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ATS&E REVIEW

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Saudi Arabia oil & gas

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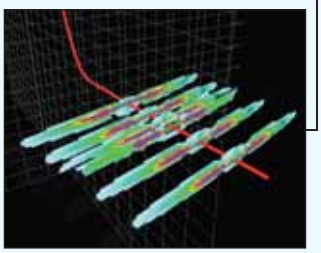

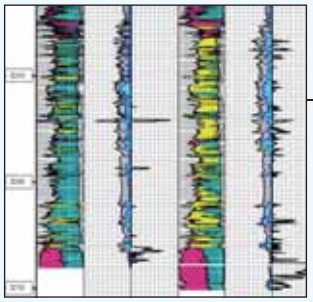

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SPE ANNUAL TECHNICAL SYMPOSIUM & EXHIBITION

Seef, Al-Khobar | Saudi Arabia

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2014 ATS&E Best Paper Awards

The technical program committee is pleased to announce the best paper and e-poster winners in the 2014 ATS&E:

1st Place:

Majid Rafie - Southern Area Production Engineering Department

The First Successful Multistage Acid Frac of an Oil Producer in Saudi Arabia

2nd Place:

Abdullah Al-Akeely - Reservoir Description & Simulation Department

Can Sourceless Density LWD replace Wireline in Exploration Wells? Case Study from Saudi Arabia

3rd Place:

Mohammed Al-Askar - EXPEC Advanced Research Center

Transport of Temperature Nanosensors through Fractured Tight Rock: an Experimental Study

Best E-Poster:

Samusideen A. Salu - Northern Area Technical Support Department

Unconventional Flare Gas Recovery Systems (FGRS)

Tariq Al-Zahrani
Co Chairman, 2014 SPE-SAS Annual Technical Program

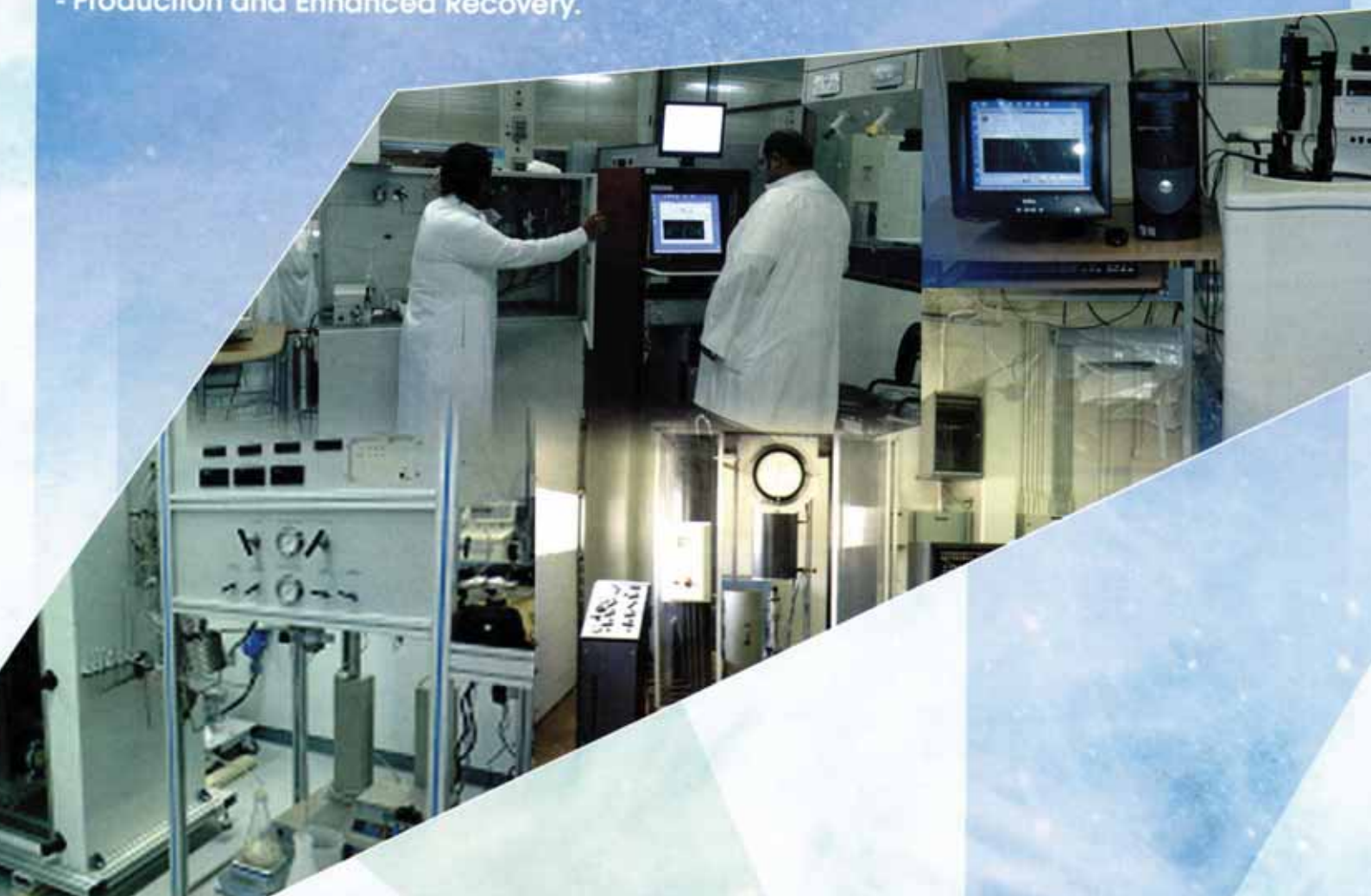
Dr. Ahmed Alhuthali
Chairman, 2014 SPE-SAS Annual Technical Symposium & Exhibition

مدينة الملك عبدالعزيز
للعلوم والتقنية KACST

Oil and Gas Research Institute

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

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



Services Provided

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

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Remarks at the 15th International Oil Summit

Paris, France, 11 April 2014

"Your Excellencies, Distinguished Guests, Ladies and Gentlemen, bonjour and good afternoon. It is wonderful to be in Paris, and I would like to thank the Institut Français du Pétrole for the opportunity to address this esteemed group.

Let me begin today with a macro view of the oil market, before moving to discuss the downstream sector.

Despite the challenges we may face, the petroleum industry has weathered the effects of the global economic downturn better than most, and I believe we are in a long stretch of an expansion phase. In fact, if anything, the industry risks being stretched by the stretch! For example, oil demand is expected to continue growing, from some 92 million barrels per day currently to roughly 115 million bpd, a quarter century from now.

Although this growth would be slower than the roughly 40% increase seen over the last 25 years, it is still substantial, especially since it will come on top of the global industry replacing more than 40 million barrels per day of natural decline in output from existing conventional fields.

Most of this growth stems from the combination of a larger global population, higher living standards, and rising urbanization, especially in the developing world where billions of new consumers will be demanding the comforts and conveniences that energy can provide.

The greatest volumes will still be going to transportation, with the number of vehicles on the world's roads growing by about three-quarters of the current level over the next quarter century and oil remaining the dominant fuel, especially in heavy transport. To put that into perspective, oil demand in transport alone could increase by more than one-third from about 50 million bpd today, with the share of distillates likely to significantly rise in the products mix. When it comes to petrochemicals, the volumes of oil feeding this segment won't match the sheer volumes in transportation, but chemicals demand growth will definitely set the faster pace.

> The costs of developing the marginal barrels of tight and heavy oil, and resources in the deep sea and Arctic, are quite high, and it is estimated that more than 10 trillion dollars of upstream investments will be needed globally over the next 25 years.

Of course, there is plentiful oil to meet this demand growth, given the large global resource base of both conventional and unconventional resources. Diversifying this base not only taps additional resources of hydrocarbons, but also ensures long-term price sustainability within a range that benefits both global consumers and producers. The costs of developing the marginal barrels of tight and heavy oil, and resources in the deep sea and Arctic, are quite high, and it is estimated that more than 10 trillion dollars of upstream investments will be needed globally over the next 25 years – even before inflation. For those investments to be forthcoming, prices must be healthy enough to make developing these more expensive and technically challenging resources not only economic, but sufficiently enticing to the capital markets.

Even when it comes to conventional oil, costs continue to rise due to multiple factors, including greater project complexity, requiring all of us to sharpen our capital discipline –something my friend Christophe has talked about many times. Even at Saudi Aramco, the industry's lowest cost producer, we've witnessed a step change in costs. Just last year, Christophe and I visited our 900 MBD Manifa crude oil program, one of the world's largest offshore oil fields, which supplies 400,000 barrels per day of oil for full conversion at our joint SATORP refinery.

I noted then that the daily barrel of production capacity at Manifa was roughly twice as expensive as at our previous increment. In fact, Manifa's total price tag of 17 billion dollars would have been higher had we

> We're so bullish on the downstream sector in part because of one simple fact: crude oil must be processed into useful products that can be consumed by the transport sector, the chemicals industry, and by other industrial and commercial applications.

not value engineered and driven our costs down by two billion dollars after contract signing, to better reflect changing EPC market conditions.

That underscores the need for strong cost discipline and a keen focus on project management all along the value chain. Total and Saudi Aramco did just that with our downstream SATORP project, which was built on time and on budget through best-in-class execution. This new venture represents a major step in achieving Saudi Aramco's vision of being among the world's top three refiners and a world-leading manufacturer of chemicals, building on its upstream leadership position

We're so bullish on the downstream sector in part because of one simple fact: crude oil must be processed into useful products that can be consumed by the transport sector, the chemicals industry, and by other industrial and commercial applications. So, incremental demand for oil inevitably leads to large downstream investments.

And as we have all seen, the downstream industry is going through a substantial shakeup, with some companies spinning off their downstream or shrinking, while others like us are expanding. Let me elaborate in some detail our views on downstream, and what is behind our downstream expansion.

We are in the process of building a world-leading downstream business that is both vertically integrated across the value chain and horizontally integrated across suitable geographies. Our goal is to add greater value to our hydrocarbon supplies while building a more robust and resilient portfolio that can better withstand market turbulence. We're doing that through what I would call "new platforms" for downstream business success, which I strongly believe represents the new model and way forward for this sector of our industry.

These platforms require four key factors, the first of which is simply large scale. They comprise massive

> Matching world-scale plants and infrastructure with strong future demand for their output is vital for downstream success, and we will continue to see most of these new platforms being built in high-growth markets like China, India, developing Asia and the Middle East.

plants, and their mega-capacity enables them to better capture operational efficiencies and economies of scale.

The second factor is related to the first, and involves integrating refining, chemicals and lubes for value addition and portfolio diversification – something best done in a facility that has a certain critical mass of processing capacity. At the same time, these mega-facilities take integration to the next higher level as they are tied to steady, reliable supplies of crude oil. Because they represent base-load production of refined products and petrochemicals, these plants will run steady at near-capacity volumes – not swing their throughput up and down depending on the availability of feedstock. So having the right kind of crude slate, reliably delivered, is essential.

The third key ingredient is building these facilities close to major markets poised for substantial long-term growth, and ensuring that they are integrated with strong marketing channels in those geographies. Matching world-scale plants and infrastructure with strong future demand for their output is vital for downstream success, and we will continue to see most of these new platforms being built in high-growth markets like China, India, developing Asia and the Middle East.

The fourth key factor is, of course, technology. That begins with more efficient and more economic process technologies that allow these plants to produce cleaner products that meet increasingly strict environmental standards while maximizing profitability—in part by cracking deep into the bottom of the barrel to produce more valuable products. The growing upgrade to cleaner products is consistent with the rising demand for more light white products as the demand for fuel oil continues to shrink.

In fact, our PetroRabigh and SATORP joint ventures in the Kingdom, our Fujian joint venture in China, and our S-Oil JV in Korea are perfect examples of such

> Against the backdrop of certain substantial growth in demand for oil, we can be equally certain that there are enormous global resources – available through a diverse portfolio of conventional and unconventional oil reserves – upon which we can draw.

new-look platforms. All of these facilities fulfill these four criteria. Take S-Oil's Onsan Refinery as just one example, where you find scale at nearly 700,000 bpd of capacity, fully integrated processing capabilities that include refining base oils and production of chemicals, a geographic position that is perfect for supplying big and growing Asian markets, and the utilization of advanced process technologies—most of which were developed by Axens, a subsidiary of IFP.

But when it comes to technology, we also need to look beyond the refinery gates, at end-user applications and efficiency gains for our consumers. These will help to reduce the environmental impact of oil on a well-to-wheel basis, in terms of greenhouse gas as well as ground level emissions, and to ensure the long-term public acceptability for our products.

At Saudi Aramco, we are substantially strengthening our R&D program, with a technology agenda that incorporates both the upstream and downstream, in keeping with our strong presence all along the petroleum value chain. In the downstream, though, we are focusing on transportation, particularly advanced, integrated fuel-engine systems. We believe there are tremendous opportunities to be realized from the synergies that can be harnessed by combining advances in both engines and fuels, and by looking closely at their interface.

This integrated approach will allow us to concurrently satisfy several stretch objectives, including radical improvements in mileage efficiency over the long term, not simply incremental enhancements; substantial reductions in emissions, with a long-term goal of going beyond the Euro 6 standards; and the economic viability of both the engines and the fuels which power them.

I would note that we are also pursuing research into carbon capture and utilization, further expanding our innovation horizon.

Such technology targets would overstretch even the

best research lab or industry player, and I would argue that no entity is in a position to go it alone and expect success. That is where a strong commitment to partnership comes into play—because none of us acting alone is as capable as several of us working together. Taking that truth to heart, Saudi Aramco has adopted an open network innovation model that integrates talent, capabilities and ideas from around the world through strategic research alliances, global satellite research centers, and investing venture capital in those startup companies who are developing the cutting-edge energy technologies of tomorrow.

In fact, one of our partners in the integrated engine-fuels research I described earlier is IFP, and we have built on our longstanding R&D relationship with the Institute by opening one of our new global satellite research centers right here in Paris—an initiative that also collaborates with PSA Peugeot-Citroën.

The Clean Combustion Center at the King Abdullah University of Science & Technology, in which we are a partner, also has a substantial French presence, with both Alstom and the University of Lille represented in the consortium. Similarly, the Dhahran Techno Valley, right next door to Saudi Aramco's headquarters, now boasts R&D centers of some of the world's leading industrial and energy companies, including IFP, CGG and Schlumberger, all of whom are among this summit's major sponsors.

We're excited by the prospects for these partnerships not only because we're working with some of the planet's leading energy researchers, including in engine-fuel systems, but also because the advanced energy and environmental solutions they will develop have the potential to serve the entire world.

But the mutual commitment to partnership finds its greatest expression through strategic energy investments, especially in the new platforms for downstream success I described earlier. Once again, we've gone beyond theory to practice, partnering in the Kingdom and around the globe with industry leaders. These are mutually beneficial relationships designed and built for the long term, which harness the capabilities and expertise of each partner for the benefit of all.

Of course, when you collaborate to combine technological know-how with industrial prowess, you have the makings of something special. One marvelous example of just such a combination is the trilateral partnership among Saudi Aramco, Total and IFP, at our recently commissioned SATORP grassroots refinery, jointly owned by Saudi Aramco and Total. In addition to fully converting 400,000 barrels per day of Arabian heavy crude into the World's cleanest white products, the project is producing more than a million tons of paraxylene, benzene and high-purity propylene, and it uses a number of refining and petrochemicals technologies once again developed by Axens.

Ladies and gentlemen, let me now conclude. Against the backdrop of certain substantial growth in demand for oil, we can be equally certain that there are enormous global resources – available through a diverse portfolio of conventional and unconventional oil reserves – upon which we can draw. At the same time, these barrels will need to be processed and provided to consumers around the world, and that calls for a new and compelling downstream model based on a "new platform" of large, strategically positioned and technologically sophisticated integrated refining and chemical facilities.

Furthermore, there is no doubt that the capital outlays needed for both the upstream and the downstream will be massive, and will rely on a healthy price environment that yields favorable returns for investors. And of course, none of this will happen automatically nor can we take such investment and development as a given; rather, as an industry we will need to execute, remain disciplined on costs, and embrace the synergies that come through cooperation and partnership.

It is my hope, and indeed my belief, that Europe's public sector, its companies and corporations, and its academic and research communities will recognize the tremendous opportunities on offer in the new downstream landscape, which can be realized through large-scale, integrated facilities located in expanding markets and leveraging advanced technology. If that is the case, the prospects for us to collectively meet the world's growing demand for petroleum products and petrochemicals while protecting the environment are indeed bright."

Saudi Aramco Makes the Case for Long Term Investment

MANAMA, 28-May-2014

Investment in the Gulf Region remains profitable. This was a common theme among participants at Petrotech 2014 in Bahrain.

The conference offered decision-makers and investors the chance to meet with personnel in the industry and get basic information about petrochemicals, including the mix of chemical products that will be available in the region starting in 2017, to sow the seeds of investment and gain a better understanding of the incentive plans available to investors.

Workshops during the conference focused on the growth of the petrochemical sector in the GCC region. Major executives of the region's industrial companies spoke at the workshops, and discussions and presentations were designed to assess current and evolving investment opportunities.

Speakers also discussed the development of global demand for end-user and advanced products from the geographic and individual product perspectives. The workshops also highlighted the special competitive advantages available in the area of hydrocarbons to producers in GCC countries and the effect of such advantages on the industry's global landscape given the developments in unconventional oil and gas.

Discussions also covered the effect of the ongoing supply side changes in the U.S. and elsewhere for producers in the Gulf, the importance of utilizing talented young professionals and the need to extract and produce materials at a competitive cost at or near potential markets. Workshops also focused on the opportunities available for producing countries in the region to play a more significant global role.

A number of participants in the discussions represented three types of institutions: banks, capital markets and

> In this conference we sought to shed light on Saudi Aramco's efforts in an area which is important to the Kingdom's economy, i.e., petrochemicals, as we seek to attract establishments and companies engaged in areas of benefit to the company.

export credit agencies. They discussed the role of regional government funds in financing various types of projects, developing human capital and supporting initiatives aimed at achieving sustainable revenues.

One finding of the discussions was that the Gulf Region is a positive environment for foreign direct investment, especially for companies that employ local talent in local manufacturing. Added to this are the incentives and advantages offered by the Gulf countries. Such a positive environment is composed of the following factors: Young employees, well-educated manpower, sufficient energy supplies, abundance of chemicals and minerals supplies, advanced industrial facilities either currently existing or under construction, proximity to regional and global markets, and positive local and regional expenditure plans to fuel business growth.

During the conference's first day, Warren W. Wilder, Saudi Aramco vice president of Chemicals, presented a history of the company, starting with the its early beginnings and then covering crude oil production, refining and petrochemicals, ending with a future that includes conversion industries. "We are proud of our success stories to date but know that that there is a lot more we can do for the company and the Kingdom," said Wilder.

Wilder stressed that the company has aggressive objectives in the area of chemicals. "Our goals in chemicals are ambitious. We plan to become a top tier chemicals company on a global level. We will integrate chemicals facilities with our refineries and maximize the value of refinery feeds," he said. "As a company, our focus has always been on good citizenship and economic diversification, industrialization and job creation. Our chemical industries will be aligned with the conversion parks associated with the chemical facilities."

Wilder participated in a workshop titled "Investment Opportunities" along with Ziyad Al-Labban, CEO of Sadara, Saudi Aramco's joint venture with Dow Chemical Co. that is building a world-class chemicals facility in Jubail.

Another workshop, "Opportunities for Development of Refining, Energy and Services Businesses," featured Abdulaziz A. Al-Judaimi, Saudi Aramco vice president of Corporate Planning, and Motassim Al-Ma'ashouq, Saudi Aramco vice president of New Business Development.

Omar S. Bazuhair, Saudi Aramco executive director of Refining and NGL Fractionation and chairman of

> An elite group of Saudi Aramco engineers and specialists contributed technical papers, sharing their successful experiences in an exchange of ideas and knowledge that aimed to benefit conference attendees.

Petrotech 2014, noted the company's petrochemical ambitions are important to the Kingdom. "Citizenship is an important value at Saudi Aramco," Bazuhair said in an interview. "The company exerts a lot of efforts to invigorate the Kingdom's economy. In this conference, we sought to shed light on Saudi Aramco's efforts in an area which is important to the Kingdom's economy, i.e., petrochemicals, as we seek to attract establishments and companies engaged in areas of benefit to the company. … Our ultimate objective is to maximize synergies and integration so materials are used inside the Kingdom and exported as end-user products.

"Saudi Aramco has made a lot of investments in this area, such as Petro Rabigh, Sadara and SATORP. We are proud of what we have achieved. However, we do not believe that we have reached the end; rather, this is merely the beginning. We will continue on the road to increasing the welfare of Saudi citizens and creating more employment opportunities for them."

After inaugurating Petrotech 2014, HH Sheikh Ali ibn Khalifah Al-Khalifah, Vice Prime Minister of Bahrain, listened with HE Sheikh Ahmad ibn Muhammad Al-Khalifah, Minister of Finance and Minister in Charge of Oil and Gas, and Khalid A. Al-Falih, Saudi Aramco president and CEO, to a number of presentations given by young employees at the company's pavilion. Malik A. Zaineldain, representing Chemicals, gave a presentation on local and global business opportunities as well as the organization's young talent. He noted that there are about 150 chemical and mechanical engineers in the company's Chemicals organization, all of whom have been enrolled in professional development programs and working with local and international joint ventures.

Arwa Al-Harbi, a member of Saudi Aramco's Young Leaders Advisory Board (YLAB), gave a general presentation on the company's operations. She started with an overview of energy and economy in the Kingdom, then moved on to the oil and gas industry, highlighting the role of energy as the main driver behind all types of businesses, investment opportunities and the creation of abundant employment opportunities.

Sarah Abduljabbar, a chemical engineer, gave a presentation on Saudi Aramco's drive into petrochemicals and the opportunities available to young people of both genders to be a part of petrochemical projects in several areas of the Kingdom.

Another presentation about the company's chemical operations was given by Mohaned Al-Faisal, despite only 10 months with Saudi Aramco. A graduate who studied abroad in the U.K. with a major in safety engineering, Al-Faisal works in the NGL Fractionation Department at Jiddah Refinery.

Fatima Al-Mousa, of New Business Development, works for the Saudi Aramco Energy Ventures (SAEV) company. Although she is still enrolled in the Professional Development Program, she has major responsibilities as she works in the area of investing in emerging companies in energy and oil-related technologies. She gave an overview of such investments worldwide.

Khalid M. Al-Gimlas, of Chemical Operations Support and Coordination Department and also a YLAB member, gave a presentation on YLAB's role.

Salem Al-Subaiey of the Chemical Projects Development Department gave a presentation on Saudi Aramco's transition to the petrochemical industry until the phase of full integration is achieved in 2020. The success of this transition will rely on the most basic resource: the young people joining the company's ranks. Al-Subaiey stressed that giving such a presentation at Petrotech 2014 was an affirmation that Saudi Aramco has already entered the world of petrochemicals.

Hytham Al-Saati of Ras Tanura Refinery's Engineering Department gave a presentation titled "Development of Refining Technologies."

An elite group of Saudi Aramco engineers and specialists contributed technical papers, sharing their successful experiences in an exchange of ideas and knowledge that aimed to benefit conference attendees. The papers received positive reactions. The contributing authors included Yasser Mowalad, Mamdouh Alderous, Mohammed Jalmood, John Haesle, Mohammad AlAbdullah, Suliman Albassam, Mohammad Mansour, Mathew Mickelson, Madhi Al-Anazi, Nimer Safi, Bruce Beadle, Mahmoud Ibrahim, Salman Al-Mishari and others.

Faisal Al-Faqeer, manager of the Ras Tanura Refinery's Engineering Department and chairman of the conference's technical committee, highlighted the importance of Saudi Aramco's presence at Petrotech 2014, stressing that the company's sponsorship and participation stems from a culture of supporting such conferences. More than 1,000 participants were present at the inauguration session, which, in itself, was a sign of the unique conference's success.

Asked about the papers submitted to the conference, Al-Faqeer said: "The technical program is so rich in information. We selected working papers with utmost care, applying quality standards in terms of subject and presentation. The papers came from countries around the world and dealt with the subjects of refining, marketing, safety, modern technologies and petrochemicals.

"It is not easy to write a working paper for a scientific, engineering and technical conference like this one," he said. "It takes a lot of effort and accumulated experience. This is why it is necessary for the committee to have members capable of evaluating papers from the scientific, technical and engineering points of view and ensuring they are up to the required level."

Hamad Al-Mehthel, also a member of the technical committee and the official in charge of conference communications, noted the importance of the conference's emphasis. "This is the only conference in the region that deals with the refining business with such a focus," Al-Mehthel said. "We did something different during the current conference. We gathered a large number of participants from all fields to urge them to invest in the petrochemical industry. All the attendees, either industry experts or investment firms that will fund future projects, had authorities and decision-making capabilities."

Earlier, as reported in the May 21 edition of The Arabian Sun, during the conference inauguration, Al-Falih had described the resources available to the refining and petrochemical industry in the Gulf Region as "historic opportunities." The rest of the conference agenda offered ample evidence.

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ATS&E
ANNUAL TECHNICAL SYMPOSIUM & EXHIBITION

SPE Saudi Arabia Section 2014 Annual Technical Symposium and Exhibition Review

Opening ceremon with (from right) Mr. Khalid Al-Buraik, Dr. Jeff Spath, Mr. Amin Nasser, Mr. Khalid Nouh, Mr. AbdulRahman Al-Wuhaib and Dr. Mohammed Al-Qahtani.

Jeff Spath
President
Society of Petoleum Engineers

AbdulRahman AlWuhaib
Senior Vice President, Downstream
Saudi Aramco

Ashok Belani
Executive Vice President, Technology
at Schlumberger

Khalid Nouh
President APME Region
Baker Hughes

The Society of Petroleum Engineers – Saudi Arabia Section successfully completed its 2014 Annual Technical Symposium and Exhibition (ATS&E) on April 21 – 24 at Seef Hall in Al-Khobar, attracting about 3,000 visitors. As the premier gathering of the oil and gas professionals in the region, the symposium served as the platform of knowledge transfer and experience sharing in the Gulf region specifically as well as internationally, serving the men and women who empower the energy hub of the world. Saudi Arabia Oil and Gas Magazine was the official magazine for the 6th year running and was distributed at the Exhibition entrance free of charge at the event.

The symposium continued the tradition of putting together an impressive technical program consisting of two pre-event courses, two pre-event workshops, 20 technical sessions, four e-poster sessions, three luncheon keynote speeches and a high-profile panel discussion. The exhibition attracted 17 exhibitors, two of which were new to the ATS&E, and brought forward new technologies and services that enriched the exhibition and benefited its attendees. The symposium continues to be recognized by SPE International as the event was listed in the Meetings' Calendar. The symposium also applied the strict "no paper, no podium" policy to ensure the level and quality of participation remains high.

The symposium enjoyed a high-level of participation throughout its activities, with excellent organization by the responsible committees. The theme of the symposium – "Unattainable, Unsustainable, Unconventional, Made Possible" – accentuated the excellent industry efforts in energizing the globe and delivering a sustainable future for upcoming generations by unlocking industry challenges. The recent advances – digital energy, unconventional resources exploitation, drilling practices and ultimate oil recovery processes – testify that our industry is reliable and can evolve to meet global demand.

Opening Ceremony

The 2014 ATS&E opening ceremony was attended by over 600 guests from varied professional backgrounds including operators, service providers, and academia based in the region and internationally. The opening ceremony commenced with welcoming remarks from

the symposium's Chairman, Dr. Ahmed Alhuthali, after which four distinguished keynote speakers took the stage; Mr. AbdulRahman AlWuhaib (Senior Vice President of Downstream at Saudi Aramco), Dr. Jeff Spath (2014 SPE President and Vice President of Industry Affairs at Schlumberger Limited), Mr. Khalid Nouh (President of MEAP Region at Baker Hughes Incorporated), and Mr. Ashok Belani (Executive Vice President of Technology at Schlumberger).

Mr. AbdulRahman AlWuhaib addressed unconventional gas development in Saudi Aramco and its importance to the company's Accelerated Transformation Program (ATP) and to national growth. A prime example is the government-initiated industrial development, Wa'ad AlShamal. Such developments aim to replace liquid fuels used in the Kingdom power generation, resulting in lower environmental impact, the freeing up of liquid hydrocarbons for exports, creating a competitive Saudi energy sector, growing manufacturing of energy related goods, promoting related service industries, generating jobs for Saudis, developing investment opportunities and finally, contributing to the domestic security of supply in the oil field services.

Dr. Jeff Spath highlighted that the industry is indeed facing huge challenges. One of the major challenges is that over the past 10 years, the total E&P CAPEX has risen by 400%, while oil production increased by 15% only. He then shared the SPE's new four strategic objectives aimed at unlocking such challenges, saying that those objectives were fully met by the symposium. First is the development of critical dialog between industry and academia, fostering collaboration between the oil and gas industry and other industries and professional societies. Second, sharing the latest breakthroughs in the industry and using new methods such as combining social media and mobile computing to promote global knowledge sharing for members and the general public. Third is holding training courses and workshops. Fourth is promoting professionalism and engaging in social responsibilities. He then stated that SPE-SAS is by far the fastest growing section globally in the past five years.

Mr. Khalid Nouh's speech focused on the importance of paradigm change to achieve successful breakthroughs and expand possibilities. Two examples were shared; PDC drill bits and magnetic resonance logging. It took the industry more than 30 years to adapt to the first, and 50 years questioning the second. The issue was clearly not the technologies themselves, but the mindset, paradigms, resistance to try new things, resistance to change and fear of failure. Expanding possibilities into new realities and reaching sustainable, successful breakthroughs can only be met by challenging paradigms, admitting that we cannot deal with what we don't know by doing what we know, creating mindsets that foster change, embracing new thinking, accepting failures and turning them into success, encouraging different thinking and creating an uncomfortable environment that is productive.

Mr. Ashok Belani seconded Dr. Spath by sharing the same challenge of high CAPEX growth. He then shared four drivers of capital efficiency that aid in tackling this challenge; partnership, reliability, innovative technologies and integration. With the strongest partner of Schlumberger being Saudi Aramco; two examples were shared, the land seismic system (UniQ) and extreme reservoir contact wells completion systems. Reliability in unconventional and deep water is a key important factor. In unconventional, reliability of individual products directly affects many actions and functions working simultaneously for the efficiency of the complete process. For deep water, reliability is important in keeping the cost low and the delays under control. Innovative technologies are only beneficial when the products and services fit into the process model. Finally is integration, which is driven by software platforms where services and products are

Panel discussion.

integrated to remove insufficiencies at the interfaces or handoffs between services.

Panel Discussion

In addition to the technical program, a panel discussion was held on the second day of the event under the theme "How to Unlock the Full Potential of Upstream Technology?".

The panel was moderated by Mr. Samer Ashgar (Manager of EXPEC ARC, Saudi Aramco), and was composed of industry leaders in the area of research & development and technology deployment strategies with a balanced mix of technical and managerial and leadership roles; Tim Probert (President, Strategy and Corporate Development), Nicholas Gee (Founder, Ingenium Energy Ltd.), Judson Jacobs (Director, IHS Cambridge Energy Research Associates), Dr. Ali Dogru (Saudi Aramco Fellow), and Pieter Kaptejin (Upstream Consultant). Each panelist gave a presentation addressing the theme from different point of views, ranging from concept to conception to deployment. Dr. Dogru gave a talk on computational modeling as the next big thing in terms of disruptive technology. Mr. Pieter addressed big data tsunami in terms of volume, velocity and variety and smartly integrating it. Mr. Judson listed the steps needed to develop a disruptive technology. Mr. Gee talked about R&D intensity and the

drivers and enablers behind idea transformation to adoption. And, last but not least, Mr. Probert gave examples distinguishing between invention and innovation, where the former comes about occasionally and the latter is where the envelope is frequently pushed and inventions continuously evolve. The engaging talks stimulated an excellent Q&A session kicked off by a question from the moderator, Mr. Samer, followed by a good number of questions from the audience.

Sponsorship

The symposium provided a great opportunity for companies to promote their names, technology and expertise at the event. The entire venue was themed so that the sponsors' logos were displayed based on their sponsorship levels.

Keynote Speakers

During the symposium, two luncheon keynote speeches and one luncheon video broadcast were delivered.

The first luncheon keynote speech was delivered by Mr. Vincent Tourillon, Vice President HSE MEA at Schlumberger. His speech revolved around safety in exploration and production activities and shared three elements that makes a zero defect goal attainable. The elements are: leadership, management and accountability, learning and corporate memory and engagement, behavior and culture.

The second luncheon keynote speech was delivered by Dr. Mario Ruscev, Chief Technology Officer at Baker Hughes. His speech revolved around seismic resolution and measurement capabilities, wild-cat exploration and development of wireline logging tools. In addition, he elaborated on unlocking tight potential using hydraulic fracturing and mapping the man-made fracture, using well-to-well high seismic geophones to monitor and evaluate future performance.

The video broadcast was provided by Halliburton and covered technologies that unlock some of the current industry challenges.

Technical Program

The Technical Program comprised 20 technical sessions and four e-poster sessions with over 90 presentations and keynote invited speakers tackling subjects related to the following 10 major areas:

1. Petrophysics
2. Drilling Operations
3. Production Operations
4. Reservoir Engineering
5. Reservoir Characterization
6. Well Completion
7. Reservoir Simulation
8. Unconventional Resources
9. Enhanced Oil Recovery
10. Stimulation and Productivity Enhancement

Best Paper Award winner Majid Rafie (right), with second place winner Abdullah Al-Akeely (center) and Mohammed Al-Askar (left), who came in third place.

Best Paper Awards

The technical program covered a wide range of novel case studies and technologies that upstream business requires to make exploiting unconventional resources possible. In order to promote excellence and also reward technical contribution, 2014 ATS&E technical committee extended the awards to the best three technical papers and best e-poster. Comprehensive feedback was received from all 20 technical sessions' chairpersons and other four e-poster sessions.

This year's event winners received by far the highest ratings amongst other presenters and they are all Saudi Aramcons. The winner of first place in best Paper Award was Majid Rafie from Southern Area Production Engineering Department for his paper entitled "The First Successful Multistage Acid Frac of an Oil Producer in Saudi Arabia". The second and third place winners respectively are Abdullah Al-Akeely, from Reservoir Description and Simulation Department for his paper "Can Sourceless Density LWD replace Wireline in Exploration Wells? Case study from Saudi Arabia", and Mohammed Al-Askar from EXPEC ARC for his paper "Transport of Temperature Nanosensors through Fractured Tight Rock: an Experimental Study". The best e-poster award went to Samusideen Salu from Northern Area Technical Support Department for his poster "Unconventional Flare Gas Recovery Systems (FGRS)". The 2014 ATS&E chairman received the awardees and presented them with their gifts and certificates.

Courses and Workshops

ATS&E pre-event activities consisted of two workshops (one was a two-day workshop) and two courses which was attended by almost 140 participants. Below are further details on the pre-event activities.

1st Workshop: The Road to Ultimate Recovery in the Middle East: Best Practices and Innovative Technologies

This workshop was a 2-day event combining experts

speaking and engaging the essential audience about topics such as the latest industry technologies and best practices in the business. It took place in Le Meridian Al-Khobar from 7:30 am to 3:30 pm. Each day was divided into multiple sessions; where a presentation was given for 20 minutes, followed by a discussion period of 15 minutes, and lastly groups presented their findings, comments, and concerns to the rest of the attendees and speakers. Every session was then summarized with 20 minutes' summary notes presented by the chairperson.

During the first day two sessions were held: Innovative Technology Deployment and Best Practices. In the first session Dr. Gaurav Agrawel, the VP of Baker Hughes, gave an intriguing speech entitled "Road to 70% Recovery Nanotechnology Solutions for Flow Assurance in Unconventional", followed by Michael Konopczynski from Halliburton presenting the topic "Using Advanced Completions to Enhance EOR Performance", and lastly Dr. Sultan Al-Enezi from Saudi Aramco ending the morning session with a presentation about Smart-Water Flooding Technology.

The second session, Best Practices, was a shorter one. It started with a talk about "The Norwegian Road to Ultimate Recovery" given by Robert Kuchinski, from Weatherford, and ended with "Maximizing Ultimate Recovery in Nested Bimodal Carbonate Reservoirs" by Tony Pham, from Saudi Aramco. The first day had 60 attendees, all of whom were engaged during the period and had valuable discussions and feedback.

On the second day, with 50 attendees, the discussion kept its pace and participants were just as active. Another two sessions were given; Advanced Recovery Technologies and the Wrap-up session for the entire workshop. The first session had three speakers, starting with Haq Minhas from Baker Hughes presenting his interesting topic of Chemical EOR, followed by Dr. Sunil Kokal talking about CO_2-EOR, and ending

the session with Wael Abdallah from Schlumberger presenting "EOR Road Map: Screening to Successful Pilot Operation". The Wrap-up session that followed summarized all the key points mentioned through the past two days, with an open discussion and last questions asked by the audience. The workshop ended with an appreciation note, a token of appreciation to all speakers and technical committee members, and a group picture. The feedback survey received from the participants showed encouraging results indicating the success of the workshop.

2nd Workshop: Drill Ahead of Bit

PEASD jointly with SPE-SAS and Upstream Continuing Excellence Team successfully conducted a technical workshop entitled "Drill Ahead of Bit" on April 21 as part of the ATS&E technical program. More than 50 subject matter experts (SMEs) from both the oil and gas industry and academia participated and discussions concerned challenges, techniques and best practices. The participants showed a great deal of interest in the subject and some wanted to share with us their solutions in this domain over the coming few weeks. Attendees were also informed about our efforts towards establishing a Special Interest Group with SPE International on this subject. This workshop was highly appreciated by the attendees, with more than 80% ranking the workshop as excellent or outstanding.

1st Course: Introduction to Geomechanics and Hydraulic Fracturing in Unconventional Resources

This one-day course was conducted on April 20 as part of the ATS&E technical program and was sponsored by Next, a Schlumberger Company. The course was divided into two sessions, morning and afternoon. The first session of the course introduced the fundamentals of geomechanics as applied to shales, highlighting the anisotropic and heterogeneous nature of shale and its impact on stress calculations and hydraulic fracturing.

Key geomechanical parameters that help the selection of lateral landing points and optimize multi-stage frac design were also reviewed. The second session of the course gave a brief overview of shale completion techniques, selection of lateral landing points, perforation and staging evaluation. Operational aspects and guidelines on design and optimization of hydraulic fracturing, selection of fracturing fluids and proppants

were also discussed. The courses were characterized by heavy attendance and dynamic discussions between the participants and instructors.

2nd Course: Intelligent Field Infrastructure Architecture, Components and System Data Flow Overview

The course, held on 21 April, provided a detailed technical overview of the different I-Field Infrastructure components, including Electrical Submersible Pump (ESP), Multiphase Flow Meters (MPFM), Permanent Down Hole Monitoring Systems (PDHM), Smart Well Completion, surface instrumentations and supervisory control data acquisition and application systems. This session also included an overview of the data flow journey from the sensor to the engineer's desktop. Case study scenarios were used to demonstrate best practices as well as optimal deployment strategies.

Thirteen professionals attended the courses, out of 23 who confirmed their attendance. They came from different operating and service companies with different backgrounds and work experiences. The diversity of the participants enriched the discussion and maximized the knowledge and experience sharing among the participants.

The attendants were very professional in leaving the class for breaks and coming back to class on time. A group buffet lunch was served and all the participants, along with the course instructors, had lunch together in a friendly atmosphere.

At the end of the course, which was very well presented and received, attendance certificates were awarded to the participants and tokens of appreciation to the course instructors.

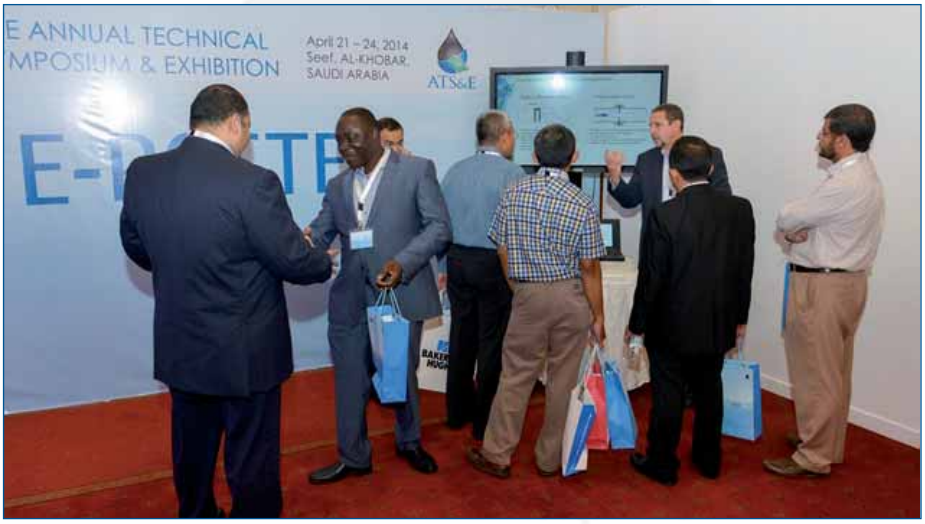
The Exhibition

The exhibition floor plan was designed with optimum walking and booth areas, ensuring smooth flow. Several exhibitors combined multiple booths, creating larger spaces.

A total of 17 exhibitors showcased the latest in technology development and products from their respective companies, as follows:

1. Saudi Aramco
2. Baker Hughes
3. Schlumberger
4. Halliburton
5. Weatherford
6. GoTech
7. Dynamic Energy
8. LindeSigas
9. Enventure
10. EnPro
11. PetroLink
12. Midad
13. AkzoNobel
14. TGT Oil
15. Naizak
16. TDE Group
17. Rawabi Holding


enpro


E ANNUAL TECHNICAL
MPOSIUM & EXHIBITION
April 21 – 24, 2014
Seef, AL-KHOBAR,
SAUDI ARABIA
ATS&E

Committee members, the 2014 Annual Technical Symposium and Exhibition.

Of the 17 exhibitors, two companies were new to the ATS&E, both locally and internationally, adding to the diversity of technologies and experiences on display. Moreover, two e-poster booths were included in the exhibition, attracting many professionals to present their technical papers.











Guests enjoying the Gala dinner.

Gala Dinner

The ATS&E organizing committee conducted a Gala dinner where more than 120 attendees from executive management, international guests and sponsors.

Aiming to have a friendly networking environment and share in Saudi Arabian culture with the international guests, the dinner was held in Movenpic Resort & Spa in a traditional set-up, cuisine and activities. The guests enjoyed a traditional Saudi dance performance with tents and local cuisine. The Gala dinner was well received and all guests enjoyed the friendly interaction and networking.

The First Successful Multistage Acid Frac of an Oil Producer in Saudi Arabia

By Majid Rafie, Rifat Said, Muhammad Al-Hajri, Tariq Almubarak, Adel Al-Thiyabi, Ikhsan Nugraha, Saudi Aramco; Eduardo Soriano, Jared Lucado, Halliburton.

This paper was prepared for presentation at the SPE Annual Technical Symposium and Exhibition held Al Khobar, Saudi Arabia, 21–24 April 2014.

Abstract

In Saudi Arabia, conventional oil reservoirs have been treated using conventional stimulation methods. The challenge is that many of the formations now are tighter and require improved stimulation methods. Fracturing is a major topic discussed in the industry as of late and as such, using it in this formation will serve as a trial to shift from conventional stimulation methods to fracturing when facing tighter formations.

This particular acid frac was performed in a tight carbonate formation. The chosen well is a newly drilled trilateral producer completed with a multistage frac completion in the motherbore and will serve as a pilot well for this reservoir in the area. The acid frac was a seven stage completion utilizing hydraulic fracturing. Several methods using pressure and injection were used to determine reservoir fracturing response and petrophysical properties.

This paper will discuss the first multistage acid frac performed in an oil producer in Saudi Arabia. It will examine the entire process of candidate assessment, job preparation, and execution. In addition, the paper will discuss challenges faced, solutions taken, and the post-decision results. The paper will show how an injectivity test performed pre- and post-frac was used as a benchmarking tool to analyze the effectiveness of the frac. Finally, we will discuss the flow back of the well, initial results, lessons learned, and optimization of future jobs.

Introduction

While developing new reservoirs in a certain area, difficulty arises in the lack of experience when deciding how to complete a well. As such, the goal is to identify reservoir characteristics and properties and align them with the most common approaches when it comes to well completion. The targeted reservoir in this case was characterized to be a porous tight carbonate formation. The reservoir displayed porosity values in areas indicating remarkable reservoir property. The method when targeting new reservoirs is to use the

Fig. 1 · Generic schematic of a multistage completion composed of swellable packers and sliding sleeves.

simplest of the most common methods, therefore, a well was drilled as a single lateral in the reservoir. The well was acid stimulated and put on production. It was later found that the production was unsustainable at the required rates. This result led us to evaluate all of the available options to complete and stimulate the well in this reservoir.

In a low permeability environment, multistage fracturing is one of the best options and increasing the number of fracturing stages will potentially give a better well productivity. This type of well completion can pose a myriad of completion challenges for operators. One challenge we are faced with on every stimulation job is proper zonal isolation and fracture stimulating multiple pay zones during the well completion process. In combination with these factors, it is especially demanding when working with cemented production casing strings, open hole completion, or open hole packers and perforated liners.

In a conventional completion/stimulation process, the cemented casing string is perforated in the toe and stimulation begins. Sequential steps in this completion process require the operator to set plugs, perforate, and fracture each zone individually. Depending on the well design and fracture treatment design requirements, several hours per zone may be required for the plug and tubing convey perforation/wireline trips, which prepare each stimulation stage, leaving the fracturing crew idle. Continued innovations have made this process somewhat more efficient in horizontal applications by use of pumpdown composite plugs, however, operators can still only perform three or possibly four fracture stages per day on a single wellbore. Due to the increased activity of today's industry, scheduling equipment and manpower for future fracture dates is becoming more difficult and could result in delays in production when multiple fracture treatments are desired.

When using an open hole completion technique, the operator drills into the formation and opens a path to the wellbore for production. This particular method works well in formations that have structural stability and contain natural fractures; however, problems arise when stimulation treatments are desired because "bullhead" fracturing treatment usually results in fracturing the weakest point in the formation without treating the entire pay zone. This complication prevents operators from achieving the maximum potential payout on their investment, and can result in additional expenses for interventions associated with re-stimulating to increase production and make the well commercially viable.

In wells that are in areas with high concentrations of natural fractures, cementing a production string in place is not always a preferable option because cement may migrate into the natural paths that allow hydrocarbons to enter the well, resulting in production losses. The situation gets even more complicated when the wellbore crosses sensitive areas, such as water zones, that must also be isolated from wellbore treatments. In this scenario, operators may choose to run a liner using open hole packers in the annulus to isolate the undesirable zones and then perforate their liners near the pay zones to allow access for treatment and production (Vargus et al. 2008).

Traditional open hole packers are either inflatable or compression set. These options introduce greater complexity into the wellbore because adding these mechanical devices into the completion string increases

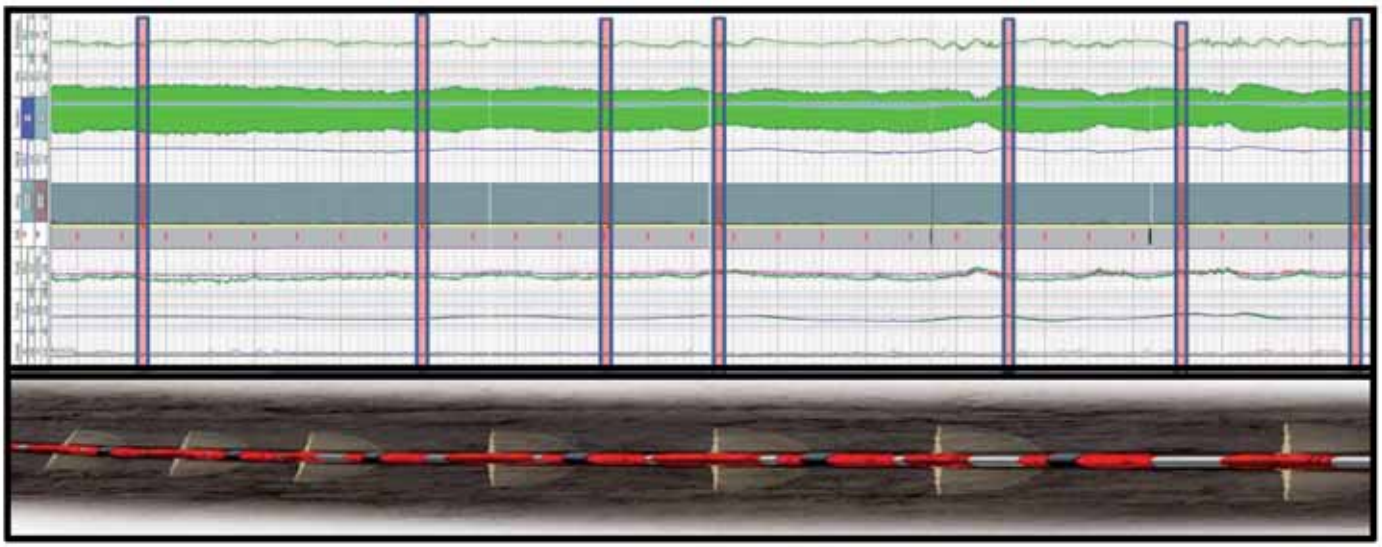


Fig. 2 · Processed log indicating the selected stages for acid fracturing.

the chances of a mechanical malfunction. Additionally, with either of these options, sealing integrity is dictated by the initial setting force introduced into the elements. These forces give a very high probability of creating unwanted fractures in your wellbore area and can lead to communication between compartments (Roundtree et al. 2009).

Saudi Aramco has installed open hole multistage systems since 2007, mainly in carbonate gas production formations and most of them have been with mechanical packer types (Rahim et al. 2008). Another multistage acid matrix stimulation trial was made in oil reservoirs, which showed promising results on the use of multistage completions (Al-Naimi et al. 2008). Initially, most of the wells completed with an open hole multistage system were drilled in the direction of maximum in-situ stress, and longitudinal fractures were expected to occur; as a consequence communication between stages was observed with the inability to create more than a single independent fracture. In such cases, the treatment for the subsequent stages was designed as matrix treatments limiting the reservoir contact and drainage area. Further effort was conducted to complete wells in the direction of minimum in-situ stress, with the target to have transverse fractures. Nevertheless, communication between stages continued to happen (Al-Ghazal et al. 2013). Some improvements were incorporated in subsequent jobs, such as installing double packers system. Based on the above evaluation, open hole with multistage completion using swellable isolation packers were chosen for the pilot well in this reservoir. The swellable packer technology is based on the swelling properties of rubber in hydrocarbons or water, or in both. Swellable packers are able to swell up to 200%, thereby sealing the annulus around the pipe to achieve effective zonal isolation. Once deployed, the rubber retains its flexibility, allowing the swellable isolation system to adapt to shifts in the formation over time, retaining the integrity of the seal. The self-healing properties make this a truly innovative technology for many zonal isolation applications. As such, it is highly recommended when dealing with a wellbore zone filled with washouts and multiple diameters. Since the rubber is bonded to the base pipe, it is extremely robust and can hold significant differential pressure between annulus compartments. It has no moving parts and requires no downhole or surface activation except it sometimes requires up to 30 days before the packer is fully set.

This multistage completion consists of the sliding sleeves system, Fig. 1, which optimizes the completion of multistage wellbores by enabling more accurate placement of stimulation treatments without intervention (when ball activated). This helps to ensure that the stimulation treatment covers the targeted areas in the wellbore and maximizes the stimulated reservoir area. The sliding sleeve system can be run into a wellbore using a casing string or an expandable liner hanger system to enable a reliable, trouble-free installation. To activate the sleeves, different sized balls are dropped in sequence, smallest to largest. The activation balls seal on a corresponding millable baffle, allowing wellbore pressure to shift the sleeve open, diverting flow into the segmented annulus area through ports in the sleeve

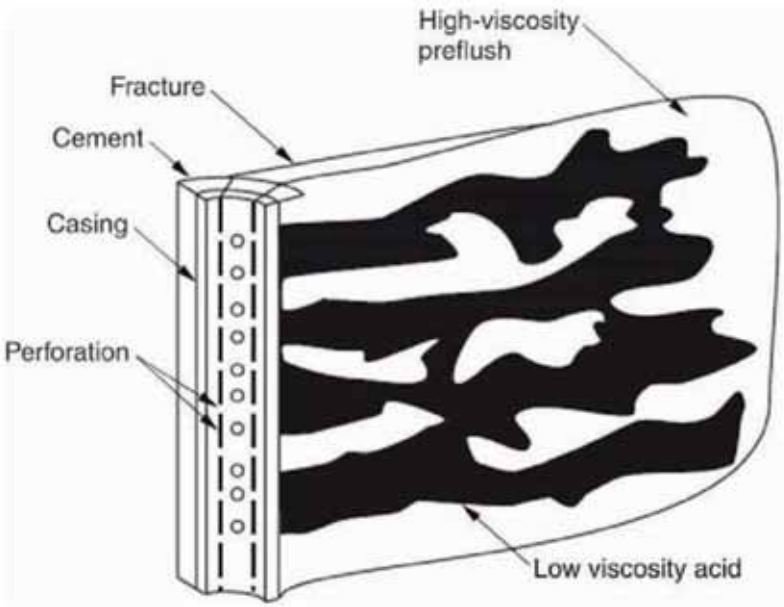


Fig. 3 · Differential etching technique to sustain conductivity

and providing isolation from previous stages below. After stimulation, cleanup is assisted by flowing all zones simultaneously. If desired, the activation balls and landing baffles can be milled out to provide a fully open internal diameter through the sleeves.

In conjunction with the uniqueness of the swellable packer system and the reliability of the sliding sleeve system, the expandable liner hanger that allows rotation and reciprocation while running in hole will be used to complete this well.

The acid fracturing design is based on the desired fracture geometry and taking into account various parameters, such as bottom-hole pressure (BHP) and temperature, reservoir fluid properties, rock mechanic.

Candidate Selection

The targeted reservoir in this case was characterized to be a porous tight carbonate formation. The reservoir displayed porosity values in areas indicating remarkable reservoir property; however, it faced an absence of effective porosity, where the permeability showed very low values.

The candidate well is a trilateral completed with two open hole and a single lateral completed with a non-cemented liner with swellable packers and sliding sleeves. The well was drilled in the direction of the minimum stress with the idea of creating transversal hydraulic fractures along the wellbore, Fig. 2. Seven acid fracturing stages were designed along the motherbore and expected to provide long fracture perpendicular to the minimum stress direction. This was the first multistage acid fracturing completion in a primarily oil producing formation in Saudi Arabia. The objective of this project was to drill a trilateral in a low permeability carbonate reservoir as a pilot well to evaluate the effectiveness of acid fracturing and improving the well productivity in this tight oil formation. This carbonate reservoir was deposited in a shallow marine intra-shelf basin. The reservoir is overlain and underlain by marls, and consists mainly of wackestones and packstones with several thin layers of grainstones capped by hardgrounds/firmgrounds. The reservoir quality is defined as poor to moderate quality.

The lateral open hole logs showed a homogenous distribution of the reservoir properties and the selection of the fracturing port locations were distributed evenly along the lateral considering that the integrity of the wellbore was not affected excessively by washouts on those points where the swellable packers were selected to be set. A six arm caliper log was run to have a more detailed picture of the wellbore integrity.

Stage Name	Fluid Name	Stage Fluid Volume		Cummulative Volume		Acid Conc.	Pump rate	Pumping Time
		gals	bbls	gals	bbls	(%)	(bpm)	(min)
STAGE -1								
Pad	Crosslink Gel - 30 #	4,000	95	4,000	95	0	25	3.8
Acid	Diesel Emulsified Acid	3,500	83	7,500	179	20	25	3.3
Pad	Crosslink Gel - 30 #	4,000	95	11,500	274	0	25	3.8
Acid	Viscosified Acid	3,500	83	15,000	357	20	30	2.8
Diversion	Logard Diversion Pill	2,000	48	17,000	405	0	30	1.6
STAGE -2								
Pad	Crosslink Gel - 30 #	2,750	65	19,750	470	0	30	2.2
Acid	Diesel Emulsified Acid	4,500	107	24,250	577	20	30	3.6
Pad	Crosslink Gel - 30 #	2,750	65	27,000	643	0	35	1.9
Acid	Viscosified Acid	4,500	107	31,500	750	20	35	3.1
Diversion	Logard Diversion Pill	2,000	48	33,500	798	0	35	1.4
STAGE -3								
Pad	Crosslink Gel - 30 #	2,750	65	36,250	863	0	35	1.9
Acid	Diesel Emulsified Acid	6,500	155	42,750	1,018	20	35	4.4
Pad	Crosslink Gel - 30 #	2,750	65	45,500	1,083	0	40	1.6
Acid	Viscosified Acid	6,500	155	52,000	1,238	20	40	3.9
STAGE -4								
Acid	Tank Bottom	4,000	95	56,000	1,333	20	5	19.0
Acid	Closed Fracture Acid (CFA)	4,000	95	60,000	1,429	20	5	19.0
Flush	Treated Water	3,700	88	63,700	1,517	0	5	17.6
Overflush	Treated Water -2	3,100	74	66,800	1,590	20	5	14.8
SHUT-IN								

Table 1 · Representative Pumping Schedule.

Acid Fracturing Design Considerations

Fracture treatments are performed on wells with varying potential to help increase production and reduce the drawdown pressure on the formation face. Many hydrocarbon-bearing carbonate formations are routinely stimulated by fracture acidizing, and the use of fracture acidizing to enhance the production of carbonate formations continues to be an effective process. Numerous authors have investigated the factors that affect the production increase of a fractured well, including special acid systems and placement techniques, etc. Although, to achieve a successful fracture acidizing treatment, three fundamental issues must be addressed: reactivity control, fluid loss control, and conductivity generation. The desire for increased production is concurrent with the need to optimize treatment designs and predict what increases might be expected.

A fundamental issue in successful fracture acidizing treatments is the generation of acceptable conductivity. Proper reactivity control and proper fluid loss control are prerequisites for obtaining good conductivity. In fracture acidizing, fracture conductivity is generated by the nonuniform dissolution of rock from the formation face. This process is referred to as "differential etching." The two primary factors influencing the resultant conductivity are the quantity of rock removed and the pattern of rock removal. While kinetic parameters govern the amount of rock removed in each segment of the fracture, formation characteristics dominate the conductivity resulting from the acidizing process. The mineralogical composition of a formation has the greatest influence on its resultant conductivity because the etching pattern is a direct result of the degree of heterogeneity in the fracture face. Any rock characteristic that contributes to heterogeneity in the formation will enhance differential etching. Physical and chemical composition of the formation rock will influence the reaction rates of acid; as a result, some areas will be dissolved to a greater extent than others.

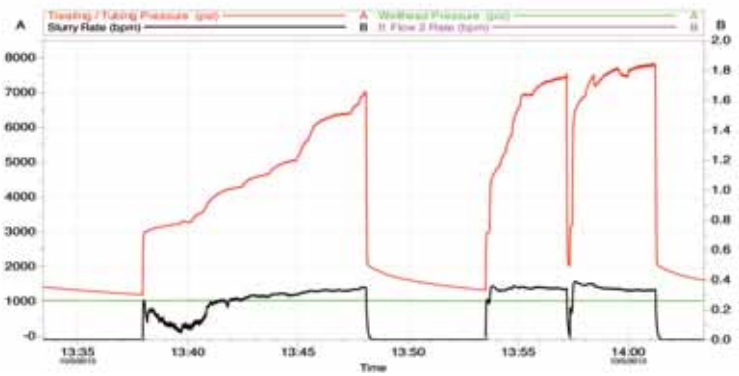


Fig. 4 · Injection test for formation breakdown.

Once differential etching is achieved, formation hardness and fracture closure stress influence the resultant conductivity. As with propped fractures, the conductivity of an etched fracture decreases as closure stress increases. The magnitude of reduction in conductivity depends on the hardness of the formation and the ratio of supporting area to etched area. To achieve a differential etching, several techniques are available. The one proposed on this project was to pump a viscous pad fluid ahead of the acid and behind an optional nonviscous, cooldown prepad. As the viscous pad is pumped, it generates fracture geometry, Fig. 3.

Because the acid that follows it is less viscous, it "fingers" through the viscous pad. This fingering process limits the acid contact to the formation face, which creates etched and non-etched areas. This process results in longer acid penetration distance and possibly more effective conductivity at a greater distance along the induced fracture. An additional etching period was conducted to simulate what is referred to as closed-fracture acidizing (CFA). CFA can be considered a technique to enhance fracture conductivity (Frederickson 1986). The technique basically involves pumping acid at low rates below the fracture reopening pressure, through the previously created fractures. The acid will follow the path of least resistance, selectively etching only a portion of the fracture face and creating deeper etching patterns than would normally be achieved using conventional etching procedures. CFA is a technique successfully employed on the acid fracturing treatments currently performed in the gas bearing formation in Saudi Arabia.

An extensive planning process was carried out previous to the execution of the main treatment. Several multidisciplinary meetings were sustained to cover all the relevant aspects of the job.

The well was completed with a 5½" sleeve completion using 10 K psi swellable packers and seven sleeves to conduct seven distinct acid fractures. The treatment was actually executed in six stages, leaving the second stage untreated. The volume used for the fracturing treatments was in the range of 400 gal per foot of net pay. The six stages were acid fractured using 20% hydrochloric (HCl) acid under the following sequence of fluids.

- Pad fluid. Consisting of crosslinked gel and designed to initiate the fracture profile.
- Emulsified acid. A retarded acid system designed to achieve deeper penetration and reaction into the formation (20% HCl acid).
- Crosslinked spacer. Pumped to create viscous fingering with the acid system to improve the differential etching.
- Viscosified acid. Crosslinked gelled acid system to reduce fluid loss as the acid leaks off through wormholes and spends (20% HCl acid).
- Diverter pill. Based on relative permeability modifiers to enhance fluid placement and improve the leakoff control.

The 20% HCl acid emulsified acid is normally recommended based on its good retarded reaction rates properties, allowing live acid penetration deeper into the formation. Another advantage of using the emulsified acid mixture used (30% diesel and 70% HCl

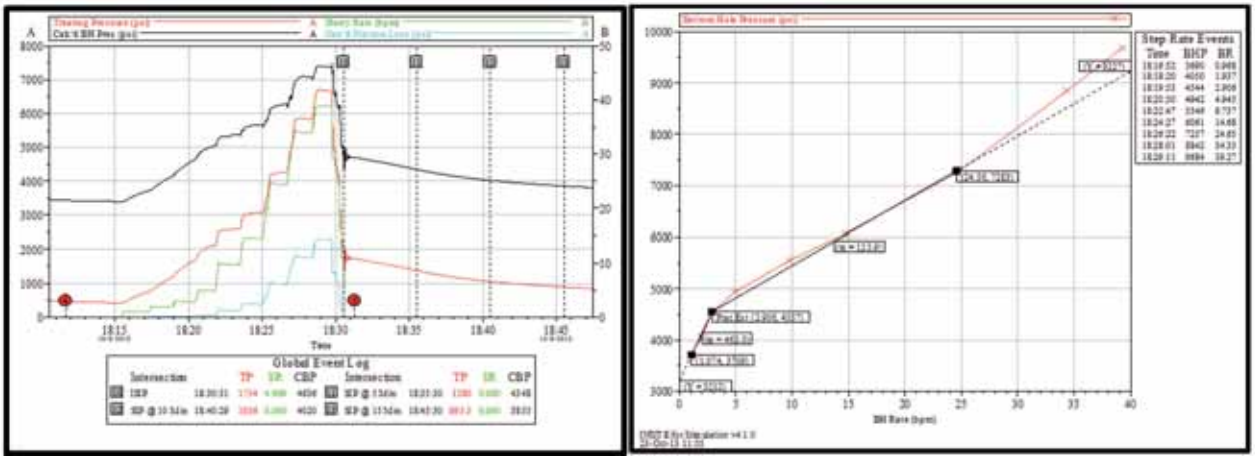


Fig. 5 · Left: Step rate test from Stage 1 and right: Step rate test vs. pressure diagnostic.

acid) is that the typical high corrosion rates associated with high HCl acid concentration is significantly lower because contact of live acid with the tubulars is reduced, thereby reducing the volume of corrosion inhibitor required in comparison with other acid systems with an equivalent concentration. The increased viscosity of the system also helps improve wellbore coverage.

Diverter pill: The material can be classified as an associative polymer capable of reducing permeability to aqueous fluids with little to no permeability damage to hydrocarbon flow (Eoff et al. 2003). Treating solutions of this polymer exhibit very low viscosity, typically less than 2 centipoise, and exhibit increased levels of adsorption to surfaces as compared to nonassociative analogs. The successful achievement of effective diversion and leakoff control using this system in matrix acidizing and acid fracturing applications in Saudi Arabian gas and oil producers (Al-Taq et al. 2007) has been reported previously (Nunez-Garcia et al. 2010)

• Fracture modeling software was used to simulate the fracture geometry using the available data; such as a sonic log, stress profile, estimated fracture gradient obtained from a neighboring well, rock/mineralogy and reservoir fluid properties and fracturing fluid properties. An acid fracturing pumping schedule was generated by alternating sequence of the fluid between PAD, emulsified acid and viscosified in three main stages, with the objective to improve the etching effect of on the fracture face as well as providing better wormhole from the use of emulsified acid. The expected BHP during the frac is in the range of ~5,500 psi, whereas the surface pressure will be in the range of ~3,500 psi to 8,500 psi at the pumping rate of ~40 bpm. Based on this simulation the completion was designed using 10,000 psi rating.

Table 1 is a typical pumping schedule for each fracturing treatment.

QA/QC

An important aspect of any chemical pumping job requires a quality study of the chemicals used in conjunction with reservoir fluids. Chemicals used in any treatment need to be put through rigorous testing to ensure that they are compatible with the reservoir and will perform as required. The array of chemicals used in acid fracturing specifically required multiple testing for concentrations, stability, salinity effect, viscosity, timing, and overall performance. Chemicals will perform differently depending on the concentrations used, fluids it contacts, and temperature among other conditions it may face. Adequate lab testing is required to ensure that there are no surprises met during the job. Multiple tests were done for this job in the lab, testing the chemical's reaction with the oil as stated above for sludging and emulsion. Also, tests were made to ensure the concentrations of chemicals performed as required in conjunction with the water that will be used for the job.

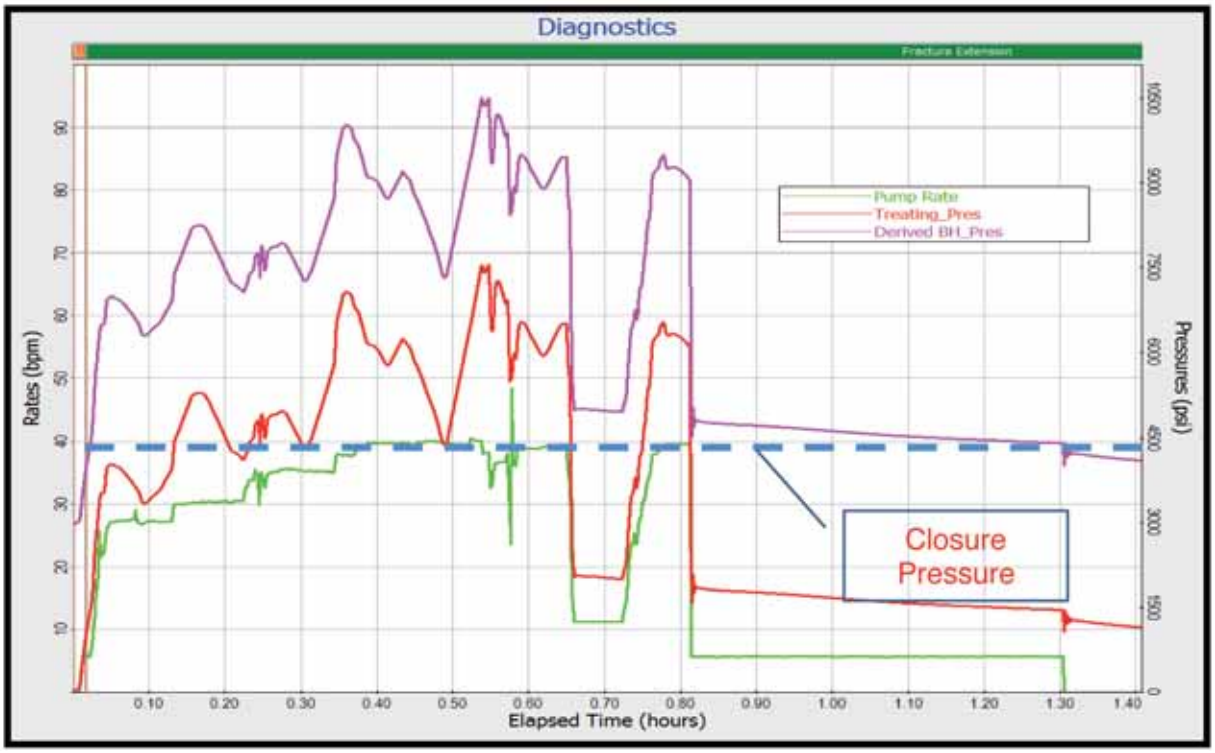


Fig. 6 · Pumping chart for Stage 1.

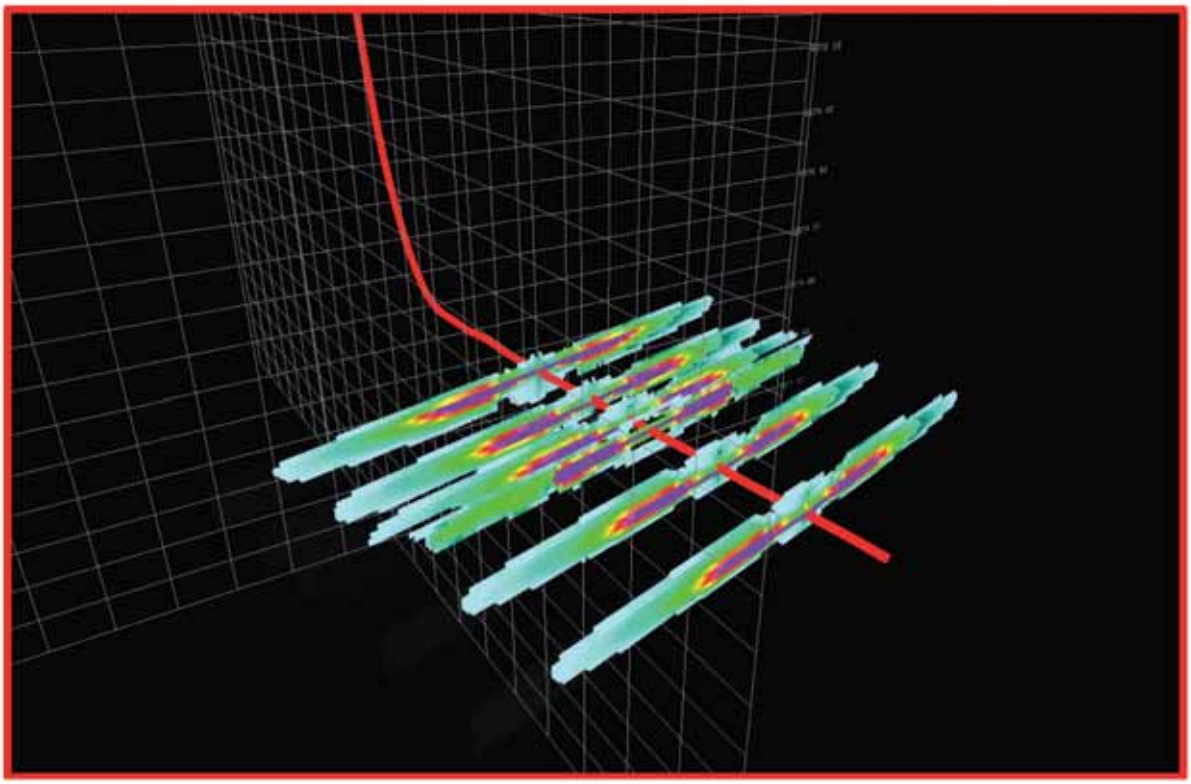


Fig. 7 · Fracture final etched profile distribution of the six stages.

	Stage 1	Stage 3	Stage 4	Stage 5	Stage 6	Stage 7	
Max Treating Pressure	7,758	8,227	7,983	7,975	7,889	8,113	psi
Max Slurry Rate	40.1	44.5	45.3	43.2	50.9	50.3	bpm
Pad – Crosslinker Gel	457	442	456	452	455	457	psi
Emulsified Acid	411	424	428	428	410	425	bpm
Viscofied Acid	347	408	417	642	433	430	psi
Diverter	97	92	96	96	98	91	
CFA	95	94	95	96	96	97	psi
Tank Bottom	52	10	23	24	19	11	psi
Water Treated W/Clay Control Agents	331	265	243	243	243	222	psi

Table 2 · Data summary of the pumping parameters for all the stages.

Different concentrations and chemical types were tested under reservoir conditions using the core flooding technique and a computed tomography scan.

More important than lab testing, is a field testing (QA/QC) of the fluid to verify the repeatability of what it has performed in the laboratory. Below are the summary of the findings of field testing:

- Different batches of chemicals that required on-site testing.
- Raw acid concentration (expected is HCl acid 31%) vs. the actual as low as 25%.
- Concentration of the emulsified acid was field adjusted during and after the execution of the first stage after observing some instability of the emulsion.
- Cross linker gel rheology.

In emulsified acid, there were several tests performed to ensure that the chemical was as it should be for the treatment. First, the emulsified acid should have a certain ratio of outer coating fluid, in this case diesel, to acid that maintains stability long enough for deep reservoir penetration. In addition, the emulsified acid needs to have enough acid to ensure optimal stimulation of the reservoir. A stable ratio of acid to diesel is 70:30, which can be verified by both volumes used and density measurement of the final fluid. Three tests were performed to verify the validity of the emulsified acid for the treatment: two drop tests and a conductivity test. In the drop tests, emulsified acid droplets are put into two containers, one with water and the other with diesel. The droplets in water should hold together and drop to the bottom of the container. In the diesel, the droplets should disperse immediately and release acid to the bottom of the container. For the final test, a conductivity meter should be put into the emulsified acid sample and measure zero due to the diesel coating. During this job, issues occurred when conducting the tests. Several batches showed unstable emulsification and required adjustments to the emulsifier concentration to ensure stability. In addition, some samples had lower acid ratios that required remixing to ensure optimal treatment. Second, a cross-linker gel, a fluid that is concentrated and time sensitive. Unlike the other chemicals used, cross- linker gel requires mixing at a certain speed and time. In a situation where the gel is rushed quickly it can start to form "fish eyes." These fish eyes are lumps of gel with extremely high viscosity that cannot be broken easily. If they are used in treatment, high friction losses would be observed and they could possibly block pores, damaging the formation. In our case, a single stage suffered from such an issue, where "fish eyes" formed due to rush mixing and required a new batch to be mixed.

Job Execution

The operation on this well started soon after the waiting time for the swell packers to function had been reached, in this case ~29 days as per required simulation. Prior to opening the port, a clean out run was done using coiled tubing (CT) to total depth to displace the well fluid (oil-based mud (OBM)) with brine.

After the wellbore filled up with clean brine, the first frac port was opened by applying pressure from the surface. The tubing pressure gradually increased to the

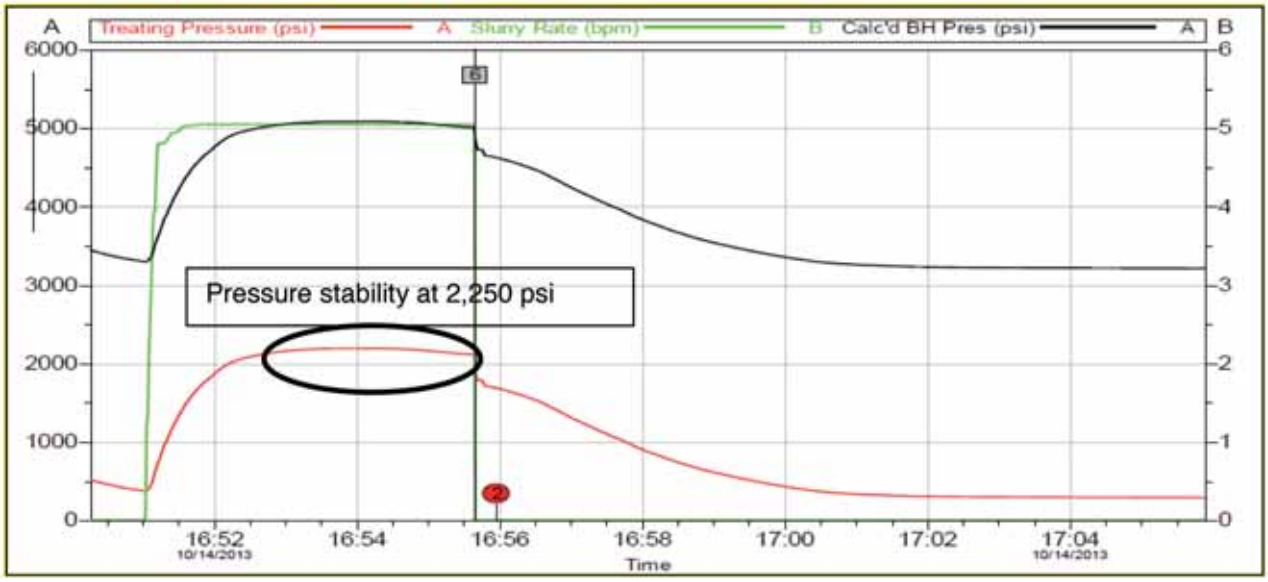


Fig. 8 · Benchmarking injectivity test prior to the frac job.

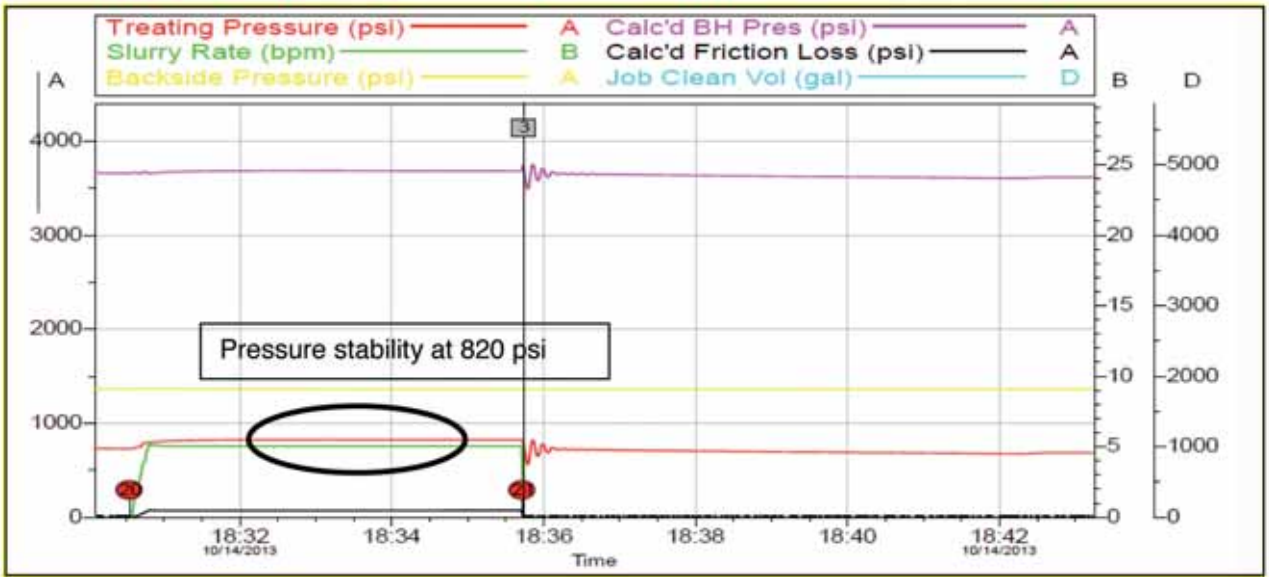


Fig. 9 · Benchmarking injectivity test post-frac job.

Stages	Pre-Frac	Post-Frac	
1	2.3	20.8	BPD/psi
3	6.8	31.3	BPD/psi
4	4.7	37.1	BPD/psi
5	9.0	36.1	BPD/psi
6	3.6	35.2	BPD/psi
7	4.5	18.4	BPD/psi

TABLE 3 · Injectivity index of each stage before and after frac.

designed port opening pressure. The pressure response indicated that port had been successfully opened but the injection was very poor (0.3 bpm at 6,600 psi), Fig. 4.

The assumption after multiple evaluations was that the OBM left in the wellbore created a sort of mud cake that was blocking injection through the ports. It was decided to perform acid wash using CT to improve the injection and significant injection improvement was obtained up to 3 bpm with 2,300 psi, which allowed us to resume our operation. Prior to the main treatment and after each fracturing port was confirmed to be opened, an injection test known as a step rate or step-up test was executed. The most common documented reason to perform a step-up test is to obtain an upper limit for fracture-closure pressure, which is identified as fracture-extension pressure (FEP). The idea behind this test is that by slowly increasing the injection rate in steps of equal time, a fracture will initiate and begin to grow, which will then produce minimal increases in bottom-hole injection pressure with an increasing rate once fracture growth continues at that rate. By plotting rate vs. pressure, it is possible to interpolate this point. An example of this test and its analysis are shown in Fig. 5.

As shown in this figure, and for simplicity in this discussion, the first line that runs through the lower rate points determined before the pressure "breakover," or FEP, is obtained will be designated as the "matrix line." The second line that runs through the points drawn after the pressure breaks over or levels off will be referred to as the "fracturing line."

Once this point is known, maintaining the BHP above the FEP helps ensure that the fracture continues to grow. The injection rate at the FEP is the minimum rate needed to maintain an open fracture in a given formation. Step-up tests in wells with good wellbore-to-fracture communication can provide good estimates of closure pressure and pore pressure, fluid leakoff and formation potential "kh" when possible if the falloff period is extended enough to observe pseudoradial flow.

Several other analytical graphs were plotted to obtain key reservoir and fracture parameters. The use of the Horner Plot, G-Function, and Square Root Analysis methods were performed with every step rate test to ensure reservoir parameter and fracture pressures at the certain stage. The different methods are to ensure the results are similar through different analysis methods to ensure fracture job integrity. In addition, as stated earlier it can be used to obtain possible "kh" and reservoir pressure.

As part of the evaluation of the sealing effectiveness of the packers, the behavior of the fall-off was also used to determine if the swellable elements were providing zonal isolation with respect to the previous acid fractured stage. The following series of graphs in the appendix (Figs. A to E) are a composed set of charts showing the overlapping of the pressure behavior of the main frac of each stage vs. the injection test of the subsequent stage. The intention of this chart sequence is to show the different pressure responses as an index of the effectiveness of the swellable packers. For this situation and assuming that, if for instance, the packer failed to provide a proper seal due to the aggressive scenario of holding pressure, plus the action of the acid eroding formation in the packer's vicinity, then the pressure behavior at the end of the fracturing stage will be equal to the pressure response of the subsequent injection test.

Figure 6 is the history rate and pressure chart from the main acid fracturing treatment from Stage 1. The

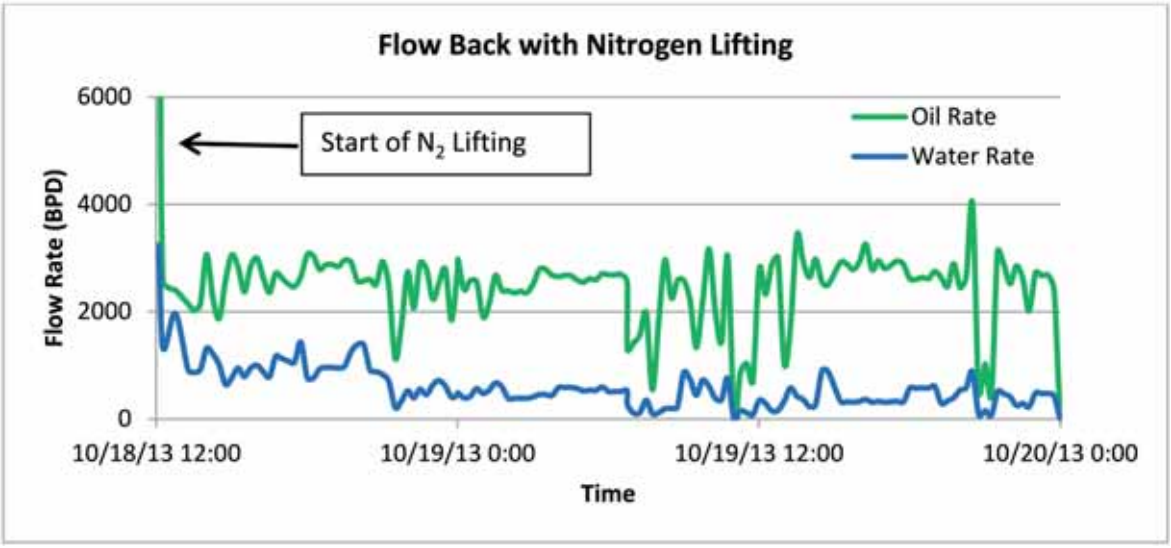


Fig. 10 · Flow back results during nitrogen pumping.

treatment was accomplished maintaining a rate of 40 bpm with an oscillating wellhead pressure between 4,000 psi and 7,200 psi. The spikes in pressure are due to the pipe friction effects of the acid emulsified stages. The bottom-hole treating pressure was continuously monitored and kept above the closure pressure to maintain the fracture open at all times with the exception of the CFA stage.

Figure 7 is the final representation of the fracture distribution along the horizontal wellbore as per the fracture simulator and the reactivity index achieved along the fracture length.

Fracturing Evaluation

The use of multistage acid fracturing in this well will determine the future of the reservoir in the area. We previously discussed the process that we went through before coming to the decision on the use of acid fracturing in developing the reservoir. The well is considered to be a pilot in a new incremental development in the area. Therefore, the evaluation with frac effectiveness in this certain case is the primary objective of the operation. The usual methods includes pressure transient analysis using a buildup test and the use of production logging tool to determine the specific stage and overall operation performance. Results using those two main methods and several other testing methods will be used to determine whether or not to continue with fracing as a means of developing this reservoir. In addition, a study of each stage performance will allow us to modify and optimize future operations to result in the best outcome. As stated earlier, in each of the stages, we experimented with the pumping rate and pressures during the treatment. In addition, in Stage 5, we modified the treatment volume of the viscofied acid by increasing it significantly to enhance near-wellbore stimulation. These different treating parameters during each of the seven stages will allow us to optimize future operations to ensure the best results. Subsequently, the well had just been recently drilled and following the operation would require a significant amount of time before putting it on production. The well would require workover to remove the upper completion and install tubing with an electric submersible pump (ESP), a common method of lifting used in this field to produce due to low reservoir pressure and production rates by natural flow. In addition, they would need to remove the blanking pipe isolating the two other laterals before testing the well completely. As a pilot well, an evaluation of the frac results was a priority required as quick as possible. The benchmark of using an injectivity test was the method used as an initial evaluation for the success of the operation.

The approach is a simple concept of relating production to injection. The testing is done prior and post-fracturing comparing the two results. When performing stimulation, we use productivity index

(PI) post-treatment and compare it to the PI before the stimulation to obtain a ratio indicating an increase of production through stimulation. The concept holds that we should be able to produce at the same rate of injection through the formation holding the same parameters. In doing so, we can use injection and compare the injectivity index post-treatment and compare it to the index prior to the treatment. Even if the injection rate is not the same, the index ratio increase from stimulation should be similar to the production ratio increase.

The injectivity test is a simple one of injecting clean brine at a certain rate, in this case 5 bpm for 5 minutes. The observed stable pressure is used to calculate the injectivity index in BPD/psi. The ratio of injecitivty index post-treatment is then compared to the index prior to treatment to be used as an initial indication for the frac. Figures 8 and 9 show the response of pressure done before and after testing. The graphs show a clear indication of easier injection where the pressure observed during pumping is lower.

Table 3 summarizes the calculated injectivity index observed in each stage. These numbers will be used to then compare to actual testing performed after the well is put on production.

Flow Back Results

Flow back is a key aspect in identifying fracturing results. There are several tests that can be used in identifying the effectiveness of operation and can be used to optimize any future operations. The best possible method is to flow back the well following every frac stage. In using this method, we would be able to identify the results from each stage separately. Subsequently, the time limitation for the operation has removed the capability for using this method. In flow back, the main objective is to clean out the well from any remaining chemicals. In addition, we can test the well's capability of producing and analyze samples for expected returns. There are different elements in each chemical that are used to identify return volumes. In addition, unique elements in the completion may be tested to ensure minimum corrosion and reaction; however, the second part is not the objective of this paper.

The design for the well is to have it on artificial lift ESP as is common practice with wells in this field. A majority part of this field has reservoir pressure that cannot sustain natural flow for the desired rates. In this specific reservoir, a study was performed using all available data to determine that the drawdown was insufficient, therefore requiring ESP. As stated earlier, the well would require time before being put on final production. To ensure well cleanout is achieved, the well was connected to a close by offset well 500 m away to be flowed through. Following frac and milling operation, design for lifting the well by nitrogen using CT.

The operation started by running CT in the hole to depth and attempt to start nitrogen lifting. The well was open and returns were seen at the surface prior to nitrogen pumping, indicating natural flow. The well was able to flow at a maximum of 8 hours before the rate was too low to consider continuing with natural flow. In that time, the well produced 600 bbl of liquid with an average flow rate of 1,800 BPD and water cut around 17%. Nitrogen pumping started at a rate of 300 scf/min and we were able to produce at an average liquid rate of 3,800 BPD and water cut at 27%. Figure 10 shows the flow back period of one day at the start of nitrogen pumping. The entire operation lasted for five days and we were able to produce 14,000 bbl of liquid with 17% water recovered.

Conclusions

1. A selective stimulation completion was successfully designed, deployed, and used for enhanced production and demonstrated the productivity potential in this first transverse multifractured horizontal oil well using swell packers. The extended flow back indicated the well production met expectation.
2. Swellable packers have proven to be effective in providing a positive annular barrier for multistage fracture treatment with transverse hydraulic fractures in oil well. Six out of seven fracs were successfully executed with no indication of communication.
3. To displace the wellbore with diesel/clean fluid prior to setting the completion packer to minimize the risk of poor injection/communication to the reservoir.
4. Proper diagnostic between before and after the frac port opening can be used to evaluate if there is any communication between the compartments.
5. QA/QC of the treatment fluids is of great importance on the success of the stimulation treatment. Field testing of the fluid is needed to verify the repeatability of what it has performed in the laboratory.
6. With the improvement pumping operational efficiency, the multistage fracturing could be completed in less time and should be considered as a future option for developing this reservoir.

Acknowledgments

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APPENDIX

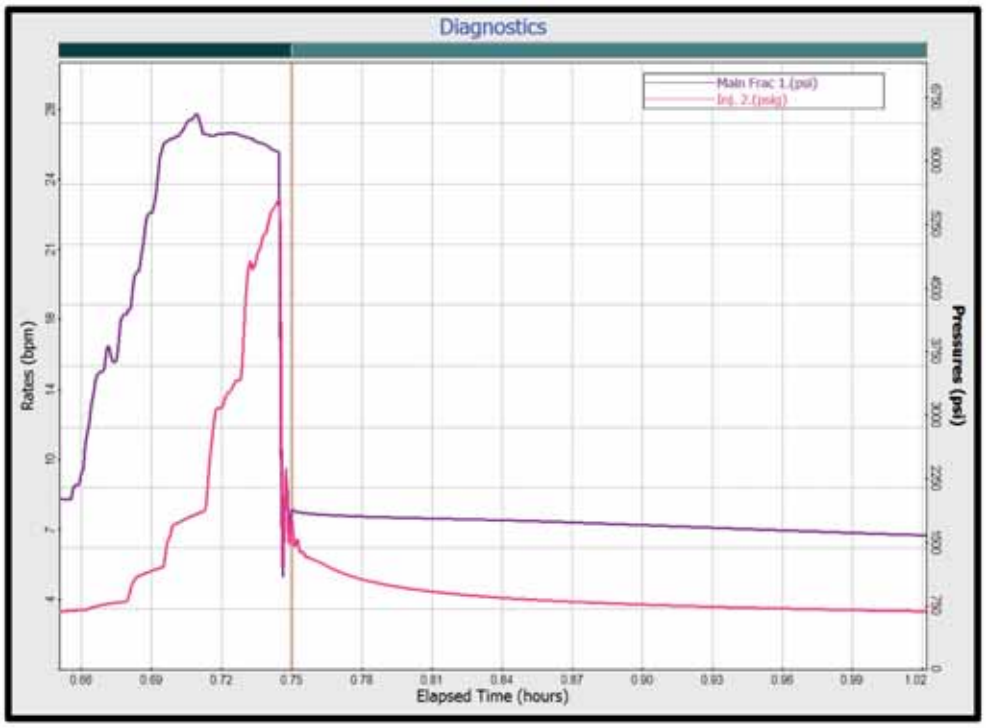

Fig. A · Curves overlapping comparing pressure response after main frac Stage 1 and subsequent injection test for Stage 2.

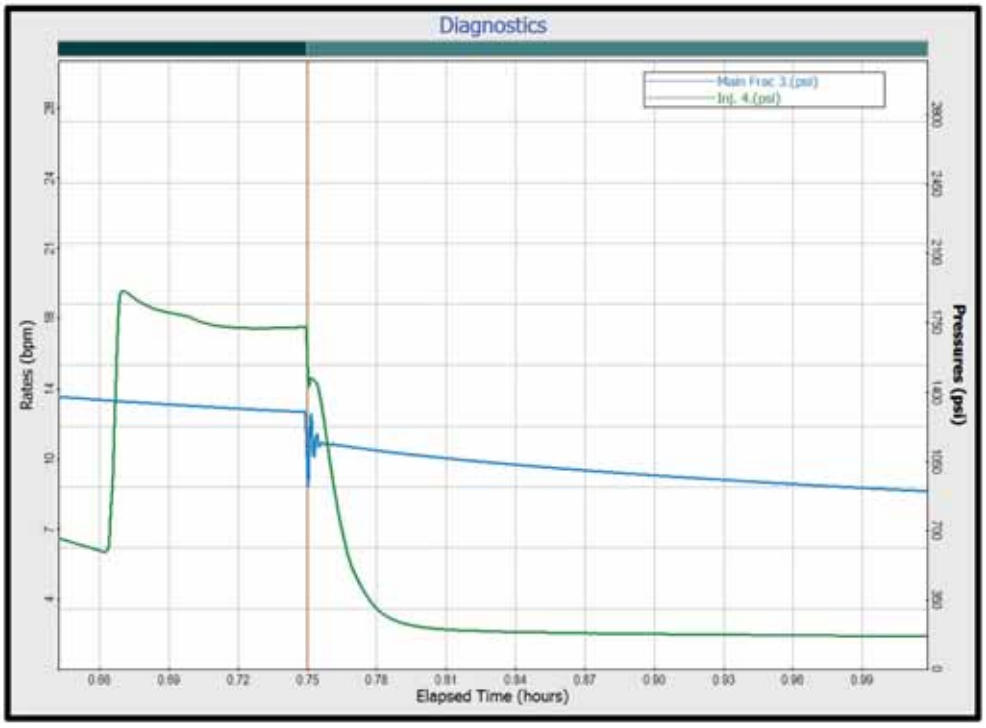

Fig. B · Curves overlapping comparing pressure response after main frac Stage 3 and subsequent injection test for Stage 4.

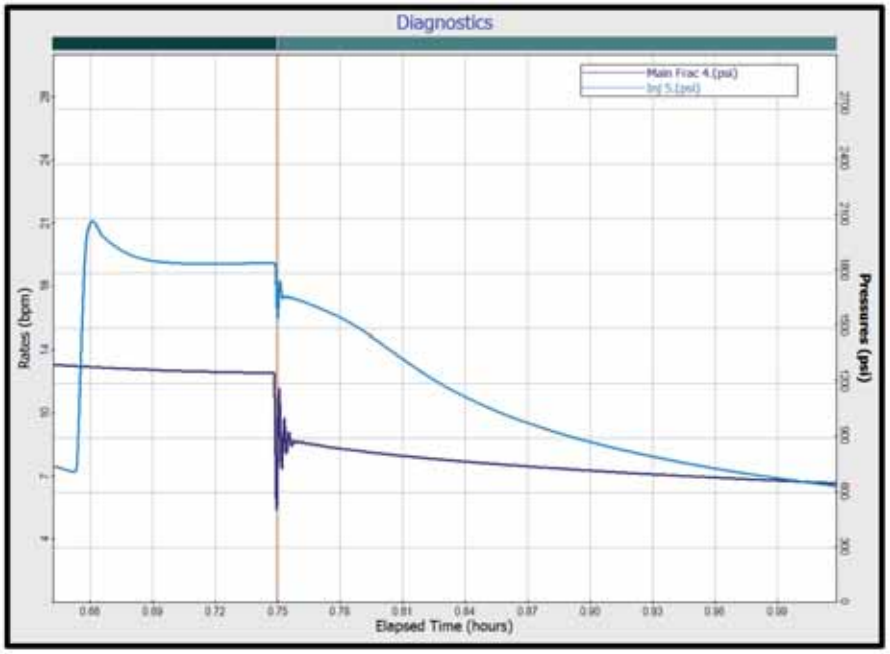

Fig. C · Curves overlapping comparing pressure response after main frac Stage 4 and subsequent injection test for Stage 5.

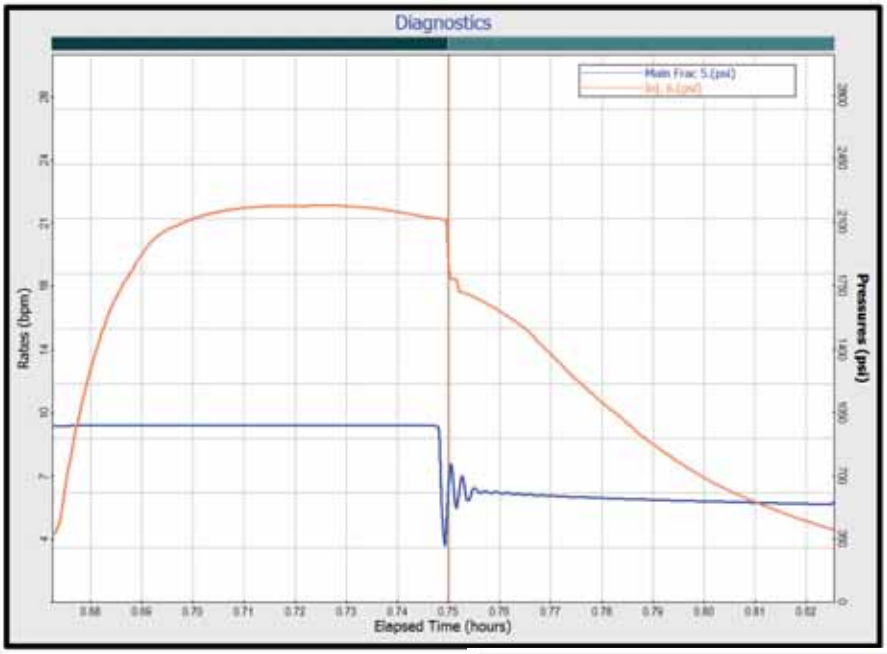

Fig. D · Curves overlapping comparing pressure response after main frac Stage 5 and subsequent injection test for Stage 6.

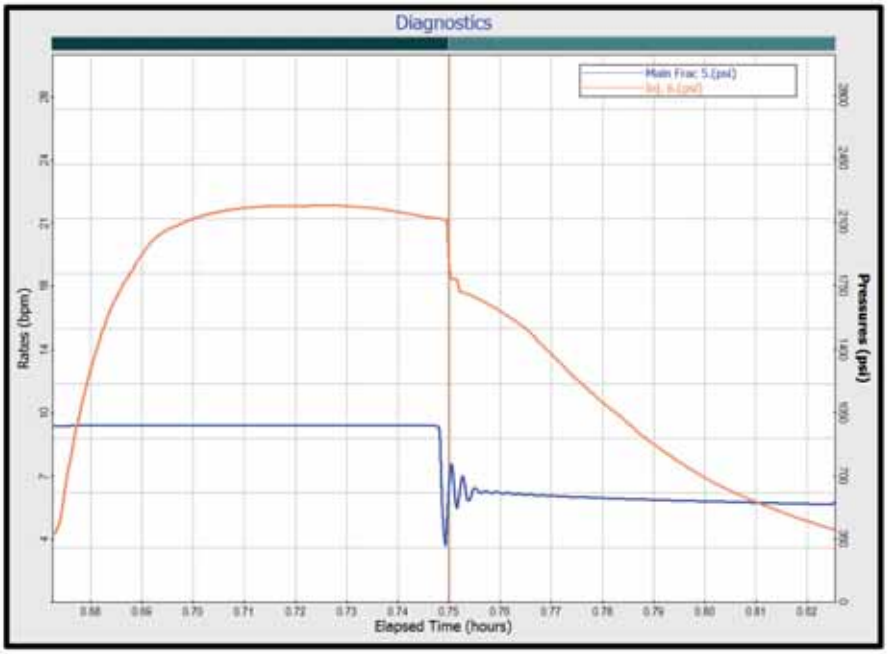

Fig. E · Curves overlapping comparing pressure response after main frac Stage 6 and subsequent injection test for Stage 7.

Can Sourceless Density LWD Replace Wireline in Exploration Wells? Case Study from Saudi Arabia

By Abdullah Alakeely, Yacine Meridji, Saudi Aramco.

This paper was prepared for presentation at the SPE Annual Technical Symposium & Exhibition held in Al -Khobar, Saudi Arabia, 21 - 24 Apr 2014.

Abstract

With the search for hydrocarbon reaching extreme and difficult frontiers worldwide, the use of tools that allow real-time monitoring of operations, such as logging while drilling (LWD) has become increasingly more attractive for both drillers and geoscientists, to safely drill and properly evaluate target formations.

In this paper we examine an alternative where a sourceless density LWD tool was used. It offers the assurance of not using nuclear sources to minimize hazards at the rig site. The tool uses a pulsed neutron generator instead of a chemical source. This allows for safe operation, safe transport and pollution free environment, in particular, in exploration wildcat environment where little is known about the area and the risks are higher.

The objective of this paper is to compare sourceless density LWD tool's performance to wireline using common logs to test the validity of this new technology replacing wireline in exploration wells.

In this investigation, real-time applications of LWD data are presented. First, general factors contributing to differences between LWD and wireline log responses are analyzed. Then, similar curves between LWD and wireline are compared. And, the formation evaluation results based on wireline versus LWD measurements are discussed.

The findings of this study will help reduce the uncertainty associated with the validity of sourceless LWD in replacing wireline in exploration wells. This has many implications for operational efficiency, duration and cost.

Introduction

Drillers have long been using MWD/LWD data to monitor drill bits' performance and to acquire real-time updates about wellbore direction. In addition, with exploration reaching deeper waters and the increased emphasis on safety, LWD became an essential component in any drilling program to reduce operational risks. Drillers and geoscientists use LWD to reduce the inherent geological uncertainty and risk associated with the search for hydrocarbons in new territories. This is achieved through improvements in the type and accuracy of measurements that an LWD tool can provide in real time. As a result, it is now possible to perform a

comprehensive formation evaluation in real time as drill bits intersect target reservoirs.

When used properly, LWD data in the exploration environment has its merits in reducing the uncertainty and increasing the chances of success of newly drilled wells. With recent advancements in LWD and the introduction of sourceless nuclear measurements, a comprehensive petrophysical evaluation is now possible in real time without the need for chemical sources. This is great news for drillers and geoscientists at the same time.

For drillers, it means the risk imposed by using chemical sources on safety, health, and environment has been eliminated at the rig site. Besides, less complicated fishing procedures are employed in the case of stuck tools. Furthermore, the slow and logistically complex transportation of chemical sources, especially in remote offshore regions, will be eliminated.

This will work well for geoscientists too; the ability to run tools without chemical sources will face less resistance, and the probability of getting nuclear measurements will rise in ever risky and more complicated environments. It is important first to understand, evaluate and validate LWD measurements obtained using this tool against the conventional wireline tools. This will help draw a better picture too; that is, if LWD can be used as an alternative to wireline in the exploration environment.

The sourceless LWD is considered a new development in the industry that requires testing and comparison with accepted existing technologies. In this paper, we compare and discuss measurements using sourceless LWD tools versus those acquired with wireline tools.

Sources of Differences Between LWD and Wireline Log Response

Sources of differences between wireline and LWD logs could be categorized into three general areas:

- Tool Design and Sensor Physics
- Logging Conditions
- Formation Alteration

Tool Design and Sensor Physics

Although tool design is not the focus of this discussion, it plays a role in understanding reasons for differences in responses between LWD and wireline logs.

It is obvious that LWD tools must be designed differently from wireline tools. This is because they measure formation properties while the well is being drilled, and they should behave as an integral part of the drill string. The harsh environment dictates that they work as drilling collars first before they function as logging tools. This requirement puts some constraint on the design of LWD tools. For example, thick steel collars are used which may affect log responses.

Besides the difference in design, LWD tools, in general, are different in how they measure formation properties, i.e., sensor physics. This partly affects the radial and axial sensitivities of the sensor to the formation.

In our case, density measurement in conventional wireline tools uses different physics from sourceless LWD. It uses a chemical source (Cesium-137) while the sourceless LWD employ a Pulsed Neutron Generator (PNG) to induce gamma rays that are sensitive to formation density.

Another example is the caliper. Wireline tools use a mechanical caliper to measure hole size, and to quantify the amount of environmental correction required. While in LWD tools, ultrasonic time-of-flight method is used to measure the tool's standoff. These differences in design and sensor physics will make ultrasonic calipers to have better coverage, and more resolution than wireline in some conditions (Jackson et al. 1994).

Logging Conditions

LWD and wireline logs are run in different hole conditions. For example, LWD is run while the well is being drilled, so no mudcake is developed. In addition, the amount of standoff, in some cases, is different across the same point of measurement. This will cause different responses, and will affect the magnitude of correction to be applied to logs (Allen et al, 1993).

One interesting difference is mud properties. In wireline operations, the mud is essentially stable and no change in its weight or composition occurs. Mud density could change throughout the section where LWD data is acquired. These changes will make the log responses vary across the same hole section (Jackson et al. 1994).

Formation Properties Alteration

By the time wireline logs are run, formation properties have gone through some alteration (i.e., invasion), which means LWD and wireline tools are no longer reading the same thing.

For instance, drilling mud would have invaded the formation, which alters the shallow resistivity response (Hansen et al. 1996).

Property	LWD	Wireline
Time since Drilling	2 min – 4 hours	1 day – 3 weeks
Mud Filtration	Dynamic	Static
Mud Properties	Dynamic, changing	Stabilized
Invasion	Active	Fully developed
Permeability High	Shallow invasion	Shallow invasion
Med	Shallow to Medium	Shallow to Medium
Low	Shallow invasion	Deep invasion
Formation Fluids	Oil, Gas, Formation water	Oil, Gas, Formation Water, Mud Filtrate
Mud Cake	Developing, dynamic	Fully Developed, static
Formation damage	Some pore bridging occurs, pore lining clays damage	Pore throats bridging, fragile clay damage, and swelling clays

Table 1: Formation Properties Difference between LWD and Wireline Runs (from SPE 28428).

Table 1 outlines some of the most important parameters that are different between LWD and wireline formation conditions.

LWD vs. Wireline Logs Comparison

Comparison Methodology

The data is collected from an offshore exploration well drilled with oil based mud (OBM) and both sourceless LWD tools and conventional wireline tools were run. The sourceless LWD logs were acquired as security logs. This was also to test if sourceless LWD data is sufficient to reduce the need for wireline logs in future wells.

The following methodology will be followed for comparison between the data from LWD and wireline.

First, the curves will be plotted for visual comparison considering wireline logs to be the reference because they are accepted to be industry standards. Then, crossplots of data and histograms are to be displayed whenever appropriate. The authors attempt to highlight differences between the curves, and provide an explanation when required.

Logs to be compared

The following logs will be compared between sourceless LWD and Wireline tools: depth, gamma ray, caliper, sonic, density, neutron and resistivity.

We will start with depth difference between LWD and wireline as received from the field, to evaluate if there is a need to depth shift the data. Then, other curves will be compared after applying the depth shift.

The logs mentioned above were selected because they are common measurements. At the end, a comparison between formation evaluation results using the two sets of logs will be discussed.

Depth

Depth is the most important petrophysical measurement in formation evaluation, as it represents the reference to where every measurement is taken. It defines formation tops and the thickness of zones of interest. Errors in depth measurement can lead to reserves estimation errors or even missing targets when sidetracking wells.

Due to differences in the logging environment between LWD and wireline, depth discrepancy is expected. It is a common standard in the industry to consider wireline depth to be superior to LWD depth, because better practices are employed, such as stretch correction before the data is finalized (Chia et al. 2006).

LWD depth is referenced to driller's depth, which is basically a hand measurement of the length of drill pipe as it is lowered into the well.

Factor	Description	Effect on String Length
Weight	Weight of the string	Increase
Temperature	Thermal expansion of metal	Increase
Axial Pressure	Pressure drop across the string at the bit	Vary
Ballooning	Differential pressure across the walls of the drill pipe will cause the pipe to expand	Decrease
Friction	Drag against the side of borehole	Increase or Decrease depending on direction of travel
Buckling	Compression effects	Vary
Weight on Bit	Weight application on bit	Decrease
Twists	Stored revolutions within the pipe	Vary

Table 2: Factors affecting driller's depth.

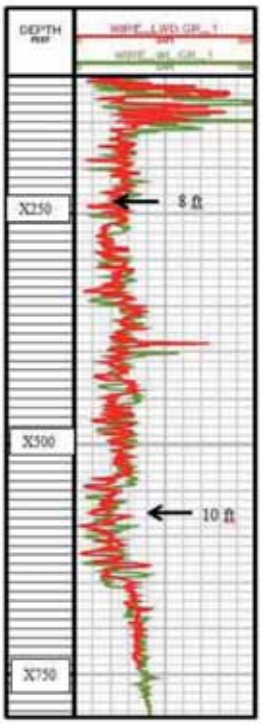

Figure 1: Comparison between LWD depth and wireline depth in the same well using the GR curve. LWD GR curve is shown in red and Wireline GR curve is shown in green, both are depth matched to the previous run. There is a depth offset of 8-10 ft between the curves (black arrows) where LWD appears shallower than wireline.

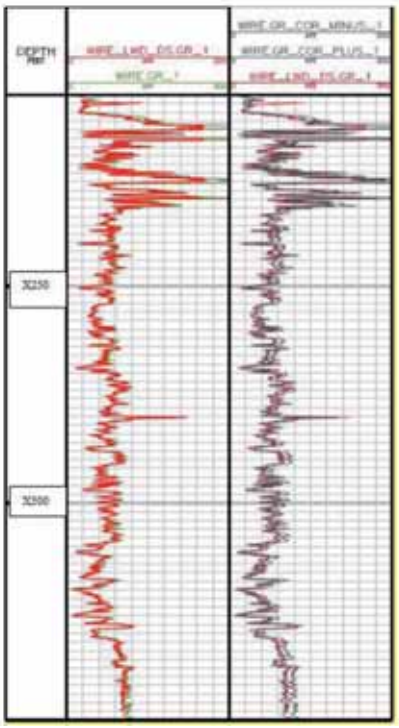

Figure 2: LWD GR (red) versus wireline GR (green) after depth shifting. The curves match each other with slight depth discrepancy, as a result of nonlinear depth offset between the two.

The drilling environment is tough and the drill pipe undergoes length changes because of many factors.

Table 2 lists some of the factors that affect the driller's depth (Chia et al. 2006)

To add complexity to drillers' depth control, these factors change if the bit is sliding or rotating. Thus, quantification of the effect of every single factor is a daunting task. Out of these factors, drill pipe stretch and thermal expansion have the highest impact (Chia et al, 2006). As a result, LWD depth usually comes shallower than wireline depth (Figure 1).

The problem arises when we try to correct the depth of LWD to wireline. We note that the depth shift is not linear, which can be explained by looking at Table 2. During drilling, factors like weight on bit and friction change in magnitude across the hole, and make variable impact on how the drill string compresses or elongates.

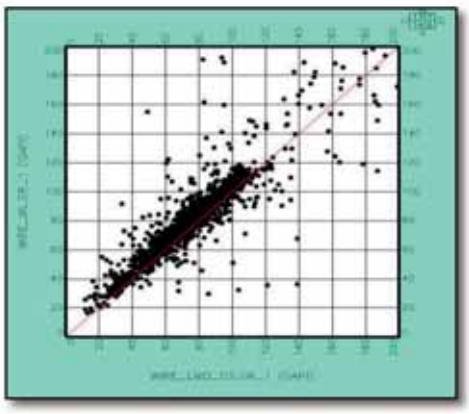

Figure 3: Crossplot LWD GR (x axis) vs wireline GR.

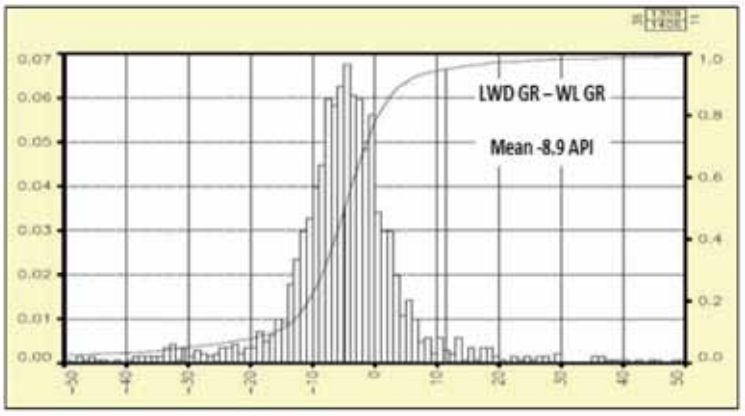

Figure 4: Histogram GR LWD and wireline data.

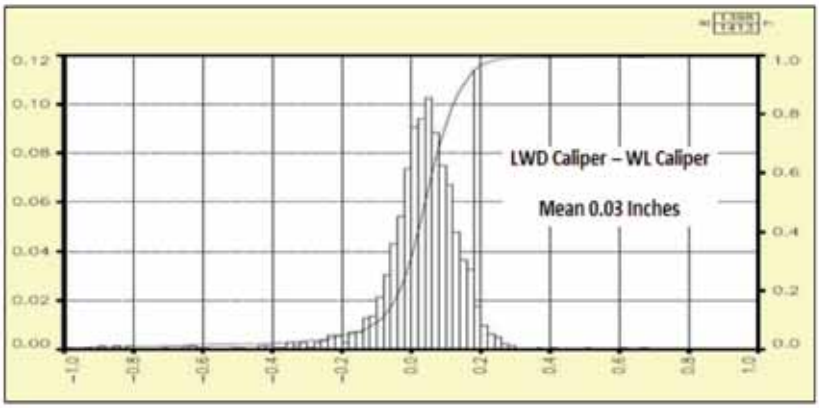

Figure 5: Histogram of difference between caliper of LWD and wireline data.

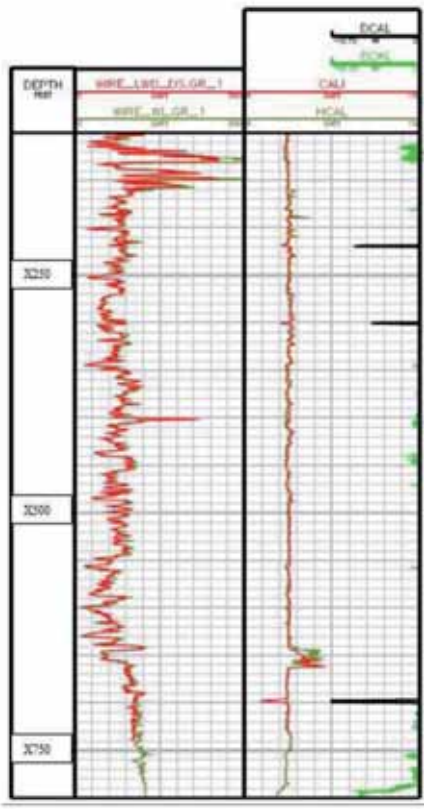

Figure 6: LWD Caliper (red second track) versus wireline Caliper (green second track) after depth shifting. On the right half of second track DCAL LWD (black) and DCAL wireline (green).

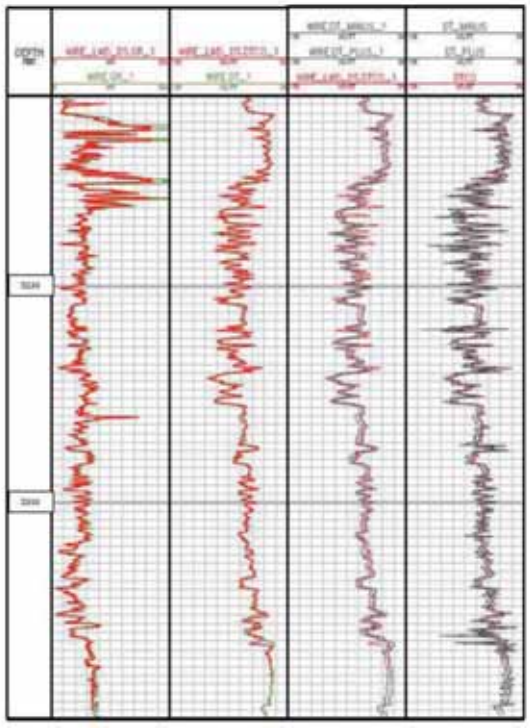

Figure 7: LWD sonic (red second track) versus wireline Sonic (green second track) after depth shifting.

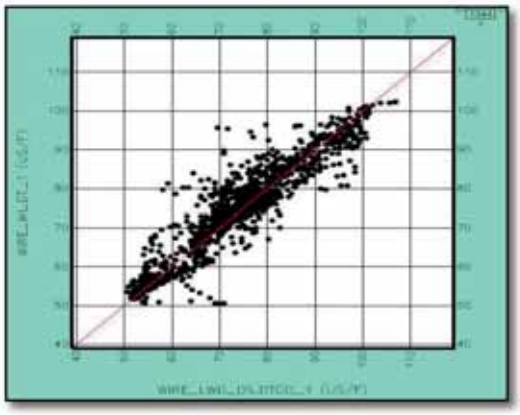

Figure 8: Crossplot of LWD Compressional slowness (x axis) versus wireline Compressional slowness (y axis).

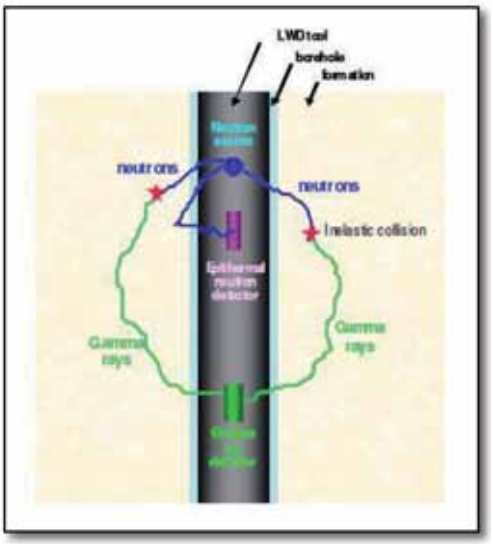

Figure 9: A schematic of NGD method of operation (Rodriguez et al, 2009).

	Neutron-Gamma Density	Gamma-Gamma Density[a]
Range	1.7 to 2.9 g/cm³	1.7 to 3.05 g/cm³
Precision[b] (ROP, rate of penetration)	0.018 g/cm³ at 2.4 g/cm³ at 61 m/h ROP	0.006 g/cm³ at 2.5 g/cm³ at 61 m/h ROP
Accuracy: Clean sandstone, limestone, dolomite Shale	 0.025 g/cm³ 0.045 g/cm³	 0.015 g/cm³ 0.015 g/cm³
Axial resolution[c]	89 cm	36 cm 15 cm (enhanced resolution)
Depth of investigation (DOI)[d]	25.4 cm	10.2 cm

[a]GGD from multifunction service (Weller, el-Halawani et al 2005; Weller, Griffiths et al. 2005)
[b]Three depth-level averages
[c]Measurement resolution along the tool axis
[d]DOI for a fresh water 33 p.u. sandstone formation

Table 3: Comparison between NGD and GGD specifications (SPE 159334).

In all examples shown from Figure 2 onwards, the LWD data is depth shifted to fit wireline data by moving the LWD data 8.5 ft down to get the best general fit. This depth shift is applied to other curves , to be used for the rest of the comparison between the logs.

This comparison brings to attention an important issue when we use LWD and wireline logs across different hole sections of the well. Because the factors affecting drill string and wireline cable are different, depth discrepancy is expected between the two and the problem becomes evident when we run correlation logs during perforation.

Gamma Ray

Gamma ray measurement is sensitive to naturally emitted gamma ray radiation from the formation. It is generally accepted that this type of logging tool will not affect the gamma ray reading.

Some discrepancies between GR reading between LWD and Wireline have been reported. The discrepancies were attributed to the fact that LWD employs thick drill collars around the sensors and these might alter the sensor's ability to detect the low end of the GR energy spectrum. Drill collars in part will cause nonlinear attenuation of the spectrum, resulting in inaccuracies even after correction. The source of inaccuracy is related to the possible difference in ratios of uranium, thorium and potassium between the formation measured and that of the API calibration facilities, from which the corrections were derived (Page 2006). This observation is not always the case. A study by (Mendoza et al. 2006) suggests that if appropriate environmental corrections are applied, LWD and wireline GR should read relatively the same.

Figure 2 shows a comparison between LWD and wireline

GR from the subject well in Track 1. It is clear that the behavior of the two curves is similar for practical purposes. In Track 2, the uncertainty band is applied to wireline GR; and shows that GR from LWD is within the accepted uncertainty; this means both measurements are comparable. A crossplot of both is shown in Figure 3.

A histogram of the difference between LWD and wireline GR is shown in Figure 4 with an average of -8.9 API. From this, it is observed that wireline GR is reading slightly higher than LWD. The difference is not significant for practical purposes.

Caliper

Calipers from LWD and wireline tools are mainly used for the same purpose, which is measuring the hole diameter and defining its shape. This measurement affects the way wells are completed and monitored (Butt et al. 2007). They are significantly different in design. While wireline caliper is mechanical, LWD uses time of flight method by inducing an ultrasonic wave because it is impossible to have a mechanical caliper in the drilling environment (Butt et al. 2007).

Besides the method of measurement, calipers from LWD and wireline should read the same. The only difference is that LWD calipers could detect features that mechanical calipers might miss, and therefore have better resolution (Jackson et al. 1994). Besides resolution, any difference between the two could be used to gain insight about the formation.

A comparison between the LWD and wireline caliper is shown in Figure 6. The comparison shows that the curves are generally in agreement because of a generally good hole, with a slight decrease in hole size in the wireline run.

In addition, it is clear that there is an increase in differential caliper value (DCAL) every time the hole size decreases. DCAL represents the difference between the actual caliper measurements to that of a gauged hole. The increase in DCAL in wireline run is indicative of mud cake buildup across clean sands.

By referring to Table 1, we note that mud cake in wireline is fully developed and static. The fact that mud cake is established can be used as a good indication of crossing a permeable zone. This can affect any pretesting and sampling programs.

Figure 5 shows the average difference between LWD and WL caliper to be 0.03 inches. In short, the difference between LWD and the wireline caliper is expected because of the difference in logging condition and tool design.

Sonic

Sonic is the deepest porosity measurement and it is less affected by the borehole condition among other porosity measurements. In addition, it is important to mention that this measurement is not a distinct part of the sourceless LWD tool.

In this comparison, except of minor depth offset, compressional slowness data showed a good match between LWD and wireline as shown in Track 2 of Figure 7. In Track 3, the uncertainty band was applied to wireline sonic, and LWD data falls within the uncertainty band implying good agreement. Some non-frequent discrepancies appear occasionally between the two, which could be attributed to resolution difference.

Figure 8 is a crossplot of LWD compressional slowness to that of wireline showing a good fit.

Density

The comparison between density measurements from both LWD and wireline is the most interesting because they are acquired in significantly different ways. It is important to note that sourceless density measurement requires characterization before running in any field. And, using it in exploration is usually not recommended. It was run to evaluate and test its comparability with conventional density. In wireline, density measurement, which is called gamma-gamma density (GGD), uses a chemical source (Cesium-137) to emit gamma rays having medium energy levels of 662 KeV. These gamma rays undergo a scattering as they interact with electrons of the atoms in the formation. This interaction is referred to as Campto n scattering, and results in a reduction of gamma ray counts of a specific energy range with the increase of electron density of passing material (Rodriguez et al. 2009). The amount of gamma ray detected is indicative of the formation's electron density, which in part is related to the formation bulk density. The wireline is sensitive to borehole washouts, and the quality of the data is dependant on pad contact with the formation.

For LWD sourcelsess density measurment, which is called neutron-gamma density (NGD), no chemical source is required. A pulsed neutron generator (PNG) is used to generate fast neutrons that bombard the formation and excite the nuclei of atoms during inelastic

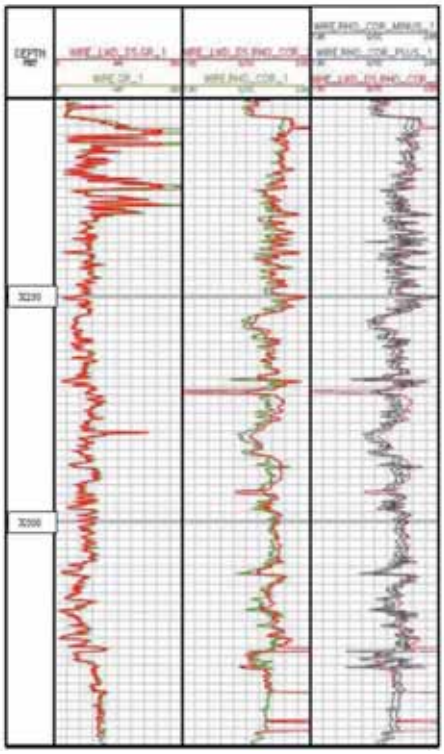

Figure 10: LWD NGD (red second track) versus wireline GGD (green second track) after depth shifting.

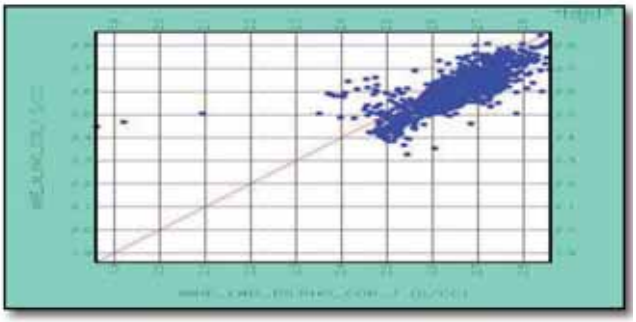

Figure 11: Crossplot LWD NGD versus wireline GGD.

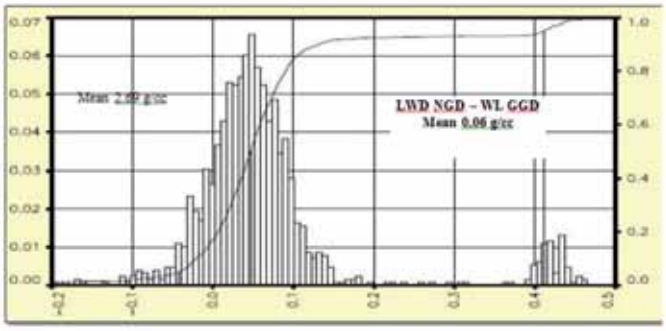

Figure 12: Histogram density LWD and wireline data.

collisions. Gamma rays are emitted from the nuclei as they return to base energy level.

The probability of gamma rays being detected is sensitive to formation density as shown in Figure 9. Unlike customary density measurement, the source of gamma rays is not a single point, but a cloud varying in size (Weller et al. 2005). The extent of this cloud is dependent on the transport of fast neutron from the source to the point of production.

There is a difference in the physics of measurment, which will lead to variance in depth of investigation and sensitivity. Table 3 compares specification of NGD and GGD in LWD environment, we can note that NGD has a deeper depth of investigation and lower resolution. This should make it superior to GGD in determining the actual formation properties without invasion effects. The resolution is lower, which is important in thin bed analysis. Additionally, accuracy of GGD density is superior to NGD, and is usable in a wider density range. One of the key differnces is that LWD sourceless density does not generate a PE curve because of the tool design. A comparison between GGD run on wireline and NGD run in LWD is displayed in track 1 of Figure 10. It is clear that GGD has better resolution than NGD. Also, NGD reads higher apparant bulk density than GGD. This could be due to mud invasion (Table 1). By the time wireline was run, some mud invasion has clearly penetrated the high salinity water formation. This change in formation pore fluid density reduces the apparent formation bulk density and was reported elsewhere (Hansen et al. 1996).

By examining Track 2 of Figure 10, it is clear that LWD density is out of the uncertainty band of wireline density; this leads to a low confidence in the data. Moreover, because these tools are using different physics and sensors, discrepancies are to be expected in their responses. For example, LWD NGD response is affected by fast neutron cross section, and this effect is corrected for when modeling and calibrating the response in clean fresh water formations (Evans, et al, 2012). In formations with varying amounts of shale and heavy elements, the correction might not be accounted for properly. In addition, shoulder bed effects on neutron transport follow asymmetrical behavior when going from the high to low porosity zone, or the reverse. This effect is also not corrected for (Evans et al. 2012).

A crossplot of NGD versus GGD is shown in Figure 11 and clearly shows the big difference between the two measurements, with NGD being higher in value.

The difference in frequency distribution is shown in Figure 12 with an average of 0.06 g/cc. This difference is

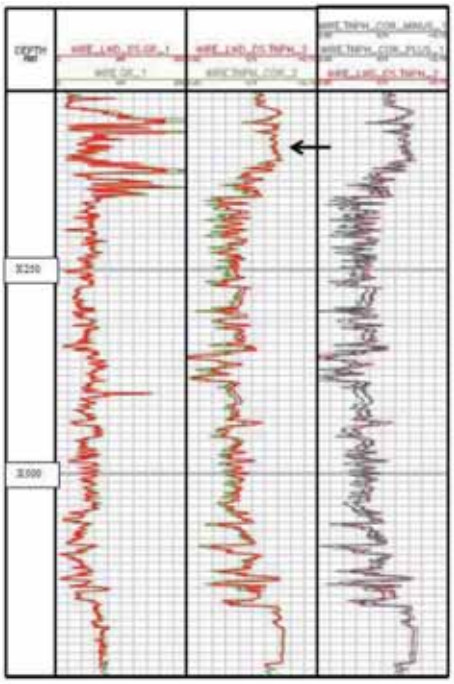

Figure 13: LWD neutron (red second track) versus wireline neutron (green second track) after depth shifting.

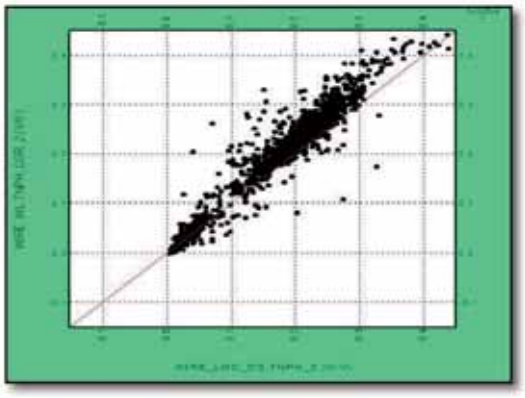

Figure 14: Crossplot LWD neutron versus wireline neutron.

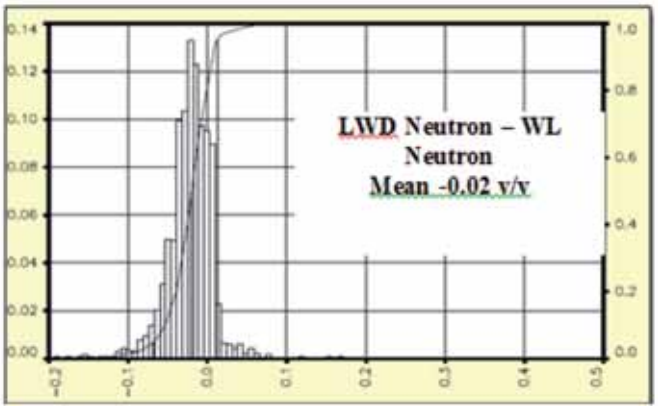

Figure 15: Histogram LWD and wireline neutron.

important to note as it affects porosity calculations and mineral identification. Also, the difference will affect pore pressure prediction and seismic calibration, since both require density measurement.

Neutron

Neutron tools respond to the hydrogen in addition to the thermal neutron capture cross section of the formation. Neutron measurements from sourceless LWD and conventional wireline tools are not the same. The difference can result from different source to detector spacing, mixes of thermal and epithermal neutrons detected, and lithology response. Invasion can cause a difference in response, since invading mud can have a significantly different chlorine content (Jackson et al. 1994).

Conventional LWD and wireline tools use a chemical source (Americium-Be 241) to generate fast neutrons, while sourceless LWD uses PNG to emit neutrons to the formation. PNG creates higher energy neutrons that penetrate deeply into the formation. These neutrons are slowed down by interacting with hydrogen in the formation. Besides hydrogen, density affects the slowing down distance of these neutrons. It was reported that the dens ity, or so called "shale effect" has a higher impact on these fast neutrons from PNG compared to a conventional chemical source (Weller et al. 2005). This difference can affect the count rate at the detector and hence the porosity measurement.

In general, differences in design parameters of neutron tools leads to differences in response. In addition, because these tools are calibrated and characterized to a specific set of conditions, which are fresh water, and clean limestone formation, it is expected that different tools will read similar in these conditions, and different otherwise.

Figure 13 illustrates this point. As shown in Track 1, neutron porosity is not the same throughout the interval with LWD being lower in reading. The only exception is the top interval where both LWD and wireline neutron readings are matching (black arrow). A close investigation reveals that this interval is mainly composed of limestone with little shale. Hence, it represents the closest condition to the tool's calibration environment. (Gilchrist 2009).

Track 2 of Figure 13 shows uncertainty bound placed on wireline neutron. LWD neutron falls within the lower limit of the uncertainty band of the wireline and is acceptable. A crossplot of LWD versus wireline neutron is shown in Figure 14 and clearly shows a slight difference between the two measurements with LWD being lower.

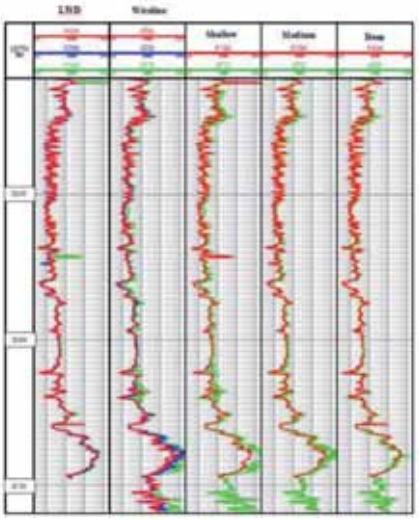

Figure 16: Wireline vs. LWD resistivity data for different depths of investigation.

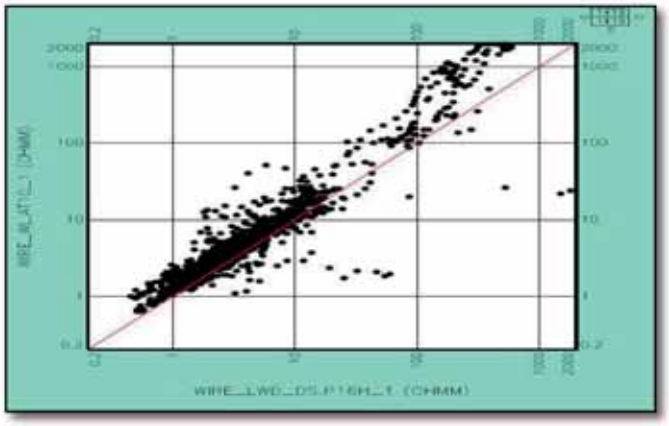

Figure 17: LWD vs. wireline shallow resistivity crossplot.

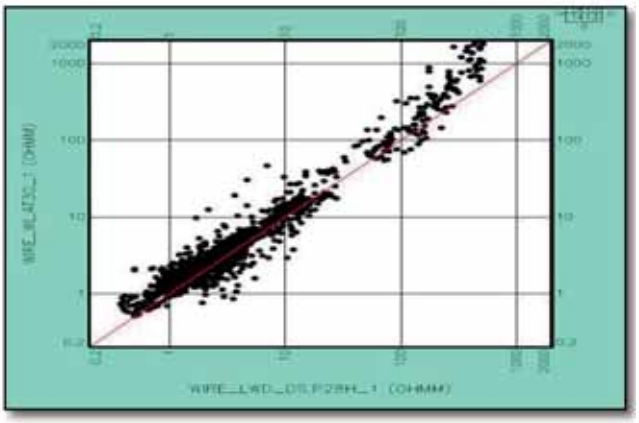

Figure 18: LWD vs. wireline medium resistivity crossplot.

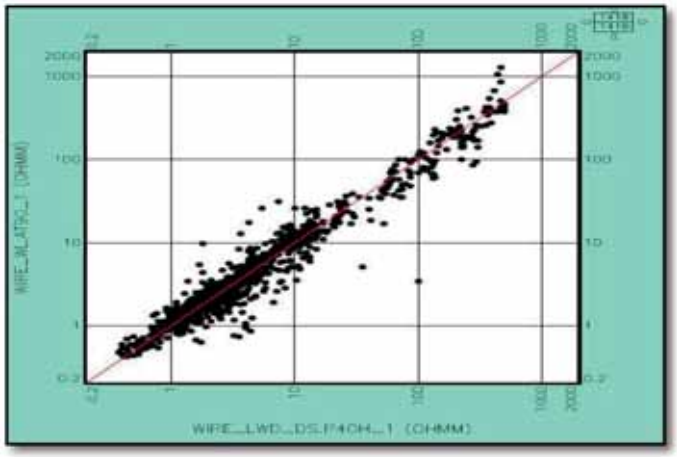

Figure 19: LWD vs. wireline deep resistivity data crossplot.

The difference distribution is shown in Figure 15 with an average of 0.02 v/v. The lower reading of LWD tools has been reported before (Afonso et al. 2004); it was attributed to the fact that LWD tools are less sensitive to thermal neutrons.The steel shielding makes the detector see more of epithermal neutrons than thermal neutrons, especially in shales, this leads to lower porosity readings. In summary, differences are expected between neutrons from LWD and wireline because of differences in design, formation properties, and responses in shale. In our example, we show that the difference is acceptable within uncertainty limits.

Resistivity

LWD resistivity operates at 2 MHz frequency and uses electromagnetic propagation to measure formation resistivity. Wireline induction tools operate at a lower frequency, around 20 kHz. This difference in operating frequency provides wireline tools the ability to have deeper radial sensitivity than LWD tools.

The deeper radial sensitivity in wireline is important in determining the original formation properties away fromthe borehole, which may be affected by mud invasion. As shown in Table 1, this effect can be neglected in LWD environment, because there is usually not enough time for invasion to happen by the time the data is recorded. Even if there is an invasion, it will be negligible, and the deep LWD resistivity curve can still measure the true formation resistivity with sufficient distance away from the borehole.

Figure 16 shows a comparison between wireline and LWD resistivity logs in the subjet well, which was drilled with OBM. In the first track, LWD resistivity data with different depths of investigation is displayed (shallow is green, medium is blue, and deep is red). It is clear that the curves stack together with no separation. This is expected because invasion has not happened by the time of logging. The second track in Figure 16 shows the resistivity data for the wireline run (shallow is green, medium is blue, and deep is red). It is clear now that there is a separation between the curves because of

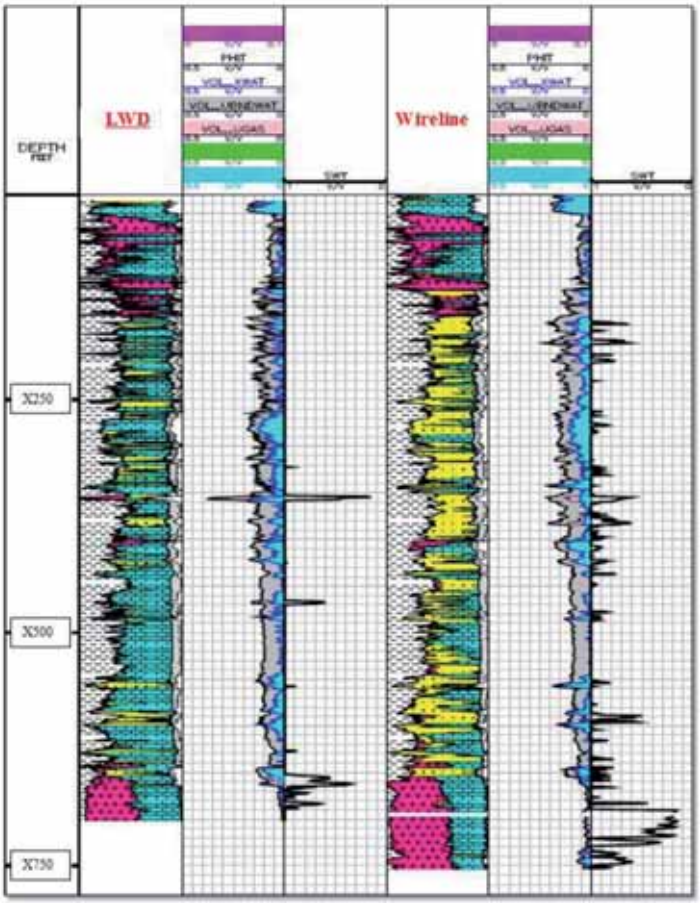

Figure 20: LWD vs. wireline formation evaluation results using basic logs.

resistive borehole fluid invading the formation. This is reflected on the shallow curve reading higher than the deep in some zones. The third track in Figure 16 shows a comparison between the shallow resistivity form wireline (green) to shallow resistivity from LWD (red). A separation is clear between the two because of OBM invasion. Although invasion is less desired when evaluating original formation properties, this phenomenon reveals important information about the formation's producibility. Based on this, any formation testing program gives priority to target these zones where the invasion happened. The fourth track in Figure 16 shows a comparison between the medium resistivity from wireline in green, to medium resistivity from LWD in red. A separation is apparent between the two, but is less severe, which suggests that invasion is not significant compared to the shallow zone. The last track in Figure 16 shows a comparison between the deep resistivity from wireline in green to deep resistivity from LWD in red. There is no clear separation between the two , and both curves are reading almost the same value, which means they are reading real formation resistivity in the virgin zone.

A crossplot of LWD versus wireline shallow resistivity data is shown in Figure 17 and clearly shows a difference between the two measurements with LWD being lower in resistivity. Again, this is because wireline shallow resistivity is affected by OBM invasion in the near wellbore region. A crossplot of LWD versus wireline medium resistivity data is shown in Figure 18, with less difference between the two measurements. This is because wireline medium resistivity is affected by OBM invasion, but to a lesser extent than the shallow resistivity. A crossplot of LWD versus wireline deep resistivity data is shown in Figure 19, with no clear difference between the two. It can be concluded that both measurements are reading the virgin formation properties.

In summary, both measurements are reading the same. The only difference could be attributed to formation property alteration by invading mud (Table 1). This can reveal important information, especially when little is known about the formation, as is the case in exploration.

Formation Evaluation

The ultimate goal of this comparison is to assess the effects and differences between LWD and wireline logs on formation evaluation. To do this, a formation analysis

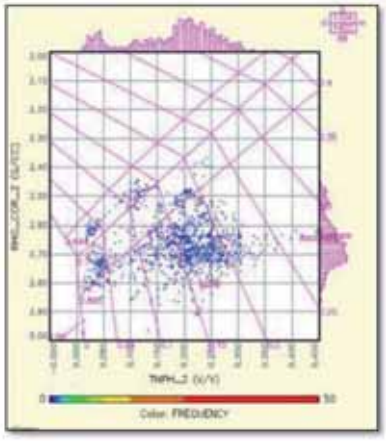

Figure 21: LWD D-N crossplot.

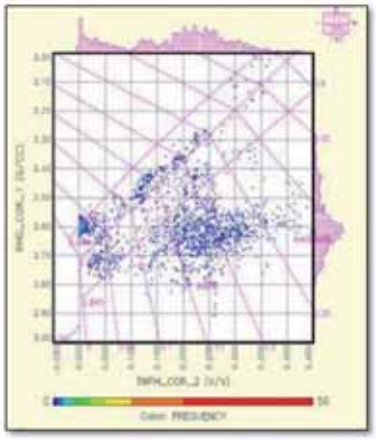

Figure 22: Wireline D-N crossplot.

using multimin will be run on both wireline and the LWD data set. And to be consistent, only common logs will be used in the evaluation. This is because wireline tools have additional logs that are not available in LWD tools. For example, PE and spectral gamma ray were acquired in wireline and not LWD.

The analysis was performed using the basic logs that were compared: gamma ray, density, neutron, sonic, and shallow and deep resistivity. Figure 20 shows the results of the analysis. Track 1 shows the lithological interpretation, Track 2 shows porosity results, and Track 3 shows water saturation results. In the same figure, wireline results are shown in Tracks 4 to 6 following the same order. Lithology interpretation is clearly different between the two analyses; LWD analysis shows most of the section to contain limestone, which is not consistent with the cuttings description. This is caused by the high density reading, which leads to an increase in the limestone volume at the expense of sandstone. The wireline analysis shows a reasonable sandstone volume, which is in agreement with the cuttings.

Figures 21 and 22 show the density-neutron core plots for LWD and wireline data, respectively. These two figures explain the results. Because of the high density in LWD, the data is lining up across the limestone line in the density-neutron crossplot, with no data on the sandstone line. The picture is different for wireline, we can see a group of data clustering around the sandstone line as expected, based on cuttings description. Figure 23 displays a total porosity crossplot of wireline and LWD data. It shows that LWD data has a lower total porosity than wireline data. The difference is insignificant. The average difference between the two total porosities is highlighted in Figure 24 is less than 0.05 pu.

From this analysis, we show that with basic logs, the effect on total porosity is minimal, but there is an effect on lithology interpretation. This is important to note, because it will give a misleading result while correlating wells, and overall understanding of the depositional environment of the area. Effects on the saturation were minor, as shown on Figures 25 and Figure 26.

Conclusions

Sourceless LWD logs were compared with conventional wireline logs to assess their reliability in exploration using data from a single well drilled with OBM. LWD has many real time applications in exploration, and is important to reduce the uncertainty and risk associated with drilling offshore and in new locations. Differences between LWD and wireline logs are expected due to sensor design, tool physics, borehole conditions, and alteration of formation properties. These differences can reveal important information about the formation.

Formation evaluation using common curves leads to comparable porosity results, with LWD showing higher value. Core data was not used in this evaluation. Finally, sourceless LWD can be used to identify the presence of hydrocarbon zones and saturation. Depth uncertainty in LWD needs to be understood and resolved.

In exploration, little is known about the formation's properties and potential to flow. Resistivity separation in wireline logs presents important information about formation fluid mobility; this cannot be inferred from real time LWD.

The following generalization can be made from this comparison:

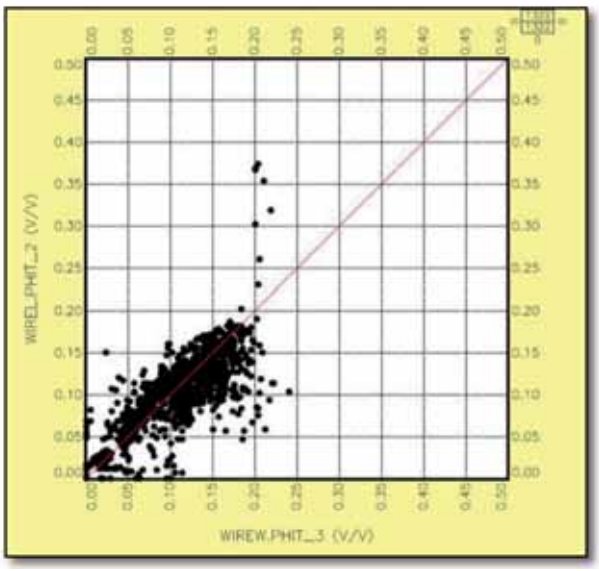

Figure 23: LWD vs. wireline total porosity.

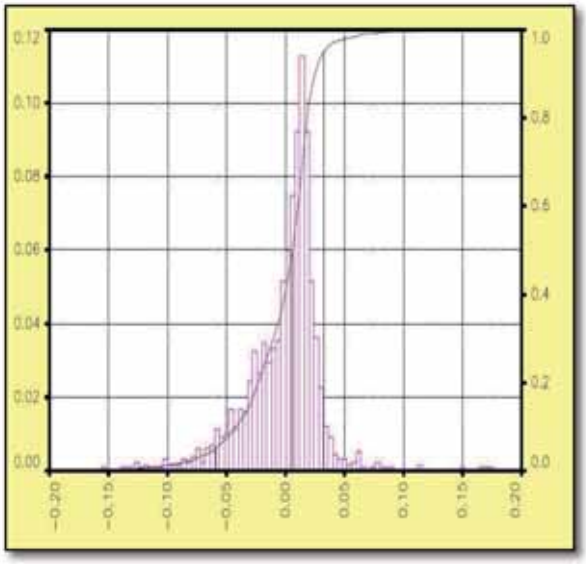

Figure 24: histogram of total porosity difference.

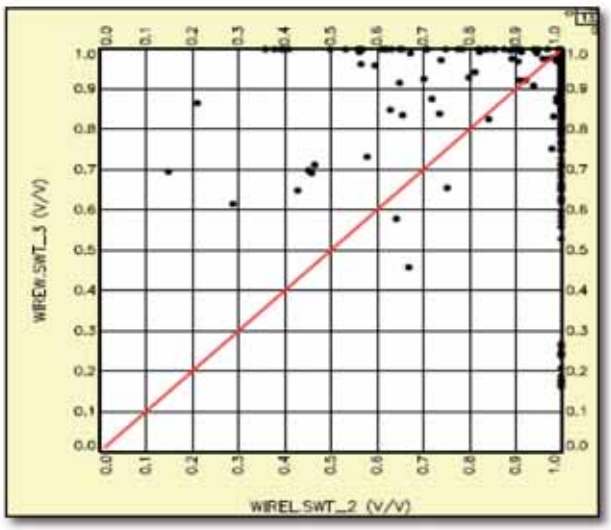

Figure 25: Crossplot SWT LWD vs. wireline.

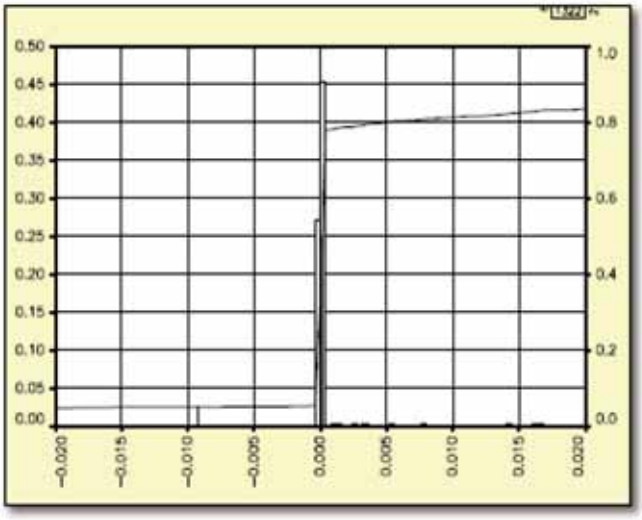

Figure 26: Histogram LWD vs. wireline saturation.

• LWD has many useful applications in exploration, and can be essential in optimizing operational decisions in newly explored basins.

• Differences are expected between LWD and wireline logs, due to tool design and the nature of the operation.

• Investigation of differences between LWD and wireline logs improves understanding of reservoir quality. Sourceless density in LWD needs to be characterized and area knowledge is critical before use in exploration.

• In this particular case study, LWD could replace wireline, because no hydrocarbon was present in this specific section.

• Sonic, resistivity and neutron could be used directly from a sourceless LWD tool.

• A time lapse run after drilling could be sufficient to assess the invasion effect and eliminate the need for additional wireline resistivity.

• High LWD density leads to high uncertainty in quantifying the lithology.

• In exploration wells when the stakes are high and

uncertainty is large. The value of information gained by running wireline logs can outweigh the cost of the operation.

• More work is needed to understand the difference between LWD and wireline elemental yields from spectroscopy tools.

Acknowledgements

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Transport of Temperature Nanosensors Through Fractured Tight Rock: an Experimental Study

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Abstract

The goal of this research was to develop methods for acquiring reservoir temperature data within the formation and to correlate such information to fracture connectivity and geometry. Existing reservoir-characterization tools allow temperature to be measured only at the wellbore. Temperature-sensitive nanosensors would enable in-situ measurements within the reservoir. Such detailed temperature information enhances the ability to infer reservoir and fracture properties and inform reservoir engineering decisions. This study provides the details of the experimental work performed in the process of developing temperature nanosensors. Specifically, particle mobility through fractured media was investigated.

The transport of silica particles through fractured rock was investigated. Experimental results showed that the recovery of the particles was dependent on the particle size and suspension concentration. It was observed that the recovery of the 2 μm particles following their injection into fractured greywacke core was affected adversely by suspension concentrations (decreasing recovery with increasing suspension concentration). Increasing concentration of the 2 μm particles resulted in more pronounced aggregation, which led to trapping by straining. Conversely, the recovery of the 5 μm and polysize particles increased with increasing suspension concentration. The particle size has a direct effect on its recovery. By comparison, the recovery of 5 μm particles was about an order of magnitude higher than that of the large particles (> 5 μm).

The controlling mechanisms for transport of silica particles were also identified. Among all, transport by gravitational sedimentation (gravity settling) was prominent. Results also showed that the existence of the fracture facilitated the particle transport. Particles were found to flow with the fast-moving streamlines within the fracture. The dominance of particle transport by

advection or diffusion was examined using the Peclet number. The high Peclet numbers indicated advection-dominated transport.

Introduction

Fluid flow through carbonate oil formations is dominated by the flow through fractures. In the development of carbonate reservoirs, the characterization of the size, shape and connectivity of fractures is crucial. Research studies have been devoted to developing methods to characterize fracture networks within a reservoir. Temperature measurements acquired by nanosensors could be used to infer information about fracture properties. Several temperature-sensitive nanosensors were investigated, including tin-bismuth alloy, dye-attached silica, thermochromic polymer and silica-encapsulated DNA particles. Details of the preliminary testing that was carried out for these four potential temperature-sensitive nanoparticles can be found in Alaskar et al. (2013).

In order for temperature nanosensors to map the reservoir temperature distribution and ultimately to characterize the fracture network, they must be transported through the reservoir without major retention within the formation pores and/or fractures. Therefore, particle mobility through fractured rocks was investigated. Specifically, various laboratory-scaled core-flooding experiments with inert silica particle suspensions were conducted.

Particle transport and retention in fractured media differ greatly from that in porous media due to differences in the geometry of the transport conduits (Knapp et al., 2000). Large flow paths facilitate deeper infiltration of particles in fractured rocks compared to porous media (Weisbrod et al., 2002). Investigating particle behavior in discrete fractures is useful for understanding the controlling transport mechanisms. Mechanisms effecting particle transport in fractured media include advection, dispersion, adsorption, desorption, physical straining and air-water interface capturing (Wei et al., 2012). Several experimental investigations of particle transport in fracture materials focused on particle transport in volcanic rocks (Champ and Schroeter, 1988; Bales et al., 1989; Reimus, 1995; Vilks and Bachinski, 1996; Vilks et al., 1997), in artificial fractures (Smith et al., 1985; McKay et al., 1993b; McKay et al., 1995; Hinsby et al., 1996; Harton, 1996) or in fractured clays (Cumbie and McKay, 1999).

Vilks and Bachinski (1996) investigated the influence of particle size, velocity and direction of water flow and flow path on the transport of particles in a fractured granite block. They concluded that particle transport was sensitive to flow path and direction, and that the recovery rates were dependent on flow velocity relative to a critical velocity below which significant particle retention was observed. It has been observed that particles transport faster than conservative solutes in fractured media (e.g., Champ and Schroeter, 1988; Reimus, 1995; Knapp et al., 2000; Zvikelsky and Weisbrod, 2006; Zvikelsky et al., 2008; Tang and Weisbrod, 2009 and 2010). Fractures are favorable flow conduits for particles because fractures represent large flow paths with high velocities relative to the surrounding matrix, the absence of diffusion between the fracture and the matrix of low permeability and/or small pore throat size and the fact that particles of the same charge as the flow medium will most likely flow following central streamlines reducing collision with matrix grains and hence lower the probability of attachment (Zvikelsky and Weisbrod, 2006). Bales et al. (1989) observed that the transport of bacteriophages in fractured porous tuff was three times faster than conservative solute tracer. McCarthy et al. (2002) studied the transport of fluorescent polystyrene particles in fractured shale saprolite. They reported that the particles arrived much sooner than bromide tracer by a factor of five. Investigators commonly attribute the enhanced transport of particles in fractured media to size and charge exclusion effects and Taylor dispersion (Becker et al., 1999; Zvikelsky and Weisbrod, 2006; Wei et al., 2012). Because of the large size of particles compared to pore throat size, particles are excluded from low flow regions of the rock matrix following fluid streamlines in fracture (Smith and Degueldre, 1993; Becker et al., 1999). Bradford et al. (2002 and 2003) in their study of particle transport in a sand column reported that size exclusion at inlet grains created dead ends, forcing subsequent particles through a larger continuous pore network. The charge exclusion comes into effect when both particles and solid surfaces are of like charge. As particles approach solid surface or grain, an electrostatic repulsive barrier forces the particles away from grain wall into fast-moving streamlines within the fracture and thus faster breakthrough of particles. When particle size increases, Taylor dispersion could significantly enhance the transport of particles. Reimus (1995) attributed the rapid breakthrough of particles compared to solute tracers in fractured tuff core to lack of molecular diffusion, which would prevent particles from migrating out of high velocity streamline in the fracture.

Physical straining of particles is directly related to the particle size and shape relative to the size and geometry

Property	Value
d (cm)	5.08
L (cm)	3.02
$\emptyset_{sat}$ (%)	2.96
θ (degrees)	40.00
k_f (darcy)	79.48
k_m (darcy)	1.5×10^{-7}
b (μm)	30.68
d_{pore} (μm)	0.06
PV (cm^3)	1.81

[a] *d and L are the core diameter and length, respectively, $\emptyset_{sat}$ is porosity by resaturation, θ is fracture orientation angle in degrees, k_f and k_m are the water permeability of fracture and matrix, respectively, b is the fracture hydraulic aperture, d_{pore} is mean pore size, and PV is pore volume.*

Table 1: Physical properties of fractured greywacke rocks[a]

Flow medium	SiO_2 suspension	q (cm^3/min)	v_m (cm/min)	v_f[c] (cm/min)	V_{inj}[b] (cm^3)	c (mg/cm^3)
Fractured greywacke sandstone	Blue	0.68	0.84	43.63	1.00	0.49
	Blue	0.68	0.84	43.63	1.00	0.98
	Green	0.78	0.96	50.05	1.00	0.49
	Green	0.78	0.96	50.05	1.00	0.98
	Red	1.00	1.23	64.16	1.00	0.49
	Red	1.00	1.23	64.16	1.00	0.98

[a] *Here q is the volumetric flow rate, v_m and v_f average fluid pore velocity in matrix and fracture, V_{inj} is the injected particle suspension volume and c is the particle suspension mass concentration.*

[b] *inj stands for injected suspension volume.*

[c] *The water velocity inside the fractured greywacke core was calculated based on total flow. All water is assumed to flow through the fracture (no flow through the matrix) since the matrix has very low permeability in the sub-millidarcy range (1.5×10^{-4} md, Table 1) and applied differential pressure used during injection of particles was a fraction of one atmospheric unit.*

Table 2: Summary of fractured greywacke rock flow experiments parameters[a]

of the flow conduit (pore throats or fracture) (Swanton, 1995). Straining could occur within the fracture at areas of small apertures. Particles flowing through a fracture may also be trapped physically in the adjacent rock matrix, given that particles can access rock matrix and their size is larger than surrounding pore throats. This would result in dead ends preventing subsequent particles from further penetration (Cumbie and McKay, 1999), and/or forcing them through larger continuous pores or fractures (Bradford et al., 2002 and 2003). Conversely, if particle size is smaller than surrounding pores, particles may enter into the rock matrix which would increase the probability of particle collision with matrix grains and thus further particle filtration (James and Chrysikopoulos, 1999; Oswald and Ibaraki, 2001; Alonso et al., 2007). It should be mentioned that matrix diffusion is proportional to rock matrix porosity, and inversely proportional to fluid velocity and particle size.

Flow medium	SiO_2 suspension	q (cm^3/min)	c (mg/ml)	τ (min)	$(C/C_o)_{max}$ -	$(C/C_o)_{cum}$ -
Fractured greywacke	Blue	0.68	0.49	0.10	0.48	N/A
		0.68	0.98	0.10	0.17	N/A
	Green	0.78	0.49	0.12	0.40	0.82
		0.78	0.98	0.12	0.55	0.93
	Red	1.00	0.49	0.03	0.03	0.08
		1.00	0.98	0.03	0.09	0.21

[a]Here q is the volumetric flow rate, c is the particle suspension mass concentration, τ is the first arrival time of particles, $(C/C_o)_{max}$ is the maximum recovered relative concentration and $(C/C_o)_{cum}$ is the cumulative relative concentration.

[b]N/A denotes that the measurement could not be determined.

Table 3: Results of fractured greywacke rock sample[a]

Flow medium	SiO_2 suspension	U_s ($\mu m/s$)	L_s (μm)	L_s/L_D -	$L_s/0.5b$ -	Pe -
Fractured greywacke	Blue	2.63	16.39	9.97	1.07	8.95×10^5
	Green	16.35	120.74	107.02	7.87	1.90×10^6
	Red[b]	65.40	113.80	293.86	7.42	1.61×10^7

[a]Here U_s is the particle settling velocity, L_s is the length scale of Stoke settling of spherical particle, L_D is the length scale of diffusion, b is the fracture hydraulic aperture and Pe is Peclet number.

[b]Parameters were calculated based on nominal size of 10 μm.

Table 4: Summary of calculated length scales and Peclet number for blue, green and red silica particles in fractured greywacke core[a].

Particles at the microscale are expected to travel along higher velocity streamlines (excluded from lower velocity regions near pore walls or fracture surfaces). Interaction among particles (Brownian motion) will result in diffusion of particles, with large particles experiencing less diffusion (as per Stokes-Einstein equation given in Russel et al., 1989) than smaller ones (Keller and Auset, 2007). Particle motion along fluid streamlines is advection. The significance of diffusion and advection on particle transport can be evaluated by examining Peclet (Pe) number (as defined by Detwiler et al. (2000) for particles in parallel plate aperture) for each particle size under a specific flow conditions (i.e. fluid velocity) (Zvikelsky and Weisbrod, 2006).

Gravitational sedimentation is recognized to be a significant filtration mechanism of particles in fractures, especially for dense particles. Gravity forces and associated settling velocity will cause the particle to move across streamlines until it reaches solid surface and deposits on it, if the conditions are favorable for attachment. Similar to particle transport by diffusion, gravitational sedimentation is a function of fluid velocity. Settled particles may be remobilized by increasing flow rates (Wei et al., 2012). Reimus (1995) described fluid advection, gravitational settling and, to lesser extent, matrix diffusion, to be the governing mechanisms of particle transport in fractures. Zvikelsky et al. (2008) studied the transport of clay, with much higher density compared to model particles, in fractured chalk. They observed that clay particles experienced higher attenuation and slower breakthrough times as compared with those of model particles, mainly due to gravity settling.

The relative effect of diffusion and gravity settling (which are highly dependent on particle size) on flowing particles of different sizes through a fracture can be assessed using their characteristic transport length scales over resident time as per the model suggested by Becker et al. (1999). The Stoke rate of settling is proportional to the square of the particle diameter, while Brownian diffusion is inversely proportional to its size.

In this work, the mobility of silica particles in fractured tight rock (greywacke sandstone) was investigated. The

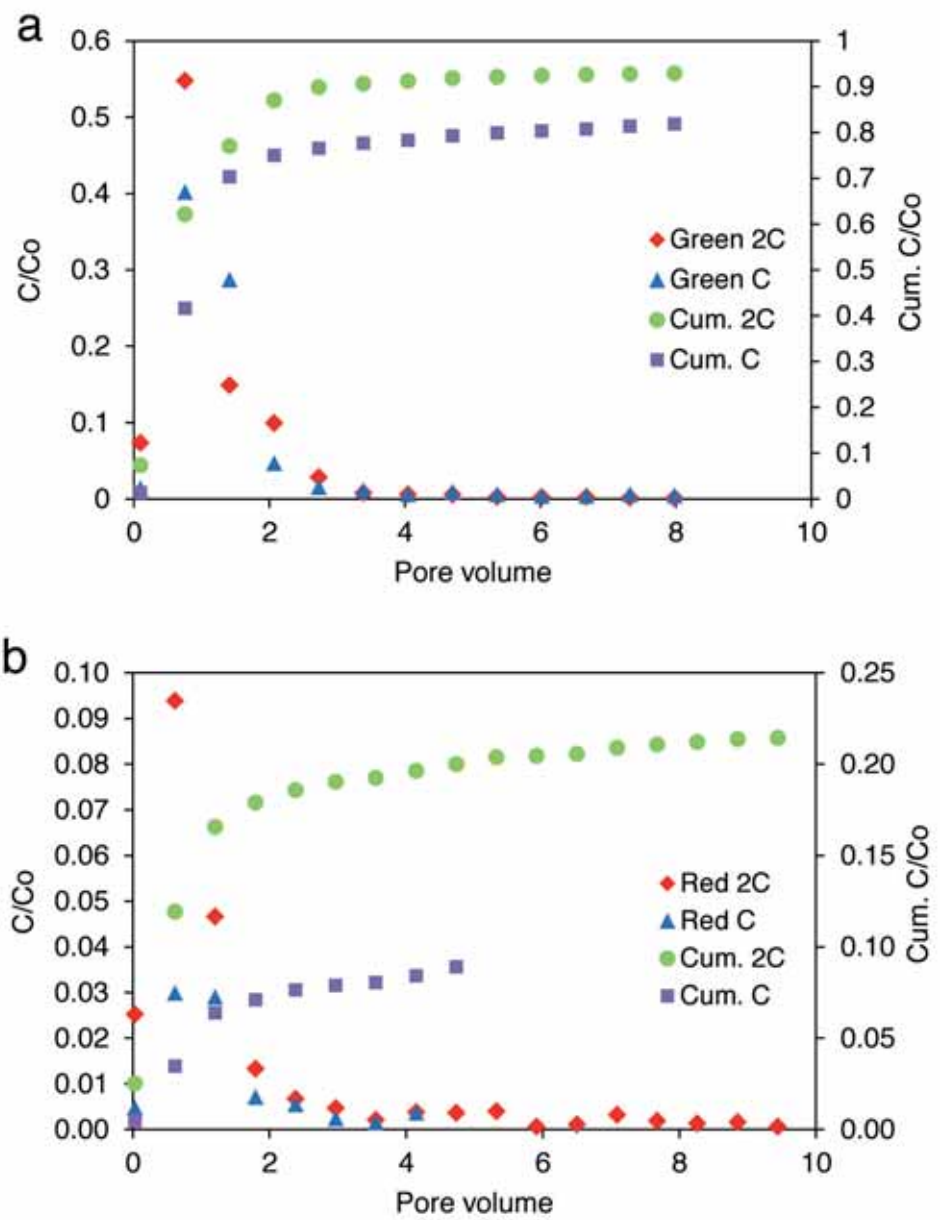

Figure 1: Relative concentrations of (a) green and (b) red silica particles at two different suspension concentrations following their injection through fractured greywacke sandstone. The cumulative relative concentration is also included. For the green particles, data points beyond the sixth pore volume represent backflushing samples. For the red particles, backflushing samples start at the sixth pore volume and third pore volume for the 2C and C suspensions, respectively.

influence of the particle size and suspension concentration on particle recovery was evaluated. Governing transport mechanisms of dense silica particles through fracture are discussed here. The effect of fractures in enhancing particle transport in fractured rocks is also discussed. The characterization of the particles and the rock core plug is included.

Materials and Methods

a) Silica particles characterization

Fluorescent silica particles (purchased from Corpuscular Inc., New York, USA) were used in this experimental study.

Fluorescent silica particles were characterized in terms of size and shape, zeta potential and light emission (fluorescence). The size and shape of the particles were characterized using an optical microscope and scanning electron microscope (SEM). Zeta potential was measured using Zetasizer manufactured by Malvern Instruments. The emission spectrum was obtained using Fluorescent Spectrometer (Fluorolog) manufactured by Horbia.

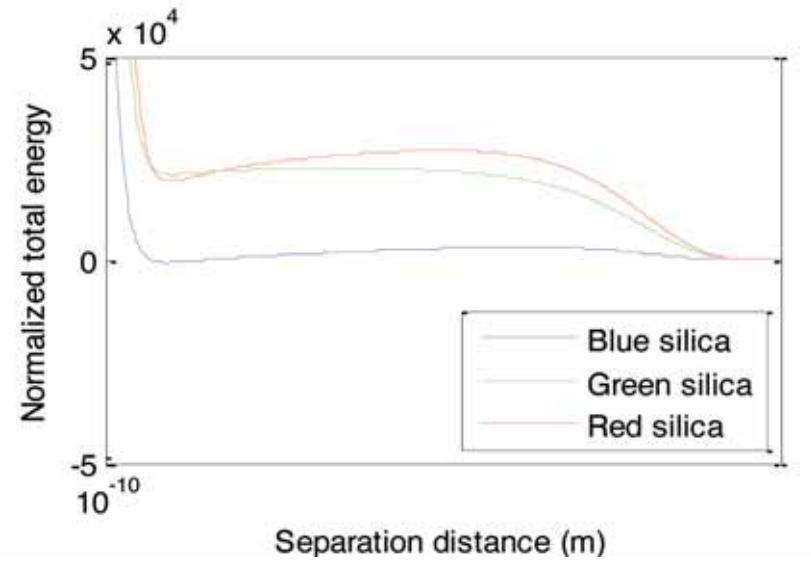

Figure 2: Total interaction energy between silica particles and surfaces. The interaction energy is normalized to the thermal energy (Boltzmann constant and absolute temperature). Hamaker constant used is 6.0x10-21 J as per Israelachvili (1992) for SiO_2/SiO_2 particles in water. The total interaction energy plot shows a strong energy barrier above 1000 k_BT for all particle sizes.

Three silica microsphere suspensions, each labeled with different fluorescent dye of blue, green and red color were used. The blue and green samples were shown to have uniformly shaped spheres with a narrow size distribution with an average particle size of approximately 2 and 5µm, respectively. The red silica spheres were polysized. The red silica sample had spheres with diameters ranging from 5 to 31 µm. The particle size was confirmed by SEM, as shown in Figure A1 in the appendix. The size was also verified by optical microscopy (images are not included). These particles had a density in the range between 2.0 to 2.2 g/cm^3. The concentration of injected suspensions varied between experiments. The excitation and emission of the blue, green and red fluorescent dyes were at wavelengths of 360/430 nm, 480/530 nm and 554/577, respectively. The emission spectra showing the peak of emission of the blue, green and red fluorescent silica particles are depicted in Figure A2 in the appendix. The effluent concentration after injecting the silica suspensions was estimated by measuring the emission intensity of the fluorescence. First, a calibration curve was constructed by acquiring the emission spectra of several dilutions of known concentration. The concentration of collected effluents was then determined using this linear correlation based on their emission intensity (see appendix Figure A3).

The particles employed in this study were negatively charged as specified by the manufacturer. Five different measurements of zeta potential (ζ) (i.e. conversion of electrophoretic mobility to zeta potential using the Smoluchowski approximation and Henry's Equation) were performed and the average zeta potentials were found to be -40.2 mV (standard deviation: 0.41 mV), -80.2 mV (standard deviation: 1.77 mV) and -56.3 mV (standard deviation: 1.32 mV) for the blue, green and red fluorescent silica particles, respectively.

Interactions between particles and/or surface of flow medium were evaluated using the extended Derjaguin-Landau- Verwey-Overbeek (XDLVO) theory (Derjaguin and Landau 1941; Verwey and Overbeek 1948). In XDLVO theory, the total interaction energy is the sum of Lifshitz-van der Waals (LW) attractive, electrostatic (EL) repulsive and short range (Born) repulsive interactions. The LW interaction energy between a flat surface and spherical particle was approximated using the expression in Gregory (1981); the EL interaction energy was approximated from an expression derived by Hogg et al. (1966), while Born interaction energy was calculated based on expression derived by Ruckenstein and Prieve (1976).

The total interaction energy between silica particles is estimated and plotted in Figure 2. All particles exhibited high repulsive energy barrier above 1000 (normalized total interaction energy), which should render them free from aggregation and/or attachment to rock walls.

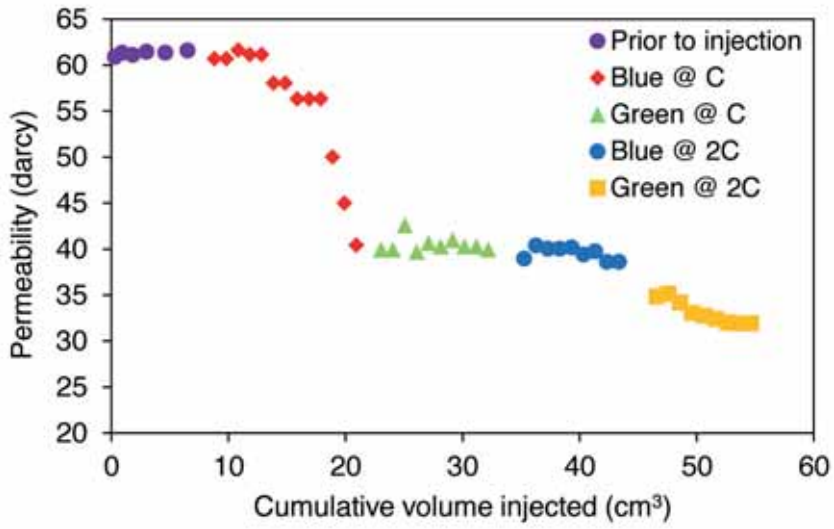

Figure 3: Permeability measurement before and during the injection of the blue and green silica particles at different concentrations into fractured greywacke core. The permeability is decreasing as more particles are injected.

b) Flow media characterization

The core sample tested was fractured greywacke sandstone from The Geysers geothermal field. Standard experiments to characterize the fractured rocks were performed, including the porosity, permeability and hydraulic aperture measurements. The physical properties of the fractured rock can be found in Table 1. The details of the porosity and permeability measurements can be found in the appendix. The pore size distribution (see appendix Figure A4) of the core sample was measured by the mercury (Hg) intrusion method, and the average pore size of the greywacke core was approximately 0.06 µm. The porosity was determined by resaturation method and found to be within 3%.

The fracture permeability was measured, using the cubic law, and found to be approximately 79.48 (±3) darcy, corresponding to a hydraulic fracture aperture of about 30.68 µm. The fracture orientation angle used in the permeability and/or fracture aperture calculation was about 40 degrees. The validity of Darcy law was confirmed by the linear relationship between the flow rate and pressure drop across the core, as shown in the appendix Figure A6.

c) Fractured greywacke experimental setup and injection method

The injection process and sampling strategies in all experiments were similar; however, they differed in some aspects such as injection flow rates and sampling frequency. A summary of the injection experiment flow parameters can be seen in Table 2. The testing apparatus allows for a switch to injection of particle-free deionized water, without interrupting the flow. The particle suspension was contained in a syringe downstream from the water pump. All equipment was the same as those used during permeability measurements. The particles were injected using the syringe. All silica suspensions (blue, green, and red fluorescent samples) were diluted to two distinct mass concentrations (i.e., C = 0.5 mg/cm^3 and 2C = 1 mg/cm^3), resulting in six influent samples (two blue, two green, and two red). The volume injected into the fractured core sample was one cubic centimeter. Prior to the injection of particle suspensions, the samples were sonicated (using Branson 2510 Bath Sonicator). The core was preflushed with several pore volumes of deionized water. Following the injection of the particles (1 cm^3), a continuous flow of deionized water was introduced.

The sequence by which the transport of the silica particles through the fractured greywacke core was investigated is as follows. Initially, the blue and green particle suspensions of mass concentration C were injected, followed by an extensive flushing until particle concentration in the flushing samples was below the detection limit of the fluorometer. Then, the blue and green particle suspensions, of mass concentration of 2C, were injected consecutively. Following each injection, effluent samples were collected. Because of

the polydisperse nature of the red silica particles and concerns regarding plugging of the fracture by larger spheres, red particle suspensions (C and 2C) were injected at the end.

Results and Discussions

This section provides the results and discussion of the silica injection experiments. Fractured greywacke sandstone represents flow mostly in fractures because of its tight matrix. We investigated the effect of the particle size and suspension concentration on the particle transport through the fractured greywacke core. The results are summarized in Table 3. Particle deposition and transport mechanisms were also discussed.

a) Impact of particle size and input concentration on particle recovery

The return curves for all silica particles showed a very fast arrival. The first arrival of the particles occurred within 0.02 to 0.09 pore volumes from the start of their injection. This shows that the recovered particles were moving through the fracture, not the core matrix. The pore-size distribution of the greywacke sandstone (see appendix Figure A4) indicated that the largest pore throat size is 0.150 µm. The largest pore is significantly smaller than the smallest the silica particles (2 µm). The first arrival of blue silica particles (2 µm) was at 0.104 min. The blue silica particles were producing at constant levels with no identifiable concentration peak. The breakthrough curves (Figure 1a) of the green (5 µm) and red (polysized, 5 – 31 µm) silica particles show that the first arrivals were at 0.123 and 0.029 min, respectively. The relative concentration of the green silica particles decreased to below 0.001 of injection concentrations following the post-injection of about four pore volumes of water. Backflushing samples (at sixth pore volume and beyond) showed very low concentration of green particles, indicating that particles were not depositing at the inlet of the fracture. The relative concentration of the red particles decreased below 0.004 of injected concentrations at the sixth post-injected pore volume, with slight fluctuation in the relative concentration of the backflushing samples (beyond the sixth and third post-injected pore volumes for the 2C and C suspension concentration injections). The cumulative relative concentrations were gradually increasing until the end of the post-injection and/or backflushing.

The maximum $(C/C_o)_{max}$ and cumulative $(C/C_o)_{cum}$ relative concentration of the silica particles varied according to suspension concentration and particle size with average values as listed in Table 3. Generally, the particle recovery increased with increasing injected suspension concentration (except for the blue particles), and decreased with increasing particle size. Similar findings with regard to the influence of injected suspension concentration to particle recovery were reported in the literature (e.g. Tan et al., 1994; Liu et al., 1995; Bradford and Bettahar, 2006). Higher particle concentrations produced more rapid filling of favorable attachment sites than lower particle concentrations, and therefore resulted in greater breakthrough concentrations. Conversely, the recovery of the blue silica particles exhibited the opposite trend. The recovery of particles was lower with increasing input mass concentration. This behavior suggested that there was particle/particle interaction, causing the particles to aggregate.

As the suspension concentration increases, more particles are present, resulting in larger aggregates or clusters. Note that although the mass concentrations of all particle suspensions were the same, the number concentration (number of particles per unit volume) was different. For the same mass concentration, the number concentration of the 2 µm particles is 15.6 times more than that of the 5 µm particles. The rate of particle collision, which is often used as a precursor to aggregation, varies proportional to approximately the square of the number concentration. Therefore, for the same mass concentration, smaller particles are expected to aggregate at much faster rate than larger particles (i.e. the 2 µm particles would aggregate 244 times faster than the 5 µm particles). Although particle suspensions were sonicated prior to injection, there was still a chance for the blue silica particles to aggregate sooner, at least when compared to the green and red particles. It was speculated that the 2 µm particles were aggregating to form larger clusters. When these clusters flow through areas of narrower aperture (areas in which fracture surfaces are closer to each other), they will be trapped because of their physical size. With the tendency to aggregate, the higher the concentration, the larger is the size of the clusters and therefore the particle retention was enhanced. This could explain the lower breakthrough concentrations of the 2 µm particles at higher input concentration.

For the 5 µm particles, the estimation of the total interaction energy (Figure 1) among the green particles suggests a high repulsive-energy barrier, along with the lower rate of collision would prevent the particles from aggregation. Instead, the particles will repel from fracture surfaces and from each other and remain disperse in solution. We speculated that the retention of the green particles within the fractured medium was related to transport by gravitational sedimentation. Note that the

density of the silica particles is more than twice that of the injected water (i.e., 2.2 g/cm^3). During transport by sedimentation, a particle moves across streamlines because of gravitational forces and associated settling velocity until it collides with the fracture surface. The calculated settling velocity, for creeping flow, of the 5 µm particles is around 16.4 µm/sec. Based on the fracture data and injection rate (i.e. 0.78 cm^3/min), the 5 µm particles are expected to settle 120.74 µm (four times larger than the estimated fracture aperture) within the fracture. This suggests that these particles were rolling along the fracture surface. Given their large size relative to the fracture aperture, and the high repulsive energy interaction, forces excerted by the flow at the fluid velocity used during injection might be sufficient to roll the particles along the lower surface of the fracture. The effect of fluid velocity was not assessed. It was concluded that the transport of the green particles was primarily governed gravity settling.

Owing to the existence of surface irregularities in fractures, it is very possible that a flow channel in the fracture at or below the size of injected particles exists along a preferential flow path. Consequently, entrapment of particles because of their physical size will result in their accumulation at narrow aperture areas and, therefore, the blockage of that flow path. Blocked flow paths are a dead end for subsequent particles, which eventually results in reduction of particle recovery. The permeability measurements (i.e., pressure data) support the fact that the number of conductive flow paths available to particles decreased because of blockage. Figure 3 shows the permeability measurements conducted before and during the injection of the blue and green particles at two different suspension concentrations through the fractured greywacke core. The permeability continued to decrease as more particles were injected. The permeability decreased to approximately 22 darcy by the end of the blue particle (of concentration C) injection. This reduction in permeability indicates a certain degree of blockage that occurred in some of the preferential flow paths. After that, the permeability decreased slightly as more particles were injected (during the injection of blue and green silica particles at concentration of 2C). The slight decrease in permeability following the injection of concentrated suspensions can be explained by the fact that small flow paths were already plugged during previous injections (injection of blue and green suspensions at concentration C), and the flow of subsequently injected particles was redirected to areas of wider apertures at which trapping by particle size is least expected.

The recovery of the larger polydisperse red particles was significantly lower than the blue and green particles. For example, the cumulative relative concentration of red and green particles at concentration C was approximately 0.08 and 0.82, an order of magnitude difference. This is consistent with the fact that increasing particle size (far from an optimum size) had an inverse effect on particle recovery. The red silica suspension had particles of sizes very comparable to the estimated hydraulic fracture aperture (i.e. aperture of 30.68 µm versus particle size of 31 µm). It was anticipated that more of the red particles would be physically trapped in the fracture. Analysis showed that effluent samples have particles 23 µm in diameter and smaller. Larger particles were trapped inside the fracture. It was also observed that increasing the input concentration resulted in higher recovery (Figure 1b). This result also demonstrated the possibility of using particles as fracture caliper to estimate the fracture aperture, by relating the recovered particle size to the fracture aperture. The fracture caliper concept was discussed in further details in Alaskar et al. (2012) and Alaskar (2013).

b) Particle deposition and transport mechanisms

Particles can be physically deposited on fracture surfaces or matrix pores due to their size, diffusion, interception and gravitational sedimentation. As mentioned earlier, particle transport through the greywacke matrix was not anticipated because the largest available pore size is significantly smaller than the smallest particle injected. Also the early breakthrough of particles suggested that their transport was mainly through the fracture. The ratio of the blue and green particle size to fracture aperture was 0.065 (2 µm divided by 30.68 µm) and 0.163 (5 µm divided by 30.68 µm), respectively, indicating that there should be sufficient space for particle flow. Note that the calculated hydraulic aperture integrates the effect of larger and smaller aperture regions. So it is very possible for the particle size to fracture ratios to be much larger in certain regions of the fracture. Herzig et al., (1970) suggested that straining is important in porous media when the particle to grain size ratio is greater than 0.2. Zvikelsky and Weisbrod (2006) modified this rule of thumb to indicate the significance of straining of particles inside the fracture. They suggested that straining is important if the particle to grain size ratio is greater than 0.02, by assuming that the pore size is about 10% of grain size. Both the blue and green silica particles exhibited particle to grain size ratio larger than 0.02 by at least a factor of three, suggesting that straining may occur within the fracture. It was concluded earlier that the blue particle were aggregating forming large clusters. The size of the clusters may have been larger

than the fracture aperture, leading to physical filtration due to size, and thus higher particle deposition inside the fracture. The concentration of the red particles in backflushing samples was fluctuating (Figure 1b) indicating some release of particles. Straining of the red particles was therefore likely to occur, especially for particles that had size comparable to the fracture aperture. Particles at that size were not observed when effluent samples were analyzed using optical microscopy.

Deposition of particles due to interception was unlikely to be important. Particle interception is highly dependent on fluid velocity. Higher fluid velocity would result in lower probability of filtration by interception. Fluid velocities used during the injection of blue, green and red silica suspensions were 43.63, 50.05 and 64.16 cm/min (Table 2), respectively, yet there was lower recovery of larger particles.

Particle deposition by diffusion and gravitational sedimentation can be assessed using the length scale analysis suggested by Becker et al. (1999). According to the length scale model, the particle deposition was due mainly to gravity settling. In general, diffusion of particles in the micron size range is known to be insignificant. A summary of length scales and Peclet number is provided in Table 4. The L_s/L_D and $L_s/0.5b$ ratios were significantly larger than 1.0, suggesting that the transport by gravity settling is dominating and the lower surface of the fracture is accessible (the $L_s/0.5b$ is also greater than 1.0). The settling distances of 120.74 and 113.80 µm for the green and red particles are about four times the fracture aperture size (30.68 µm). The fact that the lowest recovery of green particles exceeded 82% of what was originally injected suggests that they were not settled indefinitely, but rather particles were rolling along the lower surface of the fracture during most of the injection experiments. The high density of the particles (2.2 g/cm^3) relative to suspension fluid (i.e. water with density of 1.0 g/cm^3) also suggests settling.

The dominance of particle transport by advection or diffusion was evaluated using the Peclet number. The calculated Peclet numbers (as defined by Detwiler et al. (2000) for particles in parallel plate aperture) for all particle sizes under the experimental hydrodynamic conditions were of the order of 105 to 107. These values are orders of magnitude higher than 1.0, indicating advection-dominated transport. The extremely low diffusion coefficients (2.15×10-13, 8.62×10-14 and 4.31××10-14 m^2/s for blue, green and red particles), calculated using Stokes-Einstein equation given in Russel et al. (1989), and the hydrodynamic forces (lift forces) acting on the finite size of the particle may force the particles to follow high velocity streamlines within the fracture, and hence faster breakthrough. For instance, the red particles were traveling at a velocity that was about 2.11 times the average velocity of water. Advection-dominated transport of particles through fractures is well documented by other investigators (e.g. Riemus 1995; Cumbie and McKay, 1999; McCarthy et al., 2002).

Conclusions

This paper focuses on the investigation of the transport mechanisms of silica particles in fractures, as a precursor for their use as temperature nanosensors in fractured reservoirs. Experiments were conducted by injecting fluorescent silica particles of different sizes (2 µm, 5 µm and polysized sample of sizes ranging from 5-31 µm), with varying suspension concentrations, through a fractured tight greywacke sandstone core. The rapid breakthrough of particles in the core indicated that their transport was mainly through the fracture. Trapped particles were most likely retained on fracture walls in regions with small apertures. It was concluded that gravitational sedimentation, aggregation (only for the 2 µm particles) and straining due to particle or cluster size were the main particle trapping mechanisms.

It was observed that the recovery of the 2 µm particles following their injection into fractured greywacke core was affected adversely by suspension concentrations (decreasing recovery with increasing suspension concentration). It was found that the increasing concentration of the 2 µm particles resulted in more pronounced aggregation, which led to trapping by straining. This conclusion was supported by the degree and rate of reduction in permeability occurring at higher concentrations.

The recovery of the 5 µm and polysized particle suspensions was proportional to suspension concentration. Silica particles have mass density higher than water. Particles are inclined to settle as the density difference between particles and suspension fluid increases. Because two of the investigated temperature sensors were silica based particles, it is important to design or synthesize the silica particles to have lower density and/or increase the fluid velocity to offset gravitational forces.

This research study showed that synthesizing particles to respond to a specific reservoir property such as temperature is feasible. Using particles to measure reservoir properties is advantageous because particles

can be transported to areas in the reservoir that would not be accessible by other means and therefore provide measurements deep within the formation.

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APPENDIX

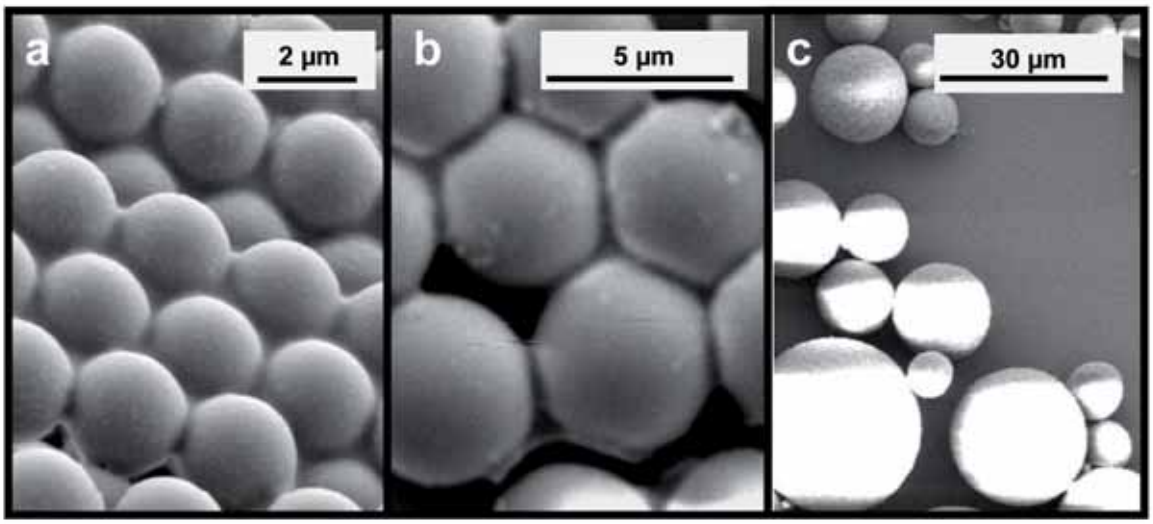

Figure A1: SEM micrographs of (a) blue, (b) green and (c) red fluorescent silica particles. The shape uniformity of the silica particles is evident. The blue and green particles have a uniform size, whereas the red particles have a wide size distribution.

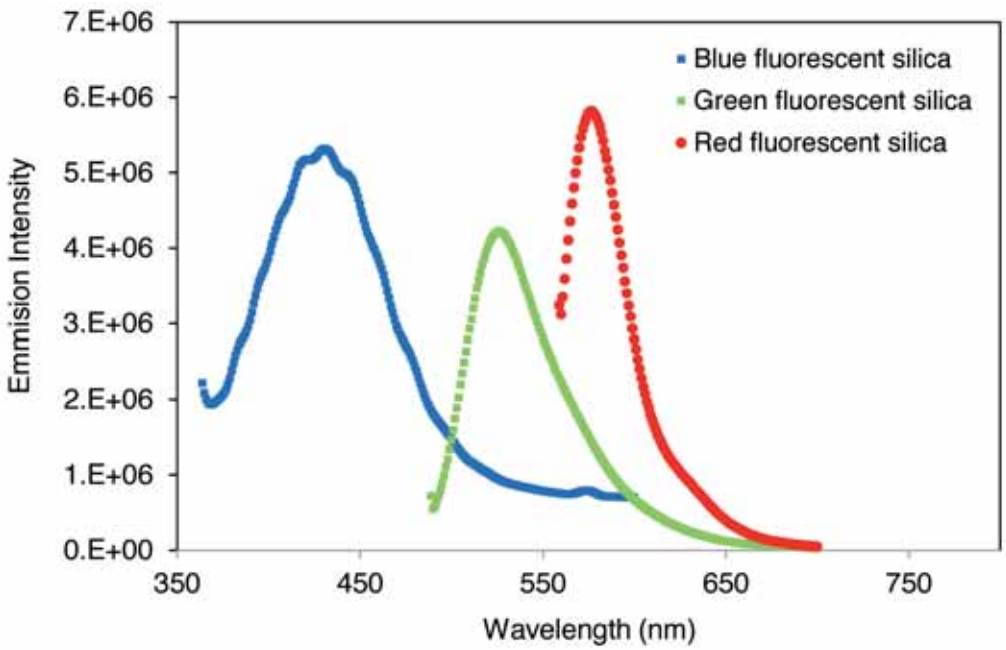

Figure A2: Emission spectrum of the blue, green and red fluorescent silica particles. The peak emission of the blue, green and red dye is at wavelength 430, 530 and 577 nm, respectively.

IA. SILICA PARTICLE CHARACTERIZATION

Silica particles were characterized in terms of shape uniformity and size using Scanning Electron Microscopy (SEM). Examples of the electron micrographs can be seen in Figure A1. Fluorescence emission spectra for the three silica suspensions were acquired using a fluorescence spectrometer (Figure A2). Dilutions of known concentrations were prepared and calibration curves were constructed (Figure A3).

IIA. FRACTURED GREYWACKE CORE CHARACTERIZATION

This section describes the measurements of the pore size distribution, porosity, permeability and pore volume of the fractured greywacke core.

a) Pore size distribution

The pore size distribution of the core samples was measured by the mercury (Hg) intrusion method.

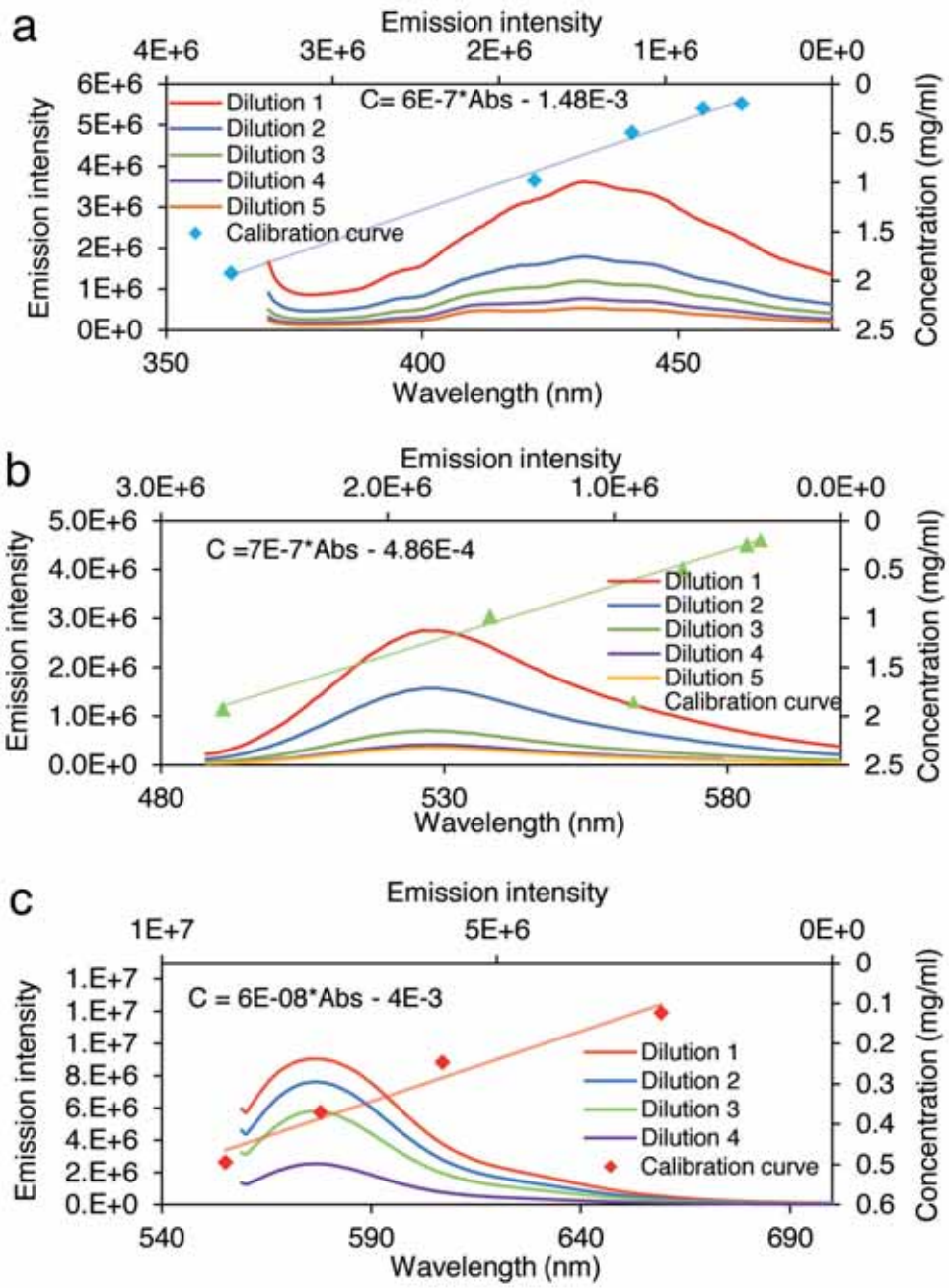

Figure A3: Fluorescent emission and calibration curve of (a) blue, (b) green and (c) red silica microparticle samples of known concentrations. The maximum emission (peak) was at wavelength of 430, 530 and 577 nm for blue, green and red silica suspensions. Note the linearity of the calibration curve, indicating the applicability of Beer-Lambert Law. The calibration equation is showing in each graph. The secondary horizontal axis of optical density is associated with the secondary vertical axis of concentration.

The intrusion of mercury was performed using the AutoPore IV 9500 Mercury Porosimeter manufactured by Micromeritics. This porosimeter covers a pressure range up to 33,000 pound per square inch (psi) and pore diameter range from approximately 360 to 0.005 micrometers. The device has two low-pressure ports and one high-pressure chamber. Measurements conducted on the greywacke rock showed the core to have pore sizes in the range between 0.01 to 0.15 µm. The pore size distribution is shown in Figure A4.

b) Porosity and permeability measurements

The core sample tested was a fractured tight greywacke rock. The core sample was fitted between the two end-pieces and wrapped with Teflon shrink tube. An electric heating gun was used to bond the assembly together. To achieve proper sealing, the heat was applied evenly starting bottom up in a round motion. The holding or confining pressure supplied by the shrink tube is expected to be below 10-15 psig. The assembly was positioned horizontally and polyethylene tubes (0.3175

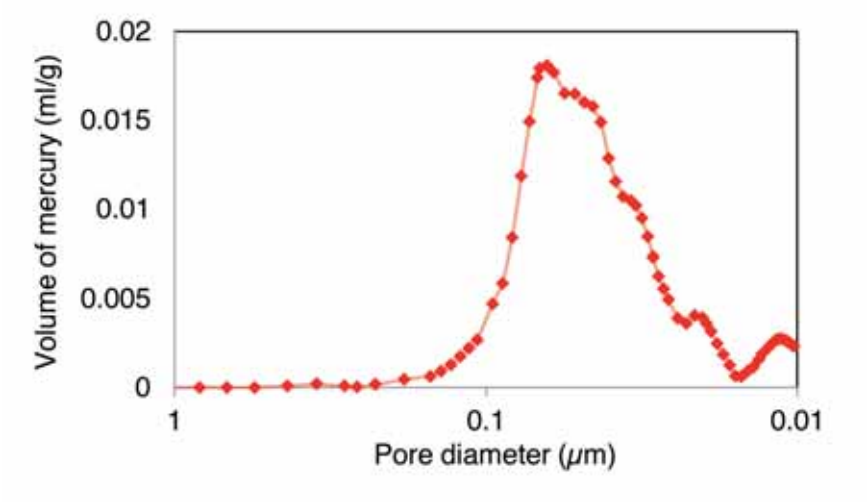

Figure A4: Pore size distribution of greywacke core sample.

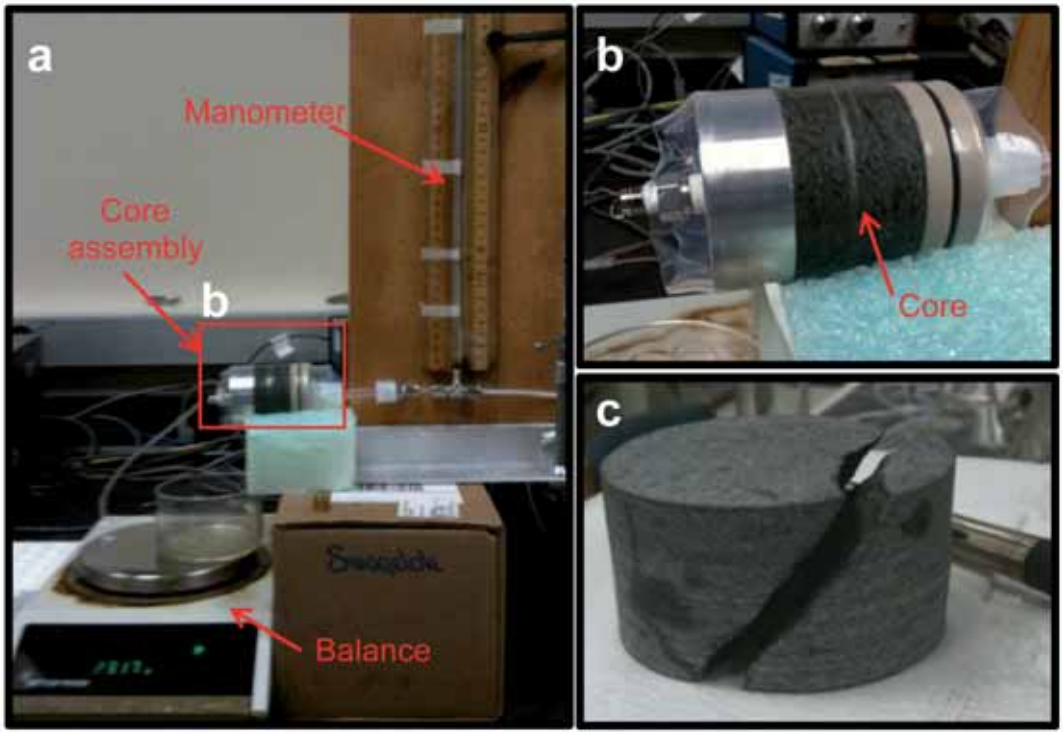

Figure A5: A picture of the experimental setup used during the permeability measurement of the fractured greywacke core, (a) showing manometer (pressure), core assembly and balance (flow rate), (b) close-up image showing the core assembly and (c) an image of the fractured greywacke core showing the orientation of the fracture.

cm in diameter) and fittings were used to connect the water pump and pressure manometer to the core assembly (Figure A5). As only a very low differential pressure was required to flow fluid through the fractured core, the inlet pressure was measured using a manometer tube rather than a transducer. The flow rate (using water pump, Dynamax, Model SD-200, manufactured by Rainin Instrument Company) was measured using a balance (Mettler balance, Model PE 300) and stop watch. The accuracy of the pump flow rate and balance were 0.01 cm^3/min and 0.01 g, respectively. Before saturation, the core was dried at 75°C under vacuum pressure of 0.09 MPa for about 3 days, using a vacuum oven. Then, the core and related system were saturated with deionized water. Initially, the system was evacuated using a vacuum pump (Welch Vacuum Pump, Model No. 8915A) under vacuum pressure of about 13 millitorr for about 4 hours. The vacuum pump was connected

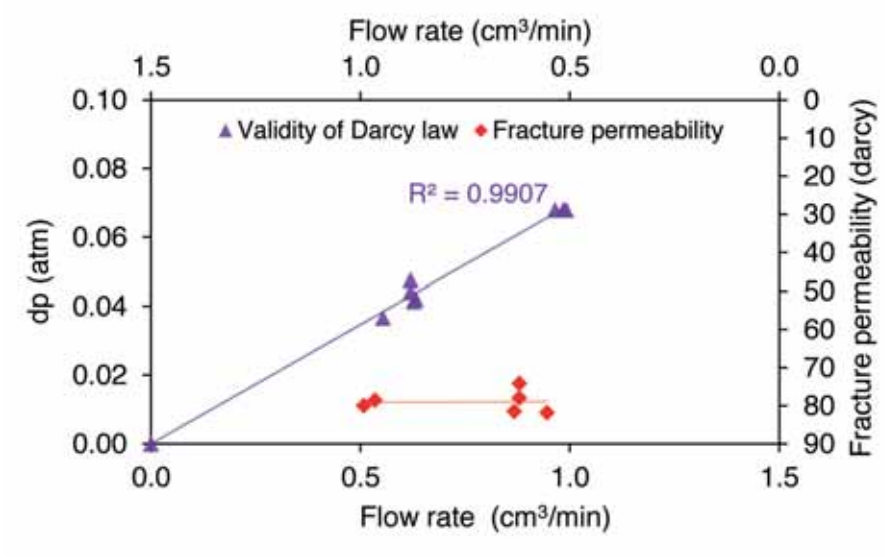

Figure A6: Fracture permeability as function of flow rate, with an average fracture permeability of about 79.48 darcy. Note that the angle by which the fracture is orientated is about 40 degrees. The validity of Darcy law under experimental conditions was confirmed through the linearity between flow rate and pressure drop (the secondary horizontal axis of flow rate is associated with the secondary vertical axis of fracture permeability)

to the system from the inlet side of the core. A water column used to saturate the system was attached at the outlet side of the core assembly. The water column was positioned on a scale to observe the weight change and hence the water volume entered the system. The pore volume of the fractured core sample was determined by subtracting the dead volume of connecting tubes, fittings and end pieces from the total volume displaced from the saturation water column.

The hydraulic aperture of the fracture was determined using the cubic law. The cubic law is given as (Van Golf-Racht, 1982):

$$q = \frac{b^2}{12}\frac{bW\cos^2\theta}{\mu}\frac{\Delta p}{L} \qquad \text{(A1)}$$

$$k_f = \frac{b^2}{12} \qquad \text{(A2)}$$

where is the volumetric flow rate in cm^3/s, is the fracture aperture in meters, W is the fracture width (same as core diameter) in meter, the fracture orientation angle, is the pressure drop across the core sample in Pascal, L is the length of the fracture in meter, is the test fluid (water) viscosity in Pascal second and is the fracture permeability in m^2 (9.86×10-13 m^2 is equivalent to 1 darcy). The validity of Darcy law was confirmed by the linear relationship between the flow rate and pressure drop across the core, as shown in Figure A6. The fracture permeability at various flow rates is shown in the same plot.

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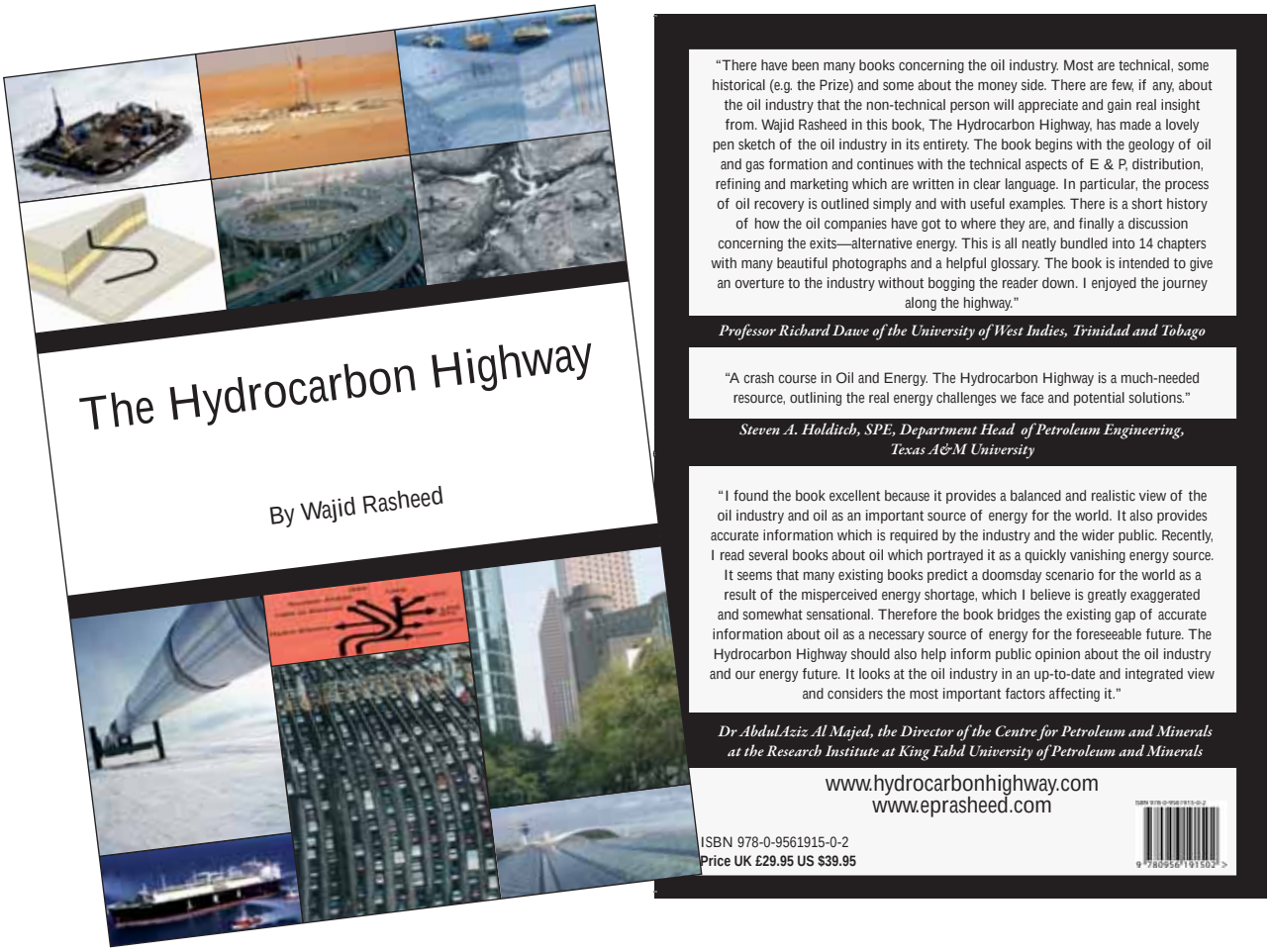
Reserves, Peak Oil and Medieval Maps



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

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

Invariably, reserves grab headlines due to their financial significance, measurement methods or the geo-political dimension. On the one hand, the sustainability of oil companies depends on reserves and, on the other, oil

> "Beyond annual profit concerns, the long-term survivability of the oil company is wholly dependent on the rate at which production and reserves are increased."

company profits depend primarily on production. By breaking down reserves and production data, analysts can derive KPIs such as net worth, reserves to production ratio, reserves replacement and production quotas and positive cash-flow. Consequently, reserves and production are inextricably linked to financial performance.

Major, National and Private

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

Reserves, therefore are a major influence on the stock price of major International Oil Companies (IOCs). Of course, IOC stock prices will be affected by quarterly profits and shareholder dividends. The oil price and other contextual factors that affect the attractiveness of the industry as a whole for investment – geopolitics, speculation and 'futures' trading – will also affect stock ratings. Beyond annual profit concerns, the long-term survivability of the oil company is wholly dependent on the rate at which production and reserves are increased. Usually this happens in one of three ways: first, through the 'drip-feed' of incremental recovery using mature field improved technology; second, by boosting reserves through the bit which means that successful wildcat strikes open new frontiers; and finally, by the acquisition of another oil company through its stock[1].

National Oil Companies

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

> It would be physically impossible to accurately measure oil and gas in place; therefore, the industry relies on extrapolated measurements as accurate measurements can only occur upon production.

situation occurs when analysts assess the attractiveness of financial instruments or debt (bonds), issued by the oil company or government, based on ROI and risk.

Certain NOCs, such as those within the Organisation of Petroleum Exporting Countries (OPEC), also depend on reserves in another way. OPEC production quotas are allocated as a proportion of total proved reserves. Consequently, countries with high reserves volumes are given higher thresholds of production[2,3].

Uncertainty

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

To make matters more complex, there is no single standard or methodology that is universally accepted by the industry or by the financial community, i.e. regulators/analysts. Substantive variations exist between institutions and nations. Exemplifying this are differences between the SPE (Society of Petroleum Engineers) and SEC (Securities Exchange Commission) criteria for reserves classification, and international variations between the Russian and Norwegian systems[4,5].

Before we go into detail, it is fair to note that the lack of a single international or institutionally recognised set of standards makes reserves measurement somewhat dependent on the system chosen[6].

Missing Barrels

With many oil companies based in the US or floated on US stock markets, the oil industry has been lobbying US regulators to overhaul the system by which the indus-try's reserves are measured[7].

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

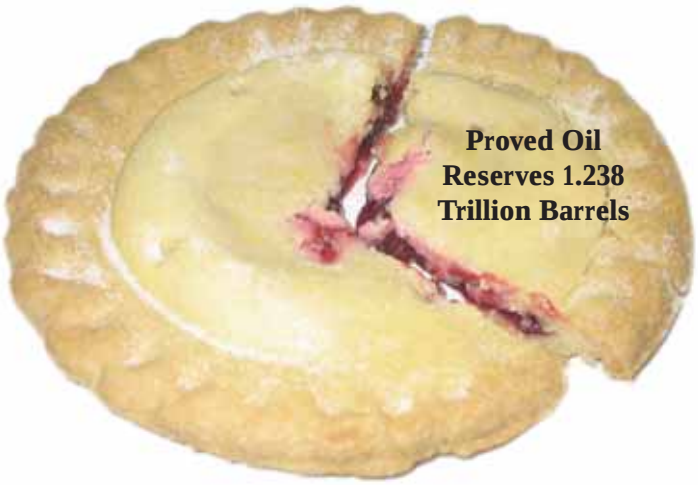


Figure 1 - The Total Size of the Oil Resource is 3.012 Trillion Barrels (EPRasheed)

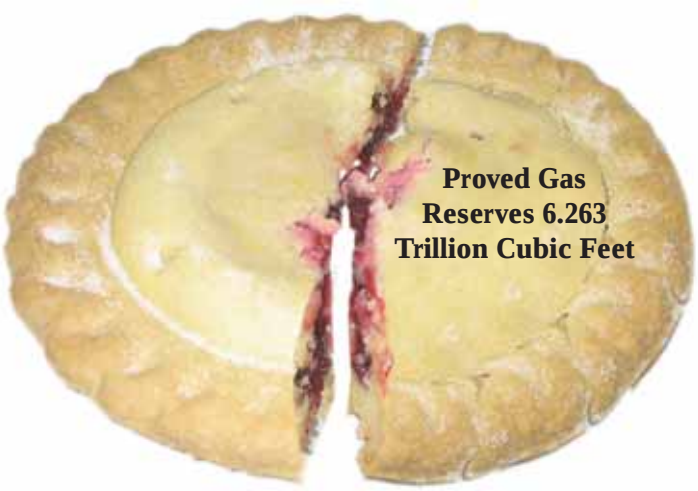


Figure 2 - The Total Size of the Gas Resource is 15.401 Trillion Cubic Feet (EPRasheed)

The SEC measurement leads to a substantive variation with internal industry measures such as the SPE which places more emphasis on technology 'unlocking' reserves to make them more recoverable. The variation often results in discrepancies that amount to billions of barrels of oil across the industry[8].

Industry analysts have lobbied the SEC to change its reserves accounting so that the benefits of E & P technology can be better applied. Essentially, this covers a raft of technologies such as seismic, geosteering and horizontal drilling which enable higher recovery rates through pinpointing reserves and well placement[9]. At issue is the realistic valuation of energy companies themselves, as well as how we calculate replaced or future reserves. While analysts look to earnings as a short-term performance measure, the more long-term measure looks to reserves to production ratios as the basic indicator of the oil company's future wealth.

What's On the Books?

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

Getting a Slice of the Pie

It is worth distinguishing between the oil and gas resource and reserves. The 'global resource' is the 'size of the pie' or the entirety of the earth's oil and gas. The slice of this pie that is recoverable using today's technology at today's cost – price structure is known

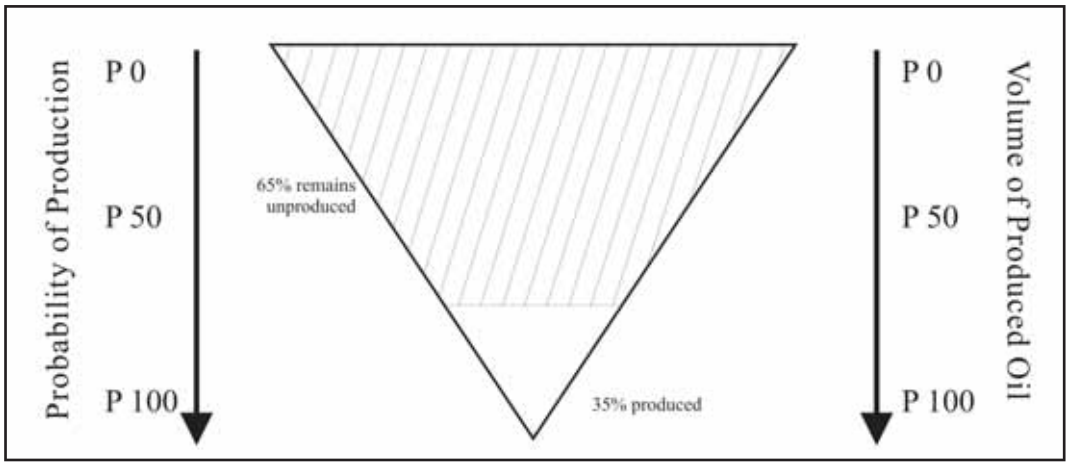


Figure 3 - The Relationship Between Probability and Volume of Oil Production (EPRasheed)

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

Once the resource is discovered, reserves need to be booked. This process involves mapping out and visualising one or more underground structures (leads or prospects) that may extend over 200 square miles. Reserves must then be classified and assigned values according to the probability of their production. Finally, the value of reserves are discounted to today's worth. For financial and asset planning purposes, the key determinants are the likely size of discovered reserves and their ease of recovery[10].

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

The Three 'Ps'

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

Corresponding to a value, i.e. P 90, P 50 or P 10, the 'P factor' simply represents the percentage chance of reserves being produced. Proved is 90%, Probable is 50% and Possible is 10%[11].

This classification uses a scale based on the development status, the infrastructure in place and the ease of recovery of oil and gas. Reserves that score lower on

> Reserves which can be produced economically through improved recovery techniques (such as water injection to maintain reservoir pressure) are included in the 'proved' classification when an increase in production is seen.

development status and infrastructure are harder to develop so their percentage chance of recovery falls; therefore, they are assigned a lower 'P' class with a lower 'P' value.

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

Reservoirs are considered 'proved' if economic production is supported by actual production or conclusive formation tests showing an increase in production. The area of a reservoir considered proved includes: the portion identified by drilling and defined by gas-oil and/or oil-water contacts and the immediately adjacent areas not yet drilled, but which can be reasonably expected as economically productive based on the available geological and engineering data[12].

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

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

'Proved undeveloped reserves' are reserves that are recoverable from new wells on undrilled acreage, or from existing wells where further major expenditure is required. Reserves on undrilled acreage are usually

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

limited to those areas where there is reasonable certainty of production when drilled. Proved reserves for other undrilled units can only be claimed where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

Russian and Norwegian Reserves Classification

Russian and Western methods of estimation and classification of reserves are somewhat different. The Russian officials have divided oil and gas reserves into six classes: A, B, C1, C2, D1 and D2. Class A represents proven reserves and B provable reserves. Class C1 represents reserves estimated by means of drilling and individual tests, and C2 reserves are based on seismic exploration. Classes D1 and D2 represent hypothetical and speculative reserves[13].

Norway uses its own definitions of reserves, which run from Category 0 – 9[14].

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

Category 9 includes resources in leads and unmapped resources and covers undiscovered, recoverable petroleum resources attached to leads. It is uncertain whether the leads, and if so the estimated resources, are actually present. The resource estimates reflect estimated volumes multiplied by the probability of making a discovery. This probability must be stated[15].

Geologic Assessment Procedures

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

Oil companies use this approach to process exploration knowledge such as seismic or aerial surveys or wildcats generated by the exploration teams. A fundamental

> A common model defines a play as 'a set of known or postulated oil and/or gas accumulations sharing similar geologic, geographic, and temporal properties such as source rock, migration patterns, timing, trapping mechanisms, and hydrocarbon types'.

part of this process is the attributing of probabilities for each petroleum play. Geologists will also assign subjective probability distributions to characterise attributes of undiscovered conventional oil and gas accumulations[16].

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

Net pay estimates are derived from the data and include the extent and distribution of the reservoir. These estimates are essentially refined and related to P values, i.e. P90, and are verified to see whether they are consistent with existing knowledge. Other factors to be considered will be hydrocarbon recovery factor, porosity and permeability forecasts and initial production[17].

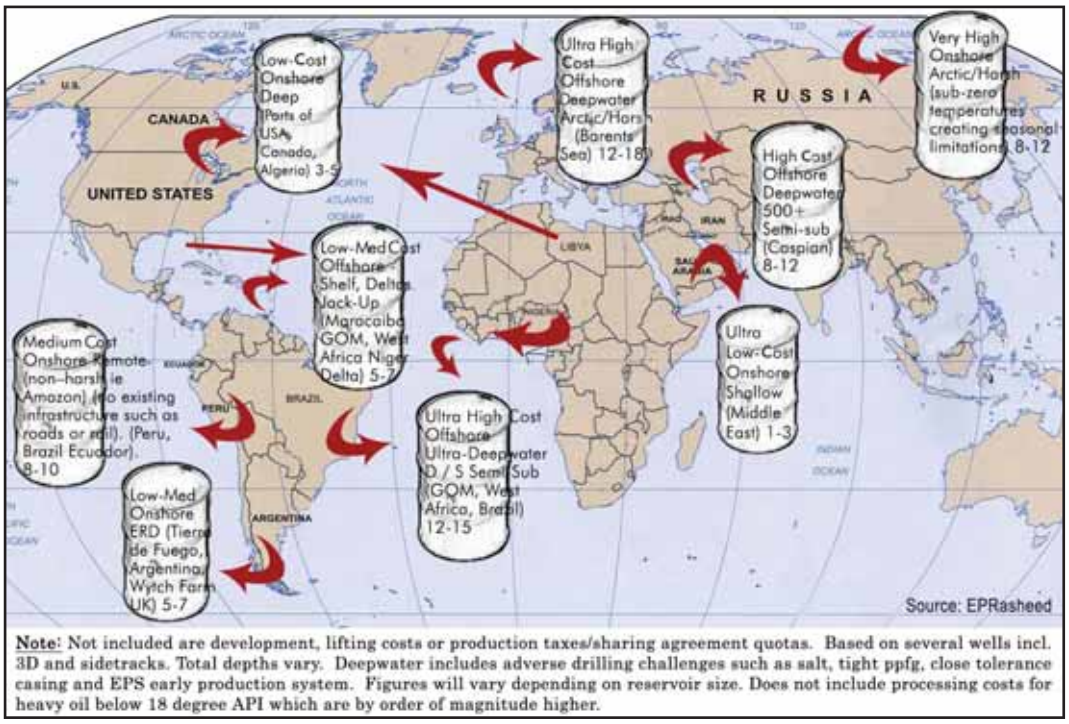
Peak Oil and Medieval Maps

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

To answer these questions, we need to adopt a global E & P perspective that integrates prospective E & P areas with technology applications. Equally we need to recognise the limits of conventional wisdom. Are we navigating with a 'medieval map' of worldwide hydrocarbon reserves – one that does not adequately reflect the total resource?[18].

Optimist or Pessimist?

Two schools of thought exist. Optimists state there is an abundance of oil and gas and that there is enough for everyone, while pessimists state there is a deficit and we are doomed. These two positions, and the consequent debate, have generated much emotion, not to mention a multi-million dollar niche industry. What appears to



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

Figure 5 - Finding Costs for Oil Companies in US $

be important here is that no-one disagrees that a peak or decline will occur, that is the natural state of systems. Yet, no-one can agree on when or even why this event will occur. It is worth considering this debate as it can help us understand the 'psychological' supply shortfall of prospects. This has a knock-on psychological effect on supply which is compounded by a herd mentality within the oil and gas markets (see *Chapter 12: Paper Barrels* for detail).

The pessimists reason as follows:

1. Rare conditions allow petroleum reserves to be produced.
2. Once production peaks, reserves decline rapidly in output.
3. Most global petroleum reserves have peaked. Further large finds are unlikely.
4. Global production is therefore declining[19].

The optimists argue:

1. Rare conditions allow petroleum reserves to be produced.
2. Production can be made to plateau, not peak, through technology.
3. Technology finds more reserves, makes smaller reserves more accessible and sustains overall production on a global scale.
4. Global production is therefore sustainable[20].

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

1. Rare conditions allow petroleum reserves to be produced.
2. Today's theories regarding petroleum reserves and recoverability are incomplete.
3. Knowledge increases over time.
4. Many prospective petroleum plays are unexplored.
5. All known sources of petroleum systems have therefore not yet been quantified; hence, the use of the 'medieval map' analogy[21].

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

> Technology is the stock-in-trade of the service companies and a principal measure by which analysts derive multiplier or share valuations of service companies beyond earnings.

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

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

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

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

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

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

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

Worldwide Reserves

Referred to as 'the low hanging fruit' that is effortlessly picked, onshore basins are generally easy-to-access with low finding and lifting costs. Consequently, these reserves have been both extensively characterised and produced; however, several tough-to-reach onshore basins remain unexplored. Exemplifying this is the

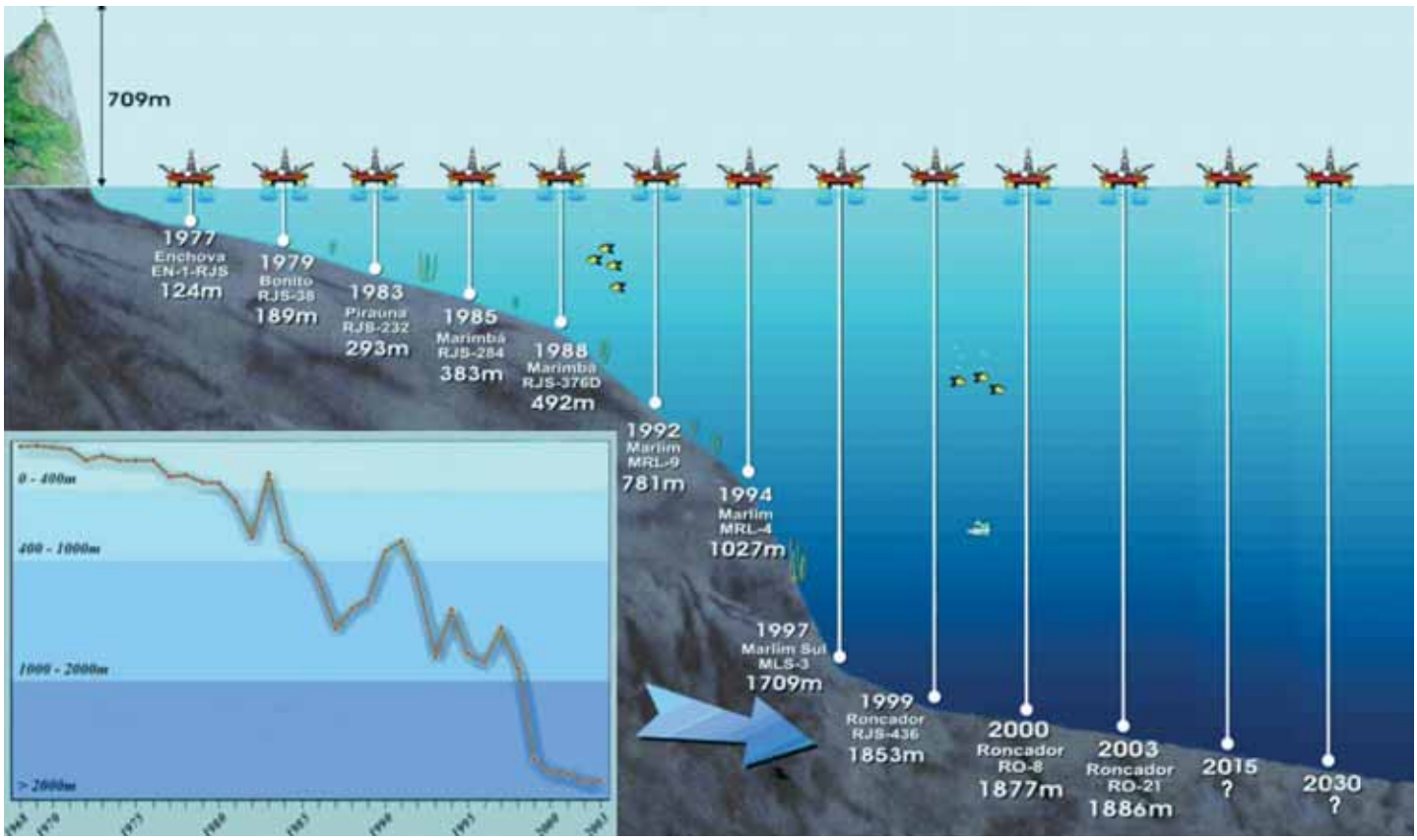


Figure 6 - The Incredible Depth Progression from Shelf to Deep Waters (Petrobras News Agency)

Amazon Complex (Brazil, Colombia, Peru and Bolivia), the Arctic Circle (the Alaska National Wildlife Reserve being part of this territory) and Antarctica[22].

No one has any real knowledge on the potential size of these onshore reserves. The historic finding and lifting costs in similar areas such as Sakhalin or Alaska , however, range on average from US $12 to US $18. With production, total costs rise further due to a lack of infrastructure in remote areas (see *Chapter 8: Extreme E & P* for detail[23]).

Middle East

More prospective areas exist in unexplored basins within the Middle East such as the Empty Quarter (Rub Al Khali) in Saudi Arabia, the Bushehr province in Southern Iran and North and South Iraq. Typically, these countries are blessed with prolific source rock, high permeability and trapping systems found at very shallow depths starting at approximately 700 m (2,100 ft) and ranging to 2,000 m (6,000 ft). New finds continue to maintain the Middle East as a dominant long-term reserve base, with common recognition that Saudi Arabia and Iran respectively are the world's largest and second largest holders of oil reserves. Further, finding, lifting and production costs are the lowest worldwide, averaging between US $1 to US $3 a barrel[24].

Lifting costs can vary, however, by way of comparison. In other relatively low-cost areas like Malaysia and Oman, lifting costs can range from US $3 to US $12 a barrel to produce. Production costs in Mexico and Russia might potentially be as low as US $6 to US $12 per barrel (higher under current production arrangements by local companies)[25].

By reviewing the world's prospective shallow coastal waters, deltas and oceans, it becomes clear that our map of global resources is incomplete. In the offshore realm, there are many unexplored basins with finding, lifting and production costs varying from US $18 to US $25 per barrel for certain deeper waters. Large tracts off the coast of West and North Africa are undeveloped. The West African margin has been extended from the high-profile plays in the shallow waters of the Niger Delta, Nigeria and the Congo Basin, Angola to deeper waters and to highly prospective sub-salt plays. Mauritania and Tanzania are other examples where new discoveries have been made[26].

> The Gulf of Mexico (GOM) has unexplored waters that stretch from the shallow waters off Florida, US and move into the territorial GOM waters of Cuba, vast areas of deep waters in the Mexican GOM and the deeper waters of the US GOM.

South of Australia in Tasmania, oil companies have been studying gas plays since 2000 which had previously been neglected due to the search for oil. This has led to indications of oil being found in Africa near Madagascar, which has been identified as a potential new petroleum province[27]. Mauritania and Tanzania are other examples where new African discoveries have been made. Another area is offshore Morocco, where the deposition of an ancient river system was found over salt. A mobile substrate, either salt or shale, is a key element all along the West African margin because it provides geological factors necessary for oil and gas[28].

Continental Plate Reconstruction

A clear example of continental plate reconstruction and conjugate oil and gas of plays is offshore West Africa and offshore Brazil. By using reconstructions, it can be seen that the Rio Muni Basin was the 'mirror' basin to the Sergipe-Alagoas Basin in Brazil, and the Congo Basin to the Campos Basin. By repeating this process along the coast of West Africa and Brazil, several emerging oil and gas plays can be drawn up. These include the sub-salt frontiers of offshore Brazil including Tupi. Although production is not likely to make a major impact on world oil exports over the next decade, the point is that new frontiers have been discovered[29].

In Central America, the offshore area between Venezuela and Trinidad, the Gulf of Paria, is largely unexplored as are the waters off Colombia and Peru[30].

The Gulf of Mexico (GOM) has unexplored waters that stretch from the shallow waters off Florida, US and move into the territorial GOM waters of Cuba, vast areas of deep waters in the Mexican GOM and the deeper waters of the US GOM. Within the US GOM, the sub-salt play has been instrumental in new finds.

Offshore production in areas like the North Sea with offshore platforms, can run to US $12 to US $18 a barrel. As reservoirs become smaller, those costs tend to rise. In Texas and other US and Canadian fields, where deep wells and small reservoirs make production especially expensive, costs can run above US $20 a barrel.

Further East, we note that certain areas of the Northern North Sea and the Barents Sea are still to be explored. While in Russia, Sakhalin Island, the Central Asian Republics, the Red Sea, the Persian Gulf, the Indian Ocean, Offshore Australia and New Zealand, several offshore basins represent prospective yet unexplored areas[31].

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

Sweating

The Finding and Development in Figure 5 clearly shows that, when crude oil prices fall below US $20 a barrel, many areas become unprofitable and production is reduced if not halted altogether. Only certain lower cost areas can remain profitable and hence maintain production during a 'good sweating' period[32].

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

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

Conventional Wisdom and the Limits of Our Map

The limitations of our map of oil and gas reserves start to become clear when we consider past theories. In the 1990s, one widely held view stated that offshore oil and gas reserves would not be found at extreme conditions, i.e. depths exceeding a TVD of 20,000 ft (6,096 m). It was suggested that overburden pressures would either cause a loss of hydrocarbons due to migration to shallower traps or compaction[33]. Now that theory has changed because oil and gas trends have been located at far greater depths than prior knowledge would indicate. Think deep gas, US GOM.

In the 1980s, another example of a change in thinking occurred concerning the flow paths of fluvial deposition. Ancient river systems account for the sedimentation that leads to accumulations of oil and gas. In river deltas worldwide, as the shallow water plays were developed, exploration efforts evolved into the deepwater usually with only major international oil companies that could qualify for the blocks[34].

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

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

Game-Changing Technology

Back in the late 1980s, it was thought that development of thin sands such as 'Norwegian Troll oil' would never be economically feasible, because the oil reserves were so thinly layered and the price of oil was US $10 per barrel. Game-changing technology such as 3D seismic improved the visualisation of reserves, while horizontal drilling and geosteering altered the definition of what was deemed uneconomic or unreachable at a given time. The billion-dollar think tanks and research and development facilities that major service companies own are continually creating new technologies that help access reserves previously considered uneconomic or unreachable. Service companies and operators develop technology in-house through joint industry projects and with best-in-class companies; for example, Shell and Petrobras respectively are involved in the monobore and the Procap 3000 initiatives—two examples of technology cascading downward. Underlying the monobore (a vision of drilling and casing a single-diameter well from top to bottom) is the creation of businesses to develop the downhole tools, tubes and markets for expandable tubulars. Procap 3000, a range of exploration and production technologies, is paving the way in ultra-deepwater development. Drilling contractors have introduced simultaneous drilling and completion of two wells by way of the dual-activity derrick system[35].

Technology

Scarcity of oil reserves and increasing reserve replacement costs are the twin factors that have accelerated the technological evolution of E & P and enabled extreme E & P (see *Chapter 8: Extreme E & P*). This evolution is most clearly visualised in the dramatic shift from onshore to offshore exploration. The incredible depth progression from land to shallow coastal waters to deep waters to the extremes of ultra-deepwater is shown in the graphic below[36].

> The billion-dollar think tanks and research and development facilities that major service companies own are continually creating new technologies that help access reserves previously considered uneconomic or unreachable.

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

Records are continually set and broken not just in deeper water depths (3,000 m) but also in deep reservoirs below salt domes, tar zones and in the remote basins of the world and in new frontiers. This includes the latest subsea water separation systems and subsea sand separation to achieve maximum production. Remarkably, however, almost all of this enabling E & P technology is considered an outsourced commodity marketed by service and supply companies, which means the NOCs have no shortage of technology vendors. The buzzwords of 'ultra-deepwater, digital oilfield and barrel-chasing' may first be heard in oil company offices due to the engineering challenges and risks oil companies 'buy'. They resonate most loudly, however, throughout the service-side: in product development, in research facilities and on test rigs before technology is commercially run in field applications[37].

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

These feats were inconceivable to Hubbert when he

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

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

We are not in fact running out of oil. We have many areas yet to explore before we have to worry about oil and gas shortages. As we have been shown, there are plenty of barrels of oil remaining. The next logical question then would be 'What is in a barrel of oil?' Everyone always talks about barrels, but no really talks about their composition or how this affects recovery.

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2. The OPEC Statute requires OPEC to pursue stability and harmony in the petroleum market for the benefit of both oil producers and consumers. To this end, OPEC Member Countries respond to market fundamentals and forecast developments by co-ordinating their petroleum policies.

3. See Booklet: What is OPEC? Production regulations are simply one possible response. If demand grows, or some oil producers are producing less oil, OPEC can increase its oil production in order to prevent a sudden rise in prices. OPEC might also reduce its oil production in response to market conditions. Public Relations & Information Department, OPEC Secretariat, Obere Donaustrasse 93, A–1020 Vienna, Austria. Tel: +43 1 211 12-279, (www.opec.org).

4. See Oil and Gas Reserves Committee (OGRC) "Mapping" Subcommittee Final Report – December 2005 p 14, Russian Reserves Classification based on Russian Ministry of Natural Resources (RF-2005).

5. Ditto p 16 Norwegian based on Norwegian Petroleum Directorate (NPD–2001).

6. There are as many as 7 different reserves classification systems in practice.

7. The SPE is seeking to overhaul and standardize current classification methods.

8. The Industry is lobbying the SEC for a rule change.

9. E & P technology clearly make reserves more accessible. The problem is at what cost? The issue is not simply related to oil price v technology cost but certainly more account should be made of the role of technology and reserves classifications.

10. This is what determines asset valuation and cash flow.

11. Standard knowledge in the industry.

12. See SPE (OGRC) "Mapping" Subcommittee Final Report Definition of Proved Reserves page 31.

13. Ditto p 14 Russian Classifications.

14. Ditto p 16 Norwegian Classifications.

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20. Optimists.

21. This is the Author's own view. The three Ps are commonly recognized measures of probability of production.

> "Coupling this with innovative thinking and cutting-edge technology makes for a convincing argument; peak oil as far as reserves are concerned, is a philosophical debate rooted in a psychological shortage not a physical one."

22. Clearly, at some point Antarctica will be opened up for E & P. See The Petroleum Potential of Antarctica, Macdonald, David University of Aberdeen, UK.

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24. From both IOC and NOC data.

25. These are not replacement costs but historic costs. Report on UK Sector NWECS 2000 Wajid Rasheed.

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27. See The Tectonic and Paleogeographic Context of Madagascan Petroleum Systems, Hoult et al Models of a pre-Jurassic Gondwana fit range from a palaeo location for Madagascar off Mozambique (Flores, 1970) to that of Reeves et al. (2004) who, like most current authors, place Madagascar off the Kenya/Somali coast. The precise tightness of fit is still a matter of debate.

28. See AAPG Explorer Magazine Nov 2002 Kathy Shirley.

29. See Brazil Oil and Gas Issue 11 p 6 Tupi's recoverable volume of 5 to 8 billion barrels of oil equivalent may place Brazil in the select group of petroleum exporting countries (www.braziloilandgas.com/issue10). In 2008, Petrobras announced new oil discoveries in the Santos, Espírito Santo, Campos, and Jequitinhonha Basins. In the Santos Basin pre-salt layer alone, the company estimates recoverable volumes of 9.5 billion and 14 billion barrels of oil and gas in barrel equivalent in the Tupi, Iara, and Jupiter areas. In September 2008, the Company started producing in the pre-salt in the Espírito Santo sea, in the Jubarte Field, located in the Campos Basin.

30. The Identification of The Depositional Environments Of The Cruse, Forest And Morne L'Enfer Formations In The Southern Half Of The Gulf Of Paria, Trinidad, West Indies Curtis Archie, PetroTrin.

31. Oil from the South: Mesozoic Petroleum Systems, Proven and Potential, in Mid to High Southerly Latitudes Bradshaw, Marita et al. Is there a

corresponding belt of petroliferous basins in the southern hemisphere? Notable oil provinces do occur in mid to high southerly latitudes. Oil source rocks include marine Early Cretaceous shales (San Jorge and Magallanes/Austral basins, South America; Bredasdorp Basin, South Africa) and Late Cretaceous to Eocene coaly sediments (Gippsland Basin, south-east Australia; Taranaki Basin, New Zealand). Frontier Mesozoic rift basins occur in offshore East Africa, along Australia's southern margin (Bight and Mentelle basins), on the Lord Howe Rise, offshore New Zealand and in the Falklands. Regional studies of the shared history of Gondwana breakup and paleoclimatic and environmental reconstructions can guide exploration in these frontier areas.

32. See page 230 The Prize: The epic quest for Oil, Money and Power Daniel Yergin Publisher: Simon and Schuster (Jan 01 1993) ISBN: 0671799320.

33. AAPG Explorer, October 2008, Independents Find Africa Success.

34. Gas Beckons in Deep Shallows. Louise Durham Gas exploration to depths of 30,000 ft.

35. The Discoverer Enterprise of Transocean is the first ultra-deepwater drillship with dual activity drilling technology, which aims to reduce the cost of an ultra-deepwater development project by up to 40 percent. Two full-sized rotary tables are designed into a drill floor more than twice as large as a conventional one.

36. The industry is looking at ultra-deepwater as 3,000 m.

37. Harts E & P Mar 2002 Drilling Column, by Wajid Rasheed. 'Small companies and tangled thickets'.

38. See The Medieval Map page 45.

39. Campbell, Peak Oil … Hubberts Peak: The Impending World Oil Shortage Deffyes.

40. Author's notes on acreage in emerging markets.

41. Lifting costs EPRasheed.

42. Idem.

43. The End of Oil: On the Edge of a Perilous New World Roberts Publisher: Houghton Mifflin; (May 15, 2004) 400 pages ISBN: 0618239774.

44. AAPG Morocco substrate.

45. Deepwater plays are among the most complex, high cost projects requiring large capital investment therefore favouring large IOCs.

46. Expand your mind, Harts E & P 2004 Wajid Rasheed.

47. Petrobras evolution offshore.

48. The Oil Factor: How Oil Controls the Economy and Your Financial Future Donna & Stephen Leeb Published: February, 2004 ISBN: 0446533173.

49. Coming Oil Crisis, Campbell Publisher: Multi-Science Publishing Co. Ltd.; (April 1, 2004) 210 pages ISBN: 0906522110.

50. Hubberts Peak: The Impending World Oil Shortage Deffyes Publisher: Princeton University Press; (August 11, 2003) 224 pages ISBN: 0691116253.

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