Paper #1-3

OFFSHORE OIL AND GAS SUPPLY

Prepared by the Offshore Supply Subgroup of
the
Resource & Supply Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White 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 and White 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 paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

Offshore Subgroup		
Chair		
Richard P. Desselles, Jr.	Chief – Resource Evaluation Methodologies Branch, Resource Evaluation Division, Bureau of Ocean Energy Management	U.S. Department of the Interior
Members		
John D. Harper	Director, Energy	Geological Survey of Canada
Sally A. Kemp	Engineering Technologist Advisor	Anadarko Petroleum Corporation
Denis Lavoie	Research Scientist, Quebec Division	Geological Survey of Canada
Dawn W. Peyton	Senior Reservoir Engineer	Anadarko Petroleum Corporation
Paul Schlirf	Geoscience Advisor, Deepwater Gulf of Mexico	Anadarko Petroleum Corporation
Thierno S. Sow	Economist, Bureau of Ocean Energy Management	U.S. Department of the Interior

SIGNIFICANT CONTRIBUTERS

Paul Mortensen
Technical Leader
Hydrocarbon Resources
National Energy Board - Canada

SPECIAL ACKNOWLEDGEMENTS

Grant Schluender, Senior Drilling Engineer — Anadarko Petroleum Corporation

Keith Mahon, Senior Geological Advisor — Anadarko Petroleum Corporation

Mike Beattie, General Manager Facilities — Anadarko Petroleum Corporation

Executive Summary

This paper is a comprehensive literature review of studies about the potential supply, production projections and technologies that have enabled access to North American offshore oil and gas resources. We begin with a background of the United States (U.S.) lower 48 offshore oil and gas industry, as well as the dynamics of development and production along the water depth dimension. We provide an outlook of the moratoria and access to offshore lands, estimates of resources in those restricted areas, and the potential effect of those policies on the prospects of US lower 48 offshore oil and gas production. Development pathways and production projections for oil and gas are documented based on the Department of Energy's Energy Information Administration annual energy outlook reports and findings. We then examine the long term prospect of offshore oil and gas production to the year 2050. These same background, development and production prospects of Canada's offshore oil and gas resources are also undertaken in this topic paper followed by a comprehensive review of the current, emerging and future offshore petroleum technologies and their effects on the expansion of North American offshore production possibility frontier. The technology chapter is built off two important technology topic papers that accompanied the 2007 National Petroleum Council's study: "Facing the Hard Truths about Energy; A Comprehensive View to 2030 of Global Oil and Natural Gas". The first of those topic papers is "Exploration Technology". It focused on five identified core technologies in which future developments have the potential to significantly impact exploration results over the next 25 years, namely: Seismic; Control Source Electromagnetism (CSEM); Interpretation Technology; Earth Systems Modeling; and Subsurface Measurements. The second of the technology papers is "Deepwater Technology". It identified four top priority deepwater-specific technological challenges most important to the future development of the world's deepwater resources, namely: 1. Reservoir Characterization; 2. Extended System Architecture; 3. High-Pressure and High-Temperature (HP/HT) Completions Systems; 4. Metocean Forecasting and Systems Analysis.

Key Findings

Offshore development and production of hydrocarbons are significant to total North American (U.S. and Canada) supply of crude oil and natural gas. The expansion of offshore development and production is ascribed overall to technological progress keeping pace with more challenging offshore environments leading to larger field discoveries in ever increasing water depths. Government economic incentives, such as the Deepwater Royalty Relief Act, have brought about renewed interest and more intense efforts in the development of hydrocarbon resources in the Gulf of Mexico (GOM). The extent to which this growth trend is expected to last depend largely on access to publicly owned offshore lands, economic incentive legislation and policies, as well as on continued increase of productivity and technological advances. Ultimately, the inherent interplay between depletion and technological progress will set the boundaries of the development and production possibility frontier for the recoverable hydrocarbon resources in offshore North America in general and in the U.S. lower 48 offshore in particular.

We expect U.S. lower 48 offshore oil production to increase from 1.8 million barrels of oil per day in 2010 to 2.3 million barrels per day in 2035 through average annual growth rates ranging between 0.2 and 0.9 percent according to the Energy Information Administration's Annual Energy Outlook 2011(AEO2011). Offshore natural gas production is expected to rise from 2.4 trillion cubic feet per year in 2010 to 3.8 trillion cubic feet per year in 2035 through a range of annual growth rates from 0.4 to 0.7 percent according to the AEO2011. These annualized growth rate ranges encompass production projections for both the constrained and unconstrained development pathways. Beginning around 2030 and extending to the year 2050, we expect the bulk of oil and natural gas production in the lower 48 offshore to originate from the deepwater Gulf of Mexico in the emerging Lower Tertiary trend and the extension of existing and new trends into areas that are currently poorly imaged. Also, we expect additional impacts on oil and natural gas production from increased access to Pacific and the Atlantic offshore regions

Technological progress and innovation are the key factors that would enable development and production of oil and gas in new frontier regions located in deep water and in deeper reservoirs. Most notably, technologies adapted to the High Pressure High Temperature environment are the key drivers for the huge oil and gas resources hosted in the Lower Tertiary formations of the GOM. Subsea technology and extended architecture systems will boost production of offshore oil and gas in remote and challenging environments of the deep and ultra deepwater areas which lack the basic infrastructure needed to produce and transport hydrocarbons to shore. Innovative seismic technologies that allow for better imaging of the sub salt horizons in the GOM are pivotal to the expansion of hydrocarbon resources via additional newer discoveries.

In the US lower 48 offshore, newer geologic plays and trends such as the Lower Tertiary and deeper reservoirs are expected to contribute to current and near future production of crude oil and natural gas. Canadian offshore production of oil and gas is relatively lower in comparison to the U.S. lower 48, and is confined to the eastern shore in Newfoundland/Labrador and Nova Scotia. Removal of the imposed and the de facto moratoria will provide better opportunities for increasing oil and gas development and production in offshore Canada.

Table of Contents

List of Figures

List of Tables

Chapter 1: Outlook for North America Offshore Oil and Gas development

1.1. Background Development and Production of U.S. Lower 48 Offshore Oil and Gas.

Offshore development and production of hydrocarbons are significant to total United States (U.S.) supply of crude oil and natural gas. In the lower 48 US, federal outer continental shelf (OCS) oil production has increased its contribution to total U.S. production from less than 1% in 1954 to more than 25% in 2008. Similarly, offshore natural gas production rose from less than 1% in 1954 to over 11% in 2008 (Federal OCS Oil & Gas Production as a Percentage of Total U.S. Production: 1954-2008; MMS 2008). The expansion of offshore development and production is ascribed overall to technological progress keeping pace with more challenging offshore environments leading to larger field discoveries in ever increasing water depths as shown in figure 1 whereby the top 20 OCS fields in the Gulf of Mexico are in water depths exceeding 1300 feet of water.

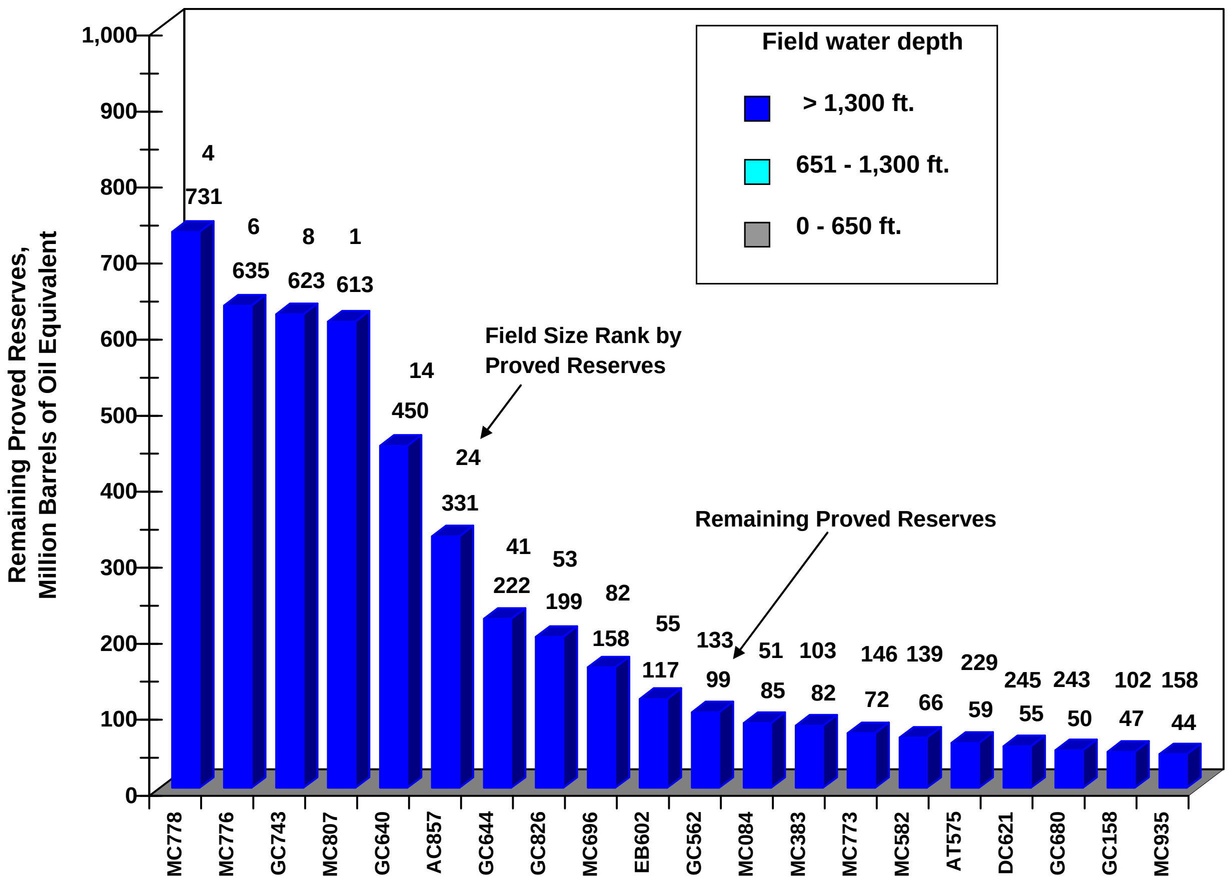


Figure 1. Top 20 Gulf of Mexico OCS Fields Ranked by Remaining Proved Reserves (source: 2006 MMS Estimated Oil and Gas Reserves Report)

Government economic incentives, such as the Deepwater Royalty Relief Act, have brought about renewed interest and more intense efforts in the development of hydrocarbon resources in the GOM. The extent to which this growth trend is expected to last depend largely on access to publicly owned offshore lands, economic incentive legislation and policies, as well as on continued increase of productivity and technological advances. Ultimately, the inherent interplay between depletion and technological progress will set the boundaries of the development and production possibility frontier for the recoverable hydrocarbon resources in offshore North America in general and in the U.S. lower 48 offshore in particular.

Currently, the lower 48 U.S. offshore oil and gas industry is largely confined to the GOM and the Pacific OCS shelf regions. Much of the Eastern Gulf of Mexico remains restricted to drilling until the year 2022, and the Pacific and Atlantic OCS areas have been restricted from leasing consideration up until 2008. For the purposes of this National Petroleum Council study, oil and gas development on the Alaska OCS is included as part of the Arctic region, rather than in the U.S. offshore region.

From its beginning in late 1940s, the U.S. federal offshore oil and gas industry has grown tremendously. In 1954 federal offshore crude oil and condensate production was around 2.5 million barrels or nearly 7 thousand barrels per day. That figure peaked to around 600 million barrels in 2002 or 1.64 million barrels per day, accounting for 29% of total U.S. crude oil and condensate production. Natural gas production from the federal offshore experienced a similar rise from about 0.06 trillion cubic feet in 1954 to a maximum of around 5.2 trillion cubic feet in 1996 which accounted for just over 25% of total U.S. natural gas production at peak. Since that time, Federal offshore natural gas production has declined to around 2.4 trillion cubic feet in 2008, or 11% of total U.S. gas production. The figures 2 and 3 show gas and oil production, as a total percentage of U.S. production from 1960 to 2009.

Expansion of the U.S. offshore oil and gas production possibility frontier is chiefly ascribed to increased productivity and to a lesser extent, Government economic incentive policies. Innovation and technological advancements, brought about by the need of US firms to improve their profit margin by lowering exploration and development costs in a market dominated by foreign National Oil Companies with access to abundant and relatively cheaper resources, constitute the main drivers of increased prospects in US offshore hydrocarbon development and production (Changing Productivity in U.S. Petroleum Exploration and Development; D. R. Bohi, 1998). The key technological drivers fueling the continuation of lower 48 offshore oil and gas productivity include: 3D seismology, computational and interpretation technologies, drilling technologies including ultra deep, extended reach and horizontal drilling, subsea completion technology, extended architecture technology, deepwater development and production systems, subsurface measurement, reservoir characterization, and Earth Systems Modeling. These and other technologies are addressed in detail in chapter 5 of this topic paper.

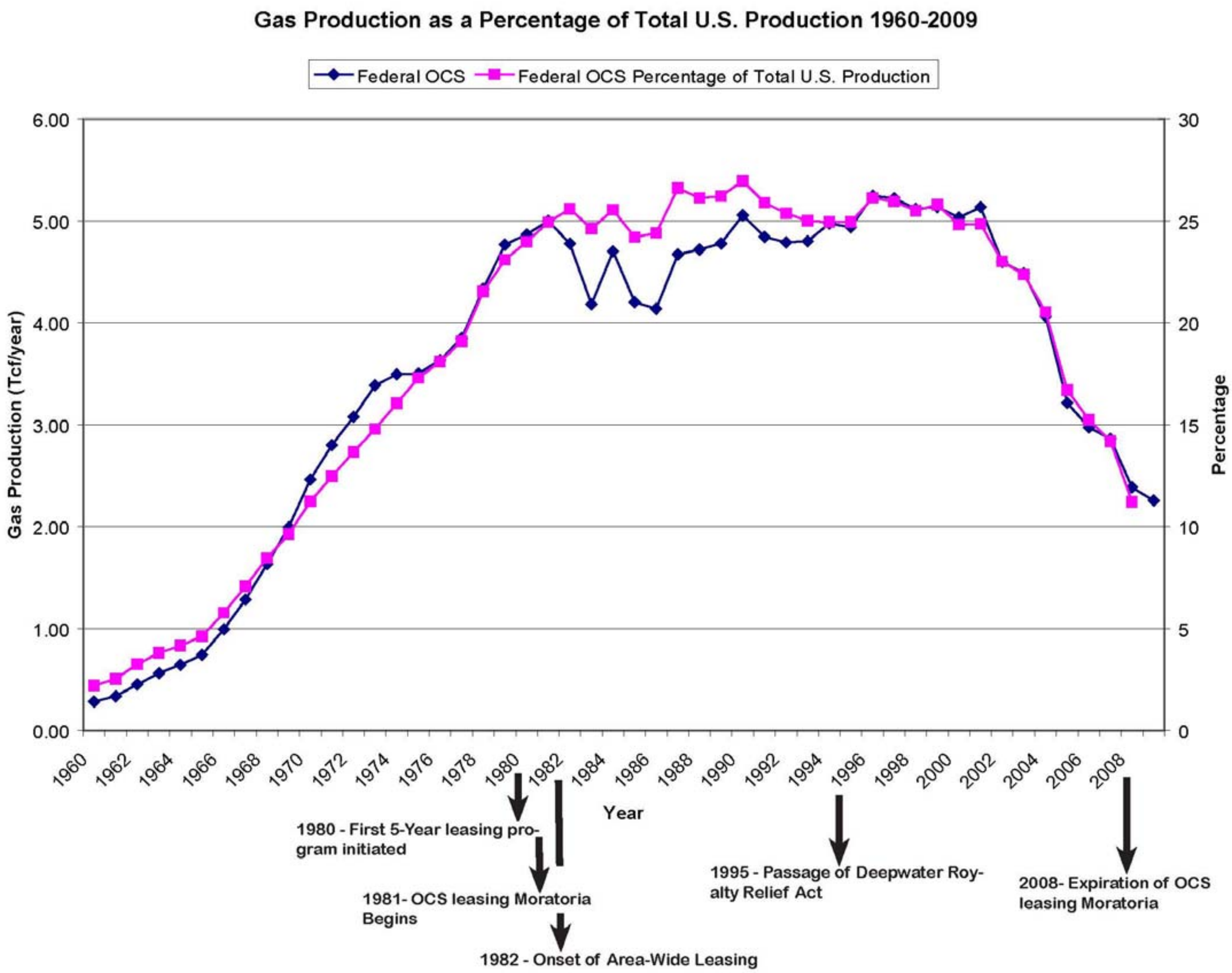


Figure 2 – Federal OCS Gas Production as a Percentage of Total U.S. Production with Policy Milestones
(Data source: BOEMRE Royalty Management Program and the TIMS Database; 2008; *www.boemre.gov/.../AnnualProductionAsPercentage1954-2006AsOf6-2008.pdf*)

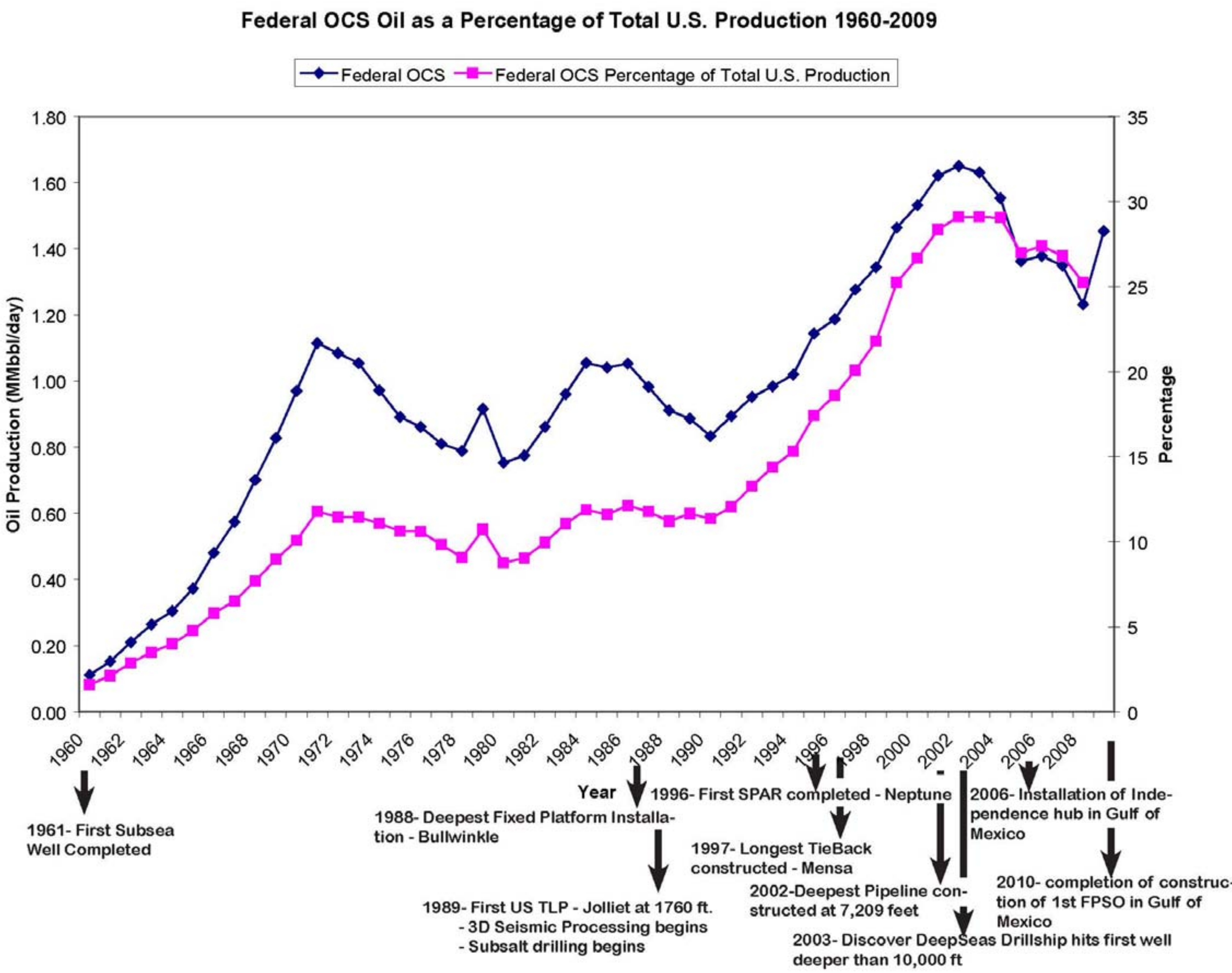


Figure 3 Federal OCS Oil Production as a Percentage of Total U.S. Production with Technological Milestones.
(Data source: BOEMRE Royalty Management Program and the TIMS Database; 2008; *www.boemre.gov/.../AnnualProductionAsPercentage1954-2006AsOf6-2008.pdf*)

Clearly, the future development of lower 48 offshore oil and gas resources rests upon the prudent development of deep and ultra-deep water prospects defined here as those exceeding 305 meters (Deep) and 1524 meters (Ultra-deep) feet of water in the GOM. This move to deepwater was made possible by way of continuous advancements in technologies that permit drilling and development in these environments. Examples of these advancing deep water technology “firsts” in the GOM include the first fixed platform, “Cognac” installed in 1979 at water depth of 1,023 feet, while the tallest steel jacket “Bullwinkle”, considered the economic limit for this fixed platform type was installed in 1989 at water depth of 1,353 feet. The first Tension Leg Platform, “Joliet” was installed in 1989 at water depth of 1,760 feet, followed by “Neptune”, the first SPAR/Subsea platform installed in 1997 in a water depth of 1,930 feet. On the ultra-deep water front, Herschel/Nakika/Fourier was the first Floating Production System installed in water depth of 6,950 feet in 2003. The first Floating Production Storage and Offloading system in the GOM was installed in 2010 at the Cascade and Chinook prospects in 8,800 feet of water. According to the MMS report on deepwater GOM, in February 1997, there were 17 producing deepwater projects, up from only 6 at the end of 1992. Since then, industry has been rapidly advancing into ultra-deep water, and many of these anticipated fields have commenced production. At the end of 2008, there were 141 producing projects in the deepwater GOM, up from 130 at the end of 2007. (Richardson et al., 2008). In March of 2010, Shell started production at the Perdido Spar complex in the Western Gulf of Mexico, and overtook the Independence Hub by setting the record for production in the deepest water. Moored 170 miles offshore in 7817 feet of water, with subsea wells in up to 9,627 feet of water, peak production should achieve 130,000 barrels of oil equivalent per day.

Development of this relatively new deepwater frontier (water depth greater than 1000 feet) is responsible for increasing overall OCS crude oil and natural gas production since 2000. In fact the year 2000 marks the transition from predominantly shallow water oil production to deepwater production. In 2000, deepwater crude oil production amounted to 271 million barrels, while shallow water production was 252 million barrels. Seven years later, crude oil production from the shallow water had dropped to 140 million barrels while deepwater regions of the GOM rose to 328 million barrels. Since 2005, the deepwater GOM has contributed about 70 percent of the total GOM OCS crude oil production. This trend is expected to continue as more discoveries and drilling activities occur in the deepwater and ultra-deepwater areas of the GOM. The bulk of natural gas production has historically originated from the shallow water areas of the GOM. Beginning around the year 2000, the Gulf of Mexico’s shallow water gas production has markedly declined while the deepwater production has been increasing. Deepwater natural gas production rose from 382 billion cubic feet (Bcf), or 7.5 percent of total GOM production in 1997 to around 1.4 trillion cubic feet in 2004, or 35 percent of total GOM natural gas production. The spur of deepwater crude oil and natural gas production can chiefly be ascribed to technological advancements in seismology, drilling, production platform, and in production strategies, such as the Hub and Tieback of subsea system from satellites and sub economic oil and gas fields. These technologies have allowed the industry to access more challenging offshore environments in terms of both water depth and reservoir depth. As of the year 2010 the distribution of production platforms by their type in the deepwater and ultra-deepwater areas of the GOM is as follows: 126 Subsea developments, 18 Tension Leg Platforms, 16 Deep Draft Caisson or SPAR, 12 Semisubmersibles, 5 Fixed platforms, 2 Compliant Towers, and 1 Floating Production Unit (Deepwater Gulf of Mexico 2009: Interim Report of 2008 Highlights. OCS Report MMS 2009-016)

The deepwater area of the GOM continues to be very important as it accounts for 70 percent of the oil and 35 percent of the natural gas production in the region. It constitutes an integral part of the US oil and gas supply, and it is viewed as one of the most important world oil and gas provinces. All this was rendered possible by means of the technological breakthroughs that have allowed Oil and Gas firms to venture out in these harsh and challenging environments. The advent of drill ships capable of drilling in water depth up to 10,000 feet and deeper reservoirs, along with the subsea completion technology and the Hub system have greatly contributed to the expansion of offshore oil and gas development and production. Subsea tieback technology coupled with innovative sub sea boosting technology also increase the ability of the industry to develop and to produce more oil and gas in fields that would be otherwise sub economical. Accounting for approximately 290 productive wells in deep water, subsea systems continue to be a key component in the success of the industry in deepwater region of the GOM.

As the U.S. offshore industry moves deeper in the GOM, new challenges emerge. The need for innovative technology to deal with increasingly higher pressure and temperature is heeded by the operating firms. One of the most challenging factors is the need to develop infrastructure and machineries that can sustain pressures exceeding 20,000 psi, and higher temperature. The industry has dubbed this challenge as the HTHP drilling environment. These environments usually are located in water depth of at least 5,000 feet and reservoirs depth of at least 10,000 feet. A typical case is the Thunder Horse project, the largest producer in the GOM with 260,000 barrels of oil per day and 211 million cubic feet per day, which is located at 6,100 feet water depth with reservoirs located at around 20,000 feet below the seabed. The wells at the Thunder Horse project reached about 29,000 feet measured depth and 26,000 total vertical depth (TVD). The pressure in these reservoirs reach 18,000 psi, at temperatures up to 270 degrees Fahrenheit ("Thunder Horse: Pushing the Technology Frontier"; Offshore, February 2009). Given these water depth and reservoir depth challenges along with their higher pressure and temperature wells, it is expected that strict enforcement of new operation safety rules and regulations will likely slow the pace of development and production of oil and gas in these frontier areas. Nonetheless, the current trend of deep and ultra deep water exploration and development drilling is the key to further expansion of the production possibility frontier of oil and gas in the Gulf of Mexico.

1.2. Moratoria and Access to U.S. Lower 48 Offshore Lands.

For a period of 26 years, beginning in 1982, moratoria provisions for the U.S. Outer Continental Shelf prohibited federal spending on oil and gas development in certain locations and for certain activities. These congressional moratoria were discontinued in

September 2008. Presidential executive orders were issued both in January 2007 and in July 2008 to lift withdrawal constraints on OCS leasing activities. These developments opened an opportunity for future offshore development and production of oil and natural gas in the US. Except for national marine sanctuaries, national marine monuments, and the currently enforced congressional moratoria areas set to expire in 2022, the remaining national outer continental shelf is available for consideration for oil and gas leasing by the Secretary of the Interior. In March 2010, the Obama Administration announced a comprehensive offshore strategy that will expand oil and gas development and exploration on the U.S. Outer Continental Shelf. This strategy includes consideration of future offshore leasing in mid and south Atlantic as well as on expanded Eastern Gulf of Mexico areas. However, this leasing strategy has been revised as of December 2010, and areas in the Eastern Gulf of Mexico that remained under a congressional moratorium and the Mid and South Atlantic planning areas are no longer considered for potential development through 2017 (source: December 1st 2010 BOEMRE Press Release- Salazar announces revised OCS leasing program).

Future expansion of offshore oil and gas production in the previously moratoria bound areas will depend on new technologies for some regions whereby restrictions are put in place in terms of surface occupancy of production platform. In those cases, industry is likely to expand their use of subsea development systems and further the advancement of extended reach drilling. Newly accessible frontier areas will benefit from technologies currently being applied in challenging environments such as the deep and ultra deep water zones of the GOM. In any rate, the industry is poised to develop resources located in these areas based on the existing drilling and development technologies.

Estimates of the undiscovered technically recoverable resources of crude oil and natural gas in the US offshore moratoria areas vary from 18.2 to 63.0 Billion barrels and 77.0 to 231.0 Trillion cubic feet, respectively. In contrast, the Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE) mean estimates of total U.S. lower 48 offshore Undiscovered Technically Recoverable oil and natural gas are 59.3 Billion barrels and 288.0 Trillion cubic feet, respectively (Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation’s Outer Continental Shelf, MMS 2006). Although these estimates include a wide range of assumptions, their sheer magnitude demonstrates that a significant resource base remains available for future offshore oil and gas production. Figure 4 shows oil and gas resource estimates in areas formerly under moratoria or considered off-limits to oil and gas production on the OCS.

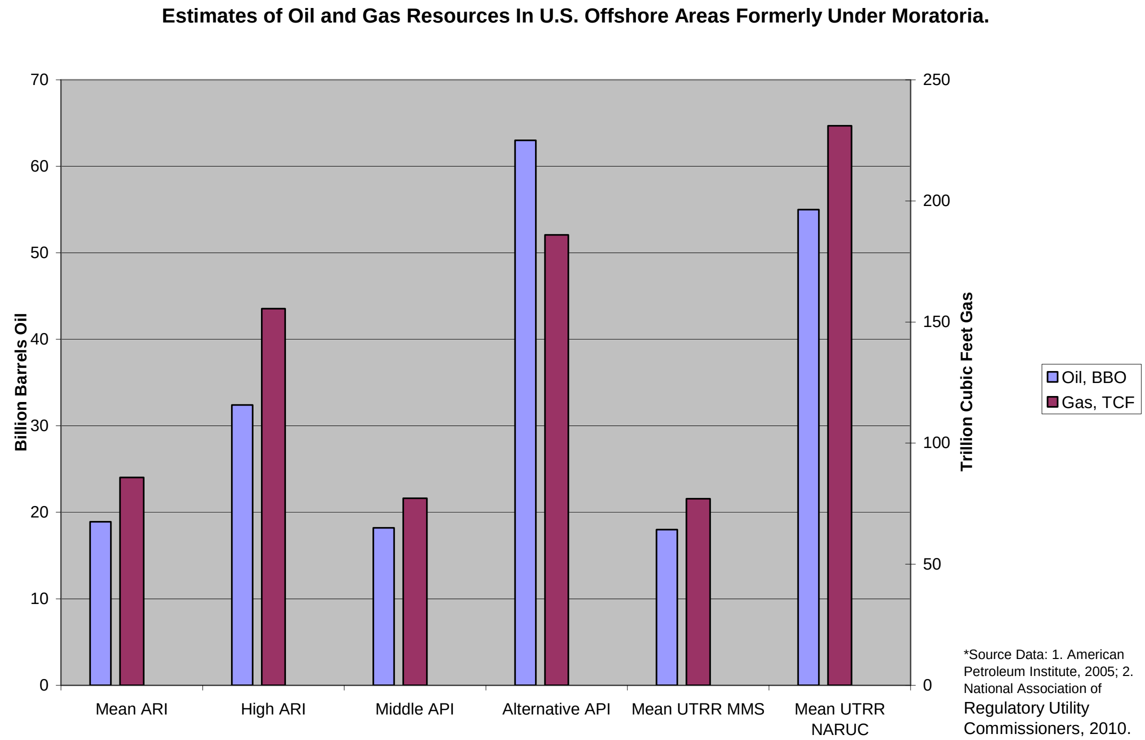


Figure 4: Estimates of Oil and Gas Resources in U.S. Offshore Areas Formerly Under Moratoria.
Data Source: 1. American Petroleum Institute, 2005; 2.National Association of Regulatory Utility Commissioners NRUC, 2010; Advanced Resources International Inc., 2006, 2009; MMS, Report to Congress, 2006.

Figure 5 provides estimates of total oil and gas production potential from offshore moratoria areas. Note that though each estimate source addresses the offshore moratoria areas, their underlying assumptions may be different.

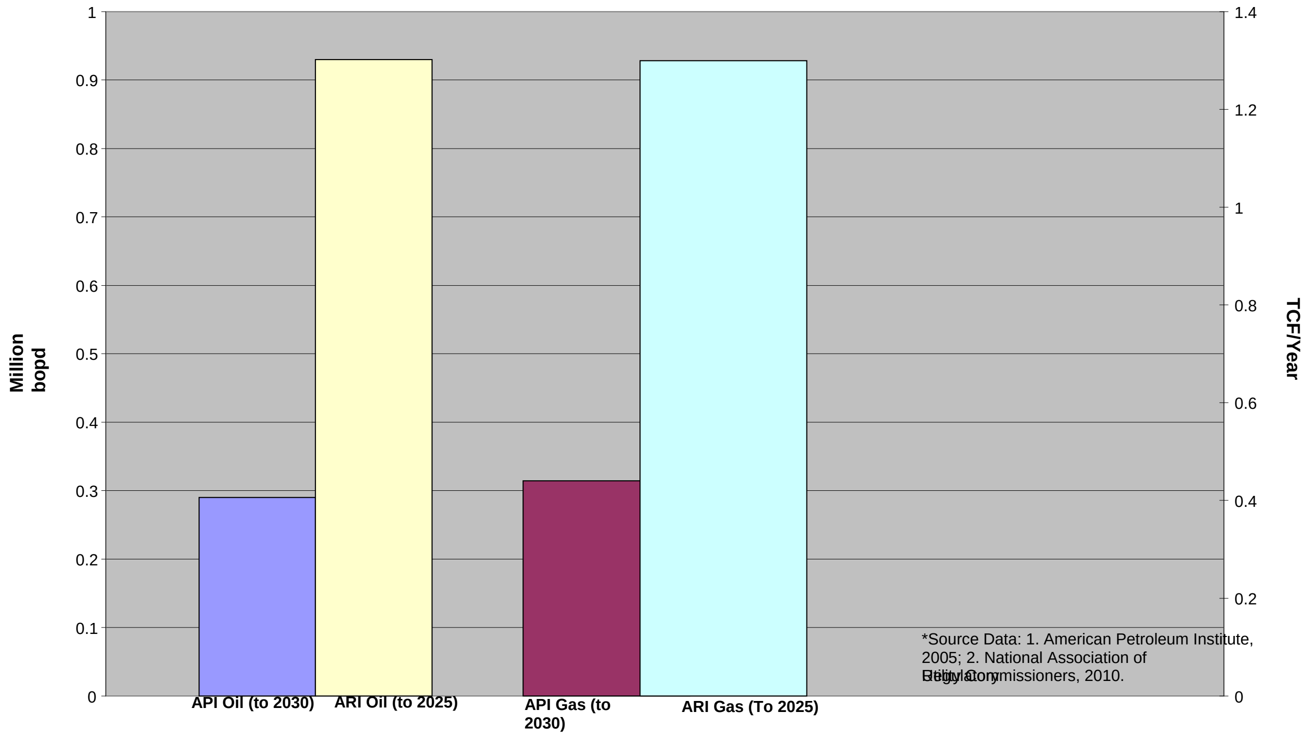


Figure 5: Estimates of U.S. Oil and Gas Production in Offshore Areas formerly Under Moratoria.
(Data source: 1. American Petroleum Institute- 2008; 2. National Association of Regulatory Utility Commissioners- 2010).

Estimates of incremental production of oil in U.S. offshore areas formerly under moratorium varies from 0.29 to 0.93 million barrels of oil per day. Additional production of natural gas in U.S. offshore areas formerly under moratoria varies from 0.45 to 1.3 trillion cubic feet per year

The resource and production estimates shown above indicate to some extent the importance of the previous moratoria areas for the potential expansion of oil and gas development in the US. Note that the estimates above are based on different models and assumptions. However, due to Deepwater Horizon event in the GOM, one must keep in mind that adverse public sentiment about offshore drilling and proactive government stance on restrictive development policies are likely to hinder and to slow the current trend of oil and gas development and production on the OCS.

Chapter 2: Development Pathways

The course of OCS oil and natural gas resource development and production is influenced by major factors such as the state of the economy, the oil and natural gas price environment, the availability of capital, the extent to which submerged lands are accessible for exploration and development, the rate and level of technological progress, government regulation and fiscal policies, and the availability of a skilled and efficient workforce. Every possible combination of these factors in time is likely to determine the intensity of future offshore oil and natural gas development. In order to cover to the largest extent possible the set of offshore development pathways, we will examine the two extreme cases: unconstrained and constrained development pathways. These two scenarios will offer different views of offshore potential depending on the relative impact of offshore development and production capacity growth challenges and enablers, as enumerated below. The unconstrained path is characterized by an affluent economic environment with buoyant oil and gas prices, an increased access to offshore lands, and accelerated technological progress. Conversely, the constrained case calls for a lower oil and gas price forecast, a limited access to offshore lands, and a slow technological and economic growth environment.

The factors that define these two scenarios are consistent with what is considered by this Offshore Subgroup's findings as the major development and production capacity growth challenges and enablers in the U.S. lower 48 offshore region. Specifically:

<u>A: Offshore production capacity growth challenges:</u>
1. Limited access to offshore acreage; 2. Constrained and expensive acquisition of capital goods and materials; 3. Uncertain capital availability; 4. Lack of better government fiscal terms; 5. Reduced government economic incentive policies; 6. Restrictive and costly new government legislation.

<u>B: Offshore production capacity growth enablers:</u>
1.Improved government economic incentive policies; 2. Better government fiscal terms; 3. Improved access to offshore lands; 4. Rapid technological advancements;

2.1. Unconstrained Development Pathway.

The unconstrained development pathway is generally characterized by the following conditions: 1. Increased access to offshore lands leading to increased availability of resources; 2. Affluent economy with buoyant oil and gas prices; 3. Moderate to rapid technological advancement; 4.Better government policies.

To fully capture the production potential of oil and gas under the unconstrained development path, we will look at the results of the AEO2011 for the reference case, the high oil price case, and the high OCS resource case. The AEO2011 assumes full access to offshore lands previously under moratoria, with the following conditions of availability: Eastern Gulf of Mexico in 2022, North Atlantic after 2035, Mid- and South Atlantic in 2018, Northern and Central Pacific after 2035, and Southern Pacific in 2023. Figures 6 through 9 below display the U.S. lower 48 offshore production forecasts for oil and gas in five year increments from 2010 to 2035.

Production of oil in U.S. lower 48 offshore varies from a minimum of 1.8 million barrels per day in 2010 in the reference case, to a maximum of 2.3 million barrel per day in 2035 in the high oil price case. This range of offshore oil production projection translates into a growth rate range of 0.2% - 0.9% per year. Projections of crude oil production in the high OCS resource case are very close to, but lower than the high price case, with an annualized growth rate of 0.3%. The range of annualized growth rate for crude oil projections in the unconstrained development path scenario is 0.2% to 0.9%.

Production of natural gas in U.S. lower 48 offshore ranges from 2.4 trillion cubic feet per year in 2010, in the reference case, to 3.8 trillion cubic feet per year in 2035, in the high oil price case. This translates into an annual growth rate range of 0.4% – 0.7%. Projections of natural gas production in the high OCS resource case are very similar to those of the high oil price case with an annualized growth rate of 0.7%. The range of annualized growth rate of natural gas projection in the unconstrained development path scenario is 0.4% to 0.7%.

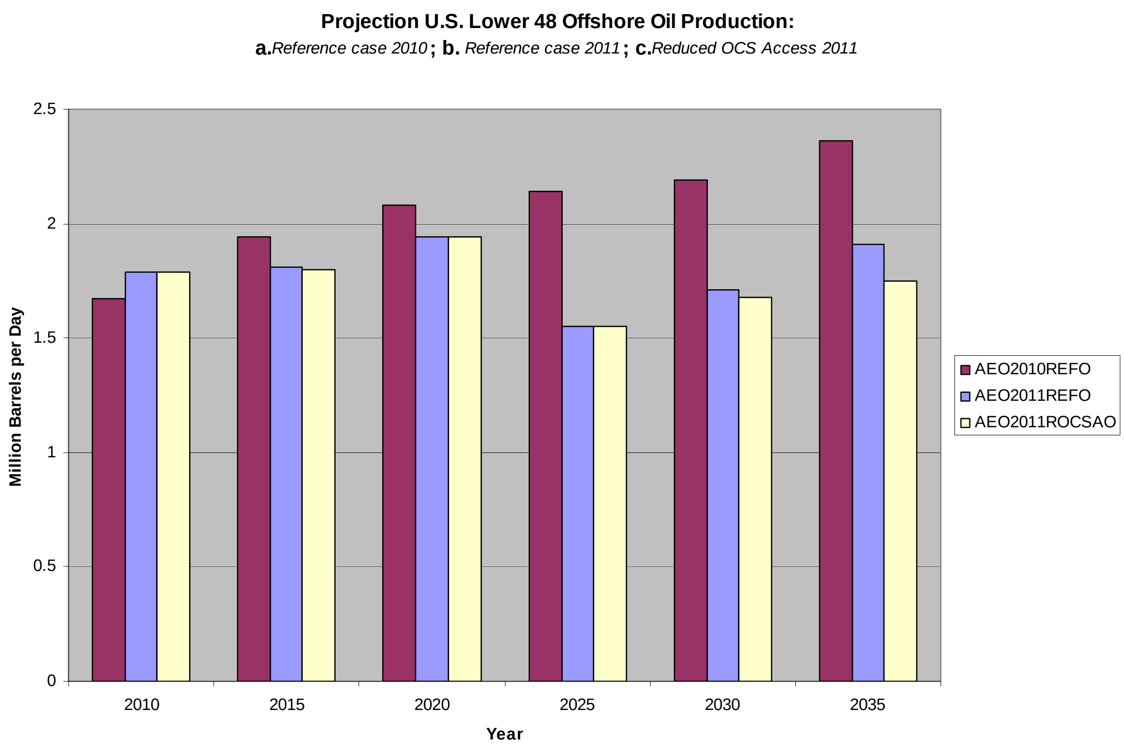
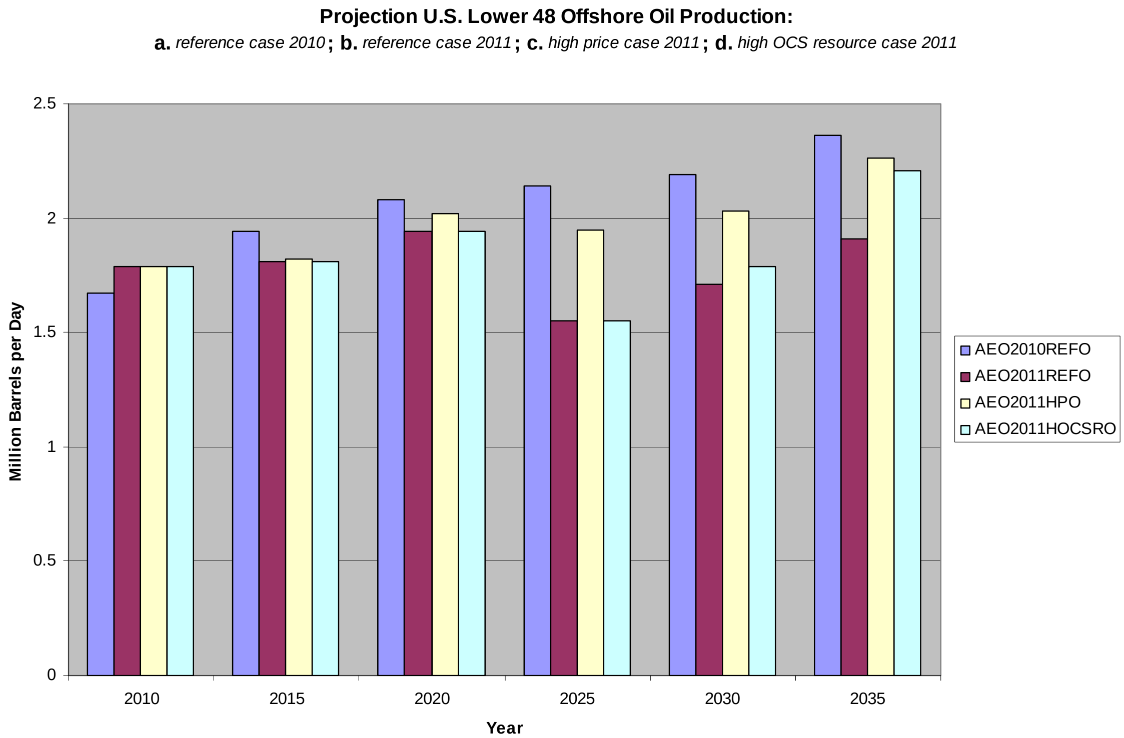


Figure 6: U.S. lower 48 offshore oil production forecast; reference cases and the OCS reduced access case.
(Data Source: EIA's Annual Energy Outlook 2010, 2011).



<u>Figure 7:</u> U.S. lower 48 offshore oil production forecast; reference cases, high oil price case and the high OCS resource case.
(Data source: EIA's Annual Energy Outlook 2010, 2011).

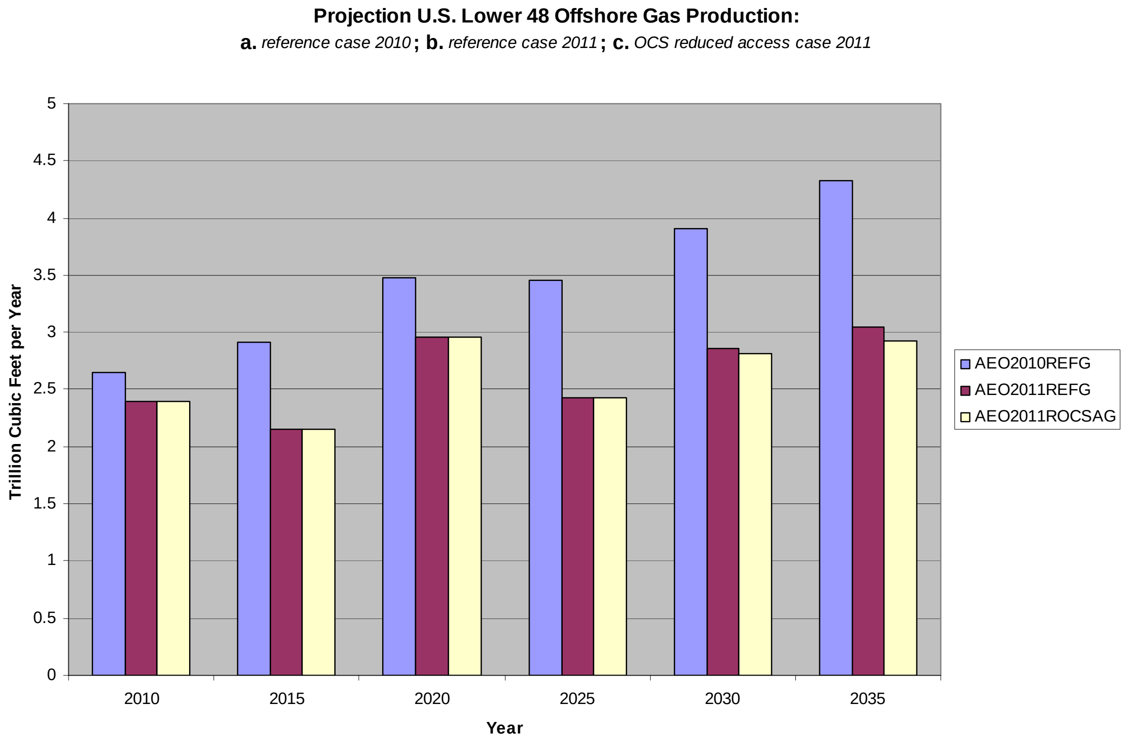
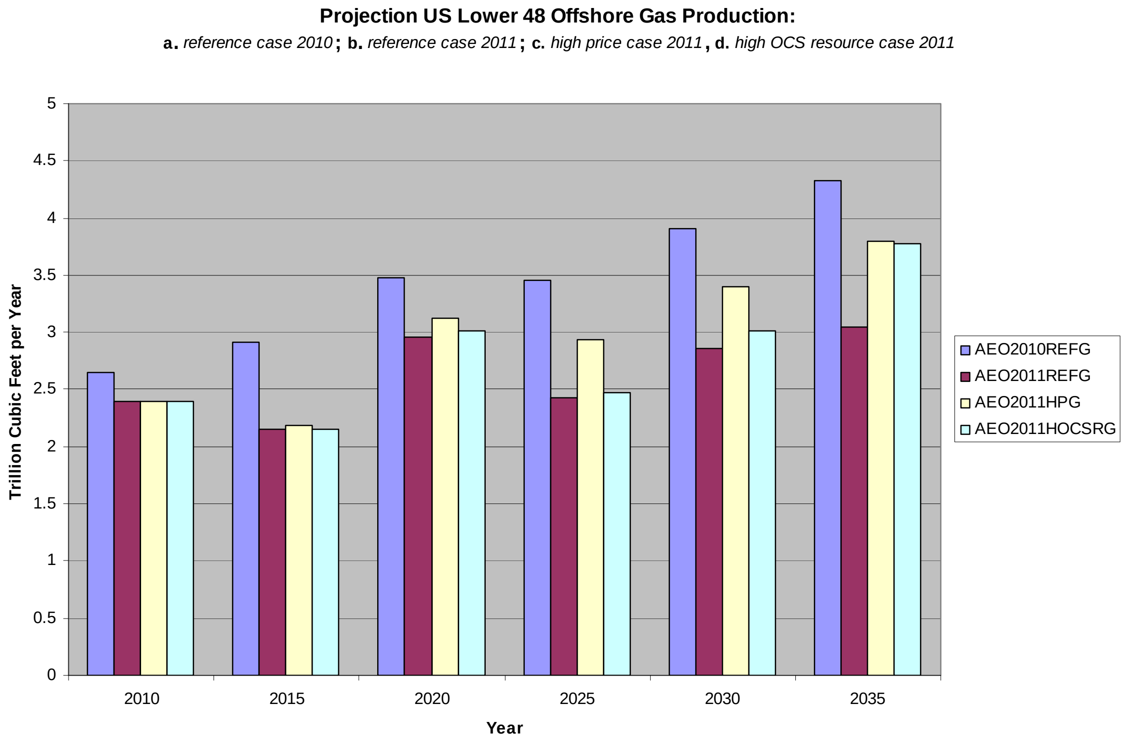


Figure 8: U.S. lower 48 offshore gas production forecast; reference cases and the reduced OCS access case.
(Data Source: EIA;s Annual Energy Outlook 2010, 2011).



<u>Figure 9:</u> U.S. lower 48 offshore gas production forecast; reference cases, high oil price case and the high OCS resource case.

(Data source: EIA's Annual Energy Outlook 2010, 2011).

The bulk of the expected increase in U.S. offshore oil and gas production is likely to come from new discoveries in deep and ultra deepwater regions of the GOM. According to Petroleum Economist (June 10th 2010 edition), "Lower Tertiary trend continues to reveal big discoveries. Significant finds have been made both in the trend's shallow and deep waters, which could hold as much as 15 billion barrels of oil, in high-pressure, high-temperature sub-salt formations at least 25,000 feet below the sea floor." The Lower Tertiary is recognized as a huge resource with the potential for long life projects of up to 30 to 40 years and the opportunity to enhance recoveries through technology (George Kirkland, vice chairman Chevron Corporation- "Chevron sanctions Jack/St. Malo project in the Gulf of Mexico", in Rigzone October 2010). The extent of the effects of the Lower Tertiary trend on the expansion of offshore gas resources is exemplified by the McMoran discovery of Davy Jones, which is located in 20 feet of water at a total reservoir depth of nearly 30,000 feet. Although the shallower, conventional horizons of the Gulf of Mexico Shelf have been heavily produced, only a small percentage of the wells have been drilled to more than 15,000 feet below the mud line. McMoran's Davy Jones prospect is believed to hold at least 1 trillion cubic feet of gas. This discovery demonstrates that hydrocarbon-saturated Lower Tertiary formations exist not only in remote, deepwater locations, but also closer to shore, where development requires much less time and money, and existing infrastructure abounds ("Big prospects in the Lower Tertiary Gulf of Mexico"; in Petroleum Economist, June 2010). A number of Lower Tertiary play prospects, which are scheduled to come on line between 2010 and 2020 hold the promise of providing a significant increase in oil and gas production in the Gulf of Mexico provided that the technical challenges of producing these prospects are overcome.

2.2. Constrained Development Pathway.

The constrained development path of offshore oil and gas resources can be characterized by the following conditions: 1. limited access to offshore lands; 2. Restrictive legislative policies and regulations; 3. Low to moderate oil and gas prices; 4. High cost OCS resources; 5. Low technological growth; 6. Low economic growth; and 7. limited access to capital.

In order to capture the full production potential of the constrained development pathway, we will analyze oil and gas production forecast provided by the EIA's annual energy outlook of 2011 (AEO2011). The reference case of the AEO2011 assumes full access to offshore lands previously under moratoria, with the following conditions of availability: Eastern Gulf of Mexico in 2022, North Atlantic after 2035, Mid- and South Atlantic in 2018, Northern and Central Pacific after 2035, and Southern Pacific in 2023. It also assumes the start of production for a number of projects is pushed forward as a result of the six-month development drilling moratoria in the GOM following the Deepwater Horizon event. We will also look at the reduced OCS access case, the high OCS cost case, and the low oil price case of the AEO2011. Note that the reduced OCS access case postpones leasing to the year 2035 for the Eastern Gulf of Mexico, the Atlantic, and the Pacific regions. The high OCS cost case assumes cost of exploration and development of offshore resources to be about 30% higher than those in the reference case. Though not intended to be an estimate of the cost impact of new regulatory or safety requirements, the high OCS cost case illustrates the higher costs of developing and producing the offshore crude oil and natural gas resources. Figures 6, 8, 10, and 11 show the EIA's forecast of offshore oil and gas production at the reference case, the reduced OCS access case, the high OCS cost case, and the low price case in five years increment from 2010 to 2035.

Projection of crude oil production varies from 1.8 million barrels per day in 2010 to 1.9 million barrels per day in 2035 for the reference case. This translates into a growth rate of 0.25 % per year in the GOM, and a growth rate of 2.8% in the Pacific region (Note that oil production in the Pacific region is much lower in comparison to that of the Gulf of Mexico). The low oil price case projects a decline in oil production from 1.8 million barrels per day in 2010 to 1.4 million barrels per day in 2035. This decline of oil production translates into a growth rate of -0.9% in the GOM, and -0.4% in the Pacific region. Crude oil projections for the lower 48 in the high OCS cost case and the reduced OCS case are not significantly different from those of the reference case, and they have a similar annualized growth rate of 0.2%. The range of annualized growth rate for crude oil projections in the constrained development path scenario is -0.9% to 0.2%.

Projected natural gas production increases from 2.4 trillion cubic feet in 2010 to 3.1 trillion cubic feet in 2035 for the reference case. This trend translates into a growth rate range of 0.4 % per year in the GOM, and 3.5% in the Pacific region. U.S. lower 48 natural gas production is projected to decline from 2.4 trillion cubic feet in 2010 to 2.1 trillion cubic feet in 2035 in the lower oil price case. This decline of gas production translates into a yearly growth rate of -1.1% in the GOM and -0.6% in the Pacific region. Again, natural gas projections in the lower 48 for the high OCS cost case and the reduced OCS access case are not significantly different from those of the reference case, and they have a similar annualized growth rate of 0.3%. The range of annualized growth rate of natural gas projection in the constrained development path scenario is -1.1% to 0.4%.

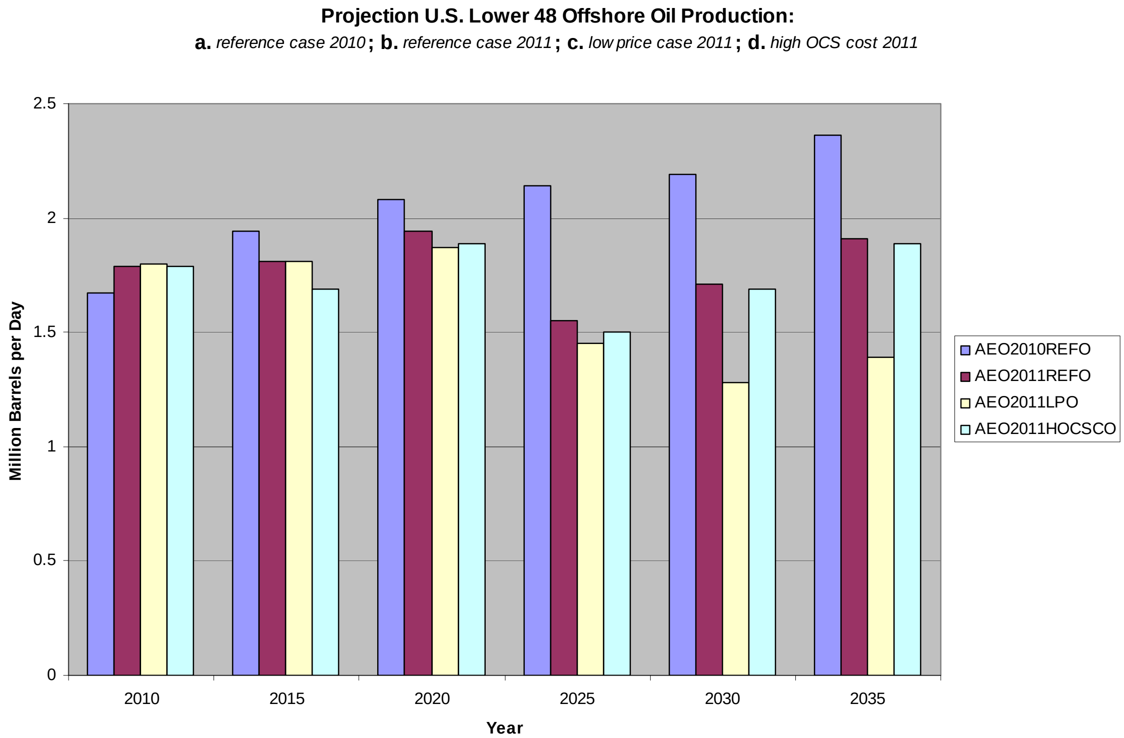


Figure 10: U.S. lower 48 offshore oil production forecast; reference cases, the low price case and the high OCS cost case.
(Data source: EIA's Annual Energy Outlook 2010 and 2011).

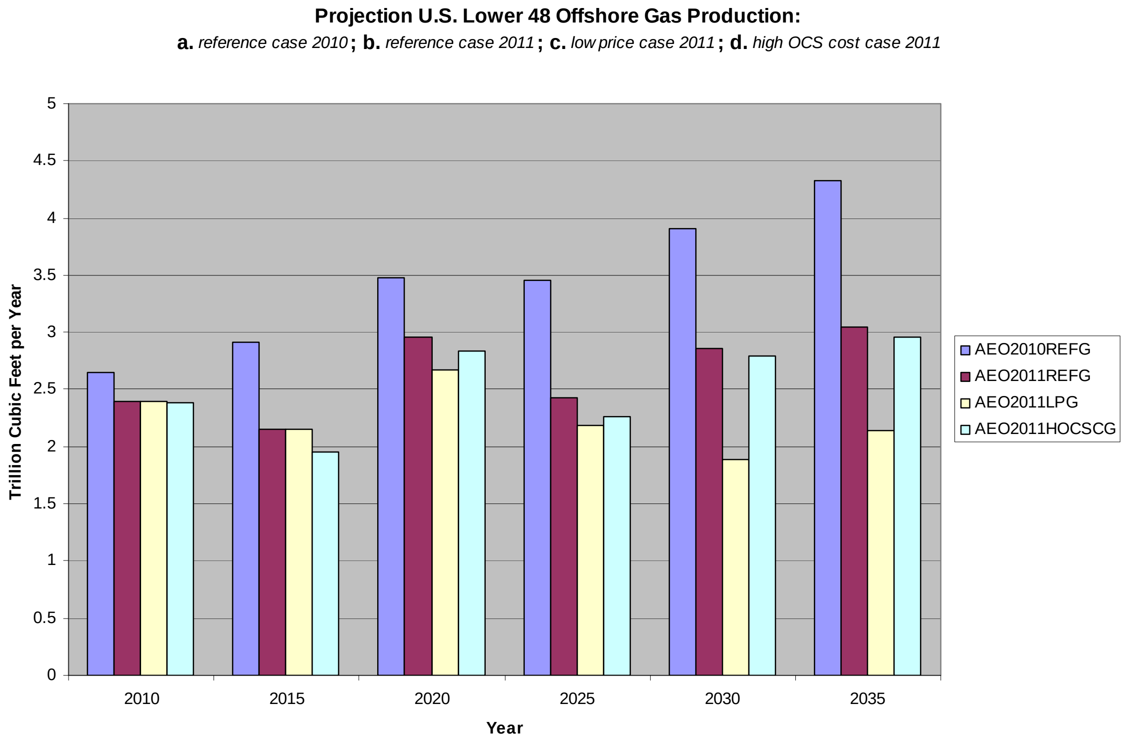


Figure 11: U.S. lower 48 offshore gas production forecast; reference cases, the low price case and the high OCS cost case.
(Data source: EIA's Annual Energy Outlook 2010, and 2011).

The AEO2011 projections for oil and gas production are markedly lower than those of the AEO2010 for the reference case. AEO2011 oil production projections are slightly lower than those of the AEO2010, while natural gas projections in AEO2011 are markedly lower than those of AEO2010. That overall decline could be partly ascribed to restrictive operation safety requirements and environment regulations implemented in the aftermath of the Deepwater Horizon event. This would also affect the rate of development and production of deep and ultra deepwater oil and gas prospects in general, and the Lower Tertiary trend in particular. Wood Mackenzie (Deepwater Horizon tragedy: near-term and long-term implications in deepwater Gulf of Mexico; May 2010) estimates that a 6-month drilling moratoria, following the Deepwater Horizon event, will have a near-term effect of deferring about 80,000 barrel of oil equivalent per day of deepwater production to later years. In the medium-term, the effect of tightened drilling safety regulations and the closer scrutiny of drilling permits are likely to slow down drilling activity, which in turn may push back production from new developments. Over 350,000 barrels of oil equivalent per day are expected to be dropped from potential project delays in 2015 and 2016, which coincides with the production commencement dates of significant Lower Tertiary fields such as Jack and St Malo. The overall effect of such a policy is to increase drill times along with exploration and development cost, which will defer expected production over the next 10 years by significant amounts and by so doing will dampen long term output from the GOM deepwater region (Wood Mackenzie, May 2010). Industry representative David Williams, CEO of Noble Corporation estimates that the oil spill disaster could increase production costs by 20 to 25%, which could lead to a 12% production decrease in the GOM to the period up to 2020. This would amount to 950 million barrels less production for the oil companies in the Gulf of Mexico (Karel Beckman, "The oil industry between hopes and fears"; European Energy Review, October 2010).

Chapter 3: Long Term Development of U.S. lower 48 Offshore Oil and Gas resources; Prospect in 2050

Crude oil and natural gas are exhaustible natural resources. These finite resources are thus subject to depletion as discoveries are developed and produced. An outlook of North America's potential oil and gas development and production for a time horizon of 40 years must take into account the multiple possibilities that emerging and future technological progress, the size and rate of new discoveries, and the relative accessibility to public submerged lands may have to offer. In the economic context, oil and gas in the ground constitute assets for their owners. As production proceeds and depletion occurs, oil and gas resources owners must explore for new fields so as to replenish their reserves.

Intensive exploration and development of hydrocarbon resources attributed to the discovery and inevitable exploitation of the Lower Tertiary plays and formations in the GOM and access to additional OCS acreage in the Eastern Gulf of Mexico, the Pacific and Atlantic offshore planning areas will likely serve to significantly improve the production potential of hydrocarbons in the U.S. lower 48 offshore. It is expected that Lower Tertiary resources in the Gulf of Mexico will deliver the first expansion of hydrocarbons development and production, followed by the Pacific OCS and later by the Atlantic OCS, which will require additional time to build-out the required infrastructure to support the development of these future oil and gas supplies.

Several prospects from the Lower Tertiary trend in the GOM region are expected to be developed and produced in the next 10 to 20 years period. For instance the following projects are expected to commence production in the time horizon 2010 to 2020:

1. Cascade/Chinook. The first floating, production, storage, and offloading (FPSO) system in the U.S. GOM, the NW Pioneer vessel, will develop the Cascade and Chinook fields in Walker Ridge, with first oil expected in 2011. Unique to the BW Pioneer is a detachable turret buoy, connecting the subsea wells to the FPSO. This project will utilize four technologies considered new to the GOM, including free-standing hybrid risers, polyester mooring, electric submersible booster pumps, and shuttle tanker for export.
2. The Phoenix/Typhoon field in Green Canyon, with a planned production startup in 2010, will be developed by the first ship-shape, dynamically positioned, disconnectable turret floating production unit, Helix Producer I, in the U.S. GOM.

3. The Perdido regional host facility will produce the Great White, Tobago, and Silvertip discoveries in Alaminos Canyon beginning in 2010.
4. The Jack and St. Malo fields, which have been hailed as the biggest domestic discovery since Alaska's Prudhoe Bay, will be developed to produce 170,000 barrels of oil per day and 42.5 million cubic feet of natural gas per day. A substantial semi-submersible facility will be used to produce the fields as a single hub. The target date for first oil is expected in 2014, and Chevron envisions the field to yield up to 40 years of oil and gas production.
5. The Tiber prospect in the GOM, expected to be larger in size than Kaskida, is expected to contain more than 3 billion barrels of oil. The Tiber well is the deepest ever drilled by the industry at a total depth of 35,000 feet. This prospect is expected to be developed in the next decade, as technology improves and the complexity of the Lower Tertiary formation is better understood. BP estimates that Tiber will contribute up to 100 to 200 million barrels of oil per day once completed.
6. The Davey Jones prospect, located in 20 feet water depth in the GOM, is a huge find in the Lower Tertiary trend estimated to hold more than 1 trillion cubic feet of gas. Baker Hughes has deployed a full suite of technologies designed for HPHT (high pressure high temperature) environments at the Davey Jones ultra-deep gas discovery. Once produced in the upcoming decade, this find will make a huge impact on the overall Gulf of Mexico's natural gas production.

The availability of previously access-restricted offshore regions for leasing is more than likely to impact outward the production possibility frontier of oil and gas resources in the U.S. Lower 48 offshore. The Energy information Agency's Annual Energy Outlook 2011 assumes additional leasing to take place in the OCS planning areas as follows: Atlantic and the Pacific regions are assumed beyond 2018, while the Eastern Gulf of Mexico planning area is expected to be available for leasing in 2022. These actions will likely provide additional technically recoverable oil and gas resources in the U.S. lower 48 offshore estimated to be at least in the range of 18.2 – 63 billion barrels of oil, and 77.0 – 231.0 trillion cubic feet of natural gas.

Emerging and future offshore petroleum technologies, covered in a subsequent chapter entitled "Offshore Petroleum Technology", are expected to further expand the amount of technically recoverable oil and gas resources, and to push outward their production possibility frontier.

Chapter 4: Background, Development, and Production of Canada's Offshore Oil and Gas.

In Canada, offshore hydrocarbon production comes exclusively from its Atlantic margin, with natural gas and oil being produced in Nova Scotia and Newfoundland offshore, respectively.

In offshore Newfoundland, production in the Jeanne d'Arc Basin of the Grand Banks started in 1997 with the Hibernia field followed by the Terra Nova and White Rose fields in 2002 and 2005, respectively. From an initial annual production of 1.3 million barrels of oil in 1997, the production reached 97,7 million barrels in 2009, with a peak production of 134.5 million barrels in 2007. In 2009, average daily production was 340 000 bpd. Cumulative oil production reached 1125 million barrels in April 2010 (Fig. 12). Cumulative natural gas production reached 1.5 trillion cubic feet in April 2010. Associated gas is re-injected in the reservoir.

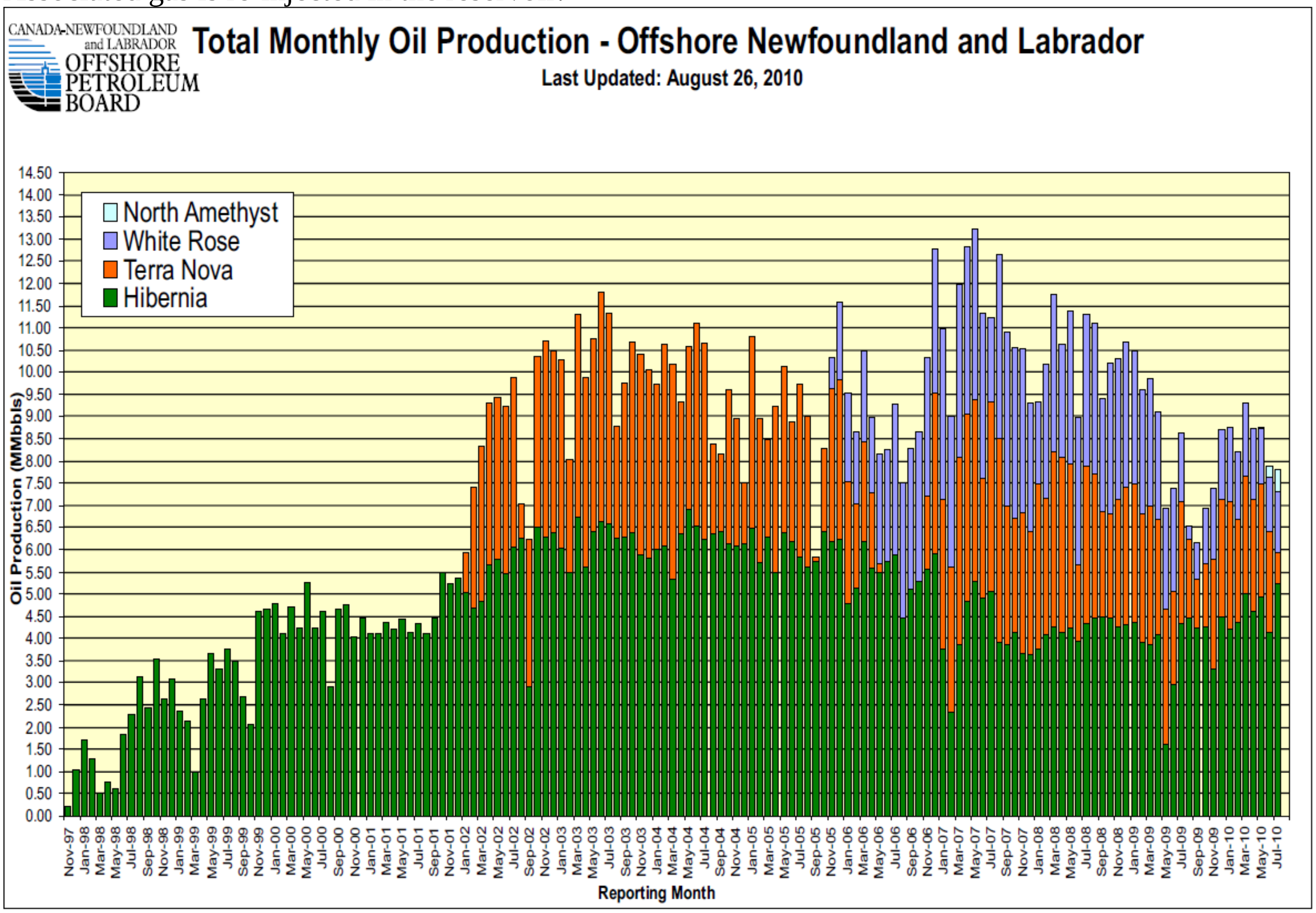
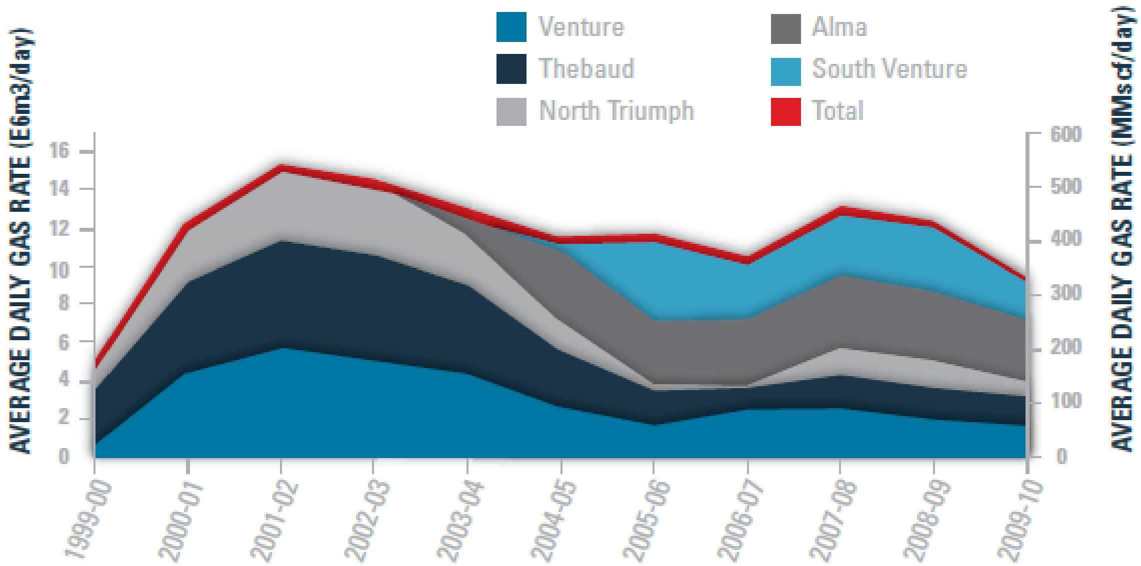


Fig 12. Offshore production – Newfoundland and Labrador. From CNLOPB web site.

In the Nova Scotia offshore, production in the Sable Island Sub-Basin of the Scotian Shelf started in 1992 with oil being produced in the Cohasset-Panuke field. From 1992 to 1999, a total of 44.5 million barrels of oil were produced before the field was shut in. Gas production from the Sable Offshore Energy Project (SOEP) comes from 5 shallow marine (25 to 75 m) fields (Thebaud, Venture, North Triumph, Alma and South Venture) that commenced production between 1999 and 2004. In 2009, 459 million cubic feet per day was produced at SOEP. In April 2010, cumulative gas production reached 1.6 trillion cubic feet (Fig. 13). Gas is piped onshore where it is distributed to North America's markets through the Maritimes & Northeast pipeline.



<u>Fig. 13</u>. Offshore production – Nova Scotia. From CSNOPB 2009-2010 annual report

Current development plans in the Canadian offshore are in progress for the Atlantic Margin. In Newfoundland, 3 oil projects are at various stages in the Jeanne d'Arc Basin. The Hebron/Ben Nevis field (730 million barrels of oil) will be developed with a Gravity Based Structure (GBS) with initial oil planned for 2017 with estimated peak daily production of 150 000 barrels. Three new satellite fields will be developed at White Rose from the FPSO; with total 3P reserves of 115 million barrels of oil, including the North Amethyst which went into production in May 2010. Finally, the Hibernia South extension will add 220 million barrels of oil with progressive development from the actual Hibernia GBS.

In Nova Scotia, the Deep Panuke gas field in the Scotian Shelf should commence production in 2011. The field is estimated to contain up to 900 billion cubic feet of gas with a planned daily production of 300 million cubic feet per day. The production will use a jack-up platform. Gas will be piped onshore, where it will be connected to North America's Markets through the Maritimes & Northeast pipeline.

Deepwater exploration along the eastern offshore margin of Canada reached a new milestone with the drilling of wells in the Orphan Basin of Newfoundland. The 2010 Lona O-55 well has been drilled in 2,600 m water depth, thus setting a new Canadian record. The previous record was 2,338 m water depth for the 2007 Great Barasway F-66 in the deep Orphan Basin. In the Nova Scotia deep slope setting, the Marathon Crimson F81 well was drilled in 2004 under 2,092 m water depth. Actually, no production or significant discoveries are reported from the very deep waters along the Canadian Atlantic margin.

The most recent exploration drilling activities in the deep water areas along the Canadian Atlantic margin has been extensively scrutinized following the deepwater accident in the U.S. Gulf of Mexico. The Canadian regulatory offices, the National Energy Board (NEB), the Canada Nova Scotia Offshore Petroleum Board (CNSOPB) and the Canada Newfoundland and Labrador Offshore Petroleum Board (CNLOPB) have all indicated that the current regulatory regime offers sufficient safety rules for the Atlantic margin exploration (CNLOPB, CNSOPB). However, current regulations are being reevaluated, in particular for eventual Arctic drilling (NEB).

For the Canadian offshore, ongoing production and development plans are restricted to the Newfoundland and Nova Scotia sectors of the Atlantic margin. Exploration activities (seismic and drilling) are planned in both areas and their less explored domains (Laurentian, Sydney, Orphan and Flemish Pass sub-basins) that are under the CNSOPB or CNLOPB rules. The Labrador Shelf (under CNLOPB rules) is likely the next area where development drilling will occur. Five significant gas discoveries with 4.2 trillion cubic feet of discovered resource support the current exploration activities.

The Gulf of St. Lawrence has been recently evaluated to host an in-place best estimate (P50) of 41 trillion cubic feet of gas and 2500 million barrels of oil, largely in Carboniferous reservoirs. A significant gas discovery (77 billion cubic feet) was made in this basin in 1970. Except for restricted zones under the jurisdictions of CNSOPB or CNLOPB, most of the Gulf area is under a de facto moratorium. The non-regulated area is currently being the subject of jurisdiction discussions between the federal and provincial governments. Areas under the jurisdiction of the CNSOPB and CNLOPB are however open for exploration. Seismic acquisition is planned in the CNLOPB area in 2011.

The Georges Bank area (offshore Nova Scotia) is evaluated to host 6.6 trillion cubic feet of gas and 3500 million barrels of oil of in-place resources. The area is currently under an exploration moratorium, which has been recently extended to 2015.

The Pacific margin of western Canada is under a de facto moratorium, though no official legislation has been put in place. There have been no discovery in this area, and the best estimate (P50) indicates the presence of in-place resources of 43.4 trillion cubic feet of gas and 9800 million barrels of oil.

Of all the areas under legislated or de facto moratoria, the Gulf of St. Lawrence is the one most likely to be opened for exploration in the next 5 to 10 years.

4.1. Moratoria and Access to Canada's Offshore Lands.

The expiration of the exploration moratorium for the Georges Bank area in the Canadian Atlantic margin has been extended to December 31, 2015. This decision was announced jointly by the Canadian and Nova Scotia governments in May 2010.

The Gulf of St. Lawrence is an interior Canadian sea that is shared by 5 Canadian provinces (Quebec, New Brunswick, Nova Scotia, Newfoundland and Labrador, and Prince Edouard Island). The provinces and the federal government have been debating over jurisdiction for many years. In 1967, a tentative accord was reached by the provinces in the splitting of the Gulf. This accord has never been legislated and the federal government does not recognize it. Recently, the government of Newfoundland has announced that it does not recognize the 1967 limit. The position of the Canadian federal government is based on the Royal Proclamation of 1790, which stipulates that all waters to the east of the western tip of Anticosti Island, which includes the entire Gulf of St. Lawrence, is under federal jurisdiction. A small domain along the western coast of Newfoundland and along the western coasts of Nova Scotia is under the regulatory regime of the CNLOPB and CNSOPB, respectively.

The recent release of a resource evaluation for the Gulf of St. Lawrence supported the likely high potential of the Carboniferous basin in the Gulf. This was instrumental in the resumption of discussions between political stakeholders of this area. The Government of Quebec has been carrying out major strategic environmental assessments that are planned to be completed in 2012 before hydrocarbon exploration is allowed to resume. The CNLOPB gave exploration licenses in areas under their jurisdiction; a major drilling program has been announced for 2012 over a seismically defined target.

In 1972, the Canadian and British Columbia government announced a moratorium on oil and gas activities along the western coast of Canada. Prior to 1972, a number of permits for oil and gas exploration were issued for offshore British Columbia. Due to environmental concerns, rights under those permits were suspended as of 1972 by way of Orders in Council, thus forming a de facto moratorium. Since, the moratorium continues to be maintained through government policy. There are currently discussions as to the potential lift of the moratorium but this is facing strong opposition from environmental groups.

The Deepwater Horizon event led to renewed Canadian public interest in the offshore regulatory regime. The various boards (NEB, CNLOPB, CNSOPB) were questioned about the regulation regimes in Canada and a special Canadian Senate Committee was set up (May – July 2010) to review the situation in the Canadian offshore.
The NEB announced that they will review their entire regulations regarding drilling in the Arctic offshore (e.g. Beaufort Sea), but the board expressed its trust in the current

regulations (NEB, CNSOPB, CNLOPB) for the non-Arctic activities that were reviewed in 2009.
The CNLOPB added special measures to their regulations specific to the then ongoing drilling of the deep Lona O-55 well; these included various tests on the blow out preventer, state of the ROVs and presence of CLNOPB observers on the drilling vessel. It is unknown if these added measures will be incorporated in the regulatory regime as the CNLOPB announced a reassessment of their guidelines and rules.
The CNSOPB expressed its entire trust in the actual strict regulations and guidelines.

4.2. Unconstrained development path of Canada's offshore oil and natural gas resources.

The most critical assumptions for an unconstrained scenario are: 1. the price of the resource, 2. the government overall regulations, 3. access to land and 4. access to rigs/equipments.

1. With a high price for the resource, the access to capital will be eased which will in turn lead to in increase exploration and developments activities in the Canadian Atlantic offshore and will jump start exploration and developments of more frontier Labrador shelf.
2. If government regulations remain unchanged from the current situation, an overall market demand in a high economic growth period will assure an increase in developments. However, the current focus on relief well (rig availability, local limited window of opportunity for drilling) might be a strong challenge to increasing development.
3. The eventual opening of currently inaccessible offshore domains for exploration and development will be a major enabler to increase production. The eventual opening of the Gulf of St. Lawrence would create major opportunities for eventual production in a favorable marine environment (shallow depth, no harsh conditions).
4. In an unconstrained scenario, the global drilling industry will have to react rapidly in order to be able to provide equipment for shallow, deep and ultra deep drilling. As in any market, the increase in demand should be matched by an increase in the offer.

<u>Newfoundland and Labrador</u>.
In the unconstrained scenario, currently planned development in the Newfoundland Grand Banks would produce up to 1.7 billion barrels from its 3P 2.9 billion barrels reserves in shallow to moderately deep water. Overall natural gas reserves of 6.6 trillion cubic feet are postulated in this area, of which 1.5 trillion cubic feet have already been produced and re-injected into the reservoir. In the area east of Newfoundland (Grand Banks, southern Grand Banks, and Laurentian), 28 trillion cubic feet of in-place natural gas is assumed, including 10 Trillion cubic feet of marketable gas. Gas resources in the Labrador shelf would likely be developed under the unconstrained scenario. Currently, five fields are identified with total 3P reserves of 4.2 trillion cubic feet of gas. Overall, 13

trillion cubic feet of in-place gas is postulated, including 9 trillion cubic feet marketable gas.

Nova Scotia.

In offshore Nova Scotia, 1.6 trillion cubic feet of gas has been produced from the SOEP, which is estimated to contain 8.9 trillion cubic feet of in-place gas, including 3 trillion cubic feet of recoverable gas resources. Overall, the Nova Scotian margin (including SOEP and Deep Panuke) has an estimated 46.1 trillion cubic feet of in-place natural gas, including 30.2 trillion cubic feet of recoverable Natural gas resources. Oil production in Nova Scotia amounts to 44.5 million barrels, and reserves estimates are relatively low. It is estimated that the Mesozoic has up to 381 million barrels of in-place oil, including 188 million barrels recoverable resources.

The Georges Bank area is under a joint Canada-U.S. moratorium, and no discoveries have been made there yet. In-place resources are hypothesized about 6.6 trillion cubic feet of gas, including 5.3 trillion cubic feet being classified as recoverable. This area is estimated to hold 3.5 billion barrels of in-place oil, including1.1 billion barrels recoverable resources.

Gulf of Saint-Lawrence

Over 90% of this area is under a de facto moratorium. High level political discussions are in progress for the opening of the entire Gulf to oil and gas exploration and production. The area is estimated to contain (P50) close to 40 trillion cubic feet of in-place gas; one discovery (77 billion cubic feet) is known in the offshore with however a 1 trillion cubic feet field in the adjacent onshore. No estimates of recoverable or marketable gas are available.

The area is estimated to hold close to 2.5 billion barrels of in-place oil. No offshore discoveries are known although a large number of small fields are known and developed onshore.

Western Pacific margin

This area is under a de facto moratorium. No discoveries are known, the area is postulated to host 40.5 trillion cubic feet of gas and 9.8 billion barrels of oil.

4.3. Constrained development path of Canada’s offshore oil and natural gas resources.

The most critical assumptions for a constrained scenario are: 1. the price of the resource, 2. the government overall regulations, 3. access to land, 4. access to rigs/equipments and 5. the competition with huge onshore shale gas production.

1. With a low price for the resource, the access to capital will be tightened which will in turn lead to a significant decrease in exploration and developments activities in the Canadian Atlantic offshore. This scenario is not favorable to exploration and development of more frontier areas.

2. If government regulations are changed to include stricter environmental and safety regulations (e.g. relief well), this will create major challenges to development.
3. The continuation of moratoria will preclude access to areas with significant potential resources.
4. In a constrained scenario, the global drilling industry will react. As in any market, the decrease in demand should be matched by a decrease in the offer.
5. Significant increase in production of relatively low cost natural gas from shale is expected in the future. This will put pressure not only on the price of gas but also will affect the development of higher cost offshore gas projects.

<u>Newfoundland and Labrador</u>
The development of the four major oil fields (Hibernia, Terra Nova, White Rose and Hebron) with their immediate satellite fields is to be pursued (1.7 billion barrels of potential future production). The more frontier Laurentian, Sydney, Orphan and Flemish Pass basins would remain undeveloped. Without higher price to support production and shipping to markets, natural gas in the Grand Banks and the Labrador Shelf would remain stranded.

<u>Nova Scotia</u>
The exploration and development of new gas fields will be highly challenged in a constrained scenario, in particular given the competition of shale gas. The Deep Panuke field (900 billion cubic feet) is possibly the only exception.

In the event offshore moratoria are not removed, oil and gas resources in the Gulf of St. Lawrence, Georges Bank, and Western Pacific margin will remain undeveloped.

4.4. Depletion vs Development of Canada's Offshore oil and natural gas resources.

<u>Newfoundland and Labrador (April 2010)</u>
In the Grand Banks, oil production is averaging around 340 000 barrels per day.

_In the Hibernia field:

1. The Hibernia reservoir still holds 8% of its proven reserves (60 million barrels of oil), 39% of its proven + probable reserves (416 million barrels of oil) and 54% of its proven + probable + possible reserves (756 million barrels of oil).
2. The Ben Nevis / Avalon reservoir still holds 48% of its proven reserves (36 million barrels of oil), 79% of its 2P reserves (143 million barrels of oil) and 91% of its 3P reserves (420 million barrels of oil)
3. The Catalina reservoir is untapped and has 3P reserves of 52 million barrels of oil.
4. Natural gas is still in the reservoirs, with volumes from all three reservoirs of 953 billion cubic feet, 1796 billion cubic feet and 2669 billion cubic feet of gas for 1P, 2P and 3P, respectively.

5. Natural gas liquids are still in the reservoirs, with volumes from all three reservoirs of 133 million barrels, 202 million barrels and 262 million barrels for 1P, 2P and 3P, respectively.

_ In the Terra Nova field,

1. The Jeanne d'Arc reservoir still holds 12% of its proven reserves (66 Million barrels), 29% of its 2P reserves (122 Million barrels) and 44% of its 3P reserves (234 Million barrels).
2. Natural gas is still in the reservoir with volumes of 46, 53 and 67 Billion cubic feet for 1P, 2P and 3P, respectively Natural gas liquids are still in the reservoirs, with volumes from all three reservoirs of 3.2, 3.8 and 4.8 Million barrels for 1P, 2P and 3P, respectively.

_ In the White Rose field,

1. The Ben Nevis / Avalon reservoir still holds 39% of its proven reserves (93 Million barrels), 50% of its 2P reserves (141 Million barrels) and 59% of its 3P reserves (205 Million barrels).
2. The Hibernia reservoir is still untapped with 13, 21 and 35 Million barrels of 1P, 2P and 3P respectively
3. Natural gas is still in the reservoir with volumes of 2499, 3023 and 3925 Billion cubic feet for 1P, 2P and 3P, respectively
4. Natural gas liquids are still in the reservoirs, with volumes from all three reservoirs of 66, 96 and 143 Million barrels for 1P, 2P and 3P, respectively.

_ In the North Amethyst field,

1. Oil production from the Ben Nevis / Avalon reservoir has just been initiated, the field is largely untapped with 1P, 2P and 3P reserves of 36.2, 67.9 and 115.2 Million barrels, respectively
2. Natural gas has untapped volumes of 267, 315 and 378 Billion cubic feet of 1P, 2P and 3P reserves, respectively.

As a whole, the Grand Banks reservoirs in offshore Newfoundland had initial 2 P reserves of 2905 Million barrels of which 1125 million barrels have been produced, and 61% of the oil reserves are still in the ground (1780 Million barrels). At the current production rate of 340 000 barrel per day (declining at Hibernia but new volume at Hebron/Ben Nevis), this would translate into 14 years of remaining production.

<u>Nova Scotia (April 2010)</u>

The SOEP consists of 5 main fields that were put in production in 1999 (Thebaud), 2000 (Venture and North Triumph), 2003 (Alma) and 2004 (South Venture). A sixth field (Glenelg) is under review for eventual development by the operators. At the start of the project, the life expectancy of the project was 25 years. The average daily production in 2008-2009 was 431 Million cubic feet per day but was significantly reduced to 329 Million cubic feet per day in 2009-2010.

In April 2010, total cumulative production for SOEP project was 1.6 Trillion cubic feet. That production came from the individual fields as follows: Thebaud: 426 Billion cubic feet; Venture: 419 Billion cubic feet; North Triumph: 239 Billion cubic feet; Alma: 295

Billion cubic feet and South Venture: 218 Billion cubic feet. With recoverable volume of 3 Trillion cubic feet, 46% (1.4 Trillion cubic feet) of natural gas is still in the ground at the SOEP. At the current (2010) rate of production, this translates into 11.5 years of remaining production.

Chapter 5: Offshore Petroleum Technology and Future North American Offshore Supply of Oil and Gas.

Over the past 100 years the petroleum industry has demonstrated an ability to develop breakthrough technologies that made a significant impact on finding and producing oil and gas. In the January 2010 JPT magazine Steve Jacobs president of RMI gave the results of an informal survey he performed for the Petroleum Equipment Suppliers Association (PESA) to create a top 10 oilfield technologies of all time list. The survey participants included various operators, technology providers, analysts and respected industry experts. The results were a range of opinions with agreement on 2 or 3 that undeniably merit being on the list. The list was further studied and tweaked by PESA who then published it in a book to commemorate the association's 75th anniversary. Separately, in 2009 at the Offshore Europe Conference in Aberdeen these topics were presented and discussed, with the audience providing their opinions on the list using voting pads. As such in no particular order the top 10 oilfield technologies of all time are **(Jacobs 2010):**

1. Wireline
2. Logging While Drilling (LWD)
3. Computer Utilization
4. Top Drives
5. Subsea Equipment
6. Geophysical Surveys
7. Drill Bits
8. Reservoir Modeling
9. Enhanced Oil Recovery
10. Drilling Rigs

No one can look at this list and not see the impact that each of these items has had in the world oil business. It has fueled an incredible century of progress. We mention these in the introduction because it is a great summary list to draw from for existing, emerging and future technologies that will expand the frontiers of exploration and production. Many of these showed up again as key technologies in the survey associated with this paper. Certainly each of them continues to play a critical role with increasing production growth in North America. But industry is now faced with a new challenge in the offshore, trying to grow production in deepwater often with poor subsurface images, in remote areas with limited infrastructure, in deeper, often hostile, high pressure high temperature environments, and finally doing all of this in a basin that is getting mature. The Gulf of Mexico offshore is one of the most important regions in the U.S. for energy resources and infrastructure. As of 2009, the Gulf of Mexico offshore accounted for 30% of the total U.S oil production and 13% of the total gas production. 80% of that offshore oil production in the Gulf comes from deepwater, as such almost ¼ of U.S. oil production comes from Deepwater and the amount is rising **(Figures 14 and 15).**

In the future, successful exploration and development in both maturing open and currently restricted OCS areas, safely and economically, will be critical to maintaining North American oil and gas production. Tackling the new challenge will involve continued use of existing technologies, but to improve success and increase production and recovery, especially in the L. Tertiary, may require quicker maturation of new technologies, and working together with others in industry to ensure challenges are overcome.

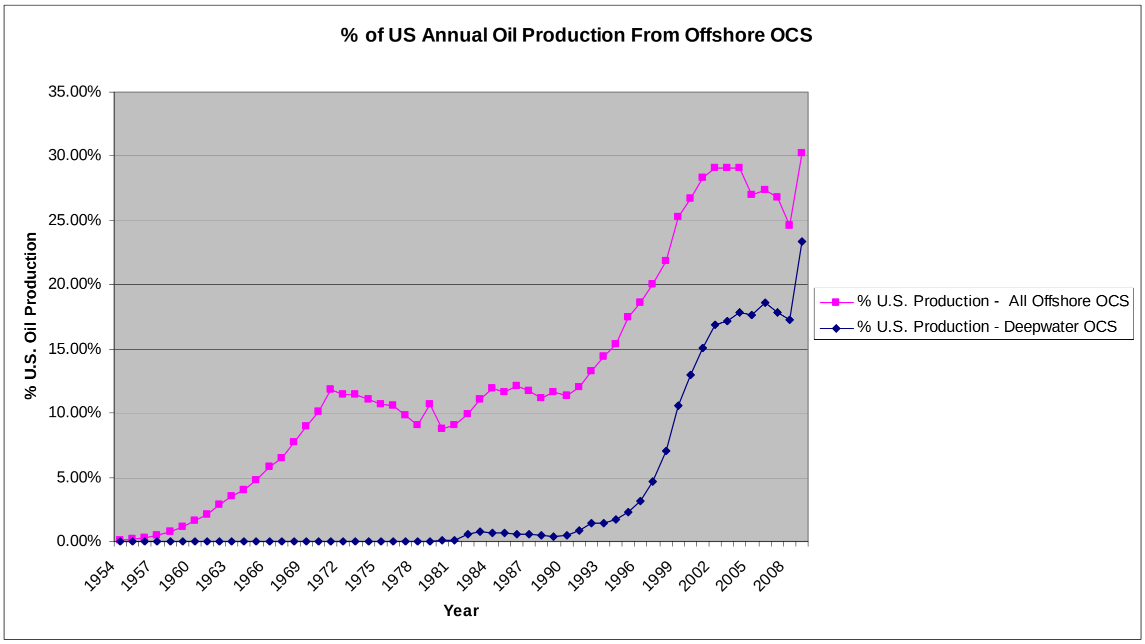


Figure 14. % of U.S. annual oil production from offshore OCS. Note 30% of total U.S. oil production is from offshore, 80% of that is from deepwater GOM. Almost ¼ of U.S. oil production is from the Deepwater Gulf of Mexico.

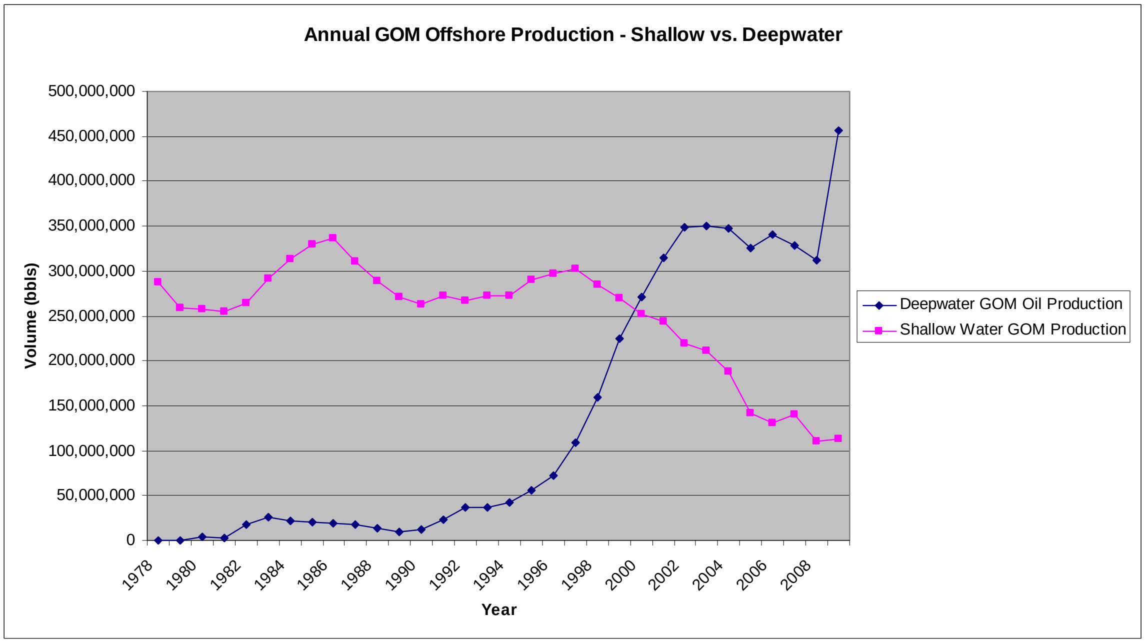


Figure 15: U.S. annual oil production trend from offshore shallow and deepwater offshore OCS.

Executive Summary

In this paper we will build off the commentary made in the two technology topic papers that accompanied the 2007 National Petroleum Council study "Hard Truths: Facing the Hard Truths about Energy, A Comprehensive View to 2030 of Global Oil and Natural Gas". The first of these papers, "Exploration Technology", identified 5 technology areas in which future developments have the potential to significantly impact exploration results over the next 25 years. The second entitled "Deepwater" identified 4 top priority deepwater-specific technological challenges most important to the future development of the world's deepwater resource. The following is a summary of the key points from the papers.

Exploration Technology Topic Paper (Cassiani et al., 2007)

Core Technology Areas:

1. Seismic
2. Controlled Source Electromagnetism (CSEM)
3. Interpretation Technology
4. Earth Systems Modeling
5. Subsurface Measurements

Auxiliary Technologies – Future developments or applications that have the potential to significantly impact exploration results by 2030

1. Drilling Technology
2. Nanotechnology
3. Computational Technology

Suggestions for Accelerating the Development and use of Technology

1. Government supported research into fundamental science areas that would underpin advances in commercial technologies
2. Judicious governmental sharing of technologies developed for defense or security applications that have significant potential for hydrocarbon exploration/exploitation.
3. Availability of highly-trained and experienced staff. Greater government support of relevant research at academic institutions can help ensure availability of staff to develop technological advances.
4. Exploration companies need to be willing to accept and implement technology at a faster pace
5. Industry and academia need to improve technical integration
6. There is a suggestion that increased industry investment into research could pay off in accelerated technology development

Research into technologies that could mitigate potential environmental impacts will continue to be important. Some examples of active areas of research include

- Riserless mud recovery, which reduces discharge
- Ultra-extended reach drilling to avoid sensitive areas
- Research into seismic sources as alternatives to conventional airgun arrays

<u>Deepwater Technology Topic Paper (Conser et al., 2007)</u>

Top Priority Deepwater Specific Challenges:

1. Reservoir Characterization
2. Extended System Architecture
3. High-Pressure and -Temperature (HP/HT) Completions Systems
4. Metocean Forecasting and Systems Analysis

Related topics discussed in other reports:

1. Subsalt imaging (Exploration Technology Paper)
2. Gas to Liquids (Supply Task Group)
3. Arctic (Baseline Technology Subtask)

Other Deepwater Technologies Considered

While important, judged to be of lower priority than those above

- Infrastructure life extension
- Virtual prototyping
- Unconventional options

Identified Two Issues Critical to the Continued Successful Development of Oil and Gas Resources in ever Harsher Ocean Environments:

1. Future Marine Technology Leadership
2. Valuing Technology to Enable Access

- Research grants to promote graduate and post-doctoral studies focused on crucial ocean energy issues
- Initiatives to re-energize university collaboration with national research centers and industry
- Incentives to elevate university priorities or delivery of research and continuing professional education
- Taking advantage of the impressive accomplishments that have from deepwater development to promote public and university pull for the physical sciences and technologies
- The better key concerns regarding restriction of access are articulated within a common dialogue, the better industry will be able to bring forth technical solutions that satisfy the broader social needs
- The act of granting access will in and of itself be *a*, if not *the* primary technology driver.

Updated Core Technology Topics

The results of our study show that most of the core technologies discussed in the 2007 "Hard Truths" technology topic papers have not changed. The differences of note are due primarily to the focus on offshore deepwater and are as follows: Drilling and Computational Technology have moved from the auxiliary level to core level and we have added the subject of Improved and Enhanced Oil Recovery to the new core list. The 2007 core technology area of Extended Systems Architecture will now contain some discussion on Completions and Digital Fields. Also the 2007 core technology of High-Pressure and High Temperature (HPHT) Completions Systems will now be addressed as HPHT environment in the various core technologies where it is pertinent. The only technology no longer on the core list will be Controlled Source Electromagnetic Resonance (CSEM). Although the tool can reduce the exploration risk in CSEM suitable settings, it was not ranked at the level of the other core technologies and would now exist at the auxiliary level. Of final note, a brief update on the status of industry sponsored plans for containment will be included under the Drilling Technology section.

The updated lists of core technologies that will be critical to oil and gas capacity growth are:

1. Seismic
2. Computational Technology
3. Interpretation Technology
4. Earth-Systems Modeling
5. Drilling
6. Subsurface Measurements
7. Reservoir Characterization
8. Extended System Architecture
9. Improved and Enhanced Oil Recovery (IOR/EOR)
10. Metocean Forecasting and Systems Analysis

5.1. Overview of Methodology

The evaluation of technologies that will enable growth of oil gas production for the next 40 years was based on discussion among the Offshore Sub-Group members, colleagues within our respective organizations, as well as extensive literature search, including the 2007 NPC Study “Hard Truths” Technology Topic Papers. To prioritize technologies, two surveys were submitted to professionals in the various key disciplines of geology, geophysics, petrophysics, reservoir engineering, drilling engineering, completion and production engineering for feedback. The first survey asked the participants to rate oil and gas production capacity growth challenges and enablers that are included in the 2010 NPC Petroleum Resource Template **(Figures 16 and 17).** The second survey was based on the 2007 NPC Topic Papers and asked participants for feedback on the previously identified core technologies (see earlier sections) and any additional ones that would significantly impact growth in production, concluding with a ranking of the technologies. Not surprisingly the surveys showed that many of the priorities have not changed from the previous Topic Papers, but some additional technologies of impact were noted. In this paper we will provide updates to the information on the 2007 core technologies and follow with more detail on the new additions to the group.

Oil Scenario Details													
Oil Production Capacity Growth Challenges	Specify Challenges and add Comments	Conventional recoverable oil (including current EOR projects) from reservoirs that have naturally occurring reservoir character in structural or stratigraphic closure, e.g. Light, Medium, and Heavy Oil > 10 API Including Californian Steam Flood			Condensate and NGL's associated with gas production e.g. Eaglesford, Marcellus			Capacity for Improved Oil Recovery - Advanced applications that could be applied (but not currently) in conventional reservoirs that increases the % of in place oil that is produced, e.g. CO2 flood and low saturation residual oil zones (like Permian). Include hydrocarbon resource/targets that have reservoir parameters outside of conventional norms such as low oil saturations zones below an oil-water contact or low permeability sands			Tight oil from low permeability or exceptionally thin reservoirs that produces from induced fractures often in combination with horizontal wells e.g. Bakken; speculative plays like the Arizona Cardium		
		Onshore	Offshore	Arctic	Onshore	Offshore	Arctic	Onshore	Offshore	Arctic	Onshore	Offshore	Arctic
		Assess each challenge in cells below from 1 to 5, with 5 equaling the greatest challenge											
Access to acreage;													
Government regulations e.g. fracturing;													
Acquiring equipment (e.g. rigs) materials, etc;													
Access to human resources/capability													
Capital availability													
Slow rate of improvements in exploration success rates and exploration and development costs due to slow technology advancements													
Water availability; specify here													
CO2 availability, e.g. EOR; specify here													
CO2 emissions; specify here													
Other environmental issues; specify here													
Other; specify here													

Figure16: Assumptions Tab, Petroleum Resource Template (part 1)

Oil Production Capacity Growth Enablers	Specify Enablers and add Comments	Conventional recoverable oil (including current EOR projects) from reservoirs that have naturally occurring reservoir character in structural or stratigraphic closure, e.g. Light, Medium, and Heavy Oil > 10 API Including Californian Steam Flood			Condensate and NGL's associated with gas production e.g. Eaglesford, Marcellus			Capacity for Improved Oil Recovery - Advanced applications that could be applied (but not currently) in conventional reservoirs that increases the % of in place oil that is produced, e.g. CO2 flood and low saturation residual oil zones (like Permian). Include hydrocarbon resource/targets that have reservoir parameters outside of conventional norms such as low oil saturations zones below an oil-water contact or low permeability sands			Tight oil from low permeability or exceptionally thin reservoirs that produces from induced fractures often in combination with horizontal wells e.g. Bakken; speculative plays like the Arizona Cardium		
		Onshore	Offshore	Arctic	Onshore	Offshore	Arctic	Onshore	Offshore	Arctic	Onshore	Offshore	Arctic
		Assess each enabler in cells below from 1 to 5, with 5 equaling the greatest enabler											
Better government fiscal terms, say on EOR production; specify here													
Improved access; specify here													
Other government incentives; specify here													
Fast rate of improvements in exploration success rates and exploration and development costs due to fast technology advancements													
Other; specify here													

Oil Infrastructure Capacity Challenges/Enablers (Identify and List)	Specify in cells below and add Comments	Conventional recoverable oil (including current EOR projects) from reservoirs that have naturally occurring reservoir character in structural or stratigraphic closure, e.g. Light, Medium, and Heavy Oil > 10 API Including Californian Steam Flood			Condensate and NGL's associated with gas production e.g. Eaglesford, Marcellus			Capacity for Improved Oil Recovery - Advanced applications that could be applied (but not currently) in conventional reservoirs that increases the % of in place oil that is produced, e.g. CO2 flood and low saturation residual oil zones (like Permian). Include hydrocarbon resource/targets that have reservoir parameters outside of conventional norms such as low oil saturations zones below an oil-water contact or low permeability sands			Tight oil from low permeability or exceptionally thin reservoirs that produces from induced fractures often in combination with horizontal wells e.g. Bakken; speculative plays like the Arizona Cardium		
		Onshore	Offshore	Arctic	Onshore	Offshore	Arctic	Onshore	Offshore	Arctic	Onshore	Offshore	Arctic
		Assess each challenge/enabler in cells below from 1 to 5, with 5 equaling the greatest challenge/enabler											
Challenge 1													
Challenge 2													
Challenge 3													
Enabler 1													
Enabler 2													
Enabler 3													

Figure 17: Assumptions Tab, Petroleum Resource Template (part 2)

5.2. Seismic Technologies

(By Paul Schlirf)

Seismic methods began in the early 1900's, when reflections and refractions of geologic interfaces were recorded from earthquake generated waves. Immediately following World War I, Ludger Mintrop, a mining surveyor, became one of the early founders of refraction seismic for oil and gas exploration. During the war he used a portable seismograph to locate the position of Allied artillery. After the war he reversed the process, by setting off explosions a known distance from the seismograph and measuring the return time of the subsurface waves to estimate the depths of geologic strata. In 1921 he founded the company Seismos and in 1924 they were credited with finding the first commercial discovery of oil using the seismic method, the Orchard salt dome in Fort Ben County Texas. An extensive campaign of refraction shooting occurred over the next 6 years and that coupled with gravity methods resulted in locating most of the shallow salt domes along the Gulf coast. By 1930 the refraction method began to give way to a new method called the reflection seismic, which was much more suitable for mapping layers in the earth. This early reflection seismic was 2D, single fold, continuous profiling and provided large scale information but lacked in detail. With the advent of 2D multifold data in the 1950's details of the subsurface image began to improve. The advent of 2D and, subsequent advances, lead to the discovery of many of the world's largest fields. 2D multi-fold seismic became the industry standard for exploration in the 1950's and in the early 1960's the analog to digital revolution ushered in better seismic processing, enabling superior imaging through digital processing (Cassiani et al., 2007). During the 1970's **3D seismic** began to emerge on a proprietary basis onshore, with offshore following in the late 1970's, primarily for field exploitation and development purposes. No longer did geoscientists have to deal with simple 2 dimensional planes in the earth, data could now be acquired and processed to deliver a full 3D cube of the subsurface. With its improved resolution and characterization of subsurface geology it grew in usage. By the 1990's it had become the tool of choice not only for development but also exploration. With the increased understanding of wavefield physics and subsurface rock and fluid properties there was a significant improvement in the acquisition parameters and processing routines for seismic. These have resulted in better signal content and 3D imaging in complex areas. A significant enabler for 3D seismic technology improvements was the increase in computing power and reduction in computer costs (Cassiani et al., 2007). A fundamental geologic tenet has always wanted to understand the subsurface with higher resolution and on a larger and larger scale. The increase in compute power gave industry the capability to apply the mathematics of more rigorous solutions in a reasonable time frame. In short, the increase has allowed algorithm development and usage that would have been unheard of even a few years before (Paul 2005). 3D surveys are now acquired over extensive areas, often up to 5400 sq miles, on a speculative basis, with imaging of such quality that companies can license the data from the vendor for exploration prospect generation, new play assessment and even detailed development planning. An explosion of 3D on the Gulf of Mexico shelf took place during the late 1980's -1990's. Directly following that was deepwater. In addition to the obvious imaging advantages of 3D several other factors influenced the move of seismic 3D to deepwater, Deep Water Royalty Relief Act (DWRRA), key deepwater discoveries, high deepwater production rates and evolution of deepwater technologies. **Figure 18** shows the change in deepwater 3D coverage in deepwater from 1992 to 2006. Today 3D coverage essentially blankets all of the accessible areas in deepwater. Many deepwater areas have been covered multiple times with 3D acquisition as better parameters and techniques have evolved.

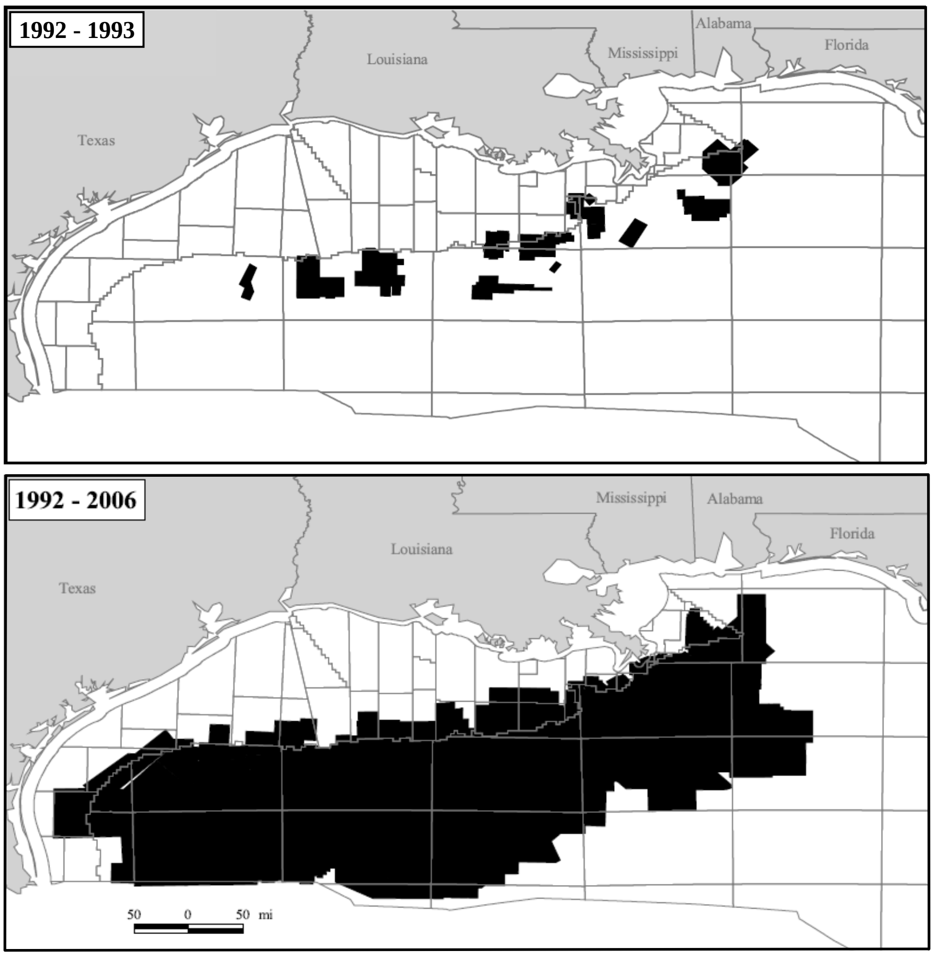


Figure 18: Deepwater Seismic 3D Permit coverage 1992 – 2006 (MMS Report 2008-13)

Improvements in exploration technology, notably 3D seismic have had significant impact on discovering resources, reducing finding costs, improving exploration success rates, decreasing dry holes and optimizing development well locations (e.g. **Bohi** contrasts exploration success rates drilled on the basis of 2D vs. 3D seismic data) both in the U.S. (an increase of 50% from 1992 - 2002) and globally **(Figure 19) (Cassiani et al., 2007).** Some of this success is also attributable to directional drilling capabilities. The data compiled was a global number based upon declared outcome from net exploration wells reported by industry both onshore and offshore.

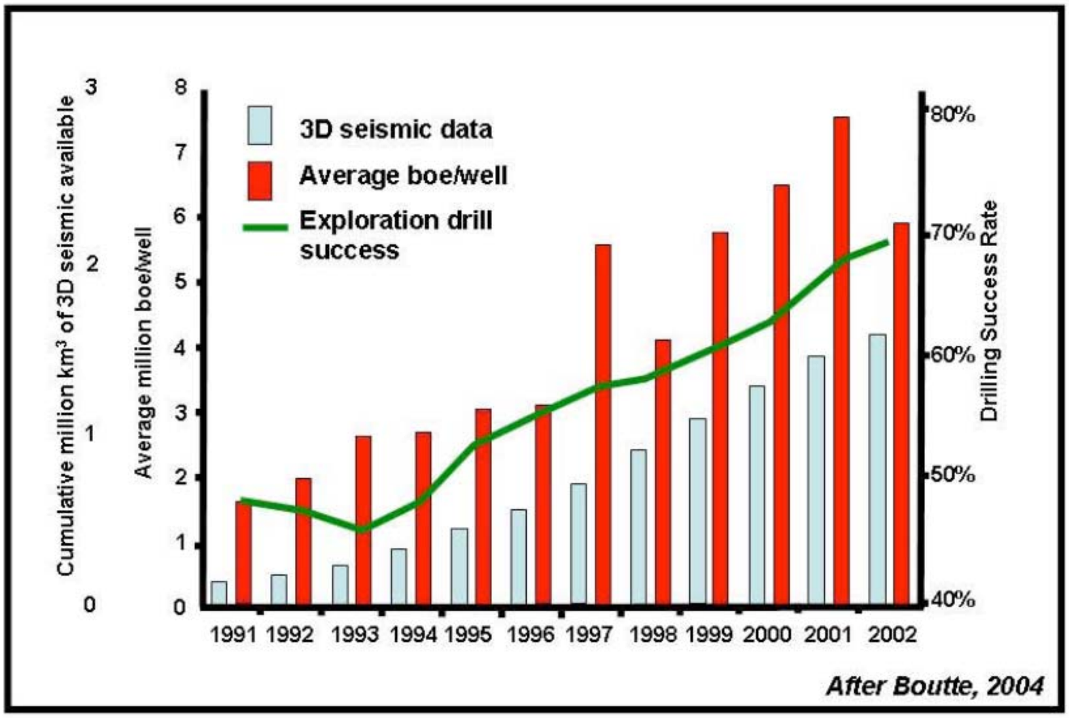


Figure 19: Global discovery success rates and total additional reserves per discovery well have increased significantly since 1991, as has the use of 3D seismic (Boutte 2004) (From 70 largest publicly traded energy companies as reported to SEC)

Because most of the Earth's giant fields, in areas that have been accessible to industry, were discovered by the 1970's, 3D surveys have not resulted in similar increases of hydrocarbons that occurred with 2D **(Figure 20).** Geologic factors are such that industry tends to find largest fields first in new play opportunities (biggest, most obvious structures were recognizable with 2D seismic or reconnaissance means). Also, the reduction in discovery volumes is a result of a decline in exploration opportunities influenced by access, subtle traps, and more focused exploration. However, as the world becomes more covered with 3D, the challenge, in areas that are accessible, will be to recognize these more subtle traps, stratigraphic and those hidden beneath the veil of a poor image, that earlier 2D and 3D could not properly image (Cassiani et al., 2007). This veil was seemingly insurmountable in the deepwater Gulf of Mexico and contrary to the statement above, while in general 3D has not resulted in the increases of hydrocarbon discovery as with 2D, it has been absolutely critical for the subsalt play.

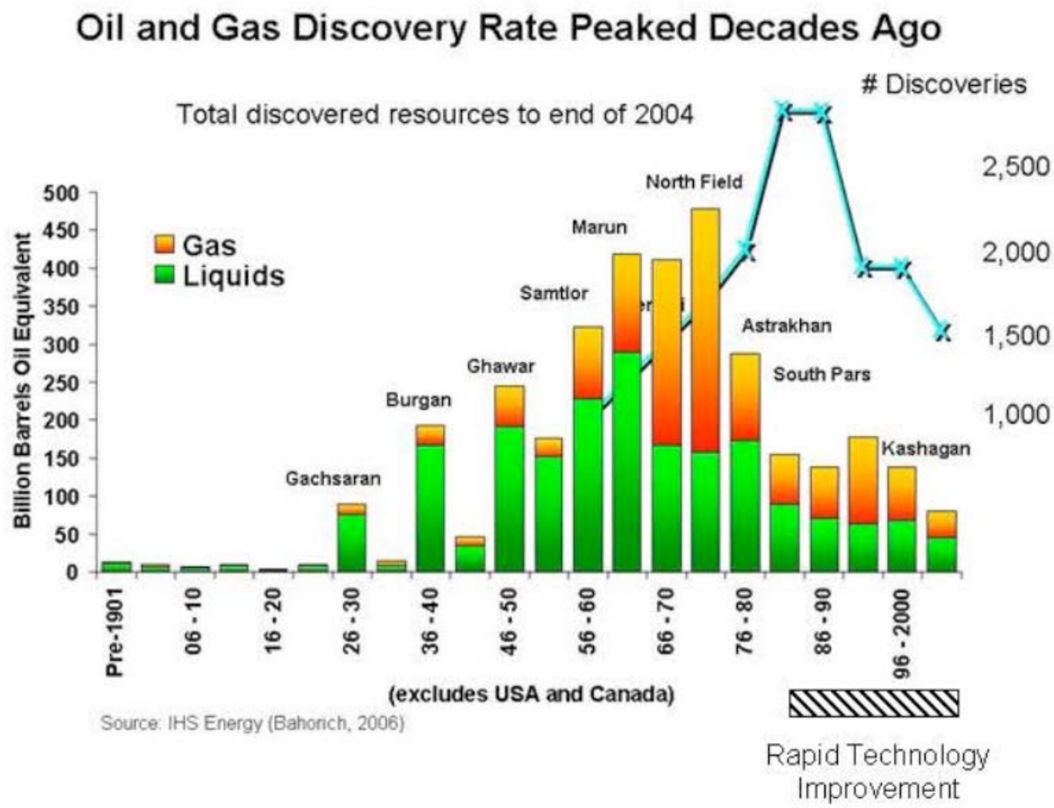


Figure 20: Evolution of oil discovery volumes with time with a significant marked decline since the 1960's and 1970's. (Bahorich, 2006).

As industry explored in deeper water one of the major technical hurdles became imaging beneath the veil of salt. Unlike most of the shelf areas where salt is structurally more vertical in nature, deepwater saw much more horizontal emplacement of salt. Due to its acoustic properties, salt zones can severely inhibit seismic resolution, so without the advent of modern 3D seismic imaging many structures would have remained hidden.

Advances in computing power enabled industry to use more robust processing algorithms capable of positioning the data more correctly in depth. **Figure 21** shows the difference when dealing with salt, between earlier 3D pre-stack time imaging and more recent 3D depth imaging of the same area. This dramatically improved the image and allowed identification of a viable geologic trap to lower the risk in the initial exploration well. Where would you have drilled the well on the line to the left? This type of image uplift has been demonstrated repeatedly in the GOM subsalt play trends. The need in deepwater with its risks, complex salt bodies, and cost profile made the technology mandatory and motivated industry for even more dramatic improvements in imaging algorithms. As such today no 3D in the GOM is acquired without performing 3D prestack depth imaging on the data. Also, today the 3D pre-stack depth imaging coverage map looks similar to the overall coverage map shown above in **Figure 18**.

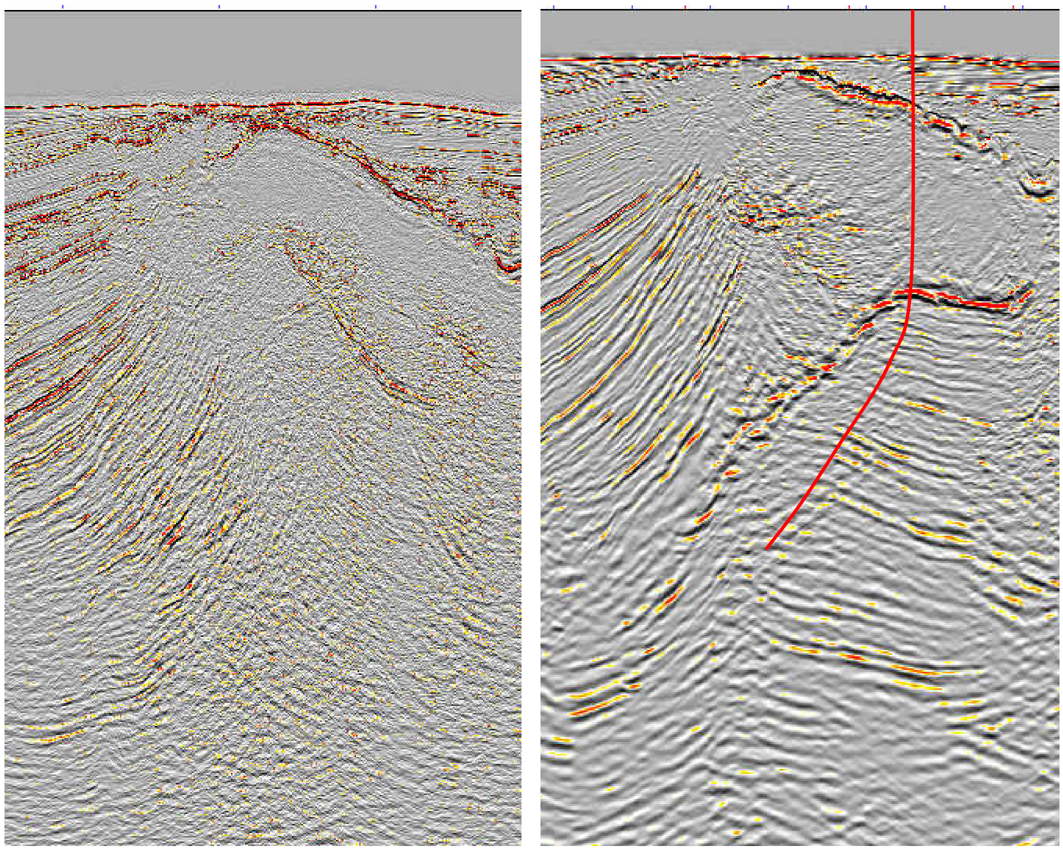


Figure 21: 3D Pre-stack time imaging 3D Pre-stack depth imaging
(Courtesy of CGGVeritas Services (U.S.) Inc., Houston, Texas)

To understand the magnitude of enhancement that 3D depth imaging provided one only has to look at the fields that would not have been identified without it, Tahiti (462 MMBOE), Tiber (560MMBOE), K2 (248MMBOE), Shenzi (400MMBOE), Kaskida (385MMBOE), Caesar/Tonga (250MMBOE) and Knottyhead (244MMBOE). Others such as Mad Dog (634MMBO), Atlantis (915MMBOE), Thunderhorse (1.092 BBOE), and Bigfoot (190MMBOE), may have been weakly identifiable as trend acreage with 2D, for the purpose of bidding in a lease sale, but none were drilled without 3D depth imaged data sets.

Just these 11 subsalt fields alone have proven plus probable reserves approaching 5.4 billion barrels. Mad Dog, Atlantis, and Thunderhorse were discovered in the late 1990's using depth imaging technology that would be considered fairly primitive by today's standards **(Mitchell, 2010).** Although the initial discovery well could be justified, the data quality was not sufficient to properly develop the fields. With this potential beneath salt and the need to understand the structure and stratigraphy in greater detail, BP and the rest of industry began to push for better images beneath salt. Two major issues were recognized as needing attention, better velocity models and multiple attenuation. The

SMAART JV industry joint venture demonstrated that surface residual multiple attenuation (SRME) was a dramatic improvement over other methods and with that it became industry standard for subsalt projects **(Bishop et al., and Miley et al., 2001).** Utilizing the robust SRME process, better velocity model building techniques and wavefield imaging technologies such as WEM, imaging at the above discoveries was improved, but it was realized they were still not good enough. Here BP took a leadership role, and after finite difference modeling studies, determined that with a change in seismic technology called wide-azimuth acquisition (WAZ), better imaging under the salt could be obtained. It was not new technology as it was used in land 3D's and offshore with the vertical cable method or bottom cable. However, these methods were not cost effective in deepwater. Up until this time in deepwater the primary acquisition mode was by streamer involving receiver cables in a linear arrangement with the sources. This provided limited lateral offset of the wavefield to the cable. But acquiring data not only in line with the receivers but also from varying distances laterally was shown to provide better subsurface illumination. As such BP proceeded on a proprietary basis to run a wide azimuth towed streamer (WATS) and ocean bottom node based wide azimuth survey for Mad Dog and Atlantis. With the success of the Mad Dog survey, towed, parallel, streamer based WAZ acquisition began on a speculative survey basis with WGeco's EOcto 1 acquisition completed in December 2006 and followed by processing in April 2008. Since that time industry has acquired 160,000 sq km of surface tow WAZ which is the equivalent of ~ 6,850 offshore deepwater blocks **(Mitchell, 2010).** Industry acquisition vendors have experimented with various geometries to speed up and reduce the cost of acquisition. Some compromises in acquisition parameters were enacted to make the costs reasonable but still providing superior illumination to narrow azimuth. The most efficient configurations today uses four vessels, two deploying up to 10 parallel streamers each with sources and two source vessels (**Figure 22).** The max cross line offset in this configuration is typically ± 4200 meters, providing improved azimuthal coverage relative to narrow azimuth (NAZ) acquisition. Retention of low frequencies (low cut at 1.5 Hz) by one major contractor for WAZ acquisition should further improve subsalt imaging. The subsurface CMP bin dimension is 6.25m x 60m at a fold of ~ 200. BP's Mad Dog proprietary survey is still the best sampled wide azimuth with 6.25m x 31.25m CMP coverage and at a fold of 432. The decimation schemes utilized by industry have allowed WAZ acquisition over much of the Gulf deepwater very efficiently and with better illumination than narrow azimuth. The consensus has been to use the spec WAZ for exploration purposes – leasing and exploratory well and if necessary follow it with an infill or new survey for development and production of the field. Orthogonal WAZ acquisition (2 WAZ surveys with prime azimuths 90^{o} apart as well as rich azimuth (3 WAZ surveys with prime azimuths 60^{o} apart) have also been acquired on a limited basis. A tighter acquisition bin on the initial surveys would improve the density of subsurface coverage, but cost improvements would be needed to encourage industry to participate.

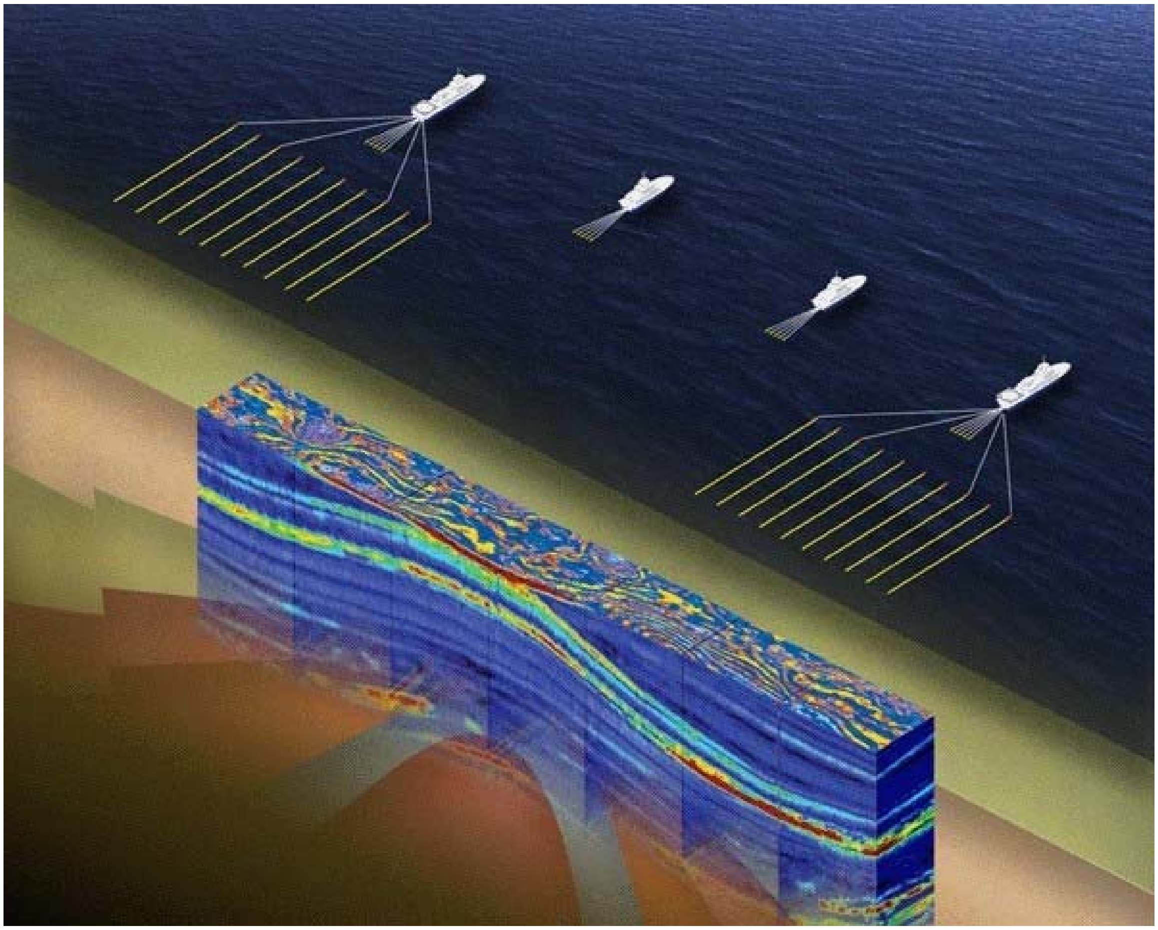


Figure 22: 4 vessel WAZ seismic acquisition configuration with a subset of the later processed 3D seismic volume (Courtesy WesternGeco)

The other method of wide azimuth acquisition that has gained some traction over the past few years is the **Ocean Bottom Survey (OBS).** This type of survey uses grids of 4 component (3 component geophone and 1 hydrophone) receivers (nodes) in stationary positions on the seafloor. A source vessel towing a marine source array shoots a predetermined dense grid on the sea surface. ROV units then move-up a group of nodes to 'roll' the receiver patch forward and the source vessel carries out a new shooting pattern. Due to the number of nodes and mobilization effort involved, OBS is best applied for targeted acquisition during the development phase. As such industry currently uses it more in the proprietary mode. OBS can deliver a better set of azimuths than towed parallel WAZ geometry. BP's experience with the surveys acquired at Dalia, Deimos and Atlantis Fields show that OBS and subsequent processing generates high resolution images. Another advantage of OBS surveys is for use with time lapse imaging or 4D, because it has minimal ambient noise and smaller upfront capital outlay compared with permanent emplacement **(Mitchell, 2010).** Both of the above acquisition methods are providing a superior sampling of the wavefield over the Narrow Azimuth (NAZ) approach.

With the rapid advancement of imaging algorithms due to computational technology advances, industry is now able to solve the wave equation with the best current imaging technique, a two-way algorithm called Reverse Time Migration (RTM). This process is a dramatic improvement over Kirchhoff, 1-way wave equation (WEM), and controlled beam (CBM) algorithms. It is a two-wave equation solution that provides superior handling of multiple ray paths and structural illumination, especially in complex imaging environments such as subsalt. RTM migration has improved NAZ data and in late 2007 became the algorithm of choice for model building and final imaging of all narrow azimuth surveys involving difficult imaging. But since 2008 this robust algorithm now has access to the superior sampling provided by WAZ to really show what it can do. In addition major vendors now have the ability to apply RTM and correct for anisotropic effects in the velocity field, both vertical and lateral, thus allowing even more accurate assessment of the subsurface structural picture. Seismic anisotropy is basically the variation of the seismic wavefield velocity in different directions. These effects, commonly known as Vertical Transverse Isotropy (VTI) in horizontal media and Tilted Transverse Isotropy (TTI) in dipping media, are most prevalent in shale sections. TTI layers can cause serious problems in conventional imaging, misplacement of key objectives, and so it is important to reconstruct the velocity model suitable for anisotropic depth migration.

A new norm has been set, but what will the next step change in imaging be. One such possibility showing promise for the industry is **Waveform Inversion**. It allows us to build better velocity models through an iterative process of updating the velocity model by minimizing the misfit between real and modeled wavefields, thus creating a more robust image. Another area of need has been subsalt reservoir imaging. Geophysicists have been spoiled by what they are able to extract from the seismic concerning reservoir and fluids above salt. However beneath salt is much more problematic. Amplitude corrections for focusing and defocusing of the wavefield will be needed to extract any usable reservoir information. This is an area of needed attention for the next few years **(Mitchell, 2010).**

Now the question remains have we achieved the optimal acquisition geometry for imaging beneath salt. It is widely known that even with towed parallel wide azimuth, salt geometries can still cause areas to lack illumination, and so industry is still searching for better sampling. **OBS** surveys mentioned above are one means of acquisition that can mitigate this issue. The other, that has been getting some press in the last two years, is **dual coiled** shooting by WesternGeco. This is a method of towed wide azimuth acquisition acquired in a circular pattern. Modeling exercises show that it delivers a better range of both offsets and azimuths than standard parallel WAZ geometry. It may be more realistic to call this **full-azimuth**. A feasibility study has been done in the Gulf, and confirmed that circular geometries could be successfully acquired and processed. Also the geometry is very efficient since no time is lost in line changes. The current 2 x 4 coil implementation utilizes two pairs of vessels – a source/streamer vessel and a source vessel on opposite sides of the circular shooting pattern. This approach yields a wide range of offsets (up to 14-15 km) over a full range of azimuths (Moldoveanu et al., 2008).

Currently WesternGeco is acquiring a speculative dual coiled shoot called Revolution I, covering ~ 160 blocks, in the southeastern East Breaks area of deepwater GOM.
Another big push in seismic, seen last year at the 2010 Society of Exploration Geophysicists Conference in Denver, was achieving greater bandwidth in the acquisition, especially on the lower frequency side. All the vendors are seeking to achieve this, due to the better penetration and signal to noise ratio for deep objectives under the salt. PGS noted their Geostreamer™ cable technology with larger bandwidth and CGGVeritas, the recently launched Broadseis™, with a bandwidth of 2.5 – 150 Hz.

So what other desires and needs are being discussed in industry? At last year's Denver geophysical meeting some key topics of interest were seismic acquisition, processing and rock physics for onshore shale gas trends, involving the potential to image or extract attributes that would help industry quantify fracture patterns. This may also have impact offshore when onshore gas supplies decline in the future. Also geophysical colleagues share the short term goal of having all major vendors move to TTI RTM and Waveform Inversion on a production basis, with the intermediate term goal of moving to Elastic RTM. Intermediate to longer term having the ability to perform near real-time migration iterations on the fly from their industry offices, through possibly distributed processing back at the vendor's headquarters, has been an ever-present goal.

To date (thru 2007) about 94% of discovered reserves in the Gulf are in Miocene and younger section. Of this 27% are in deepwater. Of recent significance, have been several successful exploration wells in the L. Tertiary Wilcox section of the Deepwater GOM. Much of this prospective section lies under extensive canopies of salt ranging from 7,000 to 20,000' thick and at target depths up to 35,000'. As mentioned above, without the advent of modern 3D seismic imaging they would have remained hidden and many would not have been drillable without current deepwater rig technology. In 2009 BP announced their L. Tertiary Tiber discovery, 3- 5 BBOE in place, ~ 500mmboe recoverable, drilled to a record setting 35,050' deep. More recently in October 2010, Chevron announced sanction for the co-development of the Jack and St. Malo fields with estimated recoverable reserves of half a billion barrels. Discoveries to date in the trend total ~ 4 BBOE recoverable and studies suggest world class reserve potential of up to **15 BBOE** and long life projects of up to 30 – 40 years. Couple that with more drilling and ever improving 3D imaging from powerful algorithms applied to the new 3D wide azimuth seismic acquisition and those resource numbers could improve dramatically.

On a world-wide basis, recent subsalt discoveries in deepwater Brazil have been the result of improved 3D imaging and deepwater capable drilling rigs. Proven reserve potential to date in this exploration area is in the range of 10 – 15 BBOE, the largest discovery in the Western Hemisphere in the last 3 decades. Brazilian officials are stating an estimated at 30 - 50 BBOE may lie in the trend, roughly the entire world oil consumption in 2010, definitely world class. As we move into deeper water and drill deeper with more capable rigs, and gain access to additional areas, it may be possible for a time to see the discovery rate and reserve volume adds level out. Technology advances of the next 30 to 40 years will be encouraged by the billions of barrels worth of potential in the Lower Tertiary. The technology to see through salt, equipment reliability and failsafe operations, drilling, HP/HT environment, fracturing long pay zones, flow assurance, production schemes and next generation completion and production tools, reservoir simulation software, stimulation vessels, all will play a vital role not only for L. Tertiary, but also for other opportunities in the Gulf and worldwide (Offshore Magazine, January 2010)**.**

5.2.1. Seismic Technology Advances – The Road Ahead

5.2.1.1. Short Term Seismic Technologies That Could Have Significant Impact:

High-density data and rapid data processing (Cassiani et al., 2007) – Industry has made great strides in seismic acquisition and imaging since 2007 with RTM depth migration currently the method of choice and 3D WAZ seismic acquisition already covering large portions of the Deepwater GOM. Also advances in computation technology have increased turnaround on processing and enabled economic access to robust algorithms. However, higher density, broader spectrum data, with the ability to improve reservoir characterization and subsalt illumination, will need improvements to have commercial impact. Here positive results from industry's OBS surveys, emerging coiled shooting, and Geostreamer ™ and Broadseis™ technologies may be critical.

Acquiring and retaining low frequencies – Critical to improving resolution and improved imaging in a subsalt environment is broadening the spectrum on both the low and high side. Retaining the low frequencies has been especially challenging to industry. Two recent seismic acquisition technology steps Geostreamer™ and Broadseis™, along with the OBS survey, are capturing lower frequencies, which will provide better penetration beneath the salt. Utilization of the Geostreamer and Broadseis cable technologies with WAZ and dual coiled shooting geometries will be of extreme interest to industry. Vendors are also working on the issue from the processing side through de-signature and de-noising.

Subsalt imaging – has contributed to the discovery of many of deepwater's largest fields. Enhanced subsalt imaging will undoubtedly result in new discoveries and improved economics **(Cassiani et al., 2007).** In the last 5 years, the L. Tertiary trend discoveries, most of which are subsalt, are gaining momentum in the Deepwater and Shelf areas of the Gulf of Mexico. As such the currently available Tilted Transverse Isotropy (TTI) & Reverse time Migration (RTM) are the "go to" migration approach, with a more realistic velocity field to provide optimum imaging. Following that, on a near term basis, building geologically constrained velocity models using **Full Waveform Inversion (FWI)** should result in better subsalt imaging. This technique involves starting with an initial velocity model, followed by computing synthetic forward modeled data, updating the starting velocity model based on differences between the real and modeled wavefields and then iterating to minimize misfit energy.

5.2.1.2. Short to Intermediate Term Seismic Advances Needed:

- **Ability to rapidly view the affects of velocity model changes –** Decreasing turn-around time of migration runs would allow the interpreter to explore several “what if” scenarios in short order. Geoscientists have been craving “real time” imaging for a number of years and the utilization of Graphics Processing Units (GPUs) in the image processing shows promising speed advantages.
- **Higher frequency RTM processing** – low frequency is not sufficient in certain cases. Need to cut down on processing time for RTM algorithm at high frequency. A leading major vendor can now migrate up to ~ 42 Hz with some competitors making more limited progress.
- **Deterministic amplitude corrections for focusing and defocusing beneath salt** - will be necessary for subsalt reservoir imaging. This technology has been available for several years using beamlet formulations with one-way operators. The challenge is to extend these capabilities to two-way solutions to the seismic wave equation.
- **Better inversion algorithms -** for extraction of rock, fluid properties and reservoir thickness. Additionally, development of improved inversion techniques to directly estimate rock properties, such as isotropic closure stress or “brittleness”, have the potential to impact efficient development of shale. Pre-stack non-linear inversions are already showing the ability to accurately estimate total impedance.
- **Elastic imaging and converted wave processing,** steady progress is being realized in more efficient codes for 3D forward elastic modeling and migration. Driven by improvements in computer hardware and more efficient codes, elastic imaging at a production level is likely within 3 – 4 years. Many of the benefits of full elastic imaging will be obtainable using specialized 3D propagators that permit the modeling and imaging of specific converted mode paths resulting in improved subsalt imaging, especially for steeply dipping interfaces.
- **Elastic modeling** to help design survey acquisition.
- **Simultaneous joint inversion of seismic, EM, MT, CSEM, gravity, magnetics, etc. for rock and fluid properties;** offers great potential for improved salt geometry characterization where the seismic alone is ambiguous or of limited value. Substantial improvements in gravity gradiometry (superconducting sensors with actively stabilized mountings) together with greater effective depth-of-penetration CSEM will continue to render simultaneous joint inversions of growing importance.

5.2.1.3. Additional short to intermediate term - The following technologies some of which were introduced above, will lead to ever improving imaging, especially when coupled with more robust seismic acquisition:

- **Elastic full waveform inversion**
- **Elastic RTM**
- **Lease Squares Migration (LSQR) –** with accurate migration amplitudes
- **Orthorhombic Tomography**
- **Elastic Tomography**
- **Wave Equation Tomography**
- **Ultra high-density data and processing –** multiple industry experts commented here. In summary their comments were that data density and processing continue to improve at incremental steps. The ability to acquire data with cross line sampling as fine as inline sampling (6.25m x 6.25m) and process this density through elastic FWI from 1 - 100Hz, rapidly and at low costs, could lead to game changing breakthroughs. These include greater efficiency in economically marginal areas, enhanced recovery, and new finds.

Figure 23 shows the evolution of seismic imaging technology since 1996 and what the future holds

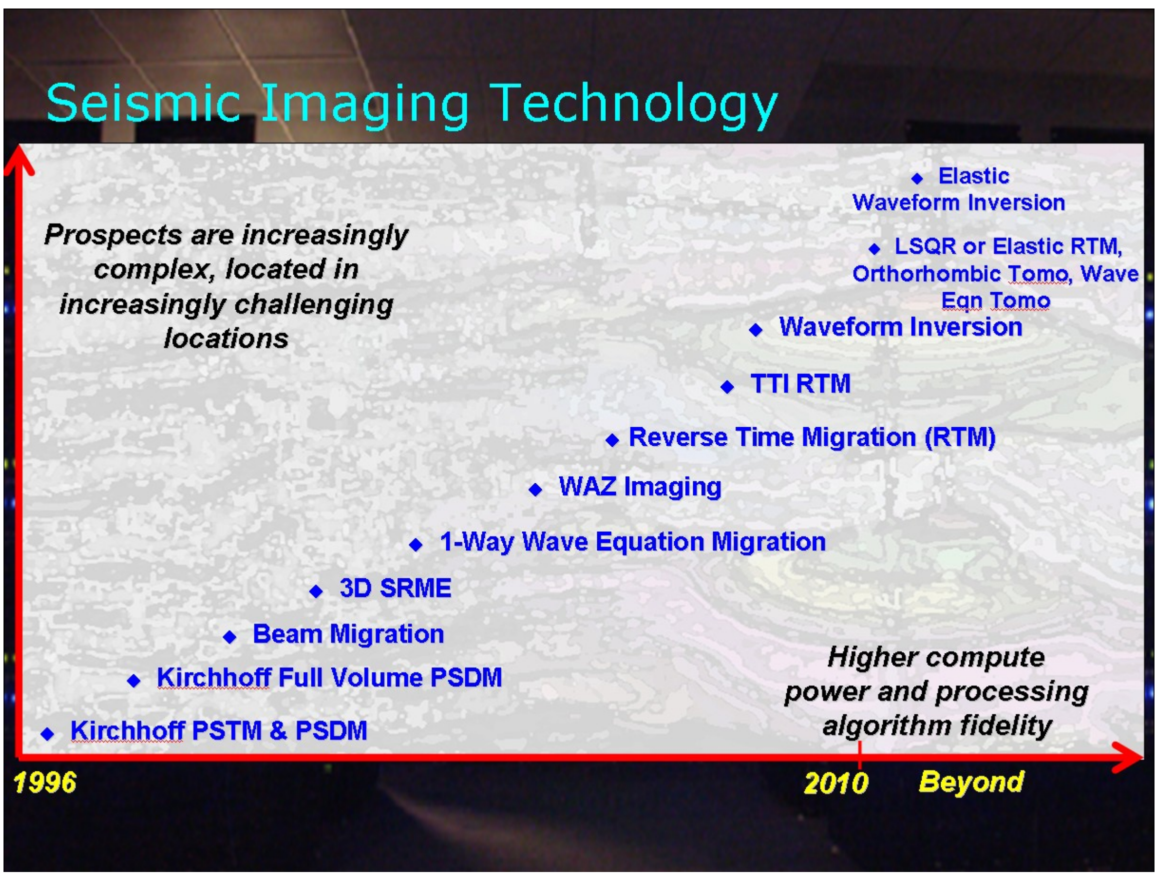


Figure 23: Evolution and future of seismic imaging

5.2.2. Additional Seismic Related Topics:

Time lapse 3D seismic – Time-lapse seismic (often called 4D seismic) allows for near real-time monitoring of changing reservoir conditions (e.g. pressure changes and fluid movements). 4D seismic is already impacting reservoir management strategies and enhancements in the technique may facilitate a better understanding of reservoir character and flow properties and could lead to enhanced recovery **(Cassiani et al., 2007).**

Seismic Attributes – an increasing number of smaller specialized vendors offer a wide range of attributes for structural and stratigraphic enhancement. These capabilities are increasingly offered with novel techniques for attribute comparison including multi-panel and multi-volume displays. These will allow the interpreter to gain a greater understanding of geologic features and contribute to a more quantitative interpretation.

Wave theory research (Cassiani et al., 2007) – Basic theory into wave theory is a continuing effort in both industry and academia. Synergistic collaboration between the two has certainly led to gradual advancements and could result in large leaps forward.

3D borehole seismic(3D VSP) (Cassiani et al., 2007) – Although borehole seismic has been used for 20 years, there is a need for improvements in imaging via enhanced acquisition and processing techniques to unlock reservoir boundaries especially in proximity to or beneath salt. The trend is toward tools with ~ 100 receivers or more from smaller vendors. Modeling studies have demonstrated that 3D VSP's acquired with several hundred receiver 'levels' can provide substantially improved imaging particularly in subsalt geometries that are poorly illuminated with surface seismic. The value of 3D VSP's can be further enhanced using special imaging conditions applied to the RTM of the 3D VSP data. This permits the imaging of particular wave paths or of shot-receiver groups that provide more optimal imaging of the subsalt target.

Microseismic mapping – is the application of earthquake seismological principles, consisting of detection, location, and analysis of extremely small seismic events induced by the hydraulic fracturing process of well stimulation. Microseismic images allow an operator to map fracture growth and geometry (azimuth, height, length and complexity). The introduction of this process has added immensely to our understanding of fracture propagation, especially in unconventional reservoirs onshore such as shale-gas. Successful development of unconventional reservoirs is enhanced by a better understanding of fracture geometry and improving the stimulated volume, both of which can be achieved through microseismic monitoring and mapping. **(MicroSeismic Inc. Website, 2010).** Microseismic is still in its infancy. There is a need to understand how pumped volumes and pressure relate to the final stimulated rock volume. Understanding how the rock breaks, not just where, and integration with engineering and production would be big developments.

5.3. <u>Computational Technology</u>

(By **Paul Schlirf)**

We all know how important computers are in today's society and the myriad of engineering, medical, entertainment marvels they have allowed, but we think William Camp and Phillipe Theirry of Intel captured it best for the oil industry and geophysics in a paper for High-Performance Computing Special Section of the Leading Edge in January 2010 by saying, "Among all scientific domains, geophysics is certainly one of the most computationally demanding, with probably the broadest requirements for performance and scalability. If we consider the whole seismic processing sequence, from data acquisition to reservoir simulation and monitoring, we have to consider accordingly all aspects of computing, including data management, processor arithmetic-unit speed, memory bandwidth and latency, interconnect performance, IO bandwidth, visualization, and power consumption." "If high-performance computing (HPC) was initially restricted to supercomputers for scientific research, we can now see it migrating to the data center as racks of cluster nodes used in many different businesses **(Camp and Thierry, 2010)."**

Engineers adopted the first computers when they saw how fast they could crunch numbers. One of the areas of early influence was reservoir simulation, with its large volume of mathematical calculations. Those who used the first computers remember them as rudimentary. Prior to the mid 1950's Exxon researchers remember getting access to accounting machines from the accounting department at night to run their calculations. In 1955, they increased the engineering computing capacity with the receipt of a Bendix G-15. It was vacuum tube based, with storage on a magnetic drum. Within a few years they obtained IBM's first widely used scientific computer the 704, a binary machine, with built-in floating point hardware. Its central memory was magnetic core with secondary storage on magnetic tape **(Lord, 2007).**

Since the invention of the integrated circuit in 1958, there has been a monumental advance in computer technology. This accelerated even more rapidly after the introduction of the first commercially available microprocessor in 1971. Gordon Moore, the founder of Intel, described the trend known now as Moore's law in a 1965 paper, noting that the number of components in an integrated circuit doubled every 2 years. His prediction has been uncannily accurate. We have gone from 2300 transistors in 1971 to over 2 billion in today's quad cores. To capture the dramatic changes in computing environment one need only look at **Figure 24** below to get a sense of how rapid it has been.

	Clock speed	Memory	Storage
Apollo lander	2 MHz	0.004 MB	?
Cell phone	600 MHz	256 MB	16 GB
Desktop computer	2500 MHz	>8000 MB	>1000 GB

Figure 24: Compute power comparison of the Apollo guidance computer with a typical cell phone and common desktop today (Sava, 2010)

The advent of 2 GHz and higher microprocessors having 2 GB and more of RAM have caused PC's to rival the UNIX mainframe world at much less expense. Such advances have encouraged most seismic processing and reservoir modeling vendors to port their code to run under Microsoft Windows NT, XP or Linux operating systems. Some offer software that runs only on a PC. These trends will continue. Just how much, read on!

As in other scientific domains, we often see in geophysics that new technology advances are led by data acquisition; and, then cascade into improvements in the later stages of seismic processing. This certainly can be seen to have occurred with 3D seismic in the 1990's and with multi and wide azimuth in this decade. Imaging has gone from ray based, followed by wavefield extrapolation and then two-way wave equation in the last 15 years. With additional enhancements, computational technology is now allowing the utilization of waveform inversion **(Camp and Thierry, 2010).**

One of the other key components to improved computational performance, other than hardware, has been the advent of parallel processing**.** Think of approaching a complex problem like a human brain simultaneously processing incoming stimuli. Parallel processing is the simultaneous use of more than one CPU or processing core to execute a program more rapidly. In the supercomputing community it is all about executions that physically take place simultaneously with the goal of solving a problem in less time or solving a larger problem in the same time. Although used in many areas of the oil industry, nowhere has this technique shown more dramatic value add than in the seismic processing area. In terms of larger problems such as seismic imaging, one only has to look at the volume of data in today's wide azimuth 3D (WAZ) seismic surveys. Some surveys measure 5300 square miles equivalent to ~ 600 OCS blocks, contain 7 billion seismic traces of data, with 3500 samples on a 14 second record at 4 ms sample rate, for a grand total of 2.45 x 10^{13} samples. That is 94 terabytes of data or 94,000 Gb. One can easily see why it would take a tremendous number of CPU's to process that amount of data into a quality 3D image of the subsurface in a reasonable amount of time. Some service companies today access up to 100,000 + CPU/GPU(graphics processing unit) cores. This would be roughly equivalent to the simultaneous running of up to 50,000+

desktop PC's with 4 cores per CPU, running parallel processing techniques, to generate such images.
Improvements in speed, memory, and cost will impact data acquisition, processing and interpretation industry-wide. In the last 10 years we have seen a step change in excess of 100x in the floating point operations per second. The large scale application of the GPU chip technology has accelerated turnaround of key algorithms (RTM) by up to 10x at certain vendors. This technology will continue to advance with increasingly efficient chip designs including CPU-GPU hybrids for even better performance.

The **Figure 25** below shows how computer performance has improved over the years allowing robust imaging algorithms to execute in stages over months vs. a lifetime 10 years ago. Several of the seismic vendors today are approaching the level of processing capability seen with these national computers. A quick extrapolation of the top 500 list predicts Exoscale computing within 10 years from now. Of course there will be major challenges to solve before getting there, one of which is power consumption, which could approach that of 1.4 EPR (Evolutionary Power Reactor) nuclear power plants at 1.6 Gigawatts. This is obviously an unrealistic solution. As a result some innovations under consideration include incorporating memory in the CPU + memory multichip package (MCP), non-silicon semiconductors allowing current to flow at lower supply voltage, utilizing silicon to send and receive optical information (silicon photonics), and changes in programming models **(Camp and Thierry, 2010).**

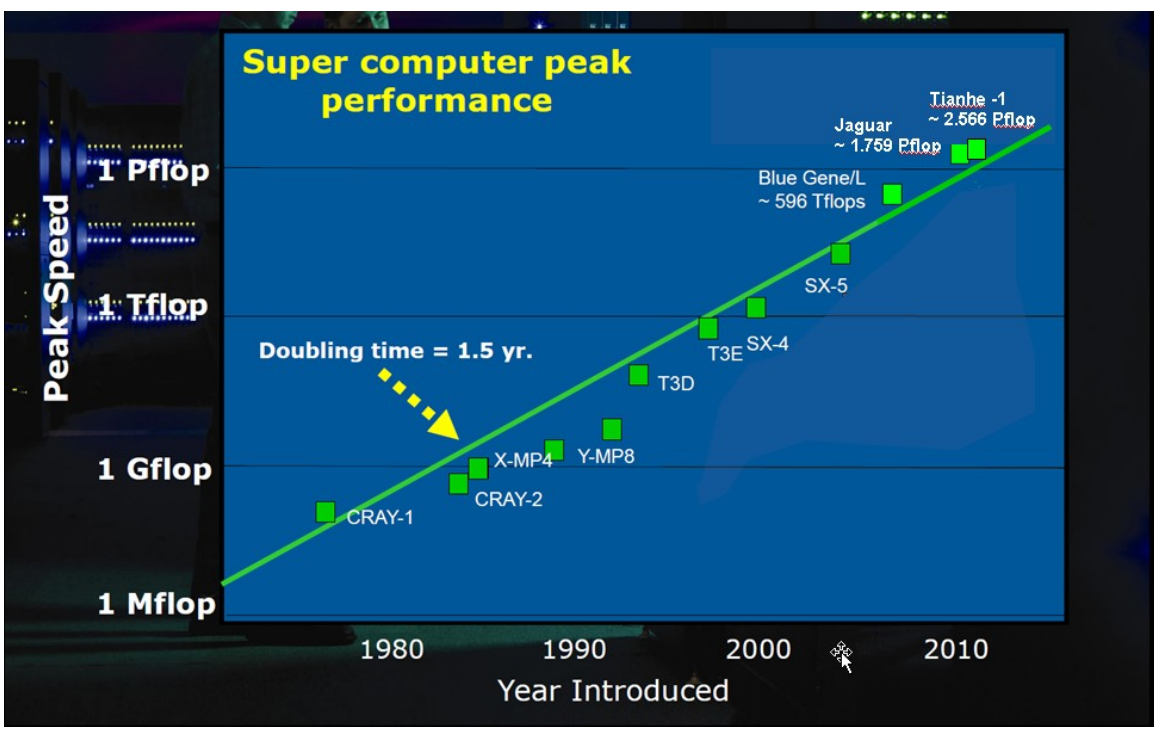


Figure 25: Supercomputer Performance TOP500

Challenges remain for computational science but the industry has come a long way in implementing new technologies. Don Paul President of Energy and Technology Strategies was involved in a 3rd party study entitled “High Performance Computing Initiative” carried out by the United States Council in Competitiveness. The study looked at how readily digital technologies were being implemented in four industries: Oil and gas, pharmaceuticals, aerospace and automobiles. “The study concluded that the oil and gas industry has propagated digital technologies, altered its management and organization, and the way people connect to the data for more than any other industry**.**”**(Moon and Paul, 2008)** With that said it will be exciting to see what challenges can be conquered with Exoscale computing.

5.4. Interpretation Technology

(By Paul Schlirf)

Interpretation technologies have seen a rapid advancement from analog single-fold seismic data in the early days. In the 1960's and 1970's structures were mapped on 2D seismic paper sections, folding and tying in each new line in to carry the horizon onward. That process was repeated throughout the entire 2D time data set until a complete map was made which was then hand migrated to the proper vertical and horizontal positions and converted to depth. Jump forward to today's office-based desktop Linux computers with dual screen monitors **(Figure 26)** and even large screen visualization centers seating up to 50, each with sophisticated computer-aided, semi-automatic interpretation and mapping tools for handling multiple large volumes of 2D and 3D data that are now accurately positioned in the depth domain through rigorous seismic image processing.

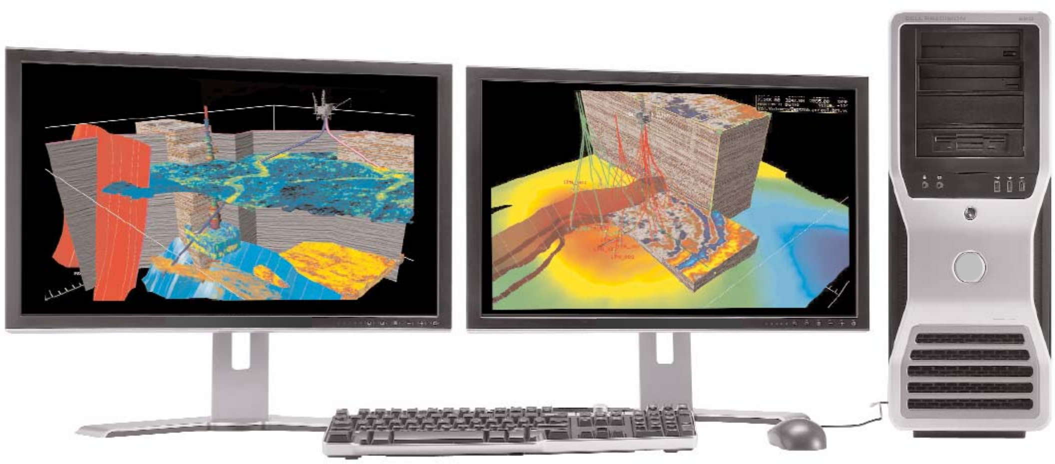


Figure 26: Office based Linux Workstation with Dual Displays (Courtesy Landmark Graphics)

Interpretation technology has played a significant role in the impact of 3D on success rates. With the adaptation of tools used in other industries, such as medical imaging, interpreters are now able to visualize and interpret data much faster. They are not limited to thinking in 3D, but literally can visualize in 3D, or "climb into" the data set. On another front, interpretation has evolved from using seismic strictly for structural assessment to extracting reservoir and fluid information from attributes and derivative properties. In the late 1970's seismic data achieved sufficient quality that when correlated to rock environments and fluid effects, it could be used to enhance the identification of hydrocarbon prospects via direct hydrocarbon indicators (DHI's), thus lowering exploration drilling risk. Later this ability to detect some hydrocarbon fluids in these environments encouraged the use of time-lapse 3D surveys (sometimes referred to as 4D), where industry could acquire 3D's at different time periods to monitor the movement of oil and gas at different stages of the field life by changes in seismic character. This allowed industry to optimize subsequent development well placements.

Along with these improvements in seismic technologies have come an increasing number of meaningful seismic attributes as well as seismic volumes of increasing size. As a result, interpreters now struggle with the sheer volume and complexity of the data. This has provided the impetus for more interpretation being done with computer-aided techniques (horizon interpolation, fault picking, etc.). New ways of looking at seismic data and derivative attributes were developed to enhance geologic features, such as reservoir/sand fairways or depositional geometries. Improved understanding of rock and fluid properties and higher resolution data have steered interpretation away from mere qualitative interpretation of attributes to an increasing demand for quantitative reservoir and fluid predictions.

To overcome these issues industry is researching technologies that are focused on **(Cassiani et al., 2007):**

1) Better integration of geophysical and geological data to develop quantitative interpretations.
2) Inclusion of more data dimensions.
3) Increasing automation of interpretation tasks, as suggested by **Barnes (2001),** with the promise that seismic search engines capable of sifting through large volumes of 3D for specific attributes and events may become a reality in the near future.

In summary, interpretation technology has impacted the oil and gas industry through direct recognition of hydrocarbons in some environments, recognition of exploration opportunities in previously difficult imaging areas, allowing better placement of exploitation and development wells when combined with subsurface well information and significantly reduced interpretation time. Bottom line is better risk quantification.

5.4.1. Interpretation Technology Advances – The Road Ahead

5.4.1.1. Short term Interpretation technologies that could have significant impact:

Improved quantitative seismic interpretation (Cassiani et al., 2007) – There is a need for more quantitative interpretation techniques with better integration of rock physics with seismic, geological and fluid data, along with consideration of uncertainty. "Trends toward more rigorous modeling and inversion of the wave propagation phenomena; combining sedimentological and diagenetic modeling with rock physics and inversion results to obtain more realistic predictions of seismic properties; probabilistic Monte Carlo simulations to capture uncertainties in both rock physics and inversion results; and incorporation of geostatistical methods to account for spatial correlations in reservoir properties **(Avseth et al., 2005)."**

<u>Inclusion of more dimensions</u> (multi-dimensional attributes, geologic data) (Cassiani et al., 2007) – Integration of more data dimensions (currently limited to a small number) using advanced statistical techniques that allow uncertainty to be addressed (Barnes, 2001). The increase in attributes beyond coherence, spectral decomposition, and AVO, to include additional geologic and geophysical attributes, many of which are not unique, is overwhelming the interpreter. Because of this, there will be a need for more advanced statistical techniques like clustering, neural networks, Bayesian frameworks, self-organizing maps, hidden Markov chains, and support vector machines to help guide the interpreter to key data structures.

With the growing volumes of data (seismic 3D and the plethora of associated attributes, well logs, and production), industry is faced with the challenge of effectively using and handling these volumes of data. One technology that has shown value in the last decade has been the adaptation of **neural networks**. These are statistical data modeling tools that are usually used to model complex relationships between inputs and outputs to find patterns in data. Neural networks are used in financial services software and other pattern recognition systems. There are several commercial applications for what are known as **"supervised" neural networks** in the upstream oil and gas industry. These work where some of the data are known at specific locations, such as well boreholes. Supervised networks link seismic data to the known results of wells. These networks are trained to analyze and classify data. However, since the earth is heterogeneous, classification of patterns away from the well information can be difficult. In an exploration mode, and or new play environment with limited to no well control, there is a need for an algorithm that can find things that are anomalous and classify them. Hence the name **'unsupervised' neural networks**. These types of networks do not require wells and can be used on seismic data alone to potentially identify geologic features that were missed by conventional analytic methods **(Smith, 2010).**

With neural networks the neurons adapt to the data following a simple set of rules. It essentially becomes a learning machine, adapting to the characteristics of the data, resulting in what are called self organizing maps (SOM's). The SOM is a robust cluster analysis and pattern recognition method developed by Prof. Teuvo Kohonen of Finland in the 1970's – 1980's.

Neural networks can assist the interpreter by an automated process that enables rapid comparison of large sets of seismic attributes often up to 25, identifying combinations of attributes that reveal seismic anomalies, patterns and trends, distilling the interpretation process to identify potential hydrocarbon zones with greater speed and certainty. In recent years, industry is using more subtle patterns and relating them to features such as porosity, lithology, and fluid content, as well as underground structure.

Besides the immediate impact with seismic interpretation, neural networks have potential applications for analyzing seismic attributes with well logs for better predictions away from wells, integrating seismic data for reservoir characterization, and incorporating microseismic events with other seismic data for fracture prediction (**Smith, 2010).**

Today's G&G interpretation systems offer increasingly integrated and realistic digital representations of the subsurface to support exploration, drilling and production decisions. However the growing complexity of these systems, combined with the explosion of data volumes (attributes etc.), points to the need to develop and deploy new generations of tools. Advanced human interfaces, data management, and search technologies have been enabled by consumer, commercial, and defense markets. When combined with more advanced representations for geologic processes and Earth models, these technologies create a platform for a new generation of G&G interpretation to support businesses from frontier exploration to producing from unconventional reservoirs **(Paul, 2007).**

Greater automation (Cassiani et al., 2007) – There is significant work going on in the service companies and the universities to increase the degree of automation (e.g. automatic fault and horizon mappers). Changes in vendor interpretation packages show a major effort toward reducing interpretation time by integrating previously "siloed" skill domains and simplifying links to additional interpretation tools. Recent focus has been on a collaborative work flow between interpreter and the advanced statistical tools **(Pederson et al., 2005).**

General Computation on the Graphics Processing Unit (GPGPU) (Kadlec and Dorn, 2010) - On the subject of automation and speed, floating point performance of GPU's has increased dramatically over CPU's in the last decade and have found increasing use in the seismic processing business discussed in an earlier section. They may even be on the verge of delivering the dream of real-time seismic imaging.

Computing graphics are parallel in nature and GPU's can dedicate the majority of the transistors to arithmetic computations vs. CPU's that are optimized for sequential codes with transistors that must be assigned with non-arithmetic tasks such as branching.

The processing capability of these GPU's has implications for volume interpretation. Leveraging the power of GPU's opens the possibility for combining the interpretation stages into a single method of calculating attributes, extracting surfaces and rendering the entire process in 3D. GPU's also have the potential to automatically map 3D surfaces from seed-picks using a growth function that is based on one or more seismic attributes and topological constraints. With immediate visualization the interpreter can adjust parameters so that the seed picks grow into the surface representing the feature.

5.4.1.2. Longer term interpretation technologies that could have significant impact:

Development of an automated "seismic search engine" to find new opportunities (Cassiani et al., 2007)– As described by (Barnes, 2001), this type of technology would take advantage of advances in computational power, advanced statistical techniques, geophysical data and geological concepts in a highly automated fashion. See the previous discussion on neural networks and pattern recognition as technology to build from.

Integration of other technologies to improve interpretation (Cassiani et al., 2007) – Advances in human cognition, as well as advances in pattern recognition technology for military, imaging and security purposes may play an important role. Human pattern recognition can be biased, especially with color, which can have a profound influence in search effectiveness. Reducing this bias by an understanding of vision science can improve best practice in interpretation **(Welland et al, 2006).**

5.5. Drilling Technology

(By Paul Schlirf and Grant Schluender)

In the late 1800's drilling for oil consisted of a steam powered rig, and the cable tool that continuously dropped a heavy bit attached to the end of a hemp rope cable, slowly chiseling away the soft rock. The drilling had to stop continuously so the workers could bail out the rock cuttings from the bottom, and drilling could resume. This original technique was perfected by the Chinese in Sichuan Province over 2,000 years ago as a means of mining salt **(Kuhn, 2004).** The penetration rates of the day were incredibly slow, sometimes taking months to drill down to depths of less than 100ft. In addition to the slow penetration rates the cable tool could not efficiently drill the deeper medium to harder formations, frustrating the early wildcatters and geologists who knew there was deeper potential. In the early 1900's, a new step change in technology called rotary drilling answered the need. Instead of dropping heavy bits to the hole bottom, pulverizing the rock and then bailing it out, rotary drilling introduced a rotating hollow drill pipe in which fluid was pumped down allowing the rock cuttings to be washed out of the hole back up the outside of the drill pipe. In 1901, wildcatter Captain Anthony Lucas, seeking oil beneath salt domes near Beaumont Texas, used a rotary rig and on January 10, 1901 ushered in the oil industry in the Gulf Coast with the Spindletop discovery rocketing oil into the air. The well was said to have produced 75,000 – 100,000 barrels a day from a depth of 1160ft. Still, even with the rotary drilling rig, there were issues with the slow rate of penetration in harder rock that kept even deeper drilling essentially out of reach. Initially these early rotaries had used what was called a fish-tail bit that could only scrape the rock; however in 1909 another step change in drilling technology occurred when Howard Hughes Sr. patented the two cone rotary bit. It had 166 cutting edges arrayed on the surface of two metal cones mounted opposite each other that could chip, cut, and powder hard formation rock **(Figure 27).** This bit unlocked the full potential of the rotary drilling system allowing for the efficient drilling of wells in much deeper, harder rock environments. By 1934 Hughes had patented the 3 cone bit which is the enduring design that remains much the same today.

Figure 27: **Fish tail bit** **Hughes Sr. Two-Cone Drill Bit**

The advent of rotary drilling would usher in the ability to deviate boreholes from vertical position; however, for industry this was initially more of a problem than a solution. In the 1920’s, Oklahoma’s boom there——were actual recorded incidents of two rigs drilling into the same hole, offset wells drilling into each other, wells intercepting producing wells, and wells in the center of the geologic structure missing the field entirely. Unbeknownst to the drillers, the deeper they went the more boreholes often deviated from the vertical. As a result of these issues, the industry developed and introduced the drill collar and stabilizers to the drill string in order to provide neutral points of bending, rigidity and a controllable fulcrum point from which they could control the direction angle. In 1929, H. John Eastman introduced controlled directional drilling in Huntington Beach, California using whip-stocks and magnetic survey instruments to drill from shore-based surface locations to oil deposits offshore. However it wasn’t until studies were performed in the 1950’s that targeted, planned, and deviated drilling became a possibility. In 1978 Teleco introduced the world’s first Measurement-While-Drilling (MWD) tool, enabling drillers to know the precise location of their well while drilling. The tool operates by converting downhole, electronic directional information to fluid pulses (pressure fluctuations in the drilling fluid) and sending that information up the wellbore. The mud pulse is then converted back to electrical information at the surface, where it can be viewed on the rig or back in the office onshore, essentially in real-time.

The next issue industry had to contend with was the increased formation pressures encountered as the boreholes went deeper and deeper. Uncontrolled hydrocarbons could “blow-out” of the hole, where any ignition source would cause devastating fires and destruction. As a result, in the 1920’s a machine shop operator named Harry Cameron was sought to design and build the first blow-out preventer (BOP); these preventers are placed at the top of the wellhead and bolted on to a casing flange, giving the ability to shut-in around drillpipe or shear the drillpipe in the case that hydrocarbons are starting to escape the well. The need for pressure control became even more pronounced with the evolution of deeper drilling and better prospects, where the combination of higher pressures and larger volumes of oil can potentially lead to even more catastrophic blowout events. Today's average deepwater BOP in the GOM is rated to15,000psi, with onshore BOP's ranging anywhere from 3000psi to 10,000psi.

Another aspect of well control that has evolved over time is the fluids used to drill the well with. Originally cable tool rigs often had to shut-down drilling when they encountered fluid and now not a single phase of drilling is performed without it. In the very beginning of rotary drilling, water mixed with the natural formation materials to form "muds" that both carried cutting to the surface and cooled the bit. While in normal pressure regimes this balances the pressure of hydrocarbons in the hole and keeps them under control, it does not provide sufficient control in over-pressured, overbalanced formations. Industry thus began to add natural weighting materials such as barite to help counter the ever increasing pressures and prevent the flow of hydrocarbons to the surface. Still, over time, industry began drilling deeper and hotter holes that encountered more sensitive formations, more reactive fluids, and in general hotter environments and that has resulted in the development of more and more specialized and engineered drilling fluids. Today's drilling fluid performs several very critical functions; it carries cuttings to the surface, creates hydrostatic pressure as the primary means and barrier to wellbore fluid control, cools and lubricates the drilling assembly, and it stabilizes the entire drill string.

Early on in the evolution of drilling it became necessary to prevent different fluids and formations in the well from collapsing, interacting, coming to the surface, cross-communications and causing mechanical trouble. As this prevention was performed early in the Chinese salt wells with hollowed tree trunks, it is now done using highly engineered casings and cement. These allow engineers to drill deeper, high pressure formations without the heavier drilling fluids fracturing shallow, exposed formations. Originally the formations behind the casing were "mudded off" with extra-thick drilling fluid to prevent fluid communication. However, this was ineffective and unpredictable, leading to the use of cement behind the casing as an isolation tool. With early casing jobs, cement was mixed by hand and installed with a dump bailer down the annulus of the casing and formation with the casing held off bottom. The casing was then lowered to the bottom into the cement, forcing cement up the back-side. Later tubing was used to convey the cement to bottom. In 1921, Erle Halliburton perfected a cement jet mixer that eliminated hand-mixing at the wellsite and allowed for cement to be placed and blended both predictably and reliably **(JPT, Frontiers of Technology, 1999).**

One of the greatest land-based economic drilling achievements of the past 25 years is construction and utilization of horizontal wells. With the ability to provide drastically more contact with the pay zone than a vertical well, horizontal wells have and continue to impact economics tremendously. While the well may cost more **2 – 3** times more, production can be enhanced as much as **15 - 20** times, depending on reservoir properties and the length of horizontal section. It has led to the development of many fields that would not have been economically viable with vertical wells and continues to give access to low-permeability reservoirs across the globe (**JPT, Special Section, 2008).**

Some of the earliest horizontal drilling success began with attempts to enhance production by John Eastman and John Zublin, drilling a 20 – 30ft build radii's with horizontal sections of 100–500ft in the early 1940's. Unfortunately, due to the availability of more easily accessed resources, the oil and gas industry did not rapidly advance this specific technique until later. That all changed in 1977, when Alan Barnes started a renaissance of the Eastman/Zublin short-radius drilling in the Empire Abo reef in New Mexico. With the success of these wells industry interest in the technology began to increase.

One of the keys to success with horizontal drilling is maintaining position within the pay zone. 30 years ago this entailed multiple trips and wireline surveys to determine the path of the bit, greatly increasing the costs associated with drilling. The general development of Measurement-While-Drilling (MWD) techniques, and subsequent enhancements therein, dramatically improved industry's ability to both get downhole measurements with the drillstring in the hole and maintain a proper wellbore trajectory by adjusting to said information. A comparison of industry's advancing technical capabilities is illustrated by the following example: in 1982, a well was successfully drilled directionally 11,000' under the Corpus Christie, Texas airport to intersect a 300–400ft radius target. In 2005, 23 years later, an almost identical well was drilled under the same airport to intersect a 50ft target. In the second well, improved technologies, including a downhole rotary-steerable system and MWD technology were applied achieving incredible accuracy over a two mile drilling distance **(Paul, 2007).** Over the last three decades, advances in technology have enabled drillers with the ability to perform real-time well logging, known as LWD, by placing sensors on an assembly directly behind the drill bit. We now have the capacity to mitigate some drilling risks by carrying out real-time analysis of downhole information.

Precise location of the drill bit was one of the first technical issues tackled but many others, soon followed: annular pressure measurement using a Pressure While Drilling (PWD) tool provides key information on downhole pressures to determine magnitude of kicks, borehole ballooning and actual downhole pressures exerted by the drilling fluid, Gamma-Ray provides key information about the type of rock being drilled, Sonic, Density and Resistivity tools provide key information on pore pressure trends, rock strengths, formation types, types of formation fluids and can now even forecast what rock and pressure lie ahead of the bit **(Moos, 2007).**

5.5.1. Offshore Drilling

Over the past 100 years of exploration and production, the Oil and Gas industry has consistently shown innovation in technology necessary to supply the world with an inexpensive and reliable energy source. We go back to days of Colonel Edwin Drake in the Northwestern hills of Pennsylvania in 1859, with the first well to be drilled for the distinct purpose of finding oil. In the late 1800's, after drilling a number of wells, early oil men in California noticed that those closest to the coast were the best producers. Then in 1887, H.L. Williams came up with the idea of combining a wharf with a cable tool drilling rig and soon the first offshore oil well was drilled 300’ from the beach **(Figure 28).** Over the next 40 years others would follow drilling in swamps near the coast, transition zones and offshore within sight of land. In the mid 1940’s significant changes began to occur with the transition from a war economy to a peace time one. The government control on crude prices ended and public demand was rapidly increasing. Chasing the potential of salt dome traps in the GOM, one of the defining moments in offshore oil and gas drilling came in 1947 with the first well, out of sight of land, 9 miles off the coast of Louisiana in 15ft of water, by Kerr-McGee (now Anadarko) at Ship Shoal block 32. The barge and platform combination used for this well was a step change in offshore drilling-unit design **(Figure 29).** This event marked the beginning of the modern offshore industry **(NOIA Website),** and with it some of the most significant achievements in the evolution of drilling technology would unfold in that environment.

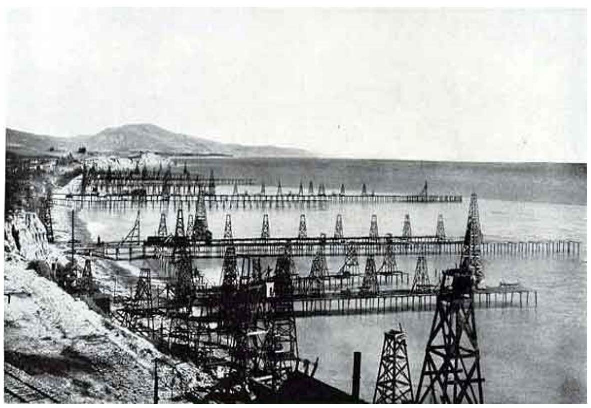


Figure 28: Wells offshore California, Summerland oilfield 1902

Figure 29: First well out of site of land Kerr-McGee 1947

In 1954, the moveable, **submersible drilling barge** was introduced in the GOM. The drilling floor and crew quarter’s level were attached by legs to a barge that could be floated to any location where water was then pumped into the barge to sink it to a resting point on the bottom. This made work offshore much more attractive. The first one constructed was called Mr. Charlie after the father of Charles Murphy Jr. of Murphy Oil. The barge, rated to 40ft water depth, went on to drill hundreds of wells in the Gulf and retired from service in 1986 when drilling activity moved into water depths beyond its capabilities **(JPT, Frontiers of Technology, 1999).** Technology continued to advance**.** The Gus 1 a **forerunner of the jack-up,** was also built in 1954 and rated to 100ft of water. In 1955, the Western Explorer was the **first floating rig** to use **subsea well control**. Le Tourneau’s Scorpion, built in 1956 for up to 80’ water depths, was the first **lattice-leg jack-up**. The jack-up is a floating barge fitted with legs that can be raised and lowered. The rig could be towed or self-propelled to the location with legs up. Upon arrival to the location the legs are jacked down to the bottom, and after preloading, the barge portion containing the drilling unit and crew quarters is jacked above the water level to a height where waves and currents have no impact on the drilling floor. In the late 1970’s a major step change in jackup design occurred with the introduction of the **cantilevered drill-floor**. As fixed platforms got bigger a jack-up design was simply too small to surround the platform in order to position its drill bit properly. The cantilever

equipped jack-up could skid the drill equipment over the platform after jacking up next to it **(Figure 30) (Childers, 2007).** Today the Rowan Company has jack-up rigs capable of drilling to 35,000ft in water depths up to 550ft. Given the recent activity in the Lower Tertiary of shallow water Gulf of Mexico, highlighted by the Davy Jones discovery, they are currently putting into service new jack-up rigs with state of the art technology capable of drilling high-pressure, high-temperature (HPHT), and extended reach wells in up to 350' of water and 35,000' deep.
With the expansion of deep potential for the Miocene and now L. Tertiary into water depths of less than 10 feet, draft limitations of the jack-up have prompted re-engineering of barge rigs capable of drilling to 30,000' in a HP/HT environment.

Figure 30: Rowan Gorilla VI Cantilevered Jack-up Drilling Rig (Rowan Companies, Inc.). Note cantilevered section extended over the top of a platform

In 1963, the Ocean Driller, designed for up to 300ft of water, was the first **semi-submersible** built from the keel up. As with most of the first generation units it could sit on the bottom or drill from the floating position. The second generation semi-submersibles, designed for some units to operate in up to 1,000ft of water, came out in the 1970's. Buoyancy was obtained from ballasted, watertight pontoons located below the ocean surface and wave action. In the mid to late 1980's third generation semis arrived that could operate in greater than 3,000ft of water. Upgrades were made in 1990's to even greater capabilities and depths that became the 4th generation. In the late 1990's the 5th generation units, such as the Ocean Nautilus, became even larger and more capable at 50,000 long-ton displacement and operating depths greater than 5,000ft of water. Today 6th generation semi-submersible units are being delivered that can operate in up to 10,000ft of water and drill to 40,000ft **(Childers, 2007), (Figure 31).**

Figure 31: Maersk Developer Semi-sub Drilling Rig (Courtesy Maersk Drilling)

Ship and barge shaped floating drilling rigs were attractive initially due to ease of mobilization, however they decreased as semi-submersibles and jack-ups became more popular. The exception was the **dynamically positioned (DP) drillship** which could be held on location by thrusters rather than the use of a tethered mooring system or legs on the seabed. The first of these units was the Glomar Challenger in mid 1960's. Although used for scientific work (seafloor cores that proved continental drift), it proved up the technology, so in the late 1960's to early 1970's the first generation drill ships were built. In the late 1970's 2nd generation ships became available that could drill in up to 3,000ft of water. Today, DP ships 2 to 3 times the size of earlier models and capable of operating in greater than 10,000ft of water are available **(Childers, 2007).** The latest 6th generations drillships come equipped with state of the art station keeping, double-hull, dual-drilling derrick capabilities, stronger and more efficient drives so wells can be drilled deeper, capable of drilling in up to 12,000ft of water and 40,000ft deep with a variable deckload of over 20,000 metric-tons **(Figure 32).** One advantage of using DP drill ships is the ability to be mobilized rapidly if hurricanes are threatening operations. This allows them to be utilized in areas with infrastructure during hurricane season. Over the last 10 years drilling companies have also increased the mobility of semi-submersibles by manufacturing them with DP capabilities and as such without the need for mooring.

Figure 32: Deep Ocean Clarion Drillship (Pride International, Inc.)

The GOM holds many offshore oil related records, but two of the most significant ones involve drilling with semi-submersibles and drillships. ChevronTexaco set the water depth drilling record of 10,011ft in 2003 with a drillship at Alaminos Canyon Block 951 and BP the vertical drilling depth record of 35,050ft in 2009 with a semi-submersible at the Keathley Canyon Block 102 Tiber discovery well.

Deepwater drilling rig update:

> In 2010 there were 128 rigs in the world capable of drilling in at least 4000' of water. An additional 67 rigs are planned, on order or under construction. Not all have contracts with oil companies at this time **(Clanton, 2010).**

At present in the GOM Deepwater there are: 6 rigs capable of drilling in 12,000ft of water, 9 additional rigs capable of drilling in 10,000ft, 3 rigs at 8,500ft, 2 rigs at 8,000ft, 7 rigs at 5,000-7,500ft, and 5 rigs 1,200-4,000ft. Of the last ten new rigs delivered, all are capable of drilling in water depths of 8,500-12,000ft and total depths of 35,000-

40,000ft. Due to lack of activity following the drilling moratorium, of the above total 32 rigs listed, 13 are stacked and of those, 4 have been returned to contractors. This leaves 19 non-platform active rigs performing completions, drilling development wells and water injectors or undergoing maintenance, with only three currently drilling exploratory wells. Not counted in the above totals is an additional 7 deepwater rigs that were planned for use in the Gulf and are now being sent overseas.

Status of new drill ships with initial operations planned in the GOM:

- **Deepwater Ascension (Pride) –** built to operate in up to 12,000ft of water and drill up to 40,000ft deep including water depth. Awaiting client orders.
- **Deep Ocean Clarion (Pride) –** Capable of dual drilling activity in up to 12,000ft of water and drill depths up to 40,000ft. Awaiting client orders.
- **Discoverer Inspiration (Transocean)–** built to operate in 12,000ft of water, and drill up to 40,000ft deep including water depth. Currently stacked waiting on permit in the GOM.
- **Discoverer Clear Leader (Transocean) -** built to operate in 12,000ft of water, and drill up to 40,000ft deep including water depth. Drilling water injection well in the Gulf.
- **Stena Forth –** rated to 10,000ft of water and 35,000ft depth of drilling. Delivered in 2009. Moving to Libya. Will return to Gulf.

Status new semi-submersibles with initial operations planned in the GOM:

- **Ensco 8500 –** rated to 8,500ft of water and 35,000ft depth of drilling. Delivered in 2008. Rig on location for completion.
- **Ensco 8501 –** rated to 8,500ft of water and 35,000ft depth of drilling. Delivered in 2009. On standby.
- **Ensco 8502 –** rated to 8,500ft of water and 35,000ft depth of drilling. Delivered in 2010. Currently performing a workover.
- **Ensco 8503 –** rated to 8,500ft of water and 35,000ft depth of drilling. Delivered 2010. Acceptance testing. Headed overseas, will return to Gulf.
- **Maersk Developer** - rated to 10,000ft of water and 40,000ft depth of drilling. Delivered 2009. Stacked.
- **Noble Danny Atkins** - rated to 12,000ft of water and 37,000ft depth of drilling. Delivered 2009. Recompletion activity
- **West Sirius (Seadrill Ltd)** - rated to 10,000ft of water and 37,500ft depth of drilling. Delivered 2008. Undergoing maintenance
- **Deepwater Driller III (Transocean)** - rated to 7,500ft of water and 37,500ft depth of drilling. Delivered 2009. Undergoing maintenance

The offshore drilling units went from wharfs in the late 1800's, to one-off barge rigs in the 1940's and 50's, to high-end, sophisticated DP drill ship rigs today capable of drilling in more than 12,000ft of water and 40,000ft deep. In a little over 60 years we have gone from the capability of drilling in 15ft of water to more than 12,000ft of water and 40,000ft deep.

What is apparent from the discussion on drilling capabilities is that there is a link between the evolution of drilling technologies and the constant rise in volumes of oil and gas discovered. Without the ability to drill and exploit deepwater reservoirs in the world, many recent large discoveries in GOM, West Africa and now Brazil would have been delayed or perhaps never happened **(Cassiani et al., 2007).**

5.5.2. Drilling Technology Status

From the previous section one can see the incredible progress made in drilling capabilities over the last 150 years. So what does the future hold? Advances in technologies over the last decade and in the next 50 years in the U.S. are and will be in response to the fact that remaining oil and gas resources exist in areas of restricted access, mature provinces, significantly depleted basins or in difficult drilling environments such as the deepwater Gulf, Arctic or deep high-pressure high-temperature trends. Included with that are fracturing long pay zones in deeper tight rock, flow assurance issues with production in deepwater, extended architecture in limited infrastructure areas, need for improved oil recovery techniques (IOR/EOR), next generation completion and production tools, reservoir simulation software and stimulation vessels and we see the breadth of technology that will play a vital roll in the growth of oil and gas production offshore North America. Tackling these issues in the GOM can and will provide valuable learning's to the rest of the world.

In the 2007, NPC Exploration Technology topic paper, drilling technology was listed as one of the auxiliary technologies where future developments could significantly impact exploration results in the next 30 – 50 years. Three key areas were cited: **1) Drilling in physically difficult areas** (high pressure high temperature, ultra-deepwater, or shallow hazards) or environmentally sensitive areas; **2) Reducing drilling and stimulation costs** such that subeconomic conventional or unconventional resources become exploration targets; **3) Dramatically reducing drilling costs** to the point where significantly more exploration wells can be drilled for the same investment costs, allowing companies to test more risky concepts. The paper comments on the relatively slow but steady movement with the first two. But more step-changing technologies such as **managed pressure drilling** and **solid-expandable-tubulars** have taken a long time to be adopted due in large part to large financial exposure with new drilling technology **(Cassiani et al., 2007).** As we will see in the next section, since the publication of the 2007 report, one of the managed pressure techniques called **dual gradient drilling** was scheduled to arrive on the deepwater GOM scene in 2011. However, since the Deepwater Horizon incident there has been no new update on when this field trial may occur. On a final note, technology advances associated with an even more dramatic drop in drilling cost is being considered with robotic drilling. However, it is felt that achieving this advance will be very difficult, with little likelihood of impact toward exploration volumes by 2030 **(Cassiani et al., 2007).**

In the drilling technology introduction we provided a summary of drilling advances over the last 150 years and concluded with a listing of new drilling rigs slated for operation in the GOM. In the following section, we will provide a status of the impact technologies introduced in the 2007 NPC topic paper. To begin the discussion, our survey of drilling engineer colleagues showed the number one technology enhancement that could be a "game changer" is dual gradient drilling.

5.5.3. <u>Dual gradient drilling systems (DGD)</u>

Ultra-deepwater drilling is done today in water depths to 10,000'. In these deepwater geological formations, the natural formation pressures are dominated by the light-density seawater column, and less so by the denser sediments below the mudline. In conventional deepwater drilling operations, a long riser filled with drilling fluid from the rig floor to the sea-bed and on to the bottom of the wellbore is used to manage all formation pressures.

This tall column of drilling fluid above the mudline imparts an unnaturally high pressure gradient on the shallower formations, and can severely reduce the safe operating window within the Pore Pressure-Fracture-Gradient (PPFG) envelope. Engineers compensate for this by setting multiple strings of casing to seal off fragile areas, adding significant time and complexity to the wellbore construction process. The excessively high number of casing strings leads to very tight tolerances between them, and that leads to a very high incidence of Non-Productive Time (NPT).

Dual Gradient Drilling (DGD) was developed in order to expand this envelope. This is done by maintaining two different density fluids in the wellbore column: one lighter density fluid in the drilling riser and one higher density drilling fluid in the wellbore. The combination of a lower density fluid over a higher density fluid is very similar to the natural pressures in deepwater: seawater over sediment.

This offers several advantages over conventional drilling. First of all, in a seawater-over-mud density pressure environment, water depth no longer is a consideration in well design regarding casing points. The consequence is that fewer casing strings will be needed to reach well objectives **(Figure 33, Smith, 2009).** Additionally, the differential pressure across the casing at any point in the wellbore is always less than with conventional single-gradient drilling, except at TD, where they converge.

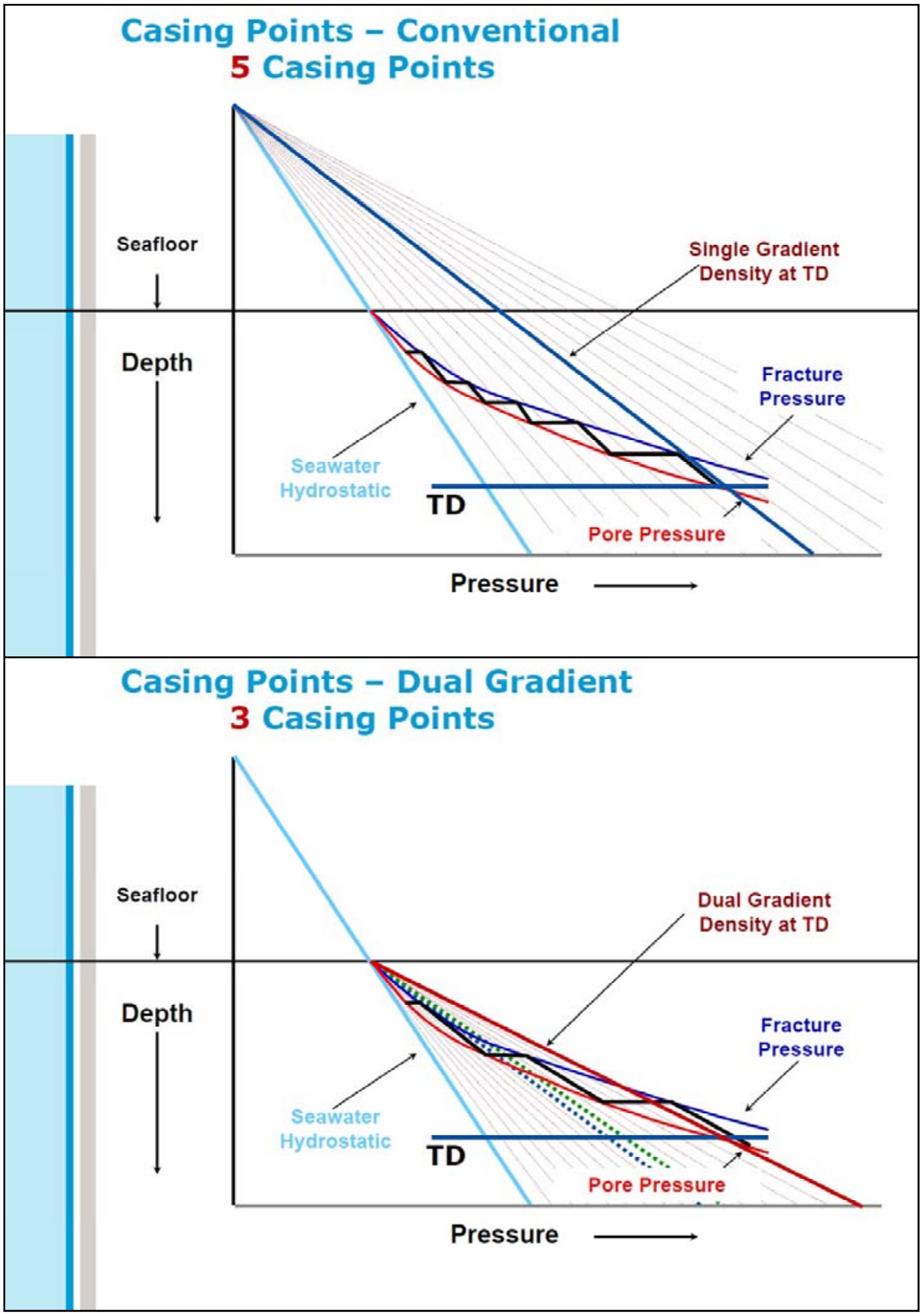


Figure 33. Conventional vs. Dual Gradient Mud Hydrostatic Plots and Example Casing Requirements (Smith, AADE Emerging Technologies Forum April, 2009)

In conventional deepwater drilling, the PPFG margin is already so slim that even slight increases in hydrostatic and flowing pressure may push operating parameters beyond the Fracture Gradient, causing lost circulation, Non-Productive Time (NPT) and potentially an unstable wellbore. One source of increased flowing pressure is the friction loss of the mud in the drilling riser. This is aggravated in deepwater, as the mud returns in the riser become chilled and sluggish due to surrounding seawater temperatures. A cold mud is generally more viscous, and it creates additional back-pressure due to the higher imposed friction pressures.

DGD is a subset of Managed Pressure Drilling (MPD). As with MPD, bottomhole pressure (BHP) is always maintained at a level intended to be balanced or over-balanced to formation pressures, so in combination, the dual densities always maintain a BHP equal to or greater than formation pressures.

Traditional MPD operations may use a combination of drilling fluid density and mechanically-imposed surface pressure to achieve this end. Technically, a surface MPD operation could utilize a drilling fluid density that would be under-balanced to the formation BHP. With DGD, that is not necessarily the case. In fact, in most cases, with DGD, the riser margin can be fully restored in deep water, meaning that even with the drilling riser removed, the well will still be dead below the wellhead, offering an improved level of drilling safety. This ability differs, depending upon the specific method of DGD employed.

The following history of DGD is provided by **J.D. Dowell in "Deploying the World's First Commercial Dual Gradient Drilling System," SPE Deepwater Drilling and Completions Conference, SPE 137319, Galveston, Texas, October 2010.**

> The investigation of DGD technology began with JIPs in the mid 1990s. They were working on ways to remove the mud from the riser and replacing it with seawater. The results of the **SubSea MudLift Drilling Joint Industry Project (SMD JIP)**, completed in 2001, was a technical success but a commercial failure. Reasons for the failure were many but a few are noted here.
>
> - The economic downturn
> - Significant rig modifications,
> - Very high equipment costs,
> - And the largest, according to one source, was that no operator had the portfolio of prospects or developments needed to support the financial commitment required to make it a reality.
>
> In 2006, Chevron tasked their Deepwater drilling group with a study of operations to improve safety, predictability and economics in the deepwater environment. They noted several improvements with rigs and tubulars, etc. but no step-changing technology jumped out. As a result, they assembled a team to revisit the DGD technology. Much work followed and eventually Chevron commissioned two companies to run studies on six different DGD deployment options.
>
> The best option resulting from that assessment was to use a single riser with a Hydril (now GE Oil and Gas) MudLift Pump™ (MLP) run in-line with riser. The technique was shown to be economic and as such, Chevron moved forward with the technology.

During the study it was shown that rig modifications would be needed with a DGD system. After reviewing multiple companies' responses to a detailed rig specification request, Pacific Drilling was selected to build the first "DGD ready" rig. The *Pacific Santa Ana* rig is a dual derrick Samsung 12,000ft class vessel due to arrive in the late 2011.

The equipment needed to complete the DGD system is explained below. Following the path of the drilling fluid through the system:

The drilling mud is pumped down the drillpipe through a **drill-string valve (DSV),** which prevents the drill pipe from u-tubing into the well when circulation is stopped. The mud continues on to the bottom-hole assembly passing out of the bit and carrying cuttings back up the annulus to the wellhead at the sea floor.

From there the mud passes through the **blowout preventer (BOP)** followed by a series of specialty riser joints. Uppermost is the **subsea rotating device (SRD)**. The purpose of the SRD is to form a mechanical barrier that separates the mud in the wellbore from the seawater or seawater density fluid in the drilling riser. The SRD diverts the mud in the annulus through a **solids processing unit (SPU).**

The SPU ensures all cuttings and debris are small enough not to plug the **MLP** and return lines. From the SPU, the drilling fluid enters the **MLP** installed on the riser above the BOPs.

The MLP is the "heart" of the system. Rig surface mud pumps are used to pump seawater down a 6" ID line built into the riser. This seawater is the "power fluid" that activates the MLP's six diaphragm chambers that allow the MLP to continuously pump mud. All six chambers can be operated simultaneously or they can be segregated into groups of three or two in the event of failure. This redundancy helps ensure continued operations. The MLP chambers send the fluid to the surface through another separate 6" ID return line attached to the riser. **Figure 34** is a schematic diagram of the Chevron DGD system.

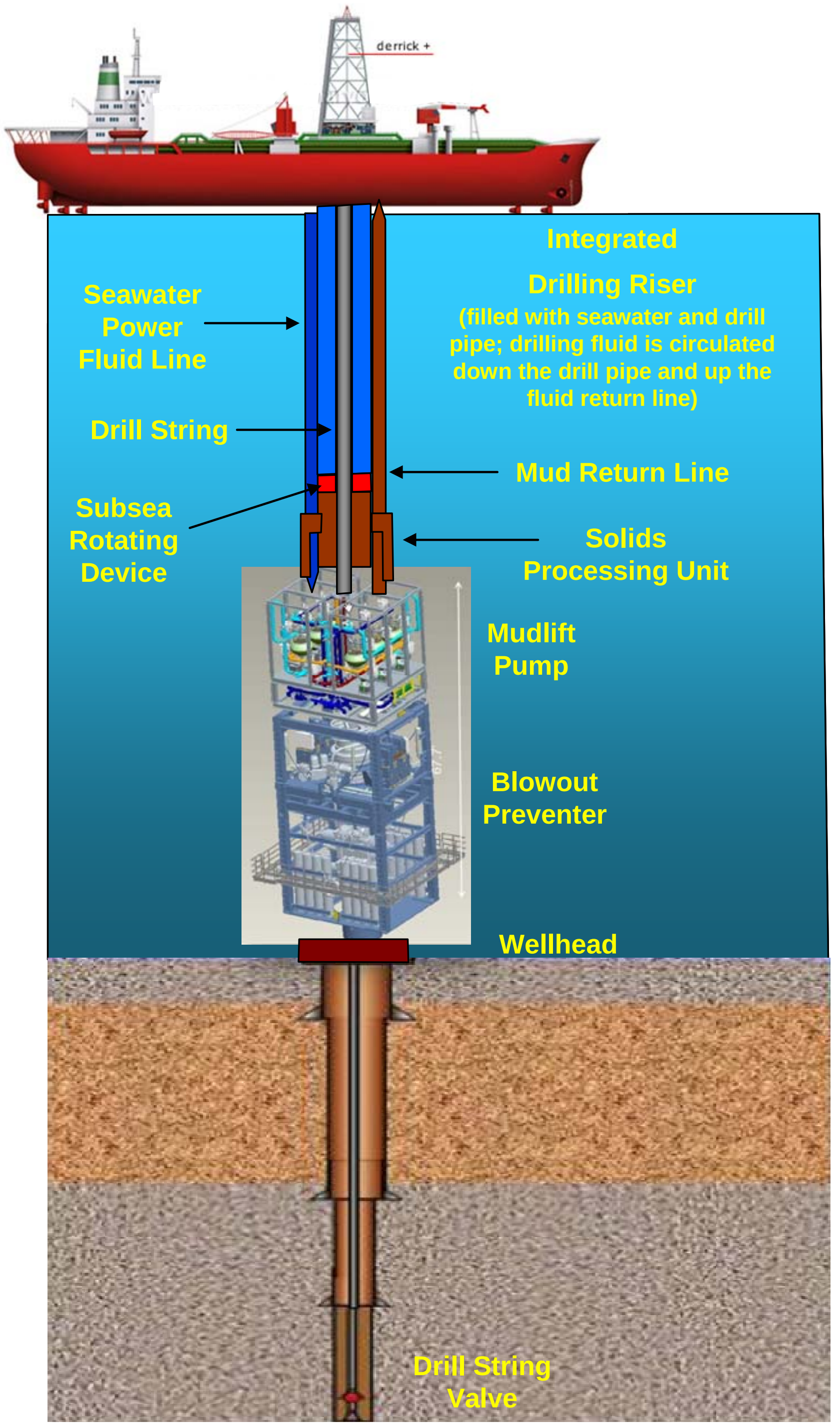


Figure 34: Chevron Dual Gradient Drilling Schematic (Thurston, 2010)

The successful deployment of DGD technology will provide a needed step change for access to energy in the 21st century. The advantages listed below have been documented by DGD developers and their industry colleagues **(Smith, 2009)**:

Enhanced safety and environmental performance and risk

- Fewer strings of casing will lead to less surface handling risk
- Larger boreholes will lead to better fluid pressure control
- Larger PPFG operating windows will allow for more predictable operations
- Better environmental footprint as fewer resources will be needed for wellbore construction
- A seawater equivalent density riser fluid results in either complete or near-complete riser margin.

Reduced drilling cost and risk

- Fewer strings of casing to TD
- Significant elimination of lost circulation due to ballooning formations
- Better cement jobs/fewer squeezes

Improve well integrity

- Greater annular clearances will allow for better cement jobs
- Greater annular clearances will allow for more stout liner hangers and packers

Improve well productivity

- Designer completions become possible with larger final stringer ID's

Improve exploration performance

- Larger casing allows for more room in geological sidetrack
- More effective reactions to changes in formation pressure

The step change impact of DGD technology will be further magnified by combining it with other potential emerging drilling innovations. DGD will likely be used in the association with various combinations of continuous circulation, borehole strengthening, wired drillpipe, geo-steering, borehole imaging and casing drilling technologies. These synergies can result in a safer drilling operation, more on-bottom time and fewer casing strings with a lower flat time.

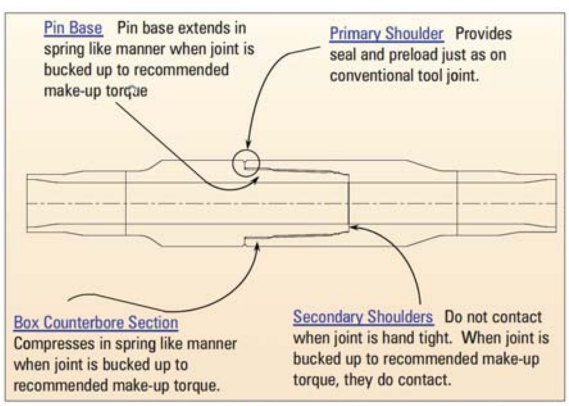
5.5.4. Ultra-deep (UDD) and Extended Reach drilling (ERD)

As industry moves to deeper targets and deeper waters, greater demands are being placed on the drillstring. High torsional capacities, better strength to weight properties and faster running and tripping speeds are required in order to effectively drill these regimes. The only way to achieve this is through the most recent advances in drill stem and drill pipe technology **(Jellison et al., 2007).** It is important to note that current drillstring limitations are not only restricted to drilling but more commonly to casing running strings or those strings of pipe used to run, set and cement casing in the hole.

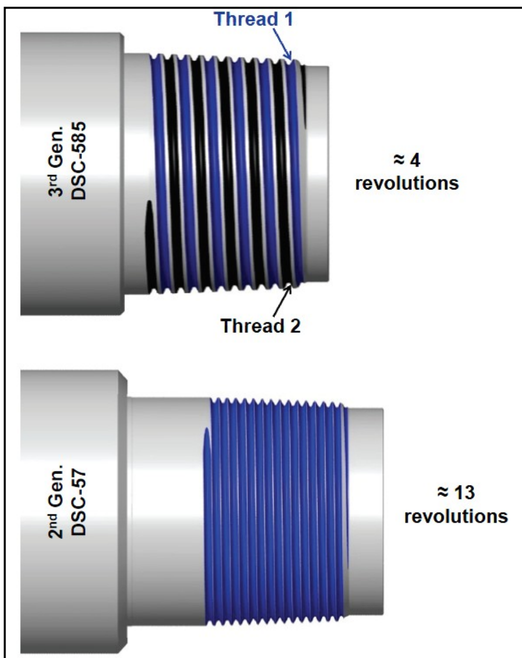
The advantages of Ultra-Deep and Extended Reach Drilling are many and the industry milestone, as seen by BP's drilling of the Tiber well to 35,050ft vertical depth in the Gulf and in the recent extended reach drilling of over 40,500ft demonstrated by Exxon at the Odoptu Field off Sakhalin Island. These continually evolving technologies allowed the for the capture of resources that would have otherwise been left untapped due to environmental constraints and opened up even more resources for the energy industry to access.

The following are descriptions of new technologies associated with extended reach drilling from the paper given by **Michael Jellison et. al., entitled "Challenging Drilling Applications Demand New Technologies at the 2007 International Petroleum Conference, Dubai, U.A.E, December 2007.**

> **New Connection Technology -** With today's higher rates for deepwater capable rigs and the drilling of deeper objectives, reducing tripping times in the well offers significant benefits. In response industry has developed a **3rd generation ultra- high torque rotary double shoulder connection (DSC).** The design incorporates double start threads, 180 degrees apart that reduce the number of turns to assemble the connection by 50%. Estimates are that the new connections will save 7.5 hours per 20,000' well. With advancements in metallurgy and heat treatment techniques the new connection produces specified minimum yield strength of 130,000 psi **(Figure 35).**



– Mechanics of double-shoulder connections (DSC). External shoulder acts as seal and primary shoulder. Internal shoulder is not considered a seal and acts as secondary torque stop to increase connection torsional strength compared to single-shoulder connections.



– Illustration comparing scale figures of 3rd Gen. DSC to 2nd Gen. DSC. All other things equal, the double-start thread form reduces revolutions from stab to makeup by 50%. Changes in thread taper and thread pitch further reduce revolutions in total from 13 to 4.

Figure 35: 3rd Generation Double Shoulder Connection (Chandler, et al., © 2007 SPE. Reproduced with permission of the copyright owner. Further reproduction prohibited without permission.)

Operator's experience with new 3rd Generation DSC shows that the design enhances running and tripping speeds at a time when rig rates and spread costs place emphasis on improved drilling efficiencies. However, the most dramatic performance improvement was the significant reduction in repair rates and ultimately reduction in repair costs. Re-cut rates reduced 98% over predecessor connections, Re-face rates 82%, and overall damage costs on a per foot per day rental basis reduced 83%. Key to realizing cost savings was proper training of crews on best practices to safely optimize running, handling, and connection make-up times, and improved equipment maintenance **(Langdon, et al., 2010).**

Advanced materials for UDD and ERD – with deeper longer reach wells industry is taking a hard look at reducing weight while maintaining strength in the drill string. This has led to some consideration of using non-steel pipe. The following is a brief description of some material considerations.

Composite – consists of carbon fibers wound over a mandral with an epoxy matrix to encase fibers and seal the assembly. Three times the cost of steel, but offers lower weight, higher strength to weight ratio, superior corrosion resistance and enhanced resistance to fatigue. However to achieve these structural advantages it must be made significantly thicker reducing the inside diameter and resulting in unacceptable pressure losses through the pipe. As such at this time composites **do not offer a preferred solution.**

Aluminum – has been used for decades, mainly in Russia. It offers some of the same advantages as composite and costs 2 times that of conventional drill pipe. **Unfortunately it has a relatively lower yield strength** and thus a lower strength to weight ratio than ultra-high strength steel pipe when the steel tool joint attached to the tube is factored in. It also requires a slightly thicker wall again affecting inside diameter and **yield strength can drop off at temperatures above 250^{o} F,** which can be a problem in HP/HT environments.

Titanium (Ti) – Cost to manufacture is 7 – 10 times that of conventional steel pipe. It has seen limited use in ultra-short radius drilling. Ti offers significant performance advantages over conventional steel pipe. The density is 56% that of steel with a strength to weight ratio improvement of approximately 37% over S-135 steel drill pipe. Ti is highly resistant to corrosion and has good fatigue resistance. Ti would certainly make a high performance drill string for use in ERD/UDD environment, but the high cost for the technology would be an order of magnitude above steel and is currently the main factor in not using this product. Chevron has a string of Ti they are currently testing, having had to redesign connections to deal with a galling issue on make-up.

Ultra-high strength Steel – Currently the only active and commonly accepted solution for extended reach and ultra-deep drilling. With only a modest uplift in cost from conventional steel, improvements in metallurgy are allowing manufacturers to improve the toughness in high strength steels and now with the development of **165ksi yield strength** they have obtained a 22% improvement in strength to weight over conventional S-135 pipe.
Another steel formula that is coming into common use is C110 which presents a much better solution for potential brittle failure that may occur in higher yield materials. The lower yield strength in C110 is countered by making the casing thicker.

Ultra-high capacity landing string system – with increasing depth of water and objectives operators are setting larger diameter and heavier casing strings to depths greater than 22,000ft. They require landing strings with setting capacities of 2 million lbf and specially designed handling systems to match. A system has been developed in response to these requirements and it incorporates three components: pipe, elevators, and slips.

Telemetry (Wired) Drill Pipe – fundamentally comprised of drilling tubulars that have been modified to incorporate a high-speed data cable running the length of the pipe. The cable terminates at inductive coils that are installed in the pin nose and corresponding box shoulder of every connection and transmit data across each tool joint interface. Data can be transmitted at 57,600 bits/sec, significantly higher that mud pulse telemetry 3 – 24 bits/sec. With a 57,600 bits/sec transfer rate from down-hole, one can greatly expand the quality and quantity of information available while drilling. MWD/LWD tools are becoming more complex and as such mud-pulse data transmission rates are becoming more paramount with complicated drilling environments. **Figure 36** shows a cross sectional view of cable and inductive coil.
This technology has been developed and field tested over the last ten years. It allows more accurate placement (geo-steering) and more rapid responses to subsurface drilling conditions. Operators are using it to steer highly deviated wells in depleted reservoirs with underbalanced or fluid loss conditions and drilling higher risk gas wells with real-time annular pressure surveillance, and will find it mandatory for drilling with a dual gradient system. The wired pipe has been designed to work in parallel with MWD/LWD mud-pulse technology providing telemetry robustness. Due to this redundancy, downtime related to telemetry problems is significantly reduced. LWD transmission can take place at any time and under any drilling condition. All downhole tool data, logs and uncompressed images can be received even when total drilling fluid losses are occurring or at any point while drilling instead of having to shut down the pumps and wait for the data to transmit. There are no drill string length limitations so extended reach and ultra-deep drilling projects can benefit from wired-pipe at virtually any well depth. Recently an expansion of the capabilities of wired pipe has come to include

measurements such as annular pressure and temperature all along the drill string, known as the networked drill string telemetry system, which can improve response time to changing subsurface conditions. All drilling operations can potentially benefit from wired-pipe technology, but it is the narrow margin ultra-deep, extended reach and HPHT wells in which the technology has the highest value **(Hovda et al., 2008).**

Wired pipe is gaining acceptance with operators around the world. Indications that the technology has been sufficiently trialed on land and the shelf are evidenced by the first deployment in the deepwater GOM in 2009. Cost remains one of the issues, however the benefits of this technology suggest that increased usage could be just around the corner for certain applications.

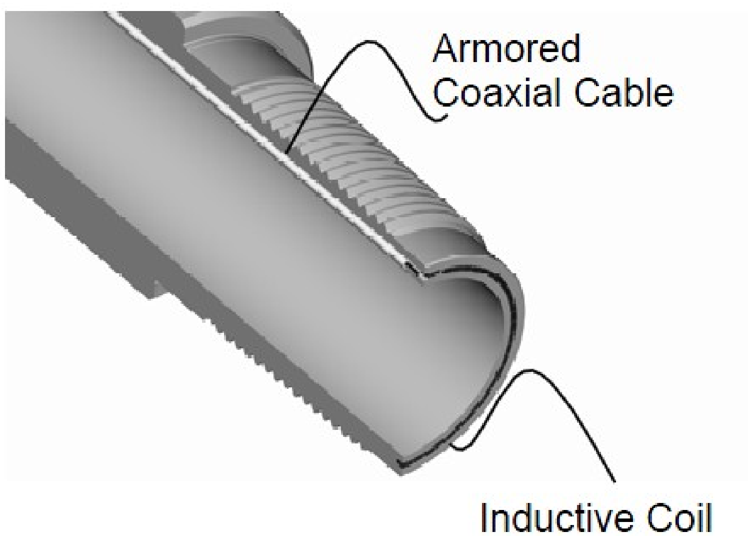


Figure 36: Cross section view of double-shouldered pin tool joint, armored coaxial cable and inductive coil used in drill string telemetry network. (McNeil et al., 2008, Graphic courtesy IntelliServ)

Rewards of Using Wired Pipe (Ali et al, 2010)

- ECD management in well control situations
- Vibration management
- Real-time accurate dip picking
- Seismic while drilling analysis real-time
- Decreasing survey/down linking time
- Distributed sensor measurements
- Improved wellbore delivery real time **(Ali et al, 2008)**

- Realtime wellbore images, real-time wellbore stability analysis, interaction of drilling dynamics with geology, high resolution images – geology while drilling.

Additional rewards suggested by industry colleagues:

- Data measurement in non-fluid muds
- Data measurement in lost-circulation environments
- Quality of data received at surface
- Instantaneous downlink to rotary steerable assembly
- Directional control improvements

Bottom Hole Assembly (BHA) Connections for ERD – With the costs for ERD, advanced drill string technology is needed to ensure against BHA connection failure. As a result drill string manufacturers have developed proprietary double shoulder connections (mentioned above) in the BHA to enable telemetry transmission and maximize fatigue performance. Results indicate it has 9 times greater fatigue resistance than its API counterpart 6-5/8" Regular of equivalent OD and ID.

BOP pipe shearing – Higher strength and higher toughness steel with increased wall thickness in both drillpipe and casing has in some cases exceeded the capacity of some BOP shear rams to predictably shear the drill pipe or landing string. As such, companies are presently working on uniquely configured shear rams that will shear more advanced strings at lower operating pressures, for example rams that will shear 6-5/8" drillpipe connections and shear and seal 13-5/8" casing.

5.5.5. Drilling Salt

With tremendous reserve potential under the salt canopies in the Deepwater Gulf of Mexico using the right tools and processes to improve drilling performance therein is paramount. Below are listed some learnings that have resulted from case studies that investigate and discuss directional drilling through salt **(Israel et al., 2008).**

-Rotary Steerable (RSS) Assemblies are the best option for drilling salt, with improvements seen in directional control, ROP and hole quality
-RSS in combination with motors can deliver higher torque and rpm and improve ROP in extended salt intervals.
-Include geomechanical considerations into directional design: Plan salt exit across a tangent section and at a flat or low dipping area of salt base
-Plan low dog-leg severity so that if steering is required you have the capability to reach the desired trajectory
-PDC bits are best for salt
-Real-time monitoring of salt drilling parameters at rigsite or remote centers to optimize drilling performance and extend BHA life

-Control drilling parameters when entering or exiting salt until bit and under-reamer are in the same formation
-Avoid drilling jars in holes sections larger than 18"

In addition to the above learnings, specially designing drill bits that can minimize stick-slip, lateral vibration and poor directional control will also improve drilling performance in salt.

5.5.6. Robotic and Laser Drilling

Robotic drilling has taken place on land for years, in that a human will input drilling parameters into a computer and the computer will constantly adjust weight-on-bit, torque, differential pressure different mechanical indexes to continually optimize the rate of penetration. So called robotic drill bits are also in use in the field today and are self-propelled BHA's that help apply weight-on-bit and control in horizontal applications. The future of automated or robotic drilling might range from a fully automated traditional rig (where all manual labor is replaced by machines remotely operated from within a safe zone) to self sufficient, submarine rigs that drill under the polar ice cap from the sea-floor.

There have been significant advances in the development of laser drilling in the past ten years. Reports show that a viable laser will start field trials in the next year with potential commercial development in the next five to ten years. Projected uses for laser drilling are vast, from drilling incredibly hard (basalt) rock formations, near limitless length horizontal wells, creating hundreds of deep skin-less perforations in one well, to drilling thousands of cheap Greenhouse Gas disposal wells. The potential for this service is incredible if the military proven technology can be scaled down to a commercial well application. Some rather large hurdles remain for the technology, such as the medium that the laser operates in (air, drilling fluid, and hydrocarbon) to scaling down the technology to operate in oil field locations.

5.5.7. Measurement While Drilling and Logging While Drilling (MWD/LWD)

Since the beginning of the oilfield, engineers and geoscientists have constantly worked on ways to get more information from downhole. Whether it was geologic, geophysical, drilling, reservoir, completions, production or any combination thereof, they are always wanting more data. With the development of MWD and LWD capabilities, measurements from the bit area can be transmitted up the hole and then to shore so both those on the rig and in the home office can analyze the data real-time and begin to answer questions more accurately and quickly.

Advances in computer hardware and software, coupled with the logging while drilling and measurement while drilling capabilities, have generated a wealth of data that allows drillers to make decisions much more rapidly than even a few years ago. What follows is a brief list of what is available:

MWD

Measurements taken at the bit need some manner of being retrieved at the surface, whether in real-time or in memory hardware retrieved on return to the surface. What follows are some of the methods used to transmit and retrieve the information.

Mud Pulse – The oldest technology uses a downhole valve to restrict the flow of drilling fluid according to digital information being transmitted. The resulting pressure fluctuations propagate up the hole within the drilling fluid, and are received by pressure sensors at the surface. These pressure signals are then processed by a computer to reconstruct the information. The technology is available in three forms – positive pulse, negative pulse and continuous wave.

EM Telemetry system – This technology transmits real-time data via electromagnetic waves (wireless) from downhole to the surface. It operates at a higher transmission rate than mud pulse technology and in situations when there is not a continuous column of fluid in the hole. Obstacles to overcome are signal strength diminishes with depth and some formations are not as suitable for transmission of EM waves.

Alternative Telemetry system – Acoustic- Recently developed in Canada, a downhole "hammer" hits the drill string where the acoustic wave is received and translated at surface. Another alternative in environments where fluid transmission is not possible

Retrievable System – Recorded data is simply stored in a data storage device in the BHA and retrieved when the bit is tripped to surface. This is usually only used for back-up information and for LWD suites that contain too much data to send up the hole.

Wired Drillpipe – As discussed in the previous section.

Transmission rates for LWD-MWD

Mud-pulse – 24 bps
EM – 100 bps
Wired – 57,600 bps
Acoustic – 20 bps

Key information transmitted up the hole:

Drilling dynamics – Pressure while drilling (PWD), Weight on bit, torque, shock, temperature, caliper, inclination, azimuth, bit face direction

Geological dynamics (LWD) – Formation resistivity, monopole and multi-pole sonic information, Gamma-Ray detection, Neutron-Density are the most acquired.

Seismic while drilling technology – Recent technology on the LWD side has provided active seismic "look-ahead" capabilities that allow for independently sourced seismic waves to be gathered at the bit, giving geologists and geophysicists the ability to place the well accurately and redefine their seismic interpretation in real time. Other new sonic technologies are able to provide the information required for Cement Bond behind pipe, geo-mechanical stress analysis and pressure trending.

Formation Pressure While Drilling (FPWD) tools - Multiple vendors have recently gained the capacity to not only take pressures but also samples of down hole fluids during the drilling process, allowing for real-time analysis of fluid-type, pressure regimes and reservoir production optimization.

Tools in the near future: The immediate future of Logging-While-Drilling and Measurement-While-Drilling is not new tools but rather the evolution of existing tools to match new environments. There will be Resistivity and Acoustic tools that operate in Non-conductive muds, all of the tools available in only one hole size will graduate to larger or smaller sizes, existing tools will be re-engineered to withstand greater operating pressures and temperatures and there will be economy of scale where current expensive and limited tools will become common place in the industry.

5.5.8. <u>Directional Drilling</u>

Directional drilling has undergone a tremendous evolution over the past five decades. Operators can now drill multiple wells from single strategically placed surface location for central placement of an offshore production facility in water depths of 8,000 ft and 200 miles from land (see Anadarko's Independence Hub and Shell's Perdido production platforms). We can now drill from remote locations to avoid sensitive surface and subsurface environmental features and hit multiple deep targets. Advances now permit multilateral drilling where multiple offshoots of a single wellbore radiate in different directions and can contact resources at different depths. The limits are no longer the directional control of the bit, but the strength of the steel and rig to pull around these doglegged sections.

The advent of the rotary steerable system in the late 1990's transformed the industry's ability to drill extended reach and horizontal wells by creating much less tortuous well paths. Where before a bent-motor assembly would need to alternate between rotating and sliding, intentionally creating a series of straight sections and directional sections (think of building a curve with a series of short straight sections), Rotary Steerable is continually correcting its direction (one long curved piece with no angles). In 1996, the first generation rotary steerable systems produced good results, but were very unreliable.

A couple years later reliability issues became better understood, improvements were made and soon everyone offshore was using Rotary Steerable Systems. This system allows drillers to hit multiple pay targets from a single wellbore and in some cases develop an entire field from a single platform. It also gives companies the confidence to re-enter a field that has been drilled multiple times before by allowing them to drill with complicated geometrical patterns, weaving around and throughout old wellbores. The future of this technology is making the smaller systems more reliable and the general system more prolific for use on land.

5.5.9. <u>High-Pressure / High Temperature Drilling (HPHT)</u>

New rigs coming out are capable of 12,000 ft water and 40,000 ft total depth. Future rig capacities will again increase operating depths in water and subsurface. The logical and progressive step in 10-20 years would be 15,000 ft of water and/or 45,000 ft of total depth. These capacities will only be reached with better steel (casing, wireline and drillstring) and the increased capacity for pressure at the surface (20k BOPE and wellheads). Also currently limiting drilling are temperatures above 450degrees Fahrenheit and downhole operating pressures of 30,000 psi, requiring better and more durable electronics, elastomeric elements, cement blends and better material that can perform without temperature degradation, more predictable drilling fluid reactions and the ability to handle hot returning fluids to surface.

5.5.10. <u>Drilling Technology Summary</u>

In summary, as the demand for oil continues to out-strip its supply, Exploration and Production companies will continue to pursue the next supply of affordable energy for both the United States and the rest of the world. Engineers and Geoscientists will follow the proven historical trends of technological evolution that have driven both discovery and production since Colonel Drake drilled his first well in 1859, with those being as follows:

First, the ability to obtain and process Geological and Geophysical information is paramount. With better information wellbore condition prediction will lead to less kicks, fewer blowouts and less overall non-productive time. Gaining an accurate structural picture and where to place the wellbore within it will increase the probability of success for finding commercial hydrocarbons and optimizing their total recovery.

Second, the trend for conventional oil and gas discovery is to drill in environments that were previously inaccessible. Traditionally this means drilling deeper into hotter and higher pressured zones and to do so in ever more extreme environments such as ultra-deep water and above the Arctic Circle (in the future these environments will include politically sensitive areas). Historically the only way to access these zones is to get bigger rigs, stronger steel and more durable tools and there is little reason to believe that this trend will not continue.

Third, there must be an economic incentive to continually push the exploration horizon. Anything that can make a field economic helps to push its development, from reducing drilling and completion times, to simplifying the wellbore, to drilling less overall wells, any little bit helps.

5.6. Subsea Well Containment, Oil Spill, Remediation and Response

(By **Paul Schlirf)**

In response to the Deepwater Horizon incident, two industry containment consortiums have been formed for participation by industry operators. Below is a brief description of them:

Subsea Containment Consortiums:

- **MWCC – Marine Well Containment Company**
    - Organized after the April 20th Deepwater Horizon incident. ExxonMobil, Chevron, ConocoPhillips and Royal Dutch Shell dedicated $1 Billion to form the company. BP later joined and agreed to make its underwater well equipment and proven procedures available to all oil and gas companies operating in the Gulf. As of 4/21/2011, Apache, Anadarko, BHP Billiton, Statoil and Hess had also joined, bringing the member total to 10.
    - MWCC is a not-for-profit, independent organization committed to improving capabilities for containing an underwater well control incident in the U.S. Gulf of Mexico.
    - Mobilization would begin immediately upon being notified.
    - The subsea containment equipment is designed to create a direct connection and seal to prevent oil from escaping into the ocean.
    - The system will be equipped with a suite of adapters and connectors to interact with various interface points, including any well design and equipment used by oil and gas operators in the Gulf.
    - Interim system, now available, has the capacity for 60,000 BOPD and 120 MMCF gas per day in water depths up to 8,000ft with potential for expansion. It includes a 15,000 psi single ram capping stack and dispersant injection capability. By 2012 the company will have a system with capacity for 100,000 BOPD and 200 MMCF gas per day in water depths up to 10,000ft. The expanded system will include a 15,000 psi subsea containment assembly with three ram stack and a dispersant injection system.
    - The system includes capture vessels that can process, store and offload the oil to shuttle tankers to take the oil to shore for further processing.
    - MWCC has awarded engineering contracts for containment equipment used on all wells in as much as 10,000ft of water. The contract covers system engineering and design of specific subsea

components, including the containment assembly, manifold, control umbilicals, accumulator, dispersant injection, risers, and flowlines. Containment assembly design is complete, construction to begin.

- Marine Well Containment Company membership is open to all oil and gas operators in the U.S. Gulf of Mexico. All members will have equal ownership, with each paying a proportional share of the system development and operating costs. System equipment and services will be available to members and non-members. Non-members will be able to enter into agreements for access on an initial per-well fee basis.

MWCC Website http://marinewellcontainment.com/

February 17, 2011, the MWCC consortium announced that the new interim response and containment system for responding quickly to a deepwater well blow out was ready to go **Figure 37.** In the past month BOEMRE approved several deepwater drilling permits that cited MWCC for containment. The higher capacity system will be ready in 2012.

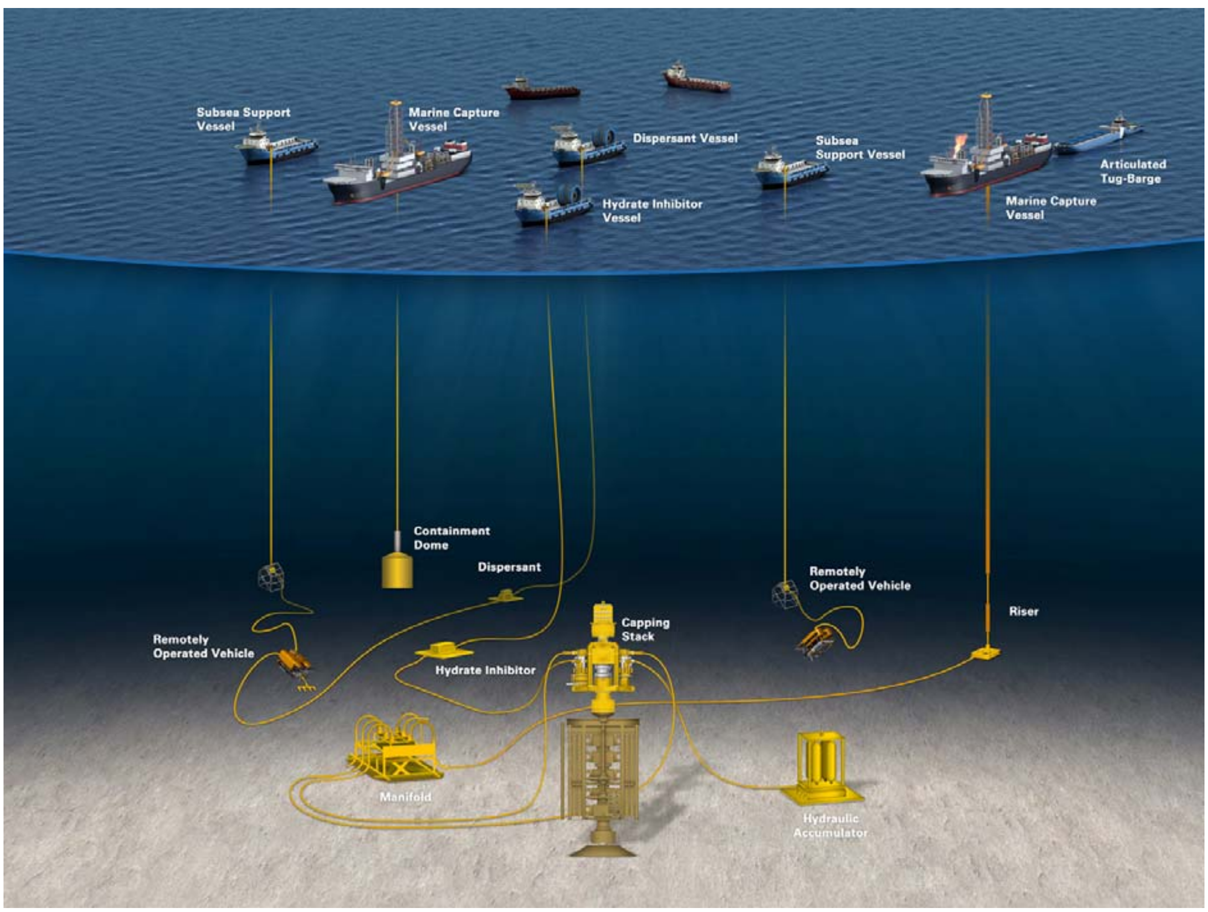


Figure 37: Graphic representation of the Marine Well Containment Company interim system currently available. (http://marinewellcontainment.com/index.php)

- **HWCG - Helix Well Containment Group**
    - Also organized after the Deepwater Horizon incident, the Helix Well Containment Group (HWCG) consists of 24 deepwater operators in the Gulf of Mexico. The membership includes Anadarko, Apache, ATP, BHP, Century Exploration, Cobalt, Deep Gulf Energy, ENI, Energy Resource Technology, Hess, LLOG, Marathon, Marubeni, Murphy, Newfield, Nexen, Noble Energy, Plains Exploration, Repsol, Statoil, Stone Energy, Walter Energy, Woodside, and W&T Offshore.

  HWCG Website http://www.hwcg.org

    - HWCG was formed as a non-profit consortia under the umbrella of Clean Gulf Associates (CGA), a non-profit spill response association for the Gulf of Mexico. All 24 members of HWCG have signed a Mutual Aid Agreement that makes available the combined technical expertise and associated response equipment of each company to any member during a subsea well control and containment response. In addition, over 30 contractors and service providers have signed master service agreements with the HWCG members and have agreed to provide critical response equipment and technical resources to a response.
    - Helix Energy Solutions Group (HESG), who provides the primary intervention and flow back vessel capability to HWCG, is a deepwater contractor in the Gulf of Mexico and was heavily involved in the response to the Deepwater Horizon incident during 2010. HESG provided 3 vessels, the Q4000, Helix Producer I and the Express in the Deepwater Horizon response. HESG has combined operations of the Q4000 and Helix Producer I, along with the associated subsea capping stacks and other equipment to form the Helix Fast Response System (HFRS), the primary system utilized by HWCG.
    - HESG has signed an agreement with CGA, making the system available for an initial 2 year term to CGA participants in the HWCG in the event of a blowout, in exchange for a retainer fee. The term is open to be extended and HWCG is actively working to extend the term.
    - Separately Helix has signed utilization agreements with the 24 participant member companies specifying the day rates should the system be deployed.

  Helix Energy Solutions Website http://www.helixesg.com/HFRS/

    - At full capacity, the HWCG response operation, including the HFRS and associated equipment from Trendsetter Engineering, is expected to handle up to 55,000 barrels of oil and 95 million cubic feet of gas per day for water depths up to 10,000 feet and at pressures of up to 15,000 psig

- The system uses proven methodologies to provide the response capacity required. The initial system will center on two vessels: 1) the Q4000 a multi-purpose oil field construction and intervention vessel that has a unique column stabilized semi-submersible design with dynamically positioned station keeping and 2) the Helix Producer I a monohull floating production and offloading vessel. Options to increase the capacity of this system are being evaluated and some initial proposals are being reviewed with the Bureau of Ocean Energy Management (BOEMRE). Key to the path forward for any capacity increases is an ongoing Well Flow Back modeling project being conducted by the HWCG Deepwater Intervention Technical Committee. Results of this study will help determine the proper capacity increase strategy for the group.
- The vessels and crews of the Q4000 and Helix Producer I are currently operating in the Gulf full time. Subsea components to transport hydrocarbons to the surface for capture and disposal are kept in inventory at Helix's Gulf of Mexico base and at Trendsetter Engineering's base in Houston, where they are maintained and ready for deployment at a moment's notice. Vessel contracts are structured so the vessels can depart any current location and enter a spill response when needed.

A schematic of the initial well control system available from Helix is displayed in **Figure 38**. Similar to MWCC, multiple deepwater drilling permits have been approved by the BOEMRE for operators that would utilize the Helix system if necessary.

Multiple Consortia Options Provides Redundancy and Flexibility

- In addition to MWCC and HWCG, other vendors, including but not limited to Wild Well Control, are working to provide containment solutions to GOM operators.
- These systems are available to members and non-members
- Multiple vendors maintains the competitive landscape in the GOM, creating different solutions to different problems
- Provides options for exploration companies to match their well needs
- Provides multiple redundancies in the case of a well control event
- Both systems are ready to go and approved by the BOEMRE, with higher working pressure systems and flow-back capacities being designed for future work. As of 5/20/2011, the BOEMRE has issued drilling permits (APD's) for 14 wells to companies who reference containment capacity from either HWCG or MWCC.

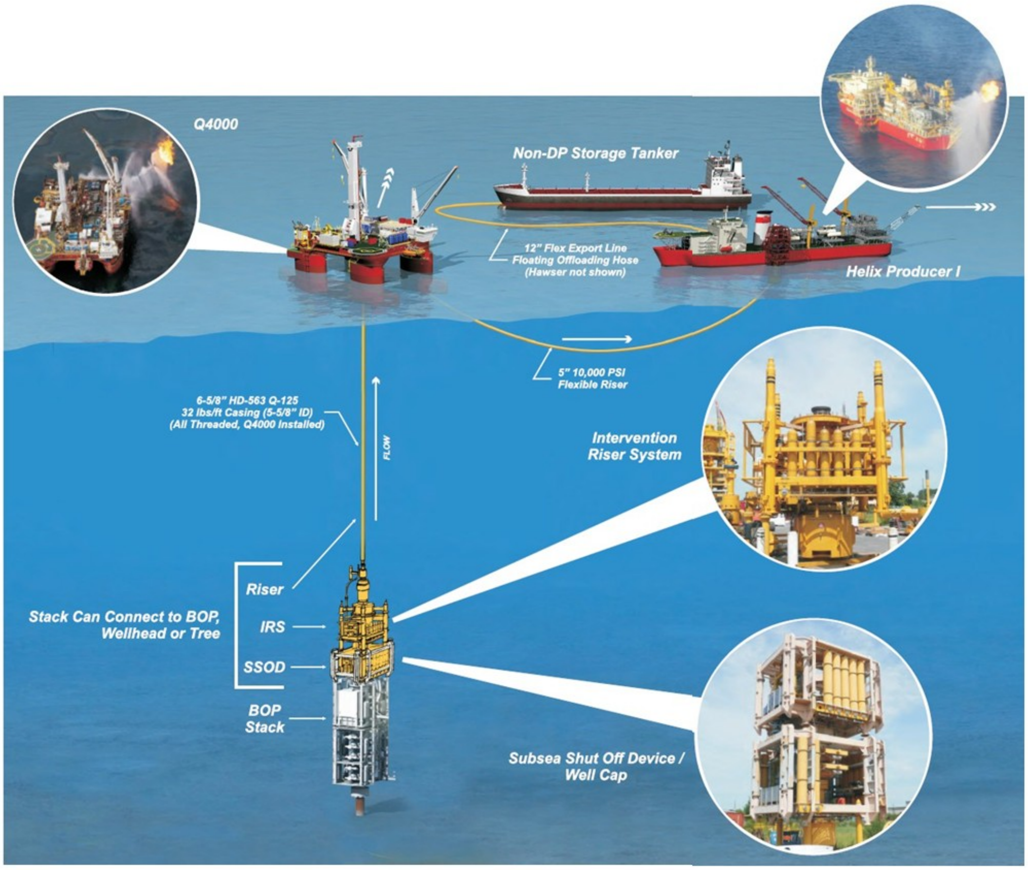


Figure 38: Helix containment equipment layout
(Helix Energy Solutions Group, Fast Response System Overture Brochure)

Last year in response to the Deepwater Horizon incident, four joint industry task forces were assembled to address issues related to the spill. They are as follows:

Operating Procedures - review critical processes associated with drilling, completion, and well control activities for deepwater wells to identify gaps between existing practices and regulations and industry best practices.
Equipment – review current BOP equipment designs, testing protocols, regulations, and documentation.
Oil Spill Preparedness and Response - examine industry's ability to respond to a spill of this significance and actual response to the subsea release based on information available at the time.
Subsea Well Control and Containment – review current subsea well control preparedness and response options.

The task forces were comprised of deepwater oil, service, and environmental companies, the American Petroleum Institute (API) and other industry consortia and affiliates. The United States Coast Guard participated in the Oil Spill Preparedness and Response group.

Initial reports with recommendations were released last year and are summarized as follows:

The **Operating Procedures and Equipment Task Forces** identified six key areas of focus: 1)Health, safety and environment; 2)Procedures related to mechanical loads, cementing practices, barriers, and well displacement procedures; 3)Secondary BOP control systems; 4)BOP testing and test data; 5)Acoustic systems and other secondary control systems; 6)Remotely operated vehicles (ROV).

The **Oil Spill Preparedness and Response Task Force** reviews included: spill response plans, oil sensing and tracking, dispersant use, in situ burning, mechanical recovery, shoreline protection and cleanup, and alternative response technologies. They made 25 recommendations for near term action (on or before April 1, 2011) and an additional 15 areas of action to be initiated on or before October 1, 2011.

The **Subsea Well Control and Containment Task Force** identified 5 key areas of focus: well containment at the seafloor, intervention and containment within with the subsea well, subsea collection and surface processing and storage, continuing research and development and relief wells. They made 29 specific recommendations within these areas with 15 for immediate action. The first listed recommendation for immediate action was establishing a coordinated industry capability providing subsea well containment technology and capability. Following this was a near term action item to establish a longer term industry capability for providing the service. These two are being addressed by the MWCC and HWCG consortia mentioned in the previous section.

The work identified by these industry task forces is now being continued by permanent sub-committees sponsored by API, along with other groups. In addition, multiple work efforts are underway within industry to address safety concerns brought to light by the Deepwater Horizon incident. For example, the DOI has announced the formation of the Ocean Energy Safety Advisory Committee, and API has announced the formation of the Center for Offshore Safety. Both of these organizations are dedicated to allow multiple stakeholders to advise on offshore oil and gas industry safety issues.

Also in response to Department of Interior recommendations after the Deepwater Horizon incident, oil and gas industry operators have organized internal work-group teams to assess:

- Offshore equipment and well control
- Deepwater well design and offshore operating procedures
- Drilling, completions and management of change (MOC) processes
- Oil spill response and subsea well control and containment

Individual companies provided feedback from these groups to help advise the joint industry tasks forces listed above, and also to help develop their own internal company policies and procedures, applying lessons learned from the Deepwater Horizon incident.

5.6.1. <u>Federal Regulatory Changes</u>

Since the Deepwater Horizon incident several new regulations have been enacted by the BOEMRE. They include:

NTL No. 2010 N05 - 6/8/10 - Safety Requirements – submission of general certification that operators are knowledgeable of all operating regulations at 30 CFR 250 and in compliance with them. Each operator must also certify that they have conducted the following specific reviews of their operations

1. Examine all well control equipment. Ensure all BOPS are able capable of shutting in the well. Ensure that ROV hot-stabs are function-tested and capable of actuating the BOP.
2. Review all drilling, casing, cementing, well abandonment (temporary and permanent), completion, and workover practices to ensure well control is not compromised while the BOP is installed on the wellhead.
3. Review all emergency shutdown and dynamic positioning procedures that interface with the emergency well control operations
4. Ensure all personnel involved in well operations are properly trained and capable of performing their tasks under both normal drilling and emergency well control operations.

Multiple FAQs subsequently published.

Interim Final Safety Rule replaced NTL No. 2010 N05 on 10/14/10

Interim Final Safety Rule – 10/14/10 – This rule will put into effect OCS-wide provisions that will:

1. Establish new casing installation requirements,
2. Establish new cementing requirements (incorporate API RP 65 – part 2, Isolating Potential Flow Zones During Well Construction),
3. Require independent third party verification of blind-shear ram capability,
4. Require independent third party verification of subsea BOP stack compatibility,
5. Require new casing and cementing integrity tests,
6. Establish new requirements for subsea secondary BOP intervention
7. Require function testing for subsea secondary BOP intervention
8. Require documentation for BOP inspections and maintenance,
9. Require a Registered Professional Engineer to certify casing and cementing requirements, and
10. Establish new requirements for specific well control training to include deepwater operations.

    (**Federal Register, October 14, 2010)**

NTL No. 2010 N06 – 6/18/10 -Worst Case Discharge (WCD) and relief wells. Pursuant to this NTL operators must provide a scenario (as required by 30 CFR

250) for a potential blowout of the proposed well in your plan or document that you expect to have the highest volume of liquid hydrocarbons. It should include estimated flow rate, total volume, and maximum duration of the blowout. Discuss the potential for the well to bridge over, likelihood for the surface intervention to stop the blowout, the availability of a rig to drill a relief well, and rig package constraints. Specify as accurately as possible the time it would take to contract for a rig, move it onsite, and drill the relief well. Describe assumptions and calculations used to determine the volume of the worst case discharge scenario. Provide all assumptions made concerning the well design, reservoir characteristics, fluid characteristics, and pressure volume temperature (PVT) characteristics; analog reservoirs considered in making those assumptions; reasons for using the analogs; and supporting calculations and models used to determine daily discharge rate possible from the uncontrolled blowout portion of your worst case discharge scenario.
http://www.gomr.boemre.gov/homepg/regulate/regs/ntls/ntl_lst.html
Multiple FAQs subsequently published.

SEMS – Safety and Environmental Management Systems – Final SEMS rule issued 10/15/10 - Began with API Recommended Practice (RP) 75 developed by MMS and industry in the mid 1990's. This was originally voluntary, but many operators adopted portions for GOM production facilities. Post Horizon incident, **The Workplace Safety Rule** makes RP75 mandatory to all operators and it is much broader applying to all life-cycle phases of "Facilities", of which a well is considered a facility. It must be implemented and auditable by 11-15-2011. SEMS includes 13 mandatory elements:

- **General provisions**: for implementation, planning, and management review and approval of SEMS program.
- **Safety and environmental information**: safety and environmental information needed for any facility, e.g. design data; facility process such as flow diagrams; mechanical components such as piping and instrument diagrams; etc.
- **Hazards analysis**: a facility-level risk assessment.
- **Management of Change:** program for addressing any facility or operational changes including management changes, shift changes, contractor changes, etc.
- **Operating procedures:** evaluation of operations and written procedures.
- **Safe work practices**: manuals, standards, rules of conduct, etc.
- **Training:** safe work practices, technical training – includes contractors.
- **Mechanical integrity**: preventive maintenance programs, quality control.
- **Pre-startup review**: review of all systems
- **Emergency response and control:** emergency evacuation plans, oil spill contingency plans, etc; in place and validated by drills
- **Investigations of incidents**: procedures for investigating incidents, corrective action and follow-up.

- **Audits:** rule strengthens RP 75 provisions by requiring an audit every 4 years, to an initial 2-year reevaluation; and then subsequent 3-year audit intervals.
- **Records and documentation**: documentation required that describes all elements of SEMS program

http://www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&PageID=45791

NTL No. 2010 N10 – 11/8/10 - Operator must include, with every application for a well permit, a statement signed by an authorized company official stating that the operator will conduct all authorized activities in compliance with all applicable regulations, including the Increased Safety Measures for Energy Development on the Outer Continental Shelf rulemaking (75 FR 63346). In addition for operations using subsea BOPs or surface BOPs on floating facilities, BOEMRE will evaluate whether each operator has submitted adequate information demonstrating that it has access to and can deploy surface and subsea containment equipment resources that would be adequate to promptly respond to a blowout or other loss of well control.
http://www.gomr.boemre.gov/homepg/regulate/regs/ntls/ntl_lst.html

12/13/10 – BOEMRE issues approval requirements for activities that involve use of a subsea BOP or surface BOP on floating structures.

3/28/11 – Supplemental information regarding approval requirements for activities that involve the use of a subsea BOP or a surface BOP on a floating facilities.

The oil and natural gas industry remains committed to working with Congress, the Administration, the Regulatory Agencies, the Presidential Commission, and interested stakeholders as we work to enhance and augment oil spill control and containment.

5.7. Subsurface Measurement

(By **Paul Schlirf)**

At the turn of the 20th century, oil industry pioneers began to search for ways to obtain information about what the drill bit was encountering. They needed the critical “ground truth” to develop geological models for exploration and development. This led to development of core sampling and mud-analysis of the wellbore cuttings (mud logging), that came to the surface. In 1912, Conrad Schlumberger came up with the revolutionary idea to use electrical measurements to map subsurface rock bodies. Later, in the early 1920’s formation evaluation took a giant leap when Conrad and brother Marcel created the first electric logs. The technology leaped forward with resistivity logs in 1927, SP log in 1931, and dipmeter in 1941. The next major breakthrough in well logging technology took place in 1962 with the invention of the formation-density log, which uses a gamma ray source and detector to measure the bulk density of formations in-situ. Within 10 years the dual laterolog tool was introduced which had the capability to produce useful resistivity measurements even when the true formation resistivity and mud resistivity are high. During the 1980’s electronic miniaturization and computer hardware/software advances enabled rapid development of new wireline technologies – sonic logs, for velocity of formation, pulsed neutron for cased-hole fluid discrimination, nuclear magnetic resonance for bound and moveable fluids, pressure-transient testers, and subsurface sampling via drill-stem and formation testers **(Lord, 2007).**

In 1978, Teleco introduced the world’s first commercial Measurement While Drilling (MWD) tool that is emplaced as close to the drillbit as possible to enable operators to know the location of their well while drilling. In 1980 Schlumberger completed the first measurement while drilling job in the GOM. In 1988, Schlumberger introduced the first Logging While Drilling tool (LWD). LWD refers to petrophysical measurements similar to openhole wireline logs and MWD tends to refer to measurements that specifically describe directional surveying or drilling related measurements. These have been two of the most influential drilling technologies developed. Today the use of these tools is routine. LWD/MWD tools are placed on the BHA directly behind the bit, from 5ft to greater than 150ft depending on the number of tools required. When that portion of the tool passes by the formation it evaluates the formation similar to wireline. The tool then converts the gamma ray (lithology), resistivity, acoustic, nuclear (porosity), and directional electrical information to a mud pulse (pressure fluctuation). This mud pulse then propagates up the hole in the drilling fluid. Once at the surface pressure sensors receive the pulses and convert them, using a computer, back to recorded electronic information. This information can then be viewed essentially real time on the rig and back on shore in the office, allowing for more timely decisions. LWD often delivers more accurate in situ formation properties, due to being taken immediately after the bit has passed a formation, versus hours or days later with subsequent wireline runs. Real-time has led to improved well steering, better resource delineation, and managed pressure drilling. In addition advances in material properties and electronics have allowed logging of increasingly hostile high temperature and high pressure environments. Improvements in computing have led to greater subsurface processing as well as better modeling of complicated subsurface environments (e.g., thin beds).

Unless certain measurements are not available with the LWD, the operator will often elect not to run wirelines, which may take multiple days to achieve, thus saving time and money. The configuration of a modern LWD/MWD with drill bit is shown below in

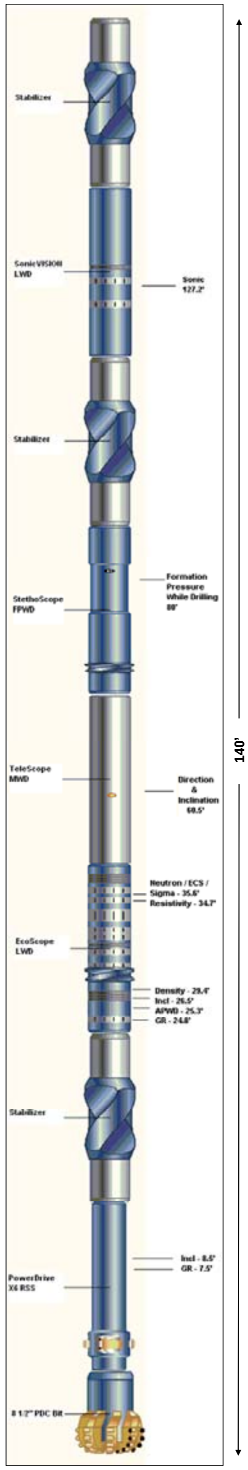


Figure 39: LWD/MWD BHA tool including Bit, Powerdrive, Gamma Ray, Density, Resistivity, Neutron, Direction and Inclination, Formation Pressure While Drilling, and Sonic

The main limitation to real-time measurements has been the speed of sending information back up the hole. Current mud pulse telemetry while drilling is only up to 24 bits per second, compared with wireline, which is many thousand bits per second. This limited transmission means that some information that could be useful for drilling decision is not available until the device is brought back to the surface and the data storage device is downloaded **(Cassiani et al., 2007).** Service companies are actively working to improve data transmission through emerging technologies such as Electro-magnetic (EM) 100 bits per second and wired pipe at 57,600 bits per second. With wired-drillpipe operations more data is available while drilling, reaming and circulating to allow more informed real-time drilling decisions.

As mentioned earlier, mudlogging, the art of analyzing the mud and well bore cuttings for what the drill bit is encountering down hole, is key ground truth information. In the 1930's, John T. Hayward's observations of geologist's tasting and sniffing well cuttings for signs of oil led him to develop a quantitative measurement scheme that was reported on a continuous strip chart known today as the mud log. These logs contain detailed descriptions of the lithology, gas encountered in parts per million for methane C_1 through Pentane C5, actual hydrocarbon show descriptions where the color of oil is noted and UV light is applied to samples, where fluorescence color can indicate hydrocarbon type. Also included on today's charts are rate of penetration, gamma ray and resistivity logs.

More recently industry has seen increased usage of advanced mudlogging known as **gas while drilling**. This technology also complements wire line logging as a real-time hydrocarbon indicator. The term advanced mud logging is applied to systems where uncertainties in data can be reduced, mainly due to improvements in the gas stream from the trap units (hydrocarbon extractors, coupling the flame ionization detector (FID analyzer) along with the use of higher resolution mass spectrometry. This type of modern mud logging is able to record volatile fractions up to C8 (Octane) and routinely analyzes gases up to C5 (Pentane). The objectives of these analyses are:

1. Identify true hydrocarbon contribution from the formations by correcting for recycled components.
2. Combining the gas response with lithologic information provided by LWD and drilling parameters to help identify hydrocarbon bearing zones.
3. Pin down low resistivity pay zones more accurately through more accurate measure of gas composition.
4. Rigorously define contacts (GOC and OWC) when penetrated.
5. Assess vertical connectivity or compartmentalization real-time by comparing ratios of light fractions (C1-C5).
6. Porous vs. tight reservoir sections can be appraised while drilling through methane and ethane gas responses.
7. Fluid biodegradation, when applicable, can be inferred while drilling through the isopentane / normal pentane ratio.
8. Correlations can be carried at field scale incorporating PVT monophasic fluid and advanced mud logging gas composition for reservoir connectivity.

The year 2010 marked the first test of an advanced mud logging technology in a well drilled horizontally within the Eagle Ford shale. The primary objective of this test was to determine if the improved quality of the mud logging system was sufficient to distinguish the target interval from units above or below. This test proved very successful and the hope is that this technique may be used to provide timely data allowing operators to maximize completion dollars by either eliminating one or more hydraulically fractured stages or spacing stages to take advantage of better reservoir properties. With more tests planned ahead in the Eagle Ford, the Niobrara formation of the Wattenberg field, and other horizontal plays, a new depth in understanding of these significant petroleum systems may be on the horizon.

Another form of crucial downhole measurement is detailed sampling of the hydrocarbon and water fluid from formations. This technology is known as drillstem and formation interval testing. The first drill stem tester was developed in 1927 and refined in the early 1930's. In normal drilling, fluid is pumped down the hole and out the drill bit sending the drill cuttings to the surface on the outside of the pipe. During a drill stem test the process is reversed and fluid from the formation is recovered up the drill pipe to the surface for analysis. Later in the 1950s, Schlumberger introduced a method for testing formations using wireline. The Schlumberger formation-testing tool, placed in operation in 1953, fired a shaped charge through a rubber pad that had been expanded in the hole until it was securely fixed in the hole at the depth required. Formation fluids flowed through the perforation and connecting tubing into a container housed inside the tool. When filled, the container was closed, sealing the fluid sample at the formation pressure. The tool was then brought to the surface, where the sample could be examined. The technology to collect downhole fluid information has evolved considerably from the early drill-stem tests and formation-interval tests to today's sophisticated wireline devices able to take multiple collections, measure pressures, compute permeability, reduce contamination and perform initial oil quality analysis.

Recently vendors have gained the capacity to not only take pressures but also samples of down hole fluids with **formation pressure while drilling tools (FPWD)**, allowing for real-time analysis of fluid-type, pressure regimes and reservoir production optimization.

As wells moved to increasingly deeper and hotter reservoirs a new generation of wireline formation tester was needed. The first generation of hostile sequence formation testing tools was introduced in 2002. Since that time industry has gained a great deal of experience in collecting pressures and fluid samples in formations as hot as 408^{o} F**.** The first phase of a second generation tool was introduced in mid-2009 with ratings to 450^{o} F and 30,000psi and includes features that are needed to allow movement toward performing fluid ID and collecting PVT - quality samples in the future. Challenges faced with development of this tool and anticipated future challenges include **(van Zuilekom and Rourke, 2009):**

- Reliability of sealing pads and packers
- Compromise between maximum tool OD and ability to work in small diameter borehole

- Minimize tool length profiles to reduce fishing
- Maximize operation temperature and time duration in high-temperature environments
- Reliability and accuracy of HPHT gauges
- Effects from drilling muds, such as gelling and high solids contents
- Pressure testing at high differential pressures in HPHT environments
- Low mobility tight sands
- Controlled pumping and evaluation of formation fluids in HPHT conditions
- Handling, transporting and testing PVT samples

Measurement of subsurface properties (fluid type, porosity, permeability, temperature, etc.) are crucial to exploration and development success. Advances in sensor types, durability, sensitivity, and deployment could impact exploration programs significantly by identifying both penetrated and bypassed pay **(Cassiani et al., 2007).**

Drilling deep oil and gas wells offers significant technical challenges that push the operational limits of equipment. Relatively little is known about these reservoirs especially the deep shelf gas trend, highlighted by the recent Davy Jones discovery, as acquisition of formation evaluation information in high temperatures, high pressure, non-fresh water mud systems and slim holes is much more challenging and exceeded the capabilities of older wireline and LWD tools.
Much of the geological and petrophysical understanding of deep reservoirs has come from core, drill cuttings and basic LWD logs acquired during drilling when the logging devices can be cooled by circulation. Since many of these deep reservoirs have low porosity and permeability, the need for a better understanding of the rock properties is critical to make decisions for testing and completing the wells. Logging tools that can handle these environments and acquire measurements with a higher level of sophistication are required (**Malcore et al., 2010).**

The following is a compilation of subsurface measurement technology needs suggested by several petrophysical colleagues that should be and are the focus of near to intermediate term research and development in the industry:

<u>5.7.1. Telemetry, Sensors and Data Transmission</u>

- The demand on increased resolution and data size, will require improved data transmission methods to rapidly transmit large volumes of information to the surface, and therefore, around the world.
- Reserving wireline measurements for ultra-special log requests, resulting in lower costs to the well due to restricted wireline logging. This will require refinements to LWD technology to allow better measurements in vertical holes and more complete logging suites.
- Increased Realtime & Remote Monitoring/Interaction for the remote user of the data. The end user should have more control of the data acquisition in real time.

Data could be automatically uploaded in real-time to 3D reservoir models, and in immersion theaters.

- As we develop unconventional resources more and more, the need to have the ability to monitor these wells and gather data continuously over very long periods of time becomes critical since these wells are long life wells and information gathered in the first few months do not give an accurate indication of how these wells will perform over the long run. Fiber optics & permanent sensors could be key technologies.

5.7.2. Core Acquisition & Evaluation

- Obtaining core from reservoirs is critical to reducing uncertainty of critical reservoir modeling parameters. There is a significant need to improve the quality of cored materials for both conventional and unconventional reservoirs. It is critical to reduce core acquisition time, while improving the mechanical integrity of cored material. We also need to improve our ability to monitor the coring process down-hole, to avoid damaging core or losing cored intervals during acquisition. Technology for preserving reservoir fluids within cores and minimizing core contamination while coring are also needed.
- Industry needs new equipment design and new measurement techniques for ultra tight rocks (nano-darcy) and the ability to accomplish them in a timely manner to influence costly development decisions. The coring and core evaluation industry needs to catch up quickly with the E&P companies as far as the speed at which these resources are being developed and exploited.

5.7.3. Pressure/Fluid Sampling & Characterization

- Down-hole pressure/fluid characterization and sampling has been the biggest area of technical achievement in the past several years, yet there still remains a tremendous need for improvement in down-hole fluid characterization and sampling. We look for improvements so that this technology will provide even more definitive in-situ fluid properties down-hole, reduced sampling time, expanded development of logging while drilling (LWD) tools to perform fluid sampling, and the ability to acquire fluid samples & reservoir properties in challenging environments.
- Mud-logging fluid analysis is another area of significant improvement, however, there is still a huge need to improve our ability to detect and quantify reservoir fluids that are liberated during the drilling process.

5.7.4. Borehole Imaging

- Significant need to improve the quality of down-hole images, especially in wells drilled with synthetic oil based mud. Tools will need to give much finer scales of resolution and deeper depths of investigation, to reduce artifacts on the logs, which may be due to the drilling processes or mud-types used.
- Provide 3D results and images of the parameters around the borehole so that we can better incorporate these data into our Reservoir Earth Model, such as in Petrel, which can then lead to full utilization of "3D immersion" type theaters containing the reservoir model.
- MRI logging, for example, results in waveforms and 2D data from the wellbore. In the medical industry, they are rendered into 3D images. Imaging from around the wellbore may give more information on the fabric of the rock as well as aerial changes in porosity and permeability.

5.7.5. Formation Evaluation

- **Elemental evaluation and mineral based formation evaluation:** This is an area of significant technical advancement within recent years, but there still remains a need for more robust and more accurate tools for quantifying elemental compositions, and the ability to use such tools in more challenging environments.
- **Direct Measurements:** Current wireline & LWD tools are still indirect measurements of desired reservoir properties such as porosity, permeability, water saturation, lithology, etc. It would be a step change in formation evaluation if we could measure these properties directly downhole and not "calculate" or "estimate" them using mathematical equations or standard FE techniques.

5.7.6. Drillstem/Production Testing of Reservoirs

- Design a system that is fully enclosed which prevents downhole fluids being exposed to the surface environment yet renders information on the producibility of the formation and its fluid content. We tend to avoid testing reservoirs in the GOM due to emission controls and costs etc.

Special thanks to colleagues Thuy Rocque, Brian O'Neil, and Kevin Corrigan for their comments on the above technology needs and support in the preparation of this discussion on Subsurface Measurement.

5.8. Earth-Systems Modeling

(By Keith Mahon)

5.8.1. Introduction

"Earth Systems" encompasses geology, hydrology, climatology, and other applied sciences involved in studying the earth as an integrated system. We will focus on earth systems modeling as it applies to **basin and petroleum system modeling (BPSM)** – the integration of basin modeling and petroleum system analysis.

Basin modeling is a quantitative model of a sedimentary basin's deposition, erosion, and heat flow history; petroleum system analysis is the study of the essential elements (source, overburden, reservoir, seal) and critical processes (trap formation, generation and migration, accumulation, preservation) during the evolution of a sedimentary basin **(Magoon and Dow, 1994)**. Applying a fully integrated basin and petroleum system approach to hydrocarbon exploration and exploitation problems helps to reduce overall uncertainty by focusing on only those solutions that are geologically reasonable, geodynamically viable, and consistent with what is known about the stratigraphic, structural, and thermal histories of the basin **Figure 40.**

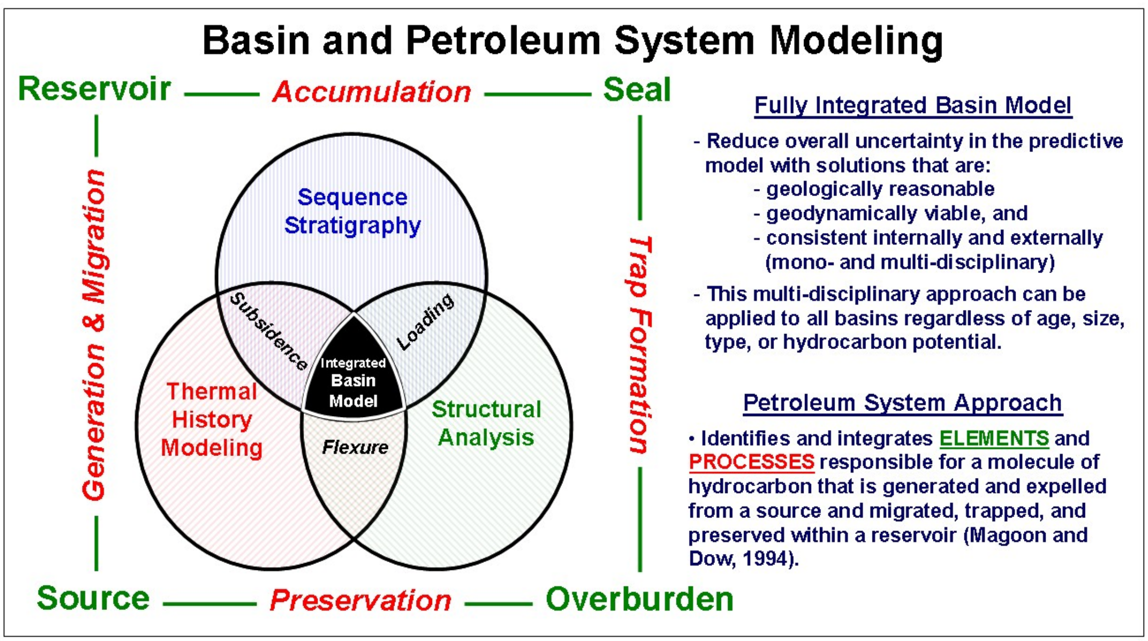


Figure 40: Modification of the "Snow-Mahon Diagram", based of conversations between J. Kent Snow and Keith I. Mahon

5.8.2. History and Exploration Applications

Laboratory-derived kerogen kinetics were incorporated into simple 1D maturity models beginning in the early 1980's to predict source rock maturity **(Tissot et al., 1980; Welte and Yukler, 1981).** These evolved into 2D and 3D models, with or without multi-dimensional heat flow. Hydrocarbon migration was first modeled as buoyancy-driven flow within highly permeable carrier beds and along faults or as Darcy flow linked to rock permeability and pore pressure gradient within all stratigraphic and structural elements of the petroleum system **(e.g., England et al., 1991)**. In recent years, some BPSM software began using capillary entry pressure (i.e., invasion percolation) as a means of secondary migration from the source rock to the trap **(Carruthers, 2003).**

The vast majority of BPSM applications have been in the assessment of hydrocarbon charge risk in oil and gas exploration. BPSM in combination with economic factors assisted the industry in exploiting frontier areas with a higher chance of overall economic success, and avoid regions with a high risk for an inactive petroleum system (e.g., immature source rock), out-of-sequence charge timing (e.g., no charge since trap formation), or poor economics (e.g., stranded gas).

5.8.3. Current Usage

Advancements in computer speed and numerical modeling led to improvement in earth-system modeling techniques and integration of software with other models, technologies, and databases. As processor speed increased, BPSM developers expanded their modeling capabilities to include more complete multi-phase fluid flow and mineral diagenesis in the models directly or as plug-ins. Other recent advances include the use of seismic attributes to map facies variation, global databases to predict organic preservation in potential source rocks and sediment sourcing, and plate tectonic reconstructions to model thermal perturbations of the paleo-heat flow. BPSM applications in frontier or under-explored basins traditionally have large uncertainties due to the lack of data, but this improved with a better understanding of regional geology and integration of other technologies and databases to lower overall uncertainty.

Structural complexities resulting in fault movement and/or erosion are modeled today. Multi-dimensional modeling of extensional systems use fault tools and improvements in data acquisition. Contractional systems are often modeled as separate blocks that are in thermal and pressure communication **(see Figure 41).** The palinspastic structural restorations of contractional systems are input in BPSM over a series of steps to reconstruct a basin's history as well as its hydrocarbon charges **(Mount et al, 2010).**

BPSM applications expanded beyond the n-component, 3 phase (water, oil, and gas) modeling to include the impact of biodegradation on a modeled oil accumulation due to reservoir temperature, time, nutrient availability, and several other factors **(Larter et al., 2006).** Models using plug-in technologies have also been applied to the amount of asphaltene (solid petroleum) that dropouts during secondary migration by tracking the temperature and pressure history of an oil volume and "reacting" when conditions dropped below a predefined set of asphaltene onset pressures and temperatures **(Mahon et al., 2009).**

Part of the current BPSM workflow is fluid rock interaction, in particular sandstone diagenesis, for "sweet spot" identification in reservoirs with a high risk of low porosity and permeability. BPSM calculates temporal and spatial variation in temperatures and effective stress. This output is used to populate diagenetic models of the nucleation and growth of quartz cement calibrated to detailed petrography of similar reservoir sands in order to predict compaction and quartz cementation **(Lander and Walderhaug, 1999)**. Calibrated temperature and pressure from BPSM are also used to improve depth imaging below salt by deriving solutions for the effective stress history and then re-migrating the seismic data using the adjusted velocity model **(Petmecky et al., 2009).**

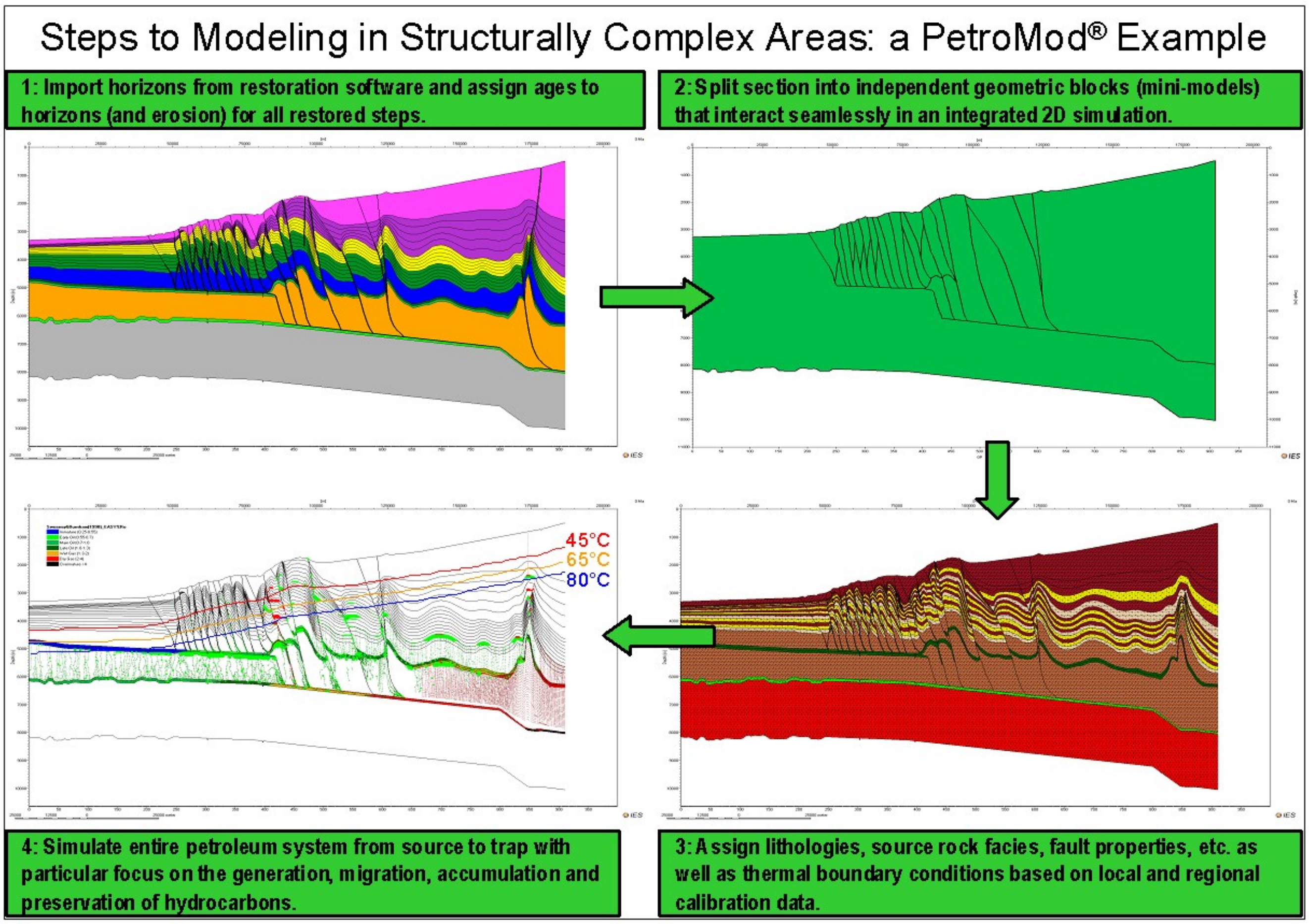


Figure 41: Steps to modeling in structurally complex region using PetroMod® 2D.

5.8.4. Improvements Expected: 2011-2015

Traditionally, BPSM has focused on the regional petroleum system over geologic time to better understand the charge history of a basin. The evolution of these models has led to very sophisticated 3D models of reservoir filling history using n-component, 3-phase systems. As the focus switches from exploration to development of structurally and stratigraphically complex reservoirs with heavy or chemically unstable oils, these regional models can be re-scaled at the reservoir level for use in “field-scale” scenario testing.

The hydrocarbon charge history of reservoirs may be as important as the present-day geology in developing a production plan. With increased fidelity of the geologic model, data acquired from the first few wells in a field (PVT fluid properties, pressures, temperatures, etc.) may be used to test the impact of increased production rates and chemical injection on heavy or chemically unstable oils. Field-scale simulators may allow for diffusive mixing on time scales of thousands of years and convective mixing that occurs on production time scales. Different reservoir drive mechanisms and connectivity scenarios can be tested rapidly on geologically realistic multi-million cell models. The computed stress history could be applied to the rock mechanics to predict a distribution of baffles (e.g., deformation bands) and barriers (e.g., high shale gouge) within the reservoir. This approach could also be applied to old fields and those in which production has been shut-in for years. Scenarios involving the redistribution of residual oil in the reservoir plus any new charge from the basin-scale model would be tested to see if it meets an economic threshold before re-entering the field.

Modeling unconventional resources is expected to considerably improve over the next few years. Shale gas models will focus on hydrocarbon retention and fracture formation within the source rock. Incorporating detailed retentive properties of source rocks and accurate geomechanical rock properties will help advance BPSM technology.

Computational speed will continue to improve by using advanced multi-core processors currently in use by the computational intensive video gaming industry for superior graphics. For example, new NVIDIA graphics processors are available with 480 CUDA cores for the desktop computer – orders of magnitude faster than today’s typical workstation. Modeling complex systems may yield unexpected results that make it a challenge to interpret. Quantifying uncertainty to non-linear responses will improve with advancements in computing speed, enabling modelers to test a broader set of the solution space.

Structural complexities associated with fault movement have been part of BPSM for several years. However, these zones have highly variable rock properties along the fault planes and within the surrounding fault zone. A greater focus on these highly variable regions will help in the prediction of subsurface flow within the petroleum system. In addition, more complicated applications of 3D BPSM in contractional systems are expected as 3D structural restorations improve.

Due to advancements in the precision and accuracy of radiometric dating techniques, absolute age-dating can be used to constrain formation ages. This includes depositional ages from uranium series disequilibrium age-dating and dating oil to determine a source rock’s age using ^{187}Re-^{187}Os as geochronometer. Unfortunately, absolute dating techniques are underutilized in exploration due in part to the belief that the analytical cost outweighs the benefit in lowering the uncertainty in depositional or source rock ages.

5.8.5. Improvements Expected: 2020

The next decade will see rapid advances in BPSM. Continued improvement in computer technology will lead to touch screen capabilities that will allow for rapid editing of 3D volumes and rapid interface with all available databases and previously built models.

Two major developers of BPSM software, IES (PetroMod) and Permedia Research (MPath), were recently acquired by Schlumberger and Halliburton, respectively. These acquisitions will improve the link between BPSM models with reservoir models and geophysical interpretations. It is plausible that the BPSM workflow will become part of seismic processing to improve depth imaging. Perhaps the conversion of seismic time to depth grids will also include grids that can be quickly imported into BPSM software with age assignments, lithologies, fault properties, and estimated pore pressures. This could be taken a step further by accessing regional databases for paleogeography, eustatic changes, environments of deposition, source rock distribution, heat flow events, etc. These advances will come quickly, shifting how BPSM is applied to exploration and field development problems.

The focus on shales, as a resource, will also lead to improvements in our understanding of some of the fundamental rock and fluid properties of fine-grained sediment. Uncertainty associated with compaction of fine-grained sediment, the most common rock type in sedimentary basins, has hampered the accuracy of BPSM. Shales have a broad range of starting conditions (e.g., initial porosity), compaction rates under similar stress, and anisotropies for fluid transmissibility and heat flow. The bulk thermal properties of shale and other sediments are a function of porosity, grain alignment, and fluids in the pore space. Very few thermal conductivity and heat capacity measurements have been made under basin conditions (temperature, pressure, and porosity) leading to simple, and possibly inaccurate, estimates. Acquiring rock properties directly from measurements or by indirect techniques (e.g., velocity inversion) will assist in decreasing uncertainty in BPSM.

Fundamental research by universities will continue to be an important component of advancing the technology throughout the next decade. Financial support by the industry is high, but the level of funding needed for universities and joint-industry projects is increasing. Although universities in the United States continue to take an active role in multi-disciplinary integration of earth systems there appears to be a shift towards universities in Western Europe. This may be due in part to the higher level of public funding available in Europe. It is unlikely that public funding will substantially increase in the foreseeable future in the United States.

5.8.6. Improvements Expected: 2050

As computer technology expands to unforeseen platforms and outrageously fast processor speeds are attained, BPSM models will approach full-physical capability. This will allow models to trace individual molecules of petroleum from time of formation to accumulation within a reservoir and all the intermediate water and rock interactions. The new technology may be used to help design exploitation plans in residual oil and gas zones in long abandoned or under-developed fields. As these full physical descriptions lower or virtually eliminate nearly all of numerical and computational uncertainty, the quality of the input data will be the sole focus for improving these models – something that may be under-appreciated even when applying today's models.

5.9. Reservoir Characterization

(By Paul Schlirf)

Reservoir characterization encompasses a broad spectrum of techniques and methods that improve our understanding of the geologic, geochemical and petrophysical controls of fluid flow. It is a continuous process that spans from the discovery well and field sanction to the last phases of production. Reservoir modeling is the final step in the reservoir characterization process, and consists of building models for input to a fluid-flow simulator. Dynamic reservoir simulation is used to forecast ultimate hydrocarbon recovery of various development schemes or to evaluate the economics of different recovery methods. Conducting the flow simulation requires several input data types. The primary input is a high-resolution geologic model consisting of a geometric description of boundary surfaces, faults, and internal bedding geometries, a 3D distribution of permeability and porosity, relative permeability and capillary pressure/saturation functions or tables. Additional necessary information may include fluid pressure/volume/temperature (PVT) properties, well locations, perforation intervals, production indices, production or injection rates and or limiting production or injection pressures **(Chamber and Yarus, 2007).**

Robust reservoir characterization is critical to predicting and monitoring the production behavior in increasingly complex reservoirs with fewer more costly direct well penetrations. In the high cost deepwater environment high per well recoveries are a necessity for economics. Literature searches, 2007 Deepwater Topic paper and discussions with staff confirm the biggest challenges are:

-Predicting and monitoring reservoir properties between well penetrations
-Understanding reservoir compartmentalization
-Deep water field analogue data

To understand the reservoir requires many critical elements including well logs, core data, quantitative study of geological analogs, well testing and seismic interpretation. However, to achieve a more accurate prediction in deepwater will require **(Conser et al., 2007)**:

-Measuring methods of greater depth of probing
-Modeling methods with more quantitative sophistication

One of the more difficult challenges in reservoir characterization is compartmentalization. This is primarily due to flow barriers that are below the resolution of toolsets even in ideal settings. Also, understanding and predicting changes in reservoir properties during production (e.g. permeability under compaction) is also a key **(Conser et al., 2007).**

Initial attack points to improve reservoir characterization should be through improved seismic imaging, resolution and attribute extraction. Example solutions would include

denser acquisition using wide azimuth, full azimuth and ocean bottom seismic, and utilization of seismic cable designed for broader bandwidth acquisition. Properly processed these will have the potential to provide greater resolution of stratigraphic detail. Also in the near future deterministic amplitude corrections for focusing and defocusing under the salt will be necessary for proper reservoir imaging.
"Deeper penetrating well tests require longer times and larger volumes creating gas handling challenges that present technical issues. Increasing technical sophistication of quantitative geologic models including depositional systems and geomechanical behavior are also crucial. Progress is needed on all fronts **(Conser et al., 2007)."**

Comments on advances needed from discussions with peers. Many of these are also mentioned in a previous topic concerning Subsurface Measurement:

- **Connectivity of reservoir** often difficult to predict, need to monitor reservoir properties between well penetrations. This requires measuring methods with greater depth of probing and modeling methods with more quantitative sophistication.
- **Broader set of field analogues (operators need to share) –** Including MDT's, earth model depletion plans, history matching projects, reservoir simulation processes and results. Because of the great expense of drilling deep water wells and often seismic data with limited resolution, the reservoir characterization and simulation modeling needs to use analogue data from fields the same geologic providence or geologic setting.
- **Companies need to acquire more logging (sonic – both pwave and shear), MDT and cores when drilling.** It is more expensive but if fewer wells are drilled, the information will be critical in the reservoir description, simulation, and management. Advancements in "remote sensing" seismic attributes can then be better calibrated.
- **Advanced well testing methods for offshore**. Better fluid samples, less contamination, for more reliable fluid characterization and production planning. This is also especially true for tighter reservoirs of the L. Tertiary in deepwater.
- **Better modeling processes –**
    - To handle compartmentalization uncertainties: faults and sealing capacities including during production, slumps, stratigraphy, tar and asphaltenes in fault planes, tar mats
    - Improve upscaling technology, such that a more coarse grid model can preserve tortuous flow characteristics of a fine scale model
    - Improve dual porosity earth model and better simulation processes to study these
    - To understand how asphaltenes affect rock and fluid properties
- **Better mitigating technologies** for asphaltenes in the high flux near borehole reservoir
- **Better reservoir simulation to model hydraulic fractures**

- **Permanent downhole sensors**
- **Automated uploading of real-time/monitored data to 3D reservoir models**
- **Production geochemistry –** GC-MS technology

The following discussion of Geostatistical Reservoir Characterization is taken directly from Volume VI Emerging and Peripheral Technologies – Petroleum Engineering Handbook (H.R.Warner, editor 2007), Chapter 2, Richard L. Chamber & Jeffrey M. Yarus, except where noted.

Geostatistics is a powerful technology toolbox for reservoir characterization that allows us to understand and model spatial variability in the reservoir. Under this umbrella is the ability to model stochastically, which is clearly not a simple game of tossing a coin for predicting what is present in the interwell space. Furthermore, numerical flow simulation and production performance are not based on the most likely P(90) scenario. Geostatistical methods allow us to test several scenarios and to select realizations representing the P10, P50, P90 and Pmean outcomes. A good reservoir model is invaluable in selecting well locations and well designs (vertical, horizontal and multilateral) and in assessing not only the number of wells needed to produce the reservoir economically but also the bypassed pay potential and value of infill drilling. A model of sufficient detail is required to make the best reservoir management decisions, accounting for uncertainty, for the most efficient recovery of hydrocarbons.

Geostatistical Technology into the Next Decade

Geostatistics is a rapidly evolving branch of applied statistics and mathematics for creating realistic models and quantifying uncertainty. There is a great deal of discussion among users and vendors on how to advance this technology. Some of the key issues are soft-data integration, uncertainty quantification, advances in computer technology and the use of intelligent workflow managers.

Soft data integration – integrating soft data (e.g. seismic attributes or well test data) into the reservoir model is possible using geostatistical methods, but the results are not always satisfactory. There are no reliable methods to integrate seismic attributes in true 3D, mainly because of low vertical resolution of the seismic information. Selecting appropriate variables from the plethora of seismic attributes is both overwhelming and confusing. Most of the attributes are highly correlated because they are derivatives of one another, but there is no guarantee that their correlation with a reservoir property is meaningful. In the future, not only will techniques need to be developed for better understanding of relationships between reservoir properties and seismic attributes but also tools that can screen and rank seismic attributes, perhaps making linear and nonlinear combinations for use in reservoir modeling. Also likely are advances in static and dynamic data integration. The earlier in the modeling process that dynamic data are integrated, the easier it is for the reservoir engineer to make a history match. **Figure 42** is an example of a geostatistical reservoir model that integrates appropriate seismic attributes with depositional facies, which in turn controls rock property modeling to achieve a robust model for reservoir simulation.

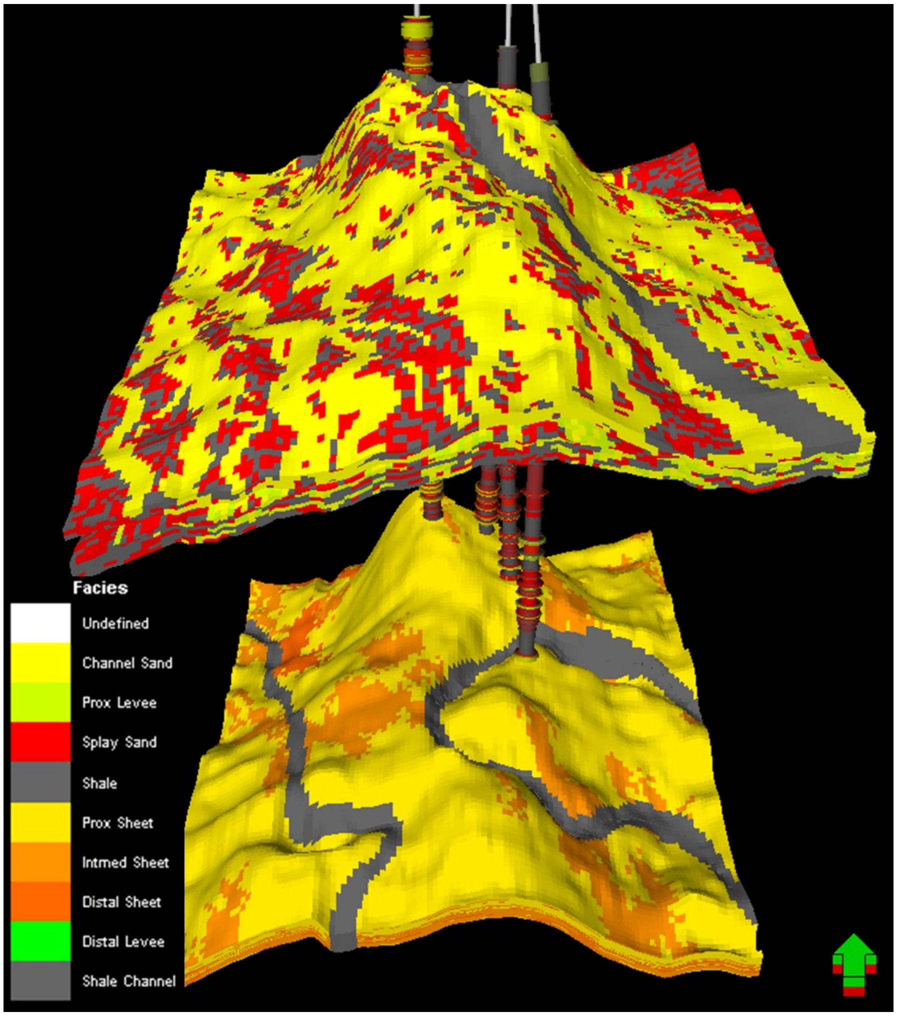


Figure 42: Reservoir facies models where thickness and channel density are controlled by seismic attributes (Courtesy Anadarko Petroleum Corporation)

Uncertainty Quantification – uncertainty can be quantified through stochastic simulation, but to avoid underestimating the uncertainties, this approach must be used with an understanding of the modeling assumptions. Many uncertainty results have been arrived at simply by calculating the variability between realizations from fixed parameters, neglecting the uncertainties in the modeling parameters themselves. Not all parameter modifications have the same impact on the amount of uncertainty. In the future a suite of tools is likely to be developed to help evaluate parameter sensitivities and their impact on sampling the space of uncertainty. Once the key parameters are determined, perturbations of them will generate a suite of simulations for uncertainty analysis.

Advances in Computer Technology – Computer technology continues to advance rapidly. With advent of GHz and higher microprocessors and more RAM memory, the PC has begun to rival the UNIX world at much less expense. As such, most reservoir modeling vendors have ported their code to run under Windows NT, XP, or Linux operating systems. Some vendors are offering parallel processing code, mentioned earlier, to run fluid flow numerical simulation code, but it is not being used to its fullest capabilities. Faster computers should advance the use of parallel processing not only for fluid flow simulation, but also for generating more and larger stochastic models to quantify uncertainty. This will accelerate the ranking, selection and upscaling of the multiple realizations. When flow simulating more geologically realistic models one should be able to accelerate the history-matching process.

Intelligent Workflow Managers (IWM's) – The introduction to geostatistical-modeling software can be overwhelming for those just beginning geomodeling. As a result they tend to choose recommended defaults when creating a stochastic model. Some commercial packages have reasonable work-flow managers to assist the user, however, in the future what we should see are IWM's. The IWM will interview the user, asking questions about quantity, quality, types of data, and assumptions about the depositional environments. This interview will lead the modeler through a series of panels recommending various options.

5.9.1. IQ Earth - Quantitative Subsurface Integration (SEG Website)

In January 2010 the Society of Exploration Geophysicists (SEG) launched an innovative new research initiative, IQ Earth, the brainchild of Statoil SEG members, to create a fundamental change in visualizing and interpreting subsurface structure, rock and fluid properties. This change is about process and will involve building a workflow that emphasizes improved integration of available data from the various oil field disciplines of geology, geochemistry, petrophysics, geophysics and reservoir engineering. These improvements will involve easier access by geoscientists for the different data types, often having their own peculiar sampling, and not only integrating them to generate a quantitative earth model which can be updated rapidly as more data arrives, but also integration built around an earth model that is shared by all the disciplines. Headway has been made over the last decade with integration and the challenge continues to be addressed by many players. However there is some feeling that further progress will involve the cooperation of all stakeholders: oil companies, service companies and universities. The Society of Exploration Geophysicists can play a key role in facilitation and was chosen to partner in this effort because geophysical data is a core platform for integration in today's workplace. **(Krokan, 2010).**

The following are measures of success for IQ Earth initiative by 2015 (SEG Website)

- General acceptance of the quantitative earth model paradigm by industry and academia
- Inclusion of geology, geochemistry, petrophysics, geophysics and reservoir engineering in the quantitative earth model
- Increased academic emphasis on quantitative geoscience
- Increased academic emphasis on geological fundamentals within the geophysics program
- More integrated geoscience departments at universities
- Increased number of students graduating with integrative quantitative geoscience expertise
- Shift in academic research towards integrative quantitative technology
- Increased papers and presentations by oil companies on the quantitative earth model value proposition and related technology development
- A realization that broad participation by the subsurface community will yield greater benefit than relying solely on internal proprietary technology development
- Increased development and commercial offering of integrative methodologies by the service sector, developed to meet customer requirements
- A new vocabulary, replacing “integration” and “interpretation”
- SEG Continuing Education and Distinguished Instructor courses
- SEG Publication (joint with SPE and AAPG) that will be a popular reference treatise and university text.

5.10. Extended System Architecture

(By Paul Schlirf and Dawn Peyton)

Driven by the depletion of shallow water reserves, onshore oil and the high demand of world oil by industrial nations and those of emerging economies, offshore exploration and production is going from deepwater (3000' – 6000') to ultra deepwater (6000' – 10,000'). The movement into deepwater and ultra-deepwater involves the continued extension of existing technologies and new technologies that may provide a step change in performance, making ultra-deepwater more economically viable **(Bell et al., 2005).** Technical challenges of deepwater development cross all the disciplines in a field's life, beginning with the explorers, who interpret seismic images to locate prospect opportunities that, in many cases lay below thousands of feet of salt and at depths reaching the limits of many of the available rigs. The next step is the drilling team, who are drilling faster and deeper and collecting critical subsurface information to help the geoscience and reservoir engineering teams appraise the discovery size. The reservoir engineer then focuses on the number of wells, location and recovery mechanism decisions. Production and completion engineers examine feasible artificial lift options and well design. At the same time, facility and subsea engineers study the subsea layout, facility size, and topsides design. Care is taken to ensure compatibility between surface and subsurface design. Fabrication begins. Drilling finishes the planned wells leaving a stable well bore that enables the completion engineers to complete the well with minimal formation damage. Finally, subsea, and facility experts step in and install subsea and surface structures kits (depending on whether completion is wet, dry, or hybrid and if there is a need for local hub facility) designed to handle a range of the field's conditions. Long-term production from deepwater fields has been a challenge and will continue to become even more challenging with the maturing of existing higher rate Pliocene – Miocene age fields. Producing beyond primary depletion will require the use of artificial lift (gas lift, electrical submersible pumps in the well or at mudline), reservoir pressure maintenance and possibly enhanced oil recovery (EOR). As we explore in deeper waters, for new horizons at depths never before completed or older formations known to have heavy oil and less permeable rock, the development of new or enhanced technologies will be needed. In these environments reservoir deliverability plays a key role for the project economics. The professionals working in the oil industry, academia and government must work together to find ways to safely and economically develop these reservoirs **(Olsen, 2008).**

Over the past 100+ years of exploration and production, industry has consistently shown innovation in technology necessary to supply the U.S with a much needed energy source. Earlier in the discussion of drilling technology it was noted that the first well offshore was drilled in the late 1800's with a cable tool rig attached to a wharf. Fortunately it turned out to be a good producer and in short order several more wharf rigs were in operation. As oil became our primary resource in the early 1900's, new and faster ways of drilling and retrieving oil were developed.

Over the following 40 years, industry pushed into swamps near the coast, transition zones and offshore within sight of land. During this time production technology continued to advance with the invention of the surface control valve and gauges – nicknamed the Christmas tree. The defining moment in offshore oil and gas drilling came with the first well out of sight of land by Kerr-McGee (now Anadarko) at Ship Shoal block 32 in 1947. The barge and platform combination was a step change in drilling-unit design offshore. This event marked the beginning of the modern offshore industry **(NOIA website).** Since then exploration and development has moved into ever deeper waters in the Gulf, with facility designs that are adapted to meet the particular environment and infrastructure needs. Up until the mid 1990's production facilities offshore were primarily fixed steel structures supported by the ocean floor. However as the shallow water, larger finds diminished and matured, industry began to move into deeper water. At these greater depths fixed platforms were not economic or practical. This led to the development of Tension Leg Platforms (TLP's), semi-submersible floaters and spars. Given the costs of surface structures for deepwater production there was a need to bring as many nearby opportunities to it for processing and transportation via pipeline to shore. There was no economic way to set an expensive surface facility above every field discovered, certainly if limited in size, but also the directional wells drilled from a central location could not reach all the key development take points necessary to optimize development of the field. As such this drove the critical companion technology to a deepwater central facility; subsea well completions.

By 2005, there were up to 90 discoveries in the (GOM) developed with subsea wells tied back to central facilities versus about 40 that had used above water platforms **(Harts E&P staff, 2007).** The majority of the tiebacks were to steel structures on the outer continental shelf, but many were to deepwater facilities. However in the last 10 years most of the subsea tiebacks in deepwater have gone to central facilities in equivalent water depths. With the analog being a bicycle wheel, the term for the deepwater central facility and associated subsea tiebacks is sometimes referred to as a hub-and-spoke development. Today there are several multi-party hub and spoke configurations in the Gulf of Mexico. One such facility, the Independence hub in over 8000' of water, has 5 companies tying subsea completions back to a deep-draft semi-submersible platform.

Spar, semi-submersible, TLP and floating production, storage and offloading (FPSO) facilities are key enabling technologies for deepwater developments **(Figure 43).** Robust and cost effective, these technologies allow for commercial development of remote and deepwater resources, enabling even a number of smaller fields into the commercial window, referred to as the "string of pearls"**.** Anadarko (Oryx/KMG) was a leader in championing this technology in 1996, with installation of the world's first production **SPAR** at the Neptune field in 1930' of water. Spar platforms have 3 design configurations: the "conventional" consisting of a large diameter, one piece cylindrical hull with a deep-draft floating caisson that supports a deck, the "truss spar" where the mid-section is composed of truss elements connecting the upper buoyant hull to the bottom soft tank containing permanent ballast, and finally the "cell spar" which is built from multiple vertical cylinders. About 90% of all spar structure is underwater and is held in place by moorings. The deep-draft hull produces favorable motion characteristics. Spars are designed to operate in up to 10,000’ of water.

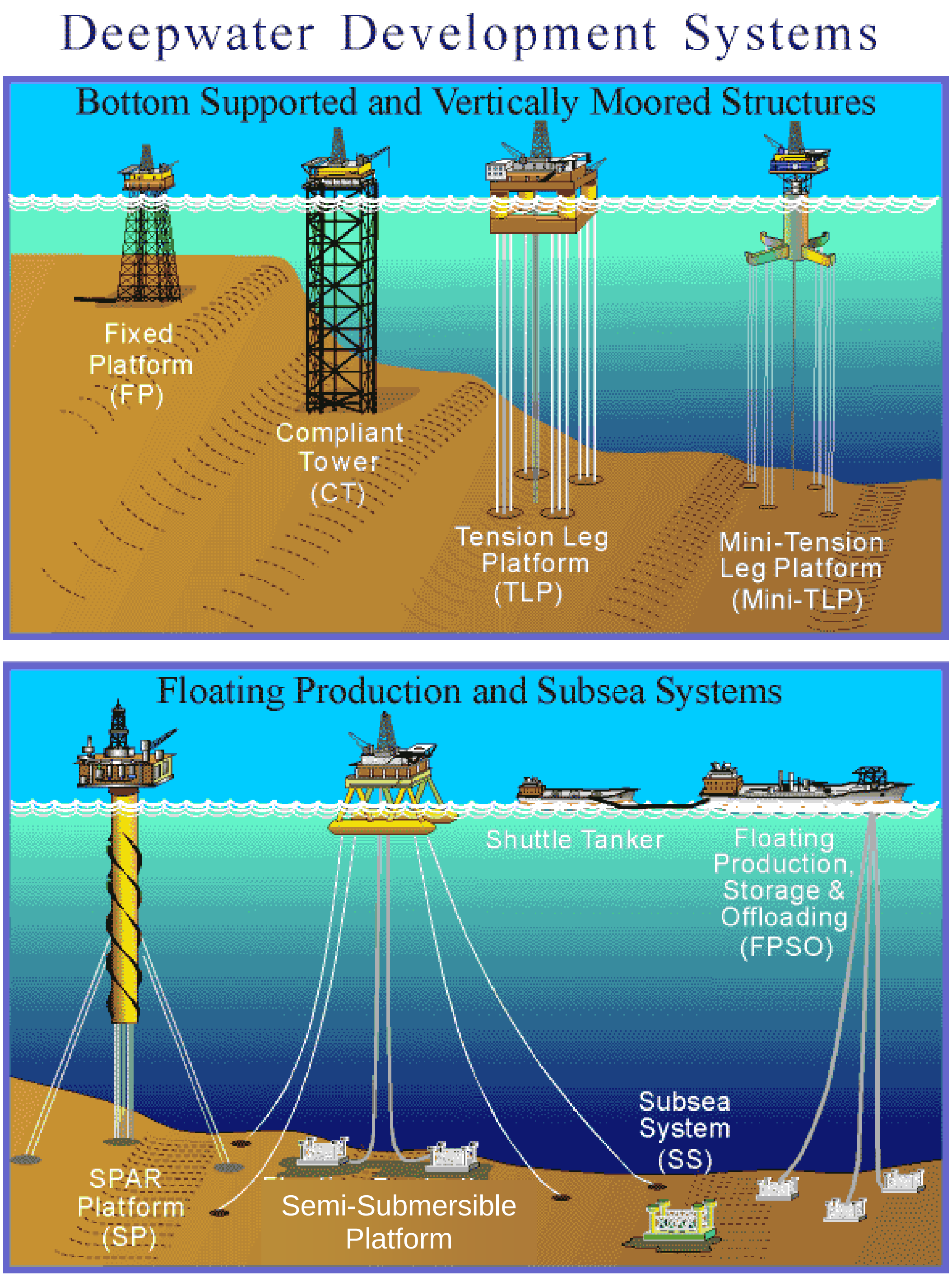


Figure 43: Offshore production facilities (BOEMRE Website)

In 2007, the Independence Hub (IHUB) **semi-submersible** in SE Mississippi Canyon, operated by Anadarko, became the world’s deepest floating production, subsea tieback and pipeline installation system. Set in 8011’ feet of water 120 miles from shore, it was a unique commercial solution to stranded resources in a frontier area. It currently produces .53 BILLION CUBIC FEET/day, 4% of U.S. residential consumption, but early on up to .93 BILLION CUBIC FEET/day or 7.1% of U.S residential consumption. It has very little above water footprint, but gathers from subsea tie backs stretching the equivalent distance from The Woodlands, 30 miles north of Houston to Galveston Island 60 miles south, ~ 1800 square miles. Subsea umbilicals have 1100 miles of steel tubing, 200 miles of flow lines, and subsea tie-back production in up to 9000' of water **(Figure 44 & 45).** Semi-submersible production platforms are supported by ballasted, watertight pontoons located below the ocean surface and wave action. The operating deck is located high above the water and therefore waves, due to the good stability of the concept. The first semi-submersible production platforms were converted from semi drilling rigs.

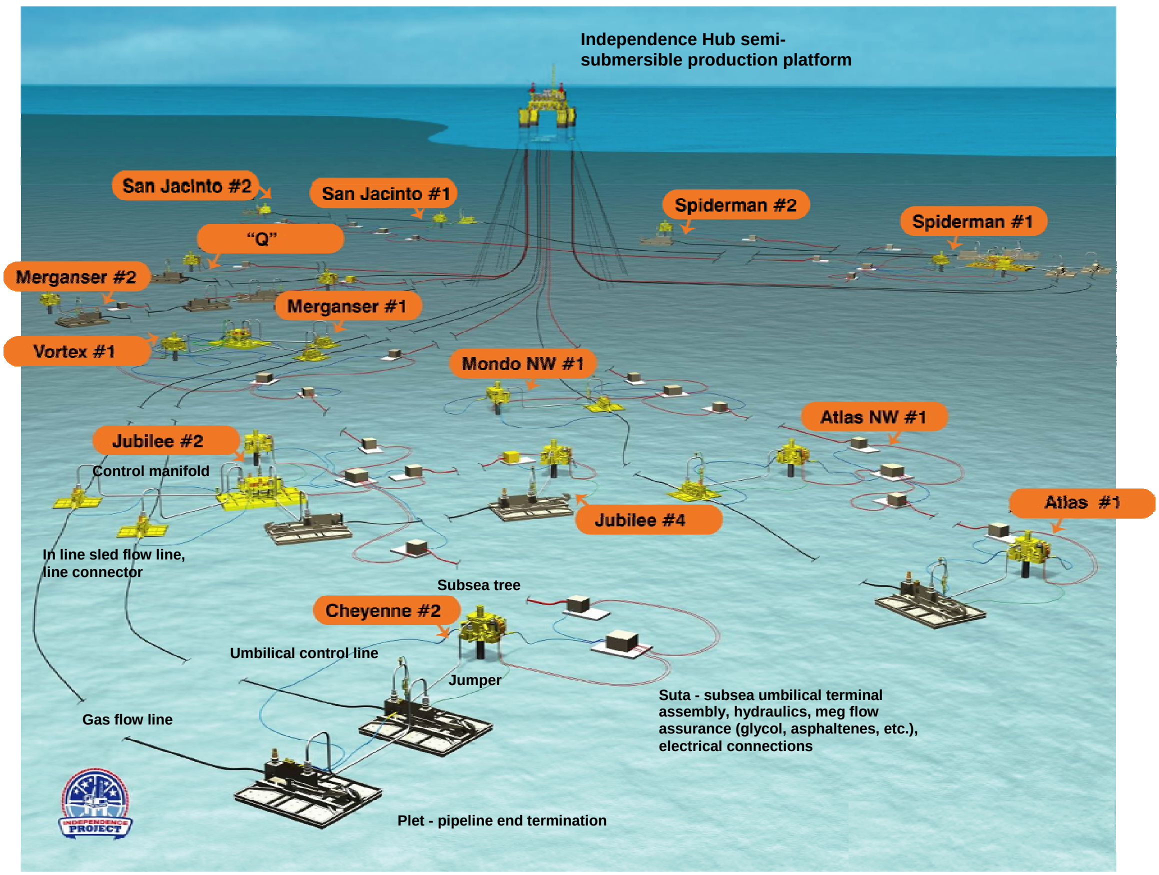


Figure 44: Independence Subsea Layout – minimal surface footprint (Courtesy Anadarko Petroleum Corporation)

Figure 45: Independence facility gathering system overlaid on Houston area for scale
60 miles x 30 miles = 1800 square miles subsurface coverage area (Courtesy Anadarko Petroleum Corporation)

Another active semi-submersible production platform to note is BP's Deepwater GOM, Thunderhorse in 6000' of water. This facility is designed to produce 250,000 bopd and 200 mmcf. In 2010 the average production was ~ 173,000 bopd and 155 million cubic feet per day, 11% of total GOM offshore oil production, 14% of deepwater oil production, with some individual wells producing ~28,000b/d. It has set a number of HP/HT development records at 12,500 psi and 275^{o} F. It is the world's largest production, drilling quarters semi built, at greater than 100,000 tons **(Figure 46).**

Figure 46: Thunder Horse Semi-Submersible Production Platform in transit to emplacement (Botros et al, © 2008 SPE. Reproduced with permission of the copyright owner. Further reproduction prohibited without permission.)

In March of 2010, Shell started production at the Perdido Spar complex in the Western GOM, and overtook the Independence Hub for deepest production in the world. Moored 170 miles offshore in 7817 feet of water with wells in up to 9,627 feet of water, the peak production should achieve 130,000 BOED. The facility is also the first application of wet tree Direct Vertical Access (DVA) well system with a full capability rig. This enables a small host design with a high well count that can be phased in over time utilizing a platform-based drilling rig. Key enabling technologies include a seafloor caisson booster system to provide artificial lift for increased productivity and the first use of subsea (located on the seafloor) multiphase flow meters (**Figure 47).**

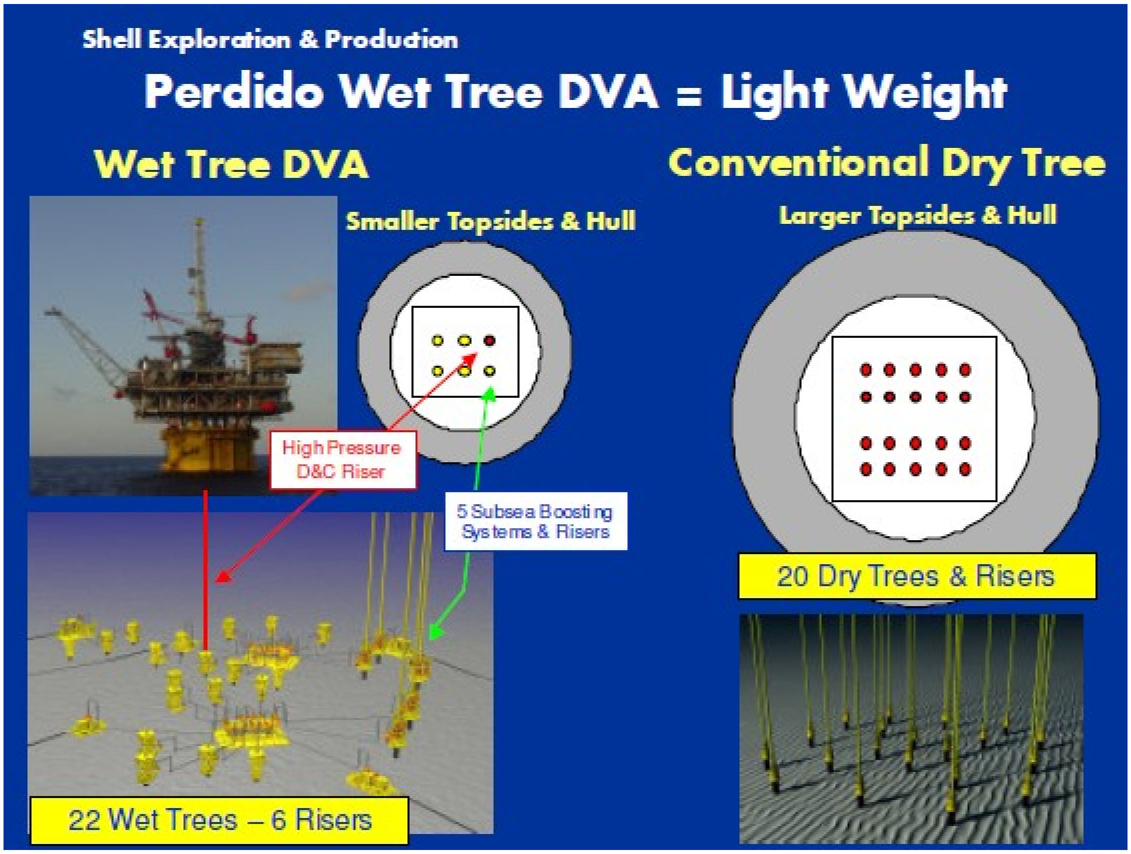


Figure 47: Perdido wet-tree, Direct Vertical Access (DVA) System. Coupled with Subsea Boosting System, production riser count is reduced from conventional dry-tree systems. (Snyder and Townsley, © 2010 OTC. Reproduced with permission of the copyright owner. Further reproduction prohibited without permission.)

A third type of floating production platform is the Tension Leg Platform or TLP. It consists of a floating platform tethered to the ocean floor with vertical tension tethers that eliminate most vertical movement in the structure. Currently the deepest one in the GOM is in 4670'of water over the Magnolia field. More recently at the Bigfoot discovery, Chevron has announced the conceptual design for a dry-tree development on an extended tension leg production facility in ~ 5,300- 6,400 feet of water. Key enabling technologies: dry tree production unit, extended tension-leg facility design with in-well electric submersible pumps (ESPs) and reservoir support injection capabilities, and an onboard drilling rig for drilling and future interventions.

In 2011, after some delays, Petrobras is scheduled to bring on line the first **FPSO (Floating Production, Storage and Offloading) facility** in the GOM at Cascade/Chinook Fields 180 miles offshore in 8500' of water. March 17, 2011 the

Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) green lighted the project with the approval of a production safety system permit and supplemental deep-water operating plan. Petrobras is studying the government approval and has not given a firm start-up date. Peak production is forecast to be 80,000 BOPD. All eyes are on this for two reasons, one, long term Lower Tertiary production in lower permeability and porosity rock, which industry has not seen to date offshore, and two, it is the first facility of its type in the GOM. An FPSO is a floating vessel designed to receive oil produced from subsea template, process it and store it until the oil can be offloaded to a tanker **(Figure 48).** This type facility will have tremendous potential in areas of limited infrastructure and bottom topography not suitable for long distance pipelines.

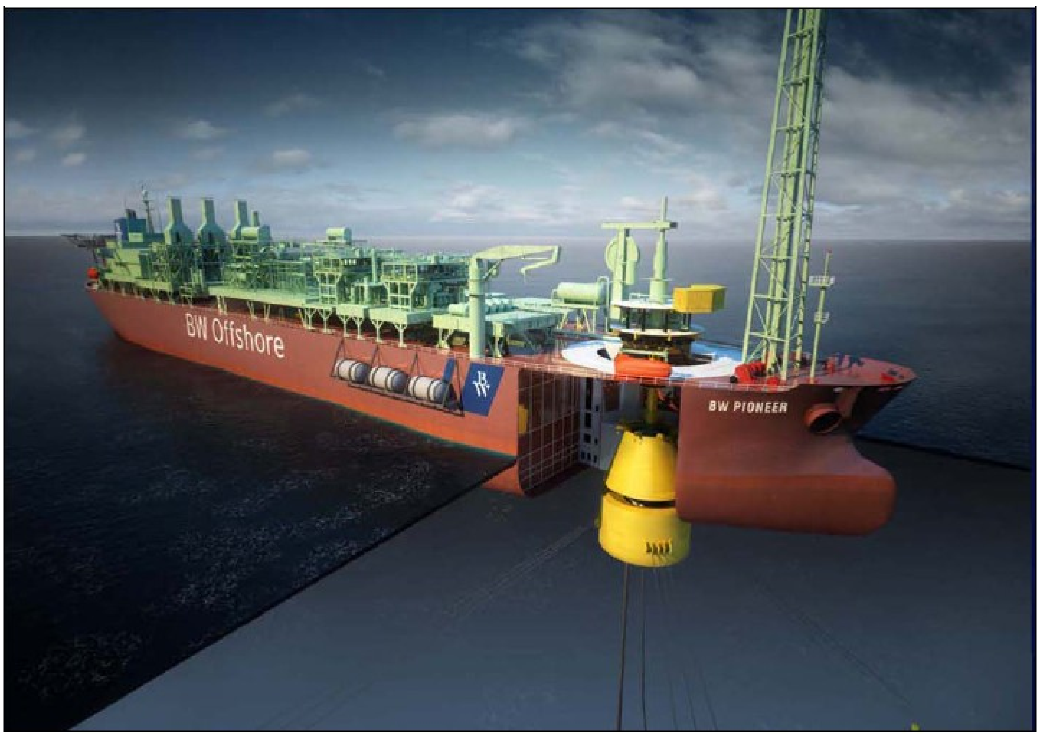


Figure 48: The BW Pioneer, a double-hulled tanker that will serve as the FPSO for the Cascade and Chinook developments. (Depiction courtesy of Petrobras) (From OCS Report MMS 2009-016)

In October 2010 Chevron Corporation gave official sanction to the $7.5 billion plan to co-develop the Jack and St. Malo fields in the Lower Tertiary trend of the deepwater Gulf of Mexico. The fields are 25 miles apart, ~ 220 miles offshore in 7000' of water. The reservoirs occur at ~ 26,500' and the combined recoverable reserves are estimated at 500 million barrels of oil equivalent. A major contract was awarded to Mustang Engineering for detailed design of topsides on a semi-submersible production platform that will be the hub for 3 subsea centers, capable of producing 170,000 barrels per day of oil and 42.5 million cubic feet per day of gas. First production is due in 2014. Key enabling technologies mentioned: One of the largest semi-submersible hulls ever constructed, seafloor boosting for late field life operations, and efficient multi-zone frac equipment for complex completions over very large reservoir intervals.

In the Gulf of Mexico today there are 47 permanent deepwater facilities in over 1000' of water, including the latest at Perdido. Tying production back to these or shelf steel structures are 279 subsea boreholes **(BOEMRE Website, 2011).**

5.10.1. Subsea Technology

As we have seen from discussion of some the discoveries currently on line and those in the process of development, the Deepwater GOM is a major hydrocarbon producing region critical to U.S. daily domestic production. With the emerging high potential Lower Tertiary play, demonstrated by Shell's Perdido complex and Chevron's sanctioning of Jack/St. Malo, together ~ 1 billion barrels recoverable, there come critical challenges for the GOM. They include higher pressure and lower permeability reservoirs, often higher temperature, more viscous oil with lower GOR and in many cases the nearest offshore infrastructure is 60 miles away. These challenges cross multiple disciplines and advances in technologies associated with seismic imaging, completion and casing designs, subsea production equipment, subsea processing, and High Integrity Pressure Protection Systems (HIPPS) are necessary. These challenges will require the collaboration and focus among operators, engineering firms and equipment suppliers similar to the cooperation that took place in the 1980's and when industry first step out into the deepwater environment **(Addison et al., 2010).**

Other than seismic processing and casing designs, which have already been discussed, we will use the technical challenges above as an outline in the discussion of designing production systems to economically, efficiently and reliably transport hydrocarbons from subsea wells to topside facilities and then on to shore, hence **Extended Architecture**. **Figure 49** below provides a simplified diagram of the various components to subsea systems and the engineering disciplines involved. Our discussion on subsea systems will highlight the following key technologies:

Risers
HIPPS
Subsea Tree
Flow Assurance
Subsea Processing
- **Subsea Boosting**
- **Subsea Separation**

Water Injection
- **Subsea Produced Water Separation and Injection**
- **Subsea Raw Seawater Injection**

Power Distribution
Subsea System Controls
Flow Assurance Lower Tertiary

Completions
Digital Field Technology (E-Field)
Field of the Future

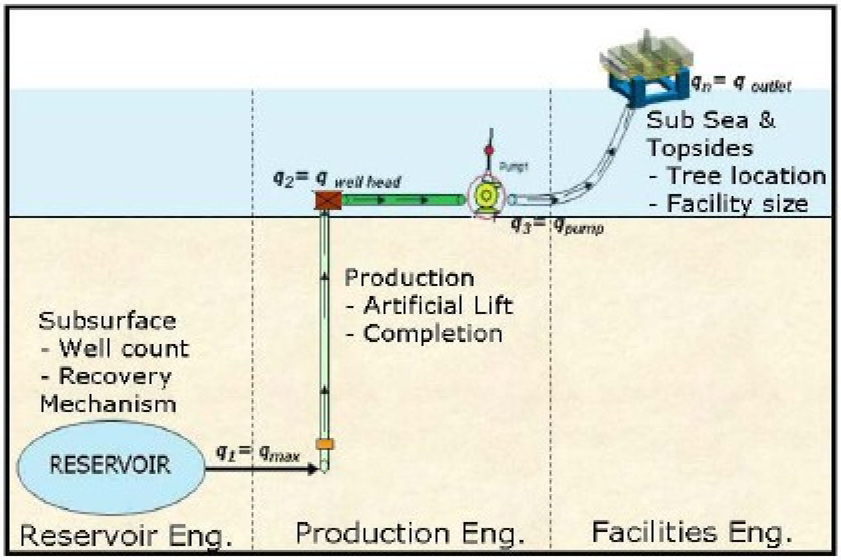


Figure 49: Distribution of engineering disciplines working concurrently during deepwater development planning (Ozdogan et al., © 2008 SPE. Reproduced with permission of the copyright owner. Further reproduction prohibited without permission.)

Subsea Riser Design is one of the most challenging engineering aspects of a deepwater field development. Risers constitute the conduit that connects the floaters at the surface to the subsea wellhead underneath the facility or terminus of flowlines to satellite fields. The primary challenge in riser design emanates from the fact that the host facilities are dynamic structures highly susceptible to environmental and operational loads. The risers themselves are very slender elements that must ride with the motions of the host facility while withstanding the current loads in the water column and the pressures and temperatures of the fluids they transport. As the global demand for hydrocarbons has increased, offshore projects have moved deeper and deeper and riser design has become more challenging than ever before, involving novel technologies and materials **(Deka et al., 2010).**

Increasingly, newly discovered fields bring higher reservoir pressures that are approaching or exceeding industry technical capabilities. Simply increasing the wall thickness of the riser systems will not be feasible as the tensions at the riser support point become infeasible and capabilities of the equipment to perform the installations is exceeded. Continued research and development is required to identify riser systems to enable production of these reservoirs to the host facilities. Below is a summary of existing technology employed or under development by industry. This list is by no means exhaustive.

Riser Technology….

Steel Catenary Riser (SCR) – pipe suspended from the host platform in a caternary configuration that transitions to a horizontal orientation at the touch-down point. These risers develop substantial hang-off loads at the host and must be designed for the mid-water forces created by currents as well as the forces induced in the touch-down region. The first SCR was installed on the Augur TLP in 1994 **(Carter et al., 1998).**

Top-Tensioned Riser (TTR) – are vertical risers that are anchored at a wellhead on the seafloor and typically supported at the host facility by a hydro-pneumatic tensioner or buoyancy can. Connections for these risers are typically threaded connections which are made on a drilling rig. These risers may consist of a single or dual casing. Typically production tubing and control and injection lines are run inside of the inner-most casing string.

Composite Riser - are risers that utilize metallic and non-metallic components. Research on this technology has been conducted for a number of years in an attempt to lighten tension load requirements. Challenges with this technology include the interface between the metallic and non-metallic components and verification of compatibility between the riser contents and the non-metallic conduit.

Titanium Riser – have been investigated for very challenging fatigue environments. Titanium has excellent fatigue characteristics. However, titanium is far more expensive than steel pipe and welding of titanium requires very closely controlled parameters and environment. This environment will be difficult to accomplish in the field. Currently the industry uses titanium in critical regions of the riser string. Titanium stress joints have been utilized on a number of projects.

Flexible Riser – is a complex pipe construction that was developed in the 1970's for dynamic applications where a pipe of variable bending radius and configuration was required. Originally used in applications for drilling choke and kill lines, the flexible pipe has since been utilized for flowlines and risers for field developments. The industry has made great strides in development of increased pressure ratings, water depth capability and temperature range.

Hybrid Riser – is riser tower technology that has been used for challenging riser system designs from a configuration and fatigue standpoint. A riser tower consists of a vertical, rigid riser element that runs from the seafloor to a buoy within roughly 100 meters of the surface. Flexible pipe(s) are then run form the riser tower to the host vessel.

Lazy wave riser, SVIR (single vertical import riser) – is a riser with buoyancy collars tethered at different locations. The advantage of these riser types are the decreased load carried by the host facility.

High Pressure (HP) Deepwater Riser Systems
"All alternative development concepts needed for deployment in the Paleogene and similar applications will require a number of HP riser options including HP steel catenary, Lazy Wave risers, and hybrid riser towers as well as dry tree risers. The combination of high pressure, water depth, and reservoir souring coupled with new regulatory requirements represent a major challenge for these riser systems and will require a considerable amount of engineering and qualification to enable such systems at pressures of 15 ksi **(Addison et al., 2010)".**

The subsea HIPPS System (High Integrity Pressure Protection System) is a solution for high pressure reservoir environments that provides a pressure break between subsea systems that are rated to full shut-in pressure and equipment downstream that are rated to a lower pressure. It uses highly reliable valves, a fully redundant pressure-control system, with sophisticated sensor technology oriented upstream and downstream of the unit. HIPPS would allow the use of lighter risers and flowlines and would significantly reduce the cost of higher pressure applications. Another big driver for HIPPS will be to tie something in that already exists but which is not rated high enough to accommodate the new production. As a result in the high cost environment of the Gulf Deepwater, it has the potential to make a financially challenged, moderate to long offset high pressure projects possible. The HIPPS system has been used in onshore and surface applications as wells as limited use in subsea processing in the North Sea. API wrote a standard 170 for HIPPS last year and it has been approved. However, the BOEMRE has been requiring that the system still be capable of handling full pressure and to date no proposal for approval has been put forward. The goal of the additional requirements is to ensure that if HIPPS fails, it does not endanger the people on the facility. Further effort is required here to develop a system that will enable pressure reduction in downstream requirements, especially risers. Industry and regulatory agencies must agree on prudent designs and operational requirements for the critical technology.

5.10.2. Subsea Tree Technology:

Per earlier discussion, critical companion technology to deepwater hubs was subsea well completions, as economics precluded setting an expensive surface facility above every field discovered, certainly if limited in size, but also the directional wells drilled from a central location could not reach all the key development take points necessary to optimize development of the field. Central to the subsea well is **subsea tree technology,** which were some of the first pieces of subsea hardware used. The primary function of a subsea tree is to provide a controllable interface for the flow of oil and gas between the well and production facilities. At the simplest level it is a set of valves installed on a subsea wellhead, but as we will see it has evolved into much more.

The first subsea trees were placed on the seafloor in the GOM in the 1960's. The 1970s and early 1980s saw subsea production activity increase in all parts of the world. Rising crude prices led to a frenzy of offshore-development projects. Investments in production facilities reached huge proportions. During this period, the first subsea tree system was installed totally below seabed. These early subsea trees had a limited ability to serve as a doorway to overcome the technology of assessing and producing volumes to the surface. As a result, the role of subsea trees has been changing to enable the innovative subsea designs such as subsea boosting and processing, flow assurance, light well construction, multi-lateral wells, intelligent completions and e-Field technology. **Figures 50 & 51** show the evolution of subsea tree interfaces and influences.

Currently complete suites of standard subsea equipment rated at15 ksi exist. These include trees, manifolds, pipeline terminations (PLETs), etc. Operators are now in the process of working with vendors to qualify subsea trees for 16.5 ksi to meet the new BOEMRE requirements for equipment exceeding 15 ksi working pressure **(Addison et al., 2010).**

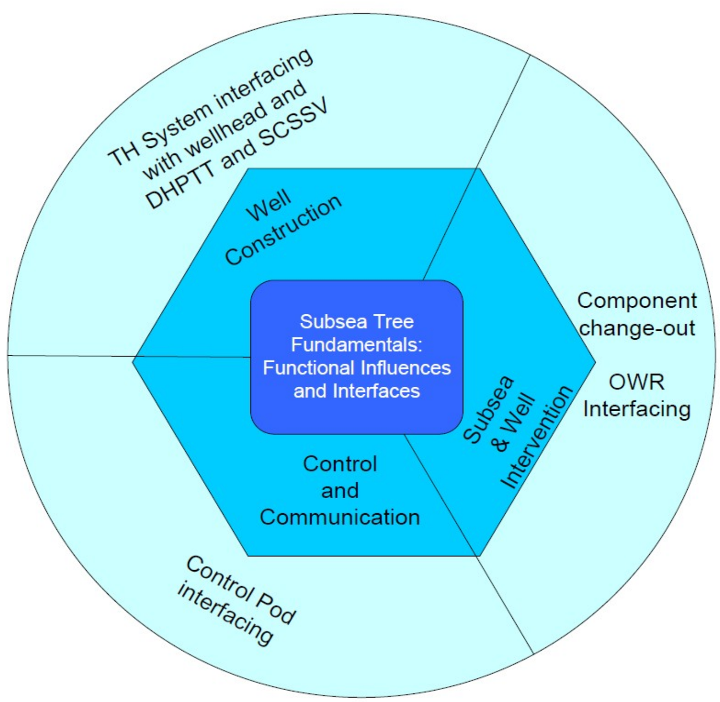


Figure 50: Historical Subsea Tree Interfaces and Influences
(Fenton, © 2009 OTC. Reproduced with permission of the copyright owner. Further reproduction prohibited without permission.)

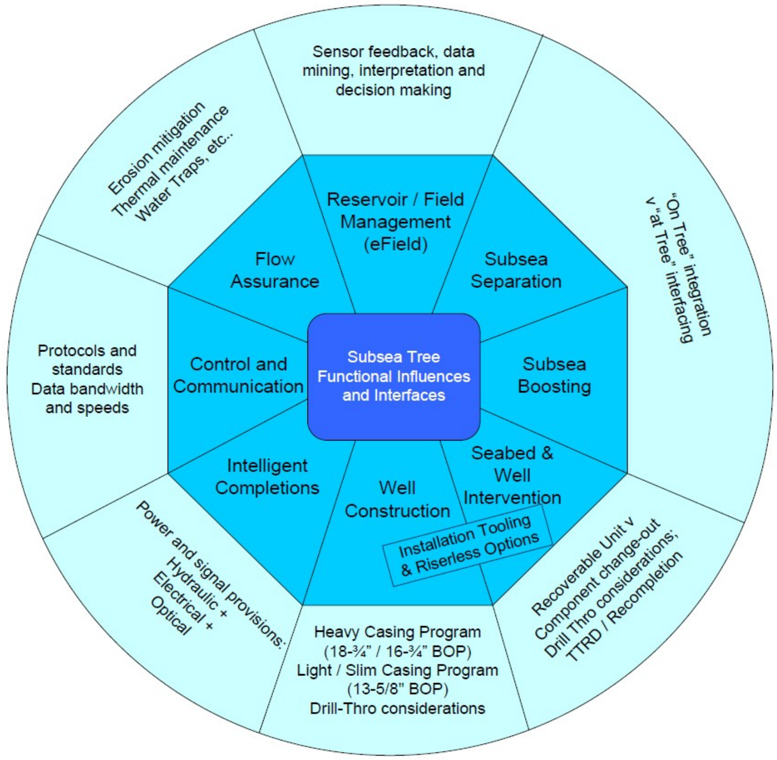


Figure 51: Present day Subsea Tree interfaces and influences
(Fenton, © 2009 OTC. Reproduced with permission of the copyright owner. Further reproduction prohibited without permission.)

An emerging technology for subsea trees is the all-electric system. The system will be powered by direct current and has no batteries or accumulators. Control commands can be sent in quick succession with no lag time needed from an accumulator charging. Communication with equipment and feedback on subsea conditions are virtually instantaneous. With no hydraulics, there are not fluid-handling and disposal issues and no leaks. This system will be beneficial could create significant cost savings from the reduced umbilical size and the elimination of hydraulic infrastructure. In the longer term, on tree processing and wireless technology could be explored
(Fenton, 2009).

Total installed the first all-electric subsea Christmas tree at the K5F gas field offshore The Netherlands in 2008. The project is in shallow water and involves no long stepout, however the achievement is important because of the potential all-electric control technology in deepwater applications **(Parshall, 2008).**

5.10.3. Flow Assurance Technology:

Flow assurance is one of the most critical issues to enable production when designing deep-water field developments **(Bell et al., 2005).** It is one of the main drivers in the selection of field architecture. Historically, subsea tieback distance has been limited by both temperature and pressure drops in the flowline. The pressures required to lift the product to the surface are substantially greater in deep water than in shallow water. Longer tieback distances from wells to surface processing platforms, while reducing costs, increase backpressure on the well, thereby reducing flow rates and recoveries. Temperature differences between the seawater and petroleum product may cause the formation of hydrates and waxes that can impede the flowlines **(Grieb et al., 2008).** Asphaltenes in some areas are an additional concern. Control of these formations via prevention and or mitigation is the mission of flow assurance, and the most cost and mechanically effective.

We have a mature understanding of the flow assurance challenges in the Deepwater Miocene production, but new and innovative approaches will be required as current challenges are combined with the future challenges of extreme well depths, extreme pressure and temperature environments, tighter reservoirs, and less than perfect fluid properties

The current focus is preventing solids from restricting to actually blocking the flow of hydrocarbons from the well to deepwater hubs and onshore processing facilities **(Denney et al., 2008).** Many treatment protocols have been used to prevent the formation of hydrates such as injection of chemical inhibitors, pipe-in-pipe (PIP) insulation, electrical heating, and separation of water and gas phases, but the most common is injection of an effective inhibitor. Still these techniques have limitations. The Nakika and Mica fields have the longest subsea oil tiebacks in the GOM and are 29 miles. Nakika utilizes both PIP technologies as well as non continuous electrical heating to keep the flowline above the hydrate formation temperature. The Mensa tieback to West Delta 143 boasts the longest subsea gas tieback in the GOM at 68 miles. Hydrates are prevented using large glycol supply lines where the chemical can be injected at the subsea wellhead **(Hydrocarbon-Technology and Offshore-Technology Websites).**

Future deepwater flow assurance will concentrate on two things. One will focus less hydrate prevention and more on allowing gas-hydrates to form but prevent agglomerations through chemical injection. Hydrates would be transported in the form of a slurry through the pipeline. Water could be added to adjust the hydrate-slurry viscosity **(Denney et al., 2008).** The second area of concentration is the movement of the production facilities to the seafloor.

5.10.4. Flow Assurance Technology:

Subsea processing involves a number of processes that can reduce the cost and complexity of developing an offshore field and increase the productivity and recovery from new fields. Originally conceived as a way to overcome challenges of deepwater environment situations, subsea processing has become a viable solution for fields located in harsh conditions where equipment on the surface may be at risk. More recently this technology is seeing application to increase the production in mature or marginal fields. The main types of subsea processing are: separation (subsea water removal and reinjection or disposal, sand and solid separation, gas/liquid separation), pressure boosting (single or multi-phase boosting of well fluids), and gas treatment and compression **(Rigzone website)**. Subsea processing can be used to reduce back pressure on the reservoir in order to improve depletion, and the same time assisting with flow assurance issues in the flowline via water and gas separation **(Fenton, 2009).**

5.10.4.1. Subsea Boosting

Most deepwater reservoirs start off with high pressure, but with time the reservoir depletes and the energy to move fluids to the surface declines. Currently there are three main subsea pressure boosting methods in use: Gas lift, Multiphase Pumps, and Electric Submersible Pumps (ESP's). Seabed processing and boosting systems have multiple benefits including **(Grieb et al., 2008):**

- Reduced development costs
- Improved recovery of resources
- Increased flow rates
- Reduced need for chemical injection
- Reduced incidence of spills and leaks due to hurricanes
- Minimization of risks to personnel

Subsea pumping technologies also address problems associated with slugging and backpressures on the wells, thereby increasing the rate and uniformity of flows. Boosting of flow rates results in increased temperature in the flowlines, which results in decreased hydrate and wax formation and reduction of slugging **(Grieb et al., 2008).**

Gas Lift is the most common artificial lift method to improve recoverable reserves in the Gulf due to the ready supply of gas, versatility and extensive experience base. It is a reliable and low cost technology utilizing injected gas to reduce the static head in a production system. It is not limited by tieback distance and can be used for production enhancement, flow stabilization (to mitigate slugging), and flowline depressurization to prevent hydrates from forming during a prolonged shut in **(Dewalt and Shields, 2010).**

One technology being developed is the idea of down-hole gas lift injection in deepwater subsea wells. Total boasts the first bottom-hole gas lift on a

deepwater subsea well in the Moho-Bilondo field, offshore the Republic of Congo, which came online in 2008. This gas injection has boosted Moho-Bilondo's recovery rate 20%. Although gas lift is widely used elsewhere, in the deepwater subsea environment it is a major innovation due to the cooling effects on the produced liquids. Gas injection rates must be controlled to avoid a plug in the line **(Total website, http://www.total.com/en/our-energies/oil/exploration-and-production/projects-and-achievements/moho-bilondo-940856.html).**
The main disadvantages to gas lift are injection depth limited by high injection pressure and increase in total volume through flowline (larger pipe may be required) **(Dewalt and Shields, 2010).**

Multi-phase pumps (MPP) are pumps designed to boost the pressure of the entire production stream without separating the fluids. The main types are twin screw pumps and helicon-axial pumps. They can be installed directly on the individual subsea trees or as an MSV retrieval pumping skid that ties into the inlet of the flow line. A number of these systems are already available and in use in subsea developments around the world. **(DeWalt and Shields, 2010)**.
In 2007, BP installed two twin-screw, positive-displacement multiphase boosting pumps in their King Field in the Gulf of Mexico. The King Field ties back 18 miles to the Marlin tension-leg platform in 5600ft of water. The pumps are now expected to increase field production rate by an average of 20% and total recovery by approximately 7%, according to BP **(Parshall, 2008 and BP Website).**
Multiphase pumps are more reliable than an electrical submersible pump (ESP) and can be retro-fitted into a subsea development. Various pump inserts can be selected based on expected fluid properties. Two pumps can be placed in series which permit a greater increase in the total overall pressure boost. The main disadvantages of multiphase pumping are the large and heavy topsides equipment required, high initial capital cost, and large power requirements **(Dewalt and Shields, 2010).**

Electric Submersible Pump (ESP) – are multi-stage centrifugal pumps driven by an electric motor and are another form of pressure boosting that is seeing more use in the GOM deepwater. They are especially effective in wells with low bottom hole pressure, low gas/oil ration, and low bubblepoint or low API gravities. They currently are in wide use in the offshore Campos Basin of Brazil and are being used in the Perdido and Cascade/Chinook deepwater GOM fields. They can provide a large pressure boost and require lower power requirements than a mudline multiphase pump. If the ESP is used in a riser application, it is not adversely affected by distance from the well to host platform as can be the case with other lift processes. They typically require a small topsides footprint and are lower cost and more efficient than a multiphase pump. A multi-well field can continue to produce if one ESP goes down. One concern with ESP's in deepwater is the need for regular replacement, which is compounded when dealing with wet trees **(Dewalt and Shields, 2010).** Future ESP technology will focus on improving reliability and optimizing ESP retrieval.

5.10.4.2. Subsea separation

Subsea gas/liquid separation and pumping is an effective means of providing artificial lift for enhanced oil production from a subsea development. Subsea separation technologies also allow control of hydrate and wax formation by separating the oil from the gas and water components.

Applications seen to date have been limited. However, one of the largest applications and first of its kind in the GOM, is at the Perdido complex located 8 miles north of the Mexico maritime border. Due to the lower temperatures and pressures and ultradeep water depths (7800ft-9600ft), subsea separation and boosting is required for reasonable production rates. There the concept in place collects produced fluids from 22 subsea wellheads, which are commingled on the seafloor then directed to 5 identical subsea boosting systems (SBS) that separate the produced fluids from gas at the sea floor and then pump the liquids to the surface using **Electric submersible pumps (ESP)** installed to 350' below mudline at the SBS's with gas free flowing to the surface in the riser annulus **(Figures 52 & 53).** The combination of separation and pumping has an energy efficiency improvement over multi-phase pumping alone by a factor of 2 to 4 depending on water depth **(Haheim and Gaillard, 2009).**

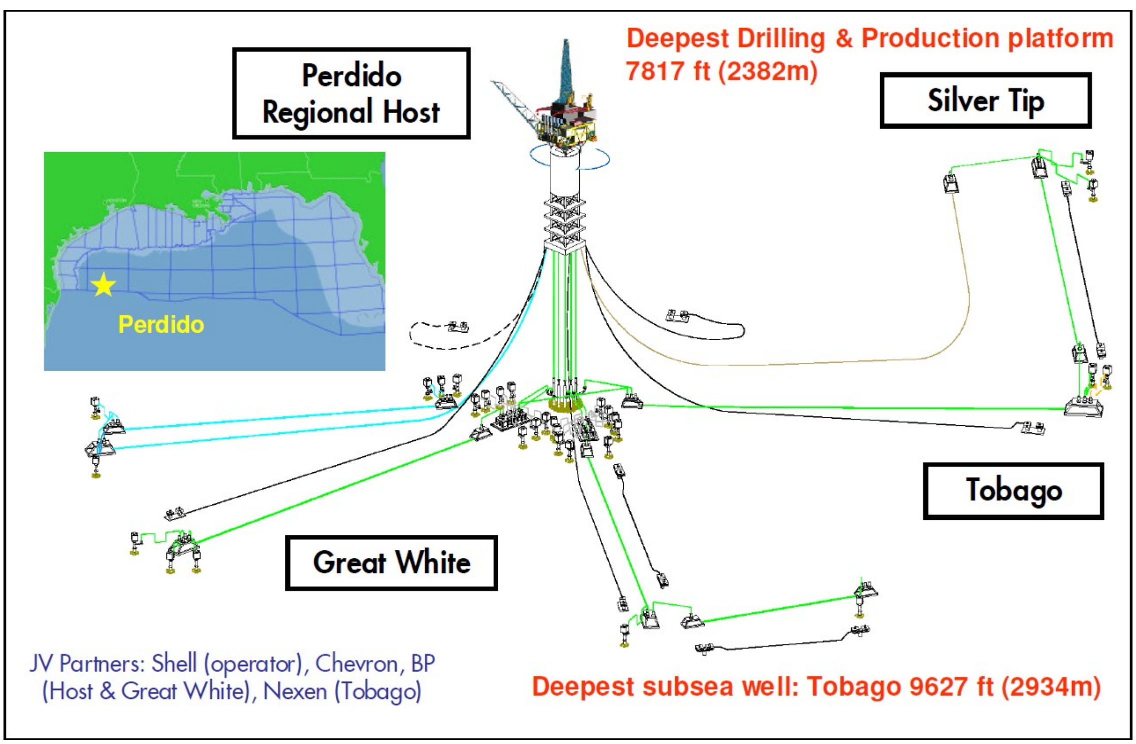


Figure 52: Diagram of Perdido Development System Layout

(Snyder and Townsley, © 2010 OTC. Reproduced with permission of the copyright owner. Further reproduction prohibited without permission.)

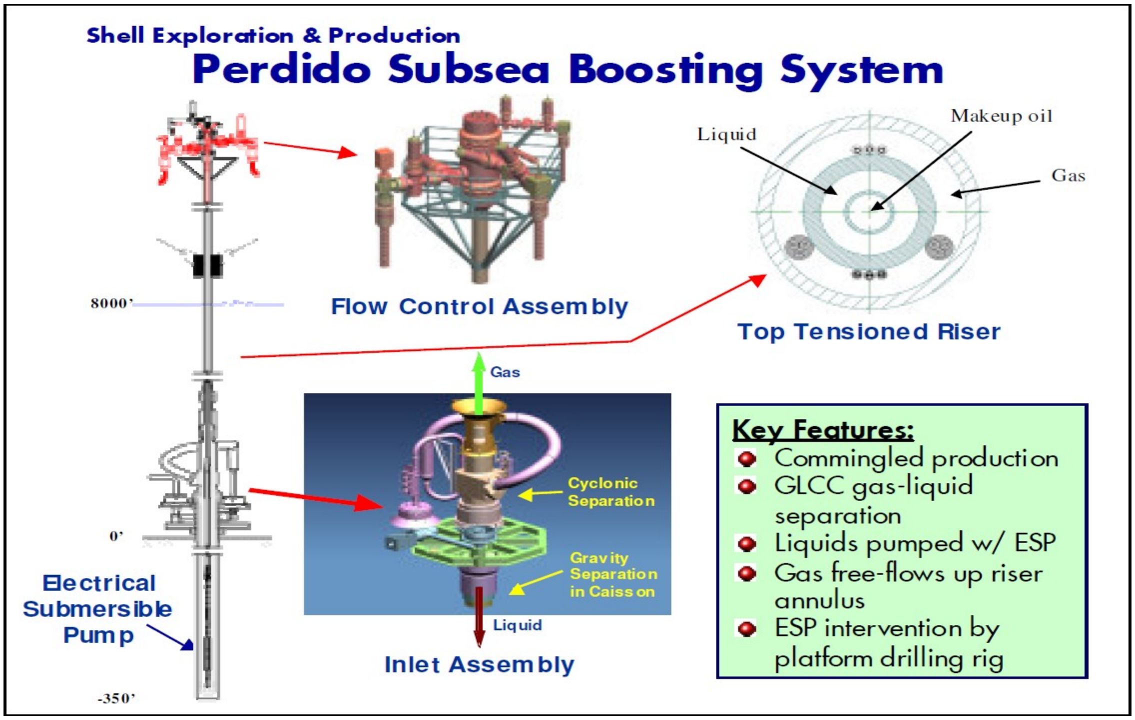


Figure 53: Diagram of Perdido Subsea Boosting System
(Snyder and Townsley, © 2010 OTC. Reproduced with permission of the copyright owner. Further reproduction prohibited without permission.)

Separating the produced water at a remote location like the seafloor can be accomplished by downhole oil/water separators. The separator is used in conjunction with ESP's, with the water being pumped into a downhole injection formation without ever coming to the surface. This is somewhat seen as a niche technology, due to the need for a disposal zone with the appropriate pressure and injectivity at the right depth relative to productive zones. Also given the additional complexity with downhole ESP's, cost effective intervention is a must. This steers the technology towards onshore or at least platform applications and away from subsea tree applications.

Another subsea system of the future is the idea of **complete separation** of the production stream which involves both separators and scrubber stages. This separation system could be combined with single or multiphase pumping or gas compression to move the product to surface. The majority of the produced water is removed and either pumped to surface, reinjected, or discharged to the sea.
Subsea separation technologies also allow control of hydrate and wax formation by separating the oil from the gas and water components **(Grieb et al., 2008).**

Taking this idea one step further would include multi-stage separators which would produce export pipeline quality oil and gas. Pumping and subsea compression could then be used to send the petroleum fluids to surface or straight back to shore. This system is in the development stage, however there has been resistance within the industry to use full subsea processing. Issues surrounding handling of sand, maintenance and repair, pressure-related failures, and environmental concerns from leaks/spills and management of produced water have not been addressed. **(Grieb et al., 2008)**

Water injection is an alternative to mechanically increasing the flowing pressure. It instead maintains reservoir pressure over the life of the field. The concept of pressure maintenance is not a new one but has challenges in deeper waters including the need for additional high cost injection wells. Currently water injection in deepwater is a combination of seawater removed of solids and oxygen, and produced water after separation. Both processes are performed on the topsides, followed by injection. In an effort to reduce surface footprint, subsea technologies for water injection are being discussed. The following is a brief description of subsea based systems:

Subsea Produced Water Separation and Injection – the driver for this technology is extended architecture, distance and depth, with the future potential of removing a deepwater host facility. The system would involve separator, water injection pump, level transmission, power supply and sand handling systems. Challenges would be separator performance, and control and monitoring. There has been one application of the technology in Norsk Hydro's Troll field in 1999 **(Chappell, 2006).** "In the first 1.5 years of operation, the separation and injection system has contributed to an increased oil production of 3.5 million barrels due to the added water treatment capacity **(Horn et al., 2003).**"

Subsea Raw Seawater Injection is a new concept where seawater is taken at seabed and filtered, chemically treated, boosted and then reinjected subsea. The host facility topsides would be used for chemicals, controls, and power. Drivers for this technology are **(Chappell, 2006):**

- Reduction in topside weight from the removal of the fine filtration and deoxygenating equipment, water injection risers and flow lines.
- CAPEX and OPEX reduction with reduction in equipment.
- Reduction/elimination of seawater injection limit constraints e.g. in the flow lines
- Greater flexibility in location of injector wells.

There would be a number of issues to consider with design of the subsea raw water injection system. Corrosion prevention due to oxygenated seawater, possibility of increased bacterial activity and reservoir souring due to such, need for fractured injection due to suspended solids, and sand control and water quality.

One of the largest projects ever on the Norwegian continental shelf, Tyrihans was developed as a subsea tieback to the Kristin platform and began production in July 2009. The project has two seafloor centrifugal pumps developed for raw-seawater injection technology for pressure support and oil-zone stabilization. Together, the pumps are expected to increase field production by approximately 10% or 19 million BOE compared to no water injection. Initially, conventional seawater injection through a flowline was evaluated but abandoned due to high cost for the flowline **(Parshall, 2008 & Statoil Website, 2011).**

Power Distribution. With the continued focus on deepwater potential and the need to economically increase recoverable reserves in remote locations, future subsea processing and boosting equipment, which consume power measured in mega-watts, will result in power distribution becoming a new driver for field architecture(**Easton, 2010).**

Since installation of the first subsea electrically driven seabed booster pumps on the Lufeng Field in South China Sea in 1997, installed power on subsea processing systems has increased substantially and is expected to increase in the years to come**.** Subsea processing systems include single and multiphase boosting, compression, separation, and as such, power demand is well above what conventional subsea systems require. Today most installations are boosting applications with approximately 35 machines on the seabed worldwide. Cost effective and reliable power systems are key elements to the success of subsea processing. Focus on development of such systems has only been in the last 5 – 10 years (**Midttveit et al., 2010).**

Present technology requires large, expensive umbilicals with high power losses. Possibly, segmentation of the power system, or components (e.g. motors) which operate at high voltages could simplify requirements (e.g. avoid transformers and variable frequency drives). Low-loss or superconducting cables would enable transmission and distribution over longer distances. In the long term, we see potential for localized power generation (e.g. fuel cells) on the seafloor as being a significant enabler to a distributed deepwater infrastructure **(Conser et al., 2007).**

Cable terminations, connectors, and penetrators, constitute very critical components in the power supply system. The majority of direct failures experienced so far are related to these components. All main components in the power supply system are dependent of penetrations in the housing and the ability to disconnect and re-connnect, and the interface to the connection cables is very important **(Midttveit et al., 2010).**

Subsea System Controls. For the data communication system, wired systems work fine, where we have them. For unwired interaction, today's technologies do reasonably well at handling low-bandwidth data transmission in the vertical plane. High bandwidth and lateral distances are remaining challenges. Future systems are likely to be hybrids of long-range, high-bandwidth, wired systems and short-ranged lower bandwidth, wireless technologies **(Conser et al., 2007).**

5.10.5. Flow Assurance in the Lower Tertiary

The Lower Tertiary Trend encompasses the Upper Paleocene and Lower Eocene of the Lower Tertiary and ranges from approximately 12,000ft to 35,000ft below the sea level in water depths between 4,000ft and 10,000ft. The Lower Tertiary Trend begins in the western GOM in the Perdido Fold Belt in Alaminos Canyon, and moves east into Keathley Canyon and Walker Ridge. It may also include portions of East Breaks, Garden Banks, Green Canyon, and Atwater Valley **(Figure 54).**

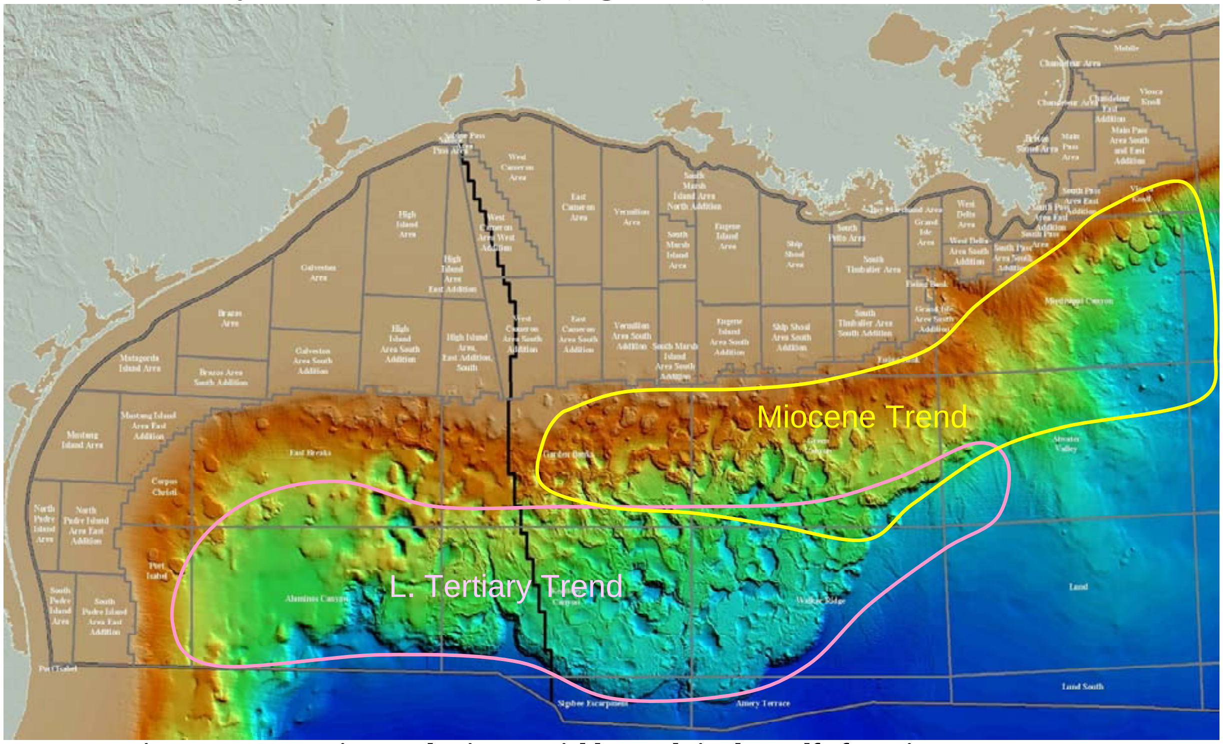


Figure 54: L. Tertiary and Miocene Field Trends in the Gulf of Mexico Deepwater

Exploration and drilling in the GOM's Lower Tertiary has steadily increased since 2001, with 15 discoveries out of 36 exploratory wells, a 42% success rate and reserves totaling 3.5 billion barrels of oil recoverable. The estimated potential of the trend is up to 15 billion barrels. Some of the key discoveries to date are: Perdido, Chinook, Cascade, St. Malo, Jack, Kaskida and Tiber. Perdido was the first Lower Tertiary production to come online in early 2010. The trend is widely seen as the next frontier in the GOM.

The Lower Tertiary has unique physical characteristics which can magnify current flow assurance challenges and require new, innovative solutions. The main challenges of the Lower Tertiary are **(Dewalt and Shields, 2010):**

- Reservoir Depth, both below sea level and below mudline. Increased depth increases the static pressure that must be overcome in order for the well to flow. This means that some type of artificial lift will likely be required.
- Less favorable porosity and permeability. When targeting high production rates, downhole pressure losses increase, making less pressure available to overcome the static pressure. These low flowrates make it difficult to flow at the necessary rates to pay out the upfront capital investment.

- High Density Crude with low GORs and bubble points. These properties make the oil viscosity higher increasing the pressure drop in the subsea system.
- Can be highly fractured with little aquifer support. This can result in a rapid depletion of reservoir pressure.
- Higher pressures and temperatures. While higher pressures and temperatures can help maintain production rates and reduce the risk of hydrates and wax deposition, it may push the limits of materials used in subsea systems. Pressures go up to 20,000psi and temperatures are up to 400 deg F.

All of the challenges described highlight the importance of subsea architecture and underscore the need for these technologies to develop to make the Lower Tertiary a viable play.

5.10.6. Completions

The increasing number of deepwater discoveries has led the energy industry to develop new completion design technologies for challenges that did not exist in the oilfield less than a decade ago **(Ceccarelli et al., 2009).** The focus today is on subsea wells and design processes that differ from conventional completions. Given the costs of operating in deepwater, completion installations account for significant portion of the risk capital. As such it is important to ensure, reliable, flexible and efficient designs. As wells are drilled to even greater depths, in deeper water, tighter rocks and in HP/HT environments, continued project success will depend on future technologies in the completion arena.

Standalone screen completions are one emerging technology that may replace gravel packing which can be expensive and time-consuming to execute **(Ceccarelli et al., 2009).** The new generation of screen technology resists plugging for a broader range of sand sizes and overcomes some of the traditional limitations of standalone screen completions **(Probert, 2009).** Standalone screens can be combined with multilateral drainage architecture for deepwater development and can create a step change in cost reduction. Although, these multilaterals have been successful in the North Sea, case histories in deepwater exist only for the last 5 years. As the reliability of this technique proves itself, its application window will broaden **(Ceccarelli et al., 2009).**

H**orizontal open hole screen completions** have gained acceptance since the early 1990's in high-permeability soft rock completions of the Gulf of Mexico, due to the higher production rates and increased percentage of recoverable reserves **(Foster et al., 1999).** However the number of failures experienced, ranging from 20 – 25%, raised concerns about reliability of this type of completion. Screen plugging, incorrect procedures, and poor understanding of the reservoir were three main failure mechanisms identified

(Foster et al., 1999). Once resolved the number of successful installations in the Gulf of Mexico increased.

An SPE paper published in 1998 talks about the first extended horizontal openhole completion located in the Viosca-Knoll Block in 3214ft of water. The lateral length was 2400ft. This completion offered a solution that combined gravel packing, enhanced downhole tool capability, and advanced fluid technology and proved the gravel packing can be successfully applied to extended horizontal wellbores **(Duhon et al., 1998).** Openhole and horizontal completions are finding increasing application in subsalt and presalt reservoirs as well as in the traditional turbidite reservoir that have been the main-stay of deepwater development **(Probert, 2009).**

In the more recently discovered, potential world class L. Tertiary trend, fracture technology will play an important role in unlocking the hydrocarbons from these lower porosity, low permeability rocks. Much work remains to fully understand the potential of this trend such as some long term production, but evaluation to date indicates that many of the fields will require fracturing and proppant to produce commercial quantities.

To economically develop the growing L. Tertiary play trend in the Gulf will require some new completion technologies to handle the long, stacked pay intervals seen to date in the discovery wells. In these reservoirs the most effective treatment is perforating, isolating and stimulating each zone independently. This is a time consuming process involving many trips in and out of the well. This has generated renewed interest **in multi-zone completion technology** that will increase completion efficiency and reduce completion cost. As a result, a robust, cased-hole, single-trip, multi-zone frac-pack completion system has been developed. This renewed interest has also been the driving force behind the development of an openhole multiple-zone frac-pack completion system that could reduce well construction costs **(Burger et al., 2010).**

The single-trip multi-zone completion technology has evolved through four generations over the last 28 years. The generation IV system focuses on today's frac-packing which requires higher pressures, higher pump rates, higher proppant placement, and capability to frac-pack longer intervals **(Burger et al., 2010).** There are several systems on the market**.**

Alternate Path Gravel Packing

This technology is not new, but could see new applications in the Lower Tertiary where long stacked pays are expected and where pump rates during gravel packing may be limited due to small casing and/or high downhole pressures. In these scenarios, premature screenouts can leave voids in the gravel pack creating the potential for screen failure during production. Alternate gravel pack technology uses shunt-tube technology to fill in these voids to fully protect downhole equipment.

High Pressure High Temperature Completions

The Gulf of Mexico is full of challenges for operators as the search for oil and gas is becoming ever more extreme in terms of depth, pressure and temperature. The recent L.

Tertiary oil and gas trends in the GOM drive this issue home, with the challenges of **high pressure, high temperature wells** that pose drilling and completion issues requiring new technologies for casing, tubing, fluids, packers, perforating equipment, BOPs, safety valves, and intelligent well monitoring. The most extreme environment seen to date in the Gulf of Mexico is that of the recent L. Tertiary ultra-deep Davy Jones gas discovery. This 2 TRILLION CUBIC FEET potential field has reservoir conditions that could exceed 400°F and pressures of 25,000psi.

The traditional understanding of HP/HT applications, 10ksi and 250° F (Tier 1), are common in today's market. The HP/HT working envelope has been successfully pushed out to 15ksi and 400° F (Tier 2), with some limited gaps related to completion size availability rather than technology needs. Now, this envelope is being pushed out further to 20-30ksi and 400-500° F (Tier3) **(Figure 55)**. The technology gaps associated with this latter frontier include casing, tubing, connections, fluids, packers, seals, perforating equipment, BOPs, safety valves, wellheads, trees, and intelligent well systems **(Maldonado et al. 2006).**

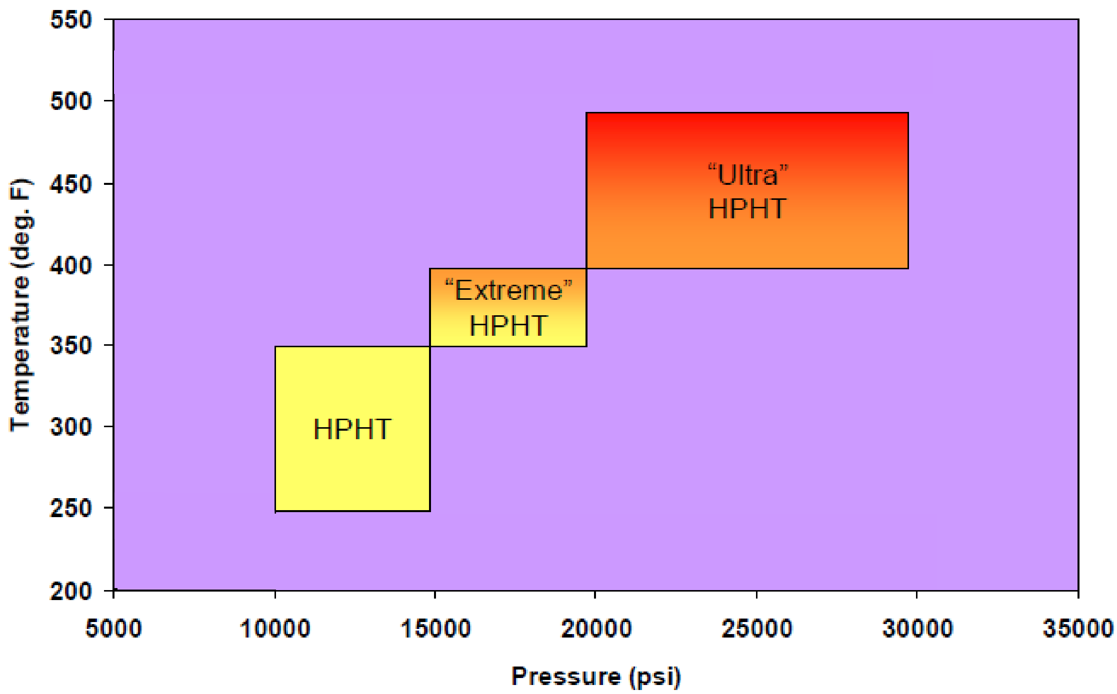


Figure 55: HPHT Classification Scheme
(adapted from Maldonado et al, © 2006 OTC. Reproduced with permission of the copyright owner. Further reproduction prohibited without permission.)

Casing/Tubing/Drillpipe/Connections – At temperatures in the 400 – 500° range, many common metals will have reduced strengths. The more extreme environments may require different metallurgy. Corrosion is also a major issue in

HPHT wells. Strict procedures and inspection will be required to ensure the manufactured tubing and casing are near-perfect to realize it high resistance to corrosion.

Pumping Equipment – In October 2009, BJ Services launched the world's largest stimulation vessel specifically for Lower Tertiary formations. The Blue Dolphin provides 20,000 psi pressure rating for these conditions, including long multiple pay zones, and intense pressure and temperature variations.

Completion Fluids – Calcium and Zinc based completion fluids have been widely used but are limited on a number of factors including weighting ability, and potential corrosion, environmental issues with the zinc based fluids. Cesium formate brine is a preferable choice not only for its weighting ability for higher pressure wells, but also because it does not have the corrosive and environmental issues associated with it. Availability is the main limitation with this fluid.

Packers – 20 ksi 450^{o} F permanent and 15ksi 350^{o} F retrievable packers have been developed, with 25ksi 500^{o} F perm. packers under development. There are considerable gaps in technology in the 30ksi and 400-500^{o}F Tier 3 arena.

Seals – Existing seal technology seems to be reaching its design limits in the 450^{o}F range. New seal technology will be required in the new frontier of 500^{o}F and 30ksi. Metal-to-metal seals will replace elastomers.

Perforating – In 2009, Halliburton announced the first 30,000psi perforation gun system which can perforate high-strength thick casing to deliver larger hole sizes for fracture jobs. A new high-temperature explosive, called HTX has a 1-hr temperature rating of 500 deg F and have recently been tested to 440 deg for 200-hrs continuously.

BOP's – Higher shear capability is needed due to new regulations on calculating required shear force (i.e. must assume no tension) and because thicker walled pipe may be required for higher pressure wells.

SCSSV's (Surface-Controlled Subsea Safety Valve) – 20ksi 400^{o} F safety valves are available and industry is developing 25ksi SCSSV's.

Subsea Trees – Trees, manifolds, pipeline end terminations (PLETs) rated to 15,000psi currently exist. Industry operators will be working with vendors to obtain 20ksi trees, meeting new BOEMRE analytical requirements for equipment exceeding 15 ksi working pressure.

Downhole Injection – The ability to inject chemicals downhole will become more difficult as injection pressures will increase. This will be an important feature of HPHT wells as asphaltene or scale interfere with other downhole equipment such as the subsurface safety valve.

Smart Well Technology – Smart well systems equipped with remote downhole flow-control devices are limited to **15,000psi? (Maldonado et al., 2006).**

Annular Pressure

HPHT wells also complicate the issue of annulus pressure build up. Trapped fluid in the annulus of subsea wells can cause casing strings to fail during production due to the heat transfer of the produced fluids to the casing strings. This heat transfer causes the temperature of the annulus fluids to increase and in turn builds pressure. In onshore wells and dry tree wells, this pressure may be bled off through accessible wellhead equipment. However, in subsea completions bleeding through outer annuli may not be possible. Deepwater developments are more susceptible to annulus pressure issues due to the temperature differential between the cold mudline temperature and the hot flowline production temperatures. **(Williamson et al, 2003)** There are several mitigation techniques currently in use including foamed cement jobs that allowed a more compressible annulus and vacuum insulated tubing that inhibits heat transfer. Emerging technology in this area will focus on the development of annulus / shrinking fluid types that are more compressible and/or more insulating as well as the development of systems which allow for pressure mitigating chambers.

Well Intervention

In deepwater fields, with subsea completions tied back to hubs, there are high costs associated with re-working wells to keep them producing, due to the need for an expensive drilling rig equipped with a riser. As a result industry has been pursuing some alternative solutions. Intervention work can generally be divided into 3 broad categories:

Light – Riserless
Medium – Rigless
Heavy – Rig

Meeting the need for a cost effective light system is **Riserless Light Well Intervention (RLWI)**. These interventions can be performed from a more economic monohull vessel without a marine riser**.** In the North Sea RWLI has now established itself as a field-proven method for wireline intervention in subsea wells. With regular operations since 2006, a statistically significant number of well interventions have been performed **(Sten-Halvorsent et al., 2010).** In February 2010 ATP and Blue Ocean announced records set for riserless light well intervention in the Gulf of Mexico with work on two production wells in 2950ft of water and 9000 ft downhole. The workover involved numerous wireline runs deploying a wireline tractor, gauges, milling tools, perforating guns and logging tools multiple times **(Crawford and Still, 2010).** At this time the technology offers only the possibility to run wireline operations and operations have been typically limited to vertical subsea tree applications, as opposed to horizontal subsea trees which require removal and replacement of large OD wireline retrievable tubing hanger or “crown” plugs. The application of **RLWI** in water depths greater than 3000ft is an area needing technology development. Currently two deepwater units are “rated to” 10,000ft water depth, but unproven at > 3000ft.

For **medium well intervention cases**, where circulation is required, a **"Non-Drilling" MODU / Workover Intervention Vessel** is warranted. It utilizes a workover riser system (4.5" – 6" ID). Compared to a drilling MODU it has a lower dayrate, improved workover efficiency (crews, deck space, switching tasks) and smaller riser – easier to handle, but can't pull tubing (except P&A). Currently only 2 vessels fit this category for deepwater, with one having provided interventions in up to 5300ft of water to date. The Q4000 vessel will have 8000' intervention capability by the end of April 2011, due to upgrade of the subsea control system. Both vessels have slick line, electric line and coiled tubing capabilities. Capabilities with medium intervention include: logging, perforation, downhole valve - retrieval, replacement, shifting, pump change-out, and stimulation and cleaning of the well bore.

Deepwater **heavy well interventions** are currently provided by a **semi or drillship MODU.** They are capable to > 7,500ft of water and utilize a 21in. marine riser & subsea BOP that allows the operator to pull tubing. In addition to capabilities listed for medium intervention, heavy operations also include scale milling, completion change-out / repair, re-drill or sidetrack, and tree change-out.

Due to the costs associated with drilling MODU's and the need for a circulation capable system, several more economical coiled tubing technologies are currently under development. One approach of note is Research Partnership to Secure Energy for America (RPSEA) project 1502 conducted by Nautilus International LLC. The objective of this project is to develop a practical, cost–effective downhole intervention system for deepwater satellite subsea wells. The system is comprised of a reusable **self standing riser (SSR)** and a cost effective vessel (not a conventional drilling rig). The SSR would attach to the subsea tree and provide the access and circulation conduit for the coiled tubing or wireline intervention system back to the vessel **(Figure 56).**

With the hope of minimizing or avoiding intervention all together, over the last decade there has also been a move toward intelligent well technologies, which are discussed in more detail in the next section.

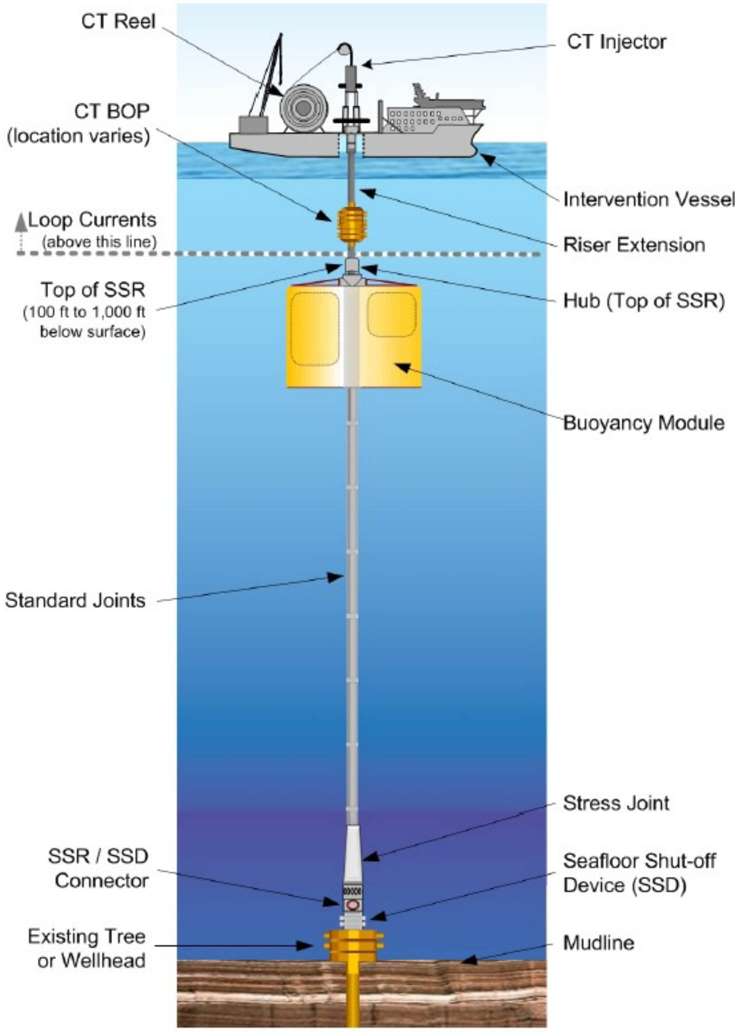


Figure 56: Overview of SSR system with Intervention Vessel (Yemington, 2011)

5.10.7. Digital Oil Field Technology (E-Field)

As we push exploration and development into deeper waters, arctic environments and unconventional resources, industry will increasingly rely on digital technologies to allow decision making and execution to begin remotely, with the ultimate goal of optimizing and maximizing production, improving capital efficiency while minimizing safety hazards**.** This technology includes automatic, real-time, remotely controlled operations and intervention with minimum human involvement. Over the past few years the "digital oil field/E-field/I -field" has moved from research to early application. Early digital oil field technology began with digitization of operational data that were previously collected manually. Instrumentation at well sites and SCADA systems enhanced the data capture aided by improvements in telecommunication. These changes enabled access to data previously unavailable, or under the most favorable circumstances, were available through indirect processes that were prone to errors. Data capture increased many fold and databases for drilling and production information were necessary to effectively process and store the volumes **(Sankarin et al., 2009).**

The next technical jump took place as a result of several factors in the late 1980's:

- Production decline in the first generation of subsea wells and the challenge to restore rates
- Planned deepwater subsea wells where intervention would be expensive
- Drilling technology that was leading to horizontal, multilateral and extended reach wells.

The challenge was to produce, monitor and control the production through remotely operated completions systems without costly intervention. This technology became known as the "intelligent well" or "smart well" and culminated with the installation of a surface controlled reservoir analysis management system in 1997 **(Mathieson, 2007).**

The key component to an intelligent well is the aptly named **intelligent completion.** This is a large category which includes using technologies to make completions more flexible. Early realization of the benefits of the digital well came from LWD and MWD logging tools that could be viewed and analyzed real-time by experts at the main office 1000's of miles from the actual sight. Decisions and corrective actions could be made and submitted to the well site directly without wasting time. Similar application of this technology can and is now being made to the completion and production side. The big difference is that completion and production operations last years, so systems will have to be operational for longer periods of time. The first of these completion technologies were integrated electrical or electrohydraulic systems that included both sensing and control capabilities. They were costly and complex, and yielded many early failures. As a result many operators were not convinced of the value. The reliability and economic viability hurdles spanned the first 5 years of development and led to the second generation development decisions: All-hydraulic solutions to minimize risk and simple open/close control in subsea wells to avoid intervention. From 1998 – 2003 most intelligent well installations were this type and applied primarily in the North Sea and GOM. With reliability concerns abated, attention shifted to production optimization. This led to internal-control valves, and while remaining hydraulic, allows finer adjustments to the flow of fluids into or out of multiple reservoirs, without the need for intervention. Although reliability is high with current hydraulic solutions the need for multiple umbilicals and connectors limits well-architecture complexity. In deepwater this can cause concerns with running successful completions. R&D efforts are shifting to address these challenges, resulting in new connector solutions, connectorless solutions built on cableless technology and interest is again rising in developing reliable all electric solutions **(Mathieson, 2007).** Together these efforts will allow for a more responsive digital field and will help as we move to more extreme environments.

Also of note, current technology allows for multiple flow-control devices as long as gravel pack equipment is not used. Only two remote flow-control devices can be used along with gravel pack assemblies due to hole size requirements. Future technology will likely not include the ability to remotely operate more than two valves unless more cost effective means of increasing hole size such as dual gradient drilling are achieved first.

Downhole monitoring technologies are critical components when optimizing productivity and recoverable reserves over the life of the well. In addition to real time optimization of production and injection, downhole monitoring can also provide the basis for well diagnostics. Traditional downhole monitoring of subsea wells has been achieved through the use of permanently installed analog electronic strain gauges, first installed in the 1980s. This was replaced in the early-mid nineties with digital electronic gauges based on quartz and sapphire transducer technology which have been deployed regularly in the deepwater environment. Today, the oil and gas industry is witnessing the emergence and adoption of the new generation downhole monitoring sensors, based on fiber optic technology. These include pressure/temperature gauges, multiphase flowmeters, distributed and multi-point temperature sensing and multi-component seismic sensors. Hundreds of optical sensors have been successfully deployed in land and dry tree platform oil and gas wells since the early 1990's, and are now moving into subsea wells. In 2008, the optical sensing system was successfully deployed and tested in a subsea well located 135 miles offshore Angola **(Shand et al., 2009).** Fiber optics have significantly improved measurement reliability and stability and the applications for downhole flow data are numerous **(Drakeley et al., 2006).**

Since the most often cited reason for running intelligent wells is the subject of intervention avoidance, reliability of the smart well technology is critical. The downhole equipment such as safety valves, gauges, sliding sleeves, allow control of flow, monitoring, and communication from wellbore to platform. Currently almost 86% of intelligent wells have experienced no failure. But most would agree that the number of failures should be even lower to consider the technology mature. If failures occur they tend to be with electronic gauges due to severe downhole conditions such as temperatures **(Ageh et al., 2010).** Thus reliability of intelligent completions in deeper formations should be an area of focus.

One technology that could provide benefits to extended architecture and E-fields is the use of Electromagnetic (EM) waves (wireless) to power downhole equipment. Over the last 35 years there have been attempts to use EM waves to communicate with and power downhole equipment that has ranged from gauges to chokes and **Surface Controlled Subsea Safety Valves (SCSSV)**. There has been some success with gauges, but almost all of this equipment has required a downhole power source (such as a battery), consequently run life is short. A number of companies have spent considerable resources trying to overcome signal to noise ratios, power consumption, ease of use and service life. Some in industry feel that these obstacles will be overcome in the next decade and powering downhole equipment with long wavelength AC power will be achieved.

The infrastructure of highly instrumented wells and surface facilities, power, and advancing network and control technologies, has set the stage for true field automation **(Paul, 2007).** Today's intelligent completion system has three main components: sensors (permanent downhole gauges, flowmeters, and densimeters at points along the reservoir face to monitor conditions), an integrated data base and analysis computer to collect and evaluate sensor output (analysis), and internal control valves to control flow from various reservoir points. As field wide application of these technologies has become more typical there still remains a challenge to bring them together for field specific solutions that span all environments and generations of surface facilities where it may be applied **(Mathieson, 2007).**

To insure the infrastructure truly meets the business needs, the following criteria are crucial: 1) Data and information must be easily delivered, visualized and analyzed by decision makers, 2) Analyzed data and decisions must be easily delivered back to the field. 3) There must be seamless interfacing between applications, visualization tools, vendors and service providers. Infrastructures need to address people, processes and technology **(Moon and Hite, 2009).** With this accomplished, true oilfield automation and optimization can provide an essential technology lever to meet the increasing economic pressures for operating cost reductions with mature producing assets and improved capital performance for major product developments **(Paul, 2007).**

5.10.8. The Field of the Future

Jim Crompton, Chevron and Helen Gilman, SAIC, gave a presentation at the 2010 SPE Intelligent Energy Conference on the status of Chevron's Integrated Operations (IO)program now in its 9th year. They closed their presentation with the illustration below of one possible future scenario for a Deepwater Gulf of Mexico digital oil field and how integrated operations will evolve. We are moving beyond simple open close solutions and responding to alarms. Our focus will be to optimize production by directing resources to the highest value activities and through better and faster decisions. Many will say we are not far from this today **(Crompton and Gilman, 2010)**.

5.10.8.1. Infrastructure – Hub over an anchor field with a number of smaller fields nearby that are tied in initially or brought on line as the key field is depleted. The satellite fields are produced via subsea completions and long tie backs. The subsea manifolds are equipped with remote power and communications capabilities, so remote surveillance and control functions are available at the hub as well as at an onshore Production Optimization Center, where a technical asset team resides.

Chemicals for flow assurance intervention and other materials for inspection and repair are stockpiled at the subsea manifold. Remotely Operated Vehicles (ROV's) are capable of doing much of the work routine. Smart equipment is deployed on the sea floor and downhole to respond to changing reservoir and well bore conditions, including changing of reservoir zones with depletion, shut off of water or gas, changing injection patterns, and dealing with sanding or scaling problems near the completion face. The smart system can accept commands from the offshore hub platform or onshore center, or can react to emergency situations through embedded operational rules.

5.10.8.2. Daily routine – Monitoring and maintenance duties are largely automated to keep offshore staff to a minimum. The asset team has the ability to completely operate the facility from a shorebase if necessary due to a storm or other situations where it's not advisable to have staff offshore. The offshore staff is busy with smaller tasks and optimization activities. Collaboration capabilities link the onshore and offshore staff, with all asset operation's information available to each.

<u>5.10.8.3. Integrated models</u> – Sophisticated models of the reservoir, well and processing systems are kept up to date and running online so that surveillance is a "manage by exception" process. Field optimization is regularly reviewed and based on analysis of alternatives, economic and technical, so that asset managers can make decisions bringing the highest value when opportunities are encountered, instead of just producing to a plan that may be months to years old.

<u>5.10.8.4.New Company Culture</u>- From a company perspective the operation is not a unique experiment. Although, each asset has been configured to take advantage of the specific conditions for each asset, the operations flexibility is due to a wide deployment integration environment, with robust standard solutions for core processes, data integration, and information visualization. Communities of practices routinely use the information gathered for training of new staff as well as studies to develop better ways of working.

<u>5.10.8.5. Regional Centers of Excellence</u> – For support and trouble shooting any unusual problems for the asset team due to economies of scale available in the Integrated Operations environment. These centers serve as a collaboration link for outside experts, suppliers, partners and regulatory bodies so they can connect to key meetings, audit procedures or participate in technical studies

BP has initiated a similar program to Chevron's Integrated Operations called the **Advanced Collaborative Environment (ACE)** for real-time drilling and production operations worldwide.

<u>5.11. Enhanced Oil Recovery (EOR)/Improved Oil Recovery (IOR)</u>

(By Paul Schlirf)

As can be expected, the big hydrocarbon discoveries generate all the excitement in industry. The world is certainly captivated by the recent subsalt discoveries in deepwater off Brazil, the new trends playing out in West Africa offshore, the deepwater GOM L. Tertiary, and onshore shale/gas, shale/oil plays, but the fact remains that 70% of the hydrocarbons produced today come from mature fields. As we spoke about earlier, most of the world's giant oil fields were discovered by the 1970's and we have been in a gradual decline since that time with the reserve volume adds, hopefully some leveling off, as a result of the new trends mentioned above, but in addition to alternative energy sources and access to new areas, what are some other solutions to slowing the decline in energy supply.

A general rule of thumb is that 30 – 35% of the original oil in place will be recoverable by the end of the normal production period. In some environments it may be as little as 10%. This leaves anywhere from 65% – 90% of the oil originally in the discovery remaining in the reservoir. Reasons for this include:
lack of reservoir drive, poor sweep efficiency, compartmentalization, and mechanical failure due to compaction.

Considering the quantities of remaining oil in place, boosting the recovery factor of world's fields just 1% has the potential to cover 3 years of worldwide production **(Ali, 2009).** As such mature and new fields have the potential to contribute significantly to future reserves, given they can be optimized. The term used for this increased productivity of hydrocarbons is known as Enhanced Oil Recovery (EOR) and Improved Oil Recovery (IOR).
Technology for these types of recovery processes are already in place at many fields around the world, with EOR primarily onshore. For the purposes of this paper, techniques for EOR are a subset of IOR that deal with the total reservoir and are designed to lower the residual oil saturation below that attained by a conventional waterflood. They include CO^2, N^2, and chemical injection, and steam flood (including in-situ combustion). Techniques for IOR, would then include: waterflood, subsea processing and pumping such as sea floor separation, gas lift, multiphase pumps, and electric submersible pumps (ESPs), horizontal and multilateral drilling to expose more of the formation or multiple formations to the open hole, improved perforation and stimulation methods, advanced logging procedures and optimal placement of wells **(Ali, 2009).**
Although these processes have already begun in the GOM, much more remains to be accomplished. Offshore lags far behind onshore in EOR usage, due to the cost of drilling additional wells for injection and infrastructure costs that include transportation of injectants such as methane, CO^2 and Nitrogen from nearby fields or onshore and producing facility modification costs. It also lags behind in older fields where IOR technology was not available at inception or general reluctance to apply newer technology due cost concerns.

Knowledge Reservoir has compiled an excellent report on IOR and EOR for the **Research Partnership to Secure Energy for America** (**RPSEA**) **entitled "IOR for Deepwater Gulf of Mexico", Project 07121-1701, December 15, 2010. The discussion that follows comes directly from that report.**

Utilizing data from more than 80 fields and 450 reservoirs developed in the deepwater GOM, for the scoping potential of this study, Knowledge Reservoir estimates the remaining oil in place target for improved and enhanced oil recovery is large, with about 44 billion barrels estimated to be left in discovered fields at abandonment. 21 bboe of this remaining oil is from Neogene age (Miocene, Pliocene and Pleistocene) reservoirs and 23 bboe from Paleogene age (Lower Tertiary). This is a sizeable amount and an important target for IOR..

The mature production experience in the deepwater is from Neogene age (Miocene, Pliocene, and Pleistocene) reservoirs. The forecast oil recovery ranges from 16% -32% -

48% (P90-P50-P10), with waterflooded reservoirs excluded. Due to typically over-pressured and highly compacting reservoirs, water injection has been implemented in only 12 fields, and in many of these fields only minor water was injected. Water injection projects have in general been very successful in achieving oil recovery greater than 45%.

The Paleogene (L. Tertiary) reservoirs are in the exploration and appraisal stage, with only the Great White,Tobago and Silvertip fields, jointly the Perdido development in Alaminos Canyon, starting production in 2010. Most of the discovered OOIP in Paleogene age reservoirs is in the Keathley Canyon and Walker Ridge protraction areas, with more challenging rock and oil properties than the shallower pay zones at Perdido. For fields in these areas, the forecast of primary recovery is only 10% of OOIP.

Some care must be taken with the target number in the younger Neogene reservoirs, because they tend to be small, 4 of 5 contain less than 56 MMSTB of OOIP. The top 25 reservoirs, only 5% of reservoirs, contain 50% of the oil in place. As a result, given the high cost of the deepwater environment, this has huge impact on the economics of improved oil recovery. The list of potential candidates for IOR/EOR projects would be impacted. Different types of IOR would need to be considered depending on reservoir size with only low cost solutions considered for small reservoirs. However, even with these caveats, there remains a significant portion of the Neogene OOIP that is a candidate for IOR/EOR.

To determine the IOR needs for deepwater reservoirs an analysis of oil trapping mechanisms or the reasons oil is expected to be left behind was made. The results of that analysis for Neogene and Paleogene reservoirs is shown in **Figures 57 & 58** with percentages of Ultimate Recovery (EUR), and remaining oil by trap mechanism.

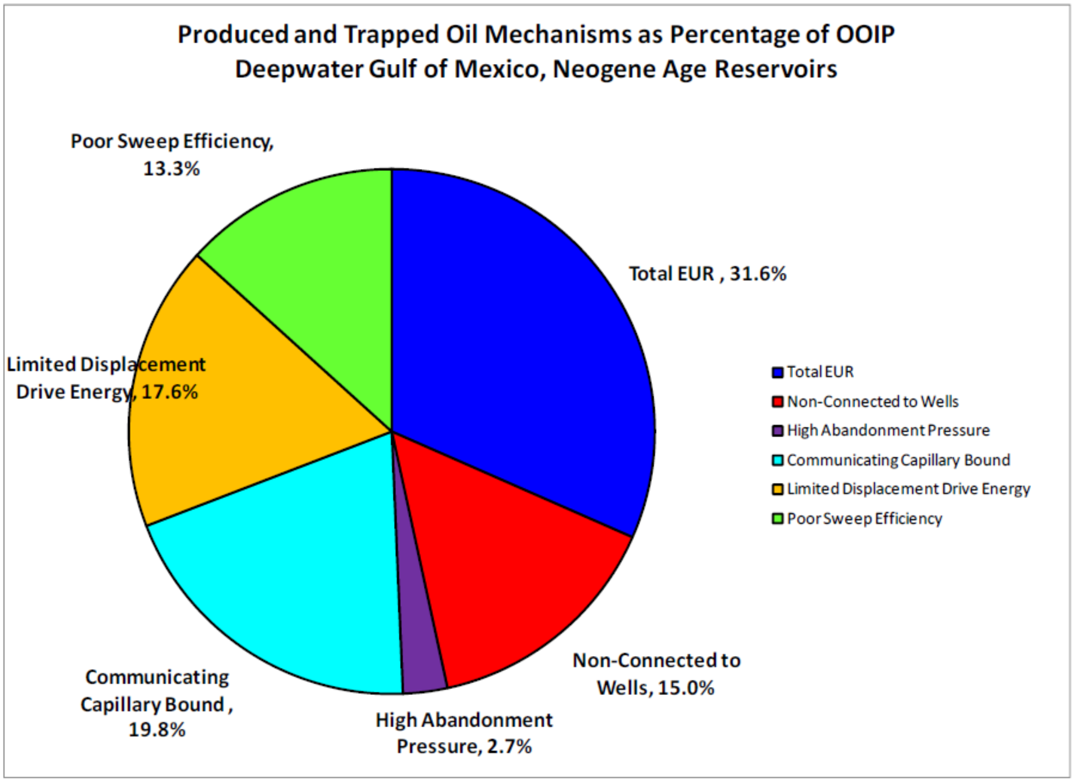


Figure 57: Neogene trapped oil as % of original oil in place (OOIP), (RPSEA 07121-1701, 2010)

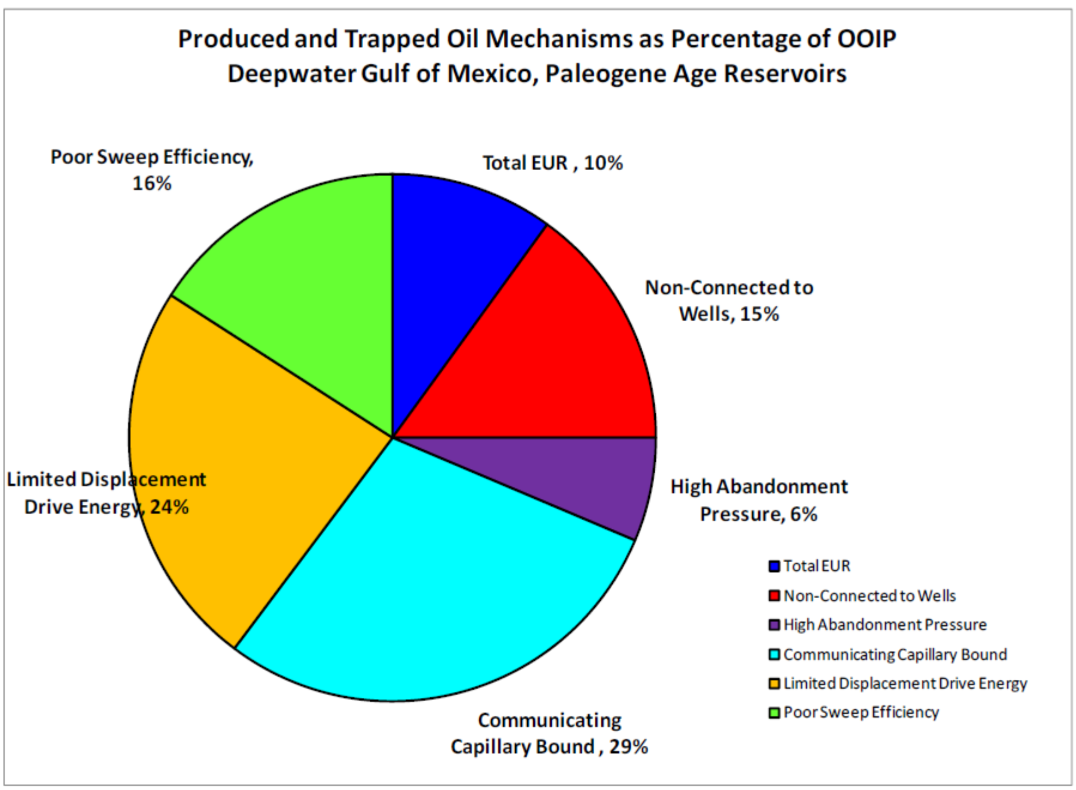


Figure 58: Paleogene trapped oil as % of original oil in place (OOIP), (RPSEA 07121-1701, 2010)

From the analysis of oil trapping mechanisms, several themes emerged for Neogene and Paleogene IOR potential

5.11.1. Neogene

1. There is a need to add reservoir energy to displaced trapped oil for limited drive energy and poor efficiency sweep. Water injection is most favorable due to the robust gas sales infrastructure.
2. There is a need for well technology or lower cost wells to target small fault blocks with stranded oil or the OOIP "non-connected to wells."
3. Subsea boosting and artificial lift are key IOR technologies for optimizing primary production and enhancing secondary recovery permitting flow to higher water cut.
4. Hybrid technology, a low cost addition to water or gas injection, is needed to displace capillary bound fluid. Leading alternatives are low salinity water injection or microbial EOR.

5.11.2. Paleogene

The Paleogene reservoirs in Keathley Canyon and Walker Ridge have significant oil recovery challenges, and there is currently no producing experience from these reservoirs. No suitable analog has been found to benchmark expectations of reservoir performance. The development risk is high due to reservoir depth, high pressure, high temperature, complex geology, and rock and fluid properties.

A forecast was made of trapped oil mechanisms for the Paleogene reservoirs in Keathley Canyon and Walker Ridge **(Figure 58).** A total of 21% of OOIP is left behind due to non-connected reservoir to well and high abandonment pressure. An additional total of 69% of OOIP is forecast to remain after primary production practices due to limited drive energy, capillary bound fluids, and poor sweep efficiency. Based on the study of oil trapping mechanisms, several themes for Paleogene IOR were identified. They include the following:

1. Similar needs to the Neogene are adding reservoir energy, for well technology, and for subsea boosting and artificial lift
2. Technology is needed for cost effective reservoir management and improvement of sweep efficiency from a thick, heterogeneous reservoir.
3. Advancement in hydraulic fracturing are required to enhance well productivity and injectivity for deep (>20,000 ft) reservoirs with permeability below 30 mD.

The following section will show detailed results of IOR processes that were reviewed to determine the range of incremental recovery potential with the various options and the technical readiness. IOR concepts were developed separately for the Neogene and Paleogene. A total of 19 concepts were evaluated for the Neogene and 10 were evaluated for the Paleogene. Each process was evaluated for a high and low incremental recovery factor, target number of field applications, and OOIP, technical readiness factor and ranking based on risked IOR potential. Economic evaluation has not been included since each field application would require specific review.

The Deepstar Technical Readiness Factor (TRF) was selected for use on determining the risk for applying various IOR technologies. Deepstar TRF was adapted to fit the RPSEA 1701 project since it is normally applied to hardware and equipment used in the field. The TRF is an 8-level grading system, with TRF 0 an unproven idea through TRF 7 a proven and deployed technology. **Table 1** shows the Deepstar TRFs and adapted RPSEA 1701 TRFs that apply to IOR processes. These adapted TRFs now range from unproven idea to deepwater field proven.

		DeepStar		RPSEA 1701	
Category	Level	Name	Definition	Name	Definition
Conception	TRL 0	Unproven Idea	A technical need is identified and a concept conceived	Unproven Idea	Observed potential in core analysis or field observations but no field pilots with positive results
Proof-of-Concept	TRL 1	Proven Concept	The concept has been refined to where the basic physical properties developed and documented	Concept with Onshore Pilot / Lab Testing	Concept with lab evaluation, flow loop testing, formulation of basis of design, and possibly some field pilot testing
	TRL 2	Breadboard Demonstration	Concept is developed into an ad-hoc system to test if components work together	Onshore Pilot Field Implementation	Technology has been pilot tested and implemented to some field-wide projects with some success
Prototype	TRL 3	Prototype Tested	The technical specifications are developed further and a prototype has been developed	Onshore Proven Technology	Technology is well established and proven in onshore fields
	TRL 4	Environment Tested	The technology meets criteria of TRL3 and testing is conducted in simulated environment over its full operating range	Offshore Tested with Limited Experience	Technology has been used onshore and tested in offshore fields but with limited operational experience
	TRL 5	System Tested	The technology meets criteria of TRL4 and is integrated into its intended operating system but the test environment may not be field realistic	Offshore Proven - Different Environment	Technology is proven offshore in <1000 ft water depth and in lower reservoir pressure/temperature regimes as observed in the deepwater GoM
Field Qualified	TRL 6	Technology Deployed	The technology has been deployed in the field but has insufficient track record of reliability	Deepwater Deployed with Limited Experience	Technology tested with limited experience in the deepwater GoM. Or the technology has been successfully deployed in other deepwater basins but under different conditions
	TRL 7	Proven Technology	The technology has been deployed in the field and has successfuly operated with good reliability for >10% of expected life	Deepwater Field Proven	Technology field proven in deepwater and in environmental conditions similar to those observed in the deepwater GoM

Table 1: Deepstar technical readiness factor (TRF) adapted for RPSEA 1701 (RPSEA 07121-1701, 2010)

Table 2 shows the technical readiness factors for Neogene IOR processes. Conventional water injection is ranked at the top since it has been applied already in a number of deepwater fields. Equally high is subsea multi-phase pumping. Ranking close in readiness are in-well ESP, in-well gas lift, subsea processing (subsea separation and pumping, Perdido development) and horizontal wells. At the bottom are hydrocarbon gas dump flooding and low cost wells which are unproven ideas.

IOR Category	IOR Process	Applications	TRL	Name	Definition
Water Injection	Conventional Water Injection	Horn Mountain, DW GoM, Waterflood Performance (AAPG Bulletin, v. 91, no. 6 (June 2007). Schiehallion Field, West of Shetlands, UK (GCSSEPM, Dec. 2008). Knowledge Reservoir review of waterflood experience in DW GoM (presented at RPSEA Committee Meeting, 16	7	Deepwater Field Proven	Technology field proven in deepwater and in environmental conditions similar to those observed in the deepwater GoM
	Seafloor Water Injection	Tyrihans Field, Offshore Norway (OTC 20078) Columba Field, North Sea (SPE 109090) Barton Field, Malaysia (SPE 88568) (Evaluation study) Albacora Field, Brazil (OTC 20186) (Plan implementation)	4	Offshore Tested with Limited Experience	Technology has been used onshore and tested in offshore fields but with limited operational experience
	Aquifer Dump Flooding Injection	October Field, Offshore Egypt (SPE 112311)	4	Offshore Tested with Limited Experience	Technology has been used onshore and tested in offshore fields but with limited operational experience
Water-Based EOR	Low Salinity Water injection	Moran / North and West Semiek Fields, Wyoming (Coreflood results) (SPE 109965) Endicott Field, Alaska North Slope (SPE 113480, 2008) Coreflood Experiments (Lager et al., 2006) Coreflood Experiments (SPE 129012, Ashraf et al., 2010)	2	Onshore Pilot Field Implementation	Technology has been pilot tested and implemented to some field-wide projects with some success
	Microbial EOR	Norne Field, Norwegian North Sea: Forecast IOR = 3% of OOIP Beatrice, Ninian, Murchison Fields, North Sea: Early 1990's trials Phoenix / Mink Unit pilots, Oklahoma (SPE 27751): IOR = 0.2-1% of ROIP	3	Onshore Proven with Some Offshore Testing	Technology is being tested offshore but has mixed history of success and failurre; pick average between 4 and 2.
	Alkaline Surfactant Polymer (ASP)	Minnelusa Fm, Wyoming: Tanner, Cambridge, West Kiehl and Mellott Ranch fields (SPE 24144, SPE 113126, SPE 55633) Daqing Field, China (SPE 84896, SPE 114343) La Salinas Field, Venezuela: Offshore ASP project planning (SPE 84775)	3	Onshore Proven Technology	Technology has been pilot tested and implemented to some field-wide projects with some success
	Chemical Augmented Waterflooding	Limited recent experience of chemical flooding	2	Onshore Pilots and Field implementation	Mature technology but mixed success history, particularly on economic viability. Average between onshore proven and testing
Gas Injection	Hydrocarbon Gas Injection	Gulfaks, Statfjord, other North Sea (SPE 99546, SPE 78344, SPE 78348) Prudhoe Bay, Milne Point, and Kuparuk Fields, North Slope of Alaska (SPE 72466, SPE 89353, and SPE 113933)	5	Onshore Proven Technology	Technology is proven offshore in <1000 ft water depth and in lower reservoir pressure/temperature regimes as observed in the deepwater GoM
	Hydrocarbon Gas Dump Flooding		0	Unproven Idea	Observed potential in core analysis or field observations but no field pilots with positive results
Gas-Based EOR	Nitrogen Injection	Analysis of USA nitrogen projects and offshore designs (SPE 11902) K2 (lab test) OTC (19624) Akal Reservoir in Cantarell Complex (gas cap injection)	4	Offshore Tested with Limited Experience	Technology has been used onshore and tested in offshore fields but with limited operational experience
	CO2 Injection	Significant number of successful applications onshore US OG21 group study, Norwegian Continental Shelf Gulf Coast CO2 Experience in Sandstone Reservoirs (SPE 113368) (upper Texas Gulf Coast and along the Louisiana coast, barrier/strandplain, submarine-fan	3	Onshore Proven Technology	Concept with lab evaluation, flow loop testing, formulation of basis of design, and possibly some field pilot testing
Diverting Agents	Foam and other chemicals	Snorre Field (SPE 75157 FAWAG application)	4	Offshore Tested with Limited Experience	Technology has been used onshore and tested in offshore fields but with limited operational experience
Seperation, Pumping & Artificial Lift	Subsea Multi-Phase Pumping	Gulfaks multiphase booseter pumps (SPE 50682) Tordis, North Sea (OTC 19328, SPE 123159). The first commercial full scale subsea separation installation. By separating out water and sand at the sea floor and injecting this waste into a dump reservoir in a	7	Deepwater Field Proven	Technology field proven in deepwater and in environmental conditions similar to those observed in the deepwater GoM
	In-Well ESP	Application of ESP at Pompano. (Offshore December 01, 2003, volume 63, issure 12) Jubarte field, Campos Basin (SPE 117174) (offshore heavy oil with large amount of water.)	6	Deepwater Deployed with Limited Experience	Technology has been applied in a large number of offhore wells with both dry and wwet trees in North Sea, Brazil and GoM. Limited experience in deepwater GoM at high pressure so keep as TRL = 6
	In-Well Gas Lift	GL is not widely used in deepwater environment because of the following reasons: most wells in DW are deviated with wellbore clearance issue, GL is not ok for sand and heavy oil, the gas availability, the GL has a lower rate potential than ESP, the limit	6	Deepwater Deployed with Limited Experience	Technology field proven in deepwater and in environmental conditions similar to those observed in the deepwater GoM
	Subsea Seperation	Tordis, North Sea (OTC 19328, SPE 123159). The first commercial full scale subsea separation installation. By separating out water and sand at the sea floor and injecting this waste into a dump reservoir in a closed loop system. BC-10, Brazil (Heavy oil,	6	Deepwater Deployed with Limited Experience	Technology field proven in deepwater and in environmental conditions similar to those observed in the deepwater GoM
Well Technology	Low Cost Wells		0	Unproven Idea	Assumption: >50% cost reduction
	Low Cost Well Intervention	The North Sea (OTC 20417), Asgard, North Sea (SPE 121481)	5	Onshore Proven Technology	The technology is always evolving for different applications. Considerable
	Horizontal Wells	Application of horizontal well at Europa, Ram Powell, Jubarte, Campos basin (SPE 117174)	6	Deepwater Deployed with Limited Experience	Technology field proven in deepwater and in environmental conditions similar to those observed in the deepwater GoM

Table 2: Technical readiness factors for Neogene IOR processes (RPSEA 07121-1701, 2010).

The results of Neogene IOR evaluation area summarized in **Table 3**. The minimum and maximum incremental recovery factors and target OOIP are used to estimate the P90, P50, and P10 values of potential incremental barrels. The target potential numbers are not additive since the IOR processes may apply to a single field and be competing alternatives.

The technical readiness factors are used for risk weighting of the P50 IOR potential. The weighting is simply the TRL value divided by 7 or the maximum possible. Hence the risk factor for conventional water injection is 1 while the risk factor for flooding is 4/7 or 0.57. The TRL risk factor is multiplied by the P50 target potential barrels to give the P50 risked IOR. Finally, the value of the P50 risked IOR is used to rank the 19 processes.
P50 risked IOR volume = P50 case volume x (TRL/7).

The results can first be looked at by the ranking of risked IOR potential. Water injection by conventional and the low-cost alternatives, sea floor water injection and aquifer dump flooding injection, stand out as having the highest potential. These results include a number of large Middle Miocene fields (Atlantis, Shenzi, Tahiti, Thunder Horse) for which water injection is already tentatively planned in the development. The second group of high ranking potential IOR is for subsea pumping, electrical submersible pumps, and gas lift. A third tier of IOR processes with the most risked potential includes hydrocarbon gas injection, nitrogen injection, chemical ASP flooding, and horizontal wells.

The ranking process, by risked reserves, should not be the only criteria used to consider other IOR technology. The target applications and OOIP is important even if the risk of applying the process is high. For example, low-cost wells have the largest target OOIP of nearly 30 billion barrels. Also low-cost well intervention has a large number of field applications due to the number of wet tree developments showing the importance of this technology, even thought the target incremental oil potential is not high.

			Technical IOR RF		Applications		Target Potential Barrels					
Process Number	IOR Category	IOR Process	Low	High	Field Count	Target OOIP of the field (MMSTB)	P90 Case (MMSTB)	P50 Case (MMSTB)	P10 Case (MMSTB)	Technical Readiness Level	P50 Risked IOR	Process Ranking
1	Water Injection	Conventional Water Injection	4%	25%	14	10,009	400	1,451	2,502	7	1,451	1
2		Seafloor Water Injection	4%	18%	18	10,338	414	1,137	1,861	4	650	2
3		Aquifer Dump Flooding Injection	4%	18%	18	10,338	414	1,137	1,861	4	650	3
4	Water-Based EOR	Low Salinity Water injection	3%	7%	26	22,344	670	1,117	1,564	2	319	11
5		Microbial EOR	1%	5%	5	7,168	72	215	358	3	92	16
6		Alkaline Surfactant Polymer (ASP)	5%	20%	7	6,481	324	810	1,296	3	347	8
7		Chemical Augmented Waterflooding	4%	16%	7	7,821	313	782	1,251	2	223	14
8	Gas Injection	Hydrocarbon Gas Injection	3%	12%	5	7,087	213	532	850	5	380	7
9		Hydrocarbon Gas Dump Flooding	3%	8%	10	4,742	142	270	398	0	0	18
10	Gas-Based EOR	Nitrogen Injection	3%	12%	8	7,970	239	598	956	4	342	9
11		CO2 Injection	3%	15%	5	1,811	54	163	272	3	70	17
12	Diverting Agents	Foam and other chemicals	1%	7%	12	12,890	129	493	857	4	282	12
13	Pumping & Artificial Lift	Subsea Multi-Phase Pumping	3%	7%	23	10,935	328	547	765	7	547	4
14		In-Well ESP	3%	7%	13	12,206	366	610	854	6	523	5
15		In-Well Gas Lift	3%	7%	21	10,506	315	525	735	6	450	6
16		Subsea Processing	2%	4%	6	5,516	110	165	220	6	141	15
17	Well Technology	Low Cost Wells	4%	9%	74	29,712	1,329	1,993	2,657	0	0	18
18		Low Cost Well Intervention	1%	4%	47	12,515	125	313	501	5	223	13
19		Horizontal / Multi-Lateral Wells	2%	9%	24	6,972	156	390	624	6	334	10

Table 3: Results of Neogene IOR evaluation and process ranking (RPSEA 07121-1701, 2010).

Table 4 shows the technical readiness factors for Paleogene IOR processes. Conventional water injection and Subsea multi-phase pumping are at the top of the list, with in-well ESP, conventional hydrocarbon gas injection and deviated horizontal wells coming in close behind. MEOR water injector diverters and low salinity water injection would be at the bottom.

Technical Readiness Levels of Potential IOR Processes			
Process Number	IOR Category	IOR Process	Technical Readiness Level (TRL 0-7)
1	WATER INJECTION	Conventional Water Injection	6
2		Seafloor Water Injection	4
3	WATER-BASED EOR	Low Salinity Water Injection	2
4	GAS INJECTION	Conventional Hydrocarbon Gas Injection	5
5	GAS-BASED EOR	Nitrogen Injection	4
6	DIVERTING AGENTS	MEOR Water Injection Diverters	1
7	PUMPING and ARTIFICIAL LIFT	Subsea Multi-phase Pumping	6
8		In-well ESP	5
9	WELL TECHNOLOGY	Hydraulic Fracturing	4
10		Deviated / Horizontal Wells	5

Table 4: Technical Readiness for Paleogene IOR Processes (RPSEA 07121-1701, 2010).

Table 5 shows the IOR Process Ranking for Paleogene fields. The metric is screened on a P50 risked incremental oil volume normalized by the technical readiness level and calculated the same as Neogene above. The top ranking processes for Paleogene are conventional water injection, subsea multi-phase pumping and in-well ESP.

On a reservoir basis, conventional water injection would have the highest expectation for success in all Paleogene reservoirs, with its long history of offshore experience. Seafloor water injection would be next, followed by nitrogen flooding then conventional hydrocarbon gas. Low salinity water injection, still in infancy, would be the lowest.

Subsea boosting by either multi-phase pumping or submersible pumps is a solution for high abandonment pressures. These technologies have the capability of raising incremental recovery 6 – 7%. A new generation of downhole ESP has a large upside potential for extending the producing life of a Paleogene reservoir.

Hydraulic fracturing, capable of tripling production rate, will prove to an effective treatment for low permeability reservoirs.

DEEPWATER GULF OF MEXICO: IOR PROCESS RANKING FOR PALEOGENE FIELDS													
				Technical IOR Recovery Factor		Applications		Target Potential Barrels					
Process Number	IOR Category	IOR Process	Trapped Oil Mechanism Target	Low	High	Field Count	Target OOIP for Field Count (MMstb)	P90 (MMstb)	P50 (MMstb)	P10 (MMstb)	Technical Readiness Level (TRL 0-7)	P50 Risked IOR (MMstb)	IOR Process Ranking
1	WATER INJECTION	Conventional Water Injection	displacement drive energy	2.0%	22.0%	14	25,000	500	3,000	5,500	6	2,571	1
2	WATER INJECTION	Seafloor Water Injection	displacement drive energy	2.0%	15.0%	14	25,000	500	2,125	3,750	4	1,214	4
3	WATER-BASED EOR	Low Salinity Water Injection	capillary bound	3.0%	7.0%	14	25,000	750	1,250	1,750	2	357	9
4	GAS INJECTION	Conventional Hydrocarbon Gas Injection	sweep efficiency	3.0%	8.0%	14	25,000	750	1,375	2,000	5	982	7
5	GAS-BASED EOR	Nitrogen Injection	capillary bound	3.0%	12.0%	14	25,000	750	1,875	3,000	4	1,071	6
6	DIVERTING AGENTS	MEOR Water Injection Diverters	sweep efficiency	3.0%	7.5%	14	25,000	750	1,313	1,875	1	188	10
7	PUMPING and ARTIFICIAL LIFT	Subsea Multi-phase Pumping	high abandonment pressure	5.0%	10.0%	14	25,000	1,250	1,875	2,500	6	1,607	2
8	PUMPING and ARTIFICIAL LIFT	In-well ESP	high abandonment pressure	3.0%	15.0%	14	25,000	750	2,250	3,750	5	1,607	3
9	WELL TECHNOLOGY	Hydraulic Fracturing	non-connected volume and sweep efficiency	5.0%	10.0%	14	25,000	1,250	1,875	2,500	4	1,071	5
10	WELL TECHNOLOGY	Deviated/ Horizontal Wells	non-connected volume and sweep efficiency	2.0%	5.0%	14	25,000	500	875	1,250	5	625	8

Table 5: IOR Process Ranking for Paleogene Fields (RPSEA 07121-1701, 2010).

For the Paleogene Fields, the contributions from select IOR processes (Table 5) sequenced in the following development scenarios are:

- **Primary = 10%**
- **Optimized Primary - IOR = hydraulic fracturing (4.3%), extended reach wells (2.5%)**
- **Secondary – IOR = conventional water injection (10.3%)**

- **Optimized Secondary = diverting agents (.8%), pumping (6.4%), ESP (6.4%)**
- **Secondary-EOR = low-salinity injection in tertiary mode (1.4%)**
- **Other ranked processes are deemed outside this feasibility window**

Depending on the particular combination of optimized primary IOR, and secondary IOR/EOR processes applied to the reservoirs, the total cumulative oil EUR obtainable ranges between 20 – 35% of OOIP

5.11.3. Conclusions

What follows are the conclusions on the potential for improved recovery in deepwater Gulf of Mexico fields taken directly from the **RPSEA project 07121-1701 "IOR for Deepwater Gulf of Mexico"**

For IOR considerations, the deepwater Gulf of Mexico fields and reservoirs are divided into two age groups due to significant property and drive energy differences:

- **Neogene: Miocene, Pliocene and Pleistocene age reservoirs**
- **Paleogene: Oligocene, Eocene, Paleocene**

5.11.3.1. Neogene aged reservoirs

Oil recovery in Neogene reservoirs ranges from 16% - 32% - 48% (P90-P50-P10). These statistics exclude reservoirs with water injection. However, when waterflooded reservoirs are included, the statistics are unchanged due to limited historical water injection.

There is a large target for improved recovery in the Neogene because:

- Average oil recovery is a modest 32% and the projected ROIP in discovered fields is **21 billion barrels.**
- Many reservoirs have only a moderate natural drive energy from rock compaction and aquifer influx.
- Only a limited number of reservoir have high recovery >50% from strong aquifer drive or engineered waterflooding.

Most promising IOR concepts for Neogene are:

- Adding reservoir energy by injecting water or gas. Water injection is most favorable due to the robust gas sales infrastructure.
- There is a need for a low-cost alternative to water injection. The most favorable alternatives are seafloor water injection and aquifer dump flooding.

- Subsea boosting and artificial lift are key IOR technologies for primary production optimization and enhancing secondary recovery permitting flow to higher water cut.
- Nitrogen is a good alternative for adding reservoir energy and with tertiary recovery benefits since it would be miscible in many reservoirs. There are many operational benefits for using inert nitrogen. The potential drawback is that asphaltenes can be more unstable in the presence of the gas.
- Injection of low salinity water is an emerging technology which can add tertiary recovery benefits to waterflood by reducing residual oil saturation (Sor). Nanofiltration membrane technology has advanced rapidly for offshore sulfate reduction plants, and is quickly becoming an industry standard for waterflood projects (deepwater Angola and Ursa and Shenzi in the GOM). A low salinity injection project would use similar hardware and is therefore near technical readiness. There is uncertainty in understanding the reservoir recovery mechanisms and the application of the IOR process has not been proven through field use. However, there are huge benefits in the deepwater GOM for the implementation of a low salinity water injection system at the same time that water injection equipment is added for secondary recovery.
- There is sufficient need for low-cost riserless light well intervention (RLWI) technology due to the number and growth rate of wet tree installations.

Main risks for implementing IOR in Neogene reservoirs:

- Average reservoir OOIP is small at ~ 50MMSTB, which combined with the high costs of deepwater operations creates challenging economics.
- Reservoirs are deep and geologically complex (structural and depositional) and the seismic image is typically of low resolution. This has led to a poor track record of predicting performance and has elevated the risk profile for all incremental projects
- The high cost of wells

5.11.3.2. Paleogene (Lower Tertiary) aged reservoirs

The L. Tertiary reservoirs of the Paleogene in Keathley Canyon and Walker Ridge have significant oil recovery challenges, and only recently has production begun at Great White. The forecast primary RF is only 10% of OOIP, and the expected remaining OOIP ROIP in discovered fields is **23 billion barrels.** There is no production experience, and no suitable analog was found worldwide. The development risk is high due to stepping out into a new frontier of depth, high pressure / high temperature, can complex geology. Of note from the current writers, the development scenario at Perdido and closely following it, Cascade/Chinook in 2011 and Jack/St. Malo in 2015, will incorporate from the start many of the processes mentioned under optimized primary and secondary recovery. As such the remaining barrels will drop unless the original oil in place number increases.

The Paleogene requires critical new technology for even primary production and development. Key IOR concepts for improving oil recovery are:

- Adding reservoir energy through water injection
- Technology for reservoir management of water injection and production from a thick, heterogeneous reservoir. This includes downhole data acquisition (pressure, rate, water cut) and control equipment for multi-zone completions with remote operation or control by RLWI vessel
- Subsea pumping and downhole pumps with high operating delta pressure to achieve lower BHFP and abandonment pressure.
- Seafloor water injection is needed for remote, ultra-deep fields which are a long distance for the host facility
- Advancement in hydraulic fracturing to enhance productivity and injectivity in a low permeability reservoir

5.11.4. Technical Gaps

Of the nineteen prime reservoir and production based IOR processing deemed suitable for Neogene reservoirs, only two concepts are considered proven technology in deepwater Gulf of Mexico. Both conventional water injection and subsea multi-phase pumping have attained the highest technical readiness level (TRL) 7. Ten potential improved oil recovery methods were evaluated and ranked for the Paleogene study area. Again, conventional water injection and subsea multi-phase pumping are the most advanced technologies, however a TRL of 6 was assigned to each to reflect limited experience with the deeper Paleogene reservoirs and their unusual high pressure-high temperature conditions.

For the most part, both Neogene and Paleogene IOR technologies are immature. Technical gaps now prevent their implementation in the deepwater Gulf, though progress is being made on proving IOR mechanisms, perfecting production technologies that enable the underlying depletion strategy, building onto the experience base, and leveraging operating synergies and business alliances to lower costs. **See RPSEA Report 07121-1701 Tables 47 and 48 for details on Technical Gaps in Paleogene and Neogene IOR processes.** Presented for each IOR process under review are the current technical readiness levels and bridging solutions - steps necessary for bringing still-to-be matured IOR concepts into the realm of deepwater field-proven technology.

5.11.5. Recommendations for Future Work to Attempt to Bridge Technical Gaps

1. The risked IOR project economics will be greatly improved with the key enabling technologies of better reservoir characterization and lower well costs as described below.
    - Fund research on improving wide azimuth seismic technology or finding alternative tools for imaging below salt and in deep reservoirs. **(See section on Seismic Technologies).**
    - Develop new remote sensing technology that provides the equivalent of dynamic data without production or testing.
    - Fund research with operators and service providers to evaluate a “paradigm shift” in drilling technology and cost.
    - Fund research for the development of riserless light well intervention (RWLI) or rigless vessels for well intervention with fit-for-purpose design in consideration of future Paleogene well completion needs.

2. Overcome the perceived risks for seafloor water injection and aquifer dump flooding in deepwater GOM.
    - Funding of a study to identify field applications and to develop a basis of design.
    - Review and capture knowledge base from North Sea studies (CAPSIS and CFAST)
    - Improve where required the accuracy of predictive tools for souring, scaling, and corrosion.

3. Technology gaps for waterflooding in the Paleogene are numerous. Fund research in conjunction with operators and service providers in defining and developing the following new equipment, techniques, and materials:

    - Completion technology to improve injectivity and provide control of injection profile.
    - Injector completion where integrity is not compromised with down-hole cross-flow
    - Reliable multi-zone completion producers with data acquisition (pressure, rate, water cut), mechanism for shut-off (or other isolation requirements), and completion control by remote intervention or RWLI.
    - A low-cost diverting agent using MEOR technology for injection well profile control needs.

4. Evaluate the necessary modifications to the current sulfate reduction nano-filtration technology to make low salinity waterflooding possible. Determine

candidate reservoirs and fields, and consider the use of shared infrastructure in mature areas with limitations of space and weight on production platforms.

- Fund research to assess a "brownfield" implementation of LowSal in the Chevron/Marathon Petronius field for tertiary recovery. The study group could include operators from nearby Neptune, King Swordfish, Horn Mountain and Ram Powell fields to gauge interest in the use of a shared facility for low salinity water supply.

5. There is a need for R&D for the development of reliable, downhole deep-set pump installation for Paleogene well to deliver high rates and to lower abandonment pressure. Due to the depth and pressure, consider the investigate the development of a hydraulic submersible pump which can deliver high delta pressure while not requiring downhole electrical connections. Otherwise, consider an electric submersible pump (ESP) with rigless access operable in a high temperature environment.

6. Microbial EOR (MEOR) technology is a potentially low-cost diverting agent for conformance control in heterogeneous formations with highly-stratified lithology. There is uncertainty in the field-scale stimulation and growth of microbes with IOR benefits, particularly the operating dimensions of an engineered MEOR application. Microbial reactions are also linked to lowering of the residual oil saturation and oil viscosity reduction. Fund research to evaluate the use of MEOR including:
   - Determine the interplay of chemical and biological controls (reservoir geochemistry, nutrient concentration, growth period etc.).
   - Establish operating scope for various strains deployed in different in-situ conditions.
   - Quantify the impact of formation temperature on microbial performance in the near-wellbore region. Assess the feasibility of thermophillic microbes for use up to 250^0 F.
   - Identify enzyme-producing microbes aimed at reducing Sor and improving sweep efficiency in a field-scale development process.
   - Evaluate microbial visbreaking of low API crude.

7. Nitrogen injection has both secondary and tertiary recovery benefits but has not been employed offshore due to the large space and weight requirements for air extraction equipment.
   - Fund research to develop the technology of advanced nitrogen extraction from air for use on deepwater facilities and at a reasonable/low cost, weight, and footprint.

8. A gap exists in the hydraulic fracturing technology used onshore for ultra-low permeability reservoirs insofar as transferring these techniques to Paleogene reservoirs for a similar gain in the productivity index.

- Fund research in coordination with operators and service providers for the development of Paleogene hydraulic fracturing technology to increase initial well PI by a factor of 3 to 5 times the current expectations.

From the RPSEA study above, there are several takeaways but we can summarize in the following two statements.

- We need to take a hard look at the enabling technologies and technical gaps to improve IOR project economics.
- Not only does IOR/EOR need to be considered for the mature field, but it should always be evaluated in the initial planning, and considered for emplacement from the start.
- A similar sizing of the remaining potential on the shelf of the Gulf of Mexico should be undertaken.

5.12. Metocean (Meteorological and Oceanography)

(By Mike Beattie)

5.12.1. Metocean forecasting and systems analysis – Integrated models to predict both above and below surface "weather" and engineering system response.
Significance – safe and reliable development

The oil and gas industry has been producing hydrocarbons from the waters of the continental shelf of the GOM for more than a half century. The ability to characterize and predict the behavior of the oceans is essential so that we can safely conduct exploration and production operations offshore. An understanding of long term extreme values of wind, waves and currents is needed to properly design offshore facilities. The ability to predict near term conditions for the seas and currents is necessary to plan and conduct safe drilling and production operations in the marine environment and to respond to any hydrocarbon spill incident. Hence a robust understanding of the marine environment has been an objective for our industry for decades.

The understanding of the metocean environment has continued to improve and mature as the industry conducted marine operations and as the industry and academia performed research on wind, wave and currents. The collective record of metocean measurements expanded through various measurement programs conducted as university research, governmental agency projects, and joint industry projects among other sources. These records were compiled at various intervals to enable detailed statistical studies and create predictions on expected maxima at a given location for a given return period. These hindcast databases have been well developed in the Gulf of Mexico through a number of joint industry projects (JIP's) such as GUMSHOE WINX, GLOW and EJIP. There are a number of JIP's to address metocean measurements and predictions in other regions throughout the world's oceans.

As the industry has moved from the shallow waters of the Gulf to the deeper regions of the continental shelf to the deep water, the importance of correctly assessing the marine environment has grown. The uses for this data have also evolved. The first offshore facilities were simple fixed structures which required relatively less complex metocean design criteria. Today's offshore developments involve complex floating facilities in thousands of meters of water with their attendant mooring systems, production risers, satellite flowline risers, control umbilicals and export pipelines. Design of these systems for extreme events and for day to day fatigue loads requires a comprehensive understanding of the marine environment.

Currently, the two major JIP efforts in the area of metocean studies are CASE/EJIP and DeepStar. CASE/EJIP stands for climatology and simulation of eddies and eddy joint industry project. These two JIPs were established some years back and eventually were merged. As the name indicates, they originally focused on eddy measurements, compilation of a hindcast record, and development of analytical tools to establish statistical parameters for eddy conditions at a specified location in the Gulf of Mexico. CASE/EJIP is an arena where various metocean research is evaluated, funded, conducted, and critiqued by metocean scientists from the participant companies.

DeepStar is the largest joint industry project in the energy sector and it covers a broad array of topics. Metocean measurement programs, modeling studies, and criteria development have all been supported by Deepstar.

Below are listed a number of recent research topics for joint industry projects. This list is by no means exhaustive.

- Analytical work to refine the modeling ability for Gulf of Mexico eddies
- Evaluation of potential impact to hurricane intensity from climate change
- Interactions between hurricanes and the loop currents
- Studies of currents in the deeper regions of the water column
- Wave measurement and analysis program to evaluate the potential for and magnitude of rogue waves
- Wind measurements to evaluate wind loads on structures

The hurricane seasons of 2004 and 2005 were the most severe in memory and altered the industry understanding of the Gulf environment. Hurricanes Ivan, Katrina, and Rita were far more severe than would have been predicted by existing hindcast models. These storms were added to the database and the assumed extremes from older storms in the record, storms where assumed wave heights were estimated based on less reliable sources, were omitted. The industry also gained further insight into the influence of the loop current on storm intensity. The loop current brings warmer water into northern portions of the central Gulf. This warmer water provides energy to rapidly increase the intensity of the hurricanes. These insights led to upward revisions on the maximum predicted storms, especially in the central Gulf. Industry and regulatory agency resources were called upon to form a task force to evaluate the modified understanding of the ocean environment. This task force prepared updated criteria for use in exploration and development activities.

Looking to the future, the industry will continue to conduct research in the measurement of the seas and to refine the predictive tools for the marine environment. Areas of interest include numerical ocean current models, synthetic modeling, and climate change. It should also be noted that the ocean scientific community is gradually losing the use of an important data source. Satellites with ability to study oceanography and meteorology were introduced in the 1970’s. In recent years, the government has failed to maintain many of these satellites so that this monitoring capability has reduced. The industry is not able to actually launch and maintain these satellites but should be an advocate for this initiative.

(Special thanks to Cort Cooper of Chevron for providing the above information to support the preparation of the comments on Metocean studies).

Chapter 6: Conclusions and Key findings.

Comprehensive review of North American offshore oil and gas facts and prospects has led us to the following findings:

1. Oil and natural gas development and production in the U.S. lower 48 is significant, and the expectation is that a positive production growth trend will extend to the year 2050. We expect offshore oil production to increase to the year 2035 by an average annual growth rate range of 0.2 to 0.9 percent. Offshore natural gas production is expected to annually grow by a range of 0.4 to 0.7 percent per year to the year 2035. These annualized growth rate ranges encompass production projections for both the constrained and unconstrained development pathways.

2. According to AEO2010, Crude oil production in the U.S. lower 48 offshore is expected to rise up to a range of 1.7 - 2.7 million barrels per day in 2035 for the low and high price cases respectively. Similarly, natural gas production is expected to reach 3.2 – 4.8 trillion cubic feet per year in 2035. The most recent AEO2011 calls for the following lower 48 offshore oil and gas production projections in 2035 for the low and high price cases, respectively: 1.4 to 2.3 million barrels oil per day and 2.1 to 3.8 trillion cubic feet of gas.

3. Beginning around 2030 and extending to the year 2050, we expect the bulk of oil and natural gas production in the lower 48 offshore to originate from the deepwater Gulf of Mexico in the emerging Lower Tertiary trend and the extension of existing and new trends into areas that are currently poorly imaged. Also, we expect additional impacts on oil production from increased access to Pacific and the Atlantic offshore regions.

4. Government policies favorable to accessing more U.S. lower 48 offshore lands are needed to allow for the occurrence of the oil and gas development and production growth rates mentioned above.

5. We expect a slow down and a postponement of offshore oil and gas development and production if overwhelming operation safety requirement and restrictive environmental policies are implemented in the OCS following the Deepwater Horizon drilling event in the GOM.

6. Technological progress and innovation are the key factors that would enable development and production of oil and gas in new frontier regions located in deep water and in deeper reservoirs. Most notably, technologies adapted to the High Pressure High Temperature environment, delivery rates, and reduction of drilling costs are the key drivers for the huge oil and gas resources hosted in the Lower Tertiary formations. These formations have potentially greater than 15 billion barrels of recoverable oil reserves, some of which is located in areas of at least 60 miles from the nearest infrastructure. The challenges of this environment cross multiple disciplines and advances in technologies associated with seismic imaging, completion and casing design, subsea production equipment, subsea processing, and High Integrity Pressure Protection Systems (HIPPS), while underway, need to continue. HP/HT applications to 10ksi and 250oF are common in today's market and the envelope has pushed out to 15 ksi and 400oF, with some limited gaps. However now the envelope is being pushed further to 20 – 30ksi and >400oF in the shallow water gas play of the Lower Tertiary.

7. Seismic innovative technologies that allow for better imaging of the sub salt horizons in the Gulf of Mexico are pivotal to the expansion of hydrocarbon resources via additional newer discoveries. These include imaging algorithms, acquisition geometries, inclusion of more azimuths in processing and retention of low frequencies.

8. A quick extrapolation of the top 500 supercomputer performance list predicts Exascale computing capability within 10 years. This is a 1000 fold increase in processing capability over that currently available. With some seismic vendors today approaching the level of computing capability seen with the national computers on the top 500 list, it will be exciting to see what challenges can be conquered with the Exascale computing level. Is near real-time seismic imaging around the corner?

9. The need for a reduction in drilling costs to the point where significantly more exploration wells can be drilled allowing companies to test more concepts and perhaps encourage more improved and enhanced oil recovery programs. Dual gradient drilling is one such concept scheduled to be implemented in the deepwater Gulf of Mexico this year.

10. Subsea technology and extended architecture system will boost production of offshore oil and gas in remote and challenging environments of the deep and ultra deepwater areas, which lack the basic infrastructure needed to produce and to transport the hydrocarbons to shore.

11. The offshore field of the future, which we are not far from today, will have multiple satellite fields produced via subsea completions and long tie-backs to hub facilities. The subsea manifolds will be equipped with remote power and communication ability, so remote surveillance and control functions are available at the hub as well as the onshore production center. Smart equipment will be deployed on the seafloor and downhole that will accept commands from the offshore hub or onshore center to improve reservoir production efficiency. Sophisticated models of the reservoir, well and processing systems will be kept up to date and running online, so surveillance is a "manage by exception" process. Field optimization will be regularly reviewed and based on analysis so that asset managers can make decisions when opportunities are encountered, instead of producing to a plan that may be months to years old (Crompton and Gilman, 2010).

12. There have been significant advances in subsurface measurement over the last decade however the demand for increased resolution and data will require improved real-time transmission methods. The need to improve down-hole fluid characterization and reservoir parameter data for in-situ properties, and to monitor wells down-hole for longer periods will be critical to predicting field performance in more challenging environments.

13. Utilizing improved and enhanced oil recovery techniques could target an additional 44 billion barrels of oil equivalent (BBOE) left in discovered fields at abandonment. This is based on data from more than 80 fields and 450 reservoirs developed in the Deepwater Gulf of Mexico RPSEA project 07121-1701 entitled “IOR of the Deepwater Gulf of Mexico”.

14. Moderate to high oil and gas prices are necessary for the significant development and production of North American offshore oil and gas resources. A rebounding of natural gas prices in the next decade will favor an expansion of high cost offshore gas development and production.

15. In the U.S. lower 48 offshore, newer geologic plays and trends such as the Lower Tertiary and deeper reservoirs are expected to contribute to current and near future production of crude oil and natural gas.

16. Canadian offshore production of oil and gas is relatively lower in comparison to the U.S. lower 48, and is confined to the eastern shore in Newfoundland/Labrador and Nova Scotia. Removal of the imposed and the de facto moratoria will provide better opportunities for increasing oil and gas development and production in offshore Canada.

17. Along the Canadian Atlantic margin, current development and producing areas are estimated to hold remaining 2P reserves of 1.8 billion barrel of oil and 2.4 trillion cubic feet of gas (SOEP and Deep Panuke. These reserves translate into 14 years and 12 years of production at current production rates, respectively.

18. Significant increases in production would occur under an unconstrained scenario, in particular in the Labrador shelf where 4.2 trillion cubic feet of reserves has been assigned to 5 fields. Three major areas are under exploration moratoria. The end of one of these has been extended from 2012 to 2015. Significant in-place resources (P50) are proposed for the other two areas under de facto moratoria; the Gulf of St. Lawrence (41 trillion cubic feet and 2.5 billion barrels of oil) and along the Pacific margin (43.4 trillion cubic feet and 9.8 billion barrels of oil).

19. Most of the actual Canadian production is from the Mesozoic sandstone and carbonates reservoirs. Cenozoic plays have not been seriously explored so far. Moreover, some predicted high potential resides in Carboniferous plays that remained little explored.

20. Exploration and development drilling in the Canadian offshore faces different challenges compared to areas further to the South. Even if the Atlantic margin is not within the Arctic domain, the more northern areas (Labrador shelf, Grand Banks, Orphan Basin) are sites of harsh conditions with frequent storms and icebergs threats. This scenario makes environmental concerns even more critical of development/use of specific technology for exploration and development of these areas.

References:

1. Advanced Resources International, Incorporated (January 2009). Outer Continental Shelf Moratoria Areas: Impacts of Various Assumptions on Oil and Natural Gas Production Potential.

2. ICF International (December 2005). Strengthening our Economy: The Untapped U.S. Oil and Gas Resources.

3. SAIC and GTI (February 2010). Analysis of the Social, Economic and Environmental Effects of Maintaining Oil and Gas Exploration and Production Moratoria on and Beneath Federal Lands.

4. Douglas R. Bohi; Resource for the Future (June 1998). Changing Productivity in U.S. Petroleum Exploration and Development.

5. BOEMRE (August 2006). U.S. Offshore Milestones. Http://www.mms.gov/stats/PDFs/milestones.pdf

6. BOEMRE (2008). Federal OCS Oil and Gas Production as a Percentage of Total U.S. Production: http:*www.boemre.gov/.../AnnualProductionAsPercentage1954-2006AsOf6-2008.pdf*

7. BOEMRE (2009). Deepwater Gulf of Mexico 2009: Interim Report of 2008 Highlights. OCS Report mms 2009-016.

8. BOEMRE (2006). Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation’s Outer Continental Shelf.

9. BOEMRE (2006). MMS Estimated Oil and Gas Reserves Report.

10. Energy Information Administration (2009). Annual Energy Outlook 2009.

11. Energy Information Administration (2010). Annual Energy Outlook 2010.

12. Energy Information Administration (2010). Preliminary Results, Annual Energy Outlook 2011.

13. Energy Information Administration (2009). Impact of Limitations on Access to Oil and Natural Gas Resources in the Federal Outer Continental Shelf. Http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_2009analysispapers/aongr. html

14. Offshore, (February 2009). Thunder Horse: Pushing the Technology Frontier.

15. Petroleum Economist (June 10th 2010). Big Prospects in the Lower Tertiary GOM.

16. Rigzone (October 2010). Chevron sanctions Jack/St. Malo project in the Gulf of Mexico.

17. PennEnergy (2010). Lower Tertiary Play: Is it Gulf of Mexico's Final Frontier? http://www.pennenrgy.com/index/petroleum/display/7102345141/articles/offshore/vol

18. Roger N. Anderson & al. (undated). Prospectivity of the Ultra-Deepwater Gulf of Mexico. http://www.leanenergy.Ideo.columbia.edu

19. Journal of Petroleum Technology (December 2006). Lower Tertiary Trend: A Study in the Impact of Advancing Technology. http://www.spe.org/spe-app/spe/jpt/2006/12/lower_tertiary_trend_study.htm

20. European Energy journal (October 2010). The Oil Industry Between Hopes and Fears. http://www.europeanenergyreview.eu/site/pagina.php?id=2442&print=1

21. Tim Beims, American Oil and Gas Reporter (November 2010). Davy Jones Discovery Opening New Shelf Frontier in Ultradeep Geology below Salt. http://www.aogr.com/index.php/magazine/cover_story_archives/april_2010_cover_story/

22. Karel Beckman, European Energy Review (November 2010). Fatih Birol and the World Energy Outlook 2010 - What is needed is a clear signal for the energy sector to transform itself'. http://europeanenergyreview.eu/site/pagina.php?id_mailing=129&toegang=d1f491

23. Addison F., Kennelley K., Botros F.: "Future Challenges for Deepwater Developments", Offshore Technology Conference, OTC 20404, 2010, Houston Texas.

24. Ageh E.A., Uzoh O.J., Ituah I.: "Production Technology Challenges in Deepwater Subsea Tie-Back Developments", SPE 140620, 34th Annual SPE International Conference and Exhibition Tinapam, Nigeria, August 2010.

25. Ali S.A.:"Mature Field Revitalization," Technology Focus: Journal of Petroleum Technology, January, 2009, 58.

26. Ali, T.H., et al.: "High Speed Telemetry Drill Pipe Network Optimizes Drilling Dynamics and Wellbore Placement", SPE 112636, IADC/SPE Drilling Conference, Orlando Florida, March 2008.

27. Ali T., Mathur R., Sharma N., “Built to Suit, Technologies for Wellbore Construction in Deepwater and Ultradeepwater Gulf of Mexico”, SPE Deepwater Drilling and Completions Conference, Galveston, Texas, October 2010.

28. Alwazzan A., Utgard M., Barros D.: “Design Challenges for Wax in a Fast-Track Deepwater Project”, OTC 19160, Offshore Technology Conference, Houston, Texas, 2008.

29. Author unknown, “Drilling Achievements: Past, Present, and Future,” Special Section, Journal of Petroleum Technology, 2008.

30. Avseth P, Mukerji T., Mavko G.: “Quantitative Seismic Interpretation: Applying Rock Physics to Reduce Interpretation Risk”, Cambridge University Press, 2005, p. 256.

31. Bahorich, M.: “The End of Oil? No, It’s a New Day Dawning,” Oil and Gas Journal (August 21, 2006): 30–34.

32. Barnes: “Seismic Attributes in your Facies”, CSEG Recorder, September 2001, 41 – 47.

33. Barton S., Weeden R., Mensa-Wilmont G., Harjadi Y.: “Solving the Salt Challenge: Unique Drill bit Philosophy Delivers Breakthrough Performance in the Gulf of Mexico,” Offshore Technology Conference, OTC 20425, Houston, TX 2010.

34. Bell J.M., Chin Y.D., Kvaerner A., Hanrahan S.:”State-of-the-Art of Ultra Deepwater Production Technologies,” Offshore Technology Conference, OTC 17615, May 2005.

35. Bishop K., Keliher P., Paffenholz J., Stoughton D., Mitchell S,. Ergas R., Hadidi M.: “Investigation of vendor demultiple technology for complex subsalt geology,” 71st Ann. Internat. Mtg: Soc. of Expl. Geophys, 1273-1276.

36. WWW.BJService.com/website/completions.nsf.

37. Boutte D.: “The Role of Technology is Shaping the Future of E&P Industry”, The Leading Edge 23, No. 2 (2004), 156–158.

38. Burger R., Grigsby T., Ross C., Sevadjian E., Techentien B.: “Single-Trip Multi-zone Completion Technology Has Come of Age and Meets the Challenging Completion Needs of the Gulf of Mexico’s Deepwater Lower Tertiary Play., SPE 128323, SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Lousiana, February 2010.

39. Camp W., Thierry P.: Intel, “Trends for High-Performance Scientific Computing” Special Section, The Leading Edge, January 2010.

40. Carruthers D. J., 2003, Modeling of secondary petroleum migration using invasion percolation techniques, in S. Duppenbecker and R. Marzi, eds., Multidimensional basin modeling, American Association of Petroleum Geologists Datapages Discovery Series 7, Tulsa, Oklahoma, p. 21-37.

41. Carter B.A., Hamersley I., Ronalds B.F.: “Deepwater Riser Technology”, SPE 50140, SPE Asia Pacific Oil & Gas Conference and Exhibition, Perth, Australia, October 1998.

42. Cassiani S.M., Bahorich M.S., Converse D.R., Fisher W.L., Nichols D.E., Riese W.C., Saleh S.J., Schollnberger W.E., Toksoz M.N.: “Exploration Technology”, Topic Paper, National Petroleum Council Study “Hard Truths: Facing the Hard Truths about Energy, A Comprehensive View to 2030 of Global Oil and Natural Gas,” 2007.

43. Ceccarelli T., Albino E., Watson G., Deffieux D.: “Deepwater Completion Designs: A Review of Current Best Practices, SPE 122518, SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, Indonesia, August, 2009.

44. Chamber R.L., Yarus J.M.: “Geologically Based, Geostatistical Reservoir Modeling,”Volume VI Emerging and Peripheral Technologies – Petroleum Engineering Handbook (H.R.Warner, editor 2007), Chapter 2, 51 – 103.

45. Chandler R. B., Muradov, A., Jellison, M. J., Gonzalez M. E., Wu, J.: “ Drill Faster, Deeper, and Further with Ultrahigh-Torque Third-Generation Double-Shoulder Connections”, 2007 SPE/IADC Drilling Conference, Amsterdam, The Netherlands, February 2007.

46. Chappell S.D.: “Waterflooding in Deepwater Environments”, OCT 18345, Offshore Technology Conference, Houston, Texas, 2006.

47. Childers M.: Volume II Drilling Engineering, Petroleum Engineering Handbook, p. 589-602.

48. Clanton B.: Houston Chronicle, article quoting Tom Kellock head of consulting at ODS-Petrodata, April 8, 2010.

49. Conser R.J., Bass R.M., Chryssostomidis C., Danenberger III E.P., Garcia, C.C., Grecco M.G., Longbottom J., Sandstrom R.E., Tranter P.: “Deepwater”, Topic Paper, National Petroleum Council Study “Hard Truths: Facing the Hard Truths about Energy, A Comprehensive View to 2030 of Global Oil and Natural Gas,” 2007.

50. Crawford N.C., Still I.R.: “Riserless Subsea Well Intervention: Technology and Practice”, OTC 20420, 2010 Offshore Technology Conference, Houston, Texas.

51. Crompton J., Gilman H.: (SPE 127715 Jim Crompton et al., “The Future of Integrated Operations,” SPE 127715, SPE Intelligent Energy Conference and Exhibition March 2010, The Netherlands.

52. Daneshy A.: ”The Future Technology Challenge – Perfecting the Digital Wellbore”, Guest Column, Journal of Petroleum Technology, October 2007.

53. Deepstar Jules Verne OTC 20687.

54. Deka D., Campbell M., Kakar K., Hays P.R.: “Gulf of Mexico Wet Tree Deepwater Riser Concepts with Sour Service”, Offshore Technology Conference. OTC 20437, 2010, Houston, Texas.

55. Denney D., Parshall, J., Moon T., Donnelly J.: “Technical Innovation, Industry Insight Draw Huge Crowds to OTC”, Journal of Petroleum Technology, July 2008.

56. Devegowda D. and Scott S.L. 2003: “An Assessment of Subsea Production Systems. In: Proceedings of the 2003 SPE Annual Technical Conference. Denver, CO. Report No. SPE 84045. 9pp.

57. DeWalt B., Shields D.: “Flow Assurance Choices in the Lower Tertiary”, Offshore Magazine, Volume 70, Issue 6, June 2010.

58. Dittrick P.: “MWCC Venture to Design Oil-Spill Containment Equipment”, Oil & Gas Journal, October 17, 2010.

59. Dowell D., Smith T.: “A Deepwater Breakthrough: The Launch Window for Dual Gradient Drilling Technology”, Clear Leader Magazine, Chevron, 2010.

60. Dowell J.D.: “Deploying the World’s First Commercial Dual Gradient Drilling System,” SPE Deepwater Drilling and Completions Conference, SPE 137319, Galveston, Texas, 2010.

61. Drakeley B.K., Johansen E.S., Zisk E.J., Bostick F.X.: “In-Well Optical Sensing-State-of –the-Art Applications and Future Direction for Increasing Value in Production Optimization Systems”, SPE 99696, SPE Intelligent Energy Conference and Exhibition, Amsterdam, the Netherlands, April, 2006.

62. Duhon P., Holley A., Gardiner N., Grigsby T.: “New Completion Techniques Applied to a Deepwater Gulf of Mexico TLP Completion Successfully Gravel Pack an Openhole Interval of 2400 Feet”, SPE 50146, SPE Asia Pacific Oil & Gas Conference and Exhibition, Perth Australia, October, 1998.

63. Easton S.: “Case Study: Optimized Field Architecture for Electrical Boosting in Deepwater, OTC 20509, Offshore Technology Conference, Houston, Texas, 2010.

64. England, W.A., A.L. Mann, and D.M. Mann, 1991, Migration from source to trap, in Merrill, R. K., ed., Source and migration processes and evaluation techniques: AAPG Treatise of Petroleum Geology, p. 23-46.

65. Fenton S.P.: “Emerging Roles for Subsea Trees: Portals for Subsea System Functionality”, OTC 20108, Offshore Technology Conference, Houston, Texas, 2009.

66. Foster J., Grigsby T., LaFontaine J.: “The Evolution of Horizontal Completion Techniques for the Gulf of Mexico: Where Have We Been and Where Are We Going?”, SPE 53926, SPE Latin American and Caribbean Petroleum Engineering Conference, Caracas, Venezuela, April 1999.

67. Greenwood J., Russell R., Dautel M.: “The Use of LWD Data for the Prediction and Determination of Formation Pressure,” 2009 SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta Indonesia, August 2009, SPE Paper 124012.

68. Grieb T.M., Donn T.E, Collins J., Radde J., Perez C., Smith J.B., Rowe G., Scott S., Ririe G.T.: “Effects of Subsea Processing on Deepwater Environments in the Gulf of Mexico, U.S.Dept. of Interior, Minerals Management Service, Gulf of Mexico Region, New Orleans, LA, OCS Study 2008-022. 66p.

69. Haheim S., Gaillard X.: “A Simplified Subsea Separation and Pumping System”, SPE 124560, 2009 SPE Annual technology Conference and Exhibition, New Orleans, LA, October,2009.http://www.halliburton.com/ps/default.aspx?navid=1239&pageid=2964&prodid=PRN::KLEO26C4S.

70. Harts E&P Editors and Staff, “Independence Project: An Innovative and Coordinated Infrastructure Solution to Economically Develop Deepwater Offshore Production”, Harts E&P, September 2007. 84 pages.

71. Helix Energy Solutions Website: http://www.helixesg.com/HFRS/.

72. Horn T., BAkke W., Erikson G.: “Experience in Operating the World’s first Subsea Separation and Water Injection Station at Troll Field in the North Sea,” OTC 15172, 2003 Offshore Technology Conference, Houston, Texas.

73. Hovda S., Wolter H., Kaasa G., Olberg T.: “Potential of Ultra High-Speed Drill String Telemetry in Future Improvements of the Drilling Process Control”, IADC/SPE 115196, 2008 IADC/SPE Asia Pacific Drilling Technology Conference and Exhibition, Jakarta, Indonesia, August, 2008.

74. Hydrocarbons-Technology Website, http://www.hydrocarbons-technology.com/projects/nakika/.

75. Israel R.R., D'Ambrosio P., Leavitt A.D., Shaughnessy .JM., and Sanclemente J.: Challenges of Directional Drilling Through Salt in Deepwater Gulf of Mexico," IAD/SPE Drilling Conference, IADC/SPE 112669, Orlando Florida, March 2008.

76. Jacobs S.: "Breakthroughs: Top 10 Oilfield Technologies of All Time," Guest Editorial, Journal of Petroleum Technology, January 2010.

77. Jayawardena S.S., Zabaras G.J., Dykhno L.A.: "The Use of Subsea Gas-lift in Deepwater Applications," OTC 18820, Offshore Technology Conference, Houston, Texas, 2008.Jellison M., Chandler B.R., Shepard J.: "Challenging Drilling Applications Demand New Technologies", International Petroleum Technology Conference, Dubai, U.A.E, December 2007.

78. Journal of Petroleum Technology Online, September 1999, http://www.spe.org/spe-app/spe/jpt/1999/09/frontiers_drilling_tech.htm.

79. JPT Online January 12, 2009, Industry Updates.

80. Kadlec B.J., Dorn G.A.: "Leveraging graphics processing units (GPUs) for real-time seismic interpretation," Special Section: High Performance Computing, The Leading Edge, January 2010.

81. Knowledge Reservoir: "IOR for Deepwater Gulf of Mexico," a Report to Research Partnership to Secure Energy for America, Subcontract #07121-1701, September 14, 2010, 184 pages.

82. Lander, R. H., and O. Walderhaug, 1999, Predicting porosity through simulating sandstone compaction and quartz cementation: AAPG Bulletin, v. 83, p. 433-449.

83. Langdon S., Conner J., Chandler B.R., Jellison M.J.: "Deepwater Drilling Challenges Demonstrate Learning Curve with New Connection Technology", IACD/SPE Drilling Conference and Exhibition, New Orleans, February 2010.

84. Larter, S., H. Huang, J. Adams, B. Bennett, O. Jokanola, T. Oldenburg, M. Jones, I. Head, C. Riediger, and M. Fowler, 2006, The controls on the composition of biodegraded oils in the deep subsurface: Part II. Geological controls on subsurface biodegradation fluxes and constraints on reservoir-fluid property prediction: AAPG Bulletin, v. 90, p. 921-938.

85. Lord R.: "Technological Breakthroughs Advanced Upstream E&P's Evolution", Technological Milestones, Journal of Petroleum Technology, October 2007.

86. Magoon, L. B., and W. G. Dow, 1994, The petroleum system, in L. B. Magoon and W. G. Dow, eds., The petroleum system—From source to trap:

American Association of Petroleum Geologists Memoir 60, Tulsa, Oklahoma, p. 3-24.

87. Mahon, K.I., H. Dembicki, Jr., A. Chaouche, J. Meredith, H. J. White, N. Kalyanaraman, D. Kennedy, and D. Carruthers, 2009, Intergranular Tar in a Deepwater Reservoir: Part I – Mechanisms of Asphaltene Deposition: in AAPG Search and Discovery Article #90091 AAPG Hedberg Research Conference, May 3-7, 2009 - Napa, California, U.S.A.

88. Malcore E., Hani Q., Kuchinski R.: "New Generation of MWD, LWD, and Image Logging Opens New Possibilities for Data Acquisition and Evaluation of Deep Gas Reservoirs, SPE 132157, SPE Deep Gas Conference and Exhibition Manama, Bahrain, January 2010.

89. Maldonado B., Arrazola A., Morton B.: "Ultradeep HP/HT Completions: Classification, Design Methodologies, and Technical Challenges", OTC 17927, Offshore Technology Conference, Houston, Texas, 2006.

90. Mathieson D.: "Forces that will shape Intelligent-Wells Development", Journal of Petroleum Technology, August, 2007.

91. MicroSeismic Inc. Website, December 20, 2010, http://www.microseismic.com/.

92. Midttveit S., Monsen B., Frydenlund S., Stenevik K. A.: "Subsea Power Systems – a Key Enabler for Subsea Processing", OTC 20621, Offshore Technology Conference, Houston, Texas, 2010.

93. Miley M., Paffenholz J., Hall K., Michell S.: "Optimizing surface related multiple elimination on a synthetic subsalt data set," 71st Ann. Internat. Mtg: Soc. of Expl. Geophys, 1277-1280.2001.

94. Mitchell S.: "Subsalt Exploration and Development: Fifteen Years Later…Four Years Later… Four Years from Now……" Need to confirm function presented at, 2010.

95. Moldoveanu N., Kapoor J., Egan M.: "Full Azimuth Imaging Using Circular Geometry Acquisition," The Leading Edge, July 2008.

96. Moon T.: "Firm Provides Insights on R&D Trends for the E&P Sector", JPT Online, January 12, 2009, Industry Updates.

97. Moon T., Hite R.: "Digital Oil Field Workshop Addressed in Join Workshop", Techbits, Journal of Petroleum Technology, June 2009.

98. Moon T., Paul D.: "Digital Technologies for the Next Trillion Barrels", Journal of Petroleum Technology, September 2008.

99. Moos D.: Volume II Drilling Engineering, Petroleum Engineering Handbook, p. 78.

100. Mount, V.S., K.I. Mahon, and S.H. Mentemeier, 2010, Structural restoration and basin modeling in north-central Gulf of Mexico deepwater subsalt plays: Gulf Coast Association of Geological Societies Transactions, v. 60, p. 503-510.

101. Munkerud, P.K., Inderberg O.: "Riserless Light Well Intervention (RWLI), OTC 18746 Offshore Technology Conference, Houston, Texas, 2007.

102. National Ocean Industries Association Website, "History of Offshore, http://www.noia.org/website/article.asp?id=123.

103. Norske D. Veritas (USA) 2004. Technical report: "Risk Comparison – subsea vs. surface processing. Prepared for U.S. Dept. of Interior, Minerals Management Service. Project No. 70003245. 55 p.

104. Offshore Magazine, May 2009, Making MODUs Safer in Hurricanes.

105. Offshore Magazine, January 2010.

106. Offshore-Technology Website, http://www.offshore-technology.com/projects/mensa/.

107. Olsen K.: Technology Focus, Deepwater Exploration and Production: Journal of Petroleum Technology, June 2008, 52.

108. OTC 20045 – Optical Permanent Monitoring System Meets the Subsea Challenge.

109. OTC 20417.

110. OTC 20645.

111. Ozdogan, et al. SPE 113904.

112. Parshall J.: "Evolving Subsea Technology Tackles Hug New Risks of Today's Projects", Journal of Petroleum Technology, May 2008.

113. Paul D.: "The Role of E&P Technologies", Natural Resource Council Workshop October 2005.

114. Paul D.: "Technology to meet the Challenge of Future Energy Supplies", Guest Column, Journal of Petroleum Technology, October 2007.

115. Pederson S.I., Skov T., Sonneland, L.: "Automatic Fault Extraction Using Artificial Ant," in Iska A. and Randen T. (eds): Mathematical Methods and Modeling in Hydrocarbon Exploration and Production, Springer-Verlag (2005): 107 – 116.

116. Petmecky, S, M.L. Albertin, and N.L. Burke, 2008, Improving sub-salt imaging using 3D basin model derived velocities: Marine and Petroleum Geology v. 26, p. 457-463.

117. Petruska, Dave BP America Production Company Engineer, chair of API task force revising RP 2Sk.

118. Probert T.: "Deepwater Completions Offer Great Potential", Guest Editorial, Journal of Petroleum Technology, May, 2009, 18 – 21.

119. RigzoneWebsite, http://www.rigzone.com/training/insight.asp?insight_id=327&c_id=17.

120. Sankarin S., Lugo J., Awasthi A., Mijares G.: " The promise and Challenges of Digital Oilfield Solutions – Lessons Learned from Global Implentations and Future Directions", 2009 SPE Digital Energy Conference & Exhibition, Houston, Texas, April, 2009.

121. Sava P.: "Introduction to this Special Section: High Performance Computing," Special Section, The Leading Edge, January 2010.

122. Shand M.M., Birch M.C., Bostick F.X.: "Optical Permanent Monitoring System Meets the Subsea Challenge", OTC 20045, Offshore Technology Conferencence, Houston, TX, 2009.

123. Smith, K.: "Dual Gradient Drilling: Has It's Time Finally Come?," AADE Emerging Technologies Forum, 2009.

124. Smith T.: "Unsupervised Neural Networks", Oil and Gas Journal, October 4, 2010.

125. 79SPE 99696.

126. 80SPE 124705.

127. 82SPE 130522.

128. Statoil, Tyrihans SRSWI (Subsea Raw Seawater Injection), 2009.

129. Sten-Halvorsen V., Neumann B., Skeels H.B.: "Operating Experiences from Second Generation Riserless Light Well Intervention (RWLI) in the North Sea," OTC 20417, 2010 Offshore Technology Conference, Houston, Texas.

130. Thurston S.: "Chevron Overview: OE, Global Upstream & Deepwater Gulf of Mexico" Credit Suisse Virtual Tour, November 8, 2010.

131. Tissot, B.P., J.F. Bard, J. Espitalie, 1980, Principal Factors Controlling the Timing of Petroleum Generation: in Facts and Principles of World Petroleum Occurrence — Memoir 6, p. 143-152.

132. Total website, http://www.total.com/en/our-energies/oil/exploration-and-production/projects-and-achievements/moho-bilondo-940856.html).

133. Van Zuilekom A., Rourke M.: "Hostile Formation Testing Advances and Lessons Learned," SPE 124048, SPE Annual Technical Conference and Exhibition, New Orleans, La., October 2009.

134. Welland M., Donnelly N., Menneer T.: "Are We Properly Using Our Brains in Seismic Interpretation", The Leading Edge, 25, 2006, 142 -144.

135. Welte, D.H. and M.A. Yukler, 1981, Petroleum Origin and Accumulation in Basin Evolution - A Quantitative Model, AAPG Bulletin, v. 65, p. 1387–1396.