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Integrated Analysis of Pressure Transient Tests in the Gulf of Mexico

By

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A report submitted in partial fulfilment of the requirements for the MSc and/or the DIC

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DECLARATION OF OWN WORK

I declare that this thesis “Integrated Analysis of Pressure Transient Tests in the Gulf of Mexico” is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and /or with appropriate acknowledgements given.

Signature: ………………………………………………………………………………………..

Name of student: Hernán De Caso

Name of supervisor: Prof. Alain C. Gringarten

Quote

“And the day came when the risk to remain tight in a bud was more painful than the risk it took to blossom”

Anaïs Nin

ACKNOWLEDGEMENTS

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Integrated Analysis of Pressure Transient Tests in the Gulf of Mexico

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Abstract

The start of a numerical simulation study mandates the existence of a synthesis of all available static and dynamic data. Well testing is one of the most effective means to characterize hydrocarbon reservoirs under dynamic conditions. This paper presents a systematic methodology and interpretation procedure of pressure transient data combining deconvolution with conventional analysis. Deconvolution is used in the first stages of the analysis process to guide the model identification based on the late time response as well as to obtain an estimate of the initial pressure. Several real tests examples are analysed in a deepwater high pressurised commingled reservoir in the Gulf of Mexico.

The project intends to characterize a challenging seismic imaging reservoir. During the early stages of production the grade of uncertainty is always higher than in future stages. An appropriate reservoir characterization at early stages of production is essential in order to implement efficient field development strategies. The dynamic characterization presented reduces uncertainty in the location of no flow boundaries. The location of boundaries is considered of great importance when planning a water injection secondary recovery drilling campaign.

Interpretations will be used by reservoir engineers to guide the permeability distribution, improve the aquifer description, describe the reservoir-well connection (skin factor) and their evolution with time, and to constraint the geological modelling in those areas with observed boundary effects. Historical data back to first oil is also considered within the scope of this study to refine the interpretation.

Introduction

The start of a numerical simulation study mandates the existence of a synthesis of all available static and dynamic data. A reservoir description will take into consideration information from sources such as logs, cores, production and well test analysis. The following paper will focus on the use of Pressure Transient Analysis (PTA) as an essential procedure to provide a description of the reservoir flowing behaviour as well as of the refinement of the geological model.

With the introduction of the pressure-derivative analysis (Bourdet, D *et al.*1983a,1983b) to the type curve independent variable analysis (Gringarten *et al.*1979; Bourdet and Gringarten 1980) it was possible to increase the diagnosis and verification capabilities of PTA and to identify patterns for different reservoir configurations. With the development of computer-aided interpretation software packages pressure-derivative proved to be a robust diagnostic tool compared to previous PTA techniques and has become the basic tool for conventional well test analysis. The stable deconvolution algorithm developed at the beginning of the decade (von Schroeter *et al.* 2001) has provided reservoir engineers the possibility of obtaining more pressure data from well testing. This is achieved by transforming variable rate pressure data into a constant rate initial drawdown with duration equal to the total duration of the test (implying access to a greater radius of investigation). The observation of boundary effects in the constant rate drawdown is possible, whereas in a single buildup it might not have had been reached. This will facilitate the model selection regarding late time response behaviour. Deconvolution includes other advantages such as being able to estimate the initial pressure if more than two buildups are available (Levitan *et al.* 2004) and to correct errors reported in rates (Gringarten 2010).

Though deconvolution is not considered a new interpretation method, it facilitates the model identification and hence it has become a new complementary identification and verification analysis approach in the sequence of interpreting a pressure transient test. (Amudo et al, 2006). As the new technique matures, the oil industry is slowly becoming more acquainted and confident with it. In an increasing number of oil companies it has become a common practice to verify the results achieved with conventional analysis[1] with those obtained with deconvolution. The dynamic characterization carried out in the present

[1] Conventional analysis, as defined in this paper, refers to the pressure transient interpretation of individual buildups (or period at constant rate) through the use of the multirate pressure-derivative (plotted in function of the elapsed time).

paper follows the inverse approach in which deconvolution was the primary model identification tool applied, to be latter on verified by conventional analysis.

The purpose of this work is to establish a systematic methodology and interpretation procedure of pressure transient data within a given geological context in the Orchid Oil Field, Gulf of Mexico. The efficiency of deconvolution will be assessed through the complete number of real tests available. Interpretations will be used to guide the permeability distribution, improve the aquifer description, describe the reservoir-well connection (skin factor) and their evolution with time, and finally to constraint the geological modelling in those areas with observed boundary effects. Historical data back to first oil is also considered within the scope of this study to refine the interpretation.

Field overview

The Orchid Field is an deepwater high pressure oil reservoir located in the Gulf Mexico. The Orchid structure is a large anticline cored by a deeply-rooted salt diapir. The reservoir has been divided into five sandstone packages named **AA, BB12,BB, CC** and (in a single well) **DD**. The reservoir intervals are produced via commingledsingle and dual stacked Fracpack completions. All the intervals are comprised of deepwater turbidite sandstone deposited as layered sheet sands and channelized sheet sands. The reservoir package exhibits a relative constant gross interval thickness. A typical Orchid log section with main reservoir zones and surface nomenclature is presented in Figure 2.

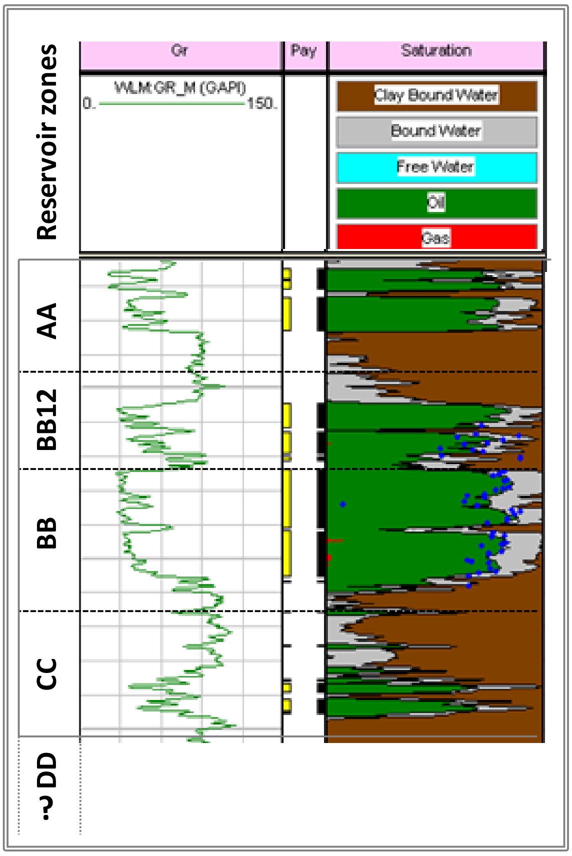

Figure 2: Log section with reservoir zone nomenclature.

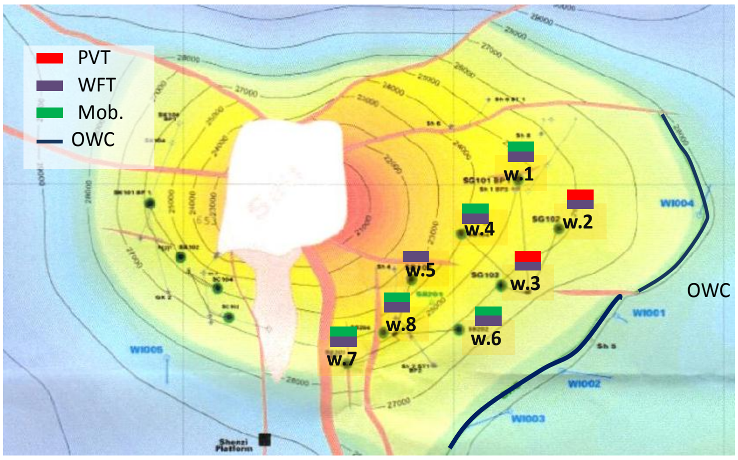

Figure 1: Structural map with the location of the wells. Availability of PVT, Distributed Pressure Measurements (WFT) and mobility (Mob.) reports per well are indicated in the boxes. OWC is also shown.

Commingle produced intervals / Well nº	AA, BB12, BB	AA, BB12, BB, CC	AA, BB12, BB, CC, DD	Fracture gravel packs
1				2
2				2
3				1
4				1
5				2
6				1
7				1
8				2

Table 1: Summary of the commingled intervals produced by each well and number of fracture gravel pack per well.

The thickness and geometry of the salt sheet, which also contains complexly-folded sediment inclusion, creates a challenging seismic imaging environment. Consequently, seismic data quality is very poor along the southwest flank (SW) and in the crestal portions of the anticlinal near the diaper. Conclusions yielded from PTA interpretation will reduce geological uncertainty in seismic data and predict the location of sub seismic boundaries.

A structural map of the Orchid Field with the available data per well and the Oil Water Contact (OWC) is shown in Figure 1.To date there are eight wells drilled with pressure transient data recorded in all of them (w1,w2,w3,w4,w5,w6,w7,and w8). First oil was achieved in March 2009. At the time of the last interpreted test, February 2011, the cumulative production was approximately 70MMstb of oil and 0.1MMstb of water. All the wells are slightly deviated and completed with one or two fracture gravel packs. The actual water cut is negligible in all the wells, being highest in the only well drilled in the lowest formation (well w5). Analysis of the well formation pressure tests (WFT) indicates the OWC to be at a depth of 27850 ft TVDSS in the Eastern section of the field. Well w7 is the exception in which the OWC is located above at a depth of 27175 ft TVDSS. This difference in OWC is an indication that well w7 might be placed in an isolated block. Table 1 shows a discriminatory summary of the commingled layers each well produces and the number of fracture gravel packs used per well.

Methodology

Data gathering for input parameters

The dynamic characterization required a synthesis of all the available field data. Required input parameters were chosen on the basis of the most consistent well, reservoir and fluid properties scena rio and all the pertinent information was previously reviewed and filtered.

Parameters	units	value	Data source
Well radius (rw),	ft.	0.41	Well completion reports
Porosity, ϕ	-	0.17-0.21	Petrophysical porosity interpretation
Pay zone, (h), ft	ft	60-300	Petrophysical interpretation
Formation Volume Factor, (Bo)	bbl/stb	1.08-1.23	PVT report
Gas Oil Ratio (GOR),	scf/stb	303-427*	Measured rates and PVT report
Oil viscosity, (µ),	cp	1.7-3.6	PVT report
Bubble point pressure (Pb)	psi	1335-2033	PVT report
Oil gravity, ºAPI	ºAPI	30.5-34.0	PVT report
Oil and water saturation	-	0.8/0.2	Real perm from Special core analysis
Formation compressibility (cf)	psi-1	(1-3) E-06	Core analysis (RCAL)
Total compressibility (ct),	psi-1	3-3.5 E-05	ct=Soco+Swcw+cf. (Saturations obtained from petrophysical interpretation.)

Table 2: Input parameters obtained from different sources required for well test analysis.

Table 2 shows the range of values of the main input parameters required from the available petrophysical, core and PVT reports. Distributed pressure measurements were recorded in all the tests. In order to be able to refer all the pressures to the same relative depth, a datum was chosen at the OWC depth of 27850ft TVDSS. Mobility reports were also available from which the pressure gradients of oil and water were obtained. One core measurement from a non-tested well was available to contrast wireline petrophysical results as well as PTA results. Fluid sample black oil PVT analyses were carried out in wells w2 and w3 in the eastern side of the field and in two other exploratory wells close to well w8. For the transient tests interpreted in this study the fluid properties are based on such PVT reports. A black oil model was considered with multiphase gas-oil flow occurring exclusively in the wellbore. It was observed that exclusively in well w5 the GOR obtained from the reported rates was substantially lower than that one reported in the PVT reports. This again is a sign that well w7 might be placed in an independent compartment with different fluid properties. Refer to Appendix B-PVT appendix for fluid input specification in each interpretation.

Interpretation methodology

A systematic approach was chosen to perform this project. The following steps were carried out:

- Establish a methodology for transient interpretation.
- Individual well pressure transient interpretation within a geological context.
- Integration at field level.

Establish a methodology for transient interpretation

Initial pressures were determined using deconvolution when possible. This is due to the sensitivity of the deconvolved derivative to variations in the initial pressure, especially if the deconvolved flow periods regime are infinite acting radial flow (IARF). The procedure employed was presented by Levitan *et al*. (2004). It is a trial and error estimation based on the concept that a correct initial pressure (*pi)* must yield the same deconvolved derivative. The correct *pi* is obtained by varying the input initial pressures and comparing the responses of two different infinite acting build ups. The pi chosen is the one that yields identical or very similar deconvolved derivatives for both buildups. In those cases where a couple of reliable build ups were not available, or if they were but their response did not match at a reasonable initial pressure[2], then the initial pressure was obtained from preliminary analysis or from distributed formation pressure tests.

[2] It occurs often that when a well is flowing at very low rates, the measured recorded rates are simplified to zero assuming this way a complete shut-in. This procedure will induce to mistake an actual drawdown for a build leading to an erroneous estimation of pi.

Rates were simplified and pressure points frequency was reduced to increase the computing speed of the deconvolution. Such reduction of data points was carried out preferably in the drawdown periods rather than in the buildups to avoid jeopardizing the buildup derivative response. Error weight and regularization parameter were introduced as a mechanism to influence the response regarding the smoothness and the degree of consistency with Duhamel´s principle[3] (von Schroeter *et al* 2001).

The validity of the deconvolution was established by verifying that the pressure history and the adapted rates did not exceed deviations from their original values by more than 10% and 20% respectively. It is suggested that any variation below such threshold will still yield an acceptable response, though it has only been proven on variations in the rates up to 10%, (von Schroeter *et al* 2001). The grade of smoothness observed in the late time behaviour deconvolved derivatives is also assessed by the fact that different flow periods should yield converging derivatives.

In those cases in which the deconvolved derivative was successfully validated, a model was chosen for the constant rate initial drawdown. Such model and the new calculated adapted rates were then introduced to the test data. The individual build ups were then analysed with the previously selected model by means of the multirate derivative. In case the model selected for the unit rate drawdown did not match with the real data buildups, then another model was chosen for the unit rate initial drawdown. The process was repeated until consistency in the model selected was achieved between the unit rate initial drawdown and the multirate buildup.

It is worth mentioning that in some scenarios the multirate derivative differs from the drawdown derivative. This happens whenever the multirate derivative is obtained from a previous flowing period which is not in radial flow (Clark and Van Golf-Racht, 1985). It also occurs in closed reservoirs once the pseudo-steady state flow has been reached. In such cases, the depletion effect will result in a stabilization of the pressure at average reservoir pressure. Also, during late time response build up derivatives tend to peak down while drawdown derivatives yield a unit slope line.

If the deconvolved pressure match or the calculated adapted rates differed by more than 10% or 20% respectively the deconvolution derivative was considered to be dubious. In such cases, the selection of the interpreted model was guided by conventional analysis.

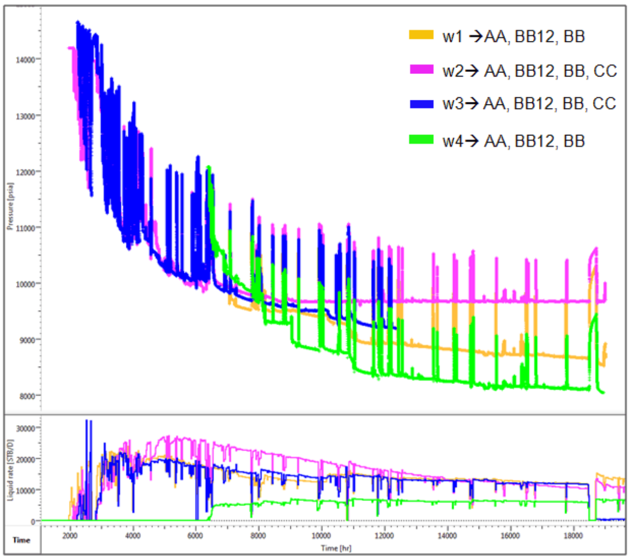

Figure 3: Pressure and production historical data for wells w1, w2, w3 and w4. Sand packages drilled in each well are also indicated. Profiles show at the end the DST campaign done recently in all wells except in well w3.

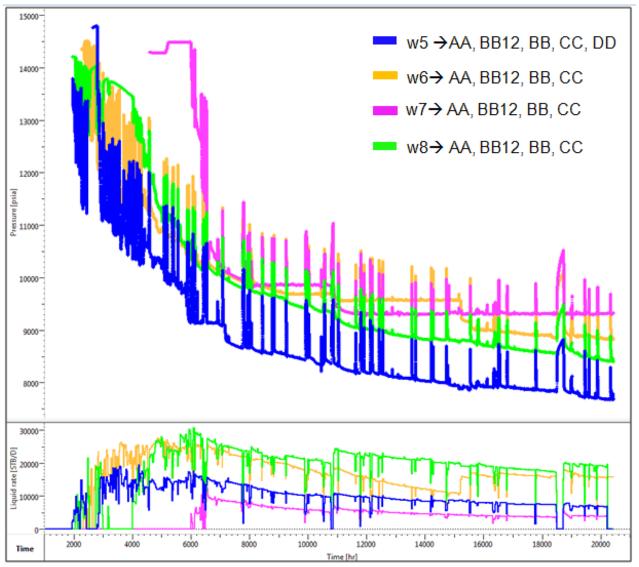

Figure 4: Pressure and production historical data for wells w5, w6, w7 and w8. Sand packages drilled in each well are also indicated

Production rates and pressure evolution since first oil are shown in Figure 3and Figure 4. They were compared between themselves to observe pressure depletion indications and production anomalies in each well, as indicated during the discussion. Pressure depletion as defined in this paper refers to the evolution of the pump-intake pressure (PIP) from the initial pressure chosen (either by means of deconvolution, preliminary analysis or WFT) to the one recorded at the end of each analysed buildup.

Errors in the derivative caused by incorrect description of the flow rates are very common and require a delicate simplification of the flow rate history. This is a time consuming process which must not be overlooked as an

[3] Duhamel's principle allows obtaining solutions to inhomogeneous linear evolution equations (such as diffusivity), and it is the basis of the fundaments of well test.

oversimplification of the rates might mask derivative responses reducing its reliability as a diagnostic tool (Gringarten 2008). Several inconsistencies in the rates were observed and reported in the discussion. The criteria employed to describe accurately the rate history was chosen so as to describe in detail the last 40% of the cumulative production period before the test and simplify more drastically the remaining 60%[4] (Daungkaew et al. 2000).

After the data was synchronized and validated, the most representative[5] shut-in periods on each well were extracted and overlaid after being rate normalized (Figure 5&6). It is necessary to normalize the rates because the real rates are not stabilized as assumed in the theory. This is done by means of a reference value for normalization that will be generally chosen to be the last stabilized rate of the interpreted period. The main advantage is the ability to observe any contrasting behaviours between the different responses and to give an estimate of the wellbore storage and permeability thickness product.

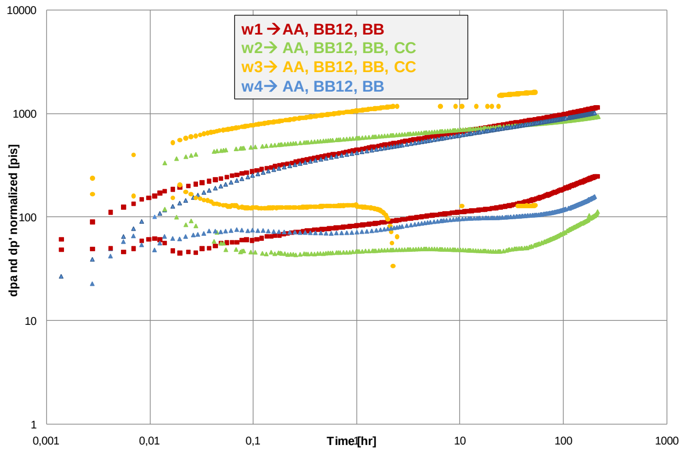

Figure 5: Log-log response of the commingled PBU tests performed in w1, w2 and w4 during the last DST campaign (except well w3 which is a previous build-up).

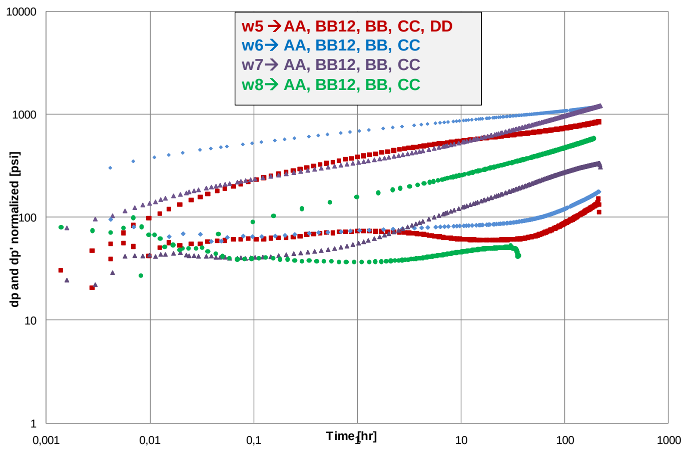

Figure 6: Log-log response of the commingled PBU tests performed in w5, w6, w7 and w8 during the last DST campaign.

A multilayered analysis was realized in three wells. A great number of studies concerning multilayer analysis, with or without cross flow, have been published in the last half century. A good literature review is presented in Ehlig-Economides, 1987. Some of these studies are highly elaborated and deal with the determination of the characteristics of the reservoir layer by layer. Never the less, multilayer analysis still remains to be highly complex and uncertain due to the great deal of parameters taken into account.

A double layer interpretation was realized in wells w1, w4 and w5 in order to verify the results obtained through conventional interpretation. These wells were selected based on their discriminatory nature of commingled layers; see Table 1. Well w5 is the only one drilled through the DD formation while wells w1 and w4 are the only ones that are not drilled through the CC formation. This allows estimating the impact of these individual layers on the overall system permeability. Interpretations from wells w1 and w4 compared with those realized in wells w2, w3, w6 , w7 and w8 will indicate if layer CC is significantly contributing to overall results. The same applies to well w5 compared to wells w2, w3, w6, w7 and w8 regarding layer DD.

For the multilayer interpretation, the five layers were simplified to two. The decision of which layers to merge was readily taken observing the log correlations (see Appendix C-Log and petrophysical data). Layer AA shows the widest separation from the subsequent layer (approximately 50ft). Moreover the remaining layers seem to be relatively close one from the other (approximately 10ft). Hence the double layer model was considered as layer AA individually and the others sandstone formations simplified to one single layer with distributed weighted parameters.

Different software packages were used for this study. Deconvolution was performed using TLSD, developed at Imperial College, and applied for research purposes only, although its algorithm has been included in commercial software packages such as PIE. Individual buildups as well as the constant rate initial drawdown yield from deconvolution were diagnosed with Interpret 2007 from Paradigm. Ecrin from Kappa was further used to confirm the interpretation model obtained.

[4] In this report the initial 60% of the production rates were not employed to calculate the equivalent Horner production time. Instead a less refined simplification of the rates was realized in the initial 60% of the cumulative production than in the remaining 40%.

[5] Ten day shut-in pressure buildups which were carried out during last well test simultaneous campaign observed at the end of the production history (approximately two years after first oil)

Individual pressure transient interpretation within geological context

Regarding the absence of selective well test realized in individual sandstone packages it becomes very challenging to characterize the reservoir by individual layer properties. The characterization was realized based on the radius of investigation of each test. Structural maps for intervals AA, BB and CC were available to help guide the interpretation in a geological context. The approach during the discussion for each interpreted well test was to describe the interpretation based in the following:

1. In terms of reservoir performance and aquifer support:

Productivity indexes and depletions were analysed based on historical data.

2. In terms of permeability and reservoir continuity:

Thickness-permeability, kh, permeability, k, and distance to boundaries, d were estimated.

3. In terms of well completion efficiency:

Skin factor, S, and its evolution with time, as well as anomalies in the production history were reported.

Results from PTA have a certain degree of uncertainty in all the different interpretation stages. The solution of the radial diffusivity equation is subjected to several assumptions, such as single-phase liquid flow, homogeneity, small pressure gradients and compressibility and constant viscosity. This is rarely the case in real scenarios and so, the final solution is subjected to variations from theoretical behaviour. Moreover errors in pressure and rate measurements contribute to another important source of uncertainty. Other uncertainties may include the non-uniqueness of the model and those arising from the quality of the match. The following discussion shows the results of each interpretation with error bounds as suggested by Azi *et al.* (2008) and shown in Table 3.

	kh	C	S	r_1	d
Well test results uncertainty	±15%	±20%	±0.5	±25%	±25%

Table 3: Well tests results uncertainty error bounds (Azi et al.2008).

Integration at field level

The final stage integrates all the results into one common geological context. A permeability distribution is proposed for the Eastern part of the reservoir as well as any suggested constraint in the geological modelling. The degree of overall uncertainty in the characterization is assessed. Conclusions are reported as well as final observations and recommendations.

Discussion

The scope of this work implied the analysis of a considerable number of buildups in eight different wells. For simplicity reasons only three of these interpretations are explained thoroughly in this section. Individual interpretations and a summary of results are included in Appendix E-Individual Interpretations.

Well w6

Well w6 started production in April 2009 (as all the other wells except well w4 and w7). It is one of the most productive wells with an actual production of approximately 15000bbl/d. Up to date its cumulative production has been approximately 12.4MMstb.Its production and pressure profile do not show any ambiguities compared to other wells except a sudden pressure drop one and a half years after initial oil due to a considerable increase of its oil production (see Figure 4). This well is a good example of how the initial pressure was obtained through deconvolution. A summary of the buildups done in such well is shown in Table 4.

Flow period (Buildup)	Sands	PBU date dd/mm/yyyy	IARF identification	Late time boundary identification
6	AA, BB12, BB12, CC	13/04/2009	Good	No
354	AA, BB12, BB12, CC	27/03/2010	Good	Good
674	AA, BB12, BB12, CC	11/02/2011	Good	Good

Table 4: Commingled tests done in well w6 and degree of identification of radial flow and boundaries observed in derivative.

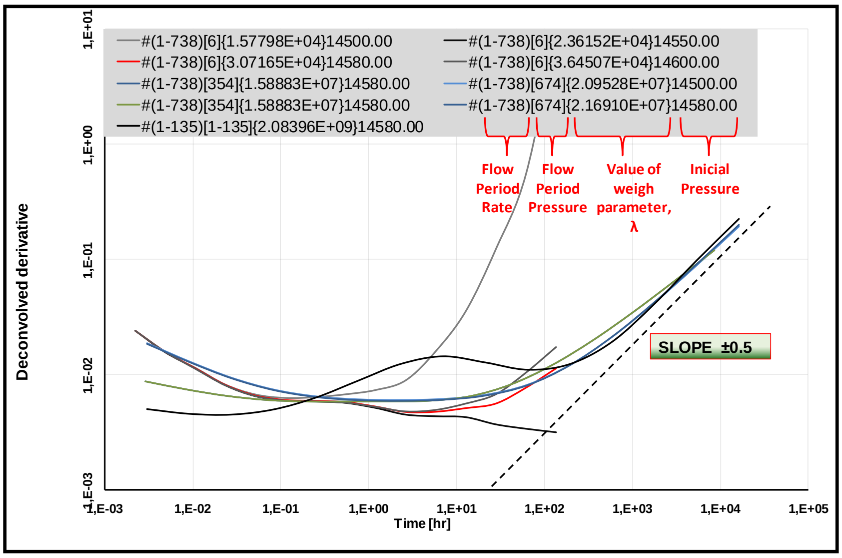

Figure 7: Deconvolution used as a tool to estimate initial pressure and determine late time boundaries.

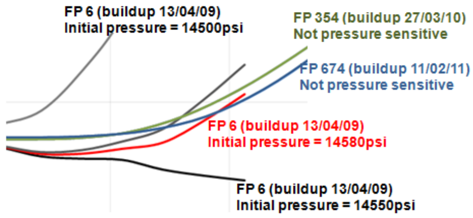

Figure 8: Estimation of initial pressure (Levitan et al 20054). Flow period 6 (IARF buildup) converges with flow periods 354 and 674 indicating a correct estimation of initial pressure.

All deconvolved derivatives should converge at late times. Flow periods which are exclusively affected by IARF are much more sensitive to initial pressure than those that reach boundaries. Figure shows that those buildups which reach boundaries (flow periods 354 and 674) are not affected by a change in the initial pressure and hence their respective derivatives are unchanged and consequently overlapping. In contrast, the buildup corresponding to flow period 6, which remains in radial flow, yields different derivatives for each different initial pressure. The initial pressure that yields a deconvolved derivative for the IARF buildup that converges with that one derived for the buildups that reach boundaries will be the correct initial pressure. In the case of well w6, as indicated in Figure , such pressure is 14580psi.

Levitan (2005) mentions that the von Schroeter et al. deconvolution algorithm fails if there are changes in skin or wellbore storage (both common in early flow data). In such cases he suggests to use deconvolution only with pressure data from individual flow periods. This report suggests quite the opposite. Using pressure data from all the flow periods, though it will camouflage the early time response, middle and late responses will not be significantly affected and thus provide an acceptable reservoir response (Gringarten 2005). The previous statement can be verified in Figure where all the derivatives converge to a half unit slope at the late times. Such half unit slope is indicative of a channel response or an open rectangle, and therefore will reduce uncertainty in the model selection further on.

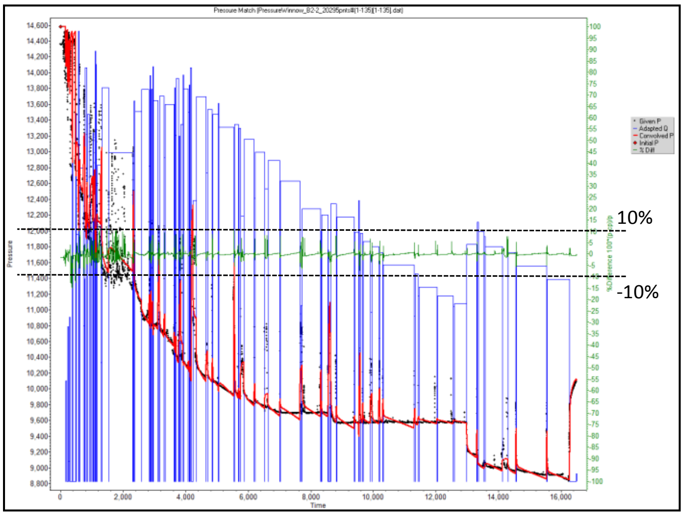

Figure 9: Deconvolved pressure history match with original pressure history. The 10% deviation limit is indicated by the dotted line.

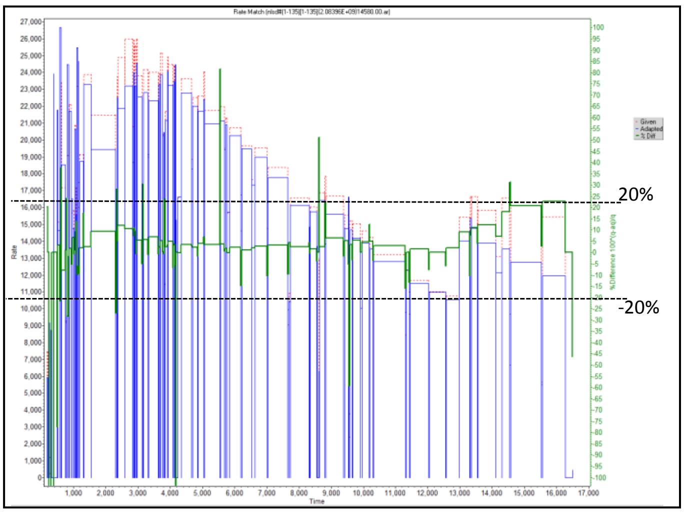

Figure 10:Given rates, adapted ones and difference between them. The 20% difference validation limit is indicated by the dotted line.

As previously mentioned, before generating the unit initial drawdown it is essential to validate the deconvolved derivative. The lack of oscillations and the fact that all derivatives from different buildups converge to one single line is a positive sign. Nevertheless the most important check is to be able to generate a convolved pressure history from the deconvolved derivative that matches the actual pressure history with a maximum error of 10% during the drawdowns. Further on, PTA focuses in matching the pressure while the rates are considered as a corrective function used in the calculation of the pressure derivative functions, model convolution and data deconvolution. It is important that the adapted rates do not differ in great measure from the original rates. In the present characterization, a limit of 20% difference between adapted and original rates is considered to assure a correct validation. Figure and Figure show the adapted rates deviations and the deconvolved pressure match respectively. The pressure match difference is less than 10% and hence considered to be good. The rate match is also considered to be acceptable. Although there are deviations in two peaks of more than 20% difference, they are considered to be punctual incidences most probable due to errors in the reported original rates.

The match being acceptable, the derivative is employed to generate a unit-rate initial drawdown with the same duration as that of the entire test. The unit rate-rate drawdown is analysed using conventional methods (Figure) and the resulting model is applied to the real measured pressure data using the adapted rates (Figure). The final match is obtained by refining the parameters in the conventional analysis way. Notice how the radius of investigation is almost two logarithmic cycles more in the deconvolved analysis than in the conventional.

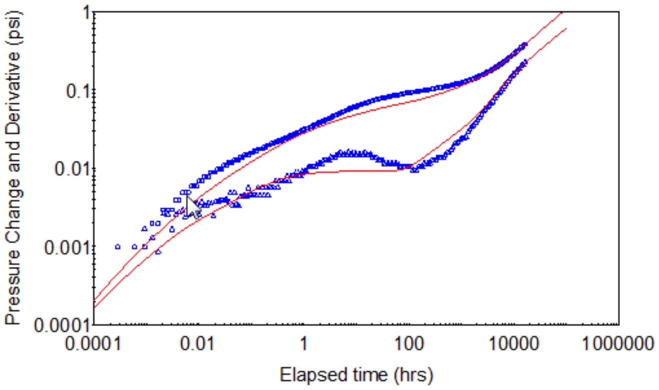

Figure 11: Unit-rate initial drawdown generated matched with a open no flow rectangle as indicated previously by the deconvolved derivative slope. Red lines indicate the match of the model applied.

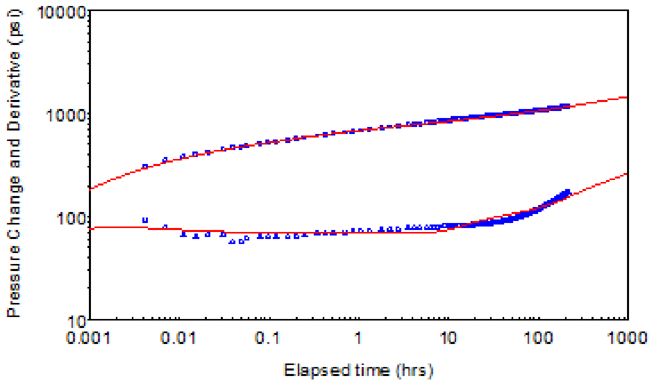

Figure 12: Open rectangle no flow model obtained in the unit-rate initial drawdown applied to real data buildup derivative with a slight refinement of the parameters. Red lines indicate the match of the model applied.

k mD	S -	d1 ft	d2 ft	d3 ft
100±15	-4.4±0.5	1675±420	6970±1750	1560±390

Table 5: Main parameters obtained from the unit-rate initial drawdown interpretation with an open rectangle no flow boundary configuration.

k mD	S -	d1 ft	d2 ft	d3 ft
205±30	-1.3±0.5	660±170	8310±2100	1970±500

Table 6: Main parameters obtained from conventional analysis, after refinement, with an open rectangle boundary configuration.

Refer to Appendix E-Individual Interpretations for further interpretation details.

In terms of reservoir performance and aquifer support:

The PBU performed on well w6 exhibits similar depletions as the ones observed in the majority of the wells, not showing a clear indication of aquifer support.

In terms of permeability and reservoir continuity:

Pressure derivative in well w6 shows a late time deviation that could be interpreted as boundaries or decreasing mobility/thickness, both suggesting a discontinuous environment. Regarding the channelized nature of the reservoir and the relative gross interval thickness observed in the logs, it is geologically sound to interpret a channel (or open/close rectangle).

Well w6	PBU 1 (13/04/2009)	PBU 2 (27/03/2010)	PBU 3 (11/02/2011)	Mobilities from MDT report, mD/cp
kh, mD*ft	37750±5600	33300±5000	46200±7000	72-202
Permeability, mD	170±25	150±20	205±30	

Table 7: Calculated permeability in well w6.

In terms of well completion efficiency:

Estimated skin factors are negative (approximately -1) for all the tests. Such estimation is consistent with the nature of a fracture gravel packs completed in the well. First water breakthrough was recorded in March 2011, still, water cut was considered negligible regarding a multiphase well test analysis interpretation.

Well w7

Well w7 started production in September 2009 (five months after the rest of the wells). It is the farthest well to the South-West of the field. Its actual production is approximately 5000bbl/d and with well w4 they are the wells with lower oil production. Its cumulative production up to date has been approximately 3MMstb. As mentioned previously, there is circumstantial evidence that it might be located in an independent block (different OWC and different GOR than rest of the field). Several inconsistencies in the reported rates were observed. The pressure profile shows the lowest depletion in the entire field which can be associated either to the low production of the well or to an aquifer support. A summary of the buildups done in such well is shown in Table 8.

This well is explained in the discussion as an example of a dubious deconvolved derivative which was not totally validated and should be refined further on. The model selection was therefore guided by conventional analysis procedure.

Flow period (Buildup)	Sands	PBU date dd/mm/yyyy	IARF identification	Late time boundary identification
12	AA, BB12, BB12, CC	10/09/2009	Good	Good
19	AA, BB12, BB12, CC	25/09/2009	Inconsistent	Inconsistent
23	AA, BB12, BB12, CC	28/09/2009	Good	Good
54	AA, BB12, BB12, CC	26/03/2010	Good	Average
91	AA, BB12, BB12, CC	11/02/2011	Average	Good

Table 8: Commingled tests done in well w7 and degree of identification of radial flow and boundaries observed in derivative

Deconvolution was used successfully to find the initial pressure. All build-ups converge at an initial pressure of 14506psia as shown in Figure . Despite the consistent behaviour between individual build-ups, the deconvolved entire pressure history derivative did not converge as expected. Different weight parameters were used to try and obtain similar tendencies but it was not possible. The entire history deconvolved derivative shows a late time behaviour not seen in the individual build ups, even though their radii of investigation are similar. The pressure check is good but the adapted rates differ more than 20% in several peaks, and most importantly, during the last hours of the test they seem to increase to values close to the 20% limit, (Figure 15 and Figure 15). The derivatives of each individual buildup are also plotted in dotted lines to verify that the response of the deconvolved derivative and the original are consistent. From such quality check it is deduced that flow period 19 is not a buildup although reported as one.

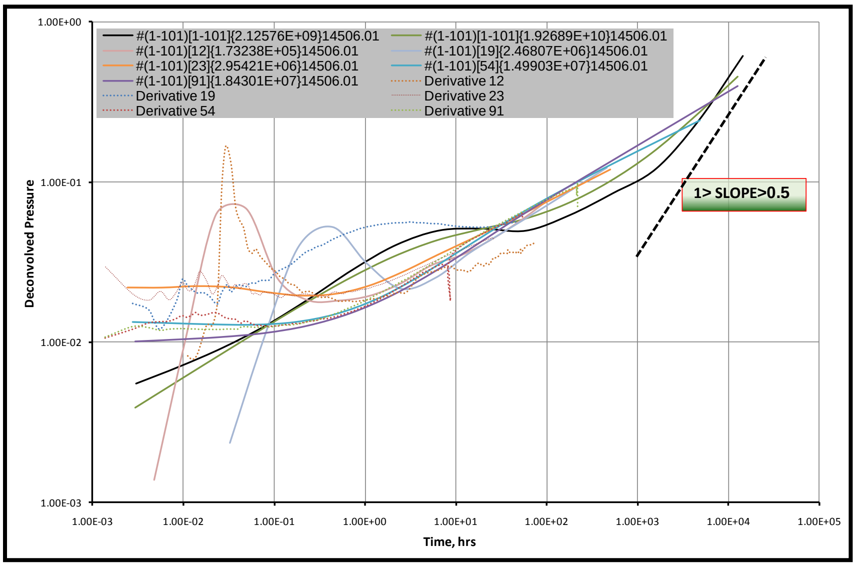

Figure 13: Deconvolution of individual buildup as well as the entire history with different regularization parameters. Buildup derivatives are also indicated.

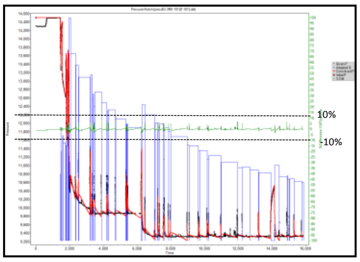

Figure 14: Pressure match is good

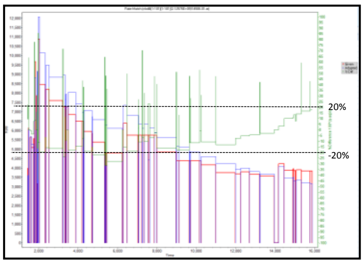

Figure 15: Rate validation is considered to be fair.

Conventional analysis was carried out for the longest build-ups (fp12 and fp91) and its derivative match is shown in Figure and Figure . Buildup fp12 was matched with a channel. The last buildup (fp91) was best matched with a channel (of similar distances to fp12) and constant pressure boundary. Though the shape of the derivative does not justify a constant pressure response, it is consistent with the low depletion observed due probably to an aquifer support. As a verification procedure, the unit rate drawdown was also analysed. It was matched with a channel of similar characteristics than that one obtained through conventional analysis, see Figure .

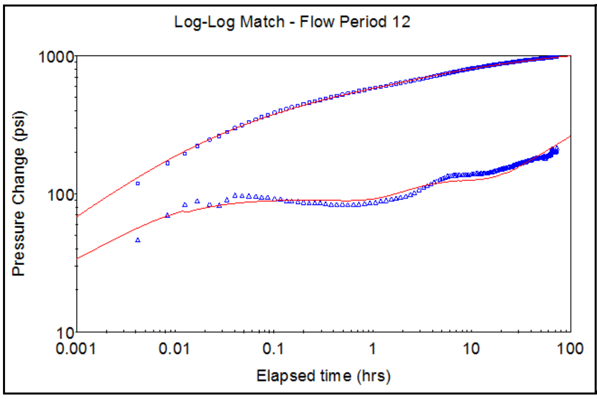

Figure 15: Channel model obtained for first buildup.

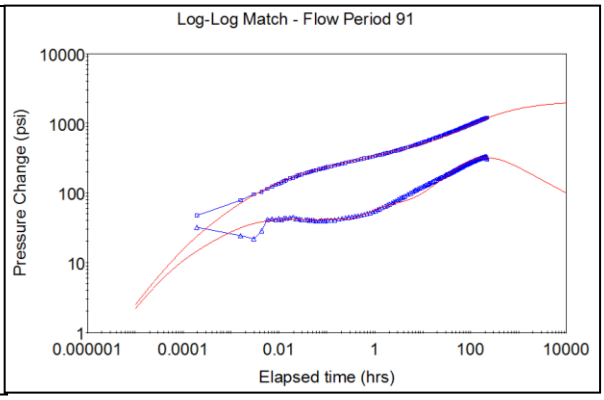

Figure 16: Open rectangle with constant pressure boundary model obtained for last buildup.

k mD	S -	d1 ft	d3 ft
40±5	-2.2±0.5	300±90	100±10

Table 9: Main parameters obtained from first buildup with a channel model.

k mD	S -	d1 ft	d2 ft	d3 ft
60±10	-1.7±0.5	290±90	1230±350	80±25

Table 10: Main parameters obtained from last buildup, with an open rectangle boundary configuration. d2 indicates distance to pressure boundary.

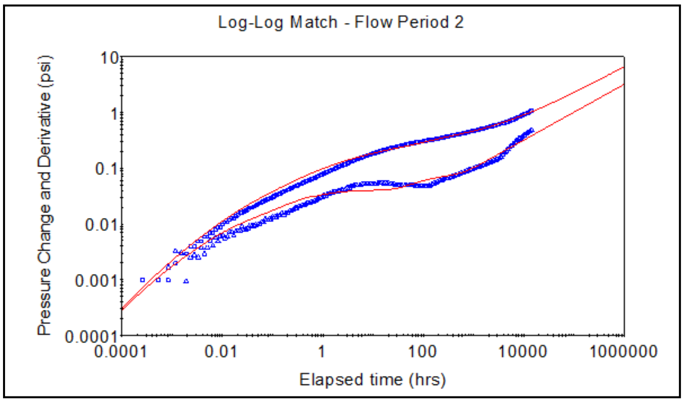

Figure 17: Channel model obtained for the unit rate initial drawdown.

k mD	S -	d1 ft	d3 ft
20±10	-3±0.5	360±100	150±50

Table 11: Main parameters obtained from unit-rate drawdown interpretation.

In terms of reservoir performance and aquifer support:

The PBU performed on well w7 exhibits considerably smaller depletions than the ones observed in the other wells. This might be due to an aquifer support. OWC is also located higher but water production is negligible.

In terms of permeability and reservoir continuity:

Permeability obtained in well w7 is almost one order of magnitude less than those observed in the rest of the field.

Pressure derivative in well w7 shows a late time deviation that could be interpreted as boundaries or decreasing mobility/thickness, suggesting both a discontinuous environment. Regarding the channelized nature of the reservoir and the relative gross interval thickness observed in the logs, it is geologically sound to interpret a channel. No clear evidence of a close system was observed (In appendix Individual interpretation there is an interpretation realized in the unit rate drawdown with a good match for a close system but it was not possible to match individual buildup derivatives with such model). Permeabilities obtained are consistent with mobilities.

Well w7	PBU 1 (10/09/2009)	PBU 2 (25/09/2009)	PBU 3 (28/09/2011)	PBU 4 (26/03/2010)	PBU 5 (11/02/2011)	Mobilities from MDT report, mD/cp
kh, mD*ft	10800±1600	-	11000±4600	16900	17500	72-202
Permeability, mD	40±5	-	40±5	60±10	65±10	

Table 12:Permeability obtained in well w6 from transient tests.

In terms of well completion efficiency:

Estimated skin factors are negative (approximately -2) for all the tests. Such estimation is consistent with the nature of a fracture gravel package completed in the well.

Well 5

Well w5 started production in late March 2009 and it is the only well drilled through the lowest layer (DD). Up to date its cumulative production has been approximately 7.5Mstb and its actual production is approximately 6500bbl/d. The pressure profile shows the highest depletion in the whole field (pressure at the end of the last build up compared to initial pressure). A summary of the buildups done in such well is shown in Table 13. The study of the transient test interpreted in this well will help to characterize the permeability of layer DD. It is also an example of initial pressure determination and use of deconvolved unit rate drawdown to confine the uncertainty in the model selection.

Flow period (Buildup)	Sands	PBU date dd/mm/yyyy	IARF identification	Late time boundary identification
22	AA, BB12, BB12, CC, DD	13/04/2009	Good	No
357	AA, BB12, BB12, CC, DD	28/03/2010	Good	No
677	AA, BB12, BB12, CC, DD	11/02/2011	Good	Good

Table 13: Commingled tests done in well w5 and degree of identification of radial flow and boundaries observed in derivative

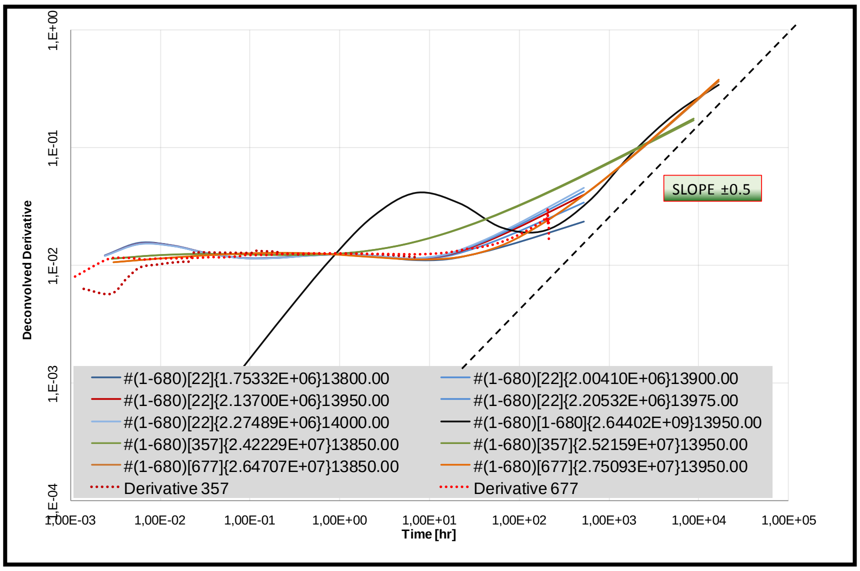

Figure 18: Deconvolution of individual buildup as well as the entire history with different regularization parameters. Buildup derivatives are also indicated

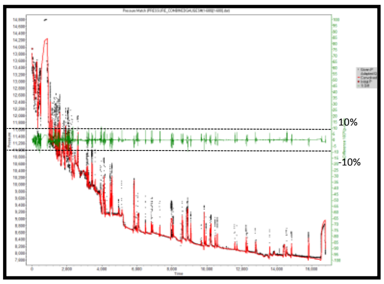

Figure 19: Good pressure match

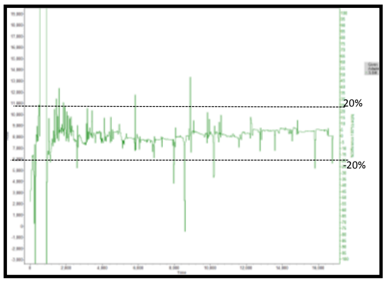

Figure 20: Acceptable adapted rates

An initial pressure of 13950psi was obtained using the same procedure as in the previous cases (Figure). This was possible as there are IARF buildups available. The pressure match was good and the adapted rates difference from the original ones was below 20% except in a few peaks (Figure 19and Figure 20). Moreover the entire pressure history deconvolved derivative converged to those ones yield by the individual buildups. In overall the deconvolution was considered acceptable and guided the model selection. It is observed in Figure that the buildup corresponding to flow period 357 did not merge with the other buildups. This flow period is not sensitive to initial pressure (both curves overlay for different pressures), even though its derivative does not show sign of boundaries at late time. The conventional derivatives are also plotted and that one from flow period 357 does not have the same tendency as its deconvolved derivative, which is a further indication that this flow period might not be a buildup. Again the cause might be error in the rates assuming the well is shut-in when it is flowing.

The unit rate drawdown was extracted and analysed the conventional way. The structural map was used to understand the geological features in the surrounding on the well and try to apply the geological features observed to the interpretation (Figure). A wedge boundary configuration model was successfully matched to the unit-rate drawdown and further on to the conventional analysis. Distances and angle of the intersecting boundaries were consistent with those ones observed in the map.

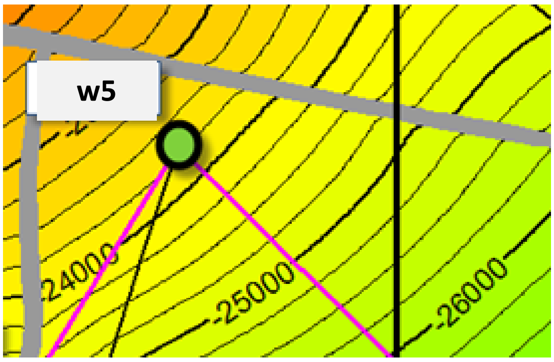

Figure 21: Structural map of the surroundings of well w5

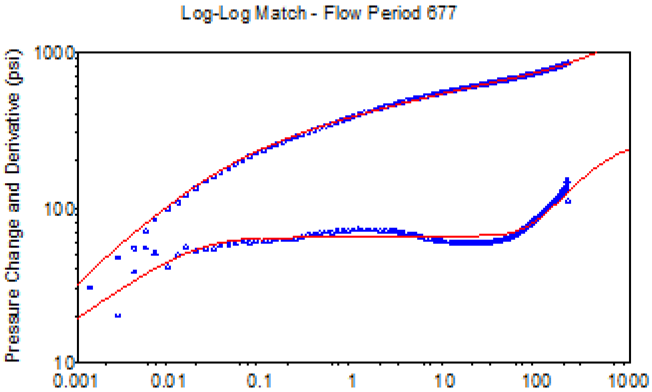

Figure 22: Conventional buildup matched with a wedge boundary

In terms of reservoir performance and aquifer support:

The PBU performed on well w5 exhibits a big depletion compared to other wells indicating little, if any, aquifer support at all.

In terms of permeability and reservoir continuity:

Table 14 shows the different permeability obtained in each transient test done in well w5.

Well w5	PBU 1 (13/04/2009)	PBU 2 (28/03/2010)	PBU 3 (11/02/2011)	Mobilities from MDT report, mD/cp
kh, mD*ft	15400±2300	13600±2000	14350±2100	NA
Permeability, mD	50±5	45±5	48±5	

Table 14: Permeability obtained in well w6 from all transient tests available.

Permeabilities obtained in well w5 are almost one order of magnitude less than those observed in the rest of the field. This might be because of a negative contribution to the overall permeability of layer DD. A multilayer test with the parameters obtained from conventional analysis was carried out to determine the permeability of each layer, see Table 15.

Multilayer test Well w5	AA	BB12	BB	CC	DD
Permeability, mD	155±20	65±10	160±25	70±10	13±2

Table 15: Obtained individual layer permeabilities from multilayer test.

The low permeability obtained for layer DD confirms the suspicion that such layer is reducing the overall permeability, and that it is indeed lower than in other layers.

In terms of well completion efficiency:

Estimated skin factors are negative (approximately -2) for all the tests. Such estimation is consistent with the nature of a fracture gravel package completed in the well. Well w5 has the highest water cut in the field. According to measured rates, water breakthrough started in August 2010. The average production of water is approximately 300bbl/d. The actual water cut is approximately 1% and it is considered negligible in this analysis.

PTA integration at field level

The final stage of a dynamic characterization is to integrate all the results into one single geological context. Information on all the transient tests available is required. Table 16 shows a summary of the results obtained from the well tests done during the last well camping (except well w3). The asterisk indicates the wells in which the initial pressure was obtained through procedures other than deconvolution due to lack of reliable IARF build-ups. Those that appear in red (w1, w2, w4 and w7) indicate that deconvolution was applied as a model verification tool instead of a model guiding tool due to inconsistencies in pressure match, rate match or deconvolved derivative. The tests shown in the table were the longest and have greater radii of investigation. Previous build-ups were also analysed to verify permeability results as well as wellbore storage and skin factor evolution.

Figure compiles all the observed boundary configurations into one single structural map. The structural map corresponds to one single horizon but similarity with other horizons is assumed due the short distance between them and relative similar gross thickness observed in logs. The distances of investigation from conventional analysis are also included (Ri). The boundaries observed are interpreted based on the most probable depositional model which is a basin-floor to lower slope high energy, turbidites sourced from the northwest. Channels are shown in red lines and aquifer influx in blue arrows. Well 3 was not tested during the last well test campaign. Individual build-ups suggest a possible aquifer influx though deconvolution on the other hand suggests an open rectangle.

Well	*Sands*	*Date test*	*Boundary configuration*	*Skin*	*Ko*h mD*ft*	*k md*	*Pi psia*	*Dinv ft*	*d1 ft*	*d2 ft*	*d3 ft*	*Angle*
w1*	AA,BB12,BB	11/02/11	Channel	-3.0	42200	410±60	14500	3975	210	1800		
w2	AA,BB12,BB,	10/02/11	Channel	0.0	30630	240±40	14200	3450	1320	2480		
w3	AA,BB12,BB,	17/04/09	Cte pressure	-1.0	25600	200±30	14670	2000	1260	-	-	
w4*	AA,BB12,BB	11/02/11	Channel	-2.0	14700	320±50	13800	2660	180	2320		
w5	AA,BB12,BB, CC, **DD**	11/02/11	Wedge	-2.4	14348	50±5	13950	1220	830	800		77
w6	AA,BB12,BB,	11/02/11	Open rec. No flow	-1.3	46198	210±30	14580	3070	650	8300	1900	
w7	AA,BB12,BB,	11/02/11	Channel	-2.0	10800	40±5	14506	760	300	100		
w8	AA,BB12,BB,	11/02/11	Channel	-3.4	86570	385±60	14209	2860	195	1010		

Table 16: Main parameters obtained from the interpretation of the transients tests realized during the last well test campaign (except well w3).

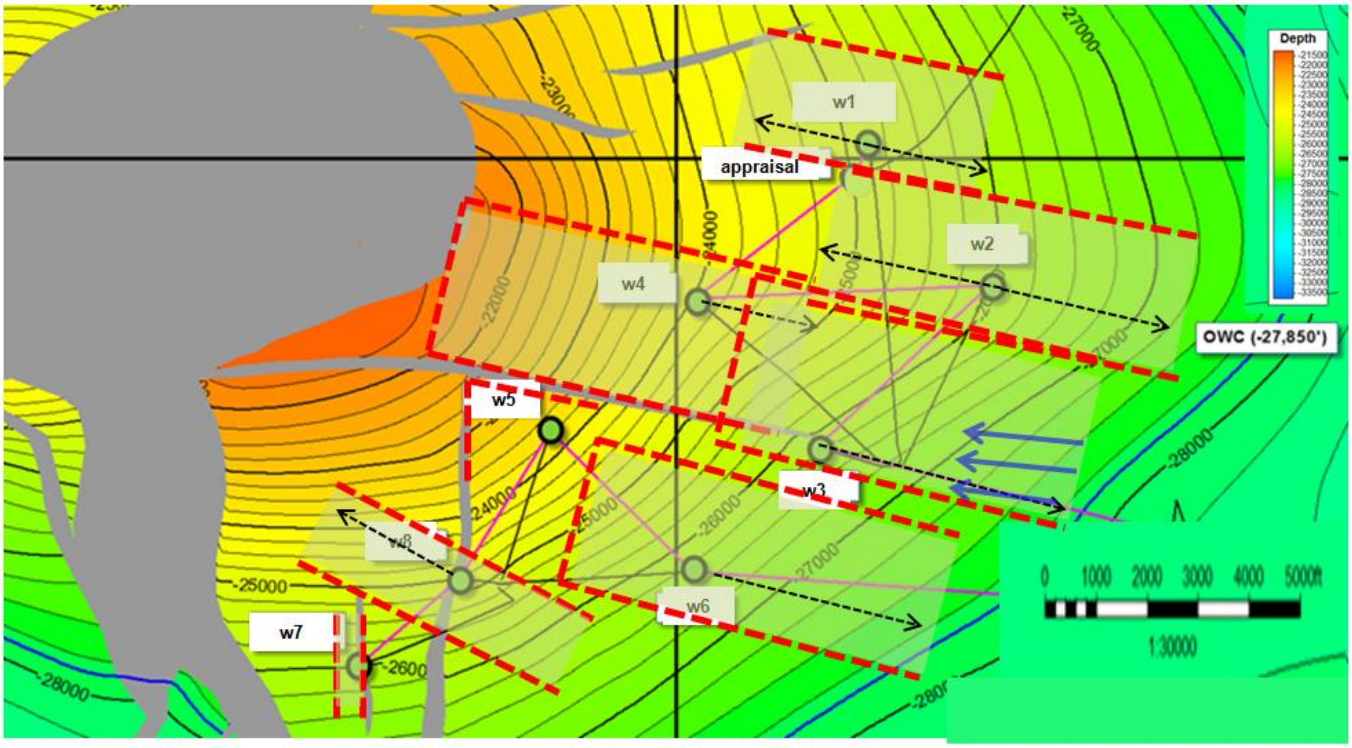

Figure 23: Structural map with the interpreted observed boundaries and the radii of investigation of each well obtained by PTA.

Figure : shows the proposed geological modelling after the PTA characterization.

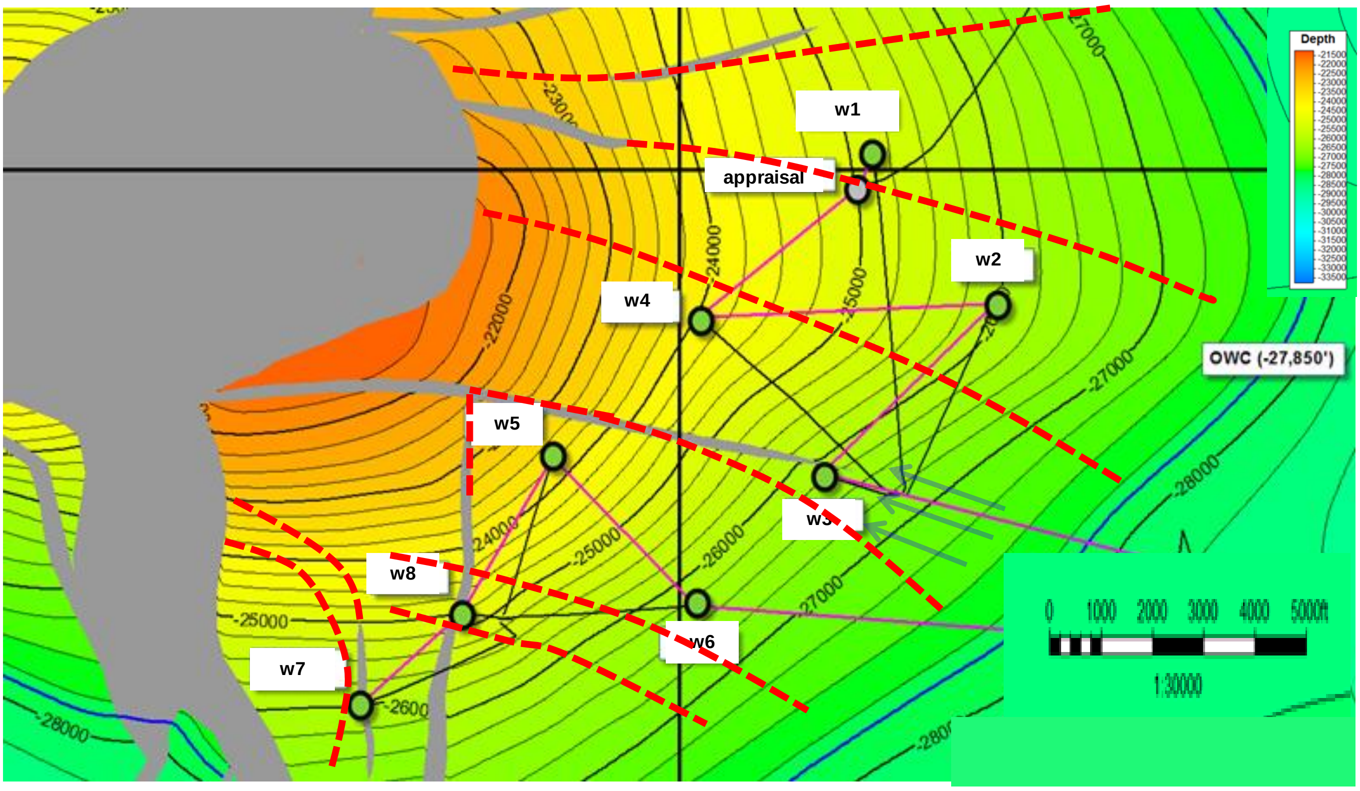

Figure 24: Geologic mapping proposed.

Conclusions

The objective of the dynamic synthesis was to interpret all the transient data available with the same methodology procedure to derive macroscopic reservoir properties in terms of effective permeability and discontinuities –pressure of flow barriers or pressure support effect- . It will guide the selection of alternative static models. The main conclusions achieved were the following:

-Linear flow- channelized sands- is clearly developed in almost all the tested wells in accordance with the geological channelized nature of the reservoir.

-Reservoir permeability is of the order of 200-400 mD with exceptions of wells w5 and w7. Such range is consistent with drawdown mobility ranges obtained in MDT reports.

-Well w5 is the only well perforated in the lower sands (DD) and yields a permeability of ±50mD suggesting that such sand is not contributing much to production.

-Well w7 yields a lower permeability distribution than the rest of the field (±50mD). It is the most southern well and has different GOR and OWC suggesting that it could be isolated. A satisfactory close system match was achieved in the unit-rate drawdown but not in any of the conventional buildup derivatives.

-No clear evidence of aquifer support was observed. Only well w3 shows a concave downwards derivative response, typical of bottom waterdrive, but it is generally noise and could be associated to end time derivative errors instead. Despite this, well w3 shows the lowest pressure depletion, although it is one of the greatest producers, suggesting again a possible aquifer support.

-Deconvolution proved to be a successful initial model identification tool in the cases in which the given rates showed fewer ambiguities with the recorded pressure response.

Recommendations

The following recommendations are proposed for future stages of the field development:

-PBU data interpretations were impaired by commingled production without Production Logging Testing (PLT) information increasing uncertainty in the results. Commingled reservoirs are complex to characterize as their well test response is very dependent on the layer properties contrast and near well bore conditions of each layer. It is recommended to do PLT in all the wells to obtain an individual layer characterization and evidence of possible crossflow.

-Further manipulation of the given rates is required to assure the validation of the deconvolved derivatives. Also, regarding rates, it is important that they are reported as precise as possible. It is strongly recommended to avoid reporting a well as a shut in when it is actually flowing, despite how insignificant is the rate it is flowing at. This will prevent from mistaking buildups for drawdowns.

-A new seismic data acquisition campaign should be carried out to reduce uncertainty in the southwest flank (SW) and in the crestal portions of the anticlinal. It will also guide the way for a future 4D seismic acquisition camping allowing to determine the changes occurred in the reservoir as a result of hydrocarbon production or future water injection.

-Pending for future work, it is recommended to integrate transient analysis with long term data throughout production analysis.

-An attempt should be made to calibrate available mobilities with SCAL data and macroscopic permeability values from PTA interpretations.

-Selective sand PBU should be done to reduce commingled uncertainty. Assuming that to close perforations in productive wells Is not an option, due to technical and economic reasons, it is recommended to do so in the appraisal well and test the BB sand individually.

-Measured rates and pressure data validation ensure that acquired data is of adequate quality and satisfies test objectives. As such, validation should be performed before leaving the well site.

Nomenclature

C	Wellbore storage coefficient, bbl/psi
Cf	Formation compressibility, psi-1
ct	Total compressibility, psi-1
d_1	Distance to first boundary, ft
d_2	Distance to second boundary, ft
d_3	Distance to third boundary, ft
k	Permeability, mD
kh	Permeability-thickness product, mD ft
p_i	Initial pressure, psi
p_{wf}	Well flowing pressure, psi
Ri	Radius of investigation, ft
S	Skin factor
λ	Regularization parameter for deconvolution (TLSD software)
μ	Oil viscosity, cp

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Appendices

Appendix A - Literature review

Referred Well Test Analysis Milestones

No	SPE PAPER	YEAR	Title	Authors	Contribution
1	8205	1979	A Comparison between Different Skin and Wellbore Storage Type-Curve for Early-Time Transient Analysis	A.C. Gringarten D. P. Bourdet P. A. Landel V. J. Kniazeff	First introduction of the concept of independent variables.
2	12777	1984	Use of Pressure Derivative in Well Test Interpretation	D. Bourdet J.A Ayoub Y.M Pirad	The pressure derivative is introduced as a new well test interpretation method.
3	19797	1989	Analysis of Pressure and Rate Transient Data from Wells in Multilayered Reservoirs: Theory and Application	L. Larsen	It presents a new solution technique to analyse multi-layered tests based on an analytical conversion of a single-layer transient response to a multilayered one.
4	24679	1992	Analysis of Pressure and Rate Transient Data From Wells in Multilayered Reservoirs: Theory and Application	P. Bidaux T.M. Whittle P.J. Coveney A.C. Gringarten	Introduction to a new solution technique based on an analytical conversion of a single-layer transient pressure response into a multi-layer response.
5	62854	2000	Multi-Phase Flow in Several Layers Limits the Applicability of Conventional Buildup Analysis	S. V. Iakovlev W. J. Lee	An estimate of the errors induced in permeability and skin factor when conventional analysis techniques are employed to solve complex commingledcases of flow of oil in the wellbore only.
6	63077	2000	Frequently Asked Questions in Well Test Analysis	S. Daungkaew F. Hollaender A.C. Gringarten	Provides a rate history simplification approach to reduce deviations in the derivative due to rate errors.
7	71574	2001	Deconvolution of Well Test Data as a Nonlinear Total Squares Problem	T. Von Schroeter F. Hollander A. C. Gringarten	Publication of the first effective algorithm for deconvolution.
8	84290	2005	Practical Application of Pressure/Rate Deconvolution to Analysis of Real Well Tests	M. M. Levitan	Refinment of Von Schroeter et al.'s deconvolution algorithm and application to real data.
9	113877	2008	Influence of Geological Features on Well Test Behaviour	M. A. Mijinyawa, A. C. Gringarten	Enhance understanding of the late time behaviour of complex geometries ignored during routine well test interpretations.
10	113888	2008	Evaluation of Confidence Intervals in Well Test Interpretation Results	A.C. Azi T.M. Whittle A.C. Gringarten	presents uncertainty in the results of well test interpretations.

SPE 8205 (1979)

A Comparison between Different Skin and Wellbore Storage Type-Curve for Early-Time Transient Analysis

Authors:
A.C. Gringarten, D.P. Bourdet, P.A. Landel, V.J. Kniazeff.

Contribution to the understanding of well test analysis:
Independent variables in type curve analysis are introduced in the well testing domain.

Objectives of the paper:
Highlight the efficiency of type-curve matching regarding specific type-curves employed during the matching. It also introduces a new type-curve for wellbore storage and skin effects.

Methodology used:
Employment of independent variables to enhance the results obtained throughout the use of types curves published by Argawal, Al-Hussainy and Ramey.

Conclusion reached:
1. Validate the type-curve matching approach in well testing.
2. The new type curve, used in a wider range of wells conditions, is more efficient as a qualitative and quantitative interpretation tool.

Comments:
In order to analyse Build-up data with drawdown type-curves, it is necessary that the production time is greater than the longest build up time.

SPE 12777-PA (1984)

Use of Pressure Derivative in Well Test Interpretation

Authors:
D. Bourdet , J.A Ayoub, Y.M Pirad

Contribution to the well understanding of Well Test Analysis:
A new method for well test interpretation based on the time rate of pressure change and the pressure response is introduced.

Objective of the paper:
The paper presents a faster, easier and more accurate method to do well test interpretations.

Methodology used:
Derivative curves are generated by taking the derivative of the pressure with respect to the natural logarithm of time. Different flow regimes have characteristic behaviours represented in the derivative.

Objective of the paper:
1. The analysis of the time rate of pressure change (derivative) makes interpretation of well tests easier and more accurate as it improves the definition of the analysis plots.
2. Importance of filtering original data in order to remove noise in the pressure signal as the derivative approach will reveal them.

Comments:
Even though it is redundant experiences shows that it is convenient to match both the pressure and the derivative curves.

SPE 19797 (1989)

Boundary Effects in Pressure-Transient Data from Layered Reservoirs

Authors:
L. Larsen

Contribution to the well test interpretation in layered reservoirs:
It presents a methodology able to generate transient response solutions through the Laplace domain with a wide variety of complex boundary configurations.

Objective of the paper:
To reduce uncertainty determining the pressure transient response in wells drilled through more than one layer close to linear boundaries.

Methodology used:
Provided that neighbour layers have common boundaries, the article presents a technique to treat separately the transformed solutions through the Stephast algorithm, such that boundary effects can be treated individually for each layer.

Conclusion reached:
1. Image-well techniques can include in its analytical solution complex boundary effects in layered reservoirs.
2. The response of boundaries is dominated by the higher permeability layers.

Comments:
It is important to do a layer refinement in order to obtain good history-matching analyses in reservoirs with crossflow.

SPE 24679 (1992)

Analysis of Pressure and Rate Transient Data from Wells in Multilayered Reservoirs: Theory and Application

Authors:
P. Bidaux, T.M. Whittle, P.J. Coveney, and A.C. Gringarten

Contribution to the well test interpretation in layered reservoirs:
It presents a new solution technique to analyse multi-layered tests based on an analytical conversion of a single-layer transient response to a multilayered one.

Objective of the paper:
Develop a new procedure to analyse multi-layer reservoirs transient response reducing uncertainty.

Methodology used:
The solution technique presented is procedure to transform any single-layer transient response into a multilayered response through the Laplace domain.

Conclusion reached:
A multi-layer description of the reservoir is obtained which enables to obtain the pressure transient behaviour as well as all the different layer rates during each flow period.

SPE 62854 (2000)

Multi-Phase Flow in Several Layers Limits the Applicability of Conventional Buildup Analysis

Authors:
S. V. Iakovlev, W. J. Lee

Contribution to the well test interpretation in layered reservoirs:
An estimate of the errors induced in permeability and skin factor when conventional analysis techniques are employed to solve complex commingledcases of flow of oil and gas in the wellbore only.

Objective of the paper:
Assess the impact of multi layered reservoir models in the calculation of permeability and Skin factor compared to a single layered reservoir model.

Methodology used:
The comparison throughout iterative simulations between a multi layered model and a single one by varying the main reservoir parameters of the model using a black oil simulator.

Conclusion reached:
In multiphase flow in two commingled layers permeability and skin factor values tend to be either over- or underestimated. Average effective oil permeability and skin factor depend on wide range of parameters. The higher the contrast between layer parameters, the greater the uncertainty in the results obtained.

Comments:
In the majority of the cases the average Skin factor tends to be underestimated while for constant Bottom Hole pressure production, the oil permeability if often overestimated.

SPE 63077 (2000)

Frequently Asked Questions in Well Test Analysis

Authors:
S. Daungkaew, F. Hollaender, A. C. Gringarten

Contribution to the understanding of well test analysis:
It presents a guide line to answers some of the most common questions and doubts frequently asked by practicing engineers.

Objectives of the paper:
It aims to provide answers to the following common asked questions:
1. Is there more information available in a build up than in a drawdown?
2. How much of the rate history is needed to realize a correct analysis?
3. Identification of a non-uniform skin effect from well test data in a fully penetrating well.

Methodology used:
Assess the impact of the Horner equivalent time and the truncation of the rate history on the derivative shape.

Conclusion reached:
1. The combination of the Horner equivalent time with a detailed history of the production rate as a refinement of the Well test conventional analysis.
2. An accurate description of the last 40% of the cumulative production followed by the use of Horner equivalent time in the remaining 60% yields an accurate derivative.

Comments:
These summary focuses on the second question presented which has been employed during this research project.

SPE 71574 (2001)

Deconvolution of Well Test Data as a Nonlinear Total Squares Problem

Authors:
T. Von Schroeter, F. Hollander, A. C. Gringarten

Contribution to the understanding of well test analysis:
Publication of the first effective algorithm for deconvolution.

Objectives of the paper:
Develop a good algorithm for the deconvolution of pressure and flow rate data.

Methodology used:
The Duhamel's principle was employed in order to solve the convolution product in time domain allowing this way to obtain the reservoir impulse response.

Conclusion reached:
Improvements in the deconvolution as a nonlinear Total Least Squares problem include:
1. A nonlinear encoding of the reservoir response which does not require sign constraints.
2. A modified error model is developed which accounts for errors in both pressure and rate data.

Comments:
The deconvolution algorithm requires the rate data to not be more than 10% corrupted. Within this range it will yield interpretable response functions taking into account that error weight and regularization parameters are selected with proper criteria.

This paper was updated in 2004.

SPE 77688 (2002)

Deconvolution of Well Test Data as a Nonlinear Total Squares Problem

Author(s):
T. Von Schroeter, F. Hollander, A. C. Gringarten

Contribution to the understanding of well test analysis:
First Empirical well test analysis using deconvolution realized on permanent downhole gauges.

Objectives of the paper:
Practical procedure of how to analyse a well test data with deconvolution.

Methodology used:
Two large sets of field data we used to implement the algorithm and further on contrast results. .

Conclusion reached:
1. Unlike the multirate extension of derivative analysis, deconvolution does not suffer from any bias due to implicit model assumptions.
2. Deconvolution has no restriction regarding the choice of pressure data window.
3. Errors in the rates are coped with in a more sensible approach increasing flexibility.

Comments:
Some corrections in the deconvolution algorithm are done regarding the previous paper published in 2001.

SPE 84290 (2005)

Practical Application of Pressure/Rate Deconvolution to Analysis of Real Well Tests

Authors:
M. M. Levitan

Contribution to the understanding of well test analysis:
Refinment of Von Schroeter et al.'s deconvolution algorithm.

Objectives of the paper:
Present and enhanced deconvolution algorithm applied to real test data.

Methodology used:
Several real test examples are employed to analyse real test data.

Conclusion reached:
1. The Von Schroeter et al. deconvolution algorithm fails if there is a changes of wellbore storage or skin during the well test sequence, as it is often the case in real test data.
2. This problem can be tackled using the deconvolution algorithm with pressure data from individual flow periods.

Comments:
According A.C. Gringarten (2005 publication), deconvolution applied to the complete test will still yield an acceptable reservoir response.

SPE 102079 (2008)

From Straight Lines to Deconvolution: The Evolution of the State of the Art in Well Test Analysis

Author(s):
A. C. Gringarten

Objectives of the paper:
Compile the mile stones and evolution of Well test analysis throughout its history.

Methodology used:
Describe the use of straight line analysis and the introduction and methodology of the log-log and then pressure-derivative analysis. The paper concludes with the development and application of the Deconvolution algorithm as a new procedure to realize a well test interpretation.

Conclusion reached:
The importance of reservoir characterisation based on reliable well test analysis is becoming more important as new instrumentation and new supportive analysis techniques become more widely employed.

Comments:
The article was very helpful summarising the different techniques in pressure transient analysis.

SPE 113877 (2008)

Influence of Geological Features on Well Test Behaviour

Author(s):
M. A. Mijinyawa, A. C. Gringarten

Contribution to the understanding of well test analysis:
Enhance understanding of the late time behaviour of complex geometries ignored during routine well test interpretations.

Objectives of the paper:
Research the response of complex geological features as a semi-infinite channel with non-parallel boundaries (wedge) , a T-shaped channel, a meandering channel and a pinch out boundary.

Methodology used:
Then these pressure responses created in complex geometry models were analysed using simpler interpretation models available in the literature.

Conclusion reached:
Complex geometries are revealed on the well test pressure derivative by a non-standard transition between the main radial flow derivative stabilisation and the late time boundary behaviour.

Comments:
The paper was used to understand responses of complex geometries present in the studied reservoir.

SPE 113888 (2008)

Evaluation of Confidence Intervals in Well Test Interpretation Results

Author(s):
A.C. Azi, T.M. Whittle, A.C. Gringarten.

Contribution to the understanding of well test analysis:
Enhance understanding of the uncertainty in the results of well test interpretations.

Objectives of the paper:
To determine the magnitude of errors induced in interpretation results and evaluation of their typical ranges.

Methodology used:
Probability density functions for well input data and match parameters were generated and applied to well test analysis results.

Conclusion reached:
Estimation of the impact of errors in both well and reservoir input data. Results achied yield the following: permeability thickness 15%, the permeability 20%, well bore storage constant 20%, the Skin Factor ±.3 and the distances 25%.

Comments:
The paper was used to calculate the range of uncertainties in the result obtained in the interpretations.

Appendix B – PVT input data

PVT parameters were obtained mainly from well w2 and w3 for the eastern side of the reservoir. Fluid samples were also carried out in exploratory wells but were considered less relevant because the formation sampled has lower oil saturation.

PVT parameters are shown in Table B-1.

FLUID PROPERTY SUMMARY (EAST)			
			East (M9/M10)
Fluid Data:	**Units:**		DD/EE/FF/GG Sands
Oil Gravity	°API		30.5 - 34.0
Oil FVF	bbl/stb		1.08 - 1.23
Oil viscosity	cp		1.70 - 3.59
Gas FVF, bg	SCF/cu ft		-
Z			-
Oil Compressibility (psi-1):	psi-1		$3.4 - 5.2 \times 10^{-6}$
Gas Compressibility (psi-1):	psi-1		-
Paraffin	%		3.2 - 5.4
Asphaltene	%		2.1 - 6.7
Sulphur	%		1.1 - 2.6
H_2S	ppm		0 - 2
CO_2	%		-
N_2	%		-
GOR	scf/bbl		303 - 427
CGR	bb/mmscf		-
LPG yield	bb/mmscf		-
Ethane yield	bb/mmscf		-
Pb	psi		1,335 - 2,033

Table B-1; PVT input data used for interpretations

Comparison between GOR PVT reports available and GOR calculated from given rates. Analogue PVT reports for each well are also indicated. Notice that well w7 shows a clear difference as indicated in Table B-2.

Well name	GOR from rates scf/bbl	Analogue PVT report	GOR From Analogue scf/bbl
w1	320-420	w2	356
w2	350-365	w2	356
w3	320	w3	376
w4	300-420	w3	376
w5	300-420	Orchid-4/w3	456
w6	300-420	Orchid-4/w-3	376
w7	200-400	Orchid-4/w3	376
w8	300-450	w3	376

Table B-2: GOR comparison between PVT reports and the one derived from given rates.

Appendix C – Log and Petrophysical data

Log wells correlation, perforations, gross and net zones observed in wireline.. Porosities and permeability obtained from wireline is also presented in this appendix as well as formation bulk compressibility. Notice greatest separation between layer AA and BB12 than in between any other. layers. Layer DD only shows oil saturation in well w5.

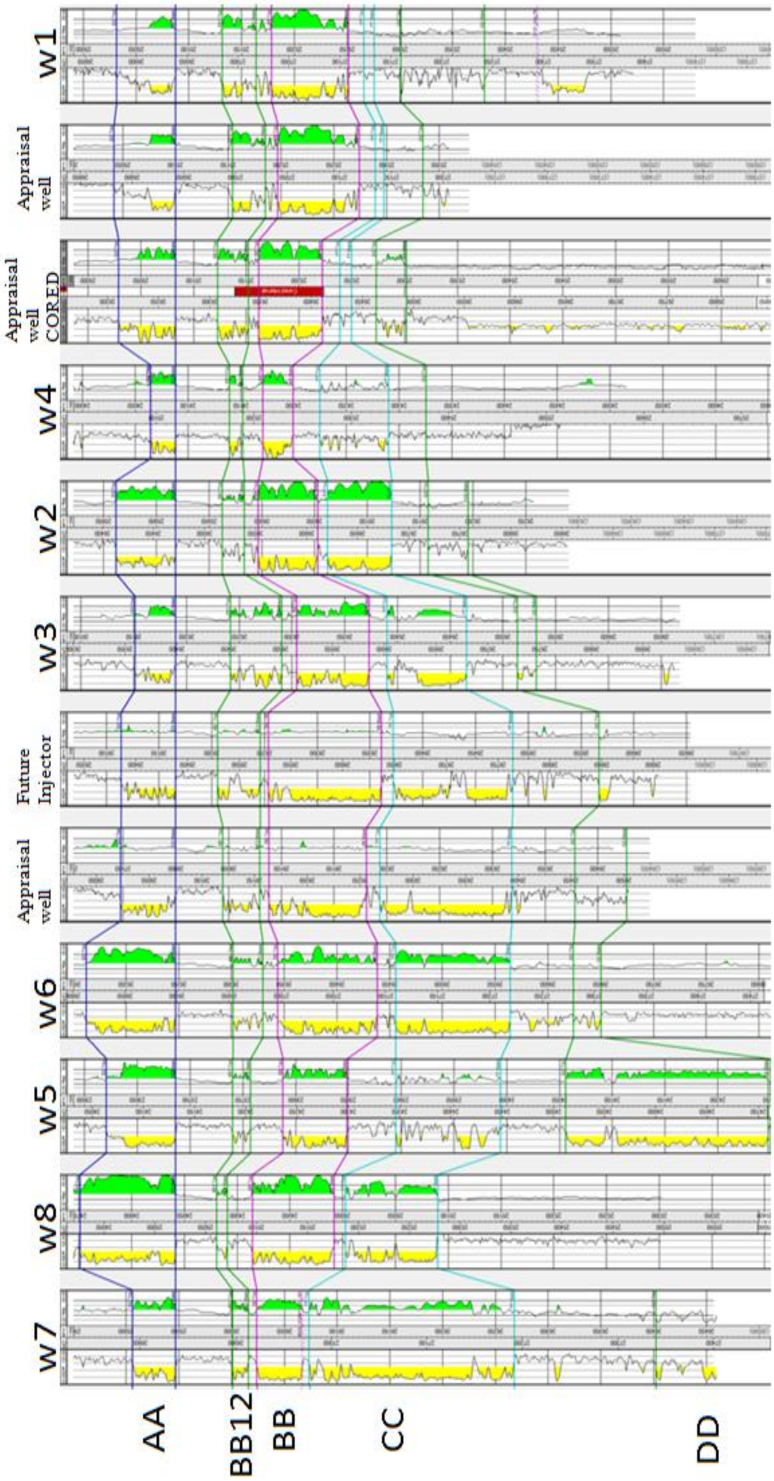


Figure C-1: Log correlations

PETROPHYSICAL AND LOG DATA FOR INTERPRETATIONS						
WELL	SAND PACK	DEPTH INTERVAL	GROSS	NET ZONE	AV. PHIE	K
		MD, ft	ft	ft		mD
w1	AA	26883-26943	60	20.5	0.1973073	351.57956
w1	BB12	**26997-27029**	**32**	**22**	**0.222**	**545.567**
w1	BB	27041-27119	78.67	60	0.206	534.27
w1	CC	27135-27143	8.5	0	-	-
w2	AA	26414-26472	58.25	16	0.196	243.248
w2	BB12	**26518-26540**	**21.93**	**7**	**0.1803429**	**52.291986**
w2	BB	26553-26611	58.07	42.5	0.2005353	933.34442
w2	CC	26621-26683	62.88	60.5	0.171	48.971
w2	DD	26719-26758	39.05	2	0.171375	13.956775
w3	AA	26360-26399	39.57	16	0.1708214	84.722676
w3	BB12	**26452-26502**	**49.95**	**19.5**	**0.1812619**	**265.26149**
w3	BB	26516-26586	69.95	46	0.1795582	258.33052
w3	CC	26603-26680	76.6	49.5	0.1709561	48.971107
w3	DD	26729-26747	18.4	0	N/A	N/A
w4	AA	25094-25120	26.37	18	0.216025	302.58682
w4	BB12	**25175-25189**	**13.81**	**6.5**	**0.1908692**	**148.9217**
w4	BB	25209-25241	31.22	21.5	0.2098279	254.6315
w4	CC	25268-25339	70.55	12.5	0.185416	36.888324
w5	AA	24063,79-24132	68.02	47.5	0.2164084	167.90839
w5	BB12	**24186,98-24205**	**17.71**	**4**	**0.186575**	**26.962501**
w5	BB	24236,27-24299	62.39	49.5	0.1973965	170.74142
w5	CC	24346,53-24448	101.93	22.5	0.1952241	122.00646
w5	DD	24512,42-24710	197.7	176	0.2133333	166.9583
w6	AA	26813,29-26899	85.74	57.5	0.1695904	242.43237
w6	BB12	**26954,03-26982**	**28.23**	**0.5**	**0.1517**	**732.4749**
w6	BB	26996,8-27092	95.25	59	0.1733508	152.83532
w6	CC	27109,82-27220	109.92	102	0.1905	215.22693
w6	DD	27280,25-27307	26.51	3	0.1648667	16.205217
w7	AA	26792-26838	46	35	0.1821957	222.56061
w7	BB12	**26896,92-26914**	**17.08**	**8.5**	**0.1794353**	**138.18317**
w7	BB	26922-26970	48	45.5	0.1995308	240.44071
w7	CC	26978-27192	214	182	0.1901173	142.86627
w8	AA	24926,93-25021	93.98	83.5	0.2163837	379.20713
w8	BB12	**25061,2-25071**	**10.24**	**2**	**0.1616628**	**65.01895**
w8	BB	25096,15-25176	80.08	69	0.2013466	306.14025
w8	CC	25187,67-25278	90.37	70	0.201573	201.92203

Table C-1: Well depth interval per zone in each well. Groos and net zone and average porosities yield from wireline

Averaged Cbp (x10-6 psi)	0.38	0.46	0.55	0.30	0.39	0.40	0.28	0.43	0.43	0.64
Averaged Cpp (x10-6 psi)	1.00	1.78	2.16	1.03	1.38	1.44	1.00	1.59	1.58	2.57
Averaged Cppm (x10-6 psi)	1.05	3.18	2.91	1.42	2.44	2.60	1.57	2.77	2.76	4.73

Cbp = Bulk compressibility
Cpp = Pore compressibility based on pore pressure
Cppm = Pore compressibility based on effective mean stress

Table 2: Average bulk formation compressibility. Pore compressibility based on effective mean stress was used.

WELL PERFORATIONS			
WELL	***Sands***	***PERF depth***	***Frac Pack***
G1-1	DD EE12&EE	N/A	2 frac packs
G1-2	DD&EE&FF	?-26,688.95	2 frac packs
G1-3	DD EE12&EE FF	26,380-26,395 26,453 - 26,581 26,603- 26,675	1 frac pack
G1-4	DD&EE12&EE	25,097 - 25,237	1 frac pack
B1-2	DD EE12 EE&FF GG	24,084-24,130 24,187-24,203 24,234-24,434 24,526-24,708	2 frac packs
B2-2	DD EE12&EE&FF	26,818-26,897 26,954-27,206	1 frac pack
B2-3	DD EE12 EE FF	26,767 - 26,806 26,868 - 26,883 26,896 - 26,930 26,950 - 27,150	1 frac pack
B2-4	DD EE12&EE&FF	24,944-25,020 25,060-*25,271*	2 frac packs

Table 3: Perforation interval in each as well as number of frac gravel packs completed.

Appendix D – Distributed Formation Pressures (MDT)

Comparison between initial pressures obtained in MDT refered to datum (OWC) to those ones obtained by means of deconvolution or initial pressures recorded in gauges. Similar pressures were obtained. It is interesting to point out that initial pressures obtained by deconvolution were slightly closer to those ones obtained in the MDTs than those ones recorded in the gauges at their completion time.

MDT Well Name	Pressure	Depth	Depth difference	Pressure referred to datum
w5	14296.53	24235.39	3614.61	15496.5809
w6	15117.47	26550.99	1299.01	15548.74002
w7	14938.66	26294.60	1555.40	15455.05344
w8	14587.47	25080.18	2769.82	15507.05158
w1	14652.51	25271.69	2578.31	15508.50741
w2	14949.14	26112.86	1737.14	15525.87029
w3	15082.05	26451.67	1398.33	15546.29606
w4	14270.00	24259.54	3590.46	15462.03334
				15506.26663

Well Name	TVDss Lower Gauge Depth	Pressure psi		Depth difference	Pressure referred to Datum	
	TVDss (ft)	DECONV	CONVEN		DECONV	CONVEN
SB102	22836	13950	13850	5014	15614.648	15514.648
SB202	25163	14579	14570	2687	15471.084	15462.084
SB203	25039	14506	14506	2811	15439.252	15439.252
SB204	23923	14208	14208	3927	15511.764	15511.764
SG101	24169	14500	14500	3681	15722.092	15722.092
SG102	23977	14196	14197	3873	15481.836	15482.836
SG103	25382	14671	14561	2468	15490.376	15380.376
SG104	23767	13799	13799	4083	15154.556	15154.556
					15485.701	15458.451

Initila pressures referred to Datum (OWC)

Appendix E – Individual Interpretations

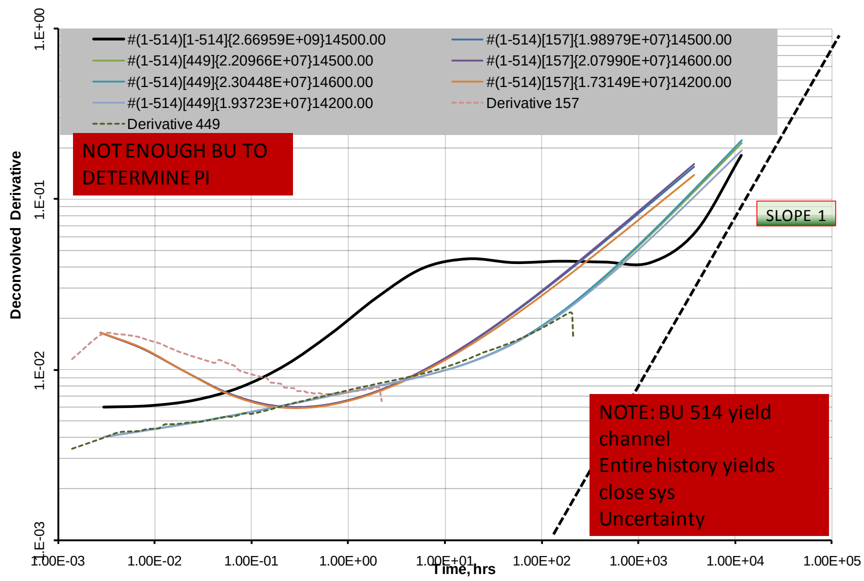
All results are affected by uncertainty and the following error bounds are considered in results (Azi et al. 2008)

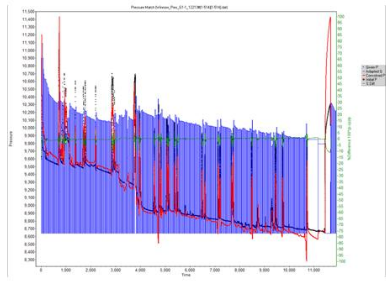
	kh	C	S	r_1	d
Well test results uncertainty	±15%	±15%	±0.5	±30%	±30%

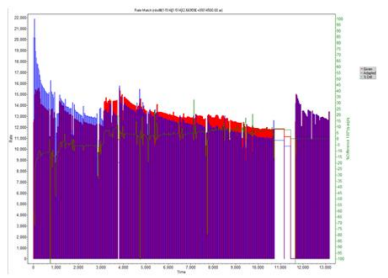
Table 1: Errors bounds in results as presented by Azi *et al*. 2008

Well w1

PBU 1 (24/08/2009)	PBU 2 (11/02/2011)







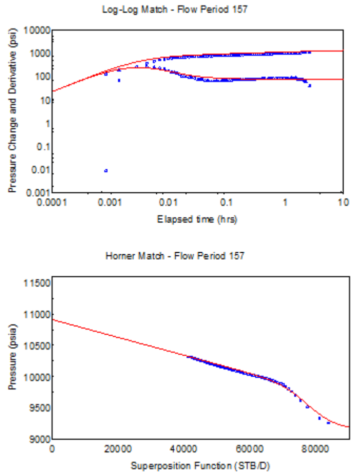
Validation	Good	Acceptable/ Average	Poor
Pressure Match	x		
Adapted rates match		x	

Pi: Not sufficient IARF build-ups to determine initial pressure

Similar tendency of entire history deconvolved derivative with individual buildup deconvolved derivative was not observed.

Model selection initial guide: Conventional Analysis.

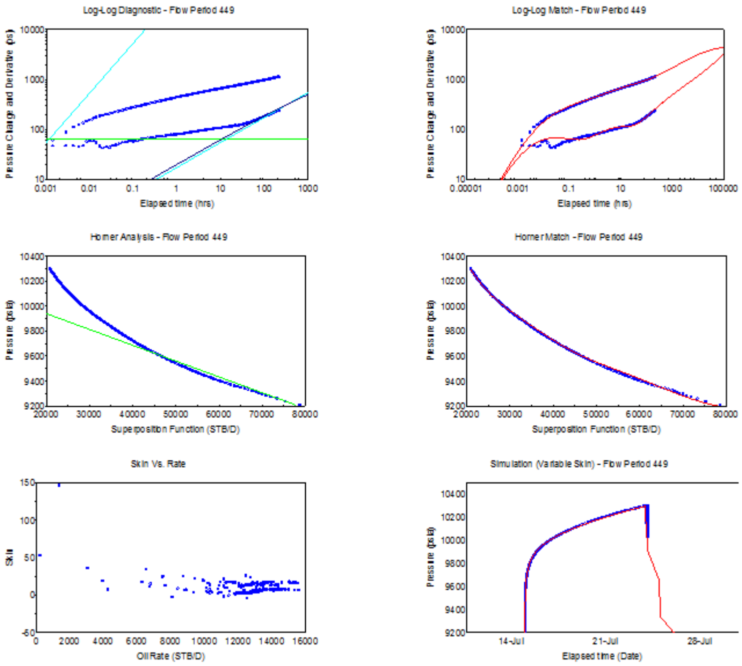
PBU 1 (24/08/2009)



Model
Wellbore Storage and Skin (C and S)
Homogeneous
Infinite Lateral Extent

Results		
(pav)i	14376.423	psia
pwf	9263.568	psia
kh	37689	mD.ft
k	367.7	mD
C	0.002769	bbl/psi
S	1.05	
ri	383	ft
PI	2.384	B/D/psi
FE	0.9691	fraction
Dp(S)	158.0	psi

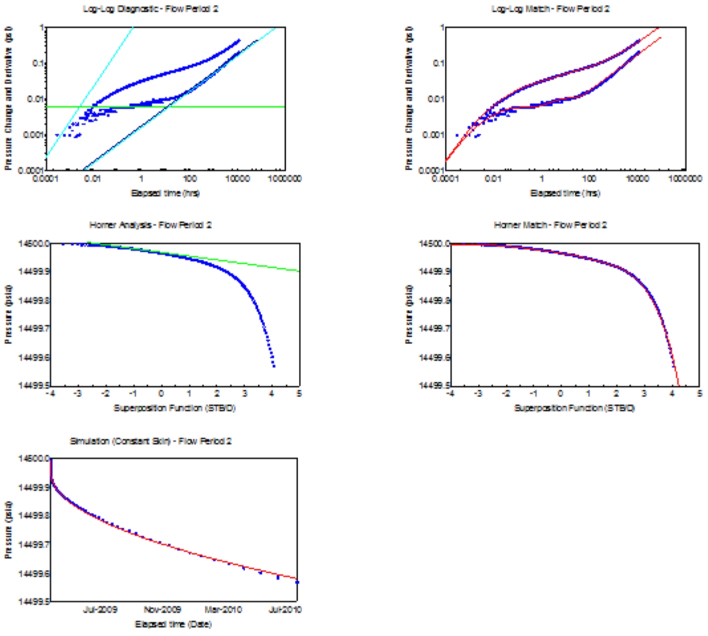
PBU 2 (24/08/2009)



Model
Wellbore Storage and Skin (C and S)
Homogeneous
Channel Boundaries

Results		
(pav)i	14500.000	psia
pwf	9149.986	psia
kh	42182	mD.ft
k	411.5	mD
C	0.01080	bbl/psi
S	-3.05	
d1	1790.83	ft
d3	216.004	ft
Type d1	No Flow	
Type d3	No Flow	
Dinv	3975	ft
PI	2.081	B/D/psi
FE	1.070	fraction
Dp(S)	-374.6	psi

Deconvolution verification:



Model
Wellbore Storage and Skin (C and S)
Homogeneous
Channel Boundaries

Results		
(pav)i	14499.996	psia
pwf	14499.585	psia
kh	40596	mD.ft
k	396.1	mD
C	0.02304	bbl/psi
S	-3.91	
d1	266.378	ft
d3	1841.02	ft
Type d1	No Flow	
Type d3	No Flow	
Dinv	28832	ft
PI	2.432	B/D/psi
FE	1.109	fraction
Dp(S)	-0.04487	psi

In terms of reservoir performance and aquifer support:
High depletions observed compared to other wells. No indication of aquifer support.

In terms of permeability and reservoir continuity:
Permeability obtained in well w1 is the highest obtained in all the wells but in accordance with overall reservoir permeability.

Pressure derivative in well w1 shows a late time deviation that could be interpreted as boundaries or decreasing mobility/thickness, suggesting both a discontinuous environment. Regarding the channelized nature of the reservoir and the relative gross interval thickness observed in the logs, it is geologically sound to interpret a channel.

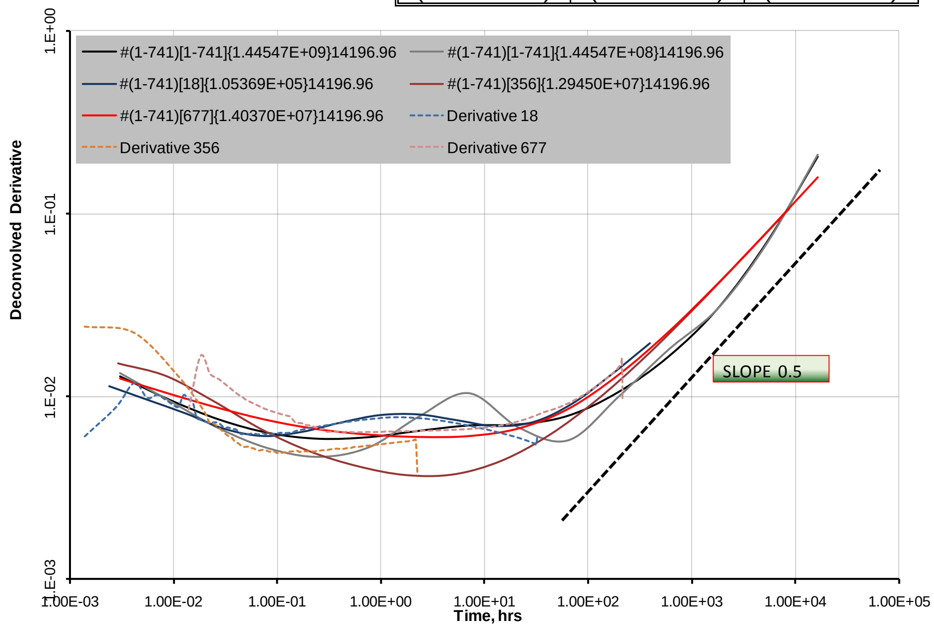
Well w1	PBU 1 (24/08/2009)	PBU 2 (11/02/2011)	Mobilities from MDT report, mD/cp
kh, mD*ft	37700±6000	42180±6300	±134-270
Permeability, mD	365±55	410±60	

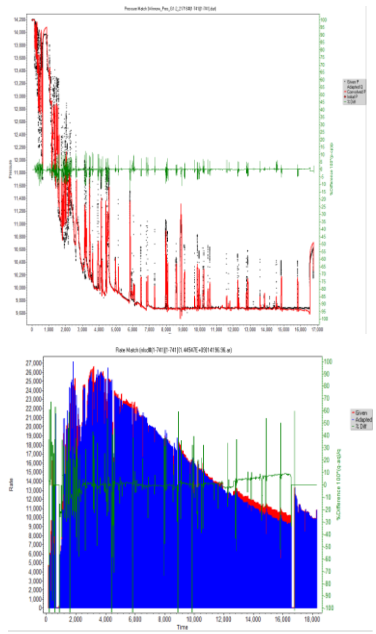
Table E-2: Permeability obtained in well w1 from transient tests

In terms of well completion efficiency:
Estimated skin factors for last buildup is approximately -3 consistent with the nature of a fracture gravel package completed in the well.

Well w2

PBU 1 (03/04/2009)	PBU 2 (19/04/2009)	PBU 3 (11/02/2011)





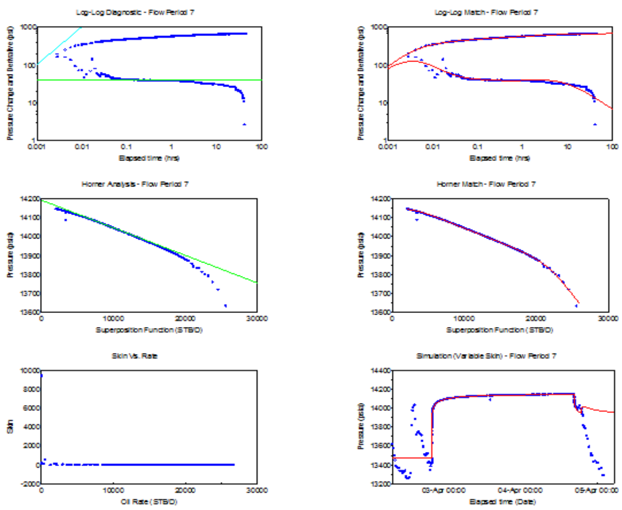
Validation	Good	Acceptable/ Average	Poor
Pressure Match		X	
Adapted rates match			x

Pi: Determined by means of deconvolution

Similar tendency of entire history deconvolved derivative with individual buildup deconvolved derivative was not as précised as demanded.

Model selection initial guide: Conventional Analysis.

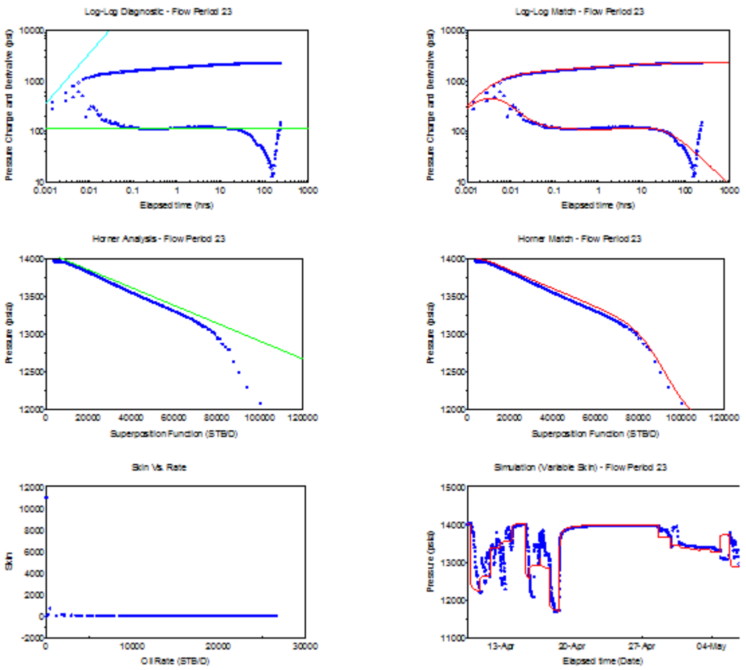
PBU 1 (03/04/2009)



Model
Wellbore Storage and Skin (C and S)
Homogeneous
Single Boundary

Results		
(pav)i	14196.960	psia
pwf	13467.569	psia
kh	30337	mD.ft
k	237.0	mD
C	0.002868	bbl/psi
S	1.10	
d1	534.274	ft
Type d1	Const Pres	
Dinv	1555	ft
PI	8.322	B/D/psi
PI-SS	8.760	B/D/psi
FE	0.8771	fraction
Dp(S)	85.15	psi

PBU 2 (19/04/2009)



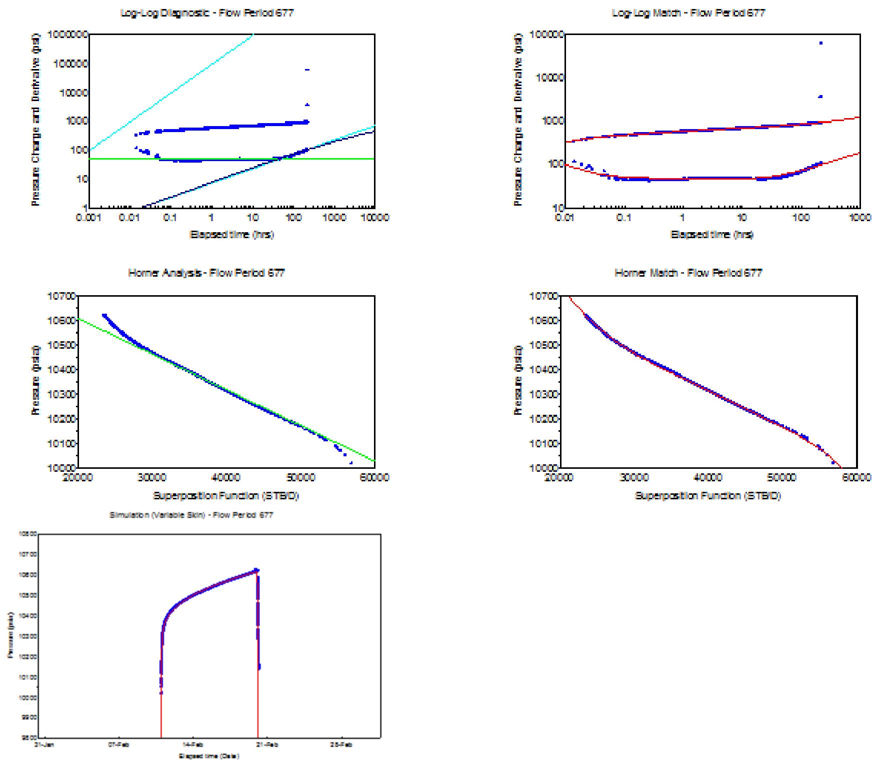
Model

Wellbore Storage and Skin (C and S)
Homogeneous
Single Boundary

Results

(pav)i	14066.691	psia
pwf	11713.005	psia
kh	37568	mD.ft
k	293.5	mD
C	0.002929	bbl/psi
S	2.25	
d1	1169.31	ft
Type d1	Const Pres	
Dinv	3994	ft
PI	9.007	B/D/psi
PI-SS	8.927	B/D/psi
FE	0.7937	fraction
Dp(S)	490.0	psi

PBU 3 (11/02/2011)



Model

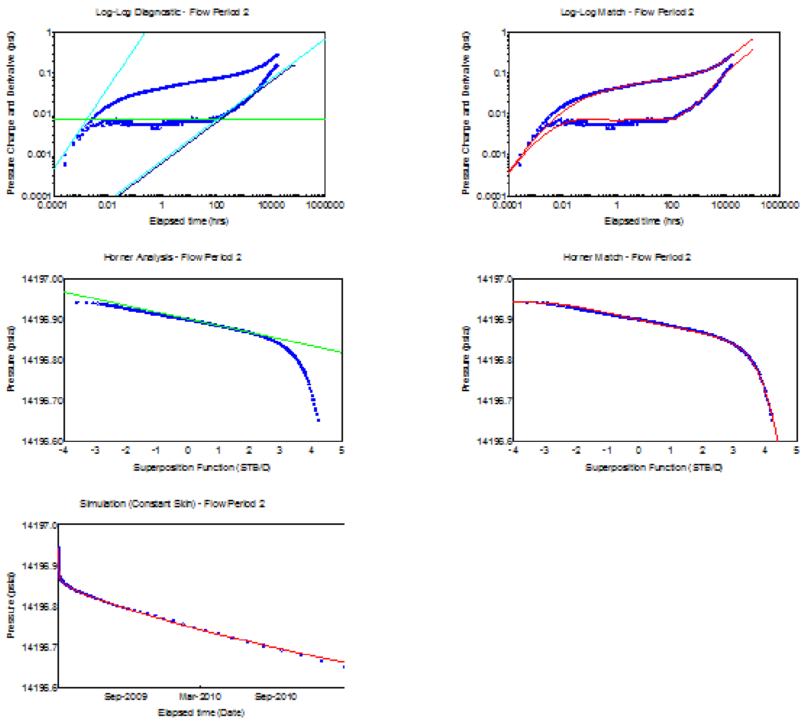
Wellbore Storage and Skin (C and S)
Homogeneous
Channel Boundaries

Results

(pav)i	14196.960	psia
pwf	9686.685	psia
kh	30630	mD.ft
k	239.3	mD
C	0.003879	bbl/psi
S	-0.04	
d1	1318.02	ft
d3	2481.96	ft
Type d1	No Flow	
Type d3	No Flow	
Dinv	3447	ft
PI	1.614	B/D/psi
FE	1.001	fraction
Dp(S)	-3.670	psi

Deconvolution verification:

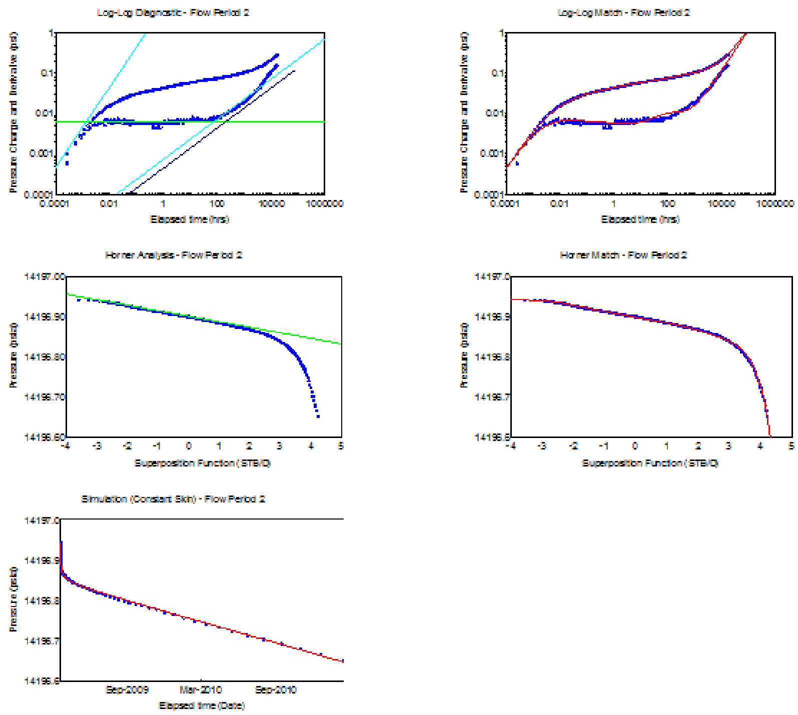
Option 1) _ Open rectangle



Model
Wellbore Storage and Skin (C and S)
Homogeneous
Open Ended Rectangle

Results		
(pav)i	14196.942	psia
pwf	14196.666	psia
kh	26982	mD.ft
k	210.8	mD
C	0.01132	bbl/psi
S	-3.21	
d1	2713.07	ft
d2	9264.28	ft
d3	3342.99	ft
Type d1	No Flow	
Type d2	No Flow	
Type d3	No Flow	
Dinv	28330	ft
PI	3.618	B/D/psi
FE	1.166	fraction
Dp(S)	-0.04589	psi

Option 2) Close rectangle



Model
Wellbore Storage and Skin (C and S)
Homogeneous
Rectangle

Results		
(pav)i	14196.942	psia
(pav)f	14196.743	psia
pwf	14196.666	psia
kh	32333	mD.ft
k	252.6	mD
C	0.01093	bbl/psi
S	-2.65	
d1	937.255	ft
d2	6828.29	ft
d3	7038.39	ft
d4	13391.1	ft
A	1.6126E+008	ft2
Type d1	No Flow	
Type d2	No Flow	
Type d3	No Flow	
Type d4	No Flow	
PI	12.96	B/D/psi
PI-SS	10.28	B/D/psi
FE	1.325	fraction
Dp(S)	-0.03165	psi

In terms of reservoir performance and aquifer support:
Average to high depletions observed indicating no aquifer support

In terms of permeability and reservoir continuity:
Permeability obtained in accordance with overall reservoir permeability.

Pressure derivative in well w2 in teh initial BU shows a concave downwards shift indicating a possible constant pressure boundary. It is not observed in the last buildup which yields a channel so such behaviour is associated to late time errors. Regarding the channelized nature of the reservoir and the relative gross interval thickness observed in the logs, it is geologically sound to interpret a channel.

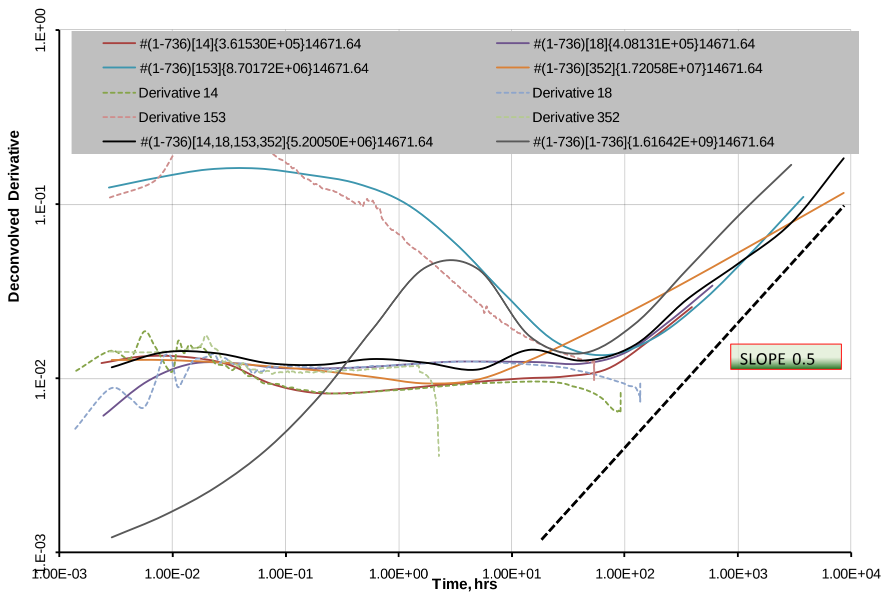
Well w1	PBU 1 (03/04/2009)	PBU 2 (19/04/2009)	PBU 3 (11/02/2011)	Mobilities from MDT report, mD/cp
Permeability, mD	240±35	300±45	240±3540	N/A

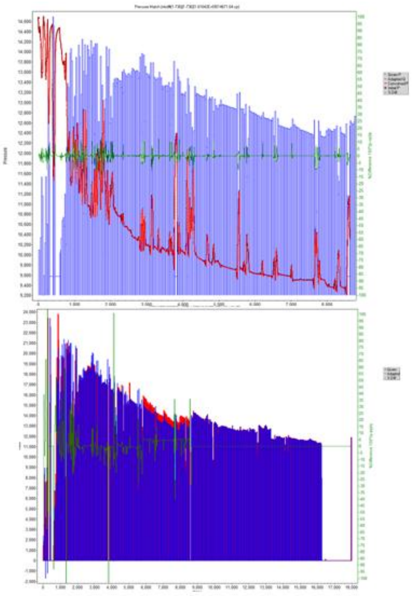
Table E- 3: Permeability obtained in well w2 from transient tests

In terms of well completion efficiency:
Estimated skin factors are the highest observed of approximately 2.

Well w3

PBU 1 (17/04/2009)	PBU 2 (22/04/2009)	PBU 3 (27/03/2010)



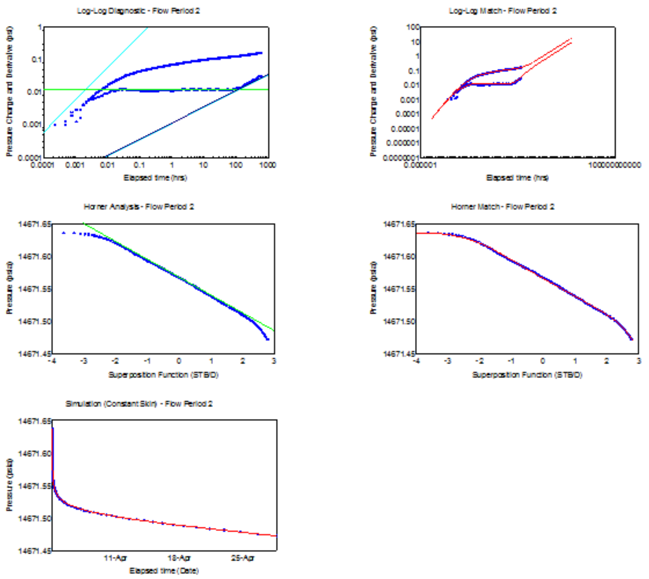


Validation	Good	Acceptable/ Average	Poor
Pressure Match	x		
Adapted rates match		x	

Pi: Determined by means of deconvolution

Similar tendency of entire history deconvolved derivative with individual buildup deconvolved derivative was acceptable

Model selection initial guide: Deconvolution



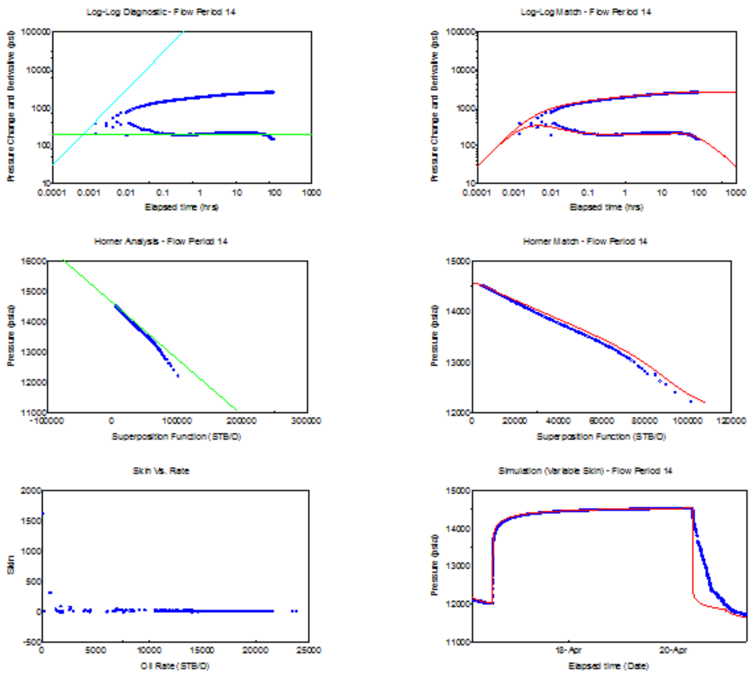
Model
Wellbore Storage and Skin (C and S)
Homogeneous
Open Ended Rectangle

Results		
(pav)i	14671.637	psia
pwf	14671.476	psia
kh	17265	mD.ft
k	131.8	mD
C	0.008226	bbl/psi
S	-3.06	
d1	1514.66	ft
d2	3104.23	ft
d3	2847.65	ft
Type d1	No Flow	
Type d2	No Flow	
Type d3	No Flow	
Dinv	4118	ft
PI	6.206	B/D/psi
FE	1.454	fraction
Dp(S)	-0.07323	psi

.

Conventional analysis:

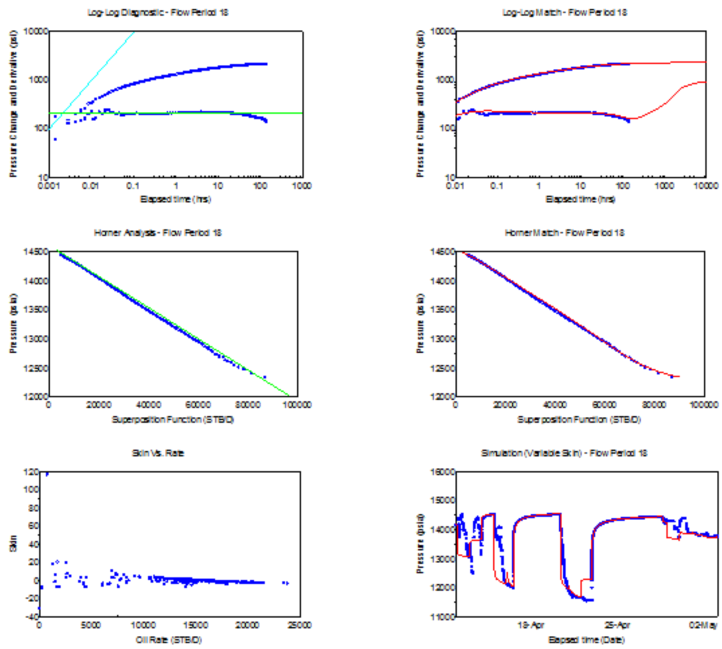
PBU 1 (17/04/2009)



Model
Wellbore Storage and Skin (C and S)
Homogeneous
Single Boundary

Results		
(pav)i	14671.600	psia
pwf	12016.233	psia
kh	25611	mD.ft
k	195.5	mD
C	0.003801	bbl/psi
S	-1.08	
d1	1260.88	ft
Type d1	Const Pres	
Dinv	1972	ft
PI	8.815	B/D/psi
PI-SS	8.116	B/D/psi
FE	1.141	fraction
Dp(S)	-407.2	psi

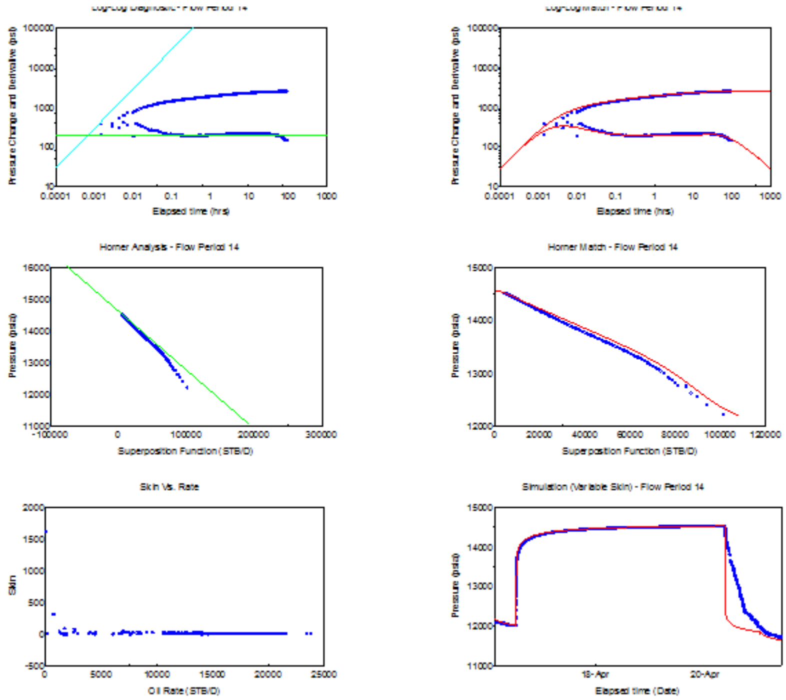
PBU 2 (22/04/2009)



Model
Wellbore Storage and Skin (C and S)
Homogeneous
Open Ended Rectangle

Results		
(pav)i	14671.000	psia
pwf	12276.157	psia
kh	17737	mD.ft
k	135.4	mD
C	0.008779	bbl/psi
S	-2.79	
d1	2196.6	ft
d2	9480.5	ft
d3	2487.37	ft
Type d1	No Flow	
Type d2	Const Pres	
Type d3	No Flow	
Dinv	2014	ft
PI	7.494	B/D/psi
PI-SS	2.497	B/D/psi
FE	1.162	fraction
Dp(S)	-1164.5	psi

PBU 3 (27/03/2010)



Model
Wellbore Storage and Skin (C and S)
Homogeneous
Single Boundary

Results		
(pav)i	14671.600	psia
pwf	12016.233	psia
kh	25611	mD.ft
k	195.5	mD
C	0.003801	bbl/psi
S	-1.08	
d1	1260.88	ft
Type d1	Const Pres	
Dinv	1972	ft
PI	8.815	B/D/psi
PI-SS	8.116	B/D/psi
FE	1.141	fraction
Dp(S)	-407.2	psi

In terms of reservoir performance and aquifer support:

Average to low depletions observed indicating possible aquifer support

In terms of permeability and reservoir continuity:

Permeability obtained in accordance with overall reservoir permeability.

Pressure derivative in well w3 shows a concave downwards shift indicating a possible constant pressure boundary. It is not observed in deconvolution which yields an open recatbngle associated with a no flow channel. Regarding the channelized nature of the reservoir and the relative gross interval thickness observed in the logs, it is geologically sound to interpret a channel.

Well w1	PBU 1 (03/04/2009)	PBU 2 (19/04/2009)	PBU 3 (11/02/2011)	Mobilities from MDT report, mD/cp
Permeability, mD	200±30	130±20	200±30	N/A

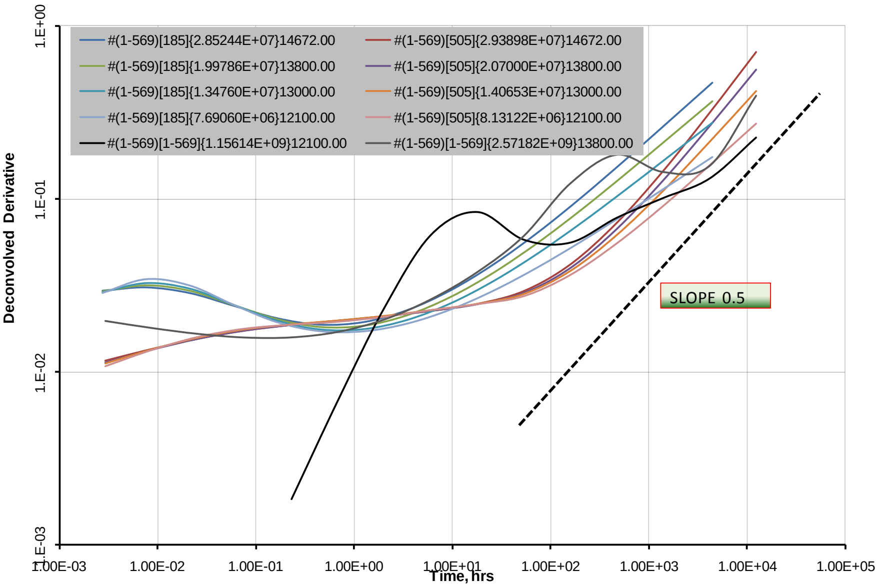
Table E-4: :Permeability obtained in well w3 from transient tests.

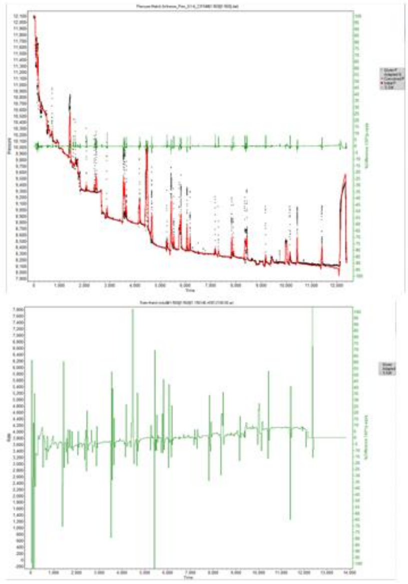
In terms of well completion efficiency:

Estimated skin factors are of the order of -1.5 being consistent with a frac gravel pack.

Well w4

PBU 1 (27/03/2010)	PBU 2 (11/02/2011)





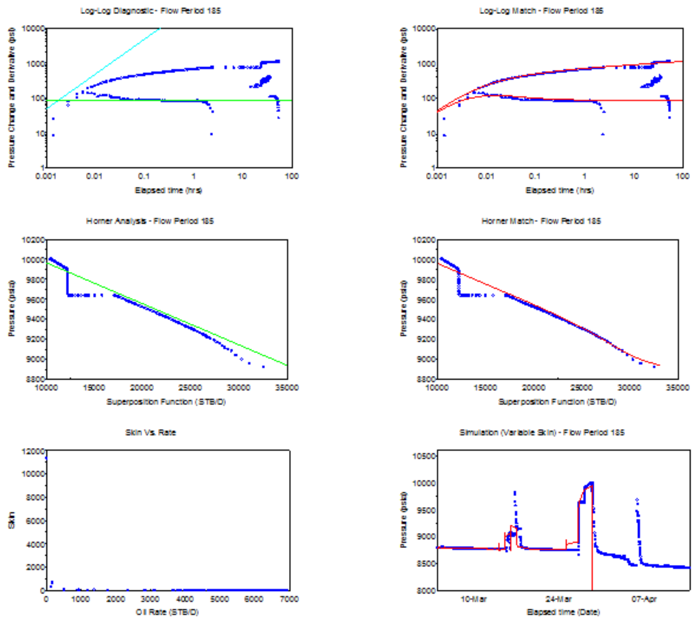
Validation	Good	Acceptable/ Average	Poor
Pressure Match	x		
Adapted rates match			x

Pi: Determined by means of MDT pressure

Similar tendency of entire history deconvolved derivative with individual buildup deconvolved derivative was not acceptable

Model selection initial guide: Conventional analysis

PBU 1 (27/03/2010)



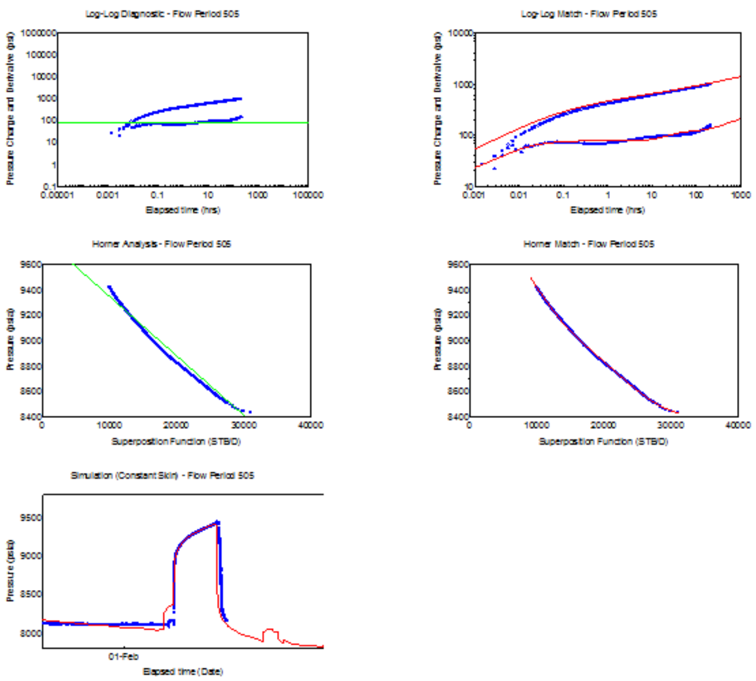
Model

Wellbore Storage and Skin (C and S)
Homogeneous
Infinite Lateral Extent

Results

(pav)i	13800.000	psia
pwf	8895.597	psia
kh	11524	mD.ft
k	250.5	mD
C	0.004765	bbl/psi
S	-1.92	
ri	1445	ft
PI	0.9720	B/D/psi
FE	1.067	fraction
Dp(S)	-328.0	psi

PBU 2 (11/02/2011)



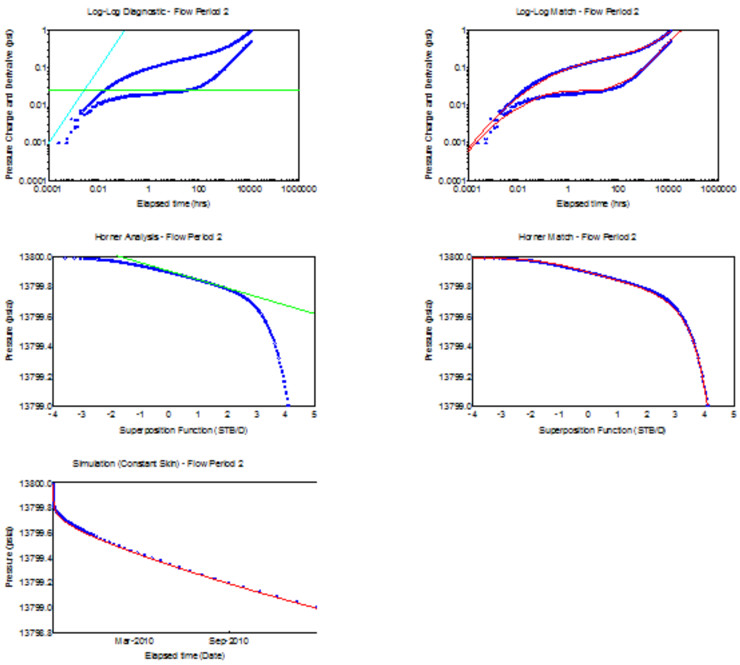
Model

Wellbore Storage and Skin (C and S)
Homogeneous
Open Ended Rectangle

Results

(pav)i	13800.000	psia
pwf	8409.938	psia
kh	10174	mD.ft
k	173.9	mD
C	1.3391E-009	bbl/psi
S	-3.13	
xf	18.8017	ft
d1	662.628	ft
d2	6990.51	ft
d3	2301.98	ft
Type d1	No Flow	
Type d2	No Flow	
Type d3	No Flow	
Dinv	2564	ft
PI	0.7146	B/D/psi
FE	1.091	fraction
Dp(S)	-488.8	psi

Deconvolution verification



Model
Wellbore Storage and Skin (C and S)
Homogeneous
Open Ended Rectangle

Results		
(pav)i	13799.990	psia
pwf	13799.049	psia
kh	8346.7	mD.ft
k	142.7	mD
C	0.005072	bbl/psi
S	-4.08	
xf	48.806	ft
d1	2280.29	ft
d2	7589.49	ft
d3	915.466	ft
Type d1	No Flow	
Type d2	No Flow	
Type d3	No Flow	
Dinv	18141	ft
PI	1.062	B/D/psi
FE	1.214	fraction
Dp(S)	-0.2018	psi

In terms of reservoir performance and aquifer support:
Highest depletions observed indicating no aquifer support

In terms of permeability and reservoir continuity:
Permeability obtained in accordance with overall reservoir permeability.

Pressure derivative in well w3 shows a concave downwards shift indicating a possible constant pressure boundary. It is not observed in deconvolution which yields an open recatbngle associated with a no flow channel. Regarding the channelized nature of the reservoir and the relative gross interval thickness observed in the logs, it is geologically sound to interpret a channel.

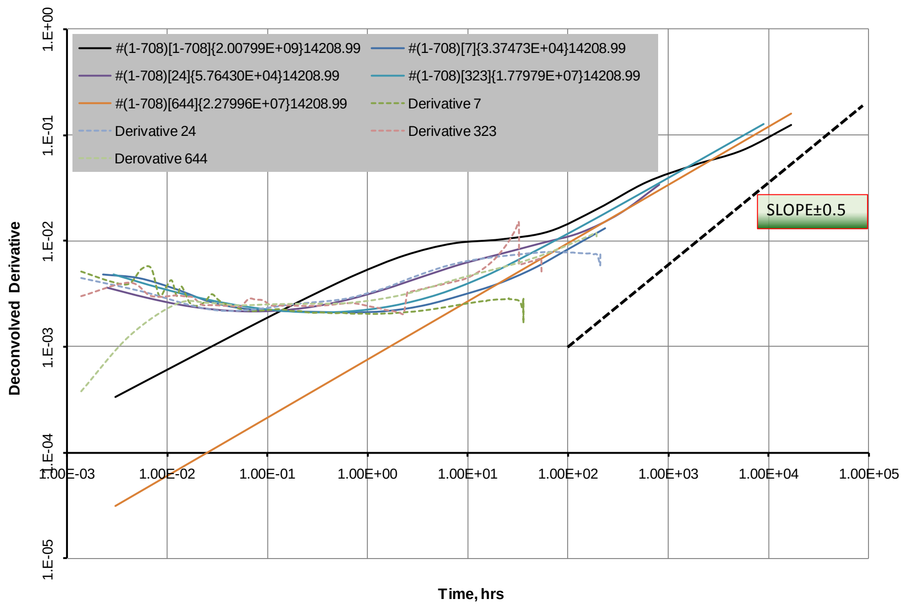
Well w1	PBU 1 (27/03/2010)	PBU 2 (11/02/2011)	Mobilities from MDT report, mD/cp
Permeability, mD	250±35	170±25	±135

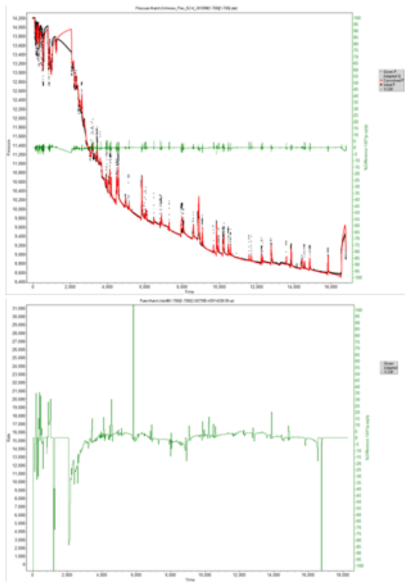
Table E-5: Permeability obtained in well w4 from transient tests.

In terms of well completion efficiency:
Estimated skin factors are of the order of -2 being consistent with a frac gravel pack.

Well 8

PBU 1 (31/03/09)	PBU 2 (27/03/2010)	PBU 3 (11/02/2011)





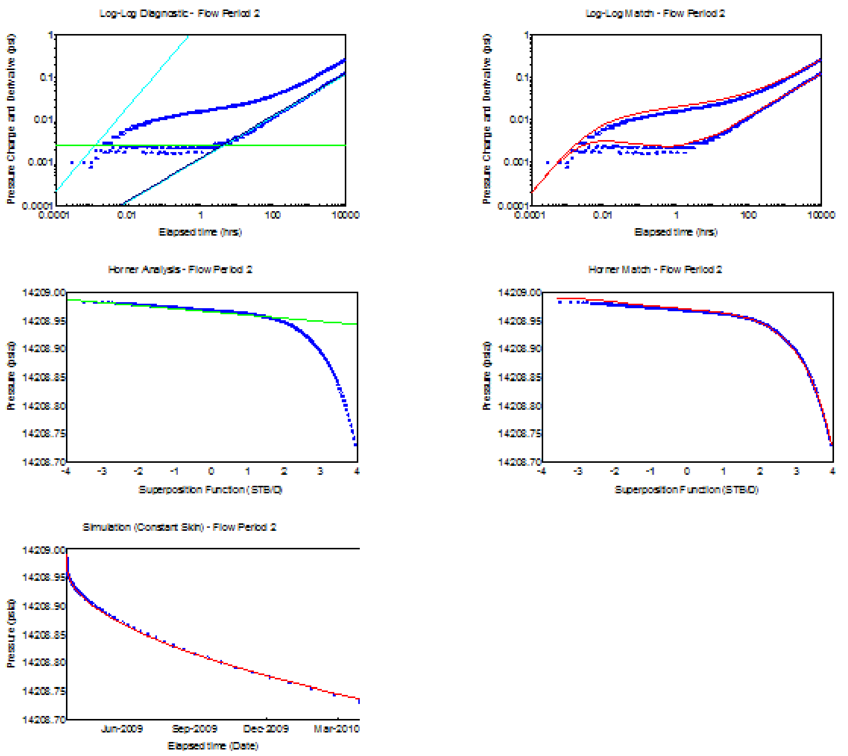
Validation	Good	Acceptable/ Average	Poor
Pressure Match	x		
Adapted rates match		x	

Pi: Determined by means of Deconvolution

Similar tendency of entire history deconvolved derivative with individual buildup deconvolved derivative was acceptable

Model selection initial guide: Deconvolution

Deconvolution:

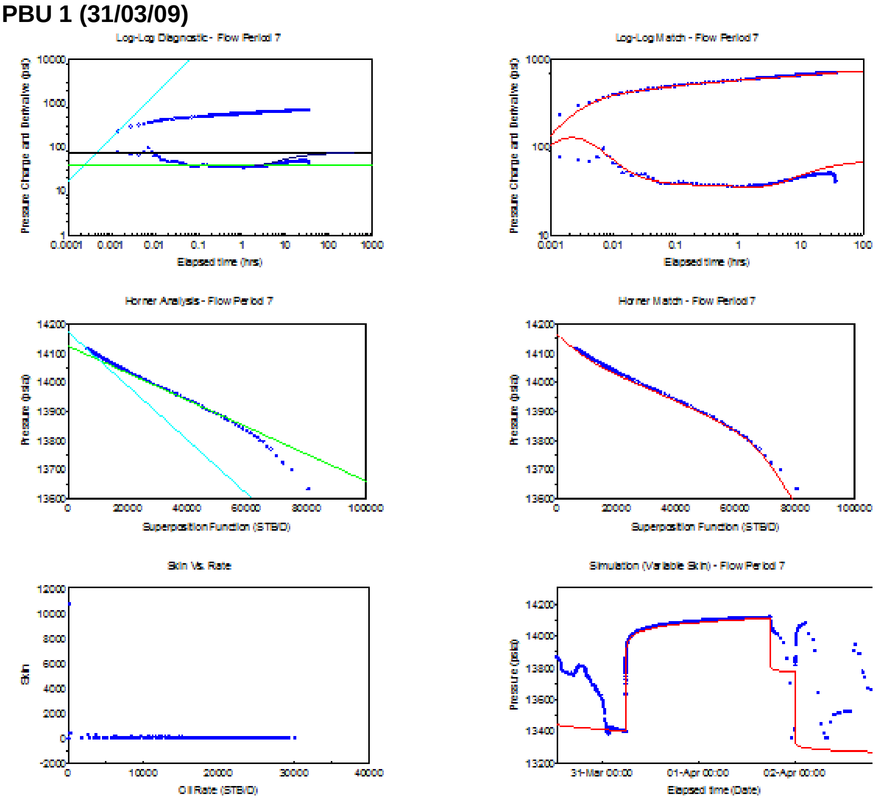


Model
Wellbore Storage and Skin (C and S)
Homogeneous
Channel Boundaries

Results		
(pav)i	14208.990	psia
pwf	14208.743	psia
kh	84884	mD.ft
k	378.1	mD
C	0.02336	bbl/psi
S	-2.03	
d1	262.803	ft
d3	685.581	ft
Type d1	No Flow	
Type d3	No Flow	
Dinv	19330	ft
PI	4.047	B/D/psi
FE	1.040	fraction
Dp(S)	-0.009866	psi

Conventional Analysis

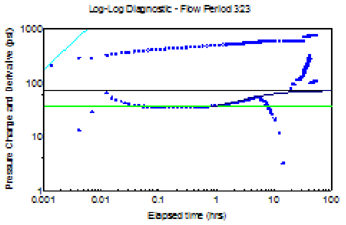
PBU 1 (31/03/09)

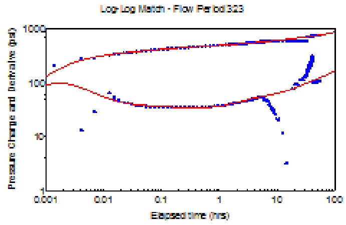


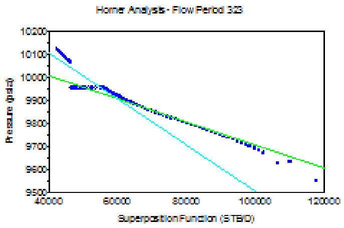
Model
Wellbore Storage and Skin (C and S)
Homogeneous
Single Boundary

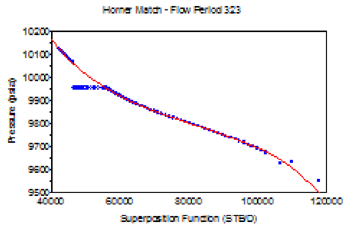
Results		
(pav)i	14209.000	psia
pwf	13401.082	psia
kh	1.0228E+005	mD.ft
k	455.6	mD
C	0.005130	bbl/psi
S	1.75	
d1	440.054	ft
Type d1	No Flow	
Dinv	1349	ft
PI	22.25	B/D/psi
FE	0.8431	fraction
Dp(S)	126.7	psi

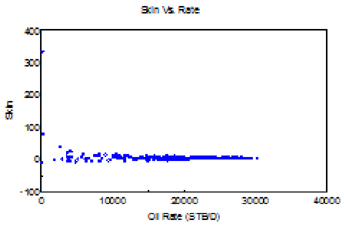
PBU 2 (27/03/2010)

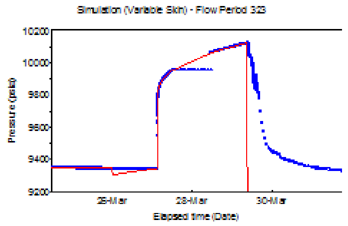








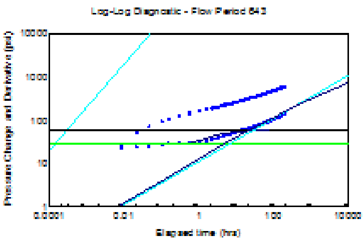


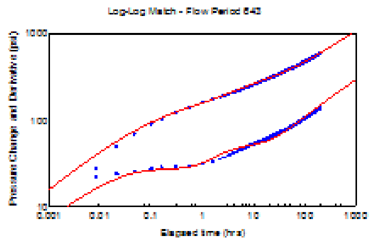


Model
Wellbore Storage and Skin (C and S)
Homogeneous
Channel Boundaries

Results		
(pav)i	14209.000	psia
pwf	9343.627	psia
kh	94874	mD.ft
k	422.6	mD
C	0.004358	bbl/psi
S	0.89	
d1	248.128	ft
d3	758.276	ft
Type d1	No Flow	
Type d3	No Flow	
Dinv	1592	ft
PI	3.300	B/D/psi
FE	0.9872	fraction
Dp(S)	62.13	psi

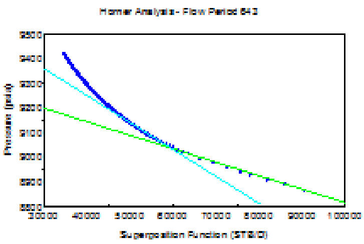
PBU 3 (11/02/2011)

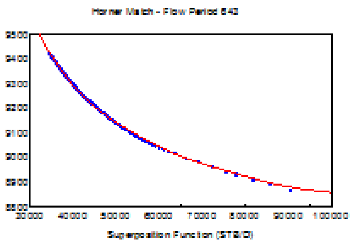


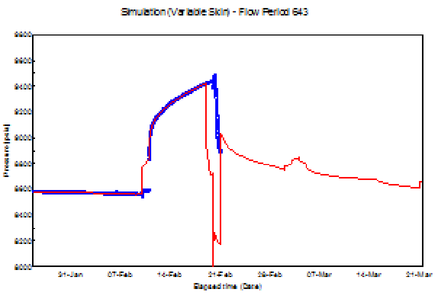


Model
Wellbore Storage and Skin (C and S)
Homogeneous
Channel Boundaries

Results		
(pav)i	14209.000	psia
pwf	8839.980	psia
kh	86570	mD.ft
k	385.6	mD
C	0.002814	bbl/psi
S	-3.43	
xf	25.3868	ft
d1	194.215	ft
d3	1009.74	ft
Type d1	No Flow	
Type d3	No Flow	
Dinv	2863	ft
PI	2.169	B/D/psi
FE	1.035	fraction
Dp(S)	-190.3	psi







In terms of reservoir performance and aquifer support:

High depletions observed indicating no aquifer support

In terms of permeability and reservoir continuity:

Permeability obtained are in the highest range but in accordance with overall observed reservoir permeability.

Pressure derivative in well w8 shows a late time deviation that could be interpreted as boundaries or decreasing mobility/thickness, suggesting both a discontinuous environment. Regarding the channelized nature of the reservoir and the relative gross interval thickness observed in the logs, it is geologically sound to interpret a channel.

Well w1	PBU 1 (27/03/2010)	PBU 2 (11/02/2011)	Mobilities from MDT report, mD/cp
Permeability, mD	450±60	420±60	385±60

Table E-6: Permeability obtained in well w8 from transient tests

In terms of well completion efficiency:

Estimated skin factors are of the order of -2 being consistent with a frac gravel pack.