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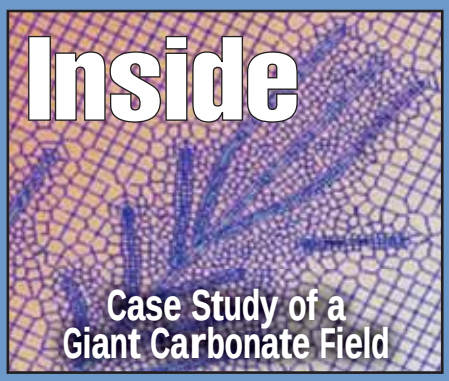
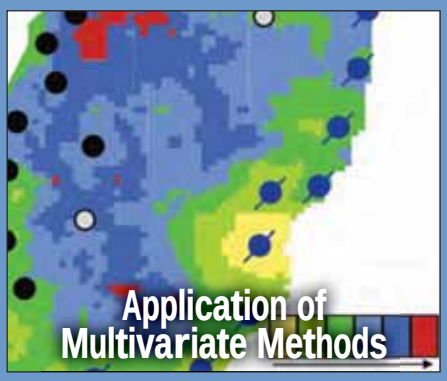
Optimization of Downhole Sand Screens




Case Study of a Giant Carbonate Field



Application of Multivariate Methods

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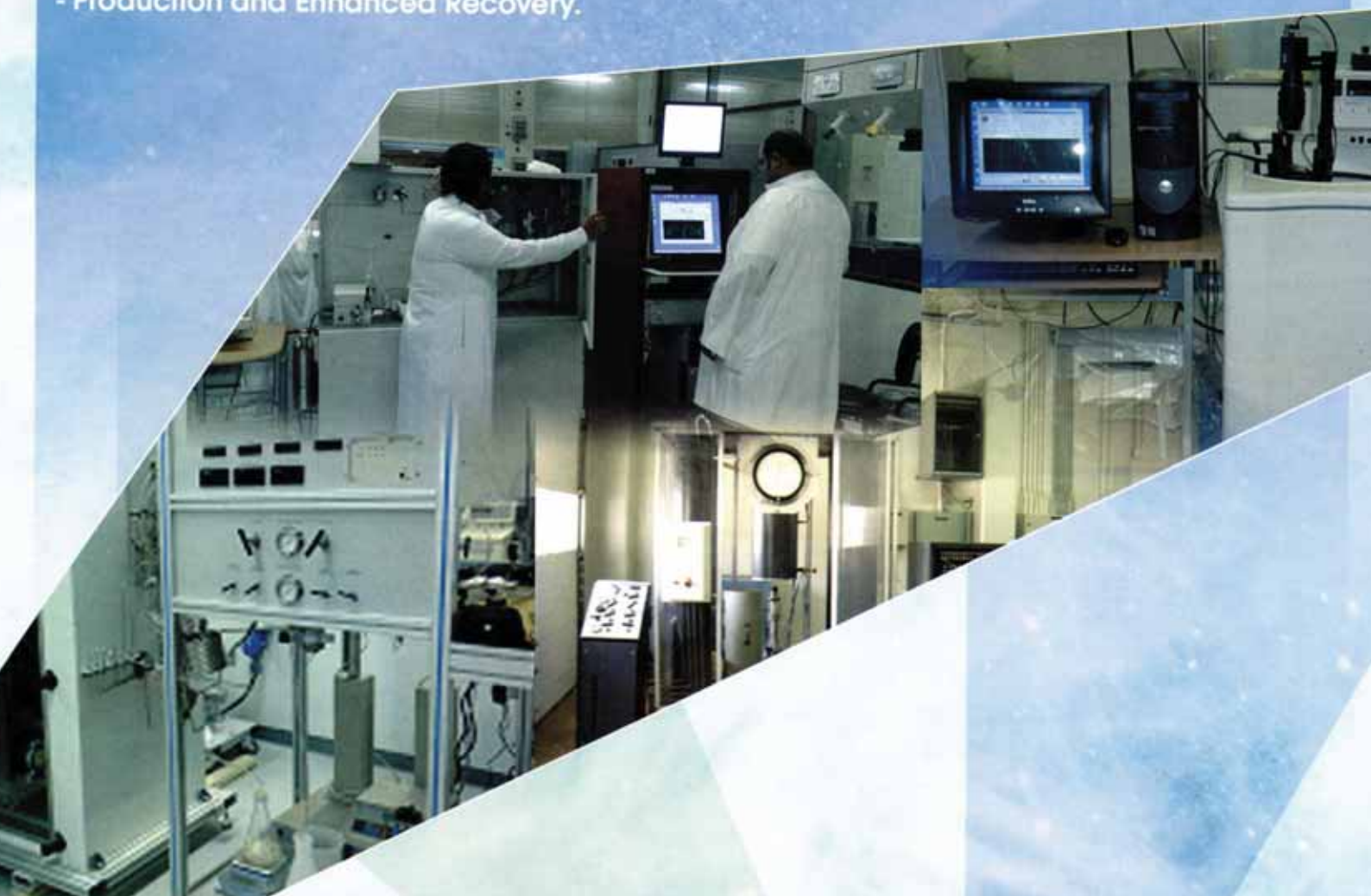

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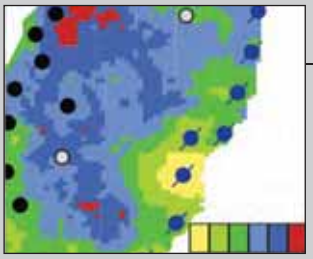




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# State-of-the-Art Rig in Service

DHAHRAN, 23 January 2013

In October 2012, a valuable new asset was added to the Saudi Aramco Rigs group. The new rig arrived in the Kingdom after the completion of its construction and signing of the "protocol of delivery" three months ahead of schedule at Keppel FELS shipyard in Singapore.

The new rig, considered state-of-the-art in the offshore drilling world, is equipped with 6+1 Engines/generator sets. These six generators can be used to power up the entire rig facilities. Plus, it has an equivalent emergency generator for backup in case of power failures.

Its 54-motor jacking system will allow it to carry a greater load than the normal 36-motor rigs. Also, its water cooling system will enable quicker heat removal compared with the traditional air cooling of other rigs.

The new offshore jack-up rig will be the second to be owned and fully operated by Saudi Aramco. It is also the first offshore jack-up rig that Saudi Aramco built from scratch to fit the Arabian Gulf's offshore fields.

The rig is capable of accommodating 114 personnel and is equipped with jack-up legs more than 400 feet long, which allows it to operate in the deepest Gulf fields of Marjan, Karan, Arabiya and Hasbah. It also has the capability to drill as deep as 30,000 feet.

Although the rig is equipped with the latest technologies, its construction was completed ahead of schedule in 24 months between August 2010 and August 2012.

An official ceremony took place in September 2012, and the rig arrived in Saudi Arabia ahead of schedule in October after less than a month's journey from Singapore.

The new rig is to commence operation in January with its first spud (drilling start) in the Arabian Gulf.

# ASC Hosts Houston Half Marathon

HOUSTON, 23 January 2013

Thousands of runners crowded the start lines of both the full marathon and half marathon on race day, Jan. 13, to fulfill their dream of participating in one of the most celebrated running events in the United States – and indeed around the world – despite bouts of pouring rain that continued to drench the streets of Houston.

It was the official 41st running of the Houston Marathon – an annual tradition that has grown into the city's largest single sporting event. This year, the marathon weekend drew 25,000 registrants – a record number – from all 50 states and 26 countries.

Of the total number of runners, about 10,000 participated in the Aramco Houston Half Marathon. This was the ninth consecutive year for Aramco Services Co. (ASC) to sponsor the half marathon.

Joining the runners this year were 27 ASC employees who participated in the half marathon, four who participated in the marathon, and 21 who joined the 5K race held the previous day.

Also present were more than 200 ASC volunteers, their family members and friends who distributed race packets, shirts, finisher medals and breakfast to the runners and also assisted with cleanup activities.

Since ASC first began sponsoring the half marathon in 2005, the number of participants has nearly doubled. "As a company, Aramco Services has chosen to sponsor this race because of our long-standing commitment to the communities where our employees live and work," ASC Public Affairs director Ali Al-Mutairi said. "The goal of this partnership is simple: to help make a positive difference in the city of Houston."

Ethiopian Feyisa Lilesa, 22, won the men's half marathon with a time of 1:01:54. The women's top finisher was Mamitu Daska, 29, also from Ethiopia, who crossed the finish line with a time of 1:09:53. Lilesa won the title last year as well, and Daska is the first-ever woman to win the marathon and half marathon at Houston.

Full marathon winners were Bazu Worku, 22, for the men's race and Merima Mohammed, 20, for the women's race – with respective times of 2:10:17 and 2:23:27. Both are also from Ethiopia.

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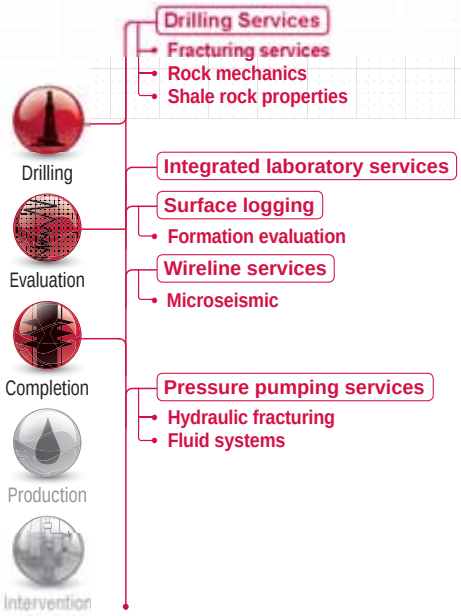


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# Shaybah Operations Cleans Up

SHAYBAH, 23 January 2013 – The Shaybah Producing Department, recipient of the 2011 Saudi Aramco President's Stewardship Award, once again exhibited its commitment to environmental sustainability through its annual Clean Up Campaign held Dec. 25.

The event brought together more than 300 leaders and staff members from the department, support organizations and contractors to embark on a desert-wide mission to pick up waste, leftover construction materials and debris.

While the flurry of new projects presently gaining ground in Shaybah has led to heavier traffic in the oil field, participants rose to the challenge by putting in the extra effort to clean up facilities, roads, sand dunes and salt flats.

"Through active communal engagement in our battle against negligent waste disposal," said Fahad al-AbdulKarim, department manager, "we hope to impress a deeper understanding of the importance of preserving the environment upon our small community."

The cleaning campaign saw employees collect nearly 170 plastic bags of garbage.

This type of event is common practice for Saudi Aramco, wherever it operates in the Kingdom.

Meanwhile, the department continues its quest to create a wildlife sanctuary in the midst of the barren landscape. The reserve will protect the Oryx and other endangered desert species and will be inaugurated in 2015.

# Remarks at Offshore Middle East Conference & Exhibition

By Nasir K. Al-Naimi, Vice President Northern Area Oil Operations, Saudi Aramco.

DOHA, Qatar, 21 January 2013

"Your Excellency Dr. Mohammad Bin Saleh Al-Sada, distinguished guests, ladies and gentlemen: good morning.

Thank you Mubarak for the introduction and for providing me with the opportunity to participate at this 4th version of the Offshore Middle East Conference & Exhibition here in Doha; one of the great energy capitals of the world. It is quite an honor. Let me also take this opportunity to congratulate your Excellency on the successful COP-18 meeting for Climate Change, which was held here in Doha last December.

The theme of this year's conference is "Investing in Offshore Matters." By looking at the recent regional offshore mega-projects commissioned or currently under development, we realize that offshore exploration and production will not only continue their important role in regional economies, but are set for further growth.

Ladies and gentlemen, our history with the offshore investment started with the development of Safaniya, the world's largest offshore oil field. The field was developed in 1951 (60 years back) with the best practices available back then.

Today, Safaniya is undergoing a massive transformation of assets and facilities to not only increase efficiency and production, but also to ensure compliance with stringent safety and environmental standards. In addition, this transformation will soon render Safaniya as the world's largest offshore automated oil field.

Among those developmental and upgrade plans is the replacement of many aging trunk lines. This is further complemented with several new installations of platforms, gathering structures and laying down of the longest 230 kV cable of its kind in the world.

It is worth noting that currently, we oversee the production of five offshore oil fields (namely Safaniya, Marjan, Zuluf, Abu Safah and Berri) producing what accounts for over 20 percent of Saudi Arabia's daily production. Similar to Safaniya, the remaining four fields will witness transformation of their own.

My colleagues, recent studies have shown that over the next two decades, global demand for oil and gas will increase about 25 percent. In response to these demands, we are embarking on several mega-projects that require a fit-for-purpose adoption of technology.

Saudi Aramco has recently commissioned Karan gas field, which is the Kingdom's first nonassociated high-pressure/high temperature (HP/HT) offshore gas field. Karan was discovered in 2006 and was developed with a total production of 1.8 billion standard cubic feet per day (BSCFD) to meet the Kingdom's increasing demand for electric power generation and industrial feedstock.

Other offshore nonassociated gas development projects currently under way are the Arabiya and Hasbah gas fields, which will feed the new Wasit Gas plant, the largest nonassociated gas project undertaken by Saudi Aramco.

Wasit will avail an additional 2.5 billion standard

> Manifa Bay is a rich environment of algae and sea grass beds, which provide nutrition for thriving marine life, making it the ideal habitat for species like crabs, dolphins and shrimp.

cubic feet per day (BSCFD) in order to support the continuous growth of Saudi Arabia's economy. Both fields are targeted to commence production in mid-2014.

These two mega-projects, Karan and Wasit, feature state-of-the-art gas development technologies with unique large bore well designs, automated control systems and intelligent field infrastructure that maximize well productivity with the highest levels of safety.

Another mega-project the company is tackling offshore is Manifa. This grass root crude oil increment, which lies in a shallow marine environment, is an example of combining technology and innovation in the development of the 5th largest oil field in the world.

This increment is designed to produce 900 thousand barrels per day (MBD) of Arab Heavy crude oil in the most cost-effective, safe and environmentally responsible manner. The early production of Manifa will start in June of this year.

Manifa Bay is a rich environment of algae and sea grass beds, which provide nutrition for thriving marine life, making it the ideal habitat for species like crabs, dolphins and shrimp. This unique challenge led us to team up with international experts and institutions to assess the environmental impact in the development of the field. Manifa is situated in shallow waters where conventional rigs cannot be utilized.

Accordingly, we elected to construct 27 man-made islands connected by a 40-kilometer causeway that will not only house the production facilities but will also act as artificial coral reef, attracting birds and other marine life to the bay. Extensive studies and simulations of prevailing marine currents in the bay were utilized to optimize the placement of bridges to ensure natural circulation of seawater and minimal impact on the environment.

Ladies and gentlemen, to successfully execute such ambitious capital programs, we require talent and technology. In the remaining minutes, I will share with you how we managed to address the demand on talent and innovation.

The Upstream Professional Development Center, known as UPDC, which was inaugurated a little over two years ago, is our flagship center to prepare our workforce for complex field operations. An immersive learning environment in this center accelerates learning through allowing participants to combine field experience with high tech simulation know-how.

> Currently, there are more than 15 major companies in Dhahran Techno-Valley including Schlumberger, Halliburton, Baker-Hughes and GE, just to name a few.

Furthermore, Saudi Aramco's Exploration and Petroleum Engineering Advanced Research Center, also known as EXPEC ARC, is the upstream research arm that tackles the challenges of maximizing oil and gas recovery while reducing the developmental cost associated through innovative technologies and better understanding of our reservoirs.

The center's applied research strategy resulted in the first simulator in the industry that can handle billion-cell geologic models and currently used to simulate and optimize our giant fields in record times. The center is actively developing numerous new technologies in advanced areas such as Nano technology with a long-term strategy driven by the company's vision and long-term fields' development plans.

Many of our technologies are developed collaboratively in partnership with service companies, technology developers and academic institutions.

The Dhahran Techno-Valley is a representative example of this collaboration. This valley provides development, production, and marketing support services for innovation that originates from academic research, but under a business environment. Currently, there are more than 15 major companies in Dhahran Techno-Valley including Schlumberger, Halliburton, Baker-Hughes and GE, just to name a few.

Not only that, Saudi Aramco has articulated the decades-long vision of the Custodian of the Two Holy Mosques King Abdullah ibn Abdulaziz Al Saud, in the making of King Abdullah University of Science and Technology (KAUST) that was inaugurated four years ago. It is the newest world-class, graduate level science and technology university on Saudi soil. Its strategic intent is to become a leading center of scientific discovery and human advancement within the Kingdom, across the region and around the globe.

Ladies and gentlemen. Our focus extends beyond technology and human resources; we believe that our Corporate Social Responsibility (CSR) extends to supporting the local community through our outreach efforts, which focus on creating sustainable programs in four key areas: the economy, community, knowledge and the environment.

This CSR model owes its components equally to the historical evolution, Kingdom's rich heritage and over 80 years of Saudi Aramco corporate values and attributes.

Let me pick environmental stewardship as it is one of our main core values. I have spoken earlier on how the development of Manifa made safeguarding the delicate marine environment a critical objective from day one.

For example, we have recently planted 50,000 mangrove saplings along the Arabian Gulf coast, which represents a milestone of our plan to plant more than one million mangrove saplings in various coastal areas. Some other key initiatives are in progress,

> Aside from being a major natural gas producer, nearly one in every seven barrels of oil produced around the world today comes from Saudi Aramco.

such as the implementation of stewardship measures for ecologically sensitive habitats, the development of national framework for fisheries management and the development of a mangrove eco-park.

Furthermore, our CSR doesn't stop at the local level. As part of the company's international CSR responsibilities; Saudi Aramco conducts an international annual oil spill drill to leverage the oil spill response in cooperation with several partners and governmental agencies.

Ladies and gentlemen, Saudi Aramco fully recognizes the challenges that lie ahead. Such challenges are common to other operators in the region and the industry at large. And although the company is indeed doing well, whether in terms of financial standing, growth performance, reliability, safety trends or other aspects of its business, Saudi Aramco, in response to these and other challenges, with the goal of doing more, a lot more; made the decision to undergo a major strategic change program to become a fully integrated energy and chemicals company. In doing so we seek to transform from a company that Saudi Arabia is proud of to one that the world is proud of.

This program is being driven by the top leadership of the company. The aspirations of the Accelerated Transformation Program or ATP as we like to call it, is captured in this statement: "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."

My colleagues, over the last 80 years, we have been a major contributor in the transformation of the Kingdom of Saudi Arabia by building its national economy through unlocking the Kingdom's natural resources. We have also invested in the national infrastructure, helped to unleash the potential of our young local workforce, and provided opportunities for a better way of life.

Aside from being a major natural gas producer, nearly one in every seven barrels of oil produced around the world today comes from Saudi Aramco.

All of us at Saudi Aramco are working towards the same goal – to remain the world's most reliable supplier of energy. It's a responsibility we take very seriously.

Ladies and gentlemen, I am confident that our industry, with its innovation and collaboration, will be ready for all future challenges.

And I am sure that this venue will be an opportunity for all of us to share our collective experience towards achieving our common goals. I hope you find this conference and exhibition and its associated programs both interesting and informative, and I thank you for your kind attention."

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# Application of Multivariate Methods to Optimize Development of Thin Oil Zones in a Mature Carbonate Reservoir

By Majid H. Al-Otaibi, Dr. D. Brett Fischbuch, Obai A. Taibah and Ali H. Al-Julaih.

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## Abstract

Exploitation of thin oil zones in a mature field with complex carbonate geology under strong water drive offers many challenges. The primary objective is effective oil recovery from the thin oil zones without excessive water production. The initial development phase targeting thin oil zones remaining in a giant, mature carbonate field in Saudi Arabia was guided by reservoir simulation results, with performance generally exceeding expectations. Consequently, the performance of individual horizontal wells varied greatly. Multivariate statistical methods have been applied across the gamut of reservoir parameters for these wells to gain further insights into critical success factors and mechanisms. Response variables were established (producing time to reach various water cut thresholds) to gauge well performance. Principal component, factor and multiple regression analyses were applied to independent reservoir parameters for a population of 20 horizontal wells placed in the target zone. These parameters included zone thickness, standoff from fluid contacts, vertical permeability contrast, thickness of low permeability interval, reservoir contact, net/gross ratio, completion design, extent of fracturing, zone porosity, proximity to injectors and trajectory orientation. The multivariate analysis conclusively demonstrated that the principal factor governing well performance in the early period (up to three years) was the vertical permeability contrast or, in other words, the extent to which a permeability baffle exists between the thin low permeability zone and the underlying thick high permeability zone. Other parameters may contribute to well performance beyond the 30% water cut threshold and will be addressed in a future article. The findings from this study have been translated into best practices for exploiting thin oil zones and have been applied in further developing the thin oil zone in the subject field.


## Introduction

Arab-D Zone 1 development in North Ghawar has evolved from what was initially a set of opportunistic sidetracks targeting sweet spots into a full-fledged, field-wide development program with a goal of maximizing recovery from mature areas behind the flood front. Despite the challenges in exploiting a thin, geologically complex zone, the development has been very successful, yielding significant additional potential.

One of the methods to further optimize field development strategies is the application of a multivariate analysis. This article examines the key factors governing well performance in the initial development phase to

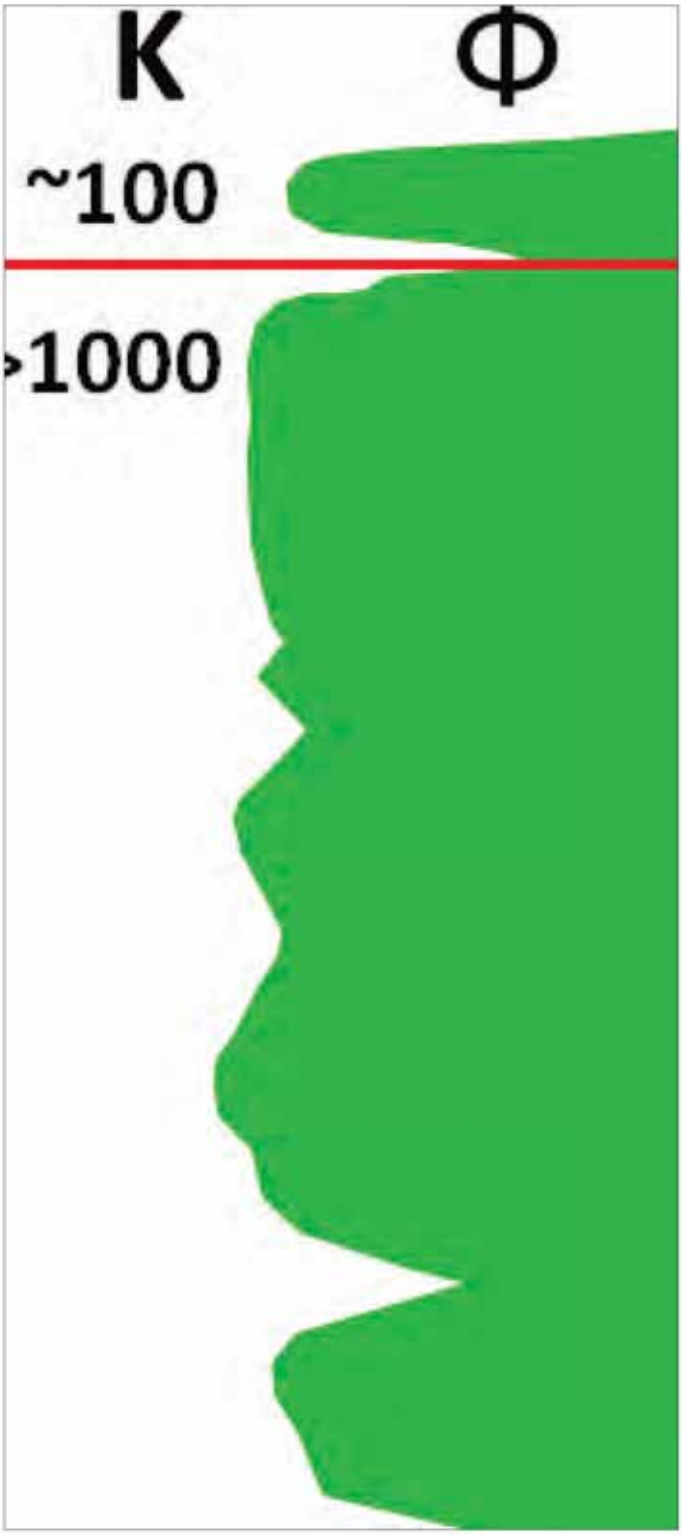



Fig. 1. Thin oil zone target.

exploit a thin oil zone in the mature peripheral regions of a large carbonate reservoir in Saudi Arabia. The development targeted oil remaining in the upper zones due to the high permeability contrast with the thick underlying formation and gravity segregation effects, as shown in the vertical porosity profile of Fig. 1. This oil could not be effectively produced using vertical wells, and therefore the development relied on horizontal wells of various configurations. The relative benefit of horizontal over vertical wells in producing thin zones is well documented[1-8].

Reservoir management considerations for the depletion of reserves from this oil zone, as addressed in this study, included locating current fluid contacts, evaluating geological complexity, assessing vertical permeability contrast, optimizing horizontal well configuration, vertical placement[9, 10] and length, utilizing appropriate

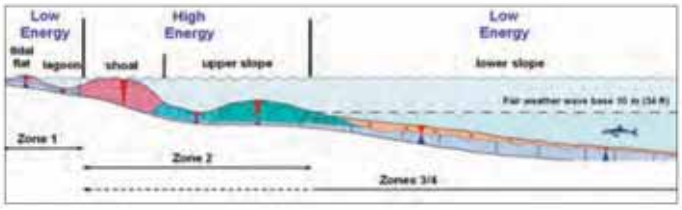



Fig. 2. Depositional environment for Arab-D carbonate reservoir.

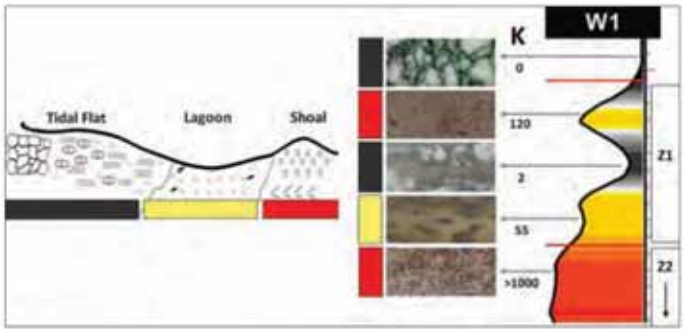



Fig. 3. Lithology variation associated with Zone 1.

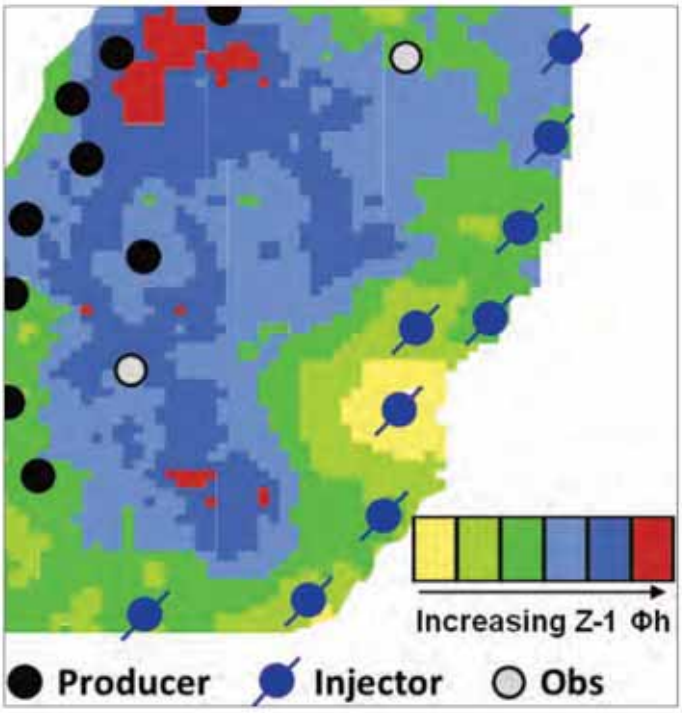



Fig. 4. Region for initial Zone 1 development.

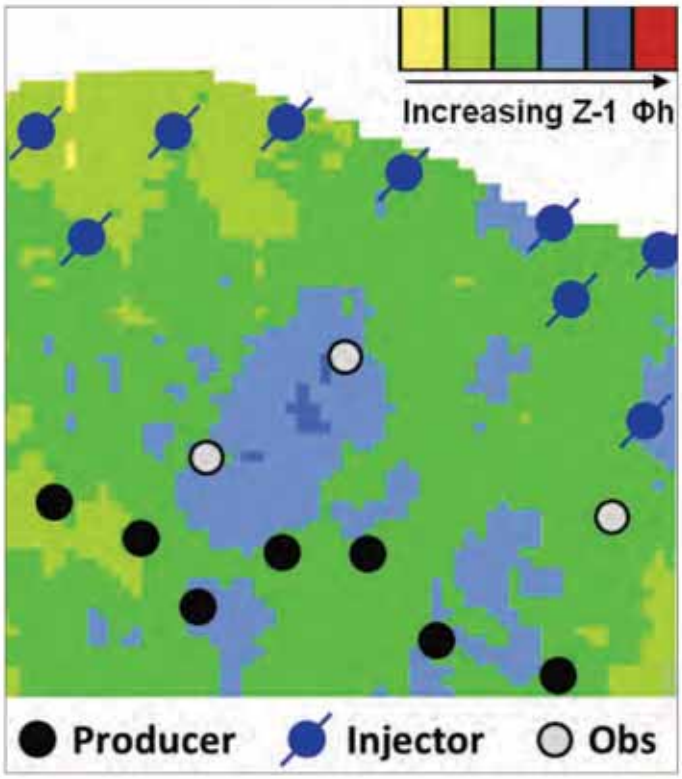



Fig. 5. Region for subsequent Zone 1 development.

geosteering techniques to ensure correct well placement and optimizing completion design. The initial development phase was based on best practices of reservoir manage- ment and the aid of reservoir simulation[11], with performance of the initial group of wells generally exceeding expectations.

## Reservoir Geology and Complexity

The subject reservoir is a complex carbonate system consisting of a coupled micro/macro porosity matrix[12]. The reservoir has localized, diffuse bed-bound fractures along with periodic fracture corridors following a dominant orientation with greater concentration

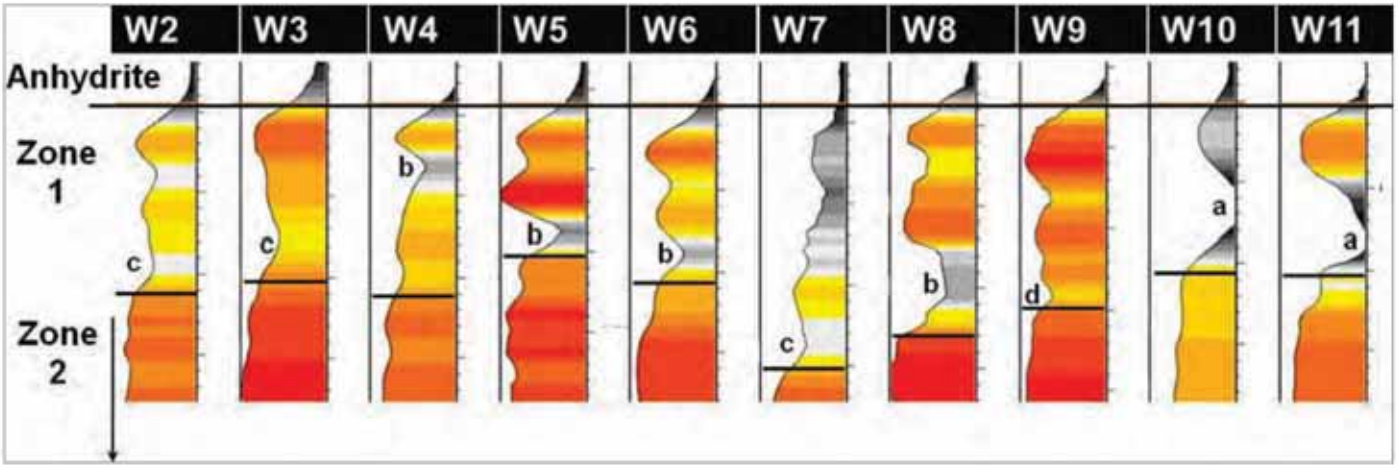



Fig. 6. Typical Zone 1 porosity profiles.

in the crestal, high curvature regions. Moreover, the reservoir has a unique geological characterization, as will be described.

The zone of interest is the uppermost permeable formation in a large carbonate reservoir in Saudi Arabia. The reservoir consists of four main zones capped by a continuous evaporate layer. The depositional environments that created this reservoir consist of lower slope marine (low energy) for Zones 3 and 4, shoal and upper slope marine (high energy) for Zone 2, and tidal flat and lagoon (low to medium energy) for Zone 1, Fig. 2[13]. The high energy environment has produced limestone facies dominated by oolites and grainstones, whereas the lower energy environment has produced varying combinations of wackestones, packstones and mudstones[13]. Zone 1 facies consist of dolomitized grainstones and wackestones, which can occur as single or dual porosity lobes and can be laterally discontinuous. Nodular anhydrite micro-stringers are frequently found between porosity lobes and often between Zones 1 and 2.

Moreover, permeability is impacted by the varying degrees of dolomitization of Zone 1 facies and the occurrence of anhydrite nodules, as depicted in Fig. 3 for Well W1. Finally, Zone 1 gross thickness is variable, ranging from 8 ft to 20 ft. Zone 1 lithology is complex, and the required geosteering techniques/ completion designs must be tailored, respectively, to the expected/ actual lithologies of each target.

## Development Targets

The field is supported by peripheral waterflood, and at this point in field development the main Zone 1 targets of interest are marginal wells in the mature areas among the first row of producers and in the regions between the first row of producers and the injectors. Two such regions are illustrated in Figs. 4 and 5, along with colored contours reflecting Zone 1 porosity-thickness.

In these perimeter areas, between 10 ft and 20 ft of oil column remain in the top of Zone 2. Since there is an order of magnitude permeability contrast between Zone 1 (~100 mD) and Zone 2 (>1,000 mD), the Zone 1 formation has remained entirely oil filled all the way to the peripheral injectors. Remaining oil in Zones 1 and 2 in some candidate wells among the first row of producers varies typically between 10 ft and 25 ft. The strategy for exploiting Zone 1 oil has evolved over time.

The variability and complexity of porosity profiles across the Zone 1 carbonate interval are illustrated for 10 different wells in Fig. 6. Porosity can be relatively uniform (W9), divided into two upper lobes (W4, W5 and W6), divided between an upper and lower lobe, grading up/down in porosity or existing as a distinct lobe completely separated from Zone 2. In addition, there are varying degrees of separation between Zones 1 and 2, as denoted by (a) total separation, (b) good separation, (c) partial separation, and (d) no separation.

With the advent of horizontal drilling, some laterals were drilled in the less mature areas of the field with coverage in both Zone 1 and Zone 2 (coupled trajectory). As expected, the Zone 1 reservoir sections contributed little to oil production. The intention was to produce from Zone 2 until it watered out and then isolate and produce only from Zone 1. These coupled wells are still producing today from Zone 2, so we have

| Parameter | | Min | Mean | Max |
|---|---|---|---|---|
| Zone 1 Thickness (ft) | | 8 | 12 | 20 |
| Remaining Oil Column at Top of Zone 2 (ft) in Mature Areas | | 0 | 10 | 20 |
| Number of Laterals | | 1 | 1 | 3 |
| Length of Lateral (ft) | | 3,000 | 4,000 | 6,000 |
| Target Oil Production Rate (MBOD) | | 1 | 3 | 10 |
| Vertical Placement of Lateral in Zone 1 | | Top | Middle | Bottom |
| Wellbore Trajectory Relative to Structural Contours | Parallel | 45° | Perpendicular | |
| Vertical Transmissibility ($k_v/k_h$) | 0 | 0.03 | 0.3 | |

Table 1. Reservoir simulation sensitivity study parameter ranges

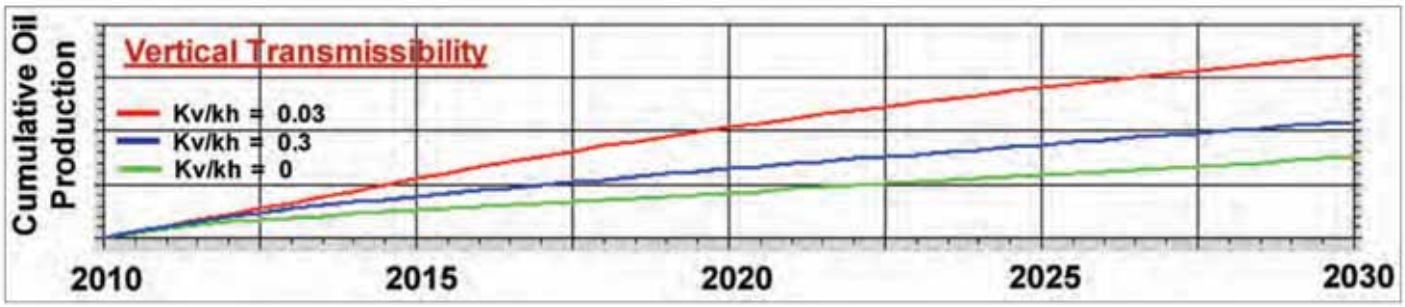



Fig. 7. Sensitivity of cumulative oil production to vertical transmissibility.

not proceeded to the point of isolating Zone 2. Reports from neighboring carbonate fields, however, indicate that isolation of lower zone(s) in horizontal wells using bridge plugs has yielded only mixed results. In some cases, coupled laterals were aligned such that the heel section of the well had a higher reservoir pressure sufficient to induce production from Zone 1. In some more recent cases, coupled laterals were equipped with inflow control devices (ICDs) placed in compartments along the wellbore to induce production from Zone 1. These experiences were useful in developing a strategy to produce the large reserves of Zone 1 oil in the perimeter of the field.

## Development Options and Reservoir Simulation

Many development options were considered for the recompletion of marginal wells and the drilling of selected new wells on the perimeter of the field. Development options were assessed by reservoir simulation and wellbore flow modeling techniques using a number of sensitivity parameters, outlined in Table 1.

Although some well placements and a number of laterals were initially evaluated using the full field model, it became immediately apparent that a full sensitivity study was required. High resolution 3D sector models (36 layers and one million cells with injection and production) were then constructed based on the various geologic scenarios. The sensitivity study yielded a number of findings:

1. As expected, productive well life was impacted favorably with higher Zone 1 thickness and a higher remaining oil column in Zone 2.

2. An increasing degree of separation between Zones 1 and 2 (i.e., lower kv/kh) increased oil recovery by delaying water breakthrough into the Zone 1 lateral. In fact, well placement at the top of Zone 1 was effective in draining the remaining oil in Zone 2. This was true for all cases, except where there was total separation between Zones 1 and 2, as illustrated in terms of cumulative oil production, Fig. 7. Obviously, with total separation, the Zone 1 lateral was not able to drain

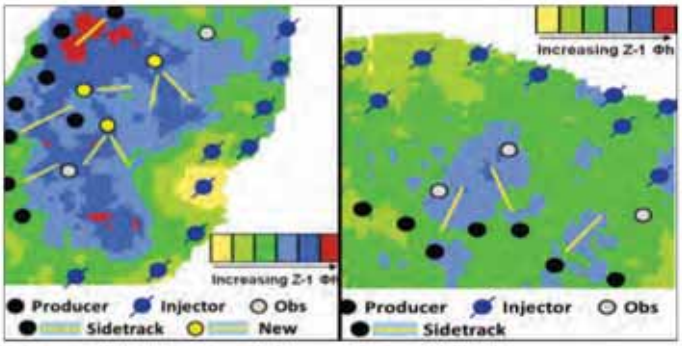



Fig. 8. Zone 1 development targets

the remaining Zone 2 reserves, provided that there was no inter-zone communication along the lateral. Given the complex and varying Zone 1 facies, however, total separation was thought to be unlikely.

3. In virtually all cases, the simulation results indicated that well placement at the top of Zone 1 (or in the upper porosity lobe) was preferred. Placement at the top of Zone 1 provided superior oil recovery compared to other placements (i.e., across both Zones 1 and 2 for a coupled trajectory, at the top of Zone 2 or along a maximum porosity trajectory within Zone 1).

4. As expected, greater reservoir contact was found to increase recovery for any given well. Multilaterals were challenging since peripheral injection led to large pressure differentials along and between each lateral, and since there was substantial structural relief between laterals due to the steepness of closure along this part of the flank near the injectors.

Maximum reservoir contact (MRC) wells (multilaterals with smart valves and ICD completions) were not considered in this study due to the complexity, cost and communication with Zone 2. Achieving greater reservoir contact by drilling laterals of greater length than the conventional 2,000 ft to 2,500 ft normally used for Zone 2 wells in thicker oil columns was considered as a simple and viable approach.

5. The sensitivity study of lateral length found that drilling to lengths of up to 6,000 ft greatly improved reservoir drainage and cumulative oil production. Wellbore modeling confirmed that frictional pressure drop along the wellbore was negligible (<5 psi) and would not lead to flow maldistribution along the wellbore.

6. Oil production rates for a single lateral of 4,000 ft in length showed proportional improvement in cumulative oil production. Higher oil rates were found to be sustainable and optimal; however, this would be dependent on geological factors, such as the intersection of fractures and uniformity of inflow along the wellbore, among other things.

## Reservoir Development

All stages of Zone 1 development were guided by reservoir simulation, as previously noted. The development targeted the region between the first row of producers and the peripheral injectors. Development comprised mainly sidetracking existing marginal wells among the first row of producers and drilling a few selected new wells in sweet spots. An areal view is provided in Fig. 8 to illustrate well targets in one of the sweet spot areas along the perimeter of the field. This areal section is shown using a porosity thickness isopach, with darker colors indicating increasing porosity thickness.

The primary approach for the Zone 1 development was to utilize existing marginal and depleted wells to sidetrack into Zone 1. Close to 95% of the development to date has been sidetracks of marginal wells, thereby minimizing unit development cost. The first few sidetracks were drilled as single laterals with between 1,000 ft and 3,000 ft of reservoir contact, but soon the standard length was increased to 4,000 ft, based on the findings previously highlighted. Several wells have also been sidetracked with single laterals having up to

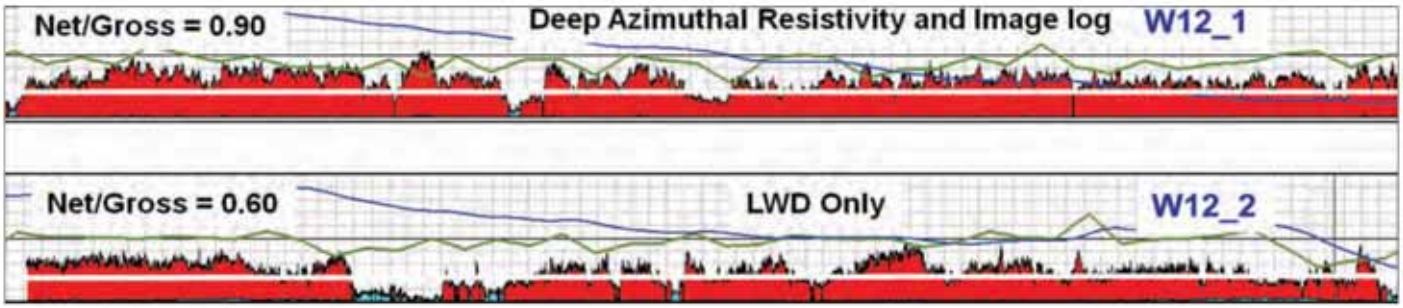



Fig. 9. Comparison of well placement results with and without advanced geosteering.

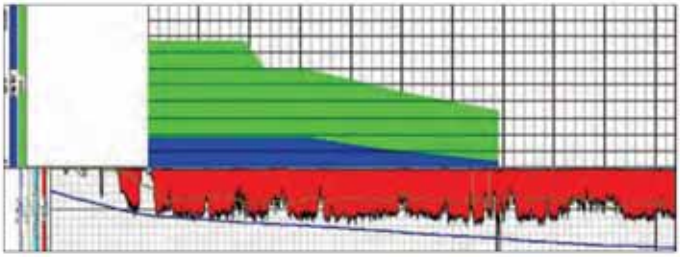


Fig. 10. Horizontal inflow profile along Well-16 wellbore.

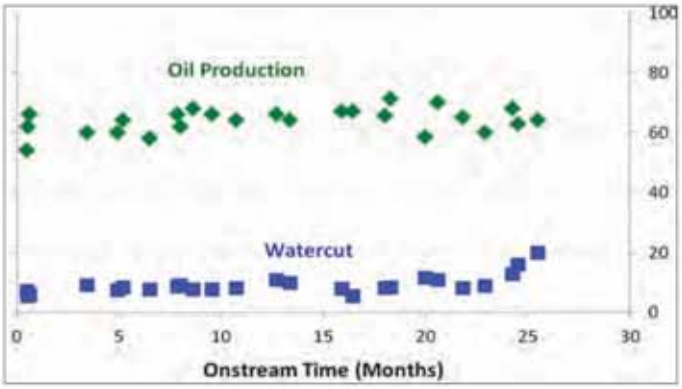



Fig. 11. Well-16 production and water cut performance.

6,000 ft of reservoir contact. To date, 18 sidetracks of existing wells, two new dual laterals and one new single lateral have been drilled, targeting Zone 1 sweet spots. Further development of perimeter areas is planned, pending availability of marginal wells and the need for additional potential.

## Well Placement

One of the most enabling technologies for drilling these Zone 1 wells with proper vertical placement is real-time geosteering. It has been observed that wells with undulating trajectories that have entered the anhydrite above or, particularly, Zone 2 below have resulted in wells with suboptimal performance. For example, in one of the early wells a large section was unintentionally drilled in Zone 2 due to poor bit control; it was planned to be isolated with packers and blank pipe, although the completion assembly got stuck and was set above the target depth.

The bare minimum geosteering requirement for these thin reservoir targets is logging while drilling (LWD) tools, including induction resistivity, density, neutron porosity and gamma ray logs along with a rotary steering system. Given the complex Zone 1 geology, with anhydrite above and nodular anhydrite stringers frequently below or within Zone 1, it has also been essential to supplement geosteering information[14-16] with shallow density or resistivity image logs and ultra-deep resistivity or deep azimuthal resistivity logs.

The importance of these additional, or "advanced," geosteering tools is highlighted in Fig. 9. This example shows a dual lateral well in an area with limited well control and a moderately steep dip. The first lateral was drilled with the aid of azimuthal deep resistivity and density image logs in addition to the standard LWD. The second lateral was drilled with nor- mal LWD, but had the advantage of the added well control

from the first lateral. Therefore, it can be readily seen that the net/gross ratio of 90% (using a reference porosity cutoff) was achieved when using the advanced geosteering tools compared to a net/gross ratio of 60% when using LWD alone. The value of advanced geosteering capabilities is even greater in complex geological formations, such as Zone 1. It should also be noted that even with advanced geosteering tools, a poor wellbore trajectory can be obtained unless there is sufficient control of the drilling bit.

## Field Results

Another factor that affects the outcome of a well is the presence of major fractured intervals. This carbonate reservoir has considerable curvature in the structural anticline, and this has led to formation fracturing in certain preferential directions. The fracturing is more common in the more porous Zone 2, but has also been encountered in a number of the Zone 1 laterals. The experience in this reservoir is that conductive fractures act as conduits, bringing water up from the lower swept zones. Wells encountering loss of circulation while drilling, or highly fractured intervals as identified in post drilling image logs, have been completed with zonal isolation and/or ICDs. The large pressure gradient arising from peripheral injection can also create an unfavorable pressure differential in the reservoir along the wellbore trajectory. When using existing marginal wells to go after Zone 1, it is not always possible to align the trajectory along reservoir isobars. Wells have been completed with ICDs allocated among compartments and/or with zonal isolation, when necessary, to provide a uniform flow contribution along the lateral. This is particularly important for Zone 1 laterals to delay as long as possible the onset of water encroachment and breakthrough.

The first well to be sidetracked and produced solely from Zone 1 was drilled as a single lateral with about 1,400 ft of reservoir contact. It has been produced for several years. Over this time, the water cut has progressively increased to about 40%. Although the early simulation model could not match the water cut, the later high resolution model has produced a better water cut match.

The recommendations drawn from the high resolution Zone 1 reservoir simulation sensitivity study were applied to most of the initial development wells. A horizontal production log was run along the wellbore of one of these wells when water cut had reached the 15% threshold – after two years of continuous production, Fig. 10. The well had a reasonably good productivity index, with a moderate drawdown of less than 100 psi, and had contribution along the wellbore except for the early heel section.

This well also achieved stable oil production and maintained water cut below 15% for a period of 24 months, Fig. 11.

Post-workover recompletion options for sidetracked wells must be examined because future flexibility depends on how the well is cased. Typically, wells are drilled from casing window to total depth (TD) with 6⅛″ hole, running a lower completion (packers and ICDs) if needed, and then running a 4½″ liner with off-bottom cementing. If the sidetrack is completed open hole with a 4½″ liner, there is no future recompletion option for isolating watered out sections, etc. The alternative is to stop drilling just before the reservoir, run 5½″ expandables and then drill a 5½″ hole through the reservoir to TD. The expandable completion allows future intervention to improve well performance.

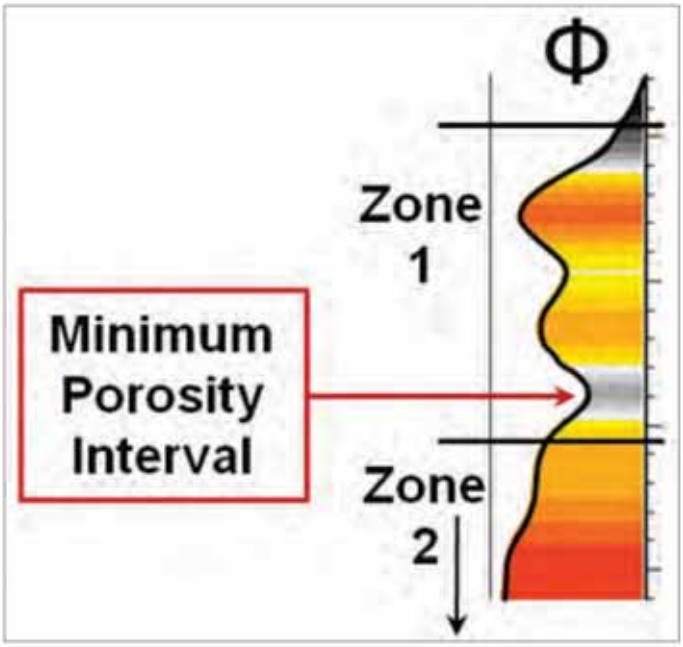
At this point, a total of 18 single lateral sidetracks, one single lateral new well and two dual lateral new wells have been drilled. Half of the laterals have ICD completions due to fractures, high toe-to-heel pressure differential or high permeability variation. Zone 1 wells that were drilled and completed using the best practices outlined in this study and that have already been put on production have exceeded target oil rates, with most producing dry oil.

The first dual lateral was completed open hole and is currently on production with about 20% water cut, presumably due to excessive production from the toe (down dip and higher pressure). A multiphase horizontal production log is planned to identify the source of water and examine the flow contribution along the motherbore. The other dual lateral was completed with ICDs in both laterals and is producing at a similar oil rate with very low water cut.

The initial phase of the Zone 1 reservoir development on the perimeter of the field has successfully met and exceeded our production performance targets. Well performance continues to be closely monitored through logging and testing to further improve future reservoir development of this large carbonate field in Saudi Arabia.

## Multivariate Analysis

After a number of Zone 1 development wells were put on production and monitored over time, considerable



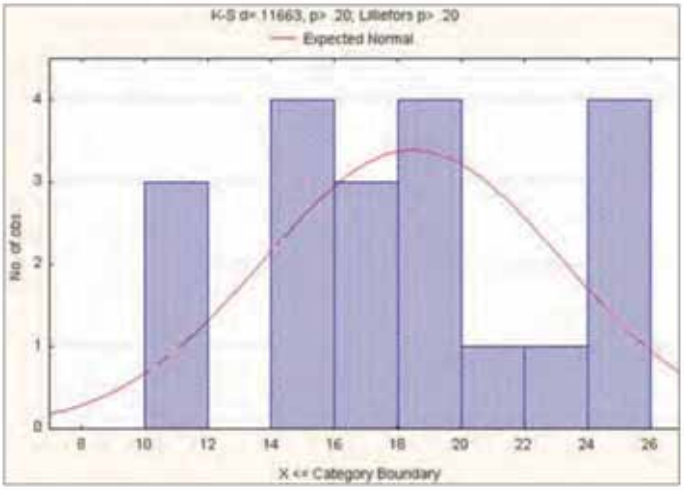




Fig. 13. Histogram of minimum porosity values for the Zone 1 wells.

Fig. 12 (left). Minimum porosity interval.

| Parameter | Value Range | Units | Comments |
|---|---|---|---|
| Vertical Permeability Contrast | 0-30 | % | Extent to which a lateral permeability baffle limits vertical flow. Determined by the minimum porosity across the vertical interval. |
| Distance to Injectors | 0-10 | km | Minimum distance to injectors. |
| Trajectory Orientation | 0-1 | | 0 = drilled toward injectors.<br>1 = parallel to injectors.<br>Any trajectory between is determined by angle to parallel. |
| Remaining Oil Column in Zone 2 | 0-20 | ft | |
| Zone 1 Thickness | 0-15 | ft | |
| Net Reservoir Contact | 1,000-6,600 | | Net Zone 1 reservoir contact across the horizontal wellbore. |
| Loss of Circulation while Drilling and/or Highly Fractured Intervals | 0-1 | | 0 = No<br>1 = Yes |
| Completion Type | 0-1 | | 0 = Open hole<br>1 = Zonal isolation and/or ICDs |
| Net/Gross | 68-100 | % | Net/Gross footage in Zone 1 across the horizontal wellbore. |
| Average Zone 1 Porosity | 15-27 | % | Average porosity across the reservoir in the horizontal wellbore. |

Table 2. Parameters for assessing well performance

| Variable | Description | # of Wells |
|---|---|---|
| T15 | Cumulative producing time (months) to reach 15% water cut. | 20 |
| T30 | Cumulative producing time (months) to reach 30% water cut. | 11 |
| T50 | Cumulative producing time (months) to reach 50% water cut. | 5 |
| T75 | Cumulative producing time (months) to reach 75% water cut. | 0 |

Table 3. Response variables

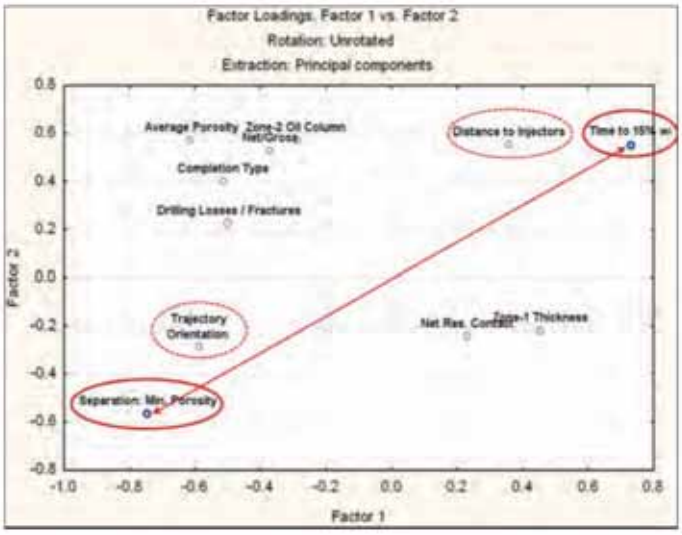



Fig. 14. Principal component analysis with factor loadings

variability was observed in well performance. A comprehensive multivariate statistical analysis was applied across the gamut of reservoir parameters for these wells to gain further insights into critical success factors and mechanisms affecting well performance. A total of 10 reservoir and completion parameters were considered in this analysis, Table 2, including the range of values, units and description.

As the first parameter in the table, vertical permeability contrast represents the degree of separation between Zones 1 and 2. The greater the degree of separation, the more pronounced will be the permeability baffle effect on flow from Zone 2 to Zone 1. The only practical way of estimating vertical permeability is by using the minimum porosity across Zone 1 from logs in nearby vertical wells. The minimum porosity interval is illustrated in Fig. 12. To determine minimum porosity across the vertical section for a specific Zone 1 horizontal well, the minimum porosity was determined for each vertical penetration in the immediate vicinity of the horizontal well trajectory, and these values were averaged. In the event that the horizontal wellbore was not kept above the minimum porosity interval and actually penetrated below or into Zone 2 during drilling, then the porosity value encountered during drilling was used in place of the minimum porosity. This occurred in five out of the 20 wells considered in the analysis. A histogram of the minimum porosity values associated with the 20 wells evaluated in this study is presented in Fig. 13. Skewness at the tail end (high minimum porosity) resulted from the fact that five of the 20 horizontal wells penetrated the minimum porosity interval and in some cases scratched the top of Zone 2.

Three of the parameters in Table 2 (trajectory orientation, loss of circulation while drilling and/or

| | Net Reservoir Contact | Losses/ Fractures | Completion Type | Average Porostiy | Net/Gross | Zone-2 Oil Column | Zone-2 Thickness | Distance to Injectors | Trajectory Orientation |
|---|---|---|---|---|---|---|---|---|---|
| Net Reservoir Contact | 1.00 | | | | | | | | |
| Losses/ Fractures | -0.14 | 1.00 | | | | | | | |
| Completion Type | -0.24 | 0.42 | 1.00 | | | | | | |
| Average Porostiy | -0.03 | 0.32 | .034 | 1.00 | | | | | |
| Net/Gross | 0.18 | 0.21 | 0.18 | 0.68 | 1.00 | | | | |
| Zone-2 Oil Column | -0.11 | 0.12 | 0.18 | 0.61 | 0.28 | 1.00 | | | |
| Zone-2 Thickness | 0.60 | -0.05 | -0.24 | -0.23 | -0.16 | 0.28 | 1.00 | | |
| Distance to Injectors | -0.14 | -0.07 | 0.29 | -0.05 | -0.06 | 0.12 | 0.03 | 1.00 | |
| Trajectory Orientation | -0.15 | 0.17 | 0.34 | 0.07 | 0.23 | -0.32 | -0.21 | -0.16 | 1.00 |
| Separation: Minimum Porosity | 0.01 | 0.21 | 0.20 | 0.17 | -0.14 | 0.02 | -0.14 | -0.45 | 0.49 |

Table 4. Cross-correlation matrix of variables for the 20 well dataset

highly fractured intervals and completion type) were quantified to perform the statistical analysis. Trajectories were oriented parallel to injectors where possible, and these were assigned a value of 0. Trajectories oriented directly toward injectors were assigned a value of 1. The value assigned to all other trajectory orientations was determined by the angle to the parallel orientation divided by 90° (i.e., a fraction between 0 and 1). Wells that encountered loss of circulation while drilling or showed significant conductive fractures from image logs were assigned a value of 1, and those that did not were assigned a value of 0. Similarly, wells completed with zonal isolation and/or ICDs were assigned a value of 1, while those completed open hole were assigned a value of 0.

Finally, the remaining parameters in Table 2 (distance to injectors, remaining oil column in Zone 2, Zone 1 thickness, net reservoir contact, net/gross and average Zone 1 porosity) were quantified as measured for the statistical analysis. These 10 parameters constitute the independent variables in this study.

A number of response or dependent variables were established to gauge well performance in this study. Since oil production targets for the Zone 1 development wells were set at a narrow range to minimize premature coning, the most useful measure of well performance was the cumulative producing time (months) required to reach various water cut thresholds. In this study several water cut thresholds were employed, Table 3.

The first step in the statistical analysis was to perform a principal component analysis to make a preliminary assessment of relationships among independent and dependent variables. Factor loadings were determined using the largest dataset, 20 wells with a T15 response, Fig. 14. The factors are selected mathematically to account for the largest proportion of variance in the data.

The resulting factor loadings, determined for each variable,cshow that the dependent variable (T15) has a strong and inverse relationship with separation: minimum porosity. Trajectory orientation shows

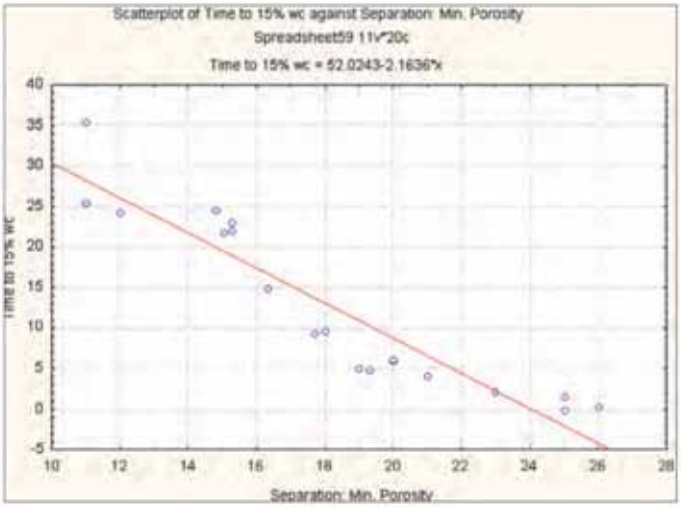



Fig. 15. T15 response to separation: minimum porosity.

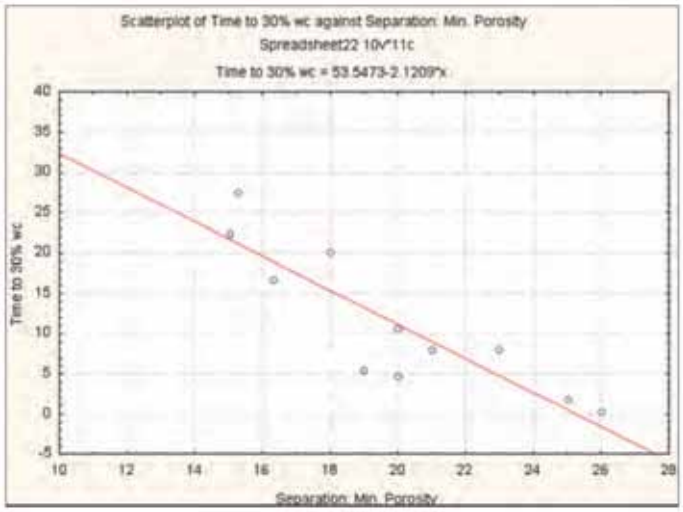



Fig. 16. T30 response to separation: minimum porosity.

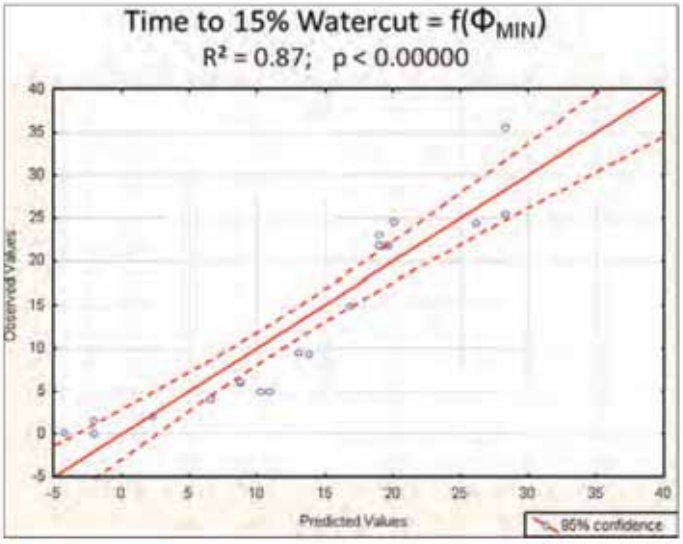



Fig. 17. Observed and predicted T15 response.

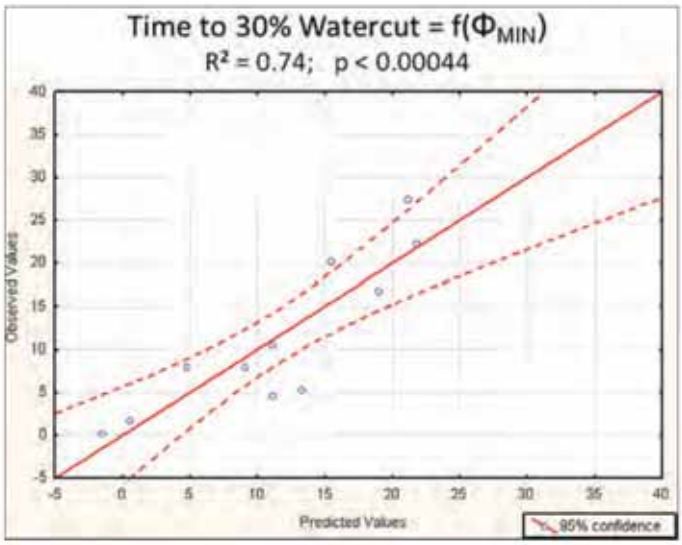



Fig. 18. Observed and predicted T30 response.

a similar inverse relationship with T15, but is less pronounced. Distance to injectors has a proportionate, and also less pronounced, relationship with T15. The remaining independent variables appear to have less influence with T15 and show similar behavior to one another in two different groupings.

Next, a cross-correlation analysis of the independent variables shows their correlation coefficients with each other and is an important precursor to the multivariate regression analysis. The cross-correlation matrix derived from the 20-well dataset is shown in Table 4.

A cross-correlation coefficient above 0.5 indicates that the two variables are strongly correlated. Highly correlated variables should be minimized to avoid complicating the multivariate regression. In this case, average porosity is cross-correlated with net/gross ratio and with Zone 2 oil column thickness. Similarly, Zone 1 thickness is strongly cross-correlated with net reservoir contact. Finally, there is a moderate degree of cross-correlation between separations: minimum porosity and two variables, and distance from the injectors and trajectory orientation. Taking a reservoir engineering perspective, average porosity in and of itself should not be as important to sustained well performance as the other two cross-correlated variables, so it was dropped. Zone 1 thickness and net reservoir contact were used alone in separate analyses to eliminate the cross-correlation issue.

A multivariate regression analysis was conducted using the remaining nine independent variables in terms of T15 response for the 20-well dataset. Seven of these variables showed no statistical significance: net reservoir contact, losses/fractures, completion type, average porosity, net/gross, Zone 2 oil column and Zone 1 thickness. The remaining three variables showing some degree of statistical significance are separation: minimum porosity, trajectory orientation and distance to the injectors.

Consequently, the statistical significance of the distance to the injectors and trajectory orientation was found to be inconsistent between the backward stepwise elimination and forward stepwise insertion methods of multivariate regression. This may have something to do with the moderate statistical cross-correlation of both variables with separation: minimum porosity, just below 0.5. The full effect of these two variables may also be held back due to the short time of production (one to three years). In later time periods, these two parameters may exert a much larger effect. Similar results were found with multivariate analysis of T30 using the 11-well dataset.

The dominant statistical effect on water cut performance for sustained oil production is clearly the separation: minimum porosity between the Zone 1 wellbore and Zone 2, shown in terms of T15 for 20 wells and T30 for 11 wells, respectively, in Figs. 15 and 16.

There is a pronounced relationship between well water cut performance and the degree of separation between the Zone 1 wellbore and the underlying Zone 2. This relationship or correlation explains 87% of the variability in T15 response for the 20-well dataset. The amount of variability explained by this single parameter drops to 74% for the 11-well dataset that has reached the 30% water cut threshold. T15 and T30 responses in observed and predicted performance are shown in Figs. 17 and 18, respectively. Notice the broader 95% confidence T30 in Fig. 18.

Other parameters may contribute to well performance beyond the 30% water cut threshold and will be addressed in a future article.

## Conclusions

1. Horizontal wells have provided an effective means of producing the Zone 1 reserves. The development of Zone 1 on the perimeter of the field between the injectors and the first row of producers relied mainly on sidetracking existing marginal producers. This maximized the use of existing assets, while minimizing unit development cost. A select few, new single and dual lateral wells were drilled to target sweet spots inaccessible from sidetracks of existing marginal wells.

2. The optimal length of the single lateral sidetracks was found to be between 4,000 ft and 6,000 ft. Frictional pressure drop at rates below 6 MBOD was found to be negligible. Multilaterals with individual lateral lengths of 3,000 ft to 4,000 ft have also been successful.

3. Placement of the lateral in the top of Zone 1 yielded superior oil recovery compared to the other vertical placement options: top of Zone 2, coupled trajectory in Zones 1 and 2, a trajectory chasing the maximum porosity and an undulating trajectory intersecting anhydrite above and Zone 2 below.

4. Maximum oil recovery is achieved for laterals with good but not total separation between Zones 1 and 2 (kv/kh ~ 0.03). Separation between the zones with good transmissibility greatly delays the onset of water encroachment and breakthrough, extending productive well life. Limited vertical communication is necessary, however, to allow drawdown and gravity segregation effects to bring Zone 2 oil to the Zone 1 lateral.

5. Multilaterals drilled to date have been effective. MRC wells have not been attempted in this region between the first line producers and the injectors, given the added complexity, cost and risk. In reservoirs with similar conditions but with a very tight, thin oil zone, however, MRC wells may be more attractive.

6. Effective geosteering in thin oil zones with complex geological facies is best achieved using advanced geo-steering tools (density or resistivity image logs and ultra-deep resistivity or deep azimuthal resistivity logs). A rotary steering system is preferred to improve the response of the drilling bit. It cannot be overemphasized that control of the drilling bit must be maintained, and unintended wellbore undulations should be minimized.

7. Well trajectories and completions should be designed to ensure uniform flow contribution along the wellbore. Zonal isolation and ICDs distributed among appropriate compartments may be necessary to deal with fractured intervals, unfavorable toe-to-heel pressure differentials, proximity of toe or heel to water and/or permeability variations. Again, it is important that the completed well have a uniform flow contribution and minimal drawdown, to delay water

encroachment and production.

8. Completions for sidetracked wells that are left open hole across the reservoir require foresight to determine whether the option for future intervention is needed. Expandable liners may be required if future recompletion across the reservoir is expected.

9. A multivariate analysis conclusively demonstrated that the principal factor governing well performance in the early period (up to three years) was the vertical permeability contrast or, in other words, the extent to which a permeability baffle exists between the thin low permeability zone and the underlying thick high permeability zone. Other parameters may contribute to well performance beyond the 30% water cut threshold and will be addressed in a future article. The findings from this study have been translated into best practices for exploiting thin oil zones and have been applied in further developing the thin oil zone in the subject field.

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## Biographies

Majid H. Al-Otaibi has 15 years of experience with Saudi Aramco. During this time, he has worked in a variety of disciplines, including production facilities, production engineering, drilling engineering and reservoir management. Majid has participated in multiple increments that Saudi Aramco has put onstream in recent years, including HRDH-III, KHRS and NYYM. In reservoir management, he led the upscale development of a thin oil zone in a giant mature carbonate reservoir in Saudi Arabia. Majid now works as the Upstream Team Leader for the Manifa Increment.

He received his B.S. degree in Chemical Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia, and his M.S. degree in Petroleum Engineering from the University of Texas at Austin, Austin, TX.

Dr. D. Brett Fischbuch is currently involved in reservoir management activities for North Ghawar in the Southern Area Reservoir Management Department. Prior to joining Saudi Aramco in 2006, he worked in a variety of engineering positions with ExxonMobil and Chevron over a 17-year period.

Brett received his B.S. degree in Chemical Engineering from Brigham Young University, Provo, UT, and his Ph.D. degree in Petroleum Engineering from Texas A&M University, College Station, TX.

Obai A. Taibah has been with Saudi Aramco since 2005. In that time, he has spent 1 year in production in Abqaiq and the remainder as a Reservoir Engineer in North Ghawar.

Obai received his B.S. degree in Petroleum Engineering from the Colorado School of Mines, Golden, CO, in 2005. He is a member of the Society of Petroleum Engineers (SPE).

Ali H. Al-Julaih works with Shedgum Reservoir Management as a Reservoir Engineer and is heavily involved in development programs for exploiting thin targeted zones in a fractured carbonate reservoir. He previously worked with the Reservoir Description, Production Engineering and Reservoir Management Departments.

In 2005, Ali received his B.S. degree in Petroleum Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia, and is currently pursuing a M.S. degree in Petroleum Engineering, also at KFUPM.

# Utilizing New Proven Technologies in Enhancing Geological Modeling and Reservoir Simulation History Matching: Case Study of a Giant Carbonate Field

By Bevan B. Yuen, Dr. Olugbenga Olukoko, Rida Abdel-Ghani, Saad A. Al-Garni and John Temaga.

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## Abstract

In the 21st century, intelligent field data, high resolution geological and mega-cell simulation modeling, and supercomputing computer clusters are all technologies that have revolutionized reservoir simulation in oil and gas field developments. The high resolution reservoir simulation model is essential for understanding the field/reservoir and for making future performance predictions. This article elaborates on how these technologies are utilized in building geological and simulation models for a giant carbonate oil field, in understanding well and reservoir performance, and in quantifying inter-reservoir communication between the two stacked carbonate reservoirs. The model building process includes: advanced fracture characterization and modeling; generation of matrix permeability by artificial intelligence; derivation of conditioning to dynamic permeability from pressure transient tests and flow meter profiles; Thomeer-based water saturation modeling; and matching of intelligent field well production, injection and pressure data.

The high resolution modeling process captures detailed heterogeneity in wells and minimizes the error associated with model upscaling. Use of smart and assisted history matching tools, coupled with the availability of powerful hardware clusters, enhances the use of different discriminators to quickly test the following geological features that are not easy to map: possible baffles and barriers, global high flow layers and local high permeability conduits. Matching of the abundant intelligent field well production, injection and pressure data improves the reliability of the simulation model. The eventual outcome of employing these technologies is a simulation model that reproduces short- and long-term production performance that can be employed to support field operations and proactive reservoir management.


## Introduction

Reservoir characterization is the foundation of any reservoir simulation model, as a reservoir model is only as good as the underlying geological model. Reservoir characterization includes rock characterization and fracture characterization. In Saudi Aramco, subsurface geoscientists commonly utilize both facies and petrophysical rock typing in rock characterization. By taking a novel approach, developed in-house[1], they have successfully characterized the Arab-D carbonate reservoirs in Saudi Arabia. This novel method analyzes all pore systems with the Thomeer function[2] using an extensive mercury injection capillary pressure (MICP) data set. Thomeer parameters are then generated for each grid cell and in turn used to calculate permeability,

relative permeability and water saturation. The main advantages of this method over other available techniques are that it efficiently describes multimodal pore systems and it was developed based on basic physical principles.

Simple scoping simulation models are often used in early field development studies due to limited data availability, but reservoir heterogeneities usually become more apparent as more reservoir data and more production history are acquired. Detailed and larger reservoir simulation models are then required not only to represent the size of the reservoir, but also to capture the reservoir heterogeneities; to fulfill further development and operational requirements, such as infill well spacing; to capture water/gas coning behaviors; and to simulate intelligent well completions using inflow control devices (ICDs) and valves. It is essential that high resolution models capture the reservoir heterogeneities during the geological modeling stage, but this may be compromised during reservoir simulation modeling due to the upscaling of the geological model to a manageable size, a process that is subject to software and hardware limitations. Saudi Aramco has seen the dimensions of its reservoir simulation models grow exponentially during the last 10 years[3], from a hundred thousand cells to tens of millions of cells. As a result, Saudi Aramco recently deployed the GigaPOWERS™ reservoir simulator[4], enabling simulation engineers to routinely construct and run simulation models with tens and hundreds of millions of cells without upscaling the geological model.

GigaPOWERS can handle very large simulation models with millions of cells and still provide reasonable turnaround times, in the order of minutes or hours, because of its use of parallel computing technology. It is the backbone of mega-cell and giga-cell simulation[5], and the high computation power is provided by several PC clusters with over 2,000 nodes (200 teraflops). Consequently, most of the simulation models in Saudi Aramco do not require upscaling of the geological models, thereby retaining the high vertical (log-scale) and areal resolutions for more accurate results.

## Building a Fine Resolution Geocellular Model

Building a 3D geocellular model requires a priori knowledge of the geological concept and of the scale and magnitude of the geological heterogeneities sufficient to satisfy the objectives of the geological model. Often, these heterogeneities are inferred from directly measured data, such as wireline (including image and production) logs and cores, which provide conclusive evidence of vertical variation and distribution within all defined geological facies or stratigraphic zones.

### Capturing of Heterogeneities

When the core data of this giant carbonate reservoir complex was analyzed, results indicated that heterogeneities occur at different scales. In fact, dense core sampling suggests that there is a rapid and large vertical variation even within the same defined rock facies. Based on the available production data and other dynamic data, such as transient well tests and records from production logging tools (PLTs), these heterogeneities can have a considerable impact on the dynamic behavior of the reservoir, so it is of paramount importance to capture them in the 3D geocellular model and distribute them laterally. Therefore, much effort was spent on identifying these minute but very important geological features from available field data and incorporating them in the reservoir understanding, either as baffles or as thin intervals of exceptionally high permeability.

The identification and determination of these rapid and large vertical variations of the rock facies called for a high resolution 3D geocellular model. This model was generated using several sensitivity runs on the internal layering schemes to determine the optimum layering scheme per stratigraphic zone. From this data, the most manageable simulation model (i.e., model size vs. CPU run time) can be derived while still capturing key geological heterogeneities. In general, it is reasonable to say that a good geological/simulation model resolution strikes a balance between the model size and the capability of the modeling software and simulator in terms of CPU run time.

High resolution simulation modeling is now possible in Saudi Aramco with the advent of the GigaPOWERS™ simulator, which encourages the construction of fine scale geological/ simulation models, honoring core and log data down to the smallest measured details. This model is validated by making a direct comparison of either the core derived logs or the wireline logs at the well locations with the blocked or upscaled logs at the geological model resolution. As expected, a favorable comparison has been observed for the high resolution model, showing that it has captured all the heterogeneities (porosity and permeability), Fig. 1.

Therefore, reliable reservoir property models can be obtained that retain the rapid and large vertical variation in the rock facies without the smearing effect

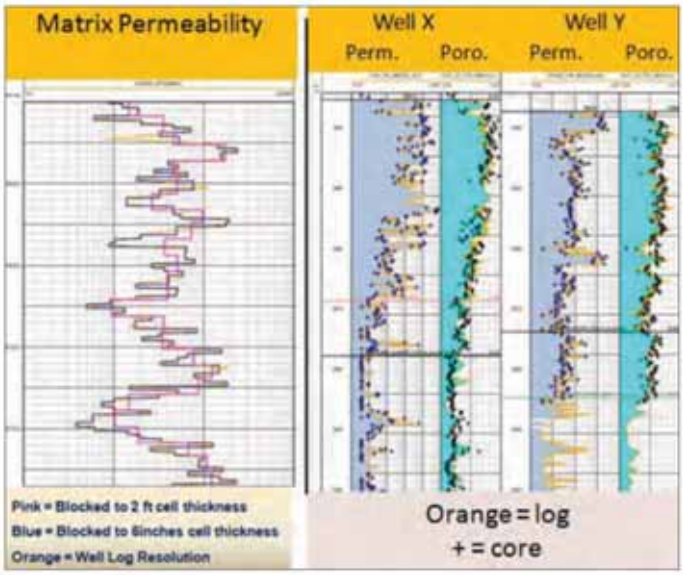


Fig. 1. Capturing of all heterogeneities in input data.

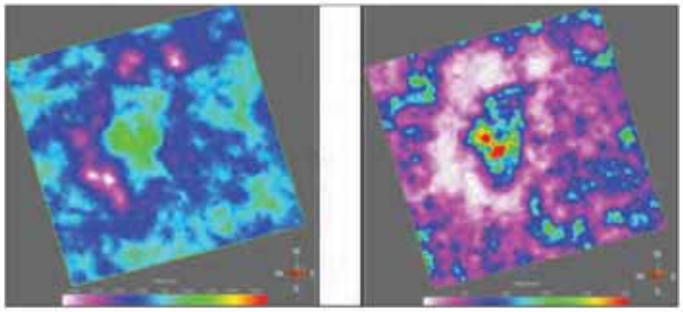

Fig. 2. High resolution porosity and permeability models.

of averaging modeled properties. This high resolution 3D geological model has integrated densely sampled permeability derived from core data and the wireline log transformed permeability curve, down to the smallest details offered by the data. This powerful combination is a significant improvement that ensures that the matrix property is modeled accurately, honoring the observed hard data, Fig. 2.

**Thomeer-based Technology**

The conventional J-function method is inadequate to model the transition zones of complex pore systems. Therefore, a more competent model, one that utilizes the distribution of Thomeer parameters using geostatistical techniques, was applied to depict static reservoir properties like multimodal porosity and permeability. This high resolution 3D geocellular model adopted a new water saturation modeling approach[6]. The Thomeer-based saturation height modeling technique enables multi-pore reservoir systems to be modeled more accurately, Fig. 3. The high accuracy is due to the upscaling of capillary pressure function from core plug scale to reservoir cell, using a closed-form analytic expression based on Thomeer-type curve matching of large amounts of MICP data. This accuracy in modeling porous reservoir systems is particularly important in our complex, multimodal carbonates where the best reservoir rocks exhibit both inter-granular macro-porosity and intra-particle micro-porosity. Moreover, free water level (FWL) and paleo-free water level can also be calculated using an inversion search.

**Conditioning with Dynamic Data**

To integrate the well flow meter and pressure transient analysis (PTA) results, an inversion or distribution of total permeability thickness according to well flow profiles was performed. The well production log should be of good quality, should be acquired from a vertical open hole to avoid partial penetration problems, and should have been acquired while the well was producing dry oil. The flow profile may include effects of differential depletion, fractures, faults, mechanical damage and acid stimulation, which are common in carbonate reservoirs. Conditioning with dynamic

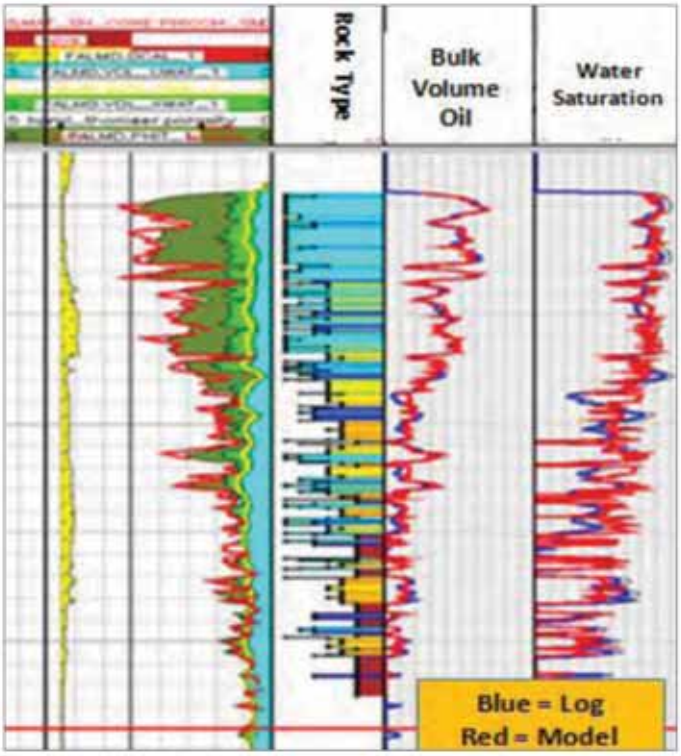


Fig. 3. Well modeling showing bulk volume oil and water saturation.

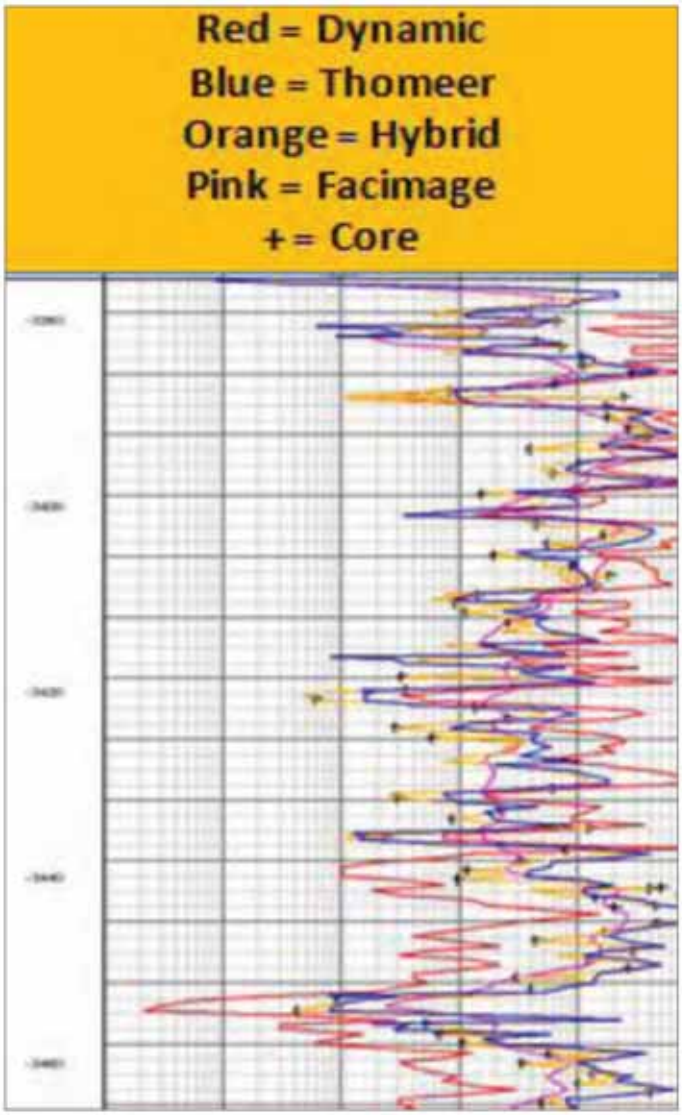


Fig. 4. Comparison of various permeability realizations.

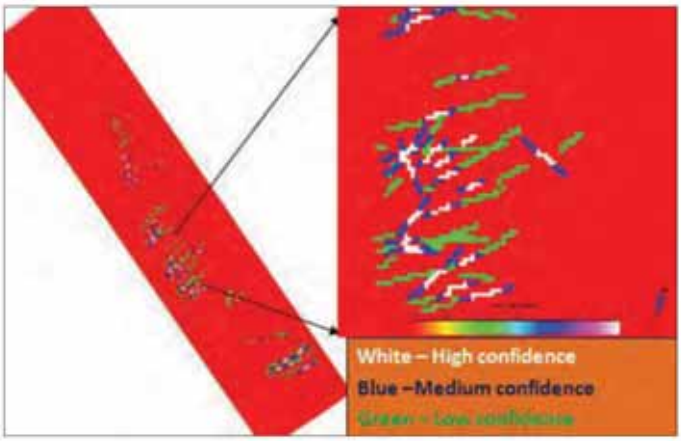


Fig. 5. Fracture realizations with different confidence levels.

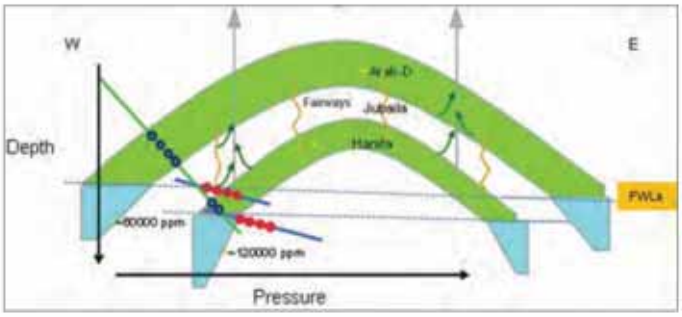


Fig. 6. Schematic of the reservoir's stacked units.

data generates a permeability realization that provides the upper limit of the cell permeability. The excess permeability of this realization over the matrix permeability indicates the possible influence of fracture lineaments and diffuse fractures. Figure 4 shows the comparison of the various permeability realizations.

### Fracture Characterization

Natural fractures are very dominant in an Arab-D carbonate reservoir. Subsequently, their detection, characterization and modeling are an integral part of understanding such a field. Saudi Aramco uses a workflow that integrates both static and dynamic data utilizing 22 methods for fracture detection[7]. One realization of the fracture map that resulted from this workflow, Fig. 5, shows the different confidence levels in the results. Fracture probability function based on confidence levels can then be generated and used during the assisted history matching process. In addition, a fracture's presence and its properties will be validated when the simulation model is calibrated to historical field performance data.

## Mega-Cell Simulation Model Initialization and History Matching Approach

This reservoir complex consists of two stacked units, Arab-D and Hanifa, separated by a 200 ft thick non-reservoir unit, the Jubaila, Fig. 6. The dual porosity/dual permeability (DP/DP) model of this giant field consists of 445 layers with approximately 28 million cells. The upper Arab-D reservoir was modeled with 235 layers, and the lower Hanifa reservoir model consisted of 209 layers with one layer representing the non-reservoir Jubaila, through which the two reservoir units communicate via natural fracture fairways. The massive field data contains over 50 years of history, and currently there are over 300 wells with intelligent field data, transmitting pressure and production from a permanent downhole monitoring system (PDHMS).

### Initialization with Different FWLs

It has been established through all available field data that the two reservoir units are in communication via natural fractures that cut through both units and the Jubaila. The historical data also hints at significantly different FWLs for these reservoir units, indicating that communication is restricted to within the oil zones. Unlike other oil fields in Saudi Arabia, where the communicating Arab-D and Hanifa reservoirs most likely have the same FWL, available data (showing different salinities and dry oil depths) indicates that the FWL of the poor quality Hanifa is deeper than that

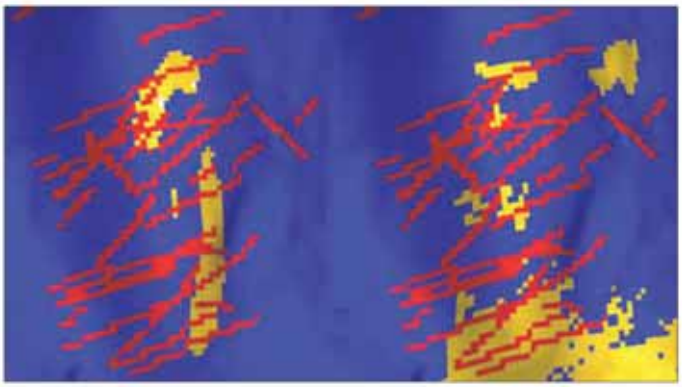

Fig. 7. Dynamic creation of fractures (additional fractures/flow features in yellow).

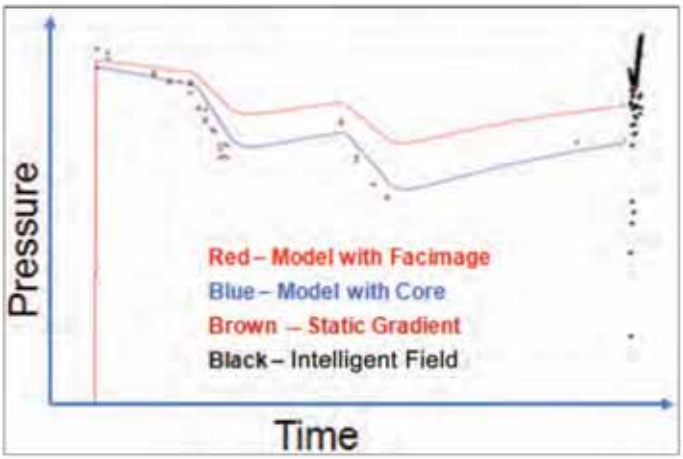


Fig. 8. Effect of various matrix permeability realizations on model well pressure.

for the Arab-D. Therefore, equilibrium initialization was carried out using different FWLs while ensuring that the communicating fractures are limited to the hydrocarbon regions. Initial water saturations consistent with vertical equilibrium oil-water capillary pressures were calculated using a combination of the Thomeer-based methodology for the Arab-D reservoir and J-function methods for the Hanifa reservoir.

**Dynamic Creation of Permeability Realizations**

The geological model includes six basic permeability realizations: Facimage™, core, hybrid (core + Facimage), Thomeer, dynamic and fracture. Facimage permeability, which is based on well logs calibrated with core data, provides matrix permeability data for wells without cores. The abundance of core data in the field, which has more than 50 cored wells, provides an added advantage for the fine scale modeling since the heterogeneities captured in the core data can be directly incorporated in the model with no or limited upscaling. The hybrid (core + Facimage) permeability approach exploits this advantage by creating a matrix permeability realization using the available core data supplemented with Facimage permeability for uncored wells/intervals. Thomeer permeability takes into account uncertainties and the upscaling from core scale to model cell size. Since the dynamic permeability is an inversion of the available PLT and PTA data, it represents the total effects of rock matrix and fractures. In this DP/DP model, the matrix permeability was assumed to be the base with the fracture network; additional fracture realizations could be generated using the difference between the dynamic permeability and the matrix permeability. A snapshot of two fracture realizations (red indicates the fracture lineaments, and yellow indicates dynamic created fractures, i.e., diffuse fracture, super-K or stratiform) is shown in Fig. 7.

A comparison of the effect of various matrix permeability realizations on well pressure is given in Fig. 8. A good history match was achieved for the reservoir model that had a hybrid permeability realization for

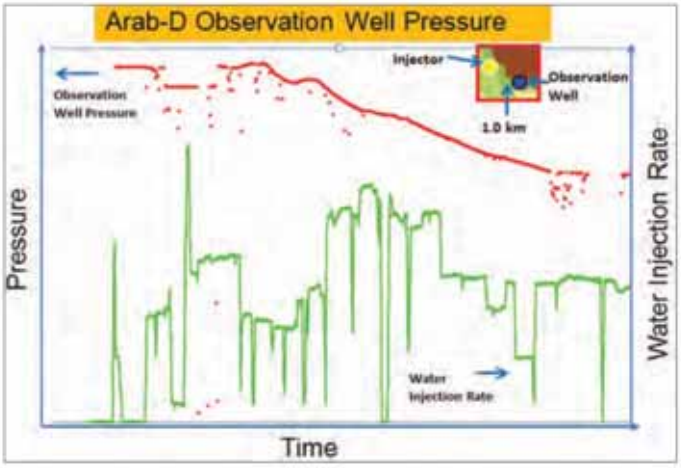


Fig. 9. No inter-well communication detected in Arab-D.

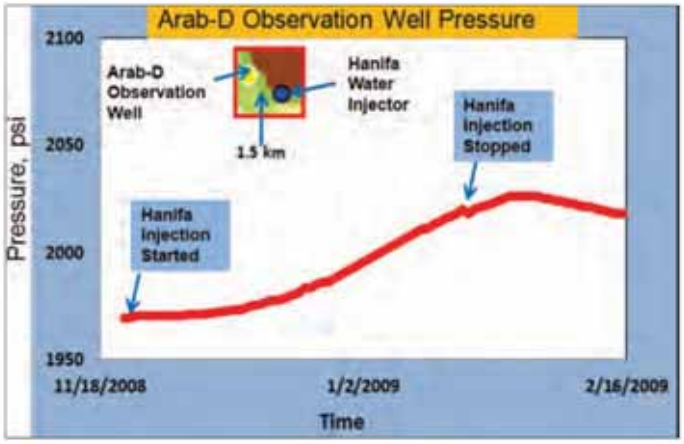


Fig. 10. Identification of inter-reservoir communication

the matrix, high confidence fracture lineaments and some diffuse fractures at various parts of the reservoirs.

## Integrating Intelligent Field Data

The giant carbonate field is equipped with advanced, state-of- the-art, intelligent field surface and subsurface infrastructure for over 300 wells. This includes smart completions, PDHMS, single and multiphase flow meters (MPFMs), and wellhead pressure and temperature gauges.

### Real-Time Monitoring and Data Gathering

A new intelligent system for data integrity was built to automate the process of delivering available and reliable data from the various intelligent field components to the engineer's desktop. This innovation takes the intelligent field beyond just surveillance, leveraging artificial intelligence to form a fully intelligent reservoir management expert system. The benefits of real-time data for oil field operation and optimization is well documented[8].

A real-time monitoring and control system enables instantaneous well testing to obtain well productivity/injectivity. It can also be used to detect inter-well and inter-reservoir communication, to alert operators to early water arrival in producers and to monitor pressure support of the field. For example, ineffective pressure support from a water injector was not seen by an observation well 1 km away, but was seen in the pressure drawdown by oil producers 3 km away, Fig. 9. Figure 10 shows the recorded increase in pressure in an Arab-D well due to water injection from the nearby Hanifa reservoir. These continuous and synchronized flow rate and pressure measurements replace the monthly average rates and periodic static pressure measurements by wireline. In addition, intelligent field data can be used to generate the field-wide pressure maps that are required for visualization and monitoring without any data interpolation. Intelligent field data is used during history matching of reservoir simulation models to enhance the reliability of the model for short- and long-term predictions.

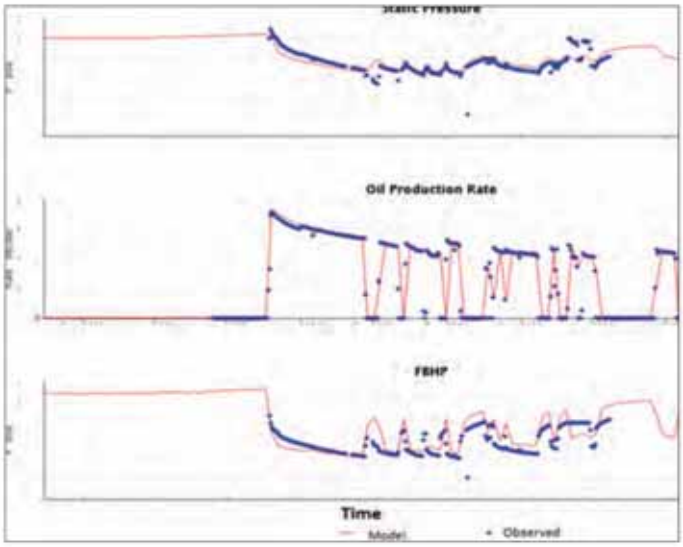


Fig. 11. Integrating intelligent field data in history matching.

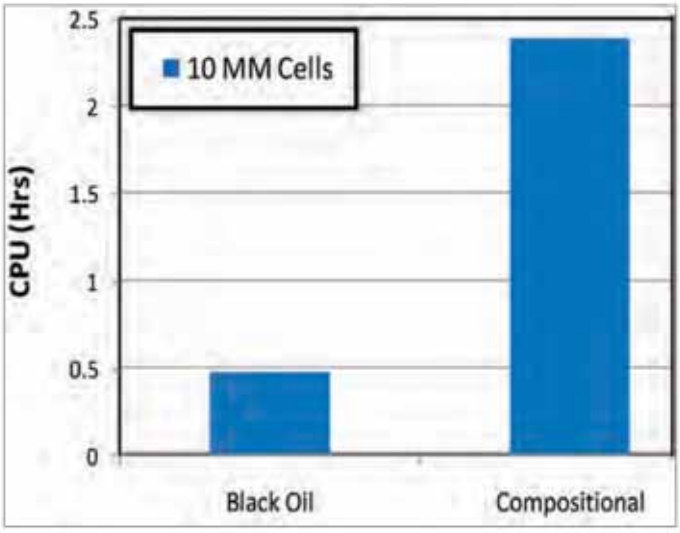


Fig. 12. Example of run times for a 10-million cell model using GigaPOWERS™.

**Application of Intelligent Field Data in History Matching**

With intelligent field data, the daily averaged well flow rates are used as input to the reservoir simulator, and the history matched reservoir model captures the trends of the corresponding daily averaged well flowing bottom-hole pressure (FBHP) or converted static well pressures (SWPs), Fig. 11. The FBHP has to be adjusted to the top or midpoint of the perforation to be comparable to the reservoir's simulator output. The conversion of FBHP to SWP introduces uncertainties due to the assumptions made regarding well productivity index. Water injector wellhead pressure also has to be converted to FBHP by use of single-phase vertical flow calculation for comparison with reservoir model results. To verify the accuracy of intelligent field data, periodic static pressure measurements by wireline were obtained.

The PDHMS performs well at steady conditions but is affected by wellbore phenomena that occur due to rate changes of the electric submersible pump. For example, when the pump intake pressure falls towards the minimum design intake pressure, the oil production rate is reduced due to insufficient artificial lift, but there is no change in well FBHP because of wellbore storage and system back pressure. When the well production rate in the reservoir simulator was reduced, however, the calculated FBHP increased instead. The PDHMS and MPFMs also suffer from gauge failure and calibration issues. The tremendous amount of digital data complicates data handling

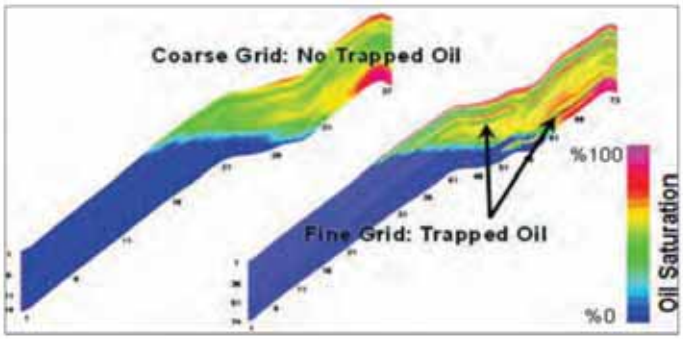


Fig. 13. Identification of bypassed oil with fine multimillion cell models.

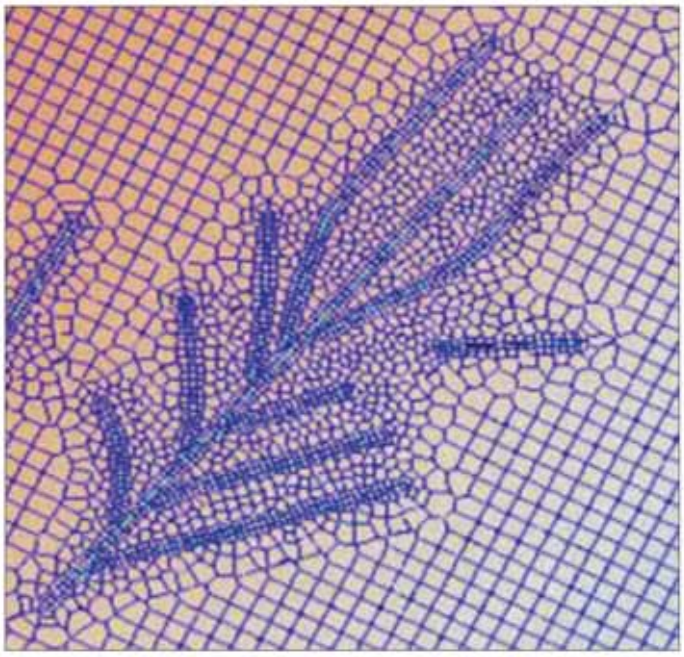

Fig. 14. Unstructured gridding around a maximum reservoir contact multilateral well

and storage, and limits the reservoir simulator to one-day time-steps for capturing the dynamic effects.

## Computing with Computer Clusters

Since its early inception in the 1950s[9], parallel computing has evolved over time to become one of the best methods for creating high performance computing machines. Parallel computing has changed from running multiple shared-memory processors that work side by side on shared data, to using the massive parallel processors that became very popular in the mid-1980s, to computing with the computer clusters that started to compete and eventually dominate in the parallel computing market from the late 1980s onward. Today, PC computer clusters, made of multi-processor nodes, possess teraflops of computation power.

**Parallel Computing and Parallel Simulator**

Parallel computing also requires parallel capable software if applications are to benefit from the available parallel computing hardware. Parallel programming is more challenging than sequential programming due to the necessary synchronization and communication that takes place between the parallel tasks.

Nowadays, several factors are encouraging parallel computing, such as the increased computational requirements for research and businesses alike, the limited vertical growth potential of sequential CPUs, the limited utility of the vector technology that is the basis for several high speed computer designs to applications utilizing matrix operations, and the advancement in networking technology that makes it available to build on multi-node parallelization.

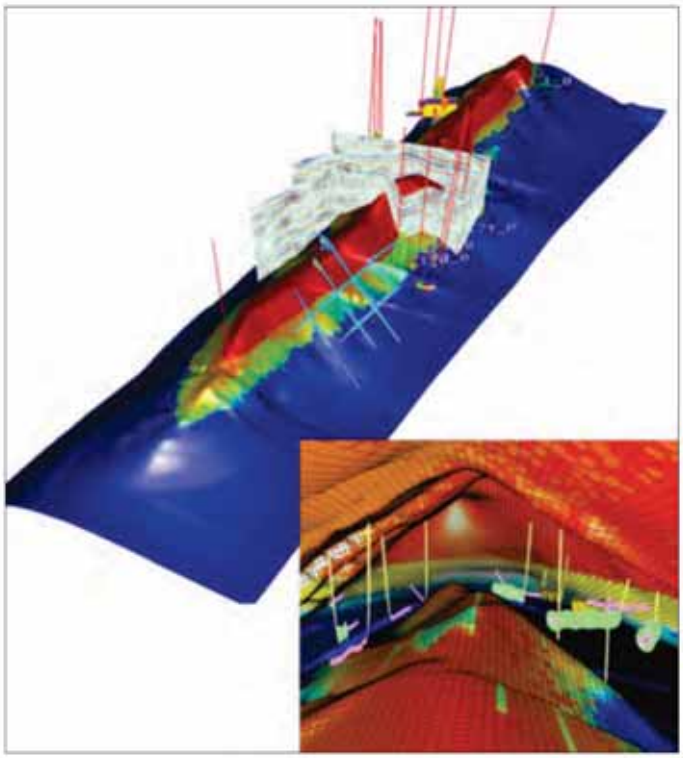

Fig. 15. Post-processing of mega-models requiring parallel clusters with remote visualization.

For Saudi Aramco, the need for parallel computing is dictated by the size of its giant reservoirs, the connectedness (hydraulic or portfolio) of the various reservoirs both laterally and vertically, the high degree of heterogeneity of the carbonate reservoirs, the state-of-the-art characterization work these reservoirs require, and the continuous striving for optimal development and recovery for the Kingdom's hydrocarbon resources.

Customized for Saudi Aramco's purposes, GigaPOWERS and its predecessor, POWERS, were both built from the ground up to run parallel computing environments, giving them a leading advantage when it comes to running mega-cell size reservoir simulations. Today, GigaPOWERS is capable of running models that are hundreds of millions of cells in size in a matter of hours. In fact, it was tested in a development environment with a one billion cell model. Figure 12 shows an example of GigaPOWERS capabilities, running a fully compositional 10 million cell model in less than 2½ hours. The figure also shows that the same model can be run in black oil mode in less than a half hour. This specific giant carbonate field model of 28 million cells with over 50 years of history has a run time between 3 and 5 hours using the black oil option, and a 48 million cell model with a shorter simulation history can run within 3 hours.

**Benefits of the Parallel Simulator**

The parallel computing capability allows simulation models to run at the same resolution as the geological model, maintaining the detailed characterization efforts put in by the geologist and geo-modelers. This reservoir model also has numerous other benefits, such as detailed tracking of hydrocarbon movement and the identification of any bypassed oil, Fig. 13; unstructured fine gridding for simulating and optimizing multilateral wells with smart downhole completions and ICDs, Fig. 14; uncertainty analysis and multiple realization modeling; capabilities for visualization of mega-models with thousands of wells and a long history, Fig. 15; and the use of assisted history match (AHM) tools for carrying out thousands of simulation runs for mega-models in a matter of days. GigaPOWERS also has progressed from double porosity to multi-porosity formulation, making possible simulation of multi-pore systems in carbonates[10].

This state-of-the-art parallel computing technology at Saudi Aramco enables accurate characterization and simulation modeling, optimized development planning and timely delivery of the results – especially with the new era of intelligent field development and real-time simulation, which will soon be the norm for operations.

## Conclusions

1. The four proven technologies that drive modern day reservoir simulation are fine resolution geological modeling, mega-cell simulation, intelligent field data and parallel computing PC clusters.

2. It is accepted that a high resolution geological model is needed to capture heterogeneities; however, many geostatistical models are relatively homogeneous. Dynamic permeability amplifies the contrasts and acts as a natural layering discriminator besides facies or geological zones.

3. Thomeer-based technology provides an alternative property modeling technique for rock typing. It can be used to model water saturation like J-function methods but is more accurate for multimodal pore systems. It also provides independent water saturation estimates based on MICP measurements other than the Archie equation.

4. The availability of matrix, fracture and dynamic permeabilities allows engineers to create various reservoir permeability realizations using different combinations of these variables. Experience shows

that highly conductive media, such as fractures and high permeability rocks, are the critical parameters in history matching.

5. The availability of intelligent field data to the history matching process improves the reliability of model predictions. The continuous and synchronized measurements not only provide quick data turnaround but also improve understanding of the interactions between wells.

6. High performance computer clusters and parallel computing are the engines driving mega-cell simulation modeling at geological modeling scales. It also enables the effective use of AHM tools to search the solution space exhaustively for most likely or equally probable cases.

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John's vast, in-depth industry experience in both clastic and carbonate reservoirs earned him several in-house awards in Shell Malaysia and Shell Netherlands. Today he applies that knowledge in many of Saudi Aramco's onshore carbonate fields, such as Ghawar field. Since joining Saudi Aramco, John has built more than 20 high resolution geological models of various scales and complexities.

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# Combined Hydrogen and Electricity Production with $CO_2$ Capture Using Liquid Petroleum Fuels

By Dr. Aqil Jamal, Dr. Thang V. Pham and Dr. Mohammed Al-Juaied.

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## Abstract

Due to the chance offered to achieve potentially higher efficiencies and lower emissions of both criteria pollutants and carbon dioxide ($CO_2$) from petroleum fuel, governments and private industries around the world are actively investigating low emission technologies addressing both the transportation and the power generation markets. Combined hydrogen ($H_2$) and electricity generation at refueling stations for fuel cell vehicles (FCVs) or electric vehicles (EVs) is one such emerging technology option of particular interest to Saudi Aramco in its capacity as one of the largest suppliers of energy to the world and traditionally an early adopter of leading-edge technologies. This article presents a summary of the results of a high-level study, including a thermodynamic analysis and cost analysis, of nine separate options to produce $H_2$ and electricity from liquid petroleum fuels at refueling stations, with $CO_2$ capture to be used for enhanced oil recovery (EOR). The study identified the two most promising options, with an estimated cost of carbon-free $H_2$ production to be around $6.5 per kg under a full deployment scenario. These two options are (1) on-site $H_2$ production utilizing a high temperature H2 selective membrane reactor in combination with selective polymeric membranes for $CO_2$ capture, and (2) centralized $H_2$ production with a $H_2$ carrier for delivery to refueling stations. The study also found that the co-production of electricity at individual refueling stations is not a cost-effective option and that the cost incurred due to $CO_2$ avoidance makes up almost half of the cost of $H_2$ production.


## Introduction

Driven by the need to achieve maximum energy efficiency while minimizing the carbon footprint resulting from the use of fossil-based fuels, the development and deployment of tech- nologies that can produce carbon-free fuels has gained significant momentum over the last decade[1-3]. Among the various emerging technologies, on-site hydrogen ($H_2$) production, fuel cells for power generation and technologies for carbon capture and storage (CCS) are of particular interest to Saudi Aramco. As a global producer and exporter of petroleum fuels, Saudi Aramco recognizes that these technologies offer considerable potential to underpin the long-term value creation of the company's natural resources. To understand the current state of the technology and develop a road map for the future direction of research and development (R&D) efforts related to carbon-free fuel generation from petroleum resources, a pre-feasibility study was commissioned by Saudi Aramco. The key objective of this study was to explore the technical feasibility and eco- nomic viability of several options that combine $H_2$ and electricity production with $CO_2$ capture to be used for enhanced oil recovery (EOR).

This pre-feasibility study evaluated the following two cases, which produce $H_2$ derived from Saudi Aramco's petroleum fuels with $CO_2$ capture for EOR:

- Case 1: On-site $H_2$ generation.
- Case 2: Centralized $H_2$ generation with a liquid petroleum-based $H_2$ carrier.

| Hydrogen and Electricity Co-production Station | | |
|---|---|---|
| Generation Capacity | Scale | # of Vehicles Served per Day |
| Hydrogen | 250 $Nm^3/hr$ | 100 FCVs |
| Power | 370 kWe | 100 EVs |
| **Hydrogen Only Production Station** | | |
| Generation Capacity | Scale | # of Vehicles Served per Day |
| Hydrogen | 500 $Nm^3/hr$ | 200 FCVs |
| Power | Imported | 0 EVs |

**Table 1. Design capacities of hydrogen refueling station with $CO_2$ capture**

In the first case, $H_2$ is produced from liquid petroleum feedstock, with $CO_2$ captured, at individual refueling stations located in Tokyo, Japan. The $CO_2$ captured on-site from each refueling station is collected and sent back to Saudi Arabia (the Kingdom) for EOR purposes using specially designed ocean tankers similar to liquefied petroleum gas or liquefied natural gas (LNG) tankers. In the second case, $H_2$ is produced in the Kingdom at a centralized facility, and the $CO_2$ is captured and utilized for EOR near the production site. The produced $H_2$ is then transported to Tokyo via a liquid petroleum-based $H_2$ carrier. Existing shipping and transportation facilities for gasoline or other commodity chemicals were deemed sufficient for the transportation of the $H_2$ carrier on land and across the ocean. The $H_2$ carrier is subsequently dehydrogenated at each station, releasing the $H_2$ for dispensing into fuel cell vehicles (FCVs). The $H_2$ depleted carrier is then shipped back to the Kingdom for re-charging and re-shipping.

Two scenarios were investigated for both of these cases – $H_2$ only production and combined $H_2$ and electricity production. The design capacities of the $H_2$ dispensed and the net power imported/exported for each scenario are shown in Table 1.

In the co-production scenario, 250 $Nm^3/hr$ of $H_2$ is produced at the refueling station serving 100 FCVs daily. In addition, power is generated from an on-site fuel cell unit. The electricity generated is matched with the refueling station's auxiliary power demand, and the 370 kWe (kilowatt electric) net exported to the grid can provide an equivalent charging of 100 electrical vehicles (EVs) daily. In the $H_2$ only production scenario, 500 $Nm^3/hr$ of $H_2$ is produced at the refueling station for dispensing into 200 FCVs daily. Instead of generating power on-site, this scenario imports carbon-free power from the grid to meet the auxiliary power demand. In both scenarios, a total of 1,200 refueling stations dispense the $H_2$. These stations are within a 50 km radius of fuel receiving terminals where naphtha, kerosene or $H_2$ carriers are loaded to storage facilities and then to tanker trucks for distribution to $H_2$ refueling stations.

## Process Configurations for the Refueling Stations

As a part of this study, a comprehensive review of commercial and emerging technologies related to the reforming of petro- leum fuels, $H_2$ production, $CO_2$ capture, fuel cells and $H_2$ carriers was performed[4]. Based on this review, both commercially ready and promising emerging technologies were selected to form different process configurations to produce $H_2$ and electricity with $CO_2$ capture. The petroleum fuel feedstock used in the refueling station scenarios includes heavy naphtha and kerosene. A brief description of each of these configurations is provided.

Under Case 1, four separate process configurations were evaluated. Conceptual schematic diagrams of each of these options are shown in Figs. 1 to 4.

For Option 1, Fig. 1, the syngas obtained by steam reforming of petroleum fuels (i.e., naphtha or kerosene) is sent for high temperature and low temperature shift reactions to convert most of the carbon monoxide (CO) to $H_2$ and $CO_2$. The $CO_2$ is captured from the shifted syngas by an amine scrubbing system. A pressure swing absorption (PSA) unit separates $H_2$ from the rest of the gases present in the shifted gas. The $H_2$ stream leaving the PSA unit meets the 99.99% purity required by FCVs. The majority of the $H_2$ is further compressed in a series of $H_2$ compressors for storage in a cascade $H_2$ storage system ready for dispensing into FCVs at 350 bar. Some $H_2$ from the PSA is fed to a proton exchange membrane (PEM) fuel cell unit to produce enough power to satisfy the station's auxiliary power consumption needs and generate 370 kW net for export. The remaining $H_2$ from the PSA is combined with the PSA off-gas and the residual $H_2$ in the PEM fuel cell anode exhaust as fuel for the reformer furnace, providing heat for the reforming process; this combined fuel stream contains mostly $H_2$ and a small amount of CO, $CO_2$ and $CH_4$. The amine system is

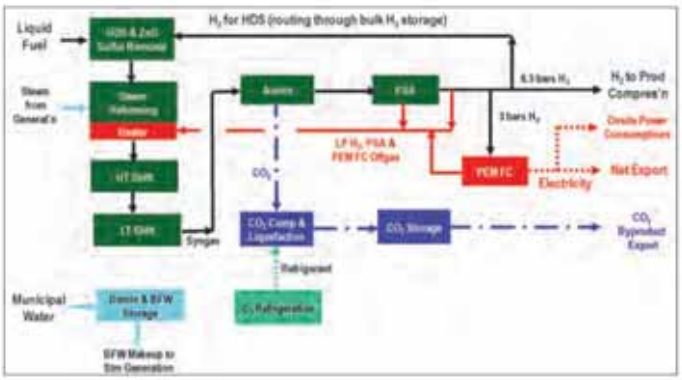


Fig. 1. Case 1, Option 1: On-site $H_2$ production with amine-based $CO_2$ capture process scheme.

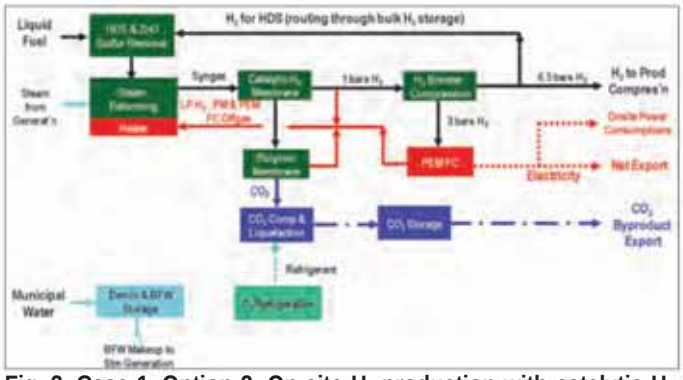


Fig. 3. Case 1, Option 3: On-site $H_2$ production with catalytic $H_2$ membrane and polymer membrane $CO_2$ capture process scheme.

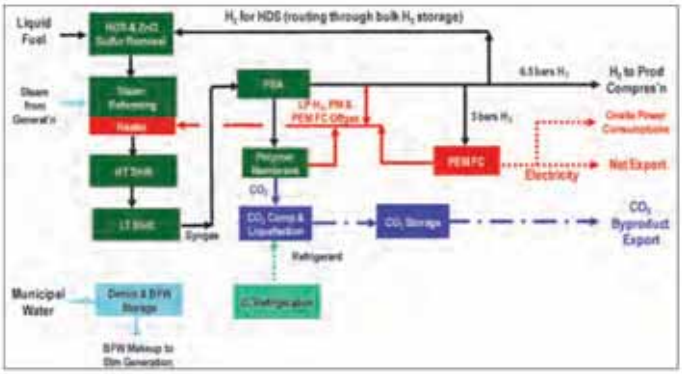


Fig. 2. Case 1, Option 2: On-site $H_2$ production with polymer membrane $CO_2$ capture process scheme.

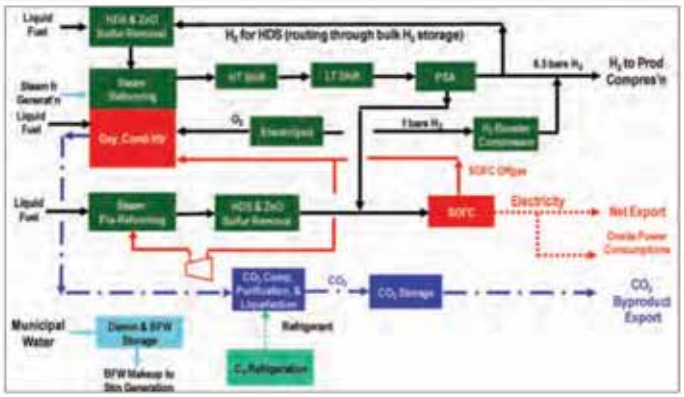


Fig. 4. Case 1, Option 4: On-site $H_2$ production with SOFC and oxy-combustion $CO_2$ capture process scheme.

designed to capture at least 99% of the $CO_2$ in the syn- gas stream, and the overall system captures 90% of the carbon in the petroleum feed, which is consistent with the goal in most CCS projects around the world. The $CO_2$ captured is compressed, liquefied and stored at the stations from which it is collected via trucks to be subsequently transported back to the Kingdom for EOR purposes.

For Option 2, Fig. 2, the syngas undergoes a high and low temperature shift similar to Option 1. The PSA unit again enables a 99.99% purity $H_2$ stream. The $H_2$ stream is then further split into three streams: one to undergo compression and storage for dispensing into FCVs, another as to be used as fuel for the PEM fuel cell for power generation and the rest to be used as fuel for the reformer furnace. Option 2 utilizes a $CO_2$ multi- stage selective polymeric membrane for $CO_2$ capture from the PSA off-gas; around 94% of the $CO_2$ in the off-gas is captured, resulting in 90% overall carbon capture of the petroleum feed. The purified $CO_2$ stream leaving the membrane is liquefied and stored for transportation back to the Kingdom. The off- gas from the polymer membrane contains $H_2$, CO, $CO_2$ and $CH_2$, and is suitable for use as fuel for the steam reformer. The off-gas, together with the $H_2$ from the PSA and from the anode exhaust, is therefore sent to the reformer furnace to provide heat for the reforming reactions.

Option 3, Fig. 3, utilizes the catalytic membrane process, combining shift reactions and $H_2$ extraction into a single step, therefore eliminating the need for separate shift reactors and PSA units. In this one-step process, palladium membrane tubes are packed with shift catalysts. The $H_2$ formed in the shifted gas permeates through the wall of the membrane tubes, resulting in high purity $H_2$. As the mode of $H_2$ transport through the palladium membrane is solution diffusion, the purity of the $H_2$ in the permeate stream is expected to be at least 99.99%. Unlike the PSA $H_2$ output, however, the permeated $H_2$ stream is at a lower pressure and requires a series of booster compressors to increase its pressure to more than 350 bar. A portion of


Fig. 5. $H_2$ carrier manufacturing in hydrogenation plant for Case 2 process scheme.

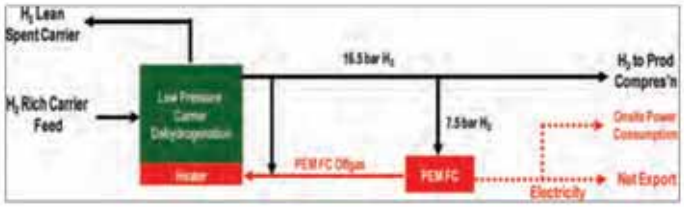


Fig. 6. Case 2: On-site delivery of $H_2$ produced in-Kingdom with $H_2$ carrier dehydrogenation process scheme.

the compressed $H_2$ stream is sent to the PEM fuel cell to generate power. The remaining portion is further compressed and stored for dispensing into FCVs. A small stream is also extracted before the booster compressors and sent to the reformer furnace as fuel. The retentate leaving the catalytic membrane contains $H_2$, CO, $CO_2$ and $CH_4$. The selective polymeric membrane employed in Option 2 is used to capture $CO_2$ from the catalytic membrane retentate. About 94% of the $CO_2$ in the retentate is captured, resulting in 90% overall carbon capture of the petroleum feed. The purified $CO_2$ stream leaving the membrane is liquefied and stored for transportation back to the Kingdom.

For Option 4, Fig. 4, the syngas obtained from steam re- forming undergoes high and low temperature shift reactions, followed by processing in the PSA unit, to recover high purity $H_2$ for dispensing to FCVs. A separate liquid fuel stream is routed to a pre-reformer unit that converts the petroleum feed into $CH_4$-rich gas in the presence of steam; the pre-reformer is hyGear technology, which is available commercially[5]. The pre-reformed gas is then combined with the PSA off-gas and fed to a solid oxide fuel cell (SOFC) unit for electricity generation. The SOFC anode exhaust contains CO, $CO_2$, $H_2$ and steam.

A portion of this exhaust gas is compressed and recycled back to the pre-reformer off-gas to provide the steam necessary for the pre-reforming reactions. The remainder of the exhaust is combined with supplemental liquid fuel and burned in the presence of oxygen to provide heat for the steam reforming reaction. The oxy-combustor effluent contains only $CO_2$, water and excess oxygen. After drying, purification and compression, the $CO_2$ stream is liquefied and stored for transportation back to the Kingdom for EOR. An electrolysis unit is included in Option 4 to provide the pure oxygen needed to burn off any unconverted fuel in the anode exhaust gas. The electrolysis unit also produces $H_2$ as a byproduct. This H2 stream requires compression in a series of H2 booster compressors for its subsequent use as a supplemental source of H2 for dispensing into FCVs.

Options 1 to 3 utilize pre-combustion $CO_2$ capture, while Option 4 takes advantage of SOFC and oxy-combustion to capture the $CO_2$. The petroleum fuel feedstock used in the refueling station includes heavy naphtha and kerosene. Based on a literature search[4], steam reforming was the most promising technology, and it was used in all options for Case 1. The hyGear pre-reforming technology was used in Option 4 in con-junction with the steam reformer to produce $CH_4$-rich feed for the SOFC.

In Case 2, $H_2$ is produced in-Kingdom at steam reforming-based $H_2$ plants using naphtha as feedstock. The $H_2$ produced satisfies the total demand for 1,200 refueling stations located in Japan. $CO_2$ from the $H_2$ plants is captured, compressed and transported via pipeline to an oil field for EOR. The $H_2$ produced is "stored" in a liquid petroleum-based $H_2$ carrier. Methylcyclohexane (MCH) was identified as the most suitable carrier. It is manufactured in hydrogenation plants, Fig. 5.

The process scheme used at the refueling station for Case 2 is shown in Fig. 6. At the refueling station, the

| $CO_2$ Pipeline Gas (Dry Basis) | Values |
|---|---|
| $CO_2$ | >97 mol% (min) |
| Hydrocarbons ($CH_4$+) | 1.0 mol% (max) |
| $N_2$ | < 2.0 mol% (max) |
| Total Sulfur ($H_2S$ and COS) | 65 ppmv (max) |
| CO | 1,000 ppmv (max) |
| $O_2$ | 10 ppmv (max) |
| $NH_3$ | 1 ppmv (max) |
| Solvent | 200 ppmv (max) |

Table 2. HECA $CO_2$ product specifications

carrier received from trucks is stored before undergoing dehydrogenation, which releases the $H_2$. The extracted $H_2$ undergoes compres- sion for dispensing into FCVs, as well as for use to generate electricity via a PEM fuel cell. The dehydrogenation process requires heat, generated by burning a mixture of the PEM anode exhaust and some of the $H_2$ released by the carrier. The spent carrier is stored and loaded into trucks for transportation to a port, ready to be shipped to the Kingdom. The spent carrier, toluene in this case, undergoes re-charging back in the Kingdom and is then re-shipped to Tokyo.

In Case 2, only heavy naphtha was analyzed for use as the petroleum fuel feedstock to the in-Kingdom $H_2$ plants.

For the $H_2$ only production scenario, the technologies considered for the $H_2$ refueling stations were the same as those in the co-production station options. The exception is that the PEM fuel cell was eliminated in each of these processes since there is no requirement for on-site power generation. The station auxiliary power demand is met by importing carbon-free electricity in Japan. As there is no $H_2$ only production station equivalent to Case 1, Option 4, it was not considered further in the analysis.

## Design Basis

For the Case 1 refueling station, up to 10% of the carbon in the liquid feed to the station is vented as $CO_2$ in the flue gas. The balance (90%) is captured and recovered as liquid $CO_2$ to be trucked back to the port for shipping back to the Kingdom. For the Case 2 refueling station, which does not produce any $CO_2$ on-site since it only involves dehydrogenation of the $H_2$ carrier, yielding only the $H_2$ fuel and the spent carrier, 90% of the $CO_2$ produced is captured in-Kingdom from the $H_2$ plants and then dried and compressed to be delivered to the EOR site by pipeline.

### Site-Related Conditions

The $H_2$ refueling stations are located in Tokyo. It was assumed that there will be a total of 1,200 of these stations in the Tokyo metropolitan area. The average distance from each station to the port was assumed to be 50 km one way or 80 km round trip.

### Petroleum Feedstock Specification

The petroleum fuel feedstocks for the Case 1 refueling station are heavy naphtha and kerosene. For Case 2, only the heavy naphtha feedstock is used.

### Utilities Consumption

Each station obtains its makeup water from the municipal water supply and discharges wastewater to the municipal sewer.

Except for water, each station is self-contained, with no natural gas imports and no electricity imports except during startup or emergencies. Due to the space limitations of the refueling station and its relatively small output, it was assumed that there are no cooling water or cooling water towers available to the refueling station. Heat load rejection is achieved via air coolers or internal refrigeration systems. Process cooling by air was assumed to go down to 38 °C.

The in-Kingdom facilities obtain makeup water from the municipal water supply and discharge wastewater to the municipal sewer. An on-site demineralization system provides makeup boiler feed water (BFW) to the gas turbine combined cycle (GTCC) plant. Given the coastal nature of the in-Kingdom facilities, once-through seawater cooling is utilized to achieve heat load rejection. Seawater was assumed to be available at 30°C with a maximum return temperature of 35°C.

### Product $H_2$ Specification

Product $H_2$ has a purity of 99.99%, and the storage and compression of the $H_2$ for dispensing into FCVs is as follows:

- Bulk storage of $H_2$ at 170 barg.
- Cascade storage of $H_2$ at 430 barg.
- Product $H_2$ dispensed to FCVs at 350 barg.

**On-site $CO_2$ Storage Specification**
For the Case 1 refueling station, $CO_2$ is chilled and condensed at -50°C and 6 barg at the station before being trucked to the loading dock for shipping by refrigerated tankers. The $CO_2$ stored on-site is EOR ready and meets the composition criteria specified in the Hydrogen Energy California (HECA) project, reproduced in Table 2.

**Dehydrogenation Specification**
For the Case 2 refueling station, the hydrogenated MCH carrier delivered to the station is at 6.1 wt% $H_2$ loading and is dehydrogenated on-site to 0.3 wt% $H_2$. The dehydrogenation reaction takes place at 3.5 bara pressure and 350°C.

**In-Kingdom Process Facilities**
For all Case 1 options, the in-Kingdom facilities mainly consist of the following:

- Shipping terminal (including pier, storage tanks/spheres, loading arms/pumps and vapor recovery system) to receive liquefied $CO_2$ from, and to send liquid petroleum to, Japan.
- $CO_2$ booster pumps to pump the liquefied $CO_2$ to 152 barg for delivery to the in-Kingdom EOR site via $CO_2$ pipeline. Costs of the $CO_2$ pipeline and the downstream EOR facilities are not part of this study.
- Packaged diesel generation units to supply power to the shipping terminals and $CO_2$ booster pumps. Due to the relatively small power demands (5 to 10 MW) and the as sociated emissions, $CO_2$ is not recovered from the diesel generator exhaust.

For Case 2, enough $H_2$ needs to be generated in-Kingdom with 90% carbon capture to meet the fueling demand for all 1,200 $H_2$ carrier-based refueling stations in Tokyo. $H_2$ is generated from $H_2$ plants using heavy naphtha as feedstock, which is also the supplemental fuel fired in the reforming furnaces. The $H_2$ produced is sent to hydrogenation plants, where the spent toluene carrier is hydrogenated to regenerate MCH for delivery to the refueling stations in Japan. Consistent with the $CO_2$ recovery design philosophy for the Case 1 $H_2$ fueling station, these in-Kingdom $H_2$ plants utilize amine-based post-combustion $CO_2$ capture ($H_2$ PCC plants) to recover 90% of the carbon in the naphtha feed and fuel consumed. The $H_2$ PCC plants also compress the captured $CO_2$ to 152 barg for delivery to the in-Kingdom EOR site via the existing $CO_2$ pipeline. Due to the large amount of power needed by the process plants (in excess of 350 MW), commercial sized naphtha-fueled GTCC power plants are included to supply power to the Case 2 hydrogenation plants, $H_2$ plants, $H_2$ PCC plants, shipping terminals and other on-site support systems. No electricity imports are necessary except during power plant start-ups, shutdowns or emergencies. Because of the large amount of carbon emissions, and to be consistent with the design philosophy with power co-production of the Case 1 $H_2$ fueling station, the GTCC power plants are also equipped with amine-based post-combustion $CO_2$ capture (GTCC PCC plants) to recover 90% of the carbon in the naphtha fuel. As with the $H_2$ PCC plants, the GTCC PCC plants also compress the captured $CO_2$ to 152 barg for delivery to the in-Kingdom EOR site via the existing $CO_2$ pipeline.

**In-Kingdom Site-Related Conditions**
The in-Kingdom process facilities are located near an undefined coastal city in Saudi Arabia where land is available to accommodate the Case 1 and the Case 2 shipping terminal and the process facilities, and where existing liquid petroleum supply and $CO_2$ delivery pipelines are available to export the liquid petroleum feed and to send the liquid $CO_2$ to the EOR site.

**$CO_2$ EOR Rate**
Each ton of $CO_2$ injected for EOR is able to recover 1.89 barrels of additional crude oil[6].

**Tanker Design and Shipping**
Due to the different types of cargo that Cases 1 and 2 carry, different tanker sizes apply to each of them. Table 3 summarizes the design bases used for the petroleum feed/$CO_2$ ships in Case 1 and the toluene/MCH ships in Case 2.

The following design bases apply to both the in-Kingdom and the Japanese terminals in Cases 1 and 2. In Case 1, $CO_2$ ships only load in Japan and unload in-Kingdom, while the liquid petroleum fuel tankers only load in-Kingdom and unload in Japan. In Case 2, the $H_2$ carrier ships both load and unload in-Kingdom and in Japan.

- Time for tanker to arrive in port and hook up: 3 hours.
- Duration for tanker in port to unload: 24 hours.
- Duration for tanker in port to load: 24 hours.
- Duration for tanker to unhook and depart: 3 hours.
- Weather and other delays: 60 hours.
- Includes the costs of storage spheres for storing liquefied $CO_2$ that has been trucked to the port.

| | Case 1: Petroleum Feed | Case 1: $CO_2$ | Case 2: Toluene/MCH |
|---|---|---|---|
| Tanker Size, MD wt | 50 | 50 | 200 |
| Distance between Saudi Arabia and Japan, Nautical Miles | 6,583 | | |
| Ship Speed, knots | 15 | | |
| Transit Time, hours | 439 | | |
| Tanker Fuel Type | Bunker Fuel | | |
| Fuel Burned in Transit, tonnes/day | 34 | 34 | 80 |
| Fuel Burned in Port, tonnes/day | 3.5 | 3.5 | 8 |
| Shipping Rate Less Port Fees and Fuel, $/bbl of Cargo | 5.16 | $67/Tonne | 2.10 |
| Associated Port Fees (Duty, Tugs, etc.), $MM | 57 | 57 | 161 |

**Table 3. Design bases for petroleum/$CO_2$ ships and toluene/MCH ships**

**Trucking**

Diesel is the fuel choice for the trucks transporting liquid petroleum fuel or $CO_2$ to and from the refueling station in Case 1. The same applies for trucks transporting the $H_2$ carrier to and from the station in Case 2. The number of trucks and the amount of diesel required is based on the yearly quantity of liquids transported.

- MCH/Toluene and petroleum fuel truck capacity: 50 $m^3$; $CO_2$ truck capacity: 30 $m^3$.
- Average truck round trip distance: 80.5 km.
- Average round trips/day: 3.
- Spare trucks as percentage above minimum required: 10%.

**$H_2$ Only Refueling Station Design Basis**

Economic analysis results, discussed later, indicated that co-production of the electricity is the major cost contributor to the overall cost of $H_2$ production for the $H_2$ refueling stations with $CO_2$ capture. These cases were, therefore, considered not economically feasible. Next, the performance of $H_2$ refueling stations in Cases 1 and 2 that produce only $H_2$ and import carbon-free electricity to satisfy the stations' auxiliary power demand was considered. In these cases, each station's nominal production capacity is 500 $Nm^3$/hr of $H_2$.

Similar to the co-production cases, up to 10% of the carbon in the liquid feed to each Case 1 refueling station is vented as $CO_2$ in the flue gas. The balance, 90%, is captured and recovered as liquid $CO_2$ to be trucked back to the port for shipping back to the Kingdom. This is not applicable to the Case 2 refueling station, which does not produce any $CO_2$ on-site since it only involves dehydrogenation of the carrier, yielding only the $H_2$ fuel and the spent carrier. Apart from carbon-free electricity imports from the grid to meet each station's power consumption, all other assumptions, including the shipping, trucking and economic analysis design bases, were identical to those used for the co-production refueling stations.

## Overall System Efficiency

The process schemes described above were modeled using Aspen Plus to determine the heat and material balances. Of the overall system efficiencies of the co-production and $H_2$ only production, only the refueling station cases are compared in Fig. 7. It can be seen from this figure that the difference in station efficiency between naphtha and kerosene is insignificant. This figure also shows that the co-production $H_2$ refueling station suffers from a significant efficiency penalty compared with the $H_2$ only refueling station with power imports. This is because in the co-production station, some of the product $H_2$, already generated at a diminished efficiency due to $CO_2$ capture, has to be withdrawn and used as fuel for the PEM fuel cell, which operates at an efficiency of around 45%. This causes the overall efficiency for the co-production

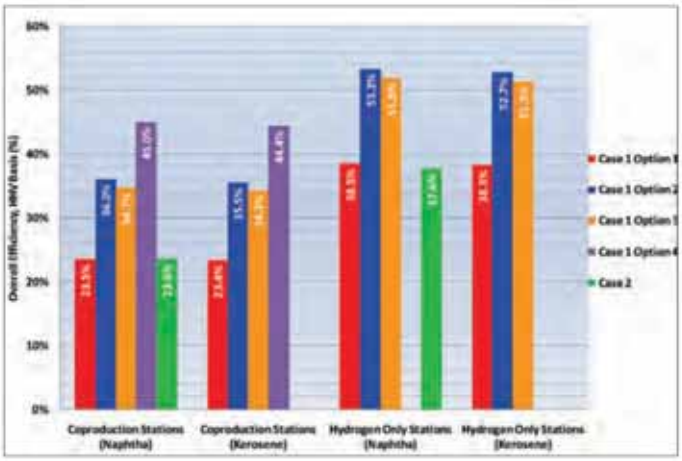


Fig. 7. Overall system efficiency of hydrogen refueling stations.

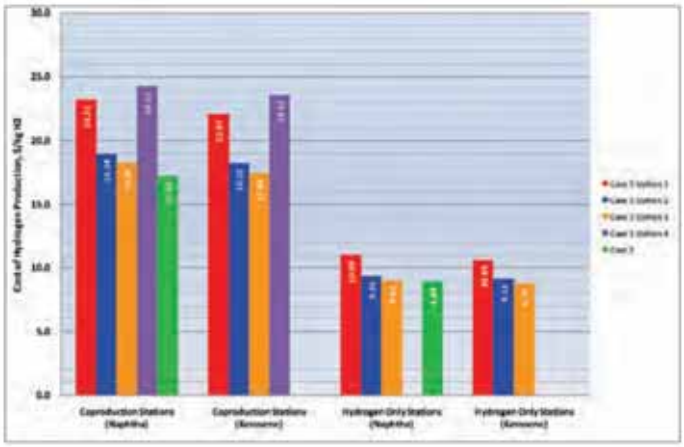

Fig. 9. Comparison of costs of hydrogen production.

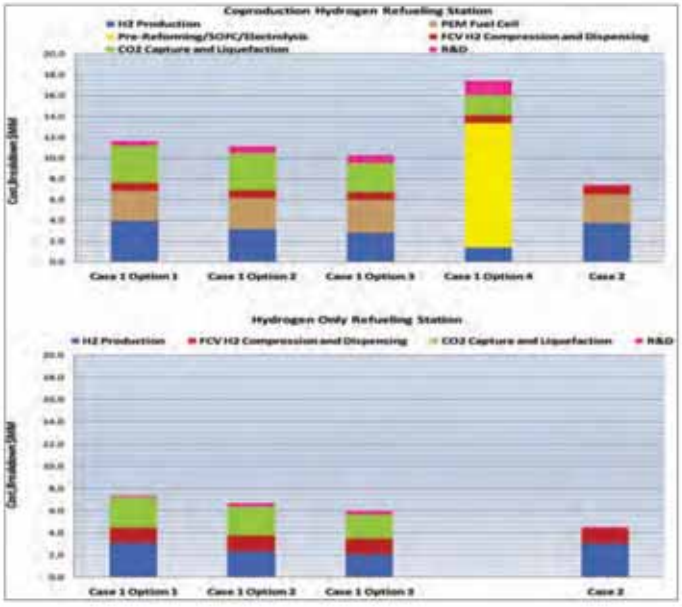


Fig. 8. Individual naphtha-based hydrogen station capital cost breakdown, $MM.

refueling station to take an extra hit as it tries to satisfy both the auxiliary power demand and the 370 kWe net export target.

## Capital Cost Estimates

Based on the mass and energy balances obtained from the Aspen Plus models, major equipment items were sized and overall capital cost was obtained by a combination of costs from the Aspen In-Plant Cost Estimator, vendor quotes and literature data. The total capital requirements and a breakdown of each of the naphtha-based Case 1 and Case 2 co-production and $H_2$ only refueling stations are compared in Fig. 8. The cost estimates were based on a "demonstration stage" $H_2$ refueling station, with the disadvantage of having only a handful of units in production. It can be seen from the difference between the co-production scenario and the $H_2$ only production scenario that the fuel cell cost (either PEM or SOFC) is a major cost driver of the overall capital cost of the individual refueling station. Figure 8 also shows that Case 2 has the least capital cost per station, and Case 1, Option 4, has the most capital cost per station, with the SOFC being the highest cost contributor. Note that kerosene-based stations have a very similar total investment and cost breakdown.

## Economic Analysis

### Cash Flow Model Evaluation Basis

A cash flow model was developed to determine the cost of $H_2$ dispensed into vehicles based on the capital and O&M cost data. The assumptions used in the cash flow model were:

- The electricity sale/import price for carbon-free electricity is $0.228/kWh. This was calculated by adding to the prevalent electricity price in Japan the price increase for including $CO_2$ capture capability to carbon-emitting power production sources.
- The price of the petroleum feedstock was correlated based on $13.7/bbl of crude oil.
- Each ton of $CO_2$ returned to the Kingdom and injected for EOR is able to recover the equivalent of 1.89 barrels of crude oil.
- Target internal rate of return (IRR) of 15%.
- Equity/Debt ratio of 100/0.
- 10-year straight-line depreciation.
- No income tax.
- Zero salvage value.

Besides the capital and O&M costs for all 1,200 stations in Tokyo, the cash flow model also takes into account the capital and O&M costs of the in-Kingdom port and process facilities, the land and sea transportation

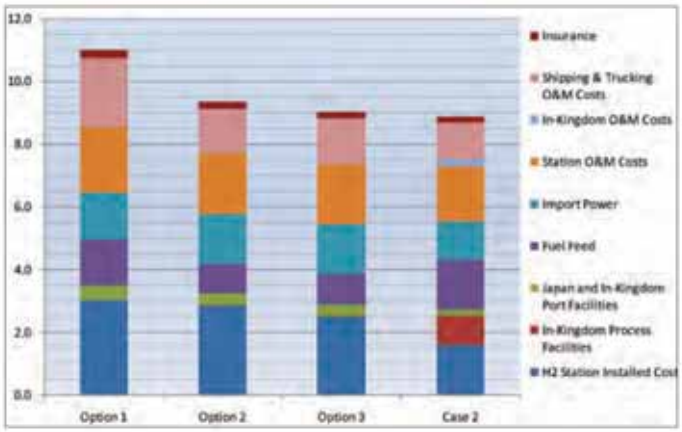


**Fig. 10. Breakdown comparison of the cost of hydrogen production for naphtha- based 500 Nm³/hr $H_2$ only hydrogen refueling station with power imports.**

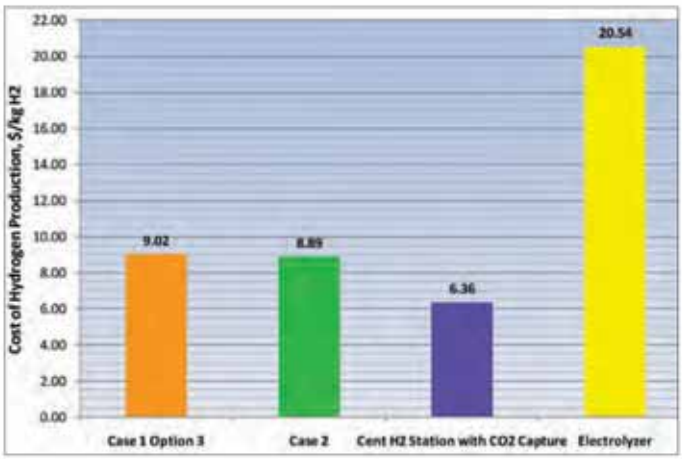


**Fig. 11. Cost comparison of naphtha-based $H_2$ only refueling stations with alternative hydrogen refueling options.**

costs of the petroleum feed and $CO_2$, or the $H_2$ carrier, and the insurance charges, as well as the credit derived from using $CO_2$ for EOR.

Figure 9 provides a graphical comparison of the cost of $H_2$ production for the various $H_2$ refueling stations.

Figure 9 also clearly shows that the cost of $H_2$ production is much lower for the 500 Nm³/hr $H_2$ only refueling station. This is because of the low overall efficiency of the co-production station, causing a greater fuel intake, which leads to an increased carbon capture capacity. The fuel cell is also very costly, whereas the payback from its sale of carbon-free electricity, at $0.228/kWh, is low. It is much more economical for the refueling station to import electricity at the same price than to self-generate it on-site. It is therefore confirmed that co-production of the electricity is the major cost contributor to the overall cost of $H_2$ production with $CO_2$ capture for both on-site and in-Kingdom $H_2$ production cases, and therefore co-

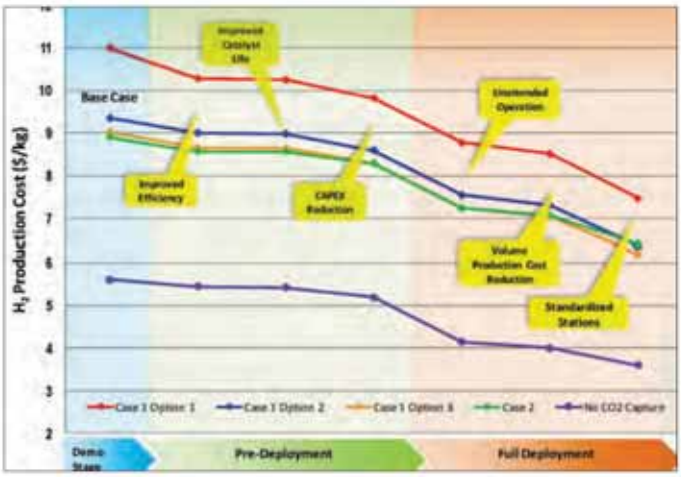


**Fig. 12. Naphtha-based hydrogen station cost reduction path.**

production was deemed not economically feasible in all cases considered in the study.

The Case 2 $H_2$ only refueling station has the lowest cost of $H_2$ production at $8.89/kg $H_2$, even though it has a low overall efficiency. This is due to the much lower per station capital cost and the economy-of-scale benefits from the large-scale in-Kingdom $H_2$ production and carrier hydrogenation facilities.

Option 3 has the lowest cost of $H_2$ production among the Case 1 naphtha-based options. At $9.02/kg $H_2$, it is most competitive with Case 2. Option 3 benefits from the relatively high efficiency of the process. It also has the lowest refueling station capital cost out of the Case 1 options.

The estimated cost of $H_2$ production for kerosene is slightly lower than that for naphtha across all the options. This is due to kerosene's lower cost than naphtha at $13.7/bbl of crude oil on a Btu basis.

Figure 10 provides a breakdown comparison of the cost of $H_2$ production for the naphtha-based 500 Nm³/hr $H_2$ only refueling station with power imports.

## Sensitivity Analysis

A series of runs on the cost of $H_2$ production were made on the naphtha-based $H_2$ refueling station economic model for sensitivity analysis purposes, using different input variables. By changing these input variables within the economic model, it can be determined how much of an impact these changes have on the cost of $H_2$ production.

Results from the sensitivity analysis indicated that

the co-production of electricity was the major cost contributor to the overall cost of $H_2$ production with $CO_2$ capture for both on-site and in-Kingdom $H_2$ production cases. The analysis also showed the cost of $H_2$ production to be most sensitive to station production capacity and attendant labor cost.

## Comparison with Other $H_2$ Supply Options

Figure 11 compares the cost of $H_2$ production in $/kg between the two best performing naphtha-based $H_2$ only refueling stations (Case 1, Option 3, and Case 2) and two other alternative H2 supply options. These two options are:

- On-site $H_2$ generation by electrolysis.
- Centralized $H_2$ production by natural gas reforming with post-combustion $CO_2$ capture; the $H_2$ produced is delivered by pipelines to $H_2$ refueling stations within a 100 km radius.

The electrolyzer-based refueling station has the highest cost of $H_2$ production, due to its high capital cost and large power import demand. The centralized $H_2$ production case from natural gas has the lowest cost at $6.36/kg of $H_2$, or about $2.5/kg cheaper than Case 2. Subsequently, in the case of the centralized $H_2$ plant, there is a need to build an extensive delivery infrastructure, such as a pipeline and distribution network, the costs of which are fairly uncertain. Also, this process does not include the capital costs of building LNG related infrastructure, such as the LNG terminal, regasification facilities and other associated capital costs pertaining to the shipping of LNG.

## Cost Reduction Path for $H_2$ Refueling Station with $CO_2$ Capture

A cost analysis was conducted to determine a $H_2$ production cost reduction path as the $H_2$ refueling station progresses from the demonstration stage to a full deployment stage, where the $H_2$ economy is mature and there are tens of thousands such $H_2$ refueling stations being put into operation. Figure 12 is a tentative demonstration and deployment strategy, or road map, for the naphtha-based $H_2$ refueling stations with $CO_2$ capture. It shows how the $H_2$ production cost can be reduced along the path for each option. These costs are compared against a similar naphtha-fed, steam reforming-based $H_2$ refueling station without $CO_2$ capture.

The cost reduction path starts from the demonstration stage, the current base case, where it was assumed that there are a handful of 500 $Nm^3$/hr $H_2$ refueling stations. Upon the successful demonstration of these $H_2$ plants, the next step is the pre-deployment stage of these stations, where it was envisaged that the $H_2$ production cost can be reduced by:

- Increasing the $H_2$ generator efficiency to save on fuel cost.
- Extending the catalyst life to save on the chemicals and catalyst cost of recovering $CO_2$.
- Design integration to reduce the capital cost.

When the $H_2$ economy takes off fully and the $H_2$ refueling station market matures, it is expected that tens of thousands of such stations will be built. Once this full deployment stage is reached, the $H_2$ production cost can be further reduced by:

- Fully automating the station and allowing it to run unmanned, thereby saving on labor cost, which is a significant O&M component.
- Increasing the volume of production to reduce the fabrication and assembly cost due to component manufacturing automation.
- Sharing the R&D charges and engineering expenses, and using the knowledge accumulated to reduce the cost components related to control/safety and civil/site.

The cost reduction path shows that at the full deployment stage for Case 1, Option 3 ($6.18/kg $H_2$), it is feasible for its $H_2$ production cost to come close to meeting the 2050 $6/kg $H_2$ target set by the Japanese government for $H_2$ production with $CO_2$ capture.

## Conclusions

In this study, Saudi Aramco evaluated nine separate options for producing $H_2$ from liquid fuels, including kerosene and naphtha, with $CO_2$ capture utilized for EOR. In general, the results indicated that, for a fixed IRR, the cost of $H_2$ production is most sensitive to station production capacity and attendant labor cost. Under a full deployment scenario, the $H_2$ production cost of the two most promising cases is similar and estimated to be around $6.5/kg. These two cases are Case 1, Option 3 – on-site $H_2$ production utilizing a high temperature $H_2$ selective membrane reactor in combination with polymer membrane for $CO_2$ capture; and Case 2 – in-Kingdom $H_2$ production in the form of a $H_2$ carrier. The cost incurred due to $CO_2$ capture for these two cases is about $3.0-$3.5 per kilogram of $H_2$ produced.

The Case 1, Option 3, and Case 2 process schemes were also compared with two $H_2$ supply alternatives

in this study. It was determined that while the electrolysis-based alternative is economically unviable, the centralized $H_2$ plant with $H_2$ delivery via pipeline has the lowest cost; however, this did not factor in the capital costs of building LNG related infrastructure.

## Acknowledgements

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## Biographies

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Prior to joining Saudi Aramco in 2010, Aqil was involved in process development research related to energy conversion, gasification and $CO_2$ capture from industrial point sources with multiple companies in the U.S., including Fluor Corp., Praxair Inc., GTI and RTI International.

He received his Ph.D. degree in Chemical Engineering from the University of British Columbia, Vancouver, British Columbia, Canada.

Dr. Thang V. Pham was a Research Science Consultant with Saudi Aramco's Research and Development Center in Dhahran between 2004 and 2011, leading oil-to-hydrogen development efforts at the Center. He is currently with the University of Queensland, working as the Director of External Research Collaboration.

Prior to joining Saudi Aramco and for more than a decade, Thang held product development and management roles in various start-ups and joint ventures in Australia and Canada, focusing on bringing the Solid Oxide Fuel Cell technology to market.

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He received his M.S. degree in Petroleum Engineering and his Ph.D. degree in Chemical Engineering from the University of Texas at Austin, Austin, TX, and an MPA from the John F. Kennedy School of Government at Harvard University, Cambridge, MA.

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# Optimization of Downhole Sand Screens by Lab Studies in Multiple Gas Fields

By Majed N. Al-Rabeh and Khalid S. Al-Mohanna.

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## Abstract

A lab study was conducted to evaluate screen performance and optimize different sand screen sizes currently being run in Saudi Aramco gas fields. The study had three phases. Phase (I) was to analyze the retention capability of the different sand screen sizes against formation core samples from gas fields A, B, C and D. Phases (II) and (III) were mud filter cake permeability damage/cleanup tests in "wellbore collapse" and "open annulus" scenarios, respectively. For all three phases, different sizes of premium sintered meshes were evaluated along with a wire wrap screen.

With regards to sand retention capabilities in the specified gas fields, only the 200 µ and 310 µ premium mesh screens met the sand retention criteria. Furthermore, there was no strong indication as to which screen size is superior to the other. It was concluded from the study, however, that the 310 µ premium mesh screen is the optimum screen for fields A and D, as it provides slightly higher retained permeability values when compared to the 200 µ screen. The study indicated that permeability damage resulting from the deposition of filter cake residue on the screen can have a negative impact on the retained permeability of the screen. A significant increase in the screens' retained permeability was achieved once the filter cake was removed, with an average increase of approximately 23%. Also, by using performance master curve predictions, it was concluded that 350 µ premium mesh screens will not provide satisfactory sand retention in fields B and D.

This article highlights the successful application of a laboratory sand control evaluation and optimization study conducted on screens being run in Saudi Aramco gas fields. In addition, performance master curves were used to predict the performance of an additional premium mesh screen size (350 µ) against formation samples from the specified gas fields.


## Background

Nowadays, the results of a sand sieve or laser analysis are not sufficient to determine the optimum screen size. A physical laboratory retention test is recommended to confirm satisfactory sand retention. To find the optimum screen performance, the effects of the mud filter cake permeability damage need to be studied via a laboratory retention test using the mud filter cake recipe used in the field. This knowledge is needed as the filter cake will flow back and deposit on the screen, causing a reduction in the screen permeability. As a result, the subject optimization study not only takes into account sand sieve and laser particle distributions, but also conducts physical laboratory retention testing in the presence of a mud filter cake.

## Introduction

Saudi Aramco is currently running stand-alone screen completions (SAS) for its unconsolidated, open hole, sandstone gas wells. This is because SAS completions offer sand retention and ease of deployment at a competitive cost when compared to other sand control completion methods. For SAS completions, proper

| | Gas Field A | | Gas Field B | | Gas Field C | | Gas Field D | |
|---|---|---|---|---|---|---|---|---|
| | Prod. Solids (lb/ft²) | Retained Screen Perm. (%) | Prod. Solids (lb/ft²) | Retained Screen Perm. (%) | Prod. Solids (lb/ft²) | Retained Screen Perm. (%) | Prod. Solids (lb/ft²) | Retained Screen Perm. (%) |
| 254 µ Wire Wrap | 0.135 | 63 | 0.105 | 51 | 0.122 | 47 | 0.079 | 44 |
| 200 µ Premium Mesh | 0.086 | 56 | 0.117 | 100 | 0.07 | 61 | 0.067 | 56 |
| 310 µ Premium Mesh | 0.084 | 80 | 0.113 | 85 | 0.089 | 77 | 0.102 | 77 |
| 400 µ Premium Mesh | 0.102 | 58 | 0.13 | 83 | 0.089 | 70 | 0.163 | 79 |

**Table 1. Results of the sand retention testing based on the Hodge criteria for all four gas fields without the presence of a mud filter cake (phase-I)**

screen selection is necessary as the screen is the retention media that allows production yet minimizes/eliminates sand production. In other words, the screen has to be fine enough to retain the formation sand, yet coarse enough to avoid production impairment due to mechanical skin or mud filter cake permeability damage.

This article presents the findings and recommendations of lab testing done to evaluate screen performance and optimize the screen rating/type for four gas fields in Saudi Arabia. Optimizing the screen rating/type would allow drill-in solids and smaller fines to pass through the screen without the risk of plugging, which will enhance well productivity and prolong the life of the SAS completion.

Overall, the lab study was conducted in three phases. Phase (I) evaluated the retention capabilities of the different screen sizes against formation core samples from the specified gas fields. Phases (II) and (III) of the study were mud filter cake permeability damage tests in "wellbore collapse" and "open annulus" scenarios, respectively. For all three phases, the screens that were evaluated were the 200 µ, 310 µ and 400 µ premium mesh screens and a 254 µ wire wrap screen.

For phase (I), the objective was to evaluate the sand retention capability of the different screen sizes. To do so, the Hodge criterion was applied1. This method uses produced solids and the screens' retained permeability as a guideline to identify screens that will perform well in the field. This method differs from other laboratory sand retention testing methods as it applies a constant pressure drop instead of a constant flow rate[1]. The use of a constant pressure drop ensures that pressure increases resulting from the deposition of the formation onto the screens are not misinterpreted as screen plugging. For this criterion, the maximum acceptable value for produced sand was established by comparing results from previous laboratory tests with the screen performance history in the field. Based on this comparison, screen sizes that produce less than 0.12 lb/ft² of solids and retain at least 50% of their permeability in the lab tests will achieve successful formation sand retention.

With regards to phases (II) and (III), the objective was to evaluate the damaging effects of filter cake residue on the retained permeability of the screens. For these phases, the recipe of the water-based drill-in fluid was provided. In the scenario of wellbore collapse, phase (II), a rapid collapse of the formation and remaining filter cake on the screen was simulated using unconsolidated formation samples. For the open annulus scenario, phase (III), a 0.5" open annulus was left between the screen and the formation core. The open annulus scenario was achieved by using consolidated core samples.

Also, performance master curves were applied to predict the performance of a 350 µ screen and further were applied to screens that were not included in the laboratory testing[2]. The performance curves were generated using the data that was obtained from testing the 200 µ, 310 µ and 400 µ premium mesh screens. The interpretation of the performance master curves by applying the Hodge criteria indicates that the 350 µ premium mesh screen will not provide satisfactory sand retention in all four

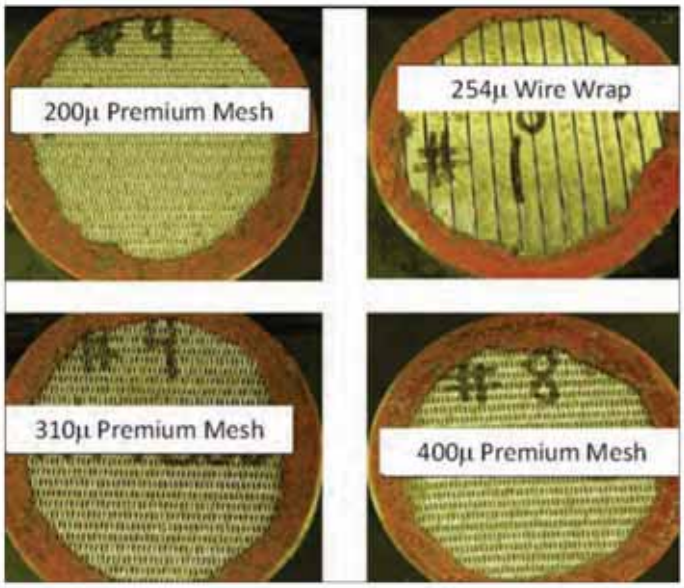


Fig. 1. The different screen coupons that were used in the test.

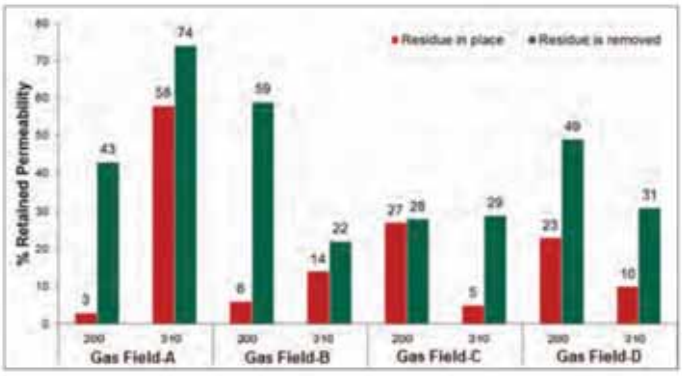


Fig. 2. Comparison of retained screen permeability – before and after residue is removed – in the open annulus scenario.

gas fields. This finding may eliminate the need for future laboratory tests of this premium mesh screen size, yielding cost savings by reducing future laboratory test requirements.

## Phase (I) Analysis of Results

Out of the four screen sizes tested for sand retention in the laboratory, only two sizes satisfied the Hodge criteria for all four gas fields. As previously mentioned, to satisfy the criteria, the test on each screen must yield a solids production content of less than 0.12 lb/ft$^2$ and a retained screen permeability of at least 50%. The results of the tests showed that only the 200 µ and 310 µ premium mesh screens met this criterion. Consequently, only the 200 µ and 310 µ premium mesh screens were selected for testing in phases (II) and (III). Table 1 summarizes the results of sand retention testing for the four gas fields, while Fig. 1 presents the different screen coupons used in these tests.

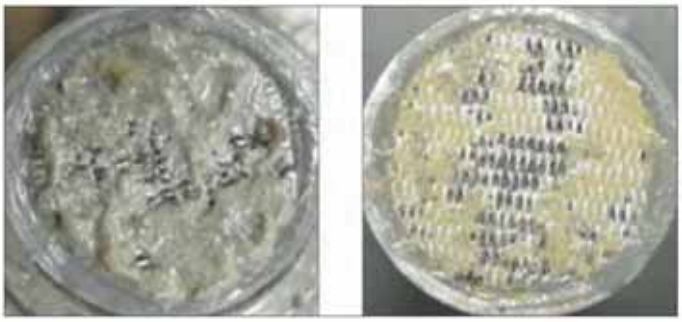

Fig. 3. Screen with filter cake residue in place (left) and screen with residue removed (right).

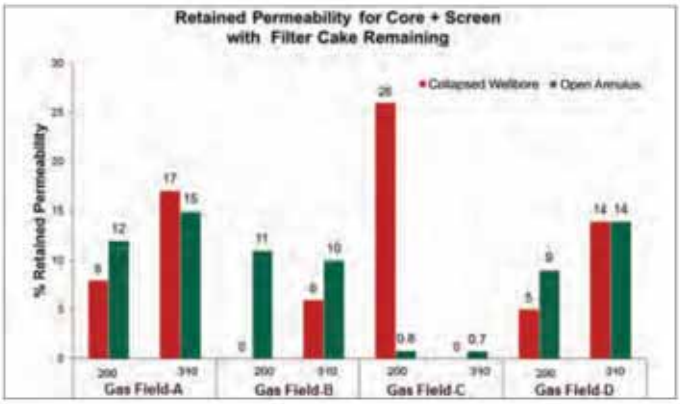


Fig. 4. Retained permeability for core + screen with filter cake remaining.

## Phases (II) and (III) Analysis of Results

Phases (II) and (III) of the lab tests were focused on permeability damage testing. The damage on the screen and formation was induced by the presence of mud filter cake residue formed using a water-based drilling mud recipe provided by Saudi Aramco to simulate collapsed wellbore and open annulus scenarios, respectively.

The simulated field conditions in the lab tests showed that the filter cake was settling on top of the screen, causing a significant reduction in the retained permeability of the screen. Figures 2 and 3 show a comparison between the retained permeability with the filter cake residue in place on the screen and the retained permeability when the filter cake residue was removed.

From the lab tests that were conducted, the test that most accurately reflected the actual field conditions was the one that took into account the core and the screen with the filter cake present as one system. The results of this test are illustrated in Fig. 4 and interpreted by highlighting that there is no strong indication as to which screen size is better between the 200 µ and the 310 µ sized screens. The 310 µ premium mesh screen

| | Field A | | Field B | | Field C | | Field D | |
|---|---|---|---|---|---|---|---|---|
| | Prod. Solids (lb/ft²) | Retained Screen Perm. (%) | Prod. Solids (lb/ft²) | Retained Screen Perm. (%) | Prod. Solids (lb/ft²) | Retained Screen Perm. (%) | Prod. Solids (lb/ft²) | Retained Screen Perm. (%) |
| 350 µ Premium Mesh | 0.09 | 69% | 0.12 | 84% | 0.09 | 74% | 0.13 | 78% |

Table 2. Results of the master curve predictions for the 350 ø premium mesh screen against the Hodge criteria

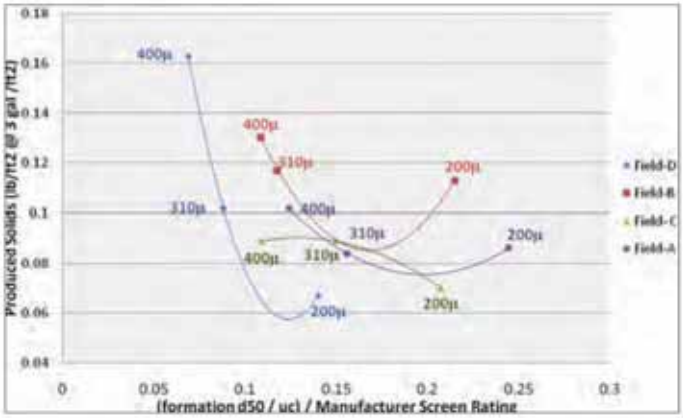


Fig. 5. Produced solids master curves for gas fields A, B, C and D.

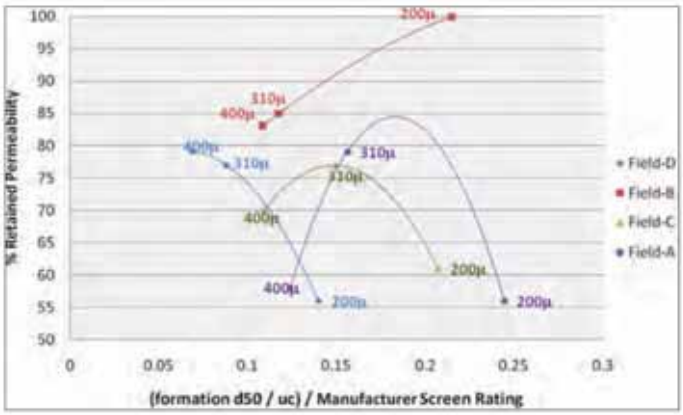


Fig. 6. Retained permeability master curves for gas fields A, B, C and D.

does show a slight improvement in retained permeability over the 200 µ premium mesh in fields A and D. As for fields B and C, the performance of the 200 µ and the 310 µ premium mesh screens was very similar.

## Performance Master Curves

Performance master curves are generated using existing laboratory test data to develop a trend that can be used to predict the performance of screens without a physical test in the lab[2]. The master curve predictions can lead to cost savings by identifying screen sizes that have a high potential of providing unsatisfactory sand retention, therefore reducing the associated laboratory testing cost. For the purposes of this study, the 350 µ screen was not tested in the laboratory. The data gathered from the laboratory testing of the 200 µ, 310 µ and 400 µ premium mesh screens instead was used to develop a performance master curve that could predict the performance of the 350 µ screen. This prediction will give an indication of the need to proceed with further testing in the lab. The performance master curves developed using the three different screen sizes in all four gas fields indicated that the 350 µ premium mesh screen will not provide successful sand retention in fields B and D. Plots were developed by applying the performance master curves to the data of gas fields A, B, C and D. Figure 5 shows the produced solids master curves, and Fig. 6 shows the retained permanent master curves.

In summary, the performance master curve predictions for the 350 µ premium mesh screens are listed in Table 2.

## Conclusions

The laboratory testing concluded that the 310 µ premium sintered mesh is the optimum sand screen size for fields A and D. Also, the practice of circulating solids-free mud is recommended to decrease the probability of permeability damage to the screens. Furthermore, the lab test results in phase (III) show a significant improvement in the screen's retained permeability once the filter cake is removed, with an average improvement of 23%. Finally, the laboratory tests highlighted a reduction of permeability that was due to stress applied on the formation.

Furthermore, the use of performance master curves indicated that the 350 µ premium mesh screens will not provide satisfactory sand retention for all the tested gas fields. This eliminates the need to perform future laboratory sand retention testing on the 350 µ, indicating that future cost savings can be achieved as a result of

the performance master curves. When combining the results of the laboratory testing with the results of the performance master curves, it was concluded that the 200 µ and the 310 µ premium mesh screens are suitable in all the tested gas fields.

## Acknowledgements

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## Biographies

Majed N. Al-Rabeh joined Saudi Aramco in 2007 as a Facilities Engineer handling the tie-in of the Southern Area gas wells. In 2010, he joined the Service Company Training Program where he worked for Schlumberger Reservoir Completions in the U.K., running sand control and permanent downhole monitoring system completions offshore in the North Sea. In 2011, Majed started work as a Well Completions Engineer with the Completions Group of the Petroleum Engineering Specialist Unit.

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Khalid S. Al-Mohanna is currently a Completions Engineer with the Upstream Technical Support Division (UTSD) of the Production and Facilities Development Department. He joined Saudi Aramco in 1984 and has worked in various disciplines,

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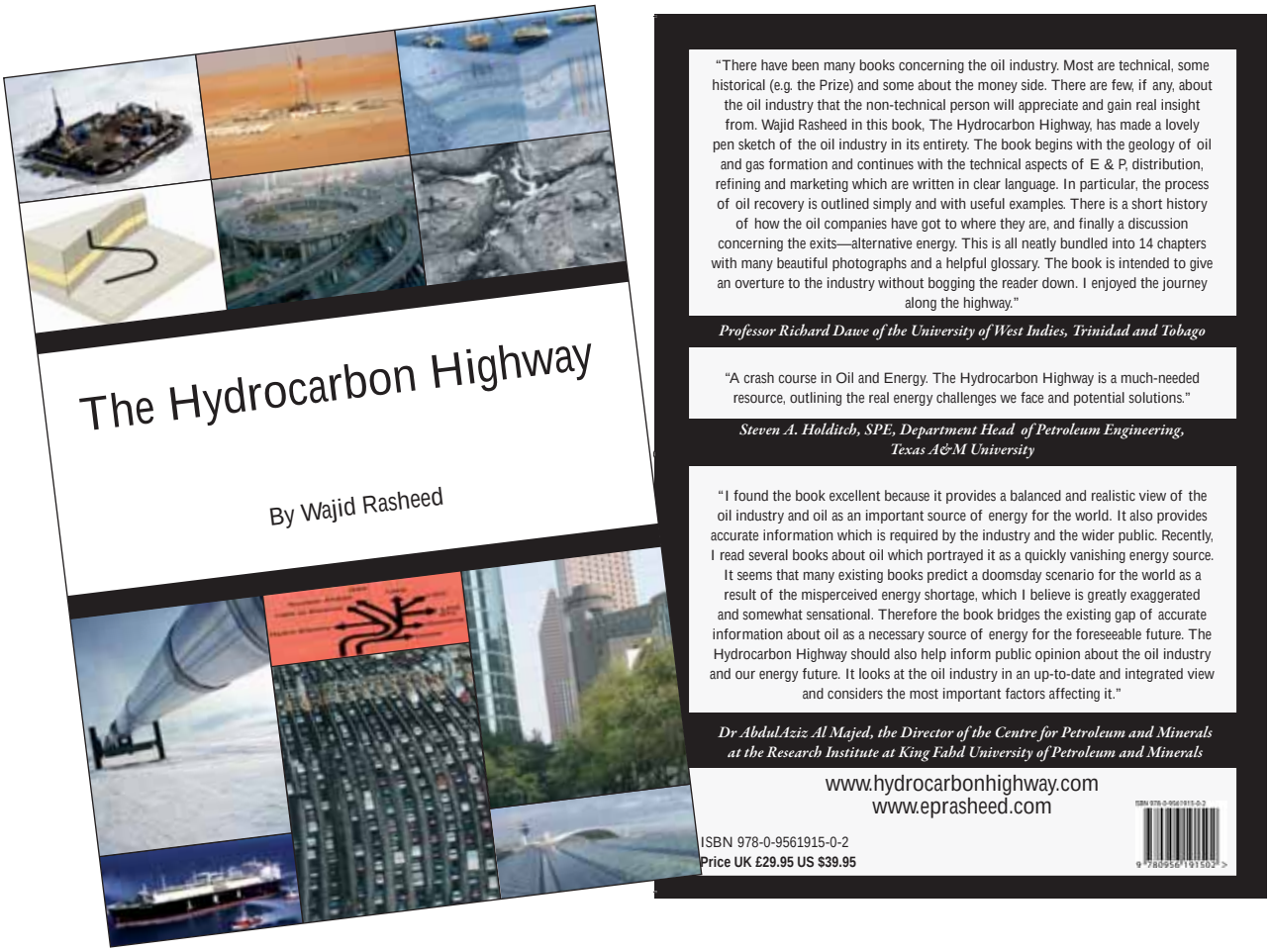
In 1997, he received his B.S. degree in Chemical Engineering from the University of Tulsa, Tulsa, OK.

# Extreme E&P




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

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

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

> Perhaps, the most difficult and costly combination for oil and gas Exploration and Production (E & P), is the well-from-hell – a combination of Arctic, deepwater and HPHT conditions.

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

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

## Location

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

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

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

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

population. Wells from these sites were directionally-drilled outward for thousands of feet to tap prolific oil reservoirs under the city.

## E & P Finding and Lifting Costs

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

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

## Keeping Costs Down

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

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

Simplified well design may be possible based on setting casing deeper. Real-time PPFG detection and prediction reduces the number of contingency strings. Eliminating casing strings by taking calculated risks during well construction can reduce mechanical risks and lower costs. Where offset data exists, more accurate pore pressure models can be constructed.

> Geotechnical and oceanographic data supplies exploratory deepwater asset teams with seabed and water column information which is necessary for well construction and production activities.

Enhanced pore pressure detection will optimise the casing programme during drilling and will reduce costs. Logistics and importation issues should be fully understood as this can reduce the need for pre-deployment of contingency equipment. All of these opportunities, combined with adequate planning processes, time and resources will cut costs[5].

## Arctic Seismic

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

## Deepwater Seismic

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

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

In certain deepwater basins, studies concentrate on mapping salt structures and seeing what lies beneath them. Active salt tectonics play an important role in

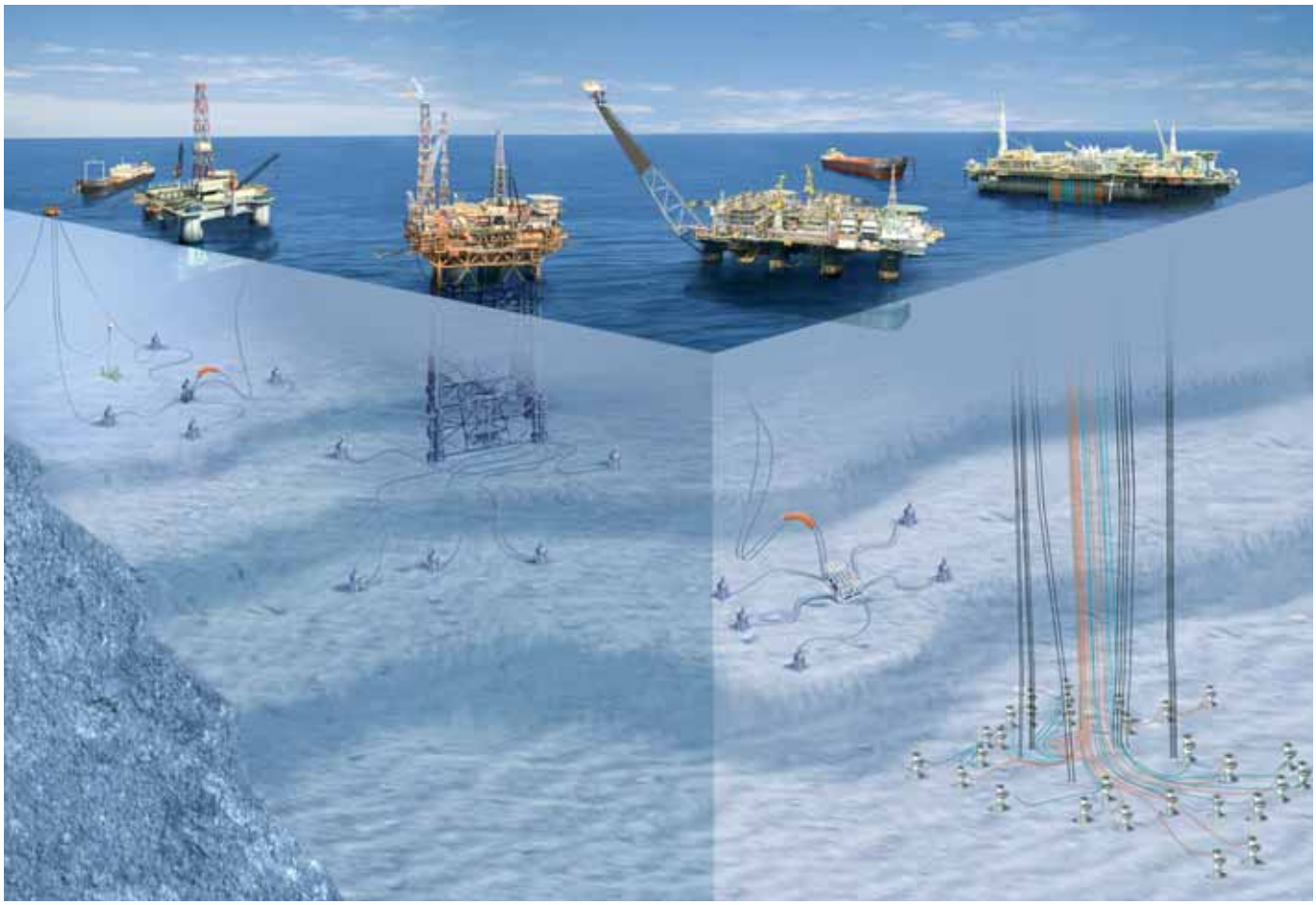


**Figure 1 - Fixed and Floating Production Units For Deepwaters (Petrobras)**

shaping the seafloor and salt-induced topography and fluid seepage are investigated. Continental slopes may be the focus of geo-hazard assessment, while oceanic current-induced seabed erosion may also be studied[10].

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

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

## Deepwater Wildcats

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

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

With the potential *dryhole* risk in mind, IOCs will seek to reduce risk by entering into agreements with other oil companies before exploring. Many of these partners

> Oceanographers know that the sea can be a complex environment with temperature inversions and subsea loop currents at different levels and in different directions.

will be companies that have similar concessions and can bring technical know-how to the deal.

## Organizational Challenge

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

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

## Planning Exploration

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

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

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

## Health, Safety and Environment (HSE) and Drilling Performance

From a safety and environmental standpoint, drilling will be completed without significant environmental damage, while a measurement of a safety 'Day Away From Work Case' (DAFWC) will be recorded and will

Figure 2 - Subsea Riser (Petrobras)

highlight the importance of conducting proper risk assessments. Performance will be measured and key criteria assessed such as days per ten thousand feet and Non-Productive Time (NPT).

## Deepwater Development

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

## Water Depth[15]

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

So where is the deepwater line drawn? According to Petrobras, waters between 3,280 ft to 6,560 ft (1,000

> Low fracture gradients can necessitate lighter drilling fluids and lighter cement slurry, while rising pore pressures can often upset the delicate fracture gradient destabilising the well-bore and jeopardising the section, if not the entire well.

m to 2,000 m) depth are classified as 'deep'. Beyond this are the ultra deepwaters which are about 11,480 ft (3,500 m) for the present. Definitions aside, deeper seas mean deeper pockets[16].

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

## Under Pressure

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

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

## Temperature Gradients

Further engineering challenges are added by temperature gradients. A negative gradient runs from surface to seafloor, but this turns positive below the mud line. Equations become more complicated as cooler surface mud alters the temperature profile as it is pumped downhole, while gas hydrate formation is a common problem that is difficult to resolve. Hydrates trap natural gas inside water molecules and bond with metal. This can result in tubing blockages which affect the valve and Blowout Preventer (BOP) operation.

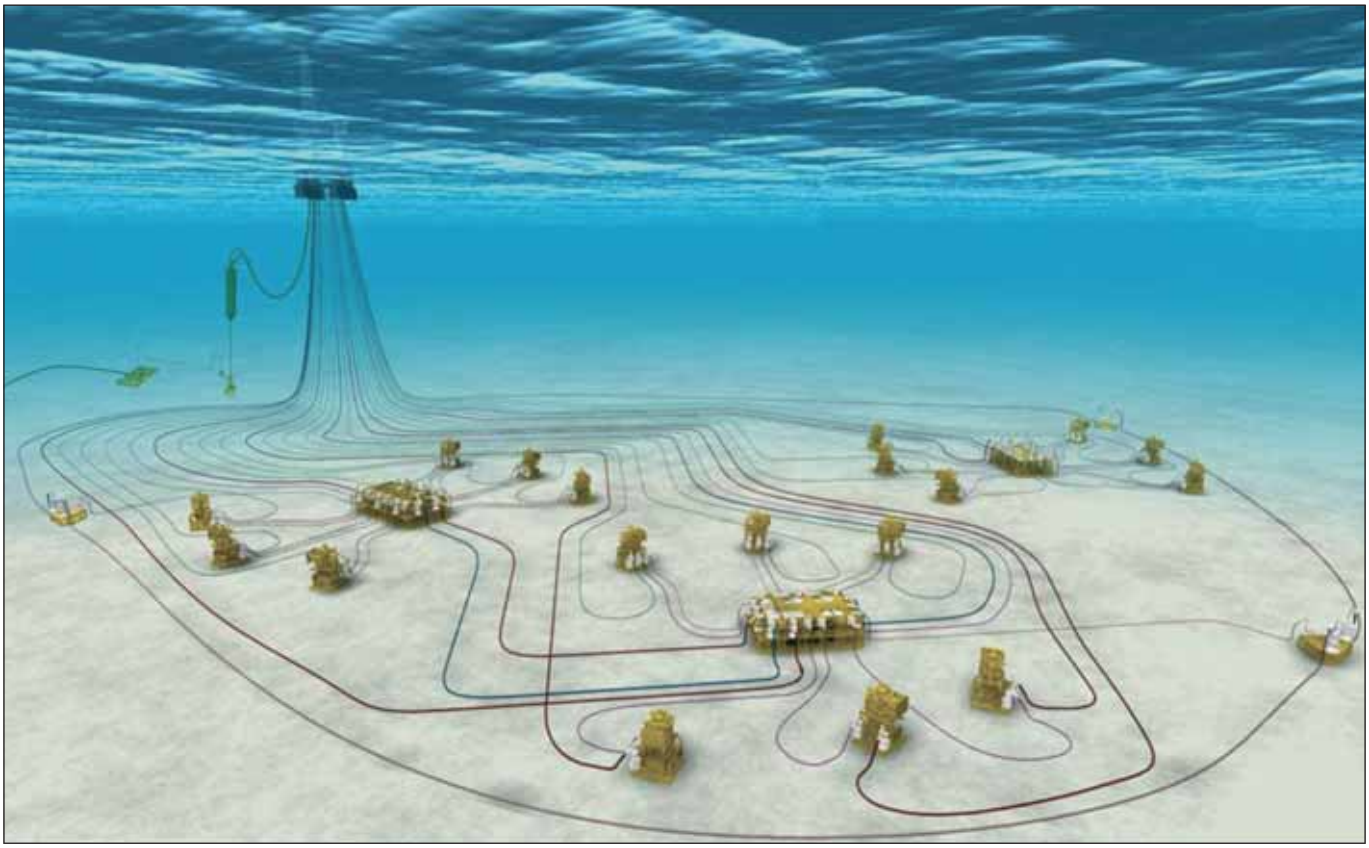


Figure 3 - Subsea Wellhead Production System (Petrobras News Agency)

Unfortunately, deepwater environments present the ideal combination of low temperatures, high seabed pressures, gas and water that cause hydrate formation. Extensive modelling is required to minimise hydrate formation. Low temperatures alter the properties of cement which mean new designs of cement slurry composition are required. Existing American Petroleum Institute (API) norms do not cover low deepwater temperatures and stringent test procedures are now determining the properties of cement slurries in deepwater operating conditions[18].

## Riser Manipulation

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

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

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

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

Mooring mechanisms that will function in greater water depths are also a challenge. Design software must

Figure 4 - Arctic Rig The Northstar Island (BP)

be able to check a specific mooring system's calculations and determine the validity of truncated scale tests as well as modelling mooring systems.

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

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

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

## Deepwater Flow Assurance

Companies are developing inter-related technologies capable of predicting and preventing subsea flow lines and pipelines from getting blocked. The technologies

> Major limitations associated with ultra deepwater developments which are associated with very expensive day rates include high installation loads of subsea equipment and high flow rate subsea wells.

here range from low-density foam cleaners to mechanical pigs to tractors for wax or hydrate plug removal.

## Arctic E & P

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

Antarctica is the third-smallest continent after Europe and Australia; 98% of it is covered in ice and is bound not to be developed until 2048 and therefore is not considered. The call for an environmental protocol to the Antarctic Treaty came after scientists discovered large deposits of natural resources such as coal, natural gas and offshore oil reserves in the early 1980s.

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

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

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

> Another way to consider pressure is to note that standard downhole tools and equipment are rated at 20,000 psi (1,361 bar) anything above this is considered high pressure.

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

## HTHP

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

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

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

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

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

## Salt Challenge

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

> Where salt is just 'salt', things are relatively simple; but, where salt sections are heterogenous containing halite, anhydrite, sedimentary channels, flows or rubble zones, things become complex.

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

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

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

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

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

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

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

Costly deep-water rig rates mean that operators are right to require high performance levels. Consequently, more rigorous Quality Assurance/Quality Control (QA/QC) standards are demanded of downhole tools to permit sections to be drilled in single runs at high penetration rates. Salt sections have higher fracture gradients (when compared with sediments located at

> Salt closure increases the loads on the casing and its cement as both must be able to withstand the forces applied by the salt as it expands radially and pinches the well.

the same depth) enabling longer sections and reduced well-control problems associated with permeable formations. Predicting PPFG in sediments below the salt, however, is tricky. Pressure regressions below the salt often dictate casing depth.

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

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

## Heavy Oil

Although large volumes of heavy and high viscosity oil have been discovered worldwide, both onshore and offshore, economic production is a challenge for the oil industry. Increased oil viscosity means increased E & P costs as well as higher refining costs. The definition and categorisation of heavy oils and natural bitumens are generally based on physical or chemical attributes or on methods of extraction. Ultimately, the hydrocarbon's chemical composition will govern both its physical state and the extraction technique applicable.

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

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

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

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

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

> Heavy oil processing in a Floating Production Unit is not straightforward and new separation technologies, as well as the feasibility of the heavy oil transportation with emulsified water, needs to be investigated.

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

New production technologies are required for the economic development of offshore heavy oil reservoirs. Long horizontal or multilateral wells, using high power pumps such as Electrical Submersible Pumps (ESPs), hydraulic pumps or submarine multiphase pumps, could partially compensate for a decrease in productivity caused by the high oil viscosity. Additionally, flow assurance could be improved with insulated or heated flow-lines, or alternatively, with the use of water as a continuous phase system. Heavy oil processing in a Floating Production Unit is not straightforward and new separation technologies, as well as the feasibility of the heavy oil transportation with emulsified water, needs to be investigated. The existence of light oil reserves in neighbouring reservoirs, even in small volumes, will play an important role in this determination.

## Reservoir Technologies for Offshore Heavy Oils

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

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

- Flow through porous media, which can be used to improve methods for understanding the relative permeability of water and heavy oil in non-consolidated, heavy oil bearing formations
- Modelling of oil varietals in offshore heavy oil reservoirs
- Optimised heavy oil field development
- Modelling to minimise remedial workovers, and

> Heavy oils are difficult to produce. From a reservoir standpoint, increased viscosities impair the flow of oil while in an offshore environment traditional enhanced recovery methods are often limited.

• Fundamental reservoir simulation studies in order to optimise the design of offshore production systems for heavy oils.

## Flow Assurance for Heavy Oil

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

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

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

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

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

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

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

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