CENTER FOR OFFSHORE SAFETY

ANNUAL PERFORMANCE REPORT

FOR 2016 REPORTING YEAR

September 19, 2017

NOTICE

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COMMONLY USED ACRONYMS

AB – Accreditation Body

API – American Petroleum Institute

APR – Annual Performance Report

ASP – Audit Service Provider

BSEE – Bureau of Safety and Environmental Enforcement

CAP – Corrective Action Plan

COS – Center for Offshore Safety

DART – Days Away from Work, Restricted Work, and Job-Transfer Injury and Illness Frequency

F/G – Fire/Gas

GoM – Gulf of Mexico

HVLE – High Value Learning Event

LFI – Learning from Incidents and HVLE

LOPC – Loss of Primary Containment

MIT – Maintenance, Inspection, and Testing

MOC – Management of Change

NC – Non-conformance

NEB – National Energy Board (Canada)

OCS – Outer Continental Shelf

OFI – Opportunity for Improvement

PRD – Pressure Relief Device

RIIF – Recordable Injury and Illness Frequency

SEMS – Safety and Environmental Management System

SIMOPS – Simultaneous Operations

SPI – Safety Performance Indicator

SWA – Stop Work Authority

UWA – Ultimate Work Authority

WPCS – Well Pressure Containment System

1.0 2016 COS MEMBERS AND PARTICIPANTS

COS MEMBERS

Operators	Rig Contractors	Service Companies	Associations
Anadarko	Diamond Offshore Drilling	Baker Hughes	ASQ
BHP Billiton	Ensco	Cameron International	IADC
BP E&P	Noble Corp	GE Oil & Gas	IMCA
Chevron USA	Pacific Drilling	Halliburton	MSRC
Cobalt	Transocean	Helmerich & Payne	NOIA
ConocoPhillips		Oceaneering	OMSA
ExxonMobil		Schlumberger	OOC
Hess			Opito
Murphy E&P			
Noble Energy			
Shell International E&P			
Statoil North America			

10 Operators and 4 Rig Contractors and Service Companies shared SPI data for use in this APR. COS members who are listed as Associations above do not provide data.

In addition to the members listed above, the following companies have joined COS in 2017.

Rig Contractors
Rowan

Service Companies
SBM Offshore
Subsea7

2.0 INTRODUCTION

The Center for Offshore Safety (COS) is designed to promote the highest level of safety for offshore drilling, completions, and operations through leadership and effective management systems addressing communication, teamwork, and independent third-party auditing and certification. COS enables operational excellence in part by enhancing and continuously improving industry's safety and environmental performance and stimulating cooperation within industry to share industry learnings.

This COS Annual Performance Report (APR) provides information shared by its members under the following COS programs:

- Safety Performance Indicators (SPI),
- Learning from Incidents and Events (LFI), and
- SEMS Audits

The COS member data provided through the LFI and SPI programs and the SEMS audit results enable continual improvement of performance-based systems

The SPI originated from major hazard bow ties, developed within COS, that cover both process safety and personal safety. The information can be used for driving improvement and, when effectively acted upon, contribute to reducing risk of major incidents by identifying weaknesses in barriers intended to prevent the occurrence or recurrence of incidents and mitigate consequences. The scope of the SPI data covers COS member wells, projects, and production facilities and operations in the U.S. Outer Continental Shelf (OCS). The LFI data covers the same scope, but also allows for the submittal of data for incidents and events which occur outside the U.S. OCS. Operators share both Operator and Contractor SPI and LFI data relative to activities that occur on their facilities and within 500 meters of their facilities. COS Rig Contractors and Service Companies share SPI and LFI data relative to activities occurring outside 500 meters of Operators' facilities. In the context of this report, the term safety is inclusive of personal safety, process safety, health, security, and the environment.

2.1 SPI Program

In January 2016, COS published an updated SPI Program User Guide for the U.S. offshore industry. The objectives of this program are twofold. First, it provides a means for sharing data related to key safety performance indicators. Second, it assesses past performance to identify potential opportunities which could lead to improvements in future performance.

The SPI used in this program were selected from assessments of major hazards in the offshore industry. Most of the SPI are outcomes or consequences of the failure of prevention and/or mitigation barriers. Over time, the intent of this program is to better identify safety performance indicators that will help detect potential problems prior to there being a major consequence.

Publications by the American Petroleum Institute, UK Health and Safety Executive, Center for Chemical Process Safety, International Association of Oil and Gas Producers, and the Organization of Economic

Cooperation and Development, as well as the experience shared by COS members, were valuable to the development of this program.

Unless otherwise specified, all frequencies stated in this report are normalized by total work hours multiplied by 200,000. Work hours are reported based on a 12-hour work day offshore.

2.2 LFI Program

In January 2016, COS published an updated LFI Program (LFIP) User Guide. The main objective of the program is to provide COS members a mechanism for sharing information from incidents that meet the criteria for an SPI 1 or SPI 2, as well as other incidents that meet the criteria of a High Value Learning Event (HVLE). The LFIP also serves to complement the SPI Program by collecting additional information on SPI 1 and SPI 2 events, which are described in more detail in Section 4. This information is analyzed and shared to enable industry learning and reduce the risk of recurrence.

2.3 SEMS Audit Program

BSEE issued its Workplace Safety Rule or Safety and Environmental Management Systems (SEMS) regulations in October 2010, requiring all Operators operating in the U.S. Outer Continental Shelf (OCS) to develop, implement and audit a SEMS. Operators were required to complete the first round of audits by November 15, 2013.

COS developed and issued a SEMS Audit and Certification Program and an Audit Service Provider (ASP) Accreditation Program in October 2012 to support its mission of improving safety and environmental performance. The program documents are published on the COS website at http://www.centerforoffshoresafety.org/, under the Documents tab. The SEMS audits are performed to verify that COS member companies have established, implemented, and maintained a SEMS throughout their U.S. OCS operations, and are looking to continually improve their SEMS. The COS SEMS Audit and Certification Program was established to recognize COS member companies who conducted their SEMS audits and completed their Corrective Action Plan (CAP), if applicable, to the satisfaction of the ASP.

In April 2013, BSEE issued its SEMS II regulations that added additional requirements regarding stop work authority, ultimate work authority, employee participation plan and reporting of unsafe conditions. The SEMS II regulations also added additional requirements regarding SEMS auditing, including incorporation by reference of the COS documents (COS-2-01, COS-2-03 and COS-2-04) that detailed the requirements of the COS SEMS Audit and Certification Program. One significant impact of the incorporation was to require all SEMS Audits conducted after June 2015 to be conducted by an Accredited ASP.

In June 2015, BSEE formally accredited the existing COS ASP Accreditation Program. COS serves as an Accreditation Body (AB) for purposes of qualifying independent, third-party ASP to perform credible, objective and comprehensive evaluations of operators' SEMS programs.

BSEE's 'SEMS II' audit requirements became effective in June, 2015 and all operators operating on the U.S. OCS must utilize an accredited ASP to evaluate their SEMS. BSEE's "SEMS II" regulation incorporated by reference the COS documents (COS-2-01, COS-2-03 and COS-2-04) which outlined the COS Program Requirements.

In 2014, COS requested COS Operator members to share the results of its first round of audits that were completed by November 2013. These results, gathered through a survey mechanism which protected the identity of the data owner, were analyzed to identify performance trends and learning opportunities that may be used by the industry and individual members to improve SEMS, and ultimately safety and environmental performance. The results of the analysis were reported publicly in the COS first APR in 2014.

In 2017, COS again requested COS Operator members to share the results of its second round of audits that were completed by November, 2016. The results were collected by completing data fields within a template and were submitted using a process that protected the data owners' identities. The data was more extensive in terms of content of the audit conclusions, deficiencies and strengths.

3.0 EXECUTIVE SUMMARY

The SPI and LFI Programs began implementation in 2014, reflecting 2013 performance. The SEMS Audit results have only been reported once previously, in 2014, after the first round of SEMS Audits was completed. This report provides the associated program information for the 2013-16 reporting years, including data for the second round of SEMS Audits.

3.1 SPI Data Summary

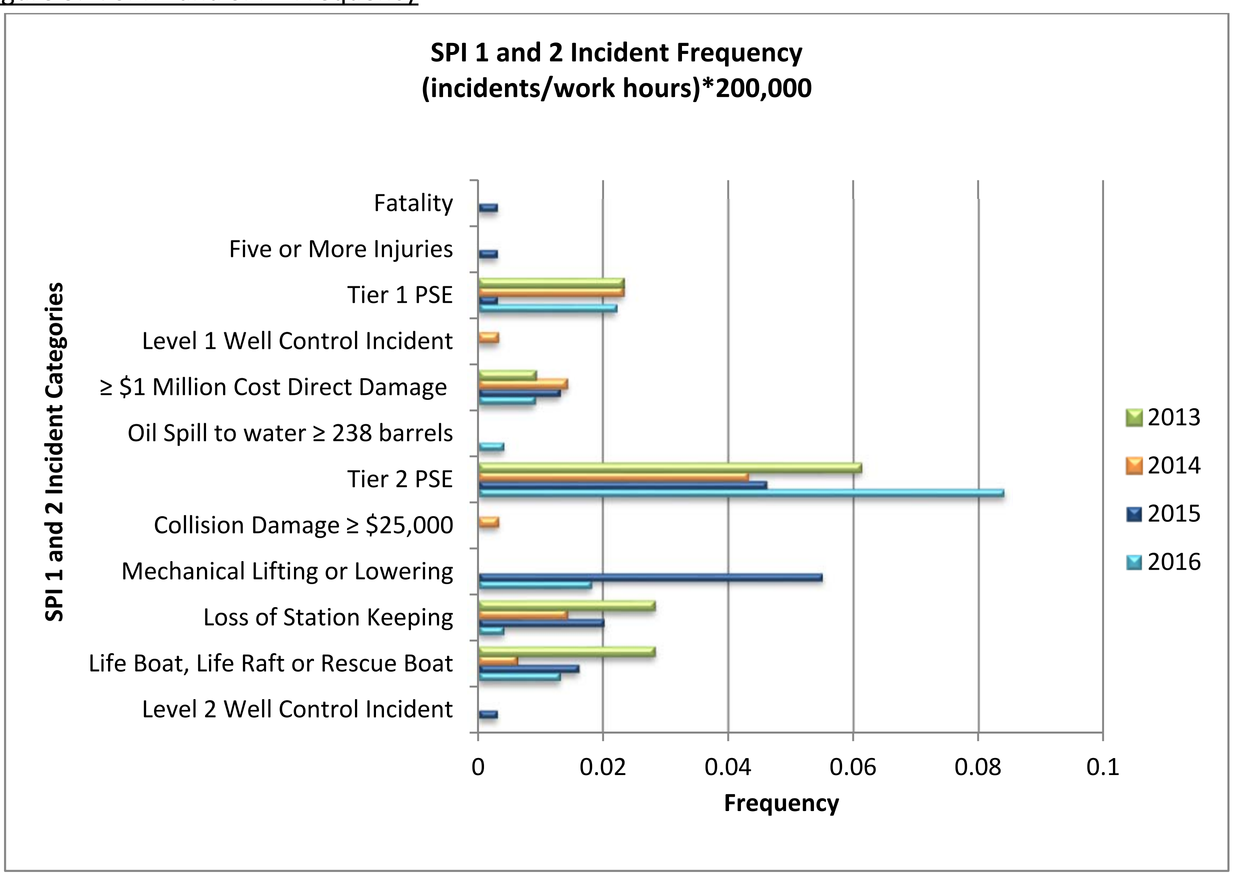
This report provides COS member data for 2013-16. The 2016 reporting year data represents over 45 million operator and contractor work hours in the U.S. OCS.

The 2016 data includes one incident that resulted in an Oil Spill ≥ 238 barrels, the first time this has been reported to COS. In addition, participating companies reported 5 Tier 1 Process Safety Events and 2 incidents Involving ≥ $1 Million Direct Costs from Damage to a Facility, Vessel, or Equipment. No incidents resulting in Fatalities, Five or More Injuries, or Level 1 Well Control Incidents were reported for 2016.

Participating members also reported 19 Tier 2 Process Safety Events, 4 Incidents involving Mechanical Lifting or Lowering, 1 Loss of Station Keeping Incident Resulting in a Drive Off or Drift Off, and 3 Life Boat, Life Raft, or Rescue Boat Events. No incidents resulting in Collisions with Damage ≥ $25,000 or Level 2 Well Control Incidents were reported for 2016.

The frequency of all SPI 1 and SPI 2 incidents are shown below.

Figure 3.1: SPI 1 and SPI 2 Frequency



The Tier 1 PSE frequency reported for 2016 returned to the same levels as reported for 2013 and 2014. Tier 2 PSE frequency reported for 2016 increased by 85% over that reported for 2015, and represents the highest reported frequency reported to COS in the four years of reporting.

There were 4 Incidents involving Mechanical Lifting or Lowering (2C). The definition for this safety performance indicator was changed for the 2015 reporting year; therefore, both the count and frequency of these types of incidents is provided for only the 2015 and 2016 reporting years. The data shown in the first two APR (for the 2013 and 2014 reporting years) has been moved to SPI 4. The frequency of SPI 2C events decreased by 67% for 2016 as compared to 2015.

The frequencies of both Loss of Station Keeping Resulting Drive Off or Drift Off and Life Boat, Life Raft, or Rescue Boat Events trended down for 2016 as compared to 2015. This represents the lowest frequency of Loss of Station Keeping incidents reported to COS in the four years of reporting.

16 of the 34 (48%) SPI 1 and SPI 2 incidents reported for 2016 involved failure of equipment as a contributing factor. This is an increase from 38% reported for 2015 and more closely matches the 45% reported for 2014. The largest contributors to equipment failures for 2016 are the "Other" category, followed by the Well Pressure Containment Systems and Process Equipment/Pressure Vessels/Piping categories. Specific definitions and descriptions of the equipment categories are found in Appendix 3.

SPI 2F – Level 2 Well Control Incidents – was introduced for the 2015 reporting year. The full definition may be found in Appendix 1.

Of the 10 Operators which shared SPI 5 Critical MIT data, 1 Operator reported no MIT tasks due to not having ownership of facilities or equipment. Of the 9 Operators that reported critical MIT data, the combined average for 2016 was 94.8%, ranging from 80.9% to 99.6%. This compares with an average in 2015 of 96.3%, ranging from 83.7% to 100.0%, and represents the lowest rate reported to COS in the four years of reporting. Additionally, 4 Contractors shared SPI 5 critical MIT data. The combined average for contractors for 2016 was 97.8%, ranging from 93.7% to 100%. This compares with an average in 2015 of 92.4%, ranging from 84.1% to 100.0%.

The combined Days Away from Work, Restricted Work and Transfer of Duty Rate (DART) (SPI 7) reported for 2016 was 0.168, which is a decrease from the 0.215 reported for 2015 and the 0.205 reported for 2014, and represents the lowest reported DART in the 4 years of COS data.

The combined 2016 Recordable Injury and Illness Frequency (RIIF) (SPI 8) reported for 2016 was 0.279, as compared to 0.316 in 2015 and 0.406 for 2014, and represents the lowest reported RIIF in the 4 years of COS data.

2 Oil Spills to Water ≥ One Barrel (SPI 9) were reported by participating COS members. The oil spill to water frequency was 0.009 for 2016, as compared to 0.033 for 2015, and represents the lowest reported oil spills to water rate in the four years of COS data.

3.2 LFI Data Summary

The effectiveness of this program is dependent on active participation by COS members to facilitate maximum learning opportunity through:

- Timely sharing of quality information from incidents and HVLE that meet the reporting criteria; and
- Reviewing submitted incidents and HVLE, and this COS APR in its entirety, to identify and implement applicable learnings appropriate to different levels and functions within their own organizations.

The LFI data presented in this report includes information from 61 LFI submittals received for the 2016 reporting year, with 44 of the reported incidents and HVLE occurring in the U.S. and 17 at international locations (refer to Figures 3.2 and 3.3 below). Of the 44 U.S. events, 35 occurred in water depths $\geq$ 1,000 feet, 8 in water depths < 1,000 feet, and 1 at a shore-based facility. To support COS's mission to promote the highest level of safety for the U.S. offshore oil and natural gas industry, the findings presented in this report are focused on incidents and events that occurred in the U.S. OCS. A separate section discussing data associated with incidents outside the U.S. OCS (international and U.S. shore based) is provided in this report.

Figure 3.2: Incident Category Distribution per Submittal Type (All Submittals)

Year	2013	2014	2015	2016	TOTAL
COS SPI 1	2	5	7	6	**20**
COS SPI 2	39	39	21	17	**116**
HVLE	7	8	21	38	**74**
TOTAL	**48**	**52**	**49**	**61**	**210**

Note – The definition of SPI 2C "Incidents involving Mechanical Lifting or Lowering" was modified for reporting years 2015 and beyond to include minimum thresholds to qualify as an SPI 2C. The previous broader definition has been retained as SPI 4.

Figure 3.3: Incident Category Distribution per Submittal Type (U.S. OCS Only)

Year	2013	2014	2015	2016	TOTAL
COS SPI 1	2	5	7	5	**19**
COS SPI 2	38	38	21	17	**114**
HVLE	6	8	19	21	**54**
TOTAL	**46**	**51**	**47**	**43**	**187**

Note – The definition of SPI 2C "Incidents involving Mechanical Lifting or Lowering" was modified for reporting years 2015 and beyond to include minimum thresholds to qualify as an SPI 2C. The previous broader definition has been retained as SPI 4.

A review of the 2016 reporting year incident and event data resulted in the identification of multiple learning opportunities related to the following topics:

- Process Safety
- Mechanical Lifting or Lowering
- Maintenance, Inspection and Testing

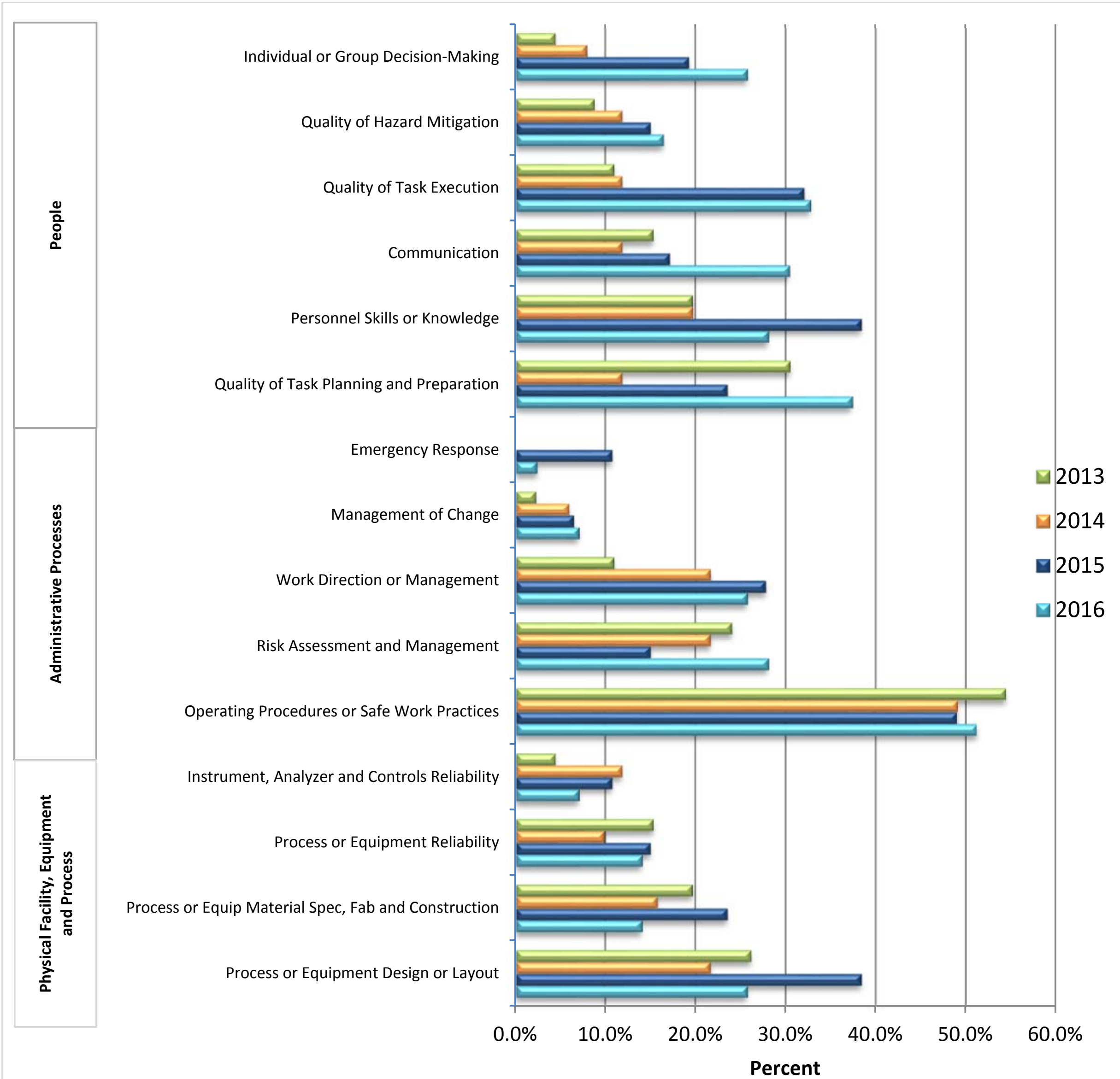
Process Safety and Mechanical Lifting or Lowering continue as focus areas, as these topics were also identified as learning opportunities for reporting years 2013-2015. Maintenance, Inspection and Testing is a new activity-based focus area in 2016 as 11 incidents represented a significant increase when normalized against previous reporting years. In addition to the topics mentioned above, there were other key learnings captured from all LFI data as presented below.

The top three Areas for Improvement (AFI) identified for 2016 were Operating Procedures or Safe Work Practices, Quality of Task Planning, and Quality of Task Execution. Across all 4 reporting years, Operating Procedures or Safe Work Practices was the most frequently identified AFI, as shown in Figures 3.4 and 3.5 below.

Figure 3.4: Area for Improvement Distribution (U.S. OCS Only, Table)

Area for Improvement	2013	2014	2015	2016	4-yr Avg (%)
Operating Procedures or Safe Work Practices	25 (54%)	25 (49%)	23 (49%)	22 (51%)	51
Quality of Task Planning and Preparation	14 (30%)	6 (12%)	11 (23%)	16 (37%)	25
Quality of Task Execution	5 (11%)	6 (12%)	15 (32%)	14 (33%)	21
Communication	7 (15%)	6 (12%)	8 (17%)	13 (30%)	18
Personnel Skills or Knowledge	9 (20%)	10 (20%)	18 (38%)	12 (28%)	26
Risk Assessment and Management	11 (24%)	11 (22%)	7 (15%)	12 (28%)	22

Figure 3.5: Areas for Improvement Distribution (U.S. OCS only, Chart)



NOTE - LFI submittals typically identified more than one AFI. The graph above illustrates the percent of times an AFI was identified relative to the number of LFI forms submitted for U.S. OCS events (46 in 2013, 51 in 2014, 47 in 2015, and 43 in 2016). Because the number of AFI exceeds the number of LFI forms, the sum of the percentages will be > 100%.

For 2016, the largest changes in AFI selection from the prior reporting year were:

- Quality of Task Planning increased from 22% to 37%
- Risk Assessment and Management increased from 15% to 28%
- Communication increased from 17% to 30%
- Process or Equipment Design or Layout decreased from 38% to 26%
- Personnel Skills or Knowledge decreased from 38% to 28%

When comparing 2016 data to the prior 3 years combined data, AFI selection has increased for 5 of the 6 "People" AFI categories.

3.3 SEMS Audits Summary

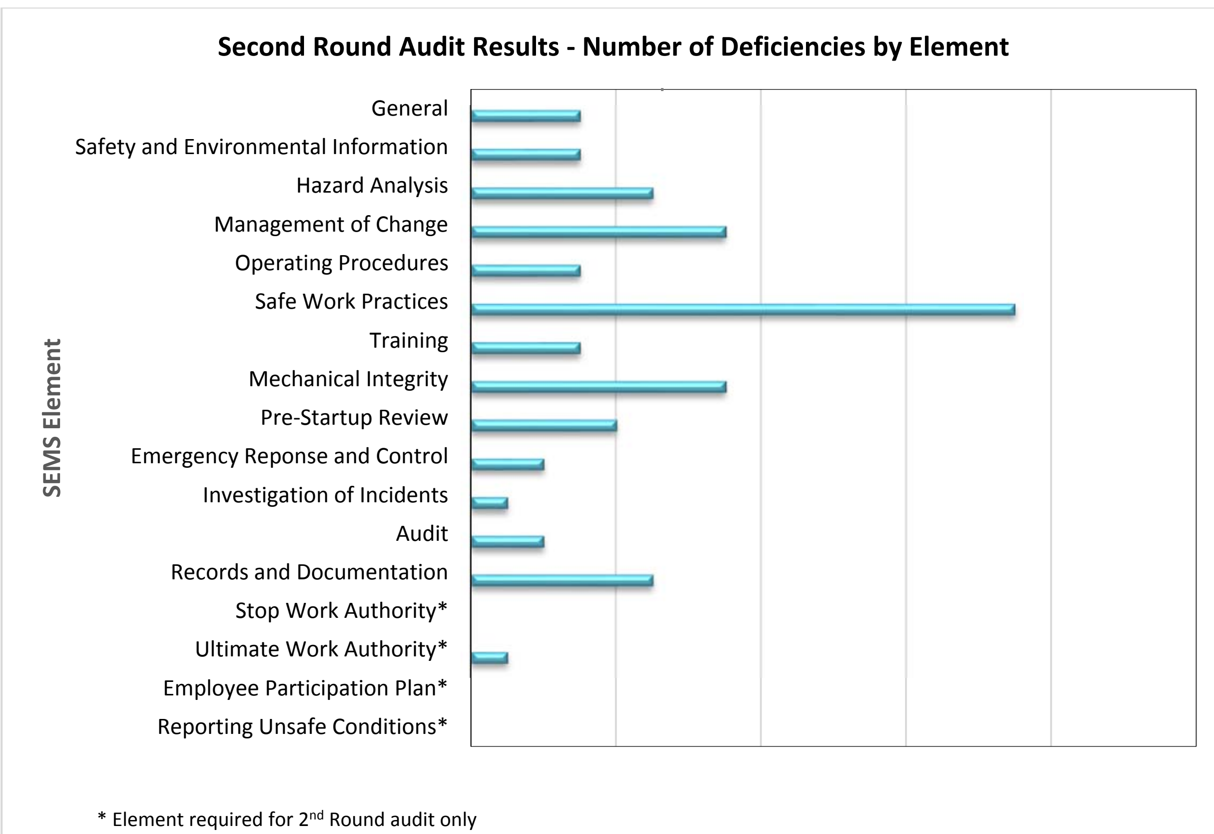
Data from the first round of SEMS audits were collected, analyzed and reported in the first APR in 2014. Data from the second round of SEMS audits were collected, analyzed and are reported in this APR. Trends and insights from the second round of SEMS audits for deficiencies, strengths, and audit conclusions are provided in the SEMS Audit Section of this report.

Ten COS Operator members shared data, including deficiencies for the second round of audits. A deficiency is either a non-conformity or a concern; specific definitions are found in Appendix 1.

Figure 6.1 shows the breakdown of deficiencies reported by SEMS Element for the second round of audits. In the second round of audits, Safe Work Practices had the most deficiencies, followed by Management of Change (MOC), Mechanical Integrity of Critical Equipment, and Hazard Analysis. These four elements accounted for 56% of the reported deficiencies. In comparison, MOC, Safe Work Practices and Emergency Response and Control had the most deficiencies in the first round of audits.

In the second round of audits, two Operators reported no deficiencies, and three Elements had no deficiencies reported by all 10 Operators: Stop Work Authority, Employee Participation Plan and Reporting Unsafe Conditions.

Figure 3.6: SEMS Audit Results - Deficiencies



3.4 Other Notable COS Accomplishments for 2016

3.4.1 SEMS Audit Service Provider (ASP) Accreditation Program

In accordance with the MOU signed in 2015, COS is currently the only accreditation body authorized by BSEE to accredit SEMS ASP pursuant to 30 CFR 250, Subpart S.

As of the writing of this report, 7 ASP have been fully accredited:

(1) ABS Quality Evaluations

(2) DNV GL Business Assurance

(3) ERM CVS

(4) Lloyd's Register Quality Assurance

(5) M&H Auditing

(6) CICS-Americas

(7) Gulf Tech

In addition, the following ASP have been provisionally accredited:

(8) AcuTech

(9) BV Certifications

3.4.2 SEMS Audit and Certification Program

As of the publication of this APR, the following COS Member Companies have successfully attained or re-attained COS SEMS Certification:

- Anadarko Petroleum Corporation
- BHP Billiton Petroleum
- BP E&P, Inc.
- Cameron International
- Chevron USA, Inc. (Deepwater Assets)
- Cobalt International Energy, LP
- ConocoPhillips Co.
- ExxonMobil Production Company
- Helmerich & Payne International Drilling Co.
- Hess Corporation
- Marathon Oil Company
- Murphy E&P, Co.
- Noble Energy
- Shell E&P Co.
- Pacific Drilling Services, Inc.
- Schlumberger
- Statoil Gulf Services, LLC.

3.4.3 COS at OTC

COS hosted its fifth-annual SEMS ½-day at the 2017 Offshore Technology Conference. Keynote speakers included:

- Aleida Rios, BP
- Ken Marnoch, Shell
- Claudine Bradley, NEB
- Doug Morris, BSEE
- Joshua Reynolds, USCG

In addition, COS hosted 2 technical sessions around the theme *Managing the Human Side of Safety* focused on Leadership and Collaboration.

3.4.4 COS Safety Leadership Award

For 2017, COS will be announcing the winners of the 2017 COS Safety Leadership Award at the 5th Annual COS Safety Forum, September 19-20 – Houston, TX. Finalists for the award are:

Operator Finalists:	Contractor Finalists:
BHP Billiton – *HSE Documents and Publication*	BakerHughes, a GE Co. – *What Lies Beneath*
Chevron – *Human Performance*	Halliburton – *HAZ ID Field Guide*
Helis Oil & Gas – *Fleet Safety Program*	Schlumberger - *HSE for Youth*

3.4.5 SEMS Maturity Self-Assessment

COS developed a new SEMS Maturity Self-Assessment model and tool to help organizations understand the extent to which their management system is mature – that is, the extent to which the systems are established, implemented, maintained and continually improved. The aim is to provide a systems-level view of the various elements of the management system, as well as providing another method to identify improvement opportunities and/or to review a company's SEMS to assess whether it remains suitable and adequate. A workshop to communicate this tool was completed in 2017.

4.0 SAFETY PERFORMANCE INDICATORS

4.1 Introduction

COS members share Safety Performance Indicator (SPI) data with COS through the SPI Program. The data is confidential and blinded. This is the fourth year that COS members have shared SPI data. Benchmarks with other data sources are shown where definitions are comparable.

While the data for 2013 was limited to reporting of deepwater (≥ 1,000 feet water depth) COS member activity only, the data for 2014-16 includes all COS member activity on the U.S. OCS. A normalization factor for work hours is utilized to enable year-to-year comparisons. The summary of the SPI can be found in Figure 4.1 below.

Figure 4.1: Safety Performance Indicators (SPI)

SPI 1 is the frequency of incidents that resulted in one or more of the following:

A. Fatality
B. Five or more injuries in a single incident
C. Tier 1 process safety event
D. Level 1 Well Control Incident - Loss of well control
E. ≥ $1 million direct cost from damage to or loss of facility / vessel / equipment
F. Oil spill to water ≥ 10,000 gallons (238 barrels)

SPI 2 is the frequency of incidents that do not meet the SPI 1 definition but have resulted in one or more of the following:

A. Tier 2 process safety event
B. Collision resulting in property or equipment damage ≥ $25,000
C. Mechanical Lifting or Lowering Incident
D. Loss of station keeping resulting in a drive off or drift off
E. Life boat, life raft, rescue boat event
F. Level 2 Well Control incident - Multiple Barrier Systems Failures and Challenges

SPI 3 is the number of SPI 1 and SPI 2 incidents that involved failure of one or more piece of equipment as a contributing factor.

SPI 4 is a crane or personal/material handling operations incident

SPI 5 is the percentage of planned critical maintenance, inspection and testing (MIT) completed on time. Planned critical MIT deferred with a formal risk assessment and appropriate level of approval is not considered overdue.

SPI 6 is number of work-related fatalities.

SPI 7 is the frequency of days away from work, restricted work, and job-transfer injury and illnesses (DART)

SPI 8 is the frequency of recordable injuries and illnesses (RIIF)

SPI 9 is the frequency of oil spills to water ≥ 1 barrel

SPI 1-5 are based on structured assessments of major hazards facing the offshore industry. SPI 6-9 are indicators that have been reported historically by industry and were not directly related to the assessment work.

There are characteristics of the data reported for SPI 1 and SPI 2 incidents that limit some aspects of the analyses and trending. An incident may have consequences that meet both SPI 1 and SPI 2 definitions, but are not counted in both classifications. The higher consequence drives the classification. For example, a collision that results in ≥ $1 million direct damage cost meets the SPI 1E definition, but also meets the SPI 2B consequence of collision resulting in ≥ $25,000 in damage. Yet per the SPI Program structure, it is only counted as an SPI 1E incident and not an SPI 2B collision.

Although definitions used for some of the SPI are the same or similar to regulatory definitions, the numbers in this APR will not necessarily match regulatory data due to this report being based on COS member company data and not all companies operating in the U.S. OCS.

4.2 Summary

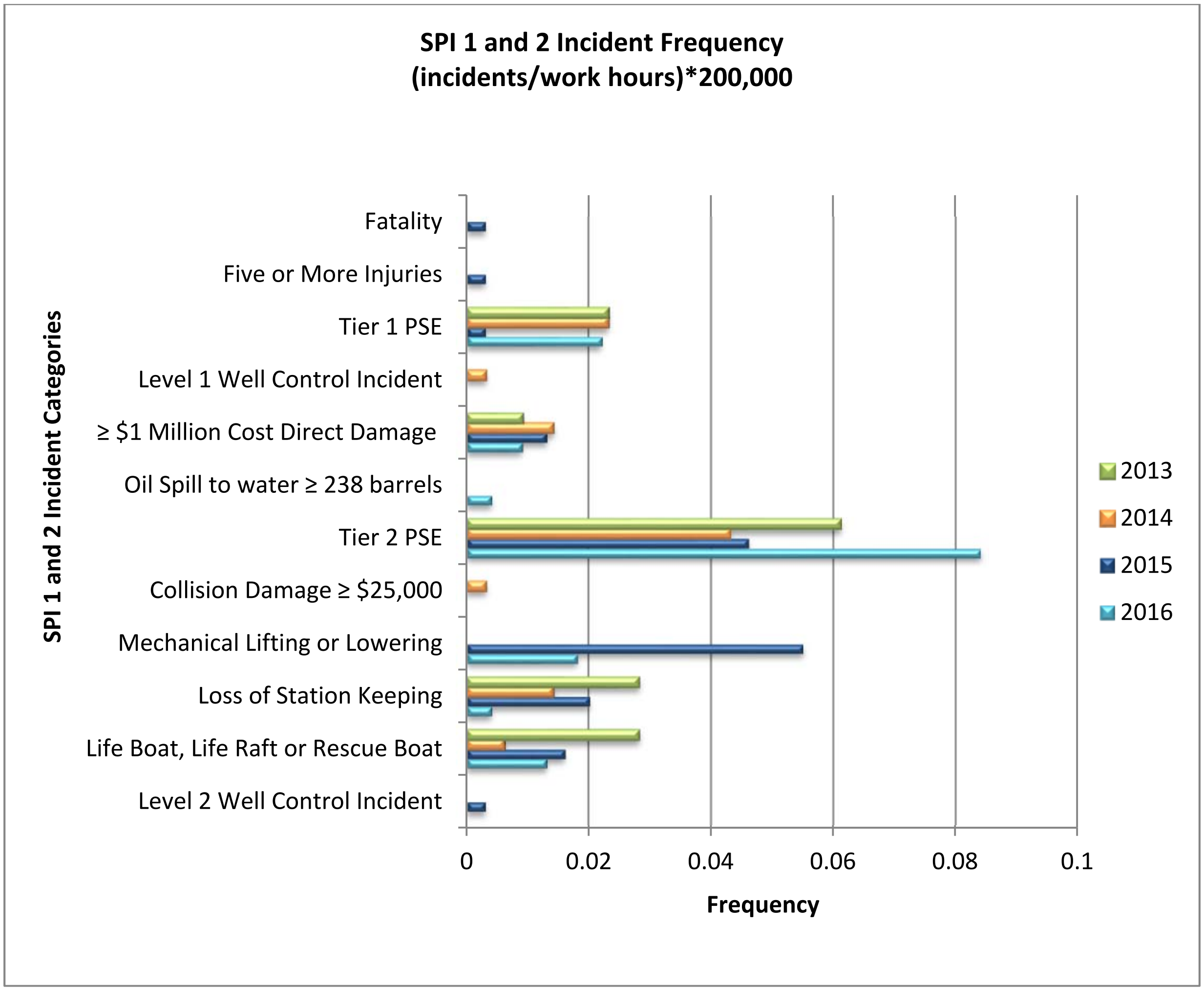
This report provides COS member data for 2013-16. The data reported for 2016 represents over 45 million operator and contractor work hours in the U.S. OCS compared to 61 and 69 million reported in 2015 and 2014, respectively. This is a decrease of over 26% from 2015.

Participating companies reported 5 Tier 1 Process Safety Events; 2 incidents Involving ≥ $1 Million Direct Costs from Damage to a Facility, Vessel, or Equipment; and 1 incident resulting in an Oil Spill ≥ 238 barrels. No incidents resulting in Fatalities, Five or More Injuries, or Level 1 Well Control Incidents were reported for 2016.

Participating members also reported 19 Tier 2 Process Safety Events; 4 Incidents involving Mechanical Lifting or Lowering (COS definition); 1 Loss of Station Keeping Incident Resulting in a Drive Off or Drift Off; and 3 Life Boat, Life Raft, or Rescue Boat Events. No incidents resulting in Collisions with Damage ≥ $25,000 or Level 2 Well Control Incidents were reported for 2016.

The frequency of all SPI 1 and SPI 2 incidents are shown below in Figure 4.2; specific definitions for the SPI can be found in Appendix 2.

Figure 4.2: SPI 1 and SPI 2 Frequency



There was one SPI 1 consequence that was reported for the first time since the SPI program was established – an incident that resulted in an Oil Spill ≥ 238 barrels, the threshold for an SPI 1 incident.

The Tier 1 PSE frequency reported for 2016 returned to the same levels as reported for 2013 and 2014. Tier 2 PSE frequency reported for 2016 increased by 85% over that reported for 2015, and represents the highest reported frequency reported to COS in the four years of reporting.

There were 4 Incidents involving Mechanical Lifting or Lowering (2C). The definition for this safety performance indicator was changed for the 2015 reporting year; therefore, both the count and frequency of these types of incidents is provided for only the 2015 and 2016 reporting years. The data shown in the first two APR (for the 2013 and 2014 reporting years) has been moved to SPI 4. The frequency of SPI 2C events decreased by 67% for 2016 as compared to 2015.

The frequencies of both Loss of Station Keeping Resulting Drive Off or Drift Off and Life Boat, Life Raft, or Rescue Boat Events trended down for 2016 as compared to 2015. This represents the lowest frequency of Loss of Station Keeping incidents reported to COS in the four years of reporting.

16 of the 34 (48%) SPI 1 and SPI 2 incidents reported for 2016 involved failure of equipment as a contributing factor. This is an increase from 38% reported for 2015 and more closely matches the 45% reported for 2014. This is below the 68% reported for 2013, though it is unclear how much further education and understanding of this safety performance indicator has contributed to the decrease and how much is due to less incidents having failure of equipment as a contributing factor. The largest contributors to equipment failures for 2016 are the "Other" category, followed by the Well Pressure Containment Systems and Process Equipment/Pressure Vessels/Piping categories. Specific definitions and descriptions of the equipment categories are found in Appendix 3.

SPI 2F – Level 2 Well Control Incidents – was introduced for the 2015 reporting year. The full definition may be found in Appendix 2.

Of the 10 Operators which shared SPI 5 Critical MIT data, 1 Operator reported no MIT tasks due to not having ownership of facilities or equipment. Of the 9 Operators that reported critical MIT data, the combined average for 2016 was 94.8%, ranging from 80.9% to 99.6%. This compares with an average in 2015 of 96.3%, ranging from 83.7% to 100.0%, and represents the lowest rate reported to COS in the four years of reporting. Additionally, 4 Contractors shared SPI 5 critical MIT data. The combined average for contractors for 2016 was 97.8%, ranging from 93.7% to 100%. This compares with an average in 2015 of 92.4%, ranging from 84.1% to 100.0%.

The combined Days Away from Work, Restricted Work and Transfer of Duty Rate (DART) (SPI 7) reported for 2016 was 0.168, which is a decrease from the 0.215 reported for 2015 and the 0.205 reported for 2014, and represents the lowest reported DART in the 4 years of COS data.

The combined 2016 Recordable Injury and Illness Frequency (RIIF) (SPI 8) reported for 2016 was 0.279, as compared to 0.316 in 2015 and 0.406 for 2014, and represents the lowest reported RIIF in the 4 years of COS data.

2 Oil Spills to Water ≥ One Barrel (SPI 9) were reported by participating COS members. The oil spill to water frequency was 0.009 for 2016, as compared to 0.033 for 2015 and 0.023 for 2014, and represents the lowest reported oil spills to water rate in the 4 years of COS data.

4.3 SPI 1 and SPI 2 Results and Trends

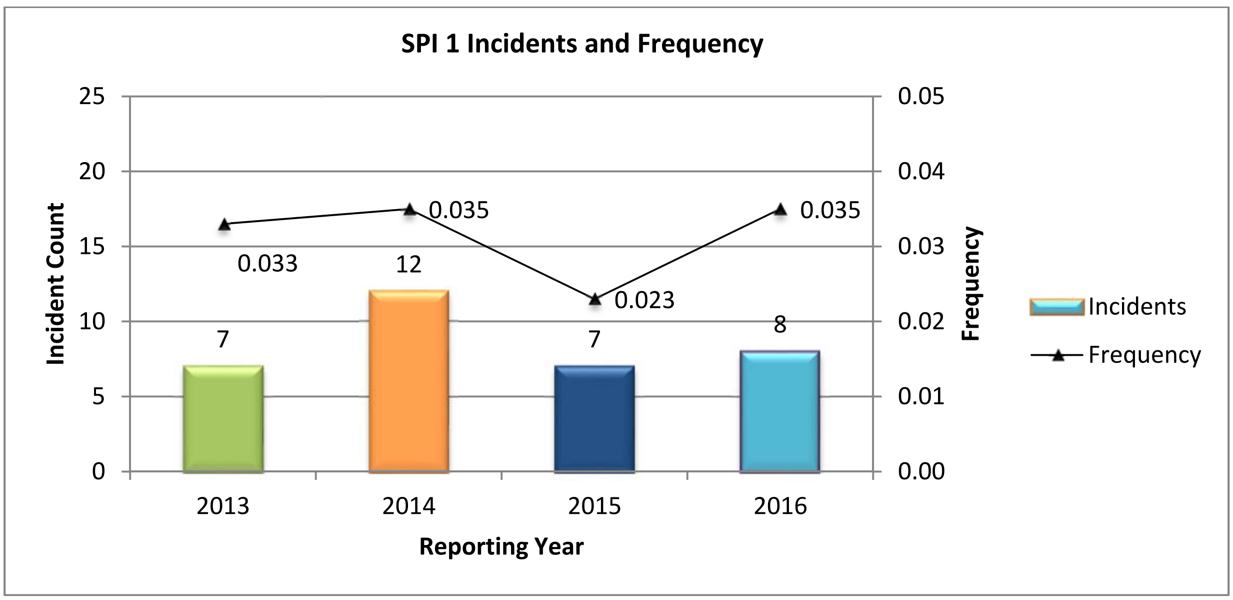
SPI 1 is the frequency of incidents that resulted in one or more of the following:

A. Fatality
B. Five or more injuries in a single incident
C. Tier 1 process safety event
D. Level 1 Well Control Incident - Loss of well control
E. ≥ $1 million direct cost from damage to or loss of facility, vessel and/or equipment
F. Oil spill to water ≥ 10,000 gallons (238 barrels)

SPI 2 is the frequency of incidents that do not meet the SPI 1 definition but have resulted in one or more of the following:

A. Tier 2 process safety event
B. Collision resulting in property or equipment damage ≥ $25,000
C. Mechanical Lifting or Lowering Incident
D. Loss of station keeping resulting in a drive off or drift off
E. Life boat, life raft, rescue boat event
F. Level 2 Well Control incident - Multiple Barrier Systems Failures and Challenges

Figure 4.3: SPI 1 Incident Count and Frequency



- A total of 8 SPI 1 incidents were reported at a frequency of 0.035 for 2016. This represents a slight increase in actual number of incidents when compared to data reported for 2015; the noticeable increase in frequency is due to the decrease in overall work hours reported, and matches the frequency reported for 2014. Only deepwater (≥ 1000 feet water depth) operations were in scope for 2013.
- All 8 SPI 1 incidents reported in 2016 occurred on or within 500 meters of a facility.

Figure 4.4: SPI 1 Incident Count per Sub Group (Chart)

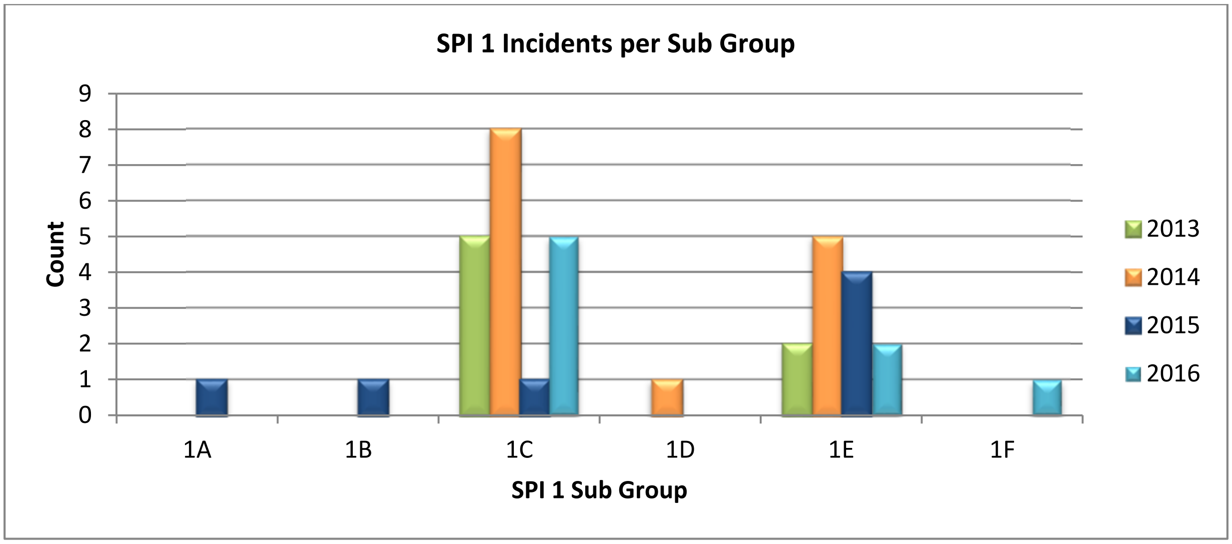
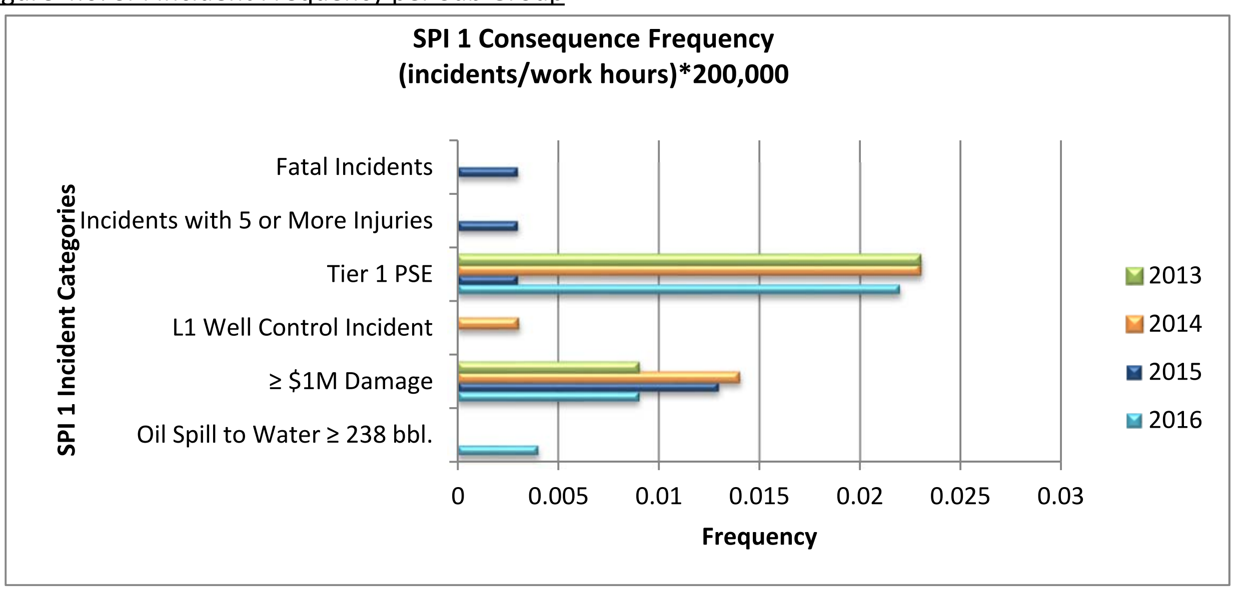


Figure 4.5: SPI 1 Incident Count per Sub Group (Table)

Year	Fatal Incidents (1A)	Incidents with 5 or More Injuries (1B)	Tier 1 PSE (1C)	Level 1 Well Control Incident (1D)	> $1MM Direct Damage (1E)	Oil Spill to Water > 238 bbl. (1F)
2013	0	0	5	0	2	0
2014	0	0	8	1	5	0
2015	1	1	1	0	4	0
2016	0	0	5	0	2	1

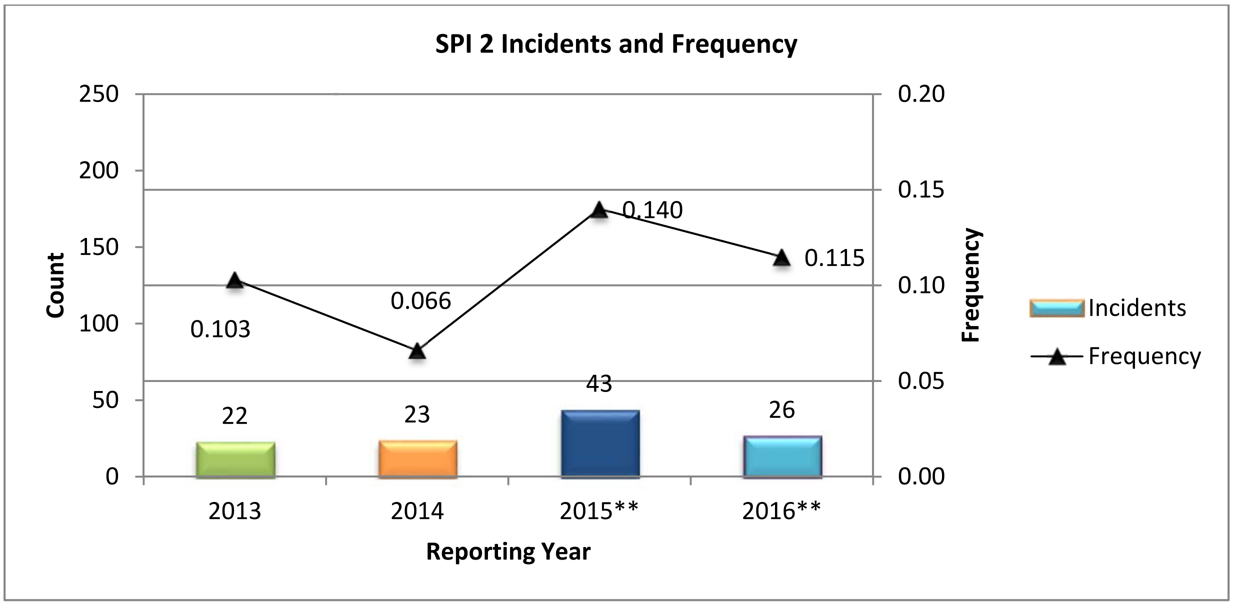
Figure 4.6: SPI Incident Frequency per Sub Group



Note – The total count of SPI consequences shown in the table above for SPI 1A-1F may be greater the total count of SPI 1 incidents, as one incident can have multiple consequences.

- No Incidents Resulting in a Fatality, (1A), in Five or More Injuries, (1B), or Level 1 Well Control Incidents (1D) were reported for 2016.
- There was one SPI 1 consequence that was reported for the first time since the SPI program was established – an incident resulting in an Oil Spill ≥ 238 barrels (1F).
- There were 5 Tier 1 PSE (1C) reported for 2016, which resulted in a frequency similar to the same levels reported for 2013 and 2014.
- Incidents Involving ≥ $1 Million Direct Costs from Damage to or Loss of a Facility, Vessel, or Equipment (1E) reported for 2016 was in line with what was reported for 2013, and is a decrease from what was reported for 2015 and 2014.

Figure 4.7: SPI 2 Incident Count and Frequency



*Note – **The definition of SPI 2C "Incidents involving Mechanical Lifting or Lowering" was modified for reporting years 2015 and beyond to include minimum thresholds to qualify as an SPI 2C. The previous broader definition has been retained as SPI 4.*

- A total of 26 SPI 2 incidents were reported for 2016 at a frequency of 0.115. This is a decrease from the 0.140 frequency reported for 2015, but greater than the frequencies reported for 2014 and 2013. The increase in 2015 and 2016 versus 2014 was partially due to the addition of two new SPI 2 categories (Mechanical Lifting or Lowering Incident and Level 2 Well Control Incident). Only deepwater (≥1,000 feet water depth) operations were in scope for 2013.
- For 2016, all 26 reported SPI 2 incidents occurred on or within 500 meters of a facility.

Figure 4.8: SPI 2 Incident Count per Sub Group (Chart)

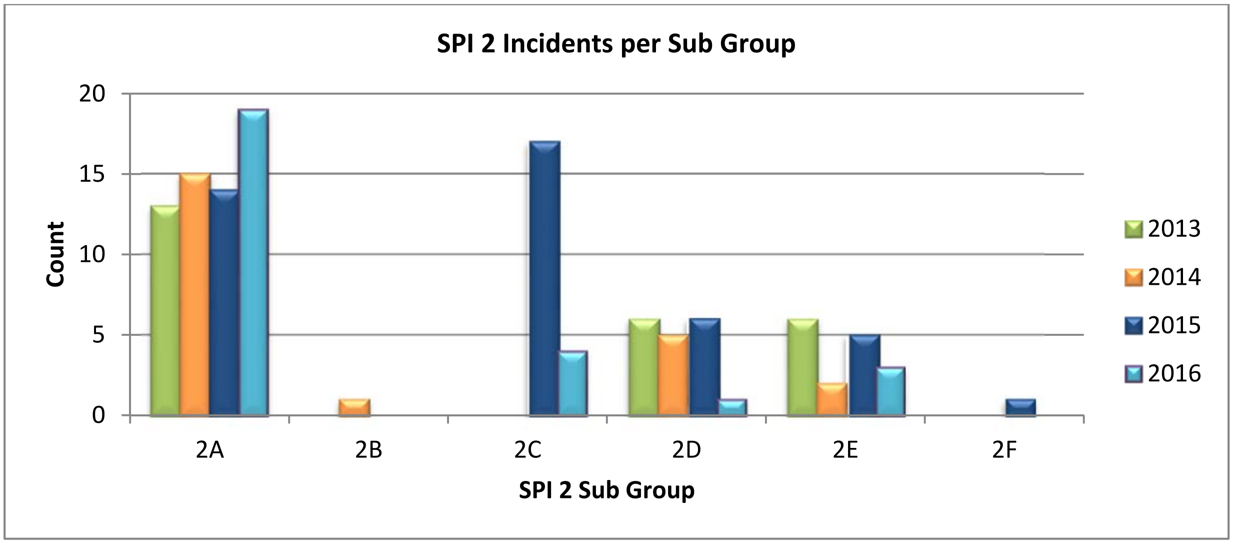
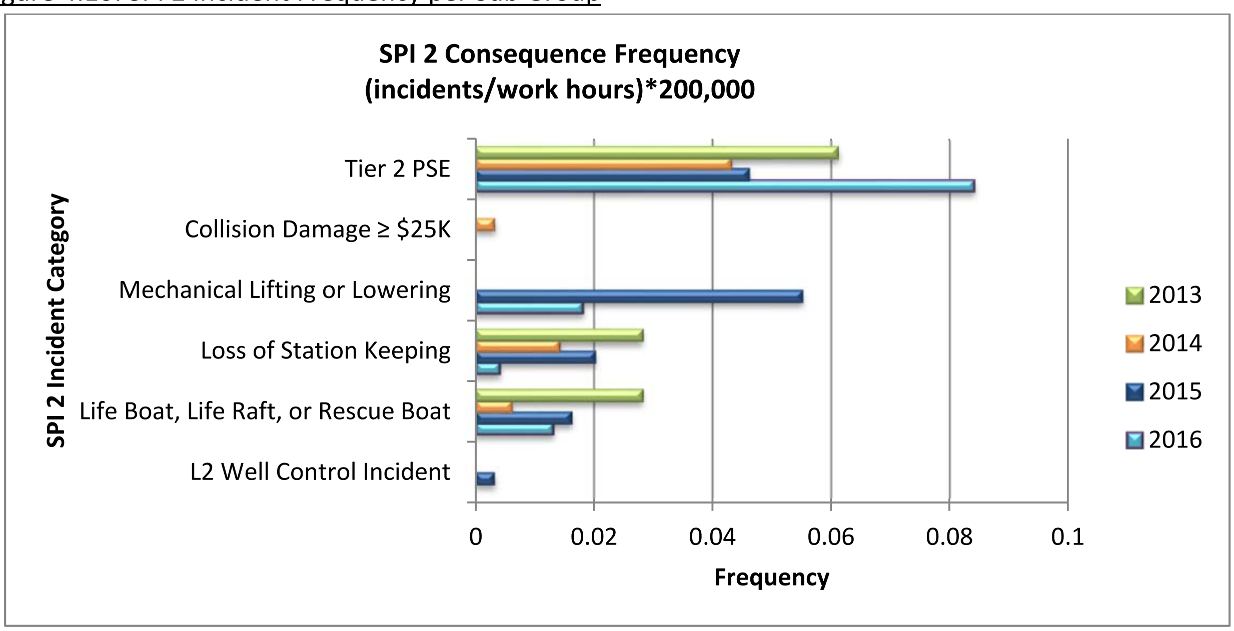


Figure 4.9: SPI 2 Incident Count per Sub Group (Table)

Year	Tier 2 PSE (2A)	Collision ≥ $25,000 (2B)	Mechanical Lifting or Lowering (2C)	Station Keeping (2D)	Life Boat, Life Raft, or Rescue Boat (2E)	Level 2 Well Control Incident (2F)
2013	13	0	NA	6	6	NA
2014	15	1	NA	5	2	NA
2015	14	0	17	6	5	1
2016	19	0	4	1	3	0

Figure 4.10: SPI 2 Incident Frequency per Sub Group



Note – The total count of SPI consequences shown in the table above for SPI 2A-2E may be greater the total count of SPI 2 incidents, as one incident can have multiple consequences.

- No incidents involving Collisions Resulting in Damage (2B) or Level 2 Well Control Incidents (2F) were reported for 2016.
- There were 19 Tier 2 Process Safety Events (2A) reported for 2016, for a frequency of 0.084. This represents the highest frequency reported to COS in the four years of reporting. There were 4 Incidents involving Mechanical Lifting or Lowering (2C). The definition for this safety performance indicator was changed for the 2015 reporting year; therefore, both the count and frequency of these types of incidents is provided for only the 2015 and 2016 reporting years. The data shown in the first two APR (for the 2013 and 2014 reporting years) has been moved to SPI 4. The frequency of SPI 2C events decreased by 67% for 2016 as compared to 2015.
- There was 1 incident involving Loss of Station Keeping Resulting in Drive Off or Drift Off reported for 2016; this represents the lowest frequency reported to COS in the four years of reporting.
- Life Boat, Life Raft, or Rescue Boat Event frequency trended down for 2016 as compared to 2015.

4.3.1 Tier 1 and Tier 2 Process Safety Event Consequences

Tier 1 and Tier 2 PSE are determined by assessing the consequences of a loss of primary containment (LOPC) event against defined thresholds (see Appendix 2). If it meets or exceeds a threshold, then it is classified as either a Tier 1 PSE or a Tier 2 PSE, but not both. In 2014, participating COS members began sharing consequence data for reported Tier 1 and Tier 2 PSE. 7 Operators reported PSE consequence data in 2016; the data is presented below.

Consequence data was collected for the 5 Tier 1 PSE shared for 2016, with the following consequences:

- 1 – Days Away from Work Injury
- 1 – Fire (≥$25,000 Direct Cost Damage)
- 3 – Release of Non-Toxic Materials
- 1 – Indoor Release
- 4 – Outdoor Release

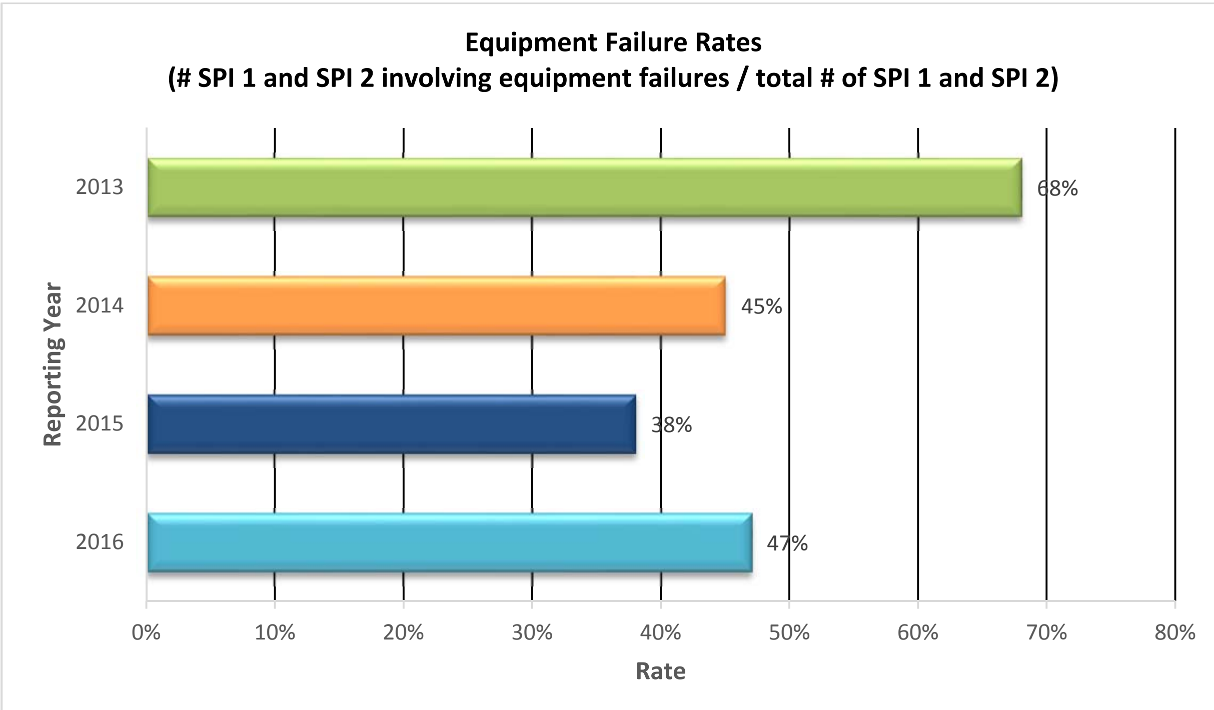
Consequence data was collected for all of the 19 the Tier 2 PSE reported for 2016, with the following consequences:

- 3 – Fire ($2,500 to $25,000 Direct Damage Costs)
- 2 – Pressure Release Device Discharge Directly to Atmosphere
- 1 – Pressure Release Device Discharge to Downstream Destructive Device
- 1 – Pressure Release Device Discharge resulting in On-Site Shelter-in-Place
- 15 – Non-Toxic Material Release
- 1 – Indoor Release
- 12 – Outdoor Release
- The type of material released was not reported for 4 of the Tier 2 PSE
- The location (i.e. indoor, outdoor) of the release was not reported for 6 of the reported Tier 2 PSE

4.4 SPI 3 Results and Trends

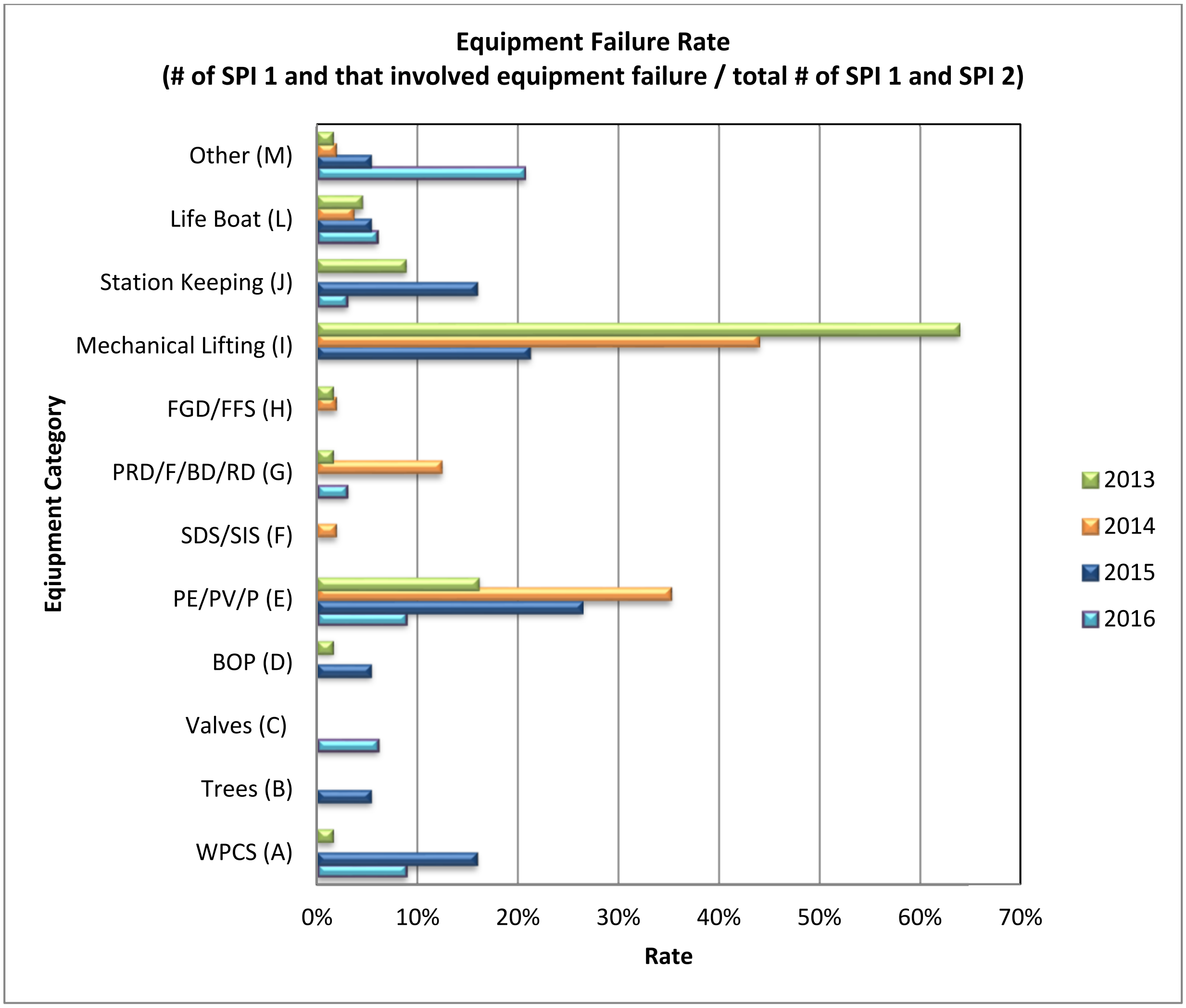
SPI 3 is the number of SPI 1 and SPI 2 incidents that involved failure of one or more piece of equipment as a contributing factor.

Figure 4.11: Equipment Failure Rates



- 16 of the 34 (47%) SPI 1 and SPI 2 incidents reported for 2016 involved failure of equipment as a contributing factor. This is an increase from 38% reported for 2015 and more closely matches the 45% reported for 2014. This is below the 68% reported for 2013. It is unclear how much further education and understanding of this safety performance indicator has contributed to the decrease, how much is due to less incidents having failure of equipment as a contributing factor, and how much is due to the change in the definition of SPI 2C.

Figure 4.12 SPI 3 Failure Rates Contributing to SPI 1 and SPI 2 Incidents – per Equipment Category



- 21% (7 of 34) SPI 3 incidents reported for 2016 involved "Other" equipment, which represents an increase from the 5% for 2015, the 2% for 2014, and the 1% for 2013. This was the most frequently picked equipment category reported for 2016.
- 9% (3 of 34) SPI 3 incidents reported for 2016 involved Well Pressure Containment Systems; this is a decrease from the 16% reported for 2015 and higher than the 0% reported for 2014 and 1% reported for 2013. The number of reported failures (3) was the same for 2015 and 2016.
- 9% (3 of 34) SPI 3 reported for 2016 involved Process Equipment, Pressure Vessels, and/or Piping, which is a decrease from the 26% for 2015, the 35% for 2014, and the 16% for 2013. This represents the lowest percentage reported to COS in the four years of reporting.
- 6% (2 of 34) SPI 3 incidents reported for 2016 involved Downhole Safety Valves. This is the first year that Downhole Safety Valve failures have been reported to COS in the four years of reporting.
- No SPI 3 incidents reported for 2016 involved Mechanical Lifting or Lowering Equipment. This is significant decrease from the 21% for 2015, the 44% for 2014, and the 64% reported for 2013; however, due to the change in the definition of SPI 2C, only the 2015 data is comparable to the 2016 data.

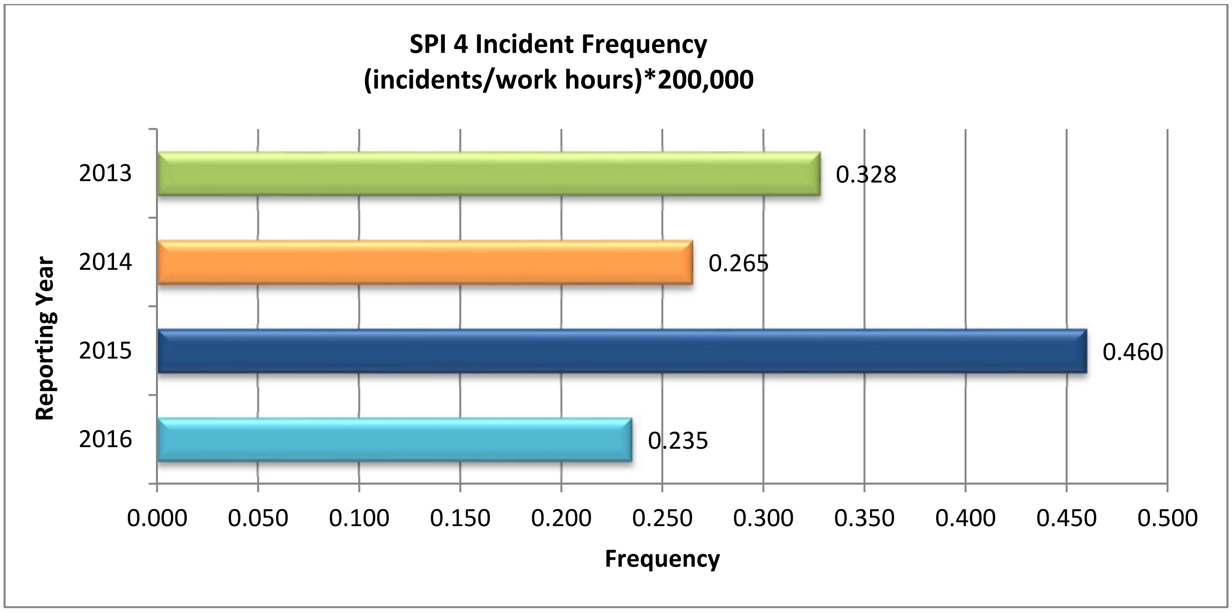
Figure 4.13: SPI 3 Incident Counts by Equipment Type

Equipment	2013 Failures (Count)	2014 Failures (Count)	2015 Failures (Count)	2016 Failures (Count)
A - Well Pressure Containment System (WPCS)	1	0	3	3
B - Christmas Trees	0	0	1	0
C - Downhole Safety Valves (Valves)	0	0	0	2
D - Blowout Preventers and Intervention Systems (BOP)	1	0	1	0
E - Process Equipment/Pressure Vessels/Piping (PE/PV/P)	11	20	5	3
F - Shutdown Systems/Automated Safety Instrumented Systems (SDS/SIS)	0	1	0	0
G - Pressure Relief Devices/Flares/Blowdown/Rupture Disks (PRD/F/B/RD)	1	7	0	1
H - Fire/Gas Detection and Fire Fighting Systems (FGD/FFS)	1	1	0	0
I - Mechanical Lifting Equipment/Personnel Transport Systems	44	25	4	0
J - Station Keeping Systems	6	0	3	1
K - Bilge/Ballast Systems	0	0	0	0
L - Life Boat/Life Raft/Rescue Boat/Launch and Recovery Systems	3	2	1	2
M - Other	1	1	1	7

4.5 SPI 4 Results and Trends

SPI 4 is the frequency of crane or personnel/material handling operations incidents.

Figure 4.14: SPI 4 Crane or Personnel / Material Handling Frequency

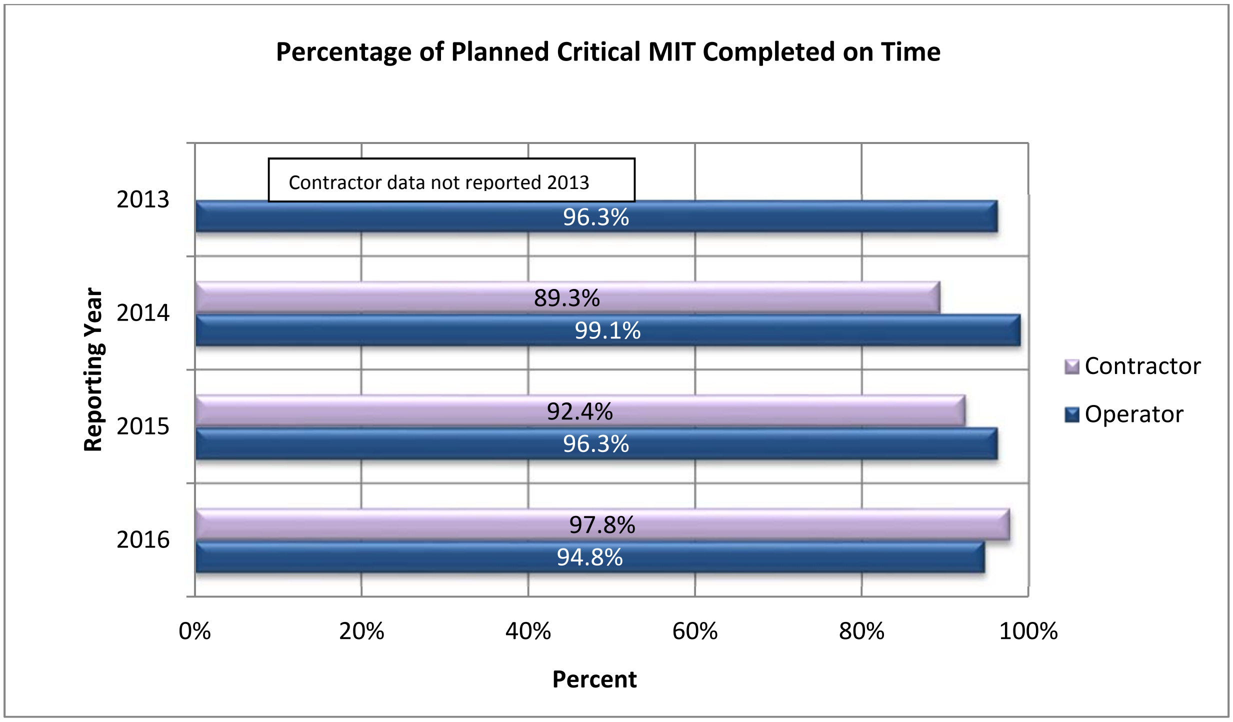


- This SPI is the old (reporting years 2013 and 2014) SPI 2C data, and has been moved to a new SPI 4 category with no change in definition.
- The incident frequency for 2016 was 0.235, which represents a 48% decrease from the 2015 incident frequency 0.460, and is the lowest frequency reported to COS in the four years of reporting.

4.6 SPI 5 Results and Trends

SPI 5 is the percentage of planned critical maintenance, inspection and testing (MIT) completed on time. Planned critical MIT deferred with a formal risk assessment and appropriate level of approval is not considered overdue.

Figure 4.15: Percentage of Planned Tasks Complete per Plan

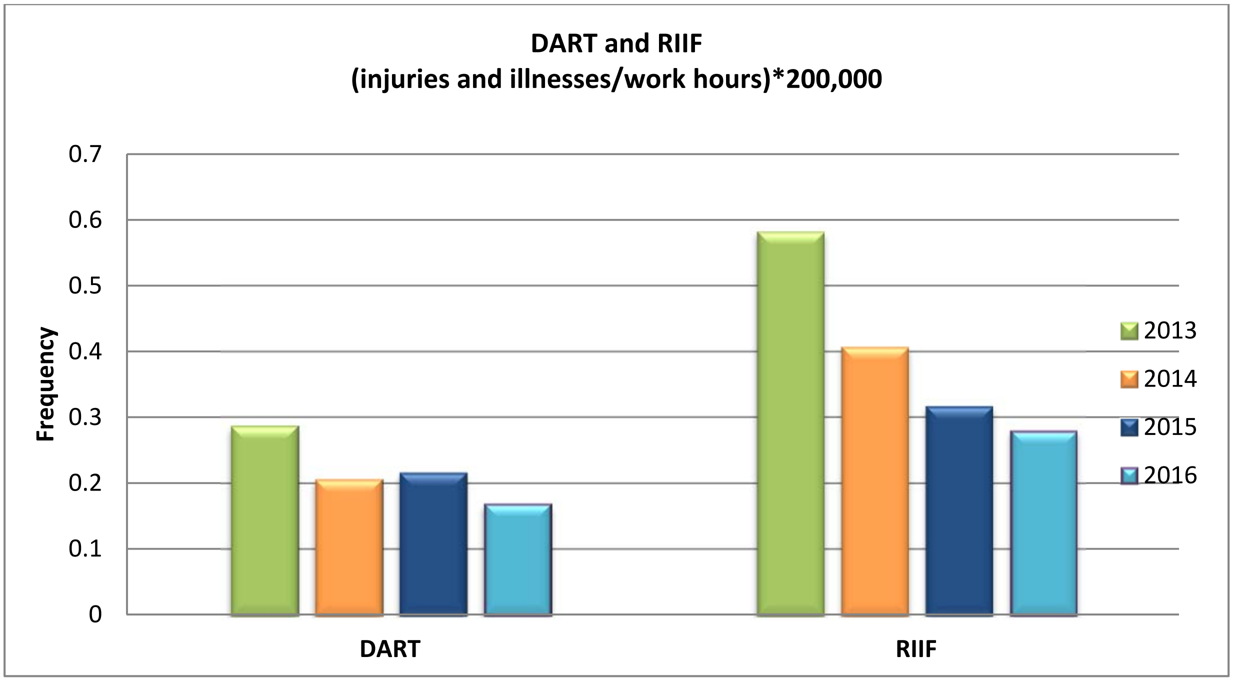


- Of the 10 Operators which shared SPI 5 Critical MIT data, 1 Operator reported no MIT tasks due to not having ownership of facilities or equipment.
- For the 9 Operators that reported SPI 5 Critical MIT data, the combined average for 2016 was 94.8%, ranging from 80.9% to 99.6%. This compares with an average of 96.3% for 2015 (ranging from 83.7% to 100.0%), 99.1% for 2014 (ranging from 97.9% to 100%), and 96.3% for 2013 (ranging from 90.5% to 100%), and is the lowest rate reported to COS in the four years of reporting.
- For the 4 Contractors that reported SPI 5 Critical MIT data, the combined average for 2016 was 97.8%, ranging from 93.7% to 100%. This compares with an average of 92.4% for 2015 (ranging from 84.1% to 100.0%) and 89.3% for 2014 (ranging from 80.4% to 98.6%), and is the highest rate reported to COS in the four years of reporting. Contractors were not asked to report SPI 5 in 2013.
- The overall SPI 5 Critical MIT data when combined for Contractors and Operators was 97.4% for 2016, as compared to 95.1% for 2015 and 94.7% for 2014.
- Note – it is up to each company to define what maintenance, inspection and testing tasks qualify as “critical”.

4.7 SPI 6-9 Results and Trends

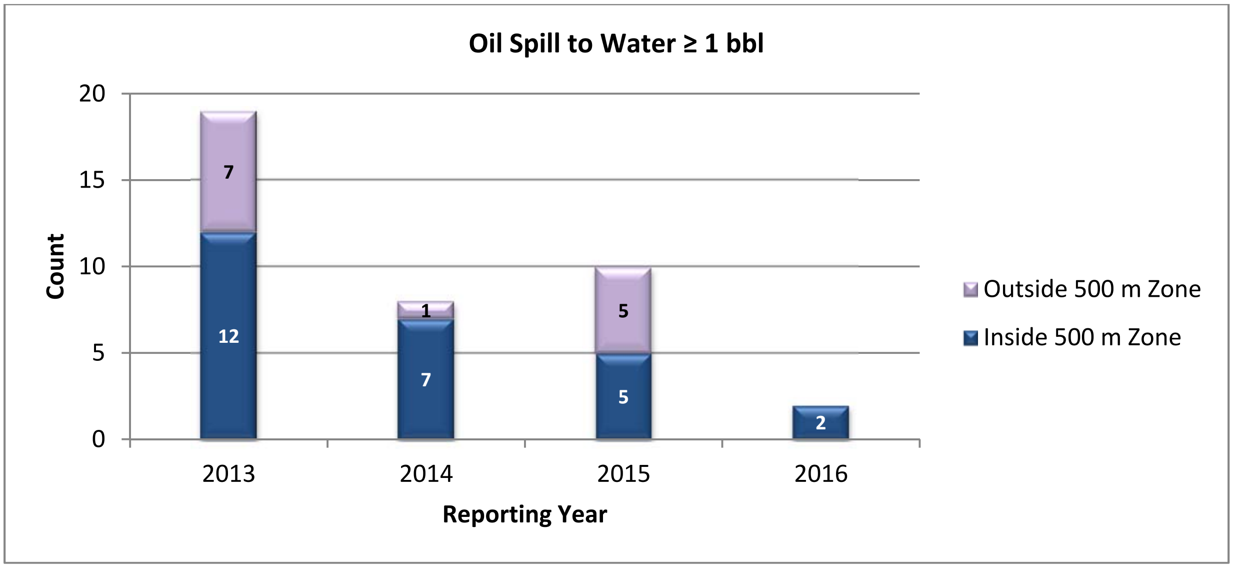
- SPI 6 is number of work-related fatalities.
- SPI 7 is the frequency of days away from work, restricted work, and job-transfer injury and illnesses (DART)
- SPI 8 is the frequency of recordable injuries and illnesses (RIIF)
- SPI 9 is the frequency of oil spills to water ≥ 1 barrel

Figure 4.16: Traditional SPI – DART and RIIF Chart



- No fatalities (SPI 6) were reported for 2016. One fatality has been reported to COS in the four years of reporting.
- The combined 2016 Days Away From Work, Restricted Work and Transfer of Duty Rate (DART) (SPI 7) for COS participating members was 0.168, which is a decrease from the 0.215 reported in 2015 and the 0.205 reported in 2014, and represents the lowest DART reported to COS in the four years of reporting.
- The combined 2016 Recordable Injury and Illness Frequency (RIIF) (SPI 8) for COS participating members was 0.279, as compared to 0.316 in 2015 and 0.406 in 2014, and represents the lowest RIIF reported to COS in the four years of reporting.

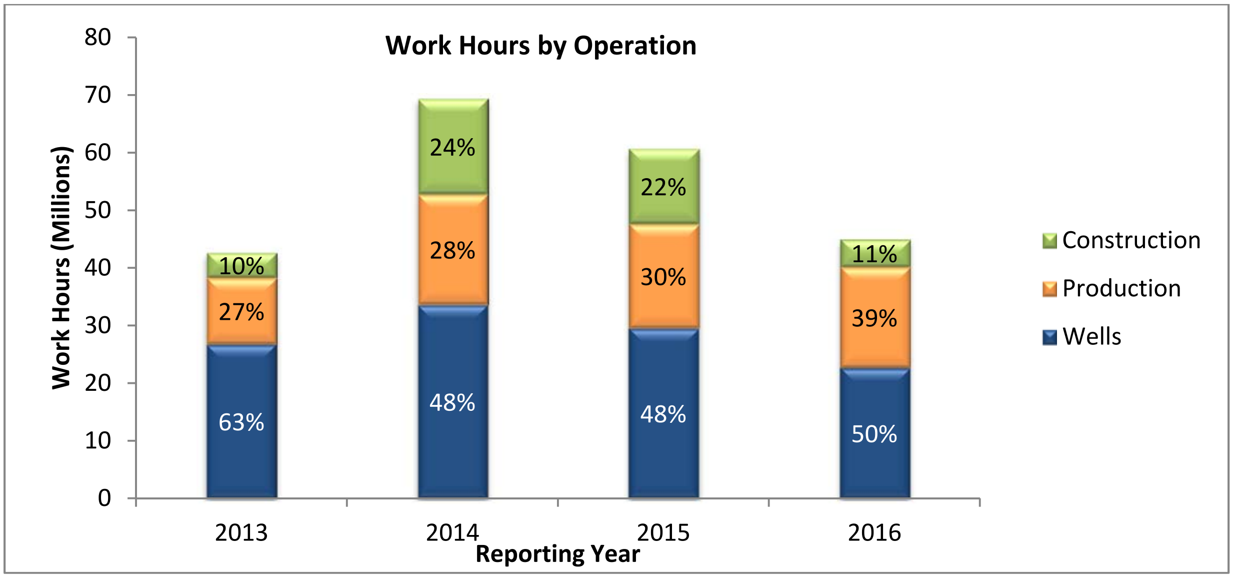
Figure 4.17: Oil Spill to Water Count



- 2 Oil Spills to Water ≥ One Barrel (SPI 9) were reported by participating COS members. The oil spill to water frequency was 0.009 for 2016, as compared to 0.033 for 2015 and 0.023 for 2014, and represents the lowest rate of oil spills to water reported to COS in the four years of reporting.

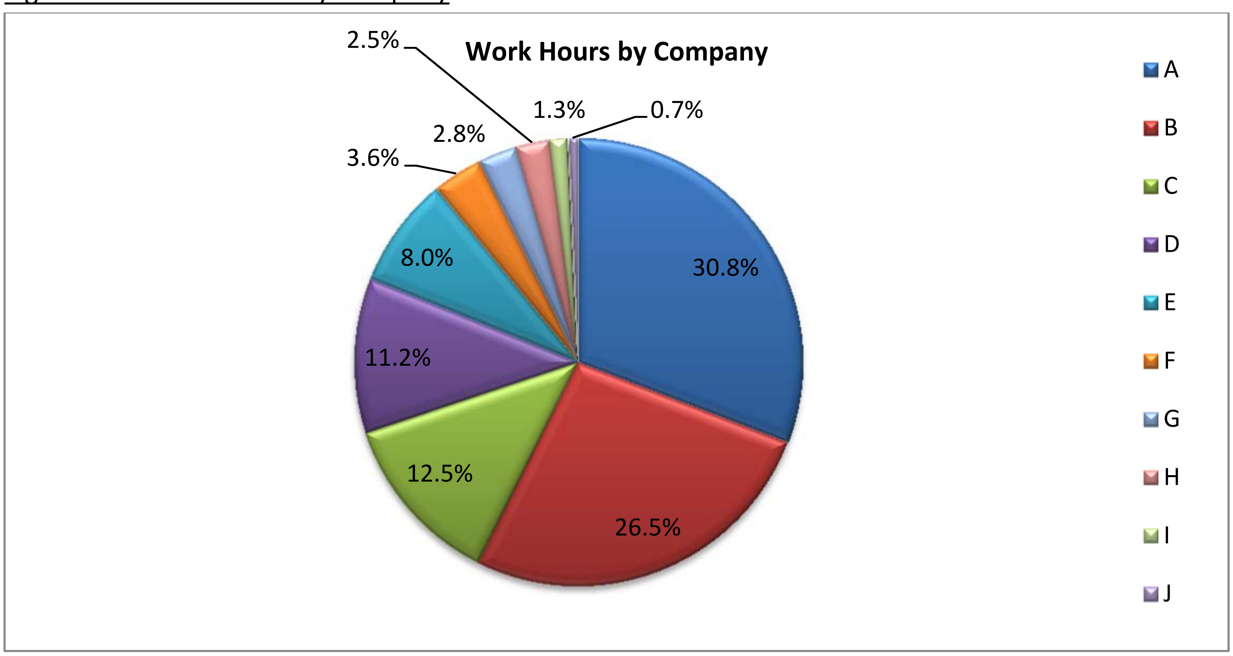
4.8 Normalization Factor

Figure 4.18: Work Hours by Operation Type



- The scope of the COS SPIP expanded in 2014 to all of the U.S. OCS vs. deepwater only for 2013.
- 45,160,461 work hours were reported by participating COS members for 2016, representing a decrease of 26.4% compared to 2015 and a decrease of 34.9% compared to 2014.
- Work hours are reported by the COS member Operator, and include both Operator and Contractor work hours.

Figure 4.19: Work Hours by Company



- Two operators reported 57.3% of the work hours reported for 2016.
- To maintain data confidentiality, letters used to designate member companies are uniquely assigned for individual companies.

5.0 LEARNING FROM INCIDENTS AND HIGH-VALUE LEARNING EVENTS

5.1 Introduction

The Learning from Incidents and Events (LFI) Program was established to provide a process for COS members to share and learn from incidents and High Value Learning Events (HVLE) that occur in offshore operations. Reporting is voluntary and data confidentiality is maintained through a process administered by a 3rd-party before submittal to COS.

The LFI section provides an analysis and comparison of the SPI 1, SPI 2, and HVLE LFI data submitted for reporting years 2013 to 2016, and includes learnings for COS members to share within their organizations to potentially prevent recurrence of similar or more severe incidents.

The data is comprised of the reported learnings from SPI 1 and SPI 2 incidents, as well as those from HVLE. A summary of the definitions for SPI 1, SPI 2, and HVLE can be found below in Figure 5.1 below.

Figure 5.1: Description of SPI 1, SPI 2 and HVLE

SPI 1 is the frequency of incidents that resulted in one or more of the following:

A. Fatality
B. Five or more injuries in a single incident
C. Tier 1 process safety event
D. Level 1 Well Control Incident - Loss of well control
E. ≥ $1 million direct cost from damage to or loss of facility / vessel / equipment
F. Oil spill to water ≥ 10,000 gallons (238 barrels)

SPI 2 is the frequency of incidents that do not meet the SPI 1 definition but have resulted in one or more of the following:

A. Tier 2 process safety event
B. Collision resulting in property or equipment damage ≥ $25,000
C. Mechanical Lifting or Lowering Incident
D. Loss of station keeping resulting in a drive off or drift off
E. Life boat, life raft, rescue boat event
F. Level 2 Well Control incident - Multiple Barrier Systems Failures and Challenges

HVLE is an event that may be considered by a COS member or the industry for use as a reference in process hazard analyses, management of change, project design, risk assessment, inspection, operating procedures review and / or training.

The submitted data includes 3 key fields:

- **Description of the Incident or HVLE**: A brief explanation of activities, conditions, and acts leading up to, during and after the incident or HVLE, including sufficient details to facilitate clear understanding.
- **Areas for Improvement**: A selection of pre-determined general categories and subcategories. Submitters had the option to add comments to provide further clarity and content.
- **Lessons Learned**: Companies outlined their incident investigation conclusions with the goal being to reduce the likelihood of similar incidents for other COS members.

Within the Areas for Improvement (AFI) fields, submitters choose from three general categories and 15 sub-categories. Multiple AFI can be selected for a single incident or event. The three general categories are:

- **Physical Facility, Equipment, and Process**: Enhancements in the quality of the physical process and equipment design, layout, material specification, fabrication, or construction were highlighted for improvement
- **Administrative Processes**: Enhancements in the quality, scope or structure of administrative processes for managing various aspects of work execution were highlighted for improvement
- **People**: Enhancements to the personnel actions linked to the execution of work tasks were highlighted for improvement

5.2 Summary

The effectiveness of this program is dependent on active participation by COS members to facilitate maximum learning opportunity through:

- Timely sharing of quality information from incidents and HVLE that meet the reporting criteria; and
- Reviewing submitted incidents and HVLE, and this COS APR in its entirety, to identify and implement applicable learnings appropriate to different levels and functions within their own organizations.

The LFI data presented in this report includes information from 61 LFI submittals received for the 2016 reporting year, with 44 of the reported incidents and HVLE occurring in the U.S. and 17 at international locations (refer to Figures 5.2 and 5.3 below). Of the 44 U.S. events, 35 occurred in water depths $\geq$ 1,000 feet, 8 in water depths < 1,000 feet, and 1 at a shore-based facility. To support COS's mission to promote the highest level of safety for the U.S. offshore oil and natural gas industry, the findings presented in this report are focused on incidents and events that occurred in the U.S. OCS. A separate section discussing data associated with incidents outside the U.S. OCS (international and U.S. shore based) is provided in this report.

Figure 5.2: Incident Category Distribution per Submittal Type (All Submittals)

Year	2013	2014	2015	2016	TOTAL
COS SPI 1	2	5	7	6	**20**
COS SPI 2	39	39	21	17	**116**
HVLE	7	8	21	38	**74**
TOTAL	**48**	**52**	**49**	**61**	**210**

Note – The definition of SPI 2C "Incidents involving Mechanical Lifting or Lowering" was modified for reporting years 2015 and beyond to include minimum thresholds to qualify as an SPI 2C. The previous broader definition has been retained as SPI 4.

Figure 5.3: Incident Category Distribution per Submittal Type (U.S. OCS Only)

Year	2013	2014	2015	2016	TOTAL
COS SPI 1	2	5	7	5	**19**
COS SPI 2	38	38	21	17	**114**
HVLE	6	8	19	21	**54**
TOTAL	**46**	**51**	**47**	**43**	**187**

Note – The definition of SPI 2C "Incidents involving Mechanical Lifting or Lowering" was modified for reporting years 2015 and beyond to include minimum thresholds to qualify as an SPI 2C. The previous broader definition has been retained as SPI 4.

A review of the 2016 reporting year incident and event data resulted in the identification of multiple learning opportunities related to the following topics:

- Process Safety
- Mechanical Lifting or Lowering
- Maintenance, Inspection and Testing

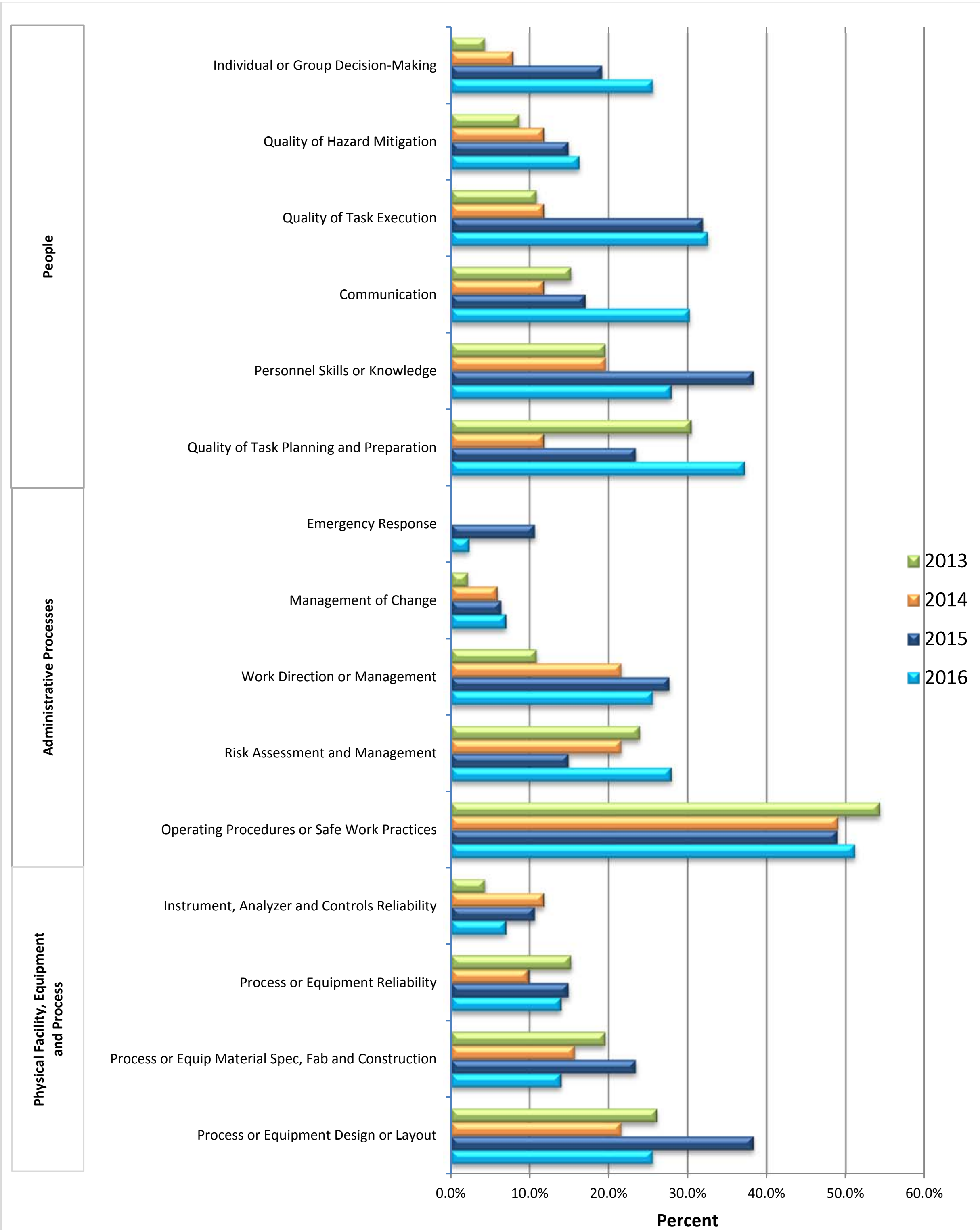
Process Safety and Mechanical Lifting or Lowering continue as focus areas, as these topics were also identified as learning opportunities for reporting years 2013-2015. Maintenance, Inspection and Testing is a new activity-based focus area in 2016 as 11 incidents represented a significant increase when normalized against previous reporting years. In addition to the topics mentioned above, there were other key learnings captured from all LFI data as presented below.

The top three Areas for Improvement (AFI) identified for 2016 were Operating Procedures or Safe Work Practices, Quality of Task Planning, and Quality of Task Execution. Across all 4 reporting years, Operating Procedures or Safe Work Practices was the most frequently identified AFI, as shown in Figures 5.4 and 5.5 below.

Figure 5.4: Area for Improvement Distribution (U.S. OCS Only, Table)

Area for Improvement	2013	2014	2015	2016	4-yr Avg (%)
Operating Procedures or Safe Work Practices	25 (54%)	25 (49%)	23 (49%)	22 (51%)	**51%**
Quality of Task Planning and Preparation	14 (30%)	6 (12%)	11 (23%)	16 (37%)	**25%**
Quality of Task Execution	5 (11%)	6 (12%)	15 (32%)	14 (33%)	**21%**
Communication	7 (15%)	6 (12%)	8 (17%)	13 (30%)	**18%**
Personnel Skills or Knowledge	9 (20%)	10 (20%)	18 (38%)	12 (28%)	**26%**
Risk Assessment and Management	11 (24%)	11 (22%)	7 (15%)	12 (28%)	**22%**

Figure 5.5: Areas for Improvement Distribution (U.S. OCS only, Chart)



NOTE - LFI submittals typically identified more than one AFI. The graph above illustrates the percent of times an AFI was identified relative to the number of LFI forms submitted for U.S. OCS events (46 in 2013, 51 in 2014, 47 in 2015, and 43 in 2016). Because the number of AFI exceeds the number of LFI forms, the sum of the percentages will be > 100%.

For 2016, the largest changes in AFI selection from the prior reporting year were:

- Quality of Task Planning increased from 22% to 37%
- Risk Assessment and Management increased from 15% to 28%
- Communication increased from 17% to 30%
- Process or Equipment Design or Layout decreased from 38% to 26%
- Personnel Skills or Knowledge decreased from 38% to 28%

When comparing 2016 data to the prior 3 years combined data, AFI selection has increased for 5 of the 6 “People” AFI categories.

5.3 2016 Learnings

A review of the 2016 reporting year LFI data resulted in the identification of learning opportunities related to the following topics:

- Process Safety
- Mechanical Lifting or Lowering
- Maintenance, Inspection and Testing

5.3.1 Process Safety

A total of 15 Process Safety Event (PSE) LFI forms were submitted in 2016 (4 Tier 1 and 11 Tier 2 PSE). This reporting represents a significant increase in 2016, compared to a total of 7 events reported in 2013, 9 in 2014, and 9 in 2015. For 2016, Operating Procedures or Safe Work Practices AFI were cited most frequently, followed equally by Process or Equipment Design or Layout, Risk Assessment and Management, Individual or Group Decision-Making, and Communication (Refer to Appendix 6, Chart 9).

Specific learning opportunities within each of the top 5 AFI categories, and Lessons Learned narratives are excerpted below:

<u>Operating Procedures or Safe Work Practices</u>

- LOTO [*note: Lockout Tagout*] procedure existed but did not stipulate cool-down time or the safest way to depressure the [flash gas compressor] FGC system.
- Procedure utilized allowed the tank to be overfilled as the tank dimensions and levels were incorrectly identified.
- The process of managing bleeds was based on individual's memory vs. a documented process. (This learning opportunity was also identified in the Maintenance, Inspection and Testing Section)
- The Operating Procedure in place did not address the proper alignment of the hazardous drain line valve.
- Well intervention/completion/workover activity procedures will be revised to include that hydrocarbons should be anticipated to be in the riser when fluid is not a barrier. Any circulation to the rig surface gas and fluid handling system should not be considered routine and should require management review approval and oversight
- The procedure used for this task was meant to be used for general transfers only and did not contain the specific guidance needed to carry out this operation successfully.

<u>Process or Equipment Design or Layout</u>

- Over time the deposited well debris changed the loading conditions on the jumper and joint in ways that were unexpected and beyond the loads considered in design. These loads, along with portions of the jumper remaining buried, resulted in the load transferred to the jumper being greater than designed.

- The equipment design lacked the addition of isolation valves or check valves to ensure that backflow could not occur into unwanted areas.
- Inspection of multimeter found that one of the two bolts that hold the transmitter body together had sheared causing the valve body to split enough under the gas pressure to create a flow path to atmosphere.

Risk Assessment and Management

- These load mechanisms were not recognized at the time when the impact of burial was evaluated. Therefore the jumper was covered and eventually failed at the joint.
- Per company policy, a [Job Safety Analysis] JSA is required when working on pressurized equipment isolating and/or opening piping or equipment and for non-routine activities. There was misunderstanding among facility personnel on when to conduct JSAs for routine vs non-routine work.
- Task Risk Assessment and Work Instruction for task did not include proper valve alignment.

Individual or Group Decision-Making

- Decision to re-configure compressor was made at the mechanic job level and not approved by [person in charge] PIC.
- Alarms were set based on what was thought to be true for the tank dimension vs. what were actual tank dimensions.
- Changes to original procedure were influenced by a desire to avoid plant upsets and sheening events. [Management of Change] MOC and risk assessment for the changes were not performed and the potential for unsafe work was not identified or fully stopped.
- The work team's interpretation of the Safe Work Planning and Authorization Procedure did not include the use of a Hazard factor calculator referenced in the procedure. Utilizing the calculator would have prompted the workers to utilize double block and bleed as required for the job. (This learning opportunity was also identified in the Maintenance, Inspection and Testing Section)
- Operators did not follow the [standard operating procedure] SOP for running the [low dosage hydrate inhibitor] LDHI pumps. The pumps were online without supply pressure and the pumps were stroked without flow established. Both actions are checks/warnings already in the SOP.

Communication

- Communication of the decision to re-configure compressor was made at the mechanic job level with no communication to Ops leadership engineering and other possible stakeholders.
- A gap existed between leadership expectation of how walk downs were conducted vs how they were actually done in the field. It was expected that drawings were used and that every orifice was checked at some point before start up. Operations admitted they don't always use drawings during walkdowns. (This learning opportunity was also identified in the Maintenance, Inspection and Testing Section)

- The [original equipment manufacturer] OEM had identified this issue but had not yet communicated it to the rig.
- The work team's interpretation of acceptable practices of depressurizing a line was different from leadership's belief that the work team would depressurize the line to atmosphere through the flare. (This learning opportunity was also identified in the Maintenance, Inspection and Testing Section)

<u>Additional Lessons Learned</u>

- **Incident Description** – "A subsea system experienced a subsea equipment leak. The location of the leak was at a rupture in a load limiting joint on a 410 stainless steel well jumper. The load limiting joint was a deliberate weak spot in the system designed to protect the tree from damage in the event of an anchor drag of the pipeline. During drilling of the riserless section of a new well in the field drilling mud cuttings and cement inadvertently were deposited on top of the surrounding subsea hardware (jumpers sleds manifold)."

  Learnings: "In the planning and drilling of subsea wells require and confirm that potential impact of drill cuttings on surrounding equipment is understood and mitigated. Avoid burial of subsea hardware unless accommodated for in the design and include mechanical overload as a result of burial in the Failure Modes Effects Analysis (FMEA) for subsea hardware. Require and confirm that non-standard components /weak points in the system (such as load limiting joints) are shown on regularly used reference documents such as Process Engineering Flow Schematic (PEFS).

- **Incident Description –** "While bunkering methanol to a Storage Tank the tank was overfilled causing methanol to be directed to the open drain sump through overfill line. During the methanol bunkering operation the control room operators noticed a rise in the oil bucket in the open drain sump. Bunkering operation was shut down and secured. At that time it was determined the rise in the open drain sump was likely due to the bunkering operation and the decision to terminate the operation was made. Calculations show that approximately 4,400 gallons overflowed from the methanol tank to the open drain sump."

  Learnings: "A Procedure utilized allowed the tank to be overfilled. Alarms were set based on what was thought to be true for the tank dimensions vs. what were actual tank dimensions. Previous quantities seen during the bunkering of methanol were limited by the size of the boat. However in the past year operations began using a much larger boat for methanol to serve many platforms. The upsized supply vessel provided enough capacity to overfill the tank. As result of the incident the procedure was updated to correctly reflect the capacity of the vessel."

- **Incident Description** – "While setting up to perform repairs on a pump, an individual heard a blowing noise. Upon investigation the individual discovered oil being released in the vicinity of a nearby separator. Initially it was believed that the release was coming from a flange on one of the meter runs adjacent to the separator. The platform was shutdown via automatic shutdown activation blown down and the area secured. It was then discovered that the release was coming from an open drain line on the level safety bridle of the separator. The 2 valves on the level safety drain line were in the open state and the line did not have a plug in it. The valves were believed to have been left open at the completion of a job a month prior to the incident."

Learnings: "A process that required the documenting of all bleeds/vents was implemented. Bleeds/vents will either be documented in the Lockout-Tagout (LOTO) certificate or on a spreadsheet if the task did not require a LOTO. This provided consistency across all locations and crews on which points were manipulated at the end of the job to ensure that they would all be closed regardless of who conducted the isolations or de-isolations. Any valves that are manipulated outside of a LOTO certificate would be tracked on the spreadsheet by the central control room and reviewed with all operators at the end of each shift." *(This learning opportunity was also identified in the Maintenance, Inspection and Testing Section)*

- **Incident Description** – "While circulating bottoms up and flushing the choke and kill lines the driller first noticed errors on the drilling power limit system (DPLS) which in turn shut down Mud Pump #1. After conferring with personnel in the pump room an unsuccessful attempt was made to bring the pump back on line. Initial trouble-shooting efforts revealed that there had apparently been a swab or liner failure. Further investigation however determined that the intermediate rod of the Hydra-line Rod system also known as the Hydraulic Sub Rod had failed. This resulted in sixty-four barrels of Synthetic Based Mud (SBM) being released and subsequently sequestered within secondary containment."

  Learnings: "Remove and perform Non-Destructive Testing (dye penetrant) of the remaining pins and sub rods to ensure fitness for duty. Create a preventative maintenance plan to ensure that pins are put on a rotation schedule after a pre-determined number of hours of operation. Contractor Drilling Management to communicate incident to fleet to inform of recent incident. Include expectations for performing recommended physical assessment of all pins and sub rods in mud pumps. It is important that [original equipment manufacturers] OEM's identify and clearly communicate the resolution of issues with the potential to occur in multiple locations to all affected users."

- **Incident Description** – "Mechanic upon entering compressor building saw a 1.5' flame from cylinder #3. Machine shutdown and facility emergency shutdown [were activated] (ESD'd). Fire went out when fuel source closed. No damage to compressor."

  Learnings: "The torque of all bolts on fuel gas lines for both compressors were checked after the incident and all coils were visually inspected. Ensure there are no other locations with silicone hose. If there are complete permanent repair. Create [a maintenance plan] to check torque on compressor fuel gas line bolts monthly for 3 months to determine if bolts are continuing to come loose. Develop plan forward based on results."

- **Incident Description** – "During an intervention operation to remove scale returns from acid jobs were flowed back to temporary equipment for disposal or rerouting to the production test separator. Produced fluids and base oil were flowed back to the subsea production manifold following the first two acid jobs. However sheening and plant upsets resulted that were believed to have been caused by hydrate inhibitor or a viscous pill. Adjustments resulted in 'yo-yo-ing' fluids in the wellbore and elimination of the flowback to the subsea manifold for acid jobs 3 and 4. Subsequent operations resulted in hydrocarbon-contamination of base oil above the subsea tree. The riser displacement that followed allowed the contaminated base oil to come to surface through the mud gas separator and sand traps activating a gas detector. A full facility muster was completed successfully."

Learnings: "Elevated gas level detection at the surface of rigs should be considered abnormal and emergency response procedures should be in place and drilled upon to verify facility and personnel response readiness."

- **Incident Description** – "During a decommissioning the well crews had completed a test of the EZSV and were conducting a test of the blind shear rams. During the pressure test the Remotely operated underwater vehicle observed a leak coming from the high pressure vent line on the subsea tree. Attempts to close the valves with the Remotely operated underwater vehicle were only partially successful until after it surfaced and retooled. Additional attempts to test the blind shears with Safety Valve 1 and Safety Valve 2 closed were also unsuccessful. After deciding to run in with the bore protector the subsequent tests were successful. At a loss rate of approximately 3 bbls/hr. the total amount of discharged Zinc Bromide was 22 bbls."

  Learnings: "Document this gap in the internal lessons learned process for this type tree. Add valve alignments to well abandonment procedures. Engage contractor in updating procedures for tubing hanger recovery to include valve alignments. Ensure [shutdown valve] SV1 and SV2 are treated equally in barrier diagrams. For all operations involving a tree conduct barrier analysis for all phases and involve contractors to clearly identify exposures. Educate the [Drilling and Completions] D&C community on the difference between bore protectors used for well heads vs. production trees. Engage contractors to develop drawings that accurately describe the system for future wells."

- **Incident Description** – "A small packing leak was discovered on the Flow Control Valve (FCV) on a condensate line. Leadership was brought down and a decision was made to isolate and bleed down the line so the packing could be changed. The operators bled down the condensate line to atmosphere through a ½" low point drain. While operating the valve a sudden burst of liquids was released. As the condensate continued to escape from the valve the operators decided not to enter the gas cloud to isolate it but to leave the area and [Emergency Shutdown] ESD the platform. The platform was mustered and after the gas detectors in the area returned to normal, a team was dispatched to the site and found gas was still coming from the valve. The platform was then blown down to stop the gas leak."

  Learnings: "The team's execution of the directions was different than leadership's expectations of how the directions would be executed. The team bypassed the single point gas detector in the area before opening the drain valve to prevent a nuisance platform [Emergency Shutdown] ESD. The team anticipated a potential gas cloud and attempted to manage through manual mitigations rather than the automated system. In this incident the team believed they could perform better than our automated safeguards. Ensure that a clear understanding and communication of the process for bleeding/venting of volatile hydrocarbons (Flash Point <140, e.g. Natural gas condensate, methanol, etc.) exist at your location." *(This learning opportunity was also identified in the Maintenance, Inspection and Testing Section)*

- **Incident Description** – "Approximately 7.73 bbls of base oil fluid spilled from base oil tank vent line to secondary containment in shaker house after the holding tank was accidentally over-filled. After initial safe transfer of base oil to designated holding tank, the worker re-opened the tank valve in anticipation of another scheduled base oil transfer. This resulted in residual base oil draining from the line into the holding tank which was still nearly full from being recently filled. This triggered a "high level" alarm which should have shut down the transfer pump but due to a software coding error it instead started up the pump without alerting the worker pumping base oil until it spilled from a vent a few decks above where an alarm was finally raised."

  Learnings: "Where possible, system commissioning procedures need to be tested comprehensively and from end-to-end (in this case with fluids) to ensure correct operation and mitigate the possibility of software errors. It is important that the possibility of human error in software coding be considered as part of commissioning activities. Strict software quality control and quality assurance standards must be rigorously employed and adhered to. System commissioning procedures often include software meant to automate certain aspects of the process. It is important to ensure that strict software quality control and assurance standards are employed and rigorously adhered to. It is also valuable to test commissioning procedures under controlled conditions to mitigate against the existence of errors that are not readily observable."

- **Incident Description** – "Suspect backfire on right bank of generator caused intake filter to catch fire."

  Learnings: "Liquid carryover was determined to be the most likely cause of engine backfire allowing pre-ignition of the fuel-air mixture from the cylinder back through the inlet air manifold and igniting the inlet air filter. There was a smaller amount of carbon build-up in the cylinder – one of the typical indications of hydrocarbon liquid carryover from the fuel gas system. Liquids carryover is a known issue at the platform and is managed via structured operator rounds and the daily draining of liquids from fuel gas system low points and fuel gas filters.

- **Incident Description** – "While bunkering methanol to a Storage Tank, the tank was overfilled causing methanol to be directed to the open drain sump through overfill line. During the methanol bunkering operation the control room operators noticed a rise in the oil bucket in the open drain sump. Bunkering operation was shut down and secured. At that time it was determined the rise in the open drain sump was likely due to the bunkering operation and the decision to terminate the operation was made. Calculations show that approximately 4 400 gallons overflowed from the methanol tank to the open drain sump."

  Learnings: "Operators on location could not see the tank or tank levels as it was below deck. The operator believed that the methanol storage hull tank had a full capacity of 21 ft. In reality the tank was 14 ft. tall with several 7 ft. "chimneys '' corresponding with each of the portholes. Additionally the level indicator was configured to read the whole length and did not take into account the 7 ft. of dead space."

5.3.2 Mechanical Lifting or Lowering

A total of 9 Mechanical Lifting or Lowering events were reported for 2016. While the relative percentage of these incidents and events was reduced in 2016 compared to prior years, this activity continues to represent a high percentage of overall activities identified. Operating Procedures or Safe Work Practices and Quality of Task Planning and Preparation were the most frequently cited AFIs, followed by Risk Assessment and Management (See Appendix 6, Chart 7).

Selected learning opportunities within these top three 2016 AFI categories and Lessons Learned narratives are excerpted below:

Operating Procedures or Safe Work Practices

- During the investigation it was discovered that several procedures were inadequate for the operation. The Risk Assessment Lift Plan and Toolbox talk were generic and therefore did not describe specific method of controlling the modules when moving into position on the cribbing and associated hazards. This may have led to better positioning of the employees and an opportunity for them to describe potential line of fire concerns.
- Procedure used did not incorporate specific safety features of the crane. A tag was not created in the maintenance system to generate specific maintenance tasks for this model. The tasks did not account for the load monitoring device option installed.
- Crew had done this lift before many times and had always accepted the placing of this equipment on timbers as a common practice (Acceptable Risk) and never recognized the need for a re-design of equipment.

Quality of Task Planning and Preparation

- A review of relevant records revealed that the [person leading the work] approved 23 Permit to Work (PTW) on average each day that month. This high volume of work impacted his ability to observe jobs on-site.
- The commissioning and acceptance testing for the crane was not completed. Personnel failed to recognize the risk associated with operating this particular model of crane without thorough commissioning and verification of included safety systems.
- Crew knew there was an issue with the height of the injector head and packoff stand thus needing to place the equipment on timbers. Proper planning would have identified the issues and required an alternative design / solution to the problem.
- An inadequate risk assessment was conducted prior to the crew starting work. The two employees completing the task and the work supervisor did not participate in the [Job Safety Analysis] JSA discussion as would have been expected.

Risk Assessment and Management:

- Complacency and a lack of operational discipline around the intent and expectations of the Permit to Work (PTW) and Job Safety Analysis (JSA) process existed. The crane crew was utilizing the same JSA each day which did not address any unique high consequence hazards.
- The risk assessment process did not include a scenario where an existing safety system failed.
- The risk assessment for the task did not anticipate the dunnage displacement and having to re-lift the load for adjustment. The need to restack the dunnage created an opportunity for the banksman and load handlers to be in close proximity of the load while it was being lifted/landed.

Additional Lessons Learned

- **Incident Description -** While a riser joint floatation module (weight 1.1 tons) was being moved from the riser to be positioned on the deck an employee sustained an injury to the right hand (off hand) while moving over the bevel at base of a Samson Post. Employee's right hand (off hand) was placed on the Samson post and employee was focusing on foot placement due to trip hazard at the base of the Samson post when the load moved towards post coming into contact with the right hand (off hand). The employee was treated for a broken finger. It was noted the employee had been using a push/pull stick but had removed the tool while repositioning to the other side of the beveled base of the Samson post.

  Learnings: During the investigation it was discovered that several procedures were inadequate for the operation. The Risk Assessment Lift Plan and Toolbox talk were generic and therefore did not describe specific method of controlling the modules when moving into position on the cribbing and associated hazards. This may have led to better positioning of the employees and an opportunity for them to describe potential line of fire concerns. It was also found that an additional banks man / spotter should have been in place as the lift was considered a blind lift. Had a second designated signal person been used they would have been able to watch the deck activity and would have been able to warn the employee of the impending danger from the moving module.

- **Incident Description -** While drilling ahead on the Main Floor the driller noticed a washout between two joints at the uppermost connection of the stand. The decision was made to lay out a single and use the joint that was already in place on the pipe cart. After laying out the single in the process of hooking up the joint it was noticed that the single did not weigh enough to fully tilt the elevators into position to latch. At this time the air tugger was utilized to assist in tilting the elevator. While taking the slack out of tugger line the employee's left thumb was pinched between the hook and the elevator.

  Learnings: Designated flagger requirements encompass all lifting/hoisting activities and are not limited to those operations involving cranes. Use of an independent flagger would have prevented this incident.

- **Incident Description -** A crane operator finished unloading a full basket of pigs to the boat. While slowly swinging the unloaded crane back towards the platform in the counter clockwise direction the crane operator heard a loud pop. When the crane operator attempted to control the swing the operator realized that the function to stop the swing or to swing the crane in either direction was no longer operable. As soon as the crane came to a stop the crane operator immediately called a crane mechanic to assist in manually placing the crane back into the crane pedestal. The crane was secured and taken out of service until it could be repaired (~1 week).

Learnings: After further investigation it was found that slew related failures had happened twice before at this asset since February 2015 including a previous incident involving a cracked secondary planet carrier on the exact same crane. Performing a [Root Cause Analysis] RCA on either incident and recommending actions to prevent re-occurrence may have prevented another repeat event. The parking brake (or static brake) is intended to keep the crane locked in place if lifting activity is on hold or has ceased altogether. The disc brakes engage completely as the pressure holding them apart vents and the friction brings the crane to a sudden stop. Dynamic brakes offer a smoother stop as foot pressure on a pedal is proportional to the breaking force applied. If done too quickly however even dynamic breaking can apply significant force to the crane.

- **Incident Description -** A crane crew was in the process of lifting a 1,400 pound 7.5 foot tall submersible electric motor mounted vertically to a wooden pallet. The motor was rigged with nylon straps running through the pallet in a "basket hitch" method to move the motor from one location to another on the facility. Upon beginning the lift the pallet hung up on an angle iron support beam approximately three (3.0) feet above the deck. This caused the lift to tilt and the motor having a high center of gravity to topple over striking and landing on a rigger who was in the vicinity of the lift in progress. The rigger sustained a recordable injury and was subsequently placed on restricted duty.

  Learnings: Unmitigated high risk tasks within an overall larger body of daily work can easily be overlooked among the daily “noise” of overall activity. Expectations and key job responsibilities for personnel involved in permitting work need to be established and understood to ensure proper oversight during high risk work activities. Complacency organizational drift and a lack of Marine shore base procedures: to ensure all loads are pre-slung before going offshore. Shore base personnel did not recognize the potential impact of the heavy contents inside the basket not being pre-slung. Easily identifiable marking on the original motor crate - e.g. STORE HORIZONTALLY - would have been beneficial to the crew. Although there was a pallet jack there were no pallet tongs (aka pallet bars) to lift pallets with either crane. However this may still not have prevented the high center of gravity load from snagging and toppling. The existing standard requires all pallets to be lifted with pallet lifting equipment but the personnel involved were not aware of this requirement. A larger “heads-up” camera display better located. Operational discipline around the intent and expectations of the [Permit to Work / Job Safety Analysis] PTW/JSA process existed.

- **Incident Description -** A member of the crew was preparing to perform testing on a [Blowout Preventer] BOP crane. While troubleshooting controls on the crane the boom was extended with inadequate slack in the hoist cable. During testing operations the end of the boom struck a block. The impact resulted in the hoist cable rupturing and the block weighing 270 pounds falling a total of 27 feet. During its 27-foot fall the block struck intervening objects before coming to rest. It first made contact with the frame of some nearby well-test equipment then it contacted a hand-rail attached to the BOP access stairway and finally the block came to rest on the BOP securing platform some 12 feet away from the Operator.

> *Learnings:* Equipment and facilities should never be operated without completion of proper commissioning and acceptance testing. Always verify the availability and adequacy of operating procedures for equipment and facilities. Always verify the completion of Commissioning and Acceptance Testing before setting up equipment in Maintenance Systems. Maintenance tasks should be developed based on [Original Equipment Manufacturer] OEM recommendations.

- **Incident Description -** A crane crew was moving casing doubles from the riser storage area to the rig floor via the forward conveyor. While attempting to re-land a double of 16-inch casing on the forward conveyor the end of the casing closest to the rig floor displaced some dunnage. As the Crane Operator lifted the load for the dunnage to be adjusted the forward end of the casing lifted first and shifted to the starboard side slightly outside the conveyor rails. As the casing settled on the conveyor (aft end first) the forward end slid off the starboard side of the conveyor and made contact with the Load Handler who was struck in the torso.

  > *Learnings:* Risk Assessments and Job Safety Analyses for work activities must include a review of current worksite conditions. This will verify that all site-specific hazards associated with the job have been identified and mitigations are in place and functional. Plans or conditions frequently change during work execution. Work crews must have the operational discipline to stop the job assess the situation identify and mitigate hazards before continuing the work. When deviations are accepted and normalized it creates the potential for incidents to occur. Both work crew members and Supervisors must utilize their authority to stop the job and take the opportunity to thoroughly assess and address abnormal conditions.

- **Incident Description -** In order to expedite the removal and repair of the quarter assemblies on the wellbay hoist a worker was tasked with transferring a load from a chain fall hoist over to a wire sling - both of which were attached to a trolley. The chain hoist was being lowered until the weight was fully supported by the wire rope sling. This required that the worker operate in a crouching position because of the restricted space available. The chain fall handle began moving in an uncontrolled manner and struck the worker in the face. The worker sustained a laceration to the neck and damage to their dental crowns. Work was immediately stopped to allow medical assistance to be given an investigation to be started and relevant mitigations to be implemented.

  > *Learnings:* Equipment design and pre-task evaluation should include consideration for the human machine interface and ergonomics. This should be confirmed via a pre-job walk of the site. It is critical that workers be familiar with and competent in the use of new tools and equipment prior to utilizing them on the job.

5.3.3 Maintenance, Inspection and Testing (MIT)

A total of 11 Maintenance, Inspection and Testing events were reported for 2016, making this the most frequently cited activity for all LFI Submittals. Operating Procedures or Safe Work Practices and Communication were the most frequently cited AFIs, followed by Quality of Task Planning and Preparation and Personnel Skills or Knowledge (See Appendix 6, Chart 8).

Selected learning opportunities within these top four 2016 AFI categories and Lessons Learned narratives are excerpted below:

<u>Operating Procedures or Safe Work Practices</u>

- The process of managing bleeds was based on individual's memory vs. a documented process. The operator chose the two upstream valves at the jobsite. The operator relied on his memory to close the valves. (This learning opportunity was also identified in the Process Safety Section)

<u>Communication</u>

- Bridge Team did not ask more questions and verifications from the Drill Floor prior to activating the Emergency Disconnect Sequence.
- A gap existed between leadership expectation of how walk downs were conducted vs how they were actually done in the field. It was expected that drawings were used and that every orifice was checked at some point before start up. Operations admitted they don't always use drawings during walkdowns. (This learning opportunity was also identified in the Process Safety Section)
- The work team's interpretation of acceptable practices of depressurizing a line was different from leadership's belief that the work team would depressurize the line to atmosphere through the flare. (This learning opportunity was also identified in the Process Safety Section)

<u>Quality of Task Planning and Preparation</u>

- It is common practice to just phone the Bridge for remote [Emergency Disconnect Sequence] EDS and [Emergency Shutdown Device] ESD function testing. Personnel familiar with the ESD test procedure should be present at each physical location where an action will take place.
- Contractor's policy for anchor points did[not] conform to applicable codes and the operator's standards.
- The work team's interpretation of the Safe Work Planning and Authorization Procedure did not include the use of a Hazard factor calculator referenced in the procedure. Utilizing the calculator would have prompted the workers to utilize double block and bleed as required for the job. (This learning opportunity was also identified in the Process Safety Section)

<u>Personnel Skills or Knowledge</u>

- The exact standards and code requirements for anchor points for using spiders were not understood by the contractor using the hanging platform. The contractor was not aware that pipe size wall thickness and pipe span were critical to having sufficient strength for the anchor point.

- Personnel involved in the investigation did not fully understand the investigation process and their roles and responsibilities most notably the Incident Investigation Lead and the Incident Owner. Thus the recommendations from the investigation were not adequately captured in for follow-up.

Additional Lessons Learned

- **Incident Description -** While changing pendent lines on the crane boom a worker was using an 8lb sledge hammer throughout the day to nail pins down. Upon striking the pin the hammer head broke free from the wooden handle and descended 25 feet to the deck below. No one was in the area where the hammer landed due to an established red barricade no-go zone. The job was stopped and reported to supervision. Post incident assessment utilizing the DROPS calculator ranked the potential outcome of this incident as a fatality.

  Learnings: The pre-use inspection performed on the hammer by visual methods was not adequate to identify the damaged wooden handle inside the hammer head. Proper tethering of the hammer to the worker did not stop the hammer head from falling. All wood and fiberglass handled hammers are prohibited for use on our offshore locations. In lieu of wood or fiberglass handles all hammer handles shall have a steel or steel / composite reinforced core with a functioning non-slip grip. As per existing policy all hammers being utilized when working at heights shall be tethered as per existing policy. As part of job planning all equipment should be inspected prior to use.

- **Incident Description –** An employee performed work on an A/C unit in the accommodations building while the anti-bacterial light was on. That evening the employee felt some discomfort and redness in their eyes and visited the medic. The employee was given some moistening eye drops and went to bed. The employee woke up with pain redness and blurred vision in both eyes the following morning. Both eyes were examined to ensure that no foreign bodies or scratches were present and lubricant eye drops were applied. Through screening the medic determined that the employee was experiencing photo keratitis (arc flash) from Ultra Violet (UV) light exposure. The employee visited a doctor after arriving home and was given prescription eye drops to treat for photo keratitis.

  Learnings: Ensure that robust barriers are in place to protect personnel from exposure to UV lights. Consider physical barriers and mechanical interlocks to prevent exposure. Ensure that Health Risk Assessments (HRA's) include potential exposure from UV lights if they are present on your location.

- **Incident Description - A**n inspection was performed on a 2" wet glycol line after personnel identified the area of severe corrosion under a process identification label/sticker. The label was removed and two areas of corrosion were identified and both were measured using ultrasonic thickness equipment and pit gauges. Significant wall loss was recorded with the thinnest section measuring 0.067" which de-rates the pressure rating of this section down to 1200 PSIG (originally rated for ~2122 PSIG). The current pressure at the corrosion site according to a pressure gauge is around ~150 PSIG but in current state there is potential for operating pressure to exceed the new 1200 PSIG pressure rating.

Learnings: The wrap-around style label that attaches by sticking to itself when applied on uninsulated pipe can create a crevice that accelerates coating breakdown and pipe corrosion.

- **Incident Description -** Rig crew was conducting pressure test on Completion Workover Riser (CWOR) when they observed pressure drop on the system. A remote-operated vehicle spotted base oil leaking out of the end fitting vent ports of a coflex hose. The annular line was displaced to seawater and the CWOR brought to surface to replace the hose. The replacement hose was pressure tested successfully and rerun. On April 11 the replacement hose experienced a leak. The CWOR was retrieved and the hose was then replaced with hard piping.

  Learnings: The coflex hose design in this incident requires the end fitting vent ports be fitted with vented plugs when deployed subsea. The hose collapse rating may be compromised if the ports are left open. Cyclic collapse can cause cracking in the inner thermoplastic layer. Conversely plugged ports trap gas that can migrate through the inner thermoplastic layer. Trapped gas from multiple deployments will expand potentially resulting in either the collapse of the inner layer or the rupture of the outer thermoplastic layer. When running coflex hose subsea the annulus layers should be vented externally but not plugged to prevent collapse failure of the pressure containing inner layers.

- **Incident Description -** While blasting and painting on a fixed leg platform it was noticed that there was a breach in the containment area for the job that was allowing garnet to spill out and onto the deck below. The job was stopped by other workers passing by when they noticed the garnet blasting media outside of the habitat. When the lower deck was investigated there was a large amount of blasting material on process equipment specifically some that was scheduled for a large maintenance job the next day.

  Learnings: Ty-wrapping (corners of) pieces of tarp (or other materials) used to seal off blasting and painting areas can be effective but only if adequate overlap is seen between the two "walls". Entrances and exits are difficult to maintain and need more careful preparation/upkeep during a long job. Anyone has the right and is capable to make a stop work intervention as evidenced by this incident.

- **Incident Description -** While performing a Safety Observation of personnel working from a Spider the anchor point for the spider was also inspected. The spider cable was anchored off to a piece of 1 ½" Sch. 40 pipe laying across fiberglass grating and spanned across two structural members 4ft. apart. The weight of the spider and personnel exceeded the allowable load of the 1 ½" Sch. 40 pipe.

  Learnings: Anchor points in this instance were not treated as safety critical which require the stenciling of safe working load labelling of spans and regular inspections. The exact standards and code requirements for anchor points for using spiders were not understood by the contractor using the hanging platform. Anchor points shall be designed in accordance with OSHA requirements for "Scaffolding" Standard Number 1926.451. Review your Fall prevention and protection standard and revise for greater clarity on anchor point requirements if gaps are identified. Label each anchor point for safe working load and span distance. Inspect anchor point(s) on a regular basis.

- **Incident Description -** While setting up to perform repairs on a pump an individual heard a blowing noise. Upon investigation the individual discovered oil being released in the vicinity of a nearby separator. Initially it was believed that the release was coming from a flange on one of the meter runs adjacent to the separator. The platform was shutdown via automatic shutdown activation blown down and the area secured. It was then discovered that the release was coming from an open drain line on the level safety bridle of the separator. The 2 valves on the level safety drain line were in the open state and the line did not have a plug in it. The valves were believed to have been left open at the completion of a job a month prior to the incident.

  Learnings: A process that required the documenting of all bleeds/vents was implemented. Bleeds/vents will either be documented in the Lockout-Tagout (LOTO) certificate or on a spreadsheet if the task did not require a LOTO. This provided consistency across all locations and crews on which points were manipulated at the end of the job to ensure that they would all be closed regardless of who conducted the isolations or de-isolations. Any valves that are manipulated outside of a LOTO certificate would be tracked on the spreadsheet by the central control room and reviewed with all operators at the end of each shift. (This learning opportunity was also identified in the Process Safety Section)

- **Incident Description -** A small packing leak was discovered on the Flow Control Valve (FCV) on a condensate line. Leadership was brought down and a decision was made to isolate and bleed down the line so the packing could be changed. The operators bled down the condensate line to atmosphere through a ½" low point drain. While operating the valve a sudden burst of liquids was released. As the condensate continued to escape from the valve the operators decided not to enter the gas cloud to isolate it but to leave the area and [Emergency Shutdown] ESD the platform. The platform was mustered and after the gas detectors in the area returned to normal a team was dispatched to the site and found gas was still coming from the valve. The platform was then blown down to stop the gas leak.

  Learnings: The team's execution of the directions was different than leadership's expectations of how the directions would be executed. The team bypassed the single point gas detector in the area before opening the drain valve to prevent a nuisance platform ESD. The team anticipated a potential gas cloud and attempted to manage through manual mitigations rather than the automated system. In this incident the team believed they could perform better than our automated safeguards. Ensure that a clear understanding and communication of the process for bleeding/venting of volatile hydrocarbons (Flash Point <140, e.g. Natural gas condensate, methanol, etc.) exist at your location. (This learning opportunity was also identified in the Process Safety Section)

- Incident Description - In 2016 a tool bag with an end wrench protruding approximately 4" out of the top of the bag was being lifted out of a hull column. Upon reaching the top of the hull column the end wrench caught on the lip of the access hatch which upended the bag allowing the wrench to fall to the bottom. A similar incident happened in 2015 on another platform. A bundle of scaffold poles was being lowered into a hull column and was dropped falling. Leadership expected that the formal investigation on the first incident would create systemic changes across all locations. Instead we found that the formal investigation was completed on one location and implementation of the solutions seem to have been limited to that location.

Learnings: Ensure that Incident Owners understand their responsibility to follow up until all objectives of the investigation Terms of Reference (TOR) are met. Ensure Investigation Team Leaders are aware of their roles and responsibilities prior to the start of the investigation. Utilize detailed TOR for formal investigations that clearly outlines expectations and outputs for all involved personnel. Issue a formal action item in for Incident Owners to follow up on action items at an appropriate time after the investigation is completed to confirm implementation and effectiveness of action items. The investigation was completed at approximately the same time that the Incident Investigation Lead was moving on to a new role in the organization. This directed the focus of the team lead away from rigorous follow-up. Because there were no formal action owners there was no clear accountability or visibility on the follow-up.

- **Incident Description -** The lower spotter window fell out of the Crane while the Crane Operator was cleaning the window (from inside the cab). The crane was static during the event with the engine off. The window is located in the cab below the Crane Operators feet and is held in place with a molded rubber weather strip. The weight of the window is 25 pounds and it fell approximately 15 feet from the cab to the top of the Warehouse building. No personnel were below the crane cab at the time of the event. The DROPS calculator indicates a potential outcome of fatality.

  Learnings: Downward facing windows should have a guard to prevent the glass from falling out in the event of failure. Update work instructions to include specific line items for confirming glass tolerance and weather stripping is within [Original Equipment Manufacturer] OEM recommendations. Replacement window retrofitted to eliminate fall potential.

5.3.4 Additional Learnings

This section highlights observations from a variety of incidents and categories, and includes selected AFI and Lessons Learned opportunities.

- A non-critical function ([Pilot Operated Check Valve] POCV button) was linked with a critical function ([Lower Marine Riser Package] LMRP connector button) under the same protective cover. Once this cover was raised this allowed the opportunity for the inadvertent activation of the LMRP connector button. Protective covers are intended to prevent inadvertent activation of the buttons they cover. A single protective cover should not cover both critical and non-critical functions.
- [Lockout tagout] LOTO procedure existed but did not stipulate cool-down time or the safest way to depressure the FGC system.
- Misunderstanding among facility personnel on when to conduct [Permit to Work] PTW for routine vs non-routine work.

- [Injured Person] IP knowledge of Company [Job Safety Analysis] JSA, [Management of Change] MOC, [Permit to Work] PTW, [and Lockout Tagout] LOTO requirements was insufficient.
- During bleed down operations conducted prior to opening equipment [Injured Persons] IPs did not check panel to see if system pressure was low enough to open localized bleed valve to relieve final pressure.
- Senior Leadership displayed insufficient curiosity regarding follow-up of the original 2015 incident.
- Personnel involved in the investigation did not fully understand the investigation process and their roles and responsibilities most notably the Incident Investigation Lead and the Incident Owner. Thus the recommendations from the investigation were not adequately captured in for follow-up.
- The actions proposed by the investigation team remained as recommendations in the investigation report and were not tracked to completion. The actions taken at the location that were effective at preventing reoccurrence of similar incidents were not reviewed for wider applicability and implementation.
- Ensure that Incident Owners understand their responsibility to follow up until all objectives of the investigation Terms of Reference (TOR) are met. Ensure Investigation Team Leaders are aware of their roles and responsibilities prior to the start of the investigation. Utilize detailed TOR for formal investigations that clearly outlines expectations and outputs for all involved personnel. Issue a formal action item in for Incident Owners to follow up on action items at an appropriate time after the investigation is completed to confirm implementation and effectiveness of action items.

5.3.5 Noteworthy Trends for 2013-2016 Data (U.S. OCS)

2016 represents the fourth year of data collection, and the following observations relate to the entire data set of 187 U.S. OCS submittals for the reporting period from 2013 to 2016.

- The total number of LFI shared in 2016 was 43. While this number is slightly down from prior year reporting totals, the 21 HVLEs reported in 2016 represents 49% of the total submittals. The increase in the absolute number and percentage of HVLEs for each of the past four years suggests increased sharing behavior amongst COS Members.
- Site Type selection from 2013 to 2016 has moved from predominantly drilling rigs to a balance of drilling rigs and floating production facilities, and this appears reflective of the continued reduction in offshore drilling activity. Similarly, the Operation Type reporting shows a continued shift from wells towards production.
- AFIs associated with the “People” category continued to lead the AFI selections, with increases in Communications, Quality of Task Planning and Preparation, and Individual or Group Decision-Making.
- Risk Assessment and Management, Communication, and Individual or Group Decision-Making also showed significant increased frequency per the number of LFI shared as compared to previous three years.

5.4 Areas for Improvement

This section summarizes the improvement areas identified across all 43 LFI submittals in reporting year 2016. The following information may be used by COS members to gain insight into potential improvement opportunities for their own operations.

A total of 146 Areas for Improvement (AFI) were selected for the 43 incidents and HVLE (Refer to Chart 5.1 above). Multiple improvement areas relating to a single incident or HVLE is consistent with industry experience, and demonstrates that a majority of incidents and HVLE can have multiple factors and associated barrier failures.

Within the AFI fields, submitters chose from 3 general categories (Physical Facility/ Equipment/ Process, Administrative Processes, and People), and 15 sub-categories.

The AFI data were distributed across the 3 general categories listed above, with a much higher occurrence noted in the People category. People category AFIs were selected over three times as often as Physical Facility, Equipment and Processes, and almost 50% more often than Administrative Processes.

Among the 15 sub-categories, the most frequently reported improvement areas are listed below along with the percentage of reports that selected this improvement area:

- Operating Procedures or Safe Work Practices (51%)
- Quality of Task Planning and Preparation (37%)
- Quality of Task Execution (33%)

The selection of Operating Procedures or Safe Work Practices continued as the most often identified AFI for the past four years. For 2016, Quality of Task Planning and Preparation and Quality of Task Execution were the 2nd and 3rd most frequently selected AFIs. The associated AFI comments, not already shared in Section 5.3 Learnings are presented below:

5.4.1 Operating Procedures or Safe Work Practices AFI Comments:

- A grating checklist for engineering to evaluate modifications and alterations required during the installation campaign for adequacy of design and aligned to installation sequences was not in place.
- There is an opportunity to streamline the Permit to Work (PTW) process and better identify what forms are required. Streamlined paperwork process may have provided more time for the observation of the actual work itself.
- The process of equalizing pressure across the [Pilot Operated Check Valve] POCV is not documented in any work instruction or policy because it is not a daily operation.
- Develop non-standard rigging management plan. Onsite rigger training to include non-standard rigging.

5.4.2 Quality of Task Planning and Preparation AFI Comments:

- Job planning accounted for fall protection and the use of [Self-Retracting Lifelines] SRLs however access throughout the entire work location while wearing a harness and SRL was limited.

- Over time platform personnel came to believe that the caisson was an empty conductor (unlike caissons conductors are vertically supported by being driven into the seafloor). Priority for maintenance or repair on the caisson remained as a low priority as the integrity of the caisson deteriorated.

5.4.3 Quality of Task Execution AFI Comments:

- The grating that fell was supported only on two sides and was not secured by grating clips. There is no evidence it had been tack-welded. The grating was not properly re-installed after modification.
- Contractor's dedicated Working at Height watchman did not perform as required and became distracted and lost focus.
- Subsea employee lost focus on the task and did not verify the correct button before activating the function from the [Blowout Preventer] BOP panel.
- Before beginning an activity requiring working at height the workers did not walk the entire work location with their [Self-Retracting Lifeline] SRL attached to verify that the SRL placement was adequate.
- The practice of prioritizing and closing out older CMs (corrective maintenance orders) that were previously written up without management's knowledge and consent was common.

5.5 Learnings from Incidents Outside the U.S. OCS

Reporting year 2016 showed a significant increase in international LFI submittals with 17 out of 61 reports (28%) coming from events outside the U.S. For the prior 3-year period (2013-2015), a total of 3 international events were reported in the LFI program. Additionally, there were 3 onshore U.S. events reported during the same 4-year period (2 in 2015, and 1 in 2016). While the COS Mission is focused on safety in the U.S. OCS, COS recognizes the value of learnings from international events and accepts LFI Submittals for onshore and international events.

This section of the APR is new for the 2016 reporting year, and presents a summary of the onshore and international events along with associated learning opportunities.

Figure 5.6: Incident Category Distribution for Incidents Outside of U.S. OCS

Incident Location	2013	2014	2015	2016	TOTAL
International	2	1	0	17	**20**
Onshore U.S.	0	0	2	1	**3**
TOTAL	**2**	**1**	**2**	**18**	**23**

For the 2016 reporting year, 18 submittals were associated with international or U.S. onshore locations. Included in this data set was one fatality associated with a marine event. This set of 18 records included 6 process related events, and 4 incidents associated with mechanical lifting or lowering. Some of the Lessons Learned associated with these events are listed below:

- A formal control system is to be in place to control the use of Contractors hydraulics fittings for well testing operations. A locked toolbox was implemented for hydraulic fittings with access restricted to supervisors. Check competence of crews to identify high pressure fittings.
- Industry practices are based on riser analysis studies that do not identify failure mode scenarios for the transition phase after disconnecting in a harsh environment. Riser Analysis do not model the effects of damping (from Tensioner) and [Riser Anti-Recoil Systems] RARS influence on riser dynamics in soft hang-off modes or transition modes (Disconnect time from [Lower Marine Riser Package] LMRP to lift off of [Blowout Preventer] BOP hub and arrive at the point of full clearance of the BOP). Disconnect procedures describing LMRP unlatching do not always describe the post unlatching sequences of optimum tensioner position and RARS configurations.
- Good bonding of neoprene with the steel of the riser section in the splash zone is critical to prevent moisture ingress and resulting external corrosion. Increasing temperature can cause deterioration of this bonding. Pipelines should be operated within their safe operating envelope. Particularly design temperature for riser coating should not be exceeded. Increased water cut in fluid flow lines can cause pipeline temperatures to rise over time due to high heat retention capacity of water. This may start affecting neoprene bonding while invisible externally. Adequately paced inspections to determine condition of coating is key to formulating timely remedial actions.
- The process which ensures the training requirements of 3rd Party personnel have been met needs to be reviewed. 3rd party personnel training must be validated prior to their arrival at the vessel.

- The management of safety critical equipment (SCE) was inadequate. For SCE unavailability or inability to meet performance standards must be immediately communicated to the equipment owner's onshore management and the client's representative. Operations should be suspended or mitigations put in place before normal operations are allowed to continue. A full review of all alarms related to safety and operationally critical equipment should be conducted to ensure they are present in a normally manned and monitored location.
- The crew did not use appropriate mitigation methods to prevent unknown personnel from walking into the area where the unit was being lowered. This would not have prevented the incident but would have ensured that no one was in the area where the unit could have fallen to.
- The fact that the latch was previously cracked did not cause the latch to fail but a lesson learned here is that all incidents where an interaction occurs between pipe and the latch mechanism must be reported and the equipment should be checked for damage and replaced if necessary.
- Test methods for critical instrument systems must have positive proof of function of final elements. Vendor packages with critical protection systems should be risk assessed using appropriate methodologies e.g. Safety Integrity Level assessment.
- Lack of proper labelling can cause hoses that are used for non-compatible purposes and activities with different pressure rates to be mixed up. Correct labelling of hoses must be in place for HP activities. Teams/operators need to perform proper checking of hoses – condition of hose operational pressure for the task to be performed –before commencing [high pressure] HP activities.
- Verify pre-mobilization process steps through contractor onboarding. Consistently execute continued oversight and monitoring of contractors through all phases of work
- Prior to this incident Ring Type Joint connections fitted with 316 stainless steel gaskets were not considered to be an integrity threat so were not subject to any routine visual inspection. Follow up inspections on other installations on the same asset has identified other stainless steel flange connections fitted incorrectly with carbon steel Ring Type Joints gaskets. Personnel who assemble joints during construction may not be aware of the potential consequences of incorrect material selection this weak barrier can lead to loss of containment at some stage in the future. Acoustic gas detectors on unmanned installations were not considered to be Safety Critical Element's prior to this incident
- During the first failure investigation the focus was on H2S and while integrity of all the hatch coamings (skirts) was reviewed no other checks on the hatches were performed. While cargo tanks have an "inert gas" blanket there is also hydrocarbon gas flashing off the crude that makes up approximately 40% (in this case) of the content of the "inert gas" blanket. Therefore in case of a major leak there is a potential for an explosive atmosphere to develop. There was no procedure or training / drill for the investigation of a (potential) gas release e.g. use of portable detectors, number of technicians required and % [Lower Explosive Limit] LEL limit at which they must withdraw from the leak area. Even low pressure systems (pressure inside tank was barely above atmospheric) can lead to significant releases and Tier 2 / 1 events. Unlike topsides facilities pressing the ESD (Emergency Shut Down) button when the leak is detected does not stop the release or make it immediately smaller. It may take up to 2 days to depressurize a cargo tank. Therefore a specific

emergency response procedure is required with drills to practice the safe control of those types of situations. Build-up of H2S inside the cargo tanks due to bacteria is an issue particularly when the tanks are used to store off-spec produced water. Marine system integrity need to be better monitored after conversion - This [Floating Production Storage and Offloading] FPSO was converted from an aged ship.

6.0 SEMS AUDITS

6.1 Introduction

Data from the first round of SEMS audits completed by November 2013 were collected, analyzed and reported in the first APR in 2014. Data from the second round of SEMS audits completed by November 2016 was collected, analyzed and is reported in this APR.

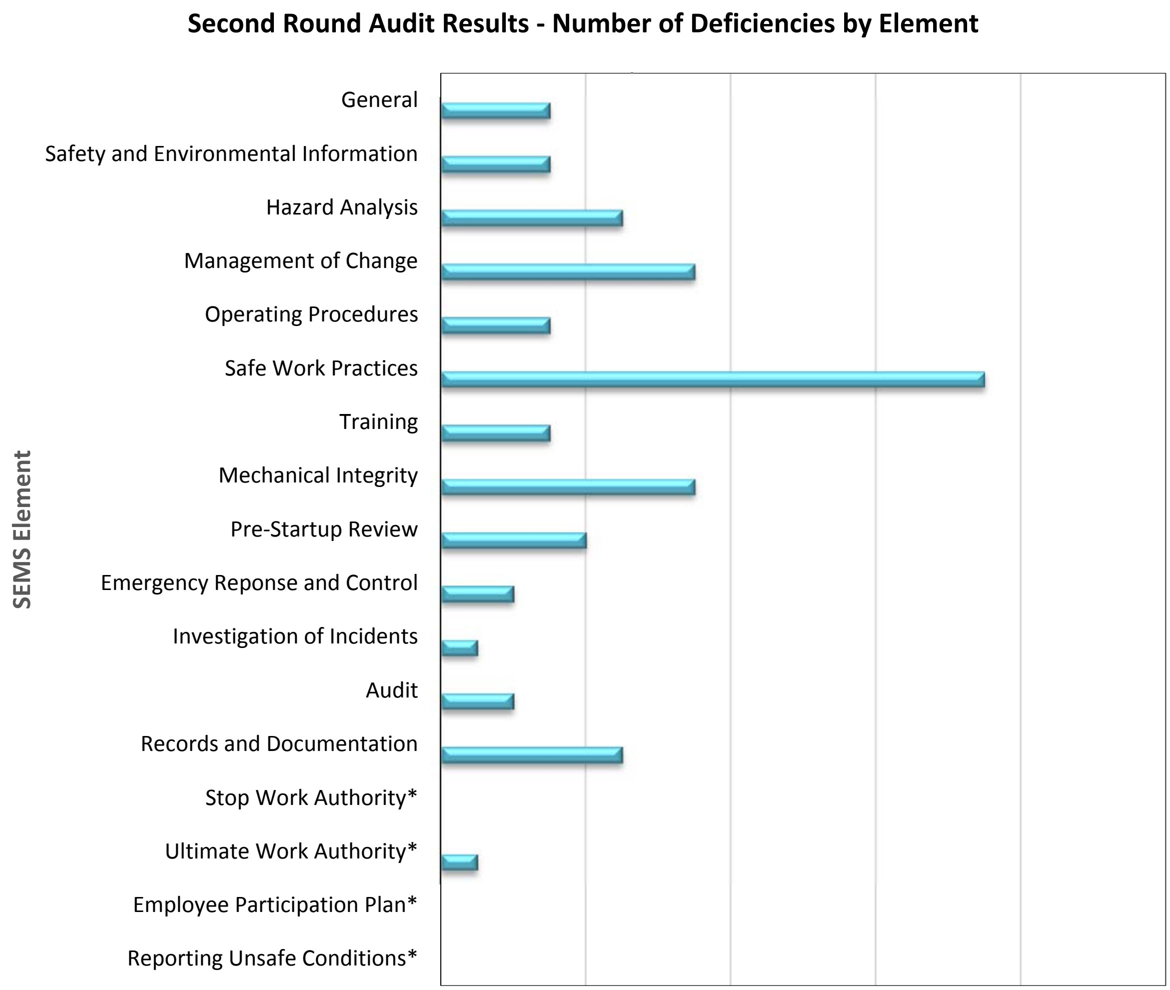
10 COS Operator members shared data, including deficiencies, for the second round of audits. A deficiency is either a non-conformity, which is less than satisfactory fulfillment of a requirement, or a concern, which is a condition that marginally meets requirements but could lead to a non-conformity if sufficient controls are not in place to maintain the management system.

Figure 6.1 shows the breakdown of deficiencies reported by SEMS Element for the second round of audits. In the second round of audits, Safe Work Practices had the most deficiencies, followed by Management of Change (MOC), Mechanical Integrity of Critical Equipment, and Hazard Analysis. These 4 elements accounted for 56% of the reported deficiencies. In comparison, MOC, Safe Work Practices and Emergency Response and Control had the most deficiencies in the first round of audits.

A deeper analysis into the four elements that had the most deficiencies in the second round showed that one Operator had 4 of the 7 deficiencies identified for MOC. The rest of the 3 element deficiencies were spread across several Operators.

In the second round of audits, two Operators reported no deficiencies and no deficiencies were reported for 3 elements by all 10 Operators: Stop Work Authority, Employee Participation Plan and Reporting Unsafe Conditions.

Figure 6.1: SEMS Audit Results - Deficiencies



* Element required for 2nd Round audit only

6.2 SEMS Audits – Deficiencies

> Deficiency - either a non-conformity, which is less than satisfactory fulfillment of a requirement, or a concern, which is a condition that marginally meets requirements but could lead to a non-conformity if sufficient controls are not in place to maintain the management system.

The following trends were observed after reviewing the deficiencies noted in the second round of SEMS Audits reported to COS. The trends are listed below by SEMS element; if a SEMS element is not presented, there were no trends observed in the reported deficiencies.

6.2.1 Element 2: Safety and Environmental Information

- A trend was noted in regard to the lack of accessibility of specific safety and environmental information (i.e. drawings), while under revision.

6.2.2 Element 3: Hazard Analysis

- A trend was noted regarding the incorrect or inadequate application and implementation of lock-out / tag-out as a control for various hazards.

6.2.3 Element 4: Management of Change

- A trend was noted regarding the MOC process not being consistently understood and/or implemented as written, including authorization, risk assessment, and closure.

6.2.4 Element 5: Operating Procedures

- A trend was noted that documented operating procedures did not consistently reflect actual field conditions or practices and/or were not known by interviewed field personnel.

6.2.5 Element 6: Safe Work Practices

- The element consists of two specific topics: safe work practices and contractor management. The deficiency trends will be provided under these two topics.
- Safe Work Practices
    - A trend was noted regarding the application and implementation of lock out / tag-out requirements, including in the areas of authorization and verification.
- Contractor Management
    - A trend was noted regarding the lack of a job-specific assessment of the skills and knowledge of contractor personnel.
    - A trend was noted regarding the inconsistent implementation or verification of the Operator/Contractor SEMS agreement or bridging document, especially contractor implementation of the agreed upon safe work practices.

6.2.6 Element 7: Training

- A trend was noted regarding the lack of sufficient evidence related to the assessment of skills or knowledge for a variety of personnel.

6.2.7 Element 8: Assurance of Quality and Mechanical Integrity of Critical Equipment

- A trend was noted regarding gaps in the maintenance, inspection and testing programs for specific equipment or systems where the program was insufficient or was not being implemented per design or on schedule. In some cases, the deficiency related to the lack of precision in how the maintenance was completed and documented.
- A trend was noted regarding the ability of critical equipment to respond on demand.

6.2.8 Element 9: Pre-Startup Review (PSR)

- A trend was noted regarding the lack of consistency in implementing established PSR procedures, particularly the use of ‘checklists’.

6.2.9 Element 13: Records and Documentation

- A trend was noted regarding the inconsistent review and document control of procedures, lack of availability of training records, and difficulty in accessing documents.

6.3 SEMS Audits – Strengths

Strength - A component that has been identified by the ASP as exceeding SEMS requirements or recommended practice which could benefit industry by being shared.

The data submitted for all 10 Operator members included strengths identified by the ASP. Strengths reported by the ASP about the Operator's SEMS exceeded requirements or recommended practices and could help strenghten other Operator's SEMS if shared and implemented with the most noteworthy strengths listed below by SEMS element.

6.3.1 Element 1: General

- Operator uses an 'After Action Review' form as a debriefing tool to evaluate a completed job and document how the job can be improved – a great continuous improvement tool.
- The interface between different business groups: Major Projects, Drilling, and Operations, were observed to be collaborative and very robust. All groups could speak to how the SEMS was applicable to them and how it was implemented for each of the groups.

6.3.2 Element 2: Safety and Environmental Information

- Operator has added a significant amount of additional information (cause and effect with barriers) to its SAFE charts and process flow diagrams that is not required by regulation. This additional information facilitates safe operation of the facility by helping emphasize additional risks and risk controls.

6.3.3 Element 3: Hazard Analysis

- The Operator's Hazards and Operability Study and Layer of Protection Analysis (LOPA) studies were well documented and followed the Operator's practices. LOPA teams only took credit for independent protection layers when the layers were specific, independent, dependable and auditable.
- The Company considers human factors as a hazard when performing Job Safety Analyses.
- Includes "Cause and Effect" on SAFE Charts to help emphasize additional risks and risk controls (barriers) beyond regulatory (14C) requirements.

6.3.4 Element 4: Management of Change

- The use of specific types of MOC checklists, which trigger checks of those type of changes, were good tools for facilitating proper MOC implementation.
- Work orders from the maintenance system are reviewed weekly to ensure changes that require an MOC don't get overlooked.

6.3.5 Element 5: Operating Procedures

- Operating procedures include content designed for training.

- Operator’s Process Control System (PCS) alarm management had enabled a reduction of its PCS alarm rate to less than five alarms per hour.

6.3.6 Element 6: Safe Work Practices

- Use of effective risk assessment prompt tools.
- The process for verifying the competency of Contractor personnel in the field also was used to coach personnel on how to perform their duties safely and garner immediate feedback.

6.3.7 Element 7: Training

- Operator has a production simulator in the building to help ensure production operators are better trained.
- Operator’s safety culture training, which is required of all employees and embedded contractors, is highly effective in establishing a work place culture that emphasizes the employee’s safety and well-being above cost and production.
- Operator’s assessment program of Contractor’s competency provides a thorough, mentor-led review of the competence of personnel in critical positions on drilling facilities.

6.3.8 Element 8: Mechanical Integrity of Critical Equipment

- The subsea mechanical integrity management program and process uses software that was impressive. The pictorial presentation of subsea equipment tied with documentation is unique, innovative, and easy to navigate.
- Operator’s corrosion prevention segment of their maintenance program has been successful in reducing waste by replacing sandblasting abrasives with garnet. Garnet, once reprocessed can be repurposed or reused for blasting, water-jetting/cutting and other uses.

6.3.9 Element 9: Pre-Statup Review

- A Plan of Action Review to identify hazards “per hole section” is performed as part of the PSSR commissioning process.

6.3.10 Element 10: Emergency Response and Control

- The diversity of emergency drill scenarios at the facilities.
- The frequency of well control drills, the complexity added to muster drills, and the drilling of Stop Work Authority (SWA) are noteworthy and promote workforce engagement.

6.3.11 Element 11: Investigation of Incidents

- Operator utilizes a digital database and software program to provide different types of data and information critical to conducting a comprehensive and effective investigation.

6.3.12 Element 13: Records and Documentation

- Accessibility of documents and programs through functional systems including use of cellphone applications.

6.3.13 Element 14: Stop Work Authority (SWA)

- Operator has taken SWA one step further by encouraging 'standard SWA' for more minor issues (not causing imminent risk or danger) that could still lead to safety or environmental threats if left unreported. This removes the burden of a worker deciding whether an identified hazard justifies SWA.
- Stop Work Authority (SWA) scenarios have been drilled on a drill ship to test the SWA culture of the drilling team.

6.3.14 Element 15: Ultimate Work Authority

- Operator has developed a very useful chart that identifies the personnel and departments with the types of expertise that the Ultimate Work Authority (UWA) should consult prior to resuming work after a 'high risk' SWA incident has occurred.

APPENDIX 1 – DEFINITIONS

Note: please reference **Appendix 2: SPI Definitions and Metrics** for detail on the SPI, their minimum-release threshold values and specific normalization factors for each SPI. Please reference **Appendix 3: Equipment Definitions** for specific definitions of equipment.

Barrier: A constraint on a hazard that reduces the probability of an incident or its consequences. There are two types of barriers: Prevention and Mitigation.

Consequence: The harm that could result from an incident.

Contractor: An individual, partnership, firm or corporation retained by the Owner or Operator to perform work or to provide supplies or equipment. The term Contractor shall also include subcontractors.

Deepwater: Exploration and production activity occurring in 1000 feet or deeper water depth.

Facility: All types of offshore structures permanently or temporarily attached to the seabed (mobile offshore drilling units, floating production systems, floating production, storage and offloading facilities, tension-leg platforms, and spars) used for exploration, development, production, and transportation activities for in the OCS, including pipelines regulated by the Department of Interior (DOI).

Formation Fluid: The subterranean fluid trapped by a reservoir formation; can include natural gas, liquid and vapor petroleum hydrocarbons, and interstitial water.

Hazard: Types of chemical, thermal, toxic, kinetic, or potential energy with the ability to cause harm to people, the environment, or facilities.

High Value Learning Event: An event that may be considered by a COS member or the industry for use as a reference in process hazard analyses, management of change, project design, risk assessment, inspection, operating procedure review, and/or training. An HVLE should meet one or more of the following criteria:

A. Identify a previously unknown risk, situation, operational or mechanical hazard, or critical equipment failure.
B. Identify a previously unknown combination of factors that resulted in an unexpected condition or event.
C. Identify a routine operation or activity that created a previously unidentified risk or consequence.
D. Identify a situation where established industry designs, controls or procedures failed to prevent an event (e.g. well kick, loss of wall thickness).
E. An event that is part of a pattern in industry events which could indicate that certain hazardous conditions are not well understood.

Incident: A work-related event that has one or more consequences.

Loss of Primary Containment (LOPC): An unplanned or uncontrolled release of material from primary containment.

Major Hazard: A **Hazard** that can reasonably be foreseen as having the potential to cause a SPI 1 consequence.

Mitigation Barrier: Barrier to the right of the top event in a bow tie that can reduce or minimize the probability of a consequence. For example, active fire protection is a mitigation barrier.

Operator: The individual, partnership, firm, or corporation having control or management of operations on the leased area or a portion thereof. The Operator may be a lessee, designated agent of the lessee(s), or holder of operating rights under an approved operating agreement.

Prevention Barrier: Barrier to the left of the top event in a bow tie that can prevent or reduce the probability of a top event occurrence. For example, a safety instrumented system is a prevention barrier.

Production: Production covers offshore oil and gas production activities including flow lines and pipelines.

Projects: Projects include all offshore construction activities.

Safety Performance Indicator (SPI): A measurement that provides insights into the strength of barriers. SPI are inclusive of those that measure performance with respect to protection of personnel, the environment, and offshore facilities and property.

Safety Performance Indicator Program: A program developed, implemented and continually improved through which SPI are established, collected, analyzed and reported for specific safety issues of concern so that actions can be taken by relevant stakeholders to improve safety performance.

Wells: Wells include all offshore exploration, appraisal and production drilling, wireline, completion, workover, and intervention activities.

APPENDIX 2 – SPI DEFINITIONS & METRICS

SPI Number	SPI Definition	SPI Metric	Reporting Entity
SPI 1	Frequency of work-related incidents resulting in one or more of the following consequences: A. Fatality: One or more fatalities. B. Injury to 5 or more persons in a single Incident C. Tier 1 Process Safety Event: (API RP 754 Tier 1 Process Safety Event) An unplanned or uncontrolled release of any material, including non-toxic and non-flammable materials (e.g., steam, hot condensate, nitrogen, compressed CO2, compressed air), from a process that results in one or more of the consequences listed below: o an employee, contractor or subcontractor “days away from work” injury and/or fatality; o a hospital admission and/or fatality of a third-party; o an officially declared community evacuation or community shelter-in-place; o a fire or explosion resulting in greater than or equal to $25,000 of direct cost to the Company; o a pressure release device (PRD) discharge to atmosphere whether directly or via a downstream destructive device that results in one or more of the following four consequences: ▪ liquid carryover ▪ discharge to a potentially unsafe location ▪ an onsite shelter-in-place ▪ public protective measures and a PRD discharge quantity greater than the threshold quantities in Table A-C in any one-hour period; or o A release of material greater than the threshold quantities described in Tables A-C in any one-hour period. D. Level 1 Well Control Incident: Loss of well control o Uncontrolled flow of formation or other fluids resulting in: ▪ Seabed/surface release.	# of SPI 1 incidents/ total work hours * 200,000	COS Operator for all incidents within the 500-meter zone and for incidents to direct employees while offshore COS Contractor for incidents outside the 500-meter zone while offshore

SPI Number	SPI Definition	SPI Metric	Reporting Entity
	▪ Underground communication to another formation or well. o Includes shallow water flows that result in damage or loss of facilities/equipment o Excludes planned shallow gas mitigation operations. E. $1 million or greater direct cost from damage to or loss of facility / vessel / equipment (excludes costs associated with downtime or production loss). F. Oil spill to water ≥ 10,000 gallons (238 barrels)		
SPI 2	Frequency of work-related incidents that do not meet the definition of a SPI 1 incident but have resulted in one or more of the following: A. Tier 2 Process Safety Event: (API RP 754 Tier 2 Process Safety Event) An unplanned or uncontrolled release of any material, including non-toxic and non-flammable materials (e.g., steam, hot condensate, nitrogen, compressed CO2, compressed air), from a process that results in one or more of the consequences listed below and is not reported as a Tier 1 PSE: o An employee, contractor or subcontractor recordable injury; o A fire or explosion resulting in greater than or equal to $2,500 of direct cost to the Company; o A pressure release device (PRD) discharge to atmosphere whether directly or via a downstream destructive device that results in one or more of the following four consequences: ▪ liquid carryover ▪ discharge to a potentially unsafe location ▪ an onsite shelter-in-place ▪ public protective measures ▪ and a PRD discharge quantity greater than the threshold quantity in Tables D-F in any one-hour period; or o a release of material greater than the	# of SPI 2 incidents / total work hours * 200,000	COS Operator for all incidents within the 500-meter zone and for incidents to direct employees while offshore COS Contractor for incidents outside the 500-meter zone while offshore

SPI Number	SPI Definition	SPI Metric	Reporting Entity
	threshold quantities described in Tables D-F in any one-hour period. B. Collision that results in property or equipment damage > $25,000 C. Incident Involving Mechanical Lifting A mechanical lifting (or lowering) incident that results in one or more of the following consequences. Mechanical lifting includes lifts of an asset or personnel (personnel transfer and man-riding). Consequences: o Four or less recordable injuries in a single incident that occurs during the lift o Between $25,000 and $1 million direct damage to or loss of an asset (including the load itself) o A loss of primary containment of a material meeting a Tier 2 Process Safety Event threshold quantity o A dropped load that strikes live process equipment o Not included: o Lifting incident resulting only in a first aid injury o Lifting incident resulting only in direct damage to an asset (including the load itself) < $25,000 o Lifting incident resulting only in a slipped load o Dropped load or object into the water valued at < $25,000 o Manual lifting incidents D. Loss of station keeping resulting in drive off or drift off defined as a malfunction or improper operation of the dynamic positioning system E. Life boat, life raft, or rescue boat event that resulted in a recordable injury or equipment damage or malfunction during life boat, life raft, or rescue boat operations or that take it out of service. F. Level 2 Well Control Incident		

SPI Number	SPI Definition	SPI Metric	Reporting Entity
	One barrier system within the well design failed and other barrier system(s) either failed or were challenged beyond design capacity resulting in an influx without uncontrolled flow.		
SPI 3	Number of SPI 1 and SPI 2 incidents that involved failure of one or more of equipment as a contributing factor. COS Equipment categories: A. Well pressure containment system B. Christmas trees C. Downhole safety valves D. Blow out preventer and intervention systems E. Process equipment/pressure vessels, piping F. Automated safety instrumented systems / shutdown systems G. Pressure relief devices, flare, blowdown, rupture disks H. Fire/gas detection and fire-fighting systems I. Mechanical lifting equipment/personnel transport systems J. Station keeping systems K. Bilge/ballast systems L. Life boat, life rafts, rescue boats, launch and recovery systems M. Other	Number of SPI 1 and 2 incidents involving failure of equipment / total number of SPI 1 and 2 incidents * 100	COS Operator for all incidents within the 500-meter zone and for incidents to direct employees while offshore COS Contractor for incidents outside the 500-meter zone while offshore
SPI 4	Crane or personnel/material handling operations defined as a failure of the crane itself (e.g., the boom, cables, winches, ball ring), other lifting apparatus (e.g., air tuggers, chain pulls), the rigging hardware (e.g., slings, shackles, turnbuckles), or the load (e.g., striking personnel, dropping the load, damaging the load, damaging the facility). Reference MMS NTL 2008-G17.		

SPI Number	SPI Definition	SPI Metric	Reporting Entity
SPI 5	Number of planned critical maintenance, inspections and tests completed on time. A planned task can be deferred if a proper risk assessment was completed and approved, and a new due date set. It is up to each company to define critical equipment	Number of critical maintenance, inspections and tests tasks completed on time / number of critical maintenance, inspections and tests tasks planned (expressed as a %)	COS Owner of Equipment
SPI 6	Number of work-related fatalities	Number of work-related fatalities	COS Operator when within the 500-meter zone and for direct employees while offshore COS Contractor when outside the 500-meter zone while offshore

SPI 7	Number of DART injuries and illnesses. BSEE defines DART injuries or illnesses as those that resulted in "Days Away from work, Restricted duty, and Job Transfer' outcomes.	# DART / total work hours * 200,000	COS Operator when within the 500-meter zone and for direct employees while offshore (same as reported on BSEE-0131 Form)
SPI 8	Number of recordable injuries and illnesses	Number of recordable injuries and illnesses/ total work hours * 200,000	COS Operator when within the 500-meter zone and for direct employees while offshore (same as reported on BSEE-0131 Form)
SPI 9	Number of spills greater or equal to 1 barrel that enter the water	Number of spills ≥ or equal to 1 barrel / total work hours * 200,000	COS Operator for all spills within the 500-meter zone COS Contractor for spills outside the 500-meter zone while offshore
Work Hours	For offshore workers, the hours worked are calculated on a 12-hour work day. Work hours are collected in the following categories: o Total U.S. OCS construction workforce hours inside 500 meters o Total U.S. OCS well workforce hours inside 500 meters o Total U.S. OCS production workforce hours inside 500 meters o Total U.S. OCS workforce hours inside 500 meters		COS Operator when within the 500 meter zone (same as reported on BSEE-0131 Form)

Table A – Tier 1 Process Safety Events - Non-toxic Material Release Threshold Quantities for LOPC

LOPC is a recordable when release is 'acute', i.e. exceeds a threshold quantity in any one hour period.

Material Hazard Classification (with examples)	**Outdoor Release**	**Indoor Release**
Flammable Gases – e.g. • methane, ethane, propane, butane, • natural gas, • ethyl mercaptan	500 kg (1,100 lb)	250 kg (550 lb)
Flammable Liquids with Boiling Point < or equal to 35˚C (95˚F) and Flash Point < 23˚C (73˚F) – e.g. • liquefied petroleum gas (LGP), • liquefied natural gas (LNG), • isopentane	500 kg (1,100 lb)	250 kg (550 lb)
Flammable Liquids with Boiling Point > 35˚C (95˚F) and Flash Point < 23˚C (73˚F) – e.g. • gasoline, toluene, xylene, • condensate, • methanol, • > 15 API Gravity crude oils (unless actual flashpoint available)	1,000 kg (2,200 lb) or 7 barrels	500 kg (1,100 lb) or 3.5 barrels
Combustible Liquids with Flash Point ≥ 23˚C (73˚F) and < or equal to 60˚C (140˚F) – e.g. • diesel, most kerosenes, • < 15 API Gravity crude oils (unless actual flashpoint available)	2,000 kg (4,400 lb) or 14 barrels	1,000 kg (2,200 lb) or 7 barrels
Liquids with flash point > 60˚C (140˚F) released at a temperature at or above its flash point – e.g. • asphalts, molten sulphur, • ethylene glycol, propylene glycol, • lubricating oil	2,000 kg (4,400 lb) or 14 barrels	1,000 kg (2,200 lb) or 7 barrels
Liquids with flash point > 60 ˚C (140˚F) released at a temperature below its flash point – e.g. • asphalts, molten sulphur, • ethylene glycol, propylene glycol, • lubricating oil	Not Applicable	Not Applicable

Table B – Tier 1 Process Safety Events - Toxic Material Release Threshold Quantities for LOPC

LOPC is a recordable when release is 'acute', i.e. exceeds a threshold quantity in any one hour period.

Material Hazard Classification (with examples)	Outdoor Release	Indoor Release
TIH Hazard Zone A materials - includes • acrolein (stabilized), • bromine	5 kg (11 lb)	2.5 kg (5.5 lb)
TIH Hazard Zone B materials- includes: • hydrogen sulphide (H_2S), • chlorine (Cl_2)	25 kg (55 lb)	12.5 kg (27.5 lb)
TIH Hazard Zone C materials- includes: • sulphur dioxide (SO_2), • hydrogen chloride (HCl)	100 kg (220 lb)	50 kg (110 lb)
TIH Hazard Zone D materials- includes: • ammonia (NH_3), • carbon monoxide (CO)	200 kg (440 lb)	100 kg (220 lb)
Other Packing Group I Materials – includes: • aluminum alkyls, • some liquid amines, • sodium cyanide, • sodium peroxide, • hydrofluoric acid (> 60% solution)	500 kg (1,100 lb)	250 kg (550 lb)
Other Packing Group II Materials – includes: • aluminum chloride, • phenol, • calcium carbide, • carbon tetrachloride • some organic peroxides • hydrofluoric acid (< 60% solution)	1,000 kg (2,200 lb) or 7 barrels	500 kg (1,100 lb) or 3.5 barrels

Table C – Tier 1 Process Safety Events - Other Material Release Threshold Quantities for LOPC

LOPC is a recordable when release is 'acute', i.e. exceeds a threshold quantity in any one-hour period.

Material Hazard Classification (with examples)	Outdoor Release	Indoor Release
Other Packing Group III Materials – includes: • sulphur, • lean amine, • calcium oxide, • activated carbon, • chloroform, • some organic peroxides, • sodium fluoride, • sodium nitrate	2,000 kg (4,400 lb) or 14 barrels	1,000 kg (2,200 lb) or 7 barrels
Strong Acids or Bases - includes: • sulphuric acid, hydrochloric acid, • sodium hydroxide (caustic), • calcium hydroxide (lime)	2,000 kg (4,400 lb) or 14 barrels	1,000 kg (2,200 lb) or 7 barrels
Moderate Acids or Bases- includes: • diethylamine (corrosion inhibitor)	None	None

Table D – Tier 2 Process Safety Events - Non-toxic Material Release Threshold Quantities for LOPC

LOPC is a recordable when release is 'acute', i.e. exceeds a threshold quantity in any one hour period.

Material Hazard Classification (with examples)	Outdoor Release	Indoor Release
Flammable Gases – e.g. • methane, ethane, propane, butane, • natural gas, • ethyl mercaptan	50 kg (110 lb)	25 kg (55 lb)
Flammable Liquids with Boiling Point < or equal to 35˚C (95˚F) and Flash Point < 23˚C (73˚F) – e.g. • liquefied petroleum gas (LGP), • liquefied natural gas (LNG), • isopentane	50 kg (110 lb)	25 kg (55 lb)
Flammable Liquids with Boiling Point > 35˚C (95˚F) and Flash Point < 23˚C (73˚F) – e.g. • gasoline, toluene, xylene, • condensate, • methanol, • > 15 API Gravity crude oils (unless actual flashpoint available)	100 kg (220 lb) or 1 barrel	50 kg (110 lb) or 0.5 barrel
Combustible Liquids with Flash Point ≥ 23˚C (73˚F) and < or equal to 60˚C (140˚F) – e.g.	100 kg (220 lb) or 1 barrel	50 kg (110 lb) or 0.5 barrel

• diesel, most kerosenes, • < 15 API Gravity crude oils (unless actual flashpoint available)		
Liquids with flash point > 60˚C (140˚F) released at a temperature at or above its flash point – e.g. • asphalts, molten sulphur, • ethylene glycol, propylene glycol, • lubricating oil	100 kg (220 lb) or 1 barrel	50 kg (110 lb) or 0.5 barrel
Liquids with flash point > 60 ˚C (140˚F) released at a temperature below its flash point – e.g. • asphalts, molten sulphur, • ethylene glycol, propylene glycol, • lubricating oil	1,000 kg (2,200 lb) or 10 barrels	500 kg (1,100 lb) or 5 barrels

<u>Table E – Tier 2 Process Safety Events - Toxic Material Release Threshold Quantities for LOPC</u>

LOPC is a recordable when release is 'acute', i.e. exceeds a threshold quantity in any one hour period.

Material Hazard Classification (with examples)	Outdoor Release	Indoor Release
TIH Hazard Zone A materials - includes • acrolein (stabilized), • bromine	0.5 kg (1 lb)	0.25 kg (0.5 lb)
TIH Hazard Zone B materials- includes: • hydrogen sulphide (H2S), • chlorine (Cl2)	2.5 kg (5.5 lb)	1.3 kg (2.8 lb)
TIH Hazard Zone C materials- includes: • sulphur dioxide (SO2), • hydrogen chloride (HCl)	10 kg (22 lb)	5 kg (11 lb)
TIH Hazard Zone D materials- includes: • ammonia (NH3), • carbon monoxide (CO)	20 kg (44 lb)	10 kg (22 lb)
Other Packing Group I Materials – includes: • aluminum alkyls, • some liquid amines, • sodium cyanide, • sodium peroxide, • hydrofluoric acid (> 60% solution)	50 kg (110 lb)	25 kg (55 lb)

Other Packing Group II Materials – includes: • aluminium chloride, • phenol, • calcium carbide, • carbon tetrachloride • some organic peroxides • hydrofluoric acid (< 60% solution)	100 kg (220 lb) or 1 barrel	50 kg (110 lb) or 0.5 barrel

Table F – Tier 2 Process Safety Events - Other Material Release Threshold Quantities for LOPC

LOPC is a recordable when release is ‘acute’, i.e. exceeds a threshold quantity in any one hour period.

Material Hazard Classification (with examples)	Outdoor Release	Indoor Release
Other Packing Group III Materials – includes: • sulphur, • lean amine, • calcium oxide, • activated carbon, • chloroform, • some organic peroxides, • sodium fluoride, • sodium nitrate	100 kg (220 lb) or 1 barrel	50 kg (110 lb) or 0.5 barrel
Strong Acids or Bases - includes: • sulphuric acid, hydrochloric acid, • sodium hydroxide (caustic), • calcium hydroxide (lime)	100 kg (220 lb) or 1 barrel	50 kg (110 lb) or 0.5 barrel
Moderate Acids or Bases- includes: • diethylamine (corrosion inhibitor)	1,000 kg (2,000 lb) or 10 barrels	500 kg (1,000 lb) or 5 barrels

APPENDIX 3 – EQUIPMENT DEFINITIONS

Equipment	Equipment Definition
Well Pressure Containment System	The casing and wellhead (with cement support and isolation where applicable)" and tubing, tubing hardware and tubing hanger represent the equipment below the BOP or Christmas Tree comprise the "well pressure containment system", and as such represent the ability to contain pressure when a BOP or Christmas Tree has been closed.
Christmas Trees	Equipment attached to the uppermost connection of the wellhead or tubing spool to contain wellbore fluids in both the tubing and in the annular space between the casing and tubing during producing operations. The subsea tree may provide locations where nitrogen and chemical additives can be injected into the annulus or tubing string. The tree consists of assembled equipment that includes a wellhead connector, valves, choke, tree cap, and control system to operate the various components.
Downhole Safety Valves	• Downhole safety valve: A device installed in a well below the wellhead with the design function to prevent uncontrolled well flow when actuated, e.g. SSCSV or SCSSV. • Subsurface controlled subsurface safety valve (SSCSV): An SSSV actuated by the pressure characteristics of the well. • Surface controlled subsurface safety valve (SCSSV): An SSSV controlled from the surface by hydraulic, electric, mechanical, or other means.
Blow Out Preventer and Intervention Systems	Equipment installed on the wellhead or wellhead assemblies to contain wellbore fluids either in the annular space between the casing and the tubulars, in the tubulars or in an open hole during well drilling, completion, and testing operations. For the purposes of SPI data collection, this also includes pressure control equipment used in intervention operations, such as wireline and coiled tubing BOPs, lubricators etc.
Process Equipment, Pressure Vessels and Piping	• Process Equipment/Pressure Vessel: A container associated with drilling, production, gathering, transportation, and treatment of liquid petroleum, natural gas, natural gas liquids, associated salt water (brine) designed to withstand internal or external pressure above ambient conditions. This definition includes containers used for pressurized storage of toxic and hazardous chemicals. • Piping System: An assembly of interconnected pipes that are used to convey, distribute, mix, separate, discharge, meter, control, or snub flows of hydrocarbons or toxic and hazardous chemicals.
Automated Safety Instrumented Systems / Shutdown Systems	• Automated Safety Instrumented System - a system implementing one or more safety functions, with specified safety integrity level(s), that detect abnormal process conditions and take automatic, necessary actions to achieve or maintain a safe state for the process with respect to a hazardous event. • Shutdown Systems - a system of manual stations that, when activated, will initiate the shutting in (isolation and cessation) of all process stations of a

Equipment	Equipment Definition
	platform production process and all support equipment for the process. May also be integrated with Fire and Gas Detection systems for automatic initiation.
Pressure Relief Devices, Flare Systems, Blowdown Systems, Rupture Disks	• Pressure Relief Device – A device actuated by inlet static pressure and designed to open during emergency or abnormal conditions to prevent a rise of internal fluid pressure in excess of a specified design value. The device also may be designed to prevent excessive internal vacuum. The device may be a pressure relief valve, a non-reclosing pressure relief device, or a vacuum relief valve. • Flare System – used to safely dispose of relief gases in an environmentally compliant manner through the use of combustion. • Blowdown System - a collection of controls, valves and pipes that allow controlled depressurization of liquid or gas pressure contained within a process, piping, or pressure vessel to reduce or eliminate pressure induced stresses during a time of potential heat weakening of vessels and piping, as well as a reduction of the inventory of fuel present on the facility. • Rupture Disk – A pressure containing, pressure and temperature sensitive element of a rupture disk device. A rupture disk device is a non-reclosing pressure relief device actuated by static differential pressure between the inlet and outlet of the device and designed to function by the bursting of a rupture disk. A rupture disk device includes a rupture disk and a rupture disk holder.
Fire and Gas Detection and Fire Fighting Systems	• Manual fire alarms (pull stations), call stations, and audible alarms / beacons • Automatic Fire Detection Systems - The primary function of an automatic fire detection system is to alert personnel of the existence of a fire condition and to allow rapid identification of the location of the fire. The detection system(s) may be used to automatically activate emergency alarms, initiate Emergency Shutdown (ESD), isolate fuel sources, start fire water pumps, shut-in ventilation systems, and activate fire extinguishing systems such as gaseous agents, dry chemical, foam or water. The types of fire detectors commonly used on offshore platforms are as follows: o Flame Detectors - e.g., Infrared (IR) Detectors, Ultraviolet (UV) Flame Detectors, Combination IR/UV) o Heat Detectors – e.g., Fusible Plugs or links, Heat-pneumatic or Theronistor Sensors, Rate of Rise Detectors, Fixed Temperature Detectors o Products of Combustion / Smoke Detectors – e.g., Ionization Detector, Photoelectric Detector • Gas Detection System – The primary function of a fixed gas detection system is to alert personnel to the presence of flammable gases, toxic gases, or a combination of both. o Flammable Gas Detection – designed to respond to a broad range of hydrocarbon gases / vapors (e.g., methane, ethane, propane and vapors from the evaporation of hydrocarbon liquids). The predominant sensors for flammable gas detection in general, normally occupied spaces are the infrared (IR) sensor or the catalytic bead sensor. o Toxic Gas Detection – many gas detection systems include both flammable

Equipment	Equipment Definition
	gas and toxic gas detection for hydrogen sulfide, sulfur dioxide, and fluorine in the same system. The semiconductor and electrochemical sensors are most commonly used for the detection of the toxic gases. o Excludes portable gas monitoring instruments. • Fixed fire-fighting systems include the following: fire water pumps & drivers, distribution piping, fire hoses, stations, and nozzles, water spray systems / monitors, foam systems (fixed or portable), dry chemical systems, gaseous systems (e.g., CO2, Halon, FM-200 & FE-13, Inergen), and water mist / fine water spray systems. • Fire water systems are installed on offshore platforms to provide exposure protection, control of burning, and/or extinguishment of fires. The basic components of a fire water system are the fire water pump, the distribution piping, the hose / nozzle, and deluge / sprinkler system. Additives such as foaming agents may be included to aid in extinguishing flammable liquid fires. • Excludes portable fire extinguishers
Mechanical Lifting Equipment / Personnel Transport Equipment	• Crane (includes base mounted drum winches) - a type of machine, generally equipped with a hoist, wire ropes or chains, and sheaves, that can be used both to lift and lower materials and to move them horizontally. Includes: o Boom chords, foot pins, hoist (hydraulics and brakes), lift cylinder, sheave assembly, stops, tip extension or jib, pendant lines o Counterweights o Gantry, mast or A-frame pins o Hook block o Overhaul ball o Main hoist (hydraulics and brakes) o Auxiliary hoist (hydraulics or brakes) o Pedestal or crane base o Load management system (MIPEG, CCM-7000 etc.) o Crane safety system (anti two block, high & low angle kick outs) • Top Drive - a device used on a drilling rig to actually rotate the drill pipe in order to drill the well. Includes main drill line hoist (hydraulics or brakes), crown-o-matic, top drive track, assembly rollers or wheels and bearings, hydramatics or hydromatics. • Pipe racking system (PRS) including main hoist (hydraulics or brakes), track, hydraulic system, claws or fingers. • Drawworks, Air Hoists, Tuggers • Chain fall - a type of hoist with a chain attached to a fixed raised structure or beam and used to lift very heavy objects. Includes clutch, brake and sprocket. • Rigging Accessories including hooks, chains, shackles, slings (below the hook), wire rope, D-ring, elevators, bails
Station Keeping Systems	The station keeping systems for a floating structure are typically a single point mooring, a spread mooring, vertical tension legs, or a dynamic positioning (DP) system. • Single point mooring components may include but not limited to: hoisting

Equipment	Equipment Definition
	system, hawser, swivels, roller bearings, risers, u-joint connectors, counter weights, chain, chain table, wire rope, synthetic rope, connecting hardware, clump weight, buoy, and anchor. • Spread mooring components: winch / windlass, chain jack, brakes, power, fairlead, wire rope, synthetic rope, connecting hardware, clump weight, buoy, and anchor • Vertical tension leg moorings are used by TLPs or tension leg platforms and are comprised of: mooring tendons, seafloor foundations • Dynamic positioning system consists of components and systems acting together to achieve reliable position keeping capability. The Dynamic-positioning system includes the power system (power generation and power management), thruster system and Dynamic Positioning control system.
Bilge/Ballast Systems	The vessel structure, machinery, piping, or controls related to ballast movement, watertight integrity and stability.
Life Boat, Life Rafts, Rescue Boats and Launch and Recovery Systems	• Life Boat / Survival craft is a craft capable of sustaining the lives of person in distress from the time of abandoning the ship. • Rescue boat is a boat designed to rescue persons in distress and to marshal survival craft. • A life raft is an inflatable appliance which depends upon non-rigid, gas filled chambers for buoyancy and which is normally kept not inflated until ready for use. • Launch and Recovery Systems - systems used to deploy or retrieve a lifeboat, life raft, or rescue boat. Components may include but not limited to: winch, fall wire (lifting wire), sheaves (pulleys), davits, davit arms, connecting hardware, secondary securing method (gripes, safety pendants), cradle, lifting points, releasing hook(s), brake, brake release, power source to winch / davit / davit arm, free fall railing.

APPENDIX 4 – LIST OF FIGURES (Body of Report)

APPENDIX 5 – LFI CATEGORY DESCRIPTIONS

Site Type: The primary site where the incident or event occurred. Only one selection can be made.

- Aircraft
- Diving Vessel
- Drilling Rig on Production Facility
- Fixed Production Facility
- Floating Production Facility
- Floating Storage and Offloading Facility
- Mobile Offshore Drilling Unit
- Offshore Supply or Support Vessel
- Offshore Construction Vessel
- Seismic Vessel
- Subsea Production System
- Other

Operation Type: The primary operation that was underway at the time of the incident or event. Only one selection can be made.

- Aviation
- Marine-diving, seismic, transportation, rig moves, etc.
- Production-petroleum/natural gas production, flow lines, pipe lines
- Projects-includes offshore construction activities
- Wells-exploration, appraisal/prod drilling, wireline, completion, workover, abandonment, intervention activities
- Other

Activity Type: The primary (most closely linked to incident or event) activity that was occurring at the time of the incident or event. Only one selection can be made.

- Confined Space Entry
- Diving
- Drilling Operations - Normal, Routine
- Energy Isolation
- Emergency Response (Actual or Drill)
- Helicopter Flight
- Helicopter Landing or Take-Off
- Hot Work
- Maintenance, Inspection and Testing
- Marine Vessel - In-Transit
- Marine Vessel - Station Keeping
- Material Transfer or Displacement
- Mechanical Lifting or Lowering
- Production Operations - Normal, Routine
- Simultaneous Operations
- Start-up or Shut-down Operations

- Working at Height
- Other

Areas for Improvement: All of the Areas for Improvement that apply to the incident or event being shared. The Areas for Improvement cover three general categories: Physical Process and Equipment; Administrative Process; or People. Multiple Areas for Improvement can be selected across the general categories.

5.11.1 Physical Facility, Equipment and Process

Select one or more of the following AFIs when enhancements in the quality of the physical process and equipment design, layout, material specification, fabrication, or construction were highlighted for improvement, including:

5.11.1.1 Process or Equipment Design or Layout – Select this AFI if the design or layout of the process or equipment was highlighted for improvement. Include cases where issues with the design or layout were significant contributors to subsequent human actions.

5.11.1.2 Process or Equipment Material Specification, Fabrication and Construction – Select this AFI if the quality and compatibility of the material specification, fabrication or construction of the process or equipment, prior to its use was highlighted for improvement, including process or equipment provided by vendors or third parties on a permanent or temporary basis. This category includes the use of defective parts or equipment, or improper installation.

5.11.1.3 Process or Equipment Reliability – Select this AFI if the ability of the process or equipment to function without defects or breakdown was highlighted for improvement, including improvement in maintenance, inspection, testing and operating requirements.

5.11.1.4 Instrument, Analyzer and Controls Reliability – Select this AFI if the ability of instrumentation, analyzers, and control systems, including software, to function without defects or breakdown was highlighted for improvement including improvement in maintenance, inspection, testing and operating requirements.

5.11.2 Administrative Processes

Select one or more of the following AFIs when enhancements to the quality, scope or structure of administrative processes for managing various aspects of work execution were highlighted for improvement. **Note** - If the identified gap was related to **"failure to follow"** Administrative Processes, do **NOT** select these categories. Instead, use the appropriate category in Section 5.11.3 People.

5.11.2.1 Risk Assessment and Management – Select this AFI if the process for systematic identification and evaluation of potentially significant risks was identified for improvement. This includes but is not limited to HAZOPS, facility hazard assessments, and Job Safety Analysis (JSA).

5.11.2.2 Operating Procedures or Safe Work Practices – Select this AFI if the improvement opportunity involves creating or modifying operating procedures or safe work practices to prevent recurrence. This includes specific operations, maintenance, testing, contractor selection or other procedures and practices.

5.11.2.3 Management of Change – Select this AFI if the process for identifying, approving, and managing significant technical, administrative or organizational changes was identified for improvement. Specific improvement areas may include MOC use not required (but should have been), MOC review incomplete or incorrect, or MOC actions not completed (e.g. drawings not updated).

5.11.2.4 Work Direction or Management – Select this AFI if the process for directing work activities or managing the number or types of work allowed at a given time or location was identified for improvement. This includes but is not limited to permit-to-work, simultaneous operations and supervision of the area or work team.

5.11.2.5 Emergency Response – Select this AFI if the capability or processes for responding to a situation to prevent the escalation of incident or event consequences was identified for improvement. This category includes opportunities related to emergency preparedness, such as access to equipment and trained personnel, insufficient or absence of drills, etc.

5.11.3 People

Select one or more of the following AFIs when enhancements to the personnel actions linked to the execution of work tasks were highlighted for improvement, including:

5.11.3.1 Personnel Skills or Knowledge – Select this AFI if personnel knowledge of the relevant tasks, or the ability of personnel to execute the task correctly and safely, was identified for improvement. This category includes gaps in training (e.g. not required, not completed, or training needs improvement), assessment/verification (not performed, needs improvement, etc.), or remediation (not required, not completed, etc.).

5.11.3.2 Quality of Task Planning and Preparation – Select this AFI if personnel planning and preparation of the task prior to initiating the activity were identified for improvement, including team actions such as reviewing procedures, and completing JSAs, toolbox talks, or job walkthroughs. Note – this category will most often apply when appropriate procedures were in place, but personnel failed to follow them in the pre-work planning phase.

5.11.3.3 Individual or Group Decision-Making – Select this AFI if decisions made by one or more people involved in the execution of the task were identified for improvement. This may be selected only if personnel involved in the task had sufficient skills and knowledge, but chose to execute the task in a manner different than the documented procedure or practice.

5.11.3.4 Quality of Task Execution – Select this AFI if the quality or thoroughness of executing the intended task procedure or practice was highlighted for improvement. This applies where the person or personnel were attempting to follow the prescribed procedures or practices, but errors or incomplete execution contributed to the incident or event.

5.11.3.5 Quality of Hazard Mitigation – Select this AFI if a person or personnel either failed to put in place barriers or the quality, number, or location of barriers were insufficient to mitigate the potential impacts of relevant hazards was highlighted for improvement.

5.11.4.6 Communication – Select this AFI if the effectiveness of communication was identified for improvement. This includes communication between team members and between the team and other individuals or groups. Also included are difficulties with language or terminology.

5.12 Additional Comments

Enter Areas for Improvement that were identified in areas outside the Physical Facility, Equipment and Process; Administrative Processes; and People categories described above. A detailed description of the identified improvements should be included. Also, any additional description of "Other" Site, Operation or Activity Types could be included in this Additional Comments section. This input cell is limited to 750 characters. The first use of an acronym should always be preceded by the term for which it is used.

5.13 Lessons Learned

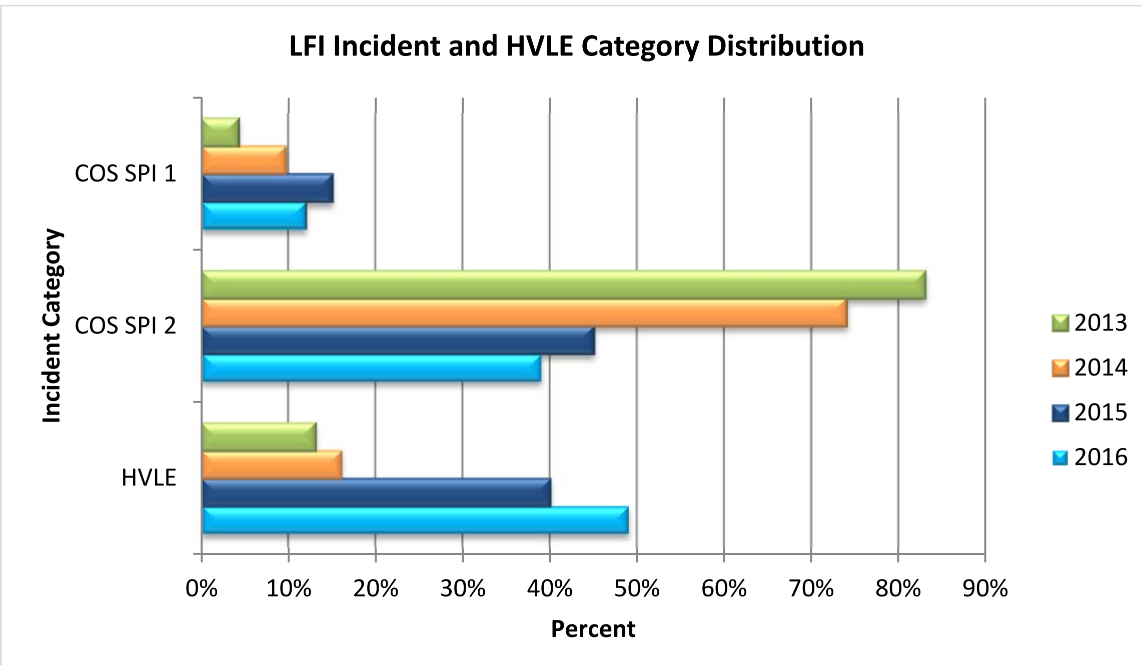
Enter a description with sufficient content to explain the context of the incident, lessons learned and actions taken to reduce the likelihood of a recurrence. These may include equipment, processes and/or human factors. Lessons Learned and actions taken should be directly related to the areas for improvement listed above. This input cell is limited to 750 characters. The first use of an acronym should always be preceded by the term for which it is used.

APPENDIX 6 – LFI DATA CHARTS (U.S. OCS Data)

Refer to the charts listed in this appendix for additional details on the distribution of incidents and HVLE across reporting fields contained in the LFI Report Form (and not previously displayed in the body of the report). The following charts are contained in this Appendix:

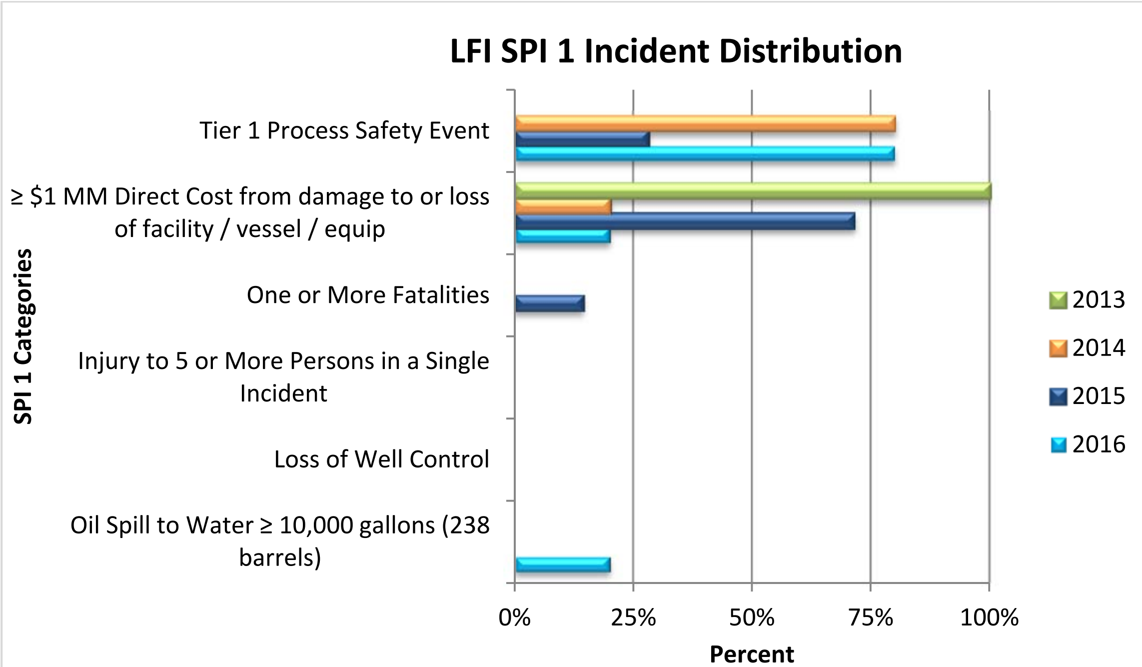
- Chart 1 – LFI Incident and HVLE Category Distribution
- Chart 2 – LFI SPI 1 Incident Distribution
- Chart 3 – LFI SPI 2 Incident Distribution
- Chart 4 – LFI Incident and HVLE Site Type Distribution
- Chart 5 – LFI Incident and HVLE Operation Type Distribution
- Chart 6 – LFI Incident and HVLE Activity Type Distribution
- Chart 7 – LFI SPI 2C (Mechanical Lifting or Lowering) AFI Distribution
- Chart 8 – Maintenance Inspection and Testing AFI Distribution
- Chart 9 - Process Safety (Tier 1 and Tier 2) AFI Distribution

Chart 1 – LFI Incident and HVLE Category Distribution



- Number of occurrences represented above (by year): 2013 = 46, 2014 = 51, 2015 = 47, 2016 = 43
- HVLE increased to 49% in 2016
- Decrease in SPI 2 incidents and increase in HVLE for 2015/2016 are due in part to SPI 2C (Mechanical Lifting or Lowering) definition changes

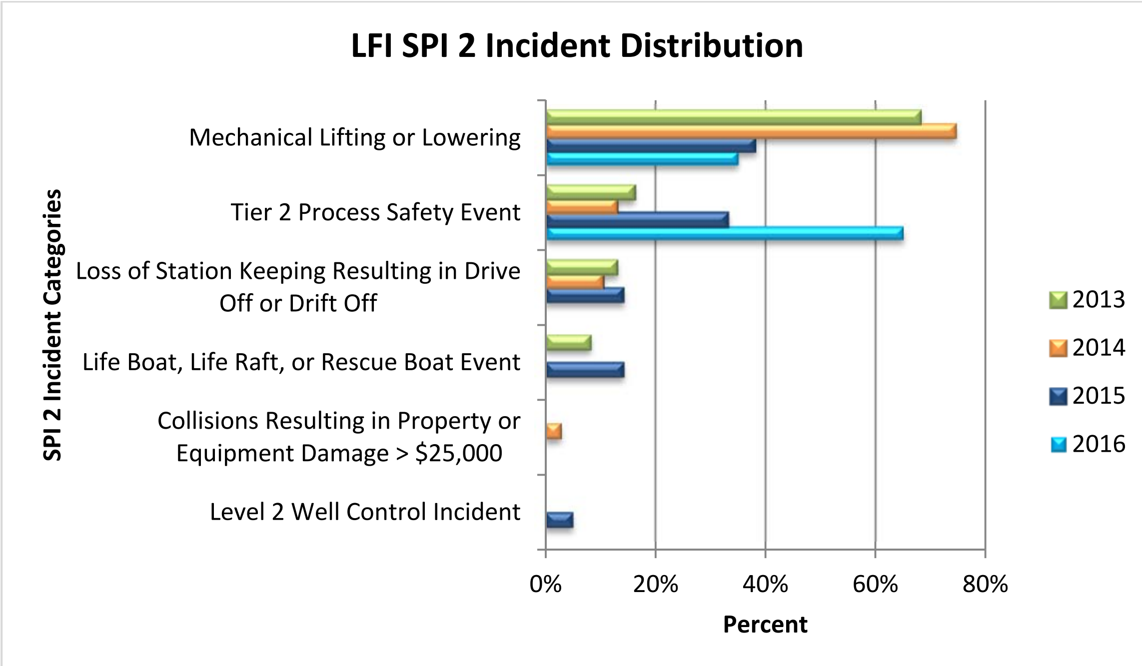
Chart 2 – LFI SPI 1 Incident Distribution



[1] *This chart depicts the number of SPI 1 consequences divided by the total number of SPI 1 LFI submitted in the given year. The total percentage in a given year can exceed 100% when multiple consequences occur for one incident.*

- 2016 is the first year an Oil Spill to Water ≥ 10,000 gallons was reported in the APR
- Number of occurrences represented above (by year): 2013 = 2, 2014 = 5, 2015 = 8, and 2016 = 6

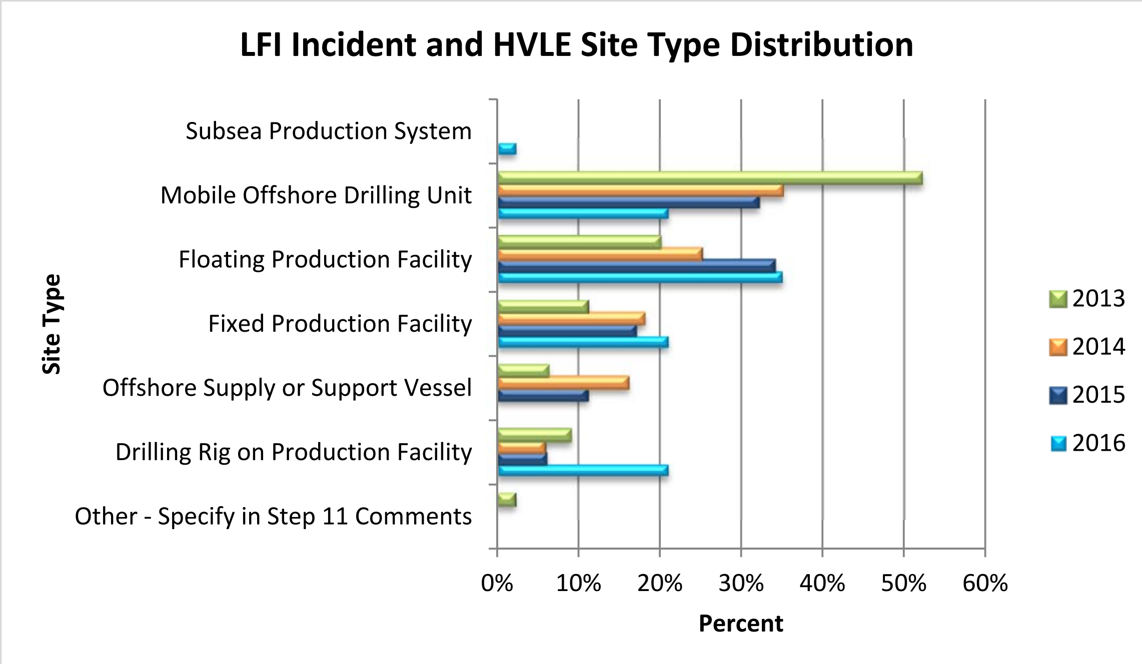
Chart 3 – LFI SPI 2 Incident Distribution



[1] *This chart depicts the number of SPI 2 consequences divided by the total number of SPI 2 LFI submitted in the given year. The total percentage in a given year can exceed 100% when multiple consequences occur for one incident.*

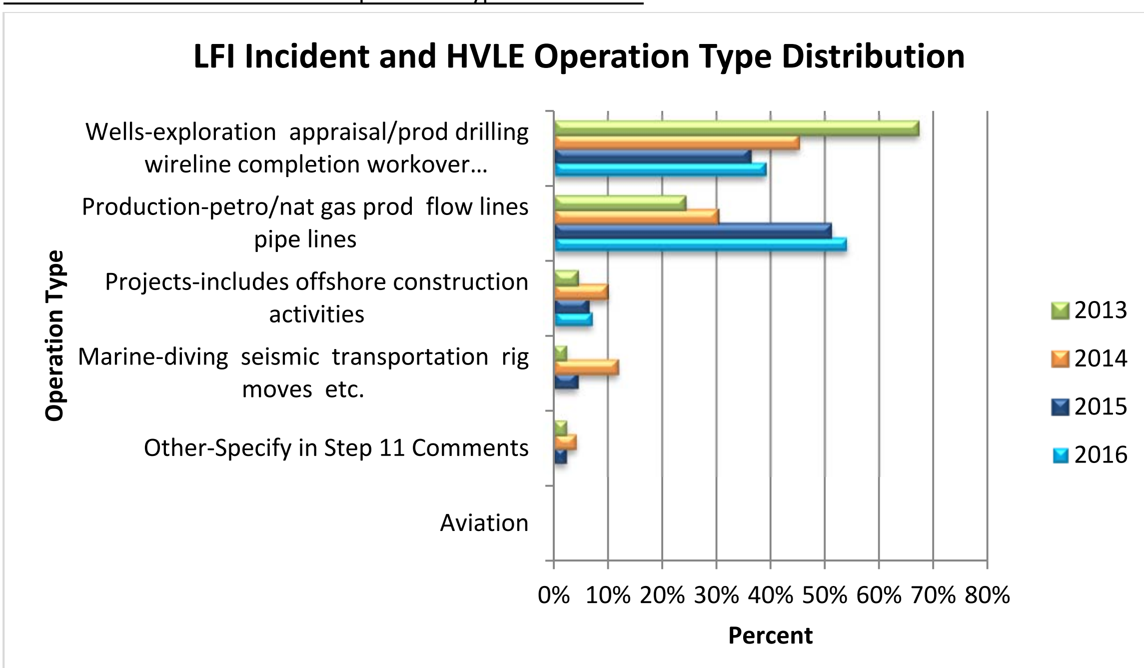
- Only 2 SPI-2 Categories reported in 2016 – Tier 2 PSE and Mechanical Lifting or Lowering.
- Mechanical Lifting or Lowering category definition was modified in 2015. As such the 2015 - 2016 data for this category can't be correlated to the corresponding data for 2013-2014.
- Number of occurrences represented above (by year): 2013 = 40, 2014 = 38, 2015 = 22, 2016 = 17
- Level 2 Well Control Incident was a new category for 2015. As such the 2015 data for this category can't be correlated to the corresponding data for 2013-2014.

Chart 4 –LFI Incident and HVLE Site Type Distribution



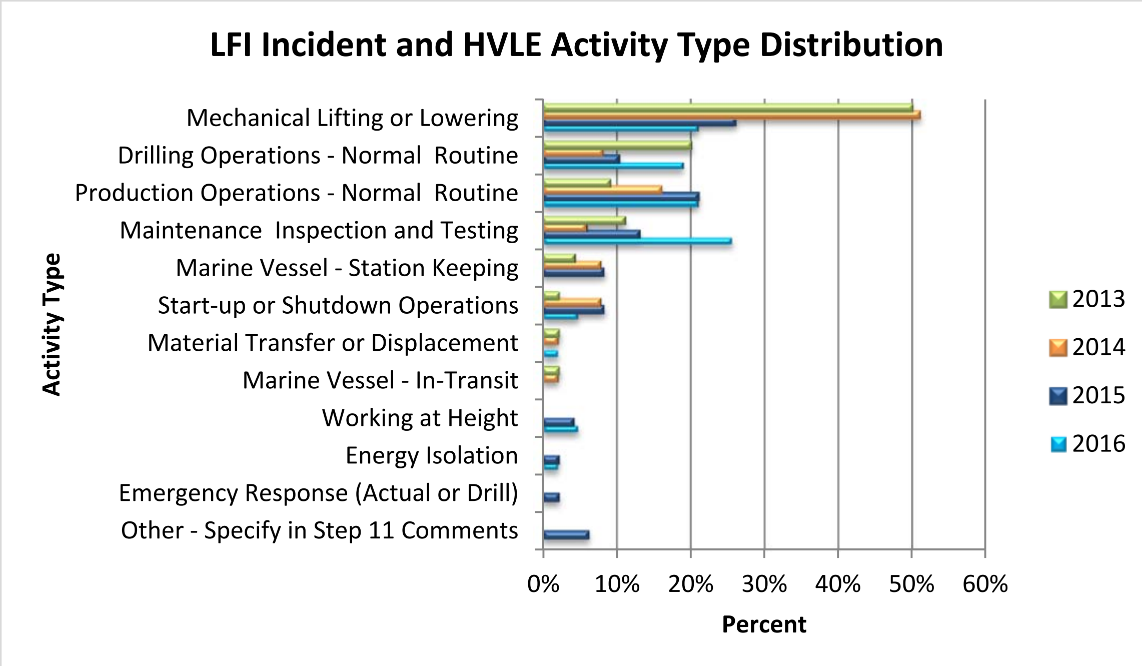
- Number of occurrences represented above (by year): 2013 = 46, 2014 = 51, 2015 = 47, 2016 = 43
- Trend from MODU to Production Facilities observed from 2013 to 2016
- 2016 is the first year a Subsea Production System incident was reported in the APR

Chart 5– LFI Incident and HVLE Operation Type Distribution



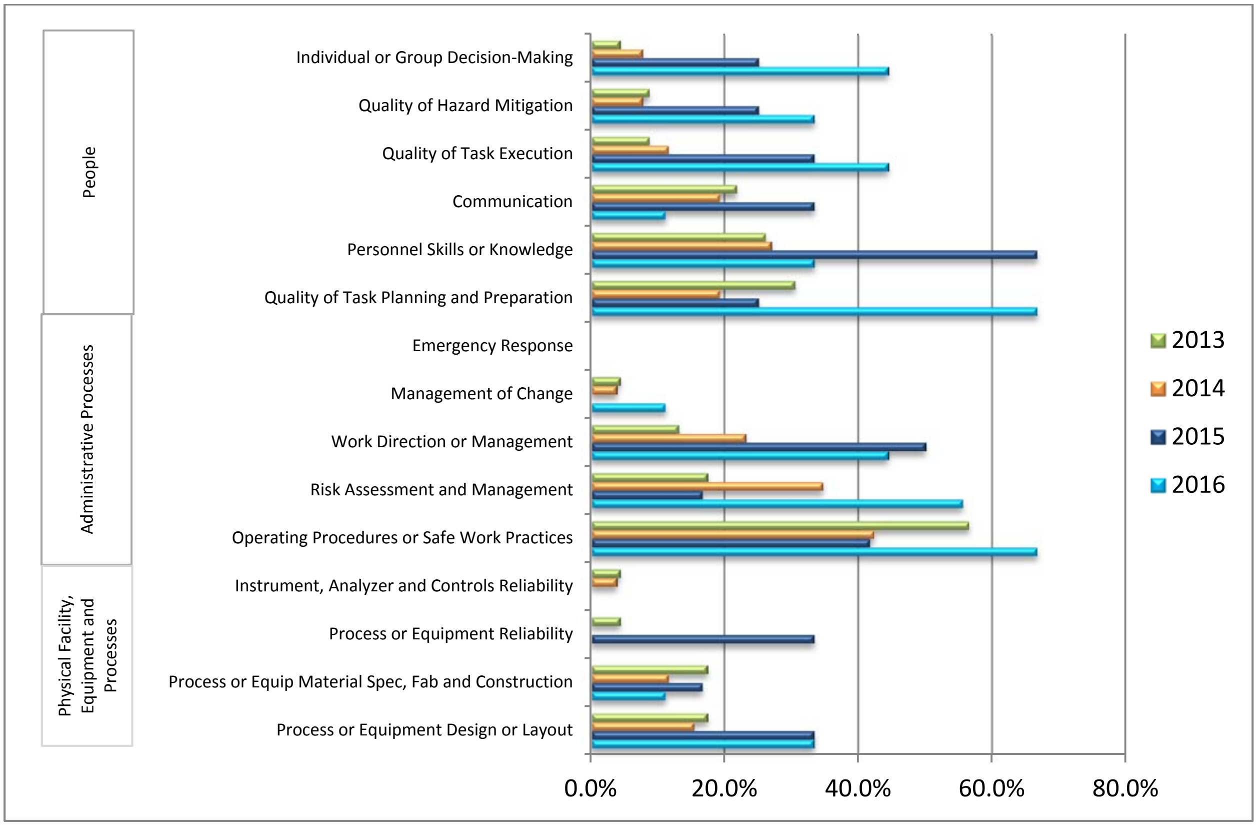
- Number of occurrences represented above (by year): 2013 = 46, 2014 = 51, 2015 = 47, 2016 = 43
- Trend from Wells to Production Operations observed from 2013 to 2016

Chart 6 – LFI Incident and HVLE Activity Type Distribution



- Number of occurrences represented above (by year): 2013 = 46, 2014 = 51, 2015 = 47, 2016 = 43
- The decrease in mechanical lifting or lowering reported in 2015-2016 is due in part to the change in SPI 2C reporting thresholds made in 2015.

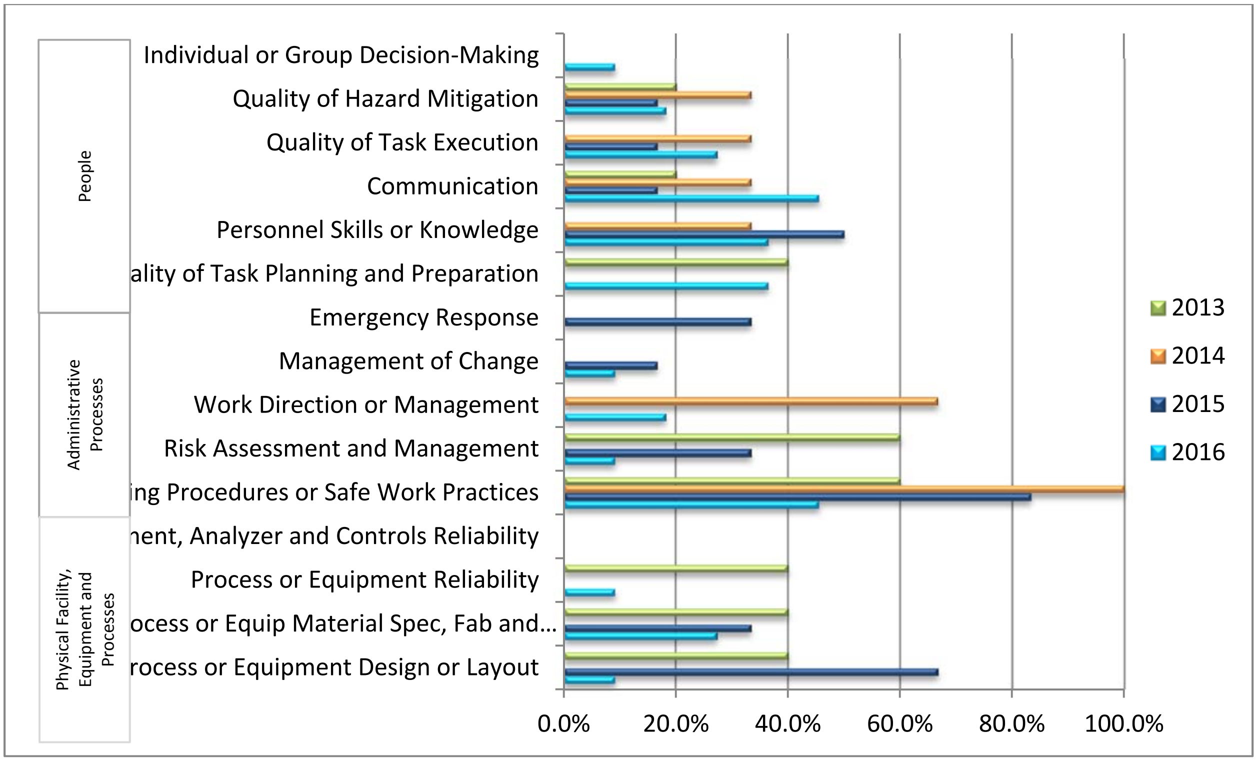
Chart 7 –Mechanical Lifting or Lowering AFI Distribution (AFI selection per total number of Mechanical Lifting or Lowering Activity submittals)



[2] *This chart depicts the number of Mechanical Lifting or Lowering Activity AFIs selected divided by the total number of Mechanical Lifting or Lowering Activity LFI submittals in the given year.*

- Number of incidents represented above (by year): 2013 = 23, 2014 = 26, 2015 = 12, 2016 = 9
- Quality of Task Execution and Individual or Group Decision-Making have increased during the past 4 years (2013-2016)

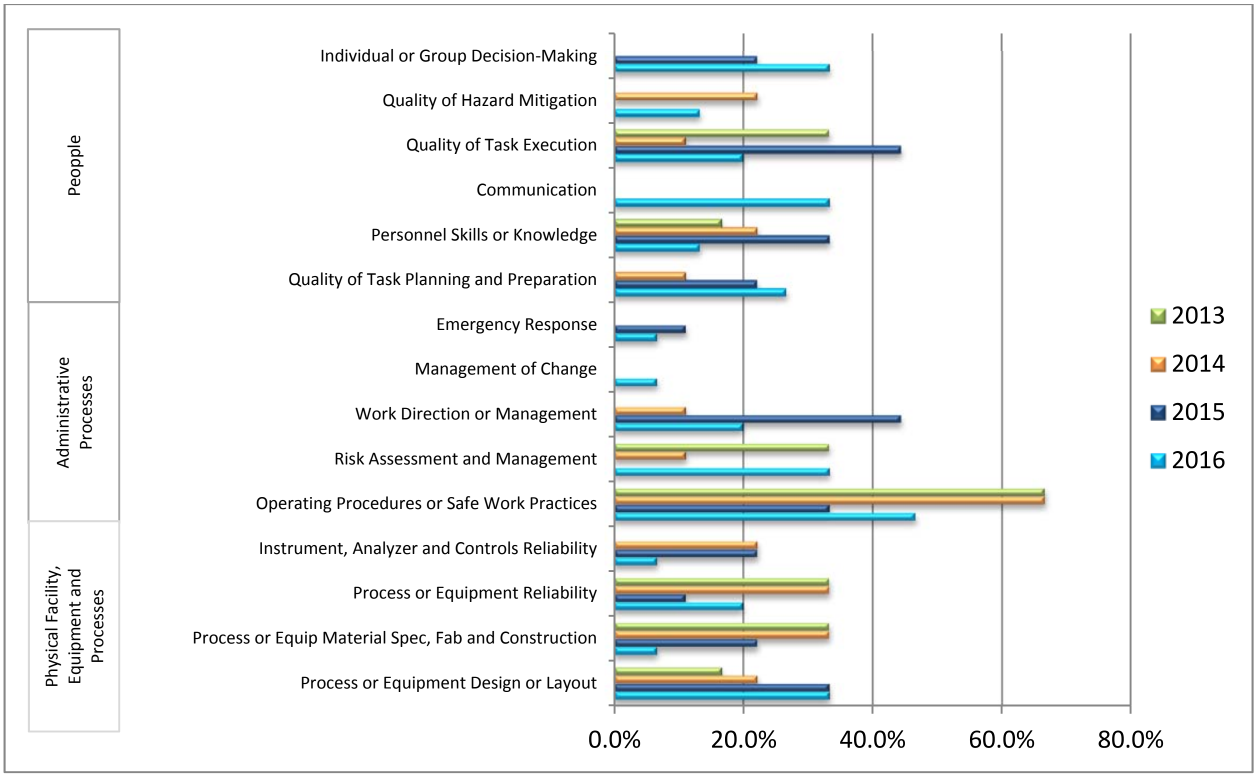
Chart 8 – Maintenance Inspection and Testing AFI Distribution (AFI selection per total number of MIT submittals)



[1] *This chart depicts the number of Maintenance Inspection and Testing Activity AFIs selected divided by the total number of Maintenance Inspection and Testing LFI submittals in the given year.*

- Number of incidents represented above (by year): 2013 = 5, 2014 = 3, 2015 = 6, 2016 = 11

Chart 9 – Process Safety (Tier 1 and Tier 2) AFI Distribution (AFI selection per total number of PSE submittals)



[1] *This chart depicts the number of AFIs selected divided by the total number of PSE submittals in the given year.*

- Number of incidents represented above (by year): 2013 = 6, 2014 = 9, 2015 = 9, 2016 = 15