Abstract

The Midland Basin Wolfcamp Shale is very early in the horizontal well development phase and has many unique technical challenges. First, the Wolfcamp has the largest vertical shale interval of active US shale plays and requires multiple stacked laterals to fully develop the field. This presents considerable challenges in determining an optimal spacing and stacking development strategy. Second, multi-phase flow complicates reservoir engineering analyses by limiting our ability to accurately predict bottom-hole pressures (BHP) from surface pressures and flow rates. Finally, many Wolfcamp shale wells require artificial lift very early in their producing lives, and the efficiency of horizontal well artificial lift techniques to drawdown the BHP must be accounted for in well performance analysis.

To help address these issues, we have run over 100 BHP gauges with real-time monitoring in Wolfcamp Shale horizontal wells. While real-time BHP gauges are common in high-rate conventional reservoirs, they are much less common in the onshore US shale environment. This paper will present several examples of real-time BHP data and analyses used to improve profitability of field development and operations. In particular, we will demonstrate how real-time BHP can be combined with other subsurface data in the Wolfcamp shale to evaluate interference between horizontal wells, quantify variability of depletion vertically in stacked pay intervals, develop flowback strategies, optimize artificial lift, and characterize the fracture system within the reservoir. These examples will demonstrate that although real-time BHP gauges have not yet been widely adopted in the onshore US shale environment, this information has yielded value far beyond the cost of obtaining the data and likely has wider application in other onshore shale plays.

Introduction

Although BHP can be calculated using surface pressure and flow rates combined with correlations, mechanistic models, or artificial neural networks, these methods lack necessary accuracy and data frequency required to effectively understand well performance and impact important development decisions in the Wolfcamp Shale. Multi-phase flow effects are the primary reason for inadequacy of the calculated BHP method. Wolfcamp horizontals produce three phases (oil, gas, and water) from nearly the first day of production and are forecasted to continue as such throughout their lives. These ever-changing
pressures and flow-regimes of the multi-phase fluid column in the vertical portion of the wellbore drastically reduce the ability to accurately calculate BHP.

The secondary reason for inadequacy of calculated BHP is lack of data frequency. Typically surface pressures are recorded daily, rounded to the nearest 10 or 50 psi, and are either an average over a 24-hour period or an instantaneous reading. For the type of analyses presented in this paper, that level of accuracy and data-frequency will not suffice. Obviously, more accurate, higher frequency surface gauges can resolve this, but the primary multiphase flow issue remains.

The two above issues exist in a naturally flowing well, which is the most stable flowing condition. Once artificial lift is introduced, these issues are amplified. Artificial lift also brings downtime and periods of lift system optimization, both of which introduce new rate and pressure fluctuations into the once stable flowing well. For example, gas-lift wells bring new challenges to calculating BHP due to compressor downtime, variations in gas injection rate, changing fluid column in the annulus impacting gas injection depth, and improperly functioning injection valves. Gauges set below these continuously-changing flowing conditions in the wellbore have significantly less noise, which results in better interpretations of reservoir performance.

The examples presented in this paper, which include horizontal wells naturally flowing or utilizing gas-lift or electronic submersible pump (ESP), will show improved analysis methods made possible through the use of measured BHP. Although only pressure data is shown in this paper, temperature data from these gauges also compliments the analysis by providing another data type, which helps educate us on the likely source and mechanism for observed pressure responses. The analysis in this paper shows the impact easily-observed qualitative pressure interactions can have on development decisions.

Method

For wells using ESPs, the method for measuring BHP is simple. ESP systems typically measure and record downhole pump-intake pressure, easily satisfying the engineer’s desire for accurate high-frequency BHP data.

For gas-lift wells, measuring real-time BHP is more complex and requires the installation of a gauge and a method for transmitting data to surface. Gas-lift wells in this study incorporated a unique system where a gauge installed at the end of the tubing string measures tubing pressure while a tubing encapsulated conductor (TEC) line is run from the gauge up the annulus to surface. The TEC line is then run through the wellhead and connects to a surface box, which records high frequency pressure/temperature and transmits to engineering offices daily or on-demand. The real-time nature of this data makes it extremely valuable for optimizing and trouble-shooting the gas-lift system. These retrievable gauge assemblies can be used for the life of the gas-lift system and reused on subsequent wells.

Fig. 1 shows the difference between high frequency measured BHP and daily calculated BHP utilizing a correlation already calibrated to Wolfcamp Shale horizontals. The calculated pressures are in the ballpark and may suffice for quick and dirty production analysis. Although the errors in calculated pressure reduce as the well reaches a stable and low flowing pressure, there is relatively less to be learned in these flowing conditions. The detailed character seen in the measured pressure is almost completely lost in the calculated values during phases that can provide the most insight, such as during initial drawdown, compressor downtime, extended pressure buildups, and offset frac hits.
Well Surveillance and Artificial Lift Optimization

Fig. 2 shows how measured BHP was used to trouble-shoot a potential artificial lift issue on an ESP well. Pump-intake pressure revealed the ESP was unable to adequately drawdown the well as seen in the flattening of BHP at an unacceptably high pressure. Attempts to improve drawdown by adjusting ESP settings were unsuccessful, therefore an acid flush was performed, resulting in increased drawdown. Production tests performed during the week before and the week after the acid flush revealed average rate increased from 460 to 1,125 BFPD. Without measured BHP, the initial production underperformance may have been simply interpreted as a bad well. With downhole pressure data, the problem was easily identified and fixed, resulting in greatly improved well performance.
It is common practice in the Wolfcamp Shale to test wells on a periodic basis after initial flowback, which helps reduce capital associated with installing production trains for each well. Fig. 3 shows how measured BHP was used as a surveillance tool in the absence of daily production tests and identified artificial lift issues on a gas-lift well. In this case, wells were being tested on a monthly basis and the well in question was assumed to be producing normally when the BHP started building, indicative of the well not flowing or flowing at a significantly reduced rate. A subsequent production test revealed the rate had dropped from 430 to 8 BFPD. Casing pressure, gas-lift injection rate, and standard surface diagnostics suggested gas was successfully injecting into the bottom gas-lift valve and the well was fine. BHP, as a unique diagnostic measurement, was the only reason to pull equipment out of the well and search for an issue. Upon pulling the tubing, a shallow gas-lift injection valve failure was discovered. The valve was replaced and the well was opened back up with an average of 800 BFPD during the first week.

The above ESP and gas-lift examples are just two of many instances where real-time monitoring of BHP in Wolfcamp horizontals allowed for rapid trouble-shooting and optimization of artificial lift systems, some of which may never have been fully understood without pressure data. These examples show how the value of having these down-hole gauges is far greater than the minor cost of deployment.

**Identifying Near-Wellbore Damage**

The example in Fig. 4 shows how measured BHP can be used to identify root causes of well underperformance by analyzing pressure buildups during unexpected shut-ins associated with operational issues. The two gas-lifted horizontal wells in Fig. 4 had similar geology, drilling practices, landing intervals, and completions but were flowed differently to test impacts of managed drawdown. Well #1 was flowed aggressively with no drawdown management, while Well #2 was flowed conservatively through extended use of chokes. Interestingly, the well with more drawdown not only had higher rate, but also higher productivity, which was opposite of what has been observed in several other shale plays. Due to operational issues, both wells were shut-in and BHP was monitored during extended pressure buildups. Log-log plots of pressure & pressure derivative vs time revealed that Well #2, with managed drawdown, had interpreted skin damage as indicated by the increased separation between the pressure and pressure derivative curves compared to Well #1. While this was one of several key field trials that supported a
flowback strategy decision for all future wells, it also demonstrated the applicability of using real-time BHP monitoring to identify near-wellbore damage during shut-ins.

Developing an Optimal Spacing and Stacking Strategy

Determining optimal well spacing early in the development of single-target shale plays has presented many technical challenges. The Wolfcamp Shale, along with the overlying Spraberry Shales, provide multiple stacked targets for horizontal well development.\textsuperscript{3,4} Introducing this third, vertical dimension increases the complexity and importance of understanding well-to-well interference and its impact on well performance. \textbf{Fig. 5} shows a type log illustrating the number of potential targets that might exist at a single well location. Given the statistical variability in well performance, it would take 50-100 wells to determine an optimal spacing and stacking strategy in a given area based on well performance alone. Given the geomechanical variability throughout the field, these pilots would have to be repeated in multiple study areas, requiring hundreds to thousands of wells to fully optimize spacing and stacking across a large acreage position. Getting up the learning curve quickly in regards to spacing and stacking has required the analysis and integration of multiple engineering and geoscience datasets, with inter-well pressure interference being at the top of the list.
**Fig. 6** shows how measured BHP and interference tests can be used to quantify magnitude and direction of time-zero well connectivity. Time-zero connectivity is used in this paper to describe connectivity observed between wells during initial flowback. **Fig. 6** shows shut-in BHP response from Well #5 as four surrounding wells are opened. Pressure begins to decline as soon as Well #1 is opened, indicating connectivity with the offset well. The pressure decline steepens as Well #2 is opened, again during Well #1 & Well #2 choke changes, and again when Wells #3 and #4 are opened. This valuable data conclusively indicates that inter-well connectivity simultaneously exists in each of four directions around Well #5.
Fig. 7 takes three wells from the previous example and shows how the observed time-zero connectivity may or may not degrade with time. Four months after time-zero connectivity was observed, an additional interference test was conducted. Wells #4 and #5 were shut-in, BHP was monitored during pressure builds, and surrounding wells kept producing. After extended and stable pressure builds were observed, Well #3 was also shut-in. Well #4 immediately responded with a more rapid pressure buildup and a step change increase in pressure derivative, indicating sustained connectivity with Well #3. Well #5, however, did not respond to Well #3 being shut-in, indicating the time-zero connectivity observed between these two wells no longer existed. This leads to a key hypothesis that connectivity observed during initial flowback doesn’t necessarily mean wells are spaced too closely due to potential rapid degradation of the connected flowpaths.
Fig. 8 shows another time-zero interference test but also includes inter-well pressure interaction during completion and adds a third stacked landing interval to the well configuration. Well #2 is landed in the Lower-B, Wells #1 and #3 are in the Upper-B, and Well #4 is in the Wolfcamp A. Wells #1 and #2 were completed first and had tubing and bottom-hole gauges installed in time to monitor shut-in pressure during a portion of Well #3’s completion.

Interference between wells is clearly observed by changes in measured pressure trends associated with offset fracturing operations, placing offset wells on production, and in extreme cases by changing chokes on offset wells. In this example, the observation that the Upper-B and Lower-B have time-zero connectivity but Upper-B and A do not complements our understanding of variable rock strength between these three landing targets and those rocks’ ability to act as frac barriers during completion. Differences in these early responses provide insight to the shape and directionality of the induced fracture system and can guide development optimization by making spacing, stacking, and completion adjustments to wells with the strongest connectivity, especially if those interactions do not adequately degrade with time.

Fig. 9 shows how a vertical well can be used to assist in understanding distance and directionality of horizontal well depletion. The vertical well in this example had previously been completed in multiple zones above, in, and below the Wolfcamp and produced for 10 months. A retrievable multi-gauge assembly was then installed in preparation for offset horizontal well activity. This assembly consisted of multiple downhole gauges each isolated between packers for monitoring zonal shut-in pressure. A TEC line connected each gauge in series and ran up to surface where real-time monitoring was recorded at a surface box. One of the most important yet difficult challenges in well spacing and stacking optimization is determining how much depletion is occurring a certain distance laterally and vertically away from a horizontal well. This multi-gauge assembly is designed to utilize vertical wells for the purpose of quantifying the shape and character of the depleting reservoir volume around a horizontal well.
While an offset horizontal well was being drilled in very close proximity to the vertical well, the multi-gauge assembly was installed and the corresponding pressure buildup is seen in the bottom left of Fig. 9. Next, pressures from each gauge abruptly increase with varying degree of intensity as a response to the horizontal well completion. There is a short period between completing and opening the horizontal well, and then pressure decline steepens when the horizontal well opens. Pressure continues to decline over time as the horizontal well produces. The red pressure curve shows the most depletion and sustained connectivity with the horizontal well, followed by the green and blue pressure curves. The purple and orange pressure curves increase during the horizontal well completion, but have very little depletion response from horizontal well production. The minimal pressure decline of these two gauges may be dominated by leak-off of post-frac, super-charged pressure or by minor communication with other gauges through a possible micro-annulus outside the vertical wellbore. The varying degree of response among the five gauges provides drastically increased understanding of horizontal well depletion with respect to distance, direction, and time; all of which improve our understanding of the fracture system feeding the well.

These pressure responses also provide some additional benefits. Pressure buildsups prior to horizontal well completion provide valuable zonal-specific information that would otherwise be very costly and difficult to observe from a fully commingled vertical well. The pressure response peaks during horizontal well completion provide direct measurement of zonal frac gradients. Zonal fluid leak-off rate is directly measured in the period between horizontal well completion and production. The gauge with the strongest connectivity shows distinct responses to horizontal well compressor downtime and provides pressure buildsups for reservoir analysis during extended shut-ins.

**Conclusions**

Multi-phase flow and artificial lift cause significant inaccuracies in calculating BHP from surface rates and pressures in Wolfcamp horizontal wells. For improved and rapid well performance analysis, measured BHP is required.
Real-time measurement of BHP can be used to optimize gas-lift and ESP design and operational settings. It is also useful in trouble-shooting operational issues and identifying where performance problems lie.

High-frequency measured BHP allows pressure buildups in Wolfcamp horizontals to accurately diagnose well performance, which leads to more informed development decisions such as optimizing spacing, stacking, flowback strategy, and completion design.

Connectivity can be easily observed through pressure interaction between horizontal wells during completion and production. Measured BHP allows us to qualitatively compare the magnitude and direction of these interactions among wells, and if continuously monitored can help us understand if and how they degrade with time. This provides a greater understanding of the fracture system within the reservoir.

Utilizing downhole gauges in offset vertical wells can drastically improve understanding of horizontal well depletion with respect to distance, direction, and time.

The value of real-time BHP measurement and the impact it can have on critical development decisions far exceeds the minor cost of deployment in Wolfcamp Shale horizontals.

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References