OIL AND GAS PRODUCTION SAFETY SYSTEM EVENTS
2021 ANNUAL REPORT

SafeOCS

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

OIL AND GAS PRODUCTION SAFETY SYSTEM EVENTS

2021 Annual Report

ACKNOWLEDGEMENTS

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EXECUTIVE SUMMARY

The *2021 Annual Report: Oil and Gas Production Safety System Events*, produced by the Bureau of Transportation Statistics, summarizes safety and pollution prevention equipment (SPPE) failures that occurred on oil and gas wells in the Gulf of Mexico (GOM) Outer Continental Shelf (OCS) during the calendar year. 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. It includes an analysis of reported events involving SPPE valves and other key information about the events such as root causes and follow-up actions.

Event reporting and oil and gas production levels increased in 2021 but remained lower than pre-pandemic levels. SafeOCS received 114 SPPE failure notifications for 2021, and an additional 100 failure events were identified in other data sources, bringing the total number of known SPPE failure events in 2021 to 214, a 24.4 percent increase from 2020. The number of active wells decreased by 5.5 percent in 2021 compared to 2020, and total average daily production increased 13.4 percent. While the number of reporting operators (14) remained the same from 2020 to 2021, the number of active operators fell from 45 to 43.

Valve Types and Failure Rates

Surface safety valves (SSVs) and surface controlled subsurface safety valves (SCSSVs) had the highest proportions of failures in 2021, comprising 61.3 percent and 24.2 percent of failures with known valve type, respectively.[1] All valve types had reported failures in 2021, and both BSDVs and GLSDVs had their highest number of failures of any reporting year so far, comprising 3.6 percent and 7.2 percent of failures, respectively. In 2021, approximately 11,600 SPPE valves were in service in 5,402 active wells in the GOM OCS. The failure rates were under 2.24 percent for each valve type.

Potential Consequences of Failures

SPPE failures were categorized based on the extent to which they degrade the installed well safety systems and pose potential consequences to personnel and the environment. None of the failures in 2021 were characterized as health, safety, or environmental (HSE) incidents, i.e., an event that results in consequences to the health or safety of personnel or the environment above a specified threshold.[2] One external leak of produced hydrocarbons was reported, involving a small leak of well fluids to the

[1] Percentages are of 194 total failures. Excludes 20 failures of subsurface safety valves identified in OGOR-A data where it could not be determined whether they were SCSSVs or SSCSVs.
[2] See Appendix F for additional detail on the definition of an HSE incident.

atmosphere. Most SPPE failures (72.1 percent of the failures where information on the event type was available) were categorized as internal leaks, meaning the valve closed but failed to seal, allowing some fluid to flow through it.

Characteristics of Wells with SPPE Failures

Over 90.0 percent of failures occurred on wells that produced at least one day in 2021. Just under three quarters of the failures (74.7 percent) occurred on wells producing less than 500 barrels of oil equivalent per day (boed), and just under half (49.5 percent) occurred on wells producing less than 100 boed. These lower-producing wells pose less risk than higher-producing wells. About 2.5 percent of failures were associated with wells producing more than 5,000 boed. The most significant event type among higher-producing wells (>1,000 bopd or mcfd) was failure to close when commanded, totaling three events, two of which were failures of tubing-retrievable SCSSVs. Wells with higher gas-oil ratio (GOR) (1,500 cf/bbl and above) experienced more failures in 2021 relative to wells with lower GOR.

Root Causes and Contributing Factors of Failures

As with previous years, wear and tear was the most frequently reported root cause, listed for 65.8 percent of failures reported to SafeOCS. Valve seat degradation was the most reported factor contributing to SPPE failures, reported for 62.2 percent of the events where information on contributing factors was available, followed by factors including operating procedures, improper maintenance or repair, assembly damage or error, company policy and practices, personnel skills or knowledge, and design issues. An analysis of contributing factors each year from 2017 to 2021 showed that valve seat degradation was more frequently reported for surface valves, while solid contaminants were more frequently reported for subsurface valve failures.

Next Steps

The close of 2021 marked the fifth full year of the SafeOCS SPPE program. Over these five years, the offshore oil and gas industry has contributed more than 750 reported events to the SafeOCS SPPE database. Several program milestones have passed: the establishment of the secure e-submit web portal for event reporting in the program's first year, the release of the SafeOCS SPPE online data dashboard in 2020, improvements to the data collection form in 2020, and several publications. BTS continues to focus on improving data quality and accessibility, including potential improvements to exposure data and measures, as well as ways to share learnings with stakeholders.

1 Introduction

The *2021 Annual Report: Oil and Gas Production Safety System Events*, produced by the Bureau of Transportation Statistics (BTS), provides information on safety and pollution prevention equipment (SPPE) failures reported to SafeOCS during the calendar year. These failures occurred during oil and gas production operations in the Gulf of Mexico (GOM) Outer Continental Shelf (OCS). Per 30 CFR 250.803, operators must submit a failure notification to SafeOCS when a specific SPPE valve does not perform as designed. This annual report includes an overview of the types of failures reported, characteristics of the wells with SPPE failures, and root causes and contributing factors.

About SafeOCS

SafeOCS is a confidential reporting program for collecting and analyzing data to advance safety in energy operations on the OCS. The objective of SafeOCS is to capture and share essential information across the industry about accident precursors and potential hazards associated with offshore operations. The program is sponsored by the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) and operated independently by the Department of Transportation's Bureau of Transportation Statistics (BTS), a principal federal statistical agency. The Confidential Information Protection and Statistical Efficiency Act (CIPSEA) protects the confidentiality of all data submitted directly to SafeOCS.[3]

The SafeOCS program umbrella comprises several safety data collections, including the SPPE failure reporting program, which is the subject of this report. Under 30 CFR 250.803, operators must follow the SPPE failure reporting procedures in specified API standards and submit failure reports to both BTS, as BSEE's designated third party to receive this information, and the original equipment manufacturer.[4] This is the fifth annual report on the SPPE failure reporting program.

Contributors to this report include subject matter experts retained by SafeOCS to provide technical knowledge in production operations, subsea engineering, equipment testing, well equipment design and manufacturing, root cause failure analysis, quality assurance and quality control, and process design. They reviewed event and investigation reports, reviewed BTS and BSEE data, and contributed to analyses of aggregated data.

[3] Confidential Information Protection and Statistical Efficiency Act of 2018, Pub. L. No. 115-435, tit. III (reauthorizing the 2002 law of the same name).
[4] See appendices A and B for additional detail on the regulatory requirements for SPPE failure reporting.

Data Adjustments

- SafeOCS may receive SPPE 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 reported results and references to previous data in this report represent updated numbers unless otherwise stated.

- Over time, data analysis methods may change to improve data accuracy and better characterize the aggregate data. Any changes to data analysis methods are noted in this report and the results reflect the current methodology.

- Due to rounding, numbers in tables and figures may not add up to totals.

2 SAFETY AND POLLUTION PREVENTION EQUIPMENT (SPPE)

In general, SPPE promotes the safety and protection of human, marine, and coastal environments. The specific SPPE covered by the Oil and Gas Production Safety Systems Rule (subpart H) protects personnel and the environment by controlling the flow of well fluids (crude oil, natural gas, and water), especially in case of an emergency or system failure.[5] The SPPE consists of specifically designated safety valves, actuators, and their control systems, which are required by BSEE regulations, industry standards, and in most cases, company policies. SPPE includes the following valve types:[6]

- Surface Safety Valves (SSVs)
- Boarding Shutdown Valves (BSDVs)
- Underwater Safety Valves (USVs)
- Subsurface Safety Valves
  - Surface Controlled Subsurface Safety Valves (SCSSVs)
  - Subsurface Controlled Subsurface Safety Valves (SSCSVs)
- Gas Lift Shutdown Valves (GLSDVs)

Location of SPPE Valves

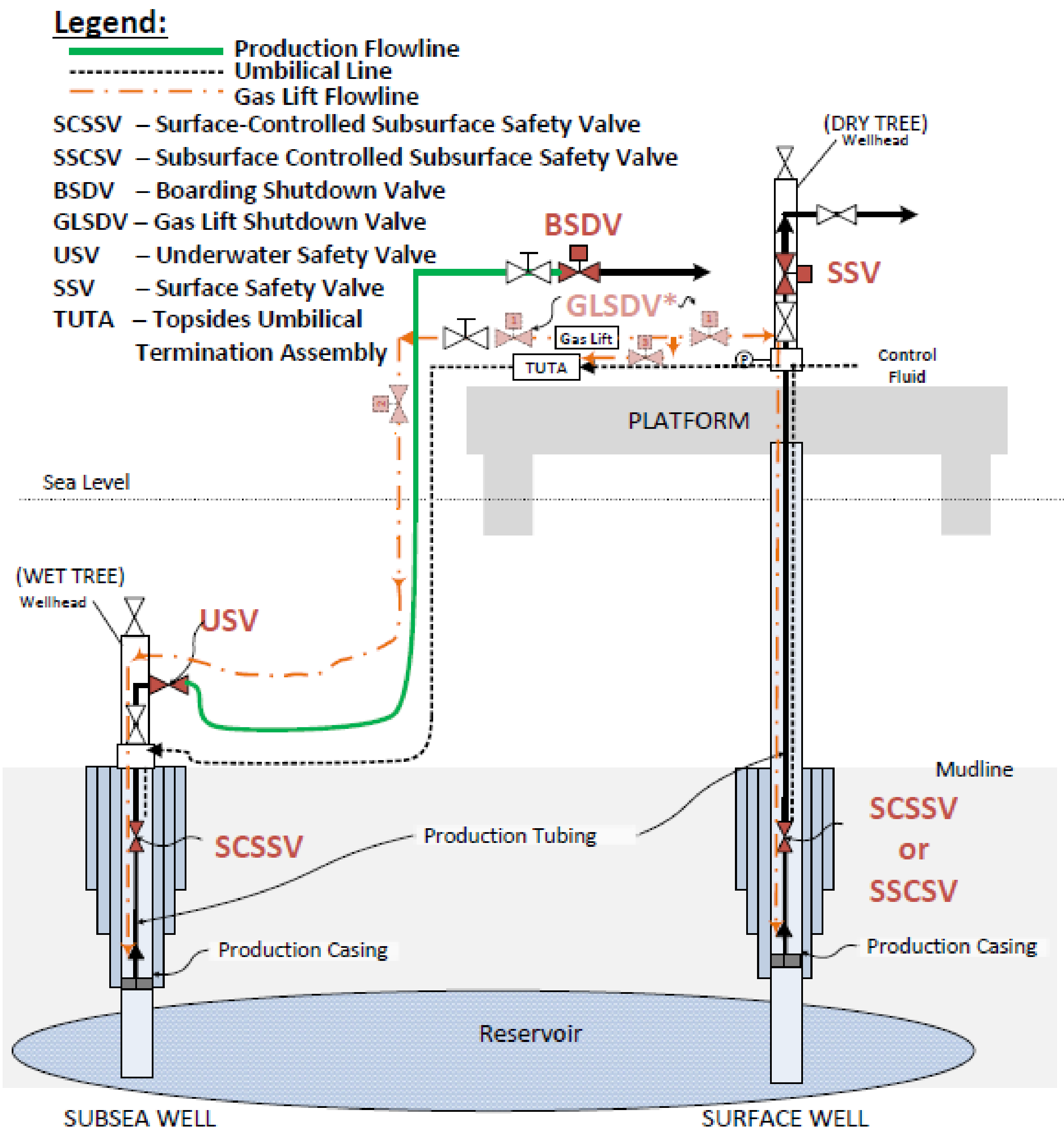
SPPE valves are found in both surface wells and subsea wells. Surface wells have dry trees or direct vertical access (DVA) trees located above sea level on top of the well. Their location allows the operator direct access to the wellbore from the production platform. Subsea wells have wet trees located on the seafloor, with access to the wellbore only via production flowlines to a permanently installed platform (for production purposes) or from a floating rig or intervention vessel (for intervention purposes). Figure 1 illustrates the typical locations of these SPPE valves, although variations exist within well trees in the field.

A typical surface well is equipped with at least one subsurface safety valve (SCSSV or SSCSV) in the tubing below the seafloor (mudline) and an SSV on the wellhead. Similarly, a subsea well is equipped with at least one subsurface safety valve and a USV. However, SSCSVs are no longer allowed by BSEE in new subsea wells due to reliability issues and long repair times caused by the need for an intervention vessel. Per subpart H, a production master valve (PMV) or production wing valve (PWV) may qualify as a USV under API Spec. 6A and API Spec. 6AV1.[7] They provide redundancy in the equipment to allow for

[5] The rule is codified primarily in 30 CFR part 250, subpart H. The failure reporting requirement is codified in 30 CFR 250.803.
[6] 30 CFR 250.801.
[7] 30 CFR 250.833.

secondary valves, should one fail. In addition, the flowline that transports well fluids from one or more subsea wells will be equipped with a BSDV located on the production facility.

Figure 1: Equipment Schematics



NOTE: GLSDVs for subsea wells may be installed in 1 of 3 alternate locations as described in 30 CFR 250.873: (1) Horizontal valve on gas lift supply line within 10 feet of the platform edge; (2) Vertical valve in gas lift supply line riser run within 10 feet above the first accessible working deck (excluding the boat landing and splash zone); (3) Gas lift supply via umbilical within 10 feet of the TUTA.
SOURCE: U.S. Department of Energy, Office of Science, Argonne National Laboratory.

How Valve Types Are Grouped in this Report

SPPE valves are often grouped in this report as either *surface* (SSV, BSDV, and GLSDV) or *subsurface* (SCSSV, SSCSV, and USV) to evaluate potential patterns or trends based on valve location (on-platform versus below the waterline). Although USVs are typically not considered subsurface valves, as the latter typically refers to valves installed below the mudline, USVs are included with subsurface valves because they are installed below the water's surface.

All SPPE valves must be function tested and leak tested per the requirements of subpart H.[8] Table 1 summarizes the general testing frequencies and leakage requirements. However, exceptions can apply for different types of wells, subject to BSEE's approval.[9]

Table 1: Typical SPPE Testing Frequency and Leakage Allowance

Valve	Allowable Leakage Rate	Testing Frequency
Surface Valves		
SSV	Zero leakage	Monthly, not to exceed 6 weeks
BSDV	Zero leakage	Monthly, not to exceed 6 weeks
GLSDV	Zero leakage	Monthly, not to exceed 6 weeks
Subsurface Valves		
SCSSV	400 cc per minute of liquid (oil or water) or 15 scf per minute of gas	Semiannually, not to exceed 6 calendar months
SSCSV	Not applicable	Remove, inspect, and repair or adjust semiannually, not to exceed 6 calendar months between tests for valves not installed in a landing nipple and 12 months for valves installed in a landing nipple.
USV	400 cc per minute of liquid (oil or water) or 15 scf per minute of gas	Quarterly, not to exceed 120 days

KEY: cc (or cm3)—cubic centimeters, scf—standard cubic feet.
SOURCE: U.S. DOT, BTS, SafeOCS Program.

Purpose and Operation of SPPE Valves

SPPE valves are operated in the open position to allow the production from the well to flow. They are designed to close automatically if a control system failure occurs (i.e., fail-safe valves) or if there is an operational need to stop the flow from the well. All SPPE valves are considered isolation valves and mechanical barriers because they are designed to stop the flow of well fluids to protect personnel, equipment, and the environment. In general, the main valve component moves from an open to a closed position, where it contacts the valve seat to seal off the internal flow in the pipe or tubing. All SPPE

[8] 30 CFR 250.873, 250.880.
[9] Additional information and requirements for new wells and wells that are completed and disconnected from monitoring capability are provided in the CFR.

valves, excluding the SSCSVs, are automatically operated, meaning a hydraulic or pneumatic actuator is used to open or close the valve. Further, all SPPE valves tie into the control system of the operating platform. SPPE valves can be opened or closed for routine operations by the operator from the platform control system.

Most SSVs and USVs are sliding gate valves operated either hydraulically (using hydraulic oil pressure) or pneumatically (using gas pressure). SSVs are found on surface wells (on dry trees), whereas USVs are located on subsea wells (on wet trees). BSDVs, utilized for flowlines of subsea wells and located on the platform, are commonly gate or ball valves. Similarly, GLSDVs are either gate or ball valves, and are most used on surface wells, but could be installed on subsea wells. In many cases, GLSDVs are located on the gas lift supply line platform for a subsea field with one or more subsea wells. Both the BSDVs and the GLSDVs protect the platform and personnel against the flow from subsea wells.

Subsurface safety valves, located in the tubing of wells, are either surface controlled (SCSSV) or subsurface controlled (SSCSV). The SCSSV is a fail-safe, flapper-type valve that uses hydraulic control pressure from the surface to hold the flapper open to allow flow from the well. SCSSVs are typically full opening valves that allow higher well production rates and intervention work below the SCSSV. The SCSSV is an integral part of the tubing and can only be retrieved for repairs if the tubing is removed from the well (i.e., tubing-retrievable SCSSV). As an alternative to pulling the tubing to retrieve a failed SCSSV, a smaller wireline-retrievable SCSSV can be installed in the well after locking open the original SCSSV. This type of valve may lower the well flow rate and needs to be pulled to allow future deeper interventions in the well. However, because it is surface controlled, it is preferred over the SSCSV.

The SSCSV is a normally open valve in the well's tubing that closes at a predetermined flow rate or pressure. The SSCSV is installed or removed (i.e., run or pulled) using a wireline and typically set in a landing nipple in the well's tubing string.[10] The valve is typically held open by a spring. The differential pressure across the valve causes it to close and stop the well from flowing at flow rates higher than the designed shutdown rate. Alternatively, the SSCSV may be a dome pressure design (e.g., a PB valve) that uses charged pressure to allow the valve to close once the tubing pressure at the valve falls below a predetermined value. Both SSCSV types can be retrieved for maintenance or to allow for other downhole operations. SSCSVs may be used in surface wells but are no longer allowed in new subsea wells, as mentioned above.

[10] A landing nipple is a type of completion component that provides a seal area and a locking profile. See Appendix C for full definition.

3 DATA COLLECTION AND VALIDATION

Data Confidentiality—CIPSEA

The Confidential Information Protection and Statistical Efficiency Act (CIPSEA) protects the confidentiality of all data submitted directly to SafeOCS. Data protected under CIPSEA may be used only for statistical purposes. This provision means that BTS can publish only summary statistics and data analysis results. Incident microdata collected by SafeOCS may not be shared or used for regulatory purposes. Information submitted under this statute is protected from release to other government agencies, including BSEE, and from Freedom of Information Act (FOIA) requests, subpoenas, and legal discovery.

To provide proof of an operator's compliance with the reporting regulation—without sharing the details of the event, which are CIPSEA-protected—the following information is shared with BSEE via an automated email following receipt of an event notification: submittal date, company identification, and event reference number.

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 additional BSEE data sources that contained information about the failure event or characteristics of the well with the failed SPPE. These data sources were also used to identify SPPE failure events that were not reported to SafeOCS.

BTS used BSEE data sources to develop exposure measures that quantify the population of SPPE that could be called upon to perform functional specifications of that population. These exposure measures, sometimes referred to as denominator or normalizing data because they represent the population in terms of statistical values, facilitate comparison among different types of SPPE and well environments. The specific BSEE data sources are listed below, including another source of BSEE data added to the analysis in 2021—BSEE incident reports. Appendix D provides more information about the methodology used in evaluating each data source.

Applications for Permit to Modify (APMs)

Operators are required to obtain an approved APM from BSEE before beginning completion, workover, or abandonment work on a well. For workover operations, the permits may contain details about SPPE valve inspection, repair, or modification that indicate that a failure has occurred. BTS reviewed the APM details to cross-reference the timing and occurrence of SPPE failures and determine which were reported to SafeOCS. As the operators use APMs to request permission from BSEE to modify an active well for repair or enhancement purposes, they typically are the precursor for any work performed on a well. It's not uncommon for the APM(s) to give a history of the well and the failure with a high-level procedure planned to repair the device. In many cases, this history and the proposed repair procedure are not found in other sources and can be invaluable in understanding certain details about the failure.

Borehole Data

Operators report to BSEE various information about OCS boreholes (i.e., the hole drilled for reservoir exploration or installation of a production well), such as location and depth information. BTS used borehole data to determine the water depth for active wells and wells with SPPE failures. This information facilitates the comparison of SPPE failures across groups of wells with similar characteristics.

Incidents of Noncompliance (INCs)

Inspection INCs may be issued by BSEE inspectors whenever they are on a platform and witness deficiencies. For SPPE, such deficiencies could be witnessed during testing as part of an annual inspection. These deficiencies are regulatory violations, and depending on the severity of the violation, BSEE may issue an INC with a warning, component shut-in, or facility shut-in enforcement action. The INC will provide the operator with direction on how to come into compliance and take appropriate action. BTS used the INCs involving 2021 SPPE failures to cross-reference and validate SPPE failures reported to SafeOCS during the same period and potentially further enhance the quality of information collected. While failures associated with INCs do not capture all possible failures that occur, the INC database provides an additional source to identify failures in the GOM that may not have been reported to SafeOCS and provides more detail for reported events.

Incident Reports

Operators are required to report incidents, spills, and pipeline damage information to BSEE under the regulations.[11] These incidents may involve, for example, releases of gas or fluids to the environment. In some cases, an SPPE valve failure was a factor in the reported incident. BTS reviewed the incident data for events involving SPPE failures and cross-referenced that data with the set of events reported to SafeOCS to build a more complete dataset.

Oil and Gas Operations Reports – Part A (OGOR-A)

Operators report well production volume information and well status to the Department of the Interior through OGOR-A submissions. The OGOR-A data provides each well's monthly status, production

[11] 20 CFR 250.186–250.190, 250.1008(e), 254.46. See also BSEE Notice to Lessees No. 2019-N05, Incident and Spill Reports.

volumes of oil, gas, and water, and the number of days each well produced during a given month. BTS used the monthly status code to determine whether a well was considered active for purposes of this report and determine the operators associated with active wells. BTS used production volume information to determine the well rate and water cut for active wells and wells with SPPE failures. This information facilitates the comparison of SPPE failures across groups of wells with similar characteristics.

In addition to well production volumes, operators also provide information on shut-in wells (i.e., closed and not producing) in their OGOR-A submissions. The OGOR-A data contains various monthly "shut-in reason" codes that can be used to determine the month and the reason for the status change. BTS used well shut-in status information from OGOR-A data to cross-reference the timing and occurrence of failures reported to SafeOCS and identify failures that may not have been reported to SafeOCS.

SPPE Installation Data

Operators report SPPE valve installations to BSEE through the production safety system permit process. These are captured in a database that includes valve data such as type of valve, location, and installation date. BTS used SPPE installation data to estimate the total number of SPPE valves associated with wells in the GOM and to calculate the denominators for SPPE failure rates.

Well Activity Reports (WARs)

Operators are required to provide to BSEE a summary of daily well activities via WARs.[12] The well activities reported in the WARs include work accomplished on OCS wells during all phases (drilling, completion, workover, recompletion, non-rig interventions, and abandonments), including any repairs or replacements of SPPE valves. BTS reviewed the WAR reports for non-rig operations (e.g., wireline operation reports) to cross-reference the timing and occurrence of SPPE failures and determine which were reported to SafeOCS.

Well Test Reports

BSEE requires operators to submit well test reports detailing daily oil, gas, and water volumetric rates at least once every six months for each producing well.[13] Well test rates are reported in barrels of oil per day, thousands of cubic feet of gas per day, and barrels of water per day. BTS reviewed well test reports to provide context for each failure's potential impact by comparing the well test rates to the production rates calculated from volumes reported in OGOR-A data.

[12] 30 CFR 250.743.
[13] Procedures for OCS well test reporting are codified in 30 CFR part 250 subparts K and L.

4 DATA ANALYSIS

SPPE Numbers at a Glance

Subpart H covers production operations on the Outer Continental Shelf (OCS), which includes BSEE's Gulf of Mexico (GOM), Pacific, and Alaska regions. For 2021, SafeOCS received equipment failure notifications for operations in the GOM only, which accounts for over 99 percent[14] of all offshore production in the United States. The exact locations of reported equipment failures are not disclosed in this document to protect the data's confidentiality.

SafeOCS received 114 SPPE failure notifications for 2021, a 12.9 percent increase from 2020. An additional 100 failure events were identified in other sources (APM, INC, OGOR-A, or WAR data), bringing the total number of known SPPE failure events in 2021 to 214, a 24.4 percent increase from 2020 and a 39.0 percent decrease from 2019. In general, analyses presented in this report consider all known failure events to the extent practicable. However, failures found in non-SafeOCS data sources are excluded from some analyses due to less complete information about the events. Each figure or table is annotated with an explanation of which failure events are included.

Table 2 provides an overview of the reported SPPE failures in 2021 compared to the previous four years. The 114 failures occurred on 115 of 5,402 total active wells (2.1 percent) in the GOM OCS.[15] Most of those failures (86.0 percent) were on valves accessible from the platform where they can be addressed more quickly, reducing potential safety and environmental risk.[16] Although failures on SPPEs associated with subsea wells increased significantly (162.5 percent), only five of the 21 failures that occurred on subsea wells, the SCSSV and USV failures, would require an intervention vessel to address. The number of active wells has continued to decrease over all five years, although production in 2021 returned to near (99.9 percent) the 2019 production volume. The number of reporting operators (operators who reported failure notifications) remained the same for the fourth consecutive year in 2021 at 14 operators in the GOM. Reporting operators contributed 73.9 percent of oil and gas production from 64.9 percent of active wells, both increases over 2020 though not as high as previous maximums of 75.7 percent production in 2019 and 70.6 percent of active wells in 2018.

[14] BSEE Data Center, Outer Continental Shelf Oil and Gas Production data, 2021 annual volumes.
[15] For purposes of this report, an active well is considered a well completion with SPPE valves providing a barrier to the fluids in the reservoir. A well was counted as active if it had an OGOR-A status code other than drilling, abandoned, or well work for at least one month of the year.
[16] Includes failures on surface wells, plus failures of BSDVs and GLSDVs associated with subsea wells.

Table 2: SPPE Numbers at a Glance

		2017	2018	2019	2020	2021
Operator Summary[1]	Active Operators	56	55	52	45	43
	Producing Operators	53	50	49	42	41
	Reporting Operators (Pct. of Active Operators)	8 (14.3%)	14 (25.5%)	14 (26.9%)	14 (30.4%)	14 (32.6%)
	Reporting Operators' Pct. of Active Wells	35.2%	70.6%	59.4%	58.0%	64.9%
	Reporting Operators' Pct. of Production	56.6%	66.6%	75.7%	57.8%	73.9%
GOM Well Production Summary[2,3]	Active Wells	6,446	6,231	6,029	5,715	5,402
	Wells with SPPE Failure	96 (1.5%)	160 (2.6%)	182 (3.0%)	90 (1.6%)	115 (2.1%)
	Daily Prod. - Total Active Wells (boed)	2,207,312	2,243,244	2,741,291	2,414,434	2,738,538
	Daily Prod. - Wells with SPPE Failure (boed)	20,028 (0.9%)	56,174 (2.5%)	71,289 (2.6%)	70,928 (2.9%)	107,649 (3.9%)
SPPE Population	Installed SPPE Valves	12,373	12,174	11,849	11,690	11,600
SPPE Failure Summary[4]	Total Distinct SPPE Failures	215	266	351	172	214
	SPPE Failures Reported to SafeOCS	**115**	**204**	**225**	**101**	**114**
	SPPE Failures Identified from Other Sources	100	62	126	71	100
	Pct. of Failures Not Reported to SafeOCS	46.5%	23.3%	35.9%	41.3%	46.7%
SafeOCS Failures Only — **Tree Types**	Surface Well SPPE Failure Events	109	195	210	93	91
	Subsea Well SPPE Failure Events	4	8	15	8	21
	SPPE Failure Events with Unknown Tree Type	2	1	0	0	2
SafeOCS Failures Only — **Event Types**[5]	HSE Incident	0	0	0	0	0
	External Leak of Hydrocarbons	1	2	5	3	1
	Failed to Close When Commanded	13	16	22	11	10
	Internal Leak	99	159	199	80	93
	Failed to Close in Required Timing	0	14	0	1	1
	Failed to Open	3	6	5	4	5
	External Leak of Other Fluids	1	11	5	4	5

KEY: HSE—Health, Safety, and Environment; INC—Incident of Noncompliance: WAR—Well Activity Report; SPPE—Safety and Pollution Prevention Equipment; Pct.—percent.

NOTES:

1 Active operator counts have been updated to reflect company mergers and acquisitions. An active operator is one with active wells in the GOM.

2 A well was counted as active if it had an OGOR-A status code other than drilling, abandoned, or well work for at least one month of the year. In 2020, BTS began counting wells by API number and completion interval. Previously, multiple well completions with the same API number were counted as one well. Previous year totals have been updated to reflect this revised methodology.

3 Wells with SPPE failure and daily production rate for wells with SPPE failure consider only failures reported to SafeOCS.

4 For 2017 and 2018, other sources include INC and WAR data. OGOR-A data was added in 2019, APM data was added in 2020, and BSEE incident data was added in 2021.

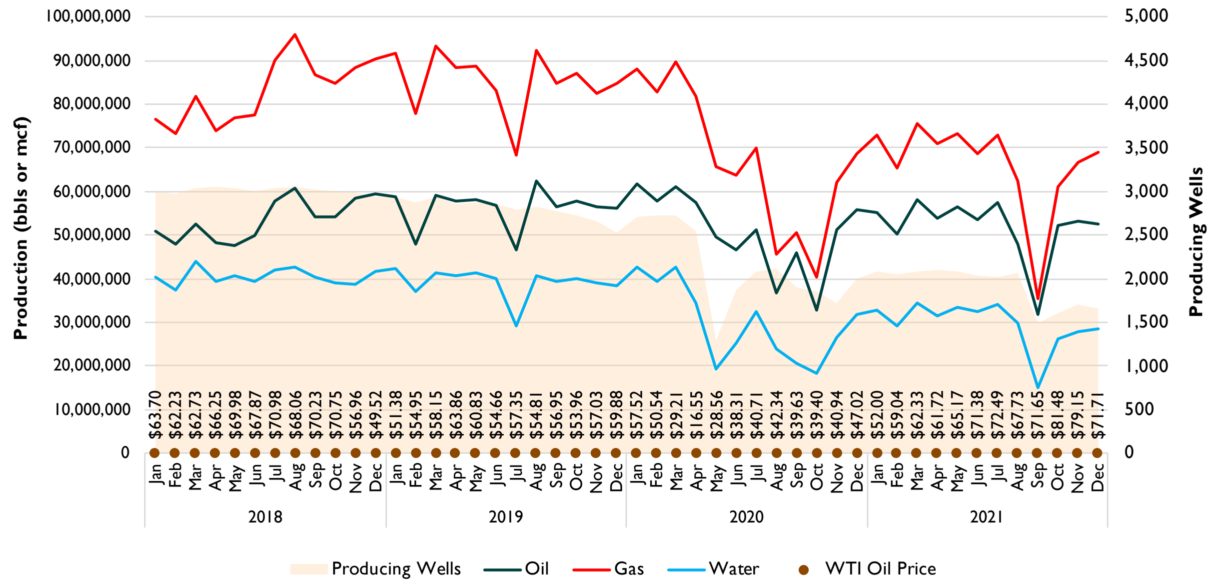
5 Total may exceed count of SafeOCS failures because more than one event type can apply to a single failure.

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Production During the COVID-19 Pandemic

The coronavirus pandemic was a significant factor in the overall decrease in both event reporting and oil and gas production levels in 2020, as reflected by the sharp decrease in production levels in the second quarter, when the pandemic slowed the economy dramatically (Figure 2). Monthly oil, gas, and water volumes produced in the GOM are shown as trend lines in Figure 2. The shaded area in the same figure indicates the number of wells that were producing each month. In 2021, production was more consistent throughout the year except for August and September, which were significantly lower due to hurricanes and tropical weather in the GOM during those months. As of the end of 2021, the number of producing wells still had not returned to levels seen during the first half of 2021.

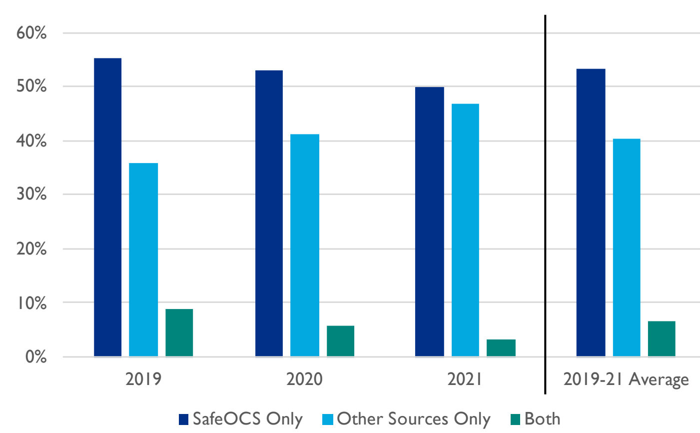
Figure 2: GOM Production, 2018-2021



SOURCES: U.S. DOT, BTS, SafeOCS Program. WTI crude oil spot prices from U.S. Energy Information Administration.

Completeness of Failure Event Reporting

Figure 3: Sources of SPPE Failure Records, 2019–21



NOTE: Other sources include APM, INC, OGOR-A, WAR, and BSEE reported incident data.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS program.

As mentioned above, the 2021 analyses reconcile the SPPE data reported to SafeOCS using APM, INC, OGOR-A, and WAR data. The use of these additional data sources resulted in a larger set of records for failure events that occurred in the GOM OCS during 2021 operations. A review of all the available data found 214 distinct SPPE failures in 2021. Figure 3 shows the overlaps between the data sources. Of the 214 failures, 107 were reported to SafeOCS only, 100 were not reported to SafeOCS, and seven were both reported to SafeOCS and found in the APM, INC, OGOR-A, or WAR data. Over a third (100 of 214 or 46.7 percent) of known SPPE failures were not reported to SafeOCS. Therefore, reporting of SPPE failures to SafeOCS appears to be incomplete and getting worse. The findings for each of the additional data sources are described in more detail below.

WAR Data

Analysis of the WAR data indicates that 15 SCSSV failures and one SSCSV failure occurred during 2021. One of the failures was also reported to SafeOCS and found in APM data.

- In one case, the tubing retrievable SCSSV was replaced.
- In four cases, a plug was set in the well.
- In five cases, the tubing-retrievable SCSSV was "locked open" and a PB type valve was installed.
- In one case, a wireline-retrievable SCSSV was installed in the well.
- In two cases, the SPPE or controls were repaired.
- In one case, the SPPE was replaced with a different model.
- In one case, the corrective action was not specified.
- The SSCSV was a PB valve that was replaced.

Twelve of the SCSSV failures and the SSCSV failure were also identified in the APM data, which could mean that the repairs were planned as opposed to found during well work. However, determining the cause of these failures is difficult as the available data is limited to the operational repair activities rather than the valve operating history.

WARs may also include preventive maintenance reports, such as the required removal of a valve for testing. Importantly, BTS distinguishes between preventive maintenance reports and failure events when evaluating the WARs, and the events identified in WAR data represent only failure events.

APM Data

Analysis of the APM data indicates that 16 SCSSV failures and two SSCSV failures were reported in APMs during 2021. One of the failures was also reported to SafeOCS and found in WAR, and most (13 of 16 or 81.3 percent) were also found in WAR data. The three SCSSV failures identified only in APM data involved producing wells, and the SSCSV failure identified only in APM data was on a well that had not produced since 2019.

INC Data

Analysis of the INC data shows that 48 SPPE failures were documented in the BSEE INC database for 2021, of which five (10.4 percent) were reported to SafeOCS. Importantly, the number of INCs involving SPPE valves represents only those failures occurring while BSEE is visiting the platform (i.e., a subset of all failures). The 48 failures identified in INCs include 25 SSV failures, 18 SCSSV failures, two BSDV failures, two GLSDV failures, and one USV failure.

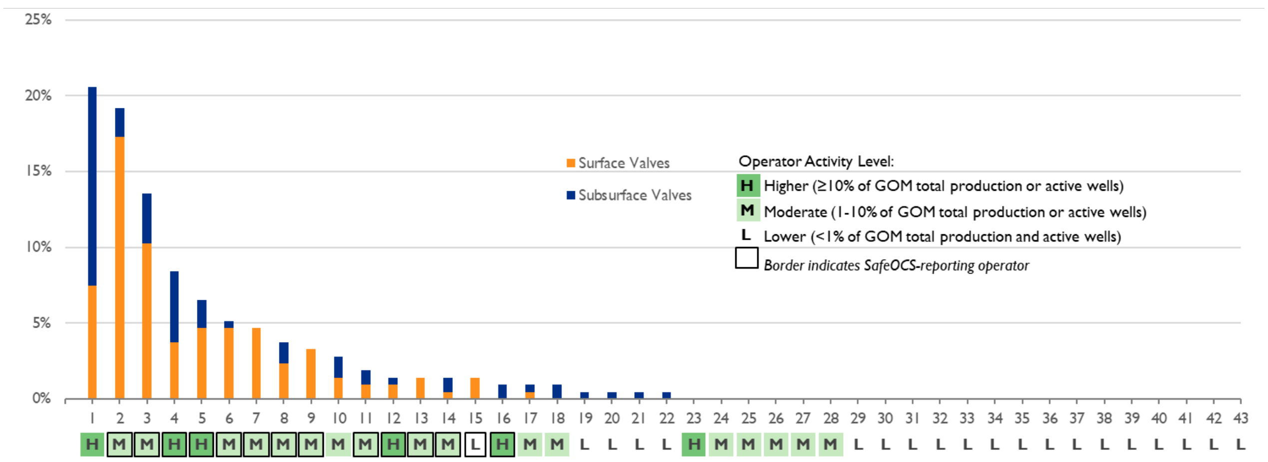
OGOR-A Data

A total of 39 SPPE failures were documented in the OGOR-A data for 2021, of which one was reported to SafeOCS. The 39 failures identified in OGOR-A data include 20 subsurface safety valves (OGOR-A does not distinguish between SCSSVs and SSCSVs), one SCSSV (valve type determined by cross-comparison with other sources of failure records), and 18 SSVs.

Who Reported Equipment Events

Figure 4 shows the percentages of 2021 SPPE reported failures by operator and the breakdown between surface and subsurface valves. The top reporting operator contributed nearly as many subsurface valve failures as all other operators combined. The reporting operator's activity level is indicated by the box below the operator number on the horizontal axis. It is notable that two operators with higher activity levels had no reported failures in 2021.

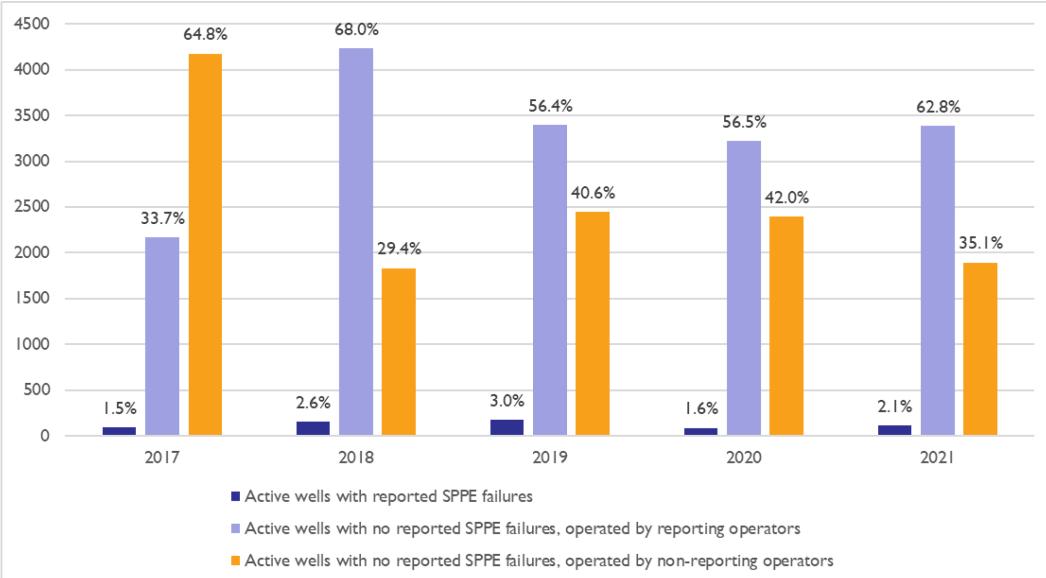
Figure 4: Reported SPPE Failure Events by Operator, 2021



NOTE: Percentage is of 214 failures from all sources.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Figure 5 shows the distribution of active wells between operators who reported at least one failure to SafeOCS and operators with no reported failures. Each year since 2018, reporting operators have been responsible for more than half of active wells. Wells with a reported SPPE failure comprised 2.1 percent of active wells in 2021, which is approximately the average of the prior four years.

Figure 5: Active Wells and Reporting Status of Operators, 2017-2021



NOTE: Includes only failures reported to SafeOCS.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Details of Reported Equipment

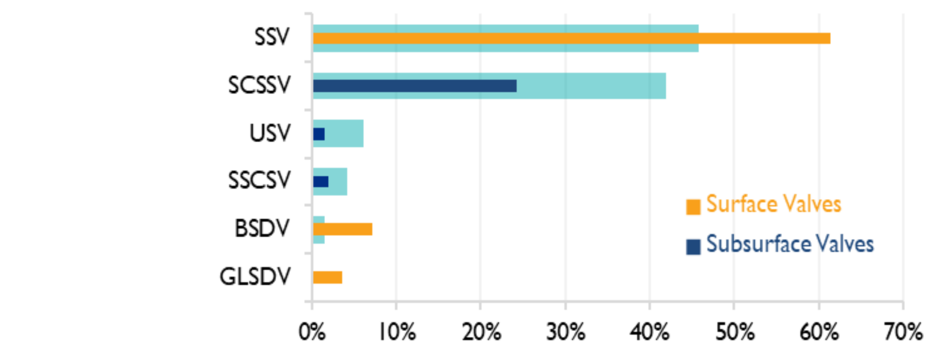
Valve Types

As stated above, SPPE includes six main valves in the well or production stream that directly control the flow of hydrocarbons:

- SSV—Surface Safety Valves,
- BSDV—Boarding Shutdown Valves,
- USV—Underwater Safety Valves,
- SCSSV—Surface Controlled Subsurface Safety Valves,
- SSCSV—Subsurface Controlled Subsurface Safety Valves, and
- GLSDV—Gas Lift Shutdown Valves.

Of the 214 failures in 2021, the specific valve type was known for 194. The remaining 20—identified in OGOR-A data—are classified as subsurface safety valves without distinguishing SCSSVs from SSCSVs. Figure 6 shows the distributions of the GOM valve population and the failures by valve type, excluding the 20 subsurface safety valve failures identified in OGOR-A data. SSVs and SCSSVs had the highest proportions of the SPPE population and failures, collectively comprising 87.7 percent of the population and 85.6 percent of failures with known valve types in 2021. All valve types had reported failures in 2021, and both BSDVs and GLSDVs had their highest number of failures of any reporting year so far.

Figure 6: Reported SPPE Events by Valve Type, 2021



	GLSDV	BSDV	SSCSV	USV	SCSSV	SSV
Percent of Population	0.2%	1.6%	4.3%	6.2%	42.0%	45.8%
Percent of Failures	3.6%	7.2%	2.1%	1.5%	24.2%	61.3%

NOTE: Includes 194 total failures. Excludes 20 failures of subsurface safety valves identified in OGOR-A data where it could not be confirmed whether they were SCSSVs or SSCSVs.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

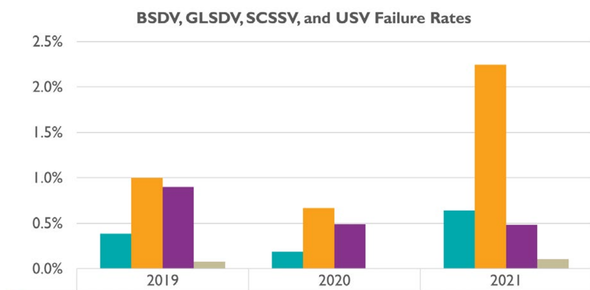
The number of failures identified for one valve type versus another is influenced by both the required testing frequency and the accepted leakage rate, which vary between valve types (see Table 1 for testing requirements). If a valve type has a higher required testing frequency or lower allowable leakage rate, more failures may be identified than for other valve types. Testing frequency is further considered in the discussion of SPPE failure rates below.

Valve Failure Rates

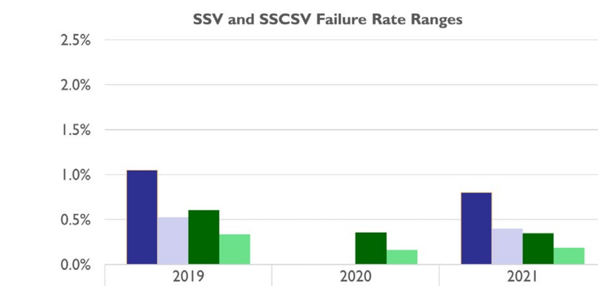
In 2021, approximately 11,600 SPPE valves were in service in the GOM OCS. Because required testing frequencies vary between valve types (i.e., valves may have a monthly, quarterly, semiannual, or annual testing frequency), the methodology for calculating failure rates considers the required testing frequency for each valve type. These adjustments reduce the potential for ascertainment bias, which can occur when some valve types in the SPPE population are evaluated for potential failure more often than others.

Figure 7 shows the SPPE failure rates over time based on the total population of each valve type and its testing frequency. The failure rate for each valve type is calculated as the number of reported failures divided by an exposure denominator of the number of installed valves multiplied by the testing frequency. Appendix E provides details of the calculated failure rates.

Figure 7: SPPE Failure Rates in the Gulf of Mexico, 2019-2021



	2019	2020	2021
BSDV	0.38%	0.19%	0.64%
GLSDV	1.00%	0.67%	2.24%
SCSSV	0.90%	0.49%	0.48%
USV	0.07%	0.00%	0.10%



	2019	2020	2021
SSCSV High	1.05%	0.00%	0.80%
SSCSV Low	0.53%	0.00%	0.40%
SSV High	0.61%	0.36%	0.35%
SSV Low	0.34%	0.16%	0.19%

NOTE: 2019 includes 329 total failures and excludes 22 failures of unknown SSSV type. 2020 includes 159 failures and excludes 13 failures of unknown SSSV type. 2021 includes 194 total failures. Excludes 20 failures of subsurface safety valves identified in OGOR-A data where it could not be confirmed whether they were SCSSVs or SSCSVs. The right-hand plot reflects a failure rate range for SSCSVs and SSVs due to variability in testing frequency, described further in Appendix E.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

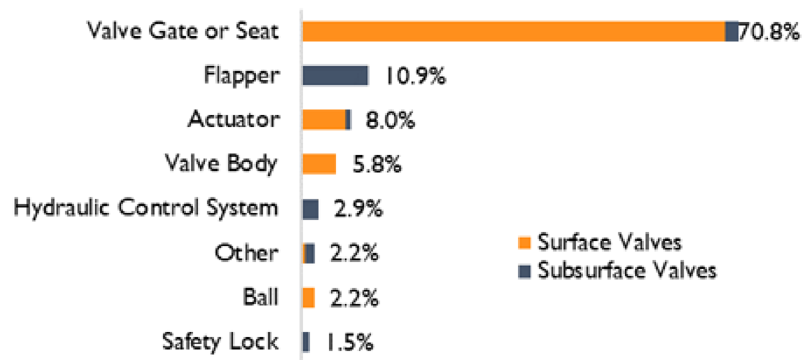
As shown in Figure 7, failure rates across years remained low at under 2.5 percent. The 2021 failure rates for each SPPE valve type span from 0.1 percent for USVs to 2.24 percent for GLSDVs, which have the lowest population of valves. None of the failure rates among other valve types exceeded 1.05 percent in any reporting period. In 2021, failure rates remained essentially the same for SCSSVs and SSVs, which were the majority of the failures. Contrary to 2020, SSCSVs and USV had reported failures in 2021. BSDV failures increased from four to 14 from 2020 to 2021, raising the BSDV failure rate from 0.19 to 0.64 percent.

Since the seven GLSDV failures in 2021 were considerably higher than in previous years, BTS analyzed them for any unusual trends. They came from three different operators, at least three (two were unknown to BTS) manufacturers and occurred at various times of the year. Of the seven failures, six were internal leaks, and one was an external leak of hydraulic oil, which is less serious than a produced fluid leak. BTS found no anomalies or explanations for the higher number of failures compared to previous years.

Valve Components

Multiple components make up each SPPE valve.[17] In 2021, the failed component was identified for 137 failures, including 110 reported to SafeOCS and 27 identified in other sources. In total, 144 failed components were reported for the 137 events (more than one failed component may be reported for a single event). As shown in Figure 8, the most common component failure for surface valves was the valve gate or seat, comprising more than half (68.6 percent) of the 137 failures. These were followed by the actuator, then the valve body. For SCSSVs, the flapper was the most reported failed component, followed by the hydraulic control system.

Figure 8: Failed Components in SPPE Valves, 2021



NOTE: Percentage is of 137 failures where the failed component was known to BTS. Total exceeds 100 percent because more than one component may be reported for a single event.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Failures of certain components could have a higher consequence than others. For example, the failure of an actuator spring could prevent the valve from closing when called upon, possibly extending the time of the event that triggered the valve closure. Flappers and valve gates and seats, on the other hand, are internal components. Therefore, if they fail to seal, leakage would initially be contained internally. For seven failures, more than one failed component was reported:

- In two cases, both the valve gate and seat and the valve body were listed.
- In two cases, the actuator and gate and seat were listed.
- In two cases, the valve seat and the safety lock were listed.
- In one case, the valve seat and the ball were listed.

Valve Certification

SPPE certifications fall under four types (Table 3). The Production Safety Systems Rule requires that SPPE be certified to ANSI/API Spec. Q1. BSEE may exercise its discretion to accept and approve SPPE certified under other quality assurance programs. ANSI/ASME SPPE-1was a previous standard (1996)

[17] Appendix E lists SPPE valves and their corresponding components.

containing certification criteria.[18] Although three failure reports in 2021 reported the valve was non-certified, they were classed per API standards for a particular service, suggesting that these were reporting errors. Nine of the 16 failures that did not report the certification were reported as classed valves per API standards. The table shows a significant shift from valves certified under the older SPPE-1 standard (decreased from 71.3 percent in 2020 to 45.6 percent in 2021) to valves certified under the newer standard, ANSI/API Spec. Q1 (16.8 percent to 34.2 percent) or unanswered.

Table 3: Certification Status of Reported SPPE, 2017-2021

Newly installed certified SPPE pursuant to ANSI/API Spec. Q1	13.9%	12.7%	14.7%	16.8%	34.2%
Previously certified under ANSI/ASME SPPE-1	69.6%	77.0%	71.6%	71.3%	45.6%
Not answered	9.6%	8.8%	11.6%	8.9%	14.0%

NOTE: Includes 759 failures reported to SafeOCS. Excludes failures found only in other sources.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Failures and Potential Consequences

It is helpful to consider the potential consequences of SPPE failures to put them in perspective based on the extent to which they degrade the installed well safety systems and the potential harm to personnel and the environment. In 2021, the event type was identified for 165 failures, including 114 reported to SafeOCS and 51 identified in other sources. In total, 167 event types were reported for the 165 failures (more than one event type may be reported for a single failure).

Figure 9 shows the distribution of event types in 2021. The types of failures are described below in order of significance, based on the extent of degradation of installed well safety systems and potential consequences to personnel and the environment. The number of reported failures notated in the bullets below and in Figure 9 includes 2021 failures from all sources (165 events) where the event type was known to BTS.

- **HSE Incident**: None of the reported failures in 2021 were associated with an event that resulted in consequences to health, safety, or the environment above a specified threshold, as described in Appendix F (e.g., injury or material environmental consequence). After the publication of the 2020 annual report, BTS became aware of an HSE event in 2020 reported to

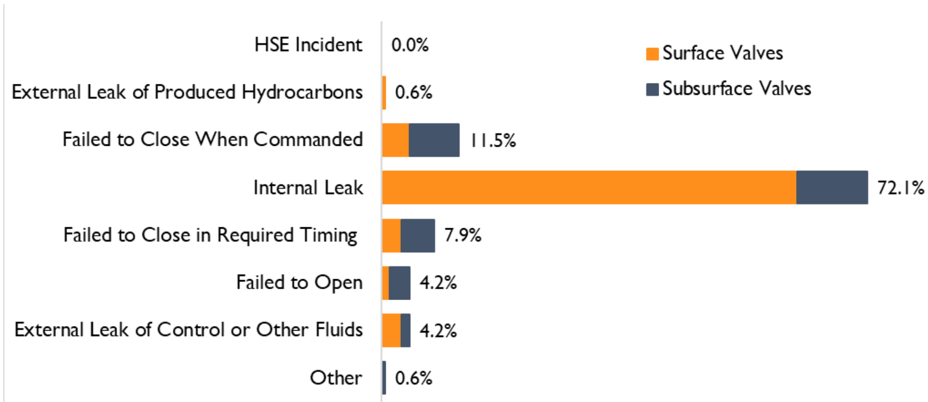
[18] The original ASME SPPE-1 certification standard was first released April 1, 1985. There have been many revisions and addendums added to the original standard over the years, including the last one on April 30, 1996.

BSEE that involved an SPPE failure. Although that failure was not reported to SafeOCS, it has been included in the aggregate analyses presented in this report.

- **External Leak of Produced Hydrocarbons**: The most significant type of failure reported in 2021 was an external leak (i.e., loss of primary containment) where produced fluids (oil or gas) could leak into the environment. One such failure was reported, which involved a trace amount of oil and water leaking from the packing of an SSV on the platform.
- **Failure to Close when Commanded**: This event type means the SPPE valve failed to close, so it would not be effective in controlling the well flow if called upon. Nineteen such failures were reported, including the two listed below under failures with multiple event types.
- **Internal Leak**: This event type means the valve closed but failed to seal, allowing some fluid to flow through it. Surface valves are allowed zero leakage, and SCSSVs are allowed 400 cc per minute of liquid (oil or water) or 15 scf per minute of gas. One hundred nineteen (119) such failures were reported. Two of the reported failures carried higher risk because there were simultaneous valve failures on the well at the same time. One of these had a failure (internal leak) on each of the two SSVs on the well, while the other well had both an SSV failure (internal leak) and a failure of the lower master valve (LMV) to close. Although both examples represent a higher risk than a single SSV failure, the one with a failure of the LMV to close is more serious as the LMV is the barrier often used to isolate the well for the SSV repair. Repair of the LMV and the SSV often requires the setting of an additional barrier(s) in the well to accomplish remediation.
- **Failure to Close in Required Timing**: This event type means the SPPE valve failed to close in the required timing of two minutes for subsurface valves and 45 seconds for surface valves, so it would be delayed in controlling the well flow if called upon. Thirteen such failures were reported.
- **Failure to Open**: This event type means the SPPE valve failed to open, so that well fluids could not flow through the tubing or piping. In cases of failure to open, the valve is still capable of performing its safety function of controlling the well flow. Seven such failures were reported, excluding the two listed below under failures with multiple event types.
- **External Leak of Control or Other Fluids**: This event type means the SPPE valve allowed a loss of primary containment of fluids other than produced oil or gas, such as hydraulic fluid, instrument air, instrument gas, or other fluids. Seven such failures were reported.
- **Other**: One failure was classified as an event type *other*, which was described as pressure build-up in the SCSSV control line, which may indicate a faulty SCSSV system.

- **Failures with Multiple Event Types**: For two failures, more than one event type was identified. In those two cases, the event involved both a failure to close when commanded and a failure to open.

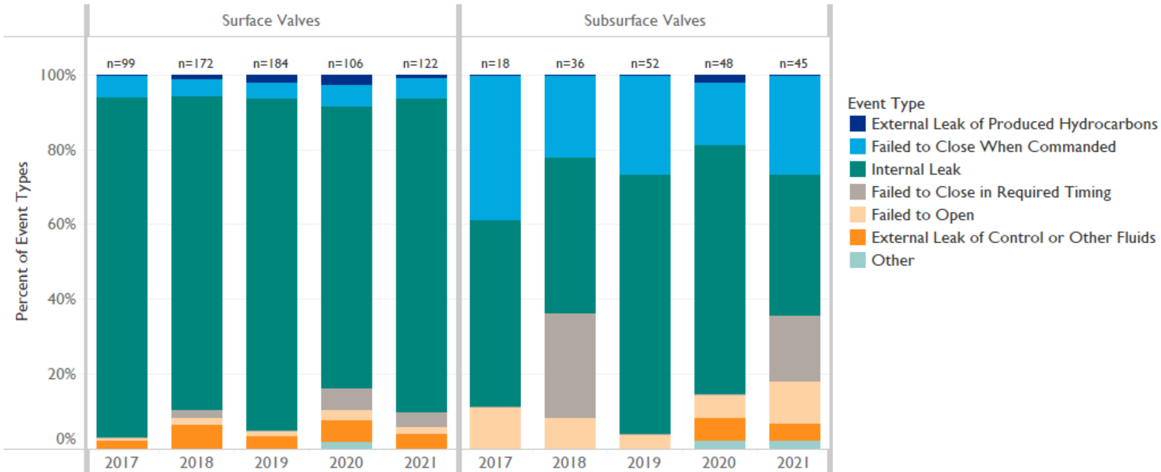
Figure 9: Event Type in Order of Significance, 2021



NOTE: Percentage is of 165 failures where the event type was known to BTS. Total exceeds 100 percent because more than event type may be reported for a single failure.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Figure 10 shows the distribution of event types each year since 2017. An internal leak is the predominant failure mode for surface valves, comprising greater than three-quarters of event types annually. For subsurface valves, the most frequent failure modes are internal leak and failure to close. In 2021, *failure to open* and *failure to close in required timing* were more prominent than in the past two years as a percentage of subsurface valve failures. Both of the two external leaks on subsurface valves were control fluid leaks.

Figure 10: Failure Events by Type, 2017-2021



NOTE: Percentage is of the number of event types reported to SafeOCS each year. 2017, 2018, and 2019 include failures reported to SafeOCS only. In 2020, 26 of the 106 surface valve event types and 25 of the 48 subsurface event types were found in sources not reported to SafeOCS. In 2021, 24 of the 122 surface valve event types and 28 of the 45 subsurface valve event types were found in sources not reported to SafeOCS. More than one event type can apply to a single failure.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Well Location and Status

Shallow Water Province versus Deepwater

Many wells are located in the GOM shallow water province, which BSEE defines as the portion of the OCS with water depths of 200 meters (656 feet) or less.[19] As shown in Table 4, most active wells in 2021 (80.8 percent) were within the shallow water province, and most SPPE failures (76.0 percent) were associated with shallow water wells. Therefore, to facilitate comparison across water depth groups, the proportion of SPPE failures for each group was evaluated against an expected proportion of failures equal to one (indicating an expected equal likelihood of failure across groups). The actual to expected

Table 4: Distribution of SPPE Failures by Water Depth, 2021

Water Depth (m)	SPPE Failures	Active Wells	Actual to Expected Failure Ratio
< 200 (656 ft)	155 (76.0%)	4,367 (80.8%)	0.94
200 - 800	25 (12.3%)	370 (6.8%)	1.79
> 800 (2,625 ft)	24 (11.8%)	665 (12.3%)	0.96
Total	*204*	*5,402*	*N/A*

NOTE: Excludes seven failures of GLSDVs or BSDVs which can serve multiple wells producing into a common subsea flowline and 3 failures where the well number is not known. Actual to expected failure ratio = percent of SPPE failures / percent of active wells.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics SafeOCS Program

[19] 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/bsee.gov/files/reports/shallow-water-report-01.pdf.

failure ratio is calculated by dividing the percentage of SPPE failures by the percentage of active wells in each group. A number higher than one indicates a greater proportion of failures than expected. Similar to 2020, in 2021 wells in the 200 to 800-meter water depth range had a higher actual to expected failure ratio compared to wells in the other water depth groups.

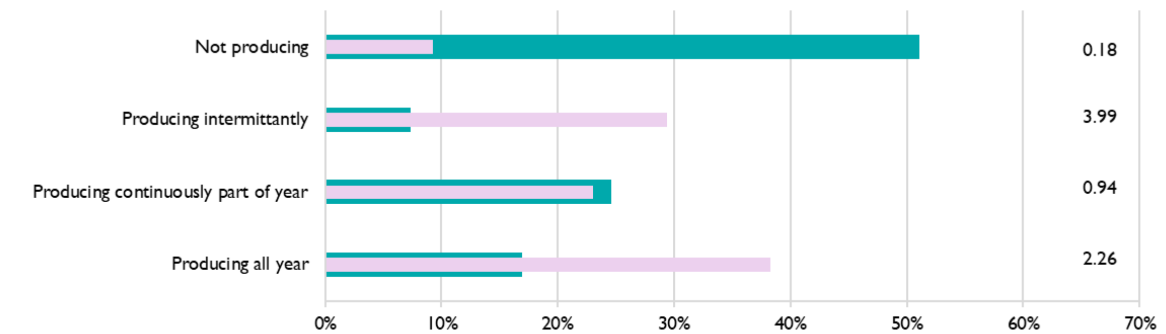
Well Status and Production Time

The well status is an indication of the type of well and its production or injection status at the time of failure. In 2020, the well status was taken from the same representative month (December 2020) as was used for the well rates of the well population. However, in 2021, the annual average well rates were used for the well population, and a new metric was introduced to characterize the amount of time over the course of the year that each well was producing. The number of months and the number of days on production in those months were considered in the new grouping, called production time (see Appendix D for more details), and the wells were placed into four production time groups:

- **Producing all year** - the well produced at least one day in all 12 months of 2021 (all but four of these wells produced at least 182 days during 2021).
- **Producing continuously part of the year** – the well produced between one to 11 months, and for the months that there was production, it produced on at least half of the days in the month.
- **Producing intermittently** – the well produced at least one day in at least one but not more than 11 months, and it produced less than half of the days in the months that it produced.
- **Non-producing** – the well did not produce a single day in 2021.

Figure 11 compares the production time grouping of the population of active wells to the production time grouping of the wells with SPPE failures. The actual to expected failure ratio, shown on the right side of the chart, is calculated by dividing the percentage of SPPE failures (surface and subsurface valve failures combined) by the percentage of active wells in each group. A number higher than one indicates a greater proportion of failures than expected. "Producing intermittently" and "producing all year" show the highest percentages of failures (29.4 and 38.2 percent, respectively) and the highest failure ratios (2.26 and 3.99, respectively). Over 90.0 percent of failures occurred on wells that produced at least one day in 2021.

Figure 11: Production Time Group of All Production Wells vs. Wells with SPPE Failure, 2021



	Producing all year	Producing continuously part of year	Producing intermittantly	Not producing
% of Production Well Population	16.9%	24.6%	7.4%	51.1%
% of Failures	38.2%	23.0%	29.4%	9.3%

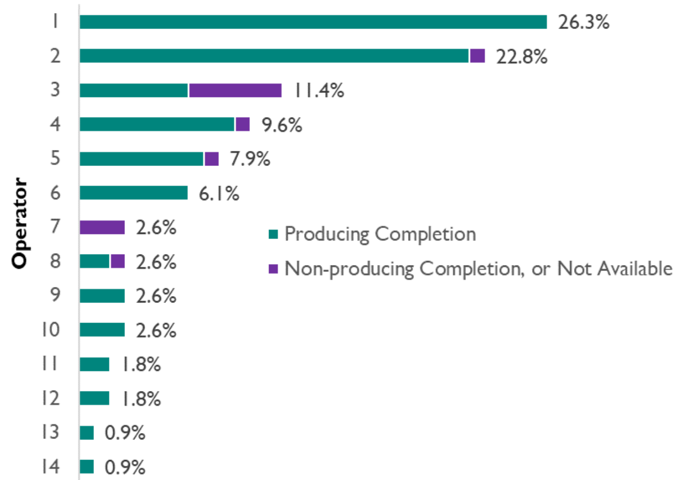
NOTES:
1. Active wells: n=5330, which excludes Injection wells. Production time group is taken from January to December 2021.
2. Wells with SPPE failure: n=204. Status is based on the days producing during the 12 months prior to the month of the failure. Excludes three failures where the well was not identified, two GLSDVs, and five failures of BSDVs, which can serve multiple wells producing into a common subsea flowline.
3. Actual to expected failure ratio = percent of SPPE failures / percent of active wells.

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Further analysis was conducted of the 19 failures in 2021 that occurred on non-producing wells. As in 2020, the failures on the wells with no production were almost evenly split between surface valves (8 of 19) and subsurface valves (11 of 19). Fifteen (15) of these 19 failures (78.9 percent) were not reported to SafeOCS.

Figure 12 shows the portion of failures on producing wells, and non-producing wells reported to SafeOCS for each operator. On average, operators reported more failures on producing wells (88.6 percent) than non-producing ones. Interestingly, the top reporting operator (along with several others) reported only failures on producing wells.

Figure 12: Reported SPPE Failure Events by Operator and Production Time Grouping, 2021



NOTE: Percentage is of 114 failures reported to SafeOCS. The well producing group is not shown for seven failures of GLSDVs or BSDVs which can serve multiple wells producing into a common subsea flowline. The API well number was unknown for three additional excluded failures.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

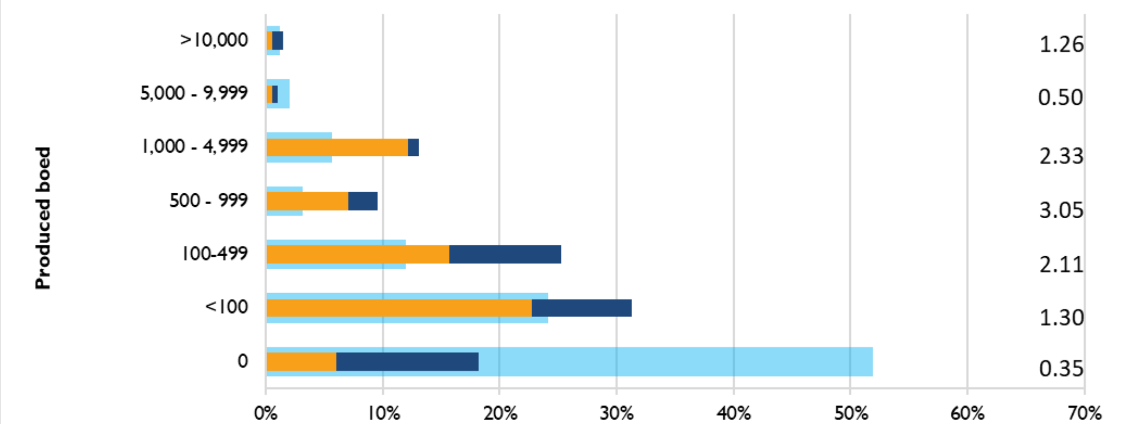
Well Fluid Rates

Operators are responsible for measuring the well production rates of oil, gas, and water for all producing wells on the OCS. To do this, operators perform periodic well tests to calculate the daily fluid volumes produced from each well in barrels of oil and water and standard cubic feet of gas, or "well rate" (see Appendix D). Depending on the well, the well rate can range from less than one barrel of oil equivalent per day (boed) to over 10,000 boed. The risk of adverse environmental consequences or production interruptions associated with a failure increases proportionally to the well rate because the potential rate of the released volume is higher for wells with higher rates.

Figure 13 compares the SPPE failures grouped by well rate range with the well rates of active wells in the GOM OCS during the month prior to the failure. Most of the failures (74.7 percent) were associated with wells that produce less than 500 boed, with nearly half (49.5 percent) producing less than 100 boed. These wells pose a lower risk than higher-producing wells. About 2.5 percent of the reported failures (on single wells where the well number was identified) were associated with wells producing more than 5,000 boed.

The actual to expected failure ratio, shown on the right side of the chart, is calculated by dividing the percentage of SPPE failures (surface and subsurface valve failures combined) by the percentage of active wells in each group. A number higher than one indicates a greater proportion of failures than expected. Wells that produced less than 100, 100-499, or 500-999 boed had the highest actual to expected failure ratios, which was also the case in 2019 and 2020. However, in 2021, failures in the 500 – 999 and 1,000 – 4,999 boed groups increased, while the percentage of failures on non-producing wells fell.

Figure 13: Well Rates for All Wells vs. Wells with SPPE Failure, 2021



	0	<100	100-499	500 - 999	1,000 - 4,999	5,000 - 9,999	>10,000
Well Population	51.9%	24.1%	11.9%	3.1%	5.6%	2.0%	1.2%
Surface Valve Failures	6.1%	22.7%	15.7%	7.1%	12.1%	0.5%	0.5%
Subsurface Valve Failures	12.1%	8.6%	9.6%	2.5%	1.0%	0.5%	1.0%

NOTES:
1. Active wells: n=5,402. Rate is taken from Jan – Dec 2021 Average.
2. Wells with SPPE failure: n=198. Rate is taken from near the time of the failure. Excludes three failures on unidentified wells, six failures on wells with no OGOR A production data reported in the prior month, and seven failures of GLSDVs or BSDVs, which can serve multiple wells producing into a common subsea flowline.
3. Actual to expected failure ratio = percent of SPPE failures (surface + subsurface) / percent of active wells.

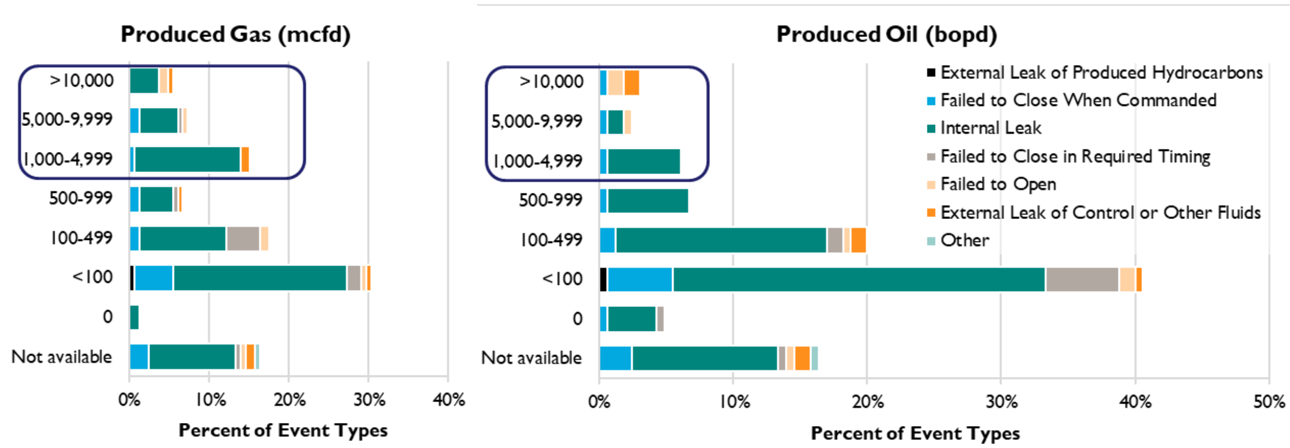
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

The average daily production rates shown in Figure 13 can offer insight into the potential environmental exposure of the failures. The total daily production volume from the wells that experienced a reported SPPE failure in 2021 was 107,649 boed. Comparing this figure to the average daily production from the GOM OCS in 2021 (2,738,538 boed) indicates that 3.9 percent of the GOM OCS production could have been directly affected by the 114 reported SPPE failures. This is an increase from 2.9 percent in 2020. Considering failures identified in all data sources (SafeOCS, APM, INC, OGOR-A, and WAR data), the average daily production volume from wells with an SPPE failure in 2021 increases to 144,588 boed, representing 5.3 percent of GOM OCS production. This percentage could be underestimated due to a small number of failures lacking production information. Also, the total prior month production rate through the five BSDVs where the well rates could be determined was 105,014 boed.

Failure Types by Well Rate

Along with the nature of the failure, the well's production rate is important in evaluating the potential environmental impact. Figure 14 shows the distribution of failures by well rate, with failure type indicated by color.

Figure 14: Type of Reported Failures by Well Rate, 2021



NOTE: Percentage is of 167 event types. In 2021, 167 event types were reported for 165 failures (more than one event type can apply to a single failure), and the event type was unknown to BTS for the remaining failures. The well rates were summed for failures of BSDVs that serve multiple wells.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

As shown in Figure 14, and like in 2020, the most significant event type among higher-producing wells (greater than 1,000 bopd or mcfd) in 2021 was a failure to close when commanded. As described below, there were a total of three events for single wells that fit into this category:

- All three single-well events occurred on wells with higher gas rates (1,000-4,999 mcfd), and two of those three events also had higher oil rates (1,000-4,999 bopd).
- Two of those three single-well events were failures of tubing-retrievable SCSSVs, one of which was on a subsea well. The installation date was reported for one of the SCSSVs (November 2017), where the operating piston seals had failed. Paraffin, asphaltenes, design, and wellbore debris were listed as contributing factors. The other SCSSV failure was reported in an INC, and limited information is available to SafeOCS.
- One event was a BSDV for a single well, and asphaltenes and improper maintenance were listed as contributing factors.
- Of the three single-well events, one was detected during a leakage test, one was detected during ESD testing, and one (an SCSSV failure that had also failed to open) was detected after bringing the well back online following a planned platform turnaround.

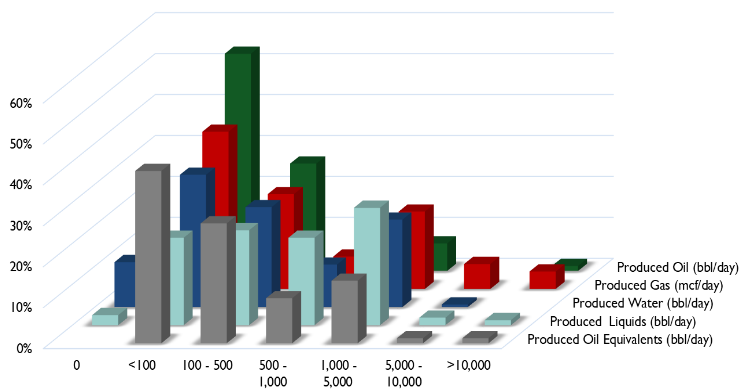
A fourth failure to close event was on a BSDV that serves two wells. The total fluid rate through the valve was from two wells and totaled > 1000 bopd or mcfd. The cause of the failure of the actuator was still being investigated at the time of this report.

The one event involving an external leak of produced hydrocarbons occurred on a well producing <100 bopd and mcfd, where a valve packing leak associated with an SSV was found during a process upset. Wear and tear was listed as the root cause, noting the valve had been last repaired in November 2016.

Rates of Oil, Gas, and Water

Some failures may have been related to the produced fluid stream passing through the valve. For most analyses presented in this section, failures not related to the fluids in the well (for example, an external leak of control fluid) are excluded. For failures affected by produced well fluids (fluid-affected failures), different parameters related to each of the three phases of the produced fluid stream (oil, gas, and water) were evaluated. Figure 15 shows the distribution of 2021 potentially fluid-affected failures independently for several production rate parameters, based on the annual average of the production from the well over the 12 months prior to the failure.

Figure 15: Failures Grouped by Well Fluid Rate Ranges, 2021



NOTE: Includes 164 total failures where produced fluids could have been a factor in the failure and well rates were available and above zero production in the past 12 months.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

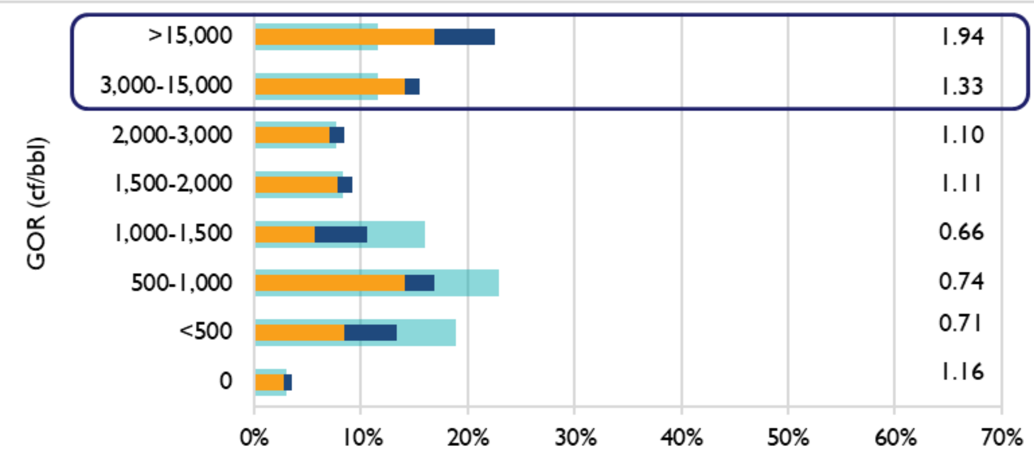
For produced oil, over 50 percent of the failures were on wells that produced greater than zero and less than 100 bopd, and most failures (82.9 percent) were on wells in the first three rate groups (0, <100, and 100-500 bopd). The breakdown is similar for produced gas and water and the two calculated parameters (produced oil equivalents and produced liquids). Compared to 2020, the 2021 failures were generally on higher rate wells for oil, gas, and water. The number of failures on wells with zero production is much lower in 2021 (18 in 2021 compared to 35 in 2020), and the percentage of failures on wells with production rates greater than 1000 bopd or 1000 mcfd increased slightly from 2020 to 2021 (27.5 percent in 2020 vs 29.3 percent in 2021).

Gas-Oil Ratio (GOR)

The fluid proportions produced from each well differ depending on the reservoir and placement of the well in that reservoir. The GOR describes the volume of gas produced from the well as compared to the volume of oil produced and can be useful in determining whether a well primarily produces gas or oil.

Figure 16 shows the breakdown of producing wells into GOR ranges. The actual to expected failure ratio, shown on the right side of the chart, is calculated by dividing the percentage of SPPE failures (surface and subsurface valve failures combined) by the percentage of active wells in each group. A number higher than one indicates a greater proportion of failures than expected based on the percentage of wells in that category. As seen in the figure, the failure ratio for wells in the highest GOR groups had higher failure ratios, indicating disproportionately more failures on these wells compared to wells in other GOR groups. This is not surprising since higher GORs may also have higher gas production rates, which result in higher velocities toward the top of the well. Any solids in the flow stream would correspondingly be more erosive and potentially lead to more failures.

Figure 16: SPPE Failures and Producing Wells by GOR Range, 2021



	0	<500	500-1,000	1,000-1,500	1,500-2,000	2,000-3,000	3,000-15,000	>15,000
Well Population	3.0%	18.9%	22.9%	15.9%	8.3%	7.7%	11.6%	11.6%
Surface Valve Failures	2.8%	8.5%	14.1%	5.6%	7.7%	7.0%	14.1%	16.9%
Subsurface Valve Failures	0.7%	4.9%	2.8%	4.9%	1.4%	1.4%	1.4%	5.6%

NOTES:

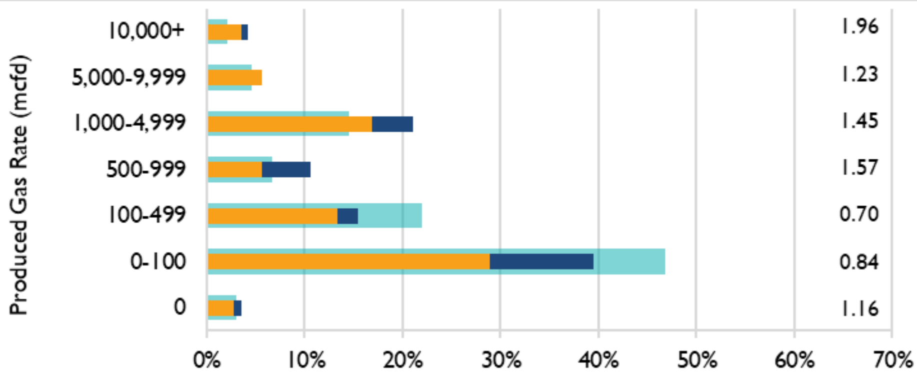
1. Active wells: n=2,597. Includes producing wells only. Rate is taken from 2021 annual average.
2. Wells with SPPE failure: n=142. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates indicated the well produced in the month prior to the failure.
3. Actual to expected failure ratio = percent of SPPE failures (surface + subsurface) / percent of active wells.

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Produced Gas Rate

Figure 17 shows the failures in each gas rate group compared to the producing well population. Almost half (46.9 percent) of the producing well population had a gas rate between zero and 100 mcfd, and many of the failures (39.5 percent) occurred on wells within that same gas rate group. The 500-999 mcfd group and the 1,000 – 4,999 mcfd group had some of the highest actual to expected failure ratios (1.57 and 1.45, respectively), indicating that more failures occurred on wells in this group compared to the population of wells in those two groups.

Figure 17: SPPE Failures and Active Wells by Gas Rate Group, 2021



	0	0-100	100-499	500-999	1,000-4,999	5,000-9,999	10,000+
Well Population	3.0%	46.9%	22.0%	6.7%	14.6%	4.6%	2.2%
Surface Valve Failures	2.8%	28.9%	13.4%	5.6%	16.9%	5.6%	3.5%
Subsurface Valve Failures	0.7%	10.6%	2.1%	4.9%	4.2%	0.0%	0.7%

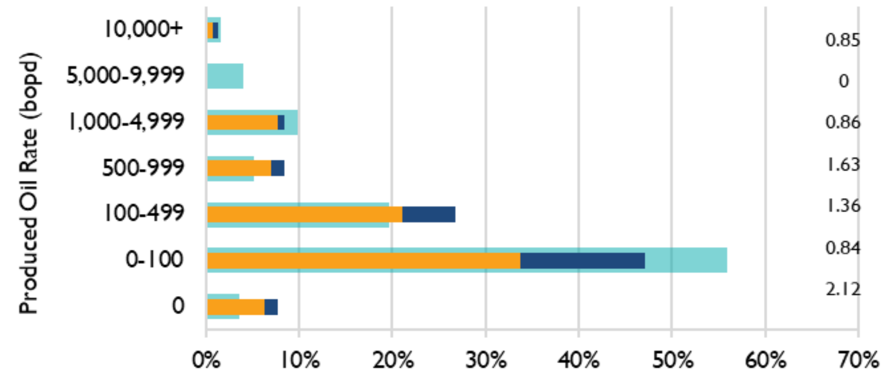
NOTES:
1. Active wells: n=2,597. Includes producing wells only. Rate is taken from 2021 annual average.
2. Wells with SPPE failure: n=142. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates indicated the well produced in the month prior to the failure. Actual to expected failure ratio = percent of SPPE failures (surface + subsurface) / percent of active wells.

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Produced Oil Rate

Figure 18 shows the failures in each oil rate group compared to the producing well population. Most of the producing well population (55.9 percent) had an oil rate between zero and 100 bopd, and many (47.2 percent) of the failures occurred on wells within that same oil rate group. More failures occurred on wells in the zero bopd group (i.e., gas wells) relative to other oil rate groups, as indicated by its higher actual to expected failure ratio.

Figure 18: SPPE Failures and Active Wells by Oil Rate Group, 2021



	0	0-100	100-499	500-999	1,000-4,999	5,000-9,999	10,000+
Well Population	3.7%	55.9%	19.6%	5.2%	9.9%	4.1%	1.7%
Surface Valve Failures	6.3%	33.8%	21.1%	7.0%	7.7%	0.0%	0.7%
Subsurface Valve Failures	1.4%	13.4%	5.6%	1.4%	0.7%	0.0%	0.7%

NOTES:

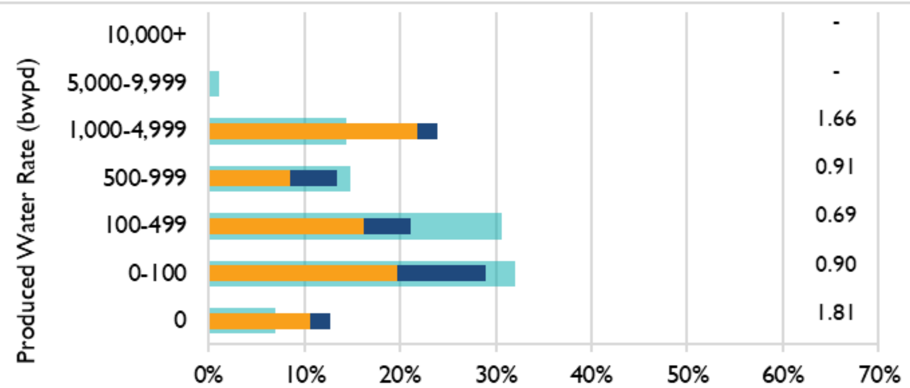
1. Active wells: n=2,597. Includes producing wells only. Rate is taken from 2021 annual average.
2. Wells with SPPE failure: n=142. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates indicated the well produced in the month prior to the failure. Actual to expected failure ratio = percent of SPPE failures (surface + subsurface) / percent of active wells.

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Produced Water Rate

Figure 19 shows the failures in each water rate group as compared to the producing well population. Most of the producing well population (62.6 percent) had a water rate between zero and 500 bwpd, and most failures (50.0 percent) occurred on wells in these groups. Although no failures occurred on wells in the 5,000-9,999 bwpd group, a small number of wells (1.1 percent) are in this category. The highest number of failures for surface valves were in the 1,000 – 4,999 bwpd group, which had a failure ratio of 1.66 and was higher than in 2020 (0.9 in 2020). The 1.66 failure ratio may lend some credence to the theory that higher water rate wells typically produce more sand/solids leading to a disproportionate number of failures. For surface valve failures in 2021 where the failure could have been fluid affected, more failures on wells with water rates of greater than 500 bwpd reported solid contaminants than wells with less than 500 bwpd (23.3 percent vs. 13.6 percent). More data on the produced fluids' composition and contaminants is needed to better understand and evaluate this relationship.

Figure 19: SPPE Failures and Active Wells by Water Rate Group, 2021



	0	0-100	100-499	500-999	1,000-4,999	5,000-9,999	10,000+
Well Population	7.0%	32.0%	30.6%	14.7%	14.4%	1.1%	0.1%
Surface Valve Failures	10.6%	19.7%	16.2%	8.5%	21.8%	0.0%	0.0%
Subsurface Valve Failures	2.1%	9.2%	4.9%	4.9%	2.1%	0.0%	0.0%

NOTES:

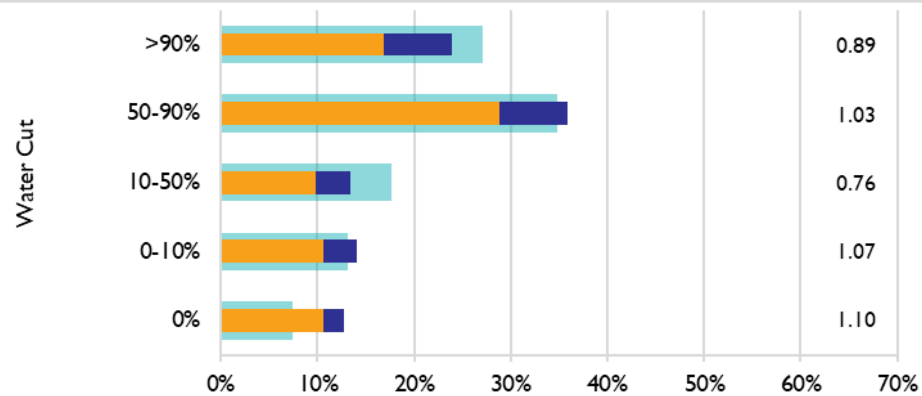
1. Active wells: n=2,597. Includes producing wells only. Rate is taken from 2021 annual average.
2. Wells with SPPE failure: n=142. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates were indicated the well produced in the month prior to the failure. Actual to expected failure ratio = percent of SPPE failures (surface + subsurface) / percent of active wells.

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Water Cut Range

A well's water cut is its ratio of produced water to total produced liquids (oil plus water). Figure 20 shows the failures in each water cut group as compared to the producing well population. The groups with the highest number of failures were the higher water cut groups, 50-90 percent, and >90 percent, but the ratios were very near expected. High water cut wells typically produce more sand than wells with low water cut due to pressure drops associated with water moving through the reservoir formation. This characteristic could result in more sand flowing through the SPPE valves (SSVs and SCSSVs), which can be erosive and cause premature valve failure. Sand was reported for two of the 51 failures (3.9 percent) in the 50-90 percent water cut group and two of the 34 failures in the >90 percent group. This topic is addressed further in the discussion of contaminants below.

Figure 20: SPPE Failures and Active Wells by Water Cut Range, 2021



	0%	0-10%	10-50%	50-90%	>90%
Well Population	7.4%	13.1%	17.6%	34.8%	27.0%
Surface Valve Failures	10.6%	10.6%	9.9%	28.9%	16.9%
Subsurface Valve Failures	2.1%	3.5%	3.5%	7.0%	7.0%

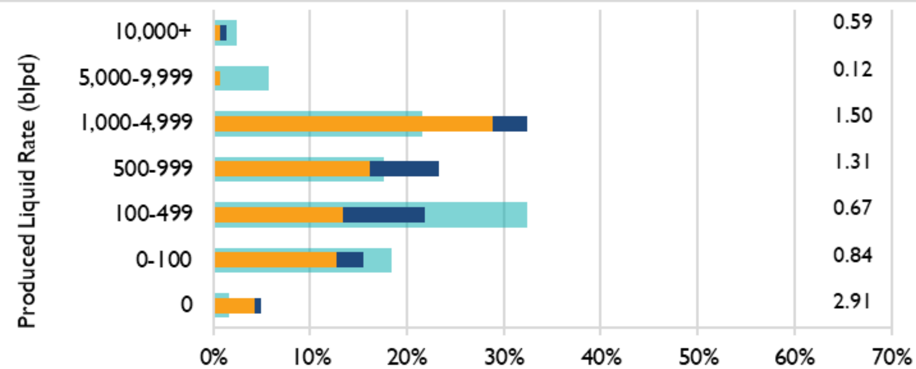
NOTES:
1. Active wells: n=2,597. Includes producing wells only. Rate is taken from 2021 annual average.
2. Wells with SPPE failure: n=142. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates indicated the well produced in the month prior to the failure. Actual to expected failure ratio = percent of SPPE failures (surface + subsurface) / percent of active wells.

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Total Liquid Rate

The total liquid rate (i.e., produced liquid rate) is calculated as the sum of the oil rate and the water rate. Figure 21 shows the failures in each liquid rate group as compared to the producing well population. Although the highest failure ratio (2.91) was in the zero blpd group, this group had the fewest number of wells (1.7 percent). The 500-999 and 1000-4,999 blpd groups had high actual to expected failure ratios (1.31 and 1.50), driven by a higher percentage of failures in those groups.

Figure 21: SPPE Failures and Active Wells by Total Liquid Rate, 2021



	0	0-100	100-499	500-999	1,000-4,999	5,000-9,999	10,000+
Well Population	1.7%	18.4%	32.4%	17.7%	21.6%	5.8%	2.4%
Surface Valve Failures	4.2%	12.7%	13.4%	16.2%	28.9%	0.7%	0.7%
Subsurface Valve Failures	0.7%	2.8%	8.5%	7.0%	3.5%	0.0%	0.7%

NOTES:

1. Active wells: n=2,597. Includes producing wells only. Rate is taken from 2021 annual average.
2. Wells with SPPE failure: n=142. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates indicated the well produced in the month prior to the failure. Actual to expected failure ratio = percent of SPPE failures (surface + subsurface) / percent of active wells.

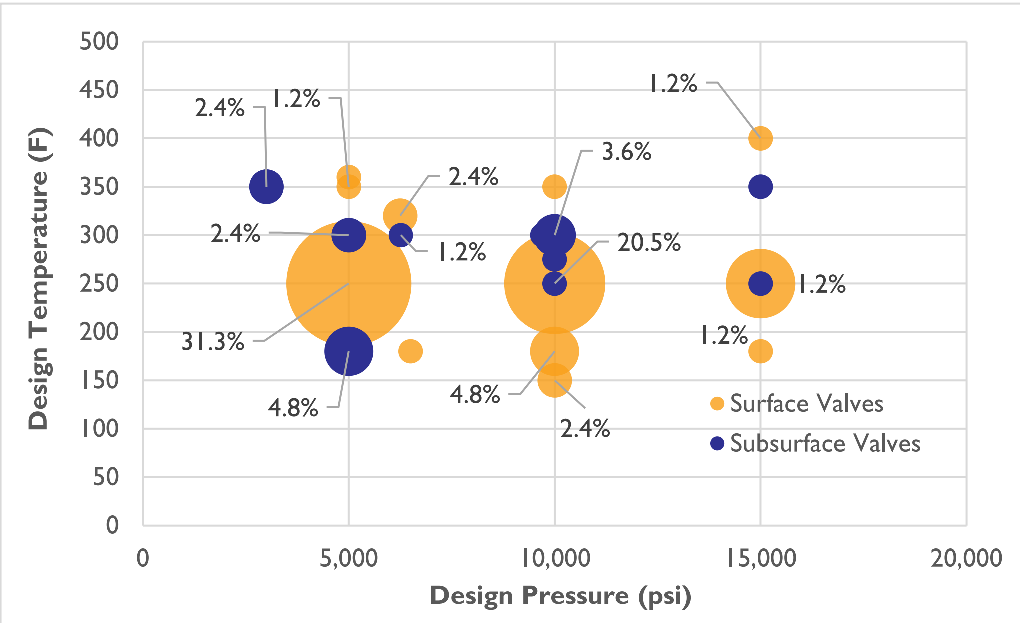
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Recalling from Figure 16 that the higher GOR groups experienced higher failure ratios and considering that the wells with 500 to 4,999 blpd total liquid rates had higher failure ratios, further exploration of the combination of these parameters is provided in Appendix H.

SPPE Pressure and Temperature Rating

Figure 22 shows the pressure and temperature ratings for 83 failures in 2021 with available data. Seventeen events involved a valve designed for high pressure or high temperature (HPHT) conditions (i.e., having a design or working pressure of at least 15,000 psi or a temperature rating of at least 350°F).[20] Fortunately, no 2021 events reported operating a valve in conditions out of its specified pressure or temperature range as a contributing factor to the failure.

Figure 22: Percent of Failures by Valve Pressure and Temperature Ratings, 2021



NOTE: Percentage is of 83 failures where both the pressure rating and the temperature rating of the valve were known to BTS.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

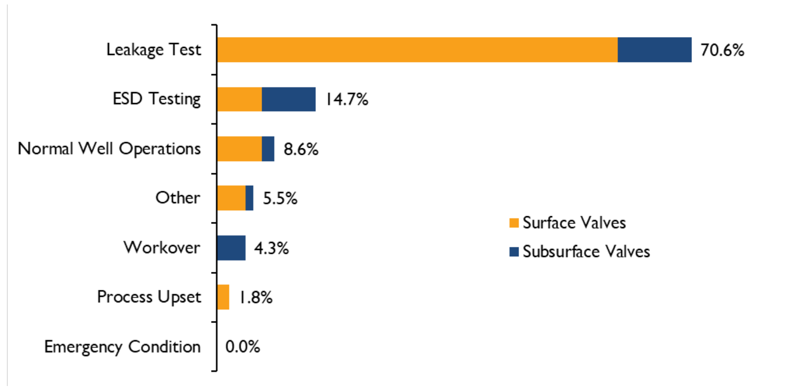
When Failures Were Detected

SPPE failures can occur when the valve is automatically or manually commanded to close via the control system. They can be detected at various times, such as during testing, while the equipment is in normal operation, or when production halts (is shut-in) due to abnormal or emergency conditions. In 2021, information on when the failure was detected was available for 163 failures, including 112 reported to SafeOCS and 51 identified in other sources. In total, 172 detection methods were reported for the 163

[20] BSEE regulations define HPHT environment as when the maximum anticipated surface pressure or shut-in tubing pressure is >15,000 psia or the flowing temperature is ≥350 F (see 30 CFR 250.804(b)). For purposes of this report, valves rated at exactly 15,000 psi (rather than strictly greater than 15,000) were considered designed for HPHT conditions.

failures (more than one detection method may be reported for a single failure). Most of those reported failures (70.6 percent) were found during routine leakage tests (see Figure 23) or during ESD testing (14.7 percent), and five failures listed both ESD testing and leakage test. Three additional failures listed more than one detection method. In one case, leak testing and an unspecified process upset were listed. In another case, the submitter reported that the failure was detected during normal well operations and "other"—bleeding down the header for repairs. In the last case, leak testing, "other"—during annual BSEE inspection, and normal well operations were listed. Seven additional failure reports indicated other detection methods, including two additional cases during BSEE inspections and four additional cases during bleeding the pressure down for repairs, and one failure was detected while testing after construction work.

Figure 23: Failure Detection Methods, 2021



KEY: ESD—emergency shutdown.
NOTE: Percentage is of 163 failures where the detection method was known to BTS. Total exceeds 100 percent because more than one detection method may be reported for a single event.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

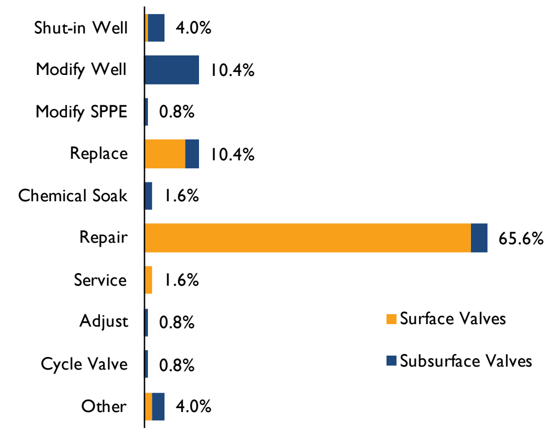
How Failures Were Addressed

In 2021, corrective actions were identified for 125 failures, including 109 failures reported to SafeOCS and 16 identified in other sources. In total, 139 corrective actions were reported for the 125 failures (more than one corrective action may be reported for a single failure). Figure 24 shows the distribution of corrective actions, which range from component servicing to repair or replacement. A repair was the most common corrective action, reported for 65.6 percent of the 125 events. Repair events were further classified based on the type of component repaired (Figure 25) to gain more insight into the corrective action taken. As expected, based on reported component failures, the most often repaired component was the valve gate or seat, which comprised 80.5 percent of repaired components.

For 12 failures, multiple corrective actions were taken to address the issue, e.g., testing to locate the failed valve, inspecting the valve to pinpoint the issue, servicing the valve, and retesting. In six cases, the valve was cycled, and then another corrective action was performed (such as well shut-in, chemical soak, repair, and service). In the remaining six cases, the SPPE was repaired and adjusted or serviced.

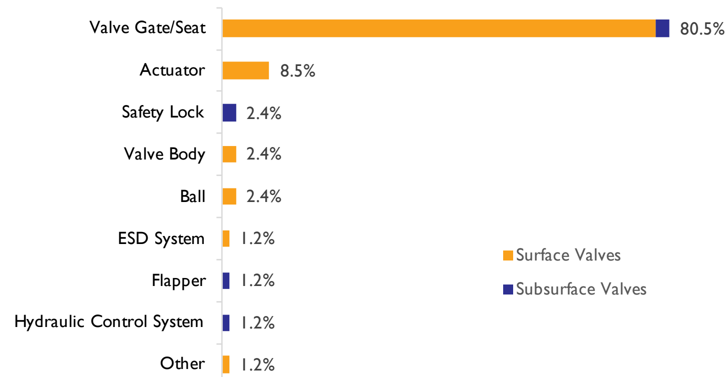
- *Shut-in Well* – the well was shut-in for at least 30 days, meaning valves were closed to halt flow from the well, either permanently or until remediation can be performed.
- *Modify Well* – a change was made to the well barrier configuration (e.g., setting a tubing plug).
- *Modify SPPE* – a change was made to the valve (e.g., replacing it with a different model or type).
- *Replace SPPE* – the entire valve was replaced with the same valve type.
- *Remanufacture* – the valve was rebuilt by the manufacturer using restored, repaired, or new parts.
- *Chemical Soak* – a chemical solvent was introduced to the valve to dissolve buildups of contaminants such as scale.
- *Repair* – the valve was repaired, or part of the valve (i.e., a component) was replaced.
- *Service* – maintenance was performed on the valve (e.g., greasing).
- *Adjust* – maintenance was performed that involved fine-tuning the valve or operational settings (e.g., control system settings).
- *Cycle Valve* – the valve was stroked, meaning it was moved from its fully open position to its fully closed position and back to fully open.

Figure 24: Reported Corrective Actions, 2021



NOTE: Percentage is of 125 failures where the corrective action was known to BTS. Total exceeds 100 percent because more than one corrective action may be reported for a single event. Corrective actions are listed from higher to lower degree of intervention.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

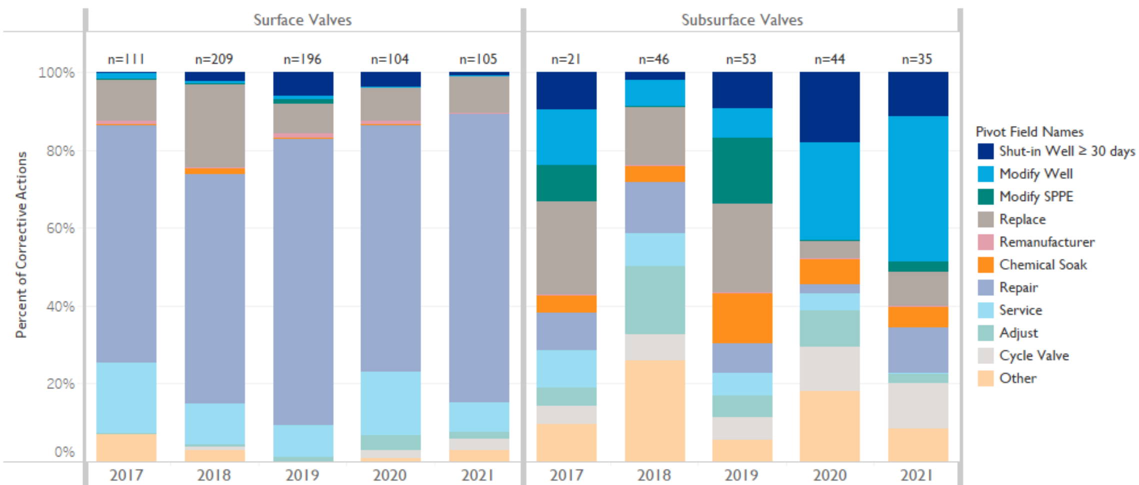
Figure 25: SPPE Components Repaired, 2021



NOTE: Percentage is of 82 repaired components.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Figure 26 shows the distribution of corrective actions each year since 2017. The 2020 and 2021 data include failures from all sources (primarily SafeOCS, APM, and WAR) where the corrective action was known to BTS. While most surface valves were corrected by repair, corrective actions were more varied for subsurface valves with a significant increase in the percentage of cases where the well was modified. The majority (11 of 15) of the "other" corrective actions for subsurface valves were cases where the subsurface valve was cleaned using a wireline scratching tool.

Figure 26: Reported Corrective Actions, 2017-2021



NOTE: Percentage is of the number of corrective actions reported to SafeOCS each year. 2017 – 2019 Include failures reported to SafeOCS only, and 2020 includes six surface valve corrective actions and 13 subsurface valve corrective actions reported in other sources 2021 includes 15 subsurface valve corrective actions found in other sources. Corrective actions were not reported for all failures, and more than one corrective action can apply to a single failure.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

In 2020, 13 of the 44 subsurface valve corrective actions were found primarily in other sources (APM, WAR, INCs, and BSEE reported incidents); in 2021, 16 of the 35 subsurface valve corrective actions were found in APM, WAR, or both. The corrective actions found in other sources were primarily to modify the well (six cases in 2020 and 13 case in 2021), and usually involved replacing a tubing retrievable SCSSV with a wireline retrievable SCSSV. These failures explain the large increase in the percentage of modified well corrective actions. Another corrective action that increased in 2020 and 2021 was to shut-in the well for 30 days or more. Three INCs where the control system was found in a state that forced the SCSSV to remain open were corrected by adjusting the valve controls.

Root Causes and Contributing Factors of Failures

Root Causes

Root cause failure analysis (RCFA) consists of various investigative methods, some more complex than others, utilized to determine failure cause(s) and contributing factor(s). Often the process includes identifying preventive actions to reduce (or, ideally, eliminate) the likelihood of reoccurrence of the failure. Eight failure reports in 2021 included information about preventive actions planned or taken, and those are summarized in Table 5. The preventive actions for the BSDV and the GLSDV each applied to two failures.

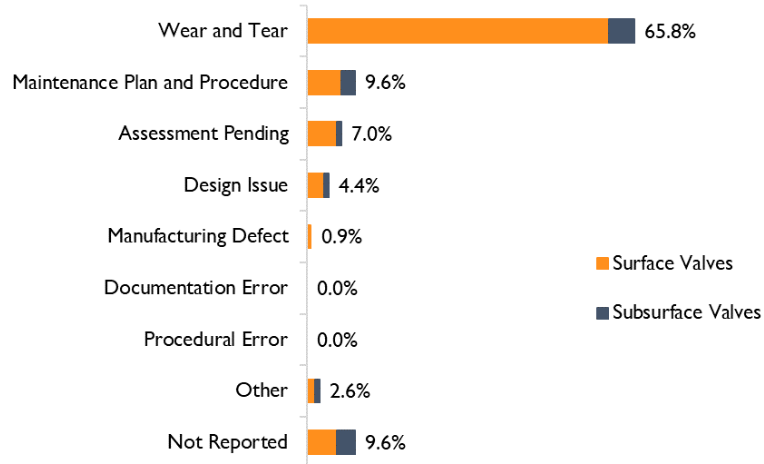
Table 5: Overview of 2021 Preventive Actions

SPPE Type	Component	Failure Type	Root Cause	Preventive Action(s)
BSDV	Valve body	Internal leak	Design issue	Replaced valve, which was the wrong valve for the application.
GLSDV	Valve Gate/Seat	Internal leak	Maintenance plan and Procedure	The operator implemented 6-month greasing program, and the OEM is considering a seat redesign.
SCSSV	Piston seals	Failed to Close and Failed to Open	Design issue	OEM recommends upgrade to improved seal design.
SCSSV	Flapper	Internal leak	Wellbore debris	Updated procedure.
SSV	Valve Gate/Seat	Internal leak	Wear and tear	Verify that the hydro-pneumatic surge dampener was installed and has proper level to slow the operation of the actuator when opening to allow the pressure to equalize and minimize scarring.
SSV	ESD System	Failed required closure timing	Wear and tear	Contractor went through panel and lubricated o-rings to prevent similar failures.

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Figure 27 shows the reported suspected root causes of SPPE failures in 2021. Wear and tear was the most reported root cause, reported for the majority of the failures (65.8 percent). Surface valves make up most wear and tear failures, with 70.4 percent of surface valve failures attributed to this. Maintenance plan and procedure was reported as the root cause for eleven failures (9.6 percent), four of which indicated the presence of contaminants (sand or paraffin).

Figure 27: Root Causes of Reported Failure Events, 2021

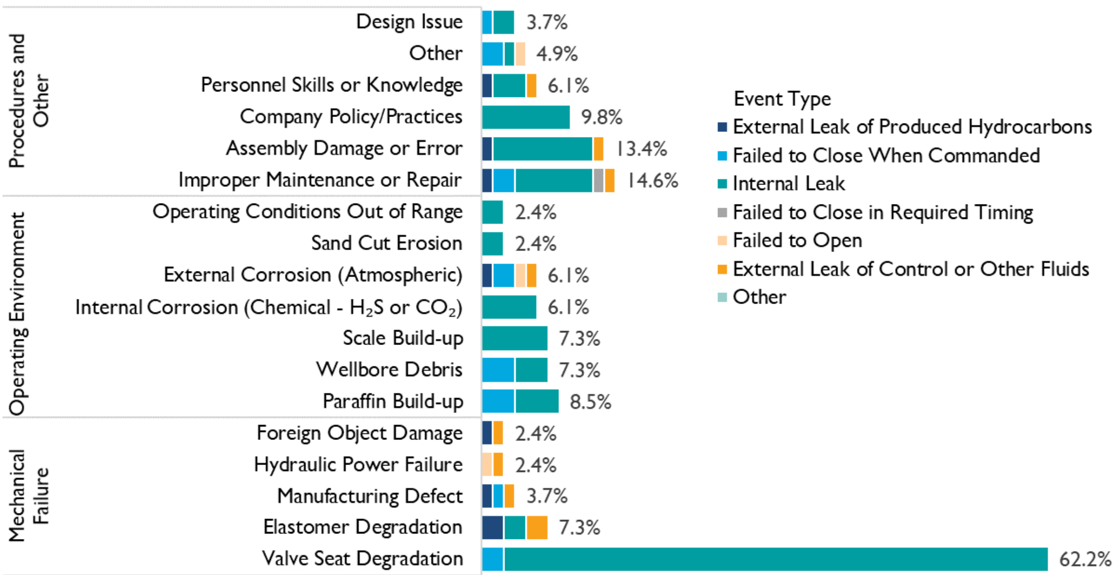


NOTE: Percentage is of 114 failures reported to SafeOCS.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Contributing Factors

Operators are asked to report all contributing factors associated with a failure. These factors can relate to procedures and practices, operating environment, mechanical failure, human error, and other areas. Information on contributing factors was available for 82 failures occurring in 2021, including 81 failures reported to SafeOCS and one identified in other sources (APM and WAR). In total, 132 contributing factors were reported for the 82 failures (more than one contributing factor may be reported for a single failure). The distribution of contributing factors for these failures is shown in Figure 28.

Figure 28: Factors Contributing to Equipment Failures, 2021



NOTE: Percentage is of 82 failures where contributing factors were known to BTS. Total exceeds 100 percent because more than one contributing factor may be reported for a single event.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Valve seat degradation was the most reported contributing factor, reported for 62.2 percent of the 82 events. This is expected since valve gates or seats were the most reported failed component. Procedures and Other had the second highest percentage of contributing factors with 52.4 percent. Factors related to the operating environment—atmospheric or chemical corrosion, sand, paraffin, debris, and scale—were designated as contributing factors in 40.2 percent of the 82 failures. Among these, chemical corrosion (internal corrosion usually caused by the presence of either H_2S or CO_2) or atmospheric corrosion (external corrosion usually caused by moisture or chlorides that affect susceptible metal surfaces) were listed as a contributing factor for 12.2 percent of the 82 failures. Depending on the metallurgy, the temperature, and the concentration of H_2S or CO_2, corrosion could occur quickly or from prolonged exposure. The four events (4.9 percent) where other contributing factors were reported included descriptions of asphaltenes, salt build-up, an actuator atmospheric vent port being plugged, and a possible defect caused by contact during well intervention work.

For 32 failures, two or more contributing factors were reported, as described in the most common combinations below:

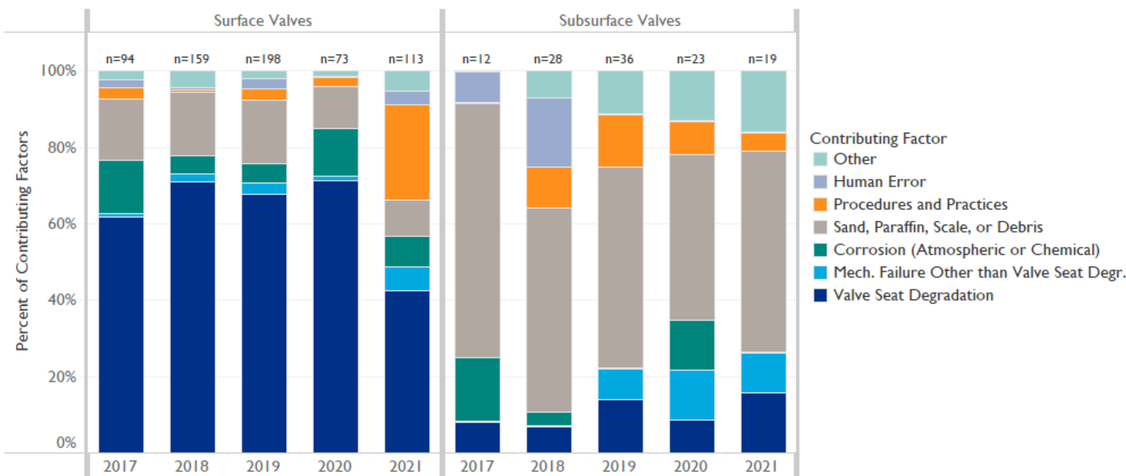
- Human error was reported as a contributing factor in four of the 2021 events, and it was always reported with improper maintenance or repair. Two of these also noted valve seat degradation.
- Six additional cases of improper maintenance or repair were reported along with other

contributing factors, including atmospheric corrosion (two), valve seat degradation (two), and design (two).

- In an additional 10 cases, valve seat degradation was reported with an operating environment factor of sand cut erosion, scale, paraffin, well debris, or chemical corrosion.
- Seven cases reported company policy or practices as a contributing factor with valve seat degradation, and five of those also reported assembly damage or error.

Figure 29 shows the distribution of contributing factors each year since 2017. Valve seat degradation was reported more frequently for surface valves, while solid contaminants (sand, paraffin, scale, or debris) were reported more frequently for subsurface valves. The "other" contributing factors, which increased again in 2021 as a percentage of the failures, included four failures with different other factors: asphaltenes, salt build-up, a plugged vent port on an actuator, and possible contact during well operations.

Figure 29: Factors Contributing to Equipment Failures, 2017-2021



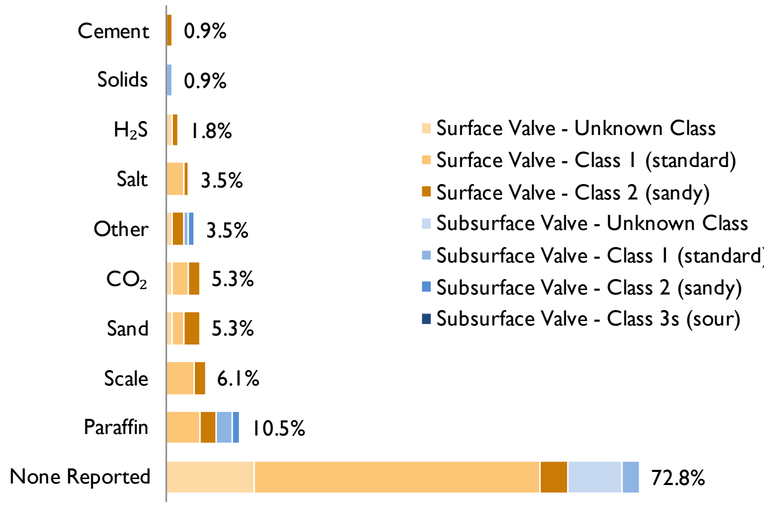
NOTE: Percentage is of the number of event types reported to SafeOCS each year. Contributing factors were not reported for all failures, and more than one can apply to a single failure.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Contaminants and Valve Class

In addition to oil, gas, and water, produced fluids may contain unfavorable contaminants, such as sand, hydrogen sulfide (H_2S), or carbon dioxide (CO_2). Although the presence of well stream contaminants is not always related to a failure, it can be a contributing factor. Well fluids can carry solids such as sand through the tree's valves during production, which can cause mechanical damage by eroding the equipment and plugging components within the production equipment. Some wells naturally contain H_2S or CO_2, both of which can lead to corrosion damage to the equipment if not properly mitigated.

The analysis of contaminants presented in this section includes only failures reported to SafeOCS because failures identified in other sources (APM, INC, OGOR-A, or WAR data) included little to no information on contaminants. Contaminants were listed for 31 of 114 failures (27.2 percent) reported to SafeOCS, shown in Figure 30, along with the service class of the failed valves. The service class corresponds to the operating conditions for which a valve is designed. SSVs, BSDVs, and USVs can be one of two service classes:

Figure 30: Well Stream Contaminants, 2021



NOTE: Percentage is of 114 failures reported to SafeOCS. Total sums to greater than 100 percent because reporters could choose more than one contaminant.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

- Class 1 indicates a performance level requirement intended for use on wells that do not exhibit the detrimental effects of sand erosion.
- Class 2 indicates a performance level intended for use if a substance such as sand could be expected in the flow stream.

Four SSV failures and two BSDV failures indicated the presence of sand; three of these involved a Class 2 valve, two were Class 1 valves, and one was missing the valve class. Thirteen SSV failures and two BSDV failures indicated the presence of other solids (paraffin, scale, salt, cement, or other solids) in the well stream, and seven of these involved Class 2 valves. Of the total 98 surface SPPE failures reported to SafeOCS in 2021, 62 (63.3 percent) were Class 1, 19 (19.4 percent) were Class 2, and the remainder did not report the service class.

Subsurface safety valves (SCSSVs and SSCSVs) have the following service classes:

- Class 1: standard service only;
- Class 2: sandy service;
- Class 3: stress cracking;
- Class 3s: sulfide stress and chlorides in a sour environment;
- Class 3c: sulfide stress and chlorides in a non-sour environment; and

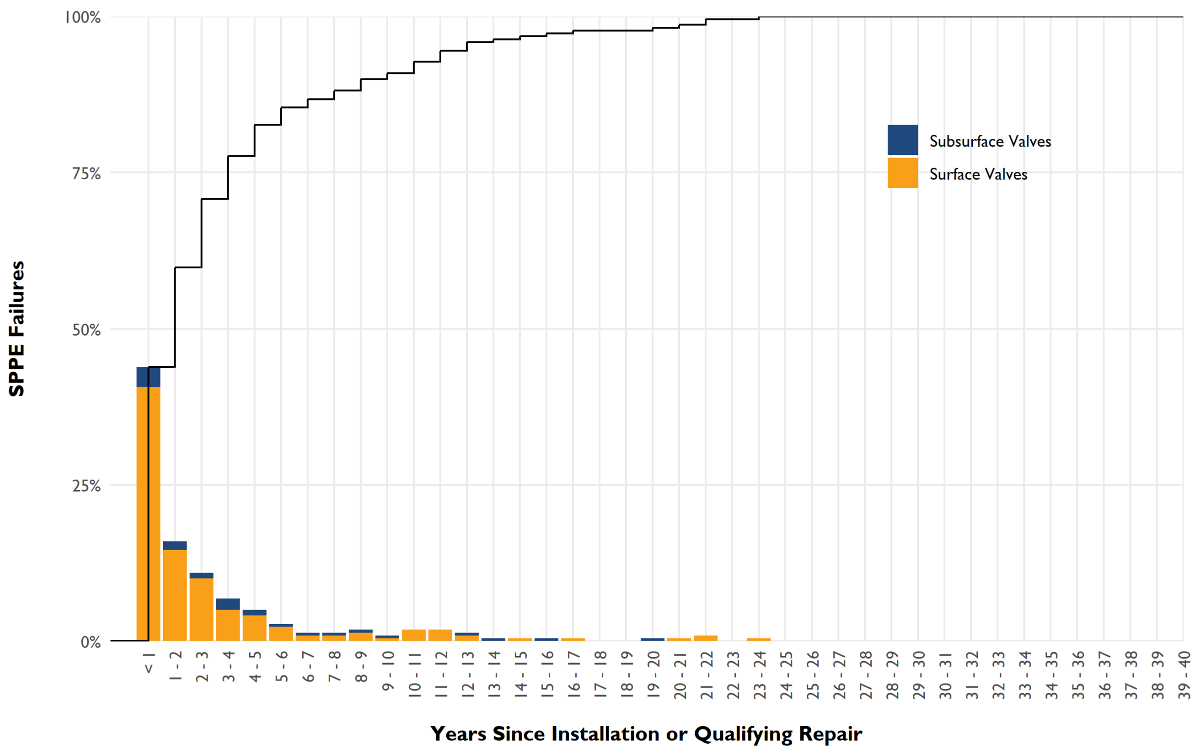
- Class 4: mass loss corrosion service.

None of the SCSSV failures indicated the presence of sand. Of 12 SCSSV failures reported to SafeOCS in 2021, four indicated the presence of other solids (paraffin, asphaltenes, salt, solids, or scale) in the well stream, and they indicated the service class of the SPPE. Two of these four were reported as a Class 1 and 2 valves, and two were Class 1 valves. The remaining eight of the total 12 SCSSV failures reported to SafeOCS in 2021 did not report any contaminants, and five of them also did not indicate the service class, two were Class 1 valves, one was a Class 3s valve.

Time to Failure

To further explore what constitutes normal wear and tear, an analysis of SPPE time to failure was performed. For 219 failures reported to SafeOCS from 2017-2021, the reporter provided either the date of installation or the date of last repair in the narrative description or the redress history. For this analysis, the repair date was used as a surrogate for the installation date, i.e., the qualifying repair date, if the repair included replacing the failed components. For example, for a failure of the valve gate and seats, a repair described in the redress history was considered qualifying if it included replacing those components. The reported dates of installation or qualifying repair ranged from less than one year to greater than 20 years, as shown in Figure 31. For 43.8 percent of these failures (96 of 219), the valve failed within one year, and for nearly three-quarters of these failures (155 of 219, or 70.8 percent), the valve failed within three years. The 219 valves comprised 192 surface valves (174 SSVs, 13 BSDVs, and five GLSDVs) and 27 subsurface valves (19 SCSSVs and eight SSCSVs).

Figure 31: Time to Failure, 2017-2021

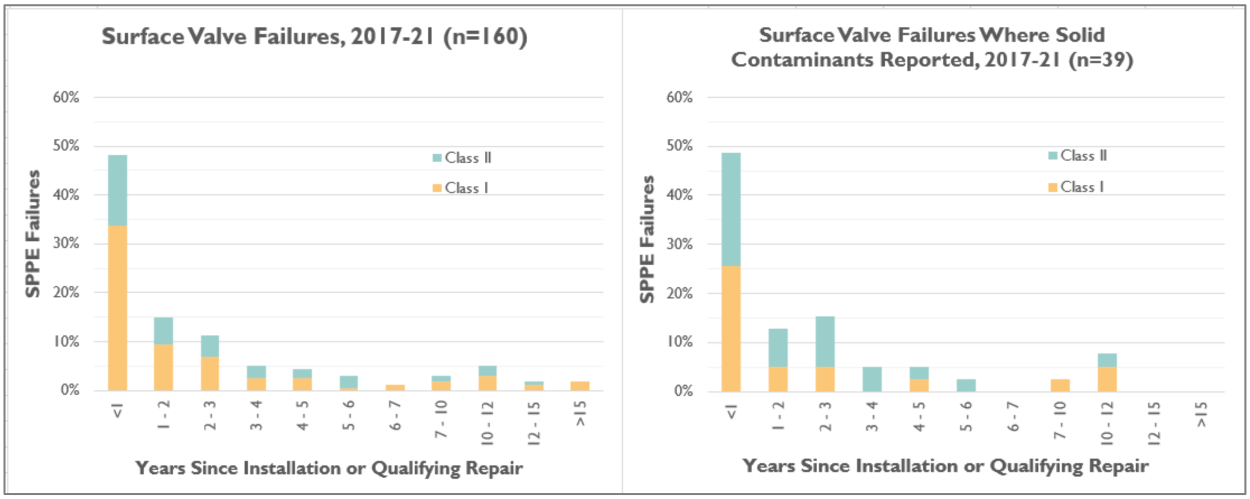


NOTE: Percentage is of 219 failures reported to SafeOCS where the installation date or qualifying repair date was available.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Regardless of known operating conditions, well rates, and equipment design, the required testing frequency for SPPEs is the same for a given SPPE type (For example, SSVs are required to be tested monthly. Refer to Table 1 above). Given that over one-quarter of the failed surface valves were in service for over three years before they experienced a failure, one might question whether there may be conditions under which the risk of failure is low enough to justify increasing the time between required tests. However, there are many unknowns, and well conditions often change over time. In addition, the vast number of valves to be tested and recorded supports maintaining simplicity in the testing requirements. A system where well conditions could be used to set different testing schedules may prove too complex and lead to less reliable testing.

To evaluate whether the earlier-life failures (less than three years) occurred more often on valves exposed to well stream contaminants, BTS examined failures with data on both time to failure and service class. Figure 32 shows the distribution of 160 surface valve failures from 2017-2021 that reported both installation or qualifying repair date and the valve service class (left) and the distribution for 39 of these failures that also reported solid well stream contaminants (right). The chart at left shows that more Class 1 valves than Class 2 were involved in earlier-life failures (50.0 percent vs. 24.4 percent from the 74.4 percent of failures during 0-3 years). However, more Class 1 valves were involved in failures after three years (15.0 percent vs. 10.6 percent from the 25.6 percent of failures). The chart at right shows that about half (53.8 percent) of the failures that also reported solid contaminants (e.g., sand, scale, paraffin) involved Class 2 valves.

Figure 32: Time to Failure and Valve Service Class, 2017-2021



NOTE: Percentage is of surface valve failures reported to SafeOCS with available data on installation or qualifying repair date, service class, and (right panel only) contaminants. Left panel includes 145 SSVs, four GLSDVs, and ten BSDVs, and right panel includes 36 SSVs and three BSDVs.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Incomplete data limit the time-to-failure analyses. However, where the installation or last repair date was known, BTS analyzed the cumulative production through the SPPE. Figure 33 shows the cumulative production to failure data for the SSVs and SCSSVs. The figure provides a starting point for further analysis of the potential relationship between cumulative production volumes passing through an SPPE and likelihood of failure.

Figure 33: Cumulative Production to Failure, 2017-2021

NOTE: The data represent the cumulative production through 157 SSV failures and 14 SCSSV failures reported to SafeOCS with available data on installation or qualifying repair date, the failure occurred on a well that produced, and the failure could have been affected by the produced fluids.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Repeated Failures

Twelve of the 114 failures reported to SafeOCS were repeated failures, defined in this report as a failure of the same component on the same valve within 12 months. The failures were internal leaks on nine SSVs and two BSDVs, and one failure of an SSCSV to close. Two of the SSVs had been reported to SafeOCS in the past (before the first failure of the repeat series); one in 2020 and the other in 2017. Eight different operators reported the 12 events. Wear and tear was reported as the root cause for half of the repeat failures, three were reported with a root cause of maintenance plan and procedure, and three root causes were unknown at the time of this report. The events are summarized in Table 6.

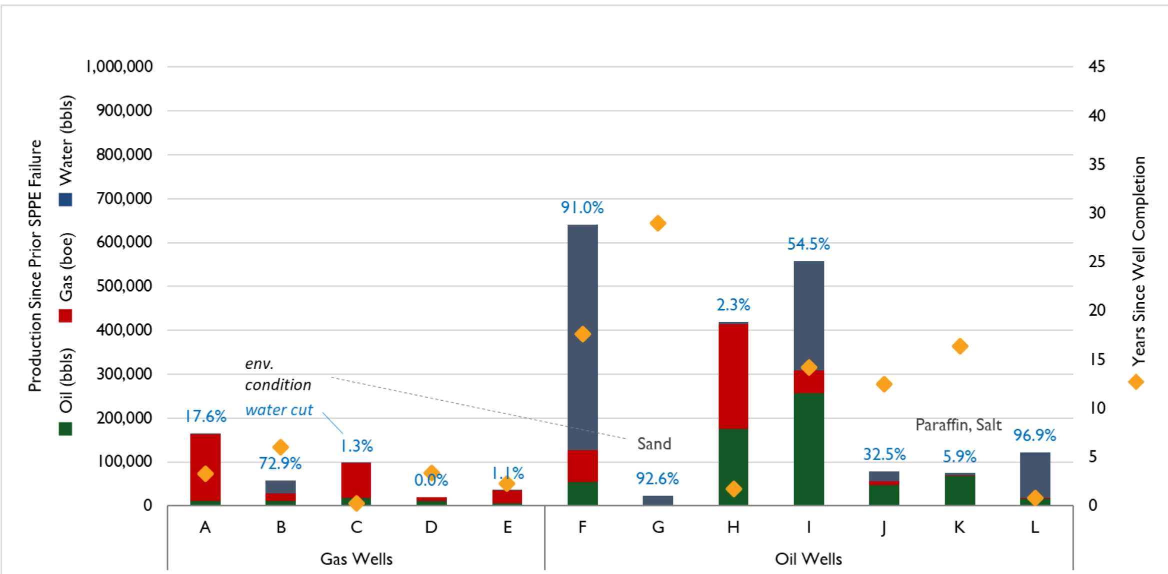
Table 6: Overview of 2021 Repeated Failures

	SSV Failures	SSCSV Failure	BSDV Failures
Number of Failures	9	1	2
Components Involved	Gate and seats for 7 events, valve body and gate and seats for 1 event, and gate and seats and actuator for 1 event.	Valve gate and seats and the safety lock ring.	Valve ball.
How Prior Failures Were Corrected	All were repaired, which for gate/seat failures typically means the components were replaced.	Repair.	Repair.
How 2021 Failures Were Corrected	Replacement of the SPPE for 2 events, repair for 6 events, and unknown for 1 event.	Repair.	Repair.
Event Type	Internal leaks for all 9 events.	Failure to close when commanded.	Internal leaks.
Detection Method	6 failures were found during leakage test and/or ESD testing,1during leakage testing that was also reported as a process upset, 1 while bleeding down the tree for header repair, and 1 not reported.	Detected during well work.	Leakage testing for 1 event and ESD testing for 1 event.
Root Cause	4 wear and tear, 2 maintenance plan and procedure, 1 is assessment pending, and 2were not reported.	Wear and tear.	Wear and tear for 1 event, and maintenance plan and procedure for 1 event.
Contributing Factors *(There may be multiple per event.)*	4 events listed no contributing factors; two events due to Valve seat degradation and improper maintenance or repair, one event noted wellbore debris, one event listed damaged during assembly, company policy/practices, valve seat degradation and mentioned that sand was present. The failure involving sand occurred on a Class 2 valve. One event listed improper repair or maintenance, valve seat degradation, and personnel skills.	Paraffin buildup, salt, and valve seat degradation.	1 event listed elastomer degradation, and 1 event listed improper maintenance or repair and personnel skills or knowledge.

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Figure 34 shows the production volumes, environmental conditions, and age of wells with repeated failures. The production volumes shown reflect the cumulative fluids that passed through the valve from the time of the prior failure until the repeated failure. Whereas in 2020 most of the repeated failures (eight of 13) were on wells with higher water cut (≥86.0 percent water cut), in 2021, just 25 percent of the repeat failures were on wells with high watercut, and another 25 percent had watercuts between 30 and 80 percent. In addition, in 2021, fewer (seven in 2020 vs. two in 2021) of the repeat failures involved a well stream contaminant. Six failures occurred on wells completed within the last five years, with two of these failures on wells completed within the last year.

Figure 34: Production from Wells with Repeated Failures, 2021



NOTE: Includes 12 repeated failures on 12 wells. Wells I and J had BSDV failures, well K had an SSCSV failure, and the other wells had SSV failures. Categorization as a gas or oil well determined from OGOR-A product code in the month prior to the failure.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

5 Conclusions and Next Steps

The close of 2021 marked the fifth full year of the SafeOCS SPPE program. Over these five years, the offshore oil and gas industry has contributed more than 750 reported events to the SafeOCS SPPE database. Several program milestones have passed: the establishment of the secure e-submit web portal for event reporting in the program's first year, the release of the SafeOCS SPPE online data dashboard in 2020, a significant improvement to the data collection form in late 2020, and publication of five annual reports and guidance documents through the years. SafeOCS has established a small cadre of SafeOCS subject matter experts to help evaluate and interpret the highly technical event reports and well activity reports. Open lines of communication have been maintained with operators and other program stakeholders.

The 2021 annual report also represents the first complete year of reported data after the implementation of the revised form in 2020, and data quality has improved. The type of failure is indicated on nearly every failure, and the API well number was available for all but two reports in 2021. There has been an increase of more than 60 percent in the number of failures that indicate the last repair date, installation date, or both. BTS will continue to work with operators to obtain better and more complete data for further evaluation of SPPE failures and develop additional metrics to track improvements and shortfalls.

The objectives of the SafeOCS SPPE failure reporting program are to capture and share essential information about SPPE failures and contribute to an improved understanding of the nature of the failures, including their operating environments and contributing factors and causes. This year's report provides more detail on exposure data and well characteristics used to support analyses, including the following.

- The well production time (i.e., producing months and percent of days on production) was analyzed and compared to the well production time across the well population.
- An additional data source—BSEE incident data —was used along with the INC, OGOR A, APM, and WAR data sources to identify failures that may not have been reported to SafeOCS. To the extent practicable, 2021 failures identified in the BSEE reported incidents, APM, INC, OGOR-A, and WAR data were included in aggregate analyses.
- Time to failure was studied for all failures with available data since 2017. In addition, cumulative production was analyzed in terms of oil, gas, water, and total liquids produced.
- Analyses comparing five years of data (2017-2020) were presented for event type, corrective

actions, and contributing factors.

- Repeated failures, in which the same component of the same valve failed within 12 months, were further evaluated by the well age and cumulative production volumes that have passed through the valve since the previous failure.

Some general observations can be drawn from the 2021 data and analyses:

- In 2021, no reported failure resulted in an HSE incident, i.e., an event with consequences to health, safety, or the environment, as defined in Appendix F.
- Reported failures in 2021 increased by 12.9 percent to 114 failures, but still remained lower than pre-pandemic levels. Likewise, in 2021 most of the failures were reported by a few operators, with four of 14 reporting operators accounting for 70.2 percent of the failures reported to SafeOCS.
- Most failures were SSV gate and seat failures (internal leakage) caused by wear and tear and corrected by repairing the valve. For SCSSVs, the most common event type was also internal leakage, with the flapper the most reported failed component.

Next Steps: Opportunities for Improvement

Entering the next five years, the SafeOCS SPPE program will focus on continuing data quality improvement efforts and root cause investigation learnings to provide more actionable information to the industry to drive safety improvements. Moving forward, the SafeOCS SPPE program will continue to prioritize collecting complete and accurate data on failures of critical safety equipment used in production operations on the OCS and sharing aggregated data and information with potential learning value. Specifically, BTS has identified several focus areas for the next steps:

- Evaluate the feasibility of expanding the use of dashboards to timely disseminate emerging safety trends.
- Work with stakeholders to improve the data collection process by focusing on the following areas:
    - Identify opportunities to improve reporting of specific root cause failure analysis results and learnings that may have industry-wide benefits.
    - Promote coverage, completeness, accuracy, and timeliness of data collected using the revised form.

APPENDIX A: OIL AND GAS PRODUCTION SAFETY SYSTEMS RULE BACKGROUND INFORMATION

The Bureau of Safety and Environmental Enforcement (BSEE) published the Oil and Gas and Sulfur Operations on the Outer Continental Shelf—Oil and Gas Production Safety Systems Final Rule (Production Safety Systems Rule) on September 7, 2016, with an effective date of November 7, 2016.[21] The rule is codified primarily in 30 CFR part 250, subpart H. In September 2018, BSEE published revisions to the 2016 Production Safety Systems Rule, which clarifies provisions for SPPE failure reporting.[22]

The rule defines an equipment failure as "any condition that prevents the equipment from meeting the functional specification," and requires reporting of such failures. More specifically, pursuant to 30 CFR 250.803, effective December 27, 2018, operators must report according to the following:

> *(a) You must follow the failure reporting requirements contained in section 10.20.7.4 of ANSI/API Spec. 6A for SSVs, BSDVs, GLSDVs and USVs. You must follow the failure reporting requirements contained in section 7.10 of ANSI/API Spec. 14A and Annex F of ANSI/API RP 14B for SSSVs (all incorporated by reference in § 250.198). Within 30 days after the discovery and identification of the failure, you must provide a written notice of equipment failure to the manufacturer of such equipment and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party* as provided in paragraph (d) of this section. A failure is any condition that prevents the equipment from meeting the functional specification or purpose.*
>
> *(b) You must ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure. If the investigation and analyses are performed by an entity other than the manufacturer, you must ensure that the analysis report is submitted to the manufacturer and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section. You must also ensure that the results of the investigation and any corrective action are documented in the analysis report.*
>
> *(c) 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 design change or modified procedures in writing to BSEE through the Chief, Office*

[21] Final Rule, 81 Fed. Reg. 61,833 (Sept. 7, 2016).
[22] Final Rule, 83 Fed. Reg. 49,216 (Sept. 28, 2018).

of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section.

(d) BSEE may designate a third party to receive the data required by paragraphs (a) through (c) of this section on behalf of BSEE. If BSEE designates a third party, you must submit the information required in this section to the designated third party, as directed by BSEE.*

- *Currently, the designee of the Chief of OORP is the U.S. Department of Transportation's Bureau of Transportation Statistics (BTS). Operators submit this information through *www.SafeOCS.gov*, where it is received and processed by BTS. Reports submitted through *www.SafeOCS.gov* are collected and analyzed by BTS and protected from release under the Confidential Information Protection and Statistical Efficiency Act.

APPENDIX B: RELEVANT STANDARDS

30 CFR Part 250 – Oil and Gas Sulfur Operations in the Outer Continental Shelf

- Subpart H - Oil and Gas Production Safety Systems (250.800 - 250.899)

Selected Relevant Industry Standards Incorporated by Reference in 30 CFR Part 250

- ANSI/API Specification 6A (ANSI/API Spec. 6A), Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004; Errata 1 (September 2004), Errata 2 (April 2005), Errata 3 (June 2006) Errata 4 (August 2007), Errata 5 (May 2009), Addendum 1 (February 2008), Addenda 2, 3, and 4 (December 2008)
- API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996; reaffirmed April 2008
- ANSI/API Specification 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition, May 2011
- ANSI/API Recommended Practice 17H, Remotely Operated Vehicle Interfaces on Subsea Production Systems, First Edition, July 2004, Reaffirmed January 2009
- ANSI/API Specification Q1 (ANSI/API Spec. Q1), Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, Eighth Edition, December 2007, Addendum 1, June 2010
- API 570, Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, Third Edition, November 2009.
- ANSI/API Spec. 14A, Specification for Subsurface Safety Valve Equipment, Eleventh Edition, October 2005, Reaffirmed June 2012.
- ANSI/API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Fifth Edition, October 2005
- API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms, Seventh Edition, March 2001, Reaffirmed: March 2007
- API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1991; Reaffirmed January 2013
- API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore, Fifth Edition, August 2007
- API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001; Reaffirmed January 2013

Appendix C: Glossary and Acronym List

Glossary

Accumulator: A pressure vessel charged with gas (nitrogen) over liquid and used to store hydraulic fluid under pressure for operation of blowout preventers (BOPs).

Active Operator: Operating company with active wells in the Gulf of Mexico (GOM).

Active Well: A well with SPPE valves providing a barrier to fluids in the reservoir. In general, this means that the well is past the drilling and completion phase, is not undergoing a workover, and has not yet been temporarily or permanently abandoned. It may or may not have production volumes reported during the year, and it may be an injection well or a production well. A well was counted as active if it had an OGOR-A status code other than drilling, abandoned, or well work for at least one month of the year. In 2020, BTS began identifying and counting active wells by the combination of the well's API number and its well completion interval, which means that a dual string well (with both production tubing strings active) was counted as two active wells. Each well production string has its own SPPE valves.

API Number: API (American Petroleum Institute) numbers are assigned by regulatory agencies, usually the oil and gas commission for the state where the well is to be drilled. For drilling operations in the GOM Outer Continental Shelf (OCS), the Bureau of Safety and Environmental Enforcement (BSEE) is the regulatory body that approves the Applications to Drill for new wells and thus assigns the API numbers. These numbers are assigned as part of the well permitting process, and they may be the same as the well permit number.

Ball Valve: A valve that employs a ball mechanism which rotates to open or close the flow passage.

Barrel: The standard unit of measure of liquids in the petroleum industry; it contains 42 U.S. standard gallons.

Barrel of Oil Equivalent (boe): The amount of energy resource (in this document, natural gas) that is equal to one barrel of oil on an energy basis. The conversion assumes that one barrel of oil produces the same amount of energy when burned as a certain volume natural gas. In this report, the factor used was 5.62 thousand cubic feet.

Borehole: When drilling to explore or develop hydrocarbon reservoirs, the hole drilled is referred to as the borehole.

Casing String: Long sections of connected pipe that are lowered into a wellbore and cemented. The pipe segments (called "joints") that make up a string are typically about 40 feet (12m) in length, male threaded on each end, and connected with short lengths of double-female threaded pipe couplings.

Check Valve: A valve that allows fluid to flow in one direction, containing a mechanism to automatically prevent flow in the other direction.

Choke: The device (also known as the well choke and installed in the wellhead) that controls the flow of fluid to or from a well by changing the flow area that the produced or injected fluids flow through.

Control Fluid: Hydraulic oil, water-based fluid, instrument gas, or instrument air which, under pressure, pilots the operation of control valves or directly operates functions.

Floating Rig (or Mobile Offshore Drilling Unit - MODU): A drilling rig that is movable, such as a drill ship or a semi-submersible rig. In some cases, a platform rig can access subsea wells.

Flowline: Piping carrying a well's fluid stream from the wellhead to the first downstream process component.

Gas-Oil Ratio (GOR): The ratio of produced gas to produced oil.

Gate Valve: A valve that employs a sliding gate to open or close the flow passage.

High Pressure High Temperature (HPHT): Per 30 CFR 250.804(b), HPHT environment means when one or more of the following well conditions exist: (1) The completion of the well requires completion equipment or well control equipment assigned a pressure rating greater than 15,000 psia or a temperature rating greater than 350 F; (2) The maximum anticipated surface pressure or shut-in tubing pressure is greater than 15,000 psia on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead; or (3) The flowing temperature is equal to or greater than 350 F on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead.

Hydrocarbons: Oil and gas.

Injection Well: A well into which fluid (water or gas) is injected for the purpose of enhancing hydrocarbon recovery.

Intervention Vessel: A marine vessel capable of performing non-rig work (such as wireline or coil tubing) on a subsea well without removing the wellhead.

Landing Nipple: A completion component fabricated as a short section of heavy wall tubular with a machined internal surface that provides a seal area and a locking profile. Landing nipples are included in most completions at predetermined intervals to enable the installation of flow-control devices, such as plugs and chokes.[23]

Loss of Primary Containment: An unplanned or uncontrolled release of any material from primary containment, including non-toxic and non-flammable materials (e.g., steam, hot water, nitrogen, compressed CO_2, or compressed air).[24]

Master Valve (also called Production Master): The main shut-in valve in the well tree is designated as the Master Valve. Most well trees have two Master Valves, an Upper Master Valve (typically designated the SSV or the USV) and a Lower Master Valve which is in the vertical run of the tree and further upstream and closest to the well.

Near Miss: An event that happened that could have led to an incident with adverse effects but did not.

Producing Operator: An operator owning wells that are in the production phase or producing oil and/or gas.

Production Platform: The structure, either fixed or floating, that contains the equipment necessary to produce well fluids including extraction, separation, treatment, and measurement.

Production Master: See Master Valve.

Production Tubing: a tube used in a wellbore through which produced fluids travel from the reservoir (production zone) to the wellhead/Christmas tree. Production tubing is installed in the drilled well after the casing string is run and cemented in place. Production tubing protects wellbore casing from wear, corrosion, and deposition of by-products (such as sand, silt, paraffin, and asphaltenes).

Production Well: A well from which oil or gas is extracted via the production tubing.

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[23] Schlumberger Oilfield Glossary, https://www.glossary.oilfield.slb.com.
[24] International Association of Oil & Gas Producers (IOGP) Report 456, Process safety – Recommended Practice on Key Performance Indicators (Nov. 2018).

Repeated Failure: A failure of the same component on the same valve within 12 months.

Tree: See Well Tree.

Water Cut: The ratio of water produced compared to the volume of total liquids produced.[25]

Wellbore: The volume contained within the cross-sectional area of the borehole, which may contain the casing, tubing, and production or injection well fluids.

Well Completion Interval (or Producing Interval): The designation given to a particular completion zone in a well. This is used to distinguish between the two production tubing strings in a dual completion well.

Well Rate Range: A range assigned to each well based on either its average production rate (sometimes referred to as "well rate") or well test rate in boed to allow grouping of wells by their flow rates. The ranges include zero (0), <100, 100-499, 500-999, 1,000-4,999, 5,000-9,999, and >10,000 boed.

Well Test: A test performed to measure the production fluid rates from a producing well or the fluid rate to an injection well, respectively.

Well Test Rate: The flow rate for a well as measured in a well test. The well test rates are reported (via a "well test report") on a 24-hour (i.e., "per day") basis and include values for oil, gas, and water volumes. For comparison purposes, these rates are sometimes converted to barrel of oil equivalents (boe), which is equal to the barrels of oil plus the barrel oil equivalent of the produced gas. A typical GOM gas conversion factor is 5.62 thousand standard cubic feet of gas is equal to one boe.

Well Tree: An assembly of valves, spools, and fittings used to regulate the flow from the pipe, or production tubing, in a producing well (oil or gas) or an injection well (water or gas). Well trees typically include two Master valves, at least one Wing valve, and the well choke. A well tree is commonly called a "Christmas tree."

Wellhead: A general term used to describe the component at the surface of an oil or gas well that provides the structural and pressure containing interface for the drilling and production equipment. The primary purpose of a wellhead is to provide the suspension point and pressure seals for the well casing strings.

[25] Schlumberger Oilfield Glossary, https://www.glossary.oilfield.slb.com.

Wing Valve: A valve in the well tree that is designated as the Wing Valve. Typically, this is the last valve on the wellhead (i.e., above or downstream of the Master Valves) and often in the horizontal section of the tree.

Wireline: a cabling technology used on oil and gas wells to lower equipment or measurement devices into the well for the purposes of well intervention, reservoir evaluation, and pipe recovery. Slick line, a type of wireline, is a thin cable introduced into a well to deliver or retrieve tools downhole as well as to place and recover wellbore equipment such as plugs, gauges, and valves.[26]

[26] Adapted from RigZone. (2017). How Do Wirelines and Slicklines Work? http://www.rigzone.com/training/insight.asp?insight_id=323.

Acronym and Abbreviation List

ANSI: American National Standards Institute

API: American Petroleum Institute

APM: Application for Permit to Modify

bbl: barrel

blpd: barrel(s) of liquid (oil plus water) per day

boe: barrel(s) of oil equivalent

boed: barrel(s) of oil equivalent per day

bopd: barrel(s) of oil per day

bwpd: barrel(s) of water per day

BSDV: boarding shutdown valve

BSEE: Bureau of Safety and Environmental Enforcement

BTS: Bureau of Transportation Statistics

cf: cubic feet

CFR: Code of Federal Regulations

CIPSEA: Confidential Information Protection and Statistical Efficiency Act

CO_2: carbon dioxide

DVA: direct vertical access

ESD: emergency shutdown

F: Fahrenheit

FOIA: Freedom of Information Act

GLSDV: gas lift shutdown valve

GOM: Gulf of Mexico

GOR: gas-oil ratio

H_2S: hydrogen sulfide

HPHT: high pressure high temperature

HSE: health, safety, and environment

INC: Incident of Noncompliance

mcf: thousand cubic feet

mcfd: thousand cubic feet per day

mmboe: million barrels of oil equivalent

NTL: Notice to Lessees

OEM: original equipment manufacturer

OCS: Outer Continental Shelf

OGOR-A: Oil and Gas Operations Report – Part A

PMV: production master valve

PWV: production wing valve

RCFA: root cause failure analysis

SME: subject matter expert

SPPE: safety and pollution prevention equipment

SSV: surface safety valve

SCSSV: surface controlled subsurface safety valve

SSCSV: subsurface controlled subsurface safety valve

TUTA: topsides umbilical termination assembly

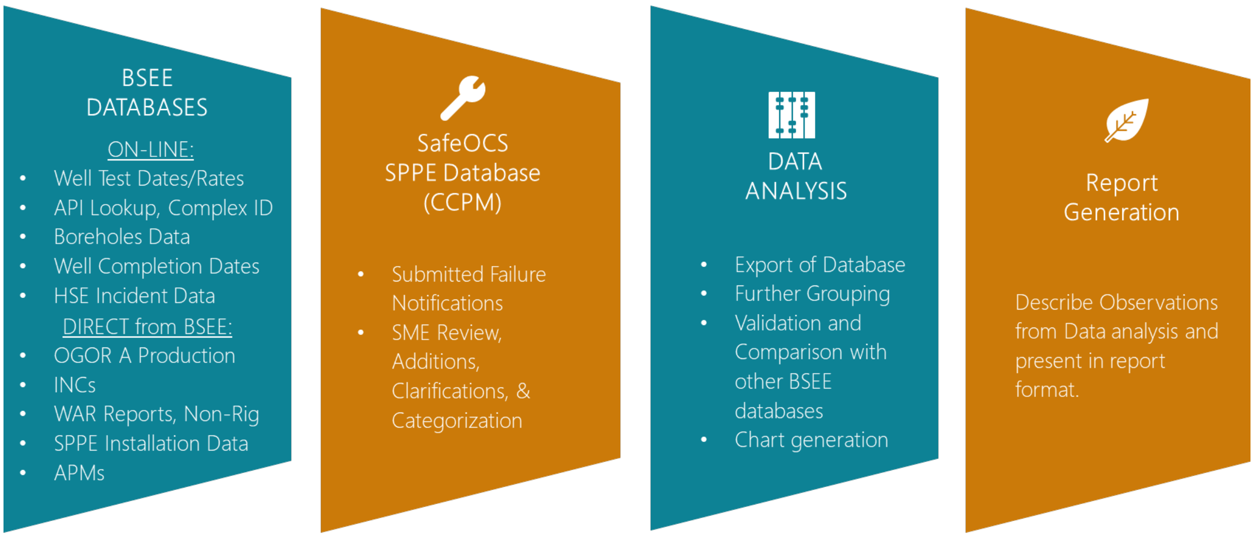
USV: underwater safety valve

WAR: Well Activity Report

APPENDIX D: DATA ANALYSIS METHODOLOGY

The diagram below depicts the major steps in developing the SPPE annual report.

Figure 35: SPPE Annual Report Steps



SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

WAR and Non-Rig WAR Reports

Operators are required to provide a summary of daily activities in all Outer Continental Shelf (OCS) regions (Gulf of Mexico (GOM), Pacific, and Alaska), reported via Well Activity Reports (WARs) on a weekly basis in the GOM Region and daily in the Pacific and Alaska Regions, per 30 CFR 250.743. The well activities reported in WAR include work accomplished on OCS wells during all phases (drilling, completion, workover, re-completion, non-rig interventions, and abandonment) including any repairs or replacements of subsurface SPPE valves (SSCSVs and SCSSVs).

BTS reviewed the non-rig WAR data to provide context for the SPPE failures reported to SafeOCS. When subsurface safety valves fail, they are often repaired, replaced, or substituted using a non-rig well intervention. The wireline operation reports in the non-rig WARs document these interventions and can sometimes be used to cross-reference the timing and occurrence of subsurface SPPE failures reported to SafeOCS.

Application for Permit to Modify (APM)

Operators must submit an APM to BSEE for approval of most well completion, workover, or decommissioning operations.[27] Well intervention operations needed to repair subsurface safety valves are approved by BSEE via APMs. BTS reviewed these to provide additional context for the SPPE failures reported to SafeOCS and identify failures that may not have been reported to SafeOCS. Often, an operation to repair a subsurface safety valve will be described in both APM and WAR data, as the APM describes the plan, and the WAR describes how the plan was implemented. It is not uncommon for an APM to give a history of the well and the failure that occurred with a high-level procedure that is planned to repair the device. In many cases, this history and procedure are not found in other sources and can be invaluable in understanding certain details about the failure.

When considering whether a failure found in an APM was the same as a failure found in another source (e.g., WAR), BTS considered it the same failure if it was the same SPPE valve on the same well completion name (same string on dual well) and the well had not produced since the date of the first reported failure. In those cases, the date of the APM was considered the date of the failure, unless a more specific failure date was provided. In cases where a failure was found only in APM, the failure date was considered the earlier of the APM approval date or the work commence date.

Well Test Reports and Well Production Volumes

Procedures for well production reporting and well test reporting in the OCS regions are codified in BSEE regulations 30 CFR 250 subparts K and L. Subpart L—Oil and Gas Production Measurement, Surface Commingling, and Security describes the measurement and production well testing requirements. Well test reports are based on BSEE procedures which require lessees (i.e., operators) to submit well test volume reports at least semiannually or at a different frequency as approved in the commingling permit for each producing well.[28] During well testing, the well's fluid stream is temporarily segregated from the other wells. While segregated, the oil, gas, and water volumes are measured using flow meters installed on the corresponding streams exiting a three-phase separator, typically called a well test separator, over a specified time (usually four hours). The well test volume (barrels of oil, thousand cubic feet of gas, and barrels of water) are then divided by the test time to establish the well test rate on a per day basis. To make comparisons between oil and gas wells, however, these rates are typically converted to barrel of oil equivalents per day (boed) by adding the oil rate to the equivalent gas

[27] 30 CFR 250.513, 250.613, 250.1712, 250.1721.
[28] 30 CFR 250.1151(a)(2), 250.1204(b).

rate. The equivalent gas rate is equal to the gas volume (in mcf) divided by 5.62.[29] The 5.62 factor is the number of cubic feet in an equivalent barrel of oil and is the industry standard to calculate an equivalent gas rate.

If the well test rate was provided in the notification, BTS compared it to the most recent well test prior to the failure using well test data from BSEE. Well test rates were used only to validate the well rate range for each well with a reported failure. The well rate range was calculated using the average production for the well (if any) in the month prior to the failure.

The well rate range for each of the producing wells in the 2021 OGOR-A database (including those with a reported SPPE failure) was determined by BTS using the average production rate for each well during 2021. The average production rate in boed was calculated by adding each well's total produced oil volume and total gas volume (after converting to boe volume) in 2021, and then dividing the sum of those two volumes by the number of days the well was on production during 2021. A similar method was used to determine each of the well rate ranges for oil, gas, water, total liquids, GOR, and water cut during 2021.

Well Production Time

In addition to each well's produced volumes, the OGOR-A data contains the number of days the well was on production each month. In 2021, a new metric was introduced to characterize the amount of the year that the well produced. Two factors were considered in the new metric, called production time.

The first factor is the number of months during the year that the well had at least one day of production. BTS found that if a well produced at least one day in every calendar month of 2021, it was almost always producing the majority of the days in the year. Consequently, this group was labeled "producing all year."

The second factor is the percentage of days in the month that the well was producing. Some wells are produced intermittently because of low reservoir pressure near the well bore. They may be shut-in for several weeks to allow the reservoir pressure near the wellbore to equalize with the higher-pressure area in the reservoir. Then the well is opened to produce again until the pressure near the wellbore is too low to flow naturally, and the cycle is repeated. Separating these intermittent producers from full or

[29] 30 CFR 203.73. See also U.S. Department of the Interior, Minerals Management Service, Appendix 1 to NTL No. 2010-N03, at page 38.

part-time continuous producers allowed BTS to compare the failures to the well population to identify whether the production time may have contributed to failures. Wells that did not produce every month in 2021 were either "not producing," "producing continuously part of the year," or "producing intermittently." Active wells, including wells with SPPE failures in 2021, were placed into these four production time groups:

- **Producing all year** - the well produced at least one day in all 12 months of 2021 (all but four of these wells produced at least 182 days during 2021).
- **Producing continuously part of the year** – the well produced between one to 11 months, and for the months that there was production, it produced on at least half of the days in the month.
- **Producing intermittently** – the well produced at least one day in at least one but not more than 11 months, and it produced less than half of the days in the months that it produced.
- **Non-producing** – the well did not produce a single day in 2021.

Well Status at the Time of Failure

If not provided in the failure report, OGOR-A data was used to determine the well's status at the time of failure:

- If there was no production during the month of failure, then the well's non-producing status was used (oil or gas, depending on the product code for that well).
- If a well had the same producing status code in the month of failure and the month prior to the failure, then that producing well status was used.
- If there was evidence (based on the production volumes, if any, and the days on production) that the well was producing at the time of failure, even if the well status at the end of the failure month was non-producing, then a producing status code was assigned based on the production history for that well (either producing oil completion, producing oil completion with gas-lift, or producing gas completion).
- If there was production in the month of failure but no production the prior month, then the well was assigned a producing status code unless information in the failure report indicated that the well was non-producing at the time of failure.

SPPE Population in the Gulf of Mexico

All SPPE installations are reported to BSEE, and these are captured in a database provided by BSEE to BTS. The database includes fields such as type of SPPE, date of installation, date of removal (if removed), removed from service flag, well API number, and other information. BTS used this information to determine the number of currently active SSVs, USVs, BSDVs, SCSSVs, SSCSVs, and GLSDVs in the GOM. This improved the population estimate and allowed the population to be reported by SPPE type. BTS determined the number of active SPPE valves by restricting the list of installed valves to those in the GOM OCS that were not flagged as removed or out of service.

Incidents of Noncompliance (INCs)

BTS reviewed INCs issued by BSEE in 2021 to determine if the deficiency described in the INC was a reportable SPPE failure.[30] The SPPE failures identified in INC data are listed in Table 7. The INCs were then used to cross-reference the SPPE failures during the same period to determine if they were also reported in SafeOCS.

Table 7: SPPE Failures Identified in INC Data, 2021

PINC	Short Description	Number of Failures		
		2019	2020	2021
G-111	SPPE corroded or leaking and needing repair	0	3	0
G-112	SPPE leaking hydrocarbons externally	0	1	0
G-113	Lessee makes facilities available for inspection	0	0	1
P-102	Shutdown valve failed to close upon receiving signal	3	0	3
P-103	SPPE bypassed or blocked out of service	0	2	0
P-240	SCSSV was not tested every 6 months	12	5	4
P-241	SCSSV failed to close within 2 minutes	18	0	10
P-261	Long term shut-in well SCSSV rendered inoperable	0	1	1
P-280	SSV failed to close within 45 seconds	16	16	4
P-307	SSV was not tested monthly	1	2	0
P-319	BSDV was not tested monthly	0	1	1
P-366	Departing subsea gaslift line equipped with GLSDV	0	0	2
P-412	SSV, USV, or BSDV had internal leakage	38	13	22
	Total	**88**	**44**	**48**

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Boreholes Data

The water depth for active wells and wells with SPPE failure in the GOM OCS was determined using boreholes data provided by BSEE. The boreholes table includes a water depth field, which was joined with the well API number to determine the water depth for active wells.

[30] The BSEE Potential Incident of Noncompliance (PINC) List can be accessed at https://www.bsee.gov/reporting-and-prevention/potential-incident-of-noncompliance-pinc.

Well API Number

In cases where the well API number was not reported on the SafeOCS notification, BTS utilized the BSEE Data Center API lookup and the OGOR-A production data to determine the well API number associated with each SPPE failure based on other information provided such as lease number, well name, and complex ID. Since GLSDVs and BSDVs are often associated with multiple wells, multiple API well numbers were assigned to those failures.

Well Count Determination from OGOR-A Data

The total GOM OCS well count was determined using production data from OGOR-A data. Each well is identified with an API number and a completion interval, and each interval has a reported well status code each month. Status codes were used to exclude well API numbers for wells that did not meet the definition of "active well" in this SPPE report. Specifically, well with the following status codes were excluded:

- 01 Actively Drilling
- 02 Inactive Drilling
- 14 Wellbore Temporarily Abandoned
- 15 Completion Abandoned
- 16 Plugged and Abandoned
- 17 Well Work in Progress

Any well that was reported as "active" in at least one month of the calendar year was counted as an active well during 2021. The active wells were similarly counted for each operator, in addition to the operators' total production.

APPENDIX E: FAILURE RATE DETAILS

Table 1 shows the SPPE failure rates based on the total population of each valve type and its testing frequency. The failure rate for each valve type is calculated as the number of reported failures divided by an exposure denominator of the number of installed valves multiplied by the testing frequency. The methodology considers the variability in testing frequency for SSVs on non-producing wells. Per 30 CFR 250.869(b), SSVs are not required to be tested if the well is disconnected from producing facilities and blind flanged, equipped with a tubing plug, or the master valves have been locked closed. The increased number of shut-in wells likely reduced the number of SSV tests performed, lowering the potential for failure identification. To account for this, a failure rate range was calculated for SSVs: the lower exposure denominator represents monthly testing for producing wells and annual testing for non-producing wells (annual testing is assumed for non-producing wells due to uncertainty in SSV testing frequency for these wells), and the higher exposure denominator value represents maximum potential testing (every SSV tested monthly).[31] The proportion of SSVs on non-producing wells was estimated as the number of installed SSVs multiplied by the percentage of non-producing active wells.

Table 8: SPPE Failure Rates in the Gulf of Mexico, 2019-2021

		Surface Valves			Subsurface Valves			
		SSV	BSDV	GLSDV	SCSSV	SSCSV	USV	*Total*
Testing Frequency		1/yr. or 12/yr.	12/yr.	12/yr.	2/yr.	1 or 2/yr.	4/yr.	N/A
Reported Failures	**2019**	221	8	3	89	6	2	329
	2020	105	4	2	48	0	0	159
	2021	119	14	7	47	4	3	194
Installed Valves	**2019**	5472	174	25	4940	569	667	11,847
	2020	5371	178	25	4914	521	681	11,690
	2021	5307	182	26	4869	497	719	11,600
Exposure Denominator	**2019**	36,409 - 65,664	2088	300	9880	569 - 1,138	2668	N/A
	2020	29,384 - 64,452	2136	300	9828	521 - 1,042	2724	N/A
	2021	34,258 - 63,684	2184	312	9738	497 - 994	2876	N/A
Failure Rate	**2019**	0.34% - 0.61%	0.38%	1.00%	0.90%	0.53% - 1.05%	0.07%	N/A
	2020	0.16% - 0.36%	0.19%	0.67%	0.49%	0.00% - 0.00%	0.00%	N/A
	2021	0.19% - 0.35%	0.64%	2.24%	0.48%	0.40% - 0.80%	0.10%	N/A

NOTES:

1. Failure rate = reported failures / exposure denominator. Exposure denominator = installed valves × testing frequency.
2. SSV exposure denominator: The calculation methodology considers the variability in testing frequency for SSVs on shut-

[31] Exposure denominator calculations for SSVs:

- Lower end = (installed SSVs × percent of wells that were non-producing × 1 test) + (installed SSVs × percent of wells that were producing × 12 tests)
- Higher end = installed SSVs × 12 tests

The percent of non-producing wells in 2019 and 2020 were 48.6 percent and 59.4 percent, respectively, based on well status in December of each year. For 2021, wells that did not produce a single day were considered non-producing.

in wells, for all years. See appendix narrative for explanation.

3. SSCSV exposure denominator: The calculation methodology considers that SSCSVs must be tested semiannually, not to exceed six months between tests for valves not installed in a landing nipple and 12 months for valves installed in a landing nipple. Therefore, the low end of the range assumes one annual test, and the high end assumes two.
4. Includes failures reported to SafeOCS and identified in other sources, except for subsurface safety valve failures identified only in OGOR-A data because the valve type (SCSSV or SSCSV) was not specified. Other sources include INC, WAR, and OGOR-A data for all three years, and APM data for 2020 and 2021, which includes three and four (respectively) failures found only in APM data (2019 did not include a review of APM data).

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

APPENDIX F: TYPICAL SPPE VALVE COMPONENTS

The following table describes the components typical of each type of SPPE valve.

Table 9: Typical SPPE Valve Components

Component	SSV	USV	SCSSV	SSCSV	BSDV	GLSDV
Actuator	x	x	x	N/A	x	x
Ball	Rare	x	Rare	N/A	x	x
Direct Hydraulic Control System	x	x	x	N/A	x	x
Electro-Hydraulic Control Umbilical	N/A	x	x	N/A	N/A	N/A
Emergency Shutdown (ESD) System	x	x	x	N/A	x	x
Flange	x	x	N/A	N/A	x	x
Flapper	N/A	N/A	x	x	N/A	N/A
Flow Coupling	N/A	N/A	x	x	N/A	N/A
Gate and Seat	x	x	Seat	Seat	x	x
Landing Nipple	N/A	N/A	x	x	N/A	N/A
Ring Joints	x	x	N/A	N/A	x	x
Safety Lock	N/A	N/A	x	x	N/A	N/A
Temperature Safety Element (TSE)	x	x	x	N/A	x	x
Valve Body	x	x	x	x	x	x

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

APPENDIX G: HSE INCIDENTS

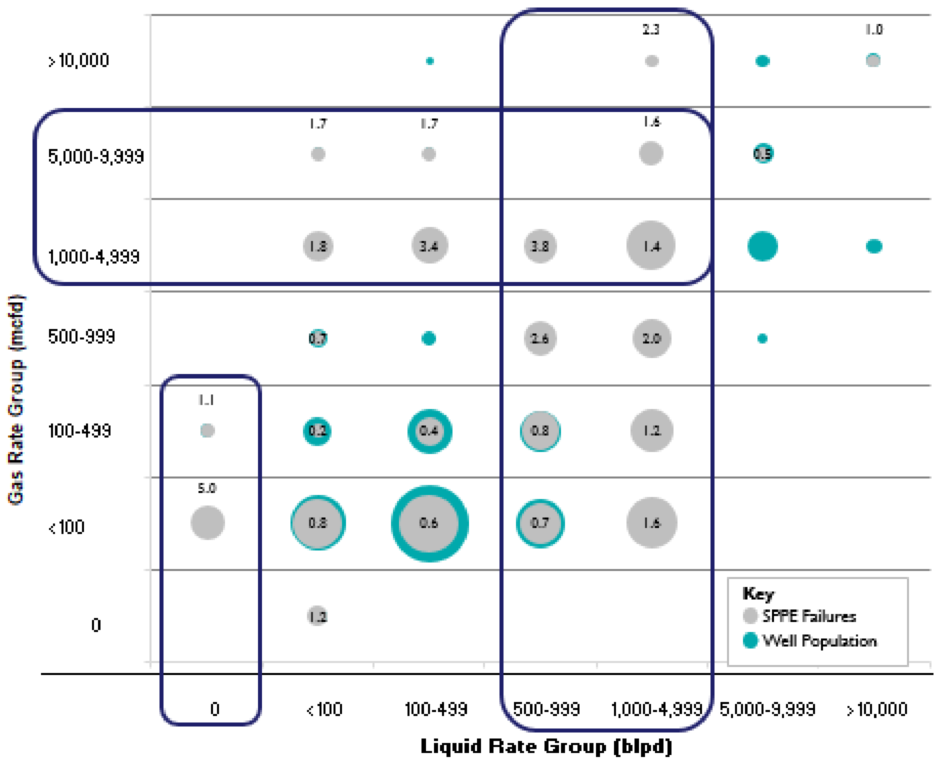
A health, safety, and environment (HSE) incident can generally be defined as an event that results in consequences to health, safety, or the environment. For purposes of this report, an HSE incident is an event that results in consequences to health, safety, or the environment above a specified threshold, as detailed below:

- One or more fatalities
- Injury to 5 or more persons in a single incident
- Tier 1 Process Safety Event (API 754/IOGP 456)
- Loss of well control
- $1 million direct cost from damage of loss of facility/vessel/equipment
- Oil in the water >= 10,000 gallons (238 bbl)
- Tier 2 Process safety event (API 754/IOGP 456)
- Collisions that result in property or equipment damage > $25,000
- Incident involving crane or personnel/material handling operations
- Loss of station-keeping
- Gas release (H_2S and Other) that result in process or equipment shutdown
- Muster for evacuation
- Structural damage
- Spill < 10,000 gallons (238 bbl)

APPENDIX H: ADDITIONAL TABLES AND FIGURES

In Figure 36, the total liquid rate group is plotted against the gas rate group for the failures and the producing well population, with bubble size representing the percent of the distribution. The failure bubble (gray) is positioned on top of the population bubble (teal), so bubbles with no teal showing indicate a high number of failures relative to the percent of wells in that group. In nearly all cases where the gas rate is greater than 100 mcfd, except those of very high liquid rate combined with high gas rate, the failure ratio is greater than one. BTS will continue to build on these analyses to better understand the relationships between well rates and likelihood of SPPE failure.

Figure 36: Gas Rate versus Liquid Rate, 2021

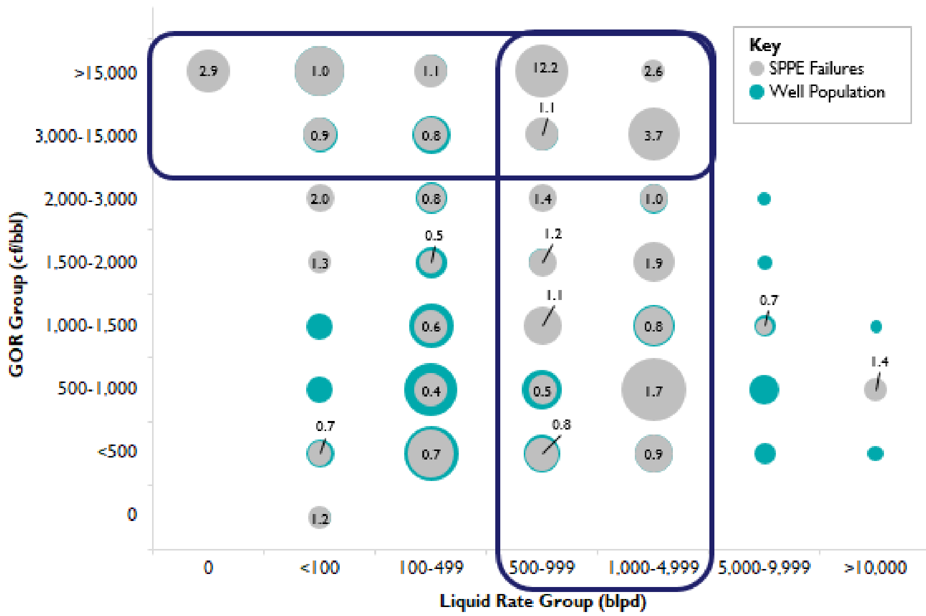


NOTES:
1. Bubble size represents the relative distribution of the well population or wells with SPPE failures.
2. To preserve confidentiality, neither wells nor failures are shown for groups that represent fewer than five operators.
3. Active wells: n=2,597. Includes producing wells only. Rates are taken from 2021 annual average.
4. Wells with SPPE failure: n=142. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates indicated the well produced in the month prior to the failure. Data labels are the actual to expected failure ratio: percent of SPPE failures (surface + subsurface) / percent of active wells.

SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.

Plotting the GOR group against the total liquid rate group (Figure 37) indicates that the higher GOR groups have the higher failure ratios regardless of total liquid rate. The highest failure ratio of 12.2 on the group that produces 500 – 999 blpd with a GOR > 15,000 is significantly higher than the others. Further analysis of the ten failures in that group were either high watercut (six were on wells with watercut of 80 percent or more) or high gas rate (four failures, including one repeat failure, were on three wells with gas rates of 10,000 mcf/d) wells. BTS will continue to build on these analyses to better understand the relationships between well rates and likelihood of SPPE failure.

Figure 37: GOR versus Liquid Rate, 2021



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SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS Program.