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2008 – Issue 7

Saudi Arabia oil & gas

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Inside


SRAK Exploration in Rub Al-Khali


KSA SPE Annual Symposium Review


Ministers' Jeddah Speech

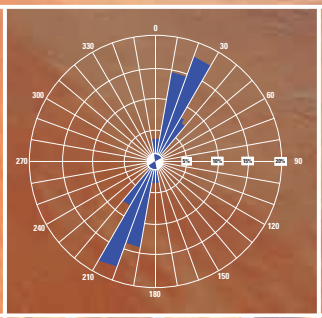
Official Technical Publication - ADIPEC

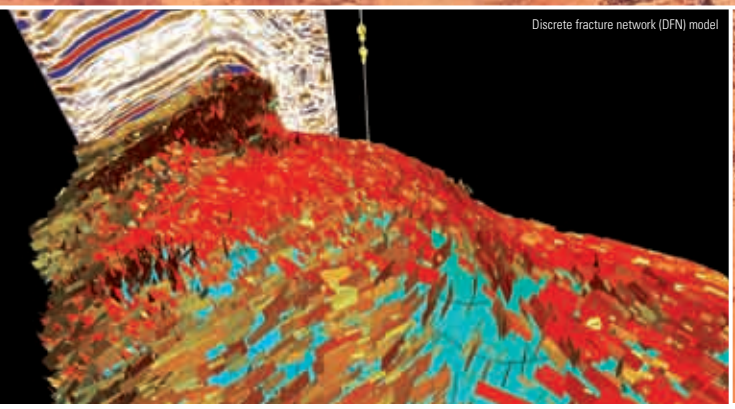
ICD / Zonal Isolation Special

Baker Oil Tools Image

Where advanced seismic **meets** ant tracking technology

Unique combinations for your fractured carbonate reservoirs




Discrete fracture network (DFN) model


FMI* Fullbore Formation MicroImager Log

Carbonate reservoirs are individual at every level. From microscopic fissures to kilometer-long fracture corridors, understanding your fracture network enables more realistic predictions of fluid flow, leading to better production performance.

Schlumberger uses a unique workflow to characterize naturally fractured reservoirs. We combine our patented FCM* Fracture Cluster Mapping workflow—used to detect and locate fluid highways in the reservoir—with discrete fracture network modeling (DFN) in Petrel* software, Q-Technology* services, borehole measurements, and expert interpretation. The result: a single unified reservoir model of your fracture network.

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Committed to carbonates

Schlumberger

Move UP to SMITH

Smith Services Means Solutions

Extensive Offering of Products & Services

Whether it is impact tools, wellbore departure, fishing tools and services, tubulars, completions equipment, or a variety of other tools and services, Smith Services has the ability to offer our customers the right solution for their application.

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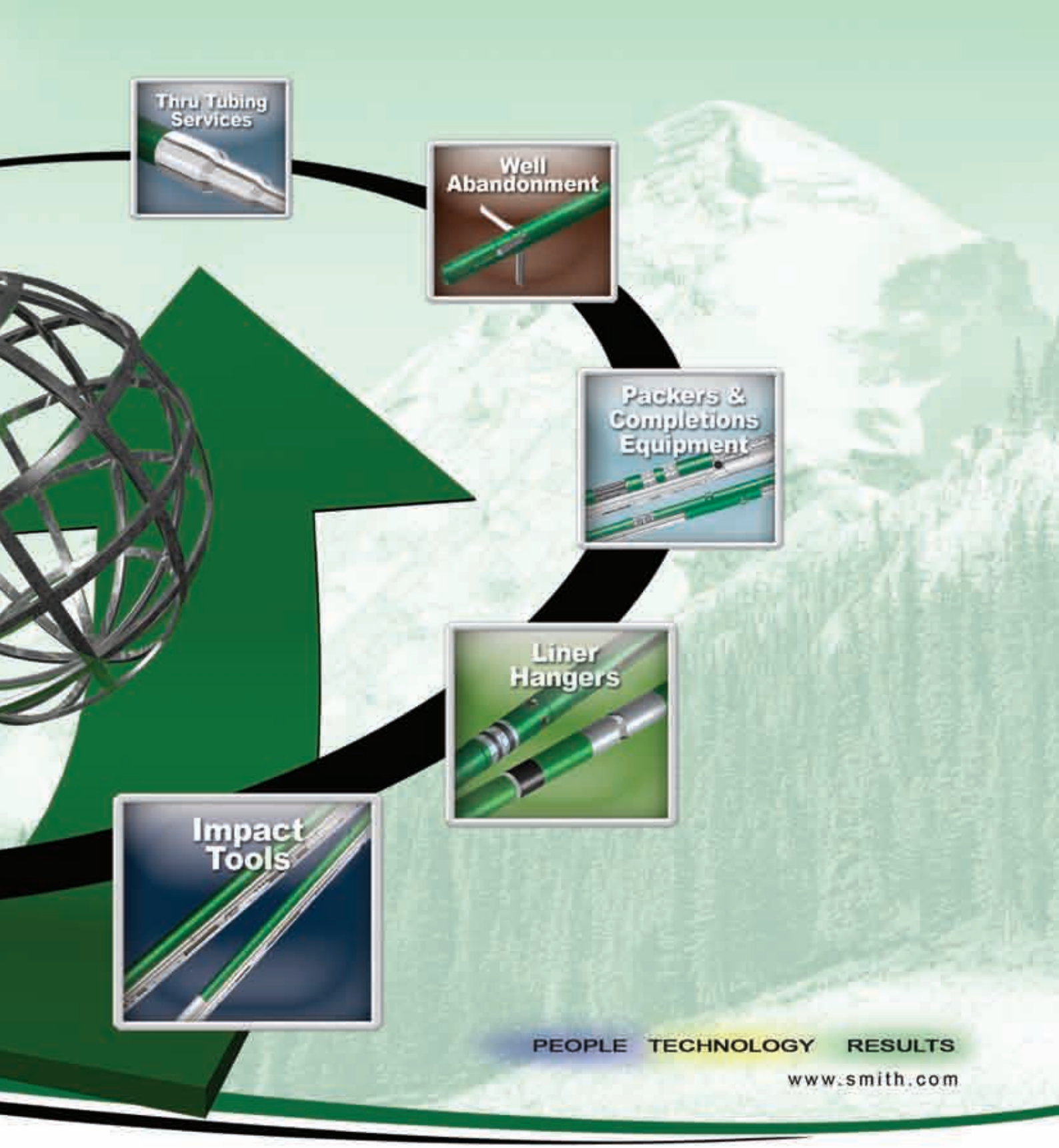

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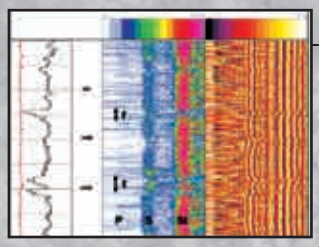

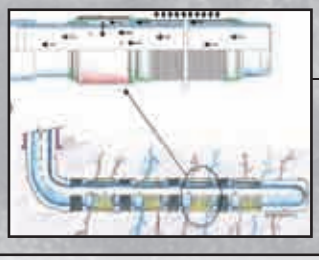

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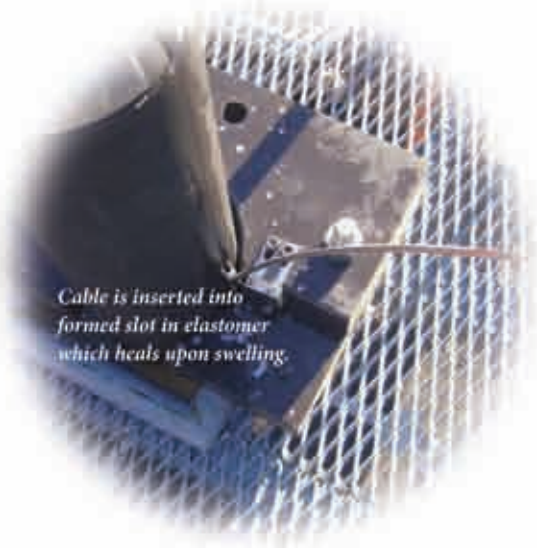
What is reliability worth?

It's the value of simplifying complex completions with a step change in performance.



Cable is inserted into formed slot in elastomer which heals upon swelling.

Industry Challenge

Improving well construction economics in multilateral SmartWell® completions.

Halliburton Solution

Easywell's **Swellpacker™ cable system** to enable the passage of single or multiple control lines or flat packs through the packer without the need to cut and splice the cables.

Operator Benefits

- Openhole SmartWell completion with increased reliability by avoiding cable splicing
- Simplifies well construction and helps reduce cost
- Helps increase efficiency with line installation of approximately 10 minutes per flat pack or control line, a significant improvement over conventional methods
- One trip solution with no mechanical packer setting requirements

To learn more about how Halliburton puts reliability in action, visit www.halliburton.com/easywell1 or email us at easywell@halliburton.com.

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NOTE FROM THE CEO

Welcome to Issue 7 of Saudi Arabia Oil and Gas which is spread across three broad topics; regional events, innovations and applications.

As part of our regional events section and with 3rd Quarter 2008 oil prices reaching highs of US$ 147 and subsiding to US$ 115 in August, it is timely and worthwhile to dedicate editorial to H.E. Ali Al-Naimi Oil Minister's speech in Jeddah (reprinted with kind permission of the KSA Ministry of Petroleum and Minerals).

The events section also includes a special review of the Society of Petroleum Engineers (SPE) Saudi Arabia Section 2008 SPE Technical Symposium which was held in Al-Khobar in May. Saudi Arabia Oil and Gas Magazine was the official magazine of the highly acclaimed symposium with high level keynote speeches, technical sessions and a panel discussion which had both local and international participation. Last but not least, this section also includes a photo story of the Graduation Ceremony and Honour Roll held in Dhahran for the BSc Class of 2003 graduating from KFUPM. KFUPM conferred academic degrees on 1,406 graduate and under-graduate students (BS: 1,246, MS & MBA: 153, and PhD: 6).

The Exploration section has a frontier feature which comprises an exclusive interview with South Rub Al-Khali Company Limited (SRAK - Saudi Aramco and Shell JV) CEO Patrick Allman Ward. Allman Ward spoke to Saudi Arabia Oil & Gas about SRAK's exploration activities in the Rub Al-Khali and the challenges stemming from EP in the worlds' largest sand desert. The interview also traces how the company has consciously grown its Saudi staff by investing in training and development.

Dr. Tariq Al Khalifah et al present an insightful seismic paper which considers how the Near Surface Challenge can be resolved within the KSA. Entitled 'The feasibility of using high resolution seismic data to model the near surface in Saudi Arabia', the paper outlines a methodology and system to acquire high resolution surface seismic data for shallow subsurface investigation and also presents the 'Zaher' case study.

Striding the Seismic and Carbonates section is the aptly entitled 'Mapping fracture corridors in naturally fractured carbonate reservoirs in the Middle East' by Mahmood Akbar et al, which highlights the value of mapping in addressing carbonate production and asset life-cycle challenges.

Drillers interested in state-of-the-art real time operation centres, drill-bits and logging-while-drilling (LWD) should refer to the drilling section which has submissions on PDC bits, Geosteering / Acoustic logging as well as real-time operations.

Globally real-time operations are being used across all types of assets from deepwater frontiers to mature onshore fields. Real-time operations centres have become a must-have for oil companies as they maximise human resource capabilities and the efficacy of decision making. This has led to substantial growth of the sector and this is likely to continue. A noteworthy example of the real-time operations business is a Saudi company, Futureware, which deserves mention due to its organic growth. Further details are found in an interview with Futureware's Managing Director Samir Al Jaiban who outlines the company's growth and vision for real time operations.

The LWD special has two articles 'Geosteering and natural fracture identification in horizontal wells in unconventional reservoirs' by Mezaro et al and 'LWD acoustic measurements for enhancing varying drilling conditions by Moore et al'.

The completion section focuses on the key areas of zonal isolation and inflow control. The editorial content provides readers with an up-to-date reference of what Baker Hughes, Halliburton and Schlumberger are doing within this ever-growing market and how each is tackling the problems and challenges associated with maximising production.

For production, there is a specially selected paper from the KSA SPE Technical Symposium – Cyclic Production Scheme by Saad Al-Mutairi, Saudi Aramco et al which illustrates the innovativeness of Saudi Aramco in meeting the industry's increasing challenges.

We look forward to your contributions across all disciplines – whether conceptual or proven. Ultimately, this is want Saudi Arabia Oil & Gas readers value.

So hit the right keys 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

Seventy-Two Years of Commitment to Saudi Aramco

1936 Hughes bit used on Saudi Aramco Dammam Well #7

1978 First "O" ring sealed journal bearing bit run by Saudi Aramco

1985 Hughes established a manufacturing facility in Saudi Arabia

1992 First metal sealed bit (ATM™) introduced to Saudi Aramco

1998 First RWD™ bit run with Saudi Aramco

2002 First EZSteer™ bit run with Saudi Aramco

2005 First PDC bit made in Saudi Arabia

2006 First ZX™ bit run with Saudi Aramco

2008 66 employees dedicated to Saudi Arabia

Since 1936, with the spudding of Dammam Well #7–Hughes Christensen has been steadfast in its commitment to provide Saudi Aramco a "total value package" of knowledge, service and products that enhance their drilling operations.

اثنان و سبعون عاما من الإلتزام والخدمات المستمرة لشركة أرامكو السعودية.

BAKER HUGHES Hughes Christensen

Remarks by his Excellency Ali I. Al-Naimi Minister of Petroleum & Mineral Resources of the Kingdom of Saudi Arabia

Jeddah Energy Meeting, June 22, 2005

By HE Ali Al-Naimi Minister of Petroleum and Minerals, Kingdom of Saudi Arabia

HE Ali Al-Naimi

Your Excellencies, distinguished guests, friends and colleagues: good afternoon, and on behalf of the Kingdom of Saudi Arabia, let me welcome you to Jeddah and today's Energy Meeting. We are pleased this group has accepted the invitation of the Custodian of the Two Holy Mosques to discuss and deliberate the prevailing oil prices which impact us all—whether we represent producers or consumers; governmental, intergovernmental or private sector entities; national or international oil companies; or organizations and institutions from beyond the realm of petroleum. Given the vital importance of petroleum to modern life, the global nature of the oil markets, and the far-ranging social, political and economic impacts of high prices and market volatility, we all have a stake in this conversation. After all, current market conditions are in the interest of neither producers nor consumers, and none of us can be content with the status quo.

Ladies and gentlemen, a year ago prices were in the range of $65 a barrel; now, they are almost double that. What has happened during this relatively short period of time? Between the second quarter of 2007 and the second quarter of 2008, global demand rose by an estimated 800,000 to 1.2 million barrels per day, but at the same time global oil supplies rose between 1.4 and 1.6 million barrels per day—substantially more than the increase in demand. Accordingly, days of forward cover increased from roughly 52 to 54 days during the last 12 months, and inventory levels are currently well within their normal range.

And yet we have seen this enormous run-up in prices, coupled with wide price swings as you recall-earlier this month WTI prices spiked nearly 11 dollars in a single trading session, despite the fact there was no major disruption of supplies or one-day spike in demand. Clearly something other than supply-demand fundamentals is at work here, and a simplistic focus on supply expansion is therefore unlikely to tame the current price behavior.

Concerns over long-term supply shortages seem to be playing a role in strong futures prices, though I believe these concerns are badly misplaced. The world has enough petroleum resources, both conventional and nonconventional, to meet oil demand for many, many decades to come, even before we factor in future technological advances which will enable us to produce our resource base even more effectively. Of course, given the changes in driving habits, purchases of more fuel efficient vehicles, CAFÉ standards and ethanol mandates we're seeing in the United States, as well as the systemic decline in Japan's petroleum consumption and the long-term price elasticity of demand, there are also downward pressures on demand which must be considered, notwithstanding demand growth in developing nations such as China and India.

What is required over the long-term, ladies and gentlemen, is not more oil in the ground, but rather the assets to bring it to the surface, to process it, and to supply it to markets around the world. The Kingdom for its part

"I would also note that while there is little or no correlation over the past two years between global crude oil inventories and crude oil prices, there has been a strong correlation between the increasing volume of crude oil futures trade on the NYMEX and rising prices."

is providing those assets through its vast integrated investment program all along the value chain—a topic to which I will return, in a moment.

Our industry is experiencing stretched refining capacity worldwide, and a number of infrastructure bottlenecks around the globe are creating difficulties. Just as importantly, a shortage of complex conversion capacity to process heavy sour crudes, coupled with increasingly stringent and varied refined product specifications, are also causing pain for consumers at the pump. This lack of conversion capacity is due to underinvestment in such facilities over the last decade; given the cyclical nature of the refining business and its relatively thin margins, especially during down cycles, this lack of investment may be understandable, but it is still constraining the ability of refiners to process heavy sour crudes whose supply is more ample.

But ladies and gentlemen, our industry has navigated such rough waters in the past without witnessing the kind of price rises and market volatility that have brought us together today. Looking at the data that are in front of us today, studying the best forecasts we have of future supply and demand trends, and considering my previous discussions with many of you, I have reached a number of conclusions about the current market situation—a set of beliefs based on facts, if you will.

First, as I noted earlier I believe that there has been a parting of the ways when it comes to oil supply-demand balances and other industry fundamentals on the one hand, and the price behavior and market volatility on the other. Industry fundamentals cannot account for today's high prices, nor for the enormous degree of market volatility that we have experienced of late.

Instead, I believe price rises and volatility are being fueled by a wide range of other factors which lie beyond the ability of the petroleum industry to address or even influence. Perhaps foremost among these are recent trends in the global financial markets, including weak equity and bond markets that have encouraged investors to move their capital into commodities like oil. Consider that the bond and equity markets in the US alone are valued at roughly 50 trillion dollars, and that if money managers decided to reallocate a nominal one-half-of-one percent of those assets into the oil commodity space, the resulting $250 billion influx of funds would equal the value of the entire NYMEX WTI market. Clearly there would be an impact on price, especially if most of this new money takes long positions.

I would also note that while there is little or no correlation over the past two years between global crude oil inventories and crude oil prices, there has been a strong correlation between the increasing volume of crude oil futures trade on the NYMEX and rising prices. According to many observers and analysts, inadequate oversight, regulation and reporting of speculative investments in commodities have further exacerbated this situation. Therefore we welcome steps like the recent agreement between the US Commodity Futures Trading Commission and the intercontinental Exchange regarding the extension of regulatory oversight to ICE Futures Europe.

Regional Events - Jeddah Energy Meeting

> Given the nature of these various drivers and the complex interactions between them, I believe this set of issues has to be addressed primarily by parties other than oil producers and yet they must be tackled if we are to resolve the current dilemma of high, unpredictable oil prices.

Of course, skewed and uneven taxation and tariff regimes; energy policy, regulatory and permitting environments which hamper oil facility construction and development and which send mixed signals to prospective industry investors; and moves to alternative fuel sources, including the introduction of subsidies for biofuels and mandates on their use, have all played a role in getting us where we are today. Nor should we forget the impact on oil markets from regional and global political tensions and confrontational rhetoric, which at times seem to outstrip all other considerations when it comes to price movements.

Furthermore, the prevailing high prices have been painful to consumers at the pump, a situation that has been exacerbated by high taxes on petroleum products in consuming countries.

Given the nature of these various drivers and the complex interactions between them, I believe this set of issues has to be addressed primarily by parties other than oil producers and yet they must be tackled if we are to resolve the current dilemma of high, unpredictable oil prices.

Saudi Arabia has had a historical commitment to market stability and for that reason, as a matter of policy we have maintained spare production capacity at high cost to the Kingdom. As you know, we have readily employed this spare capacity in the past whenever the market has justified its use. In fact, in many situations, our policy and spare capacity has stood between peril and prosperity of the world economy.

In today's environment, I am convinced that supply and demand balances and crude oil production levels are not the primary drivers of the current market situation and that markets are already well supplied. But despite this assessment, I also strongly believe that each of us must do what we can to alleviate these difficult conditions. Therefore, given our current spare capacity, today I would like to state that for the remainder of this year Saudi Arabia is prepared and willing to produce additional barrels of crude oil above and beyond the 9.7 million barrels per day which we plan to produce during the month of July, if demand for such quantities materializes and our customers tell us they are needed.

Although we already have the ability to sustain our production comfortably at increased levels for many more years, Saudi Arabia will continue to implement its slate of new crude oil increments, with projects that will see the Kingdom's maximum sustained production capacity rise to 12.5 million barrels per day by the end of next year. This will enable us to continue to maintain our spare capacity in the interest of global market stability—which is in everyone's interest. In addition, we have identified a series of future crude oil mega-increments totaling another 2 1/2 million barrels per day of capacity that could be built if and when crude oil demand levels warrant their development. Among these prospective programs are a 900,000 barrel-per-day increment in Zuluf, a 700,000 barrel-per-day increment in Safaniyah, a 300,000 barrel-per-day increment in Berri, a 300,000 barrel-per-day increment in Khurais and a 250,000 barrel-per-day increment in Shaybah.

At the same time, we will press ahead with our planned investments in the refining sector, which over the next five years total some 2 million barrels per day of new refining capacity both in-Kingdom and abroad. Later this evening, in fact, Saudi Aramco and Total of France will sign a shareholders agreement for their 400,000 barrel-per-day export-oriented refinery in Jubail—a facility which will be configured to process Arab Heavy crude,

> We must commit to working together and to aligning the efforts of all stakeholders to achieve our common objectives.

and will therefore help to close the gap between existing refinery configurations and the global crude oil slate.

These are massive investments, which over the next five years will total some 129 billion dollars between the upstream and downstream segments of the industry. As the old phrase says, we're putting our money where our mouth is. Keeping with its longstanding policies, the Kingdom has undertaken these projects and investments in the interest of global markets and in order to meet the needs of consumers around the world and we view our responsibilities and commitments as energy suppliers as a solemn trust.

Saudi Arabia is making these investments in the belief and with the expectation that other countries, corporations and institutions will also do their part to meet the multifaceted challenges posed by the current market situation, and will intensify their efforts just as we continue to strengthen our investments, capacities and operations. In light of my earlier discussion, we strongly believe that actions by consuming nations in several important areas could play a pivotal role in complementing our efforts to collectively and effectively address the prevailing market situation.

Considering the complexity of the issues that I have outlined, there are many initiatives that would go a long way toward meeting our common objectives. Of these, I would like to highlight the following:

• First, through well considered changes in a range of national and international policies, help create an enabling and stable environment in which investments and expansion would flourish across the petroleum supply chain;

• Second, further to the recent agreement involving the oversight of ICE Europe Futures, consider other appropriate regulatory, oversight and reporting enhancements to help dampen irresponsible financial speculation;

• Third, suitably relax product specifications and fuels mandates to make more products available, using the available refinery configurations and capacity from available crude oil supplies;

• Fourth, we urge everyone to help bring down the political temperature that has played a part in causing oil price spikes; and lastly

To help provide quick relief to consumers at the pump, consider suitable reduction of taxes on oil products.

Ladies and gentlemen, let me close today by saying that I believe that this is not the time to cast blame, point fingers, or play a waiting game. Rather, this is the time to stand up, step up and be part of the solution. The challenges before us require commitment, cooperation, and a lot of courage. The issues at stake are too big and too complex for any one entity to resolve, for any one sector of our industry to tackle alone, and not even for the oil industry as a whole to take on single-handedly. Instead, we must commit to working together and to aligning the efforts of all stakeholders to achieve our common objectives. In so doing, we have an opportunity to resolve the current market difficulties, and thus to promote sustained growth for the global economy, greater prosperity for our nations, and a brighter future for all of our peoples. Let us not allow that opportunity to slip from our grasp.

Thank you.

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KSA SPE Annual S

"The Ultimate Challenge: Unlocking Hydrocarb

The symposium included keynote speeches, technical sessions, poster sessions, and a panel discussion with local and international participation.

Dr. Hamoud A. Al-Anazi

Prince Abdulaziz Bin Salman Al-Saud

Keynote

The Society of Petroleum Engineers (SPE), Saudi Arabia Section (SAS), held its 2008 Annual Technical Symposium on May 10-12 at the Le Meridien Gulf Hotel, Al-Khobar, Saudi Arabia.

This symposium has become a prime E&P technical gathering for regional and international professionals. The purpose of this symposium is to share expertise, knowledge, and promote applied research and technology advancements in E&P among regional oil and gas industry professionals, researchers, academics, and geology professionals in related disciplines.

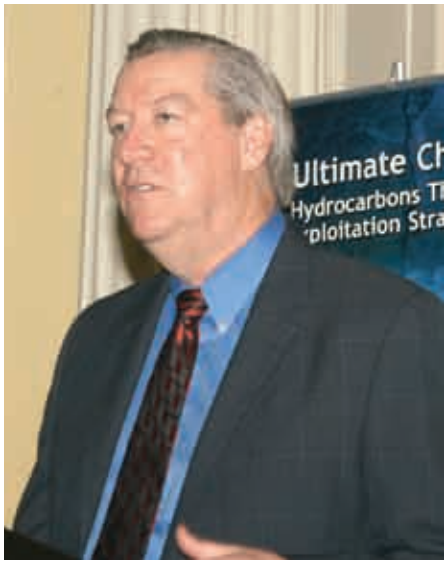
The theme of the 2008 Technical Symposium was **"The Ultimate Challenge: Unlocking Hydrocarbons Through Optimum Exploitation Strategies."** The Technical Program Committee developed this theme to reflect the current directions of oil producers as a response to the growth in global energy demands associated with the boost in oil prices.

The symposium included keynote speeches, technical sessions, poster sessions, and a panel discussion with local and international participation. The official publication of the symposium was Saudi Arabia Oil and Gas. The technical program covered the latest advances in reservoir management, reservoir characterization and simulation, reservoir description, formation evaluation, production enhancement, drilling and completion technology.

Dr. Hamoud A. Al-Anazi, Chairman of the Symposium, opened the event with a greeting and appreciation speech. Dr. Al-Anazi also shared with the 500 audiences some statistics related to the technical program: "During the call for papers, we have received 120 paper proposals submitted for review. After a thorough revision process by known specialists, 32 papers were selected for an oral presentation, while 13 papers were accepted for poster presentations" he said. "Out of these accepted papers, 41% of the authors are from Saudi Aramco, 30% are from local service companies and universities, and 28%

ymposium Review

ons Through Optimum Exploitation Strategies"



Mr. David Lesar

Mr. Amin H. Al-Nasser

Dr. Sami Al-Neaim

are out of kingdom. We are also so delighted to have 5 invited speakers who are well known and expert in the technical areas that they will address their talks in" elaborated by Dr. Al-Anazi.

At the opening ceremony, three keynote speeches were delivered. His Royal Highness Prince Abdulaziz Bin Salman Al-Saud, Assistant Minister of Petroleum Affairs in the Ministry of Petroleum and Mineral Resources of Saudi Arabia, delivered the first keynote speech, including an overview of the energy industry and the ever-growing need for energy resources around the world.

Mr. David Lesar, Chairman of the Board, president and CEO of Halliburton, gave the second keynote speech where he reflected on the theme of the symposium and the role of energy service companies in unlocking hydrocarbons through optimum exploitation strategies. Mr. Lesar discussed how service companies are employing their resources to reach operators' goals and visions through research and development.

The third keynote speech was given by Mr. Amin H. Al-Nasser, Saudi Aramco's senior vice president of Exploration and Producing, considered one of the biggest supporters of the Saudi Chapter of SPE, addressed the expected increase in energy demand and Saudi Aramco's plans to deliver its share.

Dr. Sami Al-Neaim, chairman of the Saudi Section, reflected on the 50th anniversary of the section, saying the group section emerged from a seven-member society into more than 2,000 members with three major annual conferences. Al-Neaim concluded by saying the section's success had been the result of Saudi Aramco executive commitment, service company support and extraordinary member support.

Speakers

Panel D

Dr. AbdulRahman Al-Jarri, Manager of Production & Facilities Development Department of Saudi Aramco

Rustom Mody, Vice President of Baker Oil Tools - Houston

Mohammed I. Sowayigh, Manager of the Southern Area Production Engineering Department of Saudi Aramco

Saleh M. Dawas, Manager of the Production Facilities Development Department, of Saudi Aramco

iscussion

"Smart Well Completion Unlocks Volatility" was the panel discussion topic which was moderated by Dr. AbdulRahman Al-Jarri, acting as a Manager of Production & Facilities Development Department at Saudi Aramco. Distinguished panelists were selected to address pertaining subjects related to the symposium theme. The panelists were world recognized experts that included Rustom Mody, Vice President of Baker Oil Tools - Houston, Mohammed I. Sowayigh, Manager of the Southern Area Production Engineering Department of Saudi Aramco, Saleh M. Dawas, Manager of the Production Facilities Development Department, of Saudi Aramco, Suresh Jacob, Manager for the Middle East and Asia Pacific regions for WellDynamics, and John Lovell, Downhole Monitoring Expert of Schlumberger –Houston. The panel discussion was attended by more than 200 people from oil/gas producing companies, services companies, and academia.

The 2008 SPE Saudi Arabia Section Technical Symposium was attended by more than 450 attendees. The technical sessions were cleverly distributed over 3 days to ensure a good number of attendees A special event was arranged for international authors where they visited the Heritage Village at Dammam, Saudi Arabia.

The organizing committee did an outstanding job in preparation, organizing, and managing the 2008 SPE Technical Symposium as positive feedback was heard from international and regional participants.

Suresh Jacob, Manager for the Middle East and Asia Pacific regions for WellDynamics

John Lovell, Downhole Monitoring Expert of Schlumberger – Houston

Sponsor

Awards were presented by Mr. Abdullah A. Naim (left), VP Petroleum Engineering & Development, Saudi Aramco and Hamoud Anazi (centre) Conference Chairman.

Khalid Buraik, Saudi Aramco

John Prescott, Vice President Baker Hughes Saudi Arabia

Trophies

Osama Kamal , ESG Country Vice President, Halliburton

Khaled Al Mogharbel, VP&General Manager Schlumberger

King Fahd University of

Graduation Day - Class of 2003

The graduation ceremony was attended by H.E. the Rector of the University, Dr. Khaled S. Al-
graduating students. Various dignitaries, government officials, businessmen, relatives of the gradu
the graduation ceremony on 22nd May 2008 for the class of 2003.

KFUPM conferred academic degrees on 1,406 graduate and under-graduate students (BS: 1,246, MS & MBA: 153, and PhD: 6)

Petroleum and Minerals

Sultan, vice rectors, supervisors, deans, chairmen, faculty members, administrative staff and ating students, and other distinguished guests from throughout the Eastern Province also attended

Under the patronage of H.R.H. Prince Naif Bin Abdulaziz Al-Saud, Minister of the Interior, KFUPM held its 38th Graduation Ceremony

SRAK Exploration

South Rub Al-Khali Company Limited (SRAK) CEO Patrick Allman -Ward spoke to Saudi Arabia Oil and Gas about the Company's exploration activities in the Rub Al-Khali

Q: Saudi Arabia Oil & Gas *- What are SRAK's major achievements to date?*

A: Patrick Allman Ward - The first significant achievement has been getting the Company up and running and executing its operations smoothly and efficiently. This involved bringing together the shareholders that had never worked together before and to generate trust and confidence that the Company could get the job done. In addition the staff seconded and recruited into the Company from their diverse backgrounds, with their disparate skills sets and cultures, had to be welded together to work as a high performing team, a team that together was far greater than the sum of the individual components. This has required a lot of effort in developing the Company's own Vision, Values and Behaviours and forging this into a new corporate culture. In this regard I am very proud that the Company has chosen Positive Energy, Respect, Excellence, Team-working and Creativity as its corporate values.

Another significant achievement has been in the technical arena. The size of our Contract Area totals 210,000 sq km. That is equivalent to the size of the UK and we have explored it using a play based exploration strategy. This involves creating a holistic regional geological model involving all of the plays in the basin to identify the areas with the highest probability of finding commercial non-associated gas accumulations. Given the size of the Contract Area to be explored and the relatively tight time frame of five years, envisaged in the Upstream Agreement with the Government of Saudi Arabia, this gave us the means to focus our efforts on the most prospective areas.

We have now drilled three exploration wells and although we have not yet found commercial hydrocarbons, we have established that all the basic elements for a working petroleum system are present including source rock, reservoirs, seals and structures. With the data gathered from these wells we have updated our holistic understanding of the regional geology to improve the probability of success for future wells.

We have also applied leading edge technology, to identify the sweet spots in the basin and de-risk prospects to select the best ones for drilling.

Finally, SRAK has made excellent progress increasing local content where nearly 90% of our contract values are with Saudi companies. We have invested in developing our Saudi Arabian national staff, training and nurturing their talent as the long-term future of the Company depends on them.

Q: Saudi Arabia Oil & Gas *- Can SRAK be considered a pioneer?*

A: Patrick Allman Ward - SRAK is a pioneer in many areas. First, exploring for gas in the remoteness of the Rub 'al Khali, the largest sand desert in the world is a pioneering activity in its own right. Then, I believe that SRAK has made a significant contribution in the use of Play Based Exploration in Saudi Arabia. Using this technique has allowed us to rapidly update our understanding of the basin to identify the best places to be exploring in this vast area. This means that we can identify the next best prospects to drill not in a random manner but in a scientifically sound manner.

Another of the pioneering achievements has been in the area of seismic data acquisition. Conventional seismic utilises a man-made source of high-frequency acoustic energy. In SRAK's operations in addition to this conven-

in Rub Al-Khali

> I am confident that having updated our understanding of the regional geology of the basin and using both active and passive seismic data that we will give ourselves the best possible chance of finding hydrocarbons in our Contract Area.

tional technique we are acquiring passive seismic data. Passive seismic listens to the natural earth noise that occurs at a much lower frequency range. Whilst most of the commercially available systems use special seismic geophones, one of our shareholders, Shell, has developed the technology of modifying standard geophones and boosting their low frequency signal.

Using this technology we are now pioneering the deployment of passive and active seismic data acquisition simultaneously. During the day we record conventional active seismic data using the vibrator sources. During the night we record the naturally occurring signals. We believe that this is a world first and will allow us to build up a 2D grid of both active and passive seismic data in a very cost effective manner. We hope that this will allow us to generate structural maps to identify the presence of prospects and simultaneously give us a tool to help improve our estimates of the probability for the presence of hydrocarbons in the prospect.

I am confident that having updated our understanding of the regional geology of the basin and using both active and passive seismic data that we will give ourselves the best possible chance of finding hydrocarbons in our Contract Area.

Q: Saudi Arabia Oil & Gas *- How have the shareholders contributed to SRAK?*

A: Patrick Allman Ward **-** I am pleased to say that we have leveraged the best technical knowledge and expertise from our original three shareholders, that is to say Shell, Total and Saudi Aramco. Saudi Aramco has provided us with its detailed knowledge of the geology of the Kingdom, Shell and Total with their knowledge of the geology of neighbouring countries and the wider Middle East and North Africa areas where there are many relevant geological analogues to the plays that we are exploring in Saudi Arabia.

Each of our original shareholders also has their particular areas of technical expertise. If I could highlight just a few of these, one of our shareholders has made a contribution in the area of seismic data acquisition and in providing SRAK with technology related to seismic data attribute analysis which filters the data to maximise its interpretability. In addition they have provided the Venture with proprietary modelling and interpretation software including advanced basin modelling software and the whole play-based approach to basin analysis. Another has particular strength in the areas of stratigraphy and sedimentology, particularly for carbonates and have been involved in core description and analysis work, having participated in our field trips and helped SRAK to build analogue models. The third shareholder has made a big contribution in the area of seismic processing of land data, particularly in the resolution of static corrections. So I would like to highlight that it is not a case of just taking the best of one of our shareholders but in working diligently to leverage the best from each of our shareholders.

Q: Saudi Arabia Oil & Gas *- What kinds of investment has SRAK made to the Kingdom of Saudi Arabia?*

A: Patrick Allman Ward **-** We are making substantial investments in the form of seismic data acquisition and executing our drilling operations. As indicated earlier, nearly 90% of the total contract values have been made with Saudi companies. We are also providing employment and training of Saudi staff. The exploration phase of a venture does not generate a large number of jobs but with success the company will grow and provide many

more employment opportunities. Already, we have recruited and trained Saudi Arabian national staff across all technical disciplines both for field and office work.

Q: Saudi Arabia Oil & Gas *- What challenges does the Rub Al-Khali present?*

A: Patrick Allman Ward - The The first challenge stems principally from the remoteness of our acreage and the logistical difficulty of supporting operations. The Rub 'al Khali is the largest sand desert in the world. In many respects the remoteness of our operations is similar to operating in offshore waters; not an ocean as such but in a sea of sand. Both have the common challenges of remoteness and supply. There is no infrastructure, no potable water, no food, no supermarkets! Water and fuel have to be shipped into the area. The distance from our offices in Al Khobar to our operations in the area of Sharourah is over 1000 km. From Sharourah to our field operations is at least another 500 km so, representing a round trip of over 3000 km. Twelve journeys to and from our field location is equivalent to driving around the circumference of the earth so the distances are huge. There are areas of sand seas with no sabkhas and other areas where the sand dunes can reach up to 400 m in height; this is an extreme surface topography! It is easy to get lost and hard to keep supply routes open. Clearly it is very hot at any time of the year but in summer temperatures can reach over 50° C.

The remoteness brings a challenge about what to do if somebody gets hurt or falls ill. The standard to which we hold ourselves is the ability to evacuate someone in a medical emergency to the appropriate hospital within four hours. This standard is quite challenging to achieve in such a remote area. It requires us to position aircraft in the field as well as field clinics that are more advanced than normal clinics but which allow a patient to be stabilised with a greater degree of sophistication.

Health, Safety and the Environment are important both to our shareholders and SRAK. We have had performance highs achieving over 2 million hours in 2006 without a Lost Time Injury but we have also hit lows. This HSE challenge is linked to the remoteness of our operations and the onshore exploration acreage, which means that a lot of road transport is involved.

Operating across vast sand terrains and in temperatures that exceed 50° C in summer months, means we are faced with dangerous conditions over and above the normal conditions of exploration. It is a never-ending journey of constantly striving to improve our HSE performance with the overall objective of achieving the goal of no harm to the people or environment either within or as a result of our operations.

The size of our Contract Area is equivalent to 10% of the land surface area of Saudi Arabia. Although we did not find commercial hydrocarbons in the first three exploration wells we did find all of the components required for the generation and entrapment of commercial quantities of hydrocarbons. My personal feeling is that three wells are insufficient to test the full potential of such a large area. Our Total shareholder exercised their right to exit the Venture after these first three wells were drilled but SRAK continues as a 50/50 Joint Venture between Shell and Saudi Aramco. I believe that there is sufficiently interesting acreage remaining that warrants further exploration and I am confident that the Company will go forwards to future success.

Courtesy of SRAK

The feasibility of using seismic data to model Saudi Arabia

By Tariq Alkhalifah, Majed Almalki, Ghunaim Alonazi, Falah Almutairi, and Hashem Almalki

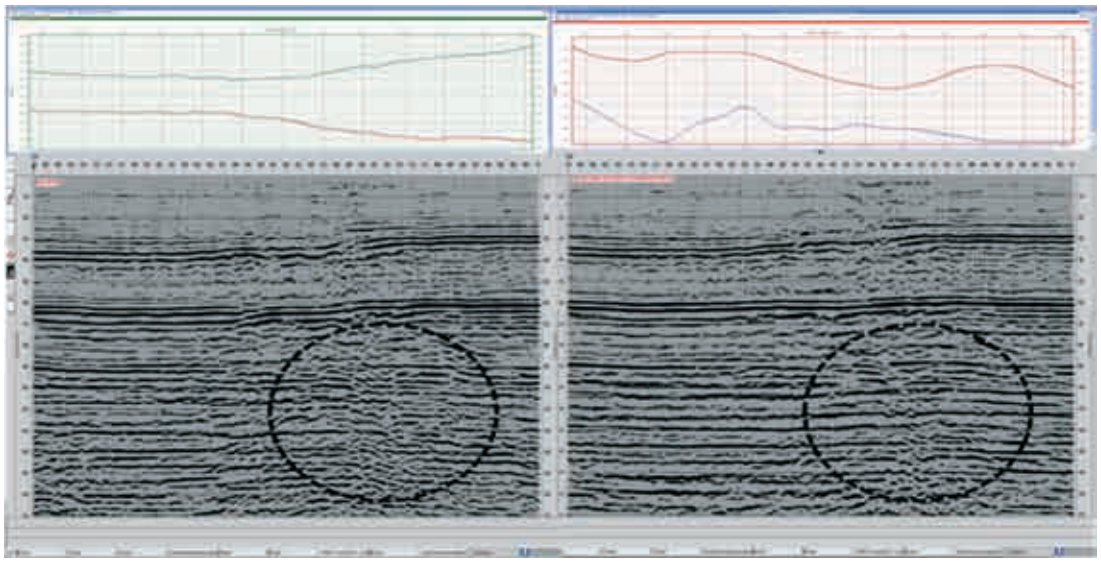
Summary

The Arabian Peninsula is plagued with a complex near-surface that has a destructive influence on the final seismic image. Causes of complexity include such features as sand dunes, Wadi systems, karsts, and rock collapses dominant in the arid Arabian Peninsula. Several techniques are used for the near surface problem. In the end, all rely on estimating an accurate near surface velocity model, which is hard to do. The use of shallow high-resolution seismic reflection data to model the near surface has yet to prove itself. The main challenge in using High resolution shallow seismic data for estimating the near surface is the maintenance of the high frequencies of the reflections from the shallow interfaces in the face of attenuation and possible aliasing.

To avoid aliasing, we compensate the coarse geophone spacing with finer source spacing. As the peak frequency of the seismic signal reaches 150 Hz, the source and receiver sampling must be fine enough to allow proper space sampling of the data, especially for non-zero offset or dip. We promote, for efficiency purposes, the concept of using the conventional acquisition layout to acquire the high resolution data. A high resolution test near an uphole showed that Hi Res data can be a viable and low cost method for near surface information. Since the loss of high frequency energy and the complicated near surface makeup made horizon picking for Prestack TAU migration complicated we relied on conventional velocity analysis for model building. After careful processing and applying the near surface Hi-Res model we obtained good quality data for the line. The added quality through focused processing and using the Hi-Res model improved imaging and made interpretation much easier.

Introduction

The difference between conventional acquisition typically used for P-wave exploration and High resolution acquisition is the frequency range of interest, and thus the detail in the subsurface investigation. While



High-resolution the near surface in

> The added quality through focused processing and using the Hi-Res model improved imaging and made interpretation much easier.

conventional acquisition is aimed to provide reasonable information of the deep subsurface for Oil and Gas exploration, high resolution seismic acquisition is aimed to provide detailed information, as compared with the conventional, of the near surface. The difference in frequency content between the two acquisition options dictates different acquisition parameters to obtain the respective objectives. High resolution seismic can define frequency ranges that reach KHz's, but for our purposes we define High resolution seismic data, as those data that include peak (dominant) frequencies ranging from 100 to 500 Hz.

To acquire high resolution surface seismic data for shallow subsurface investigation the source and receiver spacing must be fine enough to ensure no aliasing of the data. Frequencies for high resolution acquisition can reach up to 500 Hz and thus the recording time sampling as well as the geophone spacing must be fine enough and adhere to the antialiasing equations.

Our definition of high resolution acquisition also includes the possibility of merging the conventional acquisition with the high resolution one for purposes of efficient dual acquisition. This is proposed by suggesting that the sensor layout remain stationary between the two acquisition types since sensor layout is a major cost in land acquisition. In fact, we will use a receiver spacing for the high resolution acquisition equal to 5 or 10 meters typical of conventional single sensor acquisitions. To compare the acquisition parameters need for proper conventional seismic acquisition and those need for what we define as high resolution seismic data I include the table below:

Parameter	Conventional	High resolution
Receiver Interval	30 m	5-10 m
Traces/Shot	120	120
Source Interval	30 m	1 m
Spread	split	split
CMP Interval	15 m	0.5 m
Fold	60	60
Dominant Frequency	25 Hz	150 Hz
Sampling	4 ms	0.5 ms
Effective recording time	6 s	0.8 s
Max. offset	3000 m	600 m

Table - A comparison of the acquisition parameters for conventional seismic data and those for high resolution ones.

> With land acquisition, it is easier to manipulate the source locations than the receiver locations.

Though some of the parameters can vary from what we have in the table, the table was set as a comparison only. For acquisition efficiency purposes, Dablain et. al. (2001) suggested the use of a dual seismic acquisition of high resolution and conventional data by using the same sources for the two acquisition systems. The source, which is dynamite, can provide the frequency range needed for the two objectives. Veen et. al. (2001) suggested the use of a towed land-streamer for cost-effective high resolution data.

Here, we first generate synthetic high resolution seismic data with acquisition (generation) parameters that is similar to what we need in practice. We, then, investigate the frequency content and our ability to process the data. Prestack migration is used as an optimal approach to control the image resolution and this estimate velocity. We then apply the approach to data from eastern Saudi Arabia to test the methods feasibility.

A synthetic test

The purpose of the test here is to evaluate resolution and our ability to handle data with high frequencies in various acquisition configurations. Thus, the model used did not include topography as it was not an objective of this investigation, though we will tackle topography at a later stage.

The model

The model was originally built by Ramzy Alzayer of Saudi Aramco and cut and altered here to make it more realistic. Figure 1 shows the model that contains primarily three layers including the weathering layer. The model is sampled in space every one meter.

The algorithm

To generate the synthetic data to test our ability to invert for the near surface, a second order in time and fourth order in space acoustic finite difference algorithm was used. The finite difference approach can emulate the physical phenomena to a large degree, especially the critical kinematics behavior of the wave propagation.

The acquisition parameters

The acquisition parameters were picked to test our intentions with the upcoming field data acquisition. For the purposes of near surface investigation the acquisition is simulated for the case of Land data.

The source

Though for land data we will probably use a vibrator or a weight drop, in this synthetic example we will use a richer wavelet source with a maximum frequency of 500 Hz and peak frequency of 200 Hz. Figure 2 shows the source wavelet and the frequency spectrum. Clearly, the frequency content is high resolution as we defined it earlier.

The sensors

Typical of land acquisition sensors are laid and are moved in a rollout fashion, unlike marine acquisition in which the sensors streamed along with the sources. Figure 2 shows the layout in which the source spacing is 1 meters and the receiver spacing is 5 meters. This results in a CDP spacing of 0.5 meters and offset spacing of 10 meters. Despite that the offset spacing is coarse for shallow layers, mixing of CDP gathers can take care of that.

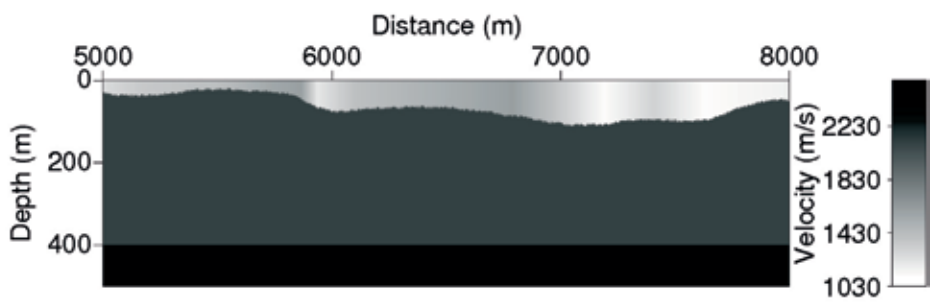


Figure 1 - The velocity model containing three layers.

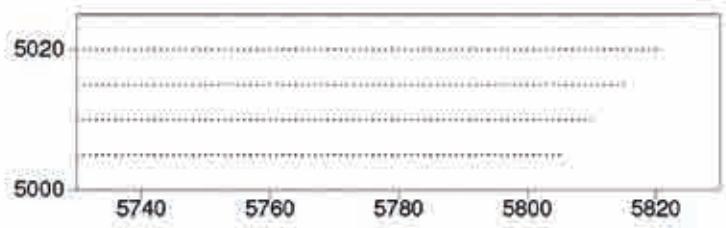


Figure 2 - The layout of the sources and receivers for part of the survey. It shows the course sampling of the receivers and the fine sampling of the sources.

The parameters

To properly process high resolution data, the acquisition parameters must be set to avoid aliasing. The table below includes a list of parameters used for the synthetic data generation.

Parameter	Values
Receiver Interval	5 m
Traces/Shot	120
Source Interval	1 m
Spread	split
CMP Interval	0.5 m
Fold	60
Dominant Frequency	200 Hz
Sampling	1 ms
Effective recording time	0.5 s
Max. offset	600 m

Table - The acquisition parameters used for the synthetic data.

The synthetic data and resolution

It took about 3 full days to generate the whole data on a dual processor Linux platform machine using the finite difference algorithm.

The frequency spectrum of the generated data for a common shot gather located at 6600 m is given in Figure 3 as most of the energy is concentrated at about 200 Hz. This is consistent throughout the data volume.

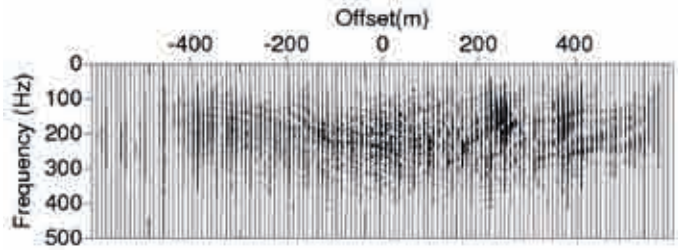


Figure 3 - The Spectrum of a common shot gather generated from a source located at 6600 m in Figure 1.

In comparison with conventional data generated using the same model but using a Ricker wavelet with 25 Hz peak frequency, Figure 4 shows

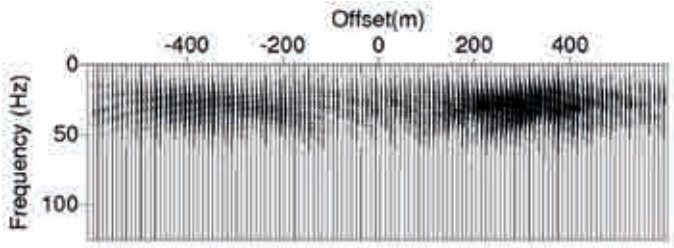


Figure 4 - The Spectrum of a common shot gather generated from a source located at 6600 m in Figure 1 using a source frequency.

Redecimation of the data

As a test, every four consecutive CDP gathers were mixed to obtain higher fold coverage for better velocity analysis of the shallow layer. This results in a two meter CDP spacing and a 2.5 meters offset spacing (The original offset spacing is 10 meters). The finer offset spacing provides more offsets for the shallow layer velocity analysis.

Another, or even better, way to obtain images with proper spacing of offset is through prestack migration. We can naturally impose the image domain that avoids aliasing and provide proper sampling of the offset axis for better velocity estimation.

Poststack migration

With the complexity of the model in Figure 1, conventional processing is not expected to produce accurate images. The shallow lateral velocity is large.

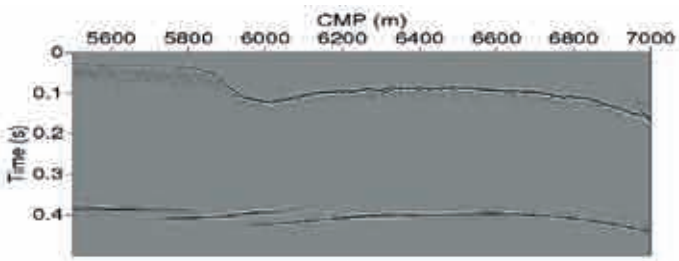


Figure 5 - A migrated image of the high resolution data using conventional processing and Stolt migration.

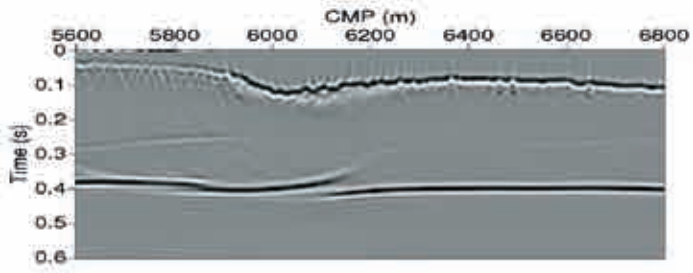


Figure 6 - A migrated image of the conventional data using conventional processing and Stolt migration.

Figures 5 and 6 show the output of Stolt migration after conventional poststack processing of the high resolution and conventional.

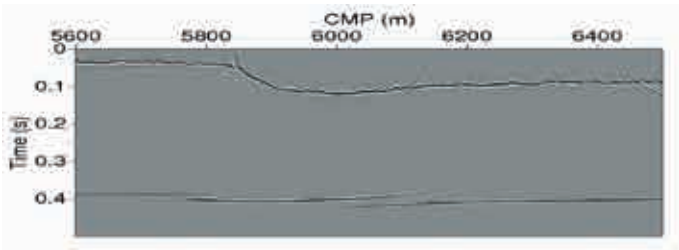


Figure 7 - The image after poststack migration of conventionally processed 0.5 meters CMP spacing data.

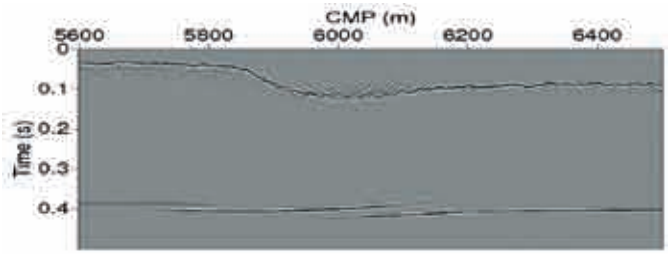


Figure 8 - The image after poststack migration of conventionally processed redecimated 2.0 meters CMP spacing data.

Prestack velocity analysis (MVA)

Using Alkhalifah's (2003) MVA in the TAU domain, we estimate the velocity model for the conventional and high resolution data. The velocity update is based on the residual moveout and based of 1-D update algorithm. We apply two iteration of MVA in the TAU domain on both data and assess the resulting velocity model and image.

Figure 9 shows the resulting velocity model for the high-resolution data. The velocity model is smoothed and converted depth for comparison with the true velocity model in Figure 1. Of course the second interface is not estimated since we do not have a reflection below the second interface. The agreement with the original model is high especially in resolving the low velocity under distance 6000 meters. The residual moveout after migrating with this velocity model is shown in Figure 10. Residuals are generally small along most of the line other than under the sharp drop in the shallow interface at location 6000 meters and some what at the right edge of the model. Probably mode iterations are required to correct those.

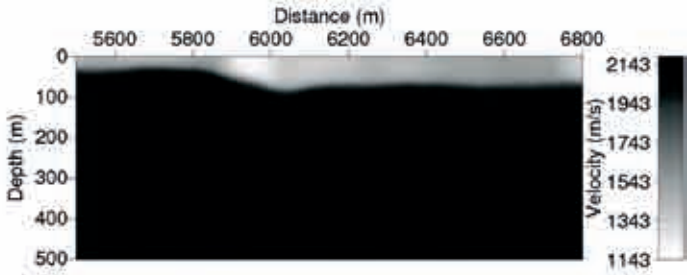


Figure 9 - The velocity model after 2-iterations of Prestack MVA of the high resolution data.

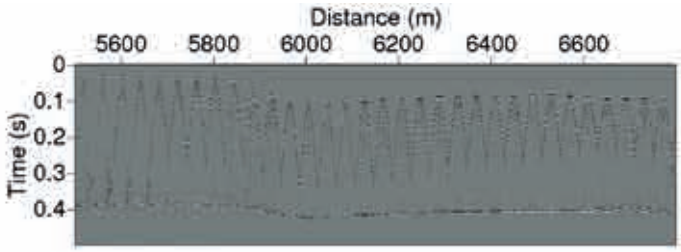


Figure 10 - Common image gathers after 2 MVA iterations shown every 40 meters of the high resolution data.

Figure 11 shows the resulting velocity model after two iterations for the conventional data. The agreement with the original model in Figure 1 is less than that of Figure 9. Specifically, the anomalies in the weathering layer are not resolved due primarily to the low resultion of the data. Though, the weathering layer shows velocity variations they are smaller than the true velocity variation. The residual moveout in Figure 12 appears to be the same as that in Figure 10, but due to the low resolution it appears even smaller.

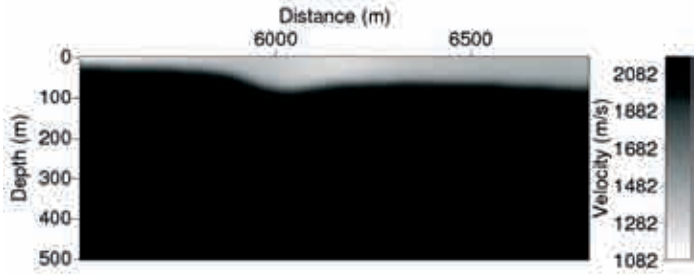


Figure 11 - The velocity model after 2-iterations of Prestack MVA of the conventional data.

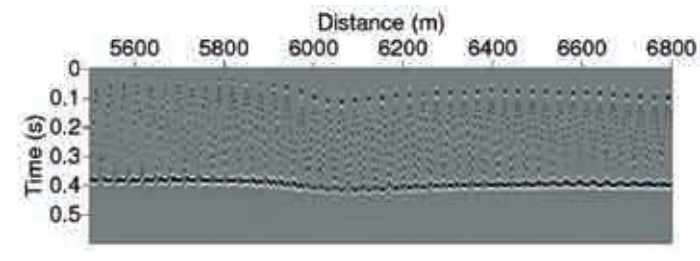


Figure 12 - Common image gathers after 2 MVA iterations shown every 40 meters of the conventional data.

In summary, the resolving power of the conventional low resolution data is less than that of the high resolution data, especially for the shallow weathering layer.

Prestack migration and sampling

Prestack migration allows for full control of the image domain as we can sample the resulting image of the data in a way that simplifies velocity estimation and avoids aliasing. Since velocity estimation is based on residual moveout along the offset axis, the velocity estimation process requires reasonable sampling of the offset axis, which may not be available with our original sampling options, especially for shallow reflections, and thus, prestack migration allows us to correct for this shortcoming. A simple rule for deciding the image sampling with out compromising the image quality is given by

$$2\Delta h \times \Delta x = \Delta s \times \Delta g$$

For our synthetic example the offset sampling is 20 meters per CDP location. A mix of two CDP can provide a 10 meters sampling. However, an intelligent and accurate mix can be done inherently in the prestack migration step. To invert for velocities from reflections that are as shallow as 30 meters depth, the moveout from this reflection will be represented by a few samples up to an offset to depth ratio of one. However, by increasing the space sampling to 2 or 4 meters in the output image we can reduce the offset sampling to 5 or even 2.5 meters. This will result in better sampling of moveout for velocity estimation on the expense of reducing the lateral resolution of the velocity estimation. However, 2 or 4 meter lateral spacing more than what is needed to correct for the near surface in conventional data.

The stack of the prestack migrated data using the velocity models in Figures 9 and 11 is given in Figures 13 for the high resolution data and 14 for the conventional data. Both results look generally accurate, however, the conventional data apparently have less errors as evidence by the horizontal interface reflection at 400 meters depth, despite that the high resolution data provided us with a mode accurate velocity model. The reason for this result is that the conventional low resolution data is less sensitive to the velocity model than the high resolution data. The low sensitivity is expected at all stages including the prestack stage where the velocity. Thus, the high resolution data requires more iterations for an accurate velocity while the conventional data probably reached its peak as allowed by the resolution limits.

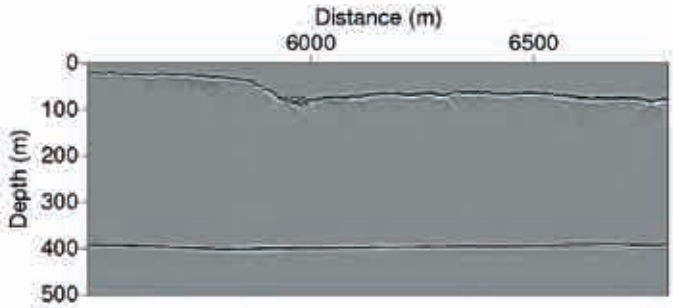


Figure 13 - The stack of the prestack of the high resolution using the velocity model given in Figure 9.

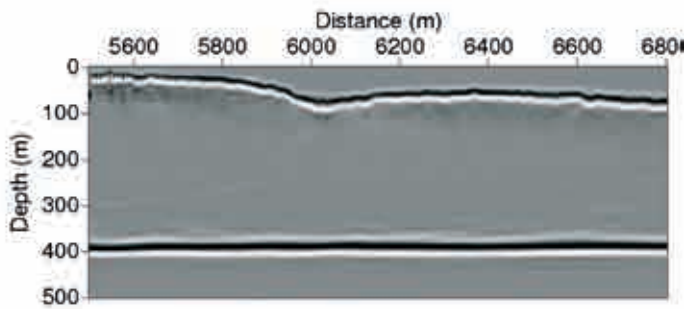


Figure 14 - The stack of the prestack of the high resolution using the velocity model given in Figure 11.

High resolution real data and sampling

Here we show the results of the first High resolution acquisition that took place to test sampling issues in almuzahemia area.

High resolution real data example

In the following real data example, we compare a fixed processing sequence applied to the data with various source and receiver spacing. To do so, we acquired 2-D high resolution data from the Arabian Peninsula near the city of Riyadh using our high resolution vibrator and a 112 channel single geophone array sampled at 5 m spacing. The vibrator was ignited every 1 m with frequencies ranging from 50 Hz to 550 Hz. The data with

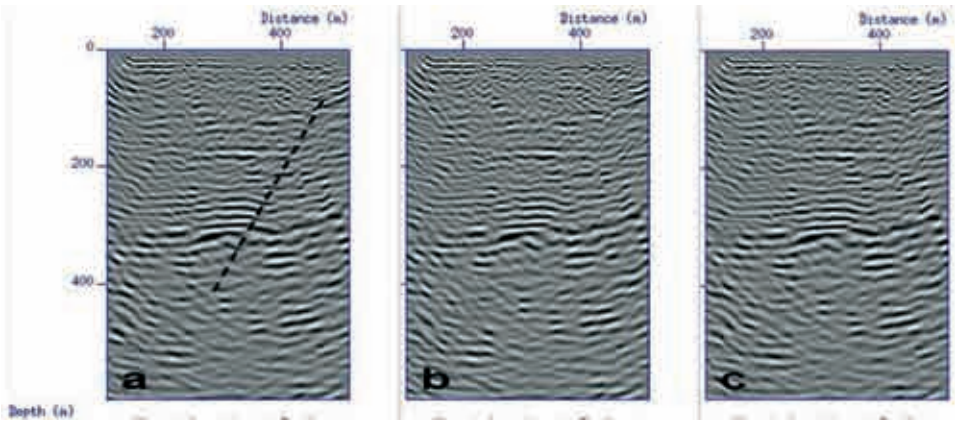


Figure 15 - Prestack depth migration of the high resolution seismic data sampled at (a) 1 m source and 5 m receiver sampling, (b) 2 m source and 5 m receiver sampling, and (c) 1 m source and 10 m receiver sampling. The dashed line in (a) represents an interpreted fault. Fig. 15: Prestack depth migration of the high resolution seismic data sampled at (a) 1 m source and 5 m receiver sampling, (b) 2 m source and 5 m receiver sampling, and (c) 1 m source and 10 m receiver sampling. The dashed line in (a) represents an interpreted fault.

this source and receiver spacing is used as a reference. The resulting peak frequency of the data is 125 Hz.

Figure 15 shows the result of prestack depth (TAU) migration on the 2-D high resolution data with various input source and receiver sampling. In all cases, the result looks incredibly similar, all indicating the presence of a major fault at the center. Thus, despite the course sampling of the receivers (10 m spacing), it has little influence on the data implying that we might be able to use conventional layout for high resolution acquisition granted we keep the source spacing fine.

The Haradh (Zaher) data

The acquisition as the where concentrated on a 3.6 km length part of the conventional line in an area that transition from an uplift in the seismic data due to a shallow anomaly. Figure 16 shows pictures from the acquisition of high resolution data that took place during the day time and night time. Figure 17 shows a raw common shot gather from the high resolution data as well as the frequency spectrum demonstrating the range of frequencies covered.

The High resolution concept

The idea here is based on performing four steps:

1. Acquisition of 2-D shallow High resolution seismic data at the location of the conventional line. This location coincides with a 2-D already acquired data with serious near surface problems.

2. Testing acquisition parameters including sampling, range, and filters for optimal results.

3. Inverting the data for a shallow velocity model to depth of approximately 500 meters.

4. Using this model to correct the conventional seismic data.

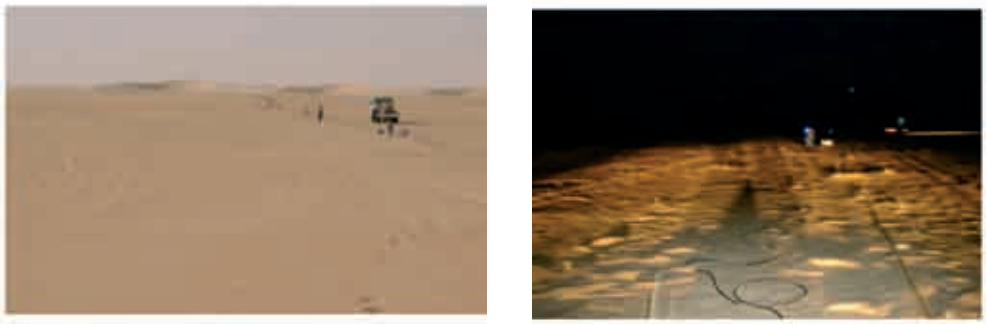


Figure 16 - Pictures from the acquisition along the Zaher line during the day time (left) and during night (right).

The High resolution data

For cost-effective acquisition of high-resolution seismic data we acquired data at coarser than usual sampling. Specifically, we acquired High resolution data along an approximately 3.6 km of 2D land original Seismic line in Dolam area. The Dataset descriptions are as follows:

Data Type	Vibroseis
Source Interval	2.5 M
Receiver Interval	5 M
No. Of Channels	112
Maximum Far Traces Offset	560 M
Minimum Offset	3 M
Processing Sample Rate	0.5 Ms
Record Length	0.6 Sec

The processing was geared to enhance the data quality for velocity extraction by using special parameters for high resolution data. The Vibrator sweep was linear ranging from 30 to 300 Hz and as a result the peak frequency of the seismic data is close to 50 Hz with reasonable amplitude extending to 160 Hz as shown in Figure 17.

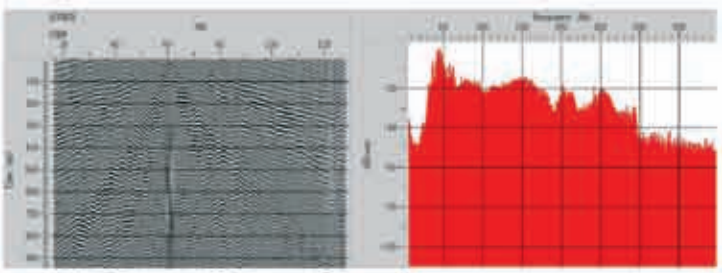


Figure 17 - A common gather of the High resolution acquisition (left) and the corresponding frequency content (right).

Results

Figure 18 shows the stacked section of the high resolution data over the 3.6 km line after stacking velocity analysis. Reflections are apparent up to 800 ms vertical two-way time. The estimated stacking velocity is used to invert for a two layer model of the near surface up to 400 meters depth to be used to correct the conventional data over this area. Figure 19 shows the migrated stacked section of the conventional data over this region after refraction-based static's correction (left) and correction using the high resolution velocity model (right). The two layer model for both cases is shown up top. The model based on the

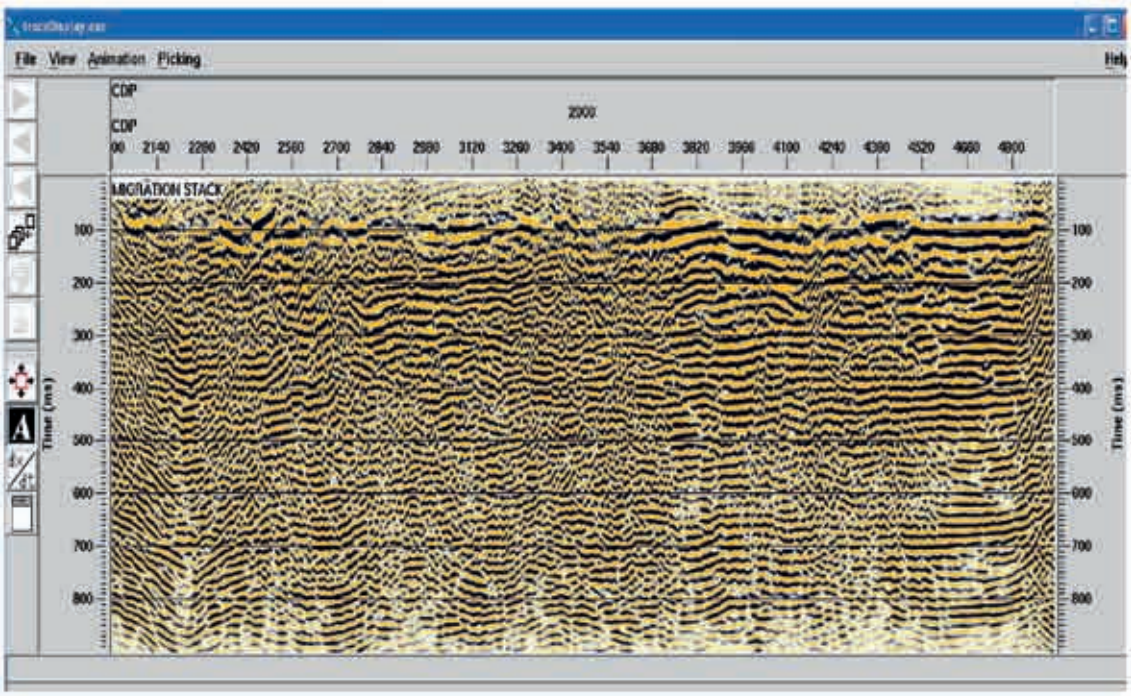


Figure 18 - A stack of the near surface High resolution data.

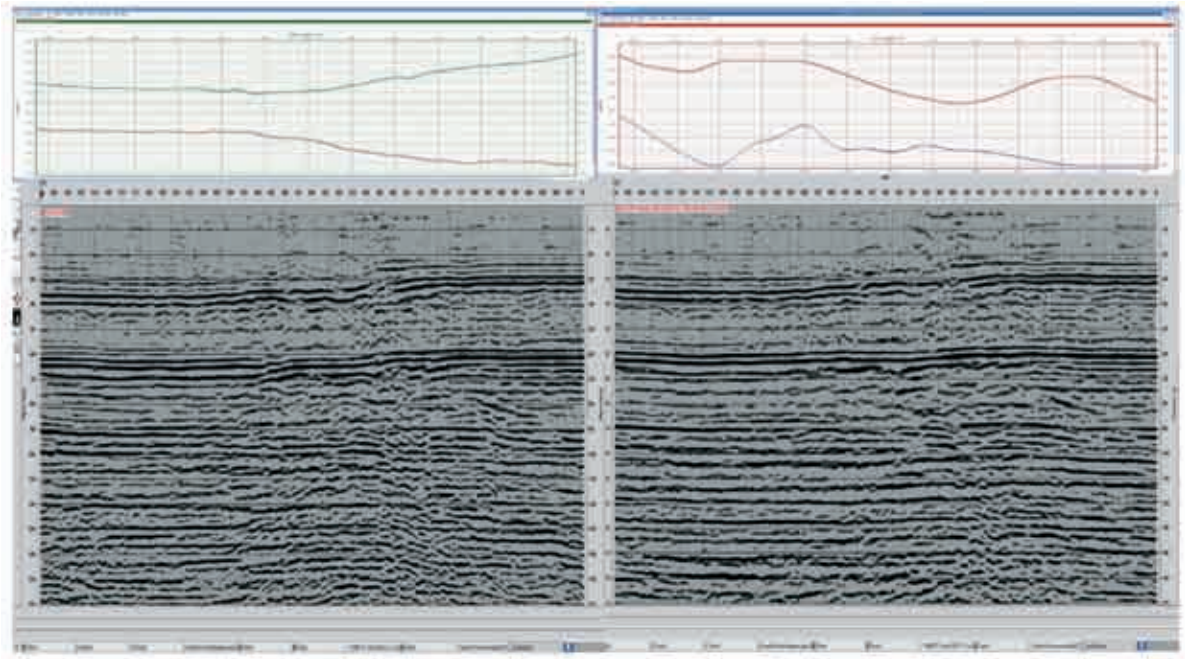


Figure 19 - Migrated images of Zaher line for the refraction-based correction data (left) and the one using High resolution data (right). The two layer velocity models for both cases on top.

high resolution data clearly has more detail over the 3.6 km line than the refraction static's, and as expected this fact is reflected in the final sections. The improvements include better continuity of reflections in this mostly fault free area. The up lift caused by the velocity anomaly which shows like a fault break in reflections is resolved using the high resolution data model.

Conclusion

Three major facts were unraveled through this study:

1. Fine source spacing can compensate for coarser geophone spacing especially when using Prestack imaging techniques. The implication is that we can acquire high resolution data from conventional single sensor layouts and thus do not need to reemploy the geophones in the single sensor case.

2. The loss of the high frequencies will influence the model building effort immensely, especially if the model building effort is based on identifying horizons like Prestack migration MVA methods.

3. High resolution models obtained from semblance estimation can improve the imaging of conventional data.

Acknowledgement

We wish to thank Saudi Aramco and especially Ramzy Alzayer, Robert Ley, and Khalid Alrufai for their support and useful discussions as well as King AbdulAziz City for Science and Technology (KACST) for their support.

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Mapping fracture corridors in naturally fractured carbonate reservoirs in the Middle East

By Mahmood Akbar & Bernard Montaron, Schlumberger and Robert Godfrey, WesternGeco

Natural fractures can be a blessing particularly in tight carbonate reservoirs. This is because they increase the rock permeability and help drain hydrocarbons. They can also bring undesired fluids such as water from the aquifer, or injected sea water towards producing wells.

Natural fractures reveal the stress history of a reservoir, with families of cracks oriented to the geologic stresses that formed them. Shear stress generally creates a crushed zone because of the shear movement of rocks on either side of the failure. This makes an angle with the

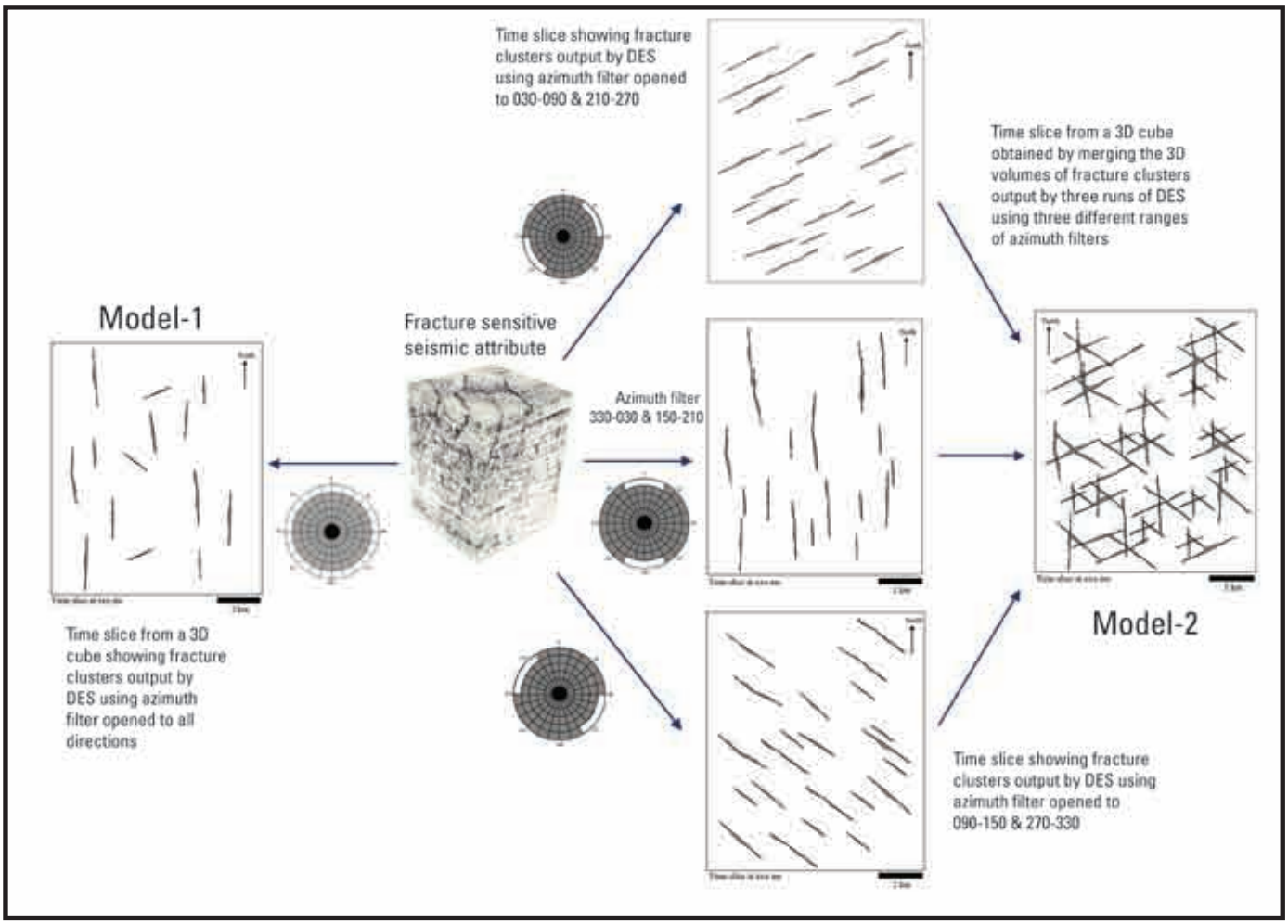


Figure 1 - Schematic showing the effect of azimuth filter on the extracted fracture clusters from the fracture sensitive 3D seismic attribute. The 3D cube of fracture clusters obtained through multiple azimuth filters gives more realistic picture fracture clusters (Model 2) than the one obtained through a single 360˚ azimuth filter (Model 1).

maximum stress, while in tensile failure rocks move in opposite directions with a crack perpendicular to the applied tensile stress.

Every brittle rock can react both ways, but not for the same state of stress. The limit between the tensile and shear modes is an intrinsic property of the rock. In many vertical wells, the stress of drilling can induce both types of fractures. Likewise, natural movements of the earth over millions of years will cause rocks to either crush or shear, depending on the type of rock.

At first, failures develop along a single plane. Movement along this plane resolves into a vertical throw and a horizontal elongation, which reduces the minimum stress in the layers above and below. If the rock layers are prone to tensile failure, a number of vertical fractures – a fracture corridor – will eventually occur through the fault zone. These vertical displacements are very difficult to observe on borehole images.

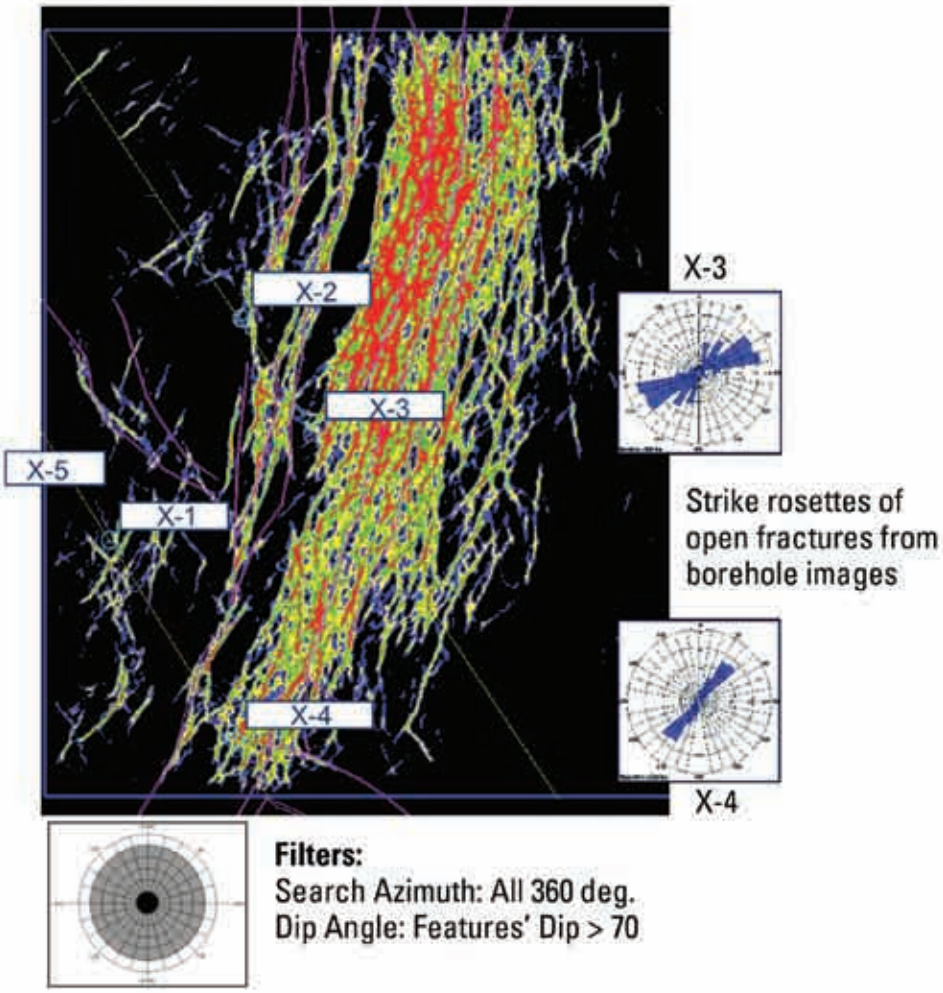


Figure 2 - A time slice from Middle Marrat showing fracture clusters orienting dominantly in NNE-SSW direction when the Azimuthal filter is not constrained.

Fracture corridors are extraordinary clusters of almost-parallel cracks that vary in length and size. A large fracture corridor might be 10 meters wide, 100 meters high and a kilometer long. A single cluster of these dimensions may include more than ten thousand individual fractures of variable length, height and aperture.

Conductive fracture corridors are the "highways" for fluids migrating through the reservoir, but you need to know where the highways are, where they go and what dimensions and orientations they have. Placing injector and producer wells without this map is a risky game: An Injector could intersect a fracture corridor that will bring water close to producers quickly, generating early water breakthrough. A producer missing a fracture corridor would see its production reduced dramatically.

FCM workflow

The following is a brief description of the Fracture Cluster Mapping (FCM) workflow that Schlumberger developed to successfully map the major fracture corridors of five carbonate fields in Kuwait.

The workflow assumed that natural fracture clusters of at least 10 to 30 meters in width, vertical and horizontal lengths should be expressed in the 3D seismic data. The workflow integrates both borehole and 3D seismic data to optimize the effectiveness of our discontinuity extraction software (DES).

To ensure that the subsequent attributes input to the DES processing contain the meaningful information needed to map fracture clusters, seismic data was acquired at the optimal spatial/temporal bandwidth and signal-to-noise ratio, which in some cases meant the use of single-sensor data.

The seismic attributes most sensitive to fracture clusters were identified and that data was input into the DES. Directional and inclination filters were based on the analysis of cores, borehole images, sonic logs, and vertical seismic profiles. A structural and tectonic history of the study area was included to optimize the parameters of the models and to assess the results.

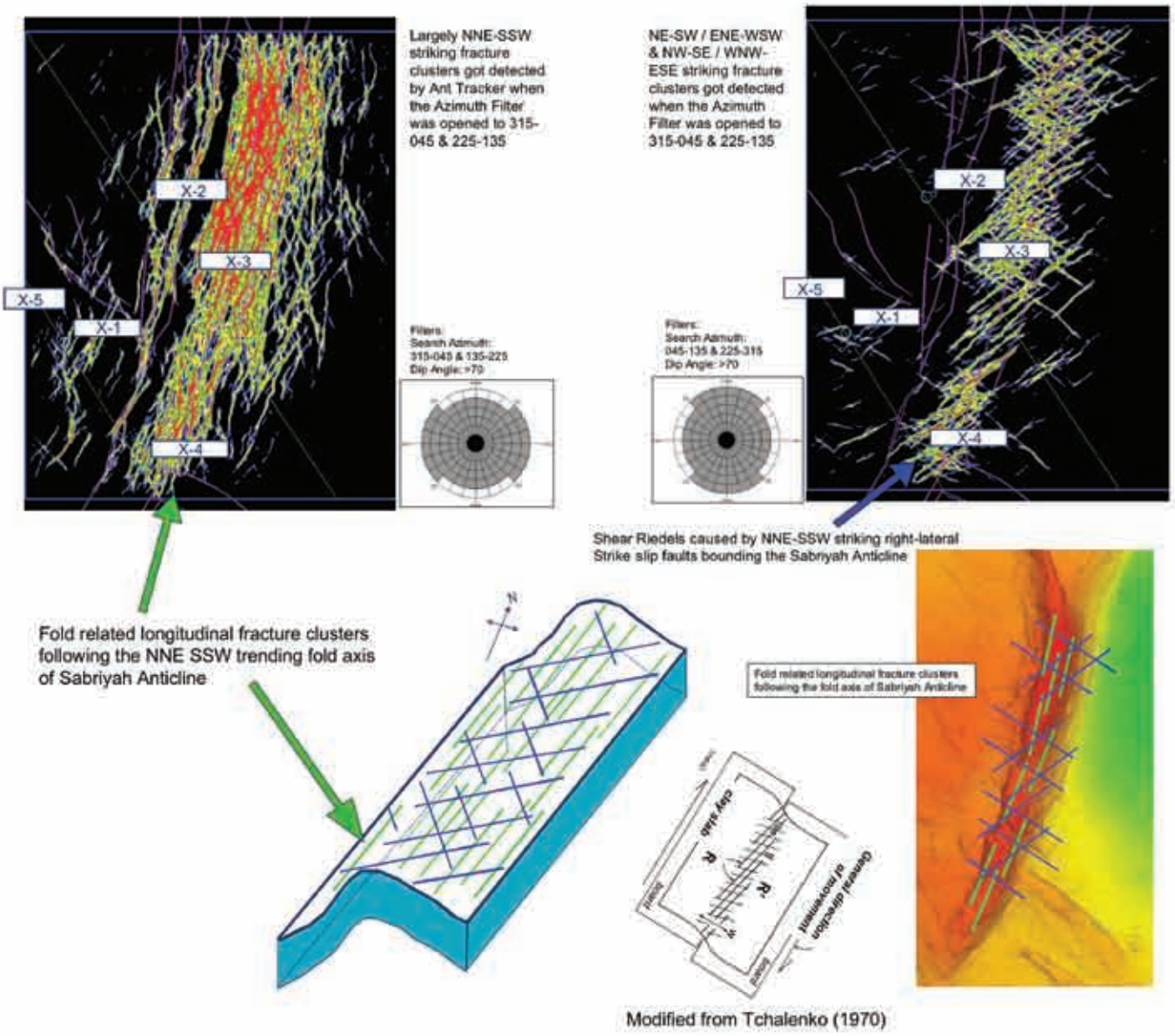


Figure 3 - As observed in the borehole images, nearly all orientations of fracture clusters were detected from the 3D seismic by running DES for two different sets of parameters. Possibly fold related longitudinal fractures and strike-slip fault related riedel shear types of fracture clusters were detected with this technique.

General DES processing can overlook medium to smaller fracture clusters when the directional filter is kept open to all 360° of azimuth with a fixed range of features' inclination. In that mode, DES processing follows the strongest lateral discontinuities in the vertical plane, but skips over the medium to weaker signatures of fracture clusters.

To capture such discontinuities, the directional filter was divided into a number of ranges and set the inclination filter to allow more than one dip inclination range. The DES processing was run separately for each set of directional and inclination filters. Each run gave a 3D volume cube of fracture clusters lineaments. Later, these individual 3D cubes were merged into a single 3D volume of fracture clusters that could be converted from time index to depth index.

The workflow was applied to the sequence of Jurassic carbonates in the NW Raudhatain, Raudhatain, Umm Niqqa, Sabriyah, and Bahra fields, all located in the northern part of Kuwait. Sabriyah was selected as the key

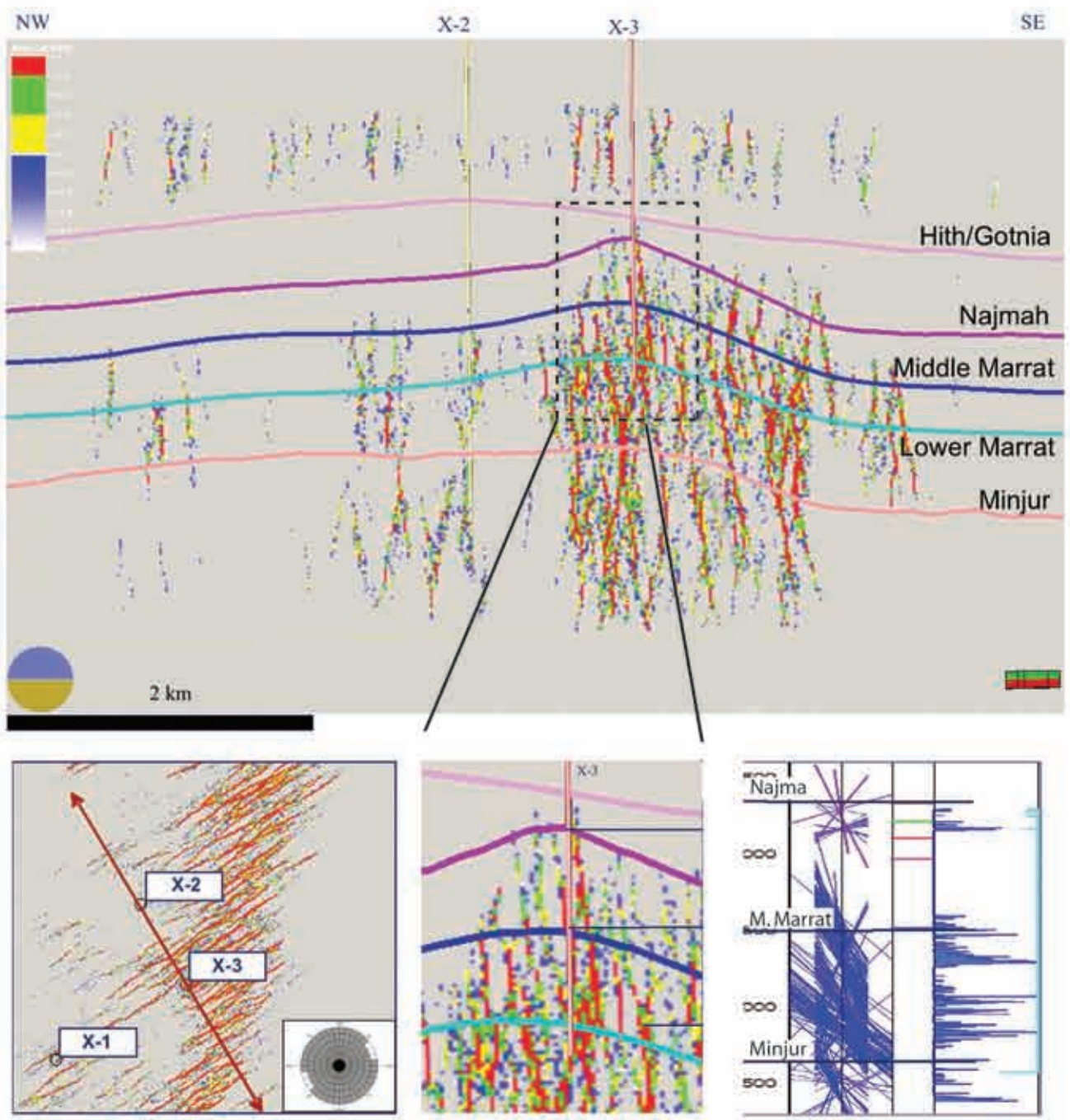


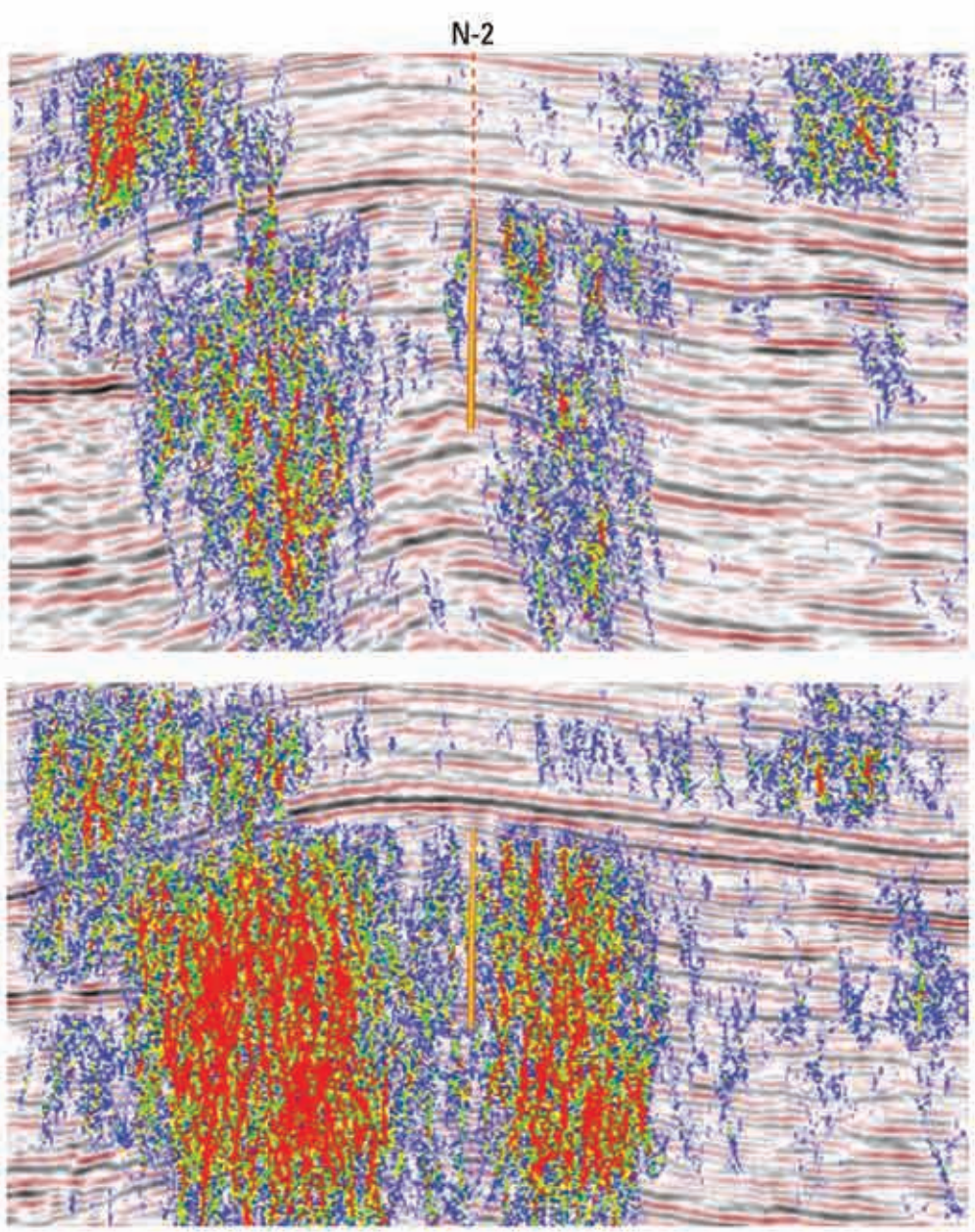
Figure 4 - A section through wells X-2 and X-3 showing fracture clusters extracted by the FCM technique using 050-080 and 230-260 filters to enhance ENE-WSW trending lineaments. The well X-3 does not intersect any fracture cluster over the interval from top Najmah to top Middle Marrat. However, it intersects a major fracture cluster in the interval from Middle Marrat to top Minjur. A similar observation was made in the wellbore using cores and borehole images as shown by the stick plot and fracture density curve for open fractures.

study area because it already had four wells, some new drilling, and a challenging structure.

Results

Images generated for the Middle Marrat carbonate reservoir showed mainly NNE to SSW trending fracture clusters. Clusters with the same orientation and inclination appeared in the 3D cube throughout the Marrat section. In contrast, borehole data at one well showed more than 400 open fractures trending ENE to WSW, primarily within Marrat.

Applying two different filters revealed additional fracture clusters, each with its' own distinct orientation. The results were validated by data from the four existing wells and the two new ones.



A section of conventional 3D seismic with fracture clusters from NW-Raudhatain Field

A section of new seismic with fracture clusters from NW-Raudhatain Field

Figure 5 - Comparison of FCM results between the ones derived using conventional 3D seismic and those obtained by using new seismic data at the NW-Raudhatain Field.

Resolution of the input seismic data is important to see the wider size range of fracture clusters, so the Fracture Corridor Mapping workflow was applied to the Q-Land seismic data from the NW-Raudhatain Field to see how much it might improve the details of fracture clusters. Then results from the conventional 3D surface seismic data were compared with the ones derived from Q-Technology single-sensor data.

This study suggested a good correlation between well productivity and the proximity of fracture clusters predicted by the FCM workflow. An accurate fracture corridor map can be an essential element for the placement of injectors and producers to maximize recovery from any carbonate field.

Application

Fracture corridors are often blamed for water breakthroughs that occur much earlier than a field's operators anticipate. With 3D maps of fracture corridors, however, these subsurface fluid highways can now be

> Equipped with good maps, operators are more likely to avoid water breakthrough surprises and use their knowledge to significantly increase recovery from carbonate and other naturally fractured reservoirs.

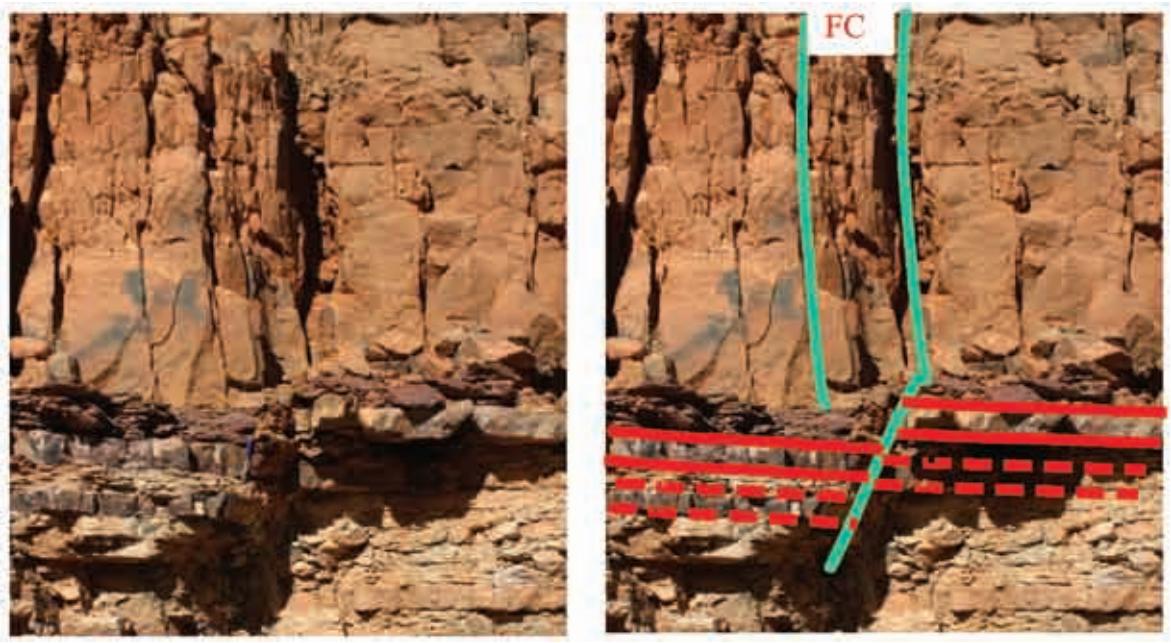


Figure 6 - Fracture corridor in quartzite developed on top of a small fault in shaly layers.

integrated into reservoir models. Reservoir engineers can now pick the optimum well locations using more realistic reservoir simulations. Fracture corridors can also be used to dramatically extend the zone drained by a producing well: A producer intersecting a fracture corridor can be equivalent to several Maximum Reservoir Contact (MRC) wells.

Equipped with good maps, operators are more likely to avoid water breakthrough surprises and use their knowledge to significantly increase recovery from carbonate and other naturally fractured reservoirs.

Further Reading

Sunil K. Singh, Hanan Abu-Habbiel, Badruzzaman Khan, Mahmood Akbar, Arnaud Etchecopar, Bernard Montaron (2008) Mapping Fracture Corridors in Naturally Fractured Reservoirs – An Example from Middle East Carbonates, First Break volume 26, May 2008.

Enhanced PDC Cutters on High Torque Motor Application

ReedHycalog DSX184M with enhanced cutters on high torque motors yields new lowest CPF and highest ROP records in the 8 ½" build section in an established Oilfield on the Arabian Peninsula.

By Dominic Carrington, Evaluation Engineer for Saudi Arabia, Andy Murdock, Product Manager and Deepthi Setlur, Fixed Cutter, Strategic Projects Manager - NOV ReedHycalog

The deep-leaching Thermostable cutter process is extensively patented by NOV ReedHycalog. Removal of the cobalt binder from the surface layer of Polycrystalline Diamond Compact (PDC) increases the abrasion resistance of the material by 400%. Standard TReX® cutters, first introduced in 2001, have a deep-leached Thermostable cutting face only. New Raptor® cutters, in addition to the cutting face, have Thermostable PDC around the complete circumference of the cutter. The material properties of these cutters made new unique cutter geometries practical in the harsh downhole environment.

One such geometry is the RazorEdge™ cutter. The objective of this new cutter was to increase the ROP potential of the bit and maintain or improve the bit's durability without modification of the bit design itself. The concept was proven using NOV ReedHycalog's laboratory test rig first and subsequent runs in the field have validated these initial findings.

> To test the concept, a series of drilling tests were performed in a laboratory test rig where the only variable was the geometry of the chamfer utilized. Bits that utilized cutters with reduced chamfer angles showed a marked increase in ROP without chipping problems, thus validating the concept.

Novel Cutters

PDC cutters fail the formation by shearing. The sharper the cutting edge presented to the formation is, and the closer the cutting face is to true vertical with respect to the formation, the faster the bit will drill.

The stresses inherent in PDC cutters necessitate a chamfer is produced around the circumferential edge of the cutting face. This lessens the hoop stresses that lead to early-life cutter chipping, either during handling on surface or on initial contact with the formation. The angle of this chamfer was optimized at 45 degrees. It also lessens the potential of early chipping damage of the sharp edge.

One undesirable effect of this chamfer is that the effective backrake of the cutter, particularly at low depth-of-cut, is increased by 45 degrees. One solution to this problem is to reduce the chamfer angle such that the bit starts out sharper, without the need for any adjustment of the bit design's backrake. This result of such a chamfer angle modification would be the potential to drill faster. Attempts to pursue this approach in the past ended in failure because anything less than a 45 degree chamfer lead to excessive early-life cutter edge deterioration and premature bit failure.

With the new cutter technology. this approach became feasible with the Thermostable diamond layer not just on the front face of the cutter but also on the circumferential edges as well, which allows the cutting edge to remain sharper longer.

To test the concept, a series of drilling tests were performed in a laboratory test rig where the only variable was the geometry of the chamfer utilized. Bits that utilized cutters with reduced chamfer angles showed a marked increase in ROP without chipping problems, thus validating the concept.

Case History

The 8 ½" DSX184M is an established product, specifically designed for use on the Arabian Peninsula for motor steerable build sections. This bit was designed with high lateral stability to reduce the vibration and cutter chipping potential. It has customized PDC inserts in the cone which act as Torque Control Components allowing more aggressive backrake angles to be used without the risk of reactive torque problems.

It delivers comparable performance to competitor bits used in the same application. To improve its ROP, the new cutters were substituted for the standard cutters in the same bit design. These bits were then run in same field to benchmark their performance against previous runs of the exact same bit type that utilized the standard TReX cutters.

> Essentially each planned section called for the well to be turned immediately to a constant Azimuth and build from vertical at an average rate of around 4°/100ft reaching approximately 80° Inclination by the 7" liner point (TD). In the wells drilled, survey data indicated that build rates ranged from 2 to 5°/100ft with a maximum of 6°/100ft.

Section used for the evaluation

Of the three subject wells drilled: Well-A and Well-B used RazorEdge™ cutter bits, while Well-C used standard TReX cutter bits.

Wells-A, B and C all had similar formations and profiles for the build section and were drilled using steerable motors.

The usual 8 ½" build section for these wells starts by kicking off from vertical below the Mid Thamama Limestone in the Yamama formation, a soft calcarentic limestone. After drilling approximately 300 ft, the top of the Sulaiy formation is reached. Similar to the Yamama, it is mostly a soft calcaranite typically 550 to 600 ft thick. As the well angle continues to build it takes about 650 feet to cross this into the Hith formation. The Hith is essentially a massive Anhydrite with a thickness of 400 to 450 feet, taking around 600 to 650 feet to drill due to the increasing inclination. The Hith forms the seal for the Arab A limestone reservoir. The Arab B limestone reservoir is around 100 feet below taking around 200 feet of drilling to reach it through an anhydrite cap. Another 100 feet below is the Arab C limestone reservoir which takes a further 200 feet of drilling to cross. The section terminates at the 7" liner point just below the Post Arab D stringer before the Arab D reservoir is reached.

In this analysis, three of the wells (Wells A, B and C) were studied in more detail to illustrate the improved ROP observed.

Essentially each planned section called for the well to be turned immediately to a constant Azimuth and build from vertical at an average rate of around 4°/100ft reaching approximately 80° Inclination by the 7" liner point (TD). In the wells drilled, survey data indicated that build rates ranged from 2 to 5°/100ft with a maximum of 6°/100ft.

All the Bits were run on motor steerable assemblies. The standard bit in Well-C used a 6 ¾" 6/7 lobe 5.4 stage motor, the two RazorEdge bits on Well-B and Well-A used a 6 ¾" 7/8 lobe 6 stage motor.

8 ½" DSX184M runs in the subject oil field listed in the order drilled

Well	Cutters	Ft	Hrs	ROP	T i	T o	M DC	Loc	B	G	OD C	RP
Well G	Standard	2,367	68.5	34.6	2	2	CT	A	X	I		TD
Well C	Standard	3,149	108.5	29.0	0	1	CT	S	X	I		TD
Well H	Standard	2,691	87.5	30.8	1	1	CT	C	X	1	WT	TD
Well B	RazorEdge	2,770	66.0	42.0	1	1	CT	A	X	I	BT	TD
Well A	RazorEdge	3,900	98.5	39.6	1	2	CT	M	X	1		TD

In each well the same geological interval to be drilled occurs at slightly different sub sea depths and there are small differences in ground elevation, however for the sections drilled the profiles and geological sequence are very similar.

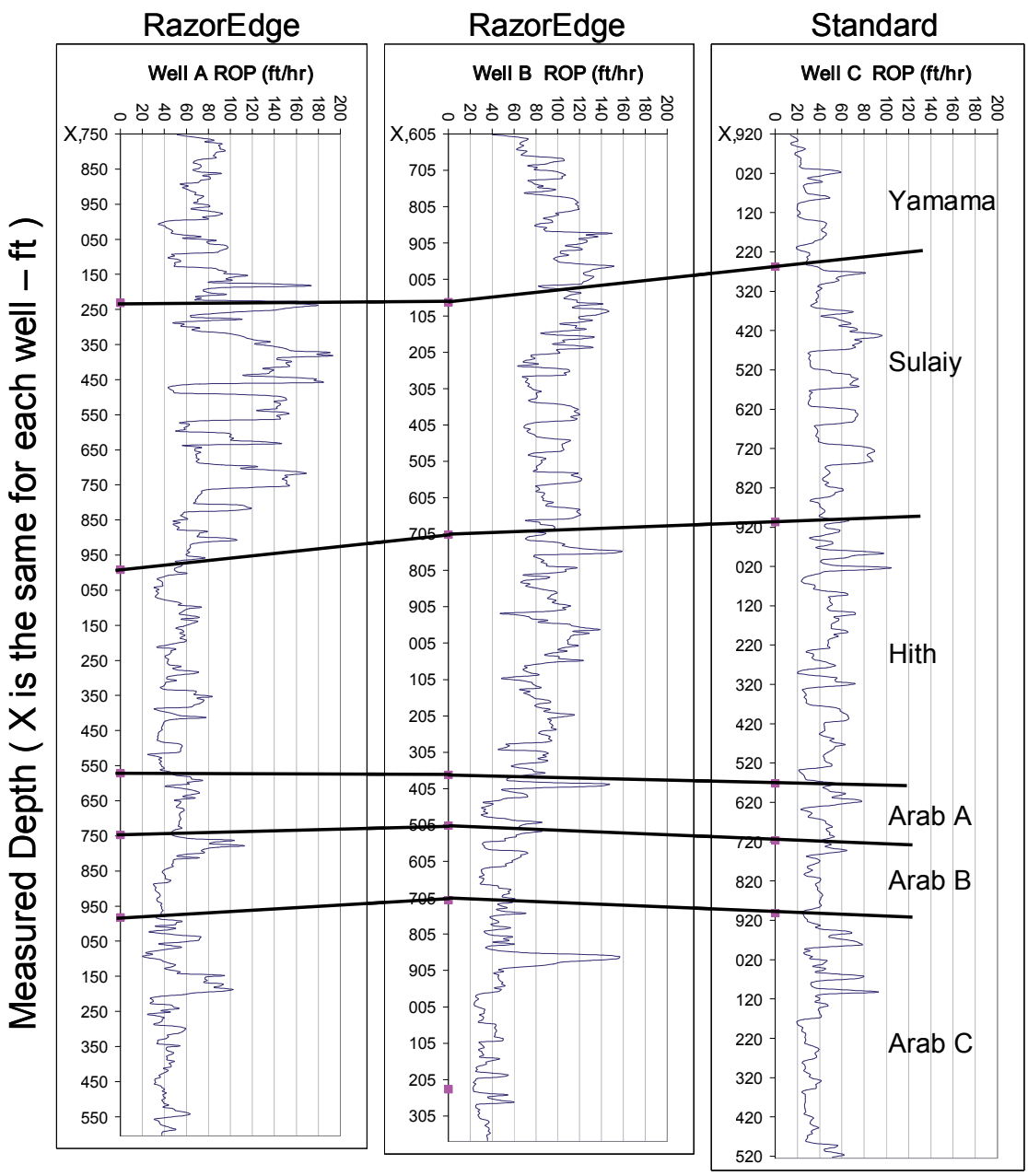
Rate of Penetration (ROP) performance

The ROP's for the section from the Yamama down to the base of the Arab B were considered. This was to eliminate the few small variations in the sections drilled above the Yamama. Well-A actually started above the Mid Thamama and Well-A and Well-C had extended tangent sections in the Arab C formation.

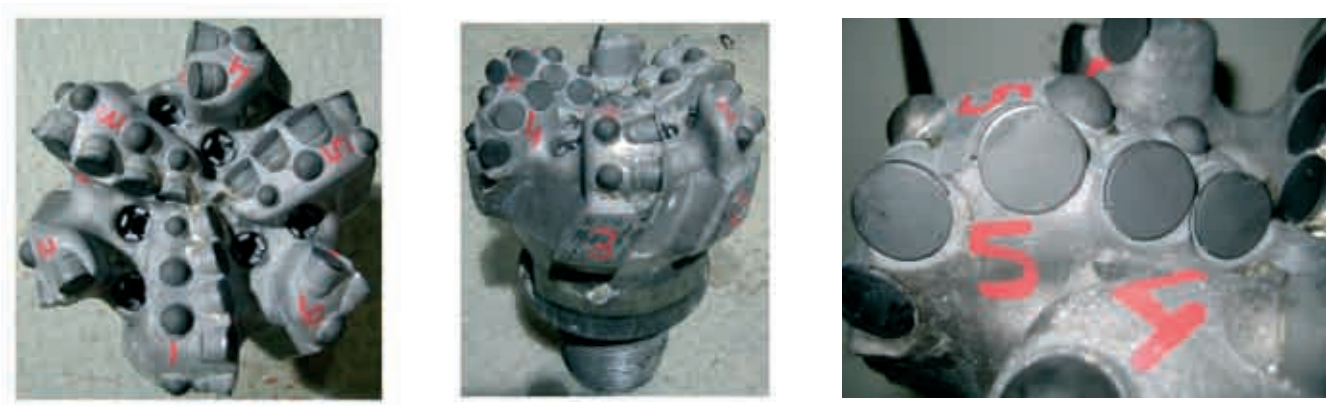
The large peaks and troughs observed in each well are largely due to sliding versus rotating during the build rather than formation changes. In fact sliding footage ranged from between 43 and 53 % of the total footage drilled.

The ROP graphs show that in the softer Yamama and Sulaiy carbonates the rotating ROPs are significantly enhanced when using the RazorEdge cutters in the order of at least 100%. For sliding ROP this is even greater in excess of 200% in some cases. In the harder Hith Anhydrite rotating and sliding ROPs are increased by at least 20 to 30%. In the firmer limestones of the Arab A and B rotating ROPs are also increased by at least 20% although sliding ROPs remain unchanged.

In all the wells studied, mud weight commenced in the range 64 to 68 pcf and increased gradually with depth



Typical Dull Condition



The photographs show the 8 ½" DSX184M that reached TD in Well-B. The chamfered RazorEdge feature can clearly be seen on the cutters which remain in very good condition. The rig grading for this bit was 1-1-CT-A-X-I-TD.

to counter the expected water flows from the Arab C reservoir. For the two wells that used the RazorEdge cutter bits, the maximum mud weight reached was 90. The three wells that used conventional TReX cutter bits required a mud weight in the range 85 to 87. The lower mud weight used in these wells should have assisted ROP; in spite of the heavier mud weights used on the RazorEdge runs, the overall ROP was significantly higher so mud weight was not a factor.

Results

Razoredge cutters were made possible by the unique material properties of Raptor technology. By modifying the angle of the chamfer, the effective backrake of Raptor cutters was reduced, rendering the cutter more aggressive. The geometry was optimized and tested in the laboratory at NOV ReedHycalog to validate both performance and its resistance to chipping, historically an unsolved problem with cutters using reduced chamfer angles.

The wells studied in this article indicate that use of RazorEdge cutter bits, in combination with high torque motors to maximize their performance potential, delivered substantially improved bit performance in the subject field. The DSX184M run on Well-A delivered the lowest Cost Per Foot for the field in this application and the DSX184M run on Well-B delivered the highest overall ROP for wells drilled overbalanced.

The top three directional wells in this oil field, in terms of Cost per foot and ROP drilled from vertical to section TD with mud, were the following:

Comparative Bit Run Evaluation

Well	Run Date	Mfg	Ft	Hrs	Cost/ft	
#1 Well A	Jun-08	ReedHycalog	3,900	98.5	54.8	Record CPF
#2 Well D	Feb-08	Other bit company	3,625	90.0	55.1	
#3 Well E	Mar-05	Other bit company	2,846	65.0	56.3	

Well	Run Date	Mfg	Ft	Hrs	ROP	
#1 Well B	May-08	ReedHycalog	2,770	66.0	42.0	Record ROP
#2 Well D	Feb-08	Other bit company	3,625	90.0	40.3	
#3 Well F	Sep-05	Other bit company	3,010	75.5	39.9	

CPF calculation: standard costs used for motors, rig rate, bit cost and trip rate.

Based on the success of these runs in the Subject Field, these new cutters will be introduced to 8 ½" DSX184M's used on all similar profile wells in different fields in the same region . Should these prove successful, the use of RazorEdge cutters for other applications will be considered.

Hughes Christensen's 72-Year Commitment to Saudi Aramco Rock Solid

Hughes Christensen, the drill bit division of Baker Hughes, has been committed to the work of Saudi Aramco since 1936. In that year, the two companies worked together on the Dammam-7 well.

The company's formal commitment to the Kingdom began in 1985 when Hughes Christensen/Medbit was established in Saudi Arabia.

The goal was to serve the country with a local entity, comprising drill bit manufacturing, sales and marketing, engineering, and administration. Today, a dedicated staff of 66 employees of 15 nationalities provide world-class drill bit technology and operations support. Forty-five percent of the workforce comprises Saudi Arabian nationals. Hughes Christensen has pledged to grow and develop this Saudi workforce.

The company's world-class drill bit products and services, recognized as the industry standard, have played a major role in helping Saudi Aramco achieve the objectives of drilling challenging formations cost effectively. Working with Saudi Aramco, Hughes Christensen continues to drive improvements in drilling efficiency with increased ROP and better well placement, enhanced data quality, optimized borehole quality, and lower overall interval cost with reduced nonproductive time.

Hughes Christensen history

The Hughes Tool Co. introduced the world's first rotary rock bit equipped with two rolling cone cutters in 1909. This invention enabled drillers to penetrate hard formations with greater oil reserves. Twenty-four years later, the company introduced the Tricone™ three-cone drill bit, still the industry standard with its numerous enhancements. In 1976, the company introduced bits with synthetic diamond cutters. These PDC bits, also continually upgraded, allow operators to solve many of their toughest energy exploration challenges. This long tradition of innovation continues as Hughes Christensen—whose research and development programs have been responsible for the systematic advancement of drill bit technology—approaches its 100-year anniversary.

Tricone and PDC technology

Hughes Christensen has invested in more R&D, received more patents, and has led the industry with more firsts than any other drill bit manufacturer. With Tricone and diamond products, Hughes Christensen staff creates technology that drills faster, stays in the hole longer, and

lowers the cost-per-foot drilled for global oil and gas operators. The following achievements, many still included in the company's drill bit designs, are the foundation of its technological superiority:

-first two-cone rotary rock bit

-first R&D lab specifically for rock bit analysis and performance

-first self-cleaning cones

-first hardfacing on roller cone bits

-first antifriction ball and roller bearing

-first and only Tricone drill bit

-first use of bit records

-first tungsten carbide insert (TCI) bits

-first surface-set diamond drill bit

-first effective self-lubricated sealed-bearing bit

-first oilfield impregnated diamond bits

-first steel tooth bit with an O-ring-sealed journal bearing

-first PDC diamond drill bits in the oil field

-first scoop-shaped chisel insert

-first thermally stable diamond bits

-first metal-sealed roller cone bit bearing

-first polished PDC cutters

-first PDC drillable casing bit system

-first drill-out ream-while-drilling tool

-first PDC cutters with greater impact and abrasion resistance

-first post-on-blade impregnated cutting-structure

-first depth-of-cut control technology.

Collaboration with INTEQ

INTEQ, a division of Baker Hughes, is a provider of advanced while-drilling technologies and services. Major capabilities include directional drilling, measurement-while-drilling (MWD), logging-while-drilling (LWD) and wellsite information management services. INTEQ, actively involved in the development of real-time software supporting its RigLinkSM service since 1998, is a founding member and active participant developing the WITSML Wellsite Information Transfer Standard Markup Language standard.

Close collaboration between INTEQ's drilling application engineers and Hughes Christensen bit design teams

produces high-performance bits matched to INTEQ's AutoTrak™ RCLS, the world's fastest and most precise rotary closed loop steerable system. This integrated approach enables drilling of a wide range of formation types at high ROP while maintaining accurate well placement with a smooth borehole that facilitates running casing. This total system approach optimizes drilling performance.

Unlike other rotary steerable tools, the AutoTrak system's steering mechanism is neither wholly push-the bit nor point-the bit technology. The mechanism used in all AutoTrak systems is described as a hybrid of push and point, alternating between the two as the well dictates. When initiating a change to wellbore trajectory—such as end of a tangent or commencing a 3D turn—the bit is pushed immediately to the side by applying precisely controlled continuous forces against the borehole wall in push-the-bit mode. Once a few feet of the new curvature is drilled, the steering mechanism is used to bend the bottomhole assembly into the new curvature and, effectively, point-the-bit mode in the direction to be steered. This hybrid approach provides more precise steering than pure point-the-bit systems while simultaneously providing better hole quality.

In multilateral wells, this hybrid steering principle also facilitates efficient and on-depth sidetracking operations. In terms of specific bit design requirements, AutoTrak systems do not require very short-gauge drill bits to steer to specification or ultralong gauge drill bits to provide superior hole quality. Very short-gauge bits deliver very poor hole quality and can be unstable, causing damage to the BHA and the borehole wall.

Similarly, very-long gauge bits can cause tripping problems and increase risk of well control problems because of swab and surge effects. The Hughes Christensen G1 gauge was designed specifically to optimize all aspects of performance, hole quality, steerability, and vibration control when used with the AutoTrak system's hybrid operating principle.

Another key advantage of the AutoTrak system is steerability, which is maintained independent of stick-slip vibration. Rotary steerables, which do not physically reference the steering vector to the borehole wall, lose steerability when stick-slip vibration is present. AutoTrak RCLS can steer challenging wells with confidence to TD. When vibration is anticipated, Hughes Christensen's patented EZSteer™ depth-of-cut control technology and/or the patented Lateral Movement Mitigator™ are included in the drill bit design. These engineered innovations reduce overall vibration, improving ROP and bit life in harsher drilling environments.

Downhole drilling dynamics are managed based on information from INTEQ's CoPilot™ service, which adds downhole WOB and torque on bit, BHA bending moment, and whirl and pressure diagnostics to the standard stick-slip and vibration measurements. This further enhances drilling performance, lowers operational risk, and improves overall borehole quality by allowing engineers to actively avoid potentially damaging, yet otherwise unseen, downhole events.

This all fits perfectly with INTEQ's Answers While Drilling℠ approach for delivering fast and accurate well placement, enhanced drilling efficiency, and maximum recovery.

A continuing commitment

The Hughes Christensen and INTEQ steadfast commitment to the Kingdom of Saudi Arabia is to deliver total drilling system reliability and predictable performance in One Fast Run™. This results in easier steerability and less stress on the drilling system. With this in mind, the two companies—working side-by-side with Saudi Aramco—are striving to deliver even greater performance that continues to reduce the drilling cost-per-foot with the fewest bits per interval.

GEOSTEERING SERVICES

People, planning, and technology.
Solutions for better real-time decisions.

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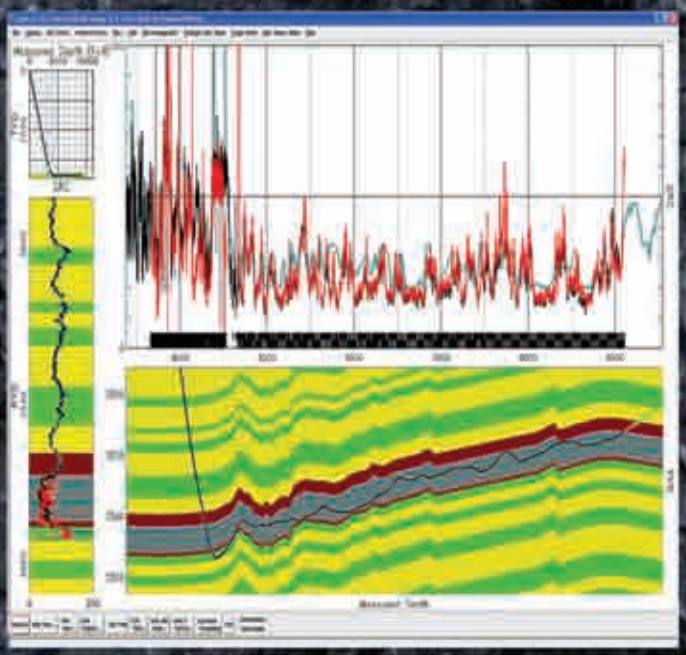

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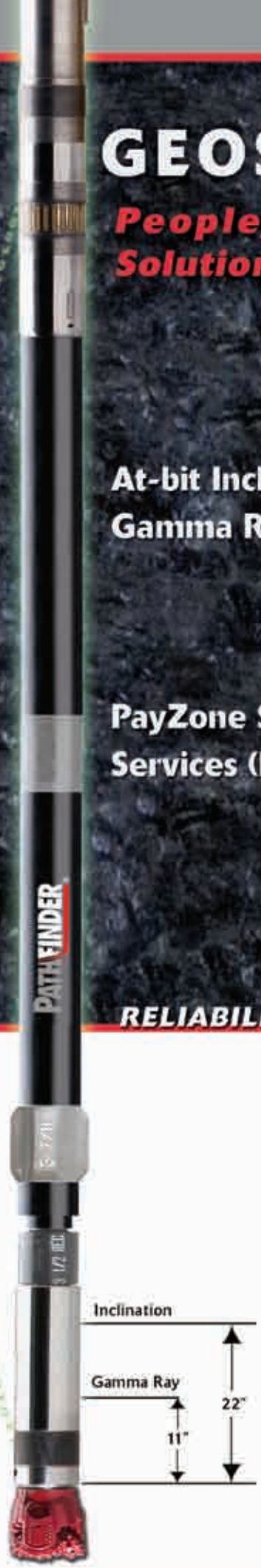

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LWD Geosteering and Natural Fracture Identification in Horizontal Wells in Unconventional Reservoirs

By Greg Meszaros and Paul Boonen, PathFinder Energy Services

Coal Bed Methane (CBM) production has grown from about 200 BCF per year in 1990 to close to 1800 BCF in 2005. The success of the Barnett shale play, in the making for the past 20 years, has spawned new or renewed interest in a number of similar shale plays such as the Fayetteville and Moore field shales, the Bakken shale play and the Woodford, Floyd, New Albany and Antrim shales amongst others. Naturally-fractured carbonates such as the Ellenberger can be produced as long as horizontal wells can be drilled to intersect as many fractures as possible. Heavy oil reservoirs are produced using multiple horizontal wells or typically using twinned well pairs and Steam Assisted Gravity Drainage (SAGD). All of these reservoir types can be considered to be "unconventional reservoirs".

Whatever the nature is of an "unconventional hydrocarbon resource" or however we define "unconventional reservoirs," one thing they seem to have in common besides a requirement for high oil and gas prices, is that they need advanced technology to be drilled and produced. Horizontal well drilling is one of the prime technologies to access these reservoirs. High angle/horizontal well drilling relates in turn directly to applications of LWD technology. Tools like 3-D Rotary Steerable Systems (RSS) and formation evaluation LWD tools are now being used in onshore drilling to position the borehole in the reservoir and to provide the necessary reservoir data. This has become economically feasible in a high priced oil and gas environment because their relative cost to the total well cost has decreased.

We concentrate in this article on a few applications of LWD tools in horizontal wells in unconventional reservoirs such as the use of at-bit measurements for real-time geosteering in CBM wells and the use of sonic logs for fracture identification in limestone reservoirs.

MWD At-Bit Gamma Ray And Inclination Measurement

An at-bit tool operates directly above the drill bit to provide real-time dynamic inclination and gamma ray measurements. The tool is designed to operate as two separate subs. Data are transferred from the at-bit sensors in the lower sub to the upper sub via an electromagnetic frequency. This allows it to operate with positive displacement motors or 3-D RSS. The upper sub is connected to the M/LWD system which in turn allows the addition of any LWD tools. The combination of continuous, dynamic inclination and gamma ray at-bit provides the data to determine well path placement and bit position while drilling. It is the combination of both at-bit inclination and at-bit gamma ray that makes this tool unique. The at-bit gamma ray and inclination sensors are offset 11-in. and 22-in., respectively, from the bit.

By providing immediate lithology and inclination data, the at-bit sensors assist in landing high angle/horizontal wells and optimize well bore position. The at-bit gamma ray is an excellent correlation tool by detecting formation changes at the bit. The at-bit inclination allows the directional driller to drill a smoother well path with reduced

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tortuosity and dogleg severity. Geosteering becomes more accurate and effective by measuring and recognizing the changing conditions that may affect the well trajectory at the bit.

Geosteering

Geosteering integrates MWD / LWD sensors, forward-modeling software, and the expertise of a highly trained geosteering specialist (Jackson, 1997). Geosteering specialists have the training and expertise to interpret all aspects of the drilling and logging operations to steer the well bore.

The first process in a geosteering project is to create a geological earth model derived from basic geologic information and logging data obtained from offset wells. Offset well resistivity data are used to create a true resistivity (Rt) profile. A 'geologic roadmap' is created utilizing offset well data, the proposed well plan and the modeled response from the gamma ray, resistivity, and density-neutron tools. The resistivity tool response is predicted using a forward model (Jackson et al., 1995). This roadmap is then adjusted as the well is drilled, using the actual trajectory. The geologic model is calibrated as the selected formation markers are encountered while drilling. Depth shifts, bed dip changes, and faults can be added to reconcile the real-time log with the geologic model. This allows the geosteering specialist to forward-model the logging response and to predict the formation in front of the bit in order to steer the well bore geologically, relative to the well plan.

Coalbed Methane Horizontal Well Positioning

At-bit sensors have found a niche in the CBM markets of North America, including the San Juan, Arkoma, and Powder River Basins. The integration of at-bit sensors and forward-modeling software has proven to be an ideal match for the nature of CBM horizontal well drilling.

There are a number of reasons why horizontal wells are important in CBM drilling (Maricic et al, 2006). The direction, shape and position of a horizontal well can be controlled so that an almost ideal well position can be achieved. Proper well positioning and borehole length contribute to draining large areas. Drilling horizontal wells is also very important for sweep efficiency. Increasing contact with the coal in longer boreholes, decreases the time for water production and gas flow peak will occur sooner after the well starts producing. Horizontal CBM wells can realize a 10 to 1 increase in production over vertical wells drilled into the same coal seam.

Coalbed Methane Horizontal Well Examples

The following examples show the results of an aggressive CBM drilling program. The drilling program rapidly increased with the success achieved by shifting the drilling focus from vertical wells to horizontal, in order to expose more of the coal seam to the well bore. The horizontal drilling program progressed by moving from drilling with (1) an MWD gamma ray service to (2) utilizing at-bit gamma ray and inclination measurements to (3) utilizing at-bit measurements, LWD resistivity, and forward-modeling software.

Figures 1 to 3 are illustrations of the pre-well modeling and real-time geosteering software screen. The top left panel shows an overview of the well plan and the geological model. The bottom left panel contains the offset well data represented on a true vertical depth scale. RVD is the reference (for offset well) vertical depth. The top right panel displays the modeled and measured log data. This can be the gamma ray only (cyan = model, black =

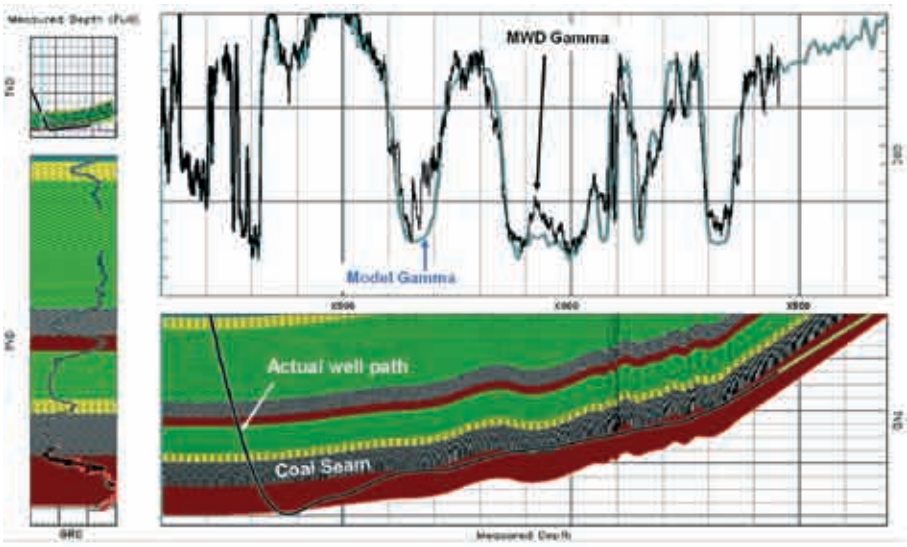

Figure 1 - Post well model of CBM horizontal well drilled with MWD gamma ray. (Vertical Scale Exaggerated)

measured) as in the first example. In the second example a modeled resistivity was added. The green blocky curve is the offset well true resistivity modeled along the proposed well plan. The four colored resistivity curves are the forward modeled resistivities for the particular LWD resistivity tool. In the last example, where a resistivity tool was run, the image also includes the measured resistivity data. The bottom left panel shows the well path progression in the geological model. It is in this panel that the geosteering specialist modifies the geological model by changing formation dips or adding faults to match the predicted log data to the real-time log data.

Figure 1 is an example of a horizontal CBM well drilled with MWD gamma ray only, but without real-time forward-modeling software. The model below was constructed after drilling. The coal seam was encountered shallower than expected and the landing point of the planned horizontal well was too deep. From the landing point to total depth of the lateral section, the well was drilled up dip attempting to re-enter the coal seam. The model and log data show that this well penetrated only the bottom of the coal seam approximately 30% of the lateral section.

Figure 2 is an example of a horizontal CBM well drilled with at-bit gamma ray and inclination measurements, but without real-time forward-modeling software. The model below was constructed after drilling. The coal seam was encountered shallower than expected and the landing point of the planned horizontal well was too deep. From the landing point, the well was steered up to 95.0° inclination to re-enter the coal seam. The amount of section lost in zone, due to missing the landing point, was approximately 25% of the total lateral section. Once the well was back in zone, drilling continued at 90°-91° inclination. Without real-time modeling, it was unknown that the bed dip had changed and was now down dip, while drilling continued slightly up dip. The well exited the top of the coal seam and never re-entered before drilling to total depth. The model and log data show that this well was drilled in zone approximately 50% of the lateral section.

Figure 3 is an example of a horizontal CBM well drilled with at-bit measurements, LWD resistivity, and real-time geosteering. Detailed pre-well modeling was prepared in addition to real-time modeling while drilling. The model below was constructed while drilling. The coal seam was encountered deeper than expected, however this was predicted by the on-site geosteering specialist utilizing the forward-modeling software, and the landing point of the planned horizontal well was adjusted. The geosteering model was adjusted to the real-time at-bit and LWD resistivity data while drilling. Prior to reaching total depth of the lateral section, the real-time model predicted that the bed dip was changing and would begin to dip steeply upwards. The client chose not to follow the bed dip any further, because the achieved horizontal section had already exceeded the client's expectations for this well. The client did want confirmation that the model was correct and drilling continued until the at-bit gamma ray showed that the well had exited the bottom of the coal seam. This confirmed the bed dip change predicted by the model. The complete geosteering service was successful in steering the well in zone for 100% of the lateral section.

Natural Fracture Identification Using Sonic Logs

Full waveform acoustic logging tools record the sonic energy received at an array of receivers over a certain period of time. Unlike conventional acoustic tools that measure only the first arrival of the compressional wave, waveform recording tools offer the opportunity to compute arrival times of compressional, shear and Stoneley waves and to determine the relative amplitudes of the different arrivals.

A plot of the raw waveform can be an excellent fracture indicator. Fractures are indicated by the following combination of features:

- No major change in the arrival time of the compressional and shear waves
- Minor to no attenuation of the compressional waves
- Strong attenuation of shear waves
- Strong attenuation of the Stoneley waves

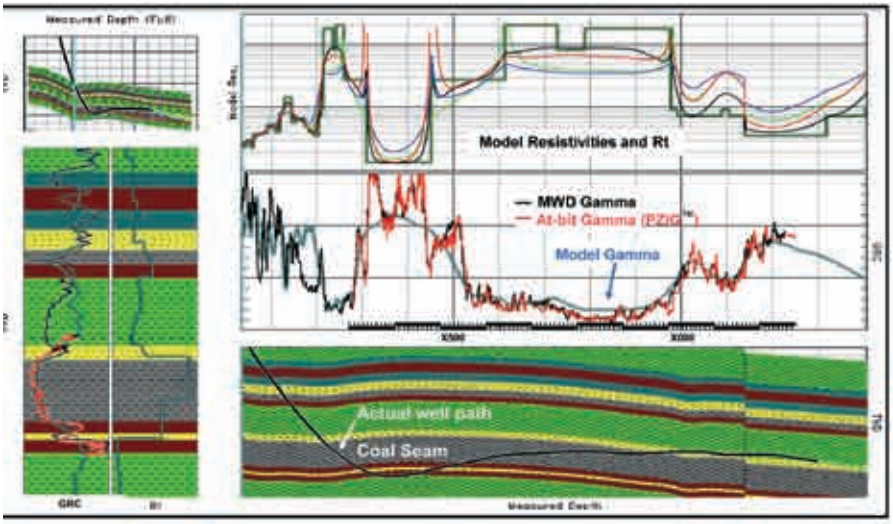

Figure 2 - Post well model of CBM horizontal well drilled with at-bit measurements. (Vertical Scale Exaggerated)

Lithology changes and particularly shale beds may show similar attenuation patterns; therefore a gamma ray curve or another shale indicator should be included to identify such shale beds. Washed out zones may also have a similar effect on the waveforms. A caliper curve should be included in the plot to check for hole enlargement. However, borehole washout is often a result of the presence of natural fractures and the caliper logs should be examined carefully. Formation gas may attenuate the compressional wave, but it does not affect the shear wave. Fluids do not support a shear wave. Hence a fluid (gas) independent porosity can be computed from the shear wave.

LWD sonic tools were introduced in the mid 1990's (Minear et al. 1995). Due to the harsh drilling environment in which LWD tools must operate, LWD sonic waveforms typically are quite noisy as compared to wireline waveforms. They also typically contain tool mode arrivals so that the effects of the presence of fractures may be difficult to interpret using the raw waveforms. A processing technique called Instantaneous Waveform Characteristics is used to enhance the fracture identification capabilities.

Instantaneous Waveform Characteristics (IWC)

Instantaneous Waveform Characteristics (IWC) processing is an application of Complex Trace Analysis (Taner et al, 1976) to acoustic waveforms recorded using a full waveform type of sonic logging tool (Knize and Patton, 1989, Boonen and Flowers, 1996). IWC processing applies a Hilbert transform to the acoustic waveform to separate energy and phase information. An IWC log provides a means of viewing acoustic waveforms in a new way. One of the main advantages of IWC processing is its ability to separate magnitude from phase and frequency. We are now able to look at the energy (magnitude) and energy changes with depth independently from phase changes.

The instantaneous magnitude of amplitude is the portion of the emitted signal that is transmitted through the formation to reach the receiver. It is called the sonic transmissivity of the formation and is defined as the envelope of a complex acoustic response to the formation. The sonic transmissivity is a direct measurement of the attenuation of acoustic energy within the formation. Any structural changes causing absorption or dispersion of the acoustic energy will affect the transmissivity. In particular, shear and Stoneley transmissivity will be lower in the presence of fractures.

The instantaneous phase emphasizes the continuity of acoustic events through the formation. The phase log reveals formation boundaries and their apparent dips, geological discontinuities, like faults and fractures, and broken or hydro-fractured formation as oblique events, splits of phase lines, and irregular patterns. The instantaneous phase is sensitive to effects of formation absorption and dispersion, to the scattering due to structural irregularities and to transitional acoustic impedance changes. It is an effective indicator of fractured zones.

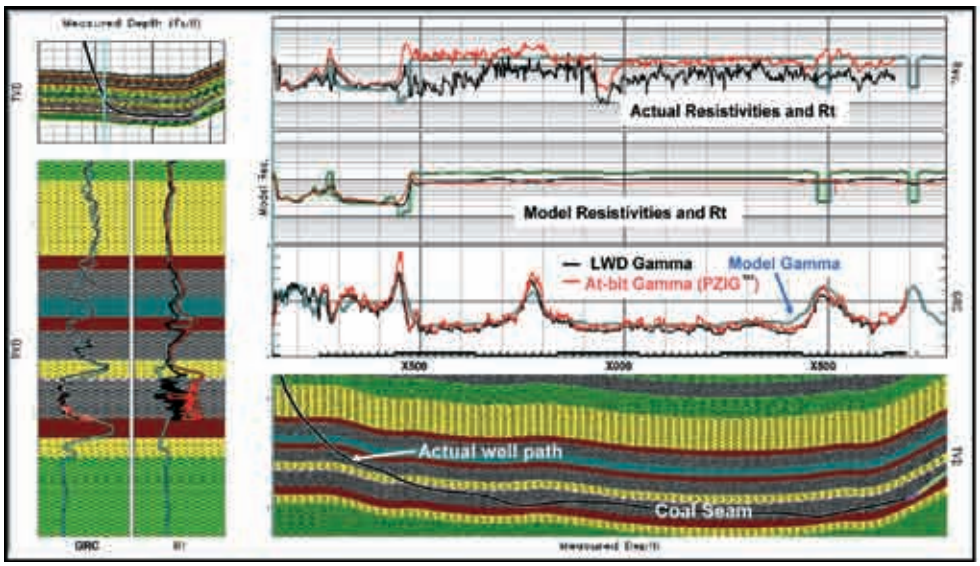

Figure 3 - Real-time model of CBM horizontal well drilled with at-bit measurements, LWD resistivity, and forward-modeling software. (Vertical Scale Exaggerated)

Figure 4 is an example of an instantaneous transmissivity and phase plot from LWD sonic waveforms recorded in a horizontal well in a fractured carbonate reservoir. On the transmissivity plot, the compressional wave shows up as the faint blue colored arrivals at about 200 microseconds. The shear wave is represented by the blue-green colors around 400 microseconds. The Stoneley wave energy is indicated by the red arrivals (high energy). Fractures are indicated by the loss of shear and especially Stoneley en¬ergy from x70 to x75 ft, x135 ft to x145 ft and x150 ft to x157 ft. At the same depth levels, the phase plot shows marked disruptions in the phases.

Maximum Stoneley Energy

The maximum Stoneley energy curve (Figure 4, track 1) represents the relative attenuation of the Stoneley wave computed across the Stoneley arrival window. In a similar way, a maximum shear energy could be computed. It appears however that the Stoneley wave energy responds better to fractures. Strong attenuation (low energy) relates to fractured zones. This computation provides a fracture identification curve as compared to a qualitative transmissivity image. The curve can easily be correlated to other log data.

Applications

It is important to remember that the sonic waveforms respond in this manner only to open (fluid filled) fractures.

The interpretation is also qualitative. The sonic energy will be attenuated in the same way by one major fracture as by multiple small fractures. The fractures need to occupy a considerable part of the circumference of the borehole. A vertical fracture in a vertical borehole will probably not be detected, whereas vertical or highly dipping fractures in a horizontal section will cause the sonic energy be strongly attenuated.

Very often these fractured carbonates need to be stimulated to attain economic production. The acid can be spotted across zones of interest indicated by the logs. The IWC logs have been used to design multiple acid fracturing jobs. The packers are set in more competent rock for better seal and the fracturing ports are positioned across fractured zones where the intent is not to create new fractures but to enhance the existing fracture system.

Conclusions

Successful introduction of an at-bit gamma ray and inclination measurement tool has greatly enhanced geosteering capabilities. The combination of continuous, dynamic inclination and gamma ray at-bit provides greater directional control and confidence in geosteering complex sections. This unique tool accurately determines well path placement and bit position while drilling. Integrating these at-bit measurements with LWD data and real-time forward-modeling software is an essential component in any geosteering project.

> A series of three examples of geosteering in coalbed methane horizontal wells shows the importance of integrating at bit measurements with pre-well modeling and real-time geosteering.

A series of three examples of geosteering in coalbed methane horizontal wells shows the importance of integrating at bit measurements with pre-well modeling and real-time geosteering. The exposure to the target coal bed increased from 30% of the horizontal section in a well where neither at-bit tools nor steering was used, to 50 % where the at-bit tools were used but without real-time modeling, to 100% exposure where the entire geosteering service was used.

Sonic logs have been shown to effectively identify fractured zones in carbonates. The introduction of LWD sonic tools, made this analysis available to the LWD market. Instantaneous Waveform Characteristics processing enhances this open fracture identification process. The analysis has been used to design well completions and acid fracturing operations.

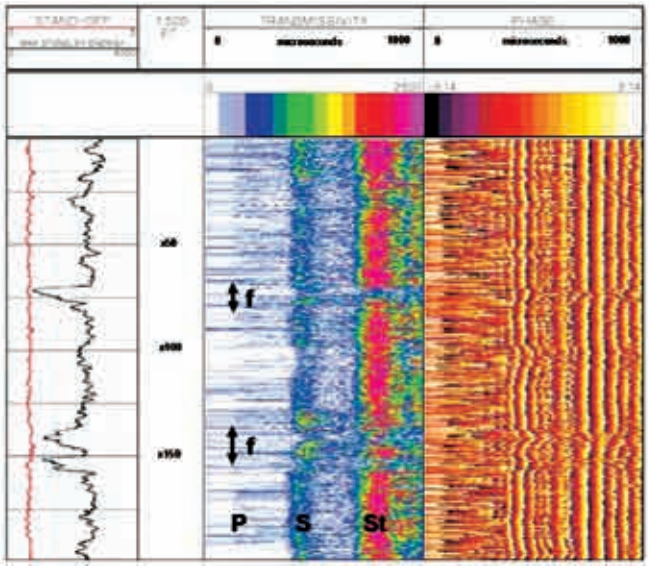

Figure 4 - Instantaneous transmissivity and phase plot.

LWD Acoustic Measure for Varying Drilling Co

By John Moore, Vladimir Dubinsky, SPE, Charles Harrison, SPE, Chen Li, Baker Hughes INTEQ

Introduction

One of the main challenges in logging-while-drilling (LWD) acoustics, as compared to wireline logging, is the ability to reliably measure compressional and shear-wave velocities in the drilling environment. Many of the LWD acoustic measurements principles were transposed from wireline acoustic logging, which has been a mature technology for many years. Over the past several years, LWD acoustics accumulated significant theoretical knowledge and practical experience, and it made a tremendous progress in delivering better data quality to the clients[1,2,3]. Wireline acoustic technology sets a benchmark for the expected quality of the LWD acoustic measurements in various environments. As a result, oil and gas production companies naturally extended these expectations to the LWD acoustic services. Although LWD acoustics is still a not fully mature technology, it has been developing rapidly for the last several years. The requirements for the LWD measurement pose serious challenges for the near-future development. Although the real-time LWD compressional measurement has now become a reality, some of these measurements can still be qualified as pseudo-real-time measurements because they require certain human interaction in the post-processing of the data recorded and stored in the LWD acoustic tool memory [1,2,3].

The most common sources and types of noise in LWD acoustic measurements include the following:

• Noise components generated by the working drill bit that propagate along the borehole to the tool receivers via the formation, drilling mud, and directly through the drill collar, and experience multiple reflections due to the presence of various abnormalities along the propagation path. The primary frequency band for such drilling noise is from a few hertz up to about 2 kHz, with some smaller spectral components extended to several kHz [2,3,6].

• Noise that is produced due to the drilling mud circulation and local cavitations occurring near the tool. Frequency band of this kind of noise spreads out to higher frequencies – up to several kHz, and is usually random and non-stationary in its nature.

• Active acoustic source that generates the informative signals of interest (formation compressional and shear waves), which propagate through the formation, as well as noise components, such as the "tool mode" (part of the source energy coupled directly through the collar) and the tube or Stoneley wave (propagate via drilling mud inside the drill collar and in the annulus).

Proper tool design (e.g., presence of the mechanical acoustic isolator in the collar section between the source and receivers, good acoustic decoupling of the source and receivers from the collar, etc.) and firing the source at the most suitable frequencies and modes for particular measurements (up to 15 kHz for Monopole, and 1-3 kHz for Quadrupole) ensure efficient dampening and minimal interference of these detrimental noise components with the signals of interest. However, some external factors associated with the drilling dynamics may artificially induce stronger acoustic noise, and these factors are sometimes beyond the driller's control. Examples of these are: (1) eccentricity of the tool within the borehole, especially for highly inclined or horizontal wells, (2) titling of the tool axis relative to the borehole axis, and (3) severe axial and lateral vibrations that could come to an extreme in certain operational conditions. In these cases, the desired dampening and attenuation of the noise components might not be achieved, and the S/N ratio becomes worse. A remaining resource in such situations is the use of effective signal processing techniques. These processing techniques can be logically grouped into two main categories: those that enhance the signal of interest, and those that dampen the noise. Both result in improved S/N ratios, and therefore, more reliable measurements of the rock acoustic velocities. In our efforts to utilize this resource, we considered, developed and tried several alternative approaches, but in this paper we present just the most promising ones.

ments Enhancements nditions

Enhancing Formation Signal of Interest

The method, which we consider the most successful in the first category, is an advanced stacking process that we call "Rotary Stacking". Acquiring and averaging (stacking) multiple signals representing the same event of interest is a very common method for signal-to-noise enhancement. In cases where noise levels are high, multiple sensors are also often utilized to further increase the number samples sets to be stacked. Using these methods as a basis, we took a step forward by offering the Rotary Stacking technique. It is an alternative to the traditional method performed by conventional Delta-T processing – such as stacking, peak identification, semblance analysis, and processing technique selection.

Rotary Stacking Methodology

Fundamental to the Rotary Stacking methodology is the preservation of out-of-phase columnar data. Rather than combining the columns into one, this process maintains intermediate processed data as separate columnar arrays only to be merged after they are transformed, near the end of processing. For brevity, the data shall be assumed to be acquired by a four-column multi-row array of sensors. Sensor arrangements involving a lesser number of columns will often need to consider additional techniques to "bin" the data, which is beyond the scope of this paper. It shall also be assumed that more than one data set has been acquired in order to stack and enhance the data.

The process begins by cross-correlating the first two acquired data sets to find the optimum stacking orientation. With four columns of sensors implemented around the circumference of tool at equal intervals, a single row would appear as shown in Figure 1a. Since the tool will have often rotated in the borehole as shown in Figure 1b, one can observe that the same sensors will no longer be at the same distance from the nearby wall. If this distance is significant enough to cause a moderate to large phase delay in the arrival of the desired signal, then it is

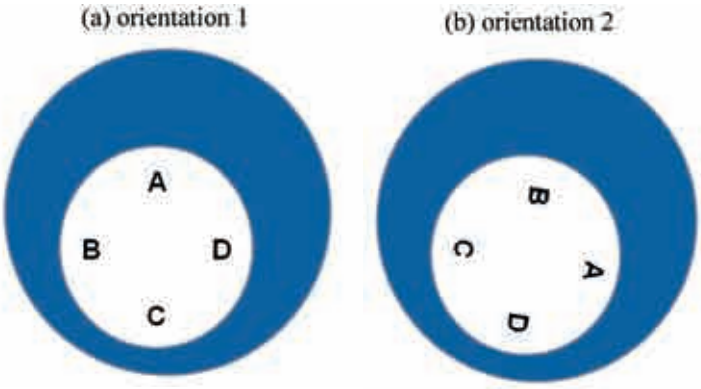

Figure 1 - Example of sensor orientations (a) and (b) and tool eccentricity in varying conditions while drilling.

beneficial to keep the waveforms separate – segregated by phase delay rather than sensor position. There can be other causes as to non-uniformity of the phase relation of acquired signals, but this process simply accommodates the phase disparity – regardless of the cause. Thus, when stacking two data sets together, the columns are correlated in multiple orientations, selecting the orientation with highest correlation value. There are 24 possible orientations (permutations) when stacking two data sets containing four columns of sensor data, but the alignments most frequently selected involve simple rotations of the four columns. In fact, early explorations of this process originally started with just the four basic rotations shown below – hence the name: Rotary Stacking.

	Orientation	Col	Col	Col	Col
Data Set1:		A	B	C	D
Data Set2:	1	A	B	C	D
	2	D	A	B	C
	3	C	D	A	B
	4	B	C	D	A

Also, the correlation formula often used for this process is shown in Equation 1:

$$C = \frac{\sum (A_i + B_i)^2}{2 \cdot \sum (A_i^2 + B_i^2)}$$

where C = correlation value, and A and B are two waveforms to be correlated.

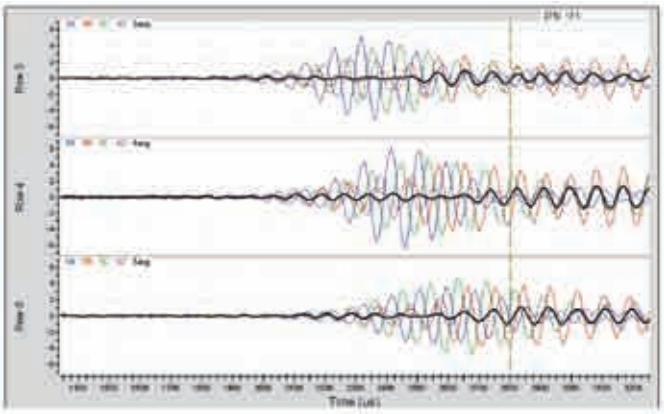

Figure 2 - Single Monopole raw waveforms.

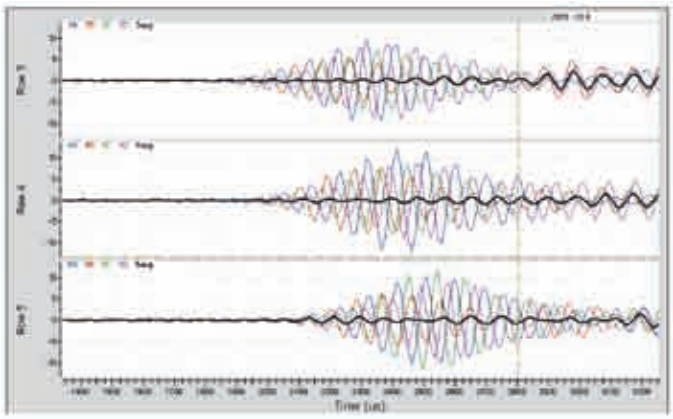

Figure 3 - Conventional and Rotary Stacked Monopole waveforms.

Once the optimum orientation has been determined, the two data sets are stacked together, producing a resultant set that contains as many columns and rows as there are in either of the two input sets. This process continues with each acquired data set being cross-correlated and stacked with the resultant set from the previous iteration. A potential by-product of this process is RPM, but this topic and related issues are not explored here. Once the data has been stacked into rows per column, the data is then processed through any conventional Delta-T processing method to produce one correlation map per column.

Another innovation found to be beneficial is the method for processing and combining the results of these correlation maps. Instead of searching each map individually for peaks in the conventional way, and then using any of a number of techniques to select and/or interpolate the dominant peak, these maps are simply stacked together into one map, as shown later. From this final correlation map, standard peak searching algorithms can be used to find the optimal answer.

Results using Field Data

Rotary stacking requires raw data sets of enormous size, which are currently unavailable. However, periodically sampled raw sets are occasionally available and one shall be utilized here. Presentation shall begin with a sample raw waveform and after some intermediate steps, a log will be shown. Additionally, a sequence of waveforms will be shown which demonstrate the visible affects of rotation on the phase relation of the columnar data.

The actual field data that we use for demonstrating the Rotary Stacking method in this paper represents a well located in the deep water Gulf of Mexico. We collected two primary sets of measurements: High Frequency (HF) Monopole, and Low Frequency (LF) Quadrupole. The borehole logged was drilled with a 17 ½-in. PDC bit and a 9 ½-in. BHA. No centralizers were installed in the BHA, which will allow for extreme BHA decentralization (up to 8 in.) in this vertically drilled borehole (1.1 deg. maximum). It made this data set a suitable example for testing Rotary Stacking and demonstrating its efficiency. Specifically, we used HF Monopole data acquired in this well.

A synthetic oil-based mud was used as the drilling fluid, with the density range 11-13 PPG. The penetrated formation consisted of primarily unconsolidated sands and shales (intermediate to slow velocity formations). The data acquisition consisted of recording a number of raw shots fired every few minutes of drilling, which is a subset of the standard stacked shots.

Waveform

In Figure 2, three rows of a raw waveform set are shown. Note that scaling has been adjusted for each row, so that the peak of the average wave form is 1.0 – based on the maximum peak values prior to 2800us (micro-seconds) and denoted by a vertical dashed line. This time period was chosen to allow more direct comparison of the waveforms in the vicinity of the desired signal. All waveforms per row have been scaled by the same factor, but each row's factor may be different. Note that the raw waveforms are significantly higher in amplitude than the combined average.

Figure 3 is the stacked version from the same wave set as that of the waveforms in Figure 2. Rotary stacking has been utilized and the column orders may have changed. Again, the values have been scaled so that the highest peak of the average waveform (in black) has a value of one. The difference between the four rotary waveforms (one per original column) and the conventionally stacked waveform has increased further. By inspection, one can

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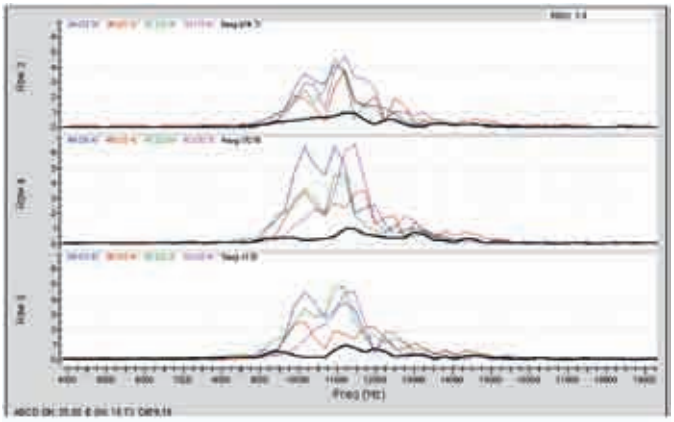

Figure 4 - Frequency spectrum of conventional (avg) and rotary stacked data.

see that the average increase is approximately 8X or 18dB. However, since each column's waveform was derived by summing ¼ of the total waveforms acquired per row, each should statistically have twice as much noise. Thus the net signal-to-noise improvement on this particular example estimates to be 4X or 12dB.

Frequency

Figure 4 shows the frequency spectrum of the same wave set shown in Figure 3. It was computed by FFT, and the magnitudes have all been scaled so that the peak magnitude of the "average" waveform is one. The number in parentheses next to each label represents a crude signal-to-noise ratio estimate (in decibels) calculated by dividing the in-band frequency energy by the out-of-band frequency energy and converting the result to decibels. In-band frequencies are defined as those within 20% of the generated signal's frequency. Out-of-band frequencies are all other frequencies produced by the FFT that are not within the in-band range. The averages of this approximate signal-to-noise ratio for all columns and rows is shown at the bottom of the graph, with the difference between the rotary stacked data and the conventionally stacked data being shown as 9.16dB.

Correlation Maps

In Figures 5a and 5b, correlation maps from the same waveform sets shown in Figures 2 and 3 are provided. While the actual formulation is proprietary, the same process and settings were used to produce each map. Below each map is a plot of the maximum correlation value for each Delta-T slowness value. The conventional map contains several potential peaks, with the highest one having a value of 140us/ft and a correlation of 0.62. The rotary map contains only two peaks with one being substantially larger than the other. The higher peak has a value of 126us/ft and correlation of 0.91. The red diagonal line represents the acquisition systems' theoretical response, or "tool line".

Delta-T Log

Due to the sparseness of data, the Delta-T Log in Figure 6 is shown in "dot" form. It contains the side-by-side plots of Delta-T values computed first conventionally, and then using rotary stacking. Also included are the correlation values, which are often used as a quality check (QC). In general, the rotary computed Delta-T shows significant improvement in consistency.

Figure 7 is a close up of one of the dense data regions at a depth D1. Although the data is plotted according to its depth along the X-axis, each point is connected to the next point in time order using a line segment. This type of plotting is useful in showing depth retracements which are occurring very frequently in this region. Since the same base data is used to derive these plots, each section contains the same number of points spaced exactly the same along the X-axis. Thus, looking at the numerous retracements occurring in the D1-D2 depth range, the repeatability of rotary in both sections of B is superior to conventional processing (Note: a spike removal process was used on both data sets to remove the errant data points that are visible in this region on Figure 6).

Observed Rotation

On rare occasions, when the RPM and circumstances are such that the columns are rotating at certain ratios relative to the firing rate, clear evidence of the rotation can be observed. Shown in Figure 8 is a consecutive sequence of waveforms whose characteristics are trading positions in a predictable manner (a through e). For example, the progression of the largest amplitude waveform in Figure 8a, which is column D, can be traced through the five wave sets as D → C → B → A → D. Each transition represents a three-column shift or 270 degrees of rotation. The other lesser amplitude waveforms follow the same sequence as well.

Dampening Noise with Identifiable Pattern

In the second category of processing techniques–those that mainly deal with rejecting the noise that has a somewhat repeatable pattern (e.g., a common mode noise, such as the "tool mode" or tube / Stoneley wave)—we would like to present two approaches: Adaptive Filter (AF) and Frequency–Wave Number (FK) Filter. Even though the basic idea of a generic Adaptive Filter is not a new one and is presented in numerous publications, we offer a special configuration and implementation that makes it practical and efficient for borehole acoustics applications.

Adaptive Filter

The fundamental concept of the Adaptive Filter for borehole acoustic applications is initially presented by Dubin-

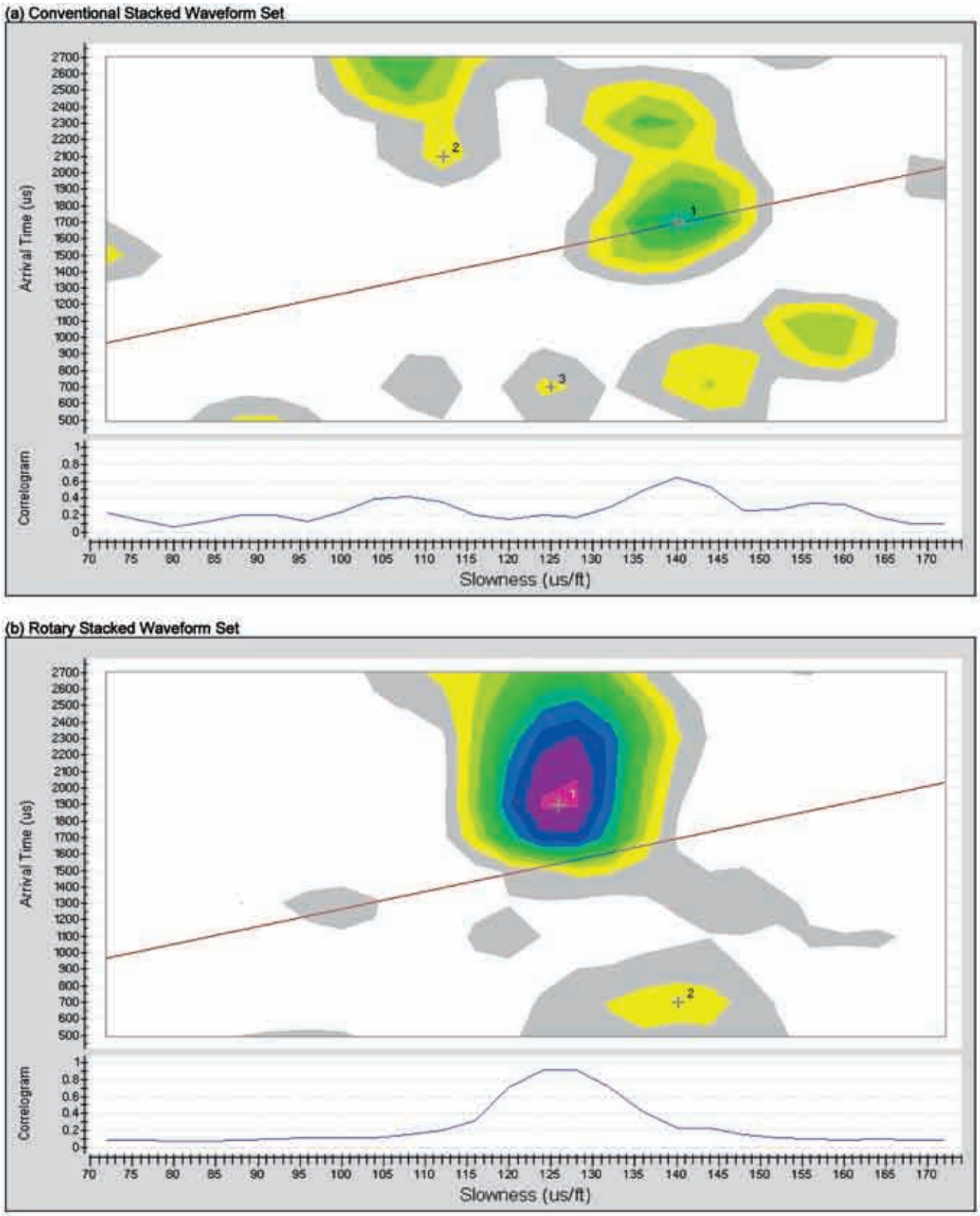

Figure 5 - Correlation Maps processed by (a) Conventional methods and (b) Rotary stacking, same data set. The red diagonal line represents the "tool line".

sky in the US Patent [7]. The key premise for this approach is that we have a somewhat repeatable noise patent across the entire data set, or at least within certain time/depth intervals of the processed data. If this noise pattern or a signal that is strongly correlated with this pattern can be either measured by a special reference sensor (e.g., an accelerometer) or identified and separated by other means from the mixture of the signal and noise, then this technique becomes potentially applicable.

To better present the core idea of the Adaptive Filter with a reference signal, let us consider a principal block diagram for its implementation. Figure 9 schematically shows a borehole tool located within a fluid-filled bore-

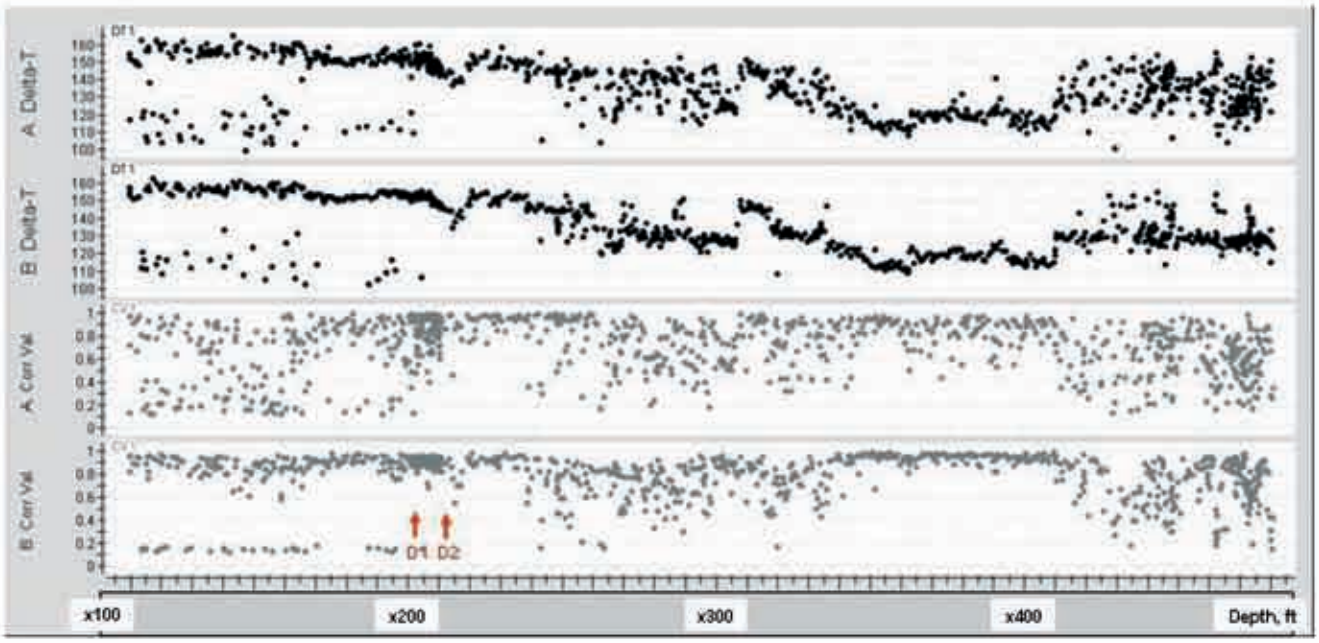

Figure 6 - Log of Delta-T and correlation values. "A. Delta-T"- conventional stacking; "B. Delta-T" - rotary stacking [us/ft] A & B Correlation Values represent conventional and rotary stacking, respectively.

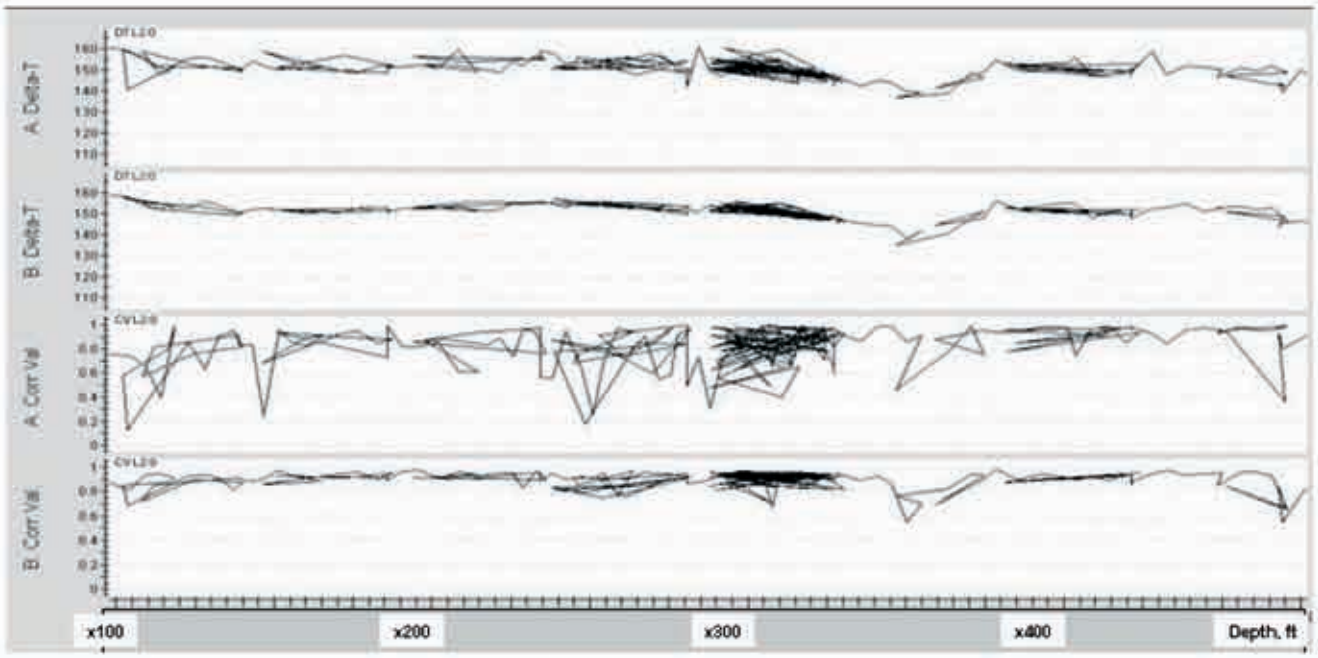

Figure 7 - Zoomed in section of the log, using "time-line" format (points connected in time order). "A" sections - conventional, "B" sections - rotary.

hole. As mentioned above, when the acoustic source generates a signal, it propagates through the formation (Formation Wave - an informative portion) and through the drill collar (Tool Mode – detrimental noise component). Receivers placed on and along the drill collar as an axial array of hydrophones sense both the Formation Wave refracted from the formation via the mud and the Tool Mode that propagates directly via the collar and couples to the hydrophones. As a result, the signal that reaches each receiver is a mixture of the informative and noise components. When the signal of interest dominates, there is no problem with extracting the desired value of formation velocity from the measurements. However, if a strong tool mode or other noticeable common mode noise components are present in the acquired signal, the quality of these measurements can be adversely affected. Numerous attempts undertaken by different researches to directly subtract the noise component from the Signal-Noise mixture have often failed because the combined signal is usually not just an algebraic sum of two independent components – Signal and Noise, but rather a complicated mixture of the two. This is why we have

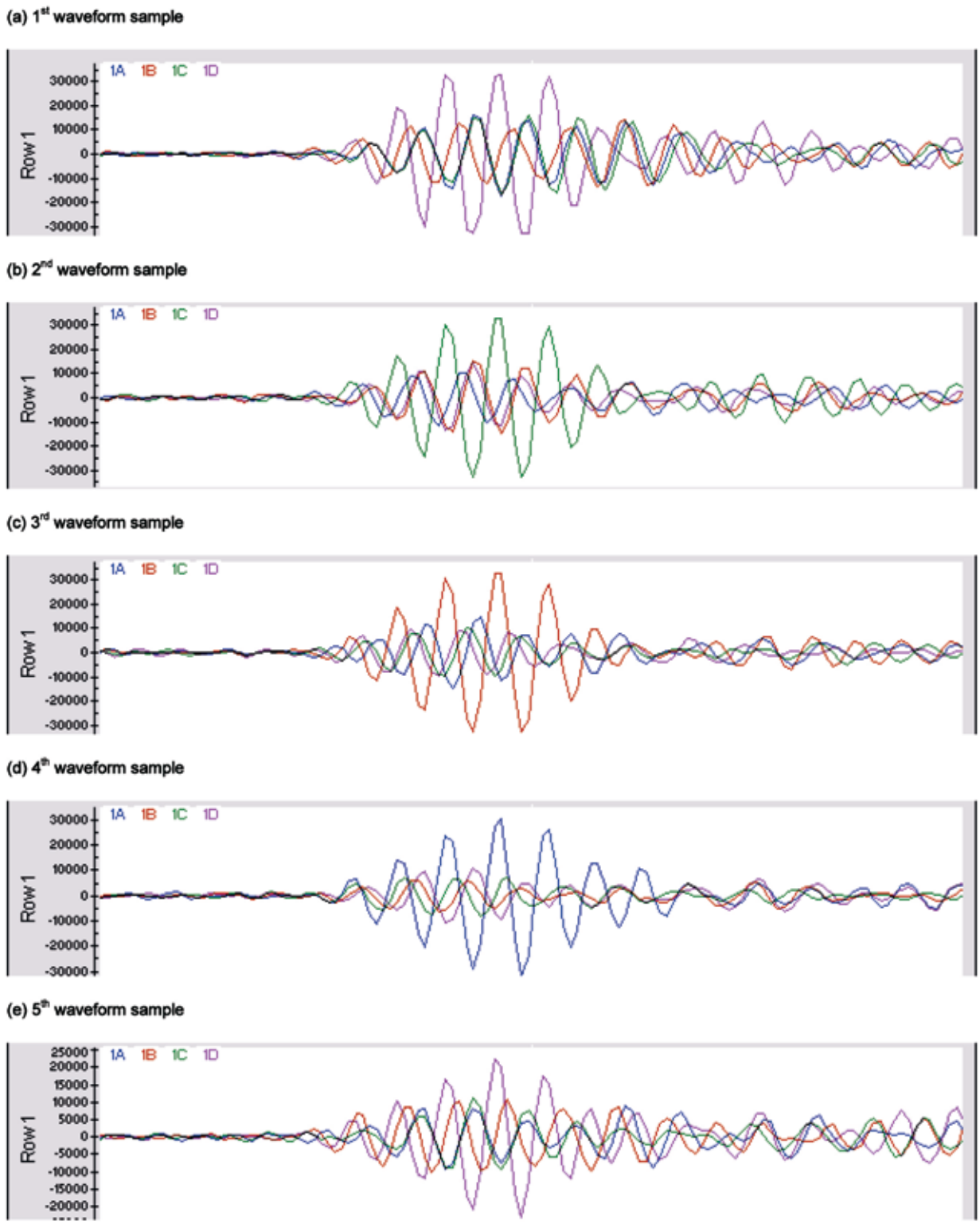

Figure 8 - Five consecutive time samples of waveforms (a, b, c, d, and e) from the same row showing evidence of rotation.

chosen a different route, and instead of direct subtraction we suggest the following approach:

Let's denote the accelerometer signal as $A(j\omega)$, a hydrophone signal as $H(j\omega)$. The tool mode will be a primary signal acquired by both the accelerometer and a hydrophone (prior to fluid arrival). The complex transfer function between the accelerometer and a hydrophone $Tah(j\omega)$, which takes into account both phase and amplitude characteristics of the signals, can be directly calculated from these measurements[7] in a calibration test setting.

In the real borehole environment, the hydrophone signal $H(j\omega)^*$ contains several wave components, e.g., the formation arrival (informative signal), tool body wave,

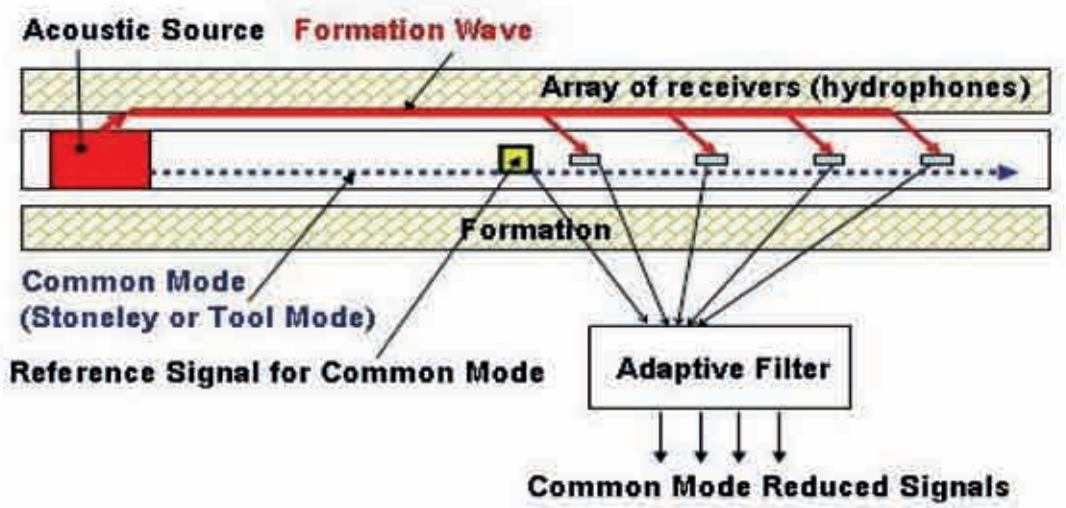

Figure 9 - Block-diagram of Adaptive Filter with a Reference Signal.

tube wave, etc. The accelerometer signal A(jω)* primarily contains the body wave. In addition, the source signature may somewhat change in the real borehole versus the one during a calibration test. However, the transfer function between the accelerometer and hydrophone usually remains the same or undertakes some insignificant changes.

To filter out the tool mode component from the hydrophone signal, the following is suggested:

$$\text{Tool Mode Reduced Signal} = H(j\omega)^* - A(j\omega)^* \times Tah(j\omega) \quad (2)$$

In our algorithms, we also perform a validation of how strong the correlation between the primary (reference) signal and its "ghost" in the hydrophone signal is, by rejecting the samples with correlation values below a predetermined threshold. Straightforward practical implementation of this approach, however, is limited due to a required hardware modification of the tool, and it might mean introduction of multiple accelerometers to the tool for generating a few reference signals at different locations for a better noise pattern identification. We found a more suitable and practical solution that does not require hardware change, but rather utilizes available hydrophone data for building a synthetic reference signal. This approach gives the User a few options for creating a synthetic signal, such as a moving depth window, stacking data for a selected depth interval, selection of a time window for a better representation, or just a discretionary visual selection of a representative noise pattern. Since the drilling environment and operational conditions may vary over time, the noise pattern may somewhat shift in time as well. To take care of this phenomenon, we introduced an automatic shift adjustment for the reference signal, so it stays maximally in phase with an actual noise component for a particular depth station.

Field Data Examples

Here we present a couple of field data examples for different modes and operational conditions that demonstrate efficiency of the proposed method.

For the first example, we use the same Monopole HF data set that was used for demonstrating Rotary Stacking method in the previous chapter. Without using Adaptive Filtering process, the acoustic log of slowness correlation image and wavetrace computed from this dataset is shown in the left portion of Figure 10. In the presented section of data, a strong tool mode is clearly identifiable as an upfront "rail road" pattern in the waveforms, and as a straight white strip on the correlation image that corresponds to the tool mode with slowness of about 60 us/ft.

In order to apply the algorithm of Adaptive Filter, various previously-mentioned options for building the synthetic reference signal were explored. For this dataset, the method of averaging the hydrophone data across adjacent depth ranges is chosen. It is believed that the tool mode across a certain depth range does not vary significantly, while the formation arrival does vary in time across this depth level. Therefore, after summing (stacking) hydrophone data across adjacent depth ranges, the tool mode gets stronger, while the averaged formation arrival diminishes. After applying the adaptive filter algorithm for each depth station with the synthetically created reference signal, the informative formation arrival stands out, as the detrimental tool mode gets significantly dampened. The acoustic log of slowness correlation image and waveforms computed from the hydrophone data after adaptive filtering is shown in the right portion of Figure 10. The strong tool modes at 60 us/ft and 110 us/ft were

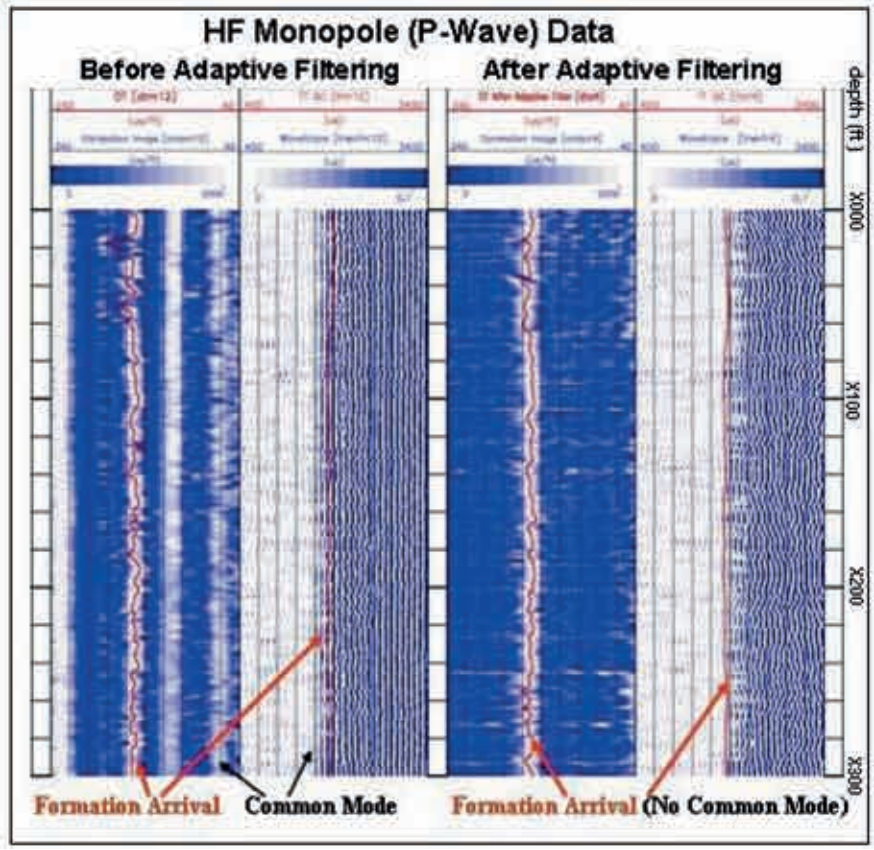

Figure 10 - HF Monopole Waveform Set, before and after Adaptive Filtering.

successfully removed in the slowness correlation image. The tool mode "rail road" pattern in the waveforms is also removed.

Another example of the adaptive filter method applied to a low frequency quadrupole shear dataset is shown in Figure 11. This data came from a well located at the Baker Experimental Test Area (BETA) in Mounds, OK. The borehole logged was drilled with a 12 ¼-in. conventional bit. A 9.5 PPG gel and water based mud was used as the drilling fluid. The borehole deviation was reported to increase, with depth, from 9 deg. to 22 deg. over the logged interval. The geology appears to be a mixture of consolidated (fast) and unconsolidated (slow) sands and shales. The data acquisition consisted of recording all the raw shots for both the monopole and LF quadrupole firings. Operation conditions in this well periodically produced some precession (whirling) of the drill collar within the borehole that caused drill collar eccentricity effects, which, in turn, might have affected the symmetry of quadrupole excitation [4,5]. As a result, a common mode noise component appeared in the quadrupole data that should not have occurred otherwise, under normal operational conditions. Furthermore, the velocity of this noise happened to be very close to the formation shear velocity. By applying adaptive filter, the noise mode is successfully removed, and the formation arrival is enhanced to allow proper formation slowness determination.

FK Filtering

Another method from the same group is the more traditional FK Filter, which we also use for rejecting repetitive common mode noise patterns, and is widely utilized in seismic data processing. It is not suitable for all noisy data sets. However, if the noise pattern stays pretty much the same through the entire data set or large segments of the data this technique may produce good results by effectively dampening the noise components. An example of the waveforms and semblance images before and after the FK processing is shown in Figure 12. This is a display of LF Quadrupole Waveforms from the GOM well mentioned earlier. The FK filtered data, shown on the right side, is a good example of how the FK filter can be used to reduce coherent waveform arrivals from the total wave field. Additionally, the shear Delta-T log curve shows enhanced character because of the FK Filters' coherent arrival suppression.

Conclusions

The proposed methods discussed in this paper have been shown to enhance the signals of interest, either by reducing unintended phase cancellation of the desired signals or by decreasing some of the various noise components

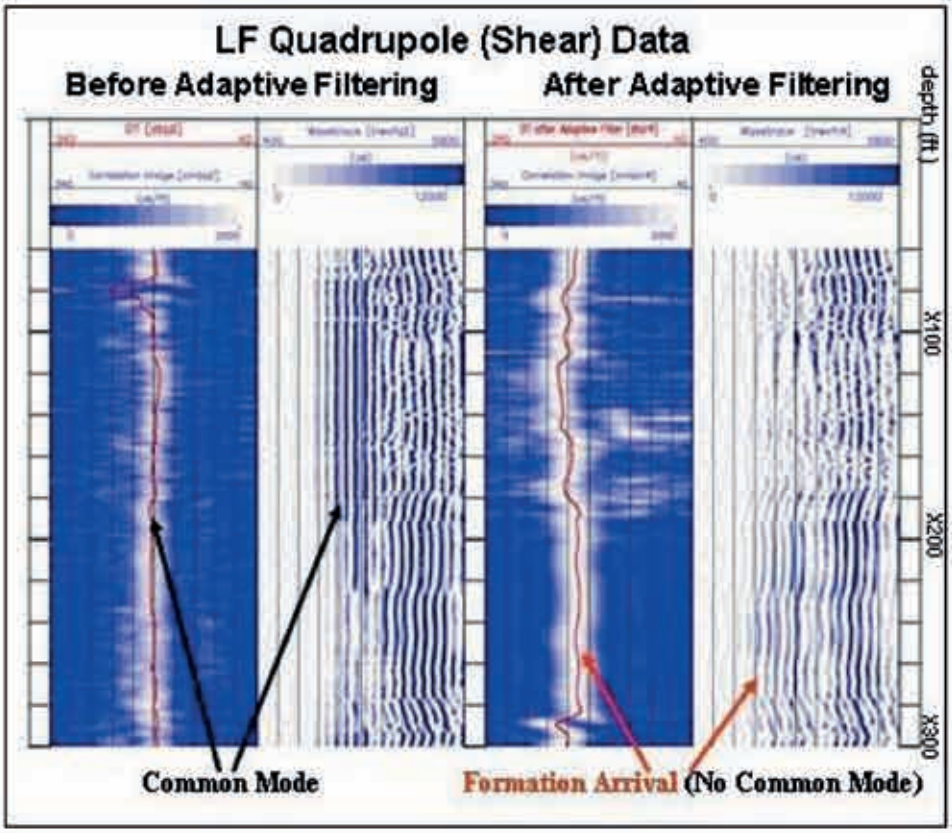

Figure 11 - LF Quadrupole Waveform Set, before and after Adaptive Filtering.

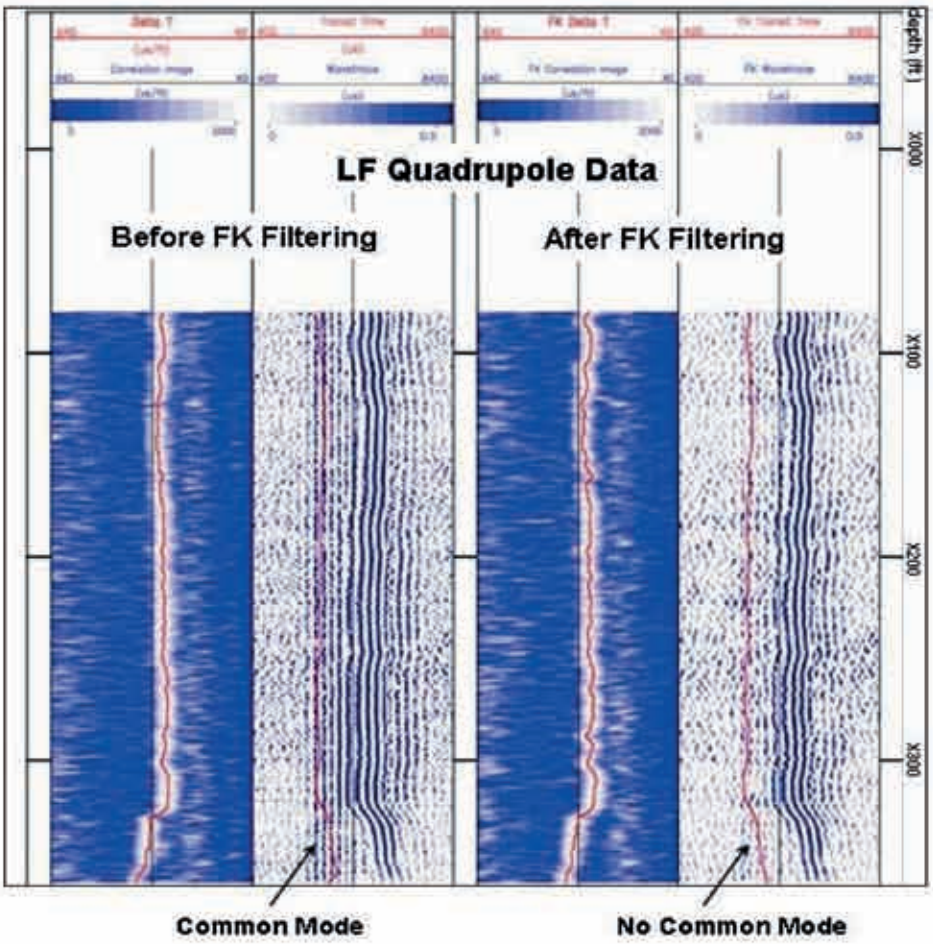

Figure 12 - LF Quadrupole Waveform set, before and after FK Filtering.

> We believe that future improvements in LWD acoustic measurement will come as much from the development of more advanced signal processing methods as it will from other types of improvements.

that often occur in varying drilling conditions of LWD acoustics. While these methods by no means overcome all issues related to acoustic signal quality, they do increase the overall resolution of the data and accuracy of the results in the cases reviewed. We believe that future improvements in LWD acoustic measurement will come as much from the development of more advanced signal processing methods as it will from other types of improvements.

Acknowledgments

We thank Alexei Bolshakov, Xiaoming Tang, Doug Patterson, Dave Lilly, and our colleagues from the Acoustic Science and Engineering teams for their contribution and support to this work. We also thank Erika Guerra for reviewing the manuscript. Finally, we thank Baker Hughes for permitting the publication of this work.

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Futureware Drilling Real

A step change in well const

Samir Al-Jaiban, Managing Director, talks about Futureware to Saudi Arabia Oil & Gas

Q: Saudi Arabia Oil & Gas - *Can you provide some detail on Futureware's history and growth and how is this related to the RTOC business?*

A: Samir Al-Jaiban - As a company, Futureware was established 3 years ago to provide a comprehensive set of Oil & Gas IT business solutions and scientific services. During this time, Futureware has grown at a phenomenal pace from building simple Oil & Gas software applications to running Saudi Aramco's Real Time Operations Center (RTOC). Of course, we started by investing in Real-Time data solutions built based on WITSML which is the blood of the RTOC. This led us to trying to find opportunities to maximize the use of WITSML to provide intelligence to the drilling operations which was a natural move to the RTOC business.

Our key staff (of battle hardened drilling optimization specialists, geoscientists, and IT professionals) had a lot of prior experience within the Oil and Gas industry so it was a logical move for Futureware.

Our growth has only been possible due to the high degree of commitment to the local market and specialization that Futureware offers in Oil & Gas IT solutions. By growing a base of local technology expertise, Futureware has acquired a substantial amount of experience in the local Oil & Gas business within Saudi Arabia by becoming a service provider to Saudi Aramco as well as a partner to major Oil & Gas technology providers.

Q: Saudi Arabia Oil & Gas - *What upstream solutions has Futureware developed?*

A: Samir Al-Jaiban - Futureware has been developing a number of solutions focusing on different areas in the upstream sector such as well construction and data management. These include Drilling Data Management solutions based on WITSML and Well Log Data Management solution.

Futureware has a strong spirit of innovation and supports research and development to provide Oil &

Time Operation Centers
ruction optimization

Gas solutions. For this reason, Futureware partnered with Dhahran Techno-Valley (DTV) to research and develop such solutions. Further details can be found at the weblink: http://dtv.kfupm.edu.sa/partners.htm

Currently Futureware major projects include manning and running Saudi Aramco RTOC as well as major upstream 3D Visualization solutions.

Q: Saudi Arabia Oil & Gas - *What is the Drilling RTOC environment?*

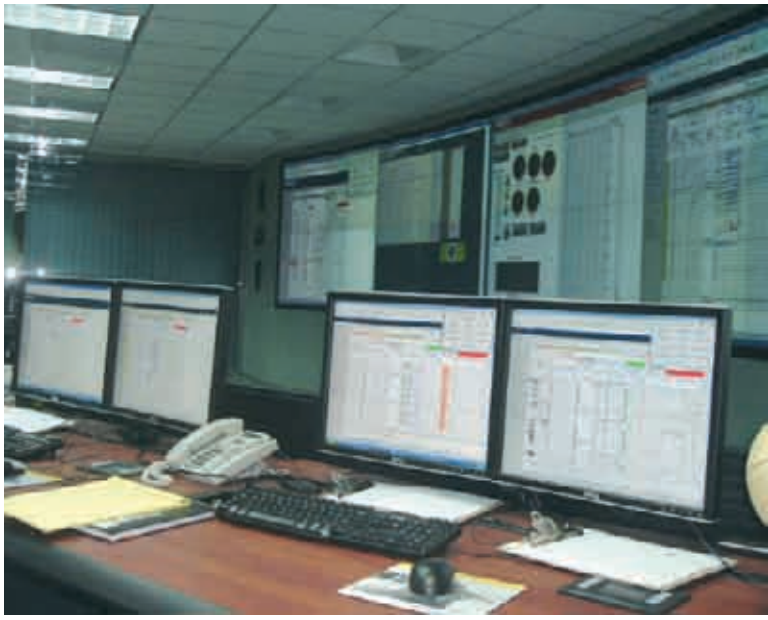
A: Samir Al-Jaiban - This is really a Large, dedicated facility that incorporates state-of-the-art technology and infrastructure. It has a large staff required to maintain 24/7surveillance. It can be called a "Space age "center of excellence and innovations. RTOC are not new idea, many industries have already applied the concept such as battlefield management, global financial centers and the oil industry.

Q: Saudi Arabia Oil & Gas - *What is the business case for the Drilling RTOC environment?*

A: Samir Al-Jaiban - Our belief is that Value is created when good decisions are made and implemented.

Computers don't produce oil–they impact the decision-making process by providing the human factor with better quality of information in a timely manner. This affects how fast decisions and analyses can actually be made and implemented i.e."Realtime". With the advent of WITSML and RTOCs, we can simply provide new vehicles to more easily deliver integrated Engineering and Geoscience solutions

Also we can provide Support on rigs in Oil & Gas and the wider oil and gas industry within the GCC. As very few old rigs are being retired RTOC can make the best of new and inexperienced operators and drilling contractors coming online. There are some estimates that 30,000 new personnel are required to staff and support this activity. This means that we must maximize resource effectiveness. For example, Drillers regularly make critical, time-sensitive decisions and there is an abundance



of data available to assist drillers. But that data must be sorted and distilled into Data into that is useful information. Information must be available at the right time to impact the decision. The key thing to remember is that 'Better decisions are made when the right person, has the right information, at the right time'.

Q: Saudi Arabia Oil & Gas - *How is information managed within the RTOC?*

A: Samir Al-Jaiban - Information within the RTOC is split into several flow elements. 1. Data acquisition, 2. Data processing, 3. Interpretation, 4. Operational impact assessment, 5. Decision to report/not report and lastly Communication to appropriate decision-maker for action.

Q: Saudi Arabia Oil & Gas - *What kinds of issues can one expect with the Drilling RTOC environment?*

A: Samir Al-Jaiban - The issues are related to security, redundancy, human factors (training, fatigue, appropriate facilities for physical and information processing needs), communication protocols, prioritization, where to focus attention (sometimes event-driven, sometimes by other considerations). The RTOC providing critical timely technical analysis of the drilling process is focused

on the safety and optimization of the process first hand. Therefore, a lot at stake here. The RTOC is a buzz with activities and the team works like bees, always on the move to tackle different levels of issues from brush fires, to issues that requires attention.

Q: Saudi Arabia Oil & Gas - *What are the challenges associated with the Drilling RTOC?*

A: Samir Al-Jaiban - Of course, one of the major challenges is to reduce NPT. This covers a whole range of activities that improve wellbore quality by reducing washouts, breakout, drilling induced fractures, and lost Circulation, to name a few. There is also a further aspect of improving logging conditions, casing runs, cement jobs and overall well productivity. A further challenge relates to Communication.

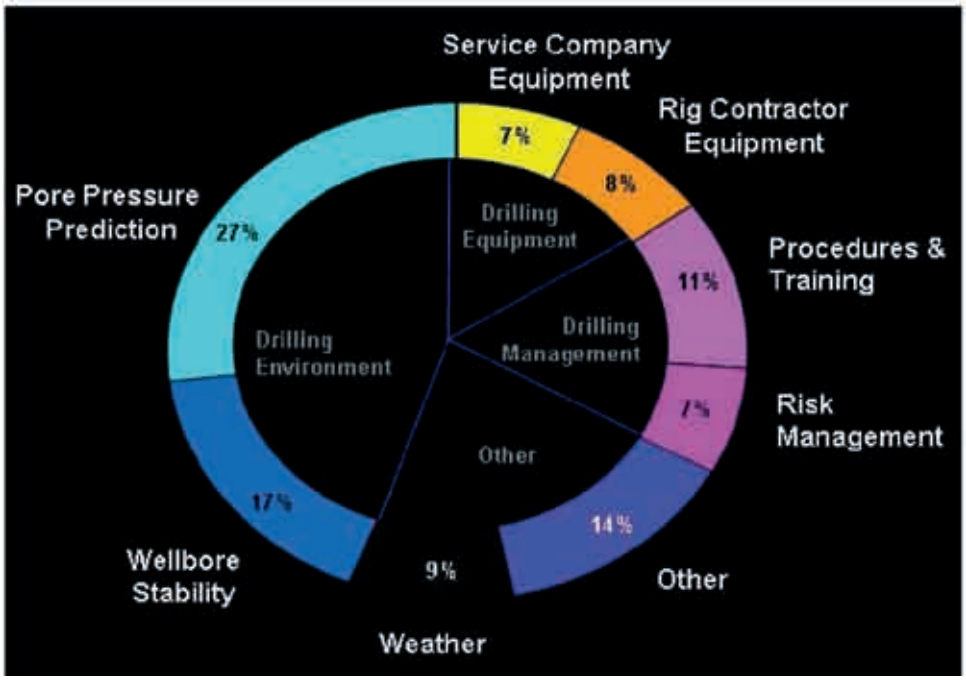
For example, to acquire, transmit and display data from surface Logging, MWD, LWD and wireline and then to transform the data into usable Information. This means that data needs to be input and operated using modeling technologies such as Trajectory, Torque and drag, Hydraulics, Pore pressure, Wellbore stability so as to allow the communication of actionable information. A further aspect is to distill data and information into recommendations. This involves the creation of timely and clear reports, meeting with drilling decision-makers and following-through on recommendations.

Q: Saudi Arabia Oil & Gas - *What is the Mechanical Earth Model - MEM?*

A: Samir Al-Jaiban - The Mechanical Earth Model - MEM incorporates initial pore pressure and fracture gradient models, based on an analysis of offset wells, seismic data and/or analog basins. The geological earth model invariably needs to be updated and refined as new data is acquired. We forsee a dedicated professional with an outstanding geomechanical background to solely focus on building MEM for each well/field under consideration. This is a core requirement for the RTOC.

Q: Saudi Arabia Oil & Gas - *What has been the focus of the RTOC?*

RTOC CHALLENGE: REDUCE NPT



A: Samir Al-Jaiban - The initial focus of the RTOC initially has been split between performance and software. The Performance aspect has focused on Stuck-Pipe,Lost Circulation,Well bore Instability and Rate of Penetration. The Software Packages currently employed are Drillworks with Connect ML and Landmark Drilling Suite.

Currently, the focus has been on wellbore geomechanics. For the near future, we are keen to develop fit for purpose drilling RTI (Real Time Intelligence tools) and the strategic development of new software which is fully automated to capture, analyze,and provide expert advice.

Q: Saudi Arabia Oil & Gas - *What kind of results have you seen to date?*

A: Samir Al-Jaiban - We have observed that the early results of implementing RTOCs are an improvement in general drilling Key Performance Indicators (KPIs) like less stuck pipes etc. Ever so slightly, we are also starting to see a reduction in non-productive time. However, results are not expected to be immediate. The RTOC requires commitment, patience, and dedication and requires passionate champions with variety of skills to work in a team effort. Long term the results are well worth it. They are the future of the industry.

To conclude, I would like to thank my Futureware colleagues and consultants for the effort they put in making this business work. In addition, I would like to thank Saudi Aramco RTOC staff and specially Abdulmohsen Al-Nasser for the effort they put in making Saudi Aramco RTOC a world class one. I would also like to thank Dr. Saad Saleh for his contribution.

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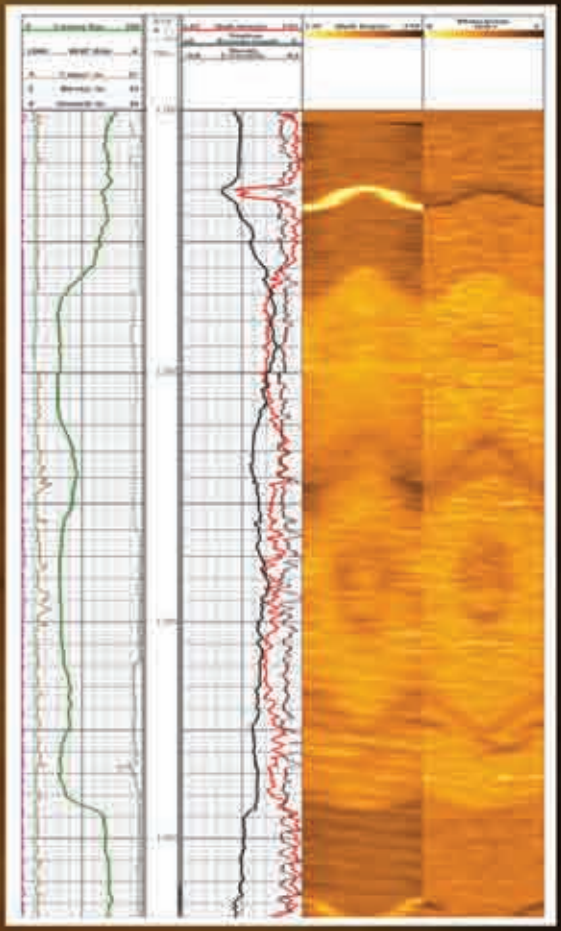

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Case Histories of Improved Ho Sweep Efficiency With Nozzle-B Sandstone and Carbonate Res

By A.G. Raffn, M. Zeybek, T. Moen, Schlumberger; J.E. Lauritzen, A.H. Sunbul, D.E. Hembling, A. Majdpour, Saudi Aramco

Abstract

This article discusses the PLT-correlated results of two test wells completed during 2006; one in sandstone and one in a carbonate reservoir, with the new completion technology of nozzle-based passive inflow control devices (ICD) which improves performance of wells with reservoir challenges as described:

1. In highly productive sandstone reservoirs, horizontal wells suffer from uneven flow profile and subsequent premature cresting/coning effects. In general, there is a tendency to produce more at the heel than at the toe of horizontal wells, which contributes to poor well cleanup at the toe. Additionally, excessively increasing the rate and/or horizontal well length can increase the risk of limiting sweep efficiency, resulting in bypassed reserves[1].

2. In carbonate reservoirs, permeability variations and fractures can cause uneven inflow profile and accelerate water and gas breakthroughs. Wells with early gas or water breakthrough have to be shut-in until remedial plans are decided and implemented, resulting in deferred production.

The main reservoir objectives for applying passive ICD technology in the two test wells are:

a. Sandstone: Decrease the influence of heel-toe effects and high permeability zones; hereby deferring water/gas breakthrough, improving well cleanup and sweep efficiency.

b. Carbonate: Control flow rates from high permeability intervals and to limit production from each compartment based on lateral offset from the gas-oil contact to prevent premature gas breakthrough.

The test well PLT-logs were correlated to static reservoir simulations. Analyses of the well performances show that the objectives of both completions were achieved. By having proper matches of the completions with ICD, the value over standard completions can be evaluated.

Post-evaluation of the completion designs based on the PLT-log results has increased our understanding of the nozzle-based ICD performance. As a result several approaches for completing wells in both sandstone and carbonate reservoirs with ICD have been recommended in order to achieve optimized inflow performance.

Introduction

Two trial wells with nozzle-based passive ICD systems were designed and completed in 2006; one for sandstone and one for carbonate reservoirs. To evaluate and approve the new ICD completion, these wells were production logged and the results were carefully analyzed.

The most important feature of the ICD completion is the self-adjusting effect of flow variations anywhere along the well trajectory and whenever they occur during entire well life. The key benefits are:

1) Increased well life and reserves due to improved sweep efficiency.

2) Delayed gas and water breakthrough.

3) Decreased water/gas rates after breakthrough when water/gas mobility is higher than oil.

4) Improved well cleanup.

The pressure drop through the ICD unit is generated by the flowing fluid through the nozzles (Figure 1a), described by a part of the Bernoulli equation:

$$\Delta p = \rho \frac{v^2}{2} \quad \wedge \quad v = \frac{q}{A} \qquad \text{(Eq. 1)}$$

Where: p=pressure, ρ=density of fluid, v=velocity, q= rate and A= total cross section area of the nozzles.

rizontal Well Clean up and ased Inflow Control Devices in ervoirs

This article discusses the PLT-correlated results of two test wells completed during 2006; one in sandstone and one in a carbonate reservoir, with the new completion technology of nozzle-based passive inflow control devices (ICD) which improves performance of wells with reservoir challenges.

The ICD unit is equipped with at least 2 or more nozzles and the pressure drop across the unit is designed based on the reservoir characteristics and flow rates in order to achieve the objectives of the well. An advantage with these nozzles is that at least one or more of the nozzles will be exposed to inflow of fluid, making the system reliable for cleaning up the well even if the well has been left with solids-laden fluids down hole for a longer period before the well is put on production.

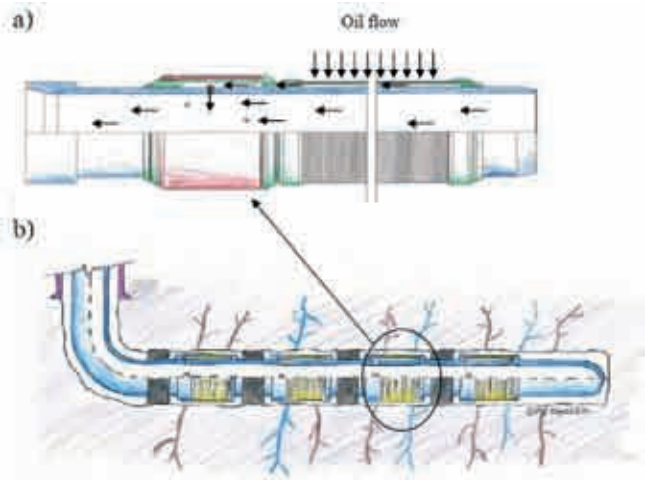

Figure 1 - a) ICD unit integrated in a sand control screen. Screen ensures a solids-managed flow (allow particles < 45 µm to be produced), length 12m=one joint. b) An ICD completion example with packers for every ICD joint in a naturally fractured reservoir.

Figure 1b shows a schematic of a well with packers to divide the lateral into compartments of permeability variations. The benefits of having packers supporting the ICD completion are:

a) Permeability variations are captured and segmented.

b) High productivity (high permeability) intervals are controlled by lower number of ICD units run in those segments, preventing cresting/coning in those segments.

c) Inflow of gas or water through fractured zones can be isolated or highly restricted.

d) Annular flow between compartments is prevented.

e) Potential wet zones can be isolated while the rest of the well can produce dry oil.

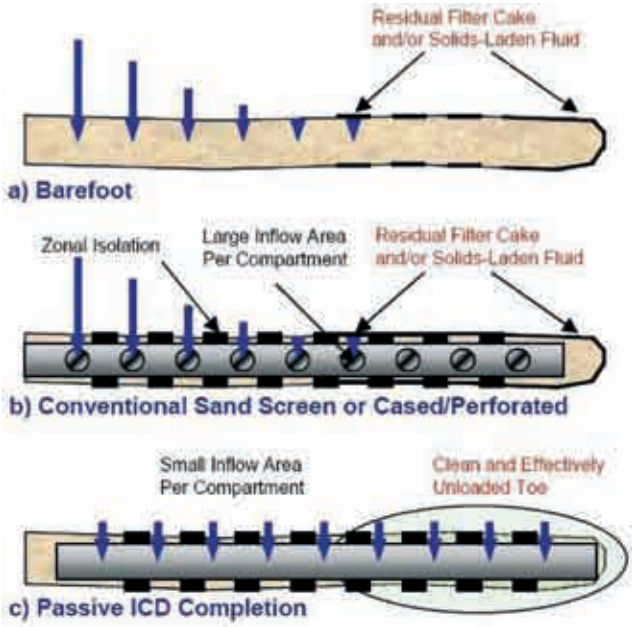

Figure 2 - Principle of improved wellbore cleanup:
a) Barefoot
b) Conventional Completion
c) Passive ICD completion

When a barefoot or a conventional horizontal well is put on production, the filter cake is preferentially lifted at the heel of the well as a function of the heel to toe pressure gradient (Figure 2a and b). This leads to poor inflow performance due to higher completion skins at the toe. Usually as the horizontal well length increases, the inflow profile and corresponding recovery degrades because of insufficient well cleanup and lesser contribution from the toe.

For a horizontal well with ICD completion, flow rate per compartment is restricted (Figure 2c). At higher rates, a higher differential pressure is created and transmitted along the completion to other compartments and eventually to the toe. This differential pressure created lifts the filter cake off the formation face and additionally cleans the near wellbore damage, resulting in:

a) Skin reduction

b) Higher well PI

c) Enhanced sweep efficiency

Once ICD units are introduced into the completion, an additional pressure drop is created in the system. It is therefore very important to design the ICD unit pressure drop in accordance with the reservoir properties to achieve a design with the lowest possible ICD pressure drop and still achieve the objectives.

Figure 3 shows the principle of a standard screen completion compared to an ICD completion in a reservoir with 1 Darcy and 2 Darcy zones simulated in a static reservoir model. The two zones are supposed to be completed with a packer separating the annular flow between the zones. For a conventional completion the draw-down into the completion is shown as the ΔPF.

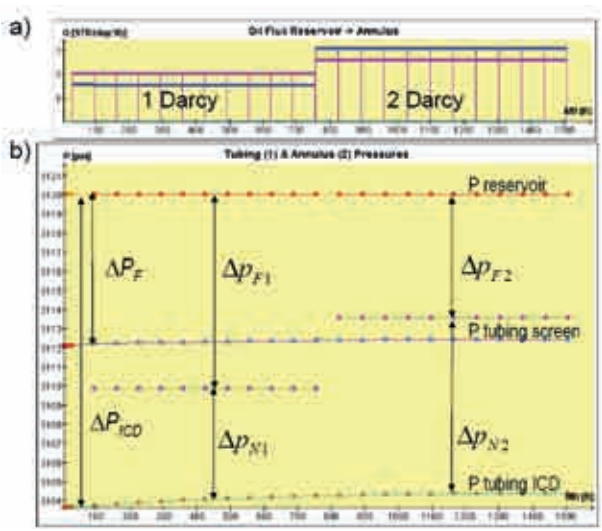

Figure 3 - Principle of a standard screen completion compared to an ICD. a) Flux into wellbore, screen completion (Blue line) and ICD completion (Pink line). b) Comparison of the pressures along the well bore.

With an ICD completion the total draw-down into the completion is described as the ΔPICD, and we observe that the draw-down pressure ΔPF of the original horizontal well is now being re-distributed between the two zones when completed with an ICD completion.

The high permeability zone of 2 Darcy is having less draw-down (ΔpF2) while the low permeability zone of 1 Darcy is having a higher draw-down (ΔpF1), and the relationship is as follows:

$$\Delta P_{ICD} = \Delta p_{Fi} + \Delta p_{Ni} = \Delta p_{F2} + \Delta p_{N2} \qquad \text{(Eq.2)}$$

Where: ΔpFi is the pressure from the reservoir into the annulus and ΔpNi is the pressure from the annulus to the tubing = pressure across the ICD unit.

Simulating the two different completion types at the same rates, the flow rates for the zones are re-distributed (Figure 3a) and as a consequence the ICD completion will be able to defer gas or water breakthrough in high permeability layers. In addition, over time this will assure a much better sweep efficiency of the reservoir, because it is less likely that oil will be left behind in low permeability intervals.

Using the principle of Figure 3, the well PI for an ICD completion at the sandface (annulus) can be estimated and because when the flow rate per segment is known from the PLT-logging, we can calculate the pressure drop across the nozzle-based ICD units per segment from Eq. 1. To compare the results with the actual PI potential for the well, it is assumed that a perfect horizontal well is performing according to[2]:

$$J = \frac{2\pi k_H h}{\mu B_o \left[\ln\left(\frac{2r_e}{L_w/2}\right) + \beta \frac{h}{L_w} \ln\left(\frac{\beta h}{2\pi r_w}\right) \right]}, \quad \beta = \sqrt{k_H / k_V} \qquad \text{(Eq.3)}$$

It should be noted that an estimate of the Pwf (flowing bottom hole pressure) from this equation is not including friction loss along the horizontal well length. The Pwf may therefore be slightly more optimistic than the actual measurement.

The evaluation of the well PI for both actual and theoretical has been completed for the two trial wells in order to measure and understand their performance.

Sandstone Reservoir Trial Well

The sandstone ICD well was completed in November 2006 (Figure 4). The objectives of the ICD completion were to reduce the heel-toe effect, deferring gas and water breakthrough.

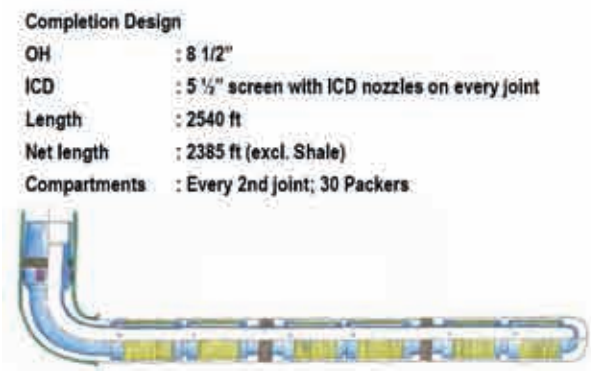

Figure 4 - Sandstone ICD completion with packers for every second joint.

It was decided to test having a large number of packers to achieve better inflow control. The well has a total of 30 packers, i.e., approximately one packer for every second joint. This can be achieved very reliably and cost-effectively with small swellable elastomer packers.

The well was put on production for approximately four months at about 6-7 MSTB/D before the PLT-logging. During logging shown in Figure 5, it became obvious that the well most likely had not been properly cleaned up, and the logging tool had problems reaching TD. At the low rate, the well stopped short of TD by 650 ft due to solids-laden mud in the toe of the well (Figure 5, Green dashed line). This was not expected because the well had produced over a relatively long time period to ensure proper cleanup prior to the PLT. After increasing the rate to about 9-10 MSTB/D for just four hours, repeating the logging at this higher rate, the well could be logged to an additional 350 feet of measured depth. Now the well showed improved flux to a nearly perfect inflow profile across the entire production interval (Figure 5, Brown dashed line).

This quantitatively demonstrates that the higher rate resulted in a significant cleanup effect. After four hours, the well was re-logged at the high rate traversing all but the last 50 ft of production interval (Figure 5, Brown solid line). For cleanup verification the log was finally repeated at the lower rate (Figure 5, Green solid line) and a permanent change in profile was noted.

This effect has also been inferentially observed in other wells. When a well is logged at two different PLT rates, occasionally when correlating a static simulation model to actual PLT results, the simulations will not match both rate curves. This can occur for one of two obvious reasons:

1) Either the simulation is simply invalid due to insufficient or invalid inputs, or

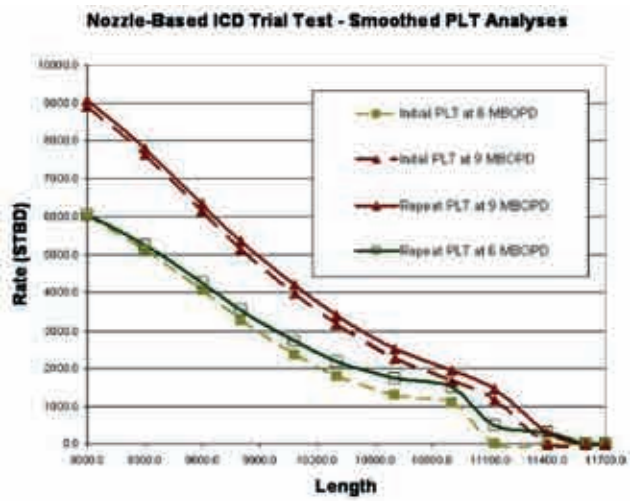

Figure 5 - Raw PLT-log data of rate vs. length of the well. Green: lower rate and Brown: higher rate. Dashed lines indicate initial PLT runs, and the solid lines indicate repeated PLT runs.

2) The production profile changed in the time it took to log the two rates.

The results of the sandstone trial test in Figure 5 indicate that unloading at high rate can result in rapid wellbore cleanup; therefore, the latter condition 2), i.e. production profile changes due to wellbore cleanup, are evident. When this occurs, the utility of the lower rate PLT dataset is greatly diminished; therefore when logging a passive ICD well, it is recommended to log the high rate first, preferably for as long as possible. Then log the lower rate afterwards.

Calculating the well PI at the sandface (annulus) based on the PLT-log results indicate clearly that the well performance improved during PLT-logging (Table 1) and that the actual well PI is approaching the theoretical well PI estimated from Eq. 3. The numbers for the Pwf from PLT are here marked with blue and are the same number for the rate variations during the PLT, because of uncertainty during the stationary readings.

Rate during PLT	Low Choke		High Choke		
	6450	6800	10150	10500	STB/D
From PLT					
Pwf	*2853*	*2853*	*2846*	*2846*	*psi*
PI PLT	717	756	634	656	STB/D/psi
PI Sandface	***1032***	***1144***	***1104***	***1205***	***STB/D/psi***
From Theory					
Pwf	*2854.3*	*2853.7*	*2847.4*	*2846.7*	*psi*
PI Sandface	***1307***	***1307***	***1307***	***1307***	***STB/D/psi***
From Static modeling					
Pwf	*2854.2*	*2853.5*	*2845.0*	*2844.0*	*psi*
PI Sandface	***1286***	***1255***	***1011***	***992***	***STB/D/psi***

Table 1 - PLT results compared to theoretical calculated well PI and static reservoir model PI with skin 0.

The well PI estimated from the static reservoir model is assuming a skin of 0 along the entire wellbore and the performance according to the Pwf is in good agreement with the actual measured Pwf; however the well PI at sandface shows that the static reservoir modeling is over predicting the PI for the low rate, which is not that odd, since the initial low rate PLT log did not perform very well. At the high rate the static model is under predicting with about 100-200 STB/D/psi, which we will look further into in details below.

Calculating the inflow per segment reveals that the toe part at the high rate has some problems (Figure 6a) because comparing actual PLT results with the static reservoir model with 0 skin along the entire wellbore, shows that segment 18 to 25 has less inflow than expected.

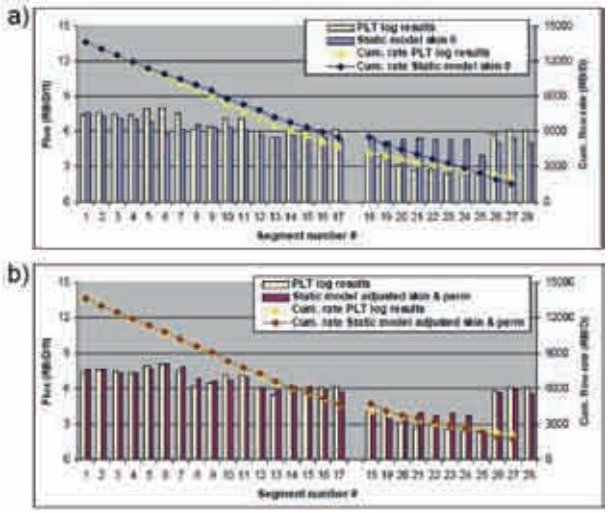

Fig. 6 - Inflow per segment and cumulative rate:
a) Comparison of the PLT results with static model skin 0.
b) Match of PLT results with static model adjusted skin and permeability.

Reviewing the permeability log for the well, there is no clear explanation for this low rate from these segments, so instead of extensive permeability changes, the skin was changed from 0 to 30 for these segments.

For segment 5 to 7 the static reservoir model predicted too low inflow (Figure 6a), so in these three segments the skin was adjusted to between -5 to -10 and the permeability slightly increased. By doing these adjustments, the static model achieved a much better representation of the actual PLT log (Figure 6b).

Once the static reservoir model with the ICD completion matches the actual PLT-log performance at the high rate with less than 5% difference, then standard procedure is to simulate how the well would have performed if the well was completed with a screen completion instead. Note: The simulation of the screen is assuming a perfectly performing conventional screen completion, and does not take into consideration the risk of improper well cleanup of the toe as we saw from the PLT-log, and which we cannot predict if the well was only having screens.

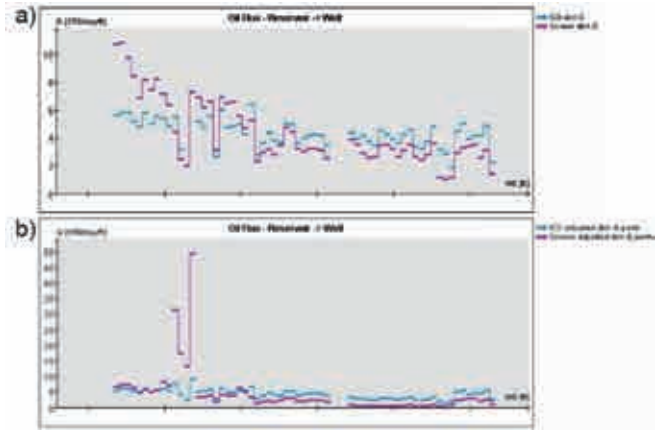

Figure 7 - Static modeling of ICD (Blue lines) and standard screen completion (Pink lines):
a) Static model skin 0.
b) Static model adjusted skin and permeability.

For the case of skin 0 along the entire well path, the simulations of the standard screen completion in Figure 7a (Pink line) shows a remarkable heel-toe effect, with almost twice as much inflow for the first two compartments which could potentially cone in gas or water within a very short timeframe. Also the screened well in this case is leaving the toe part with about 20% lesser inflow while the ICD completion has decreased the inflow in the heel from about 11 STB/D/ft to about 6 STB/D/ft; confirmed by the PLT-log and increased the contribution from the toe.

The static reservoir simulations of the ICD well match PLT-log results as shown in Figure 7b, where the heel has a negative skin and the lower part of the well has high skin due to improper well cleanup. Comparing this case with a standard screen completion, the well is very fortunate to have an ICD completion. (Please note the remarkable change in the scaling.) The well has increased contribution from the high skin compartments 18 to 25 by about 2/3rd, meaning that the ICD completion is able to help high skin areas too, just as ICD completions can help on increasing contribution from low permeability layers. The well will therefore not suffer remarkably from the skin and the ICD completion will ensure good sweep efficiency of all layers.

Carbonate Reservoir Trial Well

The carbonate well was completed during June 2006 and put on production in May 2007 (Figure 8). The objec-

tives of the ICD completion in the carbonate reservoir were to restrict inflow from the three last compartments, due to expected higher reservoir pressure towards the toe. Additionally, the toe part of the well was close to the gas-oil contact. The PLT-logging did not indicate a significant pressure gradient or free gas. Furthermore, there was no loss of circulation during drilling, which usually indicates severe fracture zones.

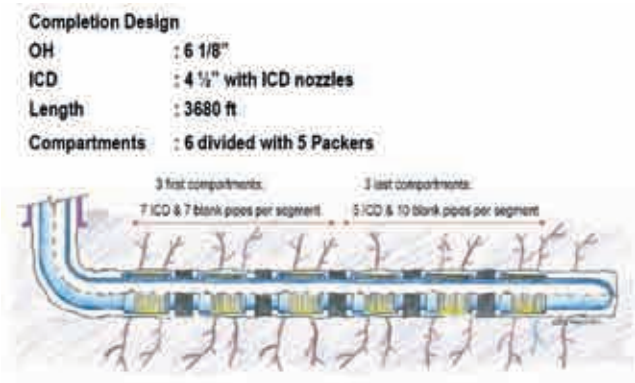

Figure 8 - Carbonate ICD completion with 5 packers and 6 compartments.

The PLT loggings were first performed at the high choke and then at a lower choke size (Figure 9a), to ensure that well had been properly cleaned up before the logging.

Since the three last compartments have fewer ICD units, the well has an artificial heel-toe inflow profile. Also there was measured crossflow of 1000 RB/D during shut-in of the well which indicated a pressure gradient of about 2 psi decreasing towards the heel.

The high rate was then matched in the static reservoir model (Figure 9b) and required a manipulation of the permeability data. The well was initially designed based on an average permeability of 500 mD however the average permeability had to be increased to about 590 mD. Also the well had a higher GOR than expected, which was accounted for in the matching process.

The well PI at the annulus was predicted to be 250 STB/D/psi, however according to actual well performance the PI is approximately 500 STB/D/psi, right on target according to the perfect horizontal well PI calculated from Eq. 3. This means that there are no indications of formation damage due to skin effects. This is also a remarkable result, since the well was shut-in for almost 10 months.

Once the passive ICD completion model correlates to the actual PLT-log performance, standard procedure is to simulate how the well would have performed if the well

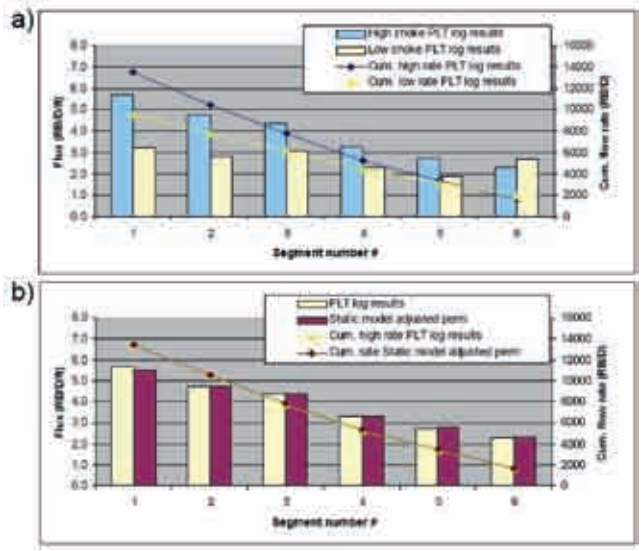

Figure 9 - Inflow per segment and cumulative rate:
a) PLT results at high and low chokes
b) Match of PLT results with static model adjusted permeability.

was open hole (OH). The passive ICD static simulation is then juxtaposed against the OH simulation to compare oil flux per compartment (Figure 10a) and pressure along the well bore (Figure 10b).

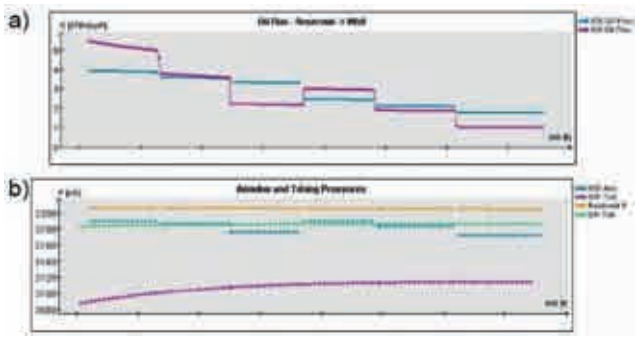

Figure 10 - Flux and pressure comparison OH vs. ICD:
a) Oil flux per compartment; comparison between ICD (Blue line) and OH completion (Pink line).
b) Pressures along well bore; ICD annulus (Blue), ICD tubing (Pink), OH (Green) and P reservoir (Orange).

Note: This should be considered as an optimistic evaluation, because the OH would most likely not have been able to perform as predicted in the passive ICD static reservoir model. Specifically, the OH well would have higher skins in the toe due to non-uniform unloading; however, for comparative analysis, the skins in the two simulation scenarios are treated as identical and zero in both cases.

The modeling results show that the pressure across the ICD completion is about 80 psi, which is a substantial pressure loss in the system. The reason for having such a

high additional pressure would be to eliminate any unforeseen events caused by fracture systems which could cone gas and cause excessive gas production. Figures 11a and 11b show the results of the open hole and ICD static reservoir simulations, evaluating the potential GOR decrease with the ICD completion if gas breaks through in the last compartment in the toe.

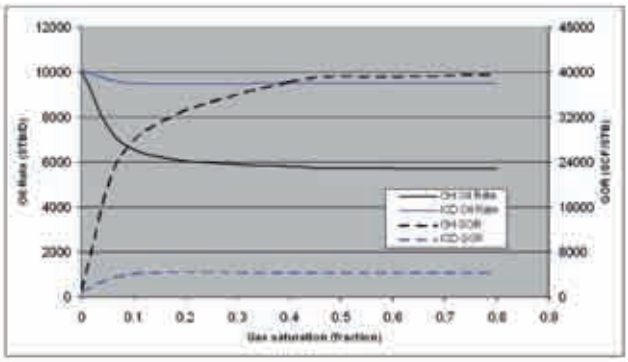

Figure 11 - Oil rate and GOR as a function of gas saturation:
a) OH completion, Oil rate (Black lines) and GOR (Dashed Black line).
b) ICD completion (Blue line) and GOR (Dashed Blue line).

As the gas saturation increases from 0 to 40% the GOR in the OH completion increases from the initial of 1000 SCF/STB to 40,000 SCF/STB, while the ICD well is predicted to maintain a GOR of only about 4200 SCF/STB. These remarkable results have however not yet been verified in true field trial wells.

Lessons Learned and Future Completion Designs

Matching the PLT-log to a static reservoir simulation for the sandstone well, then removing the ICD completion and replacing it with a conventional screen completion, the model shows the theoretical performance of the well without ICD. When the rate is increased to 15,000 STB/D for a standard screen completion, the well suffers from extreme heel-toe effect with the toe only contributing 1/4th that of the heel (Figure 12a). Increasing the rate from 10,300 to 15,000 STB/D for the ICD completion shows better balancing of the inflow including higher contribution from the toe (Figure 12b). Clearly, the sweep efficiency of the ICD completion is improved over the conventional screen completion, deferring gas or water breakthrough and draining the reservoir layers in a more balanced way.

Taking the next step by looking at new options to utilize the advantages of the ICD completion, the wells can easily be extended without compromising the balancing effect, thus expanding the drainage area resulting in an increase of well reserves (Figure 13a represents 2700ft and 10,300 STB/D and Figure 13b represents 3300 ft

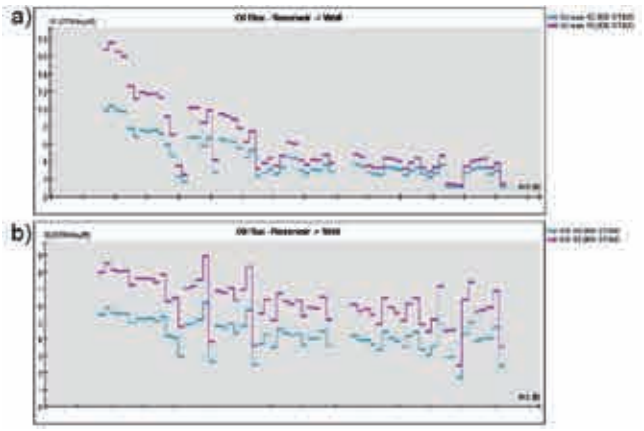

Figure 12 - Static modeling of ICD and standard screen completion, Rate 10,300 STB/D (Blue lines) Rate 15,000 STB/D (Pink lines):
a) Oil flux for screen cases
b) Oil flux for ICD cases

and 12,000 STB/D). The well PI for the 3300ft well is increased from about 1300 to 1360 STB/D/psi. As a result, fewer numbers of wells are needed to drain the reservoir volumes; however, it is recommended to perform dynamic reservoir simulation evaluations to establish a drainage strategy for the entire reservoir with the longer ICD wells.

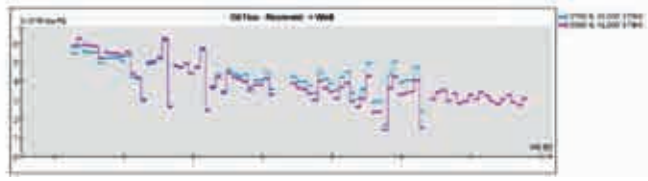

Figure 13 - Static modeling of a longer well with ICD:
a) Oil flux for 2700ft and 10,300 STB/D.
b) Oil flux for 3300ft and 12,000 STB/D.

For carbonate wells with very low PI, the potential for enhancing the well life by using ICD completions is best illustrated by simulating water breakthrough in fractures for two cases with different packer density. In this case, a sensitivity of synthetic low permeability and the impact of upscaling the magnitude of this log (Figure 14) have been performed to study the difference in the static reservoir modeling results. Additionally, this well has a large

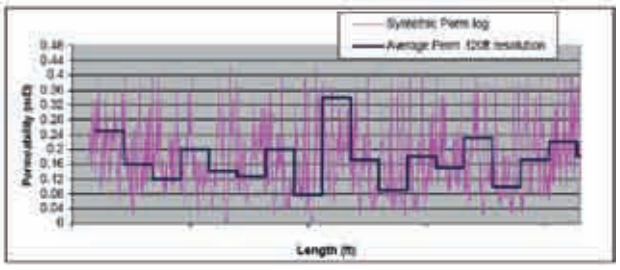

Figure 14 - Synthetic permeability log (Pink) and an upscaled Average Perm log (Blue).

pressure differential along the wellbore of about 300 psi, being high at heel and lower at toe. This gradient is caused by pressure support from water injectors and low connectivity between the reservoir layers.

The ICD completion simulations are performed with two sets of different nozzle sizes in Figure 15 and 16 respectively. The "ICD" simulations have the same nozzle size along the entire wellbore and the "ICD variable" simulations have different sizes to balance the inflow according to the large pressure differential in the reservoir. The average pressure drop across the nozzle-based ICD units is initially only half of the previous carbonate well (about 40 psi in these cases), which should be sufficient for the ICD completion to achieve the upside potential for maintaining oil production at low water cut. It should however be noted that this pressure drop is designed specifically for this well to achieve good well performance, and should not be considered as a standard ICD unit pressure for low permeability reservoirs as a generality.

Simulation sensitivities are run for different packer spacing, based on both synthetic permeability logs (Figure 15a), and an average permeability (Figure 15b). In the first set of sensitivities, packer spacing is located every 120 ft (every 3rd joint).

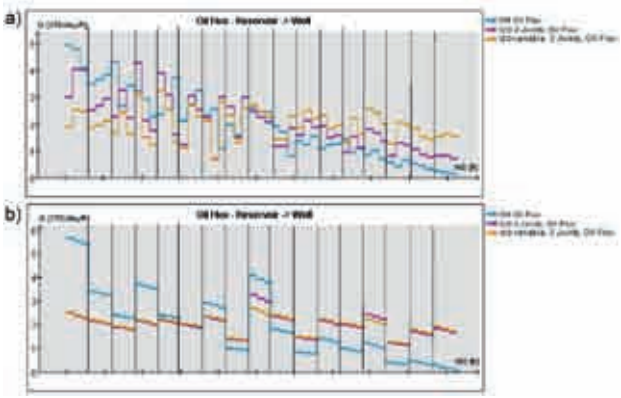

Figure 15 - Static modeling of perm variations with packers (Black lines) for every 3rd joint; OH (Blue lines), ICD (Pink lines) and ICD variable (Orange lines): a) Oil flux for Synthetic Perm log and b) Oil flux for Average Perm 120ft.

Figure 16a and 16b are sensitivities for packer spacing every 480 ft (every 12th joint = four compartments). The impact on the simulations is noticeable when simulating is based on the upscaled permeability along the wellbore instead of using the log data. Figure 16a (Orange line), clearly shows that the ICD solution with four compartments is not able to capture high inflow from the high permeability layers towards the toe, which is much better captured with a packer on every third joint (Figure 15a, Orange line).

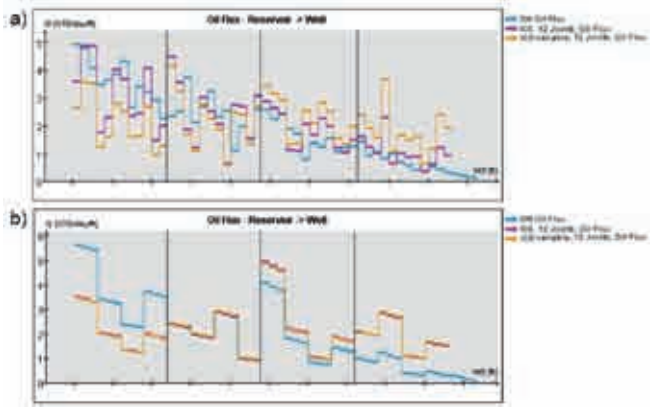

Figure 16 - Static modeling of perm variations with packers (Black lines) for every 12th joint; OH (Blue lines), "ICD" (Pink lines) and "ICD variable" (Orange lines); a) Oil flux for Synthetic Perm log and b) Oil flux for Average Perm 120ft.

Table 2 shows the results after simulating water breakthrough in 3 fractures in the heel. It is how much the ICD effectively decreases the water cut when water breaks through. If the well has "ICD variable" (designed accordingly to pressure differentials) and packers every third joint the water cut is estimated to be about 7% compared to an OH completion, which may be suffering from water cut of about 53%.

Completion Type	Oil rate	Gas rate	Water rate	GOR	WCUT	BHP
	[STB/d]	[MMSCF/d]	[STB/d]	[SCF/STB]	[%]	[Psi]
OH, Synthetic Perm log	2135.3	1.296	2437.1	606.7	53.30	3097.9
OH, Average Perm log	2140.6	1.298	2431.1	606.3	53.18	3100.2
Packers per 3 joint						
ICD, Synthetic Perm log	3544.7	2.051	575.5	578.6	13.97	3011.1
ICD, Average Perm log	3538.3	2.050	581.1	579.2	14.11	2999.8
Packers per 12 joint						
ICD, Synthetic Perm log	2914.5	1.678	1459.8	575.6	33.37	3024.1
ICD, Average Perm log	2954.2	1.628	1511.4	551.0	33.85	3018.6
Packers per 3 joint						
ICD variable, Synthetic Perm log	3792.3	2.154	292.4	567.9	7.16	2950.5
ICD variable, Average Perm log	3788.9	2.153	295.1	568.3	7.23	2934.0
Packers per 12 joint						
ICD variable, Synthetic Perm log	3240.7	1.915	937.2	590.9	22.43	2941.9
ICD variable, Average Perm log	3233.7	1.920	933.4	593.8	22.40	2944.2

Table 2 - Comparison of OH completion and ICD completions with different packer density.

This is substantial water cut decrease, which could remarkably extent the well life. The ICD solution with 4 compartments showed the water cut of 22%. With respect to evaluating the number of packers to deploy, there is a cut-off limit as how much water cut decrease will economically justify the increased quantity of packers. To accurately assess the economics, dynamic model is required, which is beyond the scope of this paper; however, inferentially even the simplest dynamic studies would likely indicate that the additional expenditure is justifiable.

Recommendations for future design workflow:

1) To propose the best ICD completion design for future wells, the field or the development area should to be evaluated as a whole.

2) The final ICD design of the completion should be performed based on LWD data and pressure gradients along wellbores. This means that drilling measurements are important to refine the ICD completion design.

3) If the well has severe pressure differentials, then firm operation guidelines for production rates should be established in order to avoid crossflow.

Conclusions

1) All completion and production objectives are met with the nozzle-based ICD completions.

2) Sandstone reservoir PLT evaluation: The well had initial indications of formation damage due to higher skin at the toe. After cleanup at higher rates, the ICD completion has increased the contribution for those zones by 2/3rd. Consequently better sweep efficiency is expected.

3) Carbonate reservoir PLT evaluation: There are no indications of formation damage in this well, because the well PI of about 500 STB/D/psi is as predicted for a perfect horizontal well PI.

4) For correlation purposes, perform PLT-logging at high rate first and low rate afterwards to ensure that well cleanup does not alter the rate-based inflow profiles while collecting data.

5) Conclusively the nozzle-based ICD completion have several advantages:

a. The ICD unit is integrated with a screen, designed to exclude abrasive particles above 45 µm, securing a long lifetime without plugging and erosion risk of the nozzles and the ICD unit.

b. The ICD unit is equipped with at least 2 or more nozzles, so at least one nozzle will be exposed to inflow of fluid, making the system reliable even if the well has been left with solids-laden fluids down hole for a longer period before the well is put on production.

6) Recommendations for future completion design options:

a. Explore options of drilling and completing longer horizontal wells.

b. Use annular packers more extensively in order to decrease gas or water rates when breaking through.

"Recommendations for future completion design options:

a. Explore options of drilling and completing longer horizontal wells.

b. Use annular packers more extensively in order to decrease gas or water rates when breaking through."

Nomenclature

A	= inflow area nozzles [sq.ft or m^2)]
Bo	= oil volume factor [RB/STB or Rm^3/Sm^3]
h	= reservoir height, ft [m]
ICD	= inflow control device
J	= productivity index (PI), STB/D/psi [Sm^3/d/bar]
k_H and k_V	= horizontal and vertical permeability, D [m^2]
Lw	= well length, ft [m]
LWD	= logging while drilling
ΔP_F	= pressure drop from reservoir pressure to *Pwf* for a conventional completion, psi [bar]
ΔP_{ICD}	= total pressure drop from reservoir pressure to *Pwf* for an ICD completion, psi [bar]
Δp_{Fi}	= pressure drop from formation into Annulus, psi [bar]
Δp_{Ni}	= pressure from the annulus to the tubing = pressure across nozzle based ICD unit
P_{wf}	= flowing bottom hole pressure, psi [bar]
PLT	= production logging tools
r_e, r_w	= external boundary radius and wellbore radius, ft [m]
ρ	= density, lb/cf [kg/m^3]
μ	= viscosity, cP [Pa*sec]

Acknowledgement

We would like to thank Saudi Aramco for the great team work leading to the success of these two trial wells and permission to publish the results.

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

By Paolo Gavioli, Baker Oil Tools

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

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

Baker Oil Tools has applied the MPas™ mechanical packer in Saudi Arabia for many different applications. By mid-year 2008, more than 85 percent of Equalizer™ Production Systems and 100 percent of zonal isolations included MPas packers. The rapid increase in MPas usage in Saudi Arabia is shown in Figure 1. These applications

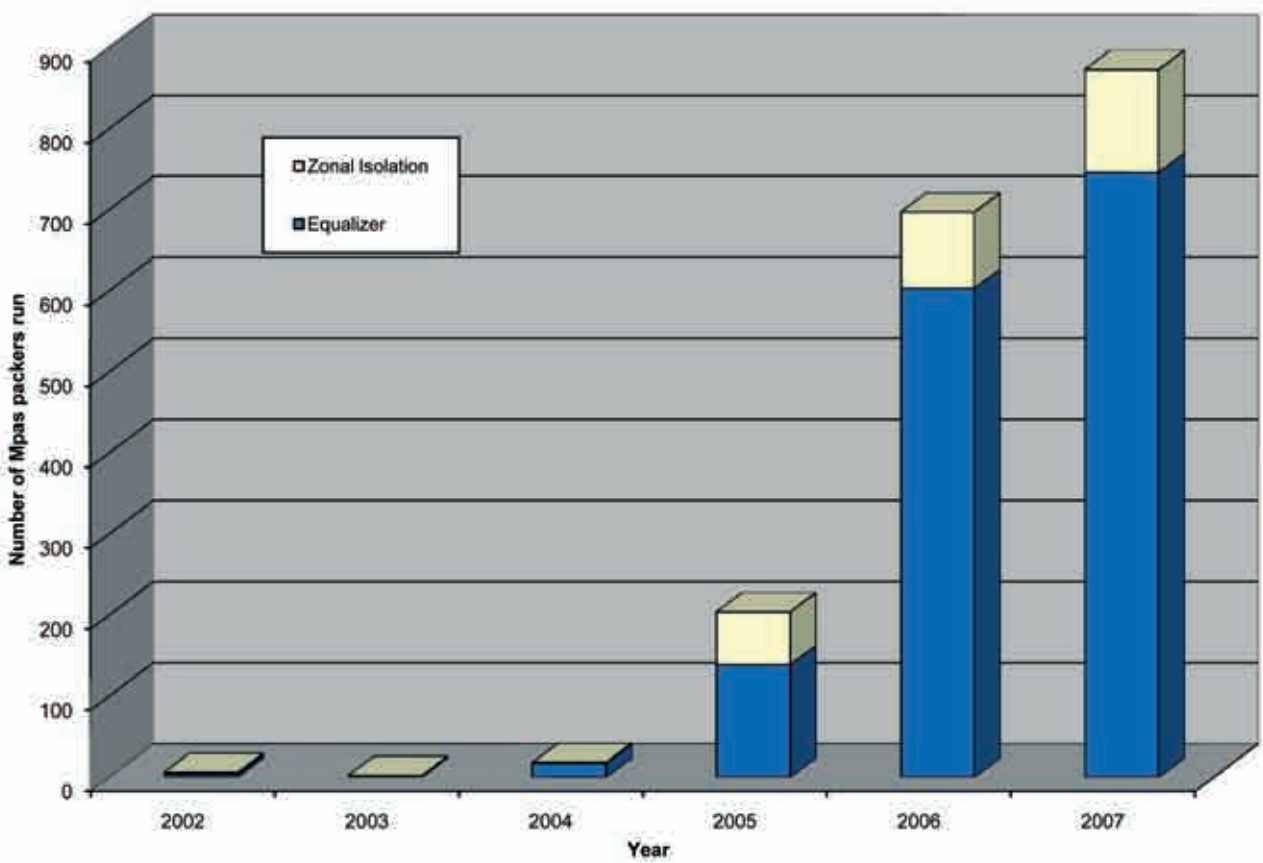


Figure 1 - Usage of MPas packers in Saudi Arabia divided by type of installation.

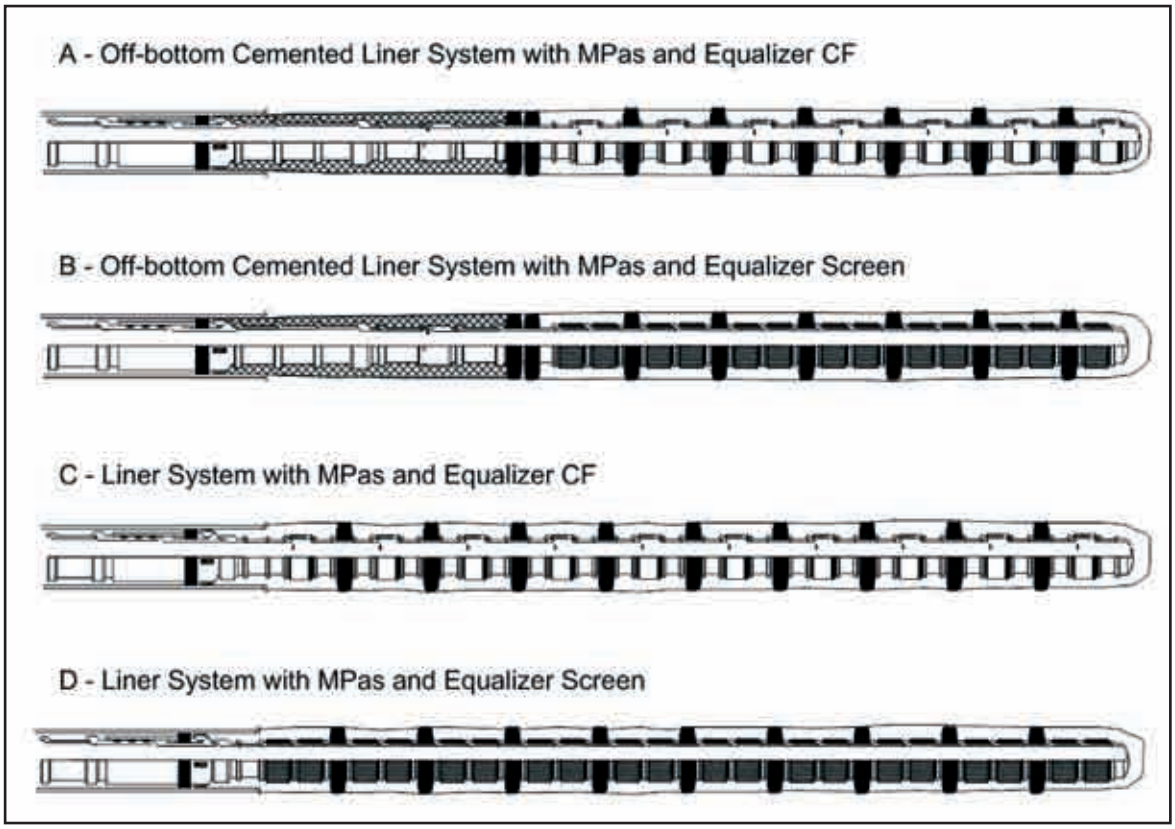


Figure 2 - Open Hole Packer Applications in Different Equalizer Completions.

include installations in sandstone and carbonate reservoirs, OH zonal isolation, casing shoe isolation and gas/water zone isolation.

MPas Packers with Equalizer Production System

In this application, MPas packers are run between sections of the tool in order to hydraulically separate producing intervals of different characteristics in porosity, permeability, or number and size of fractures. The systems divide producing intervals from zones that are not desirable to produced due to fractures/faults or water/gas coning. The design of the assembly is customized in order to meet specific reservoir engineering needs. The positioning of the MPas packers is determined by examining OH logs after drilling. These systems have been run in sandstone and carbonate reservoirs. The hook-ups for different Equalizer/MPas completion types are presented in Figure 2, A-D.

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

MPas Packers for Open Hole Zonal Isolation (OH Straddle)

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

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

MPas Packers for Plug & Abandon Kit

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

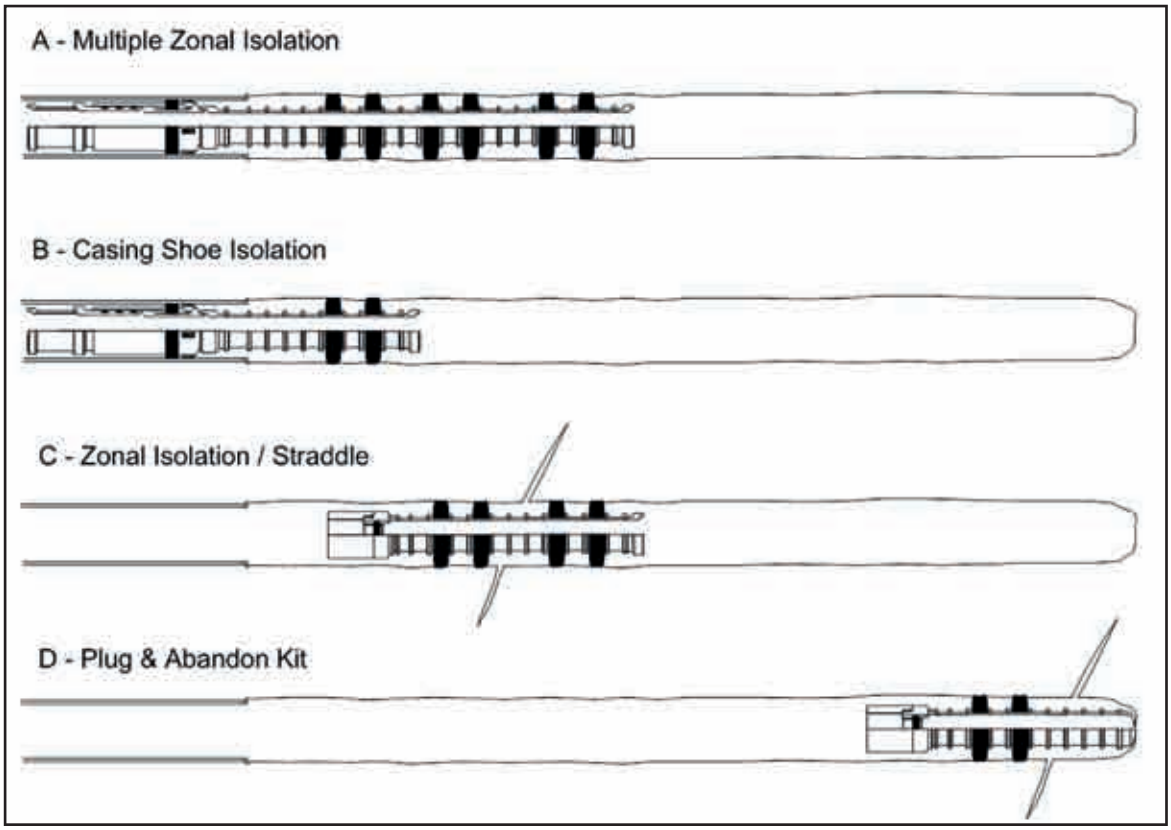


Figure 3 - Open Hole Packer Use in Different Zonal Isolation Applications.

MPas Packers for OH-Casing Shoe Isolation

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

MPas Packers for Gas Cap Isolation

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

The Concept of Compartmentalization: Reservoir Optimized Completions

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

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

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

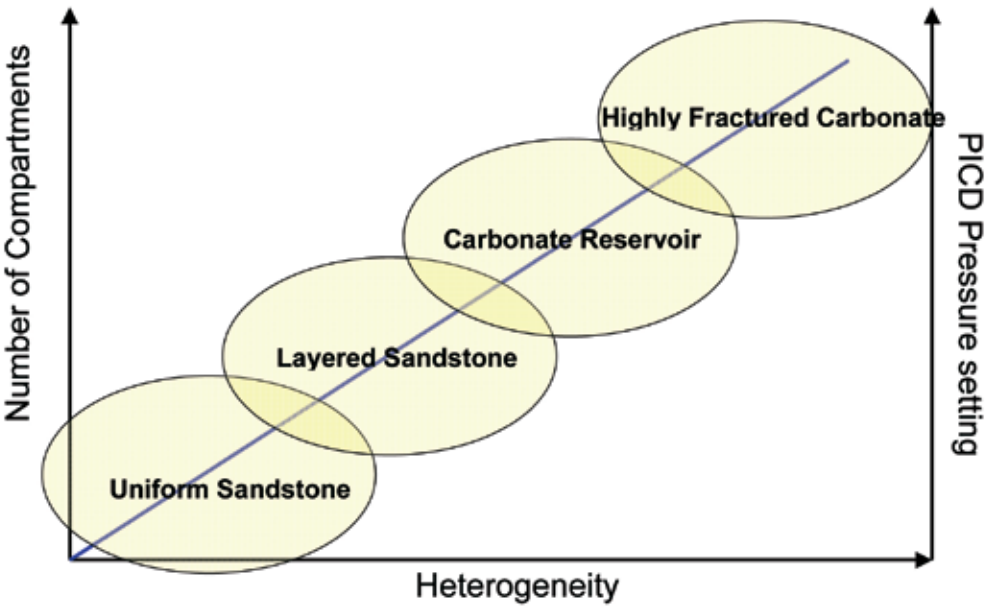


Figure 4 – Role of Heterogeneity in ICD Completions.

present, the reservoir-to-wellbore flow will be dominated by those heterogeneities, minimizing the benefits of an ICD completion.

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

Water and Gas Control

The scenario described above changes when water or free gas begin issuing into the wellbore. At this point, assuming that these undesired fluids are produced by some high PI portion of the pay and not from the entire pay, the domination of high PI features will be detected even by looking to the production data. In this case, the presence and number of compartments will play a critical role.

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

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

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

In Figure 6, the two lines represent two different ICD settings, the red being a double pressure drop through the

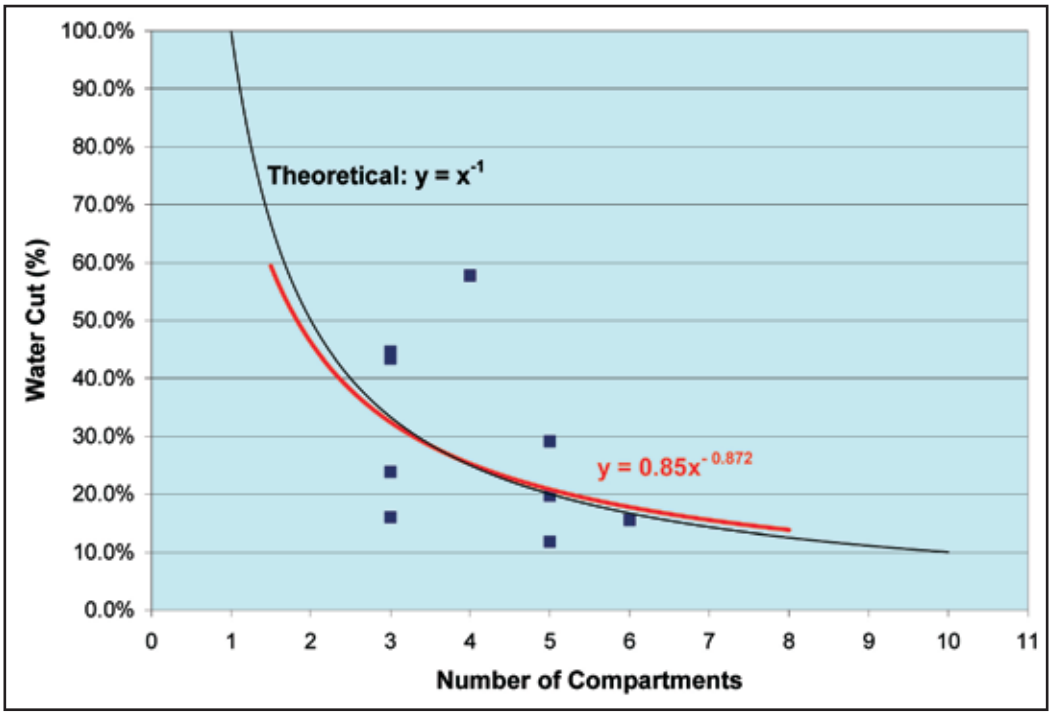


Figure 5 - Effect of Compartmentalization in Water Control.

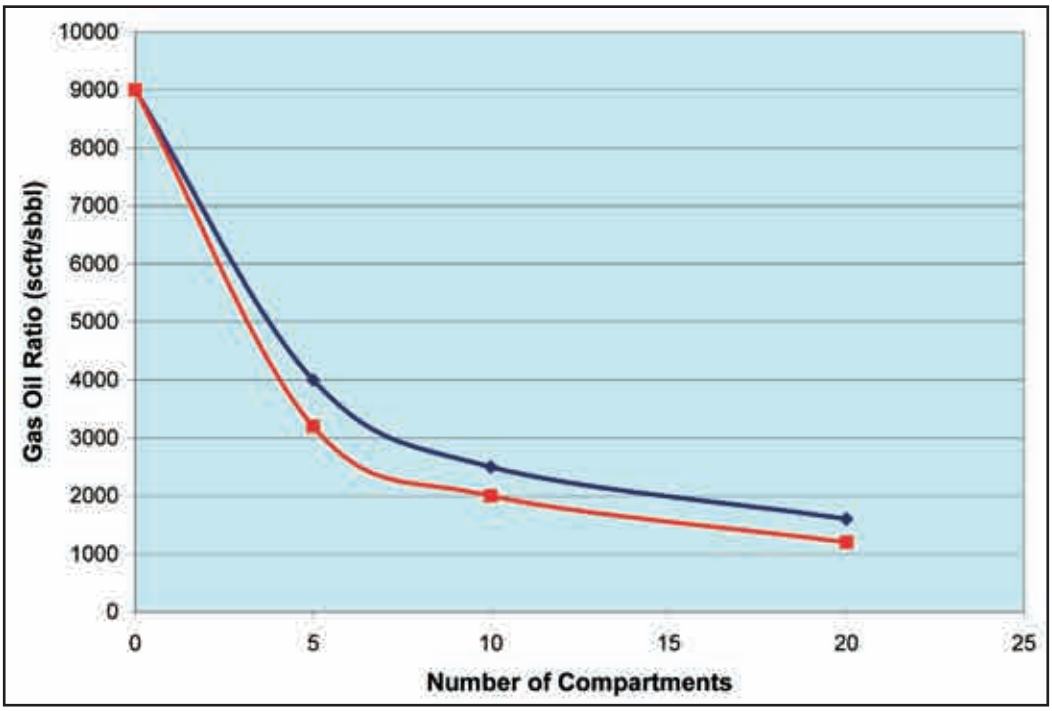


Figure 6 - Effect of Compartmentalization in Gas Control.

ICD for the same rate compared to the blue. As it can be appreciated from the figure there is a GOR reduction by using different type of Equalizer, but the GOR reduction effect is made much stronger by adding compartments than by increasing the pressure drop into the ICD.

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

Hybrid Inflow Control Technology from Halliburton Bridges the Gap

By Duke Giusti and Randy Simonds, Halliburton

In an effort to meet the global demand for hydrocarbons, operators are drilling and completing longer and longer intervals, with horizontal wellbore architecture taking the lead. Interval lengths in excess of 3,000ft in the Middle East and 5,000ft in the Norwegian sector of the North Sea are not uncommon. Fractured carbonate reservoirs are also increasingly being exploited, although at shorter interval lengths than sandstones.

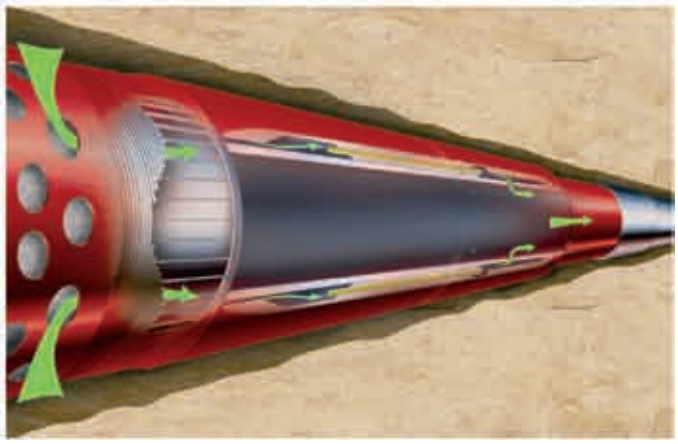
The flow dynamics of such completions, however, can be problematic. In the first case the drilling and completion intervals are very expensive to construct. Additionally, it has long been recognized that flow-induced friction makes the per unit length production contribution imbalanced, with the majority of the production being taken from the heel, rather than the toe. Thus, the expenditure to drill and complete the toe section of the well is in effect money poorly spent.

This phenomenon, often referred to as the heel-to-toe effect, also leads to the early onset of unwanted water or gas breakthrough, which typically occurs at the heel. In many cases this can result in the complete loss of the well and the resulting production and revenue. It should be noted that unwanted water or gas production does not always occur at the heel, but must be managed regardless of where it is expected to occur. These inefficiencies occur in both homogenous and heterogeneous rock.

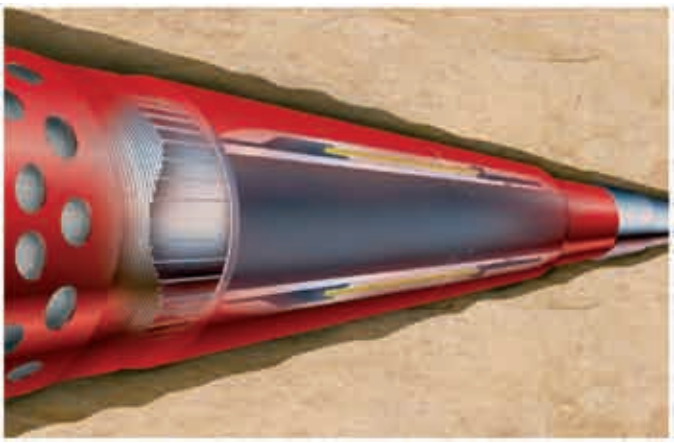
In the second case, fractured carbonates, the issue becomes one more of balancing the inflow performance in the completion due to permeability differences and fractures While the issue in sandstone is largely one of managing the frictional pressure drop in the tubing, in carbonates the emphasis shifts to inflow management. The differences are relatively subtle, one must admit, but the drivers in the completion are quite different.

To minimize the effects it is increasingly common to install Inflow Control Devices (ICD) in the completion string. ICD's are designed to create a pressure drop in the completion to balance out the inflow profile throughout the interval length. When this balance is correctly designed and installed the completion string the detrimental effects associated with long intervals are significantly reduced.

It should be noted that existing technology does not eliminate the breakthrough of unwanted fluids. By evening out the inflow profile this onset is delayed – the



EquiFlow™ ICD shown with flow arrows to indicate production path.



Cross sectional view of EquiFlow™ ICD installed downhole.

water or gas will still migrate through the rock. By delaying breakthough, the ultimate recovery of the well is increased.

A New Alternative

There are different ICD designs in the industry that have been installed with great success and serve to delay onset of unwanted water or gas production. One version uses a helical flow path to create the pressure drop required. While this technology has a large inside diameter (ID) and a low flow velocity it is mainly dependent on frictional pressure drop. This increases the viscosity dependency such that as water breaks through, in the wellbore it may result in an accelerated production of water. Due to the low flow velocity through the helical flow path, settling of solids may be a concern.

A nozzle type design ICD is also available. This type has the smallest flow area and, nozzle inner diameter and a correspondingly high flow velocity, but it is claimed independent of produced fluid viscosity and so maintains its rate at the onset of water production. The nozzles have the smallest diameter so precise gauge control of the filtration media in a sand control application is therefore critical to long term success. Due to the smaller nozzle ID a very small change in nozzle diameter can result in a large change in the pre-configured pressure drop that can, result in sub-optimal completion performance.

Cutaway version of EquiFlow™ ICD with Wrap on Pipe screen.

Recognizing the existence of a performance, reliability, and functionality gap between these technologies, Halliburton has developed and deployed a hybrid ICD; the EquiFlow™ inflow control device. The design utilizes a series of straight tubes to create the pressure drop. As with all designs and assuming a sand control application, reservoir flow travels through the screen and up the screen/base pipe annulus. Flow then enters the flow tubes, which creates the designed pressure drop. Upon exiting the tubes, flow enters the base pipe for production at the surface. The pressure drop created is dependent upon the ID of the flow tubes and the total length of the tubes installed in the device.

The advantages of this hybrid design can be significant. The resulting velocity for a given pressure drop is higher than that seen in the helix and lower than that of the nozzle design. This makes the device self-cleaning and less susceptible to fluid-settling in case of longer periods with well production shut-down. The ID of the flow tubes also bridges those of the other two designs and has larger ID than nozzle and smaller than the helix. The tube design virtually eliminates the viscosity dependence seen in the helix design. In addition, flowing through a long tube compared to a short nozzle decreases any potential erosion issues

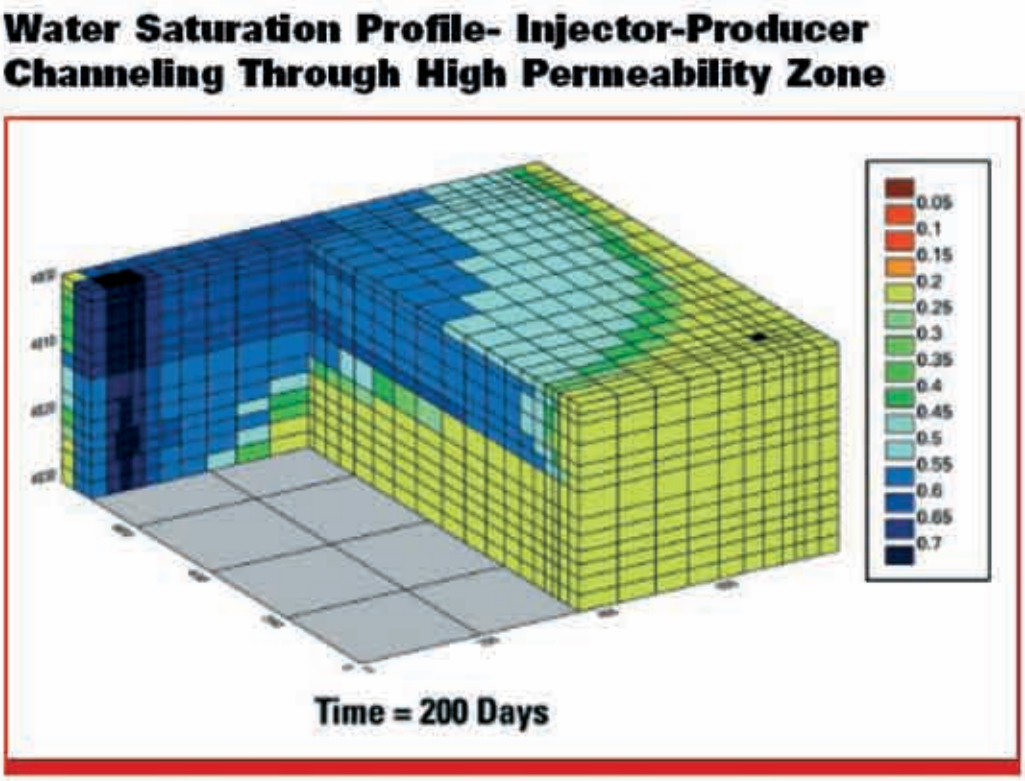
Configuring the Completion

As with all ICD technologies, the effectiveness of the ICD, in mitigating the effects of friction-induced completion inefficiency, are dependent upon the accuracy of the nodal analysis and subsequent reservoir models generated to configure the completion string.

Halliburton has incorporated the EquiFlow ICD equation into AGR's NETool™ simulator software to make nodal analysis a quicker process and more accurate. Halliburton has also created a link between NETool and QuickLook™ reservoir simulator. This link allows transient analysis of the reservoir in order to allow investigation of ICD completion performance over time. This results in more accurate modeling so any potential changes in future production can be planned for today.

Optimizing ICD completions requires the use of annular isolation to reduce annular flow. In general, the more compartments the greater effect on production. Two types of annular isolation are generally preferred. When an instant seal is required a mechanical open hole hydrostatic set packer can be used With a slight modification to the ICD joints these and other packers can be set without wellbore intervention to reduce risk and rig time expense.

In many cases swellable elastomer technology is preferred due to its easy deployment and reliability. Mechanical packers may have limitations with regards to the number of compartments that can be created, Swellpackers can theoretically be installed on every joint. A variety of types of available from very short one foot devices to



A 3-dimensional view of water distribution inside a reservoir with both an injector and a producer, after 200 days of production. This figure shows preferential water channeling from the injector to the producer through high-permeability zone at the upper part of the reservoir.

QuickLook screen shot

purpose built Swellpackers up to twenty-seven feet long. These tools are available with elastomers that can swell in both oil and water.

To investigate the benefit of and optimize an ICD completion simulation modeling is provided by Halliburton. Three cases are typically presented for each well. First, the base case run is a barefoot completion with no ICD's and no zonal isolation – a single zone open hole horizontal case. All subsequent completions are compared against this model.

The second case run is based on a minimal number of compartments either based on customer input (e.g., a desired compartment length, standard pressure drop, etc.) or illustrative of the benefits of even a minimal number of compartments. In many application this results in less smoothing of the inflow profile of the well and resulting water cut in the case of water breakthrough.

Lastly, a scenario is run where all variables are investigated (compartment length, number of ICD's per compartment, etc.) and optimized to optimize fully completion efficiency.

Technology Uptake

To date the technology has been installed in one well in Asia Pacific. By the end of July there are three more installations planned, two of which are for Saudi Aramco. In addition there are six more installations planned in the Asia Pacific region by the end of the third quarter of 2008.

The ten installations have base pipe ranging from 3-1/2" to 7" in both sandstone and carbonate reservoirs.

Summary

Halliburton's hybrid tube ICD design bridges the operational and performance gaps which exist between nozzle and helix type ICD designs. The inflow control device has been proven to provide excellent results in terms of delayed water and gas production, increased ultimate recovery, and improved completion efficiency.

With a rapid acceptance within the industry in the time it has been commercially available, the combination of unique features and a rigorous in-house modeling capability make adoption and installation a quick process.

Cyclic Production Scheme: Innovative Application in Reducing Water Production and Increasing Ultimate Recovery from Mature Areas

By Saad Al-Mutairi*, Saudi Aramco, Hasan Al-Yousef*, King Fahd University of Petroleum & Minerals, Fahad Al-Ajmi*, Saudi Aramco and Hasan Al-Hashim*, King Fahd University of Petroleum & Minerals.

*SPE Member

Abstract

Handling excessive water production is one of the most common challenges in mature oil fields. The world produces almost five barrels of water with each barrel of oil. Cyclic Production Scheme (CPS) was applied as a first field trial in the world in one of mature oil fields in Saudi Aramco to maximize ultimate oil recovery, reduce water production and enhance reservoir pressure.

The results of a conceptual simulation model that was built to assess reservoir performance under the CPS are discussed. Sensitivity cases were carried out to identify the most influential reservoir parameters on CPS. This assessment is to support the understanding and engineering interpretation behind the performance of the CPS.

Introduction

The CPS is an innovative concept to produce oil from mature fields. The scheme requires alternating shutting and flowing wells with high water cut over a predetermined period of time. CPS is not known globally in the oil industry yet.

Over the last decade, cyclic water injection has received great attention since many laboratory works, simulation studies and field tests have shown that it may lead to additional oil recovery, especially in mature oil fields. Excessive water production is one of the most common problems to be dealt with in mature fields[1]. The world produces 300-400 million barrels water per day (BWPD) for 75 million barrel of oil[2]. The world average oil recovery factor is estimated to be 35%. Additional recovery over this average dictates the application of novel technologies, economic viability, and in conjunction with effective reservoir management strategies. An estimated 30 giant fields, mostly categorized as mature fields, constitute half of the world oil reserves[1].


Saad Al-Mutairi

In this study, a conceptual simulation model is built to better evaluate the effects of the CPS on reservoir performance.

Literature Review

Although the CPS is a new concept as mentioned earlier, the cyclic term appeared in the literature since the late 1960s. All previous cyclic works were devoted

Initial Water Saturation (Swi)	0.22
Initial Oil Saturation (Soi)	0.78
Initial Reservoir Pressure	3,600 psia
Rock Compressibility	0.4×10^{-5} 1/psi

Table 1 - Basic Reservoir Properties.

Layer#	Permeability (md)	Porosity (%)
1-2	300	25
3-4	200	20
5-6	100	15
7-8	50	10
9-10	20	5

Table 2 - Model Layers Permeability and Porosity.

mainly for water injection to improve oil recovery and optimize water injection as documented extensively in the literature over the past 40 years.

Arenas[3] proposed a new method called pressure cycling which he tested utilizing a conceptual 2D generic reservoir simulation model. Pressure cycling is a technique that makes use of smart well technology to optimize waterflooding in tight fractured reservoir with horizontal wells. Four development scenarios were conducted for comparison: Conventional waterflooding, no injection, fracture shut-off at injector and pressure pulsing. In pressure cycling, selected intervals of the injection well are cycled rather than the entire well. By controlling water injection across these intervals, it is possible to prevent early water presence between producer-injector pairs due to fractures, thus greatly improving the probability of success of the waterflooding. During pressure cycling, an optimized balance is reached between periods of injection into the fractured zone and periods of injection into only the matrix. This optimized balance resulted in an increase in cumulative oil production over other scenarios like fracture shut-off in tight fractured reservoirs. Based on the ultimate recovery obtained from the simulation runs, pressure cycling is always his preferred option. Improvements in ultimate recovery compared to fracture shut-off from 10% to 60% was observed.

Elkins et al.[4] applied a new unique cyclic waterflooding in the Spraberry field of West Texas. Capacity water injection was used to restore reservoir pressure followed by many months production without water injection and the cycle was repeated. The concept consists of alternating maximum water injection with no injection. The concept was pilot tested in the fractured and very low permeability Spraberry sand, yielding an increase in oil production by 50% at lower water cut level as opposed to continuous water injection.

Felsenthal and Ferrell[5] demonstrated that a cyclic process in fractured or interconnected vugular reservoirs may have considerable merit over conventional water flooding as shown by laboratory and field data. The cyclic process consists of pressuring and depressuring the reservoir by water injection. Also, the conservation of reservoir gas and supplementary gas injection appear to be necessary for the success of pressure pulsing.

Groenenboom et al.[6] proposed the use of pulsed (cyclic) water injection to improve oil recovery in a heavy oil reservoir based on numerical simulations at a field scale. The field test was performed in an oil field in Germany. Although oil production increase was not confirmed by this field trial due to the absence of high quality data, an average increase of 30% in injectivity was recorded during the trial with a plateau injectivity enhancement of 40% during the first two months. The field trial results have enabled us to recognize the potential use of the technology for an efficient high-rate injection strategy.

Ivanov and Araujo[7] conducted two phase immiscible experiments on homogenous and layered packed glass beads cells with conventional continuous and pulsed injection. They found that the amount of oil recovered was larger for the pulsing mode on the cells with layered packed glass beads. In the homogenous case, final recovery was the same for both injection methods. Also, they observed that the displacement fronts were smoother in the pulsed (cyclic) injection compared to continuous injection. The experiment concluded that residual oil saturation under pulsed injection can be reached earlier than under continuous injection which was a very attractive feature for field applications.

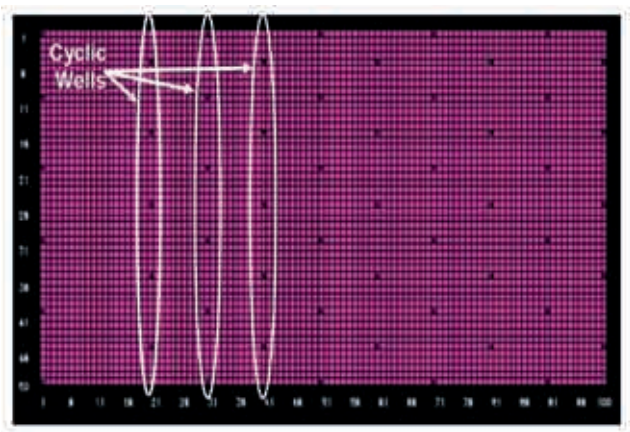


Figure 1 - Simulation Model Areal Dimensions.

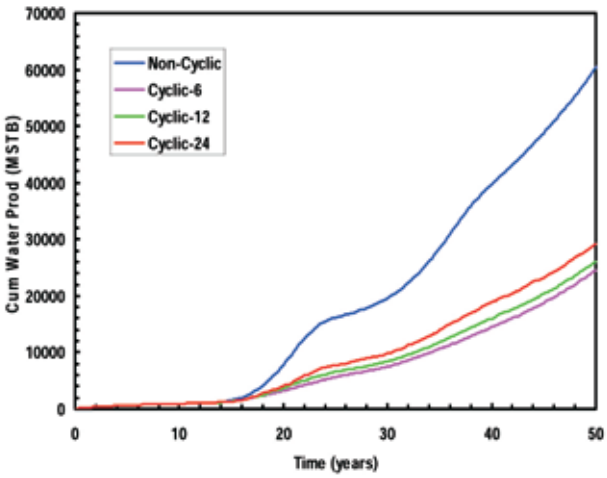


Figure 2 - Comparison of Cumulative Water Production Performance under Non-Cyclic and Cyclic Conditions.

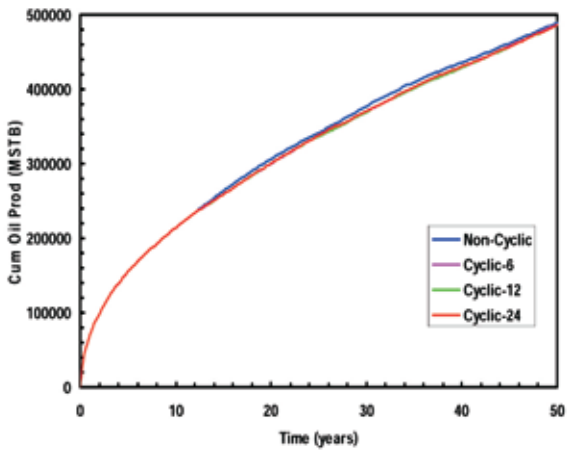


Figure 3 - Comparison of Cumulative Oil Production Performance under Non-Cyclic and Cyclic Conditions.

Stirpe et al.[8] showed that additional oil recovery can be obtained from the application of the cyclic water injection in heterogeneous oil formations in Western Venezuela. Results from a full field model were analyzed with some of the critical variables to determine the potential for cyclic water flooding. Great benefits of the cyclic water injection were observed in terms of cumulative water production. Fewer barrels of water were produced per unit of oil produced. Higher values of vertical transmissibility increased oil recovery by cyclic water flooding, but there is a threshold beyond which the benefit of cyclic is negligible. It was observed that the cyclic water flooding is beneficial at any level of reservoir pressure and for shorter well spacing. In addition, it seems a longer cyclic period (3 month case) yield better oil recovery.

Raza[9] found that additional oil from extensively fractured reservoirs could be achieved with cyclic water pulsing. The additional recovered oil was amounting as much as 25% of the pore space contacted. This method consists of alternately pressuring and depressuring the reservoir. During the pressuring phase, the injected water is forced under high- pressure from the fracture network into the low permeability (matrix). During the depressuring phase, the fluids are produced out of the matrix into the fracture network, which transmits them to the producing wells.

Simulation Work

A 3D conceptual simulation model was created to assess the reservoir performance under the CPS. Several sensitivity cases were conducted to identify the most influential parameters on the CPS in order to increase ultimate oil recovery, reduce water production and enhance reservoir pressure support in the field. The simulation work was performed using CHEARS and ECLIPSE softwares.

Model Description

The model size is 30,000 x 15,000 x 240 ft (100 cells in x-direction, 50 cells in y-direction and 10 layers in z-direction) yielding a total of 50,000 cells. Two models were considered, homogeneous and layered models. The homogeneous model has a constant permeability for all layers (kh = kx = ky = 100 md). The thickness of each layer is 24 ft. The porosity of each layer is 0.20. The heterogeneous model has a constant permeability and porosity for each layer as listed in (Table 1). To calculate the vertical permeability, kv, multipliers of kv/kh = 0.1 and 0.5 were used.

Forty-nine oil producers were populated in the model with 1 km well spacing. To replicate the peripheral water injection system, six water injectors were placed on the edge of the model (Fig. 1). The distance between the injectors and first row producers is 2 km. All wells are completed as open hole across all 10 layers initially. The model assumes no aquifer support.

The remaining basic reservoir properties used in the conceptual simulation model are presented in (Table 2).

Sensitivity Cases

Several cases were carried out in the sensitivity study by changing the cyclic period as discussed below. The kv/kh ratio of 0.5 was used for these cases.

Five parameters were chosen for comparison purposes to study the performance of the conceptual model:

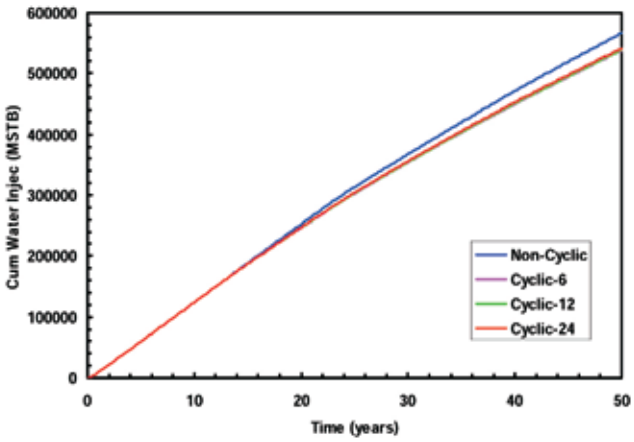


Figure 4 - Comparison of Cumulative Water Injection Performance under Non-Cyclic and Cyclic Conditions.

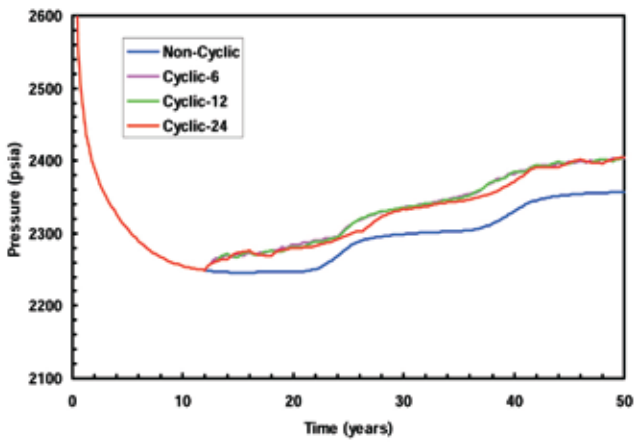


Figure 5 - Comparison of Average Reservoir Pressure Performance under Non-Cyclic and Cyclic Conditions.

1. Cumulative Water Production,
2. Cumulative Oil Production,
3. Cumulative Water Injection,
4. Average reservoir pressure, and
5. Water production rate.

The objective is to maximize cumulative oil production and minimize cumulative water production and cumulative water injection by implementing the Cyclic Production Scheme.

The base cases represent operating the model without the Cyclic Production Scheme which means all producers are active. The model was run from January 1991 until December 2040.

1. Cyclic Startup: Defines the time on which the Cyclic Production Scheme commences. The startup times are assumed in the simulation model to be the time when the water breaks through in the first row of producers. Other rows of producers will also be put on the Cyclic Production Scheme when they start producing water. This design allows us to test Cyclic Production Scheme at various maturity levels. Note that this is an operational parameter and hence can be controlled in real life. For the homogeneous model, the startup times are 12, 24 and 36 years for the first, second, and third rows of producers respectively. For the heterogeneous model, the startup times are 8, 16 and 24 years for the first, second and third rows of producers respectively.

2. Cyclic Setup: Defines the duration of shut-in and production periods of cyclic wells. Three different setups were tested. In the first setup, cyclic producers are shut-in for 6 months and produced for 6 months. In the second setup, cyclic producers are shut-in for 12 months and produced for 12 months. In the third setup, cyclic producers are shut-in for 24 months and produced for 24 months. Note that this is an operational parameter and hence can be controlled in real life.

Simulation Results

A combination of these controllable parameters is simulated using the homogeneous model to find out the best combination of cyclic setup. Simulation results showed by 2040 (proposed run end) the following (Figs. 2-5):

1. Significant reduction in cumulative water production up to 50%.
2. No change in cumulative oil production.
3. Slight reduction in cumulative water injection.
4. Small increase in average reservoir pressure by about 50 psi.

From the Cyclic Setups simulated, the shortest setup with 6 months of shut-in and 6 months of production showed the lowest cumulative water production. Although, the difference between 6 and 12 months of cycle periods is not large. From a field operation point of view, it is desirable to operate the CPS under longer cycles to reduce the operating costs. Therefore, the rest of the simulation scenarios for the homogeneous and heterogeneous cases where ran with 12 months of cycle period. Figure 6 presents the water production rate performance. This Figure shows significant reduction in the water production rate with CPS. The sudden and sharp peaks of water production rate obtained with the non-cyclic scheme were eliminated with the

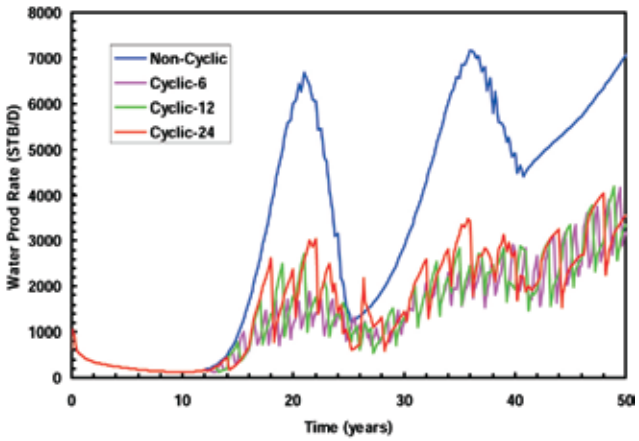


Figure 6 - Comparison of Water Production Rate Performance under Non-Cyclic and Cyclic Conditions.

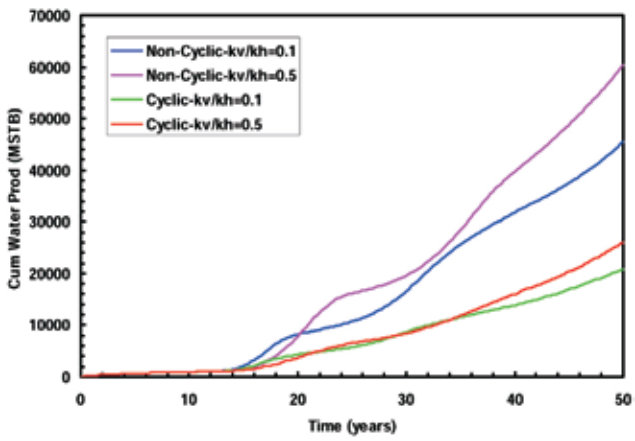


Figure 7 - Comparison of Cumulative Water Production Performance for the Homogeneous Case.

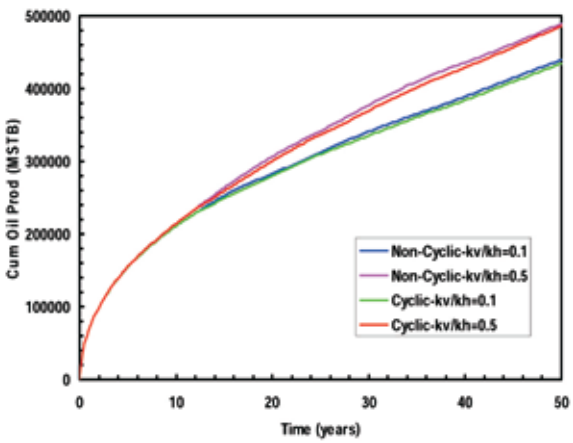


Figure 8 - Comparison of Cumulative Oil Production Performance for the Homogeneous Case.

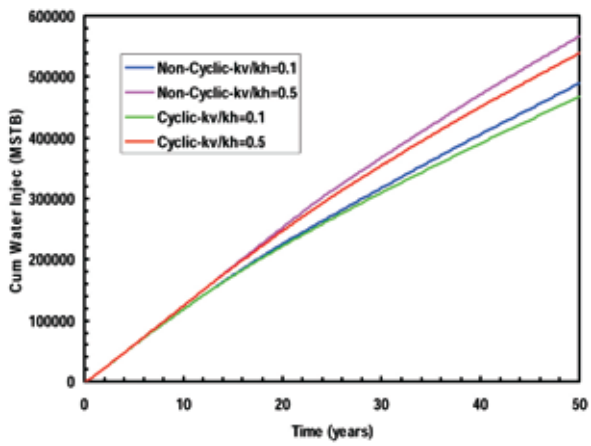


Figure 9 - Comparison of Cumulative Water Injection Performance for the Homogeneous Case.

implementation of the CPS. This is desirable as it does not require an expansion in the capacity of the surface water handling facilities when water breaks through in successive rows of producers.

1. Homogeneous Model: To investigate the benefits of the CPS and study the effect of vertical permeability, two values of kv/kh ratios of 0.1 and 0.5 were used. The results are presented in Figs. 7-11. Figure 7 shows significant reduction in cumulative water production with the CPS. It also shows that as the kv/kh ratio increases, the cumulative water production increases. This is attributed to vertical communication between the simulation layers. When water cut increases in the lower layers, these layers are plugged back. Although, water can easily flow vertically to other layers when kv/kh ratio is high. Figure 8 shows no change in cumulative oil recovery with the CPS. There is small increase in the average reservoir pressure with cyclic scheme as shown in Fig. 10. Figure 11 indicates significant decrease in water production rate with the CPS. Also, with the cyclic scheme, significant reduction in the fluctuations of the water production rate.

2. Heterogeneous Model: The heterogeneous system (Table 2) was run with kv/kh ratios of 0.1 and 0.5. The results are presented in Figs. 12-15. Figure 12 shows significant reduction in cumulative water production with the CPS up to 33% and 35% with kv/kh ratios of 0.1 and 0.5 respectively at 2040. The effect of kv/kh ratio on the cumulative water production is similar to the homogeneous system. Figure 13 shows slight improvement in cumulative oil recovery by 4% with CPS. The cumulative water injected is slightly less with the CPS for both kv/kh ratios. There average reservoir

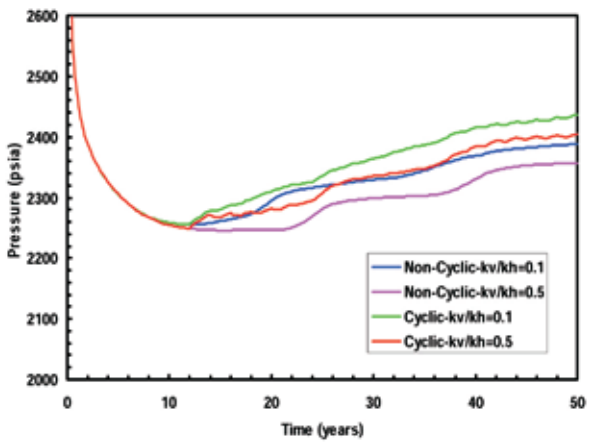


Figure 10 - Comparison of Average Reservoir Pressure Performance for the Homogeneous Case.

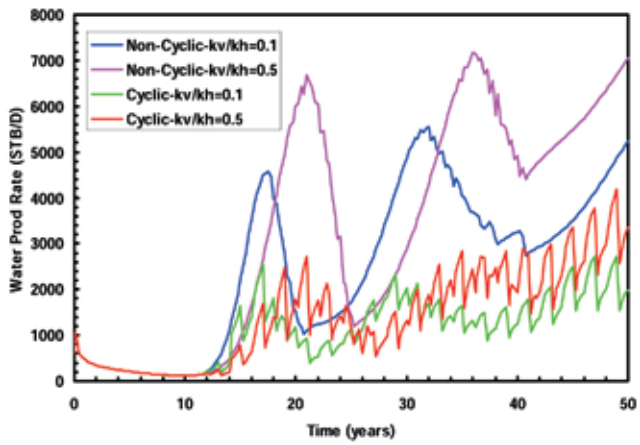


Figure 11 - Comparison of Water Production Rate Performance for the Homogeneous Case.

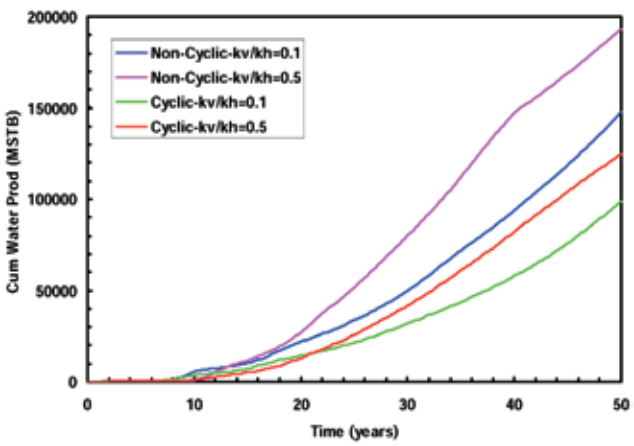


Figure 12 - Comparison of Cumulative Water Production Performance for the Heterogeneous Case.

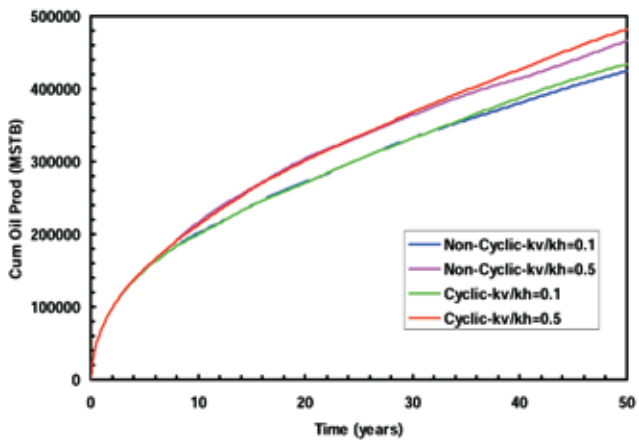


Figure 13 - Comparison of Cumulative Oil Production Performance for the Heterogeneous Case.

pressure has increased by 50 psi the CPS as shown in Fig. 15.

Conclusions

Based on the results presented in the paper, the following conclusions are reached:

1. CPS may lead to a better production performance by providing a successful managed water reduction.

2. The simulation results showed the advantage of applying Cyclic Production Scheme over the regular non-cyclic production in all cases studied.

3. Cumulative water production was reduced significantly with no impact on oil production.

4. There was less in water production rate with CPS. Therefore, there is no need for a large expansion of surface water handling facilities.

5. The promosing simualtion results bring the attention to consider CPS as a strategic solution to develop production scenarios and enhance routine reservoir management practices for specific reservoirs.

6. Short cyclic setup and early cyclic startup when water breaks through are key parameters to determine when CPS can be implemented.

Nomenclature

GOR = Gas oil ratio

ICV = Inflow control valve

md = Milli Darcy

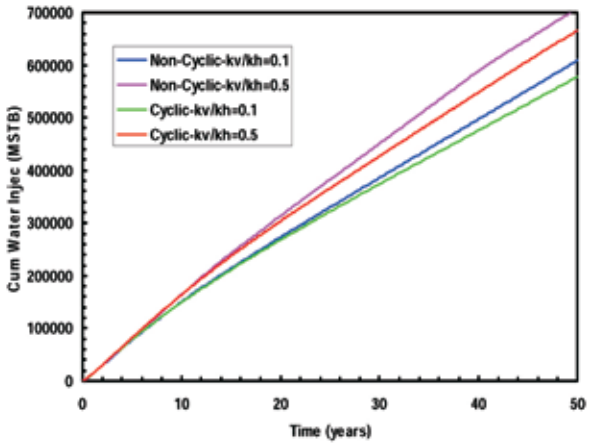


Figure 14 - Comparison of Cumulative Water Injection Performance for the Heterogeneous Case.

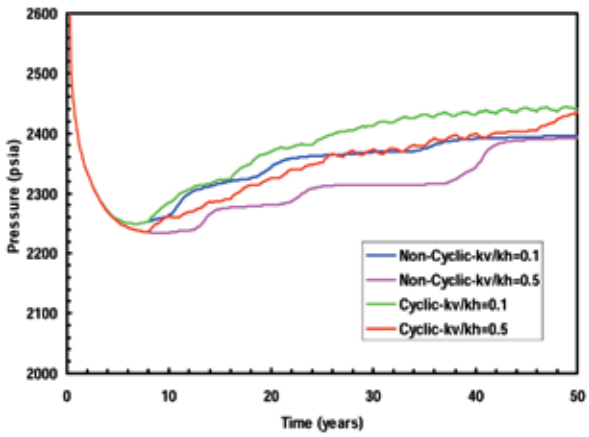


Figure 15 - Comparison of Average Reservoir Pressure Performance for the Heterogeneous Case.

MBD = Thousands of barrels per day

PDHMS = Permanent downhole measurement system

RST = Reservoir saturation tool

SCF = Stock cubic foot

STB = Stock tank barrel

Sw = Water saturation

WOR = Water oil ratio

CPS = Cyclic Production Scheme

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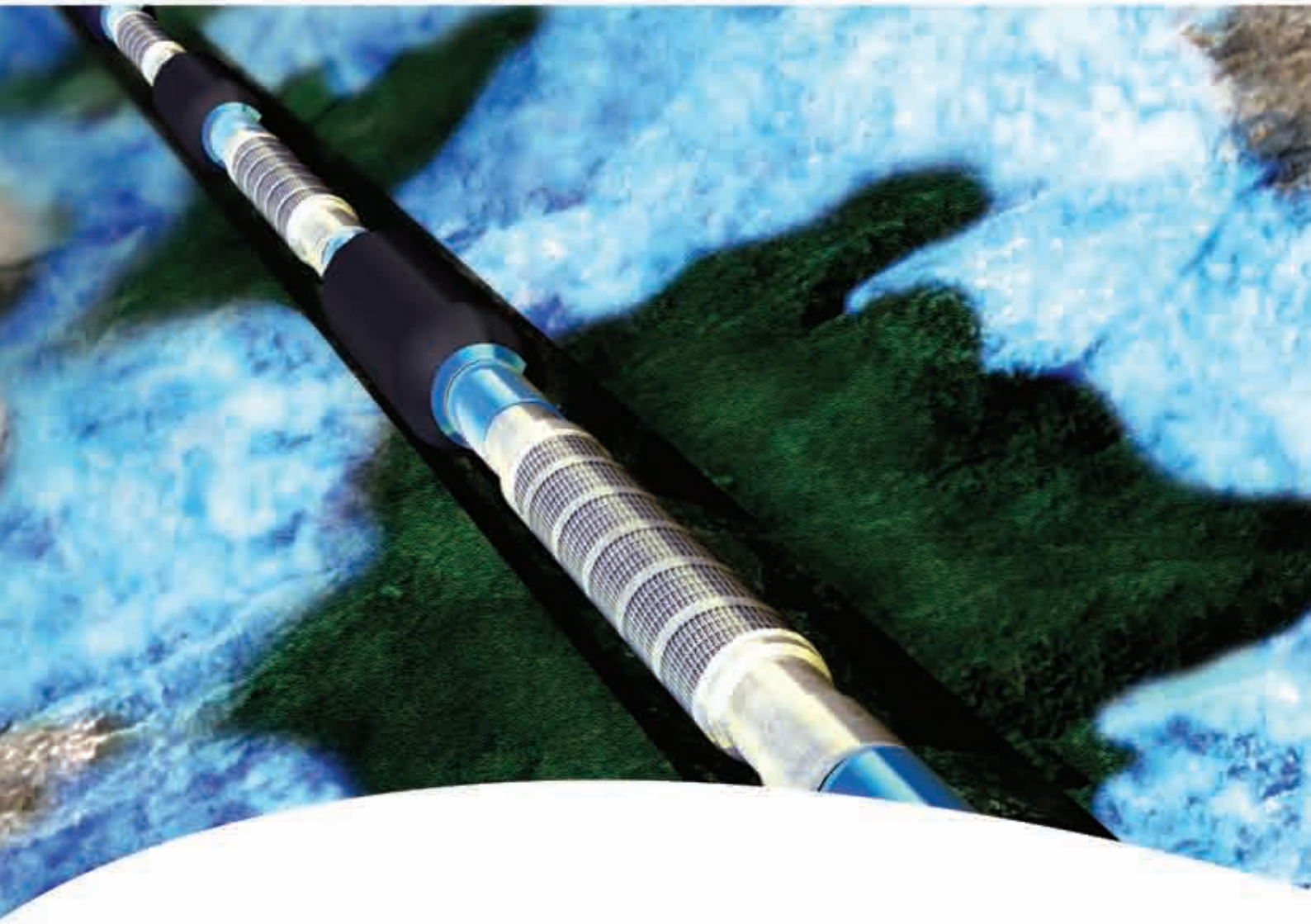

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