

IDENTIFYING RESERVOIR COMPARTMENTALIZATION USING FIELD DATA – FIELD X CASE STUDY

By

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Dissertation submitted in partial fulfilment of
the requirements for the
Bachelor of Engineering (Hons)
(Petroleum Engineering)

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the
Petroleum Engineering Programme
Universiti Teknologi PETRONAS
in partial fulfilment of the requirement for the
BACHELOR OF ENGINEERING (Hons)
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Approved by,

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September 2012

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

Nur Hidayatul Asmaa' Sazli

ABSTRACT

Identifying reservoir's compartmentalization of Field X using field data is about subdividing a reservoir into segments that behave as separate flow units during production. It is caused by barriers to fluid flow. Flow barriers can be of different strengths ,ranging from relatively minor features that may inhibit flow to major features that will not allow any fluid communication. Reservoir compartmentalization is often a key uncertainty during reservoir appraisal. It may control the spatial distributions of reserves because different compartments may contain different oil water contacts and fluids of different composition (e.g. gas-oil ratio).Ideally ,reservoir compartmentalization should be mapped during reservoir appraisal so that this knowledge can be factored into field commerciality decisions ,development planning and facility designs (e.g. number of wells needed to drain oil) . The problem is that the dynamic data so useful for identifying compartmentalization during production usually lacking at the appraisal stage. Therefore, making the best use of the data that are available during reservoir appraisal is important. The purpose of the project is to show that by integration of initial dynamic data ,it is possible to identify the reservoir compartments at an early stage in field life .Those data are :

- Pressure data
- PVT data
- Well test analysis
- Log data

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1.0 PROJECT BACKGROUND

1.1 Background of Study

Reservoir compartmentalization is about subdividing a reservoir into segments that behave as separate flow units during production (Smalley *et al.* ,1994). Many, if not all, oil field are to some degree compartmentalized. It is caused by barriers to fluid flow .These barriers that exists will divide the reservoir into compartments that do not communicate with each other or have only limited communication during oil production (Smalley *et al.* ,1996).Jolley *et al.* , (2010) define it as the segregation of petroleum accumulation into a number of individual fluid/pressure compartments that occurs when flow is prevented across sealed boundaries in the reservoir . The expected outcome of the study is the number of compartments identified in the field and where are they located, both laterally (segments) and vertically (zones), as well as supporting information based on field data (PVT, well test, pressure, fluid contact, fluid production, etc).

1.2 Problem statement

Reservoir compartmentalization is always a key uncertainty during reservoir appraisal (reservoir appraisal is a stage during the life of a field when reservoir data acquisition/gathering becomes the main activity in order to get to know the reservoir. Getting to know the reservoir is the main theme in this stage , instead of producing the hydrocarbon as much as possible. During this stage, production of the reservoir has not been started).This is due to lack of dynamic production data during early field life because dynamic data are the most definitive compartmentalization data. Only static data and initial dynamic data are available for a reservoir under appraisal stage. Thus ,in order to do this, different types of initial dynamic subsurface data available during reservoir appraisal stage will be used to identify reservoir compartments.

1.3 Objective of project

- I. To compile all the available field data (initial dynamic data).
- II. To analyse all the available data by using pressure transient analysis,formation pressure analysis,PVT analysis as well as core and log data analysis.

III. To integrate all the relevant data to identify reservoir compartments.

1.4 Scope of study

The scope of study in order to do this project will mostly covered the reservoir engineering subjects especially :

- Pressure transient analysis

PTA consist of observing the changes in pressure (and temperature) caused by changing rate .

- Formation evaluation and well logging

Study of the physical properties of rocks and the fluids contained within them.

1.5 Relevancy of topic

Identifying reservoir compartments is an integral part of so called reservoir characterization which is the act of building a reservoir model based on its characteristics with respect to fluid flow. A model of a reservoir that incorporates all the characteristics of the reservoir that are pertinent to its ability to store hydrocarbons and also to produce them. Reservoir characterization models are used to simulate the behaviour of the fluids within the reservoir under different sets of circumstances and to find the optimal production techniques that will maximize the production. For example, we will not drill more than 1 well if the reservoir is fully connected (only 1 region and good sand quality throughout). On the other hand, we will need more wells to maximizing hydrocarbon recovery if our field is compartmentalized since one well will not be able to produce hydro carbon from different compartment since they are not in communication. The benefit will be to operating company to be able to formulate an optimum field development scenario.

1.6 Feasibility of study

The project is feasible as it :

- Schedule feasibility
Can be completed in a given time which is approximately 3 months
- Scope feasibility
Covered the reservoir engineering studies

2.0 LITERATURE REVIEW

The paper by **Smalley and Hale** examined that reservoir compartmentalization is often a key uncertainty at the field appraisal stage which indirectly gives an impact on important investment decision. Identification of reservoir compartments is important in sitting and designing surface facilities, number of wells needed to drain the oil from the reservoir, and thus affecting the economics part of producing the field. The paper shows how early indications of compartmentalization can be achieved by integration of conventional data as well as novel data. By using oil compositional data (molecular maturity parameters, gas chromatography [GC] fingerprinting, pressure-volume-temperature [PVT] data) with pressure, well test, and fault seal analysis enable the field to be segmented. The paper demonstrated that there is a possibility to identify reservoir compartments at an early stage of field life even in the absence of dynamic production data, that is by making best use of the mainly static tools that are available. The key message is that no single type of static data is definitive to identify reservoir compartments but a combination of several conventional data sources with the novel ones can greatly enhance the prediction of reservoir compartments. Using an example from the Ross oilfield, U.K. Continental Shelf (UKCS), the reservoir pressure from repeat formation tester (RFT) pressure data for 6 wells are used. The RFT data successfully detected a lack of pressure communication between the two parts of the field where the pressure data from the West part of the field is 50 psi overpressure from the rest of the field. The prime candidate for a barrier feature causing this pressure differences is a large NE-SW fault which happened to be a major flow barrier on a production time scale. This evidence is then supported by examining the variations in oil compositions where small but distinct variations were seen in the molecular maturity parameters data. The data are best interpreted as a distinct change in oil composition across the major NE-SW fault separating these two areas conforming the conclusions of the RFT pressure work that this fault is an important barrier to fluid communication. Then another technique using oil GC fingerprinting helped to highlight compositional variations in the oil composition. This technique showed that a large change in oil fingerprints occurs between the central and eastern segments which reinforce the suggestion from the oil maturity data before that NE-SW fault is a significant barrier to fluid flow that prevented oil from mixing between the central and eastern areas of Ross oilfield. Then, using PVT data from DST oil samples, there are two wells that have gravitationally unstable oil densities indicating a possible fault barrier that causes a poor communication in a north-south direction in the eastern part of the Ross field which is then, this interpretation is supported by the well test data.

PVT data(oil compositional data)

Pressure-volume-temperature (p-V-T) data are the most fundamental thermodynamic data. Along the saturation line, p-V-T data constitute the primary thermodynamic data. Equations of state for all of the thermodynamic properties are most often written directly in terms of pressure, temperature, and volume, and comprehensive p-V-T data are the basis for fitting accurate equations of state. **Casto, Canas-Marin, Osorio and Soto** presented the methodology of integrated fluid analysis in order to examine reservoir compartments. Their study hold the key message that in order to identify reservoir compartments, it is crucial to have information on production as well as good PVT data ,in addition to geological and geochemical information. The methodology includes fluid sampling analysis, PVT test quality control and reservoir fluid representativeness. This method will then help to determine reservoir compartments by calibrating the equation of states and realizing predictions of compositional gradients. This is done by compositionally modelled the analysis with commercial software, matching the Peng-Robinson EOS's parameters for subsequently predicting compositional gradients. Then, by studying and analysing the compositional gradients, the fluid behaviour (GOC,API,etc.) will help determine reservoir compartments.

GC Fingerprinting(oil compositional data)

GC fingerprinting is about how the differences in the pattern of oil composition can distinguish one oil from another. This can be done by first collecting a sample and separating it into various fractions. Then, each fraction is analysed using instruments to give "printouts" of their chemical compositions. The "printouts" are in the form of graphs called "chromatograms," which are then interpreted by chemists. The technique that is used to create the chromatograms is called Gas Chromatography-Mass Spectrometry (GC-MS). GC-MS is the most reliable method to fingerprint an oil sample since it uses a multi-parameter approach in which individual compounds present in a sample are identified.

The term "oil fingerprint", as used with regard to the technique described in this article, refers to the relative abundances of closely spaced peaks on an oil GC (i.e., the values for ratios of closely spaced peaks). As Kaufman et al. (1990) noted, "The term "uniform fingerprint" is not to imply uniform hydrocarbon composition. There are many factors that may affect the composition of oil within a pool, including gravity segregation (Creek and Schrader, 1985), degradation at the oil/water contact (Dahl and Speers, 1985), and migration effects (England et al., 1987). These effects can usually be normalized by using ratios of peaks corresponding to compounds of similar, if not identical, molecular weight in the n-C7+ region of the chromatogram"

There is no argument that the composition of oil in a very thick compartment can change with depth as a result of gravitational segregation. Perhaps the most obvious expression of such segregation is a progressive increase in API gravity with decreasing reservoir depth. But, as Kaufman et al. (1990) note, such segregation often does not change the oil fingerprint substantially because compound ratios selected for the star diagrams are of closely spaced inter-paraffin peaks, and the similar molecular weight of such closely spaced compounds greatly reduces the effect of compositional variations (such as gravitational segregation) on the peak ratio values.

Pressure data (pressure vs depth plot)

In order to identify reservoir compartmentalization, a pressure plot vs depth will be plotted in order to determine the pressure gradient (as shown in fig.1). Pressure gradient definition from the perspective of well testing is a change in pressure as a function of distance. This can refer to radial change in pore pressure with distance from the well (which can be calculated from well-test analysis results), to change in pore pressure with depth (which can be measured by formation tests, and implies formation fluid density and/or fluid contacts) or to change in wellbore fluid pressure with depth (which can be measured with production logs, and implies wellbore fluid density).

- Formation/pore pressure

The pressure of fluids within the pores of a reservoir, usually hydrostatic pressure or the pressure exerted by a column of water from the formation's depth to sea level. Because reservoir pressure changes as fluids are produced from a reservoir, the pressure should be described as measured at a specific time, such as initial reservoir pressure.

- Pressure vs depth plot

Formation pressure tends to increase with depth according to the hydrostatic pressure gradient of 0.433 psi/ft. Deviations from this gradient and the associated pressure at a given depth are considered abnormal pressure.

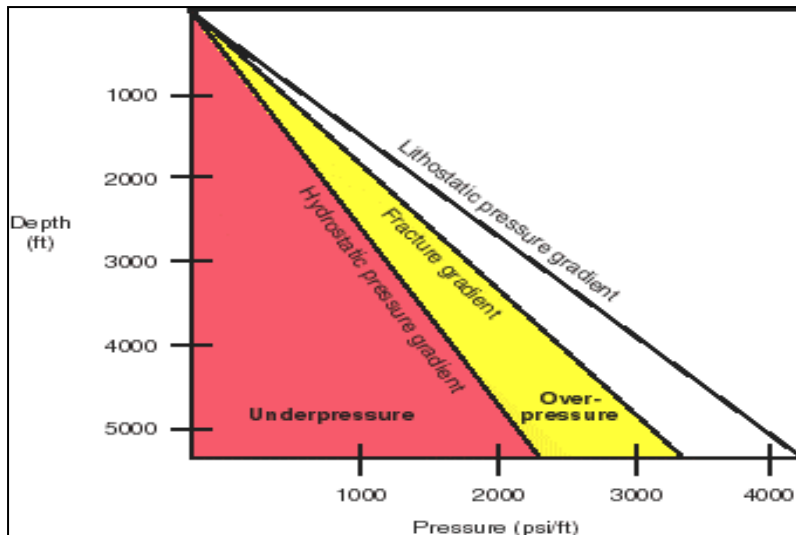


Figure 1 : Pressure vs depth

Normal pore pressure or formation pressure is equal to the hydrostatic pressure of formation fluid extending from the surface to the surface formation being considered. In other words, if the formation was opened up and allowed to fill a column whose length is equal to the depth of the formation, then the pressure at the bottom of the column will be equal to the formation pressure and the pressure at surface is equal to zero.

Abnormal pore pressure/overpressure is defined as any pore pressure that is greater than the hydrostatic pressure of the formation fluid occupying the pore space. It is sometimes called overpressure or geopressure. An abnormally pressured formation can often be predicted using well history, surface geology, downhole logs or geophysical surveys.

Subnormal pore pressure/under pressure is defined as any formation pressure that is less than the corresponding fluid hydrostatic pressure at a given depth. Subnormal pressured formations have pressure gradients lower than fresh water or less than 0.433 psi/ft (0.0979 bar/m). Naturally occurring subnormal pressure can be developed when the overburden has been stripped away, leaving the formation exposed at the surface. Depletion of original pore fluids through evaporation, capillary action and dilution produces hydrostatic gradients below 0.433 psi/ft (0.0979 bar/m). Subnormal pressures may also be induced through depletion of formation fluids. USED

The difference between normally and abnormally pressured rocks is that in abnormally pressured zones the pore fluids no longer communicate 100% efficiently with the water-table (surface communication). This is due to some mechanism is providing a seal or cap to interfere with the fluid column and preventing it from achieving normal hydrostatic equilibrium . Once the continuity of the fluid column has been broken, the pore fluids can

be acted upon in a number of ways. If we picture the area of abnormal pressure as a compartment, it can be present in three different conditions; 1) it may be perfectly sealed like a balloon, 2) it may slowly leak like a punctured tyre, or 3) it may be so leaky that it holds pressure for a short period of time (these very leaky seals are not often knowingly drilled but have other geologically important roles, such as being the cause of major landslips and slope failures).

Well test analysis

Well-test analysis has been used for many years to obtain reservoir parameters. Early interpretation methods (using straight lines or log-log pressure graphs) were limited, and consequently, well-test analysis was used mostly for the estimation of well performance. With the introduction of pressure-derivative analysis and the development of complex interpretation models that are able to account for detailed geological features, well-test analysis has become a very powerful tool for reservoir characterization.

- Pressure transient analysis theory

During a well test, a transient pressure response is created by a temporary change in production rate. The well response is usually monitored during a relatively short period of time compared to the life of the reservoir, depending upon the test objectives. For well evaluation, tests are frequently achieved in less than two days. In the case of reservoir limit testing, several months of pressure data may be needed. In most cases, the flow rate is measured at surface while the pressure is recorded downhole. Before opening, the initial pressure P_i is constant and uniform in the reservoir. During the flowing period, the drawdown pressure response is defined as follows:

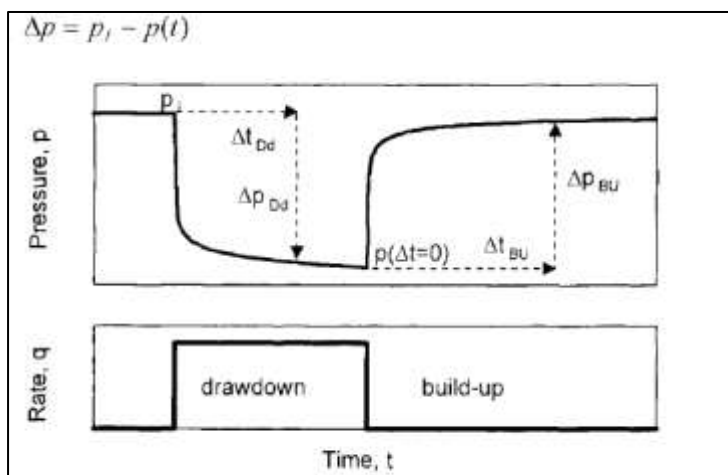


Figure 2 :Drawdown and build up test sequences

- Well test objectives

According to **Bourdet**, well test analysis provides information on the reservoir and on the well. Geological, geophysical and petrophysical information is used where possible in conjunction with the well test information to build a reservoir model for prediction of the field behaviour and fluid recovery for different operating scenarios. The quality of the communication between the well and the reservoir indicates the possibility to improve the well productivity. Usually, the test objectives can be summarized as follows:

Exploration well: On initial wells, well testing is used to confirm the exploration hypothesis and to establish a first production forecast: nature and rate of produced fluids, initial pressure and well and reservoir properties. Tests may be limited to drill stem testing only.

Appraisal well: The previous well and reservoir description can be refined by testing appraisal wells to confirm well productivity, reservoir heterogeneities and boundaries, drive mechanisms etc. Bottom hole fluid samples are taken for PVT laboratory analysis. Longer duration testing (production testing) is usually carried out.

Development well: On producing wells, periodic tests are made to adjust the reservoir description and to evaluate the need for well treatment, such as work-over, perforation strategy or completion design, to maximize the well's production life. Communication between wells (interference testing), monitoring of the average reservoir pressure are some usual objectives of development well testing.

Well log (Wireline / Logging while drilling)

A study conducted by **Hahn,Ng,Zhou,Lallemand and Pragt** discusses an approach that formation testing whether on wireline or logging while drilling can also help to evaluate reservoir compartmentalization. Important information such as reservoir fluid types, fluid contacts, can now be evaluated by this technique. The study shows that potential reservoir compartmentalization and connectivity can be detected by analysing changes in fluid densities across fluid barriers. The assumption is that fluid within the same compartment usually displays a uniform pressure system and therefore has the same density or very gradual changes in density. On the opposite, if the two set of pressure measurements display distinct pressure magnitude and slopes, there must be an impermeable formation in between them, thus, most likely they are from different reservoir compartments. This study is also supported by a paper by **Smalley and Muggeridge**, where they describe the impact of reservoir compartmentalization on oil recovery. The authors use simple analytical equations to determine the time taken for a variety of fluid properties (e.g pressure, density, composition, etc) to equilibrate. Some properties such as pressure differences within

aquifers are shown to equilibrate very rapidly (e.g less than 10 years). On the other hand, other fluid properties such as the isotopic composition of pore fluids would be expected to take tens of millions of years to equilibrate throughout a reservoir. The implications of these calculation is that one would expect to find differences in fluid properties that are slow to equilibrate even in reservoirs that are not compartmentalized. However, if there are differences in fluid properties that should equilibrate rapidly, they should be taken as a serious indication of reservoir compartmentalization.

3.0 METHODOLOGY

3.1 Research Methodology

Below are the proposed methodology and step-by step in order to identify reservoir compartmentalization:

1. Compile all relevant data
2. Analyse data :
 - Pressure transient analysis (well test evaluation)
 - Radius of investigation
 - Presence of no-flow boundary
 - PVT analysis (using PVTi software)
 - Reservoir fluid composition comparison
 - Composition versus depth gradient
 - Fluid density
 - Formation pressure analysis
 - Pressure versus depth profile
 - Logdata analysis
 - Log correlation between wells
3. Integrate all relevant data to support evidences of compartmentalization

3.2 Project Activities

3.2.1 Compilation of all relevant data

The first step is to compile all the relevant field data needed for this project. These data include static data and initial dynamic data that are available for a reservoir under appraisal stage. Below are the field data that are available for this project :

PVT (pressure-volume-temperature) data

PVT data represents the fluid properties of the reservoir. For West Field X ,there two fluid samples taken for PVT analysis. These samples are bottomhole and separator samples taken from well A-S1 and P1respectively. The fluid type for both fluid samples are oil.

Formation pressure data

The initial reservoir pressure for Field X were based on pressure build up test taken from well A1 and P1.

Pressure transient data

Pressure transient data are needed for well test evaluation. For Field X ,the data are taken from the DST (drill stem test) that are performed on well A-S1 and P1.Futher well test analysis are conducted for both wells.

Wireline Log data

Log data that are available are gamma ray and resistivity log. Log data will help determine the sand/shale formation as well as differentiating between type of hydrocarbon present in the formation. For field X , Log data are available for well AS1 ,P1 and P2.

3.2.2 Analysing field data

PVT analysis

In order to identify the reservoir compartments , by utilizing the PVT data available, that is from the two fluid samples(A -S1 and P1) , the fluid data will be used in the fluid properties simulator, PVTi (Schlumberger package).The PVTi program is an Equation of State based package for generating PVT data from the laboratory analysis of oil and gas samples.Multiple fluid samples can be defined by specifying components in the software.Experiments may be performed on the fluid systems defined using the equation of state model.

- Reservoir fluid composition comparison

The composition of the reservoir fluid has an extremely important control on its pressure-volume-temperature properties, which define the relative volumes of each fluid in a reservoir. Using PVTi,by simulating experiments such as Constant composition expansion (CCE) and differential liberation (DL) , the reservoir fluid compositions comparison can be done by observing the relative volume of each fluid in the reservoir.

- Composition vs depth gradient

One of the experiments that can also be performed in PVTi is composition vs depth experiments. By simulating this experiments in the software , the trend of fluid composition varying with depth can be profiled .

- Fluid density

Fluid data can be expressed in term of subsurface density vs depth. From this plot,we will be analysing the density gradient of the fluid.

Formation pressure analysis

For formation pressure analysis, pressure vs depth will be profiled. Since the formation pressure data are only available from 5 wells, there are 5 pressure profiles. By plotting pressure vs depth, the objective is to get the pressure gradient of the oil, water and gas column. Once the pressure gradient can be obtained, the comparison of the pressure gradient can help identify whether the wells are in communication or not. For example, in below, if the gas gradient of well 1 is similar to well 2, we can say that both wells are in communication and may be from the same system and vice versa. However, it must be supported by other analysis.

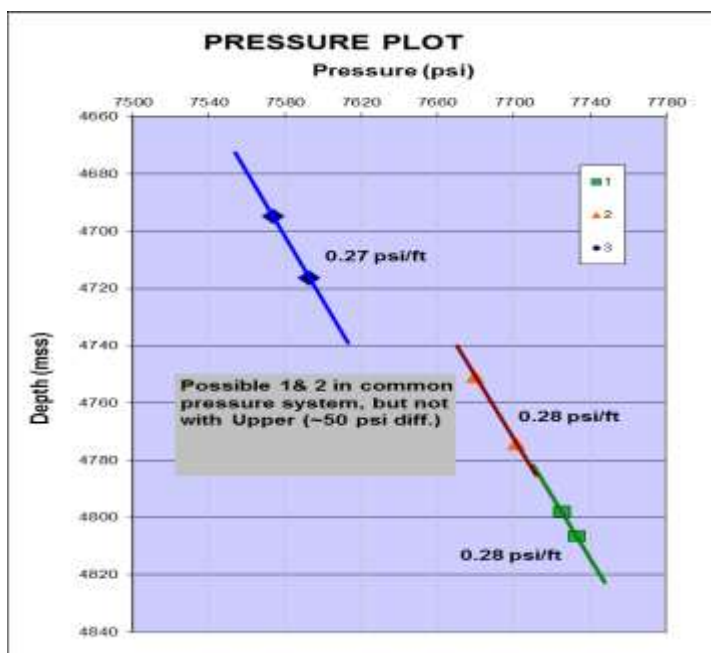


Figure 3: example of pressure plot

Pressure transient analysis

Pressure transient analysis is a period of time during which the rate and/or pressure of a well is recorded in order to estimate well or reservoir properties, to prove reservoir productivity, or to obtain general dynamic reservoir data. For Field X, the pressure transient data are obtained from the DST (drill-stem test) which are usually conducted on exploration and appraisal wells. For this project, it is important to determine:

- Radius of investigation

r_{inv} is a theoretical distance which a limiter any reservoir parameter change can be detected. It is a point before the pressure disturbance is negligible. By investigating the

value of r_{inv} , reservoir heterogeneity can be identified. But, the radius of investigation of a test must be greater than or equal to the distance to that heterogeneity. Once heterogeneous reservoir is identified, it indicates a formation with two or more non-communicating sand members, each possibly with different specific- and relative-permeability characteristics.

- Presence of no-flow boundary

No-flow boundaries can be detected when pseudo-steady state (PSS) flow occurs during the late time region. This includes not only the case when the reservoir boundaries are **sealing faults**, but also when nearby producing wells cause no flow boundaries to arise. During the PSS flow regime, the reservoir behaves as a tank. The pressure throughout the reservoir decreases at the same, constant rate. PSS flow does not occur during build-up or falloff tests.

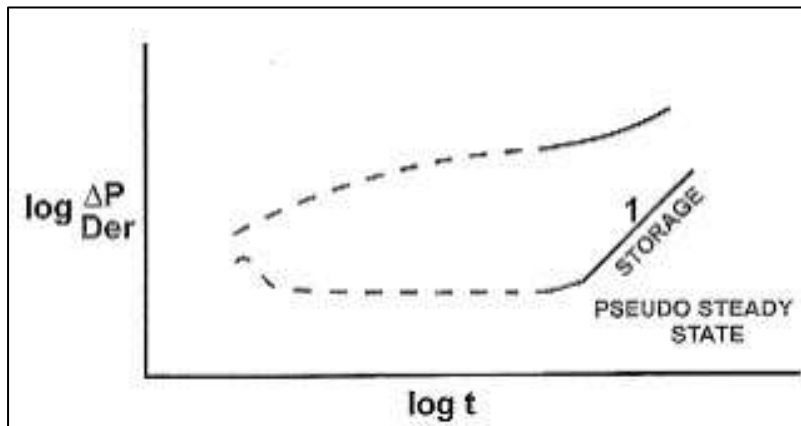


Figure 4: Derivative plot

Log data analysis

For well logging analysis, it is a record of certain formation data versus depth. It will measure the electrical, acoustic, and radioactive properties of the formation.

Basically, log and core analysis will help:

- To evaluate hydrocarbons reservoirs and predict oil recovery.
- To provide the reservoir engineers with the formation's geological and physical parameters necessary for the construction of a fluid-flow model of the reservoir.
- Measurement of in situ formation fluid pressure and acquisition of formation fluid samples.

- In petroleum exploration and development, formation evaluation is used to determine the ability of a borehole to produce petroleum.

3.2.3 Integrate all relevant data to support evidences of compartmentalization

Any of the tool used on its own will only reveal a small part of the picture ,partly because of the different spatial data coverage provided by the different tools and analysis and partly because of their different sensitivities. No single type of static data is definitive when it comes to identifying reservoir compartmentalization. However , a combination of them can greatly enhanced the ability to predict compartmentalization.

3.3 Project Milestone and Gantt Chart

PROJECT ACTIVITIES	WEEK NO / DATE																											
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
FYP Topic selection	█	█	█																									
Preliminary research work				█	█	█	█																					
Submit proposal defense report								█	█																			
Oral presentation 1										█																		
Submit interim proposal											█	█	█	█														
Compile all field data															█	█												
Analyze all data																	█	█	█	█	█	█	█					
Integrate all data																								█	█	█		
Final report and presentation																											█	█

Table 1 : Project milestone

4.0 RESULT AND DISCUSSION

4.1 Overview of West X Field

Field X is located offshore Turkmenistan. The two major reservoirs in Field X are Reservoir A and Reservoir B. The depositional environment: shallow water lacustrine. The Trap style are fault trap and stratigraphic. Field X are subdivided into 4 compartments as shown in the figure below :

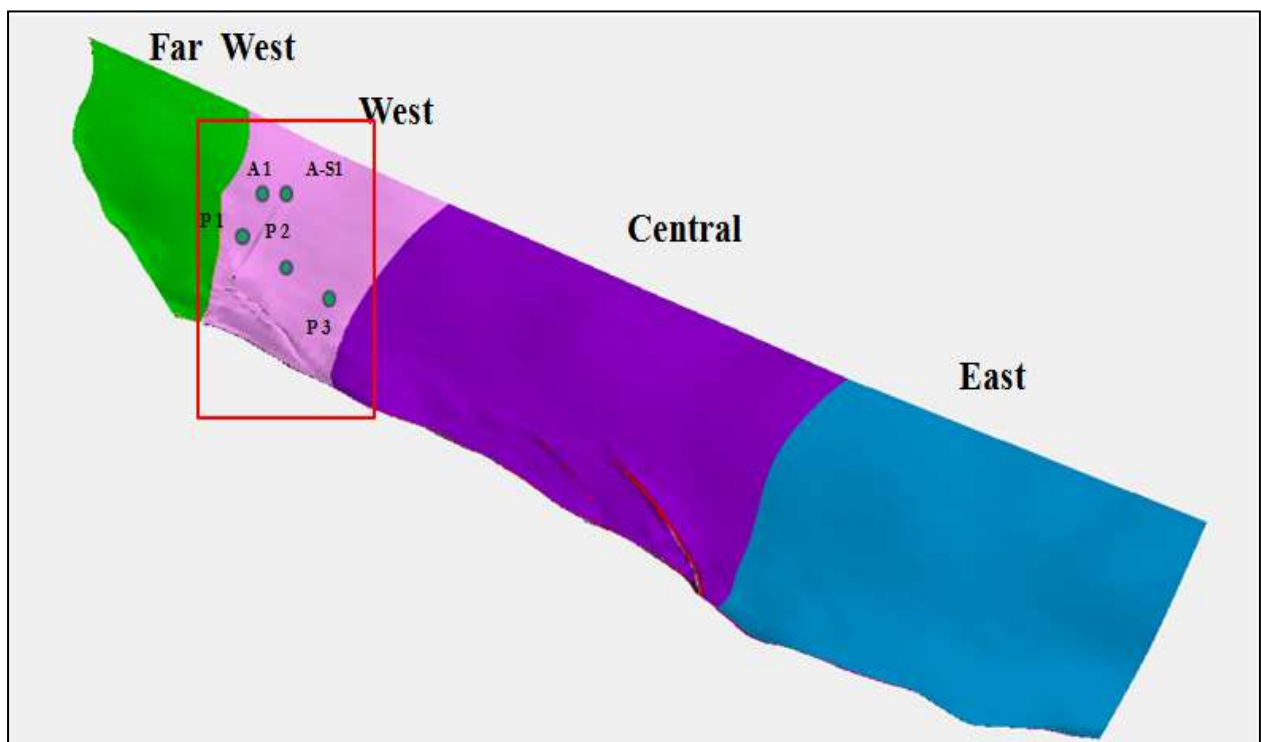


Figure 5 : Field X overview

Field X is divided into 4 compartments which are Far West, West, Central and East. Based on the RMS amplitude map as in figure below, it shows two clear breaks in continuity in the Field X area and helps, along with the fluid contacts; break the area into separate compartments (West, East and Central). The loss of the amplitude in the indicated areas is due to the **facies changes** in the primary reservoir interval Reservoir B Middle.

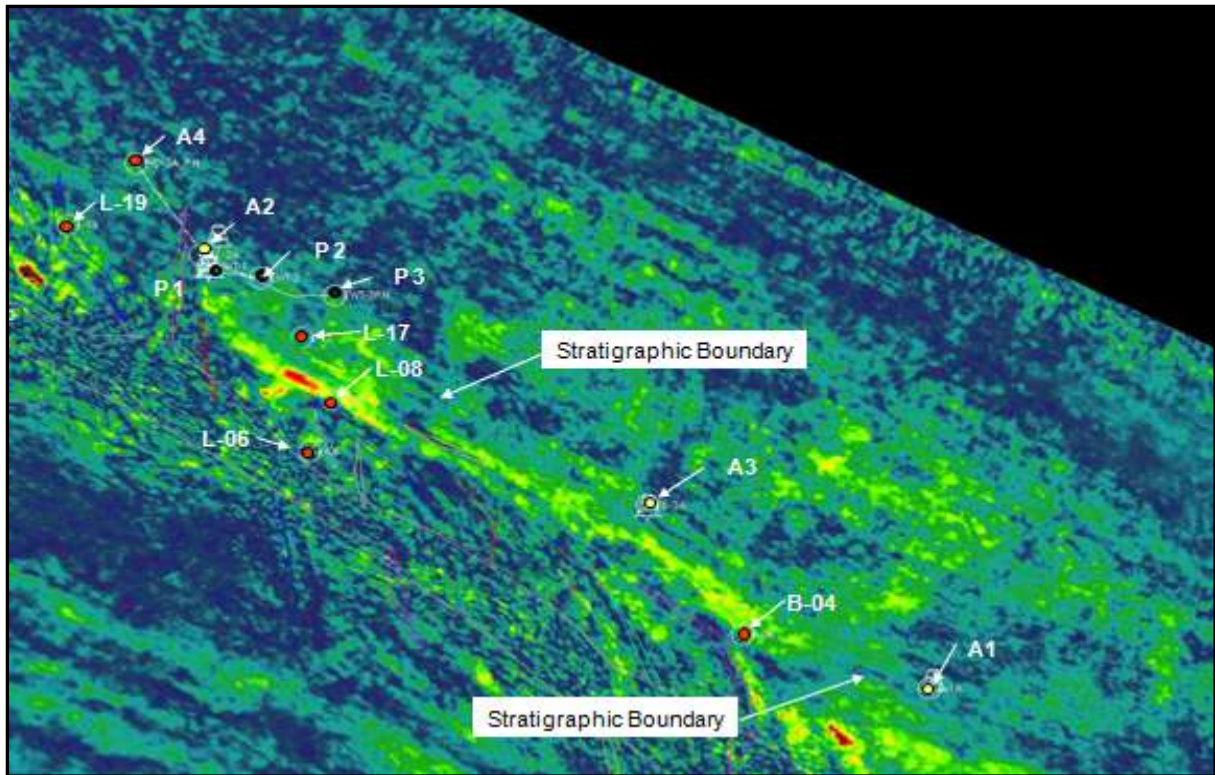


Figure 6 :Reservoir B Middle RMS Amplitude Map

This project will only focus on **West of Field X** which consists of 5 wells :

- A 1
- A – S1
- P1
- P2
- P3

Where A1 and A-S1 are appraisal wells and well A-S1 is the sidetrack for well A1. Meanwhile P1, P2 and P3 are producing wells

4.2 Log analysis

For West Field X, the **vertical compartmentalization** can be recognized by evaluating the log available for well A-S1 ,P1 and P2 . Figure 8 shows the gamma ray and resistivity log correlation for West Field X:

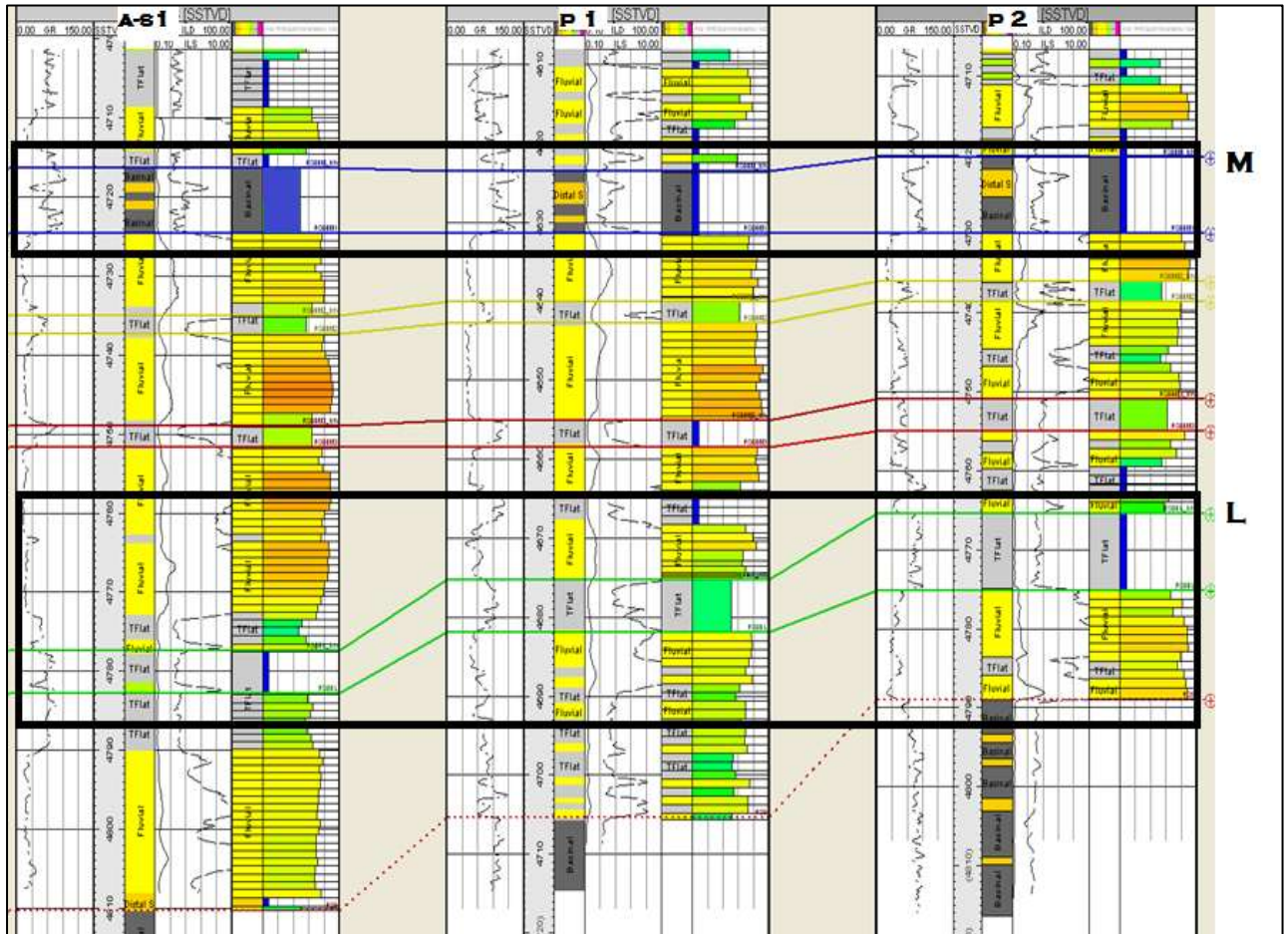


Figure 7 : Log correlation between well A-S1,P1 and P2

Gamma ray log measures the strength of the natural radioactivity present in the formation. It is particularly useful in distinguishing sands from shales in siliciclastic environments. The gamma ray reading can be read on the left side of the log. While for resistivity log, the formation resistivity for multiple depths of investigation are measured by an induction-type wave resistivity tool. The resistivity log reading are available on the right side of the log where it can distinguishes between hydrocarbon bearing zone and non-hydrocarbon bearing zone.

Log analysis

- From figure above, the yellow and orange zone represents the sand layer with gamma ray value less than 80 .
- The blue zone represents shale layer with gamma ray value more than 80.
- The blue zone also indicate water zone based on the low reading of resistivity log

- Meanwhile, the green zone indicates hydrocarbon bearing zone due to high value of resistivity.
- The zone in the black-squared box indicates shale layers between the reservoir.
- These shale layers divide the reservoir B into three zones: upper, middle and lower.

Conclusion on log analysis

- Thus, based on gamma ray and resistivity log analysis, there are 3 vertical compartments (zones) detected :
 - Upper zone of Reservoir B
 - Middle zone of Reservoir B
 - Lower zone of Reservoir B

4.3 Pressure Data Analysis

Initial reservoir pressure of reservoir B sand in the West Field X was based on well A1 and P1. The initial pressure of RB Upper was 7550 psi at a datum of 4700 m-tvdss. RB Middle and RB Lower had the same initial pressure of 7600 psi at the same datum depth. The pressure gradient is 0.16 psi/ft in the gas column, 0.28 psi/ft in oil column and 0.44 psi/ft in water column.

Available Pressure data

For West Field X, the available pressure data are taken from pressure build up test(PBU).Below are the tabulated pressure data :

- A1

DEPTH (mss)	PRESSURE (psia)	RESERVOIR
4695.0	7574	RB Upper
4716.5	7593	RB Upper
4751.0	7680	RB Middle
4774.5	7702	RB Middle
4798.0	7725	RB Lower
4806.5	7733	RB Lower

Table 2 :Pressure Build Up data for A1

- P1

DEPTH (mss)	PRESSURE (psia)	RESERVOIR
4649.0	7555	RB Middle
4655.0	7549	RB Middle

Table 3 :Pressure Build Up data for P1

Pressure plot

- A1
 - From the pressure plot of well A1,there is possible communication between RB Middle and Lower as they are on the same pressure gradient (oil gradient = 0.28 psi/ft) .
 - However , there might be no communication of both sand layer with the RB Upper as there are ~50 psi pressure difference with a slight different in oil gradient which is 0.27 psi/ft .
 - Thus, deviations of RB Middle and Lower pressure gradient from RB Upper gradient and the associated pressure at a given depth are considered abnormal pressure/overpressure.
- RB Middle sand of A1 and P1
 - There might be no communication of both well A1 and P1 even though both are at the same sand layer (RB middle sand) with ~40 psi pressure difference.

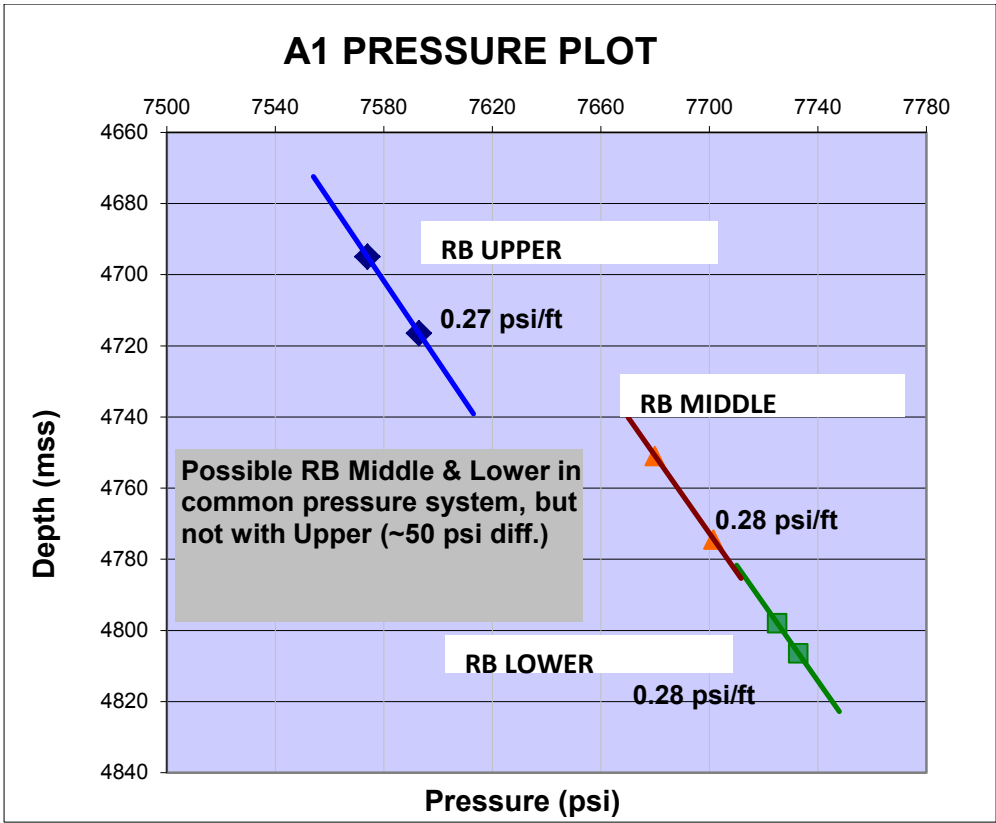


Figure 8 :Pressure vs depth of well A1

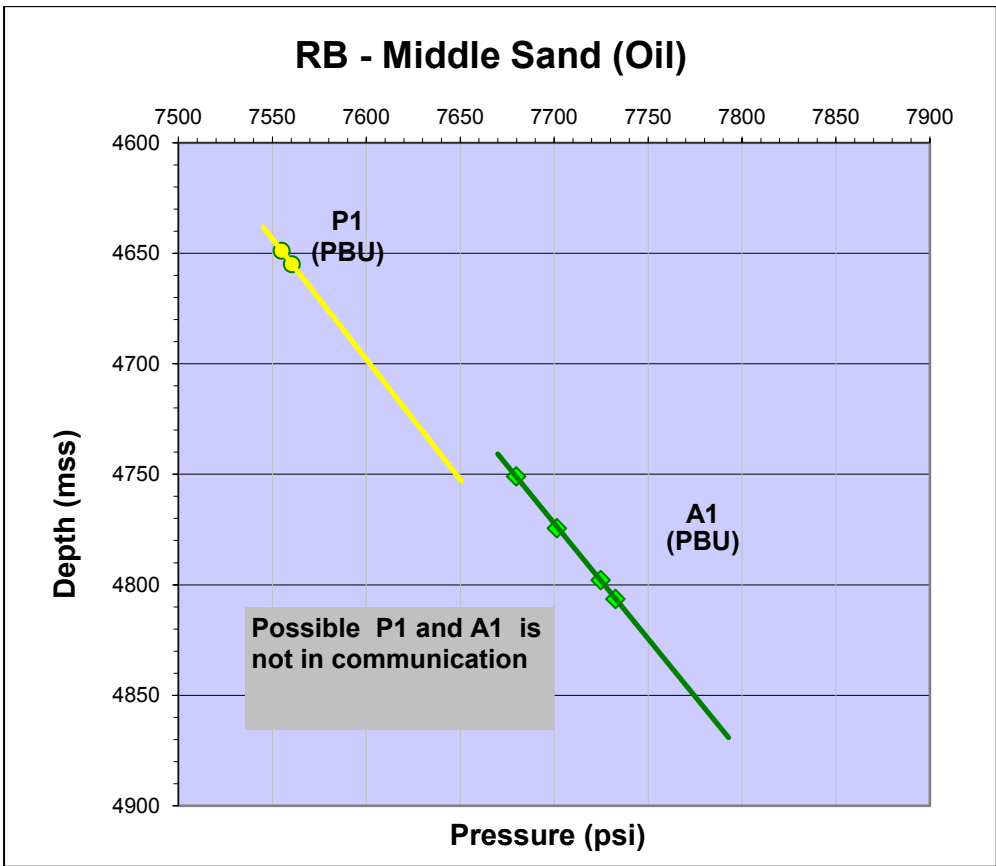


Figure 9 :Pressure vs depth of well A1 and P1

Conclusion of Pressure data analysis

- Possible communication between RB middle and lower of well A1.
- Possible no communication between both RB middle and lower with RB upper with ~50 psia overpressure.
- Possible no communication between well A1 and P1 with ~40 psia overpressure

4.4 PVT Analysis

PVT analysis were done based on Drill stem test (DST) taken from well A-S1 and P1. Below are the details :

Well	DST	Reservoir	Perforation Interval (TVDSS)	Pi @midperf (psig)	Pwf @midperf (psig)	oil gradient (psi/ft)	Fluid type
A-S1	2	RB Middle	4726.4-4774.9	7680.0	7487.8	0.280	oil
P1	1	RB Middle	4642.9-4654.9	7558.7	7356.4	0.283	oil

Table 4 :DST data for well A-S1 and P1

Then, by using fluid simulator, PVTi, both fluid data are entered for thermodynamic modelling to calibrate the equation of state to match the experimental data as well as to determine the gas oil contact (GOC) of both fluids by plotting composition versus depth plot. The steps taken are as follows:

- I. Equation of state and viscosity correlation
- II. Fluid definition
- III. Simulations of experiments
- IV. Fitting of PVT information using nonlinear regression
- V. Plotting composition versus depth to determine GOC

Equation of state and viscosity correlation

Peng-Robinson cubic equation of state (PR3) is used to describe the phase behaviour of fluids of West X field. This is because the cubic equation of state is widely used by the industry to describe phase behaviour of reservoir fluids. Viscosities are calculated using a method by **Lohrenz-Bray-Clark** method.

Fluid definition

The fluid sample for both wells (A-S1 and P1) are defined as library components where require only that the appropriate component mnemonic be entered. For both fluid sample, the components are taken directly as presented in the DST report until C20+.

Simulations of experiments

Experiments performed for both fluid samples on the fluid systems defined using the Peng-Robinson equation of state model (PR3) are as follows :

- Saturation pressure
- Constant Composition Expansion (CCE)
- Differential Liberation (DL)
- Separator

Fitting of PVT information using nonlinear regression

The equation of state is fitted to the observation data to produce a better representation of the fluid. A sensitivity analysis is carried out to determine which attributes of the fluid components improve the solution by the smallest change. The most sensitive attributes are then adjusted slightly by regression to improve the equation of state model of the fluid. The PVT data used during the step of regressions were obtained from **CCE, DL, saturation pressure and separator test** experiments as defined above. The regressions for both fluid samples are regressed for 24+ components. The results of the fitted fluid definitions are as below:

Well A-S1

- CCE Experiment

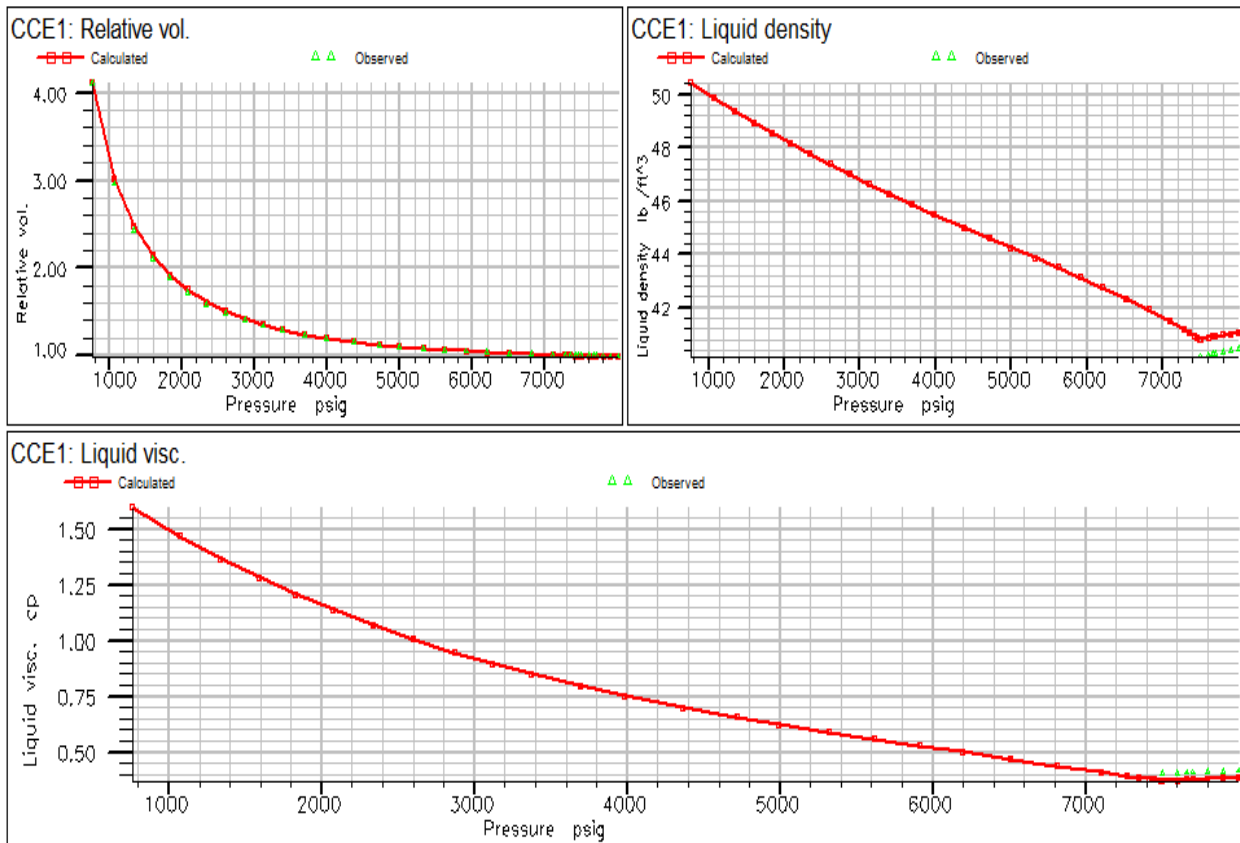


Figure 10: CCE's relative volume, liquid density and liquid viscosity

- DL Experiment

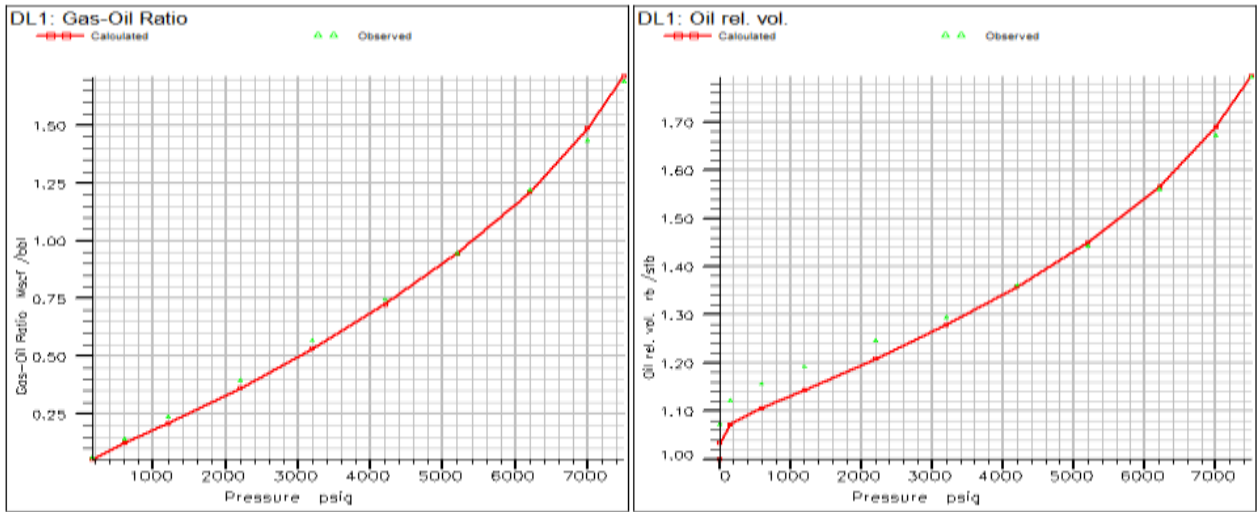


Figure 11 : DL's gas oil ratio(GOR) and oil relative volume

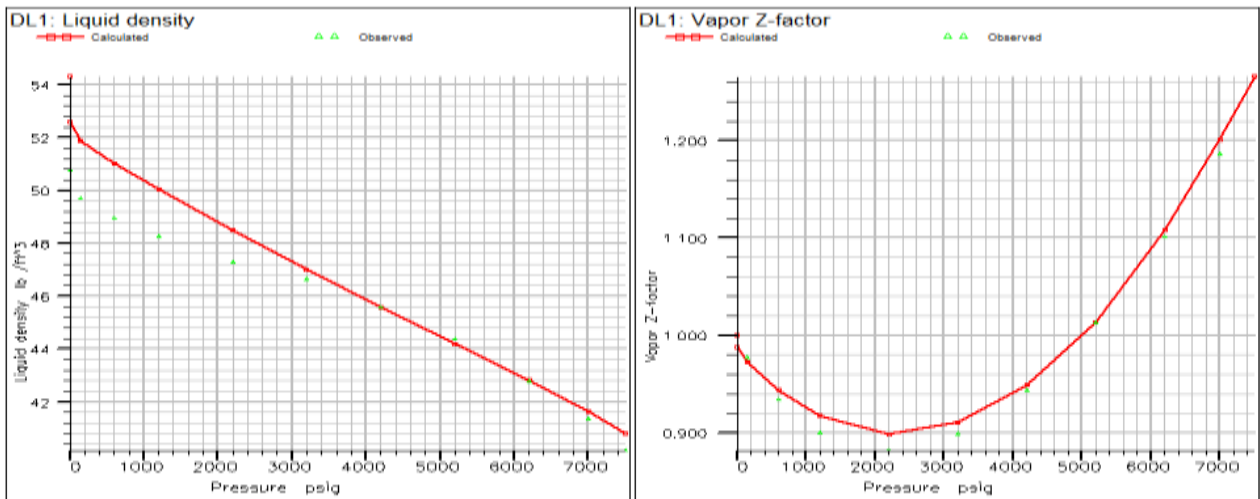


Figure 12 : DL's liquid density and vapour-Z factor

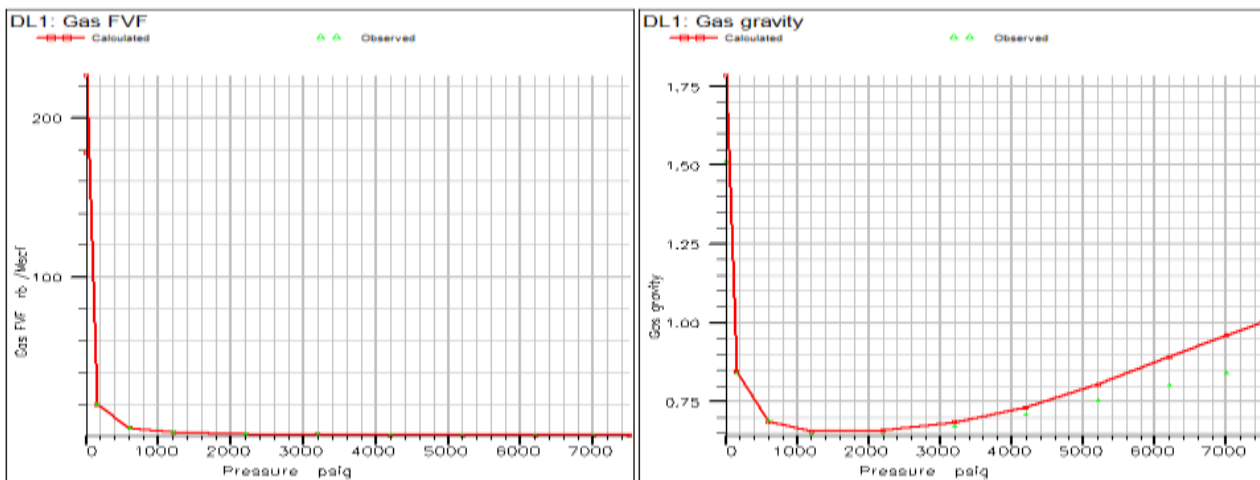


Figure 13 : DL's gas formation volume factor and gas gravity

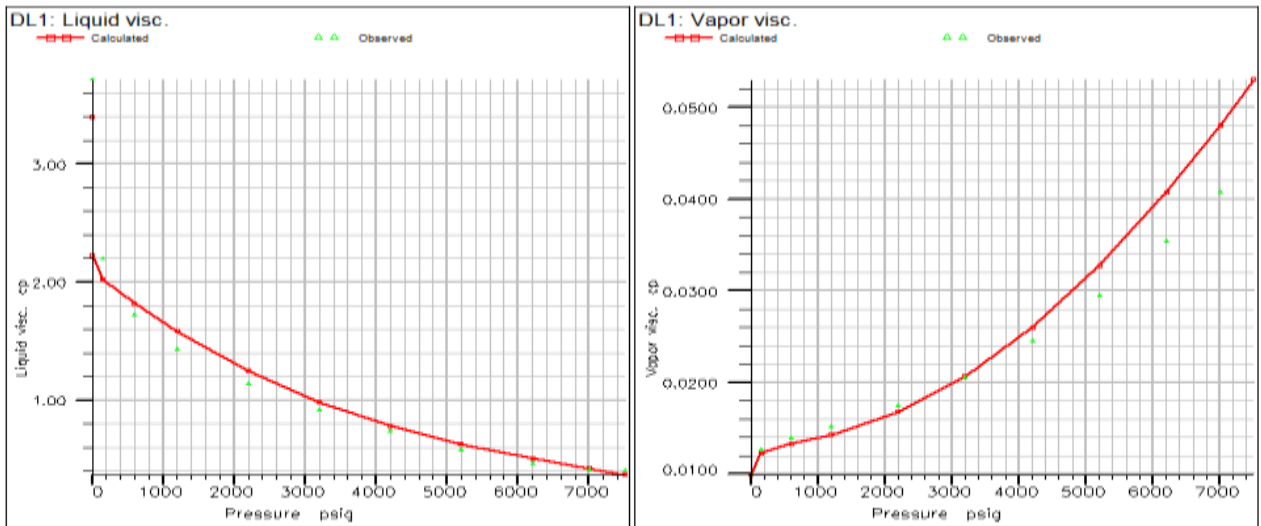


Figure 14 : DL's liquid viscosity and vapour viscosity

Well P1

- CCE Experiment

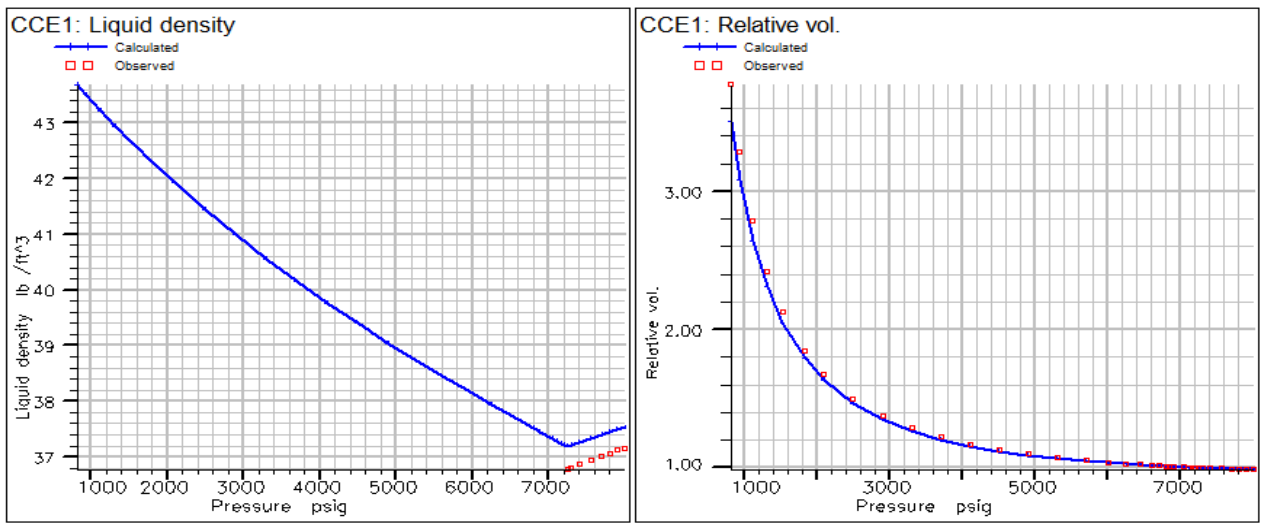


Figure 15 : CCE's relative volume and liquid density

- DL experiment

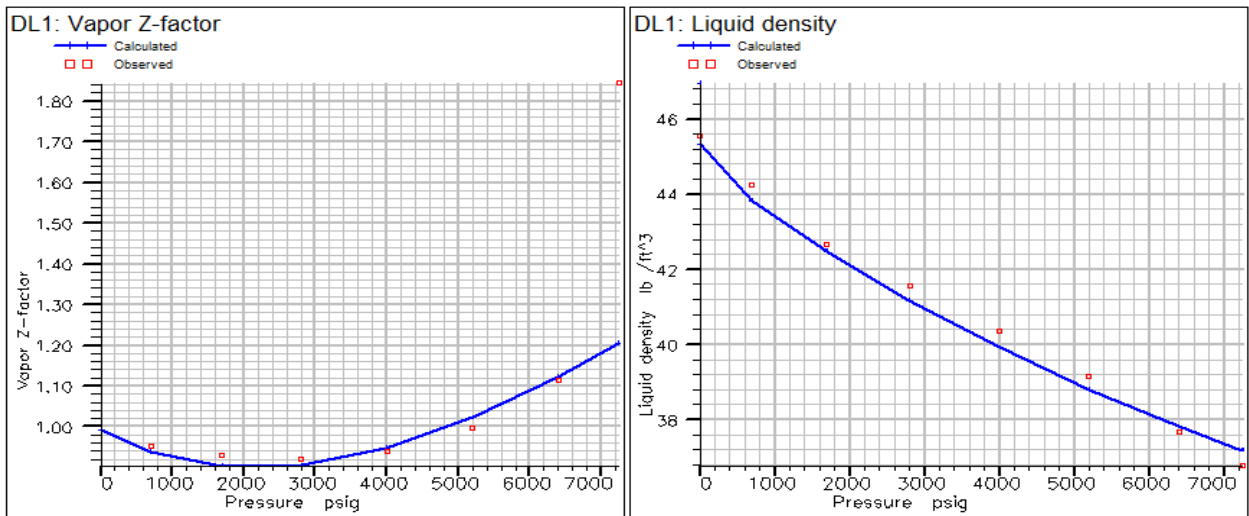


Figure 16 : DL's liquid density and vapour-Z factor

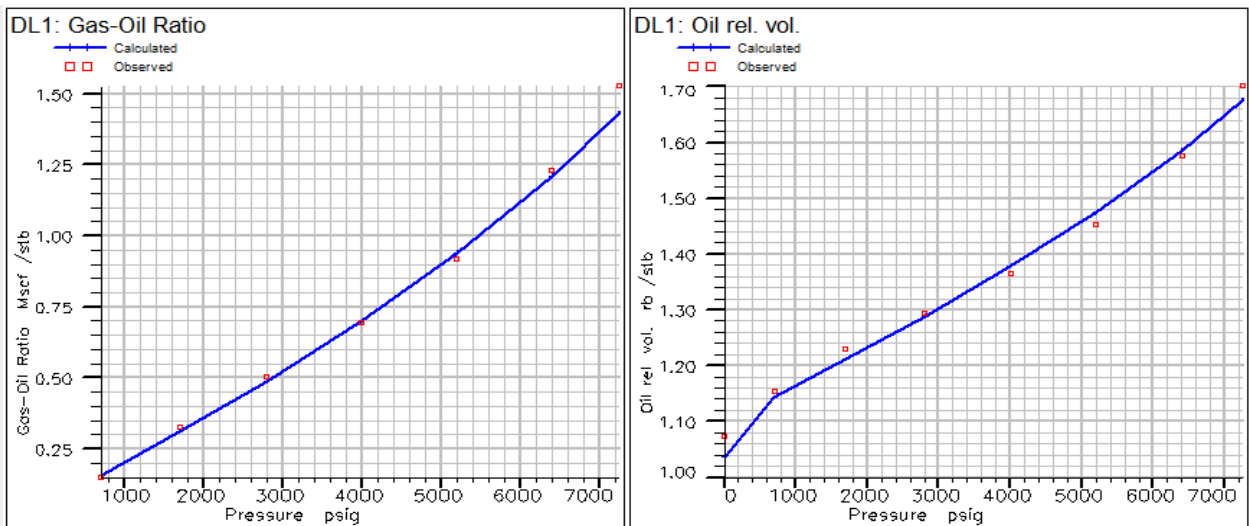


Figure 17 : DL's gas oil ratio(GOR) and oil relative volume

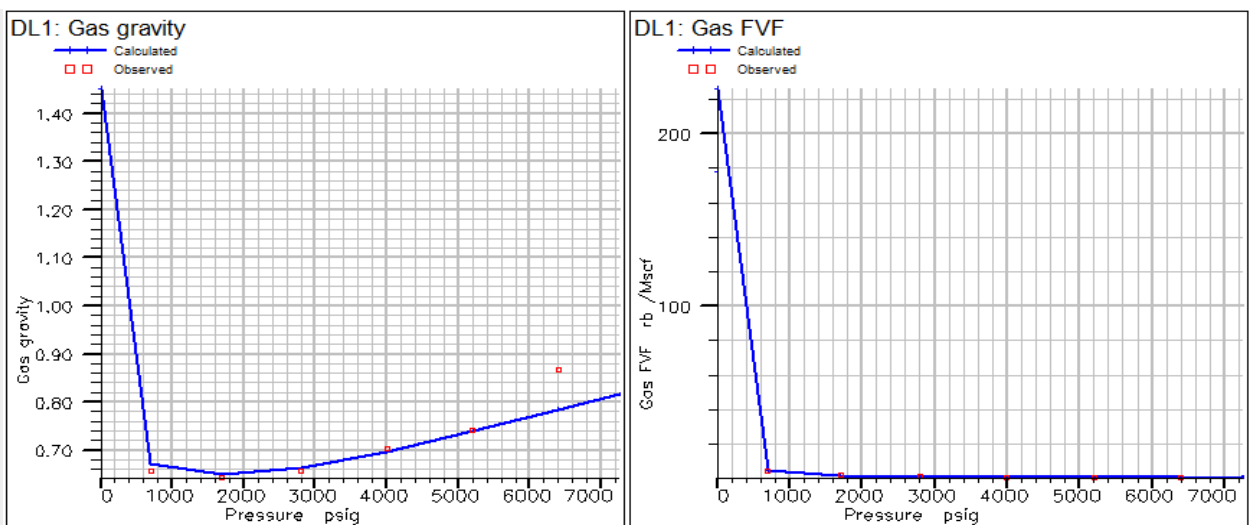


Figure 18 : DL's gas formation volume factor and gas gravity

Plotting composition versus depth to determine GOC

After the equation of state has been fitted with the experimental data, lastly, **composition versus depth plot** can be plotted for both fluid sample to determine the gas oil contact (GOC).The plot consists of pressure and saturation pressure versus depth of the fluid sample. The intersection of saturation pressure line with pressure line indicate the gas oil contact. Below shows the composition vs depth plot for both fluid sample:

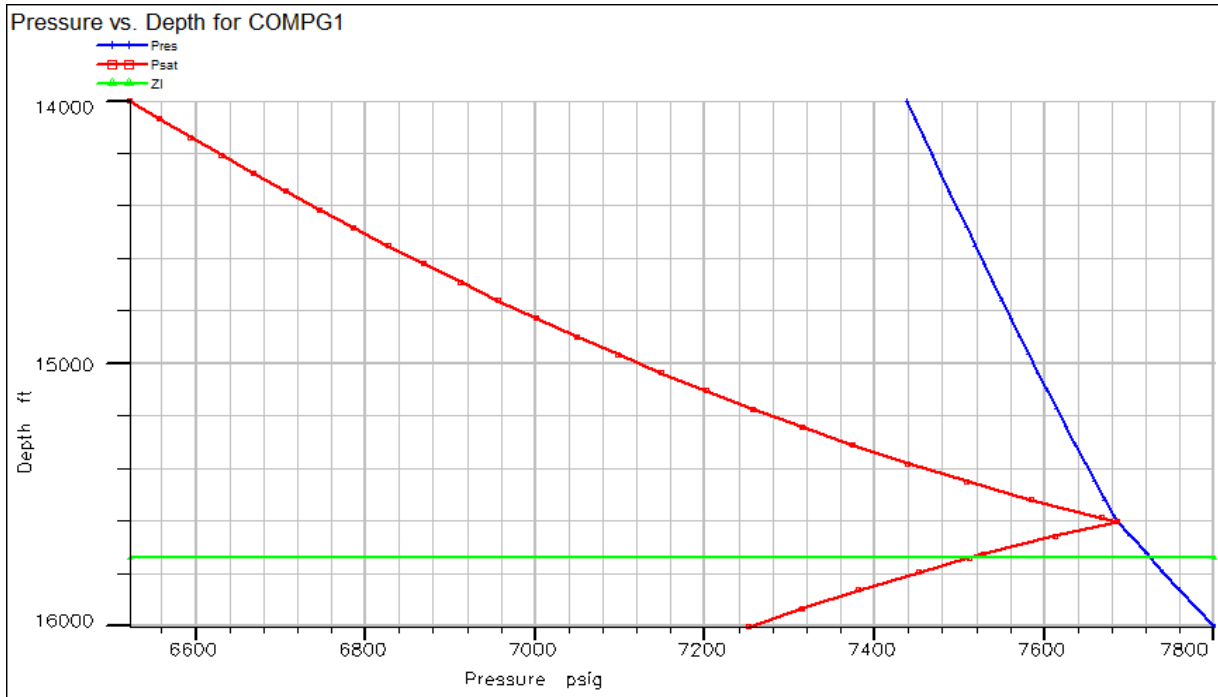


Figure 19 : Composition versus depth plot for well A-S1

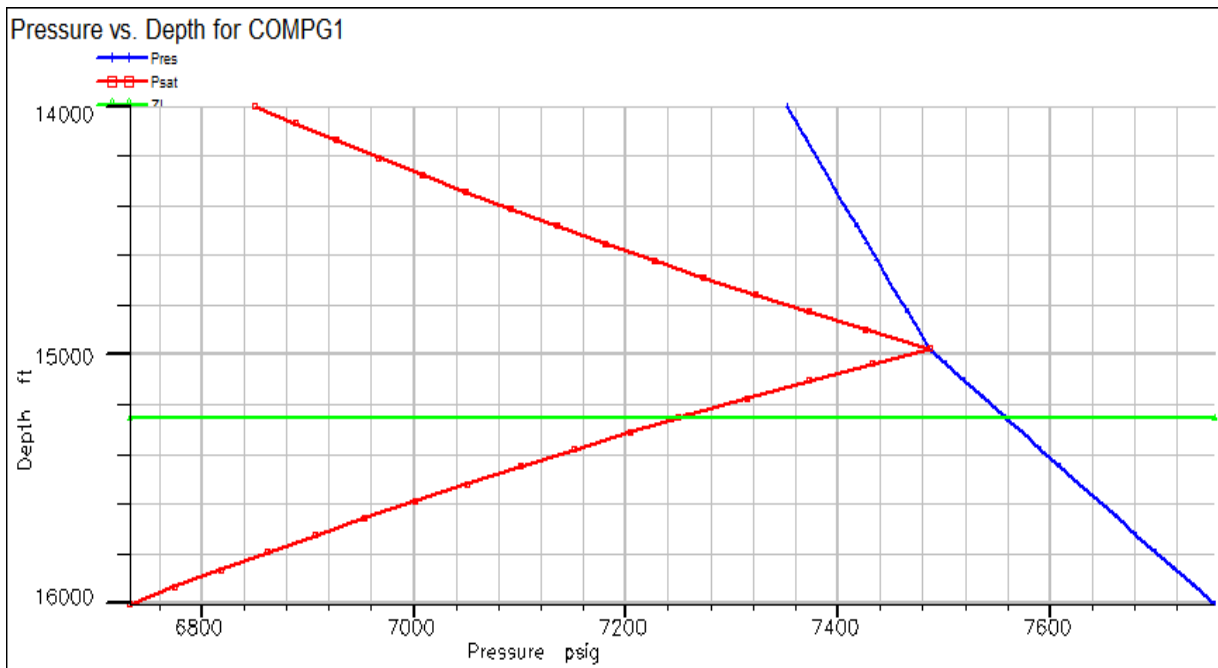


Figure 20 : Composition versus depth plot for well P1

- From the plot, the red line represents the saturation pressure behaviour with increasing depth.
- While the blue line indicate the pressure behaviour with increasing depth.
- The fluid density behaviour can be read from the pressure gradient (psi/ft) when it is converted to lb/ft³.
- The points where the saturation pressure meets the pressure line indicate the depth of gas-oil contact (GOC) for the fluid samples.
- Thus, from the plot above, the GOC for both wells are different :
Well A-S1 (GOC): 15600 ft
Well P1 (GOC): 14975 ft
- The green line indicates the sample's depth. From the plot, it is clearly shown that fluid sample is taken at :
Well A-S1 :15750 ft
Well P1 :15250 ft
- This means that fluid sample of well A-S1 is taken at deeper depth of the reservoir than well P1.
- However, the bubble point pressure (P_b) of A-S1 is higher than P1:
Well A-S1(15750 ft) : 7690 psig
Well P1(15250 ft) : 7520 psig
- If both fluids are the same (in same compartment), the bubble point pressure for both will follow a trend where **the deeper the sample's depth, the lower the bubble point pressure**. This is because the deeper the fluid ,more heavier components it contained. Thus, bubble point pressure will be lower as more pressure depletion is needed to release gas from solution as there are not much gas in solution.
- This means that even though both of the fluid samples are taken from RB middle sand, both well, **A-S1 and P1 are in different compartments** since the GOC for both wells are not the same.
- This proves that the fluids from both wells are different.
- Thus, PVT analysis supported the pressure data analysis where it claimed that both well A1 and P1 are from two different compartments.

Conclusion of PVT analysis

- **A-S1 and P1 are in possible different compartments** since the GOC for both wells are not the same (different fluids).

4.5 Well Test Analysis

The objective of well test analysis for this project are to determine:

Radius of investigation : By investigating the value of r_{inv} , reservoir heterogeneity can be identified. But ,the radius of investigation of a test must be greater than or equal to the distance to that heterogeneity. Once heterogeneous reservoir is identified , it indicate a formation with two or more non-communicating sand members, each possibly with different specific- and relative-permeability characteristics.

Presence of no-flow boundary : This includes not only the case when the reservoir boundaries are **sealing faults**, but also when nearby producing wells cause no flow boundaries to arise.

For West - X Field, well test has been done in 2 wells :

- Well A-S1
- Well P1

4.5.1 Well A-S1

Three production tests have been completed in this well at RB Upper , Middle and Lower.

The perforation intervals are as below:

TEST NO	RESERVOIR	PERFORATION INTERVAL
1	RB Lower	4847 – 4365 m-MDBRT (4814 – 4832 M-TVDBRT)
2	RB Middle	4783 – 4833 m-MDBRT (4752 – 4800 M-TVDBRT)
3	RB Upper	4728 – 4738,4750-4760 & 4766-4722 m-MDBRT (4699 – 4708,4720-4730 & 4735-4742m-TVDBRT)

Table 5: Reservoir summary

Test Results

1. Well A-S1 : Test No. 1 [RB-Lower]

The period of analysis is 9.42 hours of MAIN FLOW and 12 hours for MAIN BUILD-UP. The analysis was carried out based on build up data. The well test result are as follow :

- Radius of investigation (at the end of main build-up) : 1010 ft
- Intersecting boundaries are observed within the radius of investigation 310 ft and 80 ft respectively.

Below are the tabulated well test result with the derivative plot showing the existence of intersecting boundaries :

Property	Analysis Results
Best Fit Model	Homogenous reservoir with intersecting boundaries
Wellbore storage , bbl/psi	0.01480
Permeability , md	126
Skin	2.72
Kh , md-ft	7450
-Y Boundary , ft	310
Intersecting boundary , ft	80
Angle , deg	49
Extrapolated pressure , P*/Initial pressure, Pi at 4451.78 m-TVDBRT , psi	7337
Extrapolated pressure , P*/Initial pressure, Pi at midperf @ 4823 m-TVDBRT , psi (0.319 psi/ft pressure gradient)	7725

Table 6 : Well test analysis result summary for Test No. 1

2. Well A-S1 : Test No. 2 [RB-Middle]

The periods of analysis are 12 hours of MAIN FLOW and 32 hours for MAIN BUILD-UP. The analysis was carried out based on build up data. The well test results are as follow:

- Radius of investigation (at the end of main build-up) : 2820 ft
- An intersecting boundaries are observed within the radius of investigation and are located approximately 327 ft and 637 ft away respectively from the wellbore.
- The boundaries were also intersecting at an angle of 102 degree.
- Both of the boundaries above were interpreted as an impermeable boundary.

Below is the tabulated well test result with the derivative plot showing the existence of intersecting boundaries:

Property	Analysis Results
Best Fit Model	Homogenous reservoir with intersecting boundaries
Wellbore storage , bbl/psi	0.00140
Permeability , md	247
Skin	4.65
Kh , md-ft	40500
-Y Boundary , ft	637
Intersecting boundary , ft	327
Angle , deg	102
Extrapolated pressure , P*/Initial pressure, Pi at 4451.78 m-TVDBRT , psi	7351
Extrapolated pressure , P*/Initial pressure, Pi at midperf @ 4823 m-TVDBRT , psi (0.319 psi/ft pressure gradient)	7680

Table 7 : Well test analysis result summary for Test No. 2

3. Well A-S1 : Test No. 3 [RB-Upper]

The unit upper reservoir in test no. 3 was perforated at 3 different intervals and flowed together. The reservoir interval from 4728 to 4738 and 4750 to 4760 m-MDBRT have similar character while the reservoir interval from 4766 to 4722 m-MDBRT has better sand quality. To reduce the number of uncertainty, the analysis is simplified to two layers reservoir since the top two perforation interval has the same reservoir character. So, in this analysis as in the table below, layer 1 represent the bottom perforation interval which is the good quality sand while the layer 2 represent the top two reservoir interval with poorer sand quality. The periods of analysis are 9 hours of MAIN FLOW and 12 hours for MAIN BUILD-UP. The analysis was carried out based on build up data. The well test results are as follow:

- Radius of investigation (at the end of main build-up) : 1050 ft
- No boundaries are detected

Below is the tabulated well test result with the derivative plot showing the existence of intersecting boundaries:

Property	Analysis Results
Best Fit Model	Multilayer reservoir with no crossflow
Wellbore storage , bbl/psi	0.00070
Permeability layer 1, md	122
Permeability layer 2, md	8.39
Skin layer 1	40500
Skin layer 2	637
Kh , md-ft	327
Omega	102
Layer ($P_1 - P_2$) , psi	
Extrapolated pressure , P^* /Initial pressure, P_i at 4455.77 m-TVDBRT , psi	7351
Extrapolated pressure , P^* /Initial pressure, P_i at midperf @ 4720.5 m-TVDBRT , psi (0.303 psi/ft pressure gradient)	7680

Table 8 : Well test analysis result summary for Test No. 3

Discussion

- The best model representing Test No. 1 which is done in RB-Lower reservoir and Test No. 2 which is done in RB-Middle reservoir is **vertical homogeneous reservoir with intersecting boundaries.**
- The intersecting boundaries refers to **two intersecting fault** near the wellbore of Well A-S1 which is located :
 Lower sand : 310 ft and 80 ft respectively from wellbore
 Middle sand : 637 ft and 327 ft respectively from wellbore
- This can be seen on the derivative plot below where the late time region of pressure derivative plot is showing an upward trend after stabilisation point.

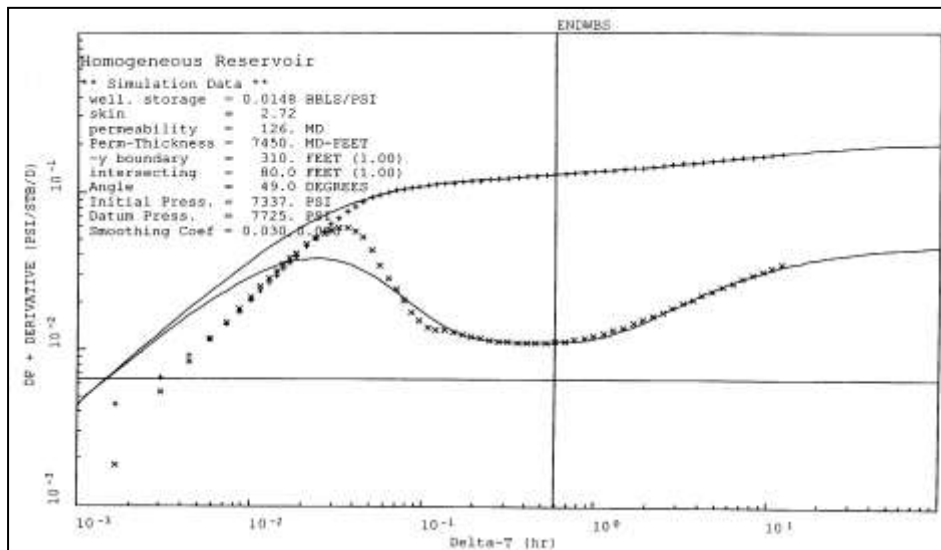


Figure 21 :Analysis of derivative plot of test no. 1

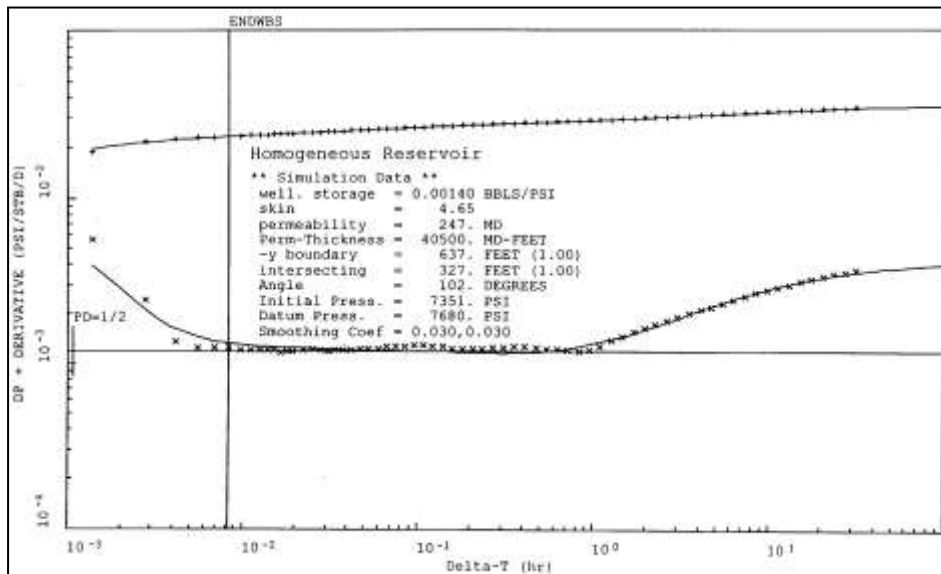


Figure 22 :Analysis of derivative plot of test no.2

- Meanwhile , the best model representing Test No. 3 which is done in RB-Upper reservoir is **multilayer reservoir with no crossflow**.
- Since well testing is done at 3 layers of the upper sand, this model assumed that all 3 layers have the same permeability and reservoir properties, but only the best layer (4766 to 4722 m-MDBRT) was perforated.
- From the derivative plot below, there is no upward trend at the late time region indicating infinite acting reservoir which means **no fault neither aquifer are detected** within the radius of investigation.
- In addition, the first stabilisation point is the stabilisation for layer 1 while the second stabilisation point is stabilisation for layer 2 .

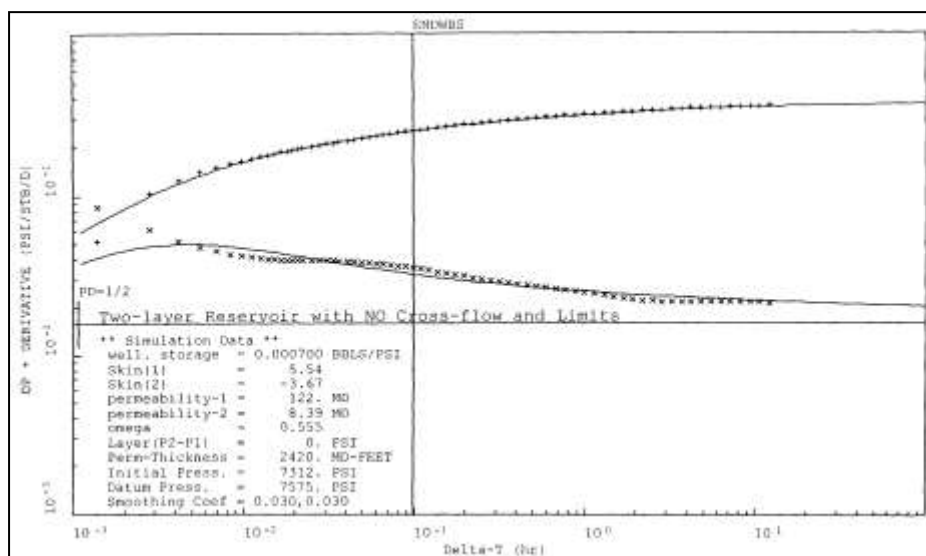


Figure 23 :Analysis of derivative plot for test no. 3

4.5.2 Well P1

Objective: To determine sand continuity since all sand packages are completed to proof test result of A-S1.

One production test was performed in this well on **RB Middle sand** . The perforation intervals are as below:

Perforation interval (m-MDRT)	4677-4689
-------------------------------	-----------

Table 9: Reservoir summary

Test Results

The periods of analysis are 12.3 hours of MAIN FLOW and 22.75 hours for MAIN BUILD-UP. The analysis was carried out based on build up data. The well test results are as follow:

- Radius of investigation (at the end of main build-up) : 194 ft
- No boundaries are detected

Below is the tabulated well test result :

Property	Analysis Results
Wellbore storage , bbl/psi	0.00577
Permeability , md	228
Skin	0.312
Kh , md-ft	17900
Simulated initial pressure , P at a gauge depth (4636.3 m-TVDRT) , psia	7505.5
Average pressure , P at a gauge depth (4636.3 m-TVDRT) , psia	7500.0
Estimated initial pressure , P atmidperf @ 4681.2 m-TVDRT , (0.3617 psi/ft oil gradient) , psia	7558.7

Table 10 : Well test analysis result summary

Discussion

- Even though the sand was partially perforated at the bottom half, partial penetration model could not meet the early transient data. Thus, the best model representing RB Middle is a **radial composite**.
- Well P1 does not see boundaries as experienced by Well A-S1 even though it is only 656 ft from Well A-S1.
- This can be seen on the derivative plot below where the late time region of pressure derivative plot is showing an infinite acting reservoir .

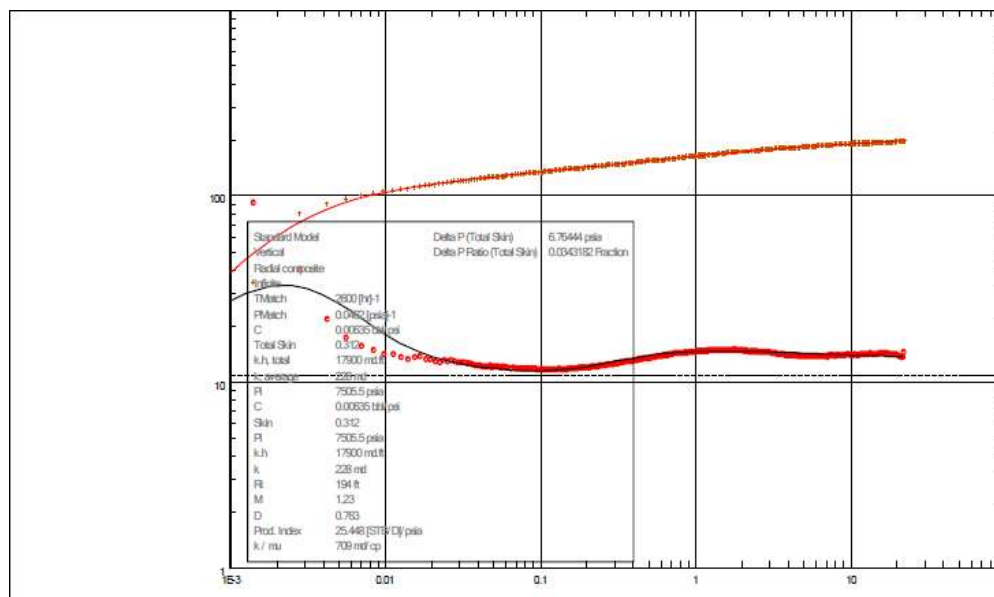


Figure 24 : Analysis of derivative plot

- The reason for choosing radial composite as the best model is because of the 2 radial flow that exists in the reservoir. This can be seen in the plot above where 2 stabilisation occurred on the derivative plot.
- The reasons for the two radial flows (stabilisation) may be due to changes in reservoir properties such as changes in permeability and porosity.
- Since the well test of Well P1 does not detect any boundaries as in well test of Well A-S1 even though the distance between the two well are closed by, there are 2 possibilities :
 - I. The fault detected by A-S1 does not exists which means the unit middle reservoir are actually in communication.

- II. The fault detected by A-S1 is not sealing causing the fluid from other reservoir to flow into RB middle of well P1 that causing the changes of reservoir properties as shown in the derivative plot of radial composite model.

Conclusion of well test analysis

- Well test interpretation of well A-S1 in unit **lower and middle** of reservoir B has confirmed the existence of an intersecting boundaries closed to the well location.

Lower sand : 310 ft and 80 ft respectively from wellbore

Middle sand : 637 ft and 327 ft respectively from wellbore

- No boundaries are detected by the **upper** layer of reservoir B.
- Well test interpretation of well P1 in unit **middle** of reservoir B has **not detected any boundaries** as claimed by the unit middle sand of well test A-S1.
- Since the well test of Well P1 does not detect any boundaries as in well test of Well A-S1 even though the distance between the two well are closed by, there are 2 possibilities :
 - I. The **fault** detected by A-S1 does **not exists** which means the unit middle reservoir are actually in communication.
 - II. The **fault** detected by A-S1 is does **exists but it is not sealing** causing the fluid from other reservoir to flow into RB middle of well P1 that causing the changes of reservoir properties as shown in the derivative plot of radial composite model.
- But, the second possibility might be the case because from the pressure plot and PVT analysis, both data supported the claim that both well A1 and P1 are in different compartments.

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

In conclusion , in order to identify reservoir compartmentalization ,all the study objectives should be answered correctly:

- All the relevant field data required to identify reservoir compartments should be compiled first and ensure that they are complete. The data include all the initial dynamic data:
 - Pressure data
 - PVT data
 - Well test data
 - Log data

- Then, by utilizing all the field data available , data analysis should be made to find any evidences of compartmentalization by :
 - pressure transient analysis
 - pressure analysis
 - PVT analysis
 - Log analysis

- There are 3 vertical compartments found supported by log data :
 - 1) Upper zone of Reservoir B
 - 2) Middle zone of Reservoir B
 - 3) Lower zone of Reservoir B

- There are 2 lateral compartments found :
 - 1) Well P1 and A1/AS1 (Reservoir B Middle) as different compartment supported by pressure plot,PVT analysis as well as well test analysis conducted at well AS1and P1.

- For vertical compartments, the pressure plot of well AS1 for the 3 zones (upper, lower and middle) detected overpressure where it is showing middle and lower zones of reservoir B as one system and the upper zone as different system. However, these data is not sufficient and must be supported by other data in the future.

5.2 Recommendations

- Conduct an interference test in observation wells near well P1. In commercially viable reservoirs, it usually takes considerable time for production at one well (P1) to measurably affect the pressure at an adjacent well (A1/AS1). This is to further clarify the well test analysis result.
- Perform Drill stem test at both RB upper and lower of well AS1 to identify the contacts.
- More static data could be used and is integrated to support evidences of compartmentalization such as :
 - 3D seismic interpretation (fault position / throw)
 - Oil geochemistry (GC fingerprinting)
 - Fault seal analysis
 - Formation water composition (RSA)
 - Fault seal analysis
 - Reservoir heterogeneity modelling
 - High-resolution stratigraphy
- Incorporate more dynamic / production data as they are a more definitive data for identifying reservoir compartmentalization .

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