REAL-TIME ANALYSIS ON A DRILLSTEM TEST USING WIRELESS TELEMETRY

Kent Holder, Halliburton Energy Services
Dick Heine, ProTechnics
Doug Perschke, Marathon Oil Co.

Abstract

The openhole drillstem test (DST) has changed little in the last 30 years; however, pressure-transient analysis recently has made significant advancements. Modern electromagnetic telemetry systems are the basis for an economical method of transmitting pressure and temperature readings in real time.[1] Improvements in information technology now allow advanced on-site analysis. This paper provides an overview of an openhole test, describes the components used during real-time analysis, and discusses the case history for a real-time job in Andrews County, TX.

Introduction

The openhole test is a common method of formation evaluation that is most often used during the drilling phase of the well. To determine reservoir content, downhole tools allow a zone of interest to produce. Downhole gauges record changes in pressure during the test, providing data that later can be analyzed to determine reservoir characteristics. Designing and performing a conclusive test is difficult when key reservoir parameters, such as permeability, reservoir description, and bottomhole pressure, are not known. On a standard test, the operator must wait until the tools are retrieved before

- determining if the test was mechanically successful
- analyzing the data
- determining if the test was conclusive
- determining the next step for the well.

Real-time data analysis allows the operator to conduct a conclusive test, analyze the data, and determine the next step, often before the tools are out of the well. The time saved by analyzing the data in real time reduces rig costs and provides owners with more time to review the well data.

Description and Application of Equipment Used

The test string is a common openhole, on-bottom test assembly consisting of

- lower gauge case
- perforated anchor
- two openhole packers
- safety joint
- jars
- above-packer gauge cases
- rotational flow/shut-in valve
- tester valve

The wireless telemetry system is housed in an above-packer gauge case with a nonconducting sub. The surface equipment system locks on the signal, decodes it, and displays the data. The telemetry system also exports the data to a PC containing a data acquisition system that can display diagnostic plots and export the data for advanced interpretation. **Figure 1** shows the screen setup for the data acquisition system. Another PC containing commercial well-test evaluation software interprets the downhole data and can print, fax, or e-mail the data during the test. The package produces a semilog analysis and pressure simulation matching based on reservoir models.

Case History Using Analysis Application

The real-time analysis application performs the following functions:

- identifies inflection points
- verifies tool opening and closing
- allows flow and close-in time adjustments based on reservoir response
- identifies problems and anomalies
- estimates flow rates
- analyzes pressure transient response

The case history well was drilled to total depth (TD) with no show in the primary target. A DST performed in an upper formation show indicated an oil show that was not commercially productive. Openhole imaging logs showed another pay interval just below the one tested. A cement plug was spotted to allow an on-bottom test. The image logs showed the zone to be a vugular, dual-porosity interval.

The well was located south of Andrews, TX. Drilled openhole size was 7 7/8 in. The test interval was 9,620 to 9,897 ft. The logs identified 39 ft of net pay with a 4% average porosity.

Figure 2 shows the complete test. The first flow period was 22 minutes, the first shut-in period was 65 minutes, the second flow period was 122 minutes, and the final shut-in period was 533 minutes. A fill or a ledge was encountered 30 ft from bottom. The tools were worked to bottom, and the tester valve was opened. **Figure 3** shows a close-up of the initial hydrostatic pressure in the inflection point. The plot shows the following problems:

- The well is taking fluid.
- The tester valve opened while operators were working tools to the bottom.
- The packer was difficult to seat
- The tools plugged before opening.

Figure 4 shows the first flow period. The opening pressure indicates that 436 ft of 9-lb/gal mud entered the pipe when the tools opened prematurely. The plot shows that the perforated anchor was plugged. If the downhole shut-in valve had closed after 15 minutes, as had been planned, the well would have closed during plugging. The test tools could possibly have become plugged completely, and the tools would have been tripped to remove the cuttings. The well was flowed until the plugging action decreased. Rate calculations were based on 100% mud recovery and total pressure change. The first-period flow rate was calculated to be 277 BOPD.

Figures 5 and 6 show the analysis from the well-test program. The shut-in period was run until the derivative log-log plot showed radial flow. A semilog line was drawn, yielding P* of 4,071.93, permeability of 0.53 md, and skin of -3.35. (P* is the calculated initial reservoir pressure, which is calculated from the semilog analyses.)

Figure 7 shows the second flow period. The recovery was assumed to be 100% 41-gravity oil. Operators used the pressure-change method to calculate the rate, which was averaged over 20 cycles during the well-test program (**Figures 8 through 10**). During the second flow period, the well-test program was used to model bottomhole pressure response and simulate the time required for the second shut-in period. Reservoir parameters from openhole logs and analysis of the first shut-in period were used in the simulation. A 7 1/2-hour shut-in period would be required to provide conclusive data.

Figures 11 through 13 show the actual data plotted with a simulation from the well-test program. The actual data and simulation are a nearly perfect match. **Figure 14** shows the shut-in periods as they would have appeared if standard shut-in times had been used. The inflection points from the shut-in periods suggest that the well was depleting, but the P* analyses indicate that the shut-in pressures were similar.

Figure 15 shows the final hydrostatic reading. At the completion of the test, the tools were stuck. The first two spikes on the chart indicate that the jars were not effective. The third spike shows a hard hit followed by the well's taking on fluid. The well was allowed to equalize, and the tools were jarred loose after two more attempts.

Conclusions

Real-time analysis increases the chance of a conclusive test and allows the operator to take advantage of modern pressure-transient analysis and advancements in information technology. The information from the test is available for review before the tools are out of the hole, which reduces idle rig time and increases the time available for making decisions.

References

1. "Wireless Telemetry for Transmitting Pressure and Temperature on a Drillstem Test," paper SPE 35241 presented at the 1996 Permian Basin Oil and Gas Recovery Conference, Midland, Mar. 27-29.

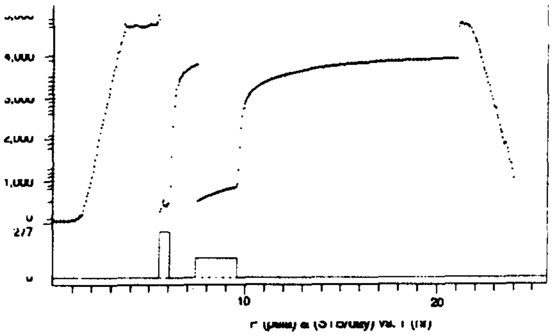

Figure 1A - Example Cartesian plot from Figure 1

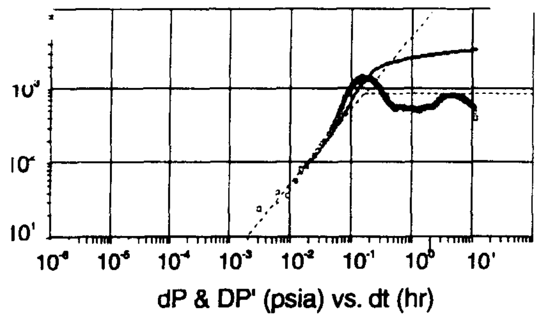

Figure 1B - Example derivative log-log plot from Figure 1

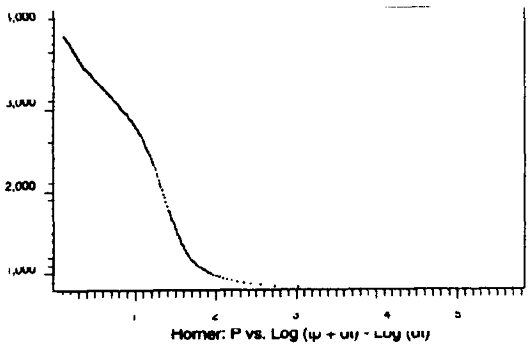

Figure 1C - Example Horner plot from Figure 1

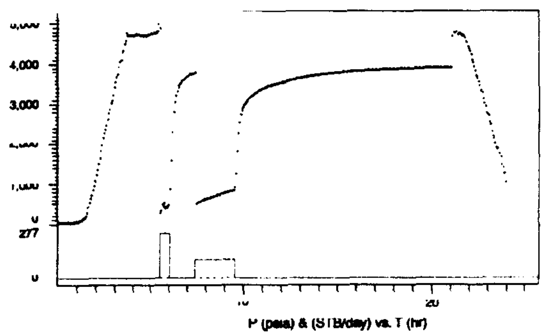

Figure 2 - A Cartesian plot of the complete test.

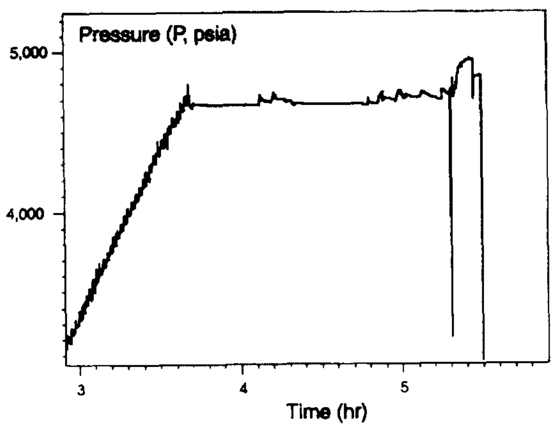

Figure 3 - A closeup of the initial hydrostatic pressure in inflection point showing several problems.

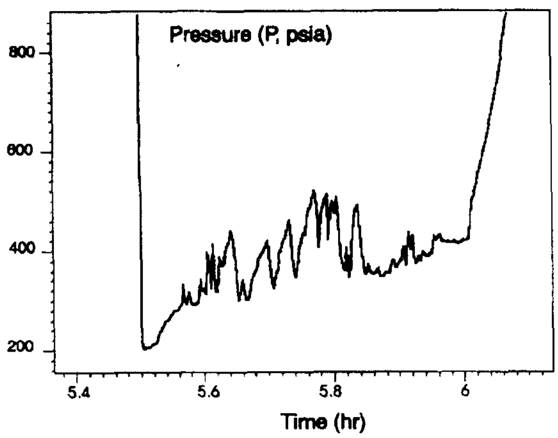

Figure 4 - Plot of initial flow period.

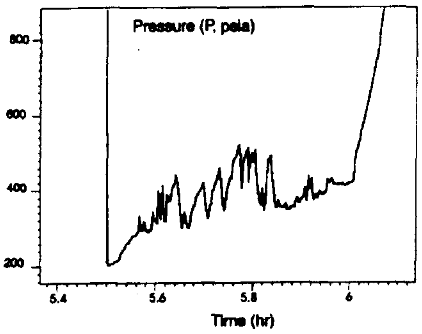

Figure 5 - Derivative log-log plot from the well-test program's first shut-in period semilog analysis.

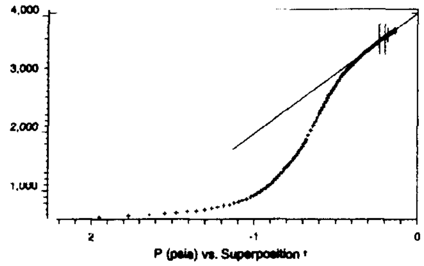

Figure 6 - Semilog plot from the well test program's first shut-in period semilog analysis. Semilog results were 0.53 md permeability, =3.35 skin, and 4,071.93 psi P*.

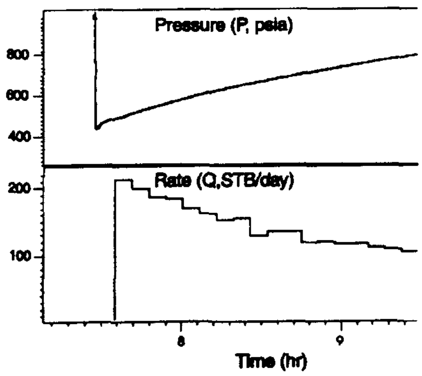

Figure 7 - The second flow period.

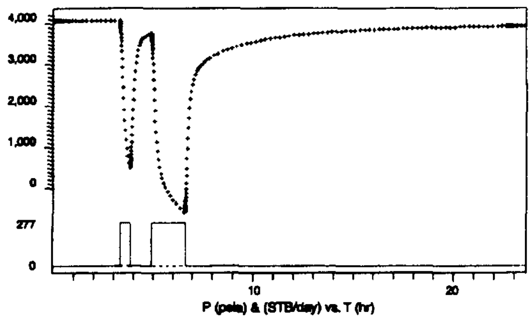

Figure 8 - Second shut-in period simulation showing P (psia) and Q (STB/day) vs. T (hr).

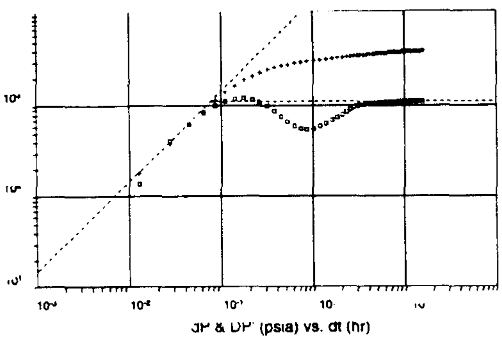

Figure 9 - Second shut-in period simulation showing dP and dP' (psia) vs. dt (hr).

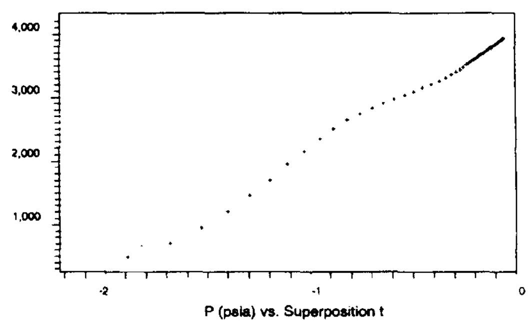

Figure 10 - Second shut-in period simulation showing P (psia) vs. Superposition t.

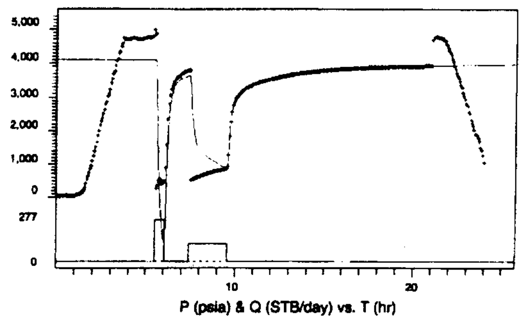

Figure 11 - Second shut-in period actual data with simulation match showing P (psia) and Q (STB/day) vs. T (hr).

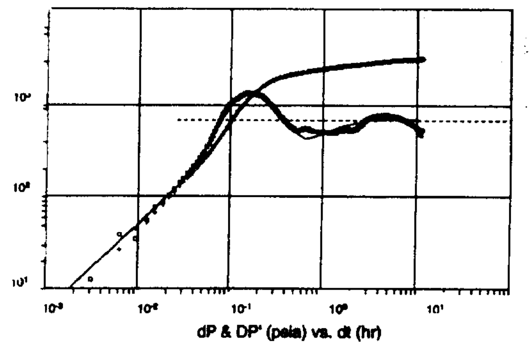

Figure 12 - Second shut-in period actual data with simulation match showing dP and dP' (psia) vs. dt (hr).

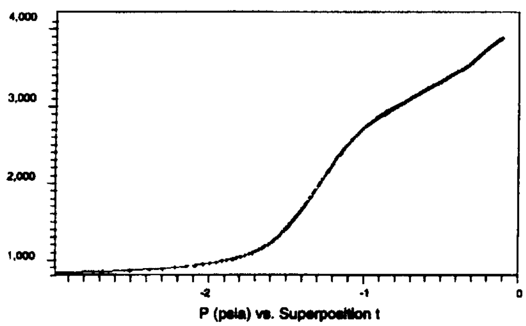

Figure 13 - Second shut-in period actual data with simulation match showing P (psia) vs. Superposition t. Semilog results were 0.33 md permeability, -2.59 skin, and 4,081.3 psi P*.

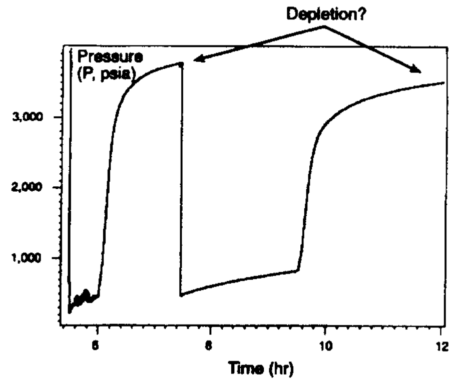

Figure 14 - Shut-in periods as they would have appeared based on standard shut-in times.

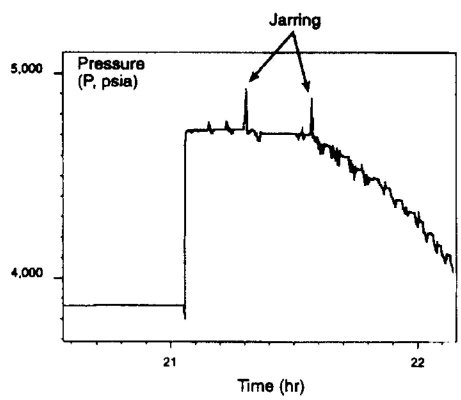

Figure 15 - Final hydrostatic pressure reading.