TOPIC PAPER #19

CONVENTIONAL OIL AND GAS

(Including Arctic and Enhanced Oil Recovery)

On July 18, 2007, The National Petroleum Council (NPC) in approving its report, *Facing the Hard Truths about Energy,* also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the Task Groups and their Subgroups. These Topic Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached Topic Paper is one of 38 such working document used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix E of the final NPC report provides a complete list of the 38 Topic Papers and an abstract for each. The printed final report volume contains a CD that includes pdf files of all papers. These papers also can be viewed and downloaded from the report section of the NPC website (www.npc.org).

NATIONAL PETROLEUM COUNCIL

TECHNOLOGY IMPACT ON CONVENTIONAL WELLS SUBGROUP OF THE TECHNOLOGY TASK GROUP OF THE NPC COMMITTEE ON GLOBAL OIL AND GAS

TEAM LEADER

Thomas H. Zimmerman
Schlumberger Fellow
Schlumberger Limited

MEMBERS

Daniel R. Burns
Researcher
Department of Earth, Atmospheric, and Planetary Sciences
Massachusetts Institute of Technology

Akhil Datta-Gupta
Professor and LeSuer Chair in Reservoir Management
Petroleum Engineering
Texas A&M University

William L. Fisher
Professor and Barrow Chair
Jackson School of Geosciences
The University of Texas

J. Heine Gerretsen
Technology Strategy Advisor (EPT-RCT)
Shell International Exploration & Production Inc.

D. Ronald Harrell
Chairman Emeritus
Ryder Scott Company, L.P.

A. Daniel Hill
Associate Department Head, Graduate Program and R. L. Whiting Endowed Chair
Harold Vance Department of Petroleum Engineering
Texas A&M University

George J. Hirasaki
A. J. Hartsook Professor in Chemical Engineering
Chemical & Biomolecular Engineering Department
Rice University

John D. Kuzan
Upper Zakum Transition Manager
ExxonMobil Upstream Research Company

John J. Pyrdol
Economist
U.S. Department of Energy

NATIONAL PETROLEUM COUNCIL

TECHNOLOGY IMPACT ON ARCTIC SUBGROUP OF THE TECHNOLOGY TASK GROUP OF THE NPC COMMITTEE ON GLOBAL OIL AND GAS

TEAM LEADER

Thomas H. Zimmerman
Schlumberger Fellow
Schlumberger Limited

MEMBER

Geir Utskot
Oilfield Services Arctic Manager
Schlumberger Oilfield Services

NATIONAL PETROLEUM COUNCIL

TECHNOLOGY IMPACT ON ENHANCED OIL RECOVERY SUBGROUP OF THE TECHNOLOGY TASK GROUP OF THE NPC COMMITTEE ON GLOBAL OIL AND GAS

TEAM LEADER

Thomas H. Zimmerman
Schlumberger Fellow
Schlumberger Limited

MEMBERS

Swapan Kumar Das
Advisor, Thermal & HO EOR
ConocoPhillips

Birol Dindoruk
Principal Reservoir Engineer
Technology Applications & Research
Shell International Exploration & Production Inc.

Daniel T. Georgi
Director, Strategic Technology and Advanced Research
INTEQ
Baker Hughes Incorporated

George J. Hirasaki
A. J. Hartsook Professor in Chemical Engineering
Chemical & Biomolecular Engineering Department
Rice University

Jairam Kamath
Team Leader
Chevron Energy Technology Company

Anthony R. Kovscek
Associate Professor
Department of Energy Resources Engineering
Stanford University

Fikri J. Kuchuk
Schlumberger Fellow and Chief Reservoir Engineer
Schlumberger Riboud Product Center

Vello A. Kuuskraa
President
Advanced Resources International

Kishore K. Mohanty
Professor and Director, Institute for Improved Oil Recovery
Chemical & Biomolecular Engineering
University of Houston

Hamdi A. Tchelepi
Associate Professor
Petroleum Engineering
Stanford University

Djebbar Tiab
Senior Professor of Petroleum Engineering
Mewbourne School of Petroleum and Geological Engineering
University of Oklahoma

John Roland Wilkinson
Regional Reservoir Manager – NA/SA/AP/ME
ExxonMobil Production Company

Impact of Technology on Conventional Wells (including EOR and Arctic)

Team leader: Tom Zimmerman

Date submitted: February 25, 2007

I. Executive Summary

This report examines the current state of conventional oil and gas wells, including enhanced oil recovery and arctic technology, and makes projections on how technology could impact these businesses in the future.

An estimated at 400 billion barrels of technically recoverable domestic oil resources remain undeveloped and are yet to be discovered, from an undeveloped remaining oil in-place of over a trillion (1,124 billion) barrels (Figure I.1).

This resource includes undiscovered oil, “stranded” light oil amenable to CO_2 enhanced oil recovery technologies, unconventional oil (deep heavy oil and oil sands) and new petroleum concepts (residual oil in reservoir transition zones). The U.S. oil industry, as the leader in enhanced oil recovery technology, faces the challenge of further molding this technology towards economically producing these more costly remaining domestic oil resources.

While pursuing this remaining domestic oil resource base poses considerable economic risk and technical challenge to producers, developing the technical capability and infrastructure necessary to exploit this resource reduces our dependence on foreign energy sources and helps our domestic energy industry maintain a technical leadership worldwide.

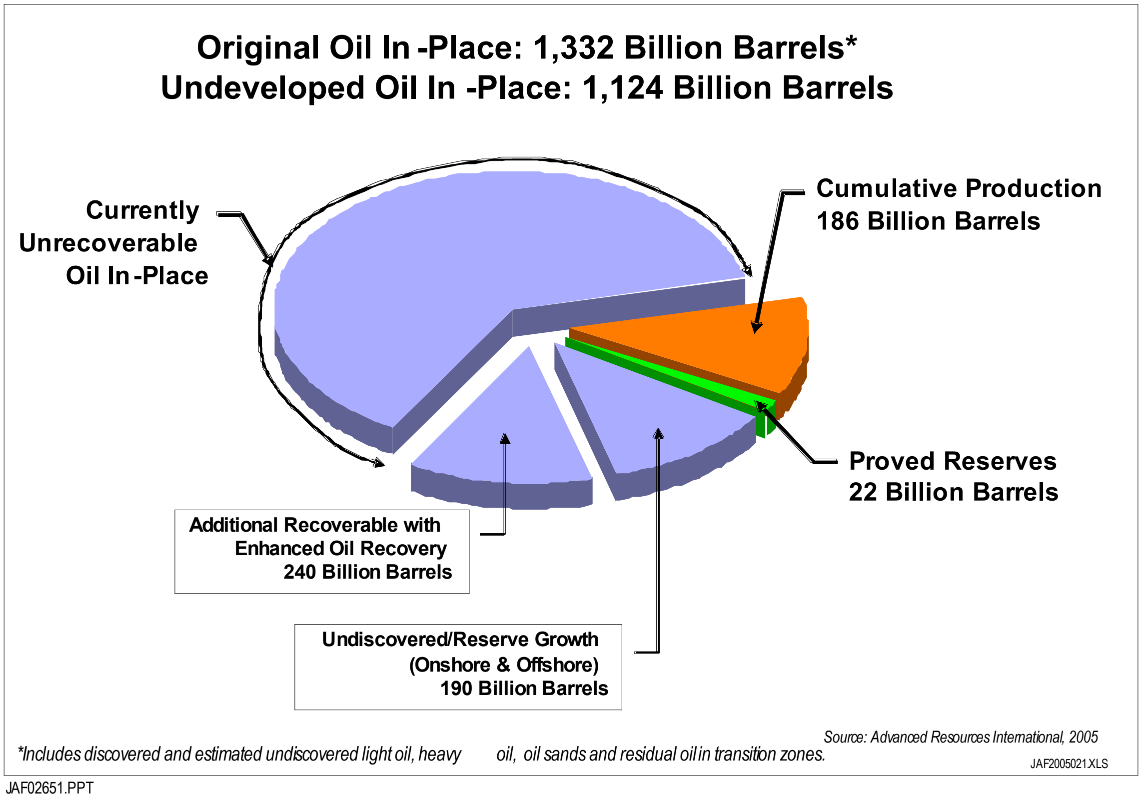

Figure I.1. Original, developed and undeveloped domestic oil resources. [1]

Table I.1 provides summary information on the size and nature of the original, developed and undeveloped domestic oil resources. Note that the domestic oil resources addressed by this report do not include shale oil.

Of the 582 billion barrels of oil in-place in discovered fields, 208 billion has been already produced or proved, leaving behind 374 billion barrels. A significant portion of this 374 billion barrels is immobile or residual oil left behind ("stranded") after application of conventional (primary and secondary) oil recovery technology. With appropriate enhanced oil recovery (EOR) technologies, 100 billion barrels of this

[1] Kuuskraa VA: "Undeveloped Domestic Oil Resources: The Foundation for Increasing Oil Production and a Viable Domestic Oil Industry," prepared for the US Department of Energy, Office of Fossil Energy–Office of Oil and Natural Gas, Advanced Resources International (2006). Available at http://www.fossil.energy.gov/programs/oilgas/publications/eor_co2/Undeveloped_Oil_Document.pdf. This chart represents updated figures available from ARI at http://www.fossil.energy.gov/programs/oilgas/publications/eor_co2/G_-_Updated_U_S__Oil_Resources_Table_2-1.pdf.
Note that the EIA estimates of remaining reserves are lower than those used here, see information in the NPC data warehouse and http://tonto.eia.doe.gov/dnav/pet/pet_crd_pres_dcu_NUS_a.htm.

"stranded" resource may become technically recoverable from already discovered fields.

Original, Developed and Undeveloped Domestic Oil Resources*

	Original Oil In-Place (BBbls)	Developed to Date: Conventional Technology (BBbls)	Developed to Date: EOR Technology (BBbls)	Remaining Oil In-Place (BBbls)	Future Recovery**: Conventional Technology (BBbls)	Future Recovery**: EOR *** Technology (BBbls)	Future Recovery**: Total (BBbls)
I. Crude Oil Resources							
1. Discovered	582	(194)	(14)	374	0	110	110
• Light Oil	482	(187)	(2)	293	0	90	90
• Heavy Oil	100	(7)	(12)	81	0	20	20
2. Undiscovered	360	0	0	360	119	60	179
3. Reserve Growth	210	0	0	210	71	40	111
4. Transition Zone	100	0	0	100	0	20	20
5. Tar Sands	80	0	0	80	0	10	10
TOTAL	**1,332**	**(194)**	**(14)**	**1,124**	**190**	**240**	**430**

*Does not include oil shale.
**Technically recoverable resources rounded to the nearest 10 billion barrels.
*** Based on ten basin-oriented assessments and residual oil zone resource potential highlighted in reports released by the Department of Energy Office of Fossil Energy in February 2006.

This table updates the table of U.S. oil resources recovery potential in the report entitled, Undeveloped Domestic Oil Resources: The Foundation for Increasing Oil Production and a Viable Domestic Oil Industry, February 2006.

Table I.1. Original, developed and undeveloped domestic oil resources.[2]

Undiscovered domestic oil is estimated to be 360 billion barrels in-place, with 119 billion barrels (43 billion barrels from the onshore and 76 billon barrels from the offshore) being recoverable with primary or secondary recovery.

EOR is the third stage of hydrocarbon production, during which sophisticated techniques that alter the original properties of the oil are used. Enhanced oil recovery can begin after a secondary recovery process or at any time during the productive life of an oil reservoir. Its purpose is not only to restore formation pressure, but also to improve oil displacement or fluid flow in the reservoir.

The three major types of enhanced oil recovery operations are chemical flooding (alkaline flooding or micellar-polymer flooding), miscible displacement (carbon dioxide [CO_2] injection or hydrocarbon injection), and thermal recovery (steamflood or in-situ combustion). The optimal application of each type depends on reservoir

[2] ARI, reference 1. This table represents updated figures available from ARI at http://www.fossil.energy.gov/programs/oilgas/publications/eor_co2/G_-_Updated_U_S__Oil_Resources_Table_2-1.pdf.

temperature, pressure, depth, net pay, permeability, residual oil and water saturations, porosity, and fluid properties such as oil API gravity and viscosity. Application of "advanced" EOR could add another 60 billion barrels of technically recoverable resource from this category.

Future reserve growth in discovered oil fields could amount to 210 billion barrels of oil in-place, with 71 billion barrels (60 billion barrels from the onshore and 11 billion barrels from the offshore) being recoverable with primary or secondary recovery. Application of "advanced" EOR could raise this technically recoverable volume by up to 40 billion barrels.

With advances in thermal EOR technology, domestic oil sands, holding 80 billion barrels of resource in-place, could provide up to 10 billion barrels of future technically recoverable domestic oil resource.

As points of comparison, current proved crude oil reserves are 22 billion barrels and annual domestic crude oil production is about 2 billion barrels.

The estimates of remaining recoverable domestic oil resources from undiscovered and reserve growth are from the national resource assessments by the U.S. Geological Survey (USGS) and the U.S. Minerals Management Service (MMS). The estimates of recoverable oil resources using EOR technology on "stranded" oil and oil sands are based on work by Advanced Resources International for DOE/FE's Office of Oil and Natural Gas.[3]

Since the preparation and publication of the Kuuskraa paper that provided the basis for this report, considerable additional work has been completed by the author's firm that further confirm the estimates of undeveloped U.S. oil resources.

A total of 10 domestic oil basins/areas have now been assessed (up from the original six). These 10 studies indicate that the technically recoverable oil resource from application of "state-of-the-art" CO_2-EOR is 89 Bbbl. This provides support to the 80 Bbbl estimate of applying EOR to the stranded light oil resource, shown in Table I.1.

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[3] Advanced Resources International, reference 1.

New work on the transition/residual oil zone resource documents the presence of 42 Bbbl of this category of oil in-place in just three domestic oil basins (Permian, Big Horn, and Williston). Detailed reservoir simulation assessment shows that 20 Bbbl of this oil in place could become technically recoverable by applying CO_2-EOR. This work provides support to the transition/residual oil zone resource estimate of 100 Bbbl in Table I.1 and indicates that an important portion of this resource may become recoverable.

Finally, the author and his firm took an in-depth look at the additional oil recovery from applying "next generation" CO_2-EOR technology. This work shows that combining: (1) advanced, high reservoir contact well designs; (2) mobility and miscibility enhancement; (3) large volumes of CO_2 injection; and (4) real-time performance feedback and process control technology could bring about "game changer" levels of improvement in oil recovery efficiency. This work provides support that a national average oil recovery efficiency target of 60% could become realistic, assuming a successful program of advanced technology development, affordable supplies of CO_2 and other EOR injectants, and appropriate risk mitigation policies.

II. Overview of Methodology

This report's contents dealing with conventional wells derives primarily from a working brainstorm meeting held on August 29, 2006, at Schlumberger's Sugar Land Product Center, located southwest of Houston. The participants in that meeting were:

Daniel Burns	MIT
John Pyrdol	DOE
John Kuzan	ExxonMobil
Dan Hill	TAMU
Heine Gerretsen	Shell
Bill Fischer	UT
George Hirasaki	Rice
Ron Harrell	Ryder Scott
Tom Zimmerman	Schlumberger

The purpose of this meeting was to capture this group's view of the key technologies impacting conventional oil and gas wells.

The portion of this report dealing with enhanced oil recovery comes primarily from a brainstorm working meeting held on November 9th, 2006, at Schlumberger's Sugar Land Product Center, located southwest of Houston. The participants in the meeting were:

Fikri J. Kuchuk	Schlumberger
Swapan Kumar Das	ConocoPhillips Co
Anthony Robert Kovscek	Stanford U.
Birol Dindoruk	Shell Intl. E&P Inc.
Dan Georgi	Baker Atlas / INTEQ
Djebbar Tiab	U. of Oklahoma
George J. Hirasaki	Rice U.
Hamdi A. Tchelepi	Stanford U.
Jairam Kamath	Chevron ETC
John Roland Wilkinson	ExxonMobil Production Co.
Kishore Kumar Mohanty	U. of Houston
Vello Alex Kuuskraa	Advanced Resources International, Inc.
Tom Zimmerman	Schlumberger

The purpose of the November 9th meeting was to capture this groups' view of the key future technologies impacting enhanced oil recovery (EOR).

The portion of this report dealing with arctic technology comes primarily from a set of interviews conducted by Geir Utskot in late November and early December, 2006. These interviews were conducted to determine the likely future technologies that would enhance arctic operations. The arctic experts polled by Geir were:

Rosemary van der Grift	Petro-Canada
Terry Moore	Chevron
Stuart Russell	Braden Bury Expediting
John Pahl	Akita Drilling
Darrell Graham	MI-Swaco
Dennis Seidlitz	ConocoPhillips
Robert Jensen	Schlumberger
Tom O'Gallagher	Schlumberger
Tom Allan	Schlumberger
Al Mahoney	Schlumberger
Allan Peats	Schlumberger
Dan Johnson	Schlumberger
Geir Utskot	Schlumberger

III. Background

Oil and gas resources are organic, formed by the effects of heat and pressure on sediments trapped beneath the earth's surface over millions of years. While ancient societies made some use of these resources, the modern petroleum age began less than a century and a half ago. Advances in technology have steadily improved our ability to find and extract oil and gas, and to convert them to efficient fuels and useful consumer products.

In the past three decades, the petroleum business has transformed itself into a high-technology industry. Dramatic advances in technology for exploration, drilling and completion, production, and site restoration have enabled the industry to keep up with the ever-increasing demand for reliable supplies of oil and natural gas at reasonable prices. The productivity gains and cost reductions attributable to these advances have been widely described and broadly recognized.

For example, to access a given amount of resource, fewer wells are required today than in the past. Compared to 1985, we today (in the USA) produce twice as much oil from half as many wells (Figure III.1). It takes 22,000 fewer wells annually to develop the same amount of oil and gas reserves as it did in 1985.

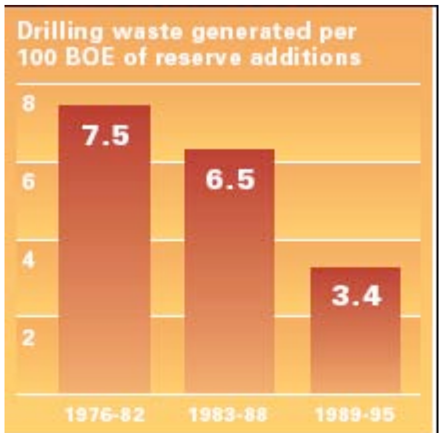

Figure III.1. Drilling waste was cut by more than a factor of two between 1976–1982 and 1989–1995.[4]

Thanks to advances in exploration and production technology, today's industry is better equipped than ever to find and produce valuable oil and gas—even as these resources become concentrated in deeper, more remote, and more technically challenging areas.

Using modular drilling rigs and slimhole drilling, operators can develop the same volume of resources with a rig up to 75 percent smaller and lighter than a standard rig, reducing impacts on surface environments. Technology has allowed an impressive reduction in surface footprint while providing a huge increase in the sub-surface accessed (Figure III.2). Today's drilling technology has allowed operators to reduce the "footprint" of well pads by as much as 70 percent, especially important in environmentally sensitive areas such as Prudhoe Bay in Alaska.

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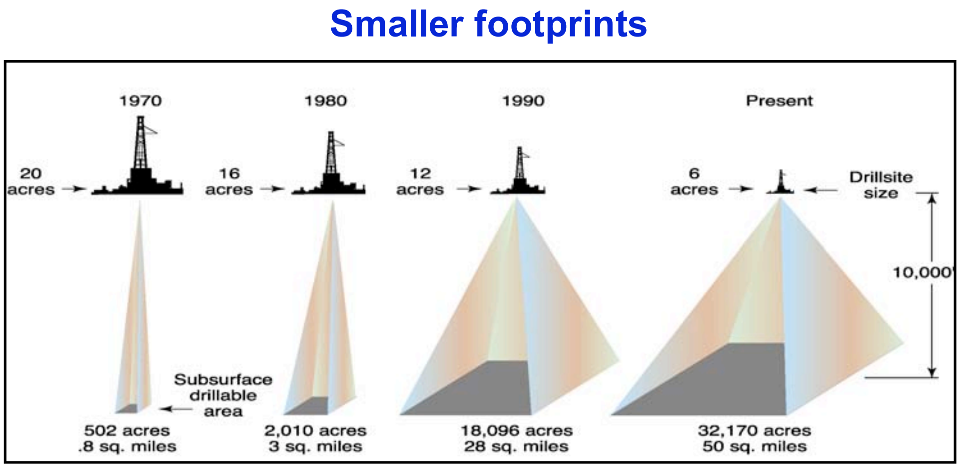
[4] U.S. DOE/EIA: *Annual Energy Outlook 1998*. See also http://www.fossil.energy.gov/programs/oilgas/publications/environ_benefits/Environmental_Benefits_Report.html.



Source: W. Harrison, Kansas Geological Survey

Figure III.2. Small footprint for drilling. [5]

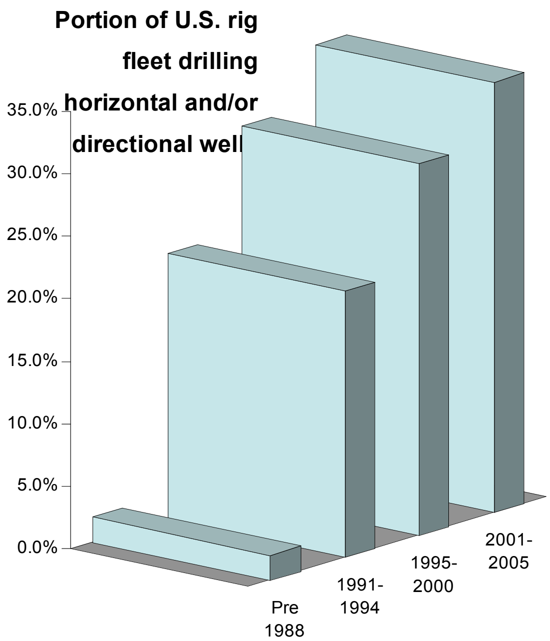


Figure III.3. Portion of U.S. rig fleet drilling horizontal or directional wells [Baker Hughes]. [6]

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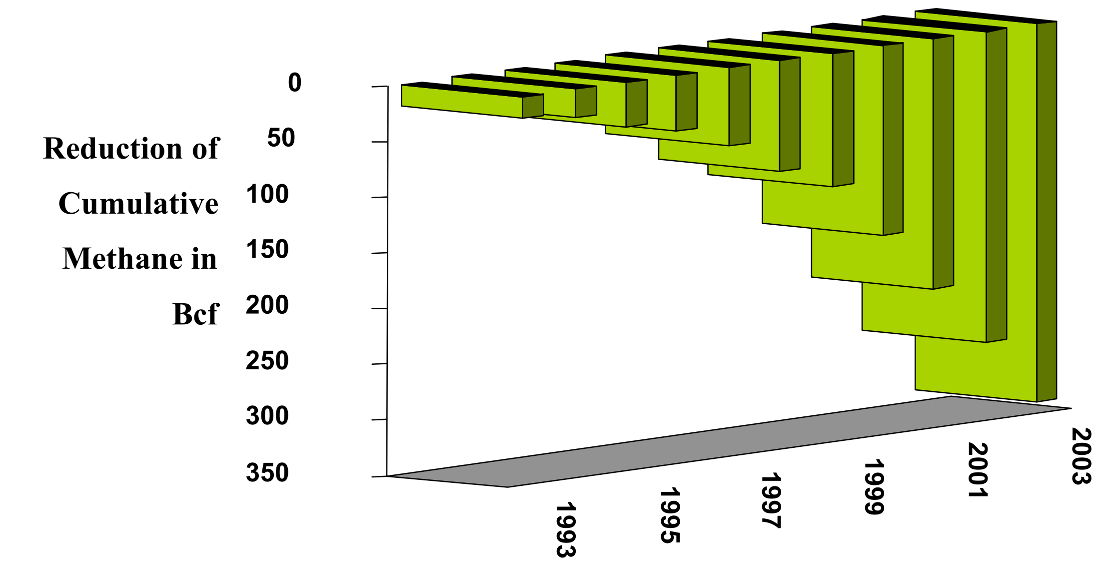
[5] Johnson N: "Environmental Benefits of Technology Progress in Oil and Natural Gas Exploration and Production," paper SPE/EPA/DOE Exploration and Production Environmental Conference, Galveston, Texas USA (March 7–9, 2005).
[6] Johnson, reference 4.

Directional drilling, slimhole rigs, and other advances enables greater production of valuable oil and gas resources with less surface presence (including near wetlands and other sensitive environments) (Figure III.3).



Source: U.S. Environmental Protection Agency

Figure III.4. Reduction of cumulative methane emissions <?> by year.[7]

Through the EPA's voluntary Natural Gas STAR program, the gas industry's use of innovative best management practices has reduced methane emissions by nearly 55 billion cubic feet since 1991, well exceeding the annual goals set by the Climate Change Action Plan (Figure III.4).

Job-related injuries and illnesses in oil exploration and production are well below the rates in the U.S. manufacturing sector. Advanced drilling, completion, and production technologies have contributed to steady improvements in worker safety, by decreasing worker's time on site and enhancing wellbore control (Figure III.5).

[7] Johnson, reference 4.

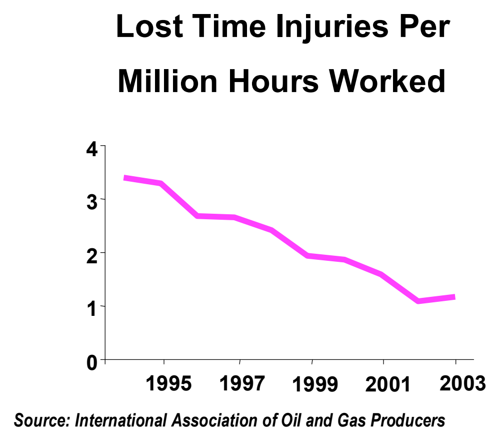
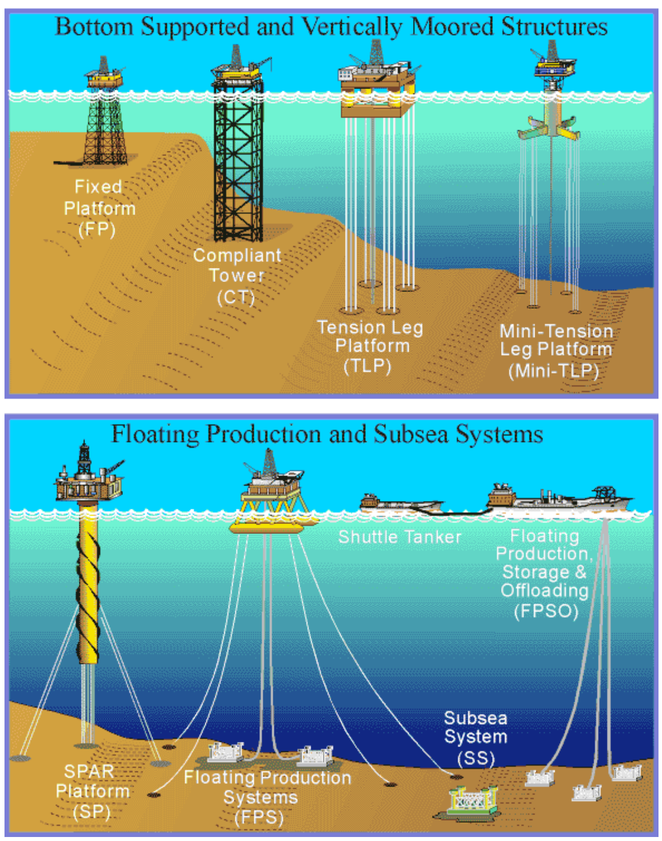


Figure III.5. Lost-time injuries.[8]



Source: Minerals Management Service

Figure III.6. Offshore structures.[9]

[8] Johnson, reference 4.

Technology continues to expand our possibilities in deep water, providing access and enabling deepwater development far beyond what was thought possible 20 years ago.

Searching for hydrocarbons today is about as far removed as possible from old movie images of wildcat drillers hoping for a gusher. It involves teams of geologists, geophysicists, and petroleum engineers seeking to identify, characterize, and pursue geologic prospects that may contain commercial quantities of oil and gas. Because these prospects lie thousands of feet below the earth's surface, uncertainty and trial-and-error pervade the exploration process. It is a painstaking and hugely expensive enterprise, with traditionally low success rates. Historically, new field wildcat exploration has succeeded at a rate of one productive well for every five to 10 wells drilled.

Over time, the more easily discovered resources in the United States have been found, developed, depleted, and then plugged and abandoned when they reached their economic limit. New fields now being discovered in the United States are generally smaller in size and found in deeper, more subtle, and more challenging geologic formations. Yet, despite the increased difficulty of discovering remaining domestic resources, technology developments have enabled the oil and gas industry to maintain or, in many cases, improve upon, historical levels of exploration success. Today, experts can interpret geological and geophysical data more completely; manage, visualize, and evaluate larger volumes of data simultaneously; and communicate interpretations based on these data more accurately. Advanced techniques now allow the scientist to virtually "see" the inside of the formation. Three-dimensional seismic technology, first commercially available nearly 25 years ago, bounces acoustic vibrations off subsurface structures, generating massive amounts of data. Then, powerful computers manipulate the data to create fully visualized multidimensional representations of the subsurface. Even more exciting is 4D, or time-lapse, imaging—which adds the dimension of time, allowing scientists to understand how the flow pattern of hydrocarbons changes in the formation over time.

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[9] Johnson, reference 4.

Improvements in 3D seismic and 4D time-lapse visualization, remote sensing, and other exploration technology allow explorationists to target higher-quality prospects and to improve success rates by as much as 50% or more (Figure III.7). The result: fewer wells need to be drilled to find a given target, and production per well is increased, in some cases by 100%. Annual reserve additions for new exploratory drilling have quadrupled, from a per-well average of about 10,000 barrels of oil equivalent (BOE) in the 1970s and 1980s to over 40,000 BOE in the 1990s. Thanks to today's technology, whole new categories of resources, considered inaccessible just 20 years ago, are now counted as part of the domestic resource base. Advances in exploration drilling technology have been particularly dramatic in deepwater areas, where significant expansion of the known resource base has resulted (Figures III.8 and III.9). In aggregate, technology improvements have slashed the average cost of finding oil and gas reserves in the United States from a range of $12 to $16 per BOE of reserves added in the 1970s and 1980s to $4 to $8 today.

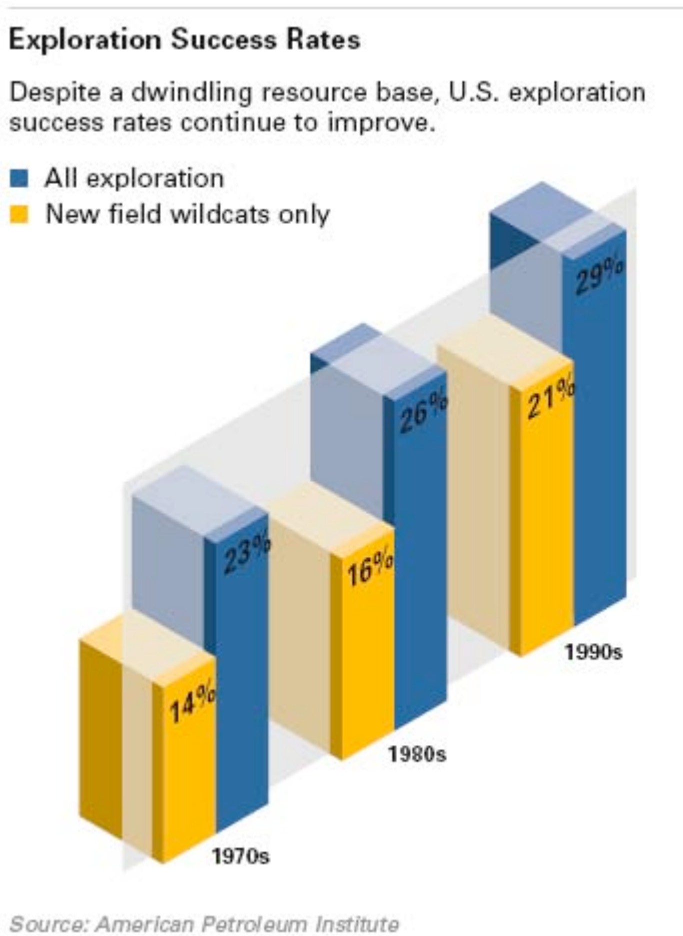


Figure III.7. Exploration success rate.[10]

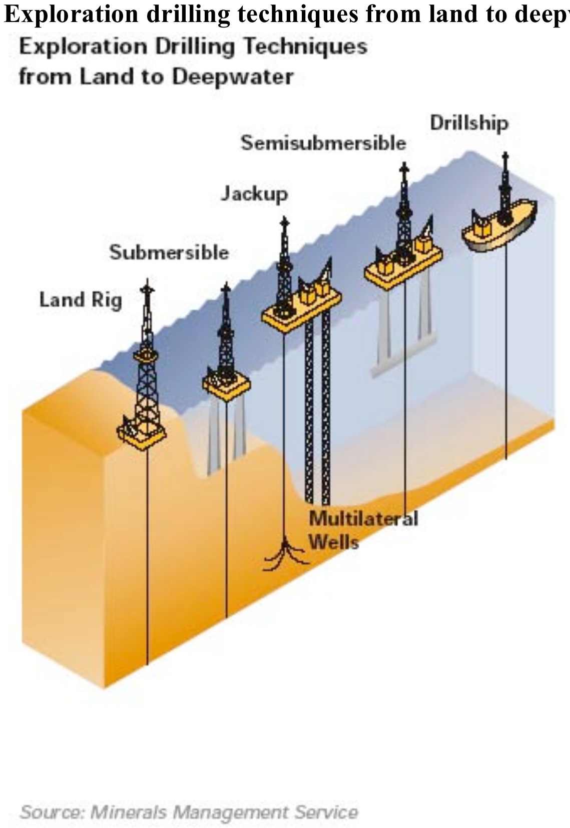
High-technology advances in widely varied technical disciplines have boosted exploration efficiency over the past 20 years:

- Advances in computer power, speed, and accuracy
- Remote sensing and image-processing technology
- Satellite-derived gravity and bathymetry data that enable remote sensing for offshore deepwater exploration
- Developments in global positioning systems (GPS)
- Advances in geographical information systems (GIS)

[10] US DOE/EIA, reference 3.

- Three-dimensional (3D) and 4D time-lapse imaging technology that permit better characterization of geologic structures and reservoir fluids below the surface
- Improved logging tools that enhance industry's geoscientific understanding of specific basins, plays, and reservoirs
- Advances in drilling that allow explorationists to more cost-effectively tap undepleted zones in maturing fields, test deeper zones in existing fields, and explore new regions.

Figure III.8. Exploration drilling techniques from land to deepwater.[11]



At BP Amoco/Shell's Foinaven field, estimated recovery rates of oil-in-place are expected to reach 65 to 70% with 4D seismic, compared to 25 to 30% with 2-D technology and 40 to 50% with 3D technology.

[11] US DOE/EIA, reference 3.

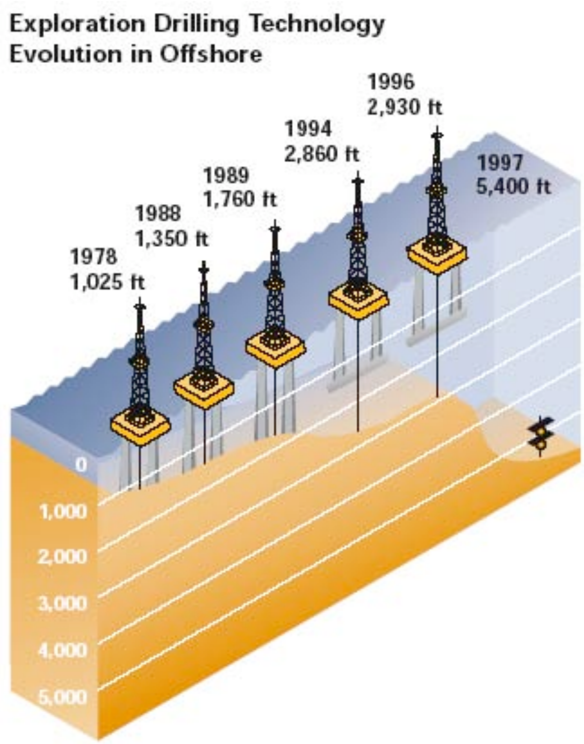


Figure III.9. Exploration drilling technology evolution in offshore areas.[12]

[12] US DOE/EIA, reference 3.

IV. Tables of Advances

Table IV.1 lists our expected future technologies that will impact conventional wells. The significance shown is determined by the difference in impact between a business as usual case and an accelerated technology case, listed with greatest impact first.

Technology	Significance/ Time frame	Discussion
Big increase in controlled reservoir contact	Large/2015	Fishbone-shaped drainage fields evolving from many wells with many multi-lateral drain holes. Biggest impact is a significant increase in recovery.
Arthroscopic production (well construction)	Large/2025	
Drilling efficiency	Large/2015	A further extension of gains already made.
Mission control for everything	Large/2020	Achieving full system control and optimization (porespace to pump).
Everything connected (network)	Medium	
Abandonment with view to arthroscopic future	Low	
SWEEP (see, access, move)	Large/2020	Full system control and optimization over the reservoir.
Reservoir vision & management in real time	Large/2020	
Smart well (injection and production)	Large/2015	
Control and measure each perforation	Medium	
Self-healing systems	Low	
Robotic intervention (easy, cheap, quick)	Medium	Automation.
Rigless subsea intervention	Medium	
Downhole refinery	Medium	From upgrading to final product.
Increased computer power	Medium	A further extension of gains already made.
Carbonates understanding	Medium	Better knowledge in the key reservoirs of the coming decades.
Sensor improvement	Medium	A further extension of gains already made.
Sensor networks	Medium	
Risk management	Medium	Better decisions.
Ability to gain isolation (cement) in horizontal wells	Medium	Horizontal wells perform fully.
Smart fluids	Medium	Ability to have the right properties at the right time.
LWD high speed telemetry	Medium	Real-time results, images and control.
More choices	Low	Ability to select from many alternatives.

Table IV.1. Future technologies impacting conventional wells, including time frame for most significant technologies.

Table IV.2 shows our expected future technologies that will impact enhanced oil recovery. As before, the significance is determined by the difference in impact between a business as usual case and an accelerated technology case.

Technology	Significance/ Time frame	Discussion
CO_2 flood mobility control	High / 2020	The ability to monitor and control a CO_2 flood front will be extremely valuable.
Reservoir characterization and simulation (multi-xcale and multi-physics) including simultaneous inversion with forward model	High / 2015	Extending current technology to include simultaneous inversion of all measurements with a forward model.
Reservoir-scale measurements plus uncertainty	High / 2020	Joint interpretation of many very deep reading measurements will allow realtime knowledge and control of the sweep front.
Horizontal, multilateral, and fishbone wells	High / 2020	Multiply placed drainholes from a main wellbore will further extend commercial access to reserves.
SAGD or steam and alkaline-surfactant-polymers (ASP)	High / 2030	Technologies to perfect and optimize SAGD operations (including the use of alkaline-surfactant-polymers) will be key to widespead economic exploitation of heavy oil.
Artificial lift	High / 2030	Produce only wanted fluids to surface.
Carbonate technology plus mobility control	Medium / 2020	Increasingly, future production will come from Carbonate reservoirs.
Rock-fluid chemistry and physics plus chemical flooding	Medium / 2020	Better understanding and control of what transpires at the pore space.
Advanced steam flooding additives including low-IFT fluids	Medium / 2020	
CO_2 + WAG + Gas Injection	Medium / 2030	
In situ processes and upgrading	Low / 2030	Produce only wanted fluids to surface.
Gravity-stable miscible and immiscible displacement	Low / 2020	Better control of flood fronts.
Hydraulic fracturing	Low / 2020	Better control of displacement and production.

Figure IV.2. Future technologies impacting enhanced oil recovery.

Table VI.3 shows our expected future technologies that will impact arctic operations.

Technology	Significance/ Time frame	Discussion
Arctic subsea-to-beach technology	Large	Overcome issues with ice scouring.
Higher definition 3D seismic	Large	Current systems have low resolution in arctic environment.
Increase amount of drilling accomplished in narrow weather window (earlier access, later departure)	Large	Greater productivity where operating expense is extremely high.
Digital processing revolution, modeling capacity	Large	Better modeling.
Drill cutting disposal: grind and inject, thermal absorption or other methods	Large	Cost and environmental improvement.
Electric submersible pump (ESP) evolution, extended run lives	Medium	
High gas volume-fraction multiphase pumping	Medium	
High-pressure gas transmission in arctic conditions	Medium	
Improved underwater slow leak detection (oil)	Medium	
Increased communications capacity allowing remote drilling, construction, and operation	Medium	
Longer distance multiphase flow with reliable modeling including hydrates and freezing	Medium	
Lower cost of physical and biophysical environmental data gathering	Medium	
Lower cost of subsea pipeline construction and protection in ice-scour areas	Medium	
New high-strength steels with welding systems, including sour service	Medium	
Other drilling innovations: coiled tubing, under-balanced, mud, and chemicals	Medium	
Refrigerated multi-year ice pads	Medium	
Roadless tundra travel (Crowley CATCO type all terrain vehicles)	Medium	
Smaller or modular purpose-built portable (Heli, Herc or CATCO) drilling rigs	Medium	

Figure IV.3. Future technologies impacting arctic operations.

V. Discussion

Looking forward, the domestic oil and gas industry will be challenged to continue extending the frontiers of technology. Ongoing advances in E&P productivity are essential if producers are to keep pace with steadily growing demand for oil and gas, both in the United States and worldwide. Continuing innovation will also be needed to sustain the industry's leadership in the intensely competitive international arena, and to retain high-paying oil and gas industry jobs at home.

Continued technology progress will be essential in meeting the challenges of the 21st century. Further increases in productivity will be essential to sustain the viability of the U.S. petroleum industry in the face of a sometimes volatile world oil market. Industry and government leadership and American ingenuity will be necessary to preserve our nation's oil and gas production capacity and energy security. In the longer term, technology innovation will be critical to ensure optimal recovery of America's oil and gas resources. Technology innovation will be key to overcoming the constraints of an increasingly challenging resource base, domestically and around the world.

Table V.1 lists the future technologies that we believe will provide the greatest impact on conventional wells (including EOR and Arctic).

Technology	Time frame	Discussion
Big increase in controlled reservoir contact	2015	Technologies allowing a continuing increase in the number of strategically placed horizontal wells will allow a much greater commercial access to reserves.
Horizontal, multilateral, and fishbone wells	2020	Multiply placed drainholes from a main wellbore will further extend commercial access to reserves.
Arthroscopic well construction	2025	The ability to place drain holes to within feet of every hydrocarbon molecule in the formation allows the ultimate in recovery.
SWEEP (see, access, move)	2020	The combined technologies (including the four immediately below) allowing us to see, access, and move the hydrocarbons in the optimum way will bring a big increase to recoverable reserves.
Smart well (injection and production)	2015	The ability to control what fluids go where (at the wellbore).
Reservoir characterization and simulation	2015	Extending current technology to include simultaneous inversion of all measurements with a forward model.
Reservoir vision and management in real time	2020	Combining reservoir scale measurements (pressure, seismic, electromagnetic, and gravity) in a joint inversion, with uncertainty and without data loss.
Mission control for everything	2020	A full representation and control of the full system (sub-surface and surface) allowing true optimization.
CO_2 flood mobility control	2020	Measurement and control of the CO_2 flood front is critical successful implementation.
Artificial lift	2030	Produce only wanted fluids to surface.
Drilling efficiency	2015	A further extension of gains already made.
SAGD or steam and alkaline-surfactant-polymers (ASP)	2030	Technologies to perfect and optimize SAGD operations (including the use of alkaline-surfactant-polymers) will be key to widespead economic exploitation of heavy oil.
Arctic subsea-to-beach technology	2020	Ice scouring of the seafloor surface presents a huge challenge to conventional approaches to subsea and subsea-to-beach operations.
Faster and more affordable, higher-definition 3D seismic	2015	Quicker, better, cheaper, could extend this already impressive 'specialized' technology into universal use.

Table V.1. Summary of highly significant technologies.

A. Big Increase in Controlled Reservoir Contact, Horizontal, Multilateral and Fishbone Wells, and Arthroscopic Well Construction

The key finding from the group was the strong belief that, by far, the biggest future impact of technology on conventional wells would come in the form of increased reserves and recovery factors. Specifically, this expert group projects that average recovery factors will rise from the current mid-30% percent to the low 50% range by 2030. The technology area expected to contribute most to this gain will be the ability to vastly increase the area and distribution of wellbore to reservoir contact.

This topic grew out of the group's perception that the greatest historic growth in recovery factor has come from a significantly increased contact area with the reservoir. An example is the evolution from a regulated, 160-acre, vertical-well spacing to our current ability to use many optimally placed (including horizontal) wells to drain a reservoir.

Looking to the future, our group believes that this improvement will come from a (further) vastly increased ability to place a wellbore (or drainhole) very close to every molecule of oil in the reservoir. Our vision of this is analogous to the vascular system where a complex network of veins and arteries provide an open pathway for blood flow to and from every part of the body. We believe that well-construction technology will evolve over the next 20 years to provide a similar network in a reservoir. This capability provides two very powerful improvements to production and recovery. First, by providing an open path to the surface, there is a significant reduction in the energy needed to move the hydrocarbons to the surface. The more subtle, but equally powerful, improvement is that by placing a drainhole within ~50 feet of every molecule in the reservoir, we've reduced the maximum size of any potentially bypassed isolated cell to ~100 feet. Ultimately, we predict that this effort will include operations similar to arthoscopic surgery, placing a minimally sized drainhole at a precisely and optimally determined location, with little adjacent disruption.

B. Drilling Efficiency

The more significant form of this technology (going forward) may come from a move to a smaller footprint, more adept processes (related to the previous topic). Additionally, traditional gains in cost, safety, and speed will occur. Another area for advance is problem avoidance (pore pressure, fracture gradient, and wellbore stability).

C. Mission Control for Everything

The basic concept is to treat the entire process (surface and subsurface; exploration through the entire life of the reservoir) as a single system to be optimized and continually improved. The objective is to make the most efficient use of our expertise base by automating tedious, repetitive, unsafe, inefficient tasks, and those tasks most prone to human error, and by enhancing the capabilities of our people through automation within: knowledge management; analysis; simulation and uncertainty management; prognosis; decision analysis; and execution (action).

In this scenario, expertise is distributed around the world in and between companies. Expertise is enhanced by automation in data management, simulation, uncertainty management, prognostics. Experts make decisions, and are part of the automation continuous improvement process. Administration is seamless with logistics automated through web services.

Field locations would have the benefits of local autonomy, with logistics and resources optimized across the company. Local staff would have access to expertise through automated systems, particularly in case of something breaking down. Work schedules would be attractive because of the elasticity of response created by automation and access to multiple remote experts

Multivendor asset equipment is fully networked from downhole to seabed to surface when this mission-control model is in place. Information about the performance of an asset and the levels of uncertainty in future performance are constantly updated. Automation plays a key role in a rolling simulation, uncertainty analysis, and optimization of asset exploitation.

In addition, surface systems are networked and can be controlled remotely. Automation drives efficiency, safety, and economics. The surface environment is safe and attractive. Dangerous, unpleasant and inefficient tasks, and tasks prone to human error are automated. Well-trained technicians operate surface equipment with input from remote experts.

Downhole information and control would be available through higher bandwidth communication channels throughout well construction, completion, and production. Installation of completion hardware would be predictable and reliable. Flexible, semi autonomous, bandwidth optimized, and context aware systems would reduce the need for intervention.

Two SPE papers discussing this topic are by Unneland and Hauser, and by Mochizuki et al.[13]

D. SWEEP (including EOR floods)

The basic concept of this approach is that the industry develops the capability to fully monitor and control the way fluids are moving through a reservoir. This is extremely challenging, but has huge implications on recovery. Much has been written about this in the literature.[14]

To improve EOR recovery it is essential to improve sweep efficiency. This will require significant improvement in reservoir-scale surveillance technology and in our

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[13] Unneland T and Hauser M: "Real-Time Asset Management: From Vision to Engagement—An Operator's Experience," paper SPE 96390, presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas (October 9–12, 2005).
Mochizuki S, Saputelli LA, Kabir CS, Cramer R, Lochmann MJ, Reese RD, Harms LK, Sisk CD, Hite JR, and Escorcia A: "Real Time Optimization: Classification and Assessment," *SPE Production & Operations* 21, Number 4 (November 2006): 455-466, also paper SPE 90213.

[14] For example:
Heir M, Nielsen PE, Pettersson SE, Mikalsen T, Lilleng T, and Garcia C: "Technology Strategy for Real Time Reservoir Management", available at
http://www.ntnu.no/gass/conferences/System_seminar271003/OG 21 - TTA Real Time Reservoir Management - LP BP - Morten Heir .pdf
Lund B and Nyhavn F:"The value of Real Time Reservoir Management and the implications from moving sensors and valves downhole", available at
http://www.spe.no/bergen/doc/one_day_seminar_04/pdf_disc/klokkeklang/6 The value of Real Time Reservoir Management.pdf

ability to interpret and make the measurements. In some cases it will be possible to improve the sweep efficiency by changing injection and production rates; in other cases it will be necessary to target unswept areas with infill or sidetrack wells. In any case, it will be critical to interpret the observations in terms of changes in saturations. Unfortunately, the observations that we can make are not direct measurements of saturation, but rather are related to physical properties (e.g. pressure, temperature, impedance, electrical resistivity, and gravity) and it is necessary to interpret the changes in physical properties in terms of the fluid-saturation changes. Today these physical properties are converted to saturations using a combination of empirical equations (e.g. Wiley time average, Archie equation) and equations based on first principles (e.g. fluid substitution) and parameters based on core analysis (m, n, Pc, k, etc.). This empirical foundation limits the accuracy of this approach and our ability to manage reservoirs. Today, to interpret the observational data, we are generally forced to run a reservoir simulator, and in parallel, compute the saturations changes based on observations, and thereby infer fluid movements. Ideally this manual means of "inverting" the data to infer the fluid distributions would be replaced with a reservoir simulator that predicts not just the changes in reservoir pressure, fluid flow, and saturations, but also changes in petrophysical properties. This type of simulator would greatly facilitate interpretation via inversion.

Fortunately, today there is significant research effort focused on pore-scale petrophysics based on micro-CT imaging of the pore space, modeling based on first principles of the fluid flow, elastic properties based on the pore and grain geometry, and capillary pressure based on assumed wettability, contact angles, and pore geometry. With pore-scale modeling, it is possible to make quantitative predictions of petrophysical properties of reservoir rocks based on representative microscopic models of the pore space as an input. Recently, there has been an explosion of interest in pore-scale modeling, which is now used to investigate various physical phenomena in rocks, such as effects of wettability (including mixed-wet conditions), three-phase flow, hysteresis in various rock properties, and reactive transport processes, to name only a few. The next-generation reservoir simulators will incorporate results from pore-scale modeling. It is unlikely that we will ever be able to model a reservoir accounting for all individual pores. However, it will be possible to upscale from the pore to the grid block honoring the correct physics.

The successful modeling of physical processes at the pore-scale demands an accurate representation of the complex geometry of the pore space. Nowadays this is usually achieved either by working with actual core images (digitized X-ray microtomographic images or thin-section data) or by creating numerical model rocks via simulation of various geologic processes involved in forming the rock (sedimentation, compaction, cementation, etc). However, complications still exist: technology today is unable to produce reliable rock images at the sub-micron scale (i.e. resolve geometric structure of clay minerals). Numerical models, which would be able to simulate processes of forming authigenic clay minerals in pore space, are not yet fully developed. Some advances have been made in modeling the coupling of fluid flow, reactive transport modeling, and chemical reactions at the pore scale, leading to realistic descriptions of authigenic processes in rocks (e.g. mineral alterations, weathering, and clay growth). Some of the most recently developed multiscale approaches in this area consider upscaling from molecular dynamics to the pore scale (i.e. from nano-scale to micron-scale). Advances and improvements in both imaging techniques and numerical reconstruction of rocks are expected in the future.

The vector in pore-scale modeling research is starting to turn toward the application of reservoir simulation in various complex conditions. The emphasis is on mixed-wet conditions, three-phase flow simulations, and dynamic (viscous) effects. Pore-scale studies and petrophysical predictions for conditions, typical for a given reservoir, can be used to upscale data for the field-scale reservoir simulation. There is a long way to go, but since there is a growing interest from the oil industry and environmental agencies (concerned about CO_2 sequestration) in such applications, the work in this direction will progress. The main obstacle is the high computational costs (for example, modeling three-phase flow in mixed-wet conditions in numerically reconstructed rock at the micron-scale) that these elaborate pore-scale algorithms demand. Another problem is that pore-scale models still require input data: either derived from core analysis or from the detailed knowledge of the geologic history of each particular formation.

Downhole logging measurements provide some of the necessary data; however, usually these data represent larger scale. Moreover, most of the developed pore-scale models are unable to work with data derived from logging measurements only. These factors (i.e. high computational costs and input data which are not readily available) preclude the widespread application of pore-scale models to produce the petrophysical parameters to upscale and use in reservoir simulation. The situation may change, however, as more powerful computational resources will be available in the future, and if the pore-scale techniques will be able to utilize logging measurements on a routine basis.

E. Artificial Lift, and a Downhole Refinery

The contribution in this case arises from being able to separate or refine the desired fluids downhole, and produce only desired fluids to the surface. Optimally, this reduces the energy required to lift produced fluids, eliminates surface disposal of unwanted fluids, and helps maintain reservoir pressure (through re-injection of unwanted fluids). At the extreme, this approach might produce only fuel (or electricity). There has been a flurry of recent patent activity addressing the in-situ refining of kerogen-laden shale oil into near-commercial grade fuels.

F. CO_2 Flood Mobility Control

CO_2 flooding is one of the most successful enhanced oil recovery techniques, and it is being applied in West Texas. If governments ban or limit CO_2 emission from power plants, more CO_2 would become available for injection into oil reservoirs, which in turn can produce oil and sequester CO_2. A recent DOE study estimates 89 billion barrels of oil can be produced by CO_2 flooding in USA alone. Also, hydrocarbon-gas flooding is quite popular in the North Slope of Alaska. Sweep efficiency is still very poor in CO_2 flooding and other gasflooding processes in heterogeneous reservoirs. The “game-changing” improvement that can make CO_2 or gas flooding more efficient in heterogeneous reservoirs is mobility control. More research is needed to develop and test foams and CO_2 thickeners for mobility control in heterogeneous and fractured reservoirs. Foams are also useful in steamfloods and chemical floods in providing mobility control and must be developed.

One means to accelerate this technology would be for the DOE to fund fundamental research in mobility control and sweep improvement for EOR. Foams and other chemicals for sweep improvement must be thoroughly researched and tested in different lithological conditions. Foams should be developed not only for CO_2 flooding, but also for steamfloods and chemical floods.

U.S. producers are comfortable with the CO_2 flooding technology because of their experience in West Texas. They would adopt mobility-control technology faster than the rest of the world.

G. Reservoir Characterization and Simulation (Multi-Scale and Multi-Physics) including Simultaneous Inversion with Forward Modeling

Numerical reservoir simulation is a primary tool for the planning and management of EOR operations. The predictive capability of reservoir simulation depends on the (a) quality and resolution of the reservoir characterization model (RCM) and (b) the ability of the numerical simulator to accurately and efficiently describe the complex multiscale physics that governs the specific EOR process under consideration.

Oil reservoirs are large-scale natural geologic formations with properties (e.g. porosity and permeability) that usually display high variability levels and complex multiscale patterns of spatial correlation. In practice, only limited information is available about a particular formation (e.g. cores, logs, transient well tests, and dynamic data from a few wells). Having limited information about these large and complex natural systems means that a certain level of uncertainty is associated with any RCM we construct. Thus, it is important to invest in efforts aimed at developing characterization methods with improved resolution and information content as well as methods that improve our ability to integrate available information of varying quality and from different sources (e.g. cores, logs, seismic data, production or injection data, outcrops and training images, and quantitative geologic interpretations) into the RCM. This includes: (a) geophysical imaging technologies aimed at resolving small-scale features; (b) high-resolution biostratigraphy and geochemistry characterization; (c) inverse modeling and the integration of all available static and dynamic data into the RCM; and (d) performance optimization under uncertainty.

As indicated above, the predictive reliability depends on both the quality of the RCM and the ability to model the dynamics of the EOR processes accurately and efficiently. EOR displacement processes involve nonlinear, multi-component, multiphase flow and transport that operate on a wide range of length and time scales. A concerted research effort aimed at improving our understanding of the complex physics associated with EOR displacements, and developing advanced numerical methods that accurately represent the relevant physics are necessary. Examples include: (a) pore-scale description of multiphase flow and transport processes in natural porous media; (b) multiscale formulations for high-resolution simulation of nonlinear reservoir-scale EOR processes; and (c) methods that integrate the behaviors governed by different physics at different scales (i.e. multi-physics, multiscale processes).

According to DOE-EIA projects the world will need more oil, natural gas, and coal in the next 20 years.[15] Those resources will come from conventional and unconventional oil and gas reservoirs. To prepare for the future, it is important that the oil and gas industry focus on the technologies that will be needed to continue the development of oil and gas from both types of reservoirs.

The final goal of any study in reservoir characterization is to use the information obtained from different scales of resolution to identify a geological model that can then be used in the simulator.

A variety of types and scales of heterogeneity are found in most reservoirs. Direct and indirect information obtained form different technologies reflect different

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[15] U.S. DOE/EIA: "Annual Energy Outlook 2007 with Projections to 2030."

aspects of reservoir at different levels. Future research should focus on the characterization of types and scales of heterogeneities, specifically in megascopic, macroscopic, and mesoscopic scales.

1. Megascopic Scale [10^4–10^5 m]

Seismic scale: Low frequency seismic will be used for characterizing the anisotropy of the reservoir (mapping heterogeneities) and monitoring the changes in the stress field of sensitive reservoirs.

One type of heterogeneous reservoir is the naturally fractured reservoir. In this reservoir, fractures are small compared to seismic wavelengths; in the limit, many small scatters are equivalent to an effective medium with decreased velocity and increased attenuation. If the medium has a preferred fracture orientation, then the effective medium can be considered anisotropic.

Figure VG.1 shows two of the three theoretical models of anisotropy: vertical transverse isotropic (VTI, not shown), horizontal transverse isotropic (HTI), and orthotropic. Compressional-wave (*P*-wave) reflection amplitudes at different azimuths produce an azimuthally dependent amplitude-variation-with-offset (AVO) response. The AVO response can be used to find the primary orientation of the factures, quantifying the degree of fracturing, fracture density, aperture, and elastic moduli.[16]

Azimuthal anisotropy caused by cracks and stress can also be related to the permeability tensor of the rock for an HTI model.[17] Inversion can be used to produce a model of the HTI elastic properties. Those elastic properties can be used to find the elastic tensor that connects the stress and strain tensors. Using Hook's law, the strain tensor can be calculated and related to changes in fracture width, so changes in permeability can be calculated.

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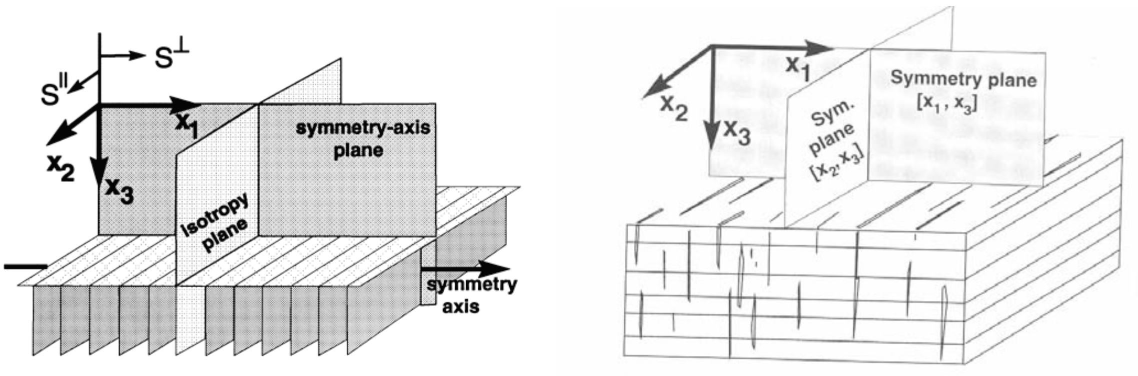
[16] Minsley B, Wills M, Burns D, and Toksos N: "Investigation of a Fractured Reservoir Using *P*-Wave AVOA Analysis: A Case Study of the Emilio Field with Support from Synthetic Examples," SEG International Exposition and 74th Annual Meeting, Denver, Colorado (October 10–15, 2004).
[17] Ruger A: "Variation of *P*-wave reflectivity with offset and azimuth in anisotropic media," SEG Expanded Abstracts, 66th Annual International Meeting, Denver (1996): 1810–1813.

New developments in AVO technique and inversion methods will be very important in this area. They may lead to better estimates of the incidence angle with depth, optimization of data discretization-stacking methods, and extension of the HTI model to the orthotropic model.[18]



HTI model Orthotropic model

Figure VG1.1. Anisotropic models [Restrepo, reference 13].

Well-test scale: The classical Warren and Root model and other related models are acceptable for determining some reservoir parameters ***if*** the fracture network can be represented by a sugar cube or slab geometry. If not, these models seem to be not very realistic and the pressure response will be difficult to interpret.

Gomez simulations in radial percolating networks of type 1 reservoirs show that the flow through connected fractures is best represented by a tortuous path, so the use of radial geometry in naturally fractured reservoirs may not be the best in all cases (see Figure VG1.2).[19]

Research in percolation networks for types 1, 2, and 3 reservoirs that include the effect of stresses is necessary: since the stress field imposes preferential flow zones, the process is not totally random.

Naturally Fractured Reservoir Types
Type 1: Fractures provide all the reservoir storage capacity and permeability.

[18] Restrepo D: "Special Studies. Low frequency seismic and fracture characterization," Dept of Petroleum Engineering, University of Oklahoma (2006).
[19] Gomez S: "Transicion de Percolacion en Flujo en Rocas y Exponents Anomalos," Phd Dissertation, Universidad Nacional de Colombia Sede Medellin, (2000).

Type 2: Matrix has very good permeability; fractures add to the reservoir permeability and can result in considerably high flow.
Type 3: Matrix has negligible permeability but contains most if not all hydrocarbons. The fractures provide the essential reservoir.
Type 4: Fractures are filled with minerals. These fractures tend to form barriers to fluid migration and partition formations into relatively small blocks. These formations are significantly anisotropic and often uneconomic to develop and produce.
Source: Tiab D and Donaldson E: "Naturally Fractured Reservoirs," Chapter 8 in *Petrophysics, Theory and Practice of Measuring Reservoir Rock and Fluid Transport Properties,* 2nd Edition, Gulf Professional Publishing (2003).

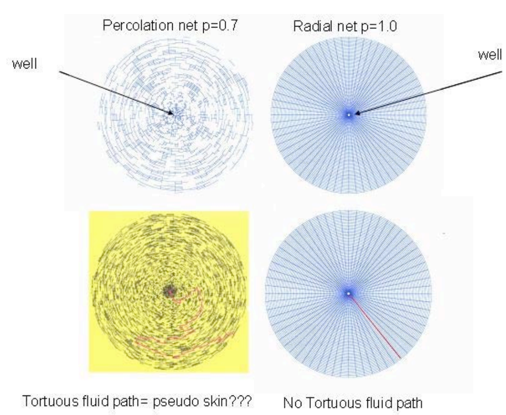


Figure VG1.2. Comparison between percolation and a radial net [Gomez, reference 14].

Research in percolation nets for types 2 and 3 reservoirs is necessary, Also new models that include dual porosity and dual permeability, random fracture distribution and no radial flow should be developed.

2. Macroscopic Scale [10^2–10^3 m]

Sub-seismic scale: The information acquired using tools in this scale allow us to more accurately investigate the architectural elements of the reservoir, such as lateral and vertical bed continuity or discontinuity. According to Slatt, the heterogeneities in this scale are difficult to identify and quantify because "technologies required to image interwell-scale heterogeneities often exhibit resolution that are too coarse for one to observe the features."[20] Tools used for these studies are crosswell and multicomponent seismic. Although resolution in the vertical direction of these methods is an order of magnitude better than conventional seismic, the horizontal resolution of these tools decreases. This implies that technological developments that improve the horizontal resolution must be conducted in the future.

3. Mesoscopic Scale [10^{-1}–10 m]

Today, formation evaluation has limits that are dictated by available logging technologies, core-analysis expertise, petrophysical models, and interpretation methods. Logging technologies have not yet enabled direct and continuous measurements of formation permeability and electrical properties. Standardization of procedures among core-analysis laboratories is also needed for better formation evaluation and petrophysics. In the future those issues will be important research topics. Some of those researches in heterogeneous reservoirs focus on well-logging scale or core scale.

Well-logging scale: Shear waves propagate through rock with different velocities in different directions (polarization). This phenomenon is called acoustic anisotropy, and it is caused by the anisotropic nature of the rock's elastic properties. During the last decade important advances have been made in sonic logging by using dipole sources.[21] New sonic tools can compute three measurements of anisotropy: energy anisotropy, slowness anisotropy and time anisotropy.[22] The energy anisotropy gives the degree of anisotropy of the formation; nevertheless, it is a qualitative

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[20] Slatt R: *Stratigraphic Reservoir Characterization for Petroleum Geologists, Geophysicists, and Engineers*, Volume 6 (Handbook of Petroleum Exploration and Production), Elsevier (2006).

[21] Brie A, Endo T, Hoyle D, Codazzi D, Esmersoy C, Hsu K, Denoo S, Mueller MC, Plona T, Shenoy R and Sinha B: "New Directions in Sonic Logging," *Oilfield Review* 10, no. 1 (Spring 1998): 40–55. <Tom: would this be relevant? It is more recent:>
Arroyo Franco JL, Mercado Ortiz MA, De GS, Renlie L and Williams S: "Sonic Investigations In and Around the Borehole," *Oilfield Review* 18, no. 1 (Spring 2006): 14–33.

[22] Franco JLA, de la Torre HG, Ortiz MAM, Wielemaker E, Plona TJ, Saldungaray P, and Mikhaltseva I: "Using Shear-Wave Anisotropy To Optimize Reservoir Drainage and Improve Production in Low-Permeability Formations in the North of Mexico" SPE paper 96808-MS, presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas (October 9–12, 2005).

measurement. Quantitative measurements would allow a classification of anisotropy that can be connected with the low-frequency seismic-anisotropic models (VTI, HTI, and orthotropic). Research in this area will be focused in quantitative measurements of anisotropy.

Core scale: New techniques for evaluating dual porosity fracture properties such as aperture, roughness, and relativity permeability, are being developed. Magnetic resonance imaging (MRI) and image-analysis integration will play important roles for characterizing fractures. For example, a direct measurement of core porosity by X-ray computed tomography (CT) has been used to determine the storage capacities (porosities) of several dual porosity systems.[23] Core constituent porosities can also be calculated using MRI. The main advantage is that MRI is fast and nondestructive, but it needs the development of special software.[24] Those techniques belong to probabilistic petrophysics, so the modeling techniques and mathematical methods involved in the solution of the problem are difficult to standardize. In the future, efforts in standardizing imagining techniques must be done.

Developments in those scales will produce information that must be integrated in order to improve the geological model. The use of complex, high-resolution, subsurface models and detailed geological features should be included in the simulators, so the upscaling process will be more accurate. The development of many orders of magnitude faster computers and greater data-storage capacity will make high-resolution simulation possible.

4. Simulators

Heterogeneous and compartmentalized reservoirs are difficult to simulate even using hybrid local grid refinements. In 1997, Verma proposed the use of flexible grids

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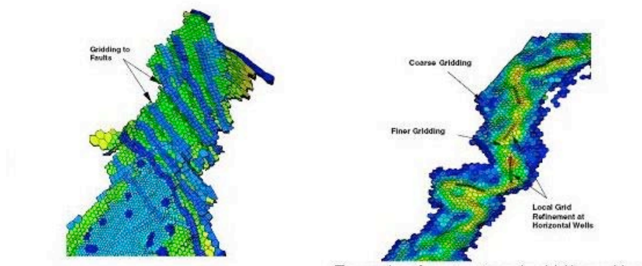
[23] Moss RM, Pepin GP, and Davis LA: "Direct Measurement of the Constituent Porosities in a Dual Porosity Matrix," paper SCA1990-03 (1990).
[24] Mattiello D, Balzarini M, Ferraccioli L, and Brancolini A: "Calculation of Constituent Porosity in a Dual-Porosity Matrix: MRI and Image Analysis Integration," paper SCA1997-06 (1997).

constructed to align the major reservoir heterogeneities using Voronoi grids.[25] However, the industry did not apply unstructured grids, due in part to concerns about potential loss in computational efficiency. In order to improve computational efficiency, flexibility, extensibility and maintainability, the software architecture of simulators is changing.[26] These requirements demand objected-oriented programming techniques that use C++ to provide maximum reuse and extensibility without sacrificing computational efficiency [13].[27]

New simulators will permit grid selection (structured and unstructured grid models), local grid refinements, and arbitrary connection to allow modeling faults and fractures and pinchouts. Figure VG4.1 shows two examples of unstructured grids.

New simulators being developed by Schlumberger (Intersect) and Halliburton (Nexus) promise to provide the computing power and reduce upscaling requirements necessary for simulation of complex reservoirs.

[25] Verma S and Aziz K: "A Control Volume Scheme for Flexible Grids in Reservoir Simulation," SPE paper 37999-MS, presented at the SPE Reservoir Simulation Symposium, Dallas, Texas (June 8–11,. 1997).
[26] Fjerstad P: "Advances in Reservoir Simulation," Schlumberger Information Solutions (2005). Available at http://www.spe.no/bergen/doc/1%20day%202005/Nina/N01%20Advances%20in%20Reservoir%20Simulation.pdf.
[27] DeBaun D, Byer T, Childs P, Chen J, Saaf F, Wells M, Liu J, Cao H, Pianelo L, Tilakraj V, Crumpton P, Walsh D, Yardumian H, Zorzynski R, Lim K-T, Schrader M, Zapata V, Nolen J, Tchelepi H: "An Extensible Architecture For Next Generation Scalable Parallel Reservoir Simulation," paper SPE 93274, presented at the SPE Reservoir Simulation Symposium, The Woodlands, Texas (January 31–Feburary 2, 2005).



Example of unstructured gridding for a series of faults

Example of unstructured gridding with a finer grid in high porosity sands and refinement around the horizontal wells.

Figure VG4.1. Examples of unstructured grids and refinement.[28]

5. Stimulation

According to a recent survey of 100 fractured reservoirs, almost half of the fields examined have an ultimate recovery less than 40%, which represent 12.6 billon barrels.[29] Research in enhanced oil and gas recovery in these reservoirs will play an important role in conventional reservoirs.

Research in stimulation in these reservoirs will be also needed. Studies of multisegmented hydraulic fractures and of multifracturing are required to optimize the hydraulic fracturing treatments.

6. Unconventional Reservoirs

One characteristic of most unconventional reservoirs is that the reservoirs have low porosity and low permeability. Since most characterizations techniques were developed to evaluate formations with high porosity, it is often the case that logging tools lose their sensitivity in low-permeability, low-porosity reservoirs. As such, better formation evaluation methods for low-porosity reservoirs will be of vital

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[28] Beckner BL, Hutfilz JM, Ray MB, and Tomich JF: “Empower: New Reservoir Simulation System,” SPE 68116, Middle East Oil Show, Bahrain, 17 – 20 March 2001.

[29] Allan J and Sun SQ: “Controls on recovery factor in fractured reservoirs: Lessons learned from 100 fractured fields,” SPE paper 84590, presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, (October 5–8, 2003).

importance. If technology can be developed that will give us a better estimate of formation permeability, along with formation porosity and water saturation, the development of unconventional reservoirs can be improved substantially.

Research in stimulation in these reservoirs will also be needed. Multisegmented and multifracturing studies are required in order to optimize hydraulic fracturing treatments.

H. Reservoir Scale Measurements Plus Uncertainty (or Deep Monitoring)

Producing oil and gas cost-effectively from the mature fields that make up the majority of today's production base is now and will in the future be a major challenge to the industry; in particular locating bypassed oil and to some extent gas between wells at the reservoir scale. This will be further complicated when mature fields go to EOR processes. In recent years, a few new deep-reading technologies with high vertical resolution have been emerging for locating bypassed oil. These include 4D-seismic, VSP, and electromagnetic imaging techniques to provide well-to-well saturation measurements. Furthermore, downhole permanent monitoring and new cased-hole, deep-reading, wireline-logging measurements are providing better understanding of formation pressure, fluid, and saturation distributions.

However, overall technology deployment has been very poor in mature fields, and it will be more difficult for EOR processes. For the successful application of EOR in mature and brown fields, over the next 10 to 20 years, oilfield challenges will include development and deployment following technologies:

- Deep reservoir monitoring
- Assessing remaining and bypassed hydrocarbons
- Adding new reserves; increase recovery factor
- Delineating heterogeneity in 3D
- Determination of residual oil saturation in 4D
- Reducing residual oil saturation

- Cost-effective use of trilaterals with three downhole control valves, with oil-water identification to maximize oil production while controlling water production
- Time-lapse, pressure, electromagnetic imaging, and seismic with better resolution.

In order to use 4D data effectively, 4D-visualization systems should be more than a depository of data, since a depository does not add value. Information about uncertainties inherent in the data and the ability to visualize data in the spatial and time domain (4D) will add value to measurements and interpretation. When data are put into a simulation model, they are upscaled and averaged, and some of the data may not even be used; therefore the 4D visualization provides a means to observe and monitor well and reservoir performance independently. This will allow us to more fully rationalize different types and qualities of data in the overall reservoir and model.

The main objective of 4D-visualization should be development of a 4D-visualization environment in which all oil field data can be displayed at true scale and resolution in their true spatial location and time. For instance, with this system one should be able to view saturation measurements and production profiles along a wellbore for a given section or whole field as a function of time.

I. SAGD, Steam flooding, Cyclic Steam, In Situ Combustion

Steam-assisted gravity drainage (SAGD) is primarily aimed at high-viscosity, thick and rich, oil-sand resources. In lighter heavy-oil areas, variations of SAGD could be applied. For example, injectors and producers could be staggered both vertically and horizontally to increase well spacing. The important research area in SAGD is improving thermal efficiency by adding small amount of solvents or by optimizing the operating pressures. With lower operating pressure, some of the shallow oil sands in Utah may be targeted. In addition, development of in situ steam generation—either through development of downhole steam generators or a controlled-combustion process—is essential for application of this technology in the offshore or North Slope of Alaska. This will unlock 20 billion bbl of resource potential in the North Slope. Development of high-temperature artificial lift is also important for this recovery technique. There are many thin reservoirs with large resources that need suitable modification of this technology such that it can be applied with energy efficiencly. High ultimate recovery in the process significantly increases the potential reserves. Worldwide, there are many resources which may benefit from application of this technology.

Steamflooding and cyclic steam processes are being used in some of the heavy oil fields in USA. Combination of existing vertical wells and infill horizontal wells may be used to capture the bypassed oil in many of those operations. Development of steam additives to improve sweep efficiency will increase recovery. Worldwide, these processes have great potential.

Once abandoned, in situ combustion technology is coming back after two decades of research and development behind the scene. This process will need a fresh look and many sincere pilot applications. If applied successfully, this can increase the recovery and reserves by factors of two to three. Areas of development should include suitable materials of construction for handling corrosive injected and produced fluids on surface and downhole. This process will be useful in recovering many mature fields that still have significant residual oil saturation. This process could be applied in the West Sak and part of Ugnu fields in the North Slope of Alaska.

J. Carbonate Technology and Mobility Control

Over half of the world's conventional oil is in carbonate reservoirs. EOR-technology needs in carbonates are different from those in sandstone reservoirs, due to much higher level of heterogeneity, presence of natural fractures, and greater oil-wetting tendency. There is a need for low-cost chemicals that can recover oil by spontaneous imbibition into the lower-permeability rocks when water flows preferentially through the higher-permeability rocks or through natural fractures. Sweep efficiency is often very poor in these formations, and more research is needed to develop and test foams and CO_2 thickeners for mobility control in these heterogeneous and fractured carbonate reservoirs.

This technology could be accelerated through US DOE funding and through formation of joint industry projects to develop and field-test technologies.

K. Rock and Fluid Chemistry and Physics, Plus Chemical Flooding

Chemical flooding EOR processes add chemicals to injected water to either improve waterflooding or recover additional oil after waterflooding. They may be classified as polymer flooding, wettability-alteration flooding, surfactant-polymer flooding, alkaline-surfactant-polymer (ASP) flooding, and alkaline-surfactant-polymer-foam (ASPF) flooding.

Polymer flooding: Polymer flooding uses high molecular-weight polymer to increase the viscosity of water and, in some cases, also reduce the water relative permeability. This process is typically used with moderate-viscosity oil (25 to 500 cp) to improve the water/oil mobility ratio. The mobility ratio is an important factor in the volume of water required to displace oil to the economic limit. Polymer flooding is sometimes used in extremely heterogeneous reservoirs even for low-viscosity oils, because reduction of mobility ratio improves sweep efficiency.

Wettability alteration: Wettability alteration is usually accomplished with alkali or surfactants or both. Wettability alteration in some cases can be simply accomplished by using fresh water for certain shaly sandstones or using sea water for chalk formations.

Surfactant-polymer flooding: Surfactant-polymer flooding has also been called low-tension flooding, micellar flooding, and microemulsion flooding (if oil is included in the injected fluids). The basis of this process is to reduce the oil-water interfacial tension by three to four orders of magnitude, such that disconnected oil drops will deform and flow with water at field pressure gradients. It has been recognized that ultra-low interfacial tensions occur at conditions where the surfactant has about equal affinity for oil and water. This usually occurs over a narrow range of electrolyte composition, termed "optimal-salinity." The challenge for this process has been to design the process such that it will be at optimal conditions in situ while avoiding the high surfactant or polymer retention that can occur at optimal salinity or over-optimal salinity conditions. One approach has been to use a salinity gradient design. It is still necessary to anticipate the electrolyte-composition change due to mixing and ion exchange with clays.

<u>Alkaline-surfactant-polymer (ASP) flooding:</u> Alkali flooding was a low-cost chemical flood because surfactant could be generated by in situ reaction between alkali and naphthenic acids present in crude oil. However, it was difficult to keep the electrolyte concentration at optimal conditions because the concentration of alkali required for propagation was usually higher than the optimal salinity. It was discovered that injection of a small amount of synthetic surfactant with the alkali made it possible to have the process pass through the optimal conditions in situ. In addition, alkali tended to reduce the adsorption of the synthetic surfactant and thus made it possible to inject a low surfactant concentration. The in situ generation of the more lipophilic naphthenic soap made it possible to inject at a salinity that was under-optimum for the synthetic surfactant and thus avoid the surfactant-polymer interactions that tend to result in large surfactant or polymer retention or both. In addition, when sodium carbonate is used as the alkali, calcium resulting from mixing and ion exchange is sequestered by formation of insoluble calcite.

<u>Alkaline-surfactant-polymer-foam (ASPF) flooding:</u> The order-of-magnitude reduction in surfactant concentration with ASP flooding makes the polymer the most expensive chemical component in the process. Since surfactant is already present, if gas is available for injection, in situ generated foam could be used for mobility control. However, some surfactants are better at stabilizing foam than others and low-molecular-weight alcohols are defoamers. Thus a possible formulation is to include polymer in the surfactant slug and use only a strong foaming surfactant and gas in the foam drive. Mobility control by foam has potential for better sweep efficiency in heterogeneous systems compared to polymer solution. This process has been successfully tested in the laboratory and is reported to have been field tested in China.

L. EOR Directions

NPC EOR studies of 1976 and 1984 presented high expectations for domestic EOR activity (projecting 3M and 2M bbl/d). This expectation has not been met. Peak domestic EOR production occurred in 1992 at 761,000 bbl/d. Current activity is 680,000 bbl/d. In the interim, many technologies have been tried; most failed. Two successes are CO_2 miscible floods and steam (cyclic, SAGD and steam flood).

A broad portfolio of oil-recovery policies and technologies, plus targeted “risk mitigation” incentives, would help industry convert these higher cost, undeveloped domestic oil resources into economically feasible reserves and production. Five specific actions would be of highest value:

Reducing the geological and technical barriers of EOR could be accomplished through an aggressive program of research and field tests. Optimizing the performance of current EOR practices and pursuing new, more-efficient technology will help lower the geological and technical risks involved with EOR, particularly for pursuing “stranded” oil and “residual oil in transition zones” with CO_2 injection.

Encouraging the production and productive use of CO_2 from natural sources and industrial emissions would greatly increase the supplies of “EOR-Ready” CO_2. Expansion and modification of natural gas treating facilities in the Green River and Wind River Basins could offer new sources of CO_2 for EOR. Other near-term options include capture of high-purity CO_2 from hydrogen, ethanol and other chemical production facilities. Finally, efficient capture and separation of by-product CO_2 from the next generation of low-emission power plants could provide massive, long-term sources of “EOR-Ready” CO_2.

Integrated energy systems would reduce the energy penalty associated with producing heavy oil and capturing “EOR-Ready” CO_2. Demonstrating an integrated “zero emissions” heat, hydrogen, and electricity generation system, which provides steam for heavy oil recovery and “EOR Ready” CO_2 from gasifying the residue products of heavy oil and oil sand upgrading and refining, would provide an improved, energy-efficient pathway for domestic oil recovery.

Collaboration with Canada on oil sands and heavy oil technology would be most valuable for increasing the recovery of domestic resources. Engaging in collaborative Canadian-U.S. efforts, such as sharing technology and conducting jointly-funded field R&D on oil sands and heavy oil, would also help develop oil-recovery technologies appropriate for domestic resources.

Increased investments in technology development and transfer would lead to higher domestic oil recovery efficiencies. New models of public-private partnerships plus field projects demonstrating optimum recovery of domestic oil resources would help foster high oil-recovery practices and technologies. An expanded program of technology transfer would help address the barriers that currently inhibit the full development and production of domestic oil by independent producers.

VI. Appendix 1: Additional Bibliography

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