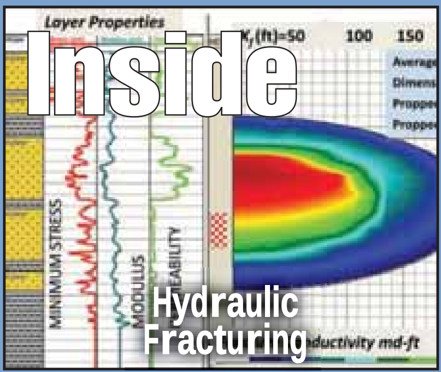
Brazil Oil & Gas, tt_nrg and Norway Oil & Gas

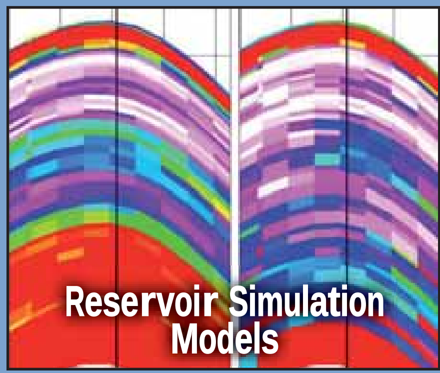
EPRASHEED
signature series

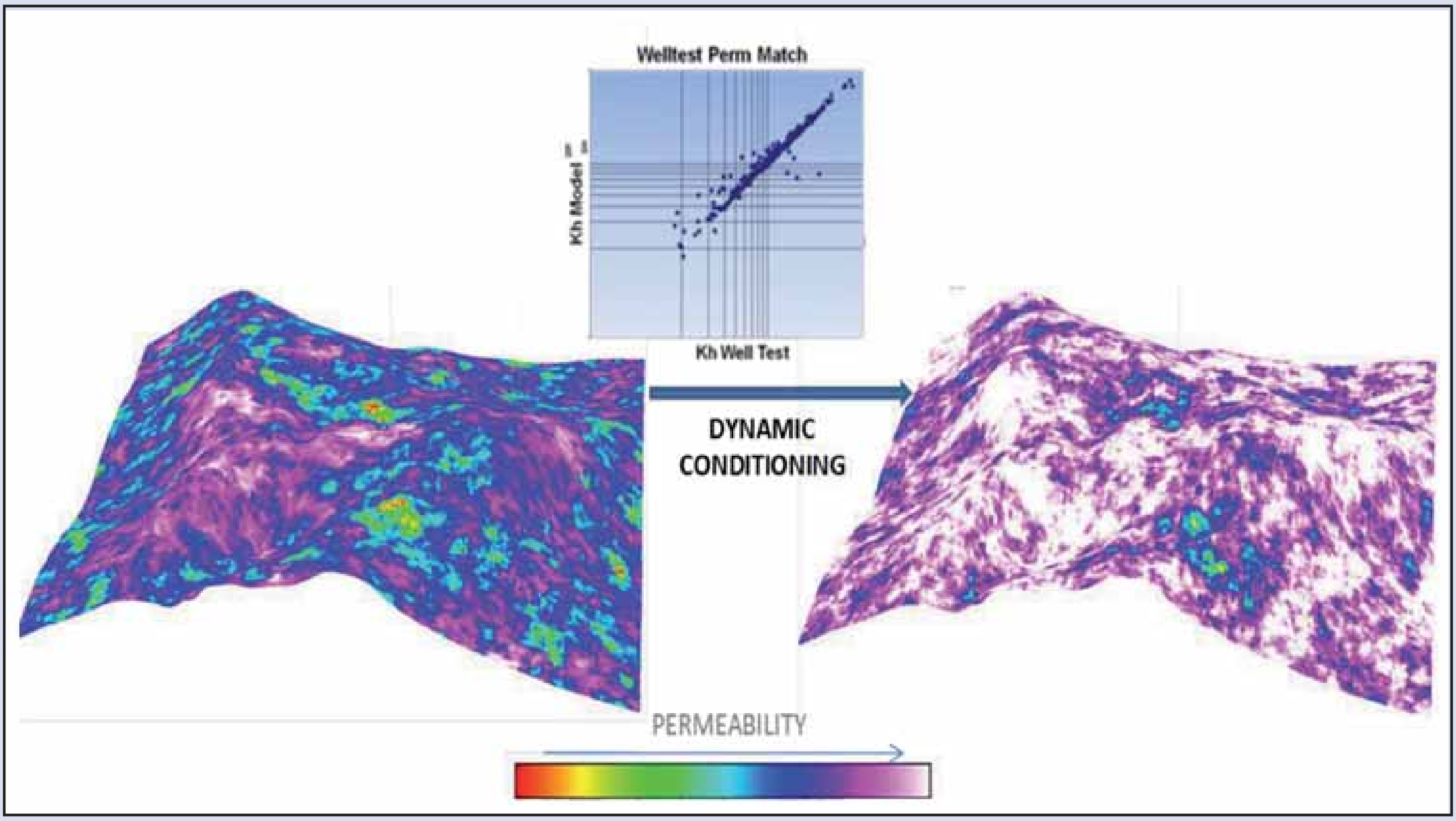
2012 – Issue 26

Saudi Arabia oil & gas

Saudi Arabia Oil & Gas (Print) ISSN 2045-6670
www.saudiarabiaoilandgas.com
Saudi Arabia Oil & Gas (Online) ISSN 2045-6689







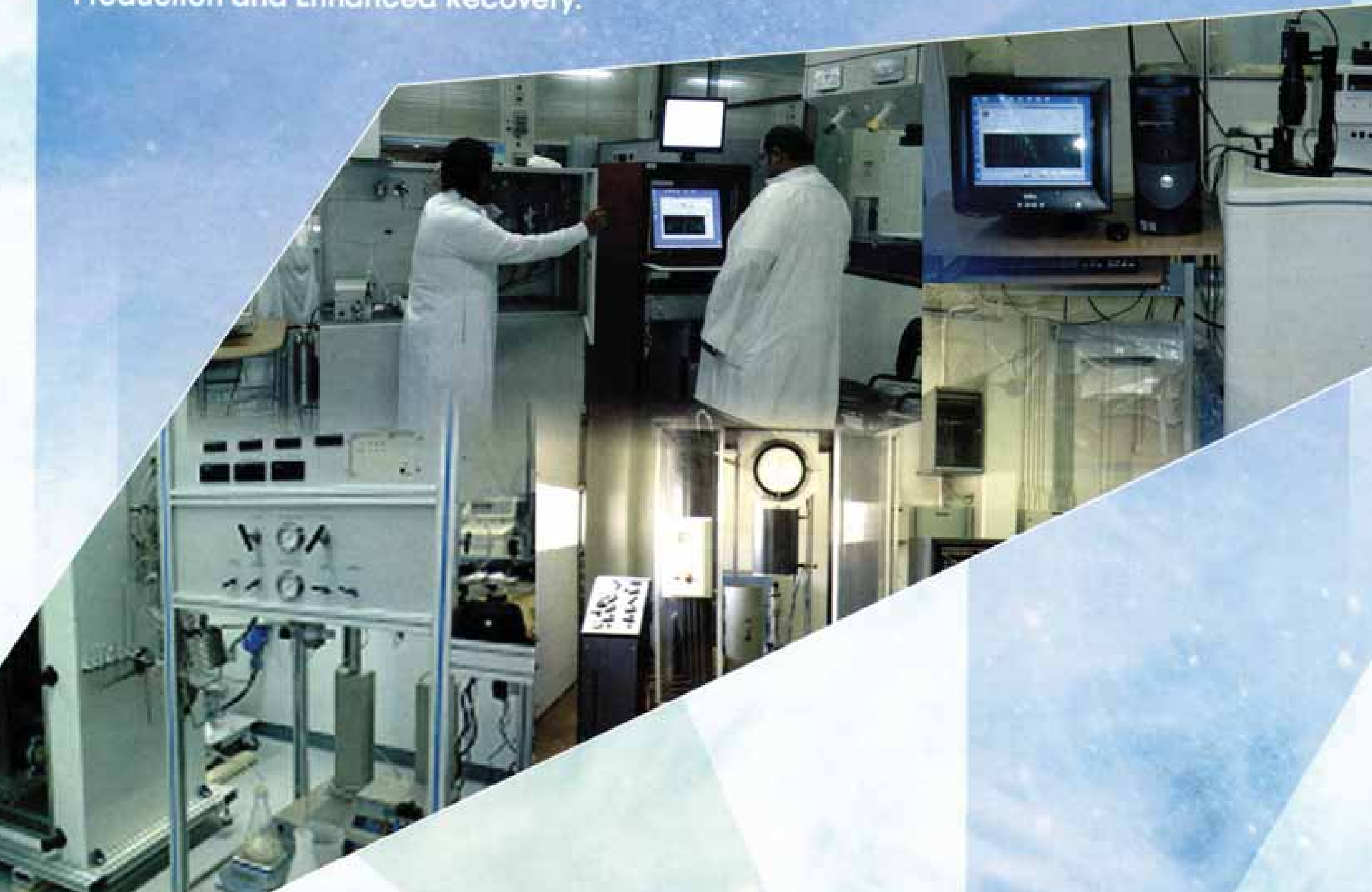
Reservoir Simulation Models.

مدينة الملك عبدالعزيز
KACST للعلوم والتقنية

Oil and Gas Research Institute

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

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



Services Provided

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

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

www.kacst.edu.sa

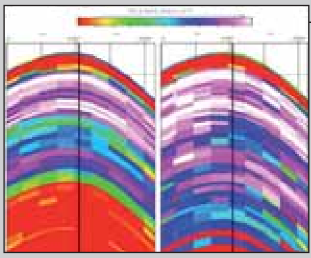
EPRASHEED signature series

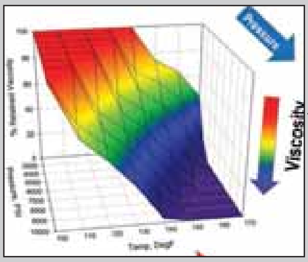
2012 – Issue 26

Saudi Arabia oil & gas

www.saudiarabiaoilandgas.com

Contents





CEO and Founder EPRasheed

Wajid Rasheed
wajid.rasheed@eprasheed.com

Editors

Majid Rasheed
Mauro Martins

Design

Sue Smith
sue.smith@eprasheed.com

United Kingdom

- Head Office
Tel: (44) 207 193 1602

- Adam Mehar
adam.mehar@saudiarabiaoilandgas.com
Main: (44) 1753 708872
Fax: (44) 1753 725460
Mobile: (44) 777 2096692

Saudi Arabia

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

- Mohanned AlSagri
mohanned.alsagri@saudiarabiaoilandgas.com

Brazil

- Ana Felix
afelix@braziloilandgas.com
Tel: (55) 21 9714 8690

- Fabio Jones
fabio.jones@braziloilandgas.com
Tel: (55) 21 9392 7821

- Roberto S. Zangrando
rzangrando@braziloilandgas.com
Tel: (55) 22 8818 8507

Change to Fracology℠

Weatherford puts the science in hydraulic fracturing for superior reservoir stimulation.

Fracturing in oil and gas environments requires an ever more sophisticated approach for maximized results.

Fracology fine-tunes the science of hydraulic fracturing by synchronizing critical services:

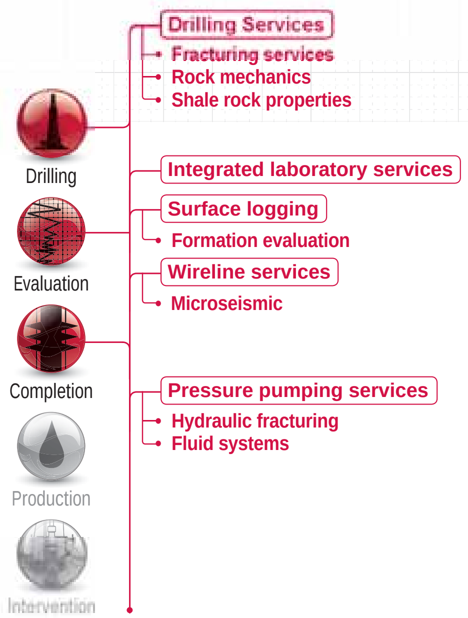
Formation Evaluation reveals candidate viability – identifies gas content, quality and storage capacity of the formation to ensure optimal drilling and fracturing approaches.

Wellsite Analysis of core and mud gas samples pinpoints pay zones and fluid types – enhances geosteering, well placement and completion operations.

Execution Monitoring allows fracturing parameters to be adjusted on the fly for optimal fluid/proppant placement and results.

Microseismic Verfication Surveys affirm completion quality and provide a 3-D view of the drainage network to ensure optimized treatment is achieved.

Fracology is another example of **Tactical Technology™** that can change the way you think about all of your service needs. Contact your Weatherford representative at **fracology@weatherford.com** or visit us online at **weatherford.com/fracology**. Put science to work in your tight shales.



The *change* will do you good℠

Weatherford
Facility Base, Dhahran Abqaiq Road,
Lot No. 6 & 7 In Plan No 404/1
P.O. Box 79106
Alkhobar 31952, Saudi Arabia
Tel: +966.(3).807.5000

Weatherford®

weatherford.com

Karan Milestone Reached

An offshore platform takes shape in the Karan gas field.

DHAHRAN, 23 April 2012

Saudi Aramco's Karan Gas Program passed another milestone with the successful start-up of its gas processing facilities at Khursaniyah, seven weeks ahead of schedule.

With one gas-treating train and one sulfur recovery train now fully functional at the Khursaniyah Gas Plant (KGP), Phase II of the Karan Gas Program is almost complete. The facility is now able to process one billion standard cubic feet per day (scfd) of non-associated gas produced from the Karan offshore field.

By the second quarter of 2012, two additional gas trains will be operational, bringing the Karan gas processing capabilities at KGP to 1.8 billion scfd.

"The new gas trains are dedicated solely to process non-associated gas extracted from the Karan gas field."

> "... Saudi Aramco paid special attention to ensuring young employees were involved in every aspect, from project execution to operating the new Karan facilities."

The completion of the first gas-processing train is another success story for the Karan program. Last year, Phase I of the program was completed, bringing on-line 500 million scfd of Karan gas. That gas however, was processed at KGP's existing associated gas processing facilities.

The new gas trains are dedicated solely to process non-associated gas extracted from the Karan gas field.

At the Karan offshore field, one tie-in platform and three production platform complexes are now complete, with a fifth platform scheduled to be operational in the third quarter of 2012.

The platforms are remotely operated and controlled from Khursaniyah. From the tie-in platform, the gas is sent, via an underwater trunk line, to the onshore processing facilities at Khursaniyah. Hydrogen sulfide, carbon dioxide and water are removed from the feed gas stream in the gas-treating trains.

The treated gas is now ready for use. The hydrogen sulfide and carbon dioxide are directed to the sulfur recovery unit, where the hydrogen sulfide is converted to elemental sulfur.

Despite the size of the program and its importance to the Kingdom's energy needs, Saudi Aramco paid special attention to ensuring young employees were involved in every aspect, from project execution to operating the new Karan facilities.

"It was great opportunity for young engineers to develop," said Muhammad Al-Saad, manager of Karan Projects Department.

"Some joined us as fresh graduates on the Professional Development Program, and they got to see the full workings of a mega-project. This is an experience that will benefit them throughout their careers."

One of those young employees is Hasan Al-Sharif.

"It's a great feeling to be part of the team – especially a team that was dedicated to executing the first Saudi Aramco offshore non-associated gas project," commented Al-Sharif.

"The Karan Program offers a lot of opportunities to grow professionally, and I am really honored that my fingerprints are on this successful story that has become a benchmark in project management globally."

First Field Test of SmartWater Flood

DHAHRAN, 08 May 2012

Saudi Aramco's EXPEC Advanced Research Center has embarked on a strategic research program tagged "SmartWater Flood" to explore the potential of increasing oil recovery from carbonate reservoirs by tuning properties of injection water (e.g., salinity, ionic composition, interfacial tension, and others).

Field tests have been recently completed successfully demonstrating the potential of increasing oil recovery from Saudi Arabian carbonate reservoirs using conventional seawater injection by tuning the ionic composition of field injection water.

Mohammad Y. Qahtani, vice president of Petroleum Engineering & Development, spoke of the trials' success: "Considering these field trials are the first-ever applications in carbonate reservoirs, they further provided another confirmation that SmartWater Flood has strong potential to be a new recovery method targeting Saudi Aramco carbonate reservoirs."

Saudi Aramco utilizes water injection in the field periphery to maintain pressure necessary for hydrocarbon production. Leveraging current field injection practices and Saudi Aramco's existing water injection infrastructure is highly attractive, as it is an efficient and economical approach to increasing recovery.

Over the last few years, in-house research efforts have revealed that injection of chemistry-optimized versions of injection seawater provided substantial oil recovery beyond conventional seawater flooding for carbonate rock samples. These results were confirmed and validated through different laboratory studies, including surface chemistry, wettability and fluid-rock interaction.

"This milestone could have a significant impact on how we will assess and conduct future waterflooding programs within the company," said Samer AlAshgar, EXPEC ARC manager. "This program is one of EXPEC ARC's research thrusts towards increasing recovery from our oil fields."

Moving this technology from lab-scale to field-scale, a roadmap for SmartWater Flood field applications is underway, targeting a full demonstration project. The first phase of the roadmap is to conduct several single well tests to prove the concept of SmartWater Flood at field environment.

The series of field trials will continue, leading to a multi-well demonstration pilot project to fully assess and optimize this new recovery mechanism.

Saudi Aramco's Presence Felt at OTC

HOUSTON, 21 May-2012

The theme for this year's Offshore Technology Conference (OTC) was "Navigating Seas of Change" with the industry moving forward with a renewed focus on safety, technology and sustainability to meet the world's growing demand for energy.

Although there is some regulatory uncertainty and changes taking place with deep-water drilling in the US Gulf of Mexico, there is no uncertainty surrounding the commitment and investment Saudi Aramco is making as it transforms into a global energy and chemicals enterprise. With billions of dollars and more being invested in oil, gas and petrochemicals, the industry took note of the company's vast expansion and the opportunities it brings.

This message came through clearly at the conference as Saudi Aramco, supported by its Houston-based affiliate

"… there is no uncertainty surrounding the commitment and investment Saudi Aramco is making as it transforms into a global energy and chemicals enterprise."

> Job seekers looking for rewarding career opportunities and a better understanding of the expatriate lifestyle, spoke to ASC recruiting staff who were available throughout the conference to answer questions and identify qualified candidates.

Aramco Services Co. (ASC), made its presence known. More than 89,400 individuals attended the event.

Corporate sponsorship of the Annual OTC Awards Dinner – with proceeds benefiting Engineers Without Borders, a nonprofit organization supporting community-driven development programs worldwide – made a strong statement about Saudi Aramco's commitment to community and charitable causes. Participation on the Annual OTC Dinner Executive Advisory Board by Mohammed Y. Qathani, Saudi Aramco's vice president of Petroleum Engineering and Development, illustrated the executives' involvement and recognition in the world's premiere oil and gas conference.

But perhaps the greatest recognition of Saudi Aramco's strength came from the conference participants themselves – engineers, manufacturers, service providers, potential job candidates – who sought out company representatives to learn more about upstream research and development technologies, business plans and career opportunities.

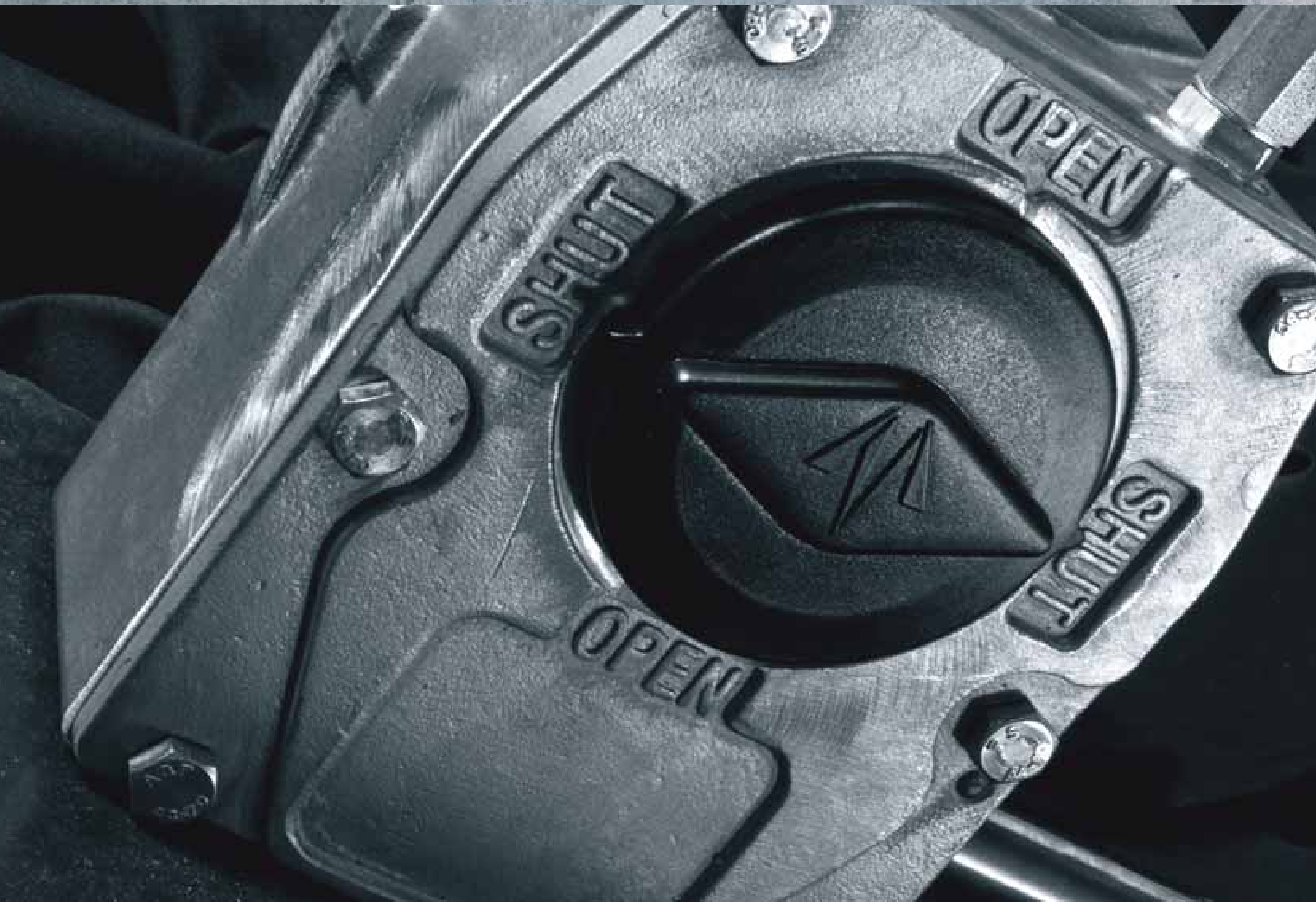
Technology interests turned to business interest for hundreds of manufacturers and service providers interested in conducting business with Saudi Arabia. ASC's Mohammed Al-Belushi, manager of Procurement and Logistics, participated in a panel discussion sponsored by the US Saudi Arabian Business Council to highlight opportunities in Saudi Arabia. The panel discussion attracted nearly 200 attendees.

Job seekers looking for rewarding career opportunities and a better understanding of the expatriate lifestyle, spoke to ASC recruiting staff who were available throughout the conference to answer questions and identify qualified candidates.

By all accounts, OTC was an effective venue for highlighting Saudi Aramco's transformational strategy and further solidifying its reputation as the world's leading energy provider.

MASTERGEAR UK

The **Stainless Steel** Gearbox Range.



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

www.mastergearworldwide.com

Saudi Aramco and Japan: an Enduring Relationship

By Khalid A. Al-Falih, President and CEO, Saudi Aramco.

"Minasama, konnichi-wa and good afternoon. It is a pleasure to join you here in Tokyo, one of my favorite world capitals, particularly in the spring. My only regret is that I missed seeing the Sakura trees in full bloom, as I hear they were particularly stunning this year. I also appreciate your gracious hospitality, as well as the chance to spend time with your chairman and my close friend, Yonekura-san.

My friends, for more than six decades, Keidanren has played an important role in developing this nation's economy and positioning Japan's corporations to compete internationally. Furthermore, the companies represented here this afternoon have helped to make the world a better place through their quality products, superior services and innovative technologies. We at Saudi Aramco very much admire – and indeed share – the values you stand for, such as hard work, discipline, integrity and partnership. Beyond a doubt, these core values have been at the heart of Japan's phenomenal success around the world.

They have also been central to Saudi Aramco's fruitful partnership with Japan going back many decades. When we decided to open our first international affiliate office in Asia, it was right here in Tokyo because of our commitment to our customers in Japan and the prospect of partnerships with our Japanese counterparts. But our long relationship with Japan goes beyond business, as it reaches out to the most important element of any engagement: people.

For example, the dozens of Saudi Aramco-sponsored students who have studied at Japanese universities over the years come not only to explore an academic field or master a professional discipline, but also to learn about Japan's society, its rich history and traditions, and its language and values.

Some of those students may have learned an old Japanese proverb which says, "Strength comes through perseverance" (kay-zoku wa, chi-kara). Never has that adage been more vigorously demonstrated by so many, and in so many local communities and neighborhoods, than in the wake of last year's tragic natural disaster. Our hearts were with you as you tirelessly worked to recover from the devastation wrought by last year's earthquake and tsunami, and the resulting nuclear disaster in Fukushima. The material cost has been heavy, but nowhere near the dreadful human toll of lives lost and disrupted. Yet each time I have come to Japan since that disaster, I have been most struck by the determination, tenacity and solidarity that are the hallmarks of the Japanese people.

Out of the ashes of the Second World War, Japan rose to retake its rightful place at the forefront of the global community, delivering products that have been the envy of the industrial world and unleashing a quality revolution which set the global standard. Today this great nation faces a set of different challenges, and as I look out from this podium, I see the architects of a new Japanese renaissance.

> "In terms of meeting this country's energy needs, I would like to stress that for Saudi Aramco, Japan is and will continue to be a core market to which we are deeply committed."

And it's in the spirit of strong bonds and shared values that I'd like to explore how the already strong relationship between Japan and Saudi Arabia can yield even greater mutual benefits in the future.

Before I do, though, I would like to share with you the perspective we have at Saudi Aramco on current global petroleum markets, which certainly affect all of us – regardless of our particular area of business.

We have been consistently arguing that the petroleum market fundamentals are sound with inventories at healthy levels and plentiful supplies, amid major downward pressure on demand emanating from the challenging global economy. In fact, there is a consensus that oil demand this year will grow by less than a million barrels per day – a relatively modest increase. This situation should have led to stable and moderate prices.

However, the turbulent geopolitical situation, currency fluctuations and financial speculation have created market anxiety complicating the short-term outlook, and lifting crude oil prices. I have repeatedly stated that the market is pricing a considerable premium for these uncertainties. In fact, had it not been for Saudi Arabia's massive investment in its substantial spare production capacity, that premium would have likely been much higher.

Last week, the inevitable happened. With geopolitical tensions easing somewhat and the bearish economic environment setting in, prices fell by about 6% to their lowest levels in many months, driven by the healthy fundamentals which I just referred to. This price correction is a welcome development, as we all seek a stable market with moderate oil prices supportive of a global economic recovery, while promoting continued investments in growing energy supplies.

In terms of meeting this country's energy needs, I would like to stress that for Saudi Aramco, Japan is and will continue to be a core market to which we are deeply committed.

As you continue to rebuild from last year's tragic natural disaster and work to hone your global competitive edge, a reliable energy supply will be key – and we will continue to be a partner on whom you can always depend. You are among our most valuable customers and your requirements are at the top of our agenda.

For instance, in 2011 we supplied 1.2 million barrels per day of petroleum to Japan, providing about 30% of this nation's imports. That means that on average, every 30 hours last year a crude, LPG or product tanker sailed from Saudi Arabia to Japanese shores. This virtual pipeline of energy will always be there for Japan — and on that Ladies and Gentlemen, you can certainly count.

And to ensure an even higher degree of reliability, "Saudi Aramco has acquired the capacity to position more than four million barrels of crude oil in Okinawa, to enhance the flexibility and responsiveness of our supply of energy to Japan and Asia as a whole."

we have also gone one extra step: Saudi Aramco has acquired the capacity to position more than four million barrels of crude oil in Okinawa, to enhance the flexibility and responsiveness of our supply of energy to Japan and Asia as a whole.

We are also determined to build on our existing investments here in Japan. We are a committed stakeholder in Showa Shell, and are particularly excited to see our partnership expand beyond petroleum through the bold steps we are taking in the area of innovative solar energy technologies through the newly created subsidiary, Solar Frontier. This includes pilot projects on both coasts of the Kingdom of Saudi Arabia undertaken in collaboration between Saudi Aramco and Solar Frontier.

And on the Red Sea, our PetroRabigh joint venture with Sumitomo Chemical has taken these partnerships to the next level with its world-scale petrochemical complex, which is poised to launch its Phase II expansion after receiving support from the Boards of Directors of both companies.

This major expansion will not only make PetroRabigh one of the largest and most diverse and integrated petrochemicals facilities in the world, but will also strengthen its profitability in the future.

Here, I would like to pay tribute to our respective Boards and particularly to Yonekura-san for his vision and leadership in joining hands with us on this visionary venture. At the time the investment decision was made it represented a new frontier for both our companies, as it was Sumitomo Chemical's first major industrial facility outside of East Asia, and our first foray into petrochemicals integrated with refining assets in Saudi Arabia.

Indeed, Sumitomo Chemical has proven itself with bold ventures elsewhere in Asia. For instance, whenever I go to Singapore and observe the phenomenal success of their petrochemicals sector, Yonekura-san is always mentioned as a visionary who is credited with anchoring what is a thriving, vibrant industry. I am convinced that in the future, observers will look back and see the investment in PetroRabigh as a transformative moment for Sumitomo and the Saudi petrochemicals industry — and as yet another concrete example of the power of partnership between our two peoples and out two countries.

Of course, this bold venture is the latest in a long line of Japanese investments in the Saudi chemical industry, stretching back to the early '80s. Companies such as Mitsubishi Chemical have been active investors and the Japan Bank for International Cooperation (JBIC) was a key financier for numerous projects.

Taken together, these partnerships underscore the strong sense of mutual commitment we have to each other. But now is an opportune time to take that same

> "… the Kingdom has plentiful supplies of oil, gas, chemicals and competitively priced utilities, and we are establishing new world-scale industries producing aluminum, phosphate and other minerals."

power of partnership a step further, to a wider range of other strategic opportunities on offer today in Saudi Arabia.

Until recently, Japanese investments in Saudi Arabia have been primarily in basic industry. We continue to welcome those investments, but I believe Japanese companies are uniquely placed to take advantage of far greater opportunities further down the value chain in a variety of sectors, building on but not limited to previous investments in energy and chemicals. Let me offer four key attractions that Saudi Arabia has for Japanese companies.

The first is economic. The Saudi economy is by far the largest in the Middle East – North Africa region and one of the fastest-growing in the world, with an exceptional growth rate of 6.5% last year. Economic growth is expected to remain healthy, which is quite remarkable in light of the overall state of the global economy. We also have a young and eager workforce, as more than half of the population is under the age of 25, with the government making concerted efforts to train young entrants into the workforce. Also, the investment and regulatory environment is increasingly progressive and highly pro-business. There are no personal income taxes; corporate tax is flexible and low at 20%; our currency, the Saudi Riyal, is one of the world's most stable; and there are no restrictions on repatriation of capital. When it comes to the domestic market, Saudi Arabia's 27 million increasingly prosperous consumers are at the heart of the MENA region's 400 million strong population.

What all these powerful economic drivers offer Japanese companies is a fast integrating, high-growth market with an educated, relatively low-cost workforce in a dynamic pro-business environment.

The second attraction is ready access to crucial enablers. We have an abundance of important resources, and so can offer a lower cost structure over the long-term.

As you know, the Kingdom has plentiful supplies of oil, gas, chemicals and competitively priced utilities, and we are establishing new world-scale industries producing aluminum, phosphate and other minerals. Then there is abundant liquidity and soft financing, an extensive modern infrastructure, and the Kingdom's strategic geographic location between East and West.

The third attraction is opportunity. The Kingdom will invest hundreds of billions of dollars in the years to come in a multitude of areas, all designed to further develop and diversify the Saudi Arabian economy. Areas like infrastructure, housing, education, healthcare, telecommunications and IT, and manufacturing of consumer goods are all ripe for investment.

And most importantly, both the Kingdom and

Saudi Aramco place great emphasis on establishing downstream conversion industries in a wide range of economic sectors which will produce finished and semi-finished products. Such competitive advantages can clearly be seen in the industrial clusters and value parks being developed by the government and Saudi Aramco. I am pleased to see these types of investments starting to take place in the manufacturing of membranes used for seawater desalination by a consortium led by Toyobo and Itochu, in submarine cables by J-Power and Marubeni, and most notably, a truck assembly plant by Isuzu.

I also see collaborative partnership opportunities in areas such as R&D and innovation. Saudi Aramco's plans to undertake cutting edge research into groundbreaking oil-based fuels and the substantial progress Japan's automotive industry is making with advanced engines is one example of the tremendous synergies here.

The fourth attraction for strategically minded Japanese investors comprises several built-in advantages which give you a head start over the competition. Japan is already the single largest foreign investor in the Kingdom, so you understand the market very well. In addition, Japanese brands enjoy tremendous respect and admiration among Saudi consumers and businesses alike. Across the Kingdom, there are waiting lists for Japanese motor vehicles, Japanese electronics command a premium; Japanese engineering is well-respected across the Middle East; and Japanese equipment is ubiquitous in the Saudi industrial and construction sectors. "Made in Japan" means top quality and value to the Saudi consumer – and that's a reputation that has been won not with clever marketing, but through consistent performance and reliability over time.

From our perspective, the key goal of the Kingdom's emphasis on investments in the downstream segments of the various value chains is to create meaningful jobs for the nation's youth, and diversify the economy with a focus on knowledge-based industries. So I see an excellent fit between the technologies, expertise and global business position that Japanese corporations command on the one hand, and the Kingdom's competitive position coupled with its developmental objectives on the other.

My friends, I also see that the challenges facing a capable nation like yours in our increasingly complex and competitive world are more than offset by opportunities. Japan has many competitive advantages centered around the ingenuity and work ethic of its people and the great companies represented here today.

To sum up, what I believe is needed at this point in time, is a broad set of mutually-beneficial partnerships that will give Japanese industry a new springboard, while meeting the Kingdom's developmental needs. This of course, will build on the existing bonds of industrial and energy cooperation that exist between us today.

But to achieve this bold objective, we will all need a comprehensive approach to make the most of this once-in-a-generation opportunity. A relationship based on trade or isolated capital investments has been good in the past but will no longer suffice. Instead, we need a relationship which goes beyond the incremental; we require partnerships which are complementary; and we must have the courage to seize the opportunities which lie before us. I invite Keidanren and all of you here today to work with us at Saudi Aramco, the Saudi business community and with the relevant governmental agencies of both our countries to elevate our partnership while driving Japan's resurgence in the years and decades to come.

Let me conclude by restating my firm belief that despite the uncertainties of the moment, Japan's best days are still ahead of her. As all of us at Saudi Aramco have seen time and again, the solidarity and determination of the Japanese people and the capabilities and vision of this country's business sector represented here today, are more than equal to the task.

Thank you for your hospitality and your attention today. I look forward to responding to your questions. Minnasan, Arigatou gozaimasu."

The View from the Top

By Khalid A. Al-Falih, President and CEO, Saudi Aramco.

"Good morning, Ladies and Gentlemen. Thank you Dean Saloner for inviting me to speak here at Stanford.

Like any good businessman, I looked at the list of recent speakers to see what works well in these sessions, and to check out the competition.

You've had the CEO of Citigroup. A partner at McKinsey. And, just last week, the President of Turkey. A banker, a management consultant, and a politician….

It's good to see that. "Big Oil" is farther down the "hit list" for a change!

Saudi Aramco & Stanford

Seriously, it's a genuine pleasure to speak at one of the finest business schools in the world, and to be back in northern California. I lived in San Francisco for a time during the early '80s and have some wonderful memories of the region. And back in the 1930s, this part of the world figured prominently in Saudi Aramco's origins. The first concession agreement was granted by the Saudi Government to the Standard Oil Company of California – predecessor of today's Chevron which was headquartered in San Francisco. In fact, our company's first name was the 'California-Arabian Standard Oil Company' – and I note that 'California' comes before 'Arabia'!

So, given my own history and that of my company, being back in the Bay Area is both a personal and professional homecoming for me.

Those historic links with California are reflected in the multi-dimensional partnerships in education, research, and innovation that Saudi Aramco and Stanford have enjoyed for many decades. Forty of my fellow Aramcons are Stanford alumni including Saudi Arabia's Minister of Petroleum & Mineral Resources and the Chairman of our Board of Directors, Ali Al-Naimi while another 13 are currently studying here.

Earlier this year, we also had the pleasure of hosting around 30 Stanford MBA students at our headquarters in Dhahran; some of you here today may have gone on that tour, and I hope you found it a rewarding experience.

Later today, I will join my good friend John Etchemendy, the Provost, in celebrating Saudi Aramco's endowment of the Max Steineke Professorship in the School of Earth Sciences, further cementing the ties between Stanford and our company, and highlighting the legacy of an outstanding Stanford alumnus and an icon in the history of the global petroleum industry.

That chair is named for perhaps the most inspirational employee to pass through these hallowed halls, a first-generation Aramco pioneer and our former Chief Geologist, Max Steineke.

Sent to Saudi Arabia by Standard of California in the mid-1930s, his resilience and optimism overcame almost five years of frustration, as a number of wells were drilled and failed to deliver. Management back in San Francisco sent a telegram to the field crews in the Kingdom to stop working. However, the men on the receiving end of that cable chose to ignore it at least for a while and Max Steineke ordered his men to 'drill a little deeper'.

When they did, they discovered the first oil in Saudi Arabia in commercial quantities, and in March 1938, Dammam Well Number 7 'Lucky Number Seven', as it was called, became our first gusher.

Now I am not advocating that in your future careers, you ignore the directives of your senior management

> "Aside from being a sizable producer of natural gas, nearly one in every seven barrels of oil that will be produced around the world today will come from Saudi Aramco..."

but I am glad that in this instance those early oil pioneers trusted their own instincts and superior local knowledge by "drilling deeper"!

And so it's with the inspiration of Steineke 'drilling a little deeper' that I'd like to approach our time together.

Today I want to drill a little deeper when it comes to understanding Saudi Aramco today, and where it is headed in the future. I want to drill a little deeper intellectually, to explore the theory and practice of leadership. And as well as drilling deeper, I'd like to talk about how we're aiming higher when it comes to unleashing the full power and potential of an already successful organization through transformative change.

Saudi Aramco Today

Let me begin by providing some context, because to appreciate the view from the top, you have to understand the organization being led and the context in which it operates. Saudi Aramco is in many ways a unique company, as are the leadership challenges it presents.

Earlier I mentioned the California Arabian Standard Oil Company, which became the Arabian American Oil Company Aramco once Texaco acquired a 50 percent stake. Eventually Exxon and Mobil also bought in investment which was welcome given the size and scale of the upstream operation in Saudi Arabia. To bring the story full circle, the Saudi government acquired Aramco from those four American parent companies by 1980 though they continued to manage it on the government's behalf until the establishment of Saudi Aramco back in 1988. And while the company began nearly 80 years ago as an upstream powerhouse, producing crude oil in one country, over time it has become an integrated global energy enterprise.

Saudi Aramco's story is one of success, and it does well by multiple measures. For example, we've produced more oil in our history than any other company on the planet. Aside from being a sizable producer of natural gas, nearly one in every seven barrels of oil that will be produced around the world today will come from Saudi Aramco, and over the next 24 hours, we will provide more than 10 million barrels of oil to the global energy market. We are also the only producer with sizable spare production capacity, which plays a critical role in helping to stabilize markets and reduce volatility. Our ability to make up for production shortfalls elsewhere around the world has been demonstrated many times over the decades, most recently when Libyan supplies were disrupted last year. No one else has the capacity or capabilities we do, and that requires large investments, operational excellence, and political prowess!

> “Downstream, we have extensive refining assets in the Kingdom and around the world through a network of joint ventures, which stretch from Texas to Tokyo.”

Downstream, we have extensive refining assets in the Kingdom and around the world through a network of joint ventures, which stretch from Texas to Tokyo. We continue to build our refining capacity and move further down the value chain initiatives I will come to later. We are in the privileged position of not carrying any debt on our balance sheet and of being able to self-finance our own industrial initiatives.

But with such scale, competence and influence comes tremendous responsibility.

Certainly there is our global responsibility as a major energy provider, but as the national oil company of Saudi Arabia, we also bear tremendous responsibilities to the Kingdom and its people. To that end, we act as the engine of the Kingdom's economy not only as the predominant source of revenue and the sole provider of energy to the nation, but also by helping to build national capacity and grow the Saudi economy.

Of course, the revenues we generate are significant, and profitability is as vital to Saudi Aramco as to any multinational oil company. Although we are a state-owned enterprise, we maintain an arm's length fiscal relationship with the government, and pay taxes and royalties now just as we did when we were an American-owned company. And we report to an independent Board of Directors comprising both international and national business leaders, educators and officials.

We also exhibit a high degree of operational complexity, even beyond the technologically sophisticated core oil and gas business. Because of the scale of our operations, we operate our own fleet of fixed-wing and helicopter aircraft; operate a healthcare system with a patient population in the hundreds of thousands; and maintain housing compounds and remote area camps, with all the logistics that entails.

Challenges

Because of the breadth and complexity of these various mandates especially the national challenge we must be absolutely clear about our mission or risk becoming distracted and unfocused. Our mission statement has profitability at its heart, and it reads, ‘Saudi Aramco's mission as an integrated international company is to engage in all activities related to the hydrocarbon industry, on a commercial basis and for the purpose of profit.’

Sounds good, but what does it mean in practice? Let me highlight four of the leadership challenges that flow from that mission.

First, we have to execute at ‘best in class’ levels, because day-to-day performance is absolutely essential for business success. That goes beyond operational excellence, and extends to high levels of performance in executing projects, maintaining fiscal discipline, and ensuring safety and environmental stewardship. It also means building capacity in our work force, to ensure our men and women have the skills, expertise and job knowledge needed to achieve those high standards day in, and day out.

Second, we have to invest wisely and ensure we direct capital in the most effective manner in what is both a resource-intensive business and a long-term industry. To give you an example of those time horizons, I was in Texas yesterday to inaugurate an expansion of our joint venture Port Arthur Refinery a ten-billion-dollar project which makes it the largest refinery in the Western Hemisphere. That facility is state-of-the-art, but it was first built in 1903 in the wake of the Spindletop oil rush, more than a century ago! And last month, at our Board meeting in Tokyo, we presented our crude oil production strategy, showing the resources we will be producing a century from now, in the first decade of the 22nd century.

It is also a far-flung enterprise, with a worldwide reach and global partnerships. For example, in March I was in Beijing to sign agreements with two leading Chinese petroleum enterprises to build a refinery on Saudi Arabia's Red Sea coast and another in China's Yunnan Province. Those ventures will join partnerships we already have with American, Anglo-Dutch, French, Russian, Italian, Korean and Japanese companies.

Third, we have to not only to achieve profitability, but also to maximize our contributions to the Saudi economy and society, leverage our core strengths for the benefit of the nation, and strengthen our ability to meet growing global demand for oil, products and petrochemicals. That entails, among other areas of focus, developing human resources, promoting innovation and entrepreneurship, and expanding in areas of the business that are richer in terms of value addition and job creation.

Fourth, one of the most complex challenges for us or any petroleum company is the central position that energy occupies on the global public agenda. Oil is inseparable from economics, politics and the environment, and is often the subject of fierce debate. Unfortunately, those debates generate more heat than light. But we do our stakeholders and wider society a disservice if we fail to correct misperceptions and encourage a more rational discussion of the energy choices we face. We have to insert ourselves into the public narrative by engaging the minds (if not always the hearts) of audiences far and wide. This is one of my most important responsibilities and it's why I am here.

To recap, we are one of the world's largest, most successful and most profitable energy enterprises. But we face tremendous challenges as an industry, and in terms of development in the Kingdom of Saudi Arabia as well as a host of exciting opportunities on the horizon.

Leading Transformative Change

Now, one response to that situation would be to focus only on our tried and true strengths and core competencies. There's something to be said for that strategy, and many companies have pursued it with success. But at Saudi Aramco, we view the situation differently. I have often compared Saudi Aramco to a high-performance racing car: if you drive it downtown through traffic and encounter lots of stoplights and intersections, it will never reach top speed. Instead, you have to get it out on the super speedway, rev the engine, and unleash the vehicle's true potential.

So we see our strengths as sources of leverage for new initiatives. Rather than being content with the status quo, we are challenging ourselves to unleash the full potential of our company and above all, of our people. Of course change is never easy or resistance-free. Some ask why we are trying to undertake sweeping change at what is already the world's most successful oil and gas company; don't fix it if it's not broken, they say. I agree it's far from broken but it's not as good as it could be. And to me that's an irresistible challenge and a personal responsibility.

That's why last year I launched a major Strategic Transformation Initiative called the Accelerated Transformation Program, or ATP which will dramatically change our company.

The goals of that initiative are captured in our Strategic Intent for the company, namely that, "In 2020, Saudi Aramco will be the world's leading integrated energy and chemicals company, focusing on maximizing its income, facilitating the sustainable and diversified expansion of the Kingdom's economy, and enabling a globally competitive and vibrant Saudi energy sector." Those 39 words are my mandate for moving our company forward over the next decade or so. We've broken that intent into 14 specific initiatives, grouped under four main focus areas, or what we've termed "pillars".

The first pillar is business strategy 101: building and developing our portfolio. That means leveraging our upstream success by exploring in frontier areas like the deep offshore Red Sea and assessing the resource potential of unconventional petroleum resources, like shale. It also means investing in the downstream space so that in the next decade our total global refining capacity both wholly owned and joint ventures will approach eight million barrels per day the largest of any oil company on earth. It also means building a top-tier chemicals business by moving further down the value chain, and getting more involved in power generation, including, it might surprise you, investments in renewables, particularly solar.

The second pillar is all about our engagement with the Kingdom, and ensuring that as Saudi Aramco enhances its global leadership position, we leverage that leadership for the progress of the Kingdom. That means helping to develop the local energy support sector, so that we can source an increasing volume of our goods and services from domestic suppliers, including more high-value products. It means helping raise educational standards and developing a knowledge base for the Kingdom's future. And it means working to reduce the Kingdom's level of energy intensity and create a more energy efficient nation, and playing our part in diversifying the Saudi economy.

Some people think those two pillars are stretch targets, but for me, it is the third and fourth pillars which will be the most challenging.

The third pillar is about expanding Saudi Aramco's capacity and capabilities through enhancing the performance of its people. We have to develop leaders, managers and professionals for a new, more complex, and faster moving business environment that rewards well-reasoned and calculated risk-taking, and pushes decision-making down in the organization. At the same time, we are bringing a new generation of young men and women into our ranks and by 2016, roughly 40 percent of our employees will be under the age of 30. They have a different worldview and different expectations, and I have spoken often of the need to not only get these young people ready for the company, but to get the company ready for these young people. That also means fostering a climate that encourages innovative thinking and solutions, and developing a technology and R&D engine that ranks among the strongest in the world.

Our fourth pillar is ultimately all about streamlining our business processes. I refer to it as fixing the plumbing and wiring in the company and we all know how disruptive a process that can be in our homes! That's one of those calculated risks I just mentioned, but we need to do it if we are going to have organizational flexibility and dexterity.

Ladies and gentlemen, when I'm asked about transformation, I am reminded of a quote by 'The Great One', Wayne Gretzky, and yes, I am probably the first Saudi oilman to derive business strategy from ice hockey! One of the keys to Gretzky's legendary success was his ability to be in the right place at the right time, which he explained like this: "I skate to where the puck is going to be, not where it's been."

But being able to do that requires hard work, as well as teamwork and coordination after all, Gretzky never skated alone against six opponents! Getting ahead of the puck also requires physical conditioning, skating and stick-handling skills, and situational analysis. And of course, sometimes hockey requires beating up on the competition, in more ways than one! Business is the same way it's not enough to aspire to be in the right place at the right time; you also have to do the hard work of building capacity and building consensus, developing people and their skills, and delivering top-notch execution every single day.

In a nutshell, that's how I see my role. Doing it can be exhausting at times, but I love my job and I'm passionate about delivering the transformation our company needs.

Thank you for your attention as I've 'drilled a little deeper'. I hope I've set the scene for what I am sure will be an interesting and enlightening discussion. Thank you."

Incorporating PLT-Distributed Dynamic Permeability into Reservoir Simulation Models Improves and Accelerates the History Matching

By Rida Abdel-Ghani, Dr. Dimitrios D. Krinis and Jorge E. Nieto Carmargo.

Abstract

Integrating dynamic data into reservoir numerical models is essential for capturing the actual dynamic flow behavior. History matching efforts could prove to be fruitless without including such data into the reservoir model. For example, open hole logs and core sampling do not provide a satisfactory characterization of fractures and super-high permeability streaks – two important flow features that can be overlooked.

Failing to incorporate these small but critical flow features can lead to inaccurate simulation models, even if the history match captures the total rates at the wellhead. This inaccuracy usually transpires when model results are compared to actual production profiles, and could go unnoticed until the field performance starts to deviate from predictions.

The inclusion of dynamic permeability data into the reservoir model can be performed, either during the static geological modeling, or into the dynamic simulation model, as a conditioning step. Either way, the process starts by comparing the correlation based permeability thickness (kh) values to those obtained from pressure transient testing (PTA). Various methods can be used to utilize the results of this comparison, which vary from simple zone averaging to highly detail vertical permeability profiling.

In the geocellular model, the adjusted dynamic profiles are input for the permeability population by using several methods that range from kriging to stochastic approaches. The final conditioned permeability fields can be in addition to incorporating discrete fracture models or stratiform characterization and mapping as 2D or 3D trend parameters.

This article explains how production logging tool (PLT) profile based distribution of the dynamic permeability resulted in a large improvement of the history match results, and just as importantly, a shorter history matching process for a giant carbonate Middle East reservoir. The article also shows alternative approaches for incorporating the dynamic permeability into the simulation model, but which did not produce the same desired results.

Introduction

Lateral and vertical permeability representation has been always a constant field of research and analysis due to the extreme influence in fluid flow behavior and ultimate control in history matching and forecasting. The normal degree of scale variability and the skewed distribution make the permeability field a complex property to model when data is limited or scattered. This target becomes more difficult when reservoir rocks have suffered diagenesis and the primary porosity-permeability relationships have changed, as commonly observed in carbonate deposits. In such cases, the presence of highly transmissible and commonly discontinuous layers or stratifoms become apparent and the necessity of proper representation in the geocellular model call for the integration of additional supporting data. Well tests and production logging profiles emerge

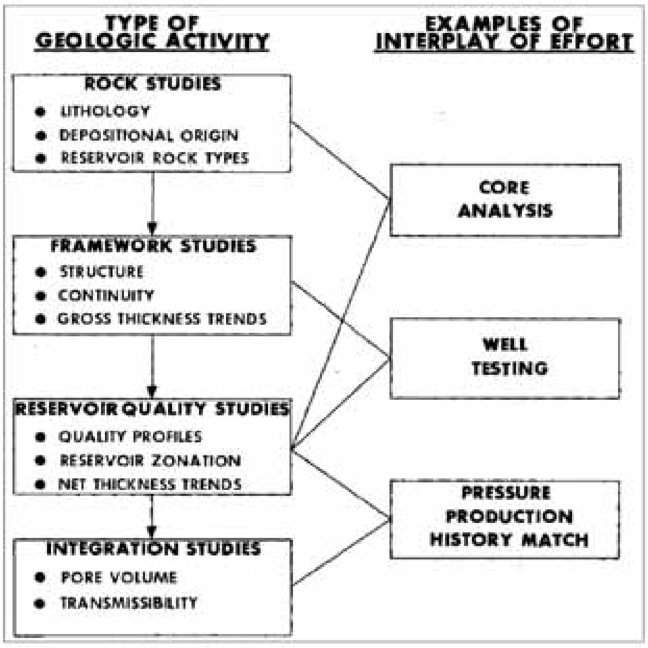


Fig. 1. Engineering data input into geomodeling workflows[4].

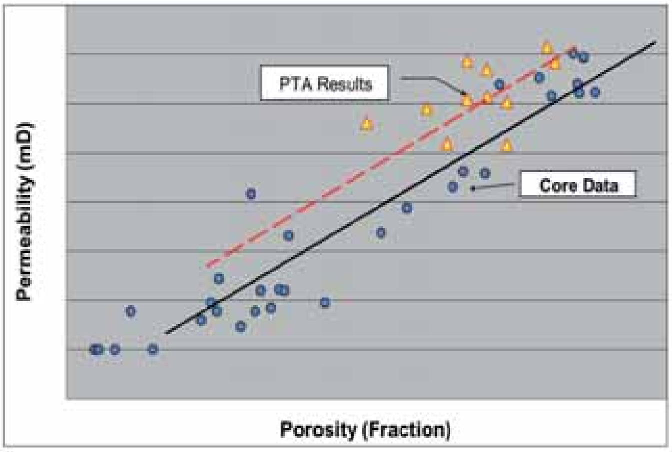


Fig. 2. Example PTA vs. core analysis permeability results showing generally higher PTA permeability values.

		Environment & Physics			
Technique	Scale	Pressure & Temperature	Saturation	Method	Quantity
Core	Macroscopic				
Absolute		Ambient*	Absolute	Direct	Permeability
Relative		Ambient*	Relative	Direct	Permeability
Wireline-log	Megascopic				
K-Φ		In-situ	Absolute	Indirect	Permeability
NML		In-situ	Absolute	Indirect	Permeability
GLT		In-situ	Absolute	Indirect	Permeability
Stoneley		In-situ	Absolute	Direct?	Permeability
RFT					
Pretest		In-situ	Absolute	Direct	Conductivity
Superflow		In-situ	Relative	Direct	Conductivity
Well-test	Gigascopic				
Short		In-situ	Relative	Direct	Conductivity
Classic		In-situ	Relative	Direct	Conductivity
Advanced		In-situ	Relative	Direct	Conductivity

*Can be measured at simulated downhole pressure and temperature.

Fig. 3. Various reservoir permeability measurement methods[8].

as vital inter- preted data to condition static property distribution, specifically the permeability field.

The importance of incorporating dynamic data into static reservoir models has long been recognized[1-4]. Figure 14 gives an example of how engineering data, such as well tests and production history, can be used during geological studies. This recognition is driven by two factors: the realization that most of the static methods, e.g., wireline logs and core analysis, investigate only a small portion of the reservoir, and as well, these could be influenced by human factors, e.g., selective sampling, tool accuracy, sample properties and/or laboratory procedures. Also, it is known that different methods of measurements produce different results, which highlights the importance of integrating all available data when building dynamic models.

As an example, large variations are usually noticed between core permeability and pressure transient analysis (PTA) test results. In some cases, well tests yielded much higher values than core data, while in other cases, the well tests yielded lower values[5]. Figure 2 illustrates an example from a Middle East reservoir where well test data showed higher permeability than core analysis results. Therefore, numerical models that are based on core and log data should be conditioned to well test permeability. When considering reservoir permeability, well tests provide the best permeability estimates over large volumes of the reservoir[5, 6], and therefore, it is a better source for the effective reservoir permeability than the much smaller-sized core plug samples.

The various methods used to obtain permeability information and their relationships have been summarized[7], Fig. 3, and concluded that many correlations are available that do not take into account the interrelationships of the various measurement techniques, resulting in inadequate answers. The authors also conclude that integrating well test data provides the best formation permeability distribution if a single-phase production profile is available. This is a key conclusion; and it will be shown later in this article that having such production profiles in heterogeneous reservoirs will make a tremendous difference to history matching of newly constructed dynamic models.

As stochastic modeling approach gained more popularity, it was also recognized that it too requires guidance from all other types of data, such as geological, production, core, log and well test analysis[8-11] stressed the importance of conditioning stochastic

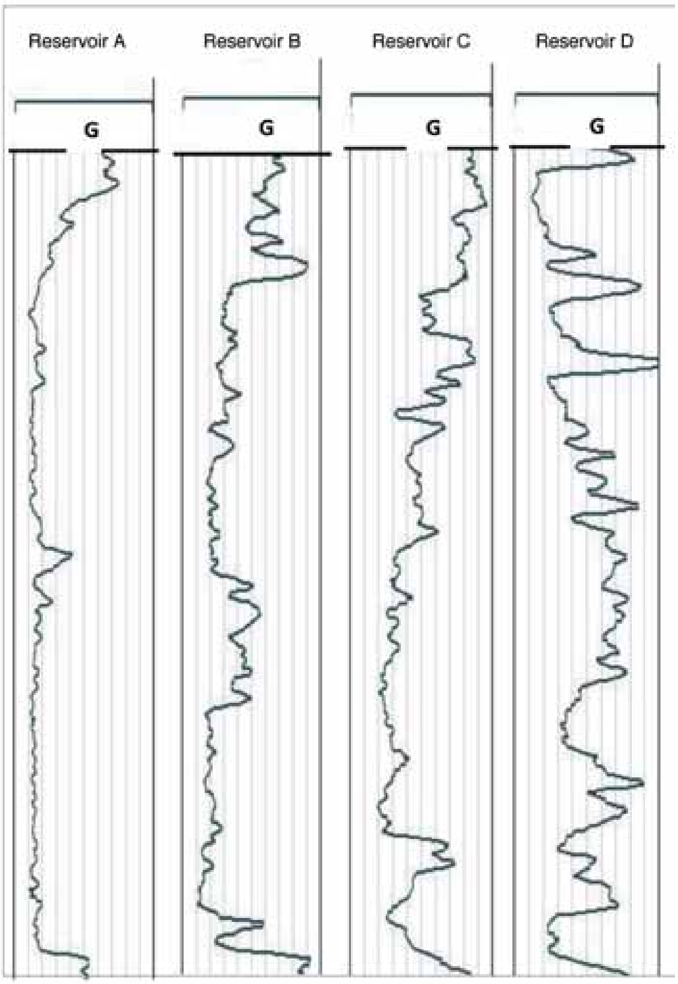


Fig. 4. Example gamma ray logs from four Middle East sandstone reservoirs showing different heterogeneity levels.

generated models to test well data, and concluded that the well test data reduced the variability of the stochastic model realizations.

Conditioning reservoir models to dynamic data can be done at the well level prior to geo-model construction, by calibrating the log-derived core based permeability[12, 13], or after model construction by calibrating the total model permeability thickness (kh) to test data. The calibration process itself can vary from a simple per- meability multiplier to a fully detailed vertical permeability profiling based on core analysis, PTA testing and production logging.

Reservoir Characterization

Various degrees of lateral and vertical heterogeneity exist in hydrocarbon reservoirs, from simple blocky and homogeneous sandstone reservoirs, to complex stacked, highly heterogeneous and naturally fractured carbonate reservoirs. Figure 4 gives some example gamma ray logs for four Middle Eastern sandstone reservoirs with various degrees of heterogeneity. The presence of highly conductive thin beds, or "Super-K" zones, will further increase the reservoir heterogeneity to a higher level. Depending on the thickness of these Super-K zones, conventional logging tools might not be capable of detecting their presence; and they are usually difficult to core due to a fragile structure. On the other hand, when intersected by the wells, their

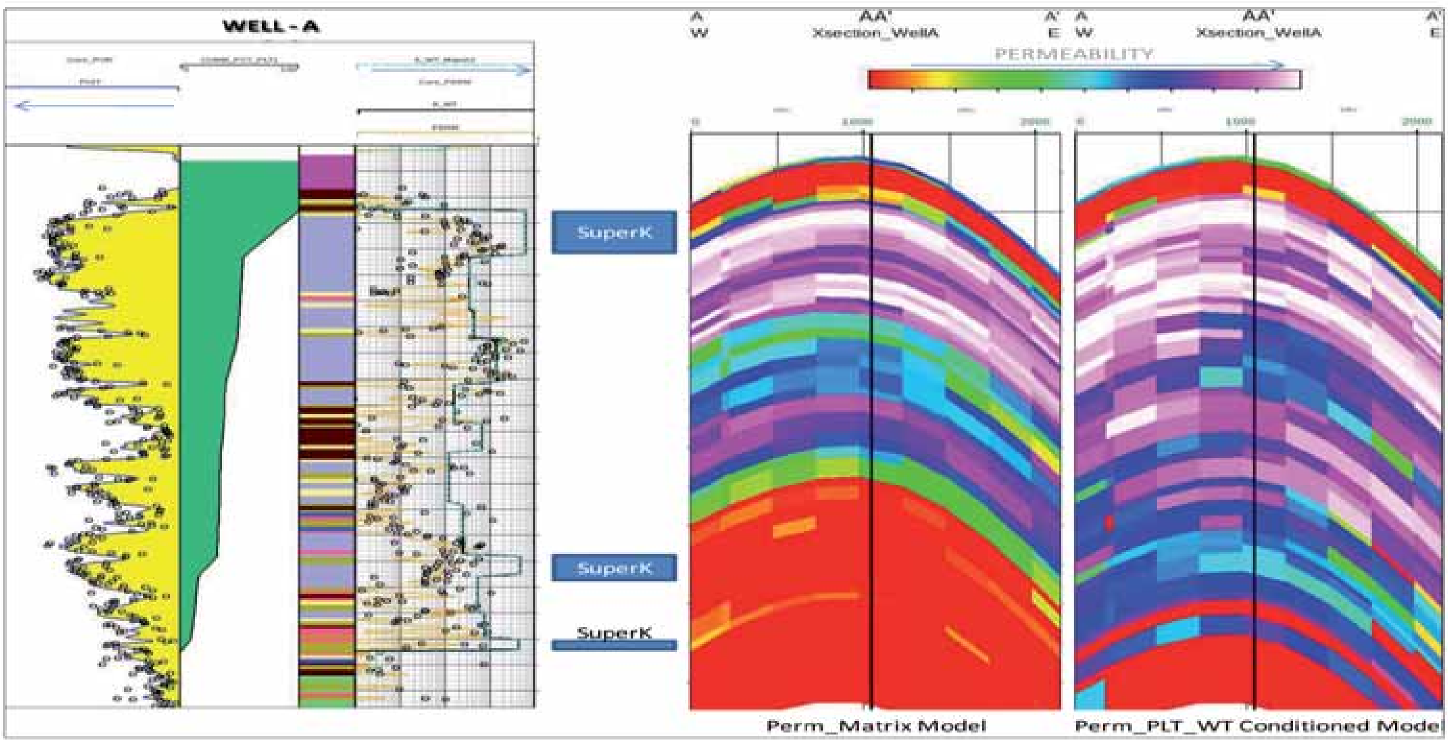


Fig. 5. Result of a selective layer at a typical Super-K location in the reservoir, prior and after permeability conditioning.

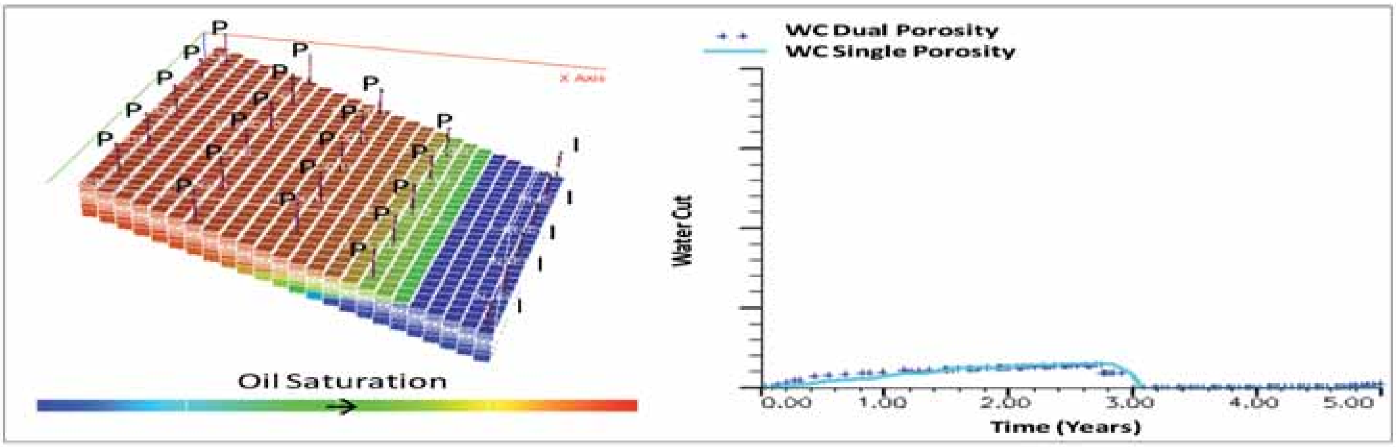


Fig. 6a. Hypothetical fractured reservoir matched with a single porosity model.

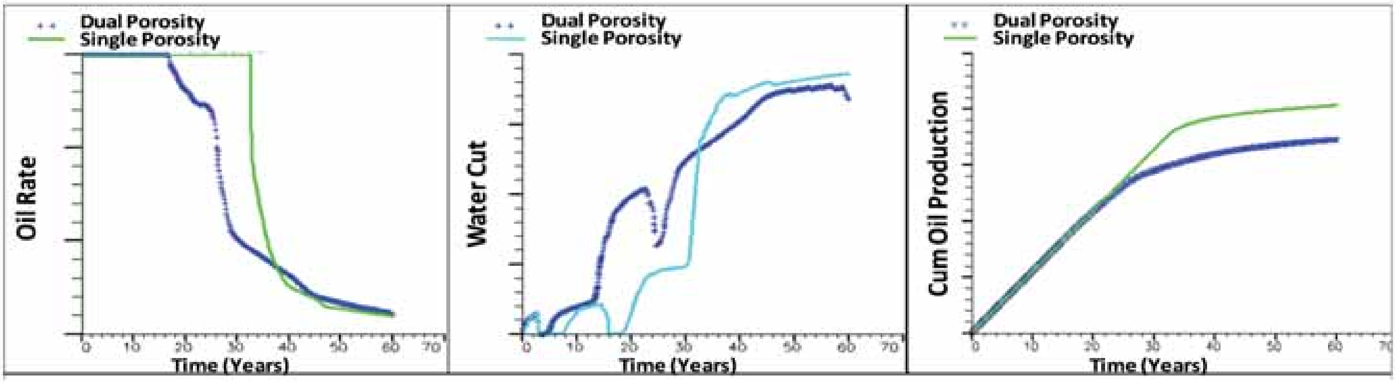


Fig. 6b. Deviation of single porosity model prediction of oil rate, water cut and cumulative oil production from fracture model.

presence can be detected during drilling operations in the form of high mud losses; and they would show on production logs as thin-but-great contributors to the total flow.

Super permeability or "Super-K" is commonly used to describe zones with higher than normal permeability values that control fluid flow or the main contribution in the vertical profile. These zones are the main pathways for fluid movement and represent important features for effective oil production; nevertheless, at later stages of production, with changes in saturation and relative permeability to water, these pathways can be preferential channels for water production reducing well productivity, and affecting sweep in the reservoir. For many years, research has been carried out to identify and operationally limit the strong effect of this permeability contrast when two-phase flow is present at wells exhibiting Super-K streaks. Use of gel treatments has been proposed and used effectively in the field for water shut-off treatments[14].

Super-K zones, as found and described in the field example for this article, correspond to stratigraphically limited units typically dominated by grain supported depositional fabrics[15]. Three different basic types of Super-K configurations can be described[15]: The strati-form Super-K, defined as a stratigraphic enclosure of high permeable facies surrounded areally and vertically by tight facies, and two kinds of open fracture Super-K fed by a permeable matrix. One is for the case when a fracture intersects the wellbore and another when faults or fractures are near, but not intersecting the wellbore.

Super-K zones vary from oolitic, skeletal grainstones and packstones to crystalline textures of partially dolomitized stromatoporoid up to massive dolomites. As stated earlier, it is clear that Super-K intervals are not necessarily distinguished by permeability magnitude, and their identification and proper mapping have to be performed with the integration of dynamic measurements, such as PTAs.

As implied by the classification of Super-K from these general assemblies, Super-K zones are not limited to a specific lithology, petrophysical rock type, or composition. Additionally, Super-K has been identified, even in intervals showing relatively low values of core permeability measurements. This is one of the most important reasons why integration of dynamic data is a key for modeling such features. A typical profile in Well-A, Fig. 5, shows porosity interpreted log and core data (Track 1), cumulative percentage of fluid contribution from production logging interpretation (Track 2), and rock type differentiation based on core description and petrophysical integration (Track 3). The figure also shows the results of matrix permeability predicted log and core data, plus the permeability profile adjusted to the PLT profile and well test interpretation (K_WT) and the reciprocal match at a 3D geological level (K_WT_Match2) (Track 4).

Conditioning Dynamic Model to Dynamic Data

Literature sources also showed that the dynamic model accuracy and history matching process benefitted from the conditioning of dynamic models to dynamic data[16-18]. Failing to incorporate the dynamic data can lead to inaccurate simulation models, even if the history match captures the total rates at the wellhead. This inaccuracy could go unnoticed for a long time until the field performance starts to deviate from the dynamic model predictions.

To illustrate this point, a hypothetical fractured reservoir simulation case was constructed in this work and run to generate a water cut signature with over five years of production history. The dual porosity model, which contained five injectors and 21 producers, was then converted to a single porosity model. The objective is to mimic a real case, where a dual porosity signature was noticeable only through well test results, but the modeler decides to ignore the dynamic data since no hard evidence of fractures were found. This means that the reservoir is treated as a single porosity system. By modifying the reservoir permeability distribution, it is possible to obtain a history match using the single porosity simulation model, Figs. 6a and 6b. Although the single porosity model matches the 5-year field water cut performance of the dual porosity model, it fails to predict the future performance (oil rate, water cut and cumuli- tive oil production) accurately, resulting in the wrong cumulative oil production forecast, Fig. 6b. This happens because the fractures were not represented in the model, neither as a separate fracture system, nor as permeability streaks in the single porosity model.

The main objective of the dynamic data integration process is to integrate reservoir related properties and characterization, observed or measured through dynamic processes, into the reservoir numerical model, either at the geological model construction phase or as a conditioning step after the dynamic model construction. This will ensure the dynamic model incorporates features that otherwise would have been missed by conventional logs and cores, such as fractures, faults and thin Super-K zones. Another benefit from this process is reaching a better quality history match in a shorter time.

Conditioning the permeability distribution in the reservoir model to observed dynamic data can be done in a number of ways, depending on the level of reservoir heterogeneity. Subsequently, before deciding on which method to use, one needs to assess the level of differ- ence between the static model permeability and the PTA permeability at the well locations. If a consistent ratio between the two values is observed, then conditioning the dynamic simulation model becomes an easy exercise.

For a homogeneous reservoir, similar to Reservoir A in Fig. 4, a global and simple average permeability multiplier might be all that is needed. A Reservoir B type might require two average multipliers for the top and bottom portions of the reservoir, which could be esti- mated through targeted zonal testing, such as drill stem testing (DST).

If the test to model permeability ratios vary significantly from one well to another, then a permeability ratio or kh ratio map would perform better than one average multiplier for the entire reservoir model. Figure 7 shows an example of a kh ratio map for the field case in this work. Figure 8 demonstrates the improvement in the history match quality, for the field case, after conditioning the dynamic model permeability to the

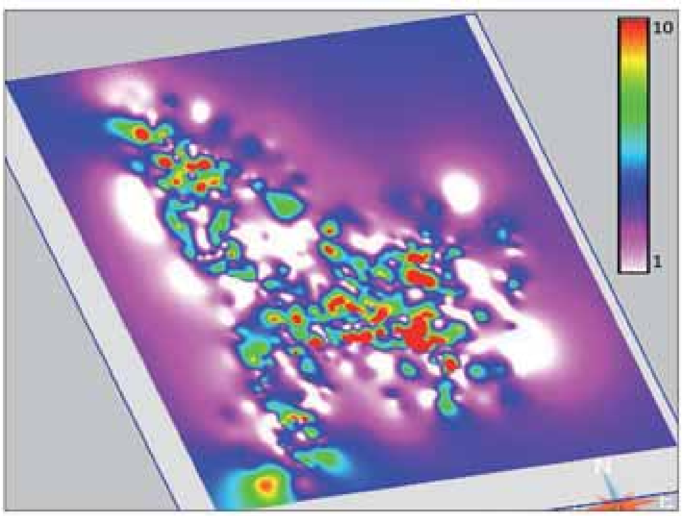


Fig. 7. Example for a PTA/model kh ration map for current field case.

PTA values using both the single value average and the PTA-to-model kh ratio map. As shown in the plot, while both methods help in improving the history match quality, using a map of the kh ratio values in the model area gives a better match than using one average value for the entire model.

The level of details added to the permeability conditioning process can increase as required by the case at hand. One example is to combine the two scenarios above, that is for a reservoir with distinct vertical zonation, such as type B in Fig. 4, and where the PTA to model kh ratios vary significantly from one well location to another. In such a case, a combination method is used to produce a kh ratio map per reservoir unit or zone. Of course, this would require more input data and detailed PTA testing and analysis. Figure 9 gives an example of using PLT profiles as a guide to generate permeability multiplier values for various reservoir zones that are then used to generate zone specific maps of kh multipliers.

Figure 10 shows porosity, permeability and production logs for one well in a large carbonate Middle Eastern reservoir, which is the subject of this work's field case. The reservoir is highly heterogeneous, as indicated by the porosity and permeability logs, with evidence of the presence of thin Super-K zones from production logs, as well as fracture lineaments from image logs and production data. The locations of the Super-K zones vary both vertically and laterally from

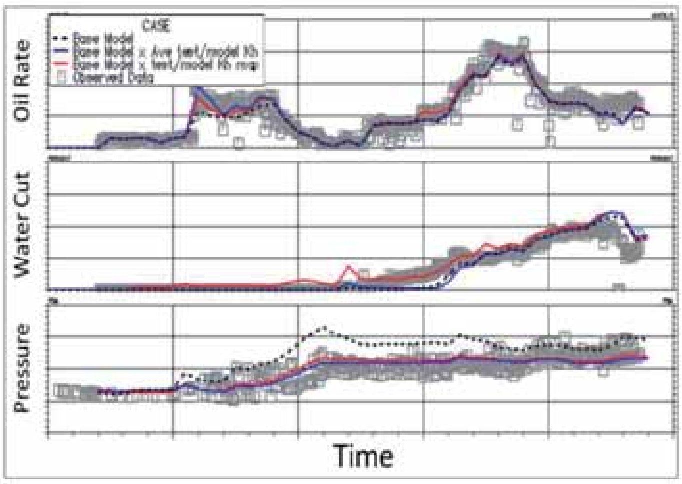


Fig. 8. Conditioning model permeability to PTA values improves history match performance.

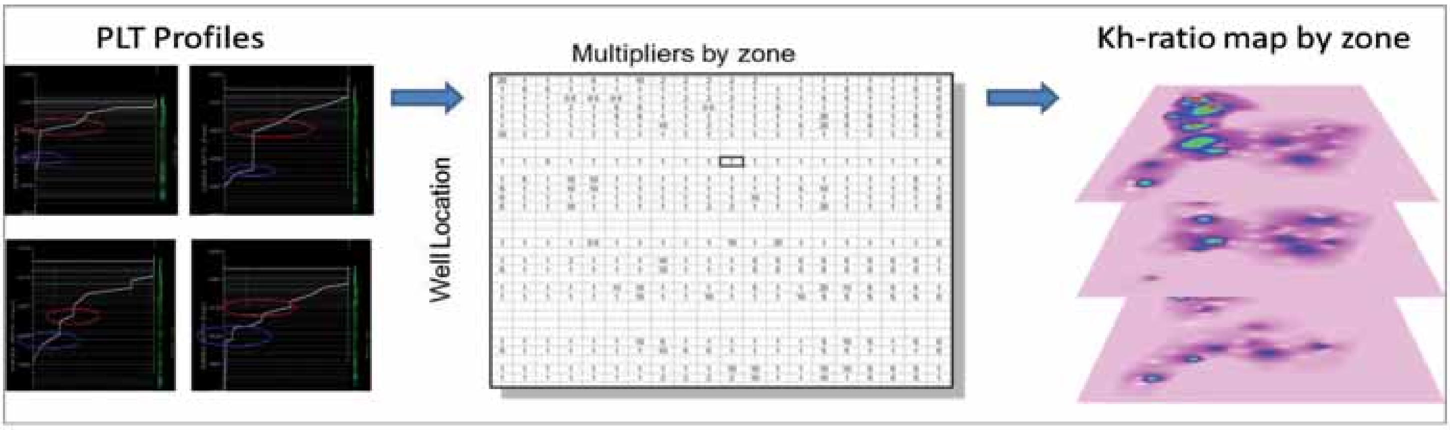


Fig. 9. Example process for generating kh-ratio map by zone for dynamic model permeability conditioning.

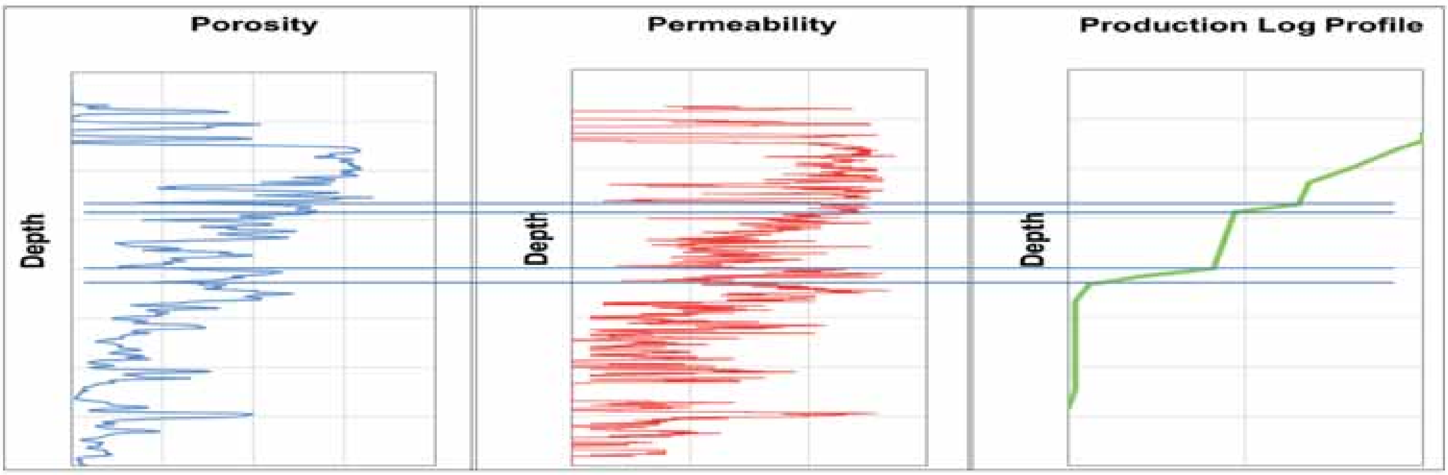


Fig. 10. Example well logs from a heterogeneous carbonate reservoir with super-permeability streaks.

one well to another. Core results would often fail to capture these zones of extremely high permeability and fragile rock structure (loss of core recovery). Reservoirs that have this type of heterogeneity will require a more elaborate effort to capture true permeability distribution. Extensive pressure testing, production logging and fracture characterization work is required to properly model permeability distribution in the reservoir. Conditioning the permeability distribution will require the use of PTA derived perms, for the total reservoir kh, and PLT profiles for distributing the kh values vertically within the reservoir.

PTAs and PLTs need to meet several conditions before proceeding with this type of permeability conditioning:

1. The pressure test results need to be valid. In cases where there is more than one test with different kh results, the engineer must decide which test is representative of the average reservoir conditions around the well, and explain why one test shows a different value for kh than the other.

2. PLTs must be from the same pressure transient tested wells.

3. PLTs should be dry oil to avoid issues related to relative permeability and fluid mobility differences.

4. All tests are preferred to be open hole with full completion across the entire reservoir. Perforated wells could suffer from partially or fully plugged perforations, which might appear as nonproductive reservoir sections on PLT profiles.

5. The engineer needs to pay attention to other reservoir conditions that might influence PTA and PLT survey results, such as pressure drainage or pressure maintenance in the reservoir, faults and baffles and wellbore skin.

Figure 11 is an example of the impact of the conditioning core based permeability logs to dynamic data (both PTA permeability and PLT profile) for one of the field case wells. The results, and the magnitude of difference between the original and final profiles, illustrate how important this type of work is in defining the proper permeability distribution in the wells, espe- cially when dealing with Super-K zones; however, conditioning the core based permeability logs at the wells to PTA and PLT profiles is only the first step in this process.

The second and most important step is proper distribution of the permeability profiles away from the wells where no data is available. It is one thing to get the right permeability distribution at the well, but without proper distribution in the reservoir, the dynamic model will fail to capture the proper fluid flow mechanism between wells, and the history matching process will prove to be iterative and lengthy, and might result in an inaccurate final reservoir model.

On the other hand, proper distribution of per- meability away from the control points, as will be discussed in the field case example, will result in a faster and less iterative history matching process. In fact, proper distribution of matrix permeability will require no further modifications, and the focus will shift to other factors affecting the history match.

Geologists must analyze the primary permeability profile in terms of syndeposit trends as the primary population of matrix permeability controlled by facies distributions and original fabrics. Diagenetic processes that affect preferential zones of the reservoir at discrete intervals can develop super permeability stratiforms. By recognizing such intervals in the vertical section, the reservoir modeler should correlate and populate zones of permeability enhancement collocated to permeability and facies distribution. The general assumption is that post deposition alterations are

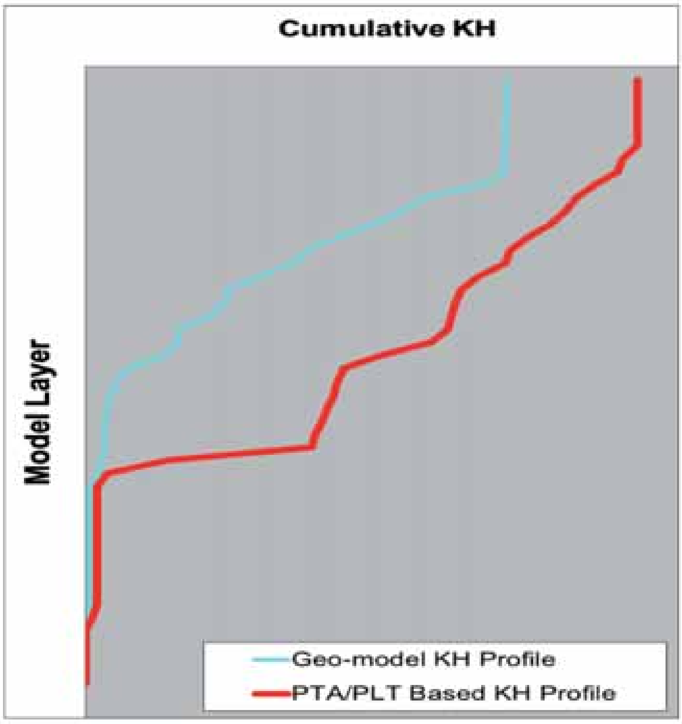


Fig. 11. Impact of conditioning log-permeability distribution to PTA and PLT results.

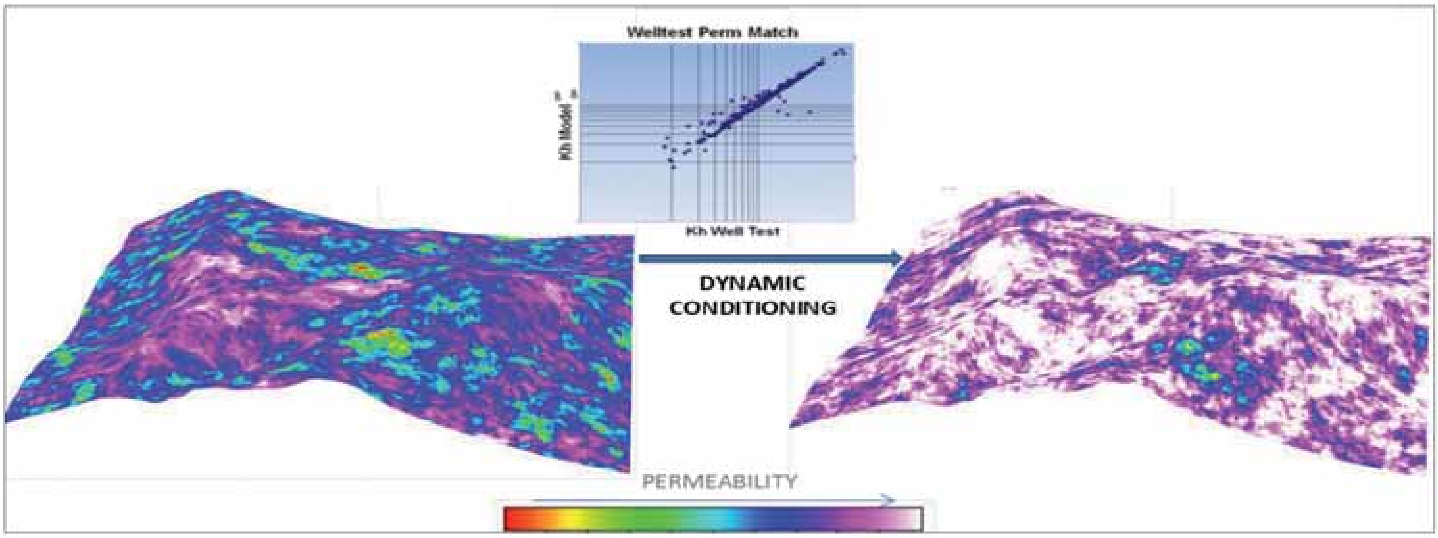


Fig. 12. Log and core porosity data and the results of permeability profile conditioning to production log data.

transforming rock properties laterally and those effects can be modeled in the stratigraphic domain.

From this, a permeability profile constrained to dynamic data should generally be modeled following the stratigraphic definition and collocated to matrix permeability. Diverse algorithms and techniques are recommended to be applied and tested under fluid flow simulation. Final models evaluated at simulation stages for the evaluated field example included kriging with drift, cloud transformations, and collocated (to matrix per- meability) cokriging approaches. Figure 5 (right) shows a cross section at Well-A with the results of the matrix permeability model and after dynamic conditioning. Figure 12 illustrates the result of a selective layer at a typical Super-K location in the reservoir, prior and after permeability conditioning. All possible scenarios were evaluated after granting a very close match of the final model kh against the representative kh from the well test.

The extension (ranges) of correlation of the semi-variograms to be used under kriging is an important variable to try under sensitivity analysis and fluid flow evaluation. In the case study for this giant Middle Eastern reservoir, the high density of wells made the analysis less uncertain and helped in the determination of the best values to represent vertical and lateral correlation. For this particular case, Super-K zones seem to be very extensive and represent major hydraulic units. Due to a very thick reservoir column at a high structural point compared to free water level, most of those Super-K units represent key paths for oil productivity. Nevertheless, their presence at levels close to free water can produce preferential paths for water overrunning and generate early breakthrough at peripheral wells. The conditioning achieved allowed us to match field and well productivity and water cut in a very robust way that was explained by the static properties' distribution with a standardized lab derived relative permeability curves.

Geo/Sim Model Considerations

When building a dynamic reservoir model for a heterogeneous reservoir, it is important to remember that maintaining the detailed geological characterization will require proper dynamic model layering. Excessive upscaling will likely dissolve much of the fine geological details that influence the flow dynamics in the reservoir. The same can be said about the areal grid size. On the other hand, having too many cells in the model, beyond the minimum required to capture the geological details, will slow down the simulation runs, especially for non- parallel simulators. Therefore, while giving priority to the model's accuracy, the engineer must keep a proper balance between the number of cells in the model and capturing the details in the reservoir.

For those reservoirs with fewer PLT surveyed wells than pressure tested wells, the modeler can use the radius of influence and proper geological setting in the modeling software to extend the permeability distribution from the wells with both PTA and PLT surveys to those with PTA only. Various realizations should be con- structed, and then tested with dynamic simulation. A proper permeability distribution will result in a good percentage of the wells matching the historical data after the first simulation run. Assuming no other significant factor has been missed, a low percentage of wells matching the observed data can be treated as an indication of an improper permeability distribution between the wells.

Field Example

The field case is a giant fractured carbonate reservoir. The fractures in the reservoir exist in the form of lineaments (or joints) extending for tens of kilometers, and provide a permeability assist to a reservoir with an already remarkable productivity. The reservoir matrix is very heterogeneous, and is divided into several zones vertically, each with variable properties and rock types. Typical well logs from the reservoir are shown in Figs. 5 and 10. Log permeability was calculated using artificial intelligence methods and matched to the core measured permeability.

The upper part of the reservoir is very permeable, with permeability values in the matrix approaching fracture permeabilities. Very high permeability and Super-K streaks exist in the reservoir. The number of the streaks, vertical placement, and the areal extent of these high permeability zones vary from one location to another in the reservoir. Conventional logs and cores are unable to capture most of these low-thickness Super-K zones, and can only be detected through dynamic data (e.g., mud losses, pressure testing and production logging) and image logs.

The large model area encompasses over 1,000 wells with long production history. The model itself is a 2.8 million grid cell model covering the study area. The large size of the model, high number of wells and the lengthy production history all demanded that global type modifications be carried out to speed up the history matching of the dynamic model. History matching through well-by-well model adjustment from start to finish would have required an extended period of time, with patchy and unrealistic modifications that do not reflect the true dynamics in the reservoir. At times, such well-by-well modifications on a very large model prove unsuccessful at the end, and fail to achieve a history match.

All the steps discussed above in the "Conditioning Dynamic Model to Dynamic Data" section were tested in this field case, in the order of their complexity. Although a group level match was achieved quickly with the application of a PTA to model kh ratio map, as pre- viously shown in Fig. 8, the well level history match statistics did not improve significantly until the model's core based permeability was conditioned using well PTA and PLT survey results, for one of the field case wells, Fig. 13.

The statistics of the well level history match improved with every method used to condition the model kh to the PTA kh values, Fig. 14. This plot, along with Figs. 8 and 13, clearly show that conditioning the model's core based permeability to the dynamic permeability will improve the results, regardless of the method of application. The figures also show that using the PTA results along with the PLT profiles offers the best method for our heterogeneous reservoir, not only because of improved statistics, but also because of the higher fraction of wells matched after the initial post- conditioning simulation run, which significantly accelerated the history matching phase.

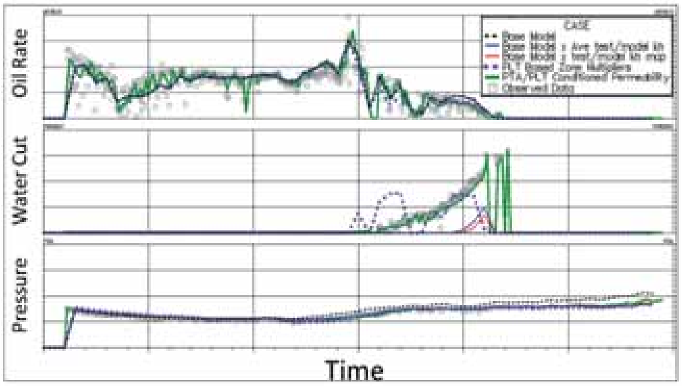


Fig. 13. Example history match quality for one of the field case wells with various permeability conditioning methods.

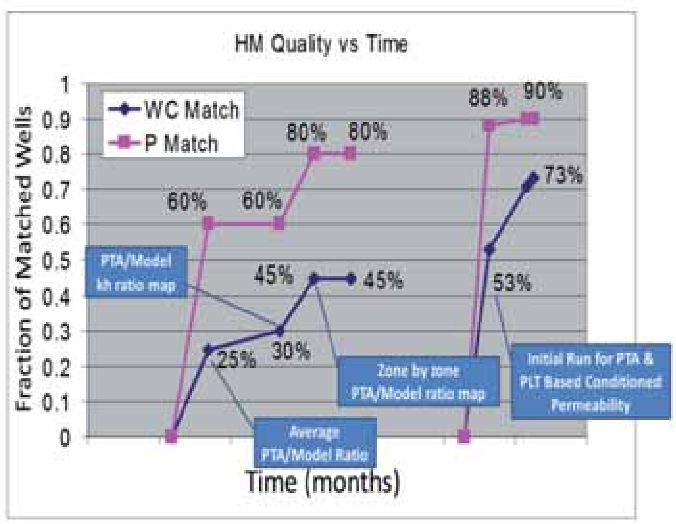


Fig. 14. History match well statistic vs. time and various permeability conditioning methods.

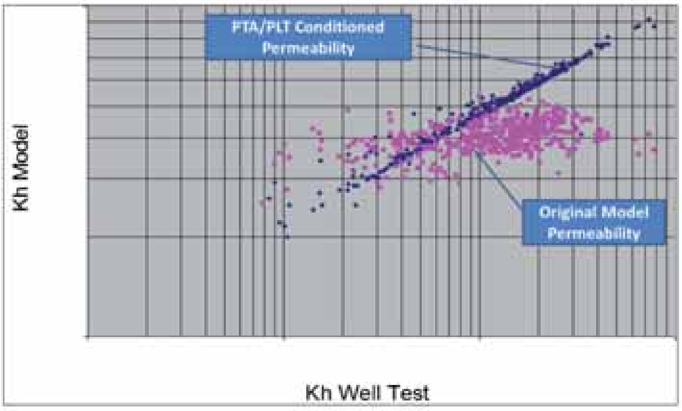


Fig. 15. Cross plot of original core-based and final PTA/PLT-based kh distribution vs. PTA kh.

When applying the simpler permeability conditioning techniques, the well's history match statistics improved slightly but stabilized very quickly. It then became a slow process of improving the history match of the remaining wells with individual and localized modifications to the matrix permeability. Obviously, the reason behind this behavior was the level of heterogeneity in the reservoir. A more homogenous reservoir would have benefitted from only a simple global average kh multiplier or a PTA to model kh ratio map.

Figure 15 shows the model to PTA permeability cross plot comparison before and after permeability conditioning. The plot clearly illustrates the improved match of the final PTA/PLT based permeability distribution to the observed well test permeability over the original core based permeability. The plot also shows that core data, due to missed core or limitation of laboratory measurements, was not able to capture the very high permeability values in the reservoir, which were measurable through pressure transient testing.

No further modification to the matrix permeability distribution was necessary once the correct permeability was achieved in the reservoir dynamic model, which led to significant savings in the overall history matching time and reduced the number of iterations required to complete the history matching phase.

Discussion

The simpler options for conditioning the dynamic model's permeability distribution, i.e., global average of model to PTA kh ratio and the model to PTA kh ratio map, re- sulted in quick improvement of the group level history match both for pressure and water cut. They also improved the well's pressure history match statistics, but did not perform as well for the water cut history match statistics. With these options, the well level history match statistics started at 10% to 15% initially, and then slowly improved to 20% to 30% with local matrix permeability modifications.

The more complex option of constructing a zone-by- zone model to PTA kh ratio map, improved the model results quickly to 45% of the well matching the observed water cut history. Nonetheless, this option was extremely time-consuming for several reasons, including having a large number of wells to work with, a highly heterogeneous reservoir and varying properties for each specific zone from one location to another within the same field. Although the results would improve for one area of the model with the next round of modifier maps, another area's history match would be lost due to the interactions in the field, and the total well history match statistics did not improve much beyond the 45%. Therefore, the next level of complete overhaul of permeability distribution was required to condition the model permeability to the actual dynamic behavior, as observed through well tests and production logging.

The field case's history match progress improved dramatically once the permeability in the model was conditioned to the PTA permeabilities using the PLT survey profiles. Several attempts at distributing the new permeability logs were attempted, but only one, as described above in the "Conditioning Dynamic Model to Dynamic Data" section, resulted in a high number (above 50%) of wells matching the observed pressure and water cut history from the initial simulation run. Once this value was achieved, no further matrix permeability modification was done, and the history matching efforts continued with focus on other features, such as fracture lineaments location, connectivity and conductivity, which were sufficient to improve the well history match statistics to over 70%.

Conclusions

This work discussed and provided examples of several options for conditioning the dynamic model permeability to PTA values, which depend on the level of hetero- geneity in the reservoir. These options varied from simple global kh ratio multipliers to as detailed as a full 3D array of multipliers based on a well-by-well profiling of PTA permeabilities using PLT survey results, and then properly distributing the permeability between the wells using proper modeling procedures.

This current field case tested all the previously discussed options, and provided some level of benefit to the history match exercise. Based on this work, the following conclusions are made:

1. Conditioning dynamic simulation models to dynamic data is important for building reliable models that represent the real reservoir dynamic conditions.

2. Several options are available for conditioning the dynamic model permeability distribution to well test results depending on the level of reservoir heterogeneity.

3. Conditioning dynamic model permeability to PTA results improves and speeds up the history matching process of newly built simulation models.

4. Conditioning dynamic model permeability to PTA results using PLT profiles improved and accelerated the history matching phase for our highly heterogeneous and fractured field case reservoir.

Acknowledgements

The authors would like to express their gratitude to Saudi Aramco Reservoir Description & Simulation Department for their support and permission to publish this article.

References

1. Odeh, A.S.: "Reservoir Simulation... What is it?" Journal of Petroleum Technology, Vol. 21, No. 11, November 1968, pp. 1,383-1,388.

2. McCulloch, R.C., Langton, J.R. and Spivak, A.: "Simulation of High Relief Reservoirs, Rainbow Field, Alberta, Canada," Journal of Petroleum Technology, Vol. 21, No. 11, November 1969, pp. 1,399-1,408.

3. Richardson, J.G. and Stone, H.L.: "A Quarter Century of Progress in the Application of Reservoir Engineering," Journal of Petroleum Technology, Vol. 25, No. 12, December 1973, pp. 1,371-1,379.

4. Harris, D.G.: "The Role of Geology in Reservoir Simulation Studies," Journal of Petroleum Technology, Vol. 27, No. 5, May 1975, pp. 625- 632.

5. Mattax, C.C. and Dalton, R.L.: Reservoir Simulation, SPE Monograph, Vol. 13, Richardson, Texas, 1990.

6. Fanchi, J.R.: Integrated Flow Modeling, 1st Edition, Amsterdam, Netherlands: Elsevier Science B.V., 2000.

7. Ahmed, U., Crary, S.F. and Coates, G.R.: "Permeability Estimation: The Various Sources and Their Interrelationships," Journal of Petroleum Technology, Vol. 43, No. 5, May 1991, pp. 578-587.

8. Haldorsen, H.H. and MacDonald, C.J.: "Stochastic Modeling of Underground Reservoir Facies (SMURF)," SPE paper 16751, presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, September 27-30, 1987.

9. Damsleth, E. and Holden, L.: "Mixed Reservoir Characterization Methods," SPE paper 27969, presented at the University of Tulsa Centennial Petroleum Engineering Symposium, Tulsa, Oklahoma, August 29-31, 1994.

10. Mezghani, M., van Lingen, P., Cosentino, L. and Sengul, M.: "Conditioning Geostatistical Models to Flow Meter Logs," SPE paper 65122, presented at the SPE European Petroleum Conference, Paris, France, October 24-25, 2000.

11. Holden, L., Madsen, R., Skorstad, A., Jakobsen, K.A., Tjolsen, C.B. and Vik, S.: "Use of Well Test Data in Stochastic Reservoir Modeling," SPE paper 30591, presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, October 22-25, 1995.

12. Blekhman, V., Diaz, D., Carrica, P., Corbett, C., Coca, B. and Gomez, U.: "Calibrating Log-Derived Permeability Data to PTA for Geostatistical Integration into a Fluid-Flow Simulation Model," SPE paper 69473, presented at the SPE Latin American and Caribbean Petroleum Engineering Conference, Buenos Aires, Argentina, March 25-28, 2001.

13. Poe Jr., B.D. and Butsch, R.J.: "Calibration of Log Permeability Models Using Fluid Flow Measurements," SPE paper 84389, presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, October 5-8, 2003.

14. Al-Dhafeeri, A.M., Seright, R.S., Nasr-El-Din, H.A. and Sydansk, R.D.: "High-Permeability Carbonate Zones (Super-K) in Ghawar Field (Saudi Arabia): Identified, Characterized, and Evaluated for Gel Treatments," SPE paper 97542, presented at the SPE International Improved Oil Recovery Conference in Asia Pacific, Kuala Lumpur, Malaysia, December 5-6, 2005.

15. Meyer, F.O., Price, R.C. and Al-Raimi, S.M.: "Stratigraphic and Petrophysical Characteristics of

Cored Arab-D Super-K Intervals, Hawiyah Area, Ghawar Field, Saudi Arabia," GeoArabia, Vol. 5, No. 3, 2000, pp. 355-384.

16. Ghedan, S.G., Boyd, D.A. and Thiebot, B.M.: "Reliable Simulation Model Permeability Arrays by Integration of Core, Test, and Log-Derived Permeability Data," SPE paper 84599, presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, October 5-8, 2003.

17. Skorstad, A., Islam, M.A. and Smorgrav, E.: "Conditioning on Effective Permeabilities from Well Tests in Geostatistical Reservoir Characterization: Real Test Case Evaluation," SPE paper 124280, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, October 4-7, 2009.

18. Khasanov, M.M., Toropov, K.V. and Lubnin, A.A.: "Calibration of Permeability Vertical Profile with Regard to Well Production Data," SPE paper 136287, presented at the SPE Russian Oil and Gas Conference and Exhibition, Moscow, Russia, October 26-28, 2010.

Biographies

Rida Abdel-Ghani is a Reservoir Engineer currently working in the Reservoir Characterization and Simulation Department of Saudi Aramco. He works within a team of professionals, responsible for carrying out reservoir simulation studies for some of Saudi Arabia's giant fields, which produce from complex fractured reservoirs. Prior to working at Saudi Aramco, Rida worked as a Reservoir Engineer for several international companies, like Talisman Energy, Anadarko, Union Pacific Resources and Norcen Energy. His oil and gas experience covers a variety of fields and locations internationally, including North America, Africa, South East Asia and the Middle East.

Rida received his B.S. degree in Chemical Engineering from Kuwait University, Kuwait City, Kuwait, and his M.S. degree in Chemical Engineering from the University of Calgary, Alberta, Canada.

Dr. Dimitrios D. Krinis is a Petroleum Engineering Consultant in the Abqaiq Reservoir Management Division of the Southern Area Reservoir Management Department. Before joining Saudi Aramco in 2000, he worked as Reservoir Engineer for AFPC in Syria. For the first 12 years of his career, Dimitrios worked for Marathon Oil and Shell in the North Sea and Malaysia as a Petroleum Engineer involved in various projects, including field development, reservoir simulation, fluid characterization, well testing and marginal oil and gas prospect evaluation.

He received his B.S. and M.S. degree in Mining Engineering from the National Technical University of Athens, Athens, Greece, in 1985, and then received his Ph.D. degree in Petroleum Engineering from Heriot-Watt University, Edinburgh, Scotland, in 1989.

Jorge E. Nieto Camargo is a Reservoir Geologist and Modeler in the Geological Modeling Division, part of the Reservoir Characterization Department of Saudi Aramco. He has more than 20 years of experience in reservoir characterization and geostatistical modeling with specific interest in dynamic data integration.

Jorge received his B.S. degree in Geology from the Universidad Industrial de Santander, Bucaramanga, Colombia. He then went on to receive two M.S. degrees, one in Geological Sciences from the University of Texas, Austin, TX, and the other in Petroleum Engineering from Texas A&M University, College Station, TX.

Jorge is a member of the American Association of Petroleum Geologist (AAPG) and the Society of Petroleum Engineers (SPE).

Enabling High Efficiency Direct Injection Engine with Naphtha Fuel through Partially Premixed Charge Compression Ignition Combustion

By Dr. Junseok Chang, Yoann Violet, Dr. Amer A. Amer and Dr. Gautam T. Kalghatgi.

Abstract

More stringent emissions standards along with higher fuel economy demands have obliged auto makers to develop technical solutions that exploit synergistic features from gasoline and diesel engines. To minimize NOx (a combination of nitric oxide and nitrogen dioxide) and soot trade-off, diesel powertrains have evolved to adopt increasingly complex and expensive technology, such as extremely high-pressure fuel injection systems, low-pressure exhaust gas recirculation (EGR), and variable valve timing. These attempts are associated with promoting partially premixed charge compression ignition (PPCI) combustion via increasing mixing time and ignition delay. Alternatively, PPCI combustion can be achieved easier by using fuels with higher resistance to auto-ignition than conventional diesel fuel. Previous work has demonstrated the possibility of reducing the cost of future diesel after-treatment systems by using gasoline-like fuels. In this study, we start with a 0.5 liter single cylinder direct injection spark ignition (DISI) engine and demonstrate that fuel economy can be improved significantly by running it in PPCI mode. Naphtha, a less processed refinery stream in the gasoline boiling and carbon number range, but with a lower octane number, has been run in a 12:1 compression ratio single cylinder engine with a DISI fuel system and shallow oval type bowl piston. Both light and heavy naphtha were successfully run in PPCI mode with regular valve events and intake charge boosting at six engine running conditions representative of a typical urban driving cycle including idle. A very low NOx level was achieved through high EGR and advanced injection timings to segregate the fuel injection from heat release. When compared to a Stoichiometric spark ignition operation with optimal valve timings, a 19% weighted cycle average fuel consumption reduction was achieved. This result demonstrates that an engine equipped with a low cost DISI system could offer noticeably better efficiency through PPCI combustion, especially when run with naphtha, which can provide lower CO_2 emissions in the refinery. Although further work is needed to develop a practical engine, high efficiency, reduced system cost and overall CO_2 footprint benefits can be achieved by matching the fuel and the combustion system.

Introduction

Spark ignition (SI) engines are much less efficient than compression ignition (CI) engines because they encounter throttling losses under part-load operation, cannot be operated with lean mixtures and their compression ratio is limited by knock. Practical CI engines, i.e., diesel engines running on diesel fuels are very efficient but have high NOx (a combination of nitric oxide and nitrogen dioxide) and particulate emissions. This is because practical diesel fuels are very prone to auto-ignition and ignite soon after the start of injection (SOI), well before the fuel has had a chance to mix properly with the oxygen in the cylinder. This causes combustion to occur in mixture packets, which are fuel- rich and leads to high soot (particulates) and NOx formation.

The requirements to control NOx and soot are becoming more stringent. Soot formation can be mini- mized by ensuring that fuel and oxygen are well mixed — the equivalence ratio, □, of the mixture packets where combustion occurs should not be exceed □ >~21. Even if soot is formed, if there is sufficient oxygen and the temperature is high enough, it will be oxidized inside the cylinder and engine-out levels will be low. On the other hand, NOx formation can be minimized if the combustion temperatures are kept below 2,200 K[1]. This can be achieved by using high levels of exhaust gas recirculation (EGR); however, high EGR reduces the in-cylinder oxygen content and combustion temperature, which reduces soot oxidation as a result. Therefore, soot formation needs to be avoided. Indeed, much of the advanced technology used in modern diesel engines is aimed at promoting a premixed combustion to avoid soot formation by overcoming the low ignition delay of diesel fuels. For instance, very high injection pressures are used to increase the mixing rate. Even then diesel engines would require after-treatment systems to further reduce NOx and particulates to meet ever tightening emissions regulations, making them even more complicated and expensive. Moreover, some of these measures, such as regeneration of particulate traps, would reduce the fuel efficiency of the engine.

Kalghatgi and co-workers[2,3] demonstrated in a 2 L single cylinder engine, that if fuels with high resistance to auto-ignition, such as gasoline, are used in diesel engines, auto-ignition occurs significantly later after the SOI at a given operating condition. The gasoline fuel has to be injected significantly earlier compared to the diesel fuel to get the same combustion phasing. This makes simultaneous control of NOx and soot much easier. If the same amount of gasoline is injected much earlier at the same conditions, i.e., with fully premixed conditions as in homogeneous charge compression ignition (HCCI), ignition might not occur at all. Therefore, the inhomo- geneity is essential to ensure combustion but the high ignition delay makes combustion happen when fuel and air are better mixed – fuel and air are "premixed enough" but must not be fully premixed. Similar studies have been conducted in a smaller single cylinder engine of 0.537 L displacement and at engine speeds up to 3,000 rpm[4-8]. Groups from Lund[9-11], Wisconsin[12,13] and Cambridge[14,15] universities have also demonstrated the benefits of running diesel engines on gasoline-like fuels.

In summary, NOx and smoke can be controlled simultaneously at much higher loads, compared to diesel fuels, if a diesel engine is run on gasoline-like fuels because premixed combustion is facilitated by the high ignition delay. In light duty engines this offers the potential for downsizing and/or down-speeding[2,9-13]; indicated thermal efficiencies of over 50% are reported[10]. At low loads, significantly lower pressure rise rates[4-6,8,14,16] and NOx can be obtained with gasoline[4-6,8]. In light duty engines, this could be exploited to further increase efficiency by avoiding enabling strategies, such as pilot injections, that are used to mitigate noise at light loads with diesel fuel. Also, in such combustion systems, the after-treatment focus is shifted to hydrocarbon and carbon monoxide (CO) control rather than NOx control with great potential for cost saving. Moreover, the octane number and the volatility of the gasoline for such com- bustion systems could be much lower compared to current market gasoline[5-8]. This might lead to significant savings in energy and CO_2 in fuels manufacture. Subsequently, there is a huge potential to develop combustion systems using gasoline-like fuels in CI engines, which are at least as efficient and clean as current advanced diesel engines but would be significantly cheaper and in the long-term, could use fuels which are easier to make than current fuels.

All the work just cited has been done with high-pressure diesel injection systems; however, when mixing is facilitated by the high ignition delay, high injection pressures are not needed. Indeed, at low loads the challenge is to avoid over-mixing and over-leaning, which lead to high hydrocarbon and CO emissions and lower injection pressures are in fact preferable[5-7]. It is also likely that larger injector holes are preferable. There is a lot of scope for simplifying and optimizing the injection system and injection strategies using gasoline in a CI engine – a recent attempt in this direction is described[17]. A worthwhile attempt would be to run an engine using gasoline as the fuel in CI mode to achieve high efficiency not attainable in the SI mode but with an injection system far cheaper than in an advanced diesel engine.

In this work we demonstrate that an engine with a compression ratio of 12 and equipped with a low-pressure direct injection spark ignition (DISI) architecture can be run on gasoline-like fuels in CI mode with much better fuel efficiency than is achievable in SI mode. Two refinery streams, light naphtha and heavy naphtha, are used in CI mode; these streams would be significantly simpler to produce in a refinery compared to gasoline. These preliminary results offer the possibility of developing an engine with much better efficiency than an SI engine but without increasing the cost to the level of advanced diesel engines by using an appropriate fuel.

Cylinder	1
Number of Valves	4
Displacement (cm^3)	499
Bore (mm)	84
Stroke (mm)	90
Compression Ratio	12
Fuel Injector	Outwardly Open Piezo-Electric
Fuel Pump/Range	External Motor Driven/ 40-150 bar
Intake System	Conditioned Air with External Boost
External EGR Line	Uncooled High-Pressure Line
Exhaust System	No Catalyst (Back Pressure Control Valve)

Table 1. Single cylinder engine specifications.

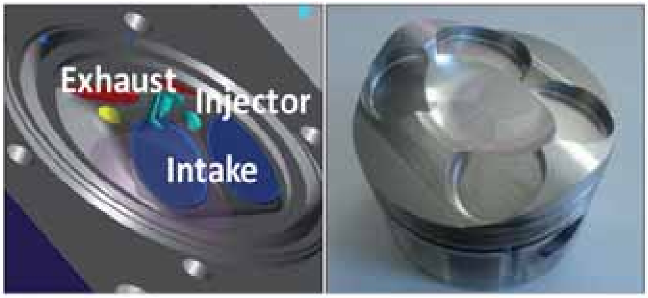


Fig. 1. Tested combustion chamber shape: Pent-roof style 4-valve head (left), piston with valve-cut and shallow oval bowl feature (right).

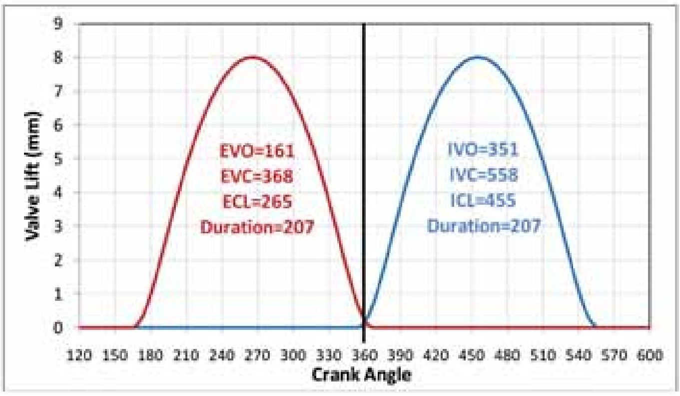


Fig. 2. PPCI valve lift profile: 8 mm peak lift, no variable valve timing with minimum valve overlap.

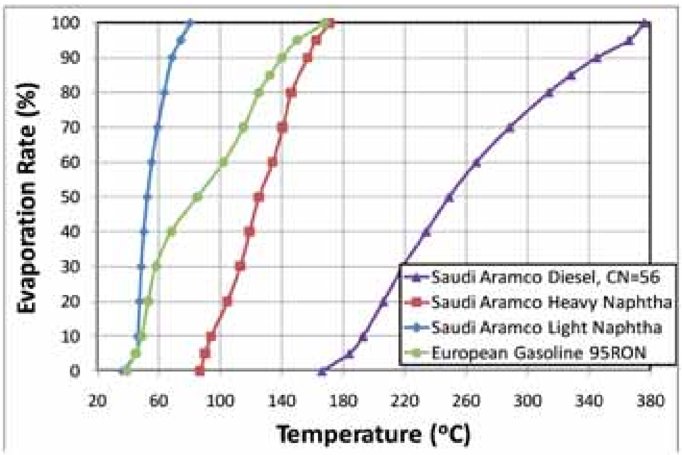


Fig. 3. Evaporation curves using ASTM D86 method: Light and heavy naphtha vs. production gasoline and diesel fuels.

Obviously, a practical engine would have to meet all the other requirements on emissions, noise, start-up ability and transient operation and this would require significant development work. The results presented in this article offer further justification for undertaking such development.

Experimental Setup

A single cylinder four valve engine with a 12:1 geometric compression ratio is used in this investigation. Table 1 shows details of the engine specifications. The combustion chamber is originally designed to accommodate stratified charge SI combustion. An outwardly opening piezo-electric production gasoline direct injector is centrally mounted adjacent to the spark plug. In partially premixed charge compression ignition (PPCI) combustion tests, the spark is disabled. As can be seen in Fig. 1, the injector is located between two intake valves and slightly skewed from the vertical direction. Fuel is introduced by an outwardly opening piezo-electric injector with a hollow cone spray. Spray is more widely distributed and less penetrated compared to a spray jet style multi-hole type gasoline direct injector. The operating fuel injection pressure range is 50-150 bars. Because fuel injection pressure is about 10 times lower than conventional diesel injector, spray atomization and penetration are expected to be quite different. In the case of PPCI combustion when fuel injection timing advances from top dead center (TDC), bulk mixing in the bowl is more dominant during the entire burn and control of air fuel ratio (A/F) in the piston bowl is important. For the purpose of accommodating the stratified burn, the piston has a very shallow and oval shape bowl, Fig. 1. This is very different from a conventional diesel engine piston bowl shape. Both the injector and piston design might not be optimum for PPCI combustion. Never- theless, the engine could be run in PPCI mode with naphtha with significant improvements in efficiency compared to the SI mode. Lower octane fuels with existing hardware can be used to get PPCI combustion.

PPCI testing reported in this work was done with fixed intake and exhaust valve events and symmetric lift profiles (8 mm peak lift and 207° crank angle (CA)

Fuel Name	Saudi Aramco Light Naphtha	Saudi Aramco Heavy Naphtha	Saudi Aramco Gasoline 91 RON
DCN from IQT	34	41	16
RON	66	62	93
MON	62	58	84
Sensitivity	4	4	9
Specific Gravity	0.66	0.73	0.74
Gross HV, MJ/kg	42.6	45.2	42.3
Low HV, MJ/kg	42.2	44.9	41.9
Normal Paraffins %	53.3	34.8	20.8
Iso-Paraffins %	39.6	35.3	30.3
Aromatics %	0.9	11.5	30.6
Naphthenes %	6.2	17.9	4.5
Olefins %	0.0	0.5	0.9
Oxygenerates %	0.0	0.0	12.3
Sulfur (ppm)	<20	<20	17.3

Table 2. Fuel analysis result: All Aramco refinery in Saudi Arabia

duration), Fig. 2. This is considered to be similar to conventional production diesel valve lift profiles, in contrast with HCCI multistep valve trains. Therefore, no negative valve overlap or re-breathing techniques were used in this study. An external EGR line is routed from the exhaust to the intake plenum. It is not insulated to minimize any artificial intake heating effect due to a hot EGR. An exhaust back pressure control valve is used to create pressure differential to drive the EGR.

Naphtha Fuel Properties

Petroleum based naphtha was used for PPCI combustion testing. In general, naphtha is categorized as light and heavy depending on its distillation cut. Figure 3 shows the American Society for Testing and Materials (ASTM) D86 distillation curves for the fuels used. Light naphtha boils below 70°C (this specific cut has an unusually lower range than typical light naphtha, i.e., 100°C to 110°C), while heavy naphtha boils between 75°C and 170°C. Specifically with light naphtha, this high volatility will lead to a different characteristic on fuel spray distribution compared to gasoline fuel. Spray tends to evaporate faster than gasoline so that it has less chance of wall fuel impingement. This will lead to lower particulate matters (PM) emission in conventional diesel combustion. In fact, previous publications had shown the dramatic reduction of PM emission on naphtha fuel from light duty diesel engines. Toyota and ExxonMobil[18] showed low smoke emission with naphtha fuels at part load conditions. Rose et al., from CONCAWE, Shell, Chevron, and FEV[19] demonstrated that two naphtha fuels could meet Euro 6 PM limits without the need of a diesel particulate filter after treatment over the new European driving cycle. Soot can also be eliminated if the ignition delay is high even if the fuel is in-volatile and has high levels of aromatics[6, 8].

Since naphtha is used as a feedstock of high octane gasoline, its carbon number overlaps with gasoline fuel. Namely, light naphtha has 5-6 carbon atoms, and heavy naphtha has 7-9 carbon atoms. Detailed fuel analysis is shown in Table 2. While light naphtha has mostly paraffins, heavy naphtha has around 12% of aromatics and olefins. The Research Octane Number (RON) and Motor Octane Number (MON) are 66 and 62 for light naphtha and 62 and 58 for heavy naphtha, respectively. The derived cetane number (DCN) is measured by ignition quality tester following the ASTM D 6890 method. DCN for light and heavy naphtha are 34 and 41, respectively. This is lower than typical diesel fuel (CN = 51 for EN590 European diesel, CN = 45 for U.S. ultra- low sulfur diesel, No. 2) and will be expected to provide longer ignition delay than market diesel fuels.

Other properties of naphtha may be a concern with engine hardware compatibility. For example, lubricity is a big factor that affects fuel injection system wear. A standard test method for the scuffing load ball-on-cylinder lubricity evaluator is commonly used to measure lubricity by ASTM D 6079. Although naphtha is consid- ered a relatively new fuel replacement for CI engine application, extensive studies have been done to improve lubricity of dimethyl ether (DME), which also has a poor lubricity, as a replacement of diesel fuel in early 2000. Many publications and products demonstrated that lubricity can be achieved via the use of a high con- centration of lubricity additives. The same lubricity enhancer has been applied regarding naphtha fuel engine testing, and it has been shown that a very small percent of lubricity additive works very well without changing the fuel's other properties. Viscosity affects fuel spray atomization, fuel system lubrication, and fuel system leakage. Kinematic viscosity (by ASTM D 445) of heavy naphtha is 1.04 mm^2/sec at 40°C, whereas typical diesel fuel is 2.0-3.5 mm^2/sec at 40°C. For comparison, kinematic viscosity of biodiesel is 6.0 mm^2/ sec, Fischer Tropsch diesel is 3.57 mm^2/sec, DME is 0.35 mm^2/sec, and methanol is 0.6 mm^2/sec at 40°C. Current European specification limits 2-4.5 mm^2/sec for diesel fuel application. Finally, fuel stability is a concern for naphtha fuel due to its low distillation characteristics. Stability properties, including oxidation, storage, and thermal stability tests have to be thoroughly investigated before marketing the fuel.

In summary, whether naphtha is a practical fuel depends on whether an engine is developed to use it. Blending is necessary at a refinery to finalize the specified CN and evaporation characteristics based on the customer's request. This request has to be decided based on the best engine and fuel matching. After the crude distillation unit, both straight run light and heavy naphtha are produced by the hydro-treating process after reducing the sulfur level (sweetened naphtha). Yield of straight run naphtha (directly from the distillation unit) varies depending on crude type, for example, about 30% naphtha can be produced with Arab Light crude oil. Also, the hydro-cracking unit yields approximately 18% of total hydro-cracking products. This is already sweetened (without sulfur), so it directly goes to use for high octane gasoline fuel feed. The Reformer unit produces high octane reformates from naphtha feed-stock, however, it incurs high operating cost and energy. The benefit of using naphtha as a primary fuel for CI combustion is due to simpler and less refinery processing. For example, it has been reported18 that 7% more CO_2 emission reduction at the power train is required if the octane number of fuel is increased from 95 to 103 at the refinery due to the refinery efficiency change. Synergy can be sought when naphtha fuel is proved to be a good candidate for CI combustion, with both improved well-to-tank and tank-to-wheel efficiencies.

Data Acquisition System

Combustion data is measured using Kislter pressure sensors and charge amplifiers along with a Leine and Linde 500 series CA encoder, Table 3. The sampling resolution was adjusted to 0.3°CA. indicated mean effective pressure (IMEP) net mean effective pressure (NMEP), pumping mean effective pressure (PMEP), heat release rate and mass fraction burned are calculated with CAS using the commercial formulas.

Emission and EGR data are obtained through the Horiba MEXA-7500D-EGR. Exhaust gases are sampled with heated lines at 190°C. NOx and hydrocarbon are measured in wet condition. The A/F as well as EGR rate is calculated by the Horiba emission bench. Lambda is calculated using the Brettschneider/Spindt formula and the EGR calculation assumes an ambient air containing 400 ppm of CO_2. The EGR rate refers to the volume fraction of exhaust gases found at the intake as a percentage of the total inlet charge. The exhaust temperature is measured via a K type thermocouple,

Measurement	Location	Type
Intake Pressure	200 mm back of valve	4045A (piezo-resistive)
Cylinder Pressure	Flush mounted Yellow spot in Figure 1	6061B (quartz water cooled)
Exhaust Pressure	160 mm back of valve	4045A (piezo-resistive water cooled)

Table 3. CA resolved sensor description.

	Engine Speed (rpm)	Engine Torque (N-m)	Engine Power (kW)	Fraction of Total Fuel (%)	Engine BMEP (kPa)	Estimated FMEP (kPa)	Estimated NMEP (kPa)
Idle	800	10	0.8	8	63	40	103
Zone 2	1,130	22	2.6	22	140	45	185
Zone 3	1,500	49	7.6	16	305	55	360
Zone 4	2,000	32	6.7	18	200	60	260
Zone 5	1,935	77	15.6	25	484	57	540
Zone 6	2,620	92	25.3	11	581	69	650

Table 4. Steady-state engine points for fuel economy evaluation.

whereas all other temperatures are measured thanks to PT100 thermocouples. Engine coolant and lubricant temperature is maintained at 90°C. Intake air supply to the engine is adjusted to 30°C without EGR activation and from that point increases gradually as a function of the EGR rate. A Siemens DI1.5 flow meter relying on the coriolis principle measures the fuel mass flow supplied to the engine. On the other hand, the airflow measurement is covered by the ABB SensyFlow hotwire mass flow meter.

Results and Discussion

The purpose of the work is to identify the potential of fuel consumption reduction with minimum engine-out NOx emission for regular gasoline direct injection engine architecture without adding extra cost and hardware. Six steady-state engine load points (zones) in Table 4 are established to evaluate driving cycle averaged fuel economy with engine dynamometer test results. These part load points, including idle, are selected to represent urban driving. The total consumed fuel mass is calcu- lated using each point's fuel consumption multiplied by the fraction of total fuel. This weighted fraction is obtained by simulating the federal test procedure (FTP) 75 city driving cycle based on an imaginary vehicle with 3,500 lb weight, automatic transmission and a 4 cylinder 2.0 liter engine. This methodology will be applied when fuel consumption comparison is made between two different combustion modes, i.e., PPCI lean A/F and DISI Stoichiometric A/F. The comparison will be presented in a later part of this section. Since a single cylinder engine is used for this study, comparisons are made based on indicated measurements. As can be seen from Table 4, net IMEP (NMEP) is obtained from assuming FMEP at each engine speed, and pumping loss is also considered with controlling exhaust back pressure. In this study, 15 kPa delta pressure is main- tained across the six different Zones.

Table 5 indicates threshold values when the engine operates with PPCI combustion mode. The primary target for NOx emission is driven by near future emission regulations, such as, 0.06 gNOx/km in Euro6 (2014), or 0.05 gNOx/km in Tier 2 Bin 5. Assuming the system still requires a small de-NOx catalyst, engine-out NOx constraint is set under the Emission Index of NOx = 2.5g NOx/kg fuel, or ISNOx = 0.5 g/kWhr. Regarding the engine combustion noise, the maximum pressure rise rate is limited up to 5 bar/CA average from 300 individual cycles. This number is defined by an audible noise level monitored by a microphone mounted next to engine block. A 6% covariance of IMEP (COVofIMEP) is applied regarding with combustion stability, including idle point.

Constraint	Parameter	Threshold
Engine-Out NOx	ISNOx	0.5 g NOx/kWhr
Combustion Induced Noise	Maximum Pressure Rise Rate (average 300 cycles)	5 bar/Crank angle
Combustion Stability	COV of IMEP %	6%

Table 5. Combustion system optimization constraints.

Results are divided into three parts. First, PPCI combustion with light and heavy naphtha along with the NOx reduction strategy is discussed. Second, DISI Stoichiometric A/F results are presented, and third, fuel consumption comparison is made between two combustion modes.

Injection Timing Effect on PPCI Combustion

Zone 3 from Table 4, 1,500 rpm, 3.6 bar NMEP, isused to demonstrate the effect of fuel injection timing. Conditioned intake air is applied through the test. Intake temperature is maintained at 30°C, which is measured 200 mm upstream of the intake valve. Two different intake manifold absolute pressure (MAP) settings are used (1.2 bar and 1.5 bar). These boosting levels are selected based on considering production turbocharger, as well as coping with relatively lower geometric compression ratio compared to a typical diesel engine. Auto-ignition depends on the temperature, pressure, mixture strength (local A/F) variation with time, and the fuel's ignition delay (which is related to its cetane number). Therefore, intake MAP boosting is used as a variable to alleviate the difficulty in auto-ignition caused by the low compression ratio used.

Figure 4 shows the result of the different SOI timing with the two naphtha fuels. Fuel injection pressure is kept constant at 130 bar. Heavy naphtha (DCN = 41, red and purple line) needs more retarded injection than light naphtha (DCN = 34, blue and green line), and it provides better combustion stability (lower COVofIMEP). The advancing heavy naphtha's SOI is limited by maximum pressure rise rate (MaxRise.Avg), which is constrained up to 5 bar/CA. In the case of light naphtha, more advanced injection is preferred to get proper ignition timing without having a pressure rise issue; however, excessive advanced timing causes over-mixing as well as less fuel containment in the bowl, which will result in an over-lean burn and higher

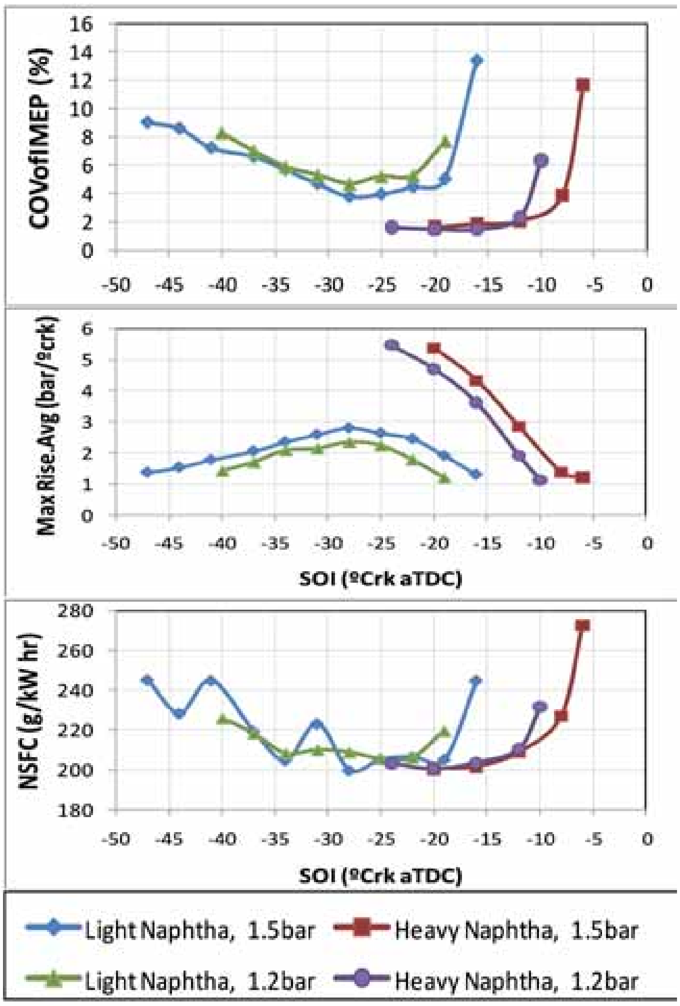


Fig. 4. Start of injection effect on combustion stability, maximum pressure rise rate, and net specific fuel consumption with 1.2 bar and 1.5 bar intake MAP at 1,500 rpm, 3.6 bar NMEP.

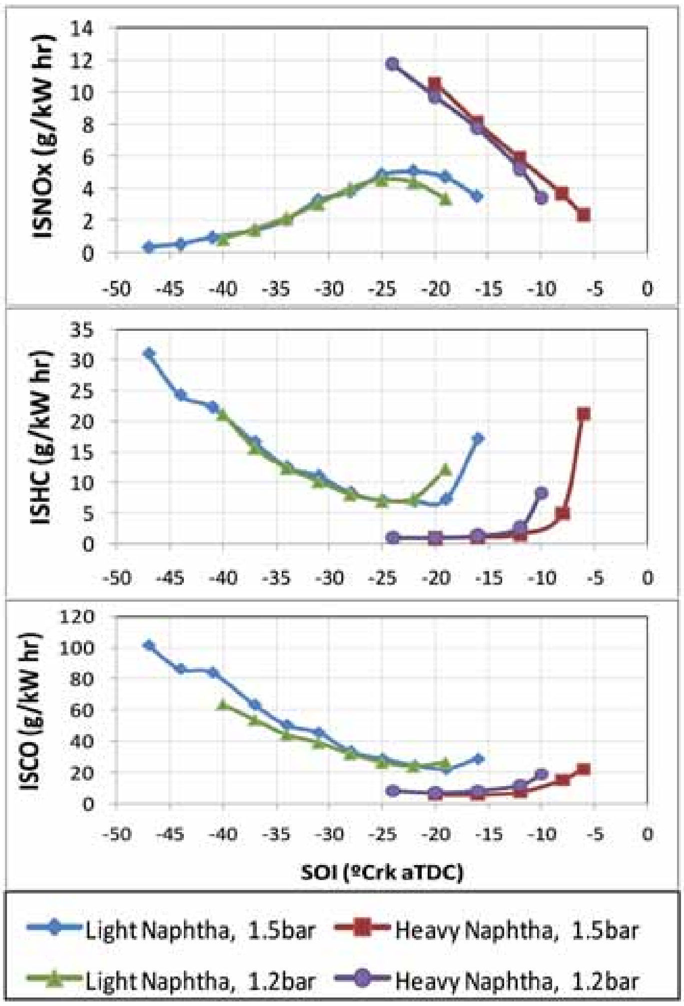


Fig. 5. Start of injection effect on emissions with 1.2 bar and 1.5 bar intake MAP at 1,500 rpm, 3.6 bar NMEP.

COVofIMEP. Based on COVofIMEP (up to 5%) and Pressure Rise Rate limit, preferable SOI window of heavy naphtha is identified between -20° to -7°CA aTDC, and light naphtha is defined -32° to -22°CA aTDC. A higher intake MAP has a small effect on COV, although light naphtha has a slight benefit. Minimum fuel consumption (shown as net indicated specific fuel consumption (NSFC)) occurs at SOI timings with stable combustion, regardless of intake MAP setting. Interestingly, higher COVofIMEP on light naphtha does not reduce NSFC significantly compared to heavy naphtha.

Exhaust emissions are presented in Fig. 5. The effect of different intake MAP from 1.2 to 1.5 bar is minimal for all emissions. This is partly because boosting the intake will increase the compression pressure at the expense of increasing A/F (more enleanment), which ultimately affects the mixture's ignitability and com- bustion progress. On the other hand, the effect of different fuels on emissions is significant. For example, NOx is generally higher for heavy naphtha and increases as SOI is advanced. With light naphtha, NOx increases until -23° CA aTDC and then gradually decreases as SOI is advanced. Hydrocarbon and CO emissions are generally lower for heavy naphtha at a given SOI than for light naphtha. Heavy naphtha with retarded SOI timings (-10° to -5° aTDC) results in high CO and hydrocarbon emissions due to short time available for mixing. Light naphtha, on the other hand, experienced poor fuel preparation and over-mixing as SOI is advanced beyond -25° aTDC). Both fuels have higher hydrocarbon and CO at extreme SOIs. When SOI is too retarded for heavy naphtha, there is not enough time for mixing, and when SOI is too advanced for light naphtha, over-mixing leads too much enleanment.

Figure 6 shows 10%, 75% and 90% mass fraction burned points. As the SOI is advanced, a 10% burn point (considered as ignition point in this article) can

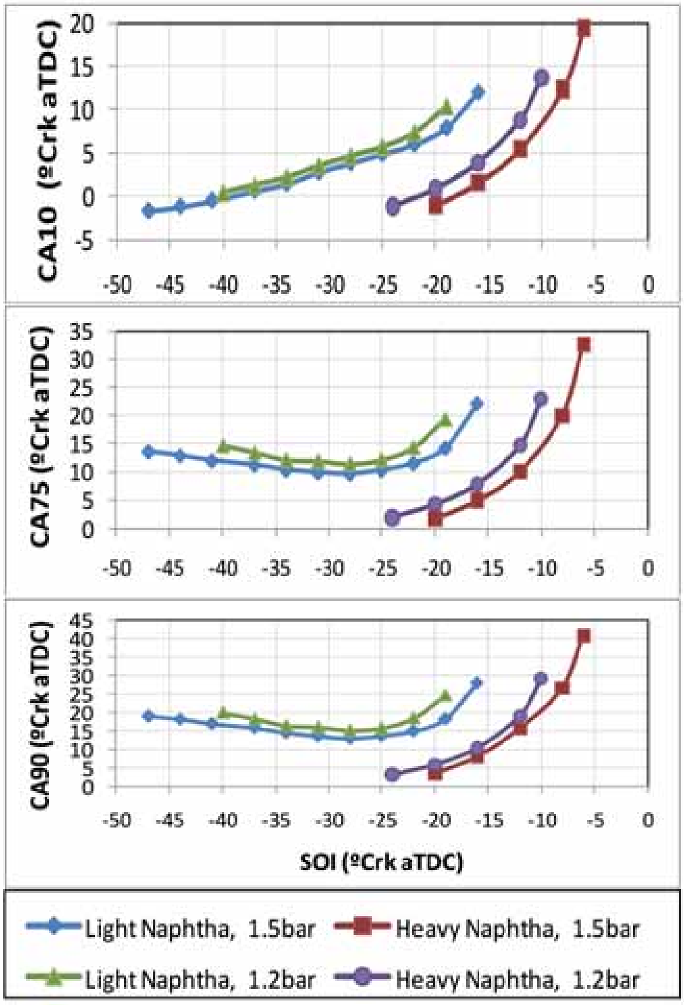


Fig. 6. Start of injection effect on each mass fraction burn point; 10%, 75%, and 90% burn point with 1.2 bar and 1.5 bar intake MAP at 1,500 rpm, 3.6 bar NMEP.

be con- trolled linearly; however, these burn phases do not respond linearly with ignition timing, especially as SOI is advanced beyond -25° CA aTDC, 75% and 90% burn points are no longer dominated by ignition timing. This is because fuel is being introduced too early to contain in the bowl, and flame cannot come across locally favorable air fuel mixture, and as a result, the main to late burn phases will progress slowly. This effect is more dominant with light naphtha due to its longer ignition delay and associated earlier injecting needed for the same ignition timing.

Emissions are determined by the mixing between fuel and oxygen, which is determined by the time available for mixing as well as by the actual combustion LightNaphtha, 1.2bar HeavyNaphtha, 1.2bar phasing. In this study, correlations between emission trends and burn duration can be seen in Fig. 7. ISNOx and ISCO have been plotted against ignition delay, defined here as CA from SOI to 10% burn location (CA10). With low

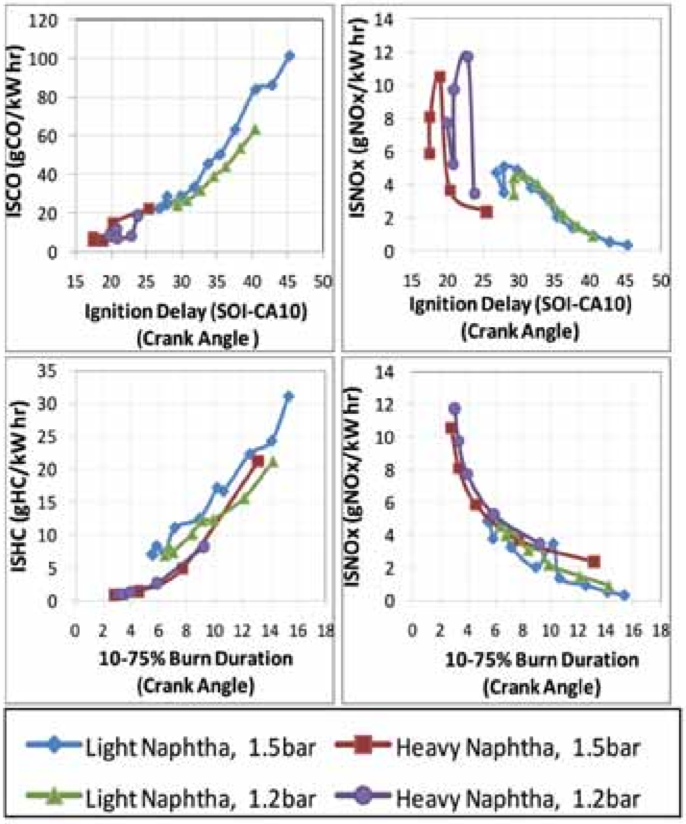


Fig.7.Corresponding burn duration to drive each emission behaviour: ISCO vs. ignition delay, ISHC vs. main burn duration (10%-75%), ISNOx vs. main burn duration (10%-75%) at 1,500rpm, 3.6 bar NMEP.

ignition delay, the mixture packets that burn, are on the rich side and hydrocarbon and CO are low while NOx is high[5,6]. A small increase in ignition delay actually increases NOx, for the reasons discussed in[5,6] while CO and hydrocarbon decrease. With a large ignition delay, the mixture packets that burn will approach the global mixture strength, which is lean and NOx is low and hydrocarbon and CO are high. Light naphtha mixes better and therefore will burn in leaner packets because of its higher volatility. There is a good correlation between ISNOx and the main burn duration (10%-75% burn duration). Obviously, ignition delay does play an important role in mixing, but subsequent fuel stratification controls the majority of burn and bulk gas temperature, which affects NOx production.

Fuel Injection Pressure Effect on PPCI Combustion

While the previously mentioned injection timing tests were done at 130 bar fuel injection pressure, the effect of fuel injection pressure is investigated with heavy naphtha. Fuel injection pressure is varied from 130 bar to 50 bar, which are typical operating pressures of this piezo-electric type gasoline direct injector and pump system. The injector needle lift height was maintained at a constant, but the duration was changed to match

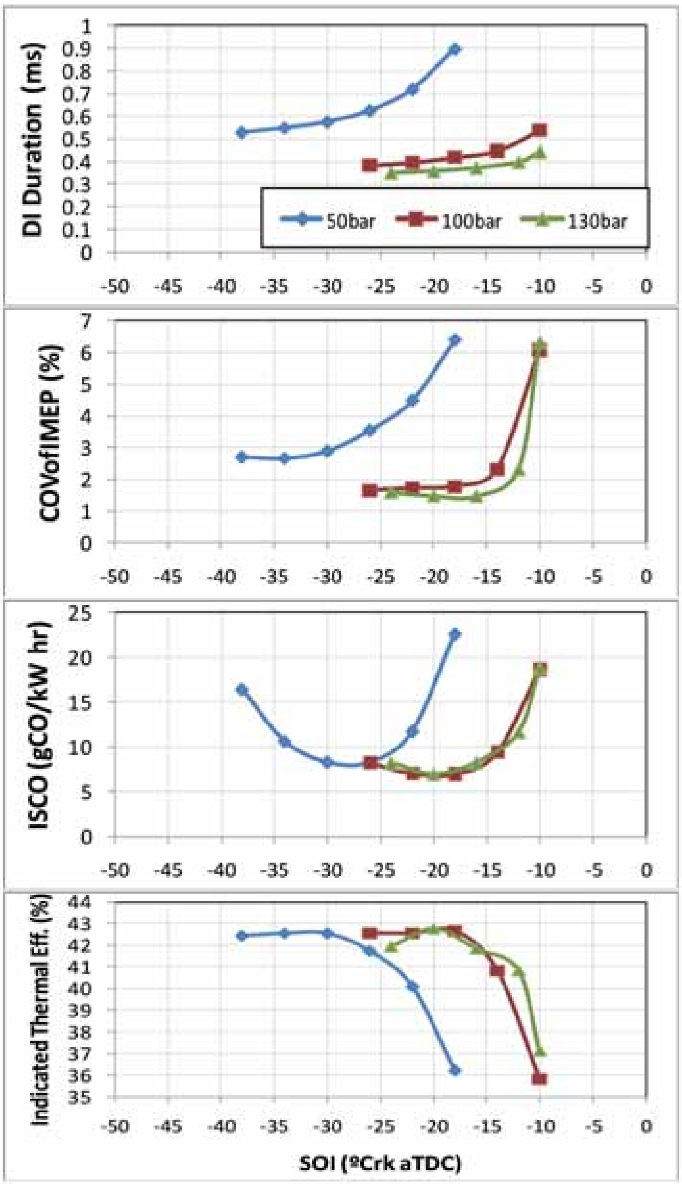


Fig. 8. Effect of fuel injection pressure on PPCI combustion with heavy naphtha fuel at 1,500 rpm, 3.6 bar NMEP, 1.2 bar intake MAP.

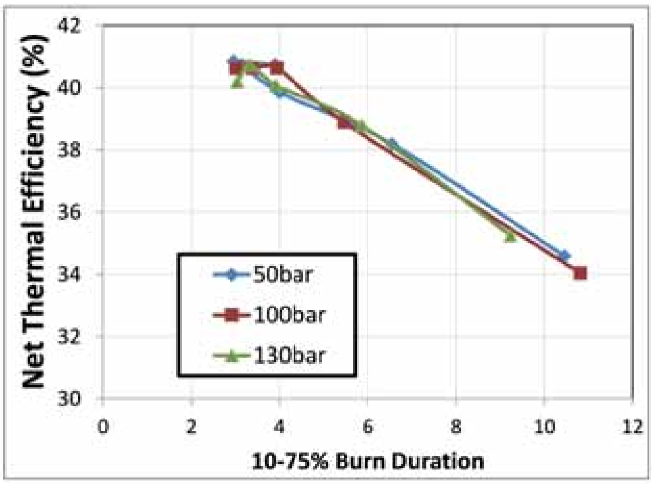


Fig. 9. Thermal efficiency vs. 10%-75% burn duration trend at different fuel injection pressure (heavy naphtha fuel at 1,500 rpm, 3.6 bar NMEP, 1.2 bar intake MAP).

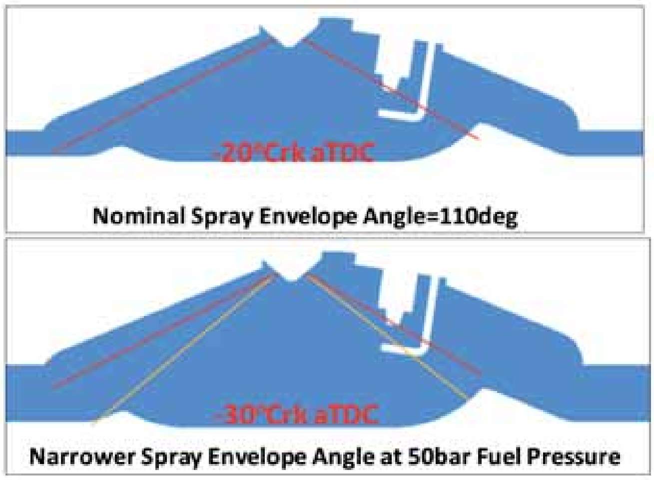


Fig. 10. Piston and imaginary spray envelope angle interaction with different piston positions (-20 and -30 °CA aTDC corresponding to 3.46 mm and 7.63 mm below TDC, respectively).

the required load (3.6 bar NMEP). As a result, longer injection duration and later end of injection timing are required for lower fuel pressure (1st plot of Fig. 8). Also, the injection duration increases as SOI is retarded toward TDC due to higher combustion chamber pressure (smaller pressure drop across the injector orifice). This effect is more pronounced at lower fuel injection pressure since the flow rate is directly proportional to the square root of pressure differential across the orifice. More importantly, combustion behavior with 50 bar injection pressure is quite different from that at 100 bar to 130 bar. SOI can be advanced without excessive increase in pressure rise rates. COVofIMEP is generally higher at 50 bar fuel injection pressure due to the poor fuel atomization. Regarding fuel containment in the bowl, CO is considered to be a good indicator in the case of stratified charge engine design. In this case, the CO trend curve for the 50 bar fuel pressure is shifted 10° CA in advanced side compared to the 100 bar and 130 bar cases. At the same time, the indicated thermal efficiency trend curve for the 50 bar fuel pressure is also shifted by about 10° CA (3rd and 4th plot of Fig. 8).

This shift is caused by combustion duration. Figure 9 shows that the indicated efficiency gain is due to shorter combustion duration and more agile and swift burn rate. The CO trend is again a good indicator for fuel bowl containment (in other words, the bowl A/F can be deduced from the CO trend). This clear CO and indicated efficiency trend indicates that varying

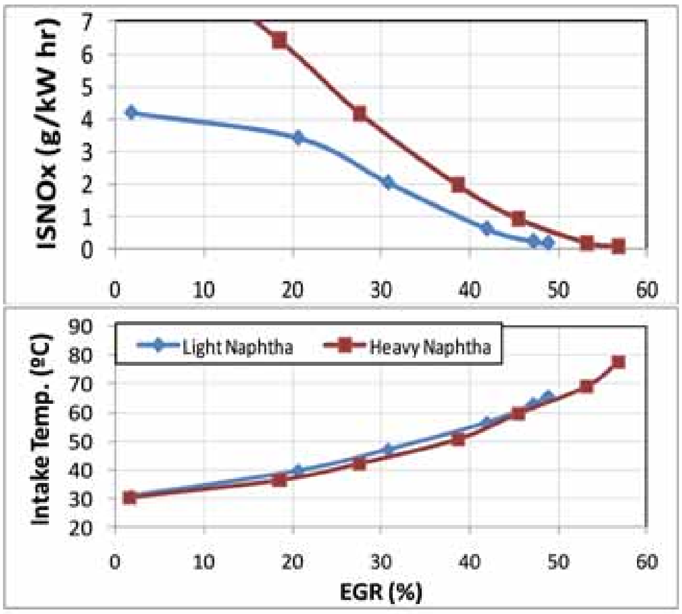


Fig. 11. Effect of external EGR on NOx emissions and intake charge temperature at 1,500 rpm, 3.5 bar NMEP, 1.2 bar intake NMEP, 130 bar fuel injection pressure.

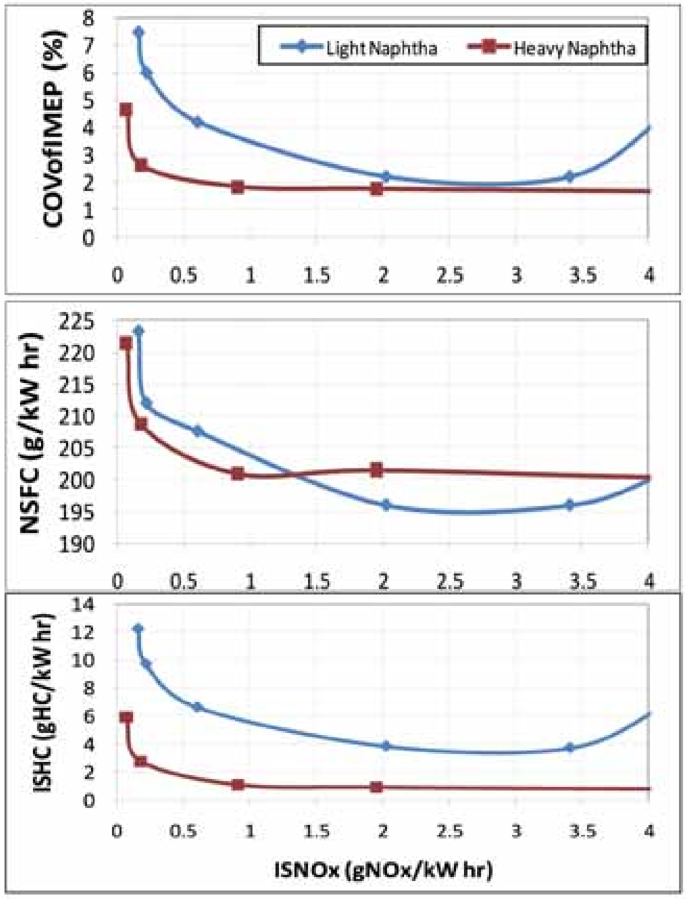


Fig.12.Effect of external EGR on PPCI combustion at 1,500 rpm, 3.5 bar NMEP, 1.2 bar intake MAP, 130 bar fuel injection pressure: COV of IMEP, NSFC, ISHC with respect to ISNOx.

fuel spray characteristics (e.g., spray cone angle, spray penetration, and atomization rate) due to changing fuel injection pressure highly affect the PPCI burn rate and duration via changing fuel bowl containment and local A/F. The biggest factor is expected to be the spray cone angle change due to smaller pressure differential across the orifice. Figure 10 illustrates this effect. Based on minimum CO window shift, i.e., -30° CA aTDC with 50 bar fuel pressure, fuel containment in the bowl is deduced to be different with a narrower spray cone angle. Accordingly, fuel injection pressure can be used to be a parameter for controlling the favorable injection timing window if necessary.

EGR Effect on PPCI Combustion

Although advancing injection timing and putting fuel more into the premixed burn helps in lowering NOx emission, more dilution is needed to reduce engine-out NOx at a satisfactory level. Engine-out NOx constraint is set under the Emission Index of NOx = 2.5 gNOx/kg fuel, or ISNOx = 0.5 g/kW-hr, shown in Table 5. If the engine cannot be operated at this target, the minimum NOx is reported under the combustion stability limit. In this article, exhaust dilution is introduced only via external EGR without any valve-train strategy. Figure 11 shows NOx behavior with varying EGR at 1,500 rpm, 3.6 bar NMEP (1.2 bar intake MAP, 130 bar fuel injection pressure case). The best SOI is selected according to the lowest COVofIMEP and fuel consumption. A 15kPa delta pressure between intake and EGR is always maintained. Although both fuels require more than 40% EGR to meet the target NOx level, light naphtha requires less EGR for a given NOx level. Less EGR is preferable because more exhaust energy can be delivered to the turbocharger if necessary. Regarding the EGR route, it's introduced at the high-pressure intake line, i.e., before the turbine to after the compressor. Since EGR is not force cooled (only natural convection from the EGR pipe), intake charge temperature somewhat increases with higher EGR. Intake charge goes up to 80°C at a maximum EGR level of 58%. This will ultimately affect the auto-ignition condition and combustion rate. On a production charging unit, a reasonable distribution of warm EGR and cold intercooled charge would be required, depending on load demand. Figure 12 shows how combustion stability and fuel consumption vary with NOx. Heavy naphtha has an overall lower COVofIMEP than light naphtha - it is under 3% COVofIMEP where Light Naphtha Heavy Naphtha ISNOx is lower than 0.5 g/kW hr. This is quite a noticeable dilution tolerance considering the fact that geometric compression ratio is only 12, and intake

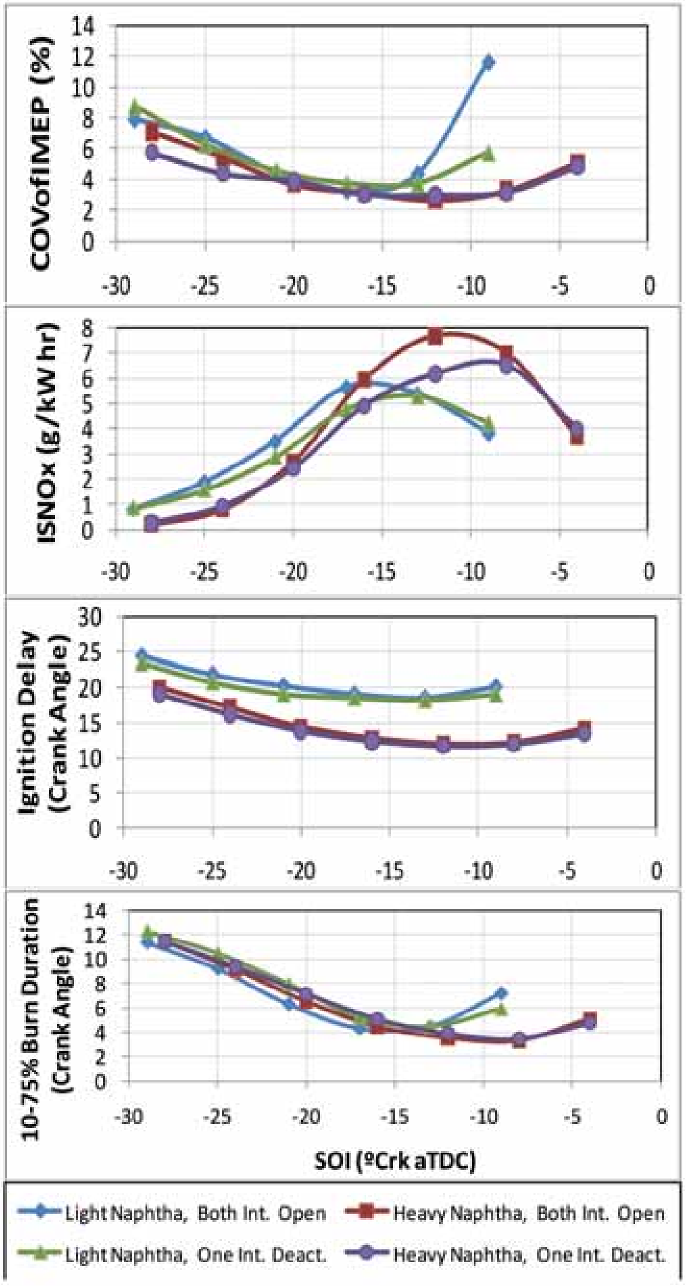


Fig. 13. Injection timing effect on PPCI combustion and emission at idle point with light and heavy naphtha: 800 rpm, 1 bar NMEP (naturally aspirated without EGR), case with both intake valve open vs. one intake valve deactivated.

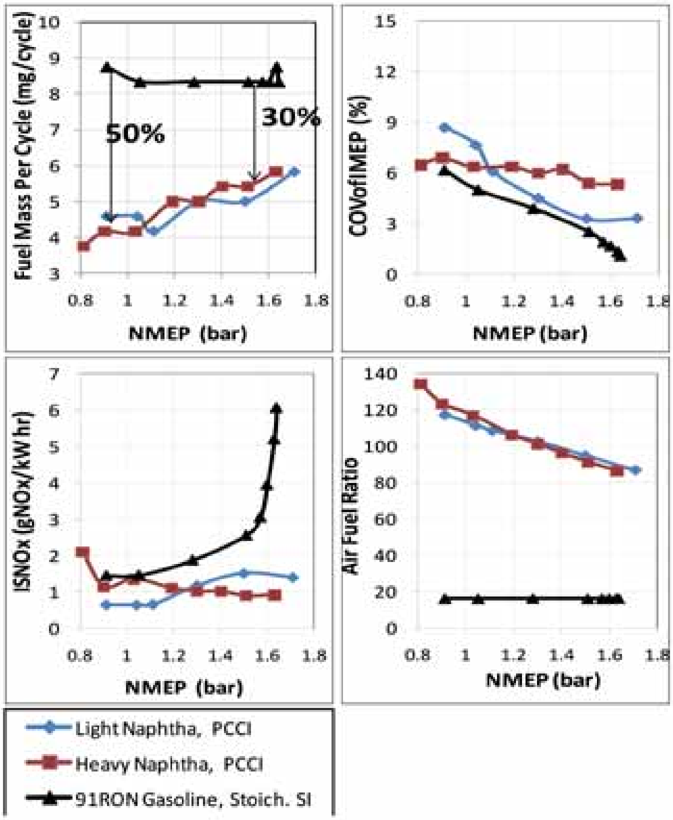


Fig. 14. Torque reserve idle comparison: Load control by naphtha fuels with PPCI combustion vs. load control by spark timing with conventional gasoline SI combustion.

MAP is 1.2 bar absolute. Compared to previous PPCI results with higher compression ratio[9,10,12] and diesel-like injection pressures, the high dilution tolerance levels measured in this work were primarily due to the in- creased stratification level caused by less atomization (low injection pressure and large orifice holes), which ensures igniting the mixture easier. Fuel consumption (NSFC) increases as ISNOx decreases. When NOx is lower than 0.5 g/kW-hr, the difference of NSFC on both fuels is small. Heavy naphtha has better combustion stability and lower unburned hydrocarbon (UBHC) emission. In the case of light naphtha with high EGR (50%), a portion of UBHC mass at exhaust gas is re- introduced to the combustion chamber and contributed to be burned at the following cycle. For example, light naphtha at ISNOx = 0.5 g/kW-hr, 10.5 mg of fuel is injected with combustion efficiency = 93% and EGR = 45%. This leads to slightly more than 3% of an incomplete burn of hydrocarbon product to be re- introduced in to the chamber.

PPCI Combustion at Idle Load

At 800 rpm, 1 bar NMEP is selected as the nominal idle point, Table 4. Only the single injection strategy is applied to optimize the combustion rate and NOx emissions. Several fuel injection pressure sweeps were performed to find the best injection pressure, and as a result, 100 bar for heavy naphtha and 60 bar for light naphtha were chosen. Intake MAP is 1 bar (naturally aspirated) and intake temperature is 30°C. Deactivating one intake valve is also attempted to help combustion stability via enhancing the charge motion. Figure 13 shows how COVofIMEP changes as SOI timing advances. Little difference can be seen with or without intake valve deactivation due to the lack of turbulence generation at such a low engine speed. Regarding the fuel effects, the lowest COVofIMEP and the highest NOx happens when SOI moves toward TDC, and heavy naphtha requiring more retarded SOI timing because of the shorter ignition delay. On the other hand, NOx decreases more rapidly with heavy naphtha as SOI timing is advanced. One interesting difference at idle point is that the main burn duration of the two fuels is similar at a given SOI timing. Therefore, even with a shorter ignition delay (or earlier 10% burn point) with heavy naphtha, the main burn duration slows down, which lowers NOx in advanced SOI. It implies that the fuel's cetane number is important in determining the ignition point, but bulk burn progress is also dependent on the local A/F.

With respect to idle speed control, Stoichiometric SI operation requires some degree of torque reserve through spark retardation to ensure a quick response from a sudden increase in load requirements (e.g., turning the air conditioning on, engaging the transmission, or applying a load to the power steering pump). This makes the SI operation more inefficient since combustion occurs later than maximum brake torque (MBT). Lean PPCI, on the other hand, uses fuel for load control, which can be run best at ignition timing. Because of that, fuel consumption comparison at idle has to be done with a certain load range equivalent to vehicle calibration torque reserve. In this case, we assume torque reserve to be 10 Nm at idle, which corresponds to 0.6 bar NMEP sweep. Figure 14 shows a comparison between lean PPCI naphtha fuel and torque reserve Stoichiometric SI with RON 91 gasoline fuel. A load sweep around the nominal idle point at 1 bar NMEP (0.8 bar to 1.5 bar) is conducted to determine the associated fuel consumption differences. A 30% to 50% fuel consumption savings is achieved by reducing pumping losses and improving indicated efficiency. A single injection timing strategy without external EGR is applied with COVofIMEP constraint below 6% for the PPCI case. To achieve this stability target, ISNOx target has to be compromised up to 1 g/kW-hr ISNOx at idle. Nevertheless, a potential to improve the idle can be accomplished by raising the compression ratio, better matching spray and piston bowl geometry, and utilization of EGR.

Fuel Consumption Comparison with Stoichiometric A/F SI Operation

For the purpose of driving cycle fuel consumption comparison to lean PPCI combustion, tests with a Stoichiometric A/F SI operation are performed at six representative steady-state engine points, Table 4. Production RON 91 gasoline fuel from a Saudi Aramco refinery is used for testing (RON/MON = 93/84, Table 2). The same engine architecture was used with a 12:1 geometric compression ratio and the same piezo-electric DISI system, but with a higher intake and exhaust valve lift and duration (9.5 mm and 227° CA, respectively), and with cam phasing capability (50°CA range of authority). The valve events were modified to simulate a modern SI engine cam design, Fig. 15. Full factorial valve timing sweeps were conducted to determine the lowest fuel consumption point while conforming to the 3% COVofIMEP constraint.

Contour plots in Fig. 16 clearly show the lowest fuel consumption point at 1,500 rpm, 3.6 bar NMEP. The top right corner is the "park" position (minimum overlap), and the lower left corner is the fully phased position (maximum overlap). Moving diagonally (from top right to low left) leads to valve overlap increase (more internal EGR) and combustion stability degradation (COVofIMEP) as a result. The minimum fuel consumption cam position is determined in the

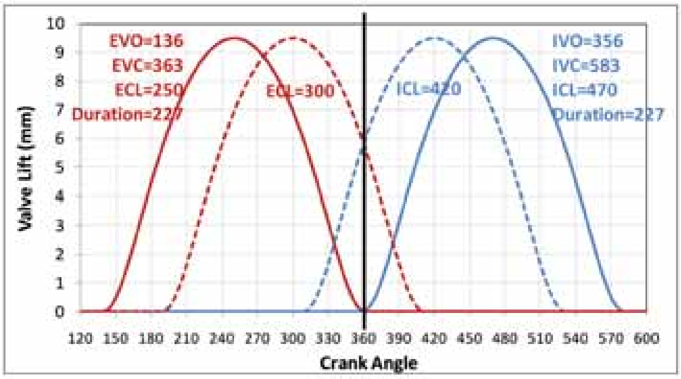


Fig. 15. Stoichiometric SI valve lift profile: 9.5 mm peak lift and 50° cam phasing authority.

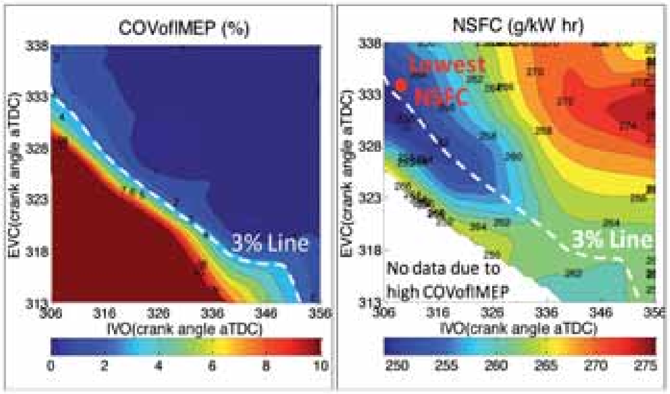


Fig. 16. Variable valve timing effect on stoichiometric SI operation at 1,500 rpm, 3.6 bar NMEP: Contour plot for COV of IMEP (left) and NSFC (right).

	Engine Speed (rpm)	NMEP (kPa)	NSFC (g/kW hr)	EVC (°Crk a TDC)	IVO (°Crk a TDC)	COV of IMEP (%)
IDLE	800	103	580	363	356	5.0
Zone 2	1,130	185	322	378	349	1.6
Zone 3	1,500	360	251	363	321	1.8
Zone 4	2,000	260	272	366	330	2.2
Zone 5	1,935	540	227	366	316	1.4
Zone 6	2,620	650	223	366	316	1.1

Table 6. Minimum fuel consumption and corresponding valve timing values on stoichiometric A/F SI operation.

	Fraction of Total Fuel (%)	Fuel Consumption Reduction from Stoichiometric A/F SI %		Weighted Fuel Mass Reduction (%)	
		Heavy Naphtha	Light Naphtha	Heavy Naphtha	Light Naphtha
IDLE	8	50	45	4.0	3.6
Zone 2	22	25	21	5.6	4.7
Zone 3	16	19	17	3.0	2.8
Zone 4	18	20	10	3.6	1.8
Zone 5	25	10	8	2.4	1.9
Zone 6	11	8	2	0.8	0.2
Driving Cycle Fuel Mass Reduction %				19.4	14.9

Table 7. Total fuel mass reduction with naphtha PPCI combustion from stoichiometric A/F SI operation based on six steady-state engine point.

vicinity of the 30% COV line. Fuel consumption (NSFC) contour does not appear to be symmetrical. Two factors affect NSFC at this load point, namely throttling and effective compression ratio. The primary factor is PMEP reduction (since air flow is controlled by valve timing), which is symmetric with valve overlap. The other factor is the higher effective compression ratio caused by early intake valve opening. Therefore, the lowest fuel consumption happens when the intake valve opens early but is limited by the amount of valve overlap (residual). This is not the case for medium load points, such as Zone 5 and 6. At these load points, knock limited spark timing is more dominant on indicated efficiency. For fuel economy comparison, torque reserve spark idle is used as presented in the previous section. Consequently, optimum valve timings are found at each zone, and minimum fuel consumption values are reported in Table 6.

Fuel consumption comparison between lean PPCI with two naphtha fuels vs. Stoichiometric A/F SI with 91 RON gasoline is made in Fig. 17. Maximum fuel consumption reduction is made at idle. At idle of PPCI case, torque control via fuel mass instead of spark advance is a key to get the biggest benefit. Light load points at Zone 2, 3 and 4, also have a fair amount of NSFC reduction, i.e., 19%-25% for heavy naphtha, and 10%-21% for light naphtha. Light naphtha has less benefit since the ignition delay of light naphtha is too long to provide stable combustion at a very light load. Moreover, long ignition delay results in high dependency on engine speed due to less time per CA leads to too much advanced injection timing, which misses fuel into the bowl. For example, COVofIMEP at Zone 4 is too high to satisfy such a high dilution for the ISNOx target. In any case, no misfire is detected for all points. One of the ways to improve combustion

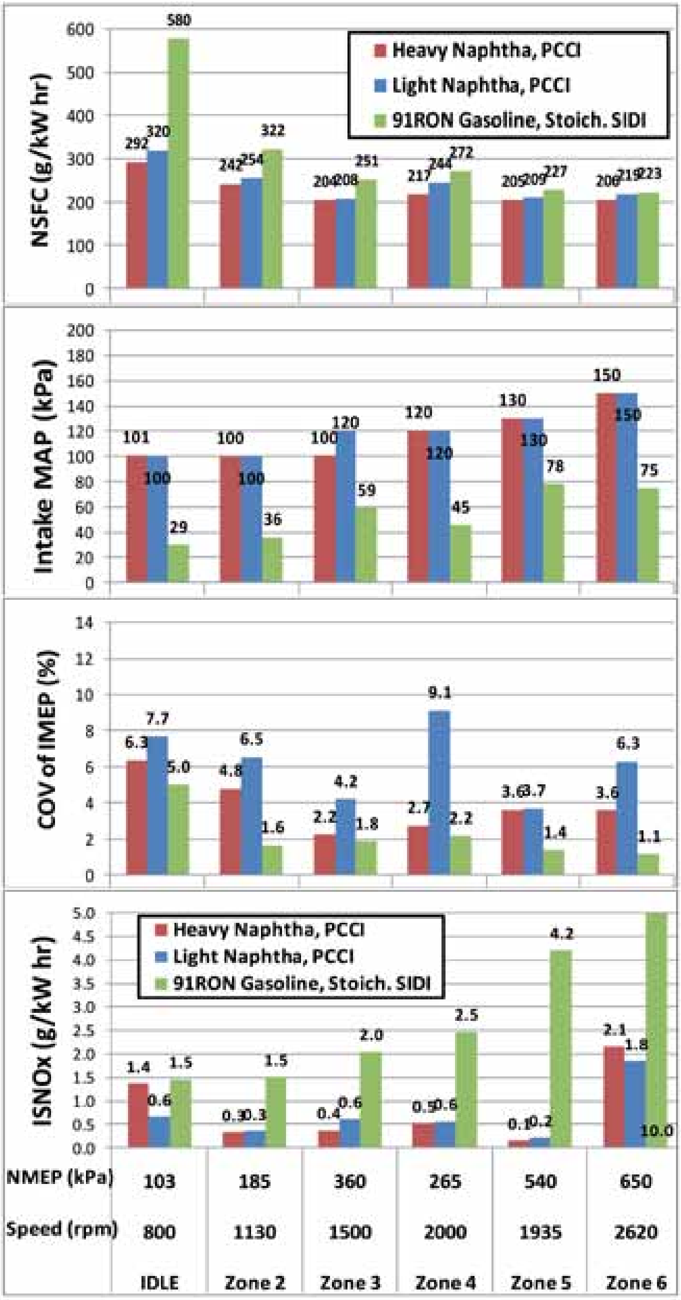


Fig. 17. NSFC, intake MAP, COV of IMEP and ISNOx comparison at six steady-state engine points: PPCI naphtha fuels vs. stoichiometric A/F SI operation.

stability can be through higher intake boosting; however, intake MAP is bounded by the current production capability of variable geometry turbochargers, Fig. 17. NOx emissions can be well controlled, i.e., ISNOx < 0.6 g/kW-hr. Only Zone 6 cannot be controlled very well, since single injection strategy is not sufficient to satisfy both combustion induced noise and sufficient fuel delivery rate. EGR has to be reduced to avoid too much local fuel enrichment. This has to be improved with better combustion chamber design, proper bowl depth and diameter with less piston valve cut feature. PM emission is not measured at this time due to the equipment unavailability. Consequently, it is certain

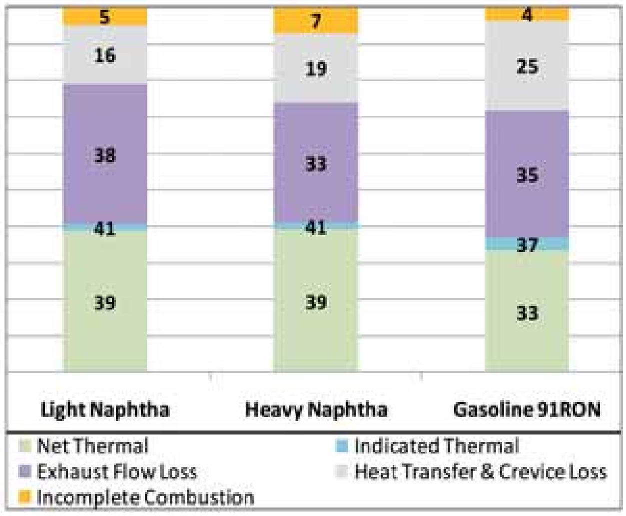
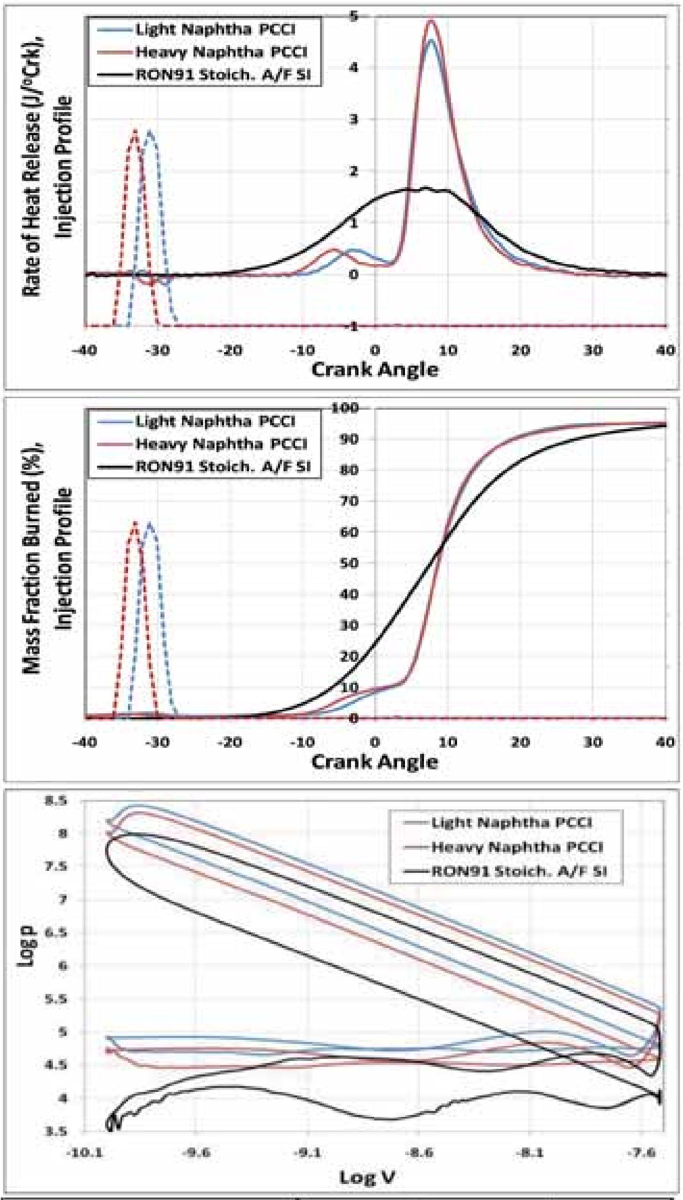


Fig. 18. Energy balance comparison between naphtha PPCI vs. stoichiometric A/F SI operation: Zone 3 at 1,500 rpm, 3.6 bar NMEP point.

there's little concern of smoke emission at this part as load conditions based on many previous results[17-20].

Based on measured fuel consumption values at six steady-state engine points, estimation of total fuel mass reduction is made by weighing the fraction of total fuel consumed on the U.S. FTP 75 city driving cycle. Table 7 shows both light and heavy naphtha's PPCI fuel consumption reduction compared to base Stoichiometric SI operation. The weighed fuel mass reductions are also shown. For example, fuel consumption reductions at Zone 3 are 19 and 17% for light and heavy naphtha, respectively. The fraction of total fuel spent during this Zone is 16%, so weighed fuel mass reduction is 3% and 2.8%, respectively. As a result, the sum of fuel mass reduction is 15% for light naphtha and 19% for heavy naphtha. Compared with other lean combustion types, such as stratified charge spark ignition or HCCI on gasoline engine platform, this 15%-19% cycle averaged fuel mass reduction is considered to be a comparable outcome. Clearly, major zones that contribute fuel mass reduction are idle and Zones 2, 3 and 4, due to the heavy time spent on light load conditions.

Figure 18 shows a detailed breakdown of energy balance comparison at the Zone 3 point. Although combustion efficiency is slightly worse with PPCI combustion, both gross and net indicated efficiency is superior to SI operation. Under PPCI combustion, 2% difference between gross and net indicated thermal efficiency is due to the pumping losses (always con- trolled to 15kPa pressure differential). Note that this may not reflect a



	A/F	Intake MAP (bar)	EGR (%)
Light Naphtha	36.0	1.2	42
Heavy Naphtha	28.0	1.0	44
Gasoline 91RON	14.6	0.6	0

Fig. 19. Heat release analysis and Logp-logV diagram comparison on PPCI vs. stoichiometric A/F SI combustion: 1,500 rpm, 3.6 bar NMEP point.

complete picture of a turbocharger pumping loss since it varies depending on the boosting demand. Under such a low boosting level at a partial load condition, however, it does not make a big difference. The gross indicated efficiency gain results from reduced heat losses and better combustion behavior. Figure 19 shows the rate of heat release and mass fraction burned profiles at each combustion mode. The dotted lines represent the commanded fuel injection profiles from the controller (not a real injector needle lift). Both light and heavy naphtha show low temperature heat release before the ignition (MFB 10%) occurs. Ignition delay of heavy naphtha is slightly longer in this case from more advanced injection timing due to higher EGR dilution. Mass fraction burned characteristics are fairly similar to those with HCCI burn, except for the early phase (0%-10% MFB). Therefore, reasonable combustion performance and good dilution tolerance is obtained only with changing the fuel's auto-ignition characteristics and fuel injection scheme without a complicated valve train.

Summary/Conclusions

Partially premixed compression ignition combustion (PPCI) is run with much simpler hardware than in a diesel engine and with a fuel, naphtha, which is much less processed than high cetane diesel fuel or high octane gasoline. With a conventional production gasoline direct injection system and a low compression ratio (12:1) with an un-optimized piston bowl shape, stable combustion could be achieved at idle and part load conditions without the aid of special valve train strategy. Effective NOx reduction is achieved through EGR.

1. ISNOx < 0.5 g/kW-hr was attained at 1,500 rpm, 3.6 bar NMEP without intake heating, with intake pressure of 1 bar abs for heavy naphtha and 1.2 bar abs for light naphtha. Good dilution tolerance (more than 40% EGR) is found for COVofIMEP < 6%.

2. Driving cycle fuel economy is evaluated based on six steady-state engine dynamometer points' fuel consumption measurement. Total fuel mass spent is calculated via weighing the fraction of fuel, and comparison is made between two naphtha fuel PPCI operations and 91 RON gasoline Stoichiometric A/F SI operation. A 15%-19% fuel mass reduction can be obtained through lean burn controlled NOx operation.

3. Although there's no artificial air inlet temperature increase at this testing, engine oil and coolant temperature is maintained at 90°C, i.e., fully warmed up condition. A cold condition evaluation is critical to make this fuel more practically feasible. A glow plug is essential equipment to cope with severe cold start condition, such as -25°C soaking temperature. Recent finding on glow plug ignition of ethanol fuel[22] shows potentials of low cetane fuel as a practical CI engine.

4. Higher engine speed is more difficult to run because of the long ignition delay. There's a limit on advancing injection timing (-35° CA aTDC) due to the improper spray-to-piston bowl alignment. Therefore, the fuel's auto-ignition property and engine geometry matching is very important to improve combustion robustness.

5. A higher compression ratio (range from 13-15) with improved bowl design is expected to give better dilution tolerance, which leads to further NOx reduction, as well as better fuel consumption. The fuel spray design has to align to the newly defined injection timing window to have better fuel-bowl containment.

6. Less processed refinery naphtha fuel provides lower CO_2 in the refinery process than either gasoline fuel, as well as, better engine efficiency than a conventional SI engine.

Previous PPCI literature, starting with diesel engines, has demonstrated the potential of simplifying the diesel engine while maintaining or improving its efficiency using gasoline-like fuels. The work described in this article has started with a gasoline engine and has demonstrated that its efficiency can be improved using diesel-like combustion using fuels less processed than gasoline. The best solution is likely to lie between these two extremes. More specifically, compression ratio, fuel atomization level, and cetane number have to be the best match. For example, compression ratio = 14, fuel system = max. 500 bar, 250 micrometer orifice diameter, and CN = 35-38 seem to be a good starting point. Regarding the light vs. heavy naphtha, it has to be selected based on cetane characteristics, which varies from crude type. Blending of two cannot be excluded depending on the best match with engine parameters.

Finally, based on the refinery and fuel retail industry point of view, the world's demand on gasoline and diesel fuel depends on geological location. From the refinery point of view, production yield is not always matched with demands at each location. For example, some countries in the Middle East and Asia export diesel fuel but import gasoline fuel due to high demand of gasoline. Subsequently, the lead time of refinery configuration modification is not fast enough to catch the trend in powertrain development. Replacing gasoline fueled powertrains through naphtha fuel PPCI powertrain can be a good scenario, not only reducing gasoline depend- ence, but also replacing high operating cost diesel into cost-effective naphtha fuel. Detailed linear programming is necessary to better understand refinery economics, as well as a life cycle analysis will provide a best carbon footprint for lowest CO_2.

Acknowledgements

The authors would like to thank Saudi Aramco management for their permission to present and publish this article.

The authors would like to express appreciation to Mosaab Alsunaidi and Waleed Bubshait for preparing all test fuels as well as performing engine testing. This work has been supported by the Fuel Technology Initiative in Saudi Aramco R&DC.

References

1. Dec, J.E.: "Advanced Compression-Ignition Engines – Understanding the In-Cylinder Processes" Proceedings of the Combustion Institute, Vol. 32, No. 2, 2009, pp. 2,727-2,742.

2. Kalghatgi, G.T., Risberg, P. and Ångström, H.E.: "Advantages of Fuels with High Resistance to Auto-Ignition in Late-Injection, Low-Temperature, Compression Ignition Combustion," SAE Technical Paper #2006-01-3385, October 2006.

3. Kalghatgi, G.T., Risberg, P. and Ångström, H.E.: "Partially Premixed Auto-Ignition of Gasoline to Attain Low Smoke and Low NOx at High Load in a Compression Ignition Engine and Comparison with a Diesel Fuel," SAE Technical Paper #2007-01-0006, January 2007.

4. Kalghatgi, G., Hildingsson, L. and Johansson, B.: "Low NOx and Low Smoke Operation of a Diesel Engine Using Gasoline-like Fuels," ASME Paper ICES 2009-76034, Journal of Engineering for Gas Turbines and Power, Vol. 132, No. 9, 2010.

5. Hildingsson, L., Kalghatgi, G.T., Tait, N., Johansson, B. and Harrison, A.J.: "Fuel Octane Effects in the Partially Premixed Combustion Regime in Compression Ignition Engines," SAE Technical Paper #2009-01-2648, September 2009.

6. Hildingsson, L., Johansson, B., Kalghatgi, G.T. and Harrison, A.J.: "Some Effects of Fuel Auto-Ignition Quality and Volatility in Premixed Compression Ignition Engines," SAE International Journal of Engines, Vol. 3, No. 1, 2010, pp. 440-460.

7. Kalghatgi, G.T., Hildingsson, L., Harrison, A.J. and Johansson, B.: "Auto-Ignition Quality of Gasolines in Partially Premixed Combustion in Diesel Engines," Proceedings of the Combustion Institute, Vol. 33, 2011, pp. 3,015-3,021.

8. Kalghatgi, G.T., Hildingsson, L., Johansson, B. and Harrison, A.J.: "Low NOx, Low-Smoke Operation of a Diesel Engine Using "Premixed Enough" Compression Ignition – Effects of Fuel Auto-Ignition Quality,

Volatility and Aromatic Content," THIESEL 2010.

9. Manente, V., Johansson, B. and Tunestål, P.: "Partially Premixed Combustion at High Load Using Gasoline and Ethanol, a Comparison with Diesel," SAE Technical Paper #2009-01-0944, April 2009.

10. Manente, V., Johansson, B., Tunestål, P. and Canella, W.: "Effects of Different Types of Gasoline Fuels on Heavy Duty Partially Premixed Combustion," SAE Technical Paper #2009-01- 2668, November 2009.

11. Manente, V., Johansson, B. and Tunestål, P.: "Half Load Partially Premixed Combustion, PPC, with High Octane Number Fuels, Gasoline and Ethanol Compared with Diesel," SIAT 2009 295, 2009.

12. Hanson, R., Splitter, D. and Reitz, R.: "Operating a Heavy-Duty Direct-Injection Compression-Ignition Engine with Gasoline for Low Emissions," SAE Technical Paper #2009-01-1442, April 2009.

13. Reitz, R.D.: "High-Efficiency, Ultra-Low Emission Combustion in a Heavy-Duty Engine via Fuel Reactivity Control," 15th Diesel Engine Efficiency and Emissions Research (DEER) Conference, Dearborn, MI, August 3, 2009.

14. Weall, A.J. and Collings, N.: "Investigation into Partially Premixed Combustion in a Light Duty Multi-Cylinder Diesel Engine Fueled with a Mixture of Gasoline and Diesel," SAE Technical Paper #2007-01-4058, October 2007.

15. Weall, A.J. and Collings, N.: "Gasoline Fueled Partially Premixed Compression Ignition in a Light Duty Multi-Cylinder Engine: A Study of Low Load and Low Speed Operation," SAE International Journal of Engines, Vol. 2, No. 1, October 2009, pp. 1,574-1,586.

16. Cracknell, R.J., Rickeard, D.J., Ariztegui, J., et al.: "Advanced Combustion for Low Emissions and High Efficiency: Part 2 – Impact of Fuel Properties on HCCI Combustion," SAE Technical Paper 2008-01-2404, October 2008.

17. Sellnau, M., Sinnamon, J., Hoyer, K. and Husted, H.: "Gasoline Direct Injection Compression Ignition (GDCI) – Diesel-like Efficiency with Low CO_2 Emissions," SAE International Journal of Engines, Vol. 4, No. 1, April 2011, pp. 2,010-2,022.

18. Akihama, K., Kosaka, H., Hotta, Y., et al.: "An Investigation of High Load (Compression Ignition) Operation of the 'Naphtha Engine' - A Combustion Strategy for Low Well-to-Wheel CO_2 Emissions," SAE International Journal of Fuels and Lubricants, Vol. 1, No. 1, 2009, pp. 920-932.

19. Rose, K., Cracknell, R.F., Rickeard, D.J., et al.: "Impact of Fuel Properties on Advanced Combustion Performance in a Diesel Bench Engine and Demonstrator Vehicle," SAE Technical Paper, 2010-01-0334, April 2010.

20. Cho, K., Han, M., Sluder, C.S., Wagner, R.M. and Lilik, G.K.: "Experimental Investigation of the Effects of Fuel Characteristics on High Efficiency Clean Combustion in a Light Duty Diesel Engine," SAE Technical Paper 2009-01-2669, November 2009.

21. Lacey, P.I., Naegeli, D.W., De La Cruz, J.L. and Whalen, M.V.: "Lubricity of Volatile Fuels for Compression Ignition Engines," SAE Technical Paper 2000-01-1804, June 2000.

22. Adomeit, P., Jakobm, M., Kolbeck, A. and Pischinger, S.: "Glow-Plug Ignition of Ethanol Fuels Under Diesel Engine Relevant Thermodynamic Conditions," SAE Technical Paper, 2011-01-1391, April 2011.

Biographies

Dr. Junseok Chang joined Saudi Aramco's Research & Development Center (R&DC) in October 2010. He has spent his entire career in the fields of internal combustion engine and advanced combustion strategy development. Prior to joining Saudi Aramco, Junseok was working at Transonic Combustion Inc. in Southern California. He was responsible for governing all engine programs, including testing, data analysis and reports, and exposure at the engine community to help better understand supercritical spray behavior. Working closely with his teammates, Junseok was also responsible for collaboration of both optical spray analysis and gasoline surrogate model validation.

Before Transonic Combustion, he had also worked at General Motors' Research & Development for about 5 years. During this time, Junseok was involved in many advanced combustion engine development projects, but his main project was to develop the lean burn spray-guided stratified charge spark ignition combustion system project collaboration with GM Europe. He also worked on the vehicle program developing dual mode lean burn idle system with de-NOx catalyst integration. Junseok worked closely with GM's advanced engineering division to explore the fuel economy enabled variable valve actuator (VVA) system, including 2-step cam phasers, valve deactivation, and cam-in-cam strategy on GM's 4 cylinder passenger vehicles.

He received his B.Eng. degree from the Yeungnam University, Daegu, Republic of Korea in 1996, In 1999, Junseok received his M.S. degree in Mechanical Engineering from the Seoul National University, Seoul, Korea, and in 2004, he received his Ph.D. degree in Mechanical Engineering from the University of Michigan, Ann Arbor, MI.

Yoann Viollet joined Saudi Aramco's Research & Development Center (R&DC) in 2007. He is part of the Fuel Technology R&D Team and works under the Engine Combustion and Efficiency Sub Team. Yoann is widely involved in the in-house fuel research being conducted in the Combustion Laboratory.

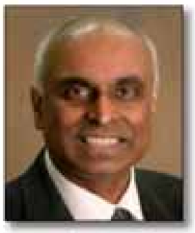
Previously, he worked in IFPEN (France) in the Energy Application Techniques division in Lyon. There Yoann focused on "clean" combustion through the development of new injection systems, homogeneous charge compression ignition (HCCI) combustion chambers and intake air boosting architectures (adaptation of turbochargers and exhaust gas recirculation loops).

He received his B.S. degree in Power Train Engineering from the Université Pierre-et-Marie-Curie (Paris VI), Paris, France, in 2003.

Dr. Amer A. Amer joined the Saudi Aramco Research & Development Center (R&DC) in 2008 after more than 12 years with the automotive industry, where he was involved in various hardware development, design and simulation activities of many V-engine programs. As a supervisor of the Numerical Simulation Group supporting Chrysler Powertrains, Amer assumed the responsibility to integrate Computer Aided Engineering and Optimization tools into the engine development process.

Since joining Saudi Aramco, he has led various research projects on engine/ fuel experimentation and combustion and kinetics simulation, and contributed to designing and executing the strategic direction for the Petroleum Fuel Formulation Initiative. Amer is currently the Team Leader for the Fuel Technology R&D.

In 1995, he received his Ph.D. degree in Mechanical Engineering from Wayne State University, Detroit, MI. Amer has coauthored more than 20 papers in the field of engine experimentation, diagnostics and simulation and organized and chaired SAE technical sessionS.



Dr. Gautam T. Kalghatgi joined Saudi Aramco in October 2010 after 31 years with Shell Research Ltd. in the U.K. From 1975-1979, he conducted post-doctoral research in turbulent combustion at Southampton University. Gautam is a Fellow of the Royal Academy of Engineering, SAE and I.Mech.E., and was adjunct/part-time/visiting Professor at Kungliga Tekniska Högskolan (KTH), Stockholm, Sweden, Eindhoven University of Technology, Eindhoven, the Netherlands and Sheffield University, Sheffield, U.K. He is on the editorial boards of the International Journal of Engine Research, Journal of Automobile Engineering and Journal of Fuels and Lubricants (SAE).

In 1972, Gautam received his B.Tech. degree from the Indian Institute of Technology Bombay, Mumbai, India, and in 1975, he received his Ph.D. degree from Bristol University, Bristol, U.K., in Aeronautical Engineering.

Gautam has authored over 100 external publications on combustion, fuels and engine research.

Productivity Increase Using Hydraulic Fracturing in Conventional and Tight Gas Reservoirs – Expectation vs. Reality

By Dr. Zillur Rahim, Dr. Hamoud A. Al-Anazi, Adnan A. Al-Kanaan, Ali H. Habbtar, Ahmed M. Al-Omair, Nejla H. Senturk and Daniel Kalinin.

Reprinted with kind permission from the Saudi Aramco Journal of Technology.

Abstract

Hydraulic fracturing technology is widely used to facilitate and enhance the gas recovery process from conventional and tight gas resources. Tight gas or unconventional reservoirs, which include very low permeability sandstones, carbonates, or shales, cannot be economically produced without hydraulic fracturing. Recently, much progress has been made in the overall hydraulic fracturing procedures and the field implementations of advanced stimulation technology have produced good results. The proper selection of well trajectory, gel concentration, polymer loading, proppant type/size and concentration, perforation method, location for packer and frac port placement in a mul- tistage fracturing (MSF) assembly, number of fracture stages to cover the net pay, etc., have all contributed to successful stimu- lation and improved gas recovery. Even though stimulating gas reservoirs has become a routine application and much experience has been gained in this area, not all treatments are straightforward without problems and challenges. Unless a stimulation treatment is carefully designed and implemented, the post-stimulation results in moderate to tight reservoirs may not be encouraging and can easily fall below expectations.

The most essential step to close the gap between expected results and actual well performance is to understand a reservoir's characteristics and its potential to produce at a sustained rate after a successful fracturing treatment. Overestimation of reservoir flow capacity and achieved fracture geometry will also over predict well performance. This article addresses the importance and impact of detailed reservoir characterization and superior stimulation processes on final well performance. Several field examples from Saudi Arabia's gas reservoirs are presented in this article, showing the value of effective well planning, reservoir characterization, application of hydraulic fracturing and proper cleanup.

This article also illustrates the impact of drilling trajectory and wellbore reservoir connectivity on the proper placement of desired hydraulic fracture treatments and sustained gas production.

Introduction

Unconventional gas resources of tight sand, carbonate, shale, and coal have tremendous potential. All reservoirs containing conventional gas have very high percentages of unconventional resources that are now being produced or need to be produced in the near future to support world energy. Figure 1 shows the distribution between conventional and unconventional resources from a few basins in the United States, indicating huge tight gas potential[1]. Figure 2 is the well-known resource triangle depicting the availability of gas resources associated with some anticipated reservoir flow capacities[2]. The unconventional gas portion is huge, with a total of 32,600 trillion cubic ft (TCF) of gas-in-place (GIP) and 7,400 TCF in tight sand only estimated across the world. Saudi Arabia is currently embarking on projects tapping into its tight sand and shale resources. Along with citing examples from conventional reservoirs, this article also focuses on tight gas reservoirs, deployment of new technology, and making realistic estimates of well deliverability to close the gap between expected production and actual well performance.

Tight gas wells present challenges. They are not expected to produce at a high rate even after stimulation. They do

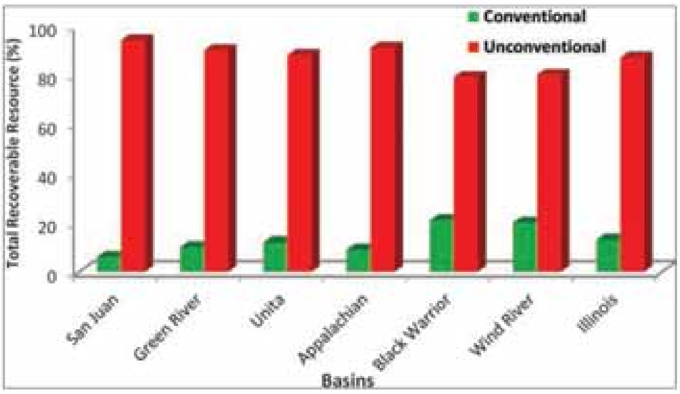


Fig. 1. Comparing conventional and unconventional gas reserves in some basins in the United States[1].

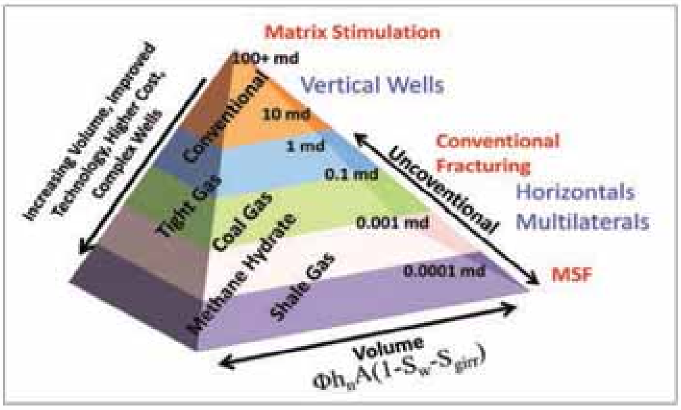


Fig. 2. Estimated reservoir properties and reserves volume[2].

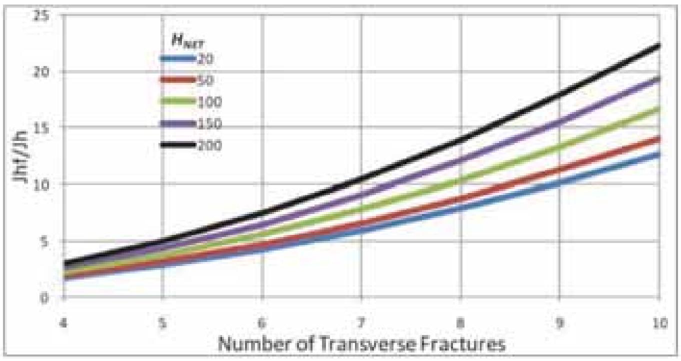


Fig. 3. Productivity increase ratio as a function of the number of fractures

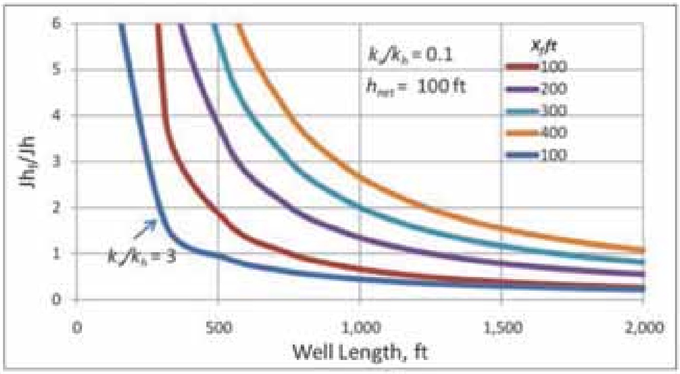


Fig. 4. Productivity increase ratio as a function of the fracture half-lengths (x_f)

not cleanup quickly after a stimulation treatment. The pressure transient tests conducted do not necessarily achieve a pseudo steady-state flow regime due to the slowness of fluid movement in low permeability. To improve the performance of wells drilled in tight gas reservoirs, the application of advanced drilling, completion and stimulation technology is required. Development and production of tight gas always faces many hurdles to overcome to achieve success. This article addresses improved well design and fracturing technology in moderate and tight gas reservoirs that help to realize full well and field potential.

Addressing the Challenges

In horizontal as well as in vertical wells, underachieved production performance is not uncommon. Some potential causes for underperforming wells could be:

• Not accounting for reservoir heterogeneity and permeability anisotropy.
• Inefficient perforations to connect the wellbore with the reservoir.
• Leftover damage from drill-in fluids that was neither cleaned up nor bypassed by stimulation.
• Ineffective well design.
• Ineffective stimulation treatment.
• Insufficient post-fracture cleanup causing fracture conductivity degradation.

Since its inception, hydraulic fracturing has become a strong technical process applied to oil and gas wells to overcome many of the aforementioned challenges. The primary objective of reservoir stimulation is to attain and sustain a higher gas rate in the early part of the well life to shorten the payout time. In the case of tight gas reservoirs in carbonates, sandstones and shales, wells cannot produce at any measurable rate without stimulation. Properly designed and implemented hydraulic fracturing treatments not only bypass wellbore damage, but also connect the virgin reservoir with long and highly conductive paths to ensure continuous gas flow into the wellbore. Good fracture conductivity is an essential element to minimize impact due to fluid blockage and to enhance production from high condensate gas reservoirs[3]. Major consideration must be given to selecting the correct stimulation fluid chemistry so that fracture fluid damage is minimized and post-treatment flow back is easily achievable.

A good perforation strategy also adds to the success of stimulation, particularly in deep tight gas formations with high in-situ stress, pressure and temperature. Jetting and creating slots with the use of acid or very small mesh size proppant in both vertical and horizontal completions, a viable alternative to the conventional charge perforation methods, has shown good results. The extremely high jetting velocity exerts an immense pressure on the target interval, producing good channeling/cavity communication of the wellbore with the reservoir. The perforation tunnels also make the subsequent fracturing treatment easier by lowering the near wellbore friction pressure loss[4].

The advanced multistage fracturing (MSF) applied to horizon- tal wells has proven to be a very useful technology. Depending on the well trajectory and azimuth, several fractures can be induced and propped in sequence in selected intervals to augment the flow path between the reservoir and the wellbore. For horizontal wells, the number of stages in a MSF completion depends on reservoir development, stress profile and wellbore trajectory. When a wellbore is placed along the direction of minimum in-situ stress ($\square_{min}$), the possibility that one induced fracture will over-lap another is nearly eliminated because the fracture plane goes in the direction of the maximum horizontal in-situ stress($\square_{max}$), perpendicular to $\square_{min}$ .This means multiple, independent fractures can be placed along the wellbore. On the other hand, when the well trajectory is in the $\square_{max}$ direction, the created fractures will be longitudinal along the wellbore plane, thereby limiting the number of independent fractures that can effectively be created and placed. Considering proper reservoir development and geomechanics, it is prudent to place wellbore trajectory toward $\square_{min}$ to ensure the inducing of multiple hydraulic fractures.

Figures 3 and 4 show results from analytical solutions of the productivity index (PI) ratio between fractured horizontal wells and unfractured wells as functions of a number of hydraulically created transverse fractures (NFR)[5]. The solutions also depend on the net pay thickness of the treated interval (H_{NET} or h_{net}) and the vertical to horizontal permeability ratio (k_v/k_h) as shown in the figures. For example, a horizontal well with net a pay thickness of 200 ft can double its productivity ratio with a respect to an unfractured horizontal well by increasing the number of fractures from 5 to 7, Fig. 3. Similarly, a horizontal well with 1,000 ft of reservoir contact and 300 ft of fracture half-length will have a productivity ratio that is twice that of an unfractured well, Fig. 4. The plots derived from these analytical solutions reinforce the need for conducting fracture treatments, even in cases of horizontal wells with high reservoir contact.

Improved Perforation Technology

Near wellbore tortuosity is one of many conditions that can cause additional friction pressure loss during the injection or production phase of a well[3]. Tortuosity can be caused by the creation of T-shaped fractures, reoriented fractures and multiple fractures. Good drilling and perforation practices are essential to minimize such pressure loss and establish good communication between the well and the virgin reservoir.

Regardless of the completion configuration, there always needs to be good communication between the wellbore and the formation to ensure full well potential. Such communication is achieved by the proper choice and placement of perforations. Two major types of perforation techniques that are widely used by the industry today are described in the following sections.

Conventional Charge Perforation (CCP)

In cased hole completions, shaped explosive perforation charges, or conventional charge perforation (CCP), is the most used perforation technique in the industry. CCP generates very high temperatures and pressures during the perforation process. This often creates localized stress and can crush cement bonds around perforations between the casing/formation annulus. Also, perforation creates crushed zones of very low permeability around the tunnels, which restricts both injection and production. Another perforation method characterized by extreme underbalance, in which a severe pressure drop is created simultaneously with the discharge of explosives, is sometimes used to immediately produce back the damage; the debris is drawn out before it concentrates and solidifies. Such underbalance technologies are usually expensive, however, and therefore prohibitive in routine activities.

For a well that is a fracturing candidate, the near well damage caused by perforations is easily overcome by the induced fracture and does not adversely affect gas production. The cost of CCP is low compared to the sand jet perforation (SJP) described in the next section, and the process is also time effective. In most cases, CCP is adequate, and with powerful, deep penetration charges, the near wellbore tortuosity and pressure losses due to inefficient perforations are minimized. In high stress intervals, however, sometimes the CCP method will not be able to establish enough injectivity to perform fracture treatments. In these specific cases, the SJP process can be used to improve access between the wellbore and the formation. A field example case is provided in the next section, showing the benefits of the SJP.

Sand Jet Perforation (SJP)

SJP involves the use of high-pressure slurry (a combination of gel, surfactant, low mesh sand and brine) to perforate and penetrate the tubular and cement sheath, and consequently create a cavity in the formation. Pumping is conducted at a high differential pressure, on the order of 2,500 psi, providing a velocity of about 600 ft per second across the cutting nozzles. The mechanism easily penetrates through tubular materials, cement sheath, and reservoir rock. Rock removal is caused by tensile failure, as the jetting is conducted below the compressive strength of the rock, avoiding compaction of the rock and thereby eliminating the possibility of lowered permeability. Specialized jetting tools and nozzles are required to provide the desired cavity in the formation.

One argument in favor of using this technique is that SJP achieves good vertical communication in horizontal wellbores, as well as easy initiation of hydraulic fractures. The perforations are smooth, and near well tortuosity and friction may be reduced. The cavities formed in the reservoir help in the faster cleanup of the well in the case of both fractured and unfractured wells. The method also eliminates the use of explosives, a much improved safety feature during operations that also reduces the potential for causing significant damage. The energy to perforate is incessant, as it is transferred to the formation through continuous injection of fluid and slurry.

The SJP technology is particularly suitable for strong rocks with high unconfined compressive strength (UCS) values. Due to the bigger opening of the rock, a rapidly increased proppant concentration schedule can be put in place when a well is perforated using SJP. It may take a particularly long time to perforate and slot the well, however, and the associated cost does not always make SJP attractive or competitive over the CCP techniques that are generally used in moderate strength rocks.

SJP Example: Well-A

Well-A is a vertical well drilled in a good permeability sand- stone section. It was initially perforated below the target interval with conventional shots across 40 ft. The intent was to induce an indirect fracture treatment through the perforation interval to connect the well to the more prolific interval 50 ft above. Direct perforation was avoided due to sanding possibility. During the initial DataFrac, several attempts to initiate a fracture turned out to be unsuccessful, as the injection pressure exceeded the tubular capacity without any indication of formation breakdown[6].

Figure 5 presents the pressure and rate profile of Well-A after conventional perforations. The dark blue and light blue lines in the figure represent the wellhead pressure response and the attempted injection rate profile, respectively. Consequently, the interval was sand jetted at the initial interval adding an additional 10 ft. The red and pink lines in Fig. 6 represent the wellhead pressure and injection rate profile, respectively, during post-jetting DataFrac treatment. These indicate that the breakdown of the formation has occurred, and a gain of about 2,000 psi in wellhead pressure was achieved.

Subsequent to the SJP treatment, the well was successfully fractured with more than 300,000 lbs of 20/40 and 16/30 mesh proppant types at a rate of 40 bpm. The treatment plot in Fig. 7 shows the

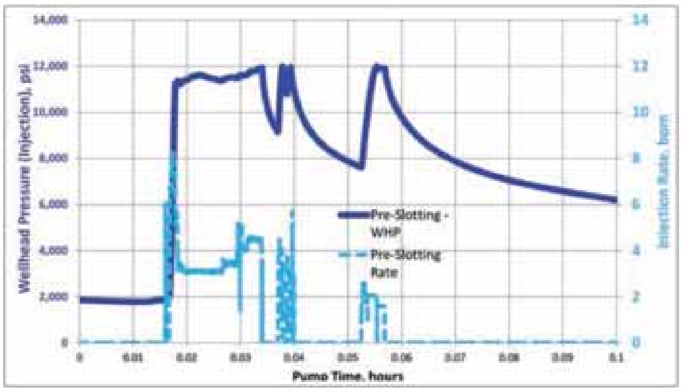


Fig. 5. Initial injection attempt after conventional perforation in Well-A.

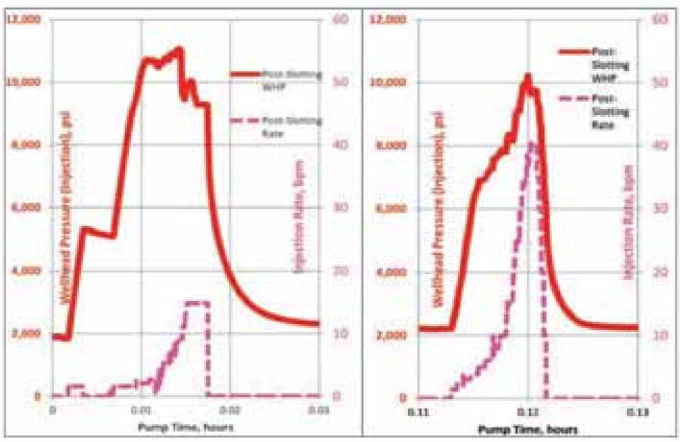


Fig. 6. Injection profile showing distinct formation breakdown and fracture extension post-SJP in Well-A.

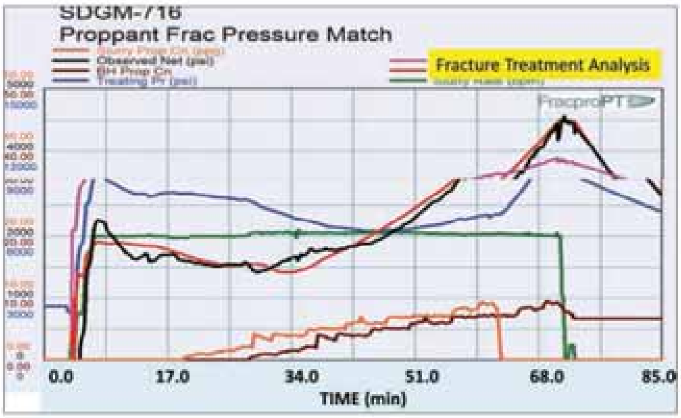


Fig. 7. Pump pressure match and injection profile for Well-A.

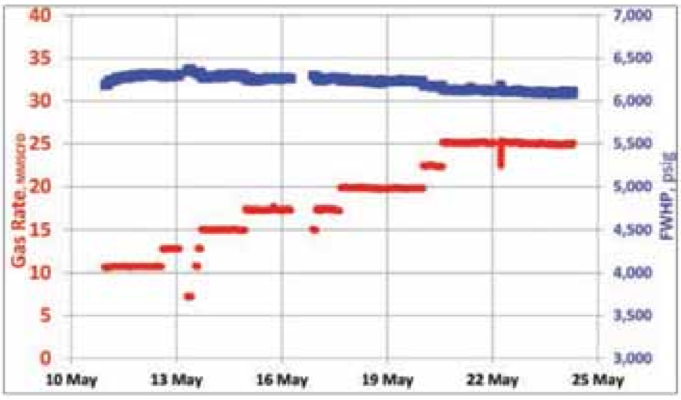


Fig. 10. Production test profile after SJP and fracturing in Well-A

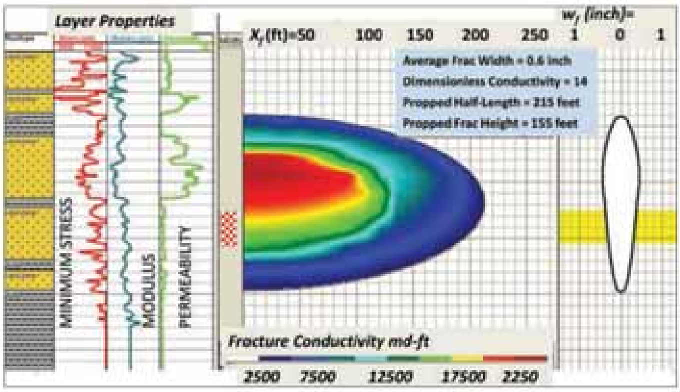


Fig. 8. Achieved fracture dimension and conductivity in Well-A.

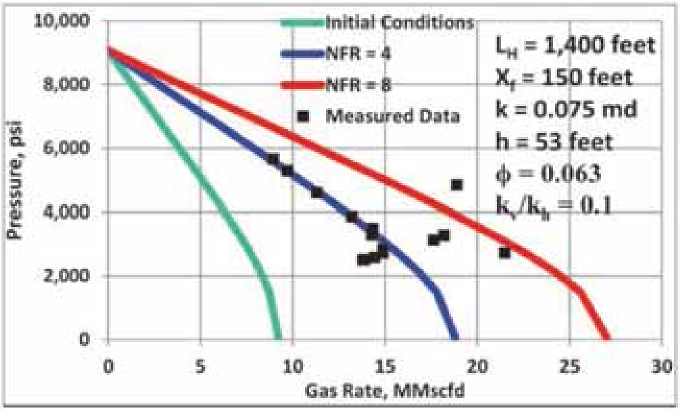


Fig. 11. Production test after stimulation treatment indicates fracturing results for Well-B in a tight reservoir.

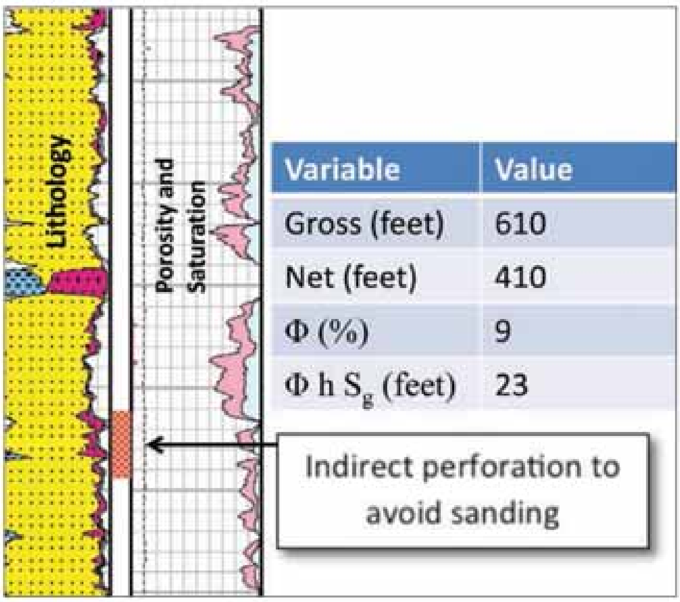


Fig. 9. Well-A formation lithology, porosity profile and perforation locations.

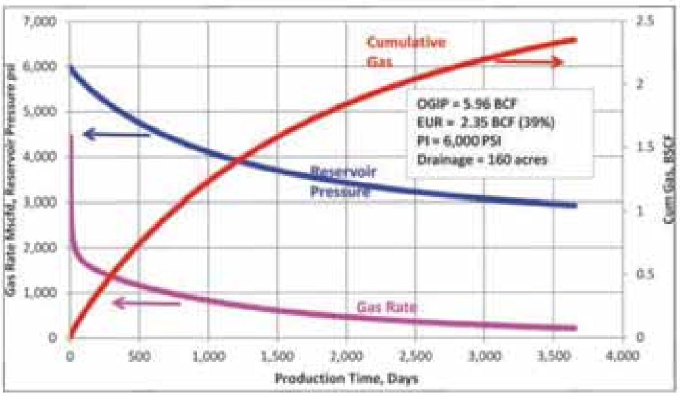


Fig. 12. 10-year flow performance shows about 2.4 BCF of cumulative production for Well-C.

proppant concentrations, wellhead pressures and bottom-hole pressures (BHPs), and injection rate, along with simulated match points to compute fracture dimension. Figure 8 presents the reservoir lithology, achieved propped fracture dimension and conductivity. The detailed formation lithology, porosity profile and fluid saturations, along with perforation locations are provided in Fig. 9. The high well performance and rate sustainability are indications of good reservoir quality, good wellbore/reservoir connectivity and a successful proppant fracturing, Fig. 10.

Tight Gas Reservoirs

A tight gas reservoir is defined as one that can neither be produced at economic flow rates nor recover economic volumes of natural gas unless a specified technique is used to stimulate production[7]. Depending on the reservoir rock properties, production from a tight gas reservoir can require either: (1) massive multiple hydraulic fracturing and/or (2) advanced drilling, such as horizontal or multilateral wells, to obtain maximum reservoir contact. Unconventional or tight gas has proven to be a large source of energy in every basin that produces a large quantity of hydrocarbons from conventional reservoirs. Optimal exploitation of tight gas needs to be studied and initiated for economic production.

It is well understood that regardless of how a stimulation job is executed, the rate and pressure at which a well produces depends entirely on the reservoir potential. Reservoir qualities, such as porosity, permeability, reservoir heterogeneity and layering, wellbore/reservoir connectivity, in-situ stress, etc., are some of the most important parameters used to predict well performance. As such, petrophysical evaluation and an understanding of the reservoir's flow and geomechanical properties are essential. In addition, the GIP and in-situ stress direction determine the number of wells to be drilled, the well spacing, the well azimuth and the hydraulic fracturing strategy needed to efficiently exploit a reservoir. Estimated ultimate recovery (EUR) helps in performing economic analyses so that realistic expectations can be set in terms of drilling and well performance prior to reservoir development.

Example Wells: Well-B and Well-C

The inflow performance rate (IPR) plot from a tight gas example, Well-B, is presented in Fig. 116. The well, initially drilled as a vertical well, tested about 8 million standard cubic feet per day (MMscfd) at 1,900 psi after hydraulic fracture treatment. The well was subsequently sidetracked, with a reservoir contact of 1,400 ft, completed with a MSF completion and successfully fractured in four stages. Under the initial well conditions (unfractured), the well was expected to produce at about 7 MM- scfd at 3,000 psi BHP. The actual measured production data after fracture treatment was matched with the predicted results of four transverse fractures (blue curve, Fig. 11). An additional run was made with eight fractures (red curve) to show that the well rate could have further improved; however, the major assumptions in prediction runs are that the reservoir and fracture properties stay constant, reservoir homogeneity is maintained throughout the drainage area, fracture treatment is implemented as designed, and post-treatment cleanup restores 80% of the original proppant conductivity.

Another actual example is Well-C is from a tight gas reservoir[6]. In this case, the reservoir pressure was lower than that of Well-B, and the formation quality was also much poorer. The post-fracture history matching showed two decent hydraulic fractures. The long-term production forecast for Well-C, performed using an analytical model and illustrated in Fig. 12, predicts about 2.4 billion cubic ft (BCF) of produced gas in 10 years. The EUR depends on the reservoir properties as well as wellbore configuration, well spacing and hydraulic fracturing characteristics.

Both Well-A and Well-B are expected to yield better performance once the fracture is properly cleaned up. The remainder of the fracture gel residue will still hamper the well performances, as will be illustrated later.

Hydraulic Fracturing

Although most moderate and tight gas wells are treated with hydraulic fracturing on a routine basis, it takes tremendous effort to optimize and conduct successful fracture treatments, where effective multiple fractures are placed in the reservoir and the post-treatment rates fall within expectations. A fracture design that is expected to improve the well rate by a certain factor must consider the "true fracture" dimensions and conductivity, which ultimately contribute to flow increase. Numerous factors can effect stimulation treatments so they do not work as designed and envisioned, resulting in the underperformance of a well. These factors and their related remedies are addressed in the following sections.

Fracture Dimensions

An important parameter in fracture dimension that contributes to well performance, other than fracture

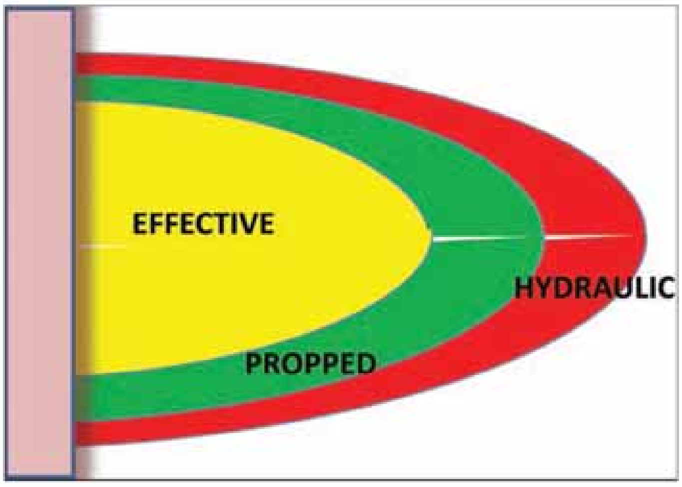


Fig. 13. Illustration of Xe, Xp and Xh indicating how $X_e < X_p < X_h$.

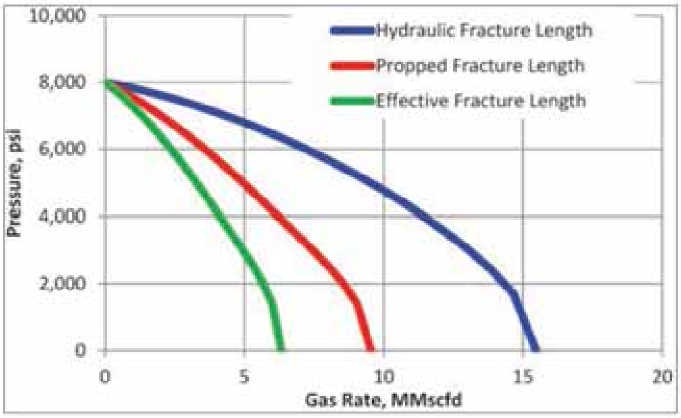


Fig. 14. Well potential as a function of X_f.

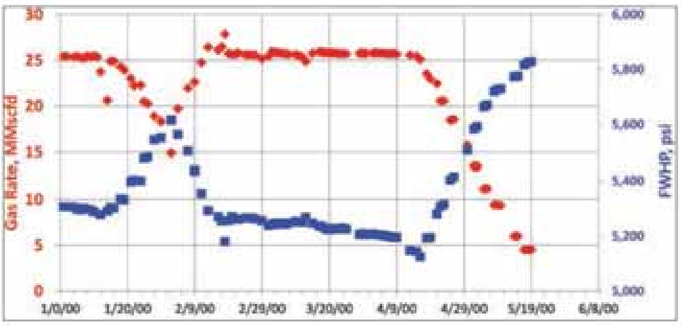


Fig. 15. Post-treatment performance of Well-D.

X_f	H_{NET}
feet	
200	100
125	75
75	50

Table 1. Reservoir and fracture properties (kh=10 md-ft).

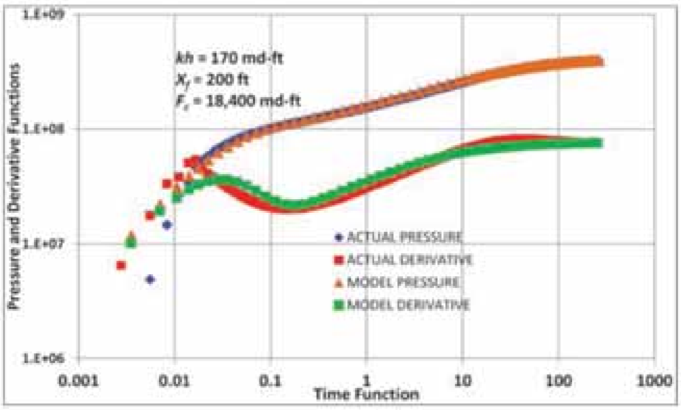


Fig. 16. Post-treatment PBU test on Well-D.

conductivity, is the effective fracture length (X_e), Fig. 13. Large discrepancies in fracture half-lengths among created fractures (also known as hydraulic fracture length, X_h), propped fractures (X_p) and X_e can cause the post-fracture flow rate to be lower than predicted[6]. The created fracture length is the fracture volume generated during pumping, based on the fluid volume balance (V_{pump} - V_{loss}) reached at the end of the job with the shutting down of the injection pumps. Determining the propped fracture length depends on the created volume and the pumped proppant mass. With good proppant transport and fluid quality assurance, a simple mass balance can provide the approximate fracture area coverage by the proppant, provided the correct stress profiles of Young's modulus are used to calculate the fracture height and width. The effective fracture geometry, which is the most important parameter since it dictates the post-treatment rate of the well, depends not only on proppant placement, but also on cleanup efficiency, residual gel damage and proppant conductivity losses due to embedment or crushing. An optimal fracturing job therefore requires scrupulous quality control and thorough post-stimulation cleanup. Well performance is directly propor- tional to effective fracture geometry. Figure 13 illustrates the possible scenario that generally occurs where $X_h > X_p > X_e$. The IPR plots illustrated in Fig. 14, which correspond to the reser- voir and fracture properties in Table 1, show how fracture half-lengths affect production rate. The impact of the effective fracture length on well performance is more pronounced in low permeability wells.

Good Proppant Transport Example, Well-D

Well-D, drilled in a good permeability sandstone reservoir, was successfully fractured with 220,000 lbs of proppant. The job went as per design, and a post-treatment stabilized rate of 25 MMscfd was achieved, Fig. 15. The pressure buildup test presented in Fig.

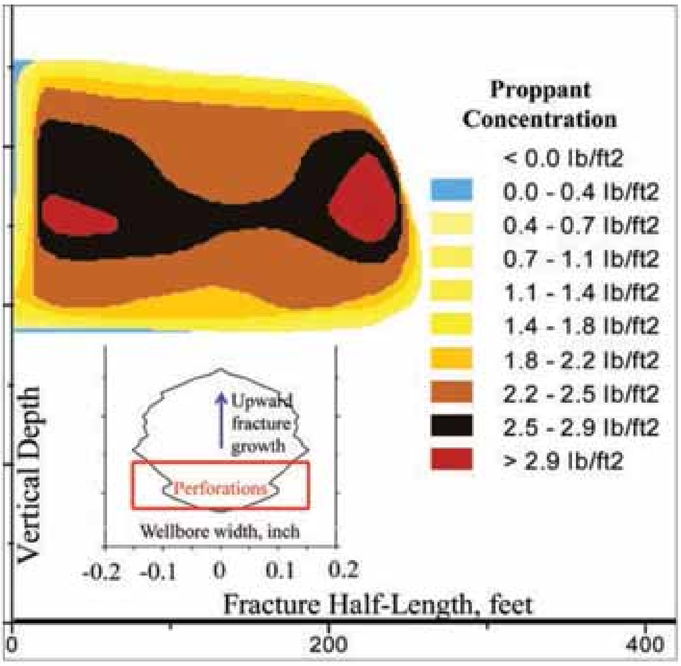


Fig. 17. Fracture geometry from pumping pressure match of Well-D.

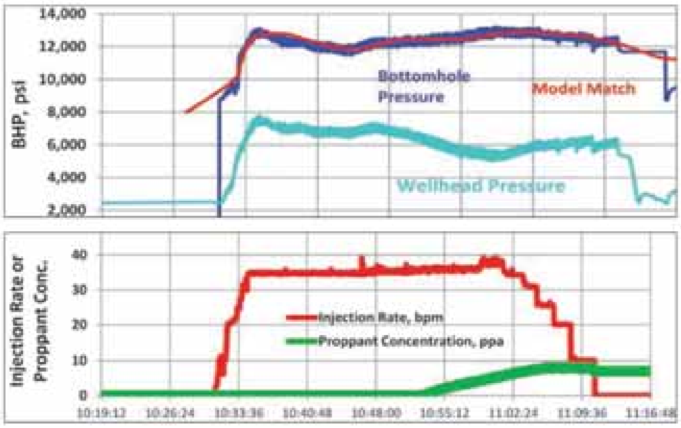


Fig. 18. Fracture treatment plot for Well-D..

Fluids	Main Components	Advantages / Disadvantages
Conventional Linear Gel	Polymer: Hydroxypropyl Guar (HPG) Carboxymethyl Guar (CMHPG) → These are dry polymers that swell up on hydration to form viscous gel	Poor proppant carrying capacity and high fluid loss Easier cleanup
Borate Cross-Linked	Guar of HPG, CMHPG and Hydroxyethyl Cellulose (HEC) →Use of Borate ions to cross-link hydrated polymers	Reversible (re-crosslink after shear degradation) – easy to break therefore gel regained permeability Stable and good transport capacity Requires hi gel pH (9-12) for viscosity yield →By far the most used fluid
Organo Metallic Cross-Linked	Titarate and Zirconate complexes of Guar	Extremely stable at high BHT (>300°) in acidic, alkaline or neutral pH fluid conditions →Shear sensitive and not reversible →Difficult to break Can cause high formation damage

Table 2. Different fracturing fluids and their advantages and disadvantages.

16 indicated near-infinite fracture conductivity with 200 ft of effective fracture half-length. The treatment pressure match, using a hydraulic fracture model, showed a propped fracture half-length of 250 ft. This is an excellent example where the effective fracture half-length was comparable with the propped fracture half-length derived from a pressure match and mass balance, so the expected rate performance compared closely with the actual performance of the well. Figures 17 and 18 present the propped fracture geometry from the injection pressure match for Well-D.

Fracturing Fluids

Fluid compatibility is a key issue in the final fracture design. Partially deteriorated or incompatible fluids, under-designed fluid additives, use of a higher polymer loading than required and other critical factors can cause formation damage, fracture conductivity reduction or premature screen-out, all leading to loss of well potential. The most important factors to be considered in selecting fluids are fluid loss properties, fluid stability under reservoir conditions (temperature and pressure), compatibility with formation fluids, friction loss,

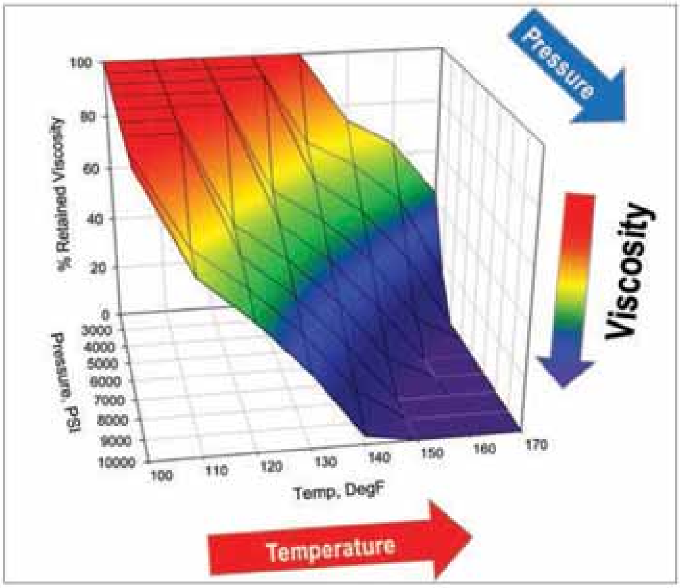


Fig. 19. Fluid behavior under temperature and pressure[9]

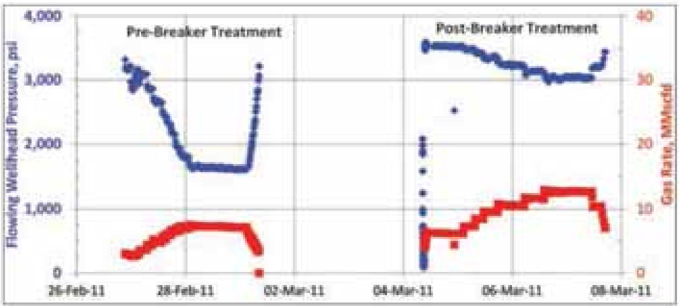


Fig. 20. Well-E performance before and after good cleanup.

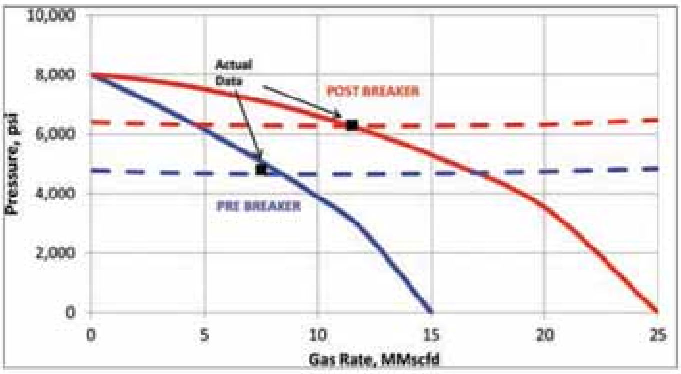


Fig. 21. Improved Well-E IPR after additional gel breaker treatment.

regained permeability (formation damage), proppant transport capability, and final fracture conductivity. More than 50 different fracturing fluids are available to address different reservoir issues during stimulation. The main types are provided in Table 28.

Pumping pressures encountered during fracturing can degrade borate crosslinked fluid viscosity[9]. The loss in fluid integrity can be negligible to complete, depending on the fluid formulation, temperature and pressure. The most recent study showing the loss of fluid viscosity as

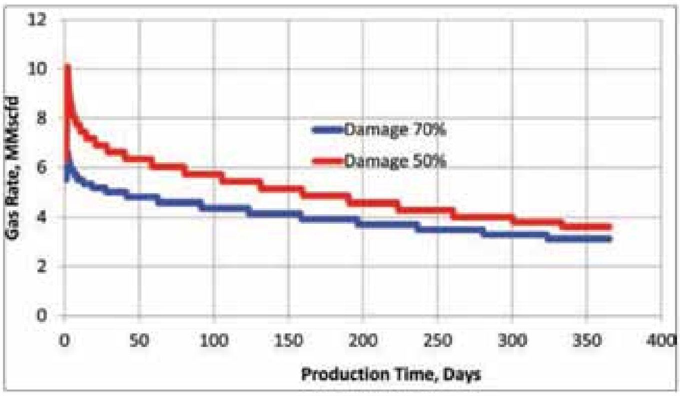


Fig. 22. Long-term production impairment due to improper cleanup in Well-F[6,10].

functions of pressure and temperature is illustrated in Fig. 19. It is therefore important to consider rheology behavior when selecting the fluid, per the functions of the reservoir and pumping conditions.

The pump volume for each stage is optimized based on reservoir properties, proppant volume and proppant concentration. The pad volume depends on the leakoff and must generate enough width before the proppant reaches the fracture.

Insufficient pad volume or rapidly degrading fluid under reservoir conditions will cause premature screen out. Over-designing the flush stage with the intent to displace all the proppant from the wellbore and into the fracture will lead to poor wellbore and fracture connectivity, and thereby significantly reduce gas flow.

Post-Fracture Cleanup

Excellent fracture fluid cleanup is required to restore proppant conductivity; otherwise it will lead to damage in the proppant pack and significantly decrease well productivity. The cleanup process can be improved with the use of: (1) a good fluid recipe (low gel loading and cross-linker concentration in addition to sufficient breaker and surfactants), and (2) quick cleanup practices after the treatment is over. If a well is not cleaned up properly, significant gel damage may occur, and proppant conductivity will be reduced permanently.

Figure 20 presents well performance profiles of an actual well, Well-E, drilled in tight sandstone, where the initial cleanup after fracture treatment was not sufficient[6]. The post-treatment well performance was gauged against reservoir characteristics and expected fracture geometry, and it was immediately concluded that the actual rate was below expectation. Since the fracture treatment had been pumped as designed, it was suspected that the proppant pack was damaged due to insufficient cleanup of the well. Consequently, a much stronger live gel breaker at a higher concentration along with a surfactant was re-injected into the well. After waiting for the reaction to occur, the well was opened for cleanup. At this time, a much higher flow rate at a higher wellhead pressure was obtained, which was comparable to the expected well performance. Both pre- and post-breaker performance points were matched, which showed, Fig. 21, that well IPR more than doubled as a result of the treatment. This actual example illustrates the two major components of a successful well stimulation process: (1) good estimation of well performance, which requires proper knowledge of the reservoir and fracture properties, and (2) identification of the cause of the problem (in cases where the well performance falls below expectations), determining remedial actions and applying necessary treatment to restore productivity.

A similar problem happened with Well-F, where the well rate fell far below predicted post-fracture performance. Similar to Well-D of the previous example, Well-F was a vertical well drilled in a low permeability interval, and it had been successfully perforated and fractured with 250,000 lbs of proppant. The initial post-fracture test rate was matched with a numerical simulator only by reducing the well's proppant conductivity by 73%. This reduction in proppant conductivity was caused by the residual gel damage that did not flow back to the surface during cleanup. Figure 22 presents a 1-year gas rate profile for Well-F with a 70% and 50% loss of proppant conductivity[6,10]. In actuality, the industry average for proppant conductivity after successful treatment and cleanup is about 80% of the theoretical permeability. This means that conductivity degradation, due to gel damage or any other factor, 20% or less, is within the tolerance criterion. Figure 23 shows that in a 1-year period, a gain in cumulative production of about 25% can be achieved if Well-F is initially cleaned up and has 80% of its proppant conductivity restored.

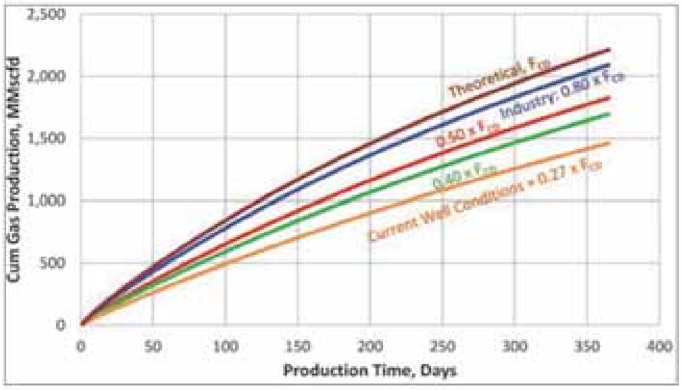


Fig. 23. Cumulative production after cleanup.

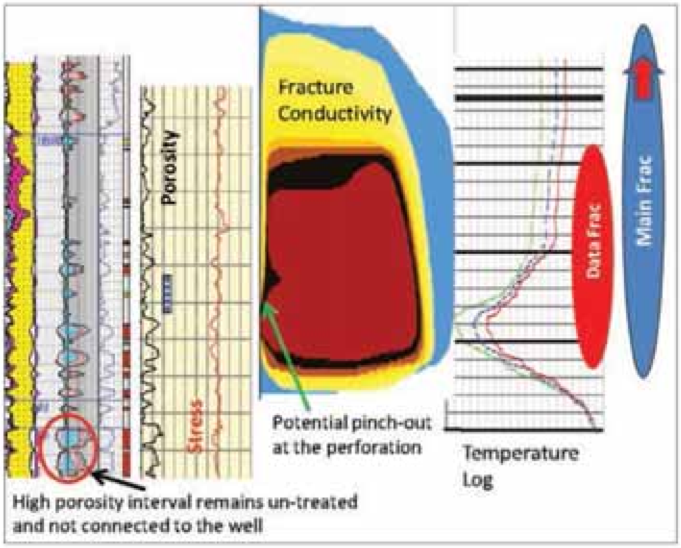


Fig. 24. Pinch out and fracture growth affecting fracture effectiveness in Well-G.

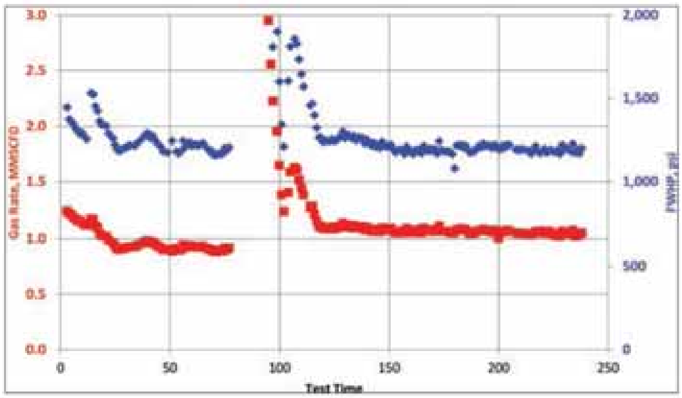


Fig. 25. Post-fracture test results confirm poor fracture placement for Well-G.

Selection of Perforation Interval

Improper placement of perforations can cause the fracture to grow outside the reservoir interval. For indirect fracture treatments, often chosen to avoid perforating high sanding intervals, perforations are sometimes placed above the zone of interest to avoid sanding. In such cases, high net pressure at the end of pumping must be built to maintain the connectivity of the perforated interval with the main gas section and to avoid creating pinch-outs due to proppant settlement. An example provided in Fig. 24, Well-G, shows that although the fracture propagated below the perforations and covered some of the high porosity intervals, a pinch-out occurred in the perforated interval due to proppant settlement[6]. This settlement was caused by high stress in the perforated interval as well as the low net pressure achieved at the end of the job, resulting in insufficient packing of the proppant. The decreasing pressure

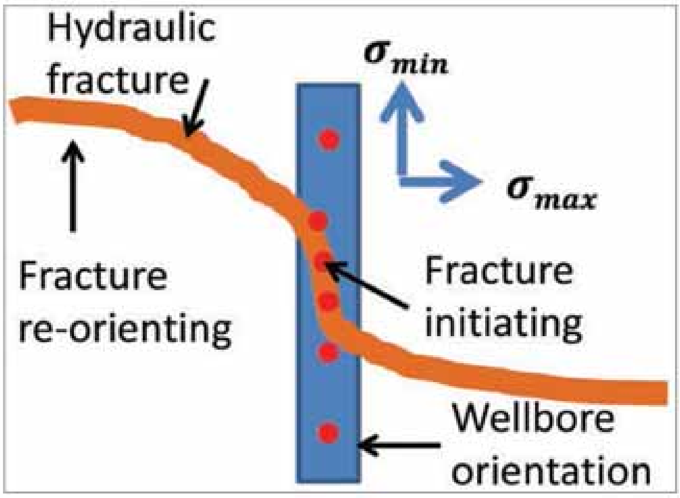


Fig. 26. Possible T-shape fracture for wells oriented toward $\square_{min}$.

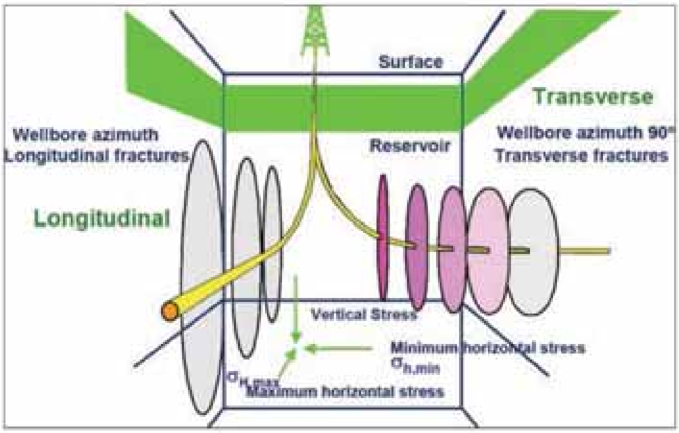


Fig. 28. Fracture development as a function of wellbore orientation (after Economides).

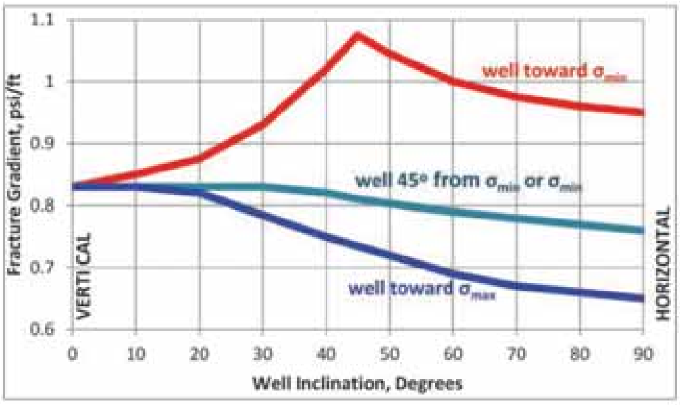


Fig. 27. Fracture initiation pressure as a function of wellbore orientation[11].

response observed in the pump pressure profile also indicates growth in fracture height, in this case more in the upward direction, which caused more proppant to be lost in the nonproductive zone. The two bottommost high permeability intervals indicated in the figure were not covered by the fracture. Although the entire treatment was successfully pumped, placing all the proppant inside the formation, the well only produced about 1 MMscfd, much below expectations, Fig. 25. To overcome the poor well performance, remedial action to re-treat the reservoir is being designed. For indirect fracture treatments, placing perforations below the zone of interest is usually a better option[6]. In this scenario, even with the proppant settlement, the connection of the fracture with the non-perforated higher productivity zone is better maintained with such placement.

Wellbore Trajectory

Wells that are drilled parallel to $\square_{max}$ will not favor creation of transverse or orthogonal fractures. In such a case, the number of hydraulic fractures that can be created is reduced significantly. That is because when a well is placed along the maximum in-situ stress direction, the induced fractures are created in the same direction, limiting the number of independent fractures that realistically can be placed without one fracture overlapping the adjacent one. It is therefore conceivable that only between two and four fractures can be placed longitudinally in a wellbore that is more than 1,000 ft long, while there is practically no limitation on the number of orthogonal fractures generated from wellbores perpendicular to $\square_{max}$. Subsequently, the optimal number of fractures is not necessarily the largest number; rather it is dictated by the reservoir flow capacity, wellbore trajectory, reservoir contact, and completion limitation.

The well azimuth and inclination may impact the fracture initiation pressure. When a wellbore is drilled in the direction of the least horizontal stress, T-shaped fractures are likely to occur, Fig. 26. This is because the tensile zone created around the wellbore in the direction of $\square_{max}$ causes the fracture to initiate in $\square_{min}$ direction, but soon the fracture turns, the propagating axis changes, and the fracture develops toward $\square_{max}$ direction. Figure 27 shows that the maximum initiation pressure is reached in a well that is 45° deviated and drilled toward $\square_{min}$[11]. A 15% increase in breakdown pressure can occur for a horizontal well drilled toward min compared to a vertical well. Proper tubular ratings are therefore needed to fracture a high stress formation having horizontal wells with an azimuth toward $\square_{min}$.

The fracture orientation with reference to the wellbore is presented schematically in Fig. 28. It should be noted that to get production impact from horizontal wells with multiple fractures, each fracture has to be of sufficient length and conductivity, and each needs to be properly cleaned up after treatment. The placement and total number of fractures should minimize interference between fractures. This requires good reservoir knowledge, proper planning and design of fracture treatment, and proper implementation. If placing more fractures causes interference, then the number of fractures should be optimized. Reservoir isotropy and homogeneity will impact well performance and ultimate recovery.

Conclusions and Recommendations

1. In-depth reservoir characterization and optimal fracture design are needed to predict a realistic gas rate and cumulative recovery.

2. The gap between expected well performance and what actually occurs can be minimized by using an appropriate reservoir model, implementing good fracturing practices and ensuring complete cleanup.

3. Selecting the correct fracture fluids is essential for a treatment to be successful. Correct gel loading, breaker concentration and addition of surfactants will enhance fluid flow back after treatment.

4. Improper cleanup reduces fracture conductivity and can significantly impact well rate and recovery.

5. Sand jetting can sometimes be used to improve communication between the wellbore and the formation.

6. In indirect fracturing treatments, care must be taken to ensure good connectivity between fracture and wellbore. Pinch-outs and proppant settlement will negatively impact the gas rate.

7. Multiple fracturing stages can be induced when wells are drilled toward the minimum in-situ stress direction. Higher fracture initiation pressure can be expected in such a configuration.

Acknowledgements

The authors would like to thank Saudi Aramco management for their permission to present and publish this article.

References

1. Holditch, S., Perry, K. and Lee, J.: "Unconventional Gas Reservoirs – Tight Gas, Coal Seams, and Shales," Topic Paper, NPC Global Oil and Gas Study, July 2007.

2. Holditch, S.A.: "Hydraulic Fracturing: Overviews, Trends, Issues," Drilling Contractor, July/August 2007, pp. 116-118.

3. Al-Anazi, H.A., Okasha, T.M., Haas, M.D., Ginest, N.H. and Al-Faifi, M.G.: "Impact of Completion Fluids on Productivity in Gas/Condensate Reservoirs," SPE paper 94256, presented at the SPE Production Operations Symposium, Oklahoma City, Oklahoma, April 16-19, 2005.

4. Surjaatmadja, J.B., Abass, H.H. and Brumley, J.L.: "Elimination of Near-Wellbore Tortuosities by Means of Hydrojetting," SPE paper 28761, presented at the SPE Asia Pacific Oil and Gas Conference, Melbourne, Australia, November 7-10, 1994.

5. Rahim, Z., Al-Kanaan, A.A. and Al-Anazi, H.A.: "Comprehensive Parametric Study of Optimal Well Configuration for Improved Gas Rate and Recovery," SPE paper SAS-59, submitted to the SPE Annual Technical Conference, Saudi Arabian Section, al-Khobar, Saudi Arabia, April 8-11, 2012.

6. GRMD internal well documentation and report.

7. Personal communication with Stephen A. Holditch.

8. Service company documentation.

9. England, K.W. and Parris, M.D.: "The Unexpected Rheological Behavior of Borate-Crosslinked Gels," SPE paper 140400, presented at the SPE Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, Texas, January 24-26, 2011.

10. Collaboration with Halliburton Service Company.

11. Baree, B.: "Perforation for Stimulation," www.baree.net/Fracture_Advances/.

Biographies

Dr Zillur Rahim is a Petroleum Engineering Consultant with Saudi Aramco's Gas Reservoir Management Division. His expertise includes well stimulation design, analysis and optimization, pressure transient test analysis, gas field development, planning and reservoir management. Prior to joining Saudi Aramco, Rahim worked as a Senior Reservoir Engineer with Holditch & Associates, Inc., and later with Schlumberger Reservoir Technologies in College Station, TX. He has taught petroleum engineering industry courses and has developed analytical and numerical models to history match and forecast production and well testing data, and to simulate 3D hydraulic fracture propagation, proppant transport, and acid reaction and penetration.

Rahim has authored 55 Society of Petroleum Engineers (SPE) papers and numerous in-house technical documents. He is a member of SPE and a technical editor for the Journal of Petroleum Science and Engineering (JPSE). Rahim is a registered Professional Engineer in the State of Texas and a mentor for Saudi Aramco's Technologist Development Program (TDP). He is an instructor for the Reservoir Stimulation and Hydraulic Fracturing course for the Upstream Professional Development Center (UPDC) of Saudi Aramco.

Rahim received his BS degree from the Institut Algerien du Petrole, Boumerdes, Algeria, and his MS and PhD degrees from Texas A&M University, College Station, TX, all in Petroleum Engineering.

Dr Hamoud A. Al-Anazi is a Supervisor in the Gas Reservoir Management Division in the Southern Area Reservoir Management Department. His areas of interests include studies on formation damage, fluid flow in porous media and gas condensate reservoirs. Hamoud has published more than 38 papers in local/international conferences and refereed journals. He is an active member of the Society of Petroleum Engineers (SPE) where he serves on several committees for SPE technical conferences.

In 1994, Hamoud received his BS degree in Chemical Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia, and in 1999 and 2003, he received his MS and PhD. degrees, respectively, in Petroleum Engineering, both from the University of Texas at Austin, Austin, TX.

Adnan A. Al-Kanaan is the General Supervisor for the Gas Reservoir Management Division, where he heads a team of more than 30 petroleum engineering professionals working to meet the Kingdom's increasing gas demand for its internal consumption.

He started his career at the Saudi Shell Petrochemical Company as a Senior Process Engineer. Adnan then joined Saudi Aramco in 1997 and was an integral part of the technical team responsible for the on-time initiation of the Hawiyah and Haradh Gas Plants, two major plants that currently process 6 billion cubic feet (BCF) of gas per day. He also manages Karan and Wasit, the two giant offshore gas increment projects, with expected total production capacity of 5.5 BCF of gas per day.

Adnan has 14 years of diversified experience in reservoir management, field development, reserves assessment, gas production engineering and mentoring young professionals. His areas of interest include reservoir engineering, well test analysis, reservoir characterization and reservoir development planning.

Adnan received his BS degree in Chemical Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.

He is a member of the Society of Petroleum Engineers (SPE).

Ali H. Habbtar is a Reservoir Engineer focusing on gas production as part of Saudi Aramco's Gas Reservoir Management Division. He has extensive experience in hydraulic fracturing for productivity improvement and sand control. Ali also has significant experience in conducting on-site operations as a Production Engineer and is a member of multiple Saudi Aramco teams tasked with stimulation design and stimulation technology introduction.

He received his B.S. degree in Petroleum Engineering from Pennsylvania State University, University Park, PA, and an MBA from the Instituto de Estudios Superiores de la Empresa Business School, Barcelona, Spain.

Ahmed M. Al-Omair is a Reservoir Engineer and Supervisor for Saudi Aramco's Gas Reservoir Management Division, overseeing Shedgum and 'Uthmaniyah fields. His expertise includes reservoir development, well testing and production forecast.

Ahmed received his BS degree from the University of Louisiana, Lafayette, LA, and his MS degree from the University of New South Wales, Sydney, Australia, both in Petroleum Engineering.

Nejla H. Senturk is a Petroleum Engineering Specialist with Saudi Aramco in the Gas Reservoir Management Division. She has been with the company since February 1982 and has held a number of reservoir engineering positions, in both oil and non-associated gas fields. Nejla is currently the Reservoir Engineer for 'Ain Dar and Shedgum non-associated gas fields, located in Ghawar field. She is specifically focused on implementing new reservoir engineering technologies to exploit the Khuff carbonate and pre-Khuff sandstone reservoirs.

Before joining Saudi Aramco, Nejla worked for the Alberta Research Council for 2 years and at Exxon (in its subsidiary Esso Resources Canada) as a Reservoir Engineer for 4 years.

She received her BS degree in Chemical Engineering from Ankara University, Ankara, Turkey, and her MS degree in Chemical Engineering from the University of Alberta, Edmonton, Alberta, Canada.

She is a certified Petroleum Engineer in Canada and has been a member of the Society of Petroleum Engineers (SPE) since 1978.

Daniel Kalinin is the Schlumberger Reservoir Stimulation Domain Manager based in al-Khobar, Saudi Arabia. He is responsible for the integration of Schlumberger expertise in reservoir evaluation and charac- terization into fracturing and stimulation in Saudi Arabia, Bahrain and Kuwait. Before coming to Saudi Arabia in 2009, Daniel was involved in G&G support of the Chicontepec integrated well construction project in Mexico, carbonate stimulation in Kazakhstan, and development of a stimulation activity in Turkmenistan and Uzbekistan. He took part in the start of the fracturing boom in Russia in the late 1990s. Before joining Schlumberger in 1999, he worked for a joint venture of Canadian Fracmaster in Western Siberia.

Daniel received his BS degree in Structural Geology from Novosibirsk State University, Novosibirsk, Russia, in 1993, and another degree in Economics from Tomsk State University of Architecture and Construction, Tomsk, Russia. He also attended various post-grad programs at the University of Tulsa, Tulsa, OK, and the Imperial College, London, U.K.

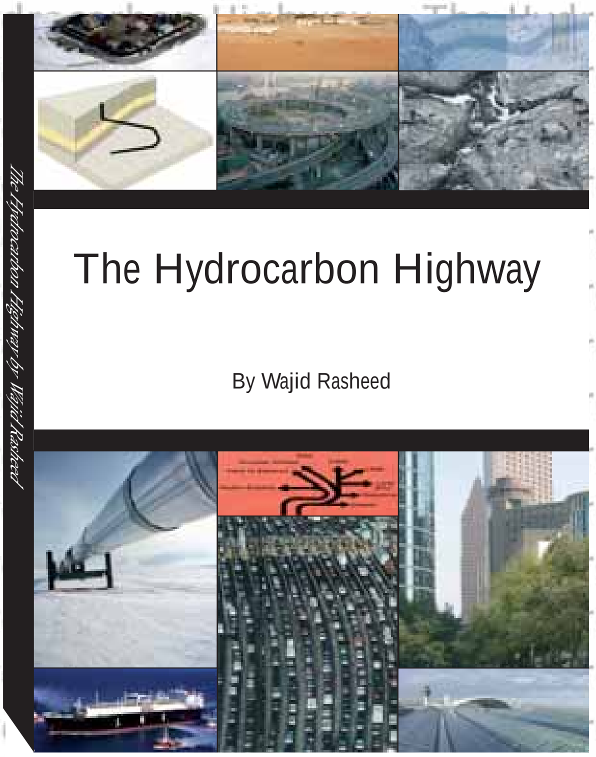
EPRASHEED
signature series

Purchase Now

The Hydrocarbon Highway

"I found the book excellent because it provides a balanced and realistic view of the oil industry and oil as an important source of energy for the world"

Dr AbdulAziz Al Majed, Chairman, Department of Petroleum Engineering, King Fahd University of Petroleum & Minerals.



Please send me ☐ copies of The Hydrocarbon Highway

Name: ....

Title: ....

Company: ....

Mailing Address ....

....

....

Phone: .... Fax: ....

Please debit my credit card:

Visa/Mastercard Number ....

Name on Card .... Expiry ....

☐ I enclose a cheque or banker's order in US Dollars, payable to EPRasheed Ltd

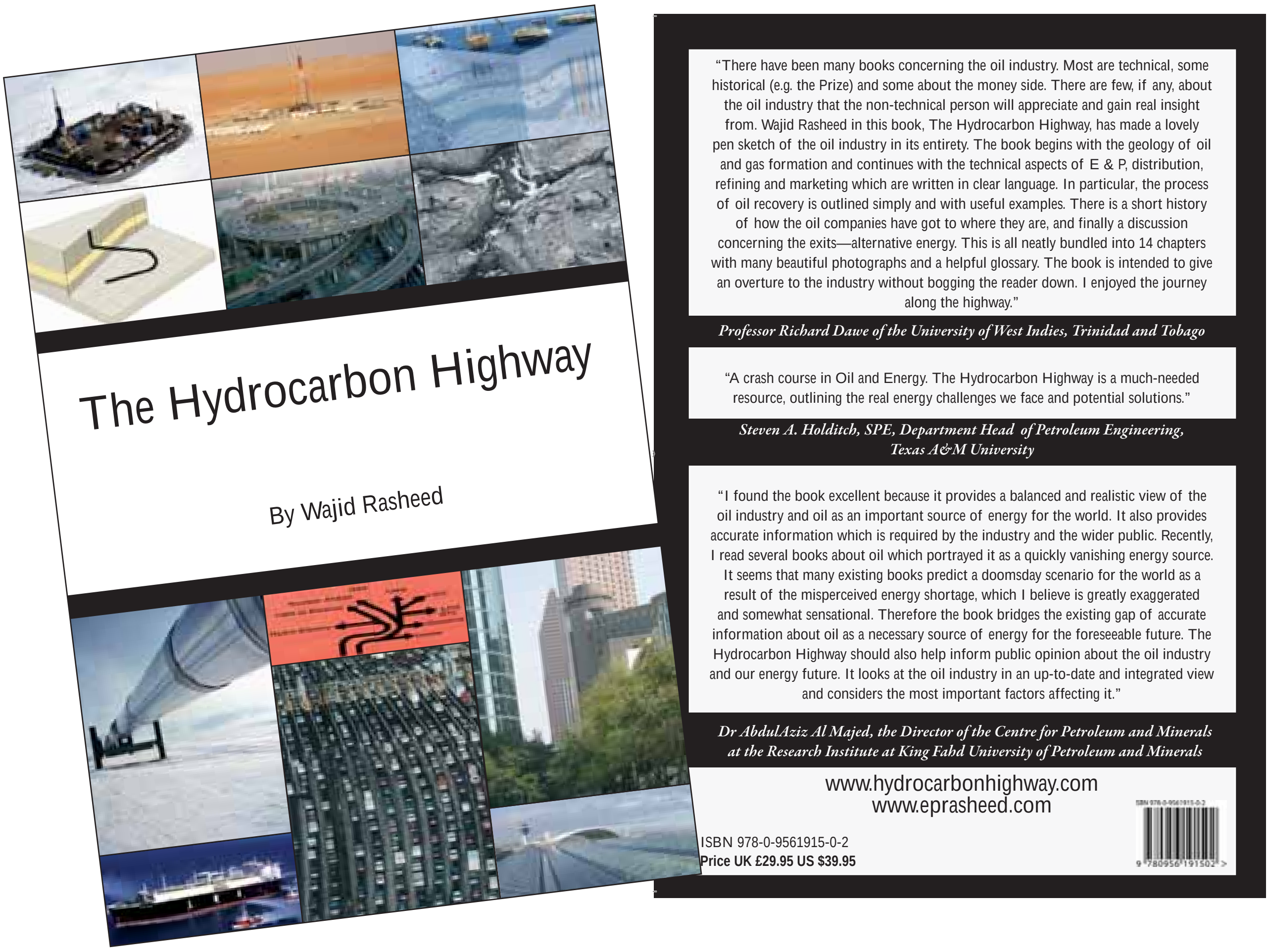
Charges Per Book:
The Hydrocarbon Highway: $39.95
Standard Delivery: $10.00 ☐ Express Delivery $30.00 ☐

Signature ....

Mail all Orders to:

11 Murray St, Camden, NW1 3RE, London, England

The Fall of the Oil Curtain



What would a sketch of the global landscape of reserves and production look like? No doubt, its most salient features would be the growing appetite for oil and gas and the drive for reserves replacement from frontiers and mature fields. In the background, would lie the cycles of 'feast or famine' and the long lead times that govern investment and returns. Yet, tantalizingly hidden away is the essence of the industry—petroleum reserves. they are measured.

The Oil Curtain neatly symbolises resource sovereignty and separates the hydrocarbon 'haves' from the 'have-nots'. It has led to the major part of proved global oil reserves being booked by National or State Oil Companies (NOCs). To illustrate the change of ownership, in 1971 NOCs held 30% of total reserves while International Oil Companies (IOCs) held 70%. Today, NOCs have increased their share to 93% while IOCs hold 7%[1]. What could have caused such a dramatic reversal in fortune?

Figure 1 - President Lula Commemorates Brazil's Self-Sufficiency

Since the early 1900s, the importance of oil in financial, political and strategic matters has been bubbling up to the surface. Eventually, this led to a pressing need for producing states to control oil. Mexico was first to 'shut' the Curtain by nationalising its oil assets and forming the wholly state-owned Pemex (Petróleos Mexicanos) in 1938[2]. By 1960, resource sovereignty had fully matured into a global force and the Central Bank of Oil[3] – OPEC (Organisation of Petroleum Exporting Countries) – was created.

The effects of the Oil Curtain have been a blunting of IOC access to oil and a partial blurring of the distinction between NOCs and IOCs. As the spheres of action of both types of companies increasingly overlap, the industry has become more geographically dispersed and institutionally fragmented. Not least, the Oil Curtain has driven certain IOCs to metamorphose into energy companies.

The Oil Is Ours

'The oil is ours' reads a sign as you leave Rio de Janeiro on the road to the oilfield city of Macaé. That sign is not a historic throwback or juvenile street graffiti, but a modern official billboard paid for by the Brazilian government. Its nationalistic message is that oil, and oil wealth, are too important to be left to foreigners and external market forces. This message is a recurrent one found worldwide. It is just the language and symbolism that changes; Russia's Shtokman field, jobs for the boys; Niger Delta, moralists decrying the excesses of ex-pats; PdVSA and Bolivia; gringo go home.

Consider Shtokman and the decision of the Russian government to develop it alone – this is a clear message that the gas reserves could and would be developed without outside help which could otherwise be perceived as 'dependence' on foreign oil companies. Continuing unrest in the Niger Delta points to a different dynamic between regional and federal revenue sharing but nonetheless still nationalism. Bolivia's nationalisation of its Gas industry sends the same clear message. What is interesting is that both fully privatised and part-privatised companies were affected. StatoilHydro bid for Shtokman and was seen as the front runner and Petrobras invested heavily in Bolivia from Exploration and Production (E & P) to pipelines to marketing. In Venezuela and the Niger delta, the effects were felt by IOCs Exxon Mobil and Shell[4].

Humble Oil

Oil has come a long way from its humble roots. Until the early 1900s, it was just a cheap fuel for lamps and heaters. How then could it be transformed into a strategic resource and military necessity within a decade? This rapid change was due to the convenience with which oil could be stored and transported, coupled with its high energy density. It was the most efficient fuel that mankind had discovered – the perfect fuel for the internal combustion engine and mechanised transportation. By 1911, it had replaced coal as the preferred fuel for the British Royal Navy. By 1918, other navies had quickly followed suit, creating a speed and logistics advantage that ultimately led to victory to those that used it. Accompanying the new-found

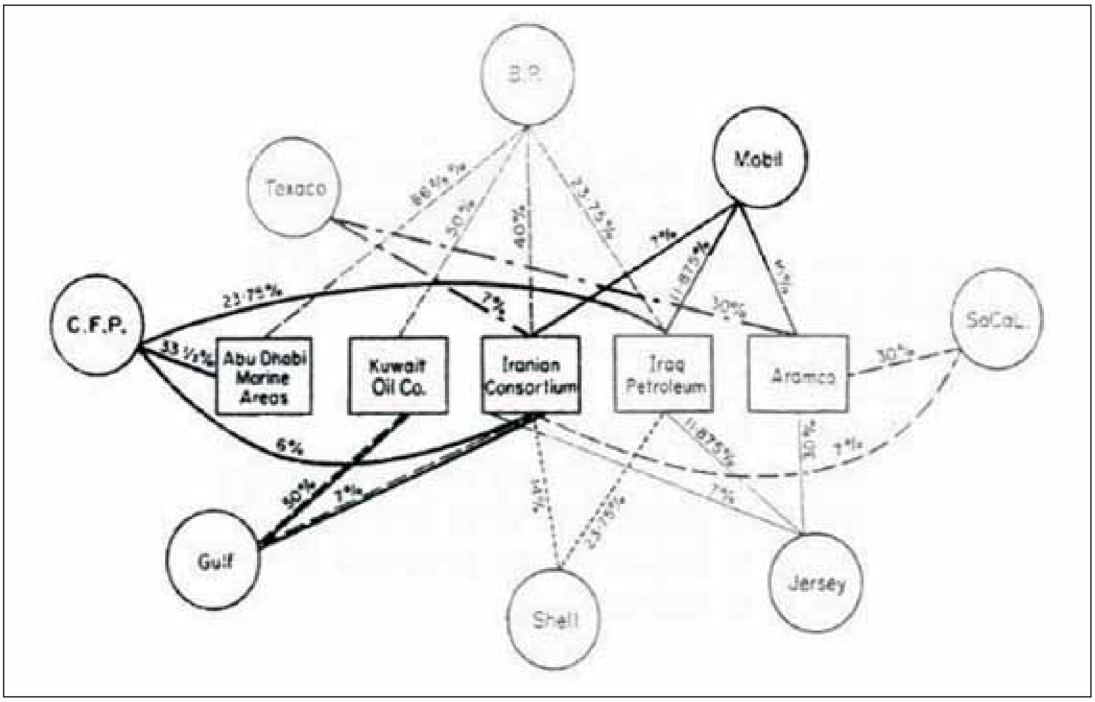


Figure 2 - Ownership Links Between Major IOCs (including Compagnie Française des Pétroles) and the Major Producing Companies in the Middle East after Edith Penrose, 1966

status of diesel oil and gasoline as the fuels-of-choice for the war machine was the struggle to secure supply amidst the geopolitical upheaval of the times. In fact, it has been postulated that fuel shortages, not the Allies' military prowess, led to the ultimate demise of the Axis powers in World War II. The race had begun[5].

Makeover

Principally driven by the British, French and American governments, numerous oil companies were set the task of securing oil supply for their countries' needs. It was through ownership of concessions in developing countries, and predominantly in the Middle East and Far East, that the IOCs grew.

Known as the 'Seven-Sisters*,' – a term coined by the Italian oil tycoon Enrico Mattei referring to Exxon (Esso), Shell, British Petroleum (BP), Gulf, Texaco, Mobil and Socal (Chevron – plus an eighth, the Compagnie Francaise Des Pétroles (CFP-Total)[6]– these companies raced to find 'the prize'[7].

During this growth period, the IOCs made huge strikes in oil and rapidly drilled the wells and built the pipelines and refineries that were needed to turn the flow of oil into revenue. This was undoubtedly the golden period of the IOCs but, despite expert negotiations and justifications, the geopolitical manoeuvering was being noticed by the producing countries.

Seeds of Discontent

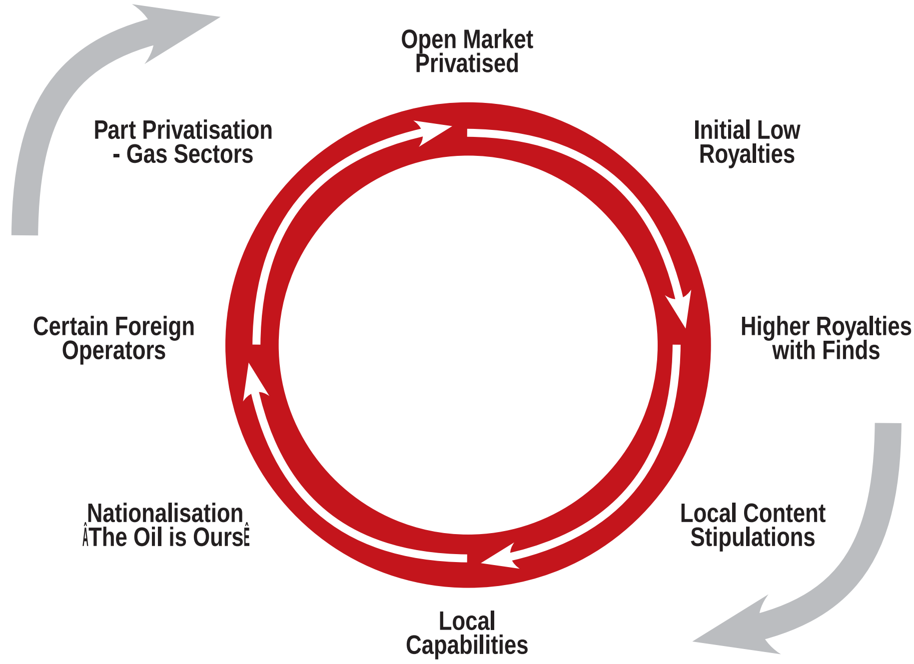
In the period between the two world wars, more and more countries began realising their futures were contingent on controlling their own resources, oil especially. At the vanguard of this realization was President Cardenas of Mexico[8,9].

The seeds of nationalisation had been sown by Mexico in 1934 when it forcibly took over the shareholdings of foreign oil companies operating in Mexico resulting in the creation of Pemex which became the first 'nationalised oil company'. Venezuela and Iran soon joined Mexico by re-nationalising their hydrocarbons.

Winds of Change

By the end of the Second World War in 1945, the knowledge that oil was of great commercial and strategic importance was commonplace. Oil was associated with vast revenue flows as well as having kept the 'war-machine' running. Consequently, colonial powers sought to control oil supplies.

In the post-war period, however, the winds of political change had swept aside the old colonial order whose



Oil and gas nationalisation has come full circle from seeking higher royalties to partial privatisation.

Figure 3 - Modern National Oil and Gas Policy

political leaders acquiesced to foreign clients and replaced them with vocal nationalists who advocated sovereignty and independence. Exemplifying this were the strong voices of Gandhi in the Indian subcontinent, as well as Nasser and the Ba'ath party in the Arab states.

Viewed through the lens of political independence, control over natural resources had become an urgent necessity and, despite geographic and ethnic separations, a unified and growing chorus emerged with Mossadegh in Iran, Qasim in Iraq, Perez Alfonso in Venezuela and Tariki in Saudi Arabia all seeking to review oil contracts[10,11,12].

Initially, these individuals and countries acted alone, but as events unfolded affecting them all, they became increasingly united. The nationalist's central message was clear; oil was too important to leave in the hands of foreigners[13]. There was a need to regulate 'oil-rents' and end arbitrary payments from foreign oil companies.

Nationalist thinking was shaped threefold. Firstly, deals favoured foreign oil companies and foreign governments, not producing states. Foreign oil companies also controlled an outward flow of profits which were often the greater part of the producing countries' Gross Domestic Product (GDP). Generally, beneficiaries were foreign governments either directly through shareholder dividends or indirectly through taxes. Secondly, foreigners took vital political decisions affecting the sovereignty of producing countries. Oil production, foreign exchange earnings through oil sales, and ultimately, national debt were unilaterally dictated by foreign oil companies. Lastly, the military and naval campaigns of the Second World War, combined with the utility of oil in general transportation, left no doubt that oil was a primary strategic asset.

These factors created resentment among the political elites and the disenfranchised in producing countries leading to the conviction among producing states that oil profits should be shared equally between producing states that had territorial ownership of resources and IOCs who conducted E & P activities for oil[14]. Producing countries became united; the old deals had to be undone. New deals would treat territorial owners of resources and the IOCs as equals.

Sovereignty Over Resources

Financial, political and strategic factors acted as a catalyst for resource nationalisation, most notably with Iran and Venezuela taking their first steps toward sovereignty during the fifties. In Iran, the government nationalised the oil assets of Anglo-Persian (the

> "By the end of the Second World War in 1945, the knowledge that oil was of great commercial and strategic importance was commonplace."

precursor to British Petroleum). In Venezuela, the government established the famous '50/50' petroleum legislation that split oil revenues affecting US oil companies. Shortly after, Saudi Arabia, Algeria, Iraq and Libya followed suit[15].

Nationalisation in Teheran and the reformulation of oil revenues in Caracas were pivotal events that directed the founders-to-be of OPEC – Juan Perez-Alfonzo, the Venezuelan Oil Minister, and Abdullah Tariki, the Saudi Arabian Oil Minister – to seek a mechanism that would stabilise prices. They found the solution in a global equivalent of the Texas Railroad Commission, which had successfully controlled US over-supply of oil to stabilise prices[16].

The Compacto

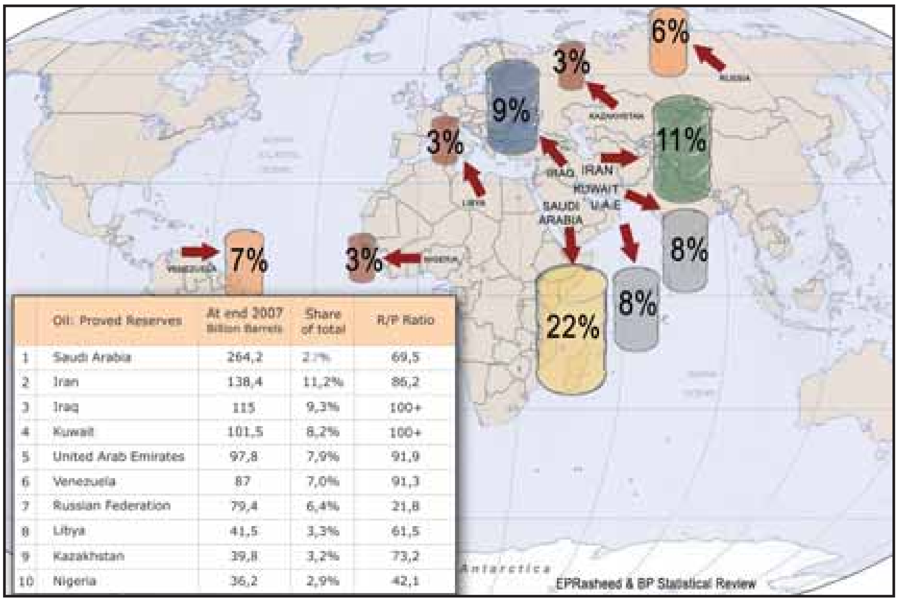
During the Arab Oil Congress meeting in Cairo, Egypt in April 1959, Tariki and Perez-Alfonzo met to discuss what had been pressing so heavily on their minds. The two gentlemen had both reached the conclusion that the 50/50 principle should be replaced by a 60/40 split in favour of the producers. Within a year, the two men created the 'Compacto Petrolero' – an 'Oil Commission' that would permanently tip the balance of power in favour of producers. In some ways, this was the precursor to the Oil Curtain – the Compacto reshaped NOCs by aiming for a 60% share of profits. In due course by integrating their E & P, distribution, refining, transportation and retail operations, the NOCs would learn to compete with the IOCs[17].

Birth of OPEC

Of course, the IOCs were avidly paying attention to the 'Compacto'. Despite feigning disinterest in events, they turned to the spot markets and cut oil prices. Anglo-Persian (BP) had cut prices on the eve of the Arab congress meeting. Then, Standard Oil of NJ (Exxon) unilaterally cut the posted price of oil. Such a Machiavellian move would immediately affect the pockets and pride of producers, facts that were not lost on the decision makers who elected to keep the producers in the dark.

Rude words could have been a fitting response and perhaps, moves such as those that the oil companies had taken would have caused Alfonzo to use such words to describe oil politic[18].

In any event, the cuts prompted a united response and a different kind of swearing. Iraq invited several major petroleum exporting countries namely Iran, Venezuela,



	Oil: Proved Reserves	At end 2007 Billion Barrels	Share of total	R/P Ratio
1	Saudi Arabia	264,2	[illegible]	69,5
2	Iran	138,4	11,2%	86,2
3	Iraq	115	9,3%	100+
4	Kuwait	101,5	8,2%	100+
5	United Arab Emirates	97,8	7,9%	91,9
6	Venezuela	87	7,0%	91,3
7	Russian Federation	79,4	6,4%	21,8
8	Libya	41,5	3,3%	61,5
9	Kazakhstan	39,8	3,2%	73,2
10	Nigeria	36,2	2,9%	42,1

Figure 4 - Top Ten Global Oil Reserves 2007

Saudi Arabia and Kuwait to Baghdad for a historic meeting which led to the birth of OPEC on September 14, 1960.

OPEC's first resolution pointed to the oil companies as the culprits: 'That members can no longer remain indifferent to the attitude heretofore adopted by the oil companies in affecting price modifications; that members shall demand that oil companies maintain their prices steady and free from all unnecessary fluctuation; that members shall endeavour, by all means available to them, to restore present prices to the levels prevailing before the reductions'[19].

The Princes Taught a Lesson

After the Second World War, the independence of former colonies sent out a shockwave – resource nationalisation. This in turn, created OPEC which signaled a decline in the hegemony of IOCs globally. By 1970, the oil companies were still enjoying a princely existence but only just. Between 1960 and 1966, their share of oil production outside North America and the Former Soviet Union (FSU) countries, had increased from 72% to 76%, leaving 24% for the NOCs[20].

Oil company profits, despite complex justifications to OPEC and despite falling prices, were still high compared to most other industries. Rates of return for most IOCs were higher in 1966 than in 1960[21], and IOCs were able to finance most E & P as well as refining, retail and petrochemicals out of crude oil profits made abroad. The IOCs argued with OPEC that the retailing network was needed to create markets for OPEC oil, which would otherwise go unsold; however, it was the scale of repatriated profits that were ultimately responsible for unraveling the IOCs' concessions[22].

Sleeping Giant

The potency of OPEC remained dormant for a decade. In November 1962, OPEC was registered with the United Nations Secretariat[23]. Yet, it was not until the mid-1970's that a growing group of countries nationalised (or in some cases re-nationalised) their hydrocarbon industries. In 1973, it was the combination of Libyan radicalism and an Arab oil embargo precipitated by US support for Israel in the Arab-Israeli war, that within a ten-month period in 1974, culminated in the price of a barrel of oil rising by 228 per cent[24].

The old order had given way to the new.

Between 1970 and 1976, nearly 20 countries asserted national sovereignty over their operations[25]. In February 1971 after acrimonious disputes about prices, Algeria nationalised all French interests within its territory[26]. Shortly after, Libya announced the nationalisation of

> "As modernity spreads, lifestyles that were once confined to wealthy classes in wealthy countries are now found up and down social classes and across the globe."

all BP's assets. This has continued to the present period where, most recently, Venezuela and Bolivia have nationalised IOC oil assets[27].

Driven by the need to develop gas reserves (to meet growing national and international demand for gas and to keep oil for exports), many countries had slowly relaxed national controls and through joint ventures, contracts with service companies and, exceptionally, ownership licences, larger oil companies were allowed to return to previously nationalised oil markets[28].

Modern national oil policy has come full circle (see Figure 3). It has evolved from seeking equal treatment to maximising royalties to stipulating local content to full re-nationalisation and now to partial privatisation for gas developments.

Yet in the latest period, nationalisation has resurged and this can be seen clearly in Russia's decision to develop the Shtokman field alone and remove certain IOCs from the Sakhalin development, while in Bolivia and Venezuela oil companies have had their licences revoked and lost production. Nationalisation has even surfaced in the North Sea with Norway's government-controlled Statoil conducting a reverse takeover of NorskHydro. The Oil Curtain has spread.

As modernity spreads, lifestyles that were once confined to wealthy classes in wealthy countries are now found up and down social classes and across the globe. Think China and India. Together this relentless demand for oil and gas, which was already a strategic resource, has meant that oil and gas have become the world's most desired commodities.

In 2008, oil prices broke through the US $125 per barrel level peaking at a ceiling of US $147 before tumbling back to US $35 all within a six month period. Nevertheless, it is easy to forget that oil is cyclical and therefore it is only a question of time before it goes up. The only question is whether the present down cycle has a prolonged hard landing from the peak[29].

New Seven Sisters

Nowadays, OPEC decisions get as much ink as those of major central banks[30]. Yet beyond the paparazzi flashes and news-wire headlines, how important will OPEC and NOCs be for future oil supply? Realistically, the production of OPEC and certain NOCs will be vital for several generations to come. To understand that reality, simply look at (see Figure 4) the top ten reserve holders worldwide: Saudi Arabia, Iran, Iraq, Kuwait, UAE, Venezuela, Russia, Libya, Kazhkstan and Nigeria. Seven of these countries – the first six and Libya –

> NOCs may not become global household brands, but they have set the trend that restricts IOC access to oil, and lately, the dividing line between the two is not so clear.

are all OPEC members. To see how important these new Seven Sisters are to future oil supplies, consider the reserves to production column (Figure 4) to see how many of today's top ten global reserve holders are likely to be producers in the US Energy Information Administration (EIA) Energy Reference Case year of 2030[31].

At that time, I will be 60 years old and probably writing about the world's next 25 years of oil production. More to the point of todays' top ten oil reserve holders, Russia will have dropped off the list while the new seven sisters and OPEC will still be producing away. What about the other current major producers? Canada has 22.9 years, the US has 11.7 years and Mexico has 9.6 years of oil reserves left at current production rates. Upshot: OPEC and the new Seven Sisters will grow both home and abroad. NOCs may not become global household brands, but they have set the trend that restricts IOC access to oil, and lately, the dividing line between the two is not so clear.

Fuzzy Logic

The fuzziness between private and state oil companies stems from the NOCs that have 'gone global'. On the one hand, for certain companies the logic and returns of going global are compelling; add new production and export 'home-grown' technology. Yet, on the other hand, there is the risk of sudden nationalisation. Once wellheads, fields, pipelines and refineries are built, they cannot be dismantled and sent back 'home'. In the event of political change or a major dispute, the oil company's bargaining power is effectively reduced. Any share or interest it may have in production can only be sold off to the state which then becomes a question of expedient valuations rather than ownership.

What actually constitutes a NOC? Is it 100% state ownership or just a state majority? What if the company floats on the world's stock markets and has private shareholders yet retains a state majority?

The distinction depends on whoever holds 51% or more of voting shares and controls overall decision making power. If the majority shareholder is a government or state, the company must answer to them; therefore, such a company is defined a NOC. The opposite also applies. If the company's 51% voting majority is privately held or listed, it would be defined an IOC.

Shareholder distinctions shed light on the responsibilities of each company too. NOCs have a strong responsibility to steward oil wealth to meet the needs of a given nation and its population in a

Figure 5 - Downtown View of Houston (EPRasheed)

sustainable way. IOCs focus primarily on maximising returns; social responsibility is important, but not to the same degree as NOCs. Most people in the industry accept that profits must be balanced with social responsibility. Private shareholders generally accept this too. Corporate Social Responsibility (CSR) programmes within IOCs are abundant and this type of social spending does raise investors' eyebrows as long as returns are healthy. Part-privatised NOCs fall into this category also. Just how much social responsibility is deemed healthy depends on the shareholders.

We Speak Your Language

Notable NOCs such as Petrobras and CNPC operate well beyond their home territories. Both companies not only retain majority government stakes, but also raise capital using a canny combination of state finance and international financial markets to develop domestic

> The ultimate interests of oil producers and consumers... always converges in promoting stability of the worldwide economic framework and minimising economic shocks.

and foreign reserves. Where they really excel is by competing internationally for capital and upstream acreage and applying their unique technologies and know-how.

Accessing reserves or holding on to them is the producer's top challenge. Consumption is a given. Subsequently, finance, Human Resources (HR), technology and processes can be acquired.

Undoubtedly, production is one end of a transaction; consumers are needed too. Both depend on each other for the respective stability of demand and supply. Whatever affects the economies of oil consumers ripples through to producers and vice versa. The ultimate interests of oil producers and consumers, therefore, always converges in promoting stability of the worldwide economic framework and minimising economic shocks.

The upshot is that reserve holders or producers, rather than retailers, determine rules. In this way, accessing reserves or holding on to them has become the producer's number one challenge—HR, technology, vertical integration and process efficiencies can all be subsequently acquired.

NOCs Go Global

Naturally then it is a 'no-brainer' for NOCs with global ambitions to compete for foreign reserves and production. Entering this competition makes sense for those NOCs such as Petrobras or the China National Petroleum Corporation (CNPC) that have limited reserves or high production costs at 'home' or where they can export 'home-grown' technologies abroad. It does not make sense for the new Seven Sisters who have abundant domestic reserves at relatively low production costs. In the latter, it makes more sense to stay 'home' and develop national reserves.

In the old days, it was fair to say that the IOCs conferred access to reserves. They had the technology, know-how and capital to create wealth from a natural resource. Naturally, they bargained hard and got the lion's share. Those 'old ways' show that oil reserve holders used to recognise IOCs as equals, perhaps even as holding the upper hand as IOC participation was required for revenues to be realised[32].

But Where Do the IOCs Fit Into All of This Today?

Much has been written on IOCs and our focus is on the growth of the NOCs which is far less documented; however, as the two are inextricably linked, it is worth

"As the Oil Curtain fell, the IOCs became accustomed to a gradually shrinking pool of accessible oil reserves that were ever more difficult and costly to produce."

briefly extracting pivotal events that are common denominators. It is widely accepted that the oil industry's fate was sealed by growing demand for transportation (military and consumer) and the steady supply of oil from refineries, pipelines and fields worldwide.

Numerous discoveries were made by geologists and drillers made production possible by always finding a way. In fact, the vertical integration and camaraderie of an inter-disciplinary approach positioned IOCs so well that it was almost as if each had its own principality of petroleum production[33].

Original Seven Sisters

A decade ago the price of a barrel of oil languished at US $10. This triggered 'mergeritis' and reformed the original Seven Sisters. During the 1990s, the new 'prize' for these companies was finding synergies and economies of scale. Management consultants were set the task of merging these great disparate entities and analysts evaluated the mergers in terms of restructuring and costs.

In the corporate cost-cutting that ensued, locations and operations were rationalised. Many IOC's consolidated their international operations in Houston. Research and Development (R & D), technology activities and technical disciplines were seen as unnecessary fixed costs that could be more profitably outsourced. At that time, only a handful of voices questioned rationalisation especially that related to technology R & D; it made sense financially and operationally. Ironically, technical outsourcing would strengthen the Oil Curtain and return to haunt IOCs.

Metamorphosis Begins

As the Oil Curtain fell, the IOCs became accustomed to a gradually shrinking pool of accessible oil reserves that were ever more difficult and costly to produce. This initiated the metamorphosis of the IOC with progressive companies such as BP and Shell repositioning themselves for the future, not just because they had seen 'beyond petroleum' but because they had felt 'the Oil Curtain' fall. This, however, does not imply the fall of the IOCs; there are still plenty of global E & P opportunities around, albeit tempered by lower margins due to higher cost and technical challenges.

Oil companies' future profits (and share prices) depend on production and reserves. As older fields decline, companies must find new production and

Figure 6 - Rabigh Refinery (Courtesy of Saudi Aramco)

decommission older structures. Our earlier look at the global reserves base shows the true significance of NOCs. Where reserves are institutionally accessible by IOCs, they are accessible only at considerably higher costs typified by technically challenging projects in ultra-deepwaters or the Arctic. In this way IOC 'replacement' costs tend to rise faster than NOC replacement costs. However, this is not always true as certain NOCs that have deepwater or heavy oil reserves may have comparable costs to those of IOCs.

The metamorphosis of more progressive IOCs into energy companies are clear trends for the future of the industry. Natural gas emerges as a bridge to alternates with certain IOCs quietly stacking up an impressive array of gas technologies and know-how. Here, BP has distinguished itself in LNG and solar know-how, while Shell has done the same in Gas-to-Liquids (GTL) and hydrogen (see *Chapter 13: Renewable Energy*).

Houston, We Have a Capital

As the industry consolidated, Houston emerged as its capital city and its downtown skyline became synonymous with the global oil business. Today, Houston represents the oil consumption capital of the world. The oil production capital lies elsewhere. Characterised by a modest skyline and towering reserves, Dhahran takes that title. Moscow becomes the natural gas production capital and Doha that of Liquefied Natural Gas (LNG). Almaty, Baku, Bushehr, Lagos, Macae, Maracaibo are other emerging oil cities as the industry realigns. The combination of oil technology as a commodity, ascendant oil prices and the realignment of cities has strengthened the Oil Curtain. Ironically, as oil production technology becomes freely available on the market, access to oil reserves becomes more restricted.

Consolidation

Whenever the price of crude oil falls below a certain cut-off point, operators cut budgets and work orders, and oil service and supply companies enter into a period where revenues drop sharply. For many oil-related companies, this means a fall in their share yields and ultimately a drop in stock prices. This increases the likelihood of takeover in two ways. First, asset rich companies with poor liquidity or cash flow difficulties find themselves financially exposed and become prime

> "Technological advancement and innovation is typical of high-cost industries where saving time and money is vital to the commercial success of companies and the industry itself."

targets for takeovers and asset stripping. Second, product or concept rich companies who have often borne high R & D costs are swallowed up by larger organisations seeking to add value to their operations and increase market shares[35].

In this way, during the 90's low oil price environment (US $10/bbl)[36], many upstream companies looked to the stock markets to increase oil and gas revenues effectively, by acquiring listed companies whose share price belied their reserve values. For this reason, cost reduction was an imperative[37] and 'performance optimisation' and 'well-cost reduction' became strategic. Nowhere was this strategy more relevant than in high-cost environments such as the North Western Euro-pean Continental Shelf. Ever since the late 1980s, this area has been characterised by the need to cut costs and to advance technology. In the 1990s, the scale of cost-cutting was widespread and was exemplified by the shedding of labour, outsourcing, contractual terminations and 'mergeritis'. The industry even institutionalised cost reduction through the creation of initiatives such as Cost Reduction in the New Era (CRINE) in the UK sector and NORSOK in the Norwegian sector[38].

Mergeritis

This gave rise to 'mergeritis' which re-formed* the world's largest oil companies – Exxon and Mobil, Chevron and Texaco, BP, Amoco and Arco. Management consultants were set the task of merging these great entities by generating synergies and economies of scale. Analysts evaluated the mergers in terms of restructuring and cost-cutting to justify the acquisition costs and remain competitive against the low oil price[39].

In the corporate cost-cutting that ensued, locations and operations were rationalised. This led to Houston's growth and importance within the oilfield. Many IOCs consolidated their international operations in Houston and it was the prevalent wisdom that R & D technology activities could be cast-off as unnecessary fixed costs that could be more profitably outsourced. At that time, the oil company rationalisation made sense financially and operationally.

Outsourcing Technology

Technological advancement and innovation is typical of high-cost industries where saving time and money is vital to the commercial success of companies and the industry itself. These factors have played a crucial part in the advancements made in well trajectories—such as seismic, multilateral, Extended Reach Drilling (ERD), horizontal and designer wells—and the enabling technologies to optimise production, and in so doing, increase profitability.

As operators became leaner, well profiles followed suit and the requirements for competitive tenders, data simulation and risk analysis increased. The bottom line was that service companies were being asked to contribute more value than ever before, in order to reduce well cost and optimise performance. In this way, the IOCs outsourced more and more, not just technology niches, but certain technical disciplines such as drilling or production engineering as well[40].

Service Sector Grows

Service companies grew in the interim. Simultaneously, they kept a watchful eye on US and international projects being planned out of Houston and carefully noted cast-off R & D projects with a view to commercialisation. In this way, Houston evolved as the E & P capital of the oil industry and its downtown skyline characterised worldwide operations.

Ironically, it has been the convergence of technology outsourcing and ascendant oil prices that have strengthened the Oil Curtain. This is the self-fulfilling prophecy; as production technology becomes easier to get on the open market, oil access becomes more restricted.

Corporate Social Responsibility (CSR)

There was always a constant suspicion amongst producing countries that the IOCs were extensions of foreign governments, acting out colonial policy as required. This suspicion may have contributed to oil companies engaging in social programmes. It is unclear which IOC started wider social engagement such as education, hospitals and the development of local skills. What is quite clear is that such engagement gave rise to a wide ranging set of IOC initiatives such as sustainable development or CSR which were designed to ameliorate a series of sore issues that were rooted in inequalities between the producers and the IOCs. These ranged from the setting of volumes of oil exports, the repatriation of profits, the heavy dependence on imported goods and services to the princely lifestyle of foreigners posted to poor countries.

Sustainable development has grown to encompass the building of local capacity that may export technology and know-how, and the savings and investments of oil profits into non-oil related industries. Essentially, it means enfranchising locals in most aspects of the oil company's business either locally owned or managed[41].

It can be argued that the geopolitical tension that lies at the heart of certain disputes results from the uneven distribution of oil-wealth. If that were not enough, the fact that oil is a finite wealth generator makes things worse. This ultimately highlights the undoing of any CSR initiative or investment. As long as disparities in the distribution of oil-wealth exist, CSR programmes are constantly in peril of being perceived at best as arbitrary acts of philanthropy or at worst empty exercises in public relations[42].

The politics of revenue distribution can be a potential minefield for oil companies. They must satisfy the powers that be – state governments – and reconcile the valid needs of local groups, whether these are communities that have right-of-way over pipelines or those that live in the state that produces oil or gas. If there are competing ethnic groups or self-perpetuating elites co-existing with poverty stricken masses, the oil company is sitting on a time-bomb. Paradoxically, sometimes it is the case that even if oil companies keep locals happy and build local industries, the government may still nationalise.

NOC/IOC—Corporate Transparency

Transparency or the lack of it was also a major influencer in the changing behaviour of IOCs. The IOCs saw that they were being targeted by savvy lobbyists and environmental activists that could impact their image (and share price) in their home countries. This coupled with anti-corporate demonstrations even led some IOCs (BP) to publish sensitive figures regarding tax payments abroad made to foreign governments in regard of operating agreements. Further, some oil companies aligned themselves to protecting human rights by joining the UN World Compact (Petrobras). Legislation that prevents corruption and emphasises due diligence has tightened up and defined the limits of ethical behaviour for companies acting abroad, and this influence has permeated the industry as a whole which has high levels of corporate governance[43].

We have seen that the real challenge facing the IOCs is that they face increasingly difficult operating conditions in E & P activities, not just regarding the physical landscape but rather a much more wide-ranging panorama of challenges. These include decommissioning, booking new reserves in a narrowing opportunity base, a socio economic and occasionally

> "Considered by many to be the world's largest oil company and the world's largest NOC, Saudi Aramco controls one-quarter of all world hydrocarbon reserves and plays a vital role in fuelling Saudi Arabia's socio-economic growth."

politically hostile landscape, a lack of E & P technology as a differentiator and environmental lobbyists. Perhaps, most of all, nationalisation has made operations more difficult. Here we trace the transformation of the NOC from quiet man to international giant[44].

NOC/IOC Distinctions

The distinction between NOCs and IOCs hinges on whether the NOC majority shareholder is the state, and therefore must ultimately answer to the state as opposed to a privately held IOC which answers to majority private shareholders only. This distinction explains why NOCs have a responsibility to meet the needs of the nation and the population that owns them, while maximising profit.

Nowadays, the industry recognises that profits must be balanced with social responsibility and private shareholders generally accept this. Most major IOCs have CSR programmes and this type of spending is not generally questioned by investors, as long as returns are healthy. Part-privatised NOCs fall into this category also. In the case studies below, we look at NOC concepts of sustainability and social responsibility from two major oil exporters—Saudi Aramco and PdVSA. Two further case studies look at the part-privatised StatoilHydro and Petrobras as they compete internationally in the US Gulf of Mexico (GOM) and apply the technical respective differentiators of deepwater E & P technology[45].

Saudi Aramco

Considered by many to be the world's largest oil company and the world's largest NOC, Saudi Aramco controls one-quarter of all world hydrocarbon reserves and plays a vital role in fuelling Saudi Arabia's socio-economic growth. In this context, Saudi Aramco routinely evaluates its development decisions on a combination of corporate and national contributions; for example, a petrochemical project with a Japanese chemical company contributes at both these levels by seeking to transform the Rabigh Refinery in Saudi Arabia into an integrated refining and petrochemical complex.

The evaluation showed that although Rabigh would be profitable, it was not the most profitable investment opportunity that Saudi Aramco was considering. What Rabigh provided, however, was 'the most combined value to the company and the nation'. The national component means that Saudi Arabian society will benefit from the foreign investment, the new jobs created and additional revenues[46]. The corporate component means that Saudi Aramco will extend its petroleum value chain, upgrade oil processing and make its portfolio more profitable[47].

In the area of Key Performance Indicators (KPIs), Saudi Aramco's approach is to use IOC yardsticks in order to be best-in-class in areas such as finding and lifting costs, corporate governance and financial discipline[48].

Venezuela

For Venezuela's PdVSA, sustainability is stated as being central to its existence[49]. Its definition of sustainability considers oil and gas resources from both a production and consumption perspective. PdVSA's stated policy is to regulate production of oil and gas so that E & P processes are optimised, while certain blocks are conserved for the benefit of future generations of both consumers and producers. Its central belief is that because oil is a finite natural resource, producing countries must exercise the sovereign right to regulate production levels so that benefits accrue to current and future generations of indigenous people.

PdVSA also sees its role as educational and to show consumers that oil is not a commodity that operates according to free market rules. It contends that energy markets do not operate in a free market fashion.

PdVSA recognizes that stability should exist in the market, but this can only occur if there is political, economic and particularly social stability. It also asks consumers to consider whether they are consuming energy in an efficient way.

For PdVSA, sustainability must include policies of integration that allow poorer countries to have access to oil and gas. This has been the reasoning behind the Petrocaribe initiative by which Venezuela supplies 200,000 barrels of oil per day (bbl/d) to more than 20 of the smallest countries of Latin America and the Caribbean under special financing[50].

For PdVSA, 'unrestricted access to (the) energy is not the same thing as sustainable access'. The company views the current model as consumers demanding unrestricted access to natural resources, but not allowing resource holders to improve the socio-economic standing of their people. According to the company, this model is characterised by infrastructure bottlenecks resulting from decades of under-investment caused mainly when IOCs held unrestricted access to reserves. PdVSA's view is that sustainability of access must mean that poor countries should be able to access sustainable energy sources[51].

Petrobras

During 2006 and Lula de Silva's successful re-election campaign, Petrobras and self-sufficiency featured prominently. Even before the election, Petrobras was participating in the Brazilian governments 'No Hunger' program. The part-privatised NOC has been playing a greater role in curing Brazil's social ills. As Brazil's largest company, the logic is understandable. Over the years, Petrobras has added tens of billions of US dollars to government coffers in the form of taxes, fees and social contributions. It is also helping by generating thousands of jobs and boosting the local economy by giving Brazilian companies preference for offshore projects[52].

This swing towards nationalism is also accompanied by a skepticism that the opening of the Brazilian E & P sector resulted in little or no gain for Brazil as production or employment increases have been minimal. Brazil, however, has certainly benefitted from technology transferred by IOCs from other areas and this would not have occurred had Petrobras' monopoly not been broken.

The arrival of the IOCs brought knowledge gained from international offshore operations and diverse basins, knowledge that was limited in Brazil. Many techniques that have been proven elsewhere—for example, ERD – are only just emerging on the Brazilian oilfield. IOCs were also accompanied by a raft of suppliers and service companies keen to offer specialised technology. Without an initial hand from IOCs to enter Brazil, many service companies would be put off by the monolithic appearance of Petrobras[53].

Appealing on the one hand, and dangerous on the other, the logic of nationalism can be difficult to counter. Part of the explanation why offshore vessels on the international market are competitively priced is because foreign governments grant favorable loans to their shipyards. Given similar credit terms, Brazilian companies can compete too. That's clear enough but the danger is that, although nationalism can boost the economy, it can also stifle new ideas.

With a 'people before profit' attitude, Guilherme Estrella (Petrobras E & P Director) has made no secret of being more concerned with generating stable and long-term oilfield employment than opening up the Brazilian E & P market further. This is good news for the offshore industry as a whole because Petrobras is the major employer and trainer of petroleum engineers in Brazil.

The tightrope that Petrobras must walk is balancing the

Figure 7 - Dubai's Palm Island

interests of two very different kinds of shareholders. The Brazilian government still owns a majority 51% of ordinary shares while the remainder is held privately. This kind of balancing is ultimately made easier because from both a medium and long term perspective, Petrobras is in an enviable position. It has helped the country reach self-sufficiency and added reserves, while growing its operations in the international arena, especially the US.

Petrobras in the GOM

Petrobras America is currently involved in four business areas which are upstream, trading, procurement and refining. Over the last four to five years, Petrobras has implemented a strategy which looked for specific core areas where it could apply its technology and expertise. These elements have proven critical to success; in frontier opportunities and also 'hard to access areas', as well as four core areas in the GOM (US Waters). One of the options for developments is a phased Floating Production Storage Offloading vessel (FPSO) programme similar to Brazil where a FPSO could sail away in case of a hurricane and reconnect after storms.

According to Petrobras its goal is 'to concentrate in key areas, certain trends and certain plays where Petrobras is bound to be a significant player'[54].

By spreading risk, Petrobras plans to build a portfolio through exploration and not acquisitions. This means testing concepts such as Early Production Facilities (EPF) to get a better idea of the reservoir/production profile before going into full production. The innovative approach of Petrobras has been applied to the western part of the US GOM. This area had not seen a single well drilled for at least a decade as the industry's general understanding was that there was no merit in drilling. During the past decade, however, major technology improvements and better geological data have changed this. These areas are gas prone with most production coming from the very shallow formations and the Great White Shell development in deepwaters, but with nothing in between.

Seismic has highlighted interesting features, although these prospects have not been properly tested. For Petrobras, two key characteristics are repeatability and having options. Prospects which have similar characteristics, are important because they allow geologists to make inferences from one area to the other. This helps Petrobras to decide whether to drill more wells or not. Options are important too, i.e. where the oil company has eight or ten prospects, there is an option to drill and that limits risk[55].

Petrobras is using technologies and new ideas to build a successful portfolio by using deepwater knowledge, but also geologic modelling from other international areas, i.e. Colombia and the deepwater US GOM.

Petrobras Trading can be seen as a set of services for the group rather than a trading floor presence. It involves finding and developing markets for surplus production. Price oscillations allow Petrobras to access production and optimise its production profile. Increasing production of Marlim crude, which has an API of 19° to 22°, means that the demand for Marlim to be processed in Brazilian refineries is set to go up as is Brazilian refining production; however, there is still a sufficient surplus of Marlim beyond that which can be handled by Brazilian refineries. This allows Petrobras America to sell and capture the best margins in the market.

Market surveys, intelligence and transactions are done by Petrobras Brazil but Petrobras America is the broker. Petrobras America gains title for certain products, i.e. gasoline and fuel oil, and sells these on. Petrobras America started a new refining business through the purchase of 50% of a refinery in Pasadena, Texas. The current capacity of 100,000 bbl/d is being increased through substantial investments that will allow for a further 70,000 bbl/d. Petrobras continues looking to both upstream and downstream opportunities within the US, which is the world's largest consumer and a strategic market[56].

StatoilHydro

StatoilHydro is the Norwegian oil company and views its introduction to the stock exchange in Norway and in the US as a favourable move. According to StatoilHydro, it has the same requirements and terms for operation as any IOC while having the Norwegian government as its main owner gives it unique advantages, as it is not up for sale[57].

When many IOCs were cutting their R & D functions to reduce costs, StatoilHydro invested more in its R & D facilities and pioneered aspects of subsea and deepwater production. This has helped the company develop certain technology inventions. Part of this is due to the close relations all operators on the Norwegian Continental Shelf have with government authorities, who challenge operators to overcome new obstacles. The company's goals are for the US GOM to become a core area for StatoilHydro by 2012 with production of 100,000 bbl/d. It cites a favourable fiscal regime, stable government and yet—to find resources as key elements to meeting growth targets in the US GOM.

StatoilHydro's development strategy for the US involves a combination of farm-ins and acquisitions. This started three years ago with the Chevron farm-in within the Perdido Fold Belt, which resulted in the Tiger discovery. This was followed by the acquisition of Encana assets. At the same time, StatoilHydro farmed-in about 70 leases in the Walker Ridge area with ExxonMobil. This strategy continues with participation in the lease sales in the deepwater GOM area.

It also has a growing business feeding LNG from the Snøhvit field in Norway and from its Algerian assets to the Cove Point LNG terminal in Maryland.

The company has imported a lot of Norwegian offshore technologies that may be applicable for use in deepwater GOM; however, further tests are needed to prove that usage in Norwegian offshore water depths of 300-500 m are suitable for much deeper US GOM waters of 2000-2500 m. Increased recovery may be possible by using a subsea processing, subsea boosting and injection system and FPSOs with risers that have the ability to disconnect. This may be a good solution to secure equipment during extreme weather conditions like hurricanes. Ultimately, StatoilHydro has a wide variety of technologies at its disposal and those are likely to provide its international operations with a competitive edge.

China National Petroleum Corporation (CNPC)

CNPC, China's flagship oil company, plays an important role in China's oil and gas production and supply. Its oil and gas production accounts respectively for 57.7% and 78.3% of China's total output. CNPC is also a global player with E & P projects in Azerbaijan, Canada, Indonesia, Myanmar, Oman, Peru, Sudan, Thailand, Turkmenistan and Venezuela.

CNPC has bet heavily on R & D to increase E & P production and reduce risk in complex basins. It has developed solutions to improve recovery factors as well as reduce development costs. It has a strong

Figure 8 - Abu Dhabi View from Emirates Palace

Figure 9 - Oil and Gas Wealth Is Not Necessarily A Trade-Off Against The Environment. There Are Wider Considerations (EPRasheed)

sense of innovation and has technologies in reservoir characterisation, polymer and chemical-flooding. Other technologies include high-definition seismic, under-balanced drilling, ultra-deep well drilling rigs and high-tensile steel pipes. According to the company, by the end of 2007, CNPC had acquired 7,010 patents out of its 9,693 patent applications.

It holds proved reserves of 3.7 billion barrels of oil equivalent. Other relevant data include:

- Oil production: 2.75 million barrels of crude oil/day (MMbbl/d)
- Gas production: 5.6 billion cubic feet/day
- Oil reserves: 3.06 billion metric tonnes, and
- Gas reserves: 2,320.1 Bm^3.

Metamorphosis of IOCs

In the old days, IOCs conferred access and monetised oil reserves. IOCs alone had the technology, capital and know-how to tap the wealth of an unknown hidden natural resource. Naturally, they bargained hard and got the lion's share. Those 'old ways' show that oil reserve holders used to recognise IOC as equals, perhaps, even as holding the upper hand as the IOC was required for revenues to be realised[58].

Even before the Oil Curtain, some IOCs noted that the pool of accessible oil reserves would one day shrink. Progressive IOCs repositioned themselves for the future; some seeing 'beyond petroleum' and others shut out by the 'Oil Curtain'. This, however, does not imply the fall of IOCs. Some are perfectly adapted to evolve and there is still a healthy global E & P environment for them to adapt to.

The drawback is that this environment of extreme E & P has high replacement costs as margins are squeezed by technical challenges. Extreme E & P opportunities exist in ultra-deepwaters, Arctic, unconventionals and in a dazzling array of gas-related technologies. These include: LNG which mobilises and commercialises stranded reserves; biogas which is renewable through biologically produced methane; Compressed Natural Gas (CNG) and LPG, that provide fuel for the transport and power-generation sectors; and, GTL which offers high quality gasoline fuel.

Of the original seven sisters, most have already adapted to an extreme E & P environment. Going further, BP has distinguished itself in LNG and solar power, while Shell has distinguished itself in Gas to Liquids (GTLs) and hydrogen.

Undoubtedly, IOCs face increasingly challenging operations – extreme E & P. Additionally, there are a wide-ranging set of challenges such as decommissioning, booking new reserves in a narrowing opportunity

Figure 10 and 11 - Developments along Sheikh Zayed Rd Dubai (EPRasheed)

base, a lack of E & P technology as a differentiator and environmental lobbyists. Perhaps, most of all, nationalisation and resource sovereignty, has made business more difficult.

Despite this, IOCs retain refineries, retailing networks, brands, and direct access to international consumers. Certain IOCs, for example BP and Shell, have continued to be early adopters of new technology. That is praiseworthy, because by supporting innovative new ideas and signposting applications[59], these IOCs have significantly contributed to many E & P innovations, i.e. rotary steerables and expandables across the industry. Those IOCs took risks to prove tools downhole and the benefits have been reaped by all types of oil companies.

Black Blessing

We have seen within a century how oil and gas have become the world's preferred energy source. Consequently, certain countries with the oil and gas wealth or the black blessing have benefitted. So which countries have made oil wealth a true blessing[60]?

Dubai and Stavanger are synonymous with oil wealth, but these cities also subtly show that the black blessing has been managed responsibly with a vision for the future. For these and other thriving cities, there are countless other stories of squandered oil-wealth and cities that have ended up as ghost towns. Yet, no single country's approach to the management of oil and gas has been perfect; it has been learned.

What works in one country is not necessarily the solution in another, but parallels and lessons exist. We shall see how the forces and needs acting on the North Sea were very different to those of the Arabian Peninsula. Each country's profile is unique but what emerges is a common lesson: oil revenues 'rollercoaster' and are subject to depletion.

Dutch Disease

Due to the highly specialised requirements of the petroleum industry, personnel and equipment are often imported. If you have a pressing deadline, it is easy to think 'don't reinvent the wheel, import'. This, however, is dangerous. Firstly, capital flows become wholly dependent on cyclical oil and gas revenues. Secondly, the creation of local jobs and local infrastructure is limited as workers and equipment are 'outsourced'. The few jobs that are created are fringe industries and are very much dependent on the migrant workers and can easily vanish. Thirdly, excessive imports and the petroleum industry itself can inflate costs so that locals are excluded from housing, social and other activities. This is a double-edged sword as the higher-paying-oil related activities push out other less lucrative activities. Without diversification, these negative factors expose a country's dependence on oil wealth. When oil prices fall, the consequences can be disastrous, i.e. Norway and UK in the 1986 crash.

Before Oil

When considering the North Sea – Stavanger, Norway, Aberdeen, UK and the Arabian Peninsula – Dhahran, Saudi Arabia and Dubai or Abu Dhabi UAE it is revealing to see how these countries existed before oil.

Figure 12 - Drilling Rig in the Middle East (EPRasheed)

All of these countries had very different socio-economic profiles; healthcare, disposable income, education levels, transport links and indeed internal infrastructures were severely limited.

Yet, in each the black blessing has improved lives within the space of a single generation and has led to the creation of new industries (see Figures 7, 8 and 9).

Pilgrims

In the Saudi Arabian peninsula, oil was discovered in the 1930s. At that time, exploration contracts for oil were scorned; in scorching desert temperatures, exploration was for a more valued resource, water.

Saudi Arabia had already been guaranteed an annual source of revenue due to the Hajj – the pilgrimage Muslims make to the city of Mecca; however, the country's infrastructure was underdeveloped which led to a weaker bargaining position. When the first contracts were signed, the Saudis received less than the equivalent of 5% royalties. With the discovery of oil and its growing geo-political importance, the Saudis' bargaining power increased.

Royalties grew to 50%. Other stipulations such as the improvement of transportation and telecommunication links followed. By the 1970s, the Saudis had started to buy-back the privatised oil company leading to the full

Figure 12 and 13 - Old Stavanger Was Built On Fishing

ownership of Aramco and the country's reserves of 264 billion barrels of oil.

In reality, national oil policy has come full circle. It has evolved from seeking maximum royalties to stipulating local capacity to full re-nationalisation and now to partial privatisation for gas developments. To illustrate Saudi Aramco's local content, as of 2007 it had a total of 52,093 employees of which 45,464 were Saudis and 6,629 were expats. It has also signed gas exploration contracts with foreign oil companies such as Shell.

Gold and Pearls

In the UAE, a union of seven Emirates, the situation was different. Dubai had long been a regional trading hub and had far fewer reserves than Abu Dhabi which meant it quickly realised its economic future lay beyond its scarce oil reserves. Dubai's souks were known worldwide for all manner of commodities, especially gold and Arabian pearls. Dubai continued to profit from trading until the cultivation of artificial pearls and world recession caught up in the 1930s.

The quality, size and quantity of artificial pearls could be controlled in such a way that demand for them grew quickly. Commerce dropped in Dubai and it was no wonder that, when news reached the ruling family in the UAE and Dubai that oil exploration licences were being sold in Saudi, negotiations quickly followed.

With the fullness of time, this led to the discovery of reserves of approximately 98 billion barrels of oil in the UAE. Presently, Dubai has developed a policy of cluster economies which have resulted in flourishing financial services, tourism and IT sectors.

A Tale of Two Cities

Before oil, Aberdeen and Stavanger were economically stable albeit sleepy fishing and maritime towns. During the early 1960s when gas was first discovered (oil came afterwards) in the Grönigen field in the Dutch Sector of the North Sea, Norway had high employment, a current account surplus and low inflation. From a socio-economic perspective, there was no pressing need to explore for and develop oil and gas.

With the 1973 oil crisis and accompanying embargo, geologists started scrambling for North Sea seismic. This instability in global geopolitics set the scene for the upper hand in negotiations with the IOCs. When the Norwegians and Scots asked for rewards beyond taxes and royalties, the oilmen obliged.

Differences Between the North Sea and Arabian Peninsula

The need to develop local knowledge was linked to the nightmarish operating conditions in Norway. In contrast, the Arabian Peninsula is an oilman's dream – punch a hole near a dome and chances are that oil will be struck. From the very start, these very different environments formed very different mindsets. This led to a historic laissez-faire approach to technology development in the Arabian Peninsula.

In contrast, Norwegian and British fields were located in the harsh North Sea, a dangerous environment

Figure 14 - Modern day Stavanger, home of Norwegian Oilfeld Technology and the Norwegian FPSO

Figure 15 - Semi-Sub Platform

where locating reservoirs was a costly, timely business. Here the application of technology made a vital difference. With good seismic, directional and real-time data, well construction costs could be halved. This was a compelling reason for the development of North Sea technology. In parallel, the gradual introduction of terms such as the famous '50% local content' stipulation in exploration contracts helped develop local content.

Game-Changing or Incremental Benefits?

Technology of every type was necessary in offshore Norway and UK. The need for reducing risks and cutting costs was acute and technology could change the nature of the game, magically making uneconomic reserves profitable. In the Arabian Peninsula, the benefits of offshore technology did not apply. While other onshore technologies could be applied their technical and financial gains were insufficient. An incremental gain in production or cost-reduction was not compelling enough for such technology to be used in the Arabian Peninsula.

North Sea offshore operations, for example, routinely cost in excess of US $200,000 per day including rig rental and crew costs. By contrast, onshore operations in the Arabian Peninsula do not often exceed US $100,000. Additionally, the profile of Arabian reservoirs, i.e. their production rates and overall production size, are order of magnitude greater than North Sea finds which leads to lower overall finding, development and lifting costs in the Arabian peninsula.

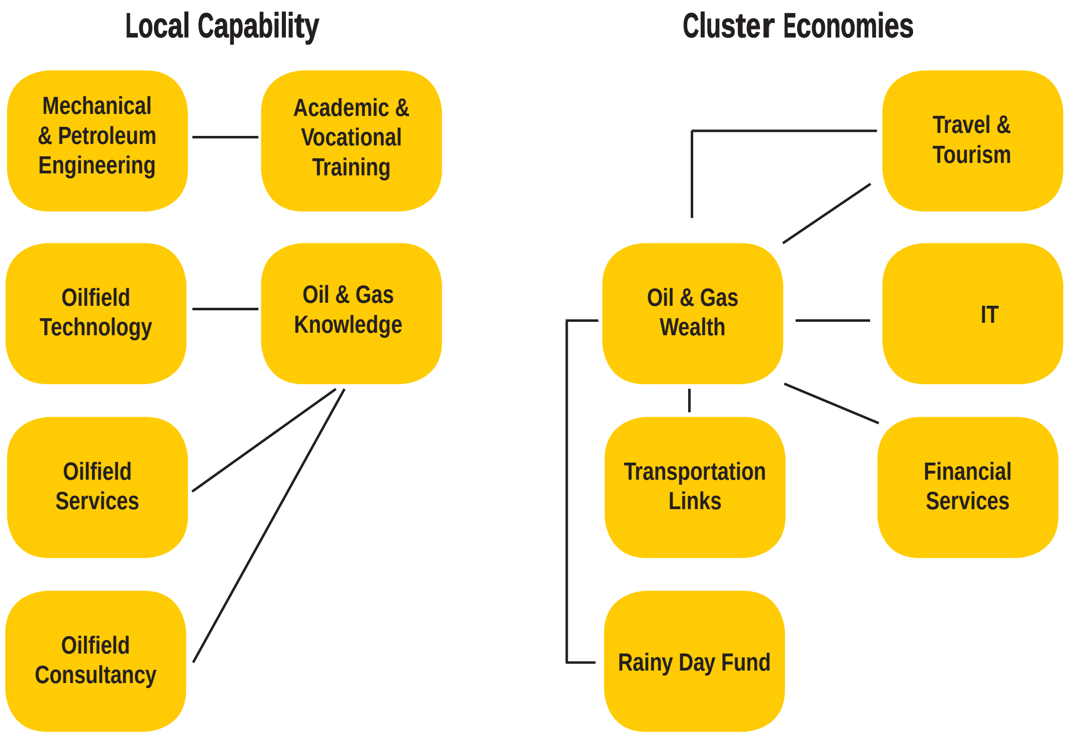
By the 1980s, greater emphasis was placed on local content and local capacity building within the Arabian peninsula. This trend had its roots in the North Sea.

Build Locally

It is worth highlighting that prior to the early 60s, there was no oil and gas industry whatsoever in the North Sea. Yet, today the industry is a prime mover in the Scottish and UK economy.

How did this transformation occur within a generation?

Building local capabilities was always a 'must-have' for the North Sea. Eventually, this led to the creation of the service sector hub which exports oil and gas technology globally. At first, technologies were invented, tested and proven in the North Sea before being exported worldwide.



We have seen that until the mid 1960s, neither Norway nor the UK had an oil industry, but within years the chorus to create one was loud enough to be heard. In the early 70s, this led to the preferential use of local goods and services at times reaching 90% as required by law. In the early 70s, the Norwegians created Statoil, the operational oil company and as policy maker the Norwegian Petroleum Directorate (NPD). Accompanying this was a preferred policy for Norwegian goods and services coupled with a clause of transfer of know-how and research cooperation.

The UK and Norway's success in achieving high local content is largely due to these policies which have encouraged partnerships between foreign and domestic companies and made research programmes mandatory. Research has helped create smaller companies which have exported technology worldwide and grown. The University of Aberdeen Oil Centre lists 175 small companies working in the oil and gas sector. These range from small independents to technology companies.

In terms of production, Norway and the UK are very different. Norwegian oil and gas production has increased over the past decade to 3.1 MMbbl/d. The UK's oil production has fallen by 30% over the same period to current levels of 2 MMbbl/d. Yet, through demand for UK oilfield goods and services, the oil sector continues to generate substantial economic activity.

Smaller independents have entered the UK sector but the oil and gas industry has developed far more due to the formation of mechanical and petroleum engineering, academic and vocational training and associated consultancy services.

Seeds of Knowledge

Licensing terms for oil contracts stipulated the transfer of skills and competence to Norwegian companies. Personnel from Norsk Hydro, Saga and Statoil (these companies have merged into StatoilHydro) received training in the IOC training programmes and overseas postings.

The situation was slightly different for the UK as BP had already had international oil and gas exposure. In fact, this helped it discover and develop Forties (the largest North Sea UK field).

These seeds grew into the commercial success of numerous oil technology companies that export goods and services worldwide.

Technology Greenhouses

Today, there is a strong culture of oil and gas R & D; several well test sites and research companies exist. Illustrating this is the Bridge of Don Test site in Aberdeen, Rogaland Research and its test well in Stavanger and SINTEF (a company specializing in R & D).

As major oil companies shed R & D internally to cut costs, more R & D has been taken up by the service companies. This is not to say that major oil companies do not use or test new technologies; they do so in low-risk developments such as mature onshore operations. For the most part, however, the development and ownership of proprietary oilfield technology no longer lies with oil companies.There are some exceptions; the development of rotary-steerable systems to access complex well trajectories and expandable-casing for well construction was initiated by oil companies. NOCs are somewhat different as can be seen by Petrobras' R & D centre which has grown to support Petrobras' deepwater needs and has become a world leader in deepwater technologies. Norway and the UK have helped develop subsea technology and especially intelligent wells and real-time operations management. It should be noted, however, that the service side has played a crucial role in technology development in all cases.

Cluster Economies

It is recognised that the Arabian Peninsula's economies have been highly dependent on oil; it accounts for more than 75% of government revenues in the region. This made it crucial that the Peninsula diversify from oil dependence and open its markets to attract foreign capital. A good example of this is seen in Dubai which briefly had revenues in oil production but realised quickly that it could become a trading hub due to its location between Europe and the Far East and links within the Peninsula between Saudi Arabia, India and Iran.

Various initiatives were undertaken in Dubai; for convenience they can be classed as cluster economies. Dubai began experimenting with cluster economies through the development of Dubai Internet City in 2000. This has grown to house over 5,500 knowledge workers today, while Dubai's Media City houses most of the leading global media companies. Dubai's financial markets have also grown.

The opening up of Dubai's real estate sector has also helped diversification. Between 2004 and 2010, investments in Dubai's real estate sector are set at US $50 billion. This is serving to support Dubai's tourism industry as it aims to increase the numbers of foreign tourists.

Dubai first sought to consolidate the economy's major components of trade, transport, tourism and real estate sectors. It then moved on to promote aspects of a 'new economy': IT and multi-media activities and e-commerce and capital intensive, high-tech manufacturing and services (see Figure 16).

Rainy Day Fund

After an economic rollercoaster that saw Norway with the highest debt ratio ever attained by any developed country, the Norwegian Parliament established the Petroleum Fund in 1990. It receives net cash flow from the oil industry as well as profits from investments. The fund is designed to protect the economy should oil prices or activity in the mainland economy decline, and to help finance the needs of an increasingly elderly population and to cope with declining oil and gas revenues. The idea is to use 4% of the fund in the annual budget, but in reality larger transfers are made.

Too Much Local Content?

Government departments provided incentives enabling operators and the private oil sector to identify technology needs and fill them. This led to a trial and error system where technologies were not always applicable; however, it is not so important to focus on any single research program that did not work because with time a local knowledge base and competence was created.

The preferential policy may have gone too far in some cases, leading to an introverted mindset. For example, in Norway in 1990 at least 80% new prospect content was domestic. The advantages were jobs and profits in Norway, but there was far too much dependence on the petroleum industry for Norwegian manufacturing while exports to markets in other oil producing countries were limited.

Undoubtedly, this shows that the black blessing has improved lives within the space of a single generation and has led to the creation of new industries. There are many ways to make the blessing last. We have seen how global power has shifted from IOCs to NOCs and how many NOCs want to compete in international markets.

We have also seen the metamorphosis of certain IOCs into Energy companies. What drives this shift is a growing awareness that, above all else, holders of the reserves determine the rules. The next question then becomes clear – who actually holds the petroleum reserves? Are they globally dispersed or centralised in a few major locations?

References

1. Rice University's Baker Institute for Public Policy Oil production of the five largest oil companies has declined since the mid-1990s. Oil production for the five largest IOCs fell from 10.25 million barrels a day (b/d) in 1996 to 9.45 million b/d in 2005 before rebounding to 9.7 million d/b in 2006. By contrast, for the next 20 U.S. independent oil firms, their oil production has risen since 1996, from 1.55 million b/d in 1996 to about 2.13 million b/d in 2005 and 2006.

2. Little did Cardenas know what train of events he would set off.

3. Timeline OPEC: Origins & Strategy 1947–1973 Editor: A.L.P. Burdett.

4. "O petróleo é nosso" ("The oil is ours") was the battle cry vocalized by students and workers on the streets of Brazil during the 40's and 50's. On October 3, 1953, President Getúlio Vargas created Petróleo Brasileiro (Petrobrás), a state monopoly in charge of E & P, refining and distributing oil in the country. See Offshore Engineer – Walks Tightrope, May 2003. See also Harts E & P Dec 2003 'Sustainable growth works' Interview with Petrobras E & P Director, Estrella.

5. Prize: The epic quest for Oil, Money and Power Daniel Yergin Publisher: Simon and Schuster (Jan 01 1993), ISBN: 0671799320, Race begun.

6. Anthony Sampson The Seven Sisters: The great oil companies & the world they shaped.

7 Prize: The epic quest for Oil, Money and Power Yergin Publisher: Simon and Schuster (Jan 01 1993) ISBN: 0671799320.

8 Oil and Politics in Latin America, Nationalist Movements and State Companies George Philip and Knight, Alan ISBN: 9780521030700.

9. Mexico's petroleum industry was taken back from the "Seven Sisters" in March 1938 by then-President Lazaro Cardenas, a revolutionary nationalist act.

10, 11, 12. F Parra, Oil Politics: A Modern History of Petroleum (IB Taurus, London 2004).

13. The Large International Firm in developing countries Allen and Unwin London 1968.

14. The late Professor Edith Penrose wrote in a book review in The Economic Journal in June 1963 (page 322): 'In the first place… the companies are truly internation-al in outlook only to a limited extent; they are Western and their interests are firmly linked to those of Western Powers. Secondly, the people of the crude-oil producing countries do not believe that the companies act independently of governments and will not in fact absolve the "imperialist" powers from responsibility for company actions'.

15. See OPEC History.

16. Texas Railroad used by Tariki and Perez.

17. This is best displayed by modern NOCs such as Petrobras, CNPC and StatoilHydro.

18. Some commentators have ascribed various comments to Perez. No doubt whatever Perez said it would not have been polite.

19. See OPEC History 1st Resolution.

20. Anthony Sampson The Seven Sisters: The great oil companies & the world they shaped.

21. See Penrose and Sampson for rates of return for IOCs.

22. See Penrose The Unravelling of IOC concessions.

23. See OPEC recent history on website.

24. This remains the highest peaking of oil prices.

25. See OPEC recent history on website.

26. See Oxford Energy Comment, July 2000 Managing Hydrocarbon Resources in a New Era: The Call from Algeria, By Ali Aïssaoui for a modern viewpoint.

27. This was widely covered by the worldwide press.

28. See the Gas ventures in Saudi Arabia and the Service contracts in Mexico.

29. Refers to the US $147 peak in mid 2008.

30. OPEC is always widely covered by the press.

31. See EIA IEO 2008 reference case.

32. See Penrose on the IOC upper hand.

33. See commentary of BP in Iran 'its principality of production'.

34. Perrone, Nico Enrico Mattei, Bologna—Il Mulino, 2001.

35. Harts E & P Sept 2002 Drilling Column. 'Manage your tapped resources'. Discussion on industry cycles.

36. A decade ago the Oil price was US $10 bbl.

37. Cost reduction by Wajid Rasheed NWECS report summed by the Arco motto 'No decline in 1999'.

38. Cost reduction by Wajid Rasheed NORSOK NWECS report.

39. Financial Analysis of Mergers for shareholders.

40. See Rice University's Baker Institute for Public Policy Exploration spending of the five largest IOCs has been flat or lower in the aftermath of OPEC's reinvigorated effort to constrain market supply in 1998. Given the uptick in costs of material, personnel and equipment such as drilling rigs, the five largest IOCs have cut spending levels in real terms over the past 10 years. This trend appears, however, to be easing, with exploration spending by the five increasing IOCs rising by 50 percent in 2006 over 2005.

Instead of favouring exploration, the five largest IOCs used 56 percent of their increased operating cash flow in 2006 on share repurchases and dividends. They have also increased spending on developed resources, presumably to realise these assets quickly while oil prices are high.

41. See Harts E & P Dec 2003 'Sustainable growth works' Interview with Petrobras E & P Director, Estrella.

42. See In the Shadow of a Saint, by journalist Ken Wiwa for an alternate viewpoint on the Niger Delta.

43. Corporate governance equally applies for individuals. Being hired by any service or oil company involves numerous due diligence and non-conflict forms.

44. The international aspect really applies to the NOCs that have high cost reserves. Rice University's Baker Institute for Public Policy Wall Street investors increasingly recognize these new exploration investment trends and the value of shares of NOCs have risen at a much faster rate than those of the largest IOCs.

45. Norway Oil and Gas Issue 1 (www.norwayoilandgas.com).

46. See Saudi Aramco Annual Report 2006 Rabigh.

47. Idem.

48. Idem.

49. PdVSA Annual Report 2006.

50. See PdVSA Annual Report 2006 Petro Caribe.

51. PdVSA Annual Report 2006.

52. Harts E & P Dec 2003 'Sustainable growth works' Interview with Petrobras E & P Director, Estrella.

53. Petrobras and Self-sufficiency The Zero fome campaign was widely by the Brazilian press.

54. Brazil Oil and Gas Issue 4 interview with Petrobras USA President Renato Bertani.

55. Idem.

56. USA President Renato Bertani Monolithic Offshore Engineer, by Wajid Rasheed.

57 Norway Oil and Gas (www.norwayoilandgas.com)

58. See Penrose.

59. The Harts E & P Mar 2002 Drilling Column. 'Small companies and tangled thickets'.

60. Black Blessing—Saudi Arabia Oil and Gas Issue 5. See Author's Interview with OPEC, Chatham House, The Royal Institute of International Affairs, NPD Norwegian Petroleum Directorate. Dubai Media City.

Saudi Arabia oil & gas
www.saudiarabiaoilandgas.com

Contribute to Saudi Arabia Oil & Gas during 2012

EPRasheed is looking for editorial submissions on the topics outlined in the editorial calendar. This can provide your company with the opportunity to communicate EP technology to the wider oil and gas community.

Please send abstracts or ideas for editorial to **wajid.rasheed@eprasheed.com**

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

Editorial 2012 Calendar

Jan/Feb	Mar/Apr	May/Jun	Jul/Aug	Sep/Oct	Nov/Dec
Ad Closing: 2 Jan 2011 **Materials Closing:** 9 Jan 2011	**Ad Closing:** 6 March 2012 **Materials Closing:** 13 March 2012	**Ad Closing:** 21 April 2012 **Materials Closing:** 28 April 2012	**Ad Closing:** 4 July 2012 **Materials Closing:** 11 July 2012	**Ad Closing:** 30 August 2012 **Materials Closing:** 31 August 2012	**Ad Closing:** 6 October 2012 **Materials Closing:** 13 October 2012
• New Stimulation Technology • Advances in Drilling Technology • Smart Reservoirs • Deep Diagnostics & Reservoir Mapping • Geosciences • E&P Software Solutions for Asset, Field and Well Management	• Intelligent Fields • Oil Field Automation and Optimization • Extreme Reservoir Contact • Seismic • Near Surface • Wide Azimuth • Near Surface Resolution	• Integration in Upstream • Shale Gas Developments • Shale Gas Technology Challenges • Real Time Operations • I Field • Drilling Automation	• Deep Water Red Sea Challenges • Assessment of KSA & IOCs Gas Exploration Initiatives • KSA Upstream Research & Development • KFUPM Techno Valley • Tight Gas Technology Development	• KSA Offshore Gas Development Projects (Karan, Wasit, Arabia, etc....) • Smart Water Chemistry in Carbonate Recovery	• Maximizing Sweep Efficiency in Heterogeneous Carbonate Reservoir Using Advanced Intelligent Completion Technology • Red Sea Salt Challenges
Issue 24 *'Deep Diagnostics'*	**Issue 25** *'The Intelligent Field'*	**Issue 26** *'Shale Gas'*	**Issue 27** *'Red Sea Challenges'*	**Issue 28** *Offshore Gas'*	**Issue 29** *'Maximising Sweep Efficiency'*
BONUS CIRCULATION					
10th Middle East Geosciences Conference & Exhibition* 4-7 March 2012 Bahrain	**SPE/IADC Drilling Conference** 6-8 March 2012 San Diego California USA **SPE/DGS Annual Technical Symposium & Exhibition*** 8-11 April 2012 Khobar Saudi Arabia **Offshore Technology Conference** 30 April - 3 May 2012 Houston, Texas USA	**The 8th Middle East Refining & Petrochemicals Conference & Exhbition** 20-23 May 2012 Manama Bahrain			**SPE Annual Technical Conference and Exhibition** 8-10 October 2012 San Antonio Texas, USA
SPECIAL PUBLICATIONS					
* Official Technical Magazine	** Official Saudi Magazine	* Official Technical Magazine			* Media Partner