EARLY-TIME ASSESSMENT OF STIMULATION EFFECTIVENESS AND RESERVOIR QUALITY FOR MULTIPLE ZONE, RAPID TURNAROUND FRACTURE STIMULATION PROCEDURES

Daniel W. Gunderson, B.J. Services, Inc.
Mark H. Yamasaki, Performance Sciences, Inc.
D. King Anderson, II, Authentix, Inc.

INTRODUCTION

For every well drilled, there is a performance expectation. At a minimum, there is a forecasted Pi, initial production rate, and time to payout. When the well's production does not meet expectations, it is common to wonder whether the problem is the reservoir, the completion, or the wellbore. Answering these questions quickly, accurately, and inexpensively is difficult enough with single-zone completions; however, it has been virtually impossible for wells with commingled production. Historically, even simple wells defied rigorous investigation without costly and time-consuming pressure buildup analysis. To determine the critical characteristics that dictate a well's performance, a non-intrusive method is necessary. This paper introduces a methodology that not only delivers robust answers for single-zone producers but, in many circumstances, also answers the same questions for wells with commingled production.

SINGLE-ZONE WELL (WEST TEXAS - CANYON)

Even in wells completed in a single zone, without the proper data and tools, determining what causes deviations from expectations is difficult. Figure 1 shows a West Texas Canyon well where the initial pressure and production rate are as expected, but the actual production deviates significantly from the forecasted production (below plan by more than 45%). Using production analysis methods to analyze the operator's daily production data, it was determined that the well is in linear flow, thereby indicating the presence of a previously unknown fault (see Figure 2).

PRODUCTION DATA ANALYSIS TOOL

The Reciprocal Productivity Index Method (RPI), authored by Dr. James Crafton, is a graphical well performance analysis tool. Developed around the premise of an extended drawdown test, the method allows production data analysis (hourly, daily, monthly, etc.) to determine permeability-thickness (kh), effective fracture half-length (skin), and drainage area. Crafton derived that the Pi-Pwf(t)/q(t), or RPI, relationship can be used to normalize noisy production data. This method allows for the use of traditional pressure transient analysis, such as the Miller Dyes Hutchinson analysis. In the relationship, Pi is reservoir static pressure, Pwf is bottomhole flowing pressure, q is flow rate, and t is time.

The method relies on three linear graphs and two additional diagnostic plots to represent reservoir, completion, and wellbore properties. Pattern recognition combined with operational knowledge enables the tool to be used in several applications, from reservoir evaluation to completion optimization. All the plots are used in concert to determine a more unique solution. The graphical portion of the analysis allows the user to examine features such as formation linear flow behavior, liquid loading in the wellbore and the fracture, reservoir pressure, multilayered effects, etc.

CHEMICAL MARKERS

There are many different families of chemical compounds that make effective markers for this type of application. Typically, these markers were developed to be conservative at reservoir conditions. In this context, "conservative" means that the markers do not absorb onto reservoir rock matrix and have a very limited partitioning coefficient for oil (stays with the water). Additionally, these tracers are stable (non-radioactive), thereby giving them the benefit of long life, which helps with different types of analysis.

Markers are added to frac fluids at concentrations of 1 to 10 parts per million. At regular intervals, after flowback commences, samples are collected and sent to the laboratory for analysis. Typically, samples are taken during the first 60 days after production begins. Depending on the amount of "free" water produced, markers can be quantified for approximately 90 days; in a few instances, marker concentrations can be quantified for up to 9 months after injection.

Running chemical markers also differentiates “load water” from “free water,” thereby allowing early time determination of an individual zone’s gas/water ratio.

WELLS WITH COMMINGLED PRODUCTION

On their own, even powerful production analytical methods like RPI cannot successfully unravel each zone’s characteristics. Analyzing commingled producers requires that production be allocated to individual zones before employing RPI. In the two examples that follow, each zone was fracture stimulated and each stimulation job was tagged using a different water-soluble, non-radioactive chemical marker. During flowback, samples were collected and analyzed for the presence and quantity of marker. Each zone’s gas/water ratio was ascertained, and, after commingling production, marker concentrations were used to determine water and gas production from each zone.

North Central Texas (Barnett Shale)

After acquiring significant acreage in the Barnett Shale, the operator was disappointed in the performance of the first well and, consequently, wanted to try differing techniques on the next three wells. In addition to employing different completion schemes, the operator wanted to compare the wells on both a reservoir and completion basis without unnecessarily shutting in the well and performing multiple production logging runs. To achieve these goals, the operator chose an analytical tool that evaluates flowing production data and used chemical markers to tag every fracture stimulation job.

On the first well, completed after these decisions were made, the operator chose to stimulate all three zones individually. Each frac job used a different marker. Figure 3 illustrates the production data from the first 60 days, and Table 1 lists the analytical results from these data. To help control liquids, the operator landed the tubing below the bottom perforations. An interesting production analysis finding from the second stage (middle zone) is the location of a boundary at 226 feet. Upon further review, the geologist confirmed the presence of a fault at about the same distance as the analysis indicated. Of particular note, the initial analysis of the allocated production data showed that the tubing was landed higher than the operator originally thought. A subsequent investigation proved that the tubing was landed “high.”

South Texas (Vicksburg)

In this instance, the operator used chemical markers to tag the top three of eight fracture stimulation jobs. After stimulation, all eight zones were commingled, as shown in Figure 4. The objective of tagging these three stages was to ascertain the gas contribution from the top versus the bottom five zones. Table 2 compares each zone’s gas contribution as measured by a production log (PLT) and chemical marker analysis. Because the water rate (240 Bbls per day) was small compared to the gas rate, the PLT could not measure the water. Both analyses concluded that the top three zones are contributing better than 80% of the total gas. Additionally, the marker analysis concluded that the majority of the water is produced from the sixth stage; consequently, the lower 5 zones are smothered with water that encumbers their rate. Furthermore, the production analysis concluded the well had a boundary at approximately 261 feet.

CONCLUSION

Using the combination of production analysis and chemical markers, three substantially geologic different gas reservoirs (one single-zone, two commingled) were evaluated for performance. In one case, production underperformance was identified because of geologic constraints – not fracture mechanics.

Because the commingled production data were interpretable, the operators could enhance economics in future completions. They were able to identify, quantify, and analyze production from the dominant reservoirs. Some reservoirs were identified as being unable to contribute to the wells’ production; therefore, future wells were not completed in the non-productive horizon. The ability to separate wellbore issues, completion issues, and reservoir issues allowed the operators to optimize economics by working over wells with wellbore and completion issues. The completion practices have been changed to reduce completion costs and increase production rates.

REFERENCES

SPE 56610 – A Novel Approach to Interwell Tracer Design and Field Case History

SPE 56427 – Application of Tracers to Monitor Fluid Flow in the Snorre Field: A Field History

Crafton, J.W.: "The Reciprocal Productivity Index Method, A Graphical Well Performance Simulator," presented at the 43rd Southwestern Petroleum Short Course, Lubbock, TX. (Apr. 16-17, 1996).

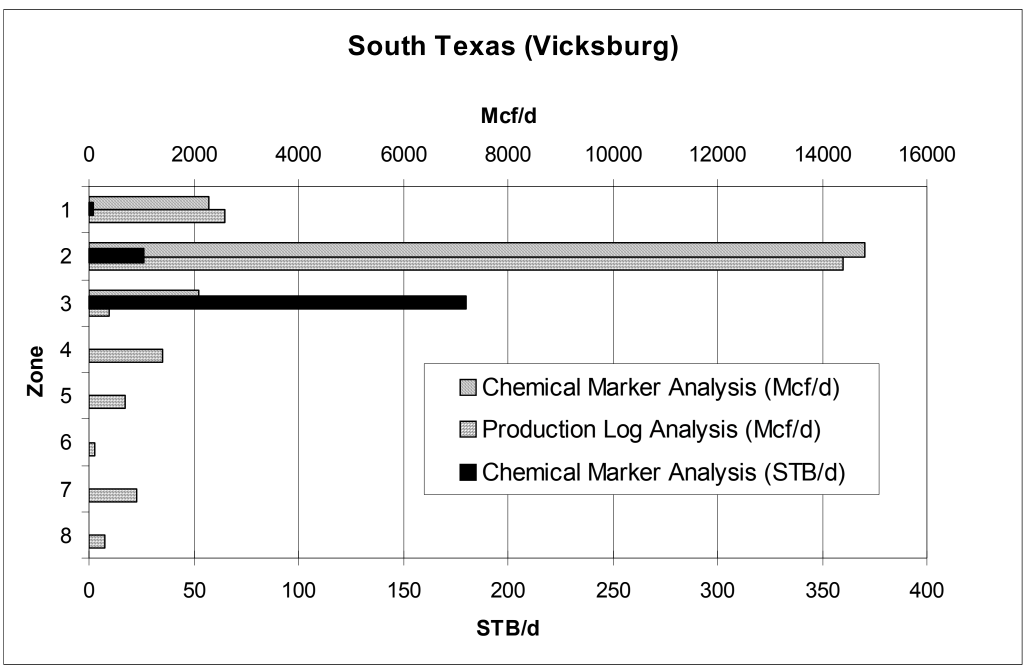
Crafton, J.W.: "Reservoir Pressure and Skin from Production Data Using the Reciprocal Productivity Index Method (The Intercept Method)," presented at the 47th Southwestern Petroleum Short Course, Lubbock, TX.

Table 1
North Central Texas (Barnett Shale) – Results (First 60 Days of Production)

Well Parameters		Total Well		1st Stage		2nd Stage		3rd Stage	
		Log	Prod	Log	Prod	Log	Prod	Log	Prod
Rate	PI (psi)	3676		3675		3576		3477	
	xf/Skin (ft)	?	52	?	31	?	153	?	74.4
	K (md)	?	2.66 md-ft	?	2.18 md-ft	?	0.8 md-ft	?	0.554 md-ft
	h (ft)	253		193				41	
Volume	h (ft)	253	230 Mcf-R	193	193 Mcf-R	19	25 Mcf-L		36.4 Mcf-R
	Φ (%)	10		10		5			
	S_w (%)	9.3		26		37			
	Area (ft^2)	?		?		?		?	

Note – Volumes depicted represent only that part of the reservoir touched by the "pressure" wave and not the total volume of original gas in place for the well.

Table 2
South Texas (Vicksburg)



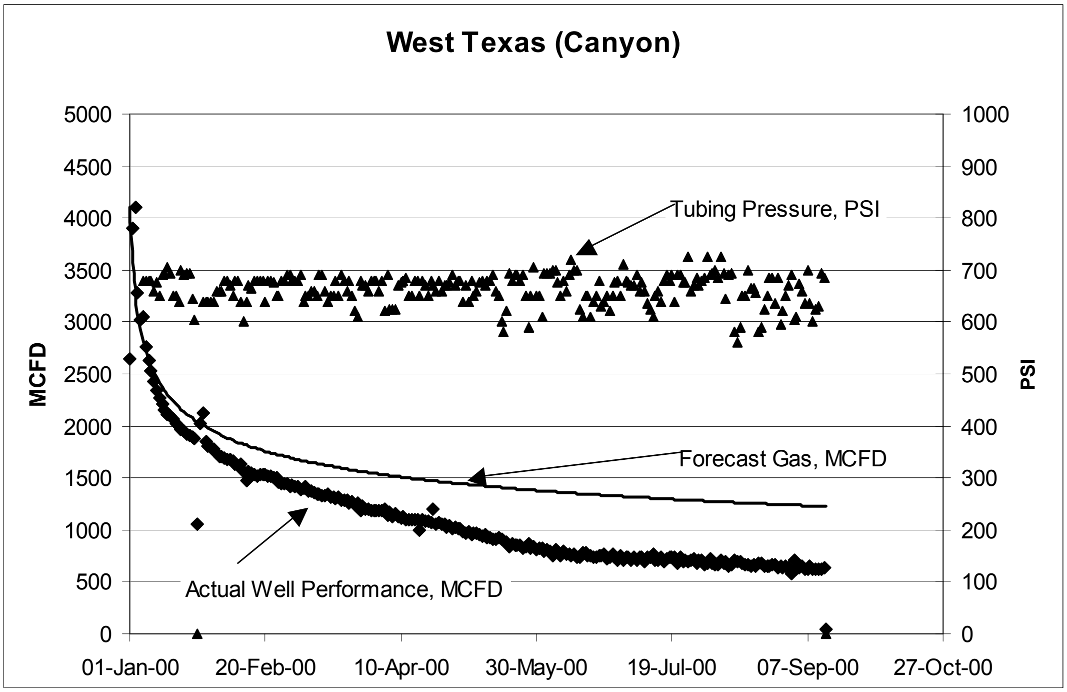


Figure 1 – West Texas (Canyon) Well Expectation vs. Actual Production

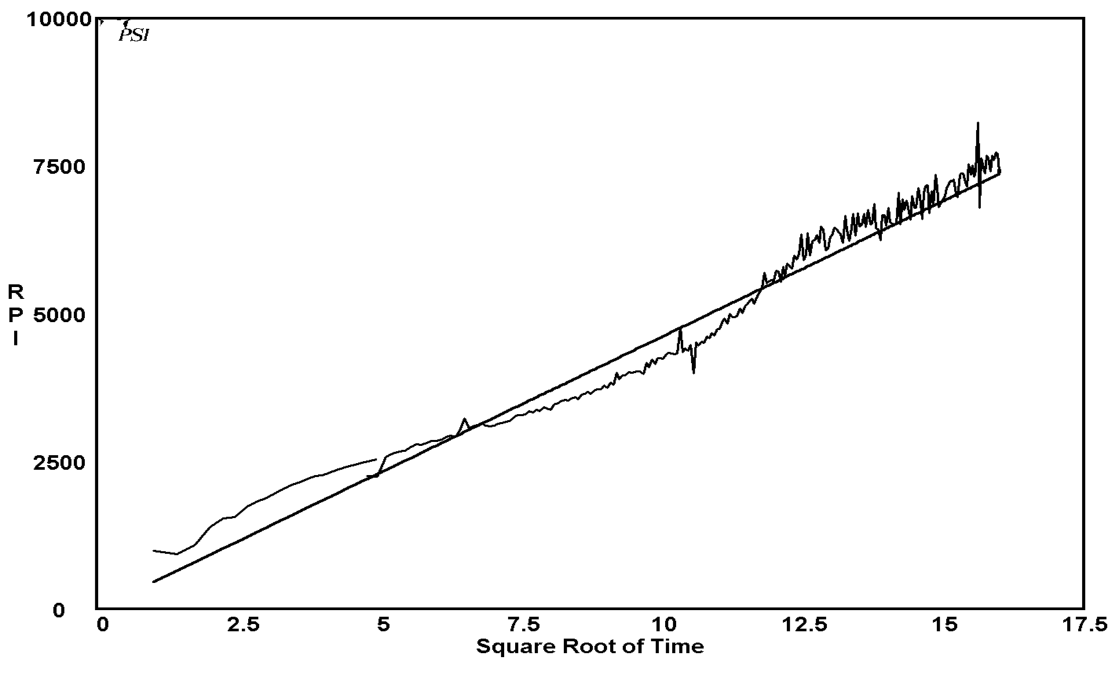


Figure 2 – West Texas (Canyon) MDH Chart of Linear Flow System

Barnett Shale Three Stage - Overall Well Production

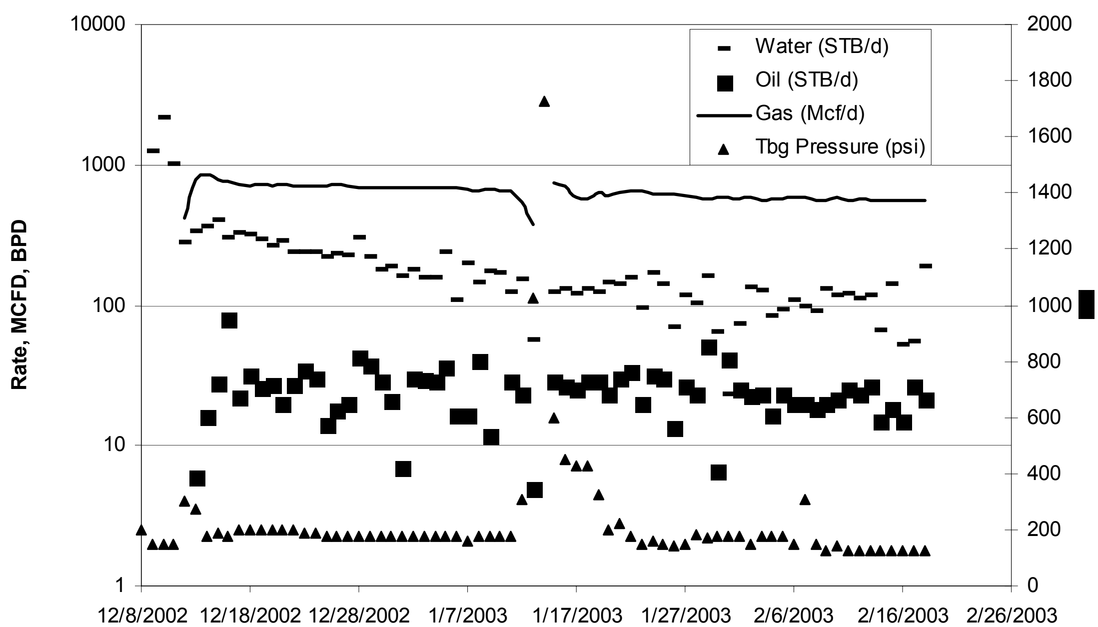


Figure 3 – North Central Texas (Barnett Shale) – Three-Stage Stimulation

South Texas

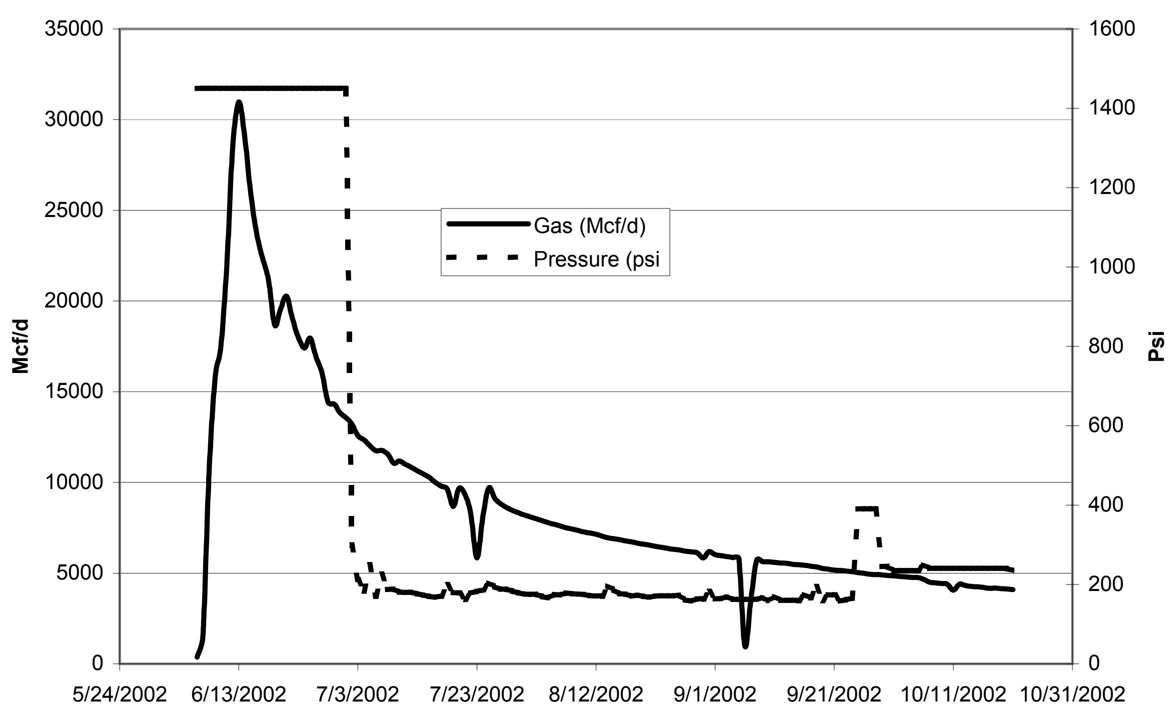


Figure 4 – South Texas (Vicksburg)