WELL CONTROL EQUIPMENT SYSTEMS SAFETY

2023 Annual Report

U.S. Department of Transportation
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Acknowledgements

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Executive Summary

The *Well Control Equipment Systems Safety – 2023 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 2023. This report is based on information collected through SafeOCS, a confidential reporting program for the collection and analysis of data to advance safety in offshore energy operations. Where possible, the report describes details about the failure events, including circumstances present when the event occurred as well as reported preventive actions aimed at reducing the likelihood of future failures.

In 2023, SafeOCS received reports for 337 events, the fewest in any year since reporting began and less than half the yearly average of 795 events from 2017 to 2023. With well activity at the highest annual level (as measured in BOP days), the event rate of 20.6 events per 1,000 BOP days in 2023 represents improved performance overall. Subsea well activity has largely driven this change, with subsea BOP days at the highest annual total and subsea events at the lowest since 2017. Approximately 23 events were reported per 1,000 BOP days in 2023, compared to 43 in 2022. In contrast, surface BOP days were at the lowest annual total since 2017, and surface events have remained relatively stable since 2021. One reported event in 2023 resulted in 48 barrels of completion fluids being released to the sea, the second reported loss of containment event since 2017.

Subsea WCE System Events

In 2023, 83.4 percent of failure events were subsea WCE system events, and subsea BOP days represented 76.5 percent of total BOP days. Since 2017, control components such as regulators, solenoid valves, SPM valves, slide (shear-seal) valves, and shuttle valves were among the most frequently reported components, each representing at least 5.0 percent of all subsea system failures. Regulators, SPM valves, and shuttle valves represented more than 5.0 percent of subsea failures each in 2023. Just over half of events since 2017 were classified as external leaks, of which 98.8 percent were control fluid leaks. Two external leak events since 2017, including one in 2023, resulted in a loss of containment of greater than one barrel of wellbore fluid. Design issues (14.9 percent), maintenance error (12.4 percent), and procedural errors (10.0 percent) follow wear and tear (46.4 percent) as the leading root causes since 2017. Forty-eight events since 2017, including seven in 2023, resulted in subsea BOP stack pulls associated with various component types. Redundant control components, annular packing elements, and ram block seals were the most common component failures associated with stack pulls.

Surface WCE System Events

In 2023, surface WCE system events comprised 16.6 percent of failures, and surface BOP days represented 23.5 percent of BOP days. Since 2017, annular packing elements, accumulators, ram block seals, gate valve hardware, choke and kill valves, general hardware, and regulators were among the most frequently reported components, each representing at least 5.0 percent of all surface system failures. Internal leaks were the most common failure type (47.3 percent of events since 2017), and wear and tear (62.9 percent of events) was the most common root cause. One hundred five events since 2017 resulted in unplanned surface BOP stack pulls, with most (92.4 percent) involving BOP stack components, such as annular packing elements (52.4 percent) or ram block seals (15.2 percent).

INTRODUCTION

The *Well Control Equipment Systems Safety – 2023 Annual Report*, produced by the U.S. Department of Transportation's (USDOT's) Bureau of Transportation Statistics (BTS), provides information on well control equipment (WCE) failures reported to SafeOCS from 2017 to 2023. 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 (refer to Appendix A).

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 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. The WCE failure reporting program began in 2016, and this is the eighth annual report.[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. These subject matter experts interpret the written reports supplied to SafeOCS, but they are not involved in any physical analysis or interviews with those involved in equipment failures. Clarifications on events are provided from operators on an as needed basis.
- **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 (p. 6).

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

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

within the hole. This process involves running lengths of various size pipes (conductor, casing, 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

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

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.

- **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 of time in which 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

[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.

reports (WARs), which oil and gas operators must submit to BSEE weekly for active well 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 describe the quantity and characteristics of the population of equipment subject to failure. 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 are 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 maintained and tested) 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 1.69, 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.

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[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 is equal to 1.69. The details of these estimates are provided in: United States Department of Transportation, Bureau of Transportation Statistics. Supplement: Estimated Well Control Equipment System Component Counts. Washington, DC: 2024. https://doi.org/10.21949/wrfz-nr33.

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 remaining 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.
- 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.
- 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.
- 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 5,562 WCE failure events (5,130 subsea system and 432 surface system) reported to SafeOCS between 2017 and 2023 (Table 1 and Appendix C Table 18). In 2023, the most recent year of reporting, there were 337 WCE failure events reported (281 subsea system and 56 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, 2017–2023

Measure		2023	Total (2017–2023)	Average (2017–2023)
Wells	Wells with activity	271	1,763	310.6
	Wells spudded	125	1,004	143.4
Rigs	Rigs with activity	43	87	51.1
	Rigs with reported events	28	73	34.3
Operators	Active operators	22	43	25.9
	Reporting operators	9	26	13.4
BOP days	Total BOP days	16,365	113,766	16,252
	Not-in-operation BOP days	7,672	51,172	7,310
	In-operation BOP days	8,693	62,594	8,942
	Subsea system BOP days	12,512	77,568	11,081
	Surface system BOP days	3,853	36,198	5,171
Component events	Total events reported	337	5,562	795
	Overall event rate	20.6	48.9	47.6
	Not-in-operation events	262	4,809	687
	In-operation events	75	753	108
	Subsea system events	281	5,130	733
	Surface system events	56	432	62
LOC events	Loss of containment events	1	2	0.29

NOTES:
- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–2023 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

SOURCE: USDOT, BTS, SafeOCS Program.

An average of 795 events per year were reported during the first 7 years of the program, from 2017 to 2023. Most of these events occurred while not-in-operation (86.5 percent on average), i.e., during maintenance, inspection, and testing activities. Two reported events during the

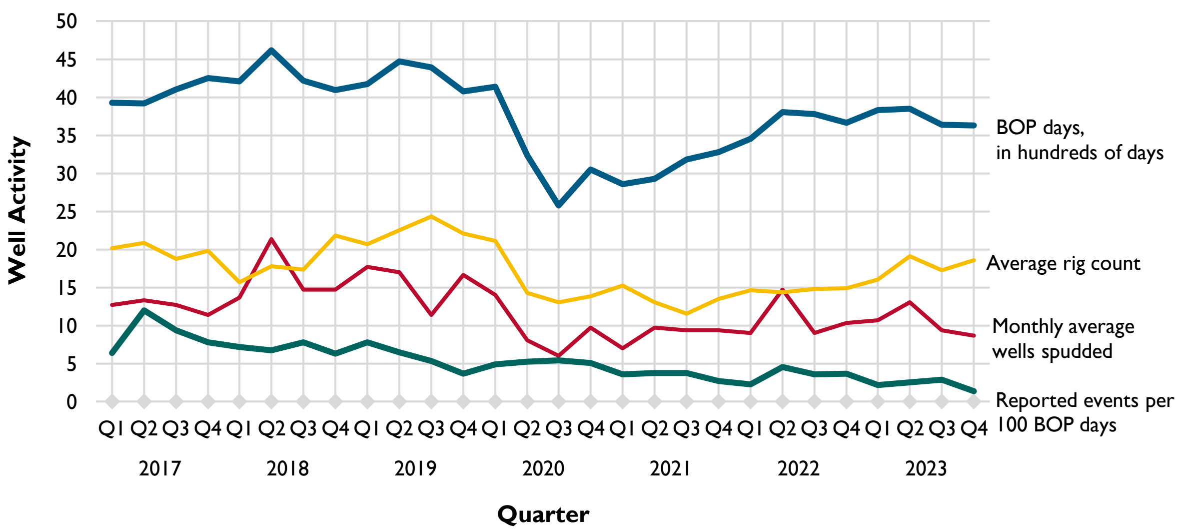
[10] Outer Continental Shelf Oil and Gas Production, BSEE, https://www.data.bsee.gov/Production/OCSProduction/Default.aspx.

7-year period, one in 2017 and one in 2023, resulted in a loss of containment of more than a barrel of wellbore fluids to the environment.

Subsea WCE system events comprised an average of 92.2 percent of failure events each year since 2017, and 83.4 percent of reported events in 2023. Most well activity took place on subsea wells, which represented 68.2 percent of BOP days since 2017 and 76.5 percent in 2023. The difference in reported event frequency between subsea and surface systems persists after adjusting for activity levels, with 66.1 events per 1,000 subsea system BOP days compared to 11.9 events per 1,000 surface system BOP days from 2017 to 2023 (refer to Appendix C, Table 19 and Table 20).

Reported events declined 35.1 percent from 2022 to 2023 and similarly declined 37.0 percent when adjusted for well operations activity as measured by the number of BOP days. This follows a slight increase in reported events and event rate the prior year. 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. Most measures of activity began to generally increase or stabilize from late 2020 into 2023.

Figure 1. Levels of Well Activity in the Gulf of Mexico OCS, 2017–2023



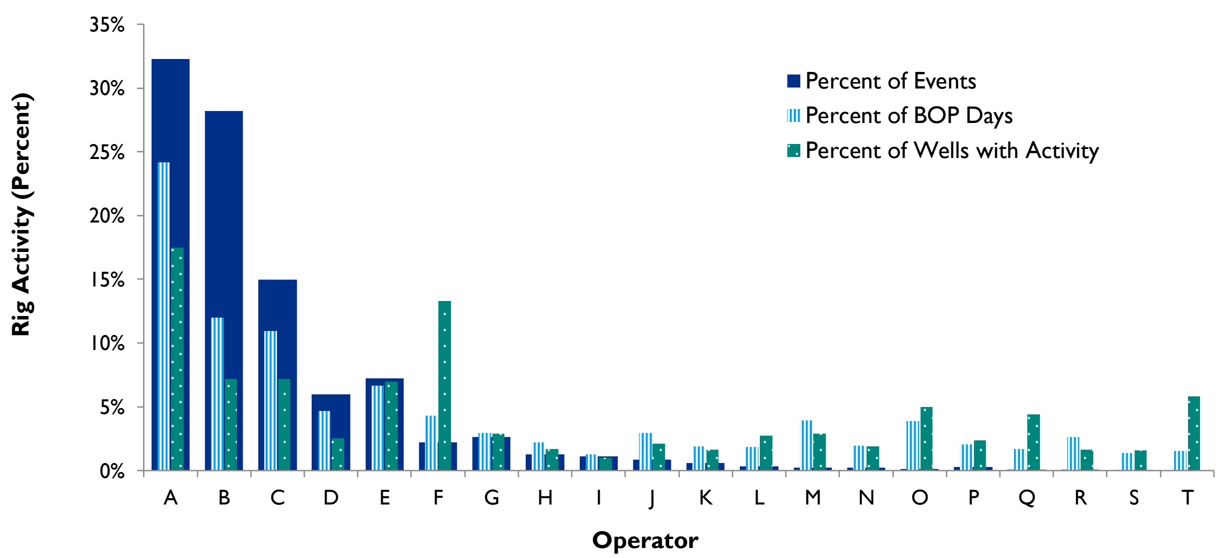
SOURCE: USDOT, BTS, SafeOCS Program. Rig counts from Baker Hughes Rig Count, https://rigcount.bakerhughes.com/.

Reporting Operators

From 2017 to 2023, a total of 43 operators conducted well activities, 23 of whom reported at least one failure event.[11] Reporting operators represent 94.2 percent of well activity (measured in BOP days) from 2017 to 2023.

Figure 2 shows the relative distribution of reported events, BOP days, and wells with activity among active operators over the past 7 years. BOP days and wells with activity indicate 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.

Figure 2. Rig Activity and Event Reporting by Operator, 2017–2023



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, 5.1 percent of BOP days, and 7.6 percent of wells with activity.
SOURCE: USDOT, BTS, SafeOCS Program.

[11]The 43 operators had at least 1 BOP day reported in well activity report data. In addition to the 23 operators who reported at least 1 failure event, 3 operators reported at least 1 WCE event to SafeOCS, but no reported BOP days in well activity report data. This is presented differently from the 2022 report, where the total number of reporting operators (25) includes 3 with no reported BOP days.

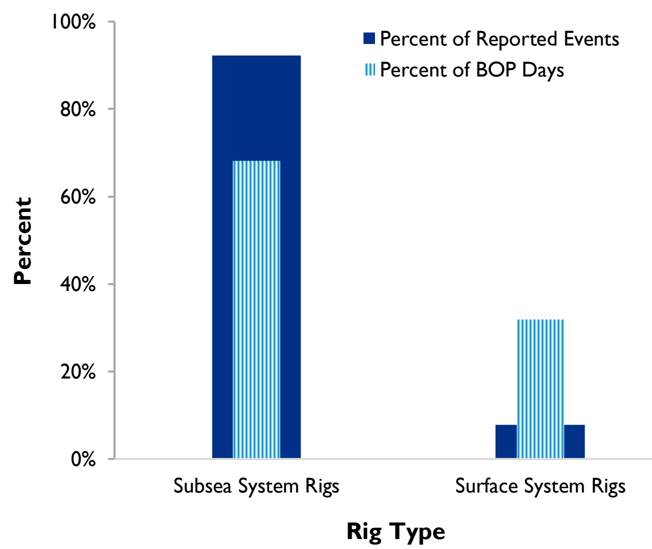
As shown in the figure, an operator's amount of activity is not always proportional to their reported events. For example, operators two and three had about the same levels of activity from 2017 to 2023 but show a relatively large difference in reported events. Factors that could explain this include differences in equipment, procedures, and maintenance practices between companies and potential underreporting.

Rigs with Events

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 2023, 87 rigs (45 rigs with subsea BOP stacks and 42 rigs with surface BOP stacks) had some level of well activity. Although the quantity of rigs is nearly evenly split, Figure 3 shows that most well activity (68.2 percent) was conducted by subsea system rigs, which contributed 92.2 percent of reported events over the 7-year period.

Of the 87 rigs with well activity from 2017 to 2023, 73 were associated with at least one reported failure event. Subsea system rigs had an average of 131.5 events per rig (standard deviation (SD) 153.2), and 102.3 events per 1,000 BOP days over the 7-year period. Surface system rigs had an average of 13.1 events per rig (SD 13.8) and 11.8 events per 1,000 BOP days. Complexity and component population may partially explain the difference in number events experienced by subsea systems as compared to surface systems.

Figure 3. WCE Reporting by WCE System Type, 2017–2023



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

WCE Events Identified in WAR Data

BTS uses BSEE well activity report (WAR) 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, SafeOCS has identified failure events including BOP stack pulls through a review of WAR data. From 2019 to 2023, 51 BOP stack pull events not reported to SafeOCS were identified from WAR data and are included in aggregated analyses presented in this report. Most of these are for surface WCE systems (refer to Table 2). The percentages shown in Table 2 represent the percent of total stack pull events for the year and WCE system type listed. While events other than BOP stack pulls are also identified in WAR data, they contain limited event information and are generally excluded from the aggregated statistics presented in this report unless specifically noted.

Table 2. Unreported BOP Stack Pull Events Identified in WAR Data, 2019–2023

System type	2019	2020	2021	2022	2023	Total
Subsea WCE system	0 (0.0%)	3 (42.9%)	1 (33.3%)	2 (33.3%)	3 (42.9%)	9 (40.9%)
Surface WCE system	16 (44.4%)	6 (66.7%)	6 (37.5%)	8 (57.1%)	6 (66.7 %)	42 (56.0%)

SOURCE: USDOT, BTS, SafeOCS Program.

Chapter 2: Subsea WCE System Events

Apart from a 22.2 percent increase from 2021 to 2022, reported subsea WCE system events have declined each year from 2017 to 2023, with 281 events reported in 2023, as shown in Table 3 and Appendix C Table 19. In 2023, subsea well activity (as measured in BOP days) reached its highest annual total since 2017. This decrease in reported events during a time of increased well activity may indicate improved performance overall.

Table 3. Subsea System Numbers at a Glance, 2017–2023

Measure		2023	Total (2017–2023)	Average (2017–2023)
Wells	Wells with activity	163	844	157.9
	Wells spudded	77	566	80.9
Rigs	Total rigs with activity	27	45	27.3
	With one subsea stack	4	13	6.7
	With two subsea stacks	23	32	20.6
	Rigs with reported events	19	40	21.4
Operators	Active operators	15	23	16.6
	Reporting operators	8	21	10.3
BOP days	Total BOP days	12,512	77,568	11,081
	Not-in-operation BOP days	6,475	40,583	5,798
	In-operation BOP days	6,037	36,985	5,284
Component events	Total events reported	281	5,130	733
	Overall event rate	22.5	66.1	65.5
	Not-in-operation events	232	4,589	655.5
	Not-in-operation event rate	35.8	113.1	113.7
	Not-in-operation events per well	1.4	5.4	4.1
	In-operation events	49	541	77.3
	In-operation event rate	8.1	14.6	14.3
	In-operation events per well	0.3	0.6	0.5
BOP stack movements	Total stack runs	167	1,240	177.1
	Successful runs	163	1,107	158.1
	In-operation stack pulls	7*	48	6.9
LOC events	Loss of containment events	1	2	0.29

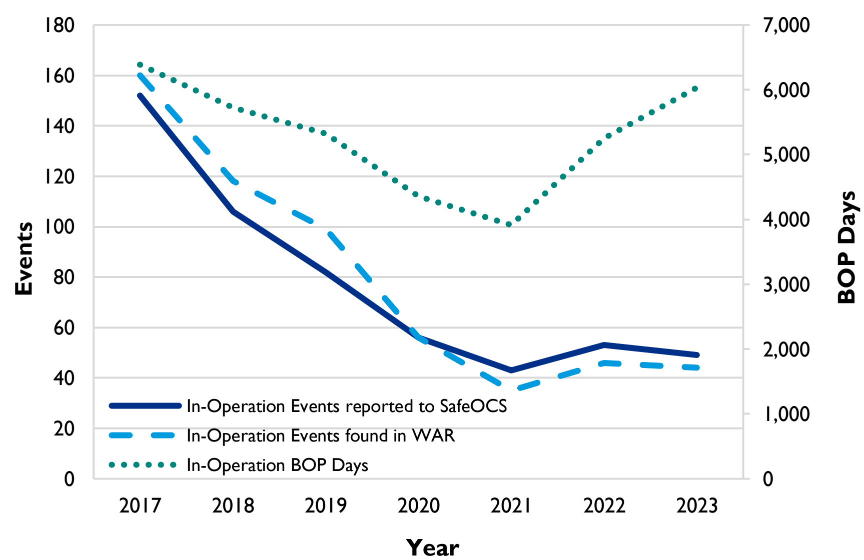
NOTES:
- * Includes some BOP stack pulls identified in WAR. Table 2 provides counts. These are not included in *Total Events Reported*.
- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–2023 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

SOURCE: USDOT, BTS, SafeOCS Program.

As in previous years, most subsea system events in 2023 (82.6 percent) were found while not in operation, i.e., during maintenance, inspection, and testing. Subsea stack pulls increased slightly from six in 2022 to seven in 2023. About 4.3 percent of successful subsea BOP stack runs—meaning the BOP stack was deployed to and latched on the seafloor wellhead and went into operation—eventually had an unplanned BOP stack pull during the 7-year period.

Event Reporting Levels

Figure 4. In-Operation Reporting and Activity Levels for Subsea Systems, 2017–2023



SOURCE: USDOT, BTS, SafeOCS Program.

As shown in Figure 4, subsea BOP stacks were in-operation more in 2023 than in any other year since 2017 (green dotted line). Figure 4 also shows that in-operation events have not increased at the same rate, resulting in a declining failure rate overall (refer to Appendix C for yearly data). One potential contributing factor to the increased in-operation activity may be well hopping, in which BOPs remain subsea when moving from one well to the next. The figure also shows similar directionality of well activity and event reporting since 2017. Beginning in 2020, the number of subsea system in-operation events reported to SafeOCS surpassed the number found in WAR reports annually, indicating more complete reporting of in-operation events to SafeOCS (note that the same event may found in both sources).

Frequently Reported Components

From 2017 to 2023, 126 different components were reported as having failed on subsea WCE systems. As in previous years, the most frequently reported components in 2023 were control valves (SPM valves and shear seal valves), regulators, shuttle valves, piping/tubing, and accumulators (refer to Appendix D). Figure 5 illustrates each reported component's percentage of events over the 7-year period compared to that component's percentage of the typical component population on a rig with two subsea BOP stacks. Note that the calculation reflects updates to the component population estimates, as detailed in the separate SafeOCS publication, *Supplement: Estimated Well Control Equipment System Component Counts*.[12] The stacked bars show the component's percentage of total subsea events, and the wider bars show each component's percentage of the typical component population. The failure ratio shown in the righthand column represents the component's percent of failures divided by that component's percent of the population.

All else being equal, one could expect a component's percentage of events to be consistent with its percentage of the population; however, as shown on the figure, that is not the case for most components. A ratio of less than 1.0 indicates that this component experienced a lower percentage of failures compared to its percentage of the population. This could be influenced by a long service life expectancy. Control valves, shuttle valves, pressure gauges, pod packers, accumulators and ram body hardware are examples of components with failure ratios less than 1.0.

A failure ratio greater than 1.0 means a component had a disproportionately high number of reports as compared to that component's population, relative to other components. Other factors can influence the number of failures, such as frequency of use, circuit complexity, operating environment, and installation and maintenance practices. Control panels, subsea electronic assembly/subsea electronic module (SEA/SEM), and ram block seals each had a failure ratio greater than one. Regulators and choke and kill valves (listed as valve assembly) are also

[12] United States Department of Transportation, Bureau of Transportation Statistics. *Supplement: Estimated Well Control Equipment System Component Counts*. Washington, DC: 2024. https://doi.org/10.21949/wrfz-nr33.

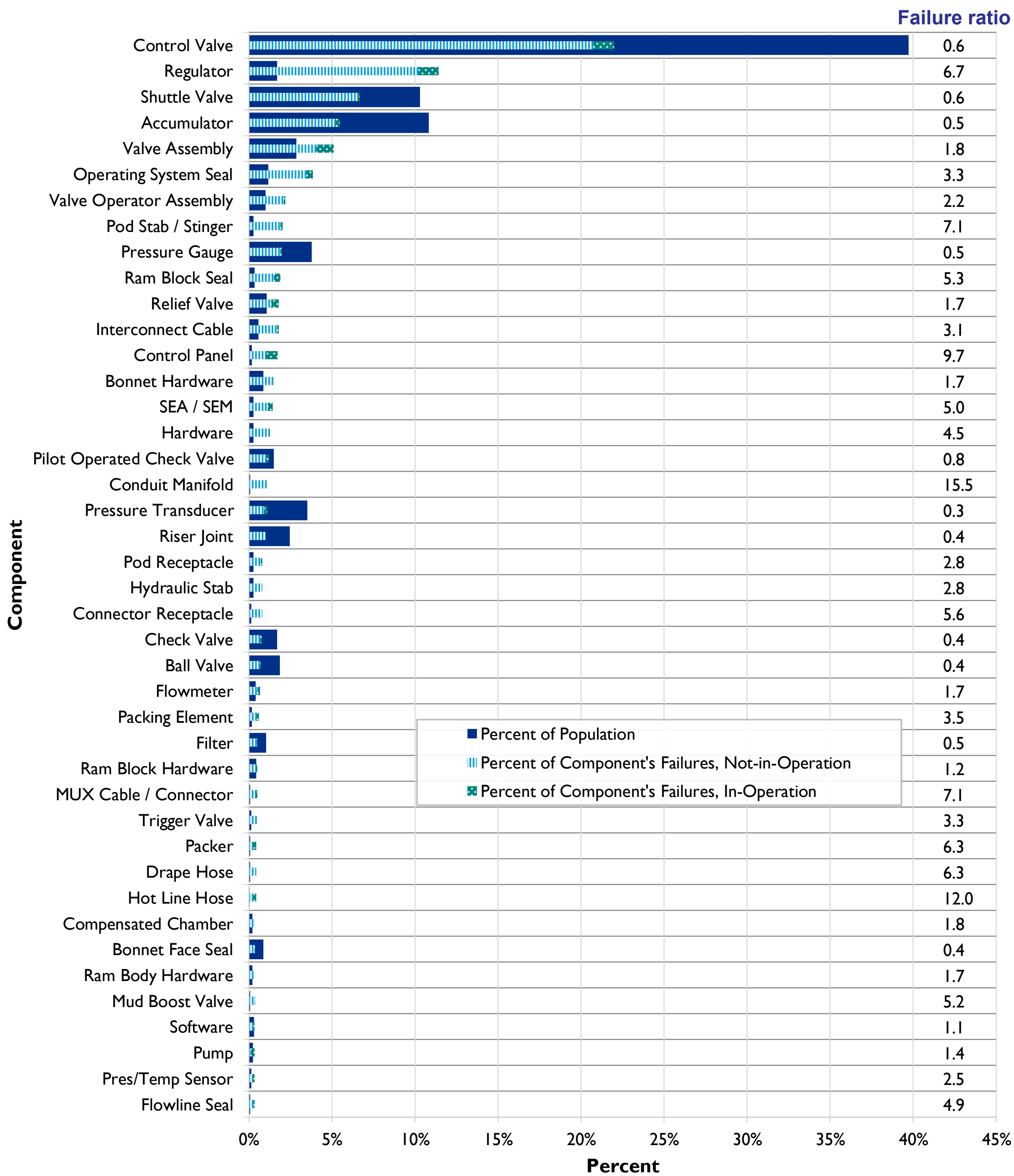
components with high failure ratios. Both represented less than 3.0 percent of the population but 11.4 percent and 5.1 percent of the failures, respectively.

As shown in the chart, most component failures are detected while not-in-operation due to extensive scheduled maintenance, inspection, and testing (MIT); however, certain components do not have specified replacement schedules or maintenance routines that might detect degradation. Many of these components, such as BOP control panels and pod stab/stinger, hot line hose, and flowline seals, are in use during the entire time that the BOP stack is in operation. From 2017 to 2023, the number of BOP days in-operation comprised just under half (47.7 percent) of total BOP days.

Other components might also be considered consumable,[13] comparatively low cost, or have no suitable early detection tests, and therefore may be "run to failure" in certain cases. The data suggest that these components tend to fail in operation at a frequency consistent with the amount of time that they are in operation, as compared to other components which are subject to more extensive on-deck MIT.

[13] Consumables, in this context, are seals that have an indeterminable expected life because of variables in the operating conditions, and therefore do not have a replacement cycle.

Figure 5. Subsea System Component Failures Relative to Component Population (Using Updated Component Population Estimates), 2017–2023



NOTE: Percent of failures represents the percentage of 5,130 surface system failures from 2017–2023. Components with 0.3 percent or less of failures are excluded and total 2.8 percent of 5,129 subsea system failures from 2017–2023. Piping/Tubing/Hose/Fitting (7.7 percent of failures) and Other (1.5 percent of failures) are not represented in the table as they do not have an estimated population average. Failure ratio, shown in righthand column, represents the component's percent of failures divided by that component's percent of the population.

SOURCE: USDOT, BTS, SafeOCS Program.

For 2023, three components were identified as having both a failure ratio greater than 1.0 and three or more in-operation events in 2023: regulators, relief valves, and telescopic joint packers. The following provides further discussion of these components.

Regulators: There were 587 reported events involving regulators from 2017 to 2023, with 35 occurring in 2023. Used on every system in sizes from 0.25 to 1.5 inches, pressure regulators have pressure ratings up to 7,500 psi. Some regulators are manually adjustable, some are hydraulically adjustable, and some are not adjustable but step the pressure down from one range to another (such as 5,000 psi to 3,000 psi). The typical subsea rig with two BOP stacks has as many as 48 regulators. Regulators can vary widely, and they are among the hardest worked hydraulic components in the system; when other equipment is on standby, they are continuously making minute adjustments due to movement or temperature fluctuations. Additionally, regulators that are in the pod(s) each supply a different circuit of various numbers of control valves. Over time, the regulator passes much more flow than any control valve and therefore has an increased risk of compromising the polished seal surfaces similar to those in the shear-seal valves.

Relief Valves: There were 119 reported events involving relief valves from 2017 to 2023, including 14 failures in 2023. Relief valves are mainly used in the BOP controls and diverter systems in sizes from 0.25 to 1.0625 inches and at relief pressures of 1,500 to 6,000 psi to protect control components from high control fluid pressures. Most of the failures involved external leakage of control fluids (65 of 119 or 54.6 percent). Another group of the relief valve events involved some type of failure to function, i.e., relieved early, failed to relieve, or failed to reseat (40 of 119 or 33.6 percent). Due in part to their low cost, nearly all were replaced rather than repaired (109 of 119 or 91.6 percent), and most provided no additional investigation and failure analysis information (108 of 119 or 90.8 percent).

Telescopic Joint (TJ) Packers: There were 10 telescopic joint packer failures in 2023 where external leaks of wellbore fluids could have occurred. The TJ compensates for rig heave and connects the top of the riser to the rig. It is made up from two main components, an upper component and a lower component. The outer barrel (lower component) is connected to the riser and remains stationary relative to the seabed. It is attached to the vessel and supported via the riser tensioning system. The inner barrel (upper component) is attached to the diverter system. It is connected to the underside of the rig and moves up and down with the rig. A pneumatic or hydraulically actuated non-metallic packing element enclosed in the upper section of the outer barrel seals around the outside of the inner barrel, thus providing riser integrity (sealing) as the vessel heaves.

As the number of telescopic joint packer failures reported in 2023 was higher than the average number of failures reported in prior years (15 events from 2017 to 2022), it was identified as a potential emerging issue. Refer to the Telescopic Joint Events section of Chapter 4: Topics of Interest for more information.

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 wellhead connector or lower marine riser package (LMRP) connector (sometimes referred to as a riser connector), which connect and seal the BOP stack to the wellhead, and the LMRP to the lower stack, respectively.

In 2023, there were three failures associated with the wellhead connector (WHC). These WHC failures were all discovered while not in operation, and they included two failures of the wellhead gasket retainer mechanisms, one due to corrosion after 2.6 years in service, and the other due to galling of the gasket retainer pins after 3.3 years. The third WHC failure, with 6.1 years in service, experienced a piston seal failure between the primary lock and primary unlock function after approximately one month since its last maintenance. Although SafeOCS received a detailed disassembly and inspection report that indicated rolled operating system seals, the root cause was not identified. Two of the WHCs were repaired, and the third was addressed by grinding off the galled retainer pin, which required BSEE approval of a management of change (MOC) to continue operating with the WHC.

In 2023, there were also three failures involving the LMRP connector. Two LMRP connector operating system seal failures involved the secondary unlatch, occurred with service times of 0.7 and 1.9 years, and were deemed to be caused by design or manufacturing issues. The third LMRP connector failure exhibited damage in the gasket seal area that required the connector to be removed from the LMRP and repaired by the OEM. The apparent cause of seal failure was debris between the gasket and the connector, reported as likely to have occurred during a previous LMRP latch-up to the lower BOP stack. An RCFA was still pending at the time of this report for the third event, and no RCFAs were received by SafeOCS on the first two LMRP connector failures.

Failure Types

As in previous years, most events in 2023 were a type of leak, comprising 71.1 percent of subsea system events overall. As shown in Table 4, 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 4. Failure Types of Subsea System Events, 2017–2023

Failure type		2017 (n=1,321)	2018 (n=1,128)	2019 (n=908)	2020 (n=643)	2021 (n=372)	2022 (n=478)	2023 (n=277)	Total (n=5,127)
Leaks	External	50.1%	46.6%	60.1%	53.5%	50.5%	42.1%	42.2%	50.4%
	Internal	28.0%	24.3%	20.6%	27.5%	21.8%	31.4%	28.9%	25.7%
	Undetermined	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Other	Communication/ signal issue	4.2%	2.8%	3.3%	3.6%	2.4%	5.6%	3.6%	3.6%
	Electrical issue	1.6%	1.8%	3.0%	2.0%	1.9%	1.7%	2.9%	2.0%
	Fail to function on command	2.6%	2.7%	2.4%	3.4%	8.9%	4.2%	2.9%	3.3%
	Inaccurate indication	2.1%	3.0%	2.5%	1.9%	3.5%	4.8%	6.9%	3.0%
	Mechanical issue	9.5%	16.7%	6.3%	5.1%	6.7%	6.9%	9.0%	9.5%
	Process issue	1.1%	1.5%	1.1%	1.9%	1.6%	0.6%	2.9%	1.4%
	Unintended operation	0.2%	0.2%	0.1%	0.0%	0.3%	0.2%	0.0%	0.1%
	Other	0.5%	0.1%	0.6%	1.1%	2.4%	2.5%	0.7%	0.8%
Total	**—**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

NOTE: — Not applicable.
SOURCE: USDOT, BTS, SafeOCS Program.

Although there is not a specific field on the data collection form to capture leak volume or rate (and leaks are rarely collected and measured), event narratives indicate that nearly all leaks reported to SafeOCS between 2017 and 2023 comprise small volume control fluid leaks. Such leaks can be categorized as (1) those that are too small in volume to register on instruments during in-operation activities but can sometimes be seen by the crew when the BOP stack is on deck during maintenance, inspection, and testing or (2) leaks at a rate that might be considered allowable by the OEM but not necessarily by the rig owner procedures. Both types of leaks may have very small volumes (visually estimated in drops per minute), and therefore do not typically affect ongoing operations.

Though leaks can affect all hydraulic components, those most subject to external leaks include several of the most frequently reported, including 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 externally visible. For shuttle valves, the most frequent failure type is internal leak. Sometimes, an internal leak is detected by visual observation (e.g., from a vent port), which could lead to some level of inconsistency in reporting of control fluid leaks as internal versus external. BTS will consider changes to the SafeOCS WCE failure notification form to clarify reporting of control fluid leaks for control valve components.

In 2023, one event involving a loss of containment of more than one barrel of wellbore fluid was reported. In addition, three events involving wellbore fluid leaks of smaller volumes were identified. The specific volumes released were not provided in the reports; however, based on review of the reported circumstances it is unlikely any of the three additional events resulted in a loss greater than one barrel. Similar to control fluid leak volumes, there is not a specific field on the data collection form to capture the leak volume or rate for wellbore fluid leaks. Further, it is difficult to measure small leaks of wellbore fluids during operations. The leaks of wellbore fluids are summarized as follows:

- While the BOP was in operation, a telescopic joint (TJ) upper packer began leaking wellbore fluids when the rig began to make a heading change. The lower packing was manually energized, and it also began leaking within 5 minutes. The BOP annular preventer was closed to stop the flow from the well, and 48 barrels of completion fluid (calcium chloride) contained in the riser above the leak point were released in the event. The root cause of the failure was determined to be a design issue with the seal, which was installed three months prior, and a redesign was implemented, described further in the Investigation and Analysis section.

- A second TJ packer seal on a different rig also leaked a small amount of wellbore fluids when the rig was changing heading. The leak was described as weeping, and the root cause was reported as the same design issue on the 6-month-old seal.
- A choke manifold pressure gauge on surface was found leaking wellbore fluids from its digital readback housing while testing a plug-in operation. The gauge, which had been in service for 33 months, was isolated and replaced. Wear and tear was the reported root cause.
- A grease fitting on a lower inner choke valve leaked wellbore fluids during in-operation testing. A procedural error introducing debris into the system was determined to be the root cause. The valve had been in service approximately 6 months.

All other reported external leaks have involved water-based control fluid, which is vented into the ocean as part of the system design.

Detection Methods

Most subsea system events from 2017 to 2023 (79.8 percent) were detected while not in operation, i.e., during maintenance, inspection, and testing. Further analysis of the detailed detection methods has been omitted from this 2023 annual report, while SafeOCS develops revisions to the detection methods selections to clarify definitions and promote consistency in reporting.

The following provides brief explanations for the revised detection method selections. Note that they are listed in a particular order. Since there can still be some overlap (e.g., a person can casually observe an electronic trend), it is important that the first method in the list that applies is selected. In that case, electronic trend would be the appropriate selection. Refer to the most recent edition of the SafeOCS WCE guidance document for complete definitions.

1. *Failed on Demand*—The component fails when called upon to function, other than for a test.

2. *Failed Pressure Test*—Detected by applying pressure to the component to test for leakage.
3. *Failed Function Test*—Detected by any means while operating a component as a test to confirm that it does what it is expected to do.
4. *Alarm*—Visual or audible alert that calls attention.
5. *Electronic Trend*—Analysis of a display of automatically generated operating variable(s) over time.
6. *Planned Monitoring*—Scheduled/periodic observance of equipment and/or local indicators.
7. *Inspection*—Discovered by methodical examination using tools, specialized methods, and/or disassembly.
8. *Casual Observation*—Unplanned observance of equipment and/or local indicators.

Root Causes of Events

While most events from 2017 to 2023 (46.4 percent) were attributed to wear and tear, the percentage citing wear and tear decreased each year, reaching a low of 32.4 percent in 2022, with a slight increase in 2023 to 35.4 percent (Table 5). After wear and tear, the most common root causes over the 7-year period were design issue (14.9 percent) and maintenance error (12.4 percent). In both 2022 and 2023, the percentage of reports with an assessment still pending showed an increase from the previous years.

Table 5. Root Causes of Subsea System Events, 2017–2023

Failure type		2017 (n=1,321)	2018 (n=1,128)	2019 (n=908)	2020 (n=643)	2021 (n=372)	2022 (n=478)	2023 (n=277)	Total (n=5,127)
Determined	Design issue	10.8%	17.6%	19.7%	19.1%	12.4%	7.7%	13.7%	14.9%
	QA/QC manufacturing	5.9%	12.2%	6.3%	5.4%	6.7%	5.2%	8.3%	7.4%
	Maintenance error	12.0%	9.3%	12.2%	12.8%	20.7%	14.0%	13.0%	12.4%
	Procedural error	2.2%	3.8%	13.2%	12.9%	16.4%	27.2%	16.2%	10.0%
	Documentation error	0.4%	0.7%	0.1%	11.0%	5.1%	0.6%	0.7%	2.1%
	Wear and tear	57.8%	52.9%	45.2%	36.1%	33.6%	32.4%	35.4%	46.4%
	Other	0.5%	0.4%	0.1%	0.3%	0.3%	0.0%	0.0%	0.3%
Other	Inconclusive	0.2%	0.0%	0.3%	0.0%	0.3%	0.2%	0.0%	0.1%
	Assessment pending	7.1%	2.7%	2.6%	2.2%	4.3%	8.6%	9.4%	4.8%
	Not reported	3.1%	0.3%	0.2%	0.2%	0.3%	4.0%	3.2%	1.5%
Total	**—**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

NOTE: — Not applicable.
SOURCE: USDOT, 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, such as the age and expected life of the component. 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 2023, as listed in Table 6. In addition to wear and tear, commonly reported root causes for each component included design issue for regulators and slide (shear-seal) valves, procedural error for solenoid valve hydraulic and shuttle valves, and maintenance error for SPM valves. Supporting information for failures attributed to design issues has been infrequent.

Table 6. Root Causes of Frequently Reported Components for Subsea Systems, 2017–2023

Reported root cause		Regulator	Solenoid valve hydraulic	SPM valve	Slide (shear-seal) valve	Shuttle valve
Determined	Design issue	19.6%	1.8%	7.0%	15.1%	4.1%
	QA/QC manufacturing	3.7%	2.5%	3.8%	4.4%	1.5%
	Maintenance error	10.4%	13.7%	15.5%	9.0%	16.6%
	Procedural error	18.9%	16.2%	3.2%	11.9%	18.9%
	Documentation error	8.4%	5.7%	0.8%	4.1%	0.0%
	Wear and tear	32.4%	55.1%	60.0%	50.6%	53.1%
	Other	0.5%	0.7%	1.3%	0.0%	1.0%
Not determined	Inconclusive	0.2%	0.0%	0.4%	0.0%	0.3%
	Assessment pending	4.3%	1.6%	3.4%	4.1%	0.8%
	Not reported	1.7%	2.5%	4.7%	0.9%	3.8%
Total	**—**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

—Not applicable
SOURCE: USDOT, BTS, SafeOCS Program.

Wear and tear continues to be the predominantly reported root cause for 2023 events, partially due to the difficulty of the varying environments (primarily wellbore fluids) under which components are subject, as compared to manufacturer's controlled tests. Equipment owners may customize their maintenance plans for a component based on their field experience with that component or in accordance with API S53 7.6.9.4, which states: "Rig-specific procedures shall be developed for the installation, operation, and maintenance of BOPs for the specific well and environmental conditions."

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. However, events occurring not-in operation are important to consider, as they may provide insight on the prevention of the same or similar events occurring in-operation. Further, failures in certain not-in-operation phases (e.g., well hopping) are particularly important to examine, as the BOP may remain subsea for extended periods of time before being retrieved to surface. From 2017 to 2023, 79.8 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, including well hopping, 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 some pressure testing are conducted during this process. In this report, failures during well hopping are counted as part of deployment testing.
- **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 effects of which cannot be checked or verified until the BOP stack is at operating depth. This testing confirms wellbore integrity. The BOP stack must pass all initial latch-up testing before going into operation.

These final testing periods are the first opportunities to test the fully assembled system and find failures after general MIT has been completed, but before the BOP stack is in operation. The BOP and BOP control systems are considered properly tested only when they are fully assembled in the configuration that will be used while constructing the well. This means that until the initial subsea testing is complete, then MIT is not finished. 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 an MOC waiver, the BOP stack must be retrieved to repair the component. Retrievals are not considered BOP stack pulls because the BOP stack has not yet gone into operation. In this case, the well is barriered (by the casing cement, cement plugs, or other plugs) and therefore is already safe for the BOP retrieval. 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 1,240 BOP stack runs between 2017 and 2023, 1,107 (89.3 percent) were successful, meaning the BOP stack passed initial subsea testing and went into operation. Of the 133 BOP stack runs that were unsuccessful, meaning that the BOP stack needed to be retrieved and retested before operations could commence, 107 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 7, from 2017 to 2023, 289 events were identified during the last two phases of testing, 132 of which resulted in a retrieval (in some cases, multiple failures were associated with a single retrieval). In the remaining cases, the component was repaired without a BOP stack retrieval, or operations continued without repair (under redundancy or an MOC waiver, for example).

Table 7. Events and Retrievals During the Last Two Phases of Testing, 2017–2023

Measure	Events during deployment and well hopping	Events during initial subsea testing	Total
Stack retrievals	**42**	**65**	**107**
Total events	**132**	**157**	**289**
Operations continued without repair	25	21	46
Component repaired (in situ)	51	60	111
Events contributing to stack retrieval	56	76	132

SOURCE: USDOT, BTS, SafeOCS Program.

Table 8 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 over half of the events involving these subunits (55.2 percent). 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 8. Events During the Last Two Phases of Testing (by Subunit) 2017–2023

	Deployment and well hopping			Initial subsea testing			
Subunit	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	Total
Auxiliary equipment	—	—	—	—	2	—	**2**
BOP controls	22	28	34	9	12	34	**139**
BOP controls emergency automated functions	1	1	7	2	3	9	**23**
BOP controls secondary ROV acoustic	—	—	—	3	4	8	**15**
BOP stack	1	4	14	7	4	25	**55**
Choke manifold system	—	3	—	—	21	—	**24**
Diverter system	—	10	—	—	14	—	**24**
Riser system	1	5	1	—	—	—	**7**

NOTE: — Not applicable.
SOURCE: USDOT, BTS, SafeOCS Program.

From 2017 to 2023, 71 different types of components failed during deployment or initial subsea testing. Table 9 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 (hardware). For some component types, such as choke and kill operator hardware, all events during these phases resulted in a BOP stack retrieval.

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.[14] Of the 289 total events, 42 (14.5 percent) found during the last two phases of testing from 2017 to 2023 involved these systems: 24 failures on the BOP control pod, 8 failures of the stack mounted electrical equipment, 2 on the telescopic joint, 2 on the wellhead connector, 1 on the riser connector, and 5 failures on the riser system. The remaining 247 events found during deployment and initial subsea testing involved components subject to thorough testing on deck before BOP stack deployment.

Table 9. Events During the Last Two Phases of Testing (by Component), 2017–2023

	Deployment and well hopping			Initial subsea testing			
Component	**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**	**Total**
SPM valve	4	3	3	—	2	8	**20**
Hardware	—	1	—	—	19	—	**20**
Regulator	1	5	2	—	5	6	**19**
Ram block seal	—	—	—	2	—	9	**11**
Hose	7	—	—	1	—	3	**11**
Slide shear seal valve	—	1	3	2	2	2	**10**
Electrical connector	2	1	5	—	—	1	**9**
Pressure transducer	2	—	4	2	—	—	**8**
Choke and kill valve	—	—	3	2	1	2	**8**
Relief valve	—	1	1	2	3	—	**7**
Pressure gauge	—	—	—	—	1	6	**7**
Ball valve	—	1	—	—	5	—	**6**
SEA_/subsea electronic assembly	4	1	—	—	—	1	**6**
Choke and kill operator hardware	—	—	6	—	—	—	**6**
Piping tubing	—	—	—	1	2	3	**6**
Pilot-operated check valve	—	1	—	—	—	4	**5**
Flowline seal	—	2	—	—	3	—	**5**

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

Component	Deployment and well hopping			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	
Locking device	—	—	—	1	1	3	**5**
Metering needle valve	—	1	—	—	2	2	**5**
Mud boost valve	1	—	3	—	—	1	**5**
Other components	4	33	26	8	14	25	**110**

NOTES:

- — Not applicable.
- Components with fewer than five failures excluded.

SOURCE: USDOT, BTS, SafeOCS Program.

In-Operation Events Including BOP Stack Pulls

From 2017 to 2023, a total of 541 in-operation events were reported for subsea WCE systems, including 39 subsea BOP stack pulls. An additional nine subsea BOP stack pulls were identified in WAR data. When adjusted for the level of activity, an average of 14.6 events occurred per 1,000 in-operation BOP days over the 7-year period, reaching a low of 8.1 events per 1,000 in-operation BOP days in 2023. While subsea in-operation activity levels in 2023 were at the highest level since 2017, as measured by the number of in-operation BOP days, in-operation events remained relatively on par with the number reported in each year since 2020 (49 events reported in 2023, and an annual average of approximately 50 since 2020).

Table 10 shows the equipment involved in events leading to subsea BOP stack pulls from 2017 to 2023, as well as the total number of in-operation events for those component combinations. Across the 30 different component combinations associated with subsea BOP stack pulls, the component associated with the most stack pulls (7) was piping/tubing. Ram block seals have been associated with five, and annular packing elements and riser joints have been associated with at least four stack pulls each, since 2017.

SPM valves, operating system seals, bonnet operating seals, choke and kill valves, and flex loop/hose have been associated with at least 2 BOP stack pulls each since 2017 (a total of 11, as shown in Table 10). Two slide shear seal valve failures resulted in stack pulls in 2023, though none of the other 14 failures of that component from 2017–2022 resulted in stack pulls.

The remaining component combinations have been associated with one BOP stack pull each since 2017.

A component's location and function 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 ram block seal failures on the pipe ram preventer, which must be tested every seven days, 3 led to a BOP stack pull (15.8 percent), compared to the 2 in-operation ram block seal failures resulting in BOP stack pulls on the shear ram preventer, which is only required to be functioned every 21 days. Less use can equate to longer life, subject to other variables. Ten of the 19 ram block failures were on test rams, which are optional equipment installed to facilitate testing but not perform well control function. These failures occurred prior to 2023; no additional ram block seal failures on either the pipe ram preventer or shear ram preventer were reported in 2023. In another example, each of the reported in-operation piping/tubing failures on the emergency automated systems led to stack pulls, while less than half of those on other systems led to stack pulls.

Table 10. Component Combinations of Subsea BOP Stack Pulls, 2017–2023

Submit	Item	Component	2017–2023 In-operation events	2017–2023 Stack pulls
BOP controls	BOP control pod	SPM valve	19	2
		Piping/tubing	6	2
		Interconnect cable	2	1
		Cylinder	3	1
		Check valve	3	1
		Slide shear seal valve	16	2
		Pod receptacle	5	1
	BOP controls stack mounted	Piping/tubing	5	2
		Shuttle valve	6	1
		Electrical connector	1	1
		Hose	12	1
	Reels hoses cables	MUX cable connector	2	1
		MUX cable	2	1
BOP controls emergency automated functions	Autoshear deadman EHBS	Piping/tubing	3	3
		SPM valve	3	1
		Timing circuit	1	1
BOP stack	Annular preventer	Packing element	10	4
		Operating system seal	7	2
	Pipe ram preventer	Ram block seal	19	3
		Bonnet face seal	1	1

Submit	Item	Component	2017–2023	
			In-operation events	Stack pulls
	Riser connector	Ring gasket	1	1
	Shear ram preventer	Ram block seal	2	2
		Ram block hardware	1	1
		Bonnet operating seal	6	2
	Stack choke and kill system	Flex loop/hose	3	2
		Choke and kill valve	5	2
Riser system	Riser	Choke and kill line	1	1
		Rise joint	4	4
	Telescopic joint	Packer	13	1
Total	**—**	**—**	**162**	**48**

NOTES:

- — Not applicable.
- 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 riser joint represents an integrated riser joint (used in managed pressure drilling) from a BOP stack pull event identified in WAR data.

SOURCE: USDOT, BTS, SafeOCS Program.

External leaks were the most frequent failure type among BOP stack pull events, attributed to 37 of 48 events from 2017 to 2023, including those found in WAR data. For those events reported to SafeOCS, design issue was the most frequently reported root cause, cited for eight events. For 12 events, no definitive root cause was listed. The seven subsea stack pulls that occurred in 2023 (reported to SafeOCS and found in WAR data) are discussed further as follows:

- After cementing a casing string, an alarm was received indicating a control pod communication issue (failure to transmit signal). After taking the necessary steps to secure the well, the BOP was retrieved, and the 720V red power wire inside the upper split section of the 29-pin connector was observed to be kinked and pushed back instead of straight, causing the exterior sheathing of the wire to separate.
- While preparing to perform the casing point shear ram pressure test revalidation, the blue pod upper blind shear ram (UBSR) (normally operated in closed position) was not giving the correct gallon count when selected to the closed position. After troubleshooting, the ROV confirmed the blue pod UBSR open SPM valve was not venting fluid when de-selected or selected.

- A pressure drop was observed while attempting to perform a low-pressure test on the upper blind shear rams from the primary panel with the blue pod. The BOP was pulled to surface and the lower blind shear ram and upper blind shear ram were repaired.
- During managed pressure drilling (MPD), the annular packer in the integrated riser joint (IRJ) leaked. After BSEE denial of request to continue operations, the LMRP was unlatched so that the IRJ could be pulled to the surface for repair.
- While running 9.88-inch casing, the well was suspended as proposed and approved. The LMRP was unlatched from the BOP and the riser joint was repaired.
- While pressure testing the upper annular down the kill line, there was an unacceptable pressure loss noted. The ROV confirmed an external leak of wellbore fluid at the lower inner choke stack valve grease fitting. The grease fitting was removed, and there were indications of a wash on the tapered area of the high-pressure body.
- During drilling operations, a leak rate of 9.85 gph was identified while on the yellow pod. The leak was confirmed using the ROV as a leak from the DRG valve vent tube. The primary pod was swapped to the blue pod, and clearance was obtained to finish drilling the section and cement the casing to secure the well prior to pulling the BOP for repairs.

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) (carried out by the OEM and/or a qualified third-party).[15] 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 expected to determine the root cause.

Table 11 summarizes the findings for 15 I&As that included recommended preventive actions and were associated with 31 events in 2023 (each row may represent more than one I&A). The

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[15] For I&As at the SME review level, the SMEs referred to are those who performed the investigation and are employed in the industry. The term does not refer to SMEs retained by SafeOCS.

I&As include five formal RCFAs, two SME reviews, and the remainder were for events with immediately known causes. Most of the events represented in Table 11 occurred while not in operation (22 of 31 events in 2023), eight of which were during well hopping. Each row also shows the total reported events from 2017 to 2023 associated with that component issue. The reported causes for the failures were design issue (five I&As), QA/QC manufacturing (two), procedural error (three), wear and tear (three), and maintenance error (two).

The TJ packer is the component in two separate I&As in Table 11, one determined to be a design issue (row 1) and the other a maintenance issue (row 8). The packer seal failures occurred on six different rigs over the 12 months, thus the packer events may be the result of the same issue (refer to Chapter 4: Topics of Interest).

Table 11. Findings From I&As for Subsea System Events, 2023

Reported root cause	Root cause details	Recommended preventive action	events since 2017	2023 events	2023 events <1 year
Design issue	Several telescopic joint flat seals failed prematurely due to a design issue per OEM.	OEM to design a new dome shaped gasket made of HNBR (Hydrogenated Nitrile Butadiene Rubber), which has superior mechanical properties at operational conditions compared to the FKM	8	8	5
Design issue	A known design issue with the seal on an SPM valve allowed leak of control fluid after 16 months.	The half-inch SPM valves are under design review at this time with a new prototype being field tested.	3	3	0
Design issue	The seal plate in a regulator was found cracked after 2.1 years of service and 0.4 years since last rebuild.	OEM is in the process of redesigning the seal plate to prevent this failure.	1	1	0
Design issue	Design issue caused a regulator to leak control fluid externally after 2 months.	Equipment owner to ensure OEM is notified of this early life failure in order to track possible issues with the regulator snap rings.	1	1	1
Design issue	Shuttle valve experienced a cracked peek seat and extruded seal material after 6 months.	Equipment owner decided to return to using the previous generation shuttle valves until further notice.	1	1	1

Reported root cause	Root cause details	Recommended preventive action	Total events since 2017	2023 events	2023 events <1 year
QA/QC manufacturing	OEM's hose crimp dies were worn out and not replaced before crimping was performed, resulting in eight hoses bulging.	OEM to add dimensional measurements from opposing angles to their QA/QC procedure. OEM will no longer allow worn crimping machine to be used for shop made subsea hose assemblies. The rig owner is working with the OEM to create a way to effectively gauge purchased hose assemblies prior to installation.	8	8	8
QA/QC manufacturing	Manufacturing issue caused a ring to be clipped and the depth compensated accumulator to leak.	OEM to allow longer time after installation of the back-up ring for it to return to original size before installing the cap.	1	1	1
Maintenance error	Incorrect seal was installed on the telescopic joint packer, resulting in an air leak during testing.	Rig owner will share information with the fleet and update the work instruction to refer to the Product Alert, which contains the gasket dimensional requirements.	1	1	1
Maintenance error	Backwards installation of the operating seal on a shear ram preventer caused premature wear of the operating seal.	Bonnet was last assembled by the OEM and lessons learned will be passed along to the OEM.	1	1	0
Procedural error	Incorrect procedure allowed trapped test pressure beneath the ram, which caused a blind shear ram seal failure during opening.	Rig owner to issue fleet wide "lessons learned" to raise awareness of trapped pressure in BOP during surface testing. Equipment owner to review all site-specific procedures to ensure this failure mode is reduced to as low as reasonably practicable.	1	1	1
Procedural error	Equipment owner observed a drop in pressure during subsea deployment testing, which resulted in a stack retrieval to repair a 4-year-old accumulator.	Equipment owner to revise the soak test procedure to include monitoring the pilot accumulator pressure along with the system pressure.	1	1	0
Procedural error	Debris caused a grease fitting leak on a lower inner choke valve while in operation.	Equipment owner to update the end-of-well preventive maintenance to include inspection of seal taper and cap to verify they are clean and free of debris, and the equipment owner to update the 90 day PM to include recording (checklist) fitting and stuffing box profile and replacing all grease fittings.	1	1	2

Reported root cause	Root cause details	Recommended preventive action	Total events since 2017	2023 events	2023 events <1 year
Wear and tear	Debris in the control system fluid damaged a check valve seal and seat, causing a control fluid leak.	Equipment owner to incorporate a filter on the hotline supply circuit to keep debris from entering the hot line manifold before the inlet supply for the pods.	1	1	0
Wear and tear	Seat scoring of accumulator charge valve seat in 1.1 years may be due to over tightening when closing the valve.	Equipment owner to adjust required torque per OEM recommendation.	1	1	0
Wear and tear	Wear and tear caused a selector manipulator valve seal to leak after 1.4 years.	Equipment owner to update the preventive maintenance system for a more frequent replacement.	1	1	0

SOURCE: USDOT, BTS, SafeOCS Program.

Many of the submitted failure reports (86) in 2023 include lessons learned that suggest more general ongoing actions, which have not been included in Table 11. With additional information from reporting operators, SafeOCS could share more detail about preventive actions taken, such as changes to procedures or practices mentioned generally but not fully explained. These lessons learned and the number of occurrences are listed as follows:

- For various events and component types, lessons learned included phrases such as "continue testing and monitoring" or "continue visual inspection during testing," without a more specific, completable task. (62 events)
- For various events and component types, the lesson learned was that the maintenance plan should be followed. (7)
- In several cases on various components, the lesson learned was to ensure seals or other parts are installed per updated OEM product advisory. (5)
- For external control fluid leaks from control valves or regulators, the lesson learned was to maintain awareness during assembly/disassembly. (3)
- For two events where bolts sheared on the riser running tool, the lesson learned was to keep spare parts (spacer bolts) on board. (2)

- For shuttle valve leaks, the lesson learned was to prevent debris ingress in the control system. (2)
- For an event involving a broken spring in a kill valve, the lesson learned was to function all choke and kill valves after retrieval of BOP. (1)
- For a leaking plug detected during the maintenance of a ram BOP, the lesson learned was to follow company policy to seal threaded plugs with Teflon tape. (1)
- For an event involving a valve failure, the lesson learned was to ensure a loose dowel pin is properly staked after assembly. (1)
- For a slide shear seal valve internal leak event, the lesson learned was to increase research of cycle counts on valves that see full working pressure. (1)
- For an event involving a piece of a ram block seal found to be missing, the lesson learned was to equalize pressure across rams before opening. (1)

Chapter 3: Surface WCE System Events

From 2017 to 2023, 432 surface WCE system events were reported to SafeOCS, averaging 61.7 events per year as shown in Table 12. The number of events has remained relatively stable since 2021, increasing slightly from 2022 to 2023 (refer to Appendix C, Table 20). Adjusting for well activity levels (which were the lowest of all years in 2023), the event rate reached the highest level since 2017, increasing 63.5 percent in 2023 from 2022.

Table 12. Surface System Numbers at a Glance, 2017–2023

Measure		2023	Total (2017–2023)	Average (2017–2023)
Wells	Wells with activity	108	919	152.7
	Wells spudded	48	438	62.6
Rigs	Total rigs with activity	16	42	23.9
	Rigs with reported events	9	33	12.9
Operators	Active operators	15	33	17.7
	Reporting operators	4	13	7.4
BOP days	Total BOP days	3,853	36,198	5,171
	Not-in-operation BOP days	1,197	10,589	1,513
	In-operation BOP days	2,656	25,609	3,658
Component events	Total events reported	56	432	61.7
	Overall event rate	14.5	11.9	11.9
	Not-in-operation events	30	220	31.4
	Not-in-operation event rate	25.1	20.8	20.3
	Not-in-operation events per well	0.3	0.2	0.2
	In-operation events	26	212	30.3
	In-operation event rate	9.8	8.3	8.3
	In-operation events per well	0.2	0.2	0.2
BOP stack movements	Total stack starts	110	1,213	173.3
	Successful starts	106	1,139	162.7
	In-operation stack pulls	9*	105	15.0
LOC events	Loss of containment events	0	0	0

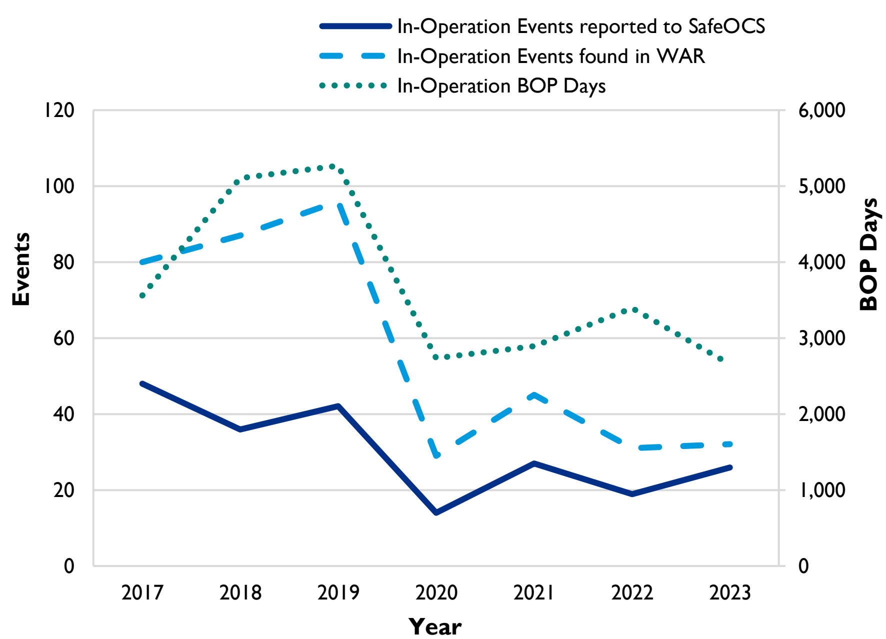
NOTES:
- * Includes some BOP stack pulls identified in WAR. Table 2 provides counts. These are not included in *Total Events Reported*.
- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–2023 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

SOURCE: USDOT, BTS, SafeOCS Program.

Events were relatively evenly split between operational states during the 7-year period, with 49.1 percent of surface system events detected while in operation and 50.9 percent while not in operation. Due to greater accessibility of equipment on surface systems as compared to subsea systems, 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, 105 surface BOP stack pulls were recorded from 2017 to 2023. About 9.2 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 7-year period.

Event Reporting Levels

Figure 6. In-Operation Reporting and Activity Levels for Surface Systems, 2017–2023



SOURCE: USDOT, BTS, SafeOCS Program.

As shown in Figure 6, surface BOP stacks were in operation fewer days in 2023 than in any other year since 2017, dropping just under the prior low in 2020 (green dotted line). This trend is in stark contrast to subsea BOP stacks, which had increasing in-operation activity over the past several years. This aligns with declining well activity on the U.S. Gulf of Mexico shelf generally, compared to continuing and new deepwater exploration and development prospects.[16] Figure 6 also shows a slight increase in both the number of events reported to SafeOCS and the number of failures found in WAR from 2022 to 2023, though they remain low compared to 2017. While events found in WAR data and reported to

[16] Bureau of Safety and Environmental Enforcement Bureau of Safety and Environmental Enforcement and Bureau of Ocean Energy Management, Information/Briefing Report: Gulf of Mexico Data and Analysis/ Leasing, Drilling and Production; Gulf of Mexico Shallow Water Potential Stranded Assets, Nov. 19, 2019, https://www.bsee.gov/sites/default/files/reports/shallow-water-report-01.pdf.

SafeOCS are not mutually exclusive, the higher number of events found in WAR data, as compared to those reported to SafeOCS, indicates incomplete reporting to SafeOCS.

Frequently Reported Components

From 2017 to 2023, 50 different components were reported as having failed on surface WCE systems. The most frequently reported components were valve assembly (which includes choke and kill valves and gate valve hardware), packing elements, ram block seals, accumulators, other hardware, and regulators, each contributing at least five percent of events and together comprising 54.4 percent of all surface system events.

Figure 7 illustrates each reported component's percentage of events over the 7-year period compared to that component's percentage of the typical population on a rig with a surface BOP stack. Note that the calculation reflects updates to the component population estimates, as detailed in the separate SafeOCS publication, *Supplement: Estimated Well Control Equipment System Component Counts*.[17] The stacked bars show the component's percentage of total subsea events, and the wider bars show each component's percentage of the typical component population. The failure ratio shown in the righthand column represents the component's percent of failures divided by that component's percent of the population.

All else being equal, one could expect a component's percentage of events to be consistent with its percentage of the population; however, as shown on the figure, that is not the case for most components. A failure ratio less than 1.0 indicates that this component experienced a lower percentage of failures compared to its percentage of the population. This could be influenced by a long service life expectancy or a relatively high population count for those components. As shown in Figure 7, accumulators, control valves, pressure switches, and ball valves are such examples, among others.

A failure ratio greater than 1.0 indicates that other factors are influencing the number of failures (e.g., frequency of use, circuit complexity, operating environment, and installation and maintenance practices). Five of the top six most frequently reported components (valve

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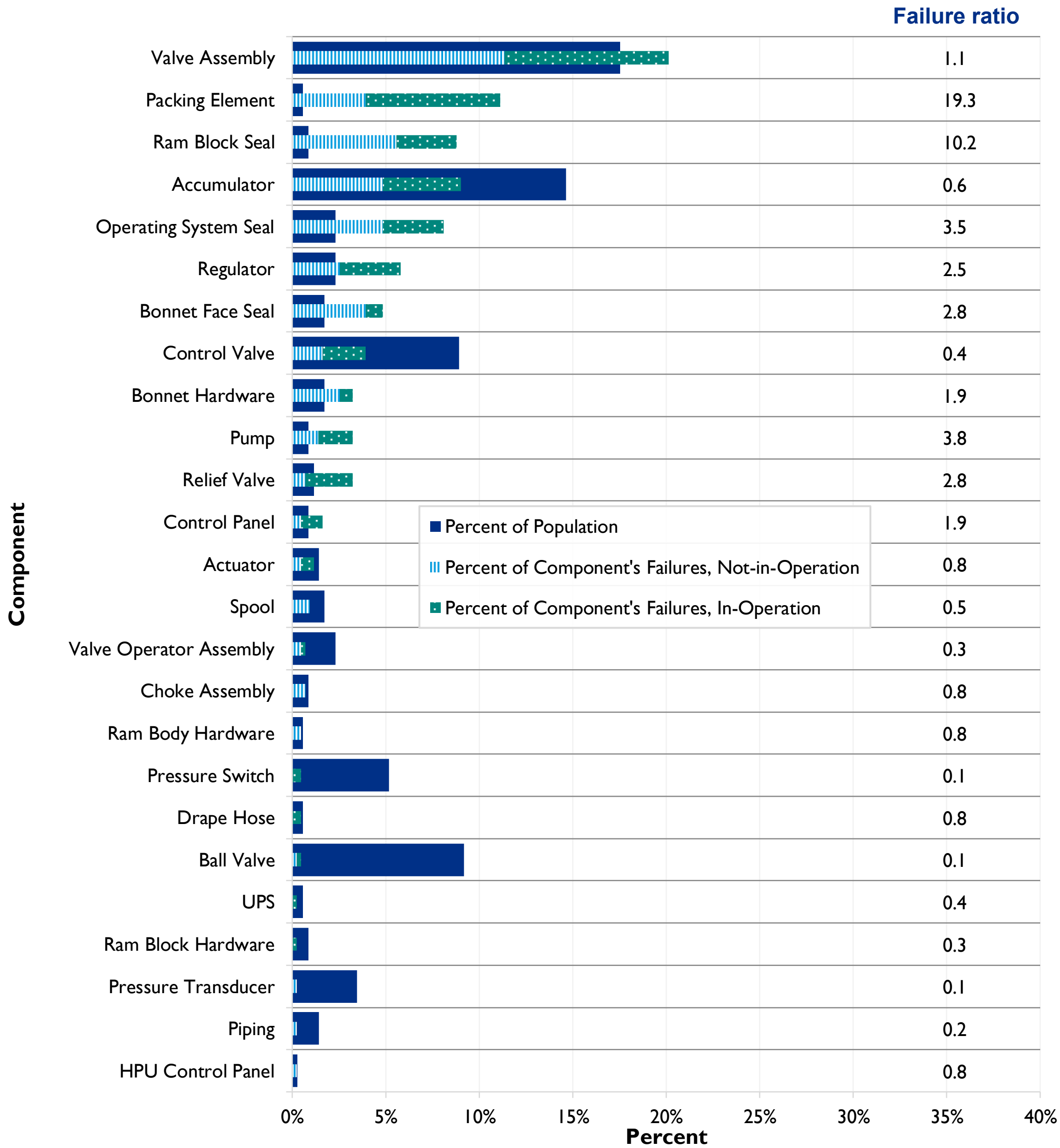
[17] United States Department of Transportation, Bureau of Transportation Statistics. Supplement: Estimated Well Control Equipment System Component Counts. Washington, DC: 2024. https://doi.org/10.21949/wrfz-nr33.

assembly, packing element, ram block seal, operating system seal, and regulator) had a failure ratio greater than 1.0, meaning they had a disproportionately high number of reports as compared to their population, relative to other components. Bonnet face seal, bonnet hardware, pump, relief valve, and control panel also had failure ratios greater than 1.0. 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.
- **Operating system seals:** This group of components includes seals in the bonnet or operator for annular preventers, pipe ram preventers, and shear ram preventers. It also includes the bonnet face seals. In 2023, there were six reported bonnet operating seal failures where in previous years there were typically just one or two failures on surface stacks. A piston coating failure due to a manufacturing issue was involved in three of the events, which are noted in Table 17.
- **Regulators:** The typical rig with a surface BOP stack has eight pressure regulators. Four reported failures of regulators on surface BOP stacks occurred in 2023, which is about the average (7.3 percent in 2023 versus 7.5 percent on average from 2017 to 2023). The failures did not indicate any emerging trends as they involved different manufacturers, different rigs, and different control fluids. One of the components failed in less than 3 months, one elastomeric/electrical component failed in less than 1 year, and one metallic component failed in less than 2 years. The elastomeric/electrical component was a bolt that was investigated and determined to be a manufacturing issue (refer to Table 17 for preventive actions taken).

Figure 7. Surface System Component Failures Relative to Component Population (Using Updated Component Population Estimates), 2017–2023



NOTE: Percent of failures represents the percentage of 432 surface system failures from 2017–2023. Piping/tubing/hose/fitting (2.1 percent of failures) and Other (8.6 percent of failures) are not represented in the table as they do not have an estimated population average. Failure ratio, shown in righthand column, represents the component's percent of failures divided by that component's percent of the population.

SOURCE: USDOT, BTS, SafeOCS Program.

Failure Types

Similar to subsea systems, most events from 2017 to 2023 on surface systems were a type of leak, comprising 80.7 percent of events (Table 13). However, in contrast to subsea systems, internal leaks were more common than external leaks on surface systems over the 7-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 13. Failure Types of Surface System Events, 2017–2023

Failure type		2017 (n=110)	2018 (n=69)	2019 (n=87)	2020 (n=21)	2021 (n=46)	2022 (n=43)	2023 (n=55)	Total (n=431)
Leaks	External leak	30.9%	34.8%	39.1%	61.9%	23.9%	32.6%	25.5%	33.4%
	Internal leak	49.1%	49.3%	40.2%	14.3%	63.0%	51.2%	49.1%	47.3%
Other	Communication/ signal issue	0.0%	2.9%	3.4%	0.0%	0.0%	0.0%	0.0%	1.2%
	Electrical issue	0.0%	2.9%	0.0%	4.8%	0.0%	0.0%	0.0%	0.7%
	Fail to function on command	2.7%	2.9%	4.6%	4.8%	4.3%	4.7%	3.6%	3.7%
	Inaccurate indication	0.0%	0.0%	1.1%	0.0%	0.0%	0.0%	0.0%	0.2%
	Mechanical issue	14.5%	2.9%	6.9%	9.5%	4.3%	4.7%	5.5%	7.7%
	Process issue	2.7%	4.3%	3.4%	0.0%	2.2%	4.7%	1.8%	3.0%
	Unintended operation	0.0%	0.0%	0.0%	4.8%	0.0%	0.0%	0.0%	0.2%
	Other	0.0%	0.0%	1.1%	0.0%	2.2%	2.3%	14.5%	2.6%
Total	**—**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

NOTE: — Not applicable.
SOURCE: USDOT, BTS, SafeOCS Program.

Component types with the most internal leaks from 2017 to 2023 include gate valve hardware, hardware, and operating system seals. 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, followed closely by mechanical issues. Of other frequently failing components, packing elements most commonly experienced general leakage (85.4 percent), and ram block seals failed to seal in all cases (38).

Detection Methods

On average from 2017 to 2023, about half of surface system events were detected while not in operation, i.e., during maintenance, inspection, and testing. As noted in the detection methods section for subsea systems (refer to p. 23), further analysis of the detailed detection methods has been omitted while SafeOCS develops revisions to the detection methods selections to clarify definitions and promote consistency in reporting.

Root Causes of Events

As with subsea systems, most surface system events from 2017 to 2023 (62.9 percent) were attributed to wear and tear. As shown in Table 14, the percentage of surface system events attributed to wear and tear decreased each year after a spike in 2020. Detailed review of notifications indicates that, like 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 14. Root Causes of Surface System Events, 2017–2023

Reported root cause		2017 (n=110)	2018 (n=69)	2019 (n=87)	2020 (n=21)	2021 (n=46)	2022 (n=43)	2023 (n=56)	Total (n=432)
Determined	Design issue	3.6%	7.2%	2.3%	0.0%	0.0%	7.0%	0.0%	3.2%
	QA/QC manufacturing	3.6%	4.3%	5.7%	0.0%	6.5%	4.7%	7.1%	4.9%
	Maintenance error	2.7%	7.2%	14.9%	0.0%	0.0%	2.3%	7.1%	6.0%
	Procedural error	1.8%	1.4%	3.4%	0.0%	2.2%	0.0%	0.0%	1.6%
	Wear and tear	48.2%	58.0%	48.3%	90.5%	89.1%	81.4%	75.0%	63.0%
	Other	7.2%	1.4%	4.6%	4.8%	0.0%	0.0%	5.4%	3.9%
Not determined	Inconclusive	0.9%	1.4%	2.3%	0.0%	0.0%	0.0%	0.0%	0.9%
	Assessment pending	5.5%	8.7%	2.3%	0.0%	2.2%	4.7%	5.4%	4.6%
	Not reported	26.4%	10.1%	16.1%	4.8%	0.0%	0.0%	0.0%	11.8%
Total	**—**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

NOTE: — Not applicable.
SOURCE: USDOT, BTS, SafeOCS Program.

Wear and tear was also the top root cause for failures of frequently reported components from 2017 to 2023, shown in Table 15. Similar to the trend in 2022, in addition to wear and tear, commonly reported root causes included 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 15. Root Causes of Frequently Reported Components for Surface Systems, 2017–2023

Reported root cause		Packing element	Ram block seal	Accumulator	Gate valve hardware	Hardware	Choke and kill valve	Regulator
Determined	Design issue	4.2%	13.2%	2.7%	0.0%	0.0%	0.0%	4.0%
	QA/QC manufacturing	2.1%	0.0%	5.4%	2.9%	0.0%	3.8%	8.0%
	Maintenance error	2.1%	5.3%	27.0%	2.9%	0.0%	7.7%	8.0%
	Procedural error	0.0%	2.6%	0.0%	9.9%	0.0%	0.0%	0.0%
	Wear and tear	70.8%	65.8%	51.4%	44.1%	96.3%	61.5%	72.0%
	Other	2.1%	0.0%	0.0%	17.6%	0.0%	7.7%	0.0%
Not determined	Inconclusive	0.0%	0.0%	0.0%	2.9%	0.0%	3.8%	4.0%
	Assessment pending	6.3%	10.5%	2.7%	0.0%	3.7%	0.0%	0.0%
	Not reported	12.5%	2.6%	10.8%	29.4%	0.0%	15.4%	4.0%
Total	**—**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

NOTE: — Not applicable.
SOURCE: USDOT, BTS, SafeOCS Program.

In-Operation Events Including BOP Stack Pulls

From 2017 to 2023, a total of 212 in-operation events were reported for surface WCE systems, including 63 BOP stack pulls. An additional 42 BOP stack pulls were identified in WAR data. When adjusted for the level of activity, an average of 8.3 events occurred per 1,000 in-operation BOP days over the 7-year period.

Table 16 shows the equipment involved in events leading to surface BOP stack pulls from 2017 to 2023, as well as the total number of in-operation events for those component combinations. There were 130 in-operation events of these component combinations, 105 of which resulted in a stack pull. Of the component types associated with surface BOP stack pulls, annular packing elements have been associated with the most stack pulls (55), followed by ram block seals (16), operating system seals (7), and bonnet operating seals (7). 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 needed to be repaired or replaced before operations could continue.

As was the case in 2022, each of the events in 2023 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.

From 2017 to 2023, 95 BOP stack pulls involved a type of leak, including 41 of the 42 identified in WAR data. For the 63 BOP stack pulls reported to SafeOCS from 2017 to 2023, 38 cited a root cause of wear and tear. The remaining cases cited design issue (5), QA/QC manufacturing (3), maintenance error (2), procedural error (1), other (1), or not root cause listed (8). For the BOP stack pulls identified in WAR data, there is typically insufficient detail available to discern the root cause.

In 2023, three surface BOP stack pulls were reported to SafeOCS and an additional six were identified in WAR data. These included six failures of annular packing elements on the annular preventer, an external leak of a wellhead connector ring gasket, a bonnet operating seal failure, and a pipe ram preventer ram block seal failure. Most of these failures involved failures to seal (six of nine), two were external leaks, and one failed to close. Additional details from the nine individual events are summarized below. Those found in WAR may contain less detail:

- After pumping proppant, a BOP test was performed and the annular element failed the leakage test. The annular element was replaced.
- During tool running operations, the tool was unable to pass through the annular BOP. The well was secured, and a new annular element was installed.
- After cementing, a tool was unable to pass through the annular BOP and a new annular element was installed.
- When preparing to test the BOP (running in hole with BOP test plug and centralizer assembly), the annular element was found to be hanging halfway across wellbore into the open hole. Large chunks of rubber were coming off the packing element, causing obstruction of the BOP test plug assembly.
- After drilling and increasing mud weight, the BOP was tested, and the annular element was replaced with BSEE approval of testing procedures.

- After setting a sump packer and performing other rig maintenance, the BOP was tested, and the annular element failed its leakage test. The annular element was replaced.
- The day after applying acid and a mini-frac, the BOP was tested. The well was secured, and the ring gasket between the surface BOP and the surface wellhead was replaced.
- After drilling a section of the wellbore, pressure loss on the manifold pressure was noted on the control system. Multiple BOP components, including the double pipe rams, were found leaking and were replaced.
- While testing the BOP, a leak was observed from the four-way control valve draining back into the unit reservoir. After changing the four-way valve and retesting, it was determined that the upper variable bore pipe ram (VBR) failure was disguised as a four-way valve failure. The upper VBRs were leaking and were replaced.

Table 16. Component Combinations of Surface BOP Stack Pulls, 2017–2023

Submit	Item	Component	2017–2023	
			In-operation events	Stack pulls
BOP controls	BOP control panel	Central control console	1	1
		Instrumentation	2	1
	HPU mix system	Regulator	3	1
		Selector manipulator valve	6	2
	Surface control system	Regulator	9	2
BOP stack	Annular preventer	Hardware_all other mechanic	1	1
		Operating system seal	9	7
		Packing element	59	55
	Pipe ram preventer	Bonnet face seal	5	3
		Bonnet operating seal	4	3
		Bonnet seal	1	1
		Ram block seal	7	6
	Shear ram preventer	Bonnet face seal	2	2
		Bonnet operating seal	5	4
		Hardware_all other mechanic	2	2
		Ram block hardware	1	1
		Ram block seal	10	10
		Unknown	1	1
	Wellhead connector	Ring gasket	1	1

Submit	Item	Component	2017–2023	
			In-operation events	Stack pulls
Riser System	Riser	Flange	1	1
Total	**—**	**—**	**130**	**105**

NOTES:
- — Not applicable.
- 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: USDOT, BTS, SafeOCS Program.

Investigation and Analysis

Investigation and failure analysis (I&A) information was received for 14 of the 55 surface system events in 2023. The I&As included one at the SME review level and 11 for events with immediately known causes. Table 17 summarizes the findings for two I&As that included at least one recommended preventive action.

Table 17. Findings from I&As for Surface System Events, 2023

Reported root cause	Root Cause Details	Recommended preventive action	Total events since 2017	2023 events	2023 events <1 year
QA/QC manufacturing	Regulator piston retention bolt loosened after 7 months, allowing a seal to leak externally.	After replacing the failed regulator, the equipment owner applied thread locking compound during reassembly of the repaired regulator. OEM to be advised of field design change.	1	1	1
QA/QC manufacturing	A manufacturing defect caused piston coating to fail on a pipe ram operator.	The OEM is working with the vendor to understand how the substrate is deemed acceptable and properly prepared for the coating application process.	3	3	1

SOURCE: USDOT, BTS, SafeOCS Program.

Many of the submitted failure reports in 2023 included lessons learned that suggest more general ongoing actions or next steps, which have not been included in Table 17. With additional information from reporting operators, SafeOCS could share more detail about preventive actions taken, such as changes to procedures or practices mentioned generally but not fully explained. These lessons learned are listed as follows:

- For several events, lessons learned included phrases such as “continue testing and monitoring” or “continue visual inspection during testing,” without a more specific, completable task.
- After a regulator failure, the lesson learned was to apply a light duty Loctite adhesive to bolting to prevent potential back out of the threaded fastener.
- A relief valve failed to reseat four months after installation. The lesson learned was that if BOP stacks are unused, some level of preservation must be performed, and the units should be functioned.
- When checking accumulator pre-charge and performing other maintenance on the unit, check four-bolt flange connections for proper tightness.
- The submitter suggested that the five-year maintenance scope be changed to replace, rather than repair, four-way control valves.
- After a shear ram preventer failed a pressure test, the reported lesson was to equalize pressure across rams before opening.

Chapter 4: Topics of Interest

Nickel Leaching

The issue of nickel binder leaching on tungsten carbide-coated seal plates in the GOM OCS began appearing with 4 events in 2018, 45 in 2019, 97 events in 2020, 24 in 2021, 20 in 2022, and 2 in 2023. The issue is discussed in previous SafeOCS annual reports. Based on submitted RCFA information, the use of demineralized water to produce makeup BOP control fluids was determined to be the cause of all 192 events.

BSEE published Safety Alert Number 443 on the topic of nickel leaching on June 23, 2022.[18] In the alert, BSEE recommended that operators and contractors consider the following:

- To prevent nickel leaching, equipment owners/operators should develop and implement a water hardening system and use water that has not been fully deionized as a base for the control fluid.
- Ensure offshore personnel operating well control equipment systems follow the OEM safety bulletins for fluid quality specifications.
- Provide detailed instructions, training, competency assessment, and supervision to equipment operators and maintenance personnel to maintain hydraulic fluid quality.
- Incorporate incidents as part of the safety talks for personnel directly involved in these operations as well as other appropriate discussions.
- Verify and document whether well control equipment systems installation and commissioning meet approved OEM specifications. If inspections do not meet OEM specifications, corrective action(s) should be taken and documented.
- Ensure personnel are trained and records documented in well control equipment systems control configurations, well control equipment systems maintenance, and maintenance of hydraulic fluid quality to the OEM specifications.

[18] Bureau of Safety and Environmental Enforcement, Safety Alert No. 443: Improperly Maintained Well Control Equipment (June 23, 2022), https://www.bsee.gov/sites/bsee.gov/files/safety-alerts//bsee-safety-alert-443-improperly-maintained-well-control-equipment.pdf.

- Share lessons learned for well control equipment systems described [in the Safety Alert] among operating companies, rig operators, system OEMs, and component manufacturers.

Telescopic Joint Events

On subsea BOP systems, the telescopic joint (TJ) is a special joint installed in the riser above sea level to accommodate vertical movement of the drilling vessel. The joint includes an inner pipe and outer pipe, separated by a sealing mechanism, which allows the effective length of the riser to change dynamically during variable sea states.

TJ failures increased from one event in 2022 to 10 in 2023, and seven of these occurred while the BOP was in operation. All 10 TJ packing seals failed due to material composition (chemistry) or due to out-of-specification gasket (seal) dimensions. The OEM redesigned the TJ to resolve the issues. Six of the 10 events occurred with less than 1 year of operation, 2 failures were within 2 years of installation, and the installation date was not provided for the remaining 2 events.

One TJ event in 2023 resulted in a loss of containment (LOC) of 48 barrels (bbls) of wellbore fluids (calcium chloride brine) during a heading change of the drillship while completing a well. The subsea BOP was closed to stop the discharge to the environment. This packing seal failure, after less than three months in service, was determined by the OEM to be a design issue, and a new design was deployed. The new design uses a modified geometry as well as a different material.

Reporting Form Update

BTS began an extensive review of the data collection form in 2023 to improve data quality without increasing reporting burden. Updates from this work include:

1. Revisions to the dropdown choices available on several data fields to avoid overlap and improve data quality.
2. Addition of data fields to improve information sharing of lessons learned.
3. Data validation on certain fields to reduce unintended entries.

4. Auto population of fields such as Region and Country based on the Well API Number entry.
5. Additional explanations and definitions in the user guidance document.

In addition, BTS is working with the industry to automate some data transfer to reduce burden on operators.

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.[19] 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 as a result of a failure, then you must, within 30 days of such changes, report the

[19] 84 Fed. Reg. 21,908 (May 15, 2019).

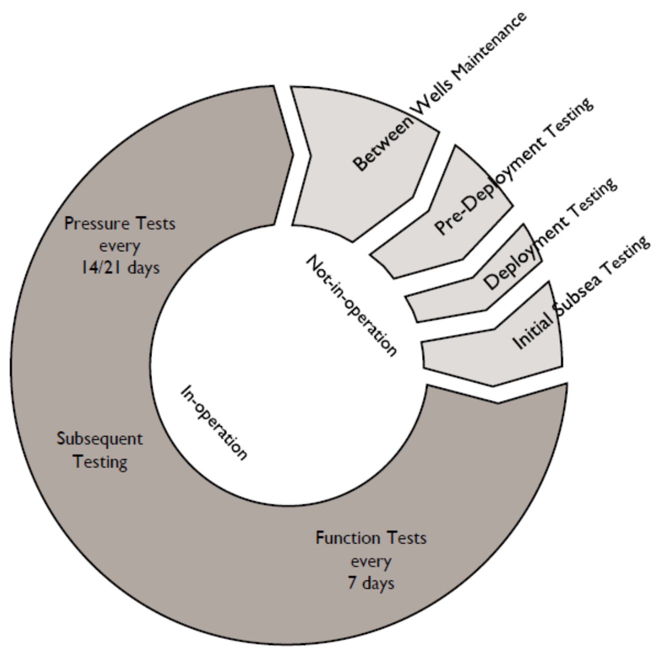
design change or modified procedures in writing to the Chief OORP, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section.

(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.

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



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: USDOT, BTS, SafeOCS Program.

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.

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.[20] The remainder of this section

[20] 30 CFR 250.737, 250.739.

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 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:

- **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 riser mounted choke and kill line sections, 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. 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 7 days,[21] all the non-latching equipment[22] is function tested; all rams, annulars, and valves are closed and opened to confirm that they can operate if required. Every 14 days,[23] all pipe rams, annulars, valves, and the choke manifold are pressure tested. Every 21 days, the acoustic batteries are checked,[24] and the shear rams are pressure-tested.[25] 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.[26] 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.

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

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[21] 30 CFR 250.737 and API Standard 53 (4th ed.) section 7.6.5.1.1.
[22] 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.
[23] 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).
[24] API Standard 53 (4th ed.) table 7.
[25] 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.
[26] API Standard 53 (4th ed.) table 7.

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: YEARLY NUMBERS AT A GLANCE, 2017–2023

Table 18. Numbers at a Glance, 2017–2023

Measure		2017	2018	2019	2020	2021	2022	2023	Total (2017–2023)	Average (2017–2023)
Wells	Wells with activity	328	397	399	265	250	285	271	1,763	313.6
	Wells spudded	150	193	188	113	106	129	125	1,004	143.4
Rigs	Rigs with activity	60	60	63	50	38	44	43	87	51.1
	Rigs with reported events	48	40	36	32	26	30	28	73	34.3
Operators	Active operators	28	30	29	27	21	24	22	43	25.9
	Reporting operators	18	14	13	14	12	14	9	26	13.4
BOP days	Total BOP days	17,467	18,389	18,305	14,068	13,264	15,908	16,365	113,766	16,252
	Not-in-operation BOP days	7,520	7,555	7,716	6,979	6,461	7,270	7,672	51,172	7,310
	In-operation BOP days	9,947	10,834	10,589	7,089	6,803	8,638	8,693	62,594	8,942
	Subsea system BOP days	12,222	11,482	11,119	9,932	9,230	11,071	12,512	77,568	11,081
	Surface system BOP days	5,245	6,907	7,186	4,136	4,034	4,837	3,853	36,198	5,171
Component events	Total events reported	1,431	1,197	995	664	418	520	337	5,562	795
	Overall event rate	81.9	65.1	54.4	47.2	31.5	32.7	20.6	48.9	47.6
	Not-in-operation events	1,231	1,055	871	594	348	448	262	4,809	687
	In-operation events	200	142	124	70	70	72	75	753	108
	Subsea system events	1,321	1,128	908	643	372	477	281	5,130	733
	Surface system events	110	69	87	21	46	43	56	432	62
LOC events	Loss of containment events	1	0	0	0	0	0	1	2	0.29

NOTES:
- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–2023 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

SOURCE: USDOT, BTS, SafeOCS Program.

Table 19. Subsea System Numbers at a Glance, 2017–2023

Measure		2017	2018	2019	2020	2021	2022	2023	Total (2017–2023)	Average (2017–2023)
Wells	Wells with activity	167	173	191	142	136	144	163	844	159.4
	Wells spudded	89	107	101	73	54	65	77	566	80.9
Rigs	Total rigs with activity	32	31	29	26	21	25	27	45	27.3
	With one subsea stack	10	9	8	6	5	5	4	13	6.7
	With two subsea stack	22	22	21	20	16	20	23	32	20.6
	Rigs with reported events	29	24	21	22	16	19	19	40	21.4
Operators	Active operators	17	16	20	19	14	15	15	23	16.6
	Reporting operators	11	10	10	11	10	12	8	21	10.3
BOP days	Total BOP days	12,222	11,482	11,119	9,932	9,230	11,071	12,512	77,568	11,081
	Not-in-operation BOP days	5,835	5,755	5,798	5,580	5,316	5,824	6,475	40,583	5,798
	In-operation BOP days	6,387	5,727	5,321	4,352	3,914	5,247	6,037	36,985	5,284
Component events	Total events reported	1,321	1,128	908	643	372	477	281	5,130	733
	Overall event rate	108.1	98.2	81.7	64.7	40.3	43.1	22.5	66.1	65.5
	Not-in-operation events	1,169	1,022	826	587	329	424	232	4,589	655.6
	Not-in-operation event rate	200.3	177.6	142.5	105.2	61.9	72.8	35.8	113.1	113.7
	Not-in-operation events per well	7.0	5.9	4.3	4.1	2.4	2.9	1.4	5.4	4.0
	In-operation events	152	106	82	56	43	53	49	541	77.3
	In-operation event rate	23.8	18.5	15.4	12.9	11.0	10.1	8.1	14.6	14.3
	In-operation events per well	0.9	0.6	0.4	0.4	0.3	0.4	0.3	0.6	0.5
BOP stack movements	Total stack runs	203	179	220	173	145	153	167	1,240	177.1
	Successful runs	166	152	171	170	144	141	163	1,107	158.1
	In-operation stack pulls	9	8	8*	7*	3*	6*	7*	48	6.9
LOC events	Loss of containment events	1	0	0	0	0	0	1	2	0.29

NOTES:
- * Includes some BOP stack pulls identified in WAR. Table 2 provides counts. These are not included in *Total Events Reported*.
- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–2023 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

SOURCE: USDOT, BTS, SafeOCS Program.

Table 20. Surface System Numbers at a Glance, 2017–2023

Measure		2017	2018	2019	2020	2021	2022	2023	2017–2023 total	2017–2023 average
Wells	Wells with activity	161	224	208	123	114	141	108	919	154.1
	Wells spudded	61	86	87	40	52	64	48	438	62.6
Rigs	Rigs with activity	28	29	34	24	17	19	16	42	23.9
	Rigs with reported events	19	16	15	10	10	11	9	33	12.9
Operators	Active operators	19	24	21	17	12	16	15	33	17.7
	Reporting operators	11	8	9	8	6	6	4	13	7.4
BOP Days	Total BOP days	5,245	6,907	7,186	4,136	4,034	4,837	3,853	36,198	5,171
	Not-in-operation BOP days	1,685	1,800	1,918	1,399	1,145	1,446	1,197	10,589	1,513
	In-operation BOP days	3,560	5,107	5,268	2,737	2,890	3,391	2,656	25,609	3,658
Component events	Total events reported	110	69	87	21	46	43	56	432	61.7
	Overall event rate	21.0	10.0	12.1	5.1	11.4	8.9	14.5	11.9	11.9
	Not-in-operation events	62	33	45	7	19	24	30	220	31.4
	Not-in-operation event rate	36.8	18.3	23.5	5.0	16.6	16.6	25.1	20.8	20.3
	Not-in-operation events per well	0.4	0.1	0.2	0.1	0.2	0.2	0.3	0.2	0.2
	In-operation events	48	36	42	14	27	19	26	212	30.3
	In-operation event rate	13.5	7.0	8.0	5.1	9.3	5.6	9.8	8.3	8.3
	In-operation events per well	0.3	0.2	0.2	0.1	0.2	0.1	0.2	0.2	0.2
BOP stack movements	Total stack runs	216	245	227	133	121	161	110	1,213	173.3
	Successful runs	183	242	214	1121	121	152	106	1,139	162.7
	In-operation stack pulls	11	10	36*	9*	16*	14*	9*	105	15.0
LOC events	Loss of containment events	0	0	0	0	0	0	0	0	0

NOTES:
- * Includes some BOP stack pulls identified in WAR. Table 2 provides counts. These are not included in *Total Events Reported*.
- Event rate is the number of events that occurred per 1,000 BOP days.
- The 2017–2023 totals for rigs, operators, and wells with activity measures represent the number of unique entities.

SOURCE: USDOT, BTS, SafeOCS Program.

Appendix D: Component Failures, 2017–2023

Table 21. Components Involved in Reported Subsea System Failures

Component	2017 (n=1,321)	2018 (n=1,128)	2019 (n=908)	2020 (n=643)	2021 (n=372)	2022 (n=478)	2023 (n=277)	Total (n=5,127)
Regulator	8.7%	12.4%	13.1%	13.2%	12.9%	9.4%	12.6%	11.4%
Solenoid valve hydraulic	9.4%	4.7%	12.4%	10.4%	3.8%	4.8%	2.9%	7.8%
SPM valve	9.8%	6.7%	6.1%	7.3%	5.1%	8.4%	9.0%	7.6%
Shuttle valve	5.3%	3.8%	6.2%	9.0%	7.0%	10.9%	13.4%	6.7%
Slide shear seal valve	6.6%	7.4%	3.1%	8.4%	7.3%	5.4%	1.8%	6.0%
Piping tubing	5.0%	7.1%	4.1%	3.9%	7.3%	2.5%	0.7%	4.9%
Accumulator	3.3%	6.6%	2.5%	2.5%	2.2%	4.4%	2.9%	3.8%
Bonnet operating seal	2.0%	2.5%	3.0%	3.1%	2.7%	2.1%	2.2%	2.5%
Choke and kill valve	3.2%	1.6%	1.8%	0.9%	7.5%	1.5%	2.2%	2.4%
Pressure gauge	2.0%	1.8%	1.7%	1.1%	1.3%	3.8%	3.6%	2.0%
Ram block seal	1.7%	1.8%	1.2%	2.0%	2.2%	3.6%	2.2%	1.9%
Hardware_all other mechanical elements	1.7%	2.7%	2.1%	0.9%	1.9%	1.7%	0.7%	1.9%
Relief valve	1.8%	1.5%	2.2%	1.4%	1.9%	1.0%	3.6%	1.8%
Choke and kill valve operator seal	1.6%	1.0%	1.3%	4.5%	1.3%	0.6%	0.4%	1.6%
Hardware	2.2%	2.7%	0.7%	1.2%	0.5%	0.8%	0.0%	1.5%
Hose	0.9%	1.3%	2.3%	0.8%	0.8%	1.5%	2.9%	1.4%
Operating system seal	1.9%	1.0%	1.0%	1.4%	0.8%	1.7%	1.8%	1.4%
Pod packer	0.1%	0.5%	4.5%	1.1%	1.3%	0.4%	1.1%	1.3%
Gas valve	0.5%	2.0%	2.8%	1.4%	0.5%	0.0%	0.0%	1.2%
Pilot-operated check valve	0.8%	0.8%	1.8%	1.7%	0.5%	1.9%	1.1%	1.2%
Pressure transducer	0.7%	0.5%	0.9%	1.1%	2.4%	1.7%	3.2%	1.1%
Interface seal	0.9%	2.4%	0.7%	0.5%	0.3%	0.4%	0.4%	1.0%
PBOF cable	0.5%	0.8%	1.2%	1.4%	0.3%	2.5%	0.7%	1.0%
Choke and kill line	0.0%	4.3%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%
Pod hose	1.5%	0.2%	2.2%	0.3%	0.3%	0.4%	0.4%	0.9%
SEA_Subsea electronic assembly	1.5%	0.6%	1.0%	0.8%	0.3%	0.2%	0.7%	0.9%
Hydraulic stab	0.8%	0.6%	0.8%	1.1%	0.5%	0.8%	1.4%	0.8%
Other	0.5%	0.1%	0.7%	1.1%	2.2%	2.1%	0.7%	0.8%
Check valve	0.8%	0.4%	0.7%	0.3%	1.6%	1.0%	1.8%	0.8%
Choke and kill connector_ receptacle_female	0.5%	0.9%	0.7%	0.6%	1.6%	1.0%	0.4%	0.7%
Ball valve	0.7%	0.2%	0.3%	1.1%	0.8%	2.1%	1.1%	0.7%

Component	2017 (n=1,321)	2018 (n=1,128)	2019 (n=908)	2020 (n=643)	2021 (n=372)	2022 (n=478)	2023 (n=277)	Total (n=5,127)
Flowmeter	0.8%	1.2%	0.3%	0.3%	0.8%	0.2%	0.4%	0.7%
Cylinder	0.1%	0.4%	0.3%	0.9%	3.0%	1.0%	0.4%	0.6%
Packing element	0.4%	0.6%	1.4%	0.2%	0.3%	1.0%	0.0%	0.6%
Electrical connector	0.7%	0.4%	0.7%	0.6%	0.8%	0.8%	0.4%	0.6%
Pod stab	1.7%	0.2%	0.3%	0.2%	0.3%	0.0%	0.4%	0.6%
Locking device	0.7%	1.3%	0.1%	0.0%	0.3%	0.6%	0.7%	0.6%
SEM_Subsea electronic module	0.7%	0.1%	0.6%	0.8%	0.3%	1.3%	0.7%	0.6%
Gate valve hardware	1.4%	0.4%	0.1%	0.0%	0.3%	0.4%	0.0%	0.5%
Filter	0.3%	0.4%	0.4%	0.5%	1.3%	1.3%	0.0%	0.5%
Ram block hardware	0.5%	0.8%	0.2%	0.0%	0.3%	0.8%	0.7%	0.5%
Trigger valve	0.7%	0.1%	0.0%	0.8%	1.3%	0.4%	0.7%	0.5%
Metering needle valve	0.3%	0.7%	0.3%	1.1%	0.3%	0.0%	0.0%	0.4%
Packer	0.4%	0.4%	0.1%	0.0%	0.3%	0.2%	3.6%	0.4%
Choke and kill operator hardware	0.3%	0.2%	0.7%	0.9%	0.5%	0.4%	0.0%	0.4%
Hot line hose	0.8%	0.1%	0.3%	0.3%	1.3%	0.2%	0.0%	0.4%
Depth compensated accumulator	1.0%	0.5%	0.0%	0.2%	0.0%	0.2%	0.4%	0.4%
Central control console	0.3%	0.5%	0.3%	0.3%	0.5%	0.6%	0.4%	0.4%
Secondary gripper	0.8%	0.7%	0.0%	0.0%	0.0%	0.4%	0.0%	0.4%
Compensated chamber	0.4%	0.5%	0.1%	0.2%	0.5%	0.8%	0.4%	0.4%
Drillers control panel	0.6%	0.3%	0.4%	0.0%	0.3%	0.8%	0.0%	0.4%
Pod receptacle	0.5%	0.5%	0.1%	0.0%	0.3%	1.0%	0.0%	0.4%
Bonnet face seal	0.4%	0.4%	0.2%	0.3%	0.5%	0.0%	1.4%	0.4%
Solenoid valve electric	0.2%	0.7%	0.3%	0.3%	0.0%	0.4%	0.4%	0.4%
Mud boost valve	0.2%	0.4%	0.4%	0.6%	0.3%	0.2%	1.1%	0.4%
Ring gasket	0.6%	0.2%	0.2%	0.2%	0.0%	0.6%	0.7%	0.4%
Flowline seal	0.2%	0.4%	0.7%	0.5%	0.0%	0.0%	0.7%	0.4%
Pump	0.4%	0.5%	0.2%	0.3%	0.0%	0.4%	0.4%	0.4%
ROV valve	0.2%	0.2%	0.6%	0.3%	0.8%	0.4%	0.0%	0.3%
Hydraulic tool	0.2%	0.4%	0.1%	0.0%	0.3%	0.8%	1.8%	0.3%
Pressure temperature sensor	0.3%	0.4%	0.2%	0.2%	0.0%	0.8%	0.0%	0.3%
End connection	0.3%	0.2%	0.4%	0.3%	0.5%	0.0%	0.4%	0.3%
Flex loop hose	0.2%	0.3%	0.7%	0.0%	0.5%	0.0%	0.7%	0.3%
Selector manipulator valve	0.4%	0.2%	0.4%	0.0%	0.3%	0.2%	0.4%	0.3%
MUX cable	0.3%	0.2%	0.1%	0.5%	0.8%	0.2%	0.0%	0.3%
HPU control panel	0.2%	0.0%	0.7%	0.3%	0.3%	0.2%	0.4%	0.3%
Instrumentation	0.5%	0.1%	0.3%	0.0%	0.0%	0.0%	1.1%	0.3%

Component	2017 (n=1,321)	2018 (n=1,128)	2019 (n=908)	2020 (n=643)	2021 (n=372)	2022 (n=478)	2023 (n=277)	Total (n=5,127)
Bonnet hardware_all other mechanical elements	0.8%	0.0%	0.0%	0.0%	0.0%	0.4%	0.4%	0.3%
Interconnect cable	0.2%	0.4%	0.2%	0.0%	0.5%	0.0%	0.7%	0.3%
Timing circuit	0.2%	0.2%	0.1%	0.9%	0.3%	0.0%	0.0%	0.2%
Choke and kill spool	0.2%	0.7%	0.1%	0.0%	0.0%	0.0%	0.0%	0.2%
Inclinometer	0.2%	0.2%	0.3%	0.2%	0.0%	0.0%	1.1%	0.2%
Quick dump valve	0.1%	0.5%	0.1%	0.2%	0.3%	0.2%	0.0%	0.2%
MUX cable connector	0.0%	0.3%	0.4%	0.2%	0.3%	0.0%	0.4%	0.2%
UPS	0.2%	0.0%	0.4%	0.2%	0.0%	0.0%	0.4%	0.2%
Auxiliary control panel	0.0%	0.1%	0.1%	0.5%	0.3%	0.2%	0.4%	0.2%
Toolpushers control panel	0.1%	0.3%	0.1%	0.5%	0.0%	0.0%	0.0%	0.2%
Primary gripper	0.1%	0.1%	0.2%	0.0%	0.0%	0.6%	0.4%	0.2%
Studs and nuts	0.0%	0.5%	0.0%	0.0%	0.0%	0.2%	0.0%	0.1%
Ram cavity	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.7%	0.1%
Wet mate connector	0.0%	0.2%	0.2%	0.0%	0.0%	0.6%	0.0%	0.1%
Software	0.2%	0.0%	0.0%	0.2%	0.5%	0.2%	0.0%	0.1%
Actuator	0.0%	0.0%	0.1%	0.0%	0.5%	0.4%	0.0%	0.1%
Side outlet	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.1%
Reel	0.2%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%	0.1%
Subsea control panel	0.1%	0.1%	0.1%	0.0%	0.0%	0.2%	0.4%	0.1%
Conduit manifold	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Hydraulic gate valve actuator	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%
Pressure switch	0.1%	0.0%	0.2%	0.2%	0.0%	0.0%	0.0%	0.1%
Kill hose	0.2%	0.0%	0.1%	0.0%	0.0%	0.2%	0.0%	0.1%
DRG valve	0.2%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.1%
Choke and kill Stab_Male	0.2%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%
Inside BOP	0.2%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.1%
Slip ring	0.0%	0.1%	0.1%	0.2%	0.0%	0.0%	0.0%	0.1%
Choke hose	0.0%	0.1%	0.1%	0.0%	0.0%	0.2%	0.0%	0.1%
Auto choke actuator	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.4%	0.1%
Riser control Box_RCB	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.4%	0.06%
HP swivel	0.1%	0.0%	0.0%	0.0%	0.3%	0.0%	0.4%	0.06%
Variable pilot valve	0.1%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.06%
Transducer	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.04%
Junction box	0.0%	0.0%	0.1%	0.0%	0.3%	0.0%	0.0%	0.04%
Locking dog	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.04%
Auto choke valve	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.04%
Cable	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.04%

Component	2017 (n=1,321)	2018 (n=1,128)	2019 (n=908)	2020 (n=643)	2021 (n=372)	2022 (n=478)	2023 (n=277)	Total (n=5,127)
Kelly valve	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.04%
Transponder	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.04%
Inner barrel lock	0.1%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.04%
Surface control unit	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.04%
Vessel piping	0.1%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%	0.04%
Riser coupling	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.04%
BLAT	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.02%
Block	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.02%
Compensator	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.02%
Insert packer	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.02%
Drillstring safety valve	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.02%
Hydraulic control interface	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.02%
Transducer deployment arm	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.02%
Battery	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.02%
Other line	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.02%
Conduit line	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.02%
Manual tool	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.02%
Choke manifold control valve	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.02%
Manual choke actuator	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%	0.02%
HFGS	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.02%
ROV stinger hot stab	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.02%

NOTE: Percent refers to percent of total reported subsea BOP component failures.
SOURCE: USDOT, BTS, SafeOCS Program.

Table 22. Components Involved in Reported Surface System Failures

Component	2017 (n=110)	2018 (n=69)	2019 (n=87)	2020 (n=21)	2021 (n=46)	2022 (n=43)	2023 (n=56)	Total (n=432)
Packing element	8.2%	18.8%	11.5%	9.5%	8.7%	11.6%	8.9%	11.1%
Ram block seal	9.1%	8.7%	6.9%	0.0%	17.4%	9.3%	7.1%	8.8%
Accumulator	9.1%	10.1%	14.9%	4.8%	2.2%	4.7%	5.4%	8.4%
Gate valve hardware	11.8%	5.8%	1.1%	0.0%	2.2%	25.6%	7.1%	7.9%
Hardware	11.8%	5.8%	1.1%	0.0%	6.5%	4.7%	7.1%	6.3%
Choke and kill valve	10.0%	5.8%	4.6%	0.0%	6.5%	7.0%	1.8%	6.0%
Regulator	1.8%	2.9%	8.0%	19.0%	10.9%	2.3%	7.1%	5.8%
Bonnet face seal	3.6%	2.9%	8.0%	0.0%	4.3%	7.0%	5.4%	4.9%
Operating system seal	1.8%	2.9%	6.9%	4.8%	10.9%	2.3%	1.8%	4.2%
Bonnet operating seal	1.8%	2.9%	2.3%	4.8%	6.5%	2.3%	10.7%	3.9%
Inside BOP	0.9%	1.4%	5.7%	0.0%	10.9%	0.0%	5.4%	3.5%
Pump	3.6%	0.0%	3.4%	4.8%	2.2%	7.0%	3.6%	3.2%
Relief valve	4.5%	1.4%	1.1%	9.5%	0.0%	2.3%	7.1%	3.2%
Selector manipulator valve	1.8%	2.9%	4.6%	9.5%	2.2%	0.0%	0.0%	2.6%
Other	0.0%	0.0%	1.1%	0.0%	2.2%	2.3%	14.3%	2.6%
Hardware_all other mechanical elements	3.6%	2.9%	1.1%	0.0%	0.0%	0.0%	0.0%	1.6%
Instrumentation	0.9%	2.9%	2.3%	0.0%	0.0%	0.0%	0.0%	1.2%
Bonnet hardware_all other mechanical elements	0.0%	1.4%	2.3%	4.8%	0.0%	0.0%	1.8%	1.2%
Piping tubing	0.0%	0.0%	0.0%	9.5%	0.0%	7.0%	0.0%	1.2%
Hose	1.8%	1.4%	1.1%	0.0%	0.0%	0.0%	0.0%	0.9%
Choke and kill valve operator seal	1.8%	0.0%	1.1%	0.0%	0.0%	0.0%	0.0%	0.7%
SPM valve	0.0%	4.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%
Drillstring safety valve	1.8%	0.0%	0.0%	0.0%	2.2%	0.0%	0.0%	0.7%
Hydraulic stab	0.0%	4.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%
Auto choke actuator	0.9%	0.0%	0.0%	0.0%	2.2%	0.0%	1.8%	0.7%
Auto choke valve	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%
Ram cavity	0.9%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%
Hydraulic gate valve actuator	0.0%	0.0%	1.1%	4.8%	0.0%	0.0%	0.0%	0.5%
Shuttle valve	0.0%	1.4%	1.1%	0.0%	0.0%	0.0%	0.0%	0.5%
Ball valve	0.9%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%
Pressure switch	0.0%	0.0%	1.1%	4.8%	0.0%	0.0%	0.0%	0.5%

Component	2017 (n=110)	2018 (n=69)	2019 (n=87)	2020 (n=21)	2021 (n=46)	2022 (n=43)	2023 (n=56)	Total (n=432)
Locking device	0.0%	1.4%	0.0%	0.0%	0.0%	2.3%	0.0%	0.5%
Gas valve	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	1.8%	0.5%
Packer	0.0%	0.0%	2.3%	0.0%	0.0%	0.0%	0.0%	0.5%
Ram block hardware	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	0.0%	0.2%
Flex loop hose	0.0%	0.0%	0.0%	0.0%	2.2%	0.0%	0.0%	0.2%
Central control console	0.0%	0.0%	1.1%	0.0%	0.0%	0.0%	0.0%	0.2%
Gooseneck	0.0%	0.0%	1.1%	0.0%	0.0%	0.0%	0.0%	0.2%
Choke and kill line	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Kelly valve	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	0.2%
End connection	0.0%	0.0%	1.1%	0.0%	0.0%	0.0%	0.0%	0.2%
Kick out sub	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Flange	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Choke and kill spool	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
UPS	0.0%	0.0%	0.0%	4.8%	0.0%	0.0%	0.0%	0.2%
Pressure transducer	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
HPU control panel	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
DRG valve	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Drillers control panel	0.0%	0.0%	1.1%	0.0%	0.0%	0.0%	0.0%	0.2%
Choke hose	0.0%	0.0%	0.0%	4.8%	0.0%	0.0%	0.0%	0.2%

NOTE: Percent refers to percent of total Surface Offshore BOP system reported failures.
SOURCE: USDOT, BTS, SafeOCS Program.

Appendix E: 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 designed to 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 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: Refer to 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.

Nipple-up: An industry term commonly used to describe the act of assembling major components on to a well.

Nipple-down: An industry term commonly used to describe the act of disassembling major components from a well.

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: Refer to 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: Refer to 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 (refer to 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. Additionally, retrieval of the LMRP for a weather-related event or evacuation is not considered a stack pull.

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: Refer to 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: Fluid of any type that could be in the wellbore, including, but not limited to, drilling mud, completion fluid, test fluid, seawater, and/or well fluids. Wellbore fluids can contain hydrocarbons only when the WCE system is in operation.

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.

Appendix F: Acronyms

API	American Petroleum Institute
BOP	Blowout preventer
BSEE	Bureau of Safety and Environmental Enforcement
BTS	Bureau of Transportation Statistics
BWM	Between wells maintenance
CFR	Code of Federal Regulations
CIPSEA	Confidential Information Protection and Statistical Efficiency Act
DOI	Department of the Interior
DOT	Department of Transportation
DP	Dynamically positioned
EHBS	Emergency hydraulic backup system
GOM	Gulf of Mexico
HPU	Hydraulic power unit
I&A	Investigation and failure analysis
IADC	International Association of Drilling Contractors
IOGP	International Association of Oil and Gas Producers
IRJ	Integrated riser joint
JIP	Joint industry project

LMRP	Lower marine riser package
LOC	Loss of containment
MIT	Maintenance, inspection, and testing
MOC	Management of change
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
SEA	Subsea electronic assembly
SEM	Subsea electronic module
SME	Subject matter expert
SPM	Sub-plate mounted
TJ	Telescopic joint
UBSR	Upper blind shear rams
USDOT	U.S. Department of Transportation

VBR Variable bore pipe ram

WAR Well activity report (per 30 CFR 250.743)

WCE Well control equipment

WHC Wellhead connector