Upstream Intelligence
Analysis for the upstream oil & gas community

OFFSHORE DIGITAL SERVICES REPORT

Well Integrity and Production Optimization

Emerging Markets

Evaluation of the future growth areas for offshore digital services

Operator Challenges

The problems operators need solving and how digital services are helping

Impact of Oil Price Environment

How operators' priorities and the digital services market structure have changed in response to lower oil prices

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Well Integrity and Production Optimization

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Executive Summary

The low oil price environment is driving a refocus from production output to operational costs amongst operators. When oil prices and margins are good, maximizing production output is the primary metric that drives all others (maintenance schedules, critical spares etc.). Recovering from production outages, including root cause analysis and follow-up investigations are a priority. When oil prices come down and margins are squeezed, operating cost optimization is the primary metric that drives all others.

The most important factor affecting the future growth of the offshore digital services market is how well vendors understand problems and present solutions in ways clients in their target market (operators and major contractors) will understand and value. Key deliverables valued by operators include enhanced safety and environmental performance, increased production rates, optimized operating costs and greater oversight of deep water production facilities.

Digital technology and service providers need to embrace the lessons learned from offshore drilling solutions. The drilling and completions community is facing many challenges, including deeper wells, deeper water, high pressure/high temperatures in the well bore, more complex wells, remote locations, a higher number of wells in an unconventional resource drilling program, greater public scrutiny on incidents and a changing and experience base. Digital service providers can offer new abilities to address these challenges, but the solutions must be tailored to the problems themselves rather than the technology platforms available.

When it comes to digital solutions for offshore production and operations, the audience is changing. Technology vendors are not selling to IT audiences; they have to sell to operation managers. They have to learn to speak their language, develop credibility and have reference cases for a brand new group of people. Vendors need to know the difference between the roles and responsibilities of corporate IT, operations technology and shadow IT stakeholders (from engineering groups). Operations management is not interested in the latest-and-greatest or best-of-breed components for digital solutions. They understand risk and ROI very well, but it has to be defined on their terms, specifically increases in hydrocarbon production, lower operating expense, lower capital expense, lower maintenance and improved well and equipment integrity. To build a business case on their balance sheets takes reference cases.

Key international markets for offshore digital technology include Brazil, west-Africa, deep water environments and the Arctic.
The pre salt discoveries in Brazil represent a major opportunity for digital service providers. Deep water projects have long-term investment and expenditure cycles and represent strategic assets for major operators. While new investment may slow in the low oil price environment, there remain many projects underway already. Downtime from equipment failures and well interventions can be extremely costly in deep-water, so predictive maintenance is critical. The amount of data from new deep-water facilities will only increase, so the challenge is to manage this data stream,

visualize current conditions. This will enable operators to recognize and analyze important patterns of possible incidents and potential value generating opportunities.

The Arctic environment is opening up to greater levels of oil and gas exploration. Vessels and rigs which serve in this frontier region will be custom-built and designed with the harsh operating conditions at the forefront. The lack of supporting infrastructure in most of the Arctic will be an initial challenge for all operators. Like most frontier basins, it will be a challenge to develop the communications links between field and office staff. Reliance on satellite communications introduces a high-latency factor to the performance of many digital solutions preventing real-time systems from working.

The integrated application of digital solutions in the offshore environment has brought benefits to those operators which have implemented them.
There are benefits to a wide range of offshore activities. For example Chevrons I-field program has led to:

- A 25% reduction in drilling days for 10,000 feet from 2013-2015.
- An increase in single-trip multi-zone frack pack completion efficiency and reduced rig time. Delivering nearly $200 million in savings.
- Seafloor pumps reduce back pressure on deep reservoirs and deliver increased recovery. For Jack-St. Malo this is expected to yield an improvement of 10-30%, which equates to 50 to 150 MMbbl of additional oil recovery.

Opportunities for digital tech vendors and service providers across data services, include collection, processing, analytics, visualization. Providing data as a service which enables operators to operate by exception is an avenue attracting increasing investment.

Introduction

Today's Offshore operators want to move beyond spreadsheets and limited business reports to gain a richer, more customized perspective of operations and build a more data-driven culture. With the significant growth of data volumes in field operations and the greater variety of data now available, engineers, operations and maintenance staff and operations management, want to explore more data and discover new insights that they can apply to improve field performance. Current low oil prices dictate that the old way of doing business is increasingly no longer good enough.

There is a significant change in the way engineers and operators want to work with data and new analytics tools. Rather than depend on traditional reports and control panel alerts, they want to ask questions, explore patterns, and try different approaches. They need to know more than just the current status; they want to know what is going to happen in the future and predict that outcome. Every organization needs to use their data to be more analytical in their approach to compete effectively. To compete and survive in today's environment, companies need to apply digital solutions, technology and methods to enable their workforce to analyze data effectively without adding burden and costs on IT departments.

This research report will look at the offshore production market and assess where the industry is regarding their Digital Oilfield/Integrated Operations investments and where the opportunities and challenges lie in the current low oil price environment.

The challenge for any operator is to figure out how to get the most value from their physical asset by deploying digital solutions as well as traditional manual ones. In the offshore production market there are a number of significant opportunities to improve performance including: operations and maintenance (equipment health, well integrity, reliability analytics, and tank monitoring); production engineering and operations (surveillance of oil, gas and water production, virtual metering and field decision making) and reservoir engineering (real-time reservoir management).

The ultimate goal of digital solutions and services is to enable better, faster and more informed decision-making. The current focus is on analytics. To support these analytics, companies need to have a strong data foundation, a clear understanding of critical workflows, strong leadership with a strategic view and an organizational culture that is data-driven, safety conscious and aims towards operational excellence with every decision.

Digital solutions have already had an impact on offshore production facilities. Case histories of facilities 'born smart', manufactured with a digital infrastructure, demonstrate the potential of combining the appropriate production and processing equipment and engineering design, with digital workflow solutions. These solutions allow operators to take advantage of process controls and new analytics insight to operate offshore assets in more challenging circumstances.

The main offshore production challenges facing operators today include deeper water, remote locations, higher pressures and temperatures, more complex reservoirs and the need to produce hydrocarbons at a profit with lower oil prices. Production requirements dictate that operators and service companies must operate and maintain facilities with greater efficiency. This includes higher levels of safety, with lower environmental impact and increased recovery of hydrocarbons over the lifetime of the asset.

At current oil and gas prices, a renewed emphasis on operating cost and optimum production levels becomes even more important. This research report will highlight current best practices as well as additional opportunities for digital solutions to impact the success of offshore operations.

The main topics and questions this report will address are:

- How offshore digital systems can be utilized to meet operators' challenges in offshore areas with a focus on well integrity, intervention and production optimization.
- The identification of other offshore applications that could benefit from digital technology.
- Production challenges and what operators value in the current price environment.
- Case histories of successful projects, what was delivered, what the benefits were, and how they were delivered.
- Lessons learned from offshore drilling solutions.
- How to approach problems and present solutions in ways the target market (operators and major contractors) will understand and value.
- Key international markets for offshore digital technology.
- The competitive environment for digital technologies and emerging solutions and new entrants into the market.
- IT challenges and opportunities across data services, including collection, processing, analytics, visualization.

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1.

Business drivers in a low oil price environment

"We are leaving an era of energy shortage and entering an age of energy abundance. The main reason oil and gas prices are in severe decline is the imbalance between supply and demand."
J.P. Chevriere, CEO, Transmar Consult.

"This industry does go through cycles of highs and lows. We have been here before. We don't have to panic. This is a long-term industry based over decades of investment."
Neil Gordon, CEO, Subsea UK

To gauge the business drivers in operating companies in the current low oil price environment, a series of interviews were conducted with decision-making personnel at operating companies. As part of the research interviews, the following questions were posed:

1. In your opinion, what are the top 3-5 priorities for an offshore operations/production superintendent?
2. What has been the impact of the lower oil and gas prices recently on these priorities?
3. How have digital technologies impacted offshore production operations including well lifecycle integrity management, well intervention/well workover and production optimization?
4. What are the barriers to adopting more of these digital technology products, services and solutions in today's industry and commercial climate?
5. What more in this area would you like to see happen? (Technology adoption, regulation, culture change, etc.)

The main findings that emerged from the responses are summarized below.

Production priorities and challenges

- **Safety and environmental performance** (including work permits, standards and procedures): This is always a priority, but many overlook the strong connection to enhanced profitability. Incidents cost and not in just dollars. Almost everyone has the processes in place, along with training to ensure increasingly better performance.

- **Maximizing production:** When oil prices and margins are good, this is the primary metric that drives all others (maintenance schedules, critical spares etc.). Recovering from production outages, including root cause analysis (RCA) and follow-up investigations are a priority.

- **Operating cost optimization:** When oil prices come down and margins are squeezed, this is the primary metric that drives all others, as the focus shifts away from maximizing production.

- **Oversight of hydrocarbon processing:** New deep-water production facilities are more like processing plants than just a collection of wells (including injection processes and other associated plant systems). The efficient operation of these sites is an important part of the total production platform. This is an area where challenges remain.

Impact of oil prices on priorities

- Hopefully, there has been no impact on safety and environmental performance, since many consider this priority to be a core value. Where a value is not considered "core", lower prices can lead to deferral of maintenance and repairs, causing more vulnerability to incidents. It can also lead to a reduction in workforce that will increase the scope of what the remaining workforce needs to be accountable for, increasing pressure on those functions.

- Maximizing production will continue, but be prioritized to those areas where the profit margins can better support the pressure on financial resources. Thinner (or negative) margin areas will be reduced or deferred as long as there are not long-term lasting negative consequences of doing so. Normal annual field decline is 10-15% without reinvestment, with spending on areas such as maintenance, workovers and infill drilling, that decline can be slowed to 3-6% annually.

- Operating cost optimization will become the all-consuming priority. In many cases, cutting costs first and sorting out the consequences second could cause short-term inefficiencies. However, if done correctly, this period of price downturn is the best time to develop a much more optimized cost management mindset.

- The impact of lower oil and gas prices has been much the same as any other position in the industry: more focus on costs which means less resources, people and money, to do the same job. It is possible that some optimization work that may have been undertaken in a higher price environment is being deferred.

Impact of digital technologies on operations

- Overall, digital technologies and services, or work process change enabled by digital technologies, have reached a point where transformational change and significant enhanced performance is possible and being applied where leadership has reinforced it as a priority.

- Well lifecycles have been increased by optimization of flow rates and recovery from the reservoir to the sales point.

- Integrity management is utilizing digital analytics to predict failures, achieve better time scheduling of maintenance, pin-pointing root causes and implementing response plans based on past events.

- Well intervention and well workover enhancements can be seen where enhanced collaboration and real-time collective decision-making can make better calls on next steps and remedial actions, limiting non-productive time and 'silo'd' decisions.

- Production optimization is the largest prize since enhancements will directly and immediately impact the bottom-line of either increased production or reduced cost. This occurs when there is: a more integrated approach between disciplines, ready access to the right information, better accuracy of information, visualization of the impact environments for better understanding of the context, and simulating decisions before making them, thereby reducing risk before implementation of a decision in a business environment full of risk.

- All the above is being enhanced, in a step-change manner, where integrated operations centers are deployed. These are connecting all involved parties between offshore and onshore to make the right decisions at the right time, significantly enhancing performance by addressing the most important areas with the most impact.

- Digital technologies continue to provide more data for analysis and better technology to undertake analyses. Real-time systems enable quick decisions to be made (sometimes automated) to avoid an incident or downtime. Analyses of failures and outages can be fed back into CMMS systems to optimize maintenance plans. Actual performance can be compared with the models to identify improvement opportunities on both existing and future wells.

The barriers to adoption of digital services

- Presenting technologies, products, services and solutions without focusing on the work processes they would be used in, along with the associated behaviors required to make them effective.
- Short-termist leaders that are overly focused on monthly and quarterly metrics.
- A commercial climate with lower prices and reduced margins is the best environment in which to aggressively pursue transformational change, as costs of implementation can be minimized, allowing enhanced optimized performance when prices recover.
- Organizational change management has historically been the major barrier to implementing more digital technology products, services and solutions. There is an additional issue of increased competition for limited capital dollars due to the lower oil price environment.
- Leadership behaviors and culture change that will enable the above as a strategic priority, for long-term success (both in the up- and down-cycles).

In addition to the priorities for production operations that have been identified through interviews, there are several additional challenges and opportunities for digital solutions related to facilities design, engineering, construction and installation:

- **Capital project management:** 64% of industry projects are facing cost overruns and 73% are running behind schedule: "Beyond concepts, we need to be strongly focused on the practicalities of project execution – simplicity, standardization, innovation, technological creativity and delivering tangible results to clients." – Thierry Pilenko, CEP Technip.

An operator perspective

Cliff McBain, supervisor of E&P application support, Marathon

McBain has worked in Upstream IT all of his 27 years with Marathon. He views production engineering and operations as having been the "poor relations" when it comes to digital oil field projects in the past. However, he sees that situation is now changing. Production engineers who in the past have just wanted to "get on with it" are now looking to technology to help them with the larger scale of operations (more wells to look after), more complexity and greater cost concerns.

With the engineering and operations community, any project that promises to add more barrels is the "quickest way to get management's attention" says McBain. But two challenges often stand in the way. The first is the need for a clear definition of the problem, well-articulated business requirements. Often project teams are too quickly attracted to the technology options before they fully understand the problems and the business case they are aiming for. A long history of this technology-centric behavior has created a credibility problem with management is some parts of companies.

The other major stumbling block, according to McBain, is the lack of data standards and questionable data quality: "The industry copes with varying data standards, often application or discipline specific, which presents a significant integration challenge when it comes to developing and deploying digital solutions to the field. As an IT professional, I'd like to see more technology adoption. I'd also like to see more standardization of systems to help simplify the data quality and data integration aspects of the analytics that are now being expected. Having those systems leverage a standard data model (e.g. PPDM) would also be beneficial".

- **Collaboration:** "There needs to be more collaboration, but collaboration with a purpose – between operator and supplier to keep costs down. The cost structure was too high at $100/bbl let alone $50/bbl. There is a need for radical change." – Bernard Looney, general manager of BP production.
- **Standardization:** BP has been working with its suppliers over the past 18 months to reduce

specifications on equipment where its specs went beyond industry standards. The options come down to:

- **Custom integration:** This leads to custom development, specific data adapters and the owner/ operator ending up responsible for sustainability of the physical and digital asset or
- **Open industrial interoperability:** This leads to configuration rather than development, based on supplier neutral open standards, plug and play model, where suppliers remain responsible for sustainability of the digital solution.

Well integrity management

All operators are aware that the loss of production due to well integrity issues has a direct impact on profitability. Management of well and production infrastructure (including pipelines) is fundamental to good performance.

However, well integrity is not solely an issue of well availability. A combination of HSE (health, safety and environment), corporate social responsibility and government regulations are driving a renewed focus on this topic. From the wellhead to the sand face, the poor condition of wells has potential HSE consequences, as operators have discovered. Ensuring the integrity of critical barriers in a well is of the utmost importance.

While new wells cannot be ignored, particularly in challenging environments such as HP/HT (high-pressure/high-temperature) or deep-water, mature brownfield assets are the traditional focus for well integrity issues. For fields in long-term decline, operators are challenged to slow the curve. Extending field life, however, only increases the scale of well integrity issues to be dealt with. Even when wells are temporarily abandoned, they still represent a sizable liability for well integrity programs. A recent study estimates that there are over 4,000 idle iron wells that have been temporarily abandoned in the Gulf of Mexico, some for over a decade.

Definition of well integrity: Application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the lifecycle of the well.

Well integrity lifecycle – stages include: Design, Construct, Operate, Maintain, Abandon

Well integrity is not just a one-time event, or a purchase of a specific type of equipment. An operator should develop a defined program and integrate training, technology and equipment procurement and operational processes into an holistic view of operations.

An operator perspective

Lars Endre Hestenes, Well Integrity Manager, BG Group

Lars elaborated that a new, single, engineering standard was introduced to integrate well integrity more firmly into production operations in 2014. BG Group had maybe 15 or 20 standards, which were combined into a single well engineering standard, now considered a minimum standard. This new standard went live in January 2015 and BG Group is now promoting well integrity as an embedded function of the production process because of problems arising from older wells, including those handed over by former owners. UK-headquartered BG Group is an explorer and producer of natural gas in more than 20 countries and as its assets age, the maintenance of wells now takes up a much larger portion of the firm's well service activity than it did in recent years.

The promotion of well integrity within BG Group could be compared with the elevation of health, safety and environment (HSE) in the industry at large, Hestenes added. "Well integrity and well engineering are similar disciplines but have not been integrated in the production operation. Now we are inviting well engineering into the space, so it's not just the well integrity engineer who is responsible for well integrity. It's what BG Group call a function-critical role, so that means the head of production is driving this, asking, how are our HSE figures? How is our well integrity? Have you had any issues? It's trying to fix things early before they escalate into multiple failures."

A contractor perspective

Kevin Borzel, Vice President, Steelhead Energy Services

Kevin found whilst working for an operator that senior executives had questions around how much money the company was spending at end of lifecycle. Once upper management grasped the liabilities associated with end of lifecycle well integrity was raised through the business. Then the awareness sets in – that in order to overcome the costs associated with the end of the lifecycle, you plan for the end of the lifecycle at the beginning of developing the asset. Senior management are realizing that to avoid those costs at the end of the lifecycle you need a proactive approach when designing and maintaining the wells, for lifecycle and the time of abandonment, and this requires additional upfront investment which in the long-term saves capital. The well integrity function is infiltrating mainstream operations across the industry, but end-of-life strategies are still largely reactive, Borzel added. More monitoring of well conditions throughout the well lifecycle is needed to move from a lagging to a leading style of well management.

The BG Group is one example of a company that is embracing well engineering standards and well integrity management from an enterprise perspective. BG Group has simplified numerous well engineering standards into one and removed organizational barriers between well integrity and production disciplines, highlighting operators' concerns over ageing assets.

One example of the elements of a well integrity management program should include is below:

Well integrity management program

1) Accountability and responsibility.
2) Well operations: Well ownership and handover, personnel competency, procedures (startup, operations, shutdown), corrosion and erosion management.
3) Well interventions: Ownership, competency, procedures, records, documents of well service events.
4) Tubing/Annulus program (assigned operating pressure limits, report anomalies and respond, every well is different.
5) Wellhead/ Tree maintenance.
6) Safety valve program.
7) Data management: Input retrieval, reporting/ regulatory.

Definition of well intervention: A well intervention, or 'well work', is any operation carried out on an oil or gas well during, or at the end of, its productive life, that alters the state of the well and or well geometry, provides well diagnostics or manages the production of the well.

The SURF IM Network program

Collaboration seems to be a popular approach for well integrity issues. It was recently announced that a Wood Group Kenny-led (WGK) forum that addresses subsea integrity management issues is to be extended for a further three years. Phase I of the **SURF IM Network** got under way last year, supported by 14 operators. Phase II, with estimated costs of £300,000 ($460,000), will run on an annual subscription basis through 2018. The program organizes face-to-face and virtual forums for knowledge sharing and devising solutions to subsea integrity and reliability problems, with a focus on subsea hardware.

Phase I priorities included improved understanding of control system module reliability, integrity challenges and ways of achieving enhanced reliability in the future. A previous WGK joint industry project on integrity management of subsea, umbilical, riser and flow-line systems. The project identified key failure mechanisms, investigated inspection monitoring technologies and developed best practice guidelines for integrity management of subsea facilities.

Integrity standards

The NORSOK D-010 standards developed by the Norwegian petroleum industry are considered the reference for well integrity in offshore operations. In 1993, the oil industry in Norway developed an initiative called NORSOK with the aim of increasing Norway's competitiveness in delivering field solutions. Out of this initiative, a number of standards were developed to make deliveries and operations more cost efficient through standardization.

Selective parts of international standards (ACME, API) and the NORSOK standards are recommended ways of complying with the regulations. Operators did not have to follow D-010 but, if they did not, the burden of proof fell on them to demonstrate that their own approach fulfilled the requirements. It gave the industry both the responsibility to justify their methods, and a way of doing it. In the 2000s D-010 became the well integrity standard.

In 2003 revision number three of D-010 was released. In this revision D-010 was significantly changed and expanded to focus on well integrity in planning and execution of all drilling and operations throughout the lifecycle of the well. Also unique about the new D-010 was its extensive use of well barrier schematics (**WBS**) to illustrate the well barriers to put in place for a specific operation. Norsk Hydro made their WBS library available to the editors of Rev. 3, resulting in the inclusion of many drawings. To supplement the WBS, a library of 50 detailed descriptions of well barrier elements – the essential building blocks of an effective well barrier – were developed.

Asset integrity safety

Regardless of where the industry operates, what technology it uses and what resources it aims to exploit, safe operations and minimal impact to the environment have to be of the highest priority. The integrity of well bores, pipelines and processing equipment are critical elements of production operations. Digital solutions have an important role to play in increasing the operating safety and preventing oil & gas, both onshore and offshore, from making the headlines for the wrong reasons.

Plains All American pipeline spill in California

Federal regulators are investigating the cause of a leak that spilled up to 105,000 gallons of crude oil from an underground pipe into a culvert and as much as 21,000 gallons into the ocean at Refugio State Beach. The pipeline that leaked thousands of gallons of oil on the California coast was the only pipe of its kind in the county not required to have an automatic shut-off valve because of a court ruling nearly three decades ago. The original owner of the pipeline received a waiver from the Santa Barbara County requirement by successfully arguing in court in the late 1980s that it should be subject to federal oversight because the pipeline is part of an interstate network. Auto shut-off valves were not required by federal regulators at that time.

Plains said the pipeline had one valve to shut it down if oil flowed in the opposite direction and three valves controlled by operators in its Midland, Texas control room. Plains defended its people-based approach to manually shutting down the system, saying that it was the standard across the country for liquid pipelines. To date, clean-up costs have exceeded $100 million and production has been shut down on several offshore facilities as the pipeline was the only way to get oil to the refinery.

Statoil Gudrun condensate leak

Statoil ASA said a condensate leak at its Gudrun platform in the North Sea could have been much worse, even fatal, had anyone been present at the time. Results of a corporate investigation revealed a 2-mm wide crack extending 90% across the circumference of a 2-in. pipeline. The volume of the leak is estimated at 4 m3, with the leak rate calculated at 8 kg/sec. The investigation team believed that pure chance prevented a full break on the line. In announcing the results, the company classified the incident to be of the highest degree of seriousness.

The company said the crack was the result of fatigue and overload. An under-dimensioned level valve led to vibrations in the valve itself and in the surrounding piping system. The vibrations resulted in the loss of level valve control. The loss of valve control caused repeating powerful vibrations and strokes in the piping system that exceeded design capacity.
Gas detectors recorded the leak, ignition sources were disconnected, and the deluge system started automatically, as did the pressure relief system and the emergency shutdown system.

Pemex: Three fires in one field in three months

Petroleos Mexicanos (Pemex) suffered three fires in 2015 on platforms in the Gulf of Mexico. An accident at the Akal-H platform, a fire at the Abkatun A-Permanete platform and the collapse of a jack-up rig in Campeche Bay.

The oil and gas industry is under pressure to reduce costs and maintain production, but safety and environmental concerns cannot be lowered despite greater economic constraints. Equipment will break, pipelines will degrade over time, and people will make mistakes in the harsh offshore operating conditions. This is the right opportunity for the industry to consider digital solutions either on facilities or at a remote support center, which offer greater insight and control through monitoring and surveillance capabilities.

Digital solutions for the offshore operating environment are not a one-size-fits-all opportunity. An operator has to start with an understanding of the problem they want to solve. Next, they need to gain clarity around the work processes related to those business requirements. After this, they can start to investigate the technology opportunities available to transform the work processes into a smarter way of doing business and help avoid accidents.

Operational excellence

Cost-cutting is set to remain the main focus for the oil industry for at least the next few years as offshore operators adjust to an environment of lower prices. If the expansion of the last few years was characterized by an emphasis on complex engineering projects in deeper water and more remote locations, the downturn will bring a renewed focus on simplification and efficiency.

The fall in oil prices has exposed an inflated cost base in many oil and gas companies, forcing the industry to reduce operating costs, rationalize investment budgets and boast operational efficiency. This is also an opportunity to drive through fundamental improvements in the way the operations function and there are a number of offshore markets where opportunities for digital services are set to expand.

2.

Emerging markets

The industry focus has been on shale oil and gas production in North America in the past few years however, the demand for offshore solutions remains strong despite the drop in oil prices and the reduction of capital budgets amongst operators. Global subsea production output is set to grow by an estimated 80% between 2015 and 2020. This represents an investment of between $30 and $55 billion.

While mature offshore basins, like the UK North Sea, are suffering from higher operating expenses, other offshore basins offer attractive opportunities. Some are well known, such as the Gulf of Mexico deep-water and West Africa (offshore Nigeria and Angola). Others are only now entering a new growth stage, such as offshore Brazil and Mexico, whilst others still are coming on the scene as pure frontier plays, such as East Africa (offshore Mozambique and Tanzania).

The current low oil prices environment has affected the project landscape. The steep decline in global oil prices has caused the cancellation or delay of 24 major deep water oil projects and complex natural gas facilities valued at a total of $200 billion. As a result, international oil companies are exploring ways to integrate flexibility into their assets. Each basin offers unique opportunities and challenges for operators who are willing to take the long-term view and invest in technologies and capabilities to make these future assets part of their portfolios.

Brazil: Deepwater subsalt prospects

The IEA predicts that Brazilian oil production, at approximately 2 MMboe/d in 2014, can be increased to 6 MMboe/d by 2035. The discovery of the pré-sal (or pre-salt) layer provides the resource base that underlies the substantial growth estimates. However, more recent estimates that take into account the financial troubles of Petróleo Brasileiro S.A. (Petrobras) and lower oil prices moderate that growth forecast to 4 MMboe/d by 2020. The company itself expects to reach total production of oil and gas (Brazil and international) of 3.7 MMboe/d in 2020, with pre-salt accounting for more than half the total oil production.

Petrobras recently announced plans to reduce capital expenditures to the end of this decade. The new investment plan prioritizes oil exploration and production projects in Brazil, focusing on the pre-salt. For other business areas, investment will be largely limited to maintaining operations, and for projects related to offloading oil and natural gas. Total investments have been reduced 37% in relation to the previous plan. Exploration and production has been allocated $108.6 billion, of that, 86% will go to production development, 11% to exploration, and 3% to operations support. New production systems investment in Brazil will total $64.4 billion, of which 91% will be for the pre-salt. Exploration activities within Brazil will be concentrated on meeting the Minimum Exploratory Program for each block.

The pre-salt layer was discovered 5,000 meters under the seabed off the Brazilian coast. The geologic basin extends for 800 km in length between the states of Espírito Santo and Santa Catarina. The pré-sal play is considered the largest new oil province found in the world within the last 30 years. The expected potential of pré-sal prospects is forecasted to be 1.6 trillion m3 of gas and oil.

The exploration of pre-salt would make the Brazilian oil industry one of the ten largest producers worldwide. The deposits discovered would add $28 billion in oil export revenue in 2020. Petrobrás has already invested $53.4 billion in pre-salt between 2011 and 2015. With this investment, pre-salt oil production increased from 2% of total Brazilian production in 2011, to 18% in 2015. Much like the deep-water Gulf of Mexico, a dramatic shift from traditional fields to the new deep-water frontier is taking place rapidly.

As a result, Brazil has become a global center for offshore oil production, especially in subsalt and subsea production technologies. The discovery of new basins and world-class fields (like Lula and Tupi) and the end of the state monopoly over oil exploration established a new era for this industry in Brazil.

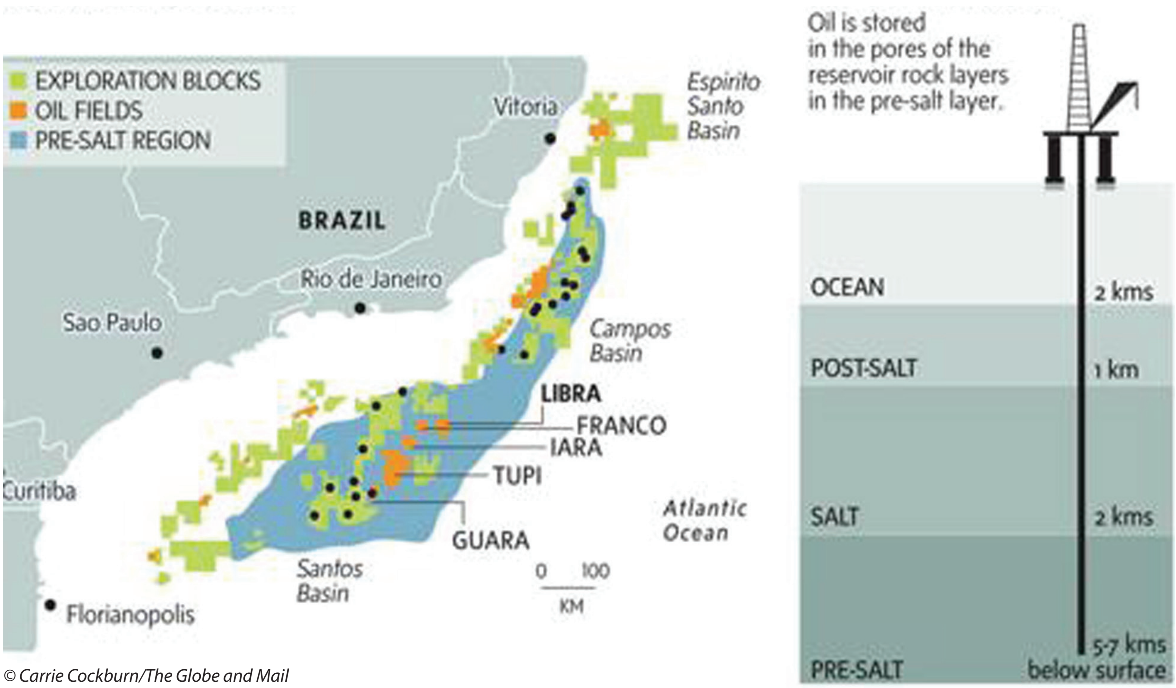
The challenges to exploit these resources are more than just technical. Lower oil prices and the procurement scandal in Petrobras will slow down some of the investment needed to access the pre-salt resources.

Opportunity for digital solutions

Brazil has become a growing center for global services companies who have established R&D centers in the country. The Global Research and Development Center in Rio de Janeiro, within the Technology Park located on the campus of the Universidade Federal do Rio de Janeiro on Ilha do Fundão (RJ), hosts R&D facilities from Intel, EMC, GE, Siemens, Tenaris and others. In-country development, or at least partnership, may be a requirement or an unstated advantage for new vendors.

Petrobras will lead the effort to design, construct and deploy modern production facilities in the pre-salt basins (Campos and Santos Basins). While the pace of new developments will be slowed, Brazil's subsalt offshore province will still be a major growth opportunity for the industry. Technology advances from service companies and technology vendors are

Figure 1: Brazilian oil fields



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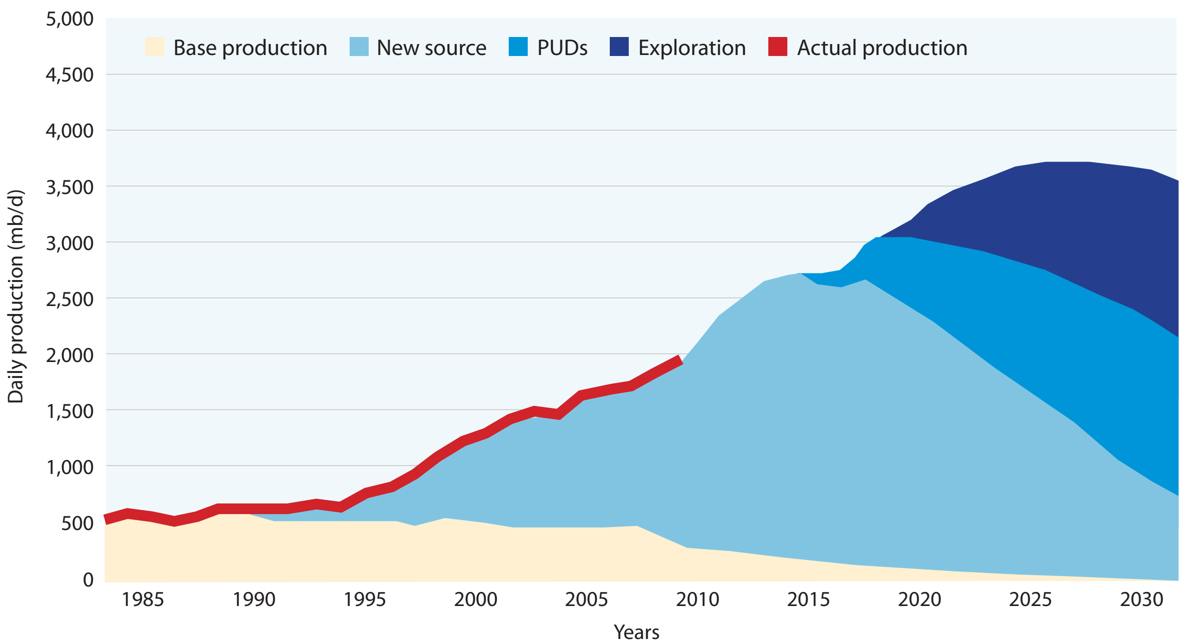
Sources: Petrobras, Wood Mackenzie, Graphics News

Figure 2: Brazil's production profile to 2030

Brazil: Oil production forecast by reservoir category



targeting these new platforms. The new platforms will be fully instrumented with many of the digital solutions that have been pioneered in the Gulf of Mexico, such as real-time drilling for complex wells, real-time reservoir management and equipment health monitoring.

Brazil does not plan to just emulate the Gulf of Mexico; the new R&D investments promise results beyond what is being done elsewhere in the industry. Large reserves and long-term production profiles will allow a more strategic perspective by operators and investors in the region. These new production facilities should be the showpiece for emerging digital technology solutions, but successful vendors will have to play by stricter procurement rules to be part of this exciting province.

Mexico: A new frontier for the Gulf

While it looks like major international oil companies are waiting on deep-water acreage to be included in bid rounds, Mexico made good on its promise to hold auctions for foreign participation in July, 2015. Mexico's first auction of offshore oil leases fell short of the country's expectations. Only two of the 14 shallow-water blocks released received qualifying bids. Exxon Mobil Corp., Chevron Corp. and Total SA passed on the country's sale of territory in the Gulf of Mexico. Nevertheless, the sale is just the beginning of a new frontier for the Gulf of Mexico.

The oil and gas auction was the first in a series that will help determine whether Mexico can reverse a decade-long decline in crude output and fulfill President Enrique Pena Nieto's pledge to double the speed of economic growth. An output drop and plunge in oil prices during the past year had already forced Mexico to trim government spending and improve the contract terms for prospective bidders.

Sierra Oil & Gas, the first private oil company formed after the country's energy overhaul, won the only two blocks of the day. Sierra bid alongside Premier Oil Plc and Talos Energy LLC to beat out companies such as Statoil ASA and a consortium led by Eni SpA to win rights to develop blocks 2 and 7, located in the shallow waters off the coasts of Mexico's Veracruz and Tabasco states, respectively.

On August 11, 2014 Mexico's president signed into law legislation that will open its oil and natural gas markets to foreign direct investment, effectively ending the 77-year-old monopoly of state-owned Petróleos Mexicanos (Pemex). These laws, which follow previously-adopted changes in Mexico's constitution to eliminate provisions that prohibited direct foreign investment in that nation's oil and natural gas sector, are likely to have major implications for the future of Mexico's oil production profile. As a result of the developments in Mexico over the past year, the EIA has revised its expectations for long-term growth in Mexico's oil production.

Although there are many complexities to the new reform and many details that still must be settled before the reforms can take effect, reform is expected to improve the long-term outlook for growth in Mexico's petroleum and other liquids production.

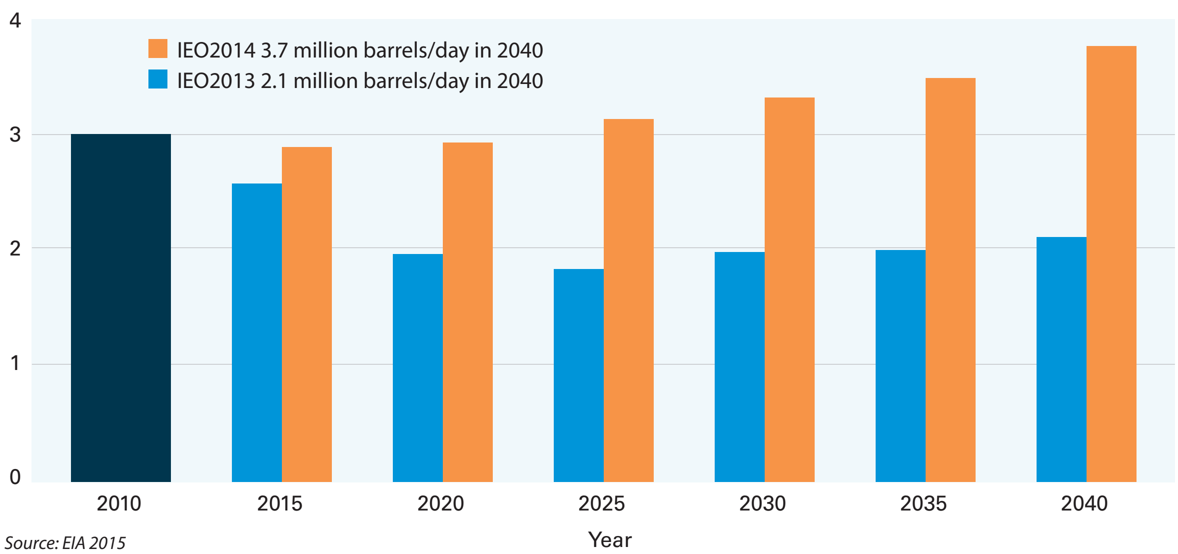
The International Energy Outlook 2014 projected that Mexico's production would continue to decline from 3.0 MMbbl/d in 2010 to 1.8 MMbbl/d in 2025 and then struggle to remain in the range of 2.0 to 2.1 MMbbl/d through 2040. The 2015 Outlook, which assumes some success in implementing the new reforms, projects that Mexico's production could stabilize at 2.9 MMbbl/d through 2020 and then rise to 3.7 MMbbl/d by 2040 – 75% higher than the previous year's outlook. Actual performance could still differ significantly from these projections because of the future success of reforms, resource and technology developments, and world oil market prices.

Since 2008, the contract structure for any private company partnering with Pemex was a performance-based service contract, which offered financial incentives to private contractors working in Mexico's upstream sector. Incentives were provided in some cases, such as when a project is completed ahead of schedule, when Pemex benefits from the use of new technology provided by the contractor, or when the contractor is more successful than originally expected. These contracts also include penalties for environmental negligence or failure to meet contractual obligations.

Mexico's legislation introduced three new contract types that will provide more opportunity for foreign investment in its energy sector:

- Profit-sharing contracts allow companies to receive a percentage of the profits resulting from oil and natural gas development. While companies entering into these contracts would not own the resources being developed, they would be allowed to include

Figure 3: Mexico petroleum and other liquids production (2010-2040)



Source: EIA 2015

the revenue from their part of the estimated future profits.

- Production-sharing contracts allow companies to own a percentage of resource volumes as they are produced.
- Licenses allow participating companies to be paid in the form of oil and natural gas extracted from each project.

The production-sharing contracts and licenses will effectively allow foreign companies to account for reserves, which is a particularly attractive incentive for investment in Mexico's energy sector. Different contract types will likely be awarded according to the degree of risk associated with specific projects. For instance, licenses will likely be used for projects that are very capital intensive and high-risk, requiring advanced technology, like oil shale or ultra-deep-water projects. Less risky onshore and shallow offshore projects would more likely use profit-sharing arrangements.

Opportunity for digital solutions

The new acreage blocks and the developments that will follow successful exploration will be good candidates for the types of digital solutions that have already been adopted in the US portion of the Gulf of Mexico. Both in shallow water, where Pemex already has considerable experience, and in deep-water developments, solutions focusing on real-time reservoir management and preventive maintenance of critical equipment will be sought. International operators will probably concentrate their investments in the available deep water tracts.

New facilities will have the chance to be launched with digital technology embedded, with designs beginning with facility instrumentation, process control automation and onshore decision support centers from initial specification. Manning expectations and the roles of offshore operations staff and onshore production and reservoir experts can be modified from current operations models (as per new North Sea developments) with digital solutions designed in, rather than added on.

There will be a need for a modern high-speed, low-latency communications infrastructure to connect field to office as with the fiber optic ring in the US sector. Pemex will still have a major role to play and will be an important customer of new digital solutions and emerging technology. Investment in declining field production in the Bay of Campeche, such as water-flooding and management of aging infrastructure, is an opportunity not to be overlooked.

East Africa: An LNG export frontier

With extraordinary discoveries of natural gas in the Rovuma Basin, East Africa is emerging as a new LNG frontier. The International Energy Agency (IEA) estimates that Africa holds nearly 74 trillion m3 of technically recoverable natural gas reserves, nearly 10% of the world's total, and it is believed that the majority of African natural resources are still undiscovered.

Oil and gas production in Africa has mainly been driven by operations in West Africa (Nigeria and Angola). However, exploration discoveries and development plans for offshore East Africa, in Mozambique and Tanzania, are changing the industry's view of Africa's potential. In 2012, African natural gas production reached 213 billion m3 (nearly twice the volume of European gas production, and nearly a third of natural gas production in the US in 2012) with an annual growth of nearly 4% since 2000. The IEA estimates that African natural gas production will nearly double by 2035, reaching 400 billion m3. Even though consumption of natural gas is expected to rise, reaching 170 billion m3 in 2035, there is still substantial room for gas exports to other markets. In 2012, Africa accounted for 16.8% of the global LNG export volumes, with Nigeria the fourth-largest LNG exporter in the world.

Mozambique and Tanzania

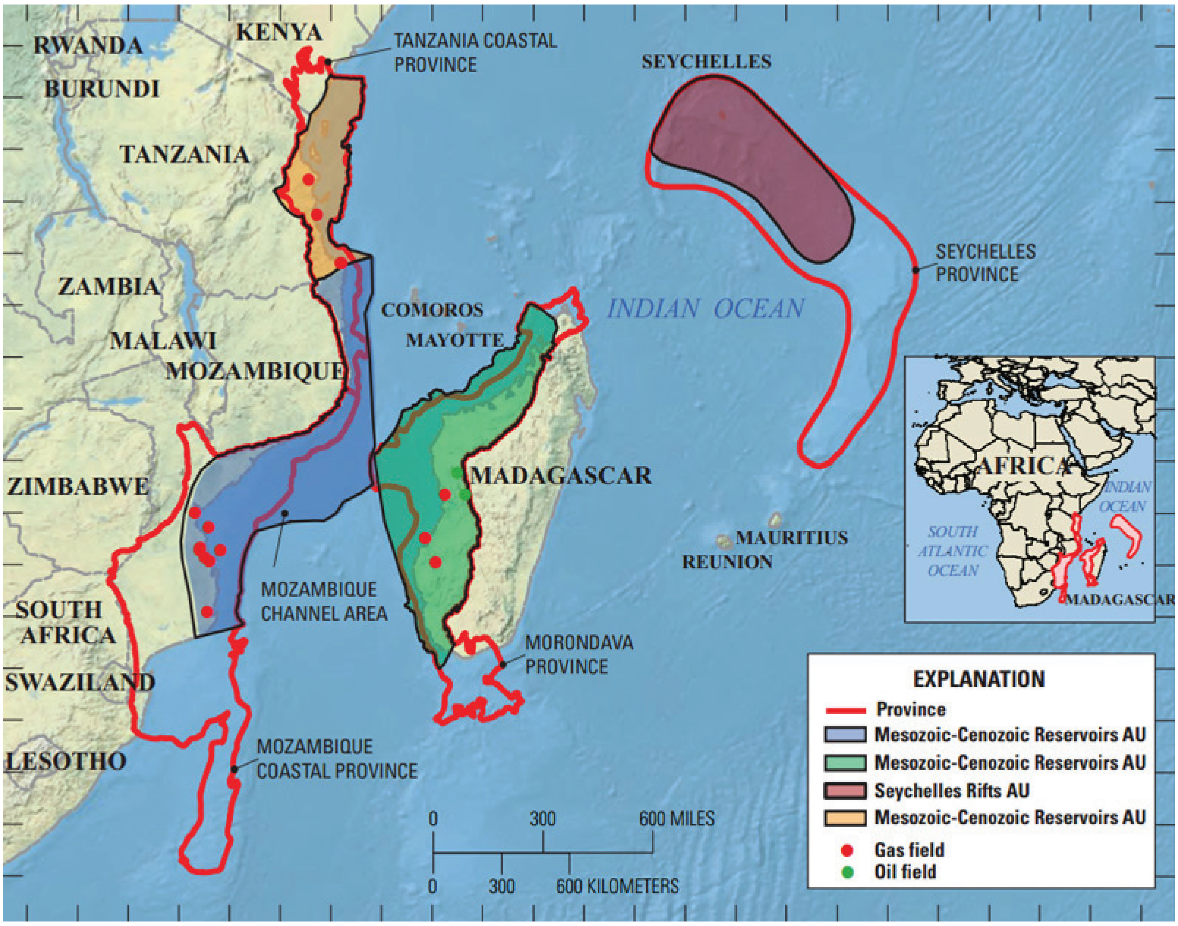
When Anadarko made its gas discovery offshore Mozambique (in Area 1 of the Rovuma Basin), East

Africa was transformed into a new global gas supply region. There were four subsequent discoveries in the area made by Anadarko, along with discoveries in the nearby Area 4 by ENI (in the Mamba prospect), resulting in nearly 2.4 trillion m3 of new recoverable gas reserves. Next to Mozambique, in the Tanzanian share of the Rovuma Basin, BG Group, Ophir Energy, Statoil and its partner ExxonMobil have also discovered major gas deposits, altogether accounting for a further 425 billion m3 of recoverable reserves. At the time of increasing global demand for natural gas, these newly discovered resources offshore Tanzania and Mozambique were substantial, and have prompted companies to develop new LNG export terminals.

In the case of Mozambique, ENI and Anadarko have agreed to unitize their new gas find and jointly develop an LNG export project in order to reduce project development cost. The new LNG facility is due to become operational in 2018 with two 5 million tpa liquefaction trains, plus opportunity for significant expansion in the future. In its published Gas Master Plan, the government of Mozambique states that it expects 10 liquefaction trains to be in operation by 2026, with an overall capacity of 69 billion m3/y. This could make Mozambique one of the world's top LNG exporters.

Anadarko Petroleum has selected a consortium for the initial development of an LNG complex onshore Mozambique to process production from the company's deep-water gas fields. Following a front-end engineering and design competition, CB&I, Chiyoda Corp., and Saipem (CCS JV) were awarded the contract. Anadarko Chairman Al Walker has

Figure 4: Natural gas discoveries, offshore Mozambique



announced the company and its co-venture partners have, to date, secured 8.8 million tons per year in non-binding long-term off-take agreements, which are now progressing toward binding sales and purchase agreements. They have additionally obtained letters of intent from lenders for project financing and are working with Mozambique's government to keep the project moving forward. They expect to submit a plan of development in 2015.

Offshore Tanzania, Statoil and BG Group are looking into a joint development of their new gas find and the construction of another LNG facility. However, the Tanzanian government has questioned whether the discovered reserves are big enough to develop a large-scale LNG export project on top of meeting domestic demand for natural gas. In order to approve the LNG export terminal construction plan, the government indicated that more gas must eventually be found. In the meantime, a final investment decision on the Tanzanian LNG export terminal is expected to take place in 2016, with the first potential LNG cargo in 2020.

Opportunities for digital solutions

All of the developments in this play will have to consider the lack of local infrastructure, both offshore and onshore. Digital solutions offer the opportunity for more remote monitoring and surveillance and expert decision support for operators. While there will likely be a call for the development of in-country skills and capabilities, operators should augment those investments with digital solutions that focus both on automation offshore and decision support in the operators' home countries. Natural gas production is simpler than a complex oil reservoir, so automation and process control offer many valuable opportunities to improve efficiency and sustainability of production and process equipment. Leveraging offshore experts through engineering and subsurface workflow solutions will keep costs down and bring existing best practices from around the world to these assets. Automation and remote monitoring will also help improve safety and environmental performance of the assets if done correctly.

Cybersecurity solutions will have to be part of every workflow design with increasing risks in the area and with the dependence on remote resources, the telecommunications infrastructure will be a critical element of the digital solution architecture. Solutions that extend from production through processing to export could be an advantage.

Global deep water: Major focus for future growth

Oil and Gas production in shallow water has become very mature in most oil and gas provinces. The challenge is to move into deeper water, more remote locations and more complex wells and reservoirs. With production in water depths of more than 2,744 m (9,000 ft.) already, operators are looking for technology solutions for water depths beyond current limits. New solutions are recquired for challenges in higher temperature and pressure fields, measurement and seabed processing requirements.

These new challenges are not stopping the industry and oil and gas production from ultra-deep-water fields (>1,000m/3,281 ft.) is expected to grow 7.7% during 2015-2021, from 6.5 MMboe/d to 10.2 MMboe/d. Growth will likely come from the drilling of 1,470 ultra-deep-water wells, an increase of 68% over the previous seven years.

> *"The world needs new sources of oil, and deep water holds the greatest promise of meeting this demand. But these sources are expensive to develop, and operators will not pursue them unless they can significantly reduce costs."*
> **John Gremp, CEO, FMC**

At these water depths, and with lower oil prices, only the most highly productive plays are being targeted. Deep-water projects typically have funding secured several years ahead of first production. The main deep-water oil producers – Angola, Brazil, Nigeria, and the US – look set to lead, with the strongest forecast growth (up from 1.2 MMb/d of deepwater production in 2015 to 1.7 MMb/d in 2021). This is due to 11 floating production platforms entering service, including Anadarko's Lucius spar, Chevron's Jack/St. Malo and BP's Mad Dog Phase 2 semisubmersibles.

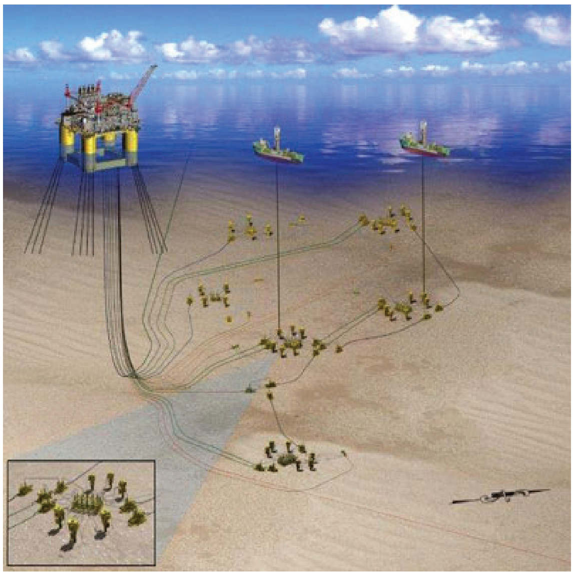
Deep-water gas production could more than double from 1.1 MMboe/d in 2015 to 2.5 MMboe/d in 2021. Although much of this growth will come from established producers, ultra-deep-water gas will start being exploited for the first time off Equatorial Guinea and Mozambique, where FLNG vessels are likely to begin operations on ultra-deep-water fields late this decade. Israel, in the Levant Basin, could also produce large volumes from various green field developments and subsea tiebacks.

The Gulf of Mexico's Lower Tertiary plays represent one of the largest prizes of any offshore development. The Lower Tertiary fields could hold between 14 and 40 billion barrels of oil. These reserves are equivalent to, or exceed, what has been found in the Gulf of Mexico shelf, but they come with a new set of challenges, including water depth, greater pressures and temperatures and complex reservoirs.

An example of a new deep-water investment is Shell's Appomattox development project in the Gulf of Mexico. This recent investment decision authorizes the construction and installation of Shell's eighth and largest floating platform in the Gulf of Mexico. The Appomattox development initially will produce from the Appomattox and Vicksburg fields, with average peak production estimated at 175,000 boe/d.

The platform and the Appomattox and Vicksburg fields will be owned by Shell (79%) and Nexen Petroleum Offshore U.S.A. Inc. (21%), a wholly owned subsidiary of CNOOC Ltd. The Appomattox development host will comprise a semisubmersible, four-column production host platform, a subsea system featuring six drill centers, 15 producing wells, and five water injection wells. Appomattox is 80 miles (129 km) off the shore of Louisiana, in approximately 7,200 ft. (2,195 m) of water. The sanctioned project includes capital for the development of 650 MMboe resources at Appomattox and Vicksburg, with start-up estimated around the end of this decade.

Figure 5: Conceptual design for Shell's Appomattox development, Gulf of Mexico



The development of Shell's recent nearby discoveries at the Gettysburg and Rydberg prospects remains under review. These could become tiebacks to Appomattox, bringing the total estimated discovered resources in the area to more than 800 MMboe. Shell Pipeline Co. LP also made a final investment decision on the Mattox Pipeline, a 24-in. corridor pipeline to transport crude oil from the Appomattox host to an existing offshore structure in the South Pass area, and then connect onshore through an existing pipeline.

Opportunity for digital solutions

The deep-water environment presents an array of technical challenges, including high water depths, high pressure/high temperature, complex reservoirs and the need for remote operations. For operators that choose subsea completions, digital solutions and automation will replace humans at the production site. Remote operations will be fully responsible for monitoring and operations decisions as well as optimization of the reservoir and asset lifecycle investment decisions. For other deep-water facilities, real-time reservoir management can accelerate cash flows by achieving production targets faster. Automation can also optimize the fluid management by starting water flood and gas injection operations from day one.

Downtime from equipment failures and well interventions can be extremely costly in deep-water, so predictive maintenance is critical. The amount of data from new deep-water facilities will only increase. The challenges are to manage this data stream, visualize current conditions recognize important patterns of possible incidents and identify potential value generating opportunities. Any repeat of the Macondo incident cannot be tolerated by the industry or by regulatory agencies. Health, environment and safety applications backed by sophisticated risk management solutions will be required.

Due to the high cost of deep-water major capital projects (often exceeding $10 billion), project management solutions from material management, coordination of construction from several sites, technology for construction sites and mobile IT will be valued. A smooth turnover-to-operations commission process will demonstrate value as will processes that will accelerate production to help to recover the high capital costs involved.

The Arctic: The exploration of a new frontier

As climate change renders the Arctic region increasingly accessible, there has been a substantial uptick in industry interest in the area, up to $100 billion could be invested in the Arctic over the next decade. Shell is taking a leadership position and despite delays in permits, began its 2015 Arctic oil exploration drilling in July. The Arctic is forecasted to contain vast oil and natural gas reserves — the US Geological Survey estimates the Arctic could contain 1,670 trillion cubic feet (tcf) of natural gas and 90 billion barrels of oil, or 30 percent of the world's undiscovered gas and 13 percent of oil.

As conventional production has declined in traditional basins, the oil and gas industry has had to focus more on difficult-to-access and unconventional oil and gas plays throughout the world, including those in the Arctic. Exploration and development in the Arctic requires expensive, custom technologies as well as safeguards adapted to the extreme climatic conditions.

In the wake of the 2010 Deepwater Horizon incident, there have been additional costs associated with emergency response and containment requirements.

Although the pace of Arctic exploration activity in the Barents Sea, Alaska (Beaufort and Chukchi Sea), Russia, Canada, and Greenland is picking up, viable commercial production is still probably decades away. In the meantime, producers will have to raise the profile of the industry and increase support for Arctic resource extraction by applying the highest safety standards to exploration activities and continuing to consult with and incorporate the interests of the many different stakeholders in the region.

Risk mitigation

The Arctic region is not uniform with respect to hazards and risks. The subject of Arctic risks illustrates the significance of perceptions and subjective judgment regarding risk, risk criteria, and risk levels. Societal perceptions of risk may differ from those of the industry. The goal must be to share sufficient knowledge so that all relevant stakeholders are able to make their decisions by weighing the downside risk against the benefit of the activities. Better knowledge, transparency, and improved communication among stakeholders are important to bridge risk perception gaps.

Important remaining challenges require a strong focus on technology development. Oil spills in ice environments and plans for escape, evacuation, and rescue of personnel are lacking today. This situation calls for a major effort to reduce the probability of incidents, not only to prevent accidents from happening, but also to develop systems that can handle emergencies.

Some Arctic regions, like the coast off northern Norway, are fairly mature in terms of economic development as well as governmental regulation, while large areas toward the North Pole remain a challenge in terms of regulatory frameworks for search, rescue, evacuation, environmental clean-up, and liability for oil spill damages.

Figure 6: The Arctic Circle, a new oil and gas province

Petroleum activities and regulations

Recent high-profile forays by Shell into the Alaskan Beaufort and Chukchi Seas, by Cairn Energy with exploration drilling offshore in Greenland, and by Gazprom, Rosneft, and Statoil in far north and Arctic Russian and Norwegian waters, have raised global awareness of hydrocarbon development. These exploration efforts have led to the popular misconception that the energy industry is entering these waters for the first time. In fact, numerous producing onshore and offshore Arctic fields have been successfully developed since the late 1960s with no significant adverse incidents.

Russia will be the largest player in the Arctic, in terms of Arctic-coast length, population, resources, and relevant infrastructure and technological equipment (icebreakers, etc.). The country participates actively in relevant institutions dealing with Arctic issues. Its interest in stable and predictable Arctic governance was demonstrated by the 2010 delimitation deal with Norway. That agreement points the way toward feasible solutions to the remaining five territorial disputes in Arctic waters. However, claims by Russia for ownership of a considerable part of the Arctic can be expected.

Major international oil companies will look to partner with Russian oil and gas companies (such as Lukoil and the gas giant Gazprom) to gain a foothold into the Russian Arctic territory.

Environmental challenges

The risk of accidents involving wide dispersion of hydrocarbons is the most serious environmental concern when operating in the Arctic. Among possible impacts are habitat fragmentation, introduction of invasive species, and discharges of black carbon. Should an offshore accident occur, climate and weather conditions as well as long distances are likely to hamper response action and restoration efforts. Currently available technologies for recovery of oil from the surface perform relatively poorly in high waves and rough weather conditions. Oil spills in and under the ice constitute a special challenge.

The Arctic Council has recently stepped up its activities in support of infrastructure development for reducing navigational risks in the Arctic and for dealing with emergencies and accidents. In 2011, the Arctic states adopted a legally binding Arctic Aeronautical and Maritime Search and Rescue Agreement. This is the first legally binding instrument to be negotiated under the Arctic Council.

So far, the most comprehensive project to harmonize and strengthen development of applicable industry HSE standards is the Barents 2020 project. The idea behind Barents 2020 was that Russian cold climate experience could be merged with Norwegian offshore competence. The project was led by DNV and the industry sponsors were Gazprom, Statoil, Eni, Total, OGP, and DNV.

The Arctic represents the final frontier of conventional hydrocarbon development. Accessing these resources and bringing them to market could require another 20 years or more. Lining up these resources as the next major source of global energy supply — notably after the shale oil and shale gas boom — will require substantial investment and immediate and extensive expansion of exploration activity.

Opportunities for digital solutions

The lack of supporting infrastructure in most of the Arctic will be an initial challenge for all operators. Like most frontier basins, it will be a challenge to develop the communications links between field and office staff. Reliance on satellite communications introduces a high-latency factor to the performance of many digital solutions preventing real-time systems from working.

Geopolitical barriers, as well as physical ones, may limit the ability of the digital infrastructure to work seamlessly. Fully autonomous solutions guided by pre-defined business and technical rules and autonomous systems may be an approach for digital solutions for the Arctic.

The issue of linking communications and in achieving full situational awareness from very remote decision support centers will make the challenges of oil and gas production in the arctic even greater. Since it is expected that most of the resources will be natural gas, the reservoir and production management become more like process control problems, changing the nature of the solutions for the operator.

The high degree of environmental concern about Arctic operations will require operators, services companies and state regulators alike to operate in a very transparent manner. Digital solutions could aid in this challenge of community outreach. The current poor ability of the industry to respond to spills under the ice will double the urgency to make sure such incidents never occur in the first place. Well control assurance will be a critical challenge as will equipment health monitoring.

ConocoPhillips Norge deployment

One such example of the use of autonomous systems is the ConocoPhillips Norge deployment of six autonomous, self-propelled robotic craft in the eastern part of the Norwegian Barents Sea. The craft will collect ocean meteorological and natural resources data, following preconfigured routes at a speed of around 1 knot. Their data-gathering mission is expected to finish in 2015.

Information compiled will include wave height, current speed and direction, temperature, wind speed and direction. Onboard sensors will also investigate certain areas to determine whether hydrocarbons are emanating from natural seeps, as identified from satellite images.

The "Wave Glider" craft has a surfboard-like shape with dimensions of 1 x 3 m (3.3 x 9.8 ft). They use ocean waves and solar energy for propulsion and navigation. All are equipped with an AIS transponder that will autonomously adapt to marine traffic in the area, and all are monitored from onshore. Data are sent wirelessly to the shore via onboard communication equipment.

ConocoPhillips has commissioned this program to evaluate collection of data on the natural environment. If the pilot is successful, data collection may continue for the next three to five years and may be opened to industry participation. Each craft collects a wide range of information that is valuable for an offshore exploration and production environment. Previously, the company has conducted similar assignments in the Gulf of Mexico, the Chukchi Sea (Alaska) and Baffin Bay off the shore of Greenland.

3.

Market structure and competitive environment

The competitive environment for providing digital solutions for offshore production is made up of the following groups of companies.

1) Oil field service companies
2) Equipment manufacturers
3) EPC contractors (engineering, procurement and commissioning)
4) Process control/Automation
5) System integrators
6) IT vendors
7) Specialised consultants

1) Oil field service companies

This group is the dominant player in the market at present. The five large oil field service companies – Schlumberger, Halliburton, Baker Hughes, GE Oil & Gas and Weatherford – have traditionally provided the equipment and services needed by offshore operators for non-digital solutions and have evolved along with the business into digital solutions. The $35 billion merger of Halliburton and Baker Hughes announced last year brings the major players down to just four and represents one response to the low oil price environment through consolidation. Layoffs of field crew and support staff by these companies in response to the falling rig count is another.

Landmark is the digital solution department for Halliburton. They have been very active for a number of operating companies by both leveraging their **DecisionSpace** collaborative environment and in developing custom solutions. They have published a number of case history papers at SPE conferences and are probably the leading player in the production and operations space as well as in the drilling market.

Production Optimization: Halliburton's Landmark software business line is to team with Edinburgh (UK) Petroleum Experts (Petex) on the development of advanced production solutions for the digital oil field. Petex's IPM Field Management (IFM) and Landmark's DecisionSpace will be integrated and extended as a new joint DOF solution for production monitoring, optimization and forecasting.

Schlumberger has focused more on the reservoir management and subsurface interpretation space with their **Petrel/Ocean** application platform. **Baker Hughes** is an additional player in the reservoir management space with their **Jewel** application platform. Baker Hughes is also active in the artificial lift market and in remote operations with their **Beacon** service.

2) Equipment manufacturers

Firms such as: FMC, Aker, Cameron, Technip, ABB and other equipment manufacturers are increasing their focus on 'smart equipment'. Most offshore equipment comes with a variety of sensors, and control systems, that monitor and allow adjustments in operating parameters. Field automation represents the level one foundation layer for the Digital Oil Field IT Stack and smart equipment and process control vendors provide the technology solutions for this critical layer. Focusing on the offshore market, equipment such as blow out preventers (BoP stacks), well header stacks (often called "Christmas trees"), subsea production and processing systems, and rotating equipment (such as compressors, pumps and turbines) are high-value physical assets that are becoming "smarter" through the addition of sensors and controls.

3) EPC contractors (engineering, procurement and commissioning)

Firms such as KBR (Kellog, Brown and Root, another division of Halliburton), Fluor Offshore Solutions, WorleyParsons, Wood Group Mustang, McDermott International, Petrofrac, Samsung Engineering, Hyundai, and Saipem are embracing the growing importance of instrumentation, smart equipment, process control and engineering workflows. Getting the specifications right allows a new capital project to be fitted with digital technologies from the beginning of its active life. As the corporate engineering divisions of major operators have declined, specialist companies, like Mustang and the new IO alliance, have filled the gap. Oftentimes, it is these firms that develop the engineering designs for complex offshore projects and not the operator who acts as overall project manager and supplies business and technical requirements.

Engineering contractor WorleyParsons is set to embed its understanding of EPC projects and brownfield asset improvement to provide a "digital asset" service to clients. The service includes the creation and maintenance of digital plants leveraging Aveva's flagship PDMS toolset. The service will support lifecycle engineering data, including a handover of information in a "consistent and validated format" for brownfield "as-built" and greenfield projects. Clients include Abu Dhabi-based ADMA-OPCO.

4) Process control/Automation

Providers include firms such as: Siemens Energy and Automation, Wonderware/ Invensys (a division of Schneider Electric), ABB, Yokogawa Electric, Honeywell Process Solutions, Emerson Process Management, Rockwell Automation, OSISoft, Kongsburg as, Matrikon, KepWare).

Modern offshore production facilities are more like processing plants than an independent collection of wells. Automation and process control technologies are becoming more common, and the sophistication of process control (sometimes even remote from the physical location of the facility) is growing. The business of process automation has always been fragmented. The top companies command the largest market share, but at the bottom it is an inventor-driven business, and new companies are continually being created to leverage the latest technological trends.

The use of historians or at least data loggers (or EDR, electronic data recorders) on production facilities is helping to capture and store real-time data for subsequent analysis. The market leader for historians in the oil and gas industry is the PI solution from OSISoft. The demand now is for deeper analytics, rather than just alarm management from process control solutions.

Next-generation process control platform: Shell has teamed with Yokogawa Electric on the development of a next-generation platform for process control applications. The software speeds up and simplifies the process of designing, deploying and maintaining advanced process control solutions. The toolset leverages Shell's process expertise along with real-time control technology from Yokogawa.

5) System integrators

Firms such as Accenture, IBM, Deloitte, E&Y, Wipro, Deloitte and KPMG provide system analysis and integration services.

Complex projects require special expertise and often additional resources. That is the role that system integrators fill in digital solution projects. System integrators (SI) bring everything from project management, programming, business analysts, communications specialists and change management experience to the occasional subject matter expert, as well as knowledge from other companies and other industries. While the focus of most SIs is on enterprise-wide corporate systems (such as ERP systems), some companies have experience with offshore digital solutions.

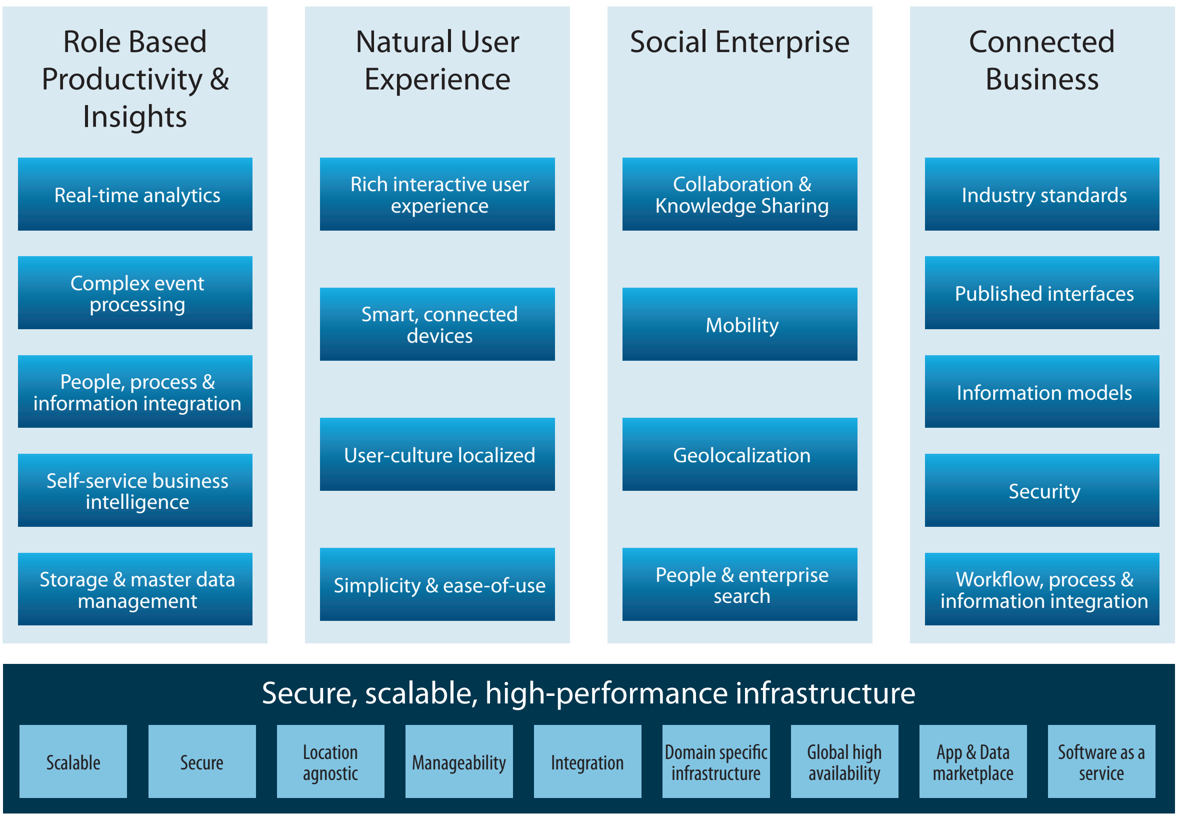
6) IT vendors

Companies include Microsoft, IBM, SAP, Oracle, NetApps, Teradata, Cisco, ESRI (for GIS), Tibco (Spotfire) and a wide variety of specialized application solution vendors (Petex (IFM Suite)), P2, CGG Geosoftware, Paradigm, TietoEnator (Energy Components), Aspen Technologies, Integraph, Bentley, iStore, Peloton (Wellview), Roxar and many others.

Whether it is the core IT foundation or integration with corporate systems, data centers or desktop environments, IT vendors are involved in supporting digital systems implementation. As custom engineering platforms evolve into commercial off-the-shelf technology platforms (COTS), the influence of the IT vendors increases, as does the utilization of commercial IT solutions. Some IT vendors have grown industry expertise and offer solutions that overlap system integrators and the digital solutions arms of the oil field service companies.

One example is the Microsoft Upstream Reference Architecture (MURA). MURA is not prescriptive—it does not lay out specifics of the architecture's structure and function. Rather, the MURA describes a set of guiding "pillars," or principles, that govern it. This descriptive approach provides an agreed-upon set of principles for establishing consistent performance, but also provides the flexibility for companies to innovate and establish competitive differences.

Figure 7: Microsoft Upstream Reference Architecture Guiding Principles



Source: Microsoft 2015

7) Specialized consultants

There are a number of consultants for digital system implementation, including data management (Noah Consulting, Entrance, Flare), communications solutions (Rignet, Pason, Harris Caprock, Petrolink), and for digital oilfield projects (Epsis, DOFAS, Merrick Systems) and commercial data vendors.

There is always a specialist niche and small-market opportunities for smaller consulting companies who make their mark from pragmatic and focused engagements with clients of all sizes. The reputation of specific individuals, along with a close relationship with client staff, keeps work flowing towards this market when larger vendors stop paying attention to small market opportunities.

New entrants into the market

While the offshore digital solutions marketplace already has a number of substantial competitors, new entrants to the market are making their presence felt. While these companies may not be new to other industries, they have found an opportunity for growth in oil and gas. Two of the major players are GE Oil & Gas and Aveva.

Because of the global, capital-intensive and process-dependent nature of the verticals typically requiring engineering information management solutions, for vendors in this market, developing both depth and breadth is critical. Products that can be configured to work alongside other software offer the most efficient solutions.

AVEVA's engineering software is used to design, build and maintain technically advanced oil and gas projects. Offshore, engineering projects include FPSO vessels and oil production platforms. AVEVA NET information management software is used for project execution through to operations support. It accelerates commissioning and enables effective Operations Integrity Management (OIM) throughout an asset's lifecycle.

The growth of digital documents and drawings places a difficult challenge on operator's facilities engineering information systems. Traditional enterprise document management solutions are becoming overwhelmed by the amount of documents coming from large capital projects. The ability to locate and use important documents and drawings in operations is getting more difficult with each new facility.

New alliances and collaborative R&D efforts

To address the current low price commercial environment, oil field service companies have been creating joint ventures to be able to perform a wider range of tasks with the goal of better coordinated design work beginning early in the major capital project process. Collaboration has emerged as a strategy during the low oil price environment for many oil and gas service companies, owner-operators and technology vendors.

A few examples of new collaborative offerings have emerged in the market:

io (GE Oil & Gas and McDermott, formed in 2014)
This joint venture describes its mission as installing greater certainty into the design and planning of offshore oil & gas fields as well as overhauling the current operator-contractor relationship. io claims that in many big projects there has been a mismatch of expectations in terms of schedule, costs, risks and the technical solution. A new engagement model and better collaboration may be the answer to the cost overrun on budget and schedule of many megaprojects.

OneSubsea (Schlumberger, Cameron and Helix Energy Solutions' joint venture, formed in 2013)
OneSubsea, a Cameron and Schlumberger company, has entered into agreement with Chevron U.S.A. Inc. to form a joint industry program (JIP) to develop subsea systems technology for 20,000-psi applications. The JIP, known as the **20Ksi Subsea System Development Program**, will address the technical challenges presented by high-pressure/high-temperature reservoir environments for development of 20,000-psi

subsea systems. OneSubsea will lead the JIP by completing a portfolio of technology development projects and managing the evolution of the required enabling technologies in order to address Chevron's high-pressure field development challenges, and those of the wider subsea industry.

Subsea Production Alliance (Baker Hughes and Aker Solutions, formed in 2014)

Aker Solutions and Baker Hughes formed the Subsea Production Alliance to address demand for subsea production solutions. This alliance combines the completions and artificial lift portfolio of Baker Hughes with the subsea boosting, controls, and intervention offerings of Aker Solutions. The alliance is aiming to bring to market fully-integrated, cost-effective in-well and subsea production systems engineered to improve recovery in deep-water developments while reducing installation and production costs. The alliance intends to provide joint development concept studies from reservoir understanding and well design to subsea and topside facilities, including flow assurances and risk management.

McDermott and Petrofrac

McDermott and Petrofrac have formed a five-year alliance to pursue top-tier SURF (subsea, umbilical, riser and flow-line) projects, with an aim to provide operators with an integrated solution across a range of the more complex engineering, procurement, construction and installation subsea projects in deep and ultra-deep-water.

Forsys Subsea (FMC Technologies and Technip)

At the 2015 Houston OTC, FMC Technologies and Technip promoted their recently formed venture, Forsys Subsea, with the promise to significantly reduce the cost of subsea field development and provide the technology to maximize well performance.

Fiatech

Fiatech is a global non-profit consortium of capital project industry stakeholders, launched in 2000 by the Process Industry Owners Forum and the UT Austin based Construction Industry Institute (CII). Fiatech's focus is on developing new technologies and innovative solutions to critical challenges that will drive the future of the capital projects industry, while CII's mission is to define and disseminate industry current best practices through academic research.

An industry perspective

Ray Topping, Director, Fiatech

The oil and gas industry, as part of their "heavy industry" category, is working with Fiatech on the front-end design of major capital projects. Recognizing the need for systematically approaching productivity improvement opportunities, Fiatech members created the comprehensive Capital Projects Technology Roadmap. Over the last 13 years, members have continually used and refined the Roadmap to provide context and foundation for Fiatech project definition and investment decisions. The Roadmap is an integral part of Fiatech and governs its overall mission and priorities. Topping said that the priorities of the oil and gas capital projects groups were around material management, technology that could be used at the construction site and mobile IT. There is a significant interest in interoperability and lifecycle information management. Current efforts around making operators' reference data libraries available and more consistent are encouraging. A common data representation for critical asset components is required. Fiatech is currently engaged in an effort with Mimosa and Posc Caesar Association to work on an industry standard for data sheet definitions.

However, one of the biggest challenges is maintaining a 3D virtual model of a facility once it enters the operations phase. According to the research on change management that Fiatech has undertaken, "over 70% of change activities (technology, workflows, etc.) do not get adopted even after they have demonstrated value to the company." Change readiness is a key theme voiced by the operators involved with Fiatech. Adoption is the beginning; sustaining use has become the key challenge.

Topping believes that the industry has only scratched the surface on opportunities to reduce costs of major facilities. Topping says that "the days of the spreadsheet rock stars propping up inefficient processes is coming to an end. The industry cannot keep operating the same way. The new generation of engineers will insist on change."

4.

Lessons from drilling

The drilling and completions community is facing many challenges. These include deeper wells, deeper water, high pressure/high temperatures in the well bore, more complex wells, remote locations, a higher number of wells in an unconventional resource drilling program, greater public scrutiny on incidents and a changing experience base.

Modern drilling rigs and drill ships have tens of thousands of sensors and instrumented pieces of equipment. The drill ship, when drilling, can produce nearly four terabytes of data per day. Key drilling measurements including the rate of penetration, number of rotating hours for the drill bit, weight on bit, mud weight and well head pressure, all of which are carefully monitored.

Standard data exchange protocols (e.g. WITS, WITSML and OPC-UA) are embedded in commercial software to transfer these measurements between the rig and shore base, and to drilling operations centers, so that it is possible for many relevant personnel to focus on critical phases of the drilling and completions operations.

To connect the drill rig with a drilling operational center, an operator needs the help of an oil field service provider. These providers offer services like the BHI Beacon platform, for remote operations and collaboration and Wellink RT for advanced visualization and analysis capabilities. BEACON consists of a global infrastructure of satellite communications and remote support centers, standardized data management and collaboration services and desks staffed 24-7 by drilling and IT specialists. Similar services are provided by companies like Schlumberger, Pason, Rignet, Harris Caprock and Halliburton.

Data-as-a-service

The industry also has the capability to capture information from the drilling assembly, located just above the drill bit, while the well is drilling. Dimensions such as measurement-while-drilling (MWD) and logging-while-drilling (LWD) are taken to gain an up-to-date understanding of the bottom hole conditions, which rocks are being penetrated and what fluids exist in those formations. This information is compared with well path predictions in real-time drilling centers (geo-steering) and the drill crew staff and operations staff collaborate to address any problems, changes from plan and surprises to optimize the safety and success of the drilling operations.

Add logging for formation evaluation and well integrity, data collected from the mud logging unit and data collected as part of the drilling rig operations and even weather data (especially important to offshore operations), and you end up with a lot of data to analyze. Micro-seismic surveys are being used in the evaluation of hydraulic fracturing jobs which adds the 'Big Data' challenge in drilling and completions.

According to the Schlumberger Oil Field Glossary, an intelligent well is "**a well equipped with monitoring equipment and completion components that can be adjusted to optimize production, either**

automatically or with some operator intervention." More of the industry's critical wells, including water injectors, are being equipped with 'intelligent' technology so that operators can monitor changes in reservoir performance, make appropriate modifications and optimize the desired production flow and minimize the unwanted returns (produced water, sand, etc.).

However, most of this information is never organized in such a way to make it available to decision makers either on the rig on onshore. It is estimated that less than 5% of the data generated on a drilling rig or a production platform ever makes its way back to a decision maker. For Diamond Drilling, only 10% of its current rig fleet (3 out of 30) is using real-time monitoring and surveillance methods. While 6th-generation rigs are equipped with a 'data backbone', most drilling operations are conducted with fairly traditional approaches with the decision maker required on the rig floor.

The other 95% of the data currently being recorded but not fully utilized represents a significant opportunity for digital service providers. False positive alarms from control systems can create a sense of complacency from operators in remote control rooms.

Operators are carefully watching the metrics and patterns they know are significant (i.e. for well control) but there are other patterns that are not fully monitored or understood by all operators that could be valuable. The industry has learned the lessons gained from past experience, but a more predictive and analytical approach to complement an experience-based and operational data-driven approach is the promise. Digital services providers targeting the 95%. It is technically possible to perform more sophisticated statistical analysis on more data from the drilling operations, but for operators, questions remain around the means and methods of making meaningful interpretations.

What the industry lacks is the integration of various rig control systems, adequate use of standards, transparency and a consensus on the right balance of instrumentation and control levels. In a real sense the drilling contractor is often just the physical host for a series of independent services sub-contractors and the well operator is taking a hands-off approach to integration.

Predictive analytics and a new analysis paradigm: Manage by exception

The principle of managing by exception is to enable routine information collection and assessment to be conducted automatically, and devote human time and attention to those areas that are performing or trending towards performing outside expectations.

Currently, an 'exception' is often a pending or actual failure of some kind. A piece of equipment breaks,

Drill String Digital Technology: Wired pipe (IntelliServ)

The IntelliServ network is a broadband telemetry system that allows instant transmission of data between the surface and the measurement tools positioned in the drill string bottom-hole assembly near the drill bit. The invention of IntelliServ technology began in 1997 with a project on hydraulic mud hammers sponsored by the company Novatek and the United States Department of Energy. The project addressed the need for instant transmission of downhole data (data acquired within the wellbore) through the drill pipe, leading to Novatek beginning a networked drill pipe development project. In 2001, the National Energy Technology Laboratory (NETL) began providing funding for the drill pipe project and an additional drill pipe data transmission project.

Five years of Department of Energy and NETL-funded research resulted in the IntelliServ network and Intellipipe, a drill pipe with an embedded data cable. In 2006, Grant Prideco bought the IntelliServ technology and launched the first IntelliServ network. Grant Prideco was purchased by National Oilwell Varco (NOV) in 2008, and the NOV-IntelliServ joint venture was formed in 2009, with 55% National Oilwell Varco and 45% Schlumberger ownership. The first commercial deployment of a drill string telemetry network occurred using IntelliServ's product in Myanmar in December 2006.

or a drilling penetration rate falls or fluids enter a wellbore under pressure. This is noticed by some level of surveillance, whether manual or automated, and is investigated and fixed. In the future, the definition of 'exception' can be expanded to include instances when something is trending away from the prediction provided by a model, indicating that some level of analysis and correction may be required.

A new drilling rig can be designed so that 'exceptions' are identified earlier – whether this is a trend indicating that the equipment needs maintenance, or the behavior of a system is moving away from the model range prediction.

The intent should be that if a situation arises, the right processes, skills and equipment are in place or can be rapidly deployed to deal with the situation. Elements of management by exception that would impact design work are:

- Ensuring that the right information is available, in real time where necessary, to individuals and teams who will be analyzing and making decisions on the exceptions.
- Designing a project with a proactive exception-based maintenance approach, rather than a time-based approach. This will impact activities such as sparing, warehousing, work management and maintenance planning. There will need to be condition-based monitoring on critical equipment and some kind of insightful predictive analytics system, as well as the roles and processes to respond to indicators of machine performance degradation.
- Considering what parameters to monitor and flag as exceptions when performance deviates from predictions, and how the asset should respond to those deviations.
- Maximizing use of automated surveillance, trending and analysis tools to identify exceptions.
- Using guided workflow to highlight exceptions to the right individual or team, and ensure that they are acted upon.

With integrated models of reservoir, well and processing systems on the production facility kept up-to-date and running online surveillance on a manage-by-exception process can be achieved. This offers superior performance over a respond-to-failure type model, where the best the staff can do is to compare current with historic trends and respond to failure alarms. The drilling and completions optimization is based not only on the pre-plan objectives but on analysis of alternatives, which include economic as well as technical perspectives, so that the drilling manager can make decisions that will bring the highest value when opportunities are encountered, instead of just producing to a plan that may be outdated.

The industry is moving towards this type of modern drilling operations. Collaboration between onshore drilling centers allows well construction planning activities to be orchestrated and drilling crews to leverage the experience of scarce experts when unexpected situations occur. These drilling operations centers are owned by either a service vendor or by the operator. Historical drilling data (from nearby or analog wells) are used for well construction planning and the well path is defined using the earth model built from the interpretation of seismic and well log data.

The case of too many standards

The ultimate goal of drilling and completion activities is articulated in the industry's vision for success. Operators and service companies need a focus on people, safety and environmental impacts. Performance improvement, both in drilling results and production results, risk management, regulatory compliance and supply chain partnerships are important deliverables.

The need to bring together technologies from seismic imaging, reservoir modeling, rock mechanics, drilling operations and real-time well monitoring is apparent from current drilling operations. Operators need to drill safe, efficient wells capable of maximum production from the reservoir. They need to drill the lowest number of wells to gain the greatest ultimate recovery of the potential hydrocarbons from the reservoir with the least impact to the environment.

Information and information technology have a big role to play in helping the drilling and completions community reach their vision. What the drilling and completions community and their IT support groups, are not concerned with is the basic computing, storage, data access, application hosting, telecommunications links that can be provided by a third party. Much of the data needed to make better decisions is becoming available, especially from newer offshore facilities, the data is captured and transmitted in a wide variety of formats, often application- or discipline-specific solutions. A consolidation or harmonization of these diverse standards will help to lower the communication burden between field and office and between specialists in different fields.

5.

Project case histories

"The successful application of technology is lowering costs, increasing recovery and improving the economic outcomes from deep-water projects."
Jay Johnson, Senior Vice President upstream, Chevron.

The industry is beginning to quantify the benefits from the application of digital solutions. At Chevron, benefits have included:

- Deep-water drilling: 25% reduction in drilling days for 10,000 feet over last two years.
- Completions: Single-trip multi-zone frack pack increase completion efficiency and reduce rig time. Total savings delivered: nearly $200 million.
- Seafloor pumps reduce back pressure on deep reservoirs and deliver increased recovery. For Jack-St. Malo this is expected to yield an improvement of 10-30%, which equates to 50 - 150 MMbbl of additional oil recovery

Digital systems can be utilized to meet operators' challenges in offshore assets. The high priority challenges are:

- Safety and environmental performance
- Maximizing production.
- Operating cost optimization
- Oversight of hydrocarbon processing.

The following examples show how leading operators have incorporated digital solutions into an overall asset management approach.

Shell's Smart Field program

According to Shell, a **Smart Field is one where the asset staff have the tools, processes and skills to maximize the asset lifecycle value, and do this on a continuous basis**. This involves optimization at several time scales, in production, reservoir management and development planning. Successful introduction of Smart Field in an asset needs to cover three aspects: Corporate and real-time data, an integrated suite of tools to turn these data to information, and a cadre of appropriately skilled professionals that use the information to make the right decisions to control and optimize the asset behavior, at surface and in the reservoir.

The business impact of the Smart Field investments is being measured by Shell. The benefits will vary with the character of the asset, the size of the field and the stage of the lifecycle of the asset, but on average, the following estimates are used:

- 8% ultimate recovery increases (5% gas and 10% oil)
- 10% increased production
- Reduced development risk and uncertainty
- Greatly improved HSE

Figure 8: Shell's Bridge offshore support center, New Orleans, LA

Source: Shell 2015

A suite of technologies, called **Foundation**, is being implemented in each project. Foundation provide both enhanced monitoring and optimization of production as well as the data and models for surveillance and reservoir management.

Shell's Perdido: Gulf of Mexico's first Smart Field

Located in the Gulf of Mexico, about 250 miles south of Houston, in nearly 8,000 feet of water, the **Perdido** development is the world's deepest spar (at the time of writing) and Shell's first fully Smart Field in the western hemisphere. Jointly developed by Shell, BP and Chevron, the spar and the subsea equipment connected to it will eventually capture more data than is collected from any other Shell-designed and managed development currently operating in the Gulf of Mexico.

The Perdido development consists of three fields – Great White, Silver Tip and Tobago – whose produced fluids are collected by the shared producing platform. The spar is equipped with full oil, gas and water processing facilities that are capable of handling production rates up to 100,000 bbls/day and 200 million scf/day of gas.

The process of developing and producing a field typically creates vast amounts of data and information, and the company's ability to collect the data is steadily increasing. A major challenge facing the industry is to use said data to optimize field development and production and to provide field managers with a degree of control that allows them to translate this knowledge into value.

Smart Field is not a standalone technology that has been developed by a single team; rather, it is based on the integration of dozens of tools, skills and workflows to improve the performance of core Shell E&P assets in a structured and sustainable way. On a technical level, this overarching objective is achieved by closing a series of value loops in which data are constantly fed back into the system such that real-time optimization is possible.

Crucially, Smart Field is not a one-size-fits-all solution. Each asset has its own unique features and challenges, and the appropriate level of "smartness" to apply will therefore vary from situation to situation. In green fields like **Perdido**, digital elements can be built in from the start, and can accordingly deliver maximum value right from the beginning of the asset's life. In brown fields, smart capabilities are applied selectively according to their economic viability, and any Smart Field implementation plan balances investment costs with the remaining field life.

The deployment strategy for disseminating Smart Field tools, technologies and workflows throughout Shell's assets consists of five separate capabilities design elements.

- Remote assisted operations
- Exception-based surveillance
- Collaborative work environments
- Hydrocarbon development tools and workflows
- IT infrastructure and applications

These elements and capabilities will collectively make it possible to optimize field development, reservoir management and production in a way that realizes Perdido's maximum value.

Statoil's Integrated Operations

Integrated operations (IO) is a whole new approach to solving the challenges of having personnel, suppliers and systems in different countries. IO involves using real-time data and new technology to remove the divides between disciplines, professional groups and companies. IO are commonly associated with cooperation between offshore and onshore teams, but it is also about how information technology makes remote operation possible, forming the basis for new and more effective ways of working.

Real-time transfer of data over great distances can be used to eliminate the physical distance between installations at sea and the support organization onshore, professional groups, and internally between the company and suppliers. When working across professional boundaries and exploiting real-time data and technology that remove divisions such as time and place, it ensures better value creation for the future.

The Snøhvit Field: The future of Arctic production

Statoil has made many significant advances for traditional oil production facilities on the Norwegian continental shelf but its greatest accomplishment may be its approach to operations in the far north. **Snøhvit** is the first offshore development in the Barents Sea. Without surface installations, this project involves bringing natural gas to land for liquefaction and export from the first plant of its kind in Europe and the world's northernmost liquefied natural gas facility. Snøhvit is the first major development on the Norwegian continental shelf with no surface installations.

The seabed facilities are designed to be over-trawlable, so that neither they nor fishing equipment will suffer any damage from coming into contact. No fixed or floating units are positioned in the Barents Sea. Instead, the subsea production facilities stand on the seabed, in water depths of 250-345 meters. A total of 20 wells are due to produce gas from the **Snøhvit**, **Askeladd** and **Albatross** fields. This output is transported to land through a 143 km pipeline to Hammerfest.

A total of nine wells are planned on **Snøhvit**: Eight for production and one for injecting carbon dioxide back below ground. Six of the producers and the carbon dioxide injector were drilled during 2004-05, with the remaining two following in 2011. In addition, the production wells were drilled on Albatross in 2005-06. This field also forms part of the **Snøhvit** development. The Snøhvit and Albatross wells came on stream in 2007.

Figure 9: Melkoya LNG terminal for Snøhvit Field

Statoil subsea factory

A subsea factory is a process plant on the seabed making it possible to utilize remote-controlled transport of hydrocarbons at any offshore facility. Future resources are further from land, at greater depths and in colder and harsher environments. The subsea factory will be vital to realize business opportunities for Statoil in these areas.

Statoil believe compact separation facilities on the seabed will be a key to success in Arctic areas or deep-water areas like the Gulf of Mexico and Brazil. Their offshore portfolio is well suited to the application of subsea production and processing. Statoil operate 500 subsea wells and have a 25-year track record of subsea technology development, implementation and operation.

Statoil has made the world's first complete subsea solution for the separation and injection of water and sand from the Tordis wellstream, and developed the first subsea facility for the injection of raw seawater on Tyrihans. Projects such as the oil-dominated multi-phase transport on Tyrihans and Snøhvit's gas condensate transport are at the forefront in the development of multi-phase transport over long distances.

Chevron's i-field program

Chevron's **i-field** vision involves the implementation and integration of a multi-disciplinary series of work processes, tools, technologies and people, that enables better and timely decision making, thereby enhancing the value of the asset. With integrated technologies, work processes and people, the result is a multi-discipline, multi-workflow and cross-functional view to asset management including:

- Optimized work flows to improve asset performance.
- Business processes incorporating execution of specific tasks in a particular workflow will be optimized through standard execution process common to all irrespective of their locations.
- Integrated processes impacting decision-making in relevant time.
- The ability to have all the relevant data required for multiple analysis and decision making will be enhanced since the engineer has more time devoted to engineering analysis rather than searching or processing data.

- Value creation and cost reduction.

- Being more proactive in the management of the asset will result in increased value and reduction in maintenance costs, since the reliability of the wells and facilities will be improved through continuous monitoring, resulting in prompt intervention before failure occurs.

- Improved ultimate recovery.

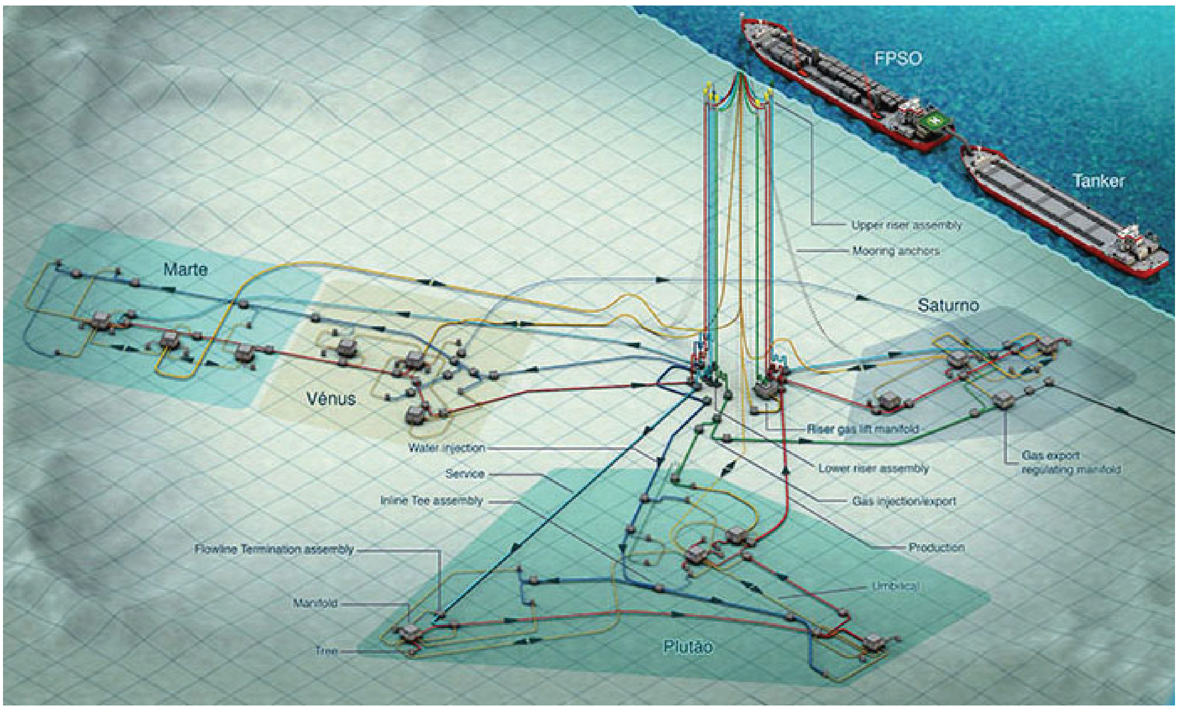
- Increased understanding through access and incorporation of continuous data into static engineering models will ensure up-to-date models that are more representative of the actual systems, thereby supporting better history matching and prediction from properly tuned models.

Chevron's Agbami field

The **Agbami** deep-water field is located approximately 200 km off the coast of Nigeria in the Gulf of Guinea. Agbami is Chevron's first operated deep-water field in Nigeria. The field is operated by Star Deep Water Petroleum, Ltd. (an affiliate of Chevron Corporation), with Famfa and Nigerian National Petroleum Corporation (NNPC) as concessionaires and Statoil and Petrobras as partners. The structure is a four-way closure anticline with steep-dip angles of 30 degrees. A major fault separates the Agbami Field into two halves. Normal faults further subdivide the field into seven fault-block areas. The high structural dips and faulted compartments are important factors influencing well placement strategies, water flooding patterns and expected ultimate recovery.

The Agbami field is comprised of four stacked reservoirs with distinct pressure profiles. The deposition of the reservoir sands at Agbami is interpreted as channelized deep-water sand with uncertain connectivity and fault seals. The fault seal characteristics are critical factors influencing connectivity between injector-producer pairs and well counts. The field development plan uses mid-flank oil production with crestal-injection and peripheral water injection as the oil recovery, pressure maintenance and gas disposition scheme in the field.

Figure 10: PSVM Field development concept



The opportunity statement for implementing a digital oil field solution (in Chevron's terminology i-fields) is the ability "to design and implement by first oil, an integrated, multi-disciplinary series of prioritized work processes with tools, technologies and decision environments that will support prompt decision making, thereby sustaining production plateaus, increasing uptime, improving reliability and efficiency for wells and facilities and ultimately increase the value of the asset." This mandate was accomplished through the deployment of the **i-connect** system in Agbami.

The (i-connect) solution is a platform for the asset team in separate locations (offshore and onshore) to access all relevant data, carry out detailed analysis, collaborate and make decisions that will ensure optimal performance of the asset from the reservoir to the loading point. From a functional perspective, the platform was designed to achieve the desired objective by performing the following tasks:

- Data and information management
- Event detection, notification and alarm management
- System integration

BP's Digital Oil Field of the Future: Deep water Angola

BP's contribution to the industry's digital oil field initiative is their Digital Oil Field of the Future program. While BP has made a number of substantial advances in offshore and onshore fields, one of the most impressive is the **PSVM** complex. At PSVM, BP is proving that subsea completions and floating production systems could be the future of many deep-water fields. BP, on behalf of Sonangol and Block 31 participants, made a series of deep-water discoveries which resulted in the development of the Plutão, Saturno, Vênus and Marte fields, collectively known as the PSVM. Located in the north-eastern part of Block 31, production started up in December 2012. PSVM is the deepest water project in Africa and has the largest subsea infrastructure in the world.

The PSVM development produces through a converted hull, floating production, storage, and offloading vessel with a storage capacity of 1.6 million bbl. BP says it is the first FPSO in ultra-deep-water Angola and will connect with 40 production, gas, and water injection wells through 15 subsea manifolds and subsea equipment.

Block 31 covers 2,065 square miles and lies in 4,921-8,202 ft. of water. BP Exploration (Angola) Ltd. has served as operator of Block 31 since May 1999 with 26.67% interest. Other Block 31 interest holders are Sonangol EP, Sonangol P&P, Statoil Angola AS, Marathon International Petroleum Angola Block 31 Ltd., and SSI 31 Ltd. . Sonangol EP is the concessionaire.

6.

IT challenges and opportunities for digital vendors

An integrated platform: The digital oilfield IT stack

When it comes to digital solutions for offshore production and operations, the audience is changing. Technology vendors are not selling to IT audiences; they have to sell to operation managers. They have to learn to speak their language, develop credibility and have reference cases for a brand new group of people.

Vendors need to know the difference between the roles and responsibilities of corporate IT, operations technology and shadow IT stakeholders (from engineering groups). Operations management is not interested in the latest-and-greatest or best-of-breed components for digital solutions. They understand risk and ROI very well, but it has to be defined on their terms, specifically increases in hydrocarbon production, lower operating expense, lower capital expense, lower maintenance and improved well and equipment integrity. To build a business case on their balance sheets takes reference cases.

Once a provider has sold a project to the operations manager, to reach the goals of the digital oilfield will

An operator perspective

Mike Hauser, former offshore superintendent, Chevron

Mike Hauser made the distinction between the priorities of a new "greenfield" facilities and a legacy "brownfield" asset. According to Hauser, the priorities for a new production facility are focused on accelerating production, getting the wells online quickly, and meeting the expectations of the production plan. A digital solution called "real-time reservoir management" has helped operators to achieve this goal. Adding incremental barrels is the highest payback from any digital solution. New fields have the attention of operators' best staff with dedicated subject matter experts and senior management watching closely to see the financial return on their large capital investments.

Brownfield assets are near the end of their commercial lives but still contribute significant cash flow to the owner. However, according to Hauser, the focus in on triage first (looking for early warning signs of potential incidents) and on redevelopment opportunities second. Expertise is spread more thinly in older assets and budgets are tighter, especially with production falling and operating expenses rising.

Mike Hauser's advice to digital solution providers is to make the upfront investments to learn more about what the production superintendent is concerned about and to focus on the critical workflows rather than selling your specific technology. Hauser also emphasized the importance of understanding the offshore operations culture. Despite the capabilities of technology advances, the culture of the industry is still to depend on decision makers being offshore where they are close to the operations. Bringing data to the hands of the offshore manager and operators, as well as the onshore specialists, is the right approach. But Hauser cautions that there is still a lack of strategic thinking along the full asset lifecycle in most companies where "the thinking only goes to first oil, not for the life of the field."

take more than just a new workflow solution. A proper digital infrastructure needs to be in place to support and sustain new solutions. This infrastructure, or foundation, is called the **Digital Oilfield IT Stack**. The infrastructure brings together the field measurement and automation technology from the operations and facilities groups with the more traditional communications and applications assets from the IT department, as well as with the data foundation maintained by the geoscience, petro-technical engineering, and other key corporate support functions.

The **Digital Oilfield IT Stack** is made up of the following levels:

Level 1: Field instrumentation and process control network
Level 2: First mile connectivity; global enterprise and supply chain network
Level 3: Real-time production and reliability surveillance
Level 4: Data foundation
Level 5: Integration framework
Level 6: Data access portal (search, presentation, and reporting)
Level 7: Geoscience and petro-technical applications environment
Level 8: Collaboration platform and decision environments
Level 9: Analytics platform (modeling, simulation, and optimization)

This system architecture is the desired state for the technical underpinnings of the digital oil field. One of the problems with current attempts by technology vendors is that they try to introduce new technology in one layer, without the required connections to the layers above and below them. There is a rush to get to the **Analytics platform** (Level 9) without supporting or providing services for the rest of the stack, especially in the **Data foundation** step (Level 4).

Feedback from operators suggests that technology vendors, if they are not responsible for the full foundation, at least perform an assessment of the capability of related levels. To focus on just one level of the IT Stack, ignoring the related components of the foundation, is a recipe for failure. Success is not measured by development and deployment metrics; it will be measured by sustained usage and bottom line results. There are opportunities for digital service vendors at each level of the digital oil field stack.

Level 1: Field instrumentation and process control network

Sensors are now placed down-hole to collect pressure and temperature measurements near the reservoir. The next step in field automation is the ability to control processes in near real-time based on operations rules, forecasts and predictions. New developments will be targeted toward the deployment of many more sensors for surveillance of the production environment. These newer sensors need to be cheaper, with more attention paid to power management and surviving harsh environments, like the borehole.

Control rooms will move from managing many single points of measurement to developing a bigger picture of the entire operating environment. By recognizing trends, proactive steps can be taken to avoid failures. Operations then can move beyond scheduled maintenance and 'respond-to-failures' towards predictive, condition-based maintenance and reliability-based engineering practices. Optimization driven by 'managing-by-exception' is possible by being able to compare, in relevant time, the actual performance with model predicted performance.

Level 2: First mile connectivity; global enterprise and supply chain network

The telecommunications suppliers have a term called 'last mile.' The last mile segment of their communication networks is the toughest as they usually serve only a few dedicated customers. Their needs are frequently unique and there are no economies-of-scale for the telecoms to leverage. The oilfield lies at the end of many of these 'last mile' connections. It is in the oilfield where the industry begins, so we have redefined this critical connectivity as the '**first mile**'. It enables data collected in the field to be linked to the monitoring and analysis of internal and external experts in central offices and to be shared with supply chain vendors, joint operations partners and regulatory agencies.

The constraints of the first mile connectivity will determine the decision latency of digital oilfield processes. Real-time connectivity is seldom possible, or practical, but collaboration and decision support environments can be designed to develop a support structure, bringing field reality/situational awareness to second and third tier experts, wherever they are. The communications technologies include fiber optics, microwave, and satellite connections, both over public and private networks and must include mobility within the network design.

Level 3: Real-time production and reliability surveillance

Meeting production targets is a continuous challenge and many components of field operations have the capacity to significantly impact the economic success of an asset. Fast and easy access to reliable information – whether real-time or historical – is critical to enable engineers and management to make the right decisions, at the right time, to meet both short-term operational and longer-term strategic objectives. This is the case whether onshore or offshore and in conventional or unconventional fields.

In most cases, production operations are becoming more complex, with field automation, the volume of measurement data is growing exponentially. In addition, engineers are being tasked with managing an increasing number of wells. To work efficiently, engineers need to be presented with information that is tuned to their particular needs, whether for routine surveillance, extensive diagnostic analysis, or as the basis for intervention and treatment programs.

A wide range of automated systems has been developed in past years to support production management, such as down-hole and surface measurement devices, business performance and reporting processes. Despite considerable, and often costly, efforts to integrate disparate software components, they often fail to communicate effectively across the whole operation.

Level 4: Data foundation

Historically, data about the oilfield have been managed and analyzed using many different proprietary and commercial systems. These systems are typically built based on unique requirements, and use different practices for identifying, gathering, transferring and interpreting information. A typical operating company may use dozens, or even hundreds, of software applications. Each department is focused on the needs of different segments of the company: Production accounting, field operations, seismic exploration, reserves management and financial departments all store information about wells in their respective software applications.

Often, these 'information systems' are little more than personal databases, spreadsheets, rolodexes or personal note pads. An appropriate data foundation starts with well-maintained systems of record. Data quality is managed at source and at all exchange steps. Data governance insures the consistency of processes, data integrity and information protection. Solutions that can enhance the quality, flexibility and integrity of the data foundation will be increasingly in demand as the amount of data gathered continues to increase, along with the demand for rapid decision-making.

Level 5: Integration framework

To gain an appreciation of the integration challenge, one needs to understand how applications are constructed. Many traditional applications are like silos – they have unique ways of capturing and storing data, a custom way of processing data through business logic or defined workflows, and a proprietary way of presenting results. When working in a large platform application environment, the individual modules are integrated inside the platform, and much of the complexity is hidden. When the application and data landscape contains solutions from many different commercial vendors, mixed with internally developed ones, the challenge of integration becomes overwhelming.

For simple solutions, the required linkages can be constructed through defined point-to-point integration techniques. This is a familiar approach for project and support teams. For more sophisticated solutions, the complexity grows, as per the number of data sources and applications. Soon, this point-to-point approach becomes part of the problem. What started as a light, 'good-enough' method becomes an expensive, brittle and overly-complicated framework.

An integration framework is the enabling technology suite that allows the seamless transfer of information from collection, to analysis and modeling. The purpose of an integration framework is to enable the transfer of information between various applications, according to a defined workflow and the presentation of information in such a way to facilitate decision making. In a word, this is about interoperability.

Level 6: Data access portal (search, presentation, and reporting)

The data access portal is the place where engineers, operators and analysts come to find the necessary data to do their jobs. In a general sense, a data access portal will incorporate key technology components as follows:

- Presentation - controls how information is presented to the user, adhering to the security and the business rules that affect the particular individual or role. Information visualization techniques (including GIS or geographic information systems) can help make sense of large quantities and different types of data.

- Search - processes user requests for business information, performs full text searches and identifies content through metadata descriptions of items that are published on the portal. The search technology will have to be federated to examine a number of different data sources.

- Security – provides authentication and authorization for the presentation layer and allows a company to control who has access to what information and more importantly who does not.

Level 7: Geoscience and petro-technical applications environment

This level contains a variety of applications supporting all the phases of upstream operations, including; drilling and completions, production, subsurface characterization, exploration, appraisal, facilities design, maintenance, health, safety, environment and other operations processes. They also encompass the commercial operations, including; Finance, human resources, procurement supply chain, legal/land, public and government affairs, including regulatory permits and reporting. Oil and gas companies have invested heavily acquiring these applications and this landscape includes hundreds of applications, from many vendors. Application and data silos can easily develop, creating challenges to link the inputs and outputs of applications along a workflow and improve the transparency and efficiency of decision making. Decisions made to acquire applications at this level are usually based on functionality and cost, while ignoring issues of interoperability, data management and information security. This tactical perspective causes the single largest problem when companies try to move to a new workflow environment.

Level 8: Collaboration platform and decision environments

The objective of collaboration is to enable the right people to work together, to make decisions at the right time, regardless of their location. Effective use of collaboration through decision environments is a key tenet of a digital oil field philosophy. Decision environments are not just meeting rooms, but work environments with appropriate collaborative tools, places to visualize data, communicate globally, and resolve issues.

Elements for consideration when designing solutions for the collaboration platform level include:

- **Enabling communications:** Ensuring that the appropriate infrastructure will be available to support collaboration from various locations.

- **Integrating data:** Providing the capability to allow data to be integrated with real-time data flowing from instruments in the field. Integrating this type of data with real-time data will help to present the right context to an individual or team making a decision. Ensuring that data quality is considered from the start of the program, not just for real-time data, but also for all other data sources including unstructured data, documents, drawings and external data from contractors, partners and service companies.

- **Focusing the collaboration:** Decision environments may be used to support diverse functional areas and workflows. These include engineering, construction, safety management, site surveillance, start-up, logistics management optimization, critical equipment surveillance, artificial lift and water-flood optimization. In addition, they can be used to support regular events and workflows, such as morning meetings, cross-functional well reviews, well planning that adapts to observed depletion patterns, well placement optimization and lease review meetings. Decision environments may be either continuously staffed or event-driven, depending on the type and nature of collaboration being supported. A decision environment will almost always need to consider both structured collaboration (in pre-defined workflows, to ensure consistency of process and quality of decision) as well as ad-hoc collaboration (in response to an unexpected event or issue).

Level 9: Analytics platform (modeling, simulation, and optimization)

The industry is recognizing the potential for significant improvements in the management and optimization of producing assets. When predictive simulations are available to a broad audience of decision makers, companies can try out several potential solutions in the modeling realm, and evaluate the benefits and consequences. Evaluate the benefits and consequences then decide on which one to put into operation. Challenges lie in information visualization for large amounts of information and software agents that will detect abnormal trends. For safety-critical systems, many processes will be automated. The interesting change management challenge will be getting people to work differently and to feel comfortable with more digital, and less physical, levels of surveillance (i.e., becoming data-driven). Getting community neighbors of the operations, as well as regulators, to be comfortable will be a challenge, especially those already mistrustful of the oil industry.

Taking these solutions together will move the oil and gas industry solution model from systems integration to systems interoperability. From the full foundation, there are four of these levels where emerging digital technologies can add value to current oil field operations:

- Data collection (or Level 1: Field instrumentation and process control network)

- Data processing (or Level 4: Data foundation)

- Data analytics (or Level 9: Analytics platform)

- Data visualization (or Level 6: Data access portal)

Data collection

In the digital oil field, the field automation network becomes more of a mesh than a hub-and-spoke architecture. Processing is distributed so all the information does not have to go back to the control center and clog the limited network bandwidth between the field and home office. Many routine tasks can be automated and more intelligence can be applied to how operational decisions are made. The need is to do more than control abnormal and hazardous conditions. The challenge is to predict when those conditions might occur, and take proactive steps to avoid equipment failure and loss of production.

Shell's Smart Fields now use down-hole wireless communications, advanced modeling software, remote sensing, control devices and telemetry to transmit the large amount of data gathered.

From the producing facility, the information is fed into the corporate IT network, a globally-standardized operating environment and high-speed network known as Data Acquisition and Control Architecture (DACA). This ensures that the real-time data arrive in the office on the engineer's desktop PC for interpretation and decision-making with the right data quality.

GE Intelligent Platform Software has begun a production optimization project to connect all of BP's oil wells globally to the Industrial Internet. The software will collect information from sensors monitoring vibrations, temperature, pressure, and other well properties. It will store, contextualize, and visualize the data to give BP real-time insights. The goal is to improve well performance and production while minimizing downtime.

BP field engineers will gain real-time access to common machine and operational data sets across all wells. The project will initially be deployed across 650 of BP's wells, expanding to 4,000 wells across the world over the next several years. "This project highlights BP's commitment to deploying technology that can not only improve efficiency and reduce the complexity of our operations, but that will also continuously make them safer and more reliable," said Peter Griffiths, BP System Optimization strategist. "In this case, we are delivering a solution on a standard platform that supports BP's move away from bespoke solutions to off-the-shelf industry solutions that integrate with our work processes, but

BP Houston

BP opened a new facility in Houston in 2013 to house the world's largest supercomputer for commercial research, highlighting its commitment to leading-edge technology in support of its core oil and gas business around the globe. The Center for High-Performance Computing, located at BP's US headquarters in Houston, will serve as a worldwide hub for processing and managing huge amounts of geophysical data from across BP's portfolio, and will be a key tool in helping scientists to "see" more clearly what lies beneath the earth's surface.

Ever-more precise images of the subsurface – made possible by greater computing power, speed and storage capacity – will enhance BP's ability to find new energy resources, by reducing the time needed to analyze massive quantities of seismic data and enabling more detailed in-house modeling of rock formations before drilling begins.

Better imaging capability will also help the company more safely and efficiently appraise new finds and manage complex reservoirs once production starts. In addition, the center opens up new possibilities for research into other important aspects of BP's business activities, from oil refining to enhanced oil recovery. For example, BP's "Digital Rocks," a proprietary technology for calculating petrophysical rock properties and modeling fluid flow directly from high-resolution 3D images, at a scale equivalent to 1/50th of the thickness of a human hair.

"BP's investment in this new supercomputing center not only highlights the increasingly high-tech nature of today's global oil and gas industry; it underscores our company's long-held belief in the vital role technology plays – and will continue to play – in solving the world's biggest energy challenges," said Jackie Mutschler, Head of Upstream Technology, BP.

The previous supercomputing facility was the world's first commercial research center to achieve a petaflop of processing speed – or one thousand trillion calculations per second. However, it had reached maximum power and cooling capacity, limiting options for growth. BP worked with HP and Intel to grow its computing power to over 2.2 petaflops. BP's new supercomputer will also boast a total memory of 1,000 terabytes and a disk space of 23.5 petabytes – the equivalent of over 40,000 average laptop computers.

without the long-term support costs that a bespoke approach often entails."

Data processing

The truth is that companies already have the majority of the information that they need somewhere in their company. However, it is not necessarily easy to pull the information together to help make effective decisions. This information is captured in back office transaction systems (ERP systems for finance and HR), in facilities maintenance and inventory systems (CMMS). It is also captured in revenue and procurement management systems. There is a real challenge to bring together structured data, documents, transaction, field measurements, emails and spreadsheets.

Advances in the processing power of end user devices (now more tablets and smart phones than PCs) and in the data center, especially around lower-cost, high-performance computing clusters) have allowed the industry to create larger simulation models. They have also enabled larger interpretation cubes and more complex processing routines, with the requirement that the results will be available much quicker than in the past. A fast answer from a complex simulation is now the expectation.

Data analytics

The oil and gas industry is increasingly recognizing the potential for significant improvements in management and optimization of producing assets. When predictive simulations are available to a broad audience of decision makers, companies can try out several potential solutions in the modeling realm. They can then evaluate the benefits and consequences before deciding on which one to put into operations.

The challenges lie in information visualization for large amounts of information and software agents that will detect abnormal trends. For safety-critical systems, many processes will be automated. The interesting change management challenge will be getting people to work differently and to feel comfortable with more digital, and less physical, levels of surveillance.

Moving from a culture that values experience in making critical decisions to one that values data and predictive models will take more than just new technology developments. If such a transformation can be achieved, efficiency in operations, effectiveness in recovering hydrocarbons and operational excellence in safety and environment metrics can be realized.

Data visualization

Data visualization is viewed by many disciplines as a modern equivalent of visual communication. It is not owned by any one field, but rather finds interpretation across many. It involves the creation and study of the visual representation of data, meaning information that has been abstracted in some schematic form, including attributes or variables for the units of information.

A primary goal of data visualization is to communicate information clearly and efficiently to users via the statistical graphics, plots, information graphics, tables, and charts selected. Effective visualization helps users in analyzing and reasoning about data and evidence. It makes complex data more accessible, understandable and usable.

The oil and gas industry certainly has a need for visualization of complex systems. These requirements start within a single discipline, like visualizing the well bore path while drilling a complex well, and grow as each additional discipline is added. The challenge of developing the dashboards, cockpits, control panels, subsurface models, for an oil and gas operator and their supply chain partners is significant. It starts with simple tools and simple visualizations but gets harder from there.

Big Data analytics meets oil and gas

With digital oil field/integrated operations programs focusing on gaining better insight into operations and optimizing key work processes, Big Data and the Internet of Things seem to be in position to make a significant impact. Big Data has been defined as: "a blanket term for any collection of data sets so large and complex that it becomes difficult to process using on-hand database management tools or traditional data processing applications." **The Internet of Things** (IoT) is understood to mean "the interconnection of uniquely identifiable embedded computing devices within the existing Internet infrastructure".

The oil and gas industry is no stranger to large volumes of data, especially seismic acquisition and processing, or to interconnected sensors with distributed control systems. The "**information intensity**" of most every discipline in oil & gas is growing. New technologies are arriving that can cope with the larger data volumes and help engineers to create new insights for all the data that are now available.

Other industries are moving faster along this Big Data trend but that does not mean that these technologies will not make a significant impact in the years to come. The industry has been busy with traditional data management techniques and improving high performance computing capabilities and now is dealing with the expectation of lower oil prices. There has been incredible growth in the amount of data acquired in the oil field and in the processing and simulation capability of data centers, but existing technologies are reaching their limits, leading to demand for analytics with greater capabilities.

Advanced analytics

The purpose of the digital oil field is not just to deploy new technology, but to add value by making better decisions. Some functional models, like a reservoir simulation or a facilities process simulation, are based on fundamental physics principles and require a lot of computing horsepower to process. Others are just intuitive interfaces from field instrumentation, like portals that allow experts to monitor the progress of drilling a complex well or geo-steering to stay in the right reservoir zone while drilling horizontally.

The initial challenge for analytics is to bring more real-time data to the monitors and dashboards for the metrics that the industry is used to looking at. Advanced analytics bring more statistical techniques into the toolkit, and the challenge of identifying and interpreting patterns to which engineers have not traditionally paid attention grows. This opportunity for new and deeper insight comes from the digitization of the E&P work processes, the capabilities of Big Data platform to store all of the data, the advanced analytics with modeling and simulation (for predictive analytics) and the creativity of data visualization to see beyond current limitations.

While the concepts of field and process automation and machine-to-machine connectivity are not that new, there is an important message here for the digital oil field. The growth of sensors and controllers in the oilfield, including many downhole, are critical for making more timely interventions. Many of the advances in this area can be deployed in field process control networks and can lead to breakthroughs for analysis of real-time data.

The impact of lower oil prices

While cost control is the highest priority at the moment, the operators that are tackling large offshore projects are taking a longer-term view. Drilling costs have gone down both in terms of day rates and drilling productivity. The large costs of major capital projects are being reduced through collaboration and standardization. New basins are opening up for exploration and the resource nationalism from several National Oil Companies is giving way to the need to attract more foreign capital.

While unconventional operators are cutting exploration budgets by 30% to 60%, large operators working offshore have been making cuts of 20% or less. While some offshore projects are being deferred and economics are being re-evaluated, the industry understands that these investments are necessary to meet future energy demand. Large investments require a longer-term perspective, so the impact of prices today are of less concern than finding ways to work smarter in tougher conditions.

Lower oil prices may slow down the adoption of digital solutions in the near- and mid-term, but the pace of technology development continues. Strategic investors should keep an eye out for emerging digital technologies even if short-term tactical budgets do not allow for adoption today.

> *"When you look at major breakthroughs and innovations, most major changes of technology happen during times of stress. If you really want to save money, you have to think differently."*
> **Neal Prescott, Executive Director of Offshore Technology at Fluor Offshore Solutions**

Conclusion

"If we are designing something, we should design to that cost. And we should ask ourselves, are we bringing complexity in where it cannot be afforded?"
David Lamont, CEO of Proserv

"Technology has its place, but currently it's not the whole answer. It's about how we do things."
Mark Richardson, group manager, Apache North Sea projects

This research report finds that the Big Data environment, if captured processed and visualized properly, can provide new insights into how physical systems perform. This insight, when turned into decisions and executed with excellence can lead to improved results.

Offshore operators are collecting large and growing volumes of data from sensors and smart equipment but only a few percent of that data reaches decision makers. Technology can deliver data on virtually every aspect of drilling, production and processing. This instrumentation is now common, especially on newer production facilities. But the capability – or in some cases, the desire – to process the data has spread much more slowly. Technology vendors and consultants suggest that operations perform below peak levels, but operators argue that the best practices still require experienced staff offshore, following long-established practices.

There is no argument that digital solutions are adding value in a variety of ways for offshore production, but the deployment of these solutions is mixed and there are significant barriers to adoption on most projects. Understanding the opportunities, the best ways to engage decision makers and developing solutions that fit the problems and the culture, rather than just taking advantage of the technology capabilities will help the industry move towards the vision of the digital oil field and accelerate the adoption of new solutions.