Increasing Reserves Through the Characterization and 3D Static Model of Thin Beds in a Middle Burgan Reservoir, Raudhtain Field, North Kuwait*

Sabry Abd El-Aziz[1], Mariam Taqi[1], Saleh Al-Rashdan[1], and Saleh Al-Rasheedi[1]

Search and Discovery Article #20330 (2015)
Posted November 2, 2015

*Adapted from extended abstract prepared in conjunction with oral presentation at AAPG/SEG International Conference & Exhibition, Melbourne, Australia, September 13-16, 2015, AAPG/SEG © 2015.

[1]FD, Kuwait Oil Company, Kuwait, Kuwait (saaziz@kockw.com)

Abstract

The Raudhtain Middle Burgan Reservoir is considered an underdeveloped minor reservoir in the North Kuwait Resource Portfolio. It has a high degree of reservoir rock heterogeneity, and until recently, the establishment of mobile oil was given low priority. In the presence of giant reservoirs, the Middle Burgan formation is one of the 'Minor Reservoirs' thought to have limited opportunity for production increase.

Improved reservoir characterization and subsequent high definition 3D Static model increased the possibility of successfully testing Middle Burgan. The successful testing results from the idle well bore penetrating the reservoir showed the reservoir to have potential for dry oil production. These results were used to support a development plan for the reservoir and to identify follow-up actions that will aid increased oil production and reserve addition.

The Middle Burgan Formation is a stacked shoreface deposit forming prograding parasequence sets made up of upward-cleaning and shallowing parasequences. The parasequence sets reflect the overall transition in depositional environment from muddy offshore deposits, through heterolithic offshore transition zone deposits, to lower shoreface sandstones.

Middle Burgan Reservoir was subdivided to four major layers and 17 sub layers based on sequence stratigraphy and rock quality index. These geological layers, combined with 3D seismic data, provided the framework for the structural model. The high-resolution geocellular model was built while integrating all the components, which included the deterministic structure maps and petrophysical results. The model and visualization proved valuable for interpreting the primary depositional and secondary digenetic processes that left their influence on Middle Burgan rocks.

The study helped in understanding the reservoir heterogeneity and reduced the uncertainty in the identification of sand. With this more accurate estimation of water saturation, resources previously qualified as "wet" in normal clastic reservoirs, can now be exploited as producible reserves. In addition, the study helped to develop the Middle Burgan Reservoir leading to new Drilling and Workover opportunities. This led to increase

in Oil Production, and estimated 100% increase in recoverable reserves. Ultimately, this study supported a long-term development plan and reserves growth for North Kuwait.

Introduction

The Raudhtain Middle Burgan Reservoir is a lower Cretaceous (Albian) age belongs to the category of "minor reservoir" in Raudhtain field, North Kuwait (Figure 1). The Middle Burgan reservoir is a part of North Kuwait resources and attempts were made to fully understand and develop the reservoir. Middle Burgan with other minors reservoirs are expected to contribute significantly to the North Kuwait production target. Middle Burgan is an extremely challenging reservoir composed of heterolithics and mud-prone sandstones and the reservoir potential is strongly controlled by mud content with bioturbation playing a role in the redistribution of argillaceous material.

It is interpreted as stacked shorefaces deposited in a progradational parasequence sets as sea level start to rise. RAMB reservoir (160 feet thickness) is classified to four major units: MB-1A, 2A, 3A, and MB-4A (from top to bottom) with a little variation between these units. All four units are dominated by marine mudrocks coarsening up into shoreface sandstones with uniform distribution. It has been penetrated by more than 500 wells and was tested in only eight wells so far with significant current production. The comprehensive study was conducted and a 3-D static model was built incorporating geophysical, geological and engineering data available to improve understanding of the potentiality of the reservoir. The study helped to identify the sweet spots for short-term potential locations and maximizing the production target, as well as lowering the uncertainty of input parameters contribute in STOOIP calculation. The 3D model is being used to build production profile forecasting.

The main factors presented in this paper are:

- Seismic data
- Petrophysical analysis
- Geology
- Geocelluar Model
- Development Strategy

Seismic Data

The structure of MB reservoir is interpreted as highly faulted domal structure. MB surface was created using the interpreted seismic data, which covers the Ahamdi Formation down to the Zubair Formation (Figure 2). Seismic data at MB level is behind seismic resolution and appear very week reflector, Top and base reservoir structure depth grids (MB-1A and LBLSID1) were generated based on Upper Burgan and MA seismic interpreted horizons.

Footprint of OOWC at reservoir top is determined for structure delineation. It varies across the field due to structure tilting which implies that the stratigraphy and faulting plays a role in compartmentalization of reservoirs. The unknown vertical separation across the faults is due to the limitation of seismic data and unlikely faults are not encountered the wells, faults potential for sealing and juxtaposition are hard to determine. In the absence of pressure data and longer production, it is hard to measures the actual fault seal capacity at present. Sixty-four faults were interpreted from seismic data .Most of the faults are trending northwest southeast with very steep dip and applied as vertical in the model. Seismic attributes could not be used as an aid when mapping the properties due to the limitation of seismic data resolution. Velocity model was created using all the Raudhtain wells penetrating the MB-1A surface, which is utilized for time depth conversion. Centerline faults were used in generating the top reservoir depth structure that was used as input to geologic static model (Figure 3).

Petrophysical Analysis

Petrophysical study of the logs was conducted to provide consistent description of reservoir properties from wells encountering Middle Burgan. The wireline log data set are of varying vintage, which limit the accuracy of calibration. In addition, the caliper log indicates that borehole breakout has occurred in most of wells and this may reduce the reliability of log response.

The petrophysical models used in estimating porosity, water saturation, lithology, and permeability (Figure 4) have been thoroughly calibrated with available core data. The model is a deterministic one, utilizing step by step with sequential computations. Various core lithofacies were grouped into five facies in wells, which have core data and calibrated with logs. These facies were applied across all un-cored wells using a variety of petrophysical properties including effective porosity, PHZ and RQI (Figure 5). The results of this study were used to populate the static reservoir model, including effective porosity, permeability, water saturation and lithofacies.

Geology

Depositional Model

Depositional setting of middle Burgan is viewed in terms of whole Burgan formation as Burgan is classified into Lower, Middle and upper Burgan as follow:

1. The fluvial dominated delta of the basal part of the Lower Burgan represented either a late highstand or falling stage systems tract.
2. As relative sea level continued to fall, the overlying stacked braided fluvial channel sandstones made up a lowstand systems tract, the base of which is a sequence boundary.
3. The marine influenced channels at the top of the Lower Burgan indicated that relative sea level was rising and was designated a transgressive systems tract.
4. The Middle Burgan was deposited in the subsequent highstand systems tract, which continued upward into the Upper Burgan and was subsequently followed by a transgressive systems tract towards the end of the Burgan.

Based on available wells with core data, the Middle Burgan represents a phased progradational shoreface succession, which has been exposed to fair-weather and storm conditions (Figure 6).Three main facies associations have been identified offshore, offshore transition zone and lower shoreface. The wave/storm-influenced lower shoreface deposits generally show the highest degree of variability as the lower shoreface setting is strongly exposed to both fair-weather and storm conditions (with fair-weather deposits only being preserved if storm intensity/frequency is not too high). Offshore transition zone and offshore deposits are less variable as these settings are dominated by fair-weather conditions with commonly variable, but less intensive storm activity. These facies associations are typically organized within upward cleaning/ shallowing successions (=parasequences) reflecting the upward change from basal offshore mudrocks (Figure 7) to offshore transition zone heterolithics/mud-prone sandstones (Figure 8) and, at the top, slightly cleaner lower shoreface sandstones (Figure 9). Each of these upward-cleaning successions/ parasequences is bound at the base and top by high-frequency flooding surfaces; these flooding surfaces record the episodic backstepping /landward retreat of the depositional system. The paleo-coastline for the Middle Burgan is thought to have a general northwesterly orientation

Reservoir Stratigraphy and Layering

Sequence stratigraphy based on the integration of core and well logs was applied and identified flooding surfaces as the key correlatable marker. A correlation framework was built and resulted in four major layers (MB4A, 3A, 2A and MB1A) from bottom to top with total 18 geological surfaces and extended over the field (Figure 10). Isopach maps for each layer have been generated and edited by hand to reflect the stratigraphic setting and then incorporated into the model. In gross terms, the sequence stratigraphic evolution of the Middle Burgan Formation can be described in terms of four low-frequency parasequence sets, each of which is bound by major flooding surfaces (Figure 11). These parasequence sets form part of an early highstand systems tract and are described below in ascending stratigraphic order.

Layer MB-4A

The MB4A Layer is the lowermost layer in the Middle Burgan and is bound at the base and the top by the LBLSID1 (Lower Burgan and MB-4A respectively, both of which have been identified as field-wide correlatable. In context with regional work for the Burgan, the LBLSID1 may correspond to the K100, which is a 2nd order maximum flooding surface (Sharland et al. 2001).

The MB-4A has been interpreted as a transgressive surface, which is correlated across the field and is potentially a 3rd or 4th-order surface. This interval stacked (potentially three to four) upward-coarsening parasequences of offshore/offshore transition zone to lower shoreface deposits. These are stacked within an overall but pulsed progradation parasequence set that corresponds to a crudely upward-cleaning gamma ray motif. The overall upward-cleaning trend is also notable from the depositional package stacking patterns.

The most representative gamma ray profile for this layer is a crude upward-cleaning trend, reflecting progradation of the shoreface. However, correlation shows that the log profiles can be variable across the field. Variations include upward-dirtying motifs and a somewhat trendless succession. Therefore, the identification of individual parasequences, noted from core cannot be confidently identified and correlated from wireline logs alone. Preliminary mapping of the distribution of these cleanest, best quality sandstones appear to have quite a wide distribution across the fields with some clustering in the central to northwestern parts. Bearing in mind that the palaeoshoreline is considered orientated in an approximate north-west/southeast direction, these sandstones appear to have good lateral extents parallel to it.

Layer MB-3A

The MB-3A layer is bound at the base and the top by correlatable transgressive surfaces, which are named the MB-4A and MB-3A, respectively. In context with the regional work and in sequence stratigraphic terms, the MB-4A may be a 3rd or 4th order surface, whereas the MB-3A is potentially a 3rd order surface.

This layer comprises five well-defined upward cleaning parasequences that are stacked into a pulsed progradational parasequence set. Overall, this layer represents a progradational upward change from offshore mudrocks, through offshore transition zone heterolithics to lower shoreface sandstones at the top. The lower shoreface sandstones are particularly well developed and include bioturbated and preserved stratified sandstones. The wireline logs, in particular the gamma ray log, demonstrate the overall upward-coarsening trend of the parasequence set. Although some variations have been noted, an upward-cleaning log profile appears to be representative for this layer. Despite this clear trend, the individual parasequences typically cannot be reconciled from the wireline logs and can be identified from core only.

It is important to note, that the sandstones at their top may have reasonable lateral extents preferentially orientated parallel to the palaeo-shoreline. The lower part of this layer is mud-prone and where core analysis it records negligible to poor reservoir quality. The sandstones at the top of the lowermost parasequence record poor reservoir quality, thought to be due to a relatively strong diagenetic overprint. In the upper part of this layer in an upward increase in reservoir quality corresponds to the upper part of the upward-cleaning trend with the best reservoir quality recorded in the stratified sandstones at the top with clean pore fabrics associated with well-connected macropores. By comparison, the sandstones near the top in some areas have only poor to moderate reservoir quality potentially due to their more argillaceous and very fine-grained nature.

Top of this layer is shows cleanest sandstones appear to be concentrated in the central part of the Field. Whereas in more the southern parts of the field, sandstones appear to very thin or absent. The more sand-prone nature in the central part of the field may be linked to concentrations of sand from storm events, where sand supply bypassed the wells in the south. The lateral extents of the thin, argillaceous, storm event sandstones are expected to be limited and unlikely to connect to the amalgamated cleaner sandstones in the central part of the field. Thinner and more argillaceous sandstones may occur lower in this layer but given the overall mud-prone nature of the lower part of the layer; these sandstones are expected to quickly pass laterally into mudrocks and heterolithics.

Layer MB-2LST

This layer is bound at the base by a correlatable transgressive surface MB-3A (3rd order surface) and by the MB2LST surface at the top, which is a candidate maximum flooding surface. This layer comprises mudrocks, heterolithics and sandstones deposited in an offshore transition zone to lower shoreface setting. Two crude upward cleaning trends are noted; motifs are not as easily identifiable from what is particularly notable about this layer is the intensely cemented nature of the deposits; siderite and ferroan dolomite cements. Paragenesis indicates that the dolomite cementation was late and while its origin is poorly understood, its distribution appears to be related to the distribution of the early-diagenetic siderite, which may have acted as precursor cement. Siderite is thought to have formed during periods of low sediment accumulation/nondeposition. Previous work has reported carbonate-rich horizons at the same level, suggesting a field-wide correlatable diagenetic modification. The preferential association of the carbonate cements with the layer (which marks the upper limit of cementation) across the field suggest that this transgressive surface may be a candidate maximum flood.

The parasequence trends noted in core cannot be reconciled from the wireline logs; this is in part due to the intensely cemented nature of the layer. However, the presence of these cements result in a highly recognisable log character, the base of which is defined by a gamma peak (the highest gamma response for any part of the Middle Burgan) and a corresponding depressed neutron porosity and increase in density. Given these distinctive wireline log characteristics, this layer can be easily picked and correlated across the Field. The lower boundary/transgressive surface MB-3A, which marks the base of the gamma peak, is used as the correlation datum. As noted above, it is not definitive what predisposed the dolomite cements to precipitate so extensively in this layer and as a result, it is not possible to confidently classify the top surface (MB-2LST) as a maximum flood. It is widely correlatable across the Fields and its sequence stratigraphic order cannot be confirmed that it is significant regionally.

The reservoir quality for this layer is typically negligible due to its intensely cemented nature. While core control imply that the cements may be tabular in form However, the basal mudrocks of the overlying parasequence set, on correlation appear to be laterally extensive and likely to act as a barrier to vertical fluid flow. The carbonate cements, therefore, whether nodular or tabular, will act to enhance this barrier.

Layer MB-2A

This layer is bound at the base and the top by the MB-LST and MB-2A surfaces, respectively. Both of these surfaces are highly correlatable across the Field. Overall, this layer represents a progradational shoreface succession with some variation across the fields. This succession comprises five well-defined small-scale parasequences, which represent a phased progradation of the shoreface (parasequence set). An upward change from offshore transition zone mudrocks and heterolithics to lower shoreface sandstones is clearly identifiable from the gamma ray; individual parasequences, however, are difficult to resolve. This phased upward-cleaning trend can also be clearly observed from depositional stacking patterns (four potential parasequences) in some areas.

A progradational shoreface parasequence makes up the lower part. In the upper part, however, bioturbated sandstones stack into bed set-scale upward-coarsening motifs, which successively fine-upward suggesting that the system is beginning to backstep. These are poorly resolved by wireline logs and correspond to two upward-dirtying gamma ray motifs. Comparison of this layer across the field implies that the overall upward-cleaning trend observed is quite widely correlatable and appears to be representative for the MB-2A layer. It is not known why the apparent backstepping appears to be restricted to the southern part of the field, but it may be due to an autocyclic control such as local subsidence.

The upward-cleaning trend observed is mimicked in the reservoir quality distribution. However, whereas the best reservoir quality is expected in the sandstones at the very top, they record only poor to moderate permeabilities, potentially related to the presence of dolomite cements. Reservoir quality is typically poor throughout, which is potentially due to poorly connected mixed pore systems. The sandstones at the top of this layer suggest is best developed in the central part of the fields where they appear to be laterally extensive parallel to the inferred palaeoshoreline. However, in a landward (west/southwesterly) and seaward (east/north-easterly) direction, these sandstones (as calculated from wireline logs), appear to become increasingly argillaceous. Furthermore, correlation of these sandstones is difficult where the sandstones are thinner, finer grained and more argillaceous and stack into a number of progressively finer bedset motifs.

Layer MB-1A

This is the uppermost limit of the Middle Burgan and is bound at the base and the top by the MB-2A and MB-1A surfaces, respectively. Both of these surfaces are transgressive surfaces and highly correlatable across the Field. The wireline log trends appear largely ambiguous for this layer. This may be due to the greater degree of facies association variability noted in core, when compared to underlying layers. However, the gross depositional trends observed from core, which can be clearly divided into two comparable intervals cannot be reconciled from the wireline logs.

- The lower interval within this layer comprises a crude upward-coarsening trend. Superimposed on the base of this trend are bedset-scale upward-fining bioturbated sandstones. Overlying this, are two small-scale parasequences of offshore transition zone mudrocks and heterolithics to bioturbated lower shoreface sandstones and, in the upper parasequence, stratified sandstones. In the more proximal, the stratified sandstones appear to be cleaner and better developed.

- The upper interval comprises two stacks of bioturbated lower shoreface sandstones (the upper stack showing a subtle upward fining motif) separated by offshore transition zone mudrocks and heterolithics. The latter muddy deposits are also evident but in this more distal area, they entirely comprise offshore mudrocks. They separate an upward-cleaning parasequence of offshore transition zone heterolithics to lower shoreface sandstones at the base from trendless bioturbated lower shoreface sandstones at the top. From depositional packages, these middle muddy deposits are thought to be significant in that they display sharp upper and basal contacts and are thought to be deposited in response to high frequency sea-level rises.

The ambiguous log responses continue across the field in this layer and are overall typically trendless. However, the upward-cleaning trend of the lower interval can be picked in a number of wells a cross the field, in the majority of wells; there is a subtle upward-dirtying (retrogradational) gamma ray motif at the top, which continues into the overlying Upper Burgan. Although difficult to resolve from core, this may reflect the initial stages of flooding prior to the main flooding event, which marks the top of the Middle Burgan.

Reservoir Quality

The principal control on reservoir quality is the relative abundance and pore-scale distribution of detrital clay (Figure 13), and localised carbonate cementation. The pore-scale fabric scheme, which captures these parameters and can be linked to reservoir quality, is difficult to definitively relate to the descriptive sedimentological schemes. It is possible to relate the better quality fabrics to specific sedimentary descriptors. The Pore-scale fabric is typically found within the clean bioturbated and massive sandstones and the stratified sandstones. The best reservoir quality occurs within the clean stratified and bioturbated sandstones. The relative lack of detrital clay and authigenic carbonate result in these deposits possessing reasonable macroporosity with good connectivity).

Original Oil Water Contact (OOWC)

The purpose of determining a best field wide original oil water contact (OOWC) is to establish the limit of the oil saturation and structure delineation of RAMB reservoir. The limit helps to define the volume of the original oil in place just prior the production start in reservoir. The OOWC is very challenging due to the nature of shoreface sandstone reservoir. The reservoir is highly shaly, bioturbated and has conductive minerals, which are all lowering the resistivity log response and negatively effecting the SW calculation (Figure 14). OWC could not be picked based on petrophysical calculation SW logs.

From the early studies, the data says that the structure began filling early Late Cretaceous, and may still be charging today. Renewed uplift structure since Pliocene caused tilting and oil to be spilled southwards to Bahrah and Burgan fields and redistributed within the RA and SA fields. Observed OOWC from MDT sample, TVDSS vs. SW plot and spill point with taking in consideration the structure tilting effect .OOWC was picked between spill point -8150 and -8220 in SW from MDT sample , and was determined to be reliable not as absolute. It is important to recognize that OOWC picks lies within a range of uncertainty. This variation might be to different reasons as changes in rock properties and/or faults acting as lateral barriers that might suggest separate initial oil water contacts. Where the faults are more extensive, it is possible that more compartments exist

Fluid Properties

Raudhtain Middle Burgan has PVT analysis for a few numbers of wells showing a variation in oil quality of the reservoir in the following fluid properties (FVF, Solution GOR, and bubble point pressure & oil viscosity) Table 1.

Integrated Reservoir Model

An independent static model was built and it was suitable for reservoir management and development planning. The model incorporated the latest reservoir description, petrophysics, fluid property, and dynamic production data to support in developing optimum strategic reservoir development, drilling, and facilities plans. The main purpose of the model is to achieve vertical resolution and lateral distribution within the stratigraphic layers, enough to capture the reservoir heterogeneity and performance. The model has 57 layers with an average vertical thickness 2-4 feet (Figure 15).

Geological Model Grid

The geological grid was constructed using the structure of the top Upper Burgan as conforming grid to derive top Middle Burgan top depth, as it is a week seismic reflector. The other sub horizons structure grids were constructed using 17 isopach grids generated. The structure grids, isopach grids and fault segments were incorporated to build the structure framework (Figure 16). The layer thickness is sufficient to capture the vertical heterogeneity. The lateral resolution of 50mx50m was chosen to provide some flexibility in the specification of the flow simulation grid. This resulted in an easy multiple of 50m and maintains the optimum grid for upscaling

Facies Log

The first step in property modeling was to distribute the various facies within the reservoir. Core lithofacies were defined and grouped into five facies. Litho-facies log was created in cored wells and extended to all Raudhtain wells, which covered reservoir interval for static model input.

Upscale Of Well Data

Before the facies and petrophysical modeling can be performed, the well data was upscaled and averaged in one value per each cell at well location. The arithmetic average has been used to upscale well data from log scale to geocelluar scale for PHIE. Geometric averaging has been used for permeability and “Most of Common” method has been used for facies. These different algorithms were used to select a representative value for each cell.

Facies Modeling

Core lithofacies were distributed in the static model by using a technique called Sequential Indicator Simulation (SIS) modeling algorithm. This method is the most appropriate either where the shape of particular facies bodies is uncertain or where you have a number of trends, which control the facies type. Geometric parameter as length, width and orientation were defined for each zone, based on depositional setting and the type of the dominant facies (Figure 17).

Petrophysical Modeling

Stochastic as well as a deterministic technique (interpolation) was applied to distribute the porosity and permeability within facies template provided by the facies modeling. Other parameters are used to create best fit properties (Phie, Perm) through all of the input data and distributed horizontally and vertically in the model.

Porosity

Data were interpolated by facies for each zone. The properties were distributed deterministically using the moving average algorithm. Geostatiscal analysis and variograms were applied and geometric parameters were defined for each zone (Figure 18).

Permeability

The permeability model was transformed from the porosity model. The porosity attribute was used for interpolate the permeability in the 3D grid, which keeps the porosity and permeability distributed simultaneously and the correlation is properly maintained (Figure 19).

Water Saturation

Water saturation was generated directly from the log data and interpolated with structure between wells, as there is no enough data to generate from a SW- height function. This is the area of uncertainty due to the nature of high argillaceous sand (Figure 20).

Volumetrics

In hydrocarbon reserve estimations, we are concerned with parameters like area (A), pay thickness (H), porosity (Φ), oil saturation (So) and formation volume factor (FVF). All of these appropriate inputs have been calculated in 3 D model. The volume was calculated with results 100% higher than what was documented.

Development Strategy

Improved reservoir characterization and build the comprehensive 3 D static model (Figure 21) helped to accelerate the development strategy of middle Burgan reservoir. The aim of the development strategy is to expedite and maximize dry oil production by determining the "sweet spot" for the short/long-term development plan to meet the production target.

1-Data acquisition

Static Data. Obtained and continue to obtain enough good data distribution to help making decisions and minimize the development risks and lowering the uncertainties. The necessary data required to be obtained from upcoming new wells penetrating the reservoir:

- Geological
  - Cutting new cores in gap areas of the field, core description, Routine and special core analysis.
- Engineering Data
  - RFT, MDT, PBU, PLT, PVT and relative permeability

2-Reserve Growth

Continue drilling vertical and plan for high angle wells (HAW) and test the reservoir in new areas. This would help in measuring the reservoir potential and understanding the uncertainty parameters contributing to STOOIP calculation. This understanding will lead to increase the recovery and add reserve.

3-Drilling Activity

Vertical and HAW Wells. The calculated STOOIP and the performance of the existing producer wells indicated that RAMB had a potential reservoir for enhancement of dry production. This detailed study helped in proper placement of the well within the 'Sweet Spots" with low risks. The new in-fill locations were selected on optimum locations (better reservoir quality, high API gravity, high structure position and high-pressure areas). Drill and plan HAW wells in thin sand layers to increase productivity and improve recovery as the long wellbore allowing longer completed intervals and therefore increased production rates. In addition, the obtained information will justify drilling more NCW (Non-Conventional Wells) wells and allow development with fewer wells. This will help to increase the recovery and avoid the surface constraint due to the conjunct other reservoirs wells.

Recompletion of ceased/abandoned wells. Continue reviewing the closed wells, which have no more production potential left in major reservoirs and to be tested and produce MB oil. Continue utilizing of ceased wells will reduce risks; cost and time scale (Figure 22).

4-Apply Technology

Successful exploitation of Middle Burgan reservoir requires advanced stimulation technology like HIWay Fracturing Application. Significant oil reserve is present in low-permeability shoreface sandstones and applying such technology helps to unlock the reservoir potential. The application was applied for two middle Burgan wells and giving a very encouraging results and leads to increase production by 22% (Figure 23). HiWay fracturing application is proved as excellent technology and continue use will support the reservoir development plan.

5- Water flood (pressure support)

Middle Burgan is a depletion reservoir and the limited production history suggests no evidence of pressure support. The interpreted RFT data before production start from reservoir indicates decline pressure due to fault juxupostion Upper Burgan Producers against Middle Burgan sands. In addition, sink pressure areas around the existing producer MB wells indicates reservoir depletion (Figure 24). WF implementation will be essential in the absence of aquifer support to deplete the reserves. Accelerate the water flood will support the pressure in sink areas and sustain the wells in production especially the wells in MB require artificial lift from the beginning.

Conclusions

The reservoir characterization study and 3D geological model built allowed better understanding of the heterogeneity and variability of the geology as well as the hydrocarbon potential distribution in the reservoir. The integration of defined core based rock-types combining with multidisciplinary approaches of geological, geophysical and reservoir-engineering techniques allowed reproducing the depositional settings and characterizing the major reservoir heterogeneities. This study resulted in a robust model suitable for reservoir simulation and well planning which led to new Drilling & Workover opportunities that would now support a short/long term development plan and reserves growth for North Kuwait.

Acknowledgment

The authors acknowledge AAPG organization for authorization of this work and the efforts of Kuwait oil company Management and the Ministry of Oil for permission to publish this paper.

Reference Cited

Sharland, P.R., R. Archer, D.M. Casey, R.B. Davies, S.H. Hall, A.P. Heward, A.D. Horbury, and M.D. Simmons, 2001, Arabian Plate Sequence Stratigraphy: GeoArabia Special Publication 2, Gulf PetroLink, Bahrain, 371 p.

Figure 1. Location map.

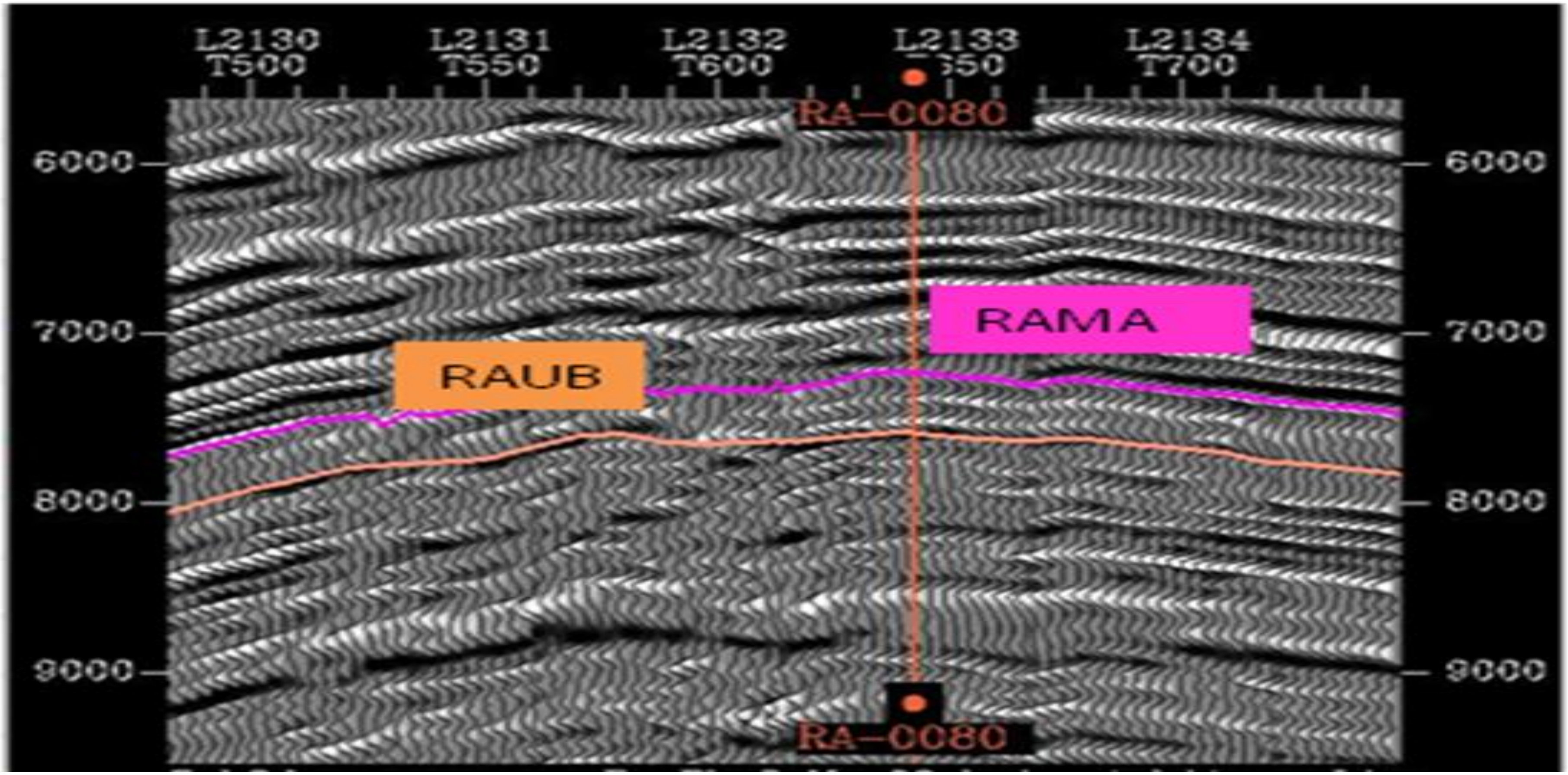


Figure 2. Seismic line.

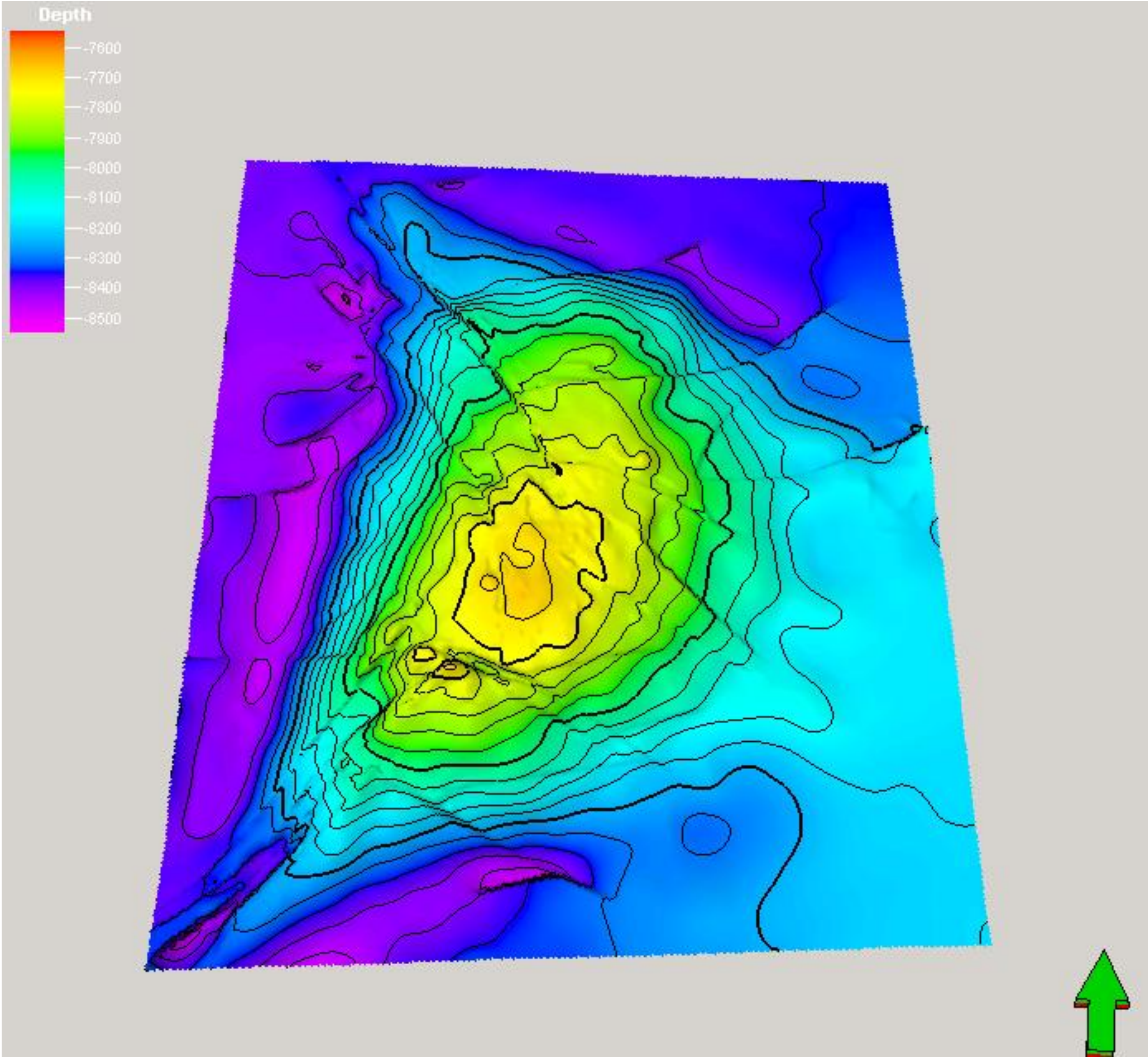


Figure 3. MB1A structure depth.

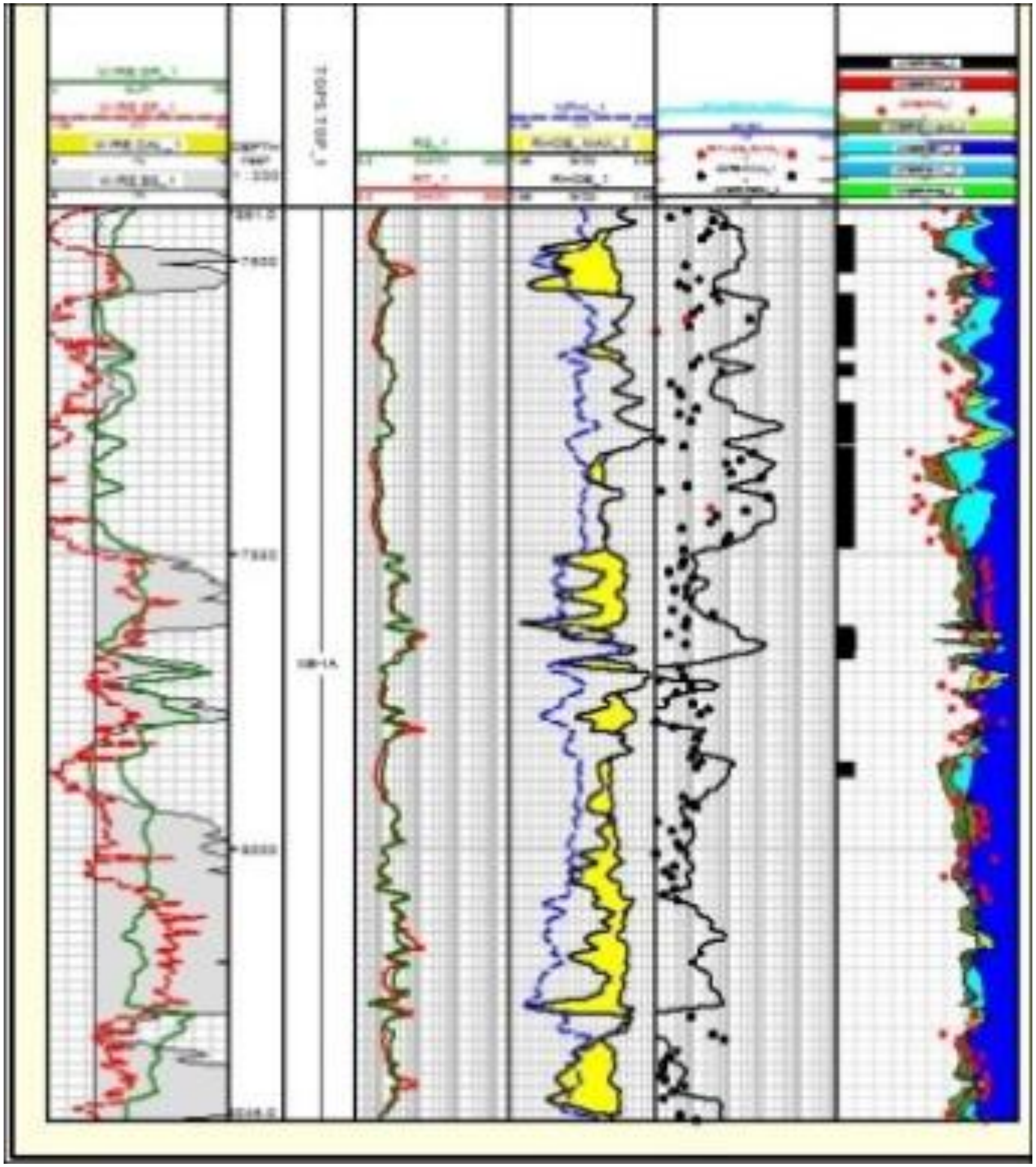


Figure 4. Petrophysical model.

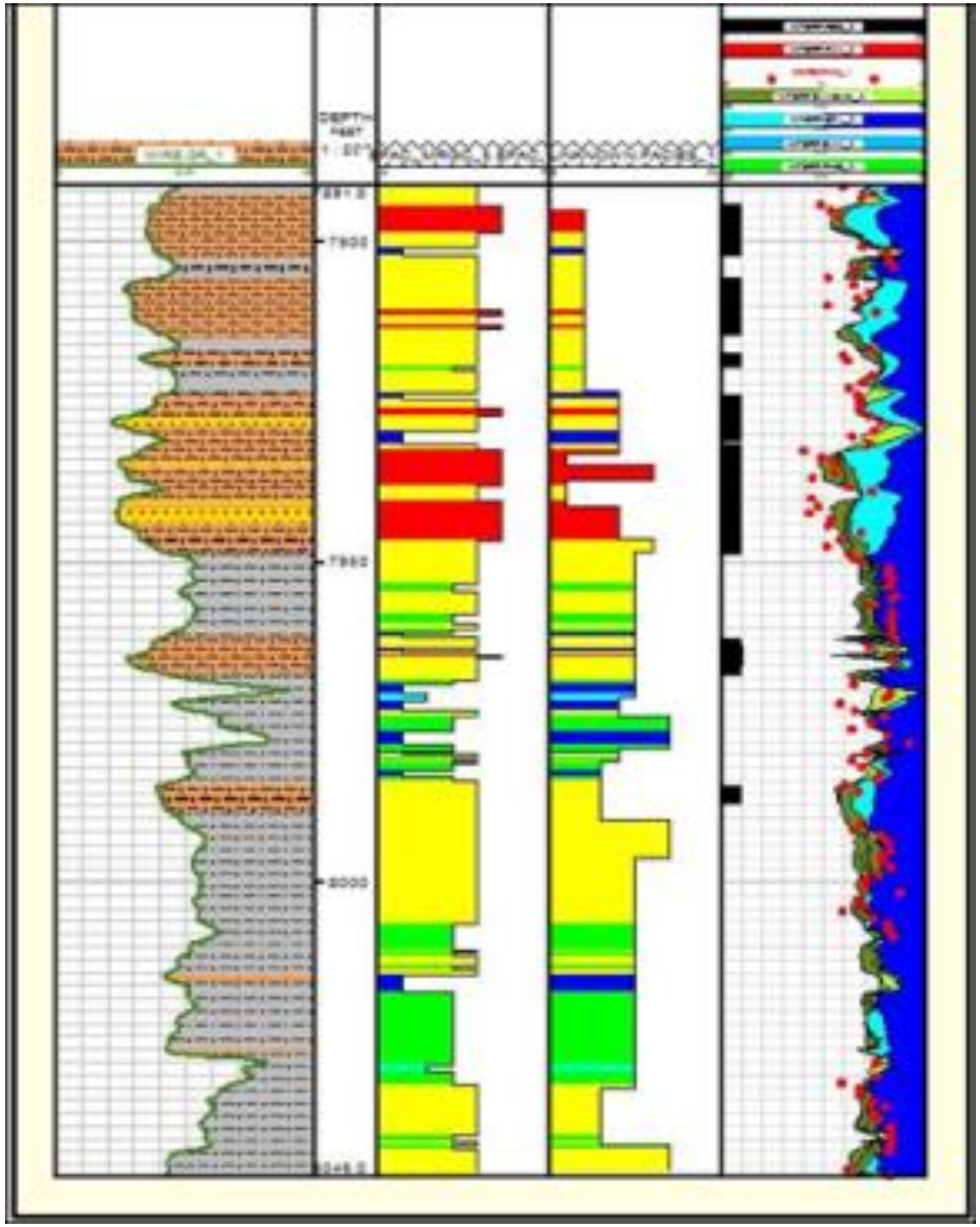


Figure 5. Facies model.

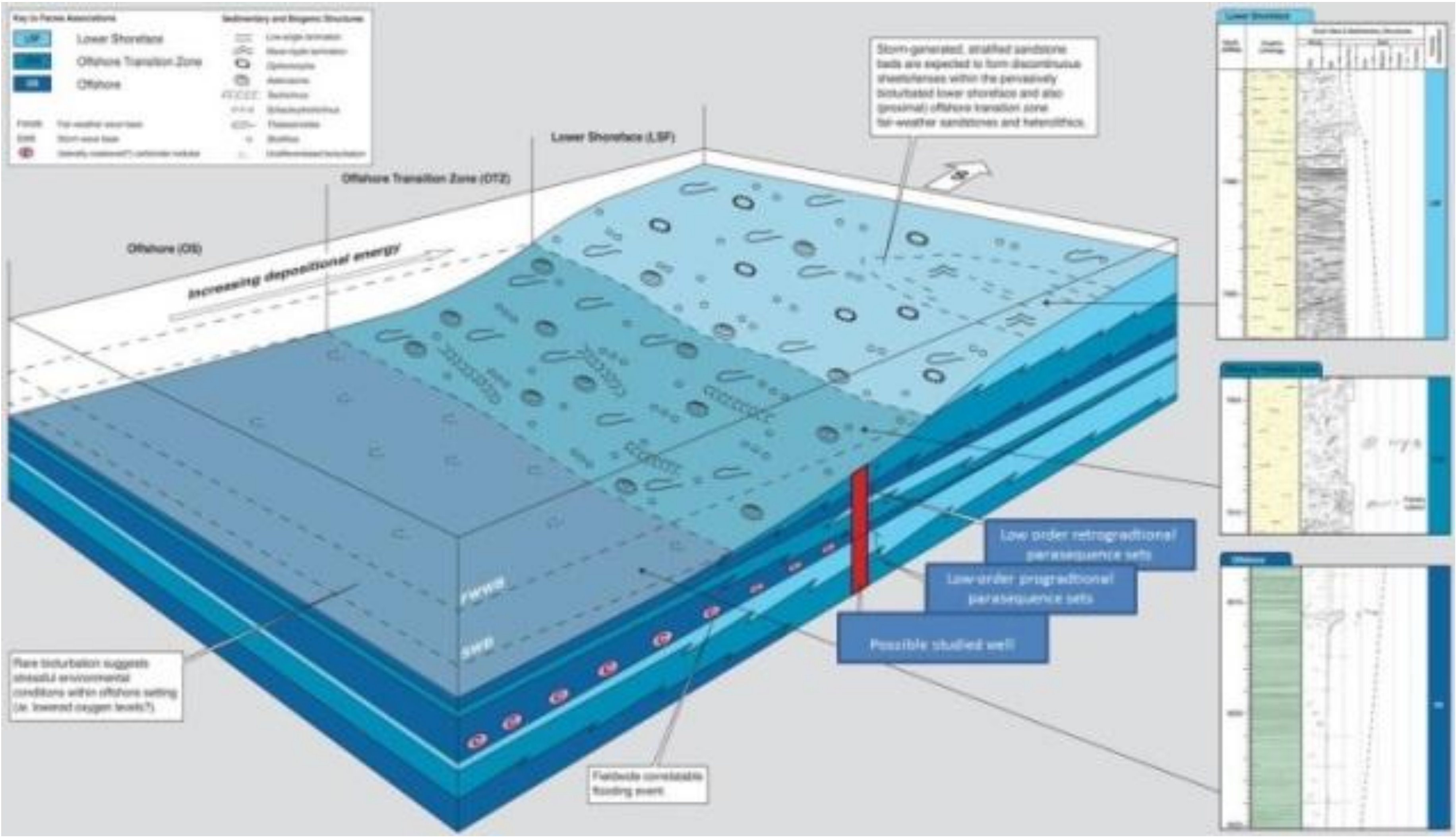
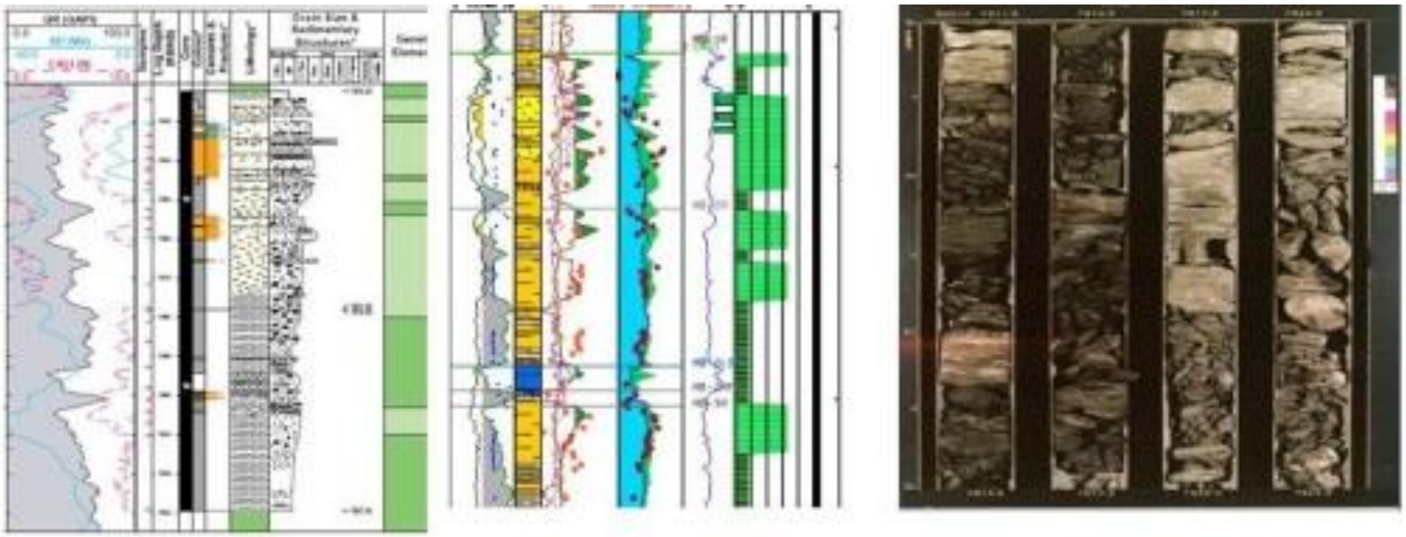


Figure 6. Middle Burgan depositional model.



General Characteristics

•Mud rock-dominated with rare , thinly –bedded siltstone and very fine grained sandstone , typically non calcareous.

•Contain wide Varity of burrows and fully marine bioclasts.

Geometries/ heterogenties

•Can be correlated across the entire field.

•Transmissibility barrier up to 40 feet thick.

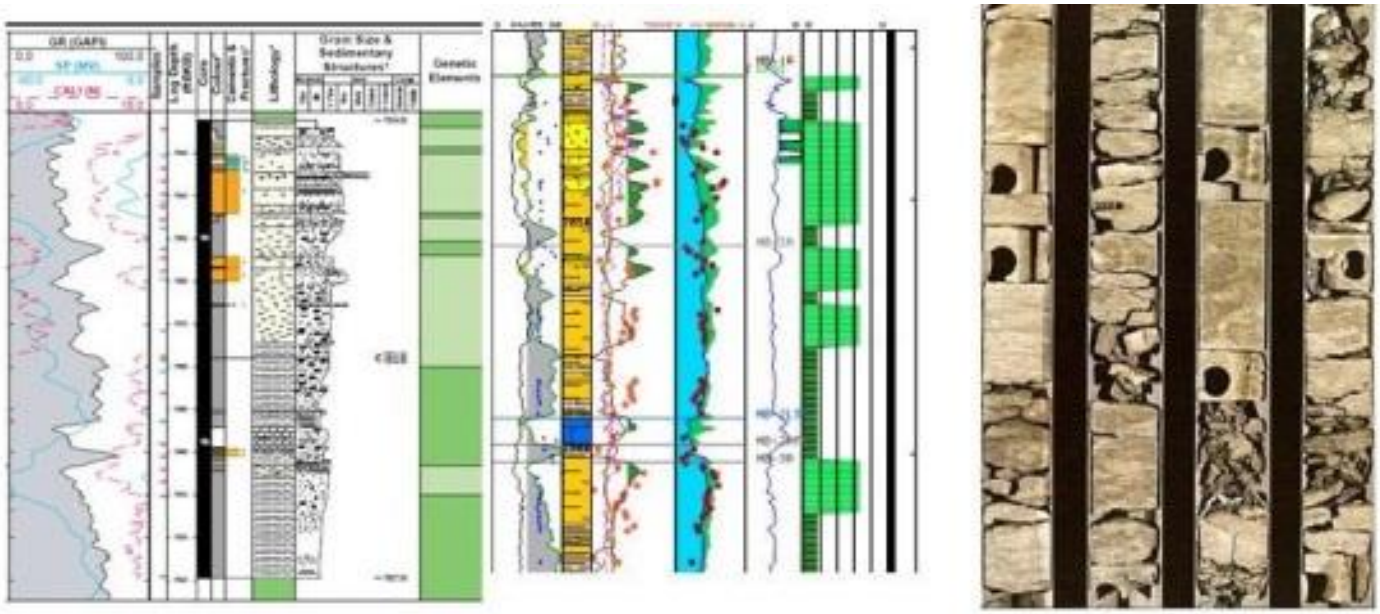
Wire line Log Characteristic

•High gamma ray response

•High and uniform resistivity trends.

•Slow sonic response with rare fast spikes that represented cemented intervals

Figure 7. Facies.



General Characteristics

- Mud prone to bioturbated argillaceous sandstone
- Contain wide varity of burrows and form the middle to upper part of upward cleaning Parasequences underlain by offshore marine mud

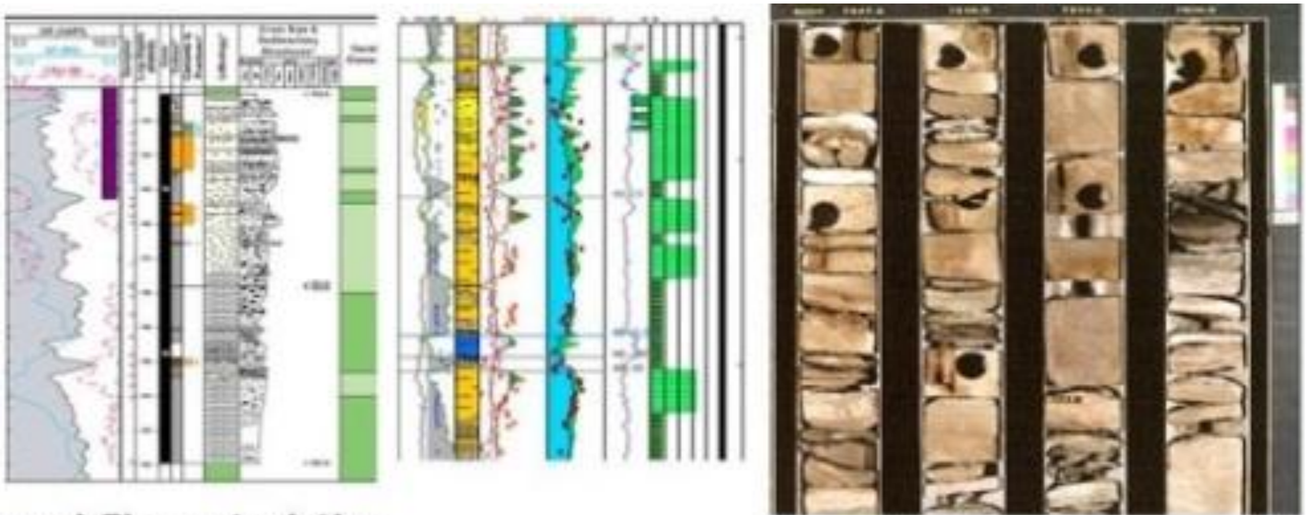
Geometries/heterogenties

- Can be correlated across the entire field.

Wire line Log Characteristic

- Moderate gamma ray response
- Low to moderate resistivity trends with tightly spaced curves

Figure 8. Offshore transition.



General Characteristics

- Coarsening upward , dominated by bioturbated sandstone litho type and wide Varity of burrows type.
- Sandstone are very fine to fine ,rarely medium grained with Laminated sandstone (Sl) are minor, Contain siderite cemented.
- Dominated in upper most part of each reservoir unit.

Geometries/ heterogenties

- Sand stone are less mud prone and increase the argillaceous to basin ward.
- Lateral continuous sandstone which could become target for HAW in-fill drilling
- Thickness rang from 10 to 15 feet and correlated across the entire field.

Wire line Log Characteristics

- Gamma ray display well developed cleaning upward trends which reflect grain size trend.
- Positive neutron log cross-over in sand prone intervals.
- Cemented intervals commonly capping upward-coarsening packages show fast sonic responses

Figure 9. Lower shoreface facies.

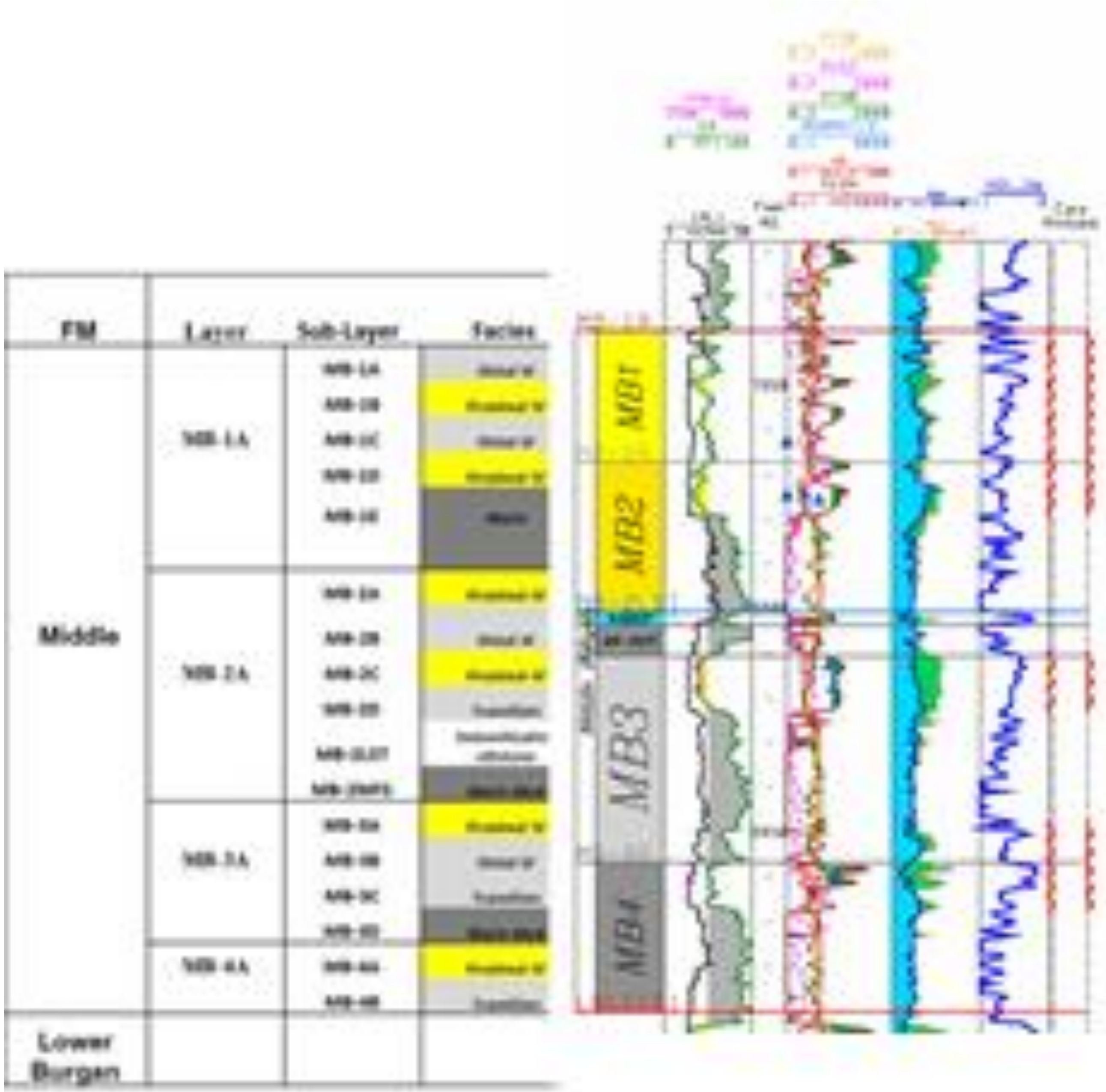


Figure 10. Layering scheme.

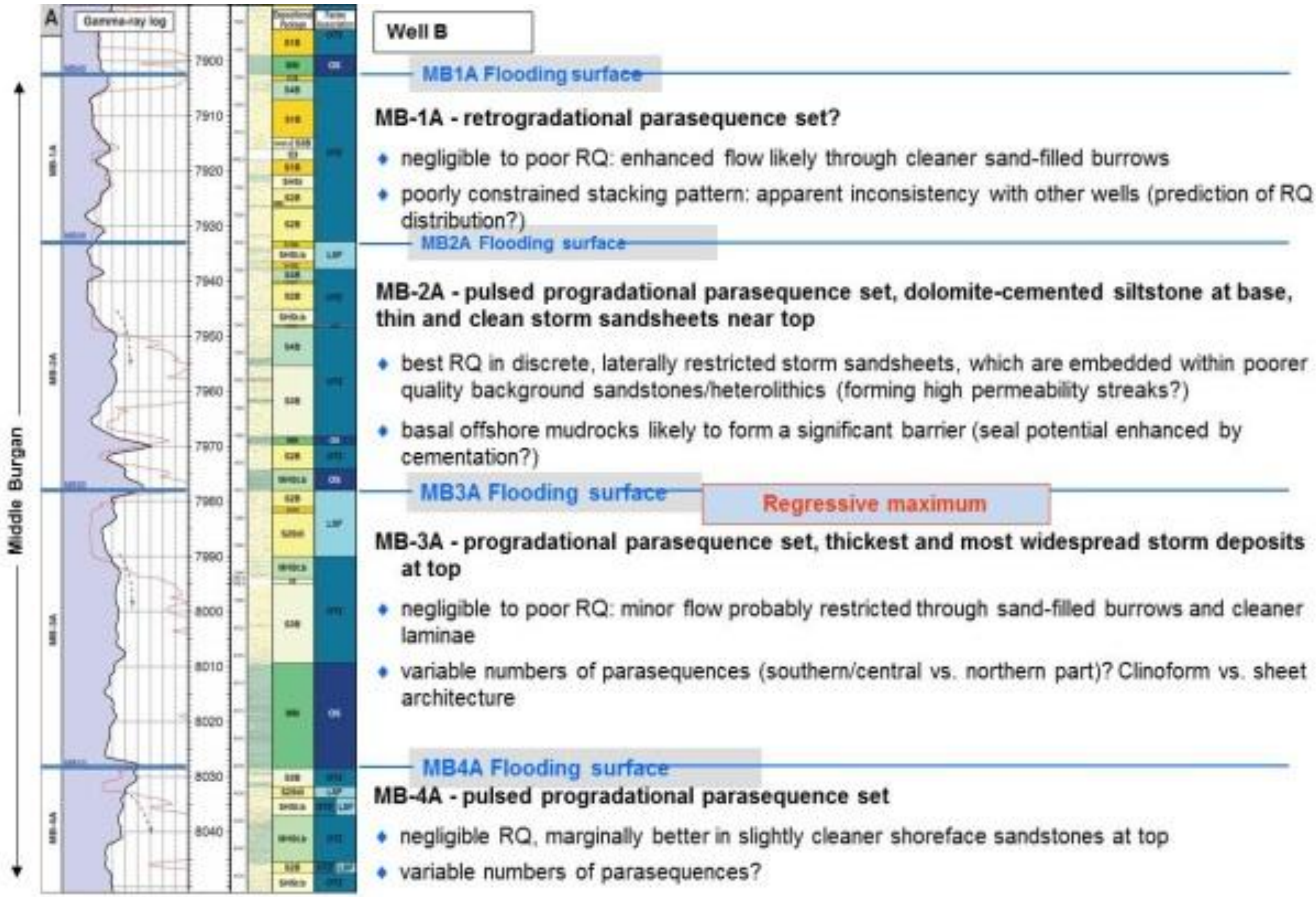


Figure 11. Layers characteristics.

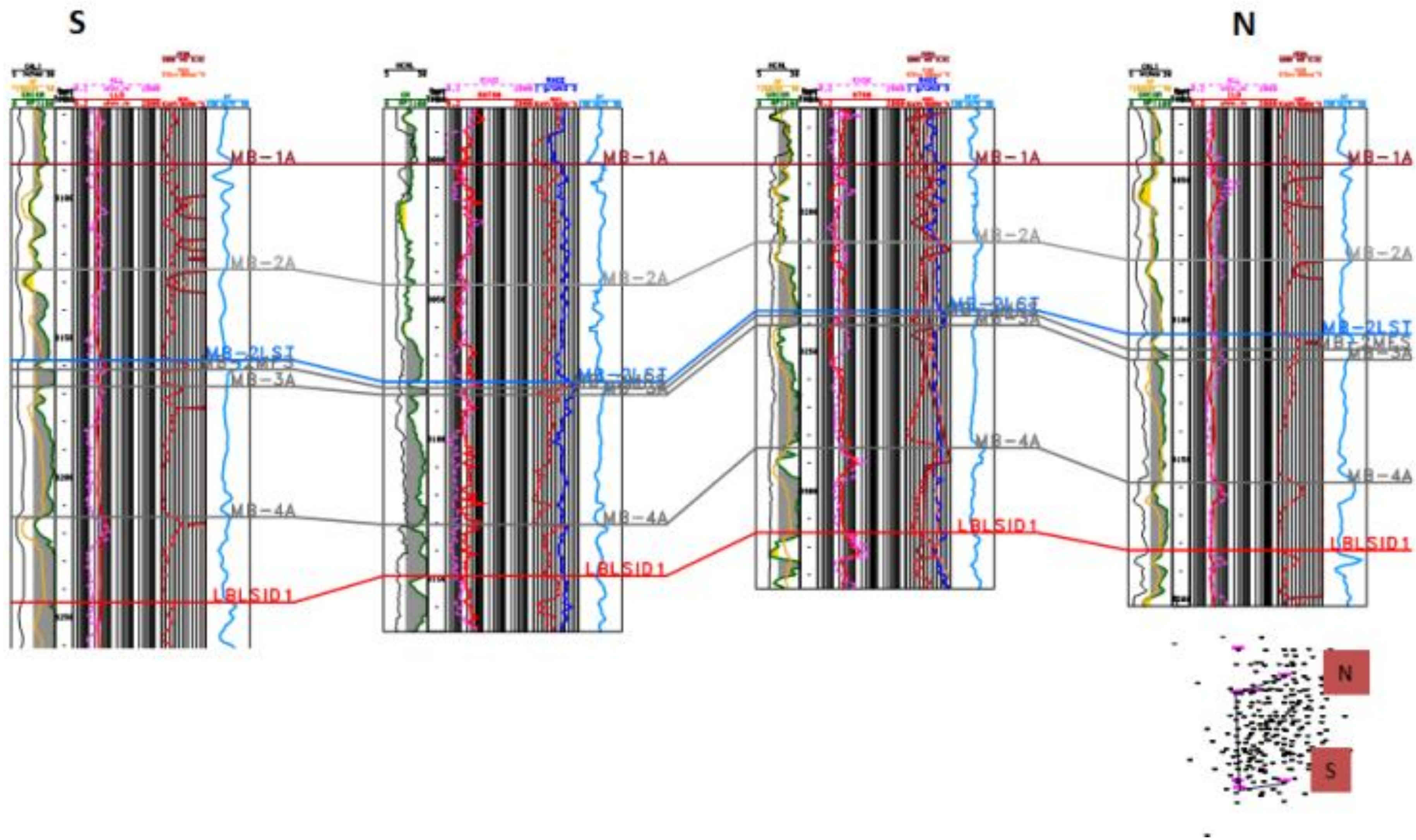


Figure 12. Cored wells correlation panel.

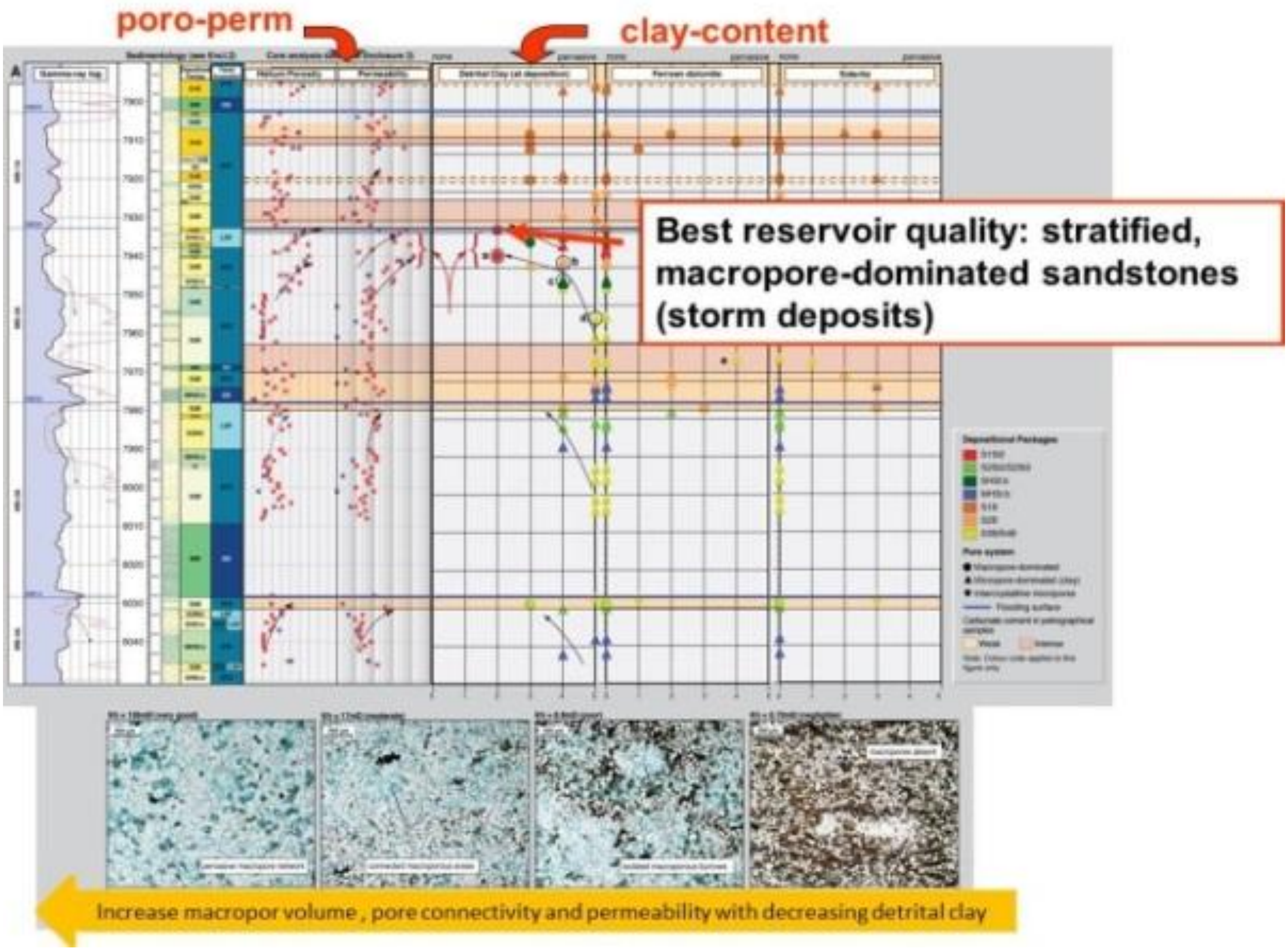


Figure 13. Controls on reservoir quality.

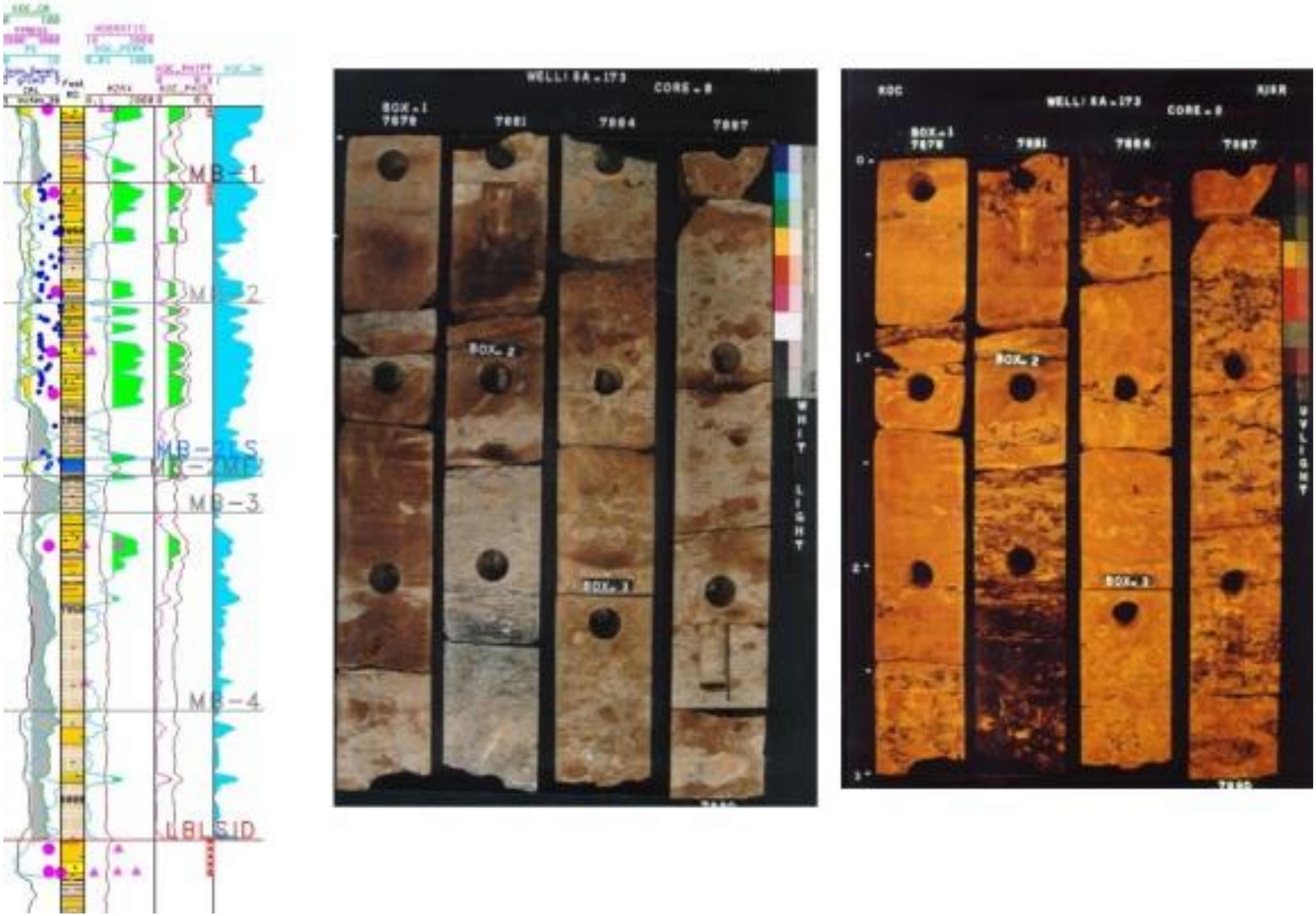


Figure 14. Oil Stain with high SW Log.

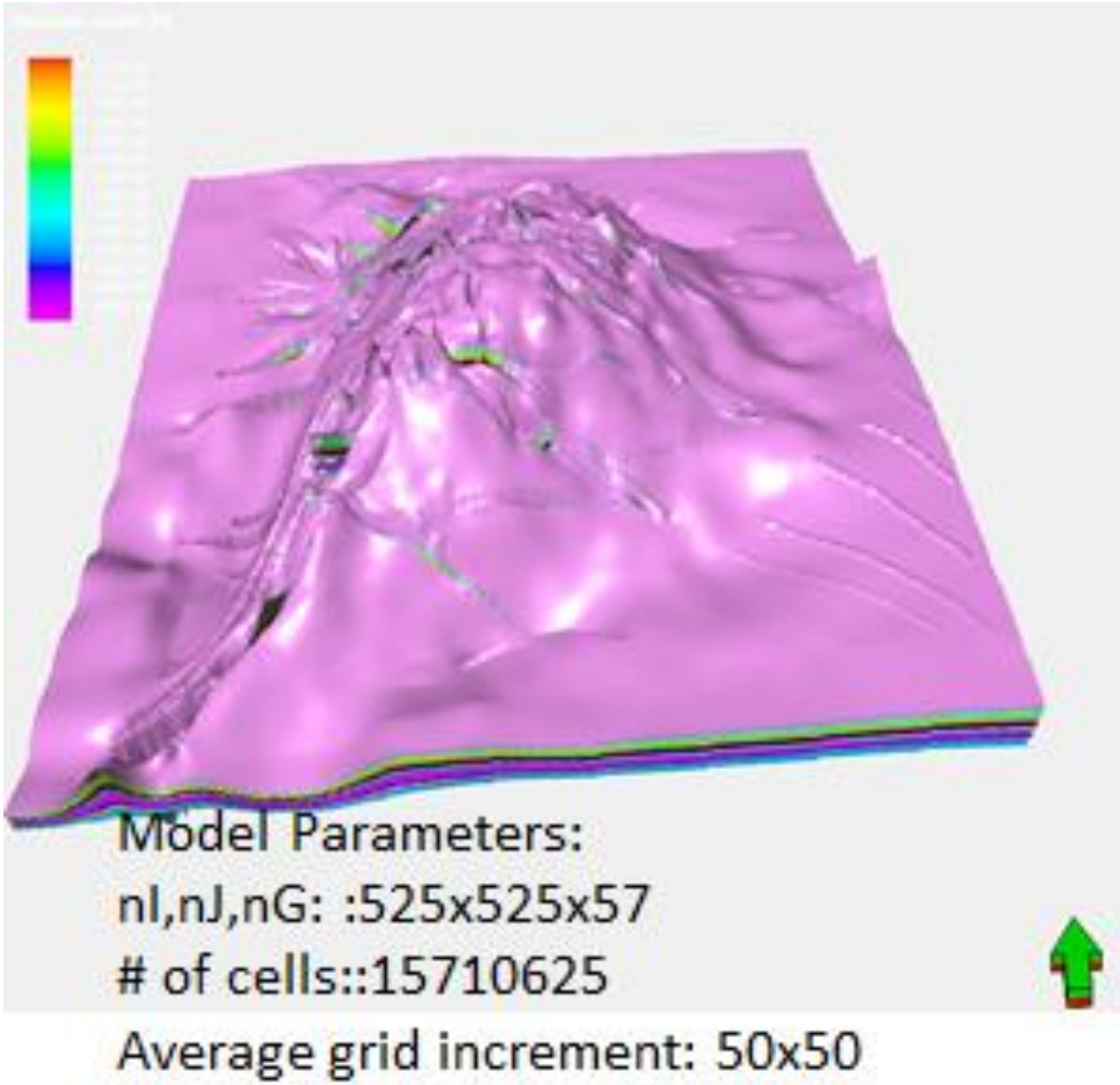


Figure 15. 3D grid identification.

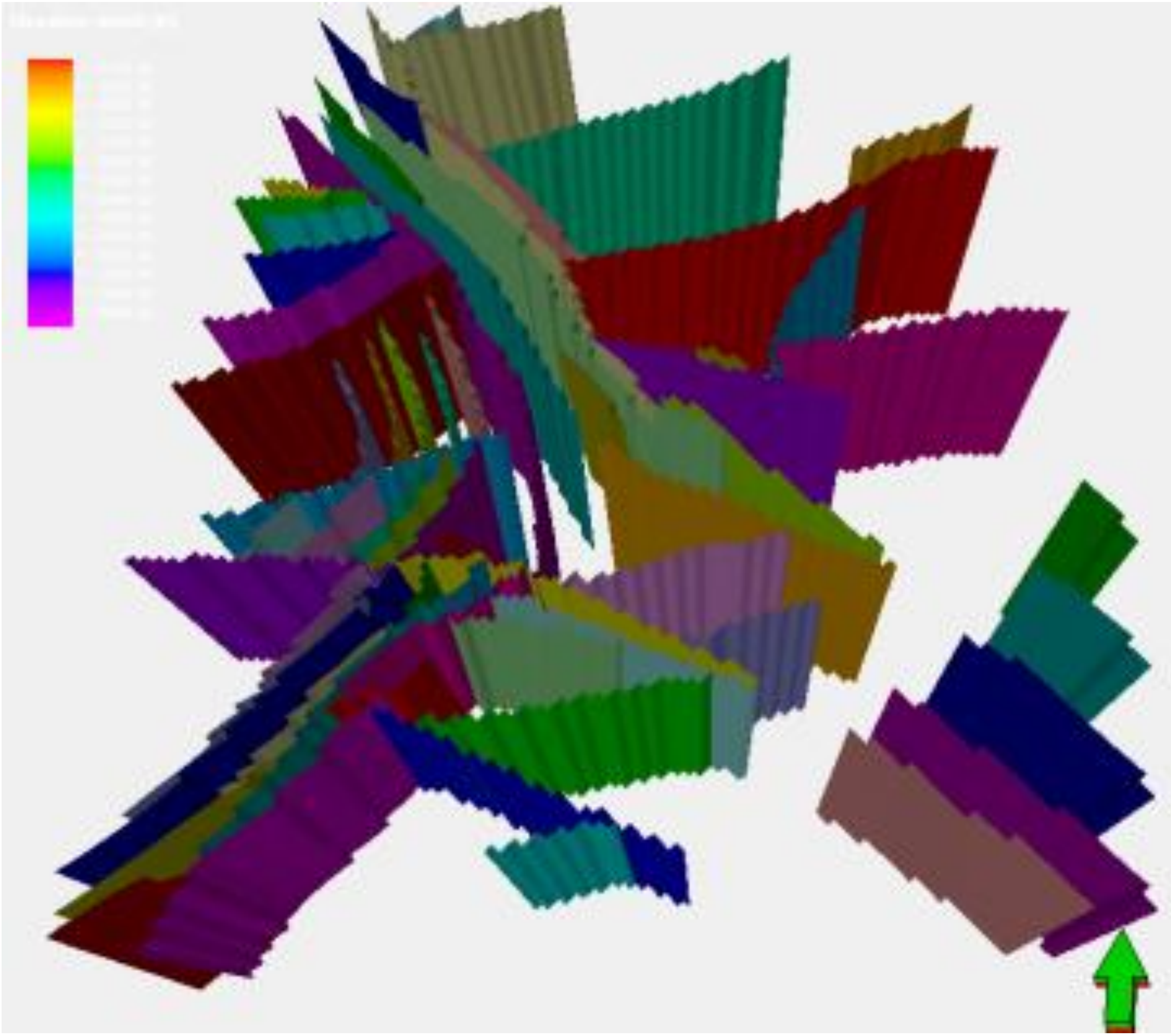


Figure 16. Fault model.

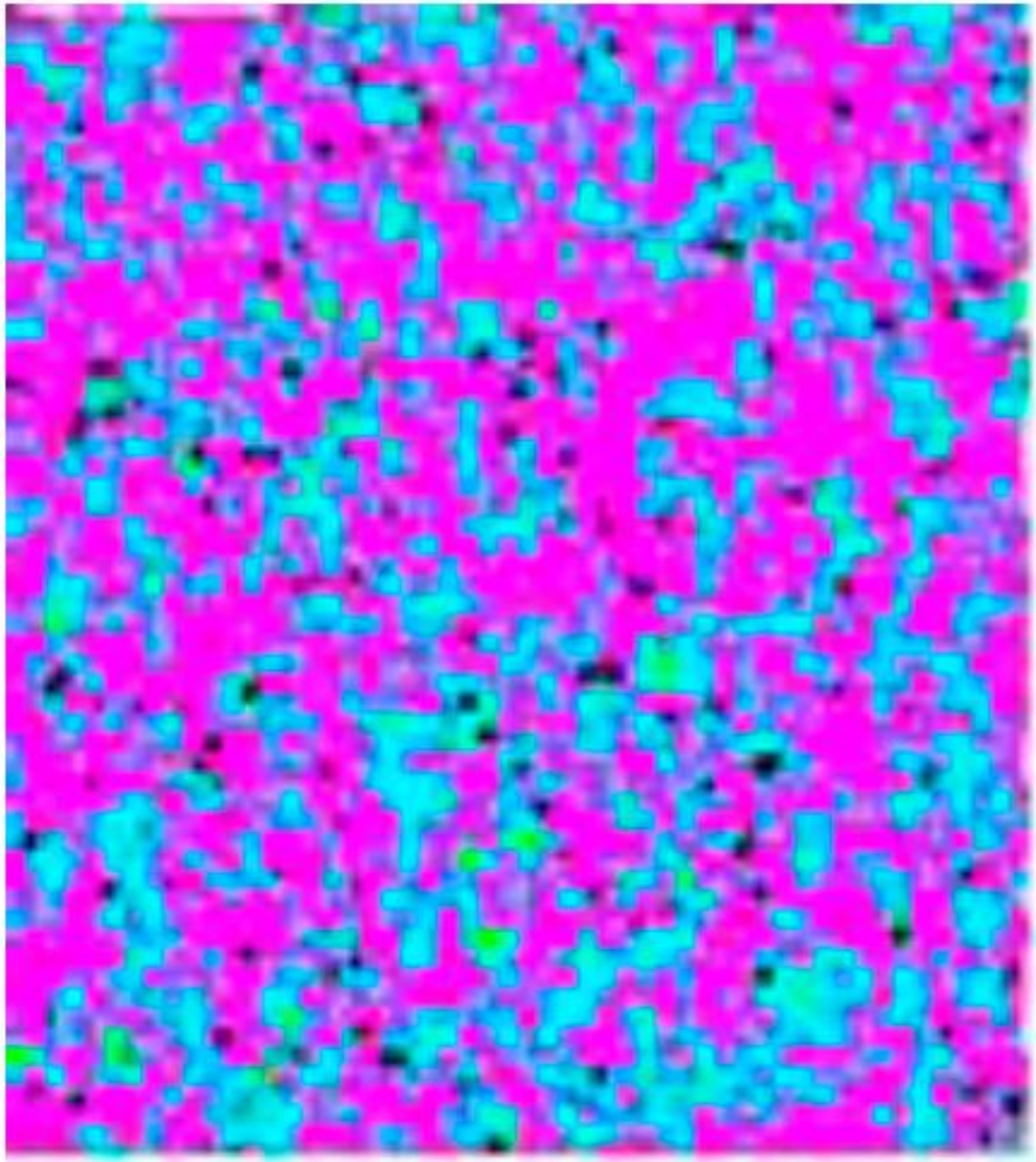


Figure 17. Rock type.

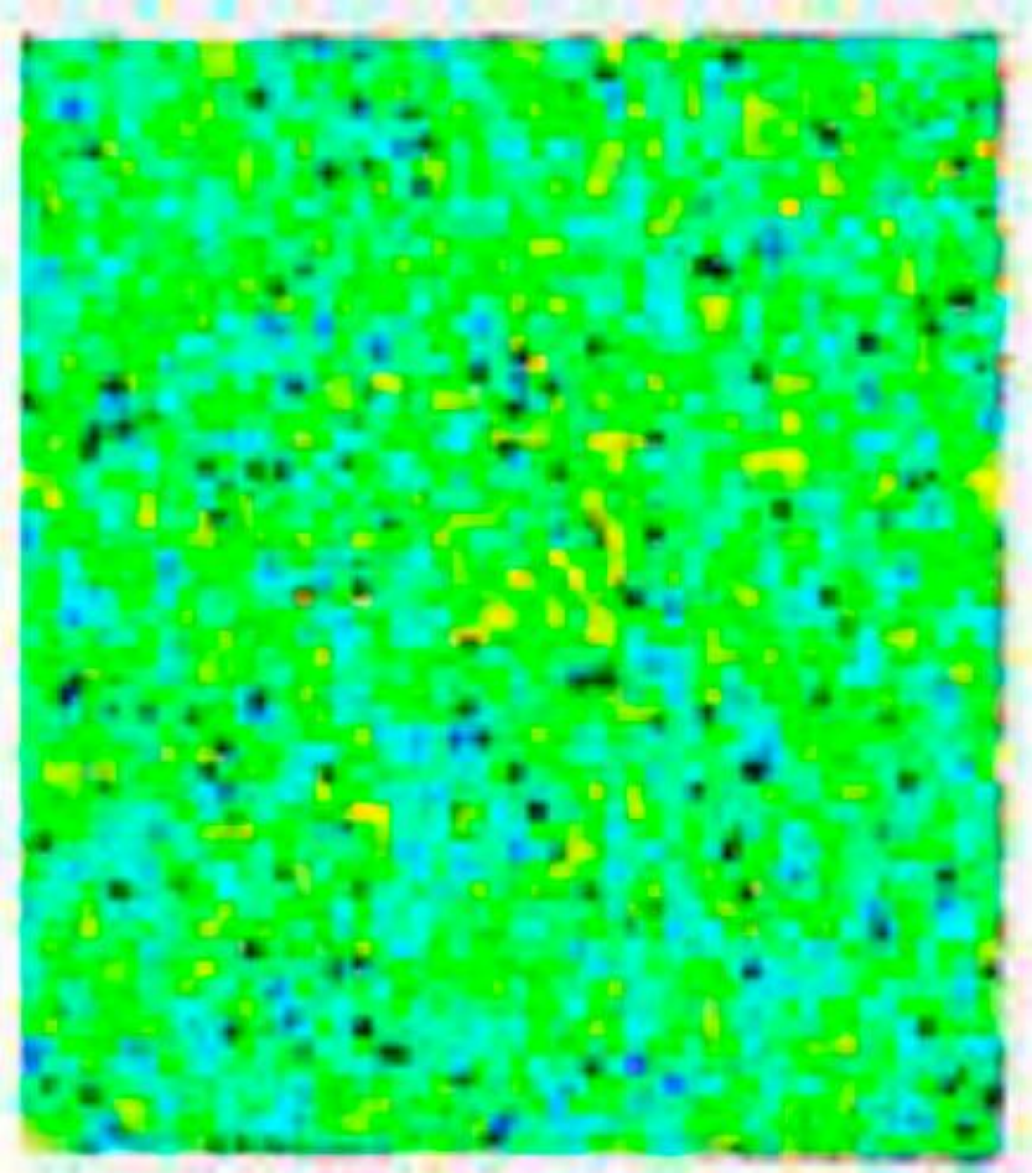


Figure 18. Porosity.

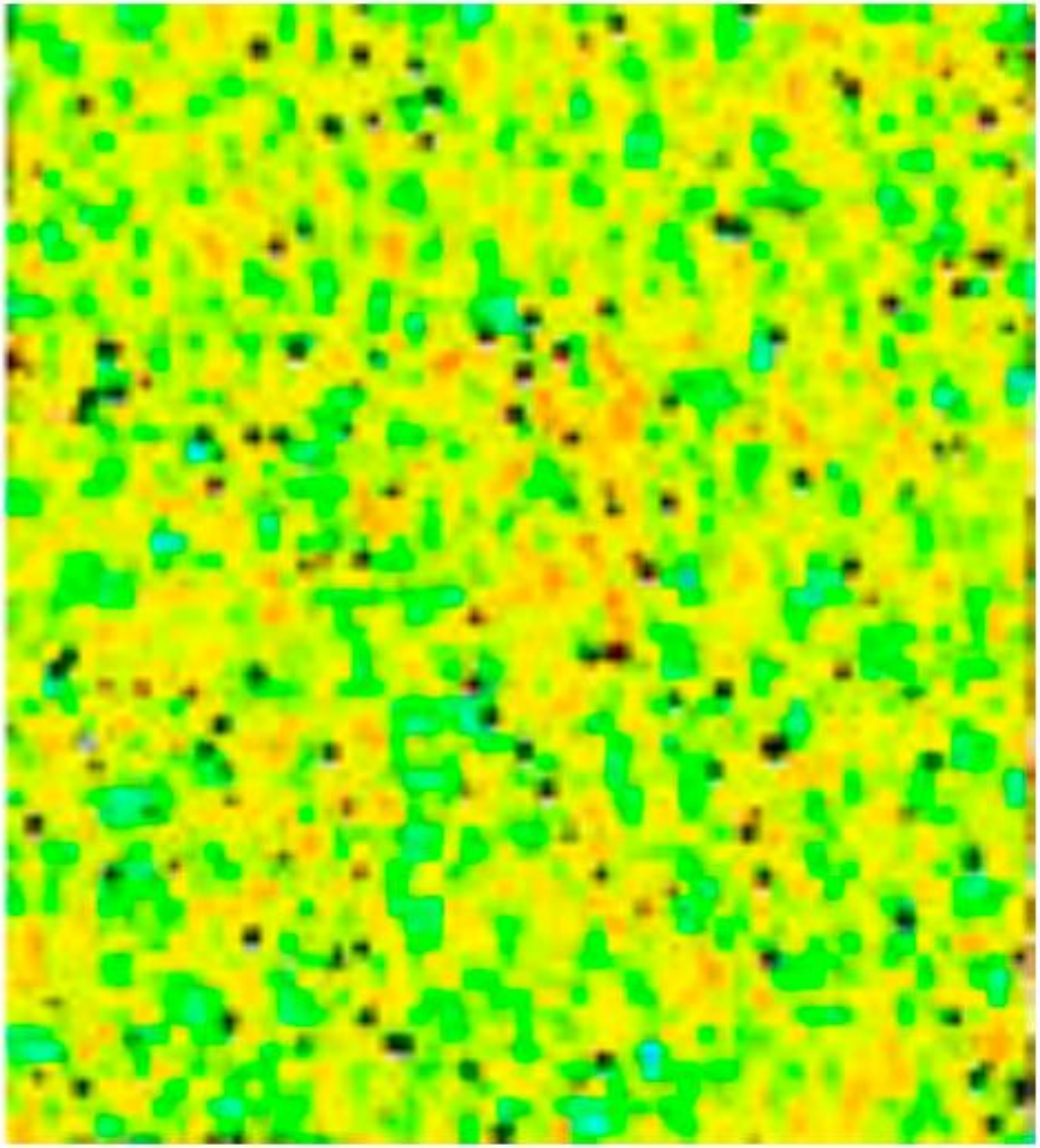


Figure 19. Permeability.

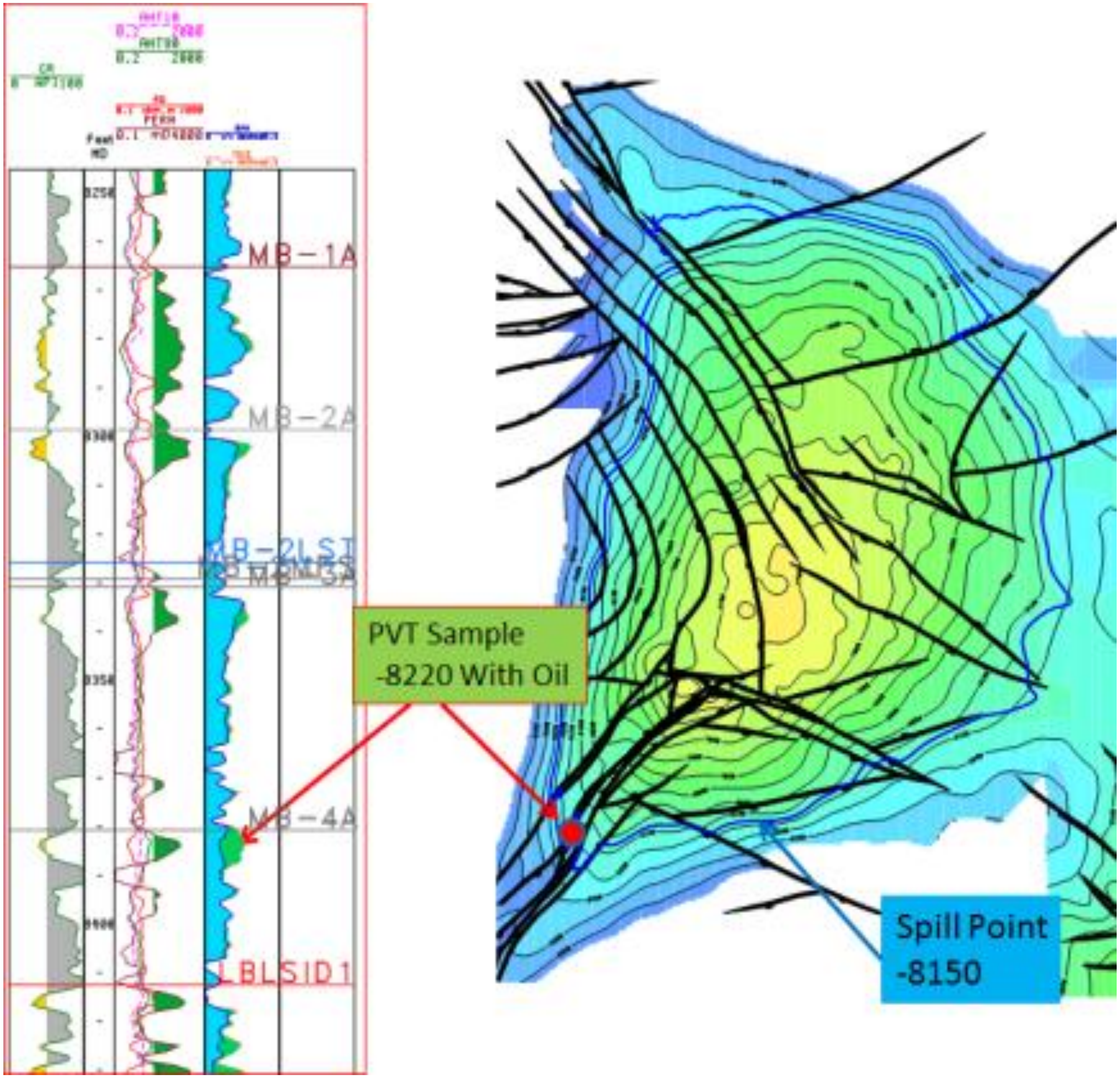


Figure 20. OWC from Spill/PVT.

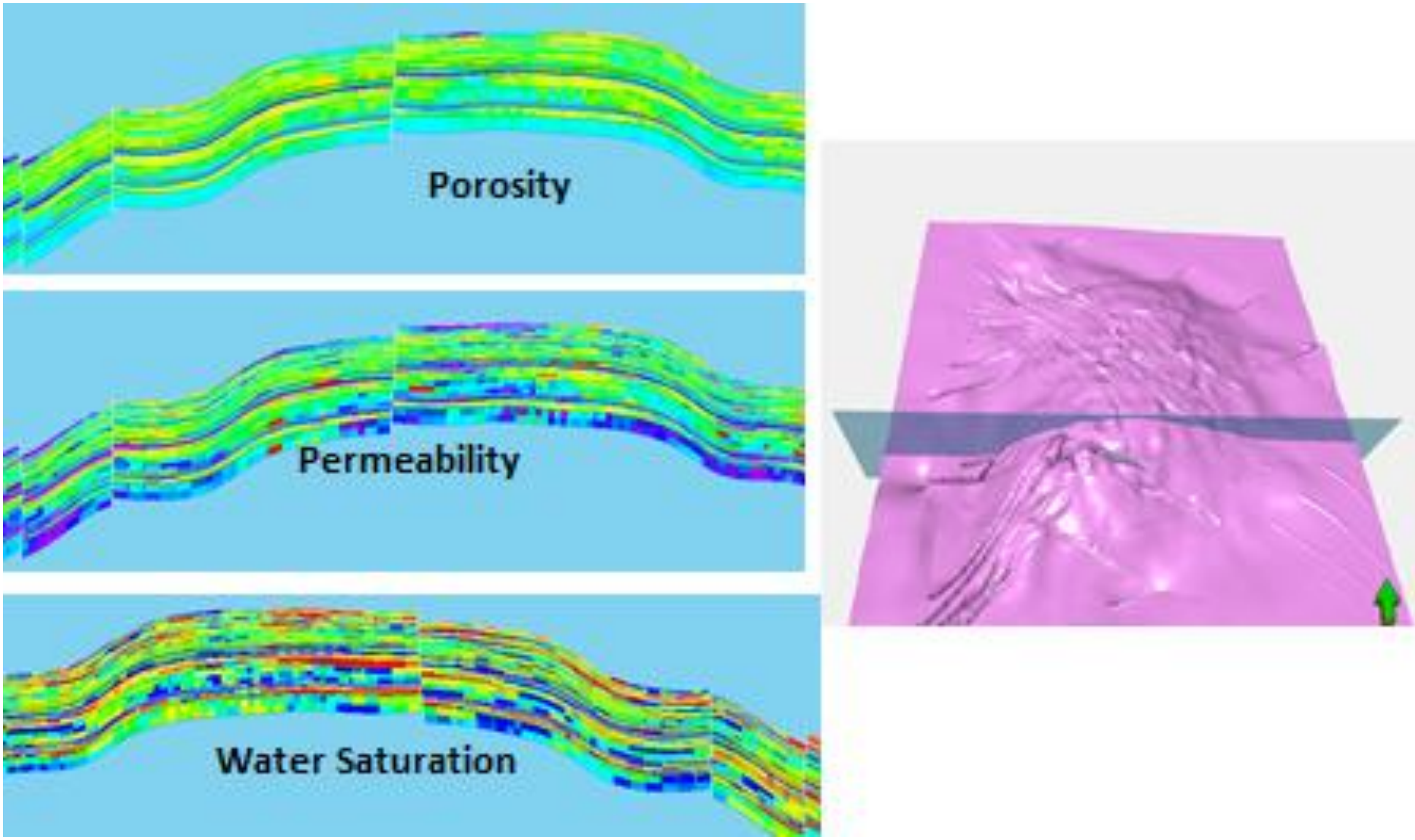


Figure 21. Property distribution.

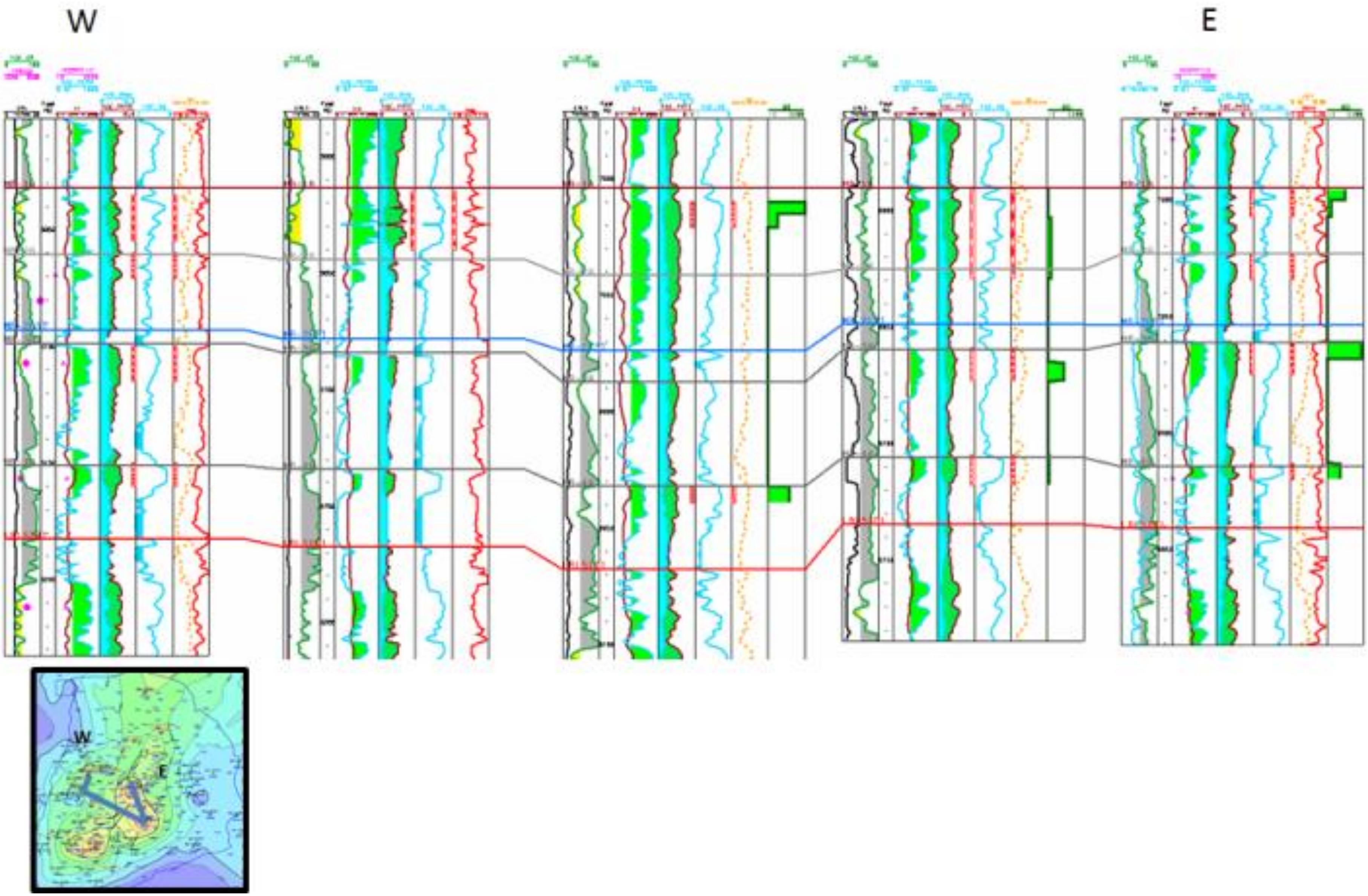


Figure 22. Middle Burgan wells tested.

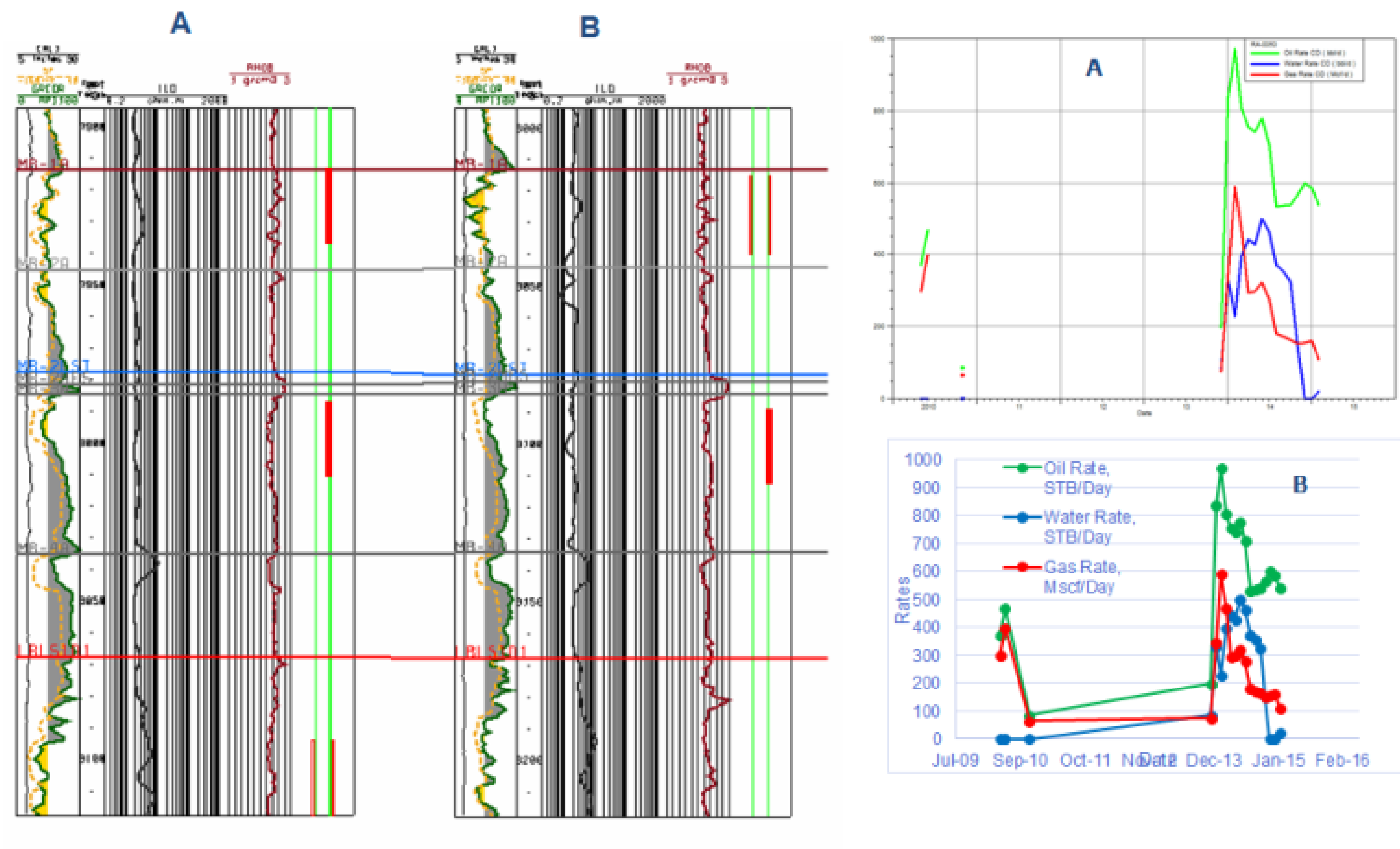


Figure 23. HiWay fracturing well results.

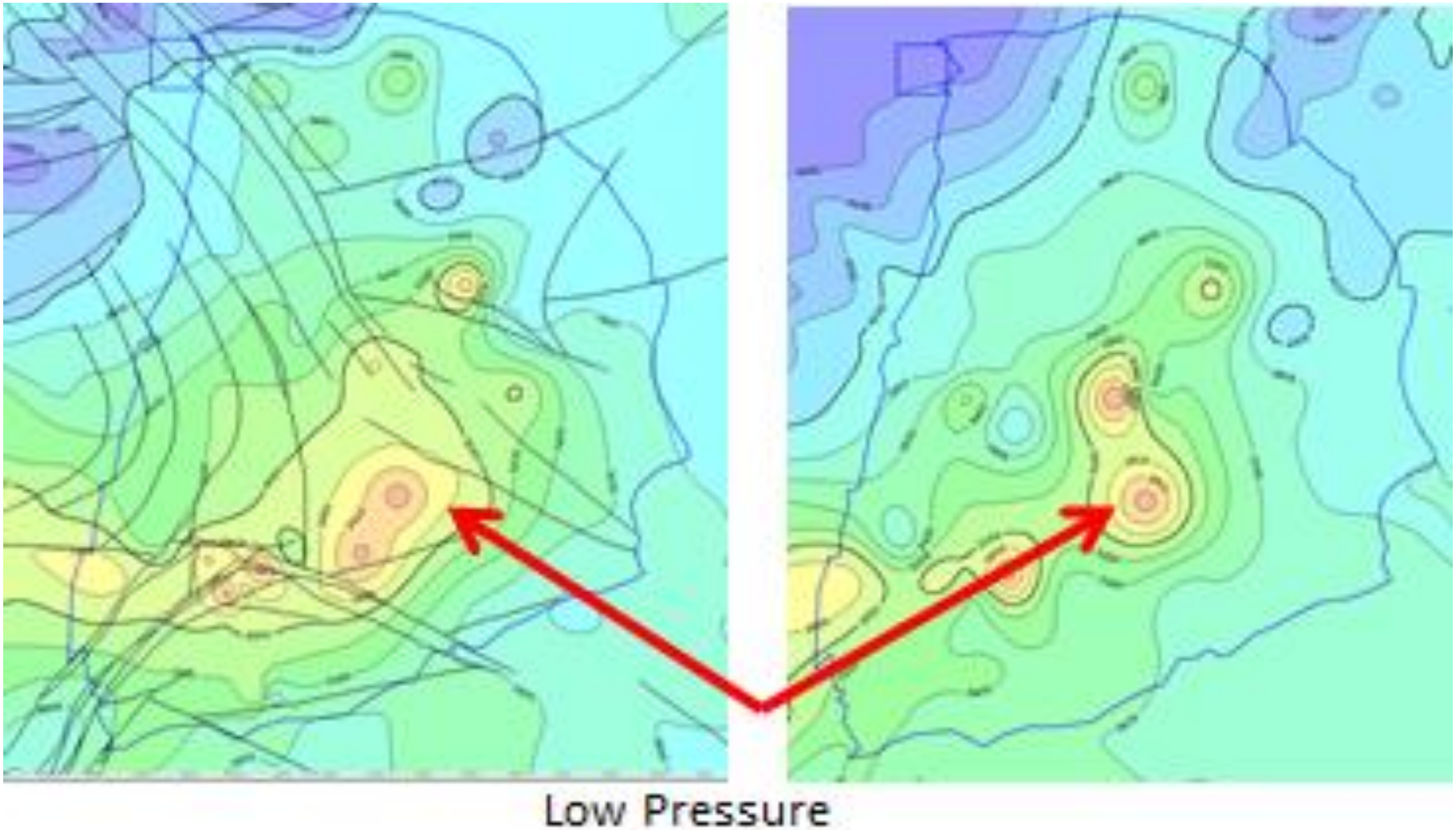


Figure 24. Pressure maps.

Datum	Pinitial	Pb	Bo	μo	FVF@Pb	Oil	GOR@pb
[ftSS]	[psi]	[psi]	[v/v]	[cP]	[rb/stb]	API	Scf/stb
7900	3600	2115-2650	1.23 -1.562	0.502-1.071	1.346-1.487	28- 32.5	626-847

Table1. PVT data analysis.