Optimizing Oil Development of a Super K Compartmentalized Reservoir with Large Gas Cap and Bottom Water Aquifer "Case Study"*

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Abstract

This article presents a case study of developing a significant volume of super K compartmentalized oil reservoir with a large gas cap and bottom water aquifer in Abu Dhabi-UAE. The reservoir is a low-relief heterogeneous carbonate, located in a complex environment represented by natural and artificial islands in the surface, shallow and medium water marine areas with subsurface lateral, and vertical heterogeneities as well as variation in reservoir fluid properties.

The static and dynamic data were utilized to construct representative geological and dynamic models for the reservoir. The field development objective focused on maximizing the oil production and achieving 70% RF while minimizing the gas cusping, water conning and early breakthrough via super K interval.

Nine years of production dynamic data were available from six oil producers in addition to well testing "14 wells", core "11 wells", MDT "17 wells" data during the appraisal phase. These data were used to quality control the initialization and history match phases. In preparation to the development options, the team included pressure support using water injection, lean gas injection, miscible gas injection, miscible WAG injection. The predicted reservoir performance of the super K oil reservoir indicated considerable gas production and high water production from the bottom water aquifer through super K interval in all the development options.

It was a big challenge to reduce the amount of gas production, water production, and early breakthrough for all development options. A new development option was introduced to perform peripheral miscible Hydrocarbon WAG injection accompanied with optimization of the wells and completion intervals locations for producers and injectors, as wells as WAG cycle to minimize the gas production from the gas cap, water production from the aquifer, and early breakthrough. This resulted in significant enhancement to plateau length, sweep efficiency, and recovery factor. This article provides the methodology followed to guide the development plan to fill in the uncertainty gap along with a detailed data acquisition and monitoring programs to better understand the reservoir behavior.

Introduction

The reservoir is a large compartmentalized oil reservoir with a significant volume of gas cap. The thin oil column (10-20 ft) is bound by a gas cap and bottom water drive with a very high permeable streak "Super K" at the upper section of the reservoir.

The reservoir is described as a heterogeneous carbonate of low-relief undulated surface extending over a tough surface environment including deep water, shallow water, Sabkha, natural and man-made islands, as well as the main land (Figure 1). The reservoir dipping is less than one degree at the crestal area and gently dips towards the flank. The reservoir is characterized by three sub zones, with eight layers, separated by two main stalyiolites (Figure 2). Subzone I is very tight, however Subzone II has the best reservoir quality, while Subzone III has good porosity, but low permeability and water bearing. Subzone I consists mainly of mudstone and wackestone (very tight interval). Subzone II consists mostly of packstone, grainstone, and wackestone. Subzone III consists of wackestone and locally, packstone.

Five main lithofacies units can be recognized from cores description, these are as follows, from top to bottom: LM/W(P), G1, P, G2, and the WP facies unit. The LM/W (fine grained Orbitolina wackestone/lime mudstone) facies cover Subzone I, while Subzone II is composed of three facies which are as follows: the G1 (skeletal peloidal grainstone), P Algal, skeletal packstone floatstone), and the G2 (algal lump, skeletal, peloidal packstone /grainstone). The G1 (Grainstone facies lies at the top of Subzone II and exhibits the best permeability values. The facies shows lateral variation in the permeability due to the lateral changes in the grains size distribution. The P (Packstone) facies has the same developed porosity but with less permeability. The lower part of Subzone II is composed of the G2 (Grainstone) facies which has the same porosity, but with less permeability than the G1 facies at the top of Subzone II. Subzone III (WP) is composed mainly of skeletal peloidal packstone/wackestone. Lithofacies showed lateral variation in grain size distribution and Stylolites development (Figure 2).

The rock properties show low to very good porosity (7-25%) and very low to very high permeability (0.1 mD to 4.0 D) with reservoir deterioration towards the flank and more so towards the south-southwest. The bubble point pressure varies from saturated conditions of 4500 psi at the GOC in the crest, to 3250 psi down dip in the flank locations.

Geological Model

The geological model with multimillion cells was constructed based on the available static data from more than 45 wells drilled and logged through the reservoir, as well as 11 cored wells. Maximum fine layering was applied to ensure proper modeling of the reservoir rock heterogeneity. The J-function technique was honored to initialize the model saturation profiles. Following initialization of the static model, the layering was up-scaled to the optimum number of layers for the dynamic model studies and initialization was honored as well (Figure 3). This model was exported for the dynamic model with dynamic data update as discussed hereafter.

Dynamic Model

The following sections describe the dynamic modeling approach followed to build up the dynamic model of the field, including model initialization, history matching, prediction and sensitivities, and identified uncertainties.

Data Availability - Rig Onsite Tests, ROS

Starting in 1994 and prior to Phase I development plan implementation, the early production scheme (EPS) in the field began with the drilling of 45 strings which penetrated the subject reservoir. This included 11 cores and 14 rig onsite tests and two long production tests in two separate wells. The major objective of the coring and testing was the gathering of the required static and dynamic data to better understand the reservoir. The data gathered from logging, coring, and testing during the early production scheme also helped in investigating different development scenarios. Other objectives of the early production scheme can be mentioned as follows:

- Understanding of reservoir productivity, presence of gas cap, and fluids contact depth.
- Investigation of the distribution of structure, thickness, porosity, permeability, digenetic trends, and the preliminary analysis of reservoir development trend across the field.
- Better understanding of the lateral and vertical variations in reservoir rock and fluid properties.
- Evaluation of optimum well completion strategies to enhance productivity and injectivity.
- Evaluation of open horizontal hole completion strategy in reducing gas cusping and water conning.
- Evaluation of the presence of faults/sub-seismic faults and fractures with regard to any sub-seismic faults that might be intersecting any of the drilled horizontal holes.

Production testing of wells in the early production scheme of the reservoir had proven high productivity. Early production tests results are given in (Figure 4). Some of the main outcomes and identified uncertainties of the early production scheme showed the following:

- Confirmed the presence of gas cap at the crestal area underlain by a thin oil column. The reservoir is bound by gas cap and active water aquifer.
- Confirmed the presence of a high permeable streak (up to 4 D) at the upper section of Subzone II which is the main productive zone.
- The high permeable streak of Subzone II dominates the drainage of reservoir. This introduced another challenge on the next phase producers, since it would lead to early gas cusping and water production.
- Confirmed high productivity of the reservoir. However, different wells, even neighboring wells by location, had shown different production performance in terms of water cut and GOR, uncertainty in predicting the well performance of future development wells and thus the design of surface facilities gas handling capacity.
- There exists considerable lateral and vertical variation in reservoir fluid properties including different API oil gravity in different wells; which might be attributed to reservoir fluid compositional variation across the reservoir.
- Deviated hole completion technique would be advisable to better manage wells that might be affected by gas cusping and/or water coning. However, this put a challenge on the drilling aspect of these kinds of completions since the target reservoir zone is thin and proper geosteering would be very essential.
- Interpreted sub-seismic faults do not intersect with any of the drilled horizontal holes.

- Possibility of reservoir compartmentalization as observed from the variation of reservoir fluid contacts depths among the different wells; probably due to fault or stratigraphic shoaling barriers. Potential shoaling is visible on the seismic and makes the tie horizon picking more challenging at this level.

MDT and PVT Samples

MDT pressures and samples identification technique were conducted for 17 wells. The gathered information from the MDT helped better understanding of the gas and oil distribution and the fluid contacts. Five reservoir oil samples from the oil rim and one gas sample from the gas cap were collected for PVT studies that helped to build the most likely fluid model based on the experienced lateral and vertical composition variation across the reservoir (Figure 5).

Determination of Fluid Contacts

Establishing a solid confidence on the correct depth of fluid contacts in the mentioned reservoir has always been a challenge. Complexity of the structure framework, depth uncertainties as well as the tightness of the reservoir properties near the base had a significant influence in determining the fluid contacts particularly during the interpretation of fluid gradients from MDT. Therefore, correlation between the Elan logs, MDT analyses and production tests were needed to build a better understanding about the fluid contacts and therefore achieving proper well placement and completion.

Log interpretation of some of the wells combined with test results showed a possible GOC at x080 ftss. However, ELAN logs in the other wells showed a possible GOC at x090 ftss. Depth uncertainty in the GOC may be in the range of +/- 10 ft.

Generally, log interpretation, test results, and MDTs showed a variable OWC/FWL at about x110 ftss, x120 ftss and x130 ftss. The variation in the OWC/FWL can be related to following reasons:

- Logging depth uncertainties.
- Undulated structure surface.
- Tilting of structure and presence of faults.
- Variation in capillary pressure.
- Separate closures.

Possibility of Compartmentalization

Compartmentalization occurs when a producing interval is not in fluid communication with the remainder of the field or zone. Compartmentalization may develop during the time of deposition or become isolated through structural changes like faulting or by lateral variation in the reservoir properties (tightness or diagenesis) or pinch-out (Alklih et al., 2014). The possibility of compartmentalization in our reservoir arises from several characteristics such as the lateral change in reservoir rock properties, presence of large faults, lateral variation in wells production, and mainly due to the abrupt changes in the GOC and OWC/FWL. One challenge that is embedded with this concept is building its simulation model. During simulation model initialization stage and to be able to relate the differing FWL to the geological model, the FWL inferred from the saturation matching needed to be compared to the FWL inferred from MDT data, the GOR, and water cut data from the tested intervals (Figure 8).

Phase I Field Development

Following the successful early production scheme results, Phase I development of the high productivity reservoir was planned and implemented. Phase I development drilling commenced in mid-2002 implementing a comprehensive data gathering program to reduce uncertainties related to structure, reservoir quality, extension of the oil pools and variation of reservoir fluid properties and fluid contacts (El Mahdi et al., 2007). Additionally, Phase I development followed several guidelines as follows:

- Depends on the natural energy present in the reservoir for production i.e. follows a natural depletion scheme. The reservoir is considered to be under active water drive. The presence of the high permeability streak within Subzone II and the water bearing Subzone III was expected to allow the existing water aquifer to provide pressure support; therefore reduction in reservoir pressure was expected to be minimal.
- Sustain the approved production target volumes from the planned wells. The wells were drilled from the well's clustering system, to minimize drilling and construction environmental foot prints, and are completed either as highly deviated or as horizontal hole.
- Findings of the dynamic data gathering of Phase I development would formulate the optimum future development plan of the entire field.

Six development oil producers were drilled as part of Phase I development plan to deliver a certain mandated rate under natural depletion and to gather the necessary dynamic data. Phase I development had been facing several challenges from well level to reservoir level. These include variations in wells performance, confirmation of reservoir drive mechanism, determination of fluid contacts, and possibility of reservoir compartmentalization as discussed below.

Dynamic Model Initialization

Fluid Model

The fluid model was created based on two EoS, honoring the available PVT studies after necessary screening and validation. The developed EoS, mimicking the compositional variation across the reservoir through eight pseudo components (Table 1), successfully matched the routine experiments of the honored PVT studies (Figure 6 and Figure 7). The CO_2 component was retained as one pseudo component to allow evaluation of CO_2 injection as a recovery mechanism (El Gazar et al., 2012). The grouping also considered evaluation of miscible hydrocarbon gas/WAG development options. The developed EoS successfully predicted the GOC based on the composition change that was necessary to evaluate the gas cusping into the oil producer based on composition change and monitoring in the compositional simulation model.

SCAL

Regional SCAL data from similar reservoirs in other fields were reviewed as there was no measured SCAL data available for the subject reservoir for the development study (Basioni et al., 2012). The regional SCAL was screened and adjusted using the conventional normalization and de-normalization technique to predict the dynamic performance of the different reservoir rock types derived from Mercury Injection tests on actual plug samples from the subject reservoir. The Mercury injection capillary pressure from the limited number of plug samples was not sufficient to represent the changes in the saturation across the field in comparison to more than 45 saturation profiles from the open hole logs. Accordingly the capillary pressure curves were derived from the wells' open hole logs saturation profiles for each rock type. 8 saturation tables (four drainage and four imbibition) were identified based on the defined four reservoir rock types. Good log saturation match was achieved in the logged wells as showed above (Figure 3).

Model Initialization

Successful model initialization was judged based on the following:

- Porosity, permeability, and water saturation profiles from openhole logs and cores.
- Integration of all static and dynamic data to identify the compartmentalization and its boundaries (Figure 8).
- Reported pore volume and volumes of hydrocarbons initially in place (OIIP and GIIP) from the up-scaled static model as well as material balance.
- Reservoir fluids vertical composition gradient and reservoir fluid properties.
- MDT fluids gradients and measured reservoir pressures.

It can be stated that successful match was achieved with all the set conditions and parameters in spite of the high heterogeneity and complexity of the reservoir rock.

History Matching

A very good history match (Figure 9) was achieved based on the following available data:

- Rig on site production and pressure tests (ROS) "14 wells".
- MDTs pressure measurements in 17 wells.
- 9 years production from 6 oil producers.
    - Production data (Oil, Gas and Water).
    - Pressure data (BHCIP, BHFP and WTHP).
- Saturation profiles from RST measurements during production history "6 wells"
- Five production log profile in five of the oil producers.

Prediction Scenarios

Following the performance of the subject complex reservoir, the development of the oil was adopted to be in phases, focusing on the best rock properties and lowest uncertainty segments of the reservoir at the start. The phased development strategy was adopted to collect the necessary information which will help for full field development plan and ensure achievement of the set production plateau. Complete data acquisition and monitoring programs will be planned during phase development to better understand the reservoir behavior and minimizing the uncertainty.

The selected bottom hole locations for the first phase of development (Figure 10) are selected in the areas where the best rock properties are identified. Selection of the new bottom hole locations was based on drilling from the mainland as well as the available natural and existing islands for cost reduction that directly impact the NPV of this challenging high productive reservoir. The development strategy calls to complete all the producers and injectors with highly slanted cased hole crossing all the layers of the oil, thus intercepting all the possible high permeable streaks and optimizing the perforation intervals at the lower part of the high permeable streaks, maximizing oil production and minimizing the gas cusping as well as high water production from the bottom aquifer. This technique should ease logging accessibility for evaluation of the production and injection across the cased hole. Many sensitivity runs were carried out to investigate the wells' optimum spacing, completion strategies, and injection schemes. It was concluded that the optimum completion strategy is optimum peripheral miscible WAG injection using the said slanted perforated cased hole and optimizing the perforation interval across the lower part of the high permeable streak as completion technique. It was also advised that future wells are located away from the gas cap to minimize the gas cusping.

The studied development options included depletion drive, water injection, lean hydrocarbon gas, miscible hydrocarbon gas, and miscible WAG injection. All the development options were carried out on the bases of no production from the gas cap to maintain the pressure support together with the adopted pressure support scheme. The production, pressure history, and the material balance suggested the presence of the active water drive. The presence of high permeable streak "super K" at the top of Subzone II bound by gas cap and bottom water would result in high GOR and water cut production (Figure 11, Figure 12, Figure 13, Figure 14, Figure 15). Such unfavorable production would result in impacting the well life.

Comparison of the different development options indicate that the miscible hydrocarbon gas injection should yield the best recovery, while water injection would be the worst. As expected, the WAG injection would be strongly affected by the heterogeneity and the complexity of the rock that would directly impact the effectiveness of the water cycle. The prediction runs suggested that WAG injection would be able to maintain the reservoir pressure compared to the combined miscible hydrocarbon gas injection (Figure 13).

Sensitivities and Optimizations

Many sensitivities and optimization scenarios were carried out to improve the plateau length, RF%, sweep efficiency, and to improve the project economics. The sensitivities and optimization scenarios can be mentioned as follows:

- Producers and injectors well locations.

- Maximum injection Rate / well and injection period
- Field target rate
- Kv/Kh ratio
- Completion (HH vs. deviated)
- WAG cycle/slugs
- Producers and injectors perforation strategy
- WAG synchronize vs. SWAP
- Delaying the injection (3, 5, 10 and 15 years)
- VRR
- WAG-Lean vs. WAG-Rich

Uncertainties

Following the performance of the complex reservoir, the development of the oil was adopted to be in phases focusing on the best rock properties and lowest uncertainty segment of the reservoir at the start. The phased development strategy was adopted to collect the necessary information which will help for full field development plan and ensure achievement of the set production plateau. Complete data acquisition and monitoring programs will be planned during phase development to better understand the reservoir behavior and to minimize the uncertainty.

As part of the simulation study, the uncertainty analysis was carried out based on many realizations of the static model (e.g. structure, porosity and permeability) that align with some dynamic uncertainties i.e. FWL, GOC, SCAL and PVT (Honarpour et al., 2006). Table 2 shows the uncertainty matrix and the mitigation plan during the coming phases.

Condensate Recovery

In addition to the recovered condensate from the gas cap as a result of gas cusping, it was noticed that the near reservoir pressure MMP of the miscible hydrocarbon gas and the production drawdown would result in considerable condensate recovery, attributed to extraction of the intermediates during the vaporization process. This was another challenge to evaluate the condensate recovery from the gas cap and the vaporization process added to the total oil recovery. The evaluation process using the compositional model and composition tracking considered the negative impact on the quality of the left behind oil after extracting the intermediates. The output of the developed workflow enabled understanding of the different recoveries from the reservoir oil as well as condensates from the gas cap and the vaporization process. This will be explained further in details in a separate article.

Conclusions

Modeling of oil production from a significant volume of oil and gas cap reservoir using compositional simulation modeling in such complex, heterogeneous and compartmentalize reservoir suggested the following:

- The subject reservoir has experienced high water cut and high GOR production due to the presence of high permeable streak bounded by gas cap at top and bottom water aquifer.
- MDT, open-hole Sw, and test data suggests a variation in FWL and GOC across the field, which may indicate compartmentalization.
- Complete data acquisition and monitoring programs will be planned during phase development to better understand the reservoir behavior and minimizing the uncertainty.
- WAG showed the best results in both: phase development and FFD.
- Decreasing WAG cycle will lead to increase length of plateau and RF%.
- Increasing field target rate will increase RF % with production acceleration (Early Cash Flow).
- Delaying injection more than 5 years will have big impact on plateau length and RF%.

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Nomenclature

BHCIP	Bottom Hole Closed-In Pressure
BHFP	Bottom Hole Flowing Pressure
EPS	Early Production Scheme
FFD	Full Field Development
FWL	Free Water Level, ft
GOC	Gas Oil Contact, ft
GOR	Gas Oil Ratio, scf/stb
HH	Horizontal Hole
MDT	Formation Modular Dynamics Tester
OWC	Oil Water Contact, ft
RF	Recovery Factor
VRR	Voidage Replacement Ratio
WAG	Water Alternating Gas Injection
WCT	Water Cut, %
WTHP	Well Tubing Head Pressure

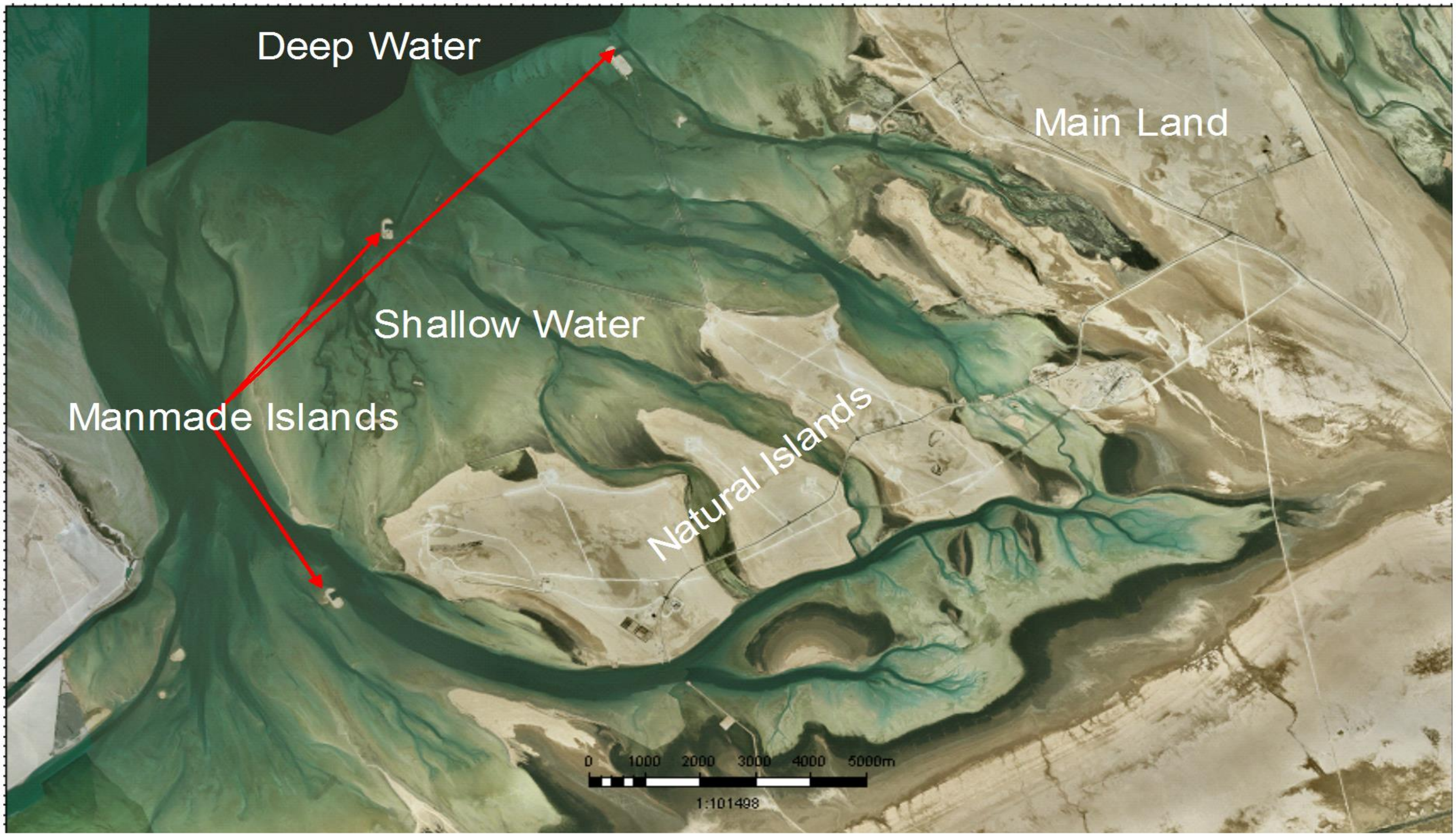

Figure 1. Surface environment.

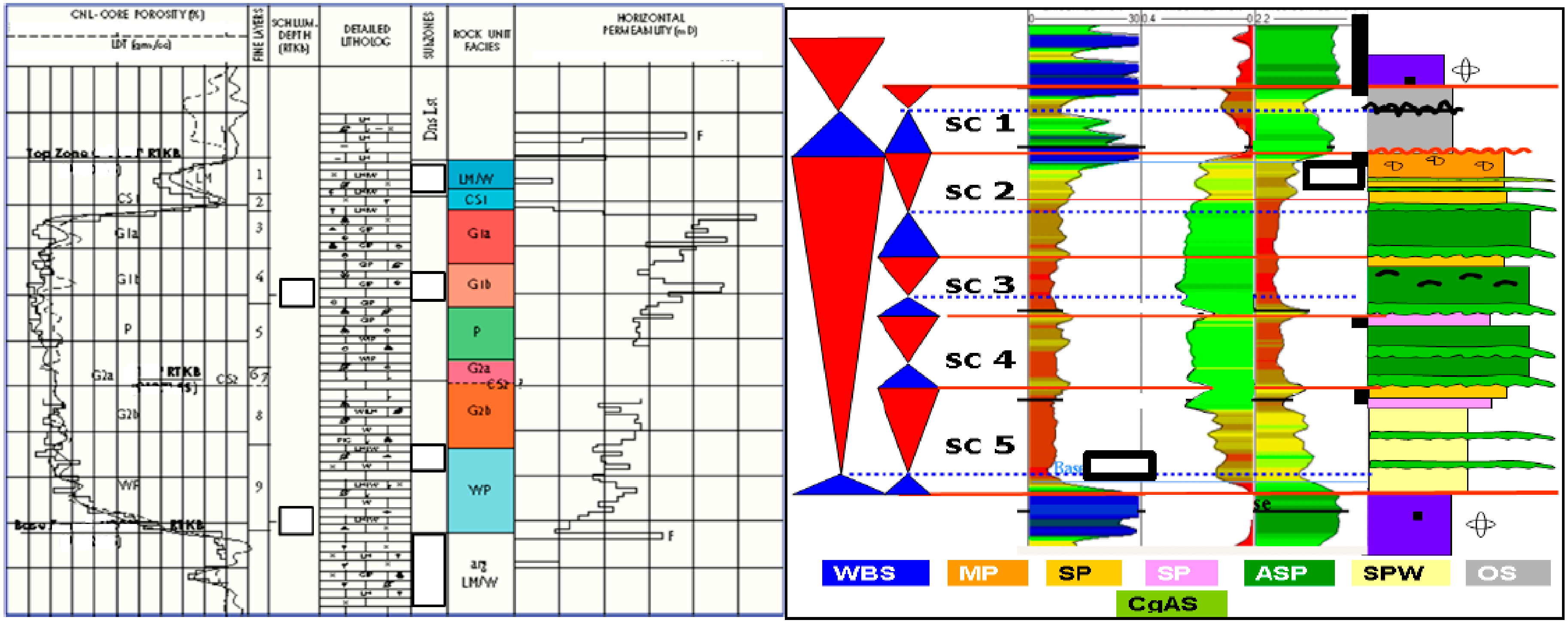

Figure 2. Reservoir layering and lithofacies.

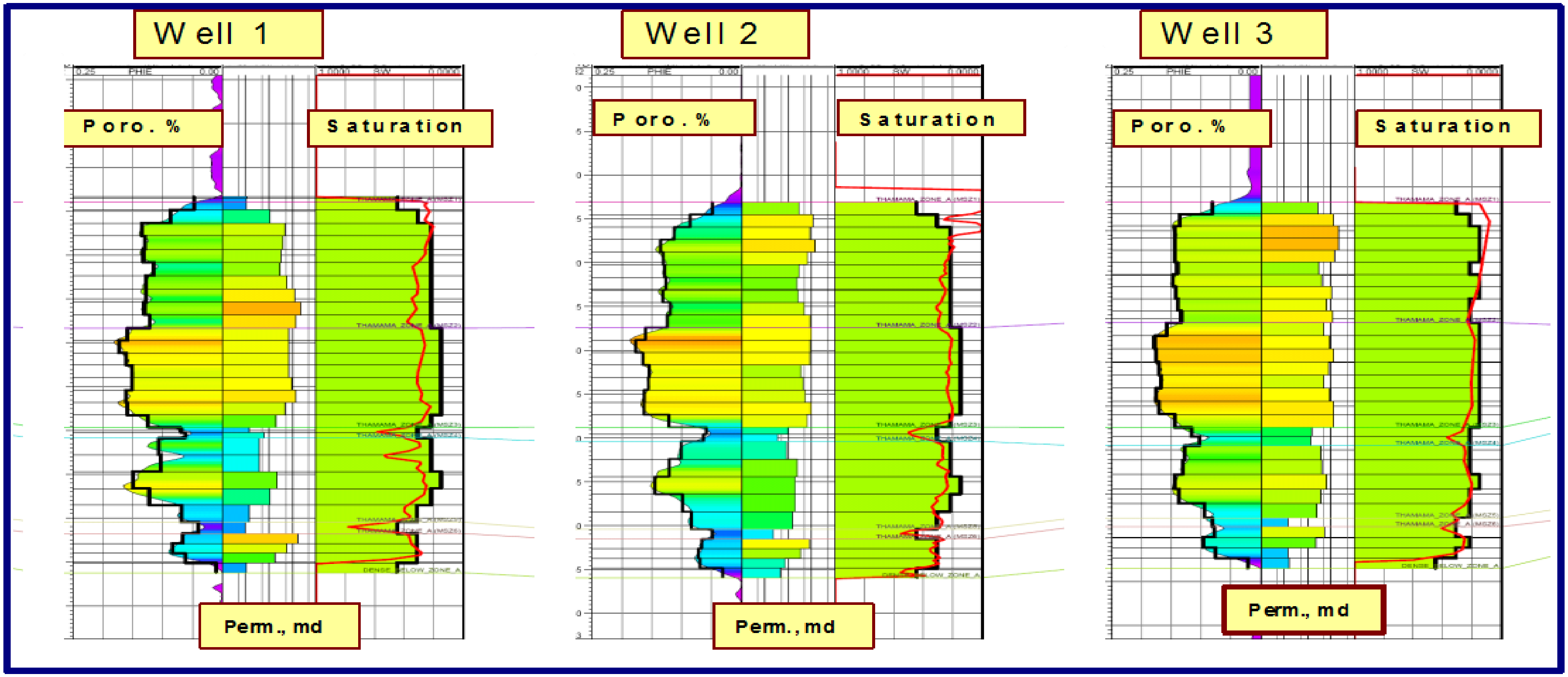

Figure 3. Initialization of the up-scaled static model.

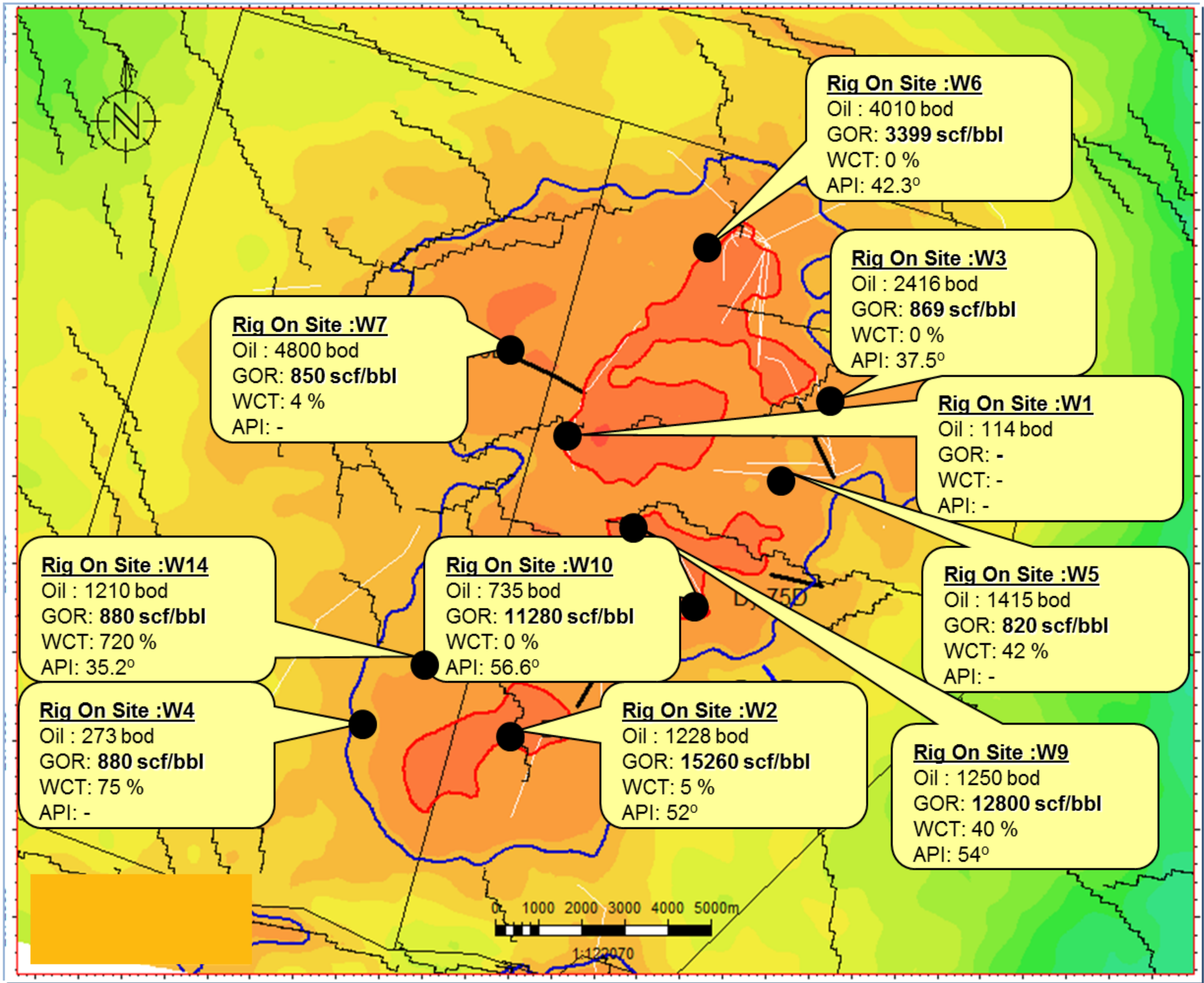

Figure 4. Rig on site tests, ROS.

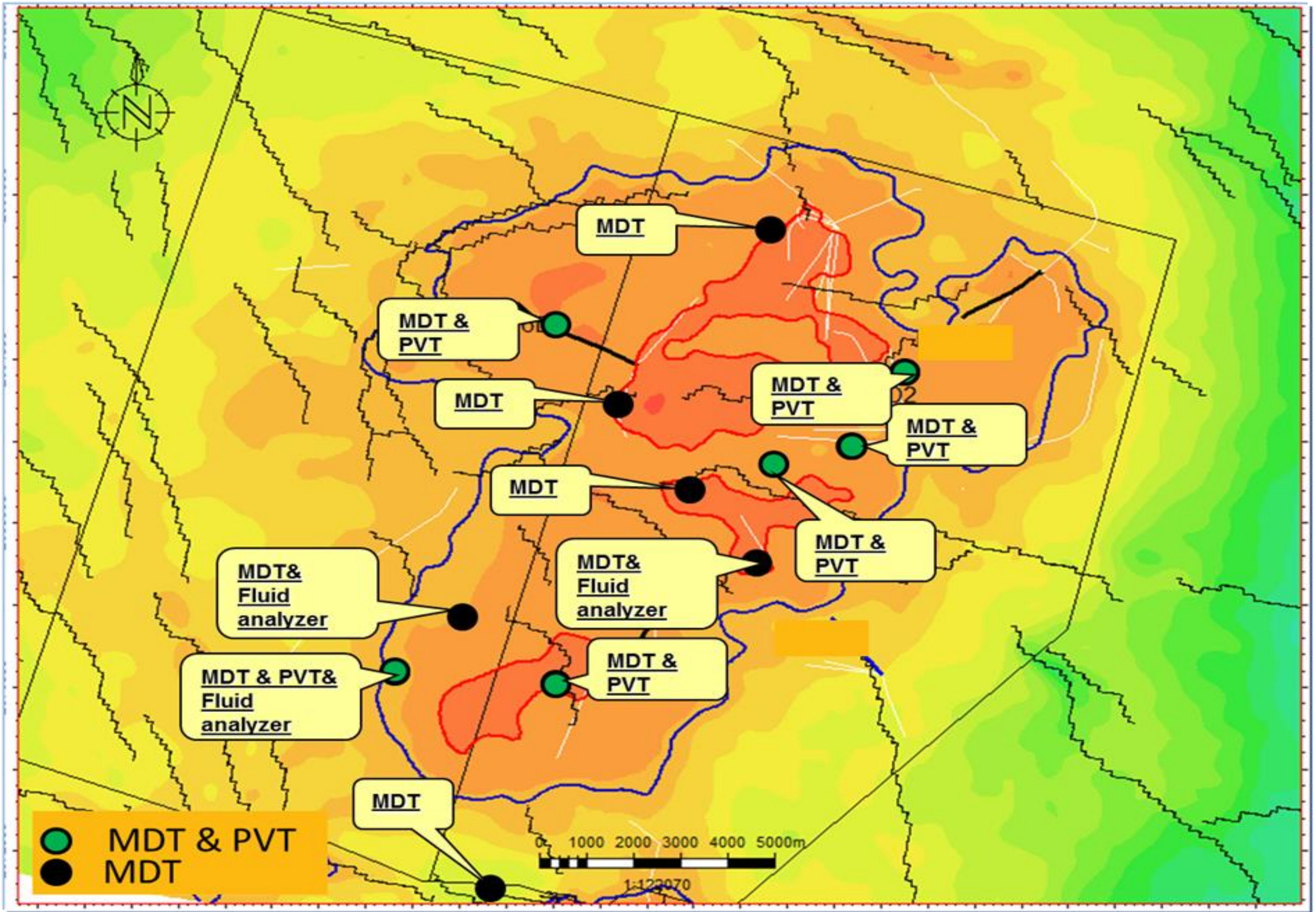

Figure 5. MDTs and PVT samples.

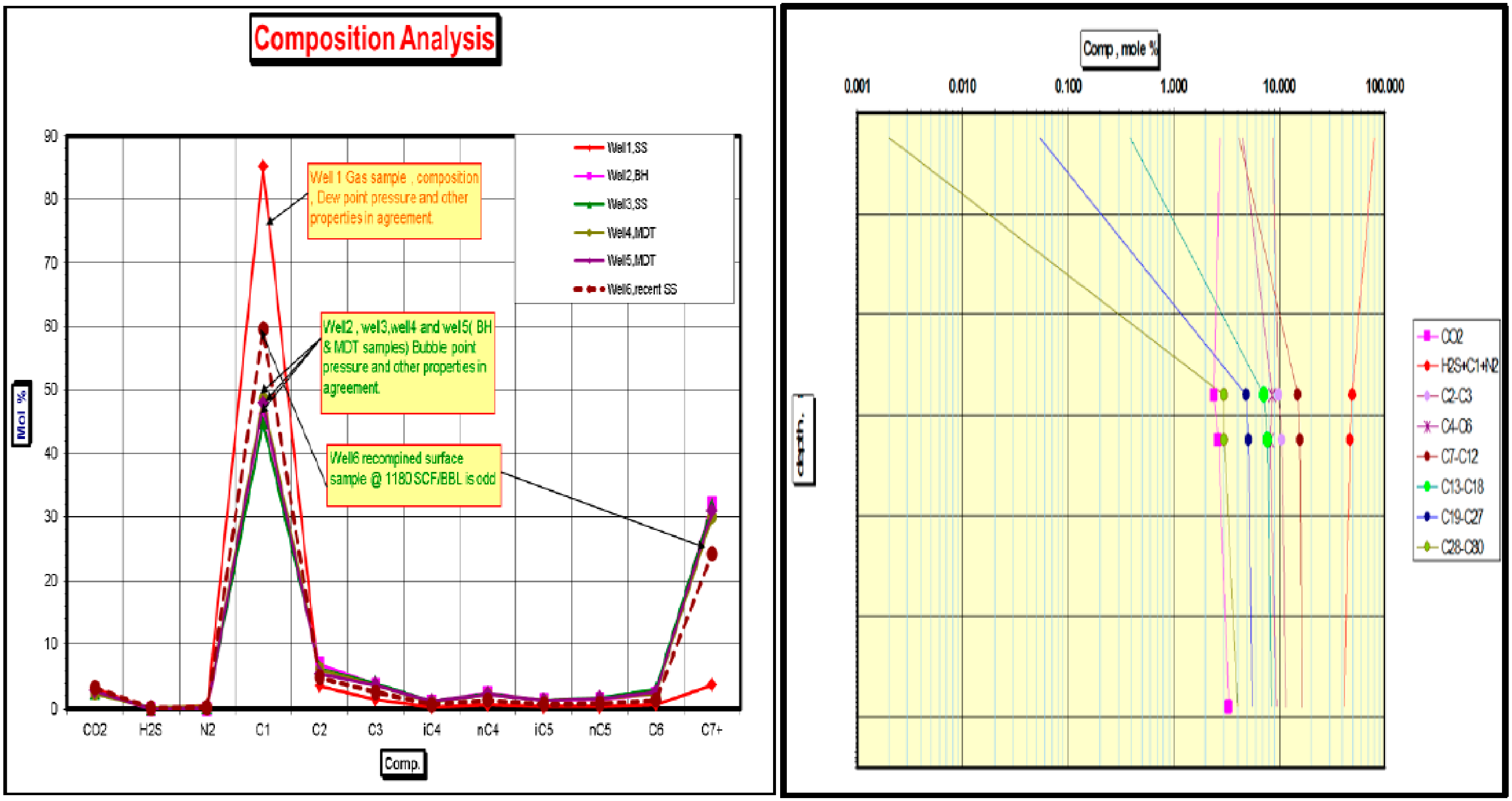

Figure 6. Valid samples compositions and compositional gradient with depth.

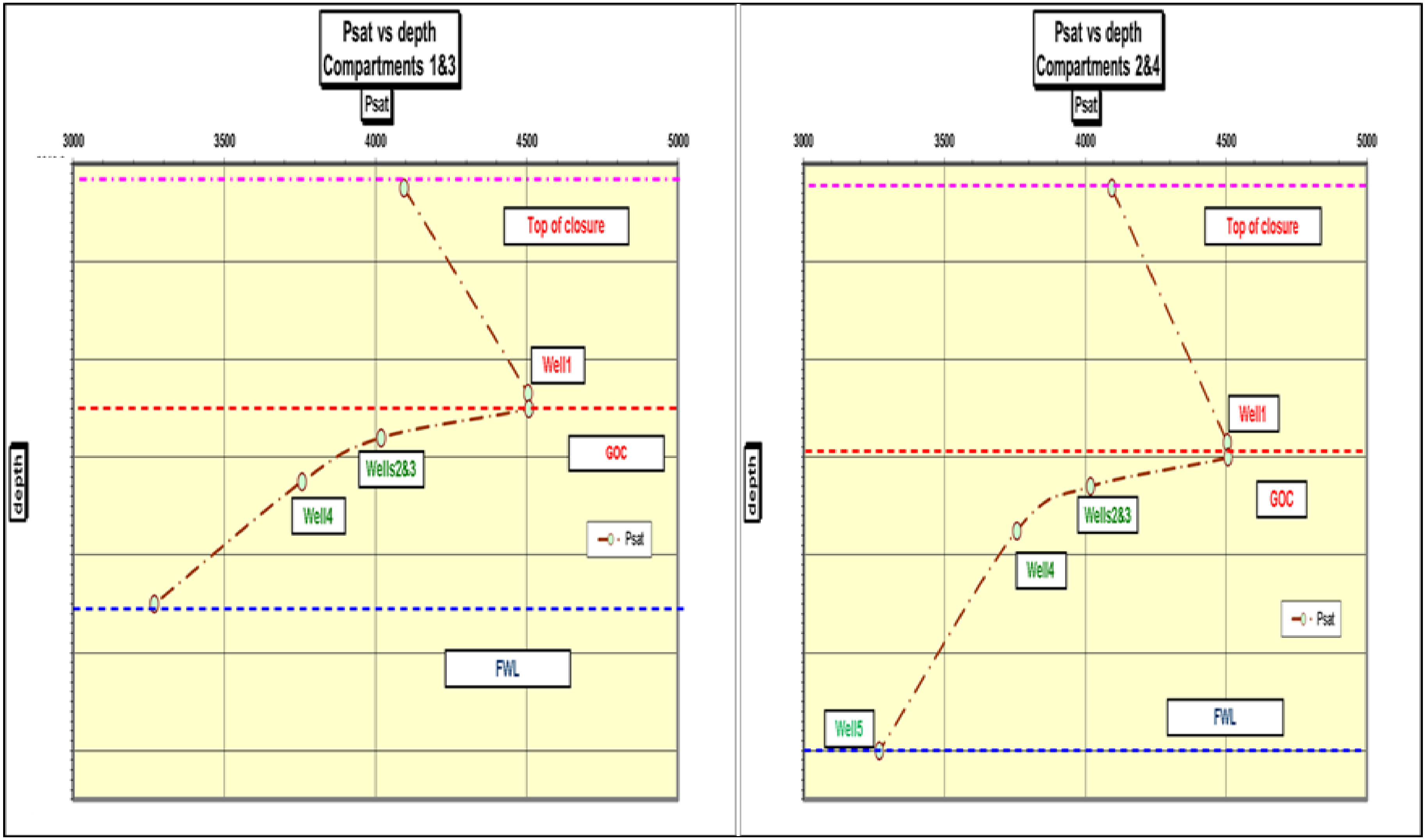

Figure 7. The saturation pressure of the reservoir fluids with depth.

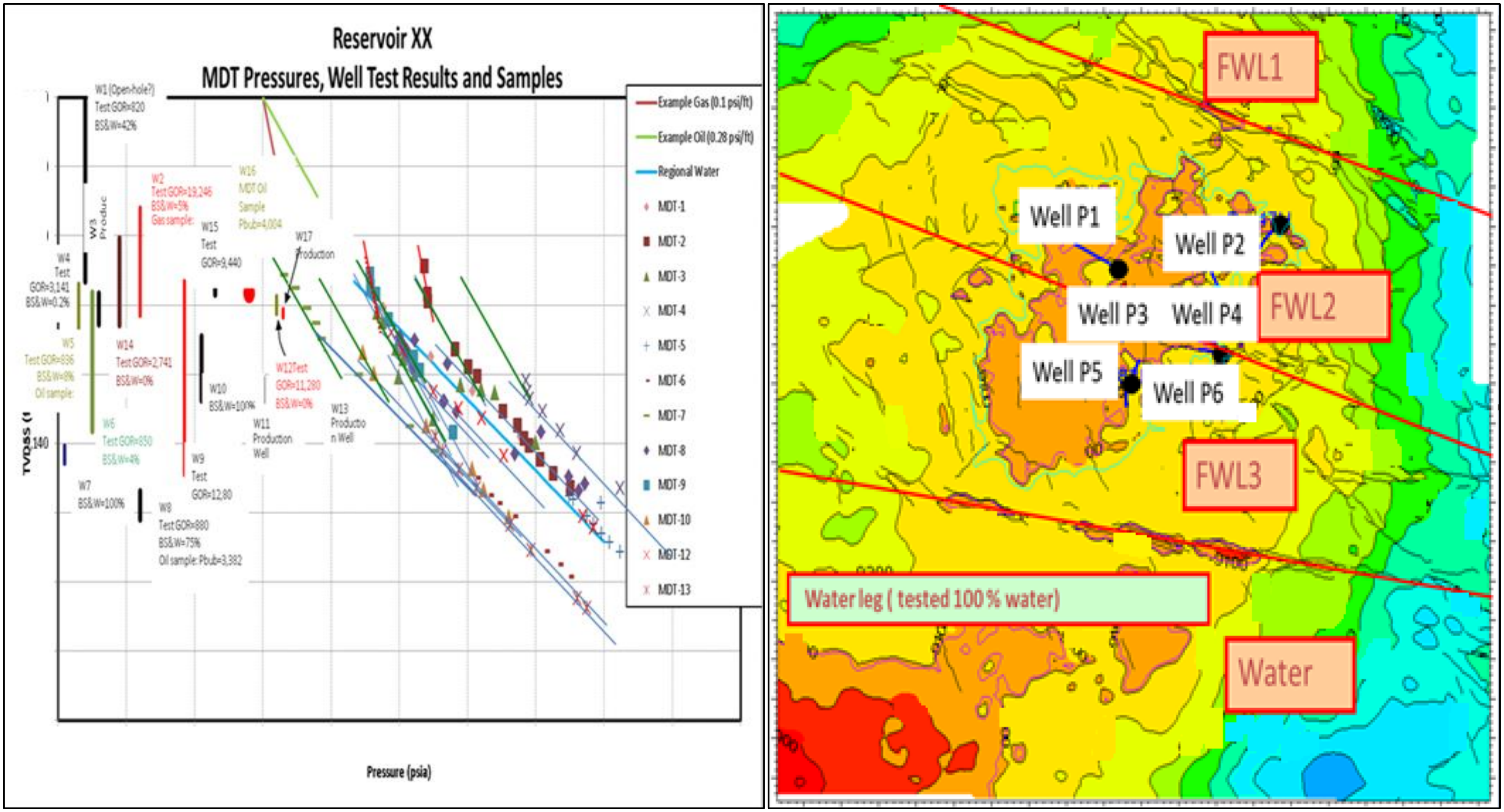

Figure 8. Static and dynamic data integration.

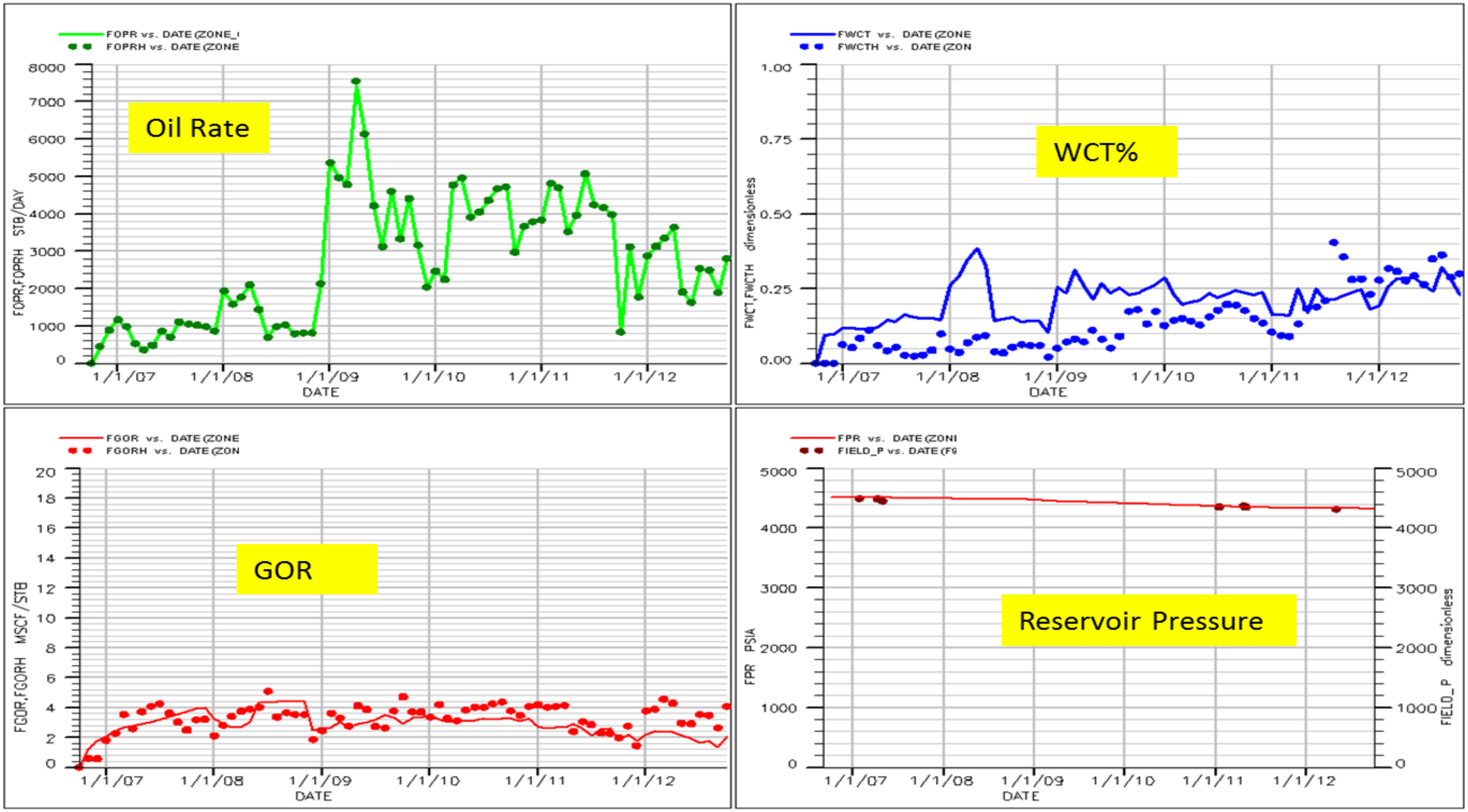

Figure 9. Field production match.

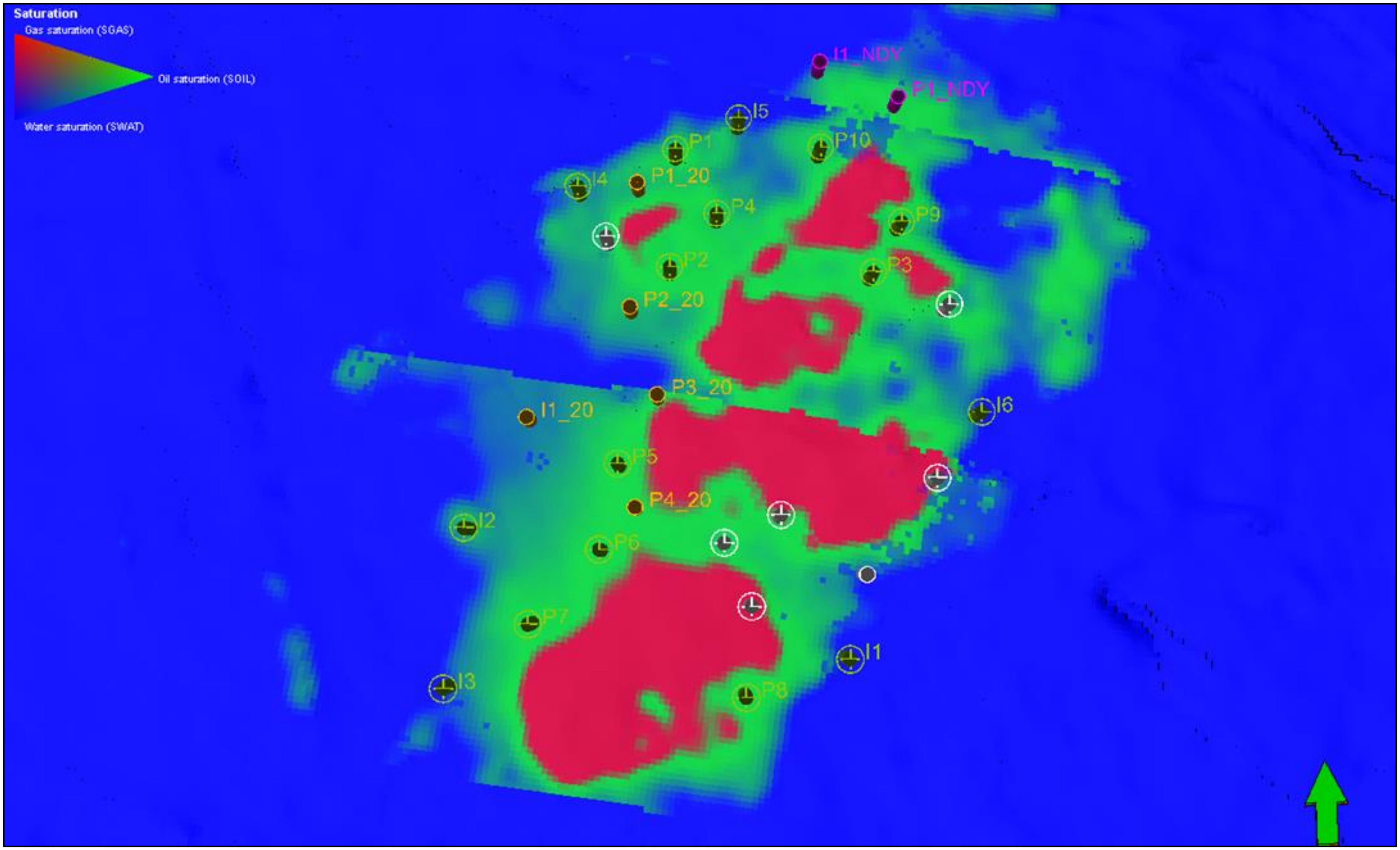

Figure 10. Proposed well locations.

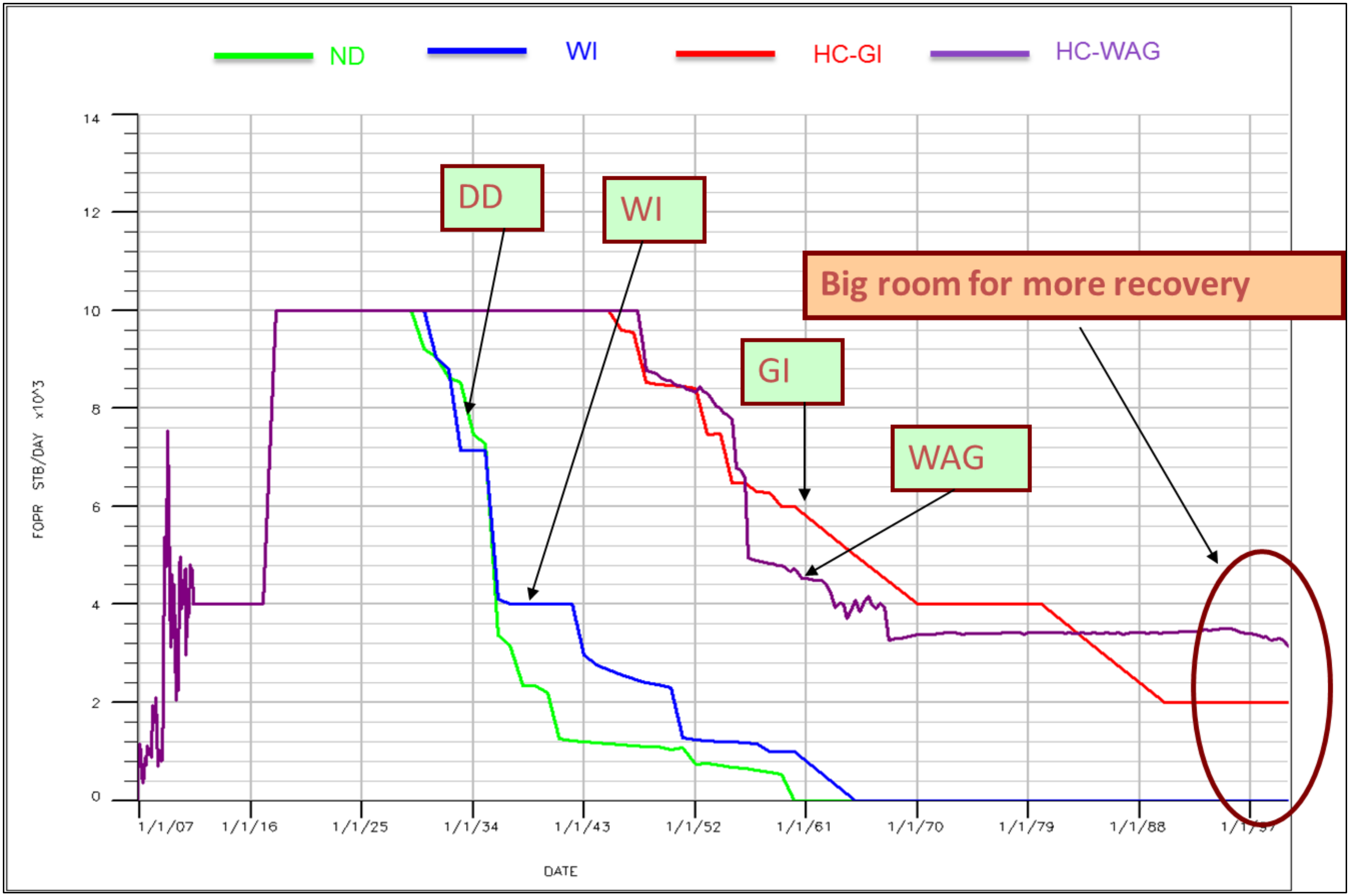

Figure 11. Field production rate for different development scenarios.

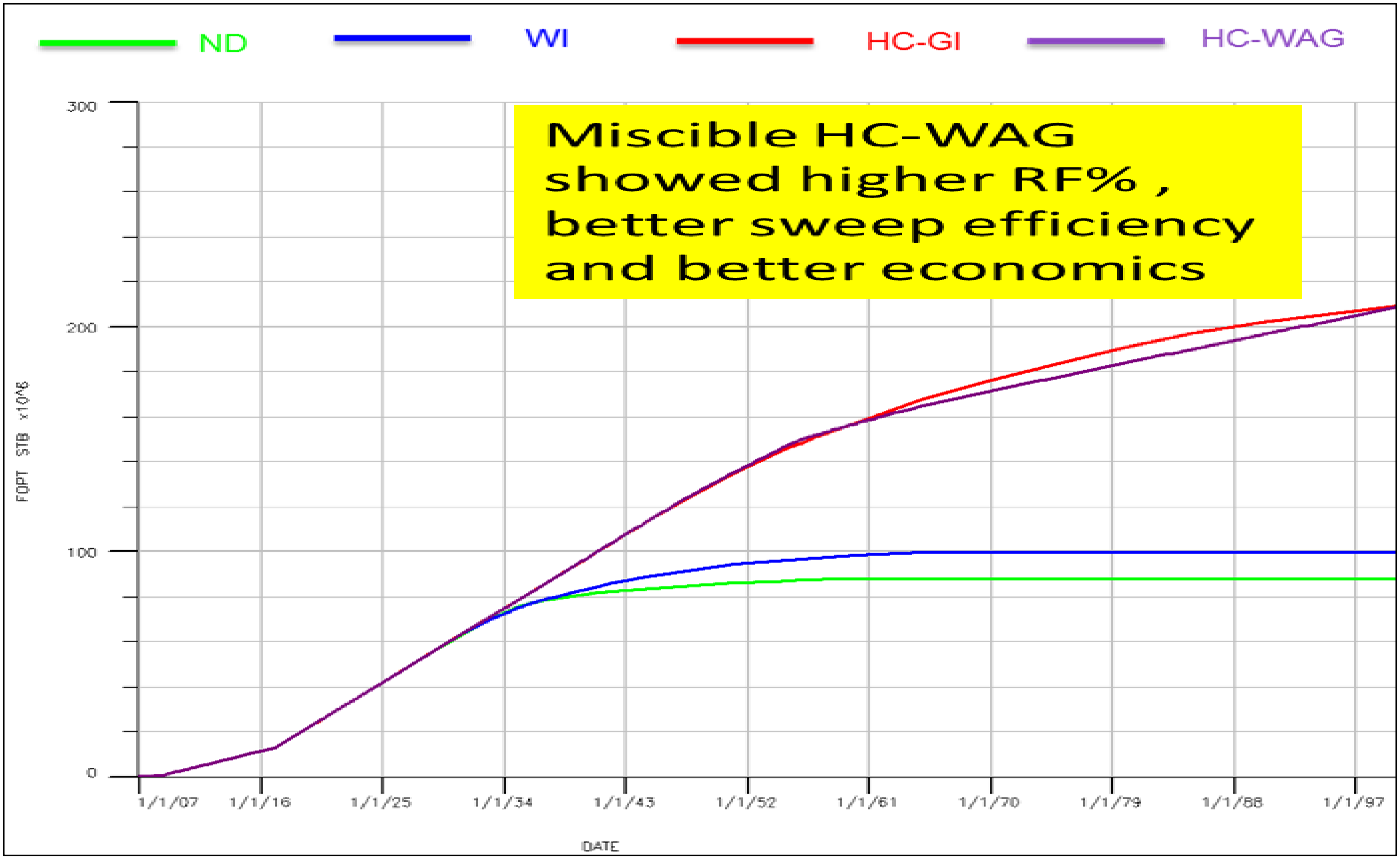

Figure 12. Field production cumulative for different development scenarios.

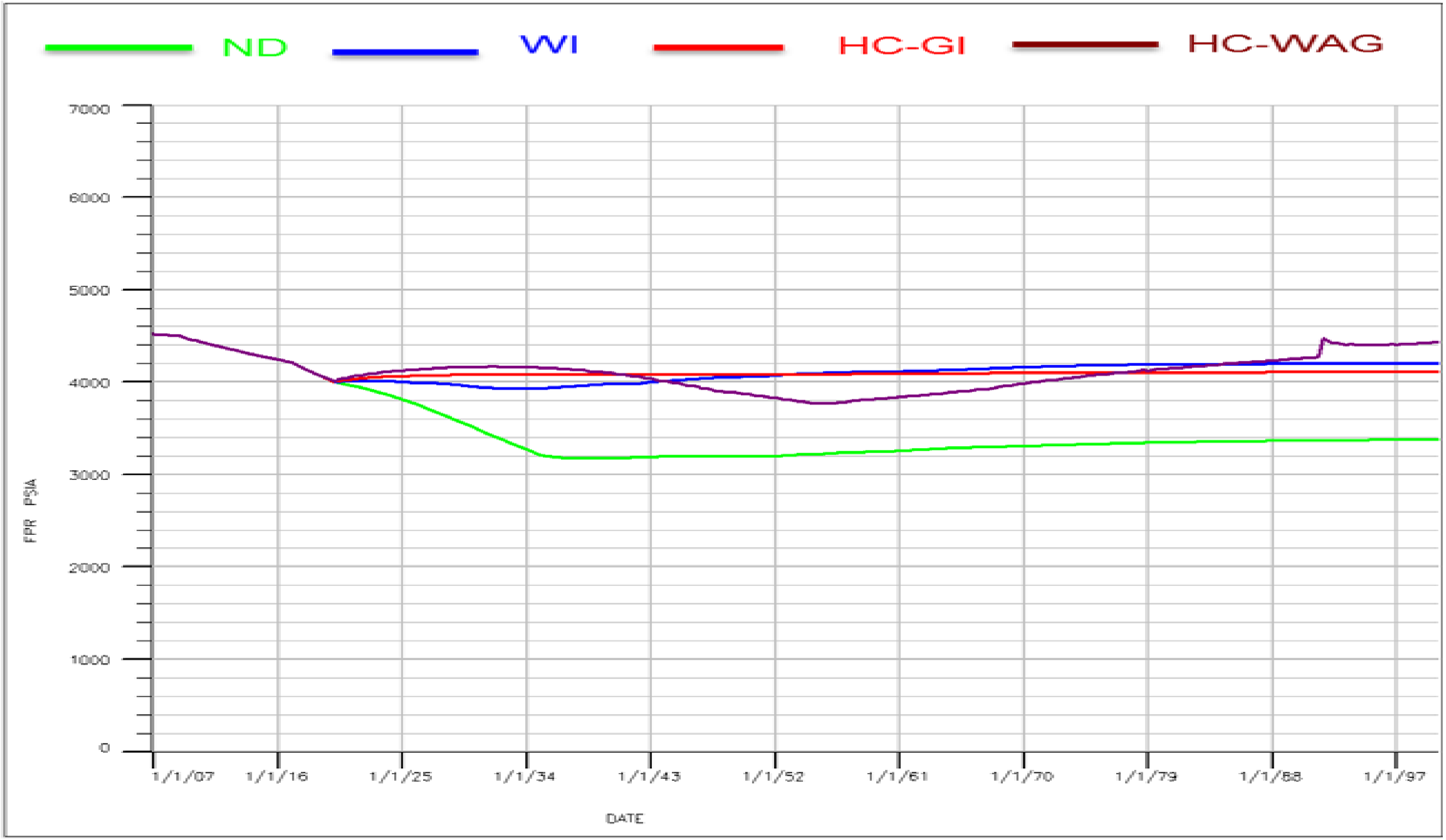

Figure 13. Field pressure profile for different development scenarios.

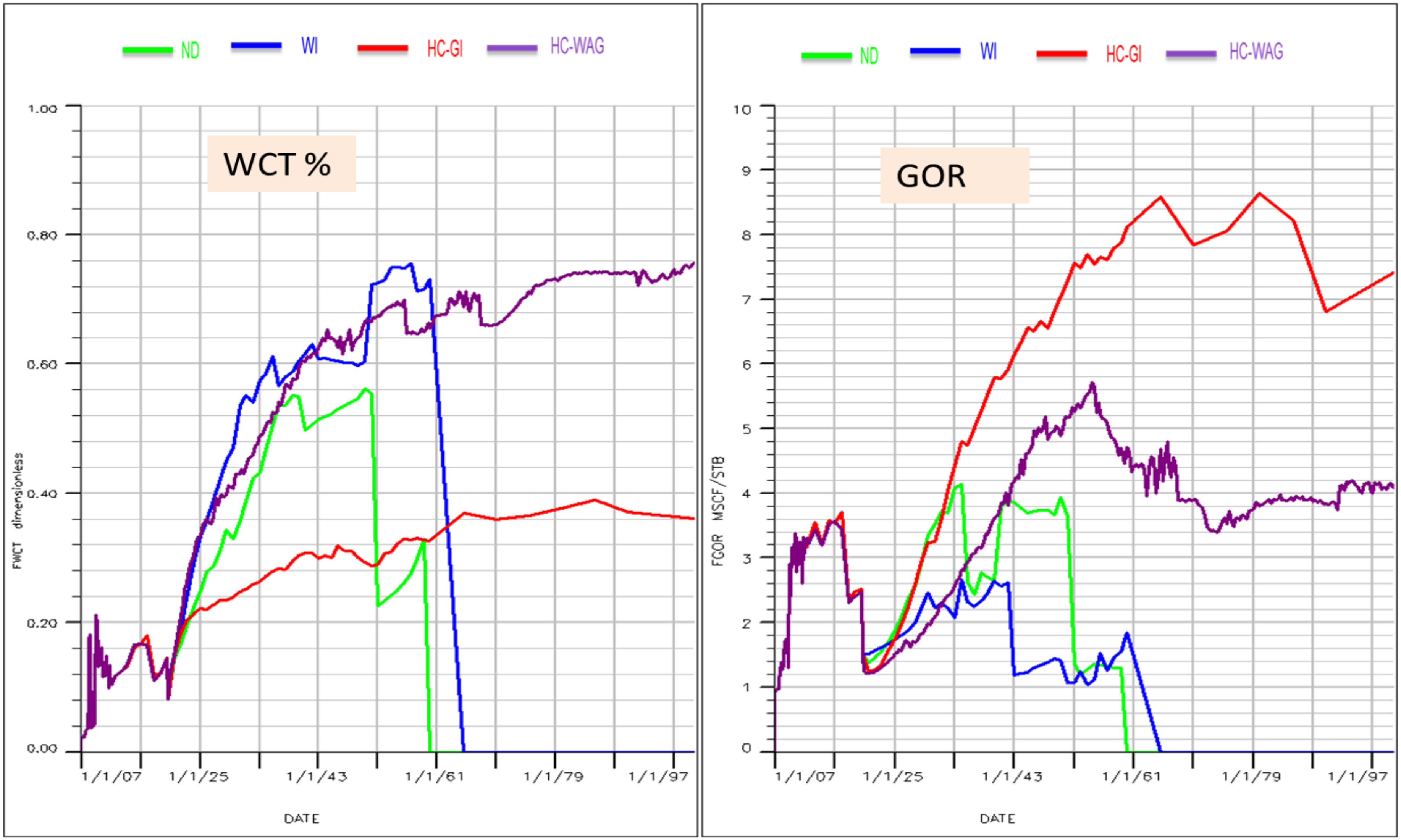

Figure 14. Field water cut and GOR performance.

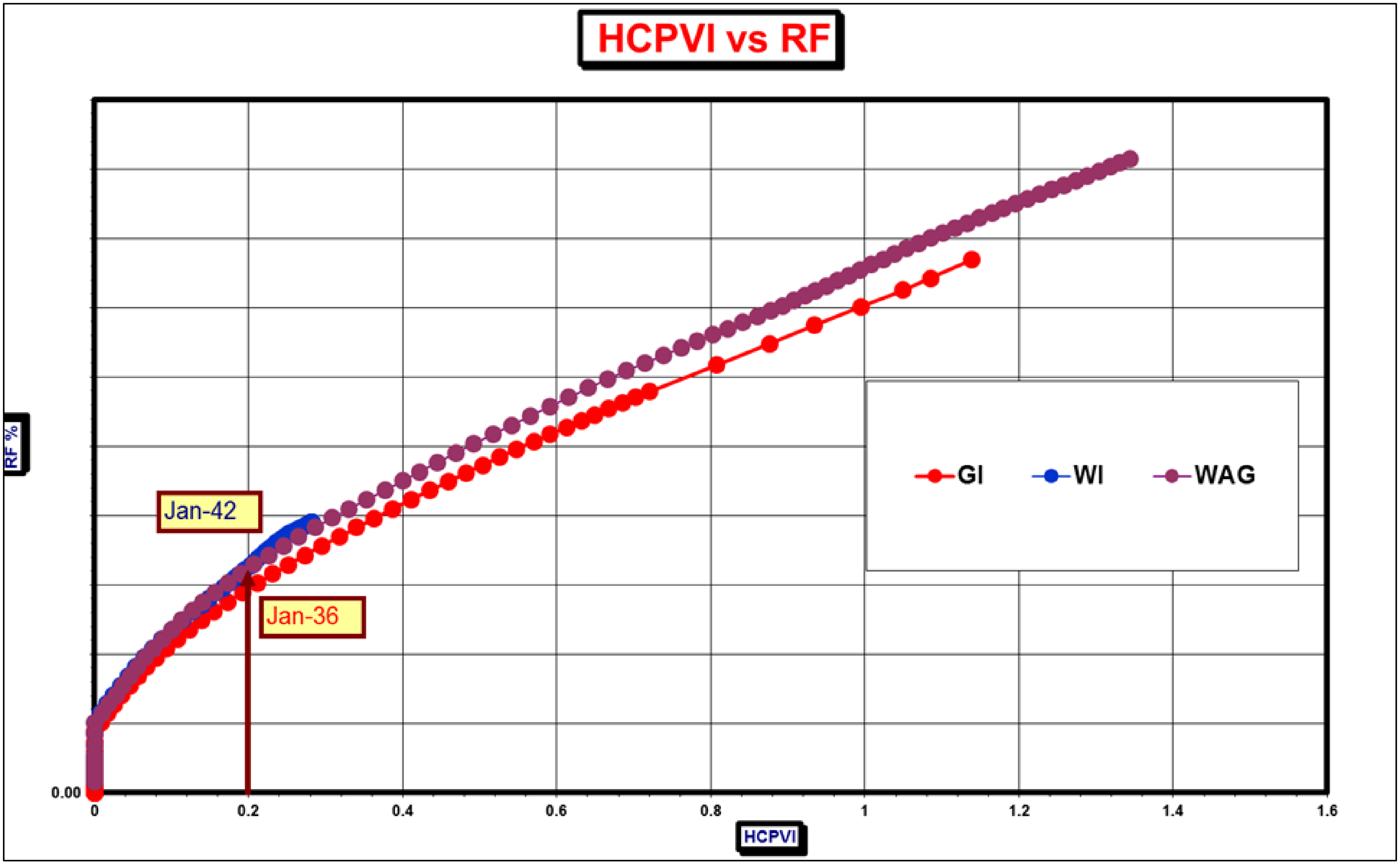

Figure 15. HCPVI vs RF%.

Reservoir fluid lumping scheme
$H_2S+N_2+C_1$
CO_2
C_2 - C_3
C_4 - C_6
C_7 - C_{12}
C_{13} – C_{18}
C_{19} – C_{27}
C_{28} – C_{80}

Table 1. Lumping scheme applied in the developed EOS model

Data Uncertainty		
Areas	**Uncertainty**	**Mitigation**
Structure, Faults and Fractures	**Medium- High**	• Re-process the old seismic. • Image log while drilling. • Seismic characterization study. • 3D seismic acquisition.
PVT	**Low - Medium**	• MDT / BH PVT samples are planned .
SCAL	**Medium- High**	• New cores and SCAL are planned.
Fluid Contacts	**Low- Medium**	• MDT, Sampling and fluid analyzer are planned .
Compartmentalization	**Medium- High**	• Re-process the old seismic. • Image log while drilling. • Seismic characterization study. • MDTs. • 3D seismic acquisition.

Table 2. Uncertainty matrix and mitigation plan.