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Field-Wide Deployment of In-Well Optical Flowmeters and Pressure/Temperature Gauges at Buzzard Field

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Abstract

The adoption rate of optical sensing technology for in-well permanent monitoring has accelerated dramatically since first introduced more than 10 years ago and a number of optical sensor types, including pressure, temperature, distributed temperature, seismic, and flowmeters have been commercialized. Although optical sensing technology has a demonstrated track record and gained industry acceptance, large-scale, field-wide commercial deployment has been slow.

This paper describes a recent example of field-wide optical sensing deployment with a planned scope of 27 wells. Multiple in-well sensors were installed in the newly developed Buzzard Field, operated by Nexen Petroleum U.K. Limited in the North Sea. This paper explores the initial results after the first 13 well completions. An assessment of the major project phases from definition, planning, and system selection to project execution, site integration testing, installation, and early life operation of the optical technology is included. A number of lessons in equipment and system design, execution, and data management have been learned and are also discussed in the paper. Whilst field development is ongoing, the initial success rates show that satisfactory performance has been obtained in all key areas including data availability, delivery, and post-processing.

This case study demonstrates that innovative optical sensing technology and downhole flow measurement is ready for large-scale adoption with minimal risk. This is an important and timely finding as the industry is introducing optical monitoring into large subsea fields.

Acknowledgements

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Background

Since the introduction of fiber-optic based reservoir monitoring systems in 1993 the adoption rate has increased dramatically. Today, most of the common electronic based technology measurements for in-well permanent reservoir monitoring have a commercially available optical equivalent, such as pressure & temperature, and seismic sensors. In fact, optical monitoring has not only equaled but added further functionality to the previously available monitoring toolset through Distributed Temperature Sensing (DTS) and non-intrusive single- and multiphase flowmeters. Currently, the only area that the optical sensing has not penetrated into is the subsea application.

Functionally, optical sensing offers a viable alternative to traditional methods of in-well permanent monitoring. However, it has not yet made significant leaps in volume deployment in comparison with these traditional methods. In 2004, this situation changed when Nexen Petroleum U.K. Limited (formerly EnCana) and its partners PetroCanada Energy North Sea, BG Group and Edinburgh Oil and Gas, awarded the Permanent Downhole Monitoring System (PDMS) contract covering the Buzzard field. It was a technologically bold decision to go for an all optical in-well reservoir monitoring system for the Buzzard field development.

The Buzzard Field

Buzzard is located in the North Sea, approximately 60 km northeast of Aberdeen in blocks 19/10, 20/6, and 19/5a, 20/1. A field location map is shown in **Fig. 1.** The field was discovered in 2001 with development drilling commencing in 2005. The Buzzard reservoir is a stratigraphic play, composed of deep marine turbidite sands which pinch out towards the West, as shown in **Fig. 2.** The sands are typically high permeability (1500md) producing oil of 32 °API. The Upper Jurassic Buzzard reservoir is completed over all sands present and selective perforation of individual sands is carried out as required. The field requires pressure support through water flood from the east over the production life of the field. First water injection into the field was in December 2006, with first production from the field following in January 2007. Field production was ramped up through the early part of 2007 to plateau at rates in excess of 200,000 stb/day.

Monitoring System

The PDMS system was selected by the Buzzard Field operator, Nexen Petroleum U.K. Limited to meet their reservoir monitoring objectives listed under the headings of Pressure Monitoring, DTS, and Downhole Flowmeters below:

Pressure Monitoring

- Regular monitoring of decline across the field and management of pressure support and water flooding.
- Pressure transient analysis for determination of near well reservoir properties such as *kh*, and *s*. In relation to this, detection of skin changes over time and identification of near wellbore features. Due to the high permeability of the Buzzard reservoir, early-time responses are fast and the pressure changes during the later build up are small. This leads to a requirement for both high frequency sampling and high resolution data.
- Inflow and lift performance monitoring to identify changes in rate and drawdown behavior.
- Drawdown management optimizing production, whilst avoiding sand or asphaltene production.
- Evaluating inter-well connectivity, especially during the start up and early production phase interference testing programs.
- Obtaining accurate temperature profiles for gas lift design.

DTS

- Completion integrity assessment through life of field, without the need for intervention.
- Monitor gas lift performance in wells once gas lift operations commence.

Downhole Flowmeters

- Allow production allocation, reducing the need for testing of wells through the surface test separator.
- Quickly identify production anomalies.
- Measure well water-cut real time.
- Downhole, the pressure is above the bubble point; therefore, 2-phase oil-water flowmeter is sufficient.

To meet the stated objectives listed above, it was decided that each well was to be monitored with three permanent optical sensors: pressure / temperature (P/T) sensor, two-phase flowmeter, and DTS. Early in the project, the option for optical in-well seismic sensors for 4-D and micro-seismic monitoring was considered, but ultimately discounted due to a number of difficulties that were envisaged in using the data. Primarily this was due to Buzzard being beyond the margins for successful 4-D in terms of reservoir fluids, reservoir rock properties, and seismic response.

In addition to the monitoring objectives, the PDMS system and supplier were expected to hold to the Nexen Petroleum U.K. Limited Buzzard development tenets of “make it safe, make it simple, and make it work”.

Buzzard Monitoring System Design

The optical PDMS system was designed to simplify the equipment as much as possible. The 2-phase flowmeter and the fiber-optic P/T gauge shown in **Fig. 3** were built as a single integrated assembly. The meter is full bore, non-intrusive, contains no moving parts or downhole electronics. The integrated design minimized additional work and interfaces necessary to integrate the P/T sensors required. The design process involved a number of iterations and considered alternative ways of connecting the optical sensors.

Although it is possible to place the flowmeter and P/T gauges on one optical fiber (Ref. 1 & 2), these were separated to ensure redundancy in fiber communication and a simplified topside fiber infrastructure. This meant that should a single fiber fail, not all system functionality would be lost. The optical P/T sensor was connected to one of the two available single-mode fibers and the other single-mode fiber was assigned to the flowmeter, whilst the multi-mode fiber was dedicated to the DTS measurement.

The in-well hardware consisted of the flowmeter, the P/T sensor, the optical cable with a pre-integrated dry-mateable optical connector, and cross-coupling cable protectors. The feed-through of the tubing hanger and wellhead was similar to a typical control line or electrical instrument cable feed-through. The tubing hanger fittings were supplied to the wellhead company specification. A cable bend restrictor was placed on top of the upper tubing hanger fitting to protect the cable from excessive bend radii. These were supplied for all the safety valve and chemical injection control lines and not only the fiber-optic cable. At the wellhead outlet, an adaptor flange was provided to adapt the wellhead exit to the standard optical wellhead outlet assembly.

From the wellhead outlet, the same principle of simplicity and redundancy continued with each wellhead being serviced by its own fiber-optic surface cable which linked the in-well sensors to the surface data acquisition equipment located in a Local Equipment Room (LER). These were installed very early in the project schedule so they could be included in the topside build phase and not require retrofit offshore once the topsides were installed. Likewise, the data acquisition equipment racks that would house the equipment were also installed in the LER during topside fabrication.

The surface data acquisition equipment provided interrogation of the three sensor functions, conversion to engineering units, local data storage, and data hand-off to the Nexen Petroleum U.K. Limited's Data Management System (DMS) using OLE (Object-Linking and Embedding) for Process Control (OPC) protocol.

The design philosophy applied to the surface equipment was similar to the downhole equipment to reduce risk through redundancy. The controlling computer was provided with dual power supplies and hard disk drives. Critically, the system was connected to the company's network allowing for remote access of the system by the company and the fiber system supplier. This functionality allowed for system software updates, configuration, data transfer, and trouble-shooting without the need to travel offshore. One key feature was the ability to remotely re-boot specific devices within the surface acquisition equipment should a problem occur, again without traveling offshore or requiring offshore instrument technician intervention. Overall, the data users were identified, the data path designed with redundancy where possible, and alternative access routes to data provided.

Project Delivery and Execution

The PDMS system was covered by a project execution plan conceived at project outset. This defined the objectives, project phases, organization, roles and responsibilities, project control, and quality aspects. A single point of contact project engineer was assigned for the PDMS system. From the outset, monthly project meetings were held and issues tracked on a rolling register.

There was an overall Quality Plan for the project. Each piece of in-well equipment was also covered by its own Manufacturing Quality Plan. Third party surveillance was applied to critical stages during manufacture and test. Audits were performed at the critical stages of post design, manufacturing of the first batch of equipment, and post installation of the first three wells. These were a mixture of internal PDMS supplier self-audit and client audit. With this approach it was possible to ensure that the project objectives were met, performance was monitored and weaknesses were addressed. Performance in all three audits was adequate with few corrective actions being required. Overall supplier performance self-assessment was also completed with no major corrections being required.

All critical equipment and data interfaces were identified, captured, and tracked on a register until tested and closed out. These tests varied according to their nature. Mechanical fit interfaces were performed for tubing hanger and wellhead, these included pressure testing verification and functional checks. The OPC data interface to the DMS had been verified very early on in the project. In-well optical cable equipment interfaces were checked at initial sub-assembly for items such as chemical injection and gas lift mandrel and safety valve, including external drift checks with a section of casing. **Figure 4** shows a typical well completion schematic. All wells are similar in completion design and all used the same flowmeter, pressure/temperature & DTS suite of sensors.

Finally, an overall onshore System Integration Test (SIT) was performed prior to the first installation to verify installation procedures, installation equipment, spares and risk event mitigation measures. Following this testing, final changes were made to installation procedures and project spares lists.

Much attention had been paid to the in-well equipment preparation and testing. However, the surface equipment side was not paid the same attention. There were a number of reasons for this. The main reason was that the platform topside installation schedule did not occur until after the first batch completions had been installed in September 2006 and hence there was less urgency. This impacted both organizations in terms of critical personnel resources and delayed decision making on certain details of system design and data delivery. Nevertheless, these difficulties were overcome in time for the installation of the surface equipment in October 2006. During the intervening period the first batch of wells had undergone perforation, clean-up, and well testing. During this phase a temporary PDMS surface data acquisition system was employed to gather data for the pressure/temperature sensor and flowmeter.

Installation

The first producer well was completed in May of 2006 from the Galaxy III jack-up rig. The PDMS system was installed with full functional success. There were minor issues relating to unreasonably high acceptance criteria for optical checks whilst running in hole. These criteria were suitably relaxed following review, with installation procedures being updated accordingly. The next four producer installations were completed back to back in a batch, again with full functional success. After this, the program reverted back to drill and complete scheduling. This continued for the next well. It was during this time that the first four wells were perforated and cleaned-up with the aforementioned temporary PDMS monitoring system. Well installations continued until thirteen wells had been installed during which time the permanent surface data acquisition equipment was installed and commissioned.

Functionally, twelve of the thirteen wells were fully operational. One system was non-operational following an operational error in installation where the fiber-optic cable exiting the top of the hanger had been excessively bent causing eventual loss of signal from the downhole fibers.

Throughout the first thirteen wells no HSE incidents were recorded. Although cut outs were available for the PDMS cables and control lines in the tubing slips arrangement, inadvertent setting of the slips damaged cables on three occasions during early installations. Later installations were successful with operational problems being remedied.

The non-productive time (NPT) for the PDMS system was limited to 2 hours for the 13 wells. The 2 hours were due to a single event relating to the optical wellhead outlet. In this case the back-up unit was used.

Initial Data and Results

The first data with the temporary PDMS system in August 2006 was gathered at 1-Hz frequency on the six wells that had been installed up to that point in time. The 1-Hz frequency was selected due to the high permeability of the reservoir to ensure that the maximum amount of early-time data could be acquired during periods of shut in and Pressure Build Up (PBU). All six wells were monitored for pressure/temperature and flow as the testing program progressed. In terms of data quality, the results of this early PDMS pressure and temperature data acquisition were poorer than expected. On a 1-Hz sampling frequency, pressure and temperature data typically showed a random scatter with a peak-to-peak spread of 4 psi and 0.03 °C, respectively. These conditions were observed in shut in wells, prior to field start up, where pressures were not changing within the field. Conversely, initial data from the in-well flowmeters during well cleanup periods correlated very well with the test separator results.

PBU analysis carried out after the well cleanup flow periods proved to be difficult during the early stages of data acquisition from the PDMS to the temporary unit. This was essentially due to 3 reasons:

1. A temporary system was initially used to acquire data. This was required prior to the initial hook up and commissioning of the permanent surface unit. Initial observations showed that there was significant scatter in the data. It is believed that the main reason for the larger-than-expected scatter on the initial data was due to the vibrations in the system. The system was installed in a temporary lab cabin above an electric generator on the rig floor. Once the permanent system was commissioned, it was found that the data scatter was reduced to around 1.5 psia at 1-Hz acquisition frequency.

2. Buzzard is a very high permeability system. Due to this, wellbore momentum effects are common in early-time data during PBU analysis (Ref. 4). This essentially means that the rate of change of pressure in the early time is too high, even for a conventional electrical quartz gauge sensor. This effect was not anticipated until dynamic data were received from the first production wells in the field and confirmed through comparison with Production Logging Tool (PLT) results.

3. The operator initially requested a 1-Hz sampling frequency for each downhole gauge. This was to enable the maximum collection of data possible so that the valuable early-time effects would not be lost. The PDMS operates by interrogating each gauge every 160msec to produce a raw value. Given the initial requested data return period of 1 sec, data were averaged over only 5 raw data points which caused considerable scatter in the data. This scatter also reduced the quality of data necessary to understand the early-time effects during PBU. To correct this problem, Weatherford and the operator agreed that the averaging should be done over a longer time period of 5 seconds. This new averaging period resulted in more stable and repeatable data with a considerably reduced amount of scatter in the expense of a better resolution for the early-time effects. The PDMS pressure resolution specification is thus dependant upon logging rate (or averaging) with the attainable resolution specification being exponential with time; the three-sigma resolution with a 99% confidence interval at 1-sec update period was 1.6 psi. At 5 seconds the value was 0.7psi and at 30 seconds 0.3 psi. The difference in data spread resulting from 1-sec and 5-sec data acquisition periods is shown in **Fig. 5** for the same Buzzard well, Well 1. Note the large reduction in data spread within the static reservoir, dependent on data acquisition period and surface acquisition system. These conclusions were reached following an extensive, integrated, collaborative approach that was adopted between Weatherford and Nexen Petroleum U.K. Limited to identify the reason for the large range of data scatter.

In some early wells and most of the later wells, PLTs were run to obtain pressure/temperature and spinner data at the gauge depth as a cross check. Given that the design of the optical flowmeter is full bore (i.e., non-intrusive), no additional wireline intervention was required to facilitate the running of a PLT (e.g. having to remove and re-run a Venturi insert). The results of the comparison between the PLT pressure gauge and the PDMS pressure readings at the gauge depth are shown on **Fig. 6.** These show the log-log plot of the interpretation of the same PBU in Buzzard Well 2. Note the difficulty in both wells to obtain a reasonable early-time interpretation due to wellbore momentum effects. The PDMS 1-sec acquisition data show a relatively large scatter, resulting in difficulty picking a suitable middle time region, when compared to the more tightly constrained PLT quartz pressure gauge data. The same wellbore momentum effects are seen on both gauge types.

In order to gain as much information as possible from the early, 1-Hz frequency data acquired, a collaborative project was launched between Nexen Petroleum U.K. Limited and Weatherford to evaluate a number of options regarding pre-processing and averaging of the raw data prior to analysis. Some of these included filtering and smoothing of the data as well as "smart" data acquisition techniques such as using a higher sampling frequency for a short term during the early part of a build up, and then moving to lower sampling frequency and longer acquisition periods resulting in better averaging during the later stages of the build up. Through close collaboration between both companies, many advances have been made in understanding and interpreting the Buzzard data during PBU`s as well as finding the best way to collect the data at the highest quality possible using the fiber-optic technology.

Following the installation of the permanent surface data collection system on the platform, less processing was required due to the 5-sec sampling period being used for the data acquisition. An example from Buzzard Well 3 is shown on **Fig. 7**, with 5-sec data sampling being recorded by the permanent surface acquisition system. Though the processing amount is still more than that of a conventional quartz gauge, the additional benefits from the use of a fiber-optic PDMS (primarily the addition of a downhole flowmeter in each well) outweigh the additional tasks.

Interference Testing

Water injection startup on Buzzard began in early December 2006, one month prior to first production from the field. This allowed the use of the PDMS pressure gauge in interference testing to understand the connectivity of the sands both vertically and laterally across the field. Due to the nature of pressure changes expected, gauge data were averaged over 5 sec during this period. During the interference tests the pressure variations monitored by the pressure sensors across the field confirmed the assumptions made for sand interconnectivity.

The surface acquisition equipment has required a number of software and hardware enhancements to improve data availability and stability for the pressure sensors. Performance in this area has improved since initial installation, although there were periods of data hand-off loss to the company's OPC interface and loss of pressure data from the PDMS unit local storage in addition to a short period of incorrect reporting of pressure values. Further enhancements to the optical acquisition software are planned to improve data acquisition and data sampling details whilst reducing overall density.

Pressure data are presently being used for real-time permeability and skin analysis in addition to drawdown management.

Flowmeter Initial Results

The fiber-optic flowmeter measures two quantities: speed of sound of the mixture and the flow velocity. By means of the knowledge of densities and speed of sound of individual phases of a two-phase flow, the fraction of the phases can be determined. Using the mixture velocity and the phase fractions yield the phase flow rates.

In the current work, the flowmeter data are recorded every two minutes through a multiplex device, thus for thirteen wells a flow update is provided every 26 minutes. The flowmeter measures downhole flow rates but also reports rates at surface conditions. The calibration of the flowmeter is performed independent of the PVT, but like most flowmeters, it relies upon good PVT data to accurately report the flow rates. Initially, all flowmeters used the PVT obtained from the 20/6-4 appraisal well Drill Stem Testing (DST). It is known that there are PVT differences across the field and it was an initial concern that the flowmeters would require extensive changes in their configuration software before good results would be obtained. This has not proved to be the case. Flowmeter performance has been verified through well testing on a number of wells. Overall results have been very encouraging with good agreement with surface separator results. In terms of total flow rate, the differences have varied between 0% and 6%. **Figure 8** shows the percentage difference between the measured total flow rate and the surface separator results for different wells. Except for one well, all the measurements are within a ±5% band. It should be noted that to date, no changes have been made to initial flowmeter calibrations.

There have been a number of challenges relating to the use of the flowmeter data for production allocation. Like most flowmeter designs there is a minimum flow threshold under which the meter will not measure. In this case with a 5.5" flowmeter design, the figure is 5,000 bbls/day. This caused problems for the Production Engineers in accurate well production allocation, specifically after shut downs. In order to use the flowmeter data for allocation, totaliser logic had to be included. This was completed by the company's Information Systems Team. The totaliser has logic to ignore any particular day's data if more than certain percentage of the data is not available. Given the threshold for the flowmeters to start recording valid data (and frequent invalid /blank points during production ramp up) the flowmeter data does not work for a certain time period directly after shut down. Nevertheless, the trends give invaluable information that helps to accurately estimate the daily volume using other methods.

The flowmeter surface data acquisition equipment also suffered a hardware failure which meant that there was a period where data updates were not obtained although the wells were flowing, resulting in under reporting of volumes. As with most optical systems, all electronic and software components are located topside, with the surface equipment readily accessible in the event of failure.

DTS data are being recorded on select wells to gather geothermal and flowing temperature profiles. These will be used to optimize selection of gas lift valves which will be required late in field life as injected water breakthrough inevitably occurs. In addition, low frequency data are gathered periodically for all wells to aid well diagnostics should a tubing or casing leak ever be suspected.

Key Findings & Lessons Learned

A number of key findings and lessons learned from the Buzzard Field experience are summarized below.

- Defining overall system objectives which drive the project are critical, along with appropriate project management delivery and controls.

- Reviews at critical stages, such as design review and pre-installation, pay dividends.

- The PDMS surface data acquisition equipment can fall between operator disciplines. This can lead to lack of a control and ownership. The PDMS vendor may need to be prepared to adopt a very pro-active approach when handling this aspect.

- Projects of such a magnitude need suitable resources. These levels should not be underestimated. Lack of personnel consistency is troublesome. Although changes are inevitable and understandable, contingency planning and flexibility help minimize negative impacts.

- Efforts spent on early education of the operator on the technology are worthwhile and eases the on-the-job training and the associated anxiety that the new technology presents. Particularly crucial are the data users, the expected data in terms of format and quality along with delivery data methods. In hindsight, more effort applied here would have helped.

- Understanding for both the data users and PDMS supplier on the DMS system operation and possible data delivery scenarios, particularly during production start-up, would have helped problem solving.

- Management of interfaces, system level and component testing and pre-installation planning have eliminated errors and delivered good well installation success.

- Remote acquisition system access, greatly reduces the time taken to remedy problems, the requirement for offshore trips and hence cost and safety risk exposure.

Conclusions

Overall PDMS system performance has proved to be adequate for its intended purpose with all key monitoring system objectives being met.

Problems with initial data have been solved by employing a multi-disciplinary teamwork approach. In the end, an improved understanding of the data characteristics and a better approach in data acquisition helped produce excellent results for reservoir pressure data analysis.

The optical flowmeters have proved to be accurate and provide a useful cross-check to surface well test results. Optical monitoring is an emerging technology, but can no longer be considered to be in field trial status. It can be applied on a wide scale with multi-sensing functions. The current work gives confidence moving forward for the technology as a viable alternative and enhancement to traditional methods.

Nomenclature

Acronyms

BHP = Bottom Hole Pressure
DMS = Data Management System
DTS = Distributed Temperature Sensing
DST = Drill Stem Test
LER = Local Equipment Room
NPT = Non-Productive Time
OLE = Object-Linking and Embedding
OPC = OLE for Process Control
PBU = Pressure Build Up
PDMS = Permanent Downhole Monitoring System
PLT = Production Logging Tool
P/T = Pressure/Temperature
PVT = Pressure Volume Temperature
SIT = System Integration Test

Symbols

k = Permeability, [md]
h = Thickness, [ft]
s = skin factor, [-]

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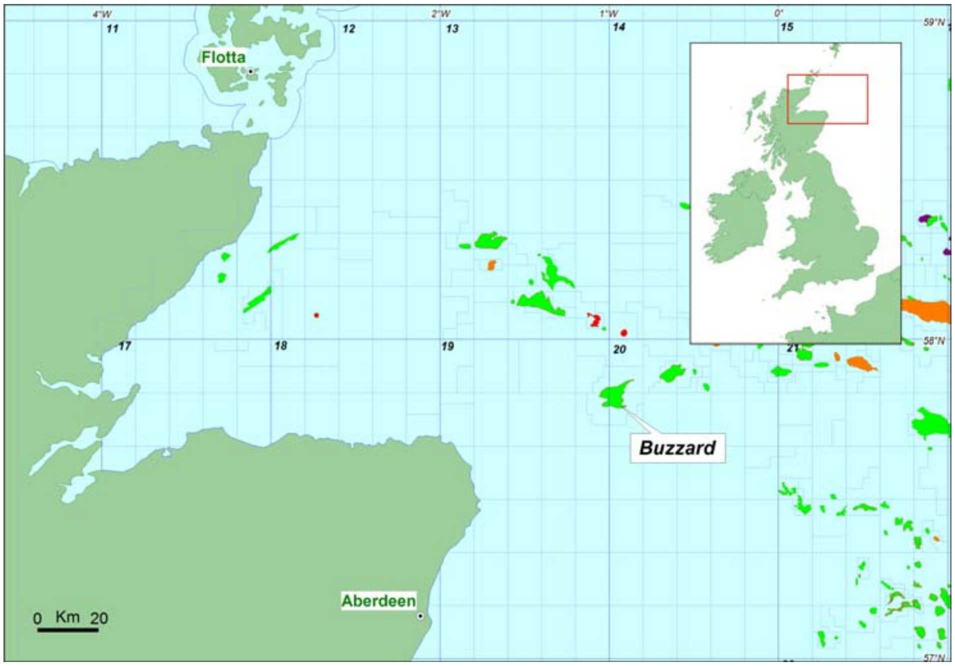

Figure 1 –Nexen Petroleum U.K. Limited Buzzard field.

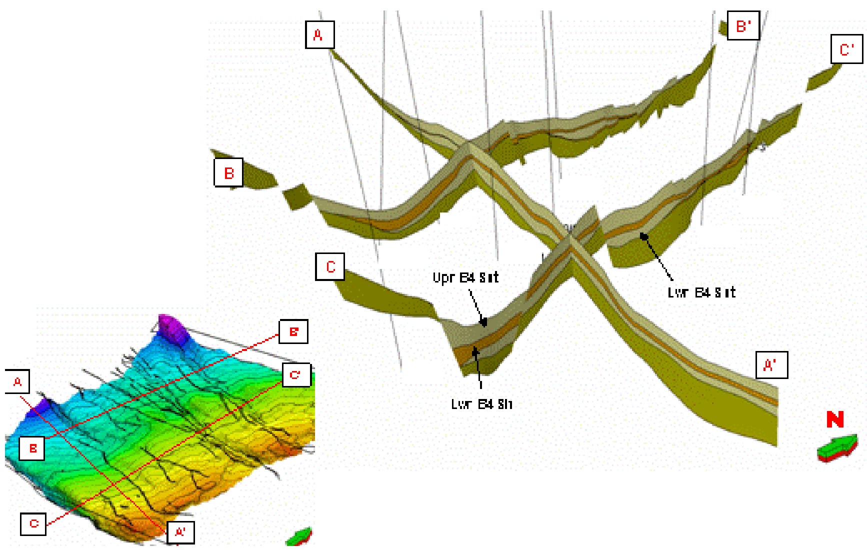

Figure 2 – Buzzard field cross-section showing sand pinchout towards the West.

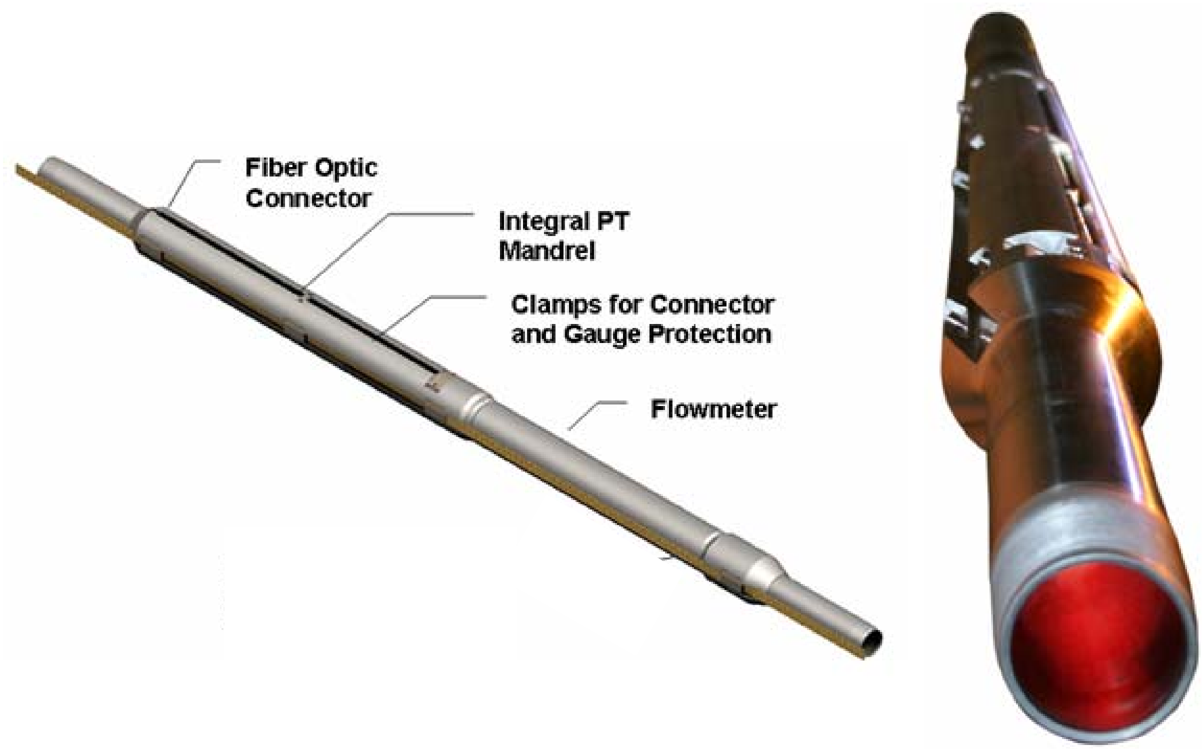

Figure 3 – Fiber optic P/T gauge - flowmeter system.

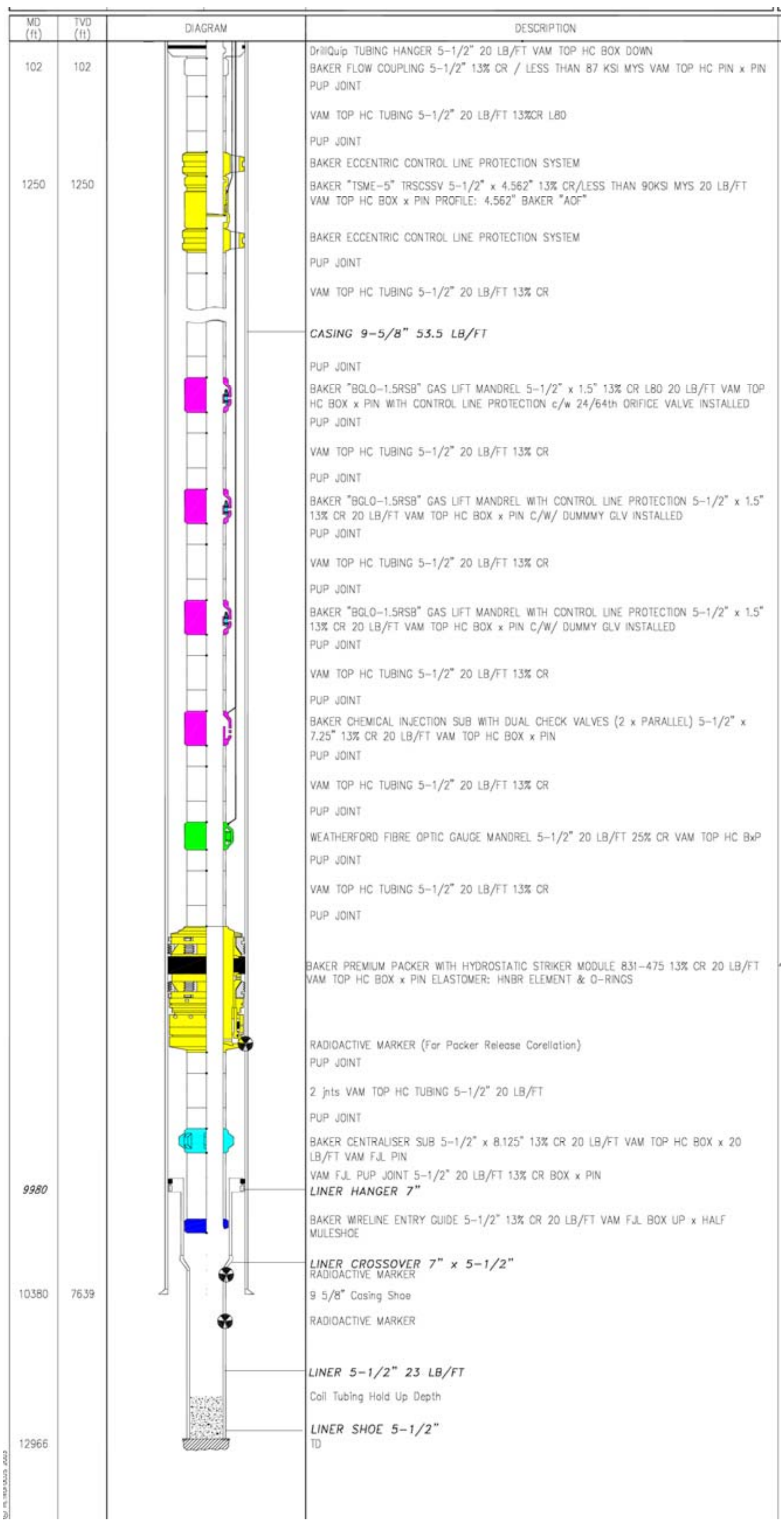

Figure 4 – Typical completion diagram.

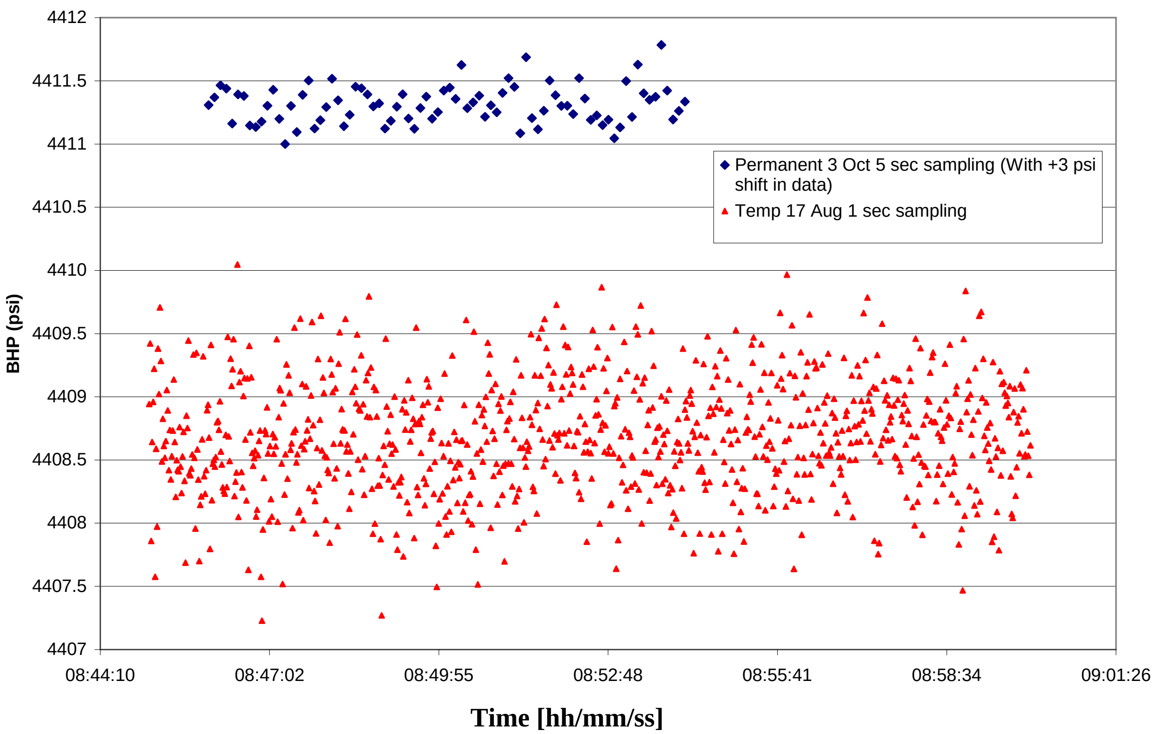

Figure 5 – Comparison of the initial 1-sec acquisition period with the final 5-sec acquisition period for Well 1, showing significantly reduced scatter due to increased averaging.

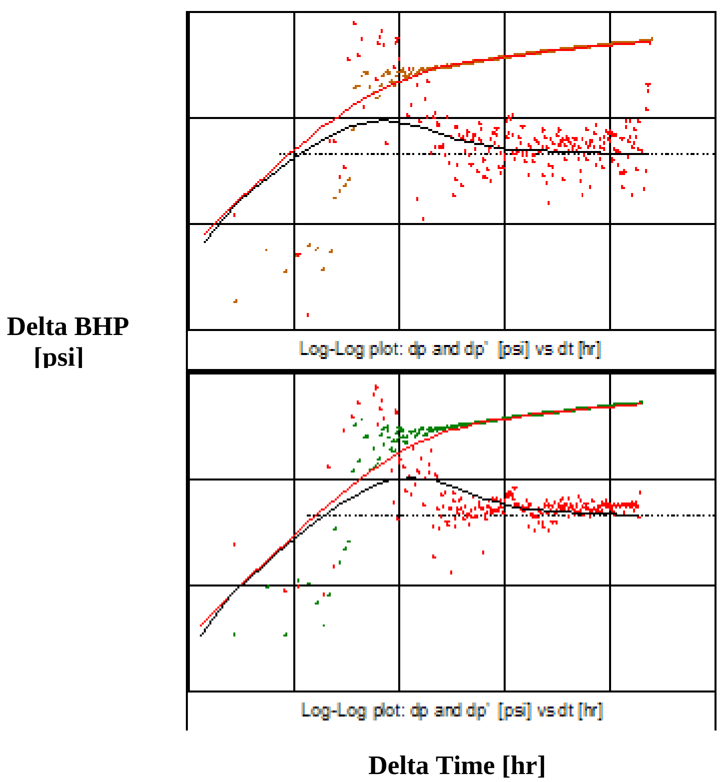

Figure 6 – Comparison of PDMS and Quartz Gauge (PLT String) PBU interpretations from the same shut-in period in Buzzard Well 2, showing interpretation difficulties with the early PDMS, 1-sec data acquisition period (above: pressure transient analysis using data from PDMS, reading into permanent system with 1-Hz frequency; below: pressure transient analysis using data from Quartz pressure gauge on PLT).

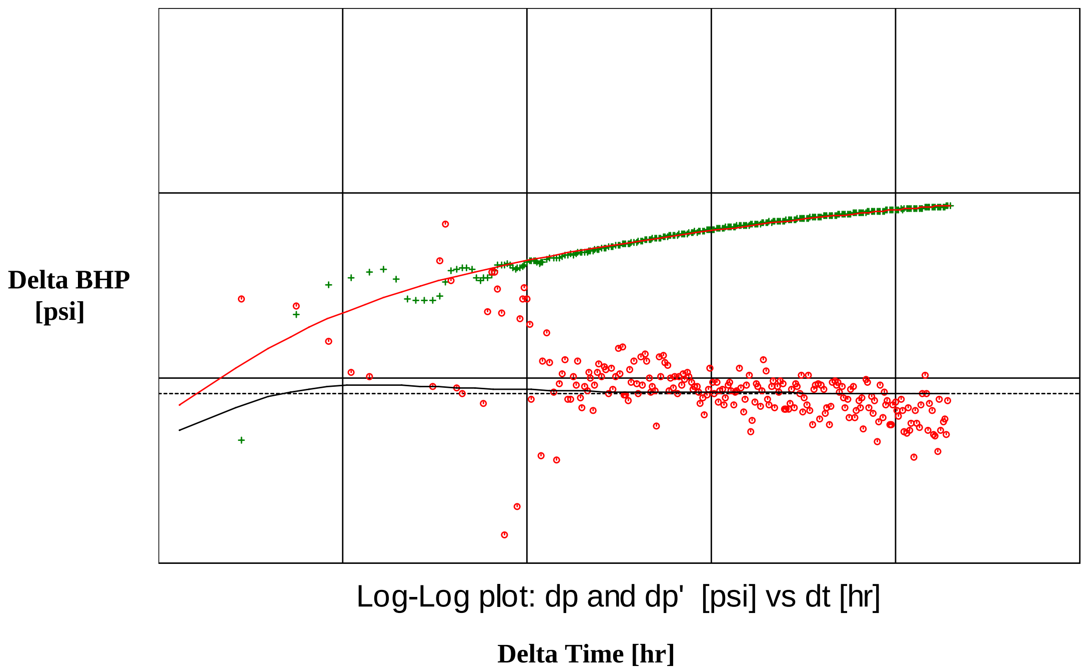

Figure 7 – PBU Interpretation of PDMS using permanent surface acquisition system and 5-sec data averaging in Buzzard Well 3, showing reduction in data spread without loss of data character.

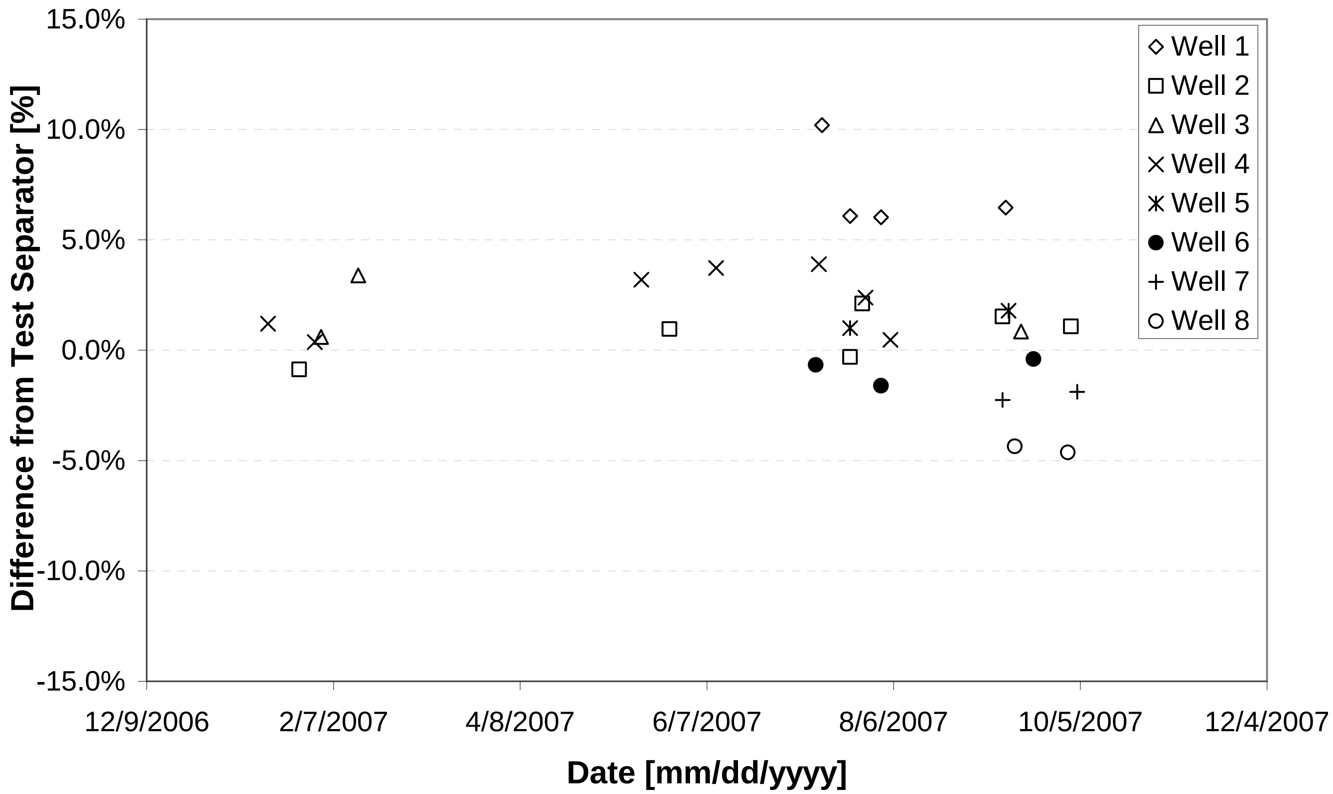

Figure 8 – Total flow rate difference from test separator for different wells.