Drilling Process Creates Data Issues Requiring Innovative Data-Gathering and Interpretation Techniques

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Extended Abstract

Introduction

The Lower Pennsylvanian Morrow sands and the Lower Pennsylvanian/Upper Mississippian Springer Group are the primary objectives of the recent directional drilling in the Cement field of Caddo and Grady counties of southern Oklahoma. These marine sands were deposited in the Anadarko Basin and then were subsequently deformed by multiple stages of Pennsylvanian wrench and compressional tectonics. The resulting formations are often found to be steeply dipping to overturned and highly faulted. These reservoirs are deep and generally not extensive in nature. High energy deposition has created discontinuous flow paths, causing compartmentalization (Figure 1) and inconsistent productive capacities. The compartmentalization creates the need to target relatively small reservoirs targets and requires precise bottom hole locations to accomplish economic production. Directional drilling with down hole motors, bent subs, stabilizers and diamond bits is the only technique that could consistently achieve these precise bottom hole locations.

In addition, there is another complication created by the almost vertical nature of the reservoir. Figure 2 is a surface outcrop that allows some visualization of the reservoir down hole. The drilling process, in many situations, was required to drill almost directly down these horizontal striations that have become vertical through subsequent earth movement.

Figure 1 – Outcrop exhibiting discontinuous flow paths

Figure 2 – Outcrop of near vertical bedding

Operational Challenge

The complex nature of the reservoir and subsequent deformation required directional drilling. In general, these bottom hole assemblies required a rotary motor at the end of the drill string with a configuration similar to that exhibited in Figure 3. This assembly has a stationary reference stabilizer with hardware between the stabilizer and bit to minimize the range of movement of the bit. Even in the best conditions, this range of movement provides an area of movement that always drills a well bore larger than the bit size. This drilling process also created a rough well bore, many a times creating spiral grooves in the wellbore. Figure 4 is an image that shows a spiral groove. The image on the left is the well bore definition by depth, the center image is looking down in to the well from the top of the image and the image on the right is oriented in the direction of the actual drilling.

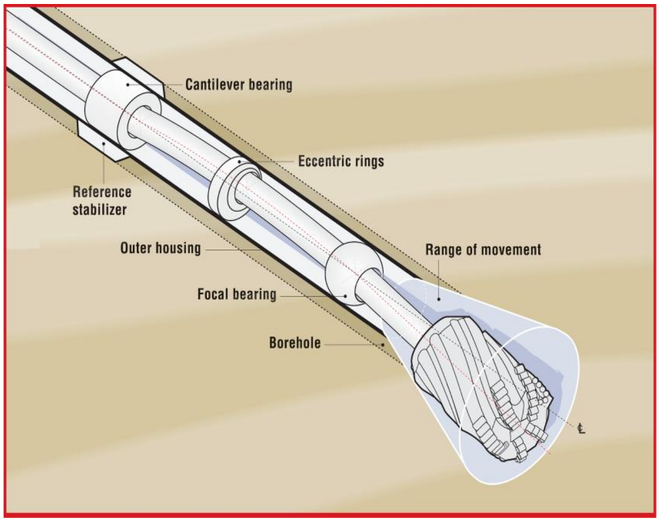

Figure 3 – Typical directional bottom hole assembly

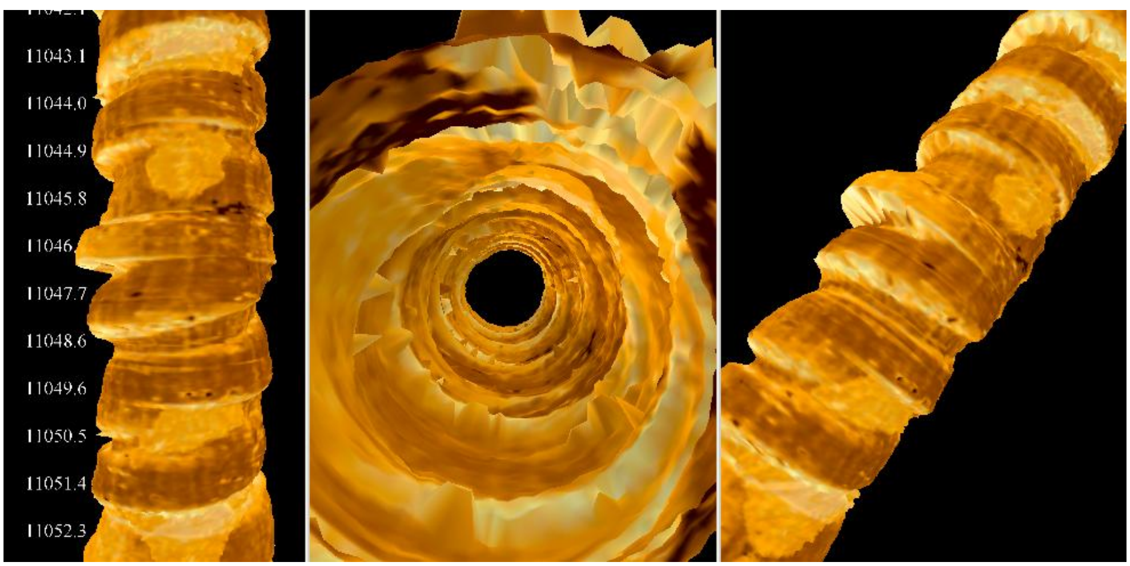

Figure 4 – Typical groove created in a well by the motorized down hole assembly for directional drilling

As this discrepancy between bit size and bore hole size becomes larger, accurate reservoir evaluation by electric logs becomes more difficult. Hence modifications had to be made to this bottom hole assembly to minimize the flex issues in the directional drilling process. Oil based mud was used to keep the wellbore surface as smooth as possible.

Reservoir Evaluation Challenge

One of the most critical issues in the development was how to define the reservoir placement and distribution in three dimensions. A precise understanding of this was necessary to continue the development of this field. Dipmeters were a part of the logging program and, when the shift to oil based mud occurred, oil based dipmeters were run. Interpretations of these dipmeters were done using computer correlations (Goetz 1988). These interpretations were intensely scrutinized but increasingly it became evident that this data was not providing needed bedding description. There was a poor relationship between the general expected bed directions and angles as defined by the seismic and that presented by the dipmeter. The high angle of the beds combined with the irregular well bore made the computer correlations of the bed definition suspect. Image logs were added to the drilling program to provide a better answer.

These image logs confirmed a couple of important well characteristics. The bottom hole assembly had created an intermittent spiral groove in the sand face of the well. This groove could confuse any automatic bed picking program and create spurious results. Figure 5a, and 5b are examples of this image data. This data has been processed to show results similar to automatic dip pick programs (Shin-Ju Ye 1997).

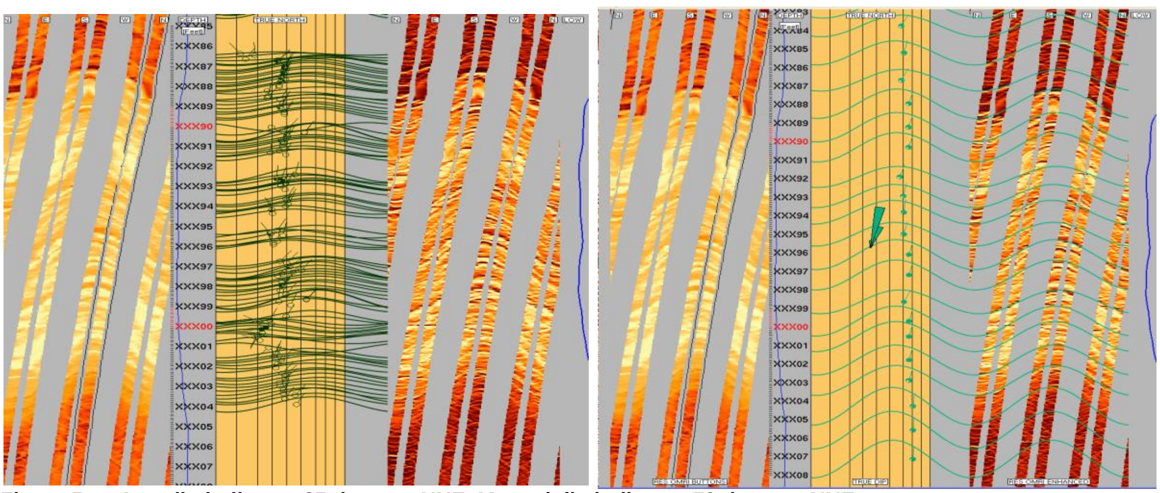

Figure 5a – Autodip indicates 35 degrees NNE, Manual dip indicates 70 degrees NNE

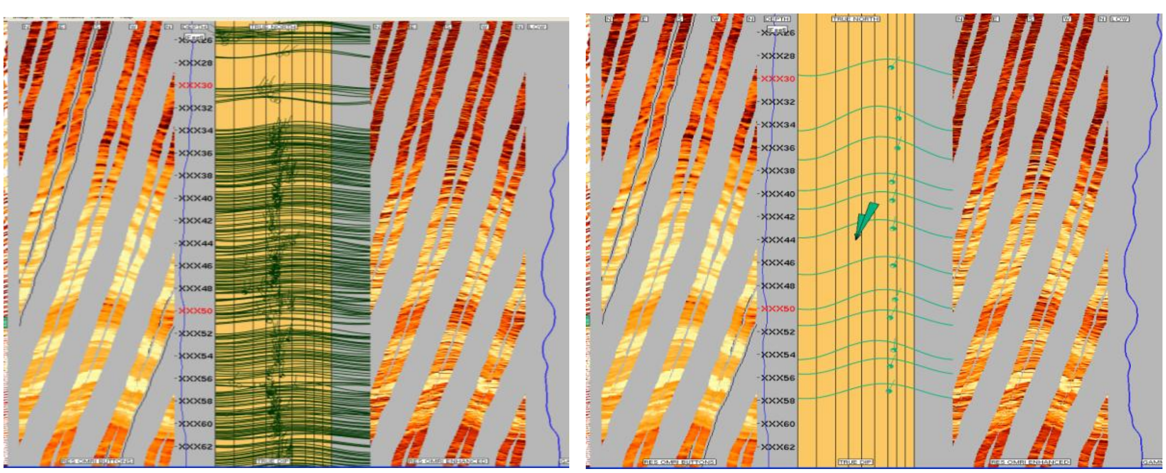

Figure 5b – Autodip indicates 35 degrees NNE, Manual dip picks indicate 65 degrees NNE

Figure 5a is an example of dip magnitude error of as much as 30 degrees along with orientation errors of 15 to 25 degrees. Figure 5b is an example where the direction of dips is the same from both interpretation techniques, but the magnitude of the computer picks is half that of geologist picks. These errors in the computed products used for geological interpretation cause misunderstanding of the placement and orientation of the reservoirs. Dipmeters were dropped from the logging program to overcome these issues. Only image logs interpreted with geological oversight were able to accomplish the required precision in this difficult environment.

Another major interpretation issue that was created by this non-uniform hole diameter was that the porosity tools would not accurately record their measurements. The density, particularly was subject to erratic results since the pad could not stay in contact with the well bore face. The neutron could also be affected if the well configuration caused the tool to oscillate and not remain vertical in the well while logging.

The solution to this was the utilization of a mandrel based Nuclear Magnetic Resonance device. Since the response is measured at fixed diameters, this allowed measurement of formation porosity without the complicating factors of the spiral groove. The tool also provided an excellent confirmation of reservoir quality through the evaluation of the T_2 relaxation times. The Bray-Smith permeability, (Smith 2008) derived from T_2 bin distribution provided an important additional piece of data.

$$BPERM = \left[(MPHI)^{n} * \left(\sum_{T2Bphi4ms}^{T2Bphi2048ms} wf * T_2 Bphi / BVI \right) \right]^{m}$$

Where:

BPERM = Bin calculated Permeability
MPHI = NMR effective porosity
wf = Bin weighting factor
Bphi = Bin porosity
BVI = Irreducible porosity fraction
Factors n and m are empirically derived constants

Conclusions

- Oil based image logs are capable of making precise bed description, even in very adverse conditions.
- Geologist oversight of the image log results is imperative for precise conclusions.
- Mandrel based NMR is capable of determining correct porosity in rugose hole conditions.
- Bin based permeability description can be applied to provide a very valuable description of reservoir quality.

References

Goetz, J.F., 1988, “Reliable Dip Data in Oil Based Mud: Hardware and Software considerations,” Transactions of the 11th European Formation Evaluation Symposium.

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