Evolution of a Horizontal Drilling Program

Glenn W. Cox,
Texaco E&P Inc

The recent development of the Bryant – G– Devonian Field (BGDF) has been a significant success for Texaco in the Permian Basin. The field had been producing about 2.0 MMCFGPD with 100 BPD associated condensate production. Through the application of enhanced reservoir imaging and horizontal drilling technology, production was increased to about 60.0 MMCFGPD and 2600 BCPD with expected recoverable reserves being increased by 300 percent. An additional benefit realized by this program was the increase in loading at the Texaco operated gas plant which processes the liquids from this gas stream.

During this ongoing program about 50 horizontal laterals have been drilled, either as re-entries from existing wells or from "grass roots" new wells, some with single laterals and some with multiple laterals. As this was the largest package of deeper (>10,000') horizontal wells Texaco had developed in the Permian Basin, the learning curve was relatively steep and often times bumpy. The discussion to follow will outline some of the progressions followed to bring our drilling practices to their current form.

Field Development **History**

The Bryant – G– Devonian Field (BGDF) is located in western Midland County, Texas, in the Midland Basin region of the Permian Basin (See Figure 1). The field was originally discovered and developed in the mid 1960's with 19 wells drilled in **8** sections. These original wells were multiple completed in the Pennsylvanian and Wolfcamp formations as well as the Devonian. A rapid decline of oil-gas ratio indicated that hydrocarbons existed as a retrograde condensate reservoir. In light of the success seen at the near-by Headlee Devonian Unit, the Devonian formation was unitized as the Bryant – G– Devonian Unit (BGDU) and a gas cycling project was initiated in the mid 1970's.

Although a moderate condensate production increase of 300 – 400 BCPD was achieved, the reservoir permeability proved to be too low and too discontinuous to allow effective sweeping between the injection and production wells. As a result, the gas cycling project was deemed an economic failure and gas re-injection was soon abandoned. After returning to primary production, the field continued to decline until stabilizing with virtually no decline at about 2.0 MMCFGPD and 100 BCPD. This production profile is again consistent with inadequate drainage of a low permeability reservoir.

In an effort to increase recovery from this field, **an** infill drilling program was carried out in 1994 and 1995. Eleven additional wells were drilled in the field, resulting in good initial production rates but rapid declines, with the wells stabilizing at around 500 MCFD per well. The vertical wells in the field are shown in Figure **2.** All of these wells were completed with 5-1/2" casing and stimulated with acid and/or sand frac's. During this time, Mobil drilled and reported good success from the first horizontal well in the adjacent Parks (Penn) field.

As Texaco was involved in an initiative to apply horizontal drilling technology in applicable reservoirs and fields, the decision was made to re-enter an existing wellbore to drill horizontally in the BGDF. By transferring technology used successfully at the Aneth Unit in southeast Utah and at the Sundown Slaughter Unit near Levelland, the BGDU #23-H was re-entered and drilled to a lateral length of 1566 feet during March 1996. After acid stimulation the well was potential tested for 4.0 MMCFPD and 100 BCPD. This success resulted in a ramped up drilling program during 1996 and 1997 consisting of 11 re-entries and 19 new wells within the unit, in addition to 13 new wells testing the flanks of the structure outside of the unit boundary. After a slowdown during 1998, the program in 1999 concentrated on adding second laterals to existing wellbores. The current field map is shown in Figure 3.

Geological Summary

The Bryant – G– Devonian Field produces from the Thirtyone Formation (known locally as "The Devonian". In central Midland County, the Thirtyone Formation comprises a 600-700 foot shoaling upward sequence of ramp carbonate debris that was derived from a prograding carbonate platform to the north. The carbonate sediment ranges from a lower ramp, chert rich, carbonate wackstone (fine grained) at its base, to a coarse grained, upper ramp crinoidal grainstone toward the top. Both the wackstones and crinoidal grainstones lack porosity and permeability. Most of the reservoir quality rocks at the Bryant – G– Devonian Field are found in sequences of packstones and grainstones rich in siliceous sponge skeletal remains known as spicules. Many of these spicules have been locally dissolved leaving a network of needle-like pores. Although the dissolution of the spicules enhance the porosity in the reservoir, much of the dissolved silica was re-precipitated above and below the reservoir layers as nodular chert. These nodular chert rich layers can play havoc on drill bits. Individual reservoir units range in thickness from 5 to 40 feet thick.

Figure 4 shows a representative type log for the field. The top of the Devonian occurs at about 11,700' with the primary pay located 100' to 200' deeper. Immediately above the Devonian is the Woodford shale. This 70' thick interval is extremely water sensitive and cannot be left exposed for long periods of time.

Re-Entry Procedures

The first horizontal tests at the BGDF were drilled as re-entries from existing wellbores in order to utilize existing well log information and to avoid the cost of a new wellbore. The 5-1/2" casing in the newer wells limited the maximum hole size to 4-3/4", while the available distance between the base of the Woodford shale and the target porosity demanded the use of what was at that time considered "short-radius" drilling technology.

For the original test, the casing exit from the 5-1/2", 20 lb/ft casing was achieved by section milling from 11,745' to 11,785'. This section was then under-reamed to 8-1/2" before setting a cement kick-off plug. After dressing the plug to a kick-off point of 11,750', a 4-3/4" curve was drilled, building angle at 48" per 100 ft. The bottom hole assembly (BHA) for drilling the curve included a 4-3/4" IADC type 537 bit, bit sub, 3-3/4" downhole motor with a 3" bend and two articulations, float/orienting sub, two flexible nonmagnetic drill collars, and 2260' (sufficient for the expected lateral length) of L-80 tubing with PH-6 connections. The remainder of the drill string was 2-7/8" drill pipe with American Open Hole connections. After drilling the kick off with gyroscopic surveys, magnetic directional surveys were obtained with wireline steering tools. The curve was landed with an inclination of 80.5° at a measured depth of 11,898' and a true vertical depth (TVD) of 11,852'. The BHA was then tripped for the lateral assembly in which the motor was exchanged for a 3-3/4" motor with 1.5° bend and a single articulation. This type of assembly was used to drill the entire lateral to a final TD of 13,316'. Throughout this entire program, laterals have been completed open-hole.

Ten wells that were drilled in 1994 and 1995 were re-entered over the course of the next 8 months. Horizontal laterals up to 3800' were successfully drilled with these techniques. As the program continued, several modifications and improvements were implemented to reduce the overall drilling costs.

Whipstocks: Section milling was eliminated in favor of using whipstocks to mill windows through the casing. At these depths, whipstocks tend to provide a more reliable and cost efficient casing exit than can be achieved with milled sections and kick off plugs. Figure 5 shows a schematic wellbore diagram of the typical re-entry horizontal.

Measurement While Drilling: MWD tools replaced steering tools as that technology adapted to the slim-hole, short-radius equipment, thus reducing the time consumed by tripping wireline for directional surveys.

Motors: When starting this program, the conventional wisdom dictated that articulated motors were necessary in this hole size to achieve the desired build rates. Application repeatedly showed that the motors built more angle than predicted by the manuals. Ultimately, fixed bend motors without articulation were used to successfully drill curves with build rates up to 48° per 100 ft. This change reduced the complexity and increased the reliability of the curve drilling assemblies.

Figure 6 shows drill time curves for the first and the last re-entries drilled in the program. Although there are still potential difficulties involved with setting whipstocks and milling windows, as seen by the extended prep times, ultimate lateral section lengths were extended significantly.

New Drill Procedures

Concurrent with the re-entry program, additional infill wells were drilled to completely develop the field consistent with field rules and to test the extent of commercial reserves. A desired hole size of at least six inches for new laterals dictated 7" casing for the production string, hence 9-5/8" intermediate casing and 13-3/8" surface casing. Surface casing was set at 350' with cement circulated to surface to protect the fresh water sands. Intermediate casing was then set at 5000' to cover the porous section of the San Andres and also cemented to surface. In order to confirm and evaluate the pay, the production holes were typically drilled through the Devonian to allow logging and possibly coring of the pay interval. Various methods to initiate the horizontal laterals were applied.

Cased Curve: The first well designed specifically as a horizontal producer was planned to have casing set around a medium radius (–500') curve. A medium radius design was selected to assure that a 4000' lateral could be achieved. The BGDU #31H was drilled vertically to a kick off point (KOP) of 11,436' before directional control commenced. Angle was built at about 12"per 100 ft to land the curve at 12,328' (11,925' TVD), Casing was then run to TD and cemented. After drilling out cement, a 6-1/8" lateral was drilled to a total measured depth of 16,308'. In order to better define the desired curve landing point on subsequent wells, pilot holes were drilled through the Devonian to about 12,200'. Open hole logs and side wall cotes were obtained before the wellbores were plugged back to 11,400'. At that point a medium radius curve and lateral were drilled as described above. A wellbore schematic of this technique is shown in Figure 7.

Top Set: As seen on the drill time curve, a significant period of costly rig time was being consumed between reaching total depth on the vertical hole and drilling new hole on the lateral. Directional tools and personnel also had to be kept on standby while running casing and drilling out cement. Since success had been seen drilling laterals in excess of 3500' in the re-entry program, a method of drilling short radius curves below the Woodford shale was developed. For the BGDU #34, the 8-3/4" production hole was drilled to 11750' and 7" casing was set in the top of the Devonian limestone. After drilling out cement, whole core was taken and a pilot hole was drilled to 12,200'. Open hole logs were run at TD and the well was plugged back to a KOP of 11,785'. Directional tools were picked up and a 6-1/8" curve was drilled and landed at 11,970'(11,917' TVD). The lateral was then drilled to a total measured depth of 15,836'.

A variation of this method was to drill 8-3/4" through the Devonian and log the entire hole. Then the hole was plugged back and casing run to the top of the Devonian. After drilling out the float equipment, directional activity commenced. This technique is shown in Figure 8.

Case Through/Whipstock: Although top setting casing in the Devonian successfully reduced the turn-around time and cost between drilling the vertical portion of the hole and drilling the lateral, there were still delays associated with obtaining competent kick-off plugs. There was also a need to more fully evaluate log information prior to selecting target depths and kick-off points. On subsequent wells, the decision was made to set casing to TD after logging and to utilize whipstocks to initiate drilling the curves. An additional benefit to the whipstock method of casing exit is that if KOP's are selected properly, multiple horizontal laterals can be drilled from a single wellbore.

Consistently prolific production rates from the first few wells demanded that the program should be accelerated on a two-year schedule. Four drilling rigs were assigned to the project with two rigs drilling and setting casing on vertical holes while the other two rigs cut windows and drilled the laterals. This method allowed use of a service unit to drill out cement and stage tools and to set whipstocks prior to moving the lateral rig on the wells. The lower cost of the service units offset the incremental cost of the additional casing and whipstocks required for the case through completions.

Mud Programs

During the early stage of the BGDF horizontal project, it was reasoned that a mud system similar to that in use while drilling vertically through the Devonian would be required. That system consisted of an 8.5 – 8.7 ppg fresh gel mud with 35-50 second funnel viscosity with a water loss around 5 cc's. The conventional thinking was that the viscous fluid would be necessary to transport cuttings out of the lateral while the low water loss would minimize filtrate invasion of the formation. However, with an average reservoir pressure equivalent to a 6.0 ppg gradient, the primary result from this mud system was the need to add large amounts of lost circulation material to the system with frequent differential sticking events and subsequent fishing jobs.

Beginning in late 1996, most laterals were drilled with clear, fresh water as the circulating medium, circulating through the reserve pit for solids control. While minor seepage losses were still seen, sticking problems were all but eliminated. System additives were limited to pH control and drill string lubricants with occasional polymer sweeps for hole cleaning. Improved performance while sliding and reduced torque and drag were obtained with the addition of solid, spherical, plastic beads. As circulation was through the reserve pit, a shaker-type bead recovery system was installed to minimize consumption of the beads.

Completion and Stimulation

As mentioned earlier, all of the laterals in this program have been completed open hole. Reservoir simulations run early in the program indicated that the wells should have been capable of flowing commercial quantities of gas without stimulation. A skin factor on the order of positive 200 was imposed on the face of the laterals before the model predicted non-commercial rates. However, the first laterals drilled in the field would not produce naturally and did require stimulation.

Early stimulation methods called for running tubing to near the end of the laterals and pumping 60 gallons of 28% HCI acid per foot of lateral length in four to twelve stages. Equivalent amounts of gelled water were pumped in alternating stages in hopes of extending or diverting acid penetration. Fluids were pumped simultaneously down the tubing and down the casing/tubing annulus. Radioactive tracer surveys indicated that the toe and heel of the laterals received most of the acid while the middle portion of the laterals received little to no stimulation. In order to increase the acid coverage of the laterals, a patented method was jointly developed by Dowell and Texaco to divert acid through a series of ports using a technique similar to limited entry. Tracer surveys indicated this method greatly improved the acid distribution.

In an attempt to optimize stimulation treatments in the field, acid volumes have been varied between 35 and 65 gallons per foot. Acid concentrations have been varied from 28% to 15%. Injection rates range from 20 to 100 barrels per minute. Emulsified acids, such as Dowell's SXE acid system have also been tested. None of these variables, nor lateral length, nor lateral diameter appear to have any reasonable correlation with initial production rates or ultimate expected recovery. The only variable that seems to have any impact on production is the location of the well in the field. While research into stimulation methods continues, the current practice is to attempt to balance the relative costs of injection rate, acid concentration, and total fluid volume for a treatment consistent with the expected quality of the reservoir.

Conclusions

Figure 9 shows the drill time curves for one of the earliest wells in the program, one well from the middle of the package, and one of the last wells drilled. The 40 percent reduction of total rig days represents savings on the order of $550,000. Efficiencies developed over the course of the program in completion methods resulted in additional per well savings in excess of $100,000. No single revelation can account for this magnitude of cost reductions. Rather, a continuous effort by everyone involved moved the project further along the learning curve. Established practices and paradigms were challenged and improvements were shared not only within the project but also with other projects world wide.

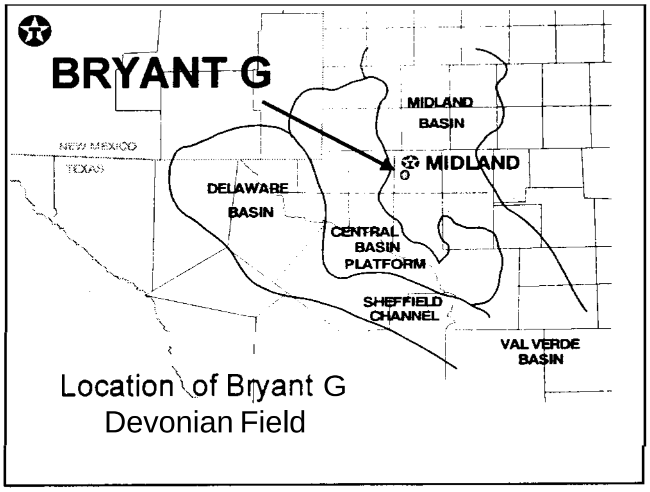

Figure 1 - Area Map

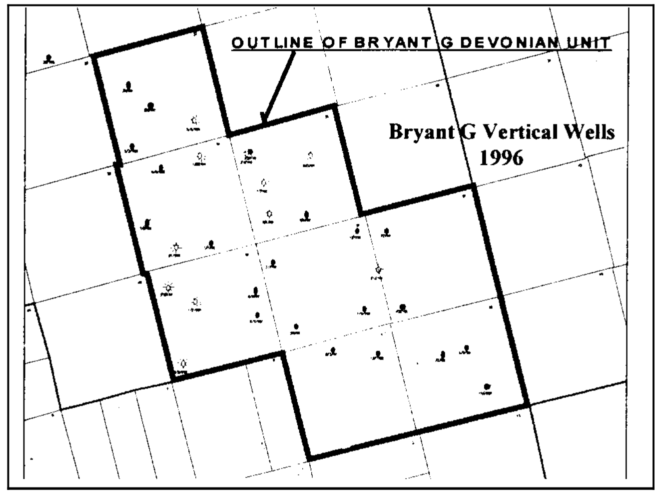

Figure 2 - Field Map — Vertical Wells

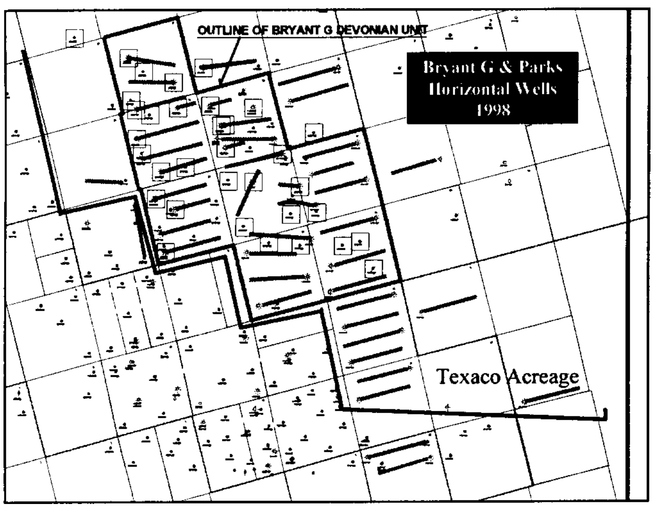

Figure 3 - Field Map — Horizontal Wells

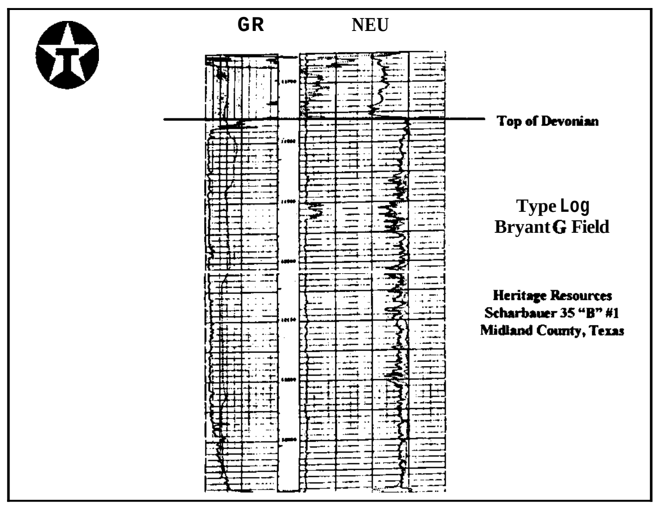

Figure 4 - Type Log

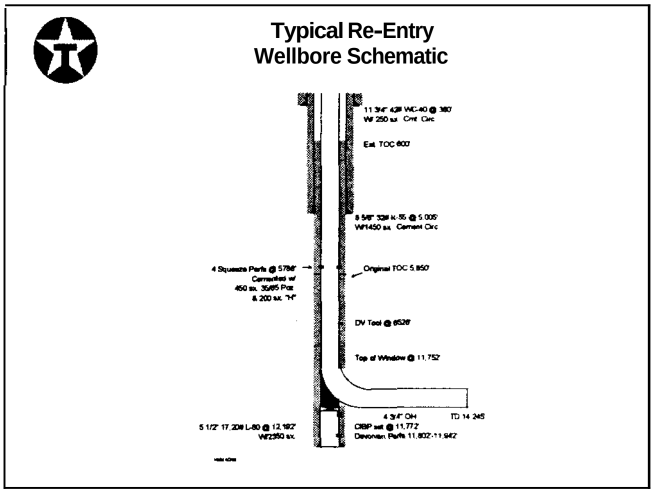

Figure 5 - Re-Entry Schematic

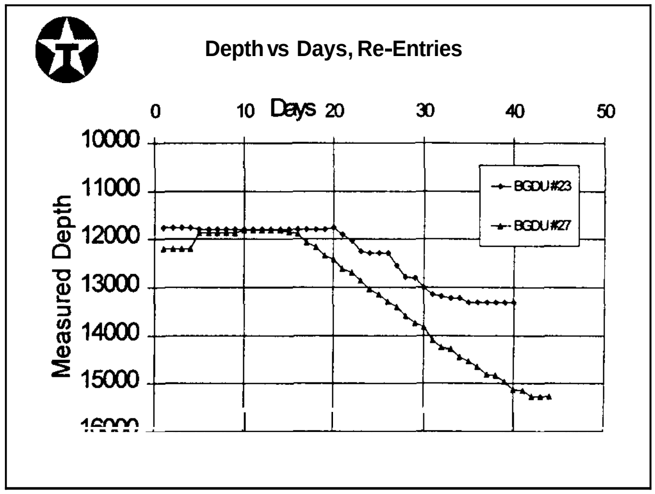

Figure 6 - Drill Time Curves — Re-Entries

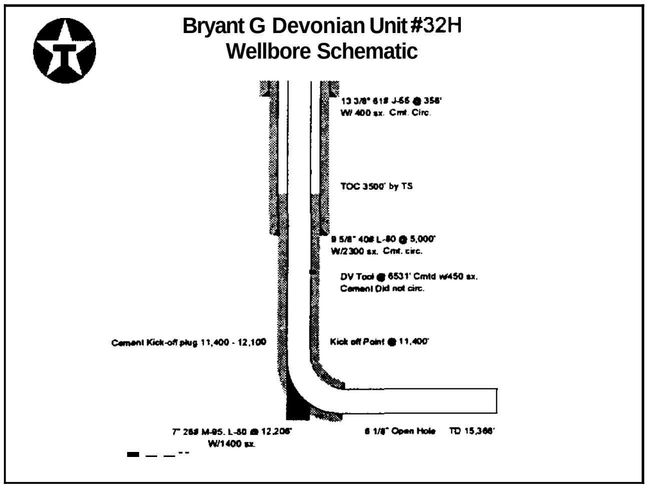

Figure 7 - Cased-Curve Schematic

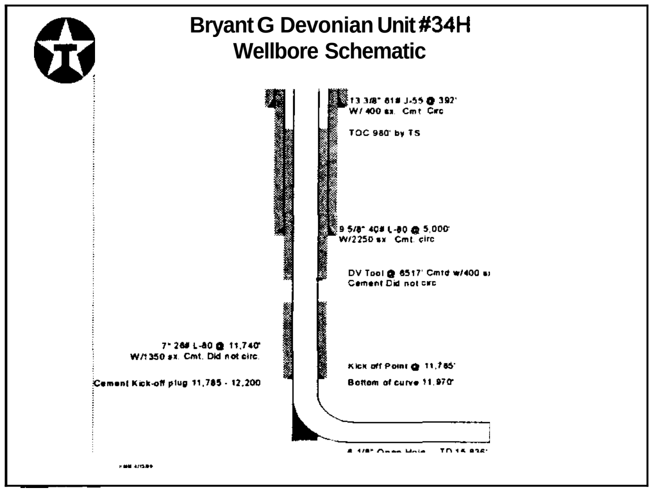

Figure 8 - Top-Set Schematic

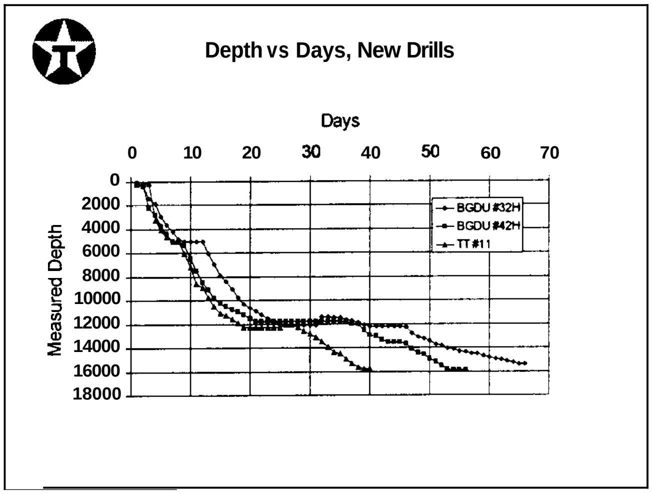

Figure 9 - Drill Time Curves - New Drills