INTEGRATION OF REAL-TIME AND DYNAMIC SURVEILLANCE DATA IN MANAGING AZERI-CHIRAG-GUNESHLI FIELD

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ABSTRACT

INTEGRATION OF REAL-TIME AND DYNAMIC SURVEILLANCE DATA IN MANAGING AZERI-CHIRAG-GUNESHLI FIELD

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By the evolving application of technology in the oil and gas fields, the volume of gathered information through the dynamic surveillance gets enormous. The importance is lying not only in the regular storage and standalone usage of such a big volume of data but also analyzing and integrating them in the light of alternative sources of data in order to turn the data to valuable field performance information.

It is aimed to investigate role of the real time (bottom hole temperature gauges and distributed temperature sensor) and dynamic surveillance (PBU/PFO, production test results etc.) data in effectively managing ACG field. The case study has been carried out by integrating various sources of surveillance data (well test, DTS, PBU) with flowing bottomhole temperature and pressure in order to show the response of production wells to offset producers as wells as water injection and gas injection wells. It has been observed that the reservoir pressure change impacts on the GOR trend which in turn is reflected on the FBHT by means of Joule-Thomson effect. Analyzed Azeri filed examples shows that the change in FBHT is dependant on the rate of change of the reservoir pressure as well as the gas saturation. Also, there are several Azeri field examples that confirm the observed FBHT and FBHP fluctuations is the informer of the instability in the lift performance as a result of GOR decline.

Along with above study, investigation of correlation between FBHT and measured GOR from an Azeri production well revealed that there exists a flow regime

dependent linear correlation between these parameters. Such a correlation is applied in Azeri wells to predict the ‘real-time’ GOR in the production wells.

ÖZ

GERÇEK-ZAMAN VERİSİ VE DİNAMİK GÖZLEM VERİLERİ ENTEGRASYONU YOLUYLA AZERİ-ÇIRAK-GÜNEŞLİ PETROL SAHASININ İŞLETİLMESİ

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Yeni teknolojılerın petrol ve doğal gaz sahalarındakı uygulamaları sonucunda elde edılen dinamik gözlem verilerinin hacmi de büyük derecede artmaktadır. Bu büyük hacimli verılerın önemi sadece onların düzenlı şekilde kaydedilmesi ve kendi başına kullanılmasında değil, diğer alternatif kaynaklardan elde edilen verilerle birlikte entegre edilerek ıncelenmesi ve verilerin değerli saha performansı bilgilerine dönüştürülmesindedir.

Bu tezde gerçek zaman verileri (kuyu dibi sıcaklık ölçer ve dağılmış sıcaklık sensörleri)ve dinamık gözlem (PBU/PFO, üretim test sonuçları)verilerinin kullanılarak Azeri-Çırak-Güneşli petrol sahasının daha efektıf işletilmesi ele alınmıştır. Kuyudibi basınç ve sıcaklık verilerinin diğer gözlem verileriyle (kuyu testleri, DTS, PBU) entegre edilerek su ve gaz enjeksiyon kuyularıyla beraber yakın mesafede yerleşen diğer üretım kuyularının üretim kuyularına olan etkisinin gösterılmesı amacıyla çalışma yapılmıştır. Rezervuar basıncının GOR üzerinde etkisinin olduğu ve bunun da Joule-Thomson efekti dolayısıyla kuyudibi sıcaklığa yansıması görülmüştür. Analiz edılen Azerı sahasının bilgileri kuyudibi sıcaklıktaki değişimler rezervuar basıncının değişim hızından ve gaz çözünürlüğünden asılı olduğunu gösteriyor. Bundan başka birçok Azerı sahasına ait bilgiler kuyudibi basınç ve sıcaklığındaki dalgalanmaların GOR-ın düşmesi sonucu oluşan kuyunun kaldırma performansındaki düzensizliğin habercisi olduğunu doğrulamaktadır. Yukarıda

gösterilen bulgularla birlikte Azerı üretim kuyularından elde edilen kuyudibi sıcaklık ve ölçülmüş GOR arasında kurulan korrelasyon akış rejiminden asılı olan doğrusal korrelasyonun olduğunu ortaya çıkarmıştır. Bu korrelasyon, Azeri sahası kuyularında uygulanarak ‘gerçek zaman’ GOR tahmin etmek için kullanılmıştır.

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CHAPTER 1

AZERI-CHIRAG-GUNESHLI FIELD OVERVIEW

1.1 Context

The ACG Oil Field is located to the SE of Baku, offshore Azerbaijan in water depths varying between 60 m and 280 m (Figure1.1). The ACG structure consists of three linked parts, which are from west to east Shallow Water Gunashli (not in PSA-operated by SOCAR), Deep Water Gunashli, Chirag and Azeri (in PSA). The ACG Structure covers area of approximately 250 square kilometers and appraisal has been carried out in two stages. The AIOC (Azerbaijan International Operating Company) consortium made up of 10 different oil companies, from 6 different countries agreed the Production Sharing Agreement (PSA) terms with Azerbaijan Government in September, 1994 in order to develop and manage ACG reserves. The PSA term is valid for 30 years, at the end of which the field is going to be given back the Government of Azerbaijan. BP as an operator operates the field on behalf of the shareholders which comprises of the following companies: BP 34.14%, Chevron 10.28%, SOCAR 10%, INPEX 10%, Statoil 8.56%, ExxonMobil 8%, TPAO 6.75%, Devon 5.63%, Itochu 3.92% and Delta Hess 2.72%.

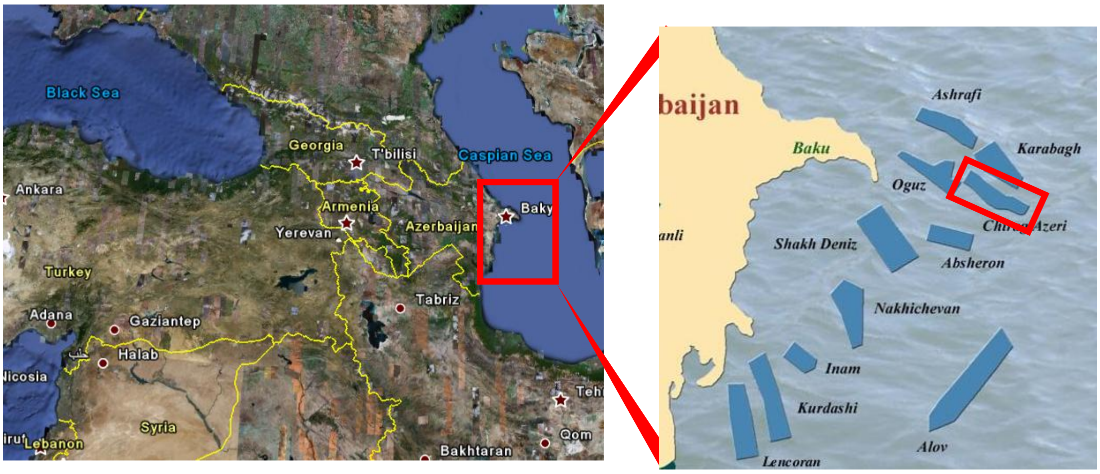

Figure 1. 1 Geographical location of ACG field

1.2 Reservoir Description

The trap, which forms the giant ACG Oil Field, is a NW-SW trending, steeply dipping thrusted anticline. There are several crestal faults within structural closure which are oriented along strike as well as mud volcanoes of varying size. Such variations further complicate the straight forward structural geometry.

Hydrocarbons are found within several different stratigraphic intervals within the Pliocene, the most important reservoirs occur in the Pereriv and overlying Balakhany Formations. The extensive oil column that characterizes the field is the outcome of high structural relief combined with excellent top and lateral seals, for instance 900 m on the North Azeri and 580 m on the South flank of the Chirag.

Differing pressure regimes combined with effective seals may be responsible for the North-South changes in oil contacts greater than 300m (Figure 1.3)
At the main Pereriv reservoir level, the ACG Field is about 50km in length and nearly 5 km in width.

Hydrocarbons are thought to have sourced and migrated from Late Pliocene to Early Pliocene aged Maykop lacustrine shale buried in the deep and rapidly subsiding South Caspian Basin to the South of ACG. The forming of ACG structure occurred in the Late Pliocene in response to compression associated with the formation of the Alpine/Himalayan mountain belts to the South. Release of overpressure from deeply buried shale exploited lines of weakness associated with the inversion and faulting forming the numerous mud volcanoes some of which are still active today.

1.3 Stratigraphy and Reservoir Development

The main formation in ACG reservoir is called Pereriv Formation and it is sub-divided into 5 units, A to E. The most significant producing intervals are the Pereriv B and D sands. Secondary reservoirs are found both beneath (NKP, PK, Kalinsk) and above (Balakhany, Sabunchi, Surakhany) the Pereriv Formation. Balakhany VIII and X being the most significant, the Balakhany Formation is subdivided from V through X (Figure 1.2). The main ACG reservoirs were deposited in a range of environments associated with a large river-dominated lacustrine delta. A dominant palaeoflow direction of NNW to SSE has been interpreted (160°). Pereriv reservoirs are laterally extensive and vary little in thickness reflecting sand-rich depositional systems and low relief palaeo-topography. Due to laterally persistent lacustrine shales Pereriv separated into five separate reservoirs and record the interplay between lacustrine expansion across a low-relief floodplain and fluvial deposition. The Pereriv and Balakhany sediments record sand-prone and shale-prone stacking patterns associated with alternation between more proximal and distal environments of deposition. Delta plain facies have better connectivity than delta front facies and are more sand-rich. The cyclicity records delta advance and retreat related to climate changes in the palaeo-Volga system producing variations in lake level.

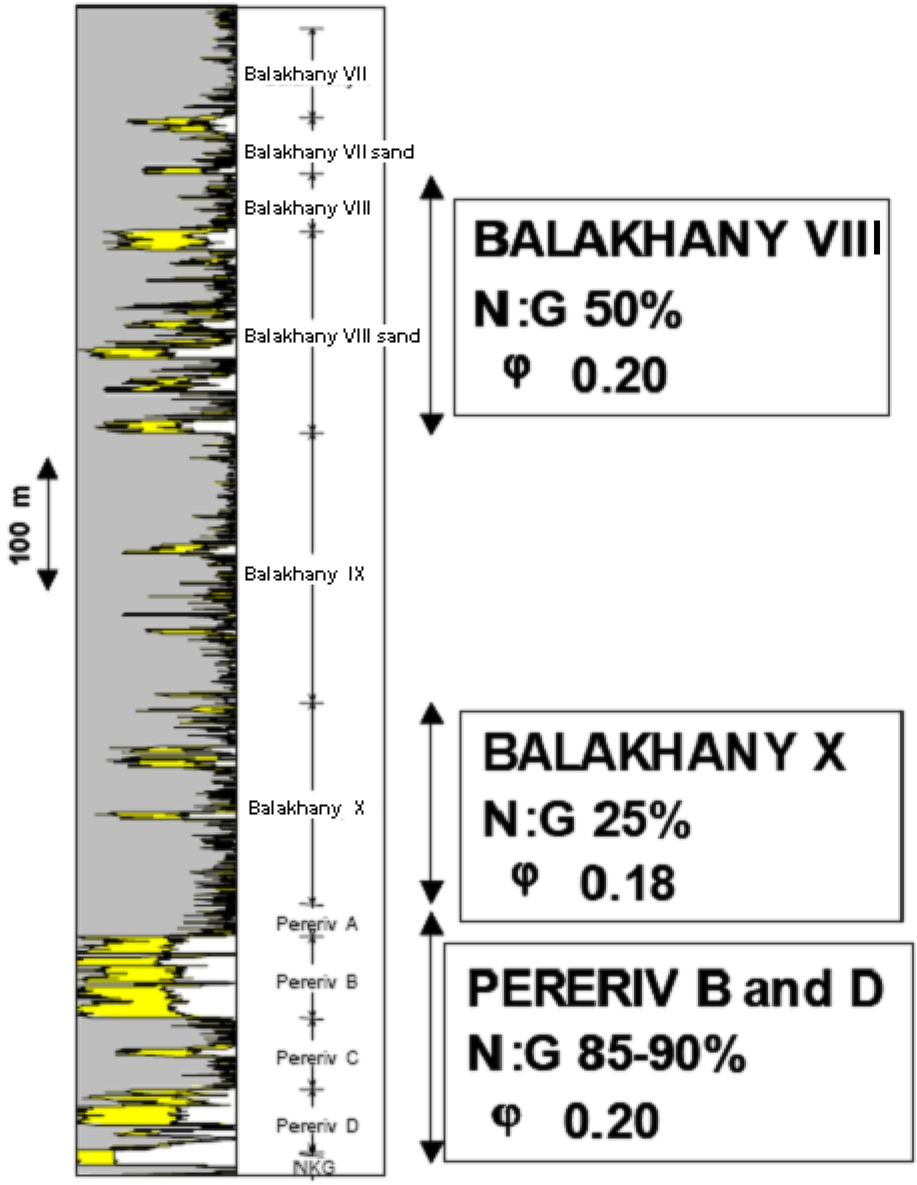

Figure 1. 2 Typical Stratigraphic view of ACG productive intervals

Reservoir quality is controlled by maximum depth of burial and facies (ductile content and grain size). Although grain sizes are dominantly fine-grained, the overall reservoir quality is good to excellent due to excellent sorting (absence of interpartical shale) and the absence of pervasive authigenic cements in the main reservoirs. For the Pereriv B and D average net to gross ranges from 0.80 to 0.95 while other reservoirs in the Pereriv and Balakhany are more variable averaging 0.12 to 0.50.

Average porosity ranges for the Pereriv B and D as well as the Balakhany VII and VIII are 0.19 to 0.22 while other reservoirs in the Pereriv and Balakhany range from 0.16 to 0.18. Average permeabilities for the Pereriv B range from 50mD - 500mD in the Chirag and Azeri Fields. There is a decrease in permeability from West Chirag to East Chirag towards the large field-bounding mud volcano. The Pereriv D reservoir has slightly lower average permeability than the overlying Pereriv B. Also, there is increasing trend of kh from West to Central and decreasing trend from Central to East Azeri.

1.4 Fluids and Fluid Distribution across the Field

Ten appraisal wells have been tested in ACG but only three have reasonable pressure build-up data. These three tests cover the Balakhany X, Pereriv B and Pereriv D reservoirs. The Chirag, Azeri and Guneshli platform wells have been production or injection tested.

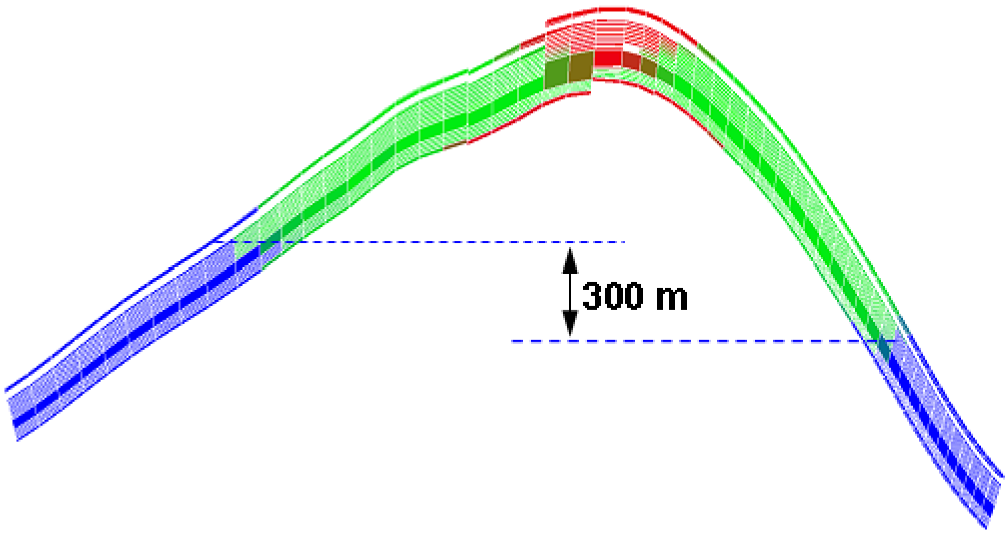

Figure 1. 3 View of fluid contacts of ACG structure

Fluid samples are available from Chirag platform wells, but elsewhere on the ACG structure representative fluid properties have only been taken in a few wells from the Balakhany X, Pereriv B and Pereriv D intervals. ACG appraisal wells GCA-1 and GCA-2 have DST data that were used to derive GORs of between 700 scf/bbl and 900 for the Balakhany X and Pereriv reservoirs. Crude oils from these reservoirs have moderate APIs, varying from 32^o to 36^o that generally increase from west to east, low sulphur, and low to moderate wax content (up to 8.5%wt in Chirag, 16%wt in Azeri). Shallower reservoirs in Chirag, for example the Balakhany VIII and VII, have suffered biodegradation leading to a reduction in API to 25 to 26 and have higher viscosities, higher sulphur and lower wax than the underlying reservoir intervals. Significant concentrations of H_2S have been found in the Pereriv D and E in the Azeri Field in association with sulphate reduction close to oil-water contacts.

Fluid contacts are defined partially by well data and partially on 3D seismic. Contacts vary between stratigraphic intervals and between fault-bounded segments. Mud volcanoes that puncture the crest of the structure also provide vertical and lateral barriers. Upper Balakhany reservoirs are generally filled with gas.

From the Balakhany VI through the Pereriv, reservoirs are oil-filled and some of the Balakhany reservoirs have extensive gas caps (Fıgure 1.3). Aquifers extending down-flank the Chirag Pereriv hydrocarbon column have provided excellent pressure support.

1.5 Existing Development

Current production in ACG is from the all three sections of this mega structure (Figure 1.4), namely, Azeri, Chirag and Deepwater Gunashli. The cumulative production to date is some 1100 MMstb. The production commenced in late 1997 with Chirag and joined by Azeri in 2005 and DWG in 2008. Presently, the production is in excess of 800 Mb/d from 54 producers. The field is being developed under both water and in gas flood. Water flood is applied in all three sections of the field, whereas gas flood is applied only in Central part of Azeri. Water flood, which commenced in mid 2000, is being carried out with 18 wells at a combined rate of 30 Mb/d. Reservoir pressure has fallen by some 1000 psi from initial conditions and is now approximately 500 psi below the bubble point. The field GOR is currently around 1110 scf/stb, some 40 % above solution GOR. Sand production is a challenge in ACG, triggered by water crossflow in the injectors and water production in the several producers to have cut water. The primary sand control completion type in ACG wells is openhole gravel pack completion. Nevertheless, expandable sand screen cased and perforated and stand alone sand screen technology is deployed in several wells across the ACG. In ACG except early wells of Chirag all of the wells are equipped with bottom-hole pressure/temperature gauges and in selective number of wells in Azeri and DWG wells distributed temperature survey (DTS) equipment has been installed.

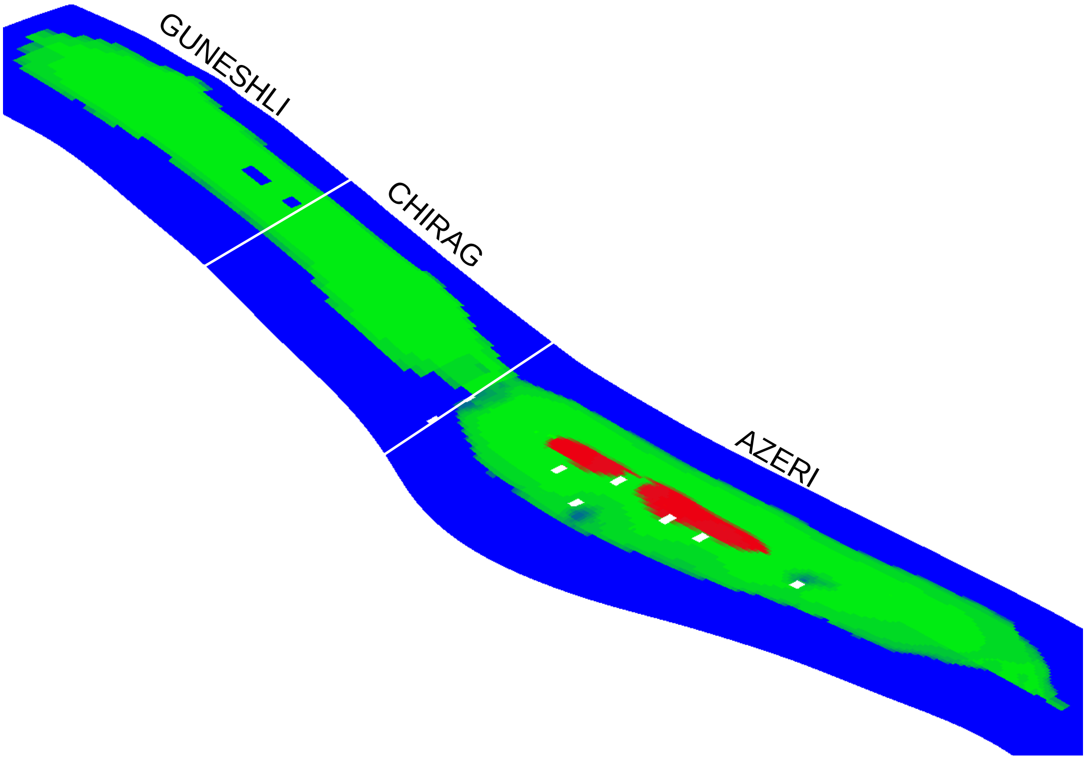

Figure 1. 4 Illustrative Map of ACG Field

RFT pressure data indicates that all parts of the reservoir so far contacted have experienced some level of depletion, i.e. there are no fully sealing compartments. There is evidence; however that pressure differences exist between groups of wells, suggesting the presence of extensive baffles within the reservoir.

CHAPTER 2

INTRODUCTION

Reservoir management is one of the key processes in delivering and addressing the differences among observed in the process of exploiting the reservoir to the depletion plan. The reservoir management process is the recurring process in which a field operator uses the learning and expertise to optimize the reservoir profitability or objectives such as optimizing oil or gas production, maximize recovery, minimize capital expenditures as well as operating costs. Historically, reservoir management used to be identified with production engineering and then became synonymous with numerical reservoir simulation. It is now understood that reservoir management is an iterative process, of which reservoir simulation and production engineering are only two components [8].

Project economics, being one of the key areas in proceeding the projects to execution, usually is hugely dependent on the reservoir properties uncertainty, rock quality and connectivity of the reservoir as well as the risks associated with application of new technologies at the early stage of the project implementation. The solid knowledge about all these concepts however, is obtainable only in the process of development and production through the field life.

In the recent few years the companies started to more focusing on concepts like risk and uncertainty management, the cost management and along with these concepts production optimization is one of the emerging processes. In order to preserve or maintain the value of the project as opposed to observed surprises, it is essential to manage the assets effectively or more importantly to maximize the recovery from available well stock. Close focus on production or injection optimization in the light of information obtained through well as well as reservoir behavior is one of the processes that helps to not only maximize daily production but also creates basis for increasing ultimate recovery.

Another step change in ‘listening to reservoir’ is made by deployment of the new technology such as permanent bottom-hole pressure or temperature gauges, distributed temperature sensing, real-time data to desktop facilities, downhole flow control and similar technologies. Although implementation of such technologies requires serious investments standalone, the value or information that they provide in return could be incomparable in adopting the critical decisions. Real –time data monitoring enabling the reservoir or production engineer to respond well behavior changes rapidly and in timely manner and tweak the choke changes accordingly.

In order to successfully implement and make maximum use of the real-time data it is also important to establish proper database to access any data at any point in the field life. In other words, so that the stored information could be turned into information which could be used from history matching to updating the depletion plan as well as from optimization of production or injection to optimization of new well locations.

In this study, by means of using the data gathered from application of above mentioned technology in ACG field, the value of the using these data in managing the Azeri field is shown. The installation of the permanent bottomhole pressure and temperature gauges in ACG is a standard practice. Therefore, application of the data analysis methods mentioned in this study is applicable across the entire ACG field.

CHAPTER 3

LITERATURE SURVEY

Together with the improvement of technology these gauges has been developed over the years since their first installations. The present technology improvements for pressure and temperature bottom-hole measurements in relation with resolution, accuracy and reliability have modified the monitoring data acquisition from traditionally less frequent data gathering to continuous data monitoring. Enhancements in data gathering frequency suggested capturing monitored and interpreted data in reservoir management process. This, in turn contributed into better reservoir understanding of a field and plan further surveillance activities in the process of updating the depletion plan. The use of bottom-hole pressure data in the industry was widely known and successfully applied from pressure transient analysis to production management and optimization processes world-wide. Whereas, nearly equally valuable analysis of temperature data most of the time is ignored and not interpreted sufficiently.

Since the beginning of the deployment of new technologies many authors have studied and interpreted the information provided from various sources. Besides, new methods of analysis is developed and used across the industry for effectively managing the reservoir.

Jones, C [2] showed that in the transient tests that were carried out, increase in bottom-hole temperature observed. The log-log diagnostic plots with change in pressure and/or temperature and time function of derivative was plotted. The three examples from field were presented which analyzed both pressure and temperature transient data. The similarities were sought between these data and it is aimed to understand the variation cause of the in temperature in the wellbore during a buildup. The conclusion was reached from the study showed that in shut-in period, the wellbore temperature declines in similar fashion to pressure fall-off trend hence it can be analyzed using pressure transient test analysis techniques. The temperature falloff may exhibit similar features as it is seen on the pressure buildup test, while the line of constant enthalpy is straight and effects due to radial diffusivity are small. Oberwinkler et al. [4] stressed the importance of the Real Time data and provided an insight to how real-time data could be useful in various ways from reservoir management to production optimization. The methods for measurement, data cleansing, aggregation and integration mentioned as suggested steps to follow in order to handle the 'real-time' data. The automation of data processing and model execution is proposed in order to be able to benefit from full potential of digital field. Stressed the importance of 24/7 data flow from field to desktop. It is also highlighted that the higher frequency data, provide the better quality reservoir surveillance and real-time optimization.

In the study that carried on by Oliveira et al [9], the incorporation of the data obtained from downhole gauges to reservoir management process has been exhibited. In this work the reservoir characterization is carried out based on the reservoirs that are exploited. Also, history match for certain wells were performed in order to reflect the observed reservoir complexities. The results from this study reflected that the data obtained from downhole gauge data is reliable. Furthermore, since their implementation the decision making in reservoir management, completion and production has become easier and faster in field development implementation.

Although the data is usually reliable and accurate from downhole gauges, but there are some precautions that needs to be taken during the installation in the well from acquiring the accurate data points standpoints. Izgec et. al. [1] investigated the placement related issues of permanent downhole gauges and their possible impacts on the surveillance data. The paper provided by authors stresses the possible inaccuracies that may arise due to the location of downhole gauge in well/formation parameters, which obtained through downhole gauges. In the study both oil and gas flow problems were analyzed in order to come up with simple design tools for reasonable gauge depth. Model validation in difficult deepwater environment is used to exhibit the factors that impact on gauge measured data versus the simulated results. Also, improvement to the analytic fluid-temperature model (by Hasan et al, 2005) has been shown. From the obtained field results it is concluded that the key factor for gathering accurate gauge data is the location of the gauge. The further it is to the perforations the more distorted becomes the data. The major effect on data distortion comes from thermal effects and its error greater in semi-log slope of pressure build-up test than in drawdown test. Some correlations are proposed to be used as guidance in placing the downhole gauges in specific reservoir. Although the usage of the permanent downhole gauge data has been studied in many ways, the usage of temperature data in interference between wells has been little studied. The paper by Kuramshina et. al. [6] shows how bottom-hole temperature is used to diagnose the inter-well communication and reservoir properties. The value of the real-time high-frequency bottom-hole temperature data is stressed. It is concluded in the paper that downhole temperature responds to the impact of pressure changes; by Joule-Thomson effect the change in GOR is felt in bottom-hole temperature by detectable change. Besides responding to direction of voidage changes, bottom-hole temperature trends are sensitive to change in bottomhole pressure due to interference between producers as well as injectors. Another paper by Pinzon et. al. [7] high-lights the abilities of DTS (Distributed Temperature Sensing) in the oil industry with particular examples from ACG field. It describes the ways the DTS is installed and shows the data as wells as results obtained where reservoir with different properties are commingled. Besides, example of monitoring gas breakthrough for high GOR wells has been shown. It is also mentioned the possibility of monitoring water breakthrough.

3.1 Converting data into information

The data is gathered and subjected to quality control. When clean and aggregated data are available, the next step is to answer how this data could be utilized in various applications? There needs to be a common platform at which different frequency data could be integrated. In addition to real-time data, other types of data are available to the engineer in various databases. To handle the data gathering frequency issue among real-time and other surveillance data, the common surveillance database needs to be designed in such a way that the time gap could be covered. After bringing all these surveillance data into common platform, an engineer could turn these data into meaningful information.

In order to bring allocated production and injection data to same platform with higher-frequency real-time bottomhole pressure and temperature data EXCEL spreadsheet was generated and plots of each data type was made for the selectively chosen wells. The stacked plots of various frequency data with common time axis were prepared. Other data such as production logging, reservoir pressure and distributed temperature sensing plots are made in different graphs with the key events highlighted on them.

3.2 Real-time data measuring tools

As development and deployment of new technology in ‘field of the future’ projects became popular then gathering, analyzing and storing the field-related data started to gain more and more importance. Before, if a well had couple of pressure transient analysis back in 70s, nowadays thanks to installation of pressure and temperature bottom-hole gauges the reservoir parameters such as reservoir pressure; permeability-thickness and skin factor could be calculated at every opportunity when the well was shut in. In the past, in order to see the instantaneous flowing wellhead pressure, annulus pressures as well as matching fluid flow correlations properly, more efforts were required getting those data from the field. Nowadays, with the introduction of D2D (data to desktop) projects, engineers’ and operators’ time was saved in a great extent and timely interventions as a result of spotting possible issues or problems in the individual wells and adopting fast decisions related to such issues. Also, it is noteworthy to mention effectiveness of reservoir management by employing the tools such as ProcessNet (Figure 3.1), which is a web based tool provides bottom-hole pressure/temperature gauge data, choke sizes, wellhead pressure/temperature as well as help to monitor annulus pressures, which notifies the engineer with alerts that has been put on certain parameters in order to make it easy to choose where to look for a specific issue, and using distributed temperature sensing (DTS). Such tools provide important surveillance input to the reservoir management process which in turn results in prompt responses to long-term reservoir management plan.

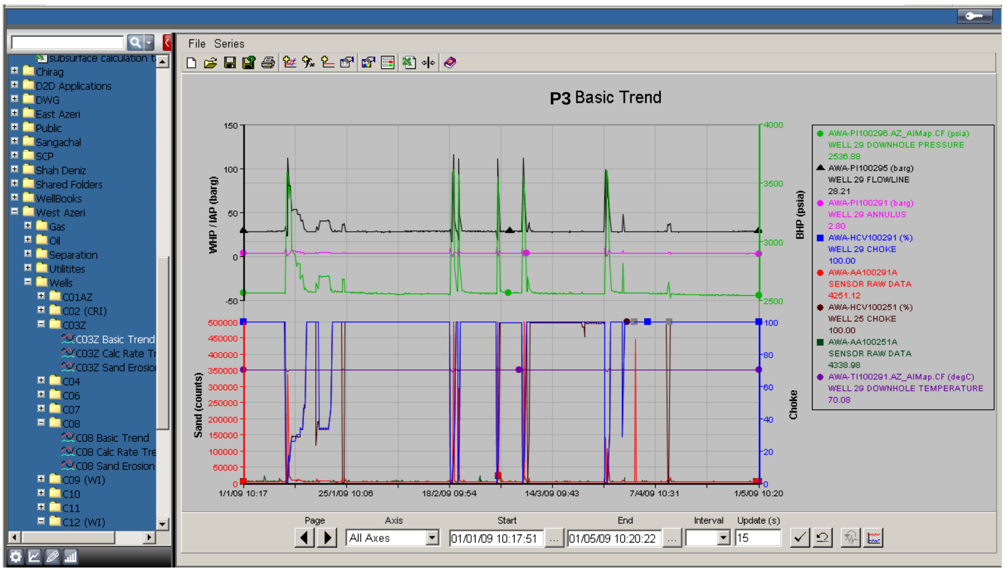

Figure 3. 1. An example of ProcessNet Display

3.2.1 Bottom-hole Pressure and Temperature Gauges (BHPTG)

With the evolvement of technology in petroleum industry, bottom-hole pressure/temperature gauges started to be recognized as one of the important components of 'future' wells. Being widely deployed in 'smart' wells, these gauges provide instantaneous data flow from the well to off-site engineer desks and are one of the key elements in passing decision from production optimization to wellwork.

Till recent times one of two outputs of these gauges, pressure data are widely used in determination of reservoir pressure, properties, inter-well interference existence, matching well performance etc. Whereas, lack of attention to temperature readings left this parameter not sufficiently used in estimation of similar processes.

The various analyses that have been performed looks at how temperature data can assist with establishing temperature profiles in the wellbore or near-wellbore region rather than studying the reservoir as a whole. The result is that temperature has not been used to provide information about reservoir properties. Further encouragement in looking at FBHT is in the fact that recent work done by Hutchinson et al. (2007) in the Chirag field in Azerbaijan led to positive results with FBHT showing some signs that it may be able to indicate reservoir behavior and this acts as a precursor to this study.

This work shows that FBHT data is sensitive to inter-well communication with interference delay times being indicative of reservoir properties such as permeability or detection of barriers to flow. The FBHT data can also highlight if a voidage change occurs from a location that is up-dip or down-dip of a producer, as increased pressure support from down-dip causes FBHT to increase whereas up-dip support of a producer (or support from the opposite flank) causes a reduction in FBHT. To explain these observations, it is proposed that FBHT responds to the impact of pressure changes in the reservoir, primarily through a change in producing GOR. This change is a function of the fluid properties, the reservoir pressure and temperature the speed that the pressure change is transmitted through the reservoir, the drainage area of the well, and the rates at which the producers produce. The effect is magnified when dealing with a steeply dipping field such as the Azeri field which results in gradients with depth for gas saturation, solution GOR and temperature. It is also amplified when the flowing bottom-hole pressure (FBHP) is below the bubble point, which is the case for the wells in Azeri.

When this is case as in Azeri, a well's FBHT will increase when down-dip pressure support is increased as the well's drainage area is skewed towards to the pressure support and hence to lower gas saturations, lower solution GOR and higher temperatures. On the other hand, if updip pressure support is introduced, the drainage area of the well is skewed toward higher gas saturations, higher solution GOR and lower temperature. The change in bottom-hole temperature is characterized by thermal properties of the reservoir, Joule-Thomson rule as well as the geothermal temperature gradient. The Joule-Thomson rule explains the temperature change by the change in the pressure depending on the composition of the fluid.

3.2.2 Distributed Temperature Sensing (DTS)

By introduction of smart wells, based on the temperature logs theory the use of distributed temperature sensors (DTS) has become increasingly common for monitoring producing sections of wells through the real-time measurement of temperature profiles. The DTS technology allows complete wellbore temperature profiles to be obtained in a short period of time without the need for any additional operational challenge or running logging tools. The information gained can potentially be inverted to infer the types and amounts of fluid entering along the wellbore (Brown et al., 2006). As more wells are being completed to produce commingled reservoirs, better methods are needed to determine zonal flow contributions and breakthrough location of unwanted fluids in order to optimize recovery and drive down production costs. Additionally, production optimization requires the constant monitoring of each layer's production performance in order to design and plan prevention and remedial actions. DTS allows for this real-time data acquisition (Johnson et al., 2006). The temperature gauge resolution is in the order of 0.001°C with a 0.16°C per year drift quoted by the manufacturer (Schlumberger, 2007).

These tools allow rapid reaction in the case of gas or water breakthrough by allowing a quick shutting in of the control valve of a lateral as well as improving the control and production measurements by not forcing engineers to wait for production tests to identify problems in the well. These intelligent completions will also maximize ultimate recovery, minimize operating expenditures by reducing the number of visits from the operator to the field, reduce well intervention costs, and accelerate production by increasing the contact area between the wellbore and the reservoir. A model of temperature behavior will help operators to understand and utilize intelligent completion more efficiently.

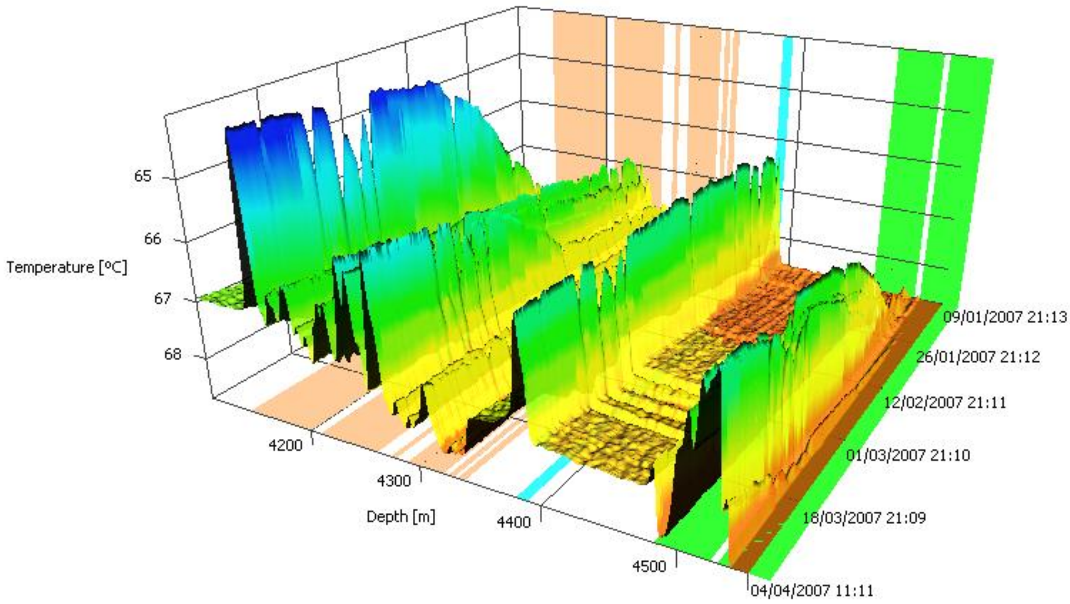

Figure 3. 2. An example from Distributed Temperature Sensing visualization

3.3 Dynamic data gathering

The lower frequency data such as production and injection allocation, production logging, as well as pressure transient analysis data are main sources of information used in integrating the dynamic to real-time data. The production and injection allocation data are obtained from the database called Business Objects, which is a web based tool that is created to handle the all of ACG data from production tests to allocated data. However, the pressure transient and production or injection logging data are located in two different databases. The preliminary work involved gathering a large amount of data and compiling it into single spreadsheet. The data which encompassed producing GOR and oil and gas rates were measured over time were all placed in various databases, so the task of bringing this information into one comprehensive spreadsheet was made more difficult.

3.3.1 Production and Injection Data

Being one of the essential parts of the surveillance program, production tests provide vital information about the performance of the well as well as the reservoir performance of the particular area of the field. By conducting production tests it is possible to determine oil, gas, water production rates, wellhead, bottomhole pressures for the specific period directly also GOR and watercut indirectly. Although it might not always be feasible to conduct tests frequently, as it causes production losses due to diverting the well to test separator, it is accepted to test wells periodically. In ACG every well is expected to be tested at least once a month. Based on the production test results well models are generated and performance of the well is predicted based on the performance curves. Performance curves help to allocate the produced oil gas or water volumes to certain wells or platforms.

3.3.2 Production Logging Tools

In the fields where there exists more than one productive layer, if there is no major handicap, it is preferred to complete the well across the multiple layers. In this case it is important to allocate the right volumes recovered from each layers in order to track the volumes committed at sanction stage. Such allocations could be performed based on the permeability-thickness value that is determined from open-hole logs. Along with open-hole logs which are conducted at pre-production period of the well, it is vital to perform production logging during the production period of the well in order to be able to identify the production or injection contributions from or to each layer.

3.3.3 Pressure Transient Analysis

Installation of bottom-hole pressure/temperature gauges in the wells sometimes considered as additional money spent to the well cost. Especially in the increased cost of wells, this might sound non-attractive option to the operator to install permanent bottom-hole pressure gauge in every well. Often installation of such gauges is even more advantageous in offshore fields when rig costs, delay of drilling operations or access to the well taken into consideration.

But when it comes to gathering critical information on well performance the use of such tools is an asset to both, the company and engineer. The reason for this are being able to surveying the well through its life without needing to shut-in the well and loose production for key parameters such as reservoir pressure measurements, identifying reservoir parameters like permeability-thickness, skin or confirming certain baffling around the well. All of the above stated learnings are mainly provided by means of conducting pressure transient analysis in the wells. Having permanent bottom-hole pressure gauge installed in the well provide the continuous pressure reading from the well and if the facilities are installed in such a way that these readings transferred to desktop of engineers then conducting opportunistic pressure transient analysis is the way often chosen by the engineers as long as there is no immediate urgency for certain reservoir parameters. When it is said opportunistic it means that pressure transient analysis interpretations are conducted whenever the well shuts-in due to platform or well shut-down due to this or that reason.

CHAPTER 4

STATEMENT OF THE PROBLEM

Along with installation of permanent downhole gauges in recent years, the usage of the data acquired from such gauges and integration with various surveillance data plays one of the key roles in understanding the overall field performance. In previous years, authors used to analyze the acquired permanent downhole gauge data standalone for various reasons such as pressure transient analysis [2], inter-well interference [6], as well as in history matching for purpose of matching flowing bottomhole pressures. Equally valuable flowing bottomhole temperature has been underestimated or often ignored for different reasons. With the evolvement of technology application in wider field level, the vast amount of data became available which in turn created more opportunity to better understand the field performance by integrating diverse source of surveillance data. Therefore, in this study, surveillance data from various sources has been gathered and responses of permanent downhole data has been analyzed from well interference point of view with further accent on flowing bottomhole temperature with distributed temperature sensing where available. Based on the information acquired as a result of analysis of integrated data from these sources, further steps on managing the reservoir and optimizing the production is taken.

CHAPTER 5

METHODOLOGY

The methodology that is used in this study consists of several parts such as raw data gathering, data quality control, plotting the cleansed data and interpreting the stacked plots of various source data. As a first step, permanent downhole data downloaded from web-based database ProcessNet, production and injection allocation data as well as production test data is acquired from another database called Business Objects. Afterwards, data quality control has been performed to check the consistency of the data points. Apart from real-time data, interpreted pressure transient analysis data is gathered in the separate excel file and plotted against time with overlay of injection profiles of the wells existing in analysed sector.

All the obtained real-time data collected in excel spreadsheet for visualization in separate plots. For easier visualization and representation of the data point of view it is preferred to plot the data in separate stacked plots. Every stacked plot included the producer flowing bottom-hole pressure and temperature, allocation oil rate and GOR, overlaid production test oil rate and GOR plot versus time as well as offset injection profiles.

Also, by using the real-time flowing bottom-hole temperature it is tried to establish correlation between flowing bottom-hole temperature and production test GOR in order to predict the future GOR performance of the well. The main changes at reservoir level due to temperature changes are explained by Joule Thomson effects.

Joule-Thomson Effect

The production or injection that occurs during the development phase of the field management results in changes in pressure, volume and temperature in the reservoir and their subsequent impact on the phases exist in the reservoir. Understanding the reasons of such changes on local basis and extending this understanding to field level play a crucial role in overall management of field.

In this study, real-time and dynamic surveillance data analyzed from reservoir performance and management point of view. Considering that the majority of the real-time data consists of flowing bottomhole and temperature data, then one of methods to explain the changes in real-time data and their reflection on dynamic data possibly could be better explained by the Joule-Thomson expansion rule.

As it is stated in the literature, Joule-Thomson effect is the change in the temperature of a fluid due to expansion or compression of the fluid in a flow process involving no heat transfer or work (constant enthalpy). This change is due to a combination of the effects of fluid compressibility and viscous dissipation. The Joule-Thomson effect due to the expansion of oil in a reservoir or wellbore results in the heating of the fluid because of the value of the Joule-Thomson coefficient of oil - it is negative for oil. The coefficient has a positive value for real gases and the consequent cooling effect is more prominent in gases.

Theoretically, the Joule-Thomson coefficient for ideal gases is zero implying that the temperature of ideal gases would not change due to a pressure change if the system is held at constant enthalpy. Combined with other factors, on expansion of the fluid and subsequently flow of liquid oil and/or water out of the reservoir, the wellbore and near wellbore areas in the reservoir become heated above the normal static reservoir temperature. By convection, diffusion and further generation of heat energy due to these effects, a non-uniform temperature is created, which spreads into the reservoir.

Conversely, during no-flow conditions (shut-ins), the regions already heated lose heat to the surrounding formation through diffusion and result in a temperature decline at a rate determined by the thermal diffusivity of the medium [11].

The coefficient of the Joule-Thomson effect is important in the liquefaction of gases because it tells whether a gas cools or heats on expansion. It turns out that this coefficient is a decreasing function of temperature and it passes through zero at the Joule-Thomson inversion temperature, TI. in an expansion $dP < 0$. Whether dT is positive or negative depends on the sign of μ_{JT}. Looking at the definition of μJT,

$$\mu_{\mathrm{JT}} = \left(\frac{\partial T}{\partial p}\right)_H,$$

it is seen that if μ_{JT} is positive then dT is negative upon expansion so that the gas cools. On the other hand, if μ_{JT} is negative, then dT is positive so that the gas warms upon expansion. [15]

CHAPTER 6

RESULTS AND CONCLUSION

17 selective well real-time and dynamic well data has been collected and analyzed. Of these 17 wells, 12 were active producers, 4 were water injectors and 1 was a gas injector. The collected data mainly consist of flowing bottom-hole temperature, flowing bottom-hole pressure, oil production rate, gas production rate, GOR, water injection rate, gas injection rate, pressure transient analysis as well as the distributed temperature sensing interpretation data where available. The producers are mainly producing from more than one interval, whereas injectors are mainly injecting into single interval. The section focuses on wells in each of the depletion sectors as much of the behavior can be attributed to local effects.

6.1 Integration of Actual Field Data

6.1.1 Well by Well Analysis of Integrated Data

West South Azeri well by well analysis

In this section the behavior of individual wells located in the West Azeri South flank is analyzed. The sector is composed of 5 producers (P3, P10, P11, P15 and P8), 2 water injectors (P12 and P16) and a gas injector (P31). The production wells are online since 2006, whereas injectors started up in 2007. Producers are mostly completed in single zone except P11 well which is completed as commingled at main productive layers Pereriv B and D. Water injectors drilled and completed as dedicated single zone injector where P12 injecting mainly into Pereriv B and P16 mainly into Pereriv D. Figure 6.1 shows the bottomhole locations of the wells as well as distribution along the sector.

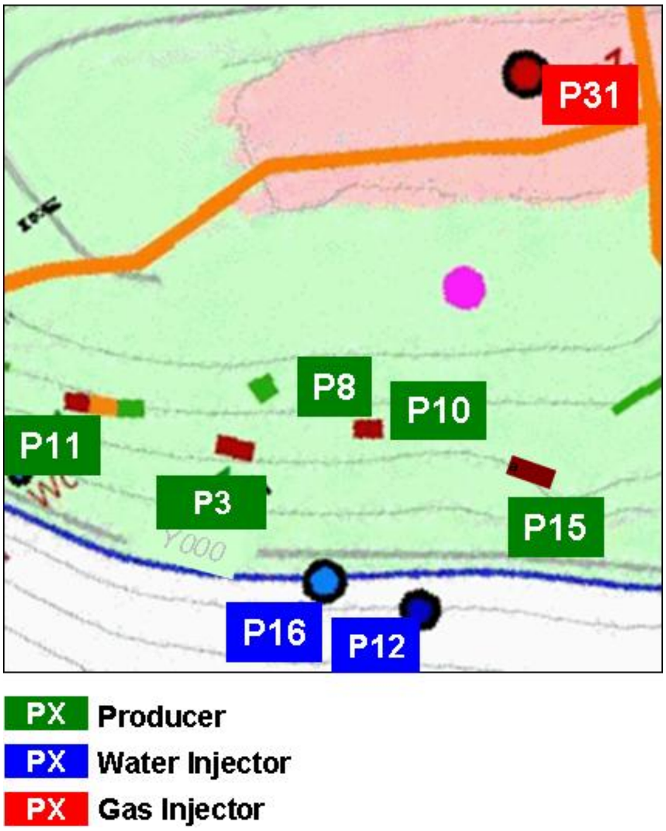

Figure 6. 1 Illustrative map of West Azeri South Flank

P3 - Producer

Figure 6.2 shows the response of oil producer P3 to the water injection from P12. It is seen from Figure 6.2 that as soon as water injection starts from P12 into Pereriv B gas-oil ratio (GOR) of an offset producer P3 starts to drop. It is observed that GOR in this well was climbing to 1000-1200 scf/stb level prior to water injection. However, after injection GOR drops to 800 scf/stb level. The reflection of this behavior is observed on P3 bottom-hole temperature (BHT). Before water injection the behavior of bottom-hole temperature dropped from 70.2 deg C to 69.4 deg C, whereas after injection start-up bottom-hole temperature starts to raise and surging behavior starts to be observed. The nature of surging is interestingly perceived most of the water injection benefiting wells. After mid-May 2008 it is observed that highly surging character of bottom-hole temperature and pressure is replaced by non-fluctuating character. Also, sudden drop in the bottom-hole pressure is not related any reservoir change but it is related to diverting the well from high-pressure separator to low pressure separator.

Between end-October 2008 and end-November 2008 period in the absence of P12 water injection, GOR trend of P3 well shows increasing behavior. Inverse, decreasing trend, behavior of flowing bottomhole temperature P3 is observed for the same period and is indication of possible GOR increase in the well.

In Appendix A, Figure A1 presents the reservoir pressure trends of producers and injectors as well as the water injection profiles of the wells located in West Azeri South Flank. From the pressure trends it is observed that P3 is responding to P10 start-up in May 2007 and P12 water injection start-up in November 2007.

Also, gas injection well P31 startup in late May 2008 overlaps with flowing bottomhole temperature increase and pressure stabilization of P3, which could be impact of gas injection support to this well. Another possible explanation of flowing bottomhole temperature could be the warm-up effect in the wellbore due to incremental oil into wellbore as a result of diverting P3 to low pressure separator. There is no clear evidence of gas injection support to P3 while the gas injection resume at the end January 2009 in P31 well.

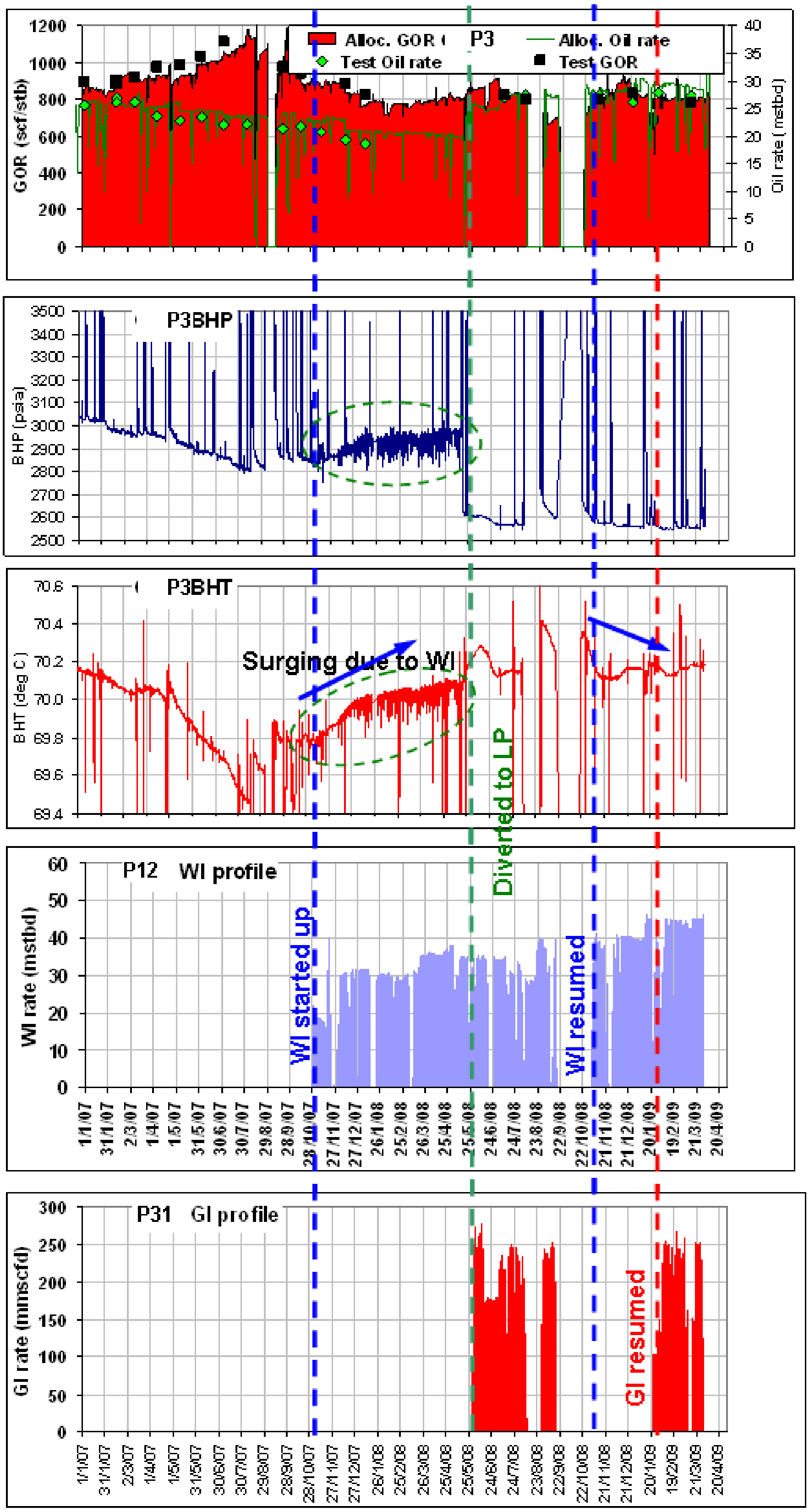

Figure 6. 2 Stacked plots for analyzing P3 well behavior

P10 - Producer

Located in the South flank of West Azeri part of the field, P10 is completed in Pereriv B only. As it is indicated in Figure 6.3 the well has shown fluctuations in terms of gas-oil ratio during its production lifetime. Later in the time, P12 Pereriv B water injection well is located offset to this producer. In the first phase production history of the well, in the absence of water injection, based on the production allocation data it is obvious that the well's gas-oil ratio started to increase at a steady rate until the water injection is started from P12, an offset well to P10, into Pereriv B. If only change in gas-oil ratio is taken into account which starts to drop after a month as water injection starts, one would conclude that the effect of injection is felt by the producer with a time lag of one month. On the other hand, combined interpretation of production and water injection data with bottom-hole pressure and temperature data, it becomes clear that it is weeks rather than months that producer reacts to pressure support. Analyzing flowing bottom-hole pressure trend, there is no clear indication of pressure support apart from anomaly observed in the flow regime behavior (based on fluctuations observed both in flowing bottomhole pressure and temperature for the mentioned period of time) after about two weeks as water injection starts up. However, flowing bottom-hole temperature trend suggests that almost from first day impact of water injection is felt in this well. By the start-up of the water injection well, P10 flowing bottom-hole temperature starts to rise which is indication of warmer oil inflow from the down-dip reservoir as a result of water injection water front push. Further in the time, namely in Mid-October 2008 declining trend detection in the flowing bottom-hole is related to outage of water injection in P12. Therefore, gas-oil ratio increase is reflected on gas-oil ratio increase in flowing bottom-hole temperature trend. But once the water injection is maintained it is detected that there is decline in gas-oil ratio and incline flowing bottom-hole temperature. Decline in the bottom-hole temperature at later time is related to choke changes on the well therefore, analysis of such data would be not accurate as there is mechanical interruption in well's performance. Also, in the analyzed period of time it is difficult to observe response of P10 to gas injection from P31.

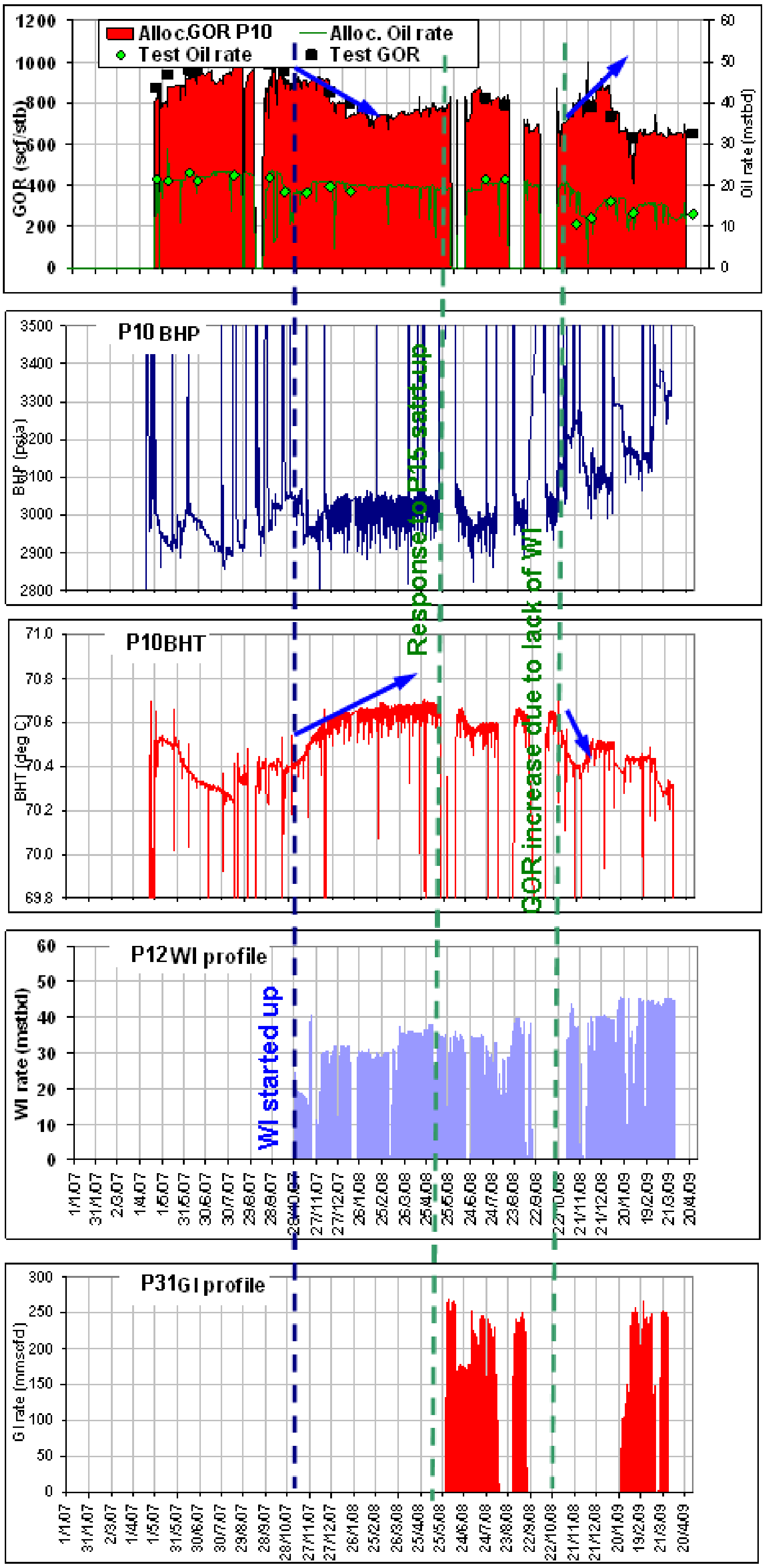

Figure 6. 3 Stacked plots for analyzing P10 well behavior

P15 - Producer

Figure 6.4 shows the similar graphs to previous ones but for P15 well, which is brought online later than rest of West Azeri South Flank wells after the water injection into Pereriv B has already started from P12. Looking at the gas-oil ratio behavior of this well, it is understood that from the very first day of production GOR stayed at solution GOR range of 600- 850 scf/stb but later on an increase in the GOR is observed with the outage of P12 water injection. As this is allocated data, it is hugely dependent on the last production test date. The allocation data is derived from well performance coefficients which are updated based on production tests. By using vertical and inflow performance lift curve models, the well performance model is matched to particular production test parameters. Based on the matched model, well head pressure dependent oil rates are derived and plotted. From the obtained plots, well head pressure dependent coefficients are derived and used as production allocation coefficients for allocating volumes to particular wells. This process is usually repeated once the new production test data is acquired and well performance model is updated. In Mid-December 2008 there is a step-change in the GOR trend as it started to behave as stabilized but at solution GOR values. Combining this data with bottom-hole pressure/temperature gauge data, it becomes clear that there is certain trend visible in temperature data during the time when P12 was not injecting. As for pressure data it is difficult to see a clear trend because of the noise in the data. Being Pereriv B producer at initial start up stage, P15 wellbore warms up with inflow of the warmer fluids. Cooling trend of P15, while P12 was absent, suggests that it reflects the direct impact from P12 well and gives indication about the connectivity of the reservoir. As there is no obvious step change in the bottom-hole temperature it suggests that continuous data from bottom-hole temperature data confirms that GOR step change is related to allocation errors rather than sudden change in the reservoir. One other observation is that the increase in water injection rate from 30 Mbd to 40 – 45 Mbd show caused slugging event as this is characteristic that has been seen by other wells in the field.

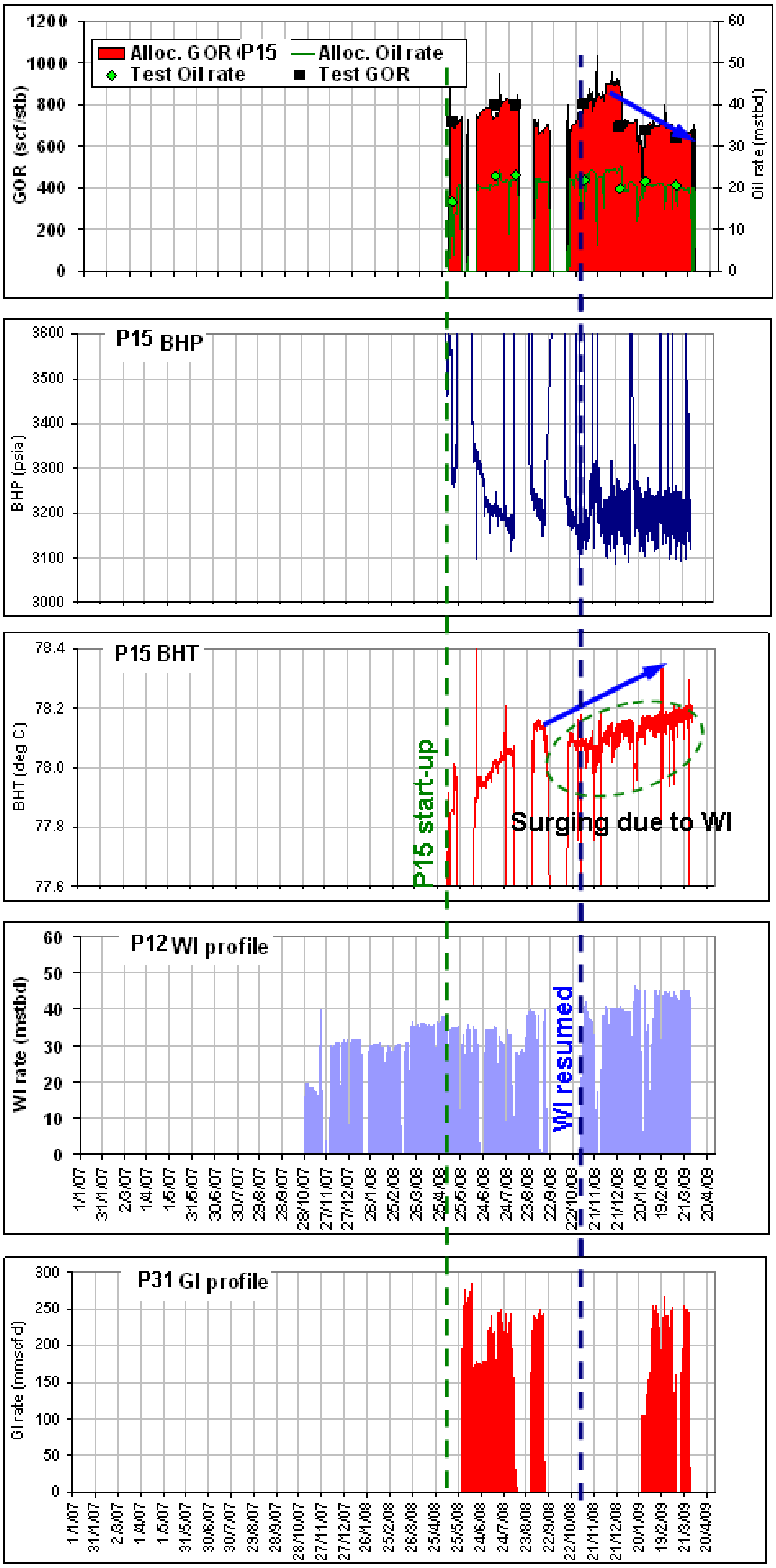

Figure 6. 4 Stacked plots for analyzing P15 well behavior

P11 - Producer

Being a commingled production well P11 differs from other West Azeri South flank producers in this sense. While analyzing the performance of the performance of the well, it is required to pay extra attention not a single formation reservoir performance but two or more formations' reservoir performance. Figure 6.5 presents the performance plots of P11 well in the light of P12 water injection well. Analyzing the GOR behavior of the P11, the first thing is observed is the stability of the GOR for certain period of time and sudden drop of it starting from early-May 2008. This, again, is the clear indication of the allocation error as the well has not been tested between January and the May of the same year. The similar behavior is observed in the oil rate performance.

Looking at the bottom-hole pressure and temperature data it is obvious that there is no major mechanical change in the well performance in that period of time but the relative reduction of average water injection from P12 well. As it is also observed from flowing bottom-hole pressure trends there is a break point in the trend of the flowing bottom-hole pressure in early-December 2007. At the same time, the flowing bottomhole temperature trend starts to increase. Relating this to flowing bottom-hole temperature trend and P12 water injection performance, it is concluded that the well started to see impact from P12 water injection well about a month and half later as the well started to inject water. This is relatively longer period for typical Azeri well which is located in the proximity of the water injection well but if the distance among these two wells taken into consideration it becomes clear that this is the farthest well in this flank to the injector. The relative step change in GOR profile possibly is indication of new production test data input into allocation system.

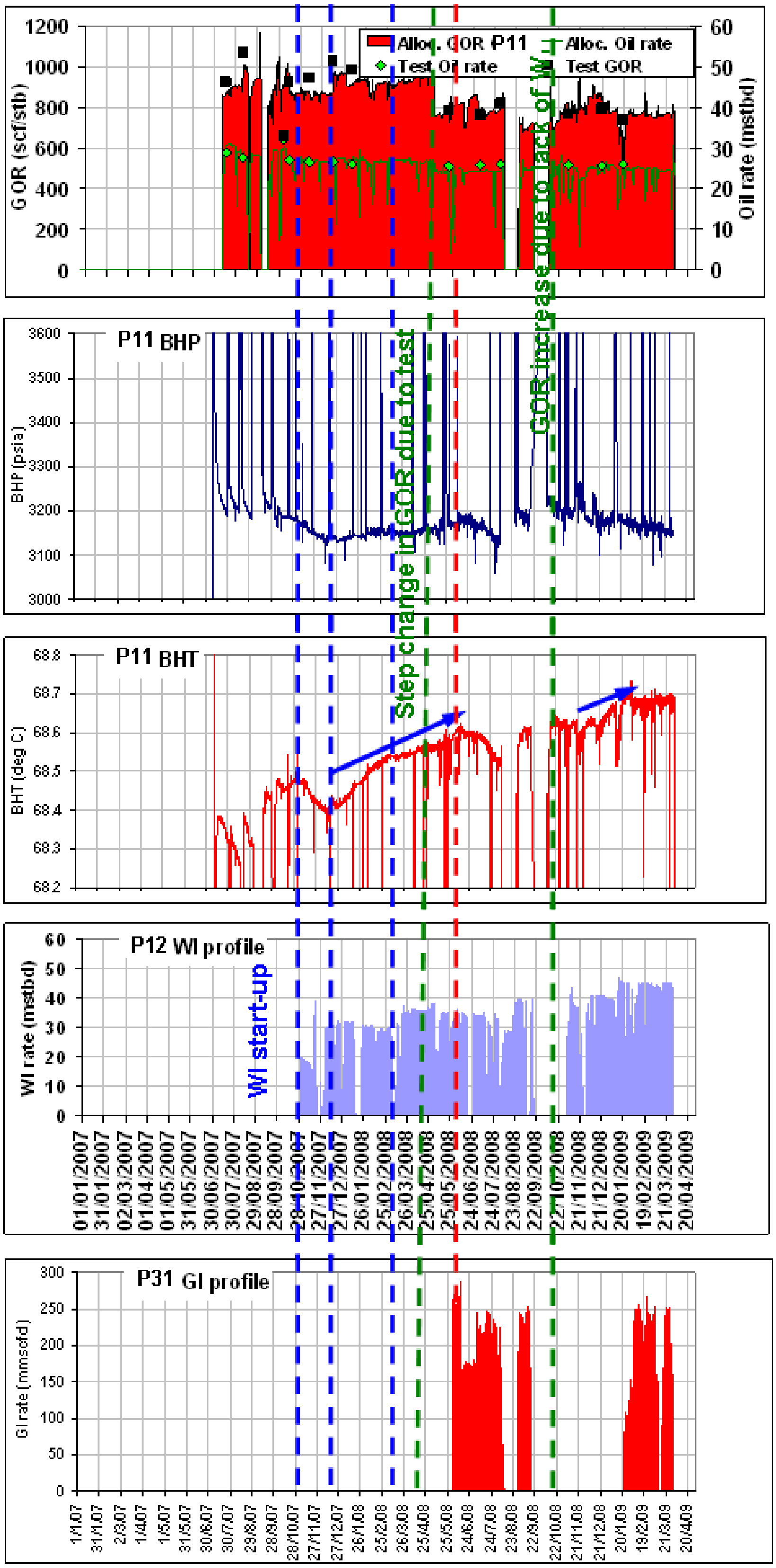

Figure 6. 5 Stacked plots for analyzing P11 well behavior

West Azeri North Flank well by well analysis

In this section the production characteristics (GOR, BHP, BHT) of individual wells located in the North Flank of West Azeri is analyzed in terms of water and gas injection. The sector is composed of 5 producers (P1, P4, P7, P14 and P18), 2 water injectors (P9 and P17) and a gas injector (P31). The wells started production since 2006 and deliver high rate production through their life. All of the producers are commingled at main productive layers Pereriv B and D. Water injectors drilled and completed as commingled but P9 ended up injecting mainly into Pereriv D and P17 mainly into Pereriv B. Below illustration (Figure 12) shows the bottomhole locations of the wells as well as distribution along the sector.

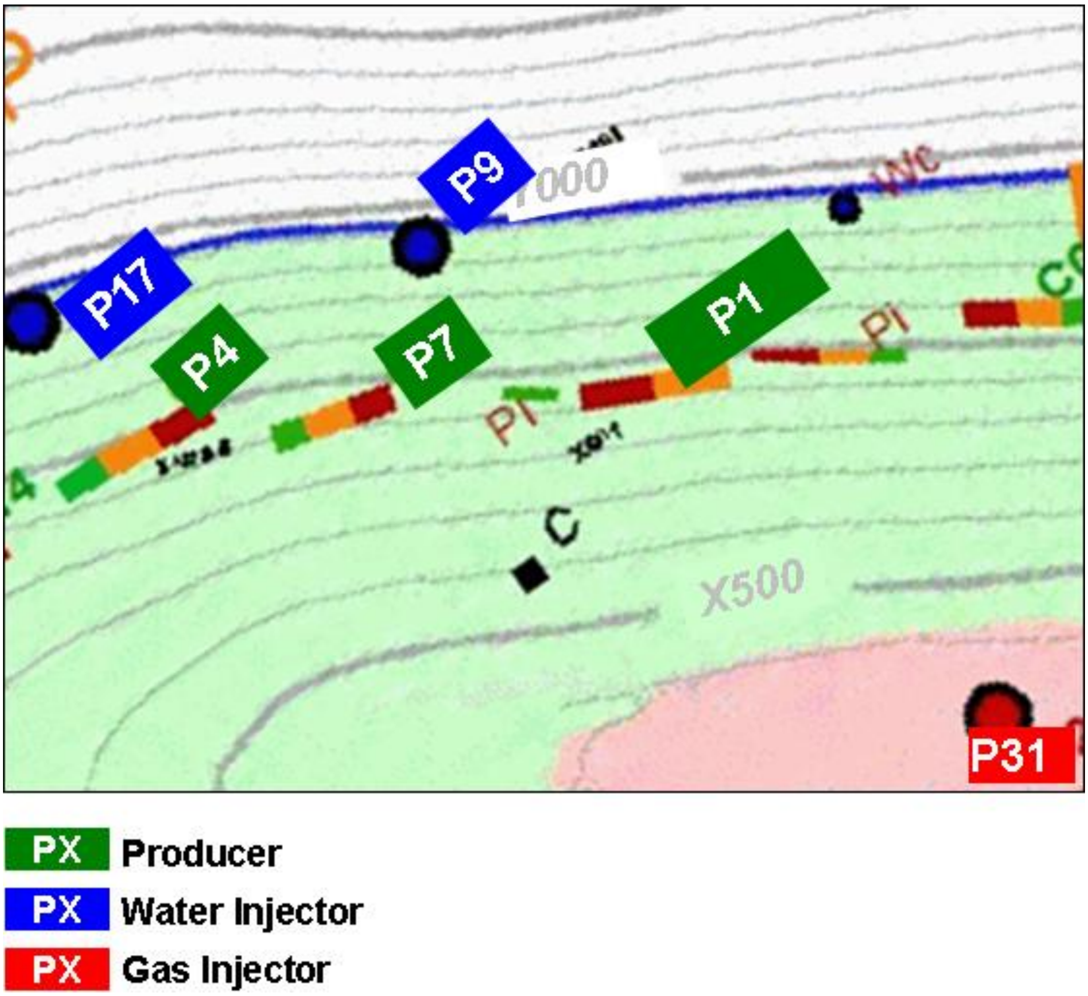

Figure 6. 6 Illustrative map of West Azeri North Flank

P1 – Producer

Providing examples from North flank of West Azeri, P1, P7 as well as P4 are taken for representing the impacts from the offset water injection as well as gas injection wells on producers.

P1 well being completed in only one of the main reservoirs, namely in Pereriv B, was brought online back in 2006 and was producing through dual flowline on the surface due to high production rate. For the first two years, producing without support of any injection, the well produced at low GOR and was recognized as a stable well.

Looking at the graph shown in Figure 6.7, the offset injector P9 starts mid-July 2007 with rate of 40mbd injecting into both of the main reservoirs (Pereriv B and D). During the initial performance of P9 there are frequent shut downs due to operational issues which is causing discontinuity in the performance of the well. Nevertheless, pressure support impact on the P1 is obvious from the early days of injection. If it is looked at the performance of the P1 well then impact from water injection well is seen from increasing bottom-hole pressure trend and confirmed by the increasing trend of bottom-hole temperature. Both pressure and temperature increase suggesting downdip support of injection brings to the well warmer oil and supports the pressure in the reservoir.

After end-September 2007, the increasing trend of bottom-hole temperature disappears and instead a decline in bottom-hole temperature is observed. This is related to longer period shut-in of the water injection well as well as possible split change among the Pereriv B and D as a result of frequent shut-in and start-ups of the P9 well.

Another obvious trend change is observed at end-May 2008. As it is seen from Figure 6.7 both bottom-hole pressure and temperature are increasing. If other parallel developing events are analyzed, it is seen that gas injection is started from P31 and hence have impacts on the bottom-hole temperature and pressure of the well. Increasing trend of bottom-hole temperature is created as a result of Joule-Thomson effects as a result of injection of gas to the gas cap from P31 well. Since pressure is increasing in the reservoir, this is being reflected on the bottom-hole temperature of the producer as well. Due to operational events in the field P31 well needs to be closed-in for about four months, which in turn expected to show its impact on P1 in negative way. When the bottom-hole temperature as well as pressure is analyzed for the periods of end-October 2008 end-January 2009, then it becomes clear that expected turnover in the bottom-hole temperature and pressure happens. As it is stated, this is another indicator of lacking pressure support to this area during the indicated period of time. When the gas injection is resumed from P31 the increasing trend of P1 bottom-hole pressure and temperature of P1 is started to again as the repetition of the behavior that was seen at the earlier start up of the P31 gas injection. Analysis of GOR behavior of P1 shows that GOR is declining for the period when the P31 gas injection is resumed. Such behavior of GOR is proving the P31 gas injection impact on this well again. The way P31 supports P1 is via providing pressure support mainly to Pereriv B (as P31 mostly injecting into Pereriv B), which in turn sweeps the oil towards P1 and provides the well to produce with lower GOR.

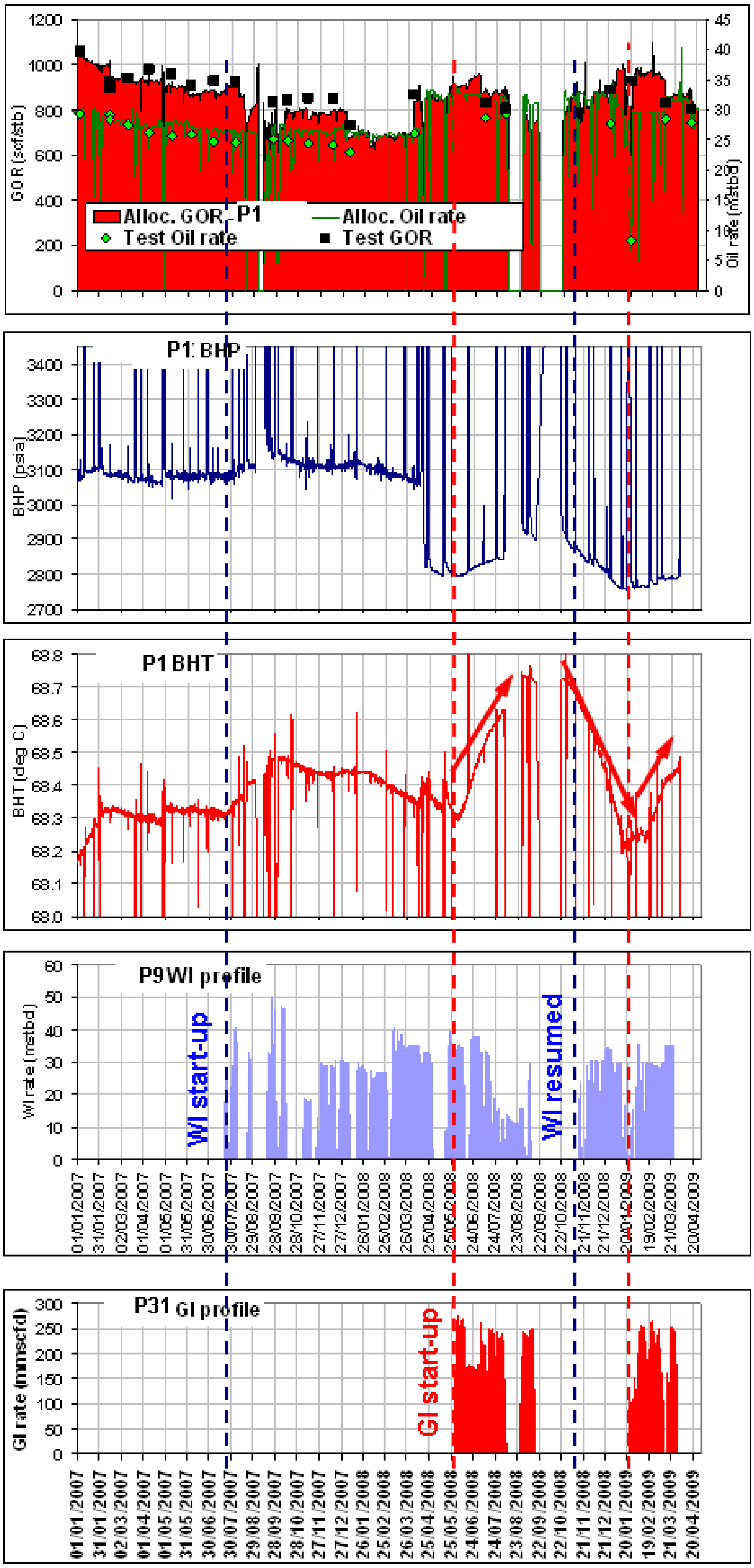

Figure 6. 7 Stacked plots for analyzing P1 well behavior

P7 – Producer

Being a commingled producer, P7 is producing from both of the main reservoir layers, Pereriv B and Pereriv D. The well is known as being a stable producer with lower GOR compared to other wells of the field.

Taking a look at the performance of the well over the producing history, it is possible to say that no significant well issues are observed in this period (Figure 6.8). Significant finger print of change in bottom-hole pressure and temperature is starting from early-July 2007 as increasing trends of both parameters. This change indicates that trends of pressure and temperature are increasing. Start of such a trend coincides with the start-up of near-by P9 water injection well. Due to the closest distance to the well and absence of geological barriers between these two wells, the P7 well almost immediately senses the pressure support by means of increasing bottom-hole pressure and temperature. Similar but opposite trend is observed from GOR trend of P7 suggesting that such impact is real and starts by the same time when P9 starts to inject water. . Joint analysis of the production and injection histories of P7 and P9 shows that P7 reacts all relatively small changes to P9. As an example, green dotted lines of Figure 6.8 indicate the period when P9 was offline and mainly bottom-hole temperature in P7 started to show a decreasing trend. Similar behavior was observed even when P9 was ceased (end-July 2008). Later, water injection from P9 was increased then bottom-hole temperature of P7 starts to recover and builds up again.

In Appendix A another aspect of data integration is shown in order to analyze the behavior or response to offset wells. Since in P7 DTS (distributed temperature Sensing) have been installed, it is possible to analyze the well's response in terms of contribution from individual layers (Pereriv B and D) over the life of the well. In Figure A2, P7 DTS based interpretation and P9 ProcessNet display is shown in order to show integration of injection and DTS data. Figure A3 shows the PLT results obtained from P9 well.

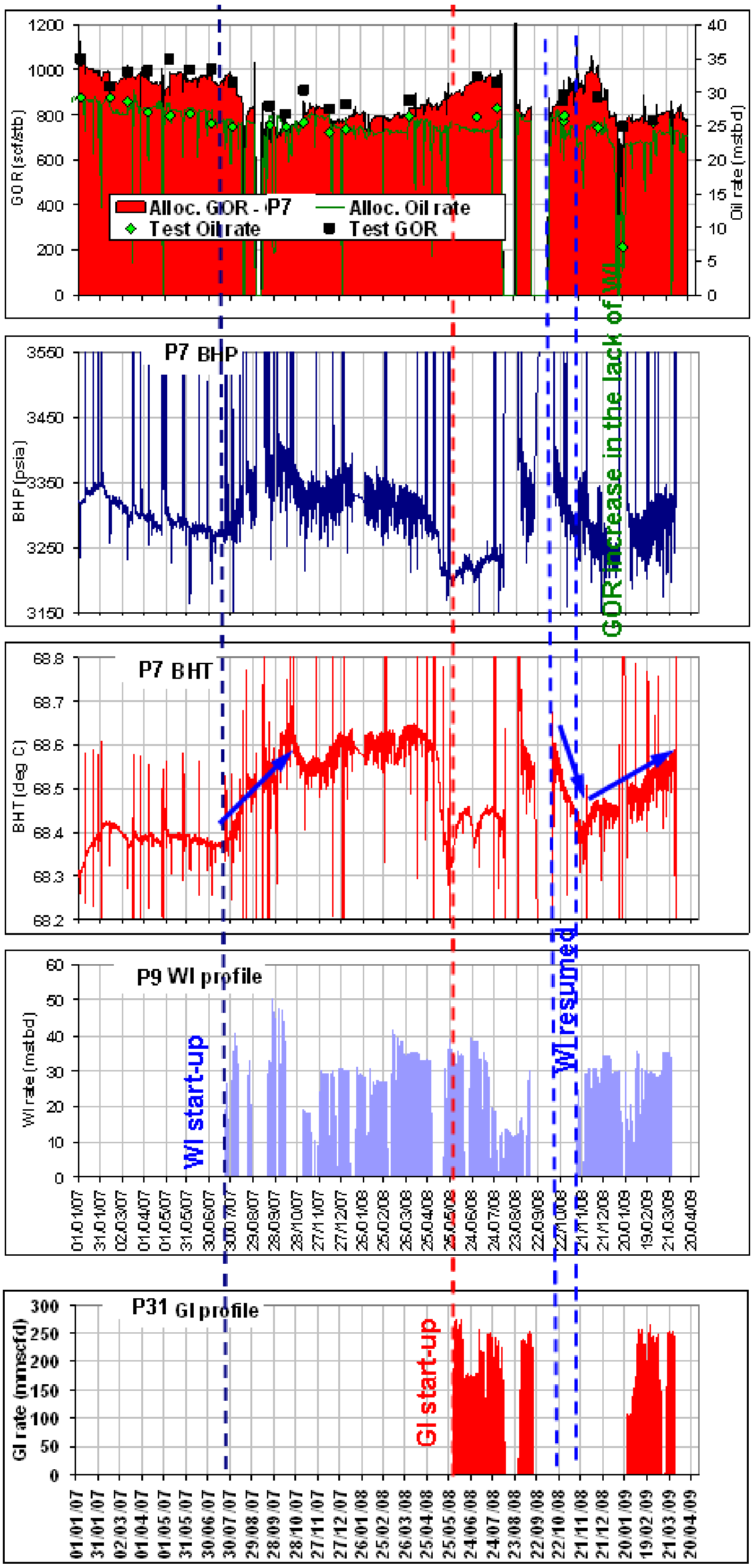

Figure 6. 8 Stacked plots for analyzing P7 well behavior

P4 – Producer

Being an offset well to P7 and P9, P4 is also known for its nature being relatively stable, lower GOR, commingled producer as well as higher productivity. Located in the same compartment with P7, this well senses the changes made in the other wells which are located in the same compartment. Starting from January 2007, when there was no pressure support into this flank of the reservoir either as water or gas injection the bottom-hole temperature showed a declining trend (Figure 6.9). This in turn looking at the reservoir pressure trends (Figure A-4) was implying that since all the wells are in the same compartment and acting as a single well, they are drawing down the pressure faster, hence bottom-hole temperature was in declining trend. Again, relating this trend to the events happening in the field it becomes clear that turnover happens in this trend once P9 as water injector comes online. Later (end-July 2007), a step down decrease in the GOR is the reflection of the pressure maintenance due to water injection from P9. Due to possible existence of errors in allocation data related with unavailability of new test data, such a change is not seen as smoother change in GOR but rather a sharp step change.

At a later time, strange behavior is seen in the performance of P4. Despite the fact that P9 injects at full rate, both P4 bottom-hole pressure and temperature starts to fell down quickly. Of course, other events in the field should not be ignored as the changes in the flowing bottom-hole pressure and temperature are directly related to such changes most of the time. This event is related to bringing online another producer which is offset to P4. This, once again is proof of how well the wells are communicating and feel each other. The reflection of the communication between wells is seen from GOR plot as well but it is seen as delayed response due to allocation issues. Later on, after stabilization period, by the help of P31 gas injection the well gets back to its previous trend. The inverse check of well's response to water injection well is available for dates between end Jul to end November 2008. While the water injection is absent it is observed that this negatively impacts on the bottom-hole pressure and temperature (end July 2008- end-November 2008). But at a later time, such behavior is being replaced by increasing flowing bottom-hole pressure and temperature as a result of maintaining the water injection in P9.

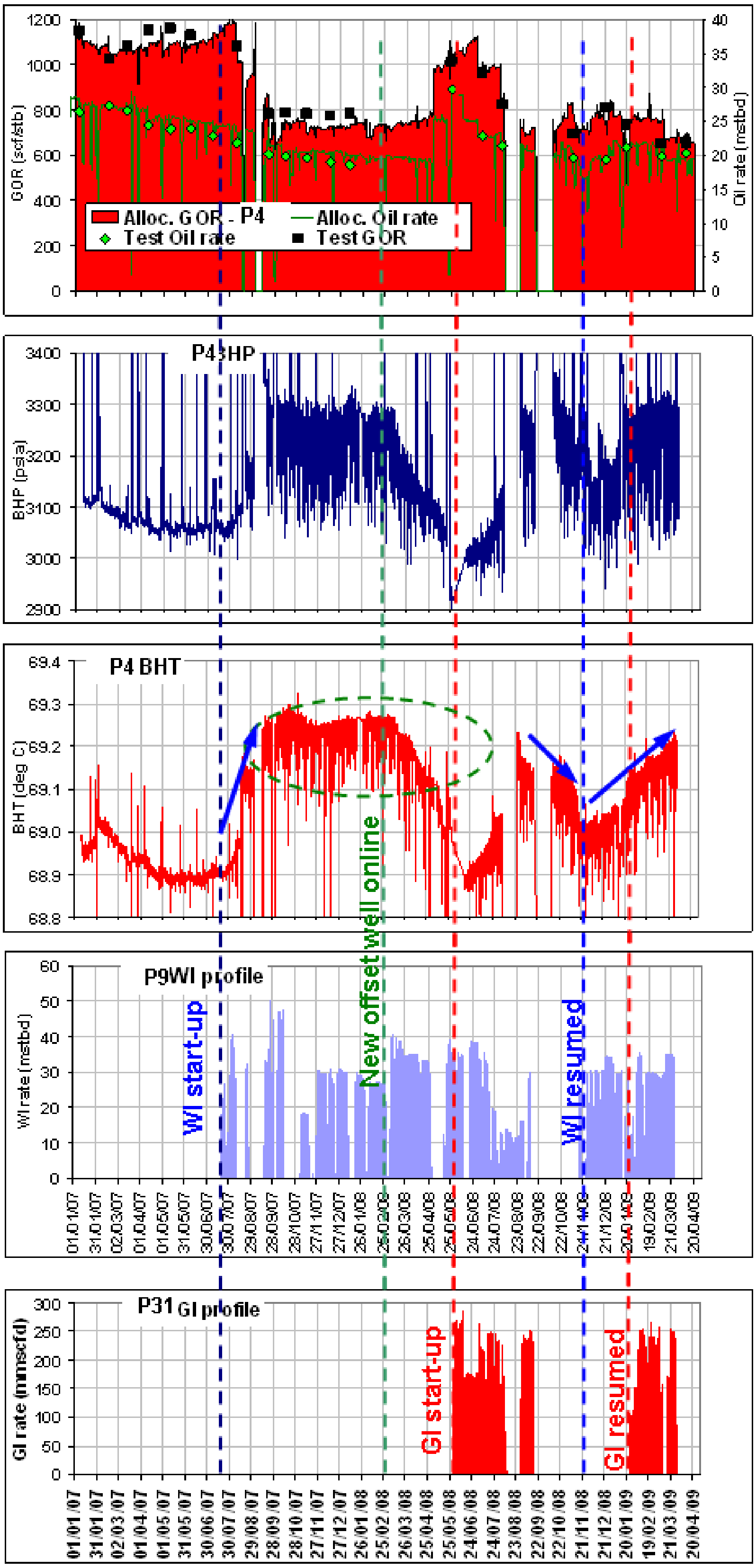

Figure 6. 9 Stacked plots for analyzing P4 well behavior

East Azeri North Flank Well by Well Analysis

The sector is composed of 7 producers (P41, P42, P43, P44, P46, P47 and P53) and 3 water injectors (P49, P50 and P52). The wells started production since 2006 and deliver high rate production through their life. All of the producers are commingled at main productive layers Pereriv B and D. Water injectors were planned to be drilled and completed as commingled. The special thing with the early water injection wells in this flank was related to installation of with downhole flow control valves, which allowed operator to have physical and volumetric control in flooding either Pereriv B or Pereriv D. Unfortunately, due to operational difficulties and problems have been faced in installation of the completions did not allow to benefit from such a technology. As a result, P49 ended up injecting mainly into Pereriv B and P50 to Pereriv D. P52, being a later well was decided to be completed as commingled and without downhole flow control valves installed. Figure 6.10 shows the bottomhole locations of the wells as well as distribution along the sector.

The graph (Figure A-5) is showing all the wells' pressure trend in East Azeri North flank. As the trend implies, the reservoir pressure of all the wells declining in similar trend which is indicating the communication of the entire wells with each other. The general pressure trend agrees also with the interference among producers and injector. Generally, offset production wells respond quickly to the injection wells which is an indication of absence of strong barriers between the majority of producers and injectors. There are certain possible exceptions to the above statements, as some wells (i.e. P42) due to their location show qualitatively similar, but quantitatively slightly different decreasing trend of pressure. Such a behavior could be a reflection of possible barrier between P42 area and the East Azeri entire wells.

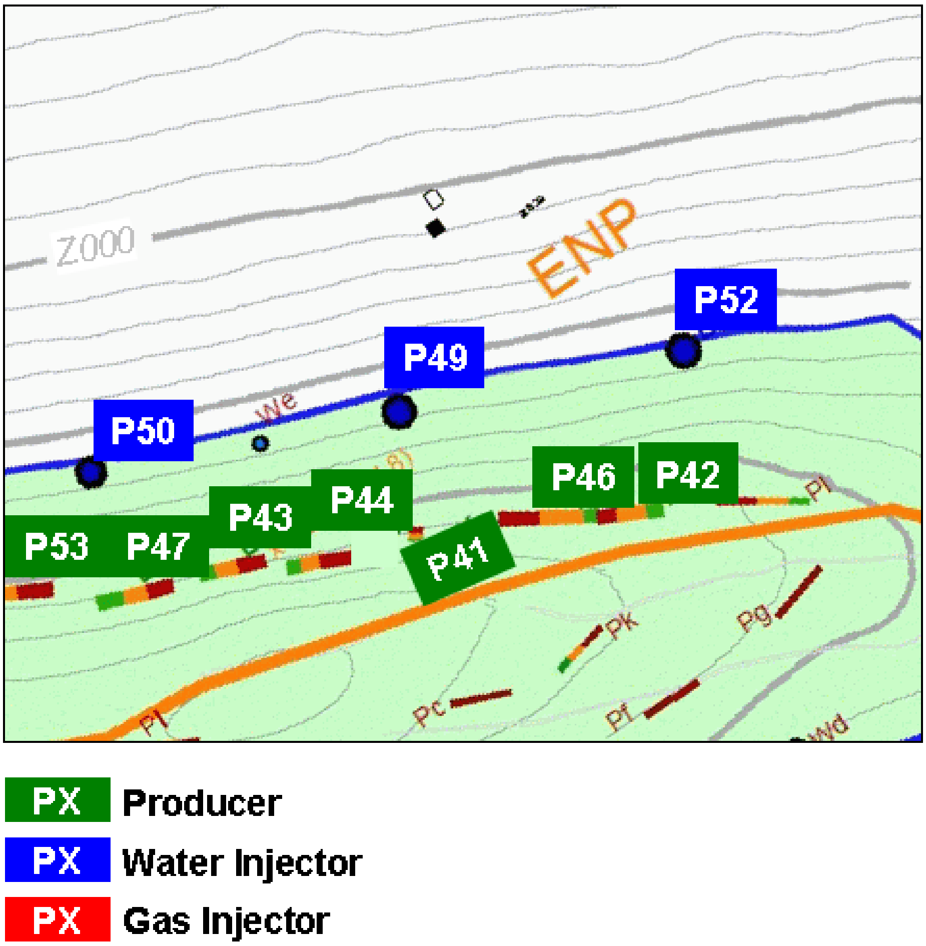

Figure 6. 10 Illustrative map of East Azeri North Flank

P41 - Producer

Starting up back in late October 2006, P41 used to be one of the highest oil rate wells in the Azeri field. The well was flowing through dual flowline due to potential erosion issues that could have been arise from the high velocity of the fluid on the surface. In the early times of production, in the absence of injection support the well is showing continuous increase in GOR which is apparent from the Figure 6.11. Continuous decline both in flowing bottom-hole pressure and temperature in the same period of time is confirming the GOR increase until late-November 2007. As soon as the offset water injection well P49 starts up, very sharp increase in flowing bottom-hole temperature is observed in very short period of time. This in turn, is impact from P49 water injection which is felt by P41 within a week period. Starting from early-March 2008 increasing P49 water injection rate by about 5mbd caused P41 flowing bottom-hole pressure and temperature to fluctuate but still remain stable at certain pressure and temperature level. Later on, choking P49 well back, resulted in such fluctuation go away which suggests that possibly there is certain water injection level that causes offset wells to operate at unstable regime.

This well, together with other offset producers were known for their higher GOR from early days of start of their production in the entire ACG field. The big change that one could notice in the performance of P41, between pre and post water injection startup in P49, is the dramatic step change in GOR of P41. The top-most plot in Figure 6.11 shows the GOR change over the life of the well and reflects how GOR declines from 2500 scf/stb to 600-700 scf/stb level after P49 water injection start-up.

Starting from late-September 2008, P49 outage occurs due to integrity problem. Within a month and half time period P41 flowing bottom-hole temperature trend almost immediately showing severe decrease whereas, this is not firmly felt in flowing bottom-hole pressure trend. Later on, when the injection in P49 well is restored, flowing bottom-hole temperature trend rolls off and starts to increase in P41. Such behaviors in flowing bottom-hole temperature are bright examples to flowing bottom-hole temperature response to water injection rate. It shows not only the impact of certain water injection well on producer but also helps to decide over the optimal water injection rate for an offset water injection.

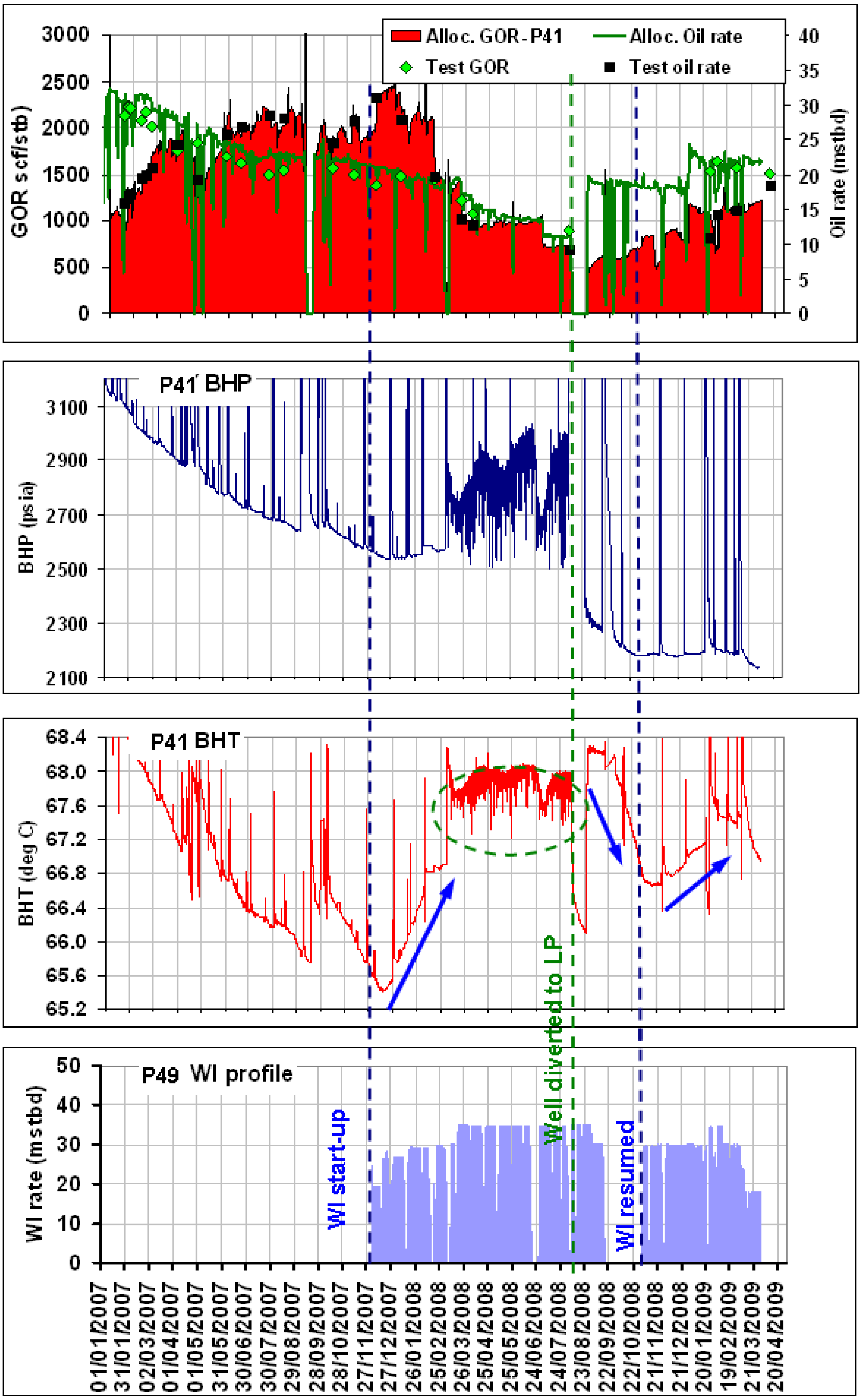

Figure 6. 11 Stacked plots for analyzing P41 well behavior

In Figure 6.12 it is shown the P41 reservoir pressure trend comparison to East Azeri water injection wells profile. As it is seen from the graph, by the start of the water injection in this sector, the sharply decreasing trend of the reservoir pressure changes is replaced by gentler decrease in this trend. Later on, after start-up of P50, second injector in this sector, even starts to increase the reservoir pressure trend of P41. This means that there is a strong interference exists among P41 and P49 water injection well. This in turn, is another confirmation of positive response to water injection that has been discussed previously from bottomhole temperature, pressure and GOR point of view.

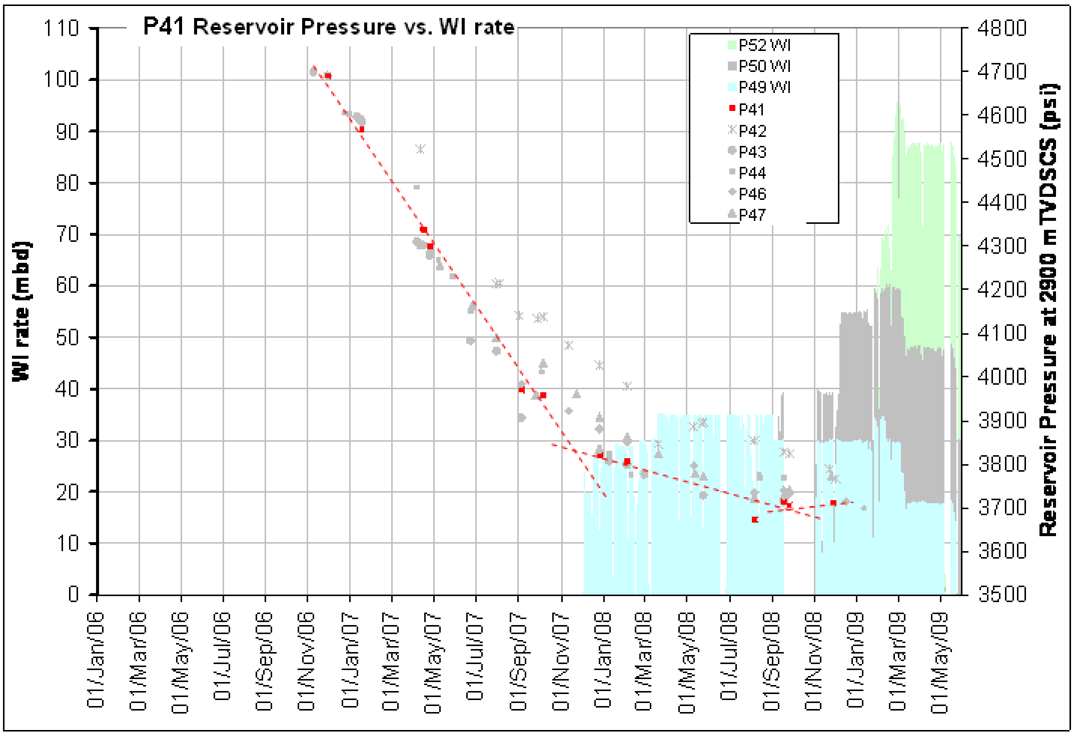

Figure 6. 12 P41 Reservoir pressure response to water injection

P42 – Producer

Having been located in far eastern part of the Azeri field, the well has been on production for about two years. Throughout its production life the well was producing with moderate GOR and relatively stable compared to offset producers. Due to being located away from early water injectors, the well sees delayed or weak response to start-up of water injection in this part of the field (Figure 6.13).

Later on, early-February 2009, when P52 water injection well is brought online, from the bottom-hole temperature data it is obvious that P42 starts to respond to injection very quickly. Partial stabilization in bottom-hole pressure and stabilization of GOR below 2500 scf/stb level is visible which confirms the well's response to water injection from P52. Being an offset well to the P46 well, due to its inertness to P49 water injection outage, as well as existence of injection, it could be concluded P42 well has very limited interference with P49 but has strong communication with P52. The reason for this could be either possible existence of baffles or barriers in between these two wells or the distance between P49 and P42 wells.

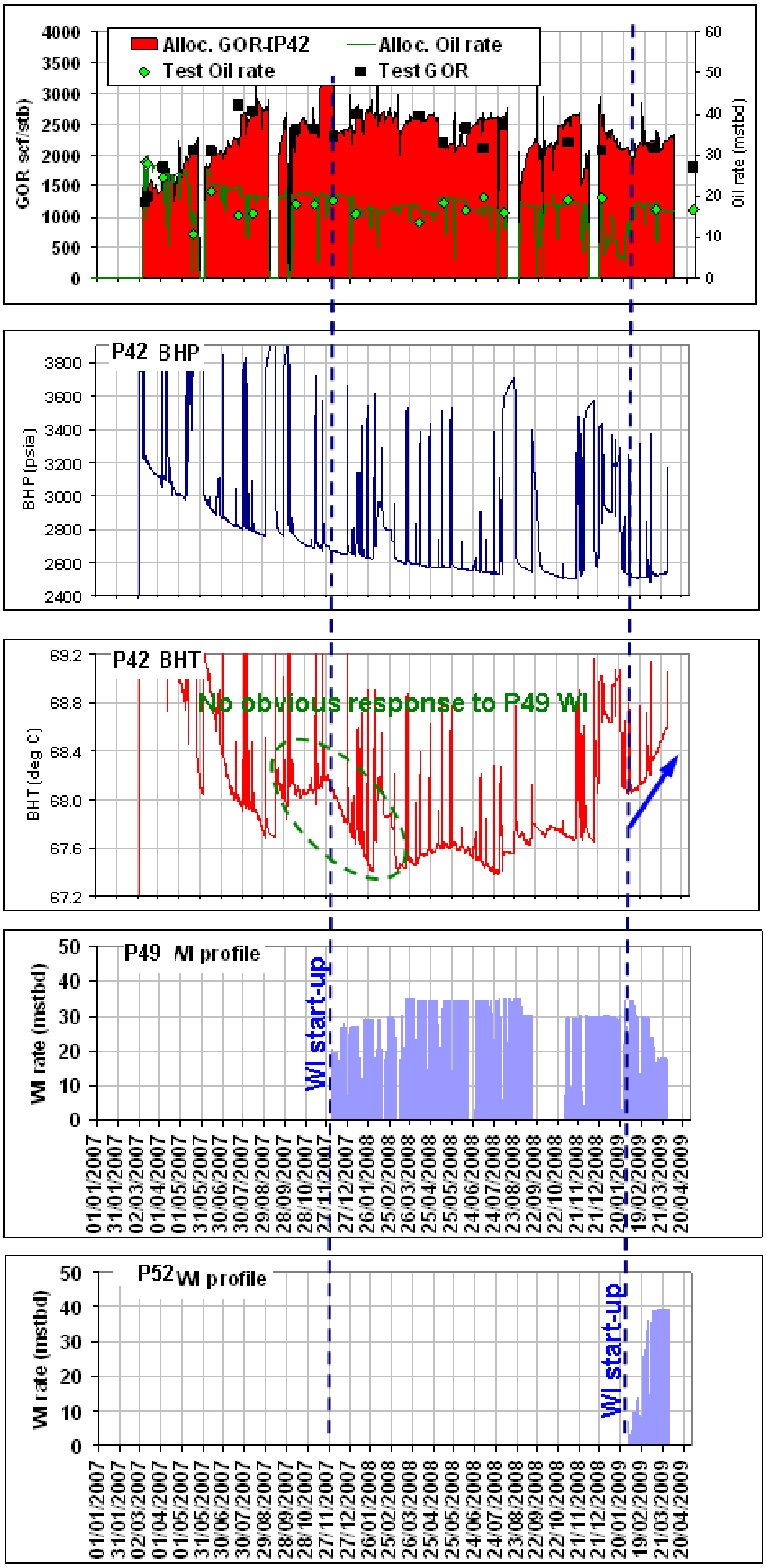

Figure 6. 13 Stacked plots for analyzing P42 well behavior

P43 – Producer

The well is the first well started up in East Azeri platform and due to its high oil rate the well has been exploited through dual flowline on the surface. In the early life of the well, the faster decline in oil rate and rapid rise of the GOR is observed from production history plot below (Figure 6.14). Such behavior of the well overlaps with the trends of bottom-hole pressure and temperature gauge, as rapid decrease in both trends are observed. Later on, with increase of water injection rate in P49 well in mid-March 2008 the GOR, oil rate and bottom-hole temperature trends show general stabilization in P43.

In the late-November 2008, after a long shut-in period the well's GOR has significantly dropped and stay at the same level. Due to the GOR's sharp decline to the level of solution GOR, the lift performance of the well is affected and this is visible from slugging or surging events seen in flowing bottomhole pressure trends for the same time frame.

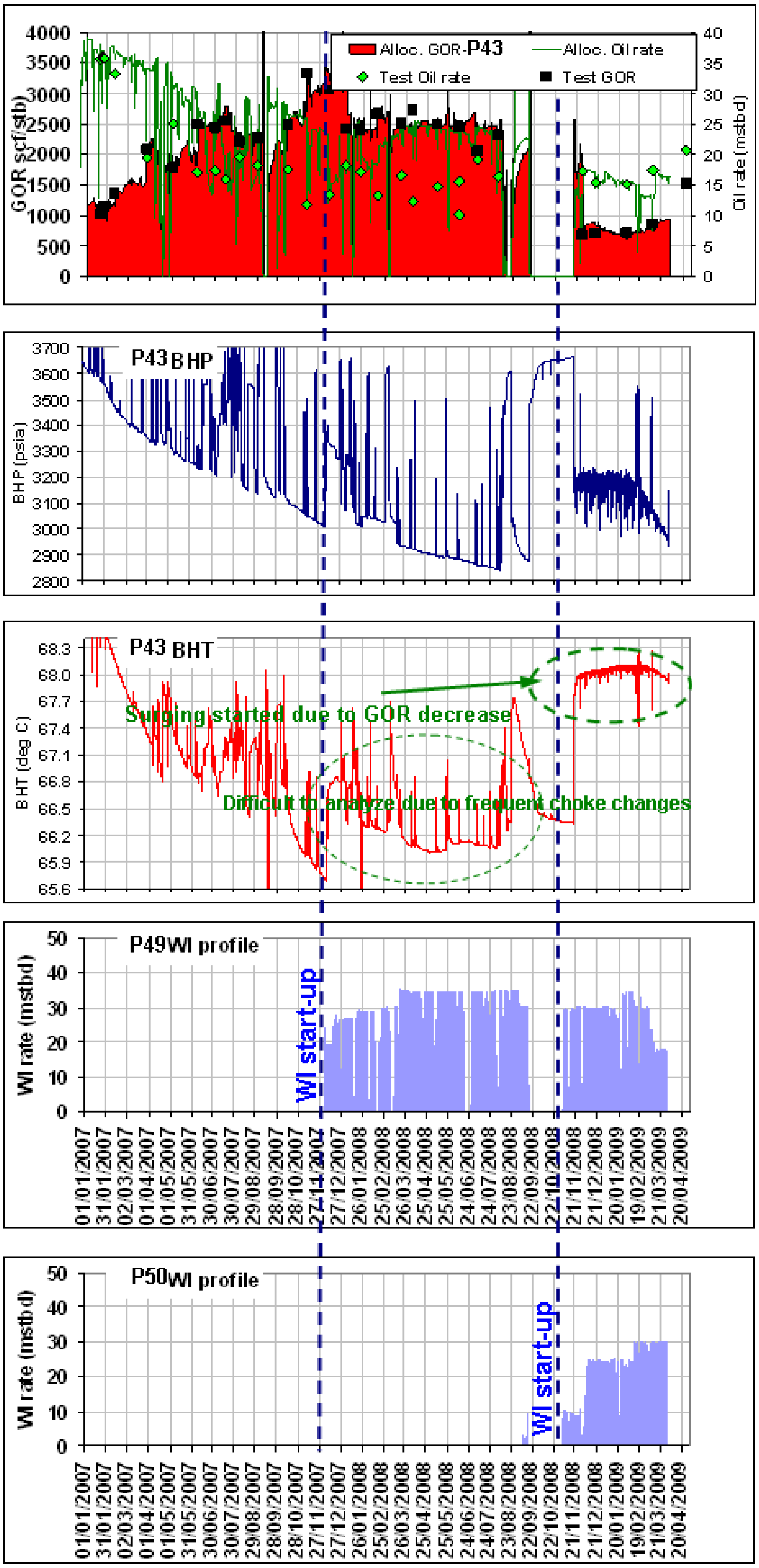

Figure 6. 14 Stacked plots for analyzing P43 well behavior

P46 – Producer

The well started up the production in April 2007 located in the easterly part of the East Azeri North Flank. The well is producing from commingled intervals and known for its GOR level being moderate compared to other wells in the sector. Despite the fact that P46 is located at a relatively longer distance from first water injection well P49, the impact of P49 water injection on this well is still observable but delayed compared to other offset producers (Figure 6.15). Looking at the performance of the P46 there are two noticeable events related to the offset water injection performances. In the first event while P49 is started water injection in late November 2007, P46 has shown positive response to water injection by bottomhole temperature increase but only after a month later. Another noticeable response of P46 to water injection is when P49 was shut-in by mid-September 2008 for more than a month. In the absence of injection bottomhole flowing temperature of P46 reflects sharp declining trend followed by bottomhole pressure declining trend. If the temperature values were ignored and only pressure values were analyzed, possibly the response of P46 to P49 post shut-in period water injection could have been missed. As it is indicated in Figure 6.15 after the water injection is resumed in P49, P46 starts to respond it by sharp increase in bottomhole flowing temperature. Although such response is delayed, from the sharp rise of bottomhole temperature trend it could be concluded that the interference among these wells is stronger. The value of integrating various sources of data not only shows existence of interference amongst wells, but also it is possible to conclude strength of interference.

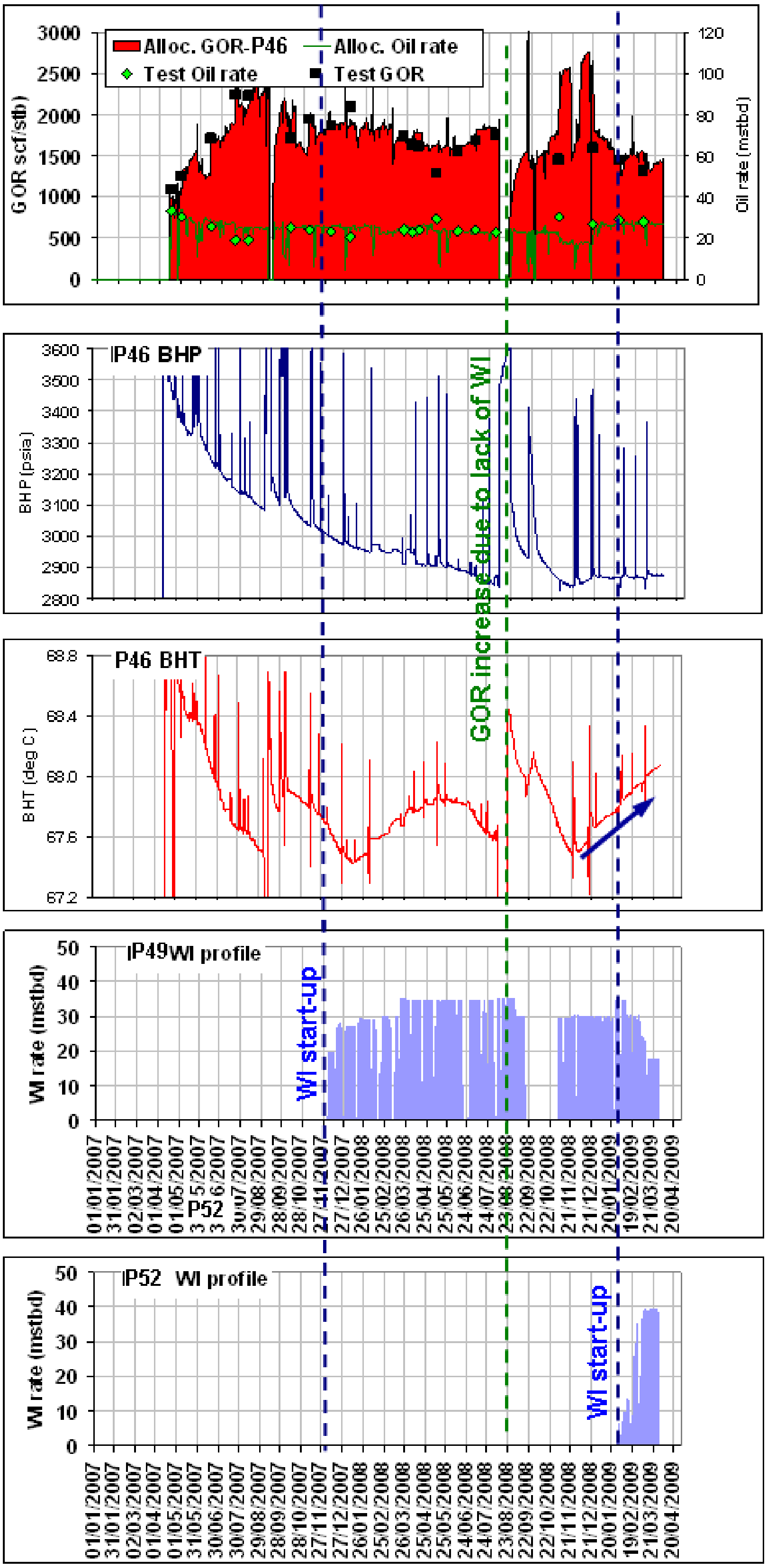

Figure 6. 15 Stacked plots for analyzing P46 well behavior

P47 – Producer

The well is producing from commingled reservoirs with the highest rate in that sector of the field. Producing for more than 2 years, as any other well in the East North sector of the field the well suffered fast reservoir pressure decline and subsequently was experiencing high GOR throughout the production life until water injection commenced in the P49 and P50 wells. As it is seen from Figure 6.16, as P49 water injection turned on the bottom-hole temperature starts to react to pressure support and starts to turn over to follow the increasing trend. The reservoir pressure trend from the Figure A-5, indicating that rapidly dropping pressures starts to stabilize once water injection well P49 is brought online. The reservoir pressure trend starts to rise after certain period of time. The confirmation to this fact is seen from the bottomhole temperature increasing and allocated GOR decreasing trends. Another observation is related to interference among producers. When P53 production well brought online in early Jan 2009, P47 well starts to show reaction to additional producer's existence by showing declining trend in bottomhole temperature and pressure as well as by GOR rise. This in turn is valuable information about inter-well interference among producers and provides information about the wells draining same compartment and not seeing significant barrier amongst each other. Such a behavior of bottomhole temperature could be explained by Joule-Thomson cooling caused by additional extraction of volume and dropping the pressure in the system.

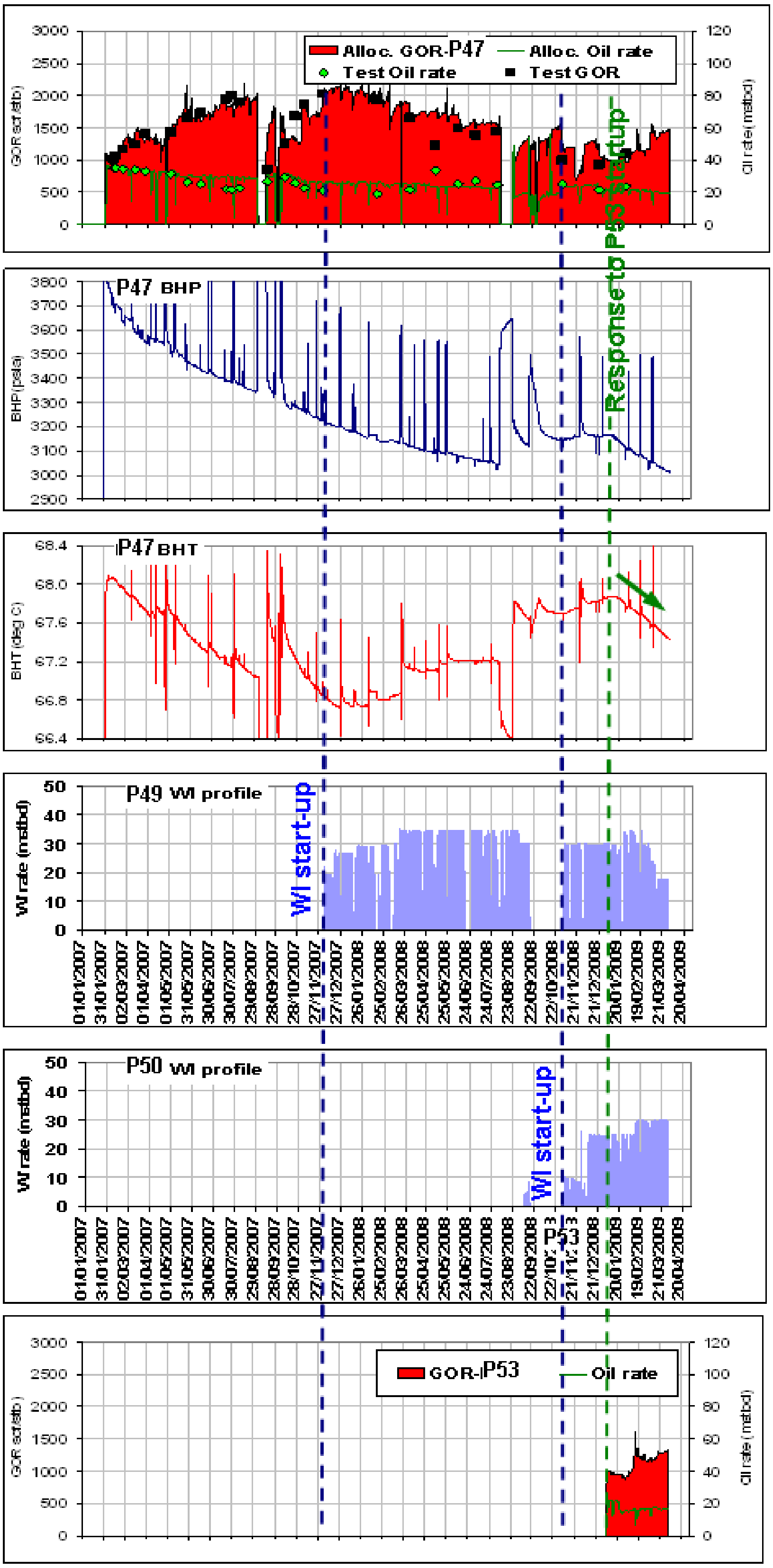

Figure 6. 16 Stacked plots for analyzing P47 well behavior

6.1.2 GOR and flowing bottom-hole temperature correlation

In the context of analyzing bottom-hole gauge responses different approaches has been applied in order to maximize the value extracted form source of data supplied by ‘smart’ wells. Flowing bottom-hole pressure data often correlated with production data to better understand the relationship between choke settings on the wells, wellhead pressures and oil and gas production data. Other than above mentioned analysis, flowing bottom-hole pressure data has been valuable source of data to work out the interference among producers as well as injector producer pairs. Also, it is often mentioned that flowing bottom-hole pressure is too sensitive to choke changes to be able to identify clear responses in the data. It is not exception that although there are certain changes in the performance of the well, there is hardly any obvious change in the flowing bottom-hole pressure data.

In this study, parallel to pressure data flowing bottom-hole temperature was taken into consideration to investigate if there exists certain correlation between gas-oil ratio data. The data considered here is production test gas-oil ratio data. This is due to the reason that allocated data could mislead to incorrect answers. From the examined examples it is concluded that there exists certain correlation between flowing bottom-hole temperature and production test gas-oil ratio data. Apart from this valuable information it is also, discovered that not only there exists certain correlation between these data but also it shows change according to changing reservoir conditions; such as water, gas injection response and well head pressure changes. Some field examples are given in this section to explain the correlations.

As it is known, every allocation process contains certain errors in their predictions. It gets even more difficult if allocation process lacks GOR prediction and assumes constant GOR for the periods between two tests. Having constant GOR creates major allocation errors which results in wrong interpretations when the performance of the well is analyzed. Such examples are seen in well GOR performance graphs, as there occurs sudden step changes as a result of new test values.

Currently, there are various approaches for predicting GOR from various sources, but flowing bottom-hole temperature correlation shows that it responds not only the well related changes but also, reservoir performance related changes. Having such correlations among gas-oil ratio and flowing bottom-hole temperature could be a good source for being utilized in daily GOR prediction. Furthermore, integration of this process into usual allocation process, could give better matches in terms of produced oil, water and gas volumes.

Another advantage of utilizing GOR versus flowing bottom-hole temperature correlations is that, an engineer might not be in need of requesting frequent production tests. In case of Azeri field it means also, reducing operational difficulty as well as it requires special effort for routing the wells into test separator. Since there are many high GOR wells especially in East Azeri part of the field, it is difficult to measure the well rates at their actual flowing conditions. This is due to the fact that, test separators can handle up to certain volume of gas and therefore, high GOR wells are often choked back to accommodate the gas produced from a high GOR well. This, in turn causes the company to loose some oil every time the high GOR wells are tested. For that reason, methods for estimating the GOR from certain parameters are vital to save the company from extra loss of the oil during the production tests. One of those parameters in ACG is found to be GOR flowing bottom-hole temperature correlation. It is relevant to use such correlation in ACG due to the fact that almost all of the wells are equipped with pressure/ temperature gauges and continuous data flow is provided.

6.1.2.1 P41 example

Figure 6.17 is the matching graph of gas-oil ratio to flowing bottom-hole temperature based on the correlations developed for these parameters. The labels in the figure indicate the real-time bottom-hole temperature as red-line, bottom-hole temperatures measured during production test as red squares, flowing bottom-hole temperature derived GOR as black line and production test bottom-hole temperature derived GOR is marked as black squares.

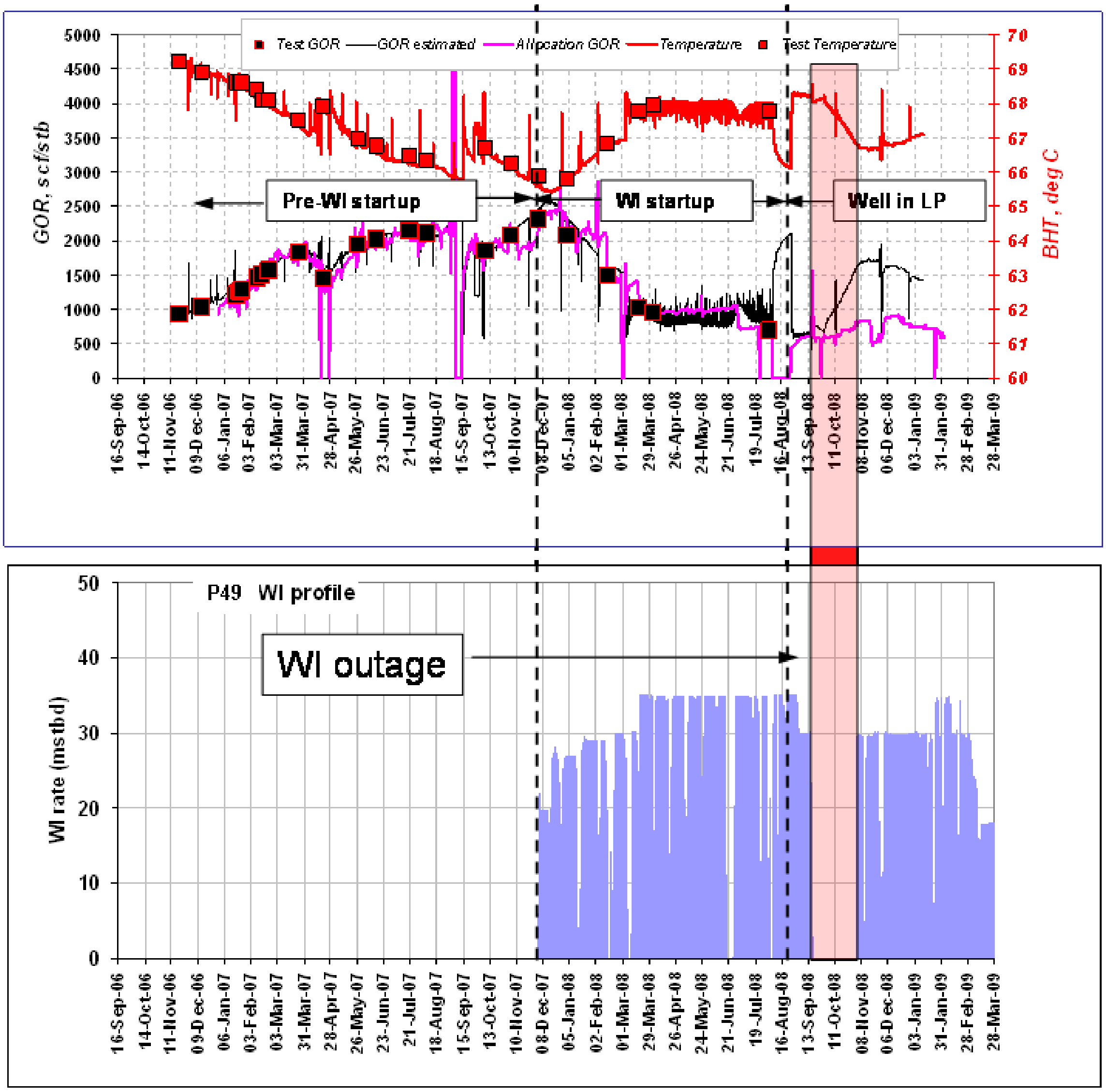

Figure 6. 17 P41 Test GOR and flowing bottomhole temperature profiles and P49 water injection profile

From the correlations between flowing bottom-hole temperature and GOR it is observed that the behavior of the P41 well could be divided into three phases:

- before P49 water injection,
- After P49 water injection started,
- After the well is diverted into low-pressure separator. All these phases are indicated on the above figure with dashed lines.

It is obvious from the analysis of first phase that the GOR in this well continuously is increasing as there is lack of pressure support. From the regional knowledge of about hydrodynamic aquifer in the South Caspian, the aquifer in the North Flank of the ACG is weak. Therefore, with 6 wells producing with lack of pressure support, results in significant reservoir pressure drop and sudden GOR increase in almost all of the sector wells. In Figure 6.17 both flowing bottom-hole temperature for P41 and water injection profile for P49 water injection well is shown.

Another good example in this well is the observation and disappearance of slugging regime in both flowing bottom-hole pressure and temperature after water injection period and the period when the well is diverted to low pressure separator, respectively. Therefore, such slugging regimes indicate that the well performance is dictated mainly by existence of lower volume of gas in the wellbore.

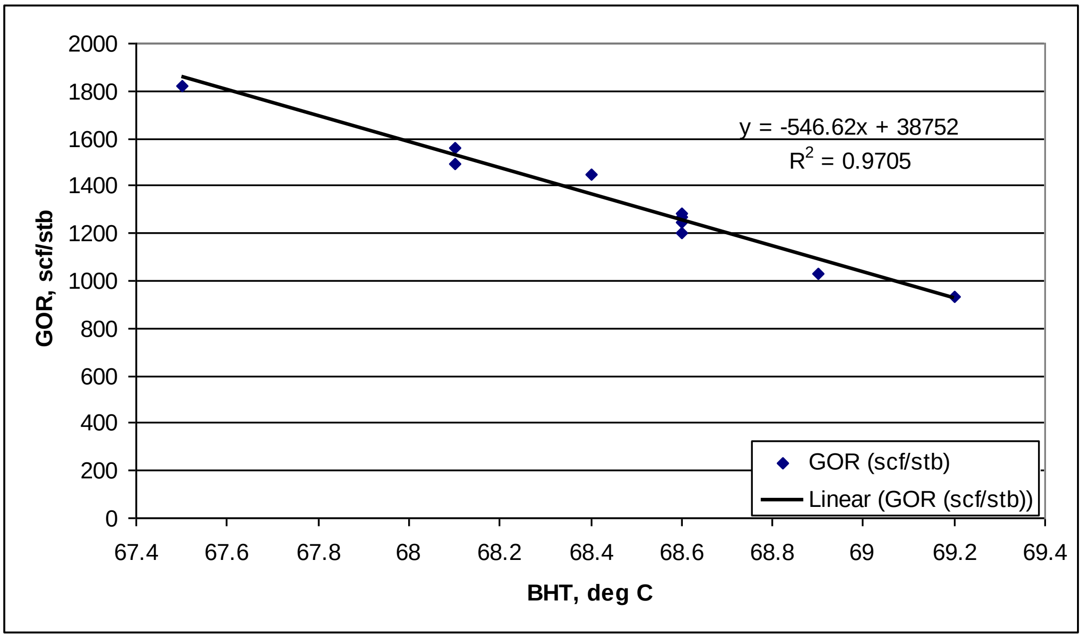

Figure 6. 18 P41 pre-water injection start-up GOR and flowing bottomhole temperature correlation

The correlation between production test gas-oil ratio and measured flowing bottom-hole temperature for the first phase, where there is no pressure support and well is working through high pressure separator given in Figure 6.18. As it is seen from this figure, there is almost perfect inverse linear relationship between these parameters. The nature of the linear correlation is indicating that for each degree Celsius of temperature drop there is 550 scf/stb rise in gas-oil ratio. As in other applications, it is important to note the role of human error in inputting the production test data which results in divergence or misfit of the straight line between gas-oil ratio and flowing bottom-hole temperature correlation. In other words, while correlating the bottomhole temperature and GOR data, it is required to carefully treat the data in the light of the quality of the test data as these data captured in the database as a result of manual input. Therefore, it is possible that there are outlying points to the fitted straight line in the sampled GOR and flowing bottomhole temperature correlation, just due to misprint.

The correlation obtained from this plot is applied to continuously recorded flowing bottom-hole temperature to compare with allocated production data (Figure 6.17). Such application is performed due to the fact that allocation data is not always reflecting the truth because of usage of different dataset to derive allocation data. This approach might introduce new methodology for calculation of allocation data.

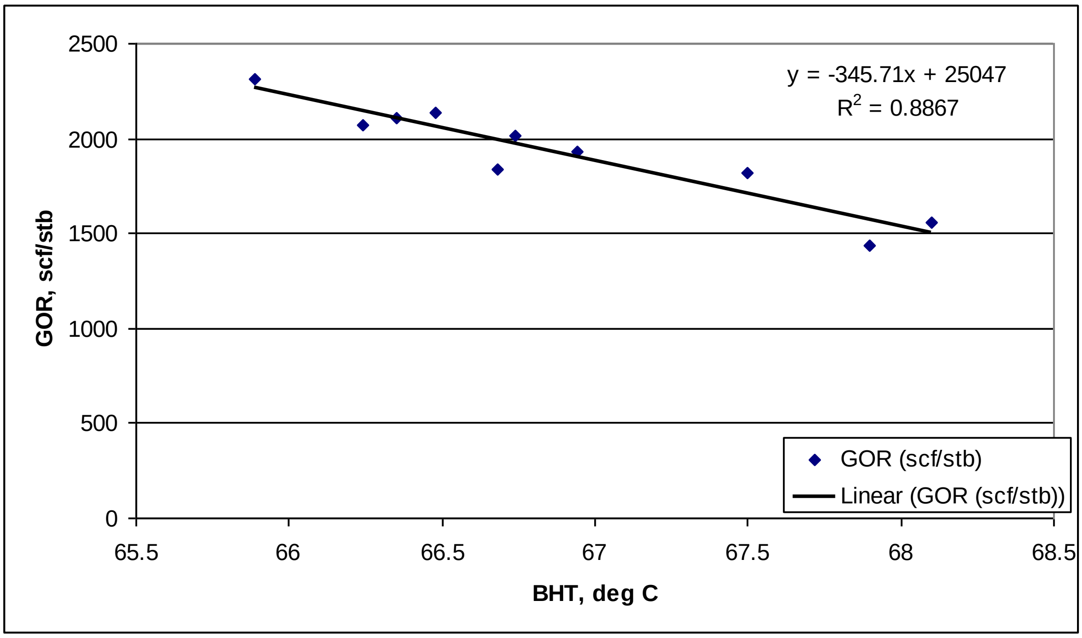

Figure 6. 19 P41 post- water injection start-up GOR and flowing bottomhole temperature correlation

The second phase correlation, indicating there is pressure support and working through high pressure separator, is shown in Figure 6.19. This correlation is showing inverse linear relationship, too. Different from first correlation the declining trend of this line is gentler. This, in turn, is indicating that for each degree of temperature drop the increase in the gas-oil ratio is less than that of the first phase. Such behavior could be explained by pressure support to this sector from P49 water injection well. The timing of the phases happening is consistent with the start-up date of P49 well.

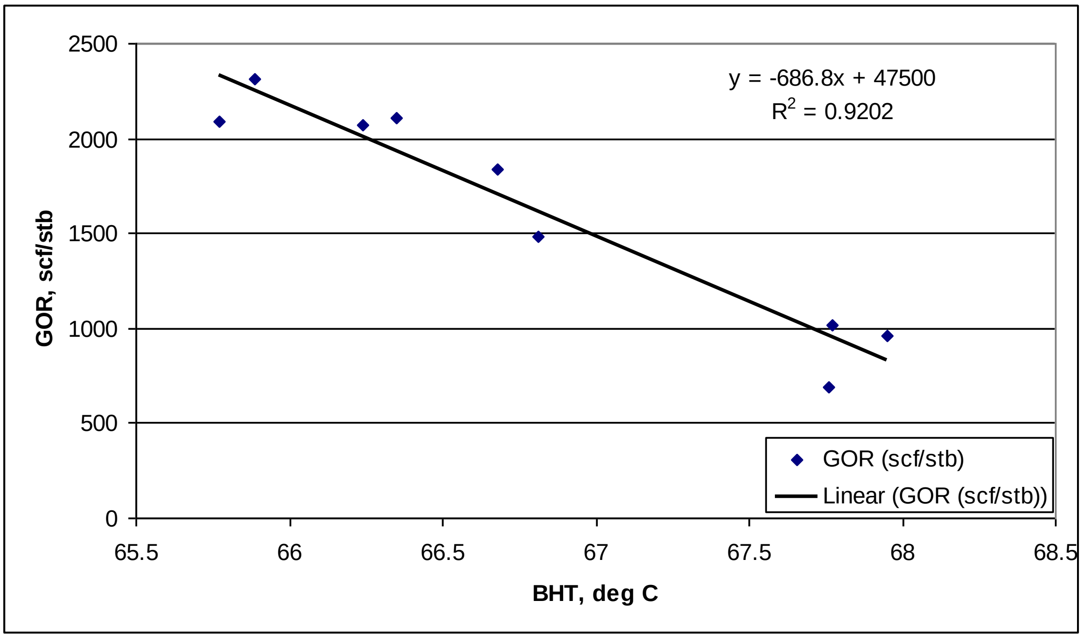

Figure 6. 20 P41 GOR and flowing bottomhole temperature correlation for period when the well is in low pressure separator

The last, third plot shown in Figure 6.20 is the representation of points at third phase, where the well is working through low-pressure separator and pressure support maintained in the flank. Although from the second graph it has been witnessed that angle of the decline in the correlation trend was gentler than first one, in this graph it is obvious that the correlation trend is the steepest of all the correlation trends of three graphs. Seemingly, dropping wellhead pressure by 30 bar (435 psi) has the greater impact than that of providing pressure support by P49 water injection well. For this correlation for every drop of temperature in the flowing bottom-hole temperature GOR is increasing up to 690scf/stb. Looking at the Figure 6.17 it is obvious that slugging behavior is already stopped as the well is diverted into low-pressure separator (end-July 2008). Also, for the first time since the pressure support started the flowing bottom-hole temperature start to go down which is indication of pressure drawdown increase and as a result of Joule-Thomson Effect flowing bottom-hole temperature decrease. As explained earlier this results in further increase in gas-oil ratio. There is another aspect of this decline in flowing bottom-hole temperature related to water injection performance of P49 well. For the period of mid-

September and early-November there is a break in water injection performance and this is reflected on the performance of P41 flowing bottom-hole temperature and gas-oil ratio (i.e. increase in gas-oil ratio and decrease in flowing bottom-hole temperature of P41). Later on, while the water injection is maintained in P49 at late December 2008, P41 gas oil ratio starts to drop and flowing bottom-hole temperature is showing warming reaction. The reason for this could be explained by the structurally downdip located P49, water injection well, pushing downdip warmer oil into the structurally updip located P41 wellbore.

6.1.2.2 P30 example

Another example to the methodology that has been used for predicting gas-oil ratio from flowing bottom-hole temperature is from P30 well, which is located in the Central South part of the Azeri field. The well is producing from single Pereriv formation and is known for its high gas-oil ratio throughout its life.

Figure 6.21 presents the life-long trend of flowing bottom-hole temperature and gas-oil ratio points from each production test.

The green circled area in Figure 6.21 indicates when the PLT was performed in the well. Figure 6.21 showing the general trend of bottomhole temperature is in decline since the production start-up in P30 well. Hence, bottomhole temperature based GOR estimation shows that the GOR in the well rises. In order to confirm the trend, the PLT was run on the well in August 2007 and results of PLT confirmed the expected raise of GOR and indicated the uppermost zone below the shale was the main contributor to the gas production.

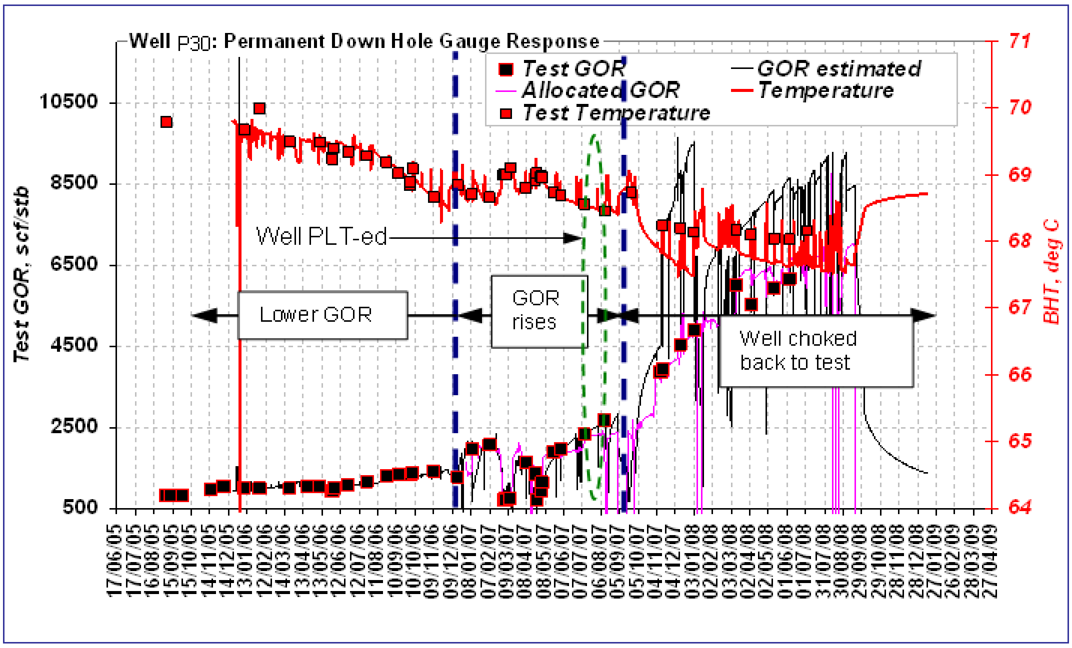

Figure 6. 21 P30 Test GOR and flowing bottomhole temperature profiles

In Figure 6.21, the general trend of production test gas-oil ratio show that there is continuous increase in GOR. At the same time, another indicator for detection of possible GOR increase, the bottomhole flowing temperature, show the continuous decreasing trend for entire period of investigation. After end-2006, as this well has been a swing well (i.e. the first well to be choked back in case of field gas production curtailment due gas production handling problems) for gas in the field for long time, the well did not work at a stable choke setting for extended period of time. Another issue related with the field constraints is the production test separator gas handling capacity. After a certain period of time, when the gas-oil ratio rise above certain level, at test periods the well was being choked back in order to accommodate the gas within production test separator gas production limits. However, at normal operating conditions the well was flowing through high pressure production separator. Analyzing the Figure 6.21 for establishing the correlation between GOR and flowing bottom-hole temperature, it is obvious that there are more than one phases for building such correlation.

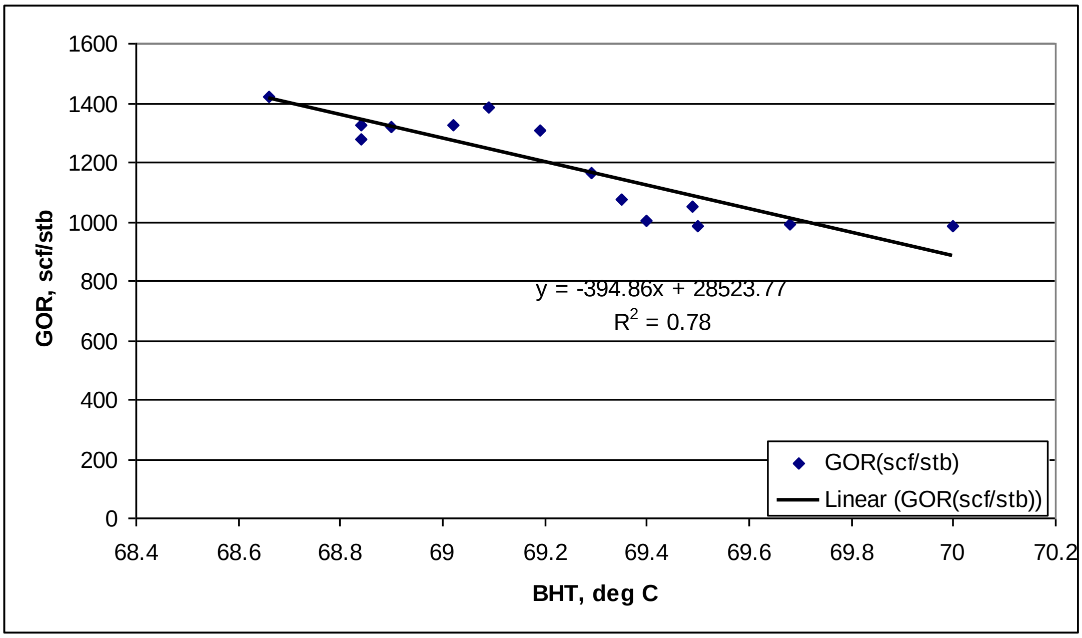

Figure 6. 22 Lower GOR period analysis for GOR and FBHT correlation for P30 well

From the above correlation it is obvious that there is relative discrepancy in correlation data which could be related with human error while measuring the test parameters. As this well was one of the early wells in the platform that has been brought online the measurement in this phase was not at required level. From the above graph (Figure 6.22) it is seen that, for every degree of temperature drop there is GOR increase of 400scf/stb. Compared for the first phase of P41, this is obvious that such an increase in GOR is inline with East part of the field. Such behavior is indicative of GOR rise is not a consequence of coning from the gas cap, yet.

The second graph (Figure 6.23) covering the phase between sudden GOR rise and the time when the well is operated at choked back position. Being in relatively better shape, the points fall mostly on the trend line indicating that the well entered into new phase. The noteworthy part of the graph is the slope of it. Different from the first trend line slope, it confirms that the GOR increased significantly and for every degree Celsius drop of the temperature, GOR raises about 3400 scf/stb, which is ten times bigger than the previous correlation slope. Looking at the location and performance behavior of the well it is obvious that in the presence of gas flooding, larger volume production and absence of water flooding in this area results in well entering into gas coning stage, hence rapid increase in GOR is observed. Nevertheless, at choke position that well is being operated in this phase while testing the well, still the test separator is able to handle all the gas that is produced by the well. Also, being a swing well due to the gas, the choke has been adjusted accordingly and performance of the well has been interrupted with such adjustments in the choke.

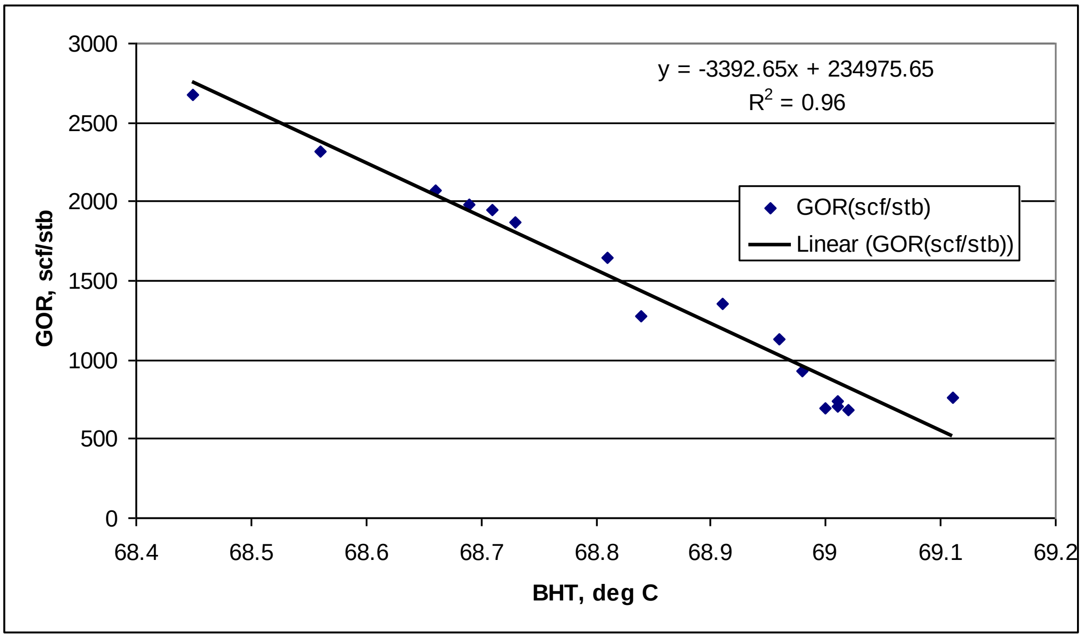

Figure 6. 23 Rising GOR period analysis for GOR and FBHT correlation for P30 well

The last, third phase correlation in the below shown graph (Figure 6.25) indicates that sharper slope correlation is obtained among GOR and flowing bottom-hole temperature data. The slope value of 6700 is specifying that further GOR increase is observed in the performance of the well. From Figure 6.21 it is perceived that there is a certain gap in between GOR points from production tests and flowing bottom-hole correlations based estimation of GOR. This is due to the fact that well is being choked back in order to flow the volume of the gas through the test separator, as test separator has certain allowed limit on gas volume. But when the points (GOR and flowing bottom-hole temperature) tied back to the observed flowing bottom-hole temperature lines it is seen that the points are the reflections of the GOR and flowing bottom-hole temperature at choked back position. Based on the correlations, estimation of true operating GORs are made and it is obvious that there is visible difference between allocated, tested and estimated GORs.

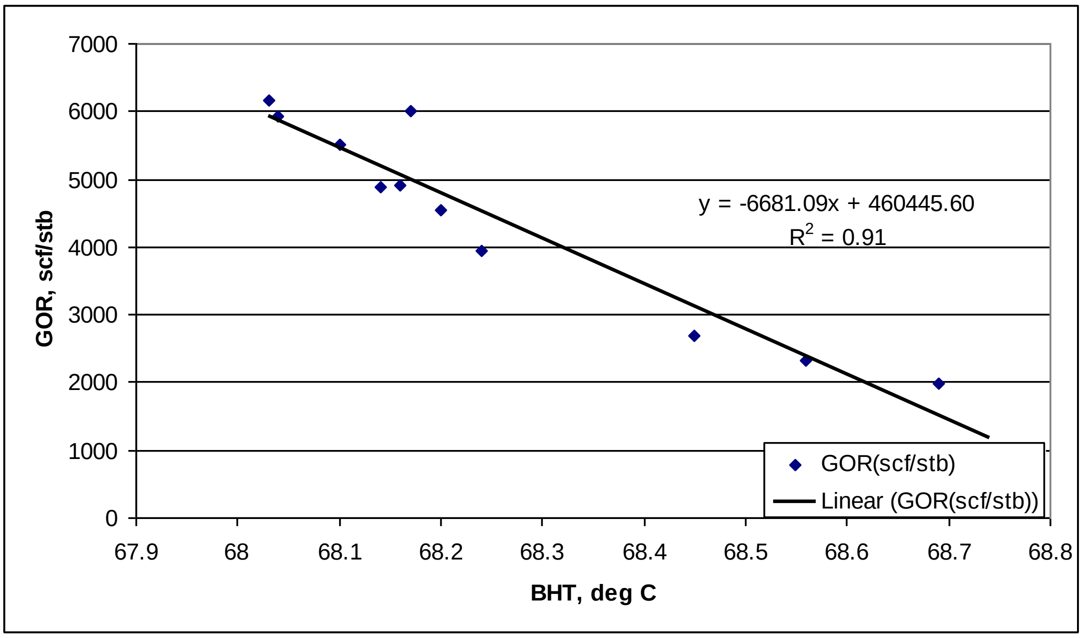

Figure 6. 24 Choked back period analysis for GOR and FBHT correlation for P30 well

6.2 Conclusion

The reservoir pressure change impacts on the GOR trend which in turn is reflected on the FBHT by means of Joule-Thomson effect. Analyzed Azeri filed examples shows that the change in FBHT is dependant on the rate of change of the reservoir pressure as well as the gas saturation.

There are several wells in the analyzed Azeri FBHP and FBHT data shows that significant reduction of the GOR in the well is reflected on the FBHP and FBHT frequent fluctuations, which is informer of the instability in the well performance. So, FBHT and FBHP could be used to diagnose the lift performance of the well.

GOR and FBHT correlations have shown that such correlations are useful in getting idea about the levels of GOR without frequently diverting them into test separators and causing production loss for higher GOR wells. The linear correlation between FBHT and GOR that has been established for producers confirmed that there is a flow regime dependent linear correlation between these parameters. Such a correlation is applied in Azeri wells to predict the 'real-time' GOR in the production wells.

Different than the conventional methods of detecting the impact of offset wells on production wells such as pressure transient analysis and well tests, this work has demonstrated that immediate response to any change at reservoir level more accurately is detectable via well flowing bottomhole temperature data. On the other hand, in the longer term by interpreting pressure transient, well tests or PLT surveys provide confirmation to the observed facts.

Integration of DTS, pressure transient analysis data, production and injection allocation data, and high frequency downhole pressure/temperature provide the valuable information not only for managing or optimizing injection or production volumes but also optimizing the location and completion zone of future injection or producer well.

CHAPTER 7

RECOMMENDATION

The examples shown in the previous section are based on the actual real-time and dynamic data. In order to get reflection of inter-well and water injection impact on bottomhole temperature simulated in reservoir model, it is required to build a thermal reservoir simulation model and history match it with available actual data. For this purposes ACG coarse grid black oil simulation model (200m x 600m) is converted into the model in which thermal outputs could be obtained. The results obtained from this model shows that resolution of coarse grid model is not good enough to reflect the changes seen in actual data due to the models nature being coarse. It is proposed to build a sector model with more refined grids for such purposes.

The key cases that need to be investigated through the thermal model would be simulating the Joule Thomson effects seen by turning on and off the water injection wells in the existence of production wells. As well as observation interference among producers by the time new producer is brought to the offset of existing producers.

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APPENDIX A

Pressure Transient Analysis, DTS and PLT plots

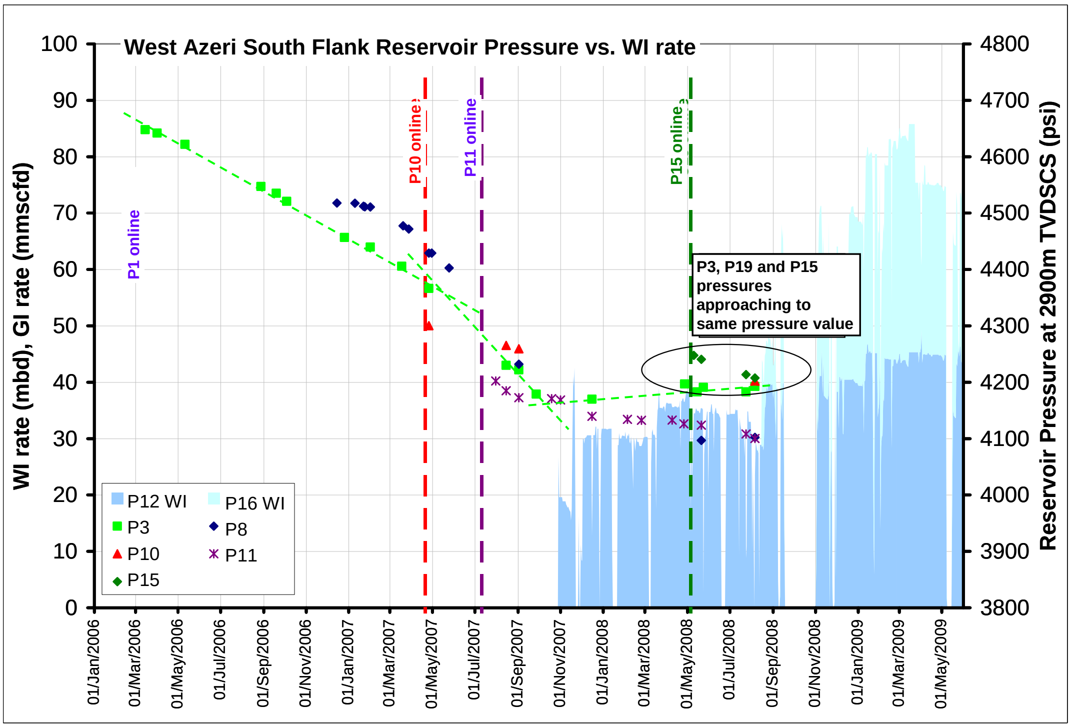

Figure A 1 West Azeri South Flank Wells Reservoir Pressure and Water Injection Rate

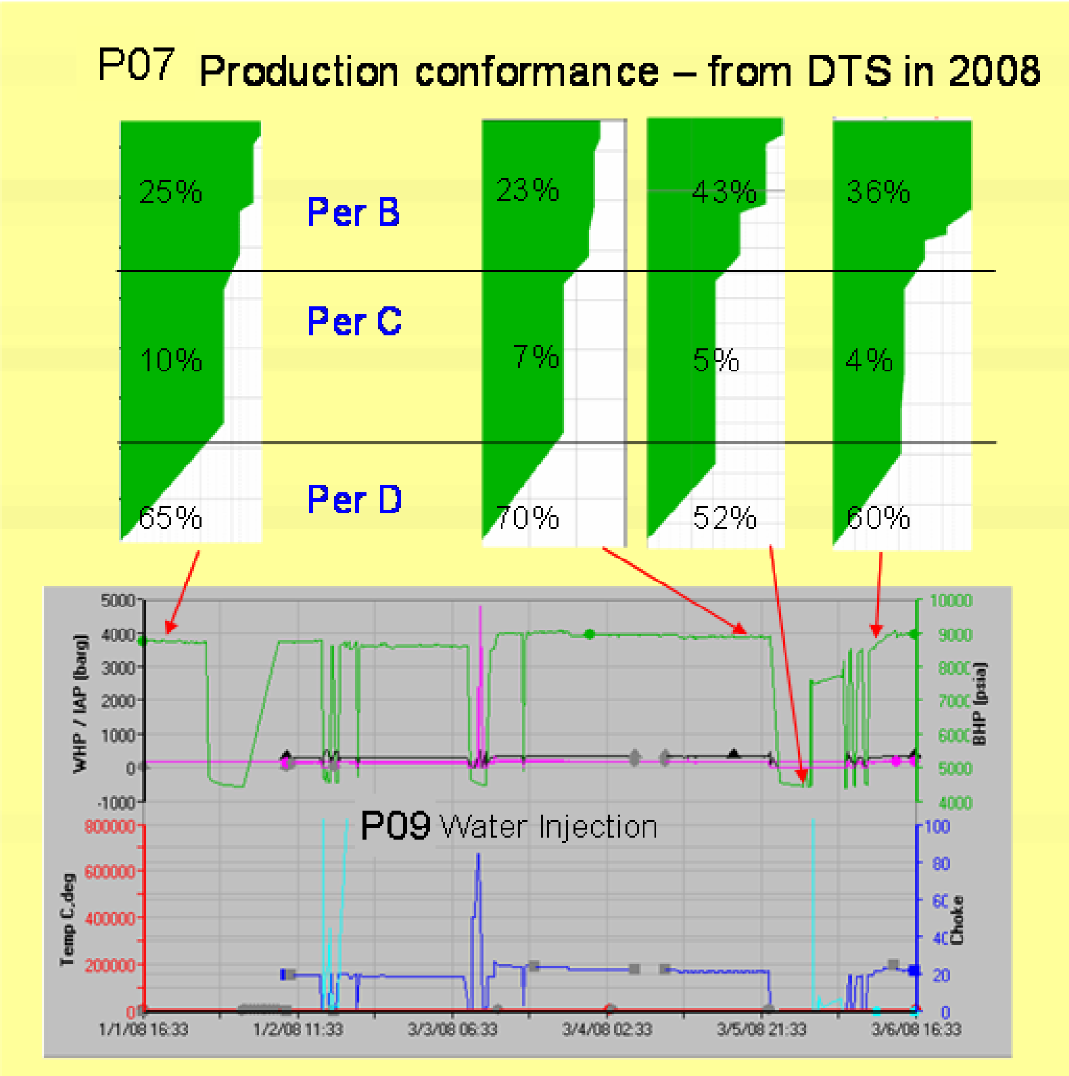

Figure A 2 P7 Integration of Production Conformance from DTS and Response to P9 water injection rate

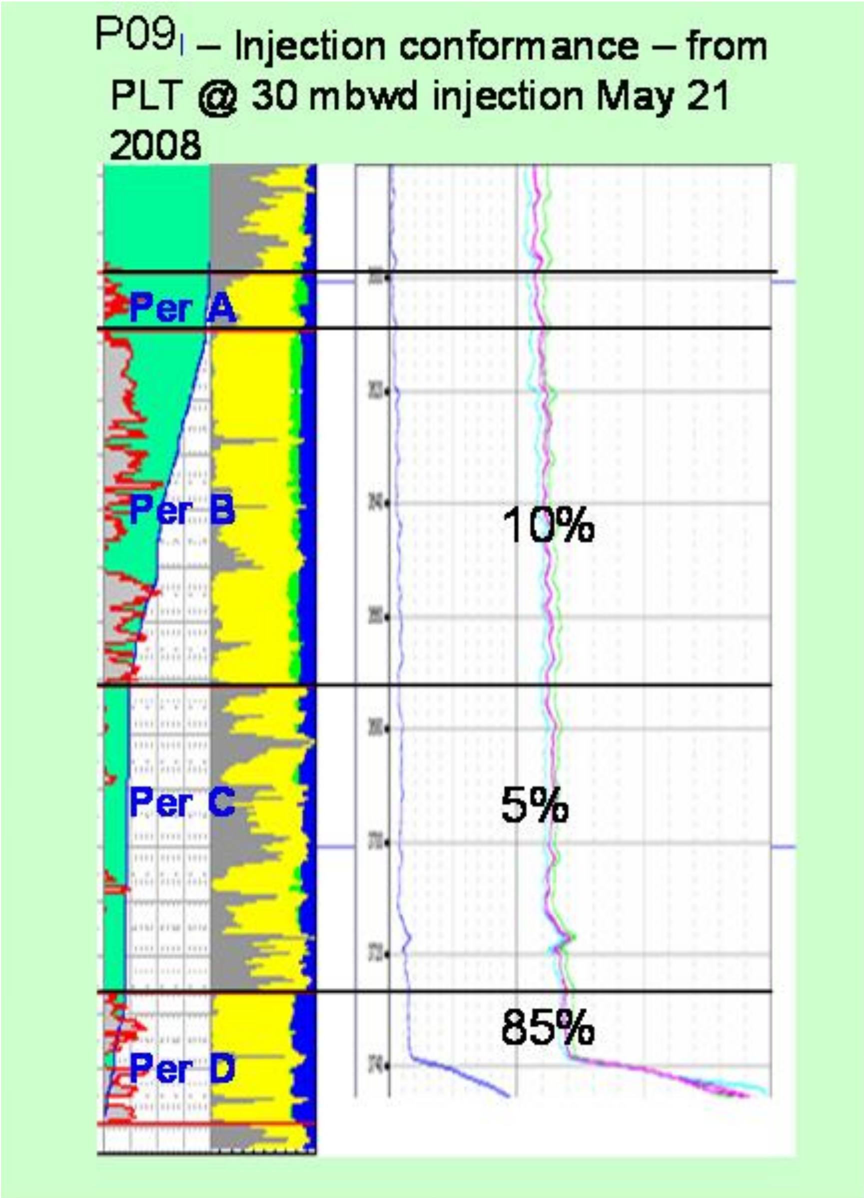

Figure A 3 P9 Injection conformance from PLT

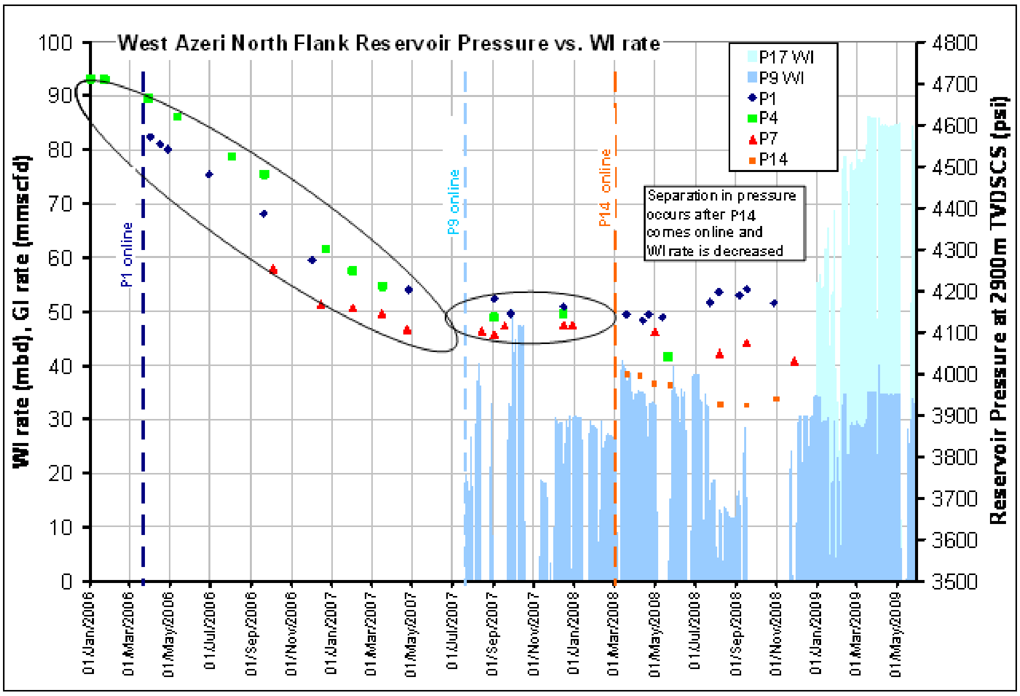

Figure A 4 West Azeri North Flank Wells Reservoir Pressure and Water Injection Rate

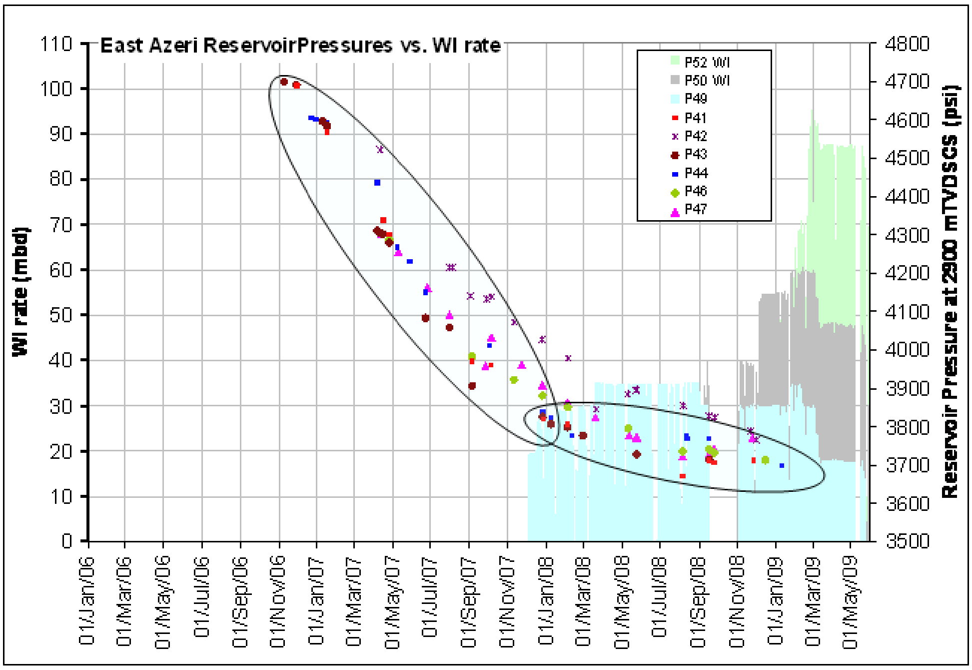

Figure A 5 East Azeri North Flank Wells Reservoir Pressure and Water Injection Rate