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2009 – Issue 10

Saudi Arabia oil & gas

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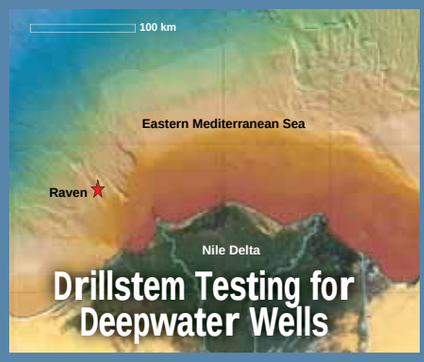
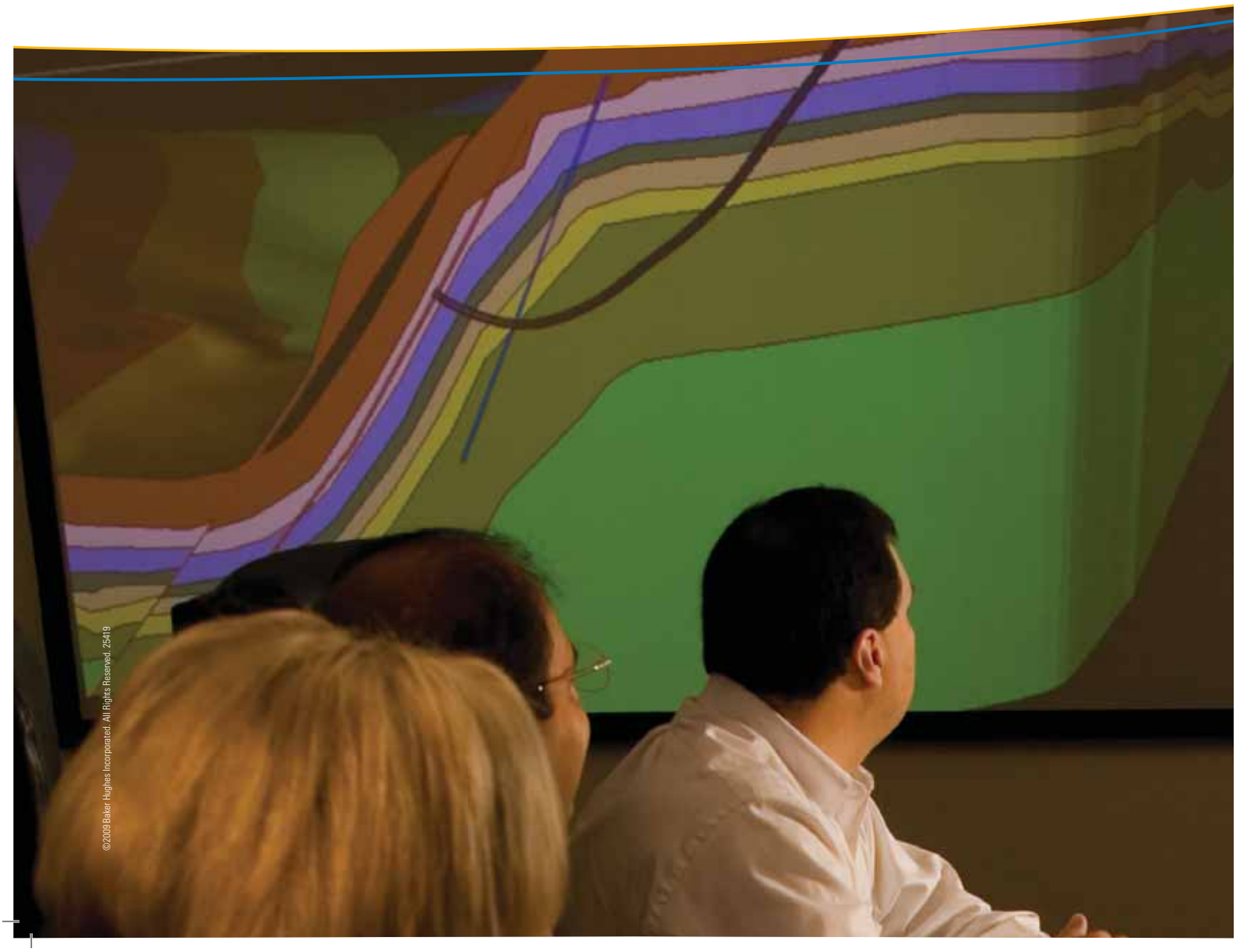
Inside



Technology and Expertise to Create More Value from Your Reservoir



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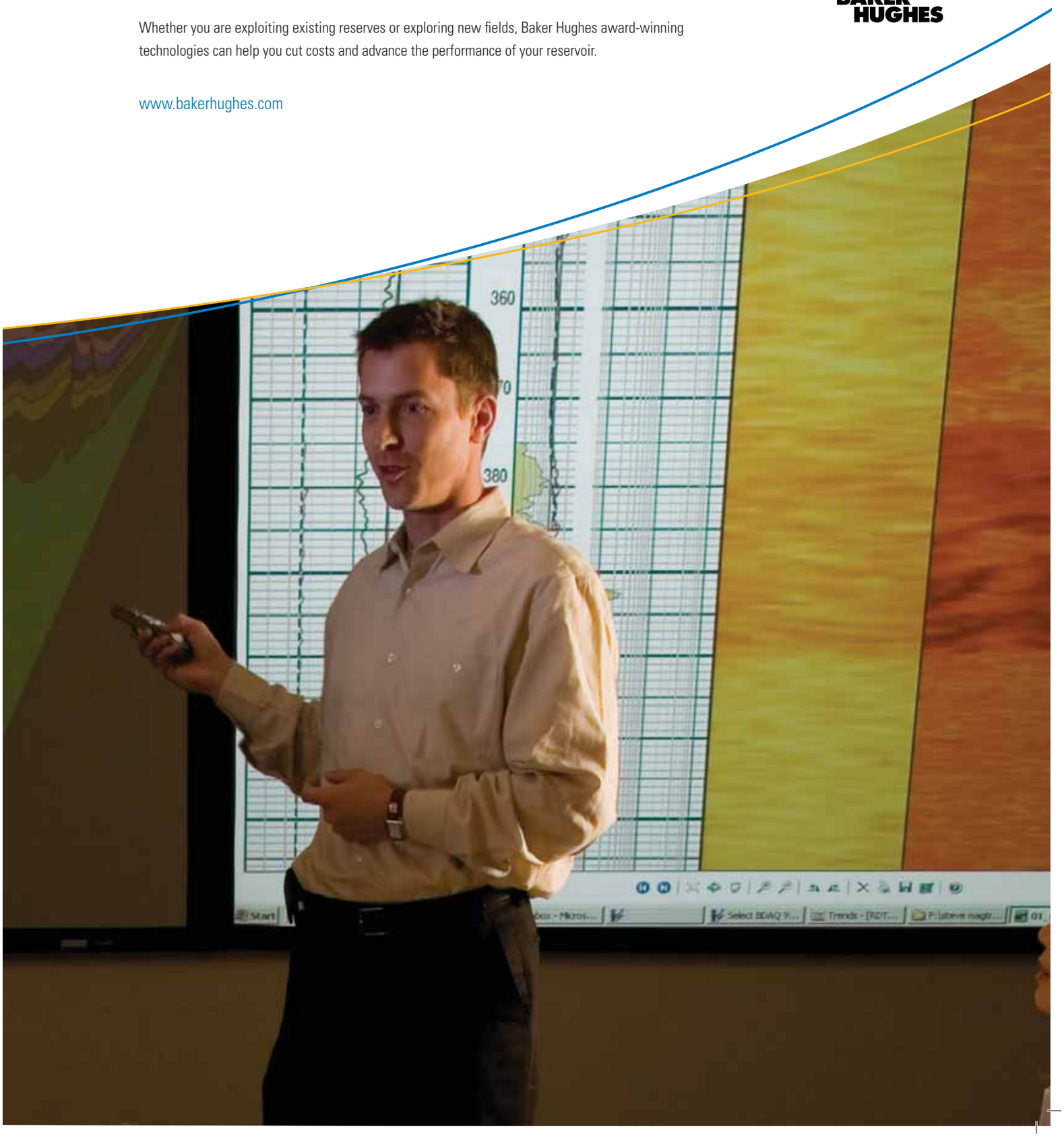

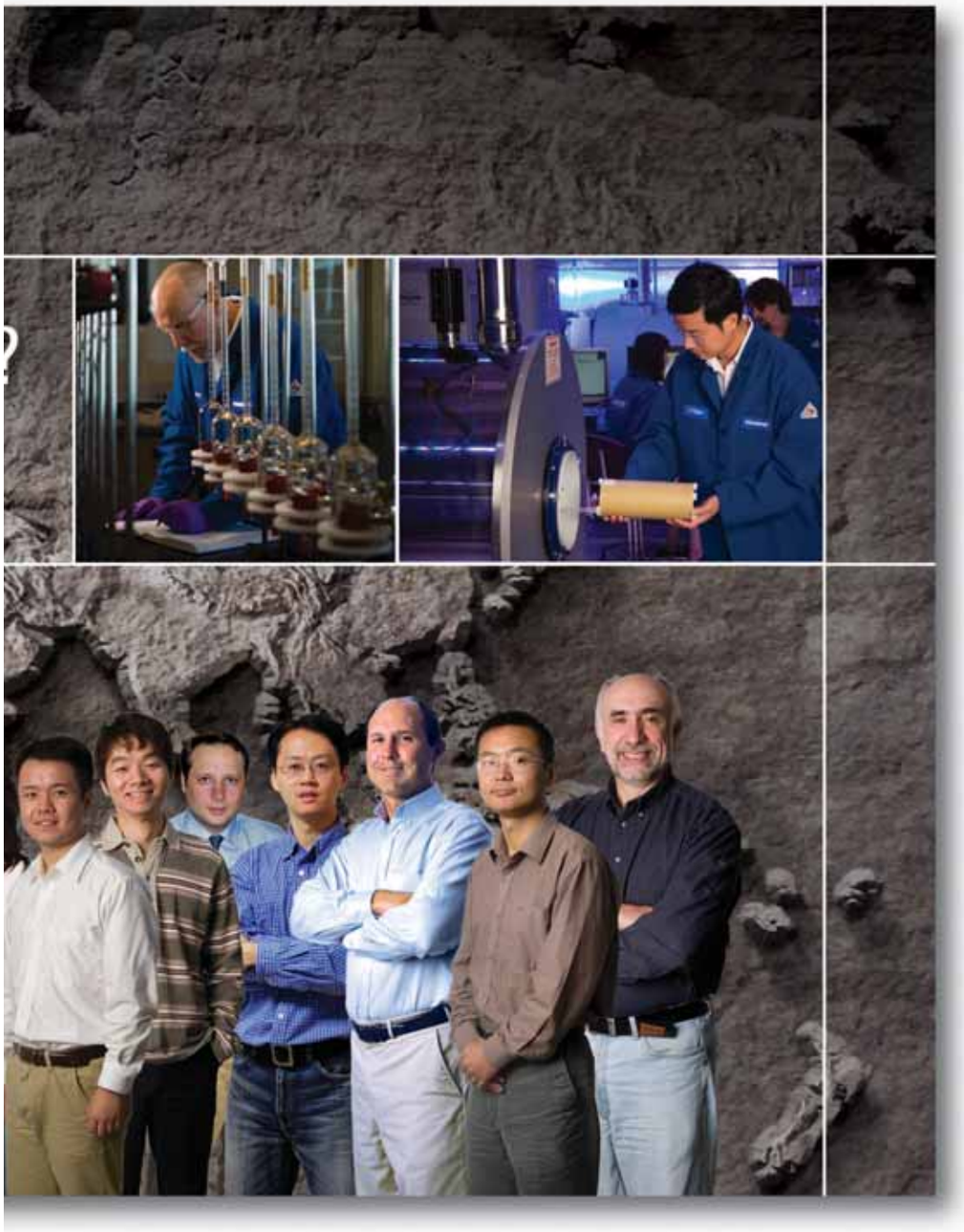

Carbonate Advisor

Schlumberger

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Saudi Arabia oil & gas

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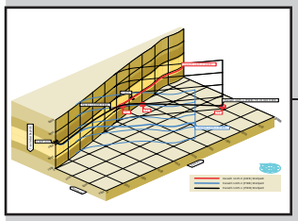

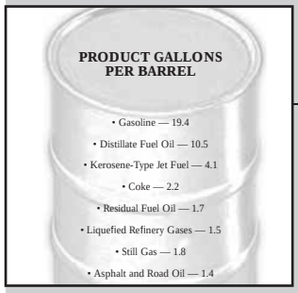

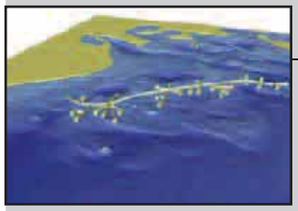

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NOTE FROM THE CONFERENCE CHAIRMAN

Welcome to Issue 10 of Saudi Arabia Oil & Gas and the 2009 SPE Saudi Arabia Technical Symposium and Exhibition

On behalf of the Society of Petroleum Engineers Saudi Arabia Section, it gives me great pleasure to welcome you to the 2009 SPE Technical Symposium and Exhibition and Issue 10 of Saudi Arabia Oil & Gas Magazine. We are aiming for the technical symposium to be one of the most important events in Saudi Arabia's petroleum sector.

The Program Committee has worked hard to bring you an exceptional Technical Symposium under the special theme "Pushing the Technology Envelope for Higher Recovery". The theme was carefully selected to promote the development and deployment of new technologies for enhanced and cost-effective discovery and recovery of hydrocarbon reserves. This correlates well with the current situation, where higher levels of operational efficiencies are more than ever needed to reduce overall field development and production costs by deploying latest technologies.

The program offers 15 technical sessions with recognized keynote and invited speakers, technical presentations and posters, and special technical sessions. The special feature of this year's event is the exhibition that has been planned for the first time to showcase latest technologies needed to boost the growth of the regional upstream industry. The response to the request for abstracts for papers and posters this year was beyond expectations. After a thorough review the technical committee has endeavored to bring the best concepts and case histories to the technical symposium with an aim to share the best practices that have been adopted in the various parts of the world.

The symposium also features a panel discussion delivered by renowned industry leaders on Tight Gas reservoirs, an area so vital to fuel the economic growth for the region in general and the kingdom in particular. The rationale is to unlock challenges involved in the regional Tight Gas market and have a strategy in place to exploit these reserves and be able to support the need for natural gas supply in the future.

This year's symposium is particularly special, as it falls after the SPE Saudi Arabia Section's celebration of the 50th anniversary. Please come and join us at what is certain to be very successful symposium and Exhibition.

On behalf of SPE KSA, we would like to thank Saudi Arabia Oil & Gas Magazine for its support in providing full coverage of the event.

In this issue, you will find articles ranging from Manifa Causeway and Islands, a host of innovative formation evaluation, drilling and completions papers as well as 'What's in a Wet Barrel – an excerpt from The Hydrocarbon Highway, by Wajid Rasheed.

The magazine helps promote interaction between petroleum experts within KSA and internationally, and has proven to provide a valuable channel for technical EP publishing.

Thank you all.

Dr. Ashraf Al-Tahini,

2009 Symposium and Exhibition Chairman

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CEO's advice – Chart Your Future

by Rahmah I. Nawwab

Khalid A. Al-Falih gives the opening remarks at the SPE Young Professionals Technical Symposium.

DHAHRAN, April 15, 2009 -- Saudi Aramco's president and CEO emphasized the importance of self-initiative to a group of young employees during the Society of Petroleum Engineers' (SPE) 2009 Young Professionals Technical Symposium.

"Just as the company is committed to a long-range program, so should each of you commit to your own agenda of planning and preparing for the future ahead," Khalid A. Al-Falih said. "You must realize the huge importance of self-initiative to your career. Take a look at your specialties and sub-specialties, and make your own roadmap to build competencies and stay current with innovation."

He added that expanding knowledge beyond one area of expertise is another key to success. "Petroleum engineers need to know about multiple disciplines, including drilling, completion and production, formation, evaluation and geology," said Al-Falih. "Similarly, a broad understanding of applicable fields and disciplines, such as economics, business, IT, project management and law, is needed as the industry gets more complex."

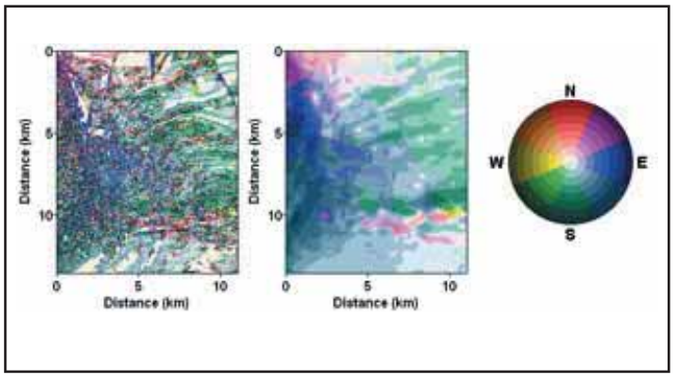
He stressed the significance of soft skills that might be overlooked in technical and scientific fields. "While technical content is essential to your development, the person who also develops critical-thinking, negotiating and problem-solving skills will be better positioned not only to contribute optimally to a project but to be more competitive in advancing to more senior levels."

He urged young engineers to take advantage of professional societies that provide opportunities for knowledge-sharing and networking. "You have already taken an important step in this particular arena by your participation in SPE International. Here, I would encourage you to take an active role — don't just be a member; be a leader," he said.

Al-Falih also noted the company's commitment to human resources development. "Given our ambitious project slate and the knowledge- and innovation-intensive future of E&P, continuous, calculated human resources development clearly is our first priority. Such strategic investments in these precious natural resources hinge on something even more crucial than oil — and that is our human resources," he said.

"Everything is possible," said Al-Falih. "You can advance quickly within your profession, your technical field as well as your management career path."

New Geoseismic Processing Method Patented



These images show the difference between raw, left, and smoothed data. The smoothing method makes the seismic data more interpretable, thus helping geoscientists as they look for hydrocarbon reservoirs.

DHAHRAN, March 04, 2009 – For some time, a challenge for explorationists has been the interpretation of data acquired from geoseismic surveys. Now a team of researchers from the EXPEC Advanced Research Center (EXPEC ARC) has been awarded a patent for a breakthrough method of processing that data.

Yuchun Eugene Wang and Yi Luo of the ARC Geophysics Technology Team, and Mohammed N. Faraj, former chief technologist of the team, were awarded U.S. Patent 7,454,292 for "Inverse-Vector Method for Smoothing Dips and Azimuths."

"We are thrilled to hear this news," said Wang, who was the team's lead author. "It is times like this that make research so rewarding as we progress in overcoming difficult challenges in upstream technology research."

This advanced method of seismic processing enhances the capability to detect anomalies below the surface. Dip and azimuth (inclination and direction) of buried geologic layers are characteristics that can be estimated from recorded seismic traces. When these characteristics are properly calculated – or smoothed – they are effective in revealing structure that is less easily detectable in the original seismic data.

The team developed its novel approach to smooth the characteristics of the subsurface obtained from seismic data, which greatly facilitates interpretation of large 3D seismic data volumes.

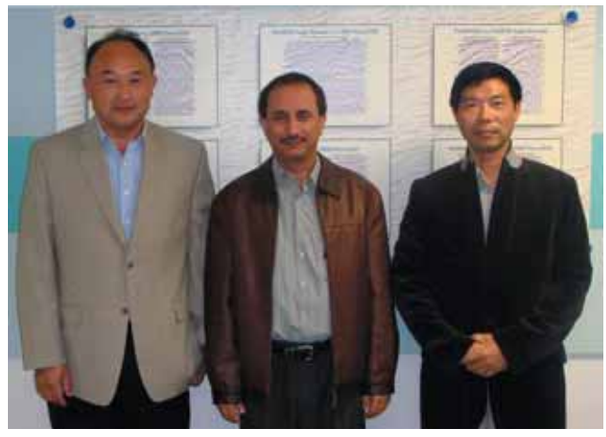
"A unique feature of this invention is that it is simple to implement and is computationally efficient," Luo said.

Several methods to compute dip and azimuth from seismic records have been proposed in the past. Some required relatively large areas of seismic data and suffered a loss of resolution. Others tended to amplify high-frequency noise.

"An additional 'icing on the cake' is that our technology overcomes these problems and offers the smoothing capability that conventional industry practices lack," said Faraj, who now is chief geophysicist of the Geophysical Technical Services Division.

This newly patented technology is applied routinely to seismic data at Saudi Aramco and has yielded accurate results.

A benefit of this method is that it contributes significantly to increasing the company's success rate in locating wildcat exploratory wells or in placing wells in existing fields to produce known accumulations of hydrocarbons.



The authors of the patented "Inverse-Vector Method for Smoothing Dips and Azimuths" are, from left, Yi Luo, Mohammed N. Faraj and Eugene Wang.

Nasser: People Bridge Gap to future

By Adil Al-Sadiq

Amin H. Nasser

MANAMA, Bahrain, March 25, 2009 – People, production and technology are the keys to the future. "These are the elements that I believe are essential to a sound strategy for ensuring outstanding performance and meeting the challenges of the future," said senior vice president of Exploration and Producing, Amin H. Nasser, setting the tone for the 16th Middle East Oil and Gas Show and Conference, MEOS 2009, held March 15-18 at Bahrain's International Exhibition Center.

Dr. Abdul-Hussain ibn Ali Mirza, Minister of Oil and Gas Affairs and chairman of the Bahrain National Oil and Gas Authority, inaugurated the conference under the theme "People, Demand, Technology – Bridging the Gaps."

The opening ceremonies, emceed by petroleum engineer Hiba A. Dialdin from Saudi Aramco's EXPEC Advanced Research Center, included addresses by Mirza, MEOS conference chairman Faisal Al-Mahroos and SPE president Leo Roodhard.

Nasser talked about Saudi Aramco's strategy to address future challenges and outlined its four principal elements: natural resources with a large reserves base; appropriate development and application of technology; qualified and well-trained human resources; and responsible stewardship of the hydrocarbon fields and the environment.

"It is estimated that the world has a total resource endowment of about 7 trillion barrels of conventional oil and another 7 trillion of nonconventional oil," he said. "Of course, not all of these barrels are recoverable."

The world has produced and consumed nearly one trillion barrels of oil and has about 1.2 trillion more in current proven recoverable reserves.

"Saudi Aramco has 742 billion barrels of discovered oil resources," Nasser said. "Some of this oil has already been produced – about 116 billion barrels – leaving 260 billion barrels as the current proven remaining reserves."

This recoverable proportion makes up 50 per cent of Saudi Aramco's total oil resources.

Nasser assured the audience that Saudi Aramco is using these resources to respond to global demand, as can be witnessed by the largest capital expansion program in the company's 75-year history, in fields such as Khurasaniya, Khurais, Nuayyim, the Shaybah expansion and Manifa.

Next, Nasser addressed investing in technologies that will help achieve four main goals: imaging and understanding the subsurface better, accessing the subsurface more easily and economically, recovering resources more efficiently, and managing the company's reservoirs with best-in-class practices.

"Saudi Aramco has taken the lead in developing the

The adviser on Industrial and Oil Affairs, Shaikh Isa bin Ali Al Khalifa, second from left, opens the MEOS 2009 Exhibit, which showcases more than 290 oil and gas company from 35 countries around the world. To his right is Dr. Abdul-Hussain ibn Ali Mirza, and behind Al Khalifa is Amin H. Nasser.

most advanced reservoir simulator in the industry, which has broken several industry records during its development," he said.

Resbots represent another technology that Saudi Aramco is developing to better map these reservoirs.

"Resbots is the name we use for our invention of reservoir robots, or reservoir nanorobots," said Nasser. He explained that large numbers of resbots will be sent into the reservoir with injected water. They will move in the reservoir, carried by the reservoir fluids, and record reservoir pressure, temperature, fluid type and other properties. The resbots will continue their journey right up through production, where they will be retrieved to download all the information they have gathered.

Equally important is the human factor, he said. "Indeed, the human capital is our most important asset."

With the advent of new technologies, there is a growing demand for competent people who are able to effectively develop and deploy these technologies.

"We are moving into a digital, intelligent era, and upstream technology is becoming highly sophisticated," Nasser said. "We have to approach bridging the gap between people and technology differently. … All disciplines have to understand each other and work in synergy."

So, how do we bridge the gap?

"We are embarking on creating a world-class Upstream Professional Development Center to be completed by next year," he said. "We expect around 500 fresh graduates and experienced professionals to participate in this center, and we want them to hit the ground running."

The Society of Petroleum Engineers held a dinner during the conference to recognize and award members that have contributed to their industry professionally and technically.Among those honored were four Saudi Aramco employees: Saeed M. Mubarak, Mohammed I. Sowayigh, Abdulaziz A. AbdulKarim and Hilal H. Waheed.

One highlight of the conference presentations was Naseem J. Dawood's discussion about Saudi Aramco's innovative development of its hydrocarbon wealth and improving well performance. He emphasized the company's use of advanced technologies to improve performance, maintain production and reserves and lower costs.

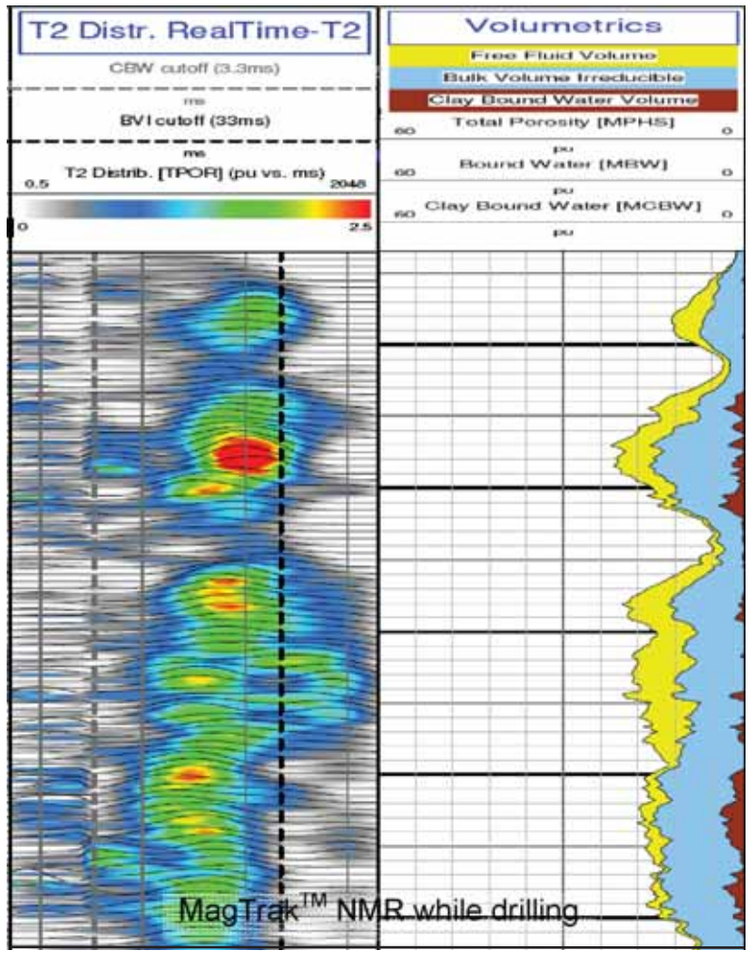
Innovative E & P Technologies Workshop Held in Al Khobar

In February and March 2009 Baker Hughes Saudi Arabia Business Development Council, chaired by Sameh Hussein Marketing Manager – Baker Oil Tools, delivered two technology workshops for Saudi Aramco in Al-Khobar, Saudi Arabia.

Managing Director, Baker Hughes KSA John Prescott, welcomed more than 120 participants across various disciplines. Prescott said, "Baker Hughes is comprised of eight product lines that provide products and services for drilling, formation evaluation and production. This workshop shows how our leading technologies and our effective application of them creates added value for Saudi Aramco. Marhaba."

After making a series of 15 technical presentations Baker Hughes product line experts were on hand to discuss the day to day needs and specific challenges faced by Saudi Aramco in its field development plans. Here we consider each of the divisions and some of the technologies presented at the workshop.

Baker Hughes INTEQ – delivers advanced drilling technologies and services that deliver efficiency and precise well placement. Major capabilities include directional drilling, Measurement-While-Drilling (MWD), Logging-While-Drilling (LWD), and



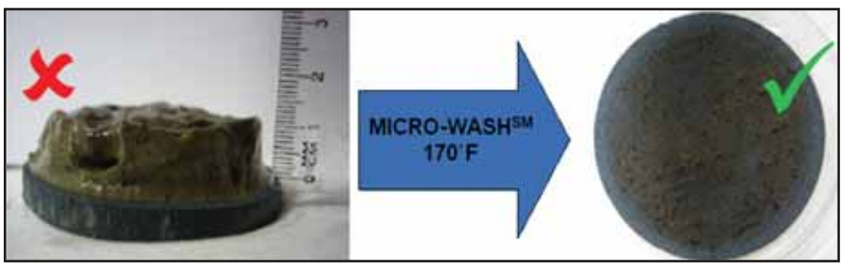
well-site information management services. The AutoTrak™ rotary closed-loop drilling system, automatically drills along a preprogrammed well path with higher penetration rates and a smoother borehole than conventional drilling systems.

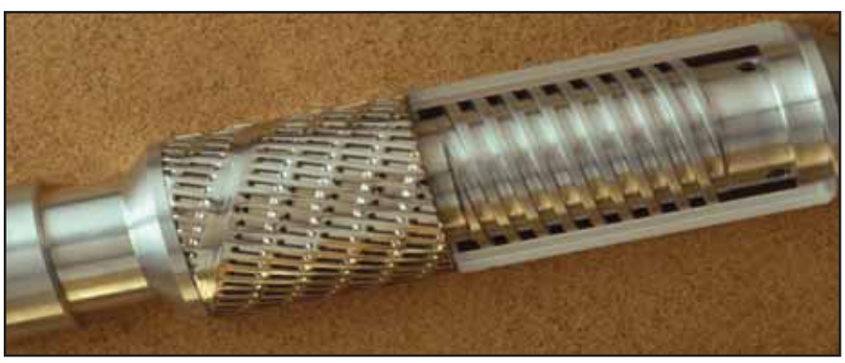
Wael Darwish Business Development Manager Baker Hughes – INTEQ began the technical workshop with a presentation entitled "What is Reservoir Navigation?".

Other presentations illustrated how real-time utilization of LWD & Directional measurements to land the well in the target horizon and maintain the placement of the well bore in the zone of the maximum interest. NMR logging was also shown to help in characterising Porosity in Complex / Mixed Lithologies as well as the identification of "Low Resistivity" Pay Zones and a host of other reservoir fundamentals.

Baker Atlas's Steve Smith said, "We provide well logging and data analysis for drilling, production, and reservoir management. Our advanced technologies help oil and gas producers evaluate their reservoirs and produce them efficiently to maximize hydrocarbon recovery".

A presentation on Borehole Imaging Technologies and Applications was made by Derick Zurcher, Geoscience Manager, Baker Hughes KSA. This covered the different types and scales of images through to optimised Well Placement and fracture modeling in carbonates and the latest geological software.

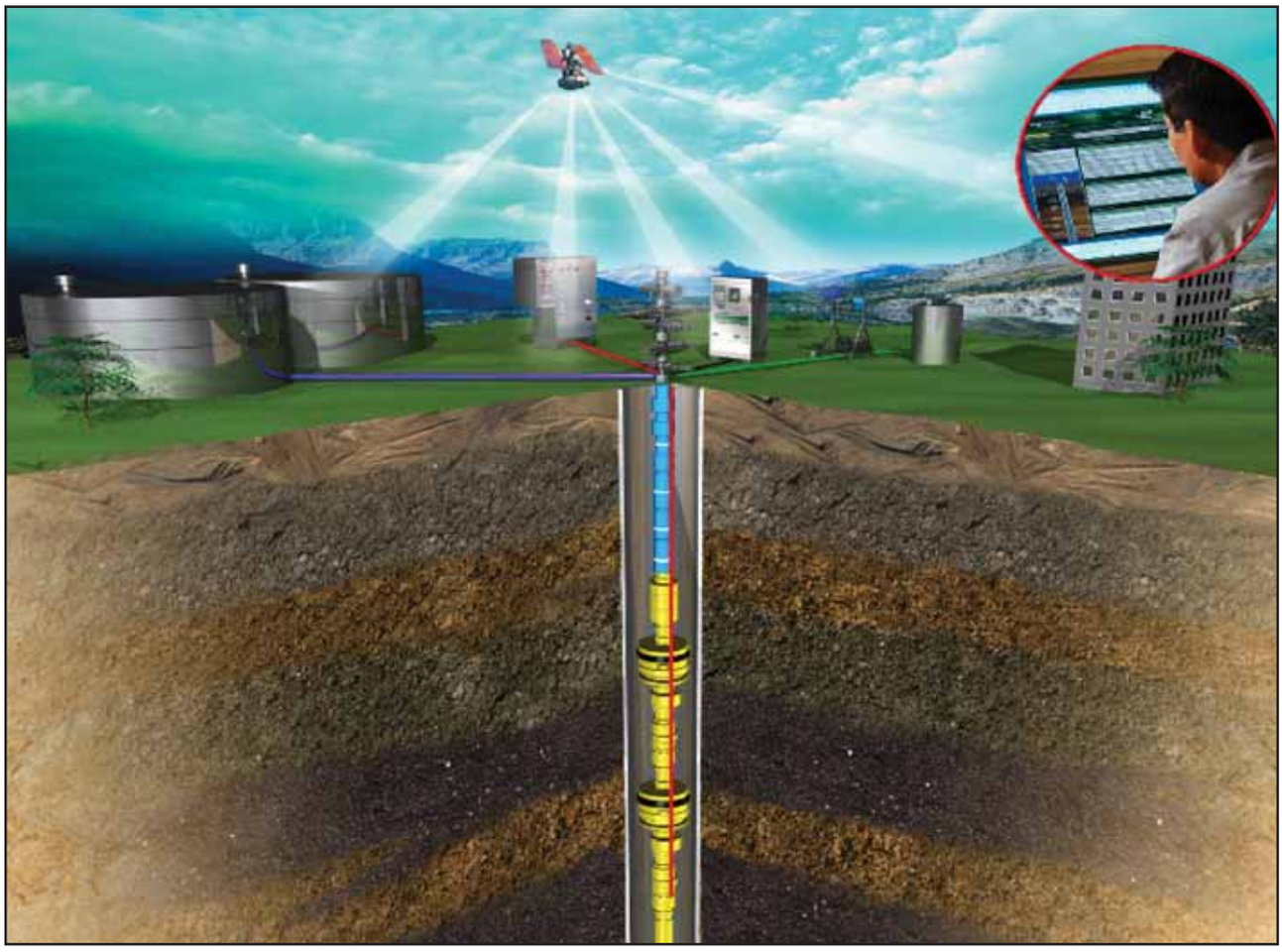




Baker Hughes Christensen's Nizar Ben Ali "We set the standard in drill-bit technology for the oil, gas, mining, and geothermal industries. Our product lines include Tricone™ roller cone bits, fixed cutter (diamond) bits and casing drilling technology. Computerized design, world class testing facilities, and state-of-the-art manufacturing allow Hughes Christensen to develop and produce drill bits that deliver optimum performance in every application".

Baker Hughes Drilling Fluids (Rafat Hammad) is committed to providing effective, environmentally sound fluids technology to achieve high performance around the world with specialty additives, completion fluids, water-base and synthetic-base drilling fluids systems. The presentation ended on micro-wash treatment for OBM filter cake applications.

Baker Oil Tool's Juan Serrano said, "We are an industry leader in completion, fishing, and work-over technologies. It excels at engineering and manufacturing products and systems to help customers reduce their well costs while enhancing oil and gas recovery. Recent innovations include intelligent completion systems, multilateral junctions, sand control completions for horizontal wells, and advanced milling systems for re-entry operations".



The presentation discussed the concept of Equalization and the importance of Compartmentalization. It also quantified the benefits from New Equalizer™ Technology. The presentation also considered the Gas and Water Adaptive type Equalizers.

Baker Production Quest's Ashraf Khateeb said "We provide Permanent Monitoring Systems Electronic Gauge Systems & Components, Fibre Optic gauges, System Flow meters, Chemical Automation, as well as Intelligent Well Systems in order to optimise production".

Baker Centrilift's Randy Birkelbach said "We are a market leader in electrical submersible pumping (ESP) systems industry for both oilfield and water well applications. It is the only provider that designs and manufactures the complete ESP system, including the down-hole motor, seal, pump, gas separator and sensors as well as power cable and surface controllers. Centrilift technology is expanding the range of ESPs in harsh environments such as wells with high gas content, viscous fluids, high bottom-hole temperatures and fluids with scale and corrosion. It also provides progressing cavity pumping (PCP) systems and horizontal surface pumping systems".

Baker Petrolite's Mamdouh Srour said "We provide oilfield chemical programs for drilling, well stimulation, production, pipeline trans-portation, and maintenance reduction. The division's products improve process efficiency, decrease operating costs, and resolve environmental problems".

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The Role of Open Hole Packers for Completion Operations in Saudi Arabia

By Paolo Gavioli, Baker Oil Tools

Open hole (OH) packers are devices that create an annular barrier between the wellbore and selected open hole completions such as stand-alone screens or pre-perforated liners. In some completions, these packers are a critical and unavoidable component. Current industry technology offers many different types of OH packers suitable for all possible applications. The most common types currently in use are inflatable external casing packers, mechanical packers and swelling elastomer packers. In a variety of customized assemblies, this technology provides operators with economical solutions that can isolate zones of high permeability, equalize production rates, and control water and gas coning.

Before 2002, the only OH packers used in Saudi Arabia were standard inflatable external casing packers (ECP). At the end of 2002, a new system was run in the Kingdom that included mechanical packers. After that event, the mechanical packer became the preference in non-cemented OH applications.

Baker Oil Tools has applied the MPas™ mechanical packer in Saudi Arabia for many different applications. By mid-year 2008, more than 85 percent of EQUALIZER™ Production Systems and 100 percent of zonal isolations included MPas packers. The rapid increase in MPas usage in Saudi Arabia is shown in Figure 1. These applications include Equalizer installations in sandstone reservoirs, Equalizer installations in carbonate reservoirs, OH zonal isolation, casing shoe isolation and gas/water zone isolation.

MPas Packers with Equalizer Production System

In this application, MPas packers are run between sections of Equalizer in order to hydraulically separate producing intervals of different characteristics in porosity, permeability, or number and size of fractures. The systems divide producing intervals from zones that are not

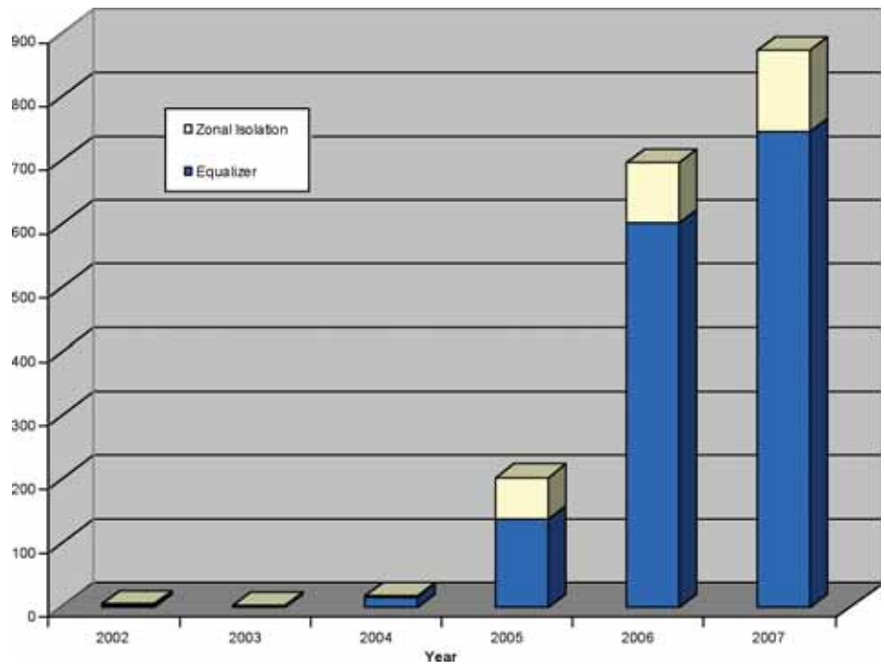


Figure 1 - Usage of MPas packers in Saudi Arabia divided by type of installation

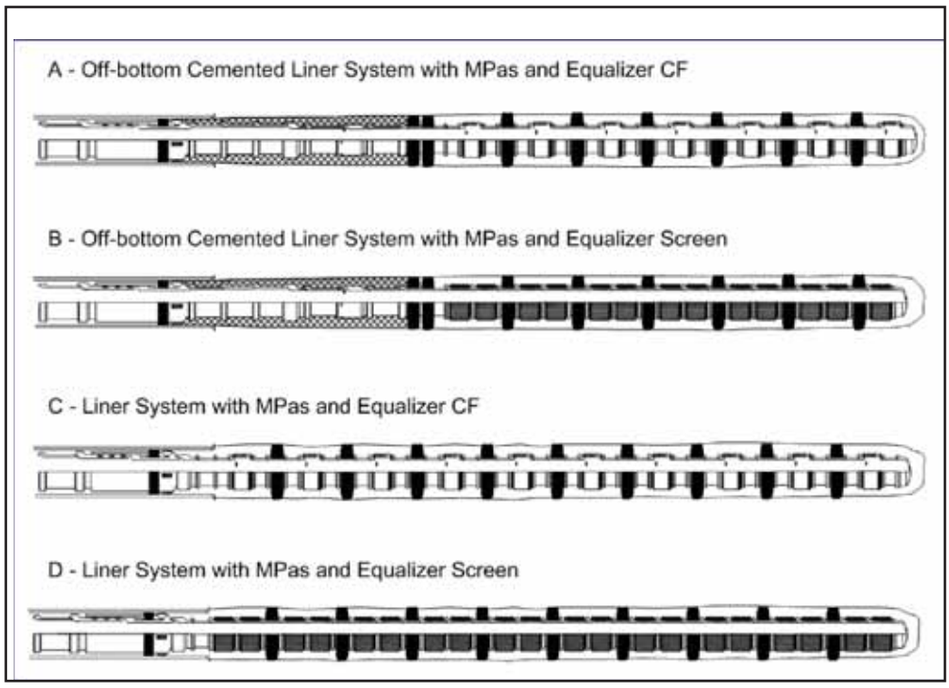


Figure 2 - Open Hole Packer Applications in Different Equalizer Completion

desirable to produced due to fractures/faults or water/gas coning. The design of the assembly is customized in order to meet specific reservoir engineering needs. The positioning of the MPas packers is determined by examining OH logs after drilling. These systems have been run in sandstone and carbonate reservoirs. The hook-ups for different Equalizer/MPas completion types are presented in Figure 2, A-D.

Production results and production logs from wells equipped with Equalizer and MPas packers are in general very positive – many wells show sustained high rate dry oil production, delayed water/gas breakthrough compared to offset wells, and by means of reservoir simulation, better sweep efficiency and ultimate recovery from the field, especially for fractured carbonate reservoirs.

MPas Packers for Open Hole Zonal Isolation (OH Straddle)

Very often while drilling carbonate reservoirs, operators encounter huge fractures or high permeability zones that cause total loss of circulation. If left untreated, these zones can dominate the overall production and lead, in a very short time, to gas or water coning problems which are extremely difficult to address when they appear. An effective way to isolate these zones is to apply MPas packers.

In this application, the desired zone is isolated by placing a selected length of blank pipes anchored to the open hole with two packers above and two packers below the zone in order to assure a perfect seal. The position of blank pipes/MPas packers is determined by examining the image and caliper logs. After the system is set, a regain of fluid circulation is expected. The hook-up example for this application is shown in Figure 3-C.

MPas Packers for Plug & Abandon Kit

When the fracture/high permeability zone is at the bottom of the open hole, MPas packers can be used as a plug and abandon kit, running a selected length of blank pipe with a bull plug at the bottom of the hole and anchoring it with two packers above the zone to be isolated. The hook-up example for this application is shown in Figure 3-D.

MPas Packers for OH-Casing Shoe Isolation

In this case, the thief zone is located just below the casing shoe, or the shoe itself is not properly sealed or leaking. To address this type of situation, a liner hanger packer is anchored at a selected height inside the casing and the bottom couple of MPas packers are set in the open hole below the zone to be isolated. The hook-up example for this application is presented in Figure 3-B.

MPas Packers for Gas Cap Isolation

This installation is designed to isolate gas zones above the oil bearing reservoir and just below the 7 in liner shoe. The idea is to separate the gas cap to the lower oil

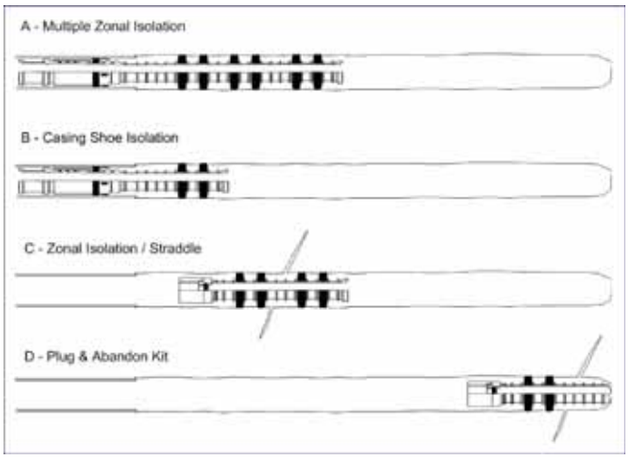


Figure 3 - Open Hole Packer Use in Different Zonal Isolation Applications

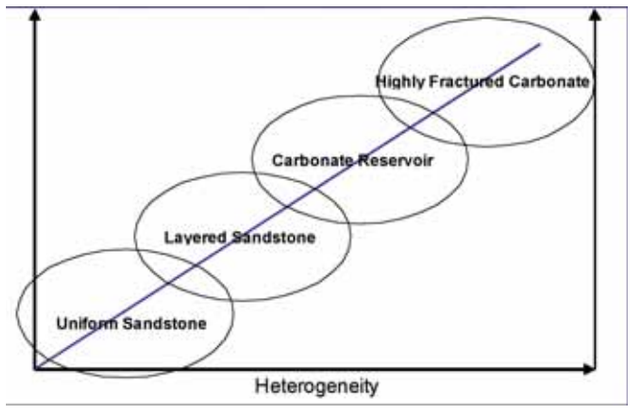


Figure 4 – Role of Heterogeneity in ICD Completions

zone, leaving the possibility to go back and perforate the blank pipe across the gas zone in order to produce it. This application allows setting the 9-5/8 in casing much higher than usual and reaches the top of the reservoir with the 7 in liner. The entire section through gas cap, as well as through the oil zone, is then drilled with a 6-1/8 in hole and isolated just at the end, after logging, leading to a much more accurate placing of the isolation system and associated cost savings. The hook up of the assembly is presented in Figure 3-A.

The Concept of Compartmentalization: Reservoir Optimized Completions

First installed in Norway in 1997, Baker Oil Tools' Equalizer system deployed the industry's first passive inflow control device, and it still represents the preferred method for this kind of completion worldwide. For the majority of these installations, MPas has been the selected method of isolation, especially for carbonate reservoirs, followed by the swelling elastomer REPacker™.

When designing a Reservoir Optimized Completion with Passive Inflow Control Devices (PICD), it is generally accepted that the ICD pressure setting and the number of compartments should increase when the degree of heterogeneity along the wellbore increases in order to optimize equalization (Figure 4).

This design concept can be simply justified by saying that, in an OH completion, each feature of heterogeneity, in order to be controlled, should be trapped in a short compartment and produced through a reduced number of Equalizer units. This concept is true, except in the case of a perfectly collapsed annulus condition; this condition can never occur in a carbonate reservoir, rarely happens in competent sandstones, yet is common in unconsolidated formations. In fact, since the annulus is open to flow, this will be the path of least resistance for the fluid after entering the wellbore from the reservoir because the completion is creating a resistance to fluid (pressure drop) that, even if minimum, is still enough to divert the flow in all directions in the annulus before entering the completion. If severe heterogeneities are present, the reservoir-to-wellbore flow will be dominated by those heterogeneities, minimizing the benefits of an ICD completion.

Moreover, this phenomenon cannot be detected by running a Production Log Tool (PLT), which most likely will show a perfect inflow profile in an ICD completion; in fact, what is seen in a PLT is the oil influx from the annulus to the completion, and events at the formation face are masked by the completion itself. Interestingly, a completion with no packers at all will show a better profile in a PLT due to the behavior explained above: the fluid enters the wellbore and flows freely in the annulus before entering the completion, so the equalization will happen only between annulus and completion, leaving the high Productivity Index (PI) zones free to dominate production in the annulus. For these reasons, there is no easy way to show the importance of compartments in case of dry oil production because the production logs currently in use to assess this kind of completion performance will not yield this information.

Water and Gas Control

The scenario described above changes when water or free gas begin issuing into the wellbore. At this point, assuming that these undesired fluids are produced by some high PI portion of the pay and not from the entire pay,

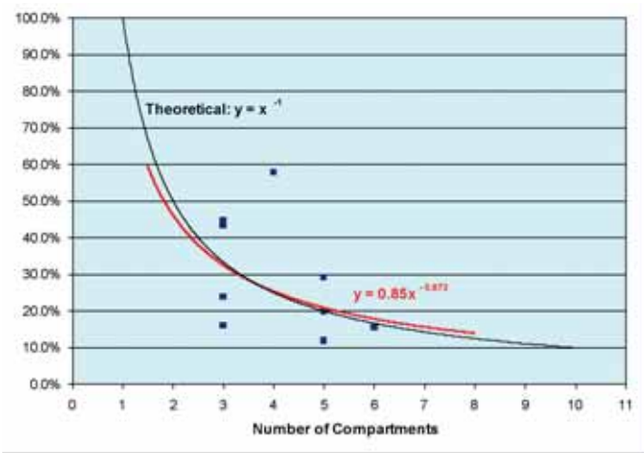


Figure 5 - Effect of Compartmentalization in Water Control

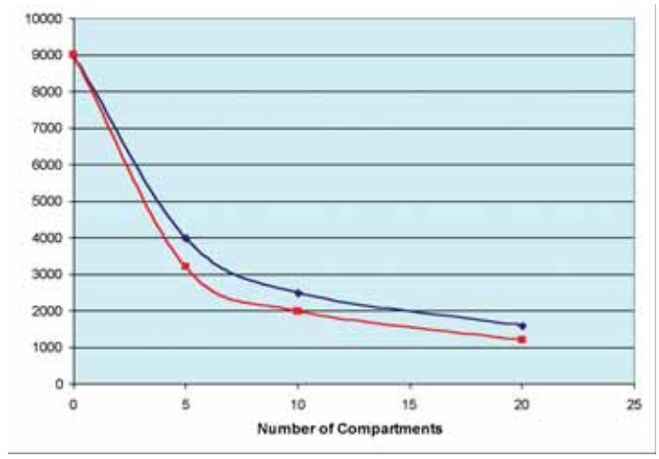


Figure 6 - Effect of Compartmentalization in Gas Control

the domination of high PI features will be detected even by looking to the production data. In this case, the presence and number of compartments will play a critical role.

Generally speaking, increasing the number of compartments results in a better control of both water and free gas production. This performance has been extensively proven by both simulation and field results. In Figure 5, the effect of number of compartments in controlling water is shown.

The data shown are from a carbonate field in Saudi Arabia. The water cut of each well experiencing water production in a certain area after at least one year of production has been plotted against the number of compartments in the well. The derived trend line approaches the theoretical expected behavior of an inversely proportional relationship between water cut and number of zones. Based upon this behavior and based upon the suspected mechanism of water production in a well (fractures, coning, fingering, etc.) the design of the optimum number of compartments can be established.

For free gas control, the number of compartments required to reach an optimum control is intuitively higher that in the water case due to higher gas mobility as shown in Figure 6. The assumption is that in a 1,500 ft wellbore, a 50 ft section is gassed out completely, and the annulus is fully open. In a scenario with ICD but no packers, the gas greatly dominates in the annulus due to the favorable mobility ratio. The Gas-Oil Ratio (GOR) rapidly decreases by adding compartments and trapping the gas-producing zone into smaller and smaller sections. All this assumes that the position of the gas producing section is not known and the compartments are all the same in length and include the same number of ICD units.

In Figure 6, the two lines represent two different ICD settings, the red being a double pressure drop through the ICD for the same rate compared to the blue. As it can be appreciated from the figure there is a GOR reduction by using different type of Equalizer, but the GOR reduction effect is made much stronger by adding compartments than by increasing the pressure drop into the ICD.

In summary, OH packers have been proven to be very effective in a range of many different applications, including curing losses, controlling high permeability zones and fractures, improving equalization in ICD completions and most importantly in controlling water and gas production in PICD completions. For all these reasons, the usage of these tools has increased exponentially in the last few years. OH packers for compartmentalization and ICD completions, especially for water and gas control, are and will remain important for the vast majority of OH applications in Saudi Arabia.

Optimizing Powered Rotary Steering through Better Understanding of the Downhole Environment

By F. Al-Bani, N.Galindez and P. Carpen, Saudi Aramco; F. Mounzer and D. Kent, Baker Hughes

Abstract

This paper discusses drilling optimization in two major fields operated by Saudi Aramco. Both fields have layered limestone reservoirs consisting of tight zones alternating with porous zones and are drained using innovative MRC (Maximum Reservoir Contact) techniques along with real-time geosteering.

The well profiles produce difficult torque and drag environments. While drilling rigs employed have upgraded to top drive systems, traditional drilling practices still rely primarily upon surface measurements provided by the drilling contractor. Often these gauges are rudimentary and their measurements unrepresentative of downhole conditions, particularly when operating at a great depth in horizontal holes.

In the applications discussed in this paper, the situation was greatly improved by introducing a new downhole drilling sensor tool. Integrated into a high-speed rotary closed-loop drilling system, powered by an integral modular motor, a step change in drilling performance has been achieved.

In most applications, the new tool has been placed between the modular motor and the steering head to give the directional drilling crew a clear understanding of the true environment being encountered by the steering head and bit. Optimization of performance with such advances has resulted in a 100% increase in overall rate of penetration (ROP) in some applications.

Using real well examples, this paper discusses: measurements the tool records and transmits; dramatic differences between downhole measurements and surface indicators; how information is applied to optimize the real-time drilling process, and how this continuous application evolved from the original research initiative.

Introduction

In the last few years, rotary steerable drilling systems (RSS) have become the preferred tools for drilling complex or lengthy drain holes, primarily because the tools can negotiate the planned well path without stopping to "steer" as with conventional steerable (motor) systems. The advantages of these tools has been exhaustively described in numerous papers and articles, in trade journals and with the SPE since the introduction of these systems began in the early 90s. One hallmark of RSS has been the ability to average a significantly higher overall ROP over a given section of hole primarily for the same reasons as described above.

A feature of these tools that most interests the reservoir department is the capability for geosteering to very precise tolerances. RSS tools can steer to a true vertical depth (TVD) target or, if preferred, hold an exact angle to intersect zones of interest.

Despite the large gains in applied technology in downhole drilling and measurement systems and widespread upgrade of rig-rotary drive systems in the last decade, drilling rig measurement gauges have seen comparatively little advancement. Used to monitor vital drilling information, many drilling rigs still rely upon dead-line weight indicators, surface rotary torque gauges, and surface standpipe pressure gauges. These gauges are typically of robust construction to withstand

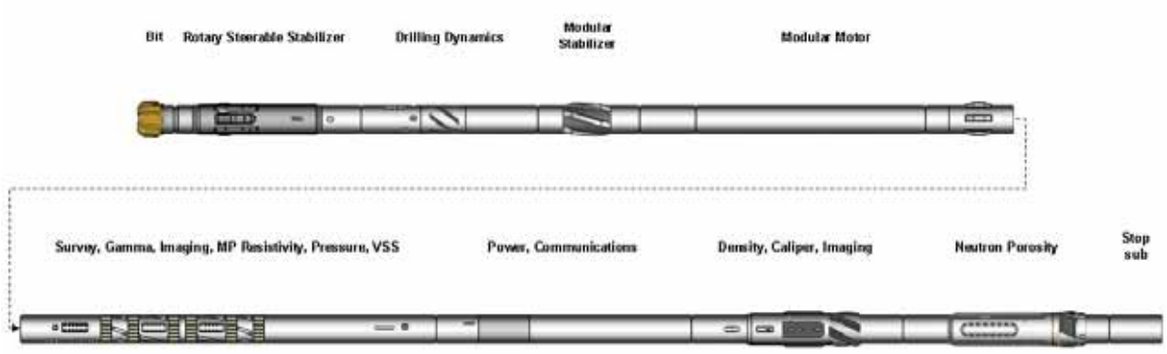


Fig. 1: *Typical BHA configuration used in the example wells described in this paper.*

the rough handling often encountered during drilling or while the rig is being moved (as in land rigs). Calibration is typically fairly rudimentary (as compared to scientific instruments), and sensitivity is poor.

In practical terms, for most operations the gauges and measurements are more or less fit for purpose. The basic measurements were never intended for use in the designer wells on the boards or currently being executed. For vertical or basic directional drilling applications with large robust tool strings, these instruments can cope with most string weight, pump pressure, and torque reading requirements.

The environment where these measurement gauges are found most lacking is in extended reach or complex horizontal drilling applications. The problems seen with inaccurate or non-responsive measurements can be exacerbated even further when small tools are run in slimmer holes (<6.5″). The inherent limber qualities of the slim drill string coupled with the tortuous well path can conspire to completely obscure the actual bottom hole conditions as seen by the drilling tools.

RSS tools do provide, theoretically, some relief from the problem by freeing up the drill string through continuous rotation.

However, slim drill strings can be subject to extreme vibration in three axes: lateral, axial, and stick/slip or torsional. Rig instruments can provide almost no data whatsoever on this aspect of the drilling process. For the most part, these vibrations will exist completely undetected, and the drilling crews are left to puzzle why drilling progress is slow or why the tools do not perform to specification or even fail to function after only short operational times.

Driven by an initiative to better understand the downhole drilling environment, a new MWD-based drilling dynamics tool was introduced. The tool is a short, modular sub that can be placed anywhere in the RSS drill string or conventional rotary drill string provided it is paired with the correct MWD tool. The concept, functionality and capability of this new tool have been described in detail by Heisig et al. (1998)[1].

Tool Description

The tool features a total of 14 drilling process sensors in a dedicated sub. (Figure 1) shows the 4¾″ tool version integrated into the RSS BHA (bottom hole assembly)used for the 6 1/8″ hole sections discussed in this paper. All sensors are simultaneously sampled at a high data rate of 1,000 Hz. A highly efficient digital signal processor (DSP) in the tool continuously monitors the data stream and diagnoses the occurrence and severity of vibration-related problems such as BHA whirl, stick-slip, bit bounce, etc.

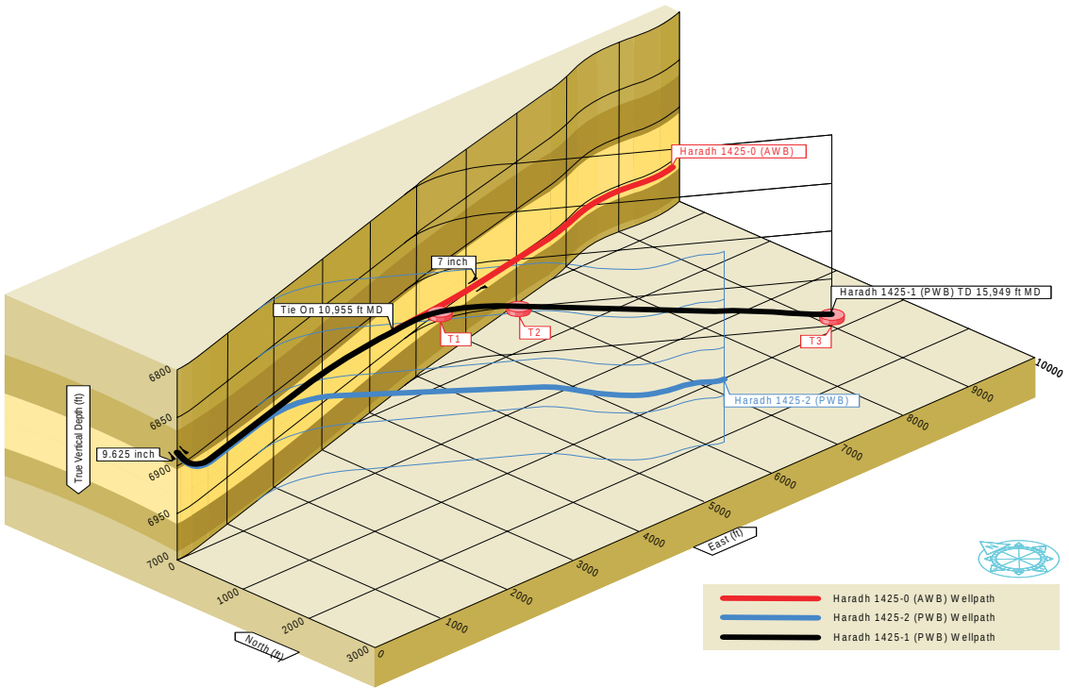


Fig. 2: *Graphical representation of the H-1 MRC well*

The dynamics diagnostics are transmitted to the surface via mud-pulse telemetry along with static measurements such as downhole weight, torque, bending moment, and annulus pressure. The system operates on a five-second loop and records all output parameters in the onboard memory. In addition, the tool offers the unique capability of storing high-frequency raw sensor data (e.g., 100 Hz data rate) onboard over periods of up to 15 minutes. The data can be retrieved later at surface for detailed evaluation.

Field Example #1

Well H-1 This is a multilateral oil producer. The well was drilled as part of the subject field Increment 3 project.

A Maximum Reservoir Contact (MRC) well can be either a multilateral or an extended single leg. The H-1 well was drilled as a three-leg multilateral with a fish bone design—an 8½″ horizontal motherbore with 7″ liner, then 3 x 6 1/8″ laterals drilled through the target pay zone.

The first lateral (_0) is generally drilled out from the shoe of the 7″ straight ahead and the second and third legs (_1 & _2) are drilled off whipstocks set in the 7” liner and oriented either right or left of the main bore (Figure 2).

All three major directional companies were involved in drilling the subject field increment 3 producer and injector wells. Due to the relative tortuosity and complexity of the well paths, RSS tools were extensively employed in the 8½″ motherbore and the 6 1/8″ lateral legs. All three companies gained experience and confidence in drilling these laterals, but there were several issues that limited each company’s ability to achieve breakthrough ROP performance.

During this period, Baker Hughes fielded the drilling dynamics tools as an engineering initiative to better understand the drilling environment as encountered by the RSS steering heads and to fast track design modifications for enhanced functionality and reliability. It was decided that it would be desirable to place the tool between the modular motor and the steering head to clearly see drilling dynamics at the steering head.

The BHA was modeled for bending moments and dogleg capability (Figure 3) and several configurations were

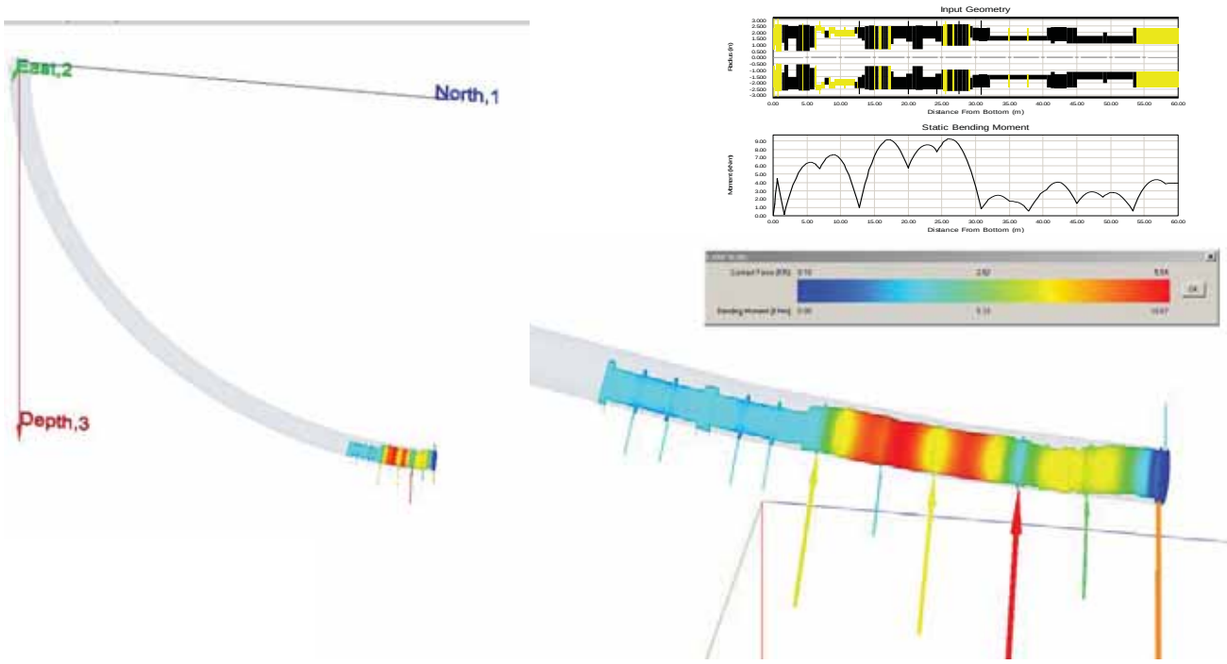


Fig. 3: *BHA modeling output typically used in the preparation phase in order to establish the most suitable configuration depending on the needs for each job.*

evaluated with one to two coming out as the best compromise between dogleg severity (DLS) capability and minimized critical bending moments through the components.

The original focus of the initiative was on capturing comprehensive data sets from both downhole and surface to provide accurate records of drilling operations. These data sets, including memory data from the dynamics tool as well as the RSS, were forwarded to various engineering groups involved for further detailed analysis.

Part of the engineering initiative was also to test drill bits for vibration characteristics, side cutting ability, and ROP potential. The directional staff were closely instructed on how to monitor and act on real-time indication of critical vibrations downhole. But, little instruction was given on how to use the other information provided by the drilling dynamics tool. New drilling data such as downhole weight on bit (DWOB) and downhole torque (DTQ) and BHA bending moment were continuously transmitted and shown on the surface displays. Considered to be gathered just for the engineering initiative, little attention was originally given to the data in real-time drilling optimization.

An interesting progression took place. The directional drillers began to note large differences between surface weight on bit (WOB), the primary string weight gauge used by both the drillers and directional drillers to control applied WOB while drilling, and the DWOB. What made the information jump out at the drillers was the large difference seen between SWOB (surface WOB) and DWOB. They observed discrepancies of more than 40%, yet they were bound by the SWOB reading. Some discussions took place between the office and the rig site, and the validity and accuracy of the DWOB sensor was confirmed to the directional staff.

The drillers started applying higher axial loads based upon the DWOB gauge while continuing to monitor DTQ and vibration parameters (Figure 4).

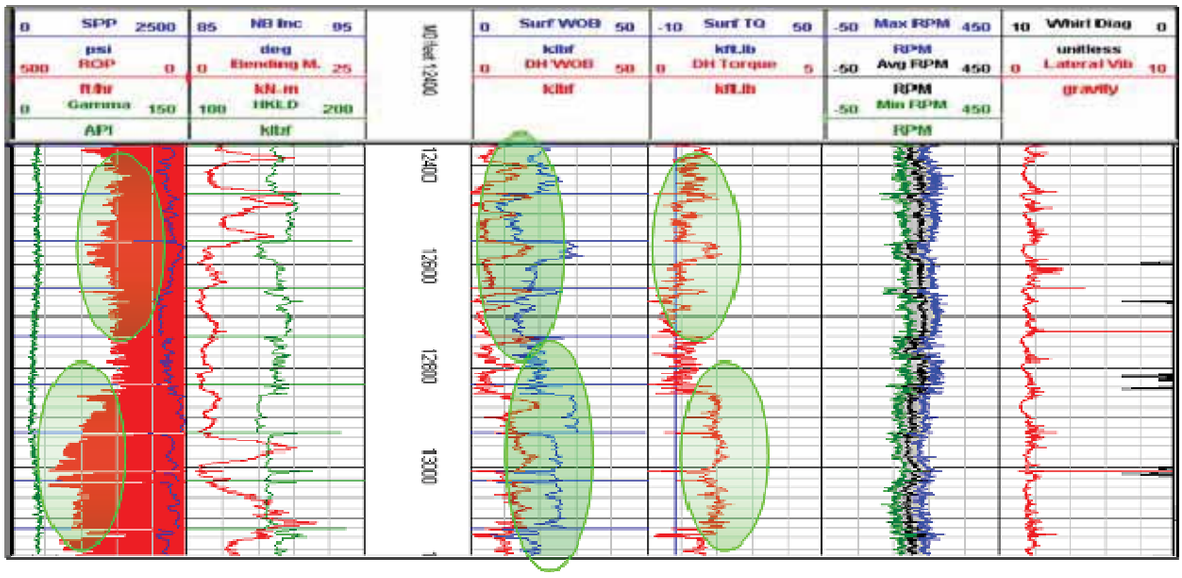


Fig. 4: *Clear difference between the weight reaching the BHA and the surface weight indicating an extra allowable tolerance in the exerted weight without exceeding tool specifications. Additional weight resulted in a better depth of cut of the bit and increased ROP.*

It has to be said that such discrepancies in weight were not evident throughout entire runs, but rather during frequent stages of the run. Sometimes the DWOB would even show as being higher than SWOB as shown in (Figure 5).

As the directional drillers became more confident with the measurement, they started increasing the WOB to bring the tool closer to proposed drilling parameters regardless of what the surface gauge showed.

The payoff was an immediate increase in ROP. When the directional drillers first started to drill the drain sections with the drilling dynamics tools as the primary measurement gauges, the average ROP for subject field Increment 3 producers was about 45 to 55 ft/hr. The use of the modular motor as part of the 4¾″ RSS system helped bring the ROP numbers up to 75 to-85 ft/hr (+/- 40% ROP increase). Within the span of one well, drillers raised ROP from 90 to 95 ft/hr (leg _0), 131 ft/hr (leg _1), and finally 136 ft/hr (leg_2)—a total ROP increase of >35% for subject field producers.

This same performance was being more or less duplicated on rig PA-125, in the same field, at the same time. This rig was also in the subject field drilling a three leg MRC producer while using the same tool suite. The lessons being learned by the directional staff on ADC-28 were transferred immediately to the crews on PA-125 with predictably the same resultant increase in ROP. During this phase there were several other aspects of the tool information output that became very useful to the drilling crews and enabled them to achieve consistently high ROP performance.

The drilling dynamics tool has as part of its sensor suite a bending moment gauge that measures how much the tool is being bent or deflected from the center axis of the tool. This feature of the tool has been fully described by Hood et al. (2003)[5]. The measurement is expressed in Newton meters (N.m) or pound force foot (lbf-ft), and enables drillers to see hole deflection even before the accelerometer has reached the target depth. This is a real-time, more or less instantaneous alert that the bit is deflecting away from its current well path. The drillers used this function to good effect in several fashions.

The directional crew could use the readings as a gauge to determine if the steering head is generating angle or azimuth changes when the tool is directed to do so. This reading gives drillers a very quick indication that the drill string is deflecting as commanded before the near bit inclination gauge even reaches that portion of the hole that receives the steering energy.

The directional drillers could use the readings to get the earliest possible indication that the bit is encountering a negative drilling break and attempting to glance or

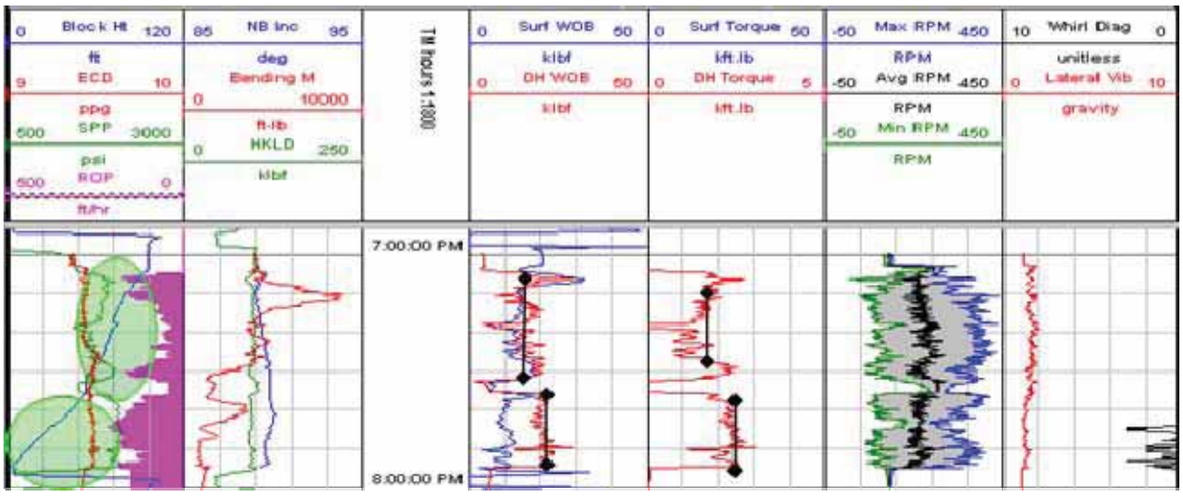
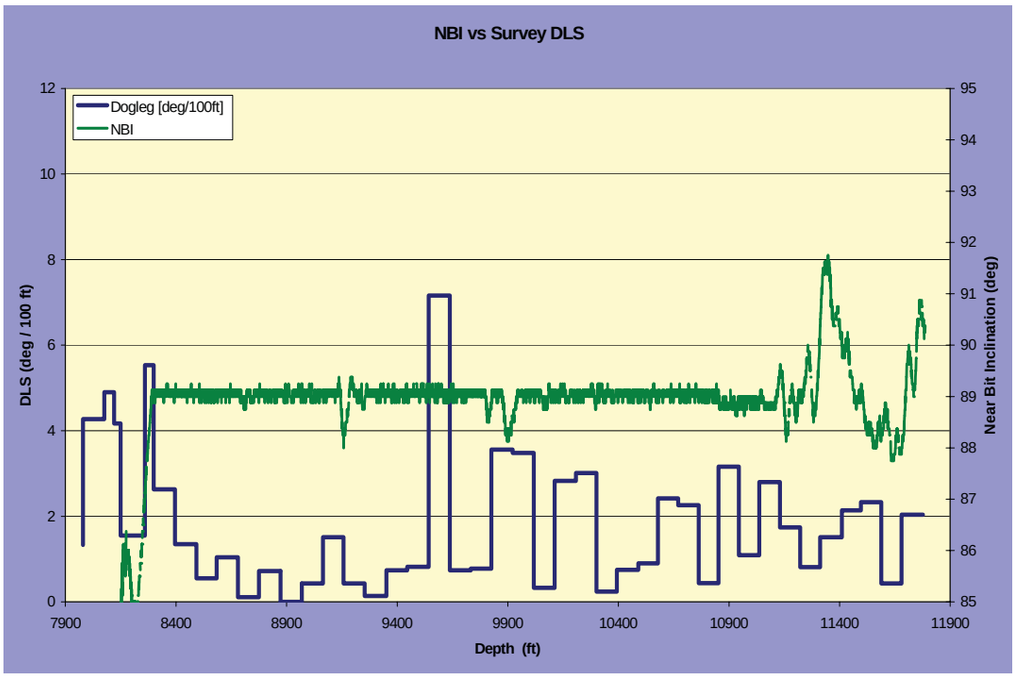


Fig. 5: *Downhole WOB showing higher readings than surface WOB. Increase in weight is confirmed by the increase in downhole torque and increase in ROP. This not only helps maintain optimum drilling parameters, but also helps prevent running equipment out of spec with possible failures and consequent extra trips.*

deflect off the formation. The bending moment output can give advance warning that the bit is deflecting, but it will not give inclination or azimuth—just the fact that the BHA is bending. This is a very reliable indicator and drillers could anticipate either an inclination change, which will show on the near bit inclinometer in the steering assembly control sub; or in the case of an azimuth change, this was seen by the MWD magnetometer (+/- 30 ft) above the bit in the BHA. By process of elimination, drillers were able to see either, as once a bending moment was detected, the inclinometer would pass it in about 5 to 6 ft. If there was no angle change the drillers could reasonably assume that the tool was deflecting left or right and wait for confirmation when the magnetometer passed the same point. Furthermore, the magnitude of the bending moment measurement offers a continuous DLS estimate compared to survey points usually taken only every ~100 ft (Figure 6).

The amount of bending moment encountered as shown by the readings from the dynamics tool could also be used to roughly quantify the rate of deflection or DLS that the bit was generating while deflecting off the hard stringer. Corrective parameter changes can then be made in a timely manner to mitigate consequent high stresses/loads subjected to the bit and BHA. In some cases it was desirable to stop drilling and pull back 2 to 3 ft and re-drill the section by slowing down the ROP or time drilling to give the steering head a chance to cut into the harder formation and reduce or eliminate the dogleg. It was also possible at the same time to downlink to the tool to increase the steer force to achieve better control. (Figure 7)

In the subject field MRC producer wells such as H-1, drillers were able to effect efficient turns toward targets with minimal steer force by using bending moment readings and walk characteristics of polycrystalline diamond compact (PDC) drill bits. MRC plans included a large amount of azimuth turn to spread the drain pattern and depart from the motherbore. In the high porosity pay zone, drillers would sometimes use up valuable drilling time trying to gain continuous turn and to stay on planned ROP. As stated earlier, the tools will turn/drop/build faster if ROP is reduced and the steering head is allowed to put more energy into the hole. One of the drilling characteristics that the PDC bits displayed was a pronounced tendency to walk right if the bit came down on top of a hard steak, or turned left if the bit came up underneath and struck a hard streak. The drillers found that by keeping track of hard streaks, it was sometimes possible to turn the well in the desired direction simply by nudging the well path up or down slightly until a hard streak was encountered and allowing the bit to walk right as required. This turn could be monitored by watching the bending moment displays as the magnetometers were +30 ft further up hole. In every case, the angle of incidence and the low rib force being used did not force the bit through the formation but allowed it to glance off in a preplanned direction along



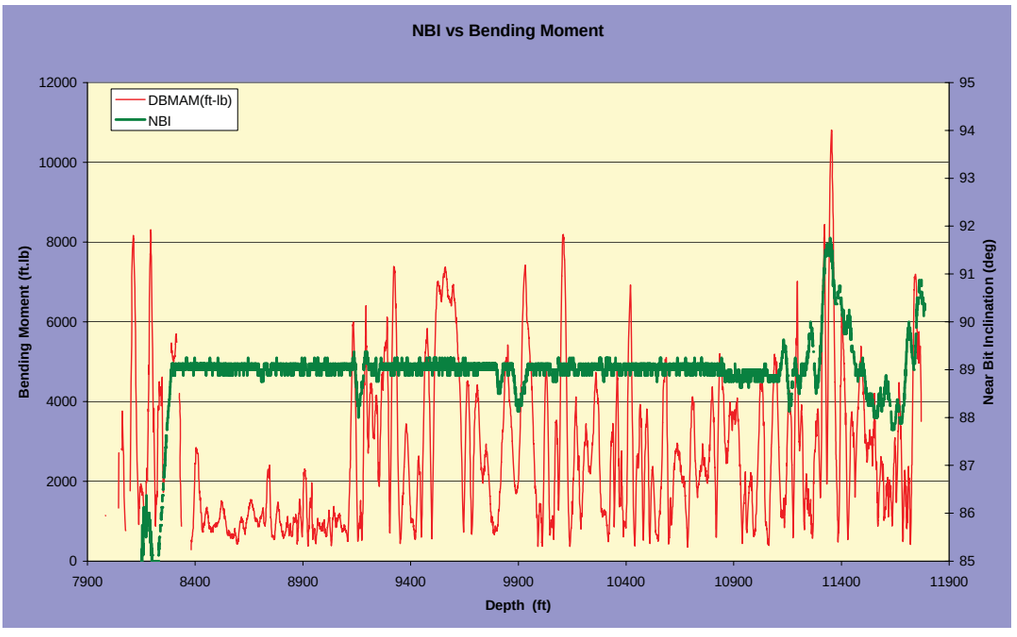


Fig. 6: *Two charts with the near bit inclination plotted against the survey DLS (chart a) and bending moment (chart b). Noticeably, these display a lot of deflections taking place in the azimuthal plane that do not necessarily show up on the usual survey listing, but that are clearly captured by the downhole bending moment measurement.*

the planned well path. This technique allowed drilling crews to maintain a very high ROP performance while staying on target with minimal input. This process took some time to master, and not every crew was confident enough to employ it; sometimes the reservoir sections did not have hard streaks close enough to the planned TVD to allow for this type of "geo-turning". This use of "geoturning" played a significant part in achieving the very high ROP results in the latter part of the subject field project.

The implementation of such an application and the

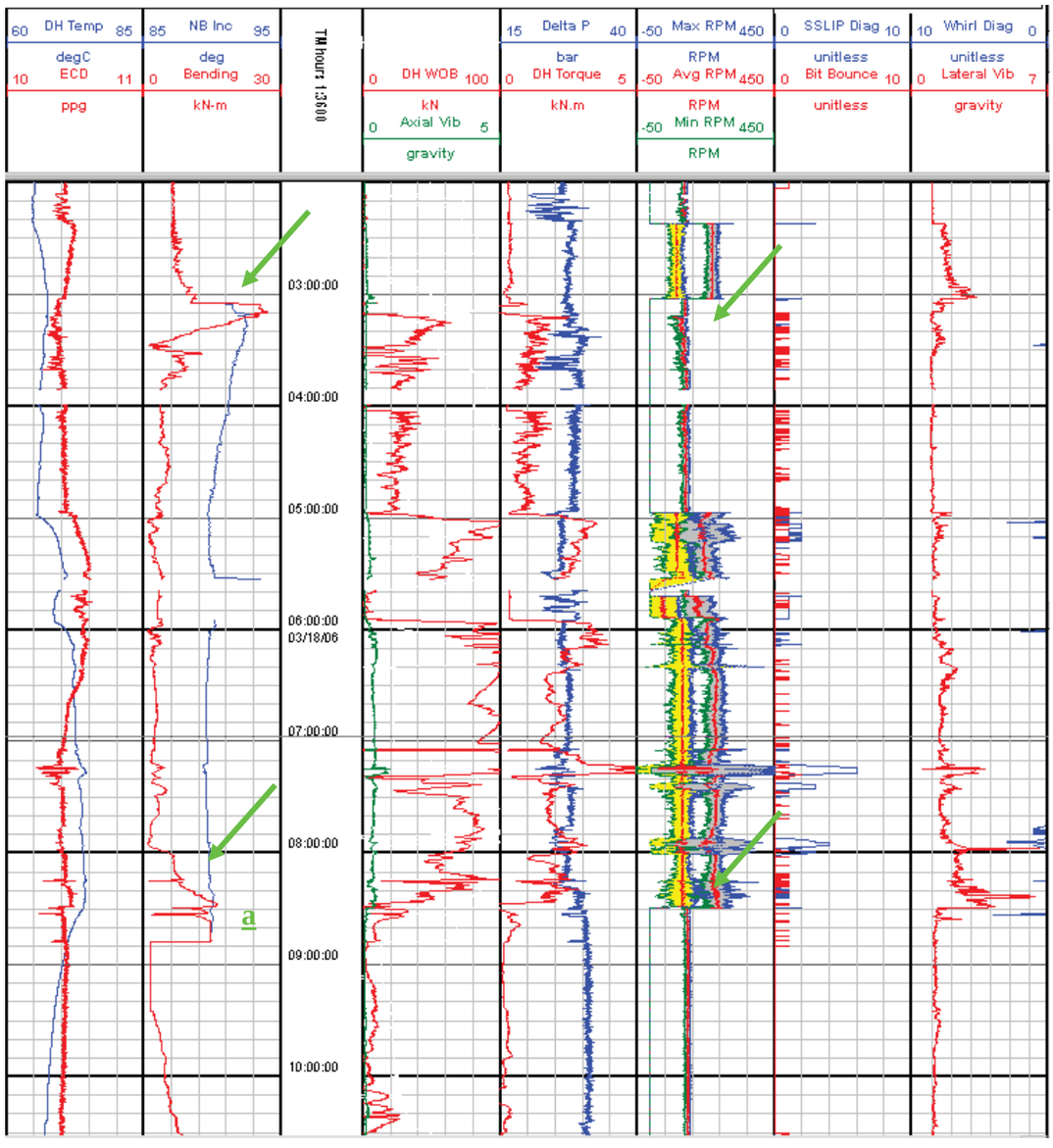


Fig. 7: *Log excerpt showing a sudden increase in bending moment (probably across the whipstock while exiting the window). Keeping a close eye on the measurement, the drillers reacted immediately by dropping the string rpm to zero to minimize the subjected load cycles on the tools following into this high local dogleg.*
After the bending moment dropped back to safe levels and the BHA had passed the dogleg, original parameters were re-established to optimize ROP.

A similar sequence of events takes place a few hours later (a), this time with no noticeable change in inclination indicating an azimuthal turn. In this case, time drilling as described in 3) was initiated to mitigate the situation.

quick learning process had a direct effect on the increase in total performance with visible improvements in ROP and reliability.

The operator's commitment to the introduction and development of the latest RSS technology in addition to the constant improvement based on continuous better understanding of the downhole conditions, were the main drivers for achieving record-breaking runs as depicted in (Figure 8.)

Field Example #2

Q-1 PWI. Q-1 well was drilled from an offshore location as a water injector in the northeastern flank of the

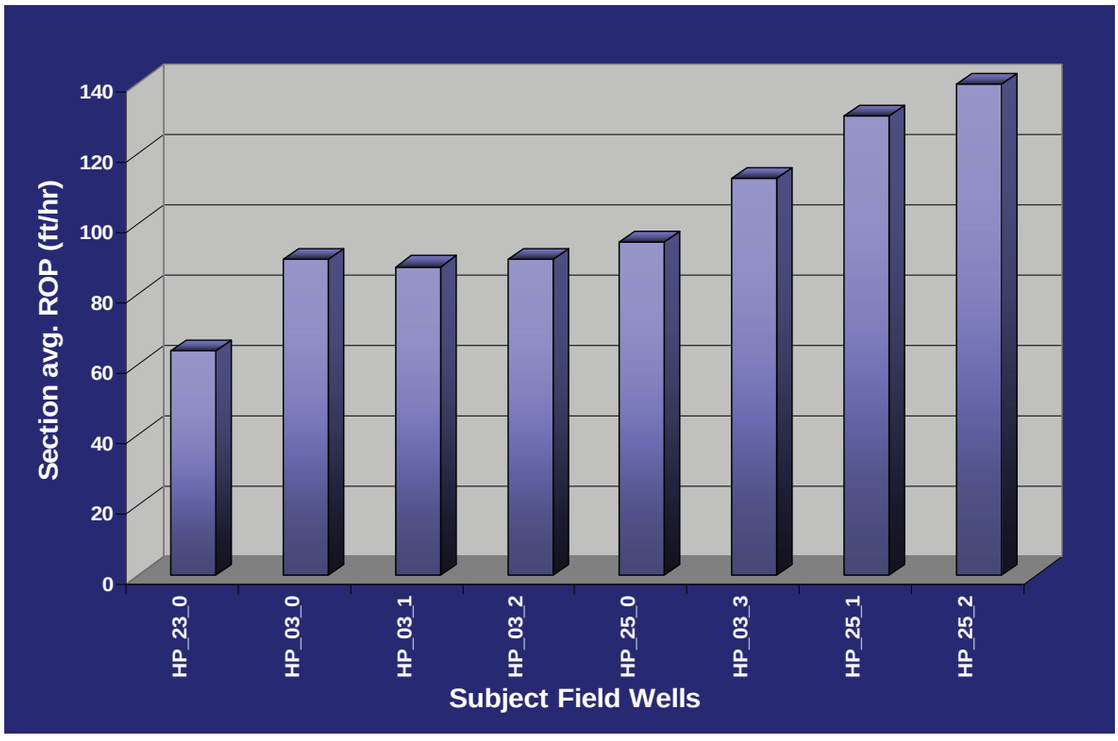


Fig. 8: *Ascending trend in improved RSS performance in the subject field due to gained insight in downhole drilling conditions.*

structure. The planned TD of Q-1 was 8,835 ft TVD, 17,012 ft MD in the lower "F" reservoir approximately 65 ft TVD below the oil/water contact (OWC).

The reservoir is comprised of layers of porous carbonate alternating between layers of denser, non-permeable anhydrite. Typical horizontal wells in this field average 60 to 80 feet/hr with the published highest ROP achieving 85.6 ft/hr from a producer. Offset PWI wells have seen lower ROP rates below 40 ft/hr on average with the highest ROP for an injector of 50 ft/hr. The issues faced by the directional drilling staff on this offshore PWI well were slightly different from the H-1 well, yet no less challenging. The "limiting factors" of this drilling environment focused upon other attributes of the drilling dynamics tools to achieve the desired results (Figure 9).

Subject field PWI wells involve drilling below the OWC into flushed and water wet formation. Targeted carbonate formation layers are typically denser than the production horizon and have intervals separated by dense anhydrite. Production technologists will seek to cross 3 to 4 layers so as to be sure of full sweep efficiency when water injection begins. The layers are fairly flat, and the planned wellbore intersects at a high angle (87°) to provide adequate vertical section.

This is one of the more difficult drilling environments for RSS tools as the bits may not engage fully and can "chip" away at the hard layers. The transitions between less dense and dense provide unequal loading across the bit face. The acute angle can mean that even though the TVD of a given hard steak may be only 10 ft thick, the drilling assembly will be in it for some hundreds of feet MD because of the high angle.

The formation is water flushed and therefore the oil in place will be low. There is no added lubricity from drilled oil as in producer wells, thus the assembly scrapes and rattles along in a high drag environment.

The product of these conditions is typically high vibration in all forms—stick-slip, laterals, and torsional. Any of these vibration modes, if of significant level for extended periods of time, will cause premature tool failure.

If these computerized RSS assemblies are run in this kind of environment without the presence of vibration

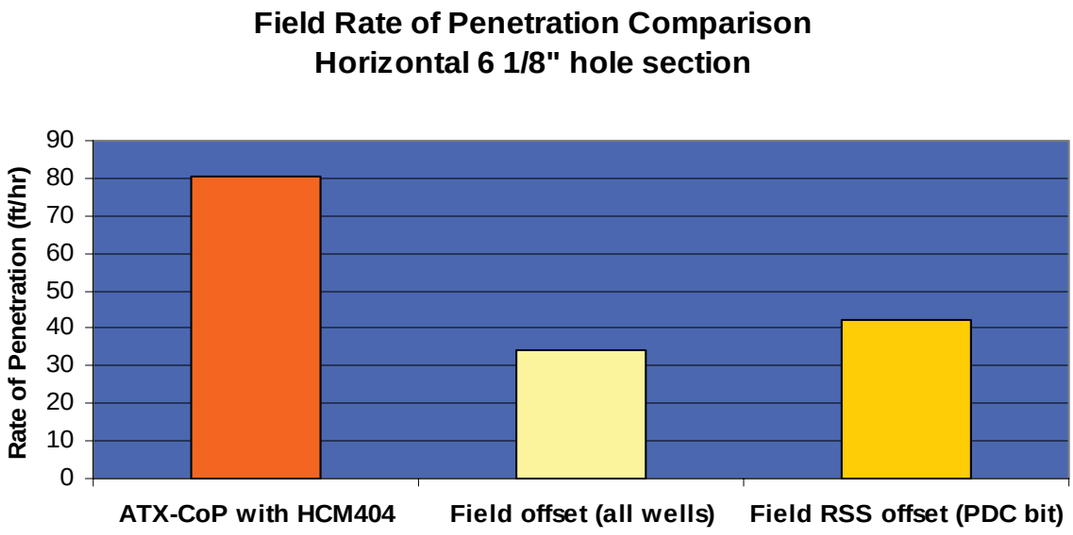


Fig. 9: *Performance chart for 6 1/8" hole sections showing the achieved improvement of ATK-CoP RSS system compared to offset and RSS offset wells.*

monitoring equipment, it can be largely left to chance as to how long the tools will last. Due to reduced wall thicknesses of all drill string components, 4¾″ drilling tools are particularly prone to borehole induced vibration. The drill string is can be either a tapered string such as 5″ x 3½″ or 5″ x 4″. In this case, a single string of 4″ drill pipe to surface. The 6 1/8″ hole is often the terminal hole section with the greatest distance from the surface.

By using the drilling dynamics tool on Q-1 well, drilling crews were able to see exactly what the vibration levels were at all times. This was of particular interest as the bit crossed each layer or adjustments were made to rpm and/or WOB to achieve maximum ROP.

Drillers could see the onset of vibrations at the bit in real time and make corrective actions to reduce or eliminate vibrations and see the effect of their action in real time (Figure 10). Drillers watched the dynamics output continuously and adjusted input parameters as required to reduce vibrations to acceptable levels as well as maintain high ROP.

Moreover, the conscious placement of the dynamics tool directly behind the steering unit and below the modular motor also offered additional insight into how effectively the motor was working. Such a BHA configuration allows a direct measurement of motor rpm. The drilling crew could then monitor how chosen drilling parameters would affect motor performance and subsequently balance the set parameters and motor response to achieve optimum ROP (Figure 11)

The very high overall ROP, together with the high obtained reliability as reflected in zero number of failures` on this run was a direct result of having a clear understanding of the drilling environment that the drilling tools and bit were seeing as the well path crossed through different densities of rock. Drillers had a clear picture of the downhole dynamics and bending loads at all times. This enabled them to react to vibration modes, and then see the results in decreased vibration. As in example 1, drillers could also chase the maximum ROP with DWOB readings instead of relying entirely on inaccurate surface readings while simultaneously ensuring that subjected loads do not exceed operational specifications of the tools.

Discussion

Both of the well types used as examples in this paper have been drilled by a number of drilling/evaluation service companies in Saudi Arabia with varying results. In both types the learning curve grew with experience gained and advances in drill bit and drilling tool technology.

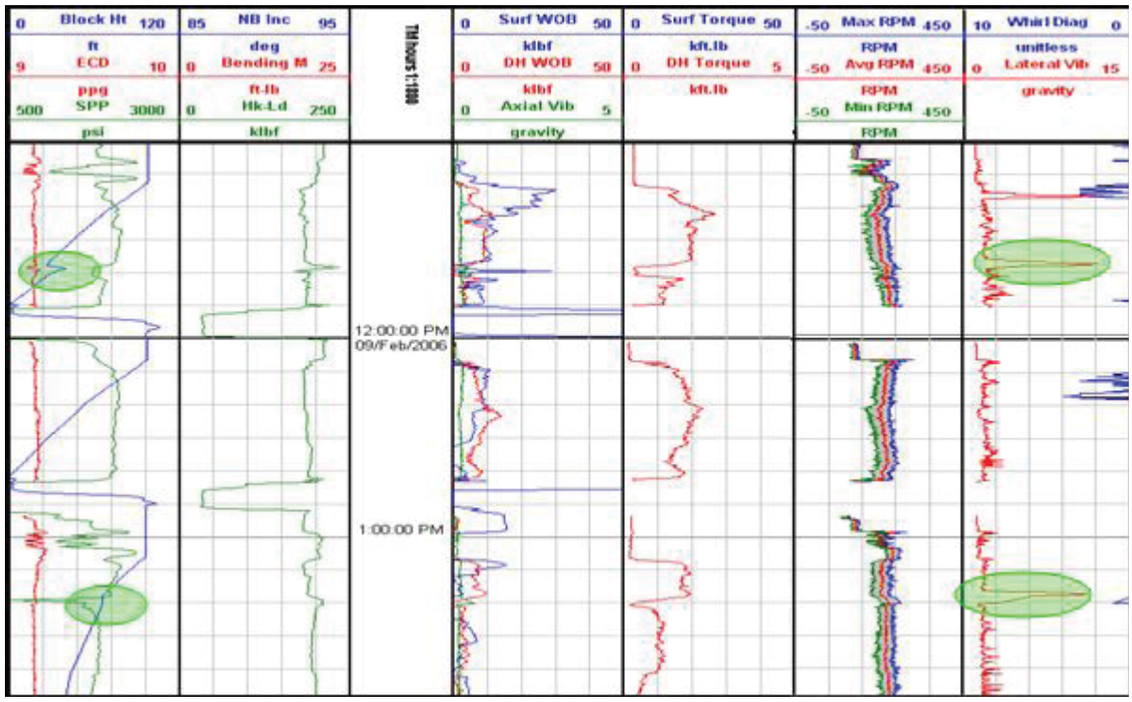


Fig 10: *Higher peaks of lateral acceleration recorded by the downhole dynamics tool are mitigated by change of parameters and/or by picking off-bottom.*

Particularly in 6 1/8″ terminal holes, downhole vibration environment can be very destructive to computerized RSS drilling tools and formation evaluation equipment. The drilling rate is usually adversely affected by any downhole vibration, and bit runs will be shortened by damage to the bit cutting structure.

None of the information that the directional drilling crews used to positively affect ROP and accuracy results could be gathered from the existing up hole sensors provided by the drilling contractor. These results would not have been possible without the drilling dynamics tool suite.

Given the evolution of the application, as portrayed in the published application examples, a new level of awareness enabled the drilling team to climb a very steep learning curve due to the accuracy and significance of data available in real-time mode at the rig site. Based on this newly gained knowledge, distinctive drilling and steering techniques as presented in the field examples above have been adopted to best cope with the reigning drilling conditions in both fields. Implementation of such drilling practices proved to be a key contributor to the noticed enhancement in performance.

Conclusions

When comparing the example wells to direct offsets, in both cases the drilling dynamics tool gave drillers a clear picture of the real-time results of their actions from a vibration viewpoint. The drillers had an array of downhole measurements at their disposal and in the case of the downhole weight on bit (DWOB) and downhole Torque (DTOQ), direct comparisons could be made with the rig surface measurements. After some time the drillers used the surface WOB and surface torque gauges only for casual reference when tripping or making connections.

In both cases the example wells eclipsed the previous best ROP records by a large margin, indicating that the use of these tools provides a step-change in drilling efficiency. Such a step-change, however, does not usually happen overnight. Commitment and a certain degree of patience and tolerance is usually required to get the full process of knowledge capture, awareness & knowledge transfer (training), and implementation of new practices into effect.

All sizes of the drilling dynamics tools continue to be successfully utilized in oil wells where the RSS tools

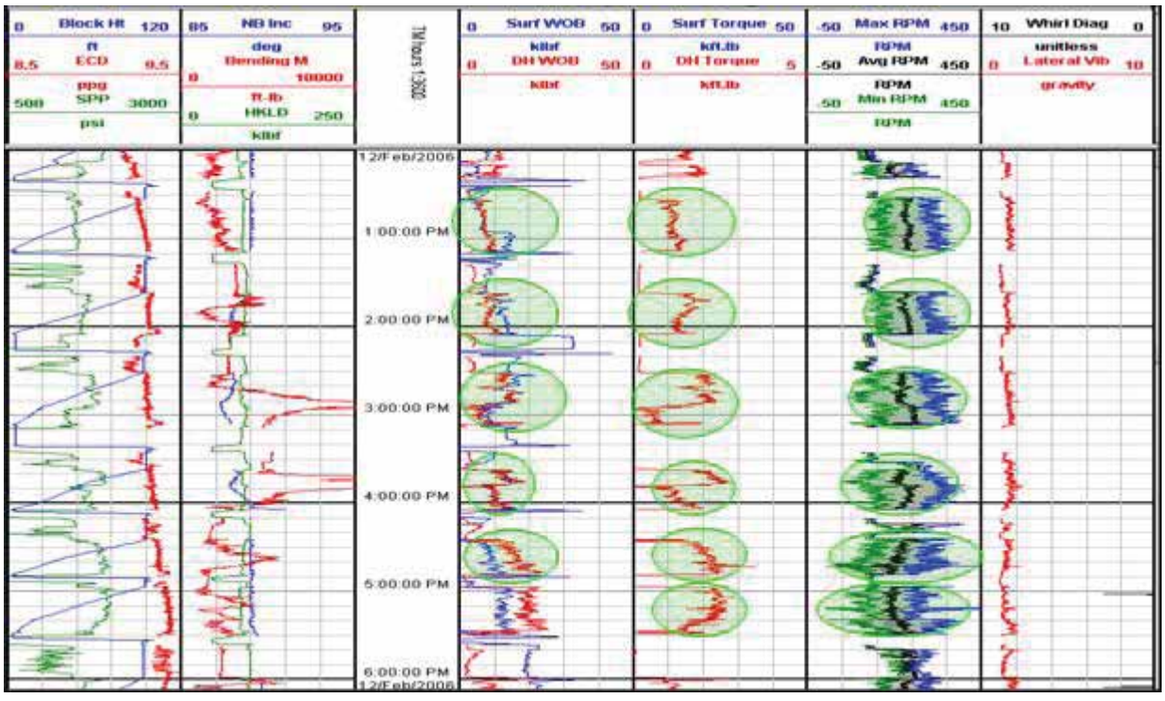


Fig. 11: *Log excerpt shows motor rpm responses to changes in weight on bit and accompanied bit torque. It also displays pro-active behavior by the drilling crew as they changed parameters in search of an "ideal" set of drilling parameters.*

are employed. As well there has been an initiative undertaken to bring the down hole dynamics tools to the deep gas horizontal drilling with steerable (motor) BHAs. Some initial runs have been completed already.

Acknowledgements

The authors would like to thank Saudi Aramco and Baker Hughes INTEQ for their support and their permission to publish this paper. They would also like to thank all individuals from Saudi Aramco Drilling Engineering Department, Baker Hughes INTEQ Saudi Arabia, and Baker Hughes Celle Technology Centre who were involved in the successful introduction of the downhole drilling dynamics tool in the 6 1/8″ hole sections in the Kingdom of Saudi Arabia. In particular, the authors would like to thank Dr Gerald Heisig for his contributions to this paper.

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Drillstem Testing for High Pressure Deepwater Wells: A Noncemented Floating Tieback Liner Technique

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This paper was prepared for presentation at the 2008 SPE Annual Technical Conference and Exhibition held in Denver, Colorado, USA, 21–24 September 2008.

Abstract

Current and future offshore exploration activity is penetrating to deeper reservoirs, driving the need for increased drillstem testing (DST) for high pressure and high temperature wells. Typically, liners are tied back to the surface to achieve reliable wellbore integrity and flow. In the past, these tiebacks require expensive cementing operations which also limit future wellbore re-entry options.

An innovative non-cemented floating liner tieback with reliable floating seals can improve the entire DST process by eliminating the cost and risk of cementing operations. In addition, the operator is able to retrieve the casing tieback and have the option to use the same well for appraisal or development phases.

The paper discusses the floating tieback system and details a case history on a high pressure well in which the operator completed the DST operation safely and met all well objectives. Discussion of system reliability includes casing design and modeling by both operator and suppliers, plan changes based upon pressure data obtained during the drilling phase, detailed operational procedure in a deepwater environment, successful tieback retrieval and future operations.

Introduction

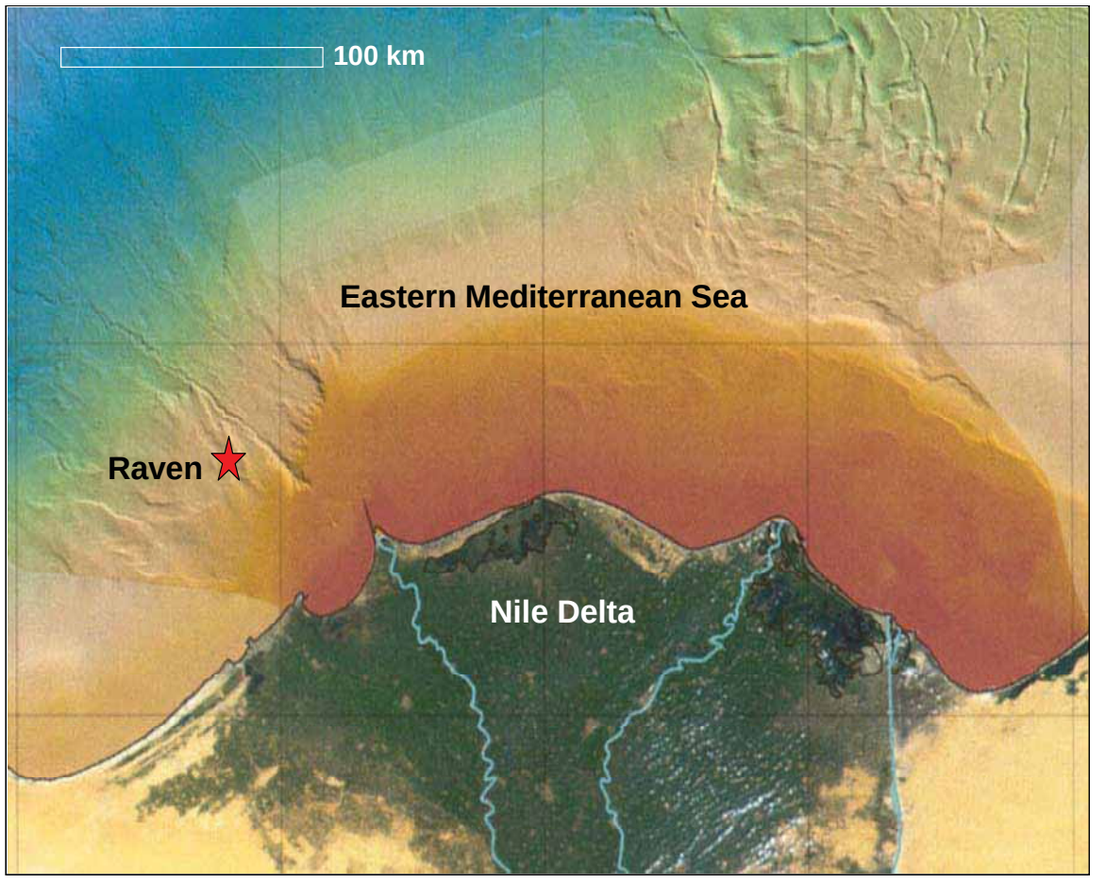
The Egyptian deepwater Mediterranean Sea was a fitting location for Raven 1 HPHT exploration well, one of the first

HPHT wells to be drilled in the Mediterranean. With a predicted 15,000 psi bottom hole pressure, the well required a special casing design capable of handling such a pressure and accordingly a fit-for-purpose liner hanger, tieback, and drillstem testing equipment.

With the conditions mentioned above, one of the challenges in the DST phase was the need to increase the burst capacity of the exposed casing prior to flowing the well. The conventional way was to run a liner tieback and cement it into place prior to running the DST completion and testing the desired zones.

During the drilling operation and with the data collected during the different well phases, the decision was made to use a new design approach employing a noncemented floating tieback liner technique. This would enable the DST operation to be carried safely without jeopardizing the well test objectives, but maintain the ability to retrieve the tieback string after the test as well as reduce the time required to run the string. Retrieval of the

FIG 1- RAVEN WELL LOCATION



string after the test significantly increases the future well re-entry and sidetracking options. A larger hole size can be drilled for any future sidetrack, thus allowing a larger diameter production liner and upper completion to be run if the well is subsequently converted to a producer.

Description and Application of Equipment and Processes

The original well plan was to run a 7-5/8 in cemented liner across the target zone for DST testing operation, run a 7-5/8 in liner tieback and cement back to surface and run a 7-5/8 in DST completion but based on the pressure data obtained during drilling operations the original plan was changed to tie back back the 7 5/8″ production liner with a 9-7/8″ upper tieback string to surface and study the possibility of achieving a seal in the PBR – tieback stem with floating dynamic seals.

A 9-7/8″ X 13-3/8″ liner hanger with liner top packer (rated 10,000 psi) was cemented in place with a 20 ft long PBR. The PBR had a burst pressure rating of 16,560 psi and collapse pressure rating of 12,549 psi. A tieback seal assembly with 3 sets of seals rated for 15,000 psi was chosen taking in consideration that out of 20 ft long PBR we will only have 14.5ft to accommodate the tube movement during the DST operation before the lower seals comes out of the PBR. Also it was confirmed with engineering what the maximum load the liner top packer could take in case the no go of the tieback seal assembly landed out on the liner top PBR as the tieback string increased in length due to thermal expansion when the well was flowed. The limit was 150 K LBS which was considered during the tube move simulation. FIG 2

Detailed modeling of the tieback string loadings and seal movements was performed and independently reviewed. The entire tieback system integrity was verified with suppliers and the operation procedure prepared with great attention to detail so that the tieback seal can be spaced out within inches of accuracy to ensure the integrity of the seal during the subsequent pressure

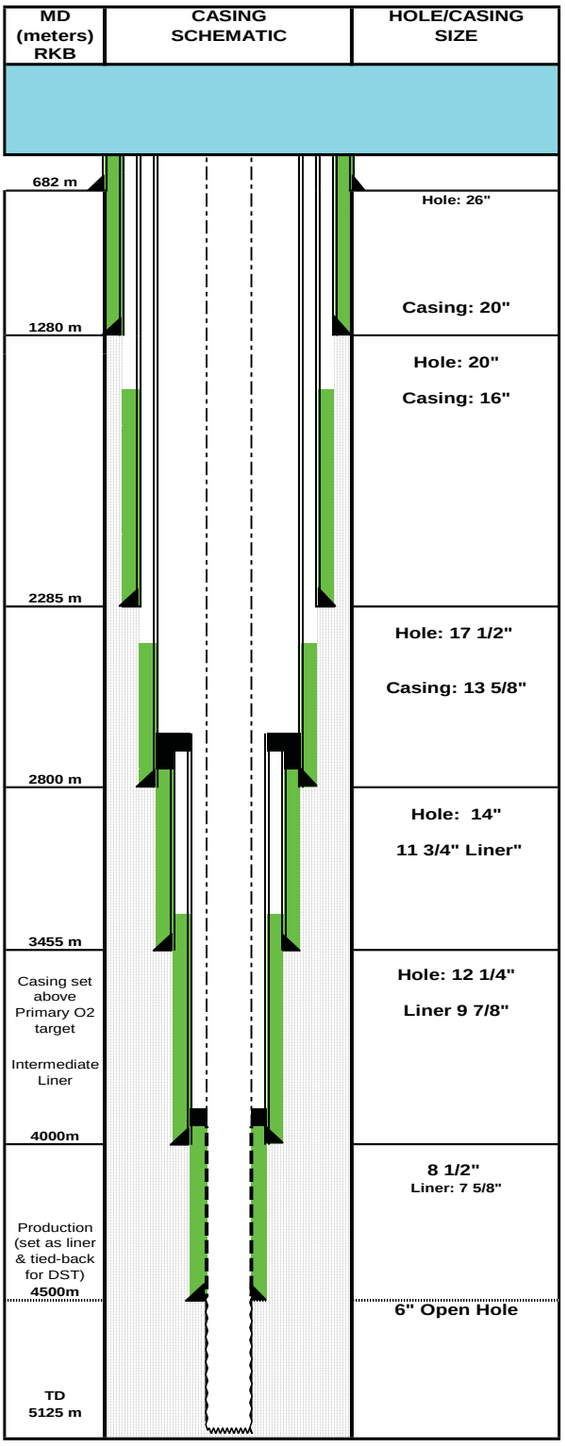


Fig 2: **WELL PROFILE WITH DST and TIEBACK STRING**

testing and DST operations.

Listed below are the major operation scenarios which were included in the tube movement simulations:

1. Landing the floating tieback seal assembly including the space out operation with the subsea well head. This was defined as the neutral point for space out considerations.

2. Pressure testing the floating tieback seal assembly from inside & outside to verify sealing integrity and simulate the pressure which will result in case of DST completion equipment leak

3. DST operation. The downhole temperature will increase as the well is flowed, resulting in an elongation of the tieback string and movement of the tieback stem further into the PBR, giving the maximum length design condition..

4. Killing the well and retrieving the DST string. The well will cool down and the tieback string will contract. The tieback stem will move upwards in the PBR, resulting in the minimum length design condition.

The liner tieback seal assembly seal type and redundancy to withhold the required pressure under a dynamic DST condition while maintaining its sealing integrity was a major factor in the acceptance of the operation , The bullet seal was recommended as it is designed for liner tieback and production type seal assemblies to withstand high pressure/high temperature (HP/HT) conditions. Durability of the downhole seals in dynamic conditions was increased with PEEK (Polyetheretherketone) backup rings located within each seal. Inherent with every tieback of a liner in a HP/HT environment is the expansion of the seals due to temperature before they are stabbed into the liner top polished bore receptacle (PBR). The Bullet Seals have been extensively tested at 15,000 psi and have proven that they can be stabbed into the liner top at high temperatures 400°F (204°C) and suffer virtually no damage. The Bullet Seals have also been rigorously tested in a dynamic mode and have proven that they will seal at high pressures while being stroked. These tests and numerous field runs have proven that the Bullet Seals can be used for such a case FIG 3

With the equipment identified for this application, modeling of the tieback string loading and seal movement scenarios was undertaken. Operator and Service Provider ran tubemove calculations independently to simulate and compare results based on the above mentioned 4 scenarios.

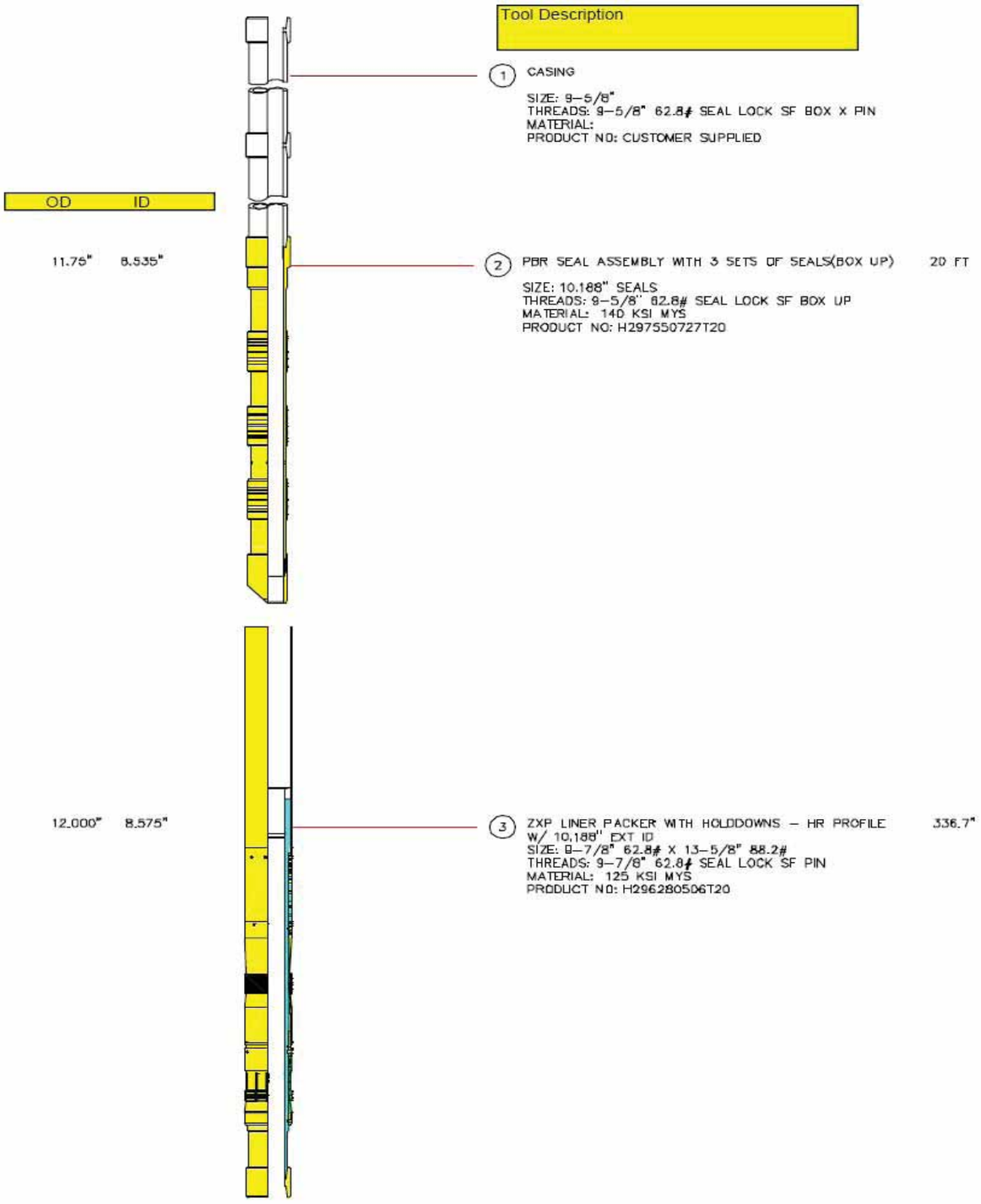


FIG 3: TIEBACK STRING DWG

In each of this stage it was necessary to discuss with the operations team to confirm that such a space out could be accomplished taking into consideration the challenge of landing the 9 7/8″ tieback string casing hanger in the subsea wellhead and at the same time achieving the correct spaceout of the tieback stem seal assembly into the PBR to accommodate both expansion and contraction length changes whilst keeping the seals within the PBR movement. Clearly, the tubing tally measurement was a critical factor in achieving the correct spaceout. FIG 4

Presentation of Data and Results

The outcomes of the simulation have been discussed between the two companies intensively and below are the results for the four cases of tube movement simulation. Taking into consideration that the length of the PBR is

Bullet Seal Stack

FIG 4: BULLET SEAL STACK AND SEAL ASSEMBLY

19.6 ft, the allowable length that the tieback can move in and out without bringing the seals out of the PBR is 14.5 ft, and this is the length we will consider in the case descriptions below – FIG 5 provides more details.

Case 1 – As landed space out

This is the base case where the tieback seal assembly will be run in the hole and spaced out for accommodating future DST operation , it was decided to sting in with 11.5 ft and leave 3 ft between the no-go of the seal assembly and the top of the PBR.

Case 2 – 10,000 PSI testing pressure

In this case, a 10,000 psi testing pressure was used. The tieback seals will move 8 ft up leaving 3.5 inside which will simulate the case if we have a leak from the DST packer.

Case 3 – DST operation

In this case, the DST completion was run and the well was perforated and flowing, and a thermal expansion of 3.6 ft was calculated based on the temperature effect due to the well heat during flow.

Case 4 – Well Kill

In this case, the well was killed through the DST completion, causing a cooling effect which impacted the tieback string by a shrinkage effect of 2.9 ft.

Conclusions

The tieback operation was conducted smoothly and the well flow-tested successfully. When compared with the original design, the benefit with the un-cemented 9-7/8" tieback is substantial:

• It resulted in several days' rig-time savings by eliminating the need to cement the tieback string in place and the associated clean up runs on slimhole 3-1/2" pipe. This pipe would have had to be picked up especially for this operation.

• It allowed for more efficient operations to recover the tieback string and provide more flexible options for future re- entry and sidetrack operations.

• It is estimated that the ultimate savings could be over $1.5 million.

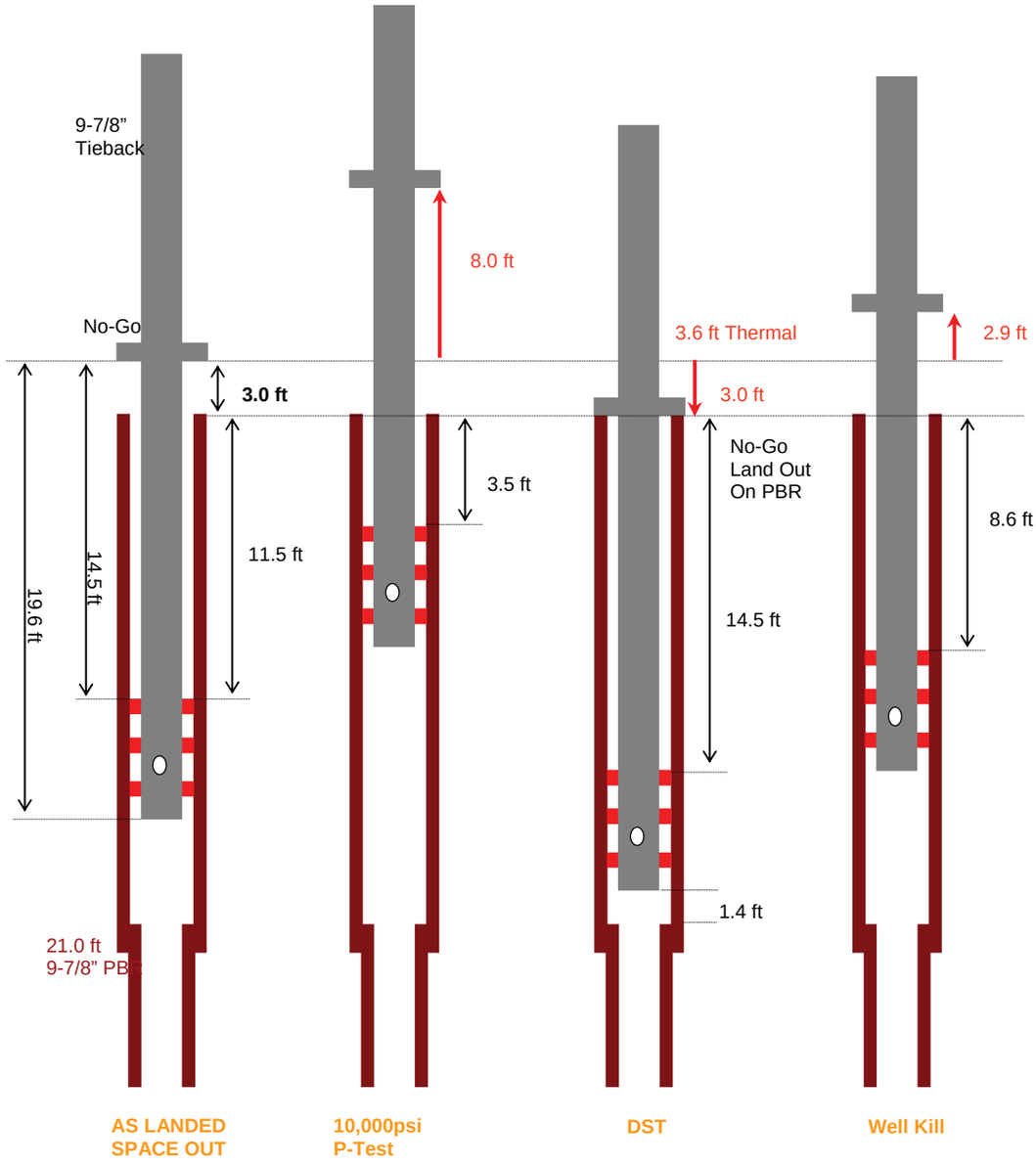


Fig 5: TIEBACK OPERATION DURING DIFFERENT OPERATIONS PHASES

Key Delivery

• Design for the 9-7/8″ tieback string.

• Detailed analysis of tieback seal movement in the liner top PBR to define the space-out requirement.

• Assistance in the preparation of the detailed procedures for the tieback string running operation.

Acknowledgments

The authors thank their respective companies for the opportunity to publish this paper. We also wish to especially thank all the operating and support personnel who contributed to the success of this work.

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Tube move program is based on S.P.E. paper #5143 (Entitled "Movements, Forces, and Stresses Associated with Combination Tubing Strings Sealed In Packers"), and, as such, is subject to the same assumptions and limitations as said paper

A Structured Approach to Benchmarking Bit Runs and Identifying Good Performance for Optimization of Future Applications

By C. Miller, Saudi Aramco, and R. Duerholt, A. Richards, and N. Briggs, Baker Hughes

This paper was prepared for presentation at the 2009 SPE Middle East Oil & Gas Show and Conference held in the Bahrain International Exhibition Centre, Kingdom of Bahrain, 15–18 March 2009.

Abstract

Performance analysis of large numbers of bit runs is often anecdotal and uses historical cost data. To this end, there are numerous problems with this approach. There is no uniform approach to identifying good performance. At best, the analysis provides an imprecise picture of overall performance. Large datasets need to be condensed into runs of interest. Difficulties arise when comparing multiple runs through long intervals with variable thicknesses of hard stringers. Since BHA, rig, and other costs change over time, it is problematic using historical cost per foot (CPF) data for the current target well. Finally, how does one determine if long slow runs or short fast ones are better since both could have the same CPF?

In this paper, the authors discuss a structured benchmarking method that can be applied regardless of the application or area studied. The basic process is simple and can be tailored to the requirements of different applications. The goal is to deliver a statistical benchmarking process that helps filter large sets of data and facilitates a consistent approach to bit performance analysis that is independent of historical cost data. A process flow chart is developed to guide engineers step-by-step through the benchmarking method. Good offsets are identified and included in the benchmarking population. Eligible bit runs are then ranked by a new key performance indicator (KPI): ROP*Distance Drilled. No historical cost data is included in the analysis. A detailed engineering study is then carried out on the identified best runs to develop recommendations for future applications. As the last step of the process, a financial analysis is carried out using cost data for the current well.

The paper will describe the use of this process to analyze bit performance in the operator's gas drilling operation and show how it allowed the identification of 'true' unbiased top performance. The benchmarking process

standardizes performance analysis and ensures sound engineering principles are applied resulting in a better understanding of past performance and better recommendations for future applications.

Introduction

The complexity and variability inherent in the drilling process magnify the difficulties in developing global benchmarking approaches for evaluating performance. Accordingly, performance comparisons primarily have been undertaken on a well-by-well or actual-versus-plan basis. [1, 2, 3] While a number of industry service-quality programs have been implemented to address trends involving multiple drilling projects, they have been only marginally successful. Most of those initiatives have sought to correlate drilling costs with key performance indicators (KPIs), individual drilling metrics, and parameters that integrate several KPIs and metrics into a single index. [4] For example, the Dodson Mechanical Risk Index (MRI) is a de facto standard that considers well depths, drilling fluid density, the number of casing strings, and various key drilling factors (KDFs) weighted by their projected impact on drilling difficulty.[5]

The Cambridge Online Dictionary defines benchmarking as a method "to measure the quality or performance of something by comparing it with something else of an accepted standard." In the exploration sector, drilling engineers try to analyze the performance of bits that drill more or less in the same application. Within one operator's drilling office, several different approaches can result in varying perceptions of bit performance, thus leading to possible misunderstandings about how performance should be measured.

More specifically, analyzing performance of a substantial sampling of bit runs is particularly problematic on a number of fronts. For one thing, the initiatives often are subjective and rely on historical cost data. Furthermore, no uniform approach exists for identifying what is satisfactory performance. Without some uniformity, such an analysis, at best, delivers an imprecise picture of overall performance. Consequently, these considerable data sets must be condensed into specific runs of interest as it is especially difficult, for instance, to compare multiple bit runs through long intervals with hard stringers of variable thicknesses. Moreover, with BHA, rig rates, and other costs changing constantly, depending solely on CPF and other historical cost data to analyze performance on a current well is unreliable. For instance, using historical cost data makes it very difficult to compare with any degree of certainty the performance of a long, slow run compared to a short fast run as both could have the same CPF.

Limitations of Historical CPF Analysis

Historically, CPF has been a widely accepted KPI for benchmarking different bit runs in a particular application. The CPF formula is expressed as:

$$\text{Cost Per Foot} = \frac{\text{Bit Cost} + (\text{Drilling Time} + \text{Trip Time})\text{Rig Rate} + \text{BHA Cost}}{\text{Footage Drilled}}$$

One of the key problems with this approach is that its limitations always are not fully appreciated, meaning benchmarking results easily can be misinterpreted. Accordingly, the operator generally discourages benchmarking of current bit runs using historical cost data. Along with their overall irrelevance to a contemporary operation, each individual element considered in the CPF approach, such as bit cost, distance, and drilling and trip time, also can distort the results of the analysis.

Bit Cost

- Bit prices occasionally are estimates only – sometimes averaged – and often historical (not current).
- Trips due to non bit-related downhole tool failure cause the first run to absorb all bit cost, while the second run often is entered at zero bit cost. A "free" bit results in an apparent – but false – improvement of economics.
- It is helpful to consolidate runs when the bit is pulled out of hole (POOH) for non-bit issues and later rerun. Often there is no clear procedure for this or it is disputed whether the reason the bit was POOH was bit-related.

Distance

- Short footage may be a result of the short distance to TD and not bit related.
- In the target application discussed later, long runs from the top of the Mid Thamama formation are more relevant than runs starting in the mid-section or deeper.
- Bits that are not the first in a section start at varying formations with varying drillability, thus making a comparison difficult.

Drilling Time

- Drilling time is defined as on-bottom drilling time plus connection time plus some non-productive time (NPT).
- Typically, the NPT included in the drilling time is not well defined. It may include short repairs, downlink times associated with communicating to certain BHAs, and other times that are not properly identified on the drilling reports. These times may be inconsistent from well to well and rig to rig. In this form, drilling time is

Depth In	Depth Out	Distance	ROP	Trip Time	Trip Cost
Ft	Ft	Ft	Ft/hr	Depth out/1,000 ft	$1250*trip time
5,000	9,000	4,000	50	9	11,250
6,000	10,000	4,000	50	10	12,500

Table 1: Illustration of trip costs

not a good measure of bit performance.

- Ideally, all NPT and connection times should be removed from the equation, but implementing this process may be difficult.
- Recording average connection times by rig also is unrealistic in many areas and, regardless, would only be an approximation.

Trip Time

- Trip rate typically is assumed to be 1,000 ft/hr.
- Trip time is dependent on depth out.

Trip time is highly variable and is affected by rig specifications, crew experience, hole conditions, and other factors.

As illustrated in Table 1, the deeper a bit drills, the more trip cost is assigned to it, thereby negatively affecting "performance".

Rig Rate

- Historical cost/ft data cannot be compared for different types of drilling rigs or rigs that are under different types of drilling contracts, e.g. footage, dayrate, turnkey. Assuming a standard rig rate to compare bit runs also renders this component of the bit economics meaningless.
- This rate does not reflect different rig types and corresponding rates.

BHA Cost

- BHA cost tends to be an estimate, as some contracts are hourly while others are footage or performance-based, making them difficult to compare.
- Some sections are drilled with MWD/LWD tools that have an associated cost, while others are drilled with very basic BHAs.
- Some sections are drilled with motors and some on rotary, while others are drilled with rotary steerable systems (RSS), again resulting in significantly different associated costs.

Proposed Benchmarking Process, New KPI

To overcome those limitations, a structured benchmarking method was developed that can be applied regardless of the application or area under study. The goal of this relatively simple approach is delivering a statistical benchmarking process that helps filter large sets of data, thus facilitating a consistent methodology for bit performance analysis that is independent of historical cost data or operating factors that can mask true bit performance. The process employs a process flow chart that guides engineers through each step of the benchmarking procedure. With this process, comparable offsets are identified and only these are included in the benchmarking population. Afterwards, those eligible bit runs are ranked by a new KPI: ROP*Distance Drilled, thus negating the use of historical cost data. A detailed engineering study on the identified best runs is conducted to develop recommendations for future applications. The final phase of the benchmarking process is the development of a financial analysis that employs current cost data applicable for the current well.

Since its inception, the process has been applied to analyze bit performance in the operator's gas drilling operation. The primary objective of the process was to identify optimum performance that is both accurate and unbiased. By standardizing performance analysis, the benchmarking process has ensured the application of sound engineering principles, thus enhancing understanding of past performance and allowing for more precise and scientifically derived recommendations for future applications.

For the chosen application, fairly basic data sets are analyzed comprising highly averaged bit record data, an issue in itself that is not discussed in this paper. The main variables examined include, but are not limited to ROP, depth in, depth out, footage drilled, WOB, RPM and dull grade.

The new KPI benchmarking formula that was suggested to the drilling team is expressed as ROP*Distance Drilled. This KPI is considered relevant in the application of interest where vertical sections typically are drilled with motors to improve performance. Some of the characteristics of the KPI include the following:

- It favors long fast runs.

• It clearly shows best performers that are ahead of the pack in terms of ROP and footage.
• It is independent of questionable CPF calculations.
• It is meaningful, especially when used in combination with distance and ROP individually.
• It correlates well with traditional CPF calculations, as illustrated in Fig. 1.
• Runs are quickly identified that combine the best bit selections with the best drilling practices. Often the best drilling practices are consistent across more than one bit type (motor selection, hydraulics, etc.).

While this KPI may not be relevant in all applications, it is conceivable that even in a directional environment, it can be oneof several important KPIs that may be employed. This is especially correct if the offset sample identification (Fig. 1) ensures the sections benchmarked against each other are comparable.

The step-by-step approach

A structured process was considered the key to improving the benchmarking process. As such, it should be self-explanatory and easy to follow without ambiguity, thus guiding the engineer in a step-by-step approach as illustrated in Fig. 2 and detailed in the ensuing discussion.

Step 1: Identification of good offsets

At this point, it is critical to select relevant runs, excluding from the sample population those that for one reason or anotherare not deemed good offsets. Factors that identify good offsets include:

• Hole size—To avoid scaling effects, runs of different drill bit diameters should be excluded from the hole size of interest.
• Time period—Runs that do not fall within a defined time frame should be excluded.
• Well location—Runs in fields, areas etc. that are not in close enough proximity or have known drillability that differs significantly from the target well should be excluded.
• Lithology—Runs that drill considerably different lithology should be excluded.
• Directional plan—Only those runs that follow a comparable well plan should be included.

Step 2: Benchmarking the offset sample using the new KPI "ROP*Distance Drilled"

The result of this identification process will be a ranking of the top 10 (top five, top three, etc.) runs out of the final sample population. If the offset sample identification was carried out carefully, these runs should represent the best performers.

Step 3: Engineering analysis of top runs

The next step is to analyze differences between these top runs and establish if the bit type used made the difference or if other factors are important as well. For example, did the BHAs used in all the top performers employ

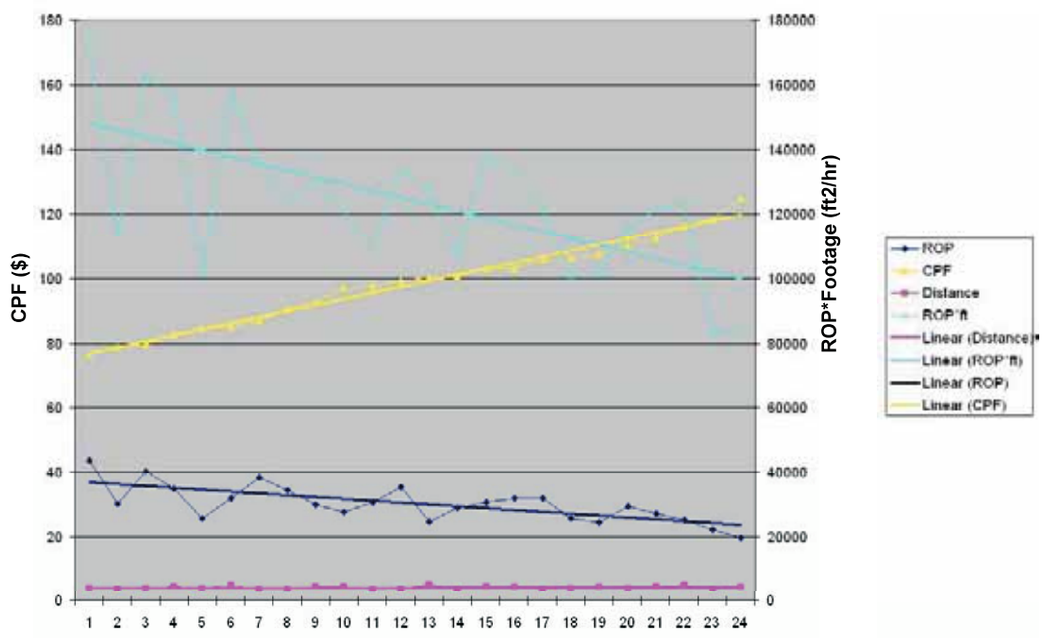

Fig 1: CPF and ROP*Footage relationship data set for 16-in. performance drilling in Saudi Arabia

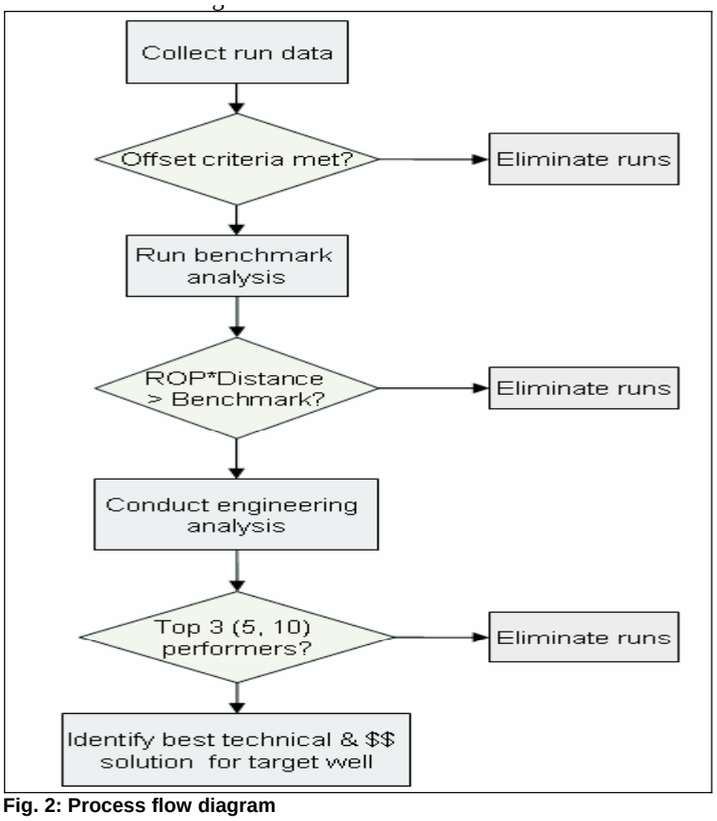

Fig. 2: Process flow diagram

MWD/LWD and motors or were some run on rotary assemblies with very basic BHAs? Did the directional plans of all the top runs employ similar trajectories? Were ROP, weight-on-bit (WOB) and other drilling parameters comparable for all top runs? Were all the identified bits run on similar aqueous or invert-emulsion drilling fluids of similar density? These are key considerations, but other elements of the sample population may also be analyzed if an interesting and uniform trend becomes apparent. For instance, was there a consistent degree of non-bit related NPT for all the top runs? It is beyond the scope of this paper to elaborate on the engineering part of the process. Detailed technical papers on approaches to in-depth engineering analysis of drilling performance have been published and are referenced at the end of this paper [6-13].

Furthermore, it should be noted that conducting a similar engineering analysis for the worst performers also can be a useful exercise in establishing lessons learned and best practices.

Step 4: Final bit selection

Of the top bit runs, some should stand out as the most preferable option/s for the target well. The preference should be based on the actual KPI number and the engineering analysis of the top runs. In terms of well profile, BHA used and other factors, the target well objectives may be very similar to one of the top five runs identified. Consequently, the top KPI performer may not always be selected as the primary bit choice, as the second best performer may be a better fit due to close similarities between its environmental attributes and those of the target well.

At this point, the top choices identified by the analysis should undergo a financial evaluation analysis that uses the actual cost of the target well to establish which combination of bit, BHA, and drilling parameters delivers the optimum result for the target application. The most important criterion for future success is to consistently repeat or improve upon the top performance achieved in the past.

Benefits

One of the primary benefits of the proposed approach is its implementation as a standard process followed by all engineers in the operator's office involved in performance analysis and benchmarking. Further, the service company can apply the same process during performance reviews to improve communication and mutual understanding. In other words, through this approach the operator and service company speak the same language. Accordingly, a consensus on what constitutes good or "best in class" performance is readily achieved.

It must be emphasized that the ROP*Distance Drilled KPI is meaningful only when used together with a structured and robust offset selection process. This ensures only runs that can be compared accurately are part of the sample population.

Application of the New Process to an Actual Dataset

The new process was put into practice in an actual field study that focused on a 16-in. vertical drilling application using PDC bits on straight motors. The 16-in section was chosen as it, historically, had been the location for a host of drilling challenges.[14,15]

Step 1: Identification of good offsets

Since only similar run conditions allow meaningful benchmarking, the first step includes identifying what constituted "good offsets" or "apples to apples" comparisons. Typically, a three or 12-month time period is defined, during which basic information for all bit runs is collected, normally including:

- Bit type, manufacturer, serial number, TFA, dull grade
- Field, well number and rig
- Run date
- Depth in, depth out
- Distance
- ROP
- RPM, WOB
- MW, PP, GPM
- Drive system

Daily drilling reports, BHA reports and other information also are required for the engineering analysis and comparison of the top runs identified during the benchmarking process. For this field study, the described data set was narrowed into more specific components, as follows:

Well location

Which wells are relevant offsets that can be compared? Can all gas field wells be included, or only specific fields such as UTMN, HWY, etc.? Depending on the circumstance, perhaps only a portion of all UTMN wells in close proximity to a target well to be drilled should be considered good offsets. Obviously, the more one constrains the valid offsets, the smaller the number of runs that will be compared. If the sample size is very small (perhaps less than 10 bit runs), the statistical validity is questionable, resulting in the non-identification of a clear winner in terms of consistently high performance. Too few constraints may lead to a large enough sample size that could contain non-relevant offsets.

Lithology and directional program

It must be determined if all runs that passed the location criteria drilled similar lithology and followed a similar directional plan, even though this pilot application comprises only vertical sections. Furthermore, is the lithology over different fields or areas of one field similar enough in terms of rock strength to generate a fair comparison? For the pilot application, for instance, it was decided to include runs that start in the Mid-Thamama formation and finish in or close to the Minjur formation. By including only runs at similar depth, all bits basically should start at the same origin. Runs starting significantly deeper were excluded as too many non-bit related variances could cause poor benchmarking. Ideally, only "shoe to shoe" runs that drilled the entire 16-in. section would be included, but at this point only a small percentage of all runs achieved this aggressive target.

Short drill-out runs are excluded, but a bit starting shortly after drill-out still can be considered as drilling from the top of the section. In the engineering analysis, this needs to be considered, as past experience shows that bits that drill out float equipment and the shoe can sustain damage that may lead to reduced footage or ROP further down the interval. Therefore bits that do not drill out are likely to have a starting line advantage.

Field comparison

To support the decision of which 16-in. sections in the gas fields to include, the average performance by gas field was compared. It was found that the average distance of the long runs is fairly similar across all the gas fields with less than a 10% variance. Conversely, the average ROP of these runs (Table 2) varies significantly between fields with more than a 40% variance. If the section overall is easier to drill, the bit may drill more of the hard and abrasive Minjur at the bottom. This will increase distance, but reduce overall ROP, resulting in a comparatively lower overall ROP. This suggests poor performance when, in reality, the run probably was satisfactory. Consequently, the engineer needs to decide its significance and include only the relevant offsets in the benchmark population.

Long runs were recorded in all fields, as well as many more short runs. Most fields show similar drillability in terms of average ROP. Generally, GHZL sections are shallower and faster to drill, while MDRK sections are deeper than average and, because of more compacted formations, slower to drill.

Short runs are not of interest and need to be eliminated from the sample population. Fig. 3 shows the runs to be eliminated, with the pink areas illustrating the short

Av Field Dist	Av Field ROP	Field
3815	35.7	GHZL
4187	28.4	HRDH
4022	40.4	HWYH
4080	24.7	OTHER
4052	29.8	SHDG
4426	31.5	UTMN
4138	30.5	
Gas Ave. Footage	Gas Ave. ROP	

Table 2: Average footage and ROP by field

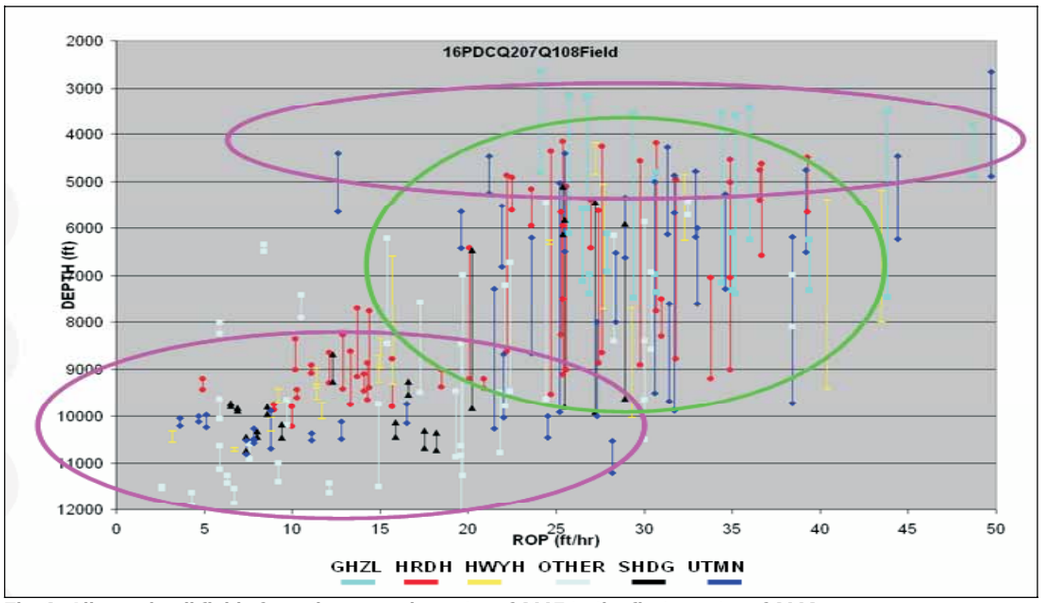

Fig. 3: All runs in all fields from the second quarter of 2007 to the first quarter of 2008

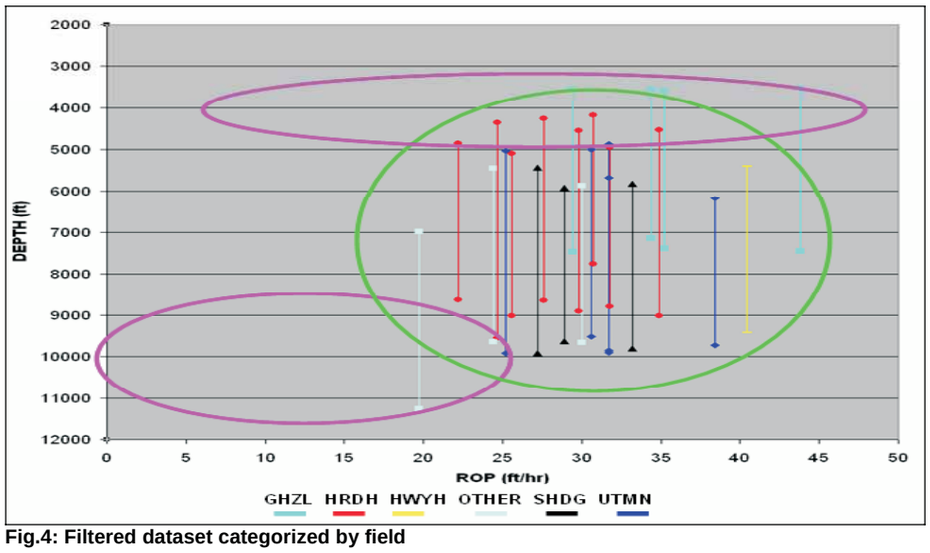

Fig.4: Filtered dataset categorized by field

runs. The green area highlights the long (>3,500 ft) and fast runs, which constitute the final sample population.

The determination of the sample population to be benchmarked comprised:

- Deep, short/slow runs that just finish off a section (lower pink circle on Figs. 4 & 5) were eliminated.

- Shallow, short runs that are mainly drill-out runs or runs terminated early because tool failures (upper pink circle on Figs. 4 & 5) were eliminated.

- Other runs pulled for tool failures or that did not drill a significant part of the section for other reasons also were eliminated.

- The remaining runs in the green area should be benchmarked against each other.

Step 2: Benchmarking

The sample shown in Fig. 6 is color-coded by bit manufacturer and reveals the dominance of one manufacturer in terms of long and fast runs. This representation does not identify clearly the true best runs overall. If ROP and distance drilled are compared individually, it remains difficult or a personal preference as to whether the long or the faster runs truly represent

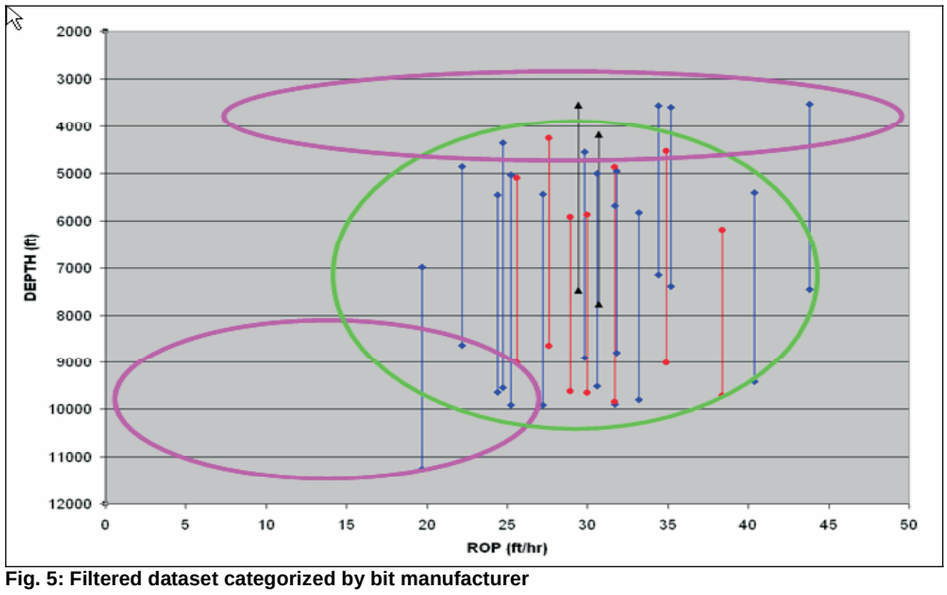

Fig. 5: Filtered dataset categorized by bit manufacturer

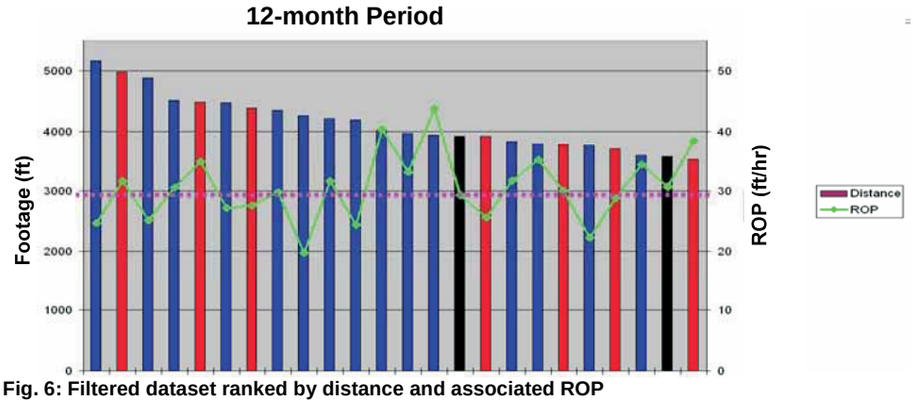

Fig. 6: Filtered dataset ranked by distance and associated ROP

best-in-class performance.

Considering the same sample population using the new KPI benchmark of ROP*Distance Drilled shows 16 runs meeting or exceeding an arbitrarily selected benchmark of 120,000 ft^2/hr in the four quarters (Fig. 7).

Step 3: Engineering analysis

Examining the data in more detail revealed that one motor type had a higher than average percentage of the good runs. This was especially true when the motor was combined with the new-generation PDC bit designed by Bit Company A. In this case, the success rate was 71% of the runs, thus beating the benchmark and indicating that optimizing the drilling system (motor plus drill bit) leads to success.

Sorting the bit runs by the new KPI has revealed a consistently superior combination of bit selection, motor selection, and drilling parameters. These are the best practices and lessons learned that should be emulated. Ocasionally there could be a "one off" bit run that outranks the crowd of best runs. This should peak the engineer's interest as it may represent a potential breakthrough in any combination of factors that affect bit performance. Finally this sorting of bit runs create a clear benchmark against which future bit selection and planning must be measured.

Step 4: Final bit selection

For the technical justification of bit selection for the target well the conclusions, lessons learned, and best practices from the engineering analysis should be applied to the target well objectives. The focus should be on the top three (or five, or 10, as appropriate) performers. Many technical objectives already may be covered, depending on how strict the benchmark offset selection criteria were in the first place. Care needs to be

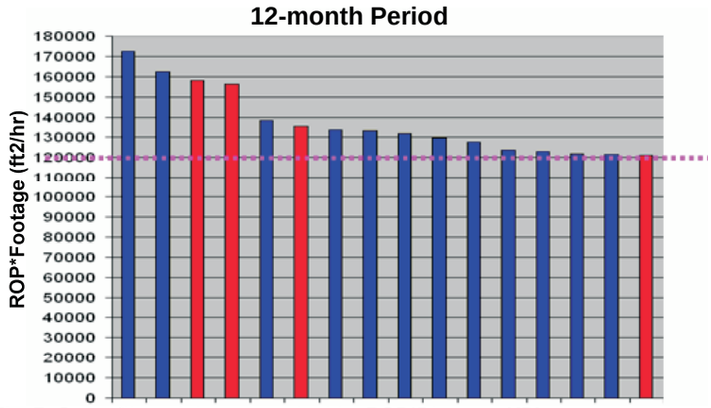

Fig. 7: Same filtered dataset ranked by ROP*Distance KPI

taken that the bit selection meets the requirements of the drilling system. For instance, a motor may require a different bit type than an RSS, as not all RSS work effectively with the same bit type and the same applies for different motors. This essentially is a system approach, where the bit selection also must meet the directional plan requirements. By way of illustration, a bit that worked in a 4°/100-ft build section may not be ideal in along tangent or vertical section. Once again, the focus should be to repeat and beat the best performance. And lastly, it is important not to merely look back, but consider new technology developments that are promising and backed up with sound engineering.

Only at this late stage of the final bit selection process should an economical evaluation be conducted. Overall drilling cost and CPF should be calculated for the target well using only actual drilling system and rig costs. For the reasons outlined earlier, no attempt should be made to compare these costs to those of older wells. In most cases a bit run designed to repeat the highest KPI historical runs will produce the lowest expected cost per foot. When confronted with more than one combination of bits and motors at the top of the KPI ranking, the economic comparison becomes meaningful.

The above performance can be used for calculating the economics of a hypothetical target well section, detailed as follows:

- Depth in 5,000 ft
- Depth out 10,000 ft
- Distance to be drilled: 5,000 ft
- Rig rate USD $35,000/day or $1,458/hr

Table 3 shows the economics for both bits on three differently priced motors. This analysis assumes performance will be affected only by the bit and not by the motor type, which typically is not the case. The technical justification needs to consider this aspect.

In this hypothetical example, the lowest expected CPF would be Bit X on Motor A. The difference in estimated section cost between these top performers is fairly small. Therefore, it is important to always use economic justification in combination with technical justification to make a final decision. For the target well, the expected ROP heavily influenced CPF as offset ROP may have been low because a bit drilled more Minjur formation or because of hole problems (Table 3: Bit Y, Motor B example). The technical analysis should always highlight such issues.

From offsets, everything else from target well

BHA	In	Out	Distance	Hours	ROP	Motor Rate	Bit Cost	Drilling Cost	Trip Cost	Motor Cost	Total Section Cost	Cost per Foot
Bit X, Motor A ($800/h)	5000	10000	5000	158	31.7	800	130000	229968	14580	126183	500731	100.1
Bit Y, Motor B ($1000/h)	5000	10000	5000	163	30.6	1000	130000	238235	14580	163399	546214	109.2
Bit X, Motor C ($32/ft)	5000	10000	5000	158	31.7	32	130000	229968	14580	160000	534548	106.9
Bit Y, Motor C ($32/ft)	5000	10000	5000	163	30.6	32	130000	238235	14580	160000	542815	108.6

Table 3: Data for cost analysis example

	Bits used	Run as 1st PDC in section	1st PDCs achieve > 120K benchmark	POOH for other than bit issue	Fair opportunities remaining	% >120K benchmark as 1st PDC
Bit 1	15	5	0	2	3	0%
Bit 2	2	2	0	1	1	0%
Bit 3	14	5	2	1	4	50%
Bit 4	12	4	1	1	3	33%
Bit 5	13	11	7	2	9	78%

Table 4: Comparison table for success rate > 120,000 ft^2/hr

Impact of New Bit/Motor Technologies

Actual performance achieved over the first six months of 2008 is encouraging. The benefit of the introduction of new bit technology and optimized performance of the bit/motor combinations becomes readily measurable. For example, the technology introductions helped surpass the benchmark in 78% of applicable runs that afforded the fairest opportunity to perform, i.e., the first PDC run in the vertical section. The achievement rate of older bit designs run previously ranged from 0% (not meeting the benchmark at all) to 50%.

Assuming all other factors remain constant, improving the success rate from 33% (Bit 4) to 78% (Bit 5) should not be attributed solely to a simple component change. Contributing heavily to this recent performance improvement includes the following:

- **A co-ordinated consultation process with the operator and the drilling system provider** – A unique bit design process [16, 17] was instrumental in the development of "Bit 5". Local application knowledge was integrated with global design and R&D expertise. Input from both the operator and drilling system provider is used to provide a "system solution" rather than focusing exclusively on bit design. The latest motor technology advances were considered and incorporated into the design process, including aligning increased motor torque capabilities with managed bit aggressiveness through depth-of-cut control technology. Details on the motor technology [13, 22] and applied bit technology[16 - 21] have been well documented in the literature.

- **Formation of a specific operating parameter guideline** – Detailed analysis of foot- and time-based drilling and vibration data identified such drilling dysfunctions as high torsional vibrations. Through Q3 & Q4 2007, a bit/motor operating guideline was developed combining theoretical and empirical criteria with suggested lithology-specific RPM and motor differential

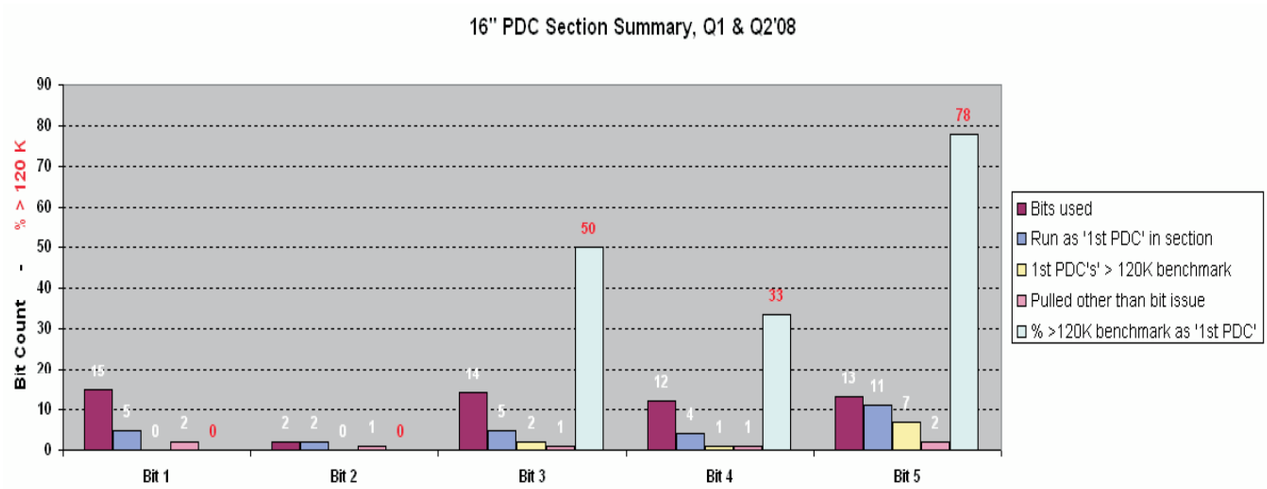

Fig. 8: Graphical representation of Table 4

pressure values. Successful field implementation aims to improve vibration mitigation, prolong component integrity, and ultimately improve drilling performance and bit/BHA system reliability. Instantaneous ROP peaks are sacrificed; however, it has been shown against field offsets that the net benefit is improved overall performance through sustaining a higher more consistent average ROP for longer distances.

Conclusions and Recommendations

The operator has defined and implemented a new benchmarking process in one specific application, that, when combined with a new KPI ROP*Distance Drilled formula, results in a better understanding of true performance. The new process has allowed for the identification of consistently good performance, which is critical when making bit selection decisions for future wells based on past performance.

Compared to past performance analysis, the new process for the first time introduces a consistent approach both the operator and service company engineering groups generally accept. Mutual understanding through a common language facilitates communication. Better and more consistent bit selection decisions can be made using the new process. Doing so means less incidental or anecdotal evidence is used to promote or demote certain bit types.

The process and the KPI also introduce a common language that can facilitate regular performance reviews between the operator and the service company. As the process has proven to be reliable, there is ample opportunity to expand its use into other applications in Saudi Arabia.

Potential application candidates for the future expansion of the process in the Gas Group include the following:

- 12-in. vertical
- 12-in. build
- 12-in. tangent
- 8 3/8-in. Sudair/Khuff build/tangent
- 8 3/8-in. Khuff C tangent only
- 5 7/8-in. Jauf horizontal
- 5 7/8-in. Unayzah horizontal

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Saudi Aramco's Research and Development Center's Upstream R&D Program

Saudi Aramco's Dominique Guérillot spoke to Saudi Arabia Oil and Gas about the company's Upstream R&D Program operated at R&D Center

By EPRasheed staff

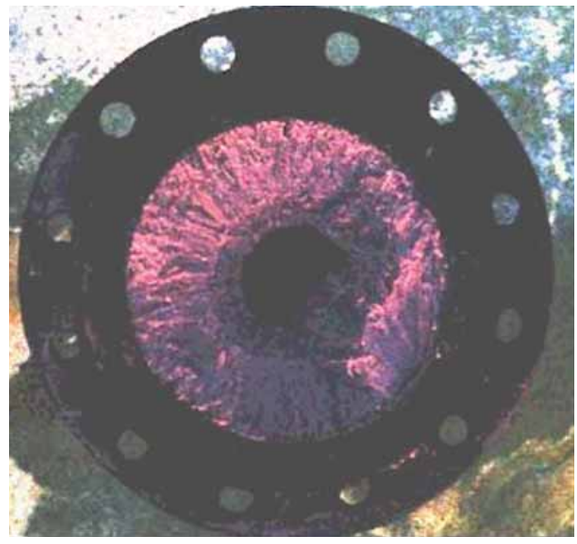
Dominique Guérillot.

... we want to encourage projects to develop competences in areas where we believe important field applications exist in the near future, such as fluid flow modeling, biological and corrosion processes.

Q: Saudi Arabia Oil & Gas – How is the Upstream R&D Program structured and what is its focus?

A: Guerillot

There is a Saudi Aramco's wide-ranging upstream R&D program managed from its R&D Center in Dhahran which complements the Research done with EXPEC ARC and which focuses on Oil Production from the wellhead to the separators, and on scale and corrosion related problems from down-hole to the separators. This upstream R&D program conducted in the R&D Center is organized into four main



projects: Crude oil stabilization; Pipeline integrity Black powder management and Water Systems.

Each project is sub-divided into different activities which aim to solve related problems.

Q: Saudi Arabia Oil & Gas – Can you expand on the Upstream Program' management and interaction with partners?

A: Guérillot

To set up these projects, we have followed key management principles. This includes ensuring a clear commitment of our proponents is obtained before pursuing or starting new projects as well as structuring the projects according to groups of activities with the same business aim. Additionally we want to encourage projects to develop competences in areas where we believe important field applications exist in the near future such as fluid flow modeling, biological and corrosion processes. We have also held back from projects that may develop competences for which we do not have a clear understanding of the possible impact on the company needs. Lastly, we have made extensive use of 'pre-project' phases as the first part of a staged, gate methodology. The goal of these pre-projects is to prepare all the necessary elements to launch a multi-year project.

This is expected to create several advantages. For example, this should lead to better responding to the actual needs of the company and an optimal resource allocation (in house or partners). It should also lead to better interactions with proponents, sister depart-ments inside the company and define a multi-year strategy following the long term strategy of the company.

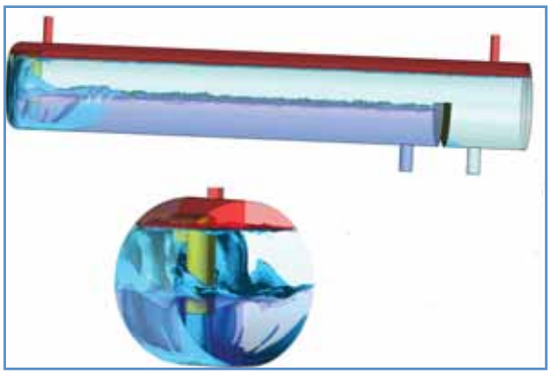
It will also help define partnerships for each project to speed up the output and reduce the risks inherent with R&D projects depending on the skills and strengths of Oil & Gas Companies, Service Companies, Public R&D Centers or Universities.

Q: Saudi Arabia Oil & Gas – How important is Black powder management and how has this shaped the research?

A: Guérillot

Over the past few years black powder has gained increasing relevance and attention throughout Saudi Aramco. In 2006, important results were obtained by our team and we can say that Saudi Aramco's approach in managing the black powder problem is unique and proactive to the rest of the industry in that it is pursuing the evaluation and implementation of several removal methods such as mechanical and chemical cleaning, installation of filters and inertial separators, installation of high erosion-resistant materials in control valves, and developing

basic understanding of black powder formation mechanisms in order to prevent it.



The latter analysis has shown that the source of black powder is internal corrosion of gas pipelines. However, despite all of these efforts several fundamental unknowns are critical for the successful and cost-effective implementation of these management methods. This year, in addition to the research done on the characterization of the black powder, a three year project has been built in close cooperation with the pipeline department to deal as a first priority with the sales gas transmission pipelines.

The main research topics are:

Determination and prediction of black powder formation rate: The formation rate of black powder will provide means to estimating the quantities of black powder generated inside the gas lines. This information is essential for proper selection and design of the various black powder removal methods such as mechanical and chemical cleaning, filtering, and separation as well as the handling and disposal of black powder.

Characterization of the erosive behavior of black powder and optimization of control valve design: This research activity is essential for cost-effective selection of materials for pipeline control valves. The end result is improved control valve integrity with significant cost savings and enhanced safety of operations by avoiding catastrophic failures of equipment due to erosion.

Development of black powder inhibition methods: When bare gas pipelines are used, as is the case in Saudi Aramco, prevention measures other than reducing the condensed moisture content in pipelines need to be practiced. Changing the electrochemical characteristics of the condensed moisture will be investigated as a technique for the prevention of internal corrosion and therefore black powder formation. This is an innovative approach that has never been tried before and has a high merit for patenting.

Internal coatings technologies: Organic solvent coatings primarily used for drag reduction in bare pipelines will be investigated as a prevention method for black powder formation in new gas pipelines.

Saudi Aramco is leading the Black Powder Project in the framework of the NOC forum. This will allow us to share our experience with, in particular, Petrobras and StatoilHydro.

Q: Saudi Arabia Oil & Gas – What does the Crude oil separation and stabilization program involve?

A: Guérillot

This focus area is composed of three applied R&D activities:

First is the numerical modeling of separation flows. The curent design methods for the internals of separators rely mainly on empirical rules which fail to take into account variable in-flow fluid characteristics due to water cut, effect of emulsion, chemical additives, inhibitors, etc.

The research ultimately aims to optimize GOSP performance considering that advanced numerical tools may improve fluid separation calculations. This will allow us address the issues of (1) gas/liquid separation and (2) water/oil separation. We will deliver a software tool for optimizing the design of new and revamped production fluids separation vessels. There will also be recommendations for best operating practices for existing GOSPs. The work will focus initially on modeling the contributions of gravity and demulsifier additives but other separation enhancement techniques (electrostatic coalescers) will also be investigated. R&D collaboration with Total and IFP is running on this subject in addition to the sponsorship of two JIP projects.

Second is the separation test unit & field testing. We need a better understanding of the physics and flow dynamics in separation vessels to develop a simulation

model for the assessment of separation vessels. Therefore this activity is linked strongly with the activity described above. A reduced size separation vessel for field use, the Separation Test Unit (STU), is currently in the engineering phase. This test facility equipped with several types of instrumentation is planned to be field tested during one full year in order to provide experimental data on fluids separation in winter and summer production conditions.

The STU could be used also for the evaluation of some advanced separation technologies (cyclonic vessel inlet device, electrocoalescers, mixer valves, degasser and demister packings) during the field test period of one year.

Therefore the targeted deliverables for this activity are:

• An experimental data bank from the field tests that will be used for validating the numerical models for crude oil separation.

• Field evaluation of some advanced separation technologies from vendors.

The third issue of interest is the online salt in crude analyzer. Saudi Aramco oilfields operators have been looking for a reliable and accurate method for monitoring the salt content in the crude oils exported from their GOSPs. The commercial technology available so far for online Salt-in-Crude measurement does not meet our requirements. R&D Center has an innovative idea and proposes to develop it in this research activity. Promising laboratory results have been obtained in 2007 using an innovative approach. A thorough literature review and patent search on Salt in Crude measurement were also conducted in 2007. A prototype online Salt in Crude Analyzer will be developed in 2008 and tested. If the measurement performances of the prototype are satisfactory a field test will be conducted in 2009.

Q: Saudi Arabia Oil & Gas – How is the Pipeline integrity program being developed and what are its main activities?

A: Guérillot

One of the main issues in production is to ensure continuous production of oil and gas. We have identified several important operational concerns to study such as Sulfur deposition prediction, prevention control of blister extension and prediction and control of sleeved pipe collapse.

Sulfur deposition prediction: Because of the reoccurring problem of sulfur deposition which all companies meet, it is essential to understand better the mechanism of its generation. The objective of this activity is to identify the optimum condition where elemental sulfur can be deposited. These conditions will be modeled and provided to plants to be able to predict sulfur deposition at their operating conditions.

The thermodynamic behavior of sulfur considered as a

solid phase in a multiphase system is not documented in the literature with the pressure and temperature corresponding to the surface conditions. There are data and Peng Robinson thermodynamic models are available for subsurface conditions but these may not be applicable to the pipeline operation conditions.

The plan is to study the parameters including critical decomposition temperature and pressure of polysulfide (H_2S_2), chemical reactivity with other species such as water, glycol, and level of hydrogen sulfide (H_2S). In addition, the critical gas composition will be determined as close as possible and will be used as a guideline to plant operations along with parameters.

Field data and plant operation parameters will be collected and compared to laboratory results so that an optimum condition can be drawn out of this study improving the accuracy of the software tool to be used by the plant operation.

Prevention and control of blister extension of metal exposed to oilfield environments containing H_2S was recognized as a materials failure problem by 1952. Laboratory data and field experience have demonstrated that even extremely low concentrations of H_2S may be sufficient to lead to Sulfide Stress Cracking (SSC) failure of susceptible materials. This project aims at defining the role of the water chemistry in the initiation and propagation of SSC as well as Hydrogen Induced Cracking (HIC). This study will permit to give guidelines to the company to enhance the material selection for this purpose. For example some process lines, where pH is stable and approximately neutral, do not necessarily require HIC resistant steel. On the opposite, severe requirements shall be given for steel exposed to fluids originator of HIC in sensitive steels. This would provide improved safety, reliability and economy.

This project for 2008 was elaborated after a pre-project conducted in 2007. The aim is to improve the crack resistant materials selection for sour service and the fluid parameters governing crack extension. Meanwhile a field test will be deployed to assess the crack extension detection.

Within the next 30 months, the proposed project will complete the development work needed to improve the materials selection for sour service, evaluate the fluid composition influence on crack extension and assess new instrumentation for blister extension measurement.

The field and laboratory activities in the project will employ a variety of competencies related to sour service already available within Saudi Aramco R&DC.

Q: Saudi Arabia Oil & Gas – How are water systems incorporated in the research?

A: Guérillot

Nitrate treatment: In several water systems of the company, it was observed that the generation of hydrogen sulfide was souring our oil. This biological generation has a number of adverse effects. In 2006, a test of nitrate injection in Hawtah field gave very interesting results. The technology is based on the approach of stimulating the activity of nitrate reducing bacteria (NRB) who will compete with sulfate reducing bacteria (SRB). Because the NRB which are not generating H_2S but nitrogen are 'better in eating' this shared carbon source, the SRB (which generates the H_2S) will not generate further H_2S. But still a lot of aspects have to be studied to fully control this biological process. It allows reducing (and it may suppress) the use of biocides and the nitrogen is an inert gas without any chemical effects.

The proposed work will complete the development work needed to extend the treatment to the oil trunklines as part of an integrated treatment strategy. It will optimize dosing regimes (concentration and squeeze, continuous or pulse) and confirm the specific control mechanism. It will also quantify beneficial and adverse side effects and help us to understand the envelope of applicability of the technology within Saudi Aramco.

The field and laboratory sub-projects utilize a variety of competencies already available within Saudi Aramco R&DC in collaboration with the Hawtah field technical team. In addition, the project will enable the expansion of the existing R&DC network of expertise in the field and allow fast tracking of the technology development by means of focused research projects with research and professional institutions such as the Calgary University.

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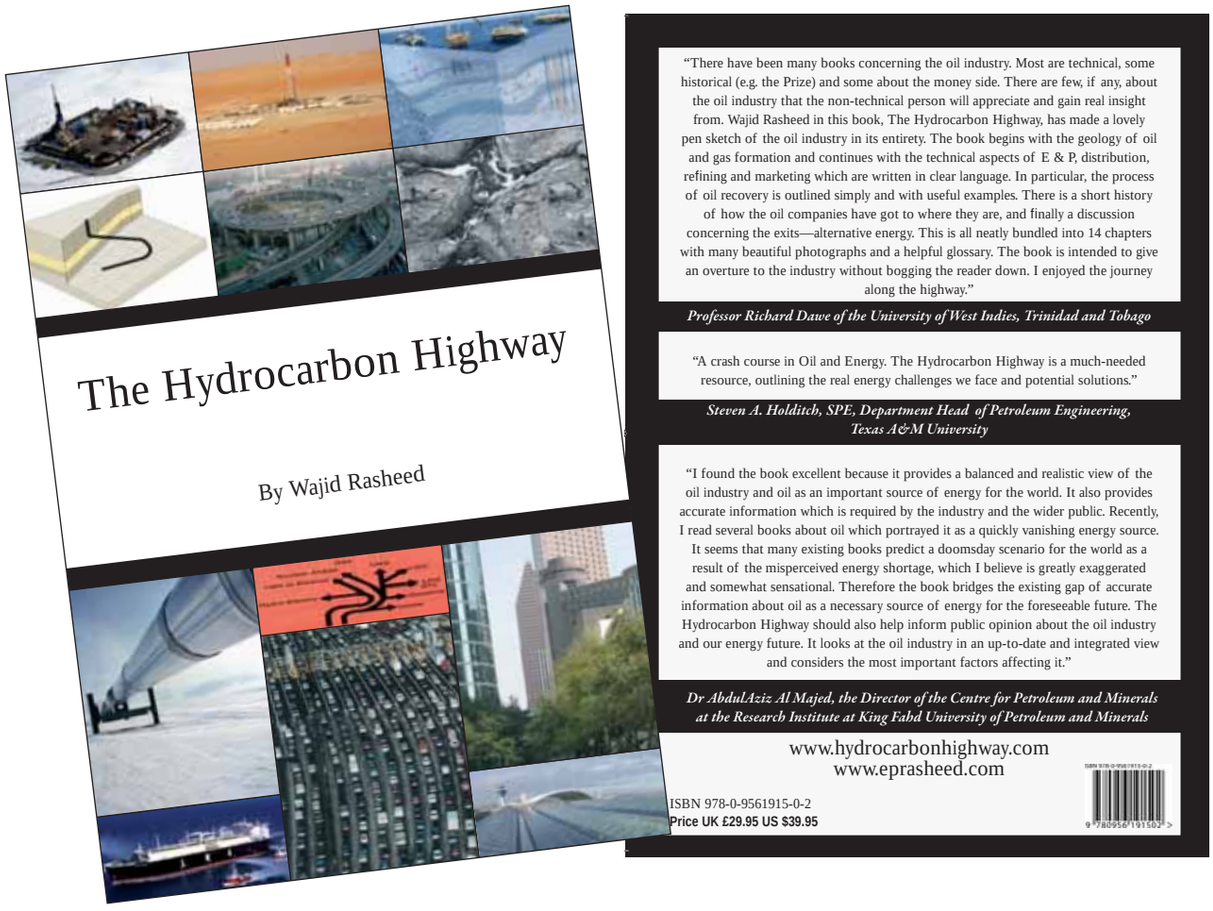
What's In a Wet Barrel?

An Extract from The Hydrocarbon Highway, by Wajid Rasheed

This chapter reveals how oil and gas asset production can be maximised through an understanding of petroleum and reservoir types.



When crude oil first came into large-scale commercial use in the 19th century, it was stored and shipped in wooden barrels with one barrel equal to 42 US gallons or 159 litres. The term 'wet' barrel denotes a physical barrel of oil that is actually delivered or consumed as opposed to a futures or other paper barrel that is traded.

Asphalt, bitumen and crude are common terms describing different forms of petroleum that can be found in a typical 'barrel' of oil[1].

The term comes from the Latin petra—"rock" and oleum—"oil". For lay people, petroleum itself is a generic term that covers all naturally occurring hydrocarbons as well as refined products or derivatives.

For purists, however, petroleum refers to chemical

HRH Prince Andrew looks throughThe Hydrocarbon Highway at the MEOS Conference, Bahrain.

compounds made up of hydrogen and carbon atoms; consequently, the classification hydrocarbon is more appropriate. Definitions aside, hydrocarbons in their 'un-produced' state are found in underground accumulations or reservoirs of oils, gases, water and impurities located at depths ranging from 2,000 ft (610 m) to 25,000 ft (7620 m). Petroleum naturally seeps to the earth's surface along faults and cracks in rocks gathering in tar, asphalt, pitch or bitumen lakes. Shortly, we will consider the make-up of reservoirs but first of all, what's in a barrel of oil?

Nature's best orange juice is sweet and light, as is its crude; however, not all of the 200 or so naturally occurring varietals of crude oil are so blessed and this affects their commercialisation. Sweet crude has less than 0.5% sulphur content—increase this figure and it turns 'sour'. Light crude has a density of 20° or more using the American Petroleum Institute's (API) specific gravity scale and has light hydrocarbon fractions. Heavy crude has more complex fractions with higher densities and lower API gravities[2].

The Colour of Oil

Generally speaking, the colour of crude oil intensifies with its density and viscosity. While black oil is hard-to-pour and has high density and viscosity, green to yellow oils are runny and have low density and viscosity. The term 'crude' refers to petroleum straight from the wellhead in its 'unrefined' state that can generally flow in atmospheric conditions. Where petroleum is unable to flow in atmospheric conditions, it is often referred to as heavy oil, tar or bitumen[3].

Technologists quibble on when crude gets heavy; some say this happens at 25°API or less and others say 20°API or less. This is important because heavy oil trades below its lighter counterpart. For our purposes, the definition of heavy oil is 20° API or lower and further detail is found in *Chapter 8: Extreme E & P*. Finding heavy or light crude oil depends entirely on the presence of cap rock and permeability, as these will prevent or permit oil and gas to leak to the surface and be dispersed. In Venezuela's Orinoco Belt, for example, heavy oil deposits are found close to the surface with the lighter frac-

Figure 1 - Nature's Best Is Sweet and Light (EPRasheed)

Figure 2 - Heavy Oil Is Unable to Flow at Atmospheric Conditions (EPRasheed)

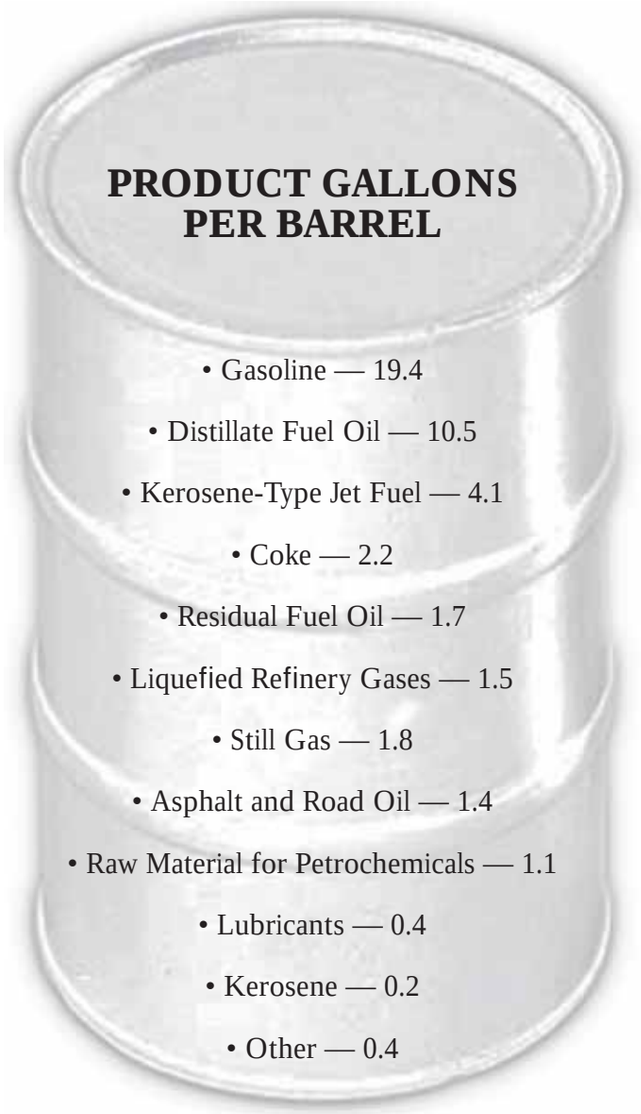


Table 1 - Products Per Barrel of Oil (in Gallons).

Note: Distillates includes both home heating oil and diesel fuel. Residual fuel oil refers to heavy oils used as fuels in industry, marine transportation, and for electric power generation. Figures are based on average yields for U.S. refineries in 2005. One barrel contains 42 gallons of crude oil. The total volume of products made is 2.7 gallons greater than the original 42 gallons of crude oil. This represents 'processing gain.' (After API)

tions of oil having migrated or dispersed over the years, leaving only the heavier residue.

Sour as a Skunk

Sour crude with its high sulphur content sells below its sweet counterpart—the gap can be US $5 or more and is likely to increase in the future. The gap exists because sour crude requires specialised refining treatment before it can be sold; however, there are more sweet than sour refineries worldwide. Consequently, a refining preference for sweeter crude exists[4].

The naturally occurring sulphur compounds or 'mercaptans' present in sour crude are powerfully smelly and are also found in garlic oils and skunk secretions. The malodorous mercaptans are by-products of decay-

Component	Boiling Point °C	Black Oil	Volatile Oil	Gas Condensate	Wet Gas	Dry Gas
Methane, CH_4	-161	49.0	64.0	86.0	87	96.0
Ethane, C_2H_6	-88	2.8	8.0	4.4	5	2.8
Propane, C_3H_8	-42	1.8	4.5	2.4	5	0.3
n-Butane, C_4H_{10}	-1	0.8	2.0	0.8	0.6	0.2
i-Butane, C_4H_{10}	-11	0.8	2.1	1.0	0.6	0.2
n-Pentane, C_5H_{12}	36	0.7	1.5	0.3	0.5	0.1
i-Pentane, C_5H_{12}	27	0.5	1.5	0.5	0.5	0.1
n-Hexane, C_6H_{14}	69	1.6	1.4	0.6	0.3	0.1
Colour of liquid at surface		black	brown	straw	white	-
Liquid Specific Gravity		0.853	0.779	0.736	0.758	none
°API		20-35	38-50	50-70	50-70	none
GOR scf/bbl		50-1500	2000-40,000	3000-18,000	>100,000	none

Table 2 - Crude Oil and Natural Gas Varietals, After Professor Richard A. Dawe

ing organic matter and they must be treated which adds to refining costs; however, mercaptans have a market value. They are used to imbue an odour to commercial natural gas so the general public can easily be alerted to a gas leak. Untreated natural gas is odourless, and without the tell-tale smell of the mercaptan additive, the public could be unaware of a gas leak until it was too late and someone was asphyxiated or an explosion occurred. Getting rid of sulphur, water, chlorides and other such impurities improves quality, increases value and stretches the world's oil reserves but it also adds to cost.

Table 2 shows a series of oil and gas compounds and their respective molecular weights and common names ranging from methane gas (CH4), petrol (C5H12 to C7H16) to asphaltene (C80H160). Many characteristics such as density, viscosity and flammability are determined by molecular weights and greater detail is available in *Chapter 11: Refining*.

The range of oil varietals is illustrated by extremely light oil, which has a relative density and viscosity below that of water, to extremely heavy oil which has a relative density close to that of water and high viscosity that can be 100 to 100,000 times that of water.

Molecular Weight

Typically, oil has a carbon content of 84 to 87% weight and a hydrogen content of 11 to 14% by weight[6].

Table 2 shows that hydrocarbons exist with varying densities and viscosities. Viscosity is a prime determinant of the ability to produce and refine oil. It is worth noting that the number of hydrocarbon compounds increases dramatically due to isomers, differing arrangements of the same number of atoms. In the case of hexane (C6) there are five isomers, for decane (C10) there are 75 and for C30 there are more than four billion. Although laboratory analyses of reservoir hydrocarbons can profile all compounds containing as many as 20 carbon atoms, it is usually sufficient to profile compounds containing up to six or seven atoms, with a general number being used to represent the total proportion of heavier molecules that are present[7].

The general trends depend on the ratios of methane (CH4) and the heavier components. The intermediates, C2-C6, control the GOR and API grade. The percentages shown are representative only and each category can be considered as flexible. Additionally, once production starts from a reservoir, the state of equilibrium that has been established over geological time is destroyed. Pressure gradients are created and the chemical composition and the physical properties of the fluids in the reservoir change. This happens as the pressure exerted on the fluids changes from the reservoir to the wellbore to the surface and, over time, as the fluids constituting the reservoir change.

Analysis is usually presented in terms of C1, C2, Cn+ with n often being 7, 12 or 20. Compounds that are not expressed in this way are usually treated as a composite fraction characterised by a molecular weight, density and/or a boiling point.

For E & P purposes, physical properties such as colour, API grade, viscosity, bubble point pressure, Gas-

Figure 3 - Checking Crude Samples (Saudi Aramco)

Oil Ratio (GOR), pour-point, and kerosene content are characterised. For downstream purposes, actual hydrocarbon compositions and fraction descriptions are required. Traditionally, the analysis of produced fluids was performed in the laboratory and could take weeks or more to obtain. Nowadays, real-time formation testing tools can provide analysis of produced fluids in near real-time at the wellsite.

Saturated Oil

Produced oil will always contain a certain amount of dissolved gas. The exact amount depends on reservoir conditions such as temperature and pressure as well as the composition of the oil. If the oil cannot dissolve any more gas under the prevailing conditions, it is termed saturated; the excess gas has moved to the top of the reservoir and formed a gas cap. If the oil can dissolve more gas, it is termed undersaturated, and no gas cap will be initially present on production. The GOR is the ratio of the volume of gas produced to the volume of liquid and may be expressed as cubic feet per barrel depending on the units used for measuring gas and liquid. For gas wells, the inverse ratio is sometimes used and the liquid-gas ratio is expressed in barrels per million m^3 (or million cubic feet)[8].

Impurities

Reservoir characteristics depend on the interplay between the molecular arrangements of the hydrocarbons, the extent of liquid and gas phases as well as the existence of impurities. Aqueous impurities are caused by differing levels of salinity and mineral salts within water that were present within rock pores before hydrocarbons migrated into the reservoir rock, displacing a certain volume of this water. The volume of water that remains after migration is known as 'connate water' and it is common for large volumes of water to be produced in conjunction with oil and gas.

Water

Water is present at all stages of oil production. Connate water found in the reservoir at discovery can occupy 5 to 50% of the pore volume and it is common for large volumes of water to be produced in conjunction with oil and gas (it is not always the case that a reservoir has reached maturity simply because it is producing water. See *Chapter 9: Mature Fields*—Water Management). It is also usually very salty, often more concentrated than seawater. Levels of water saturation can be accurately measured by well-logging, surface monitoring as well as permanent downhole monitors. Water breakthrough causes production problems including corrosion and scale, particularly as reservoir water often contains salts up to 250,000 mg/l, in comparison to sea water which contains 35,000 mg/l of salts.

Water and oil also create emulsions which are difficult to break and disposing of produced water can generate an environmental burden as it must be disposed of adequately. Further, any incompatibility between injected water and connate water can create chemical scale[9].

API Gravity (°API)	Classification	Specific Gravity (g/cc)
10° to 20°	Heavy Oil	1.0 to 0.93
20° to 30°	Medium Oil	0.93 to 0.87
>30°	Light Oil	less than 0.87

°API = (141.5°/SG - 131.5 [SG = specific gravity at 60°F = 1.0])

Table 4 - A Rough Classification of Crude Oil Is Sometimes Used Based on API Gravity

Water is nearly always present in gas reservoirs and reservoir gas is often substantially saturated with water vapour at the temperature at which it enters the wellbore. With the change in temperature and pressure from the subsurface to surface, the gas will not be able to hold as much water and it will condense both within the well during the upward travel of the gas and in surface equipment. Much of this condensed water is carried in the flow lines into the separator as entrained droplets. Water can form hydrates with natural gas, which can create production difficulties, rendering metres and valves inoperative and, on occasions, causing disasters. Low temperature separators are needed to remove the entrained water close to the wellhead before the gas arrives at trouble points. In many cases, appreciable amounts of water will settle to the bottom of the well and can, in time, saturate the zone surrounding the wellbore so that the permeability to the flow of gas may be materially reduced. This reduction can result either from water blocking or clay swelling and can be responsible for a gradual decrease in deliverability and periodic remedial work-overs[10].

Other impurities can be metallic such as vanadium or non-metallic such as hydrogen sulphide (H_2S). If there is any measurable sulphur content (more than one part per million), then the sulphur components, H_2S, can cause considerable damage to the production facilities unless they are designed to handle sulphur. The sulphur components are also poisonous to humans hence lowering the commercial value of the oil or gas. They therefore have to be extracted, but can be converted to sulphur and sold on as a useful product. The production equipment has to use special quality steels to prevent rapid corrosion. Getting rid of sulphur, water, chlorides and other such impurities improves quality, increases value and stretches the world's oil reserves but it also adds to cost[11].

Releasing Hydrocarbons

The production of underground hydrocarbons is based on the release of trapped and pressurised fluids. Production involves a reduction in pressure and temperature from downhole reservoir conditions to atmospheric or surface conditions. As a result, hydrocarbons originally present as only liquid underground will separate into liquid and gas on their way to the surface, as soon as well pressure declines below the 'bubble point'.

In a mixture of liquids, the bubble point occurs when the first bubble of vapour is formed. For single component mixtures, the bubble point and dew point are the same and are referred to as the boiling point.

Hydrocarbons originally present as gas underground will generally produce some liquid at the surface due to condensation, which occurs when the pressure and temperature are reduced. The point at which natural gas components start to condense out of the gaseous system is known as the hydrocarbon dew-point and refers to the temperature (at a stated pressure) at which this occurs. Both bubble point and dewpoint are useful data when designing distillation refinery systems.

Surface facilities will mechanically separate gas from liquid using gravity separators or de-gassing facilities after which the volumes of liquid and gas are measured separately.

Gas

Natural gas volumes are reported in standard cubic metres [(s)m^3] or standard cubic feet (scf). Quantities of natural gas are usually expressed in cubic feet; a cubic foot is equivalent to approximately 0.028 m^3 at standard conditions[12]. For reserves valuation, gas is usually expressed in thousands (10^3) of cubic feet (Mcf), millions (10^6) of cubic feet (MMcf), billions (10^9) of cubic feet (BCF) or trillions (10^{12}) of cubic feet (TCF).

Methane is the most abundant component of natural gas and has numerous fuel applications. These range from liquefaction, compression, and Gas to Liquids (GTL). For further details, see *Chapter 13: Renewable*

Energy. The second largest component is ethane which can be liquefied and sold as fuel, but is mostly used as a petrochemical feedstock. Propane and butane are also found in natural gas, albeit in smaller amounts, and are commonly separated and sold as Natural Gas Liquids (NGLs). This commercial value stems from their comparatively high-energy content. On a cubic foot basis, methane renders just over 1,000 Btu, while propane renders 2,500 Btu and butane 3,250 Btu[13].

Gas Condensate

Gas condensate or 'wet-gas' reservoirs are an important class of hydrocarbon accumulation and describe hydrocarbons which are gaseous in the underground reservoir. When the temperature and pressure of gas condensate are reduced to dew point, however, they partially condense to yield liquid condensate. Condensates are often characterised by low-density and high-API gravity (45° and above) and co-exist with natural gas.

Natural gas condensate is typically composed of pentane, hexane, heptane and octane. Liquids that condense are almost transparent or light yellow and can be refined in a way similar to very light crude oil[14].

Condensate-bearing reservoirs pose further production challenges due to the effect changes in reservoir pressure have on the hydrocarbons. Gas may be converted to liquid if its pressure drops below the dew point during production. If gas is preferable to liquid production, reservoir pressure can be maintained by fluid injection. Reservoir fluid composition determines:

- Fluid type—dry gas, condensate gas, volatile oil, black oil
- Method of fluid sampling, laboratory tests
- Surface equipment (type and size)
- Calculation procedures for determining oil and gas in place
- Techniques for predicting oil and gas reserves
- Prediction methods for future production rates, and
- Depletion plan and secondary or enhanced oil recovery methods.

Common Types of Petroleum

There are several common types of petroleum:

Associated Gas: Is the natural gas and NGLs, which under reservoir conditions, are dissolved in the crude oil or are present as a gas cap above the oil in the reservoir.

Condensate or Distillate: Is the pale straw-coloured liquid with an API of 45° to 75° produced at surface from hydrocarbons which were originally gas or liquid in the reservoir. The term is often loosely applied to any liquid produced at the separator from light volatile oil or gas fluids.[15]

Conventional Black Oils: Are the most common reservoir liquids. They have: a viscosity low enough to flow naturally into a well; gravities that are usually between 20° API to 45° API; GORs ranging from 100-2000 scf/stb (20-360 m^3/m^3); specific gravity from 0.6 to 1.0; viscosities ranging from below 1cp; and, liquids that are about as thin as water to those that are >100 cp. They are black to green-black in colour.

Crude Oil (Oil): Is the common liquid form of petroleum produced from an oil reservoir when the gaseous constituents have been removed or have escaped and ranges from heavy tarry substances to conventional oil. Most petroleum liquid products and crude oils are lighter than water and their weight is often expressed in degrees (°) API.

The higher the number of API degrees, the lighter the oil. An API rating of 46° for a crude would mean that it is super light. Heavy oil would have an API of 18° to 20° degrees. The commercial value of oil varies according to its specific gravity; heavy oil trades at a lower value, i.e. less than 20° API trades at a lower value (US $5-10) to lighter oils, i.e. from 20° API to 45° API. Above 45° API, oil is considered superlight and has a progressively higher value (US $15 or more).

Gas Condensates: Condensates that are straw coloured and usually have a specific gravity above 45° API. The distinction between gas condensate, volatile oil fields and gas fields is important in practice as the reservoir may require different production and commercialisation strategies as discussed in *Chapter 11: Refining.*

Heavy Oil: Is so viscous that it does not flow easily into a well and has a gravity below 20° API and a viscosity above 20 cp as well as extremely low (negligible) production rates which often include large quantities of loose sand.

Natural Gas: Is a mixture of hydrocarbons consisting mainly of methane but also including ethane and minor quantities of NGLs.

Natural Gas Liquids (NGLs): Light hydrocarbons consisting mainly of propane and butane, which are liquid under pressure at normal temperature.

Oil Sands: Refers to heavy black tar (similar to bitumen) which is frequently mixed with high volumes of sand. They are found principally in Canada and Venezuela. Oil Sands require mineral extraction production akin to mining which is completely different to oil and gas well production.

Volatile Oils: Oils that have low specific gravities and viscosities, 45°-70° API and GORs in excess of 360/m^3 (2000 scf/stb). They are pale red to brown in colour[16].

Although the above nomenclature for hydrocarbon accumulations is useful, it should be appreciated that reservoirs do not follow strict definitions and have been found to produce hydrocarbons in almost every conceivable ratio. Additionally, variations in pressure and temperature mean that there are no clear divisions between the classes of reservoirs.

For our purposes, production mainly depends on the physical properties and behaviour of the reservoir fluids which change once production has commenced. Those changes will depend on what is in the reservoir.

What's In a Reservoir?

Reservoirs have been found to produce almost every conceivable ratio of hydrocarbons. It is this diversity, along with variations in pressure, temperature, depth, thickness, sealing faults and potential links to adjacent reservoirs, that leads to oil and gas accumulations being characterised as uniquely different or heterogeneous structures. Carbonate reservoirs are considered highly heterogeneous. Calcium carbonate is much more chemically active than the silica that constitutes sandstones. It is easily dissolved in water, even more so in acidic water. Mechanical properties are another significant difference. Carbonate rocks tend to be more prone to fractures than sandstones. For all these reasons, carbonates form different rock types with a heterogeneous distribution throughout the reservoir. Moreover, the poor correlation between porosity and permeability, and the presence of caverns and fractures, create very complex paths for fluids making it difficult to accurately model the distribution of permeability in carbonate reservoirs[17].

Consequently, the challenge for the oil company is how best to produce a particular oil and gas accumulation considering all these factors and simulating their interaction over time.

Reservoir Fluid States

Reservoirs are found at depths varying from 2,000ft+ (610 m) to deeper than 25,000ft+ (7,620 m). As noted in *Chapter 1: The Origin of Oil—Migration*, it is known that heavy oil is usually found in shallow reservoirs while lighter oil is found in deeper reservoirs, with gas

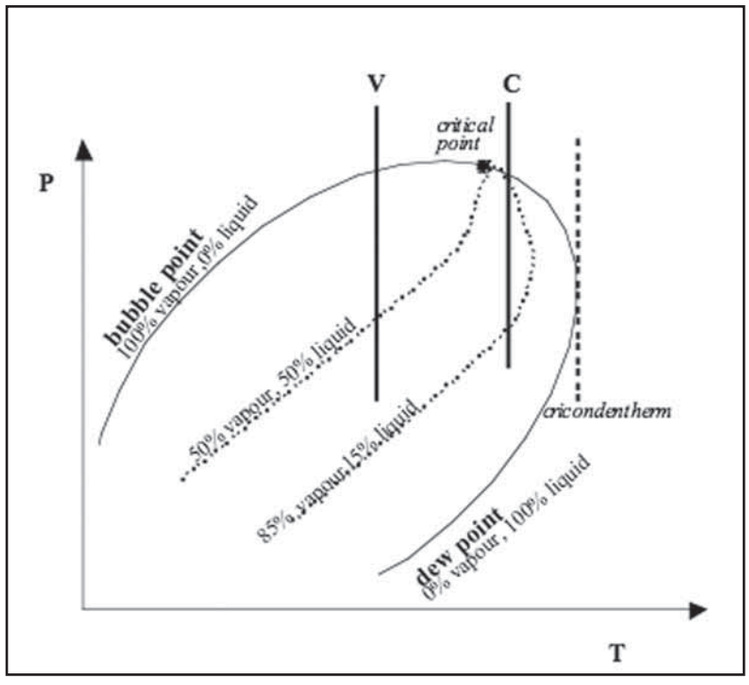


Figure 4 - Cricondentherm, After Professor Richard A. Dawe

alone found in the deepest reservoirs. Pressure and temperature conditions vary between reservoirs. Shallow reservoirs often have near standard conditions (15°C [59°F] and 15 psi [1 bar]) while deep reservoirs may have temperatures above 250°C (482°F) and pressures that may exceed 20,000 psi (1378 bar). Reservoir fluid states are held in a complex rock-gas-liquid system and can exist as aqueous and non-aqueous states or multi-phase immiscible fluids[18].

We have seen that hydrocarbons occur in unique ratios and diverse states. The same can be said of reservoirs. Reservoir engineers must have a thorough understanding of this heterogeneity, as this plays an important part in understanding how production should best be engineered. Physical properties are needed to accurately describe fluid pressures up to 1,500 bar (22,000 psi), the possibility of high temperatures (up to 250°C) and corrosive fluids (waters that contain more salt than seawater i.e. approximately 35,000 mg/l). Empirical data and laboratory modelling is often applied to field reservoir applications.

Depending on the oil and gas accumulation, and its reservoir pressure and temperature, hydrocarbons underground may be present initially as:

- Liquid only—oil reservoir
- Gas only—gas or gas/condensate reservoir, or
- Gas overlying liquid—oil reservoir with gas cap, or gas reservoir with oil ring.

The comprehension of such complex natural fluids comes from an understanding of simple and ideal systems, which are modelled in the laboratory. The data required includes: density; compressibility; formation volume factors and gas-oil ratios for determination of recovery factors; viscosity and gas-oil ratios for production rates; and interfacial tension for recovery efficiency, as it has a major influence on oil trapping. See *Chapter 1: Origin of Oil—Trapping Mechanisms*.

The Phase Behaviour of Hydrocarbons

As reservoir pressure drops, the resultant behaviour of the hydrocarbons depends upon the temperature and differential pressure as well as the composition of the hydrocarbons.

As pressure drops, gas expands and liquids tends to vaporise to gas. This is because molecules can move apart through their own kinetic energy breaking the weak bonds that hold them. (See *Chapter 11: Refining—Van der Waals Forces*). Conversely, if pressure is increased, molecules are forced closer together so that gas is compressed and forms a liquid. These changes from gas to liquid and vice versa are known as phase changes and are termed normal behaviour. Understanding this Pressure-Volume-Temperature (PVT) behaviour is essential because it controls the entire oil production process, while the physical parameters are needed to determine the process efficiency and sizing of facilities.

Multi-Component Mixtures

The behaviour of multi-component hydrocarbons presents greater complexity due to the different volatilities of the components involved. Consequently, vapour and liquid have different compositions when in equilibrium. As the pressure drops, the compositions of both the liquid and gas phases change continuously: the first gas appears at the bubble point and only liquid remains at the dew point. One consequence of this behaviour is that the pressure-temperature plot is no longer a simple curve as for the single component; instead it is an 'envelope'—see Figure 4.

The maximum pressure defined by this envelope is known as the cricondenbar; above it, the liquid and gas phases cannot co-exist. The maximum temperature defined by the envelope (the cricondentherm) is, likewise, one above which the two phases cannot co-exist. The critical point is the point in the envelope at which the properties of the gaseous and liquid phases become identical—it is not related in any simple way to the cricondenbar or the cricondentherm.

The behaviour of the fluid as it leaves the reservoir (essentially an isothermal environment) and travels through the production tubing and wellbore to the separation facilities requires more complex considerations of the thermodynamic behaviour; however, simple laboratory measurements are sufficient for design calculations[19].

If the reservoir pressure is at the bubble point, the oil is said to be saturated. If the reservoir pressure is above the bubble point, the oil is said to be undersaturated. An oil reservoir which is discovered with a gas cap is at its bubble point and is, therefore, saturated. An oil reservoir that is unsaturated describes hydrocarbons above their bubble point, where the reservoir temperature is substantially below the critical point and surface GORs are low to moderate. On production, as the reservoir pressure drops, gas comes out of the solution (solution gas drive). The first gas liberated is composed principally of the lightest components (methane, ethane and pro-

pane) as they possess the highest molecular energy and the lowest molecular attraction for other molecules.

Vaporisation of the lighter components is usually followed by quantities of heavier components until at low pressures only a fraction of the original material remains liquid. Gas has formed due to vaporisation of the light components and, as a result, the remaining liquid is described as having shrunk in volume. For a black oil, the shrinkage is only a small amount (often less than 30%). It increases rapidly, however, through the low pressure range (separator pressures) and through volumetric loss of intermediate and heavy material from the remaining liquid. Shrinkage characteristics in this range of pressures are extremely significant because surface separation of oil from gas occurs under these conditions.

Condensate Fields

A condensate field is where the reservoir temperature lies between the cricondentherm and the critical temperature. In this case, if the overall reservoir pressure is allowed to drop, liquids condense out in the formation and may be lost because their saturation is so low that no liquid flow toward the well bore occurs (zero permeabil-ity to liquid). In order to prevent this valuable loss by retrograde condensation and to extract the liquids, reservoir pressure is often kept above the dew point by recycling the gas that remains after surface processing. A gas (wet or dry) field is one in where the reservoir temperature is above the cricondentherm. Once the gas starts to expand up the tubing to the surface, the temperature as well as the pressure falls, and this continues to the final surface conditions. Liquid hydrocarbons may condense out in the tubing and surface lines and are often recoverable. Low-temperature separation increases the yield of these valuable light-end liquids. A dry gas field is one in which the final point (normally the separator) lies to the right of the envelope and no liquids are formed.

Crude Oil Properties

The PVT characteristics of oilfield liquids are more complicated than for gases and it is usual to distinguish between saturated and unsaturated conditions. In the former, gas starts to separate from the liquid as soon as pressure begins to drop with production. In the latter, the pressure at which gas begins to separate from the liquid is some distance below the initial reservoir pressure at the bubble point, (Pb). The rate of pressure drop in an unsaturated depletion type field can be quite dramatic with a pressure drop of perhaps 1,000 psi for a production of only one or two percent of the oil initially in place. The reservoir fluids have pressure-dependent properties. It is necessary to know how the crude will behave as the reservoir pressure drops, or other reservoir conditions are altered to be able to determine how best to: produce a particular crude-oil accumulation; to forecast attainable production rates and the ultimate cumulative production; and, to develop EOR plans for a reservoir. These properties are measured in the laboratory using samples of crude taken from the field[20].

PVT Data for Oil

Oil and gas behaviour can be described by using func-

Figure 5 - GOSP In The Shaybah Field Saudi Arabia (Saudi Aramco)

Depth of Reservoir	Initial Pressure	Temperature
608m (2000')	61 bar (900 psia)	21-32ºC /70-90ºF
1520 m (5000')	153 bar (2250 psia)	38-65ºC /100-150ºF
3952 m (13000')	408 bar (6000 psia)	82-149ºC /180-300ºF

Table 5 - Reservoir Pressure by Depth

tions of pressure and temperature. Various parameters such as oil and gas interaction, composition and the phase envelope need to be determined for each reservoir. This is often done by laboratory testing of bottom-hole samples or, by using Repeat Formation Testing (RFT) or Modular Formation Dynamics Tester (MDT) tools. Additionally, oil and gas collected at surface may be recombined to represent the reservoir fluid as precisely as possible. This is, however, a difficult task. In many reservoirs, there are variations across the field and also between different reservoirs. Fluid sampling should be carried out as early as possible to ensure reserve calculations, well flow calculations and facilities design are based on representative samples. Great care is needed in conditioning the well to ensure that the fluid sample is representative. Generalised correlations have been developed which give information about the PVT properties for oil and dissolved gas using the available data obtained from a producing well test, e.g. oil gravity, gas gravity, producing GOR and reservoir temperature[21].

Difficulties arise from obtaining representative samples and deciding the correct thermodynamic path the fluids should follow in the laboratory to mimic the path followed by the hydrocarbons as they move through the reservoir to the well, to the surface and finally to the gauges and the stock tanks.

The processes affecting the fluids as they flow from the reservoir to the stock tank vary, but can normally be approximated to the flash or differential process. For instance, flash liberation can simulate the process in the tubing linking the formation to the surface and in the gathering lines from wellhead to separator because the agitation of the flow keeps the two phases in contact with each other. In the surface-gas separator, the pressure on the produced fluids is suddenly dropped and the gas evolved remains, for a time, in contact with the crude, i.e. a flash liberation.

In general, less gas is evolved in differential than in flash liberation, thus a greater proportion of the lighter hydrocarbons remain in liquid form when the pressure reduction follows the differential-liberation path. For black oils, the difference is usually small, but for volatile oils it can be substantial so that two or three stage separation is needed to drop the surface pressure from that at the wellhead to atmospheric (stock-tank pressure) to get maximum liquids (perhaps 8-11% more). Determination of the number of intermediate separators (GOSP) and the pressures at which they should operate depends on oil and gas properties as well as economic considerations[22] (see Figure 5 for Gas Oil Separator Plant).

Reservoir Pressure and Temperature

In normal conditions, reservoir pressure is about equal to the hydrostatic pressure (pressure due to a column of water) measured from the surface. The hydrostatic gradient is about 0.45 psi per foot (9.6 kPa/m). Temperatures increase with depth by 10°F to 20°F per 1,000 feet (1.8-3.6ºC/100m). The table shows reservoir pressures according to depth.

In overpressured reservoirs, the initial pressure may be considerably higher. If different datum corrected pressures are found in different parts of the field, particularly after some production, it is likely that the field is not totally in communication and that there are sealing faults or isolated sands[23].

Reservoir Temperature

Primary recovery methods rely on the assumption that reservoir temperature stays constant. As fluids are produced any change in downhole temperatures due to production is compensated by heat from the cap or base rocks, which are considered to be heat sources of infinite capacity[24].

Average reservoir temperatures are therefore needed for laboratory analyses reflecting reservoir conditions. Reservoir temperatures are used to determine fluid properties such as viscosity, density, formation volume factor and gas in solution. Downhole gauges (during drilling or permanent) are used to measure reservoir temperature.

If a variation in temperature is detected across a reservoir after correcting for depth, an average value can be calculated and used as a constant reservoir temperature. For EOR, involving chemical and miscible processes, changes in temperature affect both the phase behaviour of injected and produced fluids, and therefore will affect recovery. The modelling of such processes must be accompanied by laboratory tests carried out using reservoir temperatures. In EOR processes that employ heat injection, such as steam or in-situ combustion, reservoir temperatures do not remain constant. In these cases, the reservoir temperature needs to be monitored all the time so as to detect the movement of the heat front[25].

Development of an Oil or Gas Field

Once a discovery has been made, appraisal wells are drilled to determine the extent of the accumulation. The important reservoir calculations from the discovery data are the minimum size of the accumulation and the minimum size needed for commercial production. The appraisal wells are then sited to attempt to answer the question, 'Is this economic?' rather than 'How large is it?' With each appraisal well comes a refinement of the geological model of the accumulation, as represented by maps and cross-sections, and a new economic assessment. If it becomes obvious that the accumulation contains sufficient oil or gas to be considered commercial, development plans will be formulated. The siting of development wells is different from that of the appraisal wells, as now the purpose is to produce the petroleum as efficiently as possible at the lowest unit cost. If the field is complex, with multiple reservoirs and faulting, the most efficient well-spacing may be initially difficult to decide as each fault block may have to be regarded as separate accumulations. Over time production of fluids from the reservoir will change fluid pressure and flow rates. Production engineers will critically examine these factors to ensure that production can maximised over the life of the field.

Readers note; reservoir and reservoir fluid characteristics are well covered in industry texts. Physical and chemistry texts provide the background to PVT behaviour, single and multi phase fluid flow.

References

1. Crude oil volumes are still reported in barrels and in some cases in tonnes. However, the number of barrels contained in a tonne varies according to the type and specific gravity of the crude involved. An average number would be around 7.33 barrels per ton. Surface oil is reported at stock-tank (st) conditions, with volumes in cubic metres (m^3) or barrels [stb, or (st)bbl].

2. API What a barrel of crude oil makes. API Factsheet.

3. See Petrobras Technology Harts E & P, June 2003 p45 for heavy oil definition below 19°API.

4. TTNRG Nature's Best Wajid Rasheed.

5. Pricing differential is due to higher proportion of heavier and sourer (high sulphur) crudes that relative to light sweet production. More than half the world's produced oil is heavy and sour in quality and this proportion is expected to increase. This depends on the crude oil's molecular structure and sulphur content. The oil will be classified accordingly and priced using reference crudes. Some of the common reference crudes are: West Texas Intermediate (WTI), Brent blend from the East Shetland Basin of the North Sea. Dubai-Oman, used as benchmark for Middle East sour crude oil flowing to the Asia-Pacific region, Tapis (from Malaysia, used as a reference for light Far East oil), Minas (from Indonesia, used as a reference for heavy Far East oil), The OPEC Reference Basket, a weighted average of oil blends from member countries.

6. The compositions of different crudes are measured and published in assays. Refining engineers use assays to decide which crudes will be required to formulate products.

7. API 5 RP 44 Sampling Petroleum Reservoir Fluids Proper management of production from a natural gas or petroleum reservoir can maximize the recovery of the hydrocarbon fluids (gas and oil) originally in the reservoir. Developing proper management strategies requires accurate knowledge of the characteristics of the reservoir fluid. Practices are recommended herein for obtaining samples of the reservoir fluid, from which the pertinent properties can be determined by subsequent laboratory tests.

8. For gas wells, the inverse ratio is sometimes used and the liquid-gas ratio is expressed in barrels per million m^3 (or million cubic feet).

9. Formation, Removal, and Inhibition of Inorganic Scale in the Oilfield Environment Author: Wayne W. Frenier and Murtaza Ziauddin ISBN: 978-1-55563-140-6. See also Scale formation RP 45 Analysis of Oilfield Waters 3rd Edition/August 1998.

10. Refining costs Sulphur Corrosion Control Author: Charles Kirkley See also RP 49 Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulphide Recommendations include well drilling, completion, servicing, workover, downhole maintenance, and plug and abandonment procedures conducted with hydrogen sulphide present in the fluids being handled. 2nd Edition / May 2001. Further cost is added at the refining stage.

11. The Color of Oil Economides et al. Publisher: Round Oak Publishing Company; (March 1, 2000) 220 pages ISBN: 0967724805.

12. EIA BTU fuel content.

13. See also API Manual of Petroleum Measurement Standards. This manual is an ongoing project, as new chapters and revisions of old chapters are released periodically.

14. Condensates Energy supplies are often quoted in barrel of oil equivalent (boe). The energy contained in 6000 scf (170 sm^3) of gas is about equivalent to that in one barrel of oil (0.16 sm^3), so for an oil with a gas-oil ratio of 1500 scf/bbl (266 m^3/m^3), 25% of the energy from the reservoir is contained in the produced gas. Thus for black oils about 10 % of the produced energy is in the gas, whereas for the gas condensate field about 75% of the energy is produced as gas. For this reason condensate reservoirs are not produced for the sake of the liquids only. A gas field of size 0.6 trillion scf is equivalent to an oil field of around 100 mmbbls.

15. See Advanced Reservoir Engineering Author: Tarek Ahmed and Paul McKinney ISBN: 0-7506-7733-3.

16. Saudi Arabia Oil and Gas Issue 4 The Carbonate Challenge (www.saudiarabioilandgas.com).

17. The behaviour of reservoir fluids is based on the laws of physical chemistry for perfect gases and the phase changes in gas-liquid systems.

18. The Flow of Complex Mixtures in Pipes, 2nd Edition, G.W. Govier and K. Aziz. Thirty-five years after its first publication, remains a fundamental resource, providing a unified approach to all types of complex flow.

19. Lab Crude Samples McCabe, Warren L.; Smith, Julian C.; Harriot, Peter (2005), Unit Operations of Chemical Engineering (seventh ed.), New York: McGraw-Hill, pp. 737-738, ISBN 0-07-284823-5.

20. API 5 RP 44 Sampling Petroleum Reservoir Fluids Proper.

21. SPE 102854 Performance Appraisals of Gas/Oil Separation Plants by S. Kokal, SPE, and A. Al-Ghamdi, SPE, Saudi Aramco.

22. If the field is communication similar datum corrected pressures will be found as average reservoir pressure drops.

23. Fluid Flow & Heat Transfer In Wellbores A.R. Hasan and C.S. Kabir.

24. The properties of crude oil and hydrocarbon gases have been extensively studied over the past several decades and many useful tables and correlations can be found in prior work e.g. charts (Dawe and Bradley 1987, McCain 1990).

25 The compressibility of oil is not entirely pressure dependent. The reported density of the oil is almost always that of the stock-tank oil not the reservoir oil, although reservoir oil density varies with pressure due to the associated effect of the gas in solution, which varies with pressure.

Manifa Field, Causeway and Islands, Saudi Arabia

By Osamah A. Al-Dakhil and David A. Close

Reprinted from Saudi Aramco Journal of Technology

ABSTRACT

With increasing world demand for oil, Saudi Aramco contracted to bring its mothballed Manifa heavy oil field back into production with an ultimate production capacity of 900,000 barrels of oil per day.

The Manifa oil field is situated just offshore of the Eastern Province of Saudi Arabia in the shallow coastal waters of the Western Arabian Gulf, which generally have depths of less than 5 m. The extensive shoals would require either extensive dredging to create access channels for offshore jackets or the creation of drilling islands and access causeways for road access for land-based drilling rigs. Saudi Aramco commissioned a fast track feasibility study followed immediately by procurement of a Lump Sum Turn Key (LSTK) contract for the design and construction of the preferred option.

Construction commenced in early 2007 of 21 km of main causeways and 21 km of lateral causeways connecting to the 27 drilling islands. The islands are each 9 hectare (about the size of 13 football pitches). The rock armor revetments are approximately 120 km in extent and the works require the dredging and land reclamation of approximately 37 million m^3 and the placement of 10 million tons of rock. To fulfill environmental requirements, openings have been introduced to the causeway which are bridged by 4 km of bridges, including one 2.4 km long.

CONCEPT DESIGN

Saudi Aramco had undertaken its preliminary reservoir engineering in 2005, had fixed the numbers and locations of the islands required for drilling and water injection and had made a preliminary assessment of causeway alignments and widths.

The concept study evaluated three basic schemes being:

• Scheme A:
The construction of 27 drilling islands which are linked by causeways to the land.

• Scheme B:
The construction of 27 drilling islands which are grouped in isolated clusters by means of causeways. Access to each cluster would be from the sea.

• Scheme C:
The construction of two water injection islands and associated minor causeway together with dredging works for offshore platforms. This scheme would have full offshore production.

These schemes are described very briefly here to give a flavor of the options available to Saudi Aramco at the outset of the project, but the remainder of the article focuses on the selected option.

The base case for the study was Scheme A, and Schemes A and B were investigated further with sub-options having smaller, higher islands using so-called deep cellars for drilling activities.

The primary aim of the concept study was to develop each of the above schemes, assess construction requirements (plant and materials), estimate construction

quantities and costs, and develop construction programs for each scheme.

Overall, base case Scheme A was the most expensive of the three main options studied in respect of its infrastructure capital cost, although this could have been mitigated somewhat as the deep cellar sub-option did offer commercial advantages. Although, these capital and maintenance cost advantages were considered by Saudi Aramco to be offset by operational considerations and, above all, safety.

Scheme B was estimated to be about 10% cheaper than the base case, as might be expected since less causeway and fewer bridges would have been constructed, but subsea pipeline costs obviously would be consequently higher compared with Scheme A. Furthermore, the logistical problems of the supply of drilling equipment and consumables posed significant operational costs and risks – the annual Shamal, in particular, would cause occasional downtime to supply vessels.

Scheme C was only about 20% of the cost of the first two schemes, but offshore drilling rigs could not be available on time owing both to increased international demand for new platforms and the need for the industry to replace the scores that had recently been destroyed in the Gulf of Mexico by Hurricane Katrina.

Saudi Aramco evaluated whole life costs of the three schemes (marine and civil engineering, and electrical, communications and pipelines which were the subject of separate parallel studies) and assessed program estimates and construction risks in coming to its conclusion. Scheme A was selected for the works.

DESIGN BASIS

Given the fast track nature of the works, Saudi Aramco had already commissioned the King Fahd University of Petroleum and Minerals (KFUPM) to undertake an Environmental Impact Assessment (EIA). As part of the EIA work, Danish Hydraulic Institute (DHI) had been contracted by KFUPM to investigate water circulation and had already established an offshore model for the Manifa area, Fig. 1. DHI had also been nominated as a sub-consultant for the concept design study.

The hydraulic study was tasked with providing:

- Design water level data for the perimeter structures of the islands and the causeways including sea level rise over the lifetime of the structure.
- Design waves for perimeter structures of the islands and the causeway.

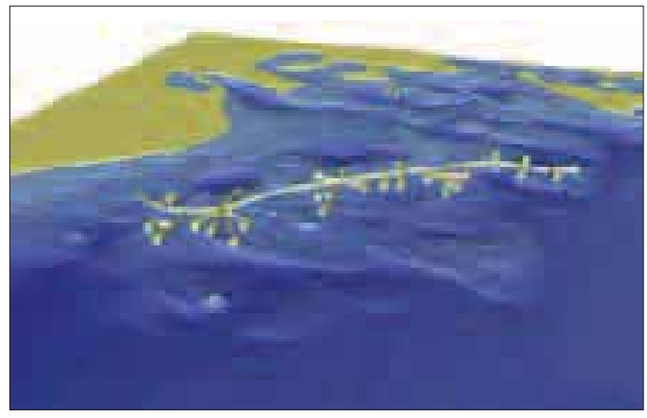


Fig. 1. Mike 21 Mathematical Model of Manifa Causeways and Islands looking from the South East.

- Overtopping for design conditions.
- Operational wave and current conditions for the planning of dredging operations.
- Input to downtime statistics in terms of wave statistics for three berthing locations.

Hydraulic parameters are considered in more detail below.

Design Water Level

The existing water level prediction for the Manifa project was not considered to be sufficiently accurate. DHI undertook a study using a combination of water level measurements recorded at Saudi Aramco's Ras Tanajib Pier (1985-2005) and the PERGOS database which includes numerical hindcast model results of more than one hundred historical storms over the period 1983-2002. The recommended values for extreme tides from the study were:

- MSL is 1.0 m above LAT.
- HAT is 1.8 m above LAT.
- 100-year storm water level is 2.2 m above LAT.

An average sea level rise of 5 mm per year has been assumed resulting in a water level increase of 0.25 m over the next 50 years. This assumption was based on the contemporary Intergovernmental Panel on Climate Change (IPCC) predictions. The end of life (50 years) prediction of the 100-year storm water level was therefore assumed to be 2.45 m above LAT, rounded up to 2.5 m above LAT.

Design Waves

For islands exposed to the most severe 100-year easterly direction, the maximum significant wave height, Figs. 2 and 3, was 2.8 m with a peak period of 9.1 s. The vari-

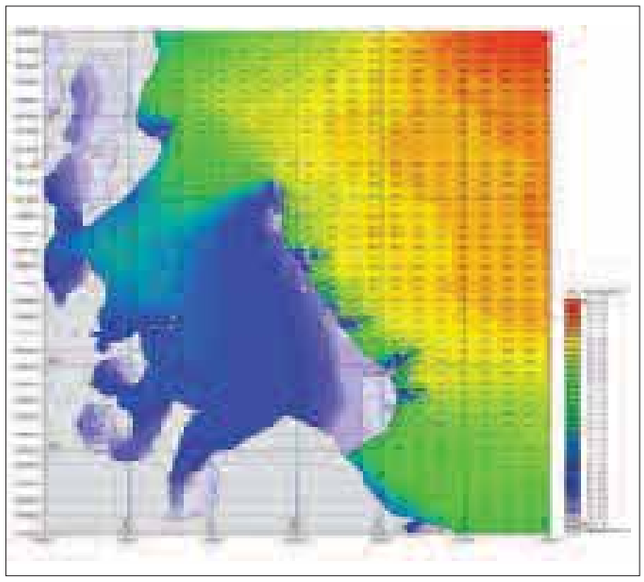


Fig. 2. Scheme A - Easterly Waves.

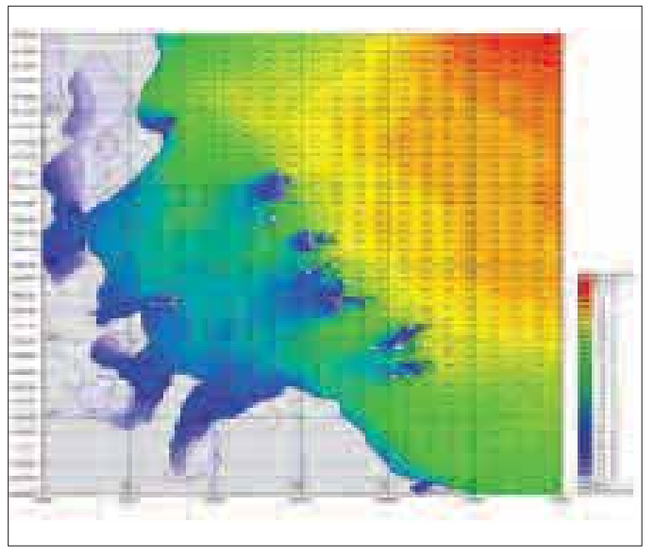


Fig. 3. Scheme B - Easterly Waves.

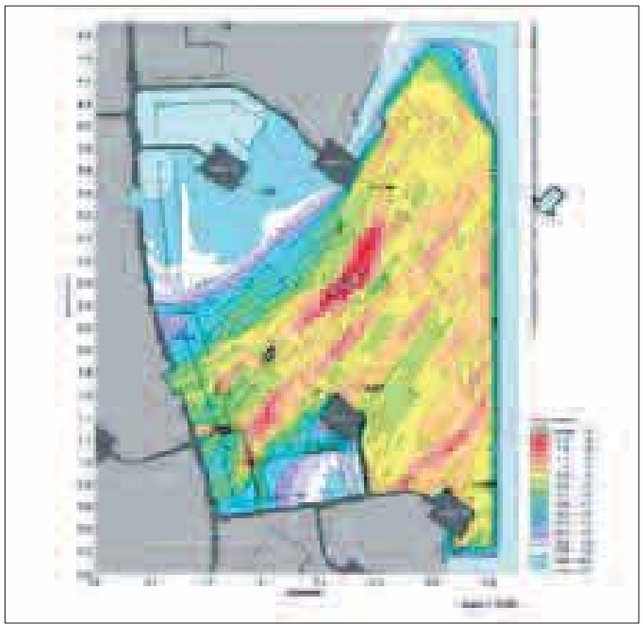


Fig. 4. Detailed Numerical Wave Modeling Islands 06-12 Northerly Waves.

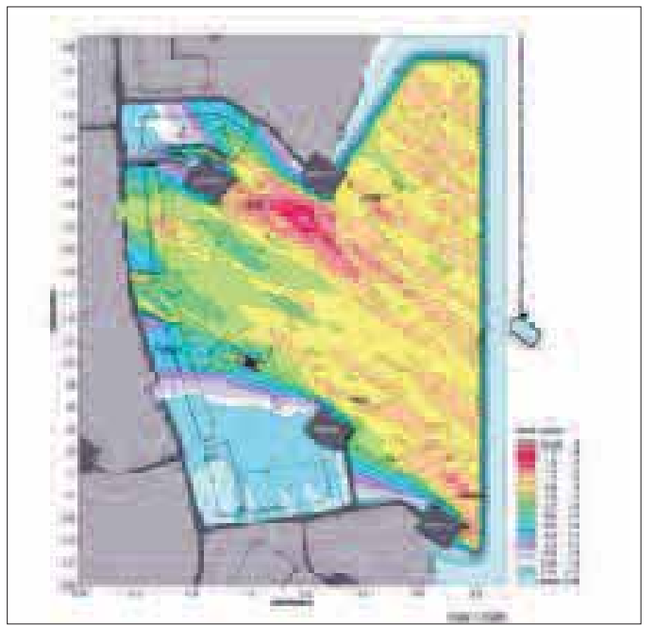


Fig. 5. Detailed Numerical Wave Modeling Islands 06-12 Easterly Waves.

ation in significant wave height was from 2.4 m to 2.8 m. This situation remained the same for both Schemes A and B, but the loss of the main causeway in Scheme B caused a significant change to design wave conditions in the westerly islands which is apparent when comparing Figs. 2 and 3.

During the course of detailed design, much more detailed investigation of the wave climate was undertaken as indicated in Figs. 4 and 5.

Overtopping

An understanding of overtopping is critical to defining the crest level. The quantity of permissible overtopping must first be defined. At the concept stage, a figure of 2 l/m/s was selected from a consideration of pub-lished overtopping damage[1] having due regard to the nature of the facilities on the causeway. There will be occasional small buildings but in the main these will be both substantial industrial structures and situated on the sheltered side of the causeway and so the

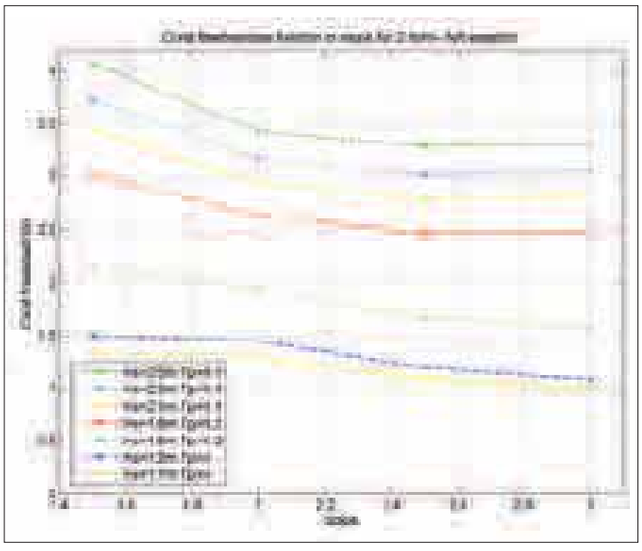


Fig. 6. Crest Freeboard as a Function of Slope under Overtopping Discharge of 2 ℓ/m/s.

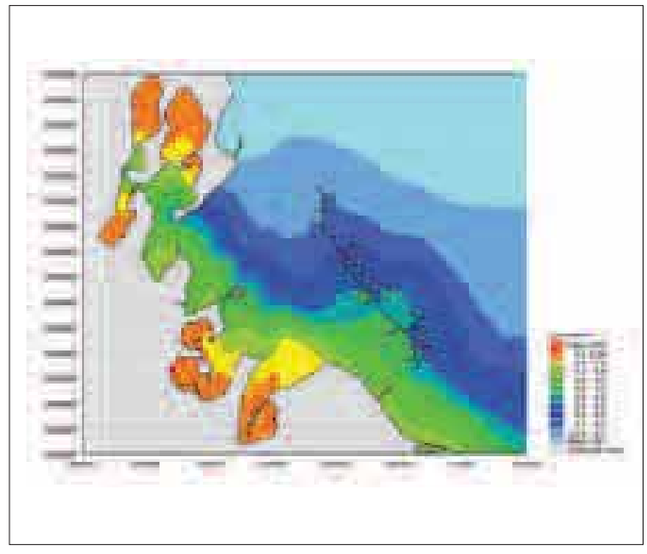


Fig. 7. Water Circulation Modeling of Optimum Scheme A Layout.

facilities on the structure for consideration of overtopping will be electrical supply cables, access roads and pipelines.

The wave overtopping criterion is traditionally presented as the volume of water per second per meter of revetment which presents the non-coastal engineer with a difficulty in comprehension as the overtopping figure seems so small. It has to be realized that the overtopping is caused by a few wave events during a storm, typically less than 2% of waves, so that the actual volumes within a single wave event can be considerable. As an illustration, assume that 1l/s/m is used as the criterion, the total volume per meter during a 3-hour storm would be 3,600 l/m. Most of this volume will be carried by, say, the largest 10 waves, which then means that a volume of approximately 3.6 m^3 of water passes over a 10 m long revetment section during such individual events.

Figure 6 was derived during the concept study as an aid to defining the necessary freeboard to fix the rock armor crest level. Overtopping is a stochastic and highly varying parameter which makes it difficult to produce empirical relationships that will produce accurate results. Different formulations can therefore produce results with large differences. Overtopping was therefore studied by physical modeling during the design process to set the crest elevation.

Wave Transmission

From early discussions with dredging and land reclamation contractors active in the region, it was envisaged that the cross-section of the causeways and islands would be sand fill with or without quarry run shoulders. Together with the rock armor, this form of construction represents a very porous structure and a major consideration in setting fill levels was therefore the degree of damping of waves by the structure and the consequent elevation of the crest of transmitted waves or standing water levels within the causeway or island body.

Empirical equations due to Barends[2] exist for the definition of water levels within land reclamations but physical modeling was undertaken during the detailed design phase to define fill levels as well as armor crest elevations.

Earthquake

The Eastern Province of Saudi Arabia is not seismically active, but, after the recent Iranian earthquake felt in the United Arab Emirates some hundreds of kilometers further south, the client imposed a cautious 5% gravity acceleration earthquake requirement for this structure.

ENVIRONMENTAL CONSIDERATIONS

Water Circulation

Scheme A represented the most potentially damaging environmental proposal as it would have closed off water circulation if constructed as a solid structure. It was therefore always envisaged that the provision for the maintenance of water circulation by the creation of openings would have a high priority.

King Fahd University of Petroleum and Minerals undertook the environmental assessment[3] with DHI modeling water circulations under KFUPM's direction. A variety of scenarios were investigated ranging from the provision of 20% openings throughout the length of the structure through to combinations of small openings throughout the length of the causeway, and a larger opening at the root of the main causeway. The optimum Scheme A causeway layout, Fig. 7, has a 2.4 km long bridge near the land connection of the main causeway from the -3 m CD to the nearest drill island and openings in the main causeway in the form of short bridges (150 m long each) and culverts (50 m long each).

The time it takes for 50% of the water in the Manifa- Tanajib bay system (or MTBS, the enclosed bays in the modeled region shown in Fig. 7) to be exchanged with the Gulf waters is 17 days in the existing situation, which would increase to about 71 days if a solid causeway were created.

Introducing large scale openings amounting to 20% of the length and distributed throughout the causeway length would reduce the T50% to 20 days. The combination of a long bridge at the southeast and 5% openings through the main causeway results in a residence time of 15 days, which represents an improvement in the current situation.

Overall, the potential hydrodynamic alterations are expected to result in tidal pumping which will generally benefit the water exchange efficiency in the MTBS and the coastal areas south of the causeway onshore approach. Tracer concentration simulation and salinity modeling revealed that water conditions will improve in these affected areas due to a higher rate of water renewal resulting from the intensified flow regime.

In connection with the effects on local hydrodynamics, changes in basic water quality conditions (water temperature, salinity and dissolved oxygen) will not be of serious concern.

The average increments in water quality parameters at the local and regional scales are generally negligible and perceived to within the tolerance limits of marine organisms. All expected increases are also within the ranges of natural variability in the MTBS and the Gulf area, in general.

Coastal Morphology

The effect on coastal morphology caused by the causeway will be very small and undetectable from all other natural changes except very locally where the causeways are connected to the shore. The coastal water along the entire stretch is very small, so larger waves which can move significant quantities of sand cannot come close to the coastline in the existing situation, so future sheltering of the coastline by the planned causeway will not have an effect.

Close to the two shore connections, some local accumulation of sand and fines will develop on the north side of the structures due to the dominant winds from northerly directions.

At the southern shore connection a similar pattern will develop on the south facing side of the structure due to the rare but more powerful south-easterly winds. These accumulations will be the result of local generated waves in the near shore zone and this pattern will develop at all sites on the coast where an obstacle across the shoreline is made. Such small changes will not have any impact on the quality of the existing coast nor will disrupt any larger sediment circulation cells.

There will be localized areas of water stagnation behind the main causeway, especially in between the projecting branches (the lateral causeways leading to the islands), which may lead to increased siltation. The same sedimentation effect and the resulting sediment accumulation are also expected to increase the extent of finer substrates within the MTBS in the medium term.

CROSS SECTION DESIGN

General Considerations

An outline design of the causeway, Fig. 8, which was to be developed and optimized, was presented to Jacobs at the commencement of the study. This outline design envisaged fill to 2 m above MSL (+3 m CD) and a rock armor revetment with its crest at 5 m above MSL (+6 m CD). The outline design envisaged the revetment to comprise 1-3 ton rock armor.

Owing to tight time constraints, the concept study wave modeling derived wave heights for island groups rather than individual islands. It did, however, derive wave heights from different directions. It was therefore possible to design rock armor for exposed and sheltered sides of islands and causeways. Concept design armor sizes were derived from the well-known van der Meer equation[4] and cross-checked using the older Hudson formula.

A concern of the concept study, and one which the client had recognized from his own studies, was the availability of rock for the works, given the very active state of

marine construction within the Arabian Gulf. Enquiries with major contractors involved in these ongoing, very large, prestigious projects confirmed that rock supply was likely to be a major concern for tenderers for the Manifa contract. This concern affected the manner in which the concept study was conducted and the concept designs were therefore optimized on 1-3 ton rock by varying slopes instead of using steeper slopes with heavier rock. It was considered that this grade of rock would be more readily available.

The concept design, Fig. 9, for the revetment on the exposed side was standardized on an average slope of 1 in 2.25 with rock armor of 1-3 tons. The crest of the causeway was set at +5 m CD (4 m above MSL and 2.5 m above the 1 in 100-year storm water level) and the crest of the armor set from overtopping considerations at +5.5 m CD (3 m above the 1 in 100-year storm water level). The sheltered side has a very limited exposure to the northerly Shamal winds over a limited fetch and was standardized at an average slope of 1 in 3 with a single

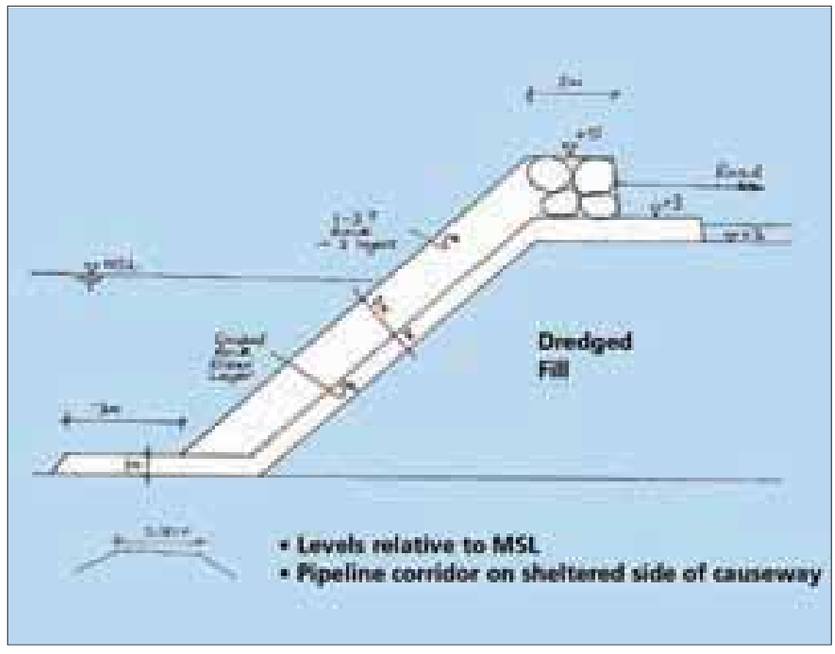


Fig. 8. Outline Causeway Design for Development.

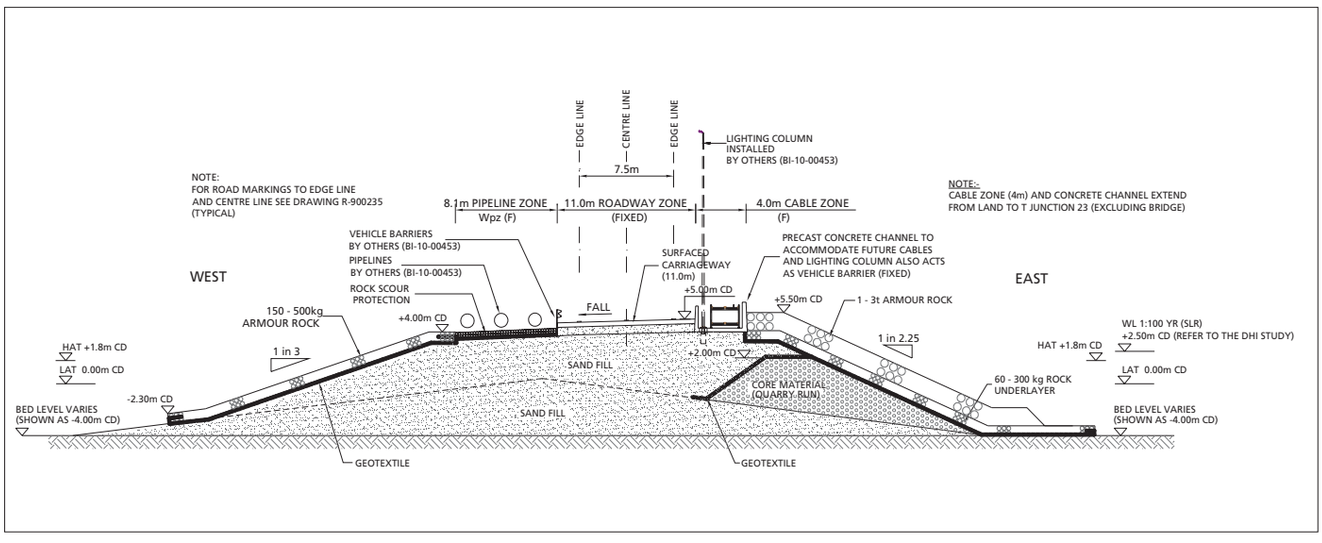


Fig. 9. Typical Cross-Section of Main Causeway looking North.

Fig. 10. Large Scale Flume Test of Cable Channel.

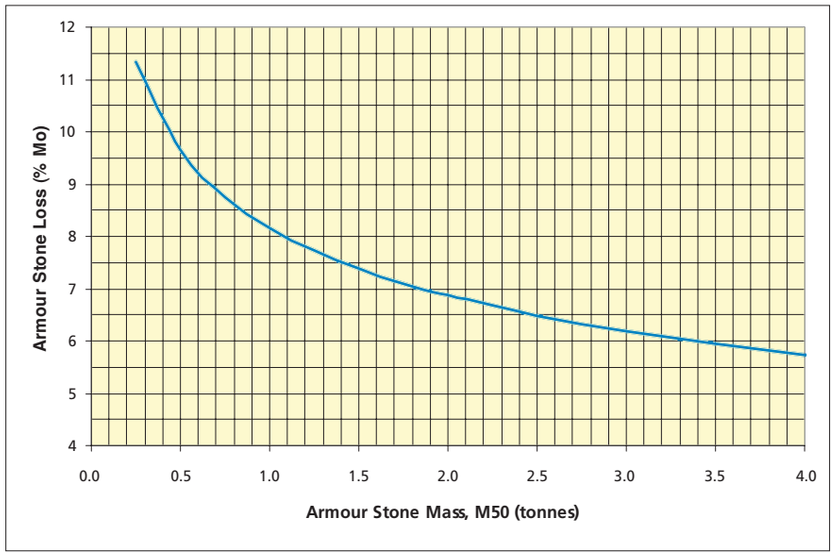


Fig. 11. Predicted Rock Degradation Loss at End of Structure Life (50 Years).

layer revetment of 150 kg - 500 kg rock. The crest of the causeway was set at +4 m CD from considerations of cross-fall and was not defined by overtopping requirements.

Figure 9 shows a cross-section of the main causeway with the pipelines set on the sheltered side and electrical cables fixed on trays in a precast U-shaped concrete channel. The concrete channel is set above the level of the rock armor crest to provide shelter to the cables from overtopping waves. The height of the seaward side of the channel has been determined by physical modeling to maintain the set overtopping limit.

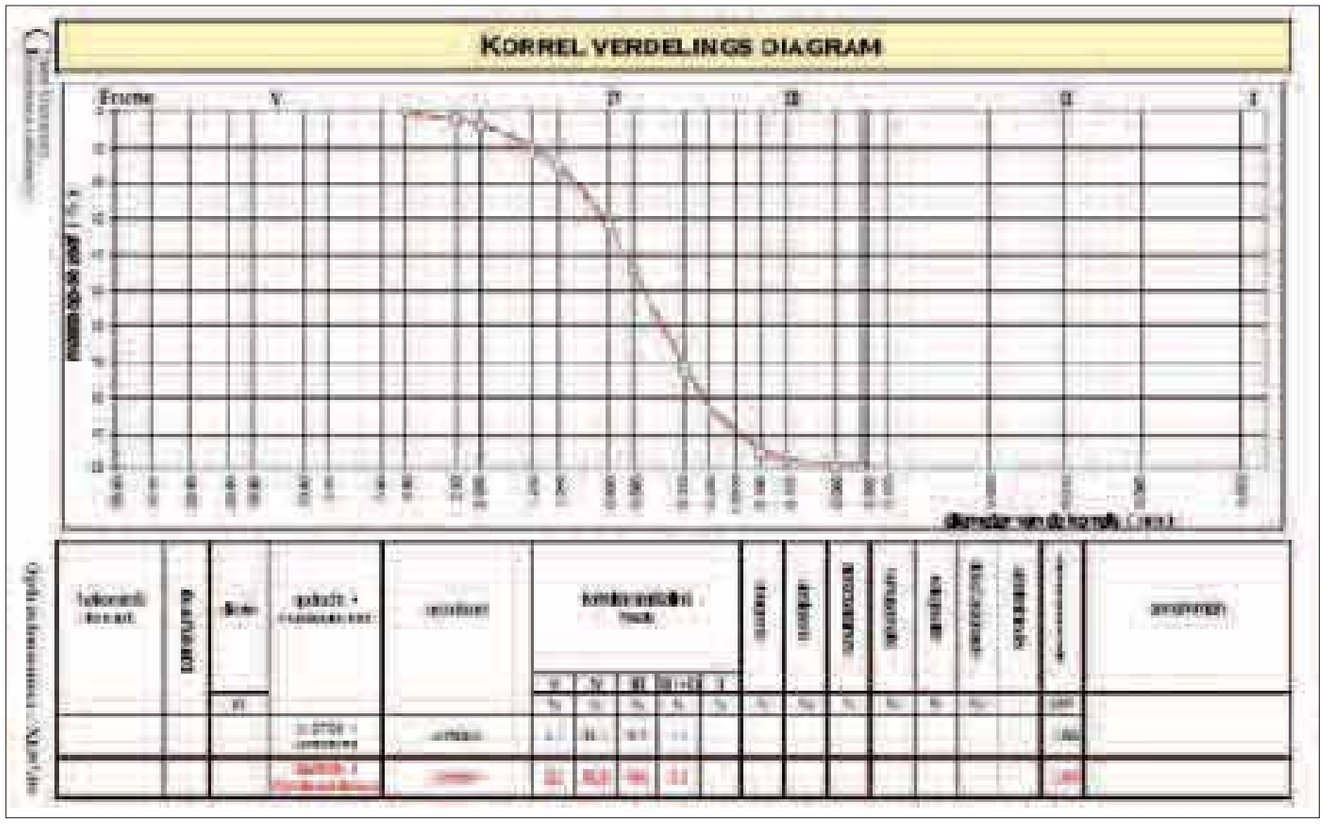


Fig. 12. Impact of Proctor Compaction on Grain Size Distribution.

Armor Stability

Armor stability of many sections, armor sizes and exposures were investigated during detailed design by physical modeling in the small scale flume at the University of Gent, and the crest and cable channel design was similarly investigated inthe university's large scale flume, Fig. 10. Owing to the strategic value of the infrastructure being designed, the design storm return period was defined in collaboration with the client at 1 in 100 years. The majority of the offshore installations in the region have also been designed for a 100-year return period event. During detailed design, consideration was given to increasing the return period to 1,000 years but a cost/damage assessment confirmed the lifetime cost-effectiveness of the 1 in 100 year specification.Owing to the relative conservatism of the concept design which limited damage in the design storm to a maximum damage number of S = 2 (equating to 0% - 5% of stones displaced from the active zone) over 3,000 waves (a storm duration of about 7.5 hours in prototype), it was not considered necessary to increase the return period of the design storm. A close view, however, was kept on the outcome of the flume tests which used waves up to a return period of approximately 1 in 1,000 years. While damage obviously increased markedly at return periods above that of the design 1 in 100-year storm, no breaches of the revetment appeared likely even under the 1 in 1,000-year storm. The estimate of the cost of damage repairs made by the concept designer (who was the Contractor) also justified the selection of the lower return period.

Rock Quality and Availability

One of the main concerns of the client before and during procurement was the availability of rock armor of sufficient quality and in sufficient quantities for the works given that 10,000 tons per day of armor rock would be required to meet his program. The tender was written around "good quality"rock[5] but with the flexibility, except for limited areas around openings, given to contractors to use "marginal quality" rock provided that provision was made for degradation in ac-

cordance with recommendations from the *Manual on the Use of Rock in Coastal and Shoreline Engineering*[6] with the exception of the option of increased maintenance. That is, increased rock degradation of "marginal quality" rock could be compensated for by:

•Over-dimensioning of Armorstone.
•Gentler seaward design slopes and increased volumes of material.
•Combinations of the above.

The shortcomings of the *Manual on the Use of Rock in Coastal and Shoreline Engineering* were apparent once the contract started owing to the lack of availability of (Queen Mary & Westfield College) abrasion mill apparatus used to define the mill abrasion index on which the recommendations were based. Accordingly, the updated test criteria were sought from the authors[7]. The rock degradation model referred to in the *Manual on the Use of Rock in Coastal and Shoreline Engineering* has been updated and is now based on the more readily available micro-Deval test. These new conditions and criteria were published shortly after contract award in the updated 2007 Rock Manual[8]. Marginal quality rock meeting the contract specifications based on the *Manual on the Use of Rock in Coastal and Shoreline Engineering* is available within a relatively short distance inland of the site. A degradation allowance was made based on curves derived from the rock degradation model described by Latham et al.[7, 8], Fig. 11, using quarry-derived material parameters.

Geotextile

The revetments of the causeway and island structures were designed at concept using geotextile below under layer and armorstone layers. This system was adopted by the contractor in his detailed design and trials of the proposed under layer were undertaken before acceptance for incorporation into the works. Full-scale trial embankments were construct-

BIOGRAPHIES

Osamah A. Al-Dakhil is a Geotechnical Engineer with 10 years experience in the Consulting Services Department (CSD). He received his M.Sc. in Geotechnical Engineering from the University of Wisconsin, Madison, WI in 2003. Osamah's core experience is in design and installation of deep foundation systems of the offshore platforms and coastal structures. He has been assigned to the Manifa Causeway Project as a Project Engineer during development of the project tender, in 2006, and execution of the project. Osamah is in-charge of the geotechnical aspects of the project that include: design and construction of slopes, geotextiles, bridge piles and sand fill.

David A. Closeis a port and coastal engineering consultant with 30 years experience in civil engineering. He has wide international experience – most recently in the Arabian Gulf. David has been responsible for managing design and feasibility studies, including major coastal and reclamation developments, port expansion and capi-

ed on land and were subsequently carefully dismantled to prove the sufficiency of the proposed geotextile.

Geotechnical

A comprehensive offshore geotechnical and geophysical investigation program was undertaken by the client prior to tendering in order to assist the bidders in evaluating the availability and suitability of locally won soil for reclamation. Minimum criteria were set pertaining to chemical properties, e.g., carbonate and organic content, physical properties, e.g., fines content, gradation, specific gravity and bulk unit weight, and in-situ properties, e.g., percentage of maximum dry density. Placement and compaction criteria were specified for fill placed above mean sea level, i.e., in the dry. Higher quality fill was specified behind or adjacent to structures, within 1,000 mm below roads, pipe and cable zones and bridge approaches. Flexibility has been given to the contractor on the placement and compaction methods to achieve the set performance criteria which included settlement limits at 5, 25 and 50 years. The design provides compensation for any remaining primary consolidation, elastic compression and any future secondary settlement/consolidation. Long-term stress-strain behavior has been studied to evaluate the residual (creep) settlement. To address concerns about the suitability of locally won sand, because of its high carbonate content crushability of two sand samples was tested by normal Proctor compaction and dynamic oedometric loading. The material did not exhibit major crushability at the above mentioned stress levels, Fig. 12, and settlements were predicted to be within the performance specification for the works.

ACKNOWLEDGEMENTS

The authors would like to thank Saudi Aramco management for permission to publish this article. Figures 1, 2, 3, 6 and 7 are courtesy of DHI. Figures 4, 5 and 12 are courtesy of Jande Nul. Figure 9 is courtesy of Jacobs UK Ltd. Figure 10 is courtesy of David Close and Figures 8 and 11 are courtesy of Saudi Aramco.

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8.The Rock Manual, CIRIA Report C683, 2007, pp. 131-147.

tal projects, and he is also experienced in the supervision of site works. In 2006 David was employed by Jacobs, who were contracted by Saudi Aramco to undertake the feasibility study for the Manifa causeway. He was Project Manager of the Jacobs team that subsequently drafted the contract documents and undertook the technical assessment of the Lump Sum Turn Key (LSTK) bids. Following the appointment of the Contractor, David was seconded to the Saudi Aramco team who were resident in the Contractor's design offices in Belgium. He has made several trips to Manifa during the early stages of construction to assist the Saudi Aramco site supervision team. David received a BEng (Hons) in Building Engineering from the University of Liverpool, Liverpool, UK in 1978, a MEng in Maritime Civil Engineering from the University of Liverpool in 1986, and a DMS in Management Studies from Brunel University, London, UK in 1994. He is a member of MICE, Member of the Institution of Civil Engineers and CEng, Chartered Engineer.

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2009 SPE Technical Symposium

Saturday, May 9 — **Al-Dana Hall 8:00 – 9:30**

Symposium Opening Ceremony

Keynote Speakers

Leo Roodhart
2009 SPE President

Chad Deaton
Chairman, President and ChiefExecutive Officer
Baker Hughes

Abdullatif A. Al-Othman
Senior Vice President of Finance
Saudi Aramco

Sunday, May 10 — **Panel Discussion** — **Al-Dana Hall 1:00 – 3:00**

" Tight Gas Sands - Unlocking their Potential: Vision, Strategy and Opportunities "

Panel Discussion Speakers

Abdulla Naim
Vice President Exploration
Saudi Aramco

Stuart Ferguson
Vice President and Chief Technology Officer
Weatherford

Nathan Meehan
Vice President
Reservoir Technology
Baker Hughes

Don Conkle
Vice President
Stimulation
Schlumberger

Hans Milatz
E&P Difficult Gas
Theme Leader
Shell International B.V.

Mohammed Al-Qahtani
Executive Director
(Moderator)
Saudi Aramco

Saturday, 9 May

Symposium Opening Ceremony

8:00 – 10:00 **Al-Dana Hall**

7:00 — 8:00	***Refreshments & Registration***
8:00 — 8:10	***Opening Remarks*** *Ashraf Al-Tahini* *SPE Technical Symposium and Exhibition Chairman* *Saudi Aramco*
	Keynote Speakers
8:10 — 8:30	***Leo Roodhart*** *2009 Society of Petroleum Engineers President* *Shell Research B.V.*
8:30 — 8:50	**Chad Deaton** *Chairman, President and CEO* *Baker Hughes*
8:50 — 9:10	**Abdullatif Al-Othman** *Senior Vice President Finance* *Saudi Aramco*
9:10 — 9:30	**Sponsors Recognition**
9:30 — 10:00	***Exhibition Tour & Break***

Session 1	**Saturday, May 9** **Drilling and Completions** ***Session Chairpersons:*** *Mohammad H. Hattab, Saudi Aramco* *Ajmal Wardak, Halliburton*	**Al-Dana Hall** **10:00 – 11:45**
10:00 — 10:25	**The Role of Drilling Technologies in Meeting Global Energy Demand** *Invited Speaker:* *Ali Al-Qarni* *Manager Drilling and Completion* *Saudi Aramco*	
10:25 — 10:45	126047	**World First 3-7/8" Multi-Lateral Short Radius Re-entry Completed with Ultra Slim ICD System** *Adib A. Al-Mumen, Ghassan A. Al-Essa, Morry Infra, Sami Bu-Zaid, Saudi Aramco; Giovanni Salerno, FloTech Ltd.*
10:45 — 11:05	126049	**Innovative Progressive Cavity Pump Design for Brown Fields in South of Oman** *Mahmoud S. AL Shukri, Abdel-Monaim Abou-ElKhair, Petroleum Development Oman*
11:05 — 11:25	126058	**Multi-Stage Acid Stimulation improves Production Values in Carbonate Formations in Western Canada** *Dan Baumgarten, Breaker Energy Ltd.; Doug Bobrosky, Packers Plus Energy Services Inc.*
11:25 — 11:45	126057	**Evolution of Roller Cone Bit Design to Improve Performance in Carbonates** *Jim Senger, Basil Al-Ramahi, Islam Ahmed Taha, Halliburton-Security DBS Drill Bits; Tamer Waheed, ADCO*

Session 2	Saturday, May 9 Petrophysics and Formation Evaluation *Session Chairpersons:* *Nihal I. Wijeyesekera, Schlumberger* *Maclean O. Amabeoku, Saudi Aramco*		Al-Mawad 5 Hall 10:00 — 11:45
10:00 — 10:25	**Petrophysics: 80 Years of Innovation** *Invited Speaker:* *Khalid A. Zainalabedin,* *General Supervisor Reservoir Description* *Saudi Aramco*		
10:25 — 10:45	126041	**Collaborative Development of a Slim LWD NMR Tool: From Concept to Field Application** *Ridvan X. Akkurt, Alberto F. Marsala, Douglas J. Seifert, Ahmed Al-Harbi, Carlos Buenrostro, Saudi Aramco; Thomas Kruspe, Holger F. Thern, Gerhard Kurz, Martin Blanz, Asbjorn Kroken, Baker Hughes*	
10:45 — 11:05	126039	**Advances in Micro-CT Based Evaluation of Reservoir Rocks** *Md. Rakibul Hashem Sarker and Shameem Siddiqui, Texas Tech University*	
11:05 — 11:25	126037	**Real-time Geology/Petrophysics in Complex Carbonate Reservoirs** *Ramsin Y. Eyvazzadeh, Rami H. BinNasser, David G. Kersey; Saudi Aramco*	
11:25 — 11:45	126036	**Improvements in Downhole Fluid Identification by Combining High Resolution Fluid Density Sensor Measurements and a New Processing Method: Cases From a Saudi Aramco Field** *Richard G. Palmer, Andre S. Silva, George X. Saghiyyah, Saudi Aramco; Marvin Rourke, Bob Engelman, Tony van Zuilekom, Mark Proett, Halliburton*	

Alternate

126042	**Neural Network Prediction of Porosity and Permeability of Heterogeneous Gas Sand Reservoirs** *Gharib M. Hamada, M.A. Elshafei, King Fahad University of Petroleum and Minerals*

11:45 — 13:00	**Lunch & Prayer Break**	**Al-Mawad Hall**
	Luncheon Generously Sponsored By BAKER HUGHES	

Session 3	Saturday, May 9 Production Enhancement & Operations *Session Chairpersons:* *Randy Birkelbach, Baker Hughes* *Nader D. Douhan, Saudi Aramco*		Al-Dana Hall 13:00 — 14:45
13:00 — 13:25	**Nasir Al-Naimi** **Invited Speaker** *Saudi Aramco*		
13:25 — 13:45	126064	**Differentiating Well Placement Expectations in Saudi Arabia with Production from Stringer Sand Reservoirs** *Phil Warran, Nidal Mishrafi, Saleh M. Dossari, Saudi Aramco; Parvez J. Butt, Mohan Javalagi, Waleed Jawad, Schlumberger*	
13:45 — 14:05	126063	**Successful Utilization of Fiber Optic Telemetry Enabled Coiled Tubing for Water Shut Off on a Horizontal Oil Well in Ghawar Field** *Ahmed K. Al-Zain, Jorge Duarte, Surajit X. Haldar, Saad Driweesh, Ahmed A. Al-Jandal, Faleh Shammeri, Saudi Aramco; Vsevolod Bugrov, Tashfeen Sarfraz, Schlumberger*	
14:05 — 14:25	126062	**Production Enhancement of Cased-Hole Wells Using Mesophase Fluids** *Chad F. Christian, Lirio Quintero, David E. Clark, Tom A. Jones, Baker Hughes*	
14:25 — 14:45	126061	**Experimental and Numerical Study on Production Performance: Case of Horizontal and Dual-Lateral Wells** *Mohammed M. Amro, Mohamed S. Benzagouta, King Saud University; Hazim A. Ayyad, Schlumberger; Mofazzal Hussain, University of Adelaide.*	

Alternate

120939	**First Regional Selective Packerless Acid-Fracture Stimulation with Coiled Tubing: a Documented Case History from Saudi Arabia** *Leopoldo Sierra, Halliburton; Robert B. Bustin, Saudi Aramco*

Session 4	Saturday, May 9 Reservoir Geology and Geophysics ***Session Chairpersons:*** *Jamil A. Hajhog, Saudi Aramco* *Michael A. Zinger, Saudi Aramco*		Al-Mawad 5 Hall 13:00 – 14:45
13:00 – 13:25	**Invited Speaker** *Mesfir AzZahrani* *Manager Reservoir Characterization* *Saudi Aramco*		
13:25 – 13:45	126086	**Electrofacies and Geological Facies for Petrophysical Rock Typing Khuff C** *Edward. A. Clerke, Saudi Aramco*	
13:45 – 14:05	126083	**Seismic Inversion Workflow for Sand Stringers Characterization in Offshore Saudi Arabia** *Thierry-Laurent D. Tonellot, Roy M. Burnstad, John C. Fitzmaurice, Saudi Aramco*	
14:05 – 14:25	126084	**Prediction of Sand Body Trend Based on Stratigraphic Dip Pattern from Microresistivity Images in Permian Sandstone Reservoir, Oman** *Da-Li Wang , Salim Al-Busaidi, Schlumberger; Desmond N.H Lee, Petroleum Development Oman*	
14:25 – 14:45	126085	**Practical application of CFP Technology to Resolve Complex Near Surface Problems and to Estimate Velocity-depth Model** *Ali A. Momin, Bouchaib A. El-Marhfoul, Saudi Aramco*	

Alternate

126087	**Advanced Processing of Walkaway VSP- Offshore India** *Nidhi Jindal, Prativadi Jyothi, Sanjay Tiwari, Ajoy Biswal, Pranaya Sanghvai, Reliance Industries Limited; Saleh Barakat, VSFusion*

Session 5	Saturday, May 9 Reservoir Engineering and Management ***Session Chairpersons:*** *Adnan A. Kanaan, Mubarak, Saudi Aramco* *Ali A. Al-Yousif, Saudi Aramco*		Al-Dana Hall 14:50 – 16:50
14:50 – 15:15	**The Importance of Critically-Stressed Fractures and Faults on Reservoir Flow at Multiple Scales** *Invited Speaker:* *Mark Zoback* *Professor of Geophysics* *Stanford University*		
15:15 – 15:30	**Prayer Break**		
15:30 – 15:50	126077	**Sub-Surface Drill Cutting Re-Injection Evaluation in Manifa Field: The Safe and Cost Effective Technology for Waste Management Case Study in the Manifa Field, Saudi Arabia** *Kirk M. Bartko, Yousef Al-Shobaili, Philip E. Gagnard, Lewis M. Warlick, Ahmed Ba Im, Saudi Aramco*	
15:50 – 16:10	SPEKSA-C6	**New Completion Methodology to Improve Oil Recovery and Minimize Water Intrusion in Reservoirs Subject to Water Injection** *Leopoldo Sierra, Loyd East, David Kulakofsky, Halliburton*	
16:10 – 16:30	126079	**Integrating Reservoir Characterization and Fracturing Analysis to Understand the Pressure Transient Response of Frac Packed Wells** *Khalid M. Al-Naimi, Faisal M. Al-Thawad, Saud BinAkresh, Kirk M. Bartko, Saudi Aramco*	
16:30 – 16:50	126078	**Minimum Miscibility Pressure Determination for Systems Carbon Dioxide, Heavy Hydrocarbon (N-Eicosane), Light Gas (Ethane or Propane) Using Peng-Robinson Equation of State** *Salem S. Al-Marri, Kuwait Institute for Scientific Research*	

Alternate

126080	**Productivity of Fractal Reservoirs** *Tom A. Jelmert, Norwegian University of Science and Technology, NTNU*
126081	**Performance of Thermal Recovery Processes in a Middle Eastern Reservoir** *Meshal K. Algharaib, Abdullah Alajmi, Ridha Gharbi, Kuwait University*

Session 6	Saturday, May 9 Reservoir Geomechanics ***Session Chairpersons:*** *Thomas Finkbeiner, Baker Hughes* *Mohammed Ameen, Saudi Aramco*		Al-Mawad 5 Hall 14:50 – 16:50
14:50 – 15:15	**The Reservoir Geomechanics Branch of the Mechanical Earth Model** *Invited Speaker:* *Harvey Goodman* *Chevron Fellow* *Chevron Energy Technology Company*		
15:15 – 15:30	**Prayer Break**		
15:30 – 15:50	126096	**A Porothermoelastic Wellbore Model in Oil and Gas Saturated Naturally Fractured Rock Formation** *Rajesh Nair, Chevron; Younane Abousleiman, University of Oklahoma*	
15:50 – 16:10	SPEKSA-E2	**Evaluation of Wellbore Stability, during Drilling and Production, of Openhole Horizontal Wells in Manifa Field** *Lewis M. Warlick, Hazim H. Abass, Cesar H. Pardo Techa, Ashraf M. Al-Tahini, Yousef M. Shobaili, Dhafer A. Al-Shehri, Hameed H. Badairy, Saudi Aramco; Thomas Finkbeiner, Perumalla, S.N., Geomechanics International*	
16:10 – 16:30	126095	**3D Reservoir Geomechanical Modeling in Oil/Gas Field Production** *Nick Koutsabeloulis, Xing Zhang, SPE, Schlumberger Reservoir Geomechanics Centre of Excellence*	
16:30 – 16:50	126094	**Prediction of Rock Mechanical Parameters for Hydrocarbon Reservoirs Using Different Artificial Intelligent Techniques** *Abdulaziz A. Abdulraheem, King Fahad University of Petroleum and Minerals*; *Mujahed Ahmed, A. Vantala, Schlumberger; Tanvir Parvez, King Fahad University of Petroleum and Minerals*	

Session 7	Sunday, May 10 Production Intelligent Field Operations ***Session Chairpersons:*** *Suresh Jacob, Halliburton* *Mohammed A. Abduldayem, Weatherford*		Al-Dana Hall 8:00 – 9:45
7:00 – 8:00	***Refreshments & Registration***		
8:00 – 8:25	**Tight Gas Technology, Halliburton's Path Forward** *Invited Speaker:* *Ron Hyden* *Strategic Business Manager for Production Enhancement* *Halliburton*		
8:25 – 8:45	126067	**Revitalization of Old Asset Oil Fields into I-Fields** *Mohammed N. Al-Khamis, Konstantin I. Zorbalas, Hassan M. Al-Matouq, Saleh M. Almahamed, Saudi Aramco*	
8:45 – 9:05	SPEKSA-C17	**High Speed Network for Intelligent Field Data Acquisition Systems** *Soliman M. Almadi, Fouad Al-Khabbaz, Soliman Al-Walaie, Saudi Aramco*	
9:05 – 9:25	126066	**Case Study: First Successful Offshore ESP Project in Saudi Arabia** *Ahmed R. Al-Zahrani, Redha H. Al-Nasser, Timothy W. Collen, Saudi Aramco; Sudhakar Khade, Schlumberger*	
9:25 – 9:45	126071	**Automatic Diverting Valve, an imminent player in ESP Sand Management** *Mohammad I. Sipra, Petroleum Development Oman; Paul Shotter, Pumptools Ltd Aberdeen*	

Session 8	Sunday, May 10 Nanotechnology in the Oil & Gas Industry *Session Chairpersons:* *Zain H. Yamani, King Fahad University of Petroleum and Minerals* *Rami A. Kamal, Saudi Aramco*		Al-Mawad 5 Hall 8:00 – 9:45
7:00 – 8:00	***Refreshments & Registration***		
8:00 – 8:25	**Toward Micro/Nano Sensors for Subsurface Oilfield Applications** *Invited Speaker:* *John Ullo* *Senior Management Advisor* *Schlumberger*		
8:25 – 8:45	110120	**Nanotechnology Advances in the Application to Rock Mechanical Characterization, the Next Revolution in Rock Mechanics** *Younane Abousleiman, Minh Tran, Son Hoang, The PoroMechanics Institute, University of Oklahoma; and Christopher Bobko, Alberto Ortega, Franz-Josef Ulm, Massachusetts Institute of Technology*	
8:45 – 9:05	SPEKSA-J9	**Reservoir Nanoagents** *Mazen Kanj, Saudi Aramco*	
9:05 – 9:25	126101	**Priority Assessment of Investment in Development of Nanotechnology in Petroleum Upstream Industry** *Peyman Pourafshary, Institute of Petroleum Engineering, University of Tehran; S.S. Azimipour, P. Motamedi, M. Samet, S.A. Taheri, H. Bargozin, S.S. Hendi, Research and Innovation Center, Research Institute of Petroleum Industry*	
9:25 – 9:45	126102	**Nano-Technology- Its Significance in Smart Fluid Development for Oil and Gas Field Application** *Md. Amanullah, Ashraf M. Tahini, Saudi Aramco*	

9:45 – 10:00	**Posters Session & Break**

Session 9	Sunday, May 10 Drilling and Completions *Session Chairpersons:* *Fahad Intisar, Baker Hughes* *Hani K. Mokhtar, Saudi Aramco*		Al-Dana Hall 10:00 – 11:45
10:00 – 10:25	**Advancing Reservoir Performance Using Advanced Drilling Technologies** *Invited Speaker:* *Friedhelm Makohl* *Vice President of Technology* *Baker Hughes*		
10:25 – 10:45	126054	**Technology and Team-Based Approach Yields Saudi Arabia's Longest Fully Cemented Horizontal Liner** *Marlio Campos Ramos, Saudi Aramco; Sameh Hussein, Kirby Wedewer, Baker Hughes; Ansgar Dieker, BJ Services Arabia Ltd.*	
10:45 – 11:05	126050	**Utilizing Expandable Casing Clad Enabled Short Radius Sidetrack in Wells with Casing Leaks** *Ali N. Al-BinAli, Zaki A. Al-Baggal, Adib A. Al-Mumen, Saudi Aramco; Yaser Aubed, Baker Hughes*	
11:05 – 11:25	126051	**A Window of Opportunity: Using Real-Time Data During Casing Exits** *Lambertus C. Joppe, Steve B. Wilson III, Raj Fernandez; Baker Hughes*	
11:25 – 11:45	126048	**Changes in Shale Strength Resulting from Interaction with Invert Emulsion Drilling Fluids** *Terry A. Hemphill, Halliburton; William Duran, Saudi Aramco; Younane N. Abousleiman, Minh Tran, Son Hoang, Vihn Nguyen, University of Oklahoma*	

Alternate

126057	**Evolution of Roller Cone Bit Design to Improve Performance in Carbonates** *Jim Senger, Basil Al-Ramahi, Islam Ahmed Taha, Halliburton-Security DBS Drill Bits; Tamer Waheed, ADCO*

Session 10	**Sunday, May 10** **Al-Mawad 5 Hall** **Unconventional Resources; Tight Gas and Heavy Oil** **10:00 – 11:45** ***Session Chairpersons:*** *Emad A. Elrafie, Saudi Aramco* *Lee Ramsey, Schlumberger*	
10:00 – 10:25	**Making Tight Gas Work** *Invited Speaker:* *Hans Milatz* *E&P Difficult Gas Theme Leader* *Shell International B.V.*	
10:25 – 10:45	SPEKSA-G5	**Application of Hybrid Fracture Treatment to Tight Gas Sands in East Texas Cotton Valley Sands** *Abu M. Sani, Sergey V. Nadezhdin, Ruben Villarreal, Thierry Chabernaud, Schlumberger; James McKenzie, Terry Sarniak, Chevron*
10:45 – 11:05	SPEKSA-G2	**Optimizing Proppant Conductivity and Number of Hydraulic Fractures in Tight Gas Sand Wells** *Hazim H. Abass, Saudi Aramco; Leopoldo Sierra, Halliburton; Ashraf M. Al-Tahini, Saudi Aramco*
11:05 – 11:25	126099	**Tight Oil Reservoir Development Feasibility Using Finite Difference Simulation and Streamlines** *Khalid M. Al-Salem, Mansour A. MohammedAli, Chung Lin, Saudi Aramco*
11:25 – 11:45	126098	**Applications of a Multi-Domain Integrated Tight Gas Field Development Process in North America & how to adapt it to the Middle East Reservoirs** *Ahmed Aly, Schlumberger, Raid Bukhamseen, LUKOIL Saudi Arabia, Lee Ramsey, Rabah Mesdour, Schlumberger*

Alternate

SPEKSA-G4	**Log Based Tar / Heavy Oil Characterization and its Impact on Manifa Field Development** *Parvez J. Butt, Schlumberger; Yousef Shobaili, Arun Garg, Saudi Aramco; Sandeep Chakravorty, Vikas Agrawal, Schlumberger*

11:45 – 13:00	**Lunch & Prayer Break**	**Al-Mawad Hall**
	Luncheon Generously Sponsored By ارامكو السعودية Saudi Aramco	

Session 11	Sunday, May 10 Panel Discussion	Al-Dana Hall 13:00 — 15:00
13:00 — 15:00	**Tight Gas Sands - Unlocking their Potential: Vision, Strategy and Opportunities** **Moderator:** **Mohammed Al-Qahtani** *Executive Director Petroleum Engineering and Development* *Saudi Aramco* **Panelists:** **Abdulla Al-Naim** *Vice President Exploration* *Saudi Aramco* **Stuart Ferguson** *Vice President and Chief Technology Officer* *Weatherford* **Nathan Meehan** *Vice President Reservoir Technology and Consulting* *Baker Hughes* **Don Conkle** *Vice President Well Production Services* *Schlumberger* **Hans Milatz** *E&P Difficult Gas Theme Leader* *Shell International B.V.*	

15:00 — 15:30	***Break and Prayer Time***

15:30 — 16:30	***Exhibition and Posters Session***

Session 12	Monday, May 11 Petrophysics and Formation Evaluation *Session Chairpersons:* *Ismail M. Buhidma, Saudi Aramco* *Derick Zurcher, Baker Hughes*	Al-Dana Hall 8:00 – 9:45
7:00 – 8:00	***Refreshments & Registration***	
8:00 – 8:25	**Advanced Formation Evaluation Measurements Changed the Role of the Petrophysics Community** *Invited Speaker:* *Moustafa Oraby* *Global Petrophysics Developments Manager* *Halliburton*	
8:25 – 8:45	126040	**New Techniques in Formation Pressure Testing Enable Real-Time Reservoir Evaluation in Ever More Challenging Environments** *Ulrich Hahne, Jos Pragt, Matthias Meister, Marco Lallemand, Baker Hughes*
8:45 – 9:05	SPEKSA-A30	**Modeling Complex Dispersive Capacitance in Carbonates using Partitioned NMR T2 Distributions** *James J. Funk, Ahmad M. Al-Harbi, Saudi Aramco*
9:05 – 9:25	126038	**Reservoir Saturation Monitoring in Saudi-Aramco; Benefits, Challenges and Opportunities** *Izu Ariwodo, Ali H. AL-Hasan, Ali R. AL-Belowi, Saudi Aramco*
9:25 – 9:45	126043	**Pore Network Modeling Of Saudi Aramco Rocks: A Comparative Study** *Mustafa Touati, Sander Suicmez, James Funk,Saudi Aramco; Yildiray Cinar, (University of New South Wales; Mark Knackstedt, Australian National University*

Alternate

126044	**From Issues to Solutions – Introducing the Multi Function Logging While Drilling Tool for Reservoir Characterization in the Greater Burgan Field of Kuwait Oil Company** *Khalid H. Al-Azmi, Hamdah Al-Enezi, Rohitkumar Kotecha, Salem Al-Sabea, Kuwait Oil Company; Ekpo Archibong, Ahmed Al-Khaledi, Oluwafemi Oyeyemi, Schlumberger*

Session 13	Monday, May 11 Intelligent Completions and Downhole Well Monitoring *Session Chairpersons:* *Abdullah Al-Qahtani, Saudi Aramco* *Steve Dyer, Schlumberger*	Al-Mawad 5 Hall 8:00 – 9:45
7:00 – 8:00	***Refreshments & Registration***	
8:00 – 8:25	**Intelligent Completions - The way forward!** *Invited Speaker:* *Ismail Nawaz* *Global Business Development Manager Intelligent Completions* *Schlumberger*	
8:25 – 8:45	126089	**Lessons Learned from 100 Intelligent Wells Equipped with Multiple Downhole Valves** *Saeed M. Mubarak, Naseem J. Dawood, Salam P. Salamy, Saudi Aramco*
8:45 – 9:05	126090	**Materials Selection for Smart Well Completions in Conjunction With Expandable Casing Technology** *Ho Choi, Saudi Aramco*
9:05 – 9:25	126091	**Designing & Constructing a Pilot of Artificial Intelligent Well** *Turaj, Behrouz, Sayyed S. Hendi, Iran Research Institute of Petroleum Industry*
9:25 – 9:45	SPEKSA-F7	**First Digital Electric Quartz System with Intellitite Welded Permanent Down Hole Monitoring System for Observation Well** *Abdullatif A. Omair, Orji O. Ukaegu, Mohammed Shafei, Saudi Aramco; Abdullah Al-Marri, Mohammed Shafiq, Schlumberger*

Alternate

126092	**First Saudi Aramco Use of Retrievable Downhole Pressure And Temperature Gauges Monitoring System: A Cost Effective Technology Solution To Manage Maturing Oil And Gas Fields** *Shaizad A. Chatriwala, Fehaed M. Al-Subaie , Dhafer A. Al-Shehri, Adeyinka X. Soremi, , Saudi Aramco, James Reaux, SPARTEK Systems*

Session 14	Monday, May 11 Drilling and Completions *Session Chairpersons:* *Qamar Sharif, Saudi Aramco* *Tim Ramsey, BJ Services*	Al-Dana Hall 10:00 — 11:20
10:00 — 10:25	**Drilling and Completion Pushing Recovery Factors and Adding New Reserves** *Invited Speaker:* *Wajid Rasheed* *CEO and Founder* *EPRasheed*	
10:25 — 10:45	126055	**Open Hole Sidetrack: A Transformation in Drilling Dual Lateral Khuff Reservoir Gas Wells in Kingdom of Saudi Aramco** *Khalid Nawaz, Omar A. Al-Faraj, Naser A. Ajmi, Saudi Aramco; A.H. Awan, Jaywant Verma, Sukesh Ganda, Schlumberger*
10:45 — 11:05	126053	**Design of New, Fit-For-Purpose, Downhole Positive Displacement Motor Improves Reliability and Enhances Performance in 16-in. Vertical Sections** *Azar Azizov, Baker Hughes; Karl Hilthon, Saudi Aramco; Fadi Mounzer, David Kent, Baker Hughes*
11:05 — 11:25	126052	**Successful Mitigation of Time-Dependent Shale Instability in Khafji Field Through Drilling Fluid Design Optimization** *Chee P. Tan, Schlumberger; Marwan A. Qadmani, Al-Khafji Joint Operations; Magdalena Povstyanova, Mohammed A. Mohiuddin, Mohd Helmi AbdRahim, Schlumberger*
11:25 — 11:45	126056	**Minimize Wellbore Damage in a Sandstone Reservoir Using Effective Mud Management Practice** *Ali S. Rabaa, James E Phillips, Saleh M. Al-Ammari, Saudi Aramco; Monir Mohamed, Halliburton Fluid System*

Session 15	Monday, May 11 Reservoir Simulation *Session Chairpersons:* *Dean Oliver, University of Oklahoma* *Fatema H. Awami, Saudi Aramco*	Al-Mawad 5 Hall 10:00 — 11:45
10:00 — 10:25	**Invited Speech: Resolution or Realisations: Where has increasing Computer power really brought us?** *Garf Bowen* *Reservoir Engineering Advisor* *Schlumberger*	
10:25 — 10:45	126072	**Smart Well Production Optimization Using An Ensemble-Based Method** *Su J. Ho, Saudi Aramco*
10:45 — 11:05	126073	**Development of Generalized Porosity-Permeability Transforms by Hydraulic Units for Carbonate Oil Reservoirs in Saudi Arabia** *Shamsuddin H. Shenawi, Hisham H. Mohammadi, Muteb H. Faqehy, Saudi Aramco*
11:05 — 11:25	126075	**Fracture Lineament Validation using Streamline Simulation in a Giant Middle East Field: an Innovative Approach** *Abdullah A. Al-Najem, Jamil S. Al-Thuwaini, Abdulatif Al-Omair, Saudi Aramco; Syed Z. Jilani, Schlumberger*
11:25 — 11:45	126074	**Model Ranking and Optimization of Fractured Reservoir Using Streamline Simulation, in One of the Iranian Gas Condensate Reservoir** *Amir Abbas Askari, Golamreza Bashiri, Mohammad Reza Kamali, Research Institute of Petroleum Industry*

Alternate

126076	**The Use of Capacitance-Resistive Model for Estimation of Fracture Distribution in the Hydrocarbon Reservoir** *M. Delshad, A. Bastami, P. Pourafshary, Institute of Petroleum Engineering, University of Tehran*

11:45 — 13:00	**Lunch & Prayer Break**	**Al-Mawad Hall**
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Session 16	Monday, May 11 Production Enhancement & Operations *Session Chairpersons:* *Hazim Abass ,Saudi Aramco* *Abdulaziz Al Amoudi, Shoaibi Group, Oil & Gas Services & Solutions*	Al-Dana Hall 13:00 – 14:45
13:00 – 13:20	SPEKSA-C12	**Long Term Evaluation of a New Liquid Resin Additives used for Fracture Conductivity Enhancement in a Gas Producer Screen Less Completion, Jauf Reservoir, Saudi Arabia** *Jairo A. Leal Jauregui, Saudi Aramco; Leopoldo Sierra, Halliburton; Fadel A. Ghurairi, Ricardo R. Solares, Saudi Aramco*
13:20 – 13:40	120651	**Horizontal wells best clean up practices for an offshore sandstone reservoir with ICD completions** *Ali M. Shahri, Khalid Kilany, Drew Hembling, J. Eric Lauritzen, Saudi Aramco; Varma Gottumukkala, Olusegun Ogunyemi, Schlumberger; Oscar Becerra Moreno, Baker Hughes*
13:40 – 14:00	126065	**Clean-Up of Oil-Based Mud Filter Cake Using an In-Situ Acid Generator System by a Single-Stage Treatment** *Khalid Bin Moqbil, Msalli A. Al-Otaibi, Mohammad G. Al-Faifi, Waleed S. Al-Khudair, Ali D. Al-Aamri, Saudi Aramco*
14:00 – 14:20	SPEKSA-C15	**Droplet Size Analysis of Emulsified Acid** *Saleh H. Al-Mutairi, Saudi Aramco; Hisham A. Nasr-El-Din, A. Dan Hill, Texas A&M University*

Alternate

126068	**Gel under Dynamic Stress in Porous Media: New insights Using Computed Tomography** *Ghaithan A. Al-Muntasheri, Saudi Aramco; Pacelli L. Zitha, Delft University*
126069	**R&D Role for Sustainable Production Operations** *Dominique R. Guerillot, Ihsan Al-Taie, Vincent Pauchard, Krishnam Raju, Peter Sanders, Abdelmounam Sherik, Regis Vilagines, Saudi Aramco*

Poster Session

**Presenters will be available at the poster sessions during the Breaks on the first and second day*

126045	**Pressure and Temperature Effect on Petrophysical Characteristics: Carbonate Reservoirs Case** *Mohammed S. Benzagouta, Mohammed Amro, King Saud University*
126046	**Advances in Sampling Methods Using a New Dual Port Straddle Packer Pumpout Tester in one of Saudi Aramco's Oilfield** *Andre Silva, Richard Palmer, A.A. Hajari, Saudi Aramco; Tony Von Zuleikom, Bob Engleman, Ashraf Rabatt, Halliburton*
126059	**Minimizing Dynamic Dysfunctions Sets New Drilling Performance Benchmark in Saudi Gas Application** *Van J. Brackin, Mike Doster, Fadi Mounzer, Baker Hughes; Luani Alfonzo, Saudi Aramco*
SPEKSA-C9	**Innovative Approach for Water Injection Trees Integrity** *Yousef A. Al-Rufaie, Hassen I. Al-Tammr, Alaa A. Kady, Saudi Aramco*
SPEKSA-C25	**Chemical Optimization in NGPD GOSPS** *Bandar J. Al-Qahtani, Saudi Aramco*
126070	**Horizontal Open Hole Dual-Lateral Stimulation Using Multi-Laterals Entry with High Jetting Tool.** *Jose R. Amorocho, J. Ricardo Solares, Abdulmohsin Al-Mulhim, Ali Al-Saihati, Saudi Aramco; Wassim Kharrat, Schlumberger*
126082	**Optimal Transformations for Multiple Regression: Application to Oil Viscosity Correlation Above and Below Bubble Point Pressures** *Salem S. Al-Marri, Kuwait Institute for Scientific Research*
126088	**Wettability Studies at the Pore Level of Saudi Aramco Reservoirs** *Mansour A. Al-Shafei, Taha M. Okasha, Saudi Aramco*
126097	**Drilling and Completing Horizontal Wells in Unconsolidated Sandstone Reservoir in Saudi Arabia; A Rock Mechanics View** *Rabba S. Ali S, Hazim H. Abass, Talal S. Mousa, Saudi Aramco*
126093	**Smart well- Benefits, Types of Sensors, Challenges, Economic Consideration, and Application in Fractured Reservoir** *Mahdi Nadri Pari, Iran Petroleum University of Technology, A.H.Kabir, Curtin University of Technology, S. Mahdia Motahhari, Turaj Behrouz, Research Institute of Petroleum Industry (RIPI)*
126100	**Performance of Hot Water Injection in Heterogonous Reservoirs using Multilateral Wells** *Abdullah Alajmi, Ridha Gharbi, Meshal Algharaib, Kuwait University*

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