Surface Pressure Data For Well-Test Analysis At A Joint Venture Gas Project In Sichuan

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Abstract

Pressure Transient Analysis (PTA) of Bottom-Hole Pressure (BHP) data is a well-established method for estimating reservoir dynamic parameters and determining well behavior under different production stages. Unfortunately, permanent recording of bottom-hole data is not always operationally possible, particularly in the case of horizontal/high deviated wells and/or H_2S (sour gas) reservoirs, for safety and cost-effective reasons. However, most wells are equipped with real time and digital gauges at the wellhead, which record well head pressure (WHP) and temperature (WHT) data continuously. What to do to maximize the value of the available information and to minimize the operational cost and execution risk?

This paper is to present the current experience at the Joint Venture gas project, utilizing the new converting technology, with which, WHP data can be converted to BHP data accurately during well shut-in. With this success, the surface wellhead pressure WHP can be used for well-test analysis (i.e., PTA). There are several advantages in deriving the useful information from wellhead surface data: (a) the cost of recording wellhead data is much less than that of a downhole survey; (b) the risks associated with running tools in the wellbore are eliminated, particularly useful in horizontal/high deviated wells where tools cannot be run deeply enough; (c) the work can be done any time where well shut-in is possible (both planned and unplanned downtime); and (d) this can reduce the significant production loss for any well intervention, particularly when spare gas supply capacity is low.

In brief, effective use of wellhead data is considered as an excellent technology application in China to minimize the traditional well-test intervention, which is with high cost and potential H_2S risk. Operational lessons learned and case studies on PTA will be shared.

Introduction

This greenfield sour gas project is developed in Sichuan, China. The full field development schematics is shown in **Figure 1.**

The project involves development of gas resources in Triassic carbonate reservoirs. The field of interest is made up of bedded dolostone and limestone facies of Early Triassic age. The depositional environment is carbonate platform and ramp with oolitic shoals. Gas is trapped in thrust-related anticlinal structures and seals comprise tight limestones and anhydrites. The structure is normally large. Rock porosity ranges from 3 to 20% and permeability ranges from 0.01 to 1,000 millidarcy (md). The reservoir fluid is dry gas, with H_2S and CO_2.

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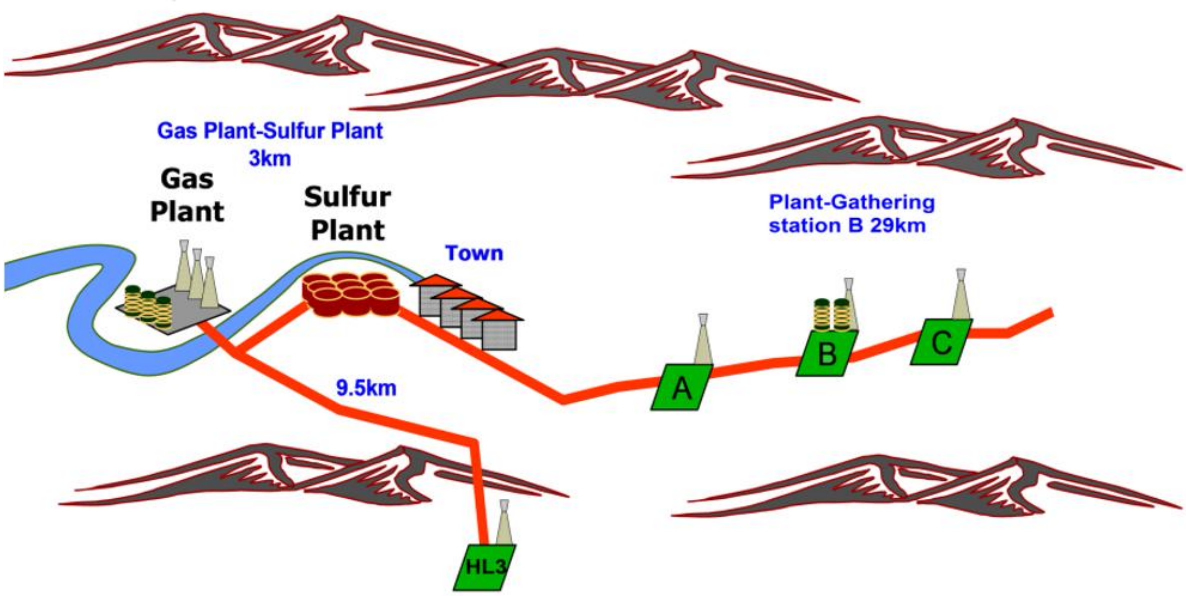


Figure 1—Sour gas development project.

Wellbore Structure. Most of the development wells in this field were drilled and completed in the 2000s. The wells are either horizontal or high angle deviated directional wells to maximize the deliverability potential and to minimize the development footprint. In 2012-2013, the wells were worked over by removing the existing completion string, running and cementing an inner combination string of 4 1/2-in.×7-in. casing with gas tight connections and H_2S service metallurgy. The wells were then recompleted with 4 1/2-in. H_2S service metallurgy production tubing. The wells remained shut-in until mid-2015. A well schematic after recompletion is shown in **Figure 2**.

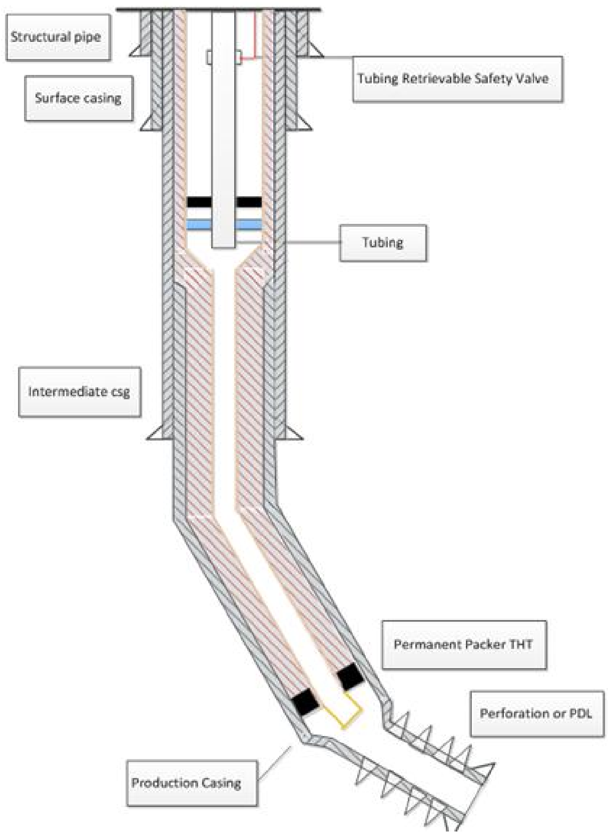


Figure 2—Typical Wellbore Schematic.

Historical Test Results and Key Challenges. Most of the development wells were tested right after they were drilled and completed, with the primary goal to unload the completion fluid, to clean up the formation, and to ensure a sustainable deliverability of the well during the production phase. During this testing, five wells obtained large production rates. The goal was thus fully achieved.

Most of the tests were short. Furthermore, to reduce potential SO_2 emissions of testing, there was an attempt to conduct a well-test using the wellhead pressure survey (convert wellhead pressure to bottom hole pressure by using the static gas column method), and perform well-test analysis, which has been proven successful in many locations worldwide. If wellhead pressure survey could be conducted to perform dynamic monitoring, work load, cost and execution risk of a well-test would be cut down significantly.

A well had been selected with the pressure transient tests conducted with both surface pressure and downhole pressure surveys. While the downhole pressure test was successful performed, and the testing goals were met, the data obtained from the wellhead pressure survey behaved abnormally, with a build-up test behaviour like a drawdown test; more specifically, after shut-in, wellhead pressure rebounded to the peak very quickly (by leaps), and then declined continuously, as seen in **Figure 3**.

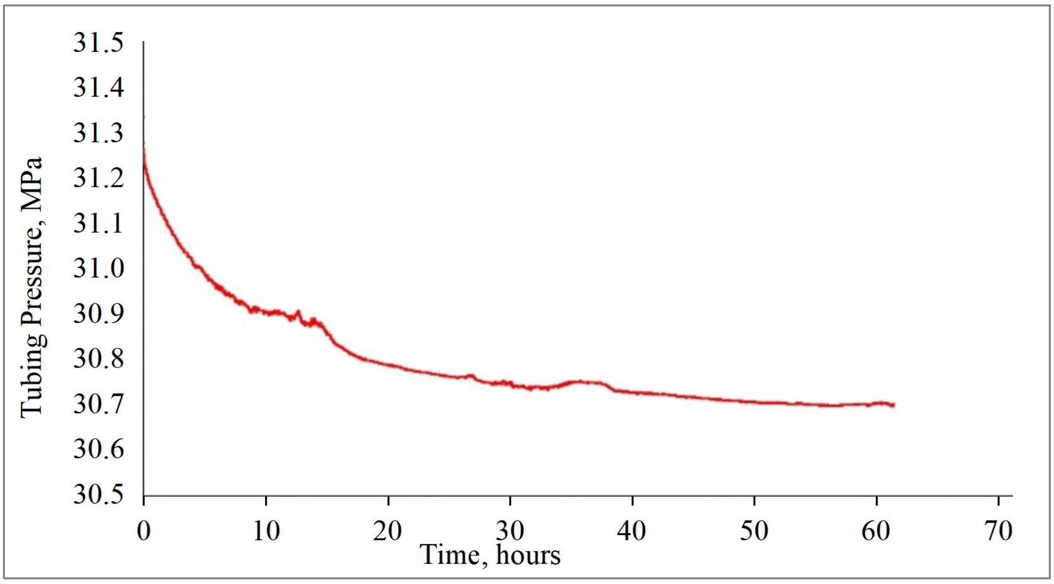


Figure 3—Change of tubing pressure at wellhead during shut-in period after stable test.

One possible reason for this behaviour could be that vaporous or annular liquid in the tubing could have segregated to the bottom-hole after shut-in and formed a section of slugged liquid column. Another possible reason could be a segregation of the fraction of H_2S and CO_2 to the bottom-hole.

New Well Design and Reservoir Surveillance. In an effort to understand the well deliverability potential, a new well has been designed and drilled. To support a long-term reservoir surveillance strategy, the well location was optimally selected, with the downhole pressure gauges (DHPG) installed. To ensure the reliability and the accuracy of the data recorded downhole, the operator selected a Halliburton WellDynamics ROC (2012), which was the first application of this technology in China. The down-hole reservoir pressure data is the most important reservoir surveillance measurement, which is to provide invaluable information about the reservoir behaviours at different production arrangements.

A well schematic after completion is shown in **Figure 4**, with the DHPG located above the reservoirs where gas is produced. Specifications of the surface pressure gauges and DHPGs can be summarized in **Table 1**.

Table 1—Specifications of permanent gauges.

	Surface Gauges	Downhole Gauges
Pressure	0-10,000 psi	0-16,000 psi
Temperature	-40~121 ˚C	25-177 ˚C

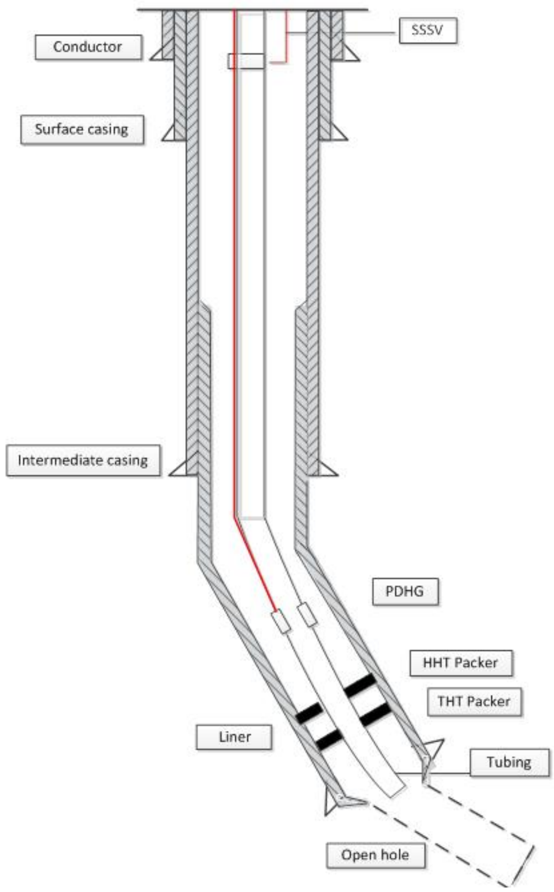


Figure 4—Schematic of new wellbore design.

With the full equipment for real time surveillance, both the wellhead and downhole pressure survey can be conducted at the same time.

After the project reached First Gas, the operator followed reservoir management and a field performance surveillance program. The well-test data that was collected is shown in **Figure 5**.

Note that, the well behaviour is similar to what was observed in the previous pressure transient test; however, it cannot definitely be concluded "abnormal" as the well has completely been cleaned up after an extensive production period and tested at the flow rate greater than the critical liquid segregation rate. So, what explains the results?

From the subject matter experts of pressure transient tests, this is one of the most significant challenges to surface test, a so-called the wellbore cooling effect. The operator has kicked off a further investigation on the issue as detailed below.

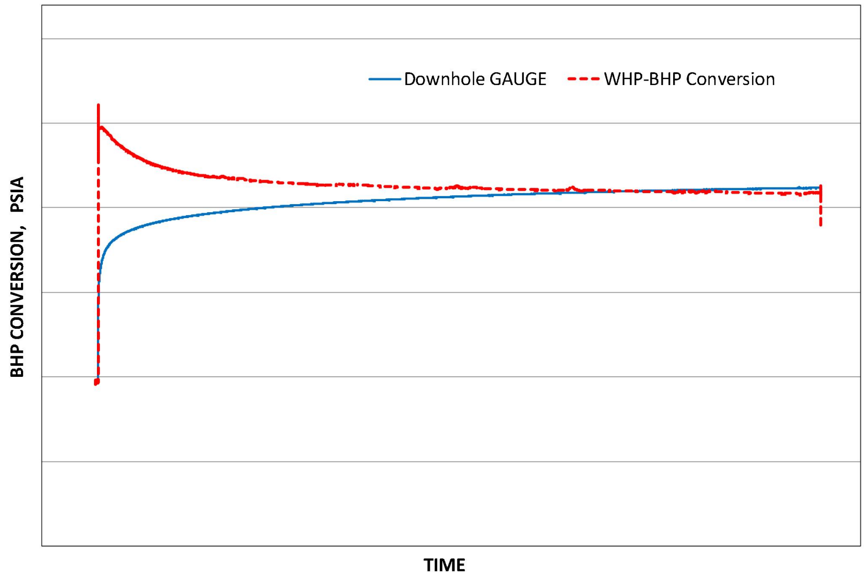


Figure 5—"Conflicting" surface and downhole pressures.

Wellhead Pressure to Bottom-hole Pressure. Calculating bottom-hole pressures from surface data has been extensively studied (Cullender and Smith 1956; Fair et al. 2002). The basic equation governing the conversion of wellhead pressure (WHP) to bottom-hole pressure (BHP) is the following,

$$BHP = WHP + \rho gh + f + a \qquad (1)$$

In **Eq. 1**, ρgh is the fluid hydrostatic head component, f is friction pressure loss along wellbore, and *a* is the kinetic energy loss, which is small and normally negligible. By estimating the change of both wellbore fluid hydrostatic head and friction loss, the total change of bottom-hole pressure can be calculated.

$$\Delta BHP = \Delta WHP + \Delta(\rho gh) + \Delta f \qquad (2)$$

Wellbore cooling effect is widely observed on gas wells, mostly wells with high gas flow. When a well is flowing, the wellhead temperature is increased since reservoir heat is brought by flowing fluid to surface, with some heat spreading to near wellbore formation. The deeper the reservoir, the higher gas rate, the more water, then the higher the wellhead temperature. When a well is shut-in for a relatively short period, wellhead temperature starts to cool down. With temperature dropping, both wellbore fluid density and hydrostatic head increase.

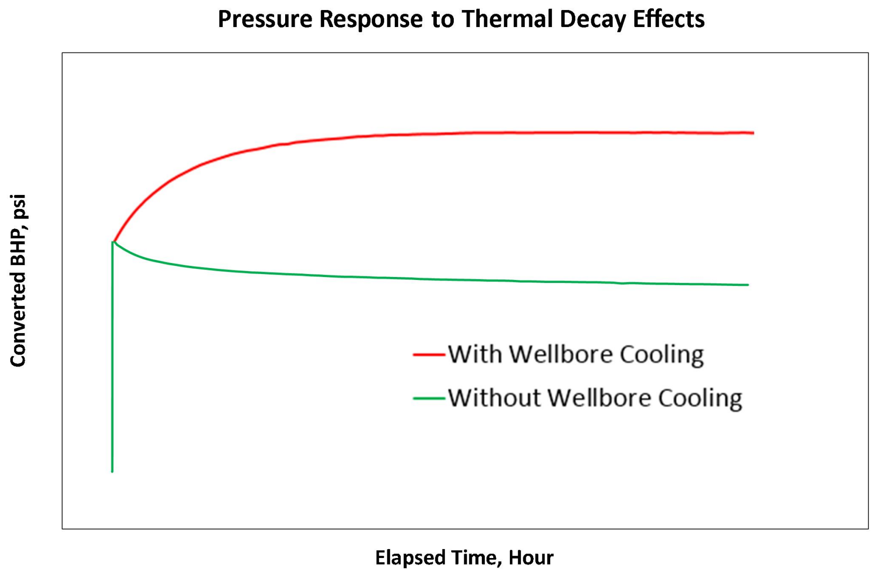


Figure 6—Wellbore cooling effect (Halliburton, 2012).

For well shut-in, friction loss is zero. For big wells with good deliverability, bottom-hole pressure drawdown is small. Wells in this JV gas project normally have pressure drawdown smaller than fluid hydrostatic head change. For these types of wells, counterintuitively, it results in a negative wellhead pressure change. This means the surface pressures will decline when well is closed. **Figure 6** illustrates the wellhead pressure change when wellhead cooling effect is applied.

Pilot Test and Testing Goals

The test procedures have been designed to determine the following reservoir properties:

1. Permeability;
2. Skin;
3. Reservoir pressure;
4. Reservoir characteristics (fracture/dual porosity); and
5. Non-Darcy skin (multi-rate test required).

Test Design

Given the reservoir characteristics (i.e., fractured dolomite), with a long bottom-hole well and reservoir interaction, associated with operational constraints prevent a long shut-in (i.e., production target to deliver), a multi-rate test is preferred. It is a combination of both drawdown test and build-up test, with different desired flow rates.

- Build-up test: the simplest test to perform would be a basic pressure build-up. Ideally, the well to be tested would be flowing stably for at least 1-2 days prior to the start of the build-up. The goal of this stable flow is to minimize any transient behavior around the wellbore prior to the start of the shut-in, and to stabilize the wellbore thermal profile. At the end of this stable flow period, shut-in the well for 3-4 days to capture the build-up. This test will accomplish goals one through four as listed above.
- Drawdown test: this type of test is simply an extension of the build-up test mentioned above. Instead of completing the test at the end of the build-up, it is continued by monitoring pressures as the well is returned to production on a constant rate/choke drawdown. The drawdown data should be recorded for the same duration as the previous build-up. For the drawdown analysis to be viable, the flowing tubing pressure (FTP) during the drawdown should exceed the flow line pressure by at least a ratio of about 2.2:1. This ensures that there is an adiabatic shock front across the choke, isolating the well from downstream operations. This test accomplishes goals one through four as listed above and, provides a second confirmation of the test analysis.
- Multi-rate test: this test begins with the build-up procedure, and followed up a drawdown test procedure. However, instead of single flow rate drawdown test, an adjustment to the choke is made to have a new gas rate. The well should be held on this constant rate/choke for about 1-2 days (like the build-up). The rate change should be significant to induce a noticeable transient in the reservoir, and the FTP constraints also apply as in the above procedures. This test could be then extended to multi-rates by making a second choke adjustment to a third flow rate. This test would accomplish goals one through five (multi-rate only).

In practice, the type of multi-rate test is less desirable given the fact that it is often difficult to maintain a constant rate/choke drawdown, and drawdown data is inherently noisier and more difficult to interpret. However, it is selected for this test as to fully understand if the new technology could help deliver the testing goals. **Figure 7** shows the conceptual well-test design.

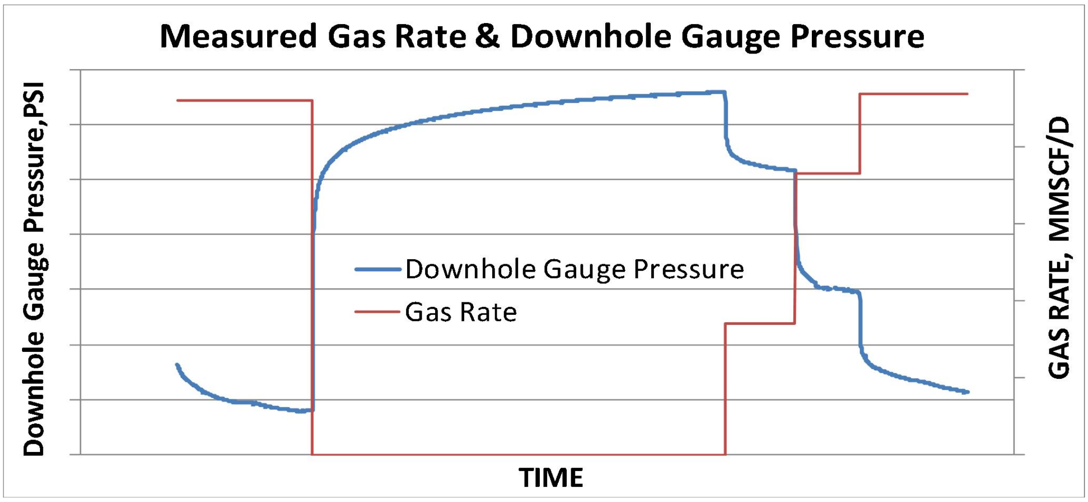


Figure 7—Conceptual well-test design.

Case Study

The pilot test was conducted on the well equipped with downhole gauge. The purpose was to compare the conversion from WHP to BHP with the measured downhole gauge data during pressure build-up test. Halliburton's in-house developed model was used to conduct the conversion. **Figure 8** shows the comparison result and the converted BHP curve was almost parallel with the measured curve indicating the conversion achieved a good build-up trend. However, the gap still existed, around 40 psi, because Halliburton's pressure conversion model is based on large amount of well-test data collected worldwide, which may not accurately match with the specific well conditions in Sichuan (such as wellbore schematic, wellbore fluid, formation stratigraphy, reservoir temperature and reservoir pressure) for the pilot test.

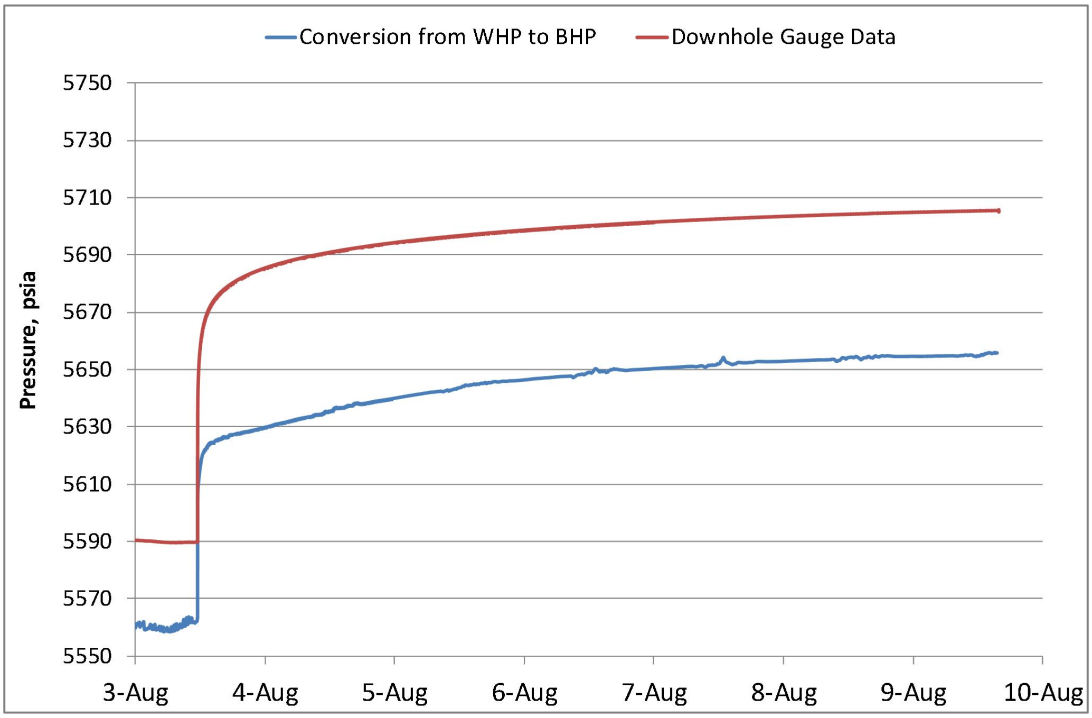


Figure 8—BHP conversion vs. downhole gauge measurement before thermal decay model tuning.

Then the specific well-data was incorporated to the thermal decay model resulting in a slower cooling down profile in the well, as illustrated in **Figure 9.**

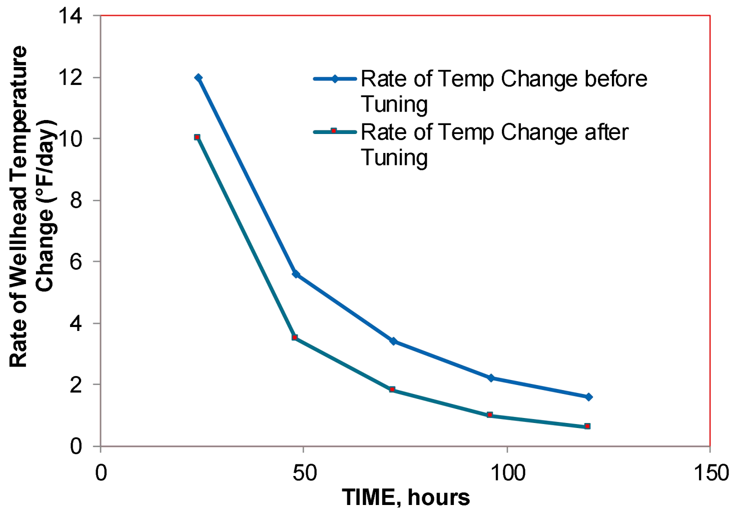


Figure 9—Model tuning with WHT change rate.

Figure 10 shows the converted BHP after model tuning, which almost overlaps with the downhole gauge data. In other words, no obvious gaps can be visually seen.

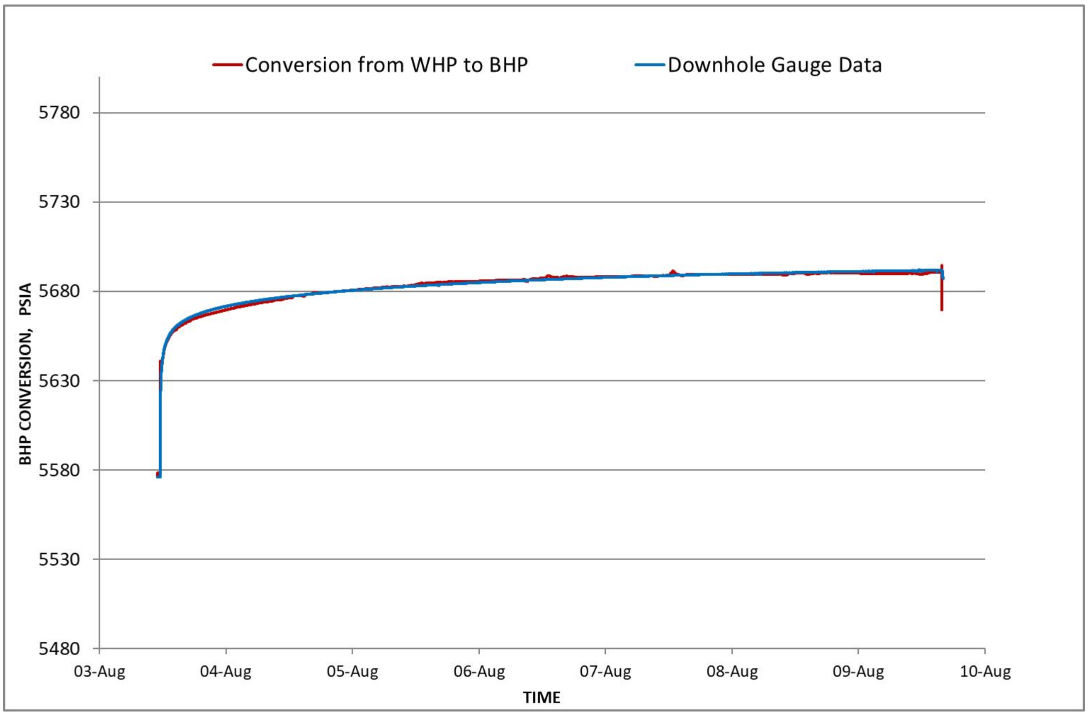
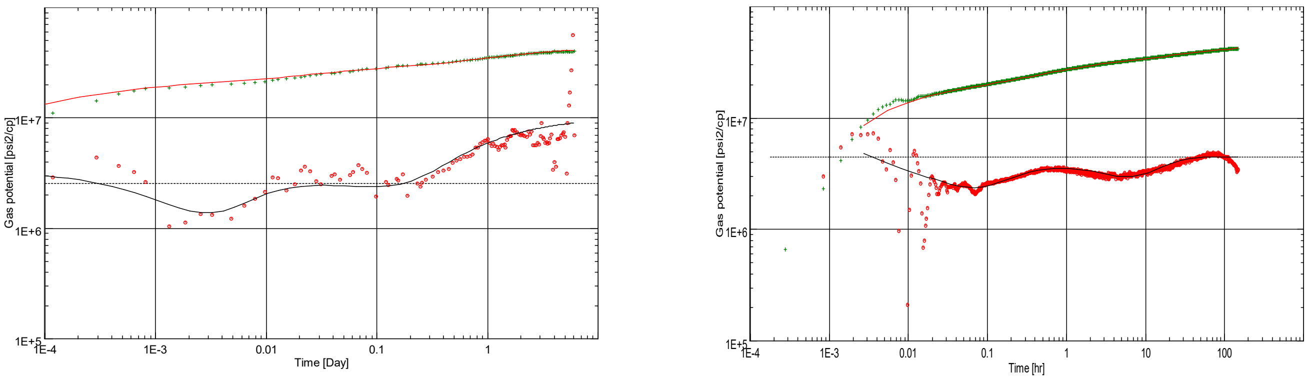


Figure 10—BHP conversion vs. downhole gauge measurement after thermal decay model tuning.

The results of PTA for both the DHPG and converted BHP at Well A are quite similar. **Figure 11(a)** shows the test interpretation using the pressure conversion data and **Figure 11(b)** using the PDHG data. Note that the data from surface gauges results in similar reservoir parameters, such as skin and permeability.



(a) **(b)**

Figure 11—PTA results. (a) PTA with Converted Data. (b) PTA with PDHG Data.

To ensure the result is reliable and the work can be repeatable, the test has been extended to Well B, where an obviously "abnormal" reservoir behaviour was observed. The thermal decay conversion model established based on the pilot test can be utilized on the other wells with the same wellbore structure, the same wellbore fluid and the same reservoir formation as the well installed with downhole gauge. Because the thermal cooling effect in the adjacent wells shall be like the pilot test well. **Figs. 12 through 14** are the PTA plots for Well B. The good matching of the log-log plot, semi-log plot and history plot indicates high quality BHP conversion. Therefore, with the mature thermal decay model, the reservoir properties such as permeability, skin damage, dual porosity parameters, and outer boundary can be analysed with WHP during pressure build-up test.

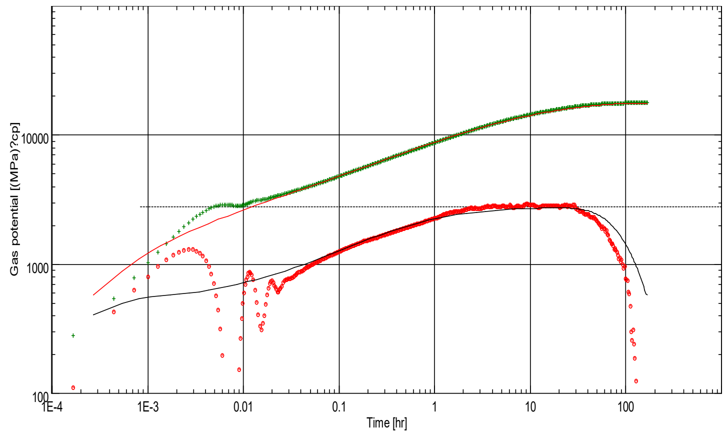


Figure 12—Log-Log plot of Well B PTA.

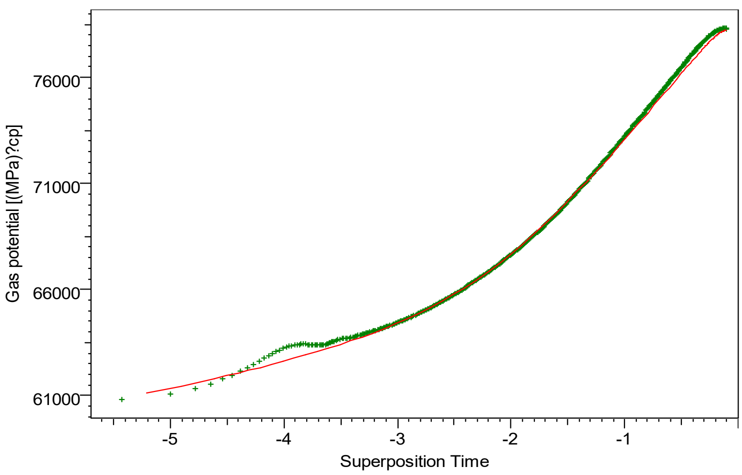


Figure 13—Semi-Log plot of Well B PTA.

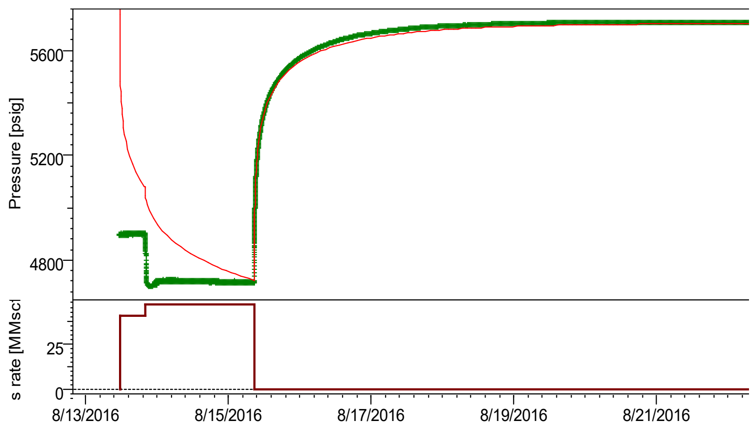


Figure 14—History plot of Well B PTA.

Lessons Learned

Several lessons were learned through this process:

- For a reservoir where fracture flow contribution is dominant, the surface pressure data during the build-up test will behave as the "normal" drawdown test. Pressure data conversion needs calibration.
- For the wells with the two-choke configuration, the adjustment automation of the second choke to stabilize the output pressure of the production system has created extra "noise" during draw-down test. Therefore, extra care is needed in the well test interpretation,
- Even with detailed well configuration modeling, the well configuration has a minimum impact on the data conversion, as all will be grouped under "skin" factor (i.e. formation damage).
- Before any installation and disconnection of wellhead gauges, ensure that double mechanical blocks to isolate pressure source shall be in place, by checking integrity of the needle valves and gate valves on the X-mas tree.

Best Practices

Several best practices have been developed through this process:

- Well locations can have Health, Safety, and Environment (HSE) hazards. Great care must be exercised when operating in such high-risk areas, which include wearing the proper personal protective equipment (PPE), knowing and following the proper procedures, job safety analysis (JSA), and permit to work (PTW) to operate safely, and checking the area for high levels of H_2S. Stop work authority is the right of all personnel when on any location; if an unsafe situation exists, stop the operation until the unsafe condition is resolved or mitigated to a safe level.
- As of the ambient temperature variance, any surface pressure survey, if possible, should be insulated from the external source; i.e., do not install surface pressure gauges near extreme ambient temperature, such as a heater, or the wellhead area should be shielded from direct sunlight to reduce the large differential between day and night.
- Liquid accumulation or drop-off may deviate the calibration of thermal cooling effect.
- Due to a high-pressure resolution, particularly high deliverability wells, the surface pressure gauges should be in a location that should be less impacted / interfered by the noise of daily production operations.

Conclusions

The data conversion technology is not new, and has been used in China in the past. However, it is the first application of this technology to sour gas field development project in China. All the primary goals for the well-test requirement have been achieved:

- Avoided the cost and risk of running equipment downhole for the conventional well-tests.
- Acquired pressure data with high resolution, high accuracy, high repeatability and effective thermal compensation for pressure transient analysis. The test can be monitored in real-time.
- Leveraged the conversion technology from surface pressure data to bottom-hole pressure data and elementary analysis with Halliburton in-house developed mode, which helped to ensure high-quality work.

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Conflicts of Interest

The author(s) declare that they have no conflicting interests.

Nomenclature

BHP	=	bottom-hole pressure, psia
BHT	=	bottom-hole temperature, °F
WHP	=	wellhead pressure, psia
DPskin	=	pressure drop due to skin, psi
ρ_o	=	oil density, lbm/ft^3

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