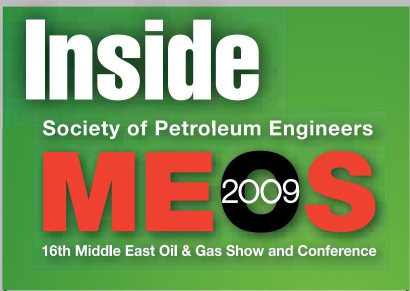
Brazil Oil & Gas, tt_nrg and Norway Oil & Gas

EPRASHEED
signature series

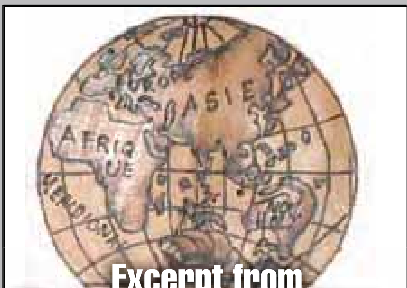
2009 – Issue 9

Saudi Arabia oil & gas

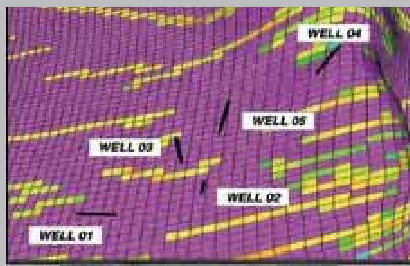
www.saudiarabiaoilandgas.com



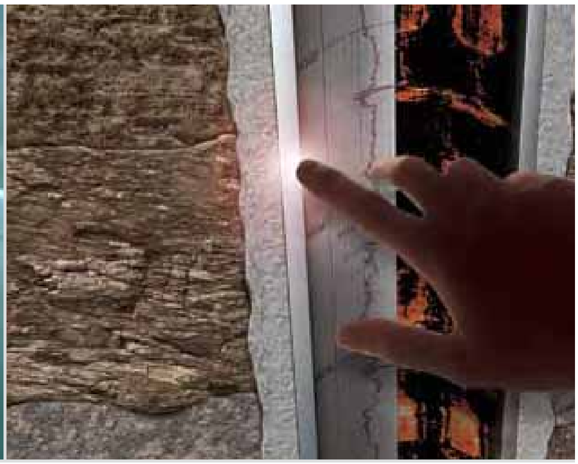
Technical Programme



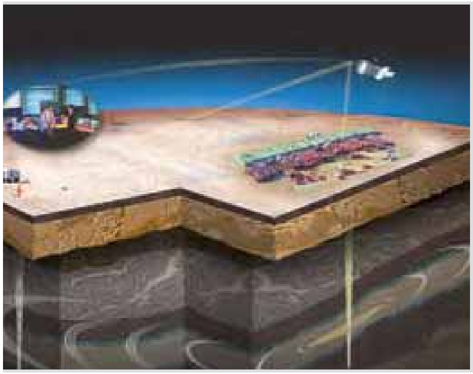
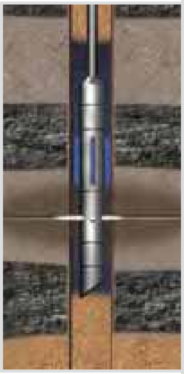
Excerpt from
The Hydrocarbon Highway



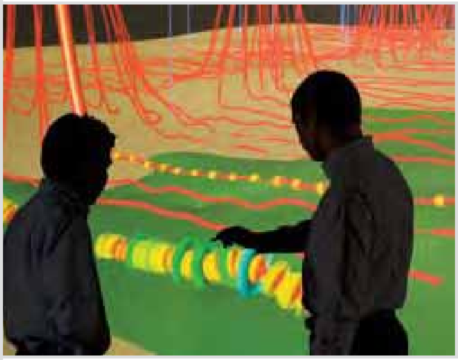
Reservoir
Characterisation

Engineered solutions for

tight-gas reservoirs in the Middle East.




Tight-Gas Challenges:

Deep wells

Reservoir characterization

HPHT, H_2S and Co_2

Low permeabilities and porosities

More precise wellbore and fracture placements

Economic production

Maximum ultimate recovery

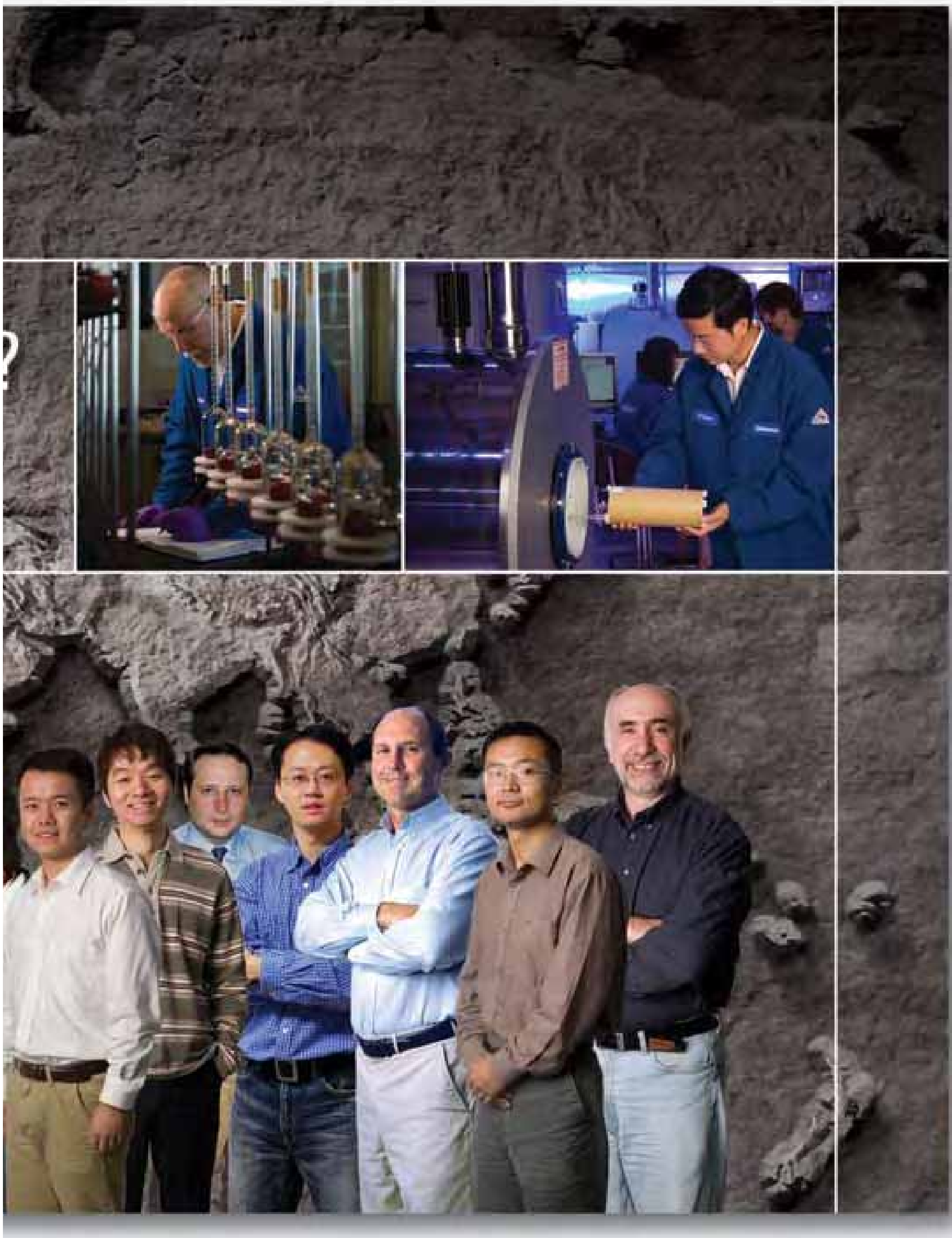
Middle East operators face significant challenges to economic tight-gas production. From reservoir to wellhead, Halliburton — the leader in tight-gas experience and technology — has the answers. Focused on maximizing the productivity of resource plays, our engineers model, design and execute drilling and completions strategies. We also help deliver superior results via an extensive line of proven services, tools and technologies.

Learn more about our unconventional-gas answers at www.halliburton.com. Or please contact us at tightgasmiddleeast@halliburton.com.

HALLIBURTON


Need rock-solid formation evaluation service?
Meet the advisors

Carbonate Advisor



Schlumberger

2008 – Issue 9

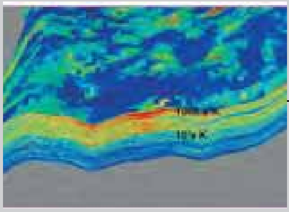
Saudi Arabia oil & gas

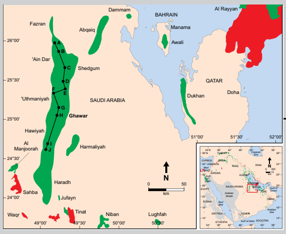
EPRASHEED

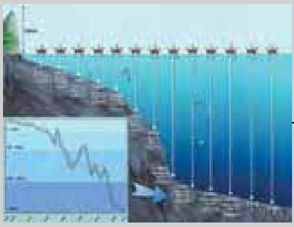
signature series

www.saudiarabiaoilandgas.com

Contents







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

Editors
JC Cunha (Technology)
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

NOTE FROM THE CEO

Welcome to Issue 9 of Saudi Arabia Oil and Gas.

Firstly, I would like to draw everyone's attention to the upcoming Society of Petroleum Engineers (SPE) Saudi Arabia Section's 2009 SPE Annual Symposium, which is entitled: "Pushing the Technology Envelope for Higher Recovery".

Saudi Arabia Oil and Gas is pleased to be the official magazine for the second year running for Saudi Arabia Section's 2009 SPE Technical Symposium and Exhibition which will be held from the 9th to the 11th May 2009 at the Le Méridien Hotel, AlKhobar, Saudi Arabia.

Dr Ashraf Tahini is Chairman of the 2009 Symposium and the confirmed keynote speakers are: Mr. Chad Deaton, Baker Hughes Chairman, President & CEO, Mr. Amin Nasser, Saudi Aramco Senior Vice President Exploration and Production, and Mr. Leo Roodhart, SPE President.

The technical program covers the following topics:

- Drilling and Completions
- Production Enhancement and Operations
- Petrophysics and Formation Evaluation
- Reservoir Management and Simulation
- Reservoir Geology and Geophysics
- Special Topics and Emerging Technologies

This issue's cover story – Schlumberger's Dhahran Oilfield Services Base – is a good example of long-term vision that goes beyond the fluctuations of the oil price cycle.

Our usual mix of 'From the Aramco Newsroom' looks at EXPEC award winners, an 'ideas factory' designed to think of new applications for oil as well as an advanced corrosion inhibitor technology.

A short technical article outlines a SPE forum on 'Overcoming Barriers to deliver ERD wells beyond 15km'. The forum will primarily explore enabling oil field technologies that will promote the cost effective delivery of future wells beyond 15km. This forum is chaired by Dr Colin Mason of BP Sunbury, a long-time colleague, and promises to be an exciting event.

Nuclear Magnetic Resonance (NMR) logging technology is enabling petrophysicists to remove some of the traditional ambiguities regarding fluid distribution. Nuclear magnetic resonance logging holds potential for solving the tough problem of determining water saturation in zones invaded with oil-based filtrate and identifying the all-important oil water contact by providing a radial profile of fluid distribution. Written by Ridvan Akkurt et al the article is entitled 'Solving Complex Interpretations'.

Emad ElRafie et al's insightful article on Integrated Field Development illustrates how best to optimise reservoir performance. The paper is written from the integrated asset team perspective and considers reservoir modelling, drilling and completions. It shows how accurate fluid flow models in naturally fractured carbonate reservoirs are critical to predicting reservoir sweep efficiency. The use of appropriate complex Horizontal and Multi-lateral wells and completion technology such as equalisers (ICD) or Inflow Control Valves (ICV) is also considered.

Decoding The Properties of the Upper Jurassic Arab D Limestone, Ghawar Field, Saudi Arabia, takes a penetrating look at the old problem of natural carbonate porosity and offers a revised way of thinking. This article is written by Edward A. Clerke et al.

Peak Oil; A Psychological or Physical Shortage? – is an excerpt from my book, the Hydrocarbon Highway, which is to be launched at the MEOS conference. This neatly takes us to the MEOS technical programme, which can be found at the end of this issue.

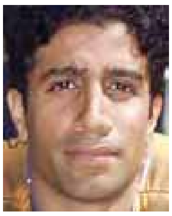
We look forward to your continuing editorial contributions across all disciplines.

Ultimately, this is what Saudi Arabia Oil & Gas reader's want.

So hit your keyboard and email: wajid.rasheed@eprasheed.com

Enjoy the magazine.

"EPRasheed's aim is to consider global EP Markets in a strategic manner and foster balanced coverage and commentary on the International Oilfield and key EP technologies. Saudi Arabia Oil & Gas intends to help bring together local Saudi experts and international people to remove barriers and promote interaction."



Wajid Rasheed

Founder EPRasheed and Saudi Arabia Oil & Gas

EXPEC ARC celebrates excellence

The EXPEC Advanced Research Center (ARC) hosted its International Advisory Council (IAC) for three days of meetings and the annual EXPEC ARC awards ceremony in January.

President and CEO Khalid A. Al-Falih congratulated the organization on a year of unprecedented achievement. "It's fair to say that the company has a decades-old reputation as the world's largest and most significant operator in oil and gas. But one thing that we have not been recognized for previously is our culture of innovation and our ability to create knowledge," he said.

Through achievements such as those honored for 2008, that perception is changing. "Throughout the year, when you opened any journal of the petroleum industry, you came across praise for Saudi Aramco, not only as a reliable, sizable, significant, important oil company, but increasingly as the most innovative and the most technology-driven company on the planet," Al-Falih said.

Farouq El-Baz, a member of the IAC, spoke about the importance of development and continuing the legacy of innovation. "An emphasis on developing the young is very important. I see that emphasis here, and I applaud you for that," he said. "We expect good work — hard work. We expect diligence, and we expect to raise the level of our intellectual prowess together. This is all happening at EXPEC ARC, with the support of Saudi Aramco management."

In 2006, EXPEC ARC established the IAC to give advice on the strategic direction of Saudi Aramco's research and development activities.

The IAC reviews EXPEC ARC's activities and performance, suggest future directions, and recommend new and emerging technologies to benefit specific business needs and challenges of Saudi Aramco. The council consists of world-renowned scientists from highly respected institutions.

The annual awards provide a platform to the researchers and initiatives that sparked innovation during the past year. This year, Al-Falih, senior vice president Amin H. Nasser and EXPEC ARC manager Muhammad M. Al-Saggaf presented the awards together.

Al-Saggaf highlighted EXPEC ARC's accomplishments. "This was the year the first experiment in industry was successfully conducted to demonstrate that nanorobots represent a reality, not a myth. It was the year the giga-cell simulation barrier was shattered, and Saudi Aramco widened its lead ahead of everyone in the industry."

EXPEC ARC award winners pose with International Advisory Council members and company management at the January awards ceremony.

"2008 was our best year yet," Saggaf concluded. "We won four SPE individual international awards — twice as many winnings as all the international oil companies combined. After all, as our motto says, we will get there: 'We will either find a way, or we will make one.'"

Sunil L. Kokal, Petroleum Engineering consultant at EXPEC ARC, recounted the achievements of his colleagues. "On a personal level, the one thing that strikes me the most about 2008

Among those who received EXPEC ARC awards were, from left, Tareq M. Al-Shaalan, Larry S. Fung and Usuf Middya.

is that EXPEC ARC became a close-knit family," he said. "It has come a long way in a very short time. It has quickly grown and strengthened to become a center of excellence. 2008 was the year of the nano and the giga: from the smallest to the largest. It was the year EXPEC ARC was recognized with its first international technology award for Resbots, a testament that we are on the right track."

With near-perfect attendance, about 240 EXPEC ARC employees turned out to congratulate their colleagues. Other guests included Abdulla A. Al Naim, vice president of Petroleum Engineering and Development; and Mohammed Y. Al-Qahtani, chief petroleum engineer.
EXPEC ARC spearheads the research and development of all upstream technology, anticipating future needs, to create innovative, high-impact solutions and tools for Saudi Aramco Exploration and Producing.

Several awards were presented for excellence in contributing to this mission. However, due to the numerous achievements attained in 2008, the most hotly contested award category was the Milestone Award, which is awarded to those who "made the most significant contribution in their projects for the year 2008 in terms of design, execution, or completion, and with the highest impact for the lifecycle of the project."

Therefore, in addition to the winning team (giga-cell simulation), other project teams received honorable mentions in this category: the cross-well electromagnetic project, Resbots™ physical experiment milestone, technology test site well completion, inline water separation project, and casing drilling and ceramic centralizers.

EXPEC ARC award winners

Team Player Award: Ali Al-Meshari.

Most Productive Technician: Ahmad A. Humaidi.

Creative Contribution Award: Yi Luo.

Best TWIX Presentation: Ghaithan A. Al-Muntasheri for "Development of a Cost-Effective Polymer for High Temperature Water Shutoff."

Effective Publication Award: Sunil L. Kokal, winner for the second year in a row.

Mentorship Award: M.D. Amanullah.

Milestone Award: Usuf Middya, Larry S. Fung, Tareq M. Al-Shaalan, for developing and implementing key components of the GigaPOWERS code that allowed the company to break the giga-cell barrier, the industry's first billion-cell reservoir simulator.

'Idea Factory' Stimulates Creativity

By Larry Siegel

At one of two R&DC "Idea Factory" sessions, participants viewed an exhibit of innovation concepts. (Photo: Faisal I. Al-Dossary)

It's a simple equation: What happens when you put dozens of creative minds with a strong scientific background together and turn them loose on a simple proposition, "Suggest alternative or nontraditional uses of petroleum"?

The answer is more than 250 ideas, of which 28 were selected for further assessment.

Promoting innovation, the Research and Development Center (R&DC) recently organized two "Idea Factory" sessions. The first was the brainstorming session, and the second was an innovation day, which included awards and an exhibition of creative ideas that have been generated and patented by R&DC employees.

At one of two R&DC "Idea Factory" sessions, participants viewed an exhibit of innovation concepts. (Photo: Faisal I. Al-Dossary)

In his opening remarks in the first session, R&DC manager Dr. Omar Abdulhamid challenged the participants to research and develop future opportunities for the nonconventional use of oil. He highlighted the current R&D programs that have been designed to further the use of oil in transportation and petrochemical manufacturing as well as capture more power-generation opportunities.

He emphasized that there is a need to complement those programs with options to create an additional demand for oil in future market sectors that will minimize the impact of oil-price fluctuations and protect the Kingdom's economy.

According to Mansour N. Lahiani, coordinator of Analytical Services and organizer of the event, R&DC promoted the session to trigger new ideas by fueling new thinking and assessment.

Members from R&DC and other organizations participated in the session.

The ideas created during the first session of the Idea Factory included converting crude oil to carbon fiber (CF) composite. Applications of CF composites include reducing the weight and size of off-shore platforms and reducing infrastructure costs.

Another idea was to convert crude oil to smart elastomers, composite-fibers, carbon nano-tubes (CNTs), polymers that can be used for memory chips, electronics parts, biomedical products, drugs and medicines, composite materials for building, and vehicle and machinery parts.

Participants also suggested synthesizing amino acids from oil for medical applications since amino acids are building blocks for a variety of prescription drugs.

Talking to Idea Factory participants and other R&DC employees in the second session, Abdulhamid challenged all the employees to take a personal interest in creating intellectual capital. "Don't wait for management to guide you," he said. "Management is committed to innovation. Are you?"

As it turns out, there are many R&DC employees who are committed to innovation. Several presentations revealed that, in patents and ideas, R&DC is growing at a very rapid rate and will continue to grow.

Lahaini said, "The idea of a brainstorming session and innovation day is not new. It's been practiced by R&DC and other departments within the company. However, the idea of combining the two and addressing a challenge that would be of utmost importance to the whole Kingdom similar to the one we addressed is new and came from the R&DC."

Invention Streamlines Corrosion Protection

A new method of injecting corrosion inhibitor into gas streams involves lower temperatures, fewer chemicals and less money, and it recently earned the company U.S. Patent No. 7,452,390.

This graphic outlines a new method of injecting corrosion inhibitor into gas streams. The patented invention means lower temperatures, fewer chemicals and less money.

The method, called "Controlled Superheating of Natural Gas for Transmission," was invented by Hani H. Al-Khalifa of the North Ghawar Producing Department, Abdulrahman H. Al-Abdullatif of the Sea Water Injection Department, and former employees Donald Delevan and Timothy Wilson.

Crude oil flows to 32 gas-oil separation plants (GOSPs) in Southern Area Oil Operations. GOSPs separate oil from associated gas and water. The oil goes to Abqaiq Plants, and the associated gas goes to 'Uthmaniyah and Shedgum Gas Plants for further processing.

To protect hundreds of kilometers of gas transfer lines, a costly corrosion inhibitor is injected into the stream before it leaves the GOSPs.

The gas typically leaves the GOSP at 74 degrees C with 3.78 liters of enhanced corrosion inhibitor injected for every million standard cubic feet of gas.

Before the invention, the amount of chemical was manually controlled, sometimes resulting in too much or too little chemical being injected and subsequent pipeline repairs.

Since the chemicals cost millions of dollars a year, an engineering team was assigned to look into what could be done to reduce this cost without jeopardizing the safety of gas transfer lines.

The inventors addressed the questions:

- What is the minimum gas temperature a GOSP must maintain?
- What would be the impact of lower temperature on gas plants?
- What would be the impact of lower gas temperature on transfer lines?
- Would the reduced corrosion inhibitor provide adequate protection?

After three years of research, they concluded that the gas temperature could be reduced to 54 degrees C, and, since the amount of chemical required is dependent on the gas temperature, the inhibitor could be reduced by 50 percent without adverse effects on the plants.

Realizing that the process would require frequent changes to GOSP processes, the inventors designed an automated system that reads parameters such as gas flow and temperature and calculates the optimum temperature. The new system then controls the amount of corrosion inhibitor that is injected.

In addition, the team found that the company could mix its own corrosion inhibitor, for even more savings.

The invention, once implemented throughout the company, is expected to reduce the amount of corrosion inhibitor by about 50 percent. But that's not all. It also will ensure that gas transfer pipelines are always protected without wasting expensive chemicals, the lower gas temperatures will prolong the life of pipelines and facilities and the drop in pressure will require less power.

WIRELESS SEISMIC ACQUISITION

GEORADAR

Georadar Levantamentos Geofísicos S/A

Belo Horizonte - Brazil
Phone: 55-31-2104-7170 Fax: 55-31-2104-7171
Website: www.georadar.com.br
e-mail: georadar@georadar.com.br

ENVIRONMENTAL EVALUATION

Inauguration of the Dhahran Oilfield Services base

Official opening of Schlumberger's largest worldwide operations base by the Corporate & Executive Management of Saudi Aramco & Schlumberger.

On November 5th, 2008 Andrew Gould, Chairman and CEO, Schlumberger, and the corporate and executive management of Saudi Aramco (the world's largest oil company) officially opened the Dhahran Oilfield Services base, Schlumberger's largest worldwide operations base. The Dhahran Oilfield Services base has over 18,000 sqm of structures within 62,000 sqm of land and demonstrates Schlumberger's long-term commitment to Saudi Arabia and Saudi Aramco.

This state-of-the-art facility houses approximately 1000 employees and encompasses the entire repair & maintenance of specialized oilfield technologies and equipment, in addition to engineering, planning and operations support expertise for the complete range of Schlumberger Oilfield Services from well logging, drilling & measurements through to well completions and production testing.

Following 17 months of construction, the facility was officially inaugurated by an opening ceremony held under the patronage of Mr. Khalid Al-Falih, President & CEO, Saudi Aramco along with distinguished guests from Saudi Aramco; the Saudi Arabia Ministry of Petroleum and Minerals; King Fahd University for Petroleum and Minerals; and the in-Kingdom international joint venture Operating Companies.

Figure 1: From left to right: Dr. Sahl Abduljawad, Vice Rector for Applied Research, KFUPM, Amin Nasser, Sr VP E&P, Saudi Aramco, Khalid Al-Falih, President & CEO, Saudi Aramco, Abdulaziz F. Al-Khayyal, Sr VP Industrial Relations, Saudi Aramco, Andrew Gould, Chairman and CEO, Schlumberger, and Khalid Mugharbel, Arabian GeoMarket VP & General Manager, Schlumberger.

> …"this world class facility is symbolic of the quality, safety and environmentally conscious level of service upon which your partners greatly rely upon here in the Kingdom". (Mr. Khalid Al-Falih)

In opening remarks from the Arabian GeoMarket VP & General Manager, Khalid Mugharbel, stated that …"the base construction was modeled on best practices and workflows captured from other bases and facilities around the world and implemented according to the highest industrial standards with focus on efficiency, integration and the workplace environment".

During the opening address by Saudi Aramco, Mr. Khalid Al-Falih said…"this world class facility is symbolic of the quality, safety and environmentally conscious level of service upon which your partners greatly rely upon here in the Kingdom".

Also during the opening ceremony Andrew Gould said …"just over 65 years ago, in October 1941, we ran our first wireline log in the Kingdom on the Dammam field in well 27. Since then, our history in Saudi Arabia has tracked our history as a company as well as our record in developing technology".

Following the opening ceremony, guests were provided with a guided tour of the facility which followed the event theme of Schlumberger Saudi Arabia past, present and future, where technologies, cross-segment integrated solutions and projects relevant to the Saudi Arabia market place were showcased. These included Tight Gas, Heavy Oil Testing, Manifa Project, MRC (Maximum Reservoir Contact) wells and Openhole Completions (the 2008 Performed by Schlumberger Chairman's award), Coiled Tubing Drilling and HFM (Hydraulic Fracture Modeling) – Microseismic in addition to joint technology collaboration projects between Saudi Aramco and the Dhahran Carbonate Research Center focused on optimizing reserves and production & recovery.

Figure 2 - Andrew Gould, Chairman and CEO, Schlumberger, with Khalid Al-Falih, President & CEO, Saudi Aramco.

Figure 3 - Visitors being given an overview of Schlumberger technologies & solutions.

Figure 4 - Dr. Mohammed Badri, SDCR Managing Director, sharing some collaborative R&D projects with Saudi Aramco.

Society of Petroleum En

Saudi Arabia Section

2009 SPE Saudi Arabia Section Tec

9-11 May 2009, Saudi Arabia

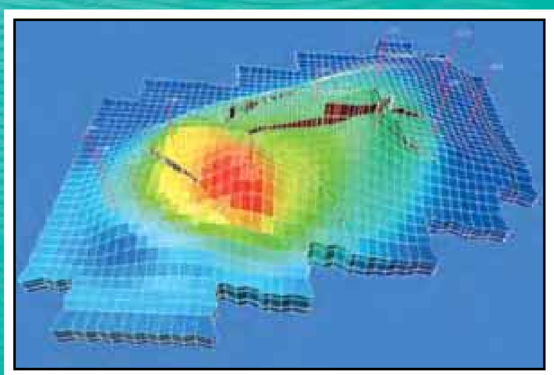
"Pushing the Technology Envelope for Higher Recovery"

The Society of Petroleum Engineers (SPE) Saudi Arabia Section is pleased to invite you to attend and participate in the 2009 SPE Technical Symposium and Exhibition to be held from 9 to 11 May 2009 at the Le Méridien Hotel, AlKhobar, Saudi Arabia.

Over the past 25 years, the SPE Annual Technical Symposium of Saudi Arabia Section has been an important E&P gathering for regional and international industry professionals to discuss and exchange expertise and to promote the latest innovations and technologies.

The technical program covers the following topics:

- Drilling and Completions
- Production Enhancement and Operations
- Petrophysics and Formation Evaluation
- Reservoir Management and Simulation
- Reservoir Geology and Geophysics
- Special Topics and Emerging Technologies



gineers Saudi Arabia Section

hnical Symposium and Exhibition

Local and international companies are encouraged to avail this event and show their state-of-the-art technologies at the recognized region of the largest oil and gas reserves and production. Make your plan to attend and actively participate in this event.

Dr. Ashraf M. Al-Tahini, Chairman
2009 SPE Annual Saudi Arabia Technical Symposium

For more information, please visit:
http://www.speksa.org/symposium.htm

Want to be a Sponsor? Please Join us.

Overcoming Barriers to Deliver ERD Wells Beyond 15 km

19-24 April 2009 • Kota Kinabalu, Sabah, Malaysia

SPE Forum Description

Technical Discipline: Drilling and Completions

Extended-Reach Drilling (ERD) is an enabling technology that has been utilized for over 20 years to deliver added value to the oil and gas industry. Extraordinary technical achievements have occurred during this period which has resulted in the drilling and completion of numerous 10 km+ wells. More recently, economic considerations, the location of future development opportunities and stringent environmental legislation have prompted operators to consider wells beyond 15 km. This has a profound consequence in that current conventional technologies will be operating outside their design limits. This means that new tools, techniques, innovation and an improved understanding of technical limits are needed now to advance the drilling and completion operability envelope.

This forum will primarily explore enabling oil field technologies that will promote the cost effective delivery of future wells beyond 15 km. A look to the far future will also investigate what achievements could ultimately be possible. Technologies from civil, mining and other industries will also be tested to seek out new ideas and opportunities.

Potential themes include:

• Barriers to Progress. What are the limitations and what approaches are needed to develop wells beyond 15 km?

• Well Planning: Caught in the Good-Fast-Cheap Triangle. Are high quality wells, expedient delivery and low cost, compatible drivers for 15 km wells?

• Tubulars and Rig Equipment. What realistic potential is there for advanced tubular material technologies, such as composites, Titanium, Aluminum and ultra-high strength steel for pushing the ERD envelope? How can advances in rig technology improve efficiency and reliability which is fundamental to success in ERD wells?

• Downhole Equipment and Data Telemetry. Uncompromising downhole tool reliability is a fundamental requirement for cost effective ERD well delivery: is this a realistic expectation? What are downhole telemetry bandwidth requirements and how can this information be readily integrated into real time drilling practices and geosteering?

• Directional Control and Torque and Drag Management. How can surveying uncertainty be improved and managed for wells beyond 15 km? Does the industry really understand torque and drag? The models are relatively simple, yet significant faith is put into them. What is the way forward?

• Wellbore Stability and ECD Management. Managing the ECD window to maintain adequate wellbore stability without inducing mud losses is a common challenge for most ERD wells. For wells beyond 15 km, what tools and techniques can the industry rely upon?

• Operational Management. Can ERD wells be delivered right the first time? How can lessons on unscheduled events in ERD wells be learned and shared effectively both locally and globally?

• Completion and Intervention Technology. What are the key challenges for effective delivery of completions in very long wellbores? What role do fluids, smart wells, artificial lift, coil tubing, perforation, swell packers and tractors play in wells beyond 15 km?

• Technology Enablers / Game Changers. Are there completely new ways of drilling, completing and intervening in wells beyond 15 km? Could wellbore intersection techniques or other concepts yet to be defined be used to extend the envelope?

Who will the forum appeal to?

This forum will appeal to multidisciplinary teams and technical experts in operating companies, service companies and academic institutions who are involved in aspects of planning, drilling, completion, intervention and production of ERD wells. Participation will also be sought from those who work in allied industries such as pipeline drilling and mining.

Attendees will

• Discuss common interests informally with colleagues from around the world.

Forum Session Topics and Descriptions

Session Title	Chairpersons
Stepping Out Past ERD Milestones	Mario Zamora, Andrew Clennet
Well Planning: Caught in the Good-Fast-Cheap Triangle	Brandon Foster, Andrew Lambert
Rig/Tubular	Michael Jellison, Jon Ruszka
Downhole Equipment/Telemetry	Greg Conran, Frank de Lange
Positioning Issues when Navigating to Distant Targets	Angus Jamieson, Greg Conran
Keeping the Open Hole Whole	Fersheed Mody, Mario Zamora
Operational Managment	Andrew Lambert, Stein Harvardstein
Completions/Cementing	Graeme Rae, Stu Keller
Technology Enablers/Game Changers	Stu Keller, Steve Loneragan

• Share knowledge and experience in an off-the-record format.

• Gain new insight and perspective through conversations with others from international companies, service companies, contracting companies, research institutes, and universities.

• Enjoy a relaxed atmosphere of learning through one-on-one interaction.

Please come prepared to be a participant, not a spectator.

Stepping Out Past ERD Milestones

This opening session will challenge all to look into the far future to investigate what step-outs could ultimately be possible. How far out will we be drilling and completing wells in 5, 10 and 20 years? Is there a limit? What are the barriers to progress and which can be "show stoppers"? What will it take to leap over these barriers?"

Well Planning: Caught in the Good-Fast-Cheap Triangle

As the industry moves to expand extreme ERD capability, we must recognise the organisational tendency to expect high quality, expedient delivery, and low cost. While desirable, these elements are often mutually exclusive. This session will explore industry shortcomings in planning quality, lead time constraints, and notions of what "low cost" really means.

Rigs/Tubulars

Tubular design and material selection to achieve the optimum balance between strength, weight and hydraulic efficiency, with minimum operational risk is critical when planning world-class ERD wells. Any discussion of drill stem and OCTG requirements for world-class ERD would be incomplete without consideration of advanced material technologies (carbon-fiber based composites, Titanium, Aluminum and ultra-high strength steel) and their potential for enabling longer reach objectives. Drilling & Completion Engineers must balance the technical and financial aspects of tubular selection while also making decisions far ahead of spud date to accommodate associated long lead times. Rig equipment technology advances can enhance the effort to expand the ERD envelope while improving efficiency and reliability. Rig equipment developments can reshape the ideal drilling rig for future generation ERD projects. These topics and more will be open to discussion in this session.

Downhole Equipment/Telemetry

As mud pulse telemetry systems are approaching their operational limits, wired drill pipe is emerging as a key replacement for existing telemetry systems and becoming an enabler to push ER wells beyond the 15 km limit. Wired drillpipe will provide "unlimited" and uninterrupted real time data transfer between surface and the various downhole components. The future holds a vision for sensors measuring drilling efficiency, hole condition, hole cleaning, drill string condition, bit condition and drilling performance which will enable real-time optimisation of the drilling process by intelligent autonomous computer systems. This session will explore the sensory requirements for ER wells and assess how we can turn the increased volume of real-time data into real benefits.

Positioning Issues when Navigating to Distant Targets

This session will begin with a fun, general knowledge quiz on positioning issues including some estimation challenges for each team followed by a short presentation of Borehole Surveying Technology and its current limitations. Delegates will then form discussion groups who will, initially, share bad experiences of misplaced wells and what the impact was. These will be summarized for a report to the wider group and the second discussion question will be novel solutions to the problems raised and what technology step changes will be needed for breaking the 15 km barrier.

Solving complex interpretations

Nuclear Magnetic Resonance (NMR) logging technology has enabled petrophysicists to solve previously impossible problems, but significant challenges remain.

By Ridvan Akkurt, Nawari A, Ahmad, Abdallah M. Behair and Ali S. Rabaa, Saudi Aramco; Steve F. Crary and Sebastian Thum, Schlumberger

One of the most difficult tasks in petrophysics is the proper evaluation of high-resistivity, low contrast (HRLC) reservoirs; a perplexing variation of the well-known low-resistivity, low contrast (LRLC) shaly-sand reservoir. Compounding the problem is the fact that many wells are drilled overbalanced with oil-base mud because of problems with wellbore stability. Oil-base mud filtrate is almost indistinguishable from crude oil using traditional methods. As a result, determining oil/water contact (OWC) can be a formidable challenge (Figure 1).

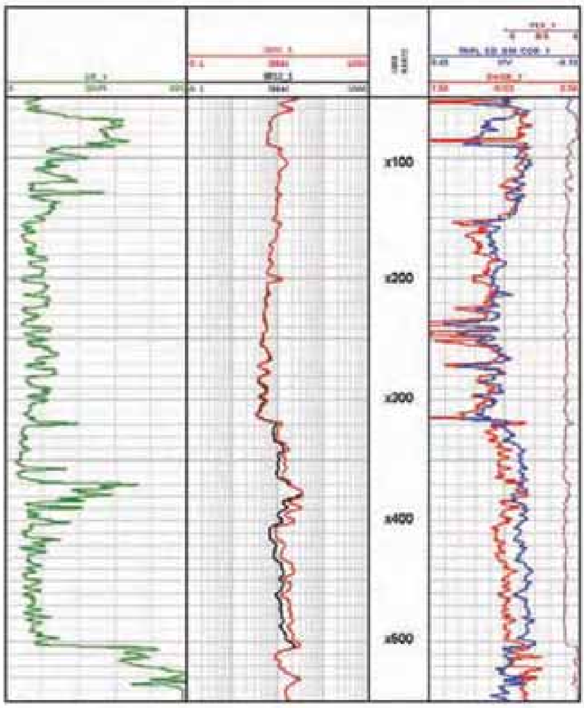


Figure 1 - Here is a triple-combo log suite from a well drilled with OBM. Can you find the OWC? (Answer to be given later).

Whereas LRLC reservoirs are difficult to recognize because everything appears to be wet, HRLC reservoirs are the opposite—everything appears to be pay. Further complexity arises when trying to determine water saturation with a sufficient degree of accuracy. Clay minerals can be present, adding electrical conductivity, which can dominate log responses. Waters of differing salinities can be present, sometimes varying from very low values around 1 kppm to that of sea water (about 30 kppm). This impairs one of the most fundamental interpretation steps—that of determining water resistivity in a nearby aquifer and using that value in the suspected pay zone.

Enter NMR

Nuclear magnetic resonance logging holds potential for solving the tough problem of determining water saturation in a zone invaded with OBM filtrate and identifying the OWC. The NMR log is a fluid device, meaning it can provide reliable fluid volume measurements irrespective of matrix or fluid salinities. The latest generation magnetic resonance tools takes measurements from several discrete concentric 'shells' each located a fixed distance from the tool, thus able to provide a radial profile of fluid distribution. MR data, when combined with traditional logging measurements, along with advanced measurements such as acoustic and induced gamma spectroscopy tools, remove considerable ambiguity from the interpretation challenge, and in fact provide a petrophysically-supportable solution to the question of saturation and fluid distribution as well as a good estimation of the location of the OWC.

Developing a sustainable NMR based answer in a challenging area in Saudi Arabia took the better part of a year. The main reservoir was a friable Aeolian sandstone

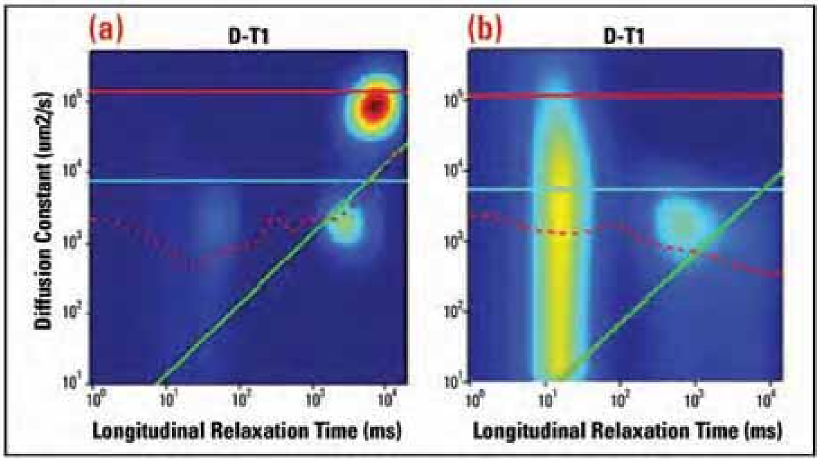


Figure 2 - NMR maps from a gas reservoir drilled with OBM plot Do in the y-axis vs. T1 in the x-axis. The red line is methane, blue is water and green is dead oil (The dashed re line is log-mean-diffusivity). On the left is the pay zone with free gas (yellow-red circles), OBM filtrate (blue-green circles) and bound water (faint blue area) evident. At right is the water zone containing only free and bound water (green-yellow bar), along with OBM filtrate (blue-green circles). (Courtesy of Saudi Aramco and Schlumberger).

of Permian age with porosity averaging 20 pu and permeability ranging from a few tens of millidarcies to several hundred millidarcies. Oil gravity was in excess of 40°API and the gas-oil-ratio (GOR) was in the low hundreds. Water salinities ranged from 5 kppm to 25 kppm. During that period, several wells were drilled and logged, each one adding to the knowledge base and contributing to the learnings of the petrophysical team. The ultimate objective was to develop a workflow that could be performed by a petrophysicist in near-real-time, so the uncertainties emanating from the interpretation in some zones could be quickly verified by fluid samples taken with an accompanying formation tester tool. The answers were not without a price. In order to obtain sufficient signal-to-noise ratio (SNR) to obtain good contrast, the measurements had to be taken with the tool stationary in the borehole.

The plot thickens

The formations were heterogeneous with high clay content that affected both the resistivity and neutron logs. The friable sands washed out in several places affecting density log quality. In addition, it was determined that the standard NMR radial profiling application could not discriminate pay from filtrate, so a collaborative effort was launched to come up with a solution.

The team determined that their best chance lay in utilizing state-of-the-art NMR fluid typing, called Diffusion Editing (DE). The Diffusion Editing technique adjusts the first two echo spaces, then uses all three NMR measurements, longitudinal relaxation time (T1), transverse relaxation time (T2) and diffusion constant (Do) crossplotted in a series of 3D maps, with color coded amplitude as the z-axis (Figure 2). Furthermore, it allows the customisation of CPMG echo-trains, whereby the tool acquisition parameters can be varied to optimize the data for each shell, thus maximizing SNR.

In the simplified example shown, all three phases typically encountered are present. The reservoir is at irreducible water saturation, meaning it would produce dry gas; nevertheless, the presence of oil-base mud filtrate is clearly evident in both the pay zone (right) and the water zone (left). No native oil is present, the oil 'show' is 100% filtrate. The maps illustrate conditions in the flushed zone. By mapping each shell's response at increasing depths of investigation (DOI) it is possible to observe decreasing influence of filtrate invasion (Figure 3). These results were instrumental in deciding to use stationary NMR measurements to get clear images deep into the formation to understand fluid distribution.

Applying the technique

Once it had been determined that stationary measurements could provide the quality and discrimination levels required to attempt an interpretation, the technique was applied in the next well drilled. The well was cored, and the logging program included triple-combo, 3D induction, induced gamma spectroscopy, NMR and formation tester. The 3D induction tool was run as an experiment to see if the OWC could be discerned

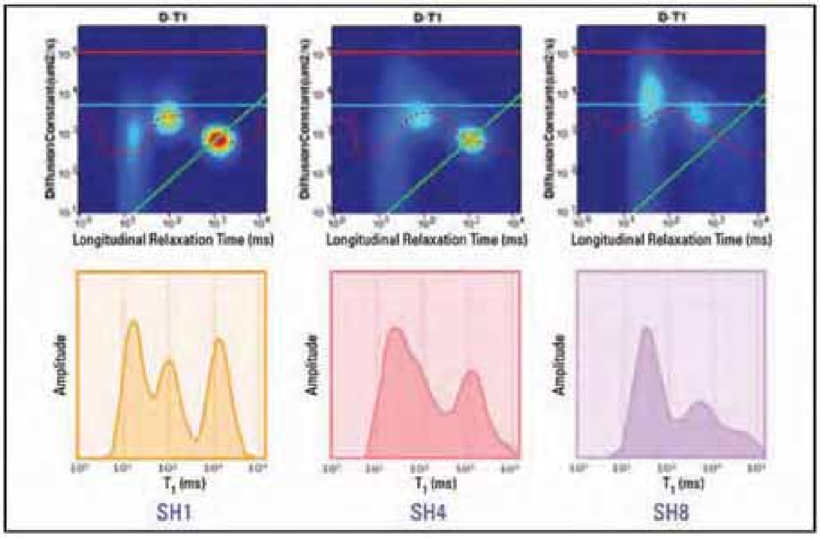


Figure 3 - Stationary measurements made at increasing DOIs in a water zone drilled with OBM illustrate the radial distribution of fluids at 1.5-in, 2.7-in and 4.0-in (SH1, SH4 and SH8) respectively. While SH1 and SH4 show bound water, free water and OBM filtrate, SH8 shows only bound and free water. (Courtesy of Saudi Aramco and Schlumberger).

based on resistivity anisotropy. The induced gamma spectroscopy tool was run to get a better indication of mineralogy and clay content. Two NMR passes were made: the first for porosity and bound fluid, the second consisting of stationary measurements required for radial saturation profiling and OWC determination.

Based on NMR real-time measurements, levels were selected for formation fluid samples and pressures to be taken. Two cased hole tests were also planned to confirm the overall findings before the well was completed. Gamma ray, resistivity NMR porosity and data from four of the stationary measurements at two DOIs allow one to make the following observations (Figure 4):

• There is pay at x190-ft. as can be seen from the high resistivity reading in a high-porosity, clean sandstone.

• The sands are wet starting at x320-ft, indicated by the resistivity invasion profile where Rxo > Rt (in an OBM environment).

• The OWC is somewhere between x200-ft and x320-ft.

• The oil can clearly be seen in the 1.5-in SH1 maps at all depths, but it is impossible to tell whether it is native crude or OBM filtrate.

• On the 4.0-in SH8 map, the ambiguity is solved. The lower two maps at X212-ft and x244-ft show that there is free water and oil. But the strong peak observed on the oil line seen in the 1.5-in. SH1 map has been replaced by a strong peak shifted toward the water line.

• There was no corresponding shift at x190-ft between SH1 and SH8. The peak remains on the oil line, and there is no apparent free water. The longer T1 value in SH8 supports the interpretation that the signal comes from lower viscosity native crude, not filtrate.

Some difficulty was experienced in taking fluid samples due to tool plugging. However, the combination of NMR and log data, plus the samples confirmed the approximate location of the OWC as x210-ft. Despite all the available data, there was still some question as to the exact location of the OWC. According to the porosity volume track, the oil extends from top to bottom, but clearly the oil below x245 is OBM filtrate, as confirmed by a water test obtained at that depth.

Upon completion, the lower perforations flowed oil with a small water cut (<5%). The upper perforations flowed dry oil with a gravity of 50°API and a GOR of about 500.

Additional information can be obtained from the fluid sample taken at x244-ft. Since only water was produced, then the oil peak in the NMR map is due to OBM filtrate, indicating that the OWC is definitely above X244-ft., adding confidence to the interpretation at x212-ft. The remaining ambiguity is whether x212-ft is in the water zone or in the transition zone. Since both NMR maps show free water and oil, there is a question whether the oil is OBM filtrate in which case the level is in the water zone, or native crude, in which case the level is in the transition zone.

Field-wide production data suggests that there is no transition zone. If one assumes this to be the case, then it can be also be assumed that the lower perforated interval actually spans the OWC, and this accounts for the small water cut on production and in the cased hole test.

Based on learnings from the first well, an additional well was drilled, logged and tested. More stationary measurements were taken. Again, trying to pick the OWC from the logs alone is impossible. The NMR radial saturation maps tell the tale (Figure 5). The SH1 maps show the OBM filtrate along with free water, but the SH8 maps clearly discriminate the lighter viscosity crude oil in the upper two plots. In this well the OWC was picked at x204-ft.

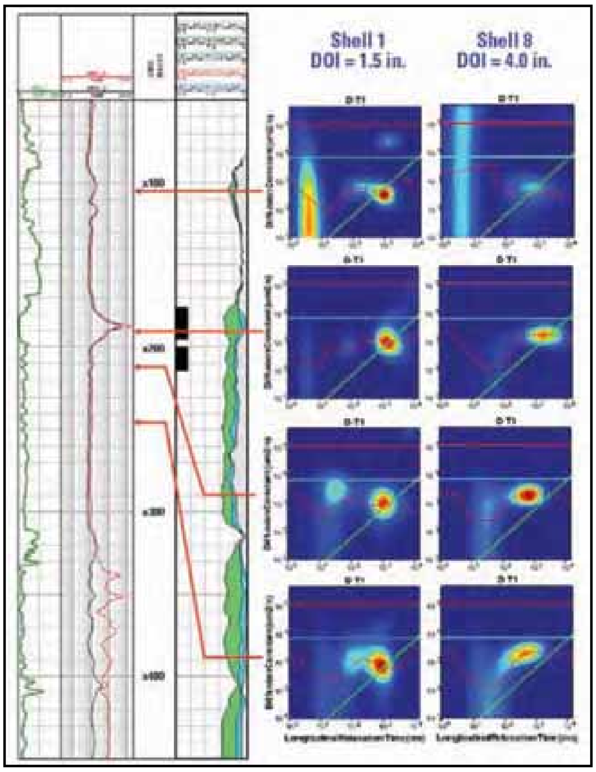


Figure 4 - Radial saturation profiles from 4 stationary measurements are shown at DOI's of 1.5-in and 4.0-in respectively. Fluid porosity volumes are shown in Track 4 with green=oil, blue=free water and gray=bound water. The well tested oil down to x215-ft. A water sample was taken at x245-ft. (Perforations are shown as black boxes in Track 4). (Courtesy of Saudi Aramco and Schlumberger).

Conclusions

Details of the work performed in this endeavor can be read in SPWLA Paper, NMR Radial Saturation Profiling for Delineating Oil-Water Contact in a High-Resistivity Low-Contrast Formation Drilling with Oil-Based Mud, by the authors and presented at the 2008 Annual logging Symposium. Work continues to refine the process and make it more robust. NMR measurements are material in making this improvement. Each piece of the puzzle will contribute to the solution of the most complex interpretation scenarios. Clearly, the NMR measurements enable major progress to be made toward the goal of discriminating OBM filtrate from crude oil and correctly interpreting HRLC zones. As for the problem shown in Figure 1, the answer is x204-ft. The process still requires the attention of an experienced petrophysicist with specialty in NMR interpretation, but it is hoped that further learnings enable that final hurdle to be overcome.

For further reference see SPWLA paper, MR Radial Saturation Profiling for Delineating Oil-Water Contact in a High-Resistivity Low-Contrast Formation Drilled with Oil-Based Mud, by Saudi Aramco and Schlumberger. This paper was originally presented at the 49th Annual Logging Symposium, May 25-28, 2008.

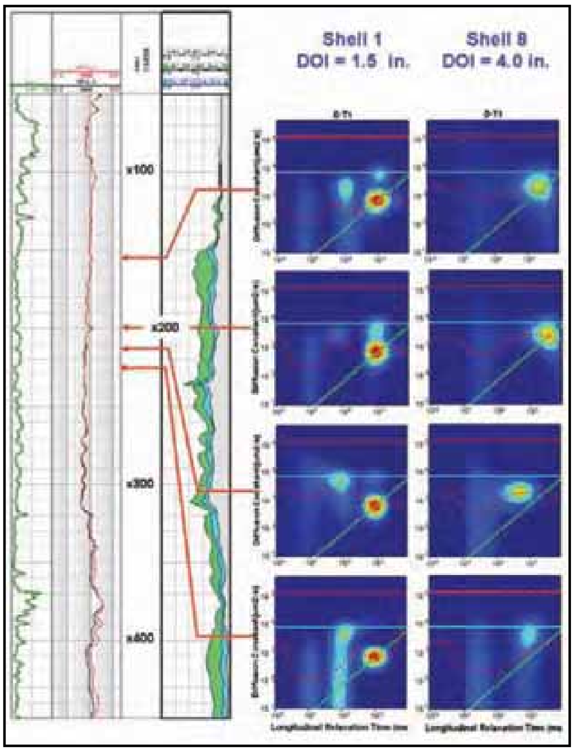


Figure 5 - In this well, SH1 data is dominated by the OBM filtrate signal. However, the upper two SH8 plots clearly show the presence of low viscosity native oil. (Courtesy of Saudi Aramco and Schlumberger).

Field Development Plans Optim Flow Impact and Assessing Int Performance

Literature presented some methodologies to numerically simulate fracture corridors and diffuse fractures systems in naturally fractured carbonate reservoirs. Halilu et al.[1] presented a method for large fields dominated by clusters of subvertical fractures called fracture corridors. In this study, the effective Warren-Root and fracture parameters were adjusted to mimic explicit fracture modeling to represent fractures corridors. The study results showed that fluid flow in these fields is largely influenced by large scale fracture corridors. These large scale fracture corridors were lately named fracture fairways.

By Emad A. Elrafie, Ghazi D. Al-Qahtani, Mohammad Agil (Saudi Aramco), Alexander Rincon (Schlumberger) and François-Michel Colomar (Beicip-Franlab).

This paper was prepared for presentation at the 2008 Abu Dhabi International Petroleum Exhibition and Conference held in Abu Dhabi, UAE, 3–6 November 2008.

Abstract

The understanding and accuracy of modeling fluid flow behavior in naturally fractured carbonate reservoir is critical in predicting reservoir sweep efficiency, remaining drilling targets and evaluating field development alternatives. The use of appropriate complex wells design such as Horizontals, (H) Multi-laterals (ML) and completion technology such as equalizers (ICD) or Inflow Control Valves (ICV) are of equal importance.

The approach presented in this paper is based on detailed integrated analysis of all available well data including logs, production, pressure transient analysis (PTA), fracture distributions, well flow profiles (PLT) etc, to provide a first-line insight of the fractured reservoir fluid flow mechanism. These first-line insights provide the basis to develop mechanistic or concept reservoir simulation models to fine-tune fluid movement understanding in fractures, reservoir matrix, well types (H, ML) and completion placement to field development strategies. Sector modeling provides further insight to well design in field areas of different rock quality and fracture density. Well type and completion strategy alternatives for each identified field area including intelligent smart well completions are developed and tested in each sector model. The combined developed understanding of fluid flow mechanisms, well type and completion strategy are rolled up and implemented into a full field simulation model, fine tuned through history match and prediction processes.

This paper describes the methodology used to study a number of naturally fractured carbonate reservoirs through the integrated "Event Solution"[2] study approach. The methodology presented in this paper was applied on a number of large Middle East carbonate fields. The fields studied have naturally fractured reservoirs with two distinct fracture systems. Namely, fracture corridors or clusters and diffuse or layer-bounded fractures. Diffuse fractures are typically horizontal (layer-bounded fractures) inter-connect with the frac-

ization by Modelling Fluids elligent Wells on Reservoir

ture corridors which are normally vertical to sub-vertical. This fracture system combination forms a highly conductive fluid flow and pressure medium which is responsible for observed water movement as well as pressure propagation from the aquifer/injectors into the reservoirs.

Background

Well test analysis provides an important and indirect indicator of fracture presence. Relevant studies include those by Al Thawad et al.[3, 4] in which signatures in derivative plots of intersecting and nearby conductive fractures on several case studies are presented. Al Ghamdi and Issaka[3] surveyed characteristic derivative plots of various cases including sealing faults, intersecting conductive fault/fracture and nearby conductive faults. These authors examined fault/fracture signatures including potential ambiguities resulting from the non-uniqueness of the derivative plots.

In the Literatures there are also several recent studies with smart well modeling. In 2006, Ebadi and Davies[5] established a screening process to determine the number and placement of inflow control valves. Holmes, et al[6,7], described, in depth, how to model smart wells in a reservoir simulator including key factors to be considered and the need to utilize multi-segment well option. The impact of flow control devices on two well types was studied using multi-segmented well modeling. The implementation of smart tools showed positive impacts in terms of accelerating production, reducing well count, maximizing plateau duration, controlled conning and improved sweep efficiency as described by Ajayi et al[8,10], Sinha et al[9] and Yu et al[11]. Augustine and Ratterman[12] summarized thoughtful insights regarding smart completions in natural fractures and their positive and negative impact on the study deliverables.

Introduction

Fluid flow in naturally fractured reservoirs primarily takes place through high permeability and low porosity fractures networks surrounding by lesser permeability matrix blocks. The simulation of such reservoirs is challenging in terms of characterization, understanding of fluid flow behaviors and numerical modeling. This paper describes the methodology used to study a number of naturally fractured carbonate reservoirs through the integrated "Event Solution"[2] study approach. This approach starts with reservoir understanding through detailed analysis of all available data to assemble an integrated understanding of the reservoir including specific well production signatures. This understanding is transcribed into a number of models including geological, production, petrophysics, operations, first-water arrival, uncertainty, and simulation. Sector models are utilized to get quick understanding of fluid flow mechanism, to assess well types and completion placement of field areas of different rock quality, fracture density and distribution to a recommended well design and completion strategy for each identified field area. The understanding of the fluid flow mechanism, optimized well types, and completion strategy are rolled up and implemented into full field simulation models fine tuned through history match and prediction processes.

The reservoir performance of the studied fractured carbonate fields normally indicates excellent vertical sweep conformance regardless of the clear vertical heterogeneity in rock quality and the existence of different levels of fractures systems (i.e., fracture corridors, fracture fairways and diffuse fractures). The understanding of injected and aquifer water movement has always been very challenging and difficult to numerically match historical behavior. This is also a major challenge in studied reservoirs originally saturated with a large gas cap.

Fracture corridors as well as high permeability (High-K) layers have been historically known to control the water and gas movements in the studied reservoirs. A fracture corridor is a cluster of vertical to sub-vertical fractures. This cluster forms a vertical feature that cuts through the entire reservoir formation and may extend laterally over several kilometers. The High-K is high permeability isolated stratiform patches that mainly occur in two or three distinct stratigraphic horizons. These High-K stratiforms are usually very thin (horizontal) layers of limited extent, either depositional or diagenetic features that form highly conductive areas. Such intervals are defined through available flow meter analysis. The extent, shape and the continuity of these bodies are largely localized.

Fracture corridors significantly impact field performance. In some areas, fractures carry injected or aquifer water several kilometers ahead of the matrix water front location.

In our studied reservoirs, Fracture corridors were characterized by integrating all available static and dynamic data. Mechanistic, dual-porosity dual-permeability, simulation models were built to investigate alternative water and gas movement scenarios to identify a representative carbonate fracture fluid flow mechanism. This fluid flow understanding was incorporated and fine tuned with history matching of dual media full-field simulation models which included fracture corridors, diffuse fractures, High-K, and other geological features. History match was applied with assisted history matching tools, permitting a range of fracture realization variations to be considered. Other variables (i.e., matrix porosity, matrix permeability, relative permeability, etc.) were also modified through assisted history matching.

In this paper, an actual integrated field study example is presented to illustrate the approach. The concluded water front behavior is described in addition to insights on the effect of a large gas cap on fluid flow behavior. Field development strategy, well type and completion placement is also presented.

Reservoir Understanding

Study approach starts with building a reservoir understanding through detailed analysis of all available data. The aim of this methodology is to assemble a fluid flow understanding from all available evidence as related to water front movement, in addition to gas movement in the case of studies including a large gas cap. Four key study tasks (reservoir characterization, first water arrival, water production signatures and pressure transient analysis) are described below:

1. Reservoir Characterization

Here we will use one field study example to illustrate the reservoir characterization methodology used in these studies. This selected carbonate reservoir can be subdivided into two main units. The top unit has zones one and two (Figure 1) which are thick bedded, highly porous and permeable. The bottom units has zones three and four which are thin-bedded wackestones with thin packstones of lower porosity and more carbonate mud content, therefore lower permeability. These differences are reflected as well in the fractures characteristics. Diffuse fractures are far more abundant in the lower unit (Figure 1). Fracture corridors (vertical to sub-vertical clusters of fractures) are wide with small fractures within the base unit, but narrow with large fractures within the top unit (Figures 1, 2 and 3).

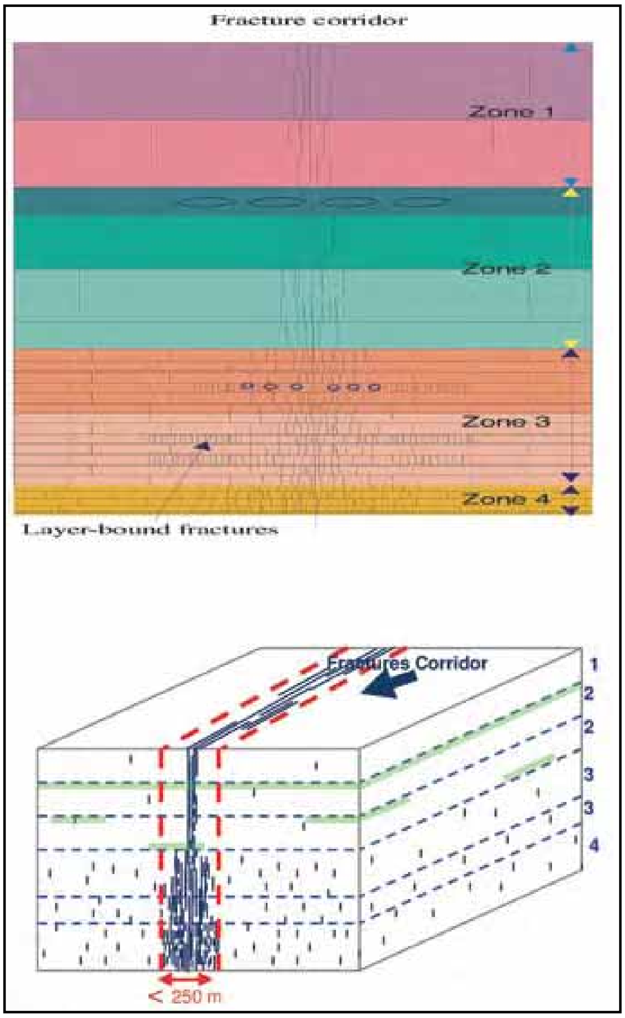


Figure 1 - Fracture corridors and layer-bound diffuse fractures are the two major fracture types in the studied carbonate reservoir. Fracture corridors are fault-related sub-vertical fracture swarms that traverse the entire reservoir and extend for tens and hundreds of meters. Fracture corridors are associated with wash out, lost circulation and wall rock alteration and leaching. Layerbound fracture density is controlled mainly by mechanical layer characteristics: e.g., porosity, dolomite volume and bed thickness.

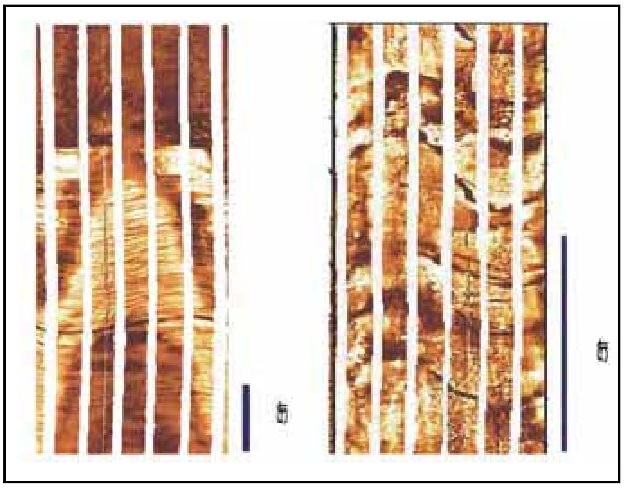


Figure 2 - Image examples of layer-bound fractures and fracture corridor. The image on the left shows a brittle resistive layer with a swarm of closely spaced uniform size fractures. The right image shows a fracture corridor as a swarm of small and large fractures. Fracture corridors are often associated with caliper enlargement, and lost circulation and wall rock cementation.

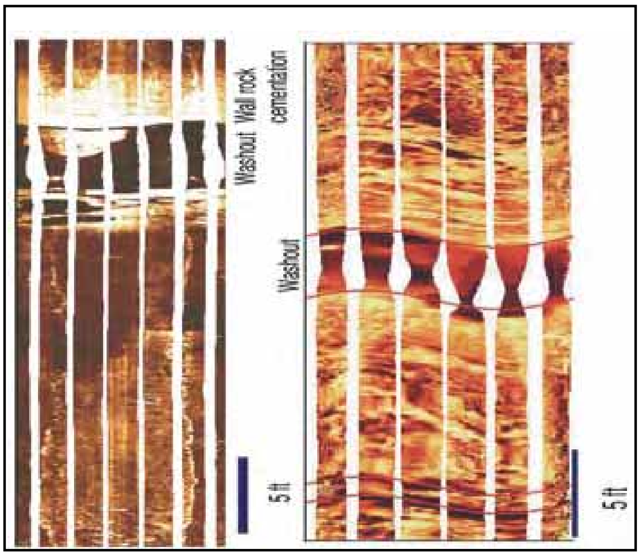


Figure 3 - Two other image examples of fracture corridors. Fracture corridors are often associated with caliper enlargement, and lost circulation and wall rock cementation.

As for fractures in the studied reservoir, three main reservoir heterogeneities were identified; (1) faults and fracture clusters, (2) diffuse fractures and (3) stratiform High-K. A Fracture Flow Index was introduced as a measure of fracture and fault flow potential, based fracture and seismic lineament orientation, dispersion, density and length. Fracture corridors are on average 50 ft (15 m) wide. This value is based on estimated fracture aperture of 0.05 mm and mega-fracture aperture of 0.5 mm. On average 65 fractures and 5 mega-fractures occur within a fracture corridor. Corridors themselves can cluster into larger corridor swaths termed fairways. Corridors in this reservoir have an average 500 mD-ft conductivity based on pressure transient analysis data.

Map distributions of stratiform High-K layers were generated statistically using Kriging method and flowmeter (PLT) data. Regarding simulation, it was decided to incorporate High-K as horizontal fractures of limited areal extent. A careful calibration of fracture permeability and shape was undertaken to adequately represent High-K behavior based on flowmeter (PLT) data. A fracture grid (permeability, porosity and matrix block sizes) was generated using advanced fracture characterization and modeling tools.

Fracture corridors, diffuse fractures and High-K layers were modeled under a wide range of uncertainty to capture all possible realizations. Similarly other variables such as matrix permeability, relative permeability, and other static and dynamic variables were modeled with uncertainty ranges. Figures 4 and 5 illustrate the range of fracture corridor realization in the selected studied reservoir with four different sets: high confidence (HC), medium confidence (MC), extended fracture (EXT) and low confidence (LC).

2. First Water Arrival (dry-oil stage)

The selected studied reservoir started production with a strict dry-oil production strategy. During this production stage any indication of possible water arrival or production in the producers was immediately handled through well shut-in or workover. Consequently, there was no allocated water production until a wet-oil pro-

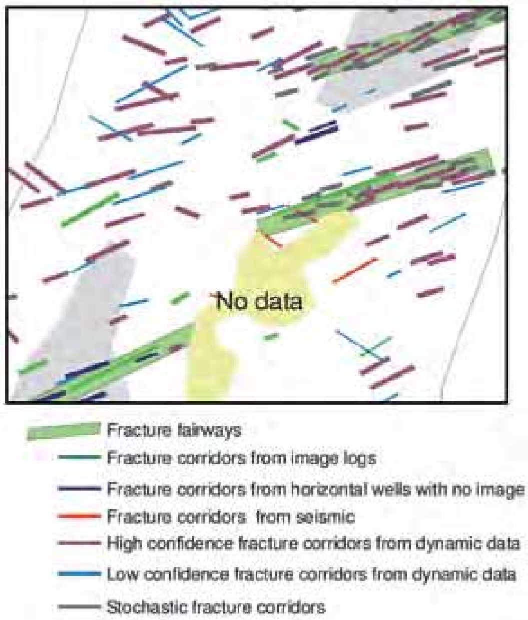


Figure 4 - Fracture corridor model of the studied field with high and low confidence fracture corridors.

duction strategy commenced in almost 30 years after production started. Mapping the flood (water and gas) front and its progress in time (4-D mapping) is one of the most powerful methods to identify and map fracture corridors. It is very important to approach this study method as a 4-dimensional exercise: the stratigraphic position of first water/gas arrival is an extremely important diagnostic. To understand first water arrival, a database with all available information as indicators to first water arrival, was constructed. The data base included total dissolved solids, salt content, solid content, workover and other indicators of possible water arrival. The analysis of this data provided a valuable representation of water movement although no actual field water was produced. Figure 6 illustrates an example of first water arrival maps to the studied reservoir. This study approach was also adopted for gas arrival in study fields that included large gas caps.

3. Water Production Signatures (wet-oil stage)
In the selected study, a wet oil production strategy was implemented in the field almost 30 years after the first production was started. Allocated produced water and water cut was used for further fracture characterization. Produced water performance signatures (Shape of produced water over time) provided indicative fracture corridor location, especially in case of fracture fairways. The rate of water cut rise and first water entry depends very much on well distance from a fracture corridor. Water movement in wells located far from corridors is characterized with a gradual increase in water cut rising from the well bottom. Wells located near fracture corridors illustrate water invasion of the entire bottom layer characterized with diffuse fractures and a rapid increase in water cut. Wells that directly intersect a fracture corridor exhibit instant water breakthrough in almost all layers. Three typical well water performance signatures as developed from mechanistic models and confirmed with actual field performance are described below:

• Wells "On" or very near to fracture corridors experience fast water breakthrough in most zones (top to bottom). The water performance signature indicates very rapid water breakthrough with initially high water cuts (70 – 80%) and building slowly to full water production (Figure 7). Because these wells are vertical producers, the numbers of wells that actually intersect or are considered to be very near to fracture corridors are limited. In the study field less than 3% of the wells fit within this category.

• Wells "Near" to fracture corridors experience delayed water breakthrough compared to wells on fracture corridors. Near wells normally experience first water breakthrough in high permeability layers causing water over-rides that disperse over time. The water per-

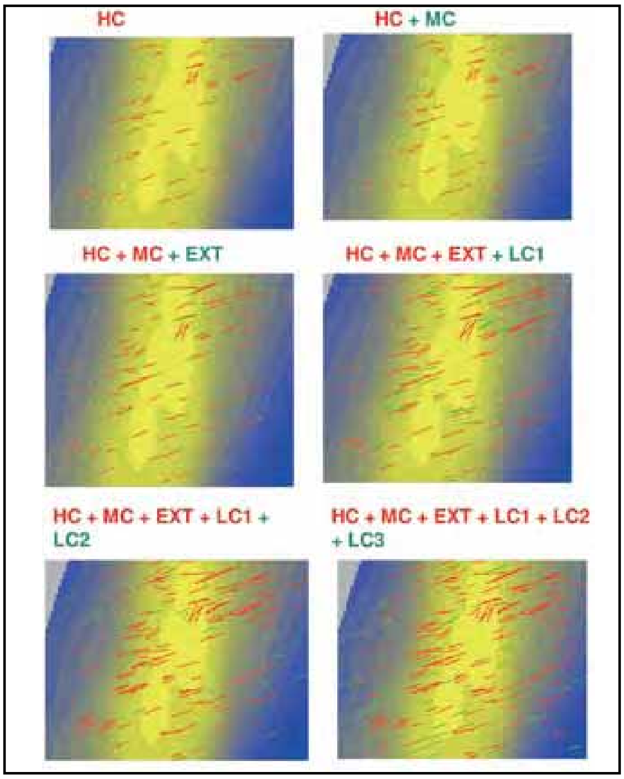


Figure 5 - Four different sets of fracture corridor: High confidence set (HC), Medium confidence set (MC), Extended fracture set (EXT), and Low confidence fracture set (LC). The first 2 sets are coming directly from the fracture characterization study. The extended fracture set contains the High and medium confidence sets extended by 40%. It will allow testing the connectivity of the fracture network. The low confidence fracture set is itself subdivided into three different sets of stochastic fracture corridors that range from a higher to a lower degree of confidence: (LC1), (LC2), and (LC3).

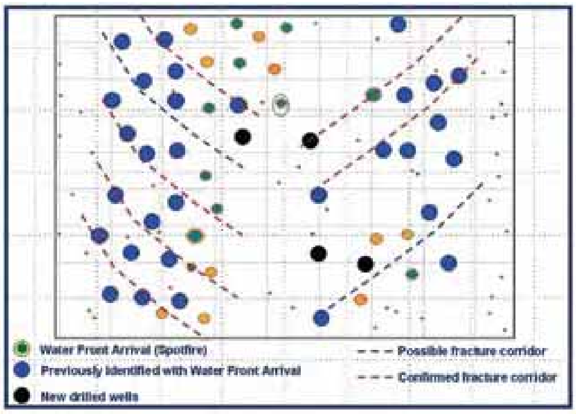


Figure 6 - The map above shows the analysis of the fractures corridors based on first water arrival analysis. This possible fractures realization from water arrival analysis to be incorporated on the original realization to identify any needed changes to the fracture realizations.

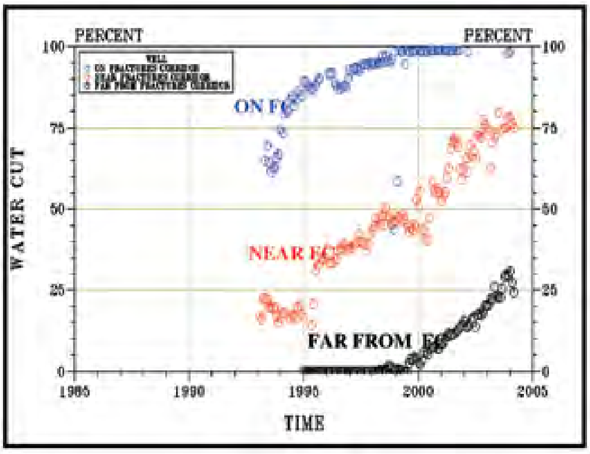


Figure 7 - Show water performance signatures of the producers were indicative of the fracture corridors locations. The rate of water cut rise and the first water entry depend very much on the distance from a fracture corridor. Well far from corridors have bottom up rise with a gradual increase in water cut. Wells near fracture corridors show water invasion of entire 2B with a rapid water cut increase. Wells that intersect a fracture corridor directly have instant water breakthrough.

formance signature of Near wells indicates a slightly delayed water breakthrough compared to "On" wells, followed by a gradual water cut rise (Figure 7).

• Wells "Far" from fracture corridors experience delayed water breakthrough and normally are characterized by bottom-up water sweep behavior. The performance signature of Far wells is characterized with a delayed water breakthrough and slow water cut rise, sometimes, followed by a steeper trend in later times, indicative of water coning (Figure 7).

The wells in "Near and Far" categories experience water coning behavior especially in the top layers where high vertical permeability exists.

In the case of a gas cap reservoir with an oil rim, the same categories described above exist. In the oil rim, the same behavior as described above is expected. In the areas below the gas cap, however, the gas movement compresses water advancement becoming more dominant. Although both water and gas breakthrough is experienced, gas breakthrough is faster, compressing and dominating water level encroachment.

4. Pressure Transient Analysis

Pressure transient analysis provides an important fracture identification information source including degree of fracture proximity to a well. Vertical well tests detect nearby conductive or cemented fracture corridors (Figure 8 A). Well tests are not only useful for

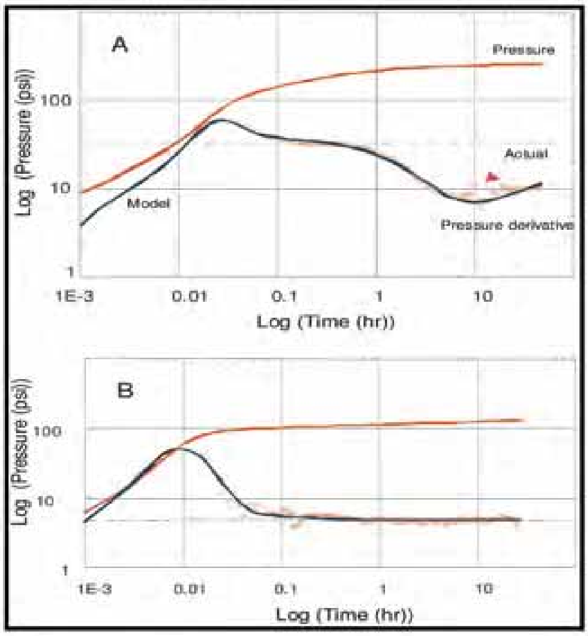


Figure 8 - (a) Build-up tests from vertical wells not only show fracture intersection, but also conductive or cemented fracture corridors nearby (top derivative plot). (b) Infinite acting homogeneous matrix defines wells with exclusion zones.

nearby conductive fault detection, but also for defining exclusion zones where no fracture corridors can pass through with infinite acting homogeneous matrix signature (Figure 8 B).

Mechanistic (Concept) Modelling

Mechanistic modeling is the next study step. Incorporating fluid flow insights and understanding gained from water production signature analysis as a 3D mechanistic reservoir simulation model. This model is used to fine-tune fracture and matrix fluid movement, develop well (H, ML) and completion alternatives to development strategy.

Three mechanistic modeling study steps are described:

1. Water Front Behavior

Mechanistic models are used to develop water front behavior understanding. The studied reservoir is characterized by high permeability rock in the top layers with rock quality degradation towards lower layers. Permeability normally ranges from hundreds of milli-Darcy (mD) to Darcy rock in the top layers to below 100 mD rock in the lower layers (Figure 9). Sector models were created to test study field reservoir behavior with no fracture corridors or diffuse fractures as a hypothetical case. With high permeability towards the top of the studied reservoir, injected water (as expected) passed over oil, sweeping the top layers first. This expected performance is different from actual historical perfor-

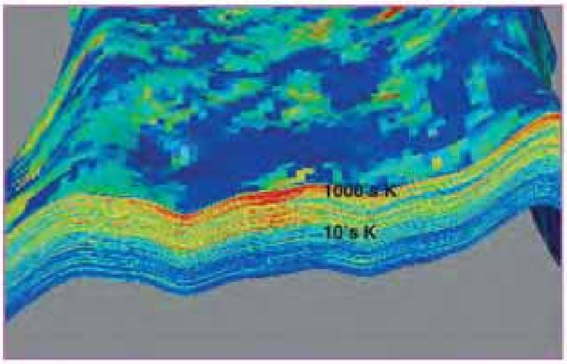


Figure 9 - The studied reservoir is characterized by having high permeability (1000,s of mD) in the top layers with clear degradation of quality towards the bottom layers. The permeability's in the top normally ranges from 500 mD to 2-3 D, relative to the below 100 mD in the bottom layers.

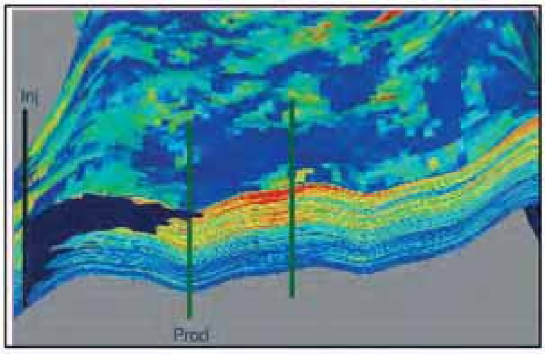


Figure 10 - With this high permeability towards the top of the reservoir, injection water is expected to over-ride the oil, sweeping first the top layers. Slumping of the water due to gravity will depend mainly on the wettability, KV and existence of barriers. In the most pronounced water slumping case (Strongly water wet, high KV, and no barriers), still there will be clear over-ride and the first row of producers will experience first water breakthrough through the top zones, then followed, in the this slumping case, with water from the bottom zone. This is different from actual historical performance that showed first water breakthrough mainly from the bottom zones and almost at the same time between flank wells and in-field wells.

mance that showed first water breakthrough mainly from bottom zones (lower permeability zones) and almost at the same time period between flank and in-field wells. Figures 9 and 10 illustrate the difference between a mainly matrix dominated reservoir compared to the actual studied reservoir performance which indicated excellent vertical conformance and sweep. Understanding this water front movement was the main challenge that many had tried to understand and model in past studies.

Based on the 3D mechanistic models, the water front movement in the complex fractured studied reservoir was reasonably understood as illustrated in Figures 11, 12 and 13. Two wells were modeled, both open-hole, one near and the other far from the fracture corridor. The study reservoir was modeled with three distinct reservoir zones:

• Reservoir zone three and four representing the bottom zones which were the main water source in the early stage of field production;
• Reservoir zone two mainly has high permeability with lateral heterogeneity;
• Reservoir zone one has mainly laterally homogenous high-K.

Figures 11 and 12 illustrate water movement before injection, from the aquifer into high-K layers. This water flows to the fracture corridors, and immediately 'slumps' due to gravity (there are no capillary forces within the fractures) to the base of the fracture corridor. At this time all wells are producing dry oil as indicated by the PLT log in the right of figure 13.

Well pressure drawdown stimulates water movement in the bottom of fracture corridors within the affected reservoir. This is supported by continued aquifer feed to the fractures as related to production maintenance. In general, fracture pressure is expected to be higher than producing well pressure.

Since the water is moving in the bottom of the fracture corridors, and all early production wells were open-hole completions (producing from all zones), it is now clear why first water production was from the high-K bottom thin zone three. This phenomenon was especially clear in wells near to the corridors.

As time progress, PLT data as shown to the right of Figure 13 indicates water cut in the range of 10% water from the bottom zones. This was a common phenomenon seen in the selected reservoir. The dry oil production strategy at the time required shutting in or working over of most wells in the lower reservoir section to avoid wet production.

As power water injection started in the studied reservoir, most of the injectors were found to have injected above fracture pressure. This was needed to allow high volume injection from a small number of injectors to balance withdrawals.

As the injectors created small fractures, water slumped to the bottom of these small fractures in a manner very similar to water slumping described in fracture corridors. This effect enhanced field performance as it provided improved injectivity above 30,000 BWPD per

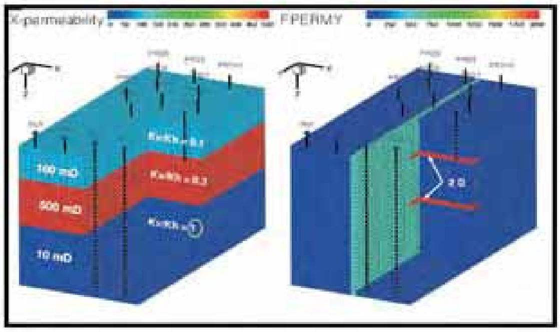


Figure 11 - The mechanistic model was build to test different concepts over short runs times. The Figure above shows the matrix model on the left hand side of the slide with the K-matrix used as well as the KV/KH applied. The sector model has flank injection as with many in-field producers. There are also two high and thinner permeability layers that each has 2 Darcie's permeability. This was modeled through the fracture model in the DPDP model. The fracture model is shown on the right hand side of the slide above.

injector. These high injection rates quickly balanced production while lowering injection in high K layers in the top of the reservoir, which would have caused significant undesirable water over-ride in the reservoir.

The studied reservoir exhibited water breakthrough to the high-K zone two as the resultant of water propagation through fracture corridors and a dry-oil strategy to avoid water production. This water breakthrough was first experienced in wells near to fracture corridors. As time progressed, water arrived at wells far from the fracture corridors as illustrated in the PLT logs to the right of Figure 13. This bottom up water breakthrough created a challenge to many conducting early studies before understanding the relation between this upward water sweep and the bottom-up water movement in fracture corridors and diffuse fracture systems.

As time progresses, it was noticed that wells far from fracture corridors that had already been swept in reservoir zone two very quickly experience water coning in the top section of this zone. This was not surprising, since vertical permeability (KV) in zone two is high.

The performance of the wells where fracture corridors does not dominate did not match the described concept above. Therefore, through additional reviews and more detailed characterization, it was concluded that the diffuse fracture system has a more significant water movement role. Study results indicate that diffuse fractures provide a means to accelerate lateral water movement in the studied reservoir, especially in lower reservoir layers. Figure 14 illustrates two diffuse fractures systems that act as water conduits. In fact these layered bounded fracture systems enhanced the already good

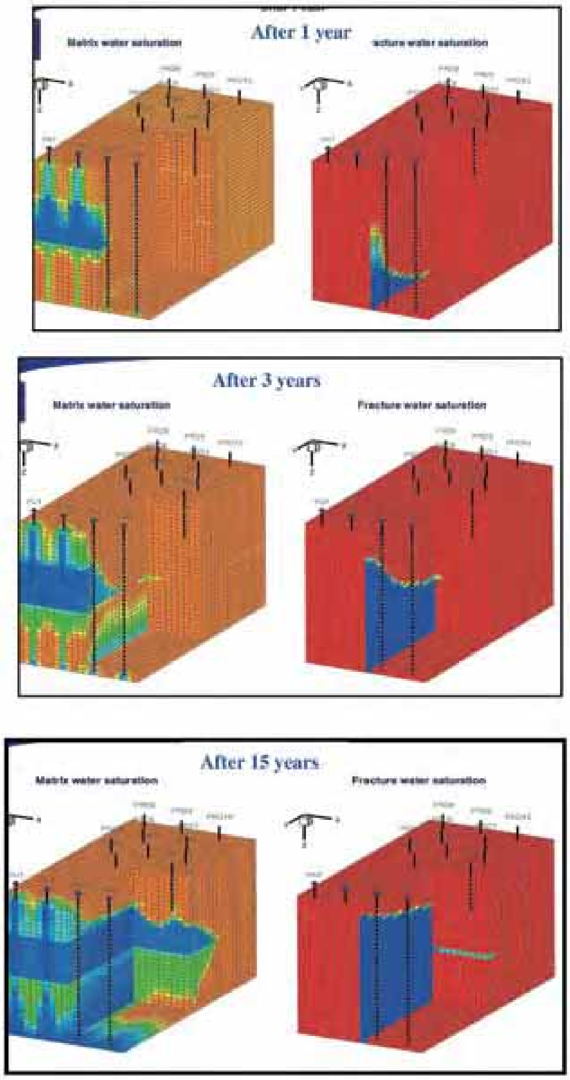


Figure 12 - Show the water movement with time in both the fracture corridors (the right hand graph in the slide) and the matrix in the left hand side. Notice that in this run the clear gravity sweep in the lower zones due to the increase in KV/KH. This would suggest that if background fractures or diffused micro fractures exist, then the lower zones will experience good sweep. Also notice that still coning effects in the top zones are experienced. The above illustrates the effect of the diffuse fractures on the gravity sweep in the lower zones.

history match that was achieved in the area dominated by mainly fracture corridors.

In the case of a gas cap reservoir with an oil rim, in the oil rim the same behavior as described above is expected. In the areas below the gas cap, however, as was previously discussed, the gas movement compresses water advancement, and becomes more dominating.

2. Water Encroachment Pattern

Mechanistic models are also very useful to understand reservoir water encroachment pattern. High resolution mechanistic modeling studies suggest that water enter-

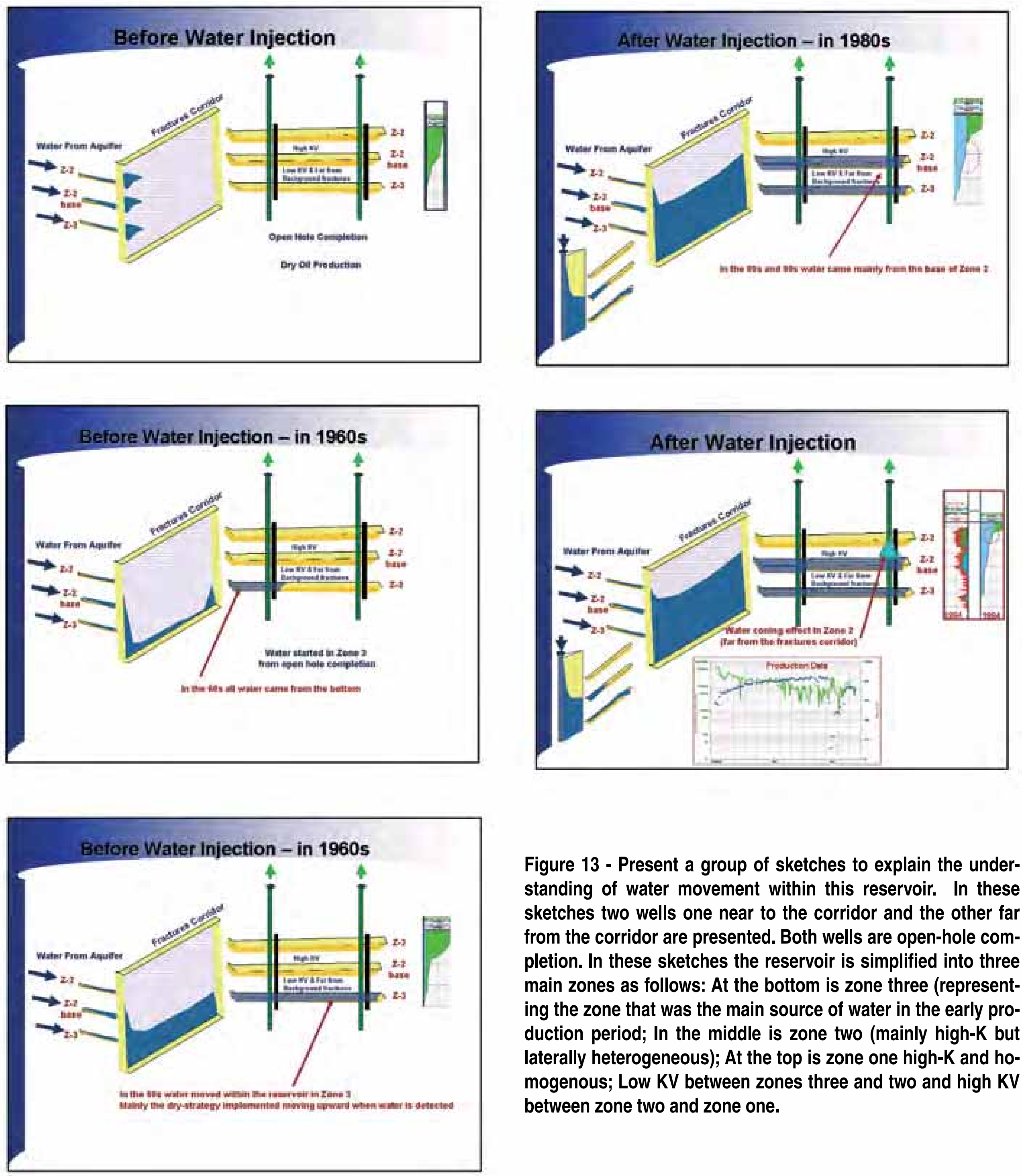


Figure 13 - Present a group of sketches to explain the understanding of water movement within this reservoir. In these sketches two wells one near to the corridor and the other far from the corridor are presented. Both wells are open-hole completion. In these sketches the reservoir is simplified into three main zones as follows: At the bottom is zone three (representing the zone that was the main source of water in the early production period; In the middle is zone two (mainly high-K but laterally heterogeneous); At the top is zone one high-K and homogenous; Low KV between zones three and two and high KV between zone two and zone one.

ing fracture corridors slumps to the bottom by gravity invading the reservoir, first from the bottom (Elrafie et al.[2]). The oil-water contact within the fracture corridor is a function of the pressure difference within the fracture corridor and the matrix. Oil production causes pressure drawdown in the matrix and continuing water injection increase pressure within fracture corridors. Consequently, water level tends to rise within the fracture corridor and as water level moves up within the fracture corridor, the flood front advances as a "wedge" into the reservoir facilitating bottom up sweep (Figure 15). The water level rises fast in wells near fracture corridors and gradually in wells further from fracture corridors. The water level is lowest and the oil column is thickest between the two fracture corridors. The corridors can act as a "line-drive" sweep and pressure support process, enhancing reservoir performance (Figures 16 and 17). The variation of oil column thickness and water level may be used to identify and map fracture corridors. If water level reaches high permeability lay-

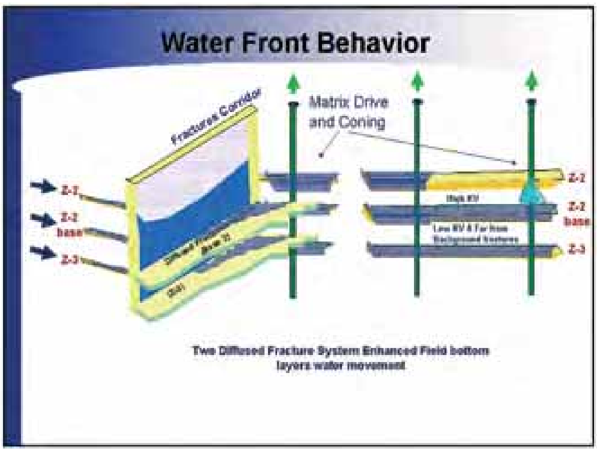


Figure 14 - Shows the two diffuse fracture systems that act as a conduit to water. In fact the two diffused systems enhanced the already good history match that was achieved in the area that was not dominated by fracture corridors.

ers at the top of the reservoir, some water overriding takes place, but overriding in such layers is confined to short distances in the vicinity of fracture corridors owing to the thick section of excellent horizontal and vertical matrix permeability encountered in the upper half of the reservoir.

Production flow profiles are the best means to determine water level, oil column thickness and water level rate. Flow profiles in combination with water cut at the time of flow profile measurement, and current water cut, are used to calculate present day water level and oil column thickness. A high water level indicates fracture corridor or injector proximity. As such, it is necessary to check well location with respect to injectors. If multiple flow profiles are available, the rate of water level rise can be estimated and compared with water cut rise from production history data.

3. Assessing Future Intelligent Well Designs

Another purpose of mechanistic models is to understand water and gas front behavior impact on well type, completion type and placement. In the studied reservoir selected well designs were evaluated in sector models covering a wide range of field areas of different oil column thickness, rock quality and fracture density. Well type and completion strategy recommendations were presented for each identified field area including intelligent/smart wells. In the selected study case, two oil producing zones were identified. The first zone is a thick oil column where oil has not been swept laterally and vertically. This target area is located in the crest of the studied reservoir and at long distance from the fracture corridors where a full oil column is expected. The second production zone is a flank area between

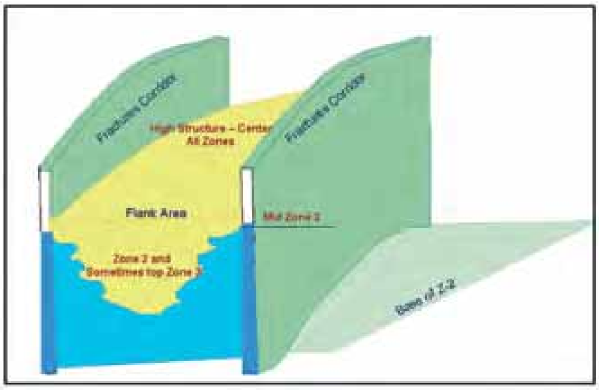


Figure 15 - Sketch illustrates the current picture for the water rise between fracture corridors; around the corridors the water is high and is currently expected to be within the top of zone two to bottom of zone one. Far from the corridors, the water raise is low, where in the flanks the water might reach zone three level, while in the center most of the zones are still above the water raise level. The variation of oil thickness column and water level may be used to identify remaining oil column in the field.

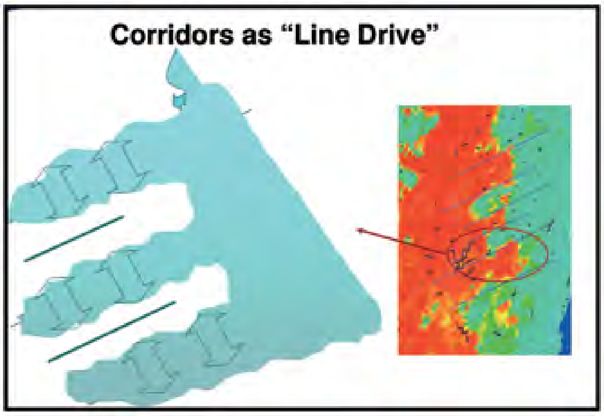


Figure 16 - For an area view it is expected that the fracture corridors are acting as line-drive injectors that are injecting in all zones.

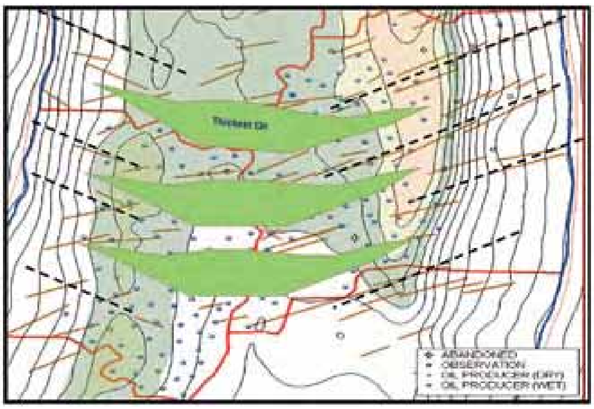


Figure 17 - The areas near the flank of the reservoir and in-between the fracture corridors appear to have low oil thickness near the flank and higher oil thickness towards the center of the reservoir. This "wing" shape oil thickness was difficult to target with dedicated wells.

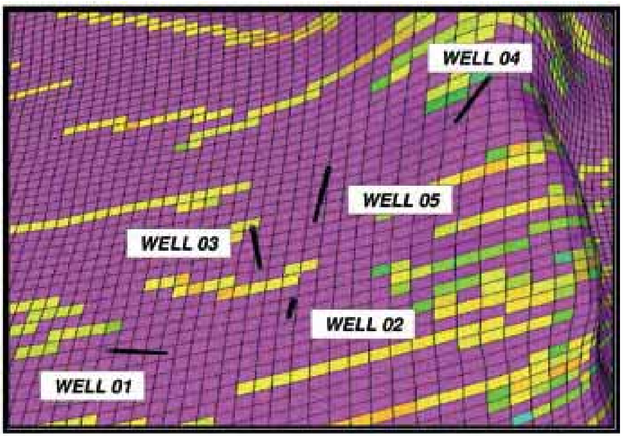


Figure 18 - Vertical wells locations relative to fractures.

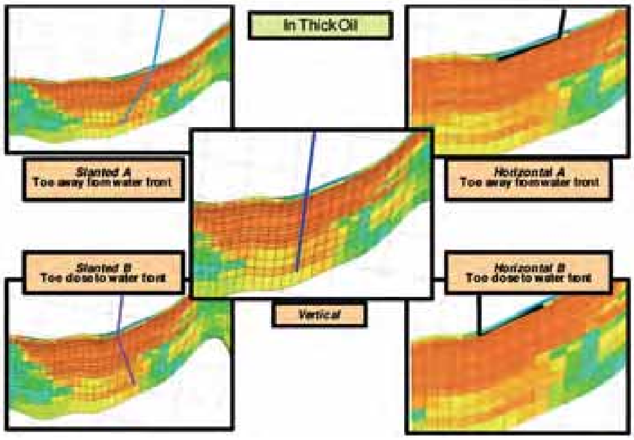


Figure 19 - Wells Types considered in the study.

fracture corridors which can be referred to as a thin oil column. Oil remains in this area only at the top of the reservoir, where water is advancing, due to: large historical production/injection, proximity to peripheral injectors and fracture corridors presence.

Well Types

Vertical, slanted and horizontal well types were modeled. For each location the impact on production of nearby fracture corridors was evaluated. Offset wells were shut-in on all cases to minimize their influence on wells under evaluation. Figures 18 and 19 illustrate proposed well location and well type. Three vertical well configurations were tested: an open-hole completion with and without any workovers and vertical wells that partially penetrated the upper reservoir section. The best performing vertical well was then compared to slanted and horizontal well types. Horizontal wells were placed as high as possible in the reservoir structure where there is no gas cap existed.

Results for vertical wells indicated that partial penetration in the upper section of the reservoir is the most profitable choice. In Figure 20, most of the invading water is in the lower units, where diffuse fractures are likely to exist as illustrated by historical flow profiles. Opening the upper portion of the reservoir through partial penetration vertical wells would delay water breakthrough compared to the other vertical well scenarios.

In thick oil column areas, the best performing vertical well (partial reservoir penetration) was compared with slanted and horizontal wells. Both slanted and horizontal wells were designed in two categories: the toe is towards water front in one case and the toe is away from water front in the other. Due to the coarse modeling grid block used and a small deviation, similar results were obtained for slanted wells compared to vertical ones. The best vertical wells (partial penetration) were performing better than slanted wells.

Horizontal wells were open hole completed, located away from any fracture corridor, with a one kilometer long reservoir section. Study results are shown in Figure 21, clearly indicating that horizontal wells in both categories outperform all other well types.

High productivity indexes and a smaller drawdown are the primary contributing factors to horizontal well performance. In addition, better lateral sweep (wider drainage area). Frictional pressure loss was also studied in the case of horizontal wells and was found to be negligible where the diameter of the wellbore is higher as shown in Figures 22 and 23.

Location, Orientation and Completion

Well location, orientation and completion alternatives were applied to thick and thin oil column targets. Horizontal wells, which were the best performing well based on well type sensitivities, were tested across and parallel to fracture corridors. In each location, horizontal wells with different orientation and completions were investigated. See Figure 24. Completion alternatives included open hole, Inflow Control Devices (equalizers), Inflow Control Valves, blank pipes and finally a combination of all.

In thick oil column areas, two sets of horizontal wells with 1 km effective length in the top section of the reservoir were designed. The first set was completed open hole and located parallel to fractures. The second set was also completed open hole but crossing fractures. Each study set composed of four wells. The results showed that the wells parallel to fracture have better performance. Water moving preferentially through the

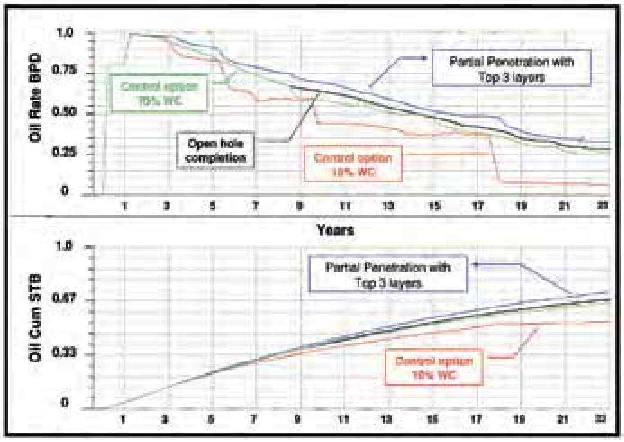


Figure 20 - Vertical well options comparison. Normalization for oil rates & oil cumulative axis is based on maximum values.

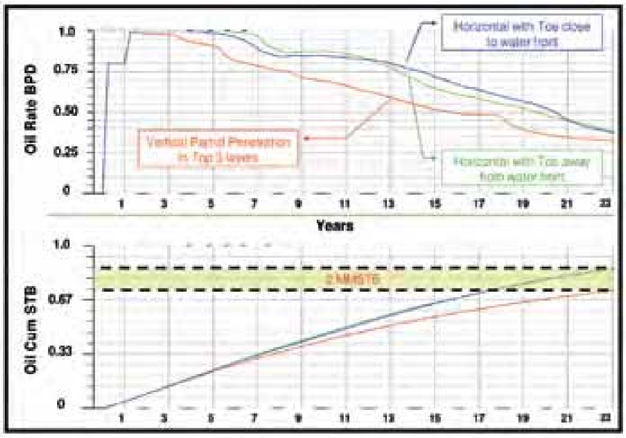


Figure 21 - Well Types comparison. Normalization for oil rates & oil cumulative axis is based on maximum values.

high conductive fractures act as an effective line drive system within the reservoir providing excellent pressure support throughout the reservoir. The wells which are not crossing fractures corridors break water later and therefore produce more oil (Figure 25). For completion sensitivities a local grid refinement area was defined. Results illustrated in Figure 26 showed that advanced completions do not provide, in general, a significant additional benefit compared to open hole production in wells located across fracture corridors. When the fracture is being crossed by the well, the production contribution from the fracture varies according to the effective length of the well. As the effective well length increases the contribution of the fractures decreases (i.e., around 15% from fractures when effective length is 1km). Smart completion objectives are to produce straight line fluid profile along the wellbore or to minimize water production. When the production from the fractures is decreased by smart tools (oil and/or water) this would aggravate water coning in the matrix along the wellbore to maintain a fixed production target. At the end of forecast period, the final oil cumulative with different smart completions configuration is similar to open-hole completion results. For wells parallel to fracture corridors, “linear” homogenous fluid profile is observed along the wellbore (matrix properties are fairly homogeneous at the top of the reservoir). Therefore, the use for smart completions is not practical.

In the thin oil column areas, three wells were investigated with the same criteria as in the thick oil column. In this case the oil water contact is located less than 20 feet below the horizontal well sections. With this configuration, water production through coning cannot be avoided (Figure 27) unless the well is produced at a very low rate (impractical). The influence of both well placement relative to fracture corridors and the type of completion used was investigated.

Wells that cross fractures perform better in terms of cumulative produced oil than wells parallel to fractures. Simulation runs show that for a horizontal well cross-

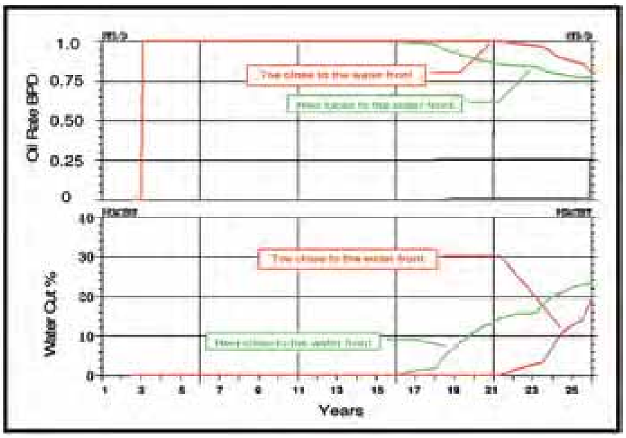


Figure 22 - Effect of friction: 3.5” inside diameter for the tubing show considerable friction losses between the heel and the toe for horizontal well. A normalized oil rate is plotted based on the maximum oil rate value.

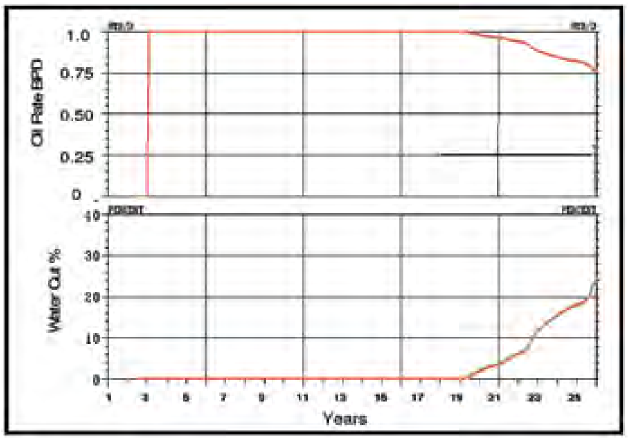


Figure 23 - Impact of friction pressure loss is minimum between the heel and the toe for horizontal well with 7” diameter for the tubing.

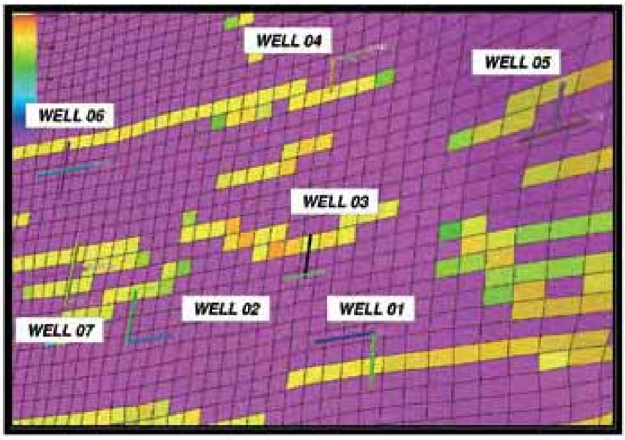


Figure 24 - Horizontal wells location relative to fractures.

ing a fracture corridor, a fair amount of oil and most of the water is produced from the highly conductive fractures. The remaining well interval, completed in the matrix, is producing mainly oil. If the well does not cross a fracture corridor, the well productivity is smaller. The water conning effect is stronger (for the same liquid rate) and occurs along most of the horizontal section.

Fracture corridors are mainly affected by gravity forces and viscous forces (capillary forces are negligible in fractures). Therefore, they create a water slumping system that enhanced the bottom-up sweep (vertical conformance) in the reservoir. Consequently, oil water contact (OWC) inside fracture corridors, in the thin oil section, is deeper relative to the OWC in the matrix. This means, the water will cone in the matrix once the well is in production. Figure 28 explains those concepts.

Effective Horizontal Length

Simulation runs showed that the appropriate effective length for a horizontal well located at the top of the structure is around 1 km. All previously discussed cases

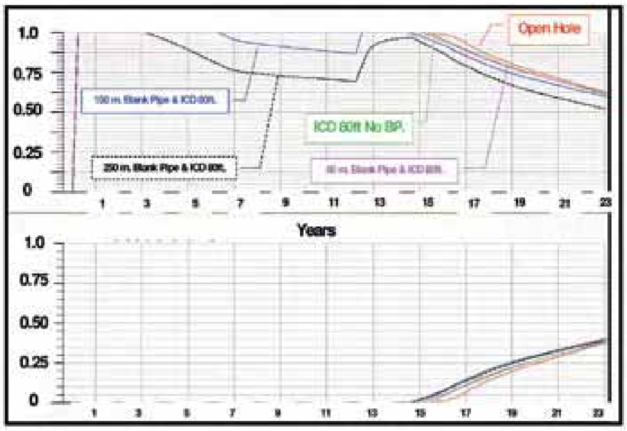


Figure 26 - In the thick oil column, the open hole completion seems more reliable than other types (See figure 31 for terminology).

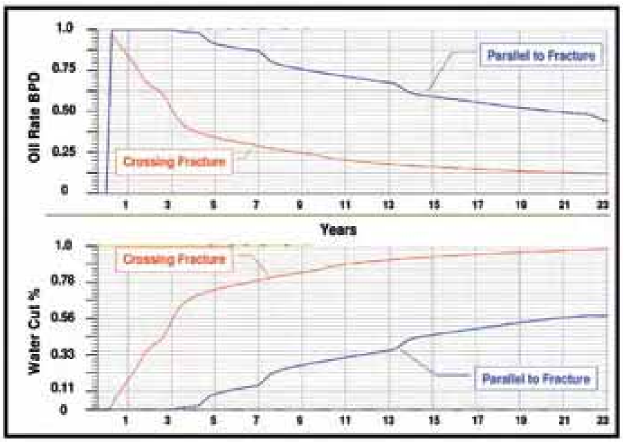


Figure 25 - Horizontal Well A. Showing the difference in performance when the orientation is varied relative to fracture. Normalization for oil rates is based on maximum values.

were run under this optimized well length. In the model, the production contribution from fractures when crossed by a producer is in the range of 15 to 25%. Production logs measured in some recently drilled wells showed higher current production coming from the fractured interval but for a smaller effective producing horizontal length. Simulation runs confirmed that there is a clear relationship between the fracture contribution and the effective length of the well on production as can be seen in Figures 29 and 30.

Effective well length sensitivity was performed on wells crossing fractures in the thick oil column to see the impact of the fracture contribution to the entire wellbore section. Flow mechanism results showed that short effective well length would result in higher production from the fracture and faster water breakthrough.

ICVs and ICDs

Effect of Inflow Control Devices and Inflow Control Valves are similar and do not give additional oil recovery when a fixed production target is required. Thus, an

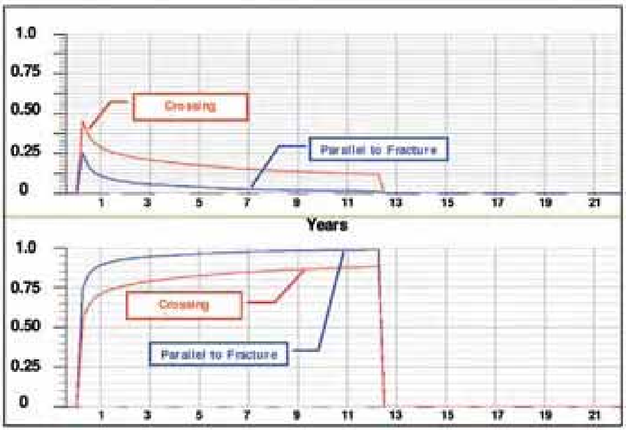


Figure 27 - In thin oil column section, crossing fractures can be more beneficial than parallel to fractures wells.

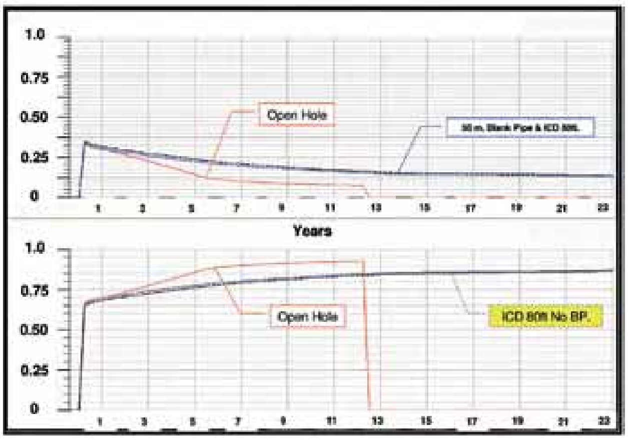


Figure 28 - Shows that in the thin oil column section, the inflow control device seems to have a positive impact on the long run.

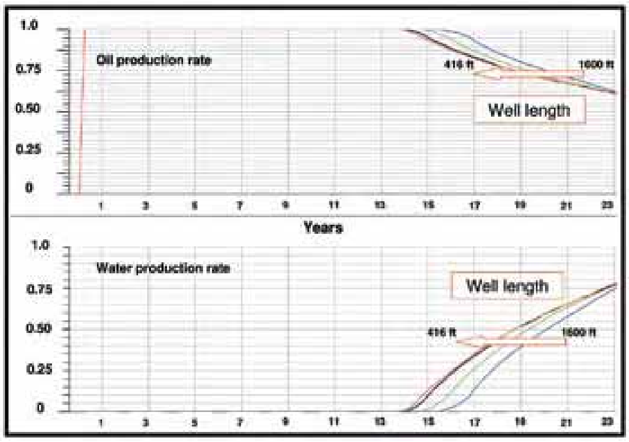


Figure 29 - Performance results showing the impact of well length in addition to different production rates. Normalization for oil & water rates is based on maximum values.

additional sensitivity was performed on an open-hole case to evaluate the flow rate effect, and as expected, water production can be minimized considerably only if low production rates are handled. Figure 31 shows the oil cumulative comparison made by completion and at different production rates for the short horizontal well of 400ft long.

Full Field Simulation Model

The understanding of the fluid flow mechanisms as well as the optimized well types and completion strategies obtained using sectors models are all rolled up and implemented into a dual media full field simulation model which will be history matched. This model will be used to evaluate and optimize different development scenarios and used to understand fluids flow mechanism across the different areas of the field.

The full field model is history matched using assisted history match tools to enable running the full field model of these studies under many different fracture realizations and water behavior hypothesis. To capture all ranges of possibilities, hundreds of history match simulation runs were conducted and a history match solution surface (i.e. Proxy) was statistically generated using the assisted history matching tools enabling to history match the water (and gas when applicable) movement in this fractured carbonate reservoirs. This match was focused on zonal water breakthrough to ensure the right mechanism was captured. The history match, generally, was straight forward and took short time to be accomplished. This is since the main reservoir fluids flow physics are captured and were understood using an integrated study methodology (described earlier) the “Event Solution” approach[1].

Although an excellent simulation history match was achieved for the first time for some of these challenging carbonate reservoirs, a lot of these matches were not unique. Several realizations of these matches with ranges of static and dynamic uncertainty variables existed. To understand the impact of this new understanding of water and gas behavior on future reservoir performance predictions, future forecast under alternative development scenarios were then simulated under uncertainty (capturing all uncertainty ranges). A more detailed description of prediction under uncertainty processes will be covered in a separate paper in the future.

Conclusions

Fracture characterizations and understanding fluids flow mechanisms were critical factors in both optimizing intelligent wells as well as assisting the history match process and field development plans. The understanding of fluids flow mechanisms showed that the fracture system actually enhanced the performance of the reservoir, where the corridors created a very effective line-drive injection system. Fracture corridors in combination with the diffuse fractures created a water slumping system that enhanced the bottom-up sweep (vertical conformance) in the reservoir.

A methodology was demonstrated that was used in studying field development plans and optimization on a number of carbonate naturally fractured reservoirs through an integrated study using the “Event Solution” approach1. The methodology was illustrated through a case study.

The presented methodology can be applied in any field study and it is being used as an established methodology for integrated study in the Saudi Aramco Event Solution Center.

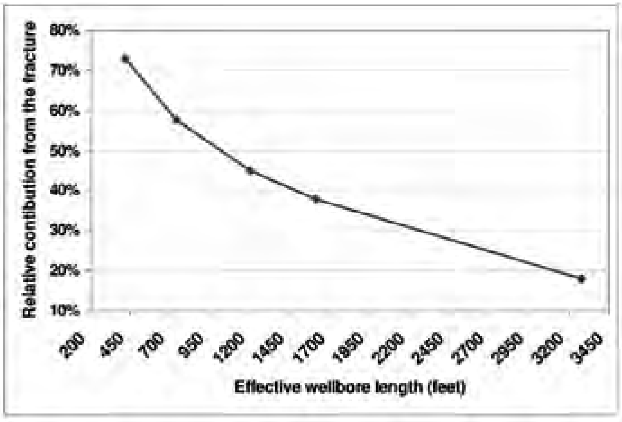


Figure 30 - Relation between the effective wellbore length and the fracture contribution to the total flow.

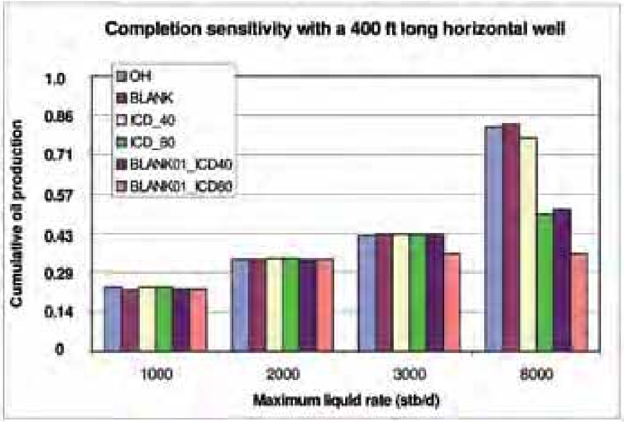


Figure 31 - Normalized Oil cumulative comparison between different completions with different rates for horizontal well of 400ft length.
OH – Open hole Completion
Blank (BP) – Completion with Blank
ICD 40 – Completion with 40 meter equalizer spacing
ICD 80 – Completion with 80 meter equalizer spacing
Blank_ICD 40 – Completion combination with 40 meter equalizer spacing and blank pipe across fracture interval

Acknowledgments

The authors would like to thank Saudi Aramco for the permission to publish this paper.

References

1. Uba, H. M., Chiffoleau, Y., Pham, T., Divry, V., Kaabi, A. and Thuwaini, J.: "Application of a Hybrid Dual Porosity Dual Permeability Representation of Large Scale Fractures to the Simulation of a Giant Carbonate Reservoir," SPE 105560, presented at the MEOS 2007, Bahrain.

2. Elrafie, E., White, J., Awani, F.: "The Event solution; a New Approach for Fully Integrated Studies Covering Uncertainty Analysis and Risk Assessment." SPE 105276, presented at the MEOS 2007, Bahrain.

3. Al-Thawad F., Agyapong, D., Banerhjee, R., Issaka, M.B. "Pressure Transient Analysis of Horizontal wells in a Fractured Reservoir; Gridding between Art and Science," SPE 87013, SPE 2004 Asia Pacific Conference, Kuala Lumpur 29-30 Mar.

4. Al-Ghamdi, A. H., Issaka, M. B. "Uncertainties and Challenges of Modern Well Test Interpretation" SPE 71589, SPE 2001 Annual Technical Conference and Exhibition, New Orleans, 30 Sep.- 3 Oct.

5. Ebadi, F., and Davies, D.: "Techniques for Optimum Placement of Interval Control Valves in an Intelligent Well," paper SPE 100191 presented at the SPE/EAGE annual conference & Exhibition, Vienna, Austria, June 12-15 2006.

6. Jonathan A. Holmes, "Modeling Advanced Wells in Reservoir Simulation," paper SPE 72493 published in the distinguished author series, JPT November 2001.

7. Holmes, J., Barkve, T.,Lund, O.: "Application of a Multisegment Well Model to Simulate Flow in Advanced Wells," paper SPE 50646, presented at the SPE European petroleum conference, the Hague, the Netherlands, October 20-22, 1998.

8. Ajayi, A. and Konopczynski, M.: "A Dynamic Optimization Technique for Simulation of Multi-Zone Intelligent Well Systems in a Reservoir Development," paper SPE 83963 presented at the SPE ATCE, Denver, Colorado, USA, October 5-8 2003.

9. Sinha, S. et al.: "Flow Equilibration Towards Horizontal Wells Using Downhole Valves," paper SPE 68635 presented at Asia Pacific Oil & Gas Conference, Jakarta, Indonesia, April 17-19 2001.

10. Ajayi, A. et al.: "Application of Intelligent Completions to Optimize Water flood Process on a Mature North Sea Filed: A Case Study," paper SPE 101935, presented at the First International Oil Conference & Exhibition, Cancun, Mexico, August 31-September 2, 2006.

11. Yu, S., Davies, D.R. and Sherrard, D.W.: "The Modeling of Advance "Intelligent" Well-An Application," paper SPE 62950 presented at the 2000 SPE ATCE, Dallas, Texas, October 1-4.

12. Augustine, J. and Ratterman, E. "Advanced Completion Technology Creates a New Reality for Common Oilfield Myths," paper SPE 100316 presented at the SPE/EAGE Annual Conference & Exhibition, Vienna, Austria, June 12-15 2006.

Application of Thomeer Hyperbolas to facies and reservoir properties of Limestone, Ghawar field, Saudi Arabia:

By Edward A. Clerke, Harry W. Mueller III, Eugene Craig Phillips, Ramsin Y. Eyvazzadeh,
David H. Jones (Saudi Aramco), Raghu Ramamoorthy and Ashok Srivastava (Schlumberger)

The long poorly understood problem of Carbonate petroleum reservoirs has been revised in a breakthrough.

Carbonate petroleum reservoirs (natural carbonate porous media) have been problematic to the oil industry for a long time. In particular, carbonates do not behave as the other major group of natural porous media (siliciclastics – sandstones). Now new data and analysis explains why. Sandstones have always been modelled as a continuum of pore sizes and pore properties. New carbonate data from the world's largest oil field shows that the carbonates (remnants of organic structures) are not a continuum but consists of a number of distinct modes called porositons!

Understanding pore systems is essential for modelling the properties and performance of hydrocarbon reservoirs. Pore systems provide the primary control on hydrocarbon distribution during reservoir charging. They control the interaction of the rock with fluids through wettability modification, and fundamentally control the hydrocarbon storage and recovery through the properties of porosity, permeability, relative permeability and microscopic-displacement efficiency. Pore systems can be examined in detail with core material and perhaps linked to well-log responses, but to fill the interwell volumes of reservoir models with pore system properties, they must also be linked to predictive geological parameters. Thompson et al. (1987) in a portentous review of the pore geometrical problems of sedimentary rocks, noted 'Prediction of rock properties, such as the transport properties of fluids in the pore space, and the elastic properties of the grain space, requires a set of statistics that embody the relevant physics'; and 'More generally, the statistical description of pore geometry awaits definition of relevant statistics. This approach could ultimately tie the geology of rock formation to their reservoir properties, a tie with important consequences for oil exploration and production.' Multiple and complex pore systems are commonly encountered in carbonate reservoirs. Studies of the Arab D limestones in Ghawar field, Saudi Arabia (Figure 1), have demonstrated the presence and approximate volumes of multiple-porosity types as two-dimensional petrographic information (Cantrell and Hagerty, 1999, 2003; Hagerty and Cantrell, 1990 unpublished report). In this paper, we extract three-dimensional pore geometrical statistics that embody the relevant physics using results from Thomeer Hyperbola (Thomeer, 1960) analysis of mercury injection capillary pressure data and qualitative analysis of nuclear magnetic resonance (NMR).

The aspects of the pore system we extract are:
(1) Pore-subsystem volume, which has a counterpart in the size-differentiated, point-count data;
(2) Pore-subsystem geometrical factor, which has a counterpart in the sorting coefficient or size distribution width of the size-differentiated point-count data;
(3) Maximum diameter of the pore-throat that controls the pore subsystem. This is only determined by Thomeer analysis of MICP data, and only has a weakly defined petrographic counterpart. This diameter value, however, plays a fundamental role in a new pore-system classification scheme, allows the pore-subsystems to be

decode the pore systems, the Upper Jurassic Arab D A 'Rosetta Stone' approach

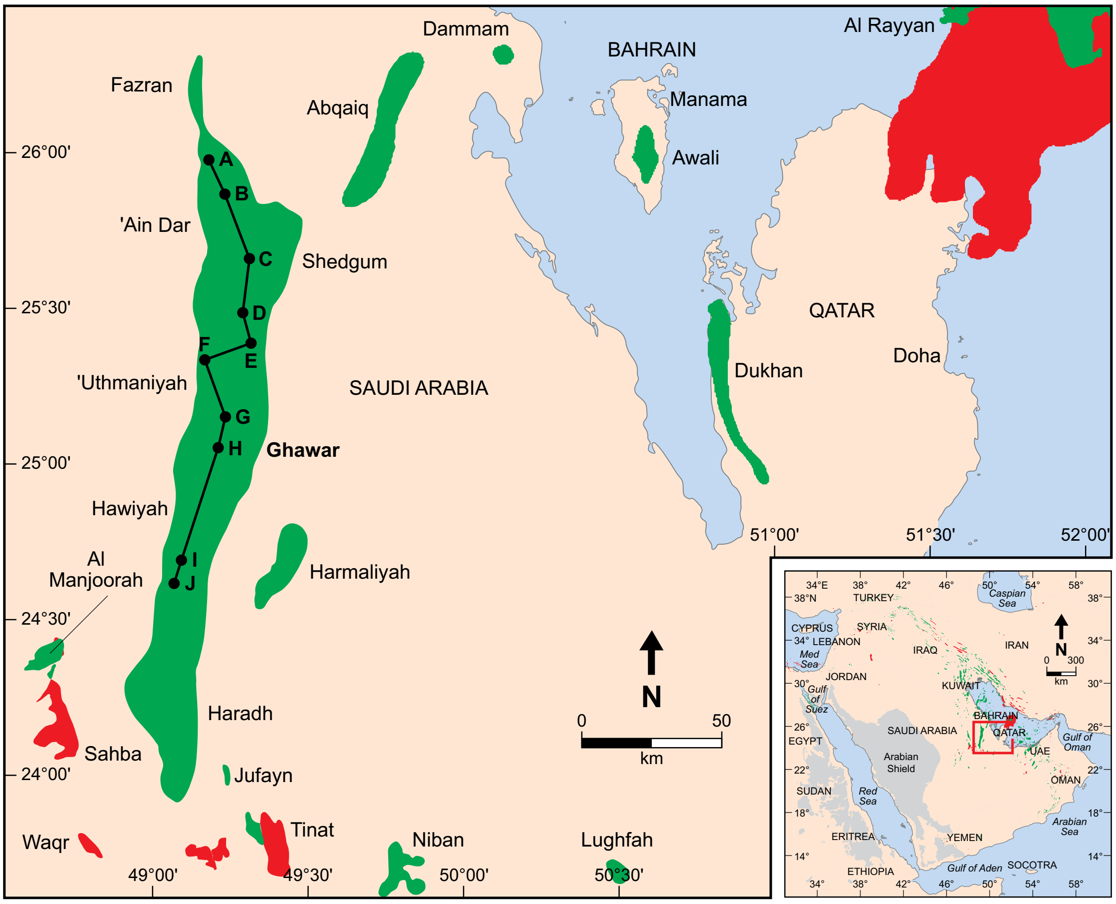


Figure 1: The Arab D limestone was sampled in ten cored wells located along a NS- transect of Ghawar field. The mercury injection capillary pressure (MICP) date base was selected using random decimation from an inventory of over 3,500 core plugs with assigned facies.

related to height above free-water level in the reservoir (effectiveness) and controls the permeability.

The results that emerge from our analysis intersect several petroleum reservoir disciplines and, more explicitly, allow us to relate their subsurface languages. Our approach is similar to the translation triangle applied to the decoding of Egyptian hieroglyphs using the Rosetta Stone. This paper focuses on the subsurface languages involving Arab D static reservoir properties: depositional facies, well-log responses and the pore systems. Other translations involve the dynamic properties of permeability, relative permeability and microscopic-displacement efficiency and speak to a petrophysical and reservoir engineering audience. These have been published in the engineering literature (Clerke, 2007).

The paper begins with some general information about the Ghawar field and previous geological studies of Arab D facies and carbonate microporosity. Our analysis is focused on limestones and does not include dolomitic facies, nor do we consider the important role of fracture porosity and permeability. We then introduce the statistics of the maximum pore-throat diameter to characterize the multimodal Arab D limestone facies. We discuss density-neutron measurements, porosity and permeability as related to multimodal limestone pore systems. Using only basics of NMR signal analysis, we demonstrate an alignment of the behaviour of maximum pore-throat diameter and NMR detected pore-body diameters. We explore relationships between facies and porositons, and the calculation of permeability. Finally, we conclude that these new investigations create many new paths for improvements in the evaluation of complex carbonate reservoirs.

ACRONYMS, ABBREVIATIONS, TERMS AND DEFINITIONS

Bv Volume of mercury injected into a porous rock sample during the mercury injection experiment, expressed as a fraction of the total sample bulk volume

$d_{THROAT,MAX}$ Diameter (microns) of the largest pore-throat in a sample containing multiple pore systems (Thomeer Hyperbolas) i.e. the largest of the largest.

Dunham textures: Carbonate fabric textural classification system separating grains and muds (Dunham, 1962).

G Pore geometrical factor, related to the uniformity of the pore-throat diameters (low G) or non-uniformity (high G) of the pore-throats.

MICP Mercury injection capillary pressure.

Mode Region or subdivision of a uniform space as defined by the relevant physics and or physical parameters. In this paper the pore system of the Arab D limestone was found to be multimodal (i.e. pore-system modality) and its modality to be monomodal, bimodal, or trimodal.

NMR Nuclear magnetic resonance.

P_d Minimum entry pressure or the maximum pore-throat diameter for a system of pores and throats that are characterized by one Thomeer Hyperbola.

$P_{d,f}$ the minimum entry pressure for a sample containing multiple pore systems (Thomeer Hyperbolas), i.e. the minimum of the minimums.

Pore subsystem: A continuum of pore-throats and pore space characterized by one Thomeer Hyberbola and one maximum pore-throat diameter; the latter of which is a member of a Porositon.

Porobodon: A postulated mode in the NMR pore body spectrum that may be directly related to a Porositon.

Porositon: A distinct and separable frequency distribution of maximum pore-throat diameters, P_d, which has a Gaussian distribution in the Log(P_d) domain, i.e. a mode in the maximum porethroat diameter space. In this paper the porosity of the Arab D limestone is characterized by the M Porositon (macroporosity) and Types 1, 2 and 3 Porositons (microporosity).

Thomeer Hyperbola: The hyperbola is characterised by (1) P_d, the minimum entry pressure or the maximum pore-throat diameter; (2) the pore geometrical factor, G; and (3) B°, the pore volume in that particular Thomeer hyperbola.

PREVIOUS STUDIES OF CARBONATE POROSITY SYSTEMS

The super-giant Ghawar oil field of Saudi Arabia is a N-trending anticline that is 230 km long and approximately 30 km wide (Figure 1). The main reservoir is the carbonate part of the D Member of the Upper Jurassic Arab Formation (Powers, 1968). The Arab-D Member is the oldest of four carbonate-evaporite cycles (from bottom to top, Arab-D, Arab-C, Arab-B, and Arab-A with the overlying Hith Anhydrite), each stratigraphically comprising a lower carbonate unit and an upper evaporite unit of which the evaporite intervals dominated by anhydrite. The D Member carbonate consists of several scales of shallowing-upward cycles dominated by burrowed mudstones and wackestones in its lower part and transitioning to skeletal packstones and grainstones and, ultimately, ooid grainstones in the upper part.

Many articles have been written on the super-giant Ghawar field, its geology and the performance of the Arab D Reservoir (e.g. Powers, 1968; Mitchell et al., 1988; Al-Husseini, 1997; Stenger et al., 2003; Figure 2 after Lindsay et al., 2006), but few have integrated its pore systems with the geology and reservoir performance. Moreover, although thousands of well logs, production surveys, cores and extensive production histories are available as data to characterise the Arab D Reservoir

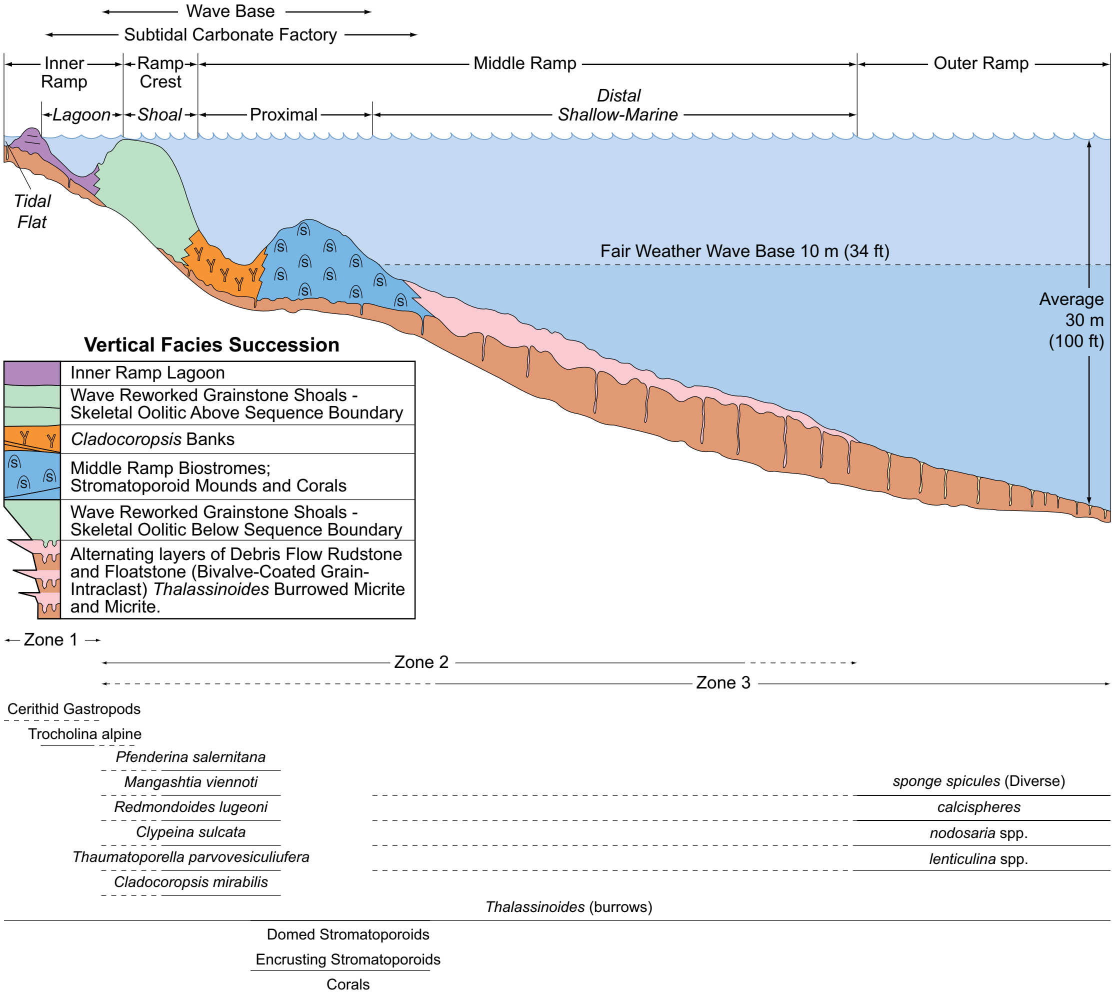


Figure 2: A single depositional cycle of the Arab D sediments that clearly identifies the main facies (Simplified after Lindsay et al., 2006). Readily identified facies within this cycle are the Cladocoropsis, Stromatoporoid-Red Algae-Coral, Bivalve-Coated Grain-Intraclasts (debris-flow deposits), Micrite and Thalassinoides Burrowed Micrite. Shoal deposits are associated with massive sands and oolitic (Skeletal Oolitic) facies in two positions in the total Arab D sedimentary column. When multiple depositional cycles are considered within the Ghawar Arab D section and sequence stratigraphy, a common simplified vertical facies succession emerges as the one shown on the lower left.

performance, the fundamental understanding of porosity and permeability and prediction of permeability remains a challenge.

With reference to the Ghawar field, Cantrell and Hagerty (1999, 2003) documented observations on the common presence of microporosity in the Arab Formation. They concluded: 'Microporosity occurs throughout the Arab Formation of Saudi Arabia, and affects the log response, fluid-flow properties and ultimate recovery of hydrocarbons in these reservoirs.' Their qualitative microporosity observations from petrographic data, were supported by displays of the pore-throat histograms from a sample subset on which MICP data were available (Figure 3, from Cantrell and Hagerty, 1999).

Early work on the presence of microporosity in carbonates by Herling (1968), contrasted the difference between carbonate and clastic sedimentary rocks. He noted, 'The good correlation between specific surfaces calculated from grain-size distribution and measured with BET method (adsorption isotherm method of Brunauer et al., 1938) for quartz sands and powdered quartz is no longer valid for calcareous sands and silts.' Pittman (1971) discussed one type of microporosity in carbonates as resulting from boring and perforating

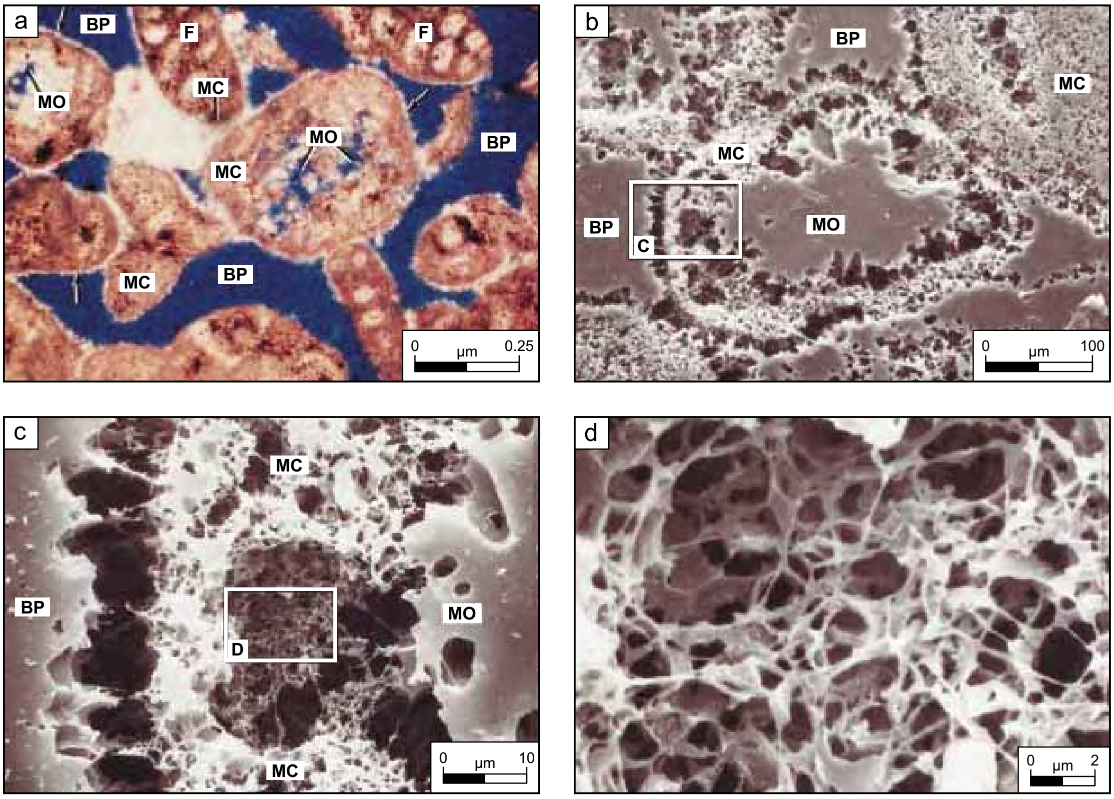


Figure 3: Microporosity petrographic images in Arab Formation carbonates (Cantrell and Hagerty, 1999). Porosity is filled by blue dye in the upper left image. The succeeding images are pore casts of increasingly higher magnification after removal of the carbonate matrix by acid. Image (a) shows abundant interparticle macroporosity (dark blue) as well as microporosity. The successive pore cast images of increasing magnification (b), (c), (d) show that the intraparticle microporosity is well-connected.

actions performed by blue-green algae into carbonate grains. A similar observation was made by Bathurst (1966) for skeletal sand grains of the Bimini lagoon.

Cantrell and Hagerty (2003) found four types of microporosity in the Arab D using an operational definition of microporosity as pores approximately 10 microns in diameter or less. Their four types of microporosity are: (1) microporous grains, (2) microporous matrix, (3) microporous fibrous to bladed cements, and (4) microporous equant cements, with microporous grains being the most volumetrically significant microporosity type. These authors stated, 'Scanning Electron Microscope examination of pore casts and fractured rock surfaces reveals that a variety of skeletal and non-skeletal grain types are microporous. The microporosity-forming process transforms different grain types into grains that are similar with respect to their internal fabrics. Microporosity thus consists of a network of highly interconnected, uniform-sized straight tubular to laminar pore-throats that intersect with less elongate, more equant pores.' Mitchell et al. (1988) characterized the Arab D carbonates in terms of five limestone facies plus Dolomite: Skeletal-Oolitic, Cladocoropsis, Stromatoporoid-Red Algae-Coral, Bivalve-Coated Grain- Intraclast and Micrite. These facies represent a classification that utilizes fauna, assemblages of Dunham (1962) textures, major and minor grain types, sedimentary structures, pore types and diagenetic modification. A key result that emerges is that these facies subdivide the MICP data set by pore-system properties more clearly than other available facies descriptors. This establishes an important and previously nonexistent link between the depositional geology-facies and the pore systems, and hence the static and dynamic properties of the reservoir.

Clerke (2004) modified the limestone facies of Mitchell et al. (1988) and arrived at six facies (Figure 2). In particular, he divided the skeletal-oolitic facies into those above and below an important sequence boundary identified in core descriptions by C.R. Handford (T. Keith, personal communication, 2001). His modification also separates-out the burrowed micritic facies. In the present study, the Clerke (2004) classification is used unless otherwise indicated.

MODES AND POROSITONS: MAXIMUM PORE-THROAT DIAMETER STATISTICS

Thompson et al. (1987) discussed the many studies of pore networks 'composed of pipes of widely varying sizes, which are distributed randomly along the links of the network'; and noted, 'there are no experimental data to contradict the assumption of random distribution of pores.' The data we have collected and present is likely the first and the most comprehensive data to show a deeper and non-random structure in the pore network parameters of the Arab D limestone.

Two data sets were used in the present study. The first consisted of 125 mercury injection capillary pressure (MICP) samples characterized by the textures of Dunham (1962) and the facies of Mitchell et al. (1988). This data set was compiled by Hagerty and Cantrell (1990, unpublished report) and quantitatively analysed (Clerke, 2003, 2004; Clerke and Martin, 2004). It is dominated by packstone (Dunham, 1962), but otherwise contains a fairly uniform selection of other Dunham (1962) textures. The collection is also fairly uniform by facies except for undersampling of the Cladocoropsis facies.

Thomeer Hyperbolas (Thomeer, 1960) were fitted to this first MICP data set using computerised spreadsheets (Appendix 1; Clerke and Martin, 2004). This analysis first yields the number of Thomeer Hyperbolas – used here as equivalent to 'pore system' – required to fit the MICP data from each sample. We call this integer the pore system modality. Thirty-five percent of the samples required a single hyperbola (Figure 4a), 62% required two Thomeer Hyperbolas (Figure 4b) and 3% required three hyperbolas. To limit trivial occurrences of multiple pore-systems in one sample, we added to the Thomeer MICP-fitting process, the requirement that a volume of at least one unit of porosity be present for a significant second or a third pore system.

Table 1 shows the occurrence of the pore-system modality (number of Thomeer Hyperbolas required for each sample) for the Dunham (1962) textures. Key results are that mudstone is dominantly monomodal,

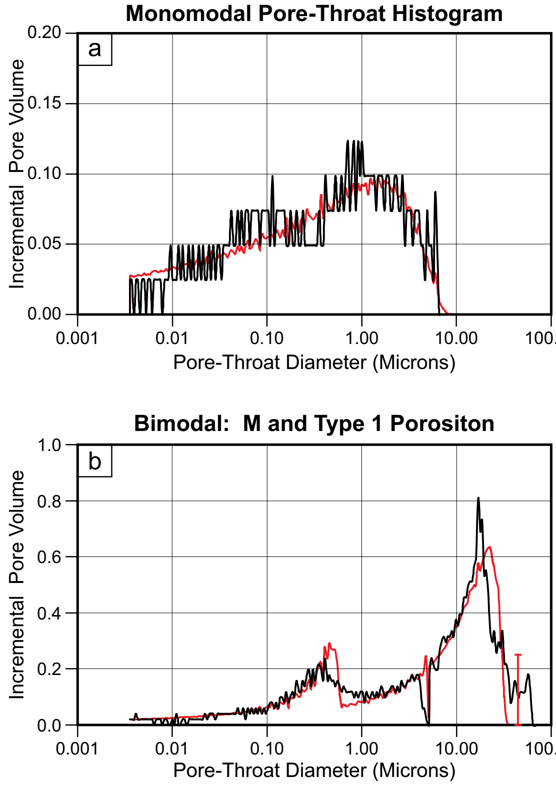


Figure 4: Histograms of pore-throat diameter from Arab D limestone MICP data along with the pore-throat diameter histogram from the Thomeer Hyperbolas (red) and closure correction (red bar); (a) pore-throat diameter histogram for a monomodal pore system; (b) pore-throat diameter histogram for a bimodal pore system

while grainstones and mudlean packstones are dominantly bimodal; packstone and wackestone showed no definitive pore system modality. Table 2 shows the occurrence of the pore-system modality for the Mitchell et al. (1988) facies. Stromatoporoid-Red Algae-Coral and Cladocoropsis are almost always bimodal. Note also the presence of 60-40 or 70-30 splits for Skeletal-Oolitic, Micrite, Dolomite and Bivalve-Coated Grain-Intraclast. Table 3 shows the poresystem modality when the Skeletal-Oolitic facies are distinguished into above-and-below the sequence boundary (Figure 2; Clerke, 2004) and the value of this split will be evident later when microporosity types are defined.

The second data set (Rosetta Stone Data) used 10 cored and described wells with full conventional well-log suites in a NS-transect across the Ghawar field (Figure 1). All of the core plugs (approximately 3,500) from these 10 wells were catalogued by the facies of Mitchell et al. (1988). Then seven to nine samples from each facies per well were selected at random to give 90 samples per facies, thus resulting in a uniform sample density for each facies. MICP experiments and analysis was conducted on these samples and the resulting data set was combined with the 125 samples of Hagerty and Cantrell (1990, unpublished report) as listed in Appendix 3. The Thomeer Hyperbola analysis was then applied to the combined MICP data using computerised spreadsheets (Clerke and Martin, 2004). Thomeer parameter, P_d, when plotted on a logarithmic axis [$Log(P_d)$ domain] showed the most significant variation, and it was considered the controlling parameter for classification. We observed four distinct and separable modes (Figure 5) and fitted each with a Gaussian distribution, termed a Porositon. Pore-size ranges and microporosity have been assigned many names and size scales (Choquette and Pray, 1970; Pittman, 1971; Cantrell and Hagerty, 1999). In contrast, Figure 5 shows that maximum pore-throat sizes of the pore systems have a few natural and distinct modes (four) and hence self-define its size-based classification. The Thomeer Hyperbola curve-matching tool is the only one which allows the microporosity volume and its largest controlling pore-throat to be quantified separately from other pore volumes.

POROSITON CLASSIFICATION

The four modes in the distribution of the maximum pore-throat diameters (Figure 5) correspond to one macroporosity (M Porositon) and three microporosity types (Type 1, 2 and 3 Porositons). The position of the four porositons is a property of the porous medium and not determined by ad hoc criteria. The term 'microporosity' is used here in the sense of Swanson, (1985). 'Micropores in reservoir rocks are defined as pores whose dimensions are significantly smaller than those contributing to the rock's permeability'. Later sections of this paper and other publications (Clerke, 2007; Buiting and Clerke, in preparation) support this naming convention by demonstrating the lack of contribution of the micropores to the measurable permeability when the M Porositon occurs, i.e. macroporosity.

Results from the fitting of the data to Gaussian distributions are shown in Table 4. The distribution parameters for the four porositons are: mean, width (standard deviation) and the best Log(Pd) cutoff parameter separating the distributions. Notice from Table 4 that the bulk of the porosity on the average is carried in the M Porositon (17.1 pu) followed by the Type 1 Porositon (5.57 pu) and finally by Types 2 and 3 (2.22 pu) Porositons. The computed Thomeer permeability for the mean values is shown. The mean Thomeer pore geometrical factor, G, ranges from 0.51

Table 1

Dunham Textures	Number of Pore Systems (%)		
	1	2	3
Grainstone	6.0	88.0	6.0
Mudlean Packstone	4.0	96.0	0.0
Packstone	37.0	58.0	5.0
Wackestone	50.0	50.0	0.0
Mudstone	100.0	0.0	0.0

The 125 MICP data of Hagerty and Cantrell (1990, unpublished report), coded with multiple descriptive terms, were used to compare pore system modality to the Dunham (1962) textures. Grainstone and mud-lean packstone are dominantly bimodal. Packstone and wackestone can be either monomodal or bimodal but mudstone is monomodal. This is important information for translating geological descriptions into quantitative pore system models.

Table 2

Facies (Mitchell et al., 1988)	Number of Pore Systems (%)		
	1	2	3
Skeletal Oolitic	32.0	63.0	5.0
Cladocoropsis	0.0	100.0	0.0
Stromatoporoid-Red Algae-Coral	11.0	84.0	5.0
Bivalve-Coated Grain-Intraclast	28.0	69.0	3.0
Micrite	71.0	29.0	0.0
Dolomite	67.0	33.0	0.0

The 125 MICP data of Hagerty and Cantrell (1990, unpublished report), coded with multiple descriptive terms, were used to compare pore system modality to the facies of Mitchell et al. (1988). The Cladocoropsis and Stromatoporoid–Red Algae-Coral are commonly bimodal. Other facies are a mixture of bimodals and monomodals at roughly 70-30% and 30-70% proportions. The number of trimodal pore systems is few and below statistical significance for the small MICP data set but it is shown for completeness.

Table 3

Facies (This Study)	Number of Pore Systems (%)		
	1	2	3
Skeletal Oolitic Above Sequence Boundary	35.0	61.0	4.0
Cladocoropsis	0.0	100.0	0.0
Stromatoporoid-Red Algae-Coral	11.0	84.0	5.0
Skeletal Oolitic Below Sequence Boundary	27.0	67.0	6.0
Bivalve-Coated Grain-Intraclast	28.0	69.0	3.0
Micrite	71.0	29.0	0.0

The 125 MICP data of Hagerty and Cantrell (1990, unpublished report), coded with multiple descriptive terms, were updated to split the Skeletal Oolitic facies into two subunits, above-and-below the sequence boundary (Clerke, 2004). No net improvement results from the statistical breakout at this stage, but later figures will show that the microporosity type in the Skeletal Oolitic facies are different when split.

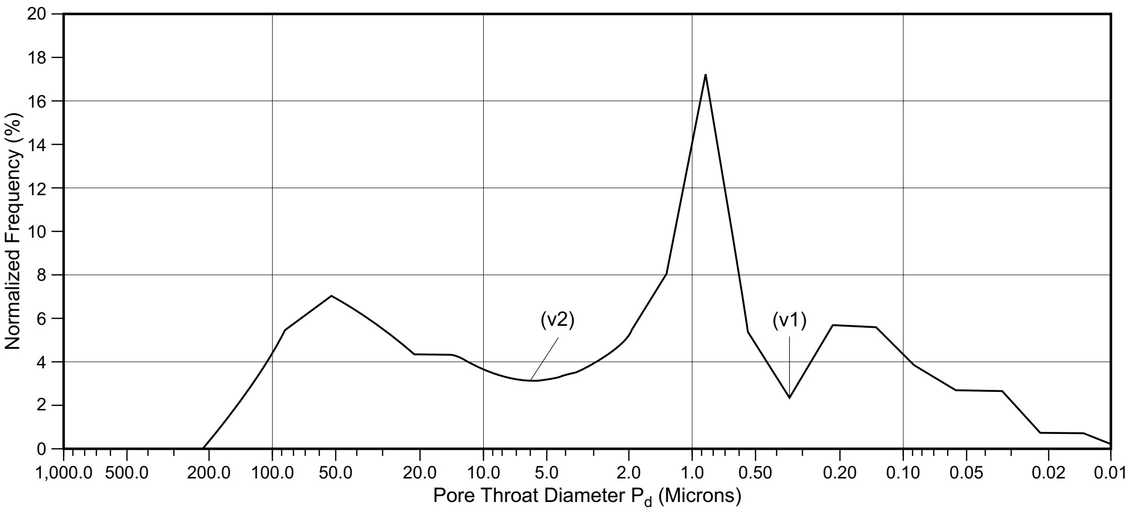


Figure 5a: Histogram of Pd values (converted to maximum pore-throat diameter [microns]) used for all Thomeer Hyperbolas is shown here. 860 hyperbolas were required to fit 454 samples from 10 wells. The data shows four distinct and separate modes, a broad mode on the left of large pore-throat diameters, a narrow and highly populated second mode at about 1 micron, and two less-frequent successive modes near 0.2 microns and 0.04 microns. The valley at 2% and 0.35 microns is very distinct (v1). Another less distinct valley is at about 6 microns (v2). The non-uniform spectrum suggests that maximum pore-throat diameters are related to an underlying discrete process.

to 0.13, with the highest values (widest distribution and poorest sorting) in the M Porositon (0.51 + 0.19). The characterization of carbonate 'heterogeneity' is captured by the width of the M Porositon and by the amount of multimodality present in the pore systems.

CORE PLUG POROSITY AND PERMEABILITY, AND MULTIMODALITY

In core plugs the pore systems of the Arab D limestone matrix are commonly bimodal and composed of a single instance of macroporosity and some amount and type of microporosity from one of three possible types (Clerke, 2004, 2007; Clerke and Mueller, 2006; Buiting, 2007; Buiting and Clerke, in preparation). We examined the trend of total plug porosity in the limestone samples as compared to the pore system modality. Figure 6 shows the modality of the maximum pore-throat diameter data with a red curve representing the rolling-window average of the data versus porosity. The data indicate that bimodality is common when the porosity exceeds 7 pu. Trimodal pore systems start to occur, along with bimodals, in the porosity range from 12 to 24 pu, and above 24 pu the systems are mostly bimodal. In Figure 7, the maximum pore-throat diameter modality is compared to core plug permeability data using the rolling average (red line). Two distinct ranges occur: (1) from 0.01 to 10 mD, which is both monomodal and bimodal in nearly equal proportions; and (2) above 10 mD, bimodality dominates with occasional trimodality.

DENSITY-NEUTRON-DERIVED POROSITY AND MULTIMODALITY

In Figure 8, the plug maximum pore-throat diameter modality versus porosity data of Figure 6 is superimposed on the conventional density-neutron well-log crossplot using multi-well Arab D log data. The combination of density-neutron logs in a known limestone matrix might show some subtle evidence of maximum pore-throat diameter modality. The deviation of the data trend from the limestone line, as porosity increases, may be related to the increasing presence of dual-porosity systems through unknown effects such as flushing phenomena and/or flushed-zone, residual-oil saturation. Porosity, determined from these two porosity tools (density-neutron), appears to only weakly indicate the modality of the pore system. Hence, we observe that these 'conventional' petrophysical data sets at most give minimal indication of multimodality. The characterization of multimodal pore systems in reservoir limestones will require new methods for full evaluation by well logs. Re-interpretation of existing (density-neutron) well-log suites even with core data and powerful reprocessing (e.g. neural nets and self-organizing maps) likely cannot begin to address this aspect of the evaluation.

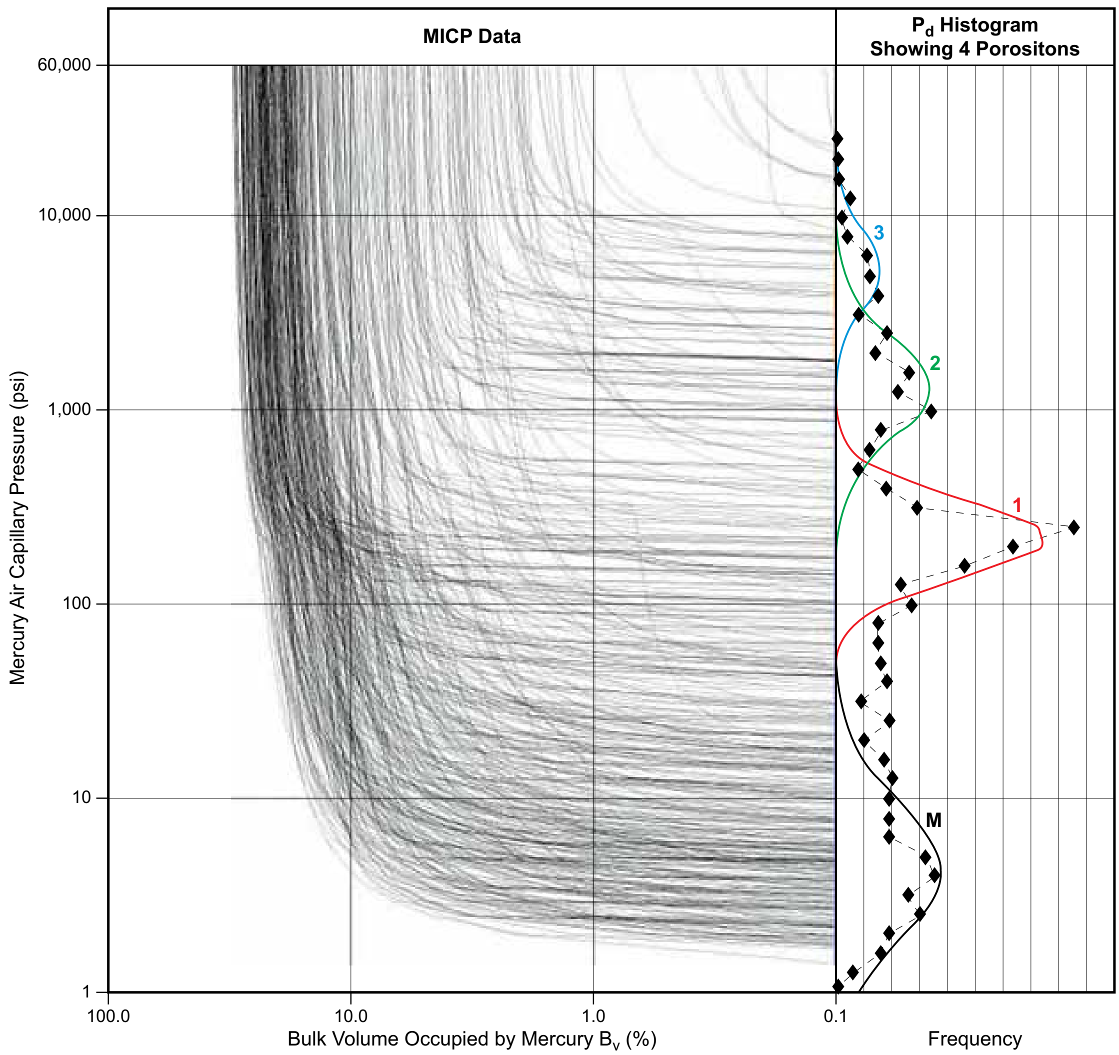


Figure 5b: Histogram of Figure 5a is shown (on the right) along with all of the graphical MICP data (on the left) after closure correction and Thomeer Hyperbola matching. Shown on the right is the frequency of occurrence of all Pd values for all Thomeer pore subsytems required (diamond shaped points connected with a faint dashed black line). This frequency is not simply the density of the number of lines to the left of the histogram because many of the pore systems exist primarily as subcomponents of a bimodal or trimodal capillary pressure curve. This is most strongly the case for Type 1 microporosity as it most commonly occurs as a second pore system in the MÐ1 configuration. The colored lines on the frequency histogram are the four fitted Gaussian distributions [porositons: M (black), 1 (red), 2 (green), 3 (blue)]. The Gaussian parameter values are compiled in Table 4. The conformance of the four Gaussian distributions to the experimental data is excellent (correlation R2 of 0.85) except between about 40 and 90 psi where a plateau occurs.

POROSITON COMBINATIONS

The porositon combination naming scheme for multimodal pore systems follows the MICP access order, i.e. it follows the order of increasing pressure or decreasing largest controlling pore-throat, i.e. M, 1, 2, 3. Hence a MICP trimodal pore systems can be described by the increasing Pd series: M-1-2, but not 2-M-1.

The major porositon combinations still exhibit order when viewed on the traditional porosity permeability crossplot (Figure 9) shown here with an overlay of constant P_d using equation A3. Hard trends and clear clusters are not present but there are still definite patterns. The M-1 bimodals with their various proportions of macro- and microporosity occupy a large area in the upper right corner of the plot. Moving to the left and reducing porosity but retaining high permeability, we find the M-1-2 and M-2 pore systems with the additional presence of micrite associated

Table 4

Ghawar Arab D Limestone Porositon Parameters						
Gaussian Model	**Thomeer Parameters**					
	Log (P_d)	P_d (psi, Hg/air)	Pore-Throat Diameter (microns)	B_v (Porosity Unit)	G	Thomeer Permeability (mD)
Porositon M						
Mean	0.57	3.67	58.27	17.10	0.51	202.6
One Standard Deviation	0.53			8.36	0.19	
Porositon Separator Value	1.67	46.3	4.62			
Porositon 1						
Mean	2.31	204.0	1.05	5.57	0.15	0.036
One Standard Deviation	0.28			3.18	0.13	
Porositon Separator Value	2.79	617.0	0.35			
Porositon 2						
Mean	3.12	1,318.0	0.16	2.22	0.15	0.00014
One Standard Deviation	0.26			0.87	0.13	
Porositon Separator Value	3.40	2,512.0	0.09			
Porositon 3						
Mean	3.73	5,370.0	0.04	2.22	0.15	0.00001
One Standard Deviation	0.20			0.87	0.13	
Porositon Separator Value	4.78	60,000.0	0.00			

Gaussian distribution parameters for the four porositons fit to the histogram (see Figure 5) of the full data set of Log(P_d) values (Appendix 3, this study). The parameters are the mean and standard deviation for each Gaussian distribution (see Figure 5). Values of P_d are in psi (Hg/air) or the equivalent Maximum Pore-Throat diameter in microns. The parameters of the fit of a Gaussian distribution to B_v and G are also displayed. A Thomeer permeability has been calculated using the mean Gaussian parameters for each porositon. Also shown is a separating value (cutoff) for each porositon.

micropores (2, 3). Trending down to the left from the M-1 cluster the Type 1 monomodals are intersected, then Type 1-2 and 1-3 bimodals and then at very low porosities and permeabilities, Type 2 and 3 monomodals associated with micrite.

The results from Table 4 and the porositon combinations were used to build average porositon combination capillary pressure curves with uncertainties (Clerke, 2004). The measured capillary pressure curve data have been disassembled using the superposition capability of the Thomeer hyperbolas followed by the porositon classification. The average capillary pressure curve for each porositon combination can similarly be reassembled using the averages and standard deviations of each porositon's Thomeer parameters and a forward superposition of the Thomeer hyperbolas.

FACIES AND POROSITON COMBINATIONS

In this section we examine the Arab D limestone pore systems and facies in terms of combinations of the four basic porositons. Two common combinations of macroporosity and the microporosity types are shown in pore-throat diameter histogram view. In the 125 sample data set of Hagerty and Cantrell (1990, unpublished report), we observed that the sequence boundary represents a distinct facies break that is associated with the microporosity Types 1 and 2. The Skeletal Oolitic facies above-and-below the sequence boundary have completely different microporosity types (Figure 3). Above the sequence boundary, Skeletal Oolitic, Cladocoropsis and Stromatoporoid- Red Algae-Coral facies share the common occurrence of the Type 1 Porositon. The strong correlation of the microporosity

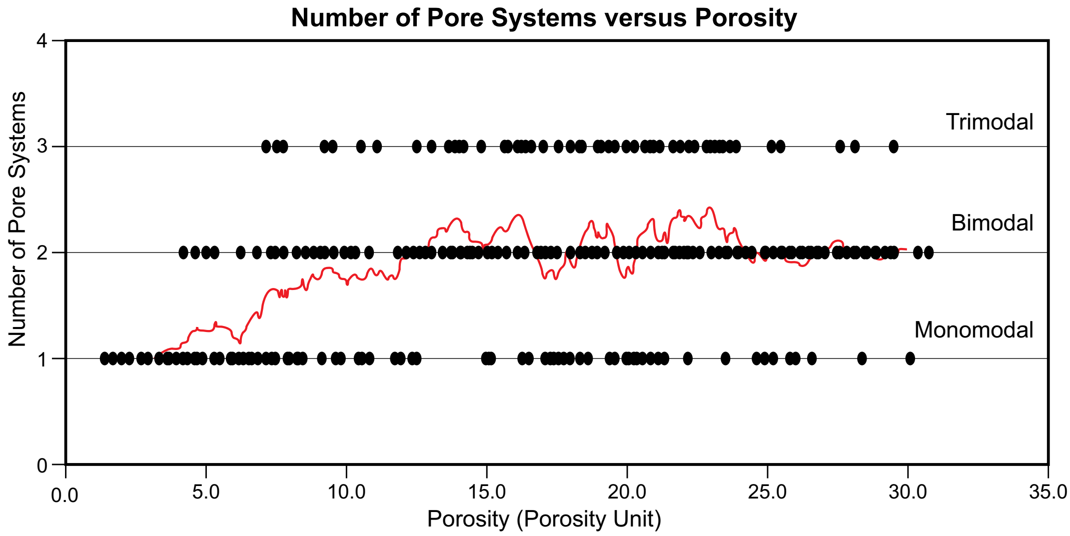


Figure 6: Maximum pore-throat diameter modality versus total porosity and a rolling average (red; average of the up-and-down rolling averages) indicates that bimodals are common above 7 pu, trimodal pore systems start to occur with the bimodals in the porosity range from 12 to 24 pu; above 24 pu the systems are with very minor exceptions, bimodal.

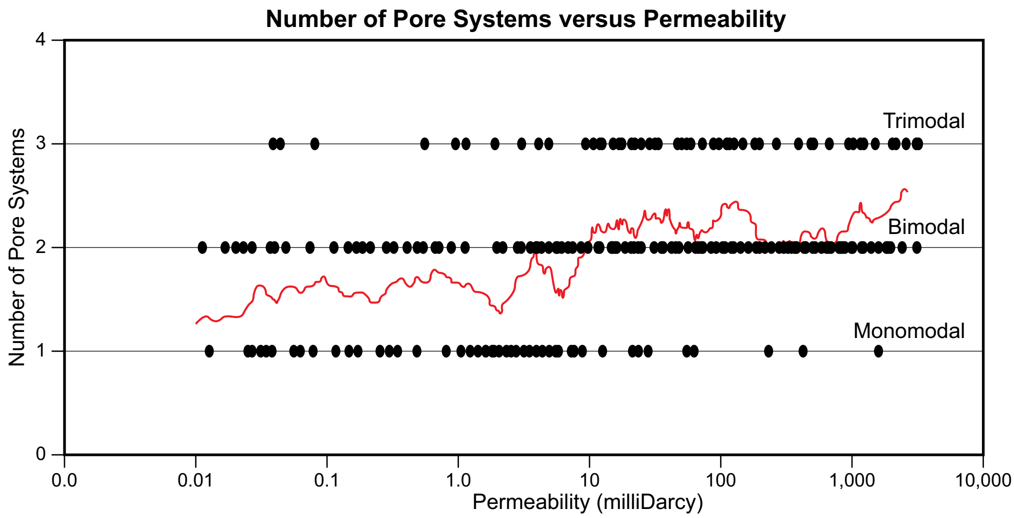


Figure 7: Maximum pore-throat diameter modality Ð permeability data and a rolling average (red; average of the up-and-down rolling averages) shows two distinct ranges: (1) from 0.01 to 10 mD, which is both monomodal and bimodal in nearly equal proportions; and (2) above 10 mD, bimodality dominates with occasional trimodality.

types against the facies is in stark contrast with the weak correlation with Dunham (1962) textures. Grainstones can either contain Type 1 or 2 microporosity as can Mud-lean Packstone and Packstone. Wackestones contain only Type 2 microporosity. Thus facies descriptors (Clerke, 2004) contain the most petrophysical pore system information.

Three of the facies tend to occur in the upper part of the reservoir interval (Skeletal Oolitic above-the-sequence boundary, Cladocoropsis and Stromatoporoid-Red Algae-Coral) and for these, only four porositon combinations are required with M-1 being dominant. Note that the monomodal, M, occurs only in the Skeletal Oolitic above-the-sequence boundary, and that the presence of Type 2 microporosity (Micrite associated) in the M-1-2 and M-2 is associated only with Stromatoporoid-Red Algae-Coral.

For the facies occurring below-the-sequence boundary,

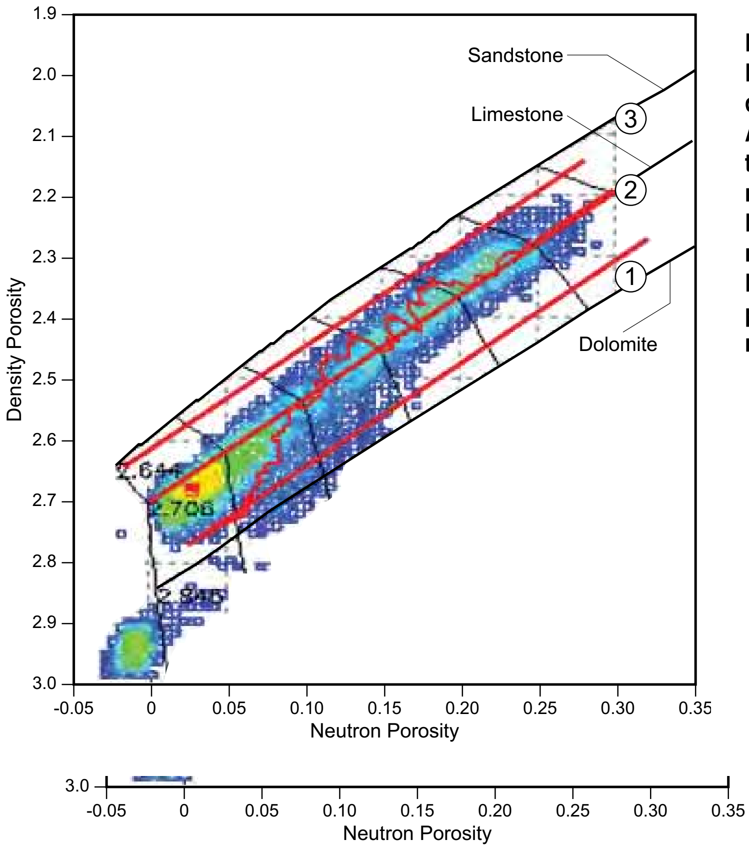


Figure 8: Maximum pore-throat diameter modality of Figure 6 is shown superimposed on a conventional density-neutron well-log crossplot using multi-well Arab D log data. The matrix porosity increases along the lithology trends from the lower left to the upper right. The tie lines (upper left to lower right) are lines of constant matrix porosity. The superimposed red lines from Figure 6 indicate porosity modality. Even with two porosity tools (density-neutron), porosity modality – if present at all – is only weakly manifested.

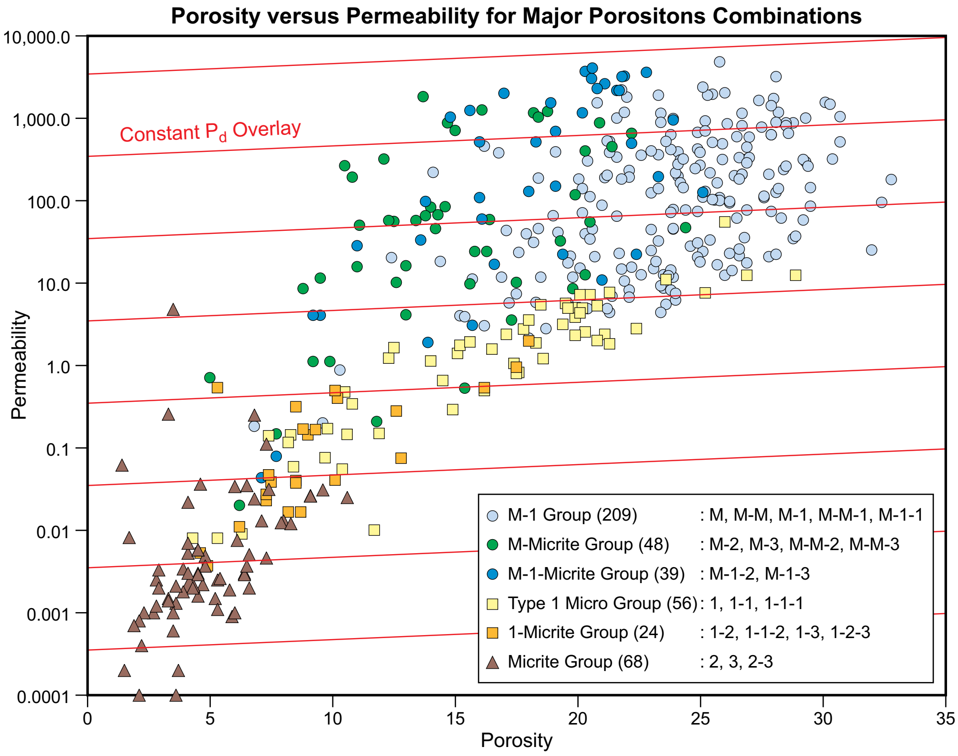


Figure 9: Petrophysical Rock Types (PRT) based on porositon combinations are shown on a conventional core data Permeability-Porosity crossplot. The six major PRTs still show order despite being based on a completely different classification scheme. An overlaying second red grid shows constant Pd (largest pore-throat diameter) as given by equation A3. Porosity versus Permeability for

Reducing Uncertainty and Costs Innovative Underreamer Verifies

By Wajid Rasheed, SPE, Petroleum Production Ltd, Shaohua Zhou, SPE, Saudi Aramco, David Jones, Consultant.

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

Applications such as close tolerance casing design and expandable liners, often necessary for deepwater and subsalt well construction, require underreaming to ensure adequate reservoir diameters. However, underreaming generates uncertainty sometimes, particularly in hard formations. Instead of direct real-time verification, reliance is placed on indirect indicators such as increased stand-pipe pressure or drilling torque. The uncertainty as to whether the desired wellbore-diameter is actually delivered exists until a calliper is run. Subsequently, a correction run may still be needed, hence additional cost.

This paper explains a design process to solve these problems. An explanation of a novel technology illustrates how it verifies and detects variations in underreaming diameter in real-time. A telemetry system alerts the user if there is a significant difference between planned and actual diameters and prompts a check of operational parameters such as WOB, drilling fluid pump rates or RPM, if needed, repeat underreaming in the uncertain interval.

A comparative evaluation was made of the drilling dynamics of underreamers and the root cause analysis of NPT. For example, bit only RoPs are higher than underreaming RoPs and in a combination BHA the bit tends to out-drill the underreamer. Not only does the underreaming have limited cutter contact with the wellbore and limited hydraulics, BHA modelling shows these limitations are worsened by wall-side forces and bending moments which are concentrated at the underreamer.

The design process sought to improve traditional technology by considering RoP, improved underreaming BHA stability and generate a more balanced cutting action. CFD (Computational fluid dynamics) show how a novel configuration of nozzle distances and orientations improves cuttings evacuation and reduces particle residence times.

In conclusion, a drilling engineering risk table presents 20 underreaming applications and is used as a benchmark for a comparative evaluation of underreaming risk types.

Introduction

Oil and gas companies are exploring and developing reserves in more challenging basins such as those in water-depths exceeding 6,000 ft (1,830m) or below massive salt sections. These wells have highly complex directional trajectories with casing designs including 6 or more well sections. Known as 'designer' or 'close tolerance casing' wells, such wells have narrow casing diameters with tight tolerances and have created a need to enlarge the wellbore to avoid very small diameter reservoir sections and lower production rates (Figure 1 PPFG). In other applications such as cemented solid expandable liners, underreamers are required to provide the tolerance for tubular expansion to occur or for increased cement sheath. The tolerances between the enlarged well-bore and the expanded tubular are very close.

Therefore, the bottom-hole assemblies that are needed to drill or complete these wells routinely include devices to underream the well-bore. In this way, underreamed hole size has become an integral part of well construction and there is now an increased dependence on underreaming to meet planned wellbore diameters across the industry (Ref 2).

Underreamer

An underreamer is used to enlarge a borehole beyond its original or pilot bit size or existing hole size (Ref 3). Enlargement is typically done below a restriction in the borehole (usually pre-existing casing), and the drilling diameter of an underreamer is always greater than that of the pass-through diameter of the restriction (or casing). Additionally, an underreamer is provided with activation and deactivation modes and mechanisms for extending and retracting cutting elements to ensure effective underreaming once it has passed below the restriction.

in Drilling and Completion: Wellbore Diameter in Real-Time

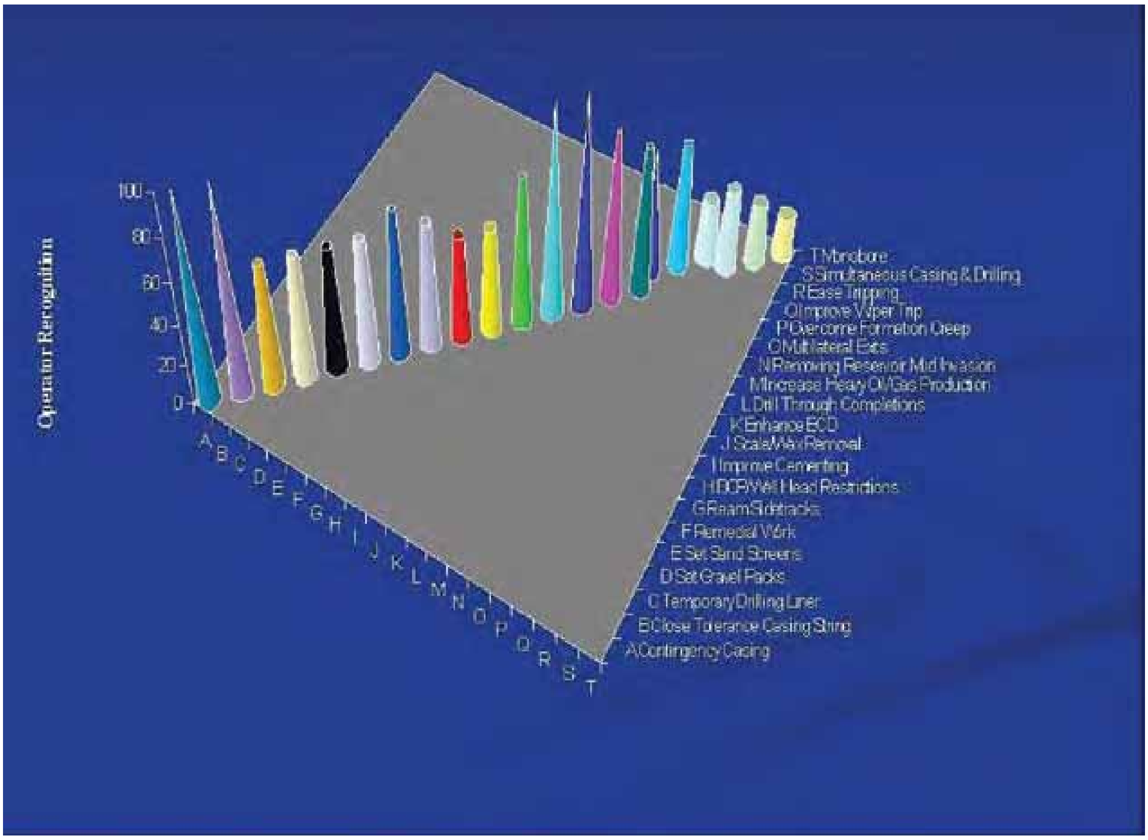


Figure 1 Shows Underreaming Applications Across The Industry

Consequently, underreaming is taken to mean 'the opening of a well-bore after passing through a restriction' and covers terms such as:

1. Underreaming/Bidirectional Underreaming
2. Hole enlargement
3. Underreaming while drilling/ back reaming
4. Simultaneous underreaming
5. Drilling with a bicentre/eccentric bit
6. Hole-opening

Underreaming in Well Construction

The list below shows a breakdown of possible well construction underreaming applications. These applications are summarised as follows:

1. Contingency Casing (Shallow Hazards)
2. Close Tolerance Casing (Narrow PPFG)
3. Cemented Expandable Liners
4. Monobore
5. Gravel Packs
6. Sand Screens
7. Casing Drilling with Retrievable System
8. Remedial Work
9. Ream Sidetracks/Ease Tripping
10. BOP/Well Restrictions (Ref 4)
11. Improve Cementing Tolerances
12. Drill Through Completions
13. Scale/Wax Removal (Ref 5)
14. Hole Cleaning/ECD Improvements
15. Increased Production
16. Improve Wiper Trip
17. Remove Heavy Mud Skin
18. Remove Formation Damage (Ref 6)
19. Remove Excess Cement
20. Overcome Formation Creep (Ref 7)
21. Reduce Stringers
22. Drill-in Liners

Time-Lag Between Underreaming and Measurement

Traditionally, underreaming and measurement have been considered as two separate and distinct operations. An underreaming run could take 24 hours, after which a further 24 hours could be required for preparation of the calliper run. A further 24 hours could be expended in the calliper run before knowledge could be gained of actual wellbore diameters. The time-lag between underreaming and calliper measurements, therefore could easily exceed 48 hours depending on the depths involved. If the actual hole diameter did not match the planned diameter, casing tolerances would not be met and therefore a correction run would be required and the whole cycle of underreaming and calliper measurements would need to be repeated.

Measurement methods

Drilling measurements may involve the acquisition and communication to surface of various types of wellbore and formation evaluation data such as resistivity, porosity, permeability, azimuth, inclination, borehole diameter or rugosity, formation dips, bedding angles, pressure and temperature. Measurement itself occurs in two modes, either wireline or logging-while-drilling.

Wireline and Calliper Log

Wireline logging is a common measurement technique and is performed as a separate and consecutive activity to drilling involving the conveyance of measurement tools on a wireline or drillpipe if hole is highly deviated or horizontal. Wireline callipers use a plurality of fingers to take borehole diameter measurements. However, wireline callipers can only take measurements in an axial direction and are not robust enough for drilling applications.

Such calliper designs are based on mechanical mechanisms i.e. pivot points or moving knuckles which are known to break or malfunction due to high bending moments or drilling fluid packing out between moving parts and causing an inability to function or an inability to retrieve the bottom-hole assembly. It is precisely due to these reasons that the design of underreamers and underreamer blocks themselves evolved from cutter arms toward solid block designs (Ref 8, 9).
LWD Callipers

Logging-while-drilling tools may acquire various data from the wellbore. Acoustic callipers may be incorporated within logging tools (Ref 10). As they can be rotated, acoustic callipers may be used while drilling to acquire measurement data. However, not all logging tools are configured with acoustic callipers due to the needs of the complex LWD system itself and Formation Evaluation requirements. Acoustic callipers may also suffer from ultrasonic signal attenuation due to changes in the density of drilling mud as well as rotational limitations occurring in slide drilling, where a downhole motor rotates the bit. In rotary steerable applications, the wall contact requirements of the steerable system will dictate the RSS be placed below the LWD in order to apply the requisite wall side-forces to the bit to control azimuth and inclination. In cases where the location of any acoustic calliper is below the underreamer, the acoustic calliper only provides indication of pilot hole size, not the underreamed hole.

It is routine for certain oil companies to take borehole measurements as a separate activity after drilling or underreaming (wellbore enlargement) has taken place. The time-lag associated with the separated operations of enlargement and measurement leads to uncertainty and unnecessary cost.

Operational Uncertainty

Traditional technology may not provide reliable information as it contains uncertainty due to the dependence on extended cutter positions or hydraulics or drilling practices as an indicative assumption that the planned underreamed hole is actually being delivered. There are no actual real-time measurements whether direct or inferred.

Indirect Indicators and Inferences

It is usual practice to depend on indirect indicators such as whether cutter blocks are open or closed or whether fluid pathways are open and a pressure spike is seen at the rig floor to indicate activation. It is known that reliance is placed on rudimentary and time-consuming indicators of verification such as an increase in drilling torque as cutters interact with the formation or pulling up the BHA to the previous hole size in order to see whether the top-drive stalls as the bottom-hole assembly gets hanged up due to the expanded underreamer. Such indicators do not provide actual measurements of the underreamed well-bore; they simply give information on the mechanical or hydraulic status of an aspect of the tool which may or may not lead to the desired well diameter. It is this fundamental uncertainty that may lead to NPT (Ref 3).

New Solution

The new technology provides a step-change in drilling efficiency as compared with traditional methods. This is because the actual diameter of the underreamed hole is measured directly behind the underreamer cutter blocks in real-time. This provides for real time performance verification and automated troubleshooting. The new technology eliminates the need for a separate calliper run and minimizes the need for corrective underreaming runs. If the wellbore is found to be undergauge, the technology automatically detects and diagnoses the faults, which may help to repeat underreaming until a satisfactory result is achieved in real-time.

Design Process

There are more than 21 underreaming applications and many operators that underream, but the skill is focussing in on where the synergy and value of hole measurement and underreamer is greatest. Underreaming applications and the usage of underreamers is not straightforward. The usage is related to differences in operator culture, perception of risks, product preferences and application complexity. Different oil companies can have very distinct approaches to the drilling or production issues encountered, and related potential underreaming applications. The design process took these factors into consideration. (See Figure 1)

To minimise or eliminate risks associated with traditional technology the design process incorporated several computerized and manual analytical tools. These were:

1. FEA (Finite Element Analysis),
2. Residual Stress Engineering,
3. BHA modelling,
4. CFD (Computational Fluid Dynamics)
5. NPT of underreaming well construction operations.

FEA

The analysis represents the tool by a finite number of elements which are identified by a computer program. The elements are then modelled according to differing levels of stress, loading and erosion. This provides an idea of where design refinements need to be made. The FEA also helps identify residual stresses that may be induced during manufacture i.e. heat induced forging, welding body, tungsten carbide insert brazing. It also helps the design of PDC cutters and cutter blocks. The loading inputs were taken from a variety of loading scenarios such as geomechanical formation hardness, directional and stabilizer positioning for BHA moments and well bore inclination i.e. horizontal and directional wells.

Residual Stress Engineering

This optimises tool life and prevents premature failures by considering such stresses. Residual stresses remain after the original source of stress has been removed. Sources vary from heat based i.e. forging, brazing, welding to mechanical i.e. inelastic loads. If the stresses go unchecked they may adversely affect the performance of the component leading to premature failure (stuckfish, LIH or in the worst cases a sidetrack). Heat from forging or welding may cause local expansion, which is taken up during welding by either the molten metal or the parts being welded. The cooling process is not uniform and certain areas contract faster than others, leaving residual stresses.

BHA Modelling

From a directional drilling perspective, the underreamer must also stabilise the BHA as a string or nearbit stabiliser. Consequently, in certain BHA placements it will help generate required directional turns as one of three known wellbore contact points. Here it will have to overcome wall-side-forces and bending-moments to provide directional control possibilities and act to minimize axial, lateral and torsional oscillation and vibration generated by the BHA or drillstring. Even where configured behind a bullnose the underreamer must still perform part of these functions. These forces were modelled on the underreamer. (See Figures 2 and 3)

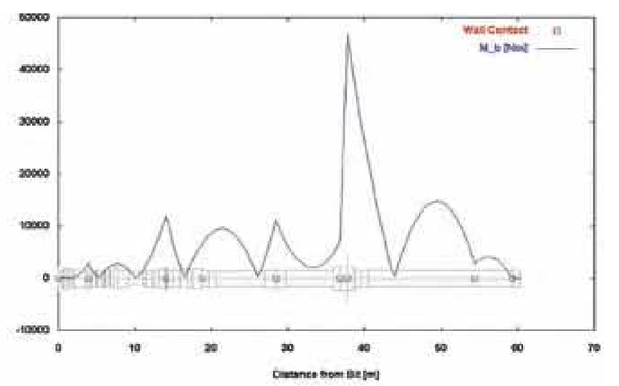


Figure 2 shows Typical Bending Moments Concentrated at the Underreamer. Note the Underreamer is Nearly 40 m Behind the Bit.

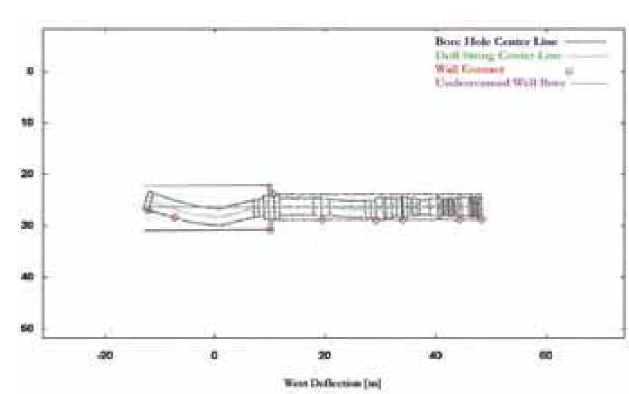


Figure 3 shows Typical Drillstring, BHA Deflection within the Underreamed Section

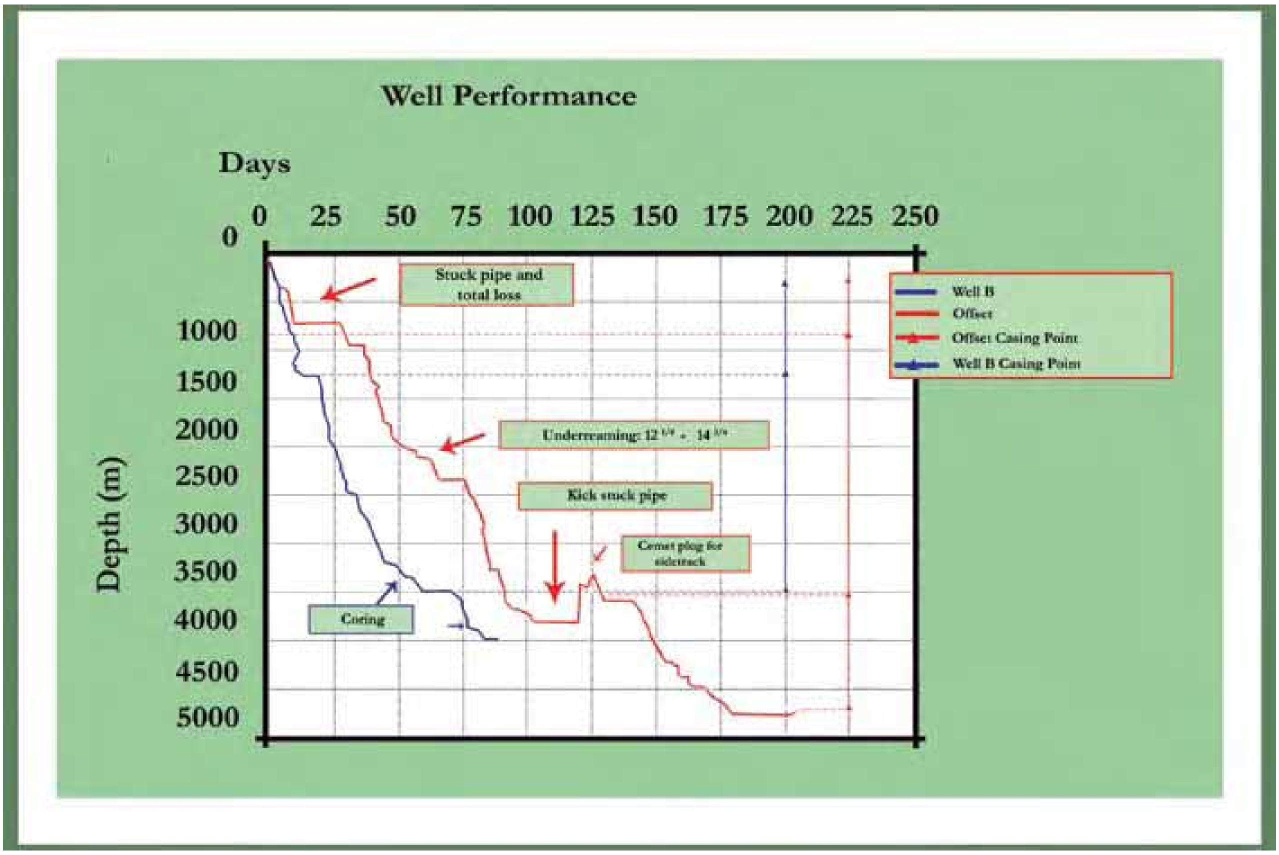


Figure 4 Shows A Typical Well Performance Plot of Days v Depth

CFD

This warns of potential areas for particle based fluid erosion and different flow regimes. Laminar flow is modelled within the tools' ID and internal components that are open to flow. Turbulent flow is modelled outside of the tool and all external faces. This improves the design from a QA/QC perspective. The flow simulation has been used to optimise both the bit and underreamer hydraulics. The model creates flow paths inside the tool and the near wellbore between the bit, BHA and the underreamer. Drilling mud, cuttings and flow path areas are simulated as turbulent flow passes through and around these elements. Tracking times identify the path taken by formation particles generated by each cutter. The objective is to achieve an optimal flow balance between the bit, the total volume of cuttings generated by the bit, the volume of cuttings generated by the underreamer and the specific volume of cuttings generated by each cutter. The design for the junk slot area can also be optimised so that flow volume for a specific junk slot is optimised.

NPT Root Causes

Our overall goal was to improve drilling efficiency by identifying root causes of NPT (Non Productive Time). Subsequently, a distinction was made between avoidable and recurrent causes of downtime or NPT and isolated or unavoidable NPT events. (See Figure 4) In order to do this, representative data related to underreaming across the industry deepwater, sub-salt and onshore assets was analysed. However this was not a simple task for several reasons.

First, it is often noted that there are 'no failures', nor 'NPT', especially at first sight. For example, a typical response is there is no underreaming NPT without looking at the broader data.

Second, failures are not always reported at the time and the root cause of failures can only be ascertained after detailed inspection reports have been completed. This may take

Underreaming Risks and Probability of Occurrence with Tool

Risk	1. Stuck Open	2. Loss of Directional Control	3. Cutter Block or Component Loss	4. Excess Overpull	5. Unplanned Activation	6. Unable to UR hard formation	7. Stuck Closed
Consequence	Stuck BHA, LIH BHA, Sidetrack	Trip, Sidetrack, Loss of target	Trip, Fishing, Sidetrack	Stuck BHA DBR	during RIH/shoe drill Trip. DBR	Trip. DBR	Trip at depth
Probability	0	0	0	0	0	0	0
Risk	8. Inability to activate or maintain tool active	9. Excessive Vibration	10. Poor Hole Cleaning Balling	11. Unable to Backream	12. Exceeding Circulating Life	13. Unable to Updrill	14. No Fishing ID
Consequence	Re-ream sections.	Unable to reach TD	Trip DBR	Poor hole condition.	Trip	Stuck	Trip. LIH LWD

Figure 5 Shows Underreaming Risks and Probability of their Occurrence with the Tool

several months after the problem occurs. Oil company personnel may have moved onto another well by then. Thirdly, failures and NPT are highly sensitive issues, not least due to their commercial and liability implications. However, by analysing industry end-of-well reports and wellbore data it was possible to identify factual NPT and identify non-confidential MTBF (Mean Time Between Failure). The data included:

1. Total underreamed footage per year,
2. Total Drilling NPT types, BHA failure events,
3. Underreaming NPT
4. MTBF for specific underreaming type

The point of the exercise was to identify underreaming design and operational improvements to be used within the overall well engineering and BHA design process.

Significant causes of NPT were highlighted as:
1. Inability to activate or maintain tool active
2. Cutter Block or Component Loss
3. Excessive Vibration
4. Loss of Directional Control
5. Excess Overpull
6. Unplanned Activation
7. Unable to underream hard formation
8. Stuck closed
9. Stuck open
10. Poor hole cleaning or balling
11. Unable to backream
12. Exceeding circulating life
13. No fishing ID

Reducing NPT

The primary cause of NPT associated with underreaming was reported as the 'Inability to activate or maintain tool active'. Essentially this was a typical scenario: 'drilling ahead' based on mechanical indication i.e. 'surface indication, SPP peaks, increase in drilling torque and/or increase of overpull. This raises the question, if mechanical indicators alone were sufficient to definitively know the status of the tool why would 'failure to activate' rank as the primary failure event? In several cases it was not known that the tool had not activated until the section had reached TD. An average industry wide statistic shows that this occurs in 1 out of 10 jobs.

The secondary cause of NPT was 'Cutter block or component loss'. In certain instances, this was only noted due to abnormal metal content being recovered on the shale shakers. However, at that point the cause of the problem was unknown.

In the case of the problematic runs, these two failure modes are not known until the section has reached TD and the morning report is in. According to a major deepwater operator the likelihood of underreamer complications is threefold as compared to non-underreaming jobs. If consideration is given to the actual downtime for the total number of underreaming failures i.e. based on 10% of Total Jobs the potential savings mount up (excluding LIH charges).

Taken individually or collectively, this data created a convincing case for a direct and real-time way of knowing what is actually going on down-hole especially with regard to underreaming.

Additionally, greater emphasis should be placed on identifying NPT for consecutive activities i.e. running casing or expandables and establishing the root causes of NPT. This is interesting as there can be a race to get to TD. However, where does casing running NPT actually get allocated? The same applies to problems created by excess cement volumes due to undergauge hole.

New Technology

The new technology aims to reduce risks associated with much of these NPT causes. The development of the technology for use in all rotary BHA types will be a step-change in drilling efficiency by reducing NPT and allowing the driller to take decisions earlier in order to maintain the wellbore within the desired diameter. The purpose of the new technology is to provide a new generation underreamer which will automatically detect and diagnose variations in wellbore diameter and rugosity. (See Figure 5)

Specific problem solving in real-time covers:

1. Probability of the tool not activating/staying deactivated
2. Probability of component loss
3. Probability of underreamer not delivering gauge hole
4. Probability of underreamer being unable to cope with hard formations
5. Probability of stuckfish due to radial closure
6. Probability of excessive overpull being required
7. Probability of poor hole cleaning/balling CFD/cuttings beds
8. Probability of being unable to backream
9 Probability of premature activation
10. Probability of exceeding circulating life

Field Development Applications

• Expandable liners. Undergauged hole size is not acceptable for these type of expandable applications and would jeopardize expansion.
• Close tolerance casing schemes
• Standard gravel packs or sand screens to avoid loss of production
• Exploratory wells such as those drilled in deepwater mature assets or radial shrinkage zones i.e. salt or swelling shale can offer a primary application for the technology. Even when a full logging suite is run LWD measurements are taken after underreaming.

Expandables

Expandables are typically a single shot at expansion which are set in place and expanded to the required diameter with push-down or pull-up expansion cone. Any part of the wellbore diameter that is undergauge may lead to possible failure in tubular expansion and the complete loss of the section (Refs 11 and 12).

The new technology reduces the risk by pinpointing undergauge hole sections and allowing for re-reaming until they are in-gauge. This increases the overall effectiveness of expandables. The technology would also improve drilling efficiency by reducing the NPT associated with casing running due to undergauge hole.

Wellbore Instability

The technology could also be very useful in addressing wellbore instability issues. It allows for timely understanding of breakouts, vugs, loss zones and washouts etc allowing for better drilling practices and more cost effective well construction. With the expandable application or narrow PPFG gradients this can be very useful in real-time optimisation of casing points.

Technology Summary

Optimisation of underreaming and associated calliper operations using Integrated and Intelligent system involves:

• Underreaming in Subsalt and other formations for Close Tolerance Casing, Expandable Liner Sections – a total of more than 21 applications

• The technology can be operated as a stand-alone system using its own mud-pulser and measurement means. The generation II design will interface with standard mud-pulsing technology provided by major service companies
• Designed to operate in all wellbore types and conditions as well as handling vugular formations and all drilling fluid types
• Enables the identification of borehole diameter variations without having a separate calliper and/or LWD run or LWD delay of post underreaming.
• Reduced drilling costs through the need for fewer underreaming correction runs from early detection of borehole diameter and failure modes.
• Ensure hole opening by real-time monitoring of under-reaming operation
• Automatic diagnostic and troubleshooting using logic circuit
• Greater operational flexibility ie run with low flow/hi flow, low WOB/high WOB

Conclusion

NPT analysis should consider root causes as well as their knock-on effect on sequential activities. The new technology reduces costs and removes uncertainty associated with underreaming. It also provides data that can be sent straight to Real-Time Operations Centres. It solves a growing drilling problem in the underreaming market which is itself a simple choice, either sections are underreamed and the target is reached, or, it is not. Therefore, there is a recognised need for under-reaming, and a compelling case for reducing the NPT and costs associated with underreaming. In the current oil price environment the ability to reduce costs by optimising drilling efficiency will only grow in importance.

Acknowledgment: The Authors would like to acknowledge Salah M. Al-Jaafari and Mohammad H. Al-Hattab of Saudi Aramco for their support of this paper.

1. SPE 102934 Solid Expandable Tubulars Facilitate Intelligent-Well Technology Application in Existing Multilateral Wells By M. Rivenbark, SPE, Enventure Global Technology, and K. Abouelnaaj, SPE, Saudi Aramco

2. Oil and Gas Journal Feb 1998 Underreaming Provides Array of Opportunities Wajid Rasheed, Mike Jones, E² Tech and Mick Betts Shell International Exploration and Production.

3. SPE 92623 Reducing Risk and Cost in Diverse Well Construction Applications: Eccentric Device Drills Concentric Hole and Offers a Viable Alternative to Underreamers Wajid Rasheed*, Oil and Gas Consultant, Jorge Trujillo, BP, Ruben van Oel, Schlumberger, Mark Anderson, Scott McDonald and Les Shale*, Hughes Christensen

4. SPE 23909 Innovative Steerable Underreaming BHA Design Overcome BOP Restrictions Raitt, Ferrier W.S. Smith International Boyle, John BP Exploration Operating Co. Ltd.

5. SPE 23106 Coil-Tubing Milling/Underreaming of Barium Sulphate Scale and Scale Control in the Forties Field Brown, A.D.F. Merrett, S.J. Putnam, J.S. BP Exploration Operating Co. Ltd.

6. SPE 23804 Formation Damage Control During Underreaming and Gravel Packing in an Overpressured Reservoir Blanton, R.J. Mobil E and P U.S.

7. SPE 15514 Bi-Center Bits for Drilling and Underreaming Moving Salt James, S.A. Consultant.

8. SPE 18693 Underreaming: Old Method With New Technology Desai, P.C. Smith Intl. Inc.

9. Drilling Column Hart E&P May 2004 Concentric Underreamers

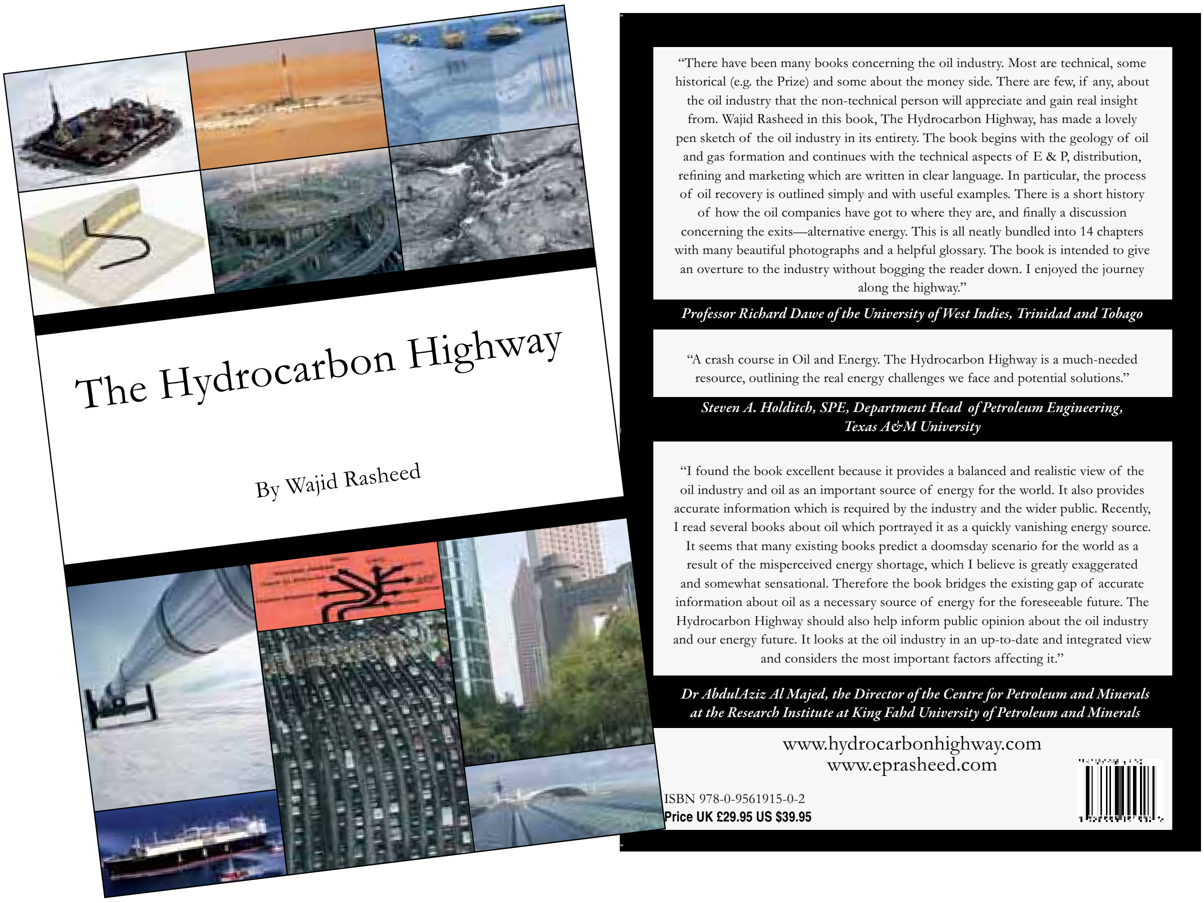
10 SPE 113486 LWD Acoustic Measurements Enhancements for Varying Drilling Conditions. Author John Moore, Vladimir Dubinsky, SPE, Charles Harrison, SPE, and Chen Li, Baker Hughes INTEQ

11. 97282-MS Expandable Sand Screens Selection, Performance and Reliability; a Review of the First 340 Installations . Author C. Jones, M. Tollefsen, P. Metcalfe, J. Cameron, D. Hillis, and Q. Morgan, Weatherford Intl.

12 SPE 84943 Finite Element Modeling of a Solid Tubular Expansion – A Typical Well Engineering Application, Author A.C. Seibi, T. Pervez, S. Al-Hiddabi, A. Karrech

Reserves, Peak Oil and Medieval Maps

Here follows a chapter from The Hydrocarbon Highway, by Wajid Rasheed



Are we running out of oil? Before we can answer that question, we need to understand what oil and gas reserves are and how they are measured.

Reserves are very significant numbers. They form the base of a slew of Key Performance Indicators (KPI) for all types of oil companies. Yet, the lack of a globally accepted standard makes the measurement and auditing of reserves a thorny issue. An integrated understanding of worldwide reserves is also lacking. In this chapter, we consider reserves measurement systems, global reserves and 'peak oil'. One key question interests us: are we navigating through global reserves using a 'medieval' and outdated map? If so, is peak oil a physical or psychological shortage?

Invariably, reserves* grab headlines due to their financial significance, measurement methods or the geo-political dimension. On the one hand, the sustainability of oil companies depends on reserves and, on the other, oil company profits depend primarily on production. By breaking down reserves and production data, analysts can derive KPIs such as net worth, reserves to production ratio, reserves replacement and production quotas and positive cash-flow. Consequently, reserves and production are inextricably linked to financial performance.

Major, National and Private

Existing irrespective of oil company size or shareholding, the link between reserves and financial performance is a fundamental one. Majors, public or 'floated' companies, will be judged by analysts on their short-term earnings and long-term prospects. Private companies will be judged by shareholders on Return on Investment (ROI). National or state companies are subject to analysis too which we will consider shortly. The stock prices of oil companies are heavily influenced by their stock-in-trade—oil. The oil company itself will use KPIs such as production rates and reserves replacement to make financial valuations and earnings projections. Financial analysts ultimately look to these figures and make 'buy, sell or hold' recommendations.

Reserves, therefore are a major influence on the stock price of major International Oil Companies (IOCs). Of course, IOC stock prices will be affected by quarterly profits and shareholder dividends. The oil price and other contextual factors that affect the attractiveness of the industry as a whole for investment—geopolitics, speculation and 'futures' trading—will also affect stock ratings. Beyond annual profit concerns, the long-term survivability of the oil company is wholly dependent on the rate at which production and reserves are increased. Usually this happens in one of three ways: first, through the 'drip-feed' of incremental recovery using mature field improved technology; second, by boosting reserves through the bit which means that successful wildcat strikes open new frontiers; and finally, by the acquisition of another oil company through its stock.

National Oil Companies

There is a common yet incorrect perception that National Oil Companies (NOC) are somewhat immune from scrutiny of financial indicators; however, there are at least two scenarios where NOCs will be judged by analysts. This primarily occurs when financial experts assess financial risk and assign credit ratings to NOCs and their countries of origin. In major oil exporters, i.e. exporting more than 2 million barrels of oil per day (MMbbl/d), the NOC is often the largest business in the country*. Country risk can therefore be considered a function of the NOC's performance. This has a direct bearing on the credit rating of countries. A secondary situation occurs when analysts assess the attractiveness of financial instruments or debt (bonds), issued by the oil company or government, based on ROI and risk.

Certain NOCs, such as those within the Organisation of Petroleum Exporting Countries (OPEC), also depend on reserves in another way. OPEC production quotas are allocated as a proportion of total proved reserves. Consequently, countries with high reserves volumes are given higher thresholds of production.

Uncertainty

Measuring reserves is difficult and involves a basic uncertainty because reserves lie hidden away in deep subterranean reservoirs. It would be physically impossible to accurately measure oil and gas in place; therefore, the industry relies on extrapolated measurements as accurate measurements can only occur upon production. Consequently, measuring, corroborating and auditing the measurement of reserves is an inexact science.

To make matters more complex, there is no single standard or methodology that is universally accepted by the industry or by the financial community, i.e. regulators/analysts. Substantive variations exist between institutions and nations. Exemplifying this are differences between the SPE (Society of Petroleum Engineers) and SEC (Securities Exchange Commission) criteria for reserves classification, and international variations between the Russian and Norwegian systems.

Before we go into detail, it is fair to note that the lack of a single international or institutionally recognised set of standards makes reserves measurement somewhat dependent on the system chosen.

Missing Barrels

With many oil companies based in the US or floated on US stock markets, the oil industry has been lobbying US regulators to overhaul the system by which the indus-try's reserves are measured.

The SEC classifies reserves using conservative and narrow definitions that do not satisfactorily account for the role of E & P technology in finding and producing reserves. This is a problem because not only does the industry have a track record of technology development, but technology is the stock-in-trade of the service companies and a principal measure by which analysts derive multiplier or share valuations of service companies beyond Earnings Before Income Tax Depreciation and Amortisation (EBITDA). Peak oil theorists also tend to minimise the value of E & P technology. We will examine the value of technology in detail shortly in the 'medieval map'.

The SEC measurement leads to a substantive variation with internal industry measures such as the SPE which places more emphasis on technology 'unlocking' reserves to make them more recoverable. The variation often results in discrepancies that amount to billions of barrels of oil across the industry.

Figure 1 - The Total Size of the Oil Resource is 3.012 Trillion Barrels (EPRasheed)

Figure 2 - The Total Size of the Gas Resource is 15.401 Trillion Cubic Feet (EPRasheed)

Industry analysts have lobbied the SEC to change its reserves accounting so that the benefits of E & P technology can be better applied. Essentially, this covers a raft of technologies such as seismic, geosteering and horizontal drilling which enable higher recovery rates through pinpointing reserves and well placement. At issue is the realistic valuation of energy companies themselves, as well as how we calculate replaced or future reserves. While analysts look to earnings as a short-term performance measure, the more long-term measure looks to reserves to production ratios as the basic indicator of the oil company's future wealth.

What's On the Books?

Due to the way financial and technological factors impact on reserves measurement, it is worth reviewing the types of reserves classifications that ultimately lead to KPI and valuation.

Getting a Slice of the Pie

It is worth distinguishing between the oil and gas resource and reserves. The 'global resource' is the 'size of the pie' or the entirety of the earth's oil and gas. The slice of this pie that is recoverable using today's technology at today's cost—price structure is known as 'global proved reserves'. According to BP's Statistical Review 2008, worldwide proved reserves of oil are 1.238 trillion barrels (see Figure 1 opposite) and those of gas are 6.263 trillion cubic feet (see Figure 2). The US Geological Survey, however, places the global resource of oil initially in place at 3 trillion barrels. We will come back to the size of the pie in the context of peak oil; however, for now it is worth noting that reserves are ranked based on their ultimate probability of production. That is to say one day in the future they will be brought to surface and sold.

Once the resource is discovered, reserves need to be

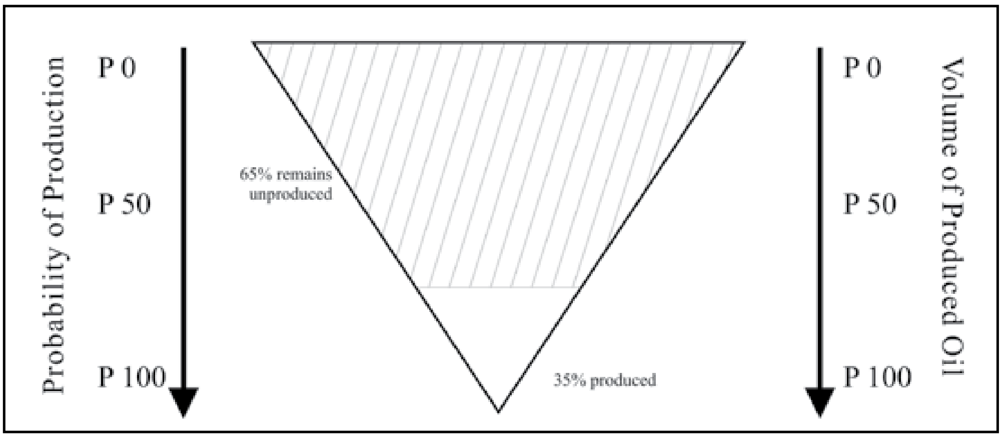


Figure 3 - The Relationship Between Probability and Volume of Oil Production (EPRasheed)

booked. This process involves mapping out and visualising one or more underground structures (leads or prospects) that may extend over 200 square miles. Reserves must then be classified and assigned values according to the probability of their production. Finally, the value of reserves are discounted to today's worth. For financial and asset planning purposes, the key determinants are the likely size of discovered reserves and their ease of recovery.

The most common classifications are the generic three 'Ps' and the more specific 'P factor'.

The Three 'Ps'

Defined according to a sliding scale of the 'probability' or percentage chance of production, the three 'Ps'—Proved, Probable and Possible—are illustrated by the figure below. They indicate the relative ease or difficulty with which the reserves in question can be produced. It is standard practice for a numerical 'P factor' to be assigned to represent the specific probability of the reserves being produced. Typically, 'P' values for ultimate recovery range from P90 for a very high probability, P50 for medium probability and P10 for a very low probability. A series of questions related to location, accessibility and technology need to be answered before 'P' values can be ascertained. Are the reserves located in easily accessible areas or shallow depths? Are there wells, platforms or pipelines in place? Does the technology exist to reach the reserves today? If the answer is 'yes' to these questions, the probability of production is clearly high so these are proved reserves. Where the answer is 'no' and nothing is in place other than outline plans, such reserves are low probability. Most reserves will fall between these two extremes in that they have varying degrees of infrastructure in place.

Corresponding to a value, i.e. P 90, P 50 or P 10, the 'P factor' simply represents the percentage chance of reserves being produced. Proved is 90%, Probable is 50% and Possible is 10%.

This classification uses a scale based on the development status, the infrastructure in place and the ease of recovery of oil and gas. Reserves that score lower on development status and infrastructure are harder to develop so their percentage chance of recovery falls; therefore, they are assigned a lower 'P' class with a lower 'P' value.

'Proved reserves' refer to the estimated quantities of crude oil, natural gas and Natural Gas Liquids (NGLs) which can be recovered with demonstrable certainty using geological and engineering data. This applies, for example, to future production from known reservoirs under existing economic and operating conditions, i.e., oil prices and lifting costs as of the date the estimate is made.

Reservoirs are considered 'proved' if economic production is supported by actual production or conclusive formation tests showing an increase in production. The area of a reservoir considered proved includes: the portion identified by drilling and defined by gas-oil and/or oil-water contacts and the immediately adjacent areas not yet drilled, but which can be reasonably expected as economically productive based on the available geological and engineering data.

Reserves which can be produced economically through improved recovery techniques (such as water injection to maintain reservoir pressure) are included in the 'proved' classification when an increase in production is seen. Estimates of proved reserves do not include the following: oil that may be produced from known reservoirs but is classified separately as 'indicated additional reserves'; crude oil, natural gas, and NGLs, the recovery of which is subject to uncertainty as to geological, reservoir characteristics, or economic factors; crude oil, natural gas, and NGLs that may occur in undrilled prospects; and, crude oil, natural gas, and NGLs that may be recovered from unconventional sources such as oil shales.

Further distinctions blur the boundaries between classes; for example, 'proved developed reserves' refers to reserves that can be recovered from existing wells using existing technology. Additional oil and gas production obtained through the application of improved recovery techniques can be included as 'proved developed reserves' only after successful testing. Tests can either be pilot projects or improved applications that show an actual increase in production.

'Proved undeveloped reserves' are reserves that are recoverable from new wells on undrilled acreage, or from existing wells where further major expenditure is required. Reserves on undrilled acreage are usually limited to those areas where there is reasonable certainty of production when drilled. Proved reserves for other undrilled units can only be claimed where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

Russian and Norwegian Reserves Classification

Russian and Western methods of estimation and classification of reserves are somewhat different. The Russian officials have divided oil and gas reserves into six classes: A, B, C1, C2, D1 and D2. Class A represents proven reserves and B provable reserves. Class C1 represents reserves estimated by means of drilling and individual tests, and C2 reserves are based on seismic exploration. Classes D1 and D2 represent hypothetical and speculative reserves.

Norway uses its own definitions of reserves, which run from Category 0 – 9.

Category 0 is defined as 'Petroleum resources in deposits that have been produced and have passed the reserves reference point. It includes quantities from fields in production as well as from fields that have been permanently closed down'.

Category 9 includes resources in leads and unmapped resources and covers undiscovered, recoverable petroleum resources attached to leads. It is uncertain whether the leads, and if so the estimated resources, are actually present. The resource estimates reflect estimated volumes multiplied by the probability of making a discovery. This probability must be stated.

Geologic Assessment Procedures

Oil companies often use models to assess geologic structures or oil and gas plays. A common model defines a play as 'a set of known or postulated oil and/or gas accumulations sharing similar geologic, geographic, and temporal properties such as source rock, migration patterns, timing, trapping mechanisms, and hydrocarbon types'.

Oil companies use this approach to process exploration knowledge such as seismic or aerial surveys or wildcats generated by the exploration teams. A fundamental part of this process is the attributing of probabilities for each petroleum play. Geologists will also assign subjective probability distributions to characterise attributes of undiscovered conventional oil and gas accumulations.

The geologic risk structure is modelled by assigning a probability to each play. This probability is based on at least one accumulation meeting the minimum size requirements (50 MMBO in place or 250 BCF gas recoverable). In particular, the oil company will assign probability distributions for reservoir attributes such as net reservoir thickness, area of closure, porosity and trap fill.

Net pay estimates are derived from the data and include the extent and distribution of the reservoir. These estimates are essentially refined and related to P values, i.e. P90, and are verified to see whether they are consistent with existing knowledge. Other factors to be considered will be hydrocarbon recovery factor, porosity and permeability forecasts and initial production.

Peak Oil and Medieval Maps

Since the publication of Hubbert's Peak in 1956, the theory of 'peak-oil' has gained in importance with a growing chorus of support from within the industry and wider society. Yet is peak oil really a physical decline in production levels or is it a philosophical debate mired in the minutiae of reserves and production systems?

To answer these questions, we need to adopt a global E & P perspective that integrates prospective E & P areas with technology applications. Equally we need to recognise the limits of conventional wisdom. Are we

Figure 4 - The Americas Do Not Exist According to Medieval Maps

navigating with a 'medieval map' of worldwide hydrocarbon reserves—one that does not adequately reflect the total resource?

Optimist or Pessimist?

Two schools of thought exist. Optimists state there is an abundance of oil and gas and that there is enough for everyone, while pessimists state there is a deficit and we are doomed. These two positions, and the consequent debate, have generated much emotion, not to mention a multi-million dollar niche industry. What appears to be important here is that no-one disagrees that a peak or decline will occur, that is the natural state of systems. Yet, no-one can agree on when or even why this event will occur. It is worth considering this debate as it can help us understand the 'psychological' supply shortfall of prospects. This has a knock-on psychological effect on supply which is compounded by a herd mentality within the oil and gas markets (see Chapter 12: Paper Barrels for detail).

The pessimists reason as follows:

1. Rare conditions allow petroleum reserves to be produced.

2. Once production peaks, reserves decline rapidly in output.

3. Most global petroleum reserves have peaked. Further large finds are unlikely.

4. Global production is therefore declining.

The optimists argue:

1. Rare conditions allow petroleum reserves to be produced.

2. Production can be made to plateau, not peak, through technology.

3. Technology finds more reserves, makes smaller reserves more accessible and sustains overall production on a global scale.

4. Global production is therefore sustainable.

There is also a third, or alternative view, to consider:

1. Rare conditions allow petroleum reserves to be produced.

2. Today's theories regarding petroleum reserves and recoverability are incomplete.

3. Knowledge increases over time.

4. Many prospective petroleum plays are unexplored.

5. All known sources of petroleum systems have therefore not yet been quantified; hence, the use of the 'medieval map' analogy.

.

In this alternate scenario, no one can state categorically that peak oil has, or has not occurred because our current knowledge is incomplete. Just as when we look at medieval maps and note the Americas are missing, so future generations will look at today's map of worldwide reserves as incomplete. Just as when previously wise petroleum engineers looked at deepwater reserves and shook their heads deeming them unrecoverable, we see the limits of their wisdom.

Deepwater production has been made routine, almost mundane through 'game-changing' and cost-effective technology. This ranges from pre-drill packages that incorporate sub-salt imaging to seabed to surface risers to directional drilling techniques that can enable multiple reservoir completions.

In this way, the ultimate recoverability of reserves is tempered by the cost of technology. If E & P technology can be made available at cost-effective prices, reserves can be developed. This is because finding and lifting costs ultimately determine development. If the costs of development outweigh the price of oil, there simply is not enough profit to develop them.

As noted earlier, the SEC classifies reserves according to very narrow definitions that do not satisfactorily account for the role of E & P technology in finding and producing reserves. Peak oil theorists tend to use such classifications too.

Peak oil theorists tend to overlook the industry's track record of technology development. Technology is the stock-in-trade of the service companies and a principal measure by which analysts derive multiplier or share valuations of service companies beyond earnings.

This does not imply that petroleum is infinite. It means that even though petroleum is a finite and scarce resource, technology can increase production and ultimate recovery.

Aside from the technology factor, there is the question of the medieval map of reserves. As our globe-trotting exercise will show shortly, there are still several petroleum provinces waiting to be mapped out.

Given that demand for oil and gas will rise in the long-term, and considering the track record of the E & P industry to date, further advances in E & P technology will permit almost all petroleum reserves, irrespective of location, to be developed before new energy sources and exits to the Hydrocarbon Highway are created. Consequently, the limiting factor for reserves will be the cost of development rather than their shortage.

Worldwide Reserves

Referred to as 'the low hanging fruit' that is effortlessly picked, onshore basins are generally easy-to-access with low finding and lifting costs. Consequently, these reserves have been both extensively characterised and produced; however, several tough-to-reach onshore basins remain unexplored. Exemplifying this is the Amazon Complex (Brazil, Colombia, Peru and Bolivia), the Arctic Circle (the Alaska National Wildlife Reserve being part of this territory) and Antarctica.

No one has any real knowledge on the potential size of these onshore reserves. The historic finding and lifting costs in similar areas such as Sakhalin or Alaska , however, range on average from US $12 to US $18. With production, total costs rise further due to a lack of infrastructure in remote areas (see Chapter 8: Extreme E & P for detail).

Middle East

More prospective areas exist in unexplored basins within the Middle East such as the Empty Quarter (Rub Al Khali) in Saudi Arabia, the Bushehr province in Southern Iran and North and South Iraq. Typically, these countries are blessed with prolific source rock, high permeability and trapping systems found at very shallow depths starting at approximately 700 m (2,100 ft) and ranging to 2,000 m (6,000 ft). New finds continue to maintain the Middle East as a dominant long-term reserve base, with common recognition that Saudi Arabia and Iran respectively are the world's largest and second largest holders of oil reserves. Further, finding, lifting and production costs are the lowest worldwide, averaging between US $1 to US $3 a barrel.

Lifting costs can vary, however, by way of comparison. In other relatively low-cost areas like Malaysia and Oman, lifting costs can range from US $3 to US $12 a barrel to produce. Production costs in Mexico and Russia might potentially be as low as US $6 to US $12 per barrel (higher under current production arrangements by local companies).

.

By reviewing the world's prospective shallow coastal waters, deltas and oceans, it becomes clear that our map of global resources is incomplete. In the offshore realm, there are many unexplored basins with finding, lifting and production costs varying from US $18 to US $25 per barrel for certain deeper waters. Large tracts off the coast of West and North Africa are undeveloped. The West African margin has been extended from the high-profile plays in the shallow waters of the Niger Delta, Nigeria and the Congo Basin, Angola to deeper waters and to highly prospective sub-salt plays. Mauritania and Tanzania are other examples where new discoveries have been made.

South of Australia in Tasmania, oil companies have been studying gas plays since 2000 which had previiously been neglected due to the search for oil. This has led to indications of oil being found in Africa near Madagascar, which has been identified as a potential new petroleum province. Mauritania and Tanzania are other examples where new African discoveries have been made. Another area is offshore Morocco, where the deposition of an ancient river system was found over salt. A mobile substrate, either salt or shale, is a key element all along the West African margin because it provides geological factors necessary for oil and gas.

Continental Plate Reconstruction

A clear example of continental plate reconstruction and conjugate oil and gas of plays is offshore West Africa and offshore Brazil. By using reconstructions, it can be seen that the Rio Muni Basin was the 'mirror' basin to the Sergipe-Alagoas Basin in Brazil, and the Congo Basin to the Campos Basin. By repeating this process along the coast of West Africa and Brazil, several emerging oil and gas plays can be drawn up. These include the sub-salt frontiers of offshore Brazil including Tupi. Although production is not likely to make a major impact on world oil exports over the next decade, the point is that new frontiers have been discovered.

In Central America, the offshore area between Venezuela and Trinidad, the Gulf of Paria, is largely unexplored as are the waters off Colombia and Peru.

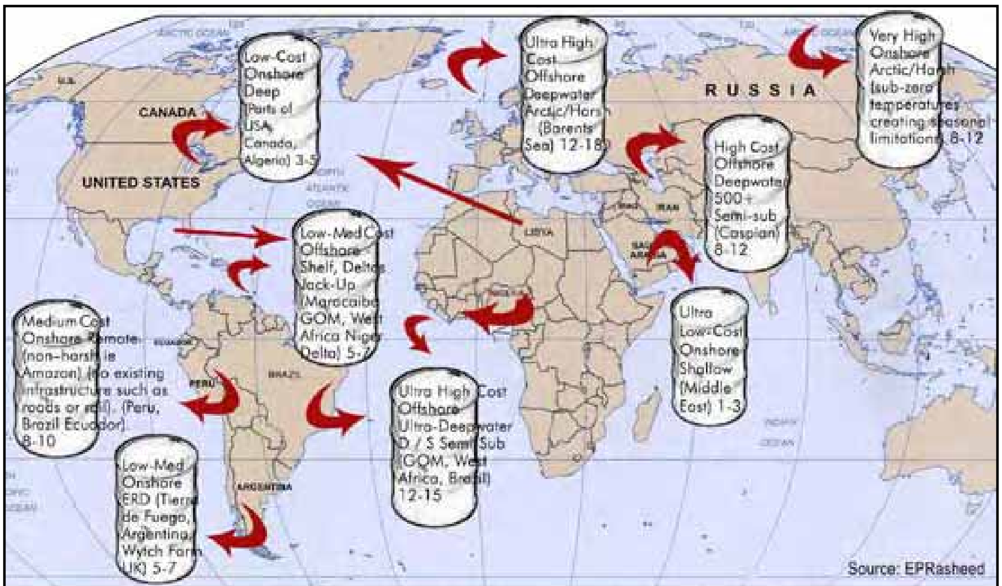
The Gulf of Mexico (GOM) has unexplored waters that stretch from the shallow waters off Florida, US and move into the territorial GOM waters of Cuba, vast areas of deep waters in the Mexican GOM and the deeper waters of the US GOM. Within the US GOM, the sub-salt play has been instrumental in new finds. Offshore production in areas like the North Sea with offshore platforms, can run to US $12 to US $18 a barrel. As reservoirs become smaller, those costs tend to rise. In Texas and other US and Canadian fields, where deep wells and small reservoirs make production especially expensive, costs can run above US $20 a barrel.

Further East, we note that certain areas of the Northern North Sea and the Barents Sea are still to be explored. While in Russia, Sakhalin Island, the Central Asian Republics, the Red Sea, the Persian Gulf, the Indian Ocean, Offshore Australia and New Zealand, several offshore basins represent prospective yet unexplored areas.

What is the total resource base? The US Geological Survey puts this at 3 trillion barrels of oil. Again, it's hard to say because we are still waiting to finalise the map.

Sweating

The Finding and Development in Figure 5 clearly shows that, when crude oil prices fall below US $20 a barrel, many areas become unprofitable and production is reduced if not halted altogether. Only certain lower cost areas can remain profitable and hence maintain production during a 'good sweating' period.



Note: Not included are development, lifting costs or production taxes/sharing agreement quotas. Based on several wells incl. 3D and sidetracks. Total depths vary. Deepwater includes adverse drilling challenges such as salt, tight ppfg, close tolerance casing and EPS early production system. Figures will vary depending on reservoir size. Does not include processing costs for heavy oil below 18 degree API which are by order of magnitude higher.

Figure 5 - Finding Costs for Oil Companies in US $

Two factors emerge from this globe-trotting exercise: first, there is a lack of characterisation in many highly prospective basins and gulfs; and second, there is high prospectivity, but it is tempered by technical limitations and increased costs.

None of these areas is mature; most are unexplored and some are even unlicensed. This is despite adjoining proven hydrocarbon producing basins or sharing geological characteristics such as source rock, trapping and faulting. It is fair to say that we have not yet characterised the world's oil and gas basins nor their accompanying reserves. Consequently, how can we even assume that global peak oil production has occurred? (Gas is another matter entirely as it can be man-made)

Conventional Wisdom and the Limits of Our Map

The limitations of our map of oil and gas reserves start to become clear when we consider past theories. In the 1990s, one widely held view stated that offshore oil and gas reserves would not be found at extreme conditions, i.e. depths exceeding a TVD of 20,000 ft (6,096 m). It was suggested that overburden pressures would either cause a loss of hydrocarbons due to migration to shallower traps or compaction. Now that theory has changed because oil and gas trends have been located at far greater depths than prior knowledge would indicate. Think deep gas, US GOM.

In the 1980s, another example of a change in thinking occurred concerning the flow paths of fluvial deposition. Ancient river systems account for the sedimentation that leads to accumulations of oil and gas. In river deltas worldwide, as the shallow water plays were developed, exploration efforts evolved into the deepwater usually with only major international oil companies that could qualify for the blocks.

Smaller oil companies, therefore, were limited to exploring other geologic scenarios and plays. They recognised that over time the places where these river sys-tems had been depositing sediment had changed, and the Independents' exploration discovered 'new' margins.

Another example of limited knowledge has been sub-salt basins. These have been discovered and are being explored in the GOM and worldwide. Sub-salt plays in West Africa, Brazil and GOM show deeper accumulations of oil and gas trends that had not been predicted or expected earlier.

Game-Changing Technology

Back in the late 1980s, it was thought that development of thin sands such as 'Norwegian Troll oil' would never be economically feasible, because the oil reserves were so thinly layered and the price of oil was US $10 per barrel. Game-changing technology such as 3D seismic improved the visualisation of reserves, while horizontal drilling and geosteering altered the definition of what was deemed uneconomic or unreachable at a given time. The billion-dollar think tanks and research and development facilities that major service companies own are continually creating new technologies that help access reserves previously considered uneconomic or unreachable. Service companies and operators develop technology in-house through joint industry

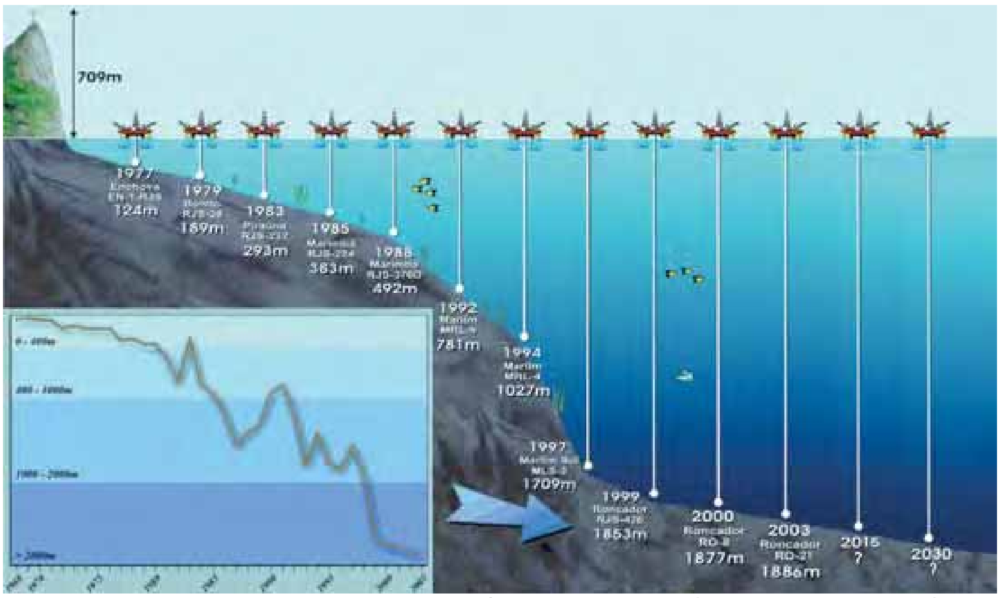


Figure 6 - The Incredible Depth Progression from Shelf to Deep Waters (Petrobras News Agency)

projects and with best-in-class companies; for example, Shell and Petrobras respectively are involved in the monobore and the Procap 3000 initiatives—two examples of technology cascading downward. Underlying the monobore (a vision of drilling and casing a single-diameter well from top to bottom) is the creation of businesses to develop the downhole tools, tubes and markets for expandable tubulars. Procap 3000, a range of exploration and production technologies, is paving the way in ultra-deepwater development. Drilling contractors have introduced simultaneous drilling and completion of two wells by way of the dual-activity derrick system.

.

Technology

Scarcity of oil reserves and increasing reserve replacement costs are the twin factors that have accelerated the technological evolution of E & P and enabled extreme E & P (see Chapter 8: Extreme E & P). This evolution is most clearly visualised in the dramatic shift from onshore to offshore exploration. The incredible depth progression from land to shallow coastal waters to deep waters to the extremes of ultra-deepwater is shown in the graphic below.

.

A few decades ago, it was not considered possible to produce in waters beyond 6,561 ft (2,000 m) depth, and accordingly, those reserves were listed as ' P 10s' with a very low possibility of production. Rigs and risers were just some of the incredible challenges. The industry has, however, progressively tapped deepwater accumulations. First, it targeted shallow onshore reserves as the less challenging 'low-hanging fruit'. As those resources became scarcer, E & P went deeper onshore and spread to shallow offshore waters. E & P operations in 8,200 ft (2,500 m) water depth are routine, and the challenge now is 9,842 ft (3,000 m) and deeper.

Records are continually set and broken not just in deeper water depths (3,000 m) but also in deep reservoirs below salt domes, tar zones and in the remote basins of the world and in new frontiers. This includes the latest subsea water separation systems and subsea sand separation to achieve maximum production. Remarkably, however, almost all of this enabling E & P technology is considered an outsourced commodity marketed by service and supply companies, which means the NOCs have no shortage of technology vendors. The buzzwords of 'ultra-deepwater, digital oilfield and barrel-chasing' may first be heard in oil company offices due to the engineering challenges and risks oil companies 'buy'. They resonate most loudly, however, throughout the service-side: in product development, in research facilities and on test rigs before technology is commercially run in field applications.

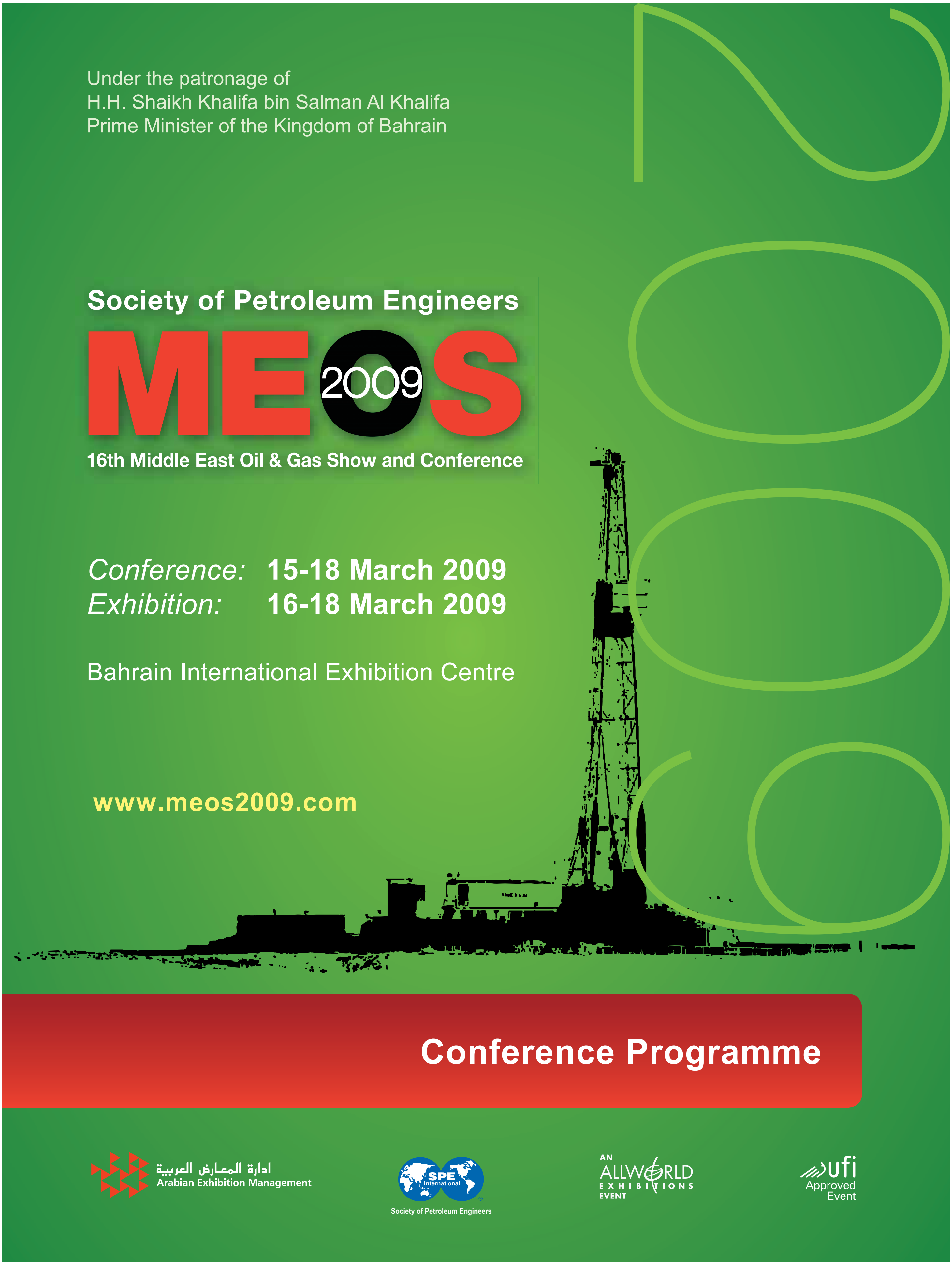
In addition to developing the technology to drill in deeper waters, the industry has developed the ability to drill extreme offsets from a single surface location. This has profound implications in reducing our environmental 'footprint' and providing economic access to thousands of 'satellite fields'. As of 2008, the world's record Extended Reach Drilling (ERD) well was drilled in the Persian Gulf from a jack-up drilling rig. The total measured depth of the well was 40,320 ft (12,293 m), and the well's bottom was offset 37,956 ft (11,572 m) from its surface location. In the UK, ERD techniques enabled BP to develop Wytch Farm, an entire oil field under an environmentally sensitive resort and vacation area on the south coast of England, with no visible footprint. Off Sakhalin Island in far east Siberia, Russian companies are exploiting oil reservoirs from land by drilling ERD wells out under sea ice that would ordinarily damage offshore facilities.

These feats were inconceivable to Hubbert when he developed his peak oil theory. Hubbert was correct to state that oil is a finite resource—and he can't be blamed for letting a medieval mentality affect his prediction of when we would run out. People today who are still letting medieval thinking guide them, however, should know better.

What emerges from the peak oil debate is that we are reading the directions to worldwide reserves from a 'medieval map'. Clearly, there are new frontiers and plays to be developed. Think Subsalt, Arctic and Deepwater E & P which is changing the definition of P 10s into P 90s. Coupling this with innovative thinking and cutting-edge technology makes for a convincing argument; peak oil as far as reserves are concerned, is a philosophical debate rooted in a psychological shortage not a physical one.

We are not in fact running out of oil. We have many areas yet to explore before we have to worry about oil and gas shortages. As we have been shown, there are plenty of barrels of oil remaining.

NB for reference material and information on how to purchase The Hydrocarbon Highway – visit **www.hydrocarbonhighway.com**


Under the patronage of
H.H. Shaikh Khalifa bin Salman Al Khalifa
Prime Minister of the Kingdom of Bahrain
Society of Petroleum Engineers
MEOS 2009
16th Middle East Oil & Gas Show and Conference
Conference: 15-18 March 2009
Exhibition: 16-18 March 2009
Bahrain International Exhibition Centre
www.meos2009.com
Conference Programme
ادارة المعارض العربية
Arabian Exhibition Management
SPE International
Society of Petroleum Engineers
AN ALLWORLD EXHIBITIONS EVENT
ufi Approved Event

MEOS 2009 Committee Members

Executive Committee

Faisal Al-Mahroos *(Conference Chairman)* .... *Bahrain Petroleum Company*
Mohamed Hashem *(Programme Chairman)* .... *Shell*
Bernard Montaron *(Programme Co-Chairman)*..................................*Schlumberger*

Abdalla Saeed Al-Suwaidi.. *NDC*
Ahmed Ali Al Sharyan .... *NOGA*
Ali H. Al-Hasan.. *SPE Regional Director*
Mamdouh Mahfouz .... *SAPESCO*
Mike Grieve .... *Shell*
Mohammed Al-Qahtani .... *Saudi Aramco*
Mohamed Husain.. *KOC*
Rick Vierbuchen .... *ExxonMobil*
Rolf Monjo.. *Oxy*
Saif Al-Hanai .... *PDO*
Sara Akbar.. *Kuwait Energy*
Sheikh Faisal Fahad Al-Thani.. *Maersk Oil Qatar AS*
Sheikh Mohamed bin Abdulla K. Al-Khalifa .... *AEM*
Sidqi A. Abu-Khamsin.. *KFUPM*
Zaki Selim.. *Schlumberger*

Programme Committee

Mohamed Hashem *(Programme Chairman)* .... *Shell*
Bernard Montaron *(Programme Co-Chairman)*.................................. *Schlumberger*

Abdul Hameed A. Al-Rushaid. *Saudi Aramco*
Adel H. Malallah...................... *Kuwait University*
Alasdair Fergusson .... *Baker Oil Tools*
Ali Bakheet.............................. *ADCO*
Amgad Younes........................ *Shell*
Artur Stankiewicz .... *Shell*
Aus Al-Tawil .... *Saudi Aramco*
Ayda Essa Abdulwahab.......... *BAPCO*
Charles Kreuz .... *Weatherford*
Farida Abdulla.......................... *KOC*
Hamoud Al-Hadrami .... *Sultan Qaboos Uni*
Haq Minhas .... *PETRONAS*
Hasan Salman Al-Hashim ...... *KFUPM*
Hisham Zubari......................... *BAPCO*
Jim Briscoe .... *Oxy*
Louai Machhour...................... *Total*
Mahmood Amani..................... *Texas A & M Qatar*
Mehdi Samama .... *Libya - NOC*
Moustafa Oraby .... *Halliburton*
Nick Nawfal .... *Baker Hughes*
Riyaz Kharrat .... *PUT - Iran*
Rutger Huijgens .... *BP*
Salim Al-Sikaiti........................ *PDO*
Salim David Khemakhem........ *RasGas*
Sridhar Srinivasan .... *Schlumberger*
Sultan Masoud Al-Merikhi....... *Qatar Petroleum*
Wael Helmy .... *ExxonMobil*
Wajid Rasheed........................ *Saudi Arabia Oil and Gas*
Waleed A. Al-Mulhim .... *Saudi Aramco*

Welcome to the 16th SPE Middle East Oil & Gas Show and Conference.

It is a pleasure and a privilege to serve as Chairman of the Executive Committee for this prestigious event in the region. The Programme Committee led by Mohamed Hashem and supported by Bernard Montaron have worked extremely hard to put a strong Technical Programme together under the special theme of:

People, Demand, Technology – Bridging the Gaps

With the continuing vibrancy of the industry, we anticipate MEOS 2009 to be bigger and better than 2007. The 2007 MEOS attracted over 6,337 trade visitors and conference delegates from around the world. The 14,000 sqm of exhibit space covers all areas of the upstream industry, including geology, geo-physics, reservoir engineering, drilling, completions, measurement systems, automation, transportation, health and safety, and information technology.

This year we open the Conference with the Executive Plenary Session, led by industry leaders who will address the very theme of this year's event, and set the scene for the next few days.

This year we have grown the Technical Programme to include 31 sessions and in addition we have 8 Panel Sessions and of course posters throughout the conference.

The conference and exhibition are now permanent entries in the calendar of the upstream E&P business community throughout the Middle East and beyond.

Please come and join us in experiencing this most special event.

Yours sincerely,

Faisal Al Mahroos
Conference Chairman, MEOS 2009
Deputy Chief Executive (E&P) (U/S)
Bahrain Petroleum Company (BAPCO)

Welcome to the 16th SPE Middle East Oil and Gas Show and Conference, or "MEOS." Since this event first took place in 1979, it has remained one of SPE's main Middle-East-focused events.

I am not surprised this has been the case for all these years, as I have seen the dedication of everyone who has contributed to make it one of the best events in the Middle East.

In addition to the robust technical programme, MEOS offers a business platform for experts, researchers, and leaders of the industry to discuss and share technical and industrial information and contribute to the growth of our industry and the development of our resources.

This year's multidisciplinary conference programme, with its theme "People, Demand, Technology: Bridging the Gaps", demonstrates the MEOS Programme Committee's standard of excellence; they have given their time and efforts to ensure the quality of the selected technical papers and the unrivalled broad scope of the topics discussed.

The committee has assembled a comprehensive programme that features presentations from all around the world. Given by renowned speakers in the industry, the presentations range from drilling and EOR/IOR to recruiting and developing people; a diversity that will enrich the knowledge of attendees employed in technical and nontechnical disciplines.

The hard work that makes MEOS a premier event is reflected in the other events SPE successfully launched this year, covering the Middle East, North Africa, and India and highlighting the major challenges, new technologies, trends, and best practices of the industry in various disciplines. Building on that success, SPE will continue to offer more high-quality events that will benefit its members and all professionals in the industry.

As the 2009 SPE President and on behalf of the programme committee, I would like to thank all who have contributed to MEOS 2009. I would also like to extend our appreciation to our sponsors and supporters, and I hope you continue to support SPE events and activities in this region.

Leo Roodhart
SPE 2009 President

Session Schedule and Programme

Day	Time	Room 1	Room 2	Room 3	Room 4	Room 5	Room 6
Sunday 15 March	PM	**16:30 – 17:00 Conference Opening Ceremony** **17:00 – 19:30 Executive Plenary:** *People, Demand, Technology – Bridging the Gaps*					
Monday 16 March	09:30	**Exhibition Opening Ceremony**					
	09:00 - 10:30	**Panel I** Facilitation: IOR/ EOR Through R&D Investment and Field Experimentation	**Panel 2** High HSE Performance Under Increased Manpower Turnover				
	10:30 - 11:00	Coffee Break					
	11:00 - 12:30	**Session 1** Well and Reservoir Management 1	**Session 2** EOR/IOR 1	**Session 3** Smart Fields/Smart Wells	**Session 4** Reservoir Modelling 1	**Session 5** Reservoir Characterisation 1	**Session 6** Improved Drilling Performance
	14:00 - 15:30	**Session 7** Well and Reservoir Management 2	**Session 8** EOR/IOR2	**Session 9** Reservoir Modelling 2	**Session 10** Reservoir Characterisation 2	**Session 11** Formation Evaluation 1	
	15:30 - 16:00	Coffee Break					
	16:00 - 18:00	**Industry Outlook Plenary** Industry Outlook in Light of World Economic Situation					
Tuesday 17 March	09:00 - 10:30	**Panel 3** NOC's/IOC's Collaboration Models	**Panel 4** CO_2: Who's Going to Sign the Bill?				
	10:30 - 11:00	Coffee Break					
	11:00 - 12:30	**Session 12** Well and Reservoir Management 3	**Session 13** EOR/IOR 3	**Session 14** Reservoir Characterisation 3	**Session 15** Formation Evaluation 2	**Session 16** Well Bore Clean Up	
	14:00 - 15:30	**Session 17** Hydraulic Fracturing	**Session 18** Production Management	**Session 19** Marginal Fields	**Session 20** Innovative Drilling Solutions	**Session 21** People First, Recruiting Development and Well Being	
	15:30 - 16.00	Coffee Break					
	16:00 - 17:30	**Panel 5** Meeting the Growing Demand on Gas?	**Panel 6** The Changing Landscape of the Middle East Oil Industry: Opportunity for Emerging Companies				
Wednesday 18 March	09:00 - 10:30	**Panel 7** Futuristic Technologies and Breakthroughs	**Panel 8** Does Petroleum Engineering Education Meet Current Needs?				
	10:30 - 11:00	Coffee Break					
	11:00 - 12:30	**Session 22** Facilities	**Session 23** Gas Challenges	**Session 24** Environment	**Session 25** New Ventures and Future Outlook	**Session 26** Zonal Isolation and Completion Technology	
	14:00 - 15:30	**Session 27** Drilling Optimisation	**Session 28** Deepwater Challenge	**Session 29** Production Monitoring and Testing	**Session 30** Production Case Studies	**Session 31** Formation Evaluation 3	
	15:30 - 16:00	Coffee Break					

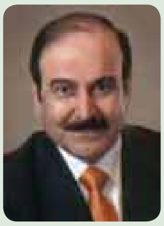
Conference Opening Ceremony & Executive Plenary Session

Conference Opening Ceremony

Sunday, 15 March | **16:30 – 17:00** | **Rooms 1 & 2**

MEOS 2009 Executive Summary

Welcome Address by



His Excellency Dr. Abdul-Hussain bin Ali Mirza
Minister of Oil & Gas Affairs and Chairman of the
Bahrain National Oil and Gas Authority

Leo Roodhart
SPE 2009 President

Executive Plenary Session

17:00 – 19:30 | **Rooms 1 & 2**

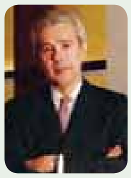
Sunday, 15 March

People, Demand, Technology –
Bridging the Gaps

Speakers

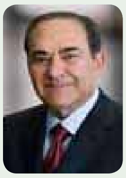
Andrew Gould
Chairman and Chief Executive Officer
Schlumberger

Amin Nasser
Senior VP Exploration and Producing
Saudi Aramco



Bernard J. Duroc-Danner
Chairman, President and
Chief Executive Officer
Weatherford International Ltd

Neil Duffin
President
ExxonMobil Development Company



Ray R. Irani
Chairman & Chief Executive Officer
Occidental Petroleum Corporation

Sami F. Al-Rushaid
Chairman and Managing Director
Kuwait Oil Company

Sunday, 15 March | **MEOS 2009 Gala Dinner** | **19:30**

Hosted by Kuwait Oil Company - Al Dana Hall, Gulf Hotel

Industry Outlook Plenary Session

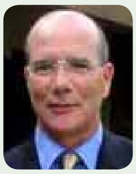
Monday, 16 March

16:00 – 18:00 **Room 1**

Industry Outlook in Light of World Economic Situation

The large increase followed by a sharp drop of the oil price observed in 2008 is indicative of the impact the global financial crisis already had on our industry and how markets speculated on the trends in hydrocarbon demand versus supply. What are the views of NOCs, IOCs, and Service Co's on what exactly happened in the last twelve months and why? What is the outlook for 2009, particularly the second half of the year, and 2010? What lessons should we retain and what possible long term consequences can we expect for our industry?

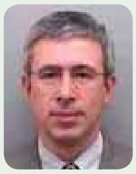
Speakers



Ali Aissaoui
Head
Economics & Research
APICORP

Farouk H. Al Zanki
Chairman and
Managing Director
KNPC

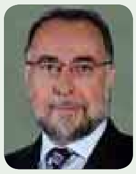
John Mills
Executive Vice President
Middle East, North Africa
& South Asia
Shell



Laurent Maurel
Vice President
Business Strategy
Total

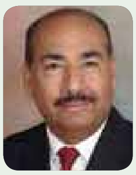
Rick Vierbuchen
Vice President
Caspian & Middle East Region
ExxonMobil

Tim Probert
Executive Vice President for
Strategy & Corporate Development
Halliburton



Vahan Zanoyan
Chief Executive Officer
1st Energy Bank

Moderated by



Abdulkarim Al Sayed
Chief Executive Officer
BAPCO

Panel Sessions

Panel 1

Monday, 16 March

9:00 – 10:30 Room 1

Facilitation: IOR/EOR Through R&D Investment and Field Experimentation

Speakers:
Alain Labastie, *Reservoir R&D Manager, Total*
Ali A.G. Gheithy, *Study Centre Manager, PDO*
Ghaniya Bin-Dhaaer Al-Yafei, *Team Leader, Enhanced Oil Recovery, ADCO*
Hani Qutob, *Principal Advisor, Reservoir Engineering, Weatherford*
Rustom Mody, *Vice President Technology , Baker Hughes*

Moderator:
Bill Roby
Vice President Worldwide Engineering and Technical Services
Occidental Petroleum Corporation

In the last ten years it looks like more R&D was invested in hard-to-produce hydrocarbons (heavy oil, oil shale, tight gas) compared to conventional reservoirs. Yet there are close to four trillion barrels of conventional oil considered non recoverable in existing reservoirs and recovering 15% of it would provide the equivalent of twenty years of world-wide oil consumption at current rates. Considerable work was done in the 1980's and early 1990's on EOR processes for sandstone reservoirs, but very little on carbonates. Developing efficient EOR techniques for carbonates will require significant R&D and field experimentation in the form of pilots at various scales. Are IOCs and NOCs prepared to invest and to commit to field experimentation programs?

Panel 2

Monday, 16 March

9:00 – 10:30 Room 2

High HSE Performance Under Increased Manpower Turnover

Speakers:
Abdulaziz Al-Rashed, *Chairman & Managing Director Kuwait Drilling Company*
Ahmed Khalil, *Manager, Fire, Health and Safety, BAPCO*
Atef Al-Mohsen, *Technical Planning Manager, RasGas*
Gary Allen, *Director HSE Middle East & Asia, Schlumberger*
Naaman Al Naamany, *HSE Manager, PDO*

Moderator:
Mike Grieve, *Vice President Production Middle East & South Asia, Shell*

Insurance company statistics show that young drivers provoke and are the victims of twice as many serious accidents than experienced drivers. In many countries it takes about three years of accident-free driving for young drivers to start enjoying good insurance premium. Driving is just one of the causes of accidents in our industry. Our task is complex. High HSE performance can only result from a very systematic and thorough training and coaching process. It takes time, it takes commitment. How can we better protect our young recruits and their colleagues against HSE risks under an increased manpower turnover environment?

Panel 3

Tuesday, 17 March

9:00 – 10:30 Room 1

NOC's/IOC's Collaboration Models

Speakers:
Amin Shibani, *Manager, Upstream Venture Department Saudi Aramco*
Billy-Dean Gibson, *Vice President Marketing Middle East & Asia, Schlumberger*
Faraj M. Saeed, *Assistant General Secretary, Libya NOC (Invited)*
Frank Kemnetz, *President, ExxonMobil*
Hisham Zubari, *Manager Petroleum Engineering, BAPCO*
Khaled A. Al-Sumaiti, *Deputy Managing Director, E&P Development, Kuwait Oil Company*

Moderator:
Jerry Kepes, *Partner Head, Upstream & Gas*

National Oil Companies (NOC's) may be tempted to handle big projects on their own in times of high oil prices and to invite International Oil Companies (IOC's) when prices are low. As fields mature, EOR and IOR projects require high technology in addition to intensive capital. Partnerships between NOC's and IOC's may bring the best of the two. Host countries appreciate IOC's investments in the communities in which they operate, while IOC's international experience is appreciated by NOC's. By bringing together people, technology and business drivers, the partnership delivers on performance with high standards and focus on safety and protection of the environment.

But what is the ideal form for cooperation? Is it partnership or service? What is the role of service providers in this partnership or phase? Speakers will discuss the collaboration models from their own perspective.

Panel Sessions continued

Panel 4

Tuesday, 17 March

9:00 – 10:30 Room 2

C0₂: Who's Going to Sign the Bill?

Speakers:
Amjad Rihan, *Director of Climate Change & Sustainability Services, Middle East and* **Jim Fitzgerald,** *Director, Energy & Environmental Infrastructure, Advisory - Renewable, Ernst & Young*
Ellen Stout, *Market Development Director, Global Oil & Gas Market, Air Liquide*
Jaques Merour, *Technical Manager, StatoilHydro*
John Barry, *Vice President, Unconventionals and EOR, Shell*
Kamel Bennaceur, *Chief Economist, Schlumberger*

Moderator:
Zara Khatib, *Technology Marketing Manager Middle East and South Asia Region, Shell*

Investments required to capture CO_2 from industrial plants, to pipe it to storage sites and to store it safely in downhole formations are enormous. The fact that the long term reliability of CO_2 storage is still not well understood and the lack of a legal framework ruling the responsibilities of the various players are additional risks that must be considered. But do we have a choice? Can CO_2 injection be applied to fulfill two goals in one go – CO_2 storage and EOR – to improve economics? How can our industry contribute to manage CO_2 in the Middle East and who is going to sign the bill?

Panel 5

Tuesday, 17 March

16:00 – 17:30 Room 1

Meeting the Growing Demand for Gas?

Speakers:
Aman Amanpour, *General Manager, New Opportunities, Middle East, South East Asia & Caspian, Shell*
Hisham Zubari, *Manager Petroleum Engineering, BAPCO*
Ieda Gomes, *Head of New Ventures, BP*
Mohamed Husain, *Deputy Chairman, Kuwait Oil Company*
Rick Westerdale, *Commercial Manager, ExxonMobil*
Waleed Al-Mulhim, *Manager, Saudi Aramco*

Moderator:
Bernard Montaron, *Theme Director, Carbonates, Schlumberger*

Recovery factors for gas typically exceed 75% and there is more to gain on increasing production capacity from existing fields, developing known (unconventional) reservoirs and – of course – discovering new resources through exploration campaigns. Other bottlenecks can come from transport and distribution issues. One can also free up valuable gas currently used for pressure maintenance by replacing it with nitrogen. Where do we stand today in the Middle East and elsewhere on these challenges? Was the rate of new discoveries in the past five years in line with objectives and long term demand? How do we foresee the evolution of the demand/supply equation in the next twenty years?

Panel 6

Tuesday, 17 March

16:00 – 17:30 Room 2

The Changing Landscape of the Middle East Oil Industry: Opportunity for Emerging Companies

Speakers:
A. Husain Shehab, *Chief Executive Officer & Managing Director, Al-Dorra Petroleum Services*
Abdul Jaleel Al-Khalifa, *Chief Executive Officer, Dragon Oil*
John McCreery, *Partner, Bain & Company, Inc.*
Robin Mills, *Petroleum Economics Manager, ENOC*
Sara Akbar, *Chief Executive Officer & Managing Director, Kuwait Energy*
Zaid Al Siyabi, *Director General for Exploration, MOG*

Moderator:
Saleh M. Al-Dawas
Manager, Production & Facilities Development, Saudi Aramco

The Middle East is the most important oil region in the world; it has two thirds of the world oil reserves and presently provides one third of the world's oil needs. Even though most of it's oilfields are still prolific, most are approaching the end of their primary production stages because of the natural maturation process. The main challenge facing the Middle East is the need to continue oil production at the present rate or more in order to satisfy the ever-increasing financial needs of the producing countries, while at the same time the productivity of the oilfields are declining. Does this situation open the door for new emerging companies to take a role facing their challenges?

Panel Sessions continued

Panel 7

Wednesday, 18 March

9:00 – 10:30 Room 1

Futuristic Technologies and Breakthroughs

Speakers:
Ahmed El-Banbi
Regional Technology Center Manager, Schlumberger
K. Sampath, *Reservoir Manager, ExxonMobil*
Manoëlle Lepoutre, *Vice President for E&P R&D, Total*
Mohamed Hashem, *Regional Technology Manager, Shell*
Muhammad M. Al-Saggaf
Manager, EXPEC Advance Research Center, Saudi Aramco
Rob Mayfield, *Investment Principal, Kenda Capital B.V.*

Moderator:
Adel Al-Abbasi
Manager, Research & Technology, Kuwait Oil Company

It is always difficult to predict the future of technology, especially from the present! However, it is always possible to speak about it. We tend to know better what we need, or what we think we need. For example: Better exploration technology able to increase probability of discovery, better technology to characterize and model complex reservoirs, better production and recovery technologies and processes. What emerging technologies could have a significant impact on our industry in the future? What specific plans are being followed by IOCs, NOCs and Service Co's to encourage R&D on possible breakthrough technologies?

Panel 8

Wednesday, 18 March

9:00 – 10:30 Room 2

Does Petroleum Engineering Education Meet Current Needs?

Speakers:
Ali Saud Al-Bimani, *Vice Chancellor, Sultan Qaboos Univeristy*
Hassan Al-Hosani, *Manager Manpower Development, ADMA-OPCO*
Ken Delve, *Manager, Petro Skills*
Riyaz Kharrat, *Director of Research Centre, PUT - Iran*
Salam Salamy, *Assistant to Vice President, Saudi Aramco*

Moderator:
Sidqi Abu Khamsin, *Professor & Chairman, KFUPM*

Asking the question is already a sign that the answer might be: No! However one must recognize that good progress was accomplished in the last five years in the Middle East region to improve petroleum engineering education. There are now a number of examples of success stories in the region with several institutes and universities that are providing excellent petroleum engineering and MSc graduates. Nevertheless the rapid aging of our industry workforce will require many more new recruits to join with adequate education levels. Will we be able to satisfy this need with what we currently have in place? What else can we do to fulfill future staffing requirements?

Technical Sessions

Session 1

Monday, 16 March

11:00 – 12:30 Room 1

WELL AND RESERVOIR MANAGEMENT 1

Session Chairpersons: Clement Edwards, Petroleum Development Oman
Atef Al-Mohsen, RasGas

11:00	120382	**Improving Oil Recovery in Heterogeneous Carbonate Reservoir by Optimising Peripheral Water Injection through Application of Innovative Techniques** • M.A. Chouhdary, A.A. Mahmeed, M.R. Wani, H.A. Mubarak and H.R. Al Rasheedi, Kuwait Gulf Oil Company
11:30	119681	**Towards the e field: Continuous Monitoring of Pore Fluid Phase Using Horizontal Wells** • B.J. Evans and N. Keshavar, Curtin University of Technology
12:00	120648	**An Integrated Approach Towards Building an Enterprise GIS System for Petroleum Industry** • N.K. Puripanda, F.A. Shamsan and Y.M. Nooraldeen, Bahrain Petroleum Company

Session 2

Monday, 16 March

11:00 – 12:30 Room 2

EOR/IOR 1

Session Chairpersons: Sidqi A. Abu-Khamsin, KFUPM
Shahin Negahban, ADCO

11:00	120205	**Steamflood Piloting the Wafra Field Eocene Reservoir in the Partitioned Neutral Zone, Between Saudi Arabia and Kuwait** • D. Barge, Falah Al-Yami, D. Uphold, A. Zahedi and A. Deemer, Saudi Arabian Chevron; P. E. Carreras, Chevron Energy Technology Company
11:30	120569	**Thermal EOR Plan for a Shallow Limestone Reservoir (Rubble Zone) in Bahrain Field** • C.R. Murty and K. Kumar, Bahrain Petroleum Company; J. De Galard, Beicip-Franlab
12:00	118746	**An Update and Perspective on Field-Scale Chemical Floods in Daqing Oilfield, China** • H. Pu and W. Wang, University of Wyoming; X. Zhao, Daqing Oilfield Company

Alternates

	120321	**Sweep Impairment Due to Polymers Shear-Thinning Behavior** • A.M. Al-Sofi, T. La Force and M.J. Blunt, Imperial College
	118825	**Sulfur and Asphaltene Deposition During CO2 Flooding of Carbonate Reservoirs** • A.Y. Zekri and R.A. Almehaideb, United Arab Emirates University; S.A. Shedid, Texas A&M University

Session 3

Monday, 16 March

11:00 – 12:30 Room 3

SMART FIELD/SMART WELLS

Session Chairpersons: John Hofland, ADCO
Klaus Mueller, Petroleum Development Oman

11:00	120303	**Two-Zone Commingled Production Using Intelligent Well Completion Coupled with ESP Through a Hydraulic Disconnect Tool** • J. Ansah, B.I. Al-Quaimi, Fahad Abdulla Al-Ajmi, M.A. Al-Shehab and F.A. Al-Bani, Saudi Aramco; S. Jacob, WellDynamics
11:30	120460	**Measurements of Streaming Potential for Downhole Monitoring in Intelligent Wells** • M. Jaafar, J. Vinogradov, M.D. Jackson, J.H. Saunders and C.C. Pain, Imperial College
12:00	120696	**Utilisation of In-Situ Gas Lift System to Increase Production in Saudi Arabia Offshore Oil Producers** • P.B. Warren, S.A. Logan, M.A. Zubail, S.P. Perez and A.A. Balto, Saudi Aramco; A.A. Villarreal, O. Beccera, Baker Oil Tools

Technical Sessions continued

Session 4

Monday, 16 March

11:00 – 12:30 **Room 4**

RESERVOIR MODELLING I

Session Chairpersons: Adel Malallah, Kuwait University
Ahmed Al-Hamadah, Saudi Aramco

11:00	120049	**Geomechanical Characterisation of a Sandstone Reservoir in Middle East - Analysis of Sanding Prediction and Completion Strategy** • M.A. Mohiuddin, Schlumberger; M.M. Najem, Aramco Gulf Operations; Y. Dhaferi, and Khafji H. Bajunaid, Al-Khafji Joint Operations
11:30	120170	**Unstructured Coarse Grid Generation for Reservoir Flow Simulation Using Background Grid Approach** • H. Mahani, Shell; M. Evazi, Sharif University of Technology; B. Honarvar, Azad University
12:00	118681	**Improved Method for Compositional Modelling Using Fine Scale Geological Description LGR within Pilot Area of Carbonate Reservoir in the Middle-East.** • T.A. Obeida, A.P. Gibson and H. Al Hashemi, ADCO; B.M. Baruah, Kelkar & Associates

Alternates

	120665	**Integrated Reservoir Connectivity and Simulation Study of Ahmadi Fractured Reservoirs in Bahrain Field** • A.E. Al-Muftah and C.R. Murty, Bahrain Petroleum Company; T. Lemaux, Beicip-Franlab
	119605	**Application of Streamline Reservoir Simulation Calculations to the Management of Oilfield Scale** • T.F. Hassan, Schlumberger

Session 5

Monday, 16 March

11:00 – 12:30 **Room 5**

RESERVOIR CHARACTERISATION I

Session Chairpersons: Hasan Al Hashim, KFUPM
Amgad Younes, Shell

11:00	120424	**Fracture and Sub Seismic Fault Characterization for Tight Carbonates In Challenging Oil Based Mud Environment - Case Study from North Kuwait Jurassic Reservoirs** • B. Li, C. Perrin and M. Al Khabbaz, Schlumberger; M.A. Al Awadi, S. Al Ashwak and B. Al Qadeeri, Kuwait Oil Company
11:30	120687	**Identification and Characterisation of Producing Fractures in Naturally Fractured Reservoirs Using PIWD** • M.M. Cherif, H.H. Qutob and N. Barakat, Weatherford; A. Berkat and K. Kartobi, Sonatrach
12:00	118895	**Integrated Fracture Study Using Electrical Borehole Image, Stoneley Waves and Formation Evaluation Results in Carbonate Reservoir at Gulf of Suez, Egypt** • D. Juandi, A. Ali and M. Emam, Schlumberger; E.A. Bassim and K. Yamaguchi, Arabian Oil Company

Alternates

	120136	**Use of Exclusion Zones In Assigning Length and Orientation to Fracture Corridors from Dynamic Data** • S.I. Ozkaya, Baker Atlas
	120723	**Assessment of Inter Reservoir Communication in a Stratified Carbonate Reservoir** • R.J. Phillips Guerrero and J. Shakhs, Saudi Aramco

Technical Sessions continued

Session 6

Monday, 16 March

11:00 – 12:30 Room 6

IMPROVED DRILLING PERFORMANCE

Session Chairpersons: Wajid Rasheed, EP Rasheed
Moustafa Bakry, Shell

11:00	120622	**A Structured Approach to Benchmarking Bit Runs and Identifying Good Performance for Optimisation of Future Applications** • N. Briggs, A. Richards and R. Duerholt, Baker Hughes; C.L. Miller, Saudi Aramco
11:30	120646	**Quest for a Pragmatic Drilling Fluid Performance Index Key to Improving Fluid Performance and Optimising Quality Well Delivery Economics** • P.I. Osode and M. Farsi, Petroleum Development Oman; E. Stevenson, Shell
12:00	120542	**Successful Application of Extra Long Expandable Cased Hole Liner Remediates Production Well** • R. Barghawi and S. Looni, Saudi Aramco; M.A. Saad,T. Sanders and David Stephenson, Weatherford

Alternates

	120290	**Enhancing Decision Making in Critical Drilling Operations** • S. Valipour Shokouhi, Norwegian University of Science & Technology; P. Skalle and F. Sormo, Volve
	120715	**Using Formation Testing While Drilling Pressures to Optimise a Middle East Carbonate Reservoir Drilling Programme** • M.A. Proett, Halliburton; R.M. Masoud, A. Gyllensten, K. Amari, J. Lawghani and G.Y. Salem, ADCO; A. Al Baloushi, ADNOC; A.C. Aki, O. Elamin, A.S. Eyuboglu and S.M. Nabawy, Halliburton

Session 7

Monday, 16 March

14:00 – 15:30 Room 1

WELL AND RESERVOIR MANAGEMENT 2

Session Chairpersons: Salim Al Sikaiti, Petroleum Development Oman
Farida Abdulla, Kuwait Oil Company

14:00	120349	**Optimising Horizontal Well Performance in Non-Uniform Pressure Environments Using Passive Inflow Control Devices** • D. Krinis, D.E. Hembling, N.J. Al Dawood and S.A. Al Qatari, Saudi Aramco; S. Simonian, FloDynamic; G. Salerno, Baker Hughes
14:30	119640	**Integrating Real Time Down Hole Data to Enhance Gas Lift Completion Strategies and Perforation Practices** • H.D. Mustafa, S. Balushi, Petroleum Development Oman; S.J. Beattie, Zenith Oilfield Technology
15:00	120372	**Opportunistic Pressure Data Gathering Campaign During Production Shut Down Added Insight into the Water Flood Response and Pressure Connectivity in Highly Heterogeneous Clastic Reservoir in North Kuwait** • B.A. Baroon, H.B. Chetri and E.H. Al Anzi, Kuwait Oil Company

Session 8

Monday, 16 March

14:00 – 15:30 Room 2

EOR/IOR 2

Session Chairpersons: Riyaz Kharrat, Petroleum University of Technology Iran
Ghaniya Bin Dhaaer, ADCO

14:00	119600	**Effect of Brine Salinity on Interfacial Tension in Arab-D Carbonate Reservoir, Saudi Arabia** • T.M. Okasha and A. Alshiwaish, Saudi Aramco
14:30	120354	**Investigating the Mechanism of Thermally Induced Wettability Alteration** • S. Ayatollahi, M. Escrochi, F. Varzandeh and J. Khatibi, Shiraz University; A. Roosta and M. Shafiei, Bahonar University
15:00	120413	**A Novel Thermal Technology of Formation Treatment Involves Bi-Wellhead Horizontal Wells** • R.R. Ibatullin, TatNIPIneft; N.G. Ibragimov and R. Khisamov, OAO Tatneft

Technical Sessions continued

Session 9

Monday, 16 March

14:00 – 15:30 Room 3

RESERVOIR MODELLING 2

Session Chairpersons: Mahmood Amani, Texas A&M University
Abdulaziz Abdulakarim, Saudi Aramco

14:00	120428	**From Data Acquisition to Simulator: Fracture Modelling in a Carbonate Heavy Oil Reservoir (Lower Shuaiba, North Oman)** • G.M. Warrlich, P.D. Richard, T.E. Johnson, A. Al-Lamki, AOM, Al-Riyami, D.M. Alexander and J.D. Gittins, Petroleum Development Oman; L.M. Wassing, Shell
14:30	119643	**Validation of Fracture Lineaments with Dynamic Well Data, Improves History Matching of a Dual Porosity Permeability Model** • S.M. Al Mubarak, Z. Ali and T.R. Pham, Saudi Aramco; F. Colomar, Beicip Franlab
15:00	120053	**Development of a Full Field Parallel Model to Design Pressure Maintenance Project in the Wara Reservoir, Greater Burgan Field, Kuwait** • E.D. Ma and M. Al Naqi, Kuwait Oil Company; L. Williams and A.K. Ambastha, Chevron

Alternates

	119255	**A Fractured Heterogeneity Composite Reservoir Seepage Model** • J. Feng, Research Institute of Petroleum Exploration and Development; R. Luo and L. Cheng, China University of Petroleum
	120433	**Fast and Efficient Sensitivity Calculation Using Adjoint Method for 3- Phase Field Scale History Matching** • R.M. Azmi, Cairo University; A.M. Daoud, Schlumberger

Session 10

Monday, 16 March

14:00 – 15:30 Room 4

RESERVOIR CHARACTERISATION 2

Session Chairpersons: Artur Stankiewicz, Shell
Mohammed Badri, Schlumberger

14:00	118862	**The Use of Tracers for Reservoir Characterisation** • L. Anisimov, Lukoil VolgogradNIPImorneft
14:30	120562	**Increasing Production from a Shallow, Underdeveloped Reservoir in the Bahrain Field Through Integrating Reservoir Analysis with Geochemistry** • N.K. Abdulla, N.A. Nedham, Y. Al Ansari and Challa R.K. Murty, Bahrain Petroleum Company
15:00	120558	**Constraining Interwell Water Flood Imaging with Geology and Petrophysics: An Example from the Middle East** • S.L. Reeder, N. Clerc and M. Wilt, Schlumberger; M. Al Ali, V.C. Vahrenkamp, S. Elsembawy and Z.N. Bhatti, ADCO

Alternates

	119120	**A Fast and Reliable Methodology for Estimating Fractured Reservoir Geometry from Tracer Test** • U. Aslam, University of Stavanger
	120423	**Characterisation of Complex Carbonate Heavy Oil Reservoir Undergoing Steam Injection - A Case Study** • A. Iqbal, John Smith, A. Zahedi, D. Arthur and F. Al-Yami, Saudi Arabian Chevron, A. Rampurawala and B. Li, Schlumberger, T. Enazi, Kuwait Gulf Oil Company

Technical Sessions continued

Session 11

Monday, 16 March

14:00 – 15:30 Room 5

FORMATION EVALUATION I

Session Chairpersons: Moustafa Oraby, Halliburton
Rutger Huijens, BP

14:00	119918	**Coring Unconsolidated Formation Lower Fars: A Case Study** • K. Ahmed, I.A. Al Sammak, S. De, F. Ahmad, F. Abbas and F. Al Bous, Kuwait Oil Company
14:30	120032	**On the Relationship Between Electro Kinetics and Reservoir Rock Physical Properties** • S.F. Alkafeef and A.M. Zaid, Gulf Centre for Petroleum Consulting and Services; A.F. Alajmi, Kuwait University
15:00	120517	**Assessment of Uncertainty in Saturation Estimated from Archie's Equation** • A.D. Zeybek and F.J. Kuchuk, Schlumberger; M. Onur and O.I. Tureyen, Istanbul Technical University; S. Ma and A.M. Shahri, Saudi Aramco

Session 12

Tuesday, 17 March

11:00 – 12:30 Room 1

WELL AND RESERVOIR MANAGEMENT 3

Session Chairpersons: Waleed Al Mulhim, Saudi Aramco
Ali Al Gheithy, Petroleum Development Oman

11:00	118836	**Reservoir Simulation Study on Improvement of Water-flooding Effect for a Naturally Fractured Low Permeability Field in Daqing, China: A Successful Case** • H. Pu, University of Wyoming; G. Wang, PetroChina
11:30	120427	**Lessons Learned from the First Water Flood Pilot Project in a Clastic Reservoir in the Greater Burgan Field in Kuwait** • M. Al Naqi, I. Al Kandari, M. Al Qattan and B.Al Rahman, Kuwait Oil Company; N.H. Gazi, Halliburton; S. Bou Mikael, Chevron
12:00	120229	**Development of an Integrated Reservoir Surveillance Process for World's Second Largest Field in Kuwait** • S.F. Desai and H.Z. Al Ajmi, Kuwait Oil Company; N.H. Gazi, Halliburton

Alternate

	120722	**Uncertainty Analysis on a Giant Fractured Carbonate Reservoir** • K.A. Alalwan and J.S. Thuwaini Saudi Aramco; A.X. Ranjan, IFP Middle East

Technical Sessions continued

Session 13

Tuesday, 17 March

11:00 – 12:30 **Room 2**

EOR/IOR 3

Session Chairpersons: Shapour Vossoughi, University of Kansas
Scott Kersey, RasGas

11:00	119747	**Thermodynamic Criteria and Final Results of WAG CO_2 Injection in a Pilot Project in Croatia** • D. Novosel, INA Naftaplin
11:30	119010	**Mechanism of Microbe Propagation in Heterogeneous Porous Media and Analysis of Various MEOR Processes Involved in Microbe Transportation** • U. Aslam, University of Stavanger
12:00	120238	**Field Experience Detailing Acrolein (2-Propenal) Treatment of a Produced Water Injection System in the Sultanate of Oman** • D.D. Horaska, Baker Hughes; J.E. Penkala, C.A. Reed, M.D. Law and M.M. Srour, Baker Petrolite; A.S. Al Harthy, Petroleum Development Oman; S. Gaffney, Baker Hughes INTEQ

Alternates

	119666	**The Application Studies of Surfactin Biosurfactant as Surfactant Coupler in ASP Flooding** • D. Wang, L. Yongjian and C. Hao, Daqing Petroleum Institute; Z. Hou, Daqing Oilfield Company
	120595	**Air Injection Potential in Kenmore Oilfield in Eromanga Basin, Australia: A Screening Study Through Thermogravimetric and Calorimetric Analyses** • H.K. Sarma, University of Adelaide; S.C. Das, Australian School of Petroleum

Session 14

Tuesday, 17 March

11:00 – 12:30 **Room 3**

RESERVOIR CHARACTERISATION 3

Session Chairpersons: Bernard Montaron, Schlumberger
Hasan Al Yousef, KFUPM

11:00	120102	**Quantifying Uncertainty in Carbonate Reservoirs Humma Marrat Reservoir, Partitioned Neutral Zone (PNZ), Saudi Arabia and Kuwait** • W.S. Meddaugh and S. Griest, Chevron Energy Technology Company; D.L. Barge, Chevron
11:30	120407	**Flow Unit Characterisation and Geo Modelling of a Structurally Complex Fluvio Deltaic Reservoir Using an Integrated Approach** • I. Barua, A.L. Mahesh and B. Bharali, Oil India; V. Sharma, S.K. Sharma and S. Dasgupta, Schlumberger
12:00	120267	**Effective Permeability vs Drainage Radius, Correlation for Turbidites Oil Reservoirs Chicontepec Paleochannel** • H. Gachuz Muro, Pemex E&P

Technical Sessions continued

Session 15

Tuesday, 17 March

11:00 – 12:30 Room 4

FORMATION EVALUATION 2

Session Chairpersons: Sridhar Srinivasan, Schlumberger
Khalid Zainalabedin, Saudi Aramco

11:00	120104	**Steady State Productivity Equations for a Multiple Wells System in Sector Fault Reservoirs and Channel Reservoirs** • J. Lu and Tao Zhu, The Petroleum Institute; D.Tiab, University of Oklahoma
11:30	120443	**Specialised Techniques for Wireline Formation Testing and Fluid Sampling in Unconsolidated Formations in Deepwater Reservoirs** • R.R. Jackson and I. De Santo, Schlumberger; P. Weinheber; E. Guadagnini, ENI Group
12:00	120705	**New Techniques In LWD Formation Pressure Testing Enable Real-Time Reservoir Evaluation In Ever More Challenging Environments.** • U. Hahne and M. Meister, Baker Hughes INTEQ

Session 16

Tuesday, 17 March

11:00 – 12:30 Room 5

WELL BORE CLEAN UP

Session Chairpersons: Jim Briscoe, OXY
Tom Thanh Lai, RasGas

11:00	119997	**An Innovative Stimulation Approach for Horizontal Power Injectors in Sandstone Reservoir, Saudi Arabia: Field Experience** • A.K. Al Zain, A.A. Al Jandal, R. Said and A.N. Abitrabi, Saudi Aramco
11:30	120487	**Productivity Enhancement of Horizontal Heavy Oil Wells in the South of Oman** • B. Zreik, A.S. Al Hattali, K.H. Al Busaidi, S.K. Tripathy and M.N. Bushara, Petroleum Development Oman
12:00	120651	**Best Clean Up Practices for an Offshore Sandstone Reservoir with ICD Completions in Horizontal Wells** • Ali M. Shahri, Khalid Kilany, D. Hembling and J. E. Lauritzen, Saudi Aramco; V. Gottumukkala and O. Ogunyemi, Schlumberger; O. B. Moreno, Baker Oil Tools

Alternates

	119675	**Case History: Sucessful Application of Combined Rotary Jetting and MLT to Stimulate Dual-Lateral Producer in Ahawar Field** • Ali M. Shari, Khalid Kilony, D. Hembling and J.E. Lauritzen, Saudi Aramco; V. Gottumukkala and O. Ogunyemi, Schulmberger; O.B. Moreno, Baker Oil Tools
	119591	**Microwash Treatment Case History** • A.A. Al Ruwaily, J.E. Phillips and Z.R. BenSaad, Saudi Aramco; C.F. Christian, Baker Hughes

Technical Sessions continued

Session 17

Tuesday, 17 March

14:00 – 15:30 Room 1

HYDRAULIC FRACTURING

Session Chairpersons: Stephen Davies, Schlumberger
Shaikhan Khadhuri, Petroleum Development Oman

14:00	120408	**Evaluation of New Stimulation Technique to Improve Well Productivity in a Long, Open hole Horizontal Section: Study Case.** • F.O. Garzon, C.A. Franco, H.M. Al Marri, K.S. Asiri and H.A. Al Saeed, Saudi Aramco; G. Izquierdo, Halliburton
14:30	119475	**New Alternative to Selectively Fracture Stimulate Extended Reach Horizontal Wells** • J.B. Surjaatmadja and L. Sierra, Halliburton
15:00	120326	**Increasing Production and Injection in Multilateral Horizontal Wells in Naturally Fractured Carbonate Reservoirs by Rigless Intervention A Case Study, Offshore, Qatar** • O. Lisigurski, W. Ferdiana, C.F. Haro, E. Maili, Occidental

Alternates

	120552	**Numerical Modeling of Multiple Hydraulically Fractured Horizontal Wells (MHFHW)** • A. Soleimani, Y. Al Guwaidi and Steve Dyer, Schlumberger; B.O. Lee, Saudi Aramco
	120029	**Chemistry Applied to Fracture Stimulation of Petroleum Wells** • P.C. Harris and A. Sabhapondit, Halliburton

Session 18

Tuesday, 17 March

14:00 – 15:30 Room 2

PRODUCTION MANAGEMENT

Session Chairpersons: Mohamed Wael Helmy, ExxonMobil
John Ramalho, Shell

14:00	120664	**Production Enhancement for Khafji Field using Advanced Optimisation Technique** • M.A. Al Khaldi and E.O. Ghoniem, Al Khafji Joint Operations; A.A. Jama, Schlumberger
14:30	120019	**Applying a New Systematic and Dynamic UBD Procedure Prevented Formation Damage, Wellbore Collapse and Improved Oil production in Hassi Massoud Field** • H.H. Qutob, N. Barakat, F. Grayson and A.S. Marei, Weatherford; A. Berkat, K. Kartobi, A. Mazouzi and O. Dhina, Sonatrach
15:00	119850	**Relative Permeability Modifiers in Fracture Stimulation Applications** • E.D. Dalrymple and O.A. Jaripatke, Halliburton

Technical Sessions continued

Session 19
Tuesday, 17 March

14:00 – 15:30 **Room 3**

MARGINAL FIELDS

Session Chairpersons: Alasdair Fergusson, Baker Oil Tools
Andy Todd, Wood Mackenzie

14:00	120319	**FDP Revisions: Keeping Your FDP's Green in a Fit for Purpose Manner** • S.V. Garimella, H.J. Kloosterman, D. Horstmann and A. Gheithy, Petroleum Development Oman
14:30	120429	**Full Field Development Plan "The Big Picture – Creating the Future from the Future and Success through Real Synergy"** • A.A. Keshka, H.H. Hafez, J.S. Gomes, S. Al Olama, S. Al Bakr, M.M. Kenawy, S. Al Dhiyebi and K.A. Samad, ADCO
15:00	120150	**Improvement of Geologic Exploration Efficiency in Mature Oil and Gas Provinces** • V.G. Bazarevskaya and R.S. Khisamov, Tatneft TatNIPIneft Institute

Alternate

	119071	**Horizontal Well Sectional Frac Technique with Dual Retrievable Packers in Daqing Oilfield** • L. Ban, H. Ban, Daqing Oilfield Company; W. Zhou, Production Engineering and Research Institute; Q. Li, Production R&E Institute of Daqing

Session 20
Tuesday, 17 March

14:00 – 15:30 **Room 4**

INNOVATIVE DRILLING SOLUTIONS

Session Chairpersons: Nick Nawfal, Baker Hughes
Shaker Al-Khamees, Saudi Aramco

14:00	120469	**Reducing Uncertainty and Costs in Drilling and Completion: Innovative Hole Opener Verifies Wellbore Diameter in Real Time** • W. Rasheed, Petroleum Production Ltd, Shaohua Zhou, Saudi Aramco, and David Jones, Consultant
14:30	120035	**Controlled Pressure Drilling (CPD) Candidate Screening Methodology** • J.J. Villatoro, S. Boutalbi and K. Schmigel, Weatherford
15:00	120219	**Prediction of Wellbore Stability Using 3D Finite Element Model in a Shallow Unconsolidated Heavy Oil Sand in a Kuwait Field** • K. Ahmed, Kuwait Oil Company; K. Khan and M.A. Mohiuddin, Schlumberger

Alternates

	118737	**Advanced Technologies for Critical Drilling Applications** • M.J. Jellison, NOV Grant Prideco; H.F. Spoerker, OMV
	117276	**Solid Expandable Technology for Zonal Isolation of Loss Circulation Formation: Case Study Shuaiba Formation** • E. Joseph and M. Emad, Lukoil Saudi Arabia Energy

Session 21
Tuesday, 17 March

14:00 – 15:30 **Room 5**

PEOPLE FIRST: RECRUITING DEVELOPMENT AND WELL BEING

Session Chairpersons: Louai Machhour, Total
Ayda Essa Abdulwahab, Bahrain Petroleum Company
David Davis, Baker Hughes

14:00	119680	**Attracting the Top Students to Study Petroleum Engineering, Curtin University** • L. Smith and B.J. Evans, Curtin University of Technology
14:30	119204	**Awareness and Expectation Gender in the Workplace** • R.A. Lau, N.M. Alhasani and L.J. Lau, The Petroleum Institute
15:00	118727	**Where is the Gap? Is It in More Reservoir (Petroleum) Engineers or in Leveraging New Skills and Workflows that Enhances Individual Productivity?** • C. Amudo, Chevron; M. Hartlieb and T. Graf, Schlumberger

Technical Sessions continued

Session 22

Wednesday, 18 March

11:00 – 12:30 Room 1

FACILITIES

Session Chairpersons: Ali Mohamed Bakheet, ADCO
Paul Wood, Shell

11:00	120480	**The Challenges of Designing and Installing High Pressure Gas Pipelines through Inshore, Shallow Waters in Bahrain** • D. McGlone, Bahrain Petroleum Company
11:30	120055	**Opportunistic Fluid Sampling and Analysis to Track Reservoir Souring in Water Flooded Operations in North Kuwait Reservoirs – Implications for the Future** • H.B. Chetri and E.H. Al Anzi, Kuwait Oil Company; S.S. Al Marri, Kuwait Institute of Scientific Research; S.F. Alkafeef, College of Technological Studies
12:00	118798	**Understanding of Oilfield Souring and Effective Monitoring: A Case Study** • A. Nengkoda, J.M. Walsh, H. Barhi, M. Hajri and K. Ghammari, Petroleum Development Oman; R. Hofland, Shell

Alternate

	120289	**PDO Front End Engineering and Design (FEED) Office** • A. Balushi, X. Jeganathan and I. Flewker-Barker, Petroleum Development Oman

Session 23

Wednesday, 18 March

11:00 – 12:30 Room 2

GAS CHALLENGES

Session Chairpersons: David Khemakhem, RasGas
Hussain Faddagh, Saudi Aramco

11:00	120161	**The Key Challenges for Optimisation of a Tight Gas Field Developments Using a Multi Domain Integrated Process Application in a Mature and Emerging Environments (North America & Middle East)** • A.M. Aly and L. Ramsey, Schlumberger
11:30	120695	**Meeting the Challenges of Natural Gas Market in Bahrain** • A. Al Anaisi and F.M. Al Mahroos, Bahrain Petroleum Company
12:00	120410	**Analysis of Deposition Mechanism of Mineral Scales Precipitating in the Sandface and Production Strings of Gas-Condensate Wells** • C.A. Franco, H.M. Al Marri, A.H. Al Saihati, A.E. Mukhles, N.H. Ramadan and J.R. Solares, Saudi Aramco

Alternate

	120088	**Gas Condensate Relative Permeability of Low Permeability Rocks: Coupling Versus Inertia** • M. Jamiolahmady, M. Sohrabi and S. Ireland, Heriot Watt University

Technical Sessions continued

Session 24

Wednesday, 18 March

11:00 – 12:30 **Room 3**

ENVIRONMENT

Session Chairperson: Zara Khatib, Shell

11:00	120278	**Improved Waste Injection Monitoring and Modified Operational Procedures: The Keys to Prolong the Well Storage Capacity** • A.P. Ovalle, J.R. Ronderos, S. Benelkadi, S. Gumarou and S.L. Simmons, MI SWACO
11:30	120445	**Climate Change: Facts, Science & the Dispute Regarding the Environment** • S. Vossoughi and J. Hamilton, University of Kansas
12:00	120129	**A New Practical Way for Calculation the Amount of Gas to Flare Based on PVs in South Pars Gas Development Projects of Iran** • M. Khazaei and M. Pakizehseresht, South Pars Gas Complex

Session 25

Wednesday, 18 March

11:00 – 12:30 **Room 4**

NEW VENTURES AND FUTURE OUTLOOK

Session Chairperson: Sultan Al-Merikhi, Qatar Petroleum

11:00	120350	**Forecasting World Crude Oil Supply** • M. AL Bisharah, Kuwait Oil Company; A. Malallah and I.S. Nashawi, Kuwait University; S.M. Al Fattah, Saudi Aramco
11:30	119607	**Holistic Approach for Regional Depletion Plan Supporting Gas Supply in the Nile Delta of Egypt** • M. Samy Hussein, BP
12:00	118276	**Evidences for New Attractive Gas Exploration Targets in Abu Dhabi Upper Permian Section** • A.K. Taher, ADNOC; A.S. Al Suwaidi and A.S. Al Habshi, ADMA OPCO

Technical Sessions continued

Session 26

Wednesday, 18 March

11:00 – 12:30 Room 5

ZONAL ISOLATION AND COMPLETION TECHNOLOGY

Session Chairpersons: Athar Ali, Schlumberger
Shalawn Jackson, ExxonMobil

11:00	118661	**Innovative Solution to Isolate Cross Communicating Reservoirs in Short Radius Wells Saves Millions** • A.A. Al Mumen, M.I. Al Umran and Z.A. Al Baggal, Saudi Aramco
11:30	119599	**Inflow Control Device an Innovative Completion Solution from "Extended Wellbore to Extended Well Life Cycle"** • S.A. Al Arfi, A.A. Keshka, S. El Abd Salem, S. Al Bakr and A. Amiri, ADCO; M.S. El Asmar and O.Y. Mohamed, Baker Oil Tools
12:00	117050	**Case History - World First Slim Open Hole Smart MRC Wells** • K.M. Al Amiri, Saudi Aramco

Alternates

	119869	**Intelligent and Interventionless Zonal Isolation for Well Integrity in Italy** • K. Ravi and N. Moroni, ENI; A. Zanchi, E. Barbieri and A. Mesmacque, Halliburton
	120061	**Increasing Certainty in the Determination of Zonal – Isolation Through the Integration of Annulus Geometry Imaging and Improved Solid Fluid Discrimination** • Z.L. Al Kindi and A. Elkadi, Schlumberger; A.S. Al Suwaidi, F.H. Al Marri, M.E. Ibrahim, E. Sultan and K. Jammeli, ADMA-OPCO

Session 27

Wednesday, 18 March

14:00 – 15:30 Room 1

DRILLING OPTIMISATION

Session Chairpersons: Abdul Hameed Al Rushaid, Saudi Aramco
Zeinoun A. Klink, Hughes Christensen

14:00	120018	**Underbalanced Drilling Technology Adds Reserves and Enhances Ultimate Recovery** • S. Babajan, Shell; H.H. Qutob, Weatherford
14:30	120015	**Well Placement by Boundary Detection / Optimization of Horizontal Well Performance. A Case Study from U.A.E.** • M. El-Hamawi, K. Al-Amari, N. Al Shehhi and M. Saleh, ADCO; E. Mirto and A. Madjidi, Schlumberger
15:00	120367	**Innovative Solution for Drilling Pre Khuff Formations In Saudi Arabia Utilising Turbodrill And Impregnated Bits** • G. Carrillo and U. Farid, Saudi Aramco; M. Albrecht, P. Cook, N. Feroze and K. Neulud, Smith International Inc.

Alternates

	118780	**Mechanical Earth Model (MEM): An Effective Tool for Borehole Stability Analysis and Managed Pressure Drilling (Case Study)** • M. Afsari, M.R. Ghafoori, M. Roostaeian and A. Maghshenas, National Iranian Oil Company; A. Aegei and R. Masoudi, PETRONAS
	120393	**Medium Radius Horizontal Sidetrack Reduces Time, Cost and Risks in Deep HT Gas Wells** • M.A. Simpson, A. Al-Hamid, Y. Faraj, M. Khalil, R. Duran, C.L. Miller and Shaker Al-Khamees, Saudi Aramco; J. Stewart, Halliburton

Technical Sessions continued

Session 28

Wednesday, 18 March

14:00 – 15:30 Room 2

DEEPWATER CHALLENGES

Session Chairpersons: Mohamed Hashem, Shell
Charles P. Kreuz, Weatherford

14:00	119867	**Precise Management of Downhole Pressure Enhances Safety and Enables Access of Challenging Offshore Reserves** • M.B. Grayson, Weatherford
14:30	120399	**Successful Mitigation of Deepwater Shallow Flows in the East Mediterranean Region Case Histories** • J. Lopez, D.R. Stewart, BP; M. Garrett, S.A. Waheed and A. Zanaty, Halliburton
15:00	120708	**Improved Wellbore Delivery in a Deepwater Reservoir via the Aid of Logging While Drilling Imaging and Formation Pressure Data** • S.A. Jebutu and H. Freitag, Baker Hughes INTEQ; R. Fisher, BP

Session 29

Wednesday, 18 March

14:00 – 15:30 Room 3

PRODUCTION MONITORING AND TESTING

Session Chairpersons: Haq Minhas, PETRONAS
Asfandiar Ansari, RasGas

14:00	119426	**Improvements in Completing and Testing Multi Zone Openhole Carbonate Formations** • R. Brooks, S.R. Scott and P. Scott, Tam International
14:30	120111	**Transient Pressure Behavior for a Reservoir with Continuous Permeability Distribution in the Invaded Zone** • N.A. El Khatib, Universiti Teknologi PETRONAS
15:00	120626	**Taking Advantage of Real Time Data in Upstream Operations** • S. Wiemers, ExxonMobil

Technical Sessions continued

Session 30

Wednesday, 18 March

14:00 – 15:30 **Room 4**

PRODUCTION CASE STUDIES

Session Chairpersons: Mehdi Z. Samama, Repsol YPF
Ibrahim Sami Nashawi, Kuwait University

14:00	120515	**Radius of Investigation for Reserve Estimation from Pressure Transient Well Tests** • F.J. Kuchuk, Schlumberger
14:30	120374	**Petroleum Development Oman's Experience in Using Near Infra Red Absorption Based Water Cut Meters for Well Testing and Production Monitoring** • K.K. Al Hanashi and S. Al Sibani, Petroleum Development Oman
15:00	120724	**A Successful Full Field Reservoir Characterization Story Utilizing Pressure Transient Analysis** • B.M. Al Harbi and S.A. BinAkresh, Saudi Aramco

Alternates

	120103	**Pressure Behavior of Horizontal Wells in Dual Porosity, Dual Permeability Naturally Fractured Reservoirs** • J. Lu and D. Tiab, University of Oklahoma
	120047	**The Oil Compressibility Below Bubble Point Pressure Revisited Formulations and Estimations** • M.A. Al Marhoun, KFUPM

Session 31

Wednesday, 18 March

14:00 – 15:30 **Room 5**

FORMATION EVALUATION 3

Session Chairpersons: Hans De Waal, Shell
Mahmood Akbar, Schlumberger

14:00	119690	**Development of Water Saturation Error Analysis Charts for Different Shaly Sand Models for Uncertainty Quantification of Volumetric in Place Estimate** • S.S. El Mahgoub, University of Wyoming; A.M. Daoud, Schlumberger; E.A. El Tayeb, Cairo University
14:30	119998	**Experimental Investigations of Stress Dependent Petrophysical Properties of Coalbed Methane (CBM)** • S.A. Shedid, Texas A&M University; K. Rahman, Helix RDS
15:00	120551	**Geosteering for Maximum Contact in Thin Layer Well Placement** • R.E. Chemali, H. Al Abri, C.A. Manrique and D. Hawkins, Halliburton; B. Al Mutairi, S.M. Jumah, H.Z. Al Ajmi, A. Ali and K. Burman, Kuwait Oil Company; D.T. Reeves, Chevron

Saudi Arabia oil & gas
www.saudiarabiaoilandgas.com

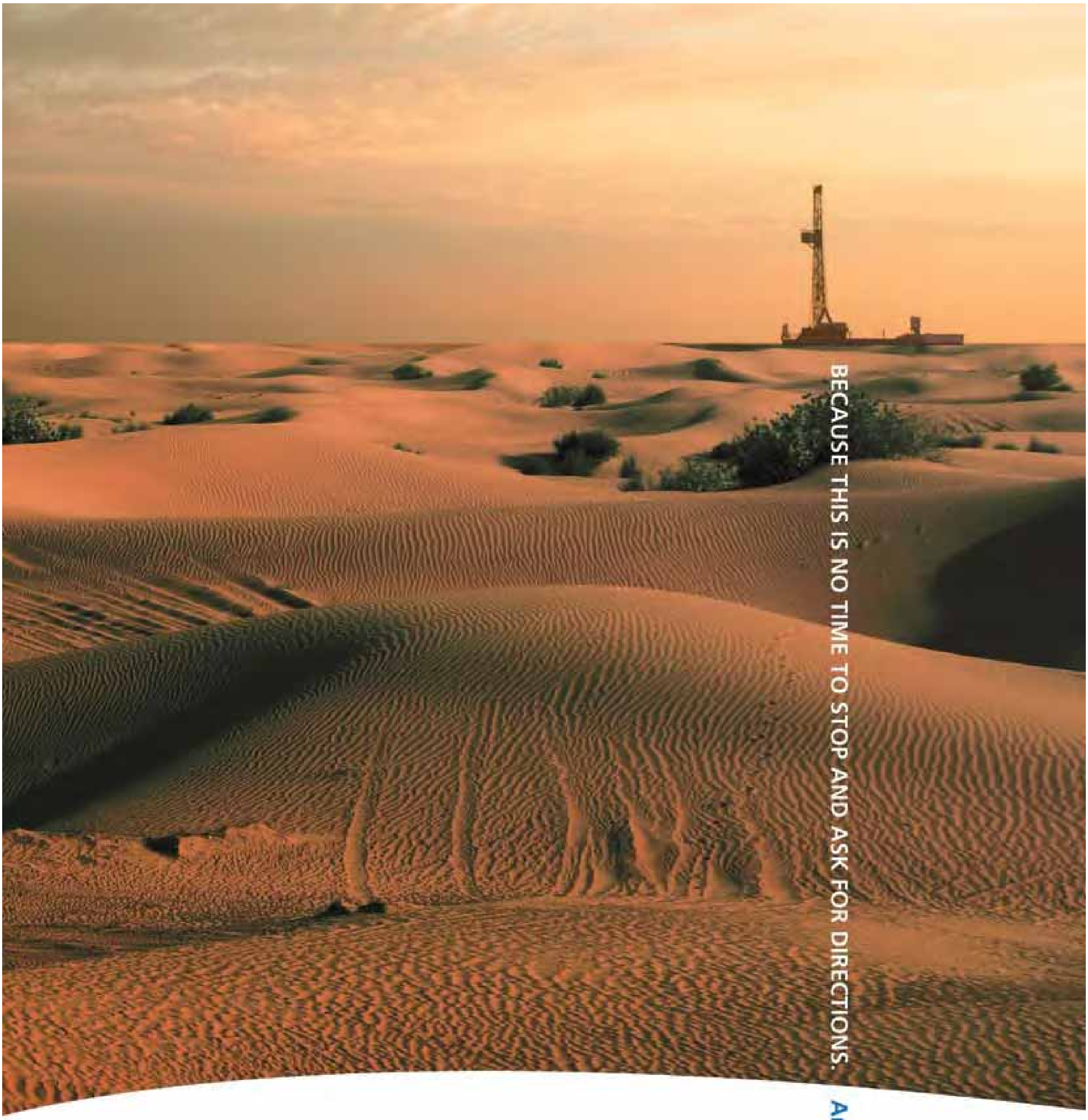
Contribute to Saudi Arabia Oil & Gas during 2009

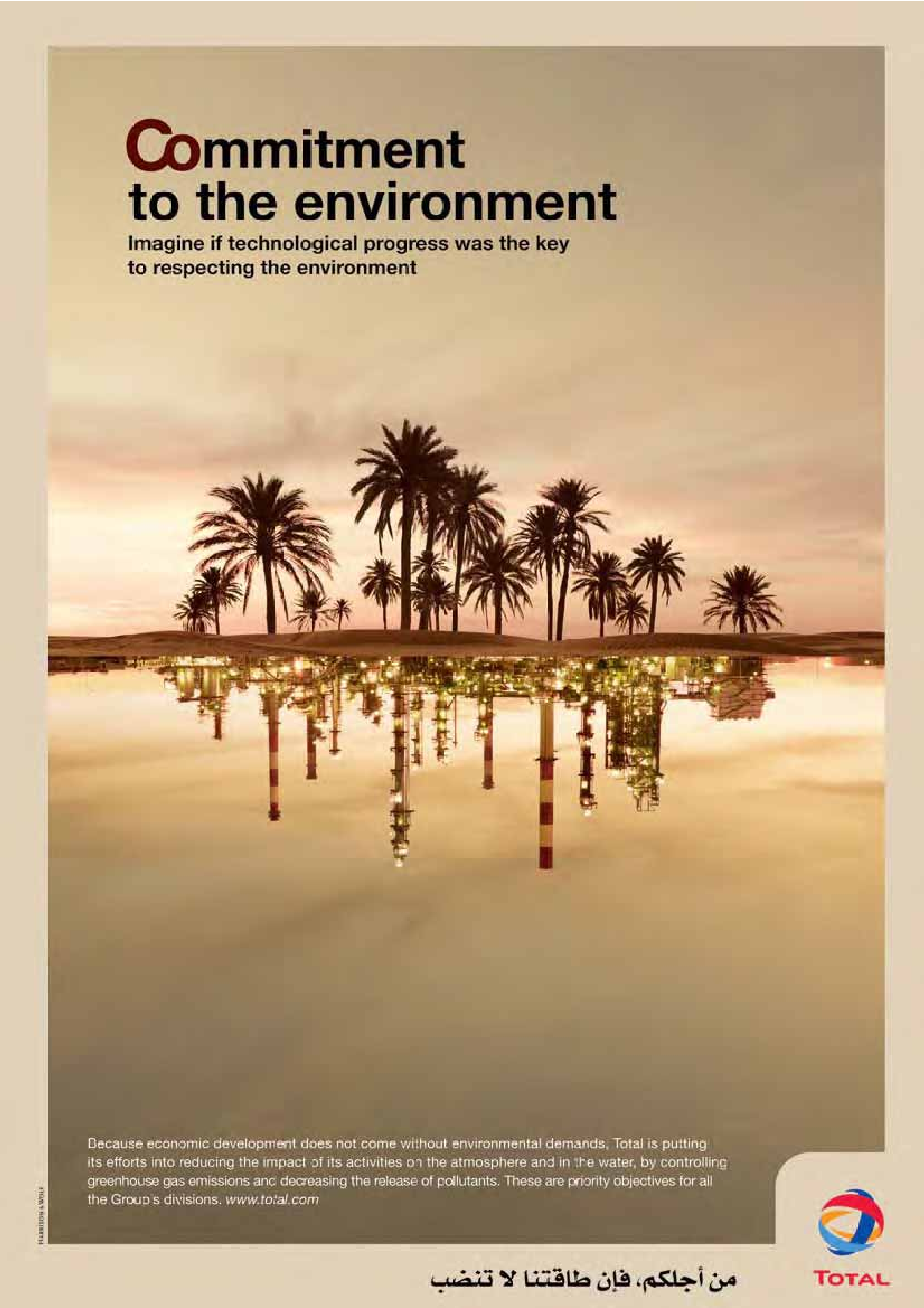
EPRasheed is looking for editorial submissions on the topics outlined in the editorial calendar. This can provide your company with the opportunity to communicate EP technology to the wider oil and gas community. Please send abstracts or ideas for editorial to wajid.rasheed@eprasheed.com

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

Editorial 2009 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	• 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
BONUS CIRCULATION					
	Middle East Oil & Gas Show and Conference March, 15-18, 2009 Kingdom of Bahrain **IADC/SPE Drilling Conference & Exhibition** March, 17-19, 2009 Amsterdam, The Netherlands	**OTC - Offshore Technology Conference** May, 4-7, 2009 Houston, Texas **SPE EUROPEC/EAGE Conference and Exhibition** June, 8-11, 2009 Amsterdam, The Netherlands		**Offshore Europe Oil & Gas Conference & Exhibition** Sept, 8-11, 2009 Aberdeen, UK **ATCE - SPE Annual Technical Conference and Exhibition** Oct, 4-7, 2009 New Orleans, Louisiana, USA **SPE/IADC Middle East Drilling Technology Conference & Exhibition** Oct, 26-28 , 2009 Manama, Bahrain	**International Petroleum Technology Conference** Dec, 7-9, 2009 Doha, Qatar
SPECIAL PUBLICATIONS					
				Saudi Aramco Supplement	


BECAUSE THIS IS NO TIME TO STOP AND ASK FOR DIRECTIONS.


Commitment
to the environment
Imagine if technological progress was the key
to respecting the environment
Because economic development does not come without environmental demands, Total is putting its efforts into reducing the impact of its activities on the atmosphere and in the water, by controlling greenhouse gas emissions and decreasing the release of pollutants. These are priority objectives for all the Group's divisions. www.total.com
من أجلكم، فإن طاقتنا لا تنضب
TOTAL