An Assessment of the Various Types of Real-Time Data Monitoring Systems Available for Offshore Oil and Gas Operations

A Service Disabled Veteran Owned Small Business

Date: February 10, 2014

E12PC00063

Table of Contents

Intentionally Left Blank

CHAPTER 1 – (Task 1) Assessment of the various types of real-time data monitoring systems available for offshore oil and gas operations

Chapter Summary

The Bureau of Safety and Environmental Enforcement (BSEE) commissioned this study to provide a broad industry overview of the use of real-time data (RTD). Of special interest is the use of real-time monitoring systems and their impact on the overall safety of operations. The study is broken down into seven tasks, each with specific deliverables answering the research questions.

This section addresses Task 1 with an assessment of the types and uses of real-time monitoring, the best available technology in use today and the Gulf of Mexico operators who are currently using real-time monitoring in their daily drilling operations.

We will address these topics in three main sections covering:

(1) Concepts of Operations;
(2) Best Available Technology; and
(3) Operators Using Real-time Data

Concepts of Operations

The use and configurations of Real-Time Operations Centers (RTOCs) throughout the industry are varied and dependent on an organization's value drivers. We found that RTOCs are generally a functional combination of Real-Time Monitoring Centers (RTMCs), collaboration centers and knowledge centers. For our purposes, these are defined as the following:

Real-time Monitoring Center (RTMC): This 24/7 function is located at a centralized, onshore location with continuous data feeds from the company's active well projects. Monitoring stations within the RTMC are staffed with highly experienced drilling experts who focus on mitigating drilling hazards and preventing non-productive time (NPT) while providing an added team member and safety observer to the onsite rig team.

Collaboration Center: A dedicated workspace, fully equipped with RTD capabilities enabling full integration of the onshore/offshore team working in a seamless environment for well planning, drilling and completion activities. Daily routine includes meetings with the onshore/offshore team, reviewing morning reports and planning current and future well activities. The Collaboration Center brings in or reaches out for the expertise necessary for achieving well development objectives and resolving issues.

Knowledge Center: An onshore RTD repository with experts that have access to all aspects of planning and analysis data. The Knowledge Center is available for services as requested by the drilling supervisor during well planning, drilling and completion operations. A Knowledge Center may work across many or all the wells in the company's portfolio and is not generally a 24/7 monitoring operation, but personnel may be on call to provide services at any time. The Knowledge Center may be considered the company's experience repository and center of excellence with respect to all phases of well development, completion and production. Two examples are ExxonMobil's worldwide Drilling Information Management Center (DIMC) and Statoil's Subsurface Support Center.

We visited four organizations during the study period with configurations utilizing some mix of these three components. All four organizations employ real-time data during the well development stages. Two of the organizations were configured with an RTMC and a collaboration center. One company combined a collaboration center and knowledge center to produce wells while a fourth company utilized only a world-wide knowledge center to advise the rig's drilling manager. All four configurations have proven valuable in meeting or exceeding each company's measures of effectiveness for well development and completions.

Best Available Technology

For the purposes of this study, the authors have identified the communications chain necessary for delivering real-time data from the drilling bit to the onshore facility. To analyze the components we found it necessary to break the chain into five separate generalized areas. We've defined preliminary descriptions of 'best available technology' (BAT) for these five areas and identified many industry and non-industry service providers purporting to provide the best solution. Many of these products overlap these divisions providing solutions in multiple areas.

Operators Using Real-time Data

In order to develop a better understanding of the current use of RTMC in the Gulf of Mexico (GOM) the authors attempted to contact and poll 164 oil & gas exploration and production companies with current operations in the GOM. At a minimum, we attempted contact with each company five times. We received eight responses to our questions from 164 companies using website contact forms or email addresses found on the 'contact us' pages. Successive calls were made through the company switchboard to the director or VP of drilling operations until a contact was reached or a contact could not be made. 76 companies provided feedback for the poll, zero declined to participate and 88 were not reached.

The aim of the poll was to determine to what extent the company used real-time data for drilling and completion operations and whether they employ a real-time monitoring system to observe well operations on a 24/7 basis.

Of the 76 respondents, 41 (54%) used RTD during drilling or production operations, while 35 (46%) hadn't used the technology for drilling or production operations. Of the 41 utilizing the advantages of RTD, 33 (81%) sent the data to an onshore storage capability and 16 (39%) used that data in a real-time operations center. And finally, among organizations using RTD, seven (17%) utilized the services of a real-time monitoring center operating on a 24/7 basis.

Introduction

The Bureau of Safety and Environmental Enforcement (BSEE) commissioned 838 Inc to provide this study as a broad industry overview of the use of real-time data (RTD), for offshore oil & gas drilling and operations and RTD impacts on the overall safety of operations.

BSEE was also interested in how the use of real-time monitoring might be incorporated into the regulatory regime in either a prescriptive or performance based manner and what burden it might place on the industry.

In addition, we have identified the necessary information which needs to be collected, calculated, or monitored during operations to improve the current level of safety to include: pressure changes, fluid influx, fluid loss and the operation of BOP functions (i.e. pressure tests, gallon counts, and accumulator tests).

While studying RTD tools and technology, the study team identified existing or proposed modeling tools that can be used in connection with RTD in order to prevent incidents. At the same time, additional attention was devoted to technologies and data that might be helpful in measuring field performance of critical equipment with the goal of predicting potential failures and areas where this technology could be used to supplement or replace current inspection techniques such as visual inspection or pressure testing of equipment.

The study also includes a cost benefit analyses detailing potential costs to industry, government resources needed for implementation, and necessary training for all parties involved.

The study is broken down into seven tasks, each with specific deliverables answering BSEE's research questions. With individual task reports that build upon each other.

This report details Task 1 and is an independent assessment of the various types of real-time data monitoring systems available for offshore oil and gas operations.

Task 1: Perform an independent assessment of the various types of real-time data monitoring systems available for offshore oil and gas operations. The focus will be on drilling activities and production technologies. Identify best available technology. Identify the operators, contractors, and service companies that currently use real-time monitoring.

The purpose of this section is to explore the use of real-time monitoring systems in use today in the oil and gas industry. This chapter is an initial assessment of the types and uses of real-time monitoring, the best available technology in use today and the Gulf of Mexico operators who are currently using real-time monitoring in their daily drilling operations.

Methodology

To collate evidence about various types of real-time data monitoring, the 838 Inc team undertook a four month survey of available literature. As part of our search, we reviewed the OnePetro electronic database and supplemented this with targeted searches of Oil & Gas Journal, Oil & Gas iQ, Offshore Magazine, Oil, Gas & Petrochem Equipment and over 47 other relevant journals and websites published between 1999 and 2013. Articles from any country and in any language were eligible for inclusion.

Any study or peer reviewed article that examined the use of real-time data for optimizing operations or enhancing safety margins was eligible for inclusion, Although the team was focusing on the oil and gas industry, we did examine other industries' real-time data monitoring operations to incorporate a wider range of systems in order to draw out the characteristics of the most successful approaches.

To ensure consistency, one reviewer scanned the abstracts of articles for relevance and selected those that outlined real-time data monitoring operational approaches in enough detail to describe processes, equipment, human factors and outcomes or effectiveness.

A second reviewer scanned additional databases and journals and analyzed all abstracts. In total, more than 3200 studies, articles, pamphlets, and websites were screened. The full text of selected articles was then reviewed in more depth.

A third reviewer scanned the web for current and emerging technologies and their service providers. He then reviewed over 200 synopses, pamphlets and articles regarding technologies in the chain to present real-time data to the operator.

The reviewers also interviewed or corresponded with 22 industry experts and visited four organizations utilizing real-time data monitoring or incorporating real-time operations centers in their work processes. Throughout this paper, we use quotations from interviews to illustrate our findings. These statements represent the views of individuals, not those of the companies involved.

Concepts of Operations

The use of real-time data during the drilling process is not new. Drilling operations have been relying on rig instrumentation since the early 20th century. With the advent of micro computing in the 70's, instrumentation data in a digital format and real-time accessible information became a reality. This, along with improvements of telecommunications technology in the early 80's gave rise to knowledge and information center concepts. These produced pilot programs commonly referred to as drilling operations centers and more commonly today as, Real Time Operations Centers (RTOC).[1]

The drilling industry today uses the term 'real-time' in a broader sense. It would be more accurately stated as 'near real-time.' This is due to inherent latencies throughout the communications chain from the drill bit to the onshore recipient. Current technology acquires and transmits data packets at frequencies ranging from seconds to minutes, which may be an eternity if it concerns the current/future position of a critical valve. Data transmissions may be delayed for minutes/hours or even days due to communications network outage, server infrastructure, or weather when streaming to onshore monitoring and operations centers.

Earlier studies defined two generations of RTOCs with the first generation facilities appearing in the early 1980s. Focus of operations was on management and distribution of data to more ambitious attempts at new ways of working. Viable business cases for central support of drilling operations were recognized, however, only one survived the low price and reduced drilling activity of the late 1980s and continues to operate today as ExxonMobil's Drilling Information Management Center in Houston. As the name implies, the focus remains on acquisition, management, and distribution of data.[1]

The current generation of RTOCs has evolved into more than just a center for monitoring activities during the well drilling phase. The model has grown to include well operations planning and drilling. It might be more appropriately called a center for well operations planning and real-time monitoring.[2] In addition, more instances of well completion, the process of making a well ready for production, are being addressed through the use of the RTOC.

It is important to note that in this study we will use the term RTOC to include those aspects of well operations planning, drilling execution and completion that are conducted using real-time data feeds into a remotely located facility utilizing real-time monitoring capabilities. We will use the term Real-time Monitoring Center (RTMC) to indicate that portion of the RTOC responsible for monitoring real-time data streams on a continuous basis, e.g. 24/7.

It is not the purpose of this study to determine or discuss the evolution of RTOCs. This was covered in great detail in previous papers.[3,4] Rather we seek to discuss the current state of the art in RTOC usage with respect to its contribution to improved Health, Safety and the Environment (HSE) as well as regulatory oversight.

One of the primary research questions of this study is if any impacts the use of RTD and/or RTOCs has on safety and how it might be used to improve the safety of overall operations. While much of the literature reviewed did not explicitly point to improved measures of safety, some papers did indicate the inherent improvements in safety through the use of RTD and RTOCs.

> *"In addition to reducing the hazards on site, another important mitigation tool involves minimizing the number of personnel who are at risk of being harmed. One advancement in technology that is particularly important to this type of risk reduction is the ability to deliver data from the wellsite to anywhere in the world instantaneously."* [5]

Aligning offshore operations and onshore support facilities, service contractors, partners and non-field professionals into a collaborative work environment has redefined the field operating model. With the introduction of reliable, high density video, audio, multidimensional presentational technologies and the ability to stay connected 24/7, collaborative work environments are able to produce timely collaboration and safer operations. These data feeds can also employ automated, advanced diagnostic tools that pinpoint relevant solutions by passing RTD through advanced multivariable models which can be scaled across multiple assets and facilities.[6]

Although the rig site remains the front line decision making location, the use of RTD and on a larger scale, an RTOC shows that the historical decision making processes are moving from a more localized, autocratic format to a collaborative, information based model that makes full use of global experience, resulting in overall safer decisions.

> *"…the collaborative planning and decision making between the onshore and offshore team… protects the operation from a single person making a really bad decision at a bad time. The most important part of what the RTOC brings is 1) the planning process and 2) the collaborative process between the onshore team and the rig and the discussions they have on an ongoing basis. Even though it's important to have the data, it's more important that the data drives this process of planning and collaboration."* [7]

The rig environment demands many time sensitive decisions. Unnecessarily eager decision making procedures under the watchful oversight of an RTMC may create a situation where the best information is provided 20 minutes late. Decision making protocols should take into account whether it might be best that the RTMC only add more info to the decision or potentially trump it rather than creating a consensus decision making process requiring excessive time.

The use of high end technology and its continual improvement over the past 15 years has also had an impact on information reliability and quality. The ability to ask for additional opinions when faced with challenging situations results in less stress, increased experience transfer and ultimately increased reliability.[8]

Although some organizations may not totally agree with this assessment as shown by this response to the authors on February 18th, 2013 to a website email might suggest:

> *"RTMC technology exists. We have seen it used at Superior Oil, Tenneco Oil, and knew Amoco did this with RTMC centers. One thing in common with these companies is that they are no longer in business. Regarding [Major Oil Company] RTMC capabilities, we do have remote access to real-time data for all of our wells, just not in a RTMC center. The most effective location for real-time data monitoring is on the rig."* [9]

The email author above is correct that these companies no longer exist, but it must be noted that the use of an RTMC was unlikely the cause of their demise. Superior was acquired and became ExxonMobil and Superior's initial efforts in RTOC is the core of Exxon Mobile's current RTMC effort. Amoco become BP and is a leader in the digital oil field. Tenneco is now Chevron and is a leader in the use of RTD and collaboration.

Other companies have limited the number of wells with access to the RTOC.

> *"As of today, only critical wells to the company are being monitored in the RTOC. Drilling engineers nominated their wells based on how critical they are for the operations and potential challenges for the drilling activity."* [10]

Some challenges in the flow of information still exist.

> *"Saudi Aramco uses many different service organizations to deliver its global drilling and completing agenda. In the past this has resulted in a lack of stability and standardization in real-time information flow. We have been unable to share data and expertise readily between different operating centers."* [10]

Categorizing the Use of RTD

During our research, we found it difficult at best, to categorize the major oil & gas operators' functional implementation of RTOCs, as did earlier research which found that each operator's implementation is as different as the drivers for success or the pain points it is attempting to eliminate.[11] For descriptive purposes, however, we categorized several components frequently used by organizations in developing their RTOCs. These components may be in-house company resources or provided wholly by a third party service provider. Second generations RTOCs consist of combinations of these components and many times subsets of the components depending on the asset or company needs.

Real Time Monitoring Center (RTMC): This 24/7 function is primarily a function for optimization, well control and live trending and is located at a centralized, onshore location with continuous data feeds from the company's active well projects. Monitoring stations within the RTMCC are staffed with highly experienced drilling experts that are well versed in pore pressure mechanics, drilling hydraulics and hole cleaning, bottom hole assembly performance and vibration, torque, drag and stickslip analysis and prevention. If there is a geosteering function, the staff will include experts in directional drilling, formation evaluation, geology and LWD sensor analysis and modeling. The RTMCC focuses on mitigating drilling hazards and preventing nonproductive time (NPT) while providing an added team member and safety observer to the onsite rig team.[12]

Collaboration Center: A dedicated workspace, fully equipped with RTD capabilities enabling full integration of the onshore/offshore team working in a seamless environment for well operations planning, drilling and completion activities. Daily routine includes meetings with the onshore/offshore team, reviewing morning reports and planning current and future well activities. Drilling and completion plans are run through mathematical models to support the expected operation. The model responses are compared with actual measurements in real-time and act as a road map for the operations team. If the actual and model agree – all is well. If the actual and model disagree – there is a need for analysis and response. The Collaboration Center brings in or reaches out for the expertise necessary for achieving well development objectives and resolving issues.[12]

Knowledge Center: An onshore RTD repository of experts that have access to all aspects of planning and analysis data for services as requested by the drilling supervisor during well planning, drilling and completion operations. A Knowledge Center may work across many or all the wells in the company's portfolio and is not generally a 24/7 monitoring operation, but personnel may be on call to provide services at any time. The Knowledge Center may be considered the company's experience repository and center of excellence with respect to all phases of well development, completion and production.

Below we describe three of the RTOCs visited and researched during the study period. Although there are numerous different variations and nuances for RTOC configuration, these facilities are typical of the industry's RTOCs:

Example 1: RTOC utilizing an RTMCRTMCC with an integrated Collaboration and Knowledge Center

This RTOC is located on the top floor of a building in a major office complex in Houston, TX. The floor has been completely renovated for the purpose of housing the company's RTOC which moved into the facility in Dec 2010 and began operations in Jul 2011. The RTMCRTMCC currently monitors eight wells on a 24/7 basis for drilling operations. Access to the floor is highly restricted with only those individuals directly working or supporting the planning and drilling operations of the wells permitted.

RTOC Layout

Full Operations View

The RTOC entry is into a large open conference area with a series of monitors on the far wall including a large (~9'x12') projection screen which is referred to as 'The Data Wall.'

Figure 1: The Data Wall[13]

The large screen displays an overhead view of much of the company's Gulf operations including rigs, ship locations (transponders), and pipeline layouts overlaid with a grid. The large screen is surrounded on each side by four columns, each of four displays representing the eight wells currently undergoing drilling operations. Each rig name is labeled below the column of monitors. The top monitor displays a live video feed from the rig. The two monitors below the live video feed display digital well data such as well depth, ROP, pressures, pump strokes, etc. and the bottom monitor displays trend traces of the digital data typical of a mudlogger's screen. The trace trend data was typically set to one hour, but may be adjusted as desired. The data displays for 'The Data Wall' are produced using Kongsberg's SiteCom®.The program aggregates real-time data from various rig data sources and makes it available through a single web-based interface. Discovery Web™ which is a fully customizable web application, allows the company to view its data from all of the rig side vendors and service companies on any of its rigs. Other displays on 'The Data Wall' include weather patterns in the Gulf, 'Gulf Loop' current location and parameters, and for vessel tracking and a common operating picture. This room is used for executive quick look, overview or presentation purposes and the displays are not necessarily monitored for operations purposes.

Collaboration Space

The facility layout is designed as a collaborative space and accommodates the well operations teams and the RTMC. Six large project rooms line one entire exterior wall of the top level and cover nearly one quarter of the floor space. Each project room has full Video Teleconference (VTC) capability, large screen projection and LCD monitors capable of displaying the well feeds to any well planning team using the room. The large conference tables in each room are fully capable of laptop integration to the screens and remote operation of all the room's electronics. The project room walls are lined with whiteboards with one of the walls employing several layers of whiteboard such that various well teams using the room at different times might leave their data on the boards and store the layer in the wall.

Well Operations Area

Opposite the project rooms is the well operations area. This area consists of eight 'pods', each dedicated to one of the well operations and construction projects. Each pod consists of six cubical desks, three on a side, surrounding a smaller collaborative work area. The cubical walls between the eight team pods are lower than normal workspace dividers allowing more crosstalk among the well planning teams. The collaborative space available in each pod work area consists of a conference table with a large LCD monitor and two smaller monitors above it. There are also four additional LCD displays off to one side for a total of seven displays capable of accessing the entire RTD set for the well. The team has three permanent members with other engineers and specialists brought in and out of the team as necessary and as the well plan progresses. The small conference table has a directional microphone above for VTC capability allowing for normal conversational volume levels. The teams seem to prefer the VTC communication over normal telephone. They feel it connects them more as a team with rig personnel.

Huddle Rooms

There are six 'huddle' rooms available for smaller meetings (three to five people).The LCDs in the huddle rooms have the capability to display data from user laptops that may include real time well data.

RTMCRTMCC

The RTMC is at the far end of the floor partitioned from the planning area and project rooms by glass walls. Access to the RTMC is highly restricted. Current operations have four individuals monitoring two wells each. The well monitors are seated facing each other on a wide rectangular table with the LCD array for each station in the center of the table surrounding them such that they are only able to see the person seated next to them.

Two supervisors sit at desks at the head of the well monitor's table, able to view the entire operation. There is also a management position in the room for problem escalation. Contractor support teams have cubicles in the far corner of the room and are responsible for monitoring the IT/telecom interfaces, network health, server health, application issues, equipment/ data and video feeds, and when necessary make changes to displays and data feed variables. The company has experimented with several layouts for the room and feels this setup is optimal and has shown improved communications between the RTMC and offshore teams.

Concept of Operations

The RTMC shifts are 12hrs on and 12hrs off, much like the shifts offshore; however, the change-out times differ from the rig crews allowing overlap and a watchful eye while the offshore shifts change out. Each monitoring specialist has an ongoing chat session with the mudlogger offshore. The chat sessions are all recorded for reference if necessary. If voice communication is necessary, the call is annotated with content and decisions agreed. The company has a working IP radio system (RoIP) to allow direct access to the rig radio on selected channels.

The RTMC team stresses simplifying tasks and minimizing multitasking as one of their main objectives. Candidates for well monitor are chosen based on their competencies, skills and time offshore. Each well monitor is trained through a mentoring process that requires at least four monitored shifts with a qualified mentor. Each well monitor must be approved to occupy the well monitor station and each is subject to periodic checks. Standard operating procedures (SOPs) have been previously developed and are currently undergoing a complete rewrite to incorporate all the lessons learned over the past year and a half. Once completed, the SOPs will be subjected to the standard revision, Management of Change (MOC) and SOP approval processes.

Well monitors may configure displays to best suit their experience and previous training. However, standardized displays, called 'Public Displays' have been developed for use when presenting data to varying teams in separated locations. The term 'Public Display' is used for the standardized data stream displays. Changes to the Public Displays require an MOC process.

During the center's developmental stage and prior to working with crews on the rigs, the RTMC team role-played among themselves using simulated data and situations in order to practice interaction behavior and styles. This was an invaluable exercise for easing the integration of the RTMC as part of the rig team.

A simulation was conducted by the RTMC team with a corresponding rig team prior to coming online. The company enlisted the help of a NASA shuttle simulation expert to develop the simulation profile. Rig personnel were given full reign on the problems they could present and it was up to the RTMC to diagnose and assist with the solution. The simulation proved to be as much a preparation for live operations as it was a team building exercise. The offshore team which participated in the simulation is still the company's best when it comes to communication and interaction with the RTMC.

Other Discussion Items

Weather causes issues with satellite transmissions. There may be data delays/outages as a direct result of weather obscuring satellite line of sight.

Reliability of the electronic equipment is relatively standard across the board causing some outages. Current RTM up time reported during active drilling operations is upward of 98%. RTOC up time is usually lower in the 95% range due to system maintenance in the onshore data center. During system maintenance or onshore data outages, RTM is monitored directly from rig based servers and systems.

The RTOC was developed using current capabilities with the expectation of 'learning while doing' as to the guiding approach.

Standard Operations Procedures (SOP's) and protocols are 'evergreen' and updated as needed e.g. when and who (onshore or offshore) has control of onboard cameras with regard to zoom, pan, and tilt.

> *"Wired pipe could potentially provide a more direct access to necessary data for decision making. For instance, pressure sensors placed on the bit and at the wellhead measure only two distinct points of pressure. With wired pipe, the distribution of pressure along the drill string could be more accurately determined allowing for a better understanding of fractures and mud losses.*
>
> *Handling issues and cost will be the detractors for wired pipe, although there seem to be some pretty exciting developments."* [14]

Lessons Learned

- Video is an important element helping to interpret the data streams. The primary video feed is from the drill floor even though the entire platform is outfitted with cameras. The view of drill floor operations helps to understand the data feeds/streams on 'The Data Wall'.
- Bringing video onboard requires a strategy for the integration. The onshore team needs to give the crews time and space to operate in order to do their business. The onshore monitoring team uses its judgment when contacting the rig based on video or data feeds.
- The experience level of the RTMC team is extensive. The company believes it is necessary to have an extensive background and time on the rig in order to be able to pick up the nuances of monitoring from a remote location.
- The company feels that it would be very difficult for non-essential personnel to walk in on a well drilling operation in progress and draw conclusions from the streams of data unless the individual has been integral to the well planning and operation process. An inspector/ auditor would need to be highly experienced in offshore rig operations.
- The company has had several issues with integrating RTD languages. The company recognized some issues with the interpretation of WITSML indicating that a more standardized language is necessary for the industry. Service providers use standardized company names/annotations; but they are defined differently across the industry creating hurdles during system integration.
- Years of experience offshore have taught many that there should not be an overreliance on the sensors. Sensor type, redundancy, accuracy, calibration and location are important when analyzing data feeds. For instance, a sensor calibration might be temperature sensitive and show different readings at different times of the days for the same physical situation. Depending on the time of day readings may or may not be within tolerable levels. Often years of drilling experience must be used when interpreting data feeds and trends.
- Using the staff from the RTMC as part of the offshore team was a change from the status quo. In order to manage the change necessary to implement the RTMC the company was very clear in providing guidance that "Real-time monitoring of operations is now a condition of employment" which helped minimize pushback from the offshore crews.
- The company noted an overall decrease in risk through more methodologies for limits and notifications.

Example 2: RTOC utilizing RTMC and an integrated Knowledge Center

The company has been using RTM since 1999 and first developed the operations room concept with integrated RTMC in Norway in 2005. In 2009, the company developed similar operations rooms in Houston, TX.

RTOC Layout

Operations Rooms

The company's RTOC consists of two operations rooms approximately 30' x 40', identically outfitted for all aspects of RTM for drilling operations. Each operations room is dedicated to one of the company's two drilling platforms in the GOM and capable of receiving and displaying all RTD and video from current operations. The teams conduct morning status meetings in the operations rooms and include the offshore team via VTC. The meetings are usually staggered by 30 minutes when two well drilling operations are underway permitting personnel to attend both meetings. The VTC feeds are constant during operations so the teams onshore can interact with the offshore teams continuously.

Team Dynamics

A specific well team is together from feasibility planning through end of well summary. The well planning process typically takes a year from proposal to a full well drilling plan. The planning process utilizes continuous risk assessment through decision gates and is an iterative, interactive process with all operational changes going thru the MOC process.

During the planning process, the service companies and peer 'assist and review members' are integrated with the well planning teams in order to provide accurate solutions to problem solving. Once a solution is proposed, the entire well team concurs before implementation. However, during execution, onshore team members have the authority to shut in a well if necessary, but it is usually a decision made in conjunction with the offshore team.

It was stressed that the use of integrated operations rooms had fostered a collaborative environment with all changes subjected to the MOC process. During planning, execution and completion, the well teams utilize a Knowledge Center for analysis of real-time problems.

The Sub Surface Support Center has six divisions of specialists:

1. Well Completion
2. Fluids
3. Rock-Mechanical
4. Well System and integrity
5. Advanced Drilling
6. Intervention

RTD Management

The company streams its data via microwave from its assets located within 30-40 miles of shore and via satellite elsewhere. Network reliability among service providers was varied with one of the company's service provider's reliability as high as 100% for the month of December 2012, while another was as low as 60% for the same period.

While the operation is drilling, the RTD feed is recorded, available and displayed continuously in the RTOC, but the RTD is not monitored for anomalies by onshore teams on a 24/7 basis. During this time, drilling teams may use the real time data that was collected as inputs to simulations that are run to trouble shoot problems.

The company uses data inputs from many service contractors, including Halliburton, Baker Hughes, and Schlumberger. In this process, they have found Kongsberg Discovery Web to be a valuable tool for displaying aggregated data from disparate contractors. The tool allows the team to aggregate all data into one display instead of constantly shifting back and forth among individual service provider displays. This view helps to more easily provide the entire data picture.

Once collected, the company stores and manages quality control of all RTD in a WITSML format at its HQ in Stavanger, Norway. Data can be recalled at any time and is periodically used for training purposes.

Lessons Learned

- Both drilling platforms have roughly 44 video cameras. Video is not stored on/offshore. The company believes video is complimentary to the data, very nice to have to understand the situation, but not totally necessary.
- The company has standardized its sensor arrays aboard the two drilling platforms. The platforms are relatively new and the sensor arrays were installed while in the shipyard.
- Wired pipe was initially considered and would have potentially provided more data sources, but the lead time was determined to be too long, ~2 years for delivery. While wired pipe might be good for data collection, right now there are few if any tools to analyze the data.
- The company sees value in 'continuous calculation' technology and real-time calculations of hydraulic readings to aid in early detection of downhole problems such as a kick and has invested accordingly. The company is also testing Early Kick Detection (EKD), auto-choke and Smart Flowback utilizing mass flow monitoring systems for more accurate reading of hydraulic flows.
- A new connections process has been developed and validated to reduce or even eliminate a potential kick. It is now standard procedure to wait one minute after a connection before pumps are turned on in order to let readings stabilize providing a more accurate depiction of pressures and downhole dynamics.
- The use of real-time data in simulations has proven to be invaluable. Service contractors typically assist with the simulations.
- Even though the company uses sophisticated Logging While Drilling (LWD) and seismic drilling tools, imaging below salt is still not good at this time and needs to be better.
- The company has found that the use of a standardized viewing platform is a necessity to monitor RTD from its various locations around the world. The diversity among contractors'

presentation styles and data available is too great to continually learn when arriving on station.

Example 3: RTOC Utilizing A Knowledge Center For Analysis With Rig Execution.

The drilling team managers on the rig have ultimate responsibility for drilling operations and are the primary decision makers for the drilling operation. RTD is transferred to the Knowledge Center and monitored at the rig. The Knowledge Center acts as a resource for the drilling team manager enabling him to make pertinent decisions regarding the drilling operation.

Concept of Operations

The offshore drilling team receives support and advice from the onshore Knowledge Center. If a situation presents itself, or assistance is necessary during drilling execution, a specific team of key personnel assembles to assist.

During normal operations, well sites transmit data to a single centralized web-based repository. Where staff monitor incoming real-time data 24/7 for quality assurance, manage morning report distribution, and provide user support. From the incoming data, reports are created and distributed to engineers and geoscientists around the world for analysis. Concurrently, other multidisciplinary teams also have access to the centralized system through a web browser interface in order to provide real-time support to the operations for issues involving well control, fluids, directional drilling, and formation identification and casing point selection.[15]

The company has been using Kongsberg Discovery Web for the past five years to make aggregated RTD displays available to key decision makers and support personnel.

The company reports that operations through its worldwide Knowledge Center have enabled low-cost, worldwide drilling surveillance, collaboration and well optimization.

RTOC Operations Summary

The various industry configurations for the use of RTD may appear, on the surface, very different, but in general, they are each using real-time data feeds and archived data to make the exploration and production of oil & gas a more efficient, cost effective prospect with an intentional byproduct of higher margins of safety.

Organizations repeatedly report that the additional cost incurred in setup and operation of an RTOC is more than offset by the benefits. One organization claimed that the use of an RTOC paid back the cost of the center and associated personnel within the first six months of operation.[10]

One company describes the value drivers for their RTOC as tangible and intangible. The tangible results are the timely delivery of high quality well programs and enhanced communication. While, the intangible value is only measurable in macro-indicators including reduced well cost across the board and a clear reduction of downhole trouble cost. Between the two, the tangible value, in essence, pays for the full expenditure of the RTOC while the intangible increases that value a magnitude higher.[5,16]

But how are the byproducts of safety manifested? The descriptions of the RTMC above assume these functions are handled onshore, but this is not to say that these same functions are not being accomplished on the rig. It is a necessary practice that the rig is monitoring the same data as the RTMC. However, the RTMC has the opportunity to cost effectively employ a multidisciplinary decision making capability with geoscientists, drilling staff, engineers and service provider experts in an integrated team. The distance between the rig and the RTMC can create a different perspective from which to see issues developing.

> *"Occasionally, perhaps once a year the RTOC will see something that the guys offshore didn't see. We call it a 'red flag' event. They'll call the guys offshore and say, "Hey we're seeing something, are you seeing it too?" And for whatever reason, it wasn't detected offshore.*
>
> *The fact that this so rarely happens is a tribute to the real safety benefit of having a sound well planning process. These collaborative processes are made possible through the introduction of real-time data. Well path optimization is a good example. Optimizing the well path is an efficiency thing, but it is also a big safety thing. Most well events occur because for some reason the fracture gradient isn't handled properly and you have a fracture and lose fluid into the well. With well optimization using real-time data you can plan for, and change significantly the density of the fluids you need to drill with thereby decreasing probabilities of hole problems which are what causes you to have an event. Well path optimization avoids these fractures."* [7]

Some organizations we've spoken to insist the RTMC is a purely financial decision:

> *"We do not deploy an RTOC (RTMC). The use of an RTOC (RTMC) is an industry financial decision not a safety decision. We contract with Baker Hughes to provide WITSML data for all our drilling parameters and we have it available through the web in real-time, but we don't dedicate someone to watch the data on a 24/7 basis.*
>
> *If we need to understand what happened during a particular drilling event we can go back to the data and get a better understanding and learn from it. The true value in the real-time data is the ability to use it in a collaborative effort to optimize well planning and construction."* [17]

Available RTD Technology

Technology development over the past 15 years in the oil & gas industry has been expanding at an incredible pace. This technology ranges from flow valves and pulse transducers to full 3-D seismic visualization centers. The old adage, 'if it works, don't mess with it' is no longer valid. Companies can no longer rely on the old ways of bringing this product to market. In order to remain competitive and safe in the market place, they must embrace new technology and continually develop new methods of exploring, planning and executing well design and production.

With the 'Big Crew Change' upon us, technology becomes an ever capable partner in continuing the quest to remain viable in the industry. We've looked at many of the technological aspects for the chain of communication necessary to acquire, transmit, receive, capture and analyze data for real-time operations under the scope of this assessment. In the pages that follow the authors identified some of the best available technology in use today and that which is necessary to continue moving the industry forward. By way of example, included are vendors' offerings which encapsulate the technology discussed. The authors are not recommending any of the vendors' products. These are listed only as examples of the technology discussed. These technologies are continuing to be evaluated for their cost and value to the industry and will be analyzed in subsequent chapters.

In our search for the best available technology to manage the real-time data chain, we found it necessary to break the chain down into logical categories for ease of discussion. Below we've provided an outline of the categories, descriptions of the technology and several examples of the technology currently available in the industry. The information for the technology examples comes directly from company brochures, websites and discussions with company representatives. In follow on chapters we will narrow the field of best available, describe the work in progress within the industry and provide examples of best available technology from other industries with potential adaptation to oil & gas.

1. Subsurface/Formation Analysis and Well Planning and Modeling Tools

Although this is not strictly part of the data chain, it is with this analysis and collaboration that operational safety first becomes pertinent. Modeling the expected behavior of the underlying formation informs and prepares the team, making them more aware of the risks and improving the margin of safety. Using these advanced tools in collaboration with all parties to the operation ensures the most efficient path to the pay zone, and with that, an operation that will afford an acceptably low risk, translating directly to HSE improvements.

These tools include 3-D subsurface and well visualization tools utilizing a shared-Earth-model prepared with inputs from seismic and offset data, updated with real-time information.

The tools are designed to integrate subsurface and drilling information from offset well analysis, perform detailed well engineering modeling and display a shared visual representation. Drilling optimization models are also part of this category which recommend drilling parameters for planning. Drilling parameters can be continuously updated during execution to provide a finely honed and optimized rate of penetration (ROP) for the highest margins of safety.

The most advanced technology will integrate these functions into a fully adaptable modeling tool accepting inputs from all sources including historical data, manual entries and real-time data necessary for updating the model during well construction.

Technology examples

Subsurface

VSG – **Avizo Earth®** – a 3D Analysis Software for Geosciences and Oil & Gas – Software for interactive exploration, visualization, analysis, comparison, and presentation of geosciences data. This 3D visualization application framework is the ideal solution, allowing you to import, manage, interact with, and visualize geosciences data from multiple sources within a single environment.

VSG – **Avizo Fire®** is the advanced 3D visualization and analysis software application for exploring core sample data sets. From straightforward visualization and measurement to advanced image processing, quantification and skeletonization, Avizo Fire delivers an extensive set of tools addressing 2D and 3D visualization, rock characterization, reconstruction of 3D rock models and pore networks analysis.

NOV/TOTCO: **TerraSCOPE®** Software – TerraSCOPE model calculates confined rock strength and predicts drillability and vibration tendencies. The formation evaluation software helps develop the most efficient drilling strategy based on the mechanical properties of the formation.

NOV/TOTCO: **VibraSCOPE™** drill string dynamics modeling software from NOV Downhole enables pre-well analysis of the BHA and drill string. The software predicts parameters that initiate vibration and high impact loading that can lead to premature bit and/or downhole tool failures, utilizing finite element analysis to model the dynamics of the entire drill string from the bit to the rig floor.

eDrilling - **PreDrill Simulations** - Evaluates planned well operations with regard to ECD, temperature, pore pressure and wellbore stability as well as Torque & Drag.

Kongsburg Gruppen AS - **SIM Resevoir** - fully interactively view and manipulate all parts of the reservoir model. The product includes the base module, the stand-alone import engine and full documentation.

2. Wellbore Stability and Drilling Integrity (Downhole) Monitoring and Analysis

Best available technology in this category includes tools such as instrumented drill string / e-lines, MWD/LWD/PWD tools, wired pipe, mud handling / fluid loss detection and kick detection that are taking advantage of integrating their data to real-time modeling and simulation software providing an accurate picture of the well construction process.

In its simplest form, active well control can be described as a function of monitoring and adjusting many variables to manage pore pressure gradients during drilling and completion operations. Until recently much of the monitoring was accomplished through indirect methods of monitoring the well's circulatory system and mostly after an event had occurred. As technology advances and the primary sensors move from the mud pits to the drill bit we are beginning to see much earlier detection of the symptoms that lead up to well events. However, transmission rates of monitoring data still pose a problem. Technology exists to develop high data resolution tools, but is limited by bandwidth out of the hole.

> *"If we are going to get better at the problem we need to get better info at the bit."* 7

With one notable exception, resolution of downhole data available during drilling operations is currently constrained by the transmission rates and bandwidth of mud-pulse and acoustic telemetry. Wired-pipe is the notable exception with the ability to increase data streams from 8-12 bits per second to over 1 million bits per second or 1 Megabit(1Mb). With new high speed data channels comes new capabilities which further enhance well control and with it, increased safety margins.

Thorogood,et.al. 2010, discusses the future of automated drilling and the necessary interoperability of these tools which describes very well where this technology is headed:

> *"Downhole tools will monitor the propagation of fractures to warn against time dependent effects. Measurements in the bit will direct actions to optimize the weight and torque transferred to the bit to prolong bit life and improve ROP. Fluid models will predict pressures along the borehole and caution against damage at the weakest zones when drilling, tripping, or circulating cement. The wellbore trajectory will be adjusted as necessary to match the updated Earth model coupled with the latest rock-mechanics interpretations from the downhole tools. A combination of surface and downhole accelerometers will measure drill string vibration and stress and will offer optimal drilling parameters to reduce risk and cost. All of these models are available today, but they are usually applied independently and may or may not be available in real-time or near real-time."* [18]

Technologies examples:

Wellbore Stability/Instrumented Drill String Tools/Mud Handling and Fluid Loss Detection/Kick Detection/Cement Analysis

Halliburton - Sperry Drilling services: **UltraHT-230™** measurement/logging while drilling (M/LWD) sensors deliver exceptional performance even at extreme high temperatures, providing accurate and timely reservoir measurements for precise wellbore placement. Designed to operate in temperatures as high as 446°F (230°C) and pressures up to 25,000 psi (172 MPa), UltraHT-230 sensors allow access to reservoirs which up to now were either inaccessible or had to be drilled 'blind.' The UltraHT-230 sensors provide accurate directional data and steering capabilities, with the option of wireline-quality formation evaluation measurements while drilling, and real-time drilling optimization sensors.

Forum Energy Technologies (FET): **The Advanced Driller Monitoring System (ADMS)** delivers drilling parameters providing an early warning system that can identify problems such as drilling breaks, flow deviations, and pressure losses. The ADMS displays real-time drilling data, enabling drillers to see signs of imminent well kicks and other deviations.

NOV/TOTCO: **The e-Wildcat**, with RigSense provides constant force and payout to generate a higher quality wellbore and optimize the rate of penetration. The system smoothly controls payout using the brake handle with precise variable frequency drive technology and multiple drilling parameter monitoring in the 'Auto Drill' mode. The e-Wildcat expands control parameters to include ROP, WOB and Torque, each of which has its own control set points.

NOV/TOTCO: **Wellsite Performance Drilling Advisor** - PDA provides accurate, repeatable and reliable real-time MSE on a per second basis on any rig via any drilling instrumentation system capable of being monitored anywhere in the world.

NOV/TOTCO: **e-Totco®** Drift Recorder - This tool improves accuracy and offers enhanced reliability and 'user friendliness.' The e-Totco tool is now offered as a multi-shot reader with significant technological advantages over single shot tools to reduce overall surveying time and costs in drilling vertical boreholes.

NOV: **BlackStar®** Electromagnetic MWD Tool: MWD applications involve the sending of measurements made by instruments located at the bottom of the hole back to the surface to all the crew to understand such things as location and orientation of the bit.

NOV: **DrillLink®** Automated Control Services is an interface package allowing third parties to deploy their proprietary algorithms to most rig designs via a common interface protocol.

NOV: **V-Stab®** tool is a unique approach to drill string vibration damping. The V-Stab is an eccentric tool that reduces stick-slip tendencies and dampens lateral shocks, by inducing Forward Synchronous Whirl (FSW) into the near V-stab section of the BHA. The V-Stab has proven effective in Borehole Enlargement applications as well as in conventional BHAs.

National Instruments: Instrumentation and control system for a mud-gas separator used in underbalanced drilling. With data acquisition hardware and LabVIEW software, developed a real-time event interpretation system.

Scientific Drilling International: **RigGRID** - Provides remote access to real-time drilling activities by means of a secure web-based portal. MWD, LWD, Directional Drilling, Geosteering and third party data are available to personnel authorized by the customer. RigGRID™ utilizes WITSML as the data transferring protocol, making it possible to retrieve data that is compatible with industry-related software and applications.

Monitor Systems Scotland Limited: Supplies drilling personnel with drilling data and relative alarm point settings in a compact drillers 19" TFT monitor unit designed for use on the rig floor. Using the industrial alarm mouse points, alarm acknowledgement and display operating parameters, such as active pits and pumps, can easily be set or modified.

eDrilling: **Integrated Manage Pressure Drilling (MPD)** - The purpose of MPD is to manage the annular hydraulic pressure profile to fit within the allowed pressure window as well as to handle a well control situation within this window with assistance from advanced model tools and automated control systems. MPD may be accomplished by many means including combinations of backpressure, variable fluid density, fluid rheology, circulating friction, hole geometry, and using an active device to manipulate the mud gradient and dynamic pressure.

Schlumberger: Periscope - Bed boundary mapper provides the ability to see the reservoir as wells are being drilled eliminating sidetracks on wells. The directional electromagnetic LWD measurement monitors the position of formation and fluid boundaries up to 21 ft away.

Schlumberger: **GeoVision** - High-resolution LWD images delivered in real-time identify formation structure and geological features, such as fractures.

SafeVision: Kick Tolerance module includes most if not all commonly used kick tolerance inputs, it can be used initially to display conventional kick tolerance values. But with the optional use of additional, selected parameters that exceed most current kick tolerance practices (temperature effects, fluid compressibility including afterflow, variable influx density, complex gas behavior, and additional wellbore weak points), SafeVision's kick tolerance displays are based on unusually sophisticated, but user friendly inputs, providing valuable detail that contributes to more effective planning, monitoring, and well control decision making. Additionally, instead of relying on kick tolerance calculated using planned mud weight, LOT results, expected weak point location, hole geometry, and formation temperatures, SafeVision continuously monitors and recalculates kick tolerance using actual, current values of these parameters.

Sekal: **DrillScene™** utilizes a dynamically-linked mechanical, hydraulic, and thermodynamic model of the drilling process to predict key drilling variables such as downhole pressure, hookload, surface torque, cuttings transport, tank volumes, and standpipe pressure in real-time, using first principles calculations. Real-time transient modeling would not be possible without the availability of real-time data to calibrate the model, such that the predictions from the model match the measurements under normal conditions. Sekal provides the industry with the unique capability to both drive the transient model in real-time using the physical measurements from the rig, and to calibrate the model based on the actual conditions in the well. This calibration occurs automatically at regular intervals whenever the system detects conditions suitable for calibration. DrillScene also calculates additional valuable parameters such as sliding friction, rotating friction, and hydraulic friction in the wellbore that perform as indicators of changing hole conditions. DrillScene Advanced Monitoring does not require any equipment or personnel on the rig and has no adverse effect on the drilling operation.

Baker Hughes: **WellLink™** Radar remote drilling advisory service enables you to deliver wells on plan by recognizing potential drilling problems before they occur. This integrated solution combines 24/7 surveillance, automated decision support from DrillEdge by Verdande Technologies and the application of Baker Hughes best drilling practices and lessons learned. It works on the premise that similar problems have similar solutions, so you can reduce uncertainty, minimize nonproductive time, increase safety, and enhance efficiency.

Verdande: **DrillEdge** case-based reasoning software automatically and consistently identifies patterns and trends from real-time drilling data and compares to historical cases. Situations that merit further investigation show up on the case radar. This allows remote engineers to focus attention where required. When they identify a potential event, they investigate, validate, and collaborate to determine the best course of action.

NOV: **IntelliServ®** and **IntelliPipe®** provides a high-speed, high-volume, high-definition, bi-directional broadband data transmission system that enables downhole conditions to be measured, evaluated, monitored and actuated in real-time. This means, that we create value by offering our customers the possibility to know facts they never even knew they could know. The Use of Wired-Pipe would allow the acquisition of high-resolution LWD data even at extremely high rates of penetration, improved geosteering capability by receiving all the data from all sensors in real-time, wellbore integrity and hydraulics control and evaluation of formation changes over time with multiple-pass repeat logging.

Schlumberger: **IpZig** - Real-Time measurements directly behind the drill bit. Provides an early indication of change in lithology. Helpful in enhancing accuracy of horizontal wells.

Schlumberger: **AutoROP module** - uses the ROPO algorithm to combine modeling of the PDC cutting process with signal-processing technique that detects changes in bit response. The ROPO algorithm characterizes bit response in real-time and determines the optimum values of rpm and weight on bit to achieve maximum ROP.

Schlumberger: **AutoSteer module** - continuously monitors the well trajectory and sends steering commands directly to the rotary steerable system through mud pump manipulation.

Schlumberger: Real-time Drilling Geomechanics analyzes in real-time all available drilling, petrophysical, mud, seismic, and geological data to visualize current downhole conditions. The real-time information acquired from the Scope family of downhole tools combined with the surface data including solids and gas monitoring.

Schlumberger: **Integrated Cement Design** utilizes all relevant LWD and laboratory measurements to provide successful cement placement and evaluation.

Schlumberger: InSituPro - InSitu Fluid Analyzer Real-time downhole fluid analysis (DFA).

Schlumberger: **CFA** - composition fluid analyzer module of the MDT modular formation dynamics tester.

Schlumberger: **EnACT** - Bi-directional wireless telemetry for control of the Intelligent Remote Dual Valve (IRDV) and acquisition of Signature quartz gauge pressure measurements. Data transmitted wirelessly between downhole and the surface.

Schlumberger: **Quicksilver Probe** - Focused fluid extraction collects formation fluids. Real-time downhole fluid analysis (DFA) for understanding of hydrocarbon properties at reservoir conditions.

Schlumberger: IntelliZone - Compact modular zonal management system is an intelligent flow control system for multizone wells. It provides a way to control wells on land and offshore.

Schlumberger: **Mi-Swaco** - **SG-SMART** - Data-acquisition system can accurately measure, monitor, and display all drilling variables in real-time. Computer-controlled data-acquisition system employs integrated micro-controller technology and fiber optics to provide accurate measurement and display drilling data.

Schlumberger - **StimMAP** - Services for hydraulic fracturing monitoring record microseismic activity in real-time during the fracturing process. Software provides modeling, survey design, microseismic detection and location, uncertainty analysis, data integration, and visualization for interpretation. Computer imagery is used to monitor the activity in 3D space relative to the location of the fracturing treatment. Then the monitored activities are animated to show progressive fracture growth and the subsurface response to pumping variations.

Halliburton: **DFG RT™ Drilling Fluid Graphics** - Provides drilling simulation utilizing input data from Sperry Drilling Services' InSite® software.

Halliburton: **DFG™ Software with DrillAhead® Hydraulics Module** - Hydraulics modeling software with wellbore pressure and ECD management using hydraulics and cuttings transport simulations.

Halliburton: **MWD/LWD Telemetry Systems** - use positive and annular venting mud-pulse telemetry with a high rate of transmission to generate real-time MWD/LWD logs on the surface. The mud pulse systems use valves to modulate the flow of drilling fluid in the bore of the drill string, generating pressure pulses that propagate up the column of fluid inside the drill string and then are detected by pressure transducers at the surface.

Halliburton: **Applied Fluid Optimization** – AFO uses DFG RT™ Drilling Fluids Graphics Real-time drilling simulation software to model bottom hole and surge / swab pressures using real-time drilling data

Halliburton: **Drillworks®** - Pore Pressure Prediction and Geomechanical Analysis Software - provides an integrated pore pressure and geomechanical solution

Halliburton: **OptiCem™** - Calculates real-time equivalent circulating densities (ECDs) based on actual job volumes, rates and fluid densities for more realistic simulator and rheology models for cementing operations.

Baker Hughes: Pore-Pressure Prediction - combining seismic data and geomechanical modeling to address wellbore stability and drilling performance.

Baker Hughes: **In-situ Fluids eXplorer™** (IFX™) service measures several in-situ fluid properties in real-time for assessing fluid type, fluid phase, and contamination monitoring under reservoir temperature and pressure conditions.

Baker Hughes: **SampleView™** service enables real-time determination of fluid type and monitoring of mud-filtrate contamination.

3. Instrumentation For Drill Floor and Rig Operations

Measurement accuracy of drilling parameters begins with the sensors. The sensors are the most fundamental part of any rig instrumentation system. While rig upgrades are in progress, older rigs are still using sensor types that have built-in inaccuracies that tend to show variations in readings and many have inadequate network and telecoms architecture to support multiple service companies.

> *"The simple fact is that, every rig in the Gulf's got a system on it, but the majority of them are older systems that don't have broadband capability. So it's something that the industry needs to address, because there is a need there. Eventually somebody's going to say all the data has to come off these rigs in real-time, or at least in one-hour increments, or whatever they decide. And a lot of those systems out there can't currently do that."* [19]

The newer sensor technology now being outfitted as standard packages on drill ships are precise and reliable with ultra-stable calibration characteristics which translate to eliminating time-consuming calibration procedures at the rig site. This technology category is meant to include just about any improved sensor located from the Blow Out Preventer (BOP) to the point of transmission off the rig.

> *"The actual hardware we are putting out on the rigs has gotten so good, that you can almost say that it is equivalent among vendors. It is your software and what user interface you are using to get that data off the rig that really differentiates all the instrumentation providers right now."* [19]

Technology examples:

Instrumentation

Pason: **Electronic Drilling Recorder (EDR)** links the rig manager and rig crew, operator, geologist, mud logger, directional hand, UBD technician, or any other rig site user together on a data network. Drilling data can be viewed on any of the workstations, and data is logged and stored onsite. Providing secure, remote access to the network, the system transfers data via broadband satellite to the office. In addition, the EDR provides the base for other instrumentation including the remote drilling Choke Actuator, Pit Volume Totalizer, AutoDriller, Mud Analyzer, Total Gas System and Hazardous Gas Alarm. The system performs the following tasks:

- Monitors bit position at all times.
- Stores all drilling data to disk every ten seconds.
- Accesses historical well data.
- Scales all sensor traces individually.
- Renumbers joints automatically on pipe tally screen.
- Provides notification of arrival of lagged samples via the sample catcher screen.
- Includes a messaging and memo system.
- Calculates and tracks drilling line wear, rate of penetration, weight on bit, and total pump output.
- Tracks bit and circulating hours.
- Displays mechanical specific energy in both vertical and horizontal/directional hole sections.
- Includes the wellsite information transfer standard (WITS) protocol to allow the system to communicate with other service companies.
- Includes easy-to-read and intuitive display screens to help monitor critical operations at the rig such as drilling, circulating, and tripping.

Pason: **Pit Volume Totalizer** - A volume monitoring system that measures, calculates, and displays readings from the mud system on the rig to alert of impending gas kicks and lost circulation issues.

NOV - **GasWatch III™ Gas Detection Services** – GasWatch III offers an increased line of reliability in gas detection by detecting C1, C3, and total gas real-time with repeatable accuracy and remote data capabilities. This system is integrated into the RigSense Electronic Drilling Recorder to assure that all data is shown to all levels of rig personnel. Gas Watch III also offers remote data capabilities through our WellData website information system.

NOV: **Remote Logging Center** – The Remote Logging Center is a proven alternative to basic mud-logging, manned by experienced loggers 24/7 monitoring, evaluating, and reporting critical data and events crucial to the success of the well plan.

Forum Energy Technologies (FET): **Electronic Inclination and Azimuth Systems**. Records even the slightest changes in the drill angle – as small as fractions of a degree – so the drill path can be quickly and efficiently corrected back to vertical.

National Instruments: National Instruments offers two main platforms for reading in the signal from these different sensors: **C Series** and **PXI**. C Series is an industrial, portable form factor that is ideal for distributed monitoring or portable diagnostics. PXI offers a higher-performance, higher-channel-count system for use in test setups or much larger monitoring systems.

Schlumberger: **FloView** - independent measurements of the multiphase fluids in each quadrant of the pipe cross section.

Halliburton: Reservoir description tool using the focused sampling probe. digital control feedback system, which makes instantaneous changes in pumpout flow rates to maintain a prescribed pressure, RDT's Zero Shock PVT sampling method eliminates pressure transients during pumping and sampling.

Fiber Optic Sensing - Provides distributed sensing to monitor dynamic wellbore conditions during production.

4. Data Collection, Transmission Points, Wireless/Wired, Standardized Languages Bandwidth Requirements

Technologies in this category consist of those necessary to collect, aggregate and transmit data from sources on the rig. The study does not specifically address technologies for the local area network such as wired (twisted pair, coax and fiber optics) and wireless which are relatively standard aboard the rigs, however, it does detail the more critical issues that need to be addressed relating to standardized data transmission languages, and bandwidth availability from rig to shore.

The National Petroleum Council's Offshore Operations Subgroup of the Operations & Environment Task Group has also addressed offshore data management and has published its findings in September 2011. The findings are summarized below:

- Many of the oil and gas data-management issues identified by the US Department of Energy (DOE) in 2004 remain unresolved and problematic in 2010-2011. The issues are not related solely to lagging deployment of best technologies but also reflect lagging attention to uniform formatting and portability, reliable retention and critical documentation that would make data seamlessly available and usable as long-term resources.
- The multiplicity of US government regulatory agencies involved in setting data reporting requirements has led to inefficiencies both in the

ability of industry operators to file reports and in subsequent retrieval of data for use in decisions about practices, permits and environmental impacts.
- US regulatory agencies have not made maximum use of successful data-management examples offered by organizations in Canada and the United Kingdom.
- Development of standards necessary for improvement of data management has been led by non-governmental organizations although progress has lagged in accomplishing adoption and integration into data systems of government regulatory agencies.[20]

Technologies examples:

Data Collection-transmission

WITSML™ (Wellsite Information Transfer Standard Markup Language) appears to be emerging as the industry standard for transmitting data. This language is relatively mature, with its origins as far back as the early 1990's; however, the extent and consistency of implementation varies. Variations on which version is in use and inherent flexibility in the specification which allows implementers to use their own sets of mnemonics, units of measure and time stamping etc. results in interpretation issues when integrating data among service providers. The WITS standard, as a result is still widely used for simple streaming of data between rig systems.

Version 1.4.1 includes some measures to promote more consistent interpretation of the WITSML standard. However, like many of us who are still using an older version internet browser on our laptop, we can understand that upgrading to the newest language version can cause issues itself and takes time and resources.

Measuresoft: **ScadaPro** is Real-time Data Acquisition software for Microsoft Windows. Optimised to use the powerful real-time, multi-tasking features of Windows, ScadaPro provides integrated data acquisition, monitoring, data logging, mimic development and report generation.

Measuresoft: **DrillPro** is a full featured addon package to ScadaPro for the purposes of Rig site surface data acquisition and processing for both Mud logging and drilling rig monitoring in general.

NOV: RigSense® Information Systems. The RigSense system is a highly advanced and reliable, yet easy-to-use drilling process information system. The RigSense EDR incorporates NOV's leading sensor technologies with the latest in computer and data acquisition systems.

Peloton – Pason: **WellView Field Solution** is a drilling data collection and reporting system deployed as an integrated addition to the Electronic Drilling Recorder (EDR). It facilitates one-time data collection. All data is displayed in standard forms on Pason's web-based Internet DataHub, which provides a mechanism to collect, store, and distribute wellsite data from the field.

Pason: **Directional System** - Software-based product transmits directional drilling information, and provides remote access to the data in real-time. Decodes mud pulse data and displays toolface, survey, gamma, and diagnostic information on the rosebud

Rig Minder: - rig monitoring package and depth tracking/logging/presentation software package engineered for drilling operations with screen interfaces.

Schlumberger: **WellWatcher** - bidirectional, high-rate data communication and transfers electrical power to downhole tools. Network configuration is based on the application and complexity of the anticipated installation. Components include surface acquisition and control systems, which provide a single interface for wellsite data acquisition, control, and transmission, and interface cards.

Telescope - high speed data transmission for sending data while drilling

CoilCAT - data acquisition system, the coiled tubing sensor interface (CTSI), with the universal tubing integrity monitor (UTIM) and software that merges design, execution, and real-time evaluation capabilities.

Halliburton: **InSite Anywhere Direct Service** - stand-alone data delivery system. View well data on third-party devices Blackberry®, iPhone®, Android™ and Windows® Mobile. Well data accessed through InSite Anywhere Mobile service

Baker Hughes: **WellLink RT™** service: visualize your well being drilled with WITSML streaming data

Baker Hughes: **WellLink Desktop™** service: automated data delivery to desktop.

5. Onshore Center - Data Aggregation Standardized Interfaces / Screens / Display of Relevant Data, User Interface (UI), Predictive Capabilities, Monitoring/ Alarming Potential

Aggregating all necessary data in real-time to an onshore center is a complex task. Making use of the data at this point becomes as much an exercise in new ways of working as it is developing the technology to best exploit the data. Best available technology in this category is characterized by its ability to display the appropriate data at the right time for full situational awareness without overwhelming the operators. It allows the operators to understand immediately what is going on at any given time and the ability to interact directly with the rig team in order to solve issues. The data is used to recognize and predict issues relating to potential well events, NPT and safety hazards.

Technologies examples:

RTMC Facilities

OSI Soft: **PI** brings information from the sensor to the boardroom. In most organizations, information originates and resides in a variety of sources and repositories including different systems, equipment, solutions, applications, locations, networks, suppliers and customers. These become, in essence, information islands, and traditionally the only way to communicate between them is through individual, human powered search-and-collation efforts. The PI System, through its infrastructure implementation, bridges these information islands, bringing all operational, business, event, and real-time data together, and makes that data easily visible to key decision makers across the enterprise.

OSI Soft: **PI Manual Logger** – Easily, securely, and reliably record data on PCs and mobile devices.

National Instruments: **LabView** - used for acquiring data and processing signals from instrument control, automating, test and validation systems using embedded monitoring and control systems.

Kongsberg Gruppen AS: **SiteCOM** - Integrates real-time data, historical data, reports, and files from all sources on the rig and makes them available to the relevant community through a single web-based interface. Automatically aggregates, distributes and manages real-time data, files, reports, and other drilling communications

Schlumberger: Connectivity, collaboration, and information service. From deepwater wells in harsh environments to shallow land wells, enables remote teams to proactively address challenges. The service provides a secure online workspace.

Avocet Surveillance: Provides graphical access to all production and operational data. No predictive capabilities.

InterACT: RTMC facility for centralized management.

Halliburton: **Real-time Centers** - Enable experts to collaborate and work on multiple wells located in different parts of the world concurrently, minimize HSE issues by reducing the number of staff who need to be on site.

InSite Data Management Service - allows drilling and other relevant rigsite data to be collected, transmitted, replicated and managed in real-time.

Baker Hughes - **BEACON Remote Operations Portfolio**:

WellLink Services — Real-Time Data Delivery, Monitoring and Management

Real-time drilling data: real-time WITSML-compliant service to host and dynamically display realtime data along with all surface sensor data or third party data feeds from multiple wellsites.

Real-time wireline data: real-time, wireline logging visualization and data retrieval service for Baker Hughes. Upgrade to the LiveDecision service for real-time geoscience interpretations while logging.

Real-time production data: comprehensive well-data communications, SCADA remote control, remote monitoring, and data analysis service to optimize and extend ESP system run-life.

Log library management: comprehensive well data distribution and retrieval service for static files.

Licensed software users can also download their entitled applications, and patches from the software menu.

Desktop service: data delivery system which automatically delivers the specific well data you want, securely and reliably, directly to your desktop.

Historian: Provides local and web-based graphical reporting of time series data of upstream and downstream processes—e.g., chemical reporting.

Field communications services: Information and software solutions for transmitting well datasets from the field to the WellLink data centers.

NOV: **Real-time Optimization Services** – NOV Real-Time Optimization Services (RTOS) offers a scaled portfolio of tailored services and tools which range from performance auto-drillers to real-time monitoring and advisory services.

Monitoring and Alarming

Forum Energy Technologies: **Advanced Driller Monitoring System (ADMS)** - delivers crucial drilling parameters at a glance providing an early warning system that can instantly identify problems such as drilling breaks, flow deviations, and pressure losses. The ADMS displays reliable and accurate real-time drilling data, enabling drillers to see signs of imminent well kicks and other deviations that can make the difference between a safe well and a costly and dangerous blowout.

NOV - **WellData** offers immediate access to your rig's process information with an up-to-the-second view of rig operations. The screens are fully customizable to monitor key variables of the drilling process, allowing contributions to operations to take place in a timely manner.

Monitor Systems Engineering Ltd.: **Machine Monitoring Alarm Systems** - Provides a visual and audible management tool covering the operating status of motors, pumps, fans, generators and other electro-mechanical utilities. The system measures key functions such as speed, temperature, oil pressure, vibration, exhaust gas, water coolant, and bearing temperatures, etc., for rig equipment, and machinery. Management data is transmitted to touch screen panels in both the control room and the mechanical or electrical workshop.

FUGRO GEOS: **Wellhead & Riser Instrumentation Systems** - Instrumentation and data acquisition packages for the offshore oil and gas industry. Strain and motion monitoring of drilling and workover risers and wellheads. Measurements include: Upper and lower flex joint angle measurement, riser tension measurement at riser adapter, Lower Marine Riser Package (BOP) motion monitoring, inputs from available vessel systems

Vortex Induced Vibration Monitoring (VIV) – Involved in the design and operation of deepwater risers and the issue of vortex induced vibrations (VIV).

DeepData - **Subsea Data Collection** - Subsea data acquisition system with modular logging system, which can collect and analyze data from a variety of sensors, up to a water depth of 3000m (9900ft). Measures the response of deep-water components such as production and drilling risers, sub-sea templates, anchors, moorings, foundations etc. Measurement areas include:

- Risers: Load, Motion and VIV (Vortex Induced Vibration)

- Wellheads: Motion and Fatigue
- Jackets: Fatigue Monitoring, Integrity
- Monitoring Pipelines: VIV and Span Assessment

Optima Riser Management System - Optima-RMS is a riser management system offered jointly by MCS Kenny and Fugro GEOS. The system uses outputs from existing vessel systems to predict the behavior of the riser in the prevailing metocean conditions. Provides real-time guidance of drilling and workover operations. Key results are presented graphically in an intuitive display.

Production Riser Monitoring: Services in connection with production risers: TLP Risers - Permanently installed on the tensioned risers of TLPs, and on other tensioned risers, to monitor VIV effects. Jacket Conductors - Lateral motions of conductors are measured to allow accurate analysis of the fatigue life of the Christmas tree pipe loops. Offset Risers - RTMS (Riser Tension Monitoring System) is used to confirm the tension in offset risers, and the integrity of the buoyancy tanks. An ROV recoverable strain bracelet and logger unit are installed at the top of the offset riser. Data is transmitted by hydro acoustic modem to the FPSO, where a real-time display of tension levels is provided. Lo and LoLo Alarm limits can be set to provide visual and audible warnings of significant tension changes.

Meshguard Wireless Gas Detection System is a deployable wireless gas detection system that provides real-time monitoring. It is used to monitor for hydrogen sulfide (H2S) and lower explosive limit (LEL) gases and vapors. It provides industry standard formats, such as RS-485, Modbus and XML (Extensible Markup Language) to allow integration with I command-and-control software packages, such as RigMinder’s EDR system.

Rig Minder - rig monitoring package and depth tracking/logging/presentation software package engineered for drilling operations with screen interfaces.

Schlumberger - **RTAC** – Supervisory Control and Data Acquisition SCADA system for interfacing with many tools. Used for downhole control and monitoring

Phoenix: Provides bidirectional, high-rate data communication and transfers electrical power to downhole tools. Network configuration is based on the application and complexity of the anticipated installation. Includes surface acquisition and control systems, which provide a single interface for wellsite data acquisition, control, and transmission, and interface cards.

Operators Using Real-time Data

The use of real-time data is rapidly becoming standard and expected practice in the oil and gas industry. In order to develop a wider understanding of current practice in the Gulf of Mexico (GOM) the authors polled 164 oil & gas exploration and production companies with current operations in the GOM (The contact list was provided by the contracting authority of this project.) At a minimum, we attempted contact with each company five times. The first attempt was through the company website 'contact us' email function. If the company had an 'info' email address, it was used in addition or as first attempt if there was not a 'contact us' email function. We received eight responses to our questions from 164 companies using website contact forms or email addresses found on the 'contact us' pages. The next contact attempt was made through the company switchboard to the director or VP of drilling operations. Successive calls were made until a contact was reached or a contact could not be made. 76 companies provided feedback for the poll, zero declined to participate and 88 were not reached.

The aim of the poll was to determine:

Does the company use real-time data (RTD) at the drill site and does the driller/drilling foreman/drill team normally make decisions based upon the information without input from onshore?

Does the company transmit the information onshore to be available to those experts that monitor well drilling operations?

Does the company use an RTOC fully integrated with a team using the RTD for well planning and daily optimization operations?

Does the company use an RTMC staffed and operating 24/7 to monitor drilling operations (or perhaps only when the bit is turning)?

The Polling Sample

It is important to note that the list of companies provided was dominated by pipeline owners/leasers. The pipeline operator uses RTM in a completely different manner than the Oil & Gas exploration and production companies. The pipeline operators monitor health of the pipeline and quantity/quality of the product. Their data is used to monitor quality control making decisions based on real-time data.

The drilling contractors were not included on our original contact list. These companies perform the drilling operations and are aware of RTMC and RTOC facilities. They drill the well as a service to the owner/leaseholder. Once they have completed the well the RTMC services used during drilling are not reflected in the operations of the company listed in the spreadsheet. Examples of drilling companies cover a spectrum of companies with varying RTMC capabilities. Examples include:

- **Pacific Drilling**: Large, worldwide drilling with sophisticated RTMC and RTOC capabilities for drilling ultra-deepwater wells.

- **Trinidad Drilling**: A medium sized company drilling in the continental US. Uses RTMC during drilling and has little RTOC experience.
- **El Dorado Drilling Company**: A small drilling company with RTMC provided by secondary service providers such as Halliburton and Schlumberger.

Polling Results

Of the 76 respondents 41 (54%) confirmed that they did indeed use RTD during drilling or production operations, while 35 (46%) told us that they did not use the technology for drilling or production operations at this time. Of the 41 utilizing the advantages of RTD, 33 (81%) sent the data to an onshore storage capability and 16 (39%) used that data in an RTOC with seven (17%) utilizing the services of an RTMC operating and staffed on a 24/7 basis.

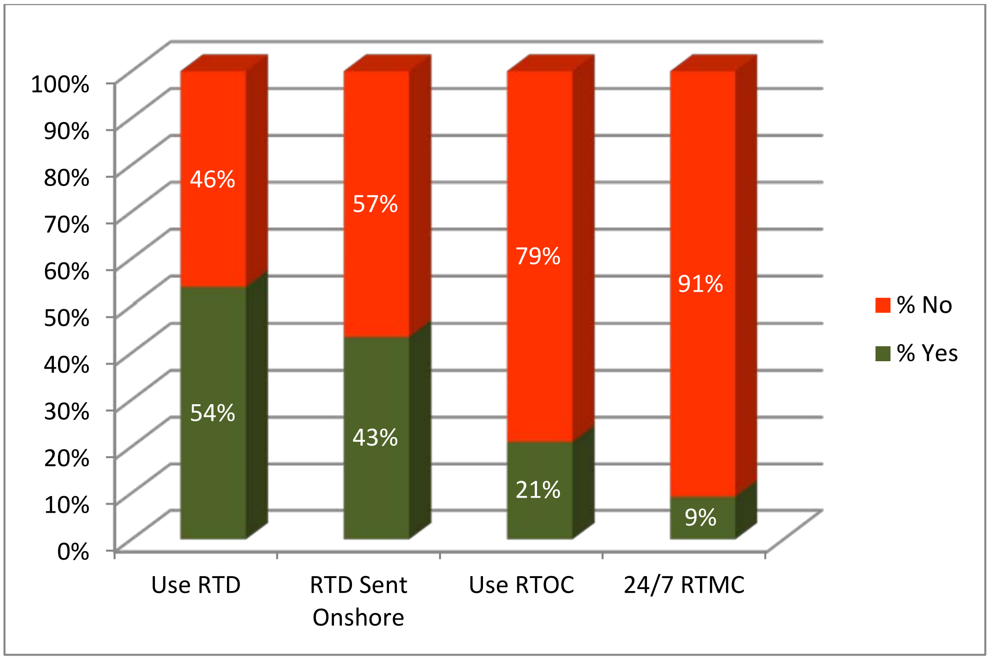


Figure 2: Use of real-time data in the Gulf of Mexico

CHAPTER 2 – (Task 3) Discuss options for training programs or contracted services which would be needed to incorporate the identified systems into BSEE's process.

Chapter Summary

This chapter discusses training options necessary to incorporate systems necessary for real-time data monitoring into an oversight role and addresses the role of standardization for the purposes of regulatory oversight. Regulatory oversight is defined as the need to monitor operator operations for the purposes of compliance with CFRs and BSEE regulations. The oversight system BSEE will operate must be clearly defined before an effective training program can be developed.

We've narrowed this discussion for Task 3 to a model of system oversight and appropriate training programs to be incorporated into BSEE processes for Real-Time Operating Centers (RTOC) and Real-Time Monitoring (RTM) as described in Chapter 1 (Task 1). This report assumes BSEE requires training options to understand all aspects of collecting, storing, and analyzing aggregated data from an operator's ongoing drilling operations.

Introduced in this task are the definitions and principles of safety oversight, system safety principles as they relate to training, and three training scenarios for the purpose of discussion.

Training Scenario 1 suggests a focused internship at an oil and gas operator with syllabus of instruction agreed upon by BSEE and the operator. This scenario would be extremely valuable as a method for an in-depth understanding of the well planning process from concept thru execution. In order to understand the data aggregated in an RTOC, the BSEE representative must be familiar with the well planning process of their specific operators.

Training Scenario 2 describes bringing real-time data technology to BSEE. This concept requires a curriculum developed by BSEE, with coordination from industry, to develop training courses designed to educate BSEE representatives on the topic of real-time data technology for the purpose of understanding the available technology within the industry.

Training Scenario 3 presumes the development of a simulation center within BSEE that is modeled from traditional Real-Time Operating Centers. Conceptually, BSEE would setup and maintain a 'training' RTOC within its structure and train personnel based on industry best practices using actual, de-identified, real-time data to run simulations or potentially replay actual events.

System Safety at the Regulator Level

System safety is an approach to manage hazards and risks in complex systems. Exploration for oil and gas is a risk-based proposition filled with uncertainties requiring decisions critical to safety at every juncture. To varying degrees, every operator has in place programs and policies and processes designed to mitigate and minimize the effect of unsafe actions and situations. These programs work well when the organization has fully invested in their execution. However, to elevate inherent levels of safety across the industry requires a more global approach. The voluntary approach initially recommended within The American Petroleum Institute Recommended Practice 75 (API RP 75), published in May 1993, established the development of a Safety and Environmental Management Program for offshore operations and facilities. These recommended practices produced some level of acceptance and standardization within the industry. Then, with the Safety Environmental Managements System (SEMS) mandate, the industry moved one step closer to a fully integrated systematic approach to safety. This is similar to the aviation and nuclear industries which have well established Safety Management Systems that continually evolve as safety understanding evolves.

System safety concepts entail a risk management strategy based on identification, analysis of hazards and application of remedial controls using a systems-based approach. The FAA System Safety Handbook defines system safety as: a specialty within system engineering that supports program risk management. It is the application of engineering and management principles, criteria and techniques to optimize safety. The goal of System Safety is to optimize safety by the identification of safety related risks, eliminating or controlling them by design and/or procedures, based on acceptable system safety precedence.

System safety is more than the traditional safety programs enacted throughout the industry. For the FAA, it's an integral part of the oversight system. The oversight system BSEE will operate must be clearly defined before an effective training program can be developed.

The development of the training scenarios discussed in this paper is dependent on how the BSEE's evaluation function is transacted in the field. Other successfully safe and regulated industries, like nuclear and aviation, have applied a 'cooperative oversight' model of interaction, which has been more successful than imposition of a rigid, prescriptive evaluation.

Example outlines of oversight programs exist today in other industries and can serve as a model to build a BSEE program. An Oil and Gas Oversight Safety (OGOS) program, if implemented needs to be based on the explicit policy of BSEE. An example policy statement may be: "BSEE will pursue a regulatory policy which recognizes the obligation of the operator to maintain the highest possible degree of safety." OGOS implements BSEE policy by providing safety controls (i.e., regulations and their application) for operators that fall under BSEE regulations. Under OGOS, BSEE's primary responsibilities might include: (1) verification that an operator is capable of operating safely and complies with the regulations and standards prescribed by the BSEE before issuance of an 'accepted Well Plan' and/or before approving or accepting operator programs; (2) to re-verify that an operator continues to meet regulatory requirements when environmental changes occur by conducting periodic reviews; and (3) to periodically validate the performance of an operator's approved and accepted programs for the purpose of continued operational safety.

The discussion of training for this task will include three variations for BSEE training. In order to implement any of the three training options, we first need to discuss the intent of an oversight system, which improves the surveillance processes by the regulator. The oversight system assesses the safety of operating systems using System Safety Principles, safety attributes, risk management, and structured system engineering practices.

The operator is the process owner of their drilling systems, which is a production system. BSEE is the process owner of the oversight system, which is a protection system. The intent of protection systems is to promote worker safety and protect the environment from potential harm of production activities. This includes potential harm from accidents, occupational hazards, loss of equipment and other property, and damage to the environment. Safety Environmental Management Systems (SEMS) and Quality Management Systems (QMS) are also protection systems. The relationship between production and protection systems requires exchanging information and exerting influence. Protection systems influence production systems by imposing controls.

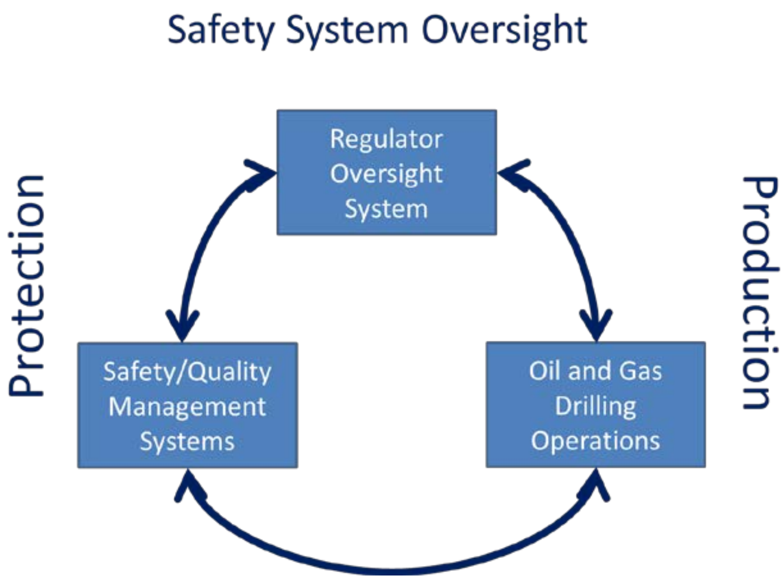


Figure 3: Safety System Oversight Process

Major Functions of Safety Oversight

A Safety Oversight System requires several levels and components of supervision. Primary responsibility falls on a Principal Inspector (PI) who ensures proper safety oversight is maintained. Safety Inspectors (SI) are the second level and apply a broad knowledge of the oil and gas industry, general principles of oil and gas safety, Federal laws, regulations, and policies. Both the PI and SI have intensive technical knowledge and skill in the operation and maintenance of drilling operations. The PI and SI employ systematic tools to ensure ongoing operations comply with regulations and industry safety standards. Three of the common tools used to ensure standards are maintained include: Design Assessment (DA), Performance Assessment (PA) and Risk Mitigation (RM).

The Design Assessment tool is a safety oversight function that ensures an operator's systems comply with regulations and safety standards, including the requirement to operate with public safety as the highest priority. An operator safety process must ensure that systems comply with the intent of the regulations and use standardized, systematic processes to determine an appropriate level of safety. The DA tools used (oversight audits, etc.) should ensure operators are meeting regulatory requirements during periodic program reviews, or when the situation dictates.

Performance Assessment (PA) tools should be used to confirm that operating systems produce intended results, including mitigation or control of hazards and associated risks. Safety Oversight systems use periodically designed PAs to detect systemic failures that may occur due to subtle operational changes. PA schedules are also adjustable based on known risks or safety priorities. Surveillance is synonymous with auditing and provides information for PAs and Risk Mitigation.

The Risk Mitigation (RM) process identifies and controls hazards and manages resources according to pre-determined risk-based priorities. Proper RM is accomplished through continuous systematic risk assessments of an operator's performance and operating environment. The potential consequences of hazards define the level of a specific hazard. The likelihood and severity of a consequence determines the risk. When multiple risks exist, a safety oversight system assesses the combined effects of likelihood and severity to determine priority. Subsequent RM action plans contain strategies to transfer, eliminate, accept, or mitigate the risk. This process validates the intended results of an action plan to ensure that a hazard is effectively eliminated or controlled. A properly structured safety oversight system deals with the hazards and associated risks that are subject to regulatory controls such as enforcement actions, certificate amendments, and rulemaking. The Risk Management Process tracks hazards that are the operator's responsibility until the operator successfully resolves them.

When the Safety Oversight System has been properly structured, the organization can begin to develop appropriate training systems to prepare the required group of employees. The focus of the training scenarios described below is limited to specific training to utilize Real-Time Operating Centers (RTOCs) in an oversight function. In order to understand the discussion, several questions needed to be asked of the regulator and assumptions made. The list of questions is below:

Who is the audience? – Who in BSEE will attend or use the training options discussed? The author makes the recommendation that the BSEE team who should be trained on the RTOC systems will be principle investigators, evaluators and auditors employed by BSEE, have a baseline understanding similar to or with a Petroleum Engineering degree (PE) and have understanding of basic drilling requirements. The expected experience lever for PE's, licensed and having 10-15 years' experience.

What are the objectives of the training? – What are the desired outcomes of the training? For the purpose of this task, the desired outcome will be for the BSEE representatives to have a full understanding of the data derived in an RTOC and how they are expected to use that data for safety evaluation purposes.

Which aspects of RTM activity should be used in BSEE's processes? - Is this activity individual component technology, or full RTOC capability? Our training options assume that BSEE needs to be able to understand the full RTOC capability. If the BSEE representative understands how all the technology fits together within the RTOC. The offshore RTOC environment can provide valuable insight to the offshore element.

What level of initial competence is necessary? The trainee for the program should be at least a qualified Petroleum Engineer, or at least 10-15 years of experience with a hands on understanding of drilling and production activities and as well as oil and gas dynamics.

Definitions of Safety and Risk

Safety is reducing the risk of harm to people or property damage, and maintaining the risk of harm at or below an acceptable level through a continuing process of hazard identification and risk management. By this definition, an operator's duty to provide service with the highest degree of safety for the public interest means that the operator must identify hazards in their operating environment and manage associated risks. Similarly, an operators' ability to manage risk is an important part of the regulators determination to ensure that the operator is equipped to operate safely under the appropriate regulations and standards prescribed by the BSEE.

System Safety

Properly designed safety systems control hazards by eliminating or mitigating associated risks before they result in accidents or incidents. In an operational context, operators fulfill their duties to provide service with the highest degree of public safety by designing their operating systems to manage hazard related risks in their unique operating environments.

Focus on Organization and Processes

In addition to issuing approval for well plans, monitoring compliance, investigating noncompliance, and administering sanctions for noncompliance, BSEE must also focus on the operator's organization and process management. Outputs and outcomes are still monitored; however, the emphasis is on maintaining a safe process and correcting deficiencies. Performance Assessments (PA) must supply objective evidence of both the adequacy and inadequacy of processes. Safe operations require constant adaptation. In a properly designed oversight system, control measures should be established to ensure operating environmental hazards and unsafe changes to the environment are mitigated. Data Collection Tools (DCT) are used to help provide information on current environmental risks and on the operator's efforts to control those risks.

Data Sharing

BSEE is responsible for independent assessment of an operator's qualification and continuing ability to comply with regulations and standards. BSEE could accomplish these independent assessments using data that has been validated by a qualified inspector provided by an operator or a third party. Cross industry communication and sharing of nonproprietary data sources assists to optimize the function of the oversight system and leverage resources to advance safety. The current lack of transparency in the industry necessitates the need for a full change in paradigm and perhaps, regulatory involvement to increase data sharing across the industry. BSEE and the industry will need to establish data types to be shared and determine how data needs to be de-identified. One of the most important aspects of oversight safety is the ability of industry players to learn from all performance errors, not just their own. Industry wide data sharing of de-identified information allows this learning system and best practices to propagate industry wide.

Safety Oversight System Design

The training scenarios in this report are optimized to work within a safety oversight system. BSEE representatives would learn how the RTOC operates and the BSEE regulatory intentions. The following list describes a possible structure for BSEE regulatory oversight and would require coordinated specific training in order to prepare BSEE representatives to enforce the regulatory principles as they relate to Inspectors:

Roles and Responsibilities

The Director of Standards

- Provides the national policy and guidance for OGOS.
- Provides and maintains national policy and guidance for baseline training and staffing standards.
- Provides adequate regional resources to support OGOS processes.

Standards Field Office

- Provides OGOS policy and procedures in accordance with OGOS.
- Completes changes and updates for the system configuration process.
- Provides analysis and program support for the OGOS process.
- Develops operator certification and data collection policy and procedures.
- Collects feedback and completes changes and updates for all OGOS processes, and assesses OGOS process effectiveness.
- Continually improves OGOS using established processes for system engineering.

Standards Training Division

- Budgets for and provides the training that meets the needs of OGOS users.
- Audits compliance with OGOS policy and procedures as well as evaluates the effectiveness of OGOS processes.

Regional Standards Division Offices

- Implements OGOS.
- Resolves any identified issues.

Principle Inspector (PI)

- Is responsible for the operator interaction and process development and delivery.
- Reviews an operator’s request for new operations, or changed scope of current operations.
- Collects and organizes information to complete an applicant assessment, solicits input from team members, and makes decisions about oversight requirements.
- Prioritizes OGOS Design Assessments (DA) and Performance Assessments (PA) by following OGOS planning procedures.

- Monitors the effects of industry changes and uses the change management tools to determine when retargeting oversight activities is required based on analysis of data or significant changes in the operating environment or other triggers such as accidents, incidents, or occurrences.
- Participates in periodic meetings with the operators to stay informed on conditions that could cause an imbalance between personnel available and current operations.
- Provides specific instructions for completing inspections using the OGOS planning procedures.
- Identifies and brings safety concerns to both the Regulator and operator's attention.
- Analyzes risk and ensures the certificate holder addresses hazards to document rationale, develop action items, and monitor progress.

Safety Inspectors (SI)

- At a high level, participates in the planning activities.
- Schedules, coordinates, and accomplishes the work assignments using OGOS tools. Inspectors may work individually or as part of a team on inspections.
- Accurately and promptly enters data collection results into the OGOS database in accordance with OGOS data quality guidelines.
- Submits reports for observations that are relevant to safety goals. These observations are incidental to other work assignments and may involve any regulation.
- Reevaluates returned inspection records and decides on the appropriate action (e.g., editing the record, conducting additional observations, or taking no action).
- Promptly identifies unsafe conditions or possible regulatory violations observed during data collection, notifies the appropriate personnel, and makes appropriate entries into BSEE data systems.
- Follows established procedures to assist PIs in determining that the operator complies with its written procedures and meets its established performance measures.
- Performs qualitative reviews of available data that falls within their subject matter expertise. Supports PIs and performs tasks associated with the Risk Management Process.
- Conducts random inspections.

Training Program Development

The training scenarios are designed to train mainly the Principal Inspectors and Safety Inspectors on Real-Time Operating Center operations and use for oversight and regulatory purposes. The transition to a Safety Management System environment between BSEE and the operator requires a change of attitude throughout the industry and its current operating environment. The attitude change is necessitated by the past appearance of collusion that resulted in the current, traditional cause and effect oversight relationship. This is a necessary step that requires a more collaborative environment.

Data collection requires a collection plan and a way to inspect the data either in real-time, or by using historical data. It is clear that there needs to be standardized data sets that the PIs are collecting. The process for collecting the data will need to follow predictable guidelines.

Standardized Industry Data

Industry data collection will require collecting streaming real-time data that conforms to a standardized set of oversight questions. The dataset of questions would need to be developed in collaboration with industry and contain data transfer from the operator that will be exempt from potential regulatory enforcement. This data is referred to as Safety Attributes and is described in detail in the following section.

Dataset questions derived from streaming real-time operational data, creates the foundation for safety oversight data collection. This data collection must be timely and accurate.

The training program design would need to incorporate RTOC operations with emphasis on the dataset questions and Voluntary Disclosure Reporting Program (VDRP) concepts, providing for a formal management framework that can serve as a valuable interface between regulator, operators and service providers. A successful training program would include the following components:

Voluntary Safety Action Program (VSAP)

Another input to the oversight dataset is established through a Voluntary Safety Action Program (VSAP) which is designed to enhance safety through the prevention of accidents and incidents. The focus of VSAP is to encourage voluntary reporting of safety issues and events by the industry workforce. The system is designed to encourage employees to voluntarily report safety issues even though they may involve an alleged violation of the regulations. Open sharing of potential, and apparent violations, plus a cooperative advisory approach to solving problems will enhance and promote safety. The intent is to change the current culture of the industry into a culture of improved safety through data sharing without retribution.

A successful implementation of a program that enhances safety by examining and limiting enforcement actions is the Aviation

Safety Action Program (ASAP). It is a program that receives information on events and/or conditions where enforcement actions are possible. Reports are submitted by the operators to a central collection facility for a decision to include or exclude the operator from the program. If the operator's report is accepted into the ASAP program the threat of enforcement is eliminated. The decision to include an operator's report into the ASAP program is based upon finding 'willful disregard' and 'intentional non-compliance.' If the report is not accepted into the ASAP program they will be eligible for enforcement actions. The ASAP program has been very successful in increasing safety by uncovering events and conditions that would have not been reported. The information received has shown that there are items that were not eligible for enforcement but were previously withheld because of the possibility of corrective action. Reporting these items had contributed greatly to the overall safety of the industry.

Similar guidelines can be implemented by BSEE to gain insight and information that would have previously been unavailable due to the possibility of punishment.

Safety Attributes

The key to safety lies in managing the quality of safety critical processes. This is a primary responsibility of an operator in meeting its regulatory obligations. Oversight safety employs six safety attributes to evaluate the design of operator systems:

Procedures—Documented methods to accomplish a process.

Controls—Checks and restraints designed into a process to ensure a desired result.

Process Measures—Validate a process and identify problems or potential problems in order to correct them.

Interfaces—Interactions between processes that must be managed in order to ensure desired outcomes.

Responsibility—A clearly identifiable, qualified, and knowledgeable person who is accountable for the quality of a process.

Authority—A clearly identifiable, qualified, and knowledgeable person who has the authority to set up and change a process.

These attributes are not necessarily standards, but provide a structure for the tools used to collect data for PIs to make informed judgments about the design of an operating system before approving or accepting the design. The judgment would be delivered when required to do so by the regulations, and during recurring assessments for continued operational safety. Industry-wide standardized data collection using dataset questions will require Data Collection Tools (DCTs) to ensure the operators are following Specific Regulatory Requirements (SRRs). DCTs are sets of questions that are designed to be part of an ongoing process to ensure continuing adherence to the SRRs. The DCT should be developed and refined over time as opposed to a reactionary generation by an operator in response to a periodic audit. The DCT questions are always applicable and should become a 'living' document. In other words, the adherence to DCTs does not become an occurrence exercised once every two years, but will always be updated and monitored to ensure continual compliance. DCTs can be broken into specific sections to ensure completeness of the data. This includes objectives and question checklists. The following paragraphs describe potential dataset question sections:

Procedures Attribute Dataset Questions

This dataset confirms the operator's documented procedures and identifies who, what, when, where, and how the operator accomplishes its processes and complies with written procedures. Operator procedures must allow all personnel to perform their duties and responsibilities with a high degree of safety. The SI will determine if written procedures exist, if the procedures contain sufficient detail, and if they comply with regulations. The SI will also determine that the procedures being performed are included in the operator's system documentation. Several questions may have SRRs for this process that apply to the entire industry and may not apply to specific operators. For this reason, a response of 'No' to one of these questions does not necessarily mean that the company is not complying with a regulation, or that any action is necessary.

Controls Attribute Dataset Questions

This dataset will help determine if the operator designed controls (e.g., checks and restraints) in the processes associated with this element follow policies and procedures. While most controls are not regulatory, they are an important safety attribute with necessary features that help to reduce unacceptable levels of risk. Some common types of controls are flags, data system backups, authorized signatures, separation of duties, or a final review. Few of these controls have their basis in SRRs. For this reason, a response of 'No' to one of these questions does not necessarily mean that the company is not complying with a regulation or that any action is necessary.

Process Measures Attribute Dataset Questions

Process measures ensure that the operator uses an internal evaluation function to detect, identify, and eliminate or control hazards and the associated risk. Negative findings could require amendments to the Safety/Internal Evaluation Programs (IEP) or checklists. In most cases, process measures are non-regulatory. For this reason, a response of 'No' to one of these questions, while not a violation, may indicate a hazard with an increased level of risk and may require additional action.

Interfaces Attribute Dataset Questions

Data collected in this section helps determine if the operator manages the interfaces (i.e., interactions) where the responsibility for accomplishing work transfers from one person, work group, or organization to another. Detailed procedures must ensure the smooth transfer of work and information.

Management Responsibility and Authority Dataset Questions

Data from this set of questions will help identify if there is a qualified (when required by regulation) and knowledgeable person who is: responsible for the process, answerable for the quality of the process, and has the authority to establish and modify the process. Often, many organizations disperse authority and responsibility. A 'person' can be an individual, a department, a committee, or a position (such as vice president of drilling operations). The intent is to identify the highest-level 'person' (at the appropriate level within the organization) who is responsible or has the authority for that particular element of the lease holder's system.

Element Performance Dataset Questions

After the Safety Attributes are established, Element Performance is the next program design step. This step collects performance data to ensure the operator is doing what their processes and procedures dictate. The Element Performance information is standardized across the industry and is used to determine if the operator follows their procedures, controls, process measures, and interfaces for the process. It also determines if the process is functioning as designed and achieving the desired results. Data collected is used to assess the system performance of the operator.

Risk Management Process

A Risk Management Process (RMP) developed from the data collected is implemented as the next design step. The RMP provides the PI with a method to oversee and evaluate associated risks and to document identified hazards. The RMP process has five major steps:

- Hazard identification (identify hazards and consequences),
- Risk analysis (analyze hazards and identify risks),
- Risk assessment (consolidate and prioritize risks),
- Decision making (develop an action plan), and
- Validation of control (evaluate results for further action).

Hazard Identification (Identify Hazards and Consequences)

A hazard is a condition, event, or circumstance that could lead to, or contribute to, an unplanned or undesired event. Hazards are identified from studying de-identified information from Real-Time Data Systems, whether it's streaming rig data or data from the above datasets, and a determination is made whether the hazards are isolated incidents or systemic problems. An operator's analyst continually monitors available data sources to identify events, trends, or patterns that indicate potential safety issues and reports them to the PI. The data that may show cause for enforcement action could be considered for the VSAP program if the entrance criteria are met. The analyst also reviews issues tracked using an RMP to avoid duplication and identify any issues that might be related. The PI analyzes and assesses systemic hazards and their potential consequences to determine the level of risk associated with the hazard. Without conducting a complete analysis, the PI may notify the operator of any isolated incidents that do not require a complete RMP.

Name and Describe the Identified Hazard

All members of the operator RTOC should be alert for potential hazards and follow the operator specific protocol. As an oversight system is developed, once these hazards reach a determined criticality, the operator will notify the PI. Once the PI has identified the hazard, the PI prepares a summary that describes the identified hazard, and includes relevant facts such as who, what, why, how often, and where. The ability to voluntarily identify hazards without retribution within the parameters of VSAP will accelerate the reporting performed by the operator.

Determine and Document Potential Consequences

The PI determines, documents, and communicates the potential consequences that could result if the operator does not address or correct the hazard. These consequences could be any one of the following:

- Equipment failure,
- Human error,
- Damage to equipment,
- Procedural nonconformance,
- Process breakdown,
- Personal injury or death,
- Regulatory noncompliance,
- Decreased quality or efficiency, or
- Other

Risk Analysis (Determine the Likelihood and severity of the consequences)

The next step in the RMP is risk analysis. The PI analyzes hazards identified by interpretation and analysis of the real-time data to identify risk factors that assist in risk analysis and provide specific targets for action plans. Risk factors identify what the operator must later mitigate to reduce the overall level of risk. An effective action plan should address risk factors by eliminating them or by reducing their impact.

Risk Assessment (overall risk assessment value determines priority)

The PI considers the overall level of risk to determine the priority in ensuring that the operator addresses the hazard and its associated level of risk. This assessment, as shown in Figure 4, assists the PI in decision making, action planning, and evaluating operator actions. The PI uses this information from the risk analysis to determine the overall level of risk using the following matrix:

Decision Making (Develop an Action Plan)

Based on the results of the risk analysis, the PI does one of the following:

- Eliminates the hazard,
- Mitigates the risk,
- Accepts the risk at its existing level, ~or~
- Transfers the risk

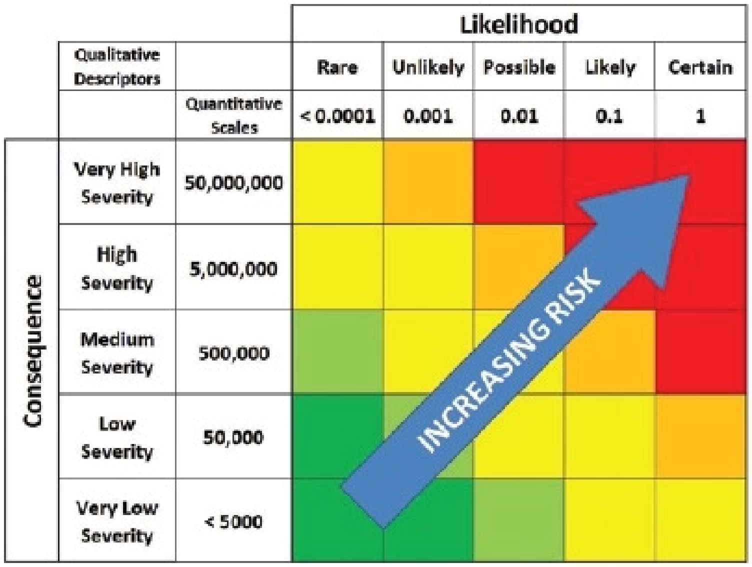


Figure 4: Example of a 5x5 risk matrix using log-log quantitative scales.

When corrective action is beyond the operator's authority, the PI may delegate the authority, responsibility, and accountability for taking corrective action for the identified hazard to the appropriate organization. The PI uses this approach to address risks that may require actions such as rule changes, policy changes, and safety recommendations. If an RM action plan is developed, the PI should include this with the information package sent to the receiving organization. Once the PI transfers responsibility, he or she will close the RMP. The PI must enter the rationale for closing the RMP. The PI might decide to follow up on the status of transferred issues.

Develop an Action Plan

The PI creates and assigns action items to ensure that the operator addresses the identified hazard and mitigates the associated levels of risk. The operator usually carries out mitigation. The operator may take actions that do not involve the participation of the operator to effectively oversee the operator's mitigation of the hazard and associated levels of risk.

Validation of Control (Evaluate results for further action).

After all action items are complete with indications that the action plan has eliminated the hazard or reduced the associated risk to acceptable levels, the PI validates the effectiveness of the selected approach. The PI reviews the status of the hazard and verifies that the operator has eliminated the hazard, or mitigated the level of risk associated with the hazard, to an acceptable level. After evaluating the results of the mitigation strategies, the PI decides whether to close the RMP or to require the development and implementation of additional action items.

Training Systems Development Methodology Overview

There are a number of training methodologies used in system level training programs, but most have similar core functionality. The author proposes using a Training and Readiness (T&R) model which focuses on building T&R requirements based on individual skill sets and incorporates knowledge, skills and abilities as well as establishes core competencies. The Training Scenarios discussed in this document are intended to be concepts for discussion, not actual detailed training syllabi. Once a training course of action has been decided upon, the following details the method used to design the actual training course using one of the Training Scenarios.

The T&R program provides:

Focus on Expected Operations: The ultimate goal of all training is to have personnel/offices prepared to perform during daily operations.

Building Block Approach to Training: The T&R concept is a building block approach. At both the individual and collective levels, the goal is to achieve and maintain a minimum standard of readiness by accomplishing a series of progressively more challenging events that include the tasks operators must be capable of performing during day to day operations.

Focus on Core Skills and Core Capabilities: In every occupational field or unit there are tasks that are the very essence of the contractors' existence and comprise the most basic Mission Essential Tasks (METs). Regardless of the geographic location where a company operates, the skills gained in learning to perform the tasks that support these METs will enable those companies to succeed.

Organization of Tasks into Executable Events: T&R Manuals define the core skills required and are normally trained in entry-level formal schools or in some instances during On the Job Training (OJT). For continued training after formal school, the T&R concept includes the gathering of associated tasks into executable events that are modeled after the essential skills needed for that job.

Sustainment of Training: T&R involves steps for helping learn skills and retain the ability to perform those skills. Periodic demonstration of skill is accomplished by establishing a sustainment interval for each event to ensure perishable skills and knowledge do not decay to the point that the employees can no longer perform the skills effectively.

The Training and Readiness (T&R) approach to managing training involves establishing a matrix/spreadsheet that will be used to track and report the training progress and rate the quality of the knowledge retained by the student.

The T&R process starts with a Front End Analysis (FEA) to assess the scope of training subjects and to develop a complete list of Mission Essential Tasks (MET) for the entire training system. The tasks are not divided into respective categories for different qualifications or training levels at this time.

Importance	Difficulty	Frequency	Training Aid
< 3.04			Exposure
> 3.04	< 2.04		Guided Exposure
> 3.04	> 2.04	< 3.04	Job Aid*
> 3.04	> 2.04	> 3.04	Guided Practice
> 3.04	> 3.00	< 3.04	Guided Practice w/job Aid*
* Tasks that would normally result in Job Aid or Guided Practice w/ Job Aid that must be completed without reference to a job aid or for which no job aid exists will be trained using Guided Practice. These tasks are identified in the task analysis as Job Aid N/A.			

Each task is examined by a subject matter expert and a list of Enabling Objectives (EO) is assigned to each task. The EOs represents the skills needed to be exhibited before the student can be considered capable of achieving the task.

An abbreviated example from a Blowout Preventer (BOP) Function Test training system for the task 'BOP Function Test' and supporting EOs is shown below. From the Code of Federal Regulations – Title 30: Mineral Resources. The purpose of the tests is to ensure the BOP system and system components are pressure tight and fit for purpose.

The tasks and EOs are collected into a Master Task List (MTL) and the job of assigning training levels is initiated. The MTL is used to describe all of the skills and knowledge for the various training levels by using the tasks and EOs to assign training requirements to individual qualifications. The qualifications generally build upon an initial qualification requirement for a new entrant into the training system.

The syllabus for training is generated from the tasks and EOs. The tasks and EOs are examined by an instructor and rated for Difficulty, Importance, and Frequency (DIF). The rating assigned will determine the type of instruction suitable for the task. A representative criterion for assigning the DIF is shown below.

The tasks needed to complete a unique level of training are collected and DIF ratings are applied to generate the type of training aid and to begin to generate a training syllabus. The training is sorted and collated to initiate an effort to determine the level of resources needed for the training.

The resources needed for 'Guided Practice w/ Job Aid' is greater than 'Exposure' and will require more resources be applied to generate the proper level of knowledge transfer. A curriculum that has many 'Guided' events will require more Instructor Led Training (ILT). A curriculum with many 'Exposure' events could be supported with printed material read at the student's pace.

	<30 Days	<90 Days	<Six Months	<Calendar Year
Reviewed RTMC system	5	4	3	2
Received RTMC training	5	5	4	4
Received Refresher RTMC training	5	5	3	1

A 'Job Aid' can be a complex simulator or a simple desktop trainer.

The construction of the syllabus is done by a team of subject matter experts with intimate knowledge of the training requirements and the goal of the training. The syllabus will be broken down into stages that use previous stages to build the necessary skills. The stages are Academic, Computer Based Training (CBT), Procedure Trainer, Simulator, Actual device. The Academic portion can be instructor led.

Once the syllabus is completed the use of the Training and Readiness (T&R) matrix is initiated. The T&R matrix will allow the tracking and reporting of the completion status of the syllabus. The T&R matrix is constructed by the organization charged with oversight of the training process. The organization will assign values for importance and frequency requirements for the training requirements for individual qualifications.

The T&R matrix uses values assigned to determine the level of training and readiness by rating the currency of training (how long since the last training event) and the importance of the training. The ratings are shown as 'T' ratings. The desired/required level of 'T' can be tracked and reported to verify the necessary training has occurred and to indicate the level of readiness the student exhibits to be able to perform the necessary tasks to accomplish their occupation/profession.

An example of a possible T&R matrix is shown below. The ratings can be adjusted to attain the desired level of skill and experience. The ratings are assigned to properly indicate the level of training attained by the student. In the example shown, the level of training and currency is more important for the 'Received Refresher RTMC training' than 'Received RTMC training' as shown by the sharp decrease in values indicating that refresher training is required within every six months.

The reporting and tracking of the T&R matrix is flexible in scale can be done at the individual level and/or at any other unit, whether that be an operator's team, group, division or other grouping. The report custodian can use the report to examine individual training levels or to assess the ability of the unit to perform the mission goals. The custodian can use the report to find resource challenges that have impacted the overall training and readiness as reported in the matrix.

The sustainment of the skills is reflected in the values assigned to each training event. After training values for the unit are assessed, continuing education can be tailored based on the indicated level of readiness and the training resources available.

Training Scenarios

The intent of the following training scenarios is to provide BSEE representatives with the tools to operate effectively in the field providing cooperative oversight, evaluation of operations and increased safety levels through the use of real-time data in aggregated formats consistent with RTOCs. Syllabus development for these scenarios should be conducted in conjunction with industry experts and other industry stakeholders such as the American Petroleum Institute (API). All scenarios are options for training programs or contracted services necessary to incorporate real-time data into BSEE processes.

Training Scenario 1: Internship

This scenario suggests a focused internship at an oil and gas operator with an agreed upon syllabus of instruction. This scenario would be extremely valuable as a method for an in-depth understanding of the well planning process from concept thru execution. In order to understand the data aggregated in an RTOC, the BSEE representative must be familiar with the well planning process of their specific operators.

Industry Feedback

The author requested industry input for the internship option and all companies contacted expressed a high level of interest in hosting BSEE personnel for potential internships as long as confidentiality and 'hold harmless' agreements could be put into place. Also recommended was that the intern not audit or inspect the company for which they trained during their internship. The following is a compilation of the interview questions and combined industry feedback:

List the goals and objectives you would like to see for a BSEE internship to learn how to monitor operations via RTMC/RTOC.

The intent of the program would be to enable the intern to understand the big picture for drilling and production operations. The program would provide high level focus into all the components of drilling; specifically identifying the reasons procedures are followed in coordination with process safety at the operational level.

What would you like the internship to achieve for someone attending?

To understand the information generated from real-time data in an RTOC operation.

The intent is to learn how to use the data/information; generate ideas about how to use different data sets better; understand what is required as 'important' information in the data; learn what decisions are being made based on the data and actual operational data from the rig; what other real-time data information is being used for decision making.

Which skills would be desired for a BSEE intern to learn during training?

A Petroleum Engineer with a background that understands the basics of drilling. The important skill is to have a basic understanding, this cannot be somebody right out of school, and the intern must understand drilling /production operations.

Briefly explain why the use of 'on the job' training for this internship is preferred to theoretical (classroom) training.

Learning in a classroom based on books provides a foundation for learning principles, on the job experience provides important context for understanding real world operations. If there is an 'on the job' level of experience, the intern will be able to understand the decisions that are being made based on the real-time data.

How do you envision this training will make the BSEE team members more efficient with respect to evaluating RTOC's?

The more the intern understands real-time data used in an operational context, the better they can understand the big picture and can key in on critical items and understand why real-time data is essential in operations.

What might a syllabus of training activity look like or encompass?

The intern will be required to actively participate and understand roles and responsibilities of all the RTOC job descriptions. A requirement will be to learn all the different RTOC functions from the people currently using the real-time data. The intern would shadow the actual employee for as long as it takes to understand individual roles and responsibilities. This could last from one day to one week.

What training activities would you recommend the intern take part in? See question #6.

Are there areas the intern would not be exposed to or you would need to keep company confidential?
Based on the confidentiality agreement, this could depend on many different variables and would have to be agreed to prior to the internship.

Given the limited time, what principles will the intern be exposed to, and what level of detail will they be able to understand following the internship? This would be designed to be 'free-flowing' to ensure the intern has a full understanding of real-time data. If the intern felt they required a more in-depth understanding, they would be able to spend additional time learning the specific function.

How long would the fellowship need to be and what would the time requirement be for each learning activity? Based on #6 and 9, the fellowship could last from 4-8 weeks.

How/who would supervise the intern?

The intern would be assigned to a specific supervisor (possible the Drilling Superintendent) who would manage the high level curriculum and ensure the appropriate level of understanding. Depending on the specific setup of the operation, there could be multiple supervisors based on the RTOC structure.

How would the intern interact with company supervisors? See question #6.

How much time will be spent learning each of the above activities? See question #6.

How will the intern be evaluated during this fellowship?

BSEE management would be expected to evaluate the interns understanding of RTOC operations following the internship. Follow up with the company could be initiated in the event the intern would need to learn more in specific areas.

What is the expected interaction between the BSEE intern and operator following the internship?

Feedback to the company that provided the internship would also be required in order to make the program better. The interns could visit more than one company to help develop a standardized program.

The internship would last roughly 2-3 months and be located in the operators' RTOC location with alternative time spent at a BSEE training facility. The intern would be a qualified Petroleum Engineer (PE) with one to five years of experience depending on the individual's hands on experience, understanding of drilling and production activities, and oil and gas exploration dynamics. Note: There is not currently an industry consensus as to the appropriate experience level of the PE. There are a number of industry opinions that indicate any person monitoring data in an RTMC should have at least 10 years of experience and should have in-depth understanding of all rig functions. The other end of the opinion spectrum believes that a certified PE with at least a year of experience can learn the requisite information gathered in the RTOC. A dedicated training course that is developed should account for different levels of experience and by the end of the training course; all experience levels should have credible experience and be able to understand all training objectives equally.

The BSEE representative would work in and around the RTOC as it relates to the well delivery process. The primary focus will be given to monitoring operations in the 24/7 center, emphasizing drilling operations on current projects and should utilize training for the representative to understand all levels of the well planning process. Basic levels of well planning process will be part of the training curriculum, but exact process may not be incorporated due to intellectual property/confidential information purposes. Secondary consideration will be given to field development planning, optimization, and application engineering support as time and operations permit. The intent is for the intern to have a high level working knowledge of the use of RTM. Additional training courses should be developed for more advanced concepts based on operator/BSEE cooperation. The following is an example outline of a possible internship at an operator and is based on the compilation of information from actual major oil and gas operators:

Timeline

The following represents a rough approximation of the amount of syllabus time dedicated to particular events within the RTOC:

- 24/7 Monitoring – 75% (Minimum 1 Month)
- workflow and integration with operations
- Field Development Planning – 5%
- Optimization – 10%
- Applications – 10%
- Understand workflow in regards to 24/7 monitoring and support for wells engineering teams

Safety Monitoring

The below timelines are initially set at industry recommended timelines, but the duration may need to be extended to ensure adequate learning by the intern. The intern will learn how the operators integrate safety monitoring into modern safety risk management and safety assurance concepts into repeatable, proactive systems. The safety monitoring portion of the syllabus will emphasize safety management as a fundamental business process to be considered in the same manner as other aspects of business management.

Interns will have the chance to observe the organization's role in accident prevention and see the following fundamentals demonstrated as part of safety monitoring:

- A structured means of safety risk decision making
- A means of demonstrating safety management capability before system failures occur
- Increased confidence in risk controls though structured safety assurance processes
- An effective interface for knowledge sharing between regulator and operator.
- A safety promotion framework to support a sound safety culture.

RTOC Monitor Overview

An intern’s experience in the RTMC environment will provide an overview to RTOC monitoring operations from spud to rig release on a given well. These include but are not limited to drilling, tripping pipe or casing, cementing operations, and wireline activities.

Responsibilities include:

- Monitoring a maximum of 3 wells per individual or station
- Making recommendations based on observations of real-time data and use of analytical tools
- Intervention when conditions warrant (Intervention protocol)
- Briefing the RTOC representatives assigned to morning meeting

- Predictive real-time whirl – monitoring Rate of Penetration/Weight on Bit (ROP /WOB)
- Pore pressure estimation in real-time
- Connection flow monitoring
- Pressure while drilling
- Correlation to previous wells
- Vibrational analysis and stick-slip monitoring
- Monitoring real-time data against drilling and tripping models provided by Applications Engineers.
- Swab/Surge, Torque and Drag
- Participation in morning operational meetings
- Daily and weekly intervention reports

Field Development Planning Objectives

During this phase, the intern would receive an understanding of Field Development Planning (FDP). The FDP engineer works with offshore and onshore assets developing the best field planning and engineered well planning solutions. The intern will need an extensive knowledge of well engineering, plus a good understanding of its relationship with other disciplines such as geology, geophysical, production, reservoir engineering and facilities planning. Expertise with well engineering and subsurface software is required and duties will include:

- Assisting asset teams with field development projects
- Setup and facilitation of collaborative well planning sessions between well delivery and subsurface teams
- Daily collaborative session organization; assisting engineers, geologists, geophysicists and petrophysicists understand where they are in the context of the earth model
- Assisting well delivery teams in building models for field development and well planning projects
- Transferring data and distribution to G&G and 3rd party well planners as necessary
- Assisting G&G teams to show objectives and risks for upcoming wells
- Anti-collision analysis
- Assisting optimization and monitoring engineers with interventions
- Mentoring personnel in the use of decision space and its associated components

Optimization Objectives

Drilling optimization service optimizes the drilling procedures through proven modeling practices to maximize performance while helping to maintain safe drilling conditions. The intern will be exposed to drilling optimization to further understand how recommendations are made to help ensure wellbore integrity and stability, maximize ROP, extend target depth criteria, optimize or eliminate casing points based on facts and results from preplanning, and modeling to actual operations outcome. It is the optimization specialist’s duty to correlate downhole data plus surface drilling parameters to take the corrective actions during operations to reduce damaging vibration and improve performance. In the event of any drilling operation incident such as damage to drill string components or borehole failures, the optimization specialist will perform a root cause analysis to determine the cause and future corrective measures with documentation of findings and lessons learned. The optimization specialist's job is to help with the continued improvement of well delivery.

Responsibilities include:

- Performance improvement during
- Well bore pre-modeling planning phase
- Active monitoring during rig floor operations
- Post operations investigation and incident investigations
- Maintaining well team communications

Applications Objectives

Applications support provides drilling engineering modeling and calibration, with an emphasis on T&D, hydraulics and swab/surge. A high level understanding of drilling dynamics is required as well as an expert understanding of the sensitivities of well planning and visualization or modeling software programs. The internship will give an understanding of application support and how the 'roadmaps' that are produced for use in the execution phase are an integral mechanism in the prevention of nonproductive time (NPT) events. The engineer also has a key role to play in performing look back studies on related NPT events.

Responsibilities include:

- Hydraulics management
- Tubular analysis
- Drill-string integrity

Determining which engineering 'roadmaps' are to be implemented on current hole section. Production of same for use in 24/7 monitoring calibration of models between downhole sections using RTOC standard operating procedures.

Training Scenario 1 - Conclusion

As mentioned above, an internship BSEE representatives at an operator location is viewed favorably by many of the oil companies that use real-time data. The industry is moving more towards the 'smart' drill field and data/technology are being heavily utilized to make safer decisions during all phases of operations. The oil and gas companies are very open to providing BSEE with the same knowledge that real-time data is giving the companies and this scenario would provide a valuable tool to increase safety oversight within the industry.

Training Scenario 2: Curriculum Development

Bringing real-time data technology to BSEE is the second scenario for discussion. This concept requires BSEE, in conjunction with industry, industry related institutions, and academia to develop training courses designed to bring real-time data technology into a BSEE classroom format for the purpose of understanding the available technology within the industry. Training scenarios could be developed by the technology companies in accordance with BSEE's curriculum outline, which would include instructional courses in application, well development, visualization, logistics, drilling, monitoring, close-out, production and other requisite information. The curriculum would also incorporate industry best practices with respect to available sensor data, data transmission and data aggregation currently used in real-time monitoring.

The syllabus objective would be to have BSEE representatives recognize the technology they will see in the field and understand its uses, advantages and limitations. This training approach would be designed to inform BSEE representatives on technologies currently in use, in development, and where technology for the industry is headed for the purposes of defining improvements in safety, automation evolution and advances in technology. The latest implementations of an RTMC is based upon the latest concepts of data analysis, communications technology, automation, and sensors. These topics need to be included in the training program to ensure a well-rounded knowledge base for trainees.

Improvements in Safety

One objective of using real-time data information is to assist operators and service providers in developing and implementing an integrated, comprehensive safety oversight system for their entire organization. An understanding of the latest technology can help trained BSEE personnel to ensure that a safety oversight system will:

- Be capable of receiving safety input from Internal and external sources and integrating that information into their operational processes
- Establish and improve organizational safety policy to the highest level
- Identify, analyze, assess, control and mitigate safety hazards
- Measure, assure and improve safety management at the highest level
- Promotes an improved safety culture throughout their entire organization
- Realize a return on safety oversight investment through improved efficiency and reduced operational risk.

Automation Evolution

Process safety through automation and digitization is a complex balance of managing risk, ensuring safety and increasing efficiency. In today's environment, efficiency through automation must be addressed in the context of security. Getting all the pieces of the safety puzzle to come together efficiently, effectively and in a cost-effective manner is an ongoing challenge for midstream operators.

Automation functions in three parts: data mining, data-driven modeling, and model analysis. First, the data, which is often more than three dimensional, is preprocessed for quality control, and is mined to discover hidden and potentially useful patterns. In the second step, the data is parsed into machine-usable form, and after defining the model the data is analyzed in the final step. As the industry moves more towards smart drilling, these automation technologies need to be understood by the BSEE team.

Advances in Technology

Arranging courses taught by industry experts could be further developed into an industry collaborative to enhance levels of safety through advancing new technology. As an example, the Federal Aviation Administration (FAA) has established a technology center called The Next Generation Air Transportation System (NextGen) which is required to meet the present and future aviation needs. Robust and dynamic aviation partnerships among government agencies, industry, and academia are a critical component of NextGen and similar oil and gas relationships would be valuable and necessary for this scenario. A similar concept may be implemented by BSEE to ensure a higher standard of safety across the oil and gas industry.

The FAA has entered many partnerships to deliver NextGen. The technical center's complex gives research park tenants access to the nation's leading aviation and air traffic management Federal Laboratory – a unique collection of laboratories situated on a 5,000 acre complex that replicates the National Airspace System – and the FAA's top-caliber technical expertise. An academic institution could be an impartial third party central collection point for contractors within the oil and gas industry to provide the same caliber of expertise.[21]

BSEE has the resources and ability to partner with the industry to provide a similar capability. Partners like API, IADC, the Center for Offshore Safety, NASA and academic institutions could form to establish a training and technology center focused on improving industry safety.

Potential Training Providers

While it makes sense to use some of the larger service providers to do the training, it is also advisable to keep BSEE representatives abreast of the emerging technology provided by start-ups and smaller companies. The Ocean Energy Safety Institute could function as a training center in addition to its initially intended research functionality. From the Task 1 report, we organized technologies into different categories. Below are examples of companies from each category that may provide the basis for curriculum development and necessary training:

1. Subsurface/Formation Analysis and Well Planning and Modeling Tools

- Visualization Sciences Group (VSG)
- National Oilwell Varco (NOV)/TOTCO
- eDrilling
- Kongsburg Gruppen AS

2. Wellbore Stability and Drilling Integrity (Downhole) Monitoring And Analysis

- Halliburton
- Forum Energy Technologies (FET)
- National Oilwell Varco (NOV)/TOTCO
- Monitor Systems Scotland Limited
- eDrilling
- Schlumberger
- SafeVision
- Sekal
- Baker Hughes
- Verdande

3. Instrumentation for Drill Floor and Rig Operations

- Pason
- Halliburton
- Forum Energy Technologies (FET)

- National Oilwell Varco (NOV)/TOTCO
- Schlumberger
- Fiber Optic Sensing

4. Data Collection /Transmission Point, Wireless/Wired, Standardized Languages Bandwidth Requirements

- Rajant Corporation
- Forum Energy Technologies
- Measuresoft
- National Oilwell Varco (NOV)/TOTCO
- Peloton – Pason
- Rig-Net
- Rig Minder
- Schlumberger
- Telescope
- CoilCAT
- Halliburton
- Baker Hughes

5. Onshore Center - Data Aggregation Standardized Interfaces/Screens/ Display Of Relevant Data, User Interface (UI), Predictive Capabilities, Monitoring/ Alarming Potential

- Rajant Corporation
- Forum Energy Technologies
- Measuresoft
- National Oilwell Varco (NOV)/TOTCO
- Peloton – Pason
- Peloton
- Rig-Net
- Rig Minder
- Schlumberger
- Telescope
- CoilCAT
- Baker Hughes
- OSI Soft
- National Instruments
- Kongsberg Gruppen AS
- Avocet Surveillance
- RT Connect
- InterACT
- Halliburton
- Forum Energy Technologies
- Monitor Systems Engineering Ltd
- FUGRO GEOS
- Vortex Induced Vibration Monitoring (VIV)
- DeepData
- Optima Riser Management System
- Production Riser Monitoring
- Meshguard Wireless Gas Detection System
- Phoenix

Training Scenario 3: Simulation

The third training scenario should be modeled from current Real-Time Operating Centers and would become a simulation center administered by BSEE.

Conceptually, BSEE would setup and maintain a 'training' RTOC within its organization and train its personnel with industry best practices using actual de-identified real-time data running simulations of actual events. The syllabus for instruction would include everything that might happen in an RTOC environment, similar to Training Scenario 1: however, the boundaries can be expanded to many training scenarios given the nature of the simulation process. Much like Training Scenario 1, the syllabus would include the reservoir application process, well development/visualization techniques, logistics, platform placement, drilling, emergencies actions, through to closing out the well and production. The syllabus should be created in conjunction with industry experts and include API input. The syllabus would need to encompass the entire spectrum of well development, exploration and production efforts in an attempt to have BSEE representatives understand all aspects of evaluation for the tasks they may encounter in the field. Industry Subject Matter Experts (SMEs) could potentially be contracted by BSEE as RTOC instructors providing expert instruction for the individual training modules. The SMEs would brief the scenarios and train the BSEE team on best courses of action for certain ‘known’ scenarios.

Simulation

The latest information technology (IT) innovation has made the intelligent oil field possible. And access to historical data in a training center environment provides BSEE representatives the chance to simulate any number of conditions in the field. Massive amounts of sensor data can now be stored and searched using aggregation software and is available to users at will. Complex data patterns can be detected automatically, so training can be conducted in close to real world scenarios. Visualization, modeling and analytics are making it easier for decision makers to understand the wealth of complex information, and would give the BSEE team unparalleled training information that would be used in support of real world field operations.

Through simulation, BSEE representatives will understand how companies use real-time data is used to achieve operational efficiency in the field. And more importantly, the syllabus will include the use of historical data to train the BSEE team to detect problem early and provide oversight on potential solutions increasing the ability of the operator to conduct operations more safely.

Communication

Simulation can help BSEE experience and therefore more fully understand operator communication issues in order to quickly understand actual operator support requirements. Employing simulation improves communication and decision-making protocols that need to be in place in order for the real-time data products and services to have any impact within the operational context. Operational communication and decision making roles and responsibilities need to be very clearly defined and standardized. The support model is not about taking responsibilities and accountabilities away from traditional decision-makers, such as rig supervisors, superintendents, and drilling engineers. Instead, it provides them with the information and tools to make much better and more pro-active decisions. If BSEE representatives better understand this communication protocol by using it in simulated environments, these same representatives will be in a position to provide more effective safety oversight. An RTOC simulator would help the BSEE team quickly understand the communication dynamic at the operational level, and allow BSEE representatives to utilize similar communications effectively.

Increase in Safety

Real-time data monitoring, whether it's used in ongoing operations, or by accessing historical data, can improve safety. By becoming familiar with the use of real-time data, BSEE can examine the details of the data at the appropriate level to understand root causes of incidents and become more proactive in developing industry solutions. Real-time data is being used in the well planning process all the way to well completion and is becoming an integral component of drilling operations. The training being suggested in this paper will allow BSEE personnel to properly assess the information presented to their office.

Regulatory Decisions

In the event of a major accident or incident, the training center could be permitted access to a data feed of the real-time field data through the affected company's web portal to allow BSEE's industry experts to assist in a regulatory oversight role. Given equal information and access, the affected company employees could use remote collaboration with the BSEE oversight team to get regulatory direction.

For example, BSEE interaction could be initiated by the operator's real-time operations center; BSEE engineers would sit before screens and monitor well operations in the Gulf of Mexico on request from the operator. If BSEE oversight or involvement is requested, BSEE Engineers could access data instantly and be quickly brought up to speed on the developing scenario. The operator's experts and consultants, as well as those of BSEE, can be called on at a moment's notice to help, online. Or if a change to a drilling plan requires BSEE approval, those changes can be addressed using visualization techniques and relayed to the appropriate BSEE representative for approval and sign off. In both cases, there is no travel time to the location, and minimal spool up time.

BSEE engineers would periodically train in order to help industry operators make decisions within regulatory requirements and improve collaborative behavior between the regulator and operator. Workflows can be easily linked to BSEE well acceptance criteria to help provide BSEE with more information about proposed well plans allowing for collaborative decision making and could be critical in helping BSEE make accurate and timely regulatory oversight decisions.

Big Brother

The BSEE training center may be viewed as 'Big Brother' watching the real-world operations. This training center is primarily used to train BSEE representatives to provide an oversight and evaluation function in the field. As the culture changes from prescriptive evaluation to cooperative oversight, so too will the attitudes toward a BSEE real-time data center. Many of the companies employing an RTOC have also seen a huge cultural shift in attitudes toward their own RTOCs. Operators cannot operate in a vacuum. Operations need oversight to ensure regulatory requirements are met. The intent of a BSEE training center would not be, nor could it be, to monitor every company's minute-by-minute operation.

Implementation of a safety oversight approach ensures BSEE and the operators work in tandem to open communications, collaborate on and solve problems and improve safety.

Pro's and Con's

There are several advantages and disadvantages for each Training Scenario and specific training curriculum will have to be developed for the decided upon training. A few of the advantages and disadvantages for each Training Scenario are:

Training Scenario 1

Advantages –

- Quick exposure to industry best practices using real-time data
- Collaboration between industry and BSEE
- Enhanced understanding of real-time data and technology

Disadvantages –

- Could encourage BSEE interns to leave BSEE
- Depending on the number of BSEE auditors/inspectors, could be challenging to manage which interns/operators cannot work together
- Necessitates an industry-wide cultural change to collaborative environment

Training Scenario 2

Advantages –

- Promotes technology understanding
- Increases interaction between industry experts and BSEE
- Provides industry collaboration on emerging technology

Disadvantages –

- The focus could be more on technology than its application
- Possibly requires more coordination among vendors and BSEE for scheduling
- Necessitates vendors sign onto the concept

Training Scenario 3

Advantages –

- BSEE is able to keep up with technology and real-time data usage
- Industry/BSEE Collaboration
- Information dissemination quicker and more efficient

Disadvantages –

- Could be expensive to setup and implement
- Not actually working in an actual environment; it's simulated
- Data acquisition; need to get the data from actual wells could be challenging considering the proprietary nature of the industry

Conclusion

Safety Oversight as defined in this paper is critical to developing collaboration between BSEE and the industry. BSEE should seek to work in partnership with industry experts and other industry stakeholders such as API to develop syllabus objectives and content. Developing an approach that defines the minimum requirements for a RTMC/RTOC would ensure data consistency and standard escalation processes creating an industry minimum safety standard and a baseline for BSEE inspectors to evaluate and audit operations via RTMC/RTOC.

By implementing the safety oversight concepts discussed, industry collaboration becomes more available and the training scenarios become viable.

Training Scenario 1 suggests a focused internship at an oil and gas operator with syllabus of instruction agreed upon by BSEE and the operator. This scenario would be extremely valuable as a method for an in-depth understanding of the well planning process from concept thru execution. In order to understand the data aggregated in an RTOC, the BSEE representative must be familiar with the well planning process of their specific operators.

Training Scenario 2 describes bringing real-time data technology to BSEE. This concept requires a curriculum developed by BSEE, with coordination from industry, to develop training courses designed to inform BSEE representatives in real-time data technology for the purpose of understanding the available technology within the industry.

Training Scenario 3 is modeled from traditional Real-Time Operating Centers, and would become a simulation center within BSEE. Conceptually, BSEE would setup and maintain a 'training' RTOC within its structure and train personnel based on industry best practices using actual, de-identified, real-time data to run simulations or potentially replay actual events.

Developing standardized training for BSEE to understand real-time data greatly enhances industry safety. The safety oversight model is a proven model that is used in other regulated industries and movement to this regulatory model can be expeditious and advantageous. The model manages standardization of training and ensures the stakeholders continually generate industry best practices, evolving as technology advances.

CHAPTER 3 – (Task 6): Identify how real-time monitoring could be incorporated into the BSEE regulatory regime in either a prescriptive or performance based manner.

Chapter Summary

In light of technology, team and process advances, incorporating real-time monitoring into the BSEE regulatory regime is a concept that not only has great benefit, but is a logical next step of regulation and oversight for any high risk industry. Implementing RTMCs in either a prescriptive (based on regulations) or performance (outcome oriented) based method should be driven by the desired end state of the oversight system. This end state is assumed to include promoting safe and efficient exploration, extraction and production of hydrocarbons. The end state solution should not only address the goal, but the path in which that goal is achieved. For BSEE to remain an effective and efficient regulatory agency, the incorporation of RTM should encompass the principles of system safety.

The body of evidence of over 400 peer reviewed articles and numerous interviews suggests the oil and gas industry is beginning to shift the culture of operations from predominantly reactionary regulation to forward-looking, performance-based operations with formalized training. In large part, this has been driven by the increase in technological innovation that promises to be the 'new normal.' This is a significant industry shift that requires a commensurate shift in regulatory approach. However, there is still some room for discussion about the direction the regulator should take. Several other industries offer effective and respected safety oversight programs that can be used to model a new direction for oil and gas regulatory processes.

The current BSEE regulations provide a solid framework for incorporating RTM into the oil and gas industry. The use of a System Safety approach can be used to enhance the current Safety and Environmental Management System (SEMS) and effectively incorporate Real-Time Monitoring (RTM). The current training and reporting requirements can be improved with modern principles of distance learning and database management. The use of a voluntary reporting system modeled after a successful program used in aviation will be a powerful addition to the existing system safety efforts to incorporate RTM.

Regulating RTM in the industry should be performed in a phased approach. The current use of RTM will smooth the regulatory debut of new rules. The use of a performance based regulation approach will provide the needed flexibility to keep pace with industry innovation. In addition, there will be an opportunity to provide a minor amount of prescriptive based regulation to ensure there is no ambiguity in certain key areas.

In implementing these changes in approach to regulation, the incorporation of RTM mandates or rules should be facilitated by working groups chaired by the BSEE with active participation from industry and academia. The primary focus of the group would be the use of industry best practices, with a goal of providing BSEE with the most timely and technically pertinent information and support for proposed rulemaking. In the end, the product of the working group would be to deliver a suggested regulatory strategy and outline for BSEE to draft regulations that have a greater degree of interaction from industry partners while keeping the BSEE firmly in control of the process.

Introduction

By promoting industry standards to shape the makeup of the regulatory environment, new programs can be developed and used with greater synergy across the industry. In addition, existing regulations should be reviewed and determinations should be made where data collection and RTM could enhance and strengthen regulatory requirements.

The industry is seeing a movement toward monitoring well development, drilling and completion operations and production in real-time. Real-Time Operations Centers (RTOC) provide a distinct improvement in efficiency and with it an improvement in the overall safety of the operation. In task 1 we defined the RTOCs components as:

Real-Time Monitoring Center (RTMC): A 24/7 function located at a centralized, onshore location with continuous data feeds from the company's active well projects. Monitoring stations within the RTMC are staffed with highly experienced drilling experts who focus on mitigating drilling hazards and preventing nonproductive time (NPT) while providing an added team member and safety observer to the onsite rig team.

Collaboration Center: A dedicated workspace, fully equipped with real-time data (RTD) capabilities enabling full integration of the onshore/offshore team working in a seamless environment for well operations planning, drilling and completion activities. Daily routine includes meetings with the onshore/offshore team, reviewing morning reports and planning current and future well activities. The Collaboration Center brings in or reaches out for the expertise necessary for achieving well development objectives and resolving issues.

Knowledge Center: An onshore RTD repository with experts that have access to all aspects of planning and analysis data. The Knowledge Center is available for services as requested by the drilling supervisor during well planning, drilling and completion operations. A Knowledge Center may work across many or all the wells in the company's portfolio and is not generally a 24/7 monitoring operation, but personnel may be 'on call' to provide services at any time. The Knowledge Center may be considered the company's experience repository and center of excellence with respect to all phases of well development, completion and production.

Prescriptive and/or performance based RTMC and RTOC programs should become a component of the established foundation of standards and will create a path for training the regulator in the principles and process of implementing RTMC.

Task 6: Identify how real time monitoring could be incorporated into the BSEE regulatory regime in either a prescriptive or performance based manner.

This task will provide an introduction of prescriptive and performance based program implementation and how such a program may be implemented into BSEE regulations.

In addition to the prescriptive and performance based system, this paper includes a discussion of a possible combination of the two methods which is defined as ‘system safety.’ System safety provides the firm foundation for implementaion of RTMC regulations and operations.

Prescriptive/Performance-Based Regulation for the Oil and Gas Industry.

In the development of regulatory oversight programs for the energy industry BSEE should determine a strategic approach to guide all of its activities. A basic tenet of the strategy should be determining if the oversight will be:

(1) Prescriptive - Entailing a detailed set of standards developed by the regulator or an industry standards setting body.

(2) Performance-based - Where the companies that operate sophisticated facilities such as offshore platforms and drilling rigs are responsible to decide the best approach to safety and efficiency.

(3) A combination of the two - For our purposes, a comparison and contrast of prescriptive and performance-based approaches is beneficial for further discussions about implementation of regulatory oversight in the oil and gas industry. We will also address in this chapter the current state of industry oversight, the desired state and present a road map from the current state to the desired state.

Prescriptive Regulation

A prescriptive based system specifies an exact method of compliance that workplace parties are required to meet. This allows for little deviation in components, plans, or processes.

Prescriptive Regulation Pros/Cons

Prescriptive regulation benefits include:

- Standardized implementation method among all operations
- Prescribed procedures that do not require interpretation or expertise to implement
- Simplified audit process
- Specifications and procedures designed to ensure that a material, product or method of service is suitable for its purpose and consistently performs in the manner it was intended

Drawbacks to prescriptive safety include:

- Inflexibility. It may be difficult to apply common regulations to uncommon conditions and environments found in the oil and gas industry
- Outdated standards as technology advances
- Overly conservative standards that may be cost prohibitive
- Operators that may only work to meet the minimum requirement in the regulation
- An over-reliance upon the regulations to ensure safety
- An system where the burden of incident/accident avoidance is on regulations, creating an atmosphere for creating more regulations

- A lack of consideration for future technology or conditions due to regulations that are based on past incidents
- Can define a material solution to an issue that is non-competitive.
- Inhibition of emerging industry best practices
- Variations and waivers which may become difficult to manage

Performance-Based Regulation

A performance-based regulation specifies a threshold of acceptable performance and a means for verifying that the threshold has been met. The method of compliance that is developed and implemented is unique to each facility and is considered the responsibility of the operator.

Performance-Based Regulations Pros / Cons

Performance-Based Regulations benefits include:

- Flexibility for the facility operator to specify the method of compliance
- The use of industry best practices that can be applied to any situation and yield the most cost-effective solution
- The reduction of barriers to technical innovation
- The methods of compliance can be less costly
- The promotion of data sharing
- Reduced regulatory footprint

Drawbacks to Performance-Based Regulation include:

- Potential difficulty in defining quantitative levels of performance
- A reliance on experienced and qualified auditor/ inspectors to recognize whether each independent operator is operating safely and within performance standards
- A need for a robust, train-to-proficiency, regulator training program to ensure that the full spectrum of performance parameters is understood
- Difficulty in evaluating compliance with established requirements due to challenges measuring parameters for evaluation
- A need for standardization of the tools used for quantification

Regulatory Involvement

As a regulator agency, BSEE must continually balance the need for control and accountability vs. industry flexibility and innovation. A prescriptive regulatory approach emphasizes control and operator accountability to rules. The regulator is accountable for ensuring correct rules are in place to achieve desired results. A performance-based approach allows implementation flexibility with operator accountability for results.

Accountability is a fundamental and challenging issue for performance-based regulations. Typical Performance-based approaches seek accountability for results, but observing or predicting results can be difficult or not feasible.[22] Prescriptive based regulatory programs attempt to achieve accountability by mandating adherence to the rules and are biased towards monitoring compliance with rules that are easy to observe. As a consequence, accountability under such systems can be haphazard and misplaced with little attention to the end result.[23]

Accountability in the oil and gas industry can be aided by the collection of detailed data. The knowledge of the types and quantity of data available can be an aid to determining accountability. Data can also be used in bounding the performance parameters to determine the measurements to be used for determining leaders and laggards in meeting or exceeding.

The regulatory issue of accountability can be determined by the involvement of industry representatives to provide insight into the details of the wide variety of operations. This approach requires that the regulatory representative be a veteran of the industry with extensive training on the interaction of the regulator and the regulated.[24]

The performance-based approach to regulation avoids partiality and bias by not prescribing particular methods or materials. Particular producers, formerly preferred providers of prescribed materials or methods are now not favored over others or at the expense of the public interest and safety. Performance-based regulation is aimed at promoting competition to provide better and more cost effective ways of complying with regulations. However, partiality and bias may be introduced through interpretation of whether the result is met.

Unreasonable regulations

Critics argue that unreasonable regulations and capricious enforcement practices impose unneeded burdens on regulated entities. For example, the National Association of Homebuilders found in a 1998 survey of association members that 10 percent of the cost of building a typical new home is attributable to unnecessary regulation, regulatory delays, and fees.[25] The goal any newly developed regulations for Real Time Monitoring (RTM) technology and operations should be to reduce the burden of regulation while allowing for proper oversight. The use of a system safety approach with industry participation will aid in right-sizing the regulations.

Balance

Any reform is at least in part a reaction to perceived failures of what preceded it. As such, the expectations for performance-based regulatory regimes are shaped as much by prior shortcomings as they are by concepts of what constitutes 'good' regulation. With this in mind, it is useful to consider performance-based approaches to regulation as a reaction to the perceptions of overly rigid rules and inflexible enforcement.

Performance-based regulations are part of the more general trend in regulatory reform, beginning with the Reagan Administration in the early 1980s, to lessen rigidity and compliance burdens while promoting innovation and allowing for lower compliance costs. One indication of the multiple objectives of regulatory reform is contained in the principles of regulation set forth in Executive Order 12866 (section (b)(5)), the primary federal regulatory planning and review directive adopted by the Clinton Administration and subsequently reaffirmed by the Bush Administration. Federal agencies are directed to take into account in regulatory design the need for, and effectiveness of, regulations along with "incentives for innovation, consistency, predictability, costs of enforcement and compliance (to the government, regulated entities, and the public), flexibility, distributive impacts, and equity." The current administration has shown support for this effort.

While a regulation may be designed to deliver safe and efficient wells through promotion of innovation, encouraging flexibility and minimizing compliance costs, the reality of enforcement rests with the regulatory agents and what they do in the field when monitoring performance. This requires high levels of agent experience to recognize the many different approaches to successful outcomes.

System Safety Programs

Even though process safety has been mostly prescriptive in the past, there has been movement to performance-based regulation by government agencies. BSEE's own SEMS program is a performance based approach.

The use of prescriptive and/or performance based regulations should be driven by a system safety approach. The determination of the method to use won't be made from using black and white information that will clearly point the way towards the proper method. The system safety approach can aid the selection and will be useful in the ability to monitor the performance of the process. There is a proper place for the application of prescriptive regulations and performance-based regulations. The tools suggested in this report should be an aid in making that determination.

API RP 75

Long before API RP 75 and SEMS were conceived, the practice of combining safety standards with regulatory oversight began in the 1960's as the American Petroleum Institute (API) wrote a Recommended Practice 14C (API RP 14C, Recommended

Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems). API RP 14C is required by government regulation for all offshore operators and the purpose is to protect personnel, the environment and facilities from threats to safety. It details the basic requirements for a safety system by identifying the 'normal' components for an offshore facility and the required safety devices. API RP 14C describes process safety and defines facility process in order to attempt to identify undesirable events and identify reliable protective measures.

In 1990, the National Research Council's Marine Board found that the Bureau's prescriptive approach to regulating offshore operations had forced industry into a compliance mentality that was not conducive to effectively identifying all the potential operational risks or developing comprehensive accident mitigation.

In the search for a more systematic approach to managing offshore operations, the newly formed BSEE concurred with the Marine Board's 1990 findings and moved forward with the American Petroleum Institute Recommended Practice 75 (API RP 75). API RP 75 recommended a voluntary approach to compliance and led to the eventual establishment of a Safety and Environmental Management Program (SEMS) for offshore operations and facilities. Subsequently, SEMS has produced a level of acceptance and standardization that has moved the industry one step closer to a fully integrated systematic approach to safety.

The purpose of SEMS is to enhance the safety of operations by reducing the frequency and severity of accidents and requiring that all operators submit performance measure data outlined in the Outer Continental Shelf (OCS) Performance Measures Program.[26] Incorporated in SEMS is the American Petroleum Institute's Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities (API RP 75). API RP 75 consists of 13 sections and states the overall principles for the SEMS and establishes management's general responsibilities for the program's success. This doctrine provides a stable framework for introduction of RTM to the oversight process and allows for complementary and enhancing programs to be added as needed.

Deciding to use prescriptive and/or performance regulation presents challenges that could be overcome by using a system safety approach. The regulator in a system safety approach needs to provide independent assurance that health and safety risks are properly controlled by the operator. The use of performance-based criteria to improve safety can aid in providing this assurance. This could be accomplished by providing continuous interaction with the operator along with regular audits and inspections. The system safety approach should work to define levels of risk, determine cause, consider human interaction/involvement, provide voluntary reporting, and analyze the data collected from the well site.

System Safety Components

SMS is not one program made up of a single product or singular service. It is comprised of many disciplines. Similar management systems are used in other areas for the management of quality, occupational safety and health, security, environment, etc.

SMS for product and operators, as well as regulators, integrates modern safety risk management and safety assurance concepts into repeatable, proactive systems. SMS emphasizes safety management as a fundamental business process to be considered in the same manner as other aspects of business management.

In a true system safety environment, there are multiple systems that make up the safety environment. Components of a successful safety program complement each other by bringing different aspects and principles for a well-rounded safety program. For example, As Low as Reasonably Practicable Risk (ALARP), Root Cause Analysis, Human Factors Analysis and Classification System (HFACS), Predictive Analytics, Data-sharing and Voluntary Safety Reporting Systems all compliment the system safety design and will enhance RTM regulations.

As Low as Reasonably Practicable Risk

The concept of "As Low as Reasonably Practical" (ALARP) can be used to determine acceptable risk. The ALARP concept is that risk should be reduced to a level that is as low as possible without requiring 'excessive' investment. The ALARP approach works well to identify the point of diminishing returns. The ALARP risk diagram is shown in Figure 5: ALARP[27]

The use of ALARP should be used by BSEE to determine the threshold for performance based RTM regulation. The cost to implement regulations is a prime concern for the industry. The use of ALARP can be a tool for the regulator to justify and/or design a regulation that is fair and defendable during deliberations.

There is often disagreement of the cost of a regulation. Recent discussions about new offshore regulations could have been a showcase for the use of ALARP. Regulations were recently introduced for drilling, well-completion, well-workover, and decommissioning related to well-control, including: subsea and surface blowout preventers, well casing and cementing, secondary intervention, unplanned disconnects, recordkeeping, and well plugging. The regulation is known as *"Increased Safety Measures for Energy Development on the Outer Continental Shelf."* In the document is a section for comments from industry on cost of implementation of new policies. Several comments on the cost of the regulation indicate there is a lack of agreement between the regulator and industry.[26]

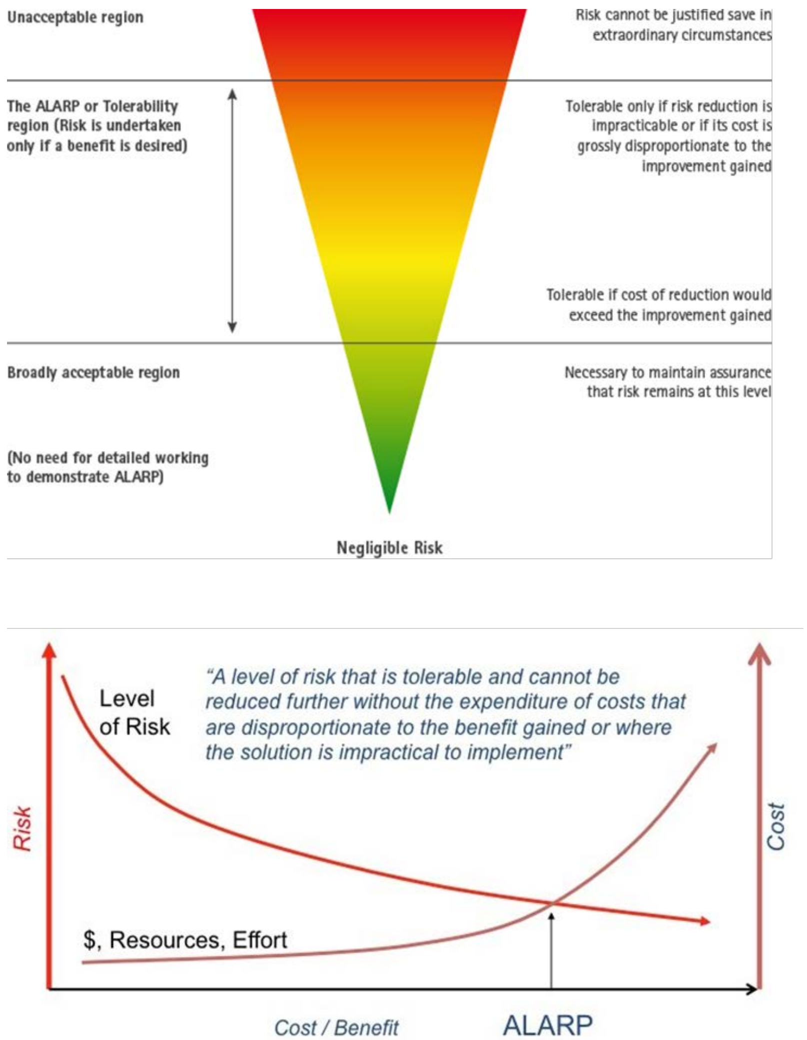


Figure 5: ALARP[27]

Beyond the disagreement on cost of the policies, for instance, how much it costs to retrieve a blow-out preventer (BOP) for mandatory testing, there were comments on the level of risk that could be mitigated by the new regulatory requirements. The use of ALARP can be beneficial to the regulator and to the operator to craft an agreement and justify the level of performance defined by a regulation. Implementation of RTM regulations can then be methodically and economically justified and defended using ALARP metrics.

Root Cause Analysis (RCA)

RCA provides a tool to try to mitigate problems by addressing the genesis of events versus addressing the symptom. RCA is used as a reactive method of identifying causes, revealing problems and solving them since analysis is done *after* an event has occurred. The effectiveness of RCA is related to the ability to collect information for analysis on a companywide up to industry wide scale. RTM is an enabler for RCA. RTM supports RCA by collecting as much data as possible/feasible to ensure the root cause is not missed. The use of RTM should accompany the mandate to perform RCA and the use of RCA can justify the need for RTM.

BSEE should determine an acceptable level of industry standardization for conducting RCA in order to assist in identifying equipment and safety issues. Using data acquired from an RTM environment, RCA can be used as a proactive tool to help predict probable events even before they occur.

The use of RCA can begin in the BSEE Investigations and Review Unit (IRU) and Panel investigations. The principles of RCA were well practiced in the Chief Counsel's report on the Macondo Gulf Oil Disaster.[28] The report was extremely detailed and showed the level of investigation required to find the root cause of the incident.

The Chief Counsel's Macondo report should serve as a template for future investigations. BSEE should establish and provide guidelines for the conduct and reporting of future incidents and accidents. US Air Force and US Navy accident investigation processes provide successful examples for conducting an inquiry. The use of a template and/or checklist would streamline the investigation process and provide structure to the proceedings. The template should only serve as a minimum guideline and the addition of information beyond the template is encouraged, but screened for pertinence and relevance.

Personnel performing the RCA should represent the most experienced available. If the workload does not permit using organic talent then the RCA should be contracted to organizations that are skilled and experienced at performing RCA in the oil and gas industry.

HFACS

When looking for safety improvements, it is also necessary to consider the human side of the equation. Most offshore oil and gas incidents can be traced to human error or poorly organized operations.[29] The regulation of RTM will be more effective and relevant if human factors are considered for all aspects of monitoring. The method of studying the human side of incidents provides information beyond the failure of components or procedures.

The Human Factors Analysis and Classification System (HFACS), was developed by S.A. Shappell and D.A. Wiegmann from their original framework called the "*Taxonomy of Unsafe Operations.*" This framework used over 300 naval aviation accidents to define its analysis categories. The original taxonomy has since been refined using input and data from other military (U.S. Army Safety Center and the U.S. Air Force Safety Center) and civilian organizations (National Transportation Safety Board and the Federal Aviation Administration) to develop the Human Factors Analysis and Classification System (HFACS).[30]

The goal of HFACS is not to attribute blame. The objective is to analyze the human interactions that preceded an accident/incident.

HFACS is used as a classification and organization component for human factors information in conjunction with RCA as the investigative component. The relationship between HFACS, RCA and RTM provide further justification for the need.

The RCA might find that a loss of well control directly resulted from an improper mud weight. While further HFACS analysis may show that a lack of training was the cause for improper mud weight. HFACS complements RCA by providing a root cause labeling system where this problem would be labeled, and more importantly tracked, as a training issue and not an equipment issue.

The HFACS was applied, for validation purposes, to four Norwegian offshore accidents that occurred during 2007. The HFACS framework was suitable for these accidents and revealed that latent failures on the organizational level were most prevalent, in particular failures related to oversight and procedures. Once classified HFACS data from these 4 accidents was collated it was able to show common problems across all 4 accidents.[31]

Once the data format and capture items are determined and agreed, HFACS can also be used proactively by analyzing historical events to identify re-occurring trends in human performance and system deficiencies. These methods will allow organizations to identify weak areas and implement targeted, RTM supplied, data-driven interventions that will ultimately reduce accident and injury rates by providing a structure to analyze and review accident and safety data. Proactively using HFACS can be used as a future accident investigation tool by building accident databases that can be accessed to analyze potential failures. Common trends can be derived, identified and prioritized within the operation to provide an intervention framework. Historical hazards can be identified and procedures can be put in place to prevent the hazards.

As a system safety component, any efforts to introduce RTM into the oil and gas industry should include HFACS. HFACS is scalable from the individual shift level of a rig to industry level application. BSEE should consider industry level application of human factors incident and accident classification as a shared database with industry. The design, installation, operation, analysis, reporting and decision making on oil rigs is performed by a human. Until the oil rig is operated and supervised without humans there will be a need for HFACS and for RTM.

Predictive Analytics

Predictive analytics should be used in the oil and gas industry to predict and prevent equipment failure. The amount of data that is available from RTD to BSEE and oil and gas companies will allow a detailed failure analysis to target specific modes of operation.

Many industries and businesses are learning how to make use of large quantities of data. Currently in the oil and gas industry, there is a tremendous amount of data that goes unused that could potentially serve to save businesses money and reduce injuries. By performing advanced analytics to make predictions about future incidents and occurrences, businesses can start to ‘predict’ future safety issues. When applied correctly, predictive analytics gives organizations the ability to analyze past data and forecast trends in order to operate optimally. Advanced and predictive analytics have revolutionized other industries, and helped those industries make money saving decisions.

Predictive analytics can be used in a number of ways, and can aid in planning by helping to determine projected requirements. It is enabled by enhanced root cause analysis which helps detect abnormal patterns in events and possibly prevent future unnoticed incidents and accidents. It enables enhanced monitoring of key components which can detect system failures and prevent outages before they occur.

RTM can be tailored to provide data that is useful to Predictive Analytics. An aggressive data mining process should be required by the industry for analysis of stored information delivered by RTM systems for use by predictive analytics. The overall goal of the data mining process is to extract knowledge from an existing data set and transform it into a human-understandable structure for further use. The extensiveness of the data mining will set the tone for the predictive analytics.

RT Data for Quality Assurance

The aviation industry uses a form of RTM to ensure adherence to industry best practices and regulatory compliance. The program is Flight Operations Quality Assurance (FOQA). The goal of FOQA is to capture all the pertinent data and present it in a usable format for analysis.

Commercial aircraft are highly instrumented and have sensors to provide an indication of many performance and status parameters in the aircraft. These measurements are stored on crash survivable recording devices for analysis in the event of a need to discover or verify the condition/position of the aircraft. Some of the data from the recorders is also transmitted in real-time and used by a FOQA team to spot trends in the industry and to facilitate RCA and Predictive Analytics.

Not all data collected by FOQA is reviewed or analyzed. The need to review recorded data could be initiated by exceeding a preset alarm, self-reporting by the aircrew, accident/incident, or initiation by a third party. Once the FOQA team collects the data, it will collate and analyze the data with other information to generate a depiction of the environment.

The use of RTM by BSEE should be used to facilitate a Petroleum Operations Quality Assurance (POQA) program. The POQA program would function in similar fashion to the FOQA program which in basic terms, provides an alerting system for dangerous company and industry trends.

The data collected can be proprietary and competition sensitive. To protect company specific data the POQA team should be an individual unit that is aligned with the company collecting the data. The composition of the POQA team would include a company representative and rig operator.

When appropriate or desired, the BSEE regulator could review the data analysis in an effort to spot trends. And, if appropriate, provide guidance or corrective action before a negative trend results in an accident/incident. In addition, data approved for release by the company could be used to show wider industry trend. This would require that the list of data parameters collected by POQA would need to be standardized throughout the industry to allow meaningful industry-wide comparison.

A POQA would be largely built upon historical data gained from RTM. Participation in a POQA program should be mandatory for 'critical' wells. De-identified, safety related data from these wells should be aggregated by BSEE with trend analysis shared across the industry.

Voluntary Reporting

Industry-wide Data Sharing

The very nature of system safety requires industry-wide data sharing to ensure incidents and accidents are understood by the industry as a whole. A system should be introduced to the oil and gas industry to allow the reporting and use of data from the operators. The data analysis reported to BSEE would be de-identified and all proprietary information would be protected. De-identified data ranging from equipment failures to job related incidents should not be a closely held organizational secret. In order for the entire industry to learn and become safer, de-identified data sharing should be implemented. BSEE would ensure that industry shared data was non-proprietary so the industry feels comfortable sharing the data. The ability to remain neutral and ensure corporate secrets are secure will facilitate further data sharing. If the system has leaks and is not trusted by the reporting individual it will become useless.

An example of data sharing that might have averted a serious accident was noted in the Macondo Chief Counsel's report. The conditions that led to the Macondo/Deepwater Horizon accident were seen many times before and more recently in the North Sea on a well being completed by Transocean, the same company working the Macondo well. On December 23, 2009, Transocean barely averted a blowout during completion activities on a rig in the North Sea. Rig personnel were in the process of displacing the wellbore from mud to seawater. They had just completed a successful negative pressure test, and they had lined up the displacement in a way that inhibited pit monitoring. During the displacement, a critical tested barrier failed, and hydrocarbons came up the wellbore, onto the drill floor, and into the sea.

The event was noted in the Chief Counsel's report to be identical to the Macondo/Deepwater Horizon accident when comparing the critical factors that led to the loss of well control. The report stated: "Transocean nevertheless failed to effectively share and enforce the lessons learned from that event with all relevant personnel."[28] This report makes a strong case for industry wide data sharing for the purposes of improving safety across the industry. Safety related RTD should be a key component of an industry wide data sharing program.

Safety Reporting Systems

The ability to gather information from the field has been shown to greatly increase the level of safety in other industries. It is recommended that BSEE implement a voluntary reporting system that expands the “Reporting Unsafe Working Conditions” section of SEMS II.

In the oil and gas industry, all information is treated as highly proprietary and generally not shared willingly. The aviation industry once held the same proprietary views, but has worked with regulators to share non-proprietary data in an effort to make the industry safer as a whole.

Although anti-trust issues need to be considered, in order to facilitate the data flow, a conduit needs to be put in place to allow the operators to freely communicate the nature of their conditions, challenges, and operating principles when involved in incidents or near incidents. The fear of reprisal from reporting has been a barrier to collecting the details that can be used for RCA, HFACS and Predictive Analytics. Notwithstanding the legal hurdles, if the barrier of punishment can be mitigated there will be more useful information provided.

NASA has developed a voluntary reporting program called the Aviation Safety Reporting System (ASRS). ASRS captures confidential reports, analyzes the resulting aviation safety data, and disseminates vital information to the aviation community. “Pilots, air traffic controllers, flight attendants, mechanics, ground personnel, and others involved in aviation operations submit reports to the ASRS when they are involved in, or observe, an incident or situation in which aviation safety may have been compromised. All submissions are voluntary.

Reports sent to the ASRS are held in strict confidence. ASRS de-identifies reports before entering them into the incident database. More than one million reports have been submitted to date and no reporter's identity has ever been breached by the ASRS. All personal and organizational names are removed. Dates, times, and related information, which could be used to identify the person reporting are either generalized or eliminated from the data.

Not all reports are accepted into the ASRS system. The first criterion is the requirement to submit the report within 24 hours of being aware of the need to report. There is a clear definition of actions that are not allowed to be free from violation or regulatory enforcement. The actions determined to be willful disregard, criminal negligence, or intentional noncompliance will not be free from regulatory prosecution. The review board of industry and government experts will consider the action and determine if the report is to be accepted onto the system.

Petroleum Safety Action Program (PSAP)

A voluntary reporting Petroleum Safety Action Program (PSAP) should be implemented by BSEE to collect data from the operators in the field. This data is currently not being collected in an organized manner. There is also no recognized method for deciding if a report should be included into the reporting system.

The Aviation Safety Action Program (ASAP) is a voluntary program derived from ASRS that should serve as a blueprint for BSEE to develop a PSAP program for the oil and gas industry. ASAP is an operator/company level program monitored by the FAA designed to improve safety and identify operational deficiencies by providing de-identified communication tools to facilitate information flow from the operators. Events submitted through reports from the operators are critical for early identification of hazards, to maintain a proactive approach regarding safety concerns, and recommend corrective action. An important component of ASAP is employee input designed to identify safety concerns, operational deficiencies, non-compliance with regulations, deviations from policies/procedures and unusual events. The program works cohesively within the context of a formal agreement among the operational partners. The FAA, company and employee group examines each ASAP report to determine if the event is included in the ASAP program. Corrective actions are determined based on a non-disciplinary approach to flight safety.

A group called the Event Review Committee (ERC), which is comprised of a representative from the FAA, the operator and the employee group, is formed to review ASAP reports. The ERC may share and exchange information and identify actual or potential safety problems from the information contained in the reports. An ERC incorporated by BSEE would be staffed by representatives from BSEE, the company and the employee group. The ERC must represent the full spectrum of talent in the industry from the rig worker to the reservoir planner.

PSAP Reporting Process

The PSAP program should encourage safety reporting from the actual employees and must be designed to ensure non-punitive action for those employees. Similar programs exist throughout the industry on a smaller scale. Consideration should be given to consolidating them into an industry wide program. The program could have the following structure:

- Reporting procedures – within 24 hours, if a worker observes a safety problem or experiences a safety-related event, he or she should note the problem or event and describe it in enough detail so that it can be evaluated by a third party. The ERC can contact the worker to resolve and information that requires further interpretation or additional information.
- ERC points of contact are established and communicated to the industry.
- A company PSAP manager will record event specifics and serve as the focal point for the report.
- The ERC will meet and review and analyze reports submitted to the program, identify actual or potential safety problems from the information contained in the reports, ensure de-identification of all reports and propose solutions for those problems.
- Once those recommendations are published by the ERC, the PSAP manager will publish the results to the employee group and provide feedback on the report.

- As information is made available, industry de-identified information sharing occurs and any specific training is conducted.
- All de-identified PSAP information is archived and is made available to a national database administered by BSEE.

System Safety and BSEE

In order to ensure both regulatory compliance and effective safety performance when implementing RTM, a system safety approach that combines prescriptive and performance-based regulations should be introduced by BSEE for the operator and contractors. To implement RTM in the oil and gas industry, BSEE should use an already established, successful system safety model from a similar industry. The current SEMS II regulations are beginning to be implemented and received few comments. The implementation of RTM for the industry will achieve greater success and will be more defendable during deliberations if the full system safety approach is used to complement and utilize RTM.

Implementation

System safety implementation has been designed to be introduced as a phased approach and can be rolled out to numerous operators concurrently. The phased introduction of system safety is well established with the roll out of SEMS. The following is meant to be used by BSEE as further guidance.

The following implementation levels are recommended:

Level Zero: Orientation & Commitment. This is more a status than a level. It indicates that the operator has not started formal SMS development or implementation and includes the time period between an operator's first requests for information on SMS implementation and when they commit to implementing an SMS. Level zero is a time for the operator to gather information, evaluate corporate goals and objectives and determine the viability of committing resources to an SMS implementation effort.

Level One: Planning and Organization. Level 1 begins when an operator's Top Management commits to providing the resources necessary for full implementation of SMS throughout the organization. Two principal activities make up level one:

Gap Analysis: The first step in developing an SMS is for the organization to analyze its existing programs, systems, and activities with respect to the SMS functional expectations found in the SMS Framework. This analysis is a process and is called a 'gap analysis,' the 'gaps' being those elements in the SMS Framework that are not already being performed by the operator.

Implementation Plan: Once the gap analysis has been performed, an Implementation Plan is prepared. The Implementation Plan is simply a 'road map' describing how the operator intends to close the existing gaps by meeting the objectives and expectations in the SMS Framework.

Level Two: Reactive Process, Basic Risk Management. At this level, the operator develops and implements a basic Safety Risk Management process. Information acquisition, processing, and analysis functions are implemented and a tracking system for risk control and corrective actions are established. At this phase, the operator develops an awareness of hazards and responds with appropriate systematic application of preventative or corrective actions. This allows the organization to address problems as they occur and develop appropriate remedial action. For this reason, this level is termed ‘reactive.’ While this is not the final objective of an SMS, it is an important step in the evolution of safety management capabilities.

Level Three: Proactive Processes, Looking Ahead. Fully functioning components of the SMS Framework expects safety risk management (SRM) to be applied to initial design of systems, processes, organizations, and products, development of operational procedures, and planned changes to operational processes. The activities involved in the SRM process involve careful analysis of tasks involved, identification of potential hazards in these functions, and development of risk controls. The risk management process developed at level two is used to analyze, document, and track these activities. Because the organization is now using the processes to look ahead, this level is termed ‘proactive.’ At this level, however, these proactive processes have been implemented but their performance has not yet been proven.

Level Four: Continuous Improvement, Continued Assurance. The final level of SMS maturity is the continuous improvement level. Processes have been in place and their performance and effectiveness have been verified. The complete Safety Assurance process, including continuous monitoring and the remaining features of the other SRM and SA processes are functioning. A major objective of a successful SMS is to attain and maintain this continuous improvement status for the life of the organization.

Oversight

This is a process that requires leadership, standardized training (for both direct employees as well as contract support), and continuous improvement. Oversight is necessary to ensure the system is implemented properly.

A shift in the traditional mindsets is necessary to more progressive safety aligned processes. The shift should include a better and closer relationship with the regulatory arm of the government. The leadership provided by BSEE when implementing performance based rules will be noticed and will create momentum for further improvements.

Operations Inspector

The commercial aviation industry has a very close working relationship with the FAA. This culture is very different from the oil and gas industry’s relationship with the regulator and should be recognized for the value of safe operations it brings. The major carriers have an FAA representative designated as Principal Operations Inspector (POI) to provide the primary interface between the air carrier and the FAA. These aviation safety inspectors apply a broad knowledge of the aviation industry, the general principles of aviation safety, and the Federal laws, regulations, and policies affecting aviation. In addition, they apply intensive technical knowledge and skill in the operation and maintenance of aircraft. The POI for commercial airlines engages primarily in the following types of assignments:

- Examining airmen for initial certification and continuing competence
- Evaluating airmen training programs, equipment, and facilities
- Evaluating the operational aspect of programs of air carriers and similar commercial and aviation operations for adequacy of facilities, equipment, procedures, and overall management to ensure safe operation of the aircraft.

They may perform a variety of other inspections, investigations, and advisory duties. However, the primary requirement for positions in this specialization is knowledge and skill in the operation of aircraft.

It is recommended that BSEE initiate steps to incorporate a POI into their audit and inspection department. BSEE should support this level of leadership to ensure standardization, training and compliance. BSEE's POI can act in a capacity similar to the FAA POI.

The POI would need to be a recognized industry expert with a career in the oil and gas industry. The knowledge and experience required to perform this job cannot be overstated. The range of tasks required to be mastered by the POI encompasses full spectrum of oil and gas production.

To complement the expertise of the POI, an extensive history with BSEE is required. The POI needs to be aligned with the regulatory goals of the government and not with industry. To increase the affiliation with the government, the experience with BSEE or a regulatory arm of the government should be mandated to be five years minimum with ten years as the desired experience level.

The embedded nature of the POI can breed an atmosphere of affiliation, favoritism and relaxed enforcement. To deter the possibility of a bias towards the company the POI should be mandated to rotate to another oil and gas company after a period of no more than five years.

The POI is assigned to one or two oil and gas companies depending upon the size of the company. The POI is an interface with BSEE inspection and audit teams to streamline their process and to provide prioritization to their efforts.

The POI is BSEE's 'boots on the ground' for drilling and completion efforts. The information passed by the POI can be useful in implementing Risk Based Inspections by other departments in BSEE. The responsibilities of the POI should not be diminished and truncated. The importance of their interaction with the operator is critical to effective government regulation. The position held by the POI in BSEE should be equivalent to a high level manager. This should be equivalent to a GS-15 with GS-14 as a minimum. The government employment level of the POI should be equal to their impact.

Controls

BSEE should ensure controls are in place to provide standardized work process and procedures. The following controls should be used throughout the life of the project:

- Safety team leadership is the focal point for system safety related rulemaking and policy development efforts
- Oversight and evaluation of collaborative projects
- Standardization of concepts, functional requirements, and terminology across managed and sponsored programs, initiatives, and contracted activities
- Development and maintenance of policy and guidance documentation
- Development of training requirements and mentorship of training
- Development of measures of safety performance and effectiveness for both internal and external programs
- Development and maintenance of data collection and auditing tools
- Development and use of standardized outreach, familiarization, and orientation materials

Coordination and management of an Implementation Support Team to assist field organizations and operators in development and implementation

How the teams are lead through the cultural shift is the key to this project. From a BSEE executive level leadership standpoint, implementing system safety can be a substantial undertaking and the only way to effect change is to be in the field, lead by example and communicate effectively.

While it would be desirable to quickly implement RTM using system safety, the above process is a proven approach in multiple industries designed to reduce implementation time and does not require reinvention. Traditional industry methods need to be revitalized with fresh perspectives, and while there is a great number of existing industry tools to enable safety, a truly progressive organization strives to maintain cutting edge policies and procedures.

BSEE Mandates and Regulations

Industry Best Practices

Best Available and Safest Technologies (BAST) and industry best practices form the backbone of safe and efficient operations for the oil and gas industry. There is a great deal of experience and knowledge resident in government, industry, academia, and trade organizations. The best equipment and practices are in place today in the industry and waiting to be recognized and promoted.

Section 21(b) of the Outer Continental Shelf Lands Act, as amended, requires the use of BAST and assurance that the use of modern technology is incorporated into the regulatory process. This report does not intend to dictate to the regulator any legal responsibilities. This is merely an indication that BAST is an established concept. It is recommended that BSEE increase discovery of, and reliance upon, best practices and modern technology.

The regulator should strive to identify, capture, and promote the industry best practices and technology. A working group sponsored by BSEE could be put in place to document and promote the current BAST and industry best practices. The working group should consist of industry, government, academia, and industry trade representatives. The working group would not be required to be a standalone entity. The responsibilities for discovery of best practices and technology could be facilitated by a working group responsible for a broad review of the industry and the regulatory landscape.

The use of RTM/RTD has been shown to be an industry best practice. It employs modern technology to increase safety and has become a common practice for high risk wells. The use of RTM should be the benchmark for industry practices. The implementation of RTM should be practiced with close coordination between government and industry by documenting and enforcing best practices of RTM.

Consideration should also be given to identifying emerging best practices. As technology moves forward, new abilities and principles emerge. The regulator should be aware of, and well briefed, on new technologies. Industry trade shows are a useful venue for identifying embryonic technology. BSEE should promote those technologies that are identified to be useful in current best practices. The ‘promotion’ by BSEE of new technology should be done with counsel from industry and academia.

The recognition of best practices and modern technology should be included in the audit process. The performance based regulatory environment is well suited to promoting best practices. BAST and best practices that are not formal regulations should be addressed by the audit team to ensure exposure and industry wide data sharing.

Audit (Assist Visit)

The term ‘audit’ is not viewed favorably and usually associated with fines. The negative nature of the term points to an adversarial relationship. A term that has been used to put a positive tone to the audit is ‘assist visit.' The term 'assist visit' (AV) will create a more positive atmosphere and will more accurately define the nature of the inspection.

The OCS Lands Act authorizes, and requires, BSEE to conduct inspections for all safety equipment designed to prevent blowouts, fires, spills, or other major accidents. The inspection programs in place at BSEE to document Potential Incident of Noncompliance (PINC) and Incidents of Noncompliance (INC) should be modified to include the use of RTM and RTD. The inspection checklist would be performance-based and would need organizing and planning to accomplish. The regulations recommended in this document will not be incorporated into a checklist easily.

The SEMS II program being initiated by BSEE is structured to facilitate the introduction of RTM into the industry. There are a few enhancements recommended to complement the robust process already in place.

Measuring Regulatory Compliance

When performance-based regulations are incorporated, it may be difficult to measure or determine compliance. There is a need for a standard of measure for assessing the level of adherence to regulations.

The standards for measurement should go beyond the use of incident statistics and include the generation of metrics that would indicate leading and lagging areas. These new prescriptive metrics should be managed with an eye towards incorporating a reasonable level of oversight without creating an undue burden.

e-Inspection

The use of RTD provides an electronic means of capturing and storing data for all the parameters and conditions of properly outfitted instrumentation.

BSEE should implement an e-Inspection system to enable timely and accurate collection of data useful to the inspector. e-Inspection will reduce costs associated with paper forms and manually entering data into the BSEE database. The system will also allow inspectors to access critical data including drilling permits while conducting inspections and will improve the quality and efficiency of the overall inspection program.

With industry-wide implementation of RTM data, all reports required by the OCS Lands Act could be generated automatically from captured data at any interval desired.

The structure for an e-Inspection program should be based upon a homogeneous reporting format for the parameters collected from the rig. The ability to perform e-Inspection is dramatically enhanced by standardized inputs that do not require conversion efforts and decisions on viability.

Risk Based Inspection

Risk Based Inspection (RBI) is a principle used by other industries and other sectors of the oil and gas industry. The principle of RBI promotes the efficient use of inspectors and inspection methods by prioritizing the risk and assigning greater oversight and inspection rates for high risk events and operations.

API Recommended Practice 580 provides users with the basic elements for developing, implementing and maintaining a risk-based inspection (RBI) program for pressure vessels. It provides guidance to owners, operators, and designers of pressure-containing equipment for developing and implementing an inspection program. These guidelines include means for assessing an inspection program and its plan. The approach emphasizes safe and reliable operation through risk-prioritized inspection. A spectrum of complementary risk analysis approaches (qualitative through fully-quantitative) can be considered as part of the inspection planning process. This API RP is useful for structuring BSEE RBI and should be used as a guide to developing RBI for the drilling and completion phases of the oil and gas industry.

An important principle of RBI is that a relatively large percentage of risk is associated with a small percentage of equipment. The key to finding the risky equipment is found in historical data on the utilization and failure rates of the equipment. The data on failure events can be used by Predictive Analytics to pinpoint the equipment and condition most likely to create a failure. The consequence of the failure is compared against the possibility of a failure to rank the risk and facilitate prioritization.

Training for Auditors

To properly assess the compliance of industry with government regulations in a performance based RTM environment, the auditor must possess the ability to work with shades of grey. The training for the auditor who meets standard acceptance criteria should be structured on a ‘Train to Proficiency’ principle. The training for an auditor with a previous career in offshore drilling operations would be much less than the training for an inexperienced new hire to the department. An experienced auditor with limited offshore exposure and a relative newcomer would need the same level of training on RTM systems.

BSEE has implemented the National Offshore Training and Learning Center (NOTLC). The NOTLC supports the Bureau’s goals by providing upfront and ongoing learning and development opportunities to Bureau staff. The principles of distance learning, knowledge management, and online assessments should be included in the NOTLC. The courses included in the NOTLC should be expanded to train the regulatory staff on the current RTM technology and the emerging capabilities.

After-Action Report To Rig Operator

The current regulations for conducting audits do not include a robust program for providing feedback to the operator. The feedback is currently in the form of penalties and enforcement actions. The after-action reports from BSEE auditors can be a useful tool to assist the operator in determining future steps to correct or enhance current operations. The use of the audit forum could also serve as a setting for introducing BAST and emerging best practices. The use of RTM should be evaluated and suggestions for better implementation included.

RTM Implementation

Implementation of RTM into the industry should be guided by performance-based regulation implemented with a system safety approach. The recommended regulations should describe a system of parameters and/or methods based on current industry best practices. The rules should avoid prescribing the nature of tool measurement or any brands or trademarks unless recommended by best practice. Organizations such as API should be requested to provide input to rule generation.

The requirement for RTM would provide opportunities to collect key compliance indicator data, equipment performance data and/or to use real-time operational data flows to complement BSEE inspection programs, enhance compliance, and address regulatory gaps. This would include the reviews necessary to determine the costs and benefits of obtaining electronic access to real-time data transmitted from offshore platforms/drilling rigs, such as BOP monitoring systems, and/or other non-proprietary automated control and monitoring systems. The goal would be to provide BSEE with additional oversight tools that can assist the agency in the inspection and oversight process.

Government Standards Framework

In order to implement RTM in the oil and gas industry using a performance based safety process, industry standard procedures and parameters will have to be identified. BSEE should generate government standards and ensure those standards coincide with industry best practice and safety procedures. Organizations such as API could be requested to provide input.

A document such as API RP 14C would frame the implementation and subsequent adoption of RTM for the oil and gas industry. Based on previous API recommended practices, structurally the implementation of this type of program for BSEE could have the following outline:

1. GENERAL
- 1.1 Introduction
- 1.2 Scope
- 1.3 Organization of Technical Content
- 1.4 Government Codes, Rules, and Regulations
- 1.5 Industry Codes, Standards, and Recommended Practices
- 1.6 Metric Conversions

2. RTM SAFETY DEVICE SYMBOLS AND IDENTIFICATION
- 2.1 Introduction
- 2.2 Functional Device Identification
- 2.3 Symbols
- 2.4 Component Identification
- 2.5 Example Identification

3. RTM MEASUREMENT
- 3.1 Parameters to be measured
- 3.2 Reporting Standards
- 3.3 Minimum Bandwidth for required transmissions
- 3.4 Data Transfer Protocols
- 3.5 Data Storage Standards
- 3.6 BSEE accepting data

Summary

This framework should build upon the current regulatory standards for drilling and well monitoring. There has been considerable work by BSEE to quantify, identify, justify, and issue regulations for the oil and gas industry. There are areas where further effort by the regulators can produce increased safety, efficiency and accountability.

The potential final drilling rule mandated:

- Procedures for monitoring the volumes and rates of fluids entering and leaving the wellbore
- Minimum training standards for persons monitoring and maintaining well-control [27]

These rules were developed as performance based regulations and left a substantial amount of implementation in the hands of the operators.

Parameter Standards

The parameters monitored through RTMC should be mandated using performance based regulations. These parameters should be communicated to be the minimum required for monitoring. Monitoring more parameters should be encouraged.

A smaller, more critical set of parameters will aid in the introduction of RTM and facilitate further regulations as needed.

Wellbore pressure

Wellbore pressure has been shown to be a causal factor in a significant portion of well incidents.[32] As shown in Figure 6: Pressure related events, 48% of well incidents were pressure related. It is recommended that the pressure of the wellbore column be included in the minimum list of parameters mandated for RTM. The monitoring of pressure in the wellbore was not included in the final drilling rule and should be added.

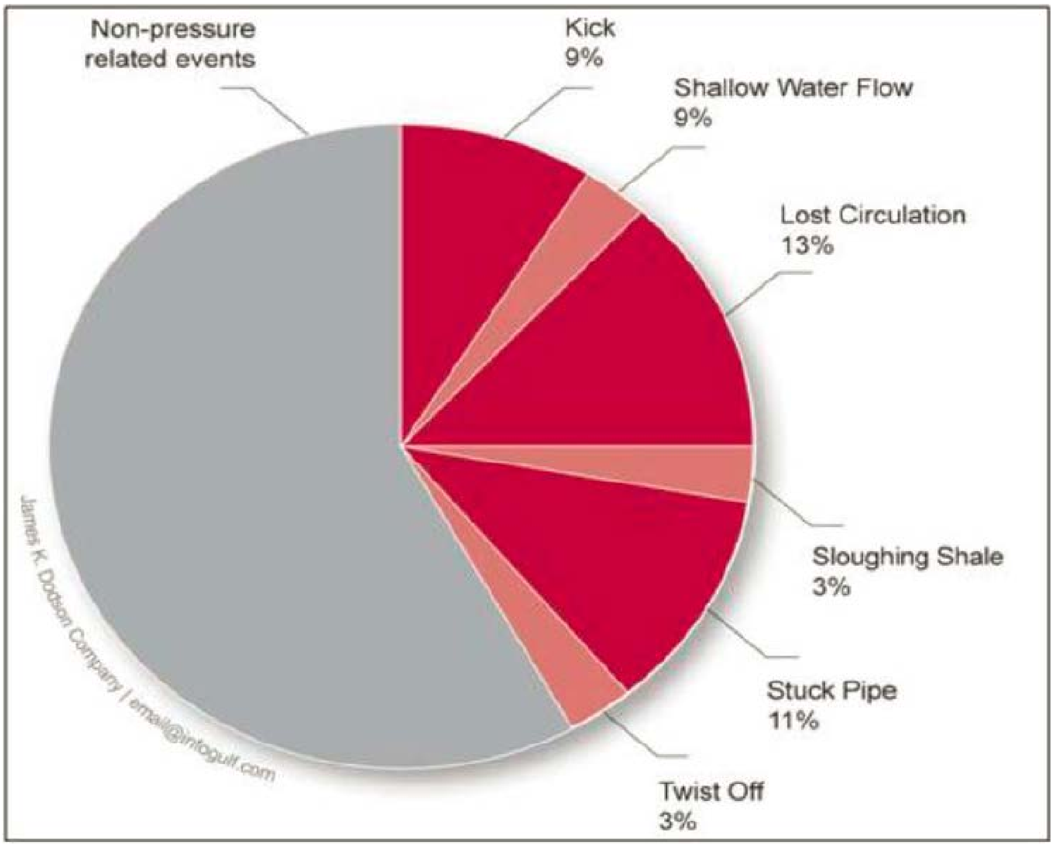


Figure 6: Pressure related events[32]

The pressure in the drill pipe should be complemented with pressure monitoring of the kill line and choke line. Depending upon the position of valves and the routing of wellbore fluids, the choke and kill lines could provide timely data on pressure events.

Gas influx and content

In a Constant Bottom-Hole Pressure (CBHP), MPD, the bottom-hole pressure is kept relatively constant which allows circulating small influxes out of the well without shutting in. The most important indicators for detecting an influx are pit gain and variations in pump pressure. In managed pressure drilling, the well control emergency may not apply, as the system is already set up for this occurrence.

One of the most important issues in drilling such wells is the narrow mud window between fracture and formation pressures. Managed Pressure Drilling (MPD) techniques rely on precisely controlling annular pressure profile in the wellbore. The intention of MPD is to avoid continuous influx of formation fluids to the surface.

Moreover, on floating rigs, because of less accurate flow and pit level measurements, the detection of gas influx is important to the ability to avoid dangerous levels of explosive gas.

Rig personnel (primarily the driller) watch several different indicators to identify kicks. One is the amount of fluid coming out of the well. If flow out of the well exceeds flow in or the volume of mud in the mud pits increases unpredictably, that may indicate that hydrocarbons are flowing into the wellbore. Data from sensors that measure the gas content of returning drilling mud can provide a warning of hydrocarbon flow.[28] This information would assist in identifying the nature of the substance entering the wellbore.

Mud pit content is another method to gauge the amount of undesired fluid entering the wellbore. The pit is usually monitored by electronic mud probes or video cameras that show mud level to the mud engineer. The nature of the video broadcast creates difficulty in transmitting the images to a remote monitoring station.

Gas content

An increase in the gas content of fluid returns over time can indicate an increase in pore pressure, penetration of a hydrocarbon-bearing zone, or a change in wellbore dynamics allowing more effective cuttings removal. But unexplained increases in gas content are always a cause for concern. They can indicate either that a kick is occurring or that wellbore conditions are becoming conducive for a kick.

Flow measurement

Rate of fluids and volume of fluids is a mandatory measurement under the final drilling rule. The use of real-time data capability to sense, collect and transmit the data should be included as a more prescriptive approach to measurement of flow. The remote monitoring of flow parameters will provide another set of eyes for monitoring a critical parameter. It will also provide data collection for studying industry trends and for reconstruction of events and/or incidents.

Remote oversight of RTMC events

Macondo did not have onshore monitoring by the operator despite classifying the well as critical. The well was being monitored from remote locations at the contractor's facility with no connection to the operator's decision makers. The report on the Macondo well accident found this surprising since the well was identified by the contractor as a high risk well.

BSEE should mandate that high risk wells should be monitored at a remote location using RTM. This would seem to be intuitive to the operator but recent events prove otherwise. Monitoring from a remote location will serve to counteract the push by the rig crew to press a risky situation in order to make schedule and reduce costs. The benefit of an outside observer has been shown many times to be useful.

Bandwidth requirements

An aid to the use of RTM for monitoring from an onshore facility is the ability to facilitate large amounts of data through the current information pipeline. The use of data to properly regulate the industry requires the full set of data without removing or truncating events to allow transmission on a clogged network.

BSEE should mandate the minimum bandwidth and latency for RTM implementation for transfer rates that are suitable for the complete set of data to be sent in real-time. This will enhance the ability to bring RTM to the industry through the development of more robust network solutions. The determination of the minimum data transfer rates or an information protocol is beyond the scope of this report.

Implementation

Introducing RTM regulations into the oil and gas industry should be accomplished with all the system safety tools identified in the previous section. The implementation should come in phases. There are many different performance safety strategies that exist today, many of which have the same basic tenets and include the following:

STEP ONE: BSEE should define goals/objectives with respect to safety.

Identifying safety goals and objectives as well as an infrastructure for implementing those goals and objectives and will include:

- Sharing program framework with stakeholders
- Providing an opportunity for input and comments
- Finalizing program details
- Developing staff protocols and training
- Providing stakeholder outreach
- Categorization of operators (Preferred, Acceptable and Unacceptable based on performance reviews with the unacceptable category receiving reviews more often)

STEP TWO: BSEE should review the guidance and choose specific targets, outcome indicators, and activity indicators that might be relevant, taking into account the overall safety objectives and the key aspects to be measured and will include:

- Implementation of the critical items inspections for the operators
- Expanding Compliance Reviews/Random Inspections to all types of operators
- Implementation of additional enforcement activities as needed.

STEP THREE: Requires BSEE and the industry to adapt and define the safety indicators. Each operator should adapt the chosen indicators so that they are consistent with local procedures and standards, using vocabulary and parameters that make sense to members of the operation. The choice of indicators, and how they are adapted, should be tied to the strategic plan, goals, and objectives of the operation. The size and structure of the operator, and the operational environment have to be considered when setting up safety monitoring arrangements in the operation.

STEP FOUR: Identify what each indicator will measure and determine the appropriate metrics (or scale) for the performance indicators.

In cooperative efforts, BSEE and the operators should clearly define each indicator and develop metrics that are both appropriate to the particular circumstances and can be easily applied, and therefore can reveal meaningful insights.

Identification of indicators to be monitored - Safety indicators can be quantitative or qualitative, leading (proactive) or lagging (reactive).

Collation of the information for safety monitoring - There should be a systematic collation and evaluation of results from all safety monitoring activities to ensure that interrelationships can be detected.

STEP FIVE: Apply the appropriate metrics to the indicators. As BSEE determines the appropriate indicators, the industry should apply the metrics to the indicators chosen and prepare a report analyzing the results and the changes that occurred since the last evaluation. The report may also set targets for progress into the future and make recommendations for follow-up.

Analysis of indicators - The evolution of the indicators should be analyzed, trends and related causes and influencing factors established.

Industry Roll-out

Rolling out a plan to the industry could be overwhelming if performed in a vacuum. Suggested models might include a pilot program with the major oil companies that already have RTM to understand from the operator standpoint the inherent trials and tribulations involved with RTM. Because the major oil companies all use real-time data in one configuration or another, BSEE should have an industry perspective understanding of established standards. A robust continuous improvement program capable of generating continuous lessons learned would be important to ensure acceptance by the industry. As programs evolve over time, continuous improvement ensures the prescribed standards don't remain stagnant. By the time the program is required for the smaller operators, a substantial amount of turmoil can be reduced, which lowers overall cost and reduces the barrier to entry.

The introduction of RTM to smaller operators may be facilitated by a third-party contractor. The contractor should not be excluded from the regulations requiring the system safety implementation of RTM.

Smaller Operators

Once a prescribed period of time transpires, perhaps two to three years, the real-time data and RTM implementation should occur in the smaller operators both in the Gulf of Mexico and possibly onshore. Many of the growing pains would have already transpired and any larger costs that would have served as barriers to entry into the real-time data use would be minimized though normal equipment upgrade cycles. In regulated industries, a method for adding regulations is through a notice of proposed rulemaking (NPRM). The proposed rule must not exclude the lowest common denominator among the group of operators.

Meaning, the rule must be achievable by the smallest operators, and in the case of implementing RTM in the oil and gas industry, would need to be considered prior to implementation.

Continuous Improvement

The safety system, including the indicators and metrics, needs to be periodically reviewed and evaluated. Performance based systems are an iterative process and should be refined as experience is gained. BSEE would need to establish a formalized process of continuous improvement that ensures the indicators are well-defined and continue to correspond with the subjects that the operation wants to measure. It provides the basis for determining whether the process and the metrics are appropriate for the operation and the indicators provide the type of information needed for an understanding of trends over time.

Application of corrective action process - Corrective actions need to be identified, and action needs to be taken when monitoring shows an indicator is approaching a safety threshold. Those same corrective actions need to be shared industry wide, documented and actions need to be taken to ensure future occurrences do not happen.

Process assessment

Health and safety controls should be integrated into the procedures and within those procedures, the organization needs to understand all safety related information in order to present accurate procedures that paint a complete picture. BSEE should make sure that once the information is correctly applied to the procedures, continual assessment needs to occur at all levels in the operation and everybody needs to understand what tasks need to be completed and who is responsible for those tasks.

Conclusion

Mandating RTM use in oil and gas drilling and production should be included as one piece of the entire oversight program. The challenge is to implement complimentary programs to support RTM and improve the chance of success. This can be done using a system safety approach. Industry and government organizations are all moving toward a system safety approach to ensure regulatory compliance as well as keeping abreast of technological advances.

The authors described and presented an example of both prescriptive and performance based systems and it should be perceived that a system safety program would be the most beneficial method of implementing RTM into the oil and gas industry using components of both prescriptive and performance regulation. Coupled with implementing monitoring process, implementing RTM would require identifying all the parameters to be measured and reported to ensure that requirements are met.

As system safety is implemented, the oversight authority should select the programs to use for each safety implementation. The true essence of a safety management system is to incorporate many different safety interdependencies in order to make the entire system work as a whole to improve safety.

The efforts of BSEE to implement system safety principles and to other proven methods should be done using examples from other industries. The use of demonstrated principles and programs can streamline the introduction of a system safety approach.

System safety implementation requires additional, complementing programs to be an all-inclusive safety program. Voluntary reporting, routine auditing, risk analysis, root cause analysis, human factors, industry-wide data reporting and other safety related programs are critical for driving down incidents and accidents.

Incorporation of RTM and additional system safety components into an actively involved oversight program as demonstrated by the aviation and nuclear industries will provide a more robust solution to safety in the oil and gas industry.

Intentionally Left Blank

CHAPTER 4 – (Task 4) Identify all necessary information which needs to be collected, calculated, or monitored during operations to improve the current level of safety. Identify any existing or proposed modeling tools that can be used in connection with real-time data to prevent incidents

Chapter Summary

As the industry is pushed into more complex exploration and production environments, more complex tools and technology are necessary to allow safe recovery of hydrocarbons. This paper explores the current information available for deep water operators in the Gulf of Mexico (GOM) and what additional information might be necessary to improve the levels of safety during exploration and production.

On newer rigs, increasingly sophisticated sensors are delivering enormous volume of data that is being harnessed to generate more efficient well delivery and production.

To best take advantage of this valuable asset, new work processes are being developed and revised on a daily basis to utilize the data. The organizations striving to be successful have adopted these advances and aggregated the data streams into real-time operations centers and collaboration centers offering real-time monitoring of day to day operations. These centers provide centralized collaboration and communication; and highly skilled expertise for creating safe operations. The aggregation and organization of the data is extremely important to all parts of the exploration and production process. In this enterprise, third party vendors offer many commercially available and custom solutions to formulate coherent information for well optimization and event monitoring. But regardless of the sophistication of the data analysis operation, the data is only as good as the sensors, and considering ever increasingly complex operations, the development and adoption of advanced measurement systems and sensors producing the data are lagging behind the requirement to produce what is fast becoming a near zero acceptable risk tolerance for well delivery and production.

The rigs operating in the GOM today range in age from brand new to over thirty years and the sensor systems aboard vary just as greatly. Generally, these sensors provide data from drilling and performance equipment which measure how the well is being delivered; lithology data which encompasses wellbore data; and information on the condition and wear of equipment to determine service and repair interventions.[33] The industry needs to embrace methods of continuous and direct measurement of well control parameters and not be satisfied with the status quo of intermittent and surface measurements that provide data requiring highly experienced drillers to infer downhole situations. These measurement changes will offer a marked decrease in the risk factor of operating deepwater well and a corresponding improvement in safety.

However, improving the technical aspect of well delivery and production is only half of the safety improvement equation. Improving the human element is the other half. People make mistakes. Human error is cited as a contributing factor in the majority (up to 80%) of industrial accidents and incidents.[31] The key to decreasing risk and improving safety requires continuous learning from the mistakes of others as well as our own. The aviation industry has embraced the study of the human factors side of accidents and uses it as a basis for training and safety improvements. The Human Factors Analysis and Classification System (HFACS) is a framework used to identify and classify the human data element thereby providing an avenue for improving human interaction with technology and painting a holistic approach to improved safety.

HFACS is based on James Reason's model of latent and active failures, the 'Swiss cheese' model. The oil and gas HFACS framework has been adapted from the aviation industry and provides a common framework to systematically classify accident and incident contributing factors.

Errors, incidents and accidents are analyzed for their root causes and categorized in the HFACS nanocodes permitting further analysis for organizational trending allowing for systematic improvements to identified problem areas and avenues for predictive analysis of the human element.

Proactively avoiding errors, incidents or accidents, with improved training can have a significant impact on safety. With advanced computing power and developments in the gaming industry, oil and gas industry engineers can now visualize the well planning process. 3D modeling and simulation enables all relevant parties to come together using common databases and common professional languages, pooling resources for the project. The efficiencies gained by these enhanced planning tools inherently plays directly into improved safety margins. The industry is also seeing a rise in Human in the Loop (HITL) simulation allowing for increased experience levels and practiced procedures prior to ever being on the rig. The use of Crew Resource Management (CRM) tools is a necessary addition to these training methods.

Every new well drilled represents new and different challenges than all previous wells. With advancing technologies and new processes becoming available almost daily, operators must accept that new drilling standards are necessary and required for safe operations in the Outer Continental Shelf (OCS) Gulf of Mexico in order to mitigate risk factors in today's 'critical' and extremely challenging well scenarios. Updating measurement, collection and monitoring systems to BAST (Best Available and Safest Technology) for the technical and human data elements along with advanced, predictive analysis open the window for improving the safety culture of the industry and lowering acceptable risk tolerance.

Introduction

The use of drill string measurements and basic sensor data has long been the key to informing the drilling process and maintaining well control within acceptable safety margins. In December 1937, time-based analog charts were introduced with the Geolograph as a basic tool for trend analysis and identification of anomalies. This invention quickly became the de-facto method for keeping a record of events.[1] The transistor's introduction in 1947 brought about another step change in well monitoring with the introduction of sensor capabilities. In the early 1970's, the oil and gas industry entered a new era by employing digital analytics throughout the exploration and production chain providing a wealth of new information about the condition of the well. The relatively low data rates at the time made for a manageable solution, but the limited information only provided part of the well environment picture.

The introduction of measurement-while-drilling (MWD) and logging-while-drilling (LWD) has enhanced the downhole picture from wireline technology bringing this data to near real-time, but low downhole data rates limited by bandwidth remain a barrier to a truly revolutionary breakthrough in real-time data and analysis of the downhole picture.

The question for this paper requires outlining the information necessary from the well site to improve margins of safety during exploration and production. Keeping within this scope, this paper will explore those data sets and information directly related to improved safety without regard for data considerations for improvements in Non-Productive Time (NPT) and other efficiencies in the exploration and production processes.

Task 4: Identify all necessary information which needs to be collected, calculated, or monitored during operations to improve the current level of safety. Data should include, but is not limited to, pressure drops, fluid influx, fluid loss, and the operation of BOP functions. Identify any existing or proposed modeling tools that can be used in connection with real-time data to prevent incidents.

The assumption should not be made that having this data or mandating its collection will inherently make the project safer. Appropriate analysis, experience and recognition are necessary to transform data into usable information for the purposes of improving margins of safety. Many of the leading operators have pooled this information in collaboration centers where the data is processed in real-time or analyzed post-process to provide enhanced business solutions and increased operating safety margins.

The industry has moved years and technological generations beyond simple mud logging. The aggregation of rig sensor data, accompanied with real-time and post-processing analysis, delivers enhanced levels of production, reduced NPT and with it, improved operating safety margins.

The technical advances and enhanced data only provide part of the palette necessary to paint the safety improvement picture. The human element plays a huge role and in effect is the most susceptible to failure in the dynamic environment of the oil and gas industry. Human error is cited as a contributing factor in the majority (up to 80%) of industrial accidents and incidents.[31]

The Human Factors Analysis and Classification System (HFACS) framework provides a common framework to systematically classify accident contributing factors and is the basis for continuous improvement of the human element in the safety equation. HFACS originates from the aviation industry and is based on James Reason's model of latent and active failures, the 'Swiss cheese' model.

And just as HFACS can lead future advancements in safety, advanced training programs can stop accidents before they happen. Gaming industry technology and advancing computing power have changed the well planning process. The addition of 3D modeling and simulation enables all relevant parties to come together using common databases and common professional languages. The efficiencies gained by these enhanced planning tools inherently plays directly into improved safety margins.

Use of human in the loop (HITL) simulation is also on the rise promoting increased experience levels and practiced procedures prior to ever being on the rig. The use of crew resource management (CRM) tools is a necessary addition to these training methods.

This paper explores collection methods, data calculation and monitoring requirements during operations for both the technical and human aspect of the safety equation. We also explore the technology currently used to acquire data and potential improvements in collection, monitoring and calculation of data ensuring a safer operating environment.

Information to Improve Levels of Safety

Data collection and organization

The collection of data is only the beginning of the process to improve industry safety levels. The collected data must be organized, analyzed and presented to enable an accurate decision which will result in improved levels of safety.

Drilling industry operations primarily produce three parallel data flows that occur with varying degrees of interdependency.

The first data stream includes all data collected for drilling and performance which measures and describes how the well is being delivered. This data is usually acquired by multiple third party contractors from sensors throughout the rig, downhole and at times, in a manually written format.

The second data stream can be generally classified as lithology data and encompasses wellbore data measured continuously and intermittently by service providers. Data is acquired by specialized sensors through surface and downhole tools and is used to update the subsurface model.

The third data stream is usually acquired by the Rig contractor and provides information on the condition and wear of equipment to determine service and repair interventions.[33]

The amount of data streaming from the rig continues to grow with new technological advancement. To utilize this data the industry has been slowly embracing the use of collaboration centers which provide handling and analysis. The collaboration centers are generally organized to use real-time streaming data or may analyze data previously collected.

Five common success factors have been observed in established collaboration centers that have demonstrated reliability and/or performance improvements:

Environment - Putting equipment operating condition into context. Equipment operating in a dynamic environment, under a range of conditions requires data to be collected and referenced with respect to the conditions encountered during the evaluated timeframe.

Data - Collecting and managing data by exception. The blizzard of data now available requires machine learning and management by exception to reduce data into usable information.

Analysis - Using both predictive analytics and deep diagnostics as complementary technologies that operate in different timeframes. Deep diagnostics may include such things as vibration signature analysis and cylinder performance analysis, while predictive analytics employs pattern recognition algorithms to detect minor events and anomalies.

Cooperation – Industry wide communication of observations, diagnoses, recommendations and lessons learned through collaboration tools. Such tools add value on multiple fronts that include knowledge transfer and equipment-specific learning such as Root Cause Analysis.

Management - Managing the findings in a knowledge-management system or collaboration system. This provides feedback for further improvement.

Collaboration centers utilizing these factors have been able to successfully meld the parameter data into a relatively accurate picture of the downhole environment allowing them to operate within an enlarged safety envelope.

Collected Data

The oil and gas industry operates in extreme conditions and encounters many types and ranges of physical conditions that can and should be measured. In conventional operations, drilling engineers track various operational parameters such as pressure, flow, torque, temperature and others. These parameters provide only a simple picture of the behavior of the drill string bottom hole assembly (BHA) and well condition. Typically, a driller will use this limited operational information, his experience and a few rules of thumb to manage drilling operations in the most efficient and safest manner possible.

In addition to these traditional tools, dynamically derived data can be useful for providing a clearer picture of the exploration and production processes. Measurements of these parameters provide the necessary data to properly control the well during exploration and production.[34] A comprehensive, but not exhaustive list of measured parameters that should be collected for operating conditions in well operations includes:

Pressure

The measurement of pressure is complicated by the wide range of requirements from small variations to large pulses. Quartz resonator technology currently dominates the single point sensor market for pressure. Pressure sensing is used throughout the industry to indicate performance and to act as an alarm to an unsafe condition. Important pressures to track include:

- fluid pressure
- hydrostatic pressure
- formation pressure
- fracture pressure
- bottom hole pressure

Each of these pressures plays a key role in well control.

Hydraulic

Hydraulic measurements involve constant monitoring and analysis of flow, flow rate, density and rheology of the drilling fluid. Flow of a fluid is performed based on the principle of a Venturi. The Venturi has two pressure sensors that measure pressure before and after the Venturi device. The measurement of flow is particularly important to drilling operations for ensuring proper flow of mud and pipeline monitoring for oil and natural gas. Flow can also be measured by counting pump strokes and applying an efficiency factor and through acoustic measurement devices. Coriolis meters continuously measure mass flow rate (density of the mud and the rate it is flowing).[33] Mud density and flow properties are also measured by a fann viscometer and others offering real- time density and viscosity measurements.

Torque

The measurement of torque is one of the most important parts of drilling a well. Historically, the torque meter has been an unusually large dial in prominent view of all personnel on the rig deck. The necessary torque applied to the drill string by the rotary table or top drive tells the driller much information about the formation through which he is drilling and stresses placed on the drill stem. Weight on bit changes, Rate of Penetration (ROP), formation transitions and stick/slip situations cause noticeable variations and/or spikes in torque as displayed on the torque meter. This alerts crews to drill stem anomalies or changing bit dynamics causing potential hazards to drilling operations. A spike in torque exceeding drill string limits will likely damage equipment and could cause injuries.

Tension

The simple force on a strain gauge is used to report tension. It is important to know the tension on riser tensioners and on mooring lines used for station keeping of floating drilling rigs and structures. Additional uses include measuring tension and compression to avoid damage to the logging tools and detecting strain on cables. Tensions measurements provide logging engineers with early indications of over-pull, tool drag, stuck tools, tool compression, and irregular tool movement.

Temperature

The extremes of temperature mirror those of pressure. Subsequently, there are many sensors that perform both functions. Quartz resonator technology currently dominates the single point sensor market for temperature. Temperature sensing is used throughout the industry and important when safe limits are exceeded for a desired operation or when there are changing conditions for fluids and pressures.

Chemical Composition

The chemical composition of the substances in the oil and gas industry is wide and varied. It is important to know the composition to be able to judge the environment for hazardous substances, flammability, consistency, density and other properties of oil, natural gas, and mud. The products going down the well need as much attention as the products coming up the well. It is critical to safety to sense the gas composition of the fluids in the well by sensing for gases such as Hydrogen Sulfide (H_2S).

Vibration

When drilling operations are underway it seems that vibration is in every part of the rig. There are limits to the vibration that certain pieces of equipment will sustain. An unexpected change in vibration can be a sign of impending failure. The vibration is measured with some of the same technology that is used to measure pressure.

Weight

Weight on bit, drill stem, and casing is critical to measure properly to assess the work being performed by the drill bit. The proper weight on bit is a balancing act that requires a constant vigil. It is an important parameter that is reported alongside the torque applied to the drill stem. Important aspects include setting/releasing mechanical set tools, indications of hanging up / restriction while tripping, and indications of amount of overpull applied.

Position

Current position and position change are necessary to ensure the intended geographic location is maintained or is attained. The location of the drill ship during drilling operations is paramount. The position can be reported in conjunction with the tension on mooring lines to anticipate movement of the vessel. Engines and thrusters are also monitored and controlled. Buoys can provide wave height by simple measurements of inertial energy. The position of the drill bit is the prime objective and must be monitored constantly. A change in position can be compared against time to produces a rate of change. Directing the position of the bottom hole assembly is also important for directional drilling where MWD tools have proven invaluable for guiding the directional drilling process.

Seismic

The use of seismic sensors has utility in the detection of production fields that contain enough valuable products to warrant exploration. Seismic sensors use the same technology as vibration sensors. They are generally deployed over a large area to gain insight to the capability of the rock strata to produce product by returning different frequencies based upon the composition of the material and the propagation of sound through different media. The vibration of the drill string and the equipment connected to the well are sensed by the toolpusher and are a valuable tool for detecting problems. Access to real-time seismic data while drilling has the ability to produce 3D imaging for deeper wells providing a more accurate picture of the formation and allowing for ‘look ahead’ to discover potentially problematic formations.

Corrosion

The chemical decomposition of structures used in the Oil and Gas Industry for production and transport of product can be measured. Corrosion is a chemical process that occurs as a result of the difference in atomic potential between two objects. The difference in atomic potential is easily measured as an electrical current when the two objects are connected. The effectiveness of an anode to protect the structure of a deep sea structure can also be assessed and reported.

Visual Conditions

The visual inspection of equipment and conditions can be done on site or remotely. The inspection criteria are limited to the conditions that are visible without dismantling or disrupting the equipment.

The environmental conditions being encountered by a piece of equipment can be measured by assessing the visual conditions in the area. The ability to assess fog, excessive vibration, external damage, movement, smoke, and fire is enabled by sensing of visual conditions.

The introduction of video surveillance aboard rigs has been instrumental to understanding the context of the working environment. Video is becoming a vital part of interpreting data streaming from the rigs. A real-time video feed from the drill floor provides an immediate context of the operations giving enhanced meaning to the streaming data. Bandwidth limitations however, hamper the streaming of all camera data to onshore facilities. The camera feeds that are streamed onshore are usually at a lower frame rate, preserving bandwidth. Camera data is not normally recorded.

Time

The time a piece of equipment is in use has direct correlation to the reliability that can be expected. The measurement of the duration of service life of a piece of equipment can also be compared against the conditions that affect lifespan. A harsh environment with large excursions of temperature and pressure will cause a reduction of lifespan compared to equipment that has remained at more optimal operating condition. Another time oriented measurement is Tripping data. Tripping data is gathered while running in/pulling out, and is a commonly reported value that is used to assess the performance of the drill team. While useful, Tripping data has little direct bearing on reliability of components.

Human Element

The elements of human actions on the rig should also be measured as aggressively as the parameters above are monitored, calculated and analyzed. Measuring the human element; however, is not so easy, though it is just as important a part of the safety of the operation.

Measurements from these parameters provide data for all aspects of well delivery, but none as important as the SAFE delivery of the well. It is widely recognized within the oil and gas industry that safety and effective well delivery are synonymous; with acceptable risk being extremely low and potential for failure a constant threat.

Monitored Data

A kick in a deepwater well is a serious threat with a huge potential for failure and loss of life. With the Blow Out Preventer (BOP) stack on the sea floor, early kick detection is extremely important. In deepwater wells, the marine risers above the BOP stack comprise a substantial portion of the total wellbore making it crucial that the kick is detected before the hydrocarbons rise above the BOP stack and into the riser. Once hydrocarbons are in the riser, the risk of a blowout increases significantly. Operation of the BOP has limited affect and well control response options become severely limited.[35]

The safety of the operation requires that the company monitor all parameters, and make decisions continually regarding the health of the operation. The numerous acceptable drilling techniques, formation types, reservoir anomalies and myriad other variables involved in the exploration and production of hydrocarbons makes a prescriptive list of required measured parameters less than ideal. Emphasis should be placed on monitoring those parameters necessary to provide for safe execution of the operation through the use of proven, *evidence based* processes and techniques along with best available and safest technology (BAST).

Industry practice shows that conduct of safe operations necessitates remote monitoring the following parameters:

- Fluid dynamics
- Mud flow – in/out
- Mud quantity and density – in/out
- Mud temperature – in/out
- Mud properties (MW, PV, YP, chlorides, pH, oil/water, low gravity solids (LGS) %
- Continuous chlorides in/out
- Drill gas - Total and/or compensated for ROP and hole volume
- Well control pressures
- Wellbore pressures (along the drill stem)
- Fluid pressures
- Fracture and formation pressures
- Pressure readings from shut-in events
- Torque
- WOB – weight on bit
- RPM – revolutions per minute of the drill stem
- ROP – rate of penetration
- Connection gas (CG), background gas (BG), trip gas (TG), short trip gas (STG), dummy trip gas (DTG)
- Gas chromatography

The oil and gas industry is still wrestling with minimum acceptable levels of BAST. An important lesson can be drawn from healthcare and evidence based medicine. The scientific based healthcare community is continually pursuing new treatments and improved methods of treatment, but not at the risk of the lives being saved. Introduction of new treatments and protocols must show a "*conscientious, explicit and judicious use of current best evidence*" [36] before widespread adoption of the processes. The lesson is not so much in the adoption of the new treatment or process, but in the development of the evidence base behind it. The oil and gas industry is in its infancy with respect to evidence based research necessary to safely field advanced drilling and production techniques and technologies.

As with healthcare, diagnosing a situation through monitored data requires correctly interpreting data for developing downhole events and is impacted by many external circumstances such as:

- Properly functioning flow meters and pedal position meters
- Correct lining up of (trip) tanks and surface lines
- Plugged lines or hydrate formation,
- Heave, roll, and pitch
- Volume transfers, solid equipment operations
- Gas remaining soluble in oil-based mud and avoiding detection until shallower depths near or even above the BOPs
- Ballooning or wellbore breathing and lost circulation[37]

Sensor Limitations

Sensor data acquired aboard offshore rigs has traditionally been of varying low quality. The hostile environment in which sensors are used and historic lack of technological investment has taken its toll on the early advancement of data quality.

The industry is, however, beginning to see marked improvements with some specialized sensors providing higher quality data. But it is still plagued by many of the more traditional sensors still in use which are inadequate for what they are expected to provide. Data also continues to be manually reported through measurements and observations when advancing sensor technology to acquire this data could provide a much more accurate representation at a much higher data rate. Additionally, the number of third party providers to the operator all but ensures separated data acquisition processes and inadequacies in identifying the gaps between them will result in a non-integrated approach while managing the drilling operations.[33]

Industry leaders continue to make new inroads to improved techniques including reams of data analysis as support. But there needs to be a recognition that basic issues in the well control equation need to be solved with new processes and technologies especially for deepwater operations to ensure the safety of workers, environment and assets. At the present time, deepwater operations' status quo is well below technological capabilities. D. Veeningen, offers the following well control observations of fundamental issues still plaguing the industry in his 2013 Offshore Technology conference paper:

- *"Reliance on predominately surface data for event detection and well control*
- *Appreciation for further technology adoption to aid early kick response, distinguish from ballooning*
- *Recognition that well control is about prevention as well as response*
- *Realization that well control events occur throughout all well construction phases, and not just while drilling ahead*
- *Need to independently verify well control barriers to ensure well integrity during all well construction phases*
- *Awareness that humans still play a significant role in identification and emergency shut-down decisions pertaining to well control while recognizing that the industry is currently challenged with a shortage of proven competent people"* [35]

Antiquated Collection Methods

Drilling rigs in the Gulf of Mexico vary in age from newly deployed to over 30 years old and some of the older rigs still employ many of the same sensors first used years ago. These are typically equipment control sensors which often measure parameters intermittently versus continuously and have limited accuracies with varying tolerances.

Weight on Bit (WOB) is a typical example of a derived parameter where a direct measurement is achievable and possibly more appropriate. WOB is generally displayed as a loss of weight from the top of the drill string and as measured includes everything exerting tension on the drill line, including the traveling blocks and cable. In order to have an accurate weight measurement of the drill string, a zero offset adjustment must be made to account for the traveling blocks and items other than the drill string. Measure-while-drilling (MWD) instrumentation has the capability to provide continuous measurements of the drill string tension and torque providing a more accurate direct measurement of WOB.[33]

Fluid Dynamics - Loss and Influx

Monitoring drilling fluid (mud) volume by using flow rate and density is critical to well control. The process involves a continuous calculation to determine loss of mud or influx of other fluids such as gases and hydrocarbons into the drilling circulatory system in order to maintain well control and gauge well integrity. However, traditional measurement systems, dynamic conditions and diverse flow patterns lead to high variability in resulting indications making it highly complex to determine influx or loss of the drilling fluid during operations.

Traditionally, density was measured intermittently, often four times an hour, even though control of mud weight on a continuous basis is one of the fundamentals of a safe drilling operation. Mud pump stroke count was used to calculate flow rate entering the well while flow rate exiting the well was normally measured using a paddle type device (Figure 7: Example of a Paddle Type Flow Measurement Device) that generally indicated only a percentage of flow in the flow line.

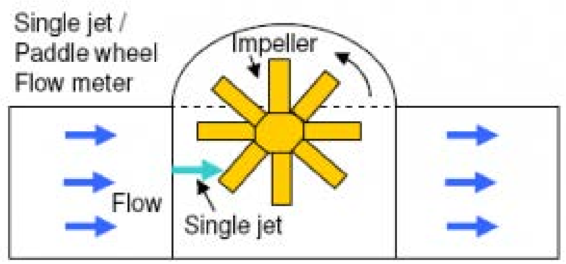


Figure 7: Example of a Paddle Type Flow Measurement Device[38]

Mud circulation in the well generally operates in a closed loop system where calculations of volume and density variations between the balance of inlet and outlet mud flow can indicate lost circulation. Fluids encountering fractures along the wellbore may flow out to the formation or fluids from the formation, such as hydrocarbons could flow into the wellbore, causing a kick and potentially a blowout. Pump strokes and paddlewheels are not accurate enough indicators of drilling fluid flow in the deepwater environment of High Pressure, High Temperature (HPHT) wells where oil based and gas injected mud is becoming the norm. In addition, volume and density variations are difficult to correlate results for showing an influx of fluids and gas to the wellbore or loss of drilling fluid to the formation. Given the varying state of rig sensors, in today's high risk wells, loss of well control can occur without real-time indications. And given the industry-wide shortage of experienced personnel, there may not be highly experienced drillers on-hand to enable appropriate action. Together, these conditions can lead to catastrophic events such as a blowout.

It is important for the safest operations to accurately account for all fluids and gases and their respective dynamic factors in the circulation system in order to accurately assess fluid losses and gains. The BAST capabilities explained below are operational today and permit operators to fully monitor fluid dynamics within the wellbore.

Pressure

Monitoring pressures within the well is a fundamental necessity for safe operations in oil and gas exploration and production. Safely drilling a well is a constant battle of maintaining bottom hole pressure (BHP) within the pore and fracture pressure window through drilling fluid densities. Too much pressure causes a formation break down or fracture resulting in a loss of drilling fluid to the formation. Too little pressure allows an influx from the formation to the wellbore leading to a kick or worse, a blowout. The very narrow margins between pore pressure and formation fracture pressure are most pronounced in high pressure, high temperature environment.

LWD and MWD technologies are utilized in Ultra Deep Water operations where these pressures must be tightly managed to maintain the drilling window. Managed Pressure Drilling (MPD) balances flow and hydrostatic pressure to allow a more precise control of BHP. This is achieved through a closed loop, pressurized fluid system. Close control of wellbore pressure is maintained and varied through drilling fluid pumps, fluid density and importantly, backpressure control on the fluid returns which is dynamically controlled using a dedicated and most times, automated choke manifold.

Highly accurate Coriolis flow meters that continuously measure mass flow rate, the density of the mud and the rate at which it is flowing are the preferred method for input to the MPD system. The continuous data produced from these highly accurate flow meters enables a significant amount of interpretation to be made on the conditions within the borehole and the ability to provide early warning systems for potential problem situations.[33]

> *"Dedicating one portion of the rig control system to the processing of continuous drilling fluids data would facilitate clear and concise displays of this information with early warning alarm indicators."* [39]

Accurate control of BHP results in fewer pressure fluctuations allowing for better control of the well and especially necessary where the difference between pore pressure and fracture pressure gradients is extremely narrow. MPD is meant to keep the well in balance at all times.

Although several different flow meters are used for MPD, the Coriolis flow meter is the most widely used for its ability to accurately and continuously measure the flow rate, fluid density and wellbore pressure, providing for an early kick detection capability. Just as in a conventional well, a kick can be detected by monitoring and comparing when flow out deviates from flow in. The tighter tolerances of the MPD closed loop, pressurized system and the accuracy and continuous measurements of the Coriolis meters allow for a much quicker recognition of fluid flow out/in differentials. Trends can be monitored through a data-acquisition system and alarms set and, depending on the MPD system being used, the kick can be controlled automatically.

After an influx is detected in an automatic MPD choke system, the choke automatically closes to increase the backpressure at the surface until the influx is controlled. No change in flow rate is required. After the influx is controlled, the annular surface pressure is controlled to circulate the influx out of the well.[40]

Dynamic Formation Integrity Tests (FITs) and cementing operations can also benefit through the use of an MPD system. FITs can be conducted more often providing more information to confirm that the wellbore integrity is suitable for planned casing. Running surge pressures and, if necessary, advanced notice to make required corrections to fluid densities.

Cementing operations can be conducted on a more stable wellbore and benefit from improvements over conventional techniques, including: proper fluid conditioning and hole cleaning prior to cementing; proper fluid dynamics and placement of cement to achieve drilling fluid removal; and sustained hydrostatic pressure during cement curing.[41]

Sensor Improvements

The industry has seen recent advances over the past ten years in drilling system sensor technology including applications for LWD and MWD capabilities. This technology provides ‘at-the-bit’ data measurement capability in memory modes and in near real-time using mud pulse telemetry and other techniques such as electromagnetic (EM) frequency communications, both of which provide limited bandwidth capability of up to a few dozen bits per second (bps).

Fiber Optic Sensors

Fiber optic cables offer many exciting new applications and are proving to be extremely versatile providing many solutions for sensors in the high pressure, high temperature environment. These sensors are replacing current legacy sensors because of the fiber optics’ advanced measurement properties and robust nature. The multidimensional ability for one sensor to measure many different parameters is accelerating the introduction of these sensors in the field. High accuracy, distributed array, temperature sensing, optical distributed pressure sensing, sand detection, and distributed strain (e.g. for riser monitoring), are just a few of the new generation of fiber optic sensing systems.

The unique properties of a fiber optic strand enable multi-sensing of parameters such as pressure, temperature, chemical composition, permeability and porosity. The state-of-the-art in optical sensing technology includes Fiber Bragg Grating (FBG) based Pressure and Temperature sensors, permanent Distributed Temperature Sensing (DTS), Single- and Multiphase Flowmeters, and Seismic sensors.[42]

FBG is a simple, robust, linear, repeatable and absolute sensor, making it ideal for long term subsea measurements. Introduction of FBG has enabled fiber optic technology to move from a single sensor per fiber optic strand to many applications by producing different measurements from the same sensor.

Wired Pipe

In the past few years Wired Drill Pipe (WDP) has emerged to fill the downhole broadband transmission void. WDP has enabled the benefits of high bandwidth telemetry for challenging drilling scenarios where high speed, bidirectional communications is necessary for control of directional, measurement and logging bottom hole assemblies.

The drill pipe consists of an embedded stainless steel, sheathed coax cable capable of bidirectional communications with speeds currently up to 57,600 bps, approximately three orders of magnitude higher than present industry standards of mud pulse and EM telemetry systems. Mud pulse and EM telemetry systems' transmission rates decrease with depth, normally operating at data rates from 1.5 to 40 bps. WDP transmission rates are independent of depth, distance, and surface induced noise.

Conventional MWD tools offer pressure measurements only at the BHA. WDP offers the added advantage of data acquisition and broadband communication along the entire drill string independent of surface measurements enabling real-time measurement of pore pressure and fracture gradient along the entire wellbore. This capability allows the continuous calculation of safe drilling margin as well as identification, analysis and control of a wellbore influx. Through distributed sensors along the entire hydrostatic column of the drill string, the system directly measures annulus pressure and can immediately identify pressure differentials in the wellbore indicating a potential influx into the wellbore. These downhole, direct pressure measurements provide early kick detection and can provide the ability to distinguish kicks from ballooning incidents, improving the ability to analyze and control an influx.

Figure 8: Pressure detection along the DrillstringDrill string, below shows the pressure differential detected by sensors 1 and 2 and traveling up the annulus where over time the remaining sensors will report a pressure change indicating an influx from the formation moving up the annulus. Utilizing the WDP network's ability to acquire high-definition log data in the absence of flow also provides the ability distinguish an influx from wellbore ballooning.[37]

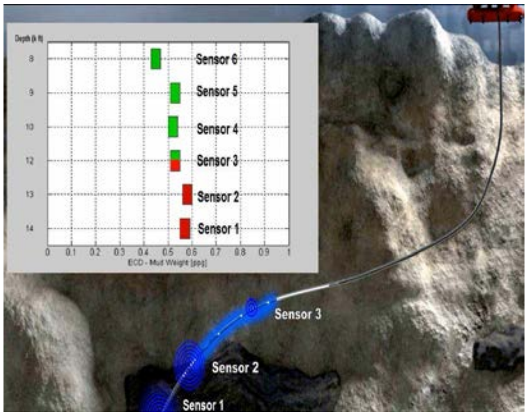


Figure 8: Pressure detection along the DrillstringDrill string[37]

Traditional mud pulse systems are unavailable when the drilling fluid is not circulating and the mud pumps are off, for example, while tripping. With the 'always on' data capability of WDP, pressure fluctuations associated with tripping and swabbing/surging operations, downhole data is now available to provide early kick detection enabling more rapid response to changing conditions and the ability to monitor and control the well more closely.[37]

Blow Out Preventer Operations

In conventional drilling, control of the well is provided through a two barrier principle for the prevention of well control issues and in the extreme, a blowout. The primary barrier is the hydrostatic column of drilling fluids bearing down on the formation inside the wellbore which acts to prevent hydrocarbons being released from the formation into the wellbore. The Blow Out Preventer (BOP) is the second barrier.

The BOP is actually an assembly of devices designed to shut in the well at varying stages and when circumstances dictate, close down the well completely. It is comprised of numerous components with a highly complex logical control system. The reliability of the entire BOP stack is the product of the reliability of each of these parts and also dependent upon the number of times each of its components is cycled. Activation cycles of each of the parts should be tracked and as a result the overall reliability of the system can be closely estimated through probability functions of success or failure to operate.

Applying basic predictive analysis tools to this information can help determine weak points in the system. Additional resources can then be allocated to increase inspection cycles of the individual parts and improve design or materials in order to increase overall BOP reliability, meet prescribed reliability factors and thereby reduce operating risk. Sharing this information on an industry-wide basis can only benefit the industry by increasing the probability of finding weak links within this safety system.

Tracking time and cycles of the BOP components and individual parts is a complex task. The BOP; however, is much more than another piece of equipment on a maintenance schedule. It is the last line of defense between continued safe operations and potential loss of life and environmental disaster. When the BOP is needed it must work and it must work correctly the first time.

A lesson on critical parts maintenance can be taken from the aviation industry. Critical aircraft parts have a manufacturer specified life span expressed in calendar terms, cycles or time-in-service with specific inspection and overhaul requirements.

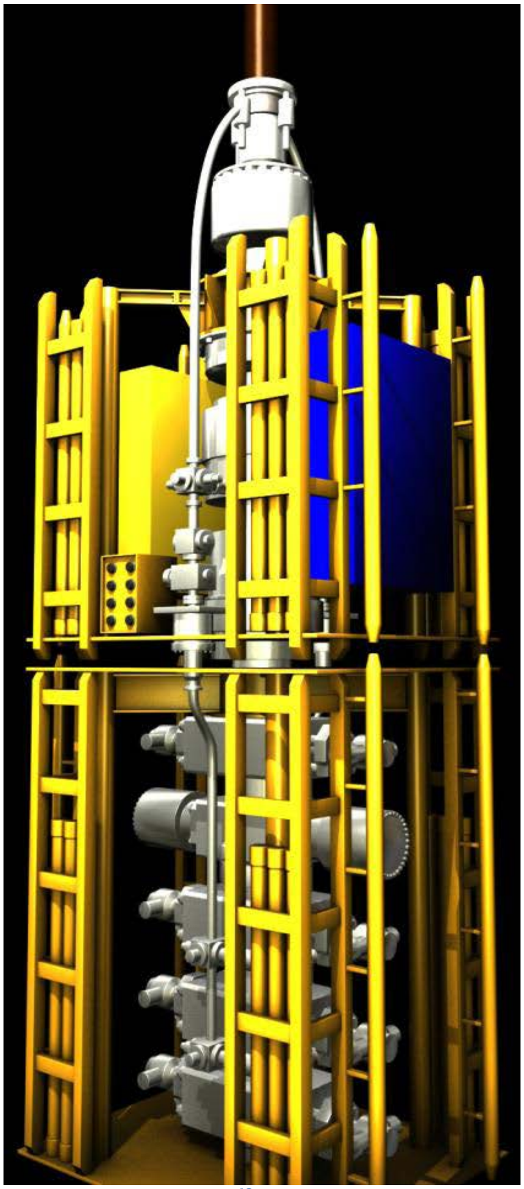


Figure 9: BOP Stack[43]

designated in these same terms. Its life history travels with the part regardless of how many different aircraft or aircraft components it has been installed in. Federal Aviation Regulations (FAR) enforce this rigorous tracking requirement by stipulating that operators will follow manufacturers' specified practices. FAR 91.403c states:

> *"No person may operate any aircraft unless …the mandatory replacement times and inspection intervals specified by the manufacturer have been complied with."*

This regulation makes it very clear that the operator must track and complete required maintenance *before* operating the aircraft. FAA certificated mechanics oversee and/or accomplish the work using accepted and approved practices and procedures providing an additional individual accountability with the threat of potential loss of license in the event required procedures are not complied with.

The potential risk to life and environment is no less with an improperly inspected BOP as that of an aircraft with pilot and passengers that has overdue inspections or critical equipment time-outs. Tracking, inspecting, overhauling and changing out critical parts in accordance with manufacturers' tested specifications has worked to improve safety levels of the aviation industry.

Human Factors Analysis and Classification System

When looking for safety improvements, we must look beyond the equipment and technology and consider monitoring the human side of the equation. Human error is cited as a contributing factor in up to 80% of industrial accidents and incidents.[31] During the last few decades, the study of human factors has become an important safety factor within central control facilities. More and more, automated, computer based systems including systems such as

Supervisory Control And Data Acquisition (SCADA) employed on production rigs are supervised by human operators.[31]

The Human Factors Analysis and Classification System (HFACS) is one of several frameworks used to identify and classify the human data element and thereby provide an avenue for improving human interaction with technology.

HFACS is based on James Reason's model of latent and active failures also known as the 'Swiss cheese' model. The oil and gas HFACS framework has been adapted from the aviation industry and provides a common framework to systematically classify accident and incident contributing factors.

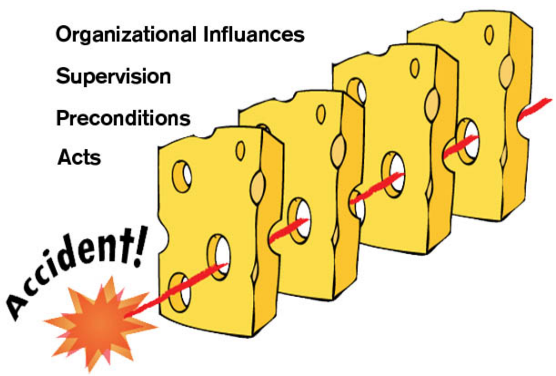


Figure 10: James Reason's Swiss Cheese Model[44]

The HFACS framework labels four main categories (cheese slices) of conditions:

1) Acts,
2) Preconditions
3) Supervision
4) Organizational Influences

Potential deficiencies in these conditions are represented by the 'holes in the cheese' of one of the four areas above. In the HFACS model, each of these four categories or slices is further reduced to subcategories which hold the classification descriptors referred to as nanocodes.

HFACS analysis results can be used as a safety performance metric on different levels depending on its scope. With the establishment of a national or perhaps international cross-company database, analysis results can be made to identify problem areas in an industrial domain, e.g. Exploration and Production. On a smaller, company level, HFACS can provide metrics for performance and identify operationally areas that contribute to accidents requiring more focus. HFACS might also be used to analyze a single installation or even a shift in performance on an installation.

A wide reaching HFACS framework database can be used to systemize data and become a knowledge database that can be used to learn from incidents and accidents. This database may be part of a formal knowledge transfer system providing a number of possibilities for data analyses. The framework can be used to identify trends and become a metric to identify accident trends and become a metric to measure the effects of risk mitigation efforts. For example, the occurrence rates of a nanocode can be used as a metric to measure the effect of a risk mitigation action.

The oil and gas HFACS was applied for validation purposes to four Norwegian offshore accidents that occurred during 2007. The framework was suitable for these accidents and revealed that latent failures on the organizational level were most prevalent in particular failures related to oversight and procedures.[31] HFACS provides a common framework for comparison of accidents and incidents on many levels, e.g. within the industry, a company or installation. The framework can be useful to systemize accident information retrieved through an MTO approach.

Calculated Data

Safety starts with a well-developed drilling plan. Analyzing a new play for exploration or dropping in another development well requires calculation of important parameters just to understand the feasibility of the project.

For years engineers have been crunching through equations with slide rules, calculators and spreadsheets attempting to predict the basic variables required for well control of the new project. While these calculations are still an integral part of well planning, computer modeling and 3D simulations run the calculations in the background as engineers, geologists and petro-physicists ponder the results, making higher level decisions on how to best pursue the well strategy.

Developing the expectations of formation pressures for the project is one of the first steps for well planning and vital to the safe planning of a well. Formation pressure predictions are used as the basis for predicting safe mud weights to prevent fracturing the formation and preventing well kicks and selection of casing weights. Initial cementing design, kick control and selection of wellhead depend on the initial predictions of formation pressures which are then updated as actual pressures are encountered in the well.

Calculated variables necessary for establishing the initial basis of planning a safely executed well include but are not limited to:

- D Exponent
- Hydrostatic pressure
- Overburden pressure/gradient
- Matrix stress
- Pore pressure
- Formation fracture pressure
- Equivalent circulating density – ECD
- Equivalent static density – ESD
- Mud densities and additives
- Torque and drag
- RPM
- WOB
- ROP
- Cutting Volume

These variables are initially estimated with relative precision using modeling software and offset well information if available. The real value and improved safety margins are gained through real-time updating during the drilling process.

Drilling the well requires keeping up with additional calculations for well control. Several of which include:

- Leak-off Test Equivalent Mud Weight
- Maximum Initial Shut-In Casing Pressure
- Kill Mud Weight to Balance Formation
- Slow Circulation Rate
- Annulus Capacity Factor
- Final Circulating Pressure

- Surface To Bit Strokes, strokes
- Circulating Time
- Capacity Factor
- Opened End Pipe Displacement
- Closed end pipe displacement

Continuously updating these parameters through real-time processing is necessary in drilling HPHT wells to ensure the well is remaining within required margins to continue drilling safely.

Real-time Processed

Drilling, completion, production and general surveillance are all areas that benefit greatly from remote real-time analysis, providing significant value to operators through proactive, rather than reactive, responses to challenges during day-to-day operation. Several different disciplines that previously operated separately are today integrated in their work; both in the field and remotely, continual monitoring and remote data analysis includes and integrates areas such as drilling optimization, pressure management, pore-pressure predictions, and wellbore stability. Software models that utilize case-based reasoning and physics, together with real-time drilling and well data, enable immediate situational analysis and trend monitoring. Advice today is provided remotely, requiring fewer personnel at a rig site.

Post Processed

The analysis of trends over long periods of time will require post processed data. The data will be selected from a repository using the proper query to extract the pertinent data. The ability to post process data allows much more computing power to be applied to a problem. It also allows the discovery of long term trends that would be missed during real-time data analysis. This type of analysis is most commonly performed, but is not limited to, analysis of Geophysical Acoustic data. Post processed data can also be used to fuel a 'learning' system that can use previous data to predict the future reliability. This would be the electronic/ database equivalent of using lessons learned for future projects. The conditions of the collected data would need to be matched to the environment under consideration. An example would be to use pump failure rates compared to the change of seasons to be able to predict the most critical time of year to prevent pump failures. To properly correlate the data pumps from similar regions would need to be compared. Data from a pump in Alaska would not be a useful prediction tool for predicting pump failures in the Gulf of Mexico.

Modeling Tools to Prevent Incidents

Modeling has become an integral part of well planning and development, from the days of manually 'drilling it on paper' to the advanced three dimensional computer programs that help visualize the entire project before spud in. It's been said many times over that all the easy wells have been drilled. While the modeling doesn't necessarily make it easy, it attempts to take away many of the unknowns enabling informed decisions for the drilling process by optimizing economic options, analyzing production requirements, determining technical risks and estimating geological uncertainties. Planning for all these factors ahead of execution coupled with risk analysis leads to improved margins of safety.

Many commercial modeling tools exist for planning purposes. This section explores the scope of these tools, discussing in more detail those that enable exploration and production companies to produce at a higher level of safety.

Available Modeling Tools

Today's technology provides models for all aspects of exploration drilling and production processes covering the gamut from strategic planning to modeling of individual pressure sensors. Many of these modeling techniques are used to plan the well before the spud date. While others require data from the well being drilled to enhance the model to enable post drilling analysis. Below is a list of many of the process models:

- Strategic planning of E&P
- Risk based process simulations
- Geologic
- Geomechanic
- Geosteering
- Well control modeling
- Fracture modeling and simulation
- Hydraulics/equivalent circulating density (ECD) modeling
- Dynamic modeling of wellbore pressures
- Torque, drag and drill string modeling
- Bottom hole assembly vibration modeling
- Reservoir characterization models
- ROV operations simulations

Modeling Geomechancial and Hydraulic/ECD

Each modeling component above plays an important role in the overall improvement in well efficiency and more importantly, improved safety levels. Hydraulics/ECD and geomechanics, however are likely the most critical parameters to properly estimate, control and understand for safely drilling the well. Carefully predicting formation strength and planning for drilling within the narrow margin between the pore pressure gradient of the formation and its fracture gradient is vital for wellbore stability. Most important is that hydrostatic pressure remains within a safe mud weight window above pore or predetermined minimum stability pressures, below the fracture initiation pressure, and that adequate hole cleaning is achieved.

Fully understanding these ratios and the uncertainties in other operational parameters such as potential salt intrusions and potential changes in the planned formation lithology is crucial to the well planning process.

Simulating the expected formation and preparing for its uncertainties along with the wellbore and drilling fluid parameters ahead of drilling operations enables the planning team to prepare for uncertainties. Geomechanics modeling enables planners to closely approximate formation lithology enabling calculations of safe mud weight parameters, optimal casing points and provides for wellbore stability analyses. Formation uncertainties are a key focus in well planning. Data from offset wells drilled in the same field if available are analyzed and used to create the mechanical model to better understand the formations and hazards likely to be encountered. Assumptions are made about the field and calculations performed based on the data to estimate the pore pressure and fracture gradient establishing an appropriate drilling pressure window.

Operating within these narrow margins in many of today's 'critical' wells require careful planning for and monitoring of drilling fluid flow and densities. Hydraulic/ECD modeling is used to develop the equivalent circulating densities necessary for keeping mud weight within the tolerances of the pressure window. This modeling enables planners to predict optimum operating parameters for ROP, adequate flow rate for proper hole cleaning and recommended tripping practices to avoid the negative effects of excessive swab/surge pressures.[45]

Hargis et al. suggests combining the geomechanical and hydraulic modeling of the wellbore at the planning stage, merging the information prior to spudding the well. Updating each of the models with real-time data during the drilling process enables an accurate feed of variables to the other model. For instance, *"the geomechanics model can use real-time ECD data from the hydraulics model when a pressure-while-drilling (PWD) tool is not being used. In turn, the hydraulics model requires updating when the safe mud weight limits are being exceeded. The two models can use information from the other when performing the post-well analysis and planning for the next well."* [45] Used individually, these models are powerful tools, but when used together and combined with real-time updates, the models can more accurately depict the downhole picture allowing for a safer overall operation.

Modeling the Cementing Process

Before pumping cement into the wellbore and cementing the casing into place, engineers use computerized models to determine the complex flow of cement and fluids within the wellbore. Using real-time data from the wellbore including casing geometry, characteristics of fluids in the wellbore, volume, placement of centralizers and pumping rates, engineers run simulations to determine the characteristics of the cementing job. Simulations help predict pressures required to pump the cement and model the complex process of displacing the mud from the annular space.

Understanding of expected behavior is an important part of evaluating the potential effectiveness of the cement job. If the mud is not properly displaced during the cementing process, channels could form. This is important because if the mud is not fully displaced during the cementing process, channels could form creating a potential for hydrocarbons to flow and thereby compromising zonal isolation.

Modeling plays an important role in the oil and gas industry, but these simulations cannot completely and precisely model these phenomena and depends entirely on the accuracy of the input data. The model's overall accuracy is greatly improved with the use of real-time data inputs and continuously updated parameters. The more complicated well designs require models to help the engineers predict the impact of changing parameters throughout the drilling process. While the principles remain the same, every well is different and modeling with the use of real-time data allows engineers to optimize interrelated parameters for individual well conditions rather than relying on rules of thumb to guide complex decisions.[43]

Simulation

Simulations vary from simple computer programs to predict pressures, fluid flow and interactions to complex drilling human-in-the-loop visualization domes giving personnel rig experience without ever being on the rig.

Today's intelligent systems can only go so far in certain circumstances to automate a process. Fully automated systems will require a higher quality data stream from improved sensors at higher data rates through improved bandwidth. At the present time only real humans in the loop can accurately judge the final design. In many highly variable scenarios the human element is still better suited at processing changing variables, applying experience and judgment to provide necessary information to the system to determine the next course of action.

Human in the Loop Simulation

Human-in-the-loop (HITL) is defined as a model or simulation that requires human interaction that allows the user to change the outcome of an event or process.

HITL has been used effectively in training scenarios. Major airlines have utilized full motion HITL simulators for years to train pilots and provide the platform to administer the qualification checkride. The pilots' first flight in the actual aircraft is with a full load of paying passengers. These simulators fully immerse trainees in the syllabus requirements without the influences of real world distractions.

HITL is also used for knowledge acquisition in regards to how a new technology or process may integrate with or impact a particular event. When testing new equipment and processes HITL allows participants to interact with realistic models utilizing the new technology or processes and perform as they would in an actual scenario. These simulations bring to light issues that would not otherwise be apparent until after deployment of the new technology or process.

Operational Simulation

Not only can today's simulators use available real-time data, including surface and downhole sensor inputs, but they also serve to include all the different disciplines involved, enabling enhanced collaboration of all drilling activities. The addition of real-time modeling, using 3D gaming software, adds to the visualization and optimization of the drilling process.

The ability to evaluate the drilling plan prior to spud in date by validating, through simulation, key drilling parameters such as ECD, temperature, pore pressure, wellbore stability and torque & drag is invaluable. Further analyzing dynamic predictions of drilling parameters will reduce the potential of drilling hazards, such as kicks, wellbore instability, stuck pipe and lost circulation contributing to reduced risks and increased safety margins.

Integration of dynamic simulations of the different drilling sub-processes and their interactions is also simulated in real-time. Enabling both looking forward during the drilling process and 'what-if' evaluations. By providing real-time data to continuously updating drilling simulations, drillers, geologists, engineers and petro-physicists all monitoring the drilling process in real-time with improved awareness through:

- Seeing if the bit follows the well path plan
- Monitoring the bit going through different geology layers in real-time
- Monitoring the bit entering seismic information layers real-time
- Visualizing accurate depth by tally/BHA in real-time
- Visualizing the bit or tool joint going through the BOP or Casing shoe
- Visualizing well pressure profile and prediction of pressure when drilling ahead through linking real-time software models with real-time performance optimization analysis
- Reviewing the processes through a 'rewind' function[46]

Training Simulation

Training simulators utilizing mockups and visualizations of the rig environment are making their way into the industry attempting to provide experience where the industry is seeing a shortage in skilled labor.

These simulators provide an improved understanding of platform theory, concepts and knowledge of the plant functions and interactions. They accelerate learning and provide operating experience in normal and abnormal operations providing practice in operating procedures, plant startup, shut down and facility optimization.

A lesson should be taken from aviation simulation where the emphasis originally was also on procedural training ensuring the pilot was proficient in all normal and emergency procedures. He was expected to know exactly how to maneuver the aircraft within acceptable parameters. The simulators were very good at what they were designed to do, but the accident and incident reports were still indicating that pilots were making inaccurate and inappropriate decisions in normal day-to-day operations and when faced with emergency situations.

While evaluation emphasis in aviation remains on procedural proficiency, the pilots are also now trained and evaluated on application of Crew Resource Management (CRM) techniques. The essence of which is: how well the crew use its resources to manage problem situations utilizing interpersonal communication, leadership and decision making tools.

CRM training is the product of NASA research into the causes of air transport accidents. This research identified that aspects of the majority of the crashes were human error failures of interpersonal communications, decision making, and leadership. United Airlines was the first major airlines to apply CRM training processes in 1981 to reduce ‘pilot error’ by making better use of the human resources on the flight deck. All major airlines now employ CRM in their training syllabi.

In commercial aviation, aircrew are trained and evaluated for proficiency, usually on an annual cycle. At the major airlines these evaluations are normally done in a simulator where the evaluator can present adverse situations which pilots may actually see in flight only once in a career. The evaluation or checkride consists of an objective evaluation for procedural proficiency and a subjective evaluation of application of CRM while handling normal and emergency situations. Just like procedural deficiencies, in the event of identified CRM deficiencies, these pilots are retrained in the CRM skillset.

If rig simulation in the oil and gas industry is to be used to its fullest potential, consideration should be given to utilizing lessons and techniques from aviation simulator training, evaluation and CRM.

Modeling of the well environment prior to spud date is important to understand the project, its expected risks, costs and to enhance safety. The use of dynamic simulation programs incorporating real-time data during drilling; however, has contributed to a quantum leap in increased safety margins, reduced risks and reduced drilling nonproductive time.

The use of training simulators will also serve to improve safety through enhancing experience levels in the industry where relative experience has been dwindling through mass exodus. The addition of CRM training will do well to help the oil and gas industry avoid relearning the early lessons of failed crew interaction within the commercial aviation industry.

Conclusion

A true cultural shift is necessary in order to improve the safety of operations in the GOM for deepwater exploration and production. This sweeping statement is made to emphasize the necessity for a change of mindset for operators. The status quo is not sufficient to sustain safe operations in the long term. Operators will need to demand higher quality from their contractors. Updating quality of measurement, collection and monitoring systems to BAST (Best Available and Safest Technology) for the technical and human data elements along with advanced, predictive analysis open the window for improving the safety culture of the industry and lowering acceptable risk tolerance. Every well drilled represents new and different challenges than all previous wells. With new technologies and processes becoming available regularly, to mitigate risk factors in today's extremely challenging well scenarios.

Although improvements are occurring daily, much of the data currently collected from the rig is of varying low quality requiring experience and human interaction to place the data into context. Test scenarios and small scale deployments of these improved systems show great promise, but availability and relative cost thwart widespread use among operators.

The industry's recent change in BOP requirements have improved the standards for the maintenance and testing of BOP operation. Predictive analysis and lessons in critical parts management from other industries such as aviation should be taken into account when developing standards of care and health monitoring of the BOP.

Technological improvements have done much to improve the safety of the oil and gas industry, but 80% of industrial accidents still have human error as a causal factor. HFACS is an analysis and classification system that provides for a robust analysis, tracking and preventative safety program for the human element of the safety equation. Analyzing and tracking the root causes of incidents and accidents on the rig, within the company and industry-wide enables users to see deficiencies, monitor trends and put in place programs to avoid potential human failures as pointed to through HFACS findings.

Modeling and simulation has become an accepted standard for well planning. The ability to model all aspects of the well before spud date including pore and formation fracture pressures, ECD, ESD and fluid dynamics greatly reduces the risk of unexpected problems and increases margins of safety. Training through simulation has also seen a rise in the industry as companies are installing visualization training simulators to add experiential learning for otherwise inexperienced rig crews. Exposing rig crews to operational and safety procedures through simulation prior to employing these concepts in actual operations has worked well to improve safety in other industries such as aviation, maritime and more recently, healthcare. Adding CRM to the training syllabus is an important aspect of training individuals to work in a crew environment. The CRM elements of interpersonal communication, leadership and decision making are crucial skill sets necessary to master when working in a high risk environment of rig operations.

CHAPTER 5 - (Task 5) Technologies and Data Helpful in Measuring Field Performance of Critical Equipment to Predict Potential Failures and Replace Current Methods

Chapter Summary

Today's operators face a number of challenges. Among them:

- Increased energy demand
- Increasingly hostile conditions
- Lack of specialist domain expertise

Due to these challenges, operators have been forced to rethink traditional asset management techniques to increase productivity, operational efficiency and reliability.

In meeting these challenges, asset teams have employed new technologies and systems to help them quickly and efficiently integrate and analyze the increasing volumes of data.

The objectives for these systems are to provide visualization of actual drilling operations and system behaviors, to enable rapid and in-context diagnostic capability for increasing production uptime and assuring oilfield process optimization through reliability of equipment and increased efficiency.

A complicating factor in these systems has been the many, and varied, environmental and performance parameters experienced by the oil and gas industry which have presented substantial challenges to the collection of data. Many of the sensors used today rely upon electrical signals to sense conditions and to relay information.

The use of electrical equipment in the wellbore has reached a level that is limited by the physical properties of current technology.

However, newer technologies are overcoming traditional obstacles. For instance, the use of Fiber Optic cable has opened new methods of sensing conditions and/or performance of equipment and the downhole environment. The unique properties of the light, going down and returning up the fiber, have enabled new parameters to be sensed and reported.

The ability to gather data in large quantities with new sensors will pose new challenges to storing, retrieving, transmitting and processing information. The large amount of information available will require a disciplined and deliberate approach to extracting the desired information. Deciding on what information is desired will be the first challenge.

The methods used to process the data will be as important as the application of sensors. The challenge will be to organize the infrastructure to handle the data. The new data available will create new methods of making decisions. The knowledge necessary to derive decisions from the many terabytes of data will be a powerful asset to improve reliability and safety. These new processes for making decisions can be identified and properly applied by the industry.

Introduction

Task 5: Identify technologies and data that might be helpful in measuring field performance of critical equipment with the goal of predicting potential failures. Identify areas where this technology could be used to supplement or replace current inspection techniques such as visual inspection or pressure testing of equipment.

The purpose of this paper is to provide a survey of current sensor technologies employed today in the Oil and Gas Industry that quantify and report the performance parameters needed to properly assess the potential for failure. This report is structured to identify the parameters/conditions necessary to be collected, identify the sensors used, and provide an assessment of emerging technologies. The replacement of current inspection techniques with the advanced sensors identified is examined within the scope of the discussions about current sensor technologies.

Technology and Data for Measuring Performance and Predicting Failure

The business of reliability management is to keep equipment in working order while managing the costs, with a corollary that properly maintained and operating equipment will increase safety. Each firm's level of investment in condition monitoring instrumentation and information infrastructure will have a unique level of diminishing returns depending on conditions, For instance, the age of the well and the technology that existed at the time of installation can be an ROI challenge to the successful implementation of sensors and collection of sensor data.

In addressing return on investment, we have found that some companies have established, centralized collaboration centers and have re-engineered their work processes in order to break through this diminishing returns barrier. Others have initiated fledgling efforts aided by the robust industry of companies providing sensors and monitors.

In optimizing the information gathered, companies have been historically limited by the ability of sensors to continue to operate in the harsh environments of the Oil and Gas Industry. And while the technology for collecting data is wide ranging, it is performed largely by employing sensors using electrical signals to collect and transmit the data. It has been the need for secure electrical connections that has been problematic in harsh environments as there is a great deal of insulation and protection required to ensure these sensors continue to operate.

Sparked by recent events, the technological advancement of sensors deployed to collect data is beginning a revolution. The emphasis on collecting data from previously inaccessible areas has fueled the need for more advanced measurement systems that are using the complex physical properties of the sensor to report desired parameters. And while the majority of data collection today in the industry is performed with sensor technology that has seen little change in the last 30 years. The new sensor systems coming into use by the industry are opening areas where data collection was previously impossible or prohibitively expensive.

For example, the use of Fiber Optic technology has enabled exciting new methods of condition monitoring. The unique properties of a fiber optic strand have been shown to enable sensing of pressure, temperature, chemical composition, permeability, porosity and many other conditions not previously possible.[42]

Sensors

Until recently, the technology used to manufacture and employ equipment to capture the performance parameters of critical equipment and/or conditions has not seen much advance in the past 30 years.

Drilling rigs employed the same sensors that were first used many years ago. These sensors had limited accuracies and often provide intermittent measurements instead of the continuous measurements needed by real-time monitors. For example: Displaying the Weight on Bit (WOB) as loss of weight from the top of the drill string when it is measured as drill line tension near the drill line anchor point. Another example is mud weight measurement. This is still measured intermittently with a labor intensive mud balance.

Now, there is a new class of sensor on the horizon that could provide a large increase in quality, capability and coverage. The use of advanced sensors in locations and conditions that were not possible ten years ago is exploding. And while sensors on older wells are not commonly employed, almost every new well drilled has several sensors from the initial drilling stage to regular operations. For instance, the use of wired drill pipe has improved production, reliability, and safety enhancements such as Logging While Drilling (LWD) and Measurement While Drilling (MWD).

Transducers and Sensors

A transducer is a device that converts a signal in one form of energy to another form of energy. Energy types include (but are not limited to) electrical, mechanical, electromagnetic (including light), chemical, acoustic or thermal energy. While the term transducer commonly implies the use of a sensor/detector, any device which converts energy can be considered a transducer. Transducers are widely used in measuring instruments.

A sensor is used to detect a parameter in one form and report it in another form of energy, often an electrical signal. For example, a pressure sensor might detect pressure (a mechanical form of energy) and convert it to electricity for display at a remote gauge.

Virtual Sensors

It is possible to use sensors employed at different locations to predict the values between the two (or more) locations. With knowledge of the conditions and a wealth of historical performance it is possible to reliably predict the conditions encountered without the use of a physical sensor. The data collected by the deployed sensors is reconciled with the historical measurements from other events and interpolated to predict conditions that go beyond the immediate sensor locations.[47]

Data reconciliation is a technique that has traditionally been used in process control to verify measured data by reference to a process model. There is a more active form of data reconciliation in which a model of the process is used to estimate a number of unknown variables on the basis of other, known variables in the process. Such estimated variables may be seen as virtual measurements of the process; therefore estimators based on data reconciliation are sometimes referred to as virtual sensors. They are also known as software sensors or soft sensors, which distinguishes them from their hardware counterparts. Soft sensors may be used with great success in the operation of chemical processes for supplementing, and in many cases even replacing, permanently installed hardware.

There is substantial potential for soft sensors in offshore oil production. Even though the added value of permanently installed sensors is undisputed, downhole equipment is particularly expensive to install because of the nature of offshore operations. Therefore it is appealing to limit the number of downhole sensors to what is minimally required in order to get sufficient insight into the production process, and to use inferential techniques to make the picture complete. Also, it is widely recognized that downhole measurement equipment and the corresponding communication systems are prone to failure during installation in the well, during special events in the life of the well, or after a few years in operation due to harsh operating conditions. Furthermore, it is exceptionally costly to repair or replace downhole equipment in offshore wells. Software sensors, as opposed to hardware sensors, typically do not break down. In fact, even though a soft sensor depends on the availability of hardware measurements that may be subject to errors, it does not necessarily depend on the availability of a particular piece of hardware. A software sensor will work as long as the total set of available data contains enough information for the system to make a decision.

Fiber Optic Sensors

The use of Fiber Optic technology has enabled exciting new methods of condition monitoring. The unique properties of a fiber optic strand have been shown to enable sensing of pressure, temperature, chemical composition, permeability, porosity, etc. without the need for different sensors.

The requirements that drove early development of optical sensing systems were not supported by comparable electrical systems. These requirements included:

- Small physical size, allowing simple integration into small locations and embedding in composite structural systems.
- Multiple sensing point and measurement types on a single fiber, replacing multiple electrical sensors, instrument types and associated electrical wiring. This reduced system complexity and weight is critical in aerospace systems.
- Silica with high temperature fiber coatings, enabling the development of sensing systems for applications with operating temperatures in excess of 1,000°C.
- High reliability maintained by having simple sensing elements at the measurement point and the sensor's instrument in a readily accessible location for servicing or repairs.
- Immunity to interference from local radio or electrical transmission sources.
- No spark hazard, reducing the risk of fire.[48]

Fiber Optic sensors are beginning to replace current legacy sensors because of their advanced measurement properties and their robust nature. The multidimensional ability for one sensor to measure many different parameters is accelerating the introduction of these sensors. High accuracy distributed array temperature sensing, optical distributed pressure sensing, sand detection, and distributed strain (e.g. for riser monitoring), are just a few of the new generation of Fiber Optic sensing systems.

The utility of Fiber Optic sensors is a product of using light to sense and report conditions. In general, light is transmitted down the fiber optic cable. As the light travels down the fiber the environmental conditions experienced by the cable will affect the physical properties of the cable. The change in properties of the cable will impart conditions and characteristics on the light that is returned to the origination point of the cable. The returned light properties are sensed and reported.

Transmitting light down the Fiber Optic cable to generate a return allows many different methods to analyze the properties of the returned light. It also allows one Fiber Optic cable to be used to collect data along the entire length. The cable has shown the ability to collect data from points along its length at intervals as small as 0.5 meters.

Chemical composition

The novel use of fiber optic technology to sense that composition has only recently been discovered. The refractive and reflective nature of certain chemicals in a well are known physical properties that can be sensed and reported. The ability to use the sensed property to classify the chemical composition of a compound has been long established. The same properties that allow the sensing of chemical composition can be employed to assess the composition of the rock strata during a drilling operation.

The light reflected through a fiber optic cable can be sensed with a high degree of accuracy over great distances with little distortion. The stability and predictability of the properties drive its use to sense many physical properties. The properties imparted on the reflected light are easily quantified and the composition can be classified by comparison and contrast. A simple graphic example of this principle is shown Figure 11: Chemical Sensing[42]

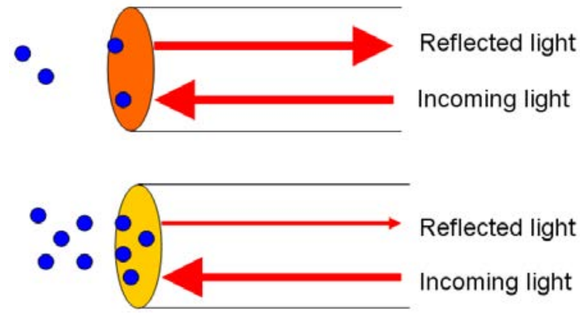


Figure 11: Chemical Sensing[42]

Limitations of Fiber optics

The use of fiber optics in the industry is in its infancy. It shows promise to become a standard technology for gathering data on exploration and production throughout the oil and gas industry. The ability to sense and report data that has been previously unavailable or too costly to collect will have a large, positive impact on the ability to detect potential failures. There are limitations that fiber optics should be acknowledged in their use. Measurement of visual conditions, corrosion, low frequency vibrations, geographic position, and time are best performed with different sensors suited to those parameters.

The largest hurdle for fiber optic systems is the reliability of the connector for the tubing that carries the fiber optic cable. The wet-mate connector for downhole completions with multi trip installation or upper completion equipment that needs to be replaced frequently has reliability issues. To properly transmit the reflected light the connection of the fiber optic cable must be mated with a high degree of quality. The constant connecting and disconnecting of equipment seriously degrades the quality of the mated surface and can corrupt data.

Fiber Bragg Grating (FBG)

The state- of-the-art in optical sensing technology includes Fiber Bragg Grating (FBG) based Pressure and Temperature sensors, permanent Distributed Temperature Sensing (DTS), Single- and Multiphase Flowmeters, and Seismic sensors.[42]

FBG is a simple, robust, linear, repeatable and absolute sensor. Making it ideal for long term subsea measurements. There are many applications of FBG that will produce different measurements from the same sensor.

It can be considered as a linear optical strain gauge responsive only to linear axial strain (i.e. strain along its own axis). The measurement of a strain gauge is very useful in drill pipe measurements. Many properties of the drill pipe can be determined using FBG.

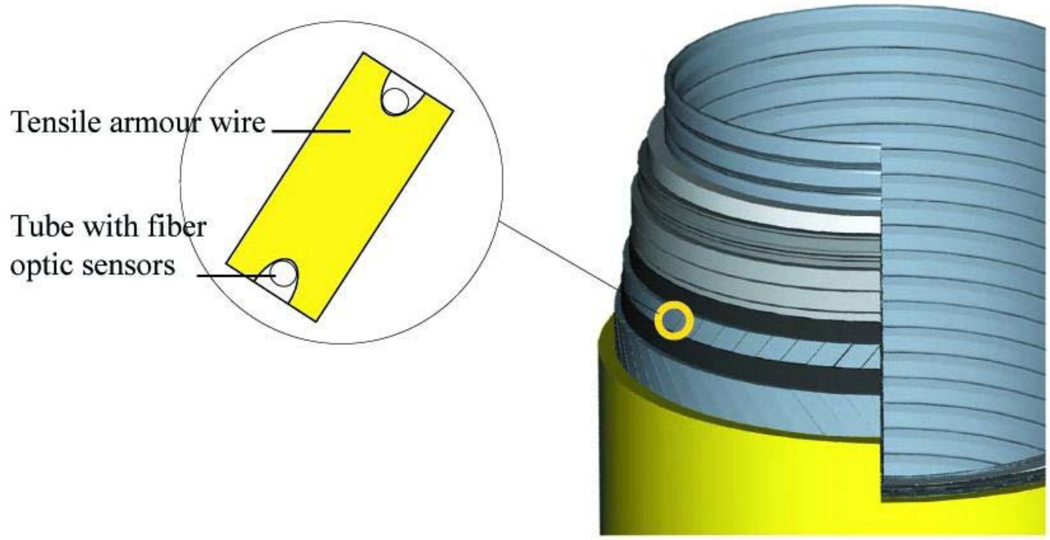


Figure 12: Drill Pipe use in FBG[42]

Application of FBG in a drill pipe is shown below. It is mounted in the collar of the drill stem and can report many parameters. An installation of FBG in a drill pipe is shown in Figure 12: Drill Pipe use in FBG[42]

During the last decade, wired pipes telemetry has emerged as a prevailing alternative to mud pulse telemetry. The current lower end of the data rate of wired pipes is 57,000 bits/s and it is expected that would be in flexible and rigid pipe systems. The long, distributed environment requiring measurement is well suited to applying

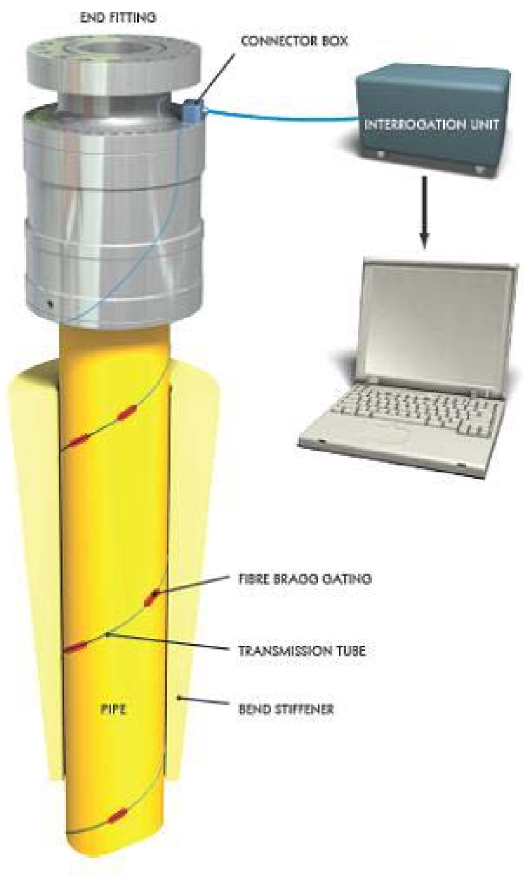


Figure 13: Use of FBG on a Riser[42]

FBG.[49] When connecting the FBG in series with a fiber optic cable the measurements of the cable can be 'distributed.' The nature of this will increase by 20 orders of magnitude to reach 1 Mb/s.[54] To take full advantage of wired pipe, such methods should be in place in order to ensure an optimal usage of the information for reducing the non-productive time and ensuring safe operations.

There are a seemingly limitless number of applications of FBG in the Oil and Gas Industry. The predominant use of FBG light reflected through the Fiber Optic cable allows measurements to be performed along the length of the cable. The desired measurement parameters are sensed at various lengths and reported to the head of the cable. A practical application of the FBG to measure strain in risers is shown in Figure 13: Use of FBG on a Riser[42]

Integration and Use of FBG

There are novel ways to employ FBG to report other parameters besides simple tension of drill pipe. Using the wide array of parameters available to be measured and reported when using fiber optic cable, the sensing and reporting of simple and complex measurements is possible.

Temperature

The FBG can be inserted in a material with a known coefficient of expansion (the ratio of expansion compared to the increase of temperature). The resulting expansion of the material will cause the FBG to measure strain. The strain measured by the FBG can be normalized to the coefficient of expansion to report the temperature of the material. Even though the material will expand in a uniform manner when heated, the installation axis of the FBG is important since it must be isolated from any strain present in the item being measured.[50]

The entire length of a fiber optic cable can be used to sense temperature. The ability to measure temperature along the length of the pipe is known as Distributed Temperature Sensing (DTS). An explanation of the physics of Raman and Brillouin backscatter that enable a strand of fiber optic cable to report temperature at intervals as small as .5m is beyond the scope of this document.

Pressure

Measurement of pressure in pipes without the need to create a hole to insert a sensor has benefits that can be quantified easily. The structure of the pipe is not weakened by adding an external port for the sensor and leaks are eliminated. The use of FBG sensors can be done in a non-invasive manner to measure the pressure in a uniform pipe as shown in Figure 14: FBG for Pressure Sensing[50].

The axis of the FBG strain is important to the measurement of the pressure being experienced by the item being monitored. Generally, pressure will expand a uniform item in a uniform manner. As the item expands due to pressure the strain exerted by the FBG will be measured and reported. The strain will be a linear increase proportional to the pressure inside the pipe.

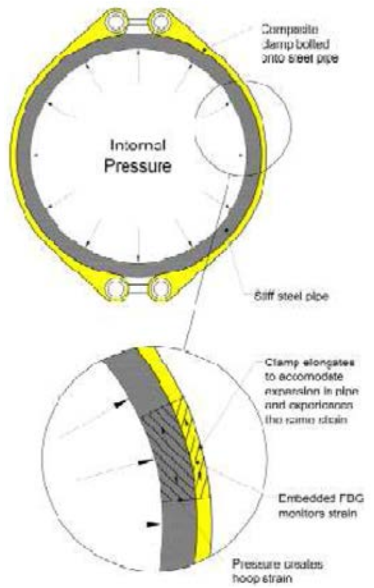


Figure 14: FBG for Pressure Sensing[50]

The application of the pressure sensor can be done at any interval desired and can be moved from the initial installed location to another location with relative ease. The application of an FBG pressure sensor to an undersea pipe is shown in Figure 15: Deep water Pipe Pressure Sensor[50]

Figure 15: Deep water Pipe Pressure Sensor[50]

The concept of a Distributed Pressure Sensor (DPS) is in development and shows promise by using polarimetry through optical time domain reflectometry. The high value of the information obtained from the DPS is fueling integration efforts.[51]

Weight

The ability to sense weight is derived from the relationship between the deformations of a material compared to the weight exerted. The relationship is linear until the material reaches the limits of elasticity and begins to permanently deform. The use of the FBG to measure weight is a simple application of the conversion tables for deformation with respect to weight.

Sound, Acoustics, Vibration

Recently, very good progress has been made in Distributed Acoustic Sensing (DAS) for hydraulic fracturing monitoring, production profiling for commingled oil and gas producers, injection profiling for water injectors, gas lift monitoring and the acquisition of wellbore seismic data such as Vertical Seismic Profile (VSP) surveys.[52]

Fiber Optic cable provides better response to acoustics and vibrations in the higher frequencies. The ability to properly report very low frequencies is inhibited by their relatively small effect on the fiber compared to upper frequency ranges.[53]

Flow

Optical, strain-based, phase flow rate measurements via turbulent structure velocity and sound speed of the turbulent flow is being implemented using FBG sensors. To measure linear flow it is necessary to generate non-linear flow into the stream desired to be measured. Turbulence is a series of pressure waves that propagate at the speed of the material. A graphical example of inducing turbulence is shown in Figure 16: Vortex Generation[51]. The turbulence is measured as pressure pulses on the sensor. The distance between the sensors is known and compared to the time between pulses to calculate flow rate in simple meters per second. The diameter of the pipe is used to determine flow in units of volume.

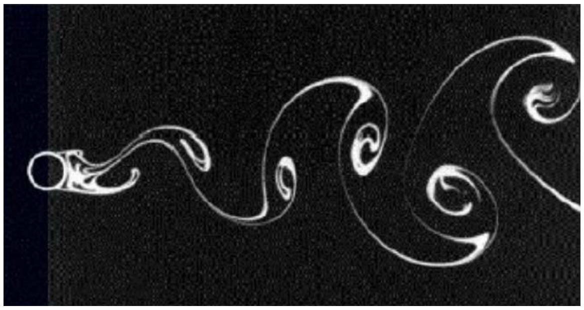


Figure 16: Vortex Generation[51]

Micro-Electro-Mechanical Systems

Micro-Electro-Mechanical Systems, or MEMS, is a technology that in its most general form can be defined as miniaturized mechanical and electro-mechanical elements (i.e., devices and structures) that are made using the techniques of microfabrication. The critical physical dimensions of MEMS devices can vary from well below one micron on the lower end of the dimensional spectrum, all the way to several millimeters.

Over the past several decades MEMS researchers and developers have demonstrated an extremely large number of microsensors for almost every possible sensing modality including temperature, pressure, inertial forces, chemical composition, magnetic fields, radiation, etc.

Remarkably, many of these micromachined sensors have demonstrated performances exceeding those of their larger counterparts. That is, the micromachined version of a pressure transducer usually outperforms a pressure sensor made using the most precise macroscale level machining techniques. Not only is the performance of MEMS devices exceptional, but their method of production leverages the same batch fabrication techniques used in the integrated circuit industry. This can translate into low per-device production costs, as well as many other benefits. Consequently, it is possible to not only achieve stellar device performance, but to do so at a relatively low cost level. Not surprisingly, silicon based discrete microsensors were quickly commercially exploited and the markets for these devices continue to grow at a rapid rate.

More recently, the MEMS research and development community has demonstrated a number of microactuators including: microvalves for control of gas and liquid flows; optical switches and mirrors to redirect or modulate light beams; independently controlled micromirror arrays for displays, microresonators for a number of different applications, micropumps to develop positive fluid pressures, microflaps to modulate airstreams on airfoils, as well as many others. Surprisingly, even though these microactuators are extremely small, they frequently can cause effects at the macroscale level. These tiny actuators can perform mechanical feats far larger than their size would imply. For example, researchers have placed small microactuators on the leading edge of airfoils of an aircraft and have been able to steer the aircraft using only these microminiaturized devices.

Use of MEMS by Oil and Gas Industry

The ability to sense relative motion is the prime application of MEMS. As such, MEMS devices are predominantly used for Strain gauges and for Seismic measurements. However, beyond these applications the ability to sense relative motion can be used in several novel ways to gain measurements of desired environmental qualities.

The device shown in Figure 17: MEMS Strain Gauge is a miniature device that can measure movement from a seismic event, elongations from applied tension, acceleration, expansion and contraction from temperature, and vibration. These measurements are all calculated from the motion of the ‘combs’ at the top and bottom of the picture. The center, dark grey section and the outer, white pieces are separate pieces that move independently. The movement of the ‘combs’ relative to each other can be sensed with very fine resolution.

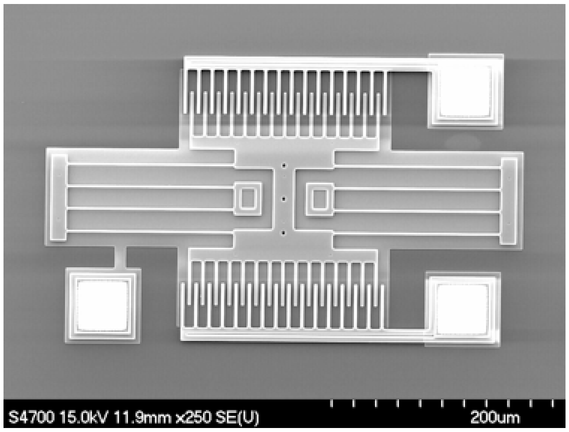


Figure 17: MEMS Strain Gauge

The use of MEMS in the Oil and Gas Industry has been growing as the technology becomes more resilient to the harsh environment encountered in normal operations. The small dimensions of the sensors enable them to be very sensitive. The small size also makes them more vulnerable to environmental forces that will damage the devices. The installation of the MEMS in the correct manner is problematic in a challenging environment since it is generally critical that the orientation and location be accomplished with the same precision as the manufacture of the device. Handling MEMS devices as wide as three human hairs is challenging, even in a laboratory condition.

Data

There is a multiplicity of names for the Digital Oil Field, coined by oil companies, some of which are Digital Oil Field of the Future, Smart Fields, Smart Wells, iField, iWells, eField, and Intelligent Field. For convenience and simplicity we combine all of these along with Fibre Optic Systems, Micro Seismic Systems, Pump Off Controllers, ESP Controllers under one catch-all acronym, namely DOF.

The Digital Oil Field (DOF) is a somewhat ill-defined, misunderstood and abstract concept. The associated functional content, scope of work and terminology is variable from company to company and vague within companies. Consequently it is unclear how to gauge DOF degree of success, business benefit and effective organizational penetration. The vision of the DOF and associated road-maps are sometimes unclear. With clear objectives, clarity of purpose and sufficient business justification there is a reasonable chance of meeting stated corporate goals. Without clarity of data all is shrouded in mystique and uncertainty.

The Digital Oil Field is based upon data. It is the foundation for all the analysis and decision making needed to ensure safe, efficient operation. The collection and handling of the data is important to ensure accurate data, pertinent to the desired results, is properly managed.

Data Collection and Storage

Collecting Data

Vast volumes of data are continuously generated in smart oilfields from swarms of sensors. While increasing amounts of such data are stored in large data repositories and accessed over high-speed networks, captured data is further processed by different users in various analysis, prediction, and domain-specific procedures that result in even larger volumes of derived datasets.

The science of collecting data has been rapidly advancing in the Oil and Gas Industry. The advanced physics and chemistry employed have given new reliability and utility to collecting data.

The collection of the data is a process that places a high importance on the accuracy of the data collected. The collection of inaccurate data is a useless endeavor that will at the least be a waste of time and, at worst, create dangerous conditions.

Data acquisition and pre-processing deal with issues such as; sampling, de-noising, removing outliers, compression, identifying missing data, and time synchronization.

The application of the proper storage principles is paramount to the quality of the data. The use of known database storage and retrieval techniques will be necessary to begin the task of data collection and storage. The database queries used by an administrator will need a specific skill for data mining the information useful to the oil and gas industry. Database software should be tailored to the needs of skilled users experienced with current techniques of oil and gas data storage and retrieval.

Choosing Data

To choose the correct data for analysis the goal of the analysis must be clearly envisioned. The terabytes of data that can be available must be filtered by selection criteria. The determination of the selection criteria will generate data that is useful for the prediction of reliability. Using data that is not pertinent to the stated goal of the analysis will provide the same results as using faulty or corrupt data. Choosing data is simple. Choosing meaningful data requires knowledge and planning. As data passes from system to system it can be mismatched. Sometimes you have multiple sensors measuring the same thing with varying results. This condition has to be rectified.

Cataloguing Data

The decision-making process in smart oilfields relies on accurate historical, real-time, or predicted datasets. However, the difficulty in searching for the right data mainly lies in the fact that data is stored in large repositories carrying no metadata to describe them. The origin or context in which the data was generated cannot be traced back, so any meaning associated with the data is lost. Integrated views of data are required to make important decisions efficiently and effectively, but are difficult to produce; data generated and stored in the repository may have different formats and schemata pertaining to different vendor products.

A challenge to the orderly collection and storage of the data is the practice of oil companies contracting multiple services for the well site with multiple data acquisition systems that are installed on the rig. The wide range of systems and sensors used to collect the data are difficult to merge into a coherent database. These systems have the capability to transmit real-time data to office locations for tracking but often do not include data processing systems to enable fast evaluation.[33]

Retrieving Data

The queries for retrieving data are not far removed from the logic that was used to catalogue the data. The use of database manipulators and Structured Query Language (SQL) to manage data held in a relational database is well established and a reliable link in the data management chain.

Transmitting Data

The current limitation for transmitting data from a remote location is the bandwidth required by Satellite Communication systems. The general current industry standard for data transmission is once per 10 seconds. This is a manageable amount of data with current transmission technologies. The bandwidth is easily exceeded if the data is transmitted at rate of once per second. The amount of data and the rate of data will determine the collection schema. The industry is aware of the limitations and do not install more sensors than can be handled by the data transmission pipeline extending down the well.

There is a fiber optic network in the GOM that does have the ability to transmit large amounts of data. However, the network was very expensive to install and is owned by BP. Bandwidth is available for purchase but the cost is quite high.

Real-Time Streaming

Oil and gas operators have a need to process, analyze, and react in real-time to increasing volumes and rates of streaming data in order to improve safety, compliance, and profit. For example, real-time analysis of streaming data from drilling rig sensors, intelligent wells, and digital oilfield installations enables early detection of drilling hazards and pending equipment failures, thereby reducing rig time, intervention, and shut-ins.

Problems with data include the lack of real-time integration of operational systems and an inability to maintain accurate and current information across all systems and data warehouses. Poor integration leads to duplication of data and systems, and a lack of visibility across all monitored assets, resulting in the delayed identification of the root cause of problems.

Analysis

Data analysis can be defined as the procedure used to transform data into knowledge for making decisions.

Real-Time

Drilling, completion, production and general surveillance are all areas that benefit greatly from remote real-time analysis, providing significant value to operators through proactive, rather than reactive, responses to challenges during day-to-day operation. Several different disciplines that previously operated separately are today integrated in their work; both in the field and remotely, continual monitoring and remote data analysis includes and integrates areas such as drilling optimization, pressure management, pore-pressure predictions, and wellbore stability. Software models that utilize case-based reasoning and physics, together with real-time drilling and well data, enable immediate situational analysis and trend monitoring. Advice today is provided remotely, requiring fewer personnel at a rig site.[54]

Post Processed

The analysis of trends over long periods of time will require post processed data. The data will be selected from a repository using the proper query to extract the pertinent data. The ability to post process data allows much more computing power to be applied to a problem. It also allows the discovery of long term trends that would be missed during real-time data analysis. This type of analysis is most commonly performed, but is not limited to, analysis of Geophysical Acoustic data. Post processed data can also be used to fuel a 'learning' system that can use previous data to predict the future reliability. The conditions of the collected data would need to be matched to the environment under consideration. An example would be to use pump failure rates compared to the depth to be able to predict the most critical depth for pump failures. To properly correlate the data pumps from similar regions would need to be compared.

Predictive Analytics (PA)

The use of data for predictions of future performance is the core principle of PA. Predictive analytics encompasses a variety of techniques from statistics, modeling, machine learning, and data mining that analyze current and historical facts to make predictions about future, or otherwise unknown, events. Predictive analytics is used in actuarial science, marketing, financial services, insurance, telecommunications, retail, travel, healthcare, pharmaceuticals, and other fields. There are very few instances of PA being used to enhance reliability in critical equipment.

An example of using PA in deep water oil exploration might be found in the study of deep sea equipment failures. If the data is properly collected, it can be charted to show trends that would be difficult to notice without looking at the results of a PA study. In this example the data would be collected on failures of a specific model of deepwater check valves on Blow out Preventers. The check valves will have a lifespan based on the number of applications. The valves will also have a lifespan that is affected by the depth they are employed. Collecting data on number of cycles and matching with data on depth the representative correlation can be graphed. An example graph using derived data is shown in Figure 18: Check Valve Probability of Failure.

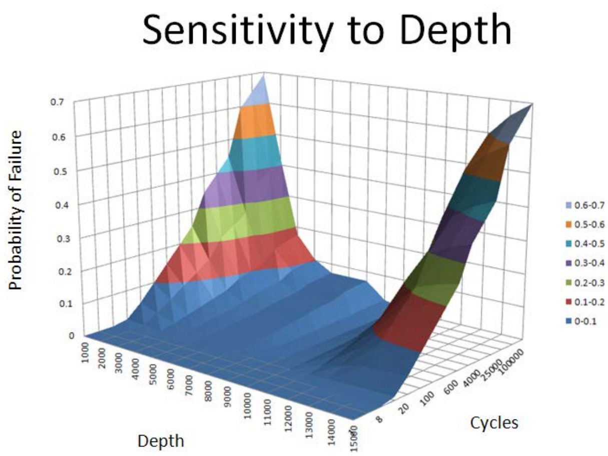


Figure 18: Check Valve Probability of Failure

The graph shows the probability of failure is when the number of cycles is small and it is not affected by depth. As the number of cycles increases, the probability of failure increases for shallow and deep applications. The check valves used in the 7000' to 9000' depth show little sensitivity to depth. This analysis would aid in the decision to use this model of check valve for applications at this depth range.

Further analysis could reveal that the seals of the check valves are not performing properly unless there is a sufficient amount of external pressure (depth). The seals work well at the proper depth but the reliability decreases and the probability of failure increases rapidly with installations at depths greater than 9000'.

The current use of PA by the oil and gas industry is focused upon predicting reservoir engineering capacity predictions. There is not much published evidence of the use of PA for predicting failure of critical equipment. This type of analysis is very data intensive and sometimes requires dedicated testing to gather the proper parameters.

Cooperation

Correlation

Correlation of data from many sources can usually reveal more about a system than the data from each source viewed separately. Most monitoring systems have software to check for abnormal behavior in the separate data streams. This could be a sudden large drop in temperature (perhaps from a breach of the outer sheath) or loss of signal from a strain sensor (perhaps from a broken tensile wire). However, if you look at all the data streams together, you can often see and identify impending failures earlier. In some cases, impending failures have a characteristic 'fingerprint' across the different variables that are being measured. A small change in one dataset would be invisible, but small changes in e.g. three separate datasets would be noticeable to software 'trained' to look for these patterns.[55]

For example, a small drop in temperature together with an increase in pressure and H2O vapor concentration could indicate an outer sheath breach, where the location of the temperature drop could be used to locate the position of the breach. This would greatly ease the task of locating and repairing the breach, thus also supporting the ROV search for the breach location. The challenge in this technique is of course learning to recognize the 'fingerprint' of the different failure modes. This will probably be done by a combination of previous experiences and a systematic collection of lessons learned during monitoring. However, the potential rewards of being able to correctly identify and prevent riser failures will certainly be worth the effort.

RTOC

The RTOC is a central location for data collection, storage, display, and analysis. The analysis provided by the RTOC can be used to monitor larger quantities of data and to enable detection of trends over large areas and/or conditions.

Workflow

In the past forty years the digital field technology has evolved from simply gathering data to making online analysis and real-time optimization. The industry also leverages the rig to reduce operational expenditures and capital expenditures by applying engineering workflows. The workflows can replace human work with a more efficient and quality job and/or provide proactive operation and optimization options. However, the Exploration and Production (E&P) industry are facing technical challenges due to the high volume of data collected and non-technical workflow challenges in keeping up with change management.

Knowledge Transfer

In studies performed by academia on knowledge transfer, the largest inhibitor to the proper transfer of knowledge was the generation gap. Inter-generational knowledge transfer requires recognition of the differences in preferred approaches to ensure the exchange is optimized. Much research has highlighted differences, for example in learning styles and communication channel preferences, between older and younger workers. Across cultures, different values, norms, and expectations can present roadblocks to effective knowledge transfer, to which many frustrated expatriate leaders will attest. The oil and gas industry has its own additional challenges: offshore oil rigs and remote sites can limit access to technology we otherwise take for granted. Together, there is any number of hindrances to the orderly and timely transfer of information from point A to B.[56]

Management

Knowledge Management (KM)

Important distinctions for knowledge management are the different concepts of knowledge. There is a distinct difference between data, information, knowledge, and wisdom. The relationship of these concepts is shown in Figure 19: Knowledge Pyramid.

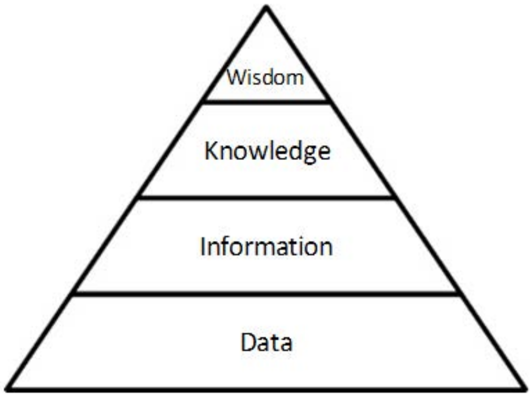


Figure 19: Knowledge Pyramid

IT infrastructure and organizational culture have significant importance in implementation of KM. The IT infrastructure will greatly affect the 'Information' and 'Data' levels of the pyramid. The organizational culture will shape the wisdom and knowledge of the pyramid.

Decision Making

The concept of decision-making can be broken down into four main parts:

- Gathering data about the problem or situation under consideration
- Generating ideas and alternative solutions to the problem situation

- Making the decision
- Communicating and executing the decision.

Hydrocarbon exploration is a complex, risk-based process based on uncertain scientific data. Decision makers are faced with different types of decisions during different stages of the exploration workflow. Relevant data reside in structured and non-structured repositories. Most data are spatially located and are connected through complex spatial relationships which make the data harder to model and visualize. New software allows the regional geologists to outline the play and assess the risks and attributes. It guides them through proper risk assessment and probabilistic uncertainty analysis of the proposed prospects and leads. All these assessments are compared against the play and regional trends. The risk and uncertainty of volumetric computations are handled using Monte Carlo simulation. Collaboration and knowledge sharing features help in reaching group consensus and reducing uncertainty. After drilling, the system captures post drill analysis which helps in identifying areas of poor predictive performances and possible remediation steps can be taken. This will in turn help in reducing risk and uncertainty of proposed prospects. Finally, the system provides an integrated view of the heterogeneous data and offers spatial analytical techniques such prospect historical analysis and prospect depth analysis. Exploration companies can create ad-hoc queries across the entire dataset to uncover trends and anomalies and then drill down to the details. Using charting tools and GIS analytics the data can be further analyzed to verify whether trends are real or anomalies explained.

The oil and gas industry has been advancing drilling automation concepts to increase safety, reduce drilling risk, and improve the overall repeatability of the drilling process. At the same time, increased drilling costs, available expertise shortage, and safety-related issues with personnel at the wellsite, have prompted the need to provide interpretation and advice remotely. Remote Operations centers enable subject matter experts (SMEs) to work on multiple, geographically dispersed wellsite operations concurrently without having to be on location. These centers facilitate the ability of multiple experts to assemble quickly and collaborate to solve complex challenges without adding the HS&E risk of additional personnel at the well site. However, the increased volume of information available from technologies like wired-pipe, combined with the shortage of experienced SMEs to quickly interpret datasets, create new challenges.

Digital oilfield applications have challenged operators and service providers to leverage remote capabilities to aggregate huge data volumes and provide expert knowledge for multiple operations. Focusing attention of personnel on the most important information to make accurate and timely decisions requires new techniques. New systems require automation so that risk recognition and advice can be automatically delivered to the right experts to streamline while-drilling decision-making.

New case-based reasoning technologies can compare the current drilling situation to similar previous case histories where problems occurred. This real-time decision automation enables identification of similar events that led to drilling problems on similar wells drilled in the past. From those historical cases, similar solutions are presented to avoid potential drilling problems before they occur. This while-drilling response provides the automated real-time connection between previous experiences and current operations that reduce drilling risk and ensure greater repeatability.

Areas Where Technology Can Replace Current Inspection Techniques

The use of inspection techniques to assess the integrity of equipment has been in place since the inception of the Oil industry. The practices were originally primitive and have since grown in sophistication.

The inspection of equipment is done to ensure integrity and fitness for service. The physical characteristics are assessed with emphasis on areas with high failure rates.

Inspection is one leg of the Inspection, Repair, and Maintenance (IRM) services. The ability to provide more cost effective inspection techniques is growing the importance of IRM services. The advances in technology have provided fuel to the reliance upon IR services.

Description of Nondestructive Inspection and Testing

Nondestructive testing (or Non-destructive testing (NDT)) is a wide group of analysis techniques used in science and industry to evaluate the properties of a material, component or system without causing damage. The terms Nondestructive examination (NDE), Nondestructive inspection (NDI), and Nondestructive evaluation (NDE) are also commonly used to describe this technology. Because NDT does not permanently alter the article being inspected, it is a highly valuable technique that can save both money and time in product evaluation, troubleshooting, and research. Common NDT methods include ultrasonic, magnetic-particle, liquid penetrant, phased array, radiographic, remote visual inspection (RVI), eddy-current testing, ferrite testing, hardness testing and integrity services (corrosion/erosion) and low coherence interferometry.

Current Inspection and Testing

Visual inspection and testing is currently performed in all phases of the Oil and Gas Industry. Some techniques are used in multiple areas.

Subsea pipelines and Risers

Radiographic, eddy current and ultrasonic devices are often deployed in subsea conditions to assess the in-service integrity of pipes and risers. These inspections are performed on the outside and inside of the pipe. The external inspection is performed by a human diver, an Autonomous Underwater Vehicle (AUV), or a towed sensor.

The underwater sensor generally uses a vision based assessment system. It assesses the integrity of the exterior and can document the presence of severe dents. Commonly, when a dent is discovered, the only available information is the actual pipe geometry (defect profile and remaining wall thickness).

The interior inspection is performed by a device known as a Pig. The Pig can be pulled, pushed, or move under its own power through the pipe. Pig inspections can be performed to assess the following conditions:

- Severity of wax and other debris.
- The presence of internal corrosion.
- The presence and severity of mechanical damage.
- The presence of pipeline shape changes (upheaval bucking, lateral buckling, sagging).

Testing in the construction phase includes automated ultrasonic, portable X-ray, and digital/ film solutions.

Re-injection stations

Rotating equipment requires regular nonintrusive inspections to help ensure the safe working of the machines. A comprehensive array of remote visual inspection, eddy current systems and unique software tools are employed to provide inspections and immediate reporting.

Offshore and land-based production

Asset integrity management and asset life extensions require inspection to provide assurance of component integrity and regulatory compliance. Inspection technologies, include continuous erosion/corrosion monitoring, remote visual inspection, digital radiography, ultrasonic thickness gauges and flaw detectors, X-ray technology and eddy current to inspect pipes, vessels and parts of a rotating plant.

Reservoir engineering

With high resolution CT, the spatial distribution of the pore network in a drilling core can be visualized and analyzed. Clear knowledge of such a pore system is important in the field of reservoir engineering. With advanced inspection techniques the wall of the well bore can be inspected.

Refining

Inspection is a critical aspect of maintenance and process management to help enable the safe and optimized operation of an oil refinery. Tools for high temperature corrosion monitoring of critical locations and piping, vessel and rotating plant inspection include ultrasonic, remote visual inspection, eddy current, digital radiography and X-ray.

Liquid storage

Storage tanks require inspection to help ensure they operate safely and within the regulatory standards. Tools for large area inspections include remote visual inspection, hydro-testing, and ultrasound technology for checking remaining wall thickness and weld quality.

Petrochemical

Nondestructive testing and inspection are part of IRM and process management and optimize the safe operation of a petrochemical facility. Current industry solutions offer high temperature corrosion monitoring of critical locations and piping, vessel and rotating plant inspections using ultrasonic, remote visual inspection, eddy current, digital radiography and X-ray.

Liquefied Natural Gas (LNG) liquefaction

Rotating equipment requires regular non-intrusive inspections. These include remote visual and eddy current systems. For new LNG projects, a large number of welds need to be inspected to ensure weld quality. Radiography and ultrasonic systems are used for weld inspection.

Compression stations

Rotating equipment requires regular non-intrusive inspections by remote visual inspection and eddy current systems.

Floating Vessels

The large investment in drilling ships and the remote location for their operation put a unique emphasis on the quality of integrity monitoring. The inspection of these ships includes:

- Hull inspection
- Underwater inspection in lieu of drydocking (UWILD) for classification requirements
- Accurate hull evaluation for life-extension purposes
- Assessment of floating assets prior to sale or conversion

Manufacturing

Testing and inspection of plate, billet, bar and pipe using ultrasonic and X-ray technology is performed to detect substandard material before it is used to construct critical components.

Replacement Technology

The process of performing integrity tests and visual inspections has not advanced significantly in the last decade. The technologies used in the past have been used in more novel solutions but there has not been a breakthrough system that has replaced the current industry standard processes.

There are several technologies that can be used to enhance and/or replace visual inspection and testing.

Finite Element Analysis/Modeling (FEA/FEM)

Finite Element Analysis/Modeling encompasses all the methods for connecting many simple element equations over many small subdomains, named finite elements. The small elements approximate a more complex equation over a larger domain.

FEA is a good choice for analyzing problems over complicated domains (like oil pipelines and mooring chains), when the domain changes (as during a solid state reaction with a moving boundary), when the desired precision varies over the entire domain, or when the solution lacks smoothness.

The application of finite element analysis to quantify the residual strength of the mooring chain and estimate remaining fatigue life can predict failures and extend the useful lifespan. A decision to extend the life of the mooring system can be made with a high degree of certainty based on the physical principles of the chain and the use of FEA.

An example of FEA applied to a mooring chain is shown in the figure below of the Finite Element Model of Chain.

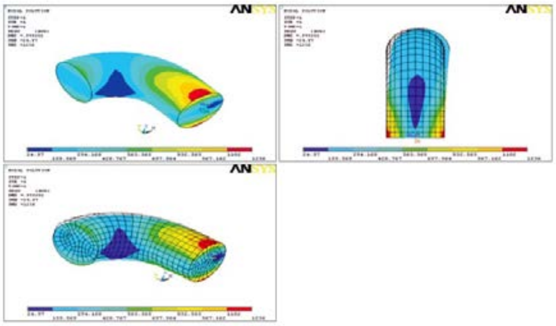


Figure 20: Finite Element Model of Chain

The information provided by the FEA can provide insight on unseen stress points and critical fracture areas. The colors on the FEA can correspond to areas of high stress. As shown above the red areas are predicted areas of high pressure and therefore the design can be modified to accept the additional load.

Using FEA can reduce the need for visual inspections by providing a more reliable product. An existing design can be analyzed to pinpoint failure areas. The knowledge of failure points is then used to influence procedures by avoiding usage of equipment in a manner that increases risk of failure. FEA can increase reliability and predictability which will have a related increase in safety to humans and the environment.

Corrosion Erosion (C/E) Monitor

Corrosion and erosion will decrease the amount of material in a structure or pipeline. The C/E can occur on the inside or outside of the pipeline but generally occurs on the outside of structure and vessels.

The thickness of the material under evaluation for C/E can be measured in very small localized measurement by ultrasonic transducers. Measuring the wall thickness of a 45 mile long pipeline ultrasonically is not practical. Measurement of the thickness of the material can be performed for the entire pipe by using a novel principle to average the thickness.

The measurement principle is based on dispersion of ultrasonic guided wave modes, and by using electromagnetism these waves can be transmitted through the pipe wall without the sensor being in direct contact with the metallic surface. It is installed on the outer pipe wall to produce real-time wall thickness information – not as a spot measurement, but as a unique average path-wall thickness. With several successful installations above the water line, the technology has now also been made available for subsea installation. The limitations for measurement and for reporting are still being explored.

Distributed Sensors

The use of distributed sensors has been used sporadically to replace inspection methods. The use of Fiber optic cable has accelerated the concept of using data from an array of distributed measurement locations. [52]

The distributed sensor will allow the development of a trend to be modeled. A prediction of the future movements of the trend can be made and the need for inspections and testing can be reduced or targeted to specific areas.

An example of using a distributed sensor would be to use Fiber Optic cable along the length of a well pipe. The sensing of the pressure along the length of the well can provide a log of pressure versus depth. If the pressure at a depth is reported to be outside the alarm limits for that section, an inspection can be made for only the areas where the pressure exceeded the alarms. Also, if the pressure was shown to have a sharp decrease, the pipe would need to be inspected only at the depth where the pressure decrease is occurring.

Visual Inspection

Vision systems employed by AUV and remote vision indicators have been using increasingly sensitive recognition software that can be post-processed to enhance clarity and allow automated pattern recognition software to detect abnormalities.

Laser

The use of lasers to produce two dimensional (2D) and three dimensional (3D) representations has slowly begun to be introduced into the oil and gas industry. The use of a laser as a tool to generate a composite picture of a critical piece of equipment has accelerated with the advancement of computing techniques to allow greater resolution of the returned signal.

The application of the laser to smaller areas has been enabled by reducing the size of the power supply required to produce a useful intensity of the laser. The small size and low power consumption of lasers has allowed them to be used for measurements by Pigs during evaluation of the interior of long sections of pipe where it is not feasible to bring a large power supply for the laser. The movement of large equipment around a congested rig floor is checked and monitored using lasers to ensure proper clearance during movements.

Conclusion

The recent innovations in sensor technologies have created a unique opportunity for the oil and gas industry to enter a new era of reliability for critical equipment. Using analysis and tools to help with data overload, the data being made available by new sensors will allow decisions to be made with a smaller margin of uncertainty. Currently, there is a fair amount of 'artistry' applied to the decisions in oil exploration. Among other factors, the intense amount of human interaction required when making decisions on future conditions or performance is a result of a lack of information from the wellbore or other areas in the production chain. And while the exploration and production areas may be able to deliver products without the very latest technology advances, operations can proceed more efficiently and with fewer incidents and accidents with improved sensor technology and modeling systems.

The fiber optic cable has shown the ability to provide data not previously available. The unique properties of light transmitted and reflected in the cable gives the analyst a new tool to collect information on conditions that provide valuable insight into the current conditions. The cable can be reliably used in lengths up to 5 miles for single mode usage. The ability to act as a distributed sensor is a powerful feature that gives an instantaneous picture of large areas under hostile conditions. However, the cable has limitations and cannot be used in all areas of oil and gas exploration and production. One of the limitations being that the connection between strands of fiber optic cable is critical and is very easily disturbed by violent conditions and environments.

Modern sensors have the potential to increase the reliability of all equipment used in the oil and gas industry. Giving operators the ability to better see current operating states and predict future conditions. The challenge to implementation for the new sensors will be that the collection of larger amounts of data will also require new, modern methods of data storage, transmission and analysis. The amount of data currently being recorded is a small subset of the total amount of data available as data handling pipelines and storage centers are not configured for the large volume of complex interrelated data.

The new sensors, and the ability to properly use the data provided, can replace many of the current labor intensive inspection methods. The removal of the human from dangerous inspection environments and the ability to make accurate, data centric, decisions has the potential to increase safety and protect the environment. The human will remain in the loop as a manager and decision maker.

CHAPTER 6 - (Task 7) Assessment of Automation Technologies Impacts on Human and Environmental Safety, Efficiency Improvements, and Cost

Chapter Summary

Automation in drilling and completion operations is coming quickly. Its rapid adoption creates a divide in the industry between those companies able to justify/afford automation and the companies clinging to the drilling practices of 30 years ago. Advances in control and automation of the whole drilling and completion processes will improve safety, performance, quality, reliability, consistency and interoperability. Progressive application of automation will also create shifts in skills and competencies, and transform the role of the driller, rig crew, and service specialists along the way. Advances in automation are being made on multiple fronts today, and many lessons are available from its adoption in other industries and the transformation it afforded in the 1990s.

Industry representatives collectively agreed that there will be a big jump forward in automation of well construction in the next 5 to 10 year time frame. Early adopters will likely progress when the vocal proponents of automation obtain funding for pilot projects. The primary application of autonomous systems will occur on multi well land locations where the drilling machines will become purpose designed for stages of the well construction operation. Interoperable systems will become plug-and-play; overall program management will be provided by remote control centers. This could occur within the next five years.

A new era in drilling is being ushered in by automation and the increased use of sophisticated sensors. Automation of the difficult and dangerous tasks in the oil and gas industry is opening the door to drilling ‘risky’ wells by improving the ability to closely control critical parameters. At the same time, the expansion and advances in automation enable it to be applied in an every expanding array of tasks and environments.

And while the primary driver of change in regards to sensors, data and automation may be the immense financial benefits that accrue with operational efficiency, these gains are also accompanied by an increase in safety and environmental protection. And with the corollary increase in safety, the reduced accident rate will also positively affect the bottom line.

Introduction

The requirements for this paper are to provide an assessment of the current automation principles and the automation available to the oil and gas industry. This paper details the impacts on human, environmental safety, efficiency as well as improvements and the cost to industry.

Task 7: Perform assessment of automation technologies and their impacts on human and environmental safety, efficiency improvements, and cost to industry.

The old focus on using automation simply to increase productivity and reduce costs was seen by the auto industry to be short-sighted, because of the necessary to provide a skilled workforce to make repairs to and manage the machinery. Moreover, the initial costs of automation were high and often could not be recovered by the time entirely new manufacturing processes replaced the old. Japan's 'robot junkyards' were once world famous in the manufacturing industry.

Automation is now often applied primarily to increase quality in the manufacturing process. For example, internal combustion engine pistons used to be installed manually. This is rapidly being transitioned to automated machine installation, because the error rate by a human for manual installment was around 1-1.5%, but has been reduced to 0.00001% with automation.

In the Oil and Gas Industry, automation is beginning to be accepted into areas where it is suitable. The places where automation is appropriate have seen small, simple systems that have been challenged by the diverse nature of tasks and the challenging environment. In these applications, the introduction of automated systems has put emphasis on the quality and robustness of the sensors to provide reliable data for control and monitoring.

The need for automation is being driven by difficulty in tightly controlling critical parameters during drilling operations for extremely deep wells. The 'easy' wells have been drilled and the remaining prospects are more challenging to drill efficiently and safely. The challenging reservoirs onshore and offshore are now being considered due to a lack of locations that are easily justifiable on a basis of return on investment.

Drilling complexity can be more pronounced in off-shore drilling. Challenges to deepwater drilling programs often include narrow, shifting, and relatively unknown drilling windows of mud weight margin between formation pressure and fracture gradient, kick-loss scenarios, risk of differentially stuck pipe, and wellbore instability. In addition, routine borehole strengthening operations and wellbore instability contribute to drilling window uncertainty. And many deepwater wells qualify as high pressure, high temperature (HPHT). Which adds complication in that the potentially serious well control incident rate for HPHT wells are 10 times the rate for normal pressure, normal temperature (NPNT) wells.[41,57]

Automation in the exploration for oil and gas has begun to be realized as an avenue for drilling high risk wells with more control to enhance safety. It is also being promoted for wells that were previously too costly due to the inefficient means used to control the drill string and fluids.

Definition of Automation

Automation has many definitions depending upon the source. In general, it is the use of machines, control systems and information technologies to optimize productivity in the production of goods and delivery of services. A common incentive for applying automation is to realize economies of scale and predictable quality levels through increased productivity, and/or quality beyond that possible with current human labor levels.

Automation is a step beyond mechanization. The metrics of improved productivity are relatively easy to quantify and catalog. There are also definitive health and safety benefits to using automated systems; however, sometimes the improvements in safety don't have units of measure and are harder to calculate. The removal of a human from a dangerous environment can be compared to historical values to show the decrease in human injuries and thereby an increase in safety. The reduced error rate can be quantified and shows a direct correlation to increased safety levels.

Automation greatly decreases the need for human sensory and mental requirements for conducting highly repetitive tasks while at the same time increasing load capacity, speed, and repeatability. Automation plays an increasingly important role in the world economy and in daily experience.

There are many applications for automation in today's society. The complete list would be too lengthy for this study. There are very few industries where automation has not been introduced, such as retail, mining, highway systems, waste management and home automation.

Mechanization

Mechanization provides human operators with machinery to assist them with the muscular requirements of work. The Industrial Revolution was made possible by the introduction of mechanical equipment. A representative list of mechanized equipment in use includes metal cutting machines, forges and presses, turbine generators, electric motors, trucks, tractors, harvesters, weaving looms, and power shovels. Agriculture was one of the first areas to introduce mechanization and it continues to employ mechanization at almost every step of the process. A weaving loom shown in Figure 21: Weaving Loom is an example of mechanization and replaced hundreds of workers.

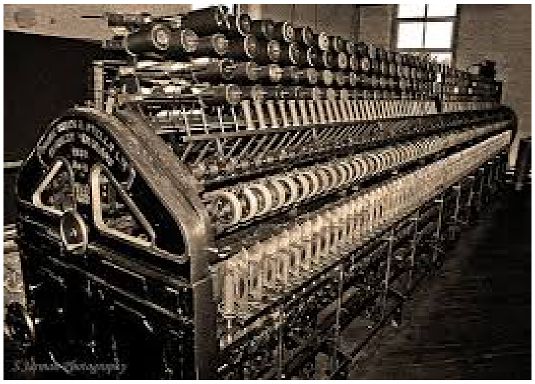


Figure 21: Weaving Loom[58]

An extreme example of mechanization is extremely large excavating equipment shown in Figure 22: Excavator.

Figure 22: Excavator

Two examples of mechanization of an oil and gas industry task are the pumpjack shown in Figure 23: Pumpjack and the make-up / break-out tongs shown in Figure 24: Tongs.

Figure 23: Pumpjack

These two devices use mechanical energy to assist or replace human muscle. The pumpjack operates without human interaction but the tongs need intense human physical interaction. Both are representative of places where automation can be implemented to varying degrees with enhancements to human and environmental safety.

Figure 24: Tongs

The use of high-output methods of mechanization of production in the oil and gas fields of Russia fostered an increase in the extraction of petroleum and gas and a rise in their share of the world's fuel balance. In oil fields, powerful drilling equipment (including rigs for drilling deep wells) is in use and multiple hydraulic drilling rigs, which perform lowering and raising operations separately and in which all drilling processes are mechanized and automated, are being introduced. The equipping of petroleum extraction enterprises with rigs designed and built for using automation is continuing. Gas pipelines with a diameter of 55 inches and an operating pressure of 1100 psi are used extensively to transport gas. The compressors and associated machinery have been designed to operate with minimum human interaction. As a result of the introduction of integrated mechanization and automation, the compressor stations of gas pipelines built in the arctic and other inaccessible regions of the country operate virtually without service personnel.

Agent Assisted Automation

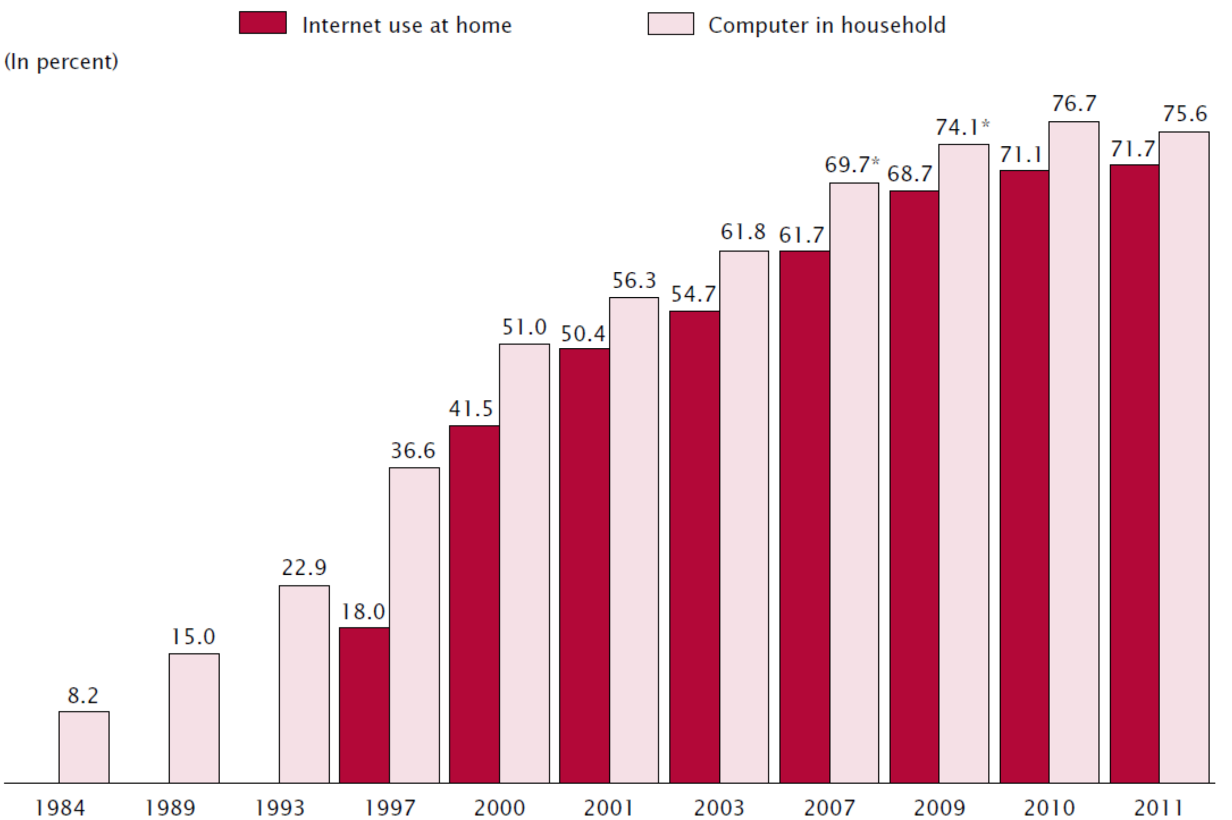
The lines of automation and mechanization blur when considering systems that are highly mechanized with small federated automation technology that are ‘operated’ by a human. This is also known as semi-autonomous operation. The level of automation can vary widely but the need for human interaction to perform the process is necessary. Many of the systems listed as mechanized equipment and automated equipment require human interaction to complete their task. Some do not have a task until directed by the human in the loop.

The large truck hauling away the cuttings of the excavator in Figure 22: Excavator is an example of agent-assisted automation. The truck has many automated systems to balance the load by sensing weight transfer, select the proper gear ratio based on terrain and load, adjust brake pressure to prevent skidding, and even adjust the temperature of the cabin. The truck and none of the systems attached will operate without the human at the controls. The need for human interaction is common in mechanized and automated systems.

Computer Automation

The use of computers to automate tasks such as adding numbers, formatting text, generating graphs, analyzing data, etc. has reached a plateau. Computer size has become smaller while memory available and the processor speed of the computer have increased at an exponential rate. However, new uses for the computer have not expanded at the same rate.

Moore’s law conjectures that the number of transistors on an integrated circuit will doubled every two years.[59] This prediction is still as accurate today as when it was first predicted in 1965. However, the use of computers by society has seen a movement toward game-playing and cloud computing that has resulted in a flat trend in the computing power of personal computers as shown in Figure 25: Computers and Internet.[60]



*Note: In 2007 and 2009 the Census Bureau did not ask about computer ownership. The estimates presented here for 2007 and 2009 reflect estimates made based on the ratio of computer ownership to Internet use in 2003 and 2010, respectively.
Source: U.S. Census Bureau, Current Population Survey, selected years.

Figure 25: Computers and Internet[60]

With the introduction of these devices the definition of 'computer' has become more ambiguous.

The remote nature of the current trend in computing can be seen in the oil and gas industry by the use of Real Time Operation Centers (RTOC). The RTOC receives data from many sources and remotely processes the data for monitoring progress, recognizing trends and health monitoring. If the trend seen in other areas continues the computing power at the site where the data is collected will be reduced to just levels necessary at the site. The timeframe for the distribution of computing power will be dependent upon the ability to justify the capital requirements and the ability to increase the bandwidth for transmitting data from the well site.

The use of 'automated' spreadsheets and graphical software to analyze and display the data has also reached a plateau. The new frontier for computers in automation will be provided by more sophisticated sensors to collect data and feed this data to the RTOC. The bandwidth available to the operators not using a fiber optic communications network will limit the amount of data that can be sent to the RTOC. There are very few installations that are limited by computing power but have an abundance of bandwidth.

The bandwidth limitation, along with network reliability and data latency will have a direct impact on the implementation of automation where it is remotely monitored. This is covered in Chapter 1(Task 1) of this paper. The ability to monitor an automated system remotely enhances human safety. If the automated system is monitored by personnel on the rig there is a limited improvement in safety. The loss of life and injuries from the Deepwater Horizon explosion could have possibly been reduced/eliminated by aggressive implementation of remotely monitoring automated rig operations.

Control

The control of an automated system is based upon a process requirement or a stated goal. A process requirement is more common in semi-autonomous systems where the environmental or process parameter or condition (temperature, pressure, etc.) to be attained and/or maintained is the target of the control system. An example of a process requirement is maintaining a desired weight on bit (WOB) during a drilling operation. Simply put, the control loop changes input forces to maintain the target number set by the operator. A stated goal is more common in autonomous systems where the target of the control loop is to perform a procedure. An example of a stated goal is to inspect and record the condition of an undersea pipeline. The autonomous underwater vehicle operates without human intervention to complete the procedure.

A closed loop control system that would enable autonomous drilling operation would include the ability to predict differences in formation structure and to adjust the WOB and fluid pressure to continue drilling without human intervention. The goal of this system would be 'Drill the borehole without fracturing the formation.' The sensors on the drilling rig would provide feedback to the control system that would automatically adjust the parameters to provide corrective inputs with higher reliability, greater accuracy, and greater speed than with human intervention.

An example of a simple control system is shown below in Figure 26: Control Loop.

Drilling operations are much more complex.

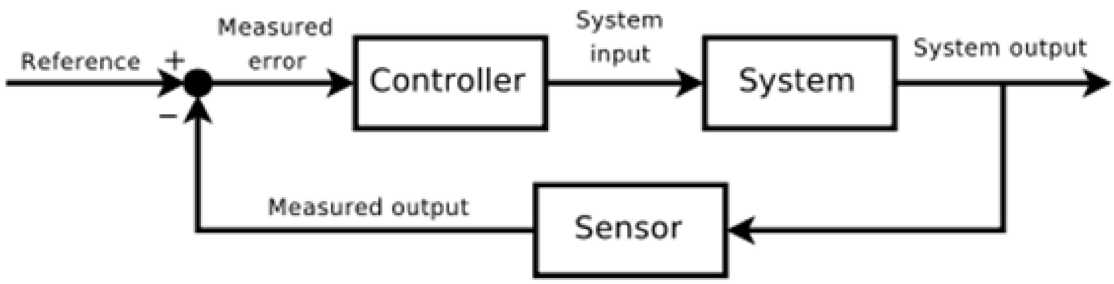


Figure 26: Control Loop

The ability for a system to operate autonomously requires a closed loop control system. The closed loop control system is a sophisticated computer software program that has complicated control laws based on modeled performance of the sensors and actuators. The closed loop system would be controlled by a separate controller that compares the current state and performance of the automated system with the desired state as set in the stated goal.

The control portion of automated systems has many different forms and capabilities. The levels of control, and the associated sensors providing information to the control loop, have a wide range of sophistication and abilities.

Process control, or machinery control, will convert a mechanized piece of equipment into an automated system. The mechanized Tongs in Figure 24: Tongs are considered 'automated' provided they have sensors to determine the location of the seam in the drill pipe; sensors to ensure the proper amount of torque on the drill pipe and the ability to move without human interaction. Figure 27: Automated Tongs shows the product of a simple sensor and control loop to properly tighten a portion of drill pipe.

The use of automated tongs can have a significant impact on the rate of pipe damage when compared to a manual system. The use of manual tongs and human make-up/break-out operations has an average damage rate of 14.7% for American Petroleum Institute (API) connections and double shoulder connections.

Figure 27: Automated Tongs

The use of automated tongs and pipe handling systems will greatly reduce the damage to the pipe and save considerable cost due to the expense of repairing/replacing specialty pipe used for extreme well drilling.[61]

Programmable Logic Controllers (PLC)

PLCs are prevalent in many industries and machines. Unlike general-purpose computers, the PLC is designed for multiple inputs and output arrangements, extended temperature ranges, immunity to electrical noise, and resistance to vibration and impact. Programs to control machine operation are typically stored in battery-backed-up or non-volatile memory. A PLC is an example of a hard real time system since output results must be produced in response to input conditions within a limited time, otherwise unintended operation will result.

PLCs are well adapted to a range of automation tasks. These are typically industrial processes in manufacturing where the cost of developing and maintaining the automation system is high relative to the total cost of the automation, and where changes to the system would be expected during its operational life. They have been introduced into the oil and gas industry due to their rugged nature.

PLCs contain input and output devices compatible with industrial pilot devices and controls; little electrical design is required, and the design problem centers on expressing the desired sequence of operations. PLC applications are typically highly customized systems, so the cost of a packaged PLC is low compared to the cost of a specific custom-built controller design. On the other hand, in the case of mass-produced goods, customized control systems are economical. This is due to the lower cost of the components, which can be optimally chosen instead of a 'generic' solution, and where the non-recurring engineering charges are spread over thousands or millions of units.

Enabling other systems

Automation requires that the system not only control sub processes, but also enable more complex intelligent systems to plan and react to real-time evaluation criteria and respond to predictive intelligence in real time. A well planned and purpose-built system will use data/information to enable a 'distributed' knowledge base. The use of automation will be a default condition of a distributed system that will rely upon, and enable, other systems and technologies to accomplish the desired task. When data is unlimited, direct human interaction will be an impediment to the operation of a system suited for automation.

Challenges and Pitfalls to Using Automation

Automation is not a panacea for solving problems. There are well documented challenges present for all applications of automation. The aviation industry is the leader in automated systems and can be used to predict the pitfalls of automation application in the oil and gas industry by serving as the example.

Mode Confusion

Mode confusion occurs when an automated system behaves differently than expected; in such a way that the operator is not aware of or does not properly understand what the system is doing. Mode confusion is well recognized in the aviation community and has been indicated in a number of high profile aviation accidents. As an example, a Jas Gripen fighter jet crashed during a test flight in the 1980s due to the pilot trying to manually correct instability while the plane's computer was automatically trying to do the same. The confusion about the automatic or manual mode of the flight controls caused excessive, and counteracting, inputs to be made.[62]

The potential for the same type of problems, and associated safety hazards, arises in drilling operations as a result of the increasing trend for automation and advisory systems. A simple example could be formation fracturing with an automated Equivalent Circulating Density (ECD) control system when displacing to higher mud weight caused by the driller relying on the automated system to maintain sufficiently low flow rate without having reconfigured the system with the new mud properties.[63]

Complacency

Accomplishing complex and difficult tasks on a routine basis will lead to a complacent trust of the system. It will lead to a sense of trust that will generate an environment where the automated system will be trusted to perform the task and little attention will be paid to the progress or performance of the task. The system will be allowed to operate on the edges of the acceptable envelope with little alarm or concern. Another example from aviation is the crash of an Airbus A-320 in 1988. Air France 296 crashed while doing an airshow flyover at minimum speed. The pilots were demonstrating that the computer system would compensate for errant pilot inputs (or lack of in this case) and keep the aircraft at a safe altitude and airspeed. The pilots' previous flying experience with this aircraft type led to overconfidence and complacency with the automated systems.[64]

Many factors can act upon the automated system to push it out of the desired parameters of acceptable performance. When an automated system is performing on the edge of its capabilities, catastrophic results can occur rapidly when the system ceases to operate automatically. Proper procedures for oversight and monitoring must be generated and practiced. The hallmark phrase for automation is 'Trust but verify.'

Preventative Maintenance

The equipment used to automate processes is complex and requires a dedicated preventative maintenance (PM) program. The majority of automated systems do not have the ability to suffer a failure and then revert to a backup system. The equipment must have a high degree of reliability, redundancy, and a PM program to ensure the required reliability is maintained.

High Reliance upon Quality Data

The automated system working in a semi-autonomous manner or in closed loop configuration has a heavy reliance upon quality data in a timely manner. At best, the lack of data, or the abundance of poor data, will render the automated system inoperative. At worst, the automated system will become dangerous and unpredictable. The accident investigation of the crash of Air France Flight 447 off the coast of South America discovered this as a contributing factor to the crash. The sensors feeding the autopilot performance parameters about the aircraft's airspeed were providing improper data indicating that the velocity of the jet was increasing. This was attributed to the blockage of a sensor by ice crystals. The autopilot disconnected and the pilots took control of the aircraft with manual control wheel inputs. The improper airspeed readings continued to be interpreted and the pilots applied improper manual control inputs that created a stalled condition. The reliance upon the computer generated airspeed and the disregard for other sensory inputs caused the condition to be misdiagnosed until water impact. The reliance upon the data provided by a faulty airspeed indication could have been reduced with practice performed in a simulator with unreliable airspeed.[65]

Improper Feedback

It is necessary to properly design the sensory perception used to regulate the amount and/or direction of human provided control force. If the feedback to the operator is improper, the assessment of the control input will be faulty. The resultant action desired by the operator will not correlate to the actual action of the system. An example of the feedback loop is in the fly-by-wire aviation flight control system. A conventional flight control system uses cables to connect the flight control surface (elevator, ailerons and rudder) to the control wheel or stick. Higher airspeed creates greater air pressure on the flight control surfaces making them harder to move with the cable system. At higher airspeeds it is important to avoid applying large control inputs that would create erratic and rough flight conditions that cause excessive airframe stress. The increase in force needed to move the flight control at higher airspeeds is a positive feedback.

In a fly-by-wire system the control wheel is connected to the flight control surfaces by an electrical connection that moves an actuator usually located near the control surface. The simple movement of the control wheel or stick will move the actuator. Since the connection is made by electrical impulses there is no feedback to the control wheel or stick on the amount of force needed to move the control surfaces. Without feedback it would be much easier to make control inputs that would cause excessive airframe stress since the force required to make the inputs does not vary with airspeed. An artificial feel system is incorporated into most modern aircraft to increase or decrease control wheel force with respect to airspeed.

Systemic Limitations

Other disadvantages of automation are:

- Security Threats/Vulnerability: An automated system may have a limited level of intelligence, and is therefore more susceptible to committing errors outside of its immediate scope of knowledge (e.g., it is typically unable to apply the rules of simple logic to general propositions).
- Unpredictable/excessive development costs: The research and development cost of automating a process may exceed the cost saved by the automation itself.
- High initial cost: The automation of a new product or plant typically requires a very large initial investment in comparison with the unit cost of the product, although the cost of automation may be spread among many products and over time.

Other Limitations

- Current technology is unable to automate all the desired tasks.
- As a process becomes increasingly automated, there is less and less

labor to be saved or quality improvement to be gained. This is an example of both diminishing returns and the logistic function.

- There are fewer remaining non-automated processes. This is an example of exhaustion of opportunities. New technological paradigms may however set new limits that surpass the previous limits.
- Maintenance of the automated systems becomes critical and strict Preventative Maintenance (PM) plans.

Replacing Humans

Many roles for humans in industrial processes lie beyond the capabilities of automation. Human-level pattern recognition, language comprehension, and language production ability are well beyond the capabilities of modern mechanical and computer systems. Tasks requiring subjective assessment or synthesis of complex sensory data, such as scents and sounds, as well as high-level tasks such as strategic planning, currently require human expertise.

In certain cases, the use of humans is more cost-effective than mechanical approaches even where automation of industrial tasks is possible. The return on investment for the capital outlay for automating a process often does not justify automation.

Processes where there is a large variation in the dynamics of the task to be performed, such as the timber industry, have shown the limits of using an automated machine to replace a human. Until recently, the drill rig floor was an area that presented a challenge to introducing automation.

Automation works well and is easily justifiable for a repetitive task. Tasks that do not repeat often may be suitable for automation but may not be justified by return on investment. For example, the use of a robot to deliver the radioactive material used for logging a well may be difficult to justify if it is only used several times during the drilling process and not used for any other task.

There are tasks where automation cannot replace a human. The dexterity of the human musculoskeletal system and the ability to adapt to new environments cannot be matched by any machine. The agility and range of motion provided by the human shoulder is not replicated in robotic equipment. The seemingly simple task of cutting hair has not been approached by any robot or automated system. The athletic ability required when performing figure skating or the pole vault are not close to being attained by any form of automation or machine. The unique ability to move and think has made the human hard to replace in certain tasks.

Assessment of Current Automation Technologies in the Oil and Gas Industry

Areas using Automation

Automation of the oil and gas process is in the initial stages of implementation. The business case for the implementation is beginning to be realized.

Fluid Control

The hydraulics of conventional drilling was developed over a century ago. The concept of rotary rigs, weighted mud systems, and jointed pipe in use today were developed early in the 20th century. They have been vastly improved and have grown larger but the basics are unchanged.

One improvement in technique and technology, Managed Pressure Drilling, (MPD) opens previously unattainable reservoirs to exploration. This access comes at the cost of complexity and the need for improved sensors. The MPD well is drilled using very tight tolerances for the pressure of the fluids in the column. It is important to control correctly, and quickly.[66]

The need for automation during fluid control has become more critical due to the nature of the wells being pursued and the nature of MPD. The need for tighter control of the parameters of the fluid column can be seen in the incident rate for Gulf of Mexico oil wells as shown in Figure 28: Fluid Control Incidents. The chart shows that 48% of incidents were the result of pressure related events.

The 'state of the art' MPD for deepwater drilling operations is practiced with semi-automatic or PLC controlled automatic choke systems. For offshore applications where the objective is to drill into narrow or relatively unknown margins between formation pressure and fracture gradient, a PLC controlled choke manifold followed by a gas chromatograph are the tools of choice.

MPD has also enabled Riserless Dual Gradient Drilling. The riserless drilling technique uses an automated subsea mud pump that is connected to the well annulus to return mud and cuttings back to the surface. The pressure generated by the seawater column above the pump is significant and is used to assist the seafloor pump with maintaining the proper wellbore pressure. The pump system is used to detect small well instabilities and provide data to the automated drilling system.

The need for frequent testing on the rock formation is a critical component of the MPD process. The tests ensure the formation can sustain the pressure of the fluid column. If the sensors used for the testing produce data that is erroneous the wellbore will have a greater risk of suffering a formation failure and the fluid will escape. Another result could be a lighter Equivalent Circulating Density (ECD) that would allow a kick.

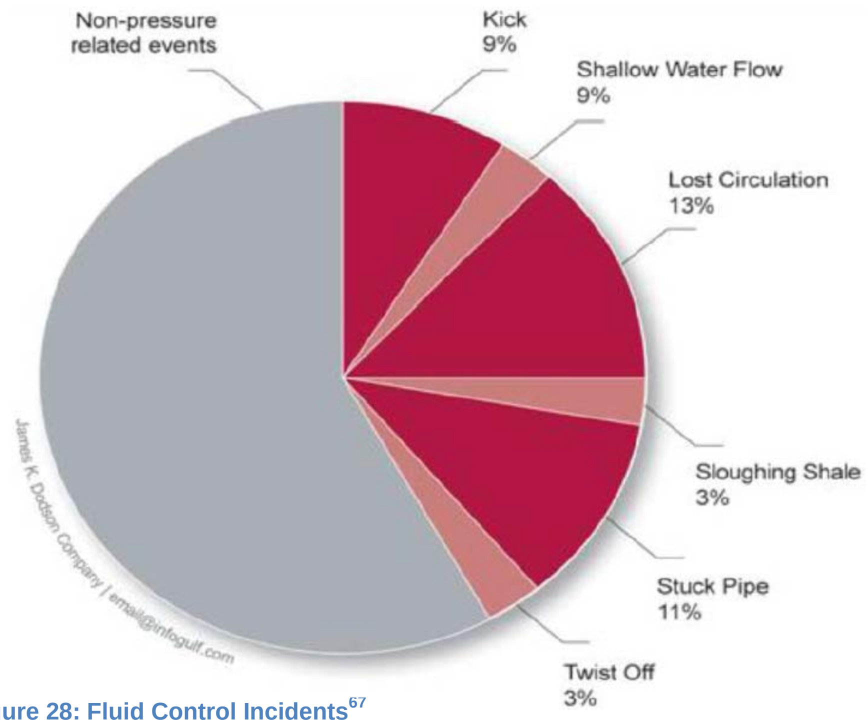


Figure 28: Fluid Control Incidents[67]

MPD has enabled the industry to drill HPHT and narrow margin wells with reduced risk. A survey has indicated that offshore drilling decision makers believe that within 5 years (2019) approximately 40% of offshore wells will be practicing MPD in some capacity Figure 28: Fluid Control Incidents.[67]

Drilling

Drilling is still at the level of automating basic functions that either cannot be controlled manually, such as dynamic positioning systems, or are better performed automatically, such as auto drillers and MPD with auto-choke controllers.[61]

The process of turning the drill string is relatively simple to model but challenging to automate. The physical values of acceleration, torque, axial velocity, friction, heave (for floating rigs) and weight on bit (WOB) are measured and compared to the modeled values. The accuracy of the modeled values is assessed and the ability to make predictions using the model is aided by a more reliable prediction. Automated adjustments to the Top drive and Draw works, based on these parameters, increases efficiency of the drilling process and creates a safer, more predictable environment.[68]

Continuous Motion Rig (CMR)

The Continuous Motion Rig (CMR) is a product of automation of the process performed by the derrickman. It uses a double hoisting system to provide continuous, uninterrupted motion of the drill string or casing in and out of the wellbore. In addition the drill floor and corresponding equipment are designed in a compact manner allowing for fast short movements to and from the well centerline to enable automation.

The basic system components of the CMR are shown in Figure 29: Continuous Motion Rig. The system consists of two hoisting systems (A and B), A retractable tool holder (c and d), and a set of tongs and slips (e and f). The grabber, tool carrier and tool slide are not shown.

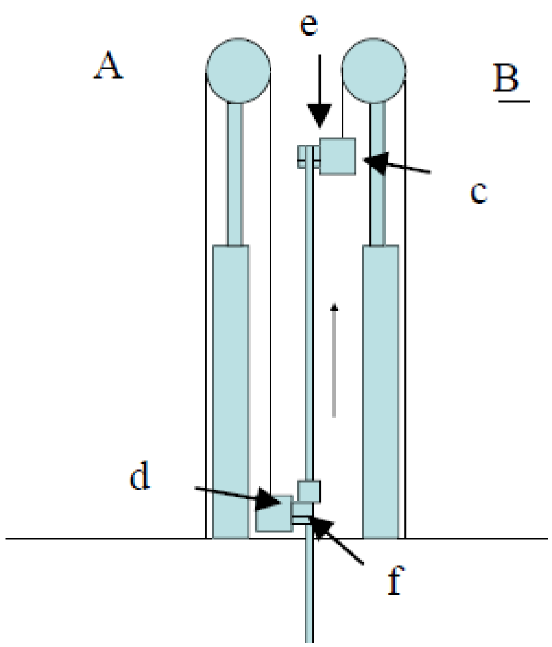


Figure 29: Continuous Motion Rig[69]

The benefits of CMR include:

- Personnel Safety by removing people from harm's way
- Wellbore stability from constant travel speed
- Improved tripping speed
- Avoiding differential sticking
- Significant improvement in time to run casing
- Facilitates built-in continuous drilling and circulation by using two tool holders
- Compact drill floor facilitating automation or roughneck operations
- Reduced power consumption
- Reduced equipment wear
- Redundant hoist equipment

Challenges exist in the automation and sensor aspects of CMR. Well construction will benefit from continuous movement by avoiding swab and surge forces and thereby increasing wellbore stability.[69]

Robotics

The use of robotic devices on the rig floor has been proposed. The use of robots can bring an increase in safety by removing people from a dangerous environment. They can be used to perform tasks that are environmentally unsuitable for humans such as handling radioactive material used in MWD/LWD. The robot shown in Figure 30: Robotic Roughneck is performing the task of the roughneck on the rig floor. The use of a robot to replace the roughneck is still in the research phase. The difficulty of replacing the human is showcased in this job. When exposed to the range of tasks needed to be performed on the rig floor, the agility and dexterity of the roughneck have not been attained by a robot or any mechanized object.

Robots are not well suited for occupying a work area with human co-workers. In industries where large automated systems are used, human interaction is tightly

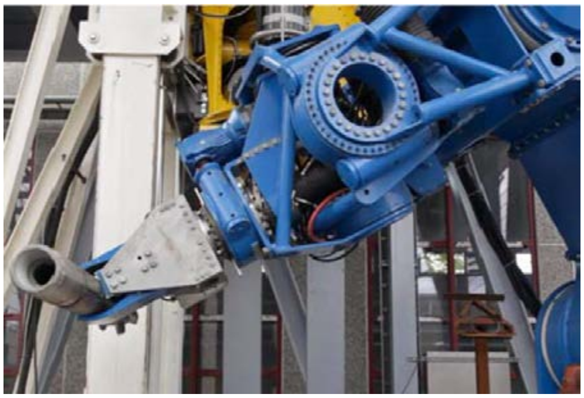


Figure 30: Robotic Roughneck[70]

controlled or prohibited when the equipment is operating. The reason is that the sensory locations in the workspace and the software capabilities are not suitable for sensing the presence of new objects at variable is not capable of avoiding a collision when the conditions change. It makes more sense, from a safety standpoint, to make all the tasks robotic or to make none of the tasks robotic.[70] The rig floor is a place where there should not be a mix of automation and humans performing makeup and/or breakout operations.

Pipe handling

During Tripping the drill pipe must be racked/unracked and placed in the proper position. This is a dangerous job performed by the derrickman from a position on the upper structure of the derrick. The ability to automate the job of the derrickman will remove the human from a dangerous environment by performing a highly repetitive task. The Iron Derrickman® (Weatherford) shown in Figure 31: Iron Derrickman is capable of tripping double and triple stands of drill pipe.

Figure 31: Iron Derrickman

Automated Tongs

As previously shown in Figure 27: Automated Tongs, the use of automated systems to replace human operated tongs and/or agent assisted tongs is an area where justification of the cost of automation is possible due to the repetitive tasks and the dangerous working conditions. Cost savings have been realized by removing the operator and providing tighter quality control of the operation. Mitigating the loss of life or loss of appendages is a large return on investment.

Cementing

Some deepwater wells have been difficult or impossible to execute on primary cement placement by manipulation of the traditional variables of cement density, flow rate, viscosity, and staging devices. Heave due to wave action on floating rigs can also contribute to the challenges of successful cementing operations. Automated features of MPD allow other tasks similar to mud management, such as cementing, to be performed with greater control and better performance on HPHT wells and other challenging drilling operations.

Fulfilling the requirements for proper cementing in challenging conditions is greatly aided by the application of an automated Closed-Loop Cementing technique. The data acquired when using an MPD system provides additional and more accurate information for improved onsite and offsite decision making during cementing operations. The data also provides inputs for improved hydraulics modeling, cementing, and wellbore behavior predictions. Additionally, the data could be a candidate to serve as documentation for regulatory compliance purposes.[61]

In addition, the advances in Riserless Dual Gradient Drilling are used to enable Riserless Dual Gradient Cementing. The automated pumping system is used to circulate displacement fluid, spacers, and cement back to the surface in a closed loop system. The pump system is also used to manage pressure to decrease pressure when the cement reaches a critical/weak zone within the open hole to avoid fracture and losses.[61]

Remotely Operated Vehicles (ROV)

The use of ROV for subsea procedures and inspection has been solidly established. The ROV is semi-autonomous, requires operator input to operate, and is tethered to the control station. They have been used most commonly to replace divers at depths and/or conditions not conducive to human operation. They also have the ability to operate at these depths for extended periods. They are employed to perform simple observation and/or data collection, light work and manipulation, and heavy work using hydraulic driven end-effectors.

ROVs in use today are generally limited to a speed of 2-3 kts and cannot execute station-keeping activities to ‘hover’ in heavy currents. They have been outfitted with increasingly sophisticated forward looking sonar sensors and modern navigation systems.[71]

Autonomous Undersea Vehicles (AUV)

The use of the AUV for undersea inspection requires a closed loop control system that operates without need for constant operator input. The AUV is used for broad area surveillance and feature recognition. The AUV is limited by the sensors used for surveillance, navigation, 3-D mapping, and feature recognition.[72]

The AUV operates on a goal-oriented set of instructions. It uses onboard navigation systems to provide accurate geolocation to correlate the information provided by the sensors.

Oil and Gas Equipment Manufacturing

Some manufacturing operations used to construct the machinery used for exploration and production are suitable for automation. The manufacturing of oil and gas equipment has realized the benefits of tighter tolerances and higher quality from introducing automation. The tasks typically performed by automation include cutting, milling, boring, painting and testing. The need for higher quality in the equipment is being driven by the tighter tolerances required by the increase in high risk / difficult wells. The devices and machinery used to automate processes used to construct oil well equipment have mirrored those in other manufacturing industries.[73]

Impacts on Human Safety

Human safety can be positively influenced by introducing mechanization to aid in the physical requirements of the task, removing the operator from the dangerous environment, or by removing/mitigating the hazards.

The study of Human-Machine Interaction (HMI) is a well-established field and will not be expanded upon in this study.

Mechanization

Mechanization is beginning to reach the limits of physics and space constraints. There are very few instances where there is not enough hydraulic power to complete a task using a tool handled by a human. The use of mechanization paved the way for automation.

In some instances of mechanization the application of forces larger than possible by human physical exertion creates an unsafe environment. The ability to apply great force requires positive control and the ability to monitor the application of force. Lack of attention to the application of force can end in disastrous results. Using a control loop on a mechanized task provides the necessary monitoring.

Removing the Operator

Removing the operator is an obvious method of improving safety if the environmental hazards cannot be mitigated or removed. The operator can be moved to a remote location or can be eliminated by using automated systems that can perform the tasks with little or no physical human interaction/presence.

The most hazardous and physically demanding jobs in the industry are the roughneck and derrickman. These jobs present great risk from close interaction with heavy machinery and large physical forces. The injury rate is high and well known as one of the world's most dangerous jobs. Removing the rig workers from close interaction with hazardous conditions is being done by some companies.

The iron roughneck and iron derrickman are products available in various forms of automation and control. In a partially automated system the operator moves the automated tongs into place for the make-up/break-out operation. The fully automated systems use a vision system to guide the automated tongs to the drill pipe seam.

The oil industry has reported a reduction in experienced crews to operate the drilling rigs. When oil was hovering around $10 per bbl there were few wells being drilled and many skilled workers went to other industries. As prices have risen, and drilling has increased, this has left a deficit in experienced labor. An iron roughneck or iron derrickman has the ability to greatly reduce the need for skilled workers by replacing the most dangerous positions with automated systems.[74]

Removing the Hazard

For some oil and gas applications it is not feasible to remove the operator. When this is the case automation can be used to decrease or remove the hazard.

Information overload

During Critical, high intensity drilling operations the driller can be overloaded with inputs and tasks. Automation can solve the information overload by reducing the physical workload and changing the nature of the work to that of manager/monitor.

A well-established principle of aviation is that automation of physical tasks allows the pilot to perform more cognitive tasks. As shown in Figure 32 - Physical and Cognitive Workload there is an inversely proportional relationship between physical tasks and being able to provide mental acuity. Automation in aviation has greatly increased safety by allowing the pilot to spend more time managing and planning and less time reacting.

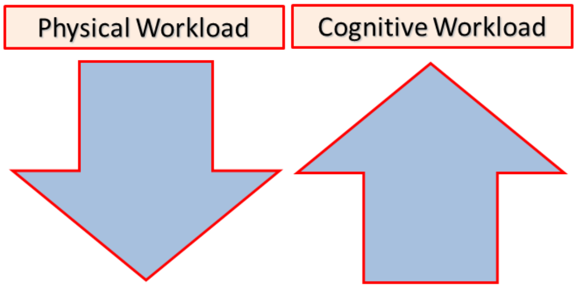


Figure 32 - Physical and Cognitive Workload

The human factors impact on automation is multi-faceted. Many of the issues relate to the human interaction with an automated system and how condition information is relayed to the human in such a manner that an appropriate response follows. A significant amount of expertise is available to identify and address the issues as an automated system is developed.

Real time monitoring systems are being developed that ensure human and automated actions are effective and auditable. Furthermore, the selection of the level of automation and skilled operator interaction must be defined based on the work system being automated. Critically, the operator workspace must be designed ergonomically to reduce stress from environmental effects and to display effectively the information required through content/layout enhancements.

Human Error

Human error can be physical errors or cognitive errors. Automation of physical and mental tasks has shown to reduce or eliminate human error. Below is list of six common, but by no means exclusive, causes of human error and how automation can eliminate/mitigate the errors.

Stress induced fatigue – replacement of a human by automating tasks that are repetitive and/or hazardous

Poor coordination/communication between team members – Automation equipment has a specific and well defined communication and coordination protocol that must be employed to create order from the chaos of the tasks and/or environment.

Inadequate operating procedures – Automated processes follow established procedures with little deviation. The challenge for automated systems is to have the correct procedures programmed.

Insufficient/inadequate information – Automated systems require and provide great amounts of information. The skill of the developer in creating the automated system will fill the information void.

Information overload – Automated systems create usable representations to the human that eliminate information overload

Insufficient training and/or practice – Automated systems do not require training.[75] Although one of the main objectives of automation is to reduce human error, several studies suggest that the introduction of automated decision aids does not unilaterally lead to a reduction in human error, but instead often simply creates opportunities for a different class of errors.[63]

Impacts on Environmental Safety

An accident free oil and gas industry will not have an adverse environmental impact. The disposal of substances used by, or created by the oil and gas industry that are harmful for the environment is covered by various regulations. Under normal conditions the industry is environmentally neutral. If there are no accidents/incidents there will be no detrimental effect on the environment. As previously noted, the proper application of automation will reduce the number of accidents/incidents.

There are several areas where automation has already shown a positive reduction in incidents and thereby a reduction in environmental impact.

Drilling Tools

Automated drilling tools for wellbore stabilization create fewer cuttings during the drilling operation. When a drill bit deviates from the desired path the driller must reduce the pressure applied to the drill bit and make frequent adjustments to the bottom hole assembly (BHA) to steer the bit back on the desired course. These corrective actions consume valuable drilling time and result in efficiency losses as high as 200%. The automated rotary steerable systems maintain the wellbore geometry and also reduce the amount of environmental waste by 30% through decreased cuttings and fuel consumption.[76]

Centrifuges, Shakers and Dryers

The tight control of environmental parameters by automated dryers, shakers and centrifuges has decreased the amount of environmentally unfriendly products from the drilling operation. The centrifuge is used to remove fine drilled solids from the drilling fluid. This prevents the volume of drilled solids from exceeding the threshold level in the drilling fluid that can cause an incident and/or damage rig equipment. The common method of correcting the drilling fluid to drilled solids ratio is to dump fluid after diluting. The desired ratio between drilling fluids and drilled solids is 95:5. Therefore, for every barrel of drilled solids an automated centrifuge removes, it eliminates the need for roughly 19 supplemental barrels of drilling fluid. The use of automated dryers further reduces environmental impact by returning base fluid back into the mud system for re-use.[76]

Computer modeling

The ability to accurately predict the drilling conditions greatly reduces the risk of incidents. Encountering unforeseen conditions that could cause instability in the wellbore will increase the risk of an accident/incident that will endanger the crews and will harm the environment. To this end, the use of computer automation to collect and process data for the accurate prediction of the geology that will be encountered is a common practice. This practice has been statistically shown to be all the more critical with high risk wells.

Improvements in Efficiency & Cost

Efficiency is a primary product of an automated system. By tightly controlling the parameters to the modeled values the gains in efficiency using automation are easily realized.

Efficiency and cost correlate directly and any gains in efficiency can be directly translated into cost savings.

Reduction in the number of workers

By automating tasks and applying the latest in sensor technology the number of workers on an oil rig will be reduced. Automation may cut up to half the number of workers needed on an offshore rig and help complete jobs 25-percent faster.[77]

Automation provides more efficient operation

As seen with the Continuous Motion Rig (CMR) robotics coupled with the CMR can save between 25-40 per cent of the drilling time required by non-interruption of the drilling process.

Tight control of drilling parameters

It has been shown that close control of the Weight on Bit (WOB), RPM, and fluid flow rate have a dramatic effect of Rate of Penetration (ROP). Application automation to control all parameters at the same time shows that overall decrease in the drilling time can be of the order of 30 to 50% on the average, thus bringing significant savings for drilling new wells.[78]

Database of prior experience

The use of automation requires a data intensive approach to collecting and interpreting the large volumes of information available. The data can be collected and stored for analysis to build a model of expected results. The ability to properly model expected results will result in greater efficiency. And to this end, the ability to construct proper models is often a product of the quality and volume of data used for the model.

Need for Standards

There is a significant division regarding the need to implement standards for interoperability. Essentially, standards have been the key in enabling islands of automation to interconnect as the penetration of industrial automation into the oil and gas industry expands. These standards are universal and are available for adoption by drilling systems automation. Experienced advanced robotics practitioners warn that standards can be a barrier to true innovation while endorsing standards that promote collaborating systems. The level of automation must clearly match the need for rapid reaction closed loop control and not superimpose itself on strategic tasking. Graphical system design tools are available to assist in the development of autonomous control systems. Offline programming can significantly reduce the lead time to develop and implement robotic systems.

Items not needed

Automated systems do not need the infrastructure that is required to sustain human life. The unmanned aircraft has benefitted from weight savings from not needing pressurization systems, ejection seats, graphic displays, flight control interfaces, etc. that were needed by the onboard operator. Not including those items also decreased the complexity of the system and increased reliability.

The oil and gas industry can see similar savings by using automation to remove human operators from the drill rig. The drilling rig without operators will not need insulation, air conditioning, shelter, catering, fire protection systems for humans, etc.[79]

Cost of implementation

The cost of automation can be substantial compared to operating with human workers. The initial capital required for automation can be justified when the return on investment is scrutinized to be able to make a business case to automate.

The cost of the modern drilling rig can be $50 million for a land rig and $150 million for an offshore rig. Some of the newer, complex offshore drilling rigs can cost $500 million or more. The construction costs to outfit the rig for human occupancy can be traded for the cost of implementing automation.

The area where automation is to be implemented needs to be prepared. Special structure needs to be designed and installed to support the increased weight and leverage requirements of the automated systems. If vision systems are to be incorporated, the environment needs to be prepared to provide the proper contrast and lighting condition to optimize the optical qualities.

The business case for automation is highlighted by drilling industry practitioners. It is anticipated that systems integration will enable plug-and-play between downhole and surface tools and machinery. It is anticipated that operators will begin to specify automation in their contracting documents with service companies and drilling companies.

CHAPTER 7 – (Task 2) Perform Cost Benefit Analysis of the systems identified that details potential costs to industry, potential increases in safety performance, government resources needed for implementation, and necessary training for all parties involved.

Chapter Summary

The ability to justify investment in new technologies and/or products is a balancing act between cost and benefits. The ability of the government to justify regulatory mandates is also rooted in the ability to prove to industry that new regulations are not a financial burden without merit.

To conduct meaningful research of cost versus benefits requires setting defined limits in scope. The cost/benefit analysis (CBA) can become cumbersome and may not generate any meaningful results if the scope is too large. It could also require more resources to conduct than is reasonable. The scope of the CBA should not include more details than is necessary to properly assess the merits of the approach selected. The scope cannot be limited to a small set of data. A small scope with a small set of parameters for comparison could indicate a false positive or negative outcome. The data set should be properly scoped to produce the desired results with the resources available to conduct the study.

The CBA performed in this document will focus on two technologies permitting a high level analysis of their value. The intent is to look at a macro scale in order to value the benefits and compare the costs as a unit. The value of the enabling technologies will be considered to be validated or disputed by the valuation of the entire system. As an example, if the Real Time Monitoring Center (RTMC) uses downhole sensors that allow Real Time Monitoring (RTM) and the RTMC can be shown to have a value, then the value of the downhole sensor is considered a worthwhile investment.

This study is scoped to consider the cost versus benefits of automation and the use of a RTMC incorporated within the function of Real Time Operations Centers (RTOC). The use of automation and RTMC is considered to have a return horizon of five years. The use of five year rate of return also aligns with the usage rate of rigs that are less than five years old. The utilization rate of newer rigs allows this CBA to be based upon a higher utilization rate that shows more likelihood to prove or disprove economic viability. As an example, if a rig is not utilized or is stacked, the ability to realize a return on investment would be difficult. The CBA will not consider the economic principles of future investment, inflation, opportunity costs, net present value, tax implications or other accounting applications specific to individual organizations and would require complex analysis and selection of values rooted in accounting best practices utilizing proprietary data.

The use of an RTMC is not a practice that has been limited to research facilities. It has been in use by large corporations monitoring six to nine wells at one time. It has been scarcely used by small offshore operators and land based operators. The use of a RTMC can be justified in other phases of exploration. Using data from other wells and previous operations can benefit the planning process and reduce the cost of bringing in a well. The use of automation on the drilling rig will enhance the ability to collect data that will allow more accurate valuation of benefits while allowing a relatively stable cost structure. The ability to reduce incidents could have benefits that are justifiable by economic measurements of reduction of ecologic impact, production inefficiencies, non-productive time and human injury. The use of an RTMC has already been shown as a tool that could have been used to avert and/or mitigate drilling incidents.

Drilling automation has great potential to provide gains in efficiency and safety that should not be ignored. A necessary first step to incorporating automation in the oil and gas industry is taken by advancing the industry in real time monitoring. Without the ability to provide data and control in real time off the rig, full automation will not be a viable option. The current use of automation has been hampered by the incremental and incomplete use of automated equipment and principles. The use of automation requires technologies that are key to proper implementation of real time monitoring and are useful in solving problems in difficult conditions. For instance, the use of the continuous motion rig (CMR) has great potential to stabilize the pressures in the wellbore and decrease non-productive time. Development of a drilling rig purposely designed and constructed to support an automated configuration shows great potential for taking people out of harm's way. There are some challenges to implementing automation that can be properly addressed with purposeful planning.

Directing the use of the RTMC principles can be justified by enabling return on investment to the operators. The use of RTMC can provide rapid returns by avoiding one rig incident. Similarly, the use of automation is easily justified by the reduction in human error resulting in lower impact to the environment and reducing loss of life or injury. The pushback from industry based on economic reasons will be easier to address with useful metrics that are general enough to cover the topic and detailed enough to provide proper justification. The use of drilling automation and RTMC has been shown to be justifiable. Regulatory incentives can be used to provide fiscal justification for adoption of these principles where the operator may be too small to realize economic gains.

Introduction

Task 2: Perform a cost benefit analysis of the systems identified that details potential costs to industry, potential increases in safety performance, government resources needed for implementation, and necessary training for all parties involved.

The cornerstone of business is the ability to return a profit on an investment of time and/or money. The ability to generate a financial gain makes a company viable and provides validation on their business model. The use of complicated fiscal calculations has become the standard for ensuring an accurate account of the costs can be realized. The full and accurate capture of the costs of the venture will also be a model for the prediction of future investments.

The ability to show a return on investment (ROI) acts as a filter to remove products, methods, models from the economic arena that do not add value. It is a ‘survival of the fittest’ style of selection. There are many factors that are used to accurately predict the anticipated margin on a company’s product. Each company has a proprietary method to perform these calculations. Each company has a different landscape where they measure the profit from their actions. The unique composition of each company makes a general statement about viability and profit a difficult discussion. Where one company cannot produce a positive financial gain in a new market, there could be several others that are capable of weathering the fiscal environment and elect to push in a new direction. Making a general statement about the ability of the oil and gas industry to invest in a technology or access a new reservoir will be difficult to justify when considering the varied financial status of all players in the industry.

The focus of this study is the offshore operator and the direct cost benefits of using RTMCs and technology that supports the use of RTMCs. The difference between onshore and offshore wells has enough variation to create error in an analysis if assuming that the RTMC cost for onshore wells is similar to offshore wells for operators of all sizes. However, the onshore operator can be examined to provide a comparison that might assist in determining the impact of regulations on the medium and smaller offshore operators.

Corporate plans are developed with a desire to return money. The return could be short term or long term. Each company uses an individual timeframe when considering the horizon for a return on investment. In some financial climates the need for return may be five years. The need to reinvest the money in the company may drive a short window for returns. A different environment may dictate, or allow, a long time span for realizing profits from investments. For example, the decision to change drilling mud from oil-based to a water-based product would expect to realize immediate, short term gains that may be easily justified. Simple metrics can be used to compare the cost of switching materials. By contrast, the large capital investment in an offshore mobile floating rig will need to be justified over a period of 10 or 15 years. In this section we will consider a mid-range period of five years for return on investment.

The justification of the values in a CBA can always become a point of debate and the valuation of intangibles can be widely disagreed upon. A properly performed CBA however will enable a company's managers to justify an optimal strategy for the allocation of valuable manpower and financial resources. It can point a company towards a technology with their 'best guess' of the possible outcome. It is the intent of this section that the regulator will use this CBA to be aware of financial impact of proposed rules and to justify the cost of regulations.

Benefits are valued and monetized to be able to predict if a decision will produce economic gain. Some benefits are difficult or impossible to valuate. The intangible parts of the oil and gas industry can be identified and there has been substantial effort to place value on these pieces of the puzzle. The benefit may not be easily monetized, as seen by an accounting term called 'Good Will.' There are no units for this term but there is an estimation of a dollar value that can be difficult to justify.

The cost of drill pipe is measured by the linear foot. Drilling costs can be quantified and charged as days per 10,000 feet. Unlike these examples in the drilling operation, however, there are no units of measure for purchasing safety.

Safety valuations are rooted in history. The consequence and cost of failure can be accurately identified after the incident/accident. It is relatively easy to determine the cost of blowouts, injuries and even fatalities. It is difficult to look forward and place a value on safety to enable purchasing of the proper amount of safety. If there are no incident and/or accidents, it is difficult to identify the amount of funding that can be removed from an effort and still retain the zero accident rate. A common method of finding the limits of safety is reducing the funding until there is an incident or accident. This is an overly crude method that does not accurately reflect the preferred method of ensuring safety. It merely points to the difficulty of determining and valuing the exact amount of resources needed to provide the minimum margin of safety required.

A term used in an attempt to find the level of justifiable investment is "As Low as Reasonably Possible (ALARP)."[80] The push by the financial arm of a corporation will be to task the managers to justify, or dispute, the current funding level in terms of ALARP. The 'R' in ALARP leaves a substantial amount of room for interpretation.

The benefit to Health, Safety and the Environment (HSE) provided by RTMCs has been realized by those companies using this technology. The enhancement to the financial bottom line can be shown to be from more than simply increasing efficiency. If the use of RTMCs averts just one accident, then the justification for use will be economically straightforward.

There is a rigorous and robust effort by individual corporations to shield their economic plans and performance from rival businesses. Rival businesses would use that data to assess ability to seize market share and work against the target company. For this reason it is very difficult to find, or be supplied, detailed financial data from the company regarding the cost of producing their product. If the information is made available, it is protected by non-disclosure agreements and other legal safeguards. If this report contained detailed, protected, financial information on costs and plans, it would not be available for public viewing. Thus, the information available was collected from peer reviewed papers, interviews, and articles from industry analysts.

There are, however, telltale signs of value. For example, the return of a company to a region to produce oil and gas would be considered a positive sign that there is a profitable product to be found in that specific region. Likewise, expanding the use of a technology for exploration can be considered an indication of feasibility and practicality of that technology. However, the use of a technology by one company may not indicate that the technology is suitable for all operators. There are resources available to large corporations that will allow them to make a profit where smaller businesses would not survive. For example, initial investment requirements and its result on cash flow may severely hamper a smaller company from investing in the new technology.

These signs can be used by regulators to promote the widespread use of a technology that can produce a product in a manner to reduce incidents and/or accidents and thus reduce threat to health and the environment. This section will attempt to reveal some of the signs available and provide an evaluation of the potential for regulatory involvement and prospective government resources needed.

The purpose of this report is to provide an analysis of the cost and benefits of technology and systems identified in other sections of this study. The results will show the feasibility and/or viability of implementing real time monitoring and automation in the oil and gas industry.

This report is not a justification of using individual components that comprise RTMC. The identification of gains in HSE and financial justification of the RTMC system will provide justification of the individual items needed to build the system.

The use of this study is not intended to be a final financial consideration for investment in these technologies by private companies. This study is intended to act as a signpost to point towards the favorable or unfavorable financial consideration of directing the use of and regulating these technologies. Further detailed and rigorous study is required to properly account for all the aspects of finance and investment. A detailed and rigorous CBA is beyond the scope of this study. Such a CBA would also be completed using proprietary values unique to each individual company.

Scope of Cost Benefit Analysis (CBA)

Knowledge by the regulator of the methods to conduct a proper CBA provides awareness of the financial implications of future mandates. The ability to defend and justify proposed regulations can streamline the review process accompanying a Notice of Proposed Rulemaking (NPRM).

In economics, cost/benefit analysis is a procedure for making long term decisions, by which implications of present actions can be evaluated far into the future. The most basic way to make a decision is to compare the present value of the costs with the present value of the benefits. The action under review will be undertaken only if the present value of the benefits exceeds the present value of the costs.[81]

There is a cost associated with conducting a full scale, financially pertinent CBA to be used by a company to make a decision on investment. A complete CBA usually requires dedicated analysis from many different disciplines in the corporation. Smaller businesses may find it hard to allocate scarce resources to perform a detailed CBA. Experience indicates that the cost of the analysis may be less than ten percent of the savings generated by avoiding ineffective and costly improvement measures.[82] Subsidizing or sharing costs of a CBA may be a method to enable smaller companies to realize gains from safety and efficiency that may have previously gone unrealized due to the cost of conducting a proper CBA.

Some benefits may be derived from long time-span macro indicators. The macro indicators cannot be quantified when looking at individual operations but they can be measured, or identified, when making a historical review of the process. The survey of companies using RTMCs indicates that the benefits outlined below are macro indicators of return on investment (ROI) that can be difficult to quantify and require a long time span to realize. These benefits will not be quantified in this CBA.

The list of macro benefits include:

- Better communication – There is no direct measure of better communications.
- Customer satisfaction – This can be seen in sales and marketing data as a positive increase in demand and/or return business based upon satisfaction with current methods. It can be very difficult to attach customer satisfaction to a specific investment.
- Employee morale – The retention of key personnel can be measured on a long-term basis. The identification of a single reason for choosing a career at a company is not realistic.
- Environmental impacts – The health of the total environment defies measurement due to the large scale of the measurement and the complex interaction with other variables. Localized, short term impacts of oil spills can be studied and documented but the long term impact is difficult to quantify.

Scope

To properly conduct the CBA, the scope must be determined to ensure the final product is suitable for the desired level of fidelity. A level of detail too fine will create a large effort and is difficult to justify the cost of performing the analysis. A detailed analysis of a large portion of the industry could take years or months to conduct and be very costly.

Limited CBA Candidate Scope

The direction of this task will be to conduct an analysis of large systems identified to be likely candidates for integration and to provide an assessment of value and cost. This section will not conduct an industry-wide cost/benefit evaluation of available technology. The technologies evaluated are made up of many separate disciplines and capabilities. For example, RTM requires a method to transmit the data in real time to an onshore facility. The financial justification of the data transmission technology is considered to be part of the financial justification of using an RTMC. The financial justification of the complete system is suggested to be a financial justification for the use of the enabling disciplines and capabilities.

Proprietary information

The monetary values presented in this study are from open sources and should not be used to make a financial decision on the individual practicality of a course of action. The values are meant to act as indicators for possible future detailed study made with proprietary information. The public nature of this report will not allow inclusion of individual financial positions.

This section is intended to provide guidance for regulatory justification and on the path for future detailed CBAs. Technologies have been identified that are advantageous to the continued safe and efficient production of petroleum products. The systems and/or technology most likely to be beneficial are studied in a broad sense of cost and benefits. This study could also be used to identify methods of justifying the mandate for implementing future technology as well as continued use of a proven product.

Financial Calculations

The use of accepted best accounting practices is paramount in the corporate world for providing an accurate picture of the detailed value and potential future returns by an investment in a technology.

A list of financial parameters used to calculate financially pertinent numbers include:

- Inflation
- Indication of recurring and non-recurring costs
- System life cost
- Net present value
- Residual value estimate
- Opportunity costs
- Tax implications
- Health and/or prediction of the financial market or commodities market

These parameters are valued differently by each individual company. As an example, the Opportunity costs and Tax implications would vary by a substantial margin between companies. They are important to a CBA used for a decision by a corporate board on whether to proceed or discontinue with a product or procedure with regard to the fine line of profitability. However, they are not critical for indicating to a regulatory body the financial impact of a proposed regulation.

Business Practices

The method of implementing new technologies is as important as justifying the value. If the CBA indicates a decision to move the corporation in a new direction has been validated, the implementation phase is engaged. The method of implementing or integrating the technology will have an impact on the future return. If the effort is not properly controlled, the predictions used to justify the investment will not be accurate. This CBA will not analyze corporate procedures nor provide an assessment of the best way to implement a decision.

Rigs newer than 5 years old.

Drilling rigs newer than five years old provide a better prospect of being capable of integrating the necessary equipment to enable RTMC capability and to be able to retrofit for automation. The graph shown in Figure 33: Rig age -vs- cost, shows that newer rigs can charge more for their services. Newer rigs are used in this analysis because they are more widely utilized and will be able to justify, or refute, the cost of implementing a rule. The graph in Figure 34: Rig utilization shows that the newer rigs are utilized more often and will have a lower

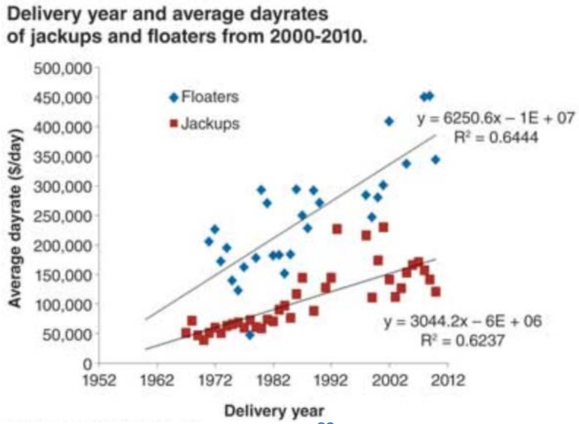


Figure 33: Rig age -vs- cost[83]

stacked percentage.**Error! Bookmark not defined.** If rigs with lower utilization rates are considered, the ability to provide a cost benefit analysis to justify any modification would be more difficult since the rig would not be utilized enough to justify the cost of the upgrade.

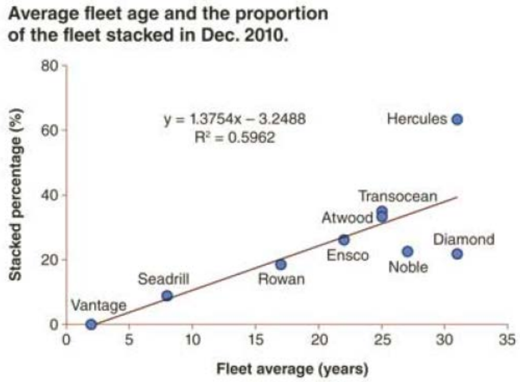


Figure 34: Rig utilization Error! Bookmark not defined.

A special category of rigs has proven to be more profitable. The ultra-deepwater and harsh environment floaters are particularly profitable due to high utilization and a large difference between day rates and operating expense.**Error! Bookmark not defined.** It makes no fiscal sense to spend money upgrading a little used rig with the intention that it will realize a higher utilization rate after being modified. These factors could be used as a guide to shift funds to rigs with high utilization to justify spending money on upgrades. These factors could also guide the regulator to limit or expand planned regulations and mandates.

Prioritizing considerations

When considering the technology to include in this CBA, priorities needed to be identified to provide the proper allocation of study to areas that would provide the largest impact.

Tasks with extensive human interaction were considered when analyzing the potential for rig automation to remove the human from the hazardous environment and to reduce the possibility of human error. The cost of human fatalities is quantified later in this section and is a significant consideration when deciding the most affordable course of action. When considering the value assigned by the legal system to a fatality there is little agreement from those affected that it is sufficient to cover the loss.

High risk operations were considered in assessing costs/benefits of rig automation due to the ability of automation to perform within a narrower band of performance criteria. The exploration of high pressure high temperature (HPHT) offshore wells requires very tight control of the parameters to ensure all values remain within the tolerances defined in the planning process. One of the costs of automation that proves difficult to quantify is the inflexibility of the automation to react to a condition that was not planned or anticipated. For example, if the planning of the well calls for a 7" casing with a 4 ½" liner, but onsite conditions were different than planned, and a single section of 5 ½"casing is needed, the retooling effort to accommodate automation could be substantial and reduce the automation gains from using a single size casing.

The ability to operate in extreme environmental conditions is a hallmark of automation. The ability of the machinery to continue working in an environment unsuitable for humans has economic benefits. Using historical figures, the ability to reduce the possibility of injury can be quantified and factored into the benefits. The ability to continue working when conditions dictate removing the human workers will reduce the non-productive time (NPT). The desire to keep in production a rig that costs over $300MM can be a factor in deciding the economic benefits of automation.

There are also benefits from removing the human from the rig and/or platform by the reduction in helicopter trips to offshore locations. The reduction in risk from exposure to helicopter accidents is tangible due to the large number of accidents/incidents.

The future of automation is tied directly to the implementation of RTM. The use of automation requires a robust RTM network. The removal of the human from the environment will only be capable with full implementation of RTM.[84] It can be said that the future of high risk wells is enabled by automation and automation is enabled by RTM.

Real Time Operations Center (RTOC)/ Real Time Monitoring Center (RTMC)

The term 'Real Time Operations Center' implies that all the activities in the RTOC take place during well execution and production. The functions of the RTOC are better described by the term 'Well planning and real time monitoring center.' RTOC services include the safe and effective delivery of a well from start to finish and include the Real Time Monitoring Center (RTMC). Core services provided by the RTOC fall into three broad categories: Collaborative Well Planning, Predictive Modeling, and 24/7 monitoring. Each of these categories adds value to the RTOC and is factored into the cost/benefit analysis.

As noted in Chapter 1 (Task 1), the term RTOC includes those aspects of well planning, drilling execution and completion that are conducted using real-time data feeds into a remotely located facility utilizing real-time monitoring capabilities. RTMCs are that portion of the RTOC responsible for monitoring real-time data streams from rig operations on a continuous basis, e.g. 24/7 as an integral rig team member although located onshore. The RTMC is a cornerstone service provided within the RTOC.

The cost benefit analysis of the RTOC/RTMC is based upon the use of real-time data (RTD). The two components share the associated costs of the infrastructure for bringing RTD to the onshore location. The cost of installing and integrating RTD is not studied in detail due to the wide array of sensors and communication methods available. General cost figures of RTMC are included.

The primary focus on this CBA is the cost associated with implementing the RTMC; however, additional benefits of implementing the entire RTOC concept are also analyzed. It is important to note that the RTOC definition in this report includes the functions of the RTMC.

Assumptions

The evaluation of the viability of the RTMC is performed in a narrow band of assumptions on the composition and location of the wells being monitored. The list of the wells currently suitable for and utilizing an RTMC is small. They are commonly known as high risk wells and are characterized by reaching total depths where the environment is determined to be high temperature and high pressure. The analysis of the costs of the RTMC may justify using this technology for smaller operations.

The capability of current technology indicates that the optimum configuration is for an RTMC to support 6-9 production or drilling wells. The cost of the RTMC will be spread over the number of wells being monitored. The use of RTMCs for monitoring and/or managing production units is an important choice. However, there is very little open source information on the use of RTMCs for production operations. The focus of RTMCs has been on the highly dynamic and dangerous exploration phase. The parameters used to monitor a production well and a drilling well are unique to each operation and will change the number of wells capable of being monitored by the RTMC.

The number of wells monitored in the RTMC was assumed to be in the range of six on the lower scale to nine at the upper end. The limitation of the RTMC to nine wells is considered a limit of communication and coordination in a 'cell' or 'unit.' The lower limit of 6 wells was chosen as a limit for the ability to financially justify the RTMC. This study uses the lower limit of six wells to allow a more conservative valuation of the financial benefit of using this technology. When fewer wells are being monitored and/or managed, the financial burden will be spread over fewer assets and it will be more difficult to show a positive return on investment. If it is shown that the RTMC is financially feasible using the minimum of six wells then the use of the RTMC will be financially viable for a higher utilization rate of nine wells.

The use of an RTMC by operators with less than six wells in operation could potentially be provided by a service that provides RTM on a contract basis when needed. A service provider could use a facility to manage and/or monitor wells from several medium or small operators and the financial burden of investing in an RTMC could be spread over several companies.

Larger companies have installed RTMCs with the capability to monitor 12 or 15 wells at one time. Industry research and discussions with industry professionals noted that even though these facilities had the ability to monitor more than 9 wells, the surplus stations are used to monitor other operations such as spudding and temporary abandonment.[2]

The current industry practice is for the operator to implement the RTMC. Per the Chapter 1 (Task 1) discussion, several service providers (Baker Hughes, National Oilwell Varco, Halliburton) have developed an RTMC function with limited ability to support several customers with limited rig activity. The facilities are not as comprehensive as those of the large oil companies. The RTMCs for these companies also integrate with the planning process and perform as a repository for lessons learned.

Highly critical, high-spend wells were considered for this study. The gains are easier to identify and there is more documentation on the costs. The valuation of the benefits for the smaller operators can be realized through collaborative efforts with a service company to provide RTMC capability.

Planning and Execution

To appropriately analyze the cost and benefits, the RTOC/RTMC should be divided into activities during the well planning phase and activities in the well execution phase.

Well planning

Planning a well could require months or even years before the design is mature.

Reducing the time and effort to plan the well has direct benefits to reducing the cycle time required to complete a well and therefore the cost of the well.

Some benefits of using an RTOC for planning are:

- Providing a collaborative work environment for multi-disciplinary well planning interaction from the time that subsurface realizations have matured to the point where more detailed well planning may proceed.
- Facilitating three dimensional subsurface well visualization for optimum well placement, well trajectory selection, and asset development using modern visualization tools.
- Providing offset well analysis using integrated subsurface and drilling information.
- Performing detailed well engineering modeling for torque and drag, hydraulic assessments, swab and surge modeling.
- Disseminating best practices and previous lessons learned in key well preparation meetings.
- Facilitating the participation of the necessary local, regional, and global subject matter experts in collaborative well planning sessions through various communication tools.
- Reducing the cycle time it takes from identifying a drilling prospect to generation of the drilling plan.

Well execution

Drilling the critical, high-risk well is becoming more difficult. The challenge is presented by tightly controlled parameters and being able to quickly react to changes in drilling conditions while maintaining Rate of Penetration (ROP). Using RTM to provide accurate data with very little latency can mean the difference between completing a well and not even attempting to do so. Below are some of the benefits of using RTM for well drilling in a full RTOC concept:

- The ability to engage an experienced staff to look at trends and critical parameters from surface and downhole telemetry sensors with the workspace to run real time analysis between actual data and modeled/predicted parameter values.
- Delivery of high quality data to the decision makers and other relevant stakeholders that has been checked and verified.
- Capture and disseminate relevant lessons learned and best practices.
- Assist with data facilitation, after action reviews, performance benchmark exercises and root cause failure analysis for improving future operations.

General Benefits

To be able to compare the cost of RTOC/RTMC against the benefits, we also need to consider benefits that are a product of good data being provided in a prompt manner.

A list of general benefits includes:

- Reducing operational costs by reduction of trouble events and associated Non-productive time (NPT)
- Improving safety margins
- Improving operational efficiency by reducing Invisible Lost Time
- Enabling management of complex wells for both exploration and production
- Becoming more pro-active and less reactive
- Providing effective communication between reservoir engineering, geology/geophysics, petrophysics and well engineering.
- Capitalizing on recent technological advances such as improved IT communications system, three dimensional visualization technology, modeling capability, etc.2
- Enabling condition monitoring to recognize impending failures and to support reduced downtime with faster response to equipment failures.

Feedback into the planning process

Well planning can be considered overhead since it is not directly involved in the rate of penetration. During drilling operations, experienced engineers look at real-time data overlaid on predictive models. If there are discrepancies, they are researched and explained. This feedback increases the knowledge base used for planning and will be used to reduce the planning time for the next well under consideration.

Use of automated drilling rigs

RTMCs have shown ability to monitor systems that have modern sensors and to transmit data to remote locations. Automated systems rely heavily upon the use of sensors and remotely monitoring their performance. Automated drilling rigs show great potential to greatly reduce the time required to drill the well. The use of Managed Pressure Drilling (MPD) and Continuous Motion Rigs (CMR) could virtually eliminate the loss of well control, loss of Bottom Hole Assemblies (BHA), the need for sidetracking after differential sticking and the exposure to dangerous conditions on tightly controlled wells. The benefits of automation are well documented. There is a growing body of research supporting implementing automation.

Directing the use of RTOC to monitor high risk drilling rigs is an opportunity the regulator could consider to tilt the industry towards a position to adopt automation and evidence-based methods of operation during critical well operations.

Current use of RTMC

The introduction of the current generations of RTMCs was initiated around a decade ago. The economics of the RTOC have been shown to be practical in the operation of large drilling rigs in the exploration of high risk wells.

The operators/owners of the rigs are not necessarily including RTOC in their system. They are using RTM to monitor the condition of the rig and for detecting/predicting failure of the equipment; however, the data is usually limited to onboard monitoring.

The large scale use of RTMCs is normally the responsibility of the owner of the well. The owner of the well is teaming with data providers to deliver the RTD parameters of the well to the RTOC. The costs of RTOC have been shouldered by the well owner with the data delivery company acting in the capacity of a service business.

The growth of the RTOC by large oil corporations has not been universal. There are large companies that do not use RTOC and may use limited RTM. There are very few users of RTMCs outside of the large corporations. The main reason cited for the lack of RTMCs was financial justification.

Macondo

According to the Chief Counsel's Report, "Redundant shoreside monitoring would clearly have helped in several instances at Macondo—for instance, during the negative pressure test".[43] The Macondo Well employed a new, up to date, drilling rig with a robust RTD sensor package provided by Sperry-Sun and Hitec. In the following paragraphs, the Chief Counsel's Report is cited for many instances where the use of an RTMC may have added an additional layer of oversight and protection allowing BP to avoid this tragedy.

The RTMC is not intended to be a silent observer simply storing the data received from the well. It is staffed and indeed intended to be an active participant in the drilling and/or production process. The team that operates the RTMC is purposely selected for their experience and charged with the ability to make decisions. The team members actively communicate with the members on the rig or platform. They cooperate and manage the risk with those operating the equipment on site.

The Executive Summary of Findings states "Better management of personnel, risk, and communications by BP and its contractors would almost certainly have prevented the blowout", Page x. The very nature of the RTMC could have provided for an entity that was charged with managing personnel and risk through active communications.

The Chief Counsel's Report concluded the cement job at Macondo was a major contributor to the loss of well control. Page 35 of the report states "The Macondo well blew out because the cement that BP and Halliburton pumped down to the bottom of the production casing on April 19 failed to seal off, or 'isolate.' On page 81-86 the report states the miscommunication and decision to use fewer centralizers was driven by a decision to not wait for the stop collars that were arriving by boat and causing a 10 hour delay. The use of six centralizers instead of the 15 delivered by helicopter was decided even though a model developed on April 18 using six centralizers "…predicted that channeling would occur." The decision to use fewer centralizers may likely have been reviewed by a team at an RTMC and the model could have been evaluated by personnel in a more controlled environment. Additionally, the coordination for ordering and delivering the proper centralizers with stop collars may have been monitored and corrected.

The use of nitrogen foamed cement offered advantages, but also introduced risks. The instability of the cement must be properly managed to prevent failure. Page 111 states “The Chief Counsel‘s team finds that Halliburton failed to review properly the results of its own pre-job tests, and that a proper review would have led Halliburton to redesign the cement slurry system.” The role of the RTMC encompasses the review of the results of cement tests. The review would have been monitored and the team manning the RTMC would have most likely noticed that the cement failed the tests. Alternate plans could have been made to reduce the risk of a failed cement job.

On page 36, the negative pressure test conducted on April 20 “…. clearly showed that the cement job had failed to isolate hydrocarbons.” The crew on the rig had collectively misinterpreted the clear results of the test. On page 143, “The Chief Counsel’s team finds that the failure to properly conduct and interpret the negative pressure test was a major contributing factor to the blowout.” The role of the RTMC would have been to analyze the results of the negative pressure test and could have properly interpreted and recommended appropriate action.

The kick that resulted from hydrocarbons entering the riser from a poor cement job was detectable. On page 165, “The Chief Counsel‘s team finds that rig personnel missed signs of a kick during displacement of the riser with seawater.” Management on the rig also allowed numerous activities to proceed that could hinder well monitoring. “Despite the masking effect, the data that came through still showed clear anomalies.” Monitoring for these ‘clear anomalies’ is the heart of the RTMC function. Protocols for intervention by the crew manning the RTMC to provide direction to the rig crew is standard procedure for an RTMC. “If rig personnel had identified the kick earlier, they could have prevented the Macondo blowout.” If the crew of an RTMC had identified the kick the Chief Counsel report indicates the loss of well control would not have occurred.

After the hydrocarbons had reached the surface the crew on the rig did not divert the influx overboard. As stated on page 196, the valves were set to divert the returns from the well to the mud gas separator. During the initial return of fluid the flow was overwhelming the mud gas separator and was detectable by many visual and acoustic sensors installed for that purpose. Reviewing the video feed of the mud gas separator in real time, ashore could have shown the members of the RTMC that the flow should be diverted overboard. The rapid decay of conditions and the chaos of the moment; however could have created challenges to the ability to remotely communicate to the rig crew to divert the influx overboard. However, if the rig crew would have been directed by a relatively calm RTMC crew to divert the fluid overboard there would have been little chance of an explosion. The reluctance of the crew to divert the flow overboard due to regulatory requirements to minimize hydrocarbons and pollutants entering the GOM is noted. However, the magnitude of this flow would have indicated to the RTMC the need for diversion to avert a larger problem.

National Oilwell Varco (NOV) and Sperry Drilling were contracted to provide a comprehensive set of sensors to measure various drilling parameters and surface conditions. The Sperry data was available in real time onshore. The NOV data and the video feeds were not sent ashore. "None of the entities receiving the Sperry-Sun data onshore appears to have monitored the data for well control purposes." This was the case even though BP had recognized the importance of using the data for well control. As stated on page 188, "But despite recognizing the risks associated with poor well monitoring and the usefulness of onshore assistance, BP did not monitor this data for well control purposes. Even though each of its working rigs had an operations room with dedicated Sperry-Sun data displays, BP typically used these rooms only for meetings and the data were 'not ever monitored.'" The data was available, a center was dedicated, but the functions of an RTMC were not established.

On December 23, 2009, Transocean barely averted a blowout during completion activities on a rig in the North Sea. Pages 189-190 of the report noted that there were critical similarities between the North Sea incident and the Macondo disaster. The report stated "Transocean nevertheless failed to effectively share and enforce the lessons learned from that event with all relevant personnel." One of the guiding principles of RTMC is knowledge sharing and collaboration.

This illustration depicts that an RTMC 'may' or 'could' have intervened and prevented the accident. It is clearly supposition. But just as clear is intervention at any of the many error points leading up to the disaster by an onshore team of a highly experience, qualified crew working in the relative calm of an RTMC would have had a high probability of preventing this disaster.

Land Operations

The use of RTMCs by land-based operators is useful for gauging the ability/desire of the smaller offshore operators to implement an RTMC. The financial motivation of the land-based operator can be used to predict the path an offshore operator will support.

Land-based rig operators have shown a dramatic rise in operations in the past three years. As shown in Figure 35: Worldwide Rig Counts, the expansion of the land-based rigs in 2010 showed a dramatic increase in the USA and Canada. The growth in land-based rigs far outpaced the growth in offshore rigs.

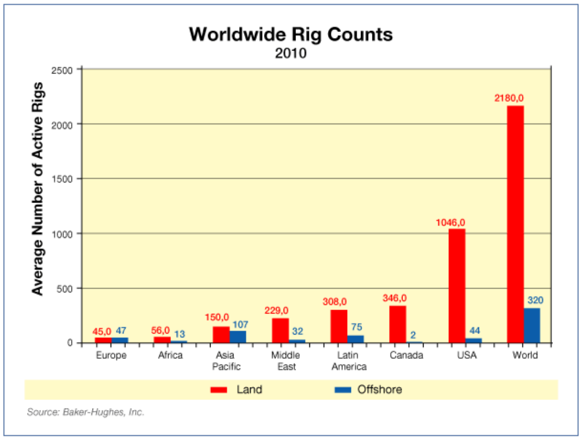


Figure 35: Worldwide Rig Counts[85]

Looking closer at the increase, one region can be identified as a major contributor to the land-based rig increase. The North Dakota region has shown a boom style increase in rig counts. The recent discoveries of shale oil and gas reserves in the Bakken formation have been shown to contain vast amounts of oil and gas. The use of horizontal drilling and hydraulic fracturing has enhanced access to these reserves. The rig count for North Dakota, as seen in Figure 36: North Dakota Rig Count 2012, has shown a ten-fold increase. This trend is expected to continue but is being hampered by the lack of infrastructure to support the sudden influx of workers and equipment. In 2007 the US Geological Survey (USGS) estimated the reserves in the Bakken formation to hold 3.0 to 4.3 billion barrels. Veterans in the industry expect the USGS estimates to be too low.[86] The current production of oil has outstripped the capacity to ship the oil from the region.

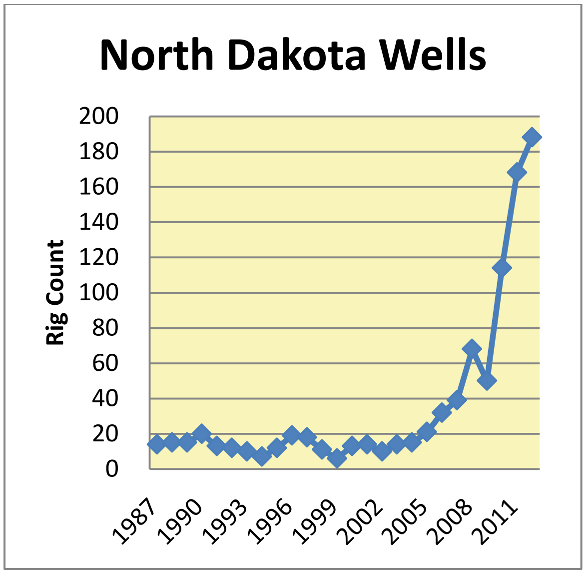


Figure 36: North Dakota Rig Count 2012[87]

The application of RTMC has lagged behind in the North Dakota oil boom and other land based exploration.

The physical parameters that comprise the variables of the land rig in the Bakken formation at depths of 10,000' are not as complicated as an offshore rig drilling to 30,000' or more. However, the challenges of horizontal drilling and the current political football over fracturing have placed emphasis on the need for oversight and control of the well parameters. There have been several accidents and incidents that are the leading edge of future incidents.

The use of RTMCs is more difficult to justify for the smaller operator. The optimization of the drilling process to improve drill rates is not disputed by the smaller operators. The ability to use a field supervisor across several platforms also provides recognized benefits.[84] The potential of return from improved safety goes well beyond the value aspect. However, the initial capital expenditure needed to build out the facility and install equipment is a primary reason small operators do not implement RTMCs. It is a common belief by the medium and small operators interviewed that it requires a substantial number of wells to be monitored concurrently to provide financial incentives for investing in RTMCs. There is little evidence that these operators conducted a CBA. The use of RTMCs could be much more common for smaller operators with the proper incentives.

Government involvement

Potential involvement by the government is not limited to financial stimuli. There are important safety and performance standards that can be introduced. The purpose of this section is to analyze the benefits and the costs of those benefits. The list of possible government regulations suitable for advancing the use of RTMC or drilling automation is beyond the scope of this

CBA. This study will be limited to indicating gains from regulatory involvement and the financial justification of those mandates.

Large Operators

For the purposes of this study, large operators in the Gulf of Mexico (GOM) are classified using 2013 production values for oil and gas. The top five companies are the highest producers of oil and gas and the list includes Shell, Chevron, Anadarko, Apache and BP by rank.[88]

The use of RTMCs by large operators has been shown to be financially viable and does not need to be stimulated with financial incentives. New rules based on current industry practices for RTMCs, should not affect these companies negatively. Moreover, the regulator would benefit from a uniform application of RTM, which would greatly aid the regulator's ability to audit operators in a consistent manner.

Medium and Small Operators

The smaller operators of offshore oil exploration can benefit from the use of RTMC but may not have the resources to field a complete solution. Medium-sized companies have a substantial amount of resources available but choose not to use RTMCs. An interview with an employee of a medium-sized oil company indicated that the company has no RTOC facilities and very little use of RTM.[89]

The RTMC function could be satisfied by the well owner or by a contractor providing RTD to a service company. The use of internally developed RTMCs could be kick-started with assistance in funding the services. Government subsidies; however, would need to be authorized by Congress and supported by a political climate that supports assisting private industry.

The profit/loss resulting from the purchase of RTMC services could be monitored for performance of the investment. If the RTOC is a profitable venture for the well owner, the subsidies could be discontinued and the RTOC could continue on the positive margin it produces. Profitability would add credibility to regulatory mandates and could pave the way for future rules requiring RTM. The expected return on investment is addressed later in this report.

Land Operators

Land operators are seeing a rapid increase in new well prospects. The new prospects are creating a boom type atmosphere. The risk of boom conditions is that growth is too fast to be supported by proper monitoring and oversight.

The use of RTMC by small land-based operators can be achieved with less cost than by the offshore operators. Even with the lower cost of RTMC, however, the land operators have shown little interest in its use. This is mirrored by the medium/small offshore operators.

Land-based operators have some options available to them that have shown to be a challenge for offshore operators. The biggest benefit from an onshore operation is the availability of affordable bandwidth when transmitting data. Fiber optic data lines and other similar technology provide data at a rate that is expected to easily support the needs of an RTOC.

The fiber optic network currently in the Gulf of Mexico was expensive and complicated to install. An industry executive noted that the network cost over $100 million. Access to the network is very expensive and cost prohibitive for medium/small operators.

There are operators that have been implementing newer sensor technologies. They have been capturing critical parameters of the drilling and production process. The challenge is to process them from a centralized location to enable a safety cell to monitor well parameters. History has shown that the initial wave of well candidates will be the easiest to produce. As the field matures, it will be harder to locate reserves and more high risk wells will be drilled. The implementation of RTMC early in the process of drilling high risk wells has a high degree of probability for preventing an accident and/or incident. Any uncontrolled events occurring to the well would bring further scrutiny to an industry that is under a microscope for the major accident in the GOM and more recently, fracking activities.

Training Necessary Personnel

The training necessary to operate an RTOC is made available by the specific company operating the facility. The training is company specific and proprietary. However, the de-identified best practices for RTMC operations are within the grasp of any operator willing to provide the financial backing to begin the process. The best practices can be identified by an independent organization such as the Offshore Energy Safety Institute.

The government auditor also will need training to properly assess the performance of the RTMC. The auditor should have a solid background in well planning, exploration and production. The vast array of well conditions and technology available make a comprehensive training program a challenge. Chapter 2 (Task 3) of this study has addressed the details of training requirements.

Drilling Automation

Automation of the drilling process greatly increases safety and efficiency. The ability to automate drilling will be built upon the use of RTMCs. The removal of humans from the drill rig will require a remote assessment of performance only provided by RTM.

The automation of the drilling process has been trying to follow a path to design and install machines to mimic human manual labor.[70] This leads to an incremental introduction of automation into the exploration industry. However, there have been recent developments to break the cycle of incremental application of automation by fully automating a drilling rig.

For an end user to justify the financial investment in new technology, it is necessary to show that it is expected to enhance safety, provide a greater revenue stream, or decrease spending. A large number of machines used today on drilling structures have increased safety and decreased hard manual labor by mimicking the way a human would perform a specific task. Replacing human tasks in a 'one at a time' manner introduces the automation incrementally. Trying to introduce automation by increments as opposed to initially designing the system for automation has not done much for efficiency and savings. It has also been stated that advancing automation by introducing robotized machines can further enhance the safety aspect and decrease the cost per well.[70]

The following is an example of the incremental approach to automation:

Incremental move #1. The first step toward an automated drilling rig was to introduce the automated Tongs. The automated Tongs provided a more reliable and repeatable method to perform the makeup/breakout of the pipe when tripping. The Tongs incorporated sophisticated sensors and powerful hydraulic motors to twist the pipe connections. Most were placed into position and removed by a human.

Incremental move #2. The next level of automation was to automate placement of the Tongs by a system that sensed pipe location and guided itself to the pipe joint. The system was usually activated by a human in the loop who signaled the system to approach the pipe and perform the desired operation. The human sequencing the automated Tong operation would also interact with the other workers on the rig to provide information on the sequencing of subsequent operations.

Incremental move #3. The next step on the rig floor was to introduce a robot to perform as an 'Iron Roughneck.' The Iron Roughneck is limited by the configuration and dimensions of the rig floor. The tools used by the robot were limited by the dimensions of the tool adapter. These are examples of limitations on the ability to adapt automation to a rig not originally designed for it.

The introduction of automation in these three increments was not as efficient as a complete redesign of the space and replacement by automation. This is due to constraints on the space where the automation was implemented, which was not suitable for the fully automated machinery.

Introducing robotic aid can also have negative influences on the number of tools available to complete a task. The conventional use of elevators and inserts can be used to illustrate this limitation.

The device shown in Figure 37: Elevator and Insert shows a tubular product (drill stem or casing) being held by the tool called an elevator. The purpose of the elevator is to grab the tube and hoist it, or lower it, to facilitate tripping in or out of the hole. Every stand of pipe will require application of the elevator while the previous stand is connected or disconnected. The motion of applying and releasing the elevator is a highly repetitive task well-suited for automation

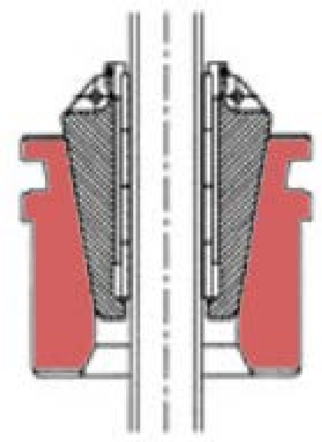


Figure 37: Elevator and Insert

.

The gray area of the elevator is the insert. It is closely matched to the dimensions of the tubular product. The red area is the elevator that attaches to the hoist mechanism. Any change in the size of the drill pipe or casing will require a new insert to be used. The elevator can only accommodate a small variation of insert sizes before a different elevator will need to be installed.

Different elevators and/or inserts could be ordered for many different sizes and tool specifications. The humans performing the tasks can easily adapt to a wide array of different sizes using the many sizes of elevators/inserts. The use of robotic aids will limit the range of sizes available since the tool holders on the robot will be set to a rigid range of sizes and will be optimized for the size and speed of the automated system. Once in place, the automated system will require a large change effort to be able to accommodate a size that was not considered in the design. The engineer will be limited on the choices without changing the automated elevators or the inserts and incurring a large delay and cost. Even when limiting the choices for tools or aids, the automation of tasks can provide economic and safety enhancements with proper planning.

The introduction of automation has monetary and safety benefits that have been illuminated by the recent accident on the Deepwater Horizon rig where lives were lost and a large financial loss incurred. It was projected that automation may cut the number of workers needed on an offshore rig in half and help complete jobs 25 percent faster.[90]

Automated Drilling Rig

The cost of a drilling rig can cost from $50 million[69] to $350 million for a complex rig such as the Deepwater Horizon fifth generation, dynamically positioned, column stabilized, semi-submersible, mobile rig.[2] With these high prices comes pressure to operate in an efficient manner to maximize the return on investment. It could be insinuated that the push to maximize efficiency was a contributing factor to the Deepwater Horizon/Macondo accident in 2010 by cutting corners and not acknowledging the associated risk.[28]

One result of employing high cost drilling rigs is that the operation of these large systems is more tightly scrutinized by managers and investors to squeeze out any efficiency that can reduce overall cost and increase profit. The large rig is a breeding ground for improvements that will save money; however, the automation of the current rigs today has not kept pace with the automation of other industries.

Widespread implementation of RTMCs is required before full scale automation can be properly monitored and/or managed. Enabling automation is an obvious benefit that is difficult to fully quantify.

Continuous Motion Rig (CMR)

The mechanics of the CMR are detailed in Task 7 of this report. The basic concept involves not stopping the movement of the drill pipe or casing while it is being tripped in or out. This is achieved by two systems that take turns moving the drill stem or casing. The concept is similar to continuously lowering a rope with two hands, hand over hand (CMR) compared to lowering the rope with one hand, stopping during hand repositioning (conventional).

CMR drilling offers many different benefits that can be identified and quantified. The list of benefits does not always contain easily identified savings. The use of RTMC on a rig practicing continuous motion can provide a great tool to quantify and justify the use of CMR. This can be done by monitoring swab/surge and documenting the reduction in stuck pipe events.

Tripping Speed

The improvement in tripping speed can be directly correlated to reduced tripping time. This is achieved through continuous motion of the tubular in the wellbore. The feasible maximum speed is in the range of 5900-11,800ft/hr. This equals approximately 64-128 stands per hour. This speed is roughly double the speed of the conventional trip speed. An example of CMR is shown in the figure below:

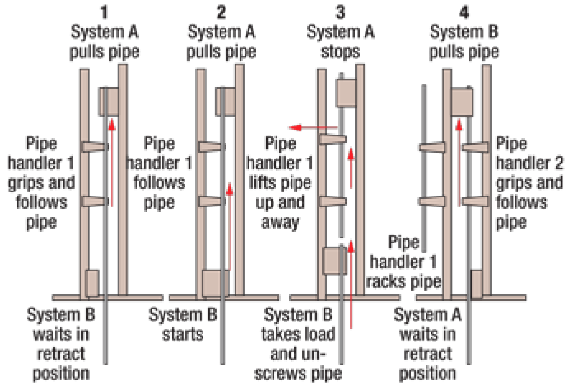


Figure 38: CMR Concept[69]

Personnel safety

The goal of the automated rig is to remove the human from the dangerous work environment. The monitoring and control of the rig are performed away from the operations area. A rig accident will damage equipment but will not risk human life. The benefits of the saving of human life are explored and monetized in the "Other benefits with economic value" section below.

Wellbore stability

The wellbore stability is improved by reducing or eliminating the swab and surge effects of running the pipe/casing in and out of the hole. Swab and surge is defined as the total pressure acting on the wellbore affected by pipe movement upwards or downwards (tripping pipe). Statistics indicate that most kicks occur during trips.[32] The reduction in swab/surge will improve hole quality by providing a narrow band of pressure in the wellbore. The improvement will be more pronounced on a deeper well due to the large column of fluid that will be affected at greater depths. The reduction in swab and surge from starting and stopping pipe travel will allow faster tripping speeds since the pressures in the well will remain stable by the continuous motion of the drill pipe or casing.

The value of the improved wellbore stability will be difficult to quantify due to the difficult nature of measuring the detrimental effects of swab and surge. There are ample peer reviewed studies that note the detrimental nature of pressure surges in the wellbore. The metrics for valuation of CMR will be found in a long term reduction of wellbore pressure issues.[32]

Differential Sticking

Differential sticking occurs when the well bore pressure exceeds the reservoir pressure as shown in Figure 39: Differential Sticking.

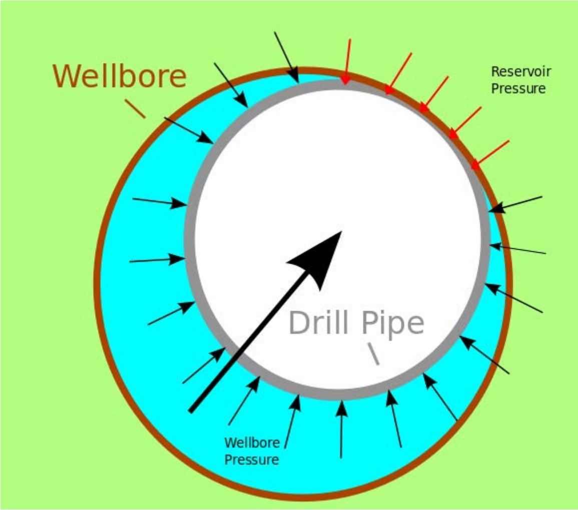


Figure 39: Differential Sticking[92]

The drill pipe is pressed against the wellbore wall so that part of its circumference will see only reservoir pressure, while the rest will continue to be pushed by wellbore pressure. As a result the pipe becomes stuck to the wall, and can require millions of pounds of force to remove, which may prove impossible.[91]

Stuck pipe incidents have been one of the major technical challenges of the drilling industry and events typically result in a significant amount of downtime and remedial costs. The recent increase in drilling activity, shortage of experienced personnel and equipment, and drilling in higher-risks areas have increased the risk of stuck pipe events in all drilling operations.[92]

The cost of stuck-pipe in the drilling industry today is significant by any standard. Sedco Forex conducted a survey of all drilling problems reported worldwide over a period of 15 months which showed that 36% of the total was due to stuck-pipe. In the North Sea, the corresponding figure over 11 rigs was 52%. No estimate was made of the cost of these incidents; however, a recent study estimated costs for one oil company at around $20 million per year with an estimated industry cost in excess of $250 million. The study reports 50% of stuck-pipe incidents occurring during tripping and an estimated 36% of incidents related to crew change over.[93]

The continuous axial motion of the drill string will reduce the chance of differential sticking by not allowing the drill string to remain in contact with the well bore. Reducing incidents of stuck pipe will also reduce the amount of time spent drilling the well by removing the need to drill a diverted wellbore around the stuck pipe. More drilling time means more chance for an incident.

Continuous circulation and drilling or MPD

Also known as Managed Pressure Drilling (MPD), continuous circulation will facilitate the ability to better control pressure during drilling in formations that exhibit small differences between pore pressure and fracture pressure. MPD will also prevent the formation of cutting beds in high angle wells that usually form when circulation ceases. This leads to high torque and possible sticking of the BHA causing the drill pipe to stop turning. A drill pipe that does not spin is a likely candidate for differential sticking. Reducing incidents of stuck pipe will also reduce the amount of time spent drilling the well by removing the need to drill a diverted wellbore around the stuck pipe. More drilling time means more chance for an incident.

The extrapolated 2009 cost of dealing with kicks, shallow water flows, loss of circulation, sloughing shale, stuck pipe and twist-offs on wells averaging 20,000ft in depth were equated to $2,500,000 on non-subsalt wells and $7,600,000 on subsalt wells. It is important to look beyond these pressure related events and realize that each problem has the potential to manifest, or contribute to, a potential well control incident.[32]

A closed loop continuous circulating system is 470 times less likely to result in a Loss of Well Control (LWC) than drilling the same well with a conventional circulating fluids system. An LWC event is defined as the uncontrolled flow of formation or other fluids, flow through a diverter, or uncontrolled flow from a failure of surface equipment or procedures. The loss of well control for an open mud returns system while drilling a HPHT well is one in 1,600.[94] These reliability values are important for the evaluation of the cost compared to the benefits of this technology. The use of these values for calculations is limited to a macro, long term examination of the returns.

An example of a jack-up rig with a surface Blow Out Preventer (BOP) was used to gauge the cost savings of using continuous circulation. The savings are shown below:

- Controlled gas influx and allowed for a controlled mud weighting using Equivalent Circulation Density from 17.5ppg to 18.6ppg. Continued drilling 48 hours after influx. Saved 5 days.
- Performed open hole Dynamic Formation Integrity Test (FIT) to 19.1ppg. Saved ½ day by avoiding tripping out time.
- Navigated a 0.4ppg pore/fracture window in 8-1/2' section avoiding kick loss through the use of one size of casing. Saved 10 days
- Held the ECD pressure during connections eliminating time needed to circulate out gas from wellbore breathing during connections. Saved 3 days.
- Total estimated time saved was 18.5 days
- At $750,000/day to operate the cost savings are $13.9MM.[94] [95]

Automated Insert/Elevator

The use of an automated insert/elevator was studied with a simple time/motion analysis. Three different sizes of pipe and BHA per section were modeled to represent the drill string. The first two sizes required 6 insert changes each and the third size required 12 changes. The amount of time required to change the insert/elevator was estimated to be 15 minutes faster for the automated machine than for a manual method. The total time savings could be calculated by:

(6+6+12) x 15 = 360 minutes or six hours.

The rig operational costs were estimated to be $1,000,000/day, which is equal to $40,000/hour. With rig operation being reduced by 6 hours, the total savings could be $240,000 per day per well.[70]

Automation Challenges

As with all complicated and expensive systems there are challenges to implementing automation.

Incremental application

As discussed earlier, automation suffers from incremental implementation. The addition of automated machinery to the drilling rig is not efficient and does not capitalize on the synergies of a fully complementary system.

The reasons for introducing automation incrementally, however, are based on incomplete financial analysis. It is much easier to justify a single robot to replace a roughneck than it is to justify a fully automated drilling rig. The true efficiency of the equipment is realized when the entire system is purpose built for the task.

Speed

Automation may not be able to produce results faster than a human rig crew. When operating at top synergy and cohesiveness, a rig crew can trip faster than an automated system. The danger with the crew operating at this level is the increased possibility of an injury and/or accident.

The drill rig crew was matched against a robot to measure the number of tasks performed. Initially, the human rig crew outpaced the robot as shown in Figure 40: Tasks per Hour #1. The light gray line showing robot tasks did not indicate an improvement over human workers.

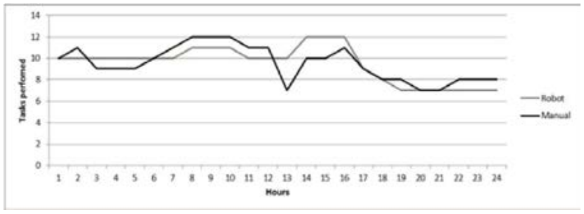


Figure 40: Tasks per Hour #1[70]

After some study and some tweaking of the robotic system, the automated drill floor was able to generate more tasks per hour as shown in Figure 41: Tasks Per Hour #2.

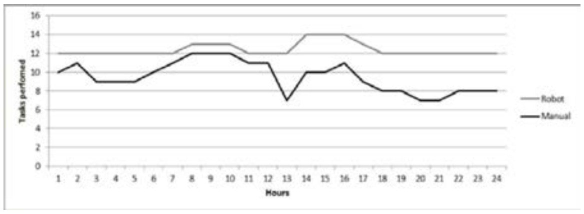


Figure 41: Tasks Per Hour #2[70]

Monetary gains

The gains of using an automated drilling system can be summarized and totaled to show the economic benefits of using the technology identified.

Reduced tripping times results in 25%-50% less time drilling the well. For a drilling operation normally requiring 60 days to reach the target depth, the reduced trip time from automation will conservatively reduce drill time by 15 days. When using $1MM/day to operate, the savings are $15MM.

With 36% of all well incidents being stuck pipe there is room for improvement. The use of a CMR will eliminate differential sticking and could save $2MM-$4MM (or an average of $3MM) per well in cost of services to unstick the pipe.

Continuous circulation of the annular fluids produces an average cost saving of $7.5MM per well for subsalt wells.

The total economic benefit from using the technologies discussed above is:

$15MM+$3MM+$7.5MM = $25.5MM

Cost of the system

The construction of a complete automated rig is under way in Norway. However, the total costs for the first rig will not be a proper indication of total lifecycle costs for future versions of the rig. The high development cost must be recouped over many years.

The estimation of the cost of the automated system can be seen in the current effort underway in Norway. The prototype for an automated drilling rig has an estimated capital cost between 150 million Kroner ($26 million US) for a land rig and 500 million Kroner ($89 million US) for an offshore rig. We will use the conservative cost of $89MM for our calculations.[96]

Using the simple calculation of $25.5MM per year in operational savings (as shown above) from using automation and automated processes results in roughly 3 ½ years to recover the costs of equipping an offshore rig with automation, given savings remain constant. While this is a simple calculation the savings from using automation indicate a relatively rapid return on investment.

The loss of human life and the impact on the environment are also benefits from the automation of the drilling rig. The value applied to a fatality is discussed in the "Other benefits with economic value" section below.

Government Resources Needed

The government may wish to consider resource expenditures to enable the research and validation efforts to introduce the automated drilling rig. The benefits to safety and the environment are well documented. Recognizing these benefits, the government of Norway has invested 25 million Kroner ($4.5 million US) to develop the robotic unmanned drilling rig.[96]

The economics of automation have shown that automation is financially viable. The benefits to safety are also not disputed. The cost of automation can prove too steep for a smaller operator. The smaller operator may need help with the capital investment necessary to install an automated system. This could come in the form of subsidies for purchase of automated equipment if a financial burden from equipping can be proven to be beyond the capabilities of the company.

Any incentives supplied by the government should be targeted towards the operators that can benefit from the technology but may not be able to justify the integration of the technology on financial grounds. The application of any incentives should be tempered with the knowledge of the financial stability of the company intended to be incentivized.

Any incentives should be thoroughly analyzed to provide justification for purchase. The proper utilization of public funds should be held to a high standard.

Training of Necessary personnel

There is a steep learning curve to the engineering principles needed to implement a robotic drill floor. The addition of a robot on the drill floor requires a multidisciplinary approach with special emphasis on ensuring that the environment is suitable for the new system.

The training of the personnel that would be auditing the use of automated drilling systems should follow the multidisciplinary requirements to integrate the automation. The ability to work beyond a checklist is important to properly assessing technology that is complicated and can change frequently depending upon the area applied.

RTMC Cost to the Industry and Returns

Specific details of costs to the industry are normally company proprietary data. There are open source documents that give generalities to the cost associated with automation and employing an RTMC.

Cost Metrics

The cost of the RTMC can be an uncomplicated measure and accounting of the price of material and services. The detailed financial returns of the RTMC can be a challenge to verify with proprietary data. There is open source information that indicates the RTMC can return the cost of the integration in as little as three months or as little as one well that was made productive.

Cost

Varying definitions and included components of the RTOC make it more difficult to extract the specific spending on RTMC alone. Research indicates spending on developing the RTMC alone, on a per rig basis as a percentage of well costs, stands at 1% for tension leg platforms and 0.5% for deepwater floating rigs.[16] Conservatively, industry data shows the average GOM drilling depth is 20,000' and the average rate of penetration (ROP) is 10'/hr. This results in an average drill time of 83 days.[43,89] These are generalized numbers that are averaged over the duration of the drilling process. They do not include the use of automated systems to increase ROP and reduce NPT.

The cost of drilling is a variable cost that is determined by the time required to drill the well. The rig is usually billed on a daily rate. The common method used to determine the cost to drill the well is to multiply the per day rig cost by the number of days drilling. When the rig encounters problems with drilling the well the delays, NPT and ILT are directly increasing the cost of the well. The ability to decrease circulation problems and sticking pipe can greatly increase the profit of the well. Stuck pipe alone accounts for 25% of NPT.[97]

The available data indicates that a conservative cost for deepwater rig operation is $1.00MM per day. The average daily rate of semisubmersible rigs capable of operating in over 4000' of water depth is close to $450,000.[98] After including the total cost of personnel, services, and material the cost roughly doubles. The Deepwater Horizon Mobile Offshore Drilling Unit (MODU) was documented at $533,000 per day but the total cost was $1.00MM per day for all inclusive operations.[43] These values come from open sources, industry experience, and interviews. The numbers represent a generalized cost.

The drilling costs and the costs of an RTMC can be compared to determine any benefits available. The estimated cost of operating an offshore platform to drill to a depth of 20,000' is roughly $104MM. Using the highest spend per rig value of the tension leg rig to provide the most conservative results, the cost of the RTMC for the floating rig would be $1.04MM, which is 1% of the total cost of the well. For six wells this equates to $6.24MM. The intent of choosing these values is to be conservative in the calculations showing the least likely opportunity for cost benefit. Even with these conservative calculations the value of RTMCs is easily identified and justified.

Adding overhead and the non-recurring cost of the purchase and installation of the RTMC yields a more accurate cost. The cost of installing an RTMC is closely guarded corporate information not disclosed in public forums. Installation costs examined in this research ranged from $3.5MM to $12.5MM.[2] The conservative estimate used for this example is $12.5MM for an RTM that can support six wells. This estimate is considered realistic and supportable.[16,99]

Amortizing the cost over the expected lifespan of the RTMC hardware and software before necessary upgrades is conservatively estimated from commercial and government experience at four years produces $3.125MM per year in development, purchase, and installation costs. This includes training and facilities costs.

Returns

The burden of the RTMC is to produce positive economic gain to justify purchase and development. The gain from the RTMC is compared to the costs to produce a net profit/loss from using the RTMC.

Calculations

The typical returns of the RTMC can be divided into tangible and intangible returns. The tangible returns are realized from reduced interventions and reduced non-productive time (NPT). The intangible gains come from increased safety margins, improved communication throughout the team, reduced well planning times, increased customer satisfaction, higher quality of the well programs, etc. The intangible returns are measured on a macro scale and would require a long duration study to properly integrate these gains into the RTMC benefits.[82] The tangible well returns will be examined.

Not only is NPT a significant part of the $1.00MM per day to the well owner, but there is also the added cost of the intervention services needed to correct the issue producing the NPT. The reduction or elimination of interventions and NPT is being realized by the use of RTMCs.[16,84,99]

The use of six stations for calculations is continuing the conservative approach identified in the other calculations used in this section. It is more difficult to justify the returned value if there are fewer stations. If the cost of the RTMC is spread over fewer wells and it is still found to be viable then the viability is easier to show when monitoring more wells. Even with the lower value of stations used for the calculation the use of RTMCs is justified. If we use our figure of $1.04MM for the cost of the RTMC per well and an average RTMC with two stations simultaneously monitoring three wells each this would equate to:

$1.04 X 2 stations X 3 wells = $6.24MM

The total cost of the two station RTMC per year when used to monitor three wells per year is $3.12MM (operational costs) +

$3.125MM/6(installation costs) = $3.63MM per year per well.

Estimating that RTMC can prevent or reduce NPT and reduce the drilling time by 2% the return is calculated as 2% X $104MM = $2.1MM per well. For three wells the savings are $6.3MM per year.

The time to return the investment and operating costs of the RTOC is measured by comparing the cost against the rate of return. The cost of operating the RTOC is $3.63MM per year per well. Realizing a cost savings of 6.3MM per year for three wells, the rate of return of approximately 13 months is considered very rapid by traditional financial models.

The return on investment of six months has been indicated in literature to be a realistic value. [99]

Other benefits with economic value

Another benefit added by the RTMC is the ability to reduce the risk and/or severity of an accident.

The cost of the human fatality has been quantified by insurance companies to allow the calculation of premiums and compensation. The term used in the industry is Implied Cost of Avoiding a Fatality (ICAF). The ICAF can be valued as a range close to $1.5MM. The courts and litigants have introduced ‘societal factors’ that have historically shown there is a need to multiply the value to show a maximum level of sacrifice that can be tolerated without being judged grossly disproportionate.[82] As noted in the reference, the value considered supportable for offshore installations is arrived at by multiplying by a factor of 6.[100] Therefore the cost of making an improvement to an offshore system would be valued and compared against a $9MM liability if the fatality occurs. If the improvement cost exceeds this value, then it will be difficult to justify.

If the Macondo well explosion had been prevented by the RTMC intervening by either properly reading the negative pressure test, mandating the proper number of centralizers, or directing the divert of the well overboard it could have prevented 11 fatalities. The calculated value of these deaths would total $99MM. The $300MM cost of the Deepwater Horizon Rig could be another asset saved. This value does not account for the estimated $1.25 billion in fines. It is clear that the RTMC could easily have been a financial windfall if properly implemented.

Recommendations

The study concludes that the use of RTMCs is financially viable. The financial return from using this technology is shown in this study and further evidence is provided by the continued use by large offshore operators. The use of RTMCs by small operators has been largely non-existent. There are several approaches that can be implemented to improve acceptance/use.

Government Regulation

The use of RTMCs should be initiated through the measured introduction of directives requiring use of RTMCs for drilling operations for high risk wells.

Directives should include the need for onshore monitoring of well parameters by a separate safety center with functions performed by a facility such as an RTMC within the RTOC. The use of an onshore monitoring station could be leveraged by other medium/small offshore operators to share the financial burden.

The RTMC operation should be audited periodically by government personnel to assure that current operations are being monitored by personnel that have the ability to provide an intervention when well parameters indicate an abnormal, unexpected, or dangerous condition. Government personnel would not need intimate knowledge of each individual RTMC and the complex makeup of the sensors and automated equipment. However, the auditor would need a firm grasp on well operations and would act in a capacity that blends performance-based and prescriptive oversight.

Government Incentives

The use of RTMCs by medium/small offshore operators has been hobbled by the initial capital expenditure needed to procure an RTMC facility. Incentivizing small and medium sized operators could be investigated as a means of introducing RTMC to these operators.

Fiber Optic Network

The use of onshore RTMCs is greatly enhanced by the ability to transfer large amounts of data from the offshore rigs. The current fiber optic network in the Gulf of Mexico is owned and operated by BP. The cost of other operators gaining access to the network is very expensive and is cost prohibitive for the smaller operator. The use of the network could be facilitated by government assistance with access. Government assistance can take many forms, from financial incentives to tax breaks to mandates for a nonprofit pricing structure.

Automation Research

There are other countries that are funding and/or supporting the introduction of automation for the oil drilling rig. The improvements in HSE are easily recognized when considering the gains in efficiency and lack of human error. The government should follow the lead of other countries and fund/promote research in automation. The government initiative could also include teaming with other private and foreign government initiatives to introduce automation to share ideas and foster an atmosphere of cooperation

Conclusion

The use of conservative estimates for using RTMCs can easily justify their use. The current use of this technology by the large corporations indicates that the value of the investment is justified. The barrier to the middle and small operators is the initial capital expenditures.

The barriers to the introduction and use of advanced principles for exploration and production are not always financial. The ability of the government to promote and/or direct the use of these advanced principles can forge the path to a safer and more cost effective oil and gas industry.

The benefits of RTMCs are not solely financial. The improvement in safety for the operators and the environment can be realized by the reduction of one accident and/or incident. The value of a human life or lost limb determined by insurance companies and accountants is little satisfaction to the survivors, but is relevant to analyzing the benefits of RTMC. The long term effect on the environment is hard to quantify and measure over many years. The ability of RTMC to avert dangerous, costly, and harmful well events such as loss of well control, stuck pipe, etc. can be shown but the value of avoidance goes well beyond financial terms. The automation of the drilling rig would reduce the footprint of the human in the dangerous environment but will require RTMCs in order to function.

RTMC is a powerful tool for increasing efficiency and elevating safety. The use of the RTOC could prevent major disasters that cost lives and billions of dollars. The avoidance of one well catastrophe can pay for RTMCs that may have been hard to justify by other metrics. This factor should be considered by the government in deciding whether to impose directives for use of RTMC.

It is the opinion of 838 Inc. that the use of the automated drilling rig could be the next step in drilling rig technology. The use of current proven principles to aid in introducing the new, untried technology will make the system viable. The knowledge to design, build, and implement an automated rig is here today. The implementation of automation on the drilling rig could provide large gains in efficiency that cannot be realized without RTMCs.

About the Authors

Greg Zackney

Greg Zackney is president and CEO of 838 Inc and an accomplished program manager and safety systems expert. He has over 21 years of Marine Corps leadership training and private sector experience working with safety management systems in the aviation and oil and gas industries. Greg can be reached at greg@838inc.com.

Mark Anderson

Mark Anderson is Chief Operating Officer of 838 Inc and has over 24 years' experience as an US Navy operational instructor, evaluator, and facilitator. He is an experienced training syllabus and curricula developer and instrumental in developing risk reduction training to include responsibilities as a Crew Resource Management (CRM) facilitator. Mark can be reached at manderson@838inc.com.

Rick White

Rick White is lead researcher and business operations analyst for 838 Inc in Durango, CO. With over 23 years of leadership, business and team development experience, he focuses on helping oil and gas companies improve organizational effectiveness and human capital productivity. He can be reached at rick@838inc.com.

References

1 Booth, J.E. “Real-Time Drilling Operations Centers: A History of Functionality and Organizational Purpose—The Second Generation”, paper 126017 presented SPE Intelligent Energy Conference and Exhibition, Utrecht, The Netherlands, 23-25 March 2010

2 van Oort, E., Rosso, R., Cabello-Montero, J., “Evolution of Real-Time Operations Monitoring: From Concept to Global Implementation”, paper 97059 presented SPE Annual Technical Conference and Exhibition, Dallas, Texas, 9-12 October 2005

3 Booth, J.E. “Real-Time Drilling Operations Centers: A History of Functionality and Organizational Purpose—The Second Generation”, journal paper 126017, SPE Drilling & Completion, volume 26, number 2, pp. 295-302, June 2011

4 Booth, J.E., “Drilling Operations Centers: A History of Functionality and Organizational Purpose–The First Generation”, paper 123225 presented SPE Digital Energy Conference and Exhibition, Houston, Texas, 7-8 April 2009

5 Knode, T. and Disatell, J.: “The health, Safety and Environmental Benefits of Real-Time Operations”, paper SPE 77470 presented at the SPE ATCE held in San Antonio, TX, 29 Sept.-2 Oct. 2002

6 Steinhubl, A., Klimchuk, G., Click, C., Morawski, P., “Unleashing Productivity: The Digital Oil Field Advantage”, http://www.booz.com/media/uploads/UnleashingProductivity.pdf, 2008 (accessed Jan. 7, 2013)

7 Unnamed source, (executive director, independent safety organization), personal interview, Feb. 19, 2013

8 Thorsen, A.K., Vargervik, E., Nygaard, V., “Combining Drilling and Evaluation Technology in Remote Operations Increases Reliability”, paper 124729 presented SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, 4-7 October 2009

9 Iles, B., e-mail message to author, February 18, 2013

10 Khudiri, M.M., Naser, N.A., AlShehry, M.A., Nassir, A.A., Mokhtar, H.K., “RTOC, Collaborative, Safe and Effective Delivery of Wells from Start to Finish”, paper 125339 SPE/IADC Middle East Drilling Technology Conference & Exhibition, Manama, Bahrain, 26-28 Oct. 2009

11 Womer, K., Kaminski, D., Hansen, O., Kirkman, M., Curry, D., “Results of the SPE Applied Technology Workshop ‘Off Well Site Decision Making’”, paper SPE 79891 presented at the SPE/IADC Drilling Conference, Amsterdam, February 2003

12 Kaminski, D., Escorcia, A., Saputelli, L., “Remote Real Time Operations Centers for Geologically Optimized Productivity”, AAPG International Conference: October 24-27, 2004; Cancun, Mexico

13 Company informational pdf, Feb. 2, 2013

14 Unnamed source, (executive VP and Regulatory Policy Advisor Gulf of Mexico Region for major oil and gas exploration company), personal interview, Jan. 10, 2013

15 Hacker, J.M., “An IOC's Experience in Implementing Digital Oilfield Technologies”, paper 117837 presented Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, UAE, 3-6 November 2008

16 Ursem, L-J., Williams, J.H., Pellerin, N.M., Kaminski, D.H.: “Real Time Operations Centers: The People Aspects of Drilling Decision Making”, paper SPE/IADC 79893 presented at the SPE/IADC Drilling Conference held in Amsterdam, The Netherlands, 19-21 Feb. 2003

17 Leimkuhler, J., VP Drilling, LLOG Exploration Company, personal interview, Mar. 6, 2013

18 Thorogood, J., Aldred, W., Florence, F., Iversen, F., “Drilling Automation: Technologies, Terminology, and Parallels With Other Industries”, SPE Journal Paper 119884-PA, 2010

19 Unnamed source, (sales director, instrumentation provider), personal interview, Nov. 20, 2013

20 Offshore Operations Subgroup of the Operations & Environment Task Group, “Working Document of the NPC North American Resource Development Study”, Offshore Data Management, Data Management, Paper #2-14, Sep. 15, 2011

21 Baker, H (2010, June 8) Fact Sheet – Technical Center Opens NextGen Integration Laboratory, retrieved 28 May 2013, https://www.faa.gov

22 Behn, R. “Rethinking Democratic Accountability”, Washington, DC, Brookings Institution Press, 2001

23 Sparrow, M., “The Regulatory Craft: Controlling Risks, Solving Problems, and Managing Compliance”, Washington, DC, Bookings Institution, 2000

24 Wilson, J., "The Politics of Regulation", The Politics of Regulation. New York, Basic Books: 357-394, 1980

25 U.S. House Committee on Small Business 2000: 42

26 DEPARTMENT OF THE INTERIOR, Bureau of Safety and Environmental Enforcement, 30 CFR Part 250, Docket ID: BSEE-2012-0002, RIN 1014–AA04

27 Valeur, J., Petersen, J., “Use of the ALARP Principle for Evaluating Environmental Risks and Impacts of Produced Water Discharged to Sea”, Offshore Technology Conference, Houston, TX May 06-09, 2013

28 Chief Counsel’s Report, “Macondo Gulf Oil Disaster”, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, 2011

29 Bureau of Safety and Environmental Enforcement FY 2013 Performance Budget

30 Shappell, S.A., Wiegmann, D.A., “The Human Factors Analysis and Classification System—HFACS”, Report number: DOT/FAA/AM-00/7, February 2000

31 Lumbe Aas, A., “The Human Factors Assessment and Classification System (HFACS) for the Oil & Gas Industry”, International Petroleum Technology Conference, Kuala Lumpur, Malaysia, 3-5 December 2008

32 Hannegan, D., “Operational Reliability Assessment of Conventional vs MPD on Challenging Offshore Wells”, SPE/IADC Drilling Conference and Exhibition, Amsterdam, Netherlands, 5-7 March 2013

33 de Wardt, J., “Industry Analogies for Successful Implementation of Drilling Systems Automation and Real-time Operating Centers”, 2013 SPE / IADC Drilling Conference and Exhibition, Amsterdam, The Netherlands, Mar 05 - 07, 2013

34 Cohen, J., Deskins, G., “Drilling Optimization Utilizing Surface Instrumentation for Downhole Event Recognition, Final Report”, February 2006

35 Veeningen, D., “Better Well Control Through Safe Drilling Margin Identification, Influx Analysis and Direct Measurement Method for Deepwater”, Offshore Technology Conference, Houston, Texas, USA, 6–9 May 2013.

36 Sackett D., Rosenberg W., Gray J., Haynes R., Richardson W., "Evidence based medicine: what it is and what it isn't", BMJ 312 (7023): 71–2, January 1996.

37 Veeningen D., “Identify Safe Drilling Margin, Detect and Distinguish Kicks from Ballooning and Better Well Control for Deepwater, Through Independent Downhole Measurements:, SPE/APPEA International Conference on Health, Safety, and Environment in Oil and Gas Exploration and Production, Perth, Australia, 11–13 September 2012.

38 Enggcyclopedia, Engineering Design Encyclopedia http://www.enggcyclopedia.com/2011/07/mechanical-flow-measurement-devices/

39 Norman, J; Coriolis sensors open lines to real-time data; IADC Drilling Contractor, September / October 2011, https://www.drillingcontractor.org/coriolis-sensors-open-lines-to-real-time-data-10682, (accessed May 5, 2013)

40 Bybee, K., Managed-Pressure Drilling: Kick Detection and Well Control, JPT, January 2010. Pp 57-58.

41 Hannegan, D., “Closed-Loop Drilling, Cementing, and Frequent Dynamic Formation Integrity Testing – “State of the Art” for Deepwater Drilling Programs”, Offshore Technology Conference, Houston, Texas, 6–9 May 2013.

42 Weppenaar, N., Kristiansen, M., “Present and Future Possibilities in Optical Condition Monitoring of Flexible Pipes”, 2008 Offshore Technology Conference, Houston, Texas, U.S.A., 5–8 May 2008.

43 National Commission on the BP Deepwater Horizon Oil Spill And Offshore Drilling “Macondo Chief Counsel’s Report, Report to the President”, 2011

44 Reason, J., Human error, 1990, Cambridge, Cambridge University Press. 199, XV, 302 s.

45 Hargis, V., Fowler, F., “Advantages of Integrating Geomechanics Modeling and Hydraulics Modeling in Well Planning and Execution”, Deepwater Drilling and Completions Conference, Galveston, Texas, 20-21 June 2012

46 Rommetveit, R., Bjørkevoll, K., Halsey, G., Fjær, E., Inge Ødegård, S., Herbert, M., Sandve, O., Larsen, B., Kvaerner, A., “e-Drilling: A System for Real-Time Drilling Simulation, 3D Visualization and Control”, Digital Energy Conference and Exhibition, Houston, Texas, 11-12 April 2007

47 Al-Jasmi, A., Fangda, Q., Zaki A., “Digital Oil Field Experience: An Overview and a Case Study”, 2013 SPE Digital Energy Conference and Exhibition, The Woodlands, Texas, Mar 05 - 07, 2013.

48 Eisenhower, F., Nash, P., Langhammer, J., Austin, E., “Fiber Optic Sensing is the Technology of Choice for Permanent Reservoir Monitoring Applications”, 2013 Offshore Technology Conference, Houston, Texas, U.S.A., 6–9 May 2013.

49 Eisenhower, F., Nash, P., Langhammer, J., Austin, E., “Fiber Optic Sensing is the Technology of Choice for Permanent Reservoir Monitoring Applications”, 2013 Offshore Technology Conference, Houston, Texas, U.S.A., 6–9 May 2013.

50 Thivend, G., “Subsea Sensors For Unobtrusive Monitoring of Temperature, Pressure, and Asset Integrity”, 2010 Offshore Technology Conference, Houston, Texas, U.S.A., 3–6 May 2010.

51 Cheng, L.K., Boering, M., Braal, R., “Towards the Next Fiber Optic Revolution and Decision Making in the Oil and Gas Industry”, 2013 Offshore Technology Conference, Houston, Texas, U.S.A., 6–9 May 2013.

52 Van Der Horst, J., Lopez, J., Berlang, W., Potters, H., “In-Well Distributed Fiber Optic Solutions for Reservoir Surveillance”, 2013 Offshore Technology Conference, Houston, Texas, U.S.A., 6–9 May 2013.

53 Thompson, R., Lesnikowski, N., Rush, B., Niccum, G., Richardson, D., “New 2D and 3D Acoustic Tools and Techniques for Underwater Metrology and Inspection”, Offshore Technology Conference, Houston, Texas, 30 April-3 May 2012.

54 Pande, A., Morrison, M., Bristow, R., “Oilfield Automation Using Intelligent Well Technology”, SPE Production and Operations Conference and Exhibition, Tunis, Tunisia, 8-10 June 2010.

55 Cramer, R., Göbel, D., Mueller, K., Tulalian, R., “A Measure of The Digital Oil Field Status - Is It The End of The Beginning?”, SPE Intelligent Energy International, Utrecht, The Netherlands, 27-29 March 2012.

56 Borousan, E., Hajiabolhassani, A., Hojabri, R., “Evaluating Factors That Cause Problem in Implementation of Knowledge Management in Iran’s Oil & Gas Industry”, Management, Multimedia University, Malaysia, undated.

57 Nadeau, P., “Lessons Learned From the Golden Zone Concept for Understanding Overpressure Development and Drilling Safety in Energy Exploration”, Deepwater Horizon Study Group Working Paper, January 2011.

58 http://flickrhivemind.net/User/SJarmanPhotography/Interesting

59 http://en.wikipedia.org/wiki/Moore's_law

60 US Census, “Computer and Internet Usage in the United States, Population Characteristics”, Thom File, May 2013.

61 Redlinger, T., Griggs, P.,Odell, A., Bergo, S., “Comprehensive Review of Damages and Repairs on Drill Pipe Connections”, IADC/SPE Drilling Conference and Exhibition, San Diego, California, 6-8 Mar, 2012

62 Thorogood, J., “Automation in Drilling: Future Evolution and Lessons From Aviation”, 2012 IADC /SPE Drilling Conference and Exhibition, San Diego, California, 6-8 Mar, 2012

63 Iversen, F., Jarle Gressgård, L., Thorogood, J., Karimi Balov, M., Hepsø, V., “Drilling Automation: Potential for Human Error”, IADC/SPE Drilling Conference and Exhibition, San Diego, California, 6-8 March 2012

64 Macarthur, J., Air Disaster Volume 3. Australia: Aerospace Publications. 1998, p. 155. ISBN 1 875671 34 X.

65 Bureau deEnquetes et d’Analysis AF447 Report http://media.webcastor.fr/vod/bea/pdf2/f-cp090601.en.pdf

66 Cayeux, E., Daireaux, B., Wolden Dvergsnes, E., “Automation of Mud-Pump Management: Application to Drilling Operations in the North Sea”, SPE Drilling and Completion, Volume 26, Number 1, March 2011

67 Dodson, J., Metricks Databases for Gulf of Mexico Drilling Operations, James K. Dodson Company, 2009

68 Cayeux, E., Daireaux, B., Wolden Dvergsnes, E., “Automation of Drawworks and Topdrive Management to Minmize Swab/Surge and Poor Downhole Condition Effects”, SPE Drilling and Completion, Volume 26, Number 4, December 2011

69 Grinrod, M., “Continuous Motion Rig: A Step Change in Drilling Equipment”, 2010 IADC/SPE Drilling Conference and Exhibition, New Orleans, La., 2-4 February, 2010

70 Sondervik, K., “Autonomous Robotic Drilling Systems”, SPE/IADC Drilling Conference and Exhibition, Amsterdam, Netherlands, 5-7 March 2013

71 Elvander, J., Halloran, W., “AUVs and ROVs: Supporting Offshore Renewable Technologies”, 2013 Offshore Technology Conference, Houston, Tx., 6-9 May, 2013.

72 Nasr, A., Courbot, A., Gilmour, B., Biedermann, C., “A New Approach to Pipeline Inspection Using Autonomous Underwater Vehicles (AUV)”, 2013 Offshore Technology Conference, Houston, Tx., 6-9 May, 2013.

73 de Wardt, J., Chapman, C., Behounek, M., “Well Construction Automation - Preparing for the Big Jump”, SPE Applied Technical Workshop, Vail, Colorado, 16-18 July, 2012

74 Blaney, B., “There Has Been Blood: Death Rate Among Oil Workers Alarmingly High”, Lubbock Avalanche Journal, 15 September, 2008, http://lubbockonline.com/stories/091508/loc_332404410.shtml

75 Greenfield, D., “Barriers to Human Reliability”, Automation World, 30 April, 2013, http://www.automationworld.com/operations/barriers-human-reliability

76 Bradley, L., Kent, J., Wagner, N., “Performance and Cost Benefits of Environmental Drilling Technologies: A Business Case for Environmental Solutions”, SPE/IADC Drilling Conference and Exhibition, Amsterdam, Netherlands, 5-7 March 2013

77 Wethe, D., “NASA Helps Hatch Robots for Drilling Oil Without Humans: Energy”, Bloomberg, 3 September, 2012, http://www.bloomberg.com/news/2012-09-02/nasa-helps-hatch-robots-for-drilling-oil-without-humans-energy.html

78 Kellessidis, V., Dalamarinis, P., “Monitoring Drilling Bit Parameters Allows Optimization of Drilling Rates”, International Multidisciplinary Scientific Geoconference & Expo, Modern Management of Mine Producing, Geology and Environmental Protection SGEM 2009, Albena, Bulgaria, June 14-19, 2009.

79 SINTEF. "Robots Taking Over The Job On Offshore Oil Drilling Platforms." ScienceDaily, 1 Jan. 2008. Web. 12 Jul. 2013. http://www.sciencedaily.com/releases/2007/12/071221230852.htm

80 Sutton, I., “SEMS II: Nonprescriptive But Not Risk-Based”, Offshore Technology Conference, Houston, Texas, May 06 - 09, 2013

81 Liu, S., Ford, J., “Cost/Benefit Analysis of Petrophysical Data Acquisition”, SPWLA 49th Annual Logging Symposium, Edinburgh, Scotland, 25-28 may, 2008.

82 Lewis, S., Alderman, J., “Tools for Identifying Truly Cost Effective Risk Reduction Measures for Offshore Facilities”, Second International Conference on Health, Safety, and Environment in Oil and Gas Exploration & Production, Jakarta Indonesia, 25-27 January, 1994

83 Kaiser, M., Snyder, B., “Reviewing newbuild drill rig strategies”, Offshore Magazine, volume 73, issue 3, 08 March, 2013

84 Hsieh, L., Remote operations centers earning keep through drilling optimization, 24/7 support, ‘remanning’, Drilling Contractor, September/October, 8 September, 2010,

85 IHRDC eLearning Solutions, Petroleum Online, Drilling and Well Completions, courtesy of Baker Hughes, http://www.petroleumonline.com/content/overview.asp?mod=4

86 http://en.wikipedia.org/wiki/North_Dakota_oil_boom

87 North American Rig Count, Baker-Hughes, http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-reportsother

88 US Department of the Interior, Bureau of Safety and Environmental Enforcement, Gulf of Mexico Region, Production by Operator Ranked by Volume, 1 November, 2013.

89 HSE Manager, personal interview, Nov. 6, 2013

90 Wethe, D., “Robots: The Future of the Oil Industry”, Bloomberg BusinessWeek, Global Economics, 30 August, 2012

91 Schlumberger, “Oilfield Glossary”, http://www.glossary.oilfield.slb.com/en/Terms.aspx?LookIn=term%20name&filter=differential%20sticking

92 Murillo, A., Neuman, J., Samuel, R., “Pipe Sticking Prediction and Avoidance Using Adaptive Fuzzy Logic Modeling”, SPE Production and Operations Symposium, 4-8 April 2009, Oklahoma City, Oklahoma

93 Jardine, S., McCann, D., Barber, S., “An Advanced System for the Early Detection of Sticking Pipe”, SPE/IADC Drilling Conference, 18-21 February 1992, New Orleans, Louisiana

94 Hannegan, D., “Operational Reliability Assessment of Conventional vs. MPD on Challenging Offshore Wells”, SPE/IADC Drilling Conference and Exhibition, Amsterdam, The Netherlands, 5-7 March, 2012.

95 Grayson, B., Gans, H., “Closed Loop circulating Systems Enhance Well Control and Efficiency with Precise Wellbore Monitoring and Management Capabilities”, MPD/UBO Conference, Milan, Italy, March 2012

96 BETECHDATA, “Digital Prototype for Robotic Oil Drilling”, Aug 2012, http://www.betechdata.com/case-studies-single/article/west-group.html

97 Muqueem, M., Weekse, A., Al-Hajji, A., “Stuck Pipe Best Practices – A Challenging Approach to Reducing Stuck Pipe Costs

98 http://www.rigzone.com/data/dayrates/

99 Halliburton, Landmark Software and Services, “Shell Aberdeen RTOC Supports Collaborative Well-Delivery Process”, https://www.landmarksoftware.com/Lists/DocumentRepository/2012-06-shell-aberdeen-rtoc-case-study.pdf

100 Health and Safety Executive, Hazardous Installations Directorate, Offshore Division, Lord Cullen House, Fraser Place, Aberdeen, Scotland.