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2015 – Issue 44

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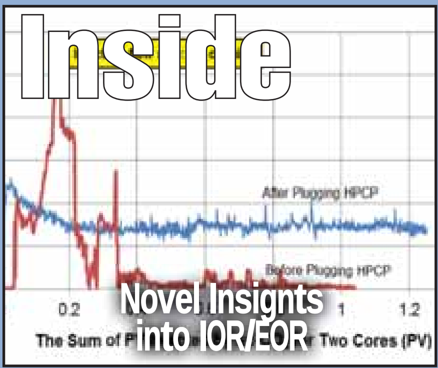

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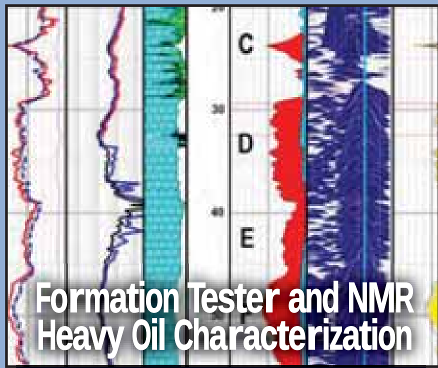

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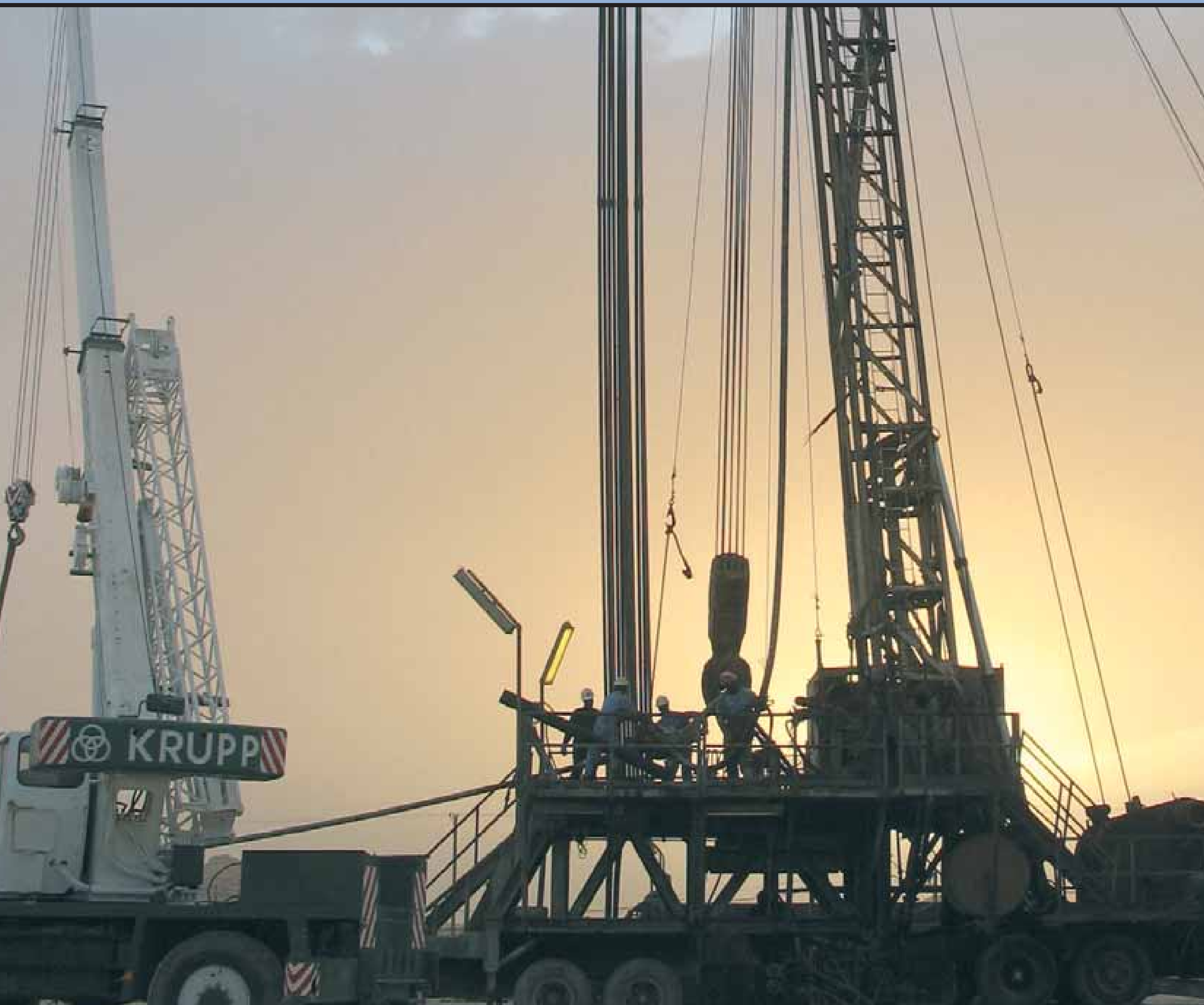
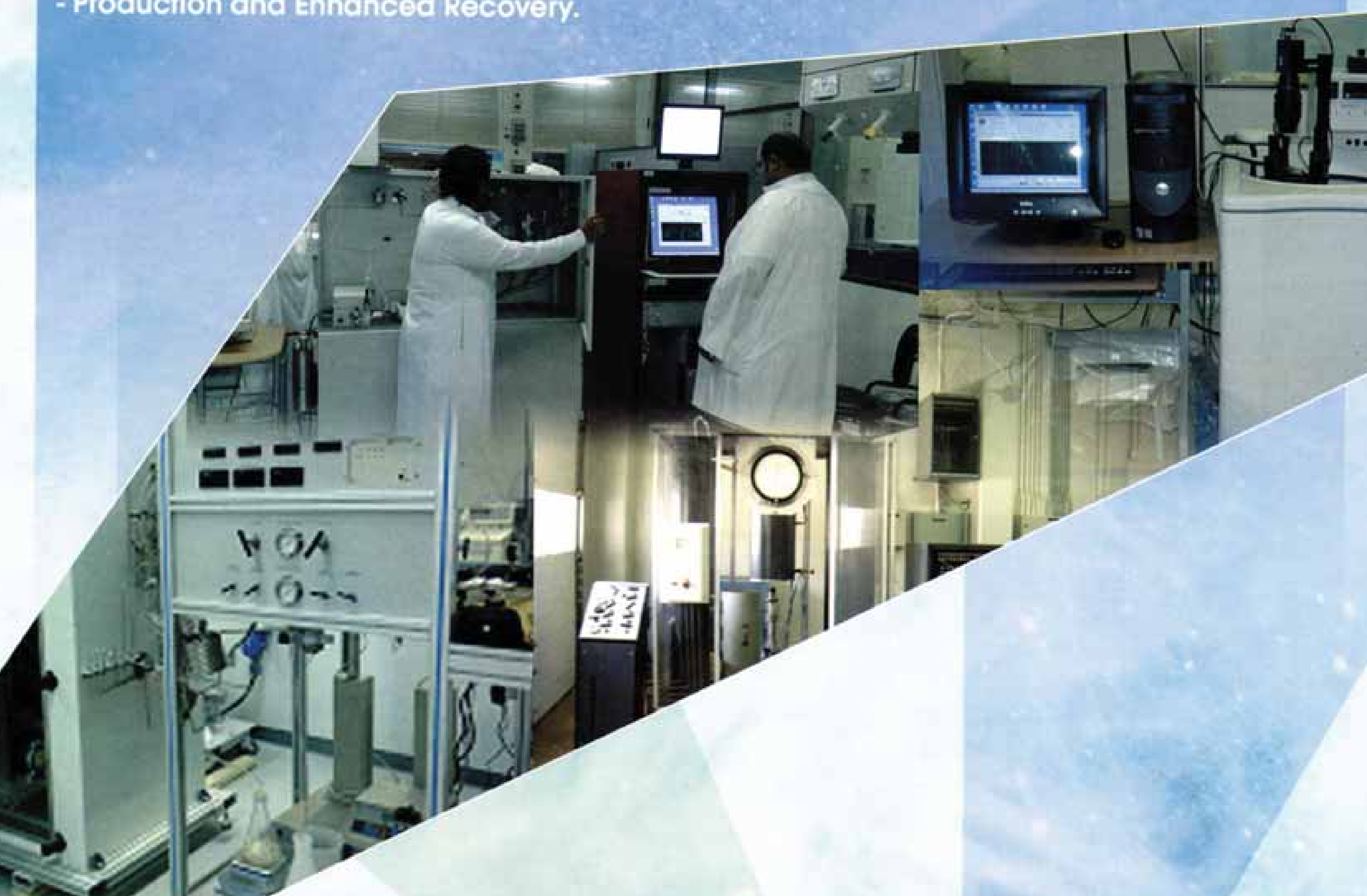


مدينة الملك عبدالعزيز
للعلوم والتقنية KACST

Oil and Gas Research Institute

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

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



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

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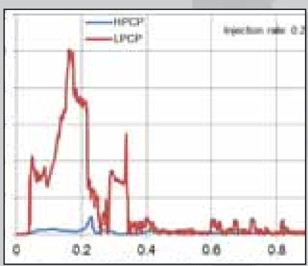

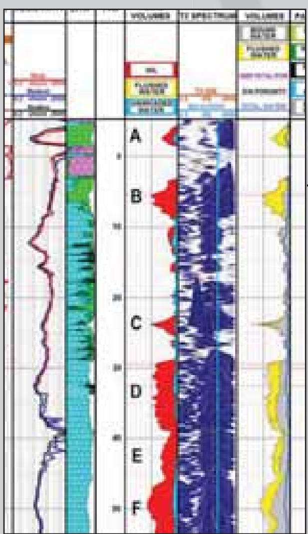

CEO and Founder EPRasheed

Wajid Rasheed
wajid.rasheed@eprasheed.com

Editors

Majid Rasheed
Mauro Martins

Design

Sue Smith
sue.smith@eprasheed.com

United Kingdom
- Head Office
Tel: (44) 207 193 1602
- Adam Mehar
adam.mehar@saudiarabiaoilandgas.com
Main: (44) 1753 708872
Fax: (44) 1753 725460
Mobile: (44) 777 2096692

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

Brazil
- Ana Felix
afelix@braziloilandgas.com
Tel: (55) 21 9714 8690
- Fabio Jones
fabio.jones@braziloilandgas.com
Tel: (55) 21 9392 7821
- Roberto S. Zangrando
rzangrando@braziloilandgas.com
Tel: (55) 22 8818 8507

IKTVA Program Launch – Keynote by Amin H. Nasser, President & CEO, Saudi Aramco

DAMMAM, DECEMBER 1, 2015

'Your Excellencies, distinguished guests, ladies and gentlemen, good morning. Thank you for joining us from near and from far, which is making this a truly global event.

We are honored that His Royal Highness, the Amir of the Eastern Province, Prince Saud bin Naif bin Abdulaziz, could join us today.

Your Royal Highness, your belief in the power of business to drive national development is an inspiration to us all.

I would also like to welcome the Minister of Commerce and Industry, His Excellency Dr. Tawfiq Al-Rabiah, and His Excellency Abdullatif Al-Othman, Governor of the Saudi Arabian General Investment Authority.

Today is a landmark day for us at Saudi Aramco and all of you – our business partners.

While you have successfully served our need for materials and services over many decades there is still a gap that needs to be closed – and that is local content.

The Saudi business community has accomplished a lot from modest beginnings, and I am inspired by success stories of local companies being able to compete internationally.

But the majority of our materials are manufactured elsewhere, and the majority of our services are provided from other countries. Consequently, our local content levels remain modest at just 35%.

For something that is so strategically important, that is not good enough for our company, for your companies, or for the country where the business is. So today we are announcing a long overdue step-change in our commitment to local content levels. We are setting three critical objectives to guide our localization program.

The first is to double the percentage of locally-produced energy-related goods and services to 70% by 2021.

The second is our local energy goods and services industry exporting 30% of its output over the same timeframe.

And the third is that we want this thriving sector to deliver half a million well-paid direct and indirect jobs for talented Saudis over the long-term. These are challenging targets, but I believe they are achievable if we work together.

Before we get into the detail, however, let me answer three simple questions:

• Number one: why are we changing our business model with our supply chain?
• Number two: what are we doing at Saudi Aramco to make it a success?
• Number three, and most important of all: why do we see this as a win-win for everyone?

So why are we changing our business model?
There is a growing recognition around the world, especially in the developing world, that suppliers and investors must build long-term partnerships with companies and countries they do business with.

They must invest in the long-term prosperity of their host nations. And they must help with long-term employment opportunities. In fact, you would be hard-pressed to find many countries that do not have this mandated by governments across a range of materials and services.

Take Norway, for example. They have successfully maximized the multiplier effects so that their local content levels have soared to nearly 80%. And over 1,000 companies support the industry with an annual turnover of $60 billion.

On the other hand, the experience of others is more mixed. In several cases, deficiencies in program design and implementation have led to significant cost increases, and delays in oil and gas field development, directly impacting revenue.

So we know what local content can deliver if correctly designed and implemented for each country's unique circumstances, and the pitfalls, if it is not. Therefore, continuing to import materials and services at growing levels cannot be our long-term strategy. What has been missing is a formal mechanism that enables fair competition as part of a local content strategy.

With our In-Kingdom Total Value Add – or IKTVA – program we now have that mechanism, which is systematic, fair, and transparent. It puts local content at the heart of our procurement process, and will be a requirement of doing business with Saudi Aramco going forward.

This does not mean we are abandoning our long-standing commitment to cost, quality, and schedule, or our commitment to safety and the environment. In fact, in the present challenging market environment, these principles are even more important to sustaining our global leadership in energy.

But we realize that favorable local conditions are necessary to make local content a reality.

Some attractive enablers are already in place such as a favorable tax regime, a stable currency, an extensive, modern infrastructure, ample and competitively-priced supplies of energy, feedstocks, chemicals, and minerals, and a large, young, and fast-learning workforce.

Furthermore, strong R&D capabilities, and entrepreneurship centers and incubation hubs such as the Dhahran Techno Valley are just a few miles from here.

Above all, let me be candid: we have the business! However, we know we must do more to improve the enabling environment and overcome challenges. That is why we are helping to improve the quality of education from primary schools to universities with a special focus on Science, Technology, Engineering and Mathematics, or the STEM disciplines.

We are leveraging our own training resources to assist Kingdom organizations to train a high quality, technical workforce that can meet our needs and yours. In fact, we are working with the Ministry of Labor to establish 22 national training centers around the Kingdom by 2025, and seven are already active.

We are also working with stakeholders to ensure that regulations help business rather than tie them up in red tape. And we are promoting economic and industrial diversification through our work on anchor projects such as the Maritime Yard at Ras Al-Khair. On top of this, we are promoting the Small and Medium Enterprises, or SME sector, and helping to create

> "There is a growing recognition around the world, especially in the developing world, that suppliers and investors must build long-term partnerships with companies and countries they do business with."

an extensive supply chain that is essential to local manufacturing.

We also want to give you a clearer view of our future requirements, and a greater understanding of the local and regional markets when you operate from here – and we will be sharing more details with you later today.

And by setting a target of 70% local content by 2021, we have given you sufficient time to deliver. So we are improving our proposition to you, just as we expect you to improve yours to us, and we will support you every step of the way.

On top of this, we believe that IKTVA offers enormous opportunities to suppliers and service providers in its own right.

I want to be absolutely clear about this: this is not about being charitable. We want IKTVA to be mutually beneficial, which means your investments making a reasonable rate of return.

If they are not, IKTVA will not be the success we all want it to be. And companies that build a deep and lasting relationship with the Kingdom by setting up shop here and investing in workforce development will capture the major share of Saudi Aramco's spend on materials and services.

To put that in monetary terms, we expect to spend more than 300 billion dollars over the next 10 years, of which 70 percent will eventually be local content.

I have no doubt that additional business will come your way – not only from Saudi Aramco, but from other entities within the Kingdom and the region.

Ladies and Gentlemen, Saudi Aramco is on the move, and so is Saudi Arabia.

The key to our long-term stability will be our economic strength. But for too long, local content has not been a formal requirement of doing business with Saudi Aramco. And current local content levels are simply unsustainable for our country, our society, and our citizens.

So things have to change. IKTVA ensures that they will change. And that change to a more strategic, sustainable, and successful relationship starts right here, right now.'

Novel Insights into IOR/EOR by Seawater and Supercritical CO_2 Miscible Flooding Using Dual Carbonate Cores at Reservoir Conditions

By Xianmin Zhou, Fawaz M. Al-Otaibi, Dr. Sunil L. Kokal, AlMohannad A. Al-Hashboul, Dr. Senthilmurugan Balasubramanian and Faris A. Al-Ghamdi.

Abstract

Oil recovery during carbon dioxide (CO_2) injection into a thick and/or fractured reservoir will be limited as a result of viscous fingering and gravity override. Due to density differences between the injected CO_2 and resident fluids in the reservoir, the CO_2, being lighter, tends to rise to the top of the reservoir, thereby bypassing some of the remaining oil. To study the impact of reservoir heterogeneity on oil recovery by seawater and CO_2 flooding, this article investigates the use of a dual-core coreflooding apparatus to evaluate the effect of both CO_2 gravity override and permeability contrast on oil recovery performance by CO_2 injection.

Experimental investigation of different oil recovery schemes, including secondary and tertiary oil recovery processes, was conducted using dual-core holders with carbonate composite stacks of different permeability. The core holders were placed vertically and each contained a high permeability core plug (HPCP) and low permeability core plug (LPCP). The permeability ratio of HPCP to LPCP was 50 to 1, with the HPCP core holder placed above the LPCP core holder. The coreflooding experiments were conducted at reservoir conditions with live reservoir fluids at a pore pressure of 3,200 psi, tempera-ture of 102 °C and confining pressure of 4,500 psi. Using this experimental setup, various experiments were conducted to determine the oil recovery performance as a function of injection rates, seawater/CO_2 injection modes, slug volume and diversion of CO_2 by HPCP plugging. The experimental procedures provided here for conducting these experiments have the potential to become a gold standard for such studies.

Results based on this study have shown that CO_2 injection following waterflooding resulted in additional oil recovery, as expected. The amount of this recovered additional oil was dependent on initial core plug permeability, injection mode and CO_2/seawater slug volume. It was observed that waterflooding recovered more oil from the HPCP, compared to the tighter core plug. On average, seawater left considerable more oil behind in the LPCP, which indicated that waterflooding would perform poorly in formations with high permeability contrast. Experiments then showed that the oil remaining in the LPCP after waterflooding could be mobilized by plugging the HPCP, using a diversion technique, and conducting a subsequent CO_2 flood.

This article provides a detailed description of the effect of different mechanisms of flooding, with both seawater and supercritical (sc) CO_2, on recovering this additional oil from the LPCP. The results bode well for CO_2 enhanced oil recovery (EOR) projects and will lead to further oil recovery potential beyond what is typical for CO_2 flooding.

Oil Recovery by Waterflooding

Waterflooding of oil reservoirs was first practiced as a displacement process and to maintain pressure in the formation. It has since become the most widely adopted improved oil recovery (IOR) technique and is now commonly applied at the beginning of reservoir development for both sandstone and carbonate reservoirs. Many improvements in IOR technologies have been proposed to recover more oil from reservoirs[1-3]. Both displacement and sweep efficiencies have to be considered when making improvements as both parameters strongly affect the oil recovery factor by any mode of waterflooding.

An important parameter that affects overall oil recovery is reservoir heterogeneity. Reservoir heterogeneity influences the microscopic, areal and vertical sweep efficiencies. One aspect of reservoir heterogeneity is permeability contrast in the reservoir. Laboratory investigation of the effect of permeability contrast on oil recovery has been limited due in part to the difficulty in representing complex geological heterogeneities or permeability contrasts in core experiments. Such studies have been mostly limited to the use of numerical simulators[4-6]. Gao and Burchfield (1995)[4] used a two-layer reservoir model – two independent, homogeneous layers with varying horizontal and vertical permeability contrasts between the layers – to simulate permeability blocking treatments using polymer gels. The horizontal permeability contrast between the layers was in the range of 0.0033 to 0.5, and the ratio of vertical to horizontal permeability was set between 0.001 and 0.1. The results show that the greatest incremental recovery was found at a permeability contrast of 0.05 and that more oil was produced when utilizing the combined gel treatment and polymer flood at the lower values of the ratio of vertical to horizontal permeability.

Experimental results have also been reported[5] using different grades of Ballotini beads in bead-pack models with different permeability contrasts. The experiments were conducted using three types of bead-pack models – homogeneous, low permeability and high permeability stripe models. The results show that the high permeability stripe model achieves lower total recovery and encounters more early breakthroughs than either the homogeneous or low permeability stripe models.

Finally, the effect of rock properties on remaining and residual oil saturation in heterogeneous carbonate rocks has been investigated using the porous plate method at reservoir conditions[6].

In this study, two dual-core holders with carbonate composite core plugs of different permeability – high permeability core plugs (HPCPs) and low permeability core plugs (LPCPs) – were vertically placed in the coreflooding apparatus to study the effect on total oil recovery of water bypassing through a higher permeability zone. Using the remaining oil saturation after waterflooding for both core plugs, experiments then assessed the tertiary oil recovery process.

Tertiary Oil Recovery by Supercritical (SC) Carbon Dioxide (CO_2) Flooding

Use of supercritical (sc) CO_2 miscible flooding to recover remaining oil after waterflooding has grown in popularity due partly to its favorable performance. The mechanisms that contribute to oil recovery using this technique include a reduction of oil viscosity and oil swelling[7, 8], and mass transfer through diffusion and dispersion, resulting in miscibility[9, 10]. The CO_2 enhanced oil recovery (EOR) process faces an inherent challenge related to high CO_2 mobility, which is aggravated even further in heterogeneous reservoirs – those with permeability contrast. Researchers and engineers therefore have investigated the impact of heterogeneity on both microscopic and macroscopic displacement efficiency during the CO_2 injection process[11-17].

Laboratory investigation of the displacement efficiency using sc-CO_2 flooding was performed by Zekri et al. (2006)[18]. The objectives of their investigation were to determine experimentally the effect of pressure, rock permeability and initial oil saturation on miscible and immiscible residual oil saturation (Sorm and Sorim, respectively). They observed that the Sorim decreased with an increase in permeability and that the highest displacement efficiency was obtained in the most permeable rock.

Research work on the effect of reservoir heterogeneity, or permeability contrast, on oil recovery by CO_2 miscible flood-ing was undertaken in a series of experiments by Shedid (2009)[19]. Several experiments were performed using different types of composite

Component	Field Connate Water (g/L)	Seawater (g/L)
NaCl	150.446	41.041
$CaCl_2 2HO$	69.841	2.384
$MgCl_2 6H_2O$	20.396	17.645
Na_2SO_4	0.518	6.343
$NaHCO_3$	0.487	0.165

Table 1. Recipes of field connate water and seawater

	Ambient Temperature, 25 °C		Reservoir Condition, 102 °C and 3,200 psi	
Fluids	Density (g/cc)	Viscosity (cP)	Density (g/cc)	Viscosity (cP)
Field Connate Water	1.1462	1.45	1.0906	0.73
Seawater	1.0385	0.97	1.0018	0.50
Dead Crude Oil	0.8810	20.51	0.8230	2.50
Live Oil	X	X	0.7550	0.73
Supercritical CO_2	X	X	0.5337	0.04

Table 2. Fluid properties of brines, oil and sc-CO_2

carbonate cores, including fractured core samples. The composites were made up of different permeability combinations (low, medium and high) and were layered in different combinations. Serial coreflooding experiments were conducted under reservoir conditions of 4,000 psia, above the minimum miscibility pressure (MMP) and at a temperature of 121 °C. The slug size of 0.15 pore volume (PV) was constant for all experiments. This EOR process was conducted for all tests as if in a secondary oil recovery mode. Comparisons of oil recovery from fractured core samples, composite cores and layered cores revealed that the best performance and highest oil recovery was achieved in the fractured core with a fracture angle of 30°; in the composite core with a low, medium and high permeability combination; and in the layered core with a medium, high and low permeability arrangement.

Results have been reported[20] on the effect of immobile water saturation, wettability, hysteresis and permeability both on recovery mechanisms and on relative permeability from experiments on gas/oil systems at near-miscible conditions. Core-flooding experiments were conducted for a gas/oil system using two sandstone cores with different permeability (high and low) and wettability – water-wet and mixed wet. An X- ray scanner was used to measure the saturation distribution of the two-phase and three-phase flow before, during and after the experiments. Gas injection was conducted in the secondary oil recovery mode. Experimental results show that the recovery factor in the high permeability core was higher than that in the lower permeability core for both water-wet and mixed wet conditions.

The purpose of the investigation described here was: (1) To develop an experimental method to investigate and evaluate the effect of reservoir heterogeneity on waterflooding and gas flooding performance in terms of oil recovery, (2) To use a dual-core coreflooding apparatus to determine the success of secondary and tertiary oil recovery by seawater and sc-CO_2 miscible flooding before and after employing a diverting system via slug injection, (3) To evaluate the effect of permeability contrast and injection flow rate on oil recovery and on the performance of seawater and sc-CO_2 miscible flooding, and (4) To gain an understanding of the mechanisms of the displacement process of sc-CO_2 miscible flooding in a heterogeneous environment.

Experimental Works

Experimental Fluids and MMP Measurement

Brines: Two types of brines were used in this study: field connate water and seawater. The field connate water was used to saturate the core plugs to achieve an initial water saturation (S_{wi}), and seawater was used for waterflooding. The components of both brines are

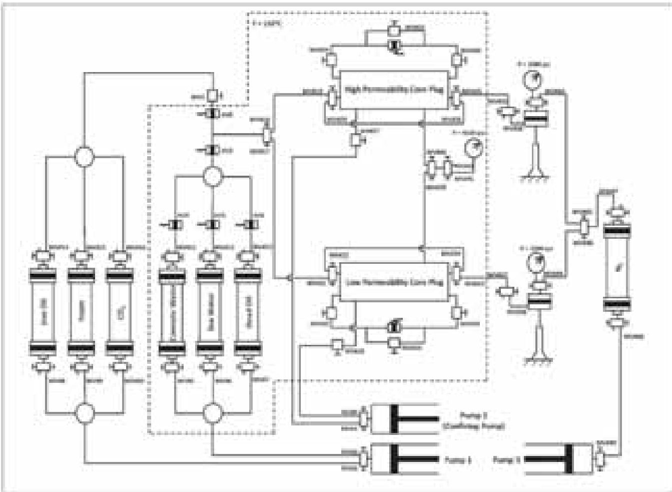

Fig. 1. A schematic for the dual-core coreflooding setup at reservoir conditions.

listed in Table 1. The total dissolved solids of the field connate water and seawater were 213,734 ppm and 57,670 ppm, respectively. The densities and viscosities of these brines at ambient and reservoir conditions are listed in Table 2.

Dead and Live Crude Oils: A dead crude oil from a carbonate reservoir was used in this study to set up S_{wi} in the core plugs. Separator crude oil and gas were collected from the same reservoir for recombining in the live crude oil sample, which was then used as an oil phase for the waterflooding and the sc-CO_2 miscible flooding experiment. The viscosity and density of the dead and live crude oils at reservoir temperature are also listed in Table 2. The molecular weight of the recombined live crude oil in this study was 121.

Sc-CO_2: sc-CO_2 was also used as a displacing agent for tertiary oil recovery at a pressure of 3,200 psi and temperature of 102 °C to create the miscible condition of live crude oil in the reservoir. The viscosity and density of the sc-CO_2 is listed Table 2. The MMP between live oil and sc-CO_2 was 2,600 psi.

MMP Measurements: The MMP measurement is a key parameter for the design of sc-CO_2 injection in the field. It is measured experimentally using the slim tube apparatus or the rising bubble apparatus at reservoir conditions. The value of the MMP depends on oil composition and reservoir temperature and pressure. Laboratory studies of the MMP have been reported in detail[21]. For this study, the MMP between sc-CO_2 and live oil was about 2,600 psi.

Experimental Setup, Preparation of Core Plugs and Procedures of Different Flooding Modes

Coreflooding Apparatus: A dual-core coreflooding apparatus was custom designed to perform tests on two stacked or composite core plug samples to determine the impact of reservoir heterogeneities, such as permeability contrast and gravity override, on oil recovery performance. A schematic of the coreflooding apparatus is presented in Fig. 1. The core holders are placed horizontally, with the HPCP core holder on top of the LPCP core holder. The tests can be run at overburden pressures up to ~10,000 psi, pore pressures up to 9,500 psi and temperatures up to 150 °C. The system is designed to be extremely versatile. All pore fluid wetted parts are constructed from corrosion-resistant materials, including Hastelloy C-276, Viton and Teflon™, except for the pressure transducers, which are constructed from stainless steel. Oil, brines, sc-CO_2 and a gel/foam diverter are delivered from high-pressure floating piston accumulators that are driven by external high-pressure pumps. These pumps have a highly accurate digital control. Fluid injection is accomplished through a metering pump connected by a valve placed ahead of the core. The pore pressure of the core plugs is maintained by two back pressure regulators at the core outlet and controlled through pressurized N_2 accumulators. Absolute and differential pressure, temperature, flow rate and other parameters during the dual coreflooding test are measured and recorded through an elaborate data acquisition system. Graduated glass tubes are used to measure individually the produced oil from the HPCP and LPCP composites during seawater and sc-CO_2 miscible flooding.

Composite ID	Sample ID	Length (cm)	Diameter (cm)	PV (cc)	Porosity (%)	Air Permeability (mD)
	35	3.030	3.8	9.50	28.1	917.3
	36	3.364	3.8	11.06	29.1	746.0
Composite #1	35+36	6.394	3.8	20.56	28.6	831.7
	285	2.878	3.8	6.25	19.4	51.5
	286	3.140	3.8	7.84	24.3	86.5
Composite #2	285+286	6.018	3.8	14.09	21.9	69.0

Table 3. Routine data of core plugs

Composite ID	Length (cm)	Diameter (cm)	PV (cc)	K_b (mD)	S_{wi} (%)	S_{oi} (% OOIC)	K_{eo} at S_{wi} (mD)
Composite #1 (HPCP)	6.394	3.8	20.567	966.7	24.64	75.36	104
Composite #2 (LPCP)	6.018	3.8	14.064	22.3	17.56	82.44	3

K_{eo}: effective oil permeability

Table 4. Initial data of live oil flooding at reservoir conditions

Properties of the Core Plugs: The core plugs were selected from a carbonate reservoir and scanned to ensure consistency, i.e., no fractures or permeability barriers within a given core plug. Nuclear magnetic resonance (NMR) analysis was also conducted to ensure that all core plugs were of a similar rock type. Based on the NMR and computed tomography scan results, two core plugs were selected for each of the HPCP and LPCP composites. Routine core analysis was first conducted to measure the dimensions, air permeability, porosity and helium PV of the core plugs. The core plugs were then saturated with field connate brine and the PV was calculated by the material balance method. The HPCP composite contained two core plugs, #35 and #36, with an average air permeability of 832 millidarcies (mD) and a porosity of 28.6%. The LPCP composite was composed of two core plugs, #285 and #286, with an average air permeability of 69 mD and a porosity of 22%. Table 3 lists the routine data of the core plugs used in this study.

S_{wi} and Original Oil in Core (OOIC): The individual dry core plugs were vacuumed for 24 hours and then saturated with field connate water. Brine volume and porosity were determined from the change in weight. The saturated core plugs were left immersed in field connate water for about 10 days to establish ionic equilibrium between the rock constituents and the field connate water. The original connate water was then displaced with about 10 PVs of fresh connate water during the course of measuring the individual core plug brine permeability (K_b). After this aging process, core plugs #35 and #36 were stacked together to form the HPCP composite #1 and core plugs #285 and #286 were stacked together to form the LPCP composite #2. The composite core plugs were then assembled into a stack using Teflon tape, aluminum foil and one layer of Teflon shrink tube. The aluminum foil functioned as a diffusion barrier between the core plug and the overburden sleeve.

The field connate water of the composite core plug was then displaced by dead crude oil at a variable injection flow rate of 0.1, 0.2, 0.4, 0.8, 1.0 and 2.0 cc/min. At each flow rate during this dead crude oil flooding, the amount of connate water produced and the differential pressure across the composite were recorded, continuing until no more water was produced. During oil flooding, the direction of oil flow was reversed to alleviate possible end effects. At this stage, the S_{wi} and original oil saturation (S_{oi}) were calculated by material balance, and the effective oil permeability was also calculated at S_{wi}.

Aged Composite Core Plugs with Live Oil: After the S_{wi} and S_{oi} were determined, live oil flooding was conducted for both HPCP and LPCP composite core plugs at a reservoir condition having a pore pressure of 3,200 psi, confining pressure of 4,500 psi and temperature of 102 °C. For three weeks, one PV of live

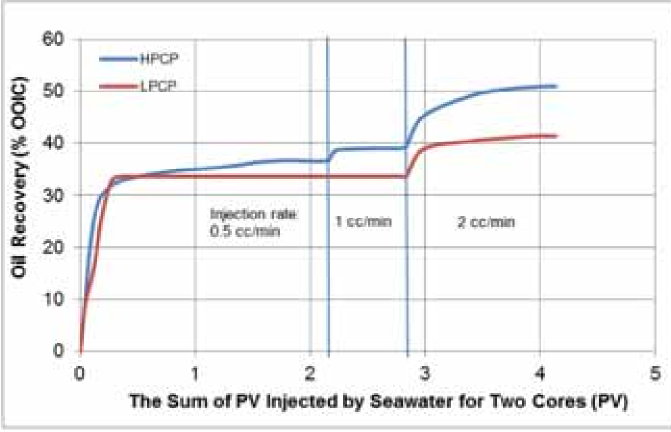

Fig. 2. Oil recovery by simultaneous seawater injection for both the HPCP and the LPCP composites at reservoir conditions.

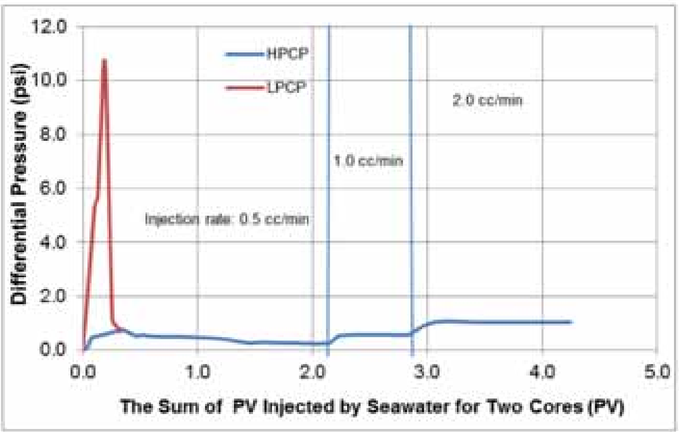

Fig. 3. Comparison of differential pressure vs. the sum of PV injected during simultaneous seawater injection for the HPCP and the LPCP composites.

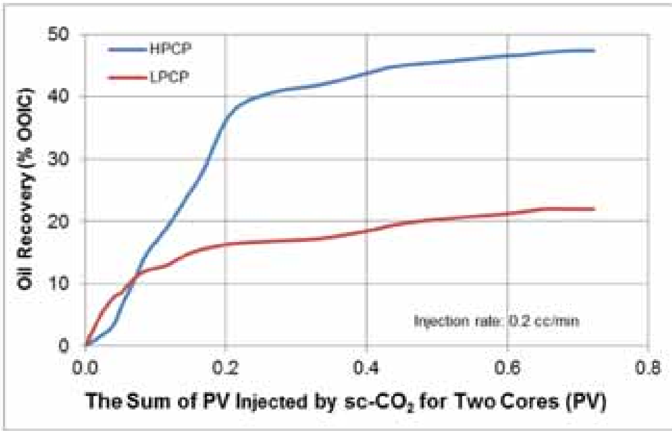

Fig. 4. Oil recovery by simultaneous injection of initial sc-CO_2 for both HPCP and LPCP composites at reservoir conditions.

oil was injected into each composite core plug per day at a flow rate of 1.0 cc/min to check the stabilization and effective oil permeability of core plugs. The S_{wi} and OOIC were 24.64% and 75.36% for the HPCP and 17.56% and 82.44% for the LPCP, respectively. Table 4 lists the initial data of live oil flooding at reservoir condition.

Experimental Procedures of Different Modes of Flooding

Several experiments were conducted with the dual-core setup described earlier. These included: (1) secondary mode oil recovery with seawater flooding, (2) tertiary mode oil recovery with an initial sc-CO_2 miscible flooding, (3) foam/gel diverter injection, and (4) a

					Seawater Flooding			Initial CO_2 Flooding			Second CO_2 Flooding		
Composite ID	L (cm)	D (cm)	PV (cc)	S_{wi} %	RF (%)	S_{orw} (%)	K_{rw} (%)	RF (%)	$S_{or}CO_2$ (%)	K_{rCO2} (%)	RF (%)	$S_{or2^{nd}}CO_2$ (%)	$K_{r2^{nd}}$-CO_2 (%)
Composite #1 (HPCP)	6.39	3.8	20.57	24.6	50.8	49.2	29	47.4	1.83	0.16	X	1.83	X
Composite #2 (LPCP)	6.02	3.8	14.06	17.56	41.4	58.6	X	21.8	36.8	X	19	17.75	4.25

L: length, D: diameter, RF: recovery factor, S_{orw}: waterflood remaining oil saturation, K_{rw}: endpoint relative permeability to water, $S_{or}CO_2$: sc-CO_2 flood remaining oil saturation, K_{rCO2}: endpoint relative permeability to sc-CO_2, $S_{or}2^{nd}$-CO_2: second sc-CO_2 flood residual oil saturation, $K_{r}2^{nd}$-$CO2$: endpoint relative permeability to second sc-CO_2.

Table 5. Summary of oil recovery and endpoint relative permeability after seawater and sc-CO_2 flooding

second sc-CO_2 miscible flooding. These are described next.

Secondary Mode Oil Recovery with Seawater Flooding: After both composites were aged with live oil at reservoir conditions, the Sorm seawater was injected simultaneously into both the HPCP and LPCP at injection rates of 0.5 cc/min, 1.0 cc/min and 2.0 cc/min until the water cut reached 99%. The recovered oil was collected separately from the two composites as a function of PVs of seawater injected. The differential pressures were also recorded across both composites.

Tertiary Mode Oil Recovery with Initial sc-CO_2 Miscible Flooding: After the seawater flooding, the composites were isolated and stabilized. All the lines filled with seawater were then displaced with sc-CO_2. Access to the two composites was opened, and sc-CO_2 was simultaneously injected into both at a rate of 0.2 cc/min. The recovered oil was collected separately from the two composites, and the differential pressures were recorded across both.

Diverting System Slug Injection: To investigate the effect of permeability contrast and to mitigate its impact on oil recovery, a diverting system was injected into the HPCP composite. The main idea was to block the HPCP composite so that the second sc-CO_2 would travel through the LPCP composite and recover the bypassed oil there. The diverting system used for this experiment is described in a separate paper[22]. Diversion involves using a slug to plug the higher permeability zone and then to improve both areal and vertical sweep efficiencies by stabilizing viscous fingering and addressing gravity override issues. In this study, the LPCP was isolated so that 0.4 PV of the diverting system was injected only into the HPCP at 0.5 cc/ min. The injection pressure and differential pressure across the HPCP were recorded during diverting system slug injection.

Second sc-CO_2 Miscible Flooding: After the diverting system injection, access to both the HPCP and the LPCP composites was opened for the second sc-CO_2 miscible flooding at an injection rate of 0.2 cc/min. Oil production and differential pressure across the composites were recorded individually for the HPCP and the LPCP.

Results and Discussion

An experimental investigation of different oil recovery schemes was conducted using dual carbonate composite stacks as described earlier. The permeability ratio or permeability contrast was 35 to 1, which is based on an effective oil permeability at S_{wi}. The HPCP core holder was placed horizontally above the LPCP core holder. Reservoir live oil, seawater and sc-CO_2 were used for dual-core coreflooding at reservoir conditions with a pore pressure of 3,200 psi, temperature of 102 °C and confining pressure of 4,500 psi. The injection of a diverting system slug was also performed at the same conditions.

Secondary Mode Oil Recovery with Seawater Flooding

The purpose of the seawater flooding in the dual-core core-flood test was to determine the oil recovery factor, evaluate the performance of seawater flooding and measure the remaining oil saturation before sc-CO_2 injection. Table 4 provides the initial conditions of water and oil saturations for both the HPCP and the LPCP cores at the beginning of the seawater injection. Simultaneous seawater injections into both the HPCP and the LPCP cores were conducted at injection flow rates of 0.5 cc/ min for 2 PVs, 1.0 cc/min for 1 PV and 2.0 cc/min for 1 PV. After total seawater injection

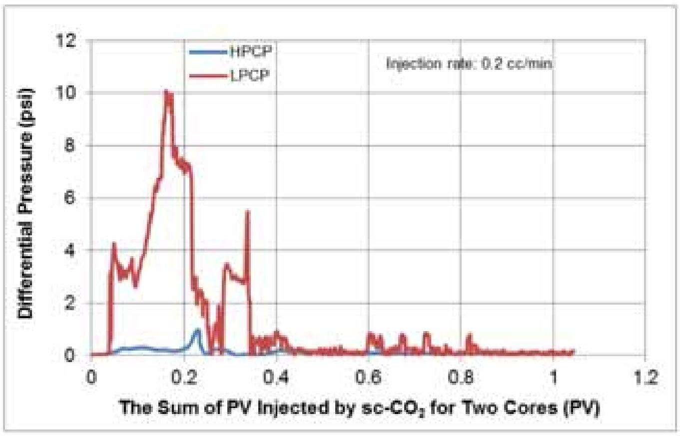

Fig. 5. Comparison of differential pressure vs. the sum of PV injected during simultaneous sc-CO_2 injection for HPCP and LPCP.

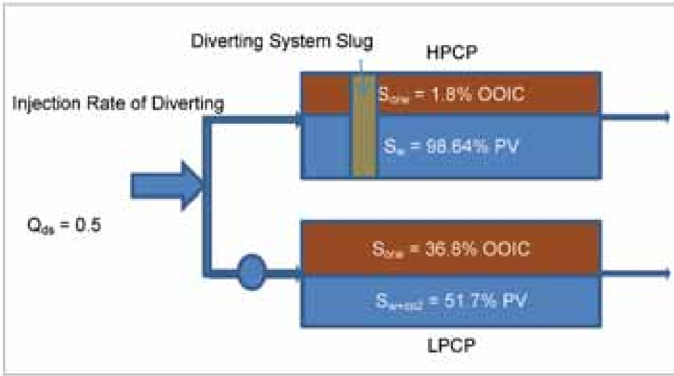

Fig. 6. Isolation of LPCP and diverting system slug injection for HPCP.

of 4.0 PVs and achieving a water cut of 99%, the remaining oil saturations were determined for both the HPCP and the LPCP composite cores.

Figure 2 shows the effect of waterflooding on oil recovery from the HPCP and LPCP composites. Oil recovery at breakthrough was slightly different for the HPCP and LPCP composites. The rate of oil recovery also was more prominent in the HPCP core compared to the LPCP composite. The results for the LPCP mimic waterflooding efficacy in a water-wet case because no more oil or only a little oil was produced at the 0.5 cc/min and 1.0 cc/min rates of seawater flooding. The carbonate core plugs used in this study were expected to be weakly oil-wet or mixed wet because the core plugs were aged with live oil for about three weeks[23-25]. The differential pressure across the HPCP and LPCP vs. total PV of seawater injection is presented in Fig. 3. The differential pressure across the HPCP core reached a maximum value of 0.8 psi until breakthrough, when it dropped to a value of about 0.2 psi at an injection rate of 0.5 cc/min. For the LPCP, the differential pressure across the core reached a maximum value of 11 psi and then dropped down to the same value as the HPCP, which is a result of the seawater bypassing the LPCP to flow through the HPCP rather than an impact of wettability. About 8% OOIC of additional oil was produced from the LPCP when the rate was changed to 2 cc/min. The remaining oil saturation after seawater flooding was about 49% OOIC for HPCP and 59% OOIC for LPCP, shown under Sorw in Table 5. The results show that oil recovery by seawater flooding depends on rock permeability and injection rate. The results also indicate that more oil is produced from the higher permeability cores, as expected.

Tertiary Mode Oil Recovery with Initial sc-CO_2 Miscible Flooding

The initial target of achieving more than 50% OOIP of the oil left after seawater injection for both the HPCP and LPCP was set for the tertiary oil recovery process. In this study, sc-CO_2 was used to displace the remaining oil after the initial seawater flood. The sc-CO_2 was injected at 0.2 cc/min into the two composites simultaneously, where the incremental water saturation was 37% PV for the HPCP and 34% PV for the LPCP after the seawater flooding. The oil recovery performance for sc-CO_2 is shown in Fig. 4 for both stacks. Final oil recovery by initial sc-CO_2 flooding was 47.4% OOIC and 21.8% OOIC for the

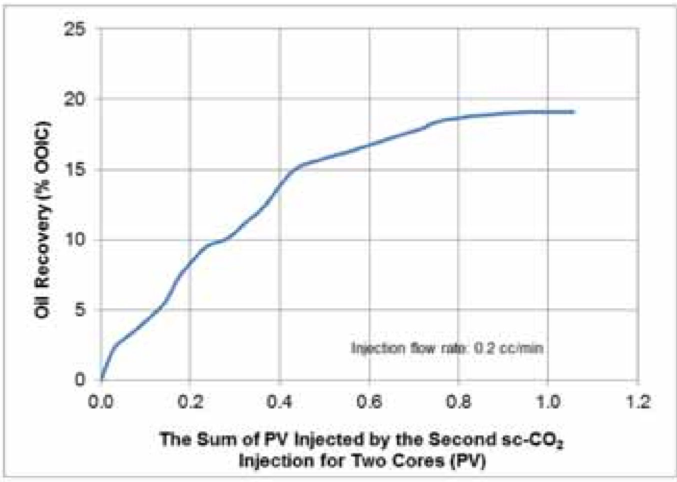

Fig. 7. Oil recovery by the second sc-CO_2 flooding for LPCP composite after diverting the system injection, at reservoir conditions.

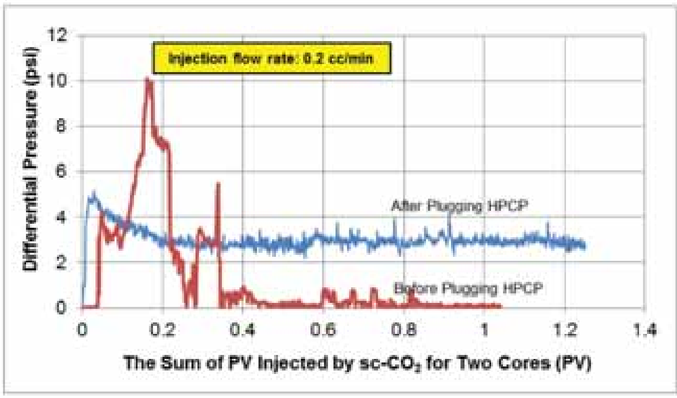

Fig. 8. Comparison of differential pressure across the LPCP composite for the initial and the second sc-CO_2 injection before and after diverting system injection.

HPCP and LPCP composites, respectively. Residual oil saturation was less than 2% OOIC for the HPCP and 37% OOIC for the LPCP composites at the end of the initial sc-CO_2 injection, Table 5. Figure 5 presents the differential pressure drop across both stacks during the initial sc-CO_2 injection. For the LPCP composite, the performance of the initial sc-CO_2 injection was quite different compared to that of seawater injection, and after sc-CO_2 breakthrough, the differential pressure drop across the two cores was different – again, unlike the case in seawater flooding. This was due to two-phase and three-phase flow in the two composites. Slow continuous oil production was observed beyond the 0.2 PV sc-CO_2 injection.

Diverting System Slug Injection and Oil Recovery Performance by the Second sc-CO_2 Miscible Flooding

The results after the initial sc-CO_2 injection indicate that most of the oil was produced from the HPCP

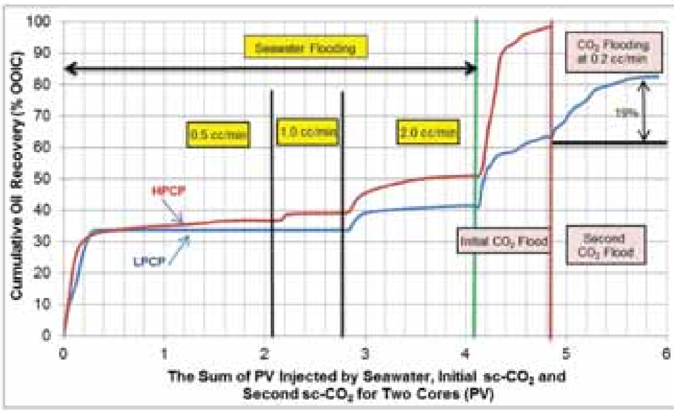

Fig. 9. Overall oil recovery by seawater, the initial sc-CO_2 and the second sc-CO_2 flooding after diverting the system slug injection at reservoir conditions.

composite and a significant amount was left behind in the LPCP composite. To recover this remaining oil and improve the displacement efficiency for the LPCP, a slug – about 0.4 PV – of a diverting system was injected into the HPCP composite at an injection rate of 0.5 cc/min, Fig. 6. During the injection of the diverting system, the LPCP was isolated and the differential pressure across the HPCP was monitored. The maximum injection pressure recorded was more than 200 psi for the diverting system at reservoir conditions. After the HPCP had been plugged with the diverting system, sc-CO_2 was injected again into both the composites to determine the oil recovery performance, now only from the LPCP. Figure 7 shows the oil recovery during the second sc-CO_2 flooding cycle, indicating that 19% OOIP of extra oil was recovered at the end of the second sc-CO_2 injection and after about 1 PV injection.

A comparison of the differential pressure across the LPCP composite is presented in Fig. 8 for the initial and the second sc-CO_2 injections – before and after diverting system slug injection. The red line represents differential pressure during the initial sc-CO_2 and the blue line shows the pressure for the second sc-CO_2 injection. The higher pressure observed for the second sc-CO_2 injection cycle is caused by the plugging of the HPCP with the diverting system slug. This diversion causes the subsequent CO_2 to go through the LPCP and produce a miscible displacement there. The ratio of the pressure during the two sc-CO_2 cycles – after the diverting system slug injection to before the diverting system slug injection – is about 15.

Figure 9 shows the overall oil recovery by seawater and sc- CO_2 flooding, the latter both before and after the diverting system slug injection, against total PV injected under each mode of injection. The results

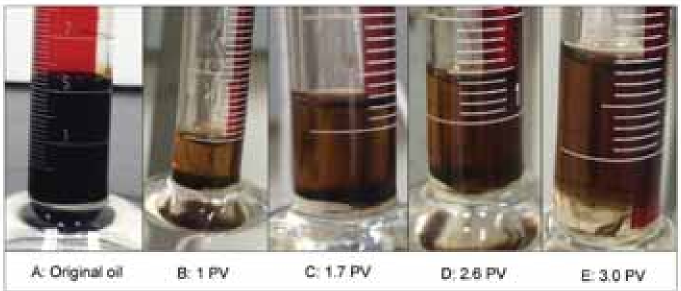

Fig. 10. Comparison of original oil with oil extracted during the second sc-CO_2 flooding.

show exceptional recovery (98%) in the HPCP composite after the seawater flooding and the first sc-CO_2 injection cycle. Due to sc-CO_2 bypassing through the HPCP, the performance of the LPCP composite was relatively poor at that point. By plugging the HPCP with the diverting system slug, the subsequent sc-CO_2 cycle was able to extract some of the remaining oil from the LPCP composite.

Displacement Mechanisms in Recovery of Remaining Oil by sc-CO_2 after Seawater Injection

Endpoint relative permeabilities were calculated for both composites as shown in Table 5. The value of endpoint relative permeability for the HPCP composite, K_{rw}, at remaining oil saturation, S_{orw}, was 29% based on effective oil permeability at S_{wi}. The distribution of remaining or residual oil strongly depends on the wettability of the rock, and it was anticipated that the wettability of the carbonate core plugs used in this study would be weakly oil-wet, based on past experience[24, 25]. In this study, a considerable amount of oil in the LPCP was left behind due to seawater bypassing through the HPCP. The following description of the mechanisms of displacing the remaining oil by injecting sc-CO_2 after seawater flooding is based on the results and observations of the dual-core core-flooding experiment that is the subject of this article. As a result of the sc-CO_2 contact and interaction with the remaining oil in the core plugs, mobilization and extraction of oil took place, and an oil bank was established gradually. Some oil and seawater were displaced at the beginning of the sc-CO_2 injection, presumably from the oil bank formation, followed by a lighter colored oil, which indicates an extraction process. After about 0.4 PV of sc-CO_2 injection, a lighter colored oil was produced gradually until the injection ended. This is most likely an extraction of oil from the oil film on the pore surfaces and from the dead end pores[26]. A similar phenomenon of extracting paleo oil has been reported[27].

After the diverting system slug injection and the plugging of the HPCP, sc-CO_2 was injected into both the HPCP and the LPCP at 0.2 cc/min. Samples of the oil produced from the LPCP at different PVs of the sc-CO_2 injection are presented in Fig. 10. Dark oil was produced at the beginning of the second sc-CO_2 injection, Fig. 10b. After that, lighter colored oil was produced gradually until the end of the injection period. This is indicative of an oil extraction process at work in the LPCP with sc-CO_2 as the dominant displacement mechanism.

Conclusions

Based on results and observations of seawater and sc-CO_2 flooding using a dual-core composite coreflood apparatus at reservoir conditions, the following conclusions can be drawn:

1. A dual-core coreflooding apparatus can be used to study the effect of permeability contrast, reservoir heterogeneities and injection flow rate on oil recovery by seawater and sc-CO_2 flooding, before and after diverting the injection fluids, in heterogeneous carbonate rocks at reservoir condition.

2. Poor sweep efficiency in the lower permeability zone caused by the bypassing of fluids through the higher permeability zone is experimentally evidenced during the seawater and sc-CO_2 flooding. Permeability contact has a significant impact on oil recovery by seawater and sc-CO_2 injection.

3. Slug injection of a diverting system – for diversion and conformance control – demonstrated that the system was an excellent plugging agent to improve sweep efficiency in heterogeneous carbonate reservoirs.

4. Oil recovery before the sc-CO_2 breakthrough was dominated by extraction from the oil bank formation.

Oil recovery after sc-CO_2 breakthrough was dominated by extraction from oil films on pore surfaces and from dead end pores.

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Biographies

Xianmin Zhou is a Petroleum Engineer with 39 years of experience currently working in Saudi Aramco's Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC). His focus areas are at present paleo oil, heavy oil recovery and CO_2 enhanced oil recovery (EOR) studies. Prior to joining Saudi Aramco in 2010, Xianmin worked as a Senior Petroleum Engineer/Senior Special Core Analyst for four major oil companies: Daqing Petroleum Research Center, China; Core Lab Inc., U.S.; Omni Labs Inc., U.S.; and Intertek Westport Technology Center, U.S.

His areas of expertise include special core analysis, CO_2 and chemical EOR studies, reservoir characterization and developing methods for measuring two-phase and three-phase relative permeability, coreflooding testing at reservoir conditions and wettability studies.

Xianmin has authored or coauthored 25 papers on the above subjects in Chinese and Canadian journals, and several Society of Petroleum Engineers (SPE) journals. He has published three patents.

In 1976, Xianmin received his B.S. degree in Petroleum Engineering from Daqing Petroleum Institute, Heilongjiang, China, and in 1996, he received his M.S. degree in Chemical and Petroleum Engineering from the University of Wyoming, Laramie, WY.

Fawaz M. Al-Otaibi is a Petroleum Engineer at Saudi Aramco's Reservoir Characterization Department. Prior to that, he worked as a Supervisor of the Petrophysics Unit in the Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC). Fawaz has worked in many technical positions and in a variety of disciplines, including production engineering and reservoir management, within Saudi Aramco. He has led research projects on both enhanced oil recovery using carbon dioxide (CO_2 EOR) and reservoir fluids. Fawaz has evaluated different CO_2 EOR methods, such as water-alternating gas (WAG) and tapered WAG during CO_2 EOR flooding. He has also taught courses on CO_2 EOR and coreflooding theories and applications. Currently, Fawaz is leading a group of scientists and technicians to conduct studies to investigate several techniques in overcoming the gravity override during CO_2 EOR.

He is an active member of the Society of Petroleum Engineers (SPE) and has published numerous SPE papers and technical journals. Fawaz also has five filed patents. He is Certified Petroleum Engineer and has received several awards and other recognition from SPE.

In December 1997, Fawaz received his B.S. degree in Chemical Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.

Dr. Sunil L. Kokal is a Senior Petroleum Engineering Consultant and a Focus Area Champion of enhanced oil recovery (EOR) in the Reservoir Engineering Technology team of Saudi Aramco's Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC). Since he joined Saudi Aramco in April 1993, he has been involved in applied research projects on EOR/improved oil recovery (IOR), reservoir fluids, hydrocarbon phase behavior, and production-related challenges. Currently, Sunil is leading a group of scientists, engineers and technicians to develop a program for CO_2 EOR and to conduct studies and field demonstration projects. The main driver for his research is to increase the ultimate oil recovery up to 70% and add billions of barrels of reserves.

Sunil has written over 100 technical papers and has authored the chapters on "Crude Oil Emulsions" and "Reservoir Fluid Sampling" for the revised edition of the SPE Petroleum Engineering Handbook (2006). He has been the associate editor for the Journal of Petroleum Science and Engineering, the SPE Reservoir Evaluation and Engineering Journal, and the Journal of Canadian Petroleum Technology. He has been a keynote speaker, helped organize several petroleum engineering-related conferences and symposia, and taught courses on EOR, reservoir fluid properties and other related topics. A Registered Professional Engineer, Sunil is a member of the Society of Petroleum Engineers (SPE) and the Association of Professional Engineers, Geologists and Geophysicists of Alberta (Canada).

He received the prestigious 2012 SPE DeGolyer Distinguished Service Medal, the 2011 SPE Distinguished Service Award, the 2010 SPE Regional Technical Award for Reservoir Description and Dynamics, and the 2008 SPE Distinguished Member Award for his services to the society. Sunil also served as a SPE Distinguished Lecturer during 2007-2008. He has received several other awards, including best paper awards from the Canadian Petroleum Society, an outstanding technical editor award, and several internal company awards for publications, service, teamwork and technical contributions. Sunil has mentored several young professionals both at Saudi Aramco and for the SPE.

In 1982, he received his B.S. degree in Chemical Engineering from the Indian Institute of Technology, New Delhi, India, and in 1987, he received his Ph.D. degree in Chemical Engineering from the University of Calgary, Calgary, Alberta, Canada.

AlMohannad A. Al-Hashboul is a Petroleum Engineer with Saudi Aramco's Reservoir Engineering Technology Team at the Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC). Since joining Saudi Aramco in July 2014, he has been involved in enhanced oil recovery (EOR) research projects, specifically CO_2 EOR.

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

In 2014, AlMohannad received his B.S. degree in Petroleum Engineering along with a Minor in both Mechanical Engineering and Mathematics from Texas Tech University, Lubbock, TX.

Dr. Senthilmurugan Balasubramanian is a Petroleum Engineer in the Reservoir Engineering Division of Saudi Aramco's Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC). He joined Saudi Aramco in 2012. He has 17 years of experience in the oil industry, particularly in upstream research in production chemistry and the flow assurance area, as well as in the refining and petrochemical industry. Senthilmurugan gained much of his work experience at different oil companies, which include the Abu Dhabi National Oil Company (ADNOC), Abu Dhabi; Bahrain Petroleum (BAPCO), Bahrain; and the Indian Oil Corporation Limited (IOCL), New Delhi, India.

His area of research interest is in enhanced oil recovery, the phase behavior of petroleum reservoir fluids, managing the scale, asphaltene, and paraffin and wax deposit prevention, inhibition and control.

Senthilmurugan has published and coauthored a number of papers and articles in journals.

He received his B.S. degree in Chemistry from Madurai Kamaraj University, Madurai, India; his M.S. degree in Chemistry from Bharathidasan University, Tiruchirappalli, India; and his Ph.D. degree in Industrial Chemistry from Alagappa University, Karaikudi, India.

Faris A. Al-Ghamdi is a Laboratory Technician working in Saudi Aramco's Reservoir Engineering Technology Division of Saudi Aramco's Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC). He joined Saudi Aramco in 2010 and began his training at the Industrial Training Center, graduating in 2013. Faris's expertise is conducting coreflood experiments.

Formation Tester and NMR Heavy Oil Characterization During Placement of a Horizontal Injector at a Tar/Oil Interface

By Stig Lyngra, Dr. Gabor G. Hursan, Dr. Murat M. Zeybek, Richard G. Palmer, K. Ahmed Qureshi and Hazim A. Ayyad.

Abstract

A case history is presented for a horizontal injector well drilled at the base of a moveable oil column on top of a tar mat in a carbonate oil reservoir in the Middle East. The well was placed utilizing real-time logging-while-drilling (LWD) nuclear magnetic resonance (NMR) oil viscosity correlations and formation tester mobility data.

As this was a pilot water injector placed at an oil/tar inter- face with limited historic oil viscosity vs. depth data, obtaining quality calibration oil samples was considered critical. Both LWD and pipe conveyed tough logging conditions (TLC) formation tester data sets were acquired. Consequently, direct comparisons of LWD acquired and TLC acquired formation pressures and formation mobilities were possible. The comparison proved the reliability of the LWD formation mobility data. The LWD measured formation pressures, however, were supercharged compared to the TLC formation tester measured formation pressures, which were largely in line with expected formation pressures.

The oil viscosity results from the TLC formation tester in situ viscosity fluid analyzer and from the NMR viscosity correlation compared favorably with the laboratory results from the fluid samples acquired by the TLC formation tester. This indicates that accurate real-time in situ fluid property determination is possible with a modern formation tester and NMR tools.

In this reservoir, during the early phase of acquiring oil viscosity vs. depth data at the oil/tar transition zone, the main lesson learned was that the deeper section of the case study well contained higher asphaltene content, which caused the wellbore plugging that prevented reservoir access after suspending the well for tie-in. A clean out operation was unsuccessful, as plugging reoccurred. Current plans are for the well to be sidetracked again in the 3 centipoise (cP) to 20 cP oil interval at the top portion of the oil/tar transition zone.

Introduction

In Saudi Arabian oil fields with reservoir situations where heavy oil zones/tar mats exist, logging-while-drilling (LWD) formation tester mobility steering is commonly used for optimization of water injector well placement[1-4]. The mobility measurements from the LWD formation tester are stationary measurements that require halting the actual drilling operation. These point tests, typically measured at regular intervals of a few hundred feet during drilling of the reservoir section, are used as positive proof that the well has not entered into the low mobility or immobile reservoir interval of high viscosity heavy oil/tar located below the recoverable oil in the reservoir.

In heavy oil/tar mat applications, the availability of realtime LWD nuclear magnetic resonance (NMR) measurements provides relatively strong evidence of heavy oil/tar. As described elsewhere[5, 6], tar can be detected using the missing porosity tar indicator and excess bound fluid concept. Moreover, a fairly robust NMR oil viscosity correlation has been developed[7] that allows for estimation of the oil viscosity on the basis of the real-time LWD NMR data. In Saudi Aramco well placement operations, the LWD NMR data is routinely processed twice a day for oil viscosity determination. If the missing porosity and/or excess bound fluid tar detectors indicate heavier oil at the drill bit, the drilling operation is stopped. The formation tester then acquires

Crude Classification	Minimum API (degrees)	Maximum API (degrees)
Light Oil	31.1°	N/A
Medium Oil	22.3°	31.1°
Heavy Oil	10°	22.3°
Extra Heavy Oil	N/A	10°

Table 1. WPC crude classification[15]

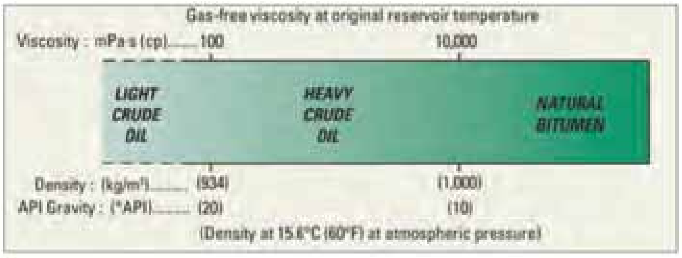

Fig. 1. Definition of petroleum types[14].

mobility measurements, and the oil viscosity correlation algorithm is run for validation. If the measurements confirm high viscosity/low mobility, a decision is made to drill stratigraphically upward to return the drill bit to the lower viscosity in situ oil.

In this reservoir, only limited historic oil viscosity vs. depth data at the actual oil/tar interface was available. As the well described in this article was a pilot water injector placed at the interface, obtaining calibration oil samples was considered critical. The NMR viscosity correlation[7] had been developed on the basis of samples from a different Saudi Arabian oil field with a similar tar mat problem. Therefore, it was necessary to verify that the NMR oil viscosity correlation provided reasonable results in this particular reservoir. Fluid samples were acquired using the pipe conveyed tough logging conditions (TLC) formation tester and tested in the laboratory to allow comparison of the actual laboratory oil viscosity and density results with the fluid analyzer viscosity and density measurements from the TLC formation tester, as well as with the oil viscosity calculated from the NMR viscosity correlation.

Since LWD formation tester data was already being acquired for mobility steering purposes and a TLC formation tester run was necessary to obtain the calibration fluid samples, a unique opportunity presented itself to acquire LWD and TLC formation pressure and formation mobility measurements at the same depths and to compare the two data sets for validation purposes.

Because Saudi Arabian water injector well placement case histories utilizing formation testers and NMR data have previously been published[6, 8, 9] – and the intent in this article is not to share the same operational information as in the previous articles – the actual well placement of this pilot water injector well is only briefly described as required for context. The focus of this publication is to present the in situ oil characterization obtained from both formation tester evaluation and NMR data, including validation with oil sample laboratory results.

Field Description and the Heavy Reservoir Development History

The well described in this article was drilled in a giant mature oil field in the Kingdom of Saudi Arabia. The field was discovered in the early 1940s and has mainly been produced from two large fractured carbonate oil reservoirs[10, 11]. The field contains various other hydrocarbon-bearing reservoirs. Many of these hydrocarbon reservoirs are associated with a high-relief dome structure[10]. Saudi Aramco is currently pursuing further delineation, including pilot production and injection programs, for several of these secondary reservoirs with the intent to cost-effectively produce all hydrocarbons through the existing infrastructure[12]. As the field is mature and the infrastructure is ageing, optimum value can only be achieved by not delaying the investment in the secondary reservoir development wells too far into the future[12].

One of the dome structure reservoirs, the “Heavy” reservoir, is an ample heavy oil accumulation located above the two main producing horizons[12]. This heavy oil accumulation was discovered in 1941 and has been produced since 1947[13]. Due to the ease of operations in extracting oil from the main producing horizons – and other highly prolific Saudi Arabian giant oil fields – the Heavy reservoir is at this point virtually undepleted[12]. An extensive data acquisition program that has taken place over the past few years made it clear that the mobile heavy oil is underlaid by 300 ft of tar, which totally separates the oil column from the aquifer[13]. In 2010, the first pilot injector well was placed at the oil/tar interface. This pilot water injector is the case history well presented in this publication.

Oil Classification and Physical Oil Properties

Crude Oil Classification

The terminologies “heavy oil,” “tar,” “bitumen” and “asphalt” are not consistently applied in the oil industry. Different definitions exist, but many apply these terms

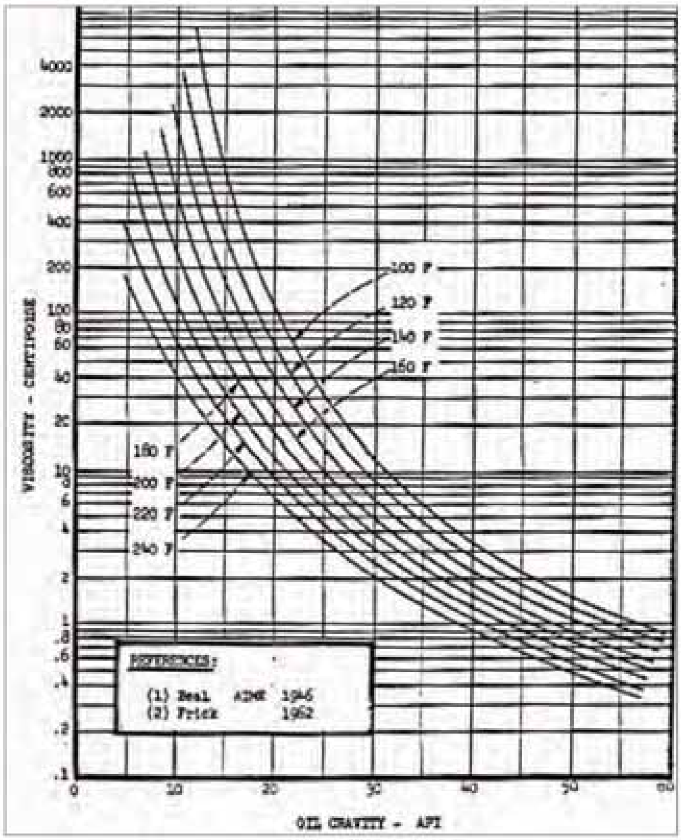

Fig. 2. Beal's gas-free (dead) oil viscosity correlation[17-19]

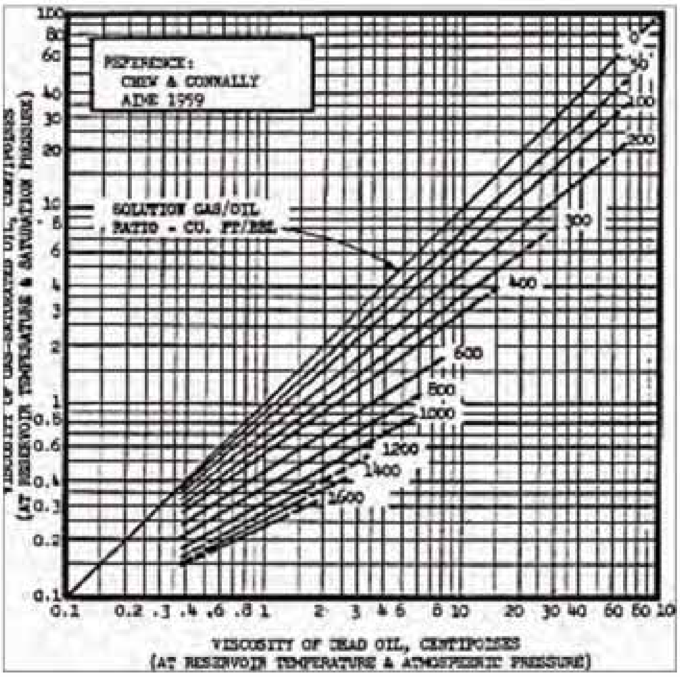

Fig. 3. Chew and Connally's gas saturated (live) crude viscosity correlation[18, 20].

almost interchangeably. A U.S. Geologic Survey (USGS) Fact Sheet14 suggests one approach to defining the petroleum types, Fig. 1.

A study group formed by the World Petroleum Congress (WPC) in 1980, with representatives from the five WPC member countries (Canada, the Netherlands, the United Kingdom, the United States and Venezuela), reviewed the oil and gas classification and nomenclature systems used by various countries and recommended the universal adoption of the classification presented in Table 1[15]. The Society of Petroleum Engineers (SPE) has adopted the WPC definitions as appropriate for reserves and resource management purposes[16].

Physical Properties and Conditions Affecting In Situ Oil Viscosity

The in situ oil viscosity is dependent upon the gas-free (dead) oil viscosity and the amount of dissolved gas in the oil, i.e., the solution gas-oil ratio (GOR), measured in standard cubic feet per standard barrel (scf/sbbl). Two classic charts, Fig. 2 and Fig. 3, demonstrate the effects that the oil API gravity, reservoir temperature and GOR have on in situ oil viscosity.

The correlation from Beal (1946)[17], Fig. 2, is used to find the gas-free crude viscosity at reservoir temperature as a function of API gravity. The chart shown in the figure is reproduced from Standing's (1974)[18] student chart book. Professor Standing based his chart on the version in the Petroleum Production Handbook (1962)[19] rather than Beal's more complicated original. Beal's correlation was based on 953 crude oil samples taken from 747 different oil fields, including approximately 500 U.S. fields.

The dead oil viscosity, as determined from Fig. 2, is then adjusted for the amount of solution gas the crude contains in the reservoir by means of the correlation from Chew and Connally (1959)[20], Fig. 3, which determines the in situ oil viscosity at saturation conditions. Figure 3 is also reproduced from Standing (1974)[18]. Chew and Connally's correlation was based on 456 crude samples, mainly from U.S. reservoirs, but the sample set also included ~20 Canadian and South American samples. If the reservoir pressure is greater than the saturation (bubble point) pressure, a further adjustment (increase) of the oil viscosity is required to account for the degree of undersaturation at reservoir conditions.

Heavy Reservoir: Crude Classification and In Situ Oil Viscosity

Table 2 presents the actual fluid data for the Heavy reservoir, or the mobile oil column located above the tar mat. Based on the USGS crude definitions[14], this oil is classified as light oil. The WPC classification[15] defines this crude as medium oil.

Based on the data reported in Table 2, using the API gravity and reservoir temperature as input for Beal's correlation in Fig. 2, the estimated dead oil viscosity is ~3 centipoise (cP). Using this estimated dead oil viscosity and the reported solution GOR, the estimated in situ oil viscosity at saturation pressure determined from Chew and Connally's correlation in Fig. 3 is ~2 cP.

Figure 4 presents the actual laboratory oil viscosity results for the Heavy reservoir at reservoir temperature as a function of pressure above crude saturation pressure, i.e., undersaturation pressure. The presented curve is a linear regression curve based on data from four fluid samples.

Using Beal's correlation combined with Chew and Connally's correlation for approximating the in situ oil viscosity appears to work reasonably well for the lighter Heavy reservoir crude located above the tar mat. As has been pointed out[21], however, these correlations do not consider the chemical nature of the hydrocarbons that make up the crude part of the reservoir oil. The actual chemistry is important in predicting liquid hydrocarbon viscosity behavior, particularly when the fraction of heavier components starts to increase dramatically at the oil/tar interface.

Fluid Parameter	Data	Unit
API Gravity	27.4	°API
Field Solution GOR	145	scf/bbl
Flash Solution GOR	205	scf/bbl
Reservoir Temperature	215	°F

Table 2. Heavy reservoir fluid properties

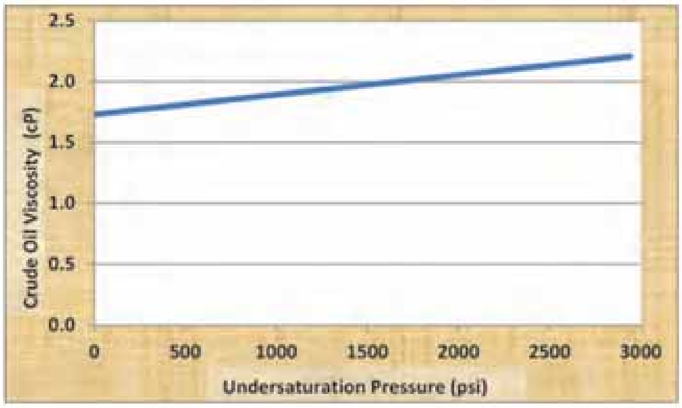

Fig. 4. Heavy reservoir crude viscosity at reservoir temperature as a function of the degree of undersaturation.

Below the Oil/Tar Interface: State-of-the-Art Heavy Oil/Asphaltene Science

In recent years, the understanding of the asphaltene's molecular properties, especially the distribution of asphaltene molecular weight, has considerably improved. The increased asphaltene understanding is a result of research and field studies conducted by Schlumberger's Oliver Mullins et al.[22-29], Andrew Pomerantz et al.[30, 31] and Julian Zuo et al.[32, 33] together with Saudi Aramco's Doug Seifert et al.[34, 35] and co-researchers from service/operating companies, universities[36, 37] and research affiliations.

A key concept in this research is that the asphaltene's aggregate structures, first found in laboratory solvents, are also found in crude oils. A simple representation of the molecular and colloidal structures of asphaltenes in crude oils and laboratory solvents was first published as the modified Yen model[22], named after the founder of modern asphaltene science, the Chinese professor Teh Fu Yen. This published model was later renamed the Yen-Mullins model[38]. The predominant molecular and colloidal structures of asphaltenes, as presented in the Yen-Mullins model[22], are shown in Fig. 5, which indicates that at low concentrations, as in condensates, asphaltenes are dispersed as a true molecular solution (left); for black oils, asphaltenes are dispersed as nanoaggregates of molecules (center); and for heavy oils, asphaltenes are dispersed as clusters of nanoaggregates (right).

Figure 6 displays the percent of asphaltene in an oil/tar transition zone for a giant Saudi Arabian Jurassic oil field. The oil samples used for deriving the previously mentioned NMR viscosity correlation[7] were obtained from this oil field. As presented in Fig. 6, the oil/tar transition zone from the mobile oil zone (asphaltene ~3%) to the immobile tar mat (asphaltene > 35%) in this oil field is approximately 275 ft true vertical depth (TVD).

A new asphaltene equation of state (EoS), the Flory-Huggins-Zuo (FHZ) EoS, has been developed as part of this re- search[32, 33]. With the particle size known, the effect of gravity can be determined. As described by Archimedes buoyancy, the asphaltene particles are negatively buoyant in the smaller particle crude oil. In the FHZ EoS, the gravity term – given by Archimedes buoyancy in the Boltzmann distribution – is combined with a chemical solubility term and an entropy term to fully describe the asphaltene behavior.

Application of Heavy Reservoir Case Study Well Fluid Samples

The purpose of acquiring the fluid samples from the case

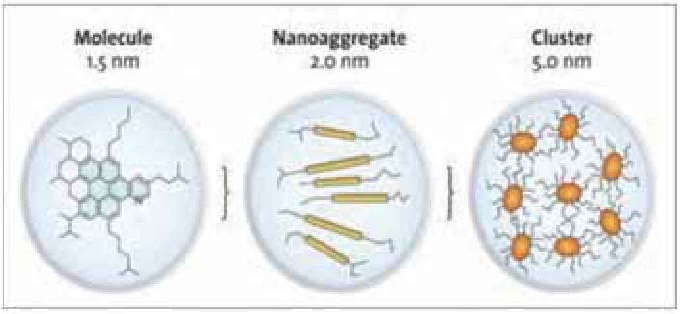

Fig. 5. The Yen-Mullins asphaltenes model[22].

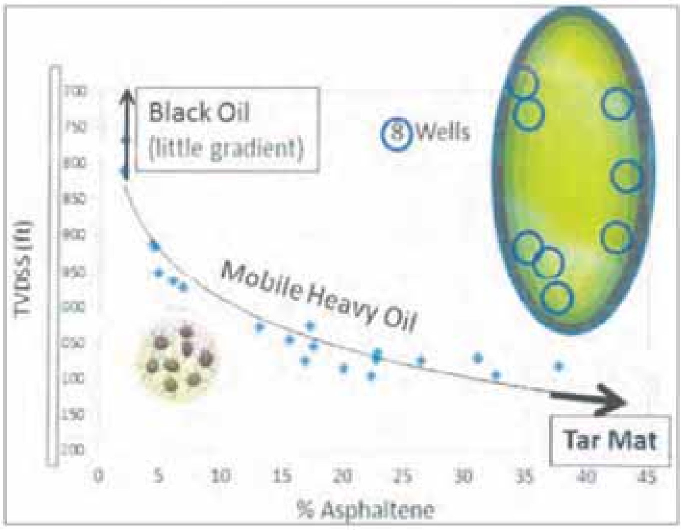

Fig. 6. Aspalthene percentage as a function of depth in a Saudi Arabian oil field[27, 28, 34, 35].

study well was to gain understanding of the asphaltene percent vs. depth at the oil/tar interface and the resulting oil viscosity relationship. This new knowledge of the crude's chemical nature will improve pre-drilling trajectory planning for future horizontal water injector wells and allow fine-tuning of the NMR viscosity correlation[7] to data from this field. After the correlation has been tuned with further crude samples, the NMR crude viscosities measured from all wells will be used with NMR data in this reservoir for a spatial oil property characterization. The tuned NMR viscosity correlation will also enhance the real-time mobility steering when placing new water injector wells. If required, once the actual asphaltene percentage vs. depth for this field is known, an FHZ EoS can be calibrated to further enhance the spatial understanding of the oil/tar transition zone.

Heavy Reservoir: Heavy Oil and Tar Indicators

Triple Combo and NMR Data Tar Indicators

Conventional log interpretation to detect viscosity variations is limited to qualitative observations, such as noting washouts in caliper logs, diminished invasion and/or unusual vertical distributions of water and oil. These circumstantial relationships do not provide operationally reliable viscosity estimations. The problem is illustrated in the side-by-side comparison of two evaluation wells, Well-1 and Well-2, drilled in the same reservoir as the case history pilot water injector, Fig. 7. The top interval in the Heavy reservoir for Well-1 was 425 ft above the target entry for the pilot water injector well, while Well-2 penetrated the structure 155 ft deeper than the case history well. Despite the 680 ft difference in structural elevation between the two wells, the conventional logs and the calculated total and water-filled porosity are remarkably similar, as seen in Tracks 1, 2 and 5 of Fig. 7. Well-2 may indicate heavy oil with less water-based mud (WBM) invasion and more borehole irregularities in the caliper logs than Well-1, but these effects could also result from differences in drilling conditions and formation permeability instead of fluid property variations.

Since the advent of NMR logging, the strong and unique connection between oil viscosity and NMR relaxation times has been the underpinning of a number of powerful downhole viscosity evaluation

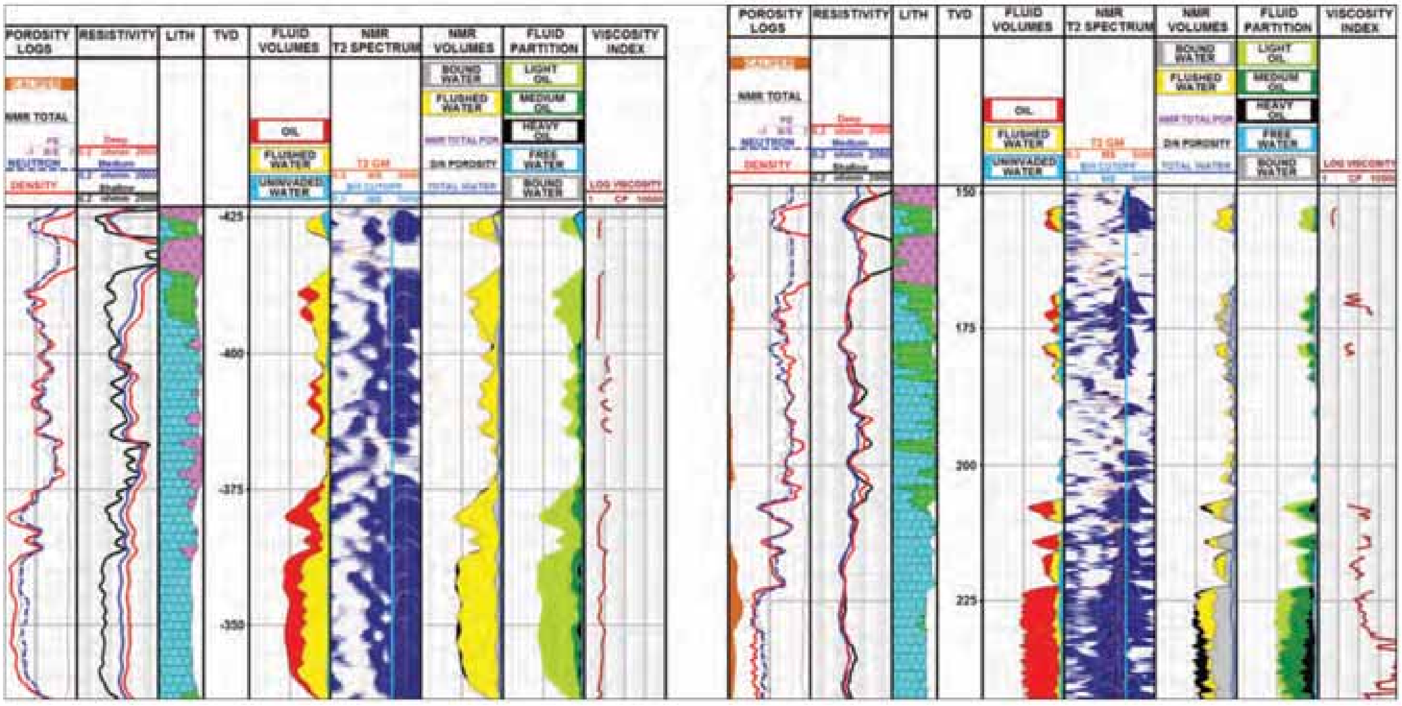

Fig. 7. Well-1 (left) and Well-2 (right) porosity and NMR logs.

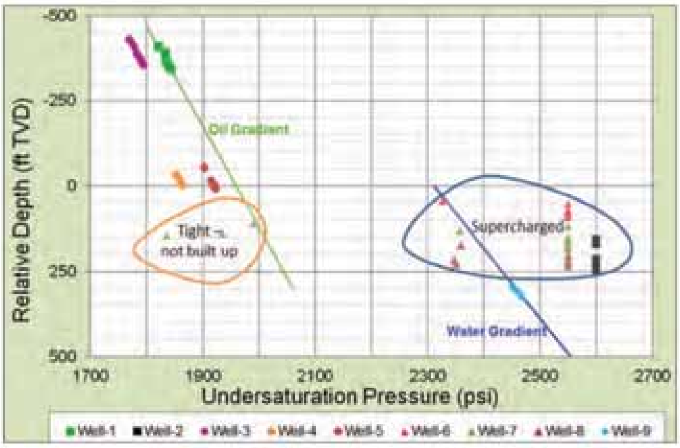

Fig. 8. Heavy reservoir formation pressure results for nine wells.

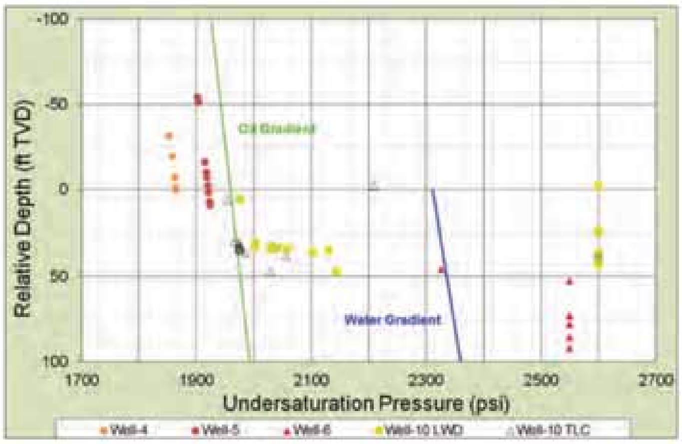

Fig. 9. Well-10 case study injector formation tester results.

techniques[5, 7, 39-46]. For this case study, the volumetric decomposition approach[7] was utilized. This method has been implemented for operational use in other Saudi Arabian fields with similar reservoir conditions. The algorithm uses conventional total and water-filled porosity, and NMR total and bound fluid porosities as inputs, and calculates three oil volumes differentiated by their NMR properties. The heaviest part, shown in black in Track 8, relaxes too fast to be measured by NMR tools. The second intermediate component appears as bound fluid in the NMR spectrum, whereas the light constituent contributes to the NMR free fluid signature. These intermediate and light components are shown in Track 8 as medium and light green, respectively. The relative contributions of medium and heavy components have been calibrated with laboratory viscosity measurements of oil samples taken by downhole formation testers[7].

The NMR-based volumetric calculations and viscosity tracks reveal a striking difference between Well-1 and Well-2. Well-1 indicates mostly light oils in the entire reservoir, whereas Well-2 presents significant volumes of medium and heavy components with a downward-trending decrease of light components to where the significant missing NMR porosity indicates very heavy oils toward the bottom of the reservoir. Well-1 and Well-2 practically demonstrate the oil viscosity endpoints for the Heavy reservoir. Other wells are expected to display oil viscosities somewhere in between these two extremities.

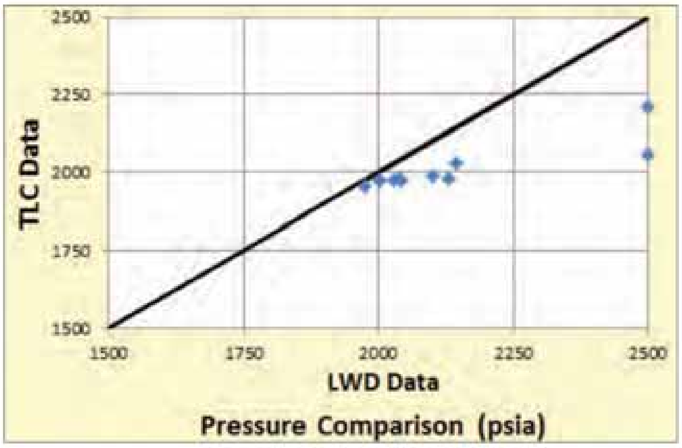

Fig. 10. LWD/TLC formation tester pressure comparison.

Heavy Oil Formation Tester Response

Prior to drilling the case study well, wireline or LWD formation testers were run in a total of nine wells. Figure 8 presents the formation pressure results. The reported formation pressures are shown relative to the saturation pressure of the Heavy reservoir crude, and the TVD scale is the same as in Fig. 7, i.e., relative to the entry point of the case study well. The Well-1 pressure profile is shown as green squares. The measured data points form a clear oil gradient consistent with the oil sample results reported in Table 2. The Well-2 pressure results, displayed as black squares, were all supercharged. Wells 3 to 5 display distinct oil gradients similar to that observed with the Well-1 measurements. The wells do not plot on the same gradient due to slight location dependent reservoir pressure differences, caused by production pressure depletion effects. All these wells are clearly drilled in the mobile oil column of the Heavy reservoir.

Wells 6 to 8 all demonstrate the same supercharged effect as observed for Well-2. Some Well-7 pressure points were also reported as tight or not built up. The pressures were reported as supercharged if the measured pressure was within 100 psi of the static mud pressure or measured higher than the original reservoir pressure prior to the 1947 production startup. The pressure points flagged as supercharged have been set to the same pressure for illustration purposes rather than using the actual measured pressure, which is only indicative of the static mud pressure at the time of the measurements. The NMR data for these three wells all show the typical missing porosity and excess bound fluid tar indicators. In essence, the supercharged effect reported by the formation tester can be considered another heavy oil/tar indicator.

The formation tester pressure data for Well-9 form a water gradient consistent with the regional aquifer's water salinity. There has been no historic water injection into the Heavy reservoir. Subsequent to Well-9, two additional aquifer wells, one well drilled 40 km (25 miles) away, confirmed that the data of Well-9 was in line with the original aquifer pressure.

The data presented in Fig. 8 reveals that the Heavy reservoir oil column and aquifer are separated by 300 ft TVD of heavy oil/tar[13], which also acts as a pressure barrier. The oil reservoir is ~350 psi to 400 psi depleted due to production, while the aquifer is at its original pressure.

The Case Study Heavy Reservoir Pilot Water Injector Well

Well Placement and Formation Tester Results

As previously shown in Fig. 8, prior to drilling the pilot water injector well, the bottom pressure point from Well-5 defined the lowest known limit of the mobile oil column as slightly below the zero reference depth. The top supercharged pressure point from Well-6 was located ~50 ft below the reference depth. Figure 9 shows these pressure results on an enlarged depth scale. This 50 ft depth band was defined as the target interval for the case study injector.

During placement of the pilot water injector, Well-10, LWD formation tester data was acquired. These results are presented in Fig. 9 with the yellow "X" symbols. Some of these pressure points were supercharged, while other measurements did not meet the supercharged criteria. It is not possible to draw any gradients from these scattered pressure points.

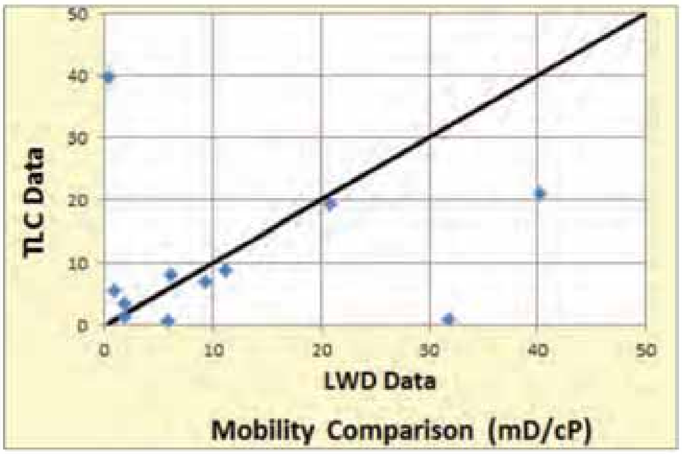

Fig. 11. LWD/TLC formation tester mobility comparison.

Because obtaining calibration oil samples was considered critical to the understanding of this complex fluid system, a TLC formation tester data set was also acquired. The Well-10 TLC pressure data are shown as black-outlined white triangles in Fig. 9. While the LWD measured formation pressures were largely supercharged, the TLC formation tester measured formation pressures were principally in line with expected formation pressure. The TLC data is more scattered than the observed pressures for the oil column wells – Well-1 and Wells 3 to 5 – but an apparent extension of the Well-1 gradient line is evident. The deviation from the gradient line with depth is expected, a result of the increased percent of asphaltenes as a function of depth.

Acquiring the two data sets made a comparison of LWD and TLC acquired formation pressures possible. The pressure results vs. depth are shown in Fig. 9. The selected depths for the TLC run were purposely picked to be the same as those for the LWD run to facilitate a direct comparison. Figure 10 is a comparison plot of the measured pressures. The plot demonstrates that the pressures measured during the LWD run were consistently higher than those measured during the TLC run. The LWD pressure results are considered largely invalid due to a slight supercharging; the exception is the two pressure points plotted close to the unit slope comparison line. Regarding the two LWD pressure points that fully meet the supercharge criteria, it should be noted that they were measured in low mobility rock with some supercharging being apparent, as was also true for the comparable measured TLC pressures. Some of the supercharged LWD pressure points presented in Fig. 9 were skipped during the TLC run; therefore they are not included on the comparison plot in Fig. 10.

Figure 11 presents a comparison of the LWD and TLC formation mobility measurements. This plot demonstrates a much better agreement than is the case for the measured pressure comparison previously presented in Fig. 10. These results are not intuitive given that even a small depth difference in a carbonate can lead to a substantial difference in formation mobility due to reservoir heterogeneity, while the formation pressure is not expected to change much. These results indicate reliable LWD formation mobility measurements, including cases where the measured pressure is clearly supercharged.

Logs and NMR Results

The impetus for conducting an in situ oil viscosity analysis in this well is twofold. The first objective is to enhance the understanding of reservoir fluids along the well path. The well intersects the boundary between the normal and the supercharged pressure measurements previously taken using the formation tester in the field. The NMR viscosity index log could provide additional support for the reasoning that the normal and supercharged pressures are largely driven by oil property variations. Second, the laboratory viscosity analysis of the TLC fluid samples in this well could determine whether the published correlation between the compositional logs and viscosity[7] is sufficiently accurate for the Heavy reservoir application.

Figure 12 presents the conventional and NMR log results, acquired while drilling, on a TVD scale. The well is subdivided into lobes A, B, C, D, E and F, as denoted in Track 5. Note that although the TVD section is short, the logged interval is ~2,700 ft. A log viscosity analysis is performed only where: (a) the conventional and NMR logs are of good quality, i.e., free of spikes and washouts,

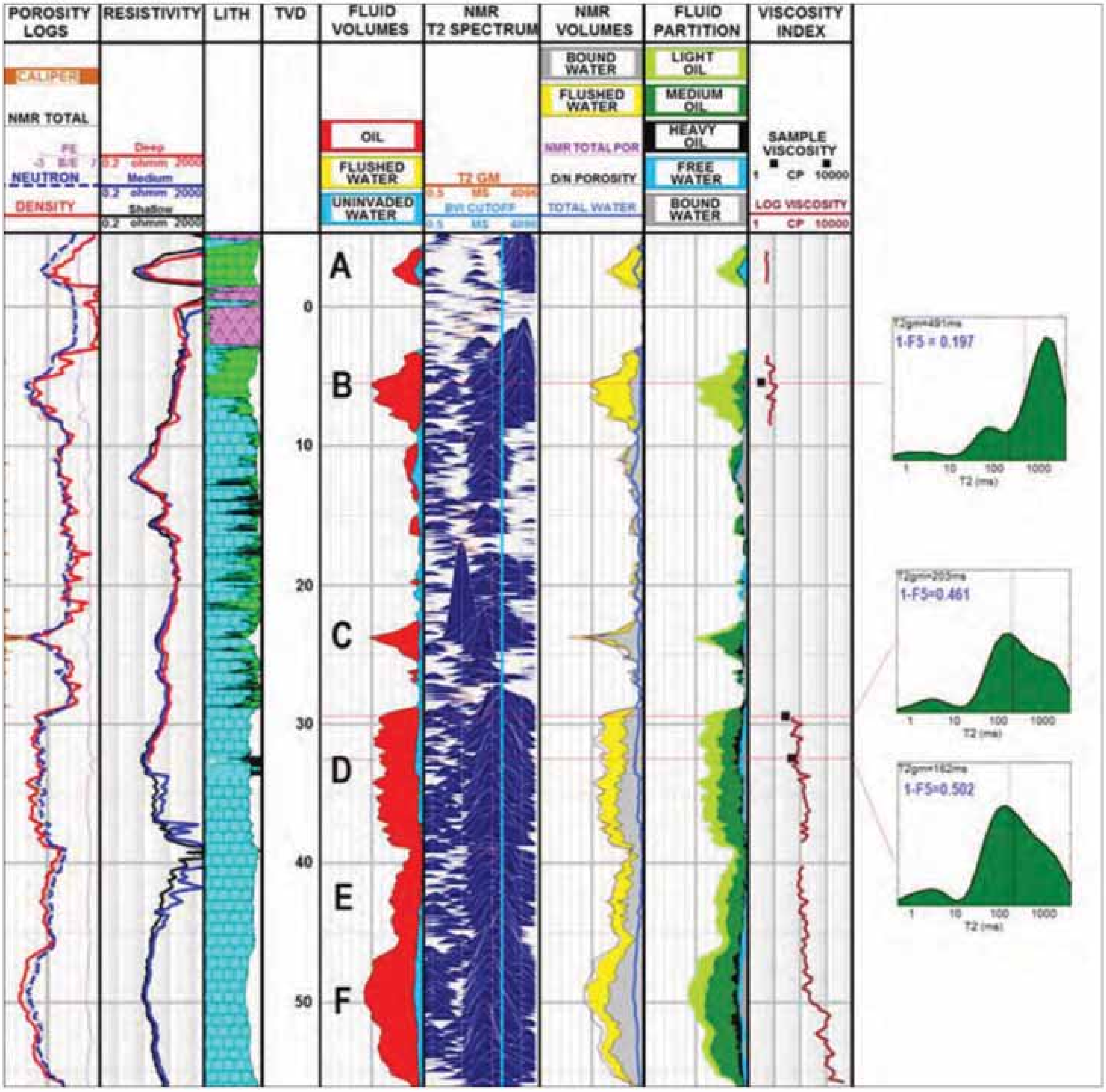

Fig. 12. Well-10 triple combo and NMR log interpretation.

and (b) the oil-filled porosity is at least 5% porosity units.

Lobes A and B are clearly dominated by light oils, as evidenced by the long T2 signatures. Lobe C was not processed and interpreted for viscosity due to the presence of washouts, as indicated by the caliper log in Track 1, and the large spike at ~10 milliseconds (ms) in the T2 spectrum. Lobe D shows elevated bound fluids compared to lobe B. This translates to an increase of an order of magnitude in the viscosity index. A systematic downward increase in viscosity can be observed within the lobe. Surprisingly, the top of lobe E shows a slight decrease in viscosity compared to the bottom of lobe D. Further confirmation is needed to prove whether this is a real phenomenon or a processing artifact due to the low porosity. Lobe F is clearly the heaviest component of this log section. The appearance of missing porosity is similar to that observed in Well-2. Overall, the NMR analysis in Well-10 demonstrates a remarkable heterogeneity in oil viscosity, ranging from a few cP to thousands of cP.

Fluid Parameter	Oil Column	Sample #1	Sample #2	Sample #3	Unit
Sample Reference Depth	<0	7	30	34	ft TVD
API Gravity	27.4	25.2	20.4	18.0	°API
Dead Oil Density	891	903	931	947	kg/m^3
Crude Classification USGS	Light	Light	Light	Heavy	
Crude Classification WPC	Medium	Medium	Heavy	Heavy	
Flash GOR	205	190	183	172	scf/bbl
C1	6.4	6.4	6.1	5.7	mole %
C7+	58	61	64	66	mole %
C10+	43	46	51	53	mole %
In Situ Liquid Density	818	832	855	N/A	kg/m^3
Asphaltenes	N/A	11	23	24	wt%
In Situ Oil Viscosity	~2	3.2	19	45	cP
Reservoir Temperature	215	215	215	215	°F

Table 3. Well-10 oil samples laboratory results

Fluid Parameter	Sample #1	Sample #2	Sample #3	Unit
Sample Reference Depth	7	30	34	ft TVD
Sample In Situ Oil Viscosity	3.2	19	45	cP
NMR Correlation In Situ Oil Viscosity	7.7	38	53	cP
Formation Tester In Situ Fluid Viscosity	~6	24	50	cP
Sample In Situ Liquid Density	832	855	N/A	kg/m^3
Formation Tester In Situ Liquid Density	850	860	890	kg/m^3

Table 4. Well-10 oil samples oil viscosity and liquid density results compared with NMR and formation tester results

Oil Sample Results

Table 3 presents the laboratory results from the three oil samples acquired during the Well-10 TLC formation tester run. The average pressure-volume-temperature (PVT) parameters from the oil column above are included for comparison purposes. One sample was taken from lobe B and two samples were acquired from the top of lobe D. The measured depth difference between sample 2 and sample 3 was approximately 400 ft. The three actual sample points are marked as black squares in Fig. 12, Track 9 (sample viscosity).

The three crude samples were taken over an interval of less than 30 ft TVD. The WPC classification places the top sample as still being medium crude oil (25.2° API), just slightly heavier than the crude in the oil column above, but the two lower samples are classified as heavy oil, 20.4° API and 18.0° API, respectively. The reported flash GOR and methane (C1) content remain surprisingly constant with only a slight light end reduction trend with increasing depth.

Figure 13 displays the asphaltene weight percent (wt%) plotted vs. depth. It is clear from these plots that the increase of aspalthenes is quite dramatic over a short vertical depth interval. When asphaltene content exceeds 35 wt%, it is expected that an impermeable tar mat has been formed. A heavy oil FHZ EoS has been applied for these data and suggests a large asphaltene gradient due to gravitational equilibrium, with cluster-type asphaltene in large particles (6.5 nm).

In the Saudi Arabian field example, Fig. 6, the distance from 10% asphaltene content to the projected oil/tar contact is ~100 ft. In Fig. 13, it is apparent that this distance is significantly shorter at < 50 ft. In Fig. 6, the asphaltene content starts to increase sharply with depth from ~15% asphaltene and up. This may also be the case in the case study field. It is possible that the two lower samples were acquired close to an even more distinct actual oil/tar contact interface. More crude samples are required to fully understand the asphaltene gradient in the vicinity of the oil/tar interface in the Heavy reservoir.

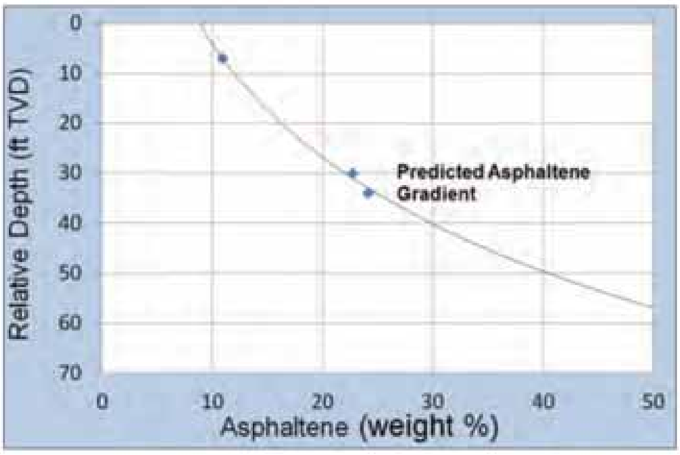

Fig. 13. Asphaltene wt% vs. depth.

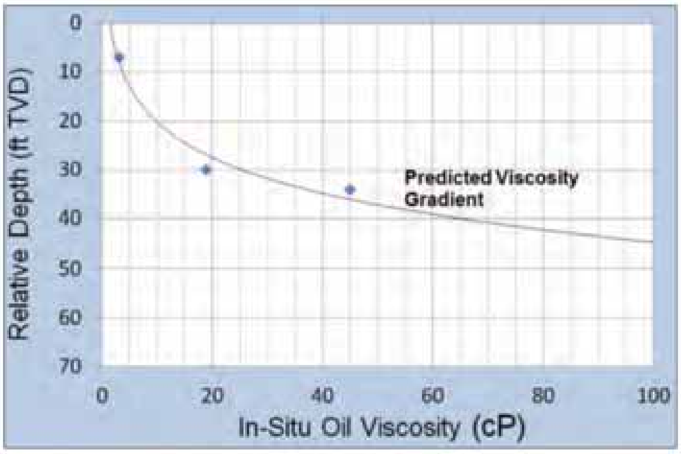

Fig. 14. In situ oil viscosity vs. depth.

The oil viscosity vs. depth data from Well-10 are presented in Fig. 14. Despite the content of the lighter hydrocarbons remaining relatively constant, the effect of the increase in asphaltene percentage creates a very sharp increase in the crude viscosity.

Using the data from Table 3 as input for the two classic crude viscosity correlations, Figs. 2 and 3, makes it clear that Standing (1977)21 is correct in his statement that these correlations do not consider the chemical nature of the hydrocarbons that make up the crude part of the reservoir oil. For the lower sample point, the Beal correlation combined with the Chew and Connally correlation estimates the in situ oil viscosity to be 6 cP to 8 cP, while the laboratory measurement of the physical sample was 45 cP. The reason for this is essentially that the correlations do not take into account the viscosity effect of nanoaggregate cluster particles.

Comparison of Measured Crude Sample Data with NMR Oil Viscosity Correlation and Formation Tester Sampling Data

In Table 4, the in situ oil viscosity and liquid density results from the TLC formation tester fluid analyzer and the NMR viscosity correlation are compared with the laboratory results from the acquired formation tester fluid samples.

Figure 15 presents the NMR oil viscosity correlation plot based on the VT-08 algorithm in Akkurt et al. (2010)7 compared with the sample data. For the log to sample calibration, the NMR and conventional volumetric logs have been averaged to the approximate size of the drawdown volume for the straddle packer system around each sample depth. The graphs next to the log plot in Fig. 12 show the averaged T2 spectrum for each sample depth, with its geometric mean and calibration factor (1-F5) calculated by the VT-08 optimization algorithm[7]. Differences between these NMR spectra at the sample locations indicate shorter decays in the heavier crude. Sample 3 shows very good agreement with the prediction. Sample 2 deviates by a factor of 2, whereas the VT-08 algorithm overestimates sample 1 oil viscosity by a factor of ~2.5. Although NMR logs are of great help in heavy oil detection, it is recommended to improve the existing oil viscosity correlation, VT-08,

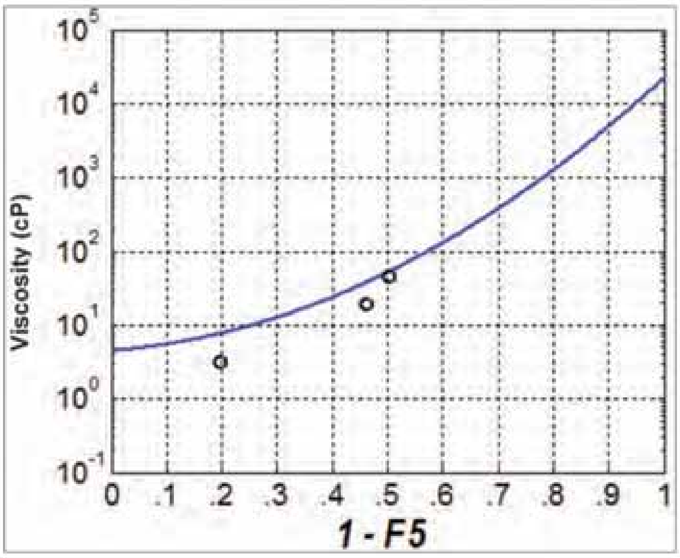

Fig. 15. NMR oil viscosity correlation plot

with calibration to lighter oil samples, < 10 cP, and to extend its validity by including sample results from very heavy oils.

Sampling of heavy oil in a WBM environment is challenging due to the large viscosity contrasts between drilling fluids and the formation fluid[47]. The high viscosity of the hydrocarbon phase usually results in high-pressure drawdown. During WBM formation tester pump out, the high-pressure drawdown is often compounded by the formation of emulsions due to the agitation of heavy oil and drilling fluids. For optimum realtime decisions during sampling, high resolution optical fluid sensors should be utilized to diagnose the formation of emulsions and determine oil fraction during cleanup flow. In addition to the basic parameters of flow rate and flowing pressure, a large number of supporting parameters are measured during sampling operations using the modern technology formation tester to ensure that representative clean samples are acquired.

Figure 16 presents a sampling plot generated while acquiring Sample 3. The flowing pressure and flow rate are represented with the green and pink lines, respectively. The cyan marking signifies the in situ fluid viscosity. As Fig. 16 shows, the measured viscosity was stable at ~50 cP for some time prior to sampling, which compares favorably with the laboratory sample result of 45 cP. As shown in Table 4, a generally good agreement can be observed for the in situ fluid viscosities and liquid densities obtained by the formation tester sensors during sampling, particularly for the two heavier samples. No laboratory liquid density was measured for Sample 3 due to insufficient sample volume, which in itself illustrates the difficulties often experienced in heavy oil sampling operations.

Lessons Learned from the Case Study Pilot Water Injector Well

The case study well was drilled at a high angle slant across the ~50 ft TVD section identified, from previous NMR and formation tester data, as the location of the oil/tar interface. The focus of this well was to maximize the data acquisition to gain as much understanding as possible about this interface for use in future development optimization. The intent was to run a flow meter after the well was put on injection to determine the highest crude viscosity that would accept injection water.

The main lesson learned was that the oil/tar transition zone is a lot shorter than observed in other Saudi Arabian reservoirs with tar mat occurrence. The post-well analyses of the data acquired suggest a large asphaltene gradient due to gravitational equilibrium, with cluster-type asphaltene with large particles (6.5 nm) occurring in the bottom ~25 ft TVD of the well. These large particle asphaltenes subsequently caused the wellbore plugging that prevented access to the reservoir section after suspending the well for tie-in. A clean out operation was unsuccessful as the plugging reoccurred. Current plans are for the well to be sidetracked again in 3 cP to 20 cP oil at the very top of the oil/tar transition zone. NMR and mobility steering will be more actively utilized in future injectors to ensure that the tar mat is not penetrated to safeguard the ability of the well to utilize injected water.

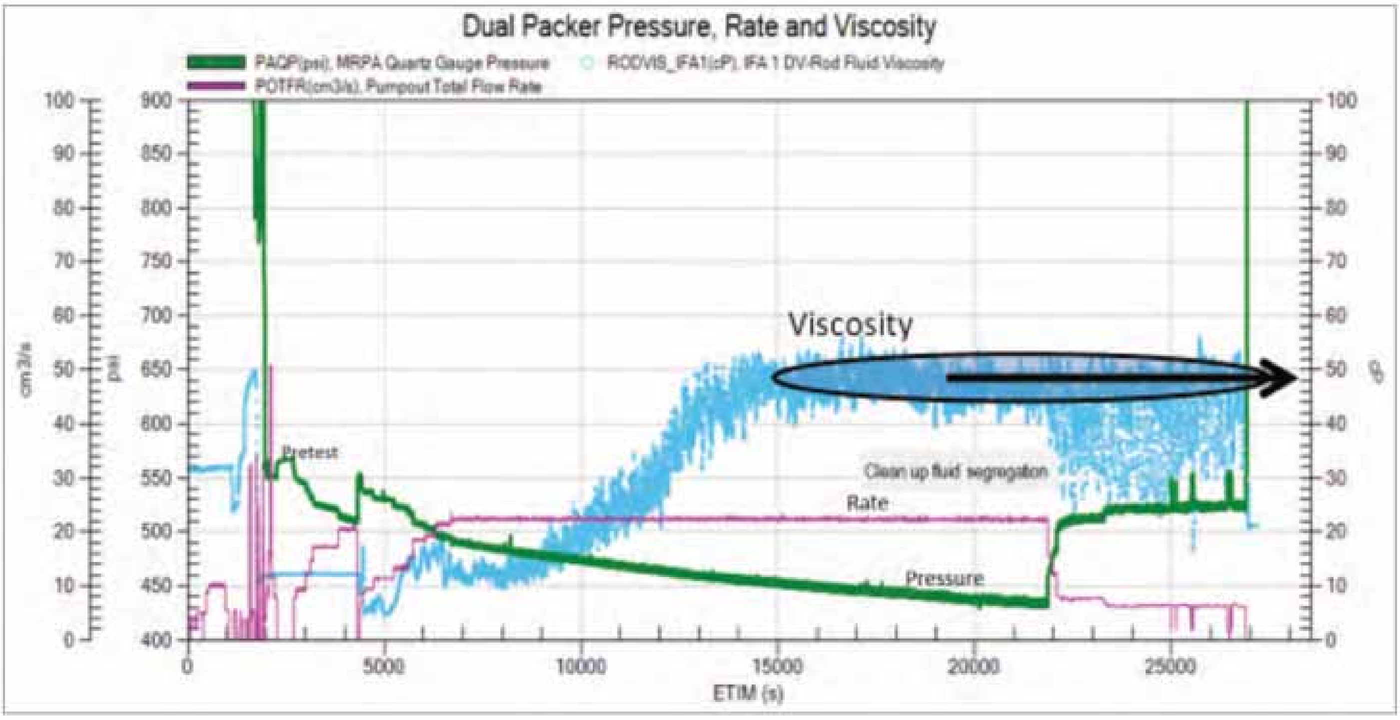

Fig. 16. Formation tester sampling data plot for Well-10 Sample 3.

Conclusions

1. The oil/tar transition zone in this reservoir is a lot shorter than observed in other Saudi Arabian reservoirs with tar mat occurrence. A large asphaltene gradient due to gravitational equilibrium is suggested, with cluster-type asphaltene with large particles (6.5 nm) occurring in the bottom ~25 ft TVD of the well. These large particle asphaltenes caused the wellbore plugging that prevented access to the case study injector reservoir section after suspending the well for tie-in.

2. NMR and mobility steering will be more actively utilized in future injectors to ensure that the tar mat is not penetrated to ensure that the well can be utilized as a water injector.

3. It is recommended to improve the existing NMR oil viscosity correlation with calibration to lighter oil samples, < 10 cP, and to extend its validity by including sample results from very heavy oils.

4. The formation tester in situ liquid density and fluid viscosity measurements acquired during sampling are in realistic agreement with the reservoir crude sample's PVT laboratory measurements. This indicates that accurate realtime in situ fluid property determination is possible with modern formation tester technology.

5. The mobility data acquired by the LWD formation tester compared favorably with the TLC acquired mobility data.

6. In this heavy oil application, the LWD formation tester pressure data all appear supercharged, while the TLC formation pressures were in line with the anticipated reservoir pressure.

Acknowledgements

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This article is an edited version of the paper presented at the 19th SPE Middle East Oil and Gas Show and Conference, Manama, Bahrain, March 8-11, 2015[50].

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Biographies

Stig Lyngra works in Saudi Aramco's Southern Area Reservoir Management Department as a Senior Petroleum Engineering Consultant. Before joining Saudi Aramco in 2001, he worked for Danop in Copenhagen, Denmark, where he was Petroleum Engineering Discipline Leader. For the first 10 years of his career, Stig worked for Conoco as a Reservoir Engineer, Supervising Reservoir Engineer and Commercial Coordinator, and in different joint asset management positions in various offices in the U.S., Norway and the U.K.

He is a member of the European Association of Geoscientists and Engineers (EAGE), the Society of Petroleum Engineers (SPE) and the Saudi Council of Engineers.

In 1987, he received his M.S. degree in Petroleum Engineering from the Norwegian Institute of Technology (NTH) in Trondheim, Norway. Stig also holds a degree in Business Administration from BI Norwegian Business School, Oslom, Norway.

Dr. Gabor G. Hursan is a Petrophysicist in Saudi Aramco's Reservoir Description and Simulation Department. He is Saudi Aramco's focal point for nuclear magnetic resonance (NMR) well logging and formation evaluation. Previously, Gabor worked as a Scientist and Project Leader on NMR technology development at Baker Hughes for 10 years.

He has published several papers and patents, teaches classes in NMR logging and is a reviewer for technical publications. Gabor is a member of the Society of Petroleum Engineers (SPE) and the Society of Petrophysicists and Well Log Analysts (SPWLA).

He received his M.S. degree in Geophysical Engineering from the University of Miskolc, Miskolc, Hungary, and his Ph.D. degree in Geophysics from the University of Utah, Salt Lake City, UT.

Dr. Murat M. Zeybek is a Schlumberger Reservoir Engineering Advisor and a Global Reservoir domain expert based in Saudi Arabia. He joined Schlumberger 19 years ago. He was previously a postdoctoral research associate at the University of Southern California, Los Angeles, CA. Murat also worked for Intera West consulting firm for one year in Los Angeles.

He has published more than 50 papers on analysis/interpretation of wireline formation testers, pressure transient analysis, numerical modeling of fluid flow, fluid flow porous media, water control, production logging and reservoir monitoring.

Murat is a technical editor for the Society of Petroleum Engineers (SPE) journal Reservoir Evaluation and Engineering. He also served as a committee member for the SPE Annual Technical Conference and Exhibition, 1999-2001. Murat has been a discussion leader and a committee member in a number of SPE and American Association of Petroleum Geologists (AAPG) Applied Technology Workshops, including a technical committee member for the SPE Saudi Technical Symposium.

He received his B.S. degree from the Technical University of Istanbul, Istanbul, Turkey, and his M.S. and Ph.D. degrees from the University of Southern California, Los Angeles, CA, all in Petroleum Engineering.

Richard G. Palmer is currently a Petrophysical Supervisor in Saudi Aramco's Reservoir Description and Simulation Department. Since joining Saudi Aramco in 2005, he has held several technical and supervisory positions in the Southern Area.

Richard's specialty is formation evaluation while drilling. Prior to joining Saudi Aramco, he was a Technical Instructor and a Senior Field Engineer with Sperry Drilling Services. Richard has also worked with Schlumberger and has authored several publications and served on technical and organizing committees of professional societies and events.

He received his B.S. degree in Civil Engineering from the University of the West Indies, St. Augustine, Trinidad and Tobago, and his M.S. degree in Petroleum Engineering from the Imperial College of Science Technology and Medicine, University of London, London, U.K.

K. Ahmed Qureshi is a Schlumberger Testing Services, Reservoir Sampling and Analysis (RSA) Business Development Manager based in Saudi Arabia. He began his career in 2001 with Schlumberger, holding a variety of critical positions that led to his extensive knowledge in reservoir characterization for heavy oil, black oil, volatile oils and gas condensates, fluid sampling and analysis. Ahmed is now responsible for technical support in job planning, execution and interpretation in sampling and analysis operations.

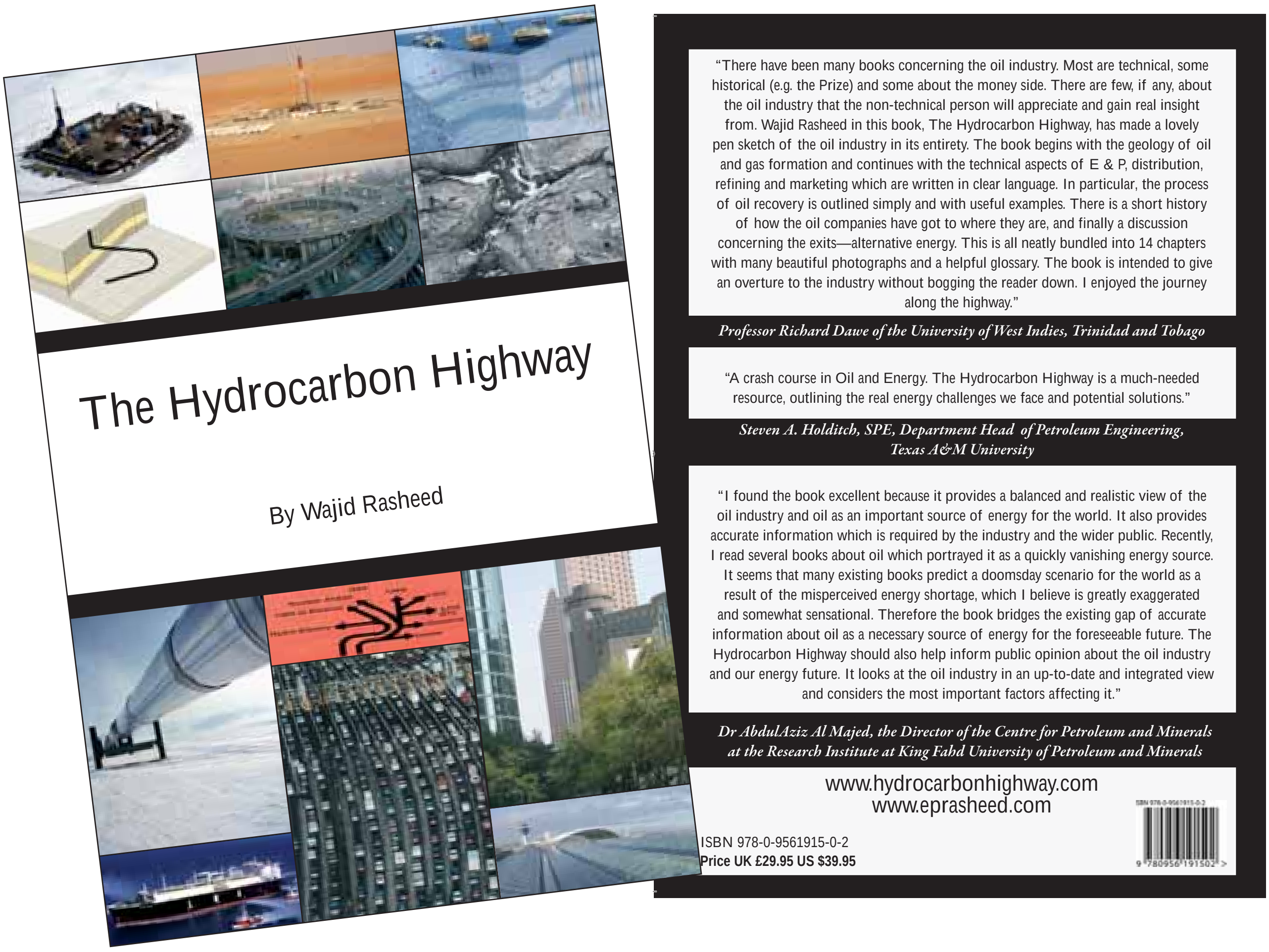
He received his B.S. degree in Chemical Engineering from the Northern Alberta Institute of Technology, Edmonton, Alberta, Canada.

Ahmed is an active member of the Society of Petroleum Engineers (SPE).

Hazim A. Ayyad is a Senior Reservoir Engineer for Schlumberger. He has been working for Schlumberger since 2006 when he started working as a Wireline Field Engineer in Saudi Arabia. Then Hazim moved to the Reservoir Data Interpretation Team in Saudi Arabia before moving to Kuwait in 2010. He is currently leading the reservoir and production teams for wireline in Kuwait.

Hazim received his B.S. degree in Petroleum Engineering from King Saud University, Riyadh, Saudi Arabia.

World Oil and Gas Production



Here we focus on the worlds' oil and gas major producers (OPEC and non-OPEC) from an export perspective. We detail the dominant oil companies behind world exports as well as each country's production level, reserves and capacity.

Although conventional oil production and reserves are globally dispersed, the highest concentration is in the Middle East. Since the 1960s, this region averages nearly 30% of total global oil production and controls 61% of world oil reserves. OPEC itself produces 43% of world oil production and controls 75% of proved oil reserves. Of the 15 countries worldwide that produced 2 MMbbl/d or more of total liquids for export, seven were OPEC members[1].

The Oil Is Ours

Any consideration of OPEC must begin with its importance as a reserves holder and major oil exporter. From this perspective, only producers that export more than 1 MMbbl/d to the global markets are considered (net of any imports for national refining or consumption). Net exporters play an extremely important role in satisfying demand in global markets because their oil supplies are real exports over and

> "The combined population of OPEC countries is just over half a billion people and most are dependent on oil revenues for sustaining their economies."

above their domestic needs and are therefore known sources of future oil supply.

Every Move You Make

Undoubtedly, every move made by OPEC gets as much headline ink around the world as any Central Bank decision. It is watched by the major press agencies who have assigned some of their brightest minds to cover the decisions that usually come out of the Austrian capital. Sitting permanently as an inter-governmental organization, OPEC has 11 members: Algeria, Indonesia, the Islamic Republic of Iran, Iraq, Kuwait, the Socialist People's Libyan Arab Jamahiriya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela. The combined population of OPEC countries is just over half a billion people and most are dependent on oil revenues for sustaining their economies. For these countries, oil is the platform for economic, social and political growth[2].

OPEC currently produces about 43% of the world's crude oil, but that is forecast to grow to more than 50% in the next quarter of a century. OPEC has 75% of the world's oil reserves and this will enable it to expand oil production to meet the growth in demand. In order to expand OPEC output, the oil industry needs the oil price to remain at a profitable level. Oil producers invest billions of dollars in exploration and infrastructure (drilling and pumping, pipelines, docks, storage, refining, staff housing, etc.) and a new oil field can take three to ten years to locate and develop. Commercialisation and profitability are complex issues which are dealt with—in the next Chapter[3].

All OPEC countries are sensitive to oil-price fluctuations because of the large contribution oil revenues make to state coffers. As one would expect, high oil prices yield larger gains in revenues from oil exports; the opposite is also true.

Before getting into detail about the major OPEC exporters of oil, it is worth mentioning the Gas Exporting Countries' Forum (GECF). This forum was formed in Teheran, Iran in 2001 with a view to managing global gas reserves and providing a stable and transparent energy market. The GECF consists of 15 gas-producing countries: Algeria, Bolivia, Brunei, Egypt, Equatorial Guinea, Indonesia, Iran, Libya, Malaysia, Nigeria, Qatar, Russia, Trinidad and Tobago, the United Arab Emirates and Venezuela. Five of these countries – Russia, Iran, Qatar, Venezuela and Algeria – control nearly two-thirds of the world's gas reserves and account for 42% of its production. The GECF has a liaison office in Qatar which is 'formulating a gas-trading model to share knowledge of supply and demand and create a level playing field in negotiations

> "Famous for its ability to 'swing' world markets into 'equilibrium', Saudi Arabia is commonly recognised as the world's leading oil exporter."

with international operators'. It is likely that the GECF will become a gas OPEC. Russia has offered to permanently host the organisation at the most recent meeting in Moscow where Equatorial Guinea and Norway were attending as observers[4].

Saudi Arabia

Saudi Arabia produced a daily average of 10.4 million barrels of oil (MMbbl) in 2007, consumed 2.15 MMbbl/d and exported 8.25 MMbbl/d.

Famous for its ability to 'swing' world markets into 'equilibrium', Saudi Arabia is commonly recognised as the world's leading oil exporter. It sits atop a quarter of world oil reserves, a fifth of international exports and more than a tenth of total world production. It has a refining capacity of 3 MMbbl/d. One of the Kingdom's goals is to maintain sufficient spare production capacity so that it can stabilise the market in a given situation. Leaving production capacity idle, and therefore forfeiting revenues, is commendable on the part of Saudis. Whether such ability continues to exist, and averts the energy crises resulting from supply level, will be dependent on investment in refining capacity and technology.

Geology

The Saudi Geographical Survey identifies the Phanerozoic cover as the geologic range of interest for oil and gas reserves. The Phanerozoic ranges from the Saudi Arabian Paleozoic (540-250 millions of years ago [Ma]) to the Cenozoic (65 Ma to recent) and it crops out as relatively flat beds of sedimentary rocks such as sandstone, siltstone, limestone, evaporites (salt deposits), and volcanic rocks. The youngest deposits in the region include coral limestone and unconsolidated sand, silt, gravel and sabkhah, which accumulated in the sand seas of the Rub al Khali and An Nafud and were deposited on to dried-up lake beds, valleys (wadis) and coastlines.

Reserves

Estimates place Saudi Arabia's proven reserves by the end of 2007 as at least 264.2 billion barrels including new finds and the mega-projects listed below. This is a consensus figure based on the inclusion of probable and possible reserves based on the Society of Petroleum Engineers (SPE) reserves criteria[5].

Although there has been recent speculation of a lower volume of reserves primarily due to watercut, this is a red-herring as the occurrence of increased water production and re-injection are standard reservoir conditions and secondary recovery mechanisms. This is discussed more fully in *Chapter 9: Mature Fields*. Based on current reserves data, it is fair to say that the last barrel of oil will likely be from Saudi Arabia.

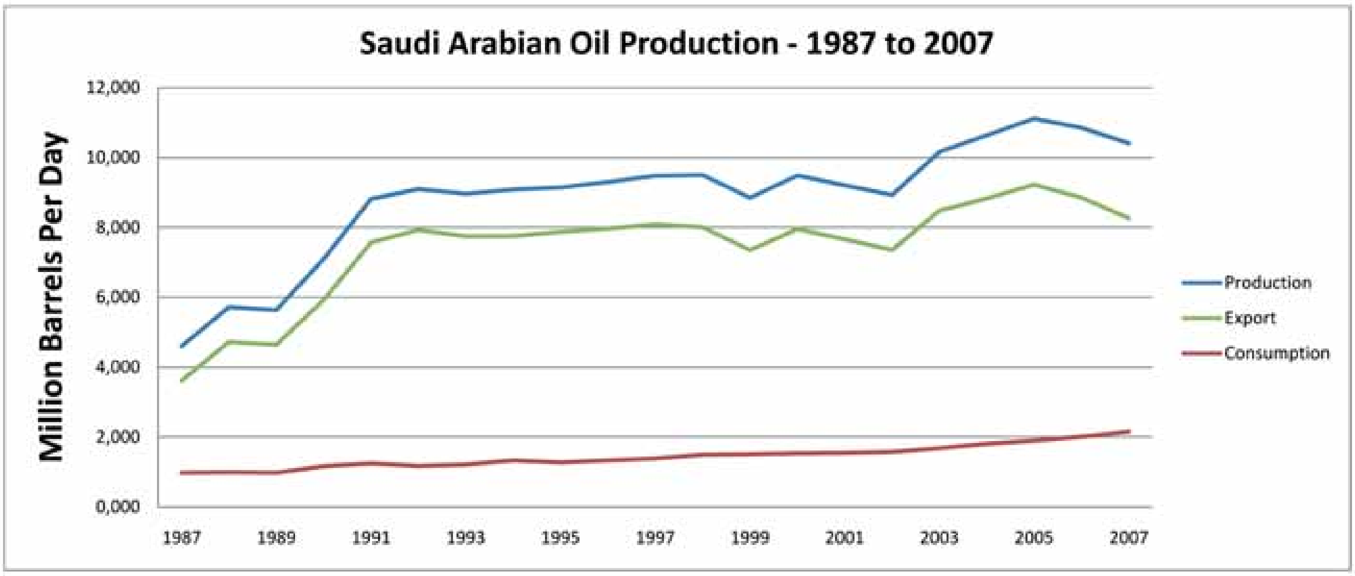


Table 1 - Saudi Arabian Oil Production (1987 to 2007)

Saudi Aramco

Saudi Aramco is the modern day legacy of the Arab American Company. It is as technically sophisticated and diverse as any major oil company with approximately 86% of its staff as Saudis and the remaining 14% employees from more than 50 countries. Saudi Aramco has invested heavily in reservoir and E & P technology and runs one of the world's largest carbonate research centres encompassing reservoir modelling, dynamics and visualisation. Contrary to the popular belief that low-cost onshore environments have limited technology applications, Saudi Aramco runs the latest in downhole drilling and completions technology such as rotary steerables, high-end logging and formation evaluation tools as well as maximum reservoir contact wells (see *Chapter 7: Pregnant Ladies and Fish Bones*). The company's flagship Research and Development Centre (R&DC) employs 350 research staff working on seismic, drilling, completion and production projects[6].

In spite of the recent surge in its oil income, stabilisation funds and foreign investments, Saudi Arabia is seeking to diversify its industrial and financial base beyond petroleum and has initiated several knowledge and industry based projects such as the King Abdullah University of Science and Technology[7].

Iran

Iran produced 4.4 MMbbl/d through 2007. It still made net oil exports of 2.78 MMbbl/d considering that Iranian domestic oil consumption was 1.62 MMbbl/d[8].

Iran's oil and gas sector is dominated by the National Iranian Oil Company (NIOC). Foreign companies are active in Iran and include Gazprom, Japanese National Oil Company (JNOC), PETRONAS, StatoilHydro and Total. Oil and gas ventures are subjected to 'buy-back' arrangements whereby ownership is retained by the Iranian state. NIOC has made several large discoveries, notably the Azadegan field which is yet to be developed and has recoverable reserves of 9 billion barrels (bbls). Other noteworthy fields include Ferdowsi (30.6 billion bbls), Moud (6.63 billion bbls), Zagheh (1.3 billion bbls), Bangestan (600 MMbbls) and Kushk. Iran relies heavily on oil export revenues for approximately 80% of total export earnings and 40% of the government budget[9].

Venezuela

Venezuela produced 2.63 MMbbl/d in 2007 and consumed 596,000[10] MMbbl/d, therefore it exported 2.03 MMbbl/d[11].

Petróleos de Venezuela S.A. or PdVSA is the state-owned oil company of the Bolivarian Republic of Venezuela and it is responsible for the majority of oil production. Although IOCs such as ConocoPhillips,

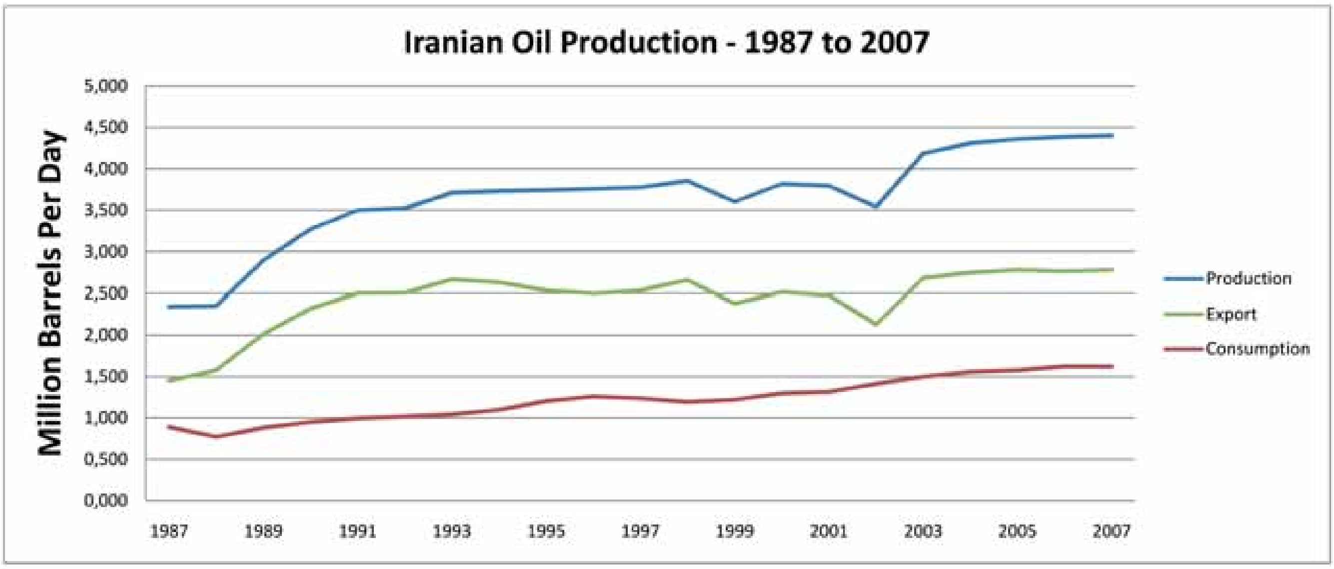


Table 2 - Iranian Oil Production (1987 to 2007)

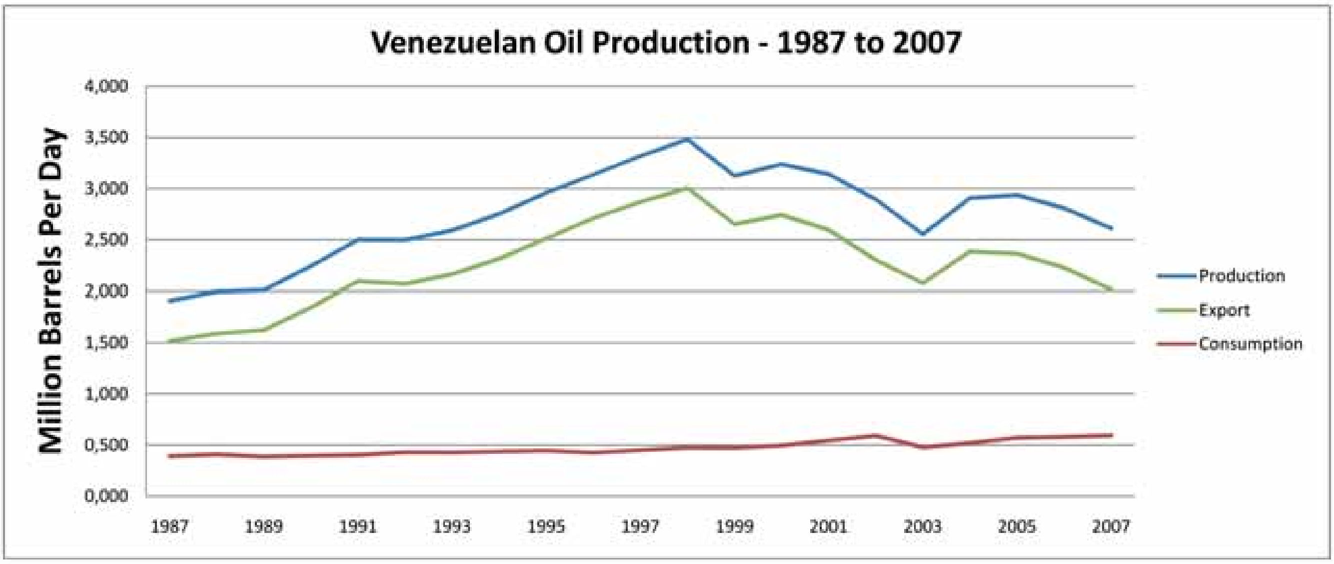


Table 3 - Venezuelan Oil Production (1987 to 2007)

Chevron and Petrobras are present, they must work with PdVSA.

The country is split into two oil provinces: Maracaibo in the West and the 'Oriente' (Spanish for East), both of which share the same prolific source rock. Oil accumulations are found in Cretaceous limestones and in overlying tertiary sandstones. The East Venezuela Basin is asymmetrical with a long, gently-dipping, southern flank. Oil has migrated up this flank to shallow depths where it has been weathered and has generated sizeable heavy oil and bitumen deposits at depths of 1640 to 4921 ft (500 to 1500 m) along the Orinoco River[12].

Oil export revenues are important for Venezuela because as much as 45% of government revenues come from oil[13].

Based on company figures, PdVSA aims to raise

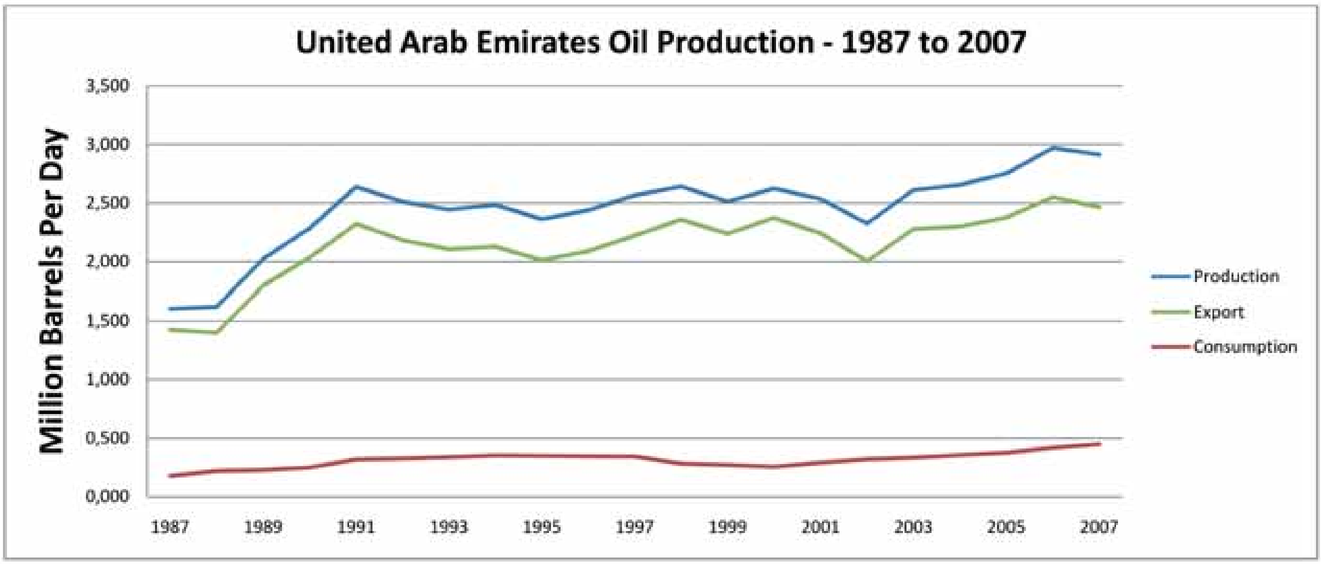


Table 4 - UAE Oil Production (1987 to 2007)

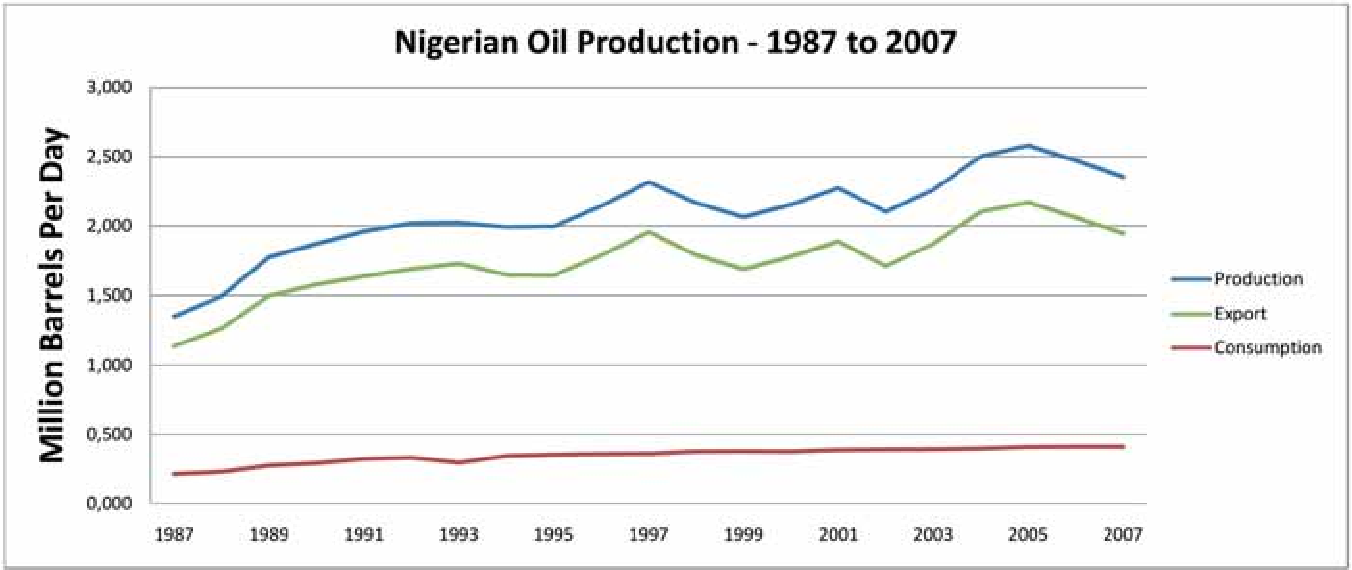


Table 5 - Nigerian Oil Production (1987 to 2007)

the country's crude oil production capacity to 5.5 MMbbl/d by 2010[14].

UAE

In 2007, the United Arab Emirates or UAE produced 2.9 MMbbl/d, consumed 0.45 MMbbl/d and exported a total of 2.45 MMbbl/d[15].

The Abu Dhabi National Oil Company (ADNOC) is the major oil and gas producer in the UAE. It is responsible for all operations in Abu Dhabi and owns the Abu Dhabi Company for Onshore Oil Operations (ADCO), which operates in onshore and shelf waters in the Emirates.

ADCO produces oil from five main fields: Asab, Bab, Bu Hasa, Sahil and Shah. The Zakum Development Company (ZADCO) is responsible for oil development and production from the Upper Zakum field. It also operates Umm Al Dalkh and Satah on behalf of its

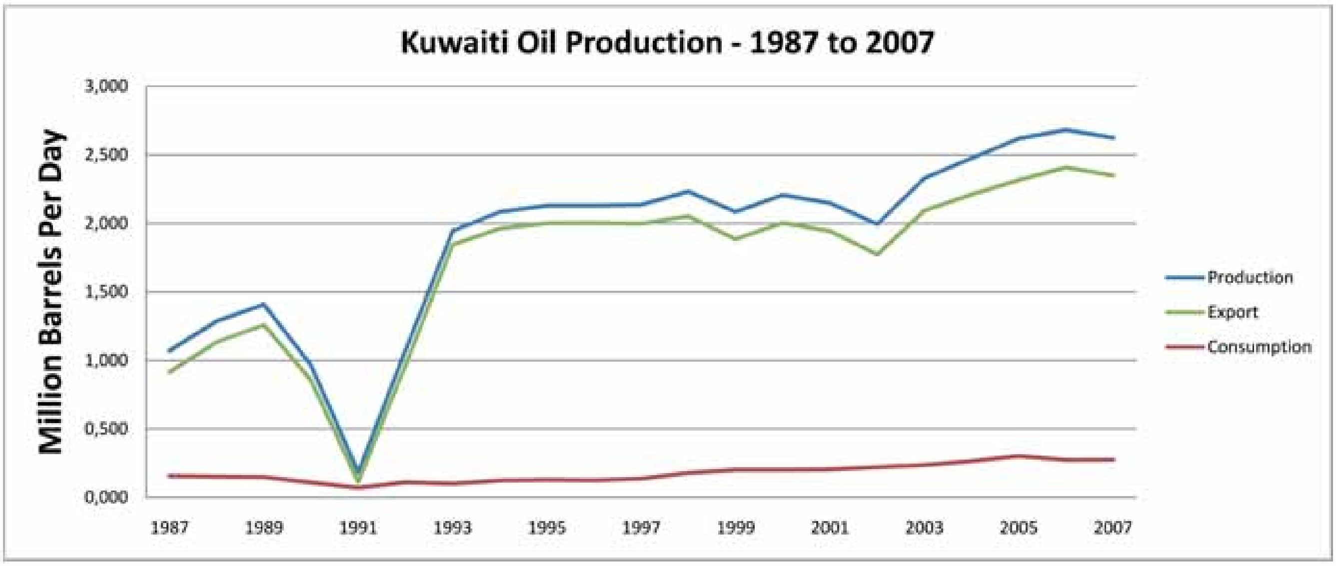


Table 6 - Kuwaiti Oil Production (1987 to 2007)

partners. There is also the National Drilling Company (NDC) for onshore and offshore drilling. As with other OPEC countries, relatively strong oil prices and revenues in recent years have helped to significantly improve the UAE's economic, trade, and budgetary situations[16].

The UAE economy is relatively diversified and is in transition from a purely oil-based economy to one that is increasingly moving towards services such as tourism, banking, re-exports, information technology, etc. Privatisation has moved ahead relatively quickly, and the country has set up various Free Zones to encourage foreign trade and investment. These moves have helped to moderate the effects of fluctuating oil prices and revenues[17].

Nigeria

Nigeria produced 2.36 MMbbl/d in 2007 and is estimated to have consumed 0.4 MMbbl/d, hence exporting approximately 1.96 MMbbl/d[18].

Most of Nigeria's crude oil production, comprising ten major crude streams (including condensate), is light sweet crude, API grades 21º-45º, with a low sulphur content. Nigeria's marker crudes on the international oil market are Bonny Light and Forcados. Numerous fields are known across the Niger Delta, and some of the more marginal fields have become the focus of redistribution with the debate favouring private local companies[19].

Nigeria's oil and gas industry is funded through Joint Ventures (JVs), with the National Petroleum Corporation (NPC) as a major shareholder and each oil company holding a share. The largest JV is operated by the Shell Petroleum Development Company (SPDC) and produces nearly half of Nigeria's crude oil, with an average daily output of approximately 1.1 MMbbl/d. Other companies working with the NPC, include ExxonMobil, Chevron, ConocoPhillips, Total and Agip. The remaining funding arrangements comprise Production Sharing Contracts (PSCs), which are mostly confined to Nigeria's deep offshore development programme.

A number of the oil companies prospecting in the offshore blocks in the Niger Delta, have built up considerable deepwater experience in the Gulf of Mexico (GOM), the Gulf of Guinea (particularly in Angola), and the North Sea. Technology developments have reduced the cost of exploration and production, although profitability is reckoned at levels exceeding 5,000 bbl/d per well.

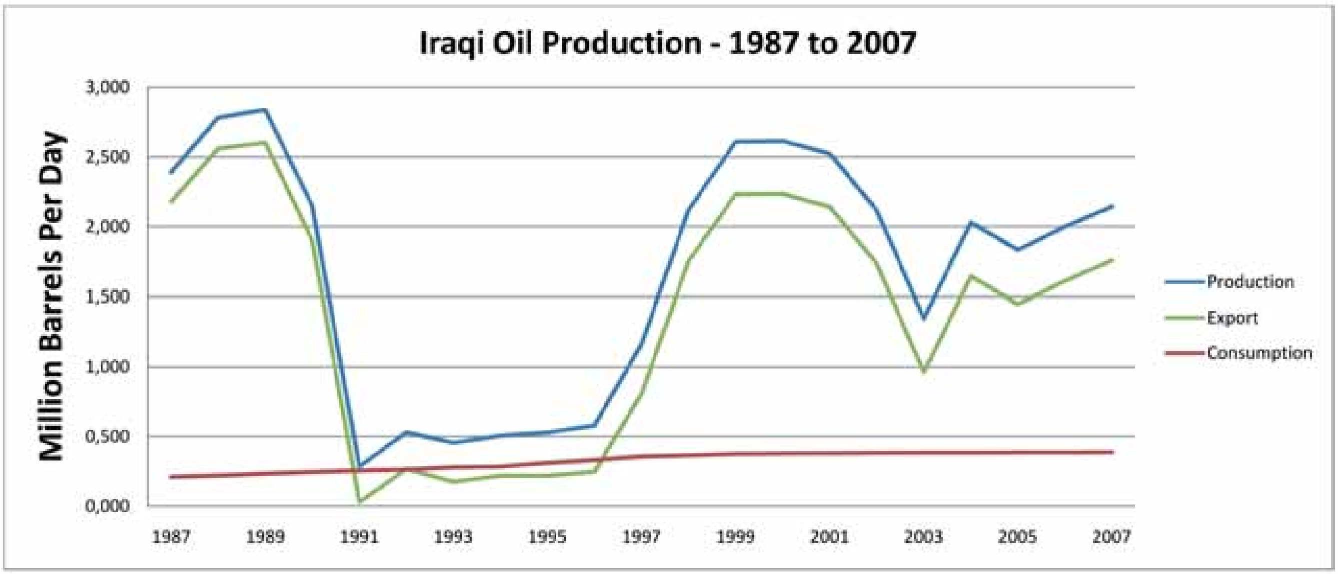


Table 7 - Iraqi Oil Production (1987 to 2007)

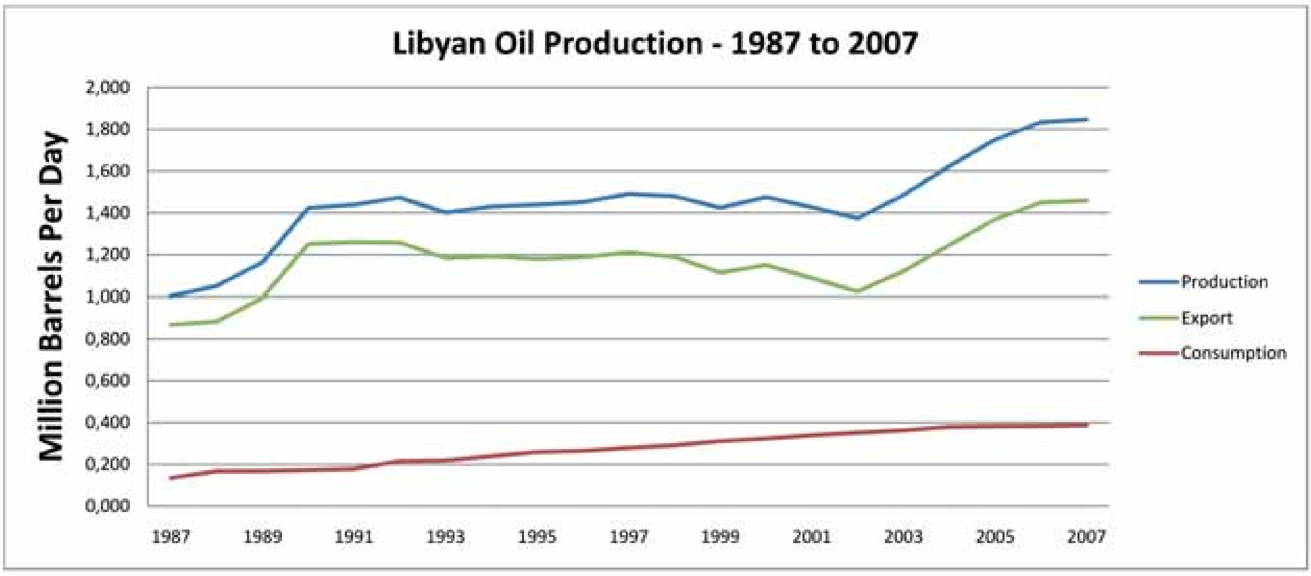


Table 8 - Libyan Oil Production (1987 to 2007)

A number of major discoveries have been recorded with Shell's Bonga and Chevron's Agbami field both estimated to hold one billion barrels each. These successes have turned the focus of Nigerian exploration into deep waters which remains a highly prospective area[20].

Kuwait

Kuwait produced 2.62 MMbbl/d in 2007 and consumed 0.28 MMbbl/d allowing it to export 2.34 MMbbl/d.

The Kuwait Petroleum Corporation (KPC) was founded in 1980 with the Government of Kuwait as its sole owner. It owns most of the oil and gas concerns in Kuwait such as the Shuaiba, Al Ahmadi and Mina Abdulla refineries. It is a shareholder, along with BP, of the Kuwait Oil Company (KOC) which produces approximately 2 MMbbl/d. KOC aims to increase production by developing more of the country's light oil and gas reserves in the Jurassic and Paleozoic formations respectively[21].

Iraq

Iraq's oil production fell severely from 2000, from 2.61 MMbbl/d to a low in 2003 of 1.34 MMbbl/d. Iraq's oil production, however, has regained capacity and it is worth noting that Iraqi E & P costs are amongst

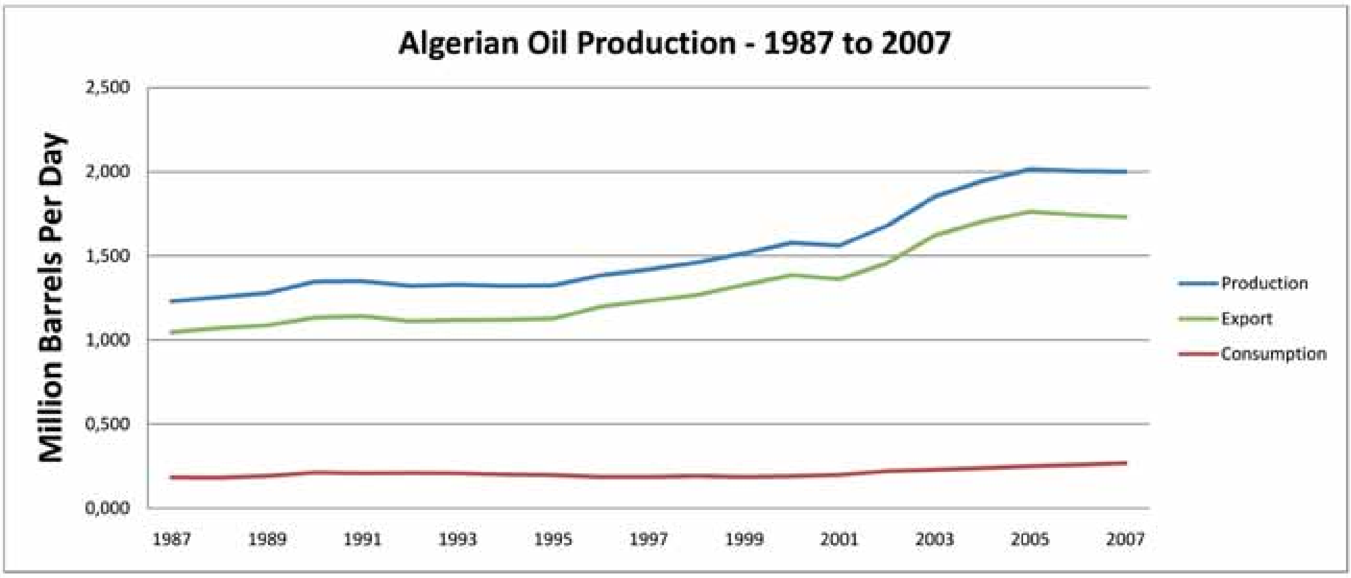


Table 9 - Algerian Oil Production (1987 to 2007)

the lowest in the world and, given the application of commonly available technology, the country has the potential to produce at far higher levels.

During 2007, Iraq produced 2.145 MMbbl/d and is estimated to have consumed 0.38 MMbbl/d. It is therefore estimated that Iraq exported 1.76 MMbbl/d[22]. Iraq has 115 billion barrels of proven oil reserves, placing it third worldwide after Saudi Arabia and Iran. Oil production in Iraq is concentrated in two oilfields: Rumaila which has 663 producing wells and Kirkuk which has 337 producing wells.

Libya

In 2007, Libya produced 1.85 MMbbl/d and was estimated to have consumed 0.30 MMbbl/d, thereby exporting 1.5 MMbbl/d[23].

Exploration onshore is concentrated in the Sirte, Murzuq and Ghadames Basins as well in the areas of Kufra and Cyrenaica.

Among Libya's largest onshore fields are the Amal field and the Gialo field, both with reserves of over four billion barrels of oil. Other large fields occur in the Sarir complex in southern Cyrenaica which is in the southeastern margin of the Upper Cretaceous-Tertiary Sirte Basin, which is one of the most highly productive oil basins in North Africa[24].

The majority of Libya's oil and gas is found onshore in three geological trends of the Sirte Basin. In the West, the known fields are Samah, Beida, Raguba, Dahra-Hofra and Bahi. In the north-centre of the country, there are the giant oilfields of Defa-Waha and Nasser and also the large Hateiba gas field and an easterly trend containing Sarir, Messla, Gialo, Bu Attifel, Intisar, Nafoora-Augila and Amal[25].

In early 2005, Libya held its first round of licences with Occidental, Woodside Petroleum, the UAE's Liwa and Petrobras gaining licences. The country continues to attract foreign investment and now has a relatively diverse E & P sector.

Algeria

In 2007, Algeria produced 2.0 MMbbl/d, consumed 0.27 MMbbl/d, and exported 1.73 MMbbl/d. Additionally, Algeria is an established Liquefied Natural Gas (LNG) exporter serving European and US markets.

The petroleum sector is dominated by the NOC Sonatrach which is owned by the Algerian government. Through its subsidiaries, the company has a domestic monopoly on oil production, refining, and transportation. Upstream activities, how-ever, are open to foreign companies, who must work in partnership with Sonatrach, with the company in question usually holding majority ownership in production-sharing agreements. The most notable of these companies are Anadarko, BHP, BP and Repsol[26]. Algeria's

> "OPEC decisions can equally affect oil exporting countries. OPEC decisions can influence oil price trends (other things remaining equal), which can affect the revenues realised by oil exporters."

Saharan Blend oil is a preferred sweet and light crude approximately 46° API. As of 2007, Algeria had 160 trillion cubic feet (Tcf) of proven natural gas reserves. Hassi Messaoud is the country's largest oilfield and is owned by Sonatrach with average production of 0.350 MMbbl/d of sweet and light 46° API crude. The Hassi Messaoud complex is reckoned to hold six billion barrels and is expected to provide approximately 0.7 MMbbl/d over the next five years. Sonatrach also operates the Hassi R'Mel field, which produced 0.18 MMbbl/d of 46.1° API crude. Anadarko produces approximately 0.5 MMbbl/d from the Hassi Berkine and Ourhound fields in eastern Algeria and is also developing further assets.

Major non-OPEC Producers

Major non-OPEC producer countries are the US, Russia, Mexico, China, Canada and Norway. The focus here, however, should be on producers that make significant oil exports after allowing for their national consumption: for example, in 2007 the US produced 6.9 MMbbl/d (8% of world crude oil) and China produced 3.7 MMbbl/d (4.8%. of world crude oil)[27]. These countries , however, consume far more than they produce. In 2007, oil consumption for the US was 20.7 MMbbl/d and for China 7.89 MMbbl/d, making these two countries the world's largest net oil importers. In the case of Canada, the oil produced was 3.30 MMbbl/d and consumption was 2.30 MMbbl/d, making net exports 1.0 MMbbl/d in 2007[28].

Consequently, after stripping out domestic consumption, significant non-OPEC* net oil exports lie in the hands of four countries: Russia, 7.28 MMbbl/d; Norway, 2.34 MMbbl/d; Mexico, 1.45 MMbbl/d; and, Kazakhstan, 1.27 MMbbl/d.

Considering net exports, the importance of OPEC exports becomes strikingly clear as ten of the world's major oil exporters (more than one MMbbl/d) belong to OPEC, a total which is roughly double that of the combined non-OPEC exports[29,30,31].

Non-OPEC and OPEC Major Net Exporters of Oil 2007

Non-OPEC oil production has risen in the past few years, notably from Russia which briefly displaced Saudi Arabia as the world's foremost crude oil producer in 2006 and from rising exports from central Asian states such as Kazakhstan[32]. It is recognised, however, that only Saudi Arabia retains the existing spare capacity required to meet the predicted total world oil demand growth over the next five years. Other areas such as Offshore West Africa (Angola) and Offshore East Brazil are increasing production, with Brazil reaching a narrow margin of self-sufficiency in April 2006. Neither, however, is likely to make a major impact on world oil exports over the next decade especially considering the high costs associated with these deepwater developments[33].

A Wider OPEC?

It is often reported that the ripples of OPEC decisions are always most keenly felt by consumers 'at-the-pump' in importing countries; however, OPEC decisions can equally affect oil exporting countries. OPEC decisions can influence oil price trends (other things remaining equal), which can affect the revenues realised by oil exporters. This has been noted by certain non-OPEC countries which may see certain advantages of some degree of co-ordinated production policies with OPEC. Russia and Norway are two examples, although they have not always actually carried out co-ordination.

While the stated volumes of non-OPEC production (or export) restrictions have usually been small, the participation of these non-member countries can lead to accentuated effects as market analysts attribute value to such actions and can lead to even greater cohesion with OPEC in restricting output. In this way, the effect of wider co-ordination with OPEC policies is not often recognised[34]. High or increasing oil prices since 2000, however, have led non-OPEC to maximise production rather than restrict output. Whether intended or not, since 2000 there have been similar actions from OPEC and non-OPEC exporters. Since 2003, Mexico, Norway, Russia, Oman and Angola have all pushed to maintain or increase production in the high price environment. The peak prices of mid 2008 of US $147 and the subsequent collapse of oil prices to US $35 by the end of 2008 prompted dramatic production cuts from OPEC. Russia participated as an 'observer' in OPEC meetings, but made no production cuts.

World Oil Consumption

Of the 85.22 MMbbl/d of oil consumed worldwide in 2007, OPEC countries together consumed approximately 7.6 MMbbl/d, which again shows their importance in sustaining production. Of the world's top ten oil consumers in 2007, only Russia has significant net oil exports. The remaining top consumers are listed as the world's largest oil importers, with the exception of Brazil, which reached oil self-sufficiency in April 2006[35].

Estimates of proven oil reserves vary, but the essential fact remains that most of the world's proven oil reserves are held by OPEC. According to OPEC statistics, world proven reserves are 1.15 trillion barrels of proven reserves, of which OPEC holds 0.9 trillion barrels[36]. According to BP's statistical review, world proved reserves are 1.2 trillion barrels, of which 0.9 trillion are held by OPEC[37] and 0.30 trillion are held by non-OPEC members. According to the US Energy Information Association (EIA) which bases it figures on the Oil and Gas Journal, total reserves are 1.3 trillion of which 0.85 trillion are held by OPEC[38]. The remaining reserves are split between Russian, the Former Soviet Union (FSU) and Canada.

Non-OPEC reserves include Canadian unconventional reserves which have higher production costs[39]. In the future, the inclusion of unconventional oil reserves for other countries may positively affect OPEC member Venezuela, as well as non-OPEC countries such as Canada, Brazil and Australia. The reserves of non-OPEC countries are being depleted more rapidly than OPEC reserves. Non-OPEC reserves-to-production ratio – an indicator of how long proven reserves will last at current production rates – is approximately 26 years for non-OPEC. OPEC reserves-to-production is 73 years based on 2007 crude oil production rates. Combining the longer reserves life and the high net oil exports figures, it is clear to see just how important OPEC production is over the long term[40].

Refinery Capacity

Countries that have high petroleum demand tend to have large refinery capacities due to proximity to end consumers. Exemplifying this, the US is the world's largest consumer and has the highest refinery capacity in the world, with 20% of the world's crude oil refinery capacity (17.59 MMbbl/d of a total 87.91 MMbbl/d).

Russia's refinery capacity stands at an estimated 5.58 MMbbl/d. Japan (4.56 MMbbl/d) and China (7.5 MMbbl/d) are the only remaining countries with refinery capacities exceeding 3 MMbbl/d[41]. There are several countries that are important to world trade in refined petroleum products despite very low (or non-existent) levels of crude oil production. For instance, Caribbean nations (including US and European territories) have very limited oil production (233,000 bbl/d in 2007), but a refinery capacity of about 2.6 MMbbl/d. Much of this refined product is exported to the US[42].

Review of Major Non-OPEC Oil Exporters

Russia

Russia produced 9.98 MMbbl/d in 2007 and consumed 2.7 MMbbl/d in the same period. The country therefore exported 7.28 MMbbl/d during 2007 making it the second largest oil exporter after Saudi Arabia.

After the break-up of the Soviet Union in the early

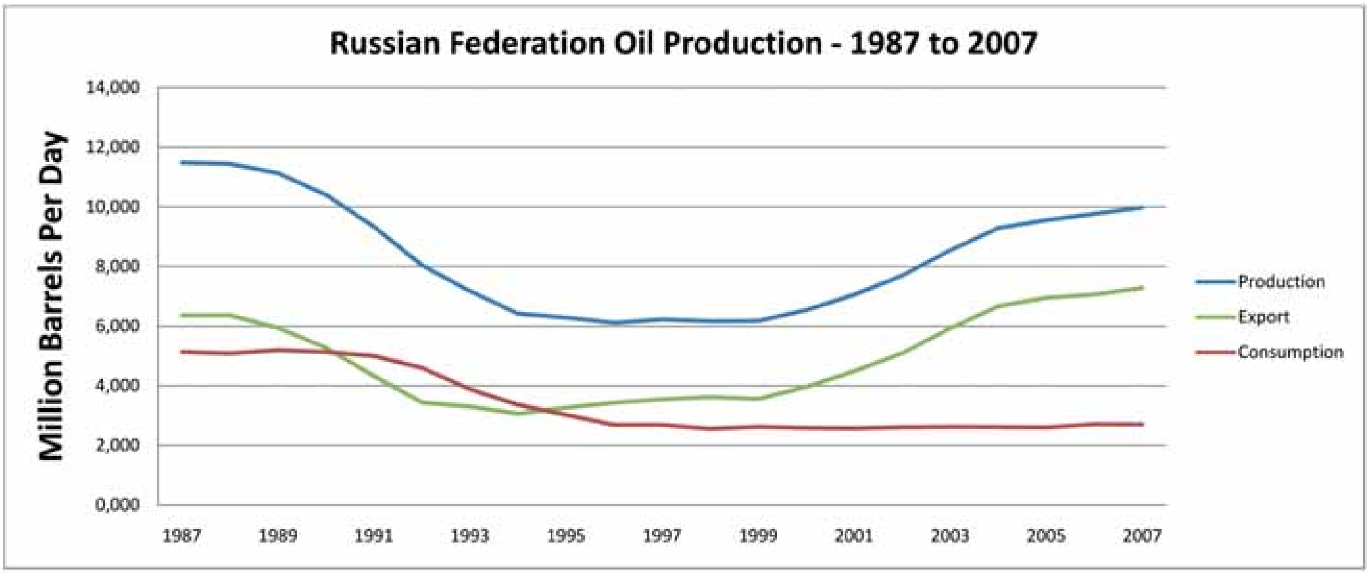


Table 10 - Russian Federation Oil Production (1987 to 2007)

1990s, the nature of the Russian oil industry changed dramatically. From being geographically dispersed and technically fragmented with numerous state-owned entities, the State set about vertically integrating these companies in the likeness of IOCs. Behind the scenes inter-related forces were at work. Central Asian states such as Kazakhstan became sovereign nations and were developing their respective oil and gas industries rapidly and independently. These Central Asian Republics had succeeded in attracting and retaining oil and gas investment capital. The Russian government acted to restructure its own industry, not only to attract investment, but also to integrate its NOCs so that they could compete both at home and overseas. It also acted to counter market volatility by channelling windfall oil revenues into a stabilisation fund that came into effect in 2004[42].

Today, several Russian oil companies compete globally and the stabilisation fund is believed to be worth almost US $60 billion—approximately 7.5 percent of the country's Gross Domestic Product (GDP). Taxes on oil exports have been raised significantly and private oil companies complain that the higher export taxes are hindering efficient allocation of profits into exploration and development[43].

The decision to develop Shtokman without foreign partners is a signal as strong as any of Russia's move toward nationalisation and emergence as an independent energy power. IOCs such as Chevron, ConocoPhilips, Total and Norwegian company StatoilHydro were excluded from the development and this came as a surprise as it was commonly thought that partnership with a foreign company would occur, especially one with technical expertise, in the harsh conditions of the Barents Sea[44].

Major Russian oil companies that have majority state holdings are Rosneft, Gazprom, Transneft and Rosgas. Other privately-owned companies such as Lukoil are locally owned, while TNK is a BP owned venture and Sakhalin Energy is a consortium of major oil companies.

Rosneft

Rosneft's E & P efforts have been growing steadily and were strengthened by the US $9.3 billion acquisition of Yuganskneftegaz (ex-Yukos), which established the company's proved oil and gas reserves at 21.69 billion barrels of oil equivalent (boe) in 2007 (including gas condensates and gas). Rosneft is also the world's seventh largest producer (in comparison to publicly traded oil companies) and Russia's second largest producer. Average daily output in 2007 was 2 MMbbl/d[45].

Central to Rosneft's cash flow and portfolio is Yuganskneftegaz, which represents approximately two thirds of the company's annual oil production and over 70% of its proved SPE oil reserves. Purneftegaz is Rosneft's second largest production asset. With large non-associated natural gas reserves at the Kharampur field, it is likely to increase in importance as Rosneft seeks to further monetise its gas reserves. Additional exploration in the Timano-Pechora oil province and expanded export capacity at the Arkhangelsk terminal have helped Rosneft grow[46].

Rosneft holds more than a third of Sakhalin's total offshore oil and gas resources. It holds sizeable stakes in all five stages of development. While still at the early stages of exploration, it holds stakes in the Sakhalin-3, Sakhalin-4 and Sakhalin-5 of 49.8%, 51% and 51%, respectively. Rosneft holds a stake in the Sakhalin-1 project, which is currently being developed under a Production Sharing Agreement (PSA) implemented in 1996 with ExxonMobil and Sodeco of Japan (and, since 2001, with India's ONGC). Sakhalin-1 began oil and gas production in late 2005 and is anticipated to experience substantial growth over the next several years[47].

Rosneft also holds interests in Eastern Siberia, in the form of the Vankor field in Krasnoyarsk and with TNK-BP, the Verkhnechonsk field in the Irkutsk.

Other resources on the Black Sea shelf, Sea of Azov and the Kurmangazy structure in Kazakhstan could help the company's future plans for growth[48].

Gazprom

In 2007, GazpromNeft's oil production was 660,000 bbl/d. It comprises nearly half a million shareholders with the Russian Federation controlling a majority of 50.002%. According to the company, it employs some 300,000 people in different operations[49]. Gazprom and its producing subsidiaries hold more than 40 oilfield exploration and development licences in the West Siberian petroleum basin, as well as in Omsk and Tomsk in Chukotka. It acquired Sibneft which has 80% of its reserves concentrated in Noyabr'sk with four large fields – Sugmutskoye, Sutorminskoye, Vyngapurovskoye and Sporyshevskoye – accounting for nearly 50% of Sibneft's reserves. Sibneft was also active in upstream oilfield services and is active in the geophysical arena through OJSC Noyabr'skneftegazgeophysica – a geophysical services company that offers borehole logging, perforation and seismic data preparation[50]. During recent years, Sibneft has spun-off several service companies that were formerly production divisions including Service Drilling Company LLC and Well Workover Service Company LLC. These service companies compete with other Russian and international drilling and service contractors, providing drilling and well work over services[51].

Gazprom – Natural Gas

Russia has the largest natural gas reserves in the world, 1.58 trillion cubic feet (Tcf). In 2007, Russia was the world's largest natural gas producer (58.8 billion cubic feet [Bcf]), as well as the world's largest exporter (16.3 Bcf)[52].

Russia's natural gas infrastructure, however, needs updating and its natural gas industry has not experienced the success of its oil industry, with limited growth in gas production and consumption[53].

Three major fields in Western Siberia – Urengoy, Yamburg, and Medvezh'ye – comprise more than 70% of Gazprom's total natural gas production, but these fields are now in decline. Although the company projects increases in its natural gas output between 2008 and 2030, most of Russia's natural gas production growth will come from independent gas companies such as Novatek, Itera and Northgaz. Barents Sea Exploration of the Russian Barents Sea began in the 1970s and to date discoveries in the area consist of ten significant gas and condensate fields, as well as a total of 125 identified fields or potential structures. Total reserves are estimated between five and ten trillion cubic metres[54].

The largest deposit is the Shtokman (Shtockmanovskoye) gas and condensate field, discovered in 1988, with total reserves of 3 trillion m^3, and with estimated recoverable reserves (C1+C2) of 2.5 trillion m^3. Gazprom plans to develop the Shtokman field on its own and expects it to become the resource base for the export of gas to Europe through the Nord Stream pipeline (which is currently under construction)[55]. The energy resources of north-west Russia remain largely unexploited. The total hydrocarbon resources of the Russian Arctic shelf are estimated at about 100 billion tonnes of oil equivalent (toe). The natural gas reserves in north-west Russia form the most important strategic energy resource in the region. Estimates placed on Barents Sea reserves vary from 2 trillion m^3 to 5 trillion m^3. In any event, these reserves offer a major supply contribution to European energy needs. In addition, it is expected that there are also oil deposits in the eastern and northern

> Gazprom and its producing subsidiaries hold more than 40 oilfield exploration and development licences in the West Siberian petroleum basin, as well as in Omsk and Tomsk in Chukotka.

areas of the Barents Sea. Furthermore, the so-called 'grey zone', formed by the sea boundary claims of Norway and Russia, is considered a promising gas or oil province.

The Timan-Pechora oil and gas region has estimated total oil resources of over 4,800 million tonnes, of which over 1,400 million tonnes is estimated to be recoverable. The Republic of Komi has 520 million tonnes of oil resources. Perhaps the most significant deposit found in the Pechora Sea is the Prirazlomnoye oil field, with estimated reserves of 56-62 million tonnes. The licence for the development of the field is held by JSC Rosshelf, and the Australian company BHP is participating in the development of this field. The exploration of Barents Sea oil resources is still at an early stage[56].

The Timan-Pechora province is considered the third most important oil producer of the Russian Federation, and there is a significant development potential in the area. If the above-mentioned oil reserves are compared world-wide, they are equivalent to Norway's North Sea reserves; however, most of the approximately 200 fields in the region are quite small. Gas reserves are rather small compared to the Barents Sea reserves, for example, which means that they are mainly of local importance[57].

Transneft Russia needs to expand export capacity for its oil and gas in order to monetise growing production. Crude oil exports via pipelines, however, are under the jurisdiction of Russia's state-owned Transneft. The Transneft system cannot meet export needs with an excess of approximately three million barrels of its total seven million barrels transported by road, rail and river routes[58]. This means substantial investments must be made to ensure growing levels of production can reach the markets, especially foreign ones.

Several proposed oil pipeline routes and pipeline expansion projects are planned including the Baltic Pipeline System (BPS), which carries crude oil from Russia's West Siberian and Timan-Pechora oil provinces westward to the newly completed port of Primorsk in the Russian Gulf of Finland[59].

Sakhalin Island

Several IOCs entered into PSAs to develop the resources in Sakhalin Island, Okhotsk Sea (see *Chapter 8: Extreme E & P*). Oil reserves in the area are estimated at around 14 billion barrels, and natural gas reserves at approximately 2.6 trillion cubic metres[60].
The Sakhalin-1 project was led by Exxon Neftegaz, in conjunction with consortium members SODECO, ONGC Videsh, Sakhalinmorneftegaz and RN Astra. The Sakhalin-2 project was developed by Shell,

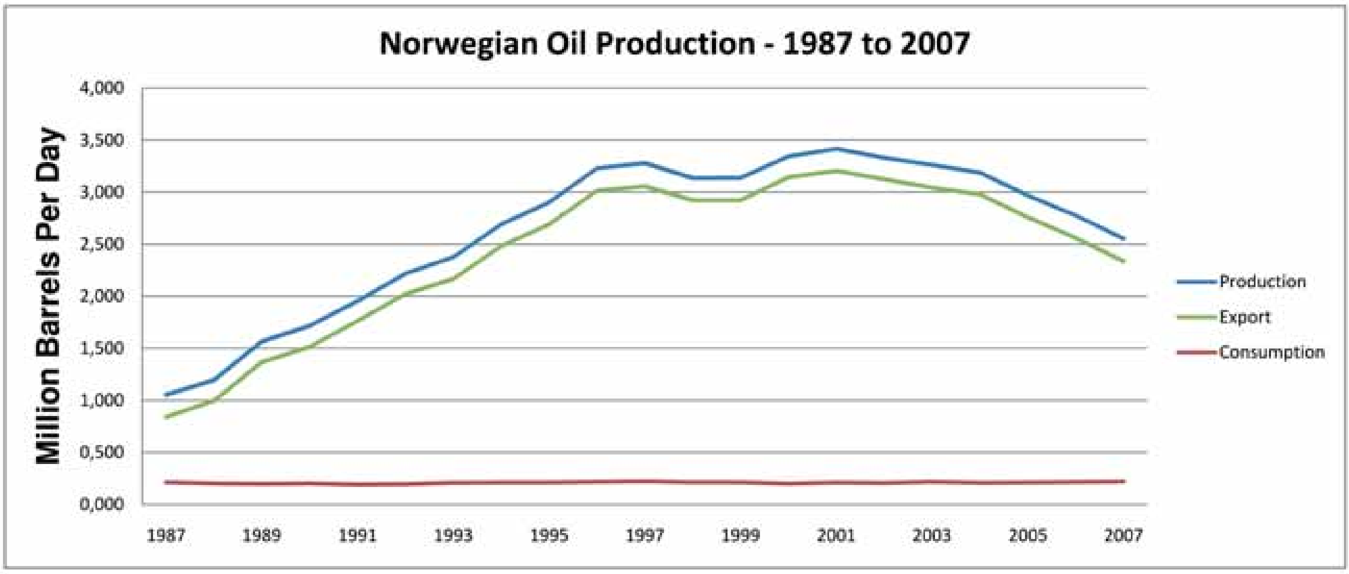


Table 11 - Norwegian Oil Production (1987 to 2007)

Mitsubishi and Mitsui, and entails the development of Russia's first LNG facility to be built on the southern tip of the island. Sakhalin-2 will also be used to supply natural gas to the United States, Korea and Japan in 2008. Sakhalin 3-6, North and South East of Sakhalin Island, are at the planning stages of development[61].

Norway

Norway had 8.2 billion barrels of proven oil reserves at the end of 2007, the largest in Western Europe. Norway's oil reserves are located offshore on the Norwegian Continental Shelf (NCS), which is divided into the North Sea, the Norwegian Sea and the Barents Sea[62].

Oil and Gas Exports

Norway produced 2.56 MMbbl/d in 2007 and consumed 221,000 bbl/d in the same period. The country therefore exported 2.34 MMbbl/d during 2007. Norway has significantly increased its natural gas production; in 2007 it produced 8.7 bcf and consumed 0.4 bcf[63].

The United Kingdom is the largest importer of Norway's oil and gas having imported 814,500 bbl/d from Norway, or 34 % of Norway's 2007 total exports.

In contrast to its maritime neighbour, the UK, Norway's government holds a dominant stake in the oil sector and controls 66.42% of StatoilHydro (the remainder of the shares are owned by international, institutional and private stockholders)[64].

StatoilHydro itself holds more than 80% of Norway's oil and gas production. Additionally, Norway's government owns approximately 40% of the country's total oil production through the State Direct Financial Interest (SDFI). State-owned Petoro administers these ownership interests, while StatoilHydro is responsible for managing actual production from SDFI assets[65].

IOCs do have a sizeable presence in the NCS, but they must act in partnership with StatoilHydro. The largest private oil producers in Norway are ConocoPhillips, ExxonMobil and BP. Petoro is the state limited company which is responsible for managing, on behalf of the government, SDFI[66].

While the state has the ownership of the SDFI's assets, Petoro acts as the licencee in production licences, pipelines and land-based plants on behalf of the government. The primary objective of Petoro's administration of the SDFI portfolio is to achieve the highest possible income for the state. The SDFI arrangement involves the state paying a share of all investments and operating costs in projects which

> The United Kingdom is the largest importer of Norway's oil and gas having imported 814,500 bbl/d from Norway, or 34 % of Norway's 2007 total exports.

correspond to its direct financial interest. On the same terms as the other owners, the government then receives a matching share of revenues from the sale of production and other income sources.

The licencees, and in particular the operator, are responsible for developing discoveries which are made within the boundaries of a licence. Should there be a need for research and technology development to overcome technological challenges in developing the discovery, the tax system provides favourable conditions to ease the burden of such efforts. Relevant expenditures on research are fully deductible against tax and there is a special tax scheme aimed at stimulating research and development in industry ('Skattefunn'). Due to the nature of oil exploration and production in the NCS, the region has traditionally been accessible only by international oil majors. Because of harsh weather and operating conditions, projects in the NCS require sizable initial investments. Further, the structure of Norway's petroleum taxes means that smaller, marginal fields often are not profitable. Finally, stringent environmental, safety, and labour regulations further increase operating costs[67].

Technology Development

The Ministry in Norway funds petroleum-related research programmes which are administered by the Norwegian Research Council. The two most important programmes are called Petromaks and Demo 2000. Petromaks deals with basic and applied research and Demo 2000 covers the demonstration/application of new technology. The main aim of both programmes is to increase value creation on the Norwegian Continental Shelf and to increase the export of Norwegian oil and gas technology. The Ministry has also established OG 21, 'Oil and Gas in the 21st Century', which provides overall guidance on priorities for the public research and technology programmes, as well as for related activities in universities, research institutes and industry through a comprehensive national R & D strategy. The OG 21 board consists of members from oil companies, the supply industry, research institutions and academia. The implementation of the OG 21 strategy is largely based on the activities of the Petromaks and Demo 2000 programmes and on joint industry projects[68].

As with any development project on the Norwegian Continental Shelf, the Ormen Lange and Snøhvit developments have been driven by commercial interests. The Ministry's role in development projects is to coordinate the administrative procedures and approval processes, ensuring that the projects comply with sound resource management practice, as well as balancing all interests with regard to value creation, environmental concerns and the fisheries. With regard to Snøhvit, minor tax regime adjustments were made to facilitate the development of the LNG projects[69].

Production

The bulk of Norway's oil production occurs in the North Sea, with smaller amounts in the Norwegian Sea. In 2007, LNG production of the Snøhvit field was scheduled to commence which brought development to Hammerfest. Most of the Barents Sea is unexplored and activity there will always be subject to high costs associated with a harsh offshore area and environmental concerns as the seas have abundant fish stocks and are considered unpolluted. The Barents Sea is likely to contain oil and gas reserves, but the question remains one of delineation. To this end, the Norwegian government has restarted licensing in the Barents Sea and companies such as StatoilHydro are looking keenly to what some consider as a new frontier for the Norwegian Petroleum Industry[70].

Exploration and Production

Norwegian oil production rose dramatically from 1980 until the mid-1990s, remained flat since (see Table 11) and has now started to decline. During the first six months of 2005, for example, Norway's oil production averaged 2.95 MMbbl/d, while in 2007 the average figure was 2.55 MMbbl/d. As North Sea fields continue to mature, Norwegian oil production will focus on mature fields, though it is expected that new developments in the Barents Sea will offset some of this decline.

One of the largest oil fields in Norway is the Troll complex operated by StatoilHydro. Other important fields include Ekofisk (ConocoPhillips), Snorre (StatoilHydro), Oseberg (StatoilHydro), and Draugen (Shell). ConocoPhillips, ExxonMobil and BP operate oilfields in Norway. There is a great emphasis on increasing production from existing projects, including the incorporation of smaller satellite fields that will take advantage of the existing infrastructure[71].

As was the case with the United Kingdom, however, many oil majors have begun to withdraw from the NCS in order to pursue projects in high-growth regions. StatoilHydro have begun to sell NCS interests in order to pursue projects in Latin America and Africa.

Mexico

Pemex (Petróleos Mexicanos) was created as a result of the 1938 Mexican President Cardenas' nationalisation of the oil industry.

Today, the company is responsible for all petroleum production in Mexico which is 3.48 MMbbl/d (2.02 MMbbl/d consumption) and 4.5 bcf of gas production (5.2 bcf consumption). The United States is the destination of over 70% of Mexico's 1.46 MMbbl/d exports[72].

A highly prospective area for Mexico are the Mexican waters of the 'Gulf of Mexico' or GOM which to date have only been developed within the US territorial jurisdiction. Mexico's reservoirs are mostly high permeability limestone reservoirs, while the US tends to be lower permeability sandstones. This in part accounts for the higher average Pemex production well rates of approximately 6000 bbl/d per well. The onshore Burgos Basin on the Mexico-U.S. border shares similar gas prone characteristics with its onshore South Texas neighbours[73].

Mexico must prove its deeper GOM trends and in recent times has issued new discoveries such as Noxal. It has been said that it could be a difficult and longwinded task for Mexico to develop its own deepwater expertise, but this argument fails to recognise that many service provisions could be made by service and supply companies rather than oil companies. However, by bringing in reputed deepwater oil companies, the best development strategies could be applied to the GOM Mexican deepwaters.

Kazakhstan

The Caspian Sea contains six separate hydrocarbon basins and has attracted much foreign investment as most of its oil and natural gas reserves are undeveloped and unexplored with the notable exception of Kashagan, which is the flagship project in the North Caspian Sea. High prospectivity is the cause of interest in the Caspian Sea region, but for net oil exports Kazakhstan alone is relevant (although Azerbaijan and Turkmenistan are worth noting for future production growth)[74].

Kazakhstan produced 1.49 MMbbl/d in 2007 and consumed 219,000 bbl/d in the same period. The country therefore exported 1.27 MMbbl/d during 2007.

Proven Kazakhstani oil reserves are 39.8 billion barrels (defined as oil and natural gas deposits that are considered 90% probable) and gas reserves are 67.2 Tcf. The figure for the Caspian sea is much higher but is split between several states. Kazakhstan's reserves are very much a work-in-progress as the country is

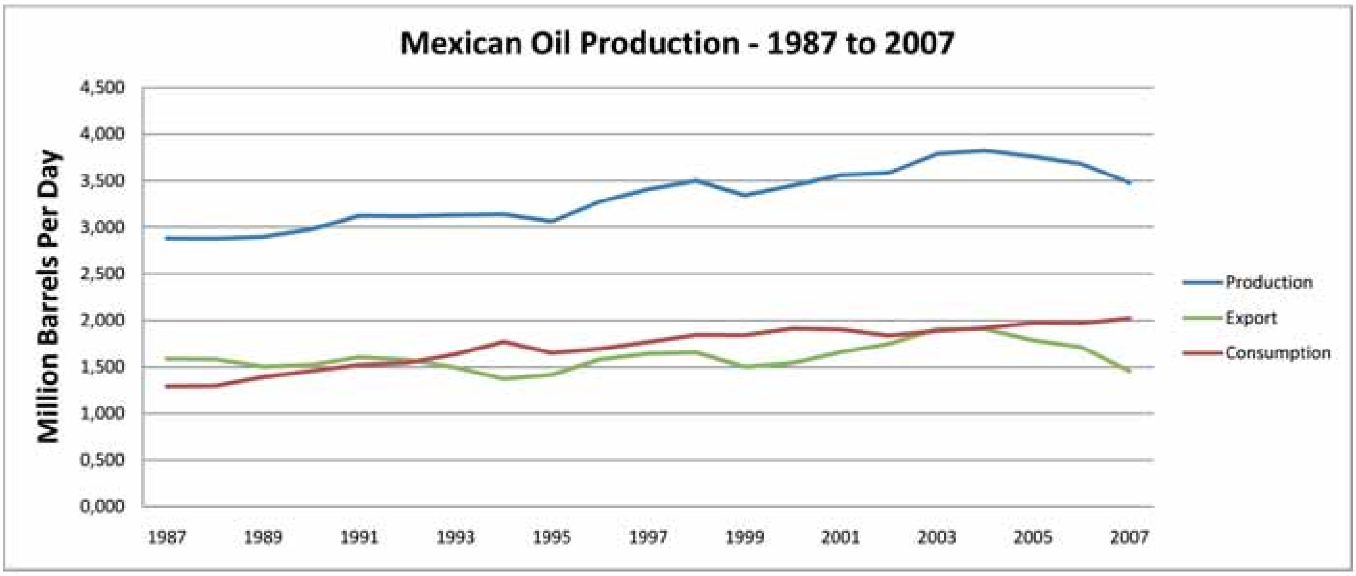


Table 12 - Mexican Oil Production (1987 to 2007)

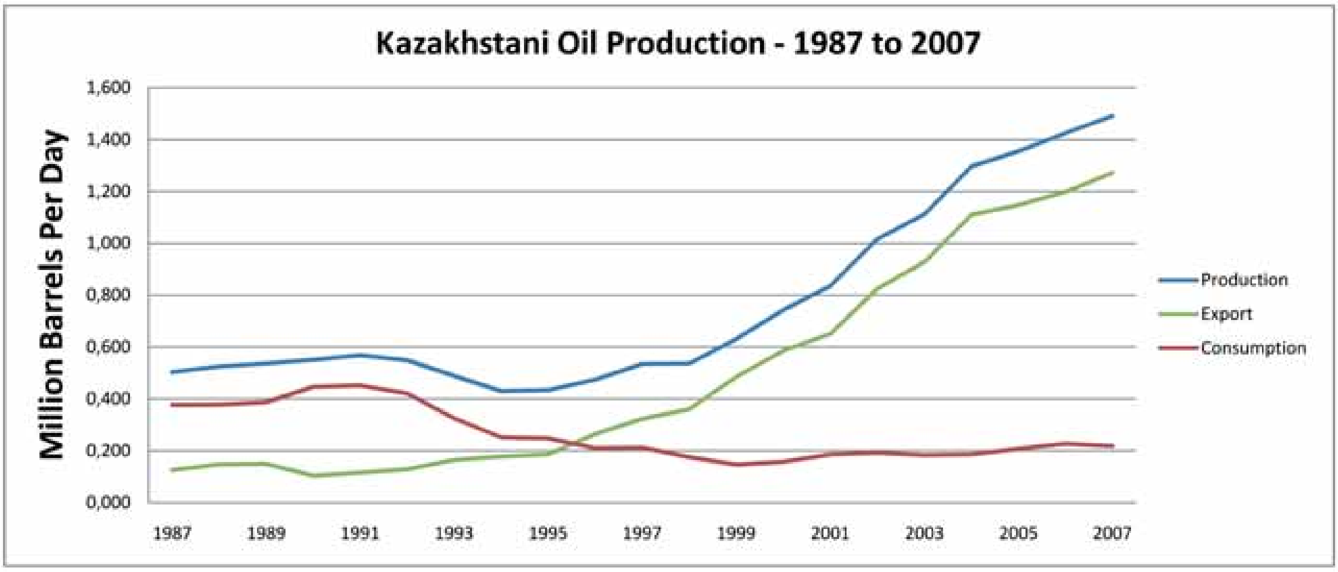


Table 13 - Kazakhstani Oil Production (1987 to 2007)

relatively unexplored and untapped. Even relatively high-profile Kashagan does not have any final proven oil reserves figures as it is still undergoing appraisal and exploratory well drilling. After Russia, Kazakhstan was the largest oil-producing republic in the Soviet Union and has successfully attracted foreign investment in its oil sector to increase oil production to 1.49 MMbbl/d in 2007, most of which came from two large onshore fields (Tengiz, and Karachaganak) and the offshore complex of Kashagan which is still under appraisal and first oil is not expected before 2011. The Tengiz oil field is estimated to contain recoverable oil reserves of six to nine billion barrels. The Kashagan complex has an unitisation agreement that covers the Kalamkas, Aktoty and Kairan blocks[75]. North Caspian Operating Company (partners include ExxonMobil, Shell, Total, Eni, ConocoPhillips, Inpex and National Oil Company KazMunaiGas) is developing the Kashagan complex. The field was discovered in June 2000, when the first exploration well (KE-1) was drilled with 13 billion tonnes of oil potentially recoverable with the use of gas re-injection[76].

Now that we have in-depth knowledge of where our oil and gas resources are located, we need to think about how one actually gets access to these resources. Does

> "The Caspian Sea contains six separate hydrocarbon basins and has attracted much foreign investment as most of its oil and natural gas reserves are undeveloped and unexplored with the notable exception of Kashagan, which is the flagship project in the North Caspian Sea."

one need to buy the land from those who own it? Are there procedures and policies in place that need to be followed? What are the legal requirements? Who can actually acquire oil or gas fields? Who are the major players in this area?

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16. Oil wealth has undoubtedly helped the UAE especially Abu Dhabi secure commercial growth.

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40. There is no doubt regarding OPEC's future importance.

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42. Idem.

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