WELL CONTROL EQUIPMENT SYSTEMS SAFETY

2021 ANNUAL REPORT

SafeOCS

U.S. Department of Transportation
Office of the Secretary of Transportation
Bureau of Transportation Statistics

WELL CONTROL EQUIPMENT SYSTEMS SAFETY

2021 Annual Report

(*Includes a five-year review*)

Acknowledgements

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Drilling platform during the coming storm. Adobe Stock.

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Executive Summary

The *Well Control Equipment Systems Safety – 2021 Annual Report*, produced by the Bureau of Transportation Statistics, summarizes well control equipment (WCE) failure events that occurred during well operations in the Gulf of Mexico (GOM) Outer Continental Shelf (OCS) from 2017 to 2021. The period represents the first five full years of WCE failure reporting to SafeOCS, a confidential reporting program for the collection and analysis of data to advance safety in offshore energy operations. This report contains an analysis of reported events involving WCE systems, including blowout preventer (BOP) equipment, and other key information about the events, such as root causes and follow-up actions.

SafeOCS received event reports for 4,633 WCE events from 2017 to 2021, averaging 927 events per year. Most of these events (85.2 percent) occurred while not in operation, i.e., during maintenance, inspection, and testing. Reported events declined each year, reaching an annual low of 389 events in 2021. Well activity levels also declined over the period. Marked declines in several measures of well operations activity (wells spudded, active rig count, and BOP days – meaning the number of days during which WCE systems were in use) coincided with the onset of the COVID-19 pandemic in the second quarter of 2020. Adjusting for well operations activity, measured by the number of BOP days, the rate of reported events declined 60.6 percent over the five-year period. Only one reported event from 2017 to 2021 resulted in a leak of wellbore fluids to the environment, classified as a loss of containment.

Subsea WCE System Events

Subsea WCE system events comprised 92.7 percent of failure events from 2017 to 2021, and subsea BOP days represented 63.5 percent of all BOP days. Over the five-year period, regulators, solenoid valves (hydraulic), SPM valves, slide (shear-seal) valves, and piping/tubing were among the most frequently reported component failures for both in-operation and not-in-operation events. Most events were classified as external leaks, none of which were leaks of wellbore fluids. The most common root causes were wear and tear (reported for 48.1 percent of events from 2017 to 2021), design issue (16.0 percent), and maintenance error (12.2 percent). Thirty-seven events over the five-year period resulted in BOP stack pulls associated with various component types. Piping/tubing (and its associated sub-components, which have no redundancy) was associated with the most (six) BOP stack pulls, and SPM valves, annular packing elements, ram block seals, operating system seals, and flex loop hose were each associated with at least two BOP stack pulls since 2017.

Surface WCE System Events

Surface WCE system events comprised 7.3 percent of failure events from 2017 to 2021, and surface BOP days represented 36.5 percent of all BOP days. Over the five-year period, accumulators, ram block seals, regulators, choke and kill valves, and annular packing elements were among the most frequently reported component failures for both in-operation and not-in-operation events. Internal leaks were the most common failure type (47.5 percent of events), and wear and tear (52.3 percent of events) was the most common root cause. Eighty-one events over the five-year period resulted in BOP stack pulls, many of these associated with an internal leak across the annular packing element.

INTRODUCTION

The *2021 Annual Report: Well Control Equipment Systems Safety*, produced by the Bureau of Transportation Statistics (BTS), provides information on well control equipment (WCE) failures reported to SafeOCS from 2017 to 2021, the first five full years of the WCE failure reporting program. These failures occurred during well operations in the Gulf of Mexico (GOM) Outer Continental Shelf (OCS). Per 30 CFR 250.730(c), operators must report any equipment failures experienced during these activities to SafeOCS.

About SafeOCS

SafeOCS is a confidential reporting program for collecting and analyzing data to advance safety in energy operations on the OCS. The objective of SafeOCS is to capture and share essential information across the industry about accident precursors and potential hazards associated with offshore operations. The program is sponsored by the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) and operated independently by the Department of Transportation's Bureau of Transportation Statistics (BTS), a principal federal statistical agency. The Confidential Information Protection and Statistical Efficiency Act (CIPSEA) protects the confidentiality of all data submitted directly to SafeOCS.[1]

The SafeOCS program umbrella comprises several safety data collections, including the WCE failure reporting program, which is the subject of this report. The WCE program includes reports of well control equipment failure events mandated under 30 CFR 250.730(c). This regulation requires operators to follow the failure reporting procedures in API Standard 53 (4th ed.), submit failure reports to BTS as BSEE's designated third party to receive this information, and submit failure reports to the original equipment manufacturer. This is the sixth annual report on the WCE failure reporting program.[2]

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[1] Confidential Information Protection and Statistical Efficiency Act of 2018, Pub. L. No. 115-435, tit. III (reauthorizing the 2002 law of the same name).

[2] Prior to 2019, the annual reports were titled *Blowout Prevention System Safety Events*.

Stakeholder Collaboration

This annual report is the product of a wide-ranging collaboration between key stakeholders in the oil and gas industry and government. They include the following:

- **The Joint Industry Project on Blowout Preventer Reliability Data (BOP Reliability JIP)**: The SafeOCS program continues to receive input from the JIP, a collaboration between the International Association of Drilling Contractors (IADC) and the International Association of Oil and Gas Producers (IOGP). The JIP developed and manages RAPID-S53, the Reliability and Performance Information Database for Well Control Equipment covered under API Standard 53.
- **Internal Review Team**: SafeOCS retained experts in drilling operations, production operations, equipment testing, and well control equipment design and manufacturing. The subject matter experts reviewed event reports, validated and clarified BTS and BSEE data, and provided input to this report.
- **BSEE**: BSEE provided BTS with well-related data used for data validation, benchmarking, and development of exposure measures, described under Data Validation and Exposure Measures (page 4).

Context for WCE Events

WCE systems, including BOP equipment, control the flow of formation and other fluids during oil and gas well operations.[3] This report focuses on events that occurred while maintaining, inspecting, testing, and operating WCE systems during offshore well operations. To understand when and how WCE is used, it is important to recognize that drilling operations encompass more than the act of drilling, and include all activities related to constructing an oil or gas well. For example, in addition to drilling the hole (wellbore) to the correct size and depth, well construction includes preventing the hole from collapsing and maintaining pressure integrity within the hole. This process involves running lengths of various size pipes (conductor, casing,

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[3] Well operations include drilling, completion, workover, and decommissioning activities. 30 CFR 250.700.

or tubing) into the wellbore, cementing them in place to isolate any potential flow zone,[4] and preparing the well for subsequent production operations.

WCE systems are critical to ensuring the safety of personnel and the environment during drilling and other well operations. WCE, for purposes of this report, is broken down into the following system subunits:

- BOP stack
- BOP controls
- Riser
- Diverter
- Choke manifold
- Auxiliary equipment

Of these, the BOP controls and the BOP stack systems, both of which comprise thousands of components and consume the most hours of maintenance of any system on the rig, are among the most important for safeguarding against adverse events. Normally, the BOP control systems and BOP stack systems are on standby, ready to respond to a well control event. Operators are required to conduct and meet API Standard 53 (4th ed.) testing criteria at various times during well operations to ensure these systems will function as expected if needed. WCE systems must be maintained and inspected before tests can be carried out and then tested again at predetermined intervals per requirements. This cycle of maintenance, inspection, and testing is further discussed in Appendix B.

This report contains a chapter about subsea WCE systems, followed by a chapter on surface WCE systems. Differences between events that occurred while in operation versus not in operation (i.e., during maintenance, inspection, and testing) are noted where relevant. In-operation events are further evaluated as to whether they led to a BOP stack pull. The following factors were considered in determining how to present the data:

- **WCE System Complexity**: Subsea WCE systems have a much higher population of components than surface WCE systems. This is due to complexity caused by the distance between the BOP stack and the rig-mounted control panels and redundancies intended to prevent single-point failures while inaccessible equipment is in use.

[4] Any zone in a well where flow is possible under conditions when wellbore pressure is less than pore pressure.

- **Accessibility of Equipment**: Most subsea system equipment is underwater and limited to observation and simple operations by a remotely operated vehicle (ROV),[5] whereas surface system equipment is always visible and accessible by the rig crew.[6]
- **Management of Equipment**: Rigs with subsea BOPs have full-time crews of dedicated subsea engineers that install and maintain the WCE. Surface BOP systems are typically operated by the drill crews and maintained by the rig mechanic, in addition to their standard duties. These crew differences lead to different operational and reporting practices for subsea systems as compared to surface systems. For example, for surface systems, WCE components are often sent to shore for major maintenance, whereas most of these activities are typically conducted onsite for subsea systems (unless OEM maintenance agreements require a return to base).
- **Risk:** Events that occur when the system is not in operation present fewer potential consequences than events that occur when the system is in operation, since not-in-operation events can be corrected before operations begin. Importantly, most in-operation events do not result in consequences because of equipment redundancy and the relatively short period that well pressures can lead to a blowout.[7] Understanding what components fail while in operation, as well as how, when, and why they fail, is critical to reduce or eliminate similar events in the future.

Data Validation and Exposure Measures

BTS used data provided by BSEE to validate SafeOCS data and develop exposure measures that help provide context for the failures. BTS validated submitted data by reviewing well activity reports (WARs), which oil and gas operators must submit to BSEE weekly for active well

[5] An ROV is required under 30 CFR 250.734 and provides a live video feed together with the capability to open and close specific control valves and perform some other simple tasks.

[6] On a subsea system, the BOP stack, the BOP control pods, hoses, cables, and the marine drilling riser are all located underwater when in use and are therefore inaccessible. The subsea BOP stack equipment is densely packed into a handling and protection frame, making access difficult and time-consuming. All the equivalent equipment on a surface system is above water and joined together using industry-standard connections, making access easier.

[7] A well can experience a blowout when the formation's pressure is higher than the drilling fluid's hydrostatic pressure.

operations in the Gulf of Mexico OCS Region, per 30 CFR 250.743. WARs were also used to identify WCE failure events that were not reported to SafeOCS.

BTS also used BSEE data sources, including WARs, to develop exposure measures that quantify the population of equipment subject to failure and its characteristics. These exposure measures, sometimes referred to as denominator or normalizing data because they represent the population based on statistical values, facilitate comparisons over time and between different types of WCE. WAR data is used to develop several measures (numbered one through seven below) that approximate the number of active operators and the amount of rig activity.[8] An additional measure, wells spudded (number eight below), is developed from the BSEE boreholes table and provides information on the extent of new well activity. The measures include the following:

1. **Active operators**: The number of operators conducting rig operations.
2. **Wells with activity**: The number of wells worked on by rigs, regardless of the well operation.
3. **Rigs with activity**: The number of rigs with operations.
4. **BOP days**: The number of days during which some or all the WCE components may have been in use (or were being tested and maintained) and had any likelihood of a failure. For rigs with one BOP stack, this is equivalent to the total number of days the rig was operating, as reported in WAR data. For rigs with two BOP stacks, the number of days the rig was operating is multiplied by 1.48, based on an estimated increase in WCE components.[9] The number of **in-operation BOP days** is the subset of BOP days when the BOP system was in operation.

[8] In developing these exposure measures, WARs associated with intervention vessels were excluded.

[9] The component count of a subsea system rig with two BOP stacks divided by the component count of a subsea system rig with one BOP stack = 1.48. The details of these estimates are provided in the SafeOCS supplement, *WCE Estimated System Component Counts*, published separately.

5. **BOP stack runs**: The number of times a subsea BOP stack was run (deployed) from the rig to the wellhead. This number also includes when the BOP stack was moved from one location to another while staying submerged (i.e., well hopping).
6. **BOP stack starts**: The number of times a surface BOP stack was assembled on a surface wellhead.
7. **BOP latches and unlatches**: The number of times a subsea BOP stack was latched or unlatched from a subsea wellhead.
8. **Wells spudded**: The number of new wells started.

Analysis Information and Data Adjustments

- The terms *subsea* and *surface* reference the type of applicable BOP system, not the equipment's location (above or below the waterline); i.e., subsea exposure measures apply to rigs with subsea BOP systems, and surface exposure measures apply to rigs with surface BOP systems.
- In general, well intervention equipment failure notifications reported to SafeOCS are excluded from this report due to data collection limitations for these types of equipment.
- SafeOCS may receive WCE event notifications after the publication of annual reports. If notifications are received after publication that meaningfully impact this report's results and conclusions, an addendum may be published.
- Numbers are adjusted in each annual report to reflect information provided after publication and may vary from those reported in the previous annual report. All results and references to previous data in this report represent updated numbers unless otherwise stated.
- Due to rounding, numbers in tables and figures may not add up to totals.

Chapter 1: Numbers at a Glance

This report is based on data from 4,633 WCE failure events (4,296 subsea system and 337 surface system) reported to SafeOCS between 2017 and 2021 (see Table 1). In 2021, the most recent year of reporting, there were 389 WCE failure events reported (344 subsea system and 45 surface system events). All reported events occurred in the Gulf of Mexico OCS, which accounts for over 99 percent of annual oil and gas production on the OCS.[10]

Table 1: Numbers at a Glance, 2017–2021

MEASURE	2017	2018	2019	2020	2021	2017-2021 Total	2017-2021 Average
WELLS							
Wells with Activity	325	389	397	264	243	1,618	323.6
Wells Spudded	150	193	187	115	104	749	149.8
RIGS							
Rigs with Activity	60	59	63	50	37	80	53.8
Rigs with Reported Events	47	40	36	32	24	66	35.8
OPERATORS							
Active Operators	27	32	29	27	20	42	27
Reporting Operators	18	14	13	14	12	23	14.2
BOP DAYS							
Total BOP Days	16,072	17,073	16,990	12,462	11,180	73,777	14,755
Not-in-Operation BOP Days	6,123	6,334	6,475	5,382	4,608	28,922	5,784
In-Operation BOP Days	9,949	10,739	10,515	7,080	6,572	44,855	8,971
Subsea System BOP Days	10,900	10,135	9,883	8,500	7,407	46,825	9,365
Surface System BOP Days	5,172	6,938	7,107	3,962	3,773	26,952	5,390
COMPONENT EVENTS							
Total Events Reported	1,420	1,196	995	633	389	4,633	927
Overall Event Rate	88.4	70.1	58.6	50.8	34.8	62.8	60.5
Not-in-Operation Events	1,181	1,027	847	569	321	3,945	789
In-Operation Events	239	169	148	64	68	688	138
Subsea System Events	1,305	1,127	908	612	344	4,296	859
Surface System Events	115	69	87	21	45	337	67
LOC EVENTS							
Loss of Containment Events	1	0	0	0	0	1	NA

KEY: In-operation Not-in-operation

NOTES:
- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–21 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

An average of 927 events per year were reported during the first five years of the program, from 2017 to 2021. Most of these events (789 per year on average) occurred while not in operation, i.e., during maintenance, testing, and inspection activities. Only one reported event during the five-year period resulted in a leak of wellbore fluids to the environment, classified as a loss of containment.

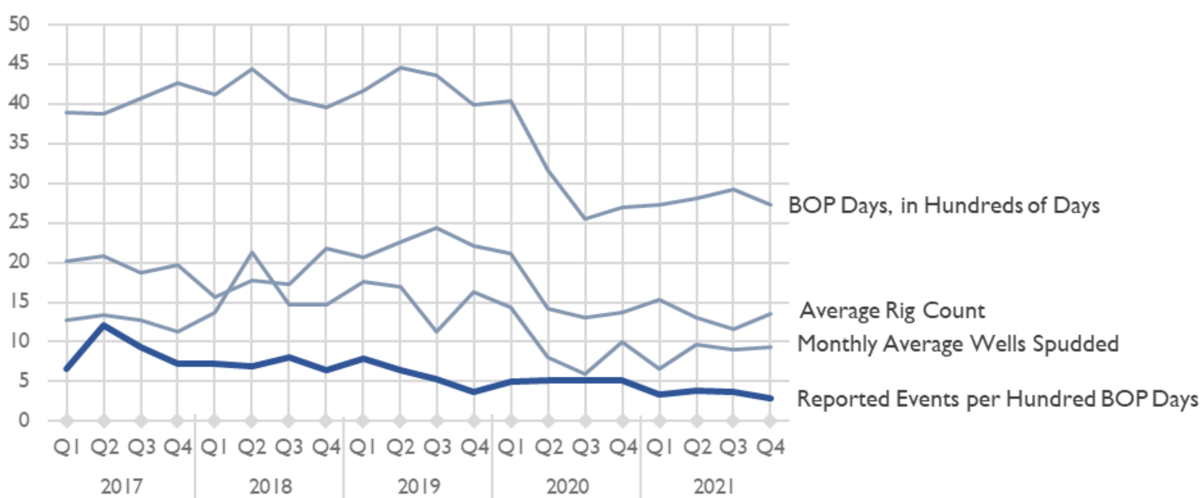
Subsea WCE system events comprised greater than 88.0 percent of failure events each year since 2017, and subsea BOP days represented 63.5 percent of BOP days overall. The difference

[10] Outer Continental Shelf Oil and Gas Production, BSEE, https://www.data.bsee.gov/Production/OCSProduction/Default.aspx.

in reported event frequency between subsea and surface systems persists after adjusting for activity levels, with 91.7 events per thousand subsea system BOP days compared to 12.5 events per thousand surface system BOP days on average from 2017 to 2021.

Reported events declined 73.6 percent overall from 2017 to 2021, reaching an annual low in 2021. When adjusted for well operations activity, measured by the number of BOP days, the rate of reported events declined 60.6 percent over the five-year period. Figure 1 shows levels of well activity as measured by BOP days, rig count, wells spudded, and reported events. Although the scale is different for each of these measures, they are shown together for the purpose of comparing trends. The figure shows declines in several measures of well operations activity coinciding with the onset of the COVID-19 pandemic in the second quarter of 2020.

Figure 1: Levels of Well Activity in the Gulf of Mexico OCS, 2017–2021



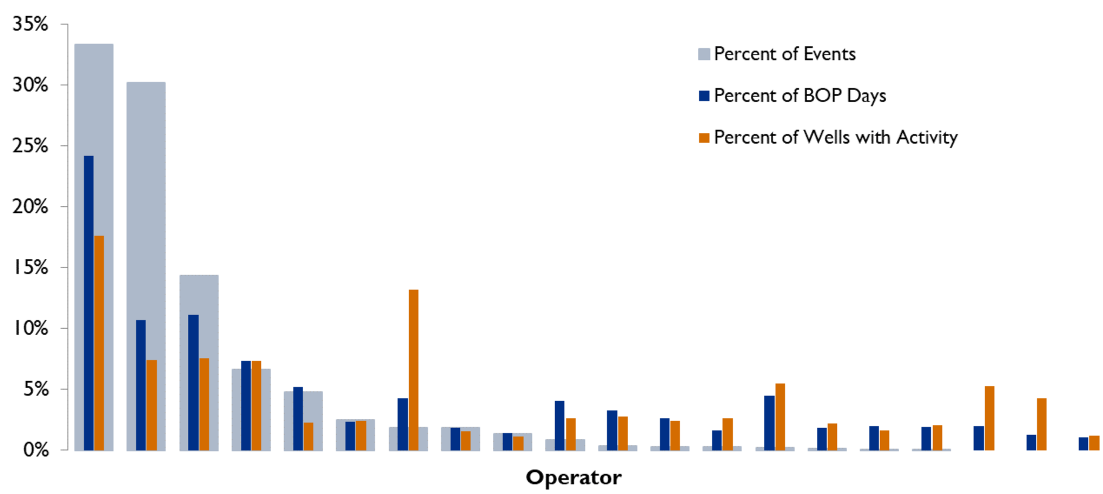
SOURCE: U.S. DOT, BTS, SafeOCS Program. Rig counts from Baker Hughes Rig Count, https://rigcount.bakerhughes.com/.

Reporting Operators

From 2017 to 2021, a total of 42 operators conducted well activities, 23 of whom have reported at least one failure event.[11] Reporting operators represent 91.5% of well activity (measured in BOP days) from 2017 to 2021.

Figure 2 shows the relative distribution of reported events, BOP days, and wells with activity among active operators over the past five years. BOP days and wells with activity are indicators of an operator's amount of well operations during the period. For most operators, the percent of BOP days and percent of wells with activity are similar. A greater percentage of wells than BOP days generally indicates the operator worked on more wells, but spent less time working on each well, compared to other operators. As shown in the figure, an operator's amount of well operations is not always proportional to their reported events. For example, operators two and three had about the same levels of activity (BOP days and active wells) from 2017 to 2021 but show a relatively large difference in reported events. Factors that could explain this include differences in safety approaches between companies and potential underreporting.

Figure 2: Rig Activity and Event Reporting by Operator, 2017–2021

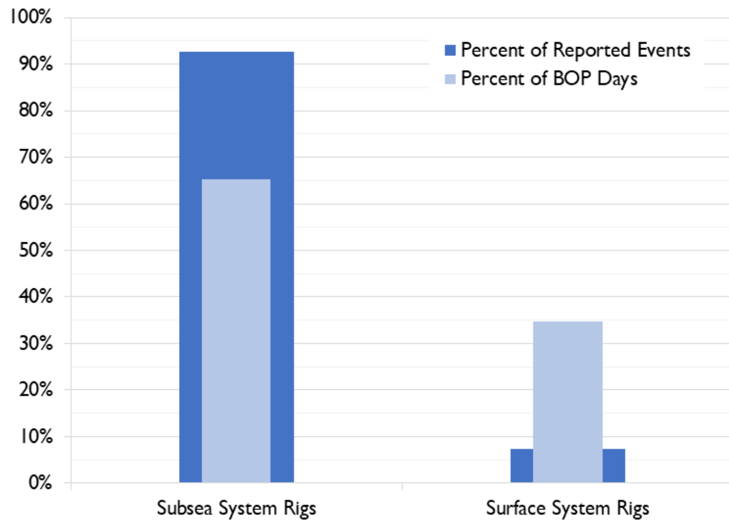


NOTE: Operators with less than 1.0 percent of total BOP days are not shown. These operators collectively represent 1.1 percent of reported events, 5.4 percent of BOP days, and 7.2 percent of wells with activity.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

[11] The total of 42 includes 39 operators with at least one BOP day reported in well activity report data and three operators with no BOP days but at least one WCE event reported to SafeOCS.

Rigs with Events

Figure 3: WCE Reporting by WCE System Type, 2017–2021



NOTE: Subsea system rigs represented include drillships, semisubmersibles, and dynamically positioned (DP) semisubmersibles. Surface system rigs represented primarily include platform rigs and jackups.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Rigs are the facilities on which well control equipment is operated. Examining the distribution of reported events among rigs can provide insights regarding failures and reporting trends. Between 2017 and 2021, 40 rigs with subsea BOP stacks and 40 rigs with surface BOP stacks had some level of well activity. Although the quantity of rigs is evenly split, Figure 3 shows that most well activity was conducted by subsea system rigs, and specifically by drillships, which contributed 82.7 percent of reported events over the five-year period. Subsea WCE systems have a much higher population of components than surface WCE systems due to their complexity.

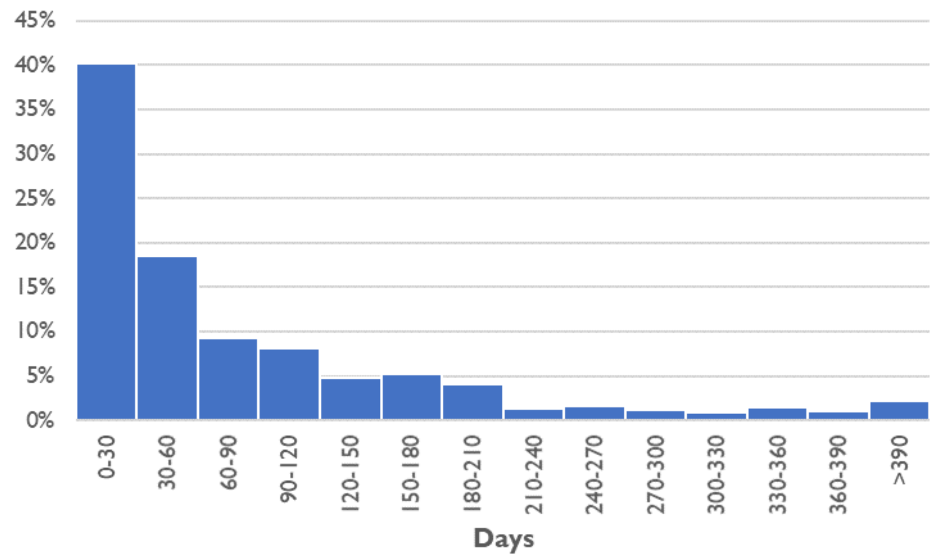
Of the 80 rigs with well activity from 2017 to 2021, 66 were associated with at least one failure event. Excluding rigs with fewer than 10 BOP days, the average subsea system rig experienced 116.1 events total (standard deviation (SD) 132.3), and 92.5 events per thousand BOP days over the five-year period. The average surface system rig experienced 8.9 events total (SD 9.8) and 13.7 events per thousand BOP days.

Timeliness of Event Reporting

More than 40 percent of reported events from 2017 to 2021 were submitted within 30 days of the event date, and 80.8 percent were submitted within 150 days (Figure 4). Of 23 operators who reported failures from 2017 to 2021, 17 submitted failure notifications within 35 days, three within 60 days, and the remaining three within 185 days, on average.

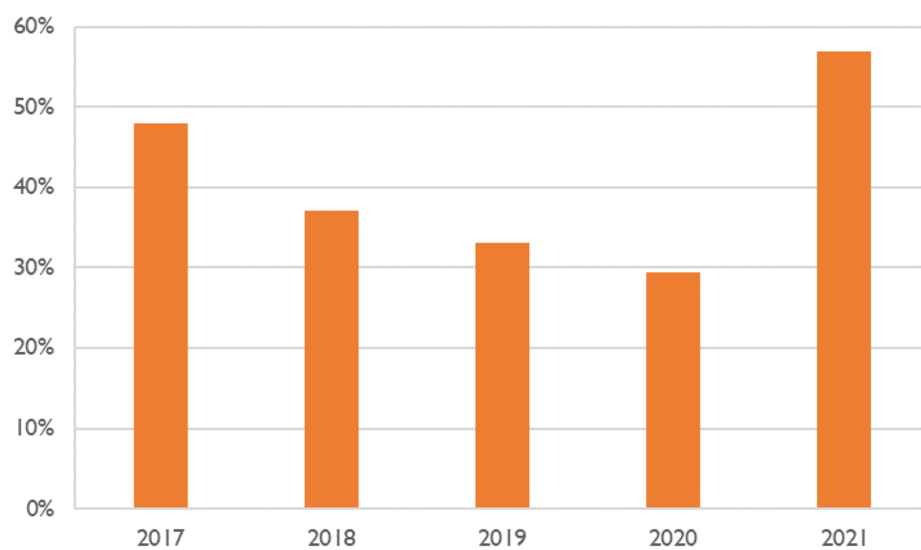
An initial event report should be submitted to SafeOCS within 30 days of the event date even if an investigation is pending, however it is plausible that some could have been delayed due to ongoing investigation and analysis. This is moderately supported by the data, which shows that on average over the five-year period, fewer events with further investigation were reported within 30 days than events where the cause was immediately known (33.3 versus 43.3 percent, respectively).

Figure 4: Distribution of Time to Event Reporting, 2017–2021



SOURCE: U.S. DOT, BTS, SafeOCS Program.

Figure 5: Events Reported Within 30 Days, 2017–2021



SOURCE: U.S. DOT, BTS, SafeOCS Program.

As shown in Figure 5, the percentage of reports submitted within 30 days of the event declined from 2017 to 2020, but showed an increase in 2021 to 57.0 percent. The practice of submitting reports in batches has contributed to reporting delays in some cases. BTS will work with reporting companies to identify technical challenges contributing to late reporting, such as batch reporting of failure events.

WCE Events Identified in WAR Data

BTS uses BSEE well activity report data not only to estimate activity levels (i.e., BOP days), but also to cross-reference the timing and occurrence of failures and identify those that may not have been reported to SafeOCS, resulting in a better approximation of the complete set of failure events. Since 2019, BTS has evaluated WAR data to identify failure events including BOP stack pulls. From 2019 to 2021, 32 BOP stack pull events not reported to SafeOCS were identified from WAR data and included in aggregated analyses. Most of these were for surface WCE systems (see Table 2). Events other than BOP stack pulls are also recorded from WAR data, however they are excluded from the aggregated statistics presented in this report due to limited available event information.

Table 2: Unreported BOP Stack Pull Events Identified in WAR Data, 2019–2021

	2019	2020	2021	Total
Subsea WCE Systems	0	3	1	4
Surface WCE Systems	16	6	6	28

SOURCE: U.S. DOT, BTS, SafeOCS Program.

CHAPTER 2: SUBSEA WCE SYSTEM EVENTS

Reported subsea WCE system events declined each year from 2017 to 2021, reaching a low of 344 reported events in 2021. As shown in Table 3, activity levels also followed a downward trend. The decline in event reporting remains after adjusting for activity levels, as seen in the 35.6 percent decline in the event rate from 2020 to 2021 and the 61.2 percent overall decline since 2017.

The declining event rate is influenced by a larger decrease in reported events relative to the decrease in BOP days. This has been true each year since 2017, meaning that events decreased at a higher rate than activity levels. The not-in-operation event rate, for example, declined 66.6 percent from 2017

Table 3: Subsea System Numbers at a Glance, 2017–2021

MEASURE	2017	2018	2019	2020	2021	2017-2021 Total	2017-2021 Average
WELLS							
Wells with Activity	165	172	189	142	133	650	160.2
Wells Spudded	89	107	101	74	53	424	84.8
RIGS							
Total Rigs with Activity	32	31	29	26	21	40	27.8
With One Subsea Stack	10	9	8	6	5	13	7.6
With Two Subsea Stacks	22	22	21	20	16	27	20.2
Rigs with Reported Events	29	24	21	22	18	37	22.8
OPERATORS							
Active Operators	17	16	20	19	14	23	17.2
Reporting Operators	11	10	10	11	10	18	10.4
BOP DAYS							
Total BOP Days	10,900	10,135	9,883	8,500	7,407	46,825	9,365
Not-in-Operation BOP Days	4,566	4,463	4,611	4,155	3,693	21,488	4,298
In-Operation BOP Days	6,334	5,672	5,272	4,345	3,714	25,337	5,067
COMPONENT EVENTS							
Total Events Reported	1,305	1,127	908	612	344	4,296	859
Overall Event Rate	119.7	111.2	91.9	72.0	46.4	91.7	88.2
Not-in-Operation Events	1,124	993	804	557	304	3,782	756
Not-in-Operation Event Rate	246.2	222.5	174.4	134.1	82.3	176.0	171.9
Not-in-Operation Events per Well	6.8	5.8	4.3	3.9	2.3	5.8	4.6
In-Operation Events	181	134	104	55	40	514	103
In-Operation Event Rate	28.6	23.6	19.7	12.7	10.8	20.3	19.1
In-Operation Events per Well	1.1	0.8	0.6	0.4	0.3	0.8	0.6
BOP STACK MOVEMENTS							
Total Stack Runs	200	179	219	160	136	894	178.8
Successful Runs	167	152	162	135	119	735	147
Stack Pulls	10	8	8*	8*	3*	37	7.4
LOC EVENTS							
Loss of Containment Events	1	0	0	0	0	1	NA

KEY: In-operation Not-in-operation

NOTES:

- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–21 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

* Includes some BOP stack pulls identified in WAR. Table 2 provides counts. These are not included in *Total Events Reported*.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

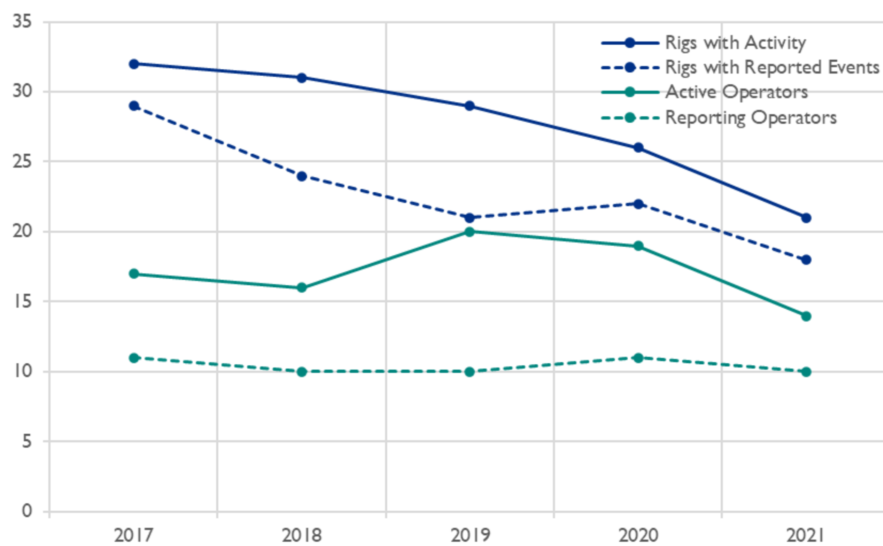
to 2021, more due to the 73.0 percent decrease in reported events than the 19.1 percent decrease in not-in-operation BOP days.

Most subsea system events from 2017 to 2021 (88.0 percent) were found while not in operation, i.e., during maintenance, inspection, and testing. Overall, 37 BOP stack pulls were recorded from 2017 to 2021. About 5.0 percent of successful subsea BOP stack runs—meaning the BOP stack was assembled on the wellhead and went into operation—eventually led to a BOP stack pull during the five-year period.

Event Reporting Levels

As shown in Figure 6, changes in the number of active operators for subsea WCE systems were greater from year to year than changes in reporting operators, which remained relatively stable at 10 or 11 operators each year. Similarly, changes in the number of active rigs are not always reflected in changes to the number of rigs with reported events, as seen in the differing directions of change from 2019 to 2020. This suggests that other factors in addition to activity levels may contribute to changes in reporting.

Figure 6: Reporting and Activity Levels for Subsea Systems, 2017–2021



SOURCE: U.S. DOT, BTS, SafeOCS Program.

Frequently Reported Components

From 2017 to 2021, 122 different components were reported as having failed on subsea WCE systems. As shown in Table 4, the most frequently reported for not-in-operation events were regulators, solenoid valves (hydraulic), SPM valves, slide (shear-seal) valves, shuttle valves, piping/tubing, and accumulators, each contributing at least 3.0 percent of events and together comprising 51.5 percent of all subsea system events. These components are more frequently in use compared to other components.

Table 4: Frequently Reported Components for Not-in-Operation Subsea Systems, 2017–2021

Component	2017 (n=1,124)	2018 (n=993)	2019 (n=804)	2020 (n=557)	2021 (n=304)	Total (n=3,782)
Regulator	8.6%	12.1%	13.3%	13.6%	11.6%	11.5%
Solenoid Valve Hydraulic	10.1%	5.3%	13.6%	11.5%	3.6%	9.3%
SPM Valve	10.5%	7.0%	6.2%	7.4%	5.9%	7.9%
Slide (Shear-Seal) Valve	7.3%	7.5%	3.2%	9.0%	6.9%	6.7%
Shuttle Valve	6.0%	4.3%	6.6%	9.2%	8.6%	6.4%
Piping/Tubing	5.7%	7.9%	3.7%	3.4%	7.6%	5.7%
Accumulator	3.5%	7.5%	2.6%	2.9%	2.6%	4.2%

KEY: Not-in-operation
NOTE: Includes components representing at least 3.0 percent of events.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

For in-operation events, as shown in Table 5, hardware, relief valves, and ram block seals are added as most frequently reported components, and shuttle valves and accumulators are dropped. Each of the components listed in Table 5 contributed at least 3.0 percent of in-operation events and together they comprise 41.4 percent.

Table 5: Frequently Reported Components for In-Operation Subsea Systems, 2017–2021

Component	2017 (n=181)	2018 (n=134)	2019 (n=104)	2020 (n=55)	2021 (n=40)	Total (n=514)
Regulator	9.4%	14.9%	11.5%	12.7%	20.0%	12.5%
Hardware	5.5%	21.6%	5.8%	5.5%	2.5%	9.5%
SPM Valve	6.1%	4.5%	4.8%	5.5%	2.5%	5.1%
Slide (Shear-Seal) Valve	2.8%	6.7%	1.9%	7.3%	2.5%	4.1%
Piping/Tubing	2.8%	2.2%	6.7%	7.3%	2.5%	3.9%
Relief Valve	2.2%	3.0%	4.8%	3.6%	5.0%	3.3%
Ram Block Seal	3.3%	2.2%	1.9%	9.1%	0.0%	3.1%
Solenoid Valve Hydraulic	5.0%	0.0%	3.8%	0.0%	7.5%	3.1%

KEY: In-operation
NOTE: Includes components representing at least 3.0 percent of events.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Most failures of the components in Table 4 and Table 5 occurred on the BOP control pod. Shuttle valves and piping/tubing experienced most failures on the BOP controls stack mounted, on the BOP controls. The following provides a brief discussion of these components:

- *Regulators:* The frequency of regulator failures can be partially explained by the fact that half are in a dynamic operating state (meaning the internal parts are always moving to keep pressures constant) in one of the pods while in operation. The remaining regulators, in the alternate pod, are on standby.
- *Solenoid valves (hydraulic):* Three options for solenoid valves can be selected on the WCE failure reporting form—hydraulic, electric, and pneumatic (as well as unspecified). Of these, only hydraulic and electric failures were reported between 2017 and 2021. The hydraulic side failures, which have moving parts and seals, are reported more frequently than electromagnet issues related to failures on the electric side.
- *SPM valves and slide (shear-seal) valves:* SPM valves and slide (shear-seal) valves are used for the same functions but with different sealing technologies. Over the five-year reporting period there were 323 SPM valve and 274 slide (shear-seal) valve events.
- *Shuttle valves*: The infrequency of reported shuttle valve failures while in operation compared to not in operation may be partially explained by the fact that in-operation leaks are often too small to affect activities, whereas not-in-operation leaks can more easily be seen during maintenance, inspection, and testing. Shuttle valve leaks are also discussed under Failure Types (page 17).
- *Piping/tubing:* The 234 events attributed to piping/tubing since 2017 consist of failures of sub-components such as adaptors, crossovers, terminations, and seals.
- *Relief valves*: There have been 77 reports of failed relief valves since 2017, 85.7% of which occurred on the BOP control systems and the remainder on the diverter system. Details from failure events are often limited for relief valves, as they are frequently replaced without further investigation, since it is often not cost effective to repair them as repair would involve hiring the services of a third-party company to recertify the valve before using it again.
- *Ram block seals*: Failures of ram block seals are more frequently found while in operation because of the temperature and chemical conditions in which they operate. These seals

are considered consumables[12] and it is difficult to forecast their life span and therefore plan proactive maintenance schedules. Not only is temperature a major factor in the life span, but the chemicals that make up the drilling fluid vary as conditions change, producing variations which affect the integrity of the seal.

Failure Types

Most events from 2017 to 2021 were a type of leak, comprising 77.2 percent of subsea system events overall. As shown in Table 6, external leaks were the most frequently observed failure, which is not unexpected as most components are used to control and contain fluids present during operations.

Table 6: Failure Types of Subsea System Events, 2017–2021

FAILURE TYPE	2017 (n=1,305)	2018 (n=1,127)	2019 (n=908)	2020 (n=612)	2021 (n=344)	Total (n=4,296)
LEAKS						
External Leak	50.1%	46.6%	60.0%	53.8%	53.8%	52.1%
Internal Leak	27.8%	24.2%	20.7%	27.9%	23.7%	25.1%
Undetermined Leak	0.0%	0.3%	0.0%	0.0%	0.0%	0.1%
OTHER						
Communication / Signal Issue	4.2%	2.8%	3.3%	2.9%	3.0%	3.4%
Electrical Issue	1.6%	1.8%	3.0%	1.8%	2.4%	2.0%
Fail to Function on Command	2.6%	2.8%	2.4%	3.4%	4.6%	2.9%
Inaccurate Indication	2.1%	2.9%	2.5%	2.0%	3.3%	2.5%
Mechanical Issue	10.0%	16.8%	6.3%	5.1%	6.7%	10.0%
Process Issue	1.1%	1.6%	1.1%	1.8%	1.5%	1.4%
Unintended Operation	0.2%	0.2%	0.1%	0.0%	0.3%	0.1%
Other	0.3%	0.1%	0.6%	1.3%	0.6%	0.5%

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Leaks that are too small in volume to register on instruments during in-operation activities can sometimes be seen by the crew when the BOP stack is on deck during maintenance, inspection, and testing. Additionally, there are leak rates that might be considered allowable by the OEM

[12] Consumables, in this context, are seals that have an indeterminable expected life because of variables in the operating conditions.

qualifications on the component. While both types of leaks have very small volumes (measured in drops per minute), and therefore do not typically affect on-going operations, they are still reported to SafeOCS. Currently, there is not a specific field on the form to capture leak volume or rate, and leaks are rarely collected and measured in the field.

Though leaks can affect all hydraulic components, those most subject to external leaks include several of the most frequently reported: regulators, solenoid valves (hydraulic), SPM valves, slide (shear-seal) valves, piping/tubing, and accumulators. This is partially explained by the nature of the component, as when most of these components leak, it is almost always an external leak. For shuttle valves, the most frequent failure type is internal leak. Together, external leaks of these seven types of components total 64.3 percent of their total failure events, 60.7 percent of all external leaks, and 31.6 percent of all events since 2017.

Except for the event that caused the loss of containment in 2017, there have not been any external leaks of wellbore fluid. There have been failures of ram BOP door seals, but all were discovered and corrected during maintenance, inspection, and testing. All other external leaks have involved water-based control fluid which is vented into the ocean as part of the system design.

Failure types for not-in-operation events are distributed similarly to Table 6. For in-operation events, external leaks comprise about 8.7 percentage points fewer total events compared to Table 6. Some of this difference is attributed to an increase in issues with communication and signals, which are more frequently used during operations. There were also fewer mechanical issues for in-operation events (5.5 percent total) compared to Table 6.

Detection Methods

Most subsea system events from 2017 to 2021 (88.0 percent) were detected while not in operation, i.e., during maintenance, inspection, and testing. As shown in Table 7, most not-in-operation events were found during function testing. For 2021, however, almost as many events were found during inspection.

Table 7: Detection Methods for Not-in-Operation Subsea System Events, 2017–2021

	DETECTION METHOD	2017 (n=1,124)	2018 (n=993)	2019 (n=804)	2020 (n=557)	2021 (n=304)	Total (n=3,782)
	Casual Observation	9.3%	7.4%	11.8%	10.6%	9.5%	9.5%
	Continuous Condition Monitoring	5.9%	3.9%	8.2%	6.1%	10.5%	6.3%
	On Demand	0.5%	0.5%	1.1%	1.8%	2.3%	1.0%
	Periodic Condition Monitoring	1.4%	1.5%	2.2%	4.1%	5.9%	2.4%
	Corrective Maintenance	1.7%	2.9%	0.2%	0.7%	1.6%	1.6%
	Periodic Maintenance	3.5%	6.5%	7.0%	5.4%	3.9%	5.3%
MIT	Inspection	16.8%	22.9%	17.7%	13.6%	23.7%	18.7%
	Function Testing	45.3%	40.2%	35.4%	41.7%	25.0%	39.7%
	Pressure Testing	15.7%	14.2%	16.3%	16.0%	17.4%	15.6%

KEY: Not-in-operation MIT: maintenance, inspection, testing
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Most in-operation events from 2017 to 2021 were detected via continuous condition monitoring (Table 8: Detection Methods for In-Operation Subsea System Events, 2017–2021Table 8). In 2021, more events were detected through periodic condition monitoring, and fewer events were detected through pressure testing compared to the five-year average.

Table 8: Detection Methods for In-Operation Subsea System Events, 2017–2021

	DETECTION METHOD	2017 (n=181)	2018 (n=134)	2019 (n=104)	2020 (n=55)	2021 (n=40)	Total (n=514)
	Casual Observation	14.9%	13.4%	14.4%	16.4%	15.0%	14.6%
	Continuous Condition Monitoring	19.9%	16.4%	26.0%	29.1%	25.0%	21.6%
	On Demand	1.7%	1.5%	1.9%	7.3%	2.5%	2.3%
	Periodic Condition Monitoring	7.2%	8.2%	6.7%	9.1%	22.5%	8.8%
	Corrective Maintenance	0.0%	1.5%	0.0%	0.0%	0.0%	0.4%
	Periodic Maintenance	0.0%	2.2%	1.9%	0.0%	0.0%	1.0%
MIT	Inspection	16.0%	18.7%	18.3%	9.1%	10.0%	16.0%
	Function Testing	17.7%	10.4%	15.4%	18.2%	22.5%	15.8%
	Pressure Testing	22.7%	27.6%	15.4%	10.9%	2.5%	19.6%

KEY: In-operation MIT: maintenance, inspection, testing
SOURCE: U.S. DOT, BTS, SafeOCS Program.

For the most frequently reported components, most events were found via functional testing, except for accumulators and piping/tubing, which were identified mostly through inspection.

Apart from accumulators, external leaks (the most frequent failure type) of each of these components were found most often during not-in-operation function testing (48.0 percent from 2017 to 2021), pressure testing, inspection, and casual observation.

Root Causes of Events

While most events from 2017 to 2021 (48.1 percent) were attributed to wear and tear, the percentage citing wear and tear decreased each year, reaching a low of 29.5 percent in 2021 (see Table 9). After wear and tear, the most common root causes over the five-year period were design issue and maintenance error. The largest change from 2020 to 2021 was an increase in maintenance error.

Table 9: Root Causes of Subsea System Events, 2017–2021

REPORTED ROOT CAUSE	2017 (n=1,305)	2018 (n=1,127)	2019 (n=908)	2020 (n=612)	2021 (n=344)	Total (n=4,296)
Design Issue	11.0%	17.6%	19.7%	19.9%	12.2%	16.0%
QA/QC Manufacturing	6.0%	12.2%	6.3%	5.9%	6.4%	7.7%
Maintenance Error	11.9%	9.3%	12.2%	12.7%	22.2%	12.2%
Procedural Error	2.2%	3.8%	13.2%	13.4%	13.7%	7.4%
Documentation Error	0.3%	0.7%	0.1%	11.6%	6.1%	2.4%
Wear and Tear	57.6%	52.9%	45.0%	33.8%	29.5%	48.1%
Other	0.5%	0.5%	0.2%	0.3%	0.0%	0.4%
NOT DETERMINED						
Inconclusive	0.1%	0.0%	0.3%	0.0%	0.3%	0.1%
Assessment Pending	7.2%	2.7%	2.6%	2.1%	9.4%	4.5%
Not Reported	3.1%	0.3%	0.2%	0.3%	0.3%	1.1%
TOTALS	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Regarding the high proportion of wear and tear relative to other root causes, detailed review of notifications indicates that the submitted information does not always provide adequate or meaningful support for the reported root cause. Additionally, depending on the OEM-designated design life of a component, wear and tear may be more acceptable for certain events than others. This is an area for further evaluation.

Wear and tear was also the top root cause for failures of frequently reported components from 2017 to 2021, listed in Table 10. In addition to wear and tear, commonly reported root causes for each component included design issue for regulators, slide (shear-seal) valves, and accumulators, and maintenance error and QA/QC manufacturing for piping/tubing. Supporting information for failures attributed to design issue has been infrequent.

Table 10: Root Causes of Frequently Reported Components for Subsea Systems, 2017–2021

REPORTED ROOT CAUSE	Regulator	Solenoid Valve Hydraulic	SPM Valve	Slide (Shear-Seal) Valve	Shuttle Valve	Piping/Tubing	Accumulator
Design Issue	24.0%	1.6%	7.1%	18.2%	4.4%	6.4%	20.7%
QA/QC Manufacturing	4.4%	2.5%	3.4%	4.0%	2.0%	19.7%	3.0%
Maintenance Error	9.0%	14.7%	16.4%	8.0%	16.9%	20.5%	6.7%
Procedural Error	13.4%	13.1%	1.9%	8.4%	14.1%	2.1%	4.9%
Documentation Error	10.8%	6.8%	1.2%	5.1%	0.0%	0.0%	0.0%
Wear and Tear	34.7%	59.4%	64.7%	54.0%	60.5%	48.7%	61.0%
Other	0.4%	0.3%	1.2%	0.0%	0.4%	0.9%	0.6%
NOT DETERMINED							
Inconclusive	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Assessment Pending	2.6%	0.8%	2.8%	2.2%	0.8%	0.9%	3.0%
Not Reported	0.6%	0.8%	1.2%	0.0%	0.8%	0.9%	0.0%

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Consequential Components

In addition to examining frequently reported component events, it is also useful to examine infrequent component events that may have higher potential consequence, such as failures of the subsea wellhead connector, which connects the BOP stack to the wellhead. Since 2017, there have been 21 reported events associated with the wellhead connector accessories, such as nudge pins and gasket retainers. Nine were a failure of the hardware, nine of the operating system seal, two of the ring gasket, and one of the end connection. All events were detected while not in operation.

Issues with the gasket and end connection are critical to the wellbore integrity. Testing of this connection is the predominant purpose of the initial subsea testing. The BOP stack does not go into operation without passing this testing. As the end connection/gasket is a static seal, if the seal is good and the test passes, the connection invariably remains sealed until the wellhead connection has been unlatched at the end of operations. These ring gaskets are made to seal between the ring grooves in the wellhead connector bottom end connection, and the top of the wellhead. The goal is to land the BOP stack on the wellhead smoothly; however, due to the weight of the equipment and ocean currents, the landing is not always smooth, and gasket damage can occur. The solution is to lift the BOP stack approximately twenty feet and allow the ROV to replace the gasket. This was the issue with one of the reported events. In the other two cases, debris became trapped between the gasket and gasket groove while the BOP stack was being deployed to the well, and when initial test pressure was applied, the grooves were pressure-cut. In one case, the gasket was replaced before operations continued. On the other, a seal was achieved, and the damage was not revealed until the end of operations when the BOP stack was back on deck.

Not-in-Operation Events

Events occurring while not in operation, when the equipment is being maintained, inspected, or tested (MIT) before or after operations, have lower safety and environmental risk than in-operation events. From 2017 to 2021, 88.0 percent of subsea system events were detected while not in operation. As discussed in more detail in Appendix B, the phases of not-in-operation MIT include between wells maintenance, pre-deployment testing, deployment testing, and initial subsea testing (sometimes referred to as initial latch-up testing). Most not-in-operation failures are found during the first two phases, while the BOP stack is on deck. The following discussion focuses on the latter two phases, after the BOP stack has begun deployment:

- *Deployment Testing:* This phase is after pre-deployment testing while the BOP is being deployed to the wellhead. System monitoring and testing are conducted throughout this process.
- *Initial Subsea Testing:* This is the final phase of not-in-operation MIT and is similar to pre-deployment testing, but with the added element of hydrostatic pressure due to operational depth. The BOP stack must pass all initial latch-up testing before going into operation.

These final testing periods are the first opportunity for testing the assembled system and finding failures after general MIT has been completed, but before the BOP stack is in operation. If a failure is found during deployment or initial subsea testing, the operator may be able to make repairs (using an ROV, or if the component is accessible on deck), or continue operations without repair while still ensuring safe operations. Without repair, redundancy, or a management of change (MOC) waiver, the BOP stack must be retrieved to repair the component. Retrievals are not considered BOP stack pulls, since the BOP stack has not yet gone into operation, the well is not open, and therefore does not need to be made safe before retrieving the BOP stack. If a component failure is not identified during the last two phases of testing, it could result in a BOP stack pull instead of a retrieval.

Of 894 BOP stack runs between 2017 and 2021, 736 were successful, meaning the BOP stack passed initial subsea testing and went into operation. Of the 158 BOP stack runs that were unsuccessful, meaning that the BOP stack needed to be retrieved and go through testing again before operations could commence, 68 retrievals were the result of a reported subsea system component failure. (Other circumstances, such as weather events, may also lead to BOP stack retrievals.) As shown in Table 11, from 2017 to 2021, 138 events were identified during the last two phases of testing, 90 of which resulted in a retrieval (in some cases, multiple failures were associated with a single retrieval). In the remaining cases, repair was accomplished without a BOP stack retrieval or operations continued without repair.

Table 11: Retrievals and Events During the Last Two Phases of Testing, 2017–2021

Measure	Events during Deployment Testing	Events during Initial Subsea Testing	Total
Stack Retrievals	27	41	68
Total Events	58	80	138
Operations Continued without Repair	11	14	25
Component Repaired (in situ)	8	15	23
Events Contributing to Stack Retrieval	39	51	90

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Table 12 lists the WCE system subunits involved in failure events that occurred during deployment or initial subsea testing. Most occurred on the BOP controls and BOP stack, and a stack retrieval was required for most events involving these subunits. Of note, the choke manifold and diverter systems are accessible on deck, and therefore failures associated with these subunits generally would not require retrieval of the BOP stack to address (with limited exceptions).

Table 12: Events During the Last Two Phases of Testing (by Subunit) 2017–2021

Subunit	Events during Deployment Testing			Events during Initial Subsea Testing			Total
	Operations Continued without Repair	Component Repaired (in situ)	Events Contributing to Stack Retrieval	Operations Continued without Repair	Component Repaired (in situ)	Events Contributing to Stack Retrieval	
BOP Controls	10	5	22	5	5	22	69
BOP Controls Emergency Automated			6		3	7	16
BOP Controls Secondary ROV Acoustic				2	3	2	7
BOP Stack	1	1	10	7	4	20	43
Choke Manifold System		1					1
Diverter System		1					1
Riser System			1				1

SOURCE: U.S. DOT, BTS, SafeOCS Program.

From 2017 to 2021, 48 different types of components failed during deployment or initial subsea testing. Table 13 lists the subset of component types that experienced at least five failures during these phases. For most of these components, redundancy can allow operations to continue without repair or the component can be repaired without retrieval. For some component types, such as regulators and choke and kill operator hardware, all events during these phases resulted in a BOP stack retrieval.

Table 13: Events During the Last Two Phases of Testing (by Component) 2017–2021

Component	Events during Deployment Testing			Events during Initial Subsea Testing			Total
	Operations Continued without Repair	Component Repaired (in situ)	Events Contributing to Stack Retrieval	Operations Continued without Repair	Component Repaired (in situ)	Events Contributing to Stack Retrieval	
SPM Valve	2	2	2	1	1	2	10
Ram Block Seal				3		6	9
Electrical Connector	2		5				7
Regulator			2			5	7
Choke and Kill Valve			2	2	1	2	7
Slide (Shear-Seal) Valve	1		2	1	2	1	7
Choke and Kill Operator Hardware			6				6
Locking Device					1	4	5
Piping/Tubing					2	3	5

NOTE: Components with fewer than five failures excluded.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Though most systems and components can be thoroughly tested prior to the last two testing phases, some systems and components can be only partially tested, as they are not physically connected to the system or exposed to the full effects of hydrostatic pressure until the BOP stack is latched to the wellhead. These include the riser system, telescopic joint, stack mounted electrical equipment, and the wellhead-connector-to-the-wellhead connection.[13] Only nine of the 138 events (6.5 percent) found during the last two phases of testing involved these systems: six failures of the stack mounted electrical equipment (three PBOF cables, two cables, and one electrical connector), one failure on the riser system, and two failures of the wellhead connector gasket. The remaining 129 events found during deployment and initial subsea testing involved components subject to thorough testing on deck before BOP stack deployment.

In-Operation Events Including BOP Stack Pulls

From 2017 to 2021, a total of 514 in-operation events were reported for subsea WCE systems, including 33 BOP stack pulls. An additional four BOP stack pulls were identified in WAR data. When adjusted for the level of activity, an average of 20.3 events occurred per thousand in-operation BOP days over the five-year period, reaching a low of 10.8 events per thousand in-operation BOP days in 2021.

Table 14 shows the equipment involved in events leading to subsea BOP stack pulls from 2017 to 2021, as well as the total number of in-operation events for those component combinations. Of the 21 different component types associated with subsea BOP stack pulls, piping/tubing (and its associated sub-components, which have no redundancy) has been associated with the most (six). SPM valves, annular packing elements, ram block seals, operating system seals, and flex loop/hose have each been associated with at least two BOP stack pulls since 2017. The remaining component types have been associated with one BOP stack pull each since 2017.

A component's location within the BOP system may influence the likelihood that an in-operation event results in a BOP stack pull. For example, of 19 in-operation SPM valve failures on the BOP controls subunit, only two led to a BOP stack pull (10.5 percent), compared to

[13] Stack mounted electrical equipment components include PBOF cables, pressure temperature sensors, electrical connectors, inclinometers, riser control boxes, cables, and pressure transducers.

two of three (66.7 percent) SPM valve failures on the BOP controls emergency automated functions subunit. Similarly, for ram block seals, two of 15 (13.3 percent) in-operation events on the pipe ram preventer led to a BOP stack pull, compared to the sole in-operation event resulting in a BOP stack pull for the ram block seal on the shear ram preventer.

External leaks were the most frequent failure type among BOP stack pull events, attributed to 54.1 percent from 2017 to 2021. Design issue was the most frequently reported root cause, cited for eight events. For nine events, no definitive root cause was listed.

In 2021, two subsea BOP stack pulls were reported to SafeOCS, and one additional BOP stack pull was identified in WAR data. The two BOP stack pulls reported to SafeOCS occurred on the BOP controls: one was an external leak on a cylinder, attributed to a design issue, and the second was due to mechanical damage on the MUX cable, attributed to high loop currents.[14] The BOP stack pull identified in WAR data was due a failure of the MPD integrated riser joint on the riser system.

[14] The root cause of the MUX cable event is categorized as "other."

Table 14: Component Combinations of Subsea BOP Stack Pulls, 2017–2021

Subunit	Item	Component	2017-2021 In-Operation Events	2017-2021 Stack Pulls
BOP Controls	BOP Control Pod	SPM Valve	19	2
		Piping/Tubing	6	2
		Interconnect Cable	3	1
		Cylinder	3	1
		Check Valve	2	1
		Gas Valve	1	1
	BOP Controls Stack Mounted	Piping/Tubing	4	2
		Shuttle Valve	6	1
		Electrical Connector	2	1
		Hose	13	1
	Reels Hoses Cables	MUX Cable	3	1
BOP Controls Emergency Automated Functions	Autoshear Deadman EHBS	Piping/Tubing	2	2
		SPM Valve	3	2
		Timing Circuit	1	1
BOP Stack	Annular Preventer	Packing Element	10	4
		Operating System Seal	5	2
	Pipe Ram Preventer	Ram Block Seal	15	2
		Bonnet Face Seal	1	1
	Shear Ram Preventer	Ram Block Seal	1	1
		Ram Block Hardware	1	1
		Bonnet Operating Seal	3	1
	Stack Choke and Kill System	Flex Loop/Hose	3	2
		Choke and Kill Valve	5	1
Riser System	Riser	Choke and Kill Line	1	1
	Integrated Riser Joint	Unknown	1	1
	Telescopic Joint	Packer	6	1
Total			**120**	**37**

NOTES:
- Each of the BOP stack pulls identified only in WAR are included in this table as both a BOP stack pull and an in-operation event.
- The component labeled unknown represents a BOP stack pull event identified in WAR data.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Investigation and Analysis

SafeOCS categorizes investigation and failure analysis (I&A) into three levels: cause immediately known (performed by the rig subsea engineer), subject matter expert (SME) review (performed by more than one subsea engineer), and root cause failure analysis (RCFA) (usually carried out by the OEM or a qualified third-party). For most events, the root cause is immediately known through visual inspection, and the component can be disposed of, repaired, or replaced. For the remaining events, further investigation is needed to determine the root cause.

Table 15 summarizes the findings for 15 I&As that included recommended preventive actions and were associated with 2021 events (each row may represent more than one I&A). The I&As include three at the RCFA level, two at the SME review level, and the remainder for events with immediately known causes. Most of the events represented in Table 15 occurred while not in operation (25 of 32 events in 2021). Each row also shows the total reported events from 2017 to 2021 associated with that component issue. Most of the I&As in 2021 were associated with a design issue.

Row 10 represents events associated with nickel leaching from the use of demineralized water in BOP control fluid systems. While nickel leaching events continued to be reported in 2021, the number of events related to the issue declined compared to 2020.

Table 15: Findings from I&As for Subsea System Events, 2021

	REPORTED ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED PREVENTIVE ACTION	TOTAL EVENTS SINCE 2017	2021 EVENTS
1	Design Issue	During testing on surface a design issue caused a subsea compensator to leak hydraulic flud externally.	Equipment owner replaced subsea compensator with a new style that has a metal cap.	12	1
2	Design Issue	A rolled o-ring caused an internal leak on the choke and kill valve operator piston seal.	OEM implemented the latest (T-seal) design.	7	2
3	Design Issue	Several failures of regulator stem orings due to water hammer effect.	Equipment owner to install a smaller orifice in the regulator control piping to reduce hydraulic surge.	3	2
4	Design Issue	The pressure port to a pressure transducer was found blocked, leading to erratic pressure readings.	OEM making modifications to remove the snubber and increase the cavity size.	1	1
5	Design Issue	Stress corrosion cracking caused cracked tie rod nuts on pod stack stinger energize cylinders.	The OEM will redesign with inconel, improve QA/QC, and update the torque specifications as needed.	1	1
6	Design Issue	Bolts backed off of the riser tension ring due to vibration in operation.	Equipment owner installed (anti-rotation) lock washers.	1	1
7	QA/QC Manufacturing	Ram failed to seal on the rig, but passed pressure testing at the shop. The OEM investigation discovered QA/QC issues, although the product had also passed fatigue testing.	The OEM is modifying the curing process for the packer seals to increase the cure time and the molding setpoint temperature.	2	2
8	Maintenance Error	A check valve leaked internally due to metal debris in the control system.	Equipment owner plans to flush the rigid conduits and change filters.	1	1
9	Maintenance Error	Bonnet o-ring clipped during door closure.	Equipment owner utilized a small amount of lubricant during assembly.	1	1
10	Procedural Error	Leaks of the shear-seal plates in pressure regulators, slide valves, and solenoid valves were reported as showing signs of nickel binder leaching. Nickel leaching is the result of the use of demineralized water in the BOP control fluid on Tungsten-Carbide seal plates that use a nickel binder.	Equipment owner to correct their mix water specification or install remineralizers to combat the issues with corrosion and binder leaching.	121	20

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Chapter 3: Surface WCE System Events

From 2017 to 2021, 337 surface WCE system events were reported to SafeOCS, averaging 67 events per year, as shown in Table 16. The number of events increased in 2021 compared to 2020, but surface system reporting generally follows a downward trend over the five-year period. Adjusting for well activity levels, the event rate declined 46.4 percent from 2017 to 2021.

Table 16: Surface System Numbers at a Glance, 2017–2021

MEASURE	2017	2018	2019	2020	2021	2017-2021 Total	2017-2021 Average
WELLS							
Wells with Activity	160	217	208	122	110	716	163.4
Wells Spudded	61	86	86	41	51	325	65
RIGS							
Rigs with Activity	28	28	34	24	16	40	26
Rigs with Reported Events	19	16	15	10	9	32	13.8
OPERATORS							
Active Operators	19	24	21	17	11	29	18.4
Reporting Operators	11	8	9	8	5	14	8.2
BOP DAYS							
Total BOP Days	5,172	6,938	7,107	3,962	3,773	26,952	5,390
Not-in-Operation BOP Days	1,557	1,871	1,864	1,225	915	7,432	1,486
In-Operation BOP Days	3,615	5,067	5,243	2,737	2,858	19,520	3,904
COMPONENT EVENTS							
Total Events Reported	115	69	87	21	45	337	67
Overall Event Rate	22.2	9.9	12.2	5.3	11.9	12.5	12.3
Not-in-Operation Events	57	34	43	12	17	163	32.6
Not-in-Operation Event Rate	36.6	18.2	23.1	9.8	18.6	21.9	21.2
Not-in-Operation Events per Well	0.4	0.2	0.2	0.1	0.2	0.2	0.2
In-Operation Events	58	35	44	9	28	174	35
In-Operation Event Rate	16.0	6.9	8.4	3.3	9.8	8.9	8.9
In-Operation Events per Well	0.4	0.2	0.2	0.1	0.3	0.2	0.2
BOP STACK MOVEMENTS							
Total Stack Starts	186	224	225	133	105	873	174.6
Successful Starts	170	217	199	112	95	793	158.6
Stack Pulls	10	10	36*	9*	16*	81	16
LOC EVENTS							
Loss of Containment Events	0	0	0	0	0	0	NA

KEY: In-operation Not-in-operation

NOTES:

- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–21 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

* Includes some BOP stack pulls identified in WAR. Table 2 provides counts. These are not included in *Total Events Reported*.

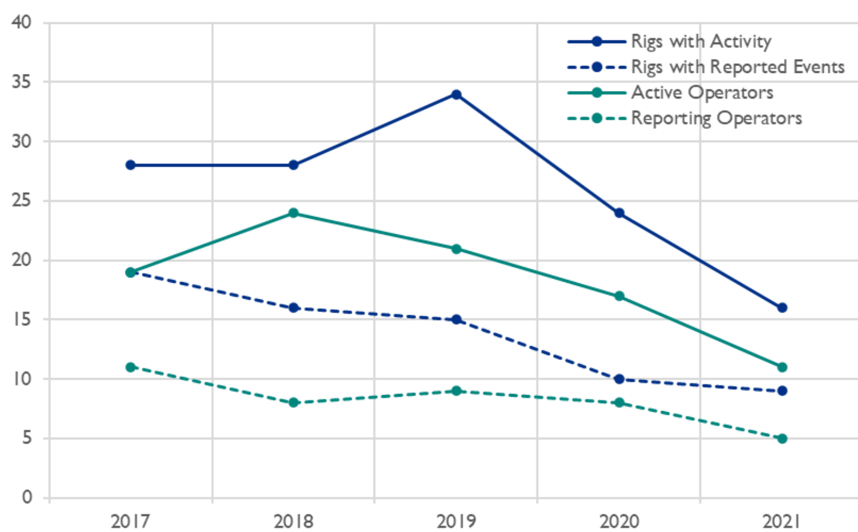
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Events were relatively evenly split between operational states during the five-year period, with 51.6 percent of surface system events detected while in operation and 48.4 percent while not in operation. Due to greater accessibility of equipment, components are often not changed out until an issue occurs, even if that is during operations. This results in a higher percentage of failures seen while in operation as compared to subsea systems. Overall, 81 BOP stack pulls were recorded from 2017 to 2021. About 10.2 percent of successful surface BOP stack starts—*meaning the BOP stack was assembled on the wellhead and went into operation*—eventually led to a BOP stack pull during the five-year period.

Event Reporting Levels

As shown in Figure 7, changes in the number of active operators and active rigs are generally greater from year to year than corresponding changes to the number of reporting operators and rigs with reported events. The direction of change from year to year is mostly consistent between active and reporting operators and rigs, except for differing directions of change from 2017 to 2018 for operators and 2018 to 2019 for rigs. This suggests that other factors in addition to activity levels may contribute to changes in event reporting.

Figure 7: Reporting and Activity Levels for Surface Systems, 2017–2021



SOURCE: U.S. DOT, BTS, SafeOCS Program.

Frequently Reported Components

From 2017 to 2021, 48 different components were reported as having failed on surface WCE systems. As shown in Table 17, the most frequently reported for not-in-operation events were accumulators, ram block seals, regulators, choke and kill valves, gate valve hardware, annular packing elements, and bonnet face seals, each contributing at least 5.0 percent of events and together comprising 60.7 percent of all surface system events.

Table 17: Frequently Reported Components for Not-in-Operation Surface Systems, 2017–2021

Component	2017 (n=57)	2018 (n=34)	2019 (n=43)	2020 (n=12)	2021 (n=17)	Total (n=163)
Accumulator	5.3%	14.7%	25.6%	8.3%	5.9%	12.9%
Ram Block Seal	10.5%	14.7%	7.0%	0.0%	29.4%	11.7%
Regulator	1.8%	2.9%	7.0%	33.3%	23.5%	8.0%
Choke and Kill Valve	14.0%	2.9%	9.3%	0.0%	0.0%	8.0%
Gate Valve Hardware	14.0%	8.8%	2.3%	0.0%	0.0%	7.4%
Packing Element	5.3%	11.8%	4.7%	8.3%	5.9%	6.7%
Bonnet Face Seal	7.0%	2.9%	7.0%	0.0%	11.8%	6.1%

KEY: Not-in-operation
NOTE: Includes components representing at least 5.0 percent of events.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

For in-operation events, as shown in Table 18, hardware and inside BOPs are added as most frequently reported components, and bonnet face seals and gate valve hardware are dropped. Each of the components listed in Table 18 contributed at least 5.0 percent of in-operation events and together they comprise 59.2 percent.

Table 18: Frequently Reported Components for In-Operation Surface Systems, 2017–2021

Component	2017 (n=58)	2018 (n=35)	2019 (n=44)	2020 (n=9)	2021 (n=28)	Total (n=174)
Packing Element	10.3%	25.7%	18.2%	11.1%	10.7%	15.5%
Hardware	22.4%	8.6%	2.3%	0.0%	10.7%	11.5%
Choke and Kill Valve	12.1%	8.6%	0.0%	0.0%	14.3%	8.0%
Ram Block Seal	6.9%	2.9%	6.8%	0.0%	10.7%	6.3%
Inside BOP	1.7%	2.9%	9.1%	0.0%	17.9%	6.3%
Accumulator	12.1%	5.7%	4.5%	0.0%	0.0%	6.3%
Regulator	3.4%	2.9%	9.1%	0.0%	7.1%	5.2%

KEY: In-operation
NOTE: Includes components representing at least 5.0 percent of events.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

For annular packing elements, ram block seals, and choke and kill valves, most of the events occurred on the BOP stack. For accumulators and regulators, most events occurred on the BOP controls, and for hardware and gate valve hardware, most events occurred on the choke manifold system. The following provides a brief discussion of selected components:

- *Annular packing elements and ram block seals:* The frequency of failure for these component types may be partially explained by the fact they are consumable seal types which are easily accessible even during operations. Therefore, they are often run until they do not pass a test, rather than being more proactively replaced.
- *Accumulators:* Accumulators on surface systems are located on deck where they are easily accessible and, similar to subsea systems, regulation requires that they are arranged in banks where no one bank can contain more than 25.0 percent of the total accumulator system capacity.[15] This allows for one bank of accumulators at a time to be isolated for maintenance. Accumulator bladders can therefore be run to failure and replaced individually as required without risk to the system.

Failure Types

Similar to subsea systems, most events from 2017 to 2021 on surface systems were a type of leak, comprising 81.6 percent of events (see Table 19). However, in contrast to subsea systems, internal leaks were more common than external leaks on surface systems over the five-year period. This is due to the disparity in population and nature of the components, as the control valves used on surface systems are closed-hydraulic, whereas those on subsea systems are vent-to-atmosphere.

Table 19: Failure Types of Surface System Events, 2017–2021

FAILURE TYPE	2017 (n=115)	2018 (n=69)	2019 (n=87)	2020 (n=21)	2021 (n=45)	Total (n=337)
LEAKS						
External Leak	27.8%	34.8%	40.2%	61.9%	24.4%	34.1%
Internal Leak	52.2%	49.3%	40.2%	14.3%	62.2%	47.5%
OTHER						
Communication / Signal Issue	0.0%	2.9%	4.6%	0.0%	0.0%	1.8%
Electrical Issue	0.0%	2.9%	0.0%	4.8%	0.0%	0.9%
Fail to Function on Command	2.6%	2.9%	3.4%	4.8%	2.2%	3.0%
Inaccurate Indication	0.0%	0.0%	1.1%	0.0%	0.0%	0.3%
Mechanical Issue	14.8%	2.9%	5.7%	9.5%	4.4%	8.3%
Process Issue	2.6%	4.3%	4.6%	0.0%	2.2%	3.3%
Unintended Operation	0.0%	0.0%	0.0%	4.8%	0.0%	0.3%
Other	0.0%	0.0%	0.0%	0.0%	4.4%	0.6%

SOURCE: U.S. DOT, BTS, SafeOCS Program.

[15] API Standard 53 (4th ed.), incorporated by reference at 30 CFR 250.198.

Component types with the most internal leaks from 2017 to 2021 include annular packing elements, ram block seals, and gate valve hardware. Component types with the most external leaks include accumulators, bonnet face seals, regulators, and bonnet operating seals. For choke and kill valves, the most frequent failure types are both internal and external leaks, and for hardware, the most frequent failure types are internal leaks and mechanical issues.

Detection Methods

Most surface system events from 2017 to 2021 (50.1 percent) were detected through pressure testing (see Table 20), with a similar distribution of detection methods between in-operation and not-in-operation events. For the most frequently reported components, most events were found through pressure testing, apart from accumulators and regulators, which were identified most frequently through casual observation and inspection.

Table 20: Detection Methods for Surface System Events, 2017–2021

	DETECTION METHOD	2017 (n=115)	2018 (n=69)	2019 (n=87)	2020 (n=21)	2021 (n=45)	Total (n=337)
	Casual Observation	13.9%	7.2%	8.0%	33.3%	13.3%	12.2%
	Continuous Condition Monitoring	11.3%	5.8%	3.4%	4.8%	6.7%	7.1%
	On Demand	1.7%	0.0%	0.0%	0.0%	4.4%	1.2%
	Periodic Condition Monitoring	1.7%	0.0%	1.1%	4.8%	0.0%	1.2%
MIT	Corrective Maintenance	0.0%	0.0%	5.7%	0.0%	0.0%	1.5%
	Periodic Maintenance	0.0%	0.0%	4.6%	9.5%	0.0%	1.8%
	Inspection	4.3%	7.2%	17.2%	9.5%	8.9%	9.2%
	Function Testing	13.0%	15.9%	14.9%	23.8%	20.0%	15.7%
	Pressure Testing	53.9%	63.8%	44.8%	14.3%	46.7%	50.1%

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Root Causes of Events

As with subsea systems, most surface system events from 2017 to 2021 (57.3 percent) were attributed to wear and tear. As shown in Table 21, the percentage of surface system events attributed to wear and tear increased in more recent years. Detailed review of notifications indicates that, similar to subsea events, the submitted information does not always provide adequate support for a root cause of wear and tear. Additionally, it may be difficult to know the details of wear and tear cases on surface systems, as WCE components such as annular preventers are often sent to shore for major maintenance.

Table 21: Root Causes of Surface System Events, 2017–2021

REPORTED ROOT CAUSE	2017 (n=115)	2018 (n=69)	2019 (n=87)	2020 (n=21)	2021 (n=45)	Total (n=337)
Design Issue	3.5%	7.2%	2.3%	0.0%	0.0%	3.3%
QA/QC Manufacturing	3.5%	4.3%	5.7%	0.0%	6.7%	4.5%
Maintenance Error	2.6%	7.2%	13.8%	0.0%	0.0%	5.9%
Procedural Error	1.7%	1.4%	3.4%	0.0%	2.2%	2.1%
Wear and Tear	47.0%	58.0%	48.3%	90.5%	84.4%	57.3%
Other	7.0%	2.9%	11.5%	9.5%	0.0%	6.5%
NOT DETERMINED						
Inconclusive	0.9%	1.4%	2.3%	0.0%	0.0%	1.2%
Assessment Pending	5.2%	8.7%	2.3%	0.0%	2.2%	4.5%
Not Reported	28.7%	8.7%	10.3%	0.0%	4.4%	14.8%

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Wear and tear was also the top root cause for failures of frequently reported components from 2017 to 2021, shown in Table 22. In addition to wear and tear, commonly reported root causes for component events include maintenance error for accumulators and design issue for ram block seals. As with subsea, supporting information for failures attributed to design issue has been infrequent.

Table 22: Root Causes of Frequently Reported Components for Surface Systems, 2017–2021

REPORTED ROOT CAUSE	Packing Element	Accumulator	Ram Block Seal	Choke and Kill Valve	Regulator	Hardware	Gate Valve Hardware
Design Issue	5.3%	3.1%	10.0%	0.0%	4.5%	0.0%	0.0%
QA/QC Manufacturing	2.6%	6.3%	0.0%	0.0%	4.5%	0.0%	0.0%
Maintenance Error	2.6%	28.1%	3.3%	7.4%	4.5%	0.0%	5.9%
Procedural Error	0.0%	0.0%	3.3%	0.0%	0.0%	0.0%	0.0%
Wear and Tear	71.1%	46.9%	66.7%	44.4%	72.7%	95.5%	0.0%
Other	2.6%	0.0%	0.0%	7.4%	0.0%	0.0%	29.4%
NOT DETERMINED							
Inconclusive	0.0%	0.0%	0.0%	3.7%	4.5%	0.0%	5.9%
Assessment Pending	0.0%	3.1%	13.3%	0.0%	0.0%	4.5%	0.0%
Not Reported	15.8%	12.5%	3.3%	37.0%	9.1%	0.0%	58.8%

SOURCE: U.S. DOT, BTS, SafeOCS Program.

In-Operation Events Including BOP Stack Pulls

From 2017 to 2021, a total of 174 in-operation events were reported for surface WCE systems, including 53 BOP stack pulls. An additional 28 BOP stack pulls were identified in WAR data. When adjusted for the level of activity, an average of 8.9 events occurred per thousand in-operation BOP days over the five-year period.

Table 23 shows the equipment involved in events leading to surface BOP stack pulls from 2017 to 2021, as well as the total number of in-operation events for those component combinations. Of the 13 different component types associated with surface BOP stack pulls, annular packing elements have been associated with the most (42), followed by ram block seals (13), operating system seals (seven), and bonnet face seals and bonnet operating seals (four each). The similarities in the numbers of total in-operation events as compared to BOP stack pulls for many component combinations means that the failed component had no redundancy and therefore needed to be repaired or replaced.

Each of the events involving annular packing elements failing to hold pressure (i.e., an internal leak) was observed during a periodic BOP stack test designed to confirm the BOP equipment's integrity. The data suggests that surface system operators often replace annular packing elements only after they have failed a pressure test. This is typical practice for surface systems where there is easier access to equipment even while in operation.

Table 23: Component Combinations of Surface BOP Stack Pulls, 2017–2021

Subunit	Item	Component	2017-2021	
			In-Operation Events	Stack Pulls
BOP Controls	BOP Control Panel	Central Control Console	3	1
		Instrumentation	2	1
	HPU Mix System	Regulator	1	1
		Selector Manipulator Valve	5	2
	Surface Control System	Regulator	8	2
BOP Stack	Annular Preventer	Hardware_all other Mechanical Elements	1	1
		Operating System Seal	8	7
		Packing Element	46	42
	Pipe Ram Preventer	Bonnet Face Seal	3	1
		Bonnet Operating Seal	1	1
		Bonnet Seal	1	1
		Ram Block Seal	6	5
	Shear Ram Preventer	Bonnet Face Seal	3	3
		Bonnet Operating Seal	4	3
		Ram Block Seal	8	8
		Unknown	1	1
Riser System	Riser	Flange	1	1
Total			**102**	**81**

NOTES:
- Each of the BOP stack pulls identified only in WAR are included in this table as both a BOP stack pull and an in-operation event.
- The component labeled unknown represents a BOP stack pull event identified in WAR data.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

From 2017 to 2021, 65 BOP stack pulls involved a type of leak, including 27 of the 28 identified in WAR data. For the 53 BOP stack pulls reported to SafeOCS from 2017 to 2021, 33 cited a root cause of wear and tear. Of the remaining 20, half either did not cite a root cause or selected "other" and offered a description such as "damage from ram block" or "bad element." The remaining 10 listed a variety of root causes such as QA/QC manufacturing or design issue. For the BOP stack pulls identified in WAR data, there is typically insufficient detail available to discern the root cause.

In 2021, ten surface BOP stack pulls were reported to SafeOCS and an additional six BOP stack pulls were identified in WAR data. All but one BOP stack pull resulted from a failure involving the BOP stack, including 11 failures of annular packing elements or operating system seals on the annular preventer, three failures of bonnet operating seals or ram block seals on the pipe ram preventer, and one failure of a ram block seal on the shear ram preventer. The remaining BOP stack pull involved the failure of a riser flange. Most of these failures involved leaks.

Investigation and Analysis

I&A information was received for 10 of the 45 surface system events in 2021. The I&As included one at the RCFA level, one at the SME review level, and eight for events with immediately known causes. Table 24 summarizes the findings for the one I&A (at the RCFA level) that included recommended preventive actions. While the reported root cause for the event was wear and tear, design-related causal factors are indicated based on the information included in the notification as well as the follow-up action recommended by the OEM.

Table 24: Findings from I&As for Surface System Events, 2021

REPORTED ROOT CAUSE	ROOT CAUSE DETAILS	RECOMMENDED PREVENTIVE ACTION	TOTAL EVENTS SINCE 2017	2021 EVENTS
Wear and Tear	Seven months after the last seal replacement, the OEM found that swarf (metal debris) wedged between the annular preventer adapter ring and the piston caused abrasive wear and internal leakage.	The OEM recommends purchasing a modified adaptor ring and an additional seal designed to prevent contaminants from getting between the components.	1	1

SOURCE: U.S. DOT, BTS, SafeOCS Program.

Chapter 4: The State of WCE Event Statistics

The close of 2021 marked the fifth full year of the SafeOCS WCE program. Over these five years, the offshore oil and gas industry has contributed more than 4,600 reported events to the SafeOCS WCE database. Several program milestones have passed, such as the establishment of the secure e-submit web portal for event reporting in the program's first year, release of the SafeOCS WCE online data dashboard in 2020, and publication of annual reports and guidance documents through the years. SafeOCS has maintained a partnership with the BOP Reliability JIP and established a small cadre of SafeOCS subject matter experts to help evaluate and interpret the highly technical event reports and well activity reports. Open lines of communication have been maintained with operators and other program stakeholders.

Entering the next five years, the SafeOCS WCE program will focus on improving the data collection instrument to enhance data quality and reduce reporting burden. Efforts to standardize definitions, such as the definition of a surface BOP stack pull, will continue. The program will also consider ways to expand the information collected for areas of interest—such as contributing factors, workover and intervention events, component design life, and component part numbers and revision levels—to improve understanding of safety events and provide more actionable information to industry to drive safety improvements.

Moving forward, the SafeOCS WCE program will continue to prioritize the collection of complete and accurate data on failures of critical safety equipment used in well operations on the OCS and the sharing of aggregated data and information with potential learning value. On data sharing, BTS will evaluate the feasibility of expanding the use of dashboards as a means of timely dissemination of emerging safety trends.

APPENDIX A: REGULATORY REPORTING REQUIREMENT

The failure reporting requirement is codified in 30 CFR 250.730(c) of BSEE's well control rule, which went into effect on July 28, 2016. In 2019, BSEE revised the reporting rule to clarify that event notifications and reports must be sent to BTS as BSEE's designated third party.[16] The rule follows ("you" refers to lessees and designated operators):

> (c) You must follow the failure reporting procedures contained in API Standard 53, (incorporated by reference in §250.198), and:
>
>> (1) You must provide a written notice of equipment failure to the Chief, Office of Offshore Regulatory Programs (OORP), unless BSEE has designated a third party as provided in paragraph (c)(4) of this section, and the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification.
>>
>> (2) You must ensure that an investigation and a failure analysis are started within 120 days of the failure to determine the cause and are completed within 120 days upon starting the investigation and failure analysis. You must also ensure that the results and any corrective action are documented. You must ensure that the analysis report is submitted to the Chief OORP, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section, as well as the manufacturer. If you cannot complete the investigation and analysis within the specified time, you must submit an extension request detailing how you will complete the investigation and analysis to BSEE for approval. You must submit the extension request to the Chief, OORP.
>>
>> (3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures

[16] 84 Fed. Reg. 21,908 (May 15, 2019).

as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to the Chief OORP, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section.

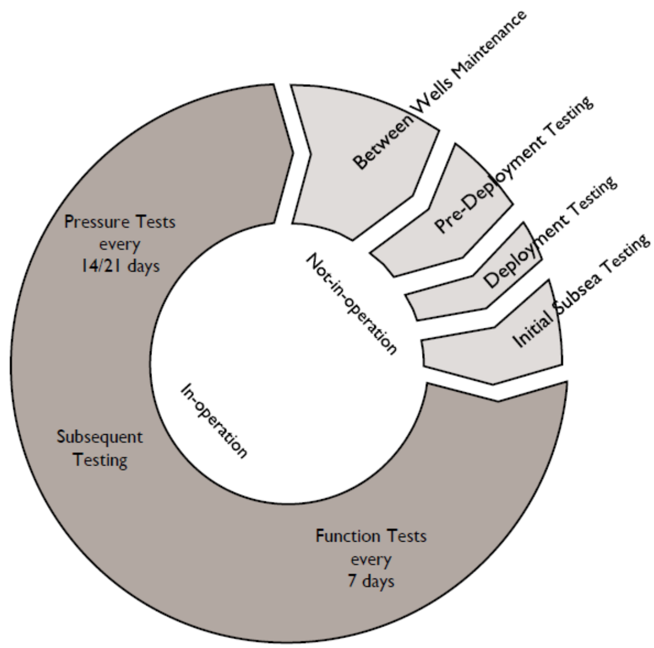
(4) Submit notices and reports to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166. BSEE may designate a third party to receive the data and reports on behalf of BSEE. If BSEE designates a third party, you must submit the data and reports to the designated third party.

Appendix B: Operational States of WCE Systems

This appendix separates events into two states, where applicable, based on when the event occurred: *in operation* or *not in operation*. This section provides an overview of these states and the various phases within them to provide additional context for failure events. Figure 8 provides a visual representation for subsea WCE systems.

An event is classified as not in operation if it occurred or was discovered during maintenance, inspection, and testing (MIT) or other preparatory work, and in operation if it occurred or was discovered after the equipment had been successfully tested and put into service. All WCE needs to be reliably available while in operation; to meet this requirement, systems are often designed with redundant components or subsystems.

Figure 8: The Cycle of Maintenance, Inspection, and Testing



KEY: In-operation Not-in-operation
NOTE: The figure illustrates the cyclical MIT regime practiced on subsea WCE systems, scaled to show the approximate time split for an average new well.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

It is important to recognize that WCE systems provide secondary well control; the primary well control is fluid management or ensuring that the hydrostatic pressure of the mud in the well is always at least equal to formation pressure. On many wells, the only time that the well control equipment is ever used is when it is being tested. Ensuring that equipment is readily available and correctly functions when needed during operations involves a detailed and cyclical MIT regime, which mainly occurs while the BOP stack is not in operation. BSEE regulations modify MIT requirements, including those of

API Standard 53.[17] The remainder of this section includes a discussion of time-based versus condition-based maintenance practices, followed by more detail about each phase of MIT.

Condition-Based Maintenance

An alternative to time-based maintenance schedules is condition- or performance-based maintenance. Instead of components having fixed maintenance periods, such as between wells, annually, or every 30 months, equipment owners utilize condition monitoring data to determine when maintenance is required. Developments in recent years have enhanced the instrumentation of WCE systems, particularly in the BOP control systems, facilitating the collection and monitoring of condition data. An example of condition-based maintenance is signature testing, where pressure and current requirements for various systems are accurately measured when new, and then subsequent measurements of those components are compared to determine when maintenance is required.

Certain component types, sometimes referred to as consumables, have typically followed condition-based maintenance. The life expectancy of a ram packer or annual packer, for example, which creates a hydraulic seal around the pipe or annulus, is difficult to forecast due to the changes in the operational environment during use. A visual inspection determines whether the component is replaced, regardless of time in use, other than upon failure. Fixed maintenance periods can result in invasive maintenance practices for some component types. For example, seals are to be replaced every time they are exposed, which may introduce the potential for maintenance errors.

MIT for Subsea WCE Systems

MIT While Not in Operation

Any events that occur during the following four phases can be resolved before the BOP goes into operation, decreasing the likelihood of an event with safety or environmental consequences.

[17] 30 CFR 250.737, 250.739.

- **Between Wells Maintenance (BWM):** This is the period between one well construction finishing and the next well construction starting. As the BOP stack is being recovered from the well, MIT commences on the equipment as it becomes accessible (e.g., telescopic joint, riser, choke manifold, surface mounted control equipment). When the BOP stack is safely on deck, BWM procedures and usually some other periodic maintenance, such as annual and five-yearly procedures, are carried out. During the scheduled BWM periods, all efforts are focused on finding and resolving any potential issues before the next well construction begins. This detailed attention to components results in the most not-in-operation event notifications compared to other MIT phases.

- **Pre-Deployment Testing:** This is the minimum required testing that must be carried out before the WCE systems can be deployed subsea. It takes place on the rig before the BOP stack is lowered into the water. Pre-deployment testing includes operating every BOP stack function from every control panel and through each control pod. It also includes pressure testing every barrier to a pressure higher than it may see on the upcoming well. Although the API S53 pre-deployment testing is typically completed with the BOP stack on the test stump in the set-back area, events discovered while moving the BOP stack to the moonpool are also categorized as occurring during this phase.

- **Deployment Testing:** Pressure tests of the choke and kill lines, which provide fluid pressure control and allow drilling or wellbore fluids to be evacuated from the well safely if needed, are carried out during BOP stack deployment. The choke and kill lines form a circuit between the BOP stack and the choke manifold and can only be tested when they are all properly connected. Control system pressures, temperatures, currents, angles, and other data received from the control pods are continuously monitored, even during this phase. Additional detail is provided in the discussion of the riser system in the SafeOCS supplement, *WCE Subunit Boundaries*, published separately.

- **Initial Subsea Testing:** This is the first time on a well that the complete system, including the wellhead connection, is pressure and function tested. These tests must be carried out before any well operations take place. If any issues are detected, the wellhead connector can be unlatched from the wellhead to retrieve the BOP stack to the surface for resolution before the commencement of operations.

MIT During Operations: Subsequent Testing

Subsequent testing regimes take place while the BOP stack is in operation. Every seven days,[18] all the non-latching equipment[19] is function tested; all rams, annulars, and valves are closed and opened to confirm that they can operate if required. Every 14 days,[20] all pipe rams, annulars, valves, and the choke manifold are pressure tested. Every 21 days, the acoustic batteries are checked,[21] and the shear rams are pressure-tested.[22] Suppose the BOP stack remains subsea for long periods. In that case, every 90 days, the high-pressure shear circuit(s) are tested. Every 180 days, the accumulators (both surface and subsea) are subjected to drawdown tests to confirm that the required volumes of pressurized BOP control fluid are available.[23] If the BOP stack is not subsea long enough for these tests to become due, then the pre-deployment testing for the next well will include them.

MIT for Surface WCE Systems

As with subsea WCE systems, an event is classified as not in operation if it occurred or was discovered during MIT or other preparatory work, and in operation if it occurred or was discovered after the equipment had been successfully tested and put into service. A surface WCE system is in operation once the BOP stack has been assembled on the wellhead and all the initial testing has been completed.

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[18] 30 CFR 250.737 and API Standard 53 (4th ed.) section 7.6.5.1.1.

[19] Latching equipment, e.g., the wellhead, LMRP, and choke/kill connectors, includes the remotely operated components that cannot be tested after the initial subsea testing without compromise. Non-latching equipment is all other WCE.

[20] 30 CFR 250.737(a)(2). Some operators may utilize a 21-day test frequency if approved by BSEE. 30 CFR 250.737(a)(4).

[21] API Standard 53 (4th ed.) table 7.

[22] Shear rams are pressure tested at least every 30 days per 30 CFR 250.737(a)(2). Operators may also follow the more frequent 21-day testing per API Standard 53 (4th ed.) table 10.

[23] API Standard 53 (4th ed.) table 7.

MIT While Not in Operation

Many surface BOPs are rented and maintained by third parties or maintained by the equipment owner at shore bases. When the well operation ends, and BWM is required, the equipment is often sent to shore for maintenance and exchange. Importantly, failure events identified onshore by third parties while the equipment is not under contract to the operator may be less likely to be reported to SafeOCS.

Since WCE on surface system rigs is accessible on deck throughout operations, and there are fewer components, the MIT conducted during BWM and before beginning operations is less intensive than for subsea WCE systems. Before beginning operations, pressure testing takes place for the rams, annulars, and valves. Initial testing is also conducted before any well operations take place.

MIT During Operations: Subsequent Testing

The basic subsequent testing regime for surface systems is similar to that of subsea systems.

APPENDIX C: GLOSSARY

Abandonment: Abandonment is a temporary or permanent subsurface isolation to prevent undesired communication between distinct zones and fluid movement out of a well using validated well barriers.

Active Operators: Operators who conducted well operations (drilling or non-drilling) in the GOM OCS during the listed period.

Annular Preventer: A toroidal shaped device that can seal around any object in the wellbore or upon itself.

Blind Shear Ram: A closing and sealing component in a ram blowout preventer that can shear certain tubulars in the wellbore, or close on an empty wellbore, and then seal off the bore.

Blowout: An uncontrolled flow of well fluids and/or formation fluids from the wellbore to surface or into lower pressured subsurface zones, per API Standard 53. A well can experience a blowout when the formation's pressure is higher than the fluid's hydrostatic pressure.

Blowout Preventer (BOP): A ram or annular device designed to contain wellbore pressure in the well.

BOP Control Fluid: A term commonly used for both the diluted biodegradable water-based fluid or the hydraulic oil used to pilot or power the WCE on BOP stacks.

BOP Control Pod: An assembly of subsea valves and regulators hydraulically or electrically operated which will direct hydraulic fluid through special porting to operate BOP equipment.

BOP Control System: The collection of pumps, valves, accumulators, fluid storage and mixing equipment, manifold, piping, hoses, control panels, and other API Specification 16D items necessary to operate the BOP equipment.

BOP Days: The number of days during which some or all the WCE components may have been in use and had any likelihood of a failure.

BOP Stack: An assembly of annular and ram type preventers, together with choke and kill valves, installed on top of the wellhead during well construction activities.

Casing Shear Ram: A closing component in a ram blowout preventer that is capable of shearing or cutting certain tubulars in the wellbore.

Choke and Kill Lines: High pressure pipes connecting the side outlet valves on the BOP stack to the choke manifold to allow controlled flow in and out of a closed BOP stack.

Consumables: For purposes of this report, consumables may include seals and other components that have an indeterminable expected life because of variables in the operating conditions.

Decommissioning: See Abandonment.

Drilling: The perforation of the earth's surface by mechanical means. It includes all operations for preventing the collapse of the sides of the hole, or for preventing the hole from being filled with extraneous materials including water.

Drilling Fluid: The fluid added to the wellbore to facilitate the drilling process and control the well.

Drilling Rig: A mobile structure housing the integrated system for drilling wells. Offshore drilling rigs are either floating (e.g., a drillship or semi-submersible) or bottom supported (e.g., a jack-up or rig unit on a production platform). Floating rigs typically use subsea WCE systems, and bottom supported rigs tend to use surface WCE systems.

Event Rate: The event rate reflects the number of reported events per 1,000 BOP days. The not-in-operation event rate considers only in-operation BOP days, and the in-operation event rate considers only in-operation BOP days. The event rate is calculated as: events / BOP days × 1,000.

In-Operation (Subsea System): A subsea BOP stack is in operation after it has completed a successful initial subsea pressure test per API Standard 53.

In-Operation (Surface System): A surface BOP stack is in operation after it has completed a successful pressure test of the wellhead connection to the wellbore per API Standard 53.

Integrated Riser Joint: A Managed Pressure Drilling (MPD) riser joint that has an annular preventer, choke and kill valves and a bearing assembly incorporated.

Intervention: A workover operation in which a well is re-entered for a purpose other than to continue drilling or to maintain or repair it.

Loss of Containment: An external leak of wellbore fluids outside of the pressure containing equipment boundary.

Managed Pressure Drilling: A method of drilling where the well bore circulation system is contained in a closed-loop allowing pore-pressure, formation fracture pressure, and bottom hole pressure to be balanced and managed at surface.

Mechanical Barrier: Subset of physical barriers that feature engineered, manufactured equipment. Does not include set cement or a hydrostatic fluid column. Examples include permanent or retrievable bridge plugs, downhole packers, wellhead hanger seals, and liner hanger seals.

Multiplex Control System (MUX): A microprocessor-based BOP control system used predominantly in deep water that sends multiple coded signals to and from the control pods through a single cable to overcome the time requirements of the hydraulic control systems used in shallow water.

Non-Drilling Operations: Well operations including, for example, intervention, workover, temporary abandonment, and permanent abandonment.

Not-In-Operation (Subsea System): The BOP stack is not in operation when it is being maintained, inspected, and tested in preparation for use. The BOP stack changes from in operation to not in operation when either the BOP is removed from the wellhead or the LMRP is removed from the lower BOP stack. When the BOP stack is on deck or is being run, pulled, or retrieved, it is considered not in operation.

Not-In-Operation (Surface System): The BOP stack is not in operation when it is being maintained, inspected, and tested in preparation for use. A surface BOP stack changes from in operation to not in operation when the external barrier is intentionally disabled for repair/replacement, or at the end of the well.

Pipe Ram Preventer: A device that can seal around the outside diameter of a pipe or tubular in the wellbore. These can be sized for a range of pipe sizes (variable pipe ram) or a specific pipe size.

Pre-Spud Operations: The period preceding the start of drilling activities.

Remotely Operated Vehicle (ROV): An unmanned underwater robot connected to the rig by a control cable which transmits commands to the robot and video signals to the rig. The ROV is used to observe the underwater equipment and to carry out some rudimentary operations when commanded by the pilot.

Rig: See Drilling Rig.

Rigs with Activity: This includes all rigs which had both a contract and permit to perform drilling and non-drilling activities on the OCS during the referenced period.

Root Cause: The cause (condition or action) that begins a cause/effect chain and ends in the equipment component failure. If eliminated, it would prevent the reoccurrence of the event (under investigation) and similar occurrences.

Shear Ram: See Blind Shear Ram or Casing Shear Ram.

Stack Pull (Subsea System): When either the BOP is removed from the wellhead or the LMRP is removed from the lower BOP stack and recovered to the rig to repair a failed component. An event cannot be classified as a BOP stack pull until after the BOP stack is in operation (see Stack Retrieval).

Stack Pull (Surface System): When a BOP component fails during operations and requires well conditioning and a mechanical barrier placement to make necessary repairs.

Stack Retrieval: The recovery of the LMRP or the BOP stack before it is in operation. If the LMRP or BOP stack is recovered to the rig any time after deployment has begun and before initial latch-up tests are passed, it is considered a BOP stack retrieval.

Stack Run: The activity of deploying a subsea BOP stack from the rig to the subsea wellhead.

Stack Start: In this report, BOP stack start means when a surface BOP stack is assembled on the wellhead.

Subunit: See Well Control Equipment Subunits.

Well Construction: A set of operations, including drilling, that create the hole and provide the barriers to fluid migration in the form of surface, intermediate and production casings, tubing, and packers installed in the well above the completion interval. This work is directed by the lease operator employing the drilling contractor and third-party services equipment and personnel.

Well Control Equipment: Systems and subsystems that are used to control pressure within the wellbore, per API Standard 53.

Well Control Equipment Subunit: Well control equipment components are categorized according to the following subunits: auxiliary equipment, BOP control systems (primary, secondary, and emergency), BOP stack system, choke manifold system, diverter system, and riser system.

Wellbore Fluid: The oil or gas diluted fluids, commonly referred to as hydrocarbons, from a reservoir that would typically be found in an oil or gas well.

Wells Spudded: The number of wells that were started, or "spudded," during the listed period. Wells spudded are a subset of total wells with activity.

Wells with Activity: The number of wells worked on by rigs, regardless of the well operation, during the referenced period.

Workover: An operation on a completed well intended to maintain or increase production but is not routine maintenance.

Detection Method Terms

Casual Observation: An unplanned or non-routine observation. This could be a simple walk by the component.

Continuous Condition Monitoring: Monitoring involving the use of intelligent instrumentation with alarms and recording devices.

Corrective Maintenance: Unscheduled maintenance or repairs.

Function Test: The operation of equipment to confirm that it does what it is expected to do.

Inspection: Company-conducted inspection, which may consist of visual or other examination.

On-demand: Inability to function when required.

Periodic Condition Monitoring: Regular checks.

Periodic Maintenance: Planned, scheduled maintenance routine.

Pressure Test: The application of pressure to a piece of equipment or a system to verify its pressure containment capability.

APPENDIX D: ACRONYMS

ANSI: American National Standards Institute

API: American Petroleum Institute

BOP: Blowout preventer

BSEE: Bureau of Safety and Environmental Enforcement

BSR: Blind shear ram

BTS: Bureau of Transportation Statistics

CFR: Code of Federal Regulations

C/K: Choke/kill

CIPSEA: Confidential Information Protection and Statistical Efficiency Act

D&I: Disassembly and inspection

DOI: Department of the Interior

DOT: Department of Transportation

EHBS: Emergency hydraulic backup system

GOM: Gulf of Mexico

HPU: Hydraulic power unit

IADC: International Association of Drilling Contractors

IOGP: International Association of Oil and Gas Producers

I&A: Investigation and failure analysis

IRJ: Integrated riser joint

JIP: Joint industry project

LMRP: Lower marine riser package

LOC: Loss of containment

MASP: Maximum anticipated surface pressure

MGS: Mud-gas separator

MIT: Maintenance, inspection, and testing

MPD: Managed pressure drilling

MUX: Multiplex control system

OCS: Outer Continental Shelf

OEM: Original equipment manufacturer

PBOF: Pressure balanced, oil-filled

QA/QC: Quality assurance/quality control

RCFA: Root cause failure analysis

ROV: Remotely operated vehicle

SD: Standard deviation

SME: Subject matter expert

SPM: Sub-plate mounted

WAR: Well activity report (per 30 CFR 250.743)

WCE: Well control equipment

WCR: Well Control Rule