# ANNEX XI
# Other OSER Research Projects

# CONTENTS

# XI.1 SUMMARY OF PROJECTS

This section of the report provides a summary of some significant recent research initiatives and challenges particular to the Other OSER environment, namely:

- Offshore Equipment Standard and Capability;
- Flow Assurance and Well Integrity;
- Integrity Management and Risk Assessment

## XI.1.1 OFFSHORE EQUIPMENT STANDARD AND CAPABILITY

As such, MMS TA&R Program has funded research into the offshore equipment standard and capability, as represented by TA&R Projects No. 618 and 446 below. Detailed summaries of these projects are provided in a later section of this Annex.

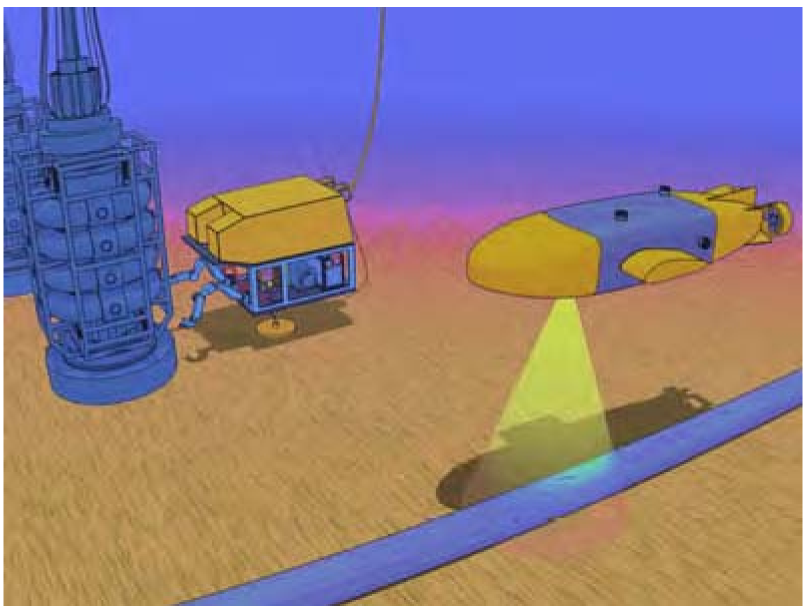

**Figure XI.1: Examples of offshore equipment: subsea systems**

### XI.1.1.1 Project No. 618 – COMPARATIVE STUDY OF OFFSHORE WIND TURBINE GENERATORS (OWTG) STANDARDS

The No 618 project was to address design standards needed for the development of offshore wind turbine generator (OWTG) in the United States. This project documents the results of a Joint Industry Project on comparing IEC design guidelines for offshore wind turbine to API offshore platform guidelines. This study was completed to provide a baseline comparison of the IEC design requirements for offshore wind turbines (IEC 6 1400-3) and the American Petroleum Institute (API) recommended practice for the design of fixed offshore platforms (API RP-2A). This comparison was specifically performed to address the effects of applying either the 50-year storm condition used by the IEC or the 100-year storm condition used by the API. Particular emphasis was placed on the assessment of hurricane and tropical storm hazards that exist in the Gulf of Mexico and along the east coast of the U.S. and how these hazards affect the application of either design guideline.

#### XI.1.1.2 Project No. 446 – ROV/AUV Capabilities

The No 446 project was to develop a technical assessment of present and future AUV/ROV capabilities relevant to subsea deepwater oil and gas developments. The project was to complete a technical assessment of present and future AUV/ROV capabilities relevant to subsea deepwater oil and gas developments. A workshop in this project was held to develop broad, objective assessment of ROV and AUV technology and capabilities relevant to subsea production systems. The assessment included present technology as well as technology and capabilities that could be available to industry in the next 5 to 10 years.

### XI.1.2 FLOW ASSURANCE AND WELL INTEGRITY

TA&R Projects No. 602 and 579 represent endeavors to understand flow assurance and well integrity and expand capabilities in this area. Detailed summaries of these projects are provided in a later section of this Annex.

#### XI.1.2.1 PROJECT NO. 602 – CEMENT FATIGUE AND HPHT WELL INTEGRITY WITH APPLICATION TO LIFE OF WELL PREDICTION

The objective of this project is to develop a better understanding of the performance of the casing-cement bond under HPHT well conditions leading to a model to predict well life. The drilling and completion of a well is a capital project that needs to be executed properly. As a consequence, a detailed design is required, putting into consideration all forces that may affect the integrity of a well throughout its life span.

An aid to such a detailed design is the analytical model which was developed in this project that utilizes the wellbore parameters to evaluate stresses in the cement sheath and has been developed into a software tool. It is a very flexible tool which enables cement designers to optimize their design for HTHP conditions while at the same time putting the design cost in perspective. Combined in synergy with finite element analysis, it can be used to evaluate the fatigue and static loading behavior of the cement, thereby helping to predict the life of the well. The analytical model can also be extended to include fatigue properties of cement in the next phase of this project.

#### XI.1.2.2 PROJECT NO. 579 – JOINT INDUSTRY PROJECT TO STUDY RISK-BASED RESTARTS OF UNTREATED SUBSEA OIL AND GAS FLOWLINES IN THE GOMR

In this project, experiments were conducted to investigate the effect of restart rate, water cut, liquid loading and oil-water distribution on the plugging tendency of crude oil–water systems upon restarts. Multiphase pumping restarts in horizontal pipes and gas-dominated restarts in low spots were conducted. Comparisons were made with simulation tools as well. Main findings show that the presence of a segregated water phase, as opposed to dispersed water phase, increases the severity of plugging, as well as an increase in water cut. Higher velocities seem to decrease the plugging severity; the decrease was more efficient in dispersed cases. Salinity had a positive effect in the sense that hydrate formation rate was reduced and/or plug permeability was higher with higher salt concentration. A mechanism of hydrate plug formation was observed, where hydrates are observed to creep up the pipeline. Finally, anti-agglomerant were proven to be an effective way to prevent plugging, even after a 5-day shut-in with a hydrate slurry already present in the line. However, to be effective, the inhibitor has to be injected prior to shut-in to be properly dispersed in the water phase upon restart.

Comparisons with transient flow simulations (without hydrate module) show that the initial water distribution is fairly well predicted, except for higher water cuts (more than 50%). However, after forming hydrates, simulations fail to predict the location of the water because of the complexity of the resulting flow patterns. A hydrate formation module such as CSMHYK-OLGA should be used to compare the experimental results with the predictions.

Figure XI.2: The hydrate formation test facility general view

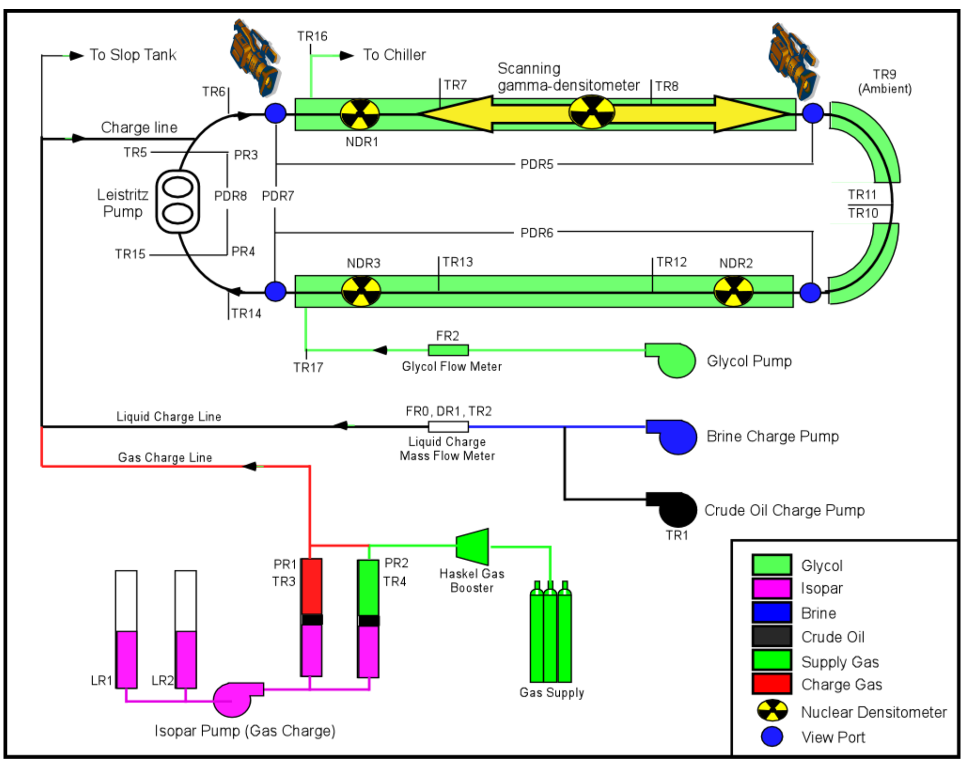


Figure XI.3: The Schematic of hydrate facility

## XI.1.3 INTEGRITY MANAGEMENT AND RISK ASSESSMENT

The projects related to integrity management and risk assessment are TA&R Projects No. 464, 459, 473, and 470. Detailed summaries of these projects are provided in a later section of this Annex.

### XI.1.3.1 PROJECT NO. 464 – DEVELOPMENT OF INTEGRITY METHODOLOGIES FOR THE TOPSIDES OF OFFSHORE PRODUCTION FACILITIES

The objectives of this study were to develop an engineering methodology for topsides structures, plant and piping integrity management and to integrate the survey/inspection process with existing defect assessment procedures. This project included the collation of pertinent codes, guidance documents, databases and literature worldwide and a number of interviews with the Gulf of Mexico offshore energy industry. This permitted the identification of regulation and code requirements and industry practice. Two relevant topsides related studies have been carried out.

A review of topsides facilities anomaly reporting showed two main findings. Firstly, many anomalies are attributable to external corrosion that can be detected by visual inspections, although only a small percentage of these led to failures. Secondly, a high proportion of internal corrosion anomalies led to failure. This leads to the conclusion that visual inspection will detect a high proportion of typical anomalies, but that this alone will not eliminate the anomalies that lead to a significant percentage of the reported failures. The report suggested an alternative methodology for an improved topsides inspection regime, which uses a risk-based approach.

The method prioritizes the inspection according to potential risks. This is likely to lead to more inspection of high-risk areas, whilst at the same time reducing inspection from the present requirements where it can be demonstrated that the risk is sufficiently low. The important aspect of the proposed methodology is the utilization of the results of pervious inspections in the risk assessment. The report also recommended that a workgroup be formed to take forward the findings from the research in order to develop a practical and usable risk-based approach to topsides integrity management and inspections.

### XI.1.3.2 PROJECT NO. 459 – COMPARATIVE RISK ASSESSMENT OF THE DECOMMISSIONING OPTIONS FOR LARGE PLATFORMS IN THE POCSR

The purpose of this project was to compare the safety risks associated with completely removing 3 representative platforms from the POCSR. The study provides a Comparative Risk Assessment of the decommissioning options for removing three specific platforms, as directed by MMS. The selected platforms are Eureka, Hidalgo, and Irene. The focus is on removal of the platforms in the Pacific Outer Continental Shelf Region (POCSR). However, the information provided is relevant to all similar platform removals. The risk assessment focuses on health and human safety (HHS). The risk assessment considers the principal options available for complete removal of the subject platforms. The assessment considers the impact of specific removal methods such as diver versus non-diver operations.

### XI.1.3.3 PROJECT NO. 473 – INTEGRATION OF HUMAN FACTORS WITHIN SAFETY ASSESSMENT AND MANAGEMENT WITH SPECIFIC REFERENCE TO HUMAN LIMITATIONS IN RESPONSE TO AUTOMATED DATA INPUTS FROM CONTROL ROOM MANAGEMENT & MONITORING SYSTEMS

The purpose of this project was to improve the way in which human factors is integrated within safety management in offshore energy industry. This was achieved through development and validation of the Influence Network (IN) technique. The IN approach is founded on systems theory and provides a method of understanding and measuring the nature of underlying influences that affect safety performance and the likelihood of an undesirable event occurring. The research was undertaken in three main stages:

- Influence Network methodology refinement and development
- Development of application support tool software
- Case studies to test and validate the methodology

The Influence Network has been tested as parts of this JIP project through a series of case studies. For each case study, the organization has chosen a risk scenario which is relevant to its business and the IN has been customized to model this. A workshop has been carried out to assess the model using people with specific knowledge of the risk scenario under consideration. Finally, a report has been produced for each case study outlining the method that was adopted, the key findings from the workshop, and recommendations for reducing risk in each case. The case studies that have been carried out are:

- An assessment of the human and organizational factors in dropped object incidents on an offshore installation in the North Sea.
- Evaluation of the key factors in process integrity incidents in the US Pacific oil and gas region and how to improve the inspection of these factors.
- Analysis of the key factors in loss of propulsion incidents on tankers and how the risk of such incidents could be reduced.

### XI.1.3.4 PROJECT NO. 470 – Coatings for Corrosion Protection: Offshore Oil and Gas Operation Facilities, Marine Pipeline and Ship Structures

This project undertook a complete assessment of opportunities for research and development of coating practice, coating materials, coating application, repair, non-destructive evaluation, and extended coating life prediction. This project offers a clear identification of research and development issues and creates a roadmap for achieving them. This project addressed specific issues and identified, prioritized, and recommended specific research and development topics for the government and industries to undertake. The recommendations are written in a format of broad agency announcement and offered in part or whole topics for consideration by agencies, technical societies, industry, and certification organizations for support and implementation.

# XI.2 OFFSHORE EQUIPMENT STANDARD AND CAPABILITY

## XI.2.1 PROJECT NO. 618 – COMPARATIVE STUDY OF OFFSHORE WIND TURBINE GENERATORS (OWTG) STANDARDS

### XI.2.1.1 Introduction

#### XI.2.1.1.1 Background

The U.S. Minerals Management Service (MMS) has been established as the lead regulatory authority for offshore wind power developments on the U.S. Outer Continental Shelf (OCS). This responsibility was established through the Energy Policy Act of 2005. There are currently no guidelines that have been accepted by the MMS or other U.S. agencies for the design of offshore wind power generators in U.S. waters. The codes and guidelines for offshore wind power development overseas have a limited history of use and have not yet been reviewed for their applicability to the conditions that exist on the U.S. OCS or for the levels of safety that would be required by the MMS and other U.S. agencies.

While the U.S. has a long history of onshore wind power development, offshore wind power resources remain largely untapped. At the time of this study, there are a few offshore wind farms proposed for U.S. waters but none have yet been constructed. Offshore wind represents a relatively new resource that can be developed with the use of today's very large, high efficiency, turbines.

Substantial experience with land-based wind farms has provided the industry with the basis to understand complex wind loading and the associated design requirements for wind power generators, support structures, and foundations. The codes and guidelines that have been developed for the design of land-based wind turbine structures have been adapted to address issues associated with the marine environment. These additional requirements have focused primarily on the loads generated from waves and currents and the effect of these loads on the design of the support structure and its foundation.

The MMS has significant experience with the design, fabrication, and installation of offshore structures. As stated in the Code of Federal Regulations, the MMS utilizes the American Petroleum Institute (API) Recommended Practice for Planning, Designing, and Constructing Fixed Offshore Platforms (API RP-2A Working Stress Design) as the basis for regulating the design and assessment of offshore structures in U.S. waters. This recommended practice is currently in its twenty-first edition, reflecting refinements based on the design of over 7,000 structures installed in the Gulf of Mexico, offshore Southern California, and in the Cook Inlet of Alaska. In addition to the application for oil and gas platforms located in U.S. federal waters, API RP-2A has been used for the design of numerous offshore platforms worldwide.

API RP-2A provides a basis for the design of offshore structures subject to wave, wind, current, and earthquake loading conditions; however, it does not address the scope and range of all conditions that are required for the design of wind turbine support structures. API RP-2A would have to be adapted or supplemented with other standards if it were to be used as the basis for wind turbine design.

#### XI.2.1.1.2 Technical Scope

The objective of this study was to compare two different design guidelines with respect to their applicability to the design of offshore wind turbine support structures in U.S. waters. The study compared the 1EC61400-3 and API RP-2A guidelines' and included a detailed assessment of the levels of structural reliability for extreme storm loading conditions that are achieved through the use of these guidelines.

This project was executed in phases over a period of two years. The first phase of the work included a definition of the specific study objectives and an identification of the design guidelines that would be used as the basis of the comparisons. This first phase assessment addressed the functional similarities and differences in the codes and compared the levels of structural reliability that are obtained using the two selected design guidelines in a generic application to offshore wind support structures.

The second phase included a more extensive study of structural reliability and addressed the significance of tropical storm hazards. The second phase has performed two site specific comparisons to enhance understanding of the effects of structure type, water depth, and environmental conditions on structural reliability. This site specific work required the selection of two hypothetical wind farm locations and the development of wind and wave data for each site. The results of the second phase of work have been integrated with those of the first phase and are documented herein as one comprehensive study report.

#### XI.2.1.1.3 Study Limitations

The IEC provides guidance specific to offshore wind turbine support structures that is not addressed in API. This more comprehensive design basis must be addressed in any design guideline adopted in the U.S. The study shows that there are several areas associated with the definition of loading that are critical to the design of the support structure and are subject to significant variability. The methods used for the calculation of wave slam forces, for example, specifically requires further study to improve the overall level of reliability in offshore wind turbine support structure design.

### XI.2.1.2 Project Conclusions

#### XI.2.1.2.1 Key Conclusions and Results

- A study of API and IEC safety factors and design recipe performed for different regions with different metocean variability indicates that the relative safety level generated when using the API or IEC design guidelines depends on the ratio of the 100- to 50-year load. This load ratio is primarily dependent upon the variability in the metocean conditions. For example, the metocean variability for the U.S. OCS regions included in the study appears to be significantly higher than that for the North Sea. As a result, for the U.S. OCS region, the API results in marginally higher safety levels compared to the IEC for a given offshore wind turbine support structure.
- The comparison of net safety factors included in the design methods for IEC (50-year) and API (100-year) show that comparable levels of reliability are achieved for a site with metocean variability somewhere between 0.12 (e.g., in North Sea) and 0.25 (e.g., Gulf of Mexico region). In other words, API appears to result in higher reliability than IEC for sites with a metocean coefficient of variation greater than 0.25. For sites with coefficient of variation smaller than 0.12, the IEC appears to result in a higher reliability than API; this is due to the effects of the safety factors in combination with the design storm used in IEC (50-year) versus the API (100-year storm). From a safety standpoint, both codes can be calibrated with appropriate safety factors with either starting point (i.e. either 50-year or 100-year metocean conditions) in order to achieve a predetermined target safety level for offshore wind turbines.

- This study has determined that period of vibration requirements that are specified by most turbine manufacturers to avoid accelerated fatigue will dominate the design requirements for most conditions, especially for mono-piles. As a result of this requirement, the difference in the design criteria that is specified within the API and IEC guidelines for extreme storm loading conditions (i.e., 50-year versus 100-year) is irrelevant for these typical conditions. The section properties that are required to ensure resonance-avoidance result in high ultimate strength capacity. This results in high reliability indices for both API and IEC designs. In this case, the difference in the API and IEC indices are irrelevant given that they are both high compared to safety levels suggested by each code.
- In protected areas that are not subject to extreme wave loading conditions, resonance-avoidance is still likely to be the dominant driver for support structure design. The next important parameter governing design would be wind load demands associated with the power generation or operating load conditions. In this situation, the difference in the design criteria that is specified within the API and IEC standards for extreme storm loading conditions is irrelevant for all types of support structures. When safety levels are compared, the API designs result in marginally higher reliability than the IEC designs, since the net safety factor for API is higher than IEC for operating case.
- In shallow water sites, the breaking wave limit may restrict wave heights to the point where both the 50- and 100-year conditions are represented with similar breaking wave conditions (once breaking happens, the slam loads become a dominant contributor to the total loads). In this situation, the difference in the design criteria specified within the API and IEC standards for extreme storm loading conditions is predominantly limited to the difference in wind speeds in a 100-year and a 50-year storm, respectively (wind load varies approximately as the square of the wind speed).
- The potential for very severe wind speeds and wave heights associated with tropical storms in the Gulf Region and also for the Northeast impacts the level of reliability for offshore structures, regardless of reference level storm condition that is adopted for design. In these locations, a greater safety factor will be required to establish the same level of performance that can be achieved in areas not subject to tropical storms. This additional margin can be established with the use of larger factors of safety for strength or load, with either the 50-year or the 1 00-year storm as the basis for the load factors. The selection of the best means to achieve consistent reliability

across different regions depends on the format of the design guideline that is adopted.

#### XI.2.1.2.2 OSER Goals

The focus of this study was to specifically assess the difference in the 50- and 100-year storm conditions that are included in the IEC and API guidelines, respectively. A comprehensive reliability assessment would also address other failure conditions including, for example, operational failures due to mechanical systems, overload of rotor blades, and fatigue. This study has specifically determined the reliability indices associated with the potential for the overload of the substructure under extreme loading conditions.

#### XI.2.1.2.3 Recommendations

The authors recommended:

- The study demonstrates that comparison of the reliability levels achieved with the IEC and API guidelines depends on a number of factors. There is no single approach using either the existing form of IEC or API that will result in a consistent reliability index for all conditions of offshore wind farm development in the U.S. OCS region. The study has shown that either guideline can be modified to achieve a target level of reliability and that factors such as met-ocean variability can be accommodated with adjustments to load and/or resistance factors.
- The U.S. wind industries address the definition of a minimum acceptable reliability index. This index can be defined either on an absolute basis (e.g., beta 3.5 or 4) or by means of comparison (e.g., following the API philosophy for oil and gas platforms in the Gulf of Mexico). This definition would allow for the calibration of either an IEC or API approach to offshore wind support structures that would address the variation of key factors across all areas in the U.S. OCS region. Such an approach would define load factors or factors of safety for met-ocean variability, tropical storm hazard, operating conditions, water depth, breaking waves, etc. on the reliability index to achieve a uniform safety level for all conditions in the U.S. OCS region.

#### XI.2.1.3 Current State of Knowledge

The study has compared the standards in terms of structural reliability for extreme storm conditions. The comparison starts with a generic assessment of each guideline and ends with site specific case studies. The results of the study show that the IEC and API design methodologies generate similar levels of structural reliability for the conditions included in this study. This is partly due to similarities in the fundamental philosophies of the guidelines and also a result of other design requirements that tend to deemphasize the influence of the extreme storm criteria.

The study also found that the levels of reliability that are achieved when using the IEC or API guidelines are significantly affected by the annual variability, or coefficient of variation (Coy), in tropical storm severity. Areas like the Gulf of Mexico exhibit large variability in storm severity, which results in a greater difference in the definition of 100- and 50-year storm conditions (i.e., wave heights and wind speeds). In this situation, the application of the API

The case studies have also shown that the need to avoid dynamic resonance with rotor frequency, amongst other issues, can affect the design of the support structure, resulting in high reliability indices regardless of the design recipe that is used. These design factors have, to some extent, offset the adverse impact of the higher CoVs associated with the tropical storms included in the case studies. It is likely that a set of conditions could be defined (i.e., latitude, water depth, support structure type and turbine size) where the support structure design would be controlled predominantly by extreme storm conditions. In these situations, the levels of reliability that would be produced using either the API or IEC design recipes would be substantially lower than those indicated for the case studies documented herein. Also, these situations could produce reliability levels that are less than the target levels inherent to API or IEC.

### XI.2.2 PROJECT NO. 446 – ROV/AUV CAPABILITIES

#### XI.2.2.1 Introduction

##### XI.2.2.1.1 Background

The Offshore Technology Research Centre (OTRC) conducted a workshop to bring offshore oil and gas operators, subsea equipment manufacturers, and remotely operated vehicle (ROV) and autonomous underwater vehicle (AUV) engineers, manufacturers, and contractors together to discuss future prospects, technology gaps and industry needs to enable better, more economical, and faster subsea deepwater development. The workshop was sponsored by the Minerals Management Service (MMS).

The workshop "Challenges of Interfacing Remotely Operated Vehicles and Autonomous Underwater Vehicles with Deepwater Subsea Systems" was conducted April 10-11, 2003 in Houston, Texas.

#### XI.2.2.1.2 Technical Scope

The scopes for this project were to develop a vision of future needs for ROV's, AUV's and subsea systems and identify the technology and non-technology gaps (needs). In addition, the groups suggested some paths forward to meet those gaps, and a course of action.

The discussions built upon the panel presentations and identified the following areas of concern: technology, reliability, economics, standardization, and human resources. All these concerns are discussed in this report.

#### XI.2.2.1.3 Study Limitations

Results and conclusions are most based on the workshop "Challenges of Interfacing Remotely Operated Vehicles and Autonomous Underwater Vehicles with Deepwater Subsea Systems" with 50 participants and duration of 1½ day.

### XI.2.2.2 Project Conclusions

#### XI.2.2.2.1 Key Conclusions and Results

Maximizing the vehicle/equipment utilization and availability is important to insure maximum uptime. In general, improvements that would enhance the reliability and uptime for AUV's and ROV's are:

- Increased power or increased power density
- Smaller vehicles those are more powerful
- Vehicles those are smaller in size
- Vehicles that have a smaller footprint.

Other technology gaps found in this project are:

- The ability to work longer distances using either a longer umbilical or no umbilical with increased battery or fuel cell power. In general, batteries and power sources or fuel cells need to be developed to give vehicles a longer-time-on-bottom and longer distance capability. Electrical voltage through the umbilical of 12,000 volts is needed. A 3 kilometer tether is needed to extend the ROV operating range.
- Better data transfer rates that allow real time communication with the AUV and possible video feedback.
- Most of the reliability problems now have moved from the ROV into the tooling. The transport systems are becoming fairly stable, but there are still big issues and the tooling is where the innovation is occurring.
- While power issues with AUV's remain, there is some improvement in this area. In addition, there is the thought that the power issues can be mitigated with good mission planning thereby reducing the amount of power needed.
- Software which allows vehicles and subsea systems to become smarter - complete with customer training which adequately educates the end-user concerning operation and benefits.
- Leak detection capabilities that allow for leak detection during pipeline surveys or cathodic protection surveys.
- AUV's that are capable of conducting well interventions without a host vessel on the surface.
- Development of full subsea processing with separation using booster pumps and subsea metering equipment. There is the need for the ability for a ROV/AUV to pull a pump, a compressor module, or a multiphase meter.
- The availability of AUV/ROV support vessels. In many cases, the proper ROV/AUV is available but the support vessel is not available.

#### XI.2.2.2.2 OSER Goals

The primary objective of this project was to develop a technical assessment of present and future AUV/ROV capabilities relevant to subsea deepwater oil and gas developments. A workshop was held to develop broad, objective assessment of ROV and AUV technology and capabilities relevant to subsea production systems. The assessment included present technology as well as technology and capabilities that could be available to industry in the next 5 to 10 years. The workshop included oil and gas operators, subsea engineers, ROV and AUV companies (suppliers and contractors), and subsea equipment manufacturers and additionally addressed the operational and safety issues.

#### XI.2.2.2.3 Recommendations

The authors recommended:

- Better cooperation is needed between the subsea hardware manufacturer and the ROV/AUV designers to share information and system needs/capabilities
- A financial model needs to be developed to demonstrate the value of the AUV. It was suggested that a small group be convened to define a case for the first use of an AUV for a futuristic application such as a subsea well intervention. The group should include the user, the clients, the hardware manufacturers, and the ROV/AUV Community. The result may be the development of a hybrid vessel rather than an AUV.
- Standardization on interfaces is needed. It was mentioned previously that the interface is either between the ROV and the tool package or between the tool package and subsea hardware. It is felt that a third-party consulting engineer or facilitator with time to devote to becoming a champion is needed to drive the standardization issue forward. This champion would be responsible for calling the meetings, setting the schedules, and publishing the minutes and results.

### XI.2.2.3 Current State of Knowledge

Hardware manufacturers aren't usually aware of what the life results of their systems are after installation, which makes design improvements allowing for increased reliability more difficult. There is a need for consistent project teams to stay involved for the duration of a system's life cycle. While there are very sophisticated tools coming out of space and military research in terms of reliability engineering the offshore energy industry has yet to implement these tools.

The automobile industry is also doing a considerably better job than the offshore energy industry due to longer car warranties. A current practice for hardware suppliers in the offshore energy industry is to issue a one year warranty; however, it is not uncommon for equipment to lay dormant on the beach for half of the warranty period. This dynamic seems to be inhibiting the production of commercially complete reliable systems. There is a need for new contracting strategies from the operators that make reliability engineering practices profitable.

There is a need to overcome existing barriers that inhibit the offshore community from incorporating the reliability engineering techniques from the space, military and automotive industries. Reliability engineering techniques need to be implemented prior to project development to allow for designs in advance of available technology.

There is a need for improved information access, allowing for remote monitoring of an ROV rather than requiring the operator to be on-site. Sensors and equipment need to be built into these new subsea systems to get information back to the remote operators. The technology exists, but a decision must be made to invest in that technology in order to reduce troubleshooting trips to the field. All-electric valve operation is needed in five years. Current technology theoretically would allow for a smart torque tool to be operated from a remote location. A web connection through the ROV umbilical would allow for tool operation from an office anywhere in the world.

# XI.3 FLOW ASSURANCE AND WELL INTEGRITY

## XI.3.1 PROJECT NO. 579 – JOINT INDUSTRY PROJECT TO STUDY RISK-BASED RESTARTS OF UNTREATED SUBSEA OIL AND GAS FLOWLINES IN THE GOMR

### XI.3.1.1 Introduction

#### XI.3.1.1.1 Background

Production shut-ins are part of any oil production operation, whether they are scheduled shut-ins to allow for maintenance or unplanned shut-ins in case of failure or emergency. In the Gulf of Mexico, shut-ins are necessary when hurricanes approach. After a hurricane, production systems are restarted following strict procedures to prevent the formation of hydrates and to prevent the formation of hydrate plugs. Some of these procedures involve flushing the lines with dead oil or inhibitors prior to shut-in or restart. In some cases, it is believed that the fluid properties combined with a proper selection of restart parameters may allow restart operations to be conducted safely without implementing these special procedure steps. Practically, this means that oil could be brought back into production faster, resulting in additional revenue for the operating companies. In the case of major hurricanes such as Rita or Katrina, a faster ramp-up of oil production also means that the supply of oil to the market would be less affected.

#### XI.3.1.1.2 Technical Scope

The project was divided in two phases. The purpose of Phase I of this study was to validate key concepts related to restart of uninhibited flow lines. Specifically, the main focus was set to:

- demonstrate the existence of an optimum restart rate capable of preventing plugging in a non-inhibited flowline,
- demonstrate how the presence of a free water phase can influence the plugging tendency of a system, and
- generate restart data in low spots where production fluids accumulate and evaluate the plugging tendency of such systems under gas-dominated restarts, which is often the case when wells are restarted after a production shut-in.

Phase II was aimed at studying the effect of other parameters, especially on low spot restarts. The parameters of interests were liquid loading in low spot, water cut, salinity and anti-agglomerant.

#### XI.3.1.1.3 Study Limitations

This study is based on physical model test; meanwhile the experiments were limited by the current facility. Additional data and test conditions (especially higher gas restart rates, vertical sections…) are required to improve the technology in this area. A new riser facility is currently in its design phase at the University of Tulsa to expand the studies and the knowledge related to hydrate plugging during steady-state and restart operations.

### XI.3.1.2 Project Conclusions

#### XI.3.1.2.1 Key Conclusions and Results

This project has highlighted some of the key factors involved in hydrate plug formation during production restarts. These findings are summarized below.

- As expected, the risk of hydrate plugging increases with water cut.
- The risk of hydrate plugging is increased significantly if the water phase is segregated.
- Lower restart velocities promote plugging for both gas dominated and multiphase or liquid-dominated restarts.
- Higher velocities reduce the risk of plugging; the effect is increased if the water is dispersed in the oil phase.
- A mechanism of plug formation with gas restart and segregated water phase has been observed; hydrates and liquid were displaced towards higher sections of the pipe by a "piston effect" created by hydrate restrictions in the lower sections.
- As salinity is increased, the hydrate formation rate slowed down and/or more permeable restrictions were formed.
- Anti-agglomerants were successful in preventing plugging as long as the right concentration is used. They remained effective even after 5-days with a hydrate slurry present in the pipe.
- The injection strategy of anti-agglomerant is critical; even if injected at the right concentration, anti-agglomerants were not effective if injected after shut-in.
- Transient flow simulations perform reasonably well in predicting the liquid displacement and water distribution along the pipe. However, once hydrates form,

simulations do not match. Also, the discrepancies are larger as water cut increases above 50%.

- These studies have emphasized that a deep understanding of the complex oil-water-gas-solid transient flow patterns taking place upon restart is required in order to understand and model hydrate formation and plugging accurately.

#### XI.3.1.2.2 OSER Goals

The purpose of this study is to conduct experiments to verify if and under what conditions restarts could be performed safely without the deployment of inhibitors or special operational steps to prevent plugging.

#### XI.3.1.2.3 Recommendations

All efforts should be made to reduce the time and effort required to implement the decommissioning process and to reduce the requirement for divers. This would include:

- Pursuing alternatives to complete removal of the jackets.
- Considering alternatives which would eliminate the requirement to cut the jackets up, such as disposal in reef sites.
- Encouraging the development and use of remote cutting technology, or other technology that would make the cutting process proceed more quickly, such as use of explosives for cutting jacket members.

### XI.3.1.3 Current State of Knowledge

A lot of work is currently devoted to the understanding and modeling of hydrate formation in pipeline under steady-state conditions. Very little work has been done or published on hydrate formation and plug development during restart operations. This work intends to fill up this knowledge gap a little more.

# XI.3.2 PROJECT NO. 602 – CEMENT FATIGUE AND HPHT WELL INTEGRITY WITH APPLICATION TO LIFE OF WELL PREDICTION

## XI.3.2.1 Introduction

### XI.3.2.1.1 Background

For a well, whether oil or gas, to maintain its integrity and produce effectively and economically, it is pertinent that complete zone isolation is achieved during the life of the well. This complete zone isolation, however, can be compromised due to factors that come into play during the operative life of the completed well. Such factors may come in the form of thermal or pressure loads generally regarded as HPHT (high temperature-high pressure) loads which can manifest themselves as a static/cyclic load or both, depending on how they are exerted. Depending on the magnitude of loading (stress level), the number of cycles and even the mechanical properties of the well cement, cyclic loading could result in failure by extensive breakdown of the microstructure of the cement.

### XI.3.2.1.2 Technical Scope

This project involves two major tasks:

- to identify the factors that affect the casing–cement integrity under HPHT conditions, and
- to understand better the fatigue of well cement.

Based on the knowledge acquired from completing these tasks, it will be possible to analyze the mechanics of casing–cement systems under HPHT conditions for the long term integrity of the system.

### XI.3.2.1.3 Study Limitations

Fatigue failure in cement occurs when microscopic damage within the microstructure of the cement, caused by initial cyclic loading, turns into macroscopic cracks under gradually increasing loads. Cyclic loading impacts initial damage and if loading is continued at load ratios above the critical ratio for a particular cement mix, failure is imminent but may undergo many cycles when loaded below this ratio. Loading conditions may affect the fatigue property of cement only when the mechanical properties are such as to withstand static loading. Designs based solely on static loading conditions may or may not be enough to ensure long term integrity depending on prevailing down-hole conditions, thus the need to take the analysis further by also examining the effect of fatigue with additional experimental studies.

### XI.3.2.2 Project Conclusions

#### XI.3.2.2.1 Key Conclusions and Results

The results of this study lead to the following key findings:

The mechanical properties of cement play a very important role in the static and fatigue performance of cement. Ductile cement systems – cements with low Young's modulus and a high Poisson's ratio – generally perform better under static and cyclic loading conditions as compared to brittle cement systems, i.e. cement systems with a high Young's modulus and low Poisson's ratio. Ductile cement systems generate significantly lower values of tangential and radial stresses, while brittle cements are more likely to generate higher tensile and radial stresses within their microstructure under a particular loading condition.

The magnitude of confining stress and the mechanical properties of the formation also play an important role in the static and fatigue behavior of both the cement and casing. A large far field stress (formation pressure) acts to increase the performance of the casing and counteracts high internal pressures, ensuring a minimal transfer to the cement sheath. Also, the more brittle the formation (in terms of Young's modulus and Poisson's ratio), the greater the stress transmitted to the casing and cement sheath.

#### XI.3.2.2.2 OSER Goals

The objective of this project is to develop a better understanding of the performance of the casing–cement bond under HPHT well conditions, leading to a model to predict well life.

#### XI.3.2.2.3 Recommendations

This study has focused on the effect of both static loading and fatigue behavior of well cement based on analytical and finite element models. A significant amount of experimental work is required in the future. This would include:

- The findings reported in this work are centered mainly on the mechanical properties of the cement and on loading conditions. The effect of other factors like cement-water ratio etc should be investigated through experimental studies.
- The effect of additives on the static and fatigue properties of well cement.
- Performance of new cement systems with special properties like foam and expansive cements should also be studied and data generated for them.

#### XI.3.2.3 Current State of Knowledge

There have been a lot of experimental investigations on the mechanism of fatigue failure of structures like buildings and bridges but the fatigue behavior of well cement is still relatively unknown to engineers. Research has led to improved cement designs and cementing practices, yet many cement integrity problems persist and this further strengthens the need to understand the mechanism of cement fatigue. Even though most structural failures are a result of fatigue rather than static loading, insights on the role of both static and fatigue loading conditions on the failure of cement sheath would hopefully lead to improvements in well design.

# XI.4 INTEGRITY MANAGEMENT AND RISK ASSESSMENT

## XI.4.1 PROJECT NO. 464 – DEVELOPMENT OF INTEGRITY METHODOLOGIES FOR THE TOPSIDES OF OFFSHORE PRODUCTION FACILITIES

### XI.4.1.1 Introduction

#### XI.4.1.1.1 Background

Though considerable effort has in recent years been expended on the integrity management of offshore fixed jackets, little has been directed towards floating topsides facilities and the linkage of routine inspection practices with defect evaluation and integrity management. A likely increase in HT/HP production places new emphasis on determining its effect on the integrity management process. Furthermore, there is wide recognition of the importance of competent personnel and the need to define baseline qualifications and training consistent with the HSE expectations of industry, regulatory bodies and the public.

MMS recognized that an integrity management methodology is necessary to facilitate continued asset utilization and field life extension consistent with the health, safety and environmental expectations of industry, regulatory bodies and the public whilst remaining within the economic realities of the modern business world. MMS appointed MSL Services Corporation (MSL) to study all available codes, standards, guidance documents, appraise current industry practice being followed by major operators/owners, examine available industry database, determine trends and consequences of damage/degradation and present a comprehensive guidance document outlining topsides integrity methodologies.

#### XI.4.1.1.2 Technical Scope

This project has included an extensive literature review and a number of interviews to identify current code requirements and industry practice. From a regulatory perspective, inspection of facilities in the Outer Continental Shelf (OCS) falls within the scope of Title 30 Code of Federal Regulations, Chapter II, Part 250. In addition to specifically identified requirements, the regulations incorporate provisions from other recognized industry codes and practices. The level of inspection for topsides facilities varies according to the type of equipment or system function. Of particular concern are platform cranes, pollution prevention, drilling operations, well completions, and safety systems.

In this report, to explore the availability and application of standards within the industry, use was made of a recent study of fabrication and in-service inspection practices for topsides structural components undertaken for the U.K. Health and Safety Executive (HSE). For this a number of international, pan-national and national documents were examined to identify clauses relevant to material classification, categorization of components, recommended inspection techniques including procedures, inspector qualifications, reject/acceptance criteria, and in-service inspection requirements. The extent of coverage by these documents is quite variable. For in-service inspection of topside structures the standards provide far less guidance than for fabrication inspection. The frequency of in-service inspections for topsides generally follows as an add-on to that for the jacket. This is likely to be both inefficient and ineffective for topsides, which need a program relating specifically to the component in-service safety criticality.

#### XI.4.1.1.3 Study Limitations

An operator wishing to route HT/HP production through existing infrastructure will have to address issues such as sealing, corrosion, expansion, waxing, logging, workover, erosion, metering, shutdown, and pressure relief. It will be necessary to reanalyze the process system for the new flow conditions, and to perform a new HAZOP for the modified facilities. An essential part of this will be to obtain a reliable assessment of the existing condition of the pipework and vessels. Given that this study points to internal corrosion as being a prime cause for concern, a detailed internal survey will always be necessary. A Level 1 survey described in this report will not be sufficient.

### XI.4.1.2 Project Conclusions

#### XI.4.1.2.1 Key Conclusions and Results

The likelihood of topsides damage or degradation has been estimated from MSL in-house data and industry feedback. MSL has compiled a reliable, industry-wide database from the collective inspection data amassed by industry over the last ten years and beyond. The database includes data from the MMS, CAIRS, and operators. The data relevant to topsides structures inspection was extracted and carefully reorganized into a more useful form for assessing the reported incidents. The original data were filtered and broken down into both anomaly type and structural component. It was found that handrails were responsible for 25% of the reported anomalies and structures for 13%. Of these anomalies the leading two attributors appear to be corrosion at 40% and separation/missing items at 23%. To assist in the determination of topsides systems failure probabilities, MSL acquired from Global X-Ray & Testing Corporation a mechanical integrity database, comprising 1,960 anomalies recorded in the Gulf of Mexico between 1995 and 2003. It should be understood that anomaly probabilities generated from this database are a simple count of the failures versus total defects recorded. They have not been normalized with reference to the number of systems or equipment items in operation. Thus the system failure statistics derived from the database do not represent the relative safety of an individual system but should represent the relative number of that system type failing in the Gulf of Mexico as a whole, oil separation system failures being the most commonly occurring. For this reason, the system failure rates were compared with HSE data, based on leaks/system year. According to this source, gas compression has the highest rate per system.

The consequence of topsides damage or degradation has been assessed with respect to safety, the environment, business disruption and reputation. Topsides structural components and other items that are typically inspected have been classified according to the consequence of their failure (A being the highest consequence and E the lowest). These classes have been assigned on the basis of personnel safety and loss of hydrocarbon inventory but not on economic grounds. A similar approach has been adopted for the topsides facilities. The consequence class has been determined on a system basis, taking into account five weighted parameters: operating pressure, inventory volume, temperature, fluid phase and hydrocarbon content.

#### XI.4.1.2.2 OSER Goals

The aims of this study are as follows:

- • To develop a reliable engineering methodology to manage the integrity of the topsides of offshore production facilities including structural systems, operating plant, piping and appurtenances e.g. risers, conductors and caissons. This objective encompasses the effects of new HT/HP production being introduced to existing platforms.

- • To integrate the inspection/survey process (data collection) with existing defect assessment procedures (engineering evaluation) as part of the integrity management strategy.

#### XI.4.1.2.3 Recommendations

It is recommended that a workgroup be formed to take forward the findings from this study in order to develop a practical and usable risk-based approach to topsides integrity management and inspection.

### XI.4.1.3 Current State of Knowledge

A lot of effort has been expended on the integrity assurance of offshore substructures such as jacket platforms. Detail guidance in this area can be obtained from API and other standards and recommended practices. By contrast, little effort has been directed to date in the field of integrity assurance for topside facilities and no effective link has been established between routine topsides inspection practices (data collection), defect evaluation and the overall integrity management process. From the standpoint of integrity of topside facilities, a number of areas of uncertainty exist at the present time, including the following.

- There is a wide range of codes and standards (i.e. regional standards and national standards). The available practices are diverse with little or no cross-discipline interface. Existing guidelines for the measurement and recording of degradation mechanisms, in particular, corrosion, are limited. Existing guidelines for the evaluation of degradation mechanisms is also limited. Those guidelines that do exist are not well integrated with inspection practices (data collection).
- Performance data from topsides inspections indicates widespread corrosion degradation of appurtenances, including risers, conductors and caissons, through the splash and atmospheric zones. Present routine surveys are ineffective in collecting data necessary to evaluate the significance of the corrosion damage. In addition, assessment methodologies are not well established.
- In the Gulf of Mexico, there is an increasing likelihood of new high temperature/high pressure (HT/HP) production streams being introduced to existing platforms. This introduction places significant emphasis on the need to determine the effects of HT/HP production streams on piping and vessels and the consequential impact on the overall integrity management process.

- Extrapolation of present-day relevant practices to cover inspection of topsides has not been examined in any detail. This applies equally to the superstructure (i.e. deck legs, trusses, girders, risers, etc.) and process/utilities/plant (i.e. system design and layout, pressure vessels, safety critical systems, piping, etc.).
- As with matters related to substructure integrity management, there is an industry – wide recognition of the importance placed on the use of competent personnel to carry out the tasks involved in topsides integrity management. There is a need to define the baseline qualifications and the training for personnel involved in the integrity management of topside facilities.

Evaluate options available for mitigation of the most risky aspects of offshore platform decommissioning, including the use of alternative technologies, e.g., diver versus non-diver methods, and alternative lifting systems.

## XI.4.2 PROJECT NO. 459 – COMPARATIVE RISK ASSESSMENT OF THE DECOMMISSIONING OPTIONS FOR LARGE PLATFORMS IN THE POCSR

### XI.4.2.1 Introduction

#### XI.4.2.1.1 Background

This study provides a comparative risk assessment of the decommissioning options for removing three specific platforms. The selected platforms are Eureka, Hidalgo, and Irene. The focus is on removal of the platforms in the Pacific Outer Continental Shelf Region (POCSR). Meanwhile, the information provided is relevant to all similar platform removals. The risk assessment focuses on health and human safety (HHS). The risk assessment considers the principal options available for complete removal of the subject platforms. The assessment considers the impact of specific removal methods such as diver versus non-diver operations.

Specifically, the study compares the risk for serious accidents or fatalities with complete removal by cutting offshore platforms up in-place (in-situ), requiring significant underwater activities, with the alternative of "hopping" the platforms into shallower water, such that most cutting can be done in air. The study assumes as a base case that all underwater cutting will be performed by divers using conventional air-arc techniques. The availability and impact of alternative cutting methods will also be considered.

#### XI.4.2.1.2 Technical Scope

The overall technical scope of the project is to examine the relevant issues and to quantify them in the context of comparative HHS risk, using state-of-practice methodology and currently available technology. The followings are more specific:

- Define/identify the principal options available for the complete removal of the POCS platforms.
- Develop plausible complete removal scenarios for three representative platforms using currently available technology. Development of these scenarios includes work plans which identify the time and resource requirements.
- Quantify the specific issues related to the decommissioning of the subject platforms which carry significant risk in terms of HHS. As part of this process, an industry forum on decommissioning safety was held and industry input was solicited.
- Evaluate the risk issues for the various decommissioning options. The HHS risk is quantified to the maximum extent allowed by the data available.
- Evaluate options available for mitigation of the most risky aspects of offshore platform decommissioning, including the use of alternative technologies, e.g., diver versus non-diver methods, and alternative lifting systems.

#### XI.4.2.1.3 Study Limitations

- The study does not encompass plugging the wells, cutting and removing the well conductors and casing or onshore dismantlement of the structures. Consideration in this study ends when structures are safely tied down on a cargo barge or other means of transport.
- Besides above, other limitations of this study are:
- As in any form of modeling, the results are only as good as the input to the model. With respect to the industry's experience, both Hidalgo and Eureka are significantly larger and also in deeper water than anything that has been removed to date.
- The decommissioning models used in this study were developed by knowledgeable and experienced people, but they contain a large number of assumptions that will eventually need to be verified.
- The accident data used to develop the rates used in this study were not as specific to the offshore energy industry in general and to decommissioning in particular as would be desired.

- The previous comment is particularly true for the diving accident data. This issue has been discussed with diving industry representatives. A convincing case has been made that the US based diving industry has a much better accident record than is reflected in the data used for this study.
- However, no data has been made available that would support that assertion. This is apparently because the data is not collected, by the government, in a manner that can be used for this type of analysis.

### XI.4.2.2 Project Conclusions

#### XI.4.2.2.1 Key Conclusions and Results

The results of this study lead to the following conclusions:

- Complete Removal In-Situ will be more time consuming and demand more human resources than the Hopping method. This assumes the use of the technology and methods that are readily available today.
- The Hopping method appears to be much safer in a relative since, when compared to In-situ jacket removal. Risk of accidents increase with water depth for both methods, both it increases much faster with the In-situ method.
- Review of the accident rate data presented in the study and the analysis results point to underwater work with divers as the major risk area.
- Every effort should be made to eliminate or reduce diver usage and to shorten the time required for decommissioning in general.

Risk of accidents increase with water depth for both methods, both it increases much faster with the In-situ method.

#### XI.4.2.2.2 OSER Goals

Review of the accident rate data presented in this report point to underwater work with divers as the major risk area. If risk based management processes are to be used to help reach decisions on alternatives that can be employed in offshore operations involving diving, then it is suggested that a sustained effort be initiated and maintained by the appropriate agencies to gather, analyze, document, and communicate the necessary information on commercial oil field diving operations. Such an initiative would require reporting by industry of all commercial diving injuries and fatalities in a given time period (annual) and the number of hours that the divers were exposed to the different categories of diving operations (air – gas and saturation).

#### XI.4.2.2.3 Recommendations

All efforts should be made to reduce the time and effort required to implement the decommissioning process and to reduce the requirement for divers. This would include:

- Pursuing alternatives to complete removal of the jackets.
- Considering alternatives which would eliminate the requirement to cut the jackets up, such as disposal in reef sites.
- Encouraging the development and use of remote cutting technology, or other technology that would make the cutting process proceed more quickly, such as use of explosives for cutting jacket members.

### XI.4.2.3 Current State of Knowledge

This study has made an effort to gather all of the accident and fatality data that is publicly available, relevant to offshore platform decommissioning. It was originally intended that individual accident rates would be provided for each of the individual labor categories. However, in the end this was not possible because of the limited availability of data. Another issue is the general lack of accident data from sources in the US offshore energy industry. To be useable in the context of this study, the "rate" of accidents for a given number of hours worked must be available. All of the sources accessible by this study reported only actual accident information for the US based offshore energy industry, without the reporting the hours worked associated with the accidents. This information is not useable in the probabilistic models used in this study. Therefore, the accident rates used are based primarily on data generated in Europe. It may be argued that the rates for the US offshore energy industry are different. However, this cannot be verified at this time.

## XI.4.3 PROJECT NO. 473 – INTEGRATION OF HUMAN FACTORS WITHIN SAFETY ASSESSMENT AND MANAGEMENT WITH SPECIFIC REFERENCE TO HUMAN LIMITATIONS IN RESPONSE TO AUTOMATED DATA INPUTS FROM CONTROL ROOM MANAGEMENT & MONITORING SYSTEMS

### XI.4.3.1 Introduction

#### XI.4.3.1.1 Background

The Influence Network (IN) approach is being tested as part of a Joint Industry Project (JIP) which is concerned with the development of an approach for human factors management in hazardous industries. The IN is a technique which is used to identify improvement measures in relation to a particular area of performance, for example, risk reduction. This is done by using a model of the typical human, organizational, strategic and external factors that influence the problem which is being analyzed.

Discussions were held with the MMS JIP representative who explained that the MMS Pacific Region office may be able to assist with the case study. Correspondence was then held with members of the MMS Pacific Region Office who suggested issues of interest to them which may be suitable for the case study, with the most significant topic emerging as process integrity. The preferred topic for the case study was analysis of the key process integrity inspection areas which MMS should be focusing on. It was then possible to shape the aims of the study which were:

- To enable MMS to get an understanding of the key areas influencing process integrity, and why they are the key areas.
- To enable MMS to identify and priorities potential improvements to the inspection process.

MMS is keen to ensure that best practices are used to mitigate and monitor internal corrosion on such facilities in order to prevent leakage.

#### XI.4.3.1.2 Technical Scope

Aims and context of this study are:

9. Underlying causes and control measures - Assessing the factors that have the strongest influence on process integrity management and how these factors could be improved.

10. Key inspection areas - Identifying the key areas which MMS should be covering in its inspections of process integrity and what specific issues / questions need to be addressed in each area. Rather than assessing how to prevent failures, the focus would be on how inspectors can identify possible shortcomings that, ultimately, may lead to failures.

11. Improving the inspection process - Assessing the factors that have the strongest influence on the effectiveness of the MMS annual inspections on process integrity and how these could be improved.

The second of these options was chosen by the MMS Pacific Region office as their preferred topic for the case study i.e. analysis of key inspection areas which MMS should be focusing on. It was then possible to shape the aims of the study which were:

- To enable MMS to get an understanding of the key areas influencing process integrity and why they are the key areas.
- To enable MMS to identify and priorities potential improvements to the inspection process.

#### XI.4.3.1.3 Study Limitations

In terms of the scope, the workshop was limited to the Pacific Outer Continental Shelf (POCS) region and that all types of processes would be considered at all stages of the process lifecycle, from design to maintenance. Of particular interest were the effects of acid gas production on process piping and vessels, as several POCS facilities process gas with varying concentrations of H2S. MMS is keen to ensure that best practices are used to mitigate and monitor internal corrosion on such facilities.

### XI.4.3.2 Project Conclusions

#### XI.4.3.2.1 Key Conclusions and Results

The results of this study lead to the following conclusions:

- The aims and scope of an IN exercise should be discussed and agreed with the client as early in the process as possible.
- Where possible, the aims of the customization should be set out before the process actually begins.

- Ideally, customization should take place before a meeting with the client, for example, using incident data and investigation reports as supplied by MMS in this case study. However, in reality, it is likely that a considerable amount of customization will need to be done in face-to-face discussions with the client.
- Based on the findings from the workshop, several recommendations were made to help MMS improve the way in which it inspects process integrity issues. For example, it was recommended that:
- Consideration should be given to the inclusion of small bore piping in the MMS Regulations.
- Whilst MMS has a checklist for inspectors to compare observations against regulatory requirements, it may be worth developing a similar checklist for 'best practice' observations.

#### XI.4.3.2.2 OSER Goals

The main aims of this project are to develop and establish the IN technique to enable the offshore energy industry to integrate human and organizational factors into health and safety management. Thus, it aligns with the second goal of OSER.

#### XI.4.3.2.3 Recommendations

Based on the findings from this project, the following recommendations are made:

- Consideration should be given to the inclusion of small bore piping in the MMS Regulations.
- Feedback from MMS inspections should be used to inform future inspections.
- MMS should review its requirements on permits to work to ensure they adequately cover process integrity risks.
- MMS should ask specific questions about process integrity in annual performance review meetings and in any employee interviews which are carried out during inspections.
- This report should be made available/disseminated to operators in the POCS and other regions, e.g. Gulf of Mexico. It should be pointed out that the report contains suggestions for operators/industry to make improvements in the reduction of process integrity risks.
- Whilst MMS has a checklist for inspectors to compare observations against regulatory requirements, it may be worth developing a similar checklist for 'best practice'

observations. Whilst the items on this checklist may not be enforceable, they will provide inspectors with an indication of what is possible among the 'best practice' organizations.

#### XI.4.3.3 Current State of Knowledge

Currently, it seems that MMS does not prescribe inspection and maintenance programs and, as such, standards in this area vary between operators. It is recommended that MMS should at least provide guidance on inspection and maintenance in order that industries are working from a common reference point. This might include assessing the adequacy of information on process equipment provided by manufacturers.

### XI.4.4 PROJECT NO. 470 – COATINGS FOR CORROSION PROTECTION: OFFSHORE OIL AND GAS OPERATION FACILITIES, MARINE PIPELINE AND SHIP STRUCTURES

#### XI.4.4.1 Introduction

##### XI.4.4.1.1 Background

There is no widely-accepted database or clearinghouse for corrosion coatings management for offshore structures, pipelines and vessels.

With the increased use of steel catenary risers (SCR's), long subsea tie-backs, higher reservoir temperatures, deepwater and Other OSER environments, not only for offshore structures but for other marine facilities such as ports and docks, vessels whether stationary or mobile and the coating materials and their application methods are in a constantly changing and developmental process. The need for a vehicle for the sharing and transfer of knowledge in these areas was / is needed. These issues generated a need for such workshops. A similar corrosion workshop was also conducted in Galveston, TX in 1999.

##### XI.4.4.1.2 Technical Scope

Although this workshop was not a technical workshop where issues would be resolved, but rather a undertook a complete assessment of opportunities for research and development of coating practice, coating materials, coating application, repair, non-destructive evaluation and extended coating life prediction, and what will be needed in the future if the energy exploration and production industry continues to grow in these environments. The workshop was divided into six different areas of industry:

- Coatings for ships
- Coatings for offshore structures
- Coatings for pipelines
- Coatings for port facilities
- Coatings materials and deposition technologies
- Coatings inspection and repair

#### XI.4.4.1.3 Study Limitations

With the wide range of applications, structures and working environments involved, a universal coating does not exist, nor is it ever expected that one coating will cover all applications. One area that does not appear to have been addressed is the corrosion control under SCR strakes.

### XI.4.4.2 Project Conclusions

#### XI.4.4.2.1 Key Conclusions and Results

The recommendations from the workshop offer a clear identification of the research and development issues necessary to create a roadmap for achieving them.

#### XI.4.4.2.2 OSER Goals

The best forum for an assessment and R&D path determinations is a dynamic workshop. The goals of this workshop were as follows:

- Transfer of information
- Learn about new technologies and materials
- Assess future needs
- Define the best opportunities for research

New technologies for remotely sensing and monitoring the corrosion damage of coated structures are important to guarantee integrity.

### XI.4.4.2.3 Recommendations

The recommendations from the workshop are classified into four areas. Within each area topic there are numerous projects and programs which must be completed to achieve the intended goal.

Research

- Quantitative evaluation of the long term field performance of pipeline coatings.
- Development of practices for evaluating pipeline coatings for service under extreme conditions such as; offshore-deepwater, offshore-Other OSER, Onshore-equator.
- Development of a non-destructive method of evaluating the application of coating systems.
- Development of specific advancements in coating materials.

Development

- Improvement in the effective use of coatings for port facilities and the development of the necessary performance-based specifications.
- Advanced methods for the applications of coatings.
- Assessment of new technologies for surface preparation before coating.

Administration

- Standardized methods for data collection and management.
- Formulation of a roadmap for coatings research and/or development that indicates the proper sequence of projects.
- A working group, national or regional, to increase exchange of information on the performance of coating products and application.
- Evaluation of the economic issues of coating materials, their application, and their service behavior.

Operations

- Advanced methods for coating repair.
- Training, education, and certification of painters, corrosion engineers, and inspectors in the marine and pipeline industry.
- Development of coating/corrosion assessment criteria and acceptable corrosion levels for use by corrosion engineers and regulators in the development and assessment of Asset Integrity management Programs.

- Address the environmental, health and safety issues regarding paint materials and their application

### XI.4.4.3 Current State of Knowledge

Some of the programs and projects mention have already been implemented. In particular, MMS has already implemented an in-service inspector training course. NACE and SSPC have developed additional Marine, Offshore and Shipboard training and certification programs. Coating manufacturers are constantly developing new corrosion and thermal insulating coatings.

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