Challenges to Explore Shallow Sandstone Reservoir for Optimized Unconventional Development Strategy in Kuwait*

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Search and Discovery Article #80290 (2013)
Posted June 20, 2013

*Adapted from extended abstract prepared in conjunction with oral presentation at AAPG Annual Convention and Exhibition, Pittsburgh, Pennsylvania, May 19-22, 2013

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Abstract

Challenges to explore a shallow poorly-consolidated, viscous, oil-bearing sandstone reservoir is presently being undertaken in Kuwait through extensive core sedimentology and integrated reservoir evaluation efforts to optimize the future development and production strategy of the reservoir.

The reservoir in general consists of two separate sand packages, predominantly of deltaic origin influenced by estuarine, transitional-marine settings. Sand bodies commonly represent multi-stacked fluvial to distributary channel-fills and associated facies resulting in stratified reservoir intervals with variable degrees of fluid saturations. High-resolution sequence correlations reveal the dominant lowstand and transgressive depositional regimes for reservoir development, which demands finer scale reservoir characterization for precise interval relationships. Reservoir characterization uncovers high matrix contents, along with various cement phases, predominantly calcite, dolomite, and clay minerals. These control the pore networks with intergranular primary porosity and generation of secondary pores and essentially portray the pore geometry, thus impacting the overall petrofacies and fluid flow-path.

Structurally, the reservoirs dip very gently towards northeast with no definite structural closure. Viscous oil accumulation is mainly controlled by lithofacies variations and extent of biodegradation which resulted in stratigraphic trapping. Lithofacies distributions and diagenetic modifications have overall characterized the petrofacies with variable fluid saturations in a stratified-reservoir. Irregular and dubious presence of free and dissolved gas furthermore enhances the overall complexity and challenges to the development strategy.

Thus, seemingly simple channel-based reservoir intervals have been greatly altered by post-depositional, diagenetic episodes that need to be understood and evaluated. This necessitates an arduous regular and unconventional drilling, completion and production strategy to pursue the precise payintervals for reservoir development.

Keeping the challenges in mind, all pertinent data related to integrated geology, drilling, and production are closely evaluated to understand the reservoir trends and embrace the needed approach, ensuring the optimal completion and production strategy to meet the long-term development plan for this viscous oil-bearing asset.

Introduction

The Miocene poorly consolidated sandstone reservoir in Kuwait (Lower Fars Formation) contains viscous, low API oil at a shallow depth, with considerably low reservoir temperature and pressure. Compared to many viscous oil deposits elsewhere in the world, this reservoir is shallower, with higher porosity and permeability, and lower viscosity. These favorable characteristics support the development potential of this reservoir with greater recovery factor and lower costs (Dusseault et al., 2008). The overall depositional environment is considered as deltaic-fluvial influenced by phases of marine incursions. The reservoir sand intervals usually show good lateral continuity: however, understanding the fluid saturation distribution within the reservoir is often quite challenging. The nature of the shale and silt zones within the sand reservoirs is another challenge that is not fully understood. The fluid property shows variation both laterally as well as vertically between the pay zones.

The reservoir was deposited in northern Kuwait (northwest of Kuwait City) within the larger Mesopotamian Foreland subaerial basinal setting during episodes of Miocene Arabian Plate collision with Eurasia, causing plate tilting towards north and narrowing and closure of Neo-Tethys Sea. The basin was semi-restricted and subjected to high evaporation due to arid environments, and was flooded time and again with sea water; this resulted in deposition of cyclic blankets of clastic wedges of variable thickness, sourced from south and west (Al-Juboury and McCann, 2008; Sharland et al., 2001). The shallow depth of the reservoir along with moderate viscosity of the oil makes it typically very attractive for thermal development. In the past, two cyclic steam stimulation (CSS) pilots were carried out in 1980's in the north and south parts of the field (Figure 1), and the results of those pilots were documented quite extensively (Milhem and Ahmed, 1987; Ahmed and Milhem, 1989; Al-Qabandi et.al., 1995). Currently pattern wells are being drilled at various spacing in sweet pay areas of the reservoir to plan pilot thermal operations of CSS using confined patterns. Considering the layered stratified nature of the pay intervals, proper heat distribution resulting in effective recovery potential needs to be evaluated in order to understand and determine the suitable well spacing for the optimized development strategy.

Currently, detailed correlation and mapping are ongoing with high-resolution sequence stratigraphic approach to identifying the predictable net-pay intervals, fluid flow compartments and pathways, facies boundaries, and their nature within the reservoir. This would assist the reservoir development with a robust conceptual sequence model because natural compartment boundaries commonly coincide with the most laterally continuous shifts of facies, and consequently, the most pronounced changes in lithological properties in numerous cases occur across those bounding surfaces.

Reservoir Geology

The unconsolidated sandstone reservoir covers a vast area in northern Kuwait (Figure 1) at shallow depth of less than 800 ft. The oil pool is overlain by 20-30 ft thick shale barrier that forms a regional barrier, the sealing unit for the reservoir system. The reservoir broadly consists of two sandstone units separated by a middle shale unit. However, intervening siltstone and shale units commonly divide the two sandstone units into four stratified reservoir units of Upper A and B and Lower-A and B zones (Figure 2). Each zone varies in pay thickness from about 10 to 30 feet. The pool shows significant variation in the north and south areas of the field, and the viscous oil property shows considerable variation both laterally as well as vertically. The oil becomes generally heavier and more viscous from top to bottom.

About 15 lithofacies have been identified in this reservoir; their facies associations and vertical and lateral distribution indicate the depositional environment as a fluvio-deltaic complex with fluvial channels that delivered freshwater and sediments from the south and west to the northerly located mouth of the river, where they fed and formed series of delta lobes. Episodically, this fluvio-deltaic complex was flooded and transgressed, at least in northern part of the field by shallow-marine deposits. These comparatively short-lived transgressive events have transformed the distal parts of the delta complex into an estuarine to shoreface depositional environments.

Detailed reservoir facies observations suggest that intervals mainly contain channel-fill and associated lithofacies, dominated by fluvial channels (FC), distributory channels (DC), and interdistributory (ID) facies associations. Usually the intervals have varying degrees of silt and mud and are overall moderately to highly dolomitized. Most sandstones are fine- to medium-grained (average grain size 250 to 400 μm), subrounded to poorly rounded, poor to moderately sorted, with variable amounts of visible porosity.

Detailed Correlation Leading to Sequence Stratigraphic Model

Field-wide regional and local correlations are ongoing with a sequence stratigraphic approach to correlate the depositional units using the conventional transgression, regression, flooding, and maximum flooding surfaces in order to develop the high-resolution sequence stratigraphy model to better understand the reservoir characterization and flow-unit development. This approach essentially subdivides the presently existing conventional reservoir units into further divisions, respecting the lithofacies types and their depositional complexities.

Integrated core sedimentology and paleogeography suggest that the reservoir sands were deposited within an incised-valley system by a large drainage network on a low relief arid coastal plain. Within reservoir sand intervals there are some silty and shaly non-reservoir “baffle” intervals. These are interpreted to have formed as a result of widespread fluvial or meandering abandonment and subsequent relative sea level rise. During abandonment, the sands were extensively bioturbated into muddy sands, and subsequently caliche (carbonate) soils were developed. Furthermore, detrital carbonates (dolomitic) with abundant shelly/foram bioclasts were also locally deposited.

In order to understand the relationship between petrofacies distribution that have been altered diagenetically by post-depositional episodes, a high-frequency sequence stratigraphic framework leading to the conceptual model for the reservoir has been developed. Once the maximum flooding surface or a sequence boundary is identified on a well log, the associated systems tracts for the reservoir interval can be identified and placed within their predictable sequence stratigraphic position. To develop and interpret the systems tracts for the reservoir, a sequence stratigraphic correlation approach (Figure 3) has been performed, using 80 wells and defining units on the basis of significant surfaces that separate stratigraphic successions ((Posamentier and Allen, 1999).

Using the conventional gamma, resistivity, and density logs and sedimentary core descriptions along with facies boundaries and contacts, four Lowstand Stystem Tracts (LST) have been identified, bounded at the bases by relative Sequence Boundary Type 1 (T1 SB) surfaces and overlain by flooding surfaces (Figures 4 and 5).

The model has been built here as a base starting point (base marker) known as the base of LST1. The surface is present at the base of stacked, braided channel deposits of the LST1 in the lower part of the model (Figures 4 and 5). The surface is essentially a subaerially exposed surface that has been diagenetically carbonate-cemented; it is also evident on gamma, resistivity, and density logs, as well as in tightly cemented interval viewed during core examination.

In the model, five Transgressive Systems Tracts (TST) have been identified; three of them (TST1, TST2, and TST4) follow the preceding LST1, LST2, and LST3, respectively; each starts with a flooding surface and ends at relative maximum FS1, FS2, and FS4, respectively, with a transgressive stacking pattern. Only TST1 was abruptly followed by a sharp drop of sea level that resulted in incised scouring of regressive stacking model (LST2), while the other two (TST2 and TST 4) are followed by HST1 and HST2 representing gradual seal level rises while sediment supply relatively increased. All major 3 Type 2SBs have essentially eroded unknown thicknesses of sediments of the prior HST and TST deposits, and represent sequence boundaries T1 SB2, T1 SB3, and T1 SB4 in the model. The lowermost sequence boundary, T1 SB1, represents a marker surface within braided stacked deposits of the entire lowstand deposit (Figures 4 and 5).

Two of the Transgressive Systems Tracts (TST2 and TST4) are followed by two Highstand Systems Tracts (HST1 and HST2); their bases start at relative maximum flooding surfaces (FS2 and FS4), and each is the beginning of increased sediment supply in a relatively high accommodation space. At the top, each of these two HSTs is overlain by Type 2 Sequence Boundary, subsequently followed by ravinement surface and transgressive deposits (TST3 and TST5, respectively; Figures 4 and 5). Type 2 Sequence Boundary is identified in GR logs between coarsening-upward and fining-upward sands, indicating rise in sea level at an increased rate with respect to sediment supply at this juncture. This acceleration in sea level suggests transgression and development of a “ravinement” surface. In the model, two Type 2 boundaries T2 SB1 and T2 SB2 have been identified between HST1/TST3 and HST2/TST5 deposits (Figures 4 and 5).

Five relative maximum flooding surfaces have been identified and correlated in the model; three of them are followed by rapid sea level drop and consequent sequence boundary type 1 resulting in fluvial deposits of stacked braided patterns with usual characteristics of the LST **(**LST2, LST3, and LST4) deposits. The other two maximum flooding surfaces (FS2 and FS4) represent the transition between TST and HST where sea level drop essentially occurred because of increased sediment supply (TST2/HST1 and TST4/HST2) (Figures 4 and 5).

The last Transgressive Systems Tract (TST5) represents the maximum sea level rise in the model with corresponding regional maximum flooding event (MFS) that deposited a thick marine shale (30 feet average). This regional deeper water event was followed by a sea level drop; abrupt erosion is indicated by the presence of T1 SB4 surface and overlying LST4 deposit characterized by scoured fluvial stacks in the model.

Depositional Environments of the Reservoir Intervals

The depositional environment interpretations of the identified sequences are based on sedimentary stacking patterns, core observations, lithology, physical and biogenic sedimentary structures, facies and their associations, facies boundary characteristics, etc. The entire interval is divided into five sequences from a boundary to the next (T1 SB or T2 SB). Considering the paleotopography of the depositional basin, the reservoir sands were deposited by a large river system on a low-relief, arid coastal plain where the changes in base level were relatively small and the variations in depositional environment are interpreted to have been between braided and meandering fluvial to estuarine tidal/distributary channels (Figures 4 and 5).

The reservoir sands display channelized bodies of fluvial origin in the lower part, but upwards show signs of marine influence with characteristic burrowing, indicating coastal plain and estuarine environments. In addition, their close association with burrowed and fossiliferous fine-grained facies further supports coastal and transitional marine settings of these channels. The small fining-upward cycles with sandstone-to-shale gradation are interpreted as crevasse-splay deposits which formed in near-channel floodplain interfluve and interdistributary bay areas. The small coarsening-upward cycles and the burrowing are also typical of interfluve and mouth-bar facies. The fine-grained shaly facies at the top of successions are interpreted as having been deposited in estuarine, coastal bay, or lower shoreface settings where conditions of deposition were quiet and conducive to out-of-suspension deposition. Such environments are suitable for churning the sediments by organisms; this explains the presence of burrowing within these fine-grained facies.

Diagenetic Alterations Leading to Petrofacies Scheme

Post-depositional diagenetic alterations have significantly influenced the rocks to develop a stratified reservoir condition within the entire reservoir. Alteration of primary porosity by carbonate cementation, dolomitization, clay-mineral precipitation, and dissolution of certain minerals to generate secondary porosity are the main factors in reservoir quality development with variable degrees of oil and water saturations. As such, a comprehensive understanding of diagenesis is required to identify degree of carbonate cementation, dissolution of calcite and dolomite cements, source of dolomite and the process of dolomitization, primary porosity and secondary porosity generation and distribution, as well as distribution of clay minerals, such as illite, smectite, and mixed-layered clays, and their dissolution.

A preliminary petrofacies classification is attempted here (Figure 6) to depict the stratified nature of the reservoir intervals. This ongoing scheme primarily considers petrophysical parameters, including V-shale, resistivity, porosity, permeability, water and oil saturations, GOR, major cement contents, etc. to characterize various petrofacies types. Detailed mercury-injection parameters will also be incorporated into the parameters in the near future. Currently there are 13 petrofacies types in the scheme, 4 of them (petrofacies 3, 6, 10, and 12) are oil-bearing. They are characterized by medium to coarse sands with variable amount of carbonate and low clay cements. From depositional perspectives, oil-bearing petrofacies are associated with variable amount of LST, HST, and LST deposits (Figure 6). Petrofacies 3 belongs to Upper-A Sand; Petrofacies 6, to Upper-B Sand; Petrofacies 10, to Lower-A Sand; and Petrofacies 12, to Lower-B Sand. There are also 4 water-bearing petrofacies characterized by good-quality sand with reasonably high porosity and permeability. Also present are 3 highly carbonate-cemented intervals with appreciable porosity and permeability that have ample potential to flow free-water. In addition, there are two shaly petrofacies in the model which have high seal and barrier capability to fluid flow which would be critical during thermal recovery.

Comprehensive understanding of the oil-water-transitional zone is critical in this viscous reservoir during in order to optimize an efficient perforation strategy. It seems that lithofacies control, primarily thinly bedded muddy to silty-facies is the dominant control on the presence or absence of wet to transitional reservoir quality. Additionally, higher amounts of cements, mainly dolomite, lesser clay and calcite, also reduce the overall porosity and permeability. However, these wet to transitional intervals have about 20% porosity and 10 to 300 md permeability. On rock micro-scale level, facies and variable degrees of cementation influence the intricate pore-throat size, geometry, and tortuosity and thereby control the capillary action of the pores and hence affect fluid mobility. This may have resulted in poor-oil migration conditions in these wet to transitional reservoir intervals. There is a need to understand these zones in the context of the overall stratified settings of the viscous reservoir.

Conclusion

The ongoing sequence stratigraphic model improves the understanding of depositional facies, evolution and distribution of reservoir sand trends within a chronostratigraphic framework. This addresses the predictability of lateral and vertical complexity and distribution of the channel sands. The model provides a greater ability to identify and predict individual pay and non-pay zones with inherent rock lithologies and heterogeneity in order for the result to be a predictive sand-architecture framework for proper EOR development. On the whole, the reservoir was deposited in a fluvio-deltaic complex that was episodically transgressed, resulting in the establishment of shallow-marine shoreface-type conditions. The degree of estuarine and tidal influence in distal parts of the fluvio-deltaic complex remains unclear from the available dataset.

Considering the vast size of the pool, enormous number of uncertainties exist both areally as well as layer-wise. Within the reservoir, facies variability produces inconsistencies in fluid saturations; likewise, intervals similar to thief zones and long transitional zones would pose severe risk under thermal operations. Moreover, discontinuous shale and siltstone baffles may cause cross-formational flow resulting to significant heat loss. Sand production is another critical issue that affects development of many viscous, oil-bearing reservoirs around the world; current development strategy will provide an opportunity to assess various perforation strategies for the future commercial development phase.

Currently, confined patterns are being planned for CSS operations in the near future. All pertinent data are closely evaluated to ensure the optimal strategy to meet the long-term development plan for this unconventional viscous oil reservoir.

Acknowledgements

The authors are thankful to Ministry of Oil, Kuwait, and Kuwait Oil Company for granting permission for publishing certain technical aspects of the development strategy. The authors also express their sincere appreciation to Heavy Oil Group management for encouraging technical discussion and documentation.

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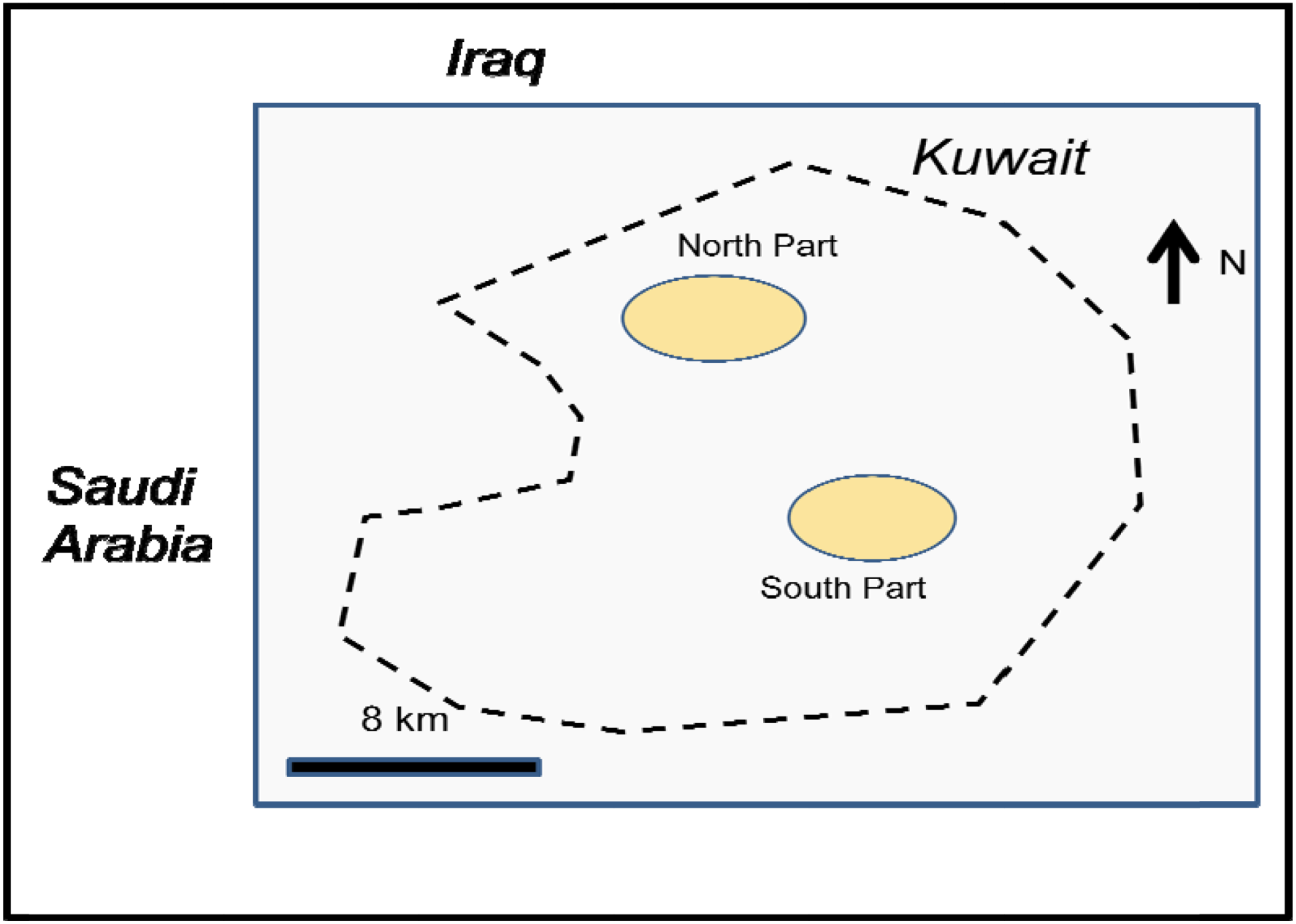

Figure 1. – Location map of the reservoir in Kuwait with north and south parts being the main focus of development.

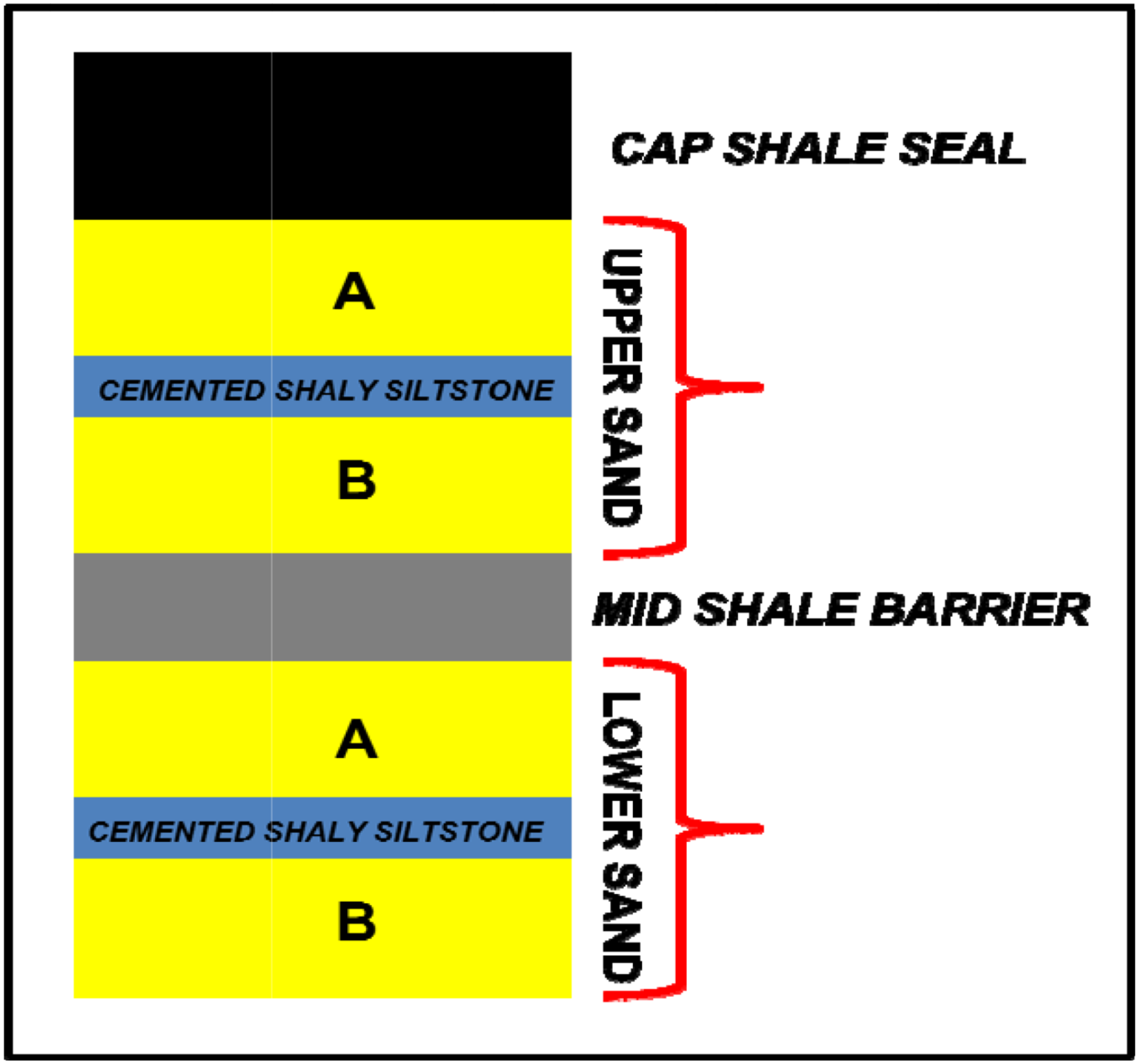

Figure 2. Generalized Reservoir Stratigraphy showing the presence of two main sands, Upper and Lower, divided by a shaly barrier. Each sand is commonly devided into A and B net pay intervals.

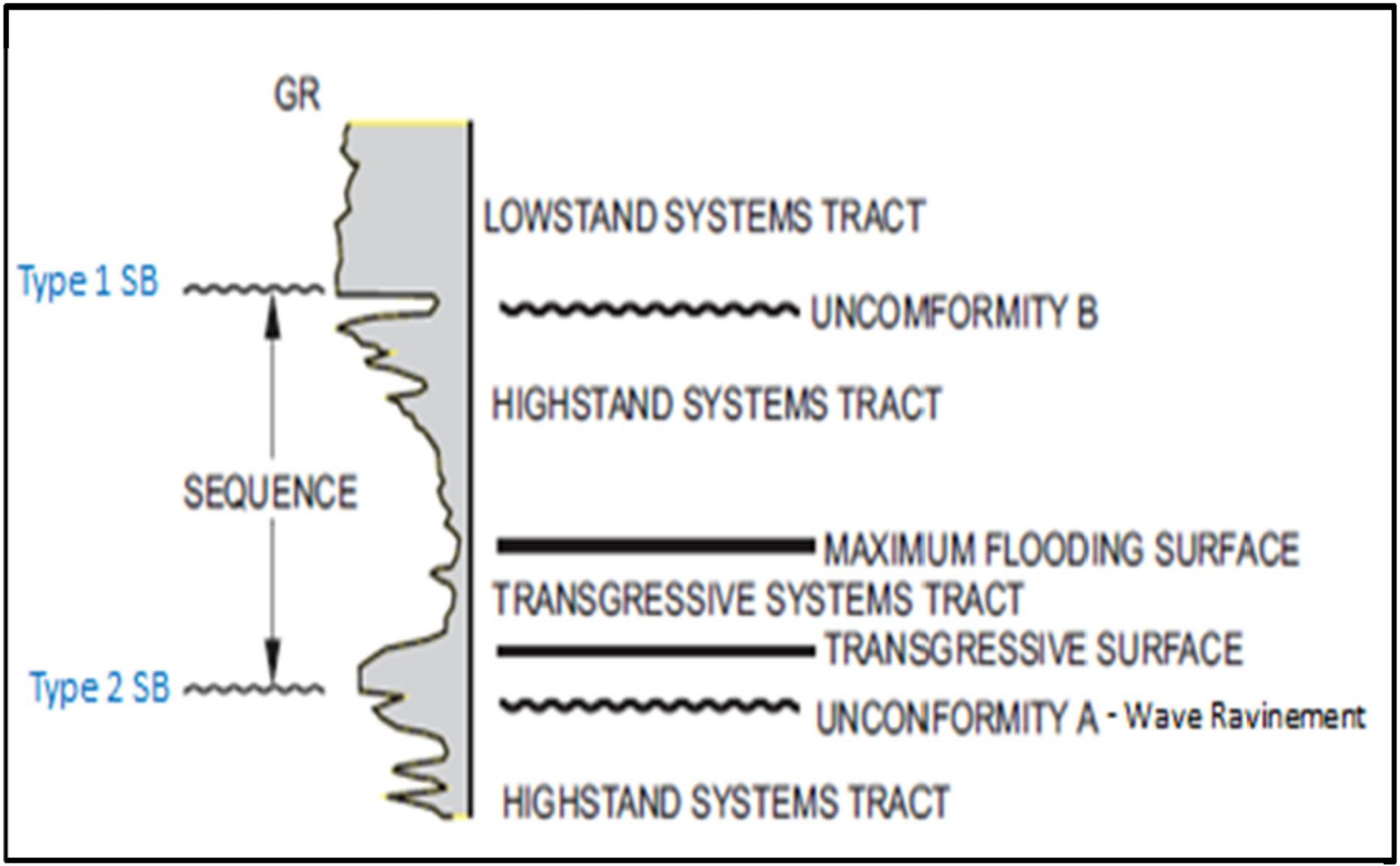

Figure 3. Sequence stratigraphic model for the reservoir is developed using the conventional sequence surfaces which are locally and regionally well correlatable across the field (Posamentier and Allen, 1999).

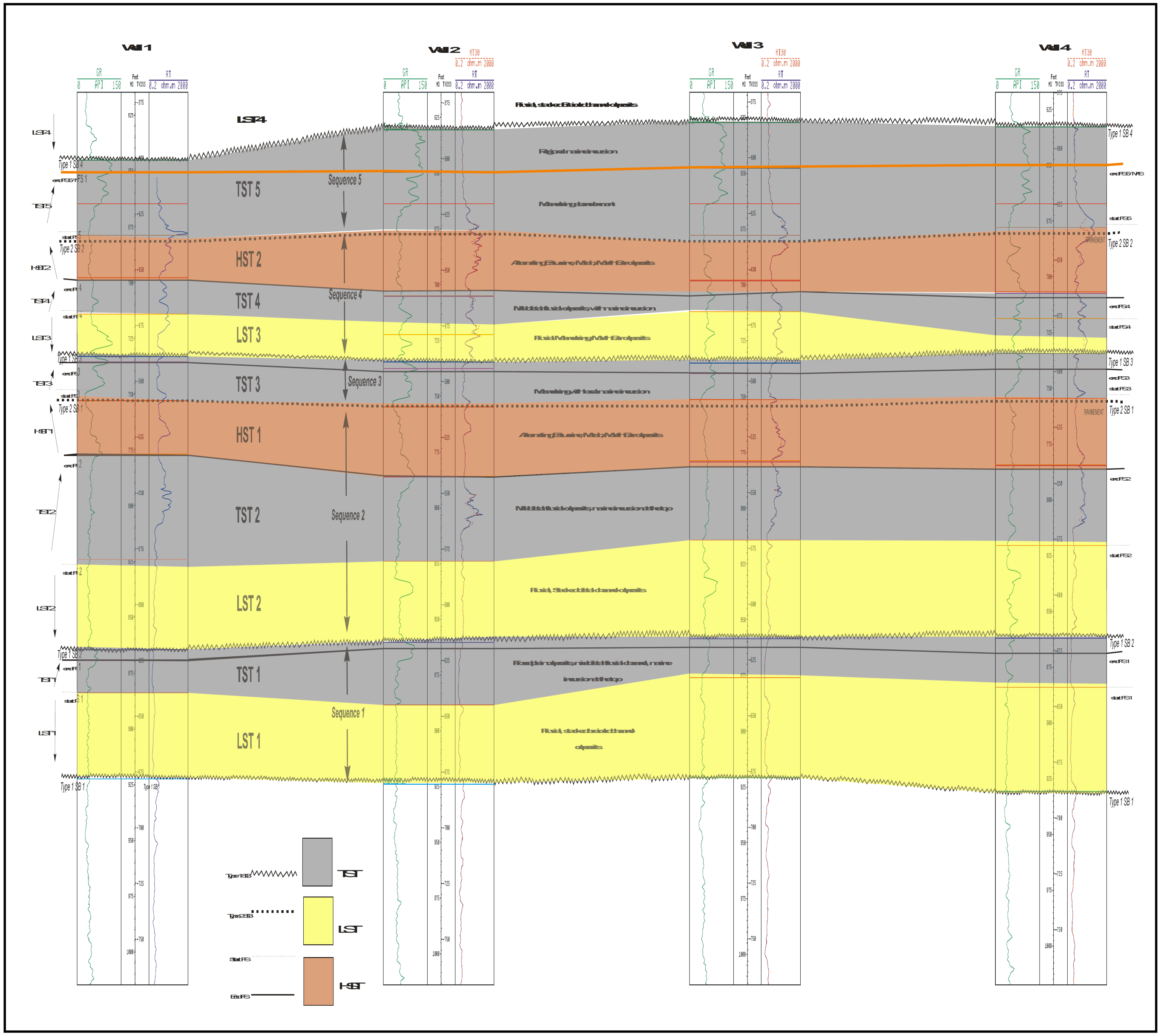

Figure 4. Sequence Stratigraphic Model in the pattern development area in dip direction, based on conventional sequence correlations, using gamma and resistivity logs. Suggested depositional environments within each systems tract are also indicated. Distance between wells 1 and 4 is about 1 km.

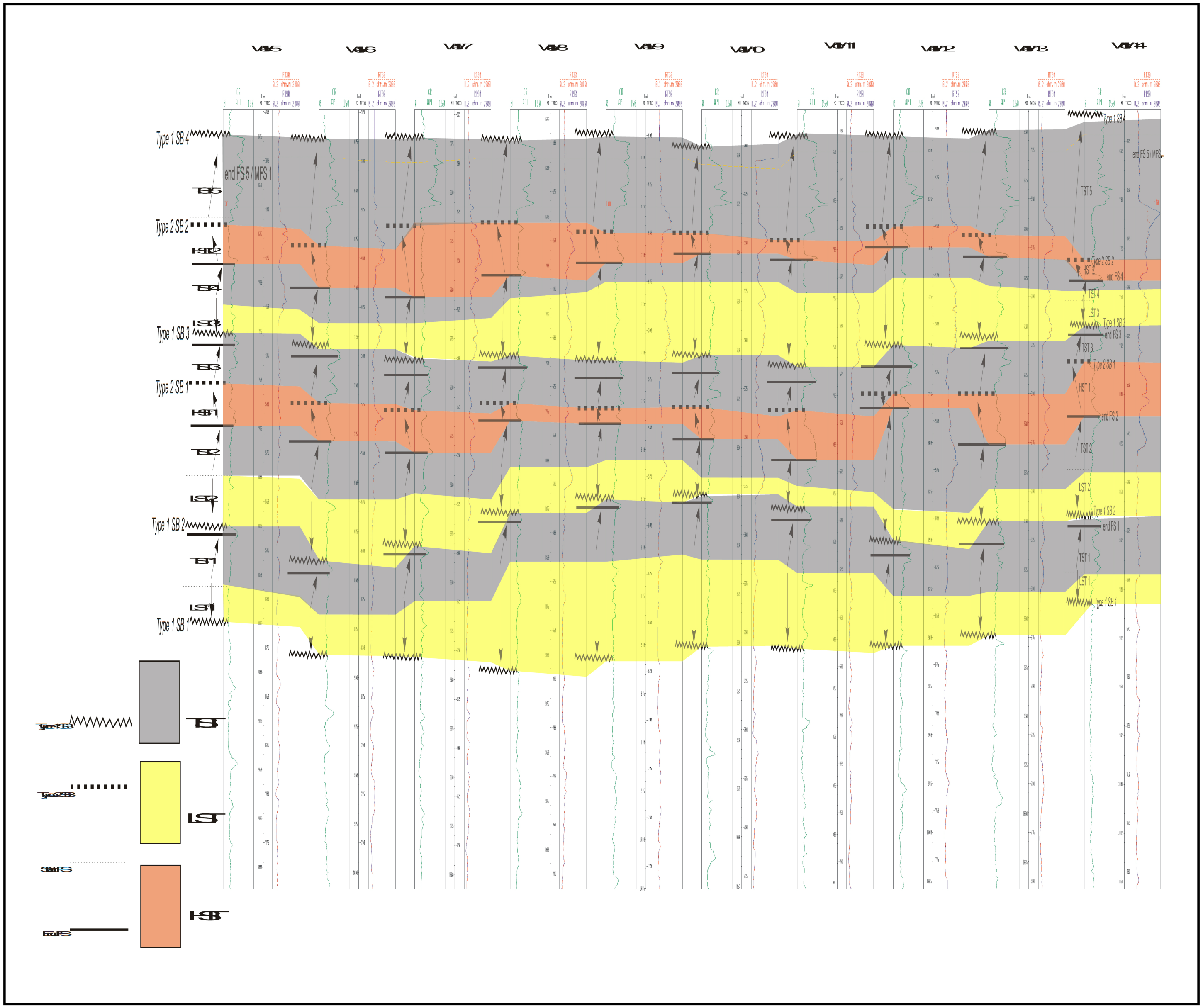

Figure 5. Regional Sequence Stratigraphic Model across the field in dip direction based on conventional seuqnece correlations. Gamma and resisitivity logs are used here. Distance between wells 5 and 14 is about 16 km.

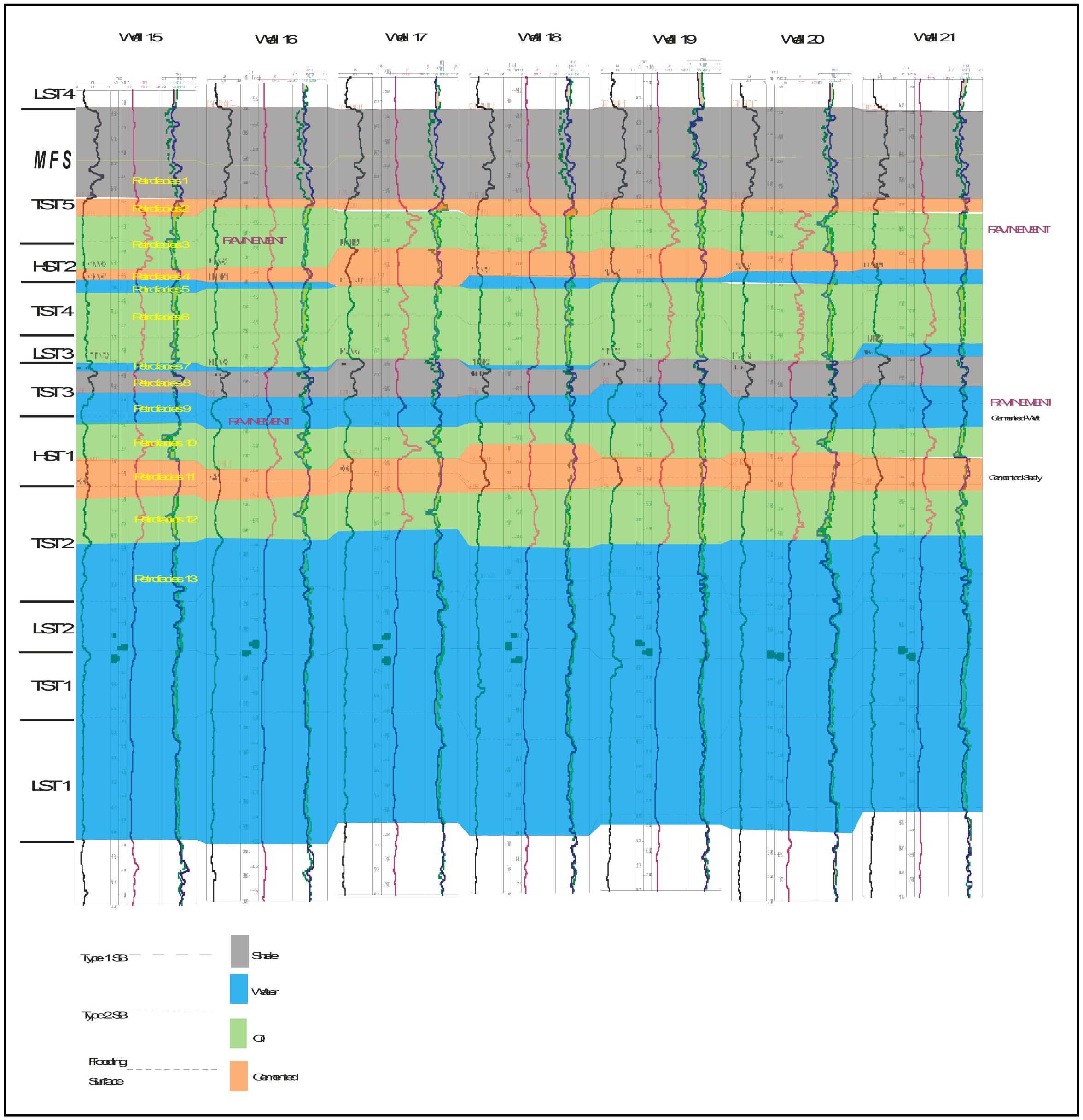

Figure 6. Petrofacies Model in the pattern development area based on rock parameters. Relationship between systems tracts and petrofacies types is attempted here. Distance between wells 15 and 21 is about 1 km.