

Managing Deepwater Corrosion

Challenges Face the Oil and Gas Industry as Offshore Assets Move into Deeper Water

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The Deepwater Horizon offshore drilling unit explosion on April 20, 2010 and resulting oil spill in the Gulf of Mexico brought worldwide attention to the difficulties and risks associated with offshore oil drilling activity in deep water. By necessity, deepwater exploration and production engages offshore and subsea assets that can effectively work at depths that are typically deeper than 1,000 ft (305 m). Industry tends to describe deep water as >3,000 ft (915 m), and ultra deep water as >5,000 ft (1,524 m). Currently there are many assets in the ultra deepwater category. Corrosion professionals that work with offshore oil and gas infrastructure are familiar with the corrosion mitigation complications the industry faces as activities take them into deeper and deeper water. At the NACE International CORROSION 2010 conference in March, the challenges of managing the

integrity of deepwater offshore assets through corrosion mitigation were addressed by a group of industry experts in the forum, “Future Challenges of Deepwater and Arctic Offshore Corrosion and Integrity Management.” The presentation by NACE member Binder Singh, principal engineer with Wood Group Integrity Management (WGIM) (Houston, Texas), an independently managed international company that provides engineering and project management solutions across a broad manufacturing and industrial base, focused in particular on the challenges of managing life-cycle corrosion in deepwater offshore operations, and argued the role of corrosion as a major root cause of pipeline failures and how engineering design and materials selection play a role in corrosion management for these subsea assets. Several key points of his presentation are highlighted in this article.

This past July marked the 22nd anniversary of the Piper Alpha disaster in the United Kingdom sector of the North Sea. An explosion and resulting fire destroyed the Piper Alpha offshore oil production platform on July 6, 1988, killing 167 and leaving only 62 survivors, many of whom were badly injured. At the time of the accident, the platform was one of the



largest in the North Sea and accounted for approximately 10% of North Sea oil and gas production. The incident has been considered the worst offshore oil disaster in terms of lives lost and industry impact.¹ However, the industry has learned many lessons regarding offshore platform design, safety, and maintenance management from the incident, and the conclusions and recommendations of the resulting inquiry, known as the Cullen Report, have served as a vital springboard for the evolution of critical concepts that include corrosion management, inspection management, integrity management, and verification of offshore assets, says Singh. Since then, studies in the late 1980s and 1990s have supported the need for best practice corrosion risk and integrity management.

“After any major disaster, the industry usually receives a jolt. Regulations

invariably get changed and tightened, and integrity and corrosion management also benefit in that more is required to be done,” Singh explains. He adds that corrosion understanding and management have been improving due to better research at universities, private research through joint industry projects (JIPs) (see sidebar on p. 30), contract research, and engineering firms analyzing materials and corrosion mechanisms almost continuously. “There is certainly an upward trend in improvement, but whether it is enough may be debatable. Certainly as we’ve gone into deeper water, the challenges have increased; whereas, previously they were leveling off, and most of the challenges were being steadily met,” he comments.

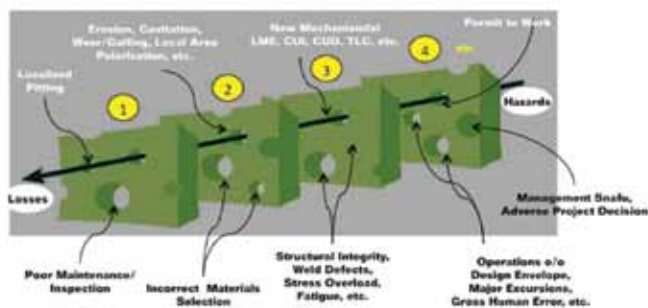
Singh affirms that one of the challenges when managing corrosion and ensuring the integrity of offshore assets

(including semi-submersible platforms, mobile offshore drilling units [MODU], Spar, and tension leg platforms [TLP]) in deep water is accessibility to pipelines and risers on the sea bed in water that can be as deep as a mile (5,280 ft [1,609 m]) or more. In this environment, inspecting pipelines and making repairs can be extremely difficult—if not virtually impossible—and costly. Permanent intrusive coupons and electrical resistance (ER) probes as well as non-intrusive acoustic (sand) monitors have been employed to monitor general corrosion and erosion inside pipelines; but retrieval is still a problem unless they are stationed topside at more user-friendly locations on the offshore asset. Other monitoring techniques typically used for land and topside facilities—such as direct ultrasonic testing, intelligent (smart) pigging, in situ spool mapping, microbial analyses, thermal imaging, selective radiography, guided wave, potential probes, fluid sampling, and linear polarization resistance (LPR) probes—may be contemplated but tend to be impracticable for use in deep water, largely due to lack of full “marinization” (modification for marine use), safety, costs, sensitivity, or accessibility for life-cycle change outs. While divers can conduct visual inspections, retrieve coupons, and take cathodic protection (CP) readings for offshore pipelines and risers in shallow water (in practice <200 ft [61 m]), a remotely operated vehicle (ROV) is required to access equipment and work safely in depths beyond that.

Similarly, monitoring with a smart pig, although feasible, may not be preferred due to costs, scope of design, and the mechanics of launching and receiving subsea pigs in deep water. As a result, Singh says, there are fewer deepwater corrosion monitoring techniques that can be used with confidence, and inspections, therefore, may be less frequent. However, creative techniques are being continually developed and various companies have started to revisit viable alternatives, such as the advanced Ring Pair Corrosion



SWISS CHEESE ANALOGY Chain of Events—Macro and Micro



An adapted Swiss cheese analogy illustrates the interactions of macro and micro events on the path to failure. Copyright 2009 OTC, reproduced with permission.



Shown is an example of localized corrosion observed in pipelines caused by sweet (CO_2) corrosion. Copyright 2009 OTC, reproduced with permission.

Monitor (RPCM[†]) and field signature method (FSM) in situ spool technologies that can integrate or multitask with other acoustic and ER sensors as well as intelligent pigging. The challenge is placing the monitors at the most effective locations.

One other approach for addressing inaccessibility when managing corrosion of offshore assets in deep water is to perform better corrosion analyses and materials selection during the design stage of “greenfield” (new build) and “brownfield” (already in service) assets. The aim is to prevent or minimize the onset and propagation of serious corrosion activity, especially when modifications are made to an existing plant. According to Singh, corrosion is frequently identified as a contributor to the root cause of almost all major disasters comparable to the Piper Alpha. Typically a catastrophe is not caused by one single event but the align-

[†] Trade name.

ment of many variables or events—sometimes referred to as the “jigsaw” or “Swiss cheese” effect—with corrosion activity often occurring at either the macro or micro level and causing severe loss of material properties and load carrying capabilities, which leads to failure. In virtually all such cases, he emphasizes, resolving the corrosion issue will provide the key barrier that eliminates the continuity of failure.

In a 2007 report, the Alberta Energy and Utilities Board (EUB) (Calgary, Alberta, Canada) reported that the predominant cause of pipeline failure (leaks and ruptures) in Alberta’s pipeline infrastructure was internal corrosion (51%), followed by external corrosion (12%), during all the years the EUB tracked failure data, from January 1, 1995 to December 31, 2005.² Although the history with deepwater steel catenary risers (SCRs) is somewhat new, similar or worse levels of internal corrosion for offshore operations can be expected because the flowing media or fluids are the same, says Singh.

“Internal corrosion is a bigger threat because it is more unpredictable and harder to quantify, both at the beginning of a new design and during an asset’s operating lifetime when companies implement integrity management to keep the pipeline working efficiently and performing as required,” he explains. “For pipelines and risers in very deep water,

once internal corrosion sets in (initiates and propagates), it’s very hard—and very costly—to locate, inspect, and make repairs,” Singh adds.

He stresses that for deepwater offshore platforms, design and material selection that focus on mitigating corrosion are vital during the front-end engineering design (FEED) phase when developing projects because intervening later in deep water is controversial, expensive, challenging, and creates many safety and load carrying concerns. “Nevertheless, if a materials or corrosion engineer is involved from the beginning of a major project as it evolves, we can be sure that the corrosion, materials, welding, and integrity angles will be better addressed so there are fewer difficulties and surprises to surmount later on,” he explains.

One of the greatest threats to asset integrity is material degradation with respect to time. Ideally, a “fit for purpose” design must address all mechanical, metallurgical, and corrosion-related mechanisms, such as stress overload, embrittlement, loss of material properties, and dissolution of metal under aggressive environments, over an asset’s life cycle; and plans should include designs, components, and materials that eliminate or minimize the potential for corrosion mechanisms to take hold, so less monitoring is required during operation.

“Because the deepwater assets are not easily accessible, you have to solve any corrosion problems in the design stage rather than the operating stage,” says Singh. “It’s essential to do enough rigorous analysis at the front end to establish if you will have localized corrosion and what type you may have, whether it is crevice, pitting, galvanic, microbial, or erosion. Hence the concepts of failure modes and effects criticality analysis (FMECA), inherently safe design (ISD), and layers of protection analyses (LOPA) are becoming more relevant to deepwater campaigns. Once you establish (via team consensus) what the major corrosion threats are, then you can determine what the remedial actions will be and what sort of materials you will select or chemicals you will use to stay ahead of

them.” Typically, he adds, the principal internal corrosion threats are localized and include mesa attack; carbon dioxide (CO₂) sweet corrosion; hydrogen sulfide (H₂S) sour corrosion and cracking; and, more recently, corrosion under deposition (CUD) via accelerated corrosion cells linked to particulate settlement; synergistic erosion-corrosion, bottom of line (BOL) corrosion (via water drop-out phenomena); top of line (TOL) corrosion (mainly in wet gas lines); horizontal or vertical flow-assisted corrosion (FAC); and sessile or planktonic microbiologically influenced corrosion (MIC). While these are predominantly in-service issues, the early preservation and corrosion control of equipment and pipelines destined for deepwater projects are also receiving greater attention, since any pre-corrosion can act as initiating points for future corrosion activity.

In many cases, Singh says, corrosion prediction work is done by scrutinizing existing data. If a particular type of corrosion is expected to be dominant, then NACE and ASTM standards-based testing may be conducted to determine what the corrosion rate might be. Internal corrosion mechanisms, however, are complex and often multifaceted, and corrosion rate values can’t always be reliably predicted, even with corrosion models that are currently available, he notes. For offshore and subsea conditions, the critical corrosion mechanisms are a function of the composition of the reservoir fluids, and the corrosion models can provide a general guide to the corrosivity of the media involved, which is crucial when making decisions regarding the materials that are used. A typical front-end study, which may require accelerated testing with corrosion inhibitors, can take anywhere from six months to a year, depending on the level of detail and the aggressiveness of the reservoir fluids.

One of the main objectives of corrosion modeling, Singh says, is to determine whether or not carbon steel (CS), usually API 5L X65 or X70, is acceptable as the main flow line material or if the analysis justifies the use of materials that possess additional corrosion-resistant proper-

ties. The materials selection decision draws heavily on the content of the reservoir, whether it’s mainly oil, gas, or multiphase (a mixture of dirty oil, water, and gas) and the decision can greatly impact the total cost for the project. He mentions that an ongoing materials selection debate is fueled by two schools of thought—whether to select the less costly steel and then spend deferred money over the life of the asset by managing the operational corrosion (i.e., using corrosion inhibiting chemicals, etc.) or choose a higher-priced, corrosion-resistant alloy (CRA) that requires higher up-front costs but minimal corrosion management costs over the asset’s lifetime. The arguments are strong on both sides.

Pipeline CS is the most widely used material of choice because the industry has significant knowledge and experience associated with it, and it is cost efficient at the fabrication stage. But, Singh points out, such steels are also the most susceptible to corrosion, especially when exposed to seawater, reservoir fluids, and production fluids. If systems are going to be too corrosive, he says, then other, more exotic materials need to be considered, such as the CRAs (stainless steels, duplex, and nickel alloys). Using a more corrosion-resistant material, however, can increase initial project costs to anywhere from three to 10 times higher than the cost of using CS. The use of CRAs for cladding or lining within segments of subsea infrastructure, such as high-temperature portions, flexible risers, or jumpers, is often justifiable. “It’s a balancing act,” says Singh, explaining that over conservatism



Shown is a failed manifold on a fixed platform due to an isolated erosion defect. Copyright 2009 OTC, reproduced with permission.



Example of severe topside crevice corrosion under supports on offshore platforms in the Gulf of Mexico. High relative humidity and warm temperatures year-round contribute to the accelerated corrosion. Photo source: Deepwater Corrosion Services, Inc. Copyright 2009 OTC, reproduced with permission.

can amplify costs significantly for large projects, while under conservatism can achieve short-term project cost goals but create long-term headaches, especially in terms of changes in risk perception, fluid corrosivity, chemical inhibitor economics, loss of efficiency, excursions, etc., over the asset’s full life cycle.

Either way, corrosion integrity management is crucial since failures can invoke the danger of professional, regulatory, or legal snafus. The best approach, he maintains, is to reconcile the design investment at the capital expenditure (CAPEX) stage with the operating expenditure (OPEX) incurred during the life of the asset with materials selection, materials fabrication, materials performance, and corrosion assessments that are based on the whole life of the asset.

Singh acknowledges that the challenges in offshore corrosion management—equipment design, corrosion monitoring, and corrosion mechanisms—increase as the oil and gas industry moves into deeper water, but along with those challenges comes better understanding of all matters related to materials and corrosion. “It’s an ongoing

work in progress, with another piece added to the enormous knowledge puzzle every time new research is done or a new corrosion mechanism (often a variance of an old one) is found, and our understanding gets a bit better," he concludes. Nevertheless, he notes the outlook is good as more engineering curricula include modules in materials and corrosion, the JIPs foster closer synergy between industry and academia, and experienced engineers transfer their experiences and lessons learned to professionals entering the industry.

Binder Singh, Wood Group Integrity Management—e-mail: binder.singh@wgim.com, has 27 years of industry experience and holds a Ph.D. from the Corrosion Center at the University of

Manchester, England. He started his career in the U.K. nuclear industry, and has worked in the marine industry in the offshore North Sea and, more recently, the Gulf of Mexico. During his career, he has witnessed a major increase in the importance of corrosion that parallels the acceleration of deep-water activity. Singh is a Chartered Engineer, Licensed Professional Engineer in the State of Texas, and Fellow of the Institution of Mechanical Engineers.

Editor's note: The opinions expressed in this article are those of Binder Singh and not necessarily of the companies mentioned. The support of WGIM, Deepwater Corrosion Services, Inc., industry colleagues, and the OTC Committee to allow adapted publication is acknowledged.

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Joint Industry Research Projects Spark Advances in Corrosion Integrity Management

Joint industry projects (JIPs) offer the oil and gas industry the means to conduct expensive research and development by spreading the project costs over a number of interested parties. Oil companies, vendors, regulators, and academic and research institutions can join various JIPs that focus on specific technology challenges facing the industry, and work together to develop the technologies necessary to successfully operate in deep water.

According to Binder Singh, principal engineer with Wood Group Integrity Management (Houston, Texas), JIPs drive research that leads to better understanding of materials and corrosion mechanisms in deepwater offshore operations, which results in better solutions for corrosion-related problems, and are a great resource for progressing applied research and development and fast tracking "fit for purpose" solutions. Their unique blend of highly motivated and qualified researchers, combined with experienced oilfield personnel, has led to many breakthroughs in offshore and subsea corrosion integrity issues, he says.

One of the advantages of the JIPs, Singh notes, is that corrosion data resulting from lab and field testing conducted by some of these projects can be used

by members to make better, more informed materials selection decisions, such as when to use corrosion-resistant alloys (CRAs) or carbon steel (CS) for example. Typically, data from the various JIPs are private and for use by member organizations only, although some data are released to the public after a certain period of time. Ongoing modeling results form an integral part of high-level corrosion management strategies for assets, as well as subsequent tactical methods at the equipment, part, and feature level. "Ultimately we hope the findings will be collated and transformed to industry codes and standards that will supplement existing guidelines, though that may take time due to the proprietary nature of the work," says Singh.

Currently several JIPs are focusing on pipeline, offshore, and deepwater corrosion issues through a combination of theoretical modeling, empirical testing, and field trials. These include the Corrosion Center Joint Industry Project (CC-JIP) through the Ohio University Institute for Corrosion and Multiphase Technology (Athens, Ohio), the Tulsa University Sand Management Projects (TUSMP) JIP (Tulsa, Oklahoma), and the DeepStar Technology Development for Deepwater Research (Houston, Texas).

Other parallel modeling studies have also been done at the University of Louisiana at Lafayette.

The Ohio University's CC-JIP, which addresses CO₂ corrosion among other things, is geared toward increasing knowledge and understanding of internal pipeline corrosion by defining the problem through theory and testing, as well as providing mechanistic modeling to document the progress and understanding of the corrosion processes encountered in internal pipeline corrosion. Tulsa University's JIP was established to address issues related to sand production and management such as solids detection and monitoring, erosion monitoring in offshore production, sand settling and blockage in offshore pipes, sand deposition in multiphase flow, sand separation, sand screens, and erosion of piping and equipment. In contrast, the DeepStar Program focuses on advancing technologies to meet its members' deepwater business needs to deliver increased production and reserves, and identifies and develops economically viable, low-risk methods to produce hydrocarbons from deep water. This joint industry technology development program is currently appraising alternative inspection methods for inline pigging. **MP**