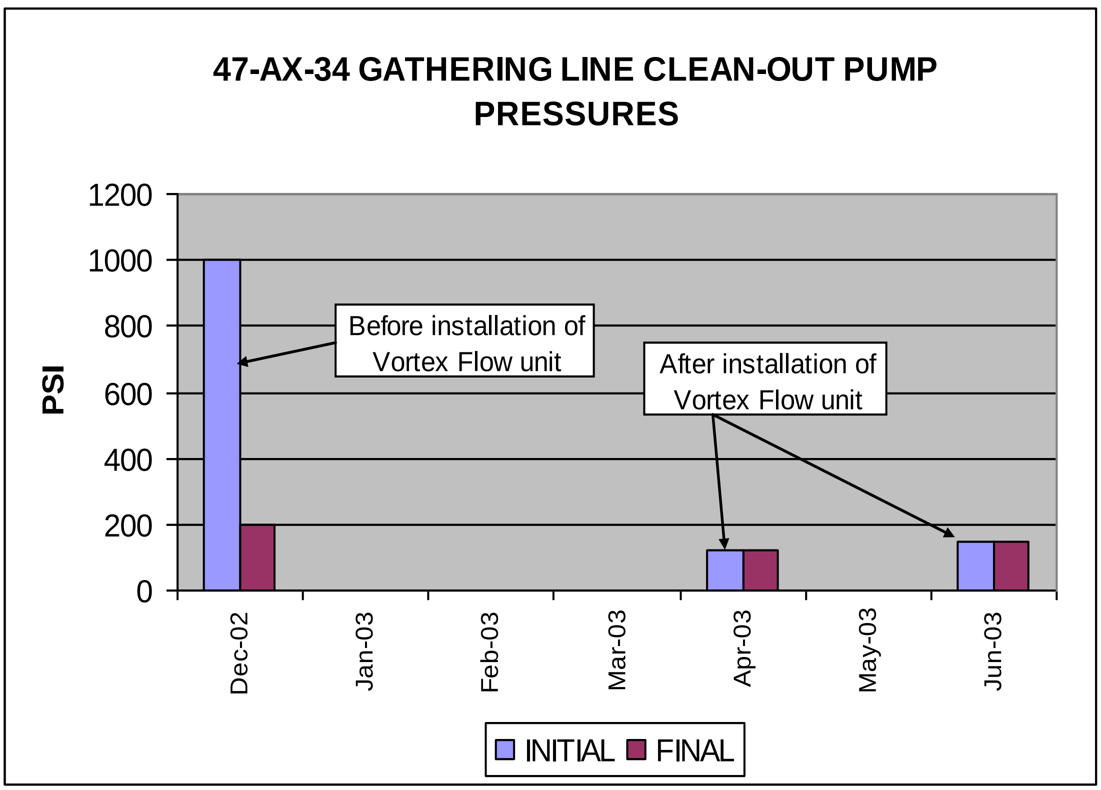

Figure 11. Clean-out pump pressures required to treat the gathering line before and after application of the VF serviceable unit. The differences between initial and final pump pressures required to clean out the gathering line are a good indication of the degree of paraffin blockage. The post-installation pressures recorded in April and June suggest little or no line blockage.

On November 25, 2003, Well 47-A-34 was treated for downhole paraffin buildup and the line flushed. Vortex Flow visited RMOTC on January 13, 2004, to witness testing of VF units. The unit at 47-AX-34 was disassembled and had only a light coating of wax (+/-1/16") after 49 days. By this time, the field manager of NPR-3 had purchased the flanged VF unit, and no further observations were made.

Paraffin Mitigation at Well 85-AX-20

Vortex Flow requested that a second paraffin test be conducted on a trouble-prone well in a different part of the field. A standard two-inch VF unit was installed on well 85-AX-20 on April 2, 2003 (Figure 12). The gathering line was flushed with hot water, and a test section similar to well 47-A-34 was installed on May 7, 2003.

Figure 12. Standard two-inch VF unit installed at well 85-AX-20

An inspection on June 3, 2003 revealed the spool to be completely free of paraffin after 62 days of operation. The spool was again inspected after 103 days of operation on July 14, and only a light film of paraffin was observed.

Well 85-AX-20 received a downhole paraffin treatment on December 11. On January 13, 2004, the VF unit was found to be completely plugged, possibly as a result of the downhole treatment (Figure 13). A similar occurrence happened at well 47-A-34. Vortex Flow requested the unit be removed.

Figure 13. Paraffin buildup at the VF unit inlet at the end of testing on 1/13/04. Blockage resulted after the well was treated for downhole buildup.

Results of Paraffin Testing

The VF 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 flow line spools after production periods exceeding 60 days. Significant wax buildup would normally have been expected during that time.

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

Two-Phase Testing and Demonstration

Gas Gathering Line Testing Under Low Temperature Conditions at 25-STX-23

Vortex Flow requested that RMOTC conduct a test of a VF unit in a two phase gas/water long distance gathering line subject to frequent freezing. Well 25-STX-23 was chosen for testing (Figure 14), and a standard two-inch VF 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 (Figure 15).

Figure 14. Walt Prince (r) approves of Dan Kelly's VF unit installation at well 25-STX-23. Two phase testing was conducted to mitigate freeze-ups.

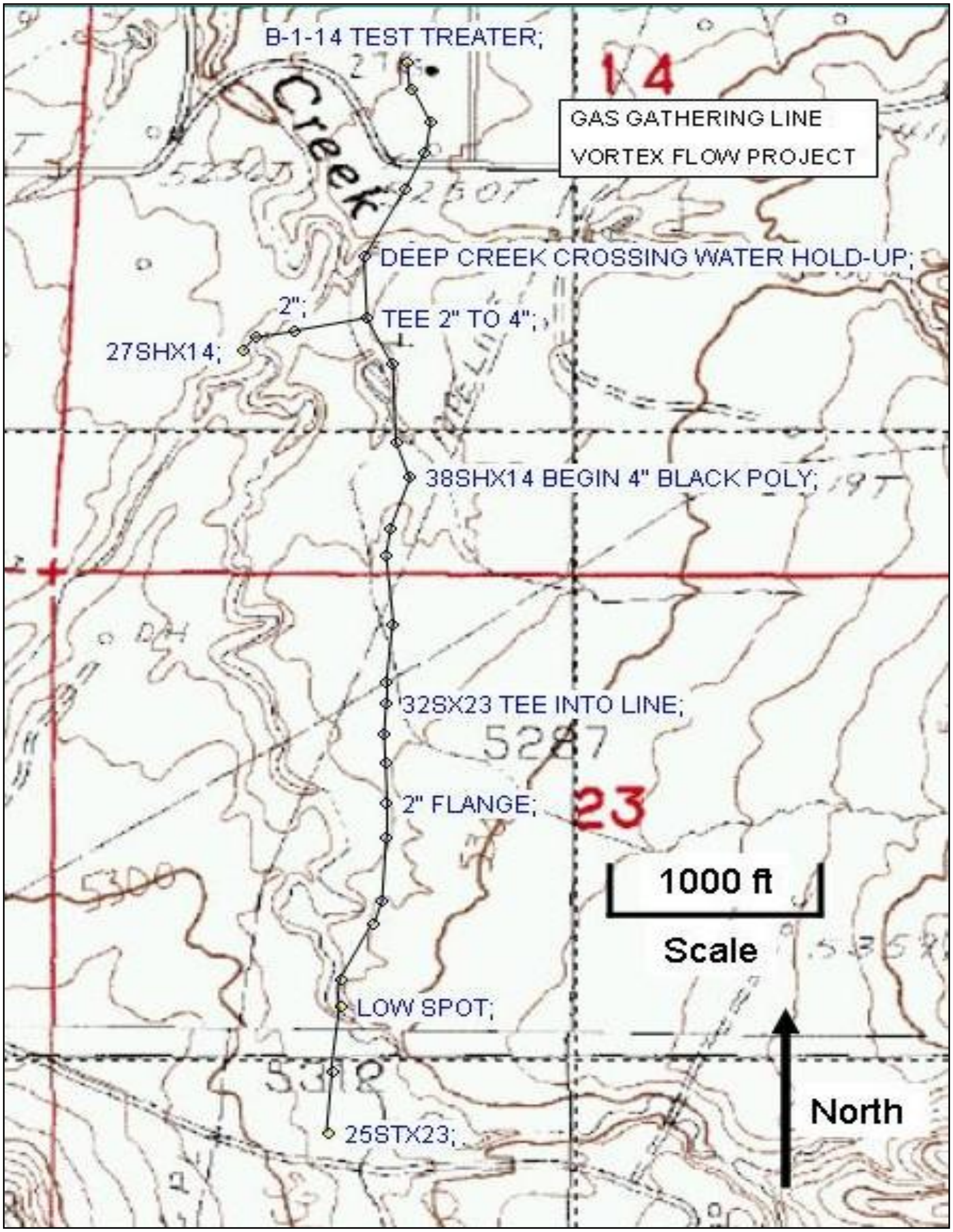

Figure 15. Surface gathering line between well 25-STX-23 and B-1-14 test treater. Overall line length is 5,400 ft. Freezing typically occurs at the deep creek crossing location, about 4,400 ft north of well 25-STX 23.

The southern segment (3,300 ft) of the gathering line is constructed of two-inch fiberglass, with the northern segment being four-inch black poly. Gathering lines from wells 32-SX-23 and 27-SHH-14 tee into main line (Figure 15). All lines are on the surface and subject to frequent freezing, particularly at the deep creek crossing (Figure 15). An elevation change of about 25 ft occurs as the line crosses the creek, resulting in water hold-up. Testing of the VF 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, Walt Prince and Mark Milliken inspected the entire line and found no evidence of water hold-up. The VF unit is still in place at 25-STX-23 during the winter of 2004-2005.

Gas/Water Demonstration at Well 76-MX-3

Vortex Flow 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 bbls. The objective was to demonstrate the separation of water into an organized flow that would keep the gathering line unloaded. Several different VF unit designs were tested. In September 2003, representatives of the Stripper Well Consortium visited RMOTC for a demonstration at well 76-MX-10.

On June 3, 2003, a standard three-inch 90° VF unit was delivered to the well. A portable separator was installed at the manifold on June 13 (Figure 16), and production resumed.

The standard three-foot unit was installed at 76-TX-3 on June 23, 2003. Prior to operation, the line was drained, with three gallons of water collected. On July 1, a special domed VF unit was installed (Figure 17). The domed unit was intended to meet Canadian specifications for pressurized vessels.

Figure 16. Portable separator and tank at 76-MX-3 manifold. Chart recorder monitored separator pressure.

Figure 17. A special domed VF unit installed at 76-MX-3. Standard 90° unit is in the background. The domed unit was designed to meet Canadian specifications.

During several occasions in July, 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. Field technician Dan Kelly said the introduced water was back-flowing into the well. On July 30, 2003, 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, Walt Prince brought two newly designed in-line VF units (Figure 18). They also brought a 10 ft section of clear Plexiglas to place in the flow line downstream from the units (Figures 19 and 20). 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. Vortex Flow 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 feet.

Figure 18. In-line VF units delivered for testing at 76-MX-3. The in-line design allows for simplified installations. The units were labeled #1 (long unit) and #2 (short unit).

Figure 19. Long in-line VF unit #1 installed at well 76-MX-3. Note Halliburton flow meter.

Figure 20. A ten-foot clear plexiglas line at the wellhead of 76-MX-3. Entrained water would form a spiral pattern on the interior wall. The long in-line VF unit gave the most efficient spiral pattern of the units tested. Stripper Well Consortium members viewed this flow character during a visit in September 2003.

About 20 members of the Stripper Well Consortium, supported by Penn State University, visited RMOTC on October 2, 2003, to view consortium projects including that of Vortex Flow. Brad Fehn of Vortex Flow was present at well 76-MX-3 to conduct a demonstration of the long in-line unit. Dan Kelly introduced five gallons of water to the line, and a successful demonstration of the spiral flow was conducted.

The separator froze up on November 3, 2003, and was removed. On November 4, Vortex Flow requested that testing be completed. The test units were removed from the 76-MX-3 site shortly after.

Summary and Conclusions

Single Phase High Rate Liquid

Testing of VF units on high flow rate 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 four-inch inlet/outlet size were tested. Based on the data trends showing greater internal volume resulted in increased unit efficiencies, RMOTC suggested that Vortex Flow provide test units up to six-inches inlet/outlet in size. Vortex Flow chose not to fabricate and test these larger units.

Paraffin Mitigation

The VF units demonstrated an ability to decrease paraffin buildup in gathering lines. The need for field serviceable units was demonstrated when RMOTC determined even small accumulations of paraffin within the unit led to decreased unit efficiencies.

Two-Phase Liquid Mobilization and Ice Mitigation

A special clear plexiglas viewing line proved the relative effectiveness of different VF 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 VF unit to sweep water and minimize freezing in a 5,400 ft long gas gathering line.

Suggestions for Further Research

Based on previous field studies, the Vortex Flow units have shown to be very effective in gathering systems where entrained solids must be kept in suspension while in transit. RMOTC sees a use for the units in gathering lines subject to ice or paraffin blockage.

The units may have a valuable application in offshore production in the prevention of hydrate blockages in production risers. Further laboratory testing specific to the hydrate environment may be required before field-scale testing would be funded by industry. Testing of large-scale VF units can be done on the RMOTC field-scale flow loops.

Contact information

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Appendix 1

44-1-TPX-10

Baseline and Vortex Flow unit
Pressure and flow rate measurements

April - May 2002

VORTEX FLOW TEST

44-1-TPX-10 2" FLOW LINE

Well 44-1-TPX-10		**BPD**			**BARTON PSI**		
							DELTA
DATE	**UNIT**	**WATER**	**OIL**	**F METER**	**HI SIDE**	**LO SIDE**	**P**
2-Apr	NONE	3641	4.2		155	145	10
3-Apr	NONE	4275	7.6		155	145	10
4-Apr	NONE	3899	4.6		155	145	10
5-Apr	NONE	4319	6.3	4186	155	145	10
6-Apr	NONE	4282	4.9	4287	155	145	10
7-Apr	NONE	4185	3.8	4134	155	145	10
8-Apr	NONE	4266	2.1	4209	155	145	10
9-Apr	NONE	4246	2.5	4215	155	145	10
10-Apr	NONE	4310	2.3	4245	155	145	10
11-Apr	#38	4232	2.3	4289	165	145	20
12-Apr	#38	4286	2.2		165	145	20
13-Apr	#38	4220	2.1	4174	165	145	20
14-Apr	#38	4235	2	4321	165	145	20
15-Apr	#38	4219	2		160	145	15
16-Apr	#38	4211	1.8	4204	160	145	15
17-Apr	#38	4250	1.9	4222	160	145	15
18-Apr	#38	4172	1.6	4189	160	145	15
19-Apr	#38	4330	1.6	4235	160	145	15
20-Apr	#38	4208	1.6	4235	160	145	15
21-Apr	#38	4195	1.6	4184	160	145	15
22-Apr	3"	4156	1.6	4162	160	145	15
23-Apr	3"	4138	1.7	4192	155	145	10
24-Apr	3"	4276	2.1	4256	170	155	15
25-Apr	3"			4137	185	165	20
26-Apr	3"			4195	168	160	8
27-Apr	3"	NO DATA		4195	168	160	8
28-Apr	3"			4195	168	160	8
29-Apr	3"			4195	168	160	8
30-Apr	3"	4243	1.8	4258	155	150	5
1-May	3"	4184	1.7	4321	155	150	5
2-May	3"	4305	0	4294	155	150	5
3-May	3"				NO DATA		
4-May	3"	4222	2.3	4295	150	145	5
5-May	3"	4268	1.6	4303	150	145	5
6-May	3"	4239	1.8	4265	150	145	5
7-May	3"	4252	1.8	4224	150	145	5

VORTEX FLOW TEST

44-1-TPX-10 2" FLOW LINE

Well 44-1-TPX-10			**BPD**			**BARTON PSI**	
8-May	3"	4217	2	4229	150	145	5
9-May	3"	4262	1.8	4257	150	145	5
10-May	3"	4312	2.1	4228	150	145	5
11-May	3"	4111	2.6	4234	150	145	5
12-May	3"	4291	2.6	4234	150	145	5
13-May	3"	4290	2.8	4234	150	145	5
14-May				4221	150	145	5
15-May			3" UNIT MOVED TO 43-2-TPX-10				

Appendix 2

43-2-TPX-10

Baseline and Vortex Flow unit
Pressure and flow rate measurements

May - August 2002

43-2-TPX-10 3" LINE TESTING

DATE	FLOW BBLS/D	HI SIDE PSI	LO SIDE PSI	UNIT	
23-May					START BASELINE TESTING
24-May	1795	35	45	90 ELBOW	
25-May	1758	35	45	90 ELBOW	
26-May	1738	35	45	90 ELBOW	
27-May	1751	35	45	90 ELBOW	
28-May	1796	35	45	90 ELBOW	
29-May	1736	35	45	90 ELBOW	
30-May	1756	35	45	90 ELBOW	
31-May	1771	35	45	90 ELBOW	BARTON METERS MAY BE MISCALIBRATED
1-Jun	1789	35	45	90 ELBOW	
2-Jun	1772	35	45	90 ELBOW	
3-Jun	1710	35	45	90 ELBOW	
4-Jun				3" UNIT	INSTALL 3" UNIT
5-Jun	1293			3" UNIT	
6-Jun	1793			3" UNIT	
7-Jun	1696			3" UNIT	
8-Jun	1696			3" UNIT	
9-Jun	1709			3" UNIT	CHANGE OVER TO 200 PSI METERS
10-Jun	1751	59.5	59.5	3" UNIT	
11-Jun	1715	59.5	61.9	3" UNIT	
12-Jun	1678	61.9	61.9	3" UNIT	
13-Jun	1681	61.9	61.9	3" UNIT	
14-Jun	1681	61.9	61.9	3" UNIT	
15-Jun	1681	61.9	61.9	3" UNIT	
16-Jun	1681	61.9	61.9	3" UNIT	
17-Jun	1681	61.9	61.9	3" UNIT	
18-Jun	1885	61.9	61.9	3" UNIT	
19-Jun	1655	61.9	61.9	90 ELBOW	CHANGE OVER TO 90 ELBOW
20-Jun	1726	60.3	60.9	90 ELBOW	
21-Jun	1726	60.3	60.9	90 ELBOW	
22-Jun	1711	60.3	60.7	90 ELBOW	
23-Jun	1682	59.5	61.9	90 ELBOW	
24-Jun	1682	59.5	61.9	90 ELBOW	
25-Jun	1675	57	57	90 ELBOW	
26-Jun	1686	60	60	90 ELBOW	
27-Jun	1658	57	57	90 ELBOW	

43-2-TPX-10 3" LINE TESTING

DATE	FLOW BBLS/D	HI SIDE PSI	LO SIDE PSI	UNIT	
28-Jun	1676	59	60	90 ELBOW	
29-Jun	1674			90 ELBOW	
30-Jun	1674			90 ELBOW	
1-Jul	1679			90 ELBOW	
2-Jul	1655	55	57	90 ELBOW	
3-Jul	1683	55	57	90 ELBOW	
4-Jul				90 ELBOW	
5-Jul				90 ELBOW	
6-Jul				90 ELBOW	
7-Jul				90 ELBOW	
8-Jul				90 ELBOW	
9-Jul	1657			90 ELBOW	
10-Jul	1750			90 ELBOW	
11-Jul	1672			90 ELBOW	
12-Jul				90 ELBOW	
25-Jul				4" UNIT	INSTALL 4" UNIT
26-Jul	1396	48	50	4" UNIT	
27-Jul	1634	48	50	4" UNIT	
28-Jul	1703			4" UNIT	
29-Jul	1703			4" UNIT	
30-Jul	1700	42	50	4" UNIT	
31-Jul	1699	50	50	4" UNIT	
1-Aug	1705	50	50	4" UNIT	
2-Aug	1650	58	58	4" UNIT	
3-Aug	1686	50	50	4" UNIT	
4-Aug	1686	50	50	4" UNIT	
5-Aug	1686	50	50	4" UNIT	

Appendix 3

Testing photographs

Vortex Flow units
and manifolding

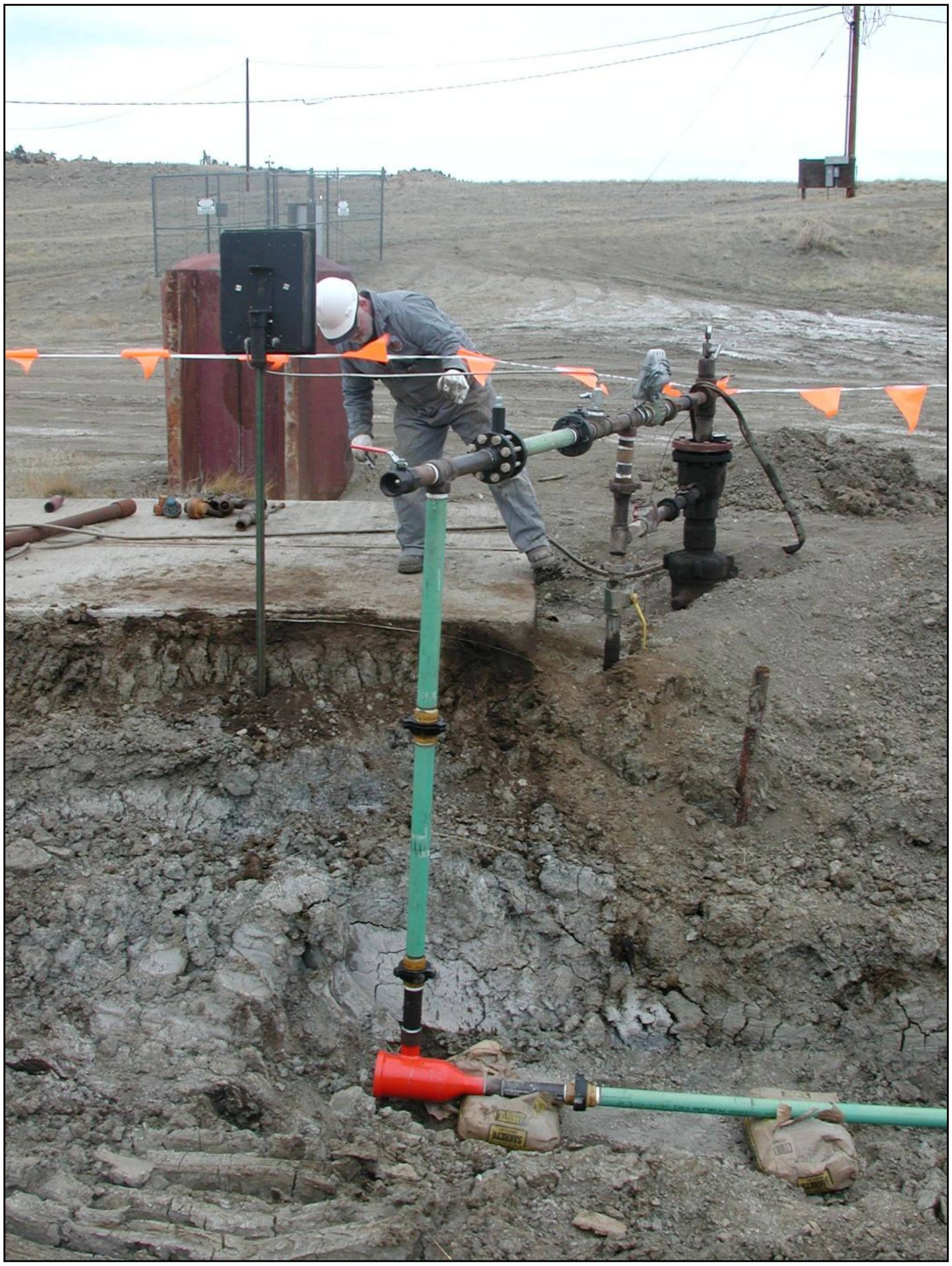
43-2-TPX-10
44-1-TPX-10

April - August 2002

Manifold close-up at 44-1-TPX-10. Black boxes are Barton pressure recorders.
Flanged device is the Halliburton flow rate measurement turbine.

Union of two-inch test manifold with existing production line at well 44-1-TPX-10. Note full bore valve and low side pressure tap for Barton Recorder. Flow is from left to right.

Connection of test manifold to the main Tensleep gathering line, 43-2-TPX-10. Gathering line was dedicated to the Vortex Flow test. Note Barton Pressure Recorder pressure tap.



Two-inch Vortex Flow unit and manifold installed at 44-1-TPX-10

Vortex Flow unit.

Three-inch Vortex Flow unit installed on three-inch line at 43-2-TPX-10.