Evaluations of Deep and Challenging Reservoirs with High Temperature Formation Tester Tools*

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Abstract

Oil and gas exploration is moving from relatively easier basins to more challenging environments. More exploration and appraisal wells are now targeting deeper horizons, which tend to have lower porosities and high temperatures (HT). Several reservoirs in the Southeast Asia region, such as the North Malay basin in Thailand and Malaysia are considered to have the highest temperature gradient due to their geological settings.

Seventy to eighty percentage of wells drilled in this area have temperature close to, or higher than 400 deg F. Apart from the variation of CO_2 content, near critical reservoir fluids and tight gas reservoirs, additional key challenges are heavy compartmentalization and granite basement reservoirs in deeper horizons. With existing liquid handling facilities and gas sale agreements, reservoir fluid information such as fluid types, Condensate-Gas Ratio (CGR) and CO_2 content, as well as zonal producibility are required to properly select perforation zones.

The main challenges to obtain accurate reservoir pressure in tight and HT reservoirs are seal capability, supercharging effect and traditional pressure gauge limitations (Daungkaew et al., 2011). In addition, characterizing the reservoir fluid type is not a trivial task, especially for near critical fluids and for fluid with a variation in CO_2 content. Typically, Wireline Formation Testers (WFT) with fluid analyzers are used for early fluid characterization and sampling. Increasing fluid complexities require a comprehensive compositional analysis with greater accuracy, repeatability and quantitative results.

This article presents our experience of using high temperature WFT in the Arthit Gas Field in the Gulf of Thailand (GoT). The challenges of logging and lessons learned are also discussed together with WFT design and improvements for high temperature environments. The results are discussed operationally and technically, in terms of data quality and accuracy compared to PVT laboratory analyses. The article outlines a significant forward step, illustrating that it is now possible to obtain accurate formation pressure data and representative fluid samples in high temperature environments where satisfactory results were not possible in the past.

Introduction

The Arthit Field is one of the main gas producing fields in the Gulf of Thailand. It is located in the North Malay Basin. This basin is of Late Eocene to Late Oligocene age and consists of Miocene retrograde gas sands. The field is located in relatively shallow water with water depths ranging from 60-80 meters in the study area. The targeted reservoirs are composed of fluvial channels and bars to shallow marine sandstones interbedded with mudstones of transgressive marine shale. The lithofacies change from reservoir to reservoir, varying from heterolithics sandstones with moderately to intensely bioturbated sandstones, deformed, loaded structures and ripple laminated sandstones. The North Malay Basin is known to exhibit a high temperature gradient, as shown in Figure 1 (Daungkaew et al., 2011). Apart from the exceptionally high temperature, variation of CO_2, near critical reservoir fluids and low porosity/permeability in deeper horizons are also the main concerns which will create an uncertainty for the Field Development Plans (FDP). The technologies to acquire the reservoir engineering data play a vital role in the FDP, especially for this kind of environment. WFT could help overcome these problems by acquiring accurate reservoir pressure and downhole fluid analysis during real-time operations.

This article addresses challenges to obtain reservoir parameters such as representative formation fluid gradient, proper identification of reservoir fluids, and also to acquire quality PVT samples in such environments. The article then discusses new High Pressure High Temperature (HPHT) formation tester tools. Actual field results are discussed with some lessons learned from operations to obtain accurate reservoir information in such challenging conditions.

Challenges

Nowadays, easy oil and gas discovery are rare. More and more exploration and appraisal wells are targeted at greater depths which result in lower porosities as well as hotter downhole environments. The North Malay Basin is of the Late Eocene to Late Oligocene age, which consists of Miocene aged retrograde gas sands. The portion of North Malay Basin in the Gulf of Thailand (GoT) is known to exhibit a high temperature gradient. Targeted reservoirs consist of highly compartmentalized formations. Many individual sands are part of the complex fluvial stratigraphic framework. Apart from the exceptional high temperature, variation of Carbon Dioxide (CO_2), near critical reservoir fluids and low porosity/ permeability in the deeper horizons are further challenges. This subsurface uncertainty affects the uncertainty for future FDP.

The most practical way to minimize the risk is to properly characterize these reservoirs to understand their production potential. Traditionally, exploration/appraisal wells were drilled with a highly deviated 8.5 and 6.125 inches hole well design. As a result, simple logging programs were executed to gather reservoir and fluid information such as gamma ray, resistivity, density, porosity, formation pressure, and segregated samples. In some wells, a full scale Tubing Stem Testing (TST) method was planned to investigate the sand producibility. However, this simple logging program cannot answer a number of questions raised to properly plan for FDP. For gas condensate reservoirs with a high amount of CO_2 content, the liquid handling facility and gas sale agreement are important pieces of information to select perforation zones. Fluid information, (CGR) and CO_2 contents are required to select completion zones to provide sufficient commingled flow. Previously, measuring surface flashed gas collected from segregated samples by dump chamber was performed to obtain reservoir fluid information. However, the traditional GoT sampling method does not allow for characterizing reservoir fluids at reservoir conditions (Kanjanavasoontara et al., 2010; Baxter et al., 2000).

The first challenge is to obtain accurate formation pressures and to use the acquired pressure data for fluid gradients to identify fluid types. The most advanced pressure gauge used in the current FT is a Crystal Quartz Gauge (CQG). The CQG gauge was designed to handle temperature transient effects with a dual mode sensor, i.e. one sensor acts as both thermometer and manometer. The same Quartz crystal is sensitive to both pressure and temperature (Schlumberger, 2006). This design ensures a quick and accurate temperature correction. From our study, the CQG has the lowest transient effect. The CQG transient effect is twenty times better than that of Quartzdyne gauges (Daungkaew et al., 2011). However, the CQG gauge is limited to a working environment below 350 deg F and 15 K psi.

In high temperature environments, usually a Quartzdyne gauge is used due to its specifications for higher temperatures (35 K psi and temperature up to 225 deg C). The Quartzdyne design consists of three quartz crytstals (www.quartzdyne.com); the first quartz is sensitive to pressure, the second one is sensitive to temperature, and the third one is the reference quartz crystal. All 3 crystals must be at the same temperature to acquire an accurate formation pressure. To avoid transient temperature effects, the recommended procedure for pressure testing with a Quartzdyne gauge is to stabilize the gauge at each test depth for a period of time (in practice, this wait time is more than 20 minutes). This waiting time for temperature stabilization period helps minimize the temperature differences between these three crystals. However, in our experience, sometimes the transient effect is still there even if the wait time is more than 30 minutes. Consequently, there is a need to have a new WFT design to minimize temperature transient effects (Daungkaew et al., 2011).

Second challenge is the CO_2 variation in these heavily compartmentalized reservoirs. The CO_2 variation is from less than 5% to more than 70% mole (Pisutha-Arnond and Sirimongkolkitti, 2004). In order to meet the sale gas agreement, CO_2 concentrations in each zone are needed to select perforation zones for the commingled production. The typical CO_2 measurement in the GoT using segregated chambers with a previous generation WFT is not accurate for wet gas, gas condensate and oil reservoirs (Daungkaew et al., 2012). Since dump chambers are operated with a water cushion, the sampled reservoir fluids will be flashed against a couple of hundred psi of water cushion pressure. The CO_2 values obtained from such sampling are similar to the values obtained from the flashed gas, i.e. not representative of the amount of CO_2 content in the total fluid system.

Third main challenge is near-critical reservoir fluids, i.e. gas condensate reservoirs. It is not straightforward to identify reservoir fluids only from pressure gradients due to associated low permeability, supercharging effects and thinly bedded reservoirs. Taking fluid samples using the “segregated sampling” technique is also not a proper way to obtain accurate fluid types since most fluids collected with dump chambers are mainly mud and mud filtrate with some traces of reservoir fluids that were flashed against the water cushion pressure. In order to obtain accurate fluid types, the recommended way is to use a modular WFT equipped with pump-out module(s). The pump-out module is designed to clean up the mud filtrate before representative fluid samples are taken into the PVT chambers. The pressure drop during pump-out period can be controlled to obtain single phase samples. These PVT samples are then sent to PVT laboratories for composition analysis and PVT properties. However, this process might take too long to obtain reservoir fluid information for selecting the target perforation zones. Wellsite Gas Chromatography (GC) is hence a popular technique to obtain fluid information while operations on the rig still continue.

New WFT for Hostile Environments

To overcome these challenges, accurate real-time reservoir pressure and downhole fluid analysis are mandatory and these could be achieved with a WFT tool. Determining accurate reservoir pressure, representative fluid type, quality fluid samples for PVT, inflow performance, and reservoir connectivity are some of the desired objectives of WFT surveys. The main challenges for formation testing acquisition at high temperatures are divided into 2 items: (1) gauge temperature sensitivity control, and (2) precise downhole fluid analyzer (DFA) sensor and improved acquisition techniques during real-time operations. Table 1 summarizes WFT survey objectives, challenges and methods to overcome these challenges.

For the first challenge, the PressureXpress-HT (Schlumberger TradeMark) was designed. This pressure only tool is rated to 450 deg F and quantified for 14 hours operation. It features a Quartzdyne gauge with a much improved stability. This tool was flasked in order to optimize the heat transfer. The thermal insulation was designed robustly for extended surveys in HT environment. Several mechanical and electronics innovations were implemented to improve its reliability - as a result, no temperature stabilization is needed, including traditional stabilization in casing shoe. The flasked gauge and electronics do not demonstrate build down effect seen in other WFT that do not place gauge in a thermally stable flask environment.

In addition, this WFT features a high precision pre-test control system that results in accurate rates and volumes, allowing pressure and mobility measurements in low permeability formations (up to 0.1 mD/cp using the conventional probe) within a fraction of time required by traditional hydraulically driven pre-test tools (10-15 seconds set and retract time compared to around 3 minutes). In addition, this WFT is fully combinable, so a dedicated run for formation testing can be eliminated and all pressure data can be acquired in the same run along with all other petrophysical data. The tool has a secondary pressure gauge and an additional flowline/pre-test temperature sensor for accurate temperature measurement and to also monitor the temperature changes during a pre-test.

Figure 3 illustrates the relationship between pre-test rate and pressure drop. The tighter the formation, the smaller the required rate to optimize the pressure drop in order to increase the chances of obtaining valid pre-tests. Figure 4 shows the relationship between build-up time, pre-test volume and differences in sandface pressure and flowing pressure. This plot shows that if we want to get a build-up pressure close to the formation pressure, the larger pre-test volume will result in a longer build-up time. As a result, in low permeability environments, the pressure drop needs to be optimized by selecting a smaller flow rate (to match with formation permeability) and a smaller volume (to have the pressure stabilize faster). However, the selected volume needs to be enough to decompress the FT pre-test flowline. Different WFT will have different pre-test flowline storage volumes. The high temperature pressure tool has a design with a small flowline volume, offering more advantages in lower mobility ranges.

For the second and third challenges, they can be overcome with the HT formation tester equipped with pump-out module and downhole fluid analyzer. These formation testing tools typically utilizes high powered downhole motor and pumps that generate considerable heat and hence flasking alone may not provide sufficient operating time without raising the temperature inside the flask to the rating of electronic components. This is particularly true for sampling operations where the downhole operating time is uncertain as it depends on various factors including formation properties and over balance, etc.

To address this challenge, engineers needed to focus on various areas including designing electronic components. The biggest challenge involved redesigning plastic encapsulated components mounted on plastic boards that typically have low life expectancy at high temperature. Proprietary ceramic electronics technology that can operate at 400 deg F was developed and met the operational requirements. Engineers also performed thermal imaging using infrared to identify localized hot spots and over loaded components. This trigged the need to changing the layout, redistributing the load or even installing heat sinks to draw away heat from specific areas. Multiple component circuits were also converted into MCM with high reliability and high temperature handling capabilities.

These improvements were integrated in to latest generation WFT. MDT-Forte* and MDT-Forte-HT* which has been reengineered to include robust telemetry system, redesigned electronics for better power and heat management, ruggedized electronics for survivability to shock and vibration, improved qualification and validation for quantified operating confidence, and predictive maintenance for consistent reliability.

MDT-Forte and MDT-Forte-HT undergoes extensive qualification and screening tests at various levels, including board level, assembly level and over all tool level. Qualification of the electronics includes 100 thermal cycles from -40 deg C to 205 deg C along with 12,000 shocks of 500 G. These tests are designed to ensure tools ability to withstand shock, vibration, thermal cycles, and exhibit high temperature endurance. In addition, the seals in the tool have been upgraded with Carbon Nano-Tube composite sealing technology proving best in class sealing up to 400 deg F and 35,000 psi. The seals are also capable of handling high concentration of H_2S and CO_2. This makes them suitable for varied challenging environments such as high temperature, high pressure, tough logging conditions, jarring and fishing, etc. as encountered in GoT.

The MDT-Forte version is rated to 350 deg F, and the MDT-Forte-HT version is rated to 400 deg F with an operating life time of 100 hours. Figure 5 and Figure 6 show the shock and heat tests conducted for each of the high temperature tools. This makes them suitable for varied challenging environments such as high temperature, high pressure, tough logging conditions, jarring and fishing, etc. as encountered in GoT.

With the modular WFT, a number of modules such as probe, pump-out module, downhole fluid analyzers, and sample chambers can be placed in the tool string to allow cleaning up of the mud and mud filtrate, until representative reservoir fluids with an acceptable contamination level are observed real time. Figure 7 shows an advanced DFA tool that consists of a spectrometer, gas detector, fluorescence, vibrating wire and rod, P/T and resistivity sensors to monitor fluid clean up and to also obtain in-situ reservoir fluid information in real time, including the CO_2 contents.

Actual Field Results and Discussion

This project has started early 2007 when we identified a need to have HT WFT that allows us to acquire an accurate formation pressure in high temperature environments. The building down effect was noticed and later identified as a result of temperature transient effects of the Quartzdyne gauge (Daungkaew et al., 2011). We noticed that even with small changes in temperature, the resulting transient significantly affects the pressure reading. Even though we stabilize the gauge at each depth for more than 30 minutes, this does not guarantee a valid formation pressure, eliminating this effect. As a result, accumulated errors in each formation pressure reading can result in unreliable pressure gradients. This is clear from the example shown in Daungkaew et al. (2011) Figure 8. The points with a red circle were pre-tests from a conventional pre-test tool, and the blue dots used for a fluid gradient were from the high temperature formation tester tool.

The pressure testing tool was designed and field tested in Thailand since 2008. This tool was redesigned to address the pressure gauge temperature sensitivity. Following the insulation of the Quartzdyne gauge from heat and placing the gauges within a flask to minimize fluid contact, there was a significant reduction in heat transfer, and as a result, the build down effect due to temperature transients was eliminated.

To date, the pressure testing only tool has been deployed for Arthit team for more than 18 wells. The range of temperature covered by this pressure only tool was between 176 and 205 deg C. Representative formation pressures were obtained in formations with mobilities as low as 0.3 mD/cp with a conventional probe. The low permeability formations were targeted with low rate and low volume pre-tests to match the formation mobility. Real-time pressure derivative was used to monitor data by reservoir engineers in town and feedback on the data quality was provided to field engineers and wellsite geologist for better decisions.

However, there are remaining challenges to obtain formation pressure in these low permeability and HT reservoirs. Those challenges are seal capability and supercharging effect. Low permeability tends to take longer time for mud cake to properly form; as a result, pre-tests in these environments were prone to no seal or seal failure using the conventional probe. In addition, characterizing the reservoir fluid type is not a trivial task, especially for near critical fluids with varying CO_2 content. Typically, WFT with fluid analysers are used for early fluid characterization and sampling together. Increasing fluid complexity requires a comprehensive compositional analysis with greater accuracy, repeatability and quantitative results.

In mid-2012, the HT pressure and sampling tool with downhole fluid analyzer was introduced in the Arthit Field to obtain reservoir fluid information in real time as well as fluid sampling in seven logging suites (three wells and one sidetrack). Reservoir fluid information was obtained in real time as well as CO_2 content and zone permeability-thickness. Figure 11 shows an example of the use of DFA together with high temperature FT to identify reservoir fluids and obtain fluid composition in real time. In this figure, the top plot shows GOR, the second plot shows fluid composition where yellow color corresponding to the amount of C_1, orange for C_2, brown for C_3-C_5, the green color shows C_6+, and the purple colour depicts the CO_2 content. The third track shows fluorescence detector results. The value of fluorescence FL0 corresponds to light hydrocarbon or condensate drop out. However, for this particular OBM, there was also some amount of light hydrocarbons, fluorescence was high when we had mud filtrate flowing in the flowline. We put the DFA tool on the high pressure side of the pump-out module. When the pump change strokes, fluids were segregated in the pump and they were pushed out into the flowline as discrete slugs. In this plot, we see the slugs of OBM filtrate and reservoir gas. The mud filtrate was cleaning up with time. The fourth track shows fluid fraction. All tracks are displayed with respect to time. In other words, the measured values were continuous readings. Here, we see a clear change from mud (brown color in fluid fraction), to mud filtrate (green colour), and reservoir gas. The mud filtrate slugs were decreasing with time. In this particular zone, DFA indicates dry gas with 14% wt of CO_2 (10% mole). The wellsite GC confirmed 13%wt of CO_2. In this station, the total time per station was 1 hour and 10 mins. This zone had a low mobility of 1 mD/cp. The total pump-out in this station was 32 liters.

In the same well, the high temperature WFT was used to obtain formation pressures, mobility and pump-out to identify reservoir fluids in four zones, i.e. three gas stations and one water station were encountered. All three gas stations have the range of CO_2 content between 13% and 18% wt, as shown in Table 2. Permeability-thickness (k.h) is another parameter that can be obtained with a WFT. The final build-up data was conducted after fluid samples were taken. Pressure transient data was analyzed to obtain zone permeability-thickness, as shown in Figure 12.

Permeability-thickness was derived from build-up data after the fluid sample was taken. Figure 12 shows pressure and rate versus time in the top plot. Log-log plot and specialized plot are shown below. From log-log plot, radial flow that is used to obtain the permeability-thickness (k.h) product is clearly seen. The zone permeability derived from this method provides reservoir information to assess the zone producibility.

In zones with temperature higher than 350 deg F, the DFA spectrometer cannot be used. The probe resistivity can be used to identify reservoir fluids. Next section will discuss the use of resistivity for fluid identification. However, since the resistivity depends strongly on temperature, the newly designed high temperature density sensor tool is recommended as the better way to help identify reservoir fluids and monitor the cleanup in high temperature wells. We did not have any examples of using HT density sensor in this paper due to the tool mobilization. However, we hope to present results in our next article.

Figure 13 and Figure 14 show a comparison of probe resistivity with DFA in two of the pumping stations. The left plot shows continuous increase of resistivity when we pump gas in the flowline. The plot on the right hand side shows a signature of resistivity in the water station. The resistivity drops to a lower value. However, resistivity is still much higher than obtained from surface measurement. This is not unusual for the resistivity cell since it is prone to be affected by OBM and hydrocarbons from a previous station. However, the trend of resistivity can still be used to identify reservoir fluids in most cases. Figure 15 shows the use of resistivity for fluid identification in one of the deep wells, where the maximum temperature for the deepest WFT station is 370 deg F. In this station, resistivity increases gradually with time. This suggests hydrocarbon (or not the water zone). Two fluid samples were taken in this station. The first sample was taken when the resistivity was still increasing with time. We waited until resistivity is quite constant before we took the second fluid sample. One of the samples was opened at the surface, and it confirmed reservoir gas in this station. However, since the fluid cleanup was monitored using the resistivity cell only, collected fluids are not clean enough for further PVT analyses.

After the use of resistivity has been compared with the spectrometer, it was used more confidently for fluid identification in high temperature environments. However, resistivity cell readings depend strongly on temperature and the WFT tool temperature increases as the survey continues and as the pump rate is increased. This needs to be considered when the resistivity cell is used to monitor filtrate clean up. It will not be as accurate as spectrometer measurements. The HT density sensor is therefore introduced for this purpose. For this article, we could not mobilize the HT density sensor together with HT WFT. If this is the case in a future well, it is recommended to divide logging into two runs.

The first run below 350 deg F where the WFT can be deployed with the DFA tool to obtain more conclusive results, and the second run should be done with the HT WFT with resistivity or HT density sensor.

The fluid composition profile versus depth allows the Arthit Field development team to use this for reservoir information, reservoir management, and asset project execution, as shown below:

Reservoir Information
✓ Obtain accurate reservoir pressure and fluid information where it could not be able to obtain before ✓ Help to select the right perforation zones ✓ Accurate fluid type zone by zone ✓ Reservoir fluid information in real time ✓ Accurate CO_2 content zone by zone at the reservoir condition
Reservoir Management
✓ Maximize value of information for reservoir management ✓ Produced liquid can be manageable according to the surface facilities ✓ Value of real time information allows decision making ✓ Time saving for total well evaluation ✓ Cost saving in term of rig time by reducing pre-test and full scale testing time
Asset Project Execution
✓ Cooperative between operation field crew, petro technical expert and asset teams ✓ Meet up with the sale gas agreement ✓ Set a new standard in HT logging in the GoT ✓ Adapt the game changing technology to help proper project management

Conclusions

This article presents actual field examples from the Arthit Field located in the North Malay Basin in the GoT. We present the use of HT formation pressure tools to obtain accurate pressure in high temperature environments. However, in low permeability zones, reservoir fluid identification from pressure gradient alone is not always possible due to supercharged effect, thinly bedded reservoirs, etc. The use of the modular WFT tool is also discussed. The example shows that more conclusive fluid identification can be obtained using the modular HT WFT tool equipped with the DFA tool. However, due to temperature limits of the DFA tool (at 350 deg F currently for spectrometer type of the DFA), the use of resistivity was found to have more uncertainty compared to the DFA tool. When the resistivity was used for reservoir fluid clean up, the results were still not satisfied for PVT analysis. The HT density sensor is therefore recommended for the next HT logging.

This project is the first project that aims to properly characterize formations in deeper reservoirs. Unlike the traditional methods, accurate reservoir pressure, fluid composition including CO_2, GOR and/or CGR, and representative fluid samples can be obtained in real time. Real-time monitoring was done with the Arthit petro technical team and operation geologists to ensure the job objectives were met within the assigned time frame. Pre-job planning, real time monitoring, good communication between different parties and post-job analyses were carried out routinely. This is the first attempt to try evaluating reservoirs in the deeper and HT sections using game changing technologies to properly understand reservoir fluids. This cooperative work allows asset teams to have accurate reservoir fluid information for their field development.

Acknowledgements

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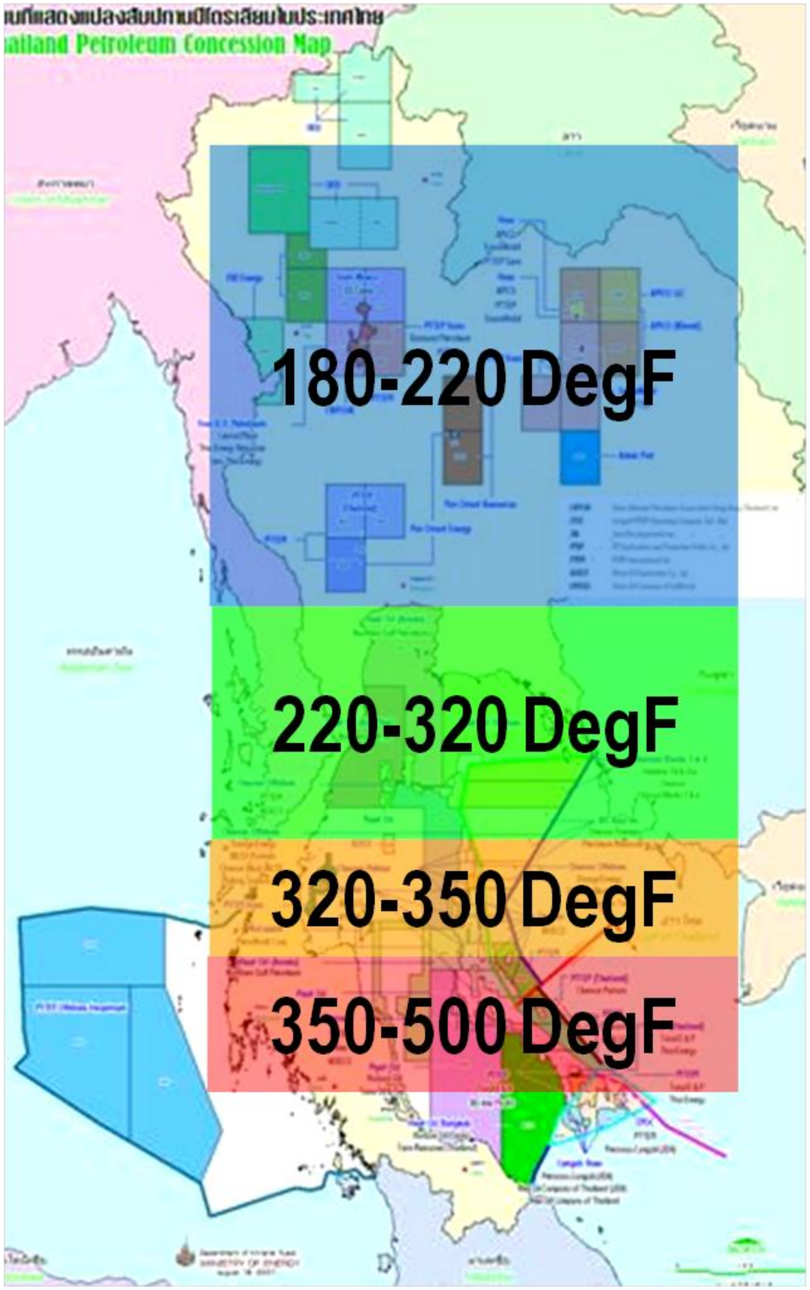

Figure 1. Generic bottom hole temperature profile for the Gulf of Thailand (GoT).

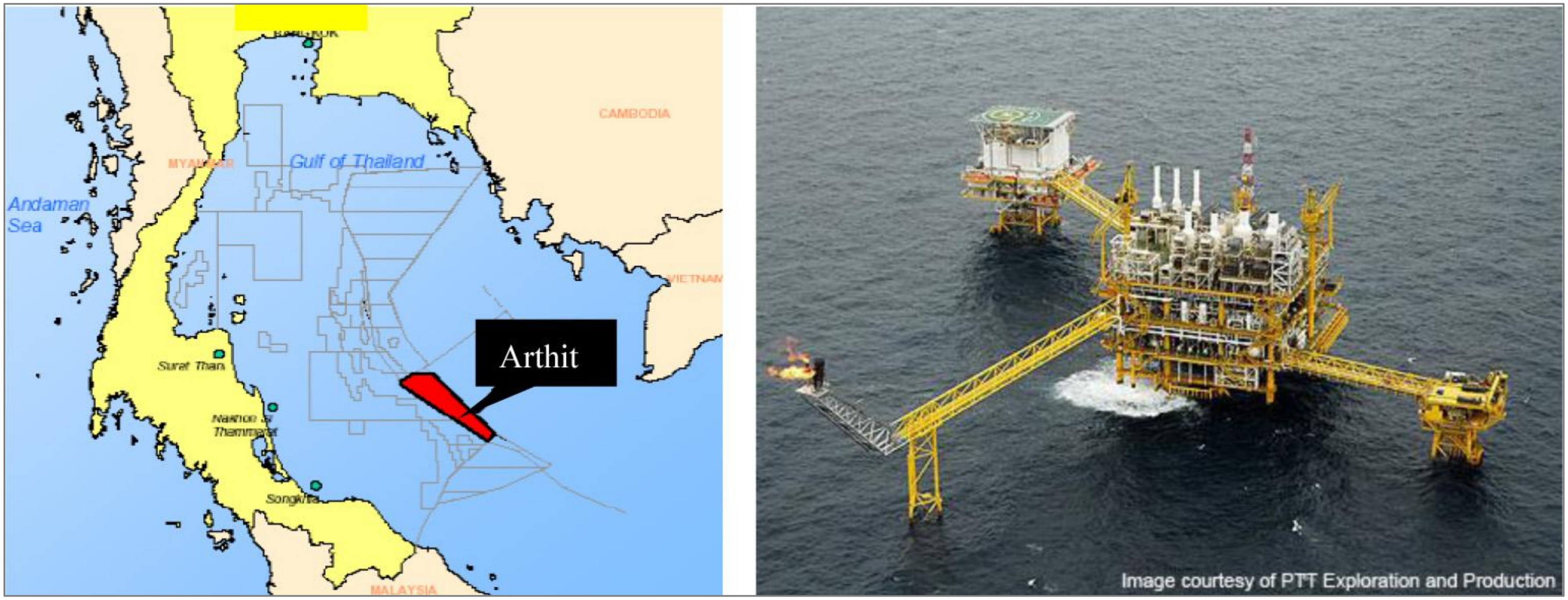

Figure 2. Arthit gas and condensate Field is located 230 km from Songkhla Province in the Gulf of Thailand.

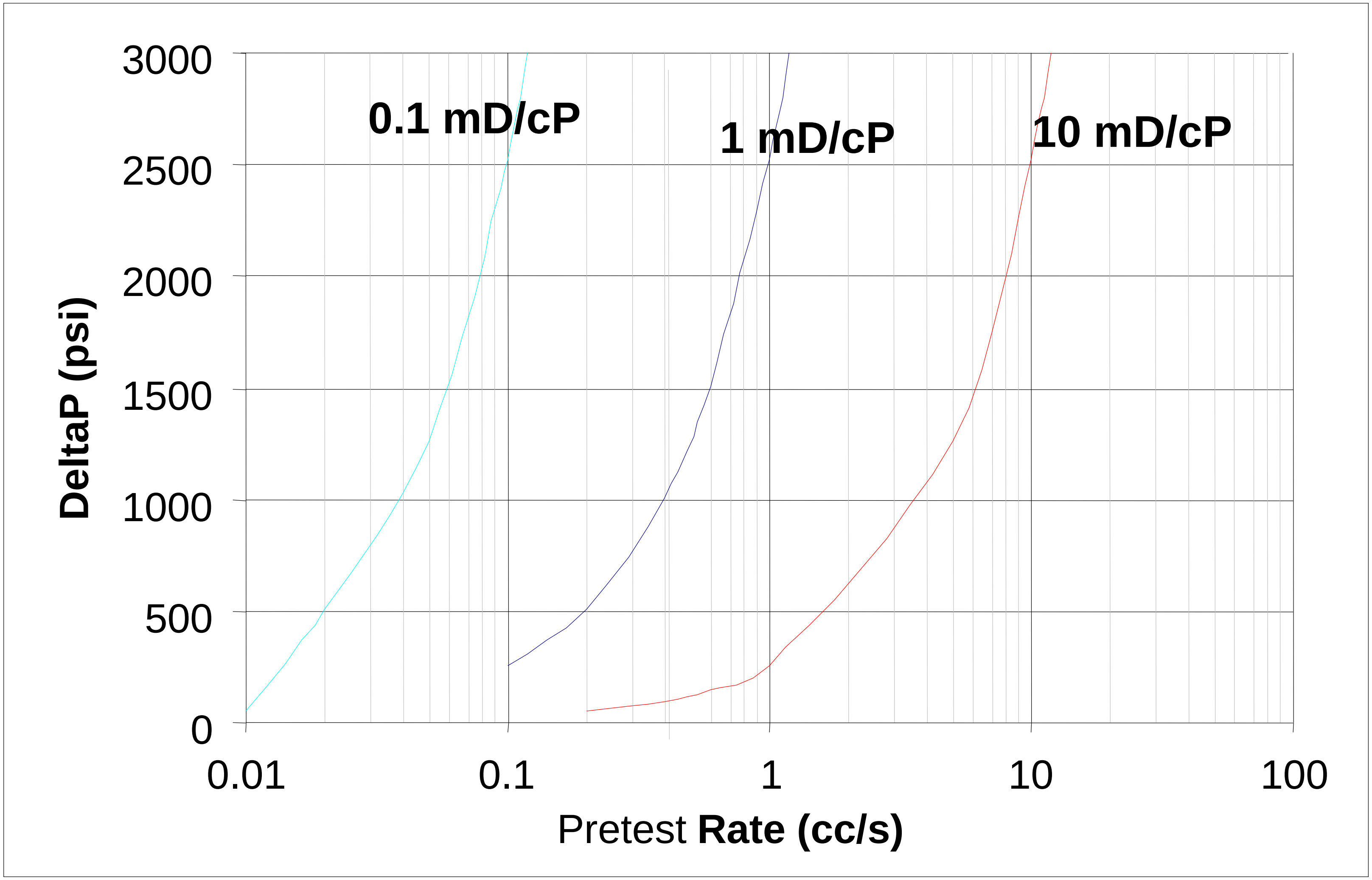

Figure 3. Relationship between pre-test rate and pressure drop for different ranges of zone mobility.

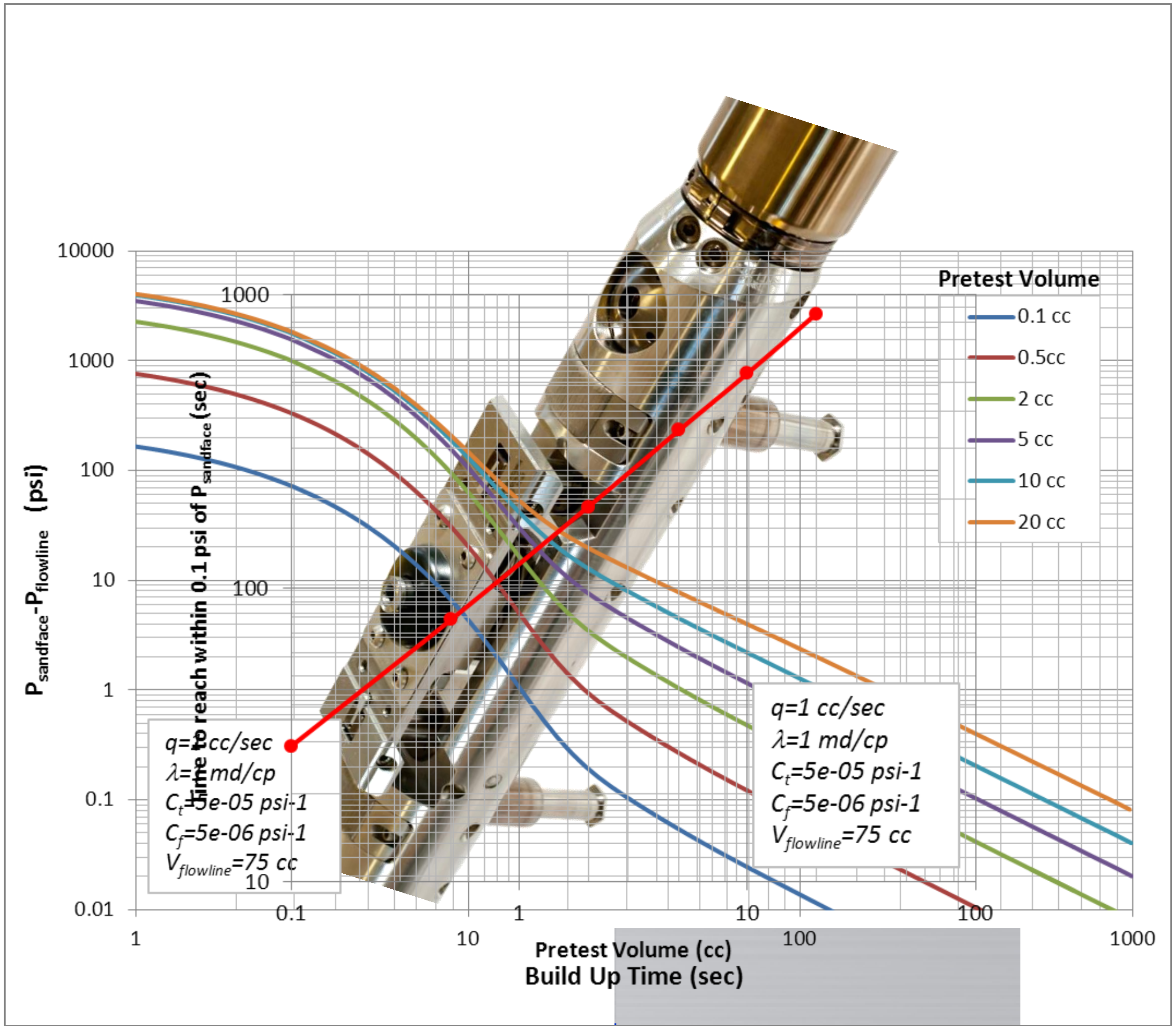

Figure 4. Relationship between build-up time, pre-test volume with delta P (sandface pressure to build-up pressure) (Manin et al., 2005).

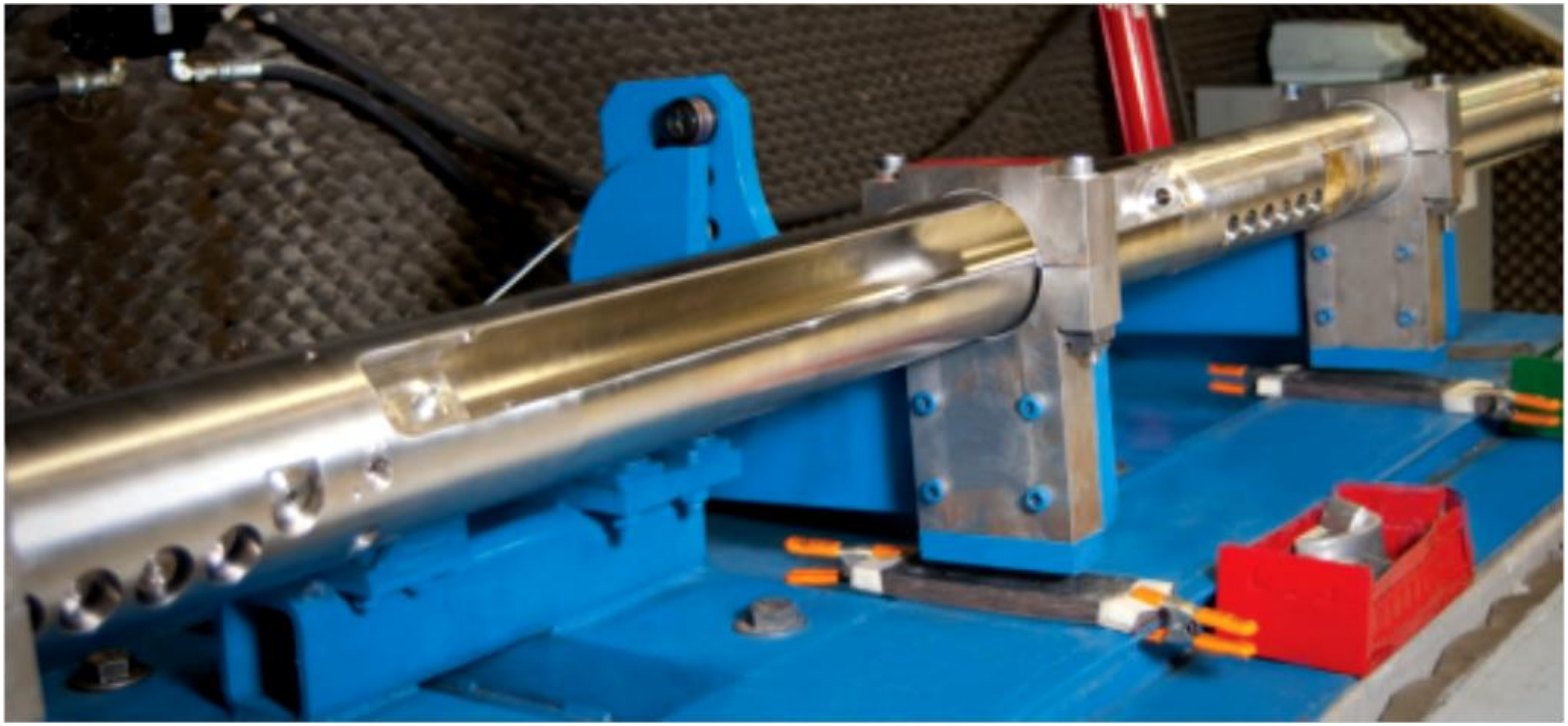

Figure 5. Shock testing of MDT-Forte platform is conducted at both ambient temperature and while heated.

Figure 6. MDT-Forte-HT modules are tested as temperature extremes including thermal cycling and aging and high-temperature life.

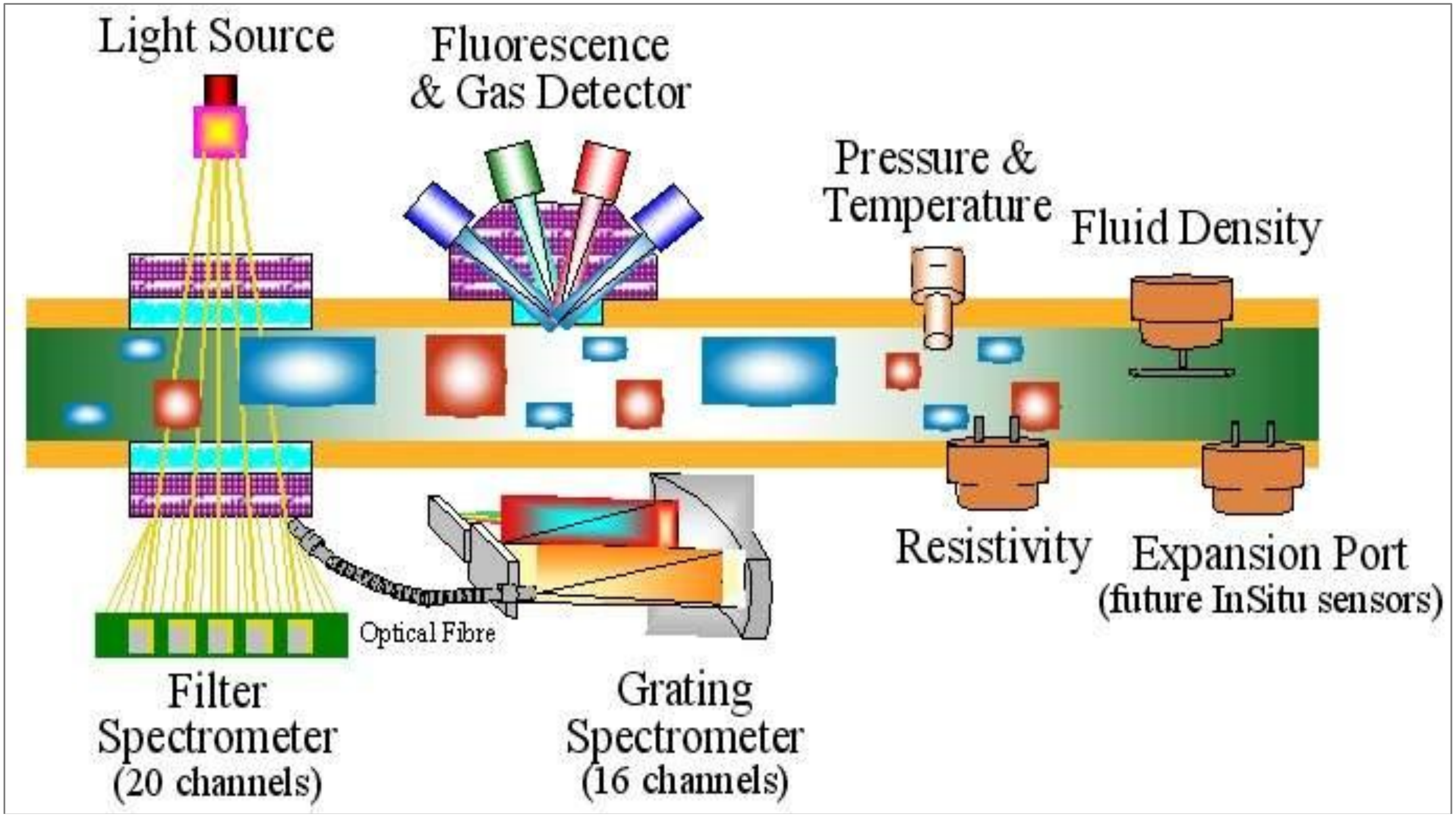

Figure 7. Schematic of the new DFA tool. This tool can provide accurate composition, including CO_2 and conclusive fluid identification from florescence, gas detector, density and viscosity.

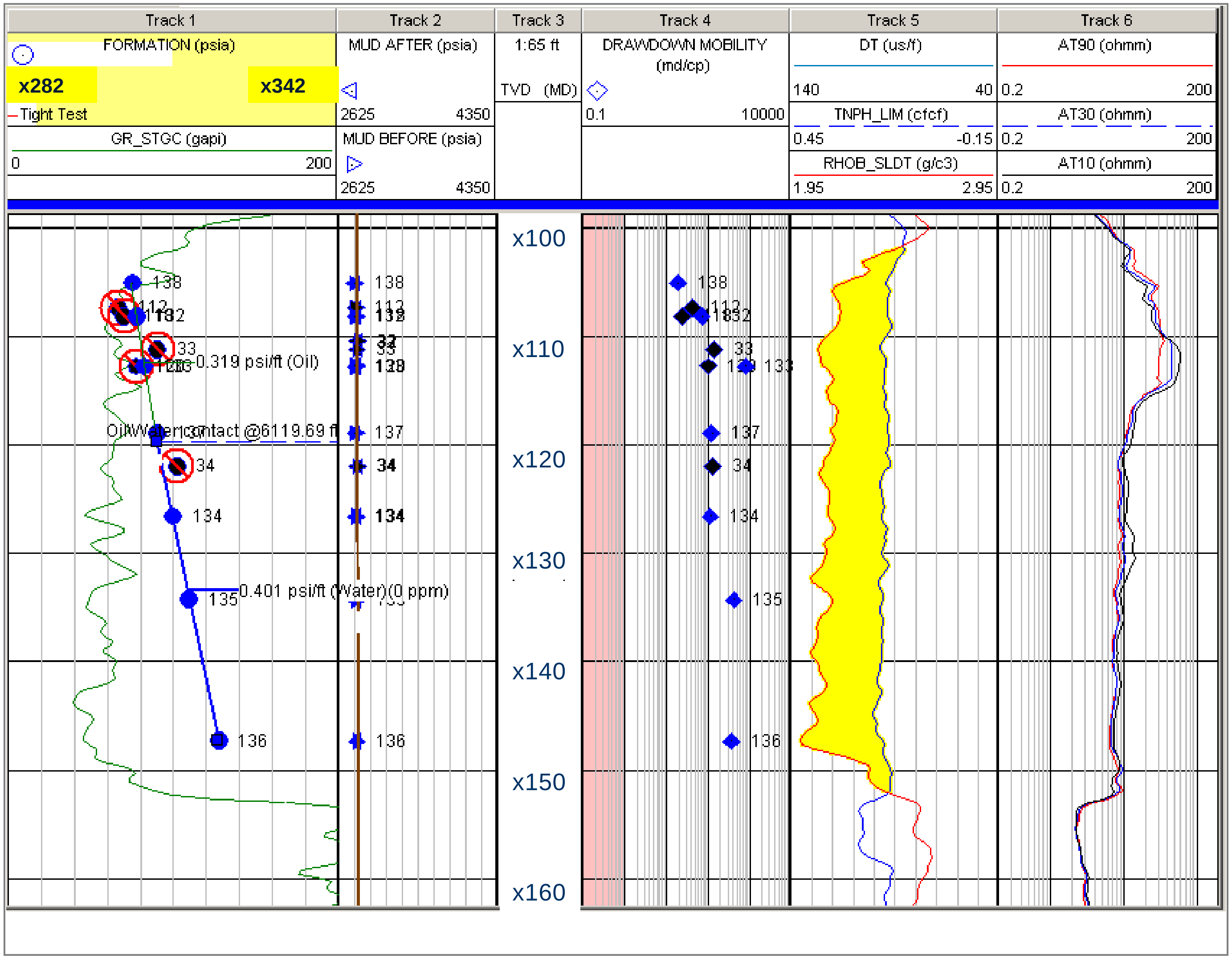

Figure 8. Direct comparison of the high temperature FT (blue dots) and the conventional FT (in red circle blue dot). Both tools were run in the same formation. The build-down was seen in the conventional FT, whereas the pressure data obtained from high temperature FT allows computation of oil and water gradients and the OWC in this formation.

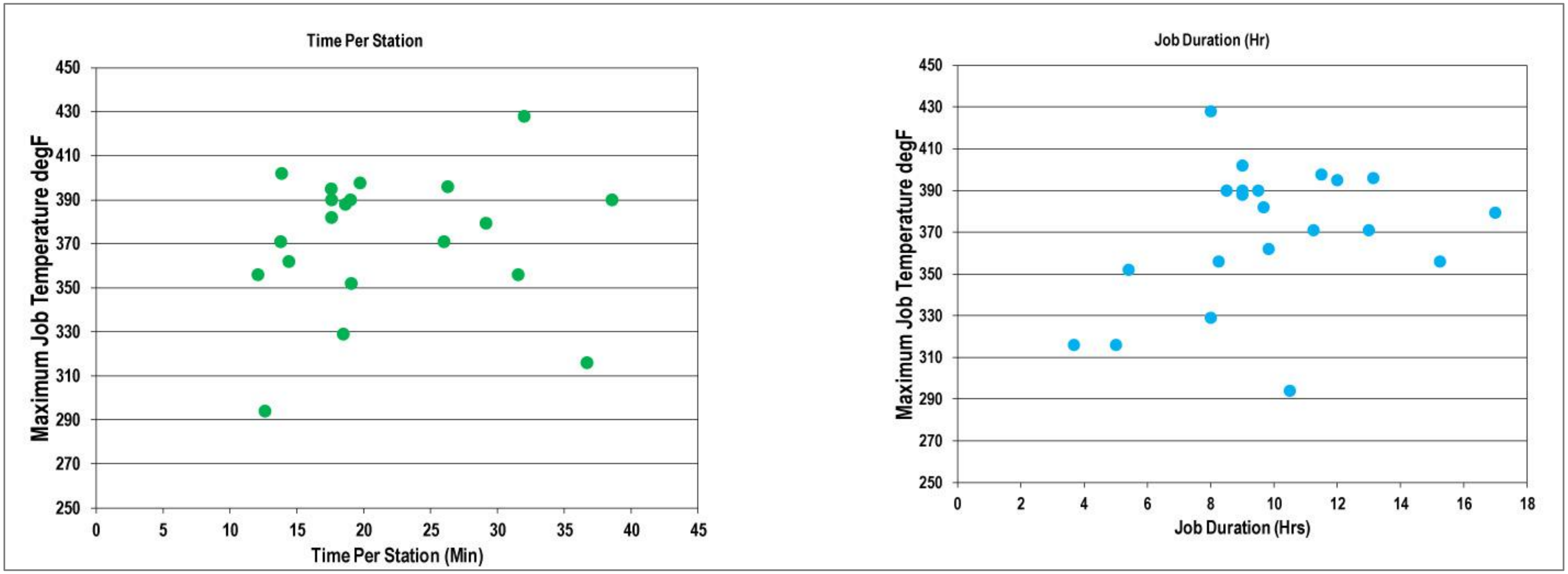

Figure 9. Operation records from Gulf of Thailand show average temperatures of around 400 deg F with maximum temperature reaching to 428 deg F. Average operation duration is 12 hrs. Average survey size is 35 points with an average pre-test duration of 20 minutes.

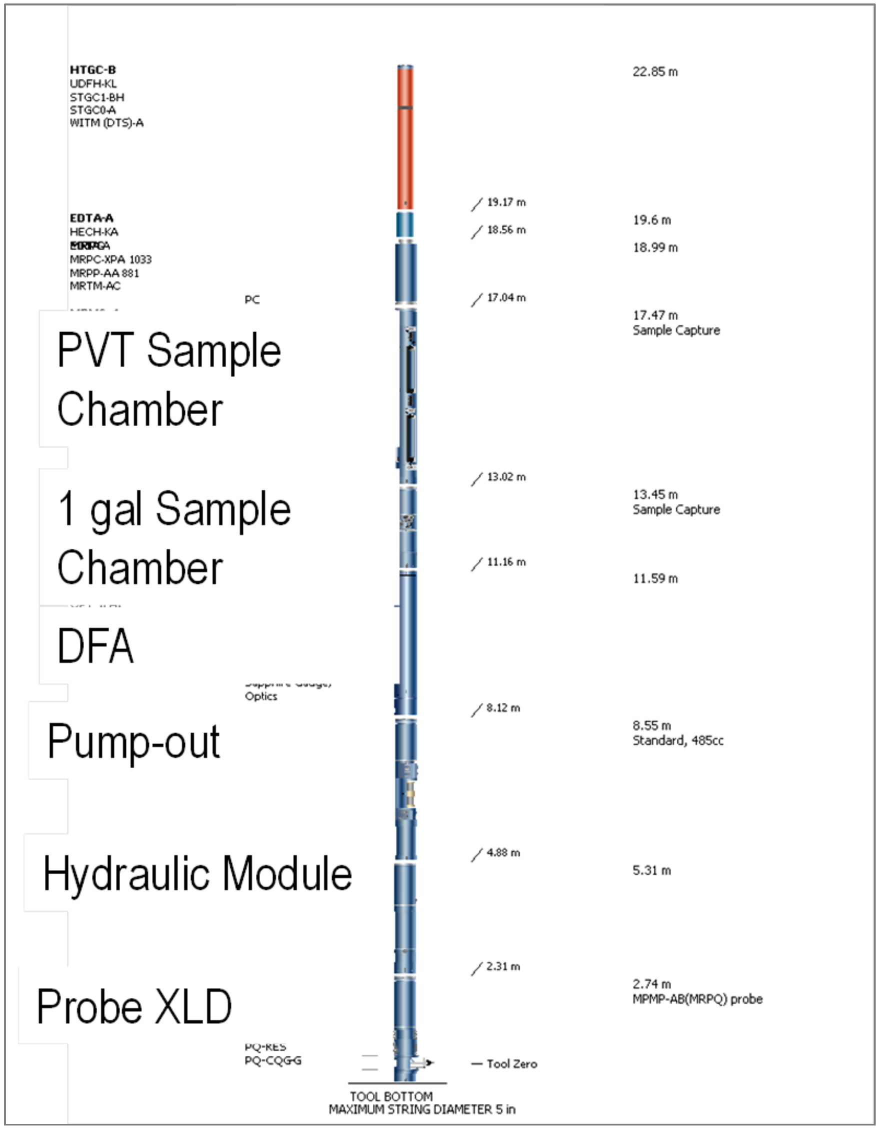

Figure 10. High Temperature MDT tool string used in the first job consists of single probe, pump-out, advanced DFA and sample chambers.

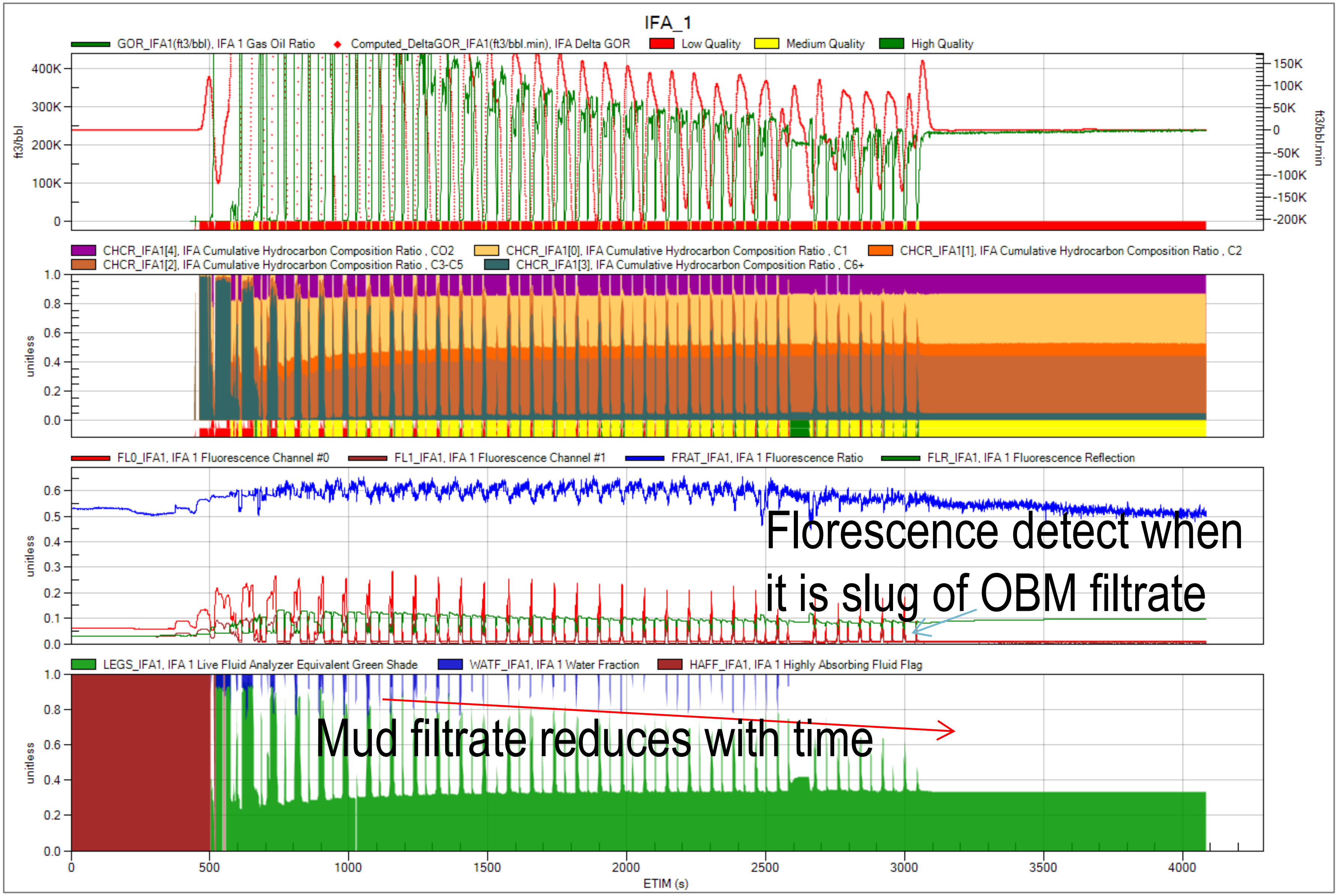

Figure 11. The DFA logs for one of the pump-out stations.

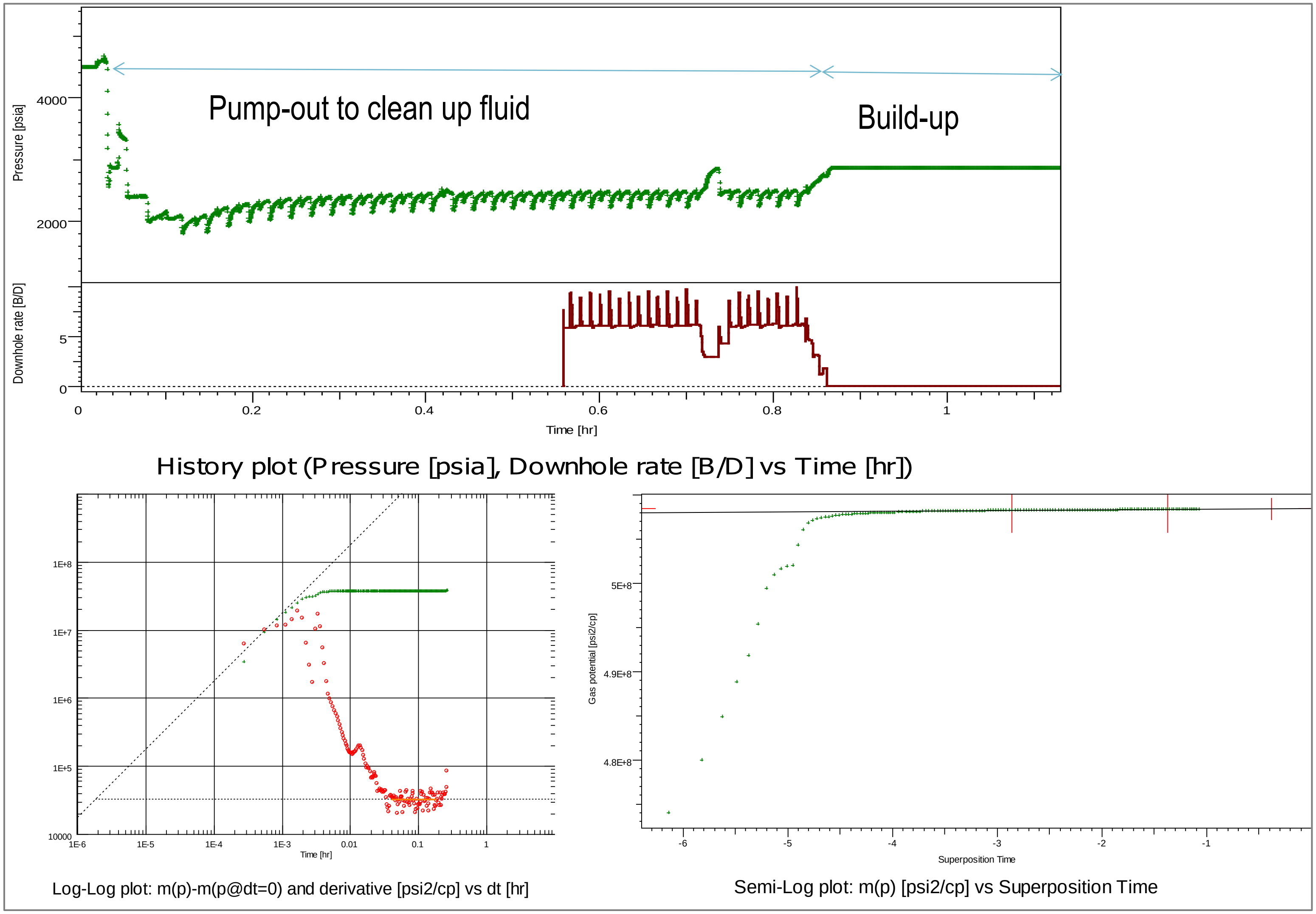

Figure 12. Pressure transient analysis for the build-up. This analysis provided zone permeability-thickness.

Figure 13. The probe resistivity shows the change in resistivity during gas pumping.

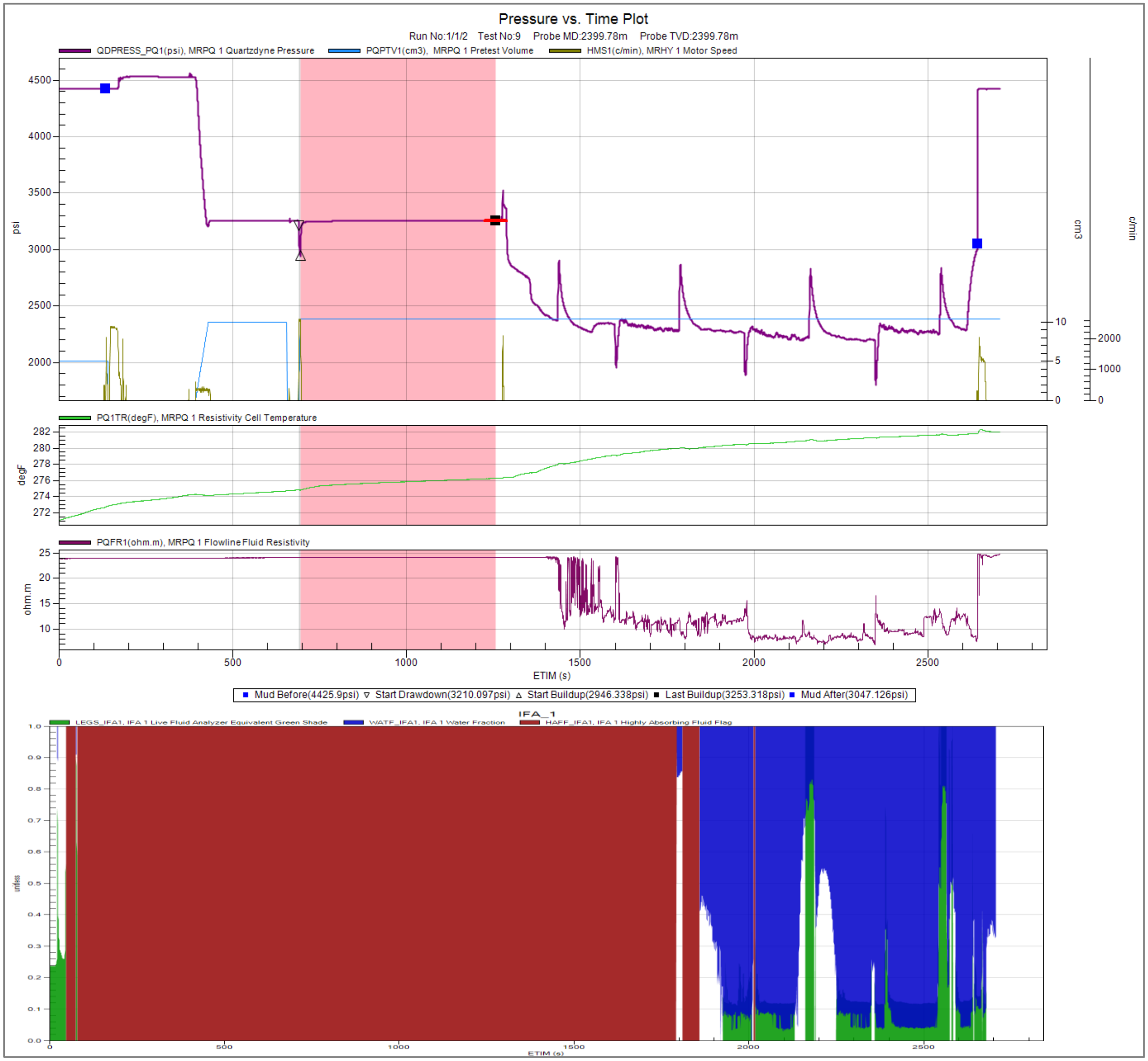

Figure 14. The probe resistivity when water is pumped. The decreasing resistivity trend is quite clear.

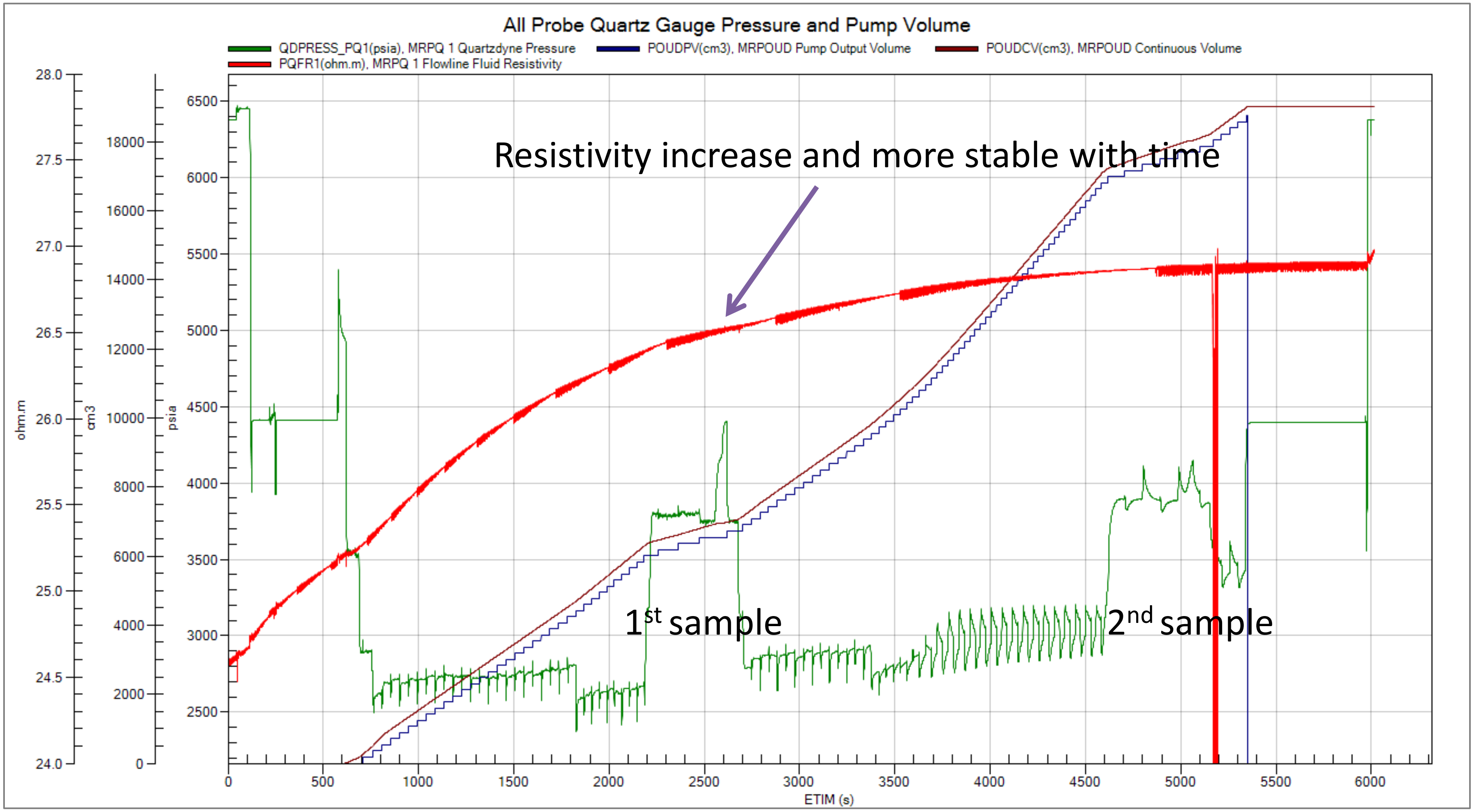

Figure 15. Station recorded with the high temperature WFT equipped only with resistivity cell to identify reservoir fluids. Resistivity increases with time and then stabilizes. This suggests formation gas. Two fluid samples were collected at different times. For this station, the time per station: 100 minutes, pump-out time: 79.7 min, and pump-out volume: 18.6 liters. The maximum temperature was 372 deg F. The mobility was in the range of less than 3 mD/cp.

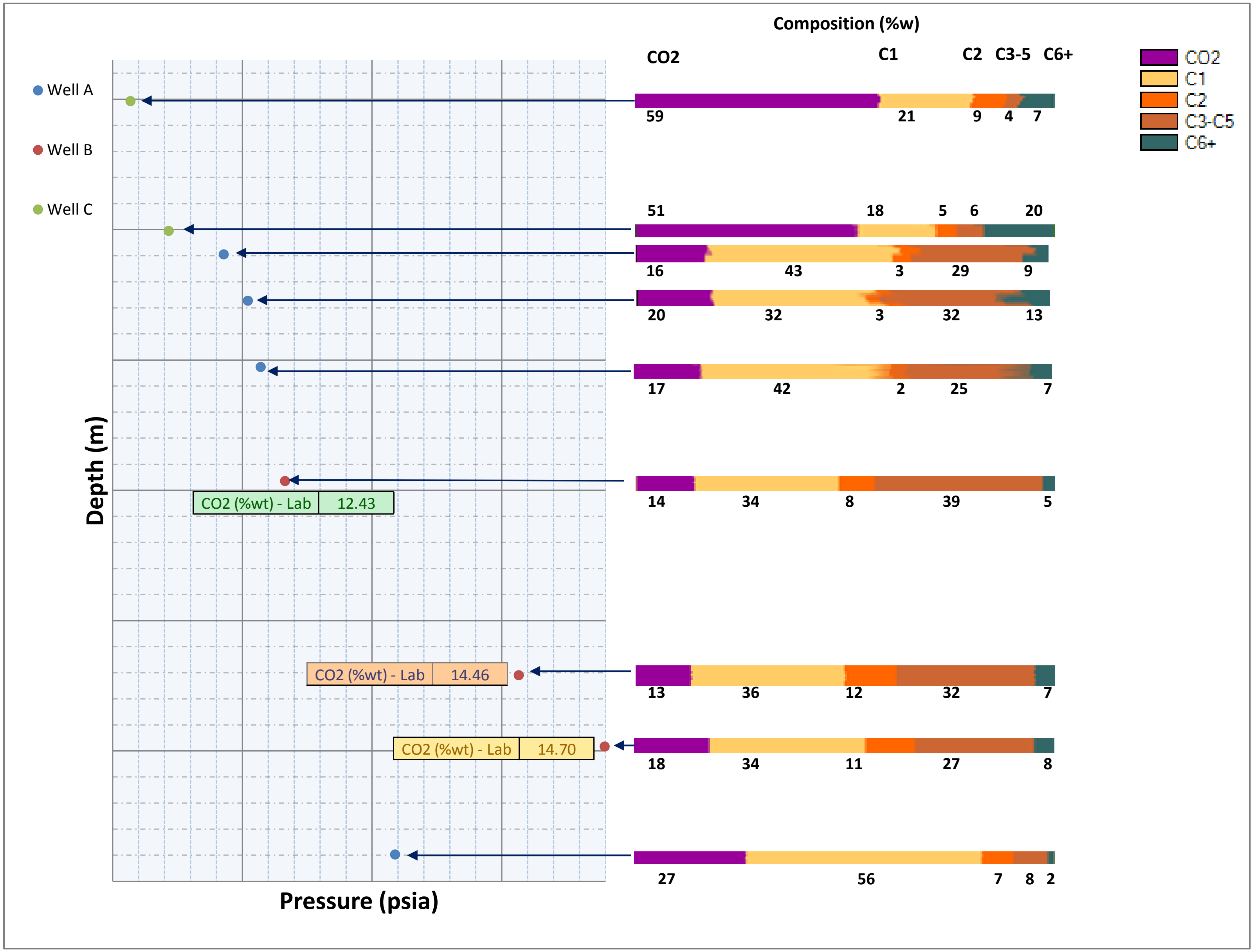

Figure 16. Example of the use of DFA data from three wells.

Job Objectives	Challenges in the GoT challenges	Overcome those challenges
(1) Obtain valid formation pressure	➢ Transient effects due to high temperature causes building down of pressure data, resulting with an inaccurate formation pressure	✓ Flasked gauge to isolate borehole temperature from the gauge temperature
	➢ Poor porosity and tight formation	✓ Design the new formation tester tools with low flowline storage to minimize the pre-test volume ✓ Use precise pre-test control mechanism to allow taking pretest with smaller rate and volume ✓ Rate and volume can be adjusted in real-time to match with formation deliverability ✓ Increase the flow area to minimize pressure drop across the packer
	➢ Extreme high temperature	✓ Design rugged electronics for harsh environments to, improve reliability and endurance ✓ Quantified and maximized operations confidence qualified for 100 hours of operations including HT Shock and vibration resistance
(2) Conclusive fluid identification	➢ Pressure gradient has limitations in low permeability environments	✓ Improved pump-out capability and downhole fluid analyzer to properly identify fluid types using optical density, fluorescence and gas detector
	➢ Identify near critical reservoir fluids such as gas condensate	✓ Able to identify mud filtrate from reservoir fluids such as gas, oil and water ✓ Differentiate between dry gas, gas condensate versus volatile oil using composition, GOR, fluorescence, density
	➢ High compartmentalization	✓ Fluid zone identification to appropriately plan for selective perforations
(3) Quantify fluid compositions, including CO_2 content	➢ Reservoir scale CO_2 variation	✓ CO_2 quantification for selective perforations
	➢ Dump chamber cannot provide accurate CO_2 in case of wet gas, gas condensate, and oil reservoirs	✓ Need to quantify CO2 in the reservoir fluid, not in the flashed gas
(4) Collecting fluid samples	➢ Mud filtrate contamination	✓ Need to be able to monitor filtrate clean up
	➢ Two phase flow during the pump-out	✓ Need to have enough pressure to decompress gas while at the same time can get rid of mud filtrate
	➢ In low to tight formations, slow pump rate is needed to match formation capability	✓ Slow pump speed is required for this environment
	➢ Different objectives for fluid sampling program	✓ Real time monitoring is a key to ensure that the objectives can be achieved in within reasonable time limits
(5) Determine reservoir potential for individual zone producibility information	➢ Identify flow and permeability range in poor porosity and tight formations	✓ Interval Pressure Transient Test (IPTT) for permeability-thickness evaluation after fluid sampling

Table 1. Summarizes WFT objectives, challenges in GoT and methods to overcome those challenges.

	File No	depth m-MD	Fluid I.D.	Mobility (mD/cp)	Permeability-thickness (mD.ft)	PO volume (liters)	PO Time (mins)	CO2 %wt with DFA	CO2%wt from PVT Lab
1st	37	xx92.97	Gas	6.5	26.7	31.5	48	14	13
2nd	41	xx42.04	Gas	61.44	166	50	57.5	13	15
3rd	45	xx96.71	Gas	2.07	6.86	25	42	18	15
4th	59	xx39.98	Water	1.5	N/A	12.3	78	-	-

Table 2. Information for 4 fluid stations with pump-out summary and pump-out time.