The Continuous Improvement of Formation Evaluation Data Assurance. A Case Study from Off-Shore Qatar.

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Abstract

Qatargas 3 and Qatargas 4 ventures are jointly developing their assigned project area of the North Field offshore Qatar, the world’s largest non-associated natural gas field. The area allocated to the joint development is a 15km by 20.5 km block and consists of 3 15-slot platforms, each with 11 wells drilled into the Khuff carbonate reservoir. Currently the Qatargas 3&4 block is in its late development phase where over 75% of its wells have been drilled, evaluated and completed. The formation evaluation is generally carried out using data acquired by wireline conveyed tools and a standard log acquisition program consist of two runs configured to record mainly resistivity, porosity, sonic and formation pressure data.

This extensive data acquisition program entails substantial operational challenges. Because of this, a clear understanding and management of human related factors such as communication, logistics and experience of personnel as well as technical challenges such as hole conditions (clean up), well trajectory, tool configuration, deployment methods and overbalance and risk management are critical to success.

This paper provides an overview of these challenges and the involved processes that drive continuous improvement. Improvement was achieved on multiple aspects of the logging program, such as efficiency increase and time optimization of over 65%, and data quality improvements. Practices commonly adhered to include pre-job planning or Log the Well On Paper exercises (LWOP), thorough follow up during execution, mandatory close out by all parties involved in regular service quality meetings, job debriefing with engineers and continuous review of standard operating procedures and best practices. Significant efforts were placed on logging tool conveyance and configuration selection which ultimately led to a decision tree being developed to accommodate the various options.

The processes developed by QG3&4 over the last three years could offer a ‘running start’ for new operators who target similar formations in the region.
Introduction

In December 2005, Qatargas3 (QG3) venture (68.5% QP, 30% ConocoPhillips and 1.5% Mitsui) finalized agreements with Qatargas4 (QG4) venture (70% QP and 30% Shell) to jointly develop the Project Area of the North Field assigned by Qatar Petroleum (QP). The agreements included joint subsurface development and construction of offshore and onshore facilities in order to capture the synergies for a 2-train LNG development. The two separate projects have a combined Joint Asset Development Team (JADT) - QG3&4 - which is staffed by secondees from Qatargas, ConocoPhillips and Shell, as well as third-party direct hires. Upon completion of the offshore development and onshore construction, the QG3&4 project will be operated by Qatargas Operating Company Limited, (OPCO), a company established with 30% Shell to jointly develop the Project Area of the North Field assigned by Qatar Petroleum (QP). The QG3&4 block is in its late development phase where over 75% of wells have been drilled, evaluated and completed. Formation evaluation is generally carried out using open hole data acquired with wireline conveyed tools. These data are not only used by QG3&4 to evaluate and model their area projects but also by QP in their field wide model. With multiple operators acquiring data across North Field, it is therefore essential that petrophysical answer products are consistent. To achieve this, the Logging Contractor was tasked with the interpretation of all data sets.

At present, the QG3&4 block is in its late development phase where over 75% of wells have been drilled, evaluated and completed. A standard log acquisition program comprises two runs configured to record mainly resistivity, porosity, sonic and formation pressure data. This extensive program can generate substantial challenges where clear understanding and management of human related factors such as communication, logistics and personnel experience are integral to success. When the technical challenges such as hole conditions (clean up), well trajectory, tool configuration, deployment method, overbalance and risk management are included, the complexity of the overall project is easily appreciated.

One team

“The success of QG3&4 project depends highly on the success of the contractors” said James Fielder, Drilling Manager. This quote summarizes the attitude of QG3&4 management right at the onset of the project in which creating a one team atmosphere, among all parties involved, would lead to continuous improvement in efficiency, service quality and cost reduction. In addition, building a strong team could also improve the communication challenge that naturally comes with the collage of different companies and contractors that bring with them different cultures and languages. Miscommunication between any parties could be potentially very costly.

At the very start, alignment between subsurface and drilling, and between QG3&4 upstream and their contractors, mainly the logging contractor, was identified as crucial in order to avoid any delays or setbacks to this mega project. In order to achieve this, an integrated subsurface and drilling approach was established very early in the project by creating Well Head Platform (WHP) teams with members from both ConocoPhillips and Shell. Team members met regularly to ensure that both sides were aligned regarding project objectives. This allowed the smooth execution of the data acquisition program while providing a degree of flexibility. Operational safety was always primary and paramount throughout the execution of this project.

The logging contractor was the main wire line contractor, and in order to ensure complete alignment with QG3&4 objectives, a significant focus was placed on creating a partnership between these entities. In order to achieve this, the following steps were taken:

• Relationships with the logging contractor personnel including their upper management were developed using the ‘Incident and Injury Free’ safety leadership program adopted by QG3&4 at the beginning of the project.

• Each service company associated with logging activities was included in the planning phase of the acquisition. All members of this composite team had an equal say in how the logging surveys should be conducted which proved exceptionally beneficial. By way of example, a series of seal failures during the pressure acquisitions was traced in part to mud chemistry. Had these joint meetings not taken place, resolution of the problem may not have been as timely.

QG3&4 also recognized and involved all the stakeholders associated with a specific activity regardless of which
company they represented. Daily face to face planning and feedback sessions, attendance at the daily morning rig calls, after action reviews, and regular visits to meet with the core team all contributed to a common understanding of both the project objectives and dynamic challenges.

The purpose of this paper is to highlight the importance of creating a single team from all players – major and minor – and in so doing how this dramatically improved efficiency and data quality, reduced cost and above all created a culture of respectful communication and problem solving within the project.

Technical Challenges

A significant contributor to the ability to log a deviated well efficiently is the condition of the well bore, especially if the program includes pressures or samples where hole rugosity and mud cake properties are of paramount importance. In the example cited here, two challenges regarding mud quality are highlighted, namely, the ability of the mud to form a competent mud cake, and secondly maintaining mud rheology to avoid ‘barite sag’. Both topics became ‘issues’ early in the log acquisition campaign when the project experienced an unacceptable frequency of seal failures during pressure testing together with a repeated inability to get the logs to TD. A review of mud property requirements highlighted the fact that they were probably too general in nature leading to an excessive variation in physical properties from batch to batch. With this identified, efforts were focused on tailoring a mud system with very consistent properties, and through laboratory experimentation a formula was developed which created a thin, tough, rubbery almost inner tube like mud cake. Mud properties were thus more defined with a much tighter acceptance tolerance, which was a key learning.

‘Sag’ can broadly be defined as the settling or stratification of any weighting compound in a drilling fluid which results in a density gradient, and operationally can have severe implications as the settled material does not form a discreet interface, but gradually thickens with depth. As logs descend into this region they can slow to a stop, and when retrieval attempts are made the viscous forces around the body of the tools can cause the wireline tension to dangerously approach that of the weak point in the cable head. As this campaign progressed it was realized that no single cause of the sag phenomenon could be identified, and therefore its resolution required a comprehensive re-assessment of the complete drilling process. Conclusions from these studies included:

- Barite sag can be managed effectively.
- Sag is always a potential in deviated wells no matter what weighting agent is used.
- No single mud parameter or test can predict the occurrence of sag.

- Mud parameters must be just greater than that required to overcome the tendencies for barite to sag, but not so thick as to impact ECD.
- Viscometer testing was inconclusive in predicting sag, but did raise an awareness which formed part of the daily drilling discussion.
- Small variances in mud properties can have a dramatic impact on ‘sag’ or ‘no sag’, meaning that strict guidelines for consistent mud mixes must be followed.
- Daily treatments of fresh pH bentonite are essential for building a good ‘gel’ structure.

Broadly connected to the ability of drilling mud to form a competent mud cake and the issue of barite sag is the topic of getting the logs physically stuck in the well bore. This excludes problems of getting ‘hung up’ on ledges which simply stops the logs moving deeper, but primarily includes problems such as differential sticking (DS). More specifically, the problem of DS was associated more with those logs requiring stationery measurements such as pressures/liquid samples rather than those recorded with the cable in motion.

Early on in the acquisition it was noted that even low permeability zones could be DS sites and therefore a series of tests was developed in an effort to predict when this may occur. Termed ‘Stickiness Tests’, this involved setting the wire line conveyed PressureXpress (XPT) probe against the formation for limited times, withdrawing the probe and then noting the tension required to release the tool. Erring on the side of caution, the first test would use a contact time of only 1 minute, and then increase in stages to as much as 15 minutes. Note that at the early stages of the project no pre-tests were performed during the stickiness tests. This would change later as it will be explained in the example section. Although quite basic in nature, these ‘stickiness tests’ were exceptionally informative and on several occasions caused a dramatic revision of the pressure testing program.

Although less dramatic that the stationery stickiness tests, the tension curve observed on the wireline while running in the hole was potentially also indicative of differential sticking. Any jagged signature – in a smooth borehole - suggested the tools were being pulled into the formation, and thus signaled the need for extra caution in that region.

Also associated with getting tools stuck requires moving back to the topic of barite sag. Being aware of this phenomenon caused increased awareness of the wire line tension whilst tools were running in the hole especially as they neared TD. On several occasions as the logs approached 300-400ft before TD, engineers would notice a dramatic decrease in wire line tension strongly suggesting that barite sag was present and that attempts to reach full TD could jeopardize the log acquisition. Such conditions ultimately led to a review of the logging program and a unanimous decision for curtailment.
Even with an increased awareness of all the challenges associated with logging these development wells, probably the most rewarding solution came from optimization of the logging runs. Intuitively, acquiring all logs during a single run would seem the most efficient, and indeed this was tried early on in the campaign. However, after multiple attempts failed to get the logs to TD because of rugous borehole, the team realized that splitting the logs into two runs was even more efficient when lost time for failed descents was included. A chronology of events based on experience is shown below.

- Two runs:  
  - (Run 1) GR– Density– Neutron– Resistivity– Sonic– Formation Images  
  - (Run 2) GR – Inclinometer– Formation Tester

Moving to two runs had the benefit of a stiffer logging assembly and an increased ability to move across even severe washouts. If Run 1 logs still failed to reach TD, knuckle joints would be removed to further increase rigidity, with even more dramatic consideration of reducing the length of the sonic tool (full sonic tool > ½ basic sonic tool), with acceptance that this would not allow acquisition of the Stoneley waves. Migrating to this conveyance strategy saw a dramatic increase in successful logging jobs reaching TD. This section would be incomplete without mention of the ‘rollers’ that were manufactured by a 3rd party vendor. These devices comprised four pairs of protruding metal rollers encased in a steel body, with the primary function of reducing the frictional drag between the main tool string and the side of the borehole. These were used successfully in a well with ~ 60Deg. deviation, although admittedly it is difficult to assess the contribution of these devices to the successful descent.

Strongly connected with the ability of the logs to reach TD were the efforts afforded by the drillers to provide a smooth and clean borehole, especially over the Sudair formation. After a learning curve, this was achieved by:

- Reducing as much as possible incidences of ‘sliding’ which reduced hole cleaning efficiency.
  - On several occasions, debris in the borehole were pushed down by the logging tools and formed a plug. This ‘plug’ could only be drilled out.
- When pulling out of hole, minimizing the pump rates as low as possible without creating an underbalance when moving across the Sudair formation.
  - The scouring effect of the fluids from the drill bit nozzle caused the Sudair to cave in, creating a severe washout and contributing to the ‘plug’ formation mentioned previously. Often logs could also not traverse the Sudair washout.
- Reducing as much as possible the time between logging the formation and the final pass of the bit assembly primarily over the Sudair.
  - Historically, it was found that the longer the Sudair formation was left open prior to logging, the greater the chances were that this formation would start to cave in. Results were increased rugosity across the Sudair and a much greater chance of debris forming a plug during the descent of the logs.

Solutions and continuous improvement

A main contributor to the success of data acquisition on this QG3&4 project was the meticulous job planning. The initial planning depended on three main factors:

- Acquisition of all required data
- Well trajectory
- Expected well conditions and challenges

The logging program determined the logging equipment to be run, and the well trajectory influenced drastically the design of the tool string combinations. Further, a good understanding of drilling challenges such as Sudair and potential unconsolidated formation, differential pressures, mud properties, losses, and wells with anticipated problems allowed the team to plan for success, predict difficulties and prepare contingencies.

The priority was always to acquire the data in the open hole. The second priority was to maximize efficiency by adopting cable conveyance and minimizing the number of runs as much as practicable. This would not only have an impact on logging time - and therefore cost -, but also on reducing the operational risks by keeping the well open for the shortest possible time.

During job planning, combinability of logging equipment was determined based on:
1. Technical limitations (combinability in general)
2. Effect of equipment combination on data quality (e.g. nuclear tools and tool positioning in the borehole)
3. Tool string weight and additional drag
4. Risk Evaluation of combining tools (nuclear tools with stationary logging tools)
5. Conveyance challenges (highly deviated wells and high differential pressures)
Another useful tool that helped designing the optimal toolstring was a tension and conveyance simulation software supplied by the wire line contractor. This software uses well trajectory and several other parameters to estimate the tensions along the cable and at the tool string head while tripping in the hole and during logging up. The drag induced by the centralizers, calipers and other stand-offs was also accounted for. In addition to the optimal toolstring configuration, this simulation leads to several critical decisions viz.:  
- Conveyance mode (Wireline vs. Drill pipe TLC)  
- Choice of cable and weak-points strengths  
- Addition of conveyance accessories (rollers, bottom hole rollers, Teflon standoffs, Teflon Ball’).  

During the logging operation, engineers updated the tension model with actual tension values measured during the trip in and out of the borehole. This permitted a fine tuning of the model and the ability to determine the actual cased hole and open hole friction coefficients as a function of well trajectory, promoting a continuous improvement in the job design process.

In addition to the tension modeling, a 'Stickiness Factor' software was used to determine the risk of differential sticking, especially during the stationary acquisition of formation pressures. These data proved invaluable when considering issues such as:  
- Conveyance method (Wireline vs. Drill pipe)  
- Maximum station time  
- Risk of combining fragile equipments such as sonic tools or tools with radioactive sources such as nuclear tools with station logging tools in order to minimize damage risk in case of fishing operations or impact of leaving tools with radioactive source in the borehole in case fishing operations are unsuccessful.

Another key success factor was the availability of real-time data transmission channels as the job was being executed. This allowed the Logging Contractor’s domain experts and QG3&4 to check the quality of the data and make real-time decisions during the acquisition from their offices. This real time facility was particularly useful during formation pressure testing in supporting field engineers.

The job design procedures and the outcome of several logging operations lead to a continuous learning and improvement of the logging operation. Local SOP were defined and continuously updated in order to capture experiences, and ensure consistency in service delivery independent of the contractor team executing the job. Best Practices were defined and documented in the Logging Contractor’s worldwide knowledge data base and by QG3&4.

After review and mutual agreement on the job design, the final logging program is issued by QG3&4 and distributed to all involved parties both onshore and offshore well before the job. Comments and feedback were then received and reviewed then integrated into the plan when adequate. At the final preparation stage a ‘Log the Well On Paper meeting (LWOP) was organized in town and attended by all individuals involved in the job to ensure that everyone understand the logging program and deliverables and appreciate the challenges. Further, responsibilities and communication flow charts were developed to ensure proper readiness for real-time interpretation and contingencies. This meeting encouraged an open discussion about any recommendation or concern any team member has.

Once an operation was concluded, an After Action Review (AAR) was organized to analyze both successes and failures. This forum was critical to promoting continuous improvement and development of improved procedures to be employed in the next operation.

Internally, the contractor followed a strict process of job briefings and debriefings where the Field Service Manager (FSM) and other domain experts met with the field crew in order to review all steps of the job execution. These meetings were documented and the process updated when necessary to reflect new challenges and findings. Technical alerts and recognition programs were also put in place and contributed greatly to knowledge sharing and the promotion of excellence.

Regular Service Quality Meetings (SQM’s) were also organized on quarterly basis to review results and performance trends of the contractor. This enabled the assessment of the overall performance in general terms instead of well specific operations.

Further, new technologies were always reviewed as they became available and assessed in terms of potential added value to the project. In particular, conveyance solutions such as the advent of ‘rollers’ were examined and their ability to address specific challenges was assessed. Drilling Department and Field Operations supervisors were involved in these new technology presentations.

Example. Formation Pressure Testing

In addition to the acquisition of open hole wireline logs for all 33 development wells, formation pressures were mandated to be taken in all wells to monitor individual reservoir depletion.

While the job effectiveness was good from the start of the development drilling campaign, the data acquisition efficiency improved significantly during the course of the program. There are four main factors determining the pressure data acquisition efficiency:

1. Conveyance method selected  
2. Seal success rate  
3. Time to obtain a reliable pressure reading
4. Time to move in between pressure points

The time in between pressure points depends on two factors: conveyance method and pressure acquisition tool. The figure below gives an overview of the various combinations and their strengths:

Figure 2: Tool and deployment platforms tested

QG3&4 used and learned from all three conveyance methods to acquire open hole formation pressures. LWD and TLC have only been used in a few cases on exception basis driven by operational circumstances. While both conveyance methods increase the operational time in excess of two folds compared to wireline, they are indicated when there is a risk of fluid losses or high differential sticking.

As observed in the early stages of the project, the main factors influencing stickiness tendencies while pressure testing are: overbalance, mud rheology, formation permeability, hole rugosity, hole deviation, surface area in contact with the formation, tool weight and contact area as well as stationary time. For the typical QG3&4 deviated wells with deviation angles of 45-50 degrees over the survey section, and overbalance up to 900psi is a significant operational risk factor.

Unfortunately, differential sticking events happened twice during the pressure acquisition campaign, incidentally within 24 hours but on two different rigs. In both cases, the stuck wireline tools were successfully retrieved in a standard fishing operation. As these events happened early in the development campaign QG3&4 benefited from their rigorous analysis, resulting in the implementation of some procedural changes.

After analyzing the root causes of the stuck tool incidents and weighting the options available, QG3&4 decided to continue using wireline conveyed pressure testing tools (XPT) as the default, but to be very cautious in the operation. The following three steps were implemented:

1. Avoid testing zones which show tool stickiness during first wireline runs

2. If logs indicate high permeable zones but no sticking tendencies were observed during conventional logging, progressively test the stickiness by keeping the tool stationary for 1, 3 and 5 minutes. The tool head tension required to move the tool was used to assess the zone. Generally tensions below 750 lbs measured at tool’s head tension device are acceptable.

3. Change the tool configuration such that the pressure probe is always facing upward

While the first two operational changes are intuitive and easy to implement, the concept and rationale to orient a wireline conveyed tool is not obvious and explained below.

As pressure testing tools are deployed on wireline, there is always the uncertainty of probe orientation if an inclinometry tool is not deployed. In deviated holes, unless some orienting device is used, the tool’s probe could be set in any orientation including the low side of the hole where thicker mud cake and drilling debris make pressure testing difficult. QG3&4 together with the Logging Contractor inferred that tool orientation could result in repeated number of lost seals. Sometimes this lost seal events were correlated with high over-pull despite wells being relatively in-gauge with low rugosity.

The use of the LWD deployed pressure tester (Stethoscope) in one well shed some light to the identification and understanding of the impact in data quality and acquisition efficiency of the preferential probe orientation. The inclinometry survey available by default in the LWD string plus the ability to rotate the drillpipe allowed the positioning of the tool’s probing device towards the high side of the hole every time a pressure test was attempted. The observed result was 100% success in terms of sealing ability. This compares very favorably to an earlier use of the Stethoscope, where less than 50% of pressure points showed a good seal with the formation. Especially the non-sealing attempts had sideway orientation.

Lessons learned from this LWD run were then transferred to the wireline arena by adding an orienting device in the string that forces the probe to face upwards all the time. Although several orienting devices were discussed, the density-neutron-resistivity quad-combo tool was used for its convenience and reliability. The configuration works using the design features of this tool in which the heavy litho density pad is located opposite to the XPT probe. This allows the heavy pad to preferably seat in the low side of the hole while forcing the pressure tester probe in the opposite direction. Important to note is that the radioactive source used for the litho density measurements is removed from the tool for the pressure testing run. For the initial trial, the toolstring was fitted with an inclinometry tool to confirm the probe’s orientation at every point. A simplified sketch of the toolstring is shown in the figure below.
Results from this trial test were deemed as very successful by the team. Overall, probe was repeatedly oriented to the high side of the hole +/- 12 deg and 100% sealing success was achieved. This configuration was used subsequently in other wells where similar results were seen consistently.

A further piece of information related to differential stickiness risk evaluation was also gathered with the subsequent use of this configuration. As mentioned earlier, stickiness tests of different duration were performed in selected intervals to predict over-pulls after pressure testing. These tests were often done without setting the probe allowing the entire tool string to “sink” in the relatively thicker mud cake on the low side of the borehole. As a result, high over pulls were observed and decisions to abort tests at given depths were taken based on these observations. With the above new configuration a different pattern emerged. Even when some high tensions were reported during the stickiness tests, considerably less over-pulls were observed after testing. The is attributed to the fact that the setting pistons of the PressureExpress lift the entire string up while pressure testing avoiding the contact with the thicker mud cake at the low side of the hole (see figure 3). Once the test is complete, the tool is retracted and gravity helps to “detach” the string from the high side.

These new approaches resulted in a considerable reduction of pressure testing time of about 6-8 hours per job and a significant reduction in the risk of getting the tool string stuck.

**Conclusions**

Conclusions and lessons learned from this project can be summarized as follows:

a) Seamless teamwork between all disciplines is essential.
b) Relationship building is integral to achieving project success.
c) Concise and timely communication between team members is critical.
d) Regular inter-discipline meetings highlight problems and allow for contingency planning.
e) LWOP / DWOP / Pre-spud meetings are valuable aids to understanding project challenges and creating a forum for inter-disciplinary problem solving.
f) All team members must be flexible.
g) There must be ‘One Team’.

The working model described in this paper could offer a ‘running start’ for new operators who target similar formations in the region.

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