EPRASHEED
signature series

2010 – Issue 15

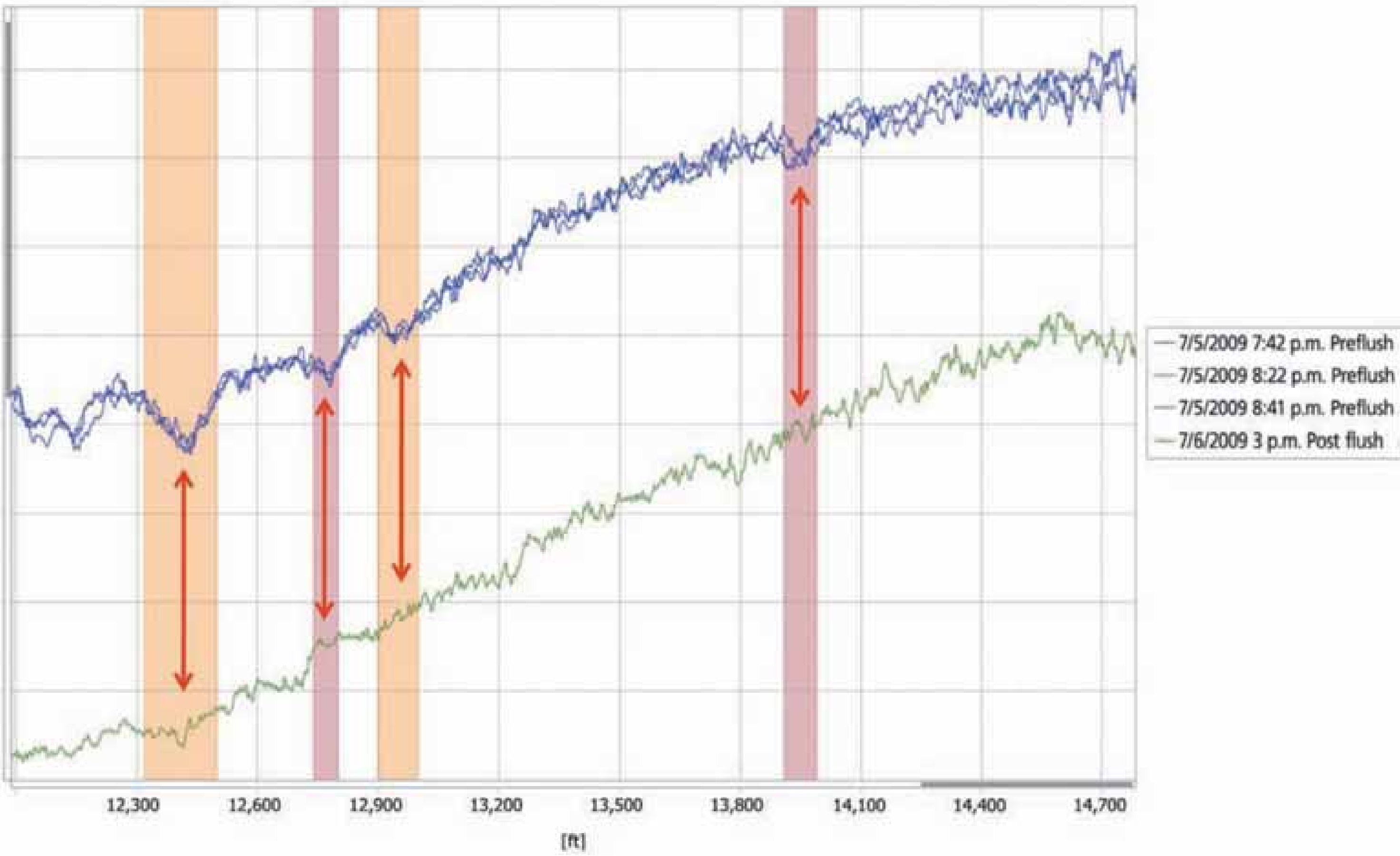
Saudi Arabia oil & gas

www.saudiarabiaoilandgas.com

KFUPM Cooperation Team

Saudi Aramco RTOC

Al-Falih Visits Oxford



Post flush temperature response (green) highlighting diversion effects obtained as compared to the preflush injection profile (blue).

مدينة الملك عبدالعزيز
للعلوم والتقنية KACST

Oil and Gas Research Institute

Hydrocarbon resources (crude oil and gas) are the main source of world energy, and as the international demand increases, the technical challenges increase to meet that demand. Hydrocarbon production optimization at minimum cost and the need to serve the national petroleum industry has been the driving force behind the establishment of the Oil and Gas Research Institute (OGRI) at King Abdulaziz City for Science and Technology (KACST).
OGRI is a governmental research and development entity. Its applied research activities concentrate on the upstream sector of the petroleum industry. Fields of interest cover most of the petroleum science and engineering aspects through four main divisions:

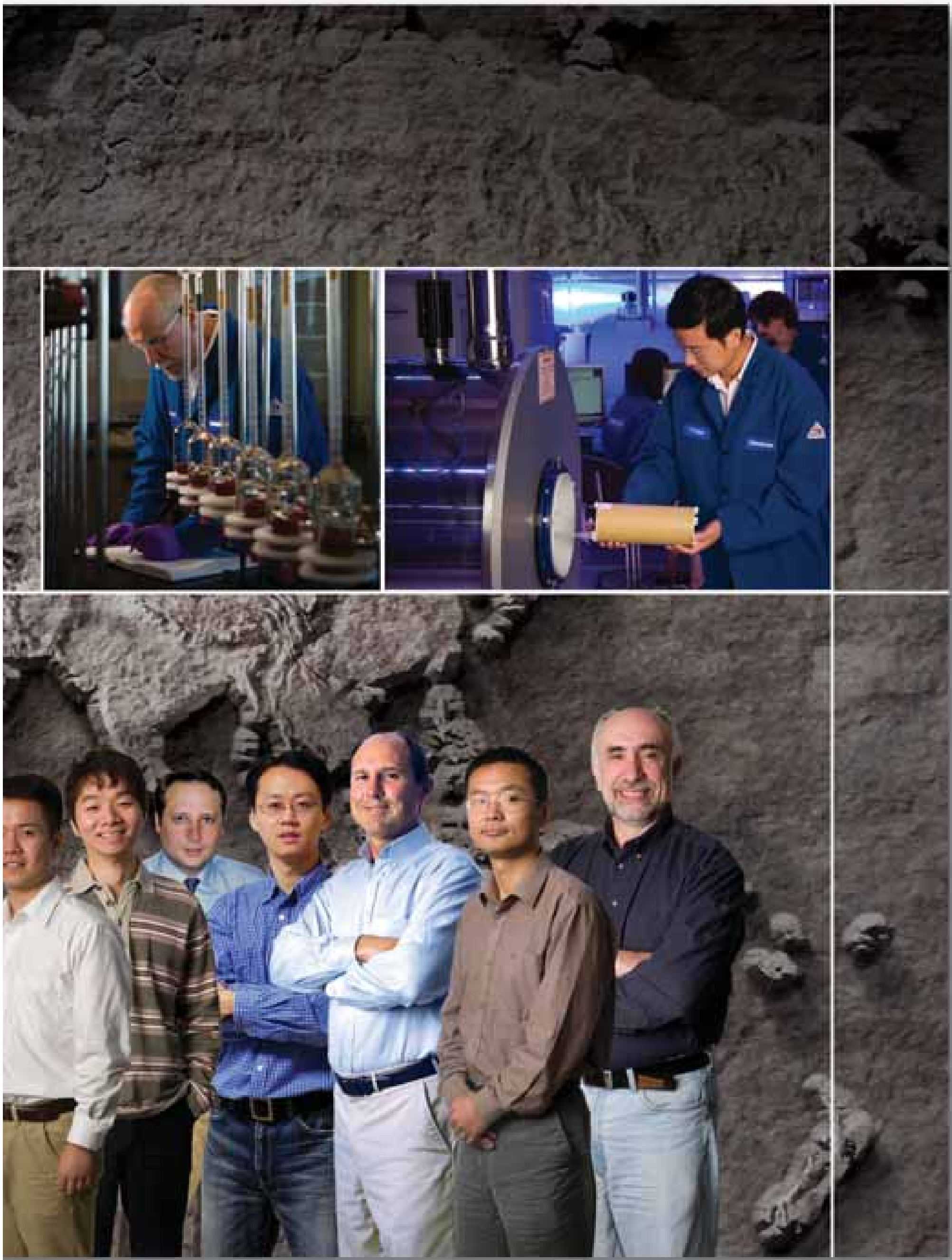
- Reservoir Characterization and Numerical Simulation,
- Drilling Engineering,
- Rock Mechanics,
- Production and Enhanced Recovery.

Services Provided

Service	Techniques
CONVENTIONAL CORE ANALYSIS	➤ Helium Porosity (Ambient Conditions) ➤ Gas Permeability & Porosity (Low and Reservoir Overburden Stress) ➤ Klinkenberg Correction ➤ Liquid Permeability (Reservoir Conditions)
SPECIAL CORE ANALYSIS (SCAL)	**CAPILLARY PRESSURE TESTS** ➤ Centrifuge Techniques (Reservoir Conditions) ➤ Low and High Pressure Mercury Injection and Withdrawal Technique ➤ Pore Size Distribution (PSD) **RELATIVE PERMEABILITY MEASUREMENTS** ➤ Unsteady State Flooding Technique (Reservoir Conditions) ➤ Centrifuge Technique (Reservoir Conditions) **WETTABILITY TESTS** ➤ Centrifuge USBM Method ➤ Contact angle Measurement (Ambient and Reservoir Conditions) ➤ Interfacial Tension Measurements **PETROGRAPHIC SERVICES** ➤ Sieve Analysis ➤ Particle Size Analysis ➤ Thin section
RESERVOIR FLUID ANALYSIS	➤ Interfacial & Surface tension ➤ Gas and Gas Condensate Viscosity ➤ Refractive index and pH ➤ Contact angle
ADVANCED RESERVOIR ENGINEERING	➤ Water-Oil /Water-Gas Displacement ➤ Gas Flooding and WAG ➤ Chemical Flooding
PETROLEUM RELATED ROCK MECHANICS	➤ Uniaxial, Triaxial, and Hydrostatic Compressive strength ➤ Stress-Strain Behavior ➤ Failure Envelope ➤ Elastic moduli ➤ Bulk and Pore Compressibility ➤ Fracture Toughness

OGRI - KACST - K.S.A - P.O. Box. 6086 Riyadh 11442
Tel. : +966 1 4813307 Fax : +966 1 4813526

www.kacst.edu.sa

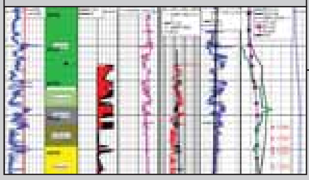


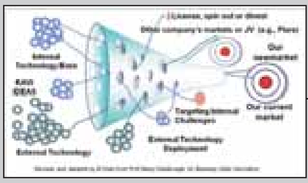
Carbonate Advisor

EPRASHEED
signature series

2010 – Issue 15
Saudi Arabia oil & gas
www.saudiarabiaoilandgas.com

Contents





ADVERTISERS: KACST - pages 2-8, SCHLUMBERGER - pages 4-5, MASTERGEAR UK - page 7, RAWABI HOLDING - page 8, BAKER HUGHES - page 83, HALLIBURTON - OBC

CEO and Founder EPRasheed
Wajid Rasheed
wajid.rasheed@eprasheed.com

Editors
Majid Rasheed
Mauro Martins

Design
Sue Smith

Contacts

United Kingdom
- Head Office
Tel: (44) 207 193 1602
- Brian Passey
brian@bspmedia.com
- Sally Cole
sally@bspmedia.com

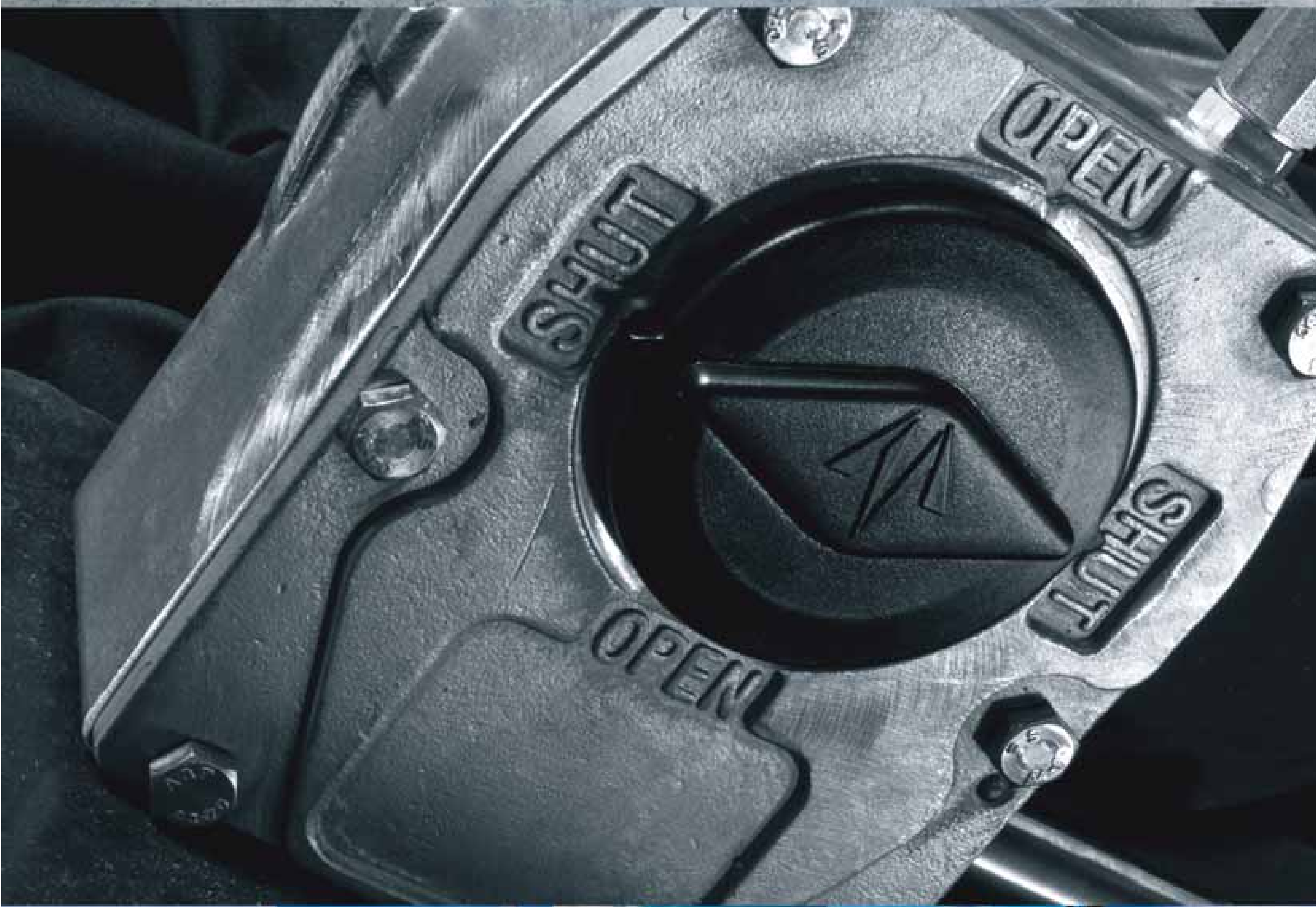
Saudi Arabia
- Akram ul Haq
PO BOX 3260, Jeddah 21471
akram.ul.haq@saudiarabiaoilandgas.com
Tel: (966) 557 276 426
- Mohanned AlSagri
mohanned.alsagri@saudiarabiaoilandgas.com

Houston
- David Jones
david.jones@eprasheed.com
Tel: (1) 281 793 4314
- William Bart Goforth
william.goforth@eprasheed.com
Tel: (1) 713 304 6119

Brazil
- Ana Felix
afelix@braziloilandgas.com
Tel: (55) 21 9714 8690
- Fabio Jones
fabio.jones@braziloilandgas.com
Tel: (55) 21 9392 7821
- Roberto S. Zangrando
rzangrando@braziloilandgas.com
Tel: (55) 22 8818 8507

MASTERGEAR UK

The **Stainless Steel** Gearbox Range.



Built to withstand the World's most **extreme environments.**

www.mastergearworldwide.com

Al-Falih Visits Oxford: Challenges, Opportunities Ahead

Khalid A. Al-Falih poses with Saudi Aramco personnel and Oxford Energy Seminar organizers.

LONDON, August 04, 2010 – Saudi Aramco president and CEO Khalid A. Al-Falih told delegates to the Oxford Energy Forum that the global petroleum industry faces trying times as a confluence of factors – demographic, political, business, macroeconomic and operational, as well as public perceptions of the industry – presents significant challenges – and, possibly, tremendous opportunities.

Speaking to the forum, held at the U.K.'s Oxford University and attended by many experts and decision makers, Al-Falih said off-and-on fears that the world's oil resources are about to be exhausted are baseless. Geological evidence, he said, shows that the world has a plentiful endowment of oil and gas, with a vast quantity of known reserves yet to be tapped and additional resources still to be discovered.

The most comprehensive analyses estimate between 6 and 8 trillion barrels of conventional oil and natural gas liquids and about 7 trillion barrels of unconventional oil in place. The ability to produce those resources hinges on a complex interplay of technology, economic, environmental and regulatory factors.

Al-Falih also touched on more serious challenges. There are, he said, negative public perceptions of the industry and doubts about its ability to supply energy responsibly and reliably. In some countries, national security, the environment and economic growth are being mixed together in an attempt to turn away from petroleum. And, of course, the industry is in the headlines because of the Macondo well incident in the Gulf of Mexico.

Al-Falih addressed the Gulf of Mexico tragedy and its possible ramifications. He referred to the incident as a wakeup call, saying that the lessons learned must be taken to heart and transformed into meaningful action.

"It is likely that there will be tighter regulations on petroleum activities in many markets, with ramifications both for the way we do business and for the cost of industry activities," he said. But in the long term, "The world will continue to rely upon oil and gas for essentially all of the energy used for transportation and much of what fuels and feeds industry."

"BP and the relevant U.S. authorities will be conducting in-depth investigations," he said, "and I am sure there will be valuable lessons there for all of us to learn. But it would be a mistake to assume that the rest of us are immune to such tragic incidents or that such a disaster could only involve just one particular set of companies and service providers. As with any such industrial incident, we will find that there were specific conditions and actions, human and mechanical, which lead to such accidents."

Al-Falih said it was important for executives to lead and communicate with subordinates, especially with regard to operational safety. Executives cannot just delegate operational safety responsibilities to their subordinates without providing adequate supervision, he said. "Senior management must lead visibly and remain engaged with the issues and operations that, taken together, constitute what we call operational excellence."

Open dialogue between executives and employees over operational safety is "an essential part of corporate leadership and an integral responsibility for senior management," he said.

"If senior management primarily talks about the bottom line and financial performance," he said, "then employees will look first and foremost at ways to cut or contain costs and juice profitability. In short, if as a leader you put pressure on people, either by design or through inadvertent signals, they will go to great lengths to fulfill what is implied by such signals – even if that means putting themselves or their colleagues at risk."

Al-Falih stressed the importance of serious dialogue between consumer nations and oil producing countries about preserving the environment. Some countries are taking unilateral steps to provide alternatives to oil and implement strict controls, he said, and that will only make it more difficult to develop long-term strategies for oil infrastructure and producing facilities.

"In my view," he said, "the perspectives of all stakeholders have a place in the discussion – and that includes a well-articulated case for petroleum as a fundamental enabler of economic prosperity and social development. Of course, to be successful in that effort we need to address not only global concerns like greenhouse gas emissions, safety and security of supply, but also market-specific issues like taxes and import tariffs, and the wisdom of subsidies and other incentives for alternative energy sources."

Al-Falih said the industry will face greater challenges in skill development. Ever more complex activities will require higher degrees of training, and keeping the work force motivated will require companies to renew their commitment to employees – guaranteeing the tools and training they need for the future – as well as to attract young, brilliant people to the oil industry.

"We need to make young people aware of the reality of the petroleum industry and the prospects it offers," he said. "We also have to give more attention the role advanced technology and R&D play in our operations, and to let young people know that a career in oil and gas can be personally as well as professionally rewarding."

"The industry – and particularly Saudi Aramco, with the role it plays in the market – cannot determine with any degree of certainty what future demand will look like," he said, "but we are required to make multi-billion-dollar investment decisions now, given the long lead times involved for oil and gas projects."

Al-Falih concluded by saying that operational excellence, especially caring for the safety and health of employees and protecting our reliability as energy suppliers to the world, is an indispensable key to sustained success.

With the dawn of every new day, hard work is needed to achieve that kind of performance. But, he added, "In my experience, there is no more rewarding, more exciting or more worthwhile business."

New Board of Directors Appointed

DHAHRAN, August 23, 2010 -- Saudi Aramco today announced the appointment by Royal Order of a new Board of Directors.

The new Board of Directors, appointed to a three-Hijrah-year term by the Custodian of the Two Holy Mosques King Abdullah ibn Abdulaziz Al Saud, as of August 25, 2010 (15 Ramadan 1431), includes:

• Minister of Petroleum and Mineral Resources, H.E. Ali I. Al-Naimi, Chairman
• H.E. Dr. Ibrahim A. Al-Assaf, Member
• H.E. Dr. Mohammed I. Al-Suwaiyel, Member
• H.E. Dr. Abdul Rahman A. Al-Tuwaijri, Member
• H.E. Dr. Khaled S. Al-Sultan, Member
• Sir Mark Moody-Stuart, Member
• Peter L. Woicke, Member
• David J. O'Reilly, Member
• President and CEO of Saudi Aramco, Khalid A. Al-Falih, Member
• Abdulaziz F. Al-Khayyal, Member
• Salim S. Al-Aydh, Member
• Amin H. Nasser, Member

The two new Directors are David J. O'Reilly, former Chairman and CEO of Chevron Corporation, and Amin H. Nasser, Saudi Aramco Senior Vice President for Exploration and Producing.

David J. O'Reilly held a range of senior-level positions across Chevron Corporation before retiring in September 2009. From November 1998 to January 2000, he served as vice chairman of the board, responsible for Chevron's worldwide exploration and production and corporate human resources. He was elected chairman and chief executive officer in January 2000.

He is widely credited with transforming Chevron into one of the world's most formidable energy companies with an unwavering dedication to operational excellence and what he often referred to as "getting results the right way". After he became CEO in 2000, the company established the best exploration record among its peers in

Left: David J. O'Reilly
Above: Amin H. Nasser

the industry and advanced its safety record to world-class levels.

A native of Dublin, Ireland, O'Reilly joined the company as a process engineer in Chevron Research Co. in 1968 after earning his bachelor's degree in chemical engineering from University College in Dublin. In 2002, University College granted him an honorary doctor of science degree in recognition of his outstanding career.

Amin H. Nasser was appointed Senior Vice President, Exploration and Producing, Saudi Aramco on May 1, 2008. His current responsibilities as Senior Vice President, Exploration & Producing include exploration, petroleum engineering, oil and gas production and processing activities.

He graduated from King Fahd University of Petroleum and Minerals in 1982 with a Bachelor of Science Degree in Petroleum Engineering. Nasser began his career with Saudi Aramco as a field Petroleum Engineer having advanced through a number of management positions during the past 28 years. In April 2006, he was appointed as Vice President, Petroleum Engineering and Development, having held the position of Executive Director, Petroleum Engineering and Development Administrative Area since May 2005.

Nasser is a member of the Society of Petroleum Engineers (SPE) and a member of the SPE Industry Advisory Council.

KFUPM Cooperation Team Gathers

Saudi Aramco-KFUPM Steering Committee gathers for a photo at its most recent meeting. (Photo: Salah A. Al-Alwan)

DHAHRAN, August 25, 2010 – A team whose purpose it is to oversee the relationship between Saudi Aramco and King Fahd University of Petroleum and Minerals (KFUPM) met recently to provide strategic guidance for that multidimensional partnership and ensure its sustainability and success.

The Saudi Aramco-KFUPM Steering Committee is chaired by president and CEO Khalid A. Al-Falih and KFUPM rector Dr. Khalid S. Al-Sultan. Among those gathered were members of corporate and executive management, KFUPM academic leaders and teams from both sides.

The committee reviewed progress and milestones in such areas of collaboration as academic programs, research and development in the upstream and downstream disciplines, business development, community and social outreach, and collaboration with top-tier universities around the world.

The committee commended the cooperation, focus and commitment of the teams to deliver tangible results so that the partnership can serve as a model of cooperation between the oil industry and academia.

The cooperation between the two organizations has become the nucleus of further opportunities for technical and scientific innovations that will continue to benefit them, the Kingdom and the energy industry.

The company has a long tradition of supporting higher education, and scientific and applied research in the Kingdom. Saudi Aramco benefits from quality graduates, cutting-edge research and innovation.


EPRASHEED
signature series
Increase Sales
Do You Want Your Advertising Message To Reach Oil Company Buyers And Decision Makers?
ADVERTISE IN EPRASHEED MAGAZINES NOW!
www.eprasheed.com
sales@eprasheed.com
Brazil Oil & Gas, tt_nrg and Norway Oil & Gas
Saudi Arabia oil & gas
Inside
GEO 2008
Norway Oil & Gas, tt_nrg and Saudi Arabia Oil & Gas
Brazil oil & gas
Inside
Brazil Oil & Gas, Norway Oil & Gas and Saudi Arabia Oil & Gas
tt_nrg
Norway oil & gas
Inside

Texas A&M Outstanding International Alumnus Awards Dinner

By Khalid A. Al-Falih, President and Chief Executive Officer, Saudi Aramco.

COLLEGE STATION, Texas, March, 2010 – "President Loftin; Your Excellency, Consul General of Saudi Arabia in Houston; Dr. Watson, Interim Provost and Executive Vice President; Professor O'Neal, Dr. Bennett and members of the Dwight Look College of Engineering; Mr. Garner, Mr. Yosufzai, Mr. Holmes, and members of the Association of Former Students; Dr. Ashworth; Distinguished guests; ladies and gentlemen:

Howdy!

It is a great pleasure to be back with you in our "hometown," College Station.

Let me begin by saying 'thank you' for the tremendous honor of the Outstanding International Alumnus Award. It is very humbling to join the long and distinguished list of fellow graduates who have received this honor in years past. As I told President Loftin, and Dr. O'Neal – my fellow Aggie who so graciously submitted my name for the OIA – just being nominated is an award in itself.

That's because this university is so much more than a school to its graduates: those of us fortunate enough to partake of the Texas A&M experience know that the expression, 'Once an Aggie, always an Aggie' is far more than a slogan. Being an Aggie is a 'gift that keeps on giving'.

Like most undergraduates, I came to A&M in search of a world-class education. What I only realized later was that joining A&M brings about a fundamental, permanent shift of mind and heart, and provides a lifetime identity as well. Some may think that the intervening three decades since my graduation, or the many thousands of miles between College Station, Texas and Dhahran, Saudi Arabia, might have diminished that connection. But anyone thinking that way obviously has not experienced the Aggie spirit, and does not know the strength of the Aggie bond.

Ever since my student days, I have felt a deep sense of belonging here. Setting foot back in Aggieland is like slipping on a comfortable boot. The generous welcome that I received today is every bit a homecoming, with a chance to visit my old college, walk the halls of the Zachry Building, spend time with students and faculty.

That enduring sense of belonging is the Aggie heritage. I can't think of another institution that cares so genuinely for its own, from that first warm Texas howdy to the last muster.

But even more significant is the ability of Texas A&M to keep its core mission and values, the foundations of this unique culture, relevant over the years.

This university has always met the right needs at the right time. As the first public land-grant college in Texas 134 years ago, A&M's agricultural and mechanical engineering instruction served the state economy. A&M then evolved into a senior military college. The student profile evolved too, from primarily male to a well-balanced mix of men and women.

Over the decades, advances were made across A&M's wide range of academic and professional fields, such as aerospace and biotechnology, as well as in significant new fields such as medicine, dentistry and public health. Today, moving from strength to strength, the university is recognized worldwide not only for its legendary success in educating professionals and preparing leaders, but as a 21st-century research university. Its strong emphasis on science, technology and engineering is helping meet global research and technology needs.

As a result, Aggies are prepared 'to address the needs of an increasingly diverse population and global economy'.

… A&M offered a real sense of community, diverse yet closely knit, as a backdrop to world-class academics.

But what about this Aggie?

Back in 1978, I had just enrolled at A&M. I was about to see for the first time how my experience at this university would be that 'gift that keeps on giving'. In those days A&M was a much smaller school, with an enrollment of about 35,000. My classmates and I lived in the Zachry Engineering Center, taking classes and talking with Dr. Albright, who was a wonderful mentor. And when we weren't studying, we were eating – and studying – late into the night at Denny's or the I-Hop across the street.

It was my first international experience. Unlike so many big, impersonal universities, A&M offered a real sense of community, diverse yet closely knit, as a backdrop to world-class academics. What's more, I quickly found that my A&M credentials would open doors. After one year, Saudi Aramco picked me up, sponsoring my degree through a scholarship as preparation for employment with the company.

In short, my Aggie experience created the perfect foundation for my career at Saudi Aramco, and this foundation still gives me an edge as it continues to inform and influence my work. Thanks to the outstanding caliber of academics at A&M, my education has stayed relevant in a dynamic field, a dynamic industry and an ever-changing world. By this I mean the process and art of learning that is a signature discipline at Texas A&M; my education here was distinguished not only by the subject material I learned but also by the process and virtue of learning that the university has embedded in me. A&M nurtures a mindset that craves knowledge and information, and teaches one to think critically and openly. That's another side of that continual "gift"—learning how to learn.

Yet A&M goes beyond shaping the mind. The university reinforces that sense of ethics and values so essential for the truly holistic development of its graduates. I recall that these principles of fairness, leadership and service were emphasized at A&M as 'The Other Education', and the very few who did not pursue them were sadly called 'two-percenters'. This limitation meant, of course, that they were missing out on their personal development and on a university culture that was designed to nurture intellectual curiosity and understanding, while also encouraging engagement with others. The A&M approach, educating mind and heart together, is preparation for a richly rewarding life in all dimensions.

There's another way that the university has generously affected my life, and that is through lasting personal and professional ties. Whether through friends and colleagues like those of you in attendance tonight or through chance meetings, it seems there's always an Aggie encounter waiting to happen. Through the years, I have met hundreds of people who have made me feel instantly at home because I'm an Aggie. Whether they are graduates of A&M themselves, affiliated with the school through work or research, or simply people who love and respect this great university, that's yet another gift: the enduring connections that keep the far-flung Aggie community vibrant and whole.

Speaking of connections, Texas A&M has long been a university of choice for Saudi Aramco. Around the world we have almost 2,000 people enrolled in the best colleges and universities, and Texas A&M is one of our top 5 institutions, not only in terms of numbers, but – more significantly – in qualitative terms.

Many of our brightest young Saudis have studied various disciplines here over the years. As of today, 165 Saudi Aramco employees have graduated from Texas A&M through our sponsored students program, and another 50 are currently enrolled here in undergraduate and graduate degree programs. Eighty-four more are participating in certification or master's degree programs in HR through an initiative we host at Saudi Aramco. I met with some of Saudi Aramco's Aggies this afternoon, and I am proud to say they are thriving, personally and academically.

In addition to sending employees to Texas A&M, Saudi Aramco hires many Aggie graduates.

These sponsored students and direct hires are essential to Saudi Aramco's culture of innovation, which drives our research and development efforts and our technology focus in the upstream and downstream sectors of the oil business.

I like to think that this long-time association is symbiotic, benefitting our company, the Kingdom of Saudi Arabia, and the university. For example, collaboration between Texas A&M and Saudi Aramco includes the much-valued participation of Dr. Stephen Holditch, head of A&M's Petroleum Engineering department, who serves on the advisory board of Saudi Aramco's EXPEC Advanced Research Center, which performs R&D supporting exploration and producing.

Saudi Aramco and Texas A&M also have a longstanding, strategic relationship in fire protection that started with our company sending fire officers to College Station to take fire and rescue training courses. In recent years, this relationship grew through the University's consultation on the design and construction of our Advanced Fire Training Center in Ju'aymah, Saudi Arabia, which is now one of the world's top facilities of its kind. We then partnered with A&M through its Texas Engineering Extension Services to use TEEX courses in Ju'aymah. TEEX continues to audit our fire protection training facilities and to certify our instructors in maintaining world-class industrial and residential fire protection at Saudi Aramco.

Alliances such as these continue to multiply. Another example is the recently announced partnership between A&M and the Kingdom's new research university, the King Abdullah University of Science and Technology, or KAUST. A&M has already brought valuable support to this bold, transformative university during its pre-opening and start-up stages, and will undergird KAUST's service to humankind while it helps build Saudi Arabia's new knowledge economy.

In fact, the Institute for Applied Mathematics and Computational Science, established at A&M to ensure that the scientific computation paradigm becomes one of KAUST's strengths and is broadly used in Saudi Arabia and the world, will host its first workshop on challenges in materials science and engineering at KAUST this month. Likewise, KAUST will hold a collaborative event here in the fall.

We in the Kingdom are pinning our hopes on KAUST to achieve something that Texas A&M has already realized: evolution over the years to continually find and deliver the right solutions at the right time to benefit both our nation and the broader world.

Partnerships like these are representative of the global cooperation and interconnection that I and my fellow international students have come to know at Texas A&M. We know we are all interdependent, and the seeds of my appreciation of such mutual reliance, planted here, have only grown stronger over time. Saudi Aramco's mission of delivering the energy that powers economic and social progress around the globe demonstrates that, when we get down to it, the world is truly small, and we have so much more in common than we have differences.

Like Texas A&M, Saudi Aramco is a truly diverse, global institution, whose 55,000 people from about 60 nations form a close-knit community through their commitment to our shared mission and values. My colleagues around the world – including here in Texas, at ASC Houston, our U.S. headquarters – work interdependently to help improve lives everywhere through stable supplies of energy.

In that spirit of inclusiveness, let me say that I accept with humility this wonderful OIA award on behalf of another international group – those 55,000 Aramcons working in Saudi Arabia and around the world – because helping deliver the energy that fuels economic and social engines worldwide is a shared success.

Ladies and gentlemen, fellow Aggies: my connection to Texas A&M is a source of constant and tremendous pride, and I will always be grateful that my path in life led to a four-year stay here, years that continue to define and enrich my life.

And now, let me invoke those famous words of wisdom, "Aggies never lose, but they may run out of time." Thus I will close my remarks so you can continue to enjoy this lovely evening – but not before saying how deeply touched and grateful I am for this honor.

And in true Aggie spirit, I will not say good night, but 'Gig 'em Ags!'

Again, I thank you".

Saudi Aramco RTOC, Collaborative, Safe and Effective Delivery of Wells from Start to Finish

By Musab M. Al-Khudiri, Naser A. Naser, Majid A. Al-Shehry, AbdulMohsin A. Al-Nassir and Hani K. Mokhtar.

Reprinted courtesy of Saudi Aramco JOT..

Abstract

The objective of this article is to discuss Saudi Aramco's drilling Real-Time Operating Center (RTOC) experience in developing personnel, establishing process workflow and acquiring technologies to deliver wells safely and effectively. The article starts by describing the IT infrastructure that facilitates rapid information flow from drilling sites to the RTOC. Then it discusses the process workflow, which includes pre-drill collaborative planning, real time predictive modeling, and 24/7 monitoring services to provide accurate response to real time trends for successful management of drilling risks, and therefore reduction of nonproductive time (NPT). Finally, overall achievements of 2008-2009 and a case study of one monitored and optimized well are presented.

Introduction

In January 2008, Saudi Aramco opened the Drilling & Workover RTOC, a state-of-the-art well visualization and real-time monitoring command center, to plan, drill and complete wells in the safest, most efficient and cost-effective manner. The RTOC involves three critical components: People, Process and Technology. We found that understanding each component role is crucial to develop a collaborative environment that helps to promote the RTOC values.

Saudi Aramco's RTOC was opened with a lot of challenging objectives. To meet the drilling management expectations, these phases were divided.

Phase 1

The initial RTOC objective was to operate the center on critical wells, mainly offshore wells to reduce occurrence of tight hole, stuck pipe, borehole collapse, sidetracked bottom-hole assemblies (BHAs) and borehole instability problems.

Phase 2

The next step was to improve drilling optimization and efficiency for the monitored wells. One of the techniques used was to monitor and implement the "Mechanical Specific Energy (MSE)" to optimize drilling parameters. Another main goal at this phase was to reduce the NPT for the monitored wells by monitoring the rig activity.

Phase 3

At this phase in the process, the RTOC might recommend the bit selection to increase rate of penetration (ROP). A main goal at this phase was to optimize hydraulics, hole cleaning and equivalent circulating density (ECD) for extended reach drilling (ERD) wells, BHA design, monitor drill string mechanics and BHAs to prevent damage and reduce well control incidents.

Saudi Aramco RTOC

The RTOC consists of a main room that is equipped with 10 main consoles; two of them are reserved for supervisors. These computers are connected to large screens on the wall to display monitored wells' real-time data. A collaborative room for day-to-day meetings is equipped with plasma screens and a PC. Another collab-

Fig 1. Overview of the RTOC.

orative room is equipped with video conferencing tools to communicate with other teams in the company and the outside world as needed. Figure 1 shows an overview of the center.

Drilling engineers nominate their wells based on how critical they are for the operation and potential challenges for the drilling activity. Once approved, the team starts by collecting and preparing required data for that well and the offset wells in the area from various sources. By using different tools and mechanisms, we predict the wellbore stability and monitor it in real-time, automatically generate targets and optimize platform placement and incorporate uncertainty. This work is being done in real-time using data coming from the surface and downhole tools. The communication is established between RTOC engineers with others using phone calls and embedded chat sessions to assist in better and faster decisions. We internally have designed our key performance indicators (KPIs) as described in the IT section to monitor the results of the RTOC and follow-up on what we have achieved so far.

Alerts are classified into two levels: Low and high levels. The low level alerts for any possible problems. Examples of cases with low level alert responses: loss of real-time data, weight on bit (WOB) deviations, reaming of stands while drilling, over pull while reaming, connection gas, low circulating time prior to pulling out of hole (POOH), low circulating rate to achieve hole cleaning, change in torque and drag trends, variation in expected hook load while running casing and deviations from program/procedures.

The high level alerts are for problems that need immediate action and response. At this level, the RTOC engineers notify drilling engineers verbally. If the drilling engineer can't be reached, the foreman is contacted directly. Then a follow-up summary is sent with real-time data capture to the drilling engineer.

Examples of cases with high level alert responses: sudden drop in standpipe pressure, sudden increase in standpipe pressure, sudden loss of string weight, flow out rate variations, alarms (washout, kick, loss circulation), erratic or sudden increase in torque while drilling, high over pulls while picking up on connections, high over pulls while POOH, and a sudden increase in drag while tripping pipe or casing and stuck pipe.

RTOC Staff

Since its first day, the RTOC began operating 24/7. It started with eight employees as follows:

RTOC Supervisor, Saudi Aramco

The RTOC Coordinator, is a senior person in both industry and Saudi Aramco, and has the overall responsibility for the RTOC activity and crew. He establishes and coordinates the levels of monitoring according to Saudi Aramco requirements and data availability.

Three Petroleum Engineers (Specialists), Saudi Aramco

These engineers are responsible for preparing the subsurface pore pressure/geomechanical model. Also, they will prepare downhole calculations for torque and drag, swab/surge and hydraulics.

One Senior Drilling Surveillance Specialist, Drilling Consultation Services

He is second in command to the RTOC Coordinator. The Senior Drilling Engineer, responsible for job activity and crew, issues a Daily Report at 6 a.m., and a Weekly update and Monthly Activity Review. He is mainly responsible for communications with Saudi Aramco personnel and he attends meetings as required and directs activity in the RTOC.

Two Staff Drilling Surveillance Engineers, Drilling Consultation Services

They ensure continuous Earth Mechanical Model build-up and update the models already built. They build and maintain mechanical and hydraulic models using complementary software. Each one works 12 hour shifts with 24/7 coverage.

Two Associate Drilling Surveillance Engineers, Drilling Consultation Services

Compare and record differences between pre-drill estimated performances with real-time data received. Main-

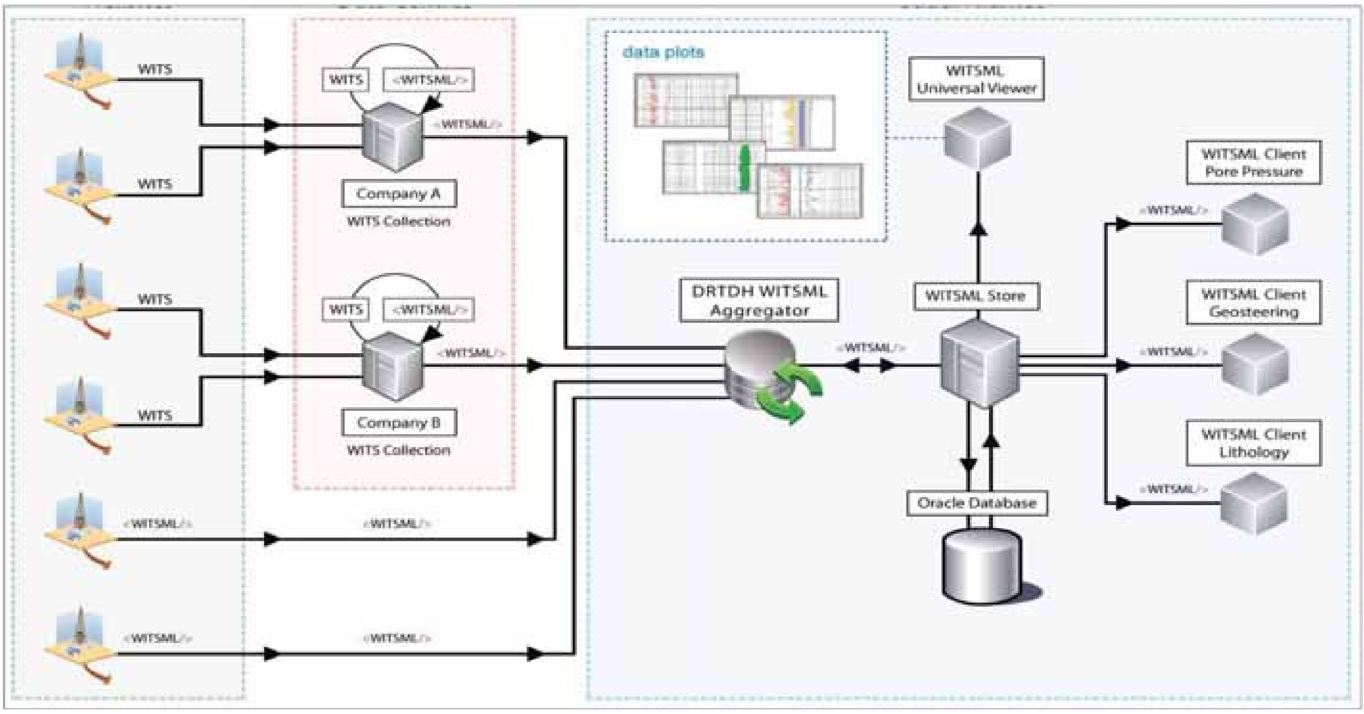


Fig 2. Current real-time well site data flow at Saudi Aramco.

tain an open communication channel with all parts involved in the project: Drilling Engineer – Geosteering Team – RT Provider – Rig Supervisor. Each one works 12 hour shifts with 24/7 coverage.

Two Technical Computer Support, Saudi Aramco
Provide offset well data available in Saudi Aramco databases. Troubleshoot network problems. Ensure required access to Saudi Aramco proprietary applications. Each one works during the daily office hours, and is on call 24/7.

IT Infrastructure

Saudi Aramco uses many different service organizations to deliver its global drilling and completions agenda. Applying a common approach to information access on a global basis has enabled us to streamline our operations and make wider use of emerging analysis, monitoring and collaboration technologies.

In early 2007, Saudi Aramco implemented new data architecture for real-time drilling and completions (D&C) information. This new architecture has enabled us to make wider use of our monitoring and collaboration centers through a common approach. It also allows us to leverage the evolving Well site Information Transfer Standard Markup Language (WITSML) standard more effectively in our drilling operations. Figure 2 shows the current real-time well site data flow at Saudi Aramco.

The WITSML is a continually developing industry standard for the transmission of real-time, historical and contextual drilling and completions information. The WITSML standard is managed by Energistics on behalf of the members. Saudi Aramco is a contributing member of Energistics and has been a member of the drilling WITSML Special Interest Group (SIG) since January 1, 2008. It is the most active user of the WITSML standard worldwide[1].

The RTOC uses different tools to collect data in real-time. These tools vary from downhole parameters measuring while drilling/logging while drilling (MWD/LWD) tools to surface parameter tools. These tools are unmanned and just need to be setup at the beginning of the job. The tools are provided by different providers, and they are based on WITSML standards. Data are collected from different rigs and sorted in Saudi Aramco's drilling real-time data hub (DRTDH)[1].

Real-time technologies have been utilized to capture, monitor and analyze drilling data from rig sites so that critical decisions can be made in real-time to help reduce and eliminate borehole problems, thereby reducing nonproductive time (NPT). This includes high-tech rigs, business continuity solutions for real-time information, collaboration tools and real-time data visualization systems.

Predictive Modeling

The RTOC runs a complete geopressure and geomechanics solution that improves drilling success. It includes all the tools needed to achieve new levels of risk reduction, cost savings, and drilling performance. This includes leading geopressure analysis, 3D visualization and analysis, seismic velocity correction, seal integrity and compartment analysis, uncertainty analysis, and fully integrated wellbore stability analysis. Figure 3 shows predictive model fed by real-time data.

Mechanical Specific Energy

Real-time MSE surveillance as described by a previous SPE paper[2] provides calculations to monitor changes in the efficiency of the drilling operation. It measures the calculated work that is being performed to destroy a given volume of rock. A MSE calculation helps to identify the best drilling parameters and justify any design changes, such as bit selection, BHA design, markup torque, directional target sizing and motor differential ratings. The MSE depends on the fact that the input energy from the rig (RPM, WOB, torque and pump pressure) is equivalent to the output energy (vibration and ROP). Vibration must be minimized to optimize the ROP. The following equation has been defined to calculate MS:

$$MSE = \frac{480 \times Torque \times RPM}{Dia^2 \times ROP} + \frac{4 \times WOB}{Dia^2 \times \pi}$$

To make our analysis more accurate, we have chosen to calculate and display the adjusted MSE by including an efficiency factor:

$$MSE_{adj} = MSE \times EFF$$

where EFF= 0.35 (Efficiency factor).

To apply MSE optimization, we have applied optimal drilling parameters to collect realistic MSE data and trend on two pilot wells for each lithological formation. The recommended parameters were passed to the bit specialist to apply them at the well site while drilling. During the drilling operation, the MSE from recommended drilling parameters were recorded for future MSE analysis against recommended drilling parameters for the next well(s). Bit specialists at the well site are a key performer for ROP optimization by utilizing MSE. Figure 4 shows a sample of how MSE curve is displayed in a real-time data viewer after calculating its value based on the MSE equation.

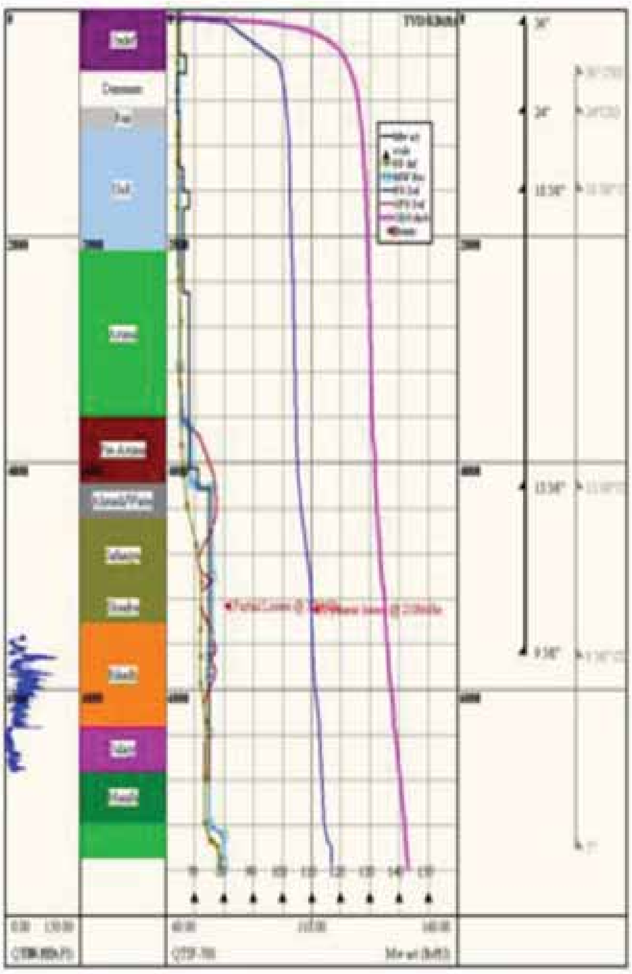


Fig 3. Predictive model fed by real-time data.

Drilling Simulation Systems

Work is in progress to implement advanced real time modeling, diagnosis, visualization and simulation systems. The systems will utilize real-time data acquired from surface and downhole sensors to simulate the drilling activities through 3D interactive visualization techniques. The systems will assist the engineers in looking forward to downhole problems, provide recommendations and develop scenarios while drilling to avoid operational risks and speed up drilling.

Measuring RTOC Value

A system was developed to help the RTOC management in defining and measuring progress towards the RTOC's main goals. The goals are to reduce NPT, to optimize drilling operations and to improve safety in drilling activities. Figure 5 shows different snapshots of the KPIs charts.

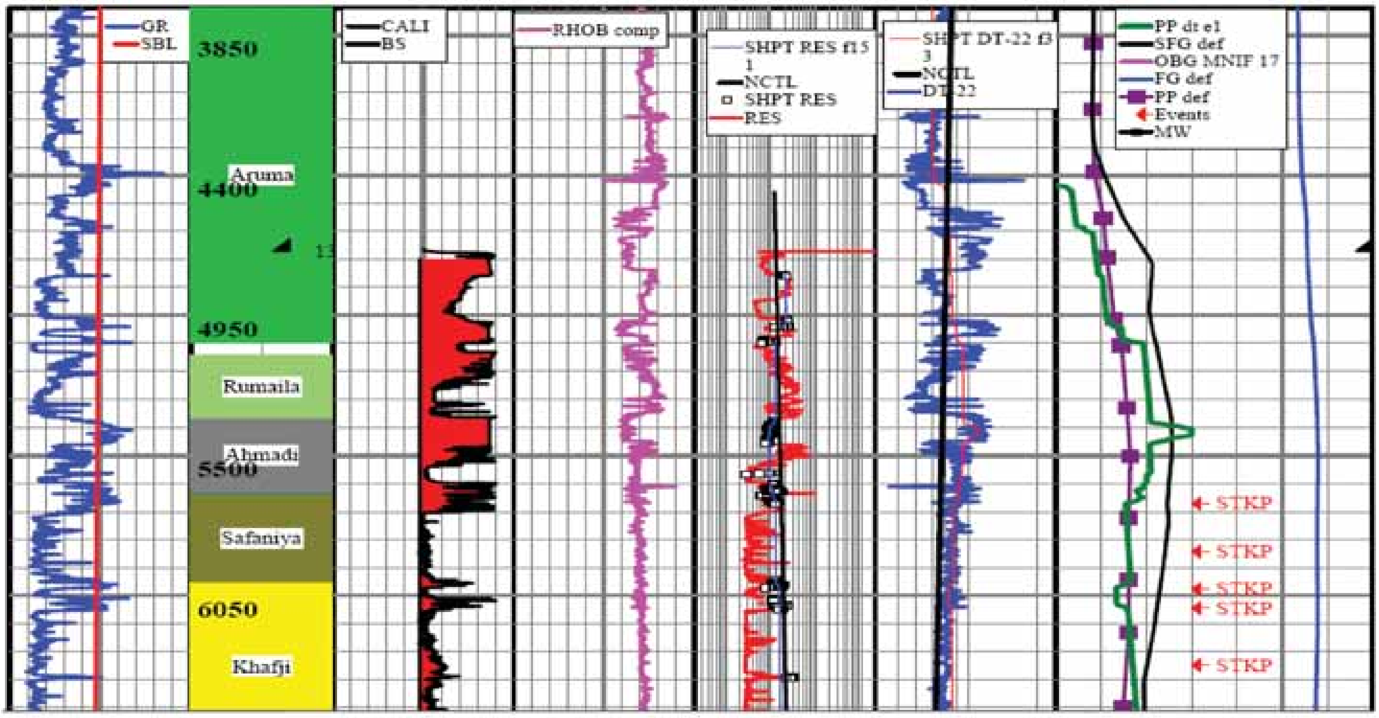


Fig 4. Displaying MSE as a curve along other logs in real-time.

So far the RTOC team has identified the following KPI definitions to be calculated:

- Average total operation time and average total lost time in RTOC vs. non-RTOC wells in the same field.
- Percentage of wells that had specific trouble (e.g., stuck pipe) per year.
- Percentage of drilling troubles per field.
- Total lost time per operation code.
- Compare how many feet per day were drilled in the RTOC and non-RTOC wells.

The first six months of operation in the RTOC has paid back the cost of the center.

A total of 90% of the stuck pipe issues were monitored and prevented. Some of the RTOC statistics reported in August 2009 are:

Total monitored sections = 232
Total alerts raised = 115
Total recommendations = 335

Challenges and Solutions

1. Many drilling engineers are not aware of what the RTOC can provide to them. Aggressive technical marketing of the RTOC is needed among the drilling engineers with the supervisor's assistance. Many training sessions were held for drilling engineers and rig foremen to overcome this challenge.

2. To enforce data analysis every 12 hours per shift to determine "a totally independent technical critique" of drilling activities. Every 12 hours, analyze real-time data and make recommendations to the drillers offshore on how to respond when parameters change, to ensure wellbore viability and bring forward what we call "Practices worth replicating" to the next phase of execution.

3. In the RTOC, we refined the process and the procedures on monitored wells like using a traffic light system for the monitored rigs. Green means the RTOC is tracking the well, amber means slight deviation from the plan executed and red means stop operations. This is to ensure the interaction between the rig and the RTOC follow clear protocol.

4. To improve collaboration with the Geosteering Operation Center (GOC), petrophysics and senior well engineers. There are some initiatives to implement a real collaborative environment between the two centers.

5. To automate rig activity detection, and to optimize and award merit based bonuses to enhance rig activity. This is needed to monitor NPT/Invisible lost time (ILT) and to create best practices and lessons learned.

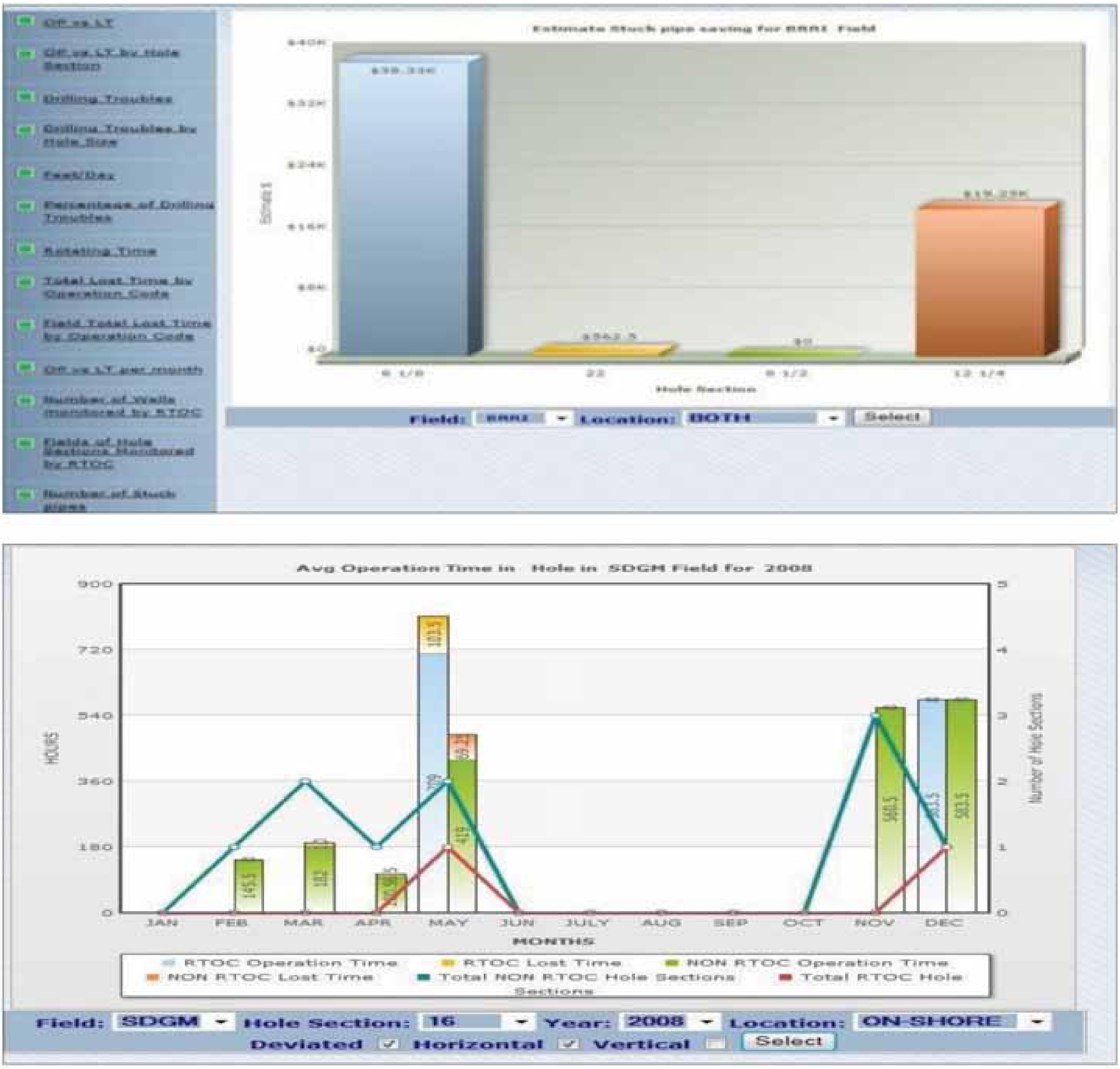


Fig 5. Snapshots of KPI charts.

Future Plans

Drilling Real Time Applications Gateway

Implement an interactive Applications Dashboard for drilling applications. The system is a business and operations management dashboard platform that can be customizable for user roles (Command Centers Manager, Drilling Supervisor, Drilling Engineer, Geologist, Geosteering Supervisor, etc.) or departmental functions (drilling geosteering, IT, etc.).

Saudi Aramco Interactive Drilling Solution (S-IDS)

Overhaul the Saudi Aramco Drilling Knowledgebase (SADK) framework to encompass real-time data, drilling simulation data and planning data in addition to the existing operation data. The morning reports and other reports will be interactively driven by the planning data and real-time data updates. SADK was developed five years ago and has been growing ever since. It is time now to build a new framework to capitalize on the introduction of new workflows as real-time data gathering and automation of drilling programs.

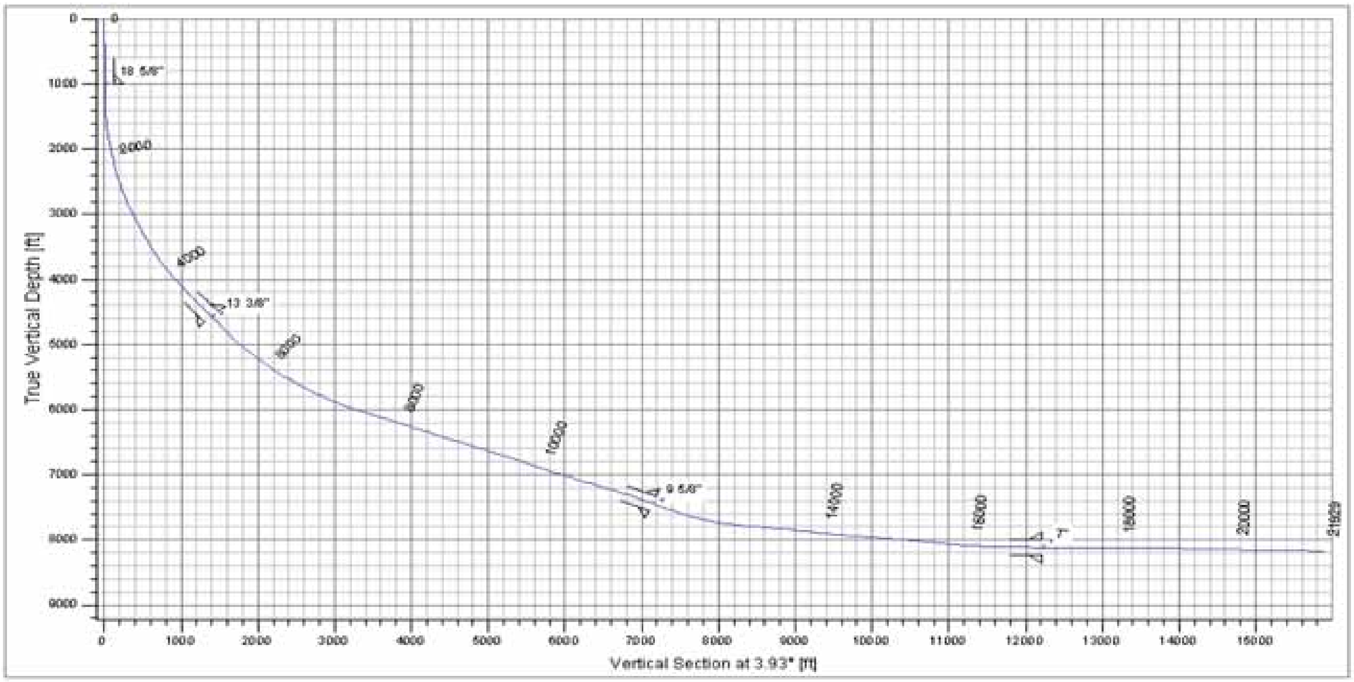


Fig 6. Well A deviation profile..

A CASE STUDY FOR WELL A WITH 8½" AND 6¹/₈" SECTIONS

Introduction

During the well planning phase, drilling engineers identified potentially difficult sections of the well based on offset well data and drilling difficulties experienced in previous well drilled. A request to monitor the well/sections in Well A is submitted to RTOC. Well A was designed as an ERD well. See well deviation profile in Fig. 6.

The RTOC team, in collaboration with the drilling engineer, identified the potential drilling problems for both sections, see Tables 1 and 2.

Pre-drill Modelling Work done by RTOC

Pre-drill models are generated by the RTOC team for optimum monitoring of Well A. These models include a Drillworks Predict Model; Torque and Drag Models; Hydraulics Model; etc. The Drillworks Predict Models simulates the expected maximum pore pressures, shear failure gradient and fracture gradient. All of these suggest to the engineer the required minimum mud weights for hole stability and minimum expected fracture pressures.

Torque and Drag Models are the main method to listen for "wellbore healthy" by monitoring torque and the hook load (HKLD) during drilling or tripping operations. By plotting the real-time HKLD on the Torque and Drag Model, effects on "wellbore healthy" would be presented in a form of friction experienced between the drilling strings and the wellbore.

The Hydraulics Models simulate the required circulation parameters needed to clean the hole based on the ROP, amount of cuttings generated, and the wellbore profile to evaluate the optimum flow parameter required to eliminate cutting beds, and compare ECDs with or without a cutting effect to avoid potential hole problems.

Real-Time Monitoring

Real time surface parameters logging data was continuously being transferred from the rig and monitored continuously in the RTOC. While drilling was going on, real time observations were made by the RTOC team and recommendations were made to avert potential drilling hazards that could jeopardize the objectives of the well. Corrective actions either suggested by the RTOC team or thought out by the Engineering team were made to avert these hazards and the well was successfully drilled

Formation	Prognosis Depth (MD)	Actual Depth (MD)	Potential Hole Problems
Buwaib	12,415 ft		
9⅝" Casing	12,790 ft		
Yamama	14,810 ft		Potential of mud losses, hole cleaning and stability.
Upper Ratawi	15,680 ft		Hole cleaning, Geometry.
Base Upper Ratawi	18,132 ft		Hole cleaning. Borehole Geometry.
Lower Ratawi Reservoir	18,723 ft		Stability, Torque and Drag, Stuck Pipe, H_2S and/or CO_2 influxes.
7" Casing Liner	20,237 ft		

Table 1. Potential hole problems for the 8½" section.

Formation	Prognosis Depth (MD) and TVD	Actual Depth (MD)	Potential Hole Problems
Lower Ratawi Reservoir			
7" Casing Liner TE	20,237 ft 8,106 ft TVD		
Lower Ratawi Reservoir-B TD	23,482 ft MD 8,106 ft TVD		Possible borehole cleaning. Excessive torque and drag. Loss circulation and stuck pipe. Possible H_2S. Induce losses.

Table 2. Potential hole problems for the 6⅛" section.

to TD. See examples below of the format of recommendations and alerts raised with the drilling engineers.

High Stick-Slip in the 8½" Hole

Consequences
High stick-slip may cause drill string torsion failure and downhole tool failure.

Remedies Suggested by RTOC
RTOC recommended changing the drilling parameters (optimize drilling parameters), increase the lubricity of mud, proper bit selection, and installing a soft torque dampening system.

RTOC Recommendations
RTOC recommended increasing RPM and/or reducing WOB and picking up off-bottom (to release stress from string). If the above actions did not help, to prevent and reduce stick-slip, circulation with pills and the increase of mud lubricity should be considered.

Results
By applying recommendations from RTOC, potential string failure was averted.

Stationary Drill String, for Long Time Periods, During Repeated Attemps to Record Pressure Points in the 6⅛" Hole

Consequence
Having a stationary drill string, for long time periods, during repeated attempts to record pressure points in the 6⅛" hole could lead to differential sticking.

RTOC Recommendations
To prevent differential sticking, RTOC recommended reciprocating the string full stand between two pressure points or in a repeat attempt at the same point.

Results
By applying recommendations from RTOC, sticking incidents did not occur.

Lessons Learned

1. While tripping in and out of the build section, it is critical to clean the hole completely before POOH. This may take three or four bottoms up cleanings, and shakers must be clean to avoid the string becoming stuck.

2. To demonstrate the hole is clean, the pipe must be pulled without rotation or pumps.

3. Back reaming in certain fields and reservoirs gives a false indication of the hole condition. This may cause lost time when running casings.

4. Raise awareness of good hole cleaning practices with rig personnel.

Involvement in the Planning Stage to Help Drilling Engineers

1. Designing the optimum directional trajectories to minimize torque, drag, improve ROPs and improve BHA design for critical well designs.

2. Modeling torque and drag to improve future well designs and to provide information to optimize drilling parameters for future wells.

3. Modeling hydraulics and ECD to optimize flow rates for hole cleaning and ROP. This is planned to be done in real time.

4. To provide input into decision making regarding running annular pressure while drilling (APWD) tools in critical wells.

5. Providing inputs and assisting in casing design based on the bore pressure prediction software results.

Involvement in Operation Stage

1. Attending daily morning meeting to discuss the recommendations for further improvement of operations.

2. To attend planning meetings and conducting post well/event meetings to add learning from the RTOC.

3. To be part of the team in planning future well designs.

Acknowledgements

The authors wish to thank Saudi Aramco management for their support and permission to present the information contained in this article.

References

1. Khudiri, M.M., Shehry, M.A. and Curtis, J.D.: "Data Architecture of Real-Time Drilling and Completions Information at Saudi Aramco," SPE paper 116848, presented at Abu Dhabi International Petroleum Exhibition and Conference (ADIPEC) in Abu Dhabi, U.A.E., November 3-6, 2008.

2. Dupriest, F.E. and Koederitz, W.L.: "Maximizing Drill Rates with Real-Time Surveillance of Mechanical Specific Energy," SPE paper 92194, presented at SPE/IADC Drilling Conference in Amsterdam, the Netherlands, February 23-25, 2005.

BIOGRAPHIES

Musab M. Al-Khudiri is a Petroleum Engineering System Analyst with more than 10 years of experience in the oil and gas industry. Since 2006, he has been assigned as a Drilling Real Time Systems Support Group Leader to support Saudi Aramco's Real Time Operating Center (RTOC).

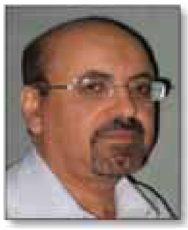
Musab's work experience is focused on drilling software technologies, such as remote monitoring and controlling and drilling optimization systems. He has been involved in several major projects, such as the establishment of the Saudi Aramco Drilling & Workover Operation Center (D&WOC) and the implementation of the Saudi Aramco Data Architecture of Real Time Drilling & Completion Information. Musab received his B.S. in Electrical Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia in 1999. In 2009, he received his M.S. degree in Petroleum Engineering.

Naser A. Al-Naser is a Petroleum Engineering System Analyst with 6 years of experience in the oil and gas industry. He has been heavily involved in analyzing both production and drilling processes to provide appropriate IT solutions, specifically in real time domain. Naser is currently supporting the Real Time Operating Center (RTOC) in its daily operations and leading various software projects for the Center.

Naser received his B.S. degree in Computer Science in 2002 from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia and his M.S. degree in Petroleum Engineering from Robert Gordon University, Aberdeen, Scotland.

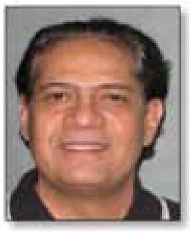
Majid A. Al-Shehry is a Petroleum Engineer System Analyst with 6 years of experience in IT and its applications for the oil and gas business. He is currently supporting the Real Time Operating Center (RTOC) in its daily operations and leading different software projects for the Center.

Majid received his B.S. degree in Computer Science from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia, in 2003. In 2009, he received his M.S. degree in Software Engineering - Development Management Track from Carnegie Mellon University, Pittsburgh, PA. Majid is also enrolled in a special Petroleum Engineer program at KFUPM. He is an active member in the Institute of Electrical and Electronics Engineers (IEEE), Association for Computing Machinery (ACM), the Saudi Computer Society, Toastmasters International and the Society of Petroleum Engineers (SPE).



Abdulmohsin A. Al-Nassir has 29 years of experience with Saudi Aramco. His current position is as a Real Time Operating Center Supervisor (PET Specialist). Abdulmohsin has vast experience in Drilling Engineering, Drilling Operation and Real Time Drilling Operation Monitoring.

In 1988, he received his B.S. degree in Petroleum Engineering from Oklahoma State University, Tulsa, OK.



Hani K. Mokhtar has 29 years of experience in Drilling and Geology, previously working with Baker Hughes, Halliburton and Schlumberger overseas as a Senior Drilling/Petroleum Engineer. He joined Saudi Aramco in March 2008 going to work in the Real Time Operating Center (RTOC).

Hani's work now includes monitoring of high profile wells in real time, comparing and recording differences between the pre-drill estimated performances with real time data received, along with monitoring daily drilling operations and providing technical and engineering support to drilling operations. He tracks and evaluates real time data from drilling operations for select wells and initiates studies to solve drilling problems and recommends ideas to enhance drilling performance.

He received his B.S. degree in General Geology from Alexandria University, Alexandria, Egypt.

Reservoir Monitoring and Performance Using Simbest II Black Oil Simulator Middle East Reservoir Case Study

By Suliman A. Al-Yahya, National Gas & Industrial Company, and Bandar Duraya Al-Anazi, King Abdulaziz City for Science and Technology.

Abstract

New Techniques capable of characterizing reservoir in real time are needed to utilize the dynamic nature of upstream oil operation and minimize the degree of uncertainty around existing reservoir models using high density of data continuously generated by smart technology. The primary objective of a reservoir study is to predict future performance of a reservoir and find ways and means of increasing ultimate recovery.

Simulation uses a lot more than just the design and use of a good model to analyze a process, be it an oil reservoir system or a network switching problem. More realistically, simulation is a process whereby the engineer integrates several factors to produce information on the basis of which managers can make intelligent decisions. At all points along the way the engineer is on top of the situation.

Reservoir simulation technology is being constantly improved and enhanced. New models to simulate more and more complex recovery schemes are being proposed all the time. In this study water flooding is used to increase the recovery and maintain the pressure to sustain the required production rate. Five-spot has been used in this study.

Introduction

Webster's dictionary defines 'simulate' as 'to assume the appearance of without the reality'. Simulation of petroleum reservoir performance refers to the construction and operation of a model whose behavior assumes the appearance of actual reservoir behavior. The model itself is either physical (for example, a laboratory sandpack) or mathematical. A mathematical model is simply a set of equations that, subject to certain assumptions, describes the physical processes active in the reservoir. Although the model itself obviously lacks the reality of the oil or gas field, the behavior of a valid model simulates (assumes the appearance of) that of the field[1].

The purpose of simulation is estimation of field performance (e.g., oil recovery) under one or more producing schemes. Whereas the field can be produced only once, at considerable expense, a model can be produced or run many times at low expense over a short period of time[1]. Observation of model performance under different producing conditions aids selection of an optimal set of producing conditions for the reservoir.

The primary objective of a reservoir study is to predict future performance of a reservoir and find ways and means of increasing ultimate recovery. Simulation uses a lot more than just the design and use of a good model to analyze a process, be it an oil reservoir system or a network switching problem. More realistically, simulation is a process by which the engineer integrates several factors to produce information on the basis of which managers can make intelligent decisions[2]. At all points along the way the engineer is on top of the situation. Nothing the simulation process does can improve the quality of his work, but it can certainly give him a great insight into the interrelationships of the processes which are occurring in his project[3]. Reservoir simulation technology is being constantly improved and enhanced. New models to simulate more and more complex recovery schemes are being proposed all the time.

Necessity for Simulating

The classical approach to solving a problem has been to formulate the problem and then try to make as many simplifying assumptions as possible to produce a new problem which is manageable.[2,5] It is here that a numerical simulation can come into play since a numerical solution does not require these simplifying assumptions, and can produce more realistic solution of the problem.

What Questions Can a Computer Model Answer:
Computer models can be used to answer many of the questions for petroleum engineers. Some of the questions are the following [3]:

1. How should a field be developed and produced in order to maximize the economic recovery of hydrocarbons?

2. What is the best enhanced recovery scheme for the reservoir? How and when should it be implemented?

3. What type of laboratory data is required? What is the sensitivity of model predictions to various data?

4. Is it necessary to do physical model studies of the reservoir? How can the results be scaled up for field applications?

5. What are the critical parameters that should be measured in the field application of a recovery scheme?

6. What is the best completion scheme for wells in a reservoir?

7. From what portion of the reservoir is the production coming?

Modelling Approach

Models are basically of two types, Physical and Mathematical models. The best example of this is the potentiometric model used to predict reservoir flow by capitalizing on the one-to-one correspondence between flow in porous media and the flow of ions in an electric potential field[6]. Mathematical models are systems of mathematical equations describing the physical behavior of the process under investigation. The technique of mathematical modeling and the role played by the engineer can be visualized by the block diagram shown in Fig. 1.

Reservoir Simulation

The area of reservoir simulation applies the concepts and techniques of mathematical modeling to the analysis of the behavior of petroleum reservoir systems. Simulation of some petroleum reservoir problems including single phase, and two-phase, also the flow behavior for water flooding and comparison of simulator results to available analytical solutions. Reservoir simulation by computers allows a more detailed study of the reservoir by dividing the reservoir into a number of blocks and applying fundamental equations for flow in porous media to each block [7]. In the description of computer model terms like mathematical model, numerical model, numerical simulators, grid models, finite difference models and reservoir simulators are used almost interchange-

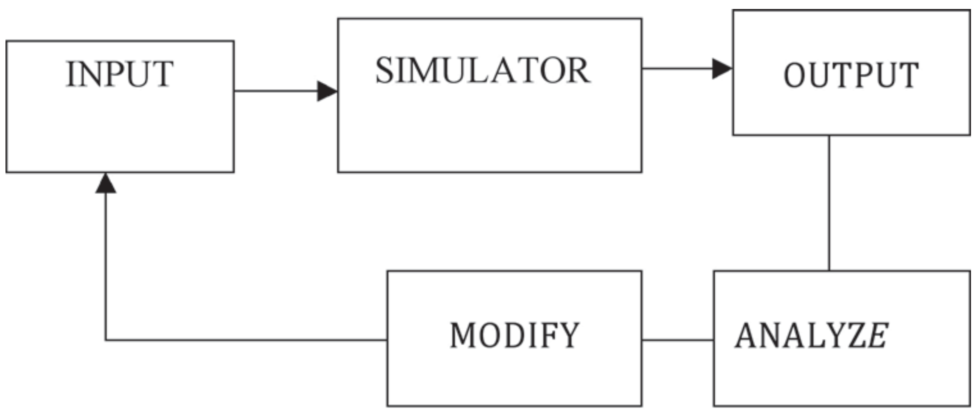


Fig. 1 : Mathematical modeling

ably[8]. The origin of the simulator and the synthesis into a coherent whole are shown in Fig. 2

The difference in the problem of the study and simulator can be attributed to the changing fluid properties in the simulator as well as the "Truncation error". One of the sources of errors in numerical simulation is truncation error. This error is introduced by truncating the infinite Taylor series describing the first and second derivatives.[6] Equation 1 shows the Central difference formula for the first derivative and equation 2 shows the Central difference formula for the second derivative

$$f'(X) = \frac{f(X+\Delta X) - f(X-\Delta X)}{2\Delta X} + O(\Delta X^2) \quad \ldots\ldots (1)$$

$$f''(X) = \frac{f(X+\Delta X) - 2f(X) + f(X-\Delta X)}{\Delta X^2} + O(\Delta X^2) \quad \ldots (2)$$

We can use implicit method or explicit method to solve and minimize this error , but if we use the explicit solution method to give reasonable result the value selected for (Δt / $\Delta x2$) must be less than ½. Although the explicit method is more simple, it requires the selection of small time steps (Δt) or a decrease in distance different (Δx),

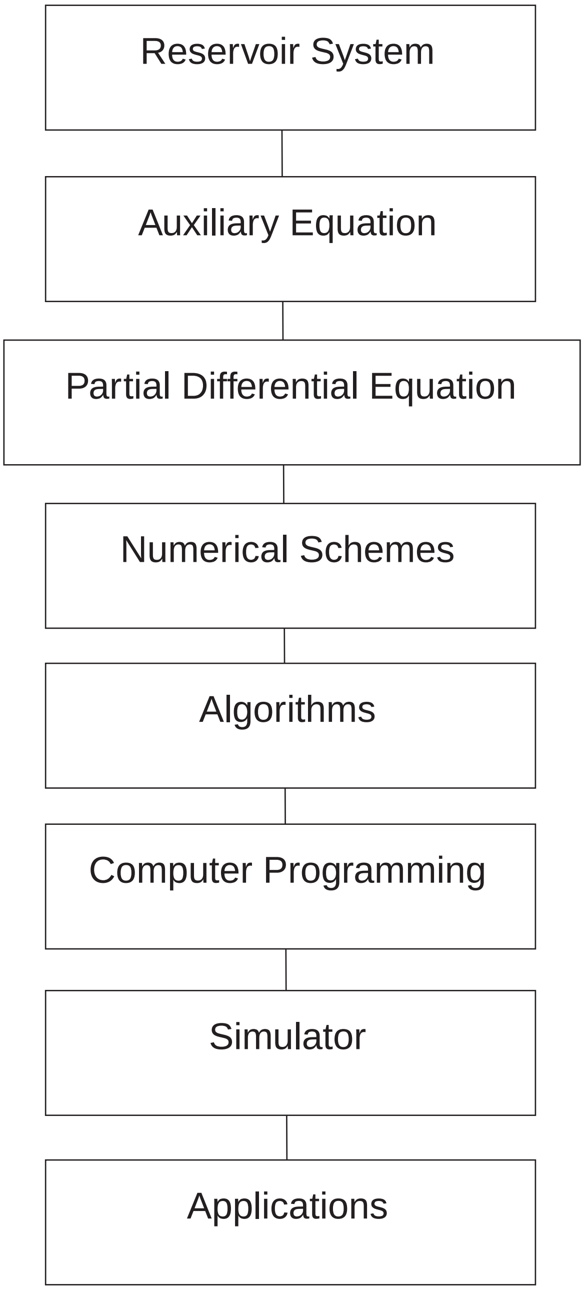


Fig. 2 :Origin of the simulator

otherwise the solution becomes unstable, but we must remember the implicit method is unconditionally stable [9,10]. Equation 3 shows the explicit method formula and equation 4 shows the implicit method formula

$$\frac{P_{i-1}^{n} - 2P_{i}^{n} + P_{i+1}^{n}}{\Delta X^{2}} = \frac{P_{i}^{n+1} - P_{i}^{n}}{\Delta t} \qquad \text{.....(3)}$$

$$\frac{P_{i-1}^{n+1} - 2P_{i}^{n+1} + P_{i+1}^{n+1}}{\Delta X^{2}} = \frac{P_{i}^{n+1} - P_{i}^{n}}{\Delta t} \qquad \text{....(4)}$$

Simulation of Water flooding

Water flooding is used to increase the recovery and maintain the pressure to sustain the required production rate. In this study we use "5-spot" four wells injection and one well production to produce maximum oil in this reservoir. This study contains two layers, and between these layers is an impermeable (i.e. KZ = 0.0) bed. In the results we need to show the change in water saturation, oil relative permeability, water relative permeability, pressure of the grid at different times, the oil recovery, and how much oil can be produced. In Table 1 is shown the input data for Water flooding simulator and fluid data for the Reservoir

Results and Conclusions

During the case study for this Reservoir Fig.3 shows the simulation runtime monitor for the oil rate, pressure with time, gas rate, gas oil ratio and water cut. Figs. 4, 5 and 6 show the water saturation in the different years and different grids. Observe the high saturation in the first year in the region of water wells only, but after three and five years it increases due to water injection. Fig. 7 shows the average pressure with time; the average pressure is high at early stages after that it decreases. Fig. 8 shows the oil, water and gas rate and cumulative change with time. Note also the two humps in the oil and water production rate. First hump is due to water breakthrough in layer 2 (k = 300 md) followed by the second hump due to water breakthrough from layer 1 (k = 200 md). Fig. 9 shows the percentage of the oil recovery with time in layer 1. Fig. 10 shows the percentage of the oil recovery with time in layer 2. Fig. 11 shows the water saturation at Jan 1997 in 3D .The conclusion in this study we study the relationship between pressure and time, pressure and radius of the two models simulator models and line source solution models. The results indicate difference which is due to the change in fluid properties in the simulator as well as the "Truncation error". We can decrease the effect of the error by decreasing the value of Δx or Δt or both. Water injection using 5-spot pattern will maintain the pressure at a good level, and will also give us high recovery. Injection by high rate result in a short life of the well.

Table 1: input data for simulator and Reservoir

Fluid type	Oil - Gas - Water
Initial reservoir temperature	200 F°
Standard reference pressure	14.7 Psia
Standard reference temperature	60 F°
Input units	English – SPE Std
Oil gravity 'API'	30
Bubble point pressure	4014.7Psia
Under-saturated oil compressibility	2.30E-05
Under-saturated oil viscosity slope	4.30E-05
Gas gravity	0.65
Density at standard conditions	62.4 Lb/Ft^3
Compressibility	2.8E-6 Psi^{-1}
Viscosity	0.3 cp
F.V.F at initial reservoir pressure	1.02 RB/STB
Maximum pressure	10000 Psi
Irreducible Water Saturation	0.11
Critical gas saturation	0.05
Residual oil saturation to water	0.18
Residual oil saturation to gas	0.18
Rel. perm. to oil at Irreducible Water Saturation	1
Rel. perm. to gas at Res. Oil saturation	0.98
Rel. perm. to gas at Res. Water saturation	1
Pore size Distribution Index	2
Capillary Entry Pressure – water/oil	0
Capillary Entry Pressure – gas/oil	0
Constant Compressibility for matrix rock	3E-6 Psi^{-1}
Grid type	Regular grid
Number of layers	2
Grid angle (X-axis)	0
Number of X-increments	30
Size of X-increment	100
Number of Y-increments	30
Size of Y-increment	100
Structure tops of layer1	-5000 ft

Residual oil saturation to gas	0.18
Rel. perm. to oil at Irreducible Water Saturation	1
Rel. perm. to gas at Res. Oil saturation	0.98
Rel. perm. to gas at Res. Water saturation	1
Pore size Distribution Index	2
Capillary Entry Pressure – water/oil	0
Capillary Entry Pressure – gas/oil	0
Constant Compressibility for matrix rock	3E-6 Psi^{-1}
Grid type	Regular grid
Number of layers	2
Grid angle (X-axis)	0
Number of X-increments	30
Size of X-increment	100
Number of Y-increments	30
Size of Y-increment	100
Structure tops of layer1	-5000 ft
Y(T) Permeability of layer2	300 md
Z Permeability of all layers	0.0001md
Porosity of all layers	0.3
Bubble Point of all layers	4014.7 Psi
API Gravity of all layers	30°
No. of production wells	1
No. of injection wells	4
Oil rate	10000 STB/Day
Total rate of water injection	6000 STB/Day
First time point date	01-01-1995
Last time point date	01-01-2002
Time step	1 month

Nomenclature

B formation volume factor, bbl/stb
C_t compressibility, psi-1
H thickness, ft
K permeability, md
P_D dimensionless pressure
P_i initial pressure, psi
P_{wf} will flowing pressure, psi
Q rate, bbl/day
r_w wellbore radius, ft
r_D dimensionless radius
t time, hr
t_D dimensionless time
S_w water saturation
μ viscosity, cp
porosity

References

1. K.H. Coats, SPE Handbook Chapter 48, Reservoir Simulation.

2. Henry B. Crichlow, 1977: "Modern Reservoir Engineering a Simulation Approach," Prentice-Hall, Inc.

3. Khalid Aziz,1979: "Petroleum Reservoir Simulation," Elsevier Science Publishing Co., Inc.

4. Simbest II black oil simulator from Baker Hughes.

5. G.W. Thomas, 1982: "Principles Of Hydrocarbon Reservoir Simulation," International Human Resources Development Corporation, Boston.

6. R.B. LANTEZ. 1971: "Title Quantitative Evaluation of Numerical Diffusion (Truncation Error)" SPE paper, 2811.

7. B.C. CRAFT and M.F. HAWKINS , 1959 : "Applied Petroleum Reservoir Engineering," Prentice- Hall, Inc.

8. Peaceman, D.W. : Fundamenta1.s of Numerical Reservoir Simulation, Elsevier Scientific Pub. Co., New York City (1977).

9. Criehlow, H.G.: Modem Reservoir Engineering – A Simulation Approach.

10. Thomas, G.W.: Principles of Hydrocarbon Reservoir Simulation, second edition, Intl. Human Resources Dev. Corp., Boston (1982).

11. Muskat, M,: Physical Properties of Oil Production, McGraw-Hill Book Co. Inc., New York City (1949).

12. Odeh, A.S.: "Reservoir Simulation-What Is It?" J. Pet. Tech. (Nov. 1969) 1383-88. Staggs,

13. H.M. and Herbeck, E.F.: "Reservoir Simulation Models – An Engineering Overview," J. Pet. Tech. (Dec. 1971) 1428-36.

14. Todd, M.R. and Chase, CA.: "A Numerical Simulator for Predicting Chemical Flood Performance," Proc., Fifth SPE Symposium on Reservoir Simulation (1979) 161-74.

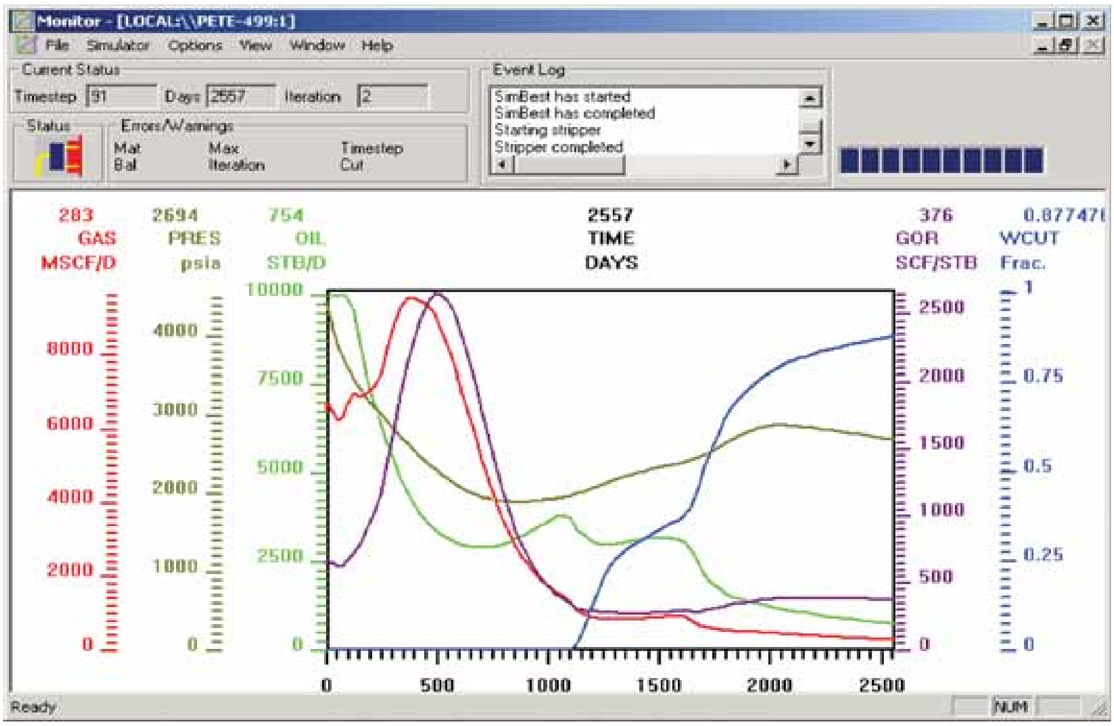


Fig 3: Simulation Runtime monitor

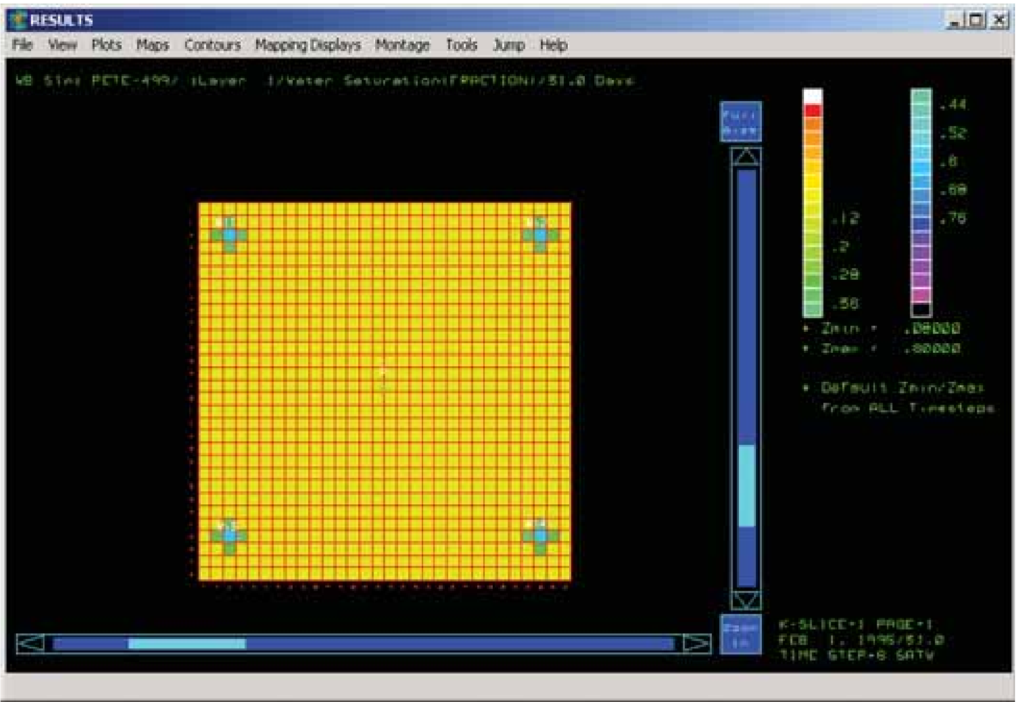


Fig.4: Water saturation at 1 FBR 1995

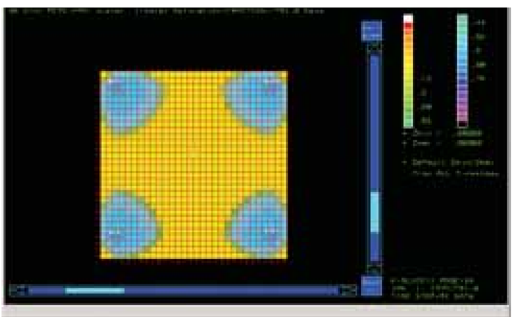


Fig.5: Water saturation at 1 JAN 1997

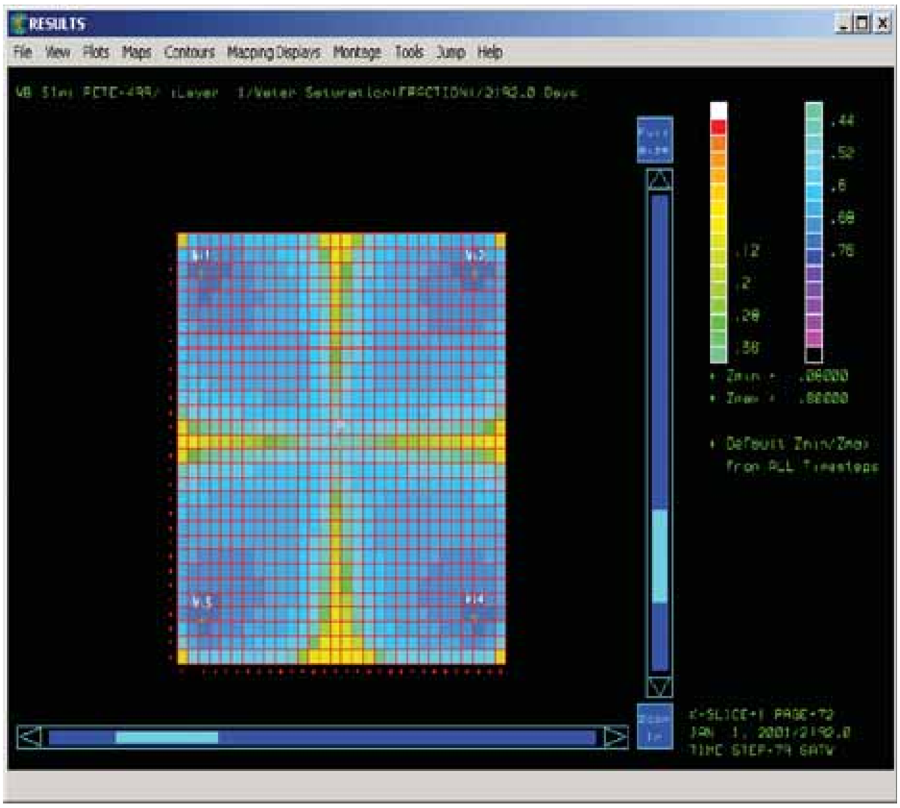


Fig.6: Water saturation at 1 JAN 2001

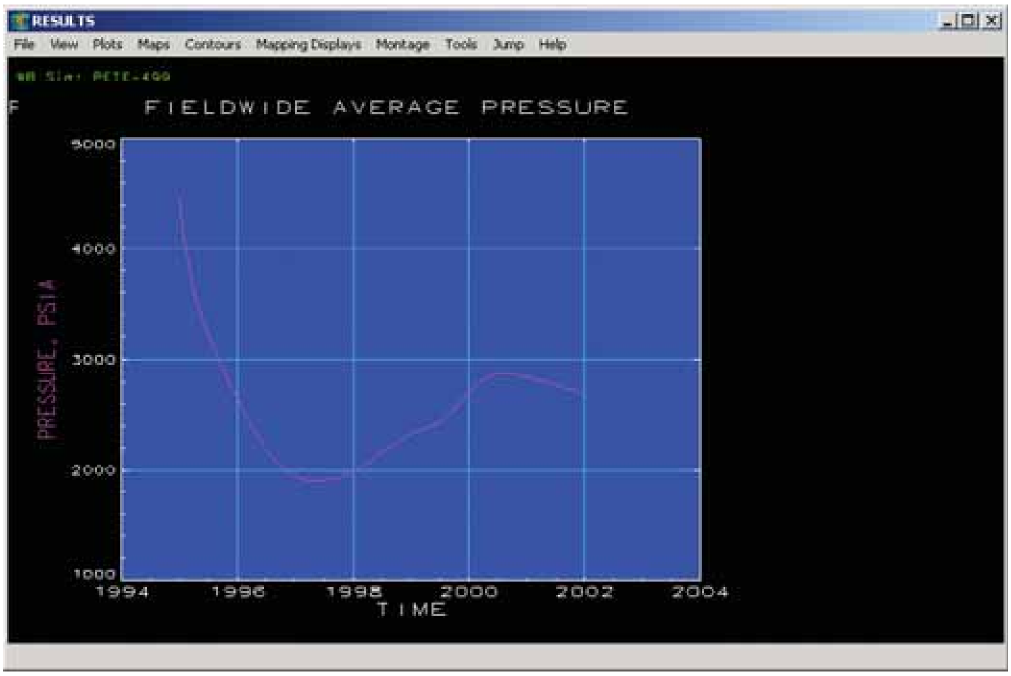


Fig.7: Average Pressure vs. Time

Fig.8: Oil, Water, gas rate and cumulative vs. Time

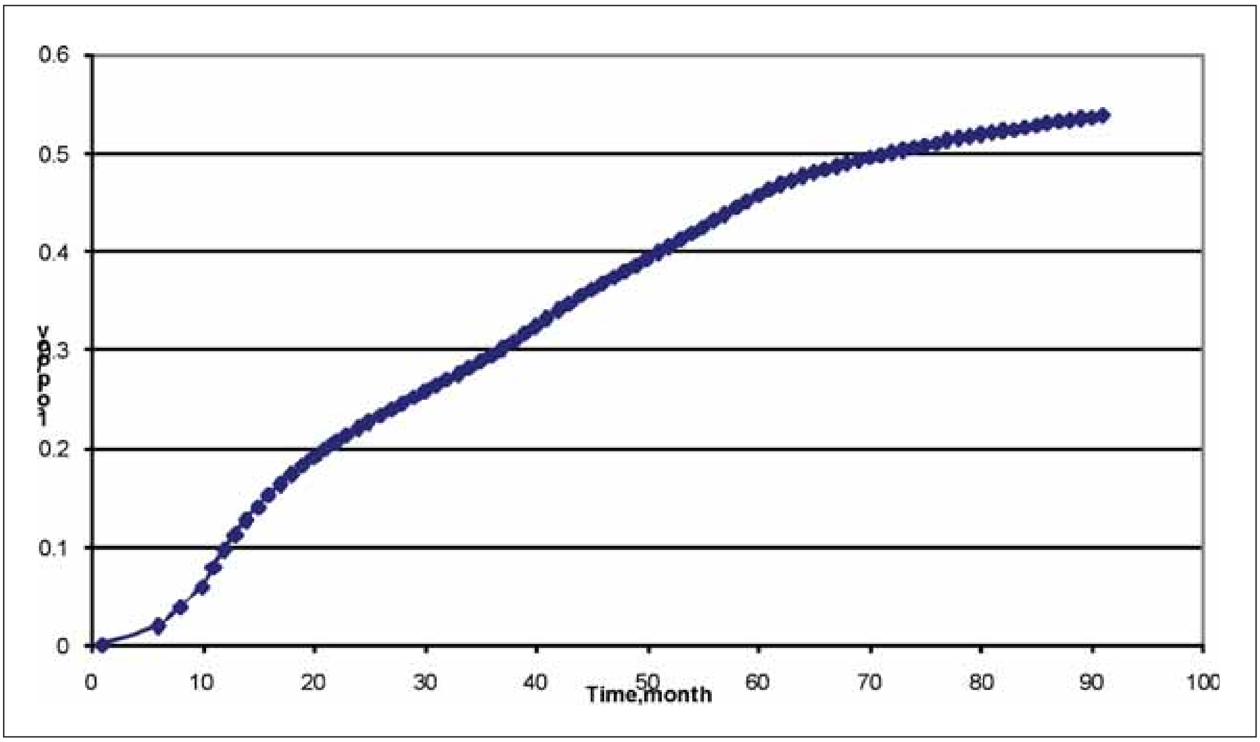


Fig. 9 Oil Recovery vs. time, in layer 1

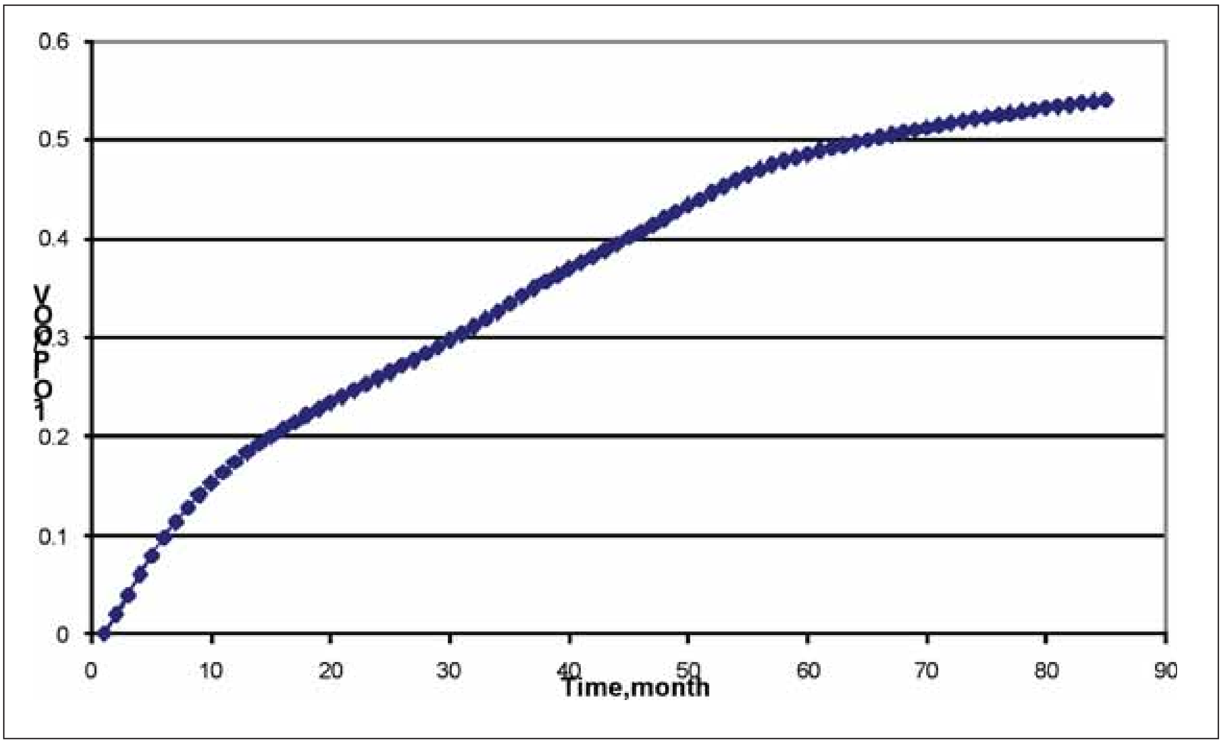


Fig.10 Oil Recovery vs. time, in layer 2

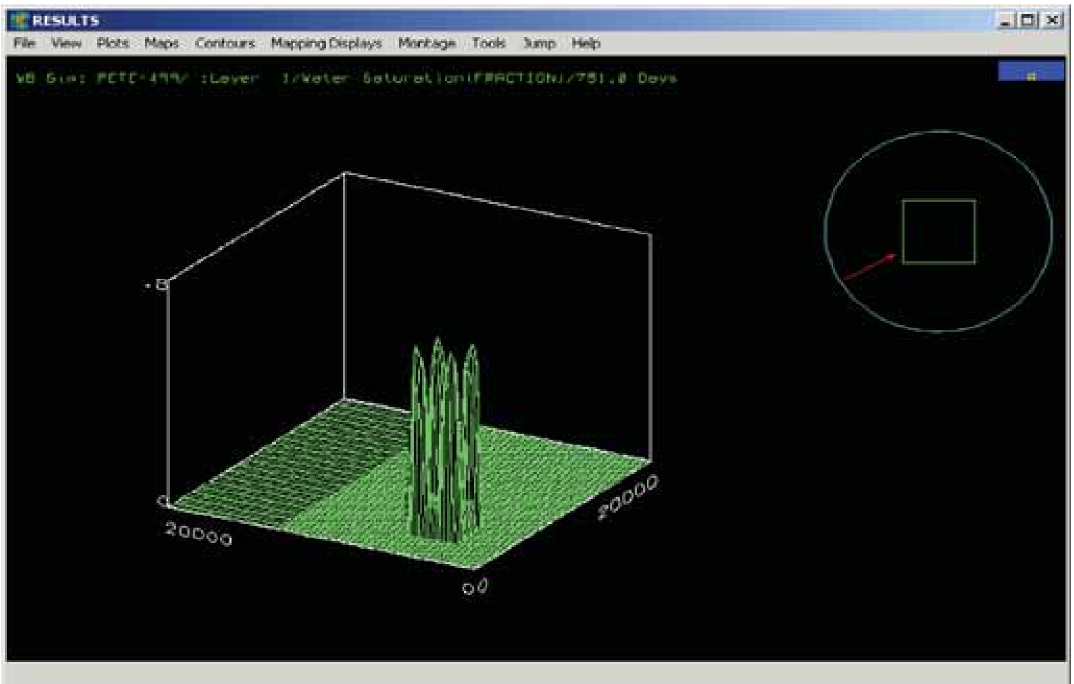


Fig.11 Water saturation at (1 JAN 1997) of 3-D

Stimulating Khuff Gas Wells with Smart Fluid Placement

By Francisco O. Garzon, J.Ricardo Amorocho, Moataz M. Al-Harbi, Nayef S. Al-Shammari, Azmi A. Al-Ruwaished, Mohammed Ayub, Wassim Kharrat, Vsevolod Burgrov, Jan Jacobson, George Brown and Vidal Noya

Abstract

The objective of many matrix acidizing treatments in the Khuff carbonate formations is to remove drilling damage and enhance productivity after the drilling process. Open hole and multilateral completed wells present several challenges that prevent an optimum intervention with coiled tubing (CT). Traditional practices have been limited to spot stages of preflushes, acid, and diversion systems in front of the formation from toe to heel without proper control over the placement process.

Using an innovative workflow, interpretation of distributed temperature survey (DTS) responses, correlated with reservoir data, assists in selectively placing fluids, and maximizing the contact of stimulation fluids with the targeted formation sections. Two field applications, in dual lateral horizontal open hole gas producers, that demonstrate how to optimize a stimulation treatment as it occurs, were implemented in a field in the Kingdom of Saudi Arabia.

In both cases, selective access to pay zones in each lateral was confirmed with DTS profiles. Following the preflush and the first acid pass, DTS measurements indicated acid effect over the permeable zones but also detected fluid movement towards non-gas bearing thief zones. Foam and energized viscoelastic diverting acid fluids were used to divert acid to the target zones, avoiding the loss of all stimulation fluids to the toe in one case and to the heel in the other well. After treatment, the gas production increased from zero to more than two times the expected rate in both wells.

Understanding of the flow patterns as fluids are placed in the wellbore was possible. Changes to the fluid placement schedule during the job resulted in optimum acid coverage and efficient diversion, confirmed by the downhole measurements. The identification of the thief zones was critical to avoid wasting fluids. This experience with the firstever gas wells in the Middle East, represents an opportunity for unlocking production potential in similar gas developments.

Introduction

The increasing domestic demand for gas in the Kingdom of Saudi Arabia is triggering more gas development projects. Challenging targets are set to increase the gas production in the coming years. Many rigs are being shifted from oil to gas developments. As a consequence, existing projects are under high-pressure to maximize the production of each gas well at the lowest operational cost possible, complying, of course,with the highest industry EHS standards.

A significant portion of the gas production is coming from the South Ghawar field developments. In this area, most wells are completed as horizontal or highly deviated wells, and it is common to find dual lateral and open hole completions, leveraging on the consolidated carbonate Khuff formations.Open hole completions offer the advantage of drilling wells with lower capital expenditure, as tubular and associated completion operations, like cementing and perforating, are not required. In addition, the wellbore in a barefoot condition, contrary to a cased and perforated completion, enables better productivity out of the formation due to a lower skin.

After the drilling process is concluded, the well is delivered to the production team. The well is flowed back for cleanup and if the flow performance is poor and productivity below expectations, an intervention with coiled tubing (CT) is scheduled to perform a stimulation of the motherbore and lateral.

> "In the past, several stimulation treatments in dual lateral wells have not achieved the objective of increasing production in spite of placing acid in both laterals – raising doubts about the effectiveness of the diversion or the placement of the fluids."

CT is the preferred method of conveyance of fluids to remove the damage and perform the acid stimulation in this kind of completion. The first challenge in this scenario is to access the laterals, and second, optimizing the performance of the fluids spotted with the CT.

In regards to the accessibility, it is critical to have a reliable technique to selectively enter into the targeted branch. Once in the lateral, confirmation of having entered the targeted branch is needed before commencing the fluid placement. This is normally done by tagging the end of the lateral to confirm total depth (TD) matching, which is time consuming and not efficient or sometimes not possible due to reach limitations. The junction in the open hole where geometries may not be necessarily uniform makes the task more difficult. Potential presence of washouts around the junction may affect the performance of the tool used to do the selective access. A trial and error process may then be needed to access the branch in such cases. After acid fluids have been pumped, the condition of the junction may change, enlarging the original diameter, due to acid reaction. The absence of downhole data makes this task more challenging.

Traditional practices have been limited to spot stages of preflushes, acid, and diversion systems in front of the formation from toe to heel without proper control over the placement process. In the past, several stimulation treatments in dual lateral wells have not achieved the objective of increasing production in spite of placing acid in both laterals – raising doubts about the effectiveness of the diversion or the placement of the fluids.

During the stimulation job with conventional CT, there are several uncertainties proving that there is no control on the job:

- Where are the thief zones?
- Are these thief zones hydrocarbon bearing or not?
- Where in the hole is the acid squeezed? Is it at the CT-bottom-hole assembly (BHA) nozzle depth?
- Does it matter where the CT end is positioned while spotting the treatment fluids?

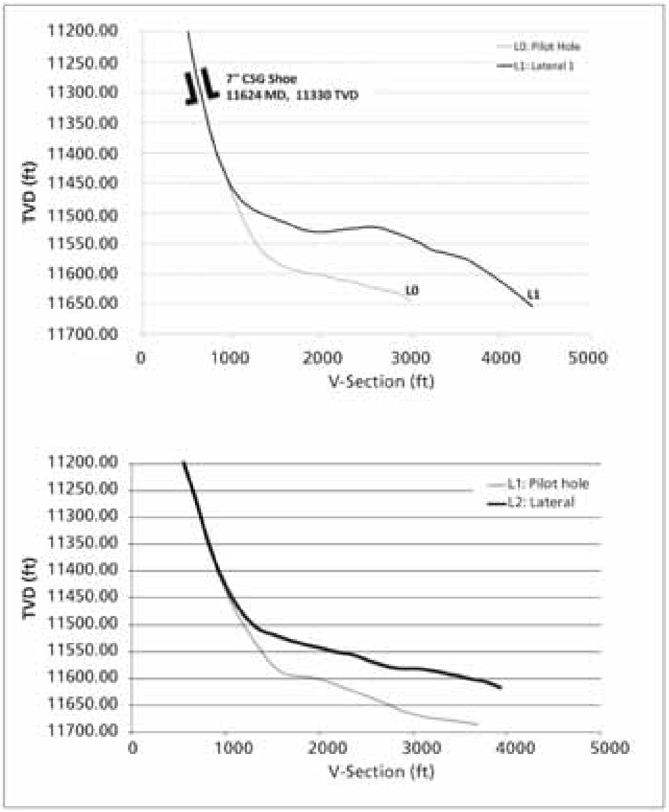


Fig 1. Well A and B trajectories.

•In the case of additional bullheading, will fluid go to the CT BHA nozzle depth, even if there is a thief zone at the heel?
•Is squeeze pressure below or above frac pressure?
•What is the downhole temperature during treatment?
•When should the pump diverter be used? Where? What volume should be pumped?
•Is the diverter working? Is the next acid stage wasted to the same thief zone?
•What type of diversion fluid should be pumped into non-hydrocarbon bearing and hydrocarbon bearing zones?
•Do we have an adequate pumping sequence? Should it be the same for all wells?
•Are the fluid volumes enough or too little?
•Is there an understanding of the injection profiles?

The availability of open hole logs helps in identifying the intervals with a higher probability of production. It is possible that one lateral holds a very good quality zone that predominates over the other, becoming a key target of the stimulation treatment. If one lateral contains predominantly higher permeability and porosity sections, it is also certain that most of the fluid volume has the tendency to go towards this section. In this case, it is likely that the damage is not removed and potential production in the other lateral is not unlocked. It would then be ideal to have a means to understand if this situation is taking place. Many of these questions can be addressed with real-time downhole measurements taken as the CT treatment progresses.

Ultimately, the objective of the stimulation treatment in gas wells with open hole completions in Ghawar field includes:

•Ensure uniform placement of acid into the targeted reservoir intervals.
•Ensure efficient diversion to stimulate the targeted zones.
•Avoid treating the same lateral twice.

A case study of utilizing the latest CT advancements, in two dual lateral horizontal open hole gas producers, that demonstrates how to optimize a stimulation treatment as it develops, is described in this article. Using an inno-

Fig 2. ACTive fibre optics.

vative workflow – interpretation of distributed temperature survey (DTS) responses, correlated with reservoir data – it is possible to selectively place treatment fluids, maximizing the contact of stimulation fluids with the targeted formation sections.

Background

Well A was completed as a dual lateral Khuff-C gas well-producer. The well was completed with a 4½" tubing string. The well is cased with a 7" liner to the top of the producing reservoir at 11,623 ft measured depth (MD). The motherbore (L0) was then drilled successfully to a TD of 13,895 ft MD. After that, the lateral (L1) was drilled, with a junction at11,652 ft MD, to 15,331 ft MD. After drilling, the well was flowed back for cleanup but was not flowing. It was decided to stimulate the well, targeting as the main priority the L1 section between 12,500 ft and 13,100 ft.

Well B was completed as a dual lateral Khuff-C gas well-producer. The well was completed with a 4½" tubing string. The well is cased with a 7" liner to the top of the producing reservoir at 11,471 ft MD. The motherbore (L1) was then drilled successfully to a TD of 14,858 ft MD (lower lateral). After that, lateral L2 (upper lateral) was drilled after opening a window in the 7" liner at 11,477 ft MD to 11,488 ft MD to14,625 ft MD. The well production was very poor. A decision to stimulate the two laterals was taken, Fig. 1.

Description of Fiber Optic Enable Coiled Tubing (FOECT) Technology

Optical fibers are widely used in communication due to the benefits they offer for data transmission. In an application to oil field services, a system based on fiber optics

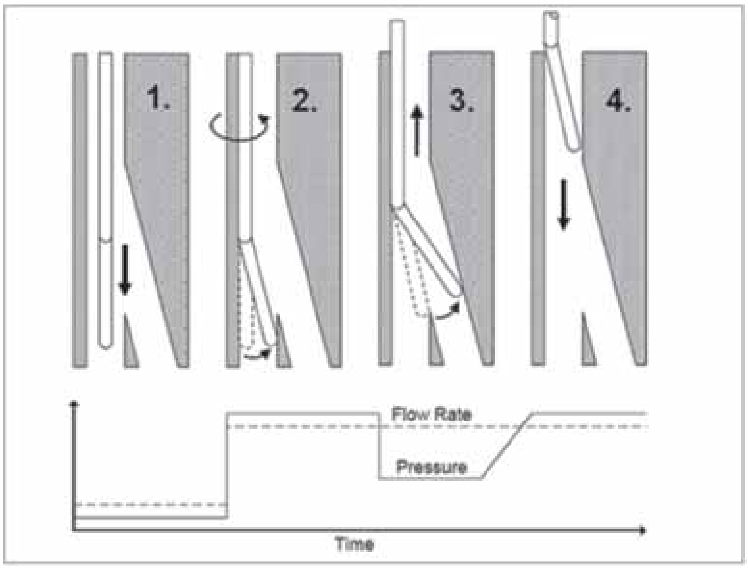


Fig 3. Multilateral selective re-entry tool operational sequence.

has been developed and adapted for use in CT operations, to enable downhole measurements in real time. FOECT system features include:

- Fiber Optic Carrier (FOC) inside the CT string
- The FOECT BHA
- Surface acquisition
- DTS system
- Interpretation services

The downhole tool includes a CT head that terminates the fiber optical connections; the electronic package that houses the downhole communication system; the battery, the sensors for internal and external pressure and temperature; and the Casing Collar Locator (CCL). The tool is flow through and made of acid and H_2S resistant materials.

The FOC, that has an outside diameter of 1.8 mm (0.071"), is previously installed in the CT string. The FOC is non-intrusive; therefore standard operations normally done with conventional strings can be carried out, including pumping corrosive fluids and dropping balls, Fig 2.

On the surface, the downhole data is transmitted from the CT working reel, via wireless and without a collector, into the CT Control Cabin, where specialized software is used to acquire, display, monitor and record the parameters of the job in real time. The surface acquisition system also has the ability to communicate with the tool downhole to send commands. API format printouts of the operation parameters can be delivered in the field.

As the fiber itself acts as a temperature sensor across the length of the CT string, a DTS monitoring system can also be used to capture reliable, accurate and real-time downhole distributed temperature profiles, along with data acquisition, analysis, and interpretation. There is no need for calibration points along the fiber or for calibrating the fiber prior to installation in the wellbore. The system enables monitoring thermal profiles of injection at different times during the treatment.

To provide greater system integration – an interpretation specialist with reservoir production background and measurements expertise – identifies the downhole events and performs an analysis of the combined data with specialized software; to adjust the treatment, as many times as needed. The interpretation specialist, who can be on the well site or in the office, interacts with the stimulation and CT engineers, as well as the well engineers, to decide the next steps.

Mulilalteral Selective Rentry (MSRT)

The BHA used in the intervention also included the Multilateral Selective Reentry Tool (MSRT), which consists of a surface-controlled orienting tool and a controllable bent sub. The system identifies the window of the selected lateral before attempting reentry, and confirmation of successful identification and entry is visible at surface through a software-displayed pressure log. The corrosion-resistant reentry tool is operated solely on flow and is conveyed with standard CT equipment.

The MSRT profiles the lateral junction during the upward passes, Fig. 3, instead of rotating a full cycle at a specified depth, which is the technique for standard access tools. The orientation of the bent sub relative to the lateral window is changed with the orienting tool, indexing 12 times to cover 360°. Even if the tool cannot be oriented, because the bent sub is locked in a washout, the upward movement of the wand allows the tool to flip in the desired orientation after the first few inches of movement.

Description of the Stimulation Campaign – Application of Fluids, Equipment and Processes

Two Khuff gas wells were treated with selective fluid-placement based on DTS data. The treatment objective of Well A was to selectively enter the upper lateral – characterized by the best pay – for acid stimulation to enhance well production. Once a fluid injection profile would be established in the targeted lateral, an optimized stimulation treatment based on interpretation of the real time downhole data provided by the FOECT would be executed and evaluated for efficiency. The treatment objective of Well B was a similar optimized stimulation of hydrocarbon bearing pay in both horizontal open hole laterals. Each well would be treated with a fluid placement schedule, open for modification based on the well response to the treatment as observed and interpreted on-site by an interpretation specialist. Real time data from the FOECT system recorded during or after key stages of each treatment provided the downhole measurements necessary for interpretation of downhole events.

The general procedure for optimized FOECT carbonate acid stimulation consists of the following stages:

•Preflush injection. Warm back analysis, identification of potential thief zones.

•Acid diagnostic stage. Heat buildup analysis, identification of potential thief zones, fluid placement schedule.

•Acid treatment stage 1. Diversion analysis: Remedial corrections to fluid placement schedule.

•Acid treatment stage 2. Diversion analysis: Further corrections to fluid placement schedule as required.

•Post flush injection. Warm back analysis: Fluid distribution confirmation and treatment evaluation.

Additional customized stages may be added as needed to aid interpretation and understanding of key downhole events or to record and document developments to the fluid injection profile during treatment. The detailed stimulation summary of Well A highlights the potential importance of this interactive approach to optimize the treatment, Fig 4.

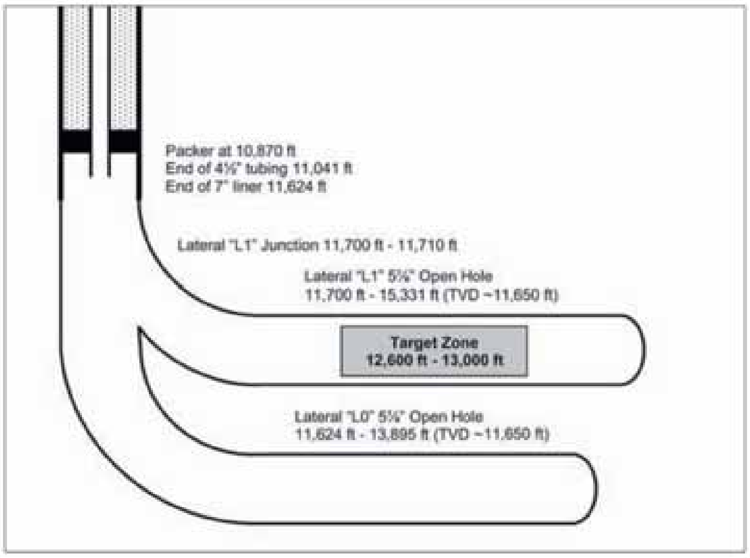


Fig 4. Well Completion for Well A.

Well A - First run in hole (RIH):

•CT was RIH from the surface. Break circulation was maintained with treated water.

•CT stopped at 12,412 ft to record the geothermal gradient baseline.

•FOECT data used for lateral confirmation (CT in target lateral L1).

•Treatment fluids prepared for stimulation of main targetpay in lateral L1.

Well A - Preflush injection in lateral L1:

•Starting from 12,445 ft, CT was RIH to 13,000 ft, then pulled out of hole (POOH) to 12,500 ft.

•Preflush (125 bbl) was pumped while reciprocating the coil.

•FOECT data analysis showed significant losses occurring to lateral L0 at the lateral junction.

•Decision was made to pump an undiverted initial acid stage to remove potential skin damage.

Well A - First acid stage in lateral L1:
•CT was POOH from 13,000 ft - 12,600 ft while pumping acid, then RIH to 13,000 ft.
•Treatment acid: 26% HCl acid (200 bbl).
•FOECT data analysis showed continued losses to lateral L0 with little or no acid going to the formation in L1.
•Decision was made to focus on diversion from lateral L0 without exiting lateral L1. L0 Log is showing 50 ft-close to the heel with double gas saturation compared to other gas bearing zones in L0 and L1.

Well A - Foam and viscoelastic self-diverting acid to divert from lateral L0 while maintaining CT inside lateral L1:
•CT pulled to 12,000 ft to pump foamed and viscoelastic self-diverting acid to lateral L0 (CT still 300 ft inside lateral L1).
•Diverter: 20 bbl foam and 10 bbl viscoelastic self-diverting acid pumped nitrified to lateral L0.

Well A - Second acid stage in lateral L1:
•CT was reciprocated from 13,000 ft - 12,600 ft while pumping acid, then RIH 13,100 ft for analysis.
•Treatment acid: 26% HCl acid (150 bbl).
•FEOCT data analysis showed reduced losses to lateral L0 and increased acid effects in the target lateral L1 in an interval extending 200 ft above the expected target pay (12,400 ft - 12,700 ft) with little acid effect across 300 ft of the pay.
•Decision was made to pump nitrified viscoelastic self-diverting acid, prior to a final acid stage targeting the under-stimulated 300 ft of the main pay with stationary acid injection in three stages.

Well A - Placement of nitrified viscoelastic self-diverting acid in L1 before final acid stage:
•CT was POOH from 13,000 ft - 12,400 ft while placing diverter, then RIH to 13,000 ft prior to final acid stage.
•Diverter: 200 bbl nitrified viscoelastic self-diverting acid.

Well A - Final L1 acid stage:
•CT was POOH from 13,000 ft - 12,600 ft, stopping at key targets at 12,900 ft, 12,800 ft and 12,750 ft in the main pay.
•Treatment acid: 26% HCl acid (250 bbl). Ten bbl acid was pumped stationary at each of the three target points.

•FEOCT analysis showed further increased acid effects across the 12,400 ft - 13,000 ft interval, covering the entire main pay and extending 200 ft above it.
•Decision was made to pump post flush while POOH to profile for lateral L0 entry with the MSRT.

Well A - Stimulation of lateral L0:
•Several attempts were made to access lateral L0 after-profiling the open hole junction with the MSRT. Despite many attempts, the MSRT did not allow access to lateral L0, suggesting washout of the open hole junction beyond what was expected during the job design. Consistent losses throughout the acid treatment of lateral L1 may have contributed to deteriorate the condition of the openhole junction prior to MSRT profiling.
•Decision was made to pump the treatment with CT stationary 100 ft above the lateral junction. To avoid re-stimulating lateral L1, the decision was taken to fill up this lateral (13,000 ft - 12,000 ft) with foam.
•The treatment targeting L0 was pumped stationary at 11,600 ft:
-Nitrified preflush (50 bbl).
-Five stages of nitrified 15% HCl viscoelastic self-diverting acid (50 bbl each) followed by nitrified 26% HCl acid (100 bbl each).
-Post flush (120 bbl).

This concluded the treatment of Well A. FOECT DTS data from key stages of the stimulation treatment is included in Appendix A, Fig. 1.

Following is the detailed stimulation summary of Well B, Fig 5:

Well B - First RIH – natural pass confirmation (targeting lateral L2):

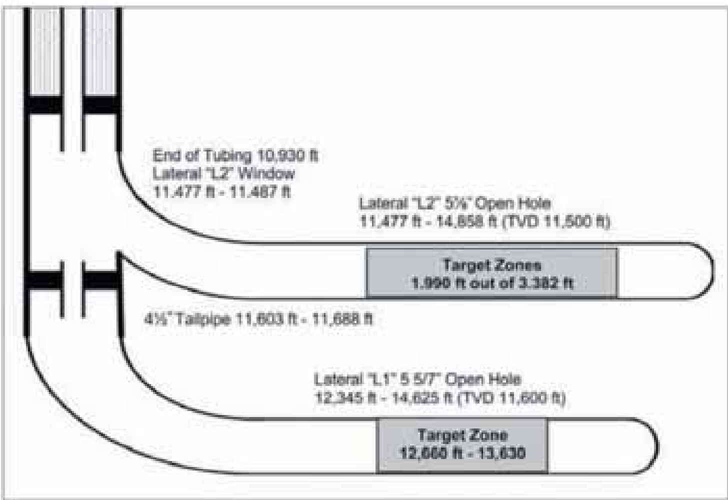


Fig 5. Well completion of Well B.

•CT was RIH from surface. Break circulation maintained with treated water.
•CT stopped at 11,800 ft for lateral confirmation with FOECT data (400 ft below lateral window).
•FOECT data gave positive indication that, CT natural pass was the non-target lateral L1.
•Decision was made to profile the window with MSRT to enter lateral L2.

Well B - MSRT profiling for lateral L2:
•CT was reciprocated across the lateral window to acquire the MSRT profile. Once established, CT was RIH attempting access to lateral L2.
•CT stopped at 11,800 ft for lateral confirmation with FOECT data (400 ft below lateral window).
•FOECT data gave positive indication that CT was again in the nontarget lateral L1.
•Decision was made to re-profile the window with MSRT to enter lateral L2.

Well B - MSRT re-profiling for lateral L2:
•CT was reciprocated across the lateral window to reacquire the MSRT profile. Once established, CT was RIH attempting access to lateral L2.
•CT stopped at 11,800 ft for lateral confirmation with-FOECT data (400 ft below lateral window).
•FOECT data gave positive indication that CT was in the target lateral L2.
•CT was run beyond L1 TD confirming that CT is indeed in L2.
•Decision was made to perform a clean out of lateral L2 (a 2⅞" high-pressure jetting tool was used), tag TD for a secondary lateral confirmation and inject preflush across the lateral L2 open hole.

Well B - Preflush injection lateral L2:
•Preflush was pumped while RIH to TD.
•FOECT data analysis showed three potential thief zones at 12,300 ft -12,480 ft, 12,740 ft - 12,800 ft and 12,900 ft - 13,000 ft. No losses were observed to occur at the lateral window.
•Decision was made to target the potential thief zones with nitrified 26% viscoelastic self-diverting acid while POOH and injecting 26% viscoelastic self-diverting acid across the other target zones while RIH.

Well B - Diversion and acid stages in lateral L2 (500 bbl of 26% viscoelastic self-diverting acid):
•CT was POOH from 14,800 ft - 11,550 ft, then RIH to 14,800 ft.
•Diverter: nitrified viscoelastic self-diverting acid pumped across the thief zones while POOH.
•Treatment acid: 26% viscoelastic self-diverting acid pumped across the target zones while RIH to TD.
•FOECT data analysis showed good diversion in the intervals 12,300 ft - 12,480 ft and 12,900 ft - 13,000 ft, but continued fluid loss to the interval 12,740 ft - 12,800 ft. No losses at lateral window.
•Decision was made to re-target the remaining potential thief zone with diversion, prior to a final acid stage targeting the main pay with stationary acid injection at three selected points, followed by post flush injected across the entire open hole section of lateral L2.

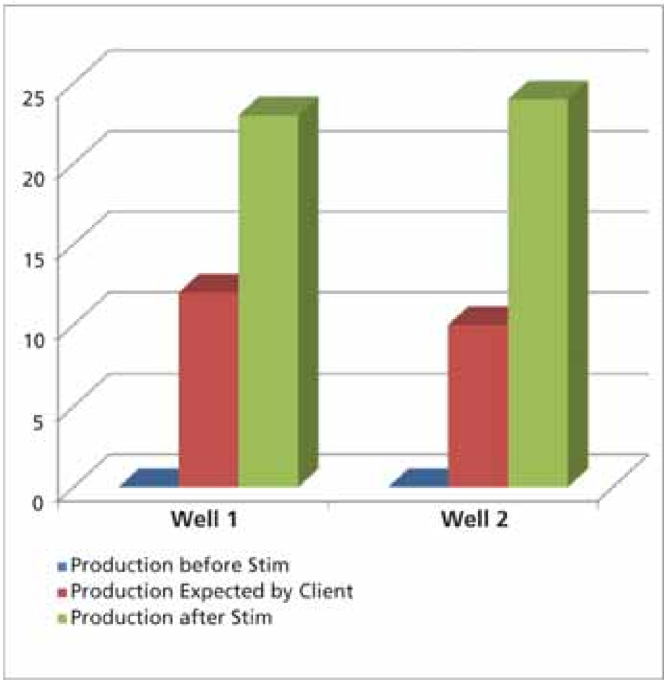


Fig 6. Post-stimulation production.

Well B - Post flush injection profile in lateral L2:
•CT was RIH from 11,550 ft - 14,800 ft (TD).
•Post flush was pumped while RIH.
•FOECT analysis showed an almost uniform injection profile with residual diversion still in effect across the interval 12,740 ft - 12,800 ft. No losses at lateral window.
•Decision was made to proceed to POOH to the lateral window and enter the CT natural pass lateral L1 for stimulation.

Well B - Natural pass confirmation (targeting lateral L1):
•CT was pulled above the lateral window, then RIH attempting access to lateral L1.
•CT stopped at 11,800 ft for lateral confirmation with-

> Uniform acid coverage across the target zones was achieved by monitoring fluid placement, and diverting with the required volumes of nitrified viscoelastic self-diverting acid across the identified thief zones.

FOECT data (400 ft below lateral window).
•FOECT data gave positive indication that CT was in the target lateral L1.
•Decision was made to perform a clean out of lateral L1, tag TD for a secondary lateral confirmation and inject preflush across the lateral L1 open hole.

Well B - Preflush injection lateral L1:
•Preflush was pumped while RIH to TD.
•FOECT data analysis showed no potential thief zones in the lateral pay. Indication of fluid loss to the toe is noticed.
•Decision was made to pump foam across 13,900 ft -13,800 ft to prevent downhole fluid loss. Then 26% viscoelastic self-diverting acid will be pumped across the target zone.

Well B - Diversion and acid stages in lateral L1 (250 bbl of 26% viscoelastic self-diverting acid):
•Diverter: foam pumped across 13,900 ft - 13,800 ft.
•Treatment acid: 26% HCl viscoelastic self-diverting acid pumped while RIH across target zone 12,660 ft - 13,630 ft.
•FOECT data suggested good diversion of the foam as no downhole fluid loss could be observed. An even temperature distribution further suggested that uniform fluid distribution was achieved.
•Decision was made to proceed with the final post flush-stage.

Well B - Post flush injection profile in lateral L1:
•Post flush was pumped while RIH to end of target zone.
•FOECT analysis indicated a near uniform injection profile. No losses were observed at the lateral window.
•Decision was made to proceed with nitrogen kick-off and final POOH. This concluded the treatment of Well B.

Results

Successful stimulation of target zones in both Well A and B was achieved with optimized smart fluid placement. Uniform acid coverage across the target zones was achieved by monitoring fluid placement, and diverting with the required volumes of nitrified viscoelastic self-diverting acid across the identified thief zones. Significant improvements to the fluid injection profile were observed after treatment.

In Well A, excessive loss of treatment fluids to the non-key lateral L0 was avoided by the early identification of lateral losses and subsequent mitigation with foam and nitrified viscoelastic self-diverting acid diversion techniques. Confirmation of gradually reduced losses to the thief zone in lateral L0 was observed.

In Well B, early lateral identification prevented the need for tagging TD, which saved time and CT pipe cycling. Complete loss of all stimulation fluids to the toe was avoided by early identification of the thief zone and subsequent mitigation with foam diversion techniques.

Based on offset wells and the type of completion, initial production expectations for Wells 1 and 2 were 12 MMscf/day and 10 MMscf/day, respectively. For Well 1, post-stimulation production increased 92% above expectations to 23 MMscf/day. For Well 2, post-stimulation production increased 140% above expectations to 24 MMscf/day, Fig. 6.

Conclusions

FOECT DTSs were used during matrix acidizing of two bi-lateral horizontal gas wells to optimize acid coverage and well productivity.

Cleanout and stimulation of each wellbore was facilitated with a 2⅞" high-pressure jetting tool. Lateral access and lateral confirmation was enabled by the use of the MSRT and real time DTS measurements.

In each well, placement of the main treating fluid was modified real time based on the temperature response observed with DTS profiles. Treatment fluid loss to the lateral window/junction or to the toe could be confirmed with downhole measurements and controlled with real time modifications of the treatment fluid pumping schedule. DTS profiles, after each of the modified acid treatment stages, indicated significant incremental improvements towards uniform fluid placement, compared to the pre-stimulation preflush injection profiles. Post flush evaluation in each lateral further confirmed diversion efficiency of the chemical diverter.

Downhole FOECT data supported by real time interpretation during key stages of the treatment resolved the uncertainties associated with conventional acid stimulation of multilateral open hole carbonate wells, and enabled proper control of CT stimulation jobs. Optimum acid coverage of target zones can be achieved through the following:

•Identification of accessed lateral.
•Identification of gas/non-gas bearing thief zones before and during stimulation, which will assist us in deciding the type and volume of diverter when required to pump it. Identification of fluids placement and diversion efficiency.
•Real time adjustment of pumping schedule (fluid type and volume) based on DTS response.
•Stop thinking that CT is a diversion means as treatment fluids will be squeezed into thief zones even with the use of high-pressure jetting tools (fluids can even travel back to a different lateral looking for the less resistant path).
•Stop pumping predetermined stages of acid and diverter from toe to heel without any real time monitoring of fluids placement and diverter efficiency.

Well production beyond expectation was achieved thanks to the smart fluid placement.

Acknowledgements

The authors thank Saudi Aramco and Schlumberger management for permission to publish and present this article.

References

1. Al-Zain, A., Duarte, J., Haldar, S., et al.: "Successful Utilization of Fiber Optic Telemetry Enabled Coiled Tubing for Water Shut-off on a Horizontal Oil Well in Ghawar Field," SPE paper 126063, presented at the SPE Saudi Arabia Section Technical Symposium and Exhibition, al-Khobar, Saudi Arabia, May 9-11, 2009.

2. Wortmann, H., Peixoto, L.P., Leising, L., Bunaes, C. and Nees, E.: "Selective Coiled Tubing Access to all Multilaterals Adds Wellbore Construction Options," SPE paper 74491, presented at the IADC/SPE Drilling Conference, Dallas, Texas, February 26-28, 2002.

3. Al-Buali, M., Al-Arnaout, I., Al-Shehri, A., Halder, S. and Al-Driweesh, S.: "Case History: Successful Application of Combined Rotary-Jetting and MLT to Stimulate Dual Lateral Producer in Ghawar Field," SPE paper 119675, presented at the SPE Middle East Oil & Gas Show and Conference, Bahrain International Exhibition Centre, Manama, Bahrain, March 15-18, 2009.

4. Parta, P.E., Parapat, A., Burgos, R., et al.: "A Successful Application of Fiber Optic Enabled Coiled Tubing with Distributed Temperature Sensing (DTS) Along with Pressures to Diagnose Production Decline in an Offshore Oil Well," SPE paper 121696-MS, presented at the SPE/ICoTA Coiled Tubing & Well Intervention Conference and Exhibition, The Woodlands, Texas, March 31 - April1, 2009.

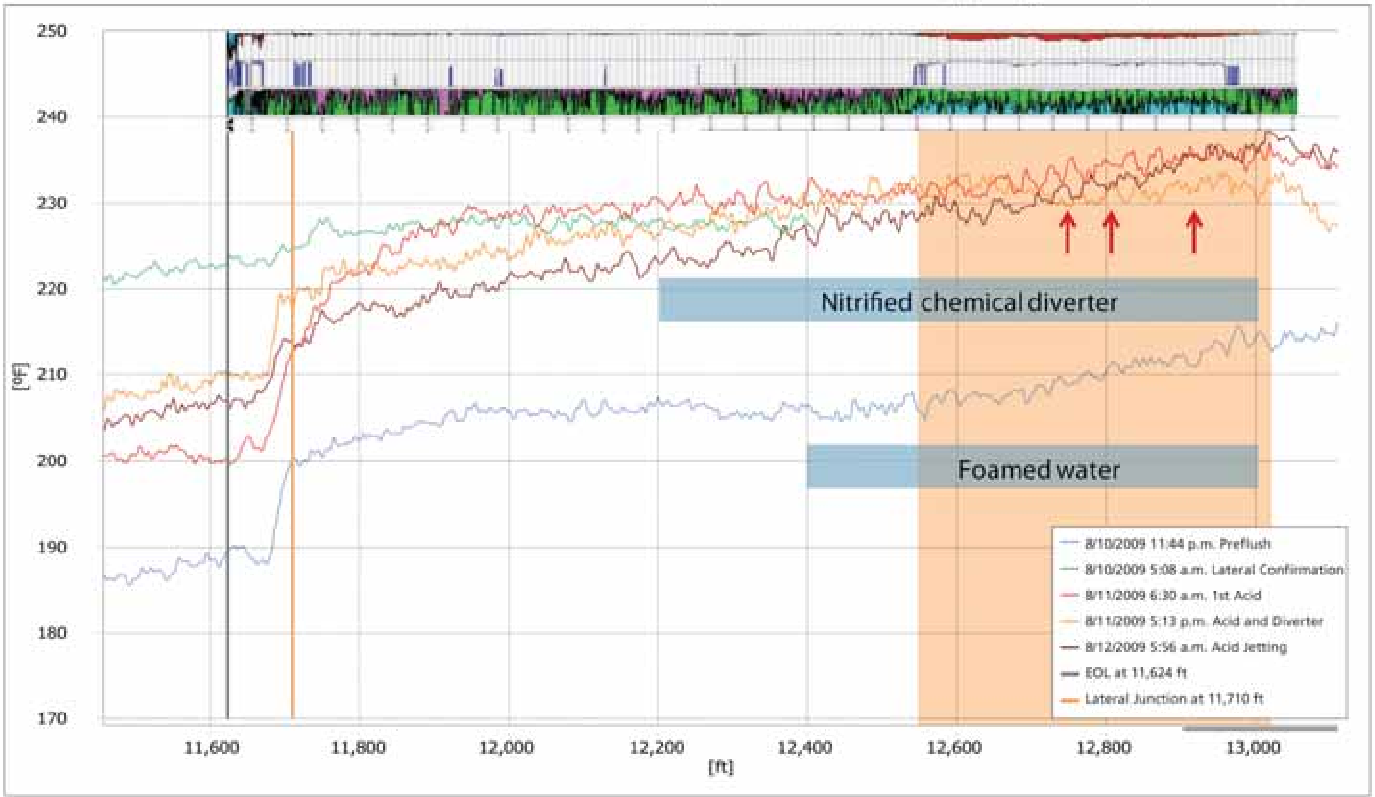


Fig A1. Well A, L1 FOECT data from key treatment stages.

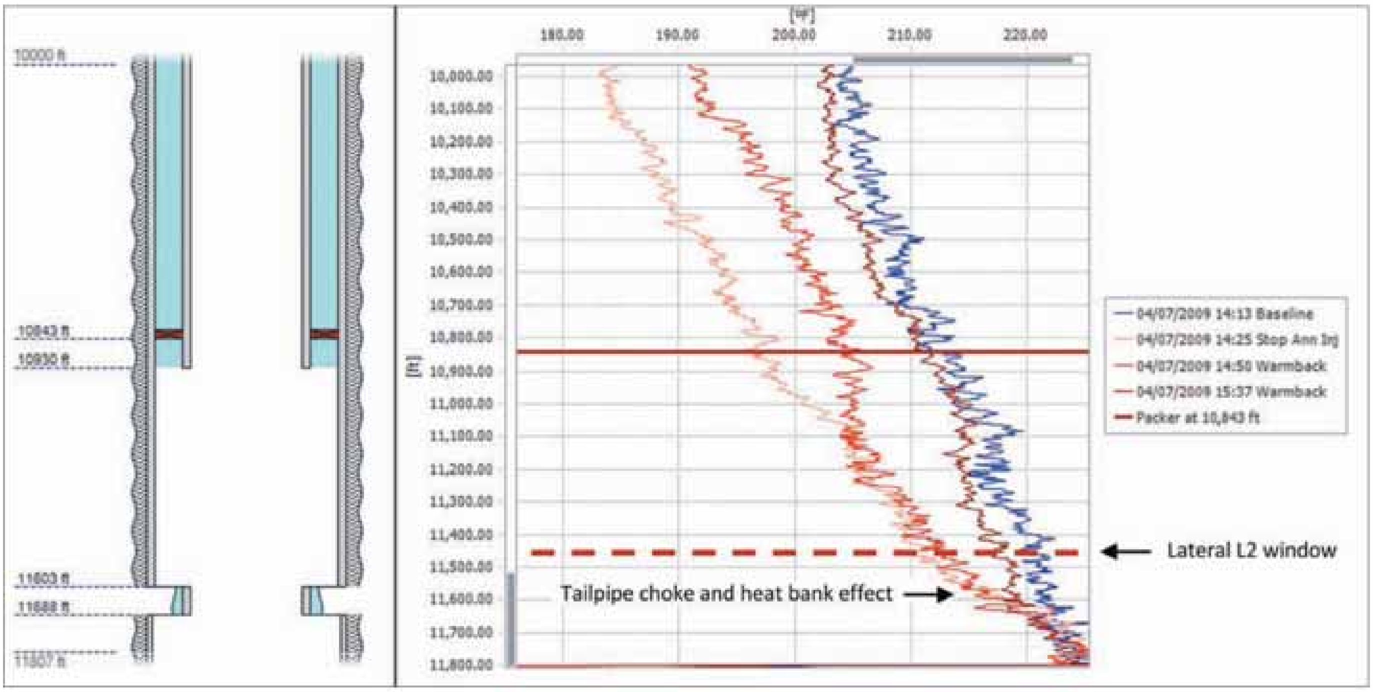


Fig A2. Well B, L1 FOECT data providing lateral confimation.

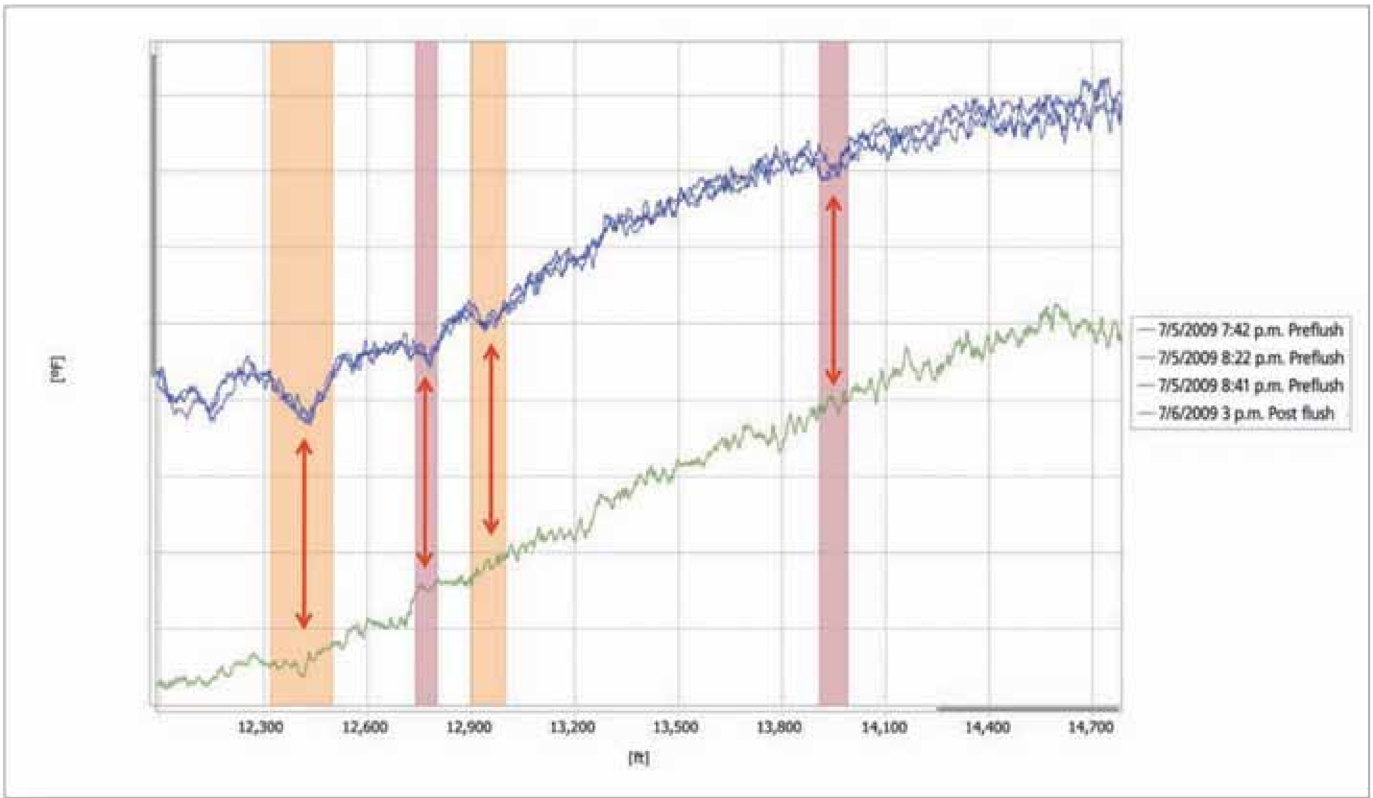


Fig A3. Post flush temperature response (green) highlighting diversion effects obtained as compared to the preflush injection profile (blue) in Well B, lateral L1.

5. Hadley, M.R., Brown, G.A. and Naldrett, G.: "Evaluating Permanently Installed Fiber Optic Distributed Temperature Measurements Using Temperature Step Resolution," SPE paper 97677, presented at the SPE International Improved Oil Recovery Conference, Asia Pacific, Kuala Lumpur, Malaysia, December 5-6, 2005.

6. Hadley, M.R. and Kimish, R.: "Distributed Temperature Sensor Measures Temperature Resolution in Real Time," SPE paper 116665, presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, September 21-24, 2008.

7. Smith, R.C. and Steffensen, R.J.: "Interpretation of Temperature Profiles in Water Injection Wells," SPE paper 4649, presented at the SPE-AIME 48th Annual Fall Meeting, Las Vegas, Nevada, September 30 - October 3, 1973.

Appendix A – Supporting Figures and FOECT Interpretation Examples

In treatment of the two candidate wells, the targeted upper lateral of Well A was selectively entered by use of the MSRT, and the CT was RIH for stimulation of the hydrocarbon bearing pay zone. While RIH a geothermal temperature profile was recorded (Fig. A1, green temperature curve) to establish a lateral junction baseline dataset for interpretation of the following recorded data. Reaching TD, preflush was injected and squeezed to formation through the CT while reciprocating once across the open hole. The warm back FOECT data following the preflush injection is highlighted inFig. A1 in light blue.

Interpretation of the FOECT preflush warm back data, suggests that significant losses occur to the non-targeted lateral L2, indicated with an orange line on Fig. A1. As fluids are pumped through CT in a well, a combination of convection heating of the pumped treatment fluids and convection cool-down of the surrounding wellbore by the passing of the colder fluids pumped from surface takes place. In cases where the fluid pumped is lost to a zone above the CT nozzle, the combination of convection heating of the fluid and convection cool-down of the wellbore typically results in a step change in temperature across a zone or a lateral junction to which signifi-

> "As fluids are pumped through CT in a well, a combination of convection heating of the pumped treatment fluids and convection cool-down of the surrounding wellbore by the passing of the colder fluids pumped from surface takes place."

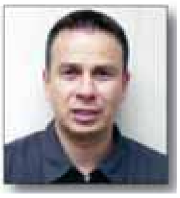
cant fluid loss occurs. In Well A, lateral L1, the pumped preflush is being heated through convection both while being pumped through the CT and while traveling up hole in the L1 CT-wellbore annulus towards the lateral junction of lateral L2. The effect on DTS profile data of the losses of heated injected fluid to the junction is a significant step change from the convection cooled wellbore above the lateral junction to the heated fluid entering the lateral junction from below. Identifying such losses early in the treatment allows for immediate remedial actions to be taken, to reduce the volumes pumped and lost to other laterals.

In Well B, both laterals were to be stimulated, but the measured TD of the two laterals (L1 and L2) was less than 250 ft apart, Fig. A2. An early lateral confirmation was in this case achieved with the FOECT by running 400 ft into the natural pass lateral. Recording FOECT data while surface injecting 40bbl treated water to the CT-wellbore annulus provided a small but measurable cool-down across the wellbore. With the CT in the main bore, the 4½" tailpipe acted as severe downhole flow restriction preventing fluid flow (and the associated cool-down) below the tailpipe. Figure A3 shows the FOECT temperature data recorded before, during and after surface injection, giving an early positive lateral confirmation 400 ft into the lateral. As two attempts were required for positive confirmation of entry to the desired L2 lateral, this early warning avoided the need for three full trips to tag TD for lateral confirmation, saving a total of 8,800 running ft in the operation.

Overlaid against the preflush injection profile in blue, Fig. A3 shows the post flush temperature profile in solid green. By comparing the pre- and post flush profiles, the diversion efficiency of the pumped may be evaluated. A near uniform temperature trend is now observed across the treated open hole section stimulation of lateral L1 in Well B. This suggests that a more uniform injection profile across the targeted pay has been achieved through diversion during the stimulation treatment. Another important observation is the lack of any observable temperature anomalies across the lateral window to the main bore. This confirms that the treatment fluids pumped to stimulate the target lateral were not lost through the lateral window.

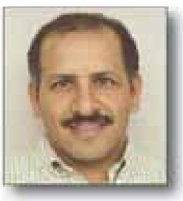
BIOGRAPHIES

Francisco O. Garzon joined Saudi Aramco in 2005. He currently works as a Lead Engineer in the Hawiyah unit. Including his time with Saudi Aramco, Francisco has more than 20 years of experience in the oil industry, working for Oxy, Schlumberger and BP. His expertise includes petroleum engineering and well interventions, well performance optimization using open/cased logs, production history, NODAL and pressure transient analysis information, coiled tubing and stimulation operations (chemical and hydraulic fracturing), workover interventions and artificial lift optimization. Francisco received his B.S. degree in Petroleum Engineering from the Universidad de America, Bogotá, Colombia in 1984 and his M.S. degree in Petroleum Engineering from Heriot-Watt University, Edinburgh, Scotland in 1991.



J. Ricardo Amorocho is a Senior Petroleum Engineer consultant withthe Hawiyah Engineering Unit in the Gas Production Engineering Division (GPED) in 'Udhailiyah. His work supports coiled tubing operations, e-Line stimulation and well work intervention. Ricardo has 16 years of diversified oil industry work, of which 10 years were with BP working in various assignments, mainly in Colombia on well intervention on CT, CTD and stimulation. Since joining Saudi Aramco in 2006, Ricardo has been involved in a wide variety of well intervention activities with special emphasis on coiled tubing operations, horizontal well cleanouts and stimulation, and fishing operations. Ricardo received his B.S. degree in Petroleum Engineering in 1993 from the Fundacion Universidad de America in Bogota, Colombia.

Moataz M. Al-Harbi is a Gas Production Engineer assigned to the Haradh Engineering Unit in the Gas Production Engineering Division (GPED) in 'Udhailiyah. He has 13 years of diversified oil industry experience. In 1996 Moataz received his B.S. degree in Mechanical Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia. After graduation, he joined Schlumberger where he specialized in stimulation operations. Moataz then joined Saudi Aramcoin 2004, and is currently participating in the Production Engineering Specialist Program (PESP) as a Stimulation and Fracturing specialist candidate. He has been actively involved in the successful implementation of a number of new technologies aimed at enhancing well productivity, and is a mentor to young Saudi engineers.



Nayef S. Al-Shammari joined Saudi Aramco in 1995 as a Production Engineer. He worked in different organizations (one year as Reservoir Engineer and two years as Well Services and Completion Engineer). Nayef has headed the Gas Well Services & Completion Division, South Ghawar Well Services Division, North Ghawar Well Services Division, Khurais and Central Arabia Well Services Division, ABQQ Production Engineering Division, Gas Production Engineering Division and the HRDH Gas Production Engineering Unit. He is currently a Supervisor in the Gas Production Engineering Division covering AinDar, 'Uthmaniyah and Shedgum's Production Engineering Division. Nayef received his B.S. degree in Petroleum Engineering in 1995 from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.

Azmi A. Al-Ruwaished is a Production Engineering assistant Superintendent in the Southern Area Production Services Department (SAPSD), where he is involved in gas production services, well completion and stimulation activities. He is mainly interested in the field of production engineering, production optimization and new well completion applications. Azmi has been working with Saudi Aramco for the past 15 years in areas related to production engineering and gas completion operations. In 2000, Azmi received his B.S. degree in Petroleum Engineering from Louisiana State University (LSU), Baton Rouge, LA. He is member of the Society of Petroleum Engineers (SPE).

Mohammad Ayub is currently working with the Planning Unit as a Supervisor. He joined Saudi Aramco in 1982 and has held various positions in the Southern Area Production Engineering Department (SAPED) and the Southern Area Production Services Department (SAPSD). Mohammad received his B.S. degree in Petroleum and Gas Engineering from the University of Engineering and Technology, Lahore, Pakistan. He is member of the Society of Petroleum Engineers (SPE).

Wassim Kharrat has been working with Schlumberger since September 1998 in several countries around the world, including Tunisia, Germany, Libya, the United States and Saudi Arabia. He built his technical and operational expertise in coiled tubing and matrix stimulation. Currently, Wassim is working as a Coiled Tubing District Technical Engineer in 'Udhailiyah with a focus on introducing and implementing ACTive new technology (real-time monitoring with fiber optic) for all types of coiled tubing jobs. In 1998, he received his M.S. degree in Mechanical and Industrial Engineering from École Nationale Supérieure d'Arts et Métiers (ENSAM), France.

Vsevolod Bugrov received his M.S. degree in Petroleum Engineering in 2003 from the Russian State University of Oil and Gas, Moscow, Russia. After graduation he started his career with Schlumberger as a Coiled Tubing Engineer. He has 6 years of experience in well intervention and stimulation services, including various applications of coiled tubing in arctic and desert conditions. Currently, he works in 'Udhailiyah providing technical support for the Southern Area Production Engineering Department (SAPED) Coiled Tubing operations.

Jan Jacobsen is the ACTive Domain Champion for Schlumberger in the Middle East. He joined Schlumberger as a Coiled Tubing Field Engineer in 2004, working in Germany and The Netherlands. In 2007 Jan joined Schlumberger Data Consulting Services for assignments in the U.K. and France. He then joined Schlumberger Well Services and Data Consulting Services in his current position in Saudi Arabia in 2009. In 2004, Jan received his M.S. degree in Civil Engineering from the Technical University of Denmark, Copenhagen, Denmark, specializing in applied geophysics.

George Brown joined Sensa in March 1999 as the Manager of Interpretation Development and is currently Schlumberger's Temperature Interpretation Advisor (Sensa was bought by Schlumberger in 2001). He is responsible for developing the interpretation methodology and software to facilitate the analysis of Schlumberger's permanent and intervention deployed distributed temperature measurements and has been analyzing distributed temperature data since 1999. Before Sensa, George spent 15 years with BP Exploration where he was Head of the Petrophysics group at the Sunbury Research Center and later Senior Formation Evaluation Consultant working with BP's "Intelligent Wells" team charged with developing new permanent monitoring systems for horizontal and sub-sea wells, which included the early trials and evaluation of fiber optic temperature measurements. Prior to BP, he spent 12 years with Schlumberger Wireline working in both the Middle East (Saudi Arabia, Dubai and Turkey) and the North Sea area (Aberdeen and Norway) in a variety of operational and management positions. George holds a first class honors degree in Mechanical Engineering, has published over 20 technical papers, been awarded several patents and was a Society of Petroleum of Engineers' (SPE) Distinguished Lecturer during 2004/5.

Vidal Noya is a Coiled Tubing Services Technical Manager assigned to the region of Saudi Arabia, Kuwait and Bahrain. He has 19 years of experience in the oil field services. Since joining Schlumberger, he has worked in several projects related to operations and technology in the area of well intervention and production. Vidal's experience includes assignments in South America, North Africa, the Middle East and Europe. He received his B.S. degree in Mechanical Engineering in1991 from the Universidad Central de Venezuela, Caracas, Venezuela.

A Smart Approach in Acid Stimulation Resulted in Successful Reviving of Horizontal Producers Equipped with ICD Completions: Saudi Arabia Case History

By Naif I. Al-Mulhem, Hemant Kumar Sharma, Ahmed K. Al-Zain, Suliman S. Al-Suwailem and Saad M. Al-Driweesh.

Reprinted courtesy of Saudi Aramco JOT.

Abstract

Passive completions comprised of inflow control devices (ICDs) and external casing packers (ECPs) are usually considered in horizontal wells located in risky or mature areas. These completions are proven techniques for reservoir conformance to mitigate water or gas coning problems and to ensure uniform production contributions along the horizontal section. After well completion or shortly after the initial production, these wells may fail to sustain production, largely due to formation damage or plugging in the ICDs. The conventional acid program, applied on wells with non-passive completions, is not suitable on these wells, due to the risk of impacting the completion integrity to the extent that it will violate the installation purposes. The requirements of acid treating wells with the same completions become inevitable due to the increasing number of wells equipped with these completions in a major carbonate reservoir in Saudi Arabia. A smart approach has been developed through innovative thinking to stimulate wells equipped with passive completions. The new approach has successfully stimulated four wells and resulted in restoring well productivity. This smart stimulation approach demonstrates a competent method to clean out the ICD completion along the horizontal section and to remove formation damage.

This article presents an in-depth discussion of rigless acid stimulation operations on oil producers to remove formation damage and improve well productivity, at a reduced cost. This article also outlines the successful application of the smart approach in acid stimulation of horizontal wells – equipped with passive completion – and discusses the post-treatment results.

Background

Water injection was started to boost and maintain the reservoir pressure. All producers were initially drilled as vertical producers, and with the advancement of the water front, a great deal of the vertical producers were converted to short radius horizontals (SRHs) that targeted the thin oil column behind the flood front. The oil was sourced from Jurassic organic-rich lime mudstones, which were laid down in inter-shelf basins. The integrity of the thick anhydrite top seal is enhanced by the general absence of faults in the Jurassic section. The main oil reservoir is the Upper Jurassic Arab-D limestone, which improves upward from mudstone to skeletal oolitic grainstone, reflecting successive upward shoaling cycles. The excellent reservoir quality is due to the preservation of the primary porosity, the enhancement of permeability, and the presence of fractures in the deeper and tighter parts.

The oil was sourced exclusively from Jurassic organic rich mudstones and is effectively sealed beneath massive anhydrite. The general absence of faults at the Arab-D level maintained seal integrity.

Introduction

Passive completions consisting of inflow control devices (ICDs) and external casing packers (ECPs) have been intensively brought into play in the highly heterogeneous carbonate reservoir, to provide consistent flow along

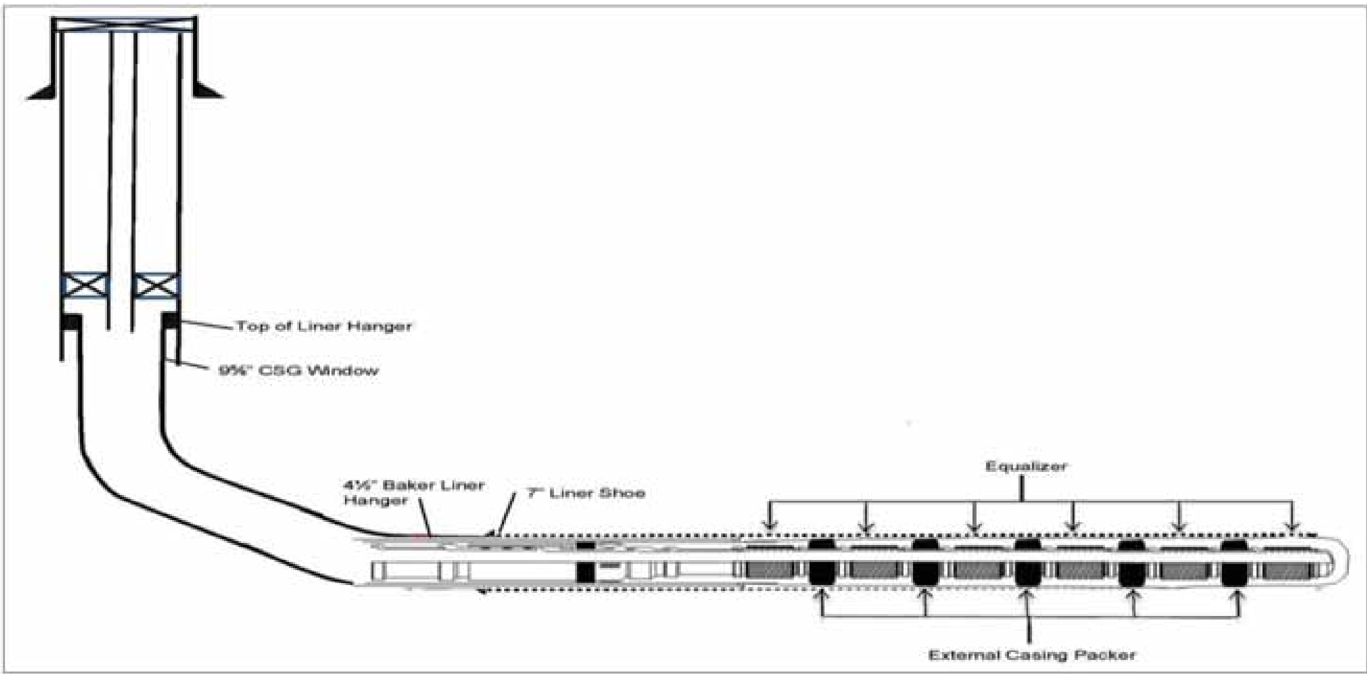


Fig 1. Typical well sketch.

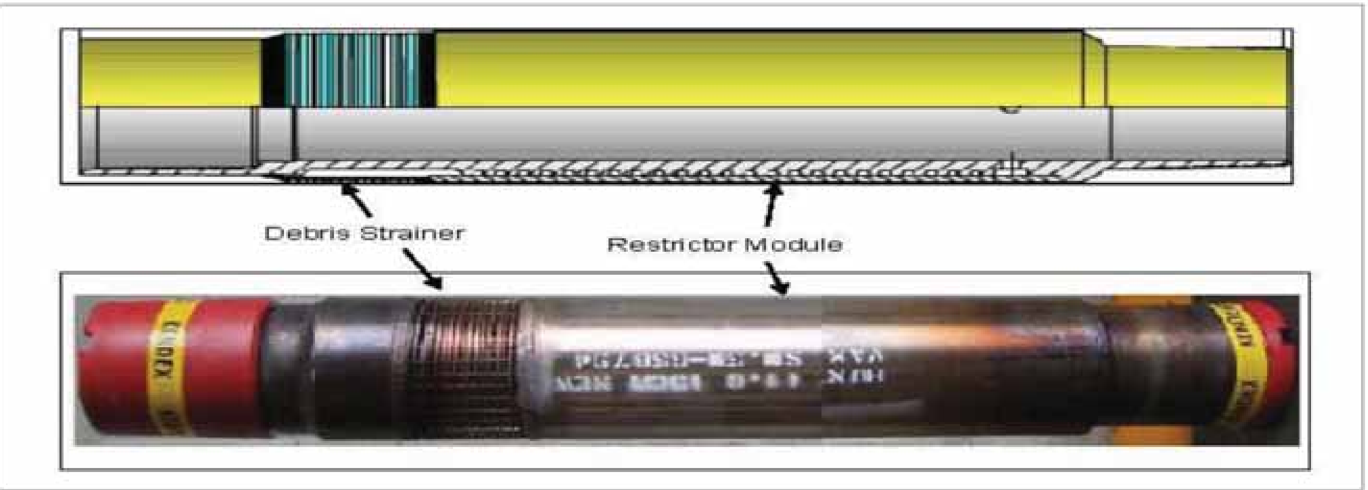


Fig 2. Equalizer screen with detailed view of regulator section.

the horizontal section. ICDs along with ECPs enhance well performance by providing a seal between sections of varying permeability, to achieve uniform contribution from the horizontal section[1-3]. ICDs were optimally installed in both new and sidetracked wells based on the interpretation of the open hole logs obtained while drilling, to locate high permeability strikes in the reservoir. The production is generally optimized by equalizing the reservoir inflow along the horizontal section. This action delays water and gas breakthroughs. The passive completion helps in increasing well productivity, prolonging well life, and ultimately improving reservoir sweep and recovery.

Passive completions consist of ICDs and annular isolation devices. The ICDs are modular equalizers optimized for the specific reservoir condition. It consists of a triple medium cross section spiral flow channel. The length of the spiral controls the pressure drop. For example, a 20.6" spiral length achieves the target pressure of 100 psi at 300 stock tank barrels per day (STBD) oil rate. The annular isolation device is mainly used for compartmentalization of flow along the length of the formation. The annular isolation devices are of various types[4], including: inflatable or mechanical ECP, swellable packers (SP), constrictors and expandable packers. In the subject wells, mechanical ECPs, SPs and constrictors were used for isolation of each compartment, and to cover fractures or high permeability zones (identified through image logs and loss circulation encountered while drilling), in conjunction with a blank pipe. A typical well completion sketch is shown in Fig. 1.

Different types of passive completion depend on the

Fig 3. Example of external casing packer (ECP).

principle of operation, e.g., channel, nozzle and orifice type or a combination of orifice and channel types[4]. The construction is broadly similar with minor differences. The pressure drop, and subsequently the regulation of the influx, is achieved across equalizers through the principle mentioned in the name itself. The equalizer for the subject wells (carbonate formation) consists of a debris strainer, Fig. 2, fitted with a proprietary restrictor module for the velocity flow regulator. The restrictor module consists of up to three spiral flow channels spinning the flow, prior to entry into the wellbore, to impose a pressure distribution; and then controls the production along the entire length of the wellbore. The objective of this regulator is to prevent highly productive zones from excessive production; thereby allowing the nonproductive zones to contribute more, due to the additional pressure drops in the wellbore. If the well path is close to either water and/or gas, the regulator will prevent any undesired coning effects that lead to premature water and/or gas breakthrough. The system requires ECPs, Fig. 3, to achieve zonal isolation, Fig. 4, to balance the inflow into the screen liner with the ICDs. The benefit of completing the well with the equalizer system is shown in Figs. 5a and5b, where uniform production was achieved throughout the horizontal section.

Numerous wellbore hydraulic simulation runs were carried out to determine the number of ICDs and compartments required for each horizontal section. The design and the number of ICDs required in each compartment in the horizontal section are based on the potential reservoir influx, which in turn is based on the variation of permeability in various sections of the wellbore. Available log interpretation while drilling the well helped to run sensitivity with expected fluid flow into the wellbore through that section and permeability of the section helped in designing the ICDs and compartment length. As a rule of thumb, 25 psi differential pressure is assumed across each compartment.

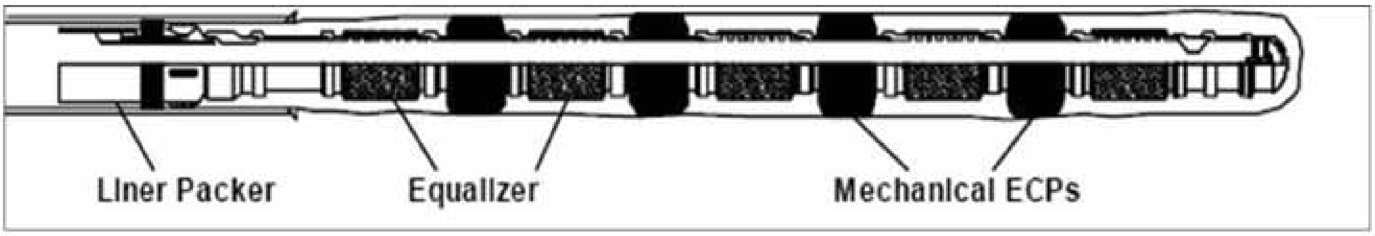


Fig 4. Equalizer system with zonal isolation.

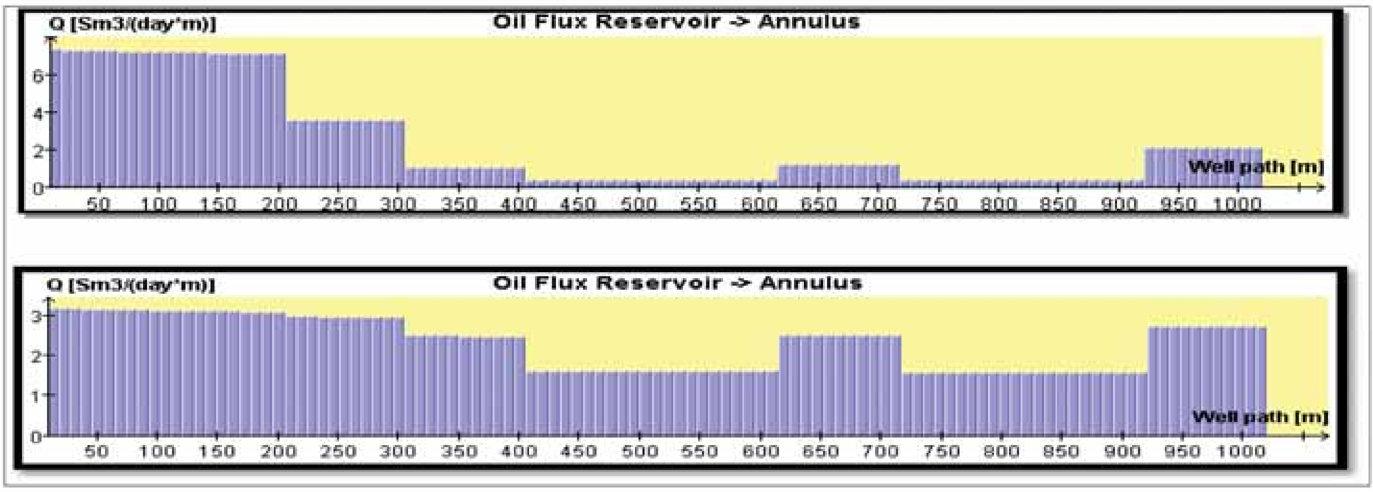


Fig 5a.Sketch of production without equlizer completion (top). Fig 5b. Sketch of production with equalizer completion.

Case Histories

Well A was drilled and completed as a horizontal producer in a 110 ft oil column and an average permeability of 208 ft measured depth (MD) in November 2006 with five mechanical packers and 14 ICDs. The well was put in production and the initial rate was 5.5 thousand barrels per day (MBD) with 7% water cut. An American Petroleum Institute (API) test showed that the well was producing below the bubble point pressure due to severe formation damage.

Well B was drilled and completed as a cased hole oil producer. The well was a dry producer with an initial oil production of 11.3 thousand barrels of oil per day (MBOD), which declined to 0.8 MBOD with an 82.5% water cut. The well was recompleted as a short radius horizontal with 16 equalizers divided into compartments in the 10 ft oil column at the top of the reservoir. The well remained dead after the workover.

Well C was drilled as a vertical open hole producer. The well was a dry producer with an initial oil production of 10 MBOD, which declined to 3.3 MBD with a 60% water cut. The well was sidetracked at the 20 ft oil column at the top of the reservoir and completed with 15 ICDs. The well remained dead after the workover.

Well D was originally drilled as a vertical open hole producer. The well was a dry producer with an initial oil production of 10.6 MBOD, which declined to 2.7 MBD with a 43% water cut. Therefore, the well was sidetracked in the 35 ft oil thickness column at the top of the reservoir and completed with 12 ICDs and ECPs. The well remained dead after the workover.

Damage Mechanism

The damage characterization is the key to proper design of treatment removal[5]. To know the cause of the damage; drilling reports, completion design, offset well performance and past treatment records were evaluated. Table 1 shows typical mud compositions and properties for drilling. The main reason for formation damage in long horizontal wells completed with equalizers[2] may be due to the following:

1. Formation damage during drilling.
2. Drilling fluids and associated solids invasion.
3. Optimum ICD completion design, which imposes a pressure drop across the ICDs and heel to toe head loss friction, due to flow induced inside the long horizontal section, resulting in limited drainage from the toe (less cleanup) and risk of water coning in the heel.
4. The cleanup process, which depends on mud cake quality, permeability heterogeneities, heel to toe effect, etc., which causes plugging of equalizers.

The suspected reasons for the damage of the subject wells, all isolated cases, were due to plugging of the equalizers

Item	Unit	Amount
Water	bbl	0.90
Defoamer	gal	0.01
XC-Polymer	lb	1.5
HEC	lb	2.0
$CaCl_2$ (78%)	lb	10.0
Diesel (if required)	bbl	0.03
Dextrid	lb	4.0
Lime	lb	1.0
$CaSO_4 \cdot 2H_2O$	lb	7.0
$CaCO_3$ "fine"	lb	6.0
Density	pcf	65
Plastic Viscosity	cp	15
Yield Point	lb/100 ft^2	30
10 sec Gel	lb/100 ft^2	6
10 min Gel	lb/100 ft^2	15
Filtrate	ml/30 min	6
pH		10
Chlorides	mg/l	19,000

Table 1. Typical mud compositions and properties.

Treatment Fluid	Additives
Pre-flush	Mutual Solvent
	Surfactant
	Water
Acid 15% HCl	Corrosion Inhibitor
	Surfactant
	31% HCl
	Water
Post-Flush	Mutual Solvent
	Water

Table 2. Treatment fluid and additives.

Sl No.	Well	Production before Acid Stimulation	Production after Stimulation (MBD)
1	A	Shut-in	8
2	B	Dead	10
3	C	Dead	9
4	D	Dead	9

Table 3. Production comparison before and after stimulation.

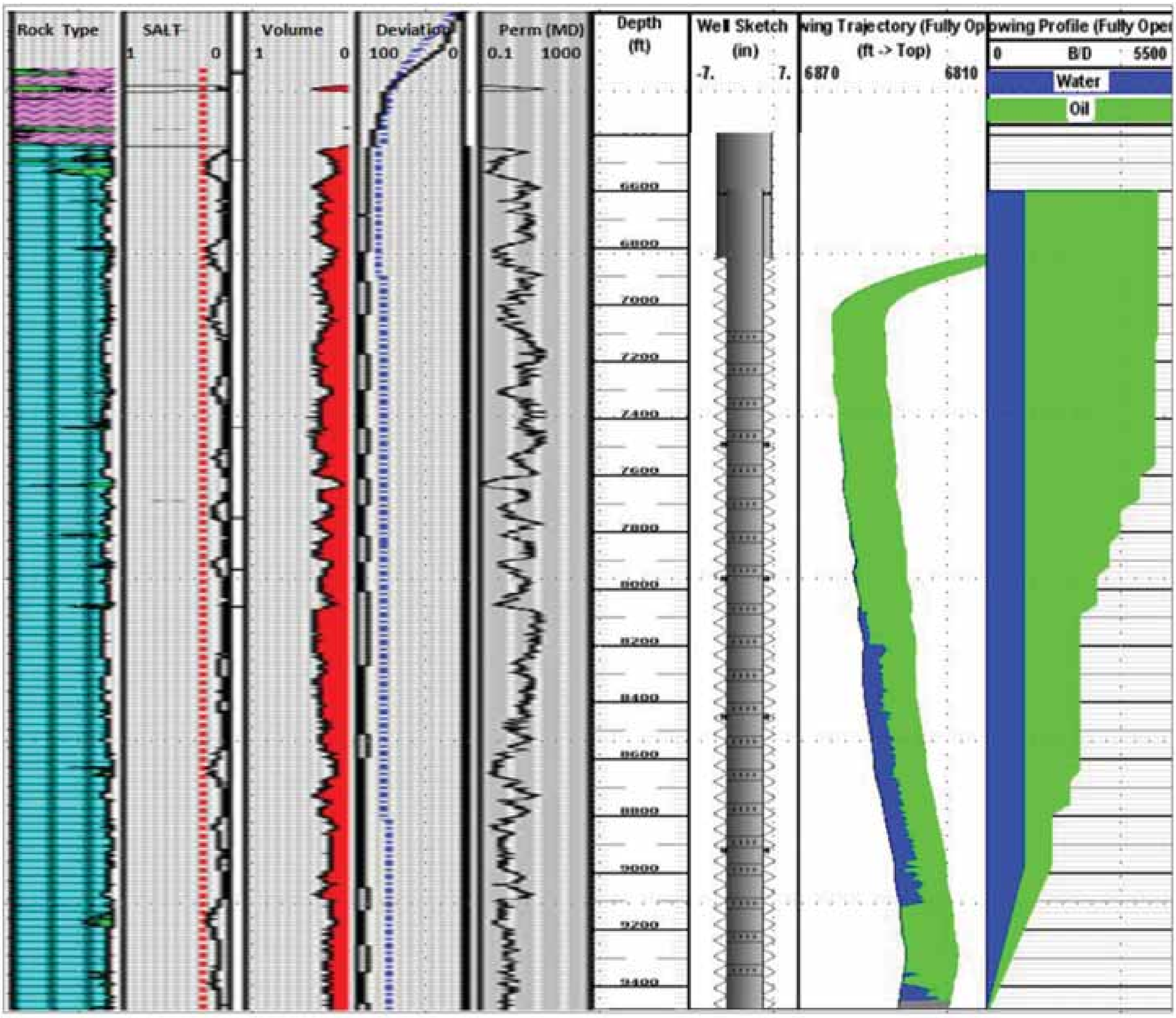


Fig 6. Well B PLT.

from improper wellbore cleaning during completion, or mud cake and filtrates that invaded the near wellbore matrix. The current practice is to clean up the horizontal section prior to installing the completion.

Treatment Design

The design of the stimulation treatment was mainly based on the type of the damage. In the subject wells, the formation damage was mainly due to interaction between the drilling and completion fluids with the formation leading to clogging of the ICD ports and blocking the near wellbore pores. Therefore, the treatment fluid was needed mainly to clean the equalizers and remove the suspected formation damage across the formation face to restore the well productivity by spotting acid across the equalizers.

The stimulation treatment volumes were designed based on the amount of probable formation damage and the rock quality. Taking into consideration that the oil-water contact (OWC) in the subject wells were in the close vicinity, the treatment was designed conservatively. Consideration for material of construction of the equalizers with exposure time of the acid (long horizontal) was taken into account while designing the concentration and volume of the main treatment fluid.

Radial penetration of the acid to around one foot was enough to liven the wells. The treatment mainly consisted of:

1. Pre-flush consisting of mutual solvent.
2. Main treatment: 15% Hydrochloric acid (HCl) with

additives at 5-10 gallons per linear foot (gal/ft).
3. Post-flush consisting of mutual solvent.
4. Displacement with diesel followed by flow back to the pit for well livening. The wells were kicked off with nitrogen, due to low reservoir pressure.

Table 2 illustrates the treatment fluid and additives used.

Coil tubing (CT) was used for even placement of the treatment fluids. Based on the reach of CT to the desired depth, CT size was selected. A friction reducer was kept as a contingency in case the CT did not reach the desired depth.

Treatment Result

The result after the acid treatment was very encouraging and all wells flowed naturally after the initial kickoff with nitrogen. There was a total oil gain of 36 MBOD from the subject four wells following the acid treatment. The comparison of each well is made in Table 3, before and after the acid stimulation treatment. The wells have sustained production from the time of the acid treatment up to the time of writing this article.

A recent Production Logging Tool (PLT) conducted on Well B after the treatment showed even contribution along the length of the horizontal section. The flow equalization through ICDs and compartmentalization through ECP/SPs and constrictors helped in achieving the desired objective of even flow through the equalizer completion system, Fig. 6.

Conclusions

1. Conservative acid treatment for wells completed with equalizers helped in restoring the production from all the subject wells.
2. The production impairment caused due to plugging the formation face and partial formation invasion was cleaned and dissolved by acid treatment.
3. The wellbore cleanup must be performed before completing the well with passive completion. This is the current practice being deployed in all new wells.
4. A gain of 36 MBOD of oil was realized from stimulating four dead wells due to the completion plugging effect.

Acknowledgements

The authors wish to thank Saudi Aramco management for their support and permission to present the information contained in this article.

References

1. Al-Ahmadi, H.A. and Al-Mutairi, S.M.: “Effective Water Production Control through Utilizing ECP and Passive ICD Completion Technologies; Case Studies,” SPE paper 120822, presented at the SPE Saudi Arabia Section Technical Symposium, al-Khobar, Saudi Arabia, May 10-12, 2008.

2. Al-Shehri, A.M., Kilany, K., Hembling, D.E., et al.: “Best Cleanup Practices for an Offshore Sandstone Reservoir with ICD Completion in Horizontal Wells,” SPE paper 120651, presented at the SPE Middle East Oil & Gas Show and Conference, the Bahrain International Exhibition Center, Kingdom of Bahrain, March 15-18, 2009.

3. Krinis, D., Al-Dawood, N. and Soremi, Y.: “Horizontal Well Performance Optimization using Linearized Inflow Control Devices,” SPE paper 117213-MS, presented at the Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, U.A.E., November 3-6, 2008.

4. Alkhelaiwi, F.T. and Davies, D.R.: “Inflow Control Devices: Application and Value Quantifications of a Developing Technology,” SPE paper 108700, presented at the International Oil & Gas Conference and Exhibition, Veracruz, Mexico, June 27-30, 2007.

5. Hill, D.G., Lietard, O.M., Piot, B.M. and King, G.E.: “Formation Damage: Origin, Diagnosis and Treatment Strategy,”Reservoir Stimulation, 2000, pp.14.1-14.39.

BIOGRAPHIES

Naif I. Al-Mulhem is a Petroleum Engineer working in the Southern Area Production Engineering Department (SAPED). He received a B.S. degree in 2007 in Applied Petroleum Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia. In April 2007, he joined Saudi Aramco, working in SAPED. He has 3 years of experience, mainly in production optimization, well integrity and production enhancement.

Hemant Kumar Sharma is a Production Engineer with more than 19 years of experience in the oil and gas industry. His oil and gas experience includes well stimulation, well completion, erection and commissioning and surface facilities. Currently, Hemant is working as a Stimulation and Water Shut-off Engineer for oil and water in the Southern Area Production Engineering Department (SAPED). He received his M.Eng. degree from Bhagalpur College of Engineering, Bihar, India in 1990 and an MBA from Indira Gandhi National Open University, Delhi, India in 2005.

Ahmed K. Al-Zain currently works as a Production Engineering Specialist in well treatments in the Southern Area Production Engineering Department (SAPED). He received his B.S. degree in 1989 in Petroleum Engineering from Tulsa University, Tulsa, OK. After his graduation, Ahmed joined Saudi Aramco as a Production Engineer and worked in various sandstone and carbonate major fields in the Southern area. He now has over 20 years of experience, mainly in production engineering as well as in reservoir and drilling engineering. Ahmed has published several technical papers on various topics, such as acid stimulation, scale inhibition, water compatibility, coiled tubing applications and automated well data acquisitions.

Suliman S. Al-Suwailem is a Production Engineer Unit Head with the Southern Area Production Engineering Department (SAPED). He has worked in various Engineering disciplines, including Drilling Engineer, Operation Engineer, Reservoir Engineer and Well Service Foreman. In 1992, he received his B.S. degree in Chemical Engineering from New Mexico State University, Las Cruces, NM.

Saad M. Al-Driweesh is a Production Engineering General Supervisor in the Southern Area Production Engineering Department (SAPED), where he is involved in gas and oil production engineering, well completion and stimulation activities. He is mainly interested in the field of production engineering, production optimization and new well completion applications. In 1988, Saad received his B.S. degree in Petroleum Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia. He has been working with Saudi Aramco for the past 19 years in areas related to gas and oil production engineering.

Some Insights into Embracing an Innovation Competition to Identify Breakthrough Technologies or Processes

By Dr. M. Rashid Khan.

Abstract

Saudi Aramco has initiated the Innovation Tournament competition. This new corporate initiative, aimed at boosting innovation within Saudi Aramco, complements the existing internal "open" innovation program. The current innovation program is designed to receive a free flow of innovative ideas to empower employee creativity through the corporate Idea Management System (IMS). This initiative added significant value to company operations. The Innovation Tournament's "theme" is based and aligned with the company's strategies and challenges by specifying a theme. That will improve the benefits of innovation and generate focused solutions that have a targeted impact on Saudi Aramco businesses. The tournament introduces a competitive and creative approach to engage people to contribute their best ideas for a specific challenge or theme. Different tournaments may focus on themes addressing real company challenges, addressing topics, such as safety, reliability, discovery, productivity and cost reduction. The First Saudi Aramco Innovation Tournament's theme is "Energy Conservation." Ideas will be evaluated for their profitability, long-term impact and practicality. This article provides some guidelines or best practices regarding the topic of innovation competition, so that before sponsoring additional tournaments some factors that should be considered to make the initiative effective to add value can be considered. Often, targeted innovation embraces an internal business plan or challenge-based competition to engage all employees of the company.

Introduction

Since Edison's Idea Factory, innovations have been the engine of long-term growth for world-class companies. Subsequently, technology giants, such as British Telecom, Siemens, Nokia, Fujitsu, DuPont, P&G and many others, are finding it difficult to make their innovation investments pay by their own limited number of scientists and engineers alone. To increase the return on the technology investment, many are finding it useful to complement their work by engaging others within and outside the company. Leaders like DuPont, Merck, IBM, GE, etc., who traditionally did most of the innovation within the confinement of "old school" (specific organizations within the company) in their respective industries — are recognizing the need to engage others, both within the company and outsiders to create new technological innovations. The perspective of internal

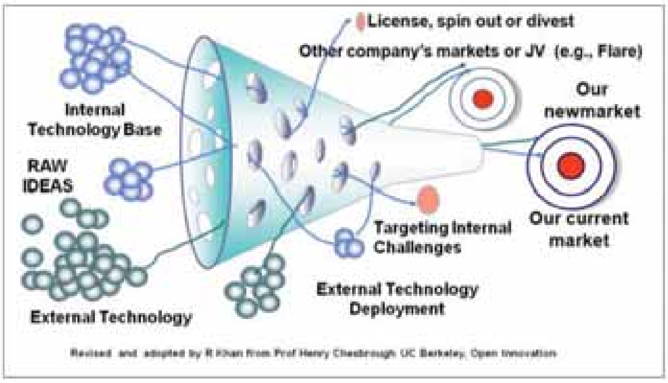


Fig 1. Raw ideas to internal deployment or market.

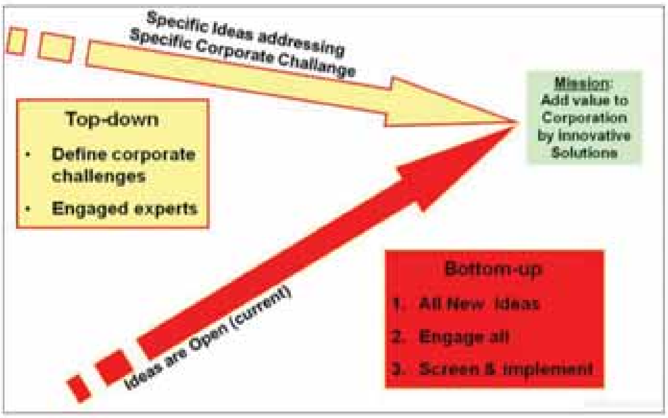


Fig 2. Target-based innovation strategy.

work is changing from depth to width and collaboration by internal and or external open innovation and/or by launching targeted innovation. Old school developed new technologies from basic science to the finished product, but the newly found open innovation model recognizes the need to develop technologies that embrace and broaden existing technologies, even those that are "not invented here." Often, targeted innovation embraces an internal business plan or challenge-based competition to engage all employees of the company. (Figure 1 describes the difference between various ways to develop value for the company starting from raw ideas). Figure 2 shows a definition of the "target" based innovation. In Saudi Aramco, each organization's potential business plan or challenge competition can be uniquely its own. Some necessary steps for building a successful competition are suggested. These steps are aimed at being the best chance of success as one works through them in planning and completing a competition with some success.

1. Establish a strategy. Define clear objectives and a theme for the initiative. In Saudi Aramco, some departments or Admin Areas already have intense responsibilities; they are not necessarily interested in sponsoring a competition for ideas. Knowing what we hope to achieve would assist us to manage the expectations of Saudi Aramco leadership and competition participants. We need to clearly define what we expect from the completion and contestants, not just during the competition, but also afterwards as well. Clarifying these expectations before one starts is important. Identify a theme that will motivate and inspire a wide range of employees to participate. One also has to define an inspirational message for the employees, building a strategy in advance that leverages the theme and informs our employees why the competition is good for Saudi Aramco and the participants. The business plan or challenge competition and the theme must also have the support of top management.

2. Develop an Organizing Team. If we want to pursue a competition, and our upper management is agreeable, developing a team is the next step. The Team or steering committee will be responsible for planning and implementing the competition with the assistance from the Corporate Innovation Team, and for setting the competition's strategic direction. The Organizing Team should include individuals who are enthusiastic about the idea and who are well-connected to various organizations in Saudi Aramco. Team members should be aware of the potential intensive work during the planning and execution stages. The Team should establish a well-defined process and address some key issues early on. What process will be used to get employees to participate? A future IMS system may allow one to frame a target based competition. How will one choose the winners in various rounds? These key questions must be answered before one starts publicizing the competition. Defining resource needs is essential. Remember that at this stage, one is looking for the right volunteers, not ideas. It's better to engage individuals with strong entrepreneurship traits. Teams may be provided with a budget.

3. Define the size and scope of the competition. Start with a relatively small pilot program in the department and plan to grow in size, if warranted. This will enable one to get the initiative off the ground faster and will also make quick adjustments easier as one proceeds. The size of the competition also impacts how well one is able to manage expectations. How many business ideas might one be able to move forward with? Considering this in advance will guide one in determining how big the competition should be. The choices one makes after a business plan or challenge competition is complete are equally as important as the ones described regarding planning. The key short-term and long-term follow-up decisions may include:

- How can we move forward with the major ideas, including the winning idea?
- What would be the role of the competition teams or significant contributors in the long run? Will they have the opportunity to continue to work to make their idea a reality?
- Who would follow-up for deployment?
- Competitions, such as this would generate huge numbers of inputs, and appropriate management of these inputs would be paramount.
- How can we capitalize on the relationships developed during the competition?
- How to form a talent pool or network to offer networking and learning opportunities?

4. Define recognition for all participants, including winners and runner ups. How will one reward employees for participating in the business plan or challenge competition? How will this help them advance? If we offer monetary awards to the competition winners, these awards should be aligned with other recognition programs. Clearly define benefits for all participants and for the winning team or individuals. Employees need to know what they stand to gain from participating in this rewarding but also time-consuming competition. The most important rewards are those that help drive participants' careers forward — the opportunity to join a network or program for entrepreneurs and, most im-

> The final piece one needs to put in place before we are ready to kickoff our business plan or challenge competition is a set of experts who can coach the teams during the competition.

portantly, the chance to work on new business ideas. Also, specify the non-tangible benefits that come with participation, including competencies in which participants will be trained during the competition, such as teamwork, innovation processes, presentation skills, and management of high-risk projects. Highlighting this professional skills building aspect should help support Team development and recruiting efforts.

5. Create a schedule. In general, a competition should last about three to four months from kickoff to the final event. This will give participants time to make serious progress while keeping the intensity alive. The major milestones on the schedule should include:

• Defining strategy.
• Team selection, jury selection.
• Announcement of chosen contestants.
• Competition kickoff.
• Selection of semifinalists and semifinalists to present to the jury.
• Final presentations to jury and selection of winner(s).
• Recognition and implementation.

6. Set evaluation criteria for judging the proposals developed by the competition teams. In addition to defining the judging criteria, we also have to determine what evaluation method we will use. For example, review factors such as market potential, technology feasibility, resource needs, organizational fit, and overall impression as criteria, along with rating how well each team or individual did on each criterion using a scale, such as of 1 (low) to 10 or 100 (high). Each criterion is weighted based on its importance. The final criteria may be different for the semifinal, which is used to ensure the ideas are adding value and appropriate documentation are provided. Ideas that are not significant should be eliminated early on. One should also look at presentation skills.

7. Assemble the judging panels. Tap the highest-ranking employees one can to serve as our competition jury. Having the rare opportunity to expose their talents to senior executives will go a long way toward assuring that our recruiting effort draws the best and the brightest in the company. One may want one judging panel for the semifinal and a different one for the Final. The Final should also be judged by a panel of senior executives. This step offers a great opportunity to further the overall objective of the innovation effort by showing that the competition has the support of top-level executives. The final piece one needs to put in place before we are ready to kickoff our business plan or challenge competition is a set of experts who can coach the teams during the competition. We want to make two types of coaches available:

• Team coaches: Team coaches bring subject matter knowledge, as well as knowledge of Saudi Aramco's competencies. The Organizing Team should assign coaches to the teams based on the match between the coaches' areas of subject matter expertise and the ideas the teams are pursuing. Team coaches should also be internal employees, so they have an overview of other ongoing Saudi Aramco activities related to the idea. Coaches should be prepared to spend 8-16 hours (minimum) with their teams during the course of the competition.

• Competency coaches or Thought Leaders: Competency coaches "Thought Leaders" are skilled in specific areas, such as taking new products or services to market, developing a value proposition or financial issues. The Organizing Team should be able to choose competency coaches as they see fit.

8. Finally, recommendations should be provided by the Organizing Team based on what was learned during the competition. A summary should be provided regarding the future improvements and accomplishments.

Conclusions

Identifying the challenge and framing the theme is the most difficult part of an innovation competition. Encourage as many raw ideas from individuals as possible. If we can follow the process as illustrated here, we should come out of the competition with a scheme on which employees can take their challenging ideas and turn them into a reality. Assuming our competition has been highly successful as an internal initiative, imagine what we can create if we are able to form on the same platform of true open innovation consisting of our own employees as well as external customers and partners. Involve "Thought Leaders," for assisting with the events and a breakthrough approach to improving idea quality, accelerating decision-making and facilitating implementation. Open-ended initiatives without deadlines can fail because employees' interest wanes. Structured initiatives create a sense of momentum and limited-time opportunity. Treat innovation competition as a process, not as an event.

For further information, please contact: Rashid.khan.1@aramco.com.

BIOGRAPHY

Dr. M. Rashid Khan is the Deputy Director of the Technology Management Program, an interdepartmental and interdisciplinary program under the Engineering Services Organization. He previously served as the Champion of the Solar Energy Program at King Abdullah University of Science and Technology (KAUST) where he developed their first Intellectual Property Policy while formulating Economic Development policies. Rashid supported development of various research initiatives and partnerships for the university.

Rashid served 5 years with the U.S. Department of Energy and 13 years with Texaco Inc. Additionally, he took assignments with the United Nations Development Program (UNDP) and served as an Adjunct Professor for New York's Vassar College. Through his career Rashid has written/edited three books used in universities and industry, as well as published over 175 papers. He's an inventor of 30 patented ideas and presented many invited lectures. As a Society of Petroleum Engineers (SPE) Distinguished Lecturer for 2006 and 2007, Rashid has given presentations around the world. Rashid received various awards for his innovative research, including the American Chemical Society Award and Texaco's High Technical Award for creativity.

He received his M.S. degree in Environmental Engineering from Oregon State University, Corvallis, OR in 1979 and his Ph.D. degree in Energy and Fuels Engineering from Pennsylvania State University, University Park, PA in 1984.

OGEP 2010
The 2nd Saudi Meeting on
Oil and Natural Gas Exploration
and Production Technologies
KFUPM Campus, Dhahran, Saudi Arabia
December 18 - 20, 2010
Call for Abstracts
Academia - Petroleum Industry
Synergy
for a
Better
Tomorrow
Organizers
وزارة البترول والثروة المعدنية
مدينة الملك عبدالعزيز
للعلوم والتقنية KACST

Invitation

The Ministry of Petroleum and Mineral Resources, King Fahd University of Petroleum & Minerals (KFUPM), and King Abdulaziz City for Science and Technology (KACST) cordially invite you to participate in the 2nd Saudi Meeting on Oil and Gas Exploration and Production Technologies (OGEP 2010). The Meeting will be held at the KFUPM Campus in Dhahran, Saudi Arabia, on December 18-20, 2010, under the auspices of His Excellency Ali Naimi, the Minister of Petroleum and Mineral Resources.

The theme of the meeting is "Academia Petroleum Industry: Synergy for a Better Tomorrow." The theme was selected to focus on enhancing the collaboration between academia and industry in research and development and to prepare a competent workforce for the future.

The OGEP 2010 will include technical sessions covering both oral and poster presentations, invited speakers, panel discussions, young professionals session, student paper contest, and an exhibition covering the latest advances in oil and gas exploration and production technologies.

The meeting is designed to provide a forum for discussion of a broad range of topics relevant to academia and E&P industry, including business relationships between academia and industry, human resources, exploration, production, drilling, reservoir, health, safety & environment, economics and energy. We particularly encourage the presentation of case histories, innovative ideas, challenges, and new technologies, as this is an excellent platform to exchange actual experiences and/or showcase new and innovative solutions with participants from local and regional academia as well as industry leaders from National and International Oil Companies (NOC/IOC) like Saudi Aramco, Chevron, and Shell as well as leading service providers such as Baker Hughes, BJ Services, Halliburton, Schlumberger, and Weatherford.

On behalf of the Technical Committee, I would like to invite you to participate in the OGEP 2010 through submittal of abstracts. I also ask for your support in distributing this announcement to colleagues and friends.

Chairman of the Technical Committee
Abdulrahman S. Al Jarri, PhD
Saudi Aramco

Co-Chairman of the Technical Committee
Abdulaziz A. Al-Majed, PhD
King Fahd University for Petroleum and Minerals

Objective

The meeting is organized for the academic community and the petroleum industry to discuss and collaborate on oil and natural gas exploration and production technologies. The meeting will provide a unique opportunity for professionals, experts, scientists, and faculty members in these fields to discuss and exchange their views and experience, with an emphasis on synergy between academia and the industry on relevant topics including human resources, research and development.

Topics

The technical program will cover numerous topics relevant to academia and oil and natural gas exploration and production including (but not limited to):

- Academia and Industry Business Relationships
- Human Resources
- Exploration Technologies
- Petroleum Geology and Reservoir Characterization
- Reservoir Related Technologies
- Production Technologies
- Drilling Technologies
- Health, Safety, and Environment
- Economics and Energy

Details of areas of interest are in the attached table.

Call for Abstracts

The Technical Committee solicits participation from international and local professionals, experts, scientists, and educators through submittal of extended abstracts (up to 4 pages) for technical presentations and posters.

Submittal Instructions:

1. Extended abstracts must be a minimum of 1000 words and up to 4 pages). Please refer to OGEP 2010 website for deadline dates.

2. Submissions should be in English and should briefly state the objectives, methodology; application conclusions of the work and future follow up if any.

3. Extended abstracts should be submitted using the attached Abstract Submission Form online through the OGEP 2010 Web Site: http://www.kfupm.edu.sa/ogep2010/ or www.OGEP2010.org and an auto-reply confirmation email will be sent to each submitter.

4. Accepted extended abstracts will be given the opportunity to submit full manuscript for publication, or published as submitted, in meeting proceedings and any

other meeting's information media, including the website.

5. Selective papers might be peer reviewed by KFUPM for potential publication in the Arabian Journal for Science and Engineering (AJSE) published by King Fahd University of Petroleum & Minerals in Dhahran, Saudi Arabia after meeting the journal's publication guidelines.

6. Authors are responsible for obtaining necessary clearance from their management, partners, and government agencies (as applicable).

7. Papers may be submitted for oral or poster presentations, and the type of presentation must be stated with the abstract submission.

8. An abstract submission form is included opposite and can also be downloaded from the meeting web site.

9. In case of several contributors, the principal author for correspondence should be designated.

Deadlines

Abstract submittal: Refer to OGEP 2010 website for deadline dates.
Acceptance Notification: Refer to OGEP 2010 website for deadline dates.

Panel Discussions

The OGEP 2010 will include three panel discussions with the following tentative subjects:

- Academia and the Petroleum Industry: working together to supply future workforce
- Partnering Technologies for a Better Tomorrow: Academic and Industrial Prospective.
- Economic Exploration, Exploitation and Development of Tight Gas

Exhibition

The venue of the Meeting will host an exhibition, to take place at the same time as the conference. The exhibition will showcase the latest technologies available in the market for oil and natural gas exploration and production including hardware, software and services. An announcement for the exhibition will follow.

Young Professionals' Session

The Technical Committee is delighted to introduce a Young Professionals Session in the OGEP 2010. This session will be fully dedicated to participation by young professionals who are less than 35 years in age. The main objective is to create a network that allows young professionals to share their experiences, discuss career issues, ideas, events, and best practices in the petroleum industry. The Technical Committee encourages and seeks participation of young professionals through submittal of extended abstracts for presentation from local, regional and international institutions and companies.

Student Paper Contest

A student paper contest will also be held during the OGEP 2010. This is to attract students from various colleges and universities in the Gulf and the Middle East region. More information is available in the attachment on the website.

Field Trip and Tours

A half-day field trip covering some geological landmarks of the Eastern province will be planned and there will be tours to operating and R&D centers in the area.

OGEP 2010 Students Contest Information

Contest Objective

To allow graduate and undergraduate students from local and Middle East Universities to propose, on a competitive basis, innovative ideas, design concepts and new enabling technologies that are relevant to the E&P industry. The contest consists of selected students or teams (undergraduate, master, and PhD divisions from participating universities). The work of each student or team will be judged for content and presentation by a panel of experts according to the guidelines below. The contest will take place during the OGEP 2010 to be held in Dhahran, on December 18-20, 2010.

Contest Participants

Interested universities from Saudi Arabia and GCC (or Middle East) countries are invited to promote the contest through participation of their graduate & undergraduate students. Each university department is entitled to present one student (or team) from each division. Accordingly, university departments (Petroleum Engineering and Earth Sciences) are encouraged to screen potential representatives internally before suggesting one for the competition. Nominees could be composed of undergraduate and graduate students. Participation of PhD students is allowed up to one per team. Each participating student or team will be supervised by one or more university professors who also act as "Student/Team Advisor(s)." Each team should have a "Team Leader" student who will also act as the main contact person for the contest.

OGEP 2010

السعودي الملتقى
الثاني
تقني

Extended Abstract Form:

In order to ensure publication on the CD-ROM, authors should submit their abstract online:

Title:____

Extended Abstract (minimum 1000 word & up to 4 pages): (please state objectives, methodology, application and conclusions)

Please specify the most appropriate technical category related to your abstract from the attached Technical Categories List:

Primary Technical Category: ____________________

Secondary Technical Category: ____________________

Please indicate whether your extended abstract is for oral or poster presentation (please tick one):

☐ Oral: I am willing to do a poster presentation in case an oral presentation is not possible. Yes ☐ No ☐

☐ Poster

☐ I would you like to submit: ☐ a paper or ☐ an extended abstract for the meeting proceeding.

Please list names in the order they should appear in publication:

Corresponding Author Information:

Name: ____________________

Company/institute: ____________________

Address: ____________________

City/Postal code: __________ Country: __________

Tel.No.: __________ Fax. No. : __________

E-mail: ____________________

Has material been presented previously? Yes ☐ No ☐

If yes, indicate place and date: ____________________

Short Biography of Presenter: ____________________

An auto-reply e-mail will be sent out upon successful submission

Technical Categories

1. Academia and Industry Business Relationships
- Academia versus Industry Perspective: Bridging the Gap
- Strategic Partnership for Maximum Returns
- Industry Oriented Academic Curriculum
- Training and Development
- Research and Technology Transfer
- HR capital
- University & High Institutes
- Internship
- Students Outreach
- Alliancing & Partnering
- Evolving Relationship between Academia & Industry
- Small & Medium Business Enterprise
- Applied Research to Commercial Development

2. Human Resources
- Coaching & Mentoring
- Education & Knowledge Sharing
- Outsourcing
- Practical Training, Development & Continuing Education
- Professionalism &Accountability
- Professional Certification
- Recruitment & Retention
- Succession Planning
- Technology Transfer
- Advances & Learning Techniques/Tools
- HR Development for E&P

3. Exploration
- Advances in Exploration Technology
- Geological Modeling and Basin Studies
- Deepwater Exploration Strategy
- Unconventional Reservoirs
- Tight Oil/Gas Reservoirs
- Fractured Reservoirs
- Applied Non Seismic Methods
- Case Studies

4. Production Optimization
- Artificial Lift
- Gas Lift, ESP, Beam, Pump, etc.
- Automation - Unmanned Platforms. Downhole Sensors Remote Well Surveillance, etc.
- Deliquification
- Integration: From Reservoir to Facilities
- Intelligent Pigging
- Modeling Gas Network
- Nodal Analysis
- Water & Gas Shut-Off Treatments
- Well Conversion
- Multiphase Metering & Pumping
- Debottlenecking

5. Drilling Technology
- Cementing
- Coring Technology
- Drilling and Casing
- Drilling with Casing
- Eliminating Drilling Surprises
- Fluids & Bits
- Slim hole, Coiled-tubing & Other Methods
- Underbalanced /Managed Pressure Drilling
- Well Control
- Wellbore Geomechanlcs
- Wellbore Stability

6. Completion Technology
- Completions
- Completion Fluids, etc.
- Expandable Tubular
- Formation Damage Management
- Intelligent Wells
- Monobore & Big Bore
- Sand Prediction & Control
- Stimulation
- Well Perforating

7. Offshore Technology
- Completions
- Development Options
- Drilling
- Flow Assurance
- Production Facilities
- Production Issues
- Subsea Completion
- Well Intervention

8. Extended Reach, Horizontal and Multilaterals
- Candidate Selection
- Drilling & Completion Methods
- Geo Steering
- Intervention
- Performance Prediction & Control

9. Petroleum Geology & Reservoir Characterization
- Reservoir Characterization Technologies
- Reservoir Modeling
- Geostatistics
- Geo-steering & Real Time Answers
- Rock Mechanics / Well Stability
- Core Analysis
- Fracture Characterization
- Pore Volume Assessment
- Rock Physics and AVO
- Case Studies

10. Formation Evaluation
- Petrophysical Technologies
- Carbonate/Clastic Petrophysics
- 3D Earth Models
- Advances in Well Testing
- Open, Cased & Slim Hole Measurements
- Mud Logging Technologies
- Saturation Monitoring
- Borehole Seismic
- Core Analysis & Petrophysics
- Imaging Technology
- Low Resistivity Pay/Thin Pay
- Measurement & Logging While Drilling
- Open & Cased Hole Methods
- Overlooked/Bypassed Oil Zones
- Tracer Flow Tests
- Wireline Formation Testing & Sampling
- Low Permeability Reservoirs

11. Gas
- C02 Storage/Sequestration
- Gas-Condensate Reservoirs
- Gas Development & Marketing
- Gas Storage
- LNG
- Tight Gas
- Sour Gas

12. HSE
- Bioremediation
- Discharge Issues/Limitations
- Downhole Separation and/or Disposal
- Emergency Response Planning/Management
- HAZOP Studies/Risk Management/ Safety Case Requirements
- Safety Behavior
- Security Issues
- Social Responsibility
- Toxic Waste Management
- Water & Solids Treatment & Disposal

13. IOR (EOR)
- Chemical, Thermal, Miscible Injections &Others (Microbial, etc)
- Heavy Oil Production
- IOR Techniques
- Water flooding, Gas Injection, Vibro Seismic, etc.

14. Information Management and Real-Time Monitoring
- Collection, Transfer, Archival, Reporting. Quality Control & Assurance
- E-business applications
- How much data is enough?
- Near Wellbore Characterization
- Neural Networks
- Applications & Benefits
- Real-time Data Analysis & Control

15. Reservoir Engineering & Management
- Description & Characterization
- Forecasting Methods
- Material Balance, Simulation etc.
- Fractured Reservoirs
- Reserves Assessment & Booking
- Reservoir Compaction & Subsidence
- Reservoir Continuity & Drive Mechanism in Deepwater – Reservoir Geomechanics
- Multidisciplinary Approaches
- Onshore Operating Centre
- Performance Monitoring
- Pressure Maintenance

16. Developing Seismic Technology
- Acquisition/Processing/ Interpretation Techniques
- 3D & 4D Seismic
- Seismic Inversion
- Borehole Seismic Methods
- Rock Physics, Seismic Forward Modeling and AVO/AVA
- Cost Effective Seismic Acquisition and Processing Practices
- Application of Seismic Attributes in Exploration and Reservoir Development
- Advances in Seismic Interpretation
- Cross-well Seismic
- Multi-component, Multi Azimuth Seismic
- Ocean Bottom Seismic
- Pattern Recognition
- Time Lapse
- Passive Seismic
- Recent Acquisition Techniques
- Advanced Seismic Data Processing Methods
- Seismic Imaging
- Near Surface Seismic
- Multiple Suppression

17. Economics & Energy
- Reserves Assessment
- Field Development and Optimization
- World Energy Outlook (Supply and demand)
- Energy prices & Markets (Oil markets and Natural gas markets)
- Project evaluation and Real Options
- Risk and uncertainty
- Energy Management, Efficiency & Security related Studies

18. Field Development
- Assets Life Cycle Depletion Plan
- Development of Mature Fields
- Fast-Track Developments
- Heavy Oil
- Marginal Fields
- Subsea Development
- Virtual Reality Techniques

19. Integrated Technologies and Case Studies
- Case studies should demonstrate the design and implementation of schemes to create or increase value.
- While successes are great and are usually what get attention, cases demonstrating failures and why a failure occurred, and lessons learned are welcomed.

Contest Topic

Participating universities may wish to choose any topic that is relevant to E&P Industry. However, when choosing topics, 'out-of-the-box' thinking is encouraged.

Contest Format

Participating students or teams will present their papers to a panel of judges during the OGEP 2010 in Dhahran. Papers are to be reviewed and judged for content and presentation in accordance with the selection criteria as per the scoring sheet prepared by the OGEP 2010 Technical Committee. The highest scoring student paper shall be recommended for the award. Where two (2) papers receive the same total score, the proposal which

Members	Affiliation
Mr. Majed Hassan Badah	MinPet
Mr. Ameen A. Al-Humidi	MinPet
Dr. Abdullatif Al-Shuhail	KFUPM
Dr. Hassan Al-Hashem	KFUPM
Dr. AbdulAziz Loubon	KSU
Dr. Emad Al-Homadhi	KSU
Dr. Hassan Naji	KAU
Dr. Omar Almisned	KACST
Dr. Fahad A Al Ajmi	Saudi Aramco
Mrs. Hiba A Dialdin	Saudi Aramco
Dr. Hamoud A Anazi	Saudi Aramco
Dr. Mohammed G. Al Otaibi	Saudi Aramco
Mr. Matter J. Al-Shammery	Saudi Aramco
Dr. Patrick Allman-Ward	Shell
Dr. Paul Thompson	Chevron
Dr. Muhammed Badri	Schlumberger
Mr. Mike Hopkins	Halliburton
Mr. Jaafar Aluzri	Baker Hughes
Mr. Charles P. Kreuz	Weatherford
Mr. Jose Reyes	BJ Services
Mr. Abdullah S. Al-Muhaish	SRACO

has the highest score in the highest weighted criteria shall be recommended by judges from Industry and/or Academia for the particular award. Where this is not possible to separate equally scored papers, a joint award shall be recommended.

Contest Award

An Award consists of a certificate, a trophy, and a monetary prize (SR 10,000 for the first, SR 5,000 for the second, or SR 7,500 each for joint award). The Award is for the winning student or to be shared amongst all members of the team and it will be presented by the OGEP 2010 Technical Committee Chairman.

OGEP 2010 Technical Committee Members

Chairman: Dr. Abdulrahman S. Al-Jarri, Saudi Aramco
Co–Chairman: Dr. Abdulaziz Al-Majed, KFUPM

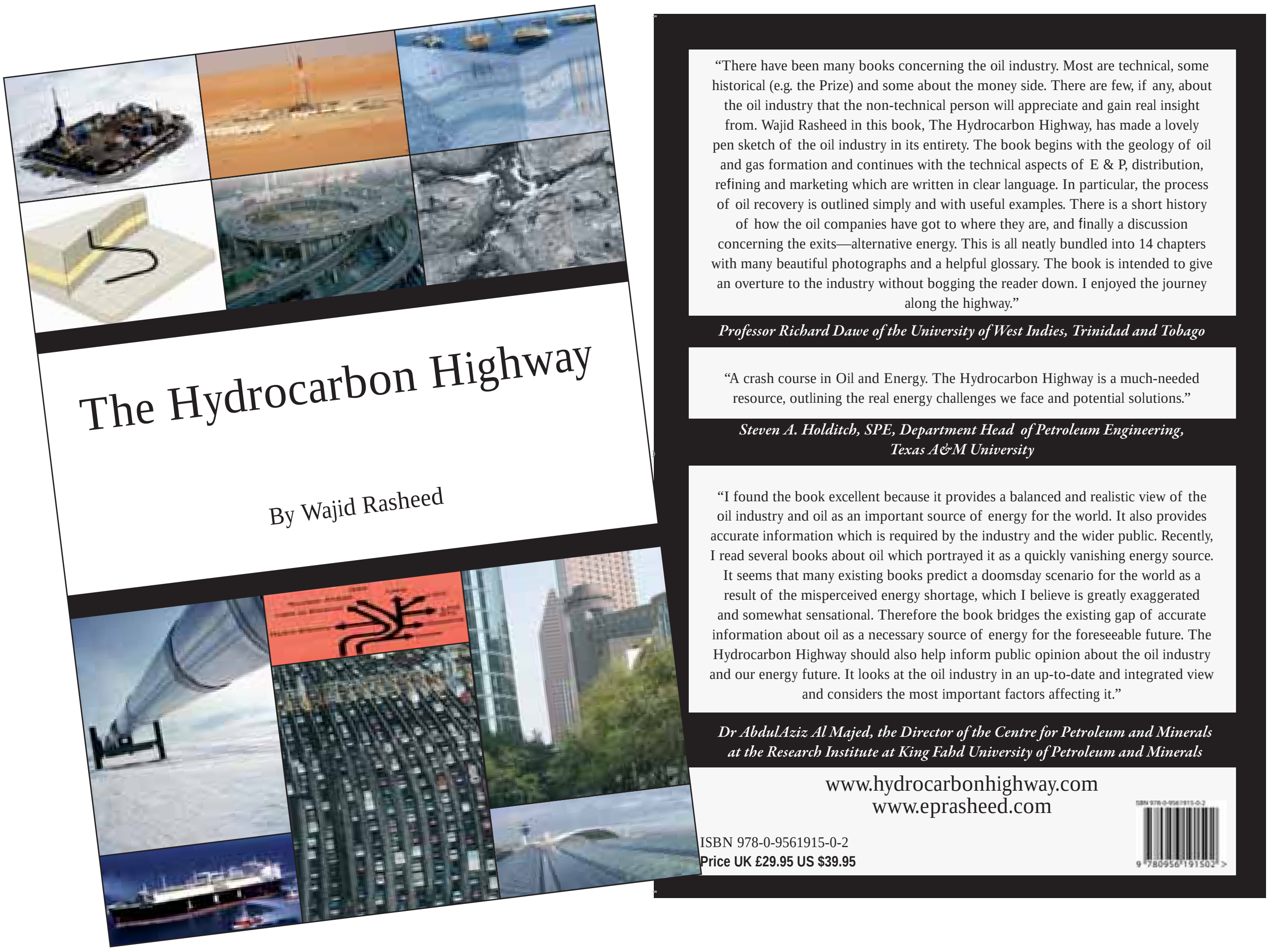
OGEP 2010 Participants

It is expected that several local and international organizations shall participate in the OGEP 2010. One of the major factors contributed to the success of OGEP 2008 was the participation of various organizations.

The following organizations participated in the OGEP 2008 technical program:

- Saudi Aramco
- King Abdulaziz City for Science & Technology
- King Fahd University of Petroleum & Minerals
- King Saud University
- Schlumberger
- Halliburton Services
- Shell
- Chevron
- Total
- South Rub Al-Khali Company LTD (SRAK)
- SAUDI ARABIA OIL AND GAS MAGAZINE
- EniRepSa Gas Ltd.
- Baker Hughes Inc.
- GETECH
- Spectraseis Technologies
- Egyptian Petroleum Research Institute (EPRI
- The University of Texas at Austin
- Azerbaijan National Academy of Science
- GeoTomo LLC
- CGGVeritas
- University of Oklahoma
- ENI E&P Div.
- King Abdulaziz University
- University of Houston
- Colorado School of Mines
- Imperial College
- LUKOIL Saudi Arabia Energy Ltd.
- Petroleum Deveolpment of Oman
- Centrilift
- LUKSAR

Extreme E&P



Worldwide, the exploration objective is clear: locate new frontiers and reserves. Every new frontier, however, brings new problems that are not always easy to predict. In this chapter, we look at the development of oil and gas reserves that are tough-to-produce due to their location in extreme environments.

It is fashionable these days to use different labels to distinguish particular types of drilling: Arctic, deepwater, and High Pressure High Temperature (HPHT) practices. The common denominator of all drilling activities is the management of people, technology and processes. Customs, environmental and legal issues also exist as does the detail of prospect selection. That's fine.

This logistical labyrinth is essentially the same whether you're sitting in a company man's office in offshore Angola or onshore Azerbaijan. Technology applications aren't necessarily exclusive to deepwater either. Smart completions using fibre optics and satellite communications are enabling the production of multiple zones to be co-mingled and controlled. Acidisation through water injection lines permits live well inter-

> Adding to the location issue are government regulations restricting vast areas of land onshore or offshore from drilling activity on environmental or public opinion grounds.

vention without skidding land rigs. New gravel packing and filtering techniques can be used to control sand production in shelf fields. In fact, it seems an equally compelling case can be made for technology to be used in onshore or shelf locations to improve marginal economics as can be made for deepwater operations[1].

So what are the differences behind the drilling labels? Let's look at them.

Location

'Location, location, location'. The mantra of property gurus could equally be applied to oil and gas reserves. After all, location determines the ease or difficulty with which reserves can be accessed and this in turn is a major determinant of finding and lifting costs.

Clearly, access to oil and gas reservoirs is restricted in extreme environments. In Arctic areas, it is restricted due to severe seasonal weather conditions. Alaskan Arctic exploration, which mostly involves onshore projects, is restricted by access to the tundra and the conditions that enable ice roads to be constructed over the permafrost or across the shallow coastal waters to get to the exploration sites. In deepwater, restrictions are created by increased water depth. HPHT conditions restrict access in other locations. Perhaps, the most difficult and costly combination for oil and gas Exploration and Production (E & P), is the well-from-hell—a combination of Arctic, deepwater and HPHT conditions.

In this way, a sliding scale of costs exists—from the deepwater Arctic wildcat (with HPHT contingency) to deepwater to the Arctic to deep shelf HPHT or deep onshore. Adding to the location issue are government regulations restricting vast areas of land onshore or offshore from drilling activity on environmental or public opinion grounds. The State of Oklahoma used to be proud of the fact that it had a pumping oil well on the property also occupied by the State Capitol building. Such a thing would be unthinkable today. Fortunately, Extended Reach Drilling (ERD) technology has alleviated many of these types of problems. The famous THUMS man-made islands offshore from Long Beach, California were constructed by a consortium of oil companies: Texaco, Humble, Union, Mobil and Signal. From the beach, they looked like beautiful semi-tropical islands housing luxury condominiums. In fact, the 'condos' concealed drilling rigs and the outbuildings concealed production facilities. Similar 'Hollywood' tactics were employed in downtown Los Angeles, where drilling rigs in soundproofed building shells were sited along famous Sunset Boulevard, unseen and unknown by the general population. Wells from these sites were directionally-drilled outward for thousands of feet to tap prolific oil reservoirs under the city.

E & P Finding and Lifting Costs

As we saw in *Chapter 4: The Fall of the Oil Curtain*, E & P in tough-to-produce environments costs more. Technically challenging environments create a series of engineering, technical and financial needs that do not exist with easier-to-access counterparts. These needs range from higher-rated equipment, such as upgraded or specialised rigs, as well as dedicated field development techniques. Wildcats or poorly characterised conditions create contingency scenarios. In these cases, a single well plan will have several casing and completion contingencies which must all be budgeted[2]. Contingencies can include HPHT conditions or tight Pore-Pressure/Fracture Gradient (PPFG) windows creating the need for revised casing depths and increased casing strings[3].

Seasonal challenges such as those associated with offshore Arctic conditions will also create technical and financial challenges due to a narrow window for operations before they are interrupted by ice formations[4].

Keeping Costs Down

Undoubtedly, deeper water environments add greater cost and complexity to operations; however, these expenses can be cut in three ways.

Firstly, we could simplify the well design. Well trajectories should not only be compared in terms of how effectively targets are reached, but also on their overall cost effectiveness. Secondly, we could reduce the number of casing strings. Casing can be set deeper, based on real-time PPFG detection. Accurate prediction will reduce contingency casing. Offset data can help to refine pore pressure models and enhanced pore pressure detection will make the best of the casing programme while drilling. Modelling steady and dynamic state fluid behavior will reduce surprises. Last but not least, costs can be cut by contracting 'fit-for-purpose' technology, especially on rigs.

Simplified well design may be possible based on setting casing deeper. Real-time PPFG detection and prediction reduces the number of contingency strings. Eliminating casing strings by taking calculated risks during well construction can reduce mechanical risks and lower costs. Where offset data exists, more accurate pore pressure models can be constructed. Enhanced pore pressure detection will optimise the casing programme during drilling and will reduce costs. Logistics and importation issues should be fully understood as this can reduce the need for pre-deployment of contingency equipment. All of these opportunities, combined with adequate planning processes, time and resources will cut costs[5].

Arctic Seismic

Acquiring and interpreting geophysical data helps reduce some of the risk associated with exploration. In Arctic environments, logistical and technical challenges accompany seismic. Shooting seismic data can only be conducted within a seasonal window of good weather (usually three to six months). Interpreting seismic data is also challenging as seismic must penetrate thick sheets of permafrost (in rare cases up to 3,280 ft [1,000 m]) which creates noise and weathering problems and ultimately interferes with attribute analysis and structural imaging[6].

Deepwater Seismic

Geotechnical and oceanographic data supplies exploratory deepwater asset teams with seabed and water column information which is necessary for well construction and production activities[7]. Getting deepwater seismic is, however, very difficult. In the case of deepwater frontier drilling – wildcats – oil companies must also perform what are at times unprecedented seismic programmes. This has led oil companies to initiate various projects to refine oceanographic data from deepwater basins. Comprising geo-hazard assessment, geo-technical characterisation and slope stability, these projects help identify and characterise potential geo-hazards. The aim of the geo-technical characterisation and slope stability analysis is to investigate seabed sedimentary properties and to model slope stability through surveys and integrated geological data. Reservoir and production engineers use data such as seabed and water column to optimise production[8].

Other projects include exploratory seismic 3D, high resolution sonar and bathymetry. Exploratory 3D seismic is used for rendering seafloor and underlying structures while the seafloor texture is mapped by sonar. Cores are used to 'ground-truth' geophysical interpretation and date geological events[9].

In certain deepwater basins, studies concentrate on mapping salt structures and seeing what lies beneath them. Active salt tectonics play an important role in shaping the seafloor and salt-induced topography and fluid seepage are investigated. Continental slopes may be the focus of geo-hazard assessment, while oceanic current-induced seabed erosion may also be studied[10].

Further oceanographic data will also be acquired using satellite images, Sea Surface Temperature (SST), Sea Surface Height (SSH) and radar data. This information, along with pre-existing data, will validate oceanic models. As a result, extreme currents will be analysed to identify instabilities. In this way, a picture of the deepwater operation is built-up and incorporated into an in-house database that can be queried.

Oceanographers know that the sea can be a complex environment with temperature inversions and subsea loop currents at different levels and in different directions. Deepwater offshore structures, for example, are the victims of Vortex-Induced Vibration (VIV) caused by sea currents interacting with tubular riser pipes. Unchecked, this VIV can totally destroy a production riser in a matter of a few days or hours. Oceanic currents affect the velocity of seismic waves, and if unaccounted for, can produce erroneous results when the seismic section is interpreted[11].

Deepwater Wildcats

Deepwater portfolios are important for the long-term renewal reserves especially for International Oil Companies (IOCs). Basins in offshore areas such as West Africa, the Caspian Sea, Gulf of Mexico (GOM) and Eastern Brazil are very highly sought after production opportunities for this reason.

Irrespective of resources or experience, however, picking and drilling deepwater prospects is tough. Imagine having to pick and drill two wells from within an unexplored area of 9,000 sq mi (25,000 sq km – equivalent to 1,000 GOM blocks)[12].

With the potential *dryhole* risk in mind, IOCs will seek

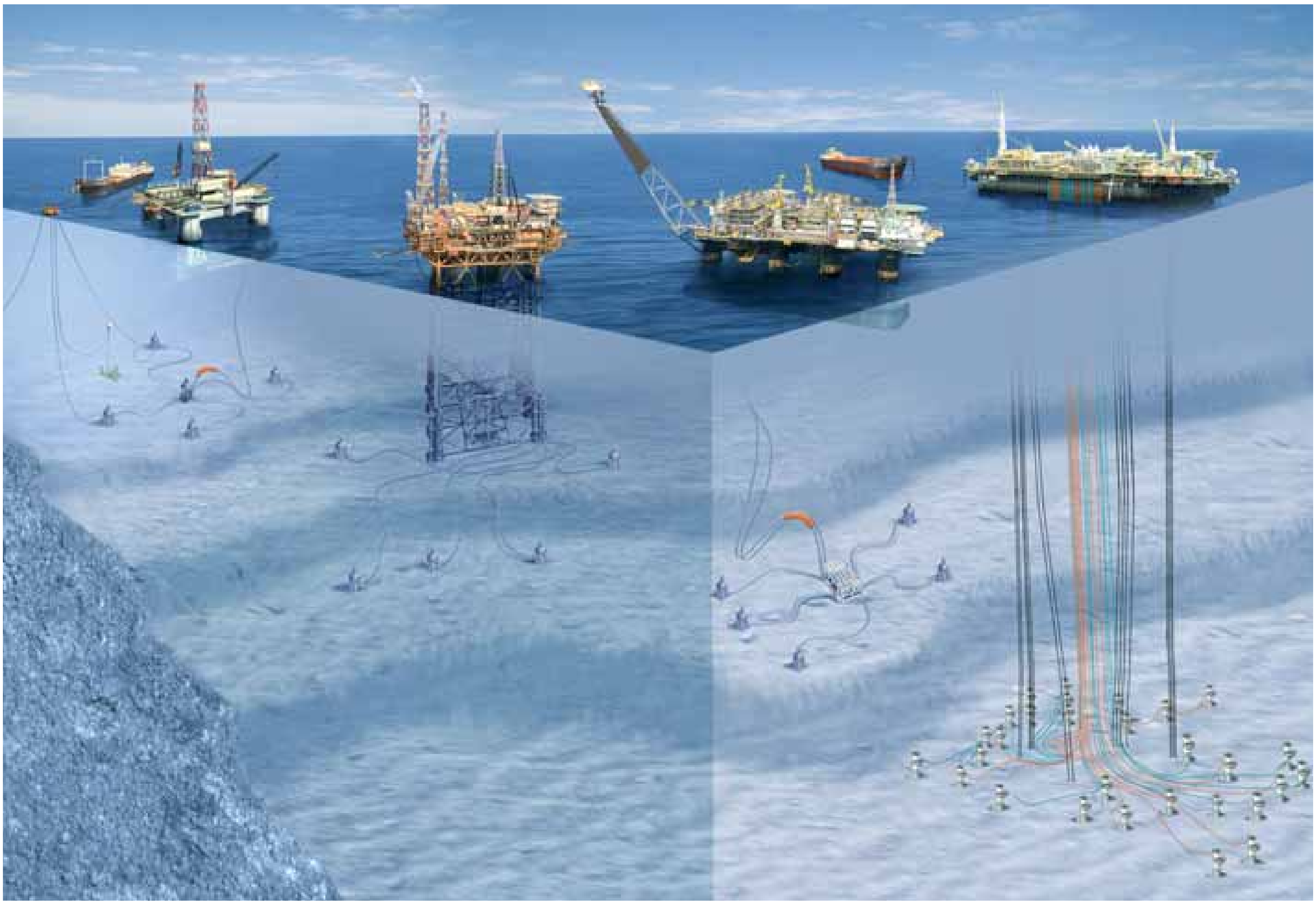


Figure 1 - Fixed and Floating Production Units For Deepwaters (Petrobras)

> In all parts of the world, environmental considerations are important, and if not properly addressed, delays in obtaining a drilling permit can result.

to reduce risk by entering into agreements with other oil companies before exploring. Many of these partners will be companies that have similar concessions and can bring technical know-how to the deal.

Organizational Challenge

In order to deliver wildcat wells in frontier regions, oil companies need to manage different working cultures, languages and physical locations. They will have to work through many issues with local government, customs, environmental, and legislative bodies. They will also have to agree on prospect selection with their oil and gas partners.

Enrolling and focusing the drilling team is often achieved through 'Training to Reduce Unscheduled Events' (TRUE) and 'Drill the Well On Paper' (DWOP) exercises. Major changes, however, can take place during operations; for example, prospects and contractors can be changed. Problems with equipment or facilities can also cause major delays. With a high-end rig on rental, these costs can quickly eat through the largest of budgets. Success in dealing with these late changes depends mostly on the support that the oil companies receive from sister deepwater teams[13].

Planning Exploration

With frontier locations, it is often the case that little or no infrastructure is in place. This means that many challenges associated with the frontiers' remoteness must be assessed and overcome. This can include setting up onshore supply bases, access routes and overcoming the logistical issues associated with the equipment and services required for E & P.

Poor transport links means that look-ahead logistics and transport options will be critical to success. Potential importation delays can also be problematic, but with good planning they can be avoided.

Rig selection will be influenced by the strength of offshore currents, environmental requirements and other challenges such as Arctic conditions. In order to ensure rigs will be capable of meeting operating conditions, potential high current studies or the impact of floating ice are carried out. Research will show whether the rig will be capable of maintaining station and whether or not VIV suppression is a requirement. In all parts of the world, environmental considerations are important, and if not properly addressed, delays in obtaining a drilling permit can result.

Health, Safety and Environment (HSE) and Drilling Performance

From a safety and environmental standpoint, drilling will be completed without significant environmental damage, while a measurement of a safety 'Day Away From Work Case' (DAFWC) will be recorded and will highlight the importance of conducting proper risk assessments. Performance will be measured and key criteria assessed such as days per ten thousand feet and Non-Productive Time (NPT).

Deepwater Development

Poised to produce hydrocarbons in waters reaching 10,000 ft (3,049 m), the industry is certainly not standing still regarding deepwater. The future is clear. Many billions of barrels of oil and gas reserves lie in deep, 3,280 ft to 8,200 ft (1,000 to 2,500 m), and ultra-deepwaters 8,200 ft+ (2,500 m+). As the industry looks to production in 10,000 ft (3,000 +m) water depth, we consider two key questions: what are the unique considerations for deepwater developments and what special technologies are required for production[14].

Water Depth[15]

What really differentiates and impacts deepwater activities are the challenges associated with incredible sea depths. Of course, block size in deepwater frontier areas such as Brazil can reach huge proportions; for example, 25,000 sq km (that's 1,000 GOM blocks). This makes picking and drilling prospects tough, irrespective of operator resources or experience; however, it is greater water depth that leads to higher pressures and overburden and that's where the problems arise. The drilling engineer has to consider and overcome bottomhole pressures that can exceed 22,000 pounds per square inch (psi) (1515 bar) and drilling fluid line temperatures that can fall below 0°C (32 °F).

So where is the deepwater line drawn? According to Petrobras, waters between 3,280 ft to 6,560 ft (1,000 m to 2,000 m) depth are classified as 'deep'. Beyond this are the ultra deepwaters which are about 11,480 ft (3,500 m) for the present. Definitions aside, deeper seas mean deeper pockets[16].

Deepwaters are characterised by strong currents, which create a need for high-specification rigs that are capable of maintaining station and in some instances of suppressing VIV. Such rigs are expensive. Contracting one in the GOM can cost a cool US $500,000 per day or more.

Figure 2 - Subsea Riser (Petrobras)

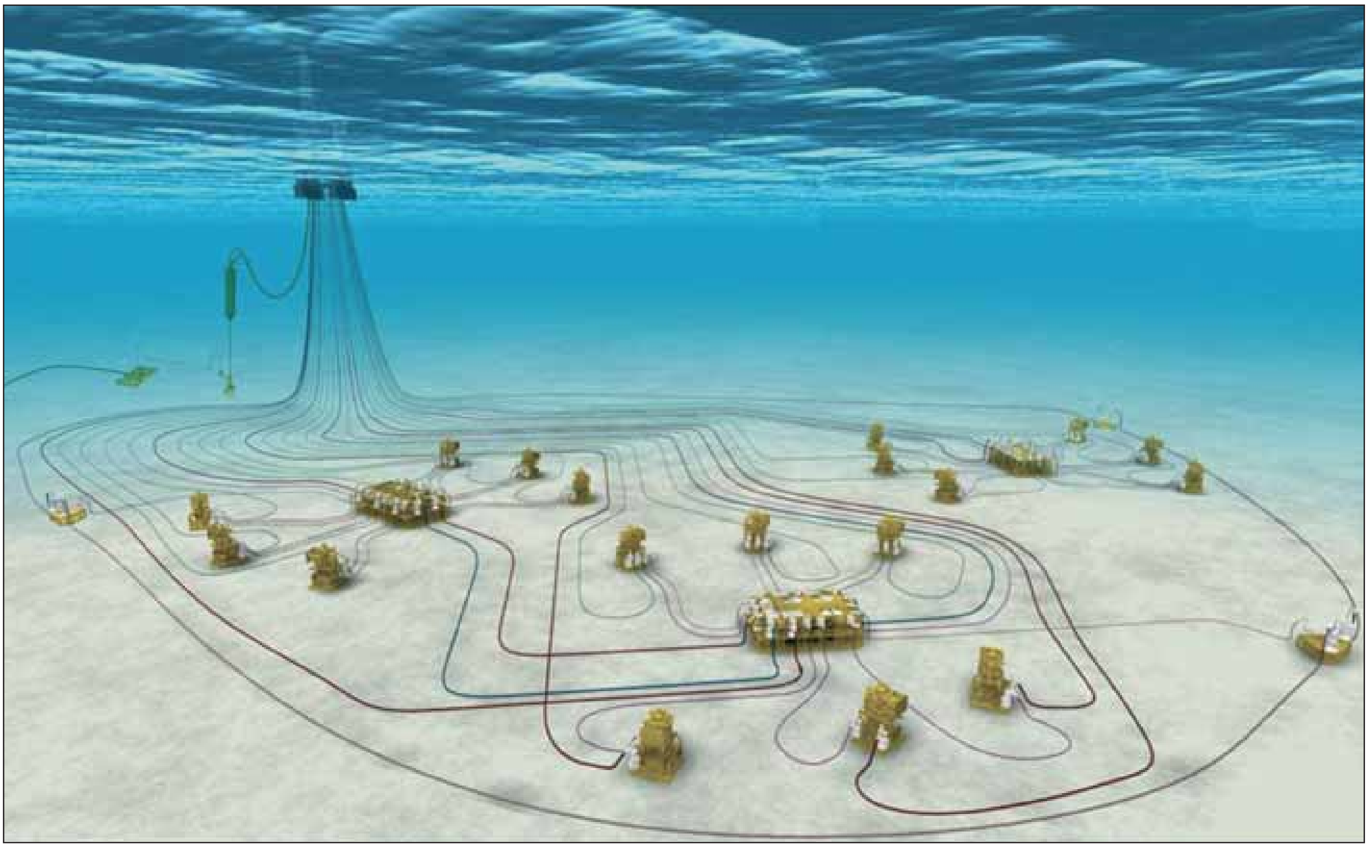


Figure 3 - Subsea Wellhead Production System (Petrobras News Agency)

Under Pressure

Deepwaters are also characterised by young depositional formations that differ from shelf and onshore scenarios. Exemplifying this is the typically narrow window between PPFG. Low fracture gradients can necessitate lighter drilling fluids and lighter cement slurry, while rising pore pressures can often upset the delicate fracture gradient destabilising the well-bore and jeopardising the section, if not the entire well.

A consequence of a narrow PPFG window is the need for close tolerance and contingency casing schemes to isolate formations. In short, deepwater operators must have an excellent knowledge of well bore stability to avoid a formation influx (kick) or a fracture of the casing shoe, which would result in losses. New well construction methods, such as the 'dual gradient system', are being developed for such an eventuality. Oil companies are presently sponsoring a Joint Industry Project (JIP) that develops a subsea pump to control the pressure at the wellhead and study gas injection systems. For this technology to work, risers must be resistant to collapse forces as soon as gas is injected into their bases[17].

Temperature Gradients

Further engineering challenges are added by temperature gradients. A negative gradient runs from surface to seafloor, but this turns positive below the mud line. Equations become more complicated as cooler surface mud alters the temperature profile as it is pumped downhole, while gas hydrate formation is a common problem that is difficult to resolve. Hydrates trap natural gas inside water molecules and bond with metal. This can result in tubing blockages which affect the valve and Blowout Preventer (BOP) operation. Unfortunately, deepwater environments present the ideal combination of low temperatures, high seabed pressures, gas and water that cause hydrate formation. Extensive modelling is required to minimise hydrate formation. Low temperatures alter the properties of cement which mean new designs of cement slurry com-

Figure 4 - Arctic Rig The Northstar Island (BP)

position are required. Existing American Petroleum Institute (API) norms do not cover low deepwater temperatures and stringent test procedures are now determining the properties of cement slurries in deepwater operating conditions[18].

Riser Manipulation

Riser manipulation is another challenge found in ultra deepwaters and beyond. Research is being carried out on innovative lightweight risers. By reducing the weight of the risers and their joints, it should be possible to use lower cost fit-for-purpose rigs in ultra deepwater. A parallel technology that has been developed is the 'slender well' concept to permit the use of smaller diameter well bores and lighter risers.

The constant development of new subsea equipment is a must in order to meet new water depth challenges while keeping costs low.

Major limitations associated with ultra deepwater developments which are associated with very expensive day rates include high installation loads of subsea equipment and high flow rate subsea wells. 'Drill-pipe risers' have been used to perform completions and workovers at water depths reaching 6,860 ft (2,000 m) and, although they are far more efficient than conventional risers, control umbilicals and hang-off equipment presented problems in 10,000 ft (3,000 m) water depths.

Control umbilicals require careful handling, particularly during the tubing hanger mode when the hanger has to be deployed inside the marine riser.

Mooring mechanisms that will function in greater water depths are also a challenge. Design software must be able to check a specific mooring system's calculations and determine the validity of truncated scale tests as well as modelling mooring systems.

Extended Reach Development (ERD) wells are being

> Because less heat is lost through the pipeline, average flow temperatures are kept higher which reduces hydrate and wax formation and ultimately maintains production rates.

successfully drilled in deeper waters. ERD wells offer the ability to reach complex targets and present good thermal flow pipeline properties which are important in deepwater scenarios due to negative temperature gradients. Widely spaced reservoir targets can be tapped using a single well bore, thereby reducing environmental impact and well construction costs. Because less heat is lost through the pipeline, average flow temperatures are kept higher which reduces hydrate and wax formation and ultimately maintains production rates. Alternatively, costly heated subsea pipelines are required.

Intelligent completions are improving hydrocarbon production from both ERD and multilateral wells. With the emphasis on reservoir management to optimise performance and maximise recovery, the likelihood for costly well intervention is reduced. Coupled with this is the deepwater gas lift optimisation project, which addresses the software, equipment and automated processes required for gas lift design.

Deepwater subsea completions often present major problems, especially with the completion riser. As a result, a lightweight composite drilling riser joint is being used with conventional risers up to 2,300 ft (700 m) water depth. More research is necessary, but results have been promising. Production risers, subsea wellheads and other production equipment designed specifically for deeper water depths and differing rig types are just some of the technologies being developed[19] (see Figures 2 and 3).

Deepwater Flow Assurance

Companies are developing inter-related technologies capable of predicting and preventing subsea flow lines and pipelines from getting blocked. The technologies here range from low-density foam cleaners to mechanical pigs to tractors for wax or hydrate plug removal.

Arctic E & P

Arctic E & P is a term that is generally applied to fields that are located within the Polar or Arctic Circle which extends from Russia, Finland, Sweden, Denmark, Norway, Canada and Alaska (US). In Alaska, where the exploration is predominantly on land, getting access to the tundra locations is actually dependent on ice and snow cover so as to avoid damage to the permafrost. This territory also covers offshore areas such as the Sea of Okhotsk, Sakhalin Island, the Beaufort Sea and the Barents Sea.

Antarctica is the third-smallest continent after Europe and Australia; 98% of it is covered in ice and is bound

> Some of the heavy oil fields are located in shallow waters, which simplifies appraisal and development strategies, while others are in deepwater, which adds complexity.

not to be developed until 2048 and therefore is not considered. The call for an environmental protocol to the Antarctic Treaty came after scientists discovered large deposits of natural resources such as coal, natural gas and offshore oil reserves in the early 1980s.

As one would expect, offshore Arctic E & P is heavily constrained by harsh weather conditions. The offshore Arctic is characterised by the ice period during which time no operations can take place. Exemplifying this is the Sea of Okhotsk which is routinely subjected to dangerous storm winds, severe waves, floating ice, icing of vessels, intense snowfalls and poor visibility. The average annual extreme low ranges between -32°C (-25.6 ºF) and -35°C (-31ºF). Ice sheets up to 5 ft (1.5 m) thick move at speeds of one to two knots. Operations in the Barents Sea need to contend with drifting sea ice, icebergs and long transportation distances[20].

Offshore structures can be exposed to icing from October through to December and the ice period extends for six months. It is only during the following six months, or the ice-free period, that operations can take place. Even so, wave heights range between 3 ft and 10 ft (1 m and 3 m) and strong winds can cause even higher waves during the ice free period.

To combat such extreme conditions, operators must use beefed-up rigs and facilities. In the case of the Sakhalin development, engineers reconditioned the Molikpaq, an Arctic offshore drilling unit originally designed for use in the Beaufort Sea in North America, where ice conditions are more severe than offshore Sakhalin Island. The Piltun Astokhskoye field is developed by the Vityaz Production Complex. This consists of the newly refitted Molikpaq, a Single Anchor Leg Mooring (SALM) 1.25 mile (2 km) away and a Floating Storage and Offloading (FSO) vessel[21].

Technical and environmental experts reconditioned the Molikpaq so that it could handle pack ice, temperatures, and strong waves in the Sea of Okhotsk. The Molikpaq required substantial modification to convert it from a drilling platform to a drilling and processing platform and it was towed 3,600 nautical miles (6,670 km) from the Beaufort Sea to the Okpo yard in South Korea. The redesign included major rig modifications including raising the height of the drilling unit by 16.4 ft (5 m) to create space for the wellheads and increasing the eight conductor slots to thirty-two. Cumulatively over seven work seasons since the first oil in 1999, the Molikpaq has produced over 70 million barrels (MMbbl) of oil.

> Pre-planning for HTHP wells can greatly benefit the operator in terms of drilling performance, but also in conventional as well as non-conventional well control operations.

HTHP

HTHP wells are generally considered to be those which encounter bottomhole temperatures in excess of 300°F (150°C) and pressures which require a mud weight of 16.0 ppg (1.92 SG) or more to maintain well control. Another way to consider pressure is to note that standard downhole tools and equipment are rated at 20,000 psi (1,361 bar) anything above this is considered high pressure.

Many offshore regulatory authorities require some sort of emergency plan be in place prior to issuing the drilling permit. In addition to the company's standard emergency plan, many operators have a Blowout Contingency Plan (BCP) that specifically covers well control events such as:

- Immediate response activities
- Emergency organisation
- Well capping and killing procedures
- Specialised well control equipment
- Hazardous fluids such as H_2S and CO_2
- Logistics, and
- Relief wells.

Pre-planning for HTHP wells can greatly benefit the operator in terms of drilling performance, but also in conventional as well as non-conventional well control operations. The pre-planning should include detailed well design engineering and HTHP awareness training.

Connections that lose their integrity impact numerous HPHT development and production operations worldwide and are responsible for huge costs as they can lead to stuck-fish, lost-in-hole and even sidetracks[22].

Salt Challenge

Prevalent worldwide, massive salt sections add to well construction challenges.

Several deepwater blocks in the GOM, West Africa (Congo Basin) and Eastern Brazil (Santos Basin) are characterised by salt provinces; for example, sub-salt wells have been drilled with total depths exceeding 30,000 ft (9,146 m) and salt sections exceeding 8,000 ft (2,439 m) in thickness.

Production companies who hold sub-salt acreage face a combination of imaging and deepwater drilling problems. Other operators in deepwater areas, such as West Africa and Brazil which have had relatively limited salt challenges to date, also need sub-salt strategies as exploration reaches salt provinces. In some cases, spanning over half a well-bore's true vertical depth, salt can present sizeable difficulties.

Where salt is just 'salt', things are relatively simple; but,

> As pressure drops due to friction are proportional to fluid viscosity, the only phase that is sheared at the wall is water; therefore, the obtained pressure drop is almost the same as if only water flow was involved.

where salt sections are heterogenous containing halite, anhydrite, sedimentary channels, flows or rubble zones, things become complex. This makes the mapping and imaging of salt a difficult process with subsurface phenomena often going unseen. Seismic data cannot always represent salt flows or channels with many anomalies only truly characterised through drilling.

Anomalies, represented or not, create drilling problems that range from loss scenarios with pore pressure regressions below salt, loss of directional control, stuck-pipe due to salt closure and destructive vibration induced by alternating salt/sediment bedding[23].

Hole stability can be affected by active salt tectonics. Intermediate sections can be subjected to geo-hazards such as faulting and fluid seepage. Salt closure increases the loads on the casing and its cement as both must be able to withstand the forces applied by the salt as it expands radially and pinches the well. Simultaneously drilling and casing the well may be a good way of overcoming this. Maintaining directional control in salt is not straightforward as there is a tendency for well-bore deviation.

Certain salts require higher weight-on-bit to drill compared with sediments.

Consequently, the higher weight-on-bit, the greater the tendency for the bottomhole BHA to build inclination.

Costly deep-water rig rates mean that operators are right to require high performance levels. Consequently, more rigorous Quality Assurance/Quality Control (QA/QC) standards are demanded of downhole tools to permit sections to be drilled in single runs at high penetration rates. Salt sections have higher fracture gradients (when compared with sediments located at the same depth) enabling longer sections and reduced well-control problems associated with permeable formations. Predicting PPFG in sediments below the salt, however, is tricky. Pressure regressions below the salt often dictate casing depth.

It is known that Synthetic Oil-Based Mud (SOBM) can be the most effective salt drilling fluids as they avoid borehole enlargement and well-bore instability.

Although many risks associated with salt can be reduced through pre-drill seismic, look-a head tools and real-time pore pressure profiling, there are still plenty of ‘unknowns’ to keep everyone excited.

Heavy Oil

Although large volumes of heavy and high viscosity oil have been discovered worldwide, both onshore and offshore, economic production is a challenge for the oil

> Some of the heavy oil fields are located in shallow waters, which simplifies appraisal and development strategies, while others are in deepwater, which adds complexity.

industry. Increased oil viscosity means increased E & P costs as well as higher refining costs. The definition and categorisation of heavy oils and natural bitumens are generally based on physical or chemical attributes or on methods of extraction. Ultimately, the hydrocarbon's chemical composition will govern both its physical state and the extraction technique applicable.

These oils and bitumens closely resemble the residue from crude distillation to about 538ºC (1,000°F). If the residue constitutes at least 15% of the crude, it is considered to be heavy. This material is usually found to contain most of the trace elements such as sulphur, oxygen, nitrogen and metals such as nickel and vanadium.

A viscosity-based definition separates heavy oil from natural bitumen. Heavy oil has a rating of 10,000 cp (Centipoise) or less and bitumen is more viscous than 10,000 cp. Heavy crude falls in the 10°-20° API range inclusive and extra-heavy oil less than 10° API.

Most natural bitumen is natural asphalt (tar sands or oil sands) and has been defined as rock containing highly viscous hydrocarbons (more than 10,000 cp) or else hydrocarbons that may be extracted from mined or quarried rock.

Other natural bitumens are solids, such as gilsonite. The upper limit for heavy oil may also be set at 18°API, the approximate limit for recovery by waterflood.

The industry reference for offshore heavy oil production is the Captain Field which is operated by ChevronTexaco and located in shallow waters in the North Sea.

Brazil, Canada, China and Venezuela are just some of the countries that hold significant heavy oil volumes within the 13° API to 17°API range. Some of the heavy oil fields are located in shallow waters, which simplifies appraisal and development strategies, while others are in deepwater, which adds complexity.

New production technologies are required for the economic development of offshore heavy oil reservoirs. Long horizontal or multilateral wells, using high power pumps such as Electrical Submersible Pumps (ESPs), hydraulic pumps or submarine multiphase pumps, could partially compensate for a decrease in productivity caused by the high oil viscosity.

Additionally, flow assurance could be improved with insulated or heated flow-lines, or alternatively, with the use of water as a continuous phase system. Heavy oil processing in a Floating Production Unit is not straightforward and new separation technologies, as well as the feasibility of the heavy oil transportation with emulsified water, needs to be investigated. The existence of light oil reserves in neighbouring reservoirs, even in small volumes, will play an important role in this determination.

Reservoir Technologies for Offshore Heavy Oils

Heavy oils are difficult to produce. From a reservoir standpoint, increased viscosities impair the flow of oil while in an offshore environment traditional enhanced recovery methods are often limited. Most of the heavy oil reservoirs in offshore Brazil, for example, are found in non-consolidated deepwater reservoirs. Potentially heavy oil cold production, caused by natural depletion or water-flooding, seems to be a practical option.

It is known however, that the displacement of oil by water is much less efficient than by using 'regular' viscosity oil. Petrobras' research on reservoir technologies for heavy oil production concentrates on the following topics:

• Flow through porous media, which can be used to improve methods for understanding the relative permeability of water and heavy oil in non-consolidated, heavy oil bearing formations
• Modelling of oil varietals in offshore heavy oil reservoirs
• Optimised heavy oil field development
• Modelling to minimise remedial workovers, and
• Fundamental reservoir simulation studies in order to optimise the design of offshore production systems for heavy oils.

Flow Assurance for Heavy Oil

In terms of physical properties, heavy oil differs considerably from lighter crudes, generating a need for new production techniques. Higher viscosities, gravity and pour point combine to make fluid flow through pipelines more difficult than for lighter oils. Higher viscosity also means higher pressure drops and the need for more powerful pumps and pipelines with higher pressure ratings. Increased oil gravity also increases the pressure gradient in upwardly flowing pipelines such as the wellbore and riser.

These issues become more important in deepwater fields as low pour points can create flow assurance concerns in the case of 'cold start-up' of pipelines or wells.

Core annular flow is being developed to flow through pipes. The idea is to use water to reduce pressure drops. Water is added in an annular flow pattern so that oil is kept at the centre of the pipeline while the water maintains contact with pipe walls. As pressure drops due to friction are proportional to fluid viscosity, the only phase that is sheared at the wall is water; therefore, the obtained pressure drop is almost the same as if only water flow was involved. This reduction in pressure drop for heavy oil can reach a magnitude of a thousand. This technology has been used already for onshore oil export pipelines and is now under development by Petrobras to be used in offshore production systems including well bores, pipelines and risers in the presence of gas.

Emulsion behaviour is an equally important issue for heavy oil production. Emulsion is a fine dispersion of two liquid phases and is generated when the fluids mixed together shear. There are also other techniques that can be used to reduce fluid viscosity and pressure drops; for example, heavier crudes can be diluted with lighter ones. Another example is the generation of an inverse emulsion (oil in water) using chemicals. Flow assurance is another concern for heavy oil production. Wax deposition and crystallisation may occur and create pour-point problems to an already viscous fluid. Also, hydrates can form in heavy oil systems creating an even more viscous slurry which may clog pipelines.

The existence and characterisation of tarmac beds, sometimes present at the bottom of the heavy oil zone close to the oil water contact, is extremely important. Limited connectivity of the bottom aquifer with the oil zone would avoid rapid increases in water coning. This would make for more efficient water injection and could radically change a development scheme.

Many issues still merit research and oil companies are pursuing both laboratory and field based technology[24].

Now that we have outlined the extreme E & P challenges faced by the industry and the difficulties faced when trying to add new reserves, we need to re-examine our thinking about the existing or mature fields that are currently in use. How do we ensure the highest recovery of oil possible? How can we improve production? The next chapter answers these questions by examining the various ways in which we can make the most of our existing assets.

References

1. Harts E & P Dec 2002 Drilling Column 'Deepwater faces its own challenges'.

2. 'Drilling', American Association of Drilling Engineers, Official publication. Sep 02 'Power steering'. Discusses the Rotary Steerable market.

3. Harts E & P Mar 2004 Drilling Column 'Deepwater drilling challenges'. Underreaming.

4. These types of contingencies can rapidly increase the costs of deepwater wells. See also RP 54. Occupational Safety for Oil and Gas Well Drilling and Servicing Operations. Includes procedures for promotion and maintenance of safe working conditions for employees engaged in rotary drilling operations and well servicing operations, including special services. Applies to rotary drilling rigs, well servicing rigs, and special services as they relate to operations.

5. Notes from Arctic drilling expert John Lewis ASRC.

6. Harts E & P May 2003 Drilling Column "Razor sharp drilling'. Simplify wells.

7. Notes from Arctic drilling expert John Lewis ASRC.

8. Petrobras Technology Bulletin 2006.

9. Petrobras Technology Bulletin 2006.

10. Petrobras E & P Technology Harts E & P.

11. Enhanced Oil Recovery, Textbook Vol. 6. by Don W. Green and G. Paul Willhite ISBN: 978-1-55563-077-5, Society of Petroleum Engineers 1998.

12. Petrobras Technology Bulletin 2006.

13. Personal experience of BP's drilling of Rebeca and Reki exploratory wells offshore North West Brazil.

14. As well as service company input.

15. See Petrobras E & P Technology Harts E & P PROCAP section.

16. Along with water depth the distance from shore or facilities will dictate costs.

17. Harts E & P Dec 2002 Drilling Column 'Deepwater faces its own challenges'.

18. See Petrobras Technology Bulletin June 2006.

19. API TR1 Cement Sheath Evaluation Provides the current principles and practices regarding the evaluation and repair of primary cementations of casing strings in oil and gas wells. Cement bond logs, compensated logging tools, ultrasonic cement logging tools, and borehole fluid-compensated logging tools are covered.

20. See Petrobras PROCAP 3000.

21. StatoilHydro Barents Sea E & P.

22. In 2007 Sakhalin Energy produced above 12.4 million barrels of oil from the Molikpaq platform. This exceeded the 2006 production by some 800,000 barrels.

23. API Bull 5C2 Performance Properties of Casing, Tubing, and Drill Pipe Covers collapsing pressures, internal yield pressures, and joint strengths of API casing, tubing, and drill pipe.

24. Harts E & P Mar 2004 Drilling Column Wajid Rasheed 'Salt Challenges'.

25. See Petrobras E & P Technology Harts E & P PROPES section.

26. Idem.

Saudi Arabia oil & gas

www.saudiarabiaoilandgas.com

Contribute to Saudi Arabia Oil & Gas during 2010

EPRasheed is looking for editorial submissions on the topics outlined in the editorial calendar. This can provide your company with the opportunity to communicate EP technology to the wider oil and gas community. Please send abstracts or ideas for editorial to wajid.rasheed@eprasheed.com

Preference is given to articles that are Oil Company co-authored, peer reviewed or those based on Academic research.

Editorial 2010 Calendar

Jan/Feb	Mar/Apr	May/Jun	Jul/Aug	Sep/Oct	Nov/Dec
• Saudi Aramco RTOC • Digitalization • While Drilling Technology • Telemetry • Production • Extended Seismic Feature (4D, OBC, Wide Azimuth)	• Khurais • Near Surface Modelling • Rotary Steerable & Motor Systems • Drill Bits and Underreamers • Complex Wells • Geophysical • Drill-Pipe Integrity	• Manifa • Remote Operation Centres • Drill-Bit Technology • Advances in Drill-Pipe • Zonal Isolation (incl. Packers, Multi-Zone Completions) • Carbonate Reservoir Heterogenity • Exploration Rub Al Khali	• Shaybah • Drilling Optimization • Formation Evaluation • Wellbore Intervention • Casing While Drilling • Multi-Laterals • Tubulars	• Khursaniyah • Passive Seismic • Expandable Completions • Tubulars • Logging and Measurement WD • Environmental Stewardship • Refining	• Hawiyah • Smart Completions • I field • Geosteering • GOSP • OGEP
BONUS CIRCULATION					
	9th Middle East Geoscience Conference & Exhibition 7-10 March 2010 Manama Kingdom of Bahrain **SPE/DGS Annual Technical Symposium & Exhibition** 4-7 April 2010 Seef Centre Khobar, Saudi Arabia	**7th Middle East Refining and Petrochemicals Conference & Exhibition** 23-26 May 2010 Kingdom of Bahrain **72nd EAGE Conference & Exhibition/SPE EUROPEC 2010** 14-17 Jun 2010 Barcelona Spain		**SPE Annual Technical Conference and Exhibition** 20-22 Sept 2010 Florence Italy	**SPE Middle East Health, Safety, Security and Environment Conference & Exhibition** 4-6 October 2010 Manama Kingdom of Bahrain **OGEP II Saudi Meeting on Oil and Natural Gas Exploration and Production Technologies** December 2010
SPECIAL PUBLICATIONS					
	• Official Magazine	• Official Magazine		Saudi Aramco Supplement	• Official Magazine

Frac-Point Openhole Fracture Completion System

The one-trip, multistage system for tight gas success

Get to TD quickly and reliably. Accurately fracture multiple intervals in a single trip. Eliminate the need for cementing and perforating operations. Turn marginal unconventional-reservoir prospects into moneymakers.

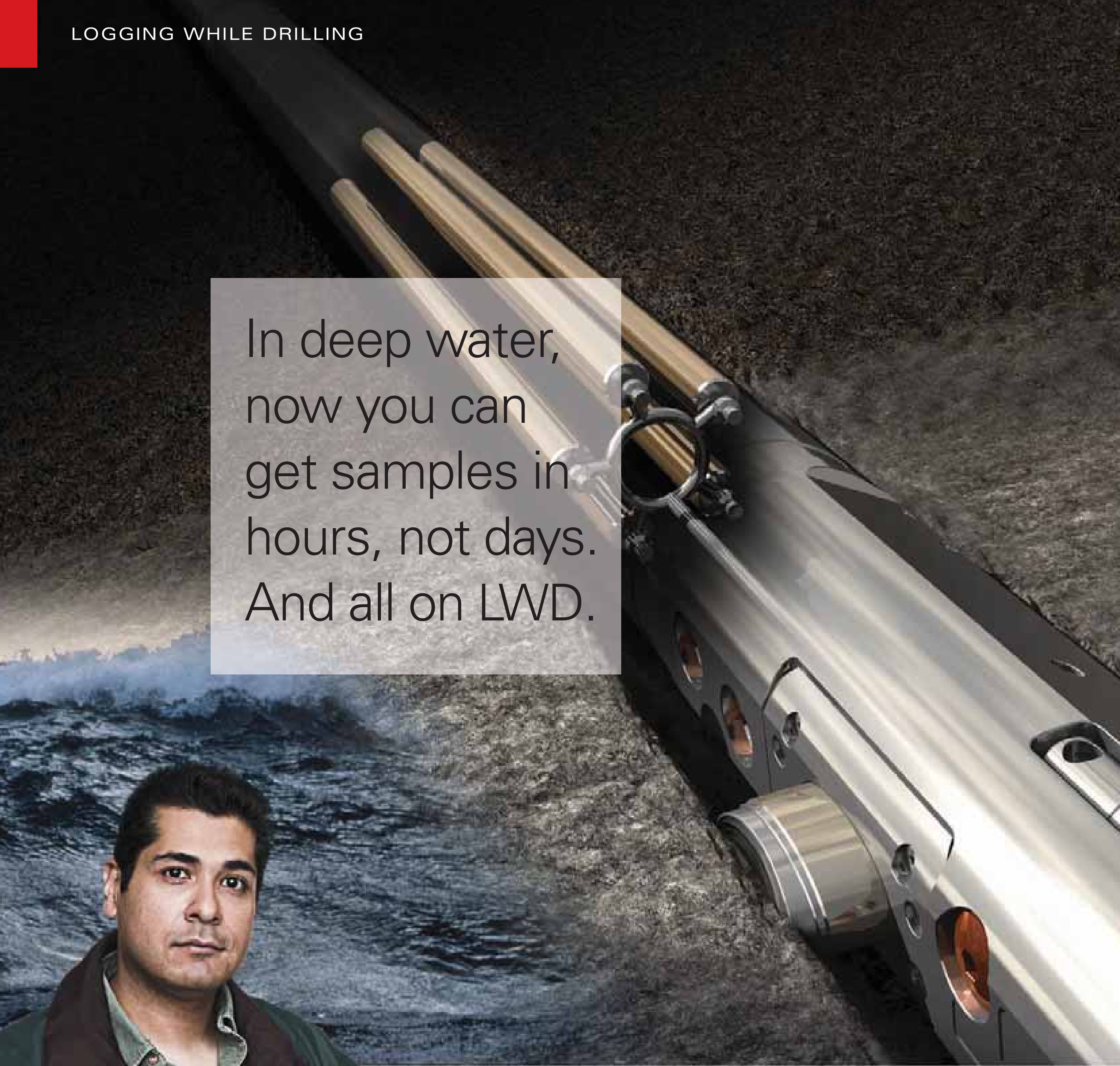
Choose the Frac-Point™ system if you want a versatile, integrated system that can be optimized for your specific needs, with proven high-performance technology from the world's largest completion toolbox.

And when you choose the Frac-Point system, you get the knowledge and global resources of Baker Hughes, a leader in completion technology.

Meet the challenge of unconventional reservoirs with the Frac-Point system.

www.bakerhughes.com/fracpoint

BAKER HUGHES



Until now, retrieving formation fluid samples during drilling couldn't be done. Perfect for deep water, the GeoTap® IDS sensor not only provides truly representative fluid identification and sampling on LWD, it can save you millions in hidden NPT costs routinely incurred with wireline sampling.

What's *your* deepwater sampling challenge? For solutions go to Halliburton.com/geotap.

Solving challenges.™

HALLIBURTON | Sperry Drilling