Geosteering through Challenging Fractured Limestone Reservoir Becomes Achievable Utilizing High Definition Multi-Layer Boundary Mapping Technology – Case Study from a Deep Gas Reservoir*

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Abstract

Kuwait Oil Company is currently engaged in an early phase development of deep sub-salt, tight, naturally fractured carbonate reservoirs. These reservoirs has been tested and found to be gas bearing. They are uniquely characterized by a dual porosity nature where natural fracture network systems are the primary flowing mechanism. The foremost challenge to produce from these reservoirs is the wellbore interaction with the natural fracture network systems. Despite drilling around 85 vertical and slightly deviated wells in this large challenging HP/HT reservoir complex, understanding and characterization of the fractures is a challenge in the absence of horizontal wells, though fracture understanding has improved over time through careful integration and interpretation of logs, core, and seismic data. To achieve the dual objective of characterizing the fractures and to boost production, the asset team recently embarked on a strategy to drill horizontal wells targeting these challenging tight reservoirs.

As a fit for purpose solution to address these challenges, “High Definition Deep Directional Multi-Layer Boundary Detecting Technology” was incorporated in the drilling plan so that horizontal producers could be geosteered in the desired target intersecting as many fractures as possible. This technology, an advancement on the 1st generation “Distance to Boundary” technology, is characterized by its extended capability to detect multiple bed boundaries based on resistivity contrast up to 20 feet around the wellbore. The significantly improved new multilayer stochastic inversion also solves for structural dip along the wellbore azimuth (longitudinal dip). In the lateral section, this technology successfully mapped the reservoir roof as well as multiple thin intra-layers inside the target reservoir along with information on longitudinal dips which helped immensely to optimize trajectory inclination and spatially position the wellbore across different layers as per plan. Apart from detecting reservoir boundaries, the inversion also mapped conductive and resistive fractures cutting the wellbore at high angles for the first time, while

the trajectory was drilling across a fracture corridor. This further added confidence to geo-steering while drilling as wellbore cutting through such a fracture corridor was highly anticipated in predrill planning. Drill-pipe conveyed borehole images acquired after drilling the well confirmed the presence of large swarms of fractures detected through inversion. The effective integration of data from different fields in a single platform, like LWD logs, boundary information, dip information, drill cuttings information and decisions taken based on the interpreted information paved the way for the successful drilling of this well and achieve the predrill objectives.

Introduction

Deep, sub-salt, tight carbonate reservoirs (average porosity of 4-6 p.u. and average permeability of 0.1 mD) are being targeted more aggressively for hydrocarbon potential. To date, most of the wells have been drilled vertically or with some level of deviation with oil-based mud through these reservoirs. The first horizontal well was planned and drilled at great depths (over 14,500 feet TVD) through tight carbonate formations. The well location was selected at a crestal area and the general direction of drilling the horizontal well was planned to be towards the northwest (309 deg), knowing the regional trend of maximum horizontal stress direction is NE-SW. The main objective of drilling the horizontal well was to intersect the natural fracture systems extending through the target reservoirs and evaluate their potential of hydrocarbon production as an aid to develop the tight carbonate reservoirs.

This article describes an application of innovative inversion technique using data from Deep Directional Resistivity logging while drilling tool during real-time geo-steering the well trajectory in the target position. Associated Gamma-Ray (GR) image during drilling complemented the bedding dips output from inversion results and critically helped in decision-making process to adjust the trajectory during drilling to achieve the plan. The new high-resolution resistivity inversion detected a series of high-angle features for the first time cross-cutting the trajectory along the section where continuous mud losses were observed and large natural fractures were anticipated. The last part of the trajectory was drilled with a change in azimuth towards the north-northwest (316 deg) to control mud losses and traverse the formation layers as planned.

Finally, borehole images (resistivity and acoustic) were acquired through drill-pipe conveyed wireline technique after the well was drilled according to the plan. The high-resolution borehole images showed presence of big open fractures across the interval of high-angle cross-cutting features observed in state-of-the-art resistivity inversion process and explained the mud losses across this interval. Detailed image interpretation showed well developed NNW-SSE trending open fractures within the first half of the drilled section, the intensity decreasing in the rest of the interval where minimal mud losses were encountered along the changed well trajectory. In addition, the bedding dips from the drill-pipe conveyed image data compared very well with the ones derived from GR-image and resistivity inversion during drilling.

Geological Setting and Reservoir Properties

The general stratigraphic column for the field under study is provided in Figure 1. The deep, sub-salt reservoir complex under discussion consists of the target tight fractured micritic limestone, underlain by and unconventional source-play formation. The unconventional part is comprised of two sub-units, namely highly organic rich NJ-Kerogen and laminated Kerogen and limestone sub-unit MFS. The oil accumulations in the target reservoirs are thought to have been generated within the organic rich mature source rock, i.e. the Najmah-Kerogen interlayered with tight fractured carbonates. The reservoirs are very tight with matrix Gotnia Formation, a massive salt/anhydrite sequence 500 to 1,500 ft. thick, which has pore pressures approaching the overburden gradient.

The area under study has structural elements in the form of NNE-SSW trending faults. These are interconnected/offset by subtle NW-SE and E-W lineaments/faults. Well data indicates increased density of natural fractures near the faults and lineaments. Fractures are developed at all scales in this reservoir, with the largest fractures oriented vertical to sub-vertical and generally trend parallel to subparallel with the major fold axes. Individual well performance has varied widely in this field and wellbore intersection with natural fractures is believed to be a dominant factor that controls production from this reservoir. Based on the breakouts and drilling induced fractures observed on borehole images, the present day in-situ maximum horizontal stress around the area of interest is NE-SW, in conformance with the stress distribution associated with the Zagros Belt.

This depositional setting is challenging for horizontal well placement where the gross thicknesses of the target reservoir is about 50 feet overlain by salt. According to the fractured reservoir types characterized by Nelson (2001), the target reservoir is a Type I reservoir with natural fractures being the main hydrocarbon storage and producer. Determination of the different types of fractures and their orientation and extent are of utmost important in such tight reservoir development.

Horizontal Well Planning

A horizontal well of ~2000 feet lateral length was planned in the tight limestone reservoir section at the northern section of the crestal part of the structure towards the northwest between two major faults. The plan was made mainly to achieve the dual objective of encountering maximum number of fractures and fracture swarms to boost production. Horizontal wells can have maximum intersection with natural fractures if proper azimuthal alignment is done to penetrate the natural fracture corridors. Finding natural fractures and mapping them while drilling can have a huge impact on a horizontal drainhole performance. The success of a horizontal well depends on how accurately it has been placed in the target with respect to reservoir boundaries and in this case also natural fractures. To address the challenges in this field, “Deep Directional Multi Boundary Distance to Boundary” technology that can map reservoir boundaries and fractures while drilling was introduced as a fit for purpose solution.

Technology Description and Pre Job Feasibility

The “High Definition Multi Boundary **D**istance **t**o **B**oundary (DTB)” technology uses the same basic measurement principle as its predecessor that involves the use of traditional axial antennas together with the novel concept of tilted antennas to provide directional and deep phase shift and attenuation measurements at multi depths of investigations and frequency while drilling. While “Distance to Boundary” technology is limited to mapping only two layers, above and below the tool, up to a distance of 15 feet around the wellbore, this technology is a step improvement on the first generation with

- Significantly improved signal to noise ratio.
- A completely new and robust multilayer stochastic inversion.

- Multiple boundaries detection capability up to 20 feet around wellbore.
- Dip and anisotropy computation.

When the 1st generation DTB technology used symmetrized directional measurements which are sensitive to formation boundaries, this technology along with the symmetrized measurements also uses the anti-symmetrized directional measurements which are sensitive to formation dip and anisotropy. The automatic stochastic real time inversion takes no user assumptions on number of layers, resistivity, anisotropy, thickness and dip. 100,000s of models are probed every two seconds in real time to provide answers on layers, resistivity of layers, anisotropy, thickness and dip with robust results compared to the 1st generation inversion (Figure 2).

Pre-Drill Feasibility Study

A pre-drill feasibility study was performed on offset well data to see the response of high definition multi-boundary detection technology in such environment (Figure 6). A 2D structural model was created along the planned trajectory. Log properties extracted from a nearby offset well were populated layer-wise in this model. Synthetic measurements were generated along the planned trajectory and inversions were performed on the simulated measurements. The results were promising with inversion detecting reservoir roof up to 7 feet away from wellbore. Also the high definition inversion could successfully map the interlayers (Figure 3).

Real-Time Inversion and Job Execution

While drilling, for the first ~200 feet MD, HD inversion mapped the reservoir roof clearly up to ~7 feet in TVD above the wellbore. Directional measurements showed the first spike close to 16,400 feet MD and HD inversion mapped wellbore cutting across numerous high angled features after this. The electromagnetic propagation directional signal response to these features was very unique and not seen or characterized in this field before. A quick analysis for this response was done in real time to approach towards a viable explanation for this response. All the concerned fields were taken into consideration, including tool electronics response to high temperature high pressure conditions, tool failure, lateral change in formation, presence of fractures, etc. The absence of high resolution azimuthal image in the drilling BHA was a constraint in identifying these features properly. Downhole BHA was working fine as per status words transmitted to surface. One significant event that happened during this time was that the well bore encountered heavy mud losses drilling through these features. Losses are normally expected in this reservoir when wellbore interacts with natural fracture corridors or fault. The well bore azimuth was planned in this reservoir with an aim to hit natural fracture corridors. So there was a suspicion that the high angled features could be possible fractures. A quick analysis was done in real time to check the directional measurement response in such scenarios and HD* inversion results when the trajectory cuts through conductive and resistive high angled fractures. Structural model was created with fractures and populated with actual resistivity values observed across these features and directional measurements were simulated in this model. HD inversions run on this scenarios showed a very good match to what inversion was mapping in real time. This gave the FD team a pretty good confidence that trajectory was cutting through a natural fracture corridor.

Based on the above results, a strategic decision was taken at this point to hold trajectory inclination parallel to formation dip and maximize wellbore exposure to natural fractures for next 700-800 feet MD, instead of cutting down structure as planned. Dips picked on real-time

Gamma-Ray (GR) image data while drilling was critical in making suitable adjustments to keep the trajectory within the same formation and at the same time continue to intersect as many fractures as possible. Inversions also showed wellbore cutting through resistive fractures in some intervals. A similar approach was taken to characterize the directional measurements for resistive fractures. Structural model was created with wellbore cutting across resistive fractures. Directional measurements were simulated in this model and inversions were run on the synthetic measurements. The results were very encouraging with a very good match with actual real time inversion results (Figure 4). A separate set of inversions were also run with unconstrained dip values to allow better mapping of fractures that usually intersects wellbore at high angles. The results were very encouraging with HD* inversion mapping both conductive and resistive fractures more clearly (Figure 5).

The continuous mud losses while drilling the well at an average azimuth of 309 deg maintaining almost the same depth within the target reservoir led to change in the azimuth to around 316 deg at around 17,200 feet. Directional measurements started stabilizing from ~ 17,200 feet MD, indicating trajectory was drilling out of the high density fracture corridor. At this point the decision was also made to start cutting down structure to sample the formation below as defined in the pre-drill objectives. The trajectory was ~10 feet below the reservoir top and beyond the boundary mapping resolution. Inversion was not mapping the reservoir roof anymore. But HD inversion started mapping formation interlayers as soon as trajectory drilled out of the high density fractured zone (Figure 6). Mapping interlayers along with information on longitudinal dips helped immensely to optimize trajectory inclination and spatially position the wellbore across different layers as per plan. Inversion clearly showed formation down dip increasing and hence inclination was needed to be dropped more than planned to cut across reservoir as desired. Inclination target was revised to 83 deg from initial plan of 87 deg to cut stratigraphically down as per information from HD inversion. Additionally, real-time GR image data helped immensely in complementing rapid dip changes observed while drilling the rest of the trajectory (Figure 7).

Post Well Simulations to Validate Results

After detailed analysis of all the existing evidence, these features were interpreted to be probable fractures. A detailed study on post drilling drill-pipe conveyed wireline borehole image data validated the presence of fracture corridors along the first half of the drilled trajectory. The borehole images showed the presence of both closed and Oil-Base Mud (OBM) invaded open fractures which correlated very well with the inversion results mapping high angled fractures cutting wellbore (Figure 8).

The high-resolution borehole image data resolved clearly the high-angle features obtained from PeriScope-HD resistivity inversion as open and closed fractures. Some of the open fractures were really big and were classified as continuous open. Others were of medium size while some minor open fractures were also observed. These open fractures are mainly concentrated at the first 500 feet of the drilled trajectory as clusters trending NNE-SSW. Very few open fractures are found in the next 500 feet. Almost no open fractures are observed in the rest of the trajectory. Also, quite a few closed fractures were identified with the same orientation as the open fractures. They are seen mainly in the last two-third section of the trajectory.

Conclusions

The use of high definition multi boundary mapping technology played a key role in the successful drilling of this well by mapping reservoir roof, interlayers as well as fractures along the drilled length. Once the distance from reservoir roof exceeded the mapping resolution, HD inversion started mapping the formation interlayers. Mapping the interlayers gave us information on formation dip even when the reservoir roof was not visible. Also correlating these interlayers with offset well signatures gave us the relative position of wellbore with respect to reservoir roof. Mapping the interlayers with dip information helped a lot especially when the decision was taken to cut down structure to sample the entire reservoir thickness by TD, once required exposure was achieved in the top part of reservoir. The wellbore encountered a fracture corridor as was expected in pre-drill strategy. The borehole resistivity and sonic images showed very good signatures of open fractures filled with oil-base mud. The fractures in images correlated very well with EMP directional measurements response and HD inversion mappings.

Acknowledgments

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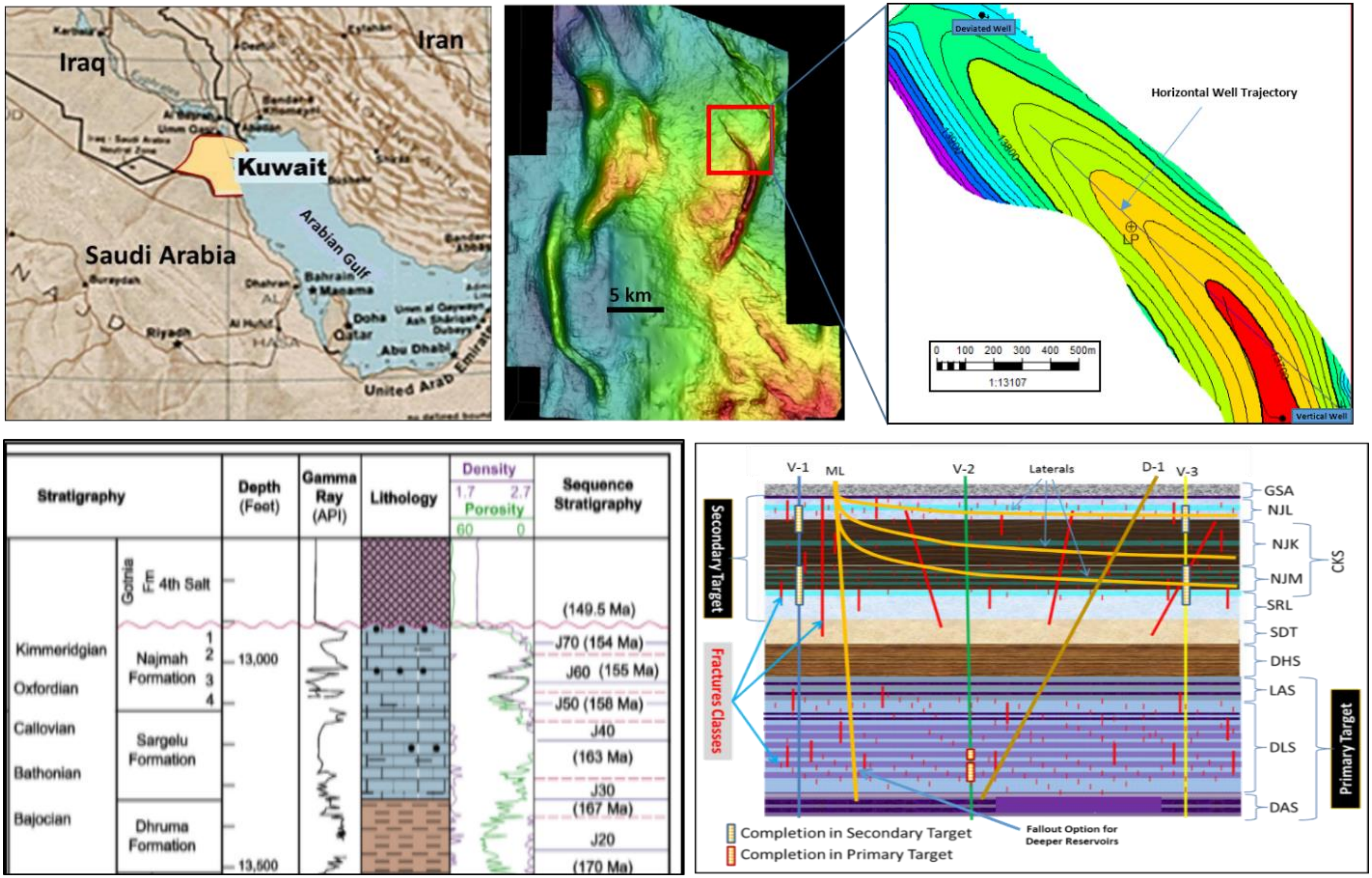

Figure 1. General field and well location map, with enhanced map of the horizontal well trajectory and nearby wells. Figure below shows the general stratigraphy and target reservoir. Schematic diagram of lithologic succession, vertical wells and horizontal wells within different targets, with fallback options in deeper reservoirs.

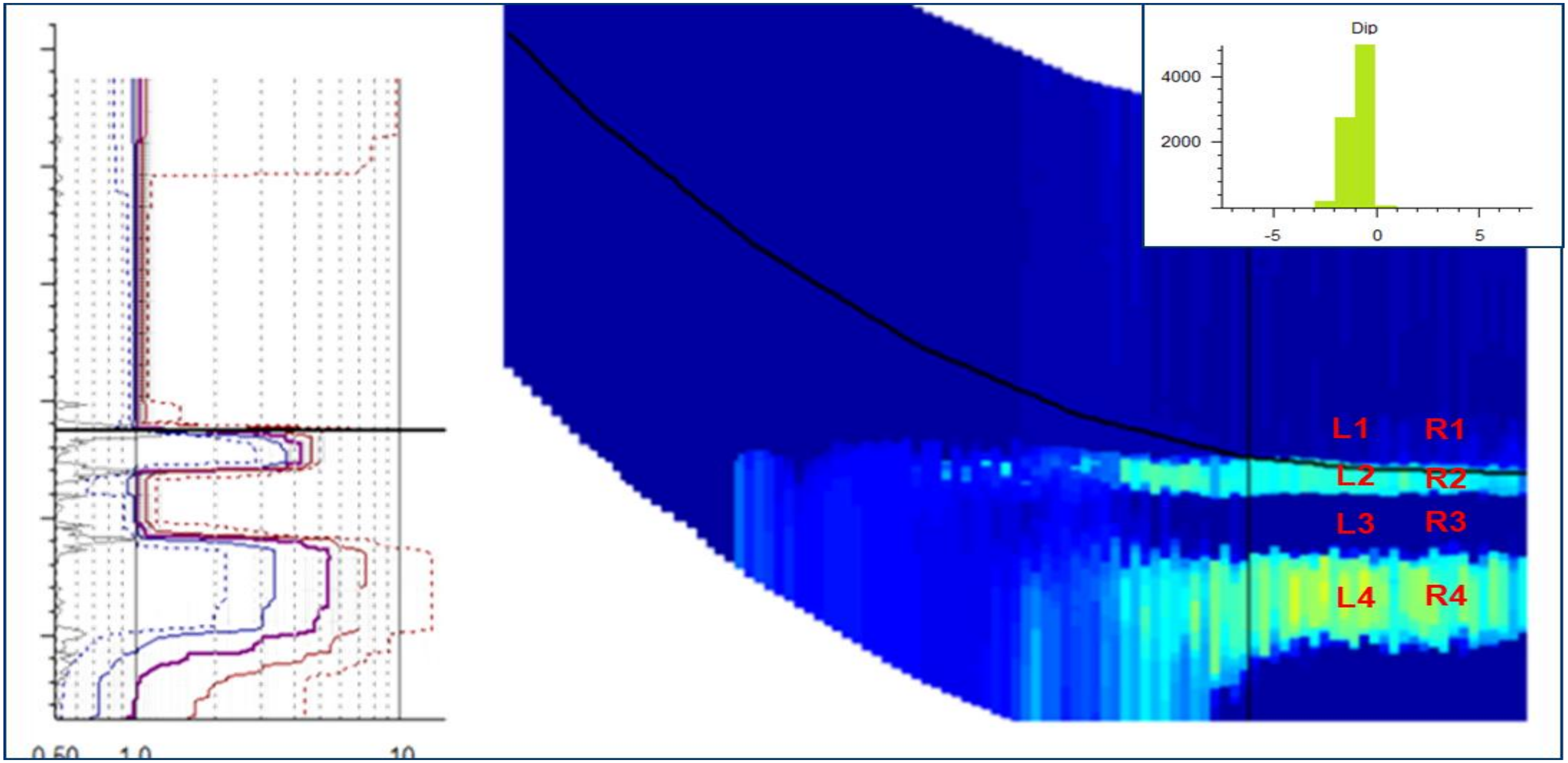

Figure 2. Illustration of the High Definition Multi boundary mapping inversion. L1, L2, L3, L4 are the layers detected with corresponding resistivity R1, R2, R3, R4. Dip output can be seen in upper right corner inset.

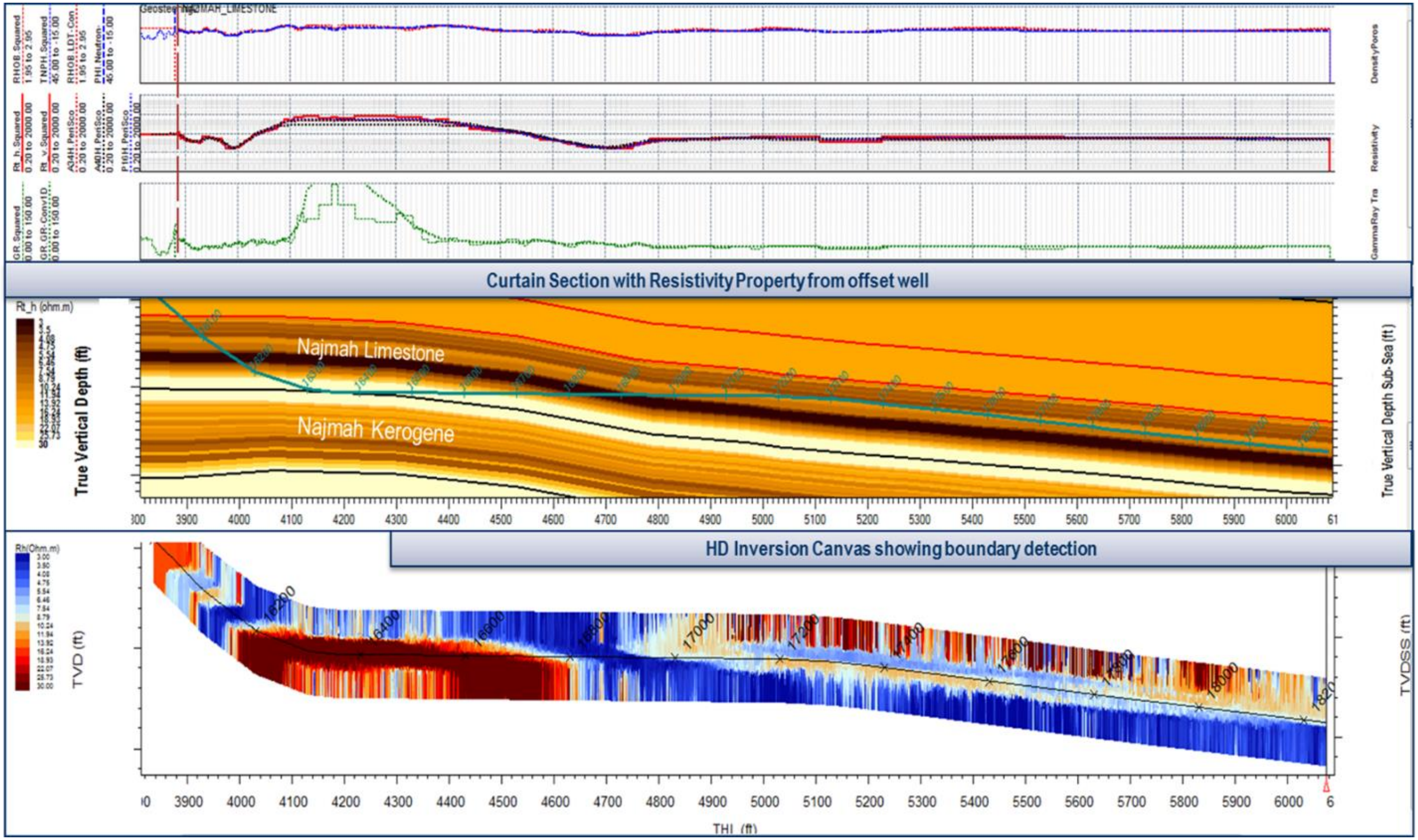

Figure 3. Predrill feasibility illustration. 2D model populated with resistivity properties from offset well and inversions were run on the simulated measurements. Inversion successfully detects the layers reservoir roof as well as interlayers.

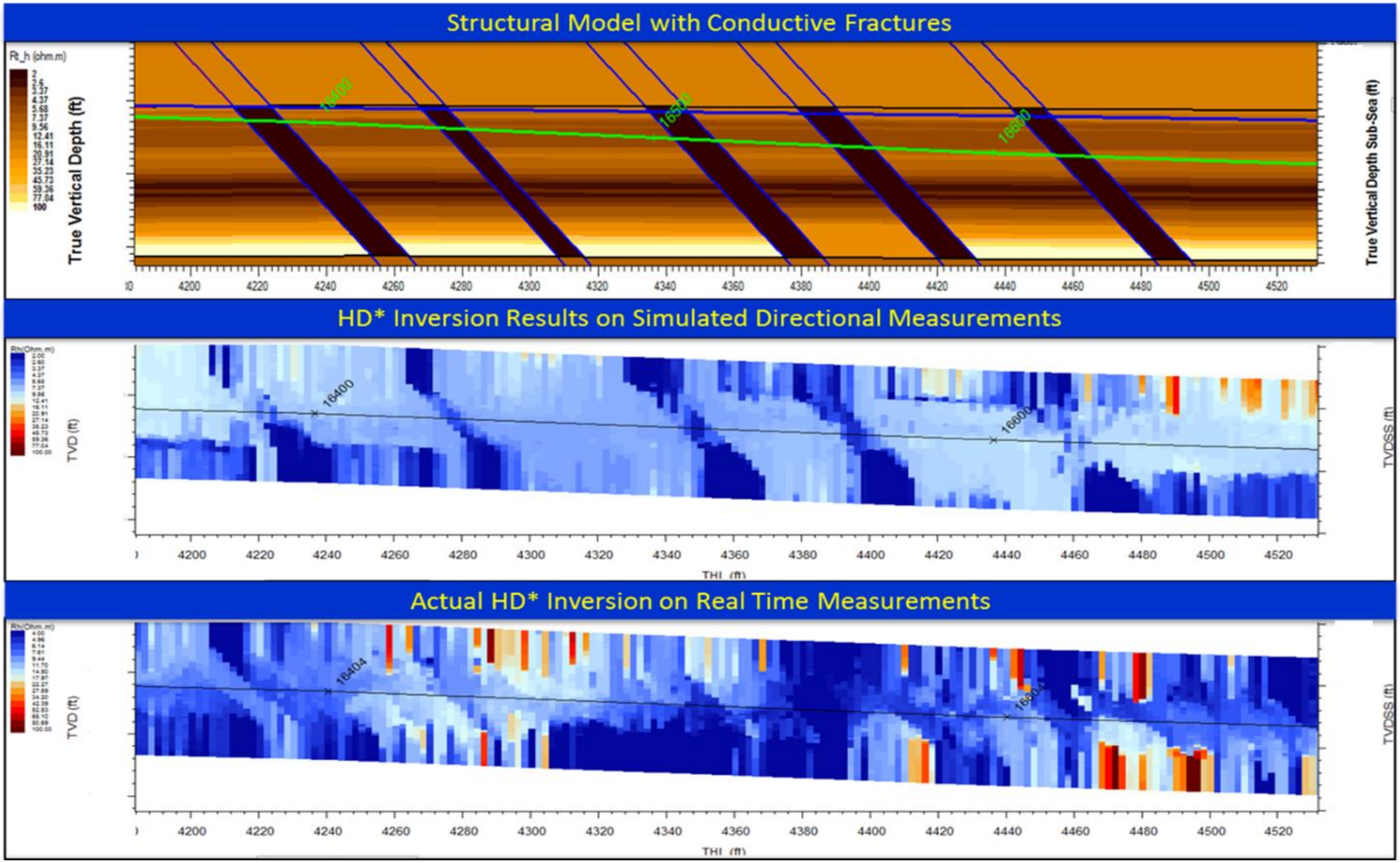

Figure 4. Structural model with conductive fractures HD inversions on simulated vs actual measurements shows very good match between modeled and actual result.

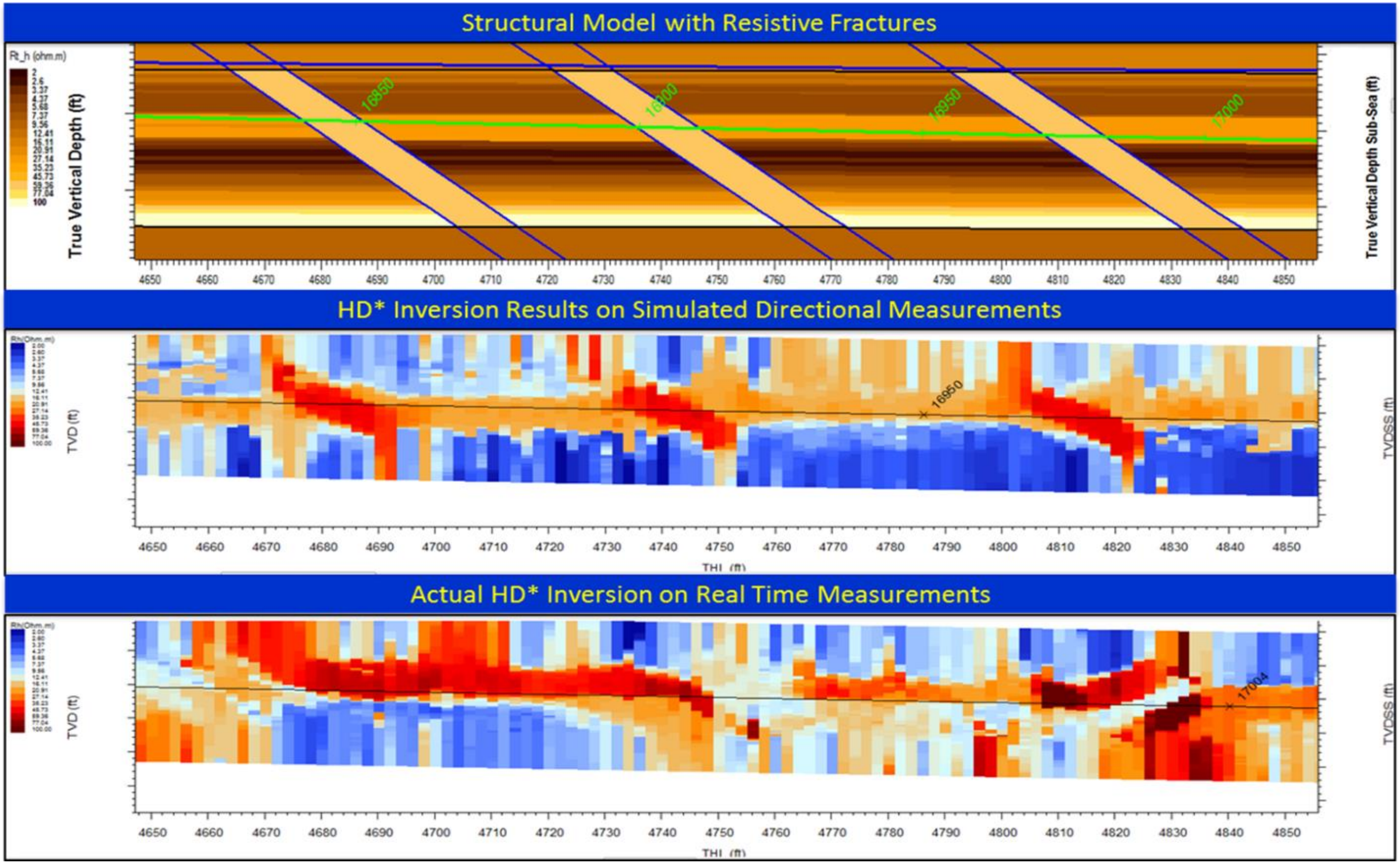

Figure 5. Structural model with resistive fractures HD inversions on simulated vs actual measurements shows very good match between modeled and actual result.

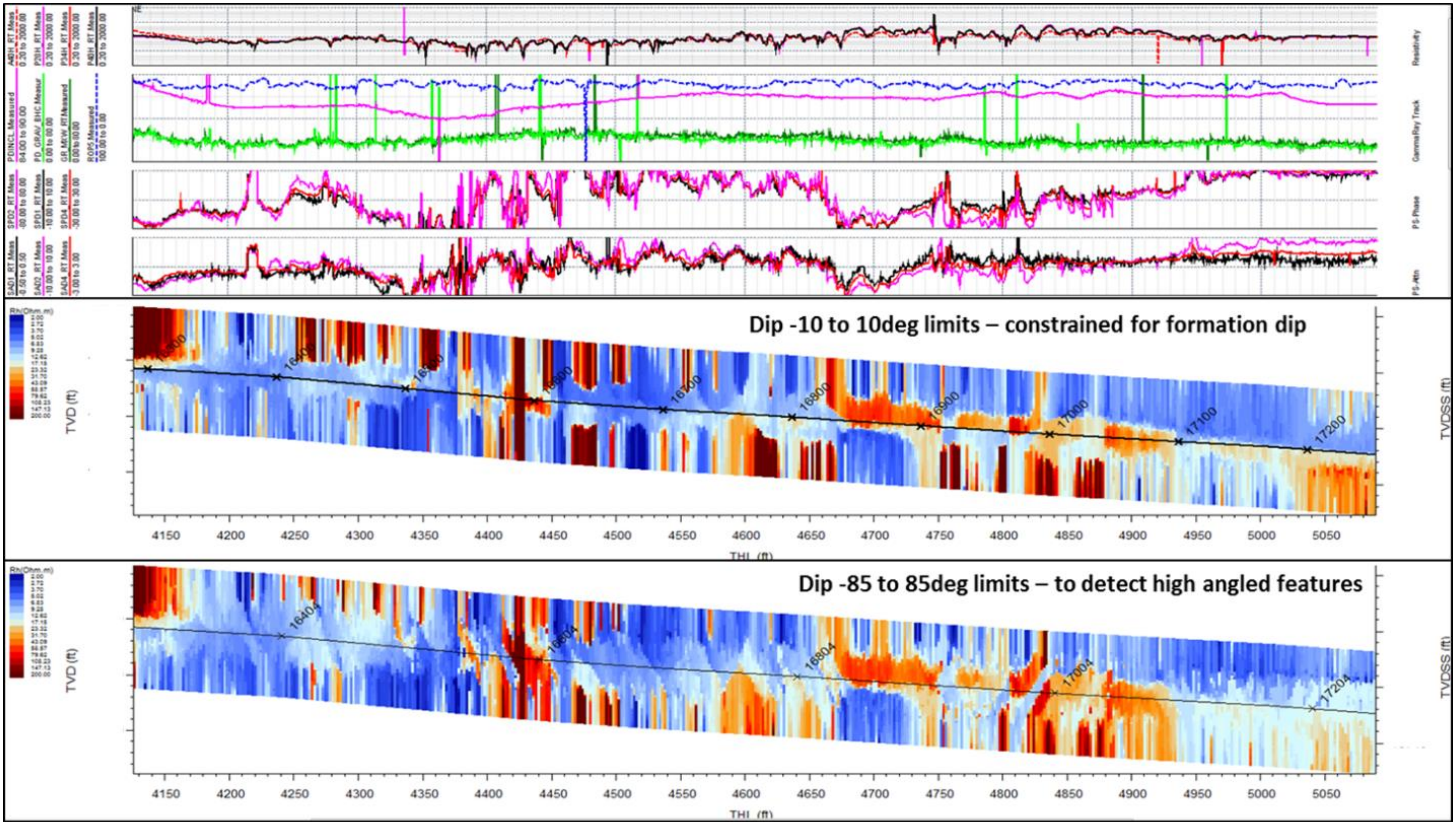

Figure 6. Comparison between HD inversions with constrained and unconstrained dip values.

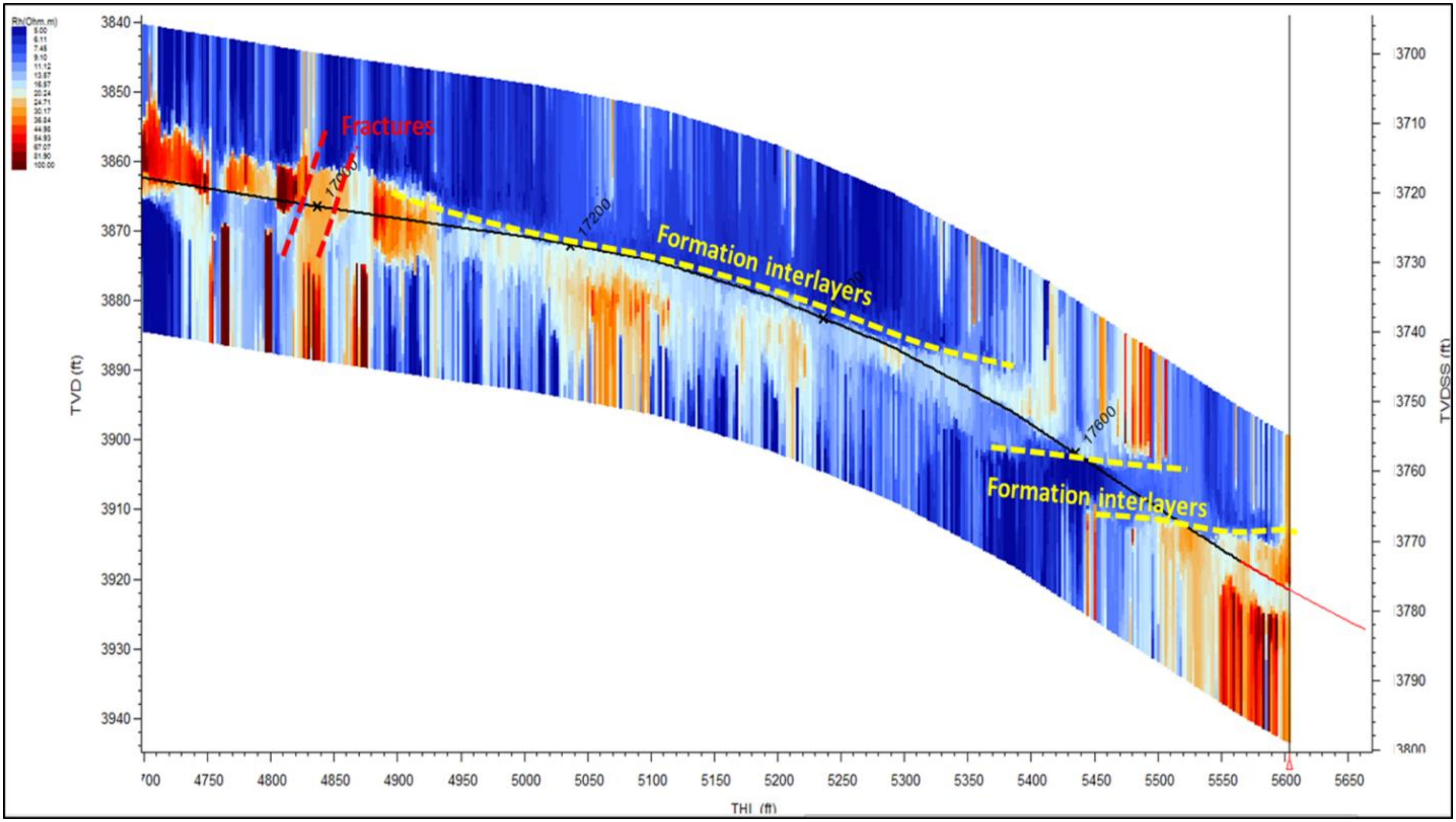

Figure 7. HD inversion mapping interlayers inside target reservoir.

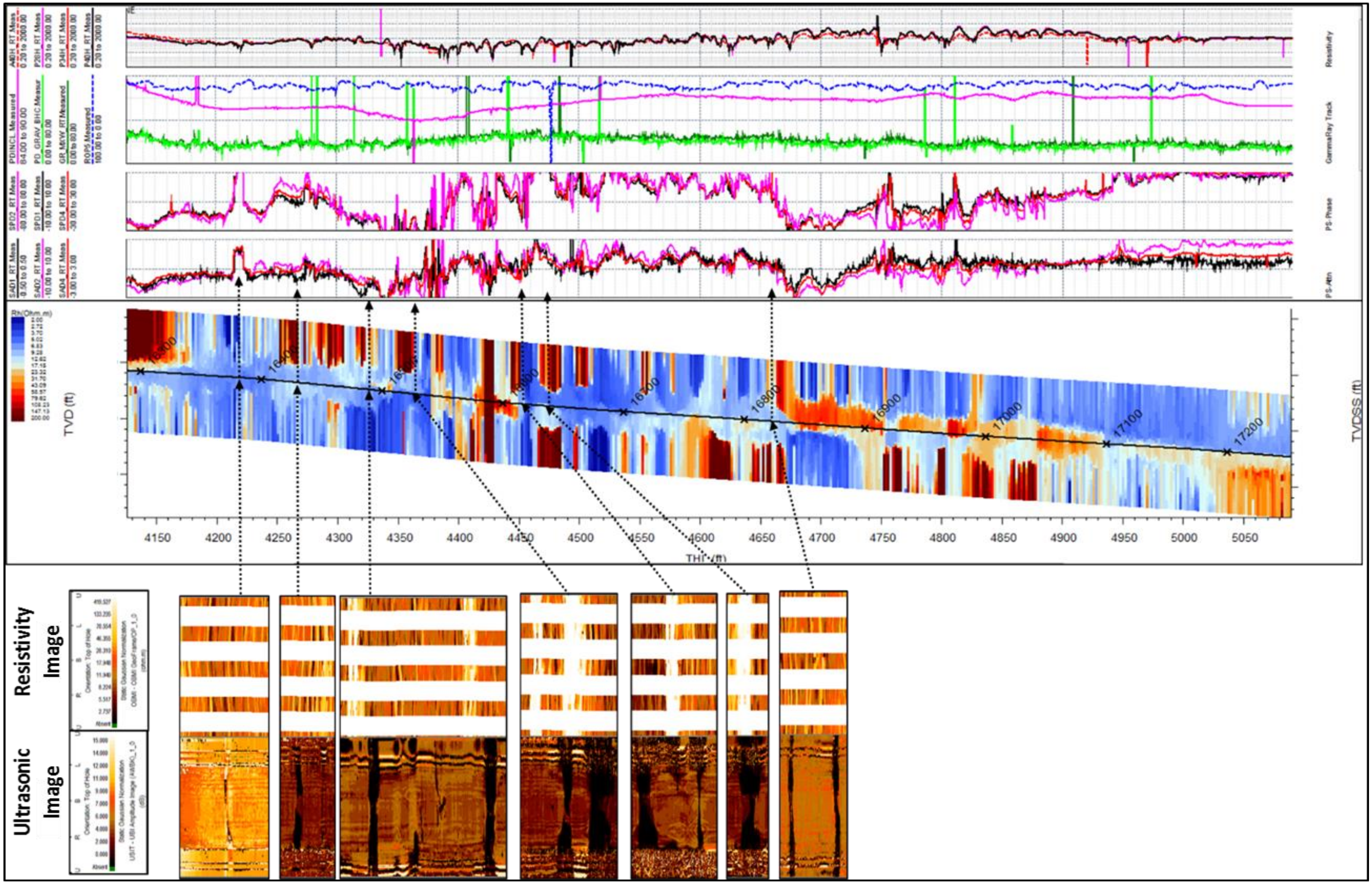

Figure 8. Borehole (resistivity and acoustic) images showing open fractures invaded with oil-based mud correlating very well with fracture detection by High Definition inversion.