Milking Data to the Last Drop: Maximizing Value of Fluid Data through Integrated Fluid Characterization*

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Abstract

Fluid characterization is critical at every stage in the lifecycle of an exploration and production project. Misinterpreting reservoir fluid properties is extremely costly, resulting in HSSE incidents, non-optimal well placement; poor completion and facilities design; or errors in reserves, drainage volume and production rate forecasts. It is therefore crucial to obtain representative fluid data at the exploration and appraisal phases when subsurface and surface uncertainties are addressed.

A multitude of techniques exists for reservoir fluid characterization such as mud-gas logging, wireline logging, and well testing. The same holds for fluid analyses such as PVT, flow assurance, and geochemistry. These techniques are often used in isolation or to different extents based on the experience of project focal points and without proper integration. Since each technique has some limitations, integration will always be more valuable than relying on any single technology or discipline.

Shell, through its FEAST (Fluid Evaluation and Sampling Technologies) center of expertise is dedicated to a comprehensive and coordinated approach for fluid evaluation by integrating multiple technologies. This team of multidisciplinary experts follows projects through planning, execution and evaluation. During planning, key subsurface and above surface uncertainties are translated into data acquisition requirements. The team then selects and executes fit-for-purpose rock/ fluid acquisition and analysis programs. During evaluation, emphasis is on generating internally consistent datasets. For example, results from independent datasets such as advanced

mud-gas data, downhole fluid analysis and PVT are integrated. A quality control process is in place ensuring only the best samples are used so that conclusions that are drawn are irrefutable. Understanding sample and analysis quality requires qualified personnel who are involved in the project through all stages, who can draw upon a multidisciplinary network of experts, and who can identify subtle differences and tie them back to real variations or to sampling/measurement artifacts.

In this paper we share operational best practices and present case studies demonstrating integrated fluid characterization workflows. This integrated and iterative approach ensures that objectives are addressed using optimal technologies and workflows. Operational decision-making is thus improved, and the value of information is maximized. Several papers on integrated fluid characterization have been published outlining the advantages of this approach (e.g. McKinney et al., 2007; Elshahawi et al., 2007 and McKinney et al., 2008). This study is a continuation of those papers.

Case Study 1

This case study describes a typical integrated fluid characterization workflow in an exploration well in a deepwater setting. Well-1 penetrated the hydrocarbon-bearing C zone in an exploration well. Well-2 was drilled to appraise stratigraphically equivalent stacked zones C1, C2, C3 and to explore a shallow target, zone D. Both wells were drilled with synthetic oil base mud. In Well-1, data were available from standard mud logging with collection of isotubes® (Isotech, Inc.), wireline formation testing (WFT, pressures and samples), as well as from PVT and geochemical analyses. Although samples from the C zone were of good quality, open-hole sampling in Well-1 from other zone proved challenging due to washouts, the combination of heavy oil and unconsolidated sands, and the sub-optimal pump-probe selection in the formation testing tool. As a result, some of the formation samples from Well-1 were highly contaminated, and there was significant uncertainty in fluid properties.

In the planning stage of Well-2, the FEAST team technical focal point worked with the subsurface and operational teams. A sound understanding of the surface and subsurface uncertainties is key to establishing the formation testing and fluid evaluation objectives. It is the FEAST focal points responsibility to deliver the objectives. The fluid evaluation focal point also coordinates communications with service companies as well as the asset team to eliminate any potential confusion. In this case, the objectives for the formation testing program were set as follows in order of priority:

1. PVT-quality fluid samples in the C1 and C2 reservoirs with oil base mud contamination <5%.
2. PVT-quality fluid samples in the D and C3 reservoirs. This may be revised to geochemistry-quality samples (10-15% OBM contamination) as dictated by fluid and rock conditions.

3. Representative formation pressures and temperatures for the target reservoirs to establish pore pressure, temperature profiles for the well and to establish HC gradients and compare to Well-1.
4. Build-up and drawdown data for pressure transient analysis (PTA) to evaluate mobility.
5. Water samples where encountered.

Early information on fluid properties, specifically density and viscosity were needed for development decisions. Because of logistical issues and since other PVT properties were not deemed immediately necessary, the team was advised to rely on downhole fluid analysis (DFA) rather than deploying onsite analysis.

With these objectives and the experiences from Well-1 in mind, an open-hole sampling and testing program was set up, and communicated to the service companies and the asset in a “Sampling the Well on Paper” (SWOP) exercise to align all stakeholders. The focal point prepares the SWOP document which outlines the objectives of the program, expected fluid/reservoir/well parameters, sampling and testing protocols/criteria, tool string design, sequence of events, notional sample points, allocated sample bottle numbers and types to meet volume requirements of PVT, geochemistry, and flow assurance analyses, communications protocol, and on-site analysis/handling procedures. All jobs are monitored real time, remotely.

A number of issues arose during the execution and evaluation stages of this project that demonstrate how the integrated workflow addresses potential inconsistencies and problems in an efficient and timely manner.

1) Pressure gradient from pretests in C1 suggested very heavy oil, which was not expected (Figure 1). Clearly, pressure gradient in Well-2 was questionable. DFA data yielded the following observations: 1) fluid coloration does not support very heavy oil, therefore contradicts gradient. The coloration agrees with offset well; 2) Well-1 downhole GOR estimate agrees well with lab GOR; 3) Well-1 downhole in-situ density and viscosity measurements agree well with lab density and viscosity; 4) Second sampling station performed in C1 yielded same coloration, GOR, density and viscosity. Moreover, a gradient constructed using post sampling pressures (Figure 1) yielded an in-situ density that agrees with in-situ density measurement and Well-1 lab data. Based on these results it was concluded that the fluid in C1 is similar to the fluid in C encountered in Well-1. PVT lab results a few weeks later confirmed the DFA data (Table 1). Further study of the pressure gradient data suggested that the pretest data may have suffered from a combination of unstable tool temperature and the presence of thin sand beds. In summary, integration of data from multiple sources was essential to reduce the uncertainty in fluid properties real time.

2) Sample validation: The standard sample quality control used in this and other projects typically includes: 1) evaluation of closing and opening pressures of sample cylinders during sampling and transfer, 2) restoration and validation of all samples (compositions, API, GOR and contamination calculation), 3) selection of samples for PVT, Flow Assurance and Geochemistry work based on validation results, 4) preparation of subsamples according to set procedures to guarantee sample integrity, 5) QC of PVT results using EOS models, and 6) management of flow and inventory of samples/cylinders/data. Sample quality and handling/analysis issues are identified very quickly using this workflow and having a focal point that follows the job from downhole sampling to PVT analysis. For example, in this case, the compositional data and contamination determination were in contradiction with the sequence samples were collected downhole, i.e. samples that were cleaned longer and collected later in the C2 zone appeared to be more contaminated than the samples captured with less clean up time at the same station. This turned out to be a lab analysis issue, and a rerun of the compositional analysis yielded results that were consistent with downhole operations. Consequently, the best samples could be chosen for further PVT analysis. If there were no coordination from execution to evaluation stage, these types of errors may never be caught in time to identify-let alone fix- the problem.

Case Study 2

In this example, a potential wet gas/light oil zone (Zone B) was identified based on the results of Advanced Mud Gas (AMG) logging. However, the resistivity, density and neutron logs did not show indication for gas or oil in zone B (Figure 2). A total of 120 liters of filtrate were pumped during Wireline Formation Testing (WFT) of this zone, where Downhole Fluid Analyzer (DFA) did not detect hydrocarbons (Figure 3). In contrast, the well test flowed up to 40 MMscf/day (Figure 4). Each individual technique was working correctly, but only through integration the apparent inconsistencies could be resolved, reducing the uncertainty about fluid properties in this zone.

Geochemical analysis on core extracts showed residual non-mobile hydrocarbon, which explains the source of the wet hydrocarbon signal. The well test compositional and compound specific isotope analyses (CSIA) show that produced gas is identical to gas from Zone A which is known to be gas-bearing (Figure 5). Finally, pressure transient analysis confirmed a fracture into Zone A through which gas was produced during the testing of the Zone B. This case study again emphasizes 1) the advantage of integration over relying on any single data source for interpretation, and 2) the importance of coordinating efforts from planning (decision to employ AMG, WFT planning) through execution (WFT execution, DFA monitoring) and evaluation (PTA analyses, geochemical analyses and integration).

References

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		Well-1 Zone C – LAB	Well-2 Zone C1 - DFA	Well-2 Zone C1 - LAB
GOR	(scf/bbl)	300	324	335
in-situ viscosity	(cP)	18	17-18	17.1
in-situ density	(g/cc)	0.884	0.880-0.882	0.872
C1	(wt%)	3.6	3.7	3.8
C2	(wt%)	0.1	0.0	0.1
C3-5	(wt%)	0.08	0.0	0.1
C6+	(wt%)	95.9	95.6	95.6
CO_2	(wt%)	0.2	0.7	0.4
Contamination (live oil basis)	(%)	7.2	6 +/-3	4.5-5.6

Table 1. Comparison of Well-1, Well-2 lab and DFA results of C1 fluid properties.

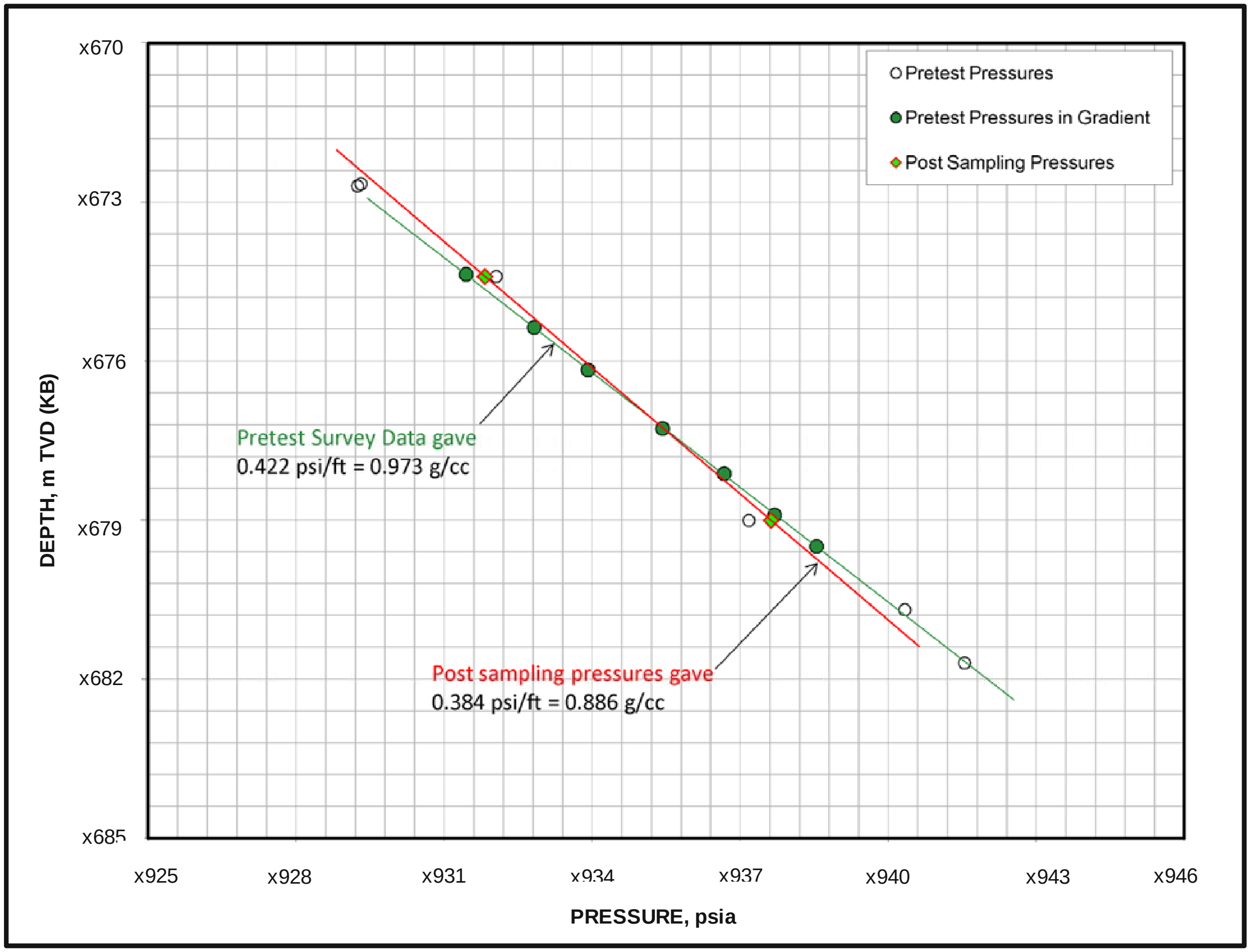

Figure 1. Pressure gradients from pretests and from post sampling are not consistent in Well 2. (Case Study 1).

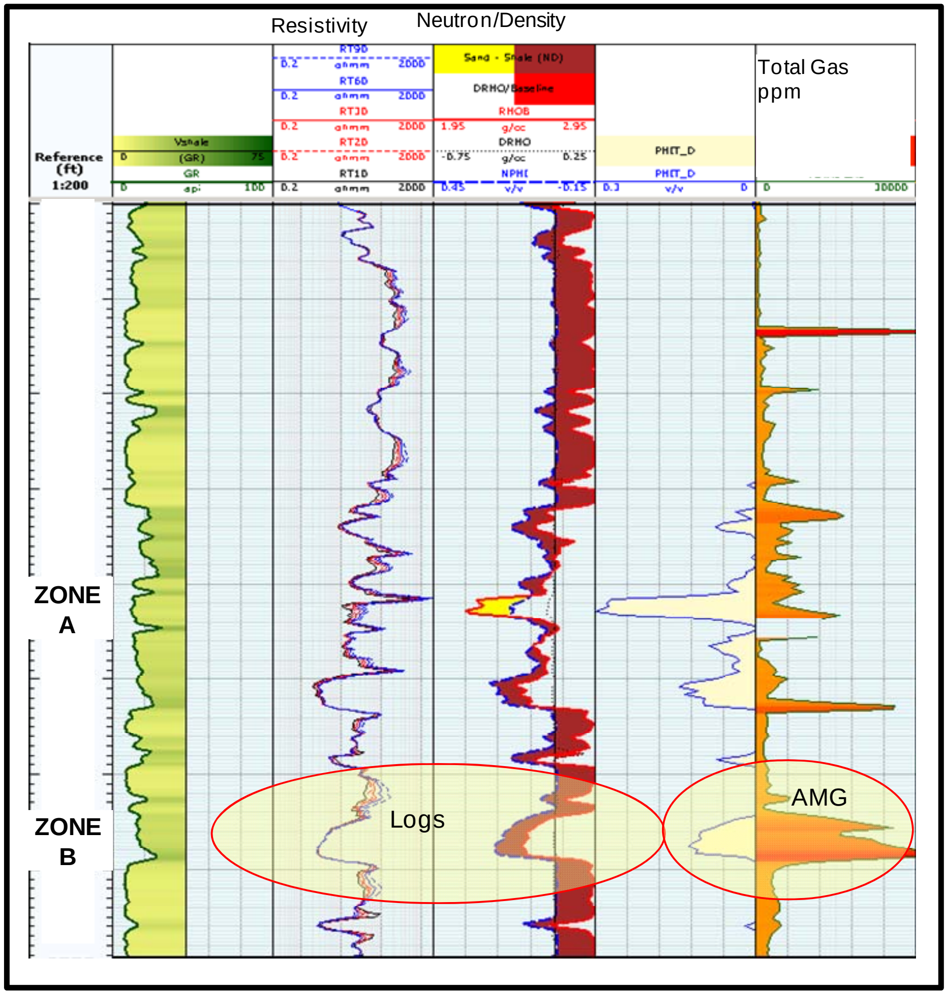

Figure 2. Total Gas and Resistivity-Neutron/Density logs showing different results for the presence of hydrocarbons in Zone B. In Zone A, AMG and traditional logs are in agreement and indicate the presence of gas (Case Study 2).

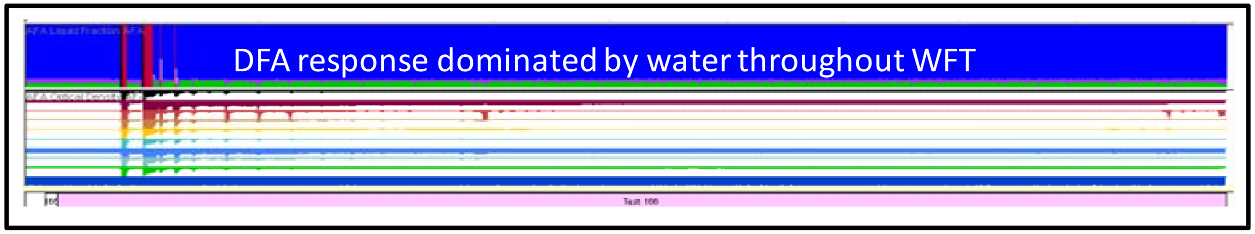

Figure 3. DFA response during formation testing of Zone B (Case Study 2).

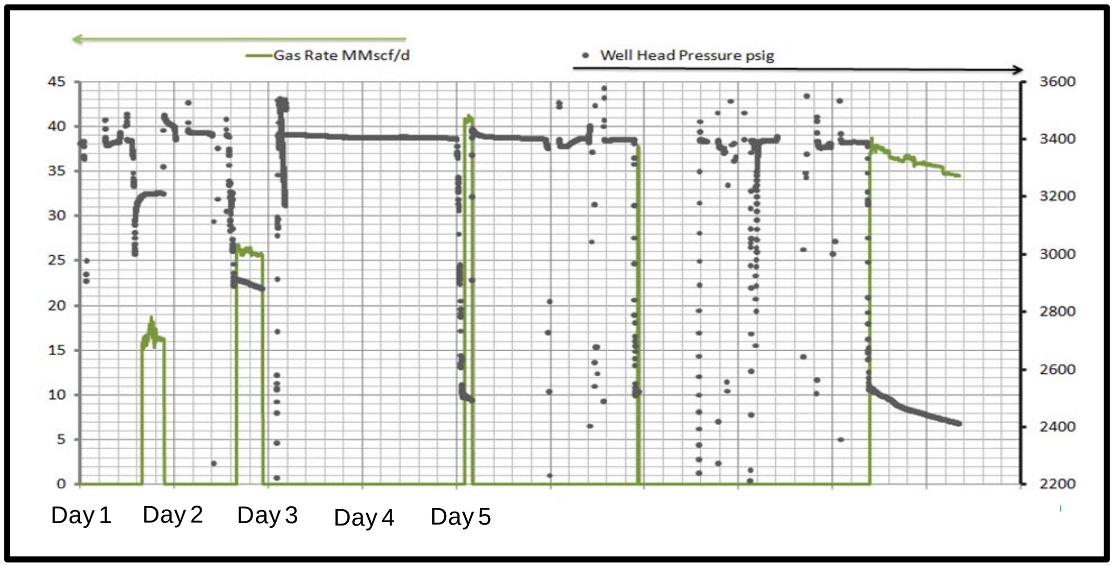

Figure 4. Well test results from Zone B confirming flowing gas (green curve) (Case Study 2).

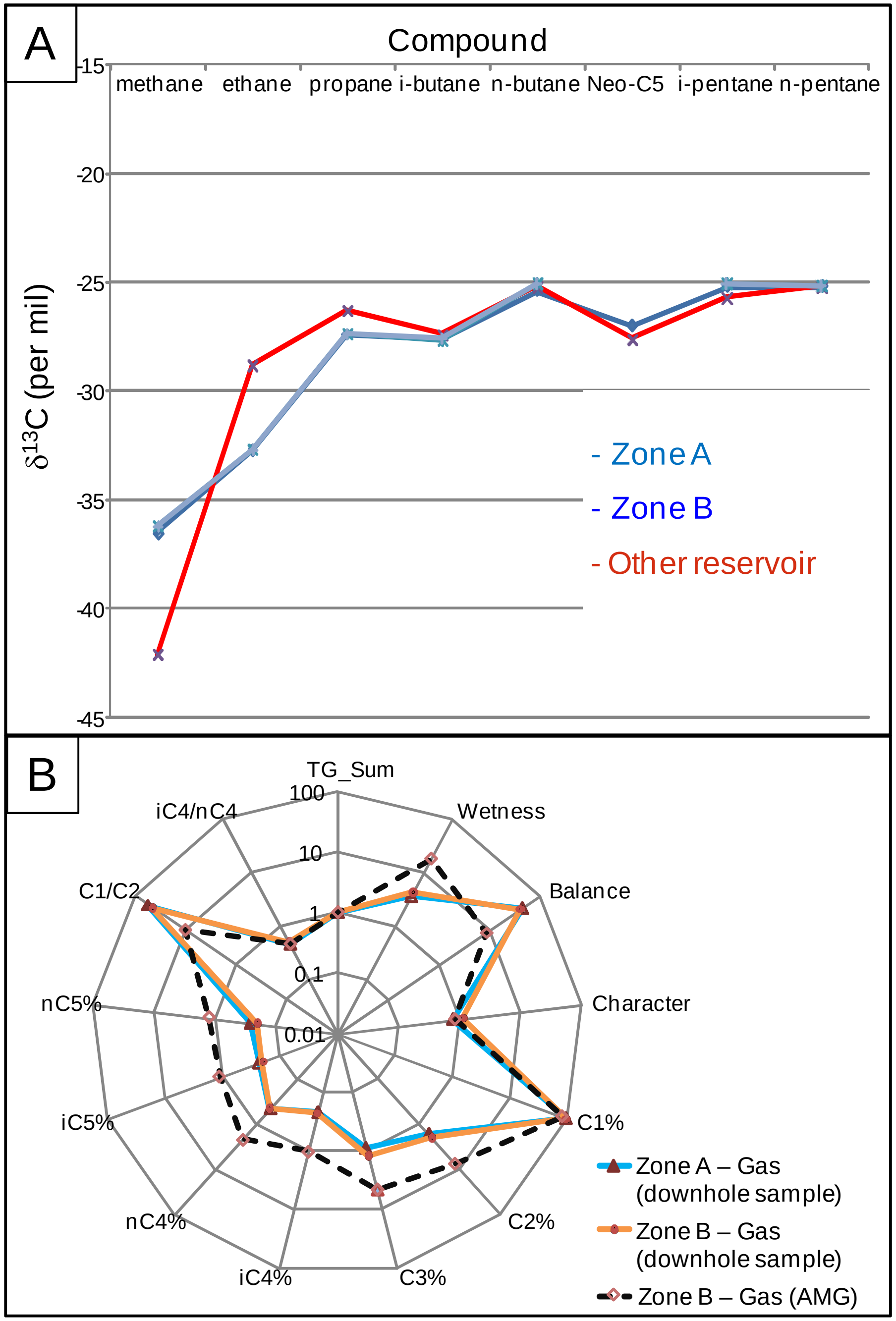

Figure 5. CSIA (A) and gas compositional data (B) showing gas produced from Zones A and B are identical, but mud gas from Zone B is different.