VORTEX TOOLS:
COMBINING WITH GAS LIFT FOR PRODUCTION ENHANCEMENT IN HORIZONTAL LATERALS

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ABSTRACT

Since 2001, over 1,600 patented Vortex tools have been sold into oil & gas markets worldwide. On the surface, these tools set up a stable, spiraling flow that keeps liquids from dropping out, prevents freezing, reduces pressure loss, and mitigates paraffin/salt build-up in gathering lines and pipelines. Downhole, Vortex tools enable wells to flow unaided below the critical rate, lowers the flowing bottom hole pressure, and reduces surfactant/chemical use by up to 50%. With no moving parts, all Vortex tools are virtually maintenance free, and no additional energy source is required.

Vortex Tools previously presented at the SWPSC in 2007 (summarizing the Department of Energy's testing of Vortex downhole tools[1]), in 2012 (on recovering 10 times more natural gas liquids than conventional methods[2]), and in 2014 (on keeping production tanks in compliance with EPA air quality standards[3]).

In a 2014 case study in the Four Corners area, Vortex downhole DX-I tools, in conjunction with gas lift, saw beneficial increases in both oil & gas production, along with enhanced water removal and reduced injection gas cost. In this case, downhole Vortex tools are added to existing oil & gas wells to enhance production and extend the flowing life of these wells. A publicly-held oil & gas operator deployed these patented Vortex DX-I tools at the end of tubing, inside the liner, and in the horizontal lateral (typically set at 80° of deviation).

In each case where Vortex tools were installed, the oil production increased significantly and, in one reported case, the oil production increased from 80 barrels of oil per day to over 400 barrels of oil per day. The utilization of the Vortex tools also permitted the tubing to be set deeper in the lateral over 200 feet on average (measured depth), thereby increasing efficiency and, in some cases, gained over 400 feet of measured depth. The production from this one reported well in a 10-day period exceeded 3,200 barrels of oil (or $345,000 in production values). As the free flow period had already occurred (before gas lift and before Vortex), the majority of the hyperbolic decline had already happened.

The Vortex tools for all five wells were paid for in less than one day and benefits remained strong in the initial 90-day trial period. In a two-year lookback of these installs, data confirmed beneficial flattening of the long-term oil decline curve in all five wells, as well as more stable gas and water rates.

OVERVIEW

With the benefits of directional drilling, horizontal wells have become the norm in many formations. However, perfectly horizontal laterals are rare and liquids typically accumulate in the heel-toe dip and in deviations in the undulating portions of the tubing. For a list of common imperfect laterals see Figure 1.

While there is a substantial bounty of increased production from directional drilling, this method of recovery also creates new load-up issues as these wells decline. This is because many deliquification technologies (increasing recovery by utilizing the natural energy of the well) and artificial lift technologies (increasing recovery by adding an energy source) are unable to function efficiently in deviated portions of many horizontal wells.

One of the obvious restrictions in using conventional lift methods to transport the oil & gas in horizontal wells are the long and deviated laterals. There are a variety of artificial lift systems that can be used in liquids production. However, each system brings its own set of challenges when applied to horizontal wells, in part, because of the deviation angle of the well:

- While beam pumping may be the most efficient, it is also susceptible to gas locking in highly deviated wells. These pumps were developed for vertical wells and the deviated section of a horizontal well can cause problems with rod wear, gas locking, and the effects of back pressure.
- Conventional gas lift also faces challenges with horizontal wells. Gas tends to "roof" when flowing in the horizontal and bend sections of the well leaving liquids behind, thereby reducing lift efficiency. By installing a Vortex tool in the horizontal or near-horizontal section, the helix created makes gas lifting more efficient.
- This customer previously tried using plunger lift in conjunction with gas lift valves, but reported that plungers typically failed when they reached deviations beyond 20°.
- ESPs and PCPs can work in fully horizontal wells, but have similar gas-lock problems, especially with high gas-to-liquid ratios. Both of these solutions handle dry operation or gas production poorly and must be set in a straight section of the wellbore to prevent bearing failure.

When used in conjunction with gas lift, Vortex tools unlock the true potential of horizontal completions with shallow or deep laterals. For a visual comparison of where lateral solutions are placed and have the best success in the life of a well, see Figure 2.

TESTING VORTEX TOOLS IN DEVIATED WELLS

Deploying a Vortex DX-I tool at the end of tubing in the lateral of a producing oil well helps organize the three-phase flow (of oil, gas, and water: see Figure 3) while reducing bottom hole flowing pressure.[4] Originally used to help clean out frac sand in deviated gas wells, several of these tools have been in continuous operation with an operator in northern Colorado gas wells (typically 4,800 feet deep) since 2006. The Vortex DX-I tool was also added to the end of tubing in several deviated gas wells in central Texas (at 7,000-9,000 feet deep, with the tool landed at 80-95° of inclination). These Texas wells saw 2-3 times greater water removal with reduced slugging and lower flowing pressures.

Gas production also increased consistently by 20-30% (with increased water removal) when Vortex was added. However, this "benefit" of increased water removal/gas production was seen against a backdrop of falling gas prices. At this time, gas prices were low enough that operators had little motivation to increase gas lift efficiency. After this, higher oil prices renewed interest in rich natural gas technology solutions. Finally, reported challenges with production deep in laterals in producing oil wells created a new opportunity to revisit the Vortex end-of-tubing tools.

Vortex Tools with Gas Lift

A major independent decided to use the Vortex DX-I tool in several of its oil and gas wells in northern New Mexico. Five wells in two different producing formations were selected for this 2014 trial. The objective of the trial was to see if:

- Production would be enhanced by adding tubing extending into the curve section; and
- Adding Vortex would help move out slugs of liquids accumulating in the lowest part of the wellbore.

These were horizontal wells flowing with a combination of gas lift valves and a two-part plunger (which was used to manage paraffin accumulation). The customer reported problems with the plungers' descent, noting that they would not fall past 20-30° of deviation. There were also reports of significant liquid loading in the horizontal portion of the well, causing higher than expected tubing and casing pressures.

During a planned work-over of each well, the Vortex tool was landed at the end of tubing at various degrees of inclination in the lateral portion of the five wells. Four of the five wells had gas-lift valves remaining in place, but the packer was removed in all wells and tubing was run deeper into the lateral, increasing the measured depth by an average of 500 feet. Vortex tools were landed at the end of tubing and set at 80° of inclination. Previously, the end of tubing was set at only 40-50° in the lateral. Finally, the gas-lift valves were removed on the fifth well and 2 & 3/8” tubing was run to surface. In the other four wells, tubing was 2 & 3/8” in the liner section with a cross over to 2 & 7/8” above.

RESULTS OF TESTING VORTEX TOOLS IN DEVIATED WELLS

One of the five wells (Well E) was discounted by the customer early in the trial due to reported problems with a hot oil treatment some months earlier. However, the data was still gathered for comparison and is reported below.

- In the first two wells (Well A and Well B), oil production increased by an average of 58%, whereas the remaining three wells all saw a beneficial flattening of the long-term decline curve, albeit with no increase in daily oil production.
- The increased oil recovered from these first two wells produced an additional 8,658 barrels in the analyzed two-and-a-half-month period following the Vortex installation.
- Water removal increased by as much as 700% while flowing tubing and casing pressures reduced substantially (52% and 42% lower respectively).
- In gas-lift operations, these wells typically “recover” less gas than the gas that is “injected” to lift and produce the oil. With the addition of the Vortex tools, gas injection rates were reduced by up to 50%, and four out of five wells moved to net recovery of gas from net injection.
- The two wells which saw the greatest increase in oil production (57.4% and 58.3%), also saw the highest increase in gas rates (76% and 95%).
- Water removal in Well A and Well B also increased substantially (600% and 700% respectively).

Even in Well E, where operational problems were previously reported (following an incorrect hot-oil treatment), the well produced more evenly and had a flattened/improved decline curve. Other longer term benefits included stable (and lower) flowing tubing/casing pressures.

Value-Added Benefits with Vortex

Table 1 provides a side-by-side summary of the three of the wells (A through C) that were the subject of this study. These wells are comparable since they are all in the same formation, with similar depths/completions (7” casing and a cross over to 2 & 7/8” tubing above Vortex), and were all operated on gas-lift without a packer. The customer noted: *“All wells have been producing for over 10 days and have not lined out.”* This was well past the benefit of flush production. They modified some of the gas-lift injection variables in the trial period and continued to see increases across the board with Vortex.

Looking specifically at Well A: When used in conjunction with gas lift, the Vortex DX-I Tool:

- Increased oil production (by 69%).
- Increased water removal (by 620%).
- Required less gas to be injected, yet recovered more gas to sales (by 92%).
- Reduced tubing pressures (by 62%).
- Reduced casing pressures (by 42%).
- Experienced an offset frac in the trial period which negatively impacted production.
- Increased the total economic value of the well (by nearly $590,000 in the analyzed data period).

For Well A charts on increased oil production, increased water removal, gas injected vs gas sold before/after Vortex, tubing/casing pressures, and a production summary, see Tables 2-6.

Well B also saw significant improvement from the addition of the Vortex DX-I tool:

- Increased oil production (by 48%).
- Increased water removal (by 700%).
- Required less gas to be injected, yet recovered more gas to sales (by 75%).
- Reduced tubing pressures (by 53%).
- Reduced casing pressures (by 41%).
- Increased the total economic value of the well (by over $460,000 in the analyzed data period).

Well C only saw marginal benefits from Vortex, yet still saw financial benefit:

- Oil production decreased slightly (by 9%), although the long-term oil production curve showed improvement.
- Increased water removal (by 57%)
- Required less gas to be injected, yet recovered more gas to sales (by 89%)
- Reduced tubing pressures (by 52%)
- Reduced casing pressures (by 44%)
- Experienced an offset frac in the trial period which negatively impacted production.
- Increased the total economic value of the well (by nearly $40,000 in the analyzed data period).

As for the remaining two wells in the second formation, here are Well D results:

- Oil production decreased (from 84 to 66 barrels/day), but showed an improved long-term decline curve.
- Water removal increased from 13 to 18 barrels/day (38% increase).
- Produced gas rates increased slightly from 361 mcf/d to 370 mcf/d.
- In percentage terms, gas recovery went from 90% of injected gas (before Vortex) to an average of 135% of injection gas rate recovered.
- Flowing tubing pressures reduced by 15%.

As mentioned previously, Well E was discounted from the trial by the customer. However, this well data was still analyzed for potential benefit with Vortex:

- Oil, gas, and water were all down marginally (although the long-term oil production curve showed improvement).
- Flowing tubing pressures reduced on average from 244 psi to 139 psi and there was a noticeable smoothing of the pressure spikes observed prior to the Vortex install.

As horizontal drilling and multistage hydraulic fracturing have unlocked vast quantities in shale plays, these same lessons learned are now being applied to unconventional tight oil plays throughout the U.S.

TWO-YEAR LOOKBACK

In June 2016, Vortex completed a lookback on the wells where Vortex tools were deployed in June 2014, reflecting a two-year period since the installation. Before and after decline curves can be found as Tables 7-11. The data was collected from the State of New Mexico's monthly production reports.

In the initial 90-day review period there were beneficial increases in oil production in Wells A and B, whereas there was marginal oil benefit with Well C. Finally, Wells D and E showed little difference. However, there were some operator problems with Well E, where an incorrect hot oil treatment was used and this impacted production. Also, in the case of Wells A and C, there was an offset frac which negatively impacted production during the 90-day trial.

In the two-year lookback, Vortex noted a beneficial change in long-term oil decline in all five wells, as well as more stable gas and water rates. Gas injection rates were not available during the look-back period, but the report does indicate benefit in all wells where Vortex was added, albeit with different degrees of improvement.

SUMMARY

Vortex Tools offer a cost-efficient technology solution to the challenges of managing and optimizing liquids recovery from horizontal wells with long laterals, thereby increasing the economic value of these wells while extending the decline curve. When used in conjunction with gas lift, these Vortex tools increase oil production and water removal, reduce tubing and casing pressures, and require less gas-lift gas to be injected with more gas going to sales.

With no moving parts, requiring no maintenance, and using no chemicals, these patented and proven Vortex tools run in all tubing and casing sizes, offer well optimization benefits, and several monetizable opportunities.

REFERENCES

1. Heim, Norm, “A Review of D.O.E. Testing of Vortex*Flow* Technology for Petroleum & Natural Gas Production and Operations,” SWPSC, Texas, 2007.

2. Haas, Richard C. & Colin McKay Miller; “Vortex Tools: NGL Technology Solution for Operators with Enhanced Recovery and Improved ROI,” SWPSC, Texas, 2012.

3. Haas, Richard C., Alan Miller, & Colin McKay Miller; “Vortex Tools: Keeping Production Tanks in Compliance with EPA Air Quality Standards,” SWPSC, Texas 2014.

4. Ali, Ahsan, et al, “Investigation of a New Tool to Unload Liquids from Stripper Gas Wells,” SPE 84136, ATCE, Denver, October 5-8, 2003.

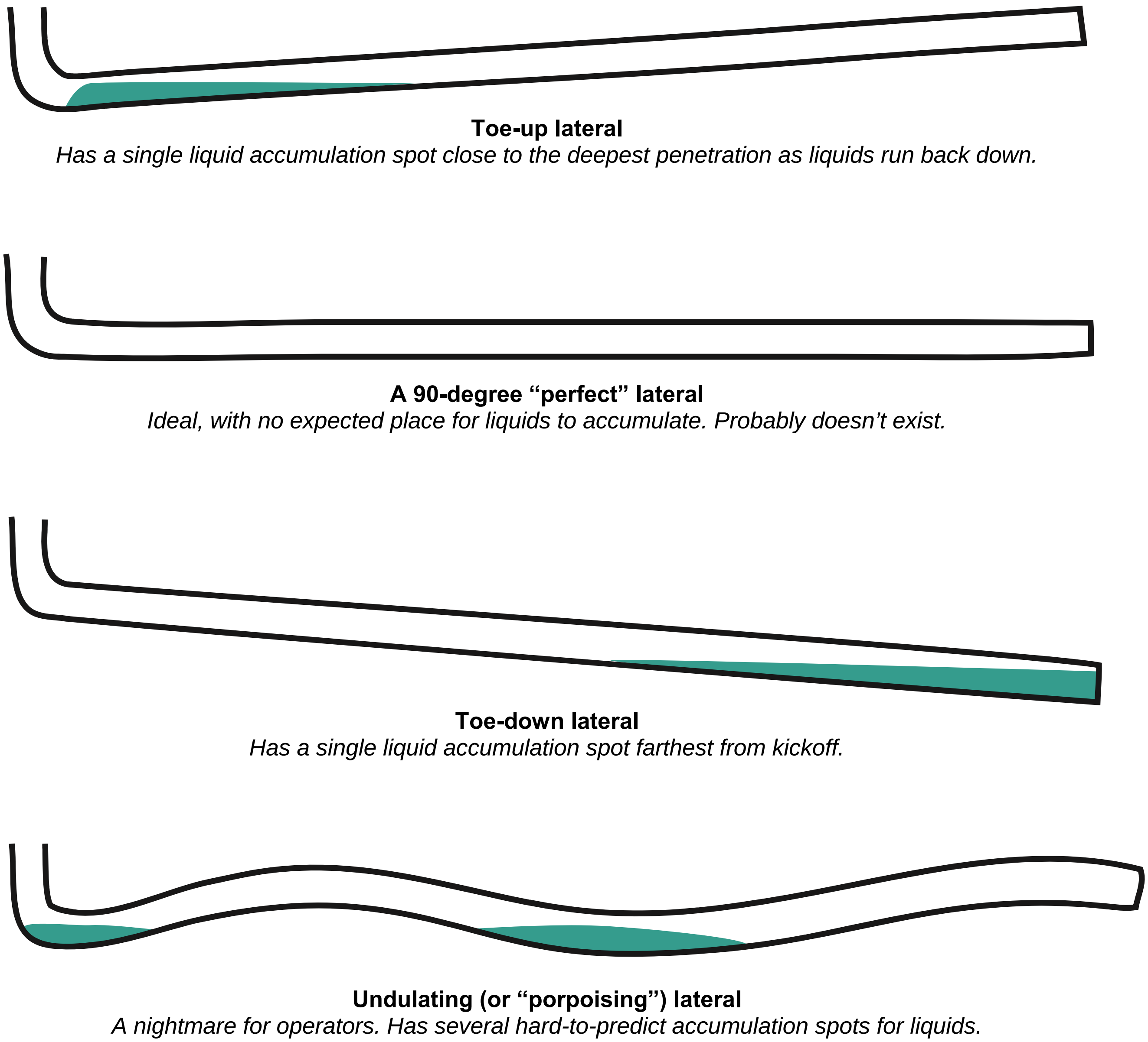

Figure 1 - Commonly drilled laterals

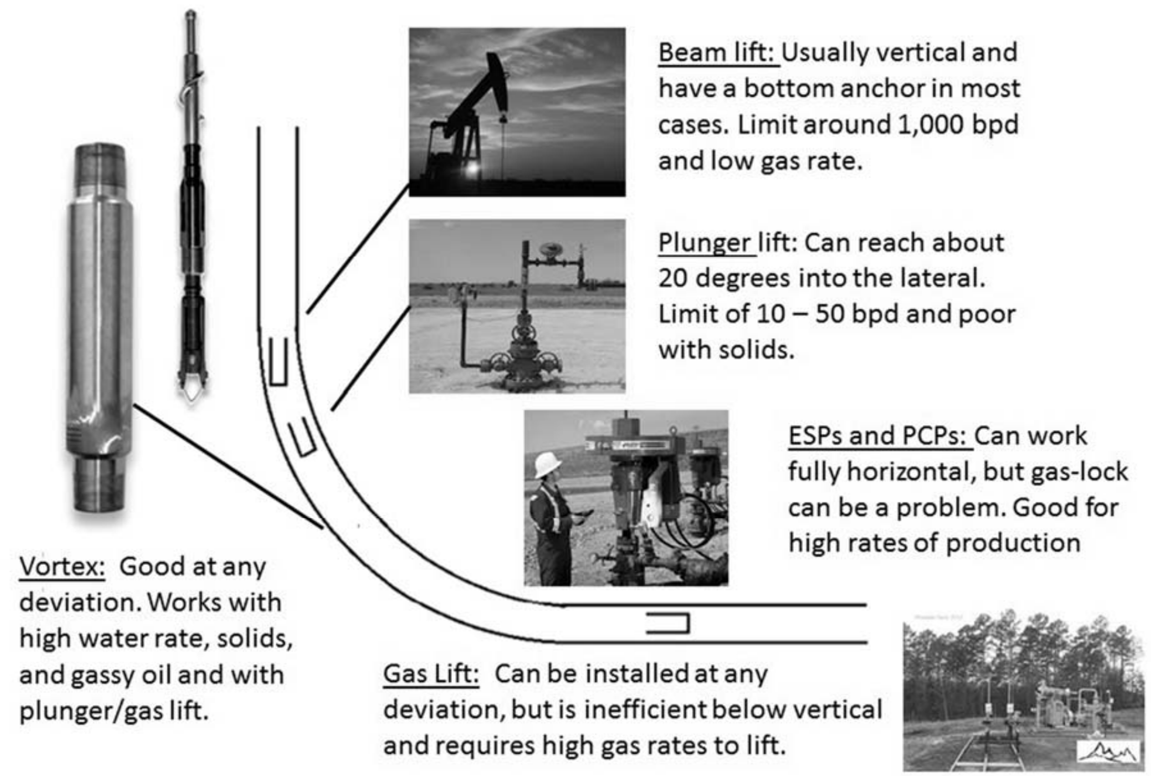

Figure 2 - Vortex versus competing horizontal technologies

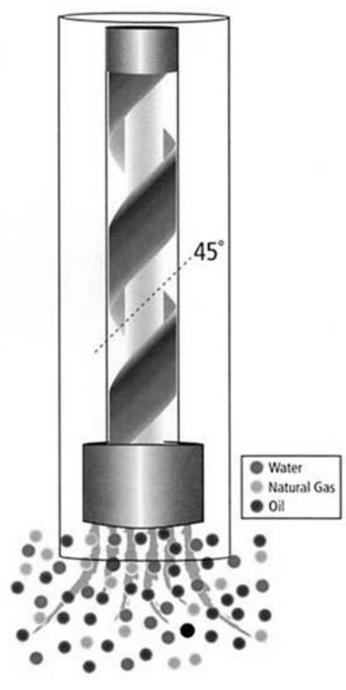

Figure 3 - Visual of Vortex Tool Organizing Three-Phase Flow
(of Water, Oil, and Gas [travelling in the middle])

	Well A	Well B	Well C
Operating method:	Gas Lift w/Vortex	Gas Lift w/Vortex	Gas Lift w/Vortex
Oil before Vortex:	81 Bbls/day	84 Bbls/day	152 Bbls/day
Oil after Vortex:	137 Bbls/day (+69%)	124 Bbls/day (+48%)	139 Bbls/day (-9%)
Oil Trend Line:	Actual/trended Up	Actual/trended Up	Trended Up
Water Removed Daily:	36 Bbls/day (+620%)	32 Bbls/day (+700%)	44 Bbls/day (+57%)
Daily Gas Impact:	170 Mcf/d increase	190 Mcf/d increase	153 Mcf/d decrease
Injected Gas rate:	200 mcf/d decrease	56 mcf/d decrease (average)	200 mcf/d decrease
Net sales gas:	675 Mcf/day average	246 Mcf/day	106 Mcf/day
% of injected gas (no Vortex) to sales:	92% of injected gas without Vortex	75% of injected gas without Vortex	89% of injected gas without Vortex
% of injected gas (w/Vortex) to sales:	344% of injected gas with Vortex	155% of injected gas with Vortex	138% of injected gas with Vortex
Tubing Pressures:	Reduced by 62%	Reduced by 53%	Reduced by 52%
Financial benefit (3 months of trial):	$587,192	$461,138	$38,196

Table 1 - Vortex Improvement Summary On Wells A Through C

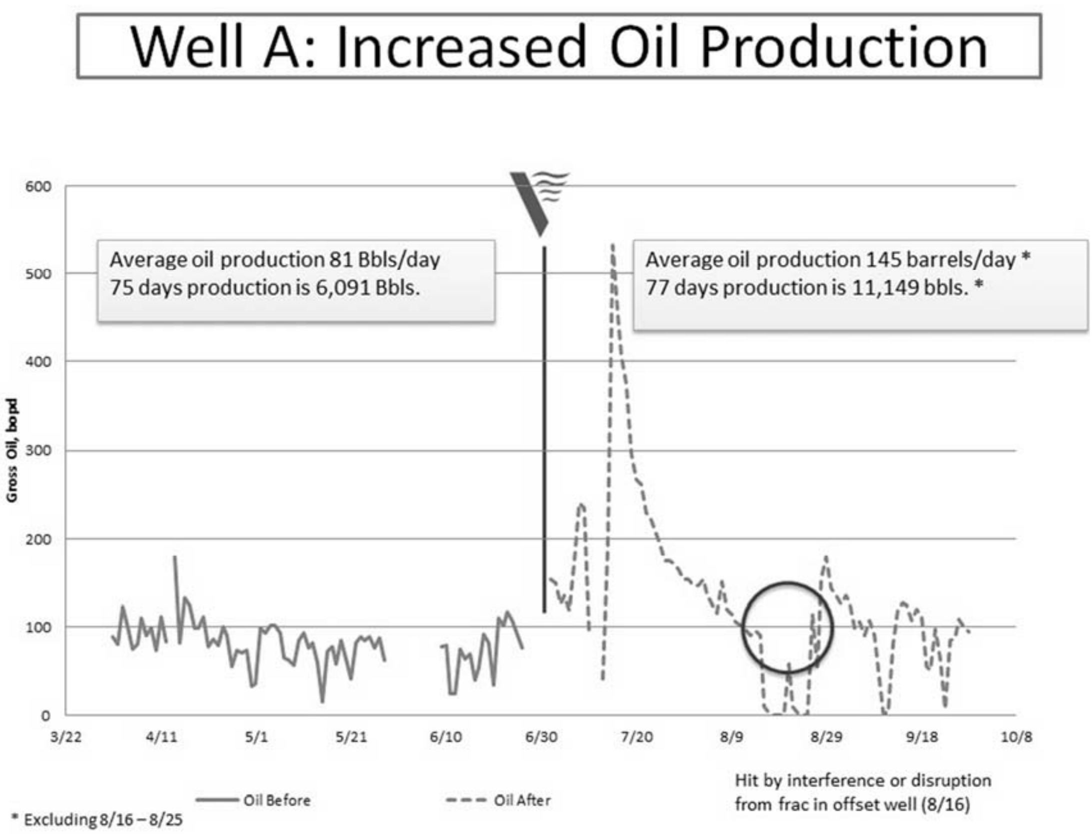

Table 2 - Well A: Oil Production

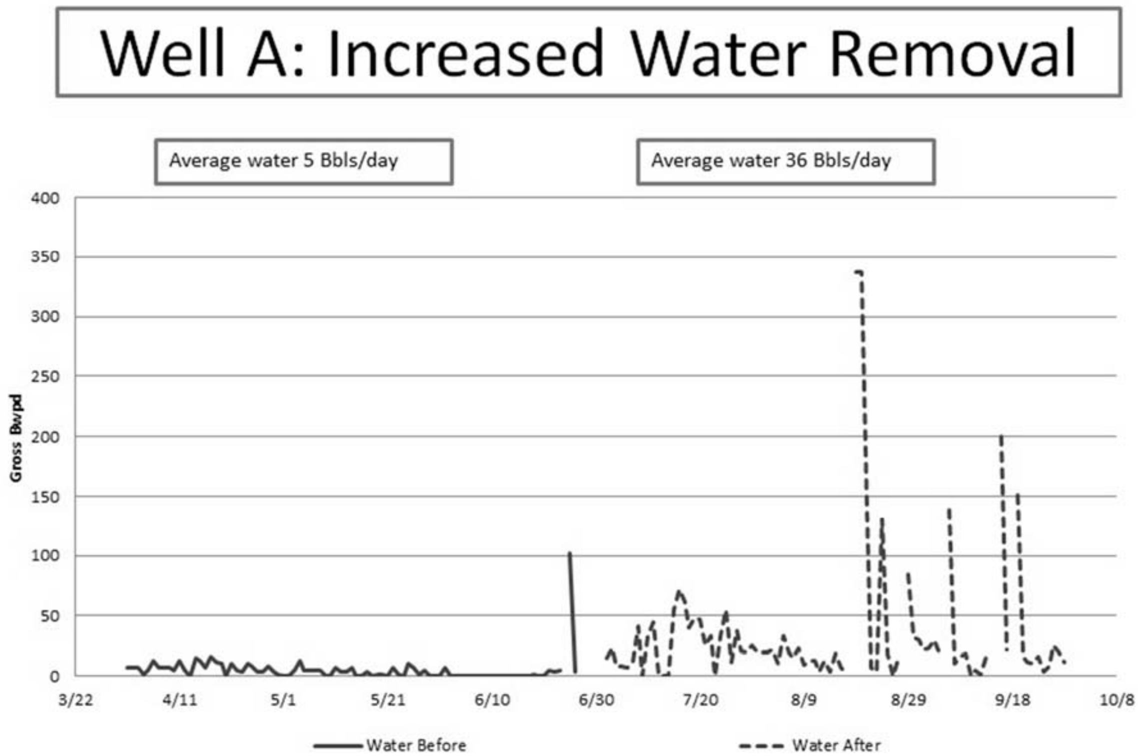

Table 3 - Well A: Water Removal

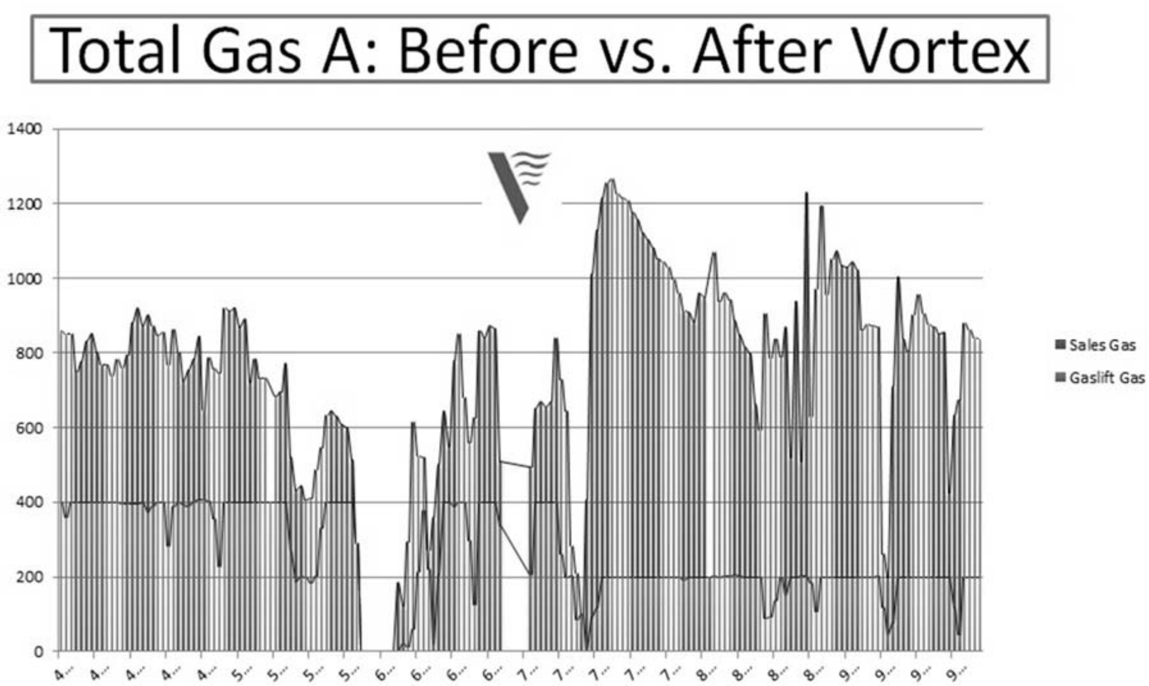

Table 4 - Well A: Gas Lift Gas Injected vs. Gas Recovered

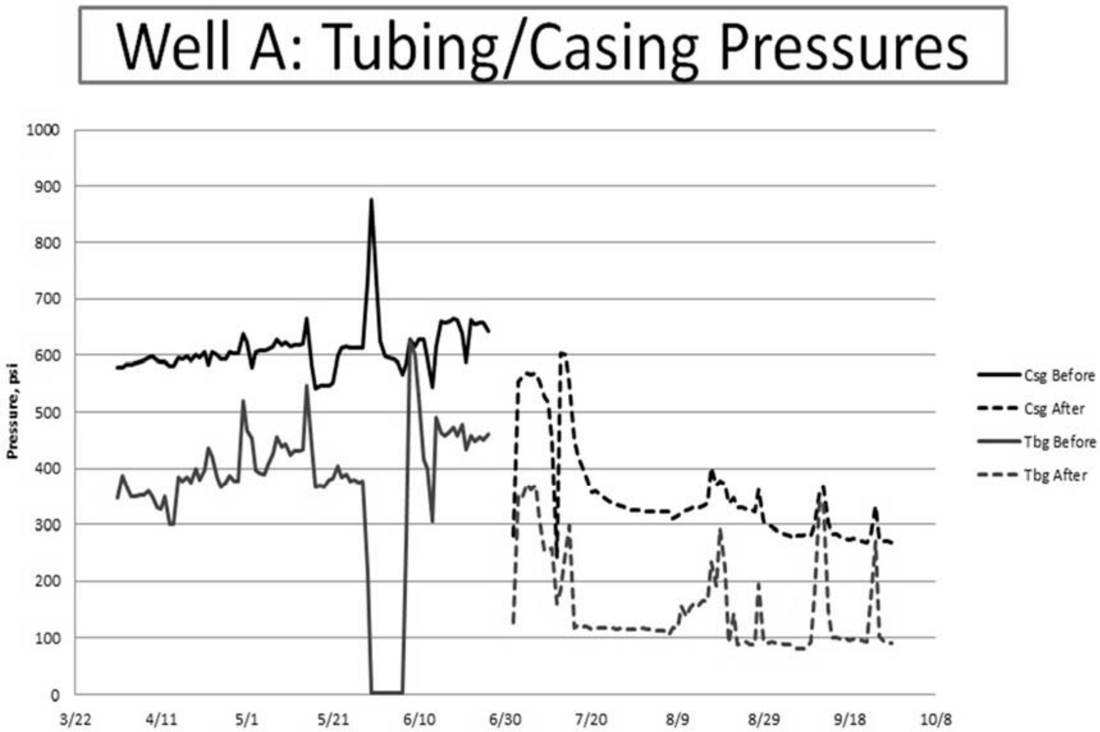

Table 5 - Well A: Tubing and Casing Pressures

Well A: Summary Results

	Before Vortex	After Vortex	Change
Daily Oil Rate	81 Bbls/day	143 Bbls/day	76% increase
Water Removal/day	5 Bbls/day	36 Bbls/day	620% increase
Daily Gas to Sales	355 Mcf/d	674 Mcf/d	90% increase
Additional Production (3 month period)	Oil Gas Sold Reduced Injection Rate Total Economic value	5,144 Bbls.	\$462,960 \$83,912 \$40,320 \$587,192

Table 6 - Well A: Summary

On the two-year lookback charts (Tables 7 through 11), the solid line is production before Vortex and the dashed line is production after Vortex. The bottom line is water; the middle line is oil; and the top line is gas. The solid horizontal line indicates the change in the oil decline curve post-Vortex:

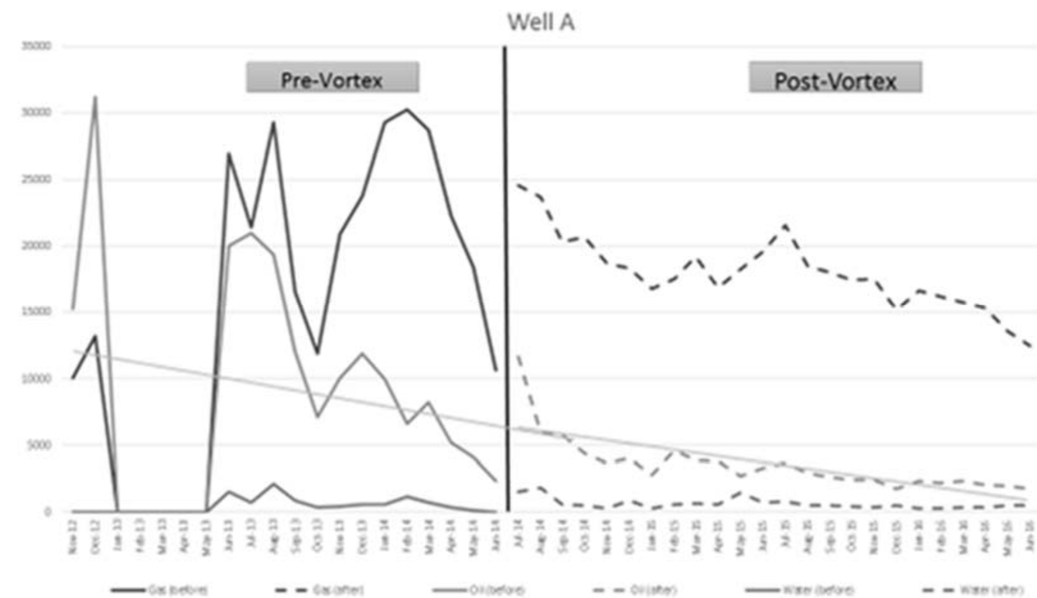

Table 7 - Well A: Two-Year Lookback: Slight Flattening of the Oil Decline Curve

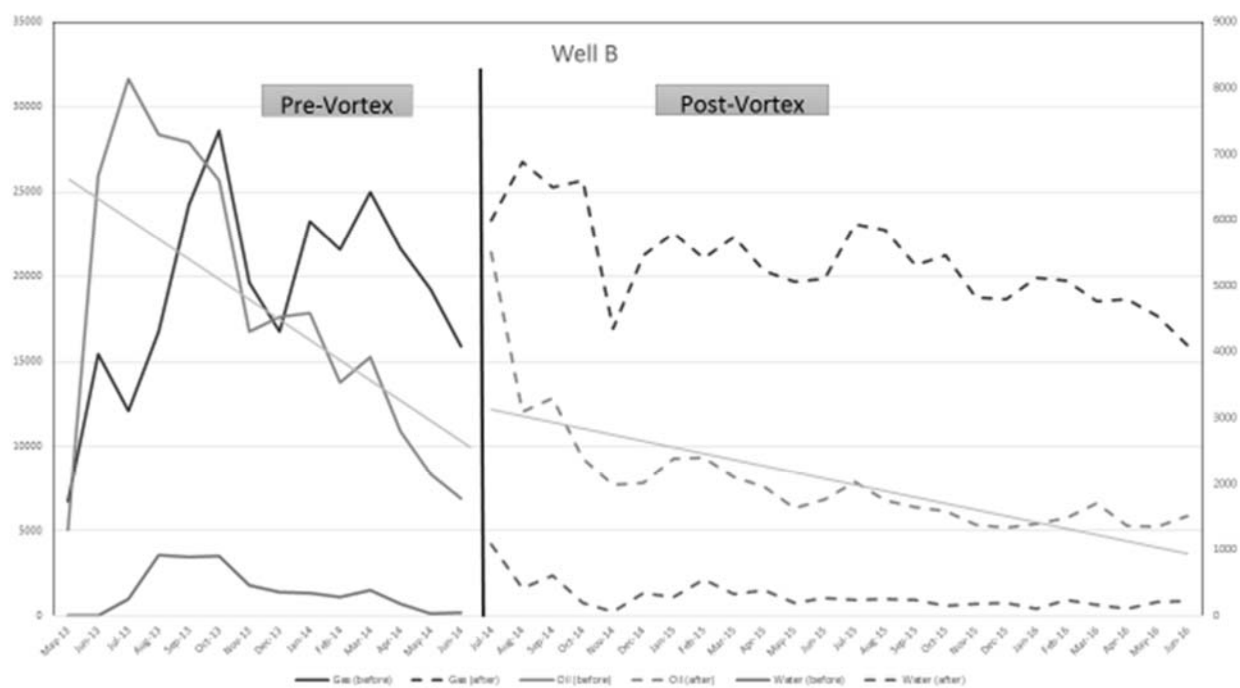

Table 8 - Well B Two-Year Lookback: Flattening of the Oil Decline Curve

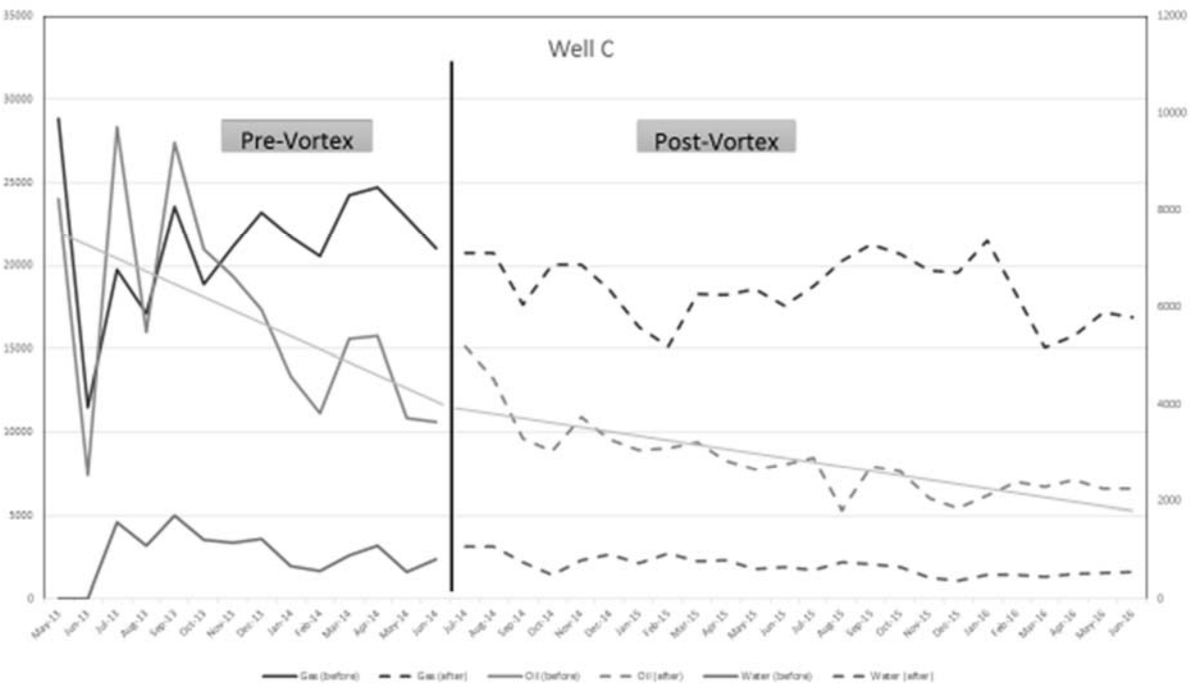

Table 9 - Well C Two-Year Lookback: Flattening of the Oil Decline Curve

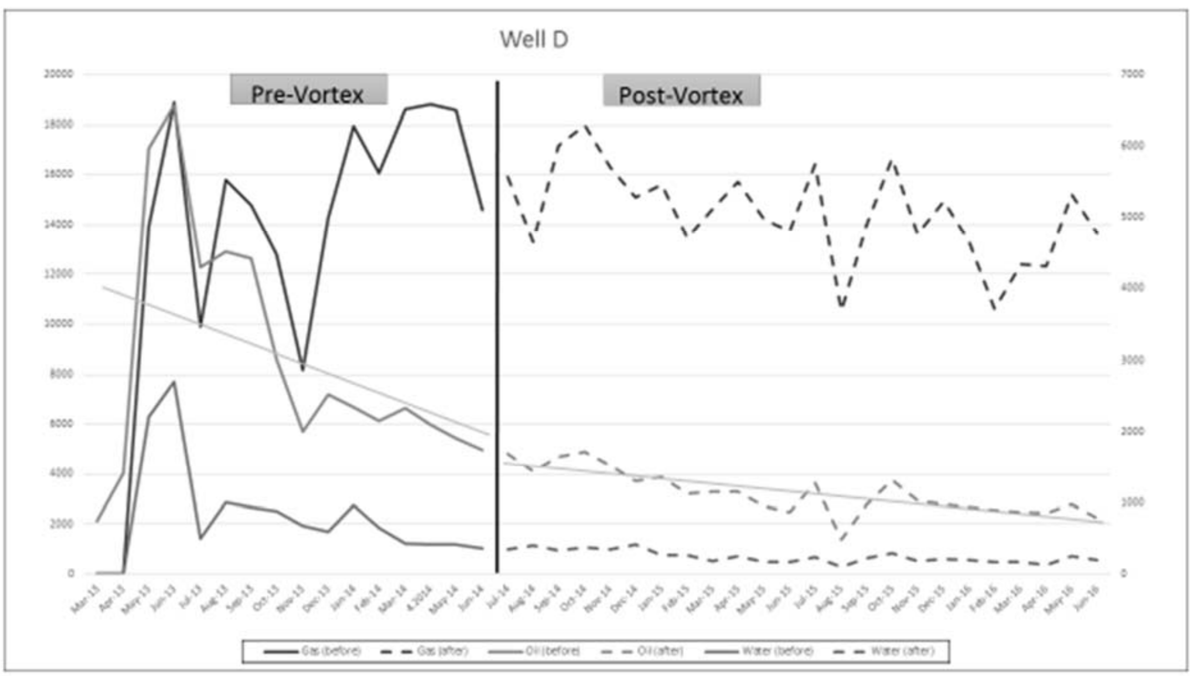

Table 10 - Well D Two-Year Lookback: Flattening of the Oil Decline Curve

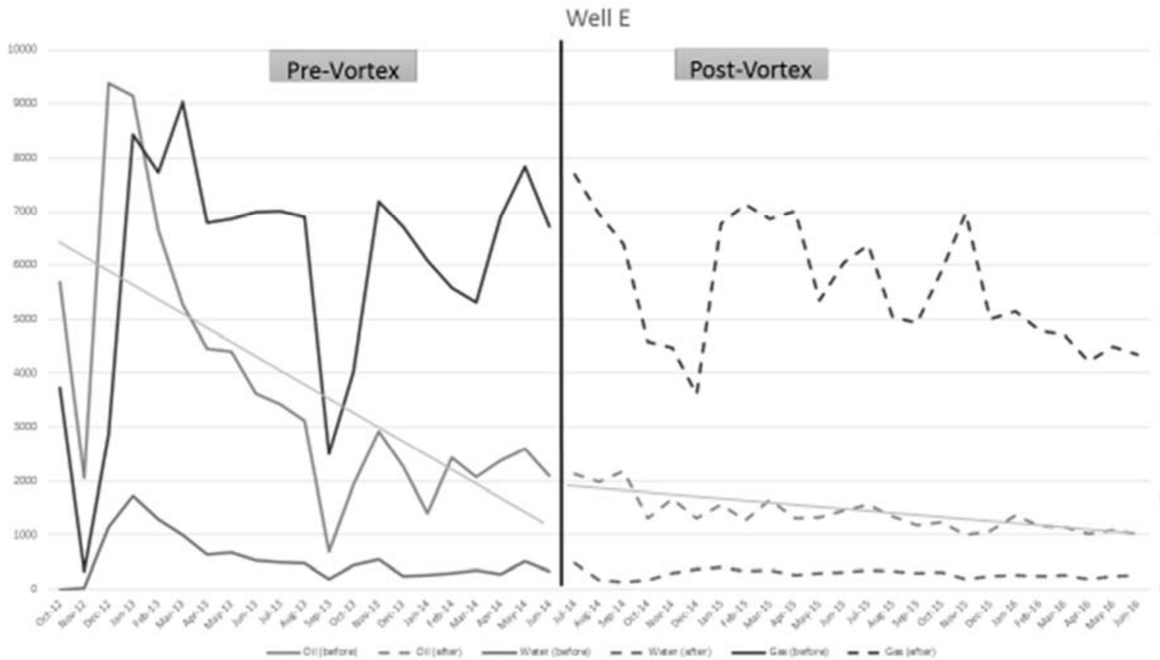

Table 11 - Well E Two-Year Lookback: Flattening of the Oil Decline Curve