OIL AND GAS PRODUCTION SAFETY SYSTEM EVENTS

2022 ANNUAL REPORT

SafeOCS

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OIL AND GAS PRODUCTION SAFETY SYSTEM EVENTS

2022 Annual Report

ACKNOWLEDGEMENTS

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TABLE OF CONTENTS

Table of Contents .... **v**

Executive Summary **1**

1 Introduction **1**

About SafeOCS 1

Data Adjustments 2

2 Safety and Pollution Prevention Equipment (SPPE) **3**

Location of SPPE Valves 3

How Valve Types Are Grouped in this Report 5

Purpose and Operation of SPPE Valves 5

3 Data Collection and Validation **7**

Data Confidentiality—CIPSEA 7

Data Validation and Exposure Measures 7

4 Data Analysis **10**

SPPE Numbers at a Glance 10

Production Levels in 2022 11

Completeness of Failure Event Reporting 12

Who Reported Equipment Events 14

Details of Reported Equipment 15

Failures and Potential Consequences 19

Well Location and Status 22

Well Fluid Rates 24

SPPE Pressure Rating 29

When Failures Were Detected 30

How Failures Were Addressed 31

Root Causes and Contributing Factors of Failures 33

Repeated Failures 41

5 Conclusions 43

Appendix A: Oil and Gas Production Safety Systems Rule Background Information 44

Appendix B: Relevant Standards 46

Appendix C: Glossary and Acronym List 47

Appendix D: Data Analysis Methodology 54

Appendix E: Failure Rate Details 61

Appendix F: Typical SPPE Valve Components 62

Appendix G: HSE Incidents 63

Appendix H: Additional Tables and Figures 64

LIST OF FIGURES

Figure 1: Equipment Schematics 4
Figure 2: GOM Production, 2019-2022 12
Figure 3: Sources of SPPE Failure Records, 2019–22 12
Figure 4: SPPE Failure Events by Operator, 2022 14
Figure 5: Active Wells and Reporting Status of Operators, 2017-2022 15
Figure 6: SPPE Events by Valve Type, 2019-22 16
Figure 7: Percentage of SPPE Events by Valve Type, 2022 16
Figure 8: SPPE Failure Rates in the Gulf of Mexico, 2019-2022 17
Figure 9: Failed Components in SPPE Valves, 2022 18
Figure 10: Event Types in Order of Significance, 2022 21
Figure 11: Failure Events by Type, 2017-2022 21
Figure 12: Status for All Wells vs. Wells with SPPE Failure, 2022 23
Figure 13: Status for Wells with SPPE Failure, by Operator, 2022 24
Figure 14: Well Rates for All Wells vs. Wells with SPPE Failure, 2022 25
Figure 15: Failure Ratios Across Well Rate Groups, 2019-2022 25
Figure 16: Type of Reported Failures by Well Rate, 2022 27
Figure 17: Failures Grouped by Well Fluid Rate Ranges, 2022 27
Figure 18: SPPE Failures and Producing Wells by GOR Range, 2022 28
Figure 19: Failure Ratios Across GOR Groups, 2019-2022 29
Figure 20: Pressure Ratings for All Wells vs. Wells with SPPE Failure, 2017-2022 29
Figure 21: Failure Detection Methods, 2022 30
Figure 22: Reported Corrective Actions, 2022 31
Figure 23: Reported Corrective Actions, 2017-2022 32
Figure 24: Root Causes of Reported Failure Events, 2022 33
Figure 25: Factors Contributing to Equipment Failures, 2022 34
Figure 26: Factors Contributing to Equipment Failures, 2017-2022 35
Figure 27: Well Stream Contaminants, 2022 37
Figure 28: Well Stream Solid Contaminants, 2019-22 37
Figure 29: Time to Failure, 2017-2022 38
Figure 30: Time to Failure and Valve Service Class, 2017-2022 39
Figure 31: Cumulative Production to Failure, 2017-2022 40
Figure 32: Production from Wells with Repeated Failures, 2022 42

Figure 33: SPPE Annual Report Steps 54
Figure 34: SPPE Failures and Active Wells by Gas Rate Group, 2022 64
Figure 35: SPPE Failures and Active Wells by Oil Rate Group, 2022 65
Figure 36: SPPE Failures and Active Wells by Water Rate Group, 2022 66
Figure 37: SPPE Failures and Active Wells by Water Cut Range, 2022 67
Figure 38: SPPE Failures and Active Wells by Total Liquid Rate, 2022 68
Figure 39: GOR versus Liquid Rate, 2022 69
Figure 40: Gas Rate versus Liquid Rate, 2022 70

LIST OF TABLES

Table 1: Typical SPPE Testing Frequency and Leakage Allowance 5
Table 2: SPPE Numbers at a Glance 11
Table 3: Certification Status of Reported SPPE, 2017-2022 19
Table 4: Events Involving Failure to Close when Commanded, 2022 20
Table 5: Distribution of SPPE Failures by Water Depth, 2022 22
Table 6: Overview of 2022 Preventive Actions 33
Table 7: Overview of 2022 Repeated Failures 41
Table 8: SPPE Failures Identified in INC Data, 2019-2022 59
Table 9: SPPE Failure Rates in the Gulf of Mexico, 2019-2022 61
Table 10: Typical SPPE Valve Components 62

EXECUTIVE SUMMARY

The *2022 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.

SafeOCS received 69 SPPE failure notifications for 2022, and an additional 83 failure events were identified in other data sources (WAR, APM, INCs, and OGOR-A), bringing the total number of known SPPE failure events in 2022 to 152, a 29.0 percent decrease from 2021.[1] The number of operators reporting at least one failure to SafeOCS decreased from 14 to 11 (21.4 percent) in 2022 compared to 2021, while the number of active operators decreased by 9.3 percent and total average daily production remained at similar levels. Failures from additional operators were also identified, and in total these operators along with reporting operators were responsible for more than 90 percent of active wells in 2022. Considering failures identified in other sources in addition to SafeOCS, the number of operators with at least one identified failure increases from 11 to 21, and these operators were responsible for 93.9 percent of active wells in 2022.

Valve Types and Failure Rates

Surface safety valves (SSVs) and surface controlled subsurface safety valves (SCSSVs) had the highest proportions of failures in 2022, comprising 62.9 percent and 28.7 percent of failures with known valve type, respectively.[2] In 2022, approximately 11,331 SPPE valves were in service in 4,613 active wells in the GOM OCS, down 2.3 percent and 14.6 percent from 2021, respectively. Failure rates remained under 0.65 percent for each valve type.

Potential Consequences of Failures

Failures are categorized based on the extent to which they degrade the installed well safety systems and pose potential consequences to personnel and the environment. In 2022, one SPPE failure resulted in a health, safety, or environmental (HSE) incident, involving the release of an estimated nine barrels of

[1] WAR: well activity report; APM: application for permit to modify; INCs: incidents of noncompliance; OGOR-A: offshore oil and gas operations reports, part A.

[2] Percentages are of 143 total failures. Excludes nine failures of subsurface safety valves identified in OGOR-A data or other sources where it could not be determined whether they were SCSSVs or SSCSVs.

produced hydrocarbons to the sea following an SCSSV rod piston seal failure. Most SPPE failures (67.9 percent), 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.[3]

Characteristics of Wells with SPPE Failures

Nearly 90.0 percent of failures reported to SafeOCS occurred on wells that produced at least one day in 2022. About two-thirds of the 69 failures (68.1 percent) occurred on wells producing less than 500 barrels of oil equivalent per day (boed), and over half of those (36.2 percent of 69 failures) occurred on wells producing less than 100 boed. These lower-producing wells pose less risk than higher-producing wells. In 2022, about 5.8 percent of failures were associated with wells producing more than 5,000 boed, which is over twice the percentage in 2021 (2.5 percent) but still just four failures. Over the reporting years, wells with higher gas-oil ratio (GOR) (1,500 cf/bbl and above) experienced more failures 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 78.2 percent of failures reported to SafeOCS. Valve seat degradation was the most reported factor contributing to SPPE failures, reported for 65.1 percent of the events where information on contributing factors was available, followed by operating environmental factors including wellbore debris, paraffin, sand, corrosion, scale, and asphaltenes.

[3] Includes events where internal leak was the most significant failure type reported.

1 Introduction

The *2022 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.[4]

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.[5] This is the sixth 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.

[4] Confidential Information Protection and Statistical Efficiency Act of 2018, Title III of the Foundations for Evidence-Based Policymaking Act of 2018, Pub. L. No. 115-435.
[5] 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) protect 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.[6] 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:[7]

- 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

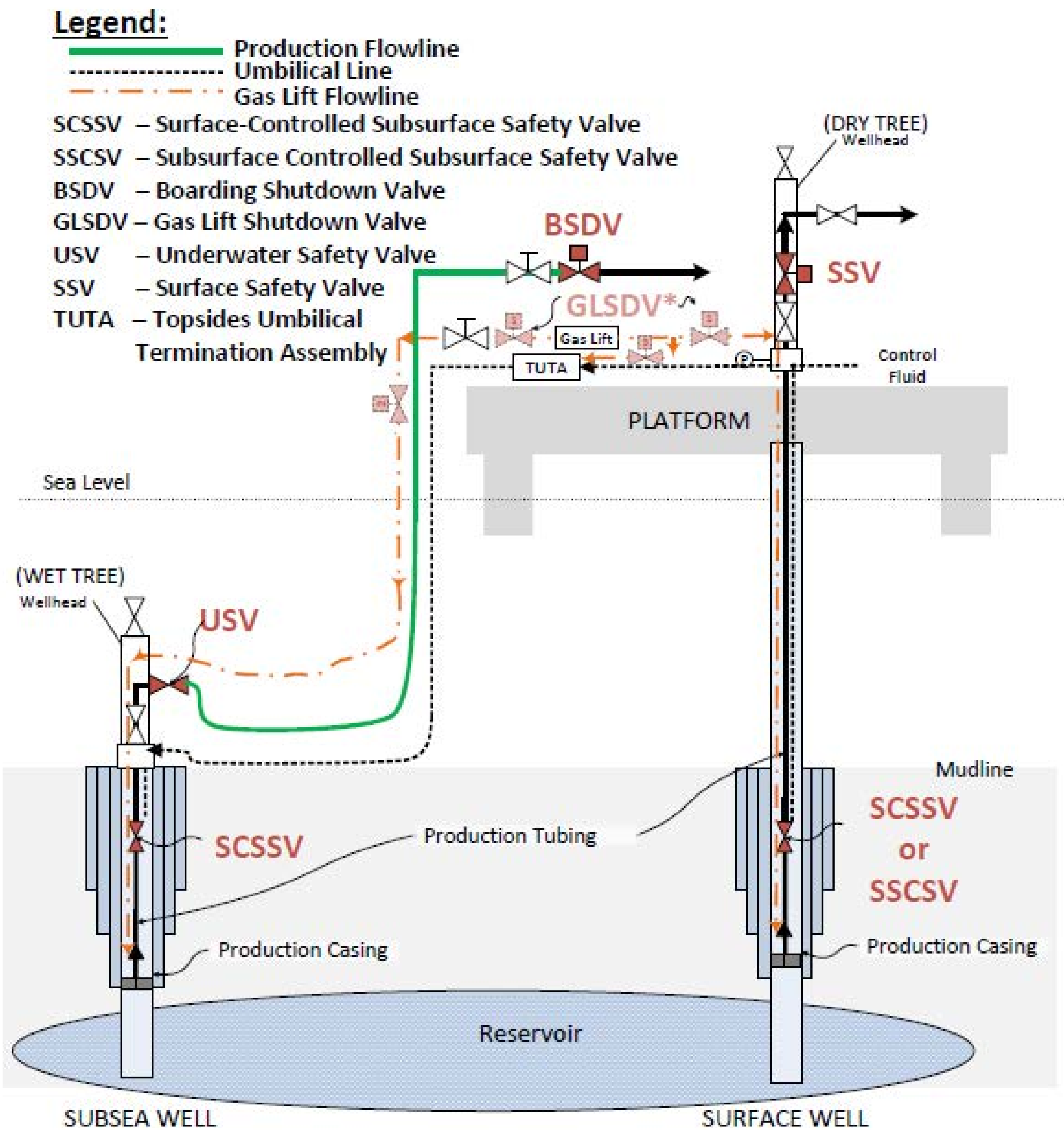
SPPE valves are found in both surface wells and subsea wells. Surface wells have dry trees or direct vertical access (DVA) trees located above sea level on top of the well. Their location allows the operator direct access to the wellbore from the production platform. Subsea wells have wet trees located 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.[8] They provide redundancy in the equipment to allow for

[6] The rule is codified primarily in 30 CFR part 250, subpart H. The failure reporting requirement is codified in 30 CFR 250.803.
[7] 30 CFR 250.801.
[8] 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 one of three 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.[9] Table 1 summarizes the general testing frequencies and leakage requirements. However, exceptions can apply for different types of wells, subject to BSEE's approval.[10]

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. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

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

[9] 30 CFR 250.873, 250.880.
[10] 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.[11] 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.

[11] 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. 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 indicating 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 is not uncommon for an APM 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 a 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 SPPE failures to cross-reference and validate SPPE failures reported to SafeOCS. While failures associated with INCs do not capture all SPPE failures, 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.[12] 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 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

[12] 20 CFR 250.186–250.190, 250.1008(e), 254.46. See also BSEE Notice to Lessees No. 2019-N05, Incident and Spill Reports.

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.[13] 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.[14] 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.

[13] 30 CFR 250.743.

[14] 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

The Oil and Gas Production Safety Systems Rule covers production operations on the Outer Continental Shelf (OCS), which includes BSEE's Gulf of Mexico (GOM), Pacific, and Alaska regions. As in prior years, in 2022, SafeOCS received equipment failure notifications for operations in the GOM region only, which accounts for over 99 percent of all offshore production in the United States.[15] To protect confidentiality, the exact locations of reported equipment failures are not disclosed.

SafeOCS received 69 SPPE failure notifications for 2022, a 35.5 percent decrease from 2021. An additional 83 failure events were identified in other sources (APM, INC, OGOR-A, or WAR data), bringing the total number of known SPPE failure events in 2022 to 152, a 29.0 percent decrease from 2021. To the extent practicable, analyses presented in this report consider failure events identified in all sources; however, failures not directly reported to SafeOCS 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, *SPPE Failure Summary* section, provides an overview of the reported SPPE failures in 2022 compared to the previous five years. The 69 failures occurred on 59 of 4,613 total active wells (1.3 percent) in the GOM OCS.[16] Most of those failures (79.7 percent) were on valves accessible from the platform where they can be addressed more quickly, reducing potential safety and environmental risk.[17] Ten failures occurred on valves associated with subsea wells, a decrease of 52.4 percent from 2021.

As shown in Table 2, *GOM Well Production Summary* section, the number of active wells has decreased each year since 2017, although production in 2021 and 2022 returned to near the 2019 production volume (99.9 percent and 99.6 percent, respectively). The number of operators who reported failure notifications fell from 14 in 2021 to 11 in 2022, discussed further below. These operators are responsible for fewer active wells (45.1 vs. 64.9 percent) and less hydrocarbon production (29.3 vs. 73.9 percent) in 2022 compared to 2021.

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[15] BSEE Data Center, Outer Continental Shelf Oil and Gas Production data, 2022 annual volumes.

[16] 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.

[17] 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	2022
Operator Summary[1]	Active Operators	56	55	52	45	43	39
	Producing Operators	53	50	49	42	41	38
	Reporting Operators (Pct. of Active Operators)	8 (14.3%)	14 (25.5%)	14 (26.9%)	14 (31.1%)	14 (32.6%)	11 (28.2%)
	Reporting Operators' Pct. of Active Wells	35.2%	70.6%	59.4%	58.0%	64.9%	45.1%
	Reporting Operators' Pct. of Production	56.6%	66.6%	75.7%	57.8%	73.9%	29.3%
GOM Well Production Summary[2,3]	Active Wells	6,446	6,231	6,029	5,715	5,402	4,613
	Wells with SPPE Failure	96 (1.5%)	157 (2.5%)	182 (3.0%)	90 (1.6%)	114 (2.1%)	59 (1.3%)
	Daily Prod. - Total Active Wells (boed)	2,207,312	2,243,244	2,741,291	2,414,434	2,738,538	2,730,825
	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%)	67,780 (2.5%)
SPPE Population	Installed SPPE Valves	12,373	12,174	11,849	11,690	11,600	11,331
SPPE Failure Summary[4]	Total Distinct SPPE Failures	215	266	351	172	214	152
	SPPE Failures Reported to SafeOCS	**115**	**204**	**225**	**101**	**114**	**69**
	SPPE Failures Identified from Other Sources	100	62	126	71	100	83
	Pct. of Failures Not Reported to SafeOCS	46.5%	23.3%	35.9%	41.3%	46.7%	54.6%
	Repeat Failures (% of Failures Reported to SafeOCS)	N/A	13 (6.4%)	14 (6.2%)	13 (12.9%)	12 (10.5%)	11 (15.9%)
SafeOCS Failures Only — **Tree Types**	Surface Well SPPE Failure Events	109	195	210	93	91	57
	Subsea Well SPPE Failure Events	4	8	15	8	21	10
	SPPE Failure Events with Unknown Tree Type	2	1	0	0	2	2
SafeOCS Failures Only — **Event Types**[5]	HSE Incident	0	0	0	0	0	0
	External Leak of Hydrocarbons	1	2	5	3	1	3
	Failed to Close When Commanded	13	16	22	11	10	8
	Internal Leak	99	159	199	80	93	55
	Failed to Close in Required Timing	0	14	0	1	1	0
	Failed to Open	3	6	5	4	5	3
	External Leak of Other Fluids	1	11	5	4	5	3

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.

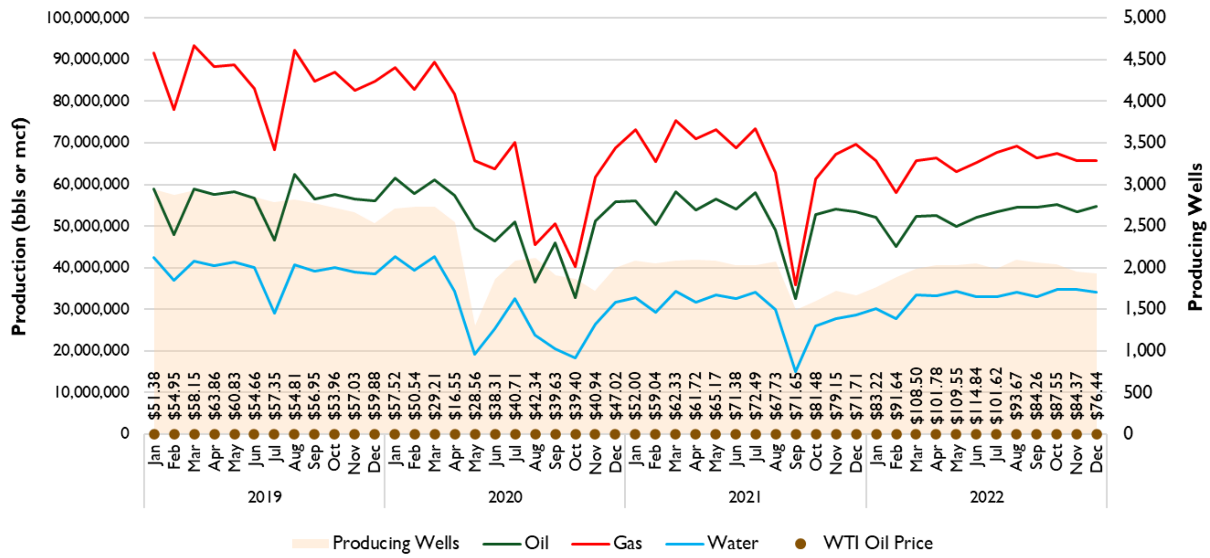
5 Includes SafeOCS failures only. Failures identified in other sources that are not reflected in this table include two HSE events involving releases of hydrocarbons to the sea, one in 2020 and one in 2022, described further in this report. Totals may exceed counts of SafeOCS failures because more than one event type can apply to a single failure.

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

Production Levels in 2022

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 2022, production levels and the number of producing wells were more consistent throughout the year than in 2021. The COVID-19 pandemic contributed to increased variability in these measures in 2020 and 2021, as did hurricane and tropical weather events in the GOM during August and September 2021. Storms had less of an impact on production in 2022. The decline shown in the number of producing wells over the total time period can be attributed in part to the decline in GOM shelf-area wells.[18]

Figure 2: GOM Production, 2019-2022

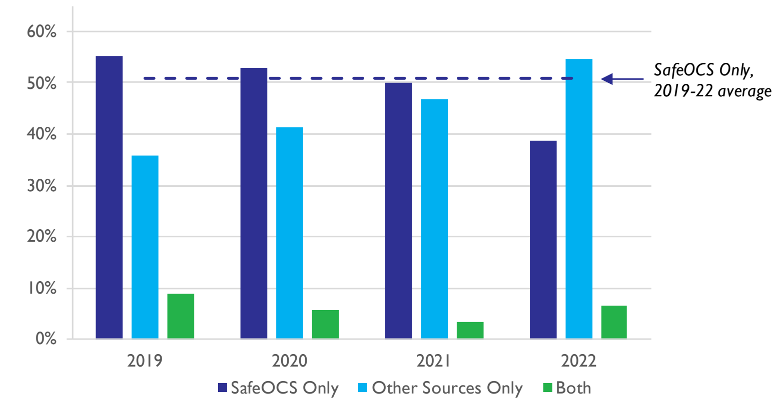


SOURCES: U.S. DOT, BTS, SafeOCS. WTI crude oil spot prices from U.S. Energy Information Administration.

Completeness of Failure Event Reporting

As mentioned above, the analyses reconcile the SPPE data reported to SafeOCS using APM, INC, OGOR-A, WAR, and BSEE reported incident 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 operations. Figure 3 shows the overlaps between the data sources. For 2022, 152 distinct SPPE failures were

Figure 3: Sources of SPPE Failure Records, 2019–22



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.

[18] 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.

reported or identified in available data, including 59 (38.8 percent) reported to SafeOCS only, 83 (54.6 percent) not reported to SafeOCS, and 10 (6.6 percent) both reported to SafeOCS and found in the other sources. Therefore, reporting of SPPE failures to SafeOCS appears to remain incomplete.

For 2022, fewer events were identified in OGOR-A data and more events were identified in INC data compared to 2021. The findings for each of the additional data sources are described in more detail below.

WAR Data

Analysis of the 2022 WAR data identified five SSV failures and 14 subsurface safety valve failures. Five of these failures were also reported to SafeOCS, 14 were found in APM data, one was associated with an INC, and one was found in OGOR-A. Failures found in both WAR and APM data could mean that the repairs were planned as opposed to discovered during intervention 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 2022 APM data identified three SSV failures and 12 subsurface valve failures. Four of these failures were also reported to SafeOCS, most (14 of 15) were found in WAR data, one was associated with an INC, and one was found in OGOR-A. Failures found in APM data have remained relatively consistent over the past three years (approximately 15-18 failures/year).

INC Data

Analysis of the INC data shows that 61 SPPE failures (33 SSVs, 22 SCSSVs, 5 BSDVs, and one SSCSV) were documented in the BSEE INC database for 2022, a 27.1 percent increase over 2021. Four of these failures were also reported to SafeOCS, and one was found in APM and WAR. 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).

OGOR-A Data

A total of 13 SPPE failures were documented in the OGOR-A data in 2022, compared to 39 for 2021, a reduction of two-thirds. None of these failures were reported to SafeOCS; however, one was also found in APM and WAR. The 13 failures identified in OGOR-A data include seven subsurface safety valves (OGOR-A does not distinguish between SCSSVs and SSCSVs), and 6 SSVs.

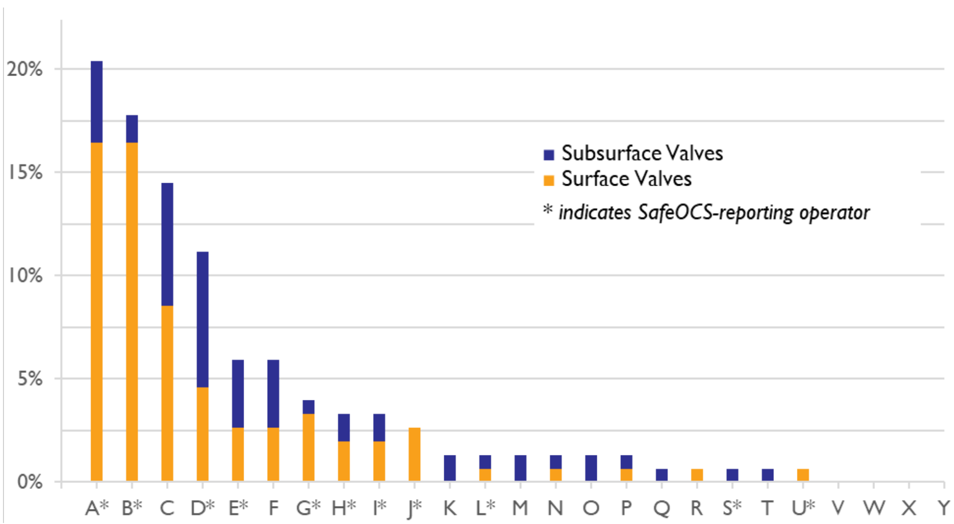
Incident Reports

One SPPE failure event was identified among BSEE investigated incidents in 2022, involving an SCSSV. This event was also found in the INC database.

Who Reported Equipment Events

Figure 4 shows each operator's contribution to 2022 SPPE reported failures and the breakdown between surface and subsurface valves. Each lettered column represents an active operator, i.e., one with active wells in the GOM. Eleven operators, noted by an asterisk next to the letter, reported at least one 2022 failure directly to SafeOCS, compared to 14 in 2021. Eight operators reported both years; the net change of three fewer reporting operators can be attributed to nine distinct operators, six reporting only for 2021 and three reporting only for 2022.

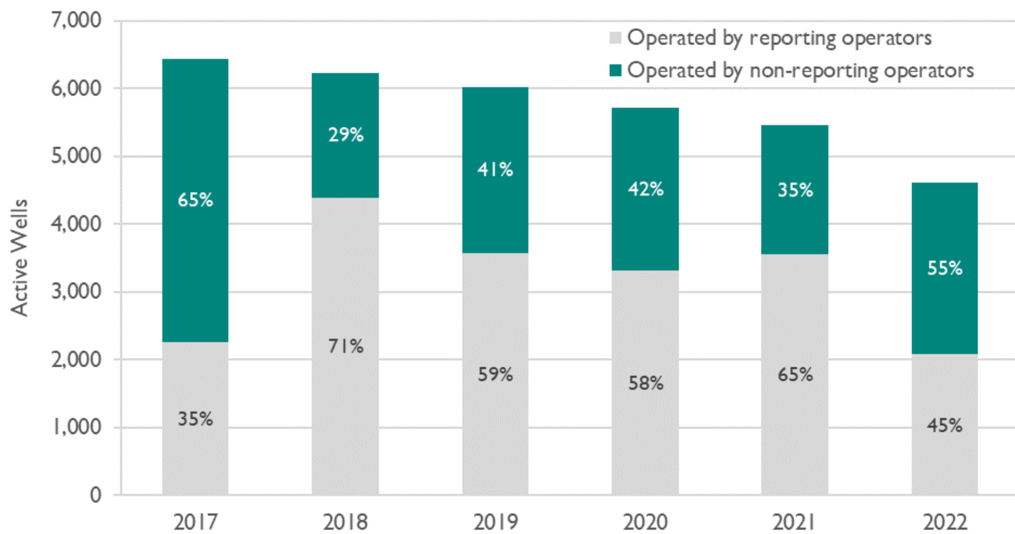
Figure 4: SPPE Failure Events by Operator, 2022



NOTE: Percentage is of 152 failures from all sources. Fourteen lower- or non-producing operators with no reported failures are not shown. Each of these operators contributed less than one percent of GOM total production and less than one percent of GOM active wells.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Figure 5 shows the distribution of active wells between operators who reported at least one failure to SafeOCS and operators with no reported failures. For the first time since 2017, reporting operators were responsible for less than half (45.1 percent) of active wells in 2022. However, considering failures identified in other sources in addition to SafeOCS (SafeOCS, WAR, APM, INCs, and OGOR-A), the number of operators with at least one identified failure increases from 11 to 21, and these operators were responsible for 93.9 percent of active wells in 2022.

Figure 5: Active Wells and Reporting Status of Operators, 2017-2022



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

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.

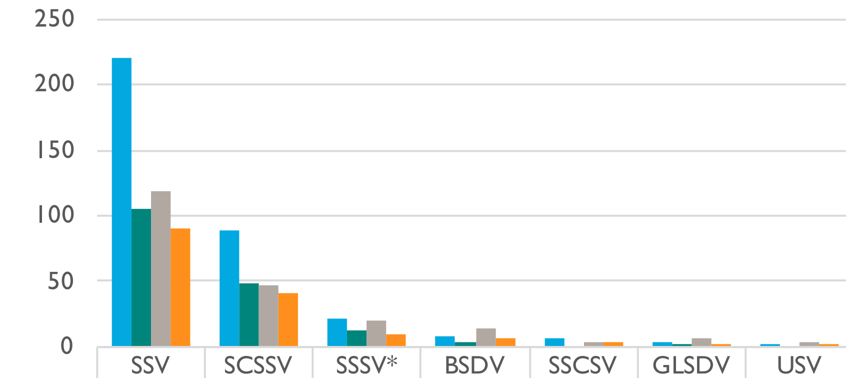
As shown in Figure 6, most SPPE failures since 2019 have occurred on SSVs and SCSSVs, which are the most common SPPE valve types.[19] Figure 7 shows the distributions of the 2022 GOM valve population and the failures by valve type. SSVs and SCSSVs had the highest proportions of the SPPE population and failures, collectively comprising 87.0 percent of the population and 91.6 percent of failures with known

[19] See Appendix E, which gives the number of installed SPPE valves in the GOM OCS each year.

valve types in 2022.

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.

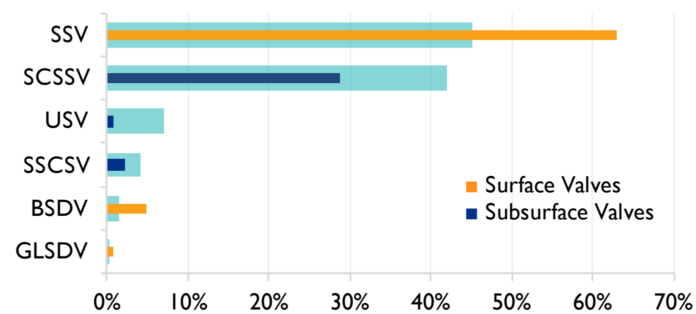
Figure 6: SPPE Events by Valve Type, 2019-22



	SSV	SCSSV	SSSV*	BSDV	SSCSV	GLSDV	USV
2019	221	89	22	8	6	3	2
2020	105	48	13	4		2	
2021	119	47	20	14	4	7	3
2022	90	41	9	7	3	1	1

NOTE: Includes failures from all sources. * SSSV = subsurface safety valve failures identified in other sources where it could not be confirmed whether they were SCSSVs or SSCSVs.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Figure 7: Percentage of SPPE Events by Valve Type, 2022



	GLSDV	BSDV	SSCSV	USV	SCSSV	SSV
Percent of Population	0.3%	1.6%	4.1%	7.1%	41.9%	45.1%
Percent of Failures	0.7%	4.9%	2.1%	0.7%	28.7%	62.9%

NOTE: Includes 152 total failures. Excludes nine failures of subsurface safety valves identified in other sources where it could not be confirmed whether they were SCSSVs or SSCSVs.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

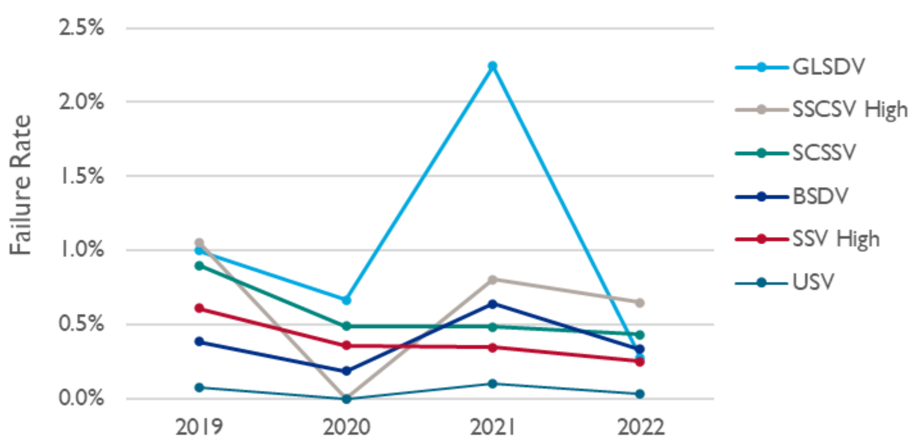
Valve Failure Rates

In 2022, BSEE records indicate that 11,331 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 tested more frequently than others.

Figure 8 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. A failure rate range is calculated for SSCSVs and SSVs due to variability in testing frequency, detailed in Appendix E.

As shown in Figure 8, failure rates across years remained under 2.5 percent. The 2021 spike for GLSDVs is influenced by a larger number of failures relative to the previous year (see Figure 6) occurring among a relatively small population of 25 to 30 valves. The 2022 failure rates for each SPPE valve type span from 0.03 percent for USVs to 0.65 percent for SSCSVs. None of the failure rates among other valve types exceeded 1.05 percent in any reporting period. In 2022, failure rates decreased for all valve types.

Figure 8: SPPE Failure Rates in the Gulf of Mexico, 2019-2022



NOTE: Considers failures from all sources, except failures of subsurface safety valves identified in other sources where it could not be confirmed whether they were SCSSVs or SSCSVs. Shows high end of the range for SSCSVs and SSVs.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

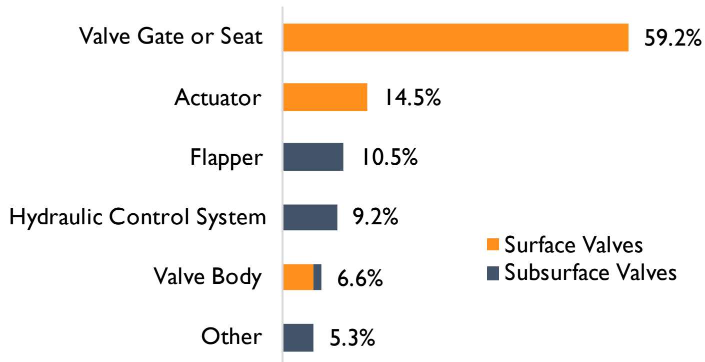
Valve Components

Multiple components make up each SPPE valve.[20] In 2022, the failed component was identified for 76 failures, including 65 reported to SafeOCS and 11 identified in other sources. In total, 80 failed components were reported for the 76 events (more than one failed component may be reported for a single event). As shown in Figure 9, the most common component failure for surface valves was the valve gate or seat, comprising more than half (59.2 percent) of the 76 failures. These were followed by

[20] Appendix F lists SPPE valves and their corresponding components.

the actuator, then the valve body. For SCSSVs, the flapper was the most reported failed component, followed by the hydraulic control system.

Figure 9: Failed Components in SPPE Valves, 2022



NOTE: Percentage is of 76 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.

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, so if they fail to seal leakage would be contained internally. For four failures, more than one failed component was reported:

- In two cases, both the valve gate and seat and the actuator were listed.
- In one case, the valve body and flapper were listed.
- In one case, the valve body and valve gate and seat 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 (beginning in 1996) containing certification criteria.[21] Of failures reported to SafeOCS in 2022, none were reported as non-certified. Three of the seven 2022 failures that did not include certification information were reported as classed valves per API standards.

[21] 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.

Table 3: Certification Status of Reported SPPE, 2017-2022

SPPE Certification	Percent of Reports					
	2017	2018	2019	2020	2021	2022
Newly installed certified SPPE pursuant to ANSI/API Spec. Q1	13.9%	12.8%	14.7%	16.8%	34.2%	34.8%
Newly installed certified SPPE pursuant to another quality assurance program	6.1%	1.0%	0.0%	1.0%	3.5%	1.5%
Previously certified under ANSI/ASME SPPE-1	69.6%	77.0%	71.6%	71.3%	45.6%	53.6%
Non-certified SPPE	0.9%	0.5%	2.2%	2.0%	2.6%	0.0%
Not answered	9.6%	8.8%	11.6%	8.9%	14.0%	10.2%

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

Failures and Potential Consequences

The event type of a reported SPPE failure is an indicator of its potential consequences, i.e., the extent of degradation of installed well safety systems and impacts to personnel and the environment. In 2022, the event type was identified for 131 failures, including 69 reported to SafeOCS and 62 identified in other sources. The remaining 21 events with unknown event type were identified in either OGOR-A (12), WAR (2), APM (1), or more than one of those sources (6), and did not provide enough information to determine the event type. The types of reported SPPE failures are described below in order of significance and shown in Figure 10

- **HSE Incident**: One SPPE failure in 2022 were identified in BSEE HSE incident data, involving an SCSSV rod piston seal failure. The event resulted in the estimated release of nine barrels of produced fluids to the environment. Although two similar events were reported to SafeOCS as HSE incidents, these involved the release of less than one barrel of produced hydrocarbons from SCSSVs and were classified as external leaks due to the smaller volumes.
- **External Leak of Produced Hydrocarbons**: In addition to the two events described above, two additional events were classified as external leaks, both involving small leaks of produced fluids from the SSV stem packing.
- **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. Sixteen such failures were reported, summarized in Table 4.
- **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. Eighty-nine (89) such failures were reported, comprising 69 surface valves (63 SSVs, five BSDVs, and one GLSDV) and 20 subsurface valves (18 SCSSVs, 1 SSCSV, and 1 USV). Five of the reported failures involved higher risk of an

external leak because hydrocarbons entered the control system, where they are more likely to reach the atmosphere.

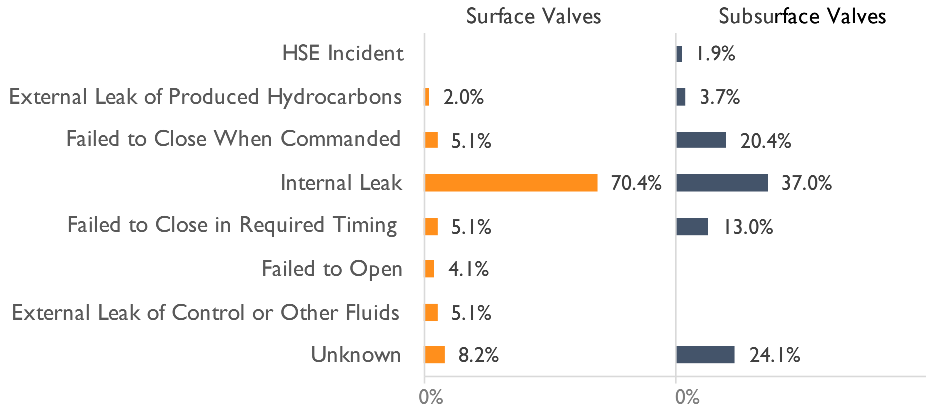
- **Failure to Close in Required Timing**: This event type means the SPPE valve failed to close in the required timing of two minutes for subsurface valves and 45 seconds for surface valves, so it would be delayed in controlling the well flow if called upon. Twelve such failures were reported, including five SSVs and seven SCSSVs.
- **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. Four such failures were reported, including three SSVs and one BSDV.
- **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. Five such leaks were reported, four from SSV actuator pistons or diaphragms and one leak of produced water from an SSV bonnet.

Table 4: Events Involving Failure to Close when Commanded, 2022

SPPE Type	Number of Events	Description	Corrective Action
BSDV	1	Flowline BSDV failed to close during process upset	Repair
SCSSV	4	Failure identified during ESD system testing	Unknown
	4	Asphaltene buildup	Chemical soak; cycle valve
	1	Pressure on control line	Modify SPPE
SSCSV	1	Damage to bellows found on PB valve	Unknown
	1	PB valve failure identified when pulled for inspection	Unknown
SSV	2	Broken spring in actuator	Repair
	1	Heavy corrosion on a shut-in well pending abandonment	Repair
	1	Testing failure; wear and tear cited (8 yrs. since installation)	Repair

NOTE: Events with unknown corrective action were identified in INC, WAR, and/or APM data.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

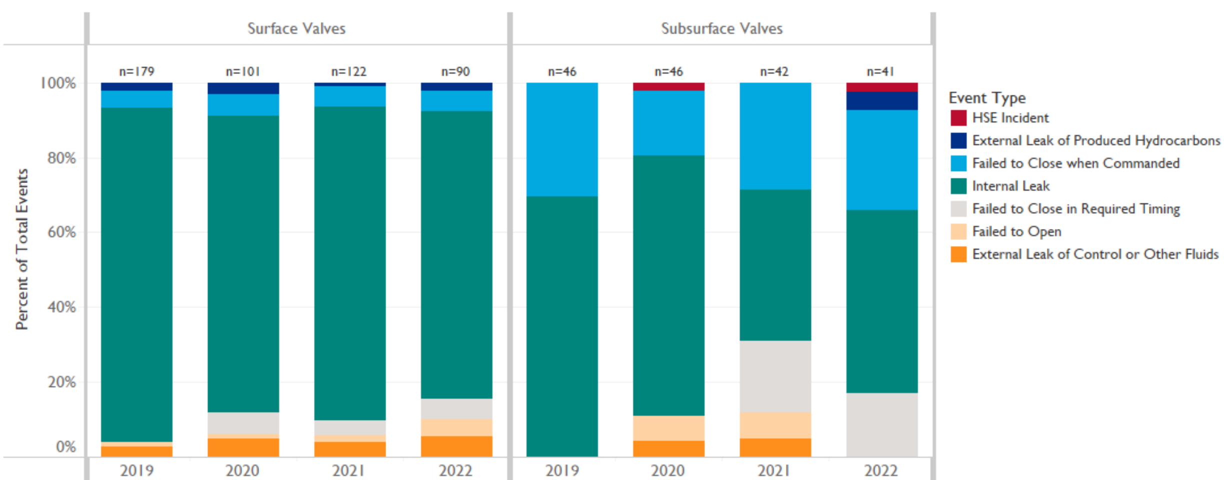
Figure 10: Event Types in Order of Significance, 2022



NOTE: Percentages are of 98 surface valve failures and 54 subsurface valve failures, respectively. Only the most significant event type is shown for the few failures with multiple reported types. Events with unknown event type were identified in other sources (OGOR-A, WAR, or APM) and did not provide enough information to determine the event type.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Figure 11 shows the distribution of event types each year since 2017. 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 2022, failure to close in required timing continued to be more prominent as a percentage of subsurface valve failures.

Figure 11: Failure Events by Type, 2017-2022



NOTE: Percentage is of the number of events, where only the most significant event type is shown for the few failures with multiple reported types. Events of unknown type are excluded. One HSE event is shown for 2020 and 2022, respectively.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Well Location and Status

Shallow Water Province versus Deepwater

As shown in Table 5, most active wells in 2022 (77.9 percent) were within the shallow water province, which BSEE defines as water depths of under 200 meters (656 feet).[22] Most SPPE failures (81.8 percent) were also 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 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 previous years, in 2022 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.

Table 5: Distribution of SPPE Failures by Water Depth, 2022

Water Depth (m)	SPPE Failures	Active Wells	Actual to Expected Failure Ratio
< 200 (656 ft)	117 (81.8%)	3,592 (77.9%)	1.05
200 - 800	14 (9.8%)	332 (7.2%)	1.36
> 800 (2,625 ft)	12 (8.4%)	689 (14.9%)	0.56
Total	*143*	*4,613*	*N/A*

NOTE: Total excludes nine failures for which water depth was not reported or multiple wells were associated with the failure. Actual to expected failure ratio = percent of SPPE failures / percent of active wells.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Well Status and Production Time

To examine potential relationships between well status and occurrence of SPPE failure, wells were categorized based on their annual average production rates as well as the amount of time over the course of the year the well was in producing status (see Appendix D for more details). These categories include:

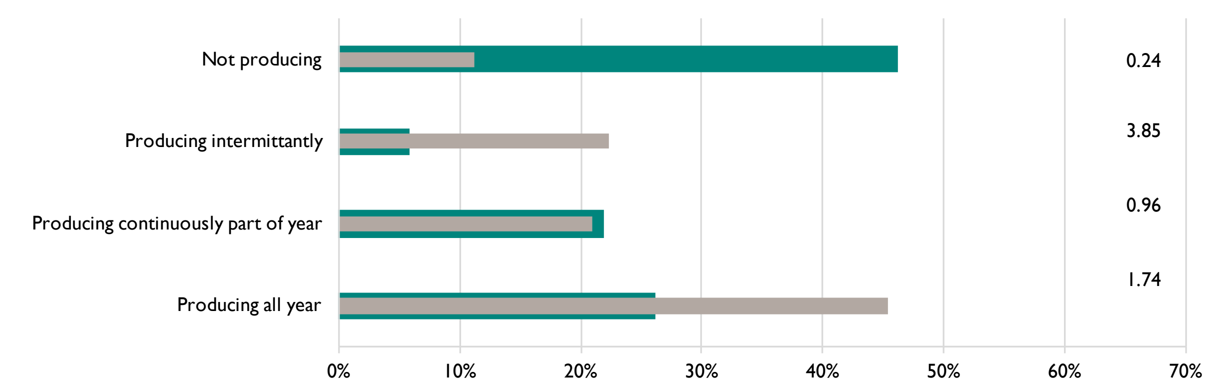
- **Producing all year** – the well produced at least one day in all 12 months of 2022.
- **Producing continuously part of the year** – the well produced between one and 11 months, and for the months that there was production, it produced on at least half of the days in the month.

[22] 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.

- **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 2022.

Figure 12 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. The 2022 "producing intermittently" and "producing all year" groups show the highest percentages of failures (22.4 and 45.5 percent, respectively) and the highest failure ratios (1.74 and 3.85, respectively). Nearly 90.0 percent of failures occurred on wells that produced at least one day in 2022.

Figure 12: Status for All Wells vs. Wells with SPPE Failure, 2022



	Producing all year	Producing continuously part of year	Producing intermittantly	Not producing
% of Production Well Population	26.1%	21.9%	5.8%	46.2%
% of Failures	45.5%	21.0%	22.4%	11.2%

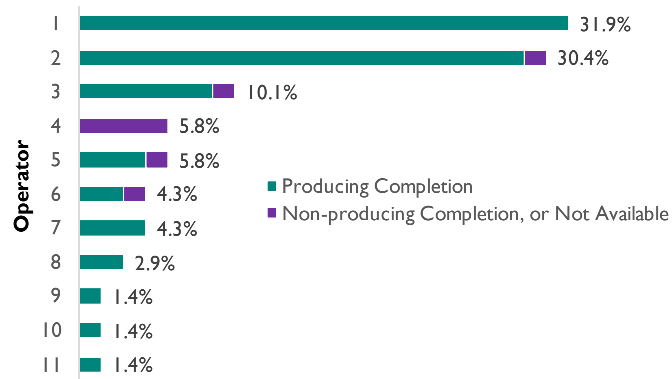
NOTES:

1. Active wells: n=4,540, which excludes water source and water injection wells.
2. Wells with SPPE failure: n=143. Status is based on the days producing during the 12 months prior to the month of the failure. Excludes eight failures where the well was not identified and one failure of a BSDV, 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.

Figure 13 shows the producing status of wells with SPPE failure, by reporting operator. On average, operators reported more failures on producing wells (88.4 percent) than non-producing ones.

Figure 13: Status for Wells with SPPE Failure, by Operator, 2022



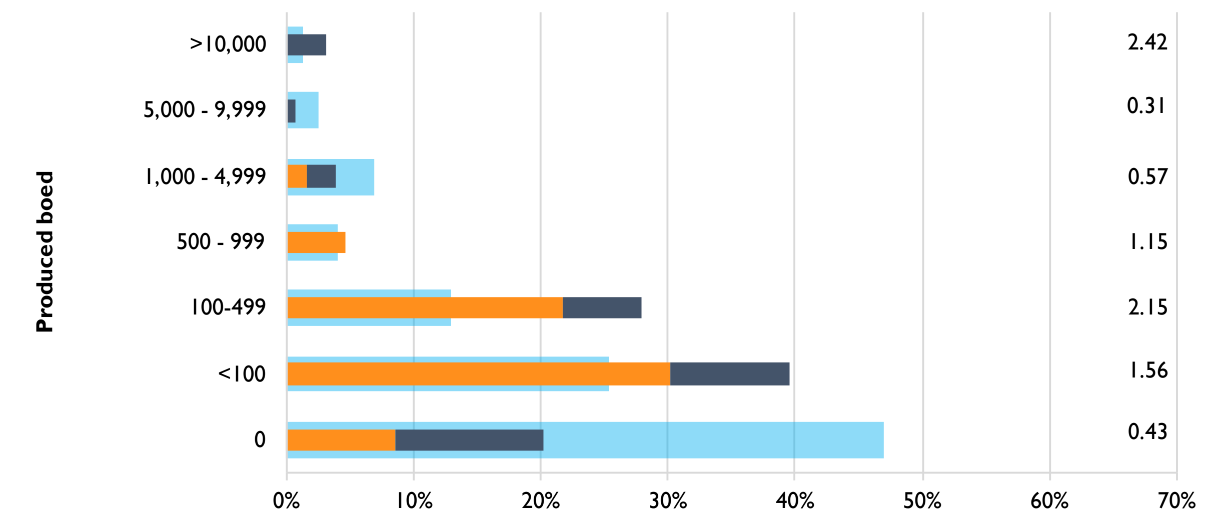
NOTE: Percentage is of 69 failures reported to SafeOCS.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

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.

Figure 14 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. In 2022, most of the failures (87.6 percent) were associated with wells that produce less than 500 boed, with over half (59.7 percent) producing less than 100 boed. These wells pose a lower risk than higher-producing wells. About 3.9 percent of the reported failures (on single wells where the well number was identified) were associated with wells producing more than 5,000 boed, which is higher than the 2.5 percent observed in 2021. 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 100-499 or greater than 10,000 boed had the highest actual to expected failure ratios.

Figure 14: Well Rates for All Wells vs. Wells with SPPE Failure, 2022



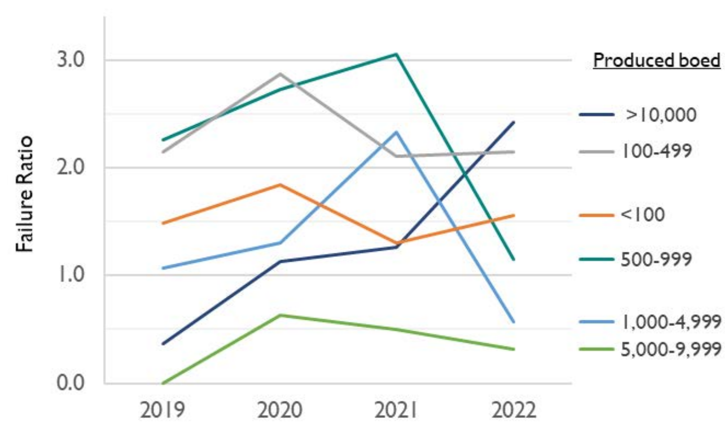
	0	<100	100-499	500 - 999	1,000 - 4,999	5,000 - 9,999	>10,000
Well Population	47.0%	25.4%	13.0%	4.1%	6.8%	2.5%	1.3%
Surface Valve Failures	8.5%	30.2%	21.7%	4.7%	1.6%	0.0%	0.0%
Subsurface Valve Failures	11.6%	9.3%	6.2%	0.0%	2.3%	0.8%	3.1%

NOTES:
1. Active wells: n=4,613. Rate is the Jan. – Dec. 2022 average.
2. Wells with SPPE failure: n=129. Rate is taken from near the time of the failure. Excludes 22 failures on wells with no OGOR-A production data reported in the prior month, and one failure of a BSDV, 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.

Figure 15 shows the well rate failure ratios for each year from 2019 to 2022. The percentage of wells in each group are more consistent than the percentage of failures from year to year. Consequently, the groups with more variability are generally those with a lower active well population. For example, the failure ratio for wells that produced 500-999 boed, comprising only about five percent of the well population, ranges from 1.15 to 3.05. Similarly, wells with the highest well rate (>10,000 boed), which represent little of the population and few failures (four in 2022), show an

Figure 15: Failure Ratios Across Well Rate Groups, 2019-2022



NOTE: Actual to expected failure ratio = percent of SPPE failures / percent of active wells.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

increasing trend since 2019. In contrast, wells that produced <100 boed and 100-499 boed, which comprise 46.4 and 23.8 percent of the 2022 well population, respectively, showed a more consistent failure ratio from year to year.

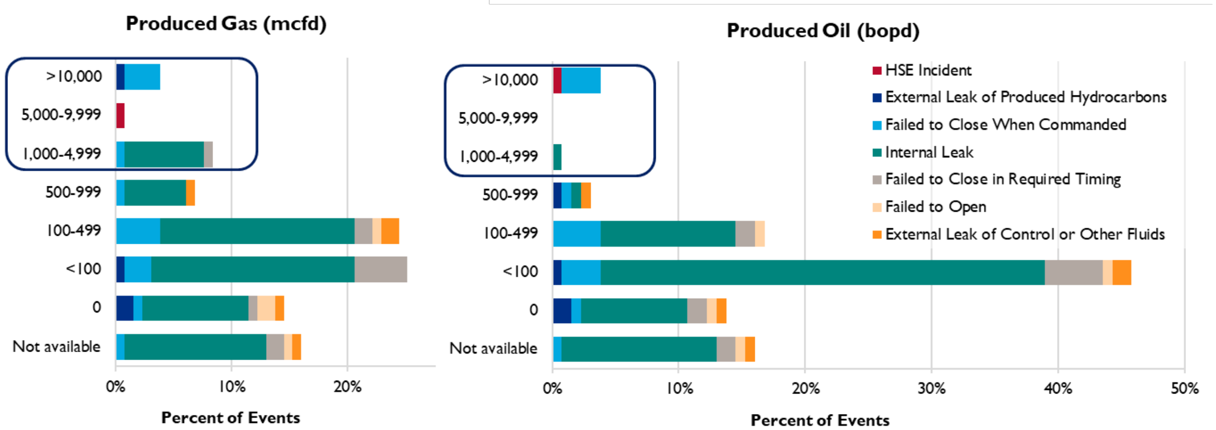
The average daily production rates shown in the figures above can offer insight into the potential environmental exposure of the failures. The total daily production volume from the wells that experienced a reported SPPE failure in 2022 was 67,780 boed. Comparing this figure to the average daily production from the GOM OCS in 2022 (2.73 million boed) indicates that 2.5 percent of the GOM OCS production could have been directly affected by the 69 reported SPPE failures. This is a decrease from 3.9 percent in 2021. 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 2022 increases to 91,600 boed, representing 3.4 percent of GOM OCS production, also less than the 5.3 percent observed in 2021. This percentage could be underestimated due to a small number of failures lacking production information.

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 16 shows the distribution of failures by well rate, with failure type indicated by color. As shown in the figure, and for the first time since SafeOCS began collecting failure data, failures among higher-producing wells (>1,000 bopd or mcfd) led to external leaks of hydrocarbons, including the HSE event and one additional event with an external leak of hydrocarbons, both on wells with high gas rates, and one also had a high oil rate. In addition, five failures to close when commanded occurred on higher-producing wells, described below:

- Three of the four single-well events occurred on the same SCSSV, which was on a well with very high gas rates (>10,000 mcfd) and oil rates (>10,000 bopd). Asphaltenes buildup contributed to the flapper sticking and failing to close. Chemical soaks were performed when cycling the valve did not resolve the issue.
- The fourth single well event was a failure of an SSCSV that was found stuck open when inspected.
- The fifth event involved a BSDV that failed to close during a process upset. The valve served four wells with an oil rate of >10,000 bopd and a gas rate >10,000 mcfd. The actuator was repaired, and valve assembly repair issue as well as corrosion were listed as contributing factors.

Figure 16: Type of Reported Failures by Well Rate, 2022



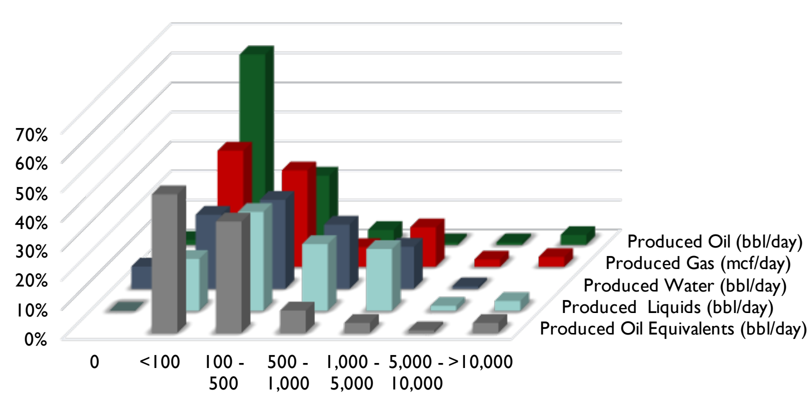
NOTE: Percentage is of the number of events with known failure type (n=131), where only the most significant event type is shown for the few failures with multiple reported types. Events of unknown type are excluded. The well rates were summed for failures of BSDVs that serve multiple wells.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

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 are excluded (for example, an external leak of control fluid). For failures possibly affected by produced well fluids (fluid-affected failures), different parameters related to the oil, gas, and water phases of the produced fluid stream were evaluated. Figure 17 shows the distribution of 2022 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. For produced oil, most failures (89.9 percent) were on wells producing less than 500 bopd. The breakdown is similar for produced gas and water and the two calculated parameters (produced oil equivalents and produced liquids).

The fluid proportions produced from each well differ depending on the reservoir and placement of the well in that reservoir. The GOR describes the

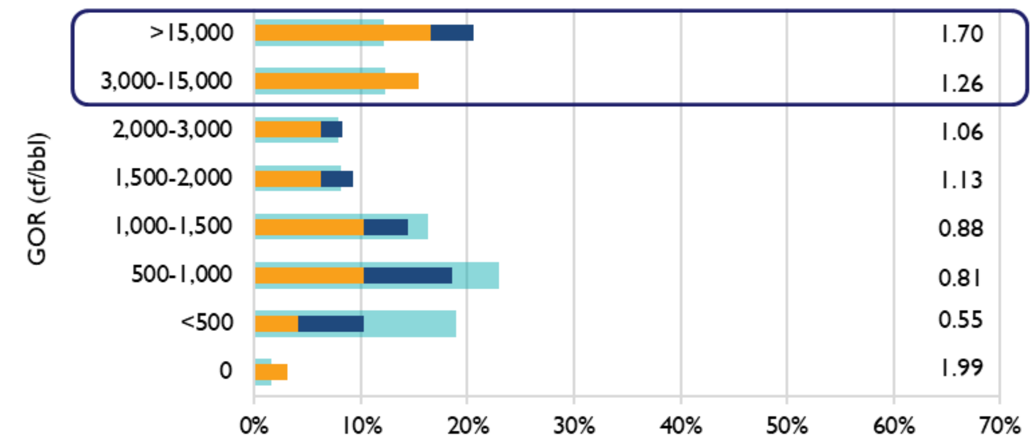
Figure 17: Failures Grouped by Well Fluid Rate Ranges, 2022



NOTE: Includes 119 total failures where produced fluids could have been a factor in the failure and well rates were available.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

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 18 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. Higher gas production rates for these wells means higher velocities toward the top of the well, potentially leading to more failures from correspondingly more erosive solids in the flow stream.

Figure 18: SPPE Failures and Producing Wells by GOR Range, 2022



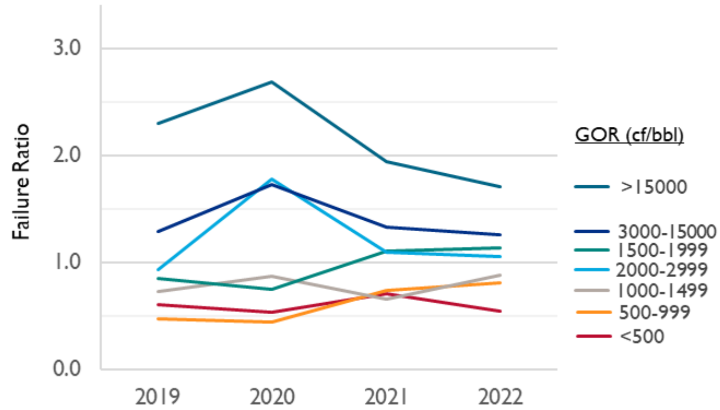
	0	<500	500-1,000	1,000-1,500	1,500-2,000	2,000-3,000	3,000-15,000	>15,000
Well Population	1.6%	18.9%	22.9%	16.3%	8.2%	7.8%	12.2%	12.1%
Surface Valve Failures	3.1%	4.1%	10.3%	10.3%	6.2%	6.2%	15.5%	16.5%
Subsurface Valve Failures	0.0%	6.2%	8.2%	4.1%	3.1%	2.1%	0.0%	4.1%

NOTES:
1. Active wells: n=2,445. Includes producing wells only.
2. Wells with SPPE failure: n=119. Includes failures on producing wells where produced fluids could have been a factor in the failure and 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.

Figure 19 shows the GOR failure ratios for each year from 2019 to 2022. Although the two highest GOR groups (3,000-15,000 and >15,000 cf/bbl) have consistently experienced failure ratios of greater than one over the four-year period, they have decreased since 2020. The three lowest GOR groups all show failure ratios consistently less than one. For comparison to prior year annual reports, various production rate failure rate analysis charts (oil rate, gas rate, water rate, etc.) are shown in Appendix H.

Figure 19: Failure Ratios Across GOR Groups, 2019-2022

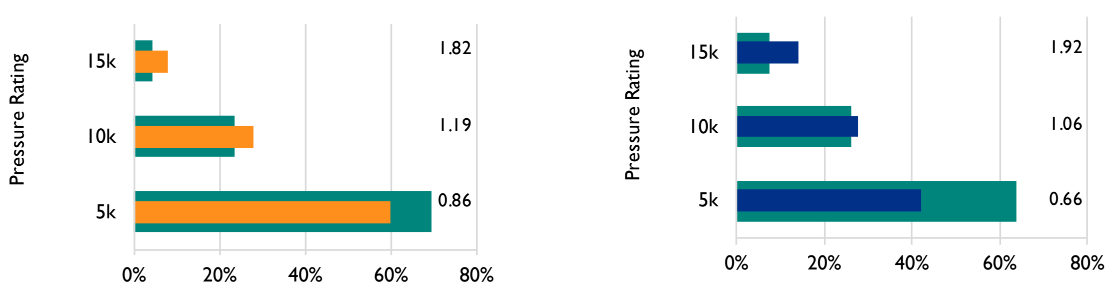


NOTE: Actual to expected failure ratio = percent of SPPE failures / percent of active wells.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

SPPE Pressure Rating

In the 2022 analysis, valve installation data provided by BSEE was used to examine the distribution of various pressure ratings of the population as compared to valves with failure events. A limitation of this analysis is that the working pressure data for the population relates to the component on which the SPPE valve is installed, which is often the wellhead of flowline, not necessarily the valve itself. Due to limited failures and lower population of other SPPE types, only SSVs and SCSSVs are discussed here. Figure 20 shows the pressure ratings for 547 SSVs and 88 SCSSVs that experienced a failure between 2017 and 2022 and had a more common pressure rating: 5,000 psi, 10,000 psi, or 15,000 psi. For SSVs and SCSSVs, the failure ratio is greater than one for the 10,000 psi and the 15,000 psi valves, indicating disproportionately more failures on these valves compared to valves with 5,000 psi ratings.

Figure 20: Pressure Ratings for All Wells vs. Wells with SPPE Failure, 2017-2022



	5k	10k	15k
SSV Population	69.4%	23.4%	4.4%
SSV Failures	59.8%	27.8%	8.0%

	5k	10k	15k
SCSSV Population	63.8%	26.1%	7.4%
SCSSV Failures	41.9%	27.6%	14.3%

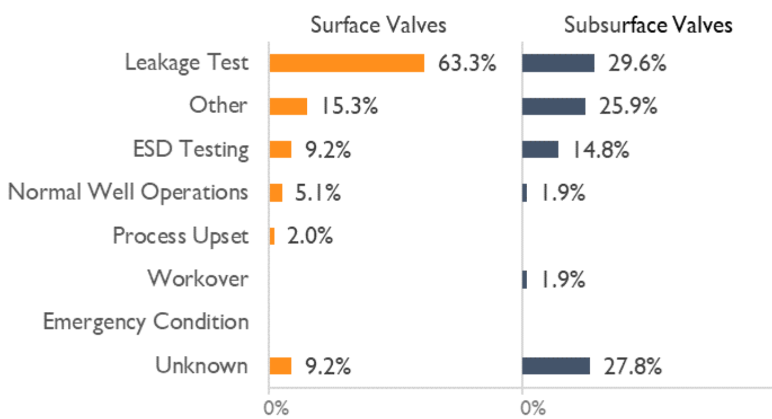
NOTE: SSV failures n=547; SSV population n=4,966; SCSSV failures n=88; SCSSV population n=4,625. Percentages sum to less than 100 because less common pressure ratings are excluded.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Between 2017 to 2022, 120 events (11 in 2022) 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).[23,24] Although designed for higher pressure or temperature, it is rare for HPHT-rated valves to operate at high pressures for extended periods. No 2022 events reported operating a valve in conditions out of its specified pressure or temperature range as a contributing factor to the failure.

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. For 2022, most failures (51.3 percent) were found during routine leakage tests (see Figure 21). Twenty-nine additional failure reports indicated "other" detection methods, including 19 found during BSEE inspections, four during bleeding the pressure down for repairs, and several found during operator inspections or while monitoring shut-in well conditions.

Figure 21: Failure Detection Methods, 2022



NOTE: Percentages are of 98 surface valve failures and 54 subsurface valve failures, respectively. Totals exceed 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.

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[23] 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.
[24] For this annual report, BTS performed a quality review of reported failure events to compare the reported pressure rating to the HPHT checkbox on the form, and updated the checkbox to match the rating where appropriate.

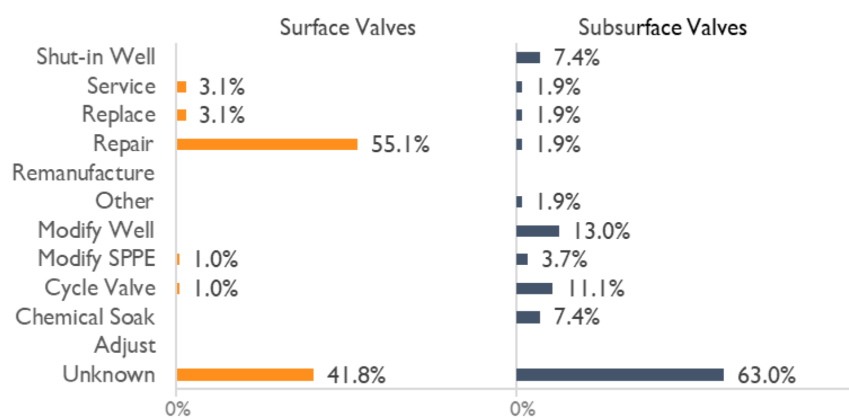
How Failures Were Addressed

In 2022, corrective actions were identified for 77 failures (50.7 percent), including 67 reported to SafeOCS and 10 identified in other sources. Figure 22 shows the distribution of corrective actions, which range from component servicing to repair or replacement. For surface valves, repair was the most common corrective action, reported for over half of events. For more than 75 percent of surface valve failures involving repair, the repaired component was the valve gate or seat.

For nine 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 four cases, the valve was cycled, and then another corrective action was performed (such as well shut-in, chemical soak, or modification). In the remaining five cases, the SPPE was repaired or serviced in addition to another action. Brief explanations of these corrective actions are provided below:

- *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 or asphaltenes.
- *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

Figure 22: Reported Corrective Actions, 2022



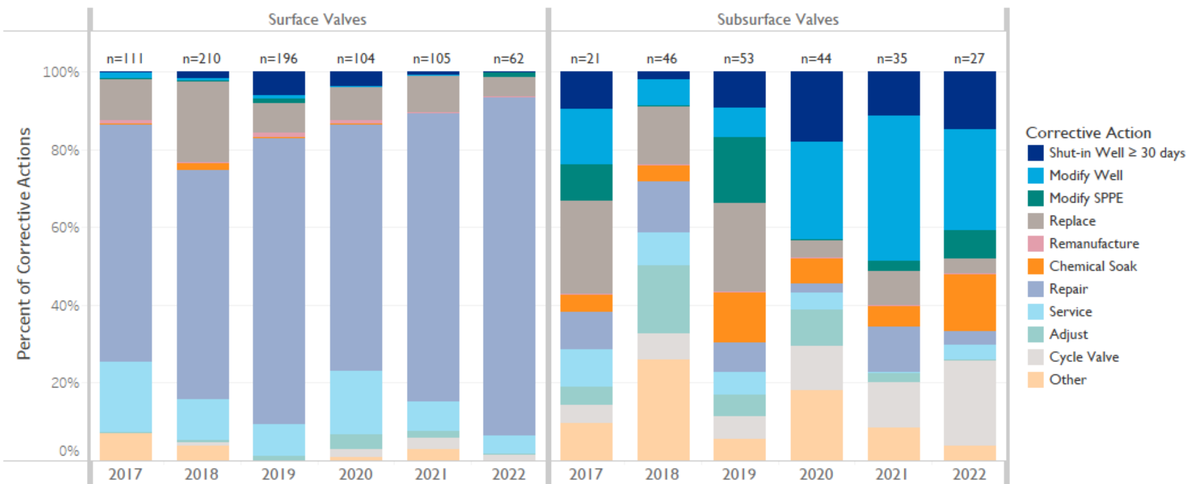
NOTE: Percentages are of 98 surface valve failures and 54 subsurface valve failures, respectively. Totals exceed 100 percent because more than one corrective action may be reported for a single event.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

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 23 shows the distribution of corrective actions each year since 2017. While most surface valves were corrected by repair, corrective actions were more varied for subsurface valves. The more common corrective actions for subsurface valves since 2019 include well shut-in, well modification, and cycling the valve. The "other" corrective actions for subsurface valves mostly involve cases where the subsurface valve was cleaned using a wireline scratching tool.

Figure 23: Reported Corrective Actions, 2017-2022



NOTE: Percentage is of the number of corrective actions identified in SPPE failures. 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.

Root Causes and Contributing Factors of Failures

Root Causes

Root cause failure analysis (RCFA) consists of various investigative methods used to determine failure causes and contributing factors. Often the process involves identifying preventive actions to reduce or eliminate the likelihood of reoccurrence. Eight failure reports in 2022 included information about preventive actions planned or taken, summarized in Table 6.

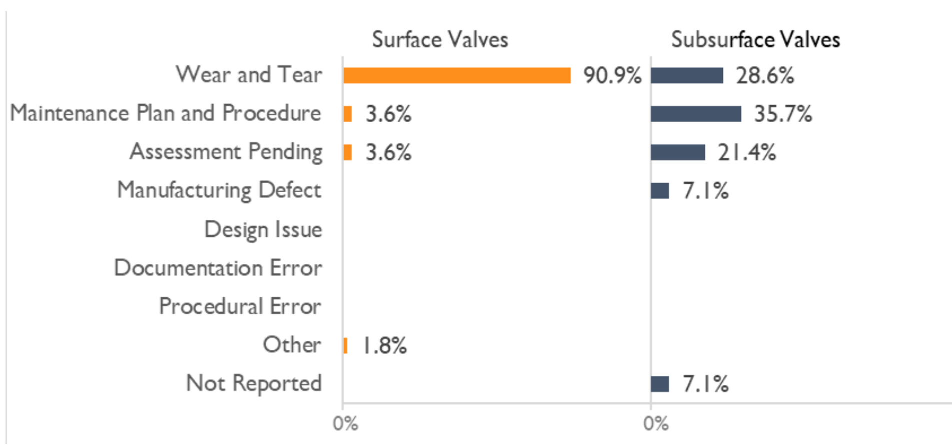
Table 6: Overview of 2022 Preventive Actions

SPPE Type	Component	Failure Type	Root Cause	Preventive Action(s)
BSDV (3 valves)	Valve Gate/Seat	Internal leak	Wear and tear	Continue recently implemented monthly greasing, verify that grease fittings on valves are protected with covers, and upgrade to newer design seats.
SSCSV	Bellows	Internal leak	Maintenance plan and procedure	Set up maintenance plan to replace the bellows every eight years.
SCSSV	Flapper	Failed to close	Maintenance plan and procedure	Planning to execute a xylene soak to dissolve any debris across SCSSV.
SSV	Valve Gate/Seat, Actuator	Internal leak	Wear and tear	Emphasized greasing frequency. Also installed a new vent on the actuator to prevent water from entering the actuator housing.
SSV	Actuator	Failed to open	Wear and tear	Cleaned and removed rust from the actuator to prevent cutting the diaphragm.
USV	Unknown	Internal leak	Unknown	Abandoned the well.

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

Figure 24 shows the reported root causes of SPPE failures reported to SafeOCS for 2022. Wear and tear was the most common reported cause of surface valve failures, reported for more than 90 percent of the 55 events. Of 14 subsurface valve failures reported to SafeOCS, the most

Figure 24: Root Causes of Reported Failure Events, 2022



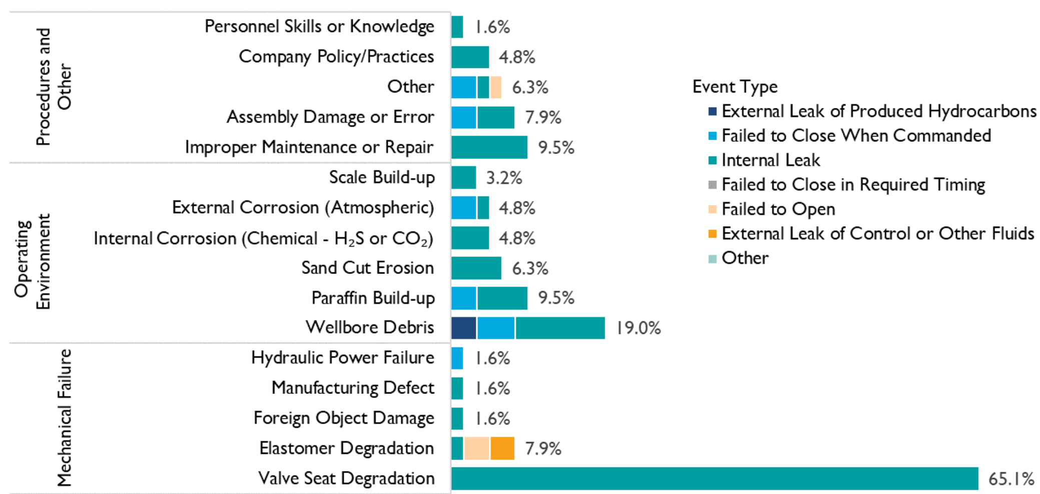
NOTE: Percentages are of 55 surface valve failures and 14 subsurface valve failures reported to SafeOCS, respectively.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

common reported cause was maintenance plan and procedure, reported for five events. Four of these noted asphaltene build-up as a contributing factor. Manufacturing defect was reported for one SCSSV failure, in which the flapper was determined to require replacement after the valve failed to seal during testing.

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 63 failures occurring in 2022, including 62 failures reported to SafeOCS and one identified in APM and WAR. In total, 98 contributing factors were reported for the 63 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 25.

Figure 25: Factors Contributing to Equipment Failures, 2022



NOTE: Percentage is of 63 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.

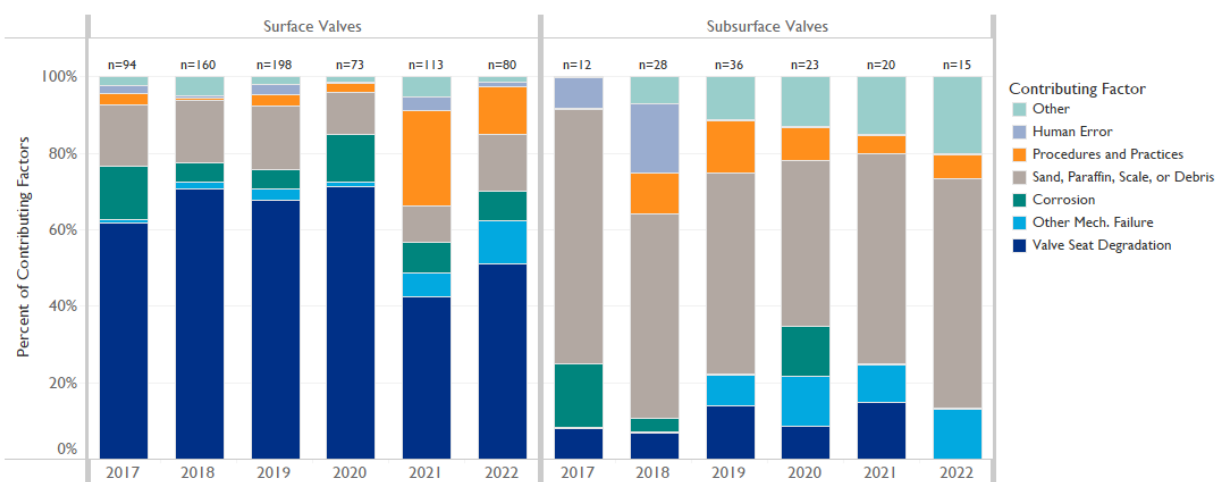
Valve seat degradation was the most reported contributing factor, reported for 65.1 percent of the 63 events. This is expected since valve gates or seats were the most reported failed component. Contributing factors related to the operating environment—atmospheric or chemical corrosion, sand, paraffin, debris, and scale—had the second highest percentage of contributing factors with 47.6 percent, up from 40.2 percent in 2021. 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 9.6

percent of the failures. Depending on the metallurgy, the temperature, and the concentration of H_2S or CO_2, corrosion could occur quickly or from prolonged exposure. However, wellbore debris contributed to the second highest number of failures (19.0 percent). The four events (6.3 percent) where "other" contributing factors were reported included descriptions of asphaltenes (a solid contaminant) and internal failure.

For 25 failures, two or more contributing factors were reported. In 20 of these cases, valve seat degradation was reported. Fourteen reported both valve seat degradation and an operating environment factor of sand cut erosion, scale, paraffin, well debris, or chemical corrosion; of these 14, four also listed improper maintenance or repair, one was listed with assembly damage or error, and one was reported with foreign object damage. Three failures were reported with contributing factors of wellbore debris with asphaltenes. In two cases, assembly damage was reported with one other factor, either paraffin or atmospheric corrosion.

Figure 26 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 2022 as a percentage of the failures, included four failures with these other factors: asphaltenes in SCSSVs (3) and internal failure of a BSDV actuator spring (1).

Figure 26: Factors Contributing to Equipment Failures, 2017-2022



NOTE: Percentage is of the number of contributing factors identified in SPPE failures. 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.

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. A greater percentage of these failures (39.1 percent) reported contaminants in 2022, increasing from 27.2 percent in 2021. These are shown in Figure 27 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 have the following service classes:

- 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.

Five SSV failures indicated the presence of sand; three of these involved a Class 2 valve, and two were Class 1 valves. Eleven SSV failures and one BSDV failures indicated the presence of other solids (paraffin, scale, salt, cement, or other solids) in the well stream, and five of these involved Class 2 valves. Of the 55 surface SPPE failures reported to SafeOCS in 2022, 28 (50.9 percent) were Class 1, 17 (30.9 percent) were Class 2, and the remainder did not report the service class.

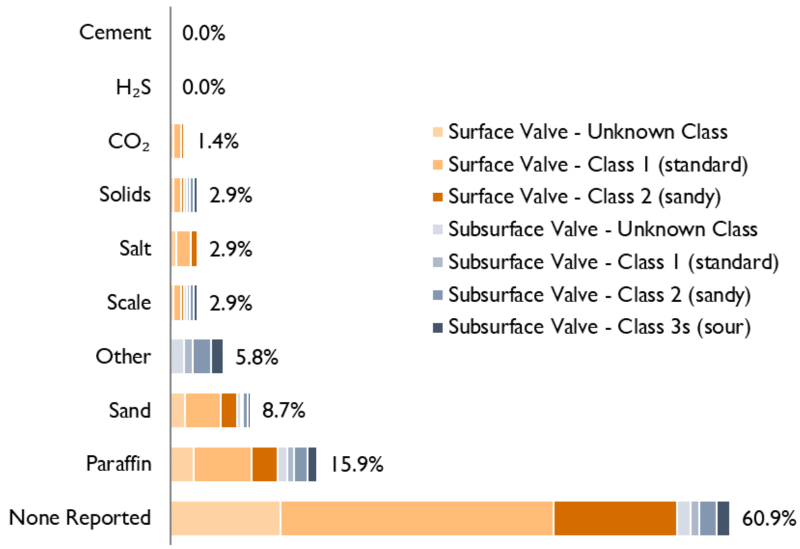
Subsurface safety valves (SCSSVs and SSCSVs) have the following service classes:

- 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.

One of the SCSSV failures indicated the presence of sand. Of 12 SCSSV failures reported to SafeOCS in

2022, nine indicated the presence of other solids (paraffin, asphaltenes, salt, solids, or scale) in the well stream. Four of these were reported as a Class I and 2 valves, two were Class 3s valves, two were Class I valves, and one did not indicate the valve class.

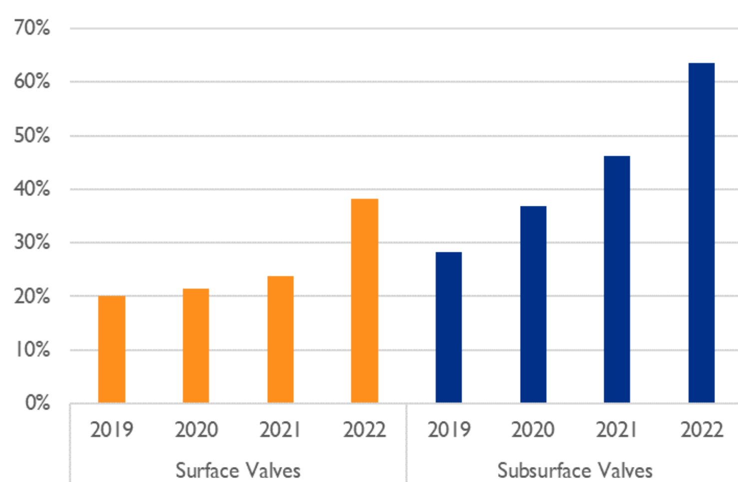
Figure 27: Well Stream Contaminants, 2022



NOTE: Percentage is of 69 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.

As shown in Figure 28, the percent of failures with reported solid contaminants has steadily increased since 2019 for both surface and subsurface valves. This could indicate contaminants are increasingly present in wells with SPPE failures, but the increase also could be driven by improved reporting of contaminants following the data collection form revision in 2020. It is uncertain whether this trend indicates improved reporting of contaminants or an actual increase in contaminants present in wells with failed SPPE

Figure 28: Well Stream Solid Contaminants, 2019-22



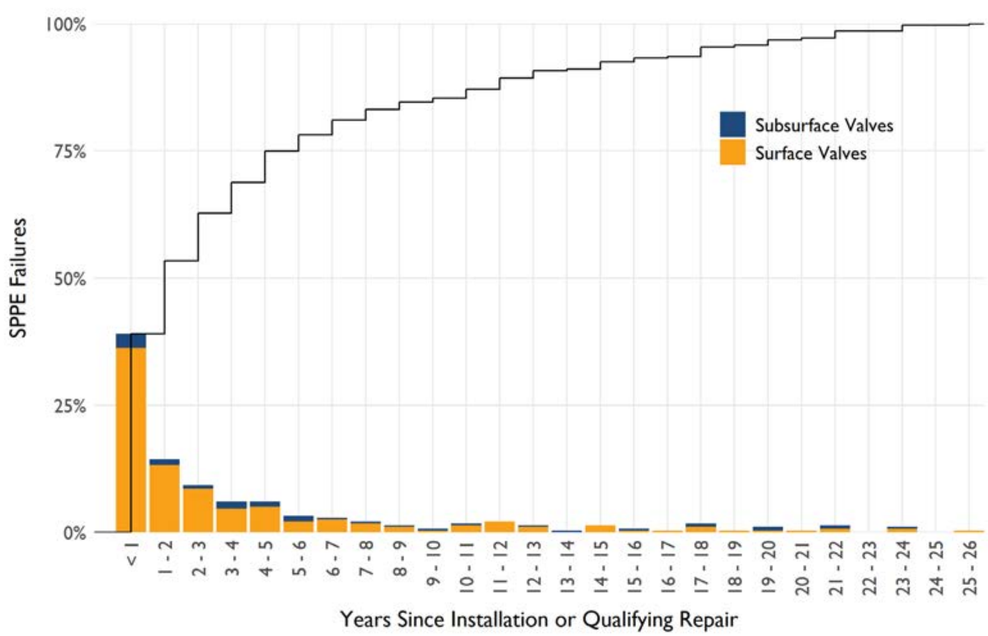
NOTE: Percentage is of failures reported to SafeOCS each year. Excludes failures identified in other sources.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

valves. The increase is not reflected in the contributing factors data presented above (see Figure 26), which could mean solids were present but determined not to be contributing to the failure.

Time to Failure

To further explore what constitutes normal wear and tear, an analysis of SPPE time to failure was performed for 2017 to 2022 (see Figure 29). For 279 failures reported to SafeOCS from 2017 to 2022, the reporter provided either the date of installation or the date of last repair. 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 25 years, as shown in Figure 29. For 111 of these failures (39.8 percent), the valve failed within one year, and for nearly two-thirds of these failures (176 of 279, or 63.1 percent), the valve failed within three years. The 279 valves comprised 241 surface valves (217 SSVs, 18 BSDVs, and 6 GLSDVs) and 38 subsurface valves (28 SCSSVs and 9 SSCSVs, and 1 USV).

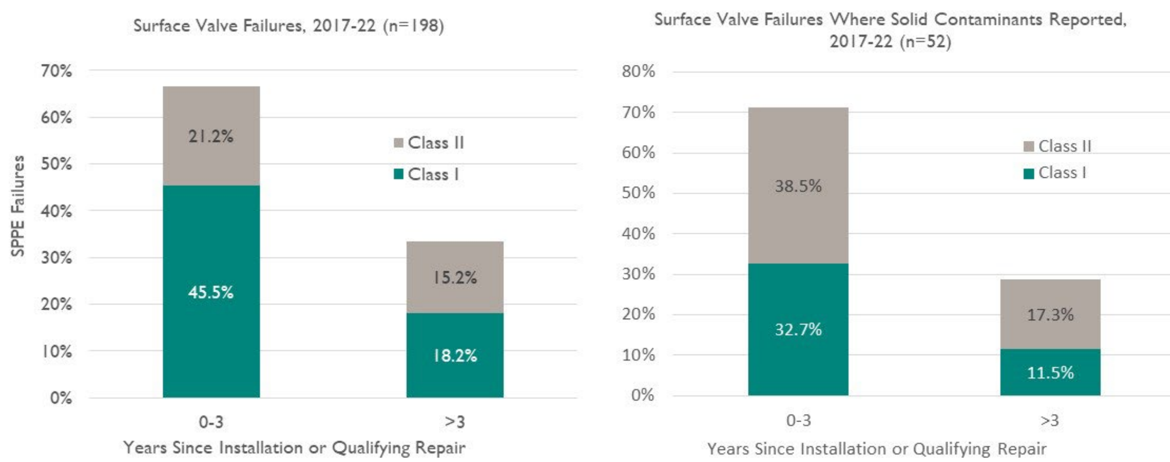
Figure 29: Time to Failure, 2017-2022



NOTE: Percentage is of 279 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.

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.) 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 30 shows the distribution of 198 surface valve failures from 2017-2022 that reported both installation or qualifying repair date and the valve service class (left) and the distribution for 52 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 (45.5 percent vs. 21.2 percent from the 66.7 percent of failures during 0-3 years). The chart at right shows that over half (55.8 percent) of the failures that also reported solid contaminants (e.g., sand, scale, paraffin) involved Class 2 valves.

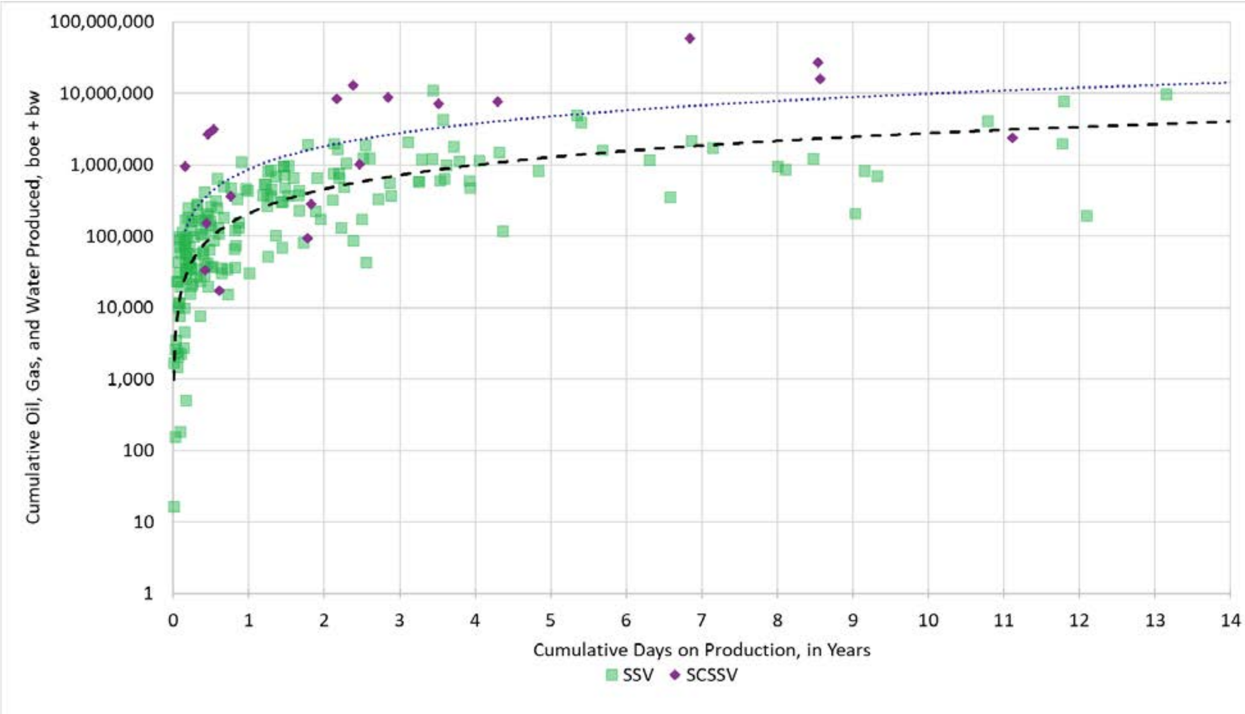
Figure 30: Time to Failure and Valve Service Class, 2017-2022



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 179 SSVs, four GLSDVs, and 15 BSDVs, and right panel includes 48 SSVs and four BSDVs.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

Incomplete data limit the time-to-failure analyses. However, where the installation or last repair date was known, analyzing cumulative production through the valve can provide a starting point for understanding the potential relationship between production passing through an SSV or SCSSV and likelihood of failure. Figure 31 shows the cumulative production to failure data for the SSVs and SCSSVs. As more data points are added each year, the theory that SCSSVs tend to tolerate higher flow conditions better than SSVs is starting to be supported.

Figure 31: Cumulative Production to Failure, 2017-2022



NOTE: The data represent the cumulative production through 190 SSV failures and 19 SCSSV failures reported to SafeOCS with available data on installation or qualifying repair date, where the failure occurred on a well that produced, and the failure could have been affected by the produced fluids. Two outlier SSV failures (18 and 20 years) and one SCSSV (18 years) are not shown due to concerns about the quality of the age information.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

(Document continues on next page.)

Repeated Failures

As summarized in Table 7, 11 of the 69 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. Four different operators reported the 11 events.

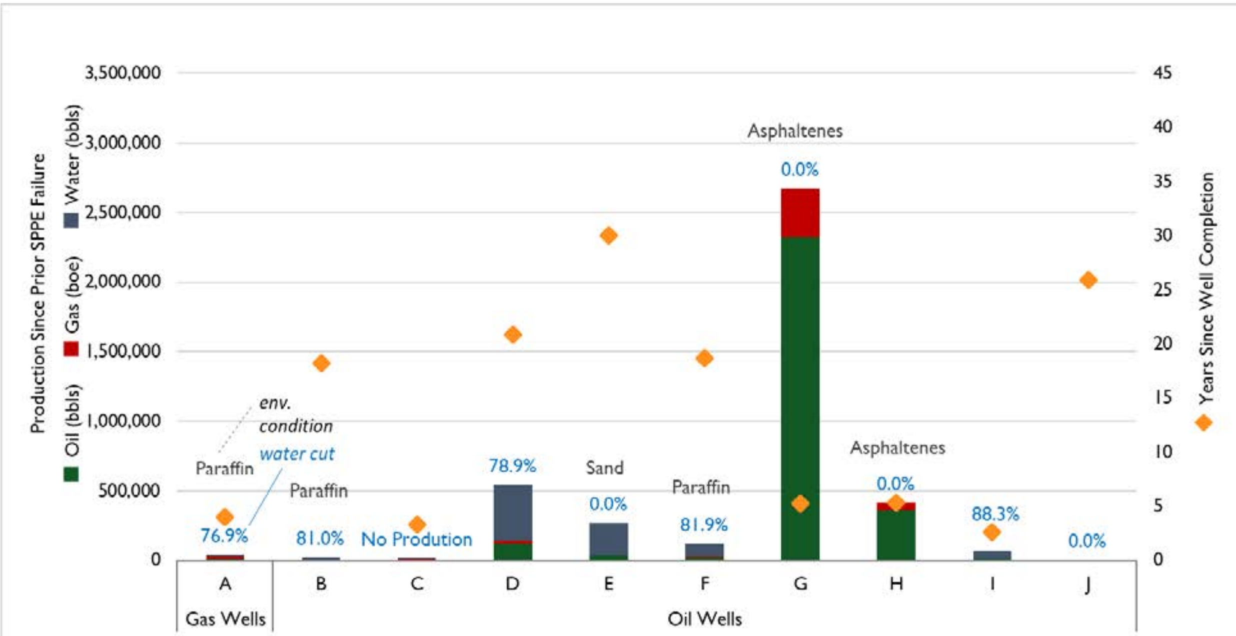
Table 7: Overview of 2022 Repeated Failures

	SSV Failures	SCSSV Failure	GLSDV Failure
Number of Failures	8	2	1
Components Involved	Gate and seats for 6 events, and actuator for 2 events.	Flapper.	Gate and seat.
How Prior Failures Were Corrected	All were repaired, which for gate/seat failures typically means the components were replaced.	Chemical soak for 1 event and cycle the valve for 1 event.	Repair.
How Failures Were Corrected	Repair for 7 events and modify and repair for one event.	Cycle valve.	Repair.
Event Type	External hydraulic control fluid leak in one event, internal leaks for 6 events and failed to open in one event.	Failure to close when commanded.	Internal leak.
Detection Method	4 failures were found during leakage test and/or ESD testing, 3 during normal well operations, and one while bleeding down the tree for header repair.	Detected during leakage testing.	Leakage testing.
Root Cause	7 wear and tear and one maintenance plan and procedure.	Maintenance plan and procedure.	Wear and tear.
Contributing Factors	6 events noted valve seat degradation - 3 with paraffin present, one also listed sand and improper maintenance or repair, and one event listed damaged during assembly and scale present. The failure involving sand occurred on a Class 2 valve. One event noted elastomeric degradation, and one event listed no contributing factors.	Wellbore debris listed for both events and asphaltene build up also reported for one event.	Improper maintenance or repair and valve seat degradation.

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

Figure 32 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. Similar to 2021, five of the 11 repeat failures were on wells with high water cut (≥75.0 percent water cut). Five failures occurred on wells completed within the last five years.

Figure 32: Production from Wells with Repeated Failures, 2022



NOTE: Includes 10 repeated failures on 10 wells. Wells G and H had SSCSV failures, and the other wells had SSV failures. Excludes one GLSDV, which does not have production fluids directly from a well flowing through it. 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.

5 CONCLUSIONS

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 causal factors. This year's report provides more detail on exposure data and well characteristics used to support analyses, including analyses comparing six years of data (2017 to 2022) for the failure ratios in the different well rate groups for production rate (boed) and GOR (cf/bl).

Some general observations can be drawn from the 2022 data and analyses:

- In 2022, one SPPE failure resulted in an HSE incident involving the estimated release of nine barrels of hydrocarbons to the environment, due to an SCSSV piston rod seal failure. Two similar events were reported as HSE incidents but were reclassified as external leaks of produced hydrocarbons due to smaller release volumes (less than one barrel). In addition, more significant failure types occurred on wells with higher production rates.
- As in previous years, 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.
- An increasing percentage of failure reports indicated the presence of solid contaminants over the past four years.
- Wells with higher GOR tended to experience more failures than those with lower GOR, potentially due to greater velocity of solids in the flow stream.
- Failures in 2022 fell by 29.0 percent compared to 2021 (214 to 152 failures, respectively), and over half of the failures were identified in OGOR-A, INC, WAR, or APM data.

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.[25] 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.[26]

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*

25 Final Rule, 81 Fed. Reg. 61,833 (Sept. 7, 2016).
26 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.[27]

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).[28]

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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[27] Schlumberger Oilfield Glossary, https://www.glossary.oilfield.slb.com.
[28] 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.[29]

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.

[29] 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.[30]

[30] 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

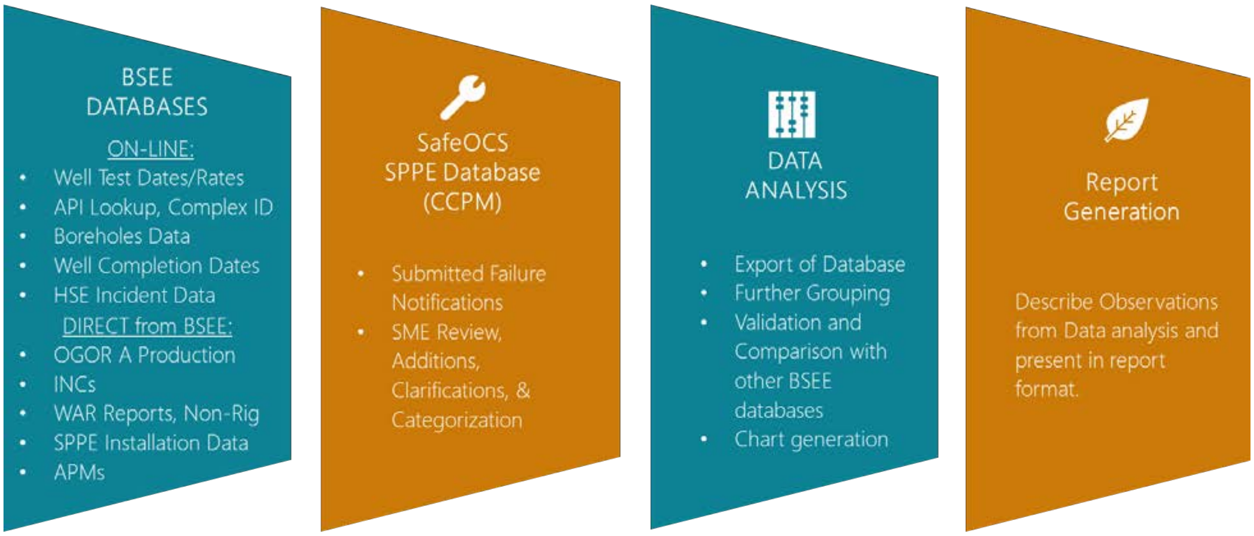
USV: underwater safety valve

WAR: Well Activity Report

APPENDIX D: DATA ANALYSIS METHODOLOGY

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

Figure 33: SPPE Annual Report Steps



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

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.[31] 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.[32] 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

[31] 30 CFR 250.513, 250.613, 250.1712, 250.1721.
[32] 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.[33] 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 OGOR-A database (including those with a reported SPPE failure) was determined by BTS using the average production rate for each well during the calendar year. 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 the calendar year, and then dividing the sum of those two volumes by the number of days the well was on production that year. A similar method was used to determine each of the well rate ranges for oil, gas, water, total liquids, GOR, and water cut.

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 the year, 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

[33] 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 the calendar year were either "not producing," "producing continuously part of the year," or "producing intermittently." Active wells, including wells with SPPE failures, were placed into these four production time groups:

- **Producing all year -** the well produced at least one day in all 12 months of the calendar year.
- **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 the calendar year.

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.

In the 2022 analysis, BTS utilized the "Working Pressure" data from the valve installation database to examine the distribution of various pressure ratings of the population as compared to the failed valves. The "Working Pressure" in the valve installation database represents the working pressure of the component that the SPPE is associated with, often a well or a flowline. BTS has assumed that the SPPE pressure rating would be equal to the component working pressure for this analysis.

Incidents of Noncompliance (INCs)

BTS reviewed INCs issued by BSEE in 2022 to determine if the deficiency described in the INC was a reportable SPPE failure.[34] The SPPE failures identified in INC data are listed in Table 8. The INCs were then used to cross-reference the SPPE failures during the same period to determine if they were also reported in SafeOCS.

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

Table 8: SPPE Failures Identified in INC Data, 2019-2022

PINC	Short Description	2019	2020	2021	2022
E-100	Unauthorized discharge of pollutants into sea	0	0	0	1
G-111	SPPE corroded or leaking and needing repair	0	3	0	5
G-112	SPPE leaking hydrocarbons externally	0	1	0	0
G-113	Lessee makes facilities available for inspection	0	0	1	0
P-102	Shutdown valve failed to close upon receiving signal	3	0	3	1
P-103	SPPE bypassed or blocked out of service	0	2	0	1
P-104	Failure to maintain the hydraulic system operating condition	0	0	0	3
P-240	SCSSV was not tested every 6 months	12	5	4	5
P-241	SCSSV failed to close within 2 minutes	18	0	10	11
P-261	Long term shut-in well SCSSV rendered inoperable	0	1	1	0
P-280	SSV failed to close within 45 seconds	16	16	4	5
P-281*	SSCSV not removed, inspected, and repaired or adjusted at 6 or 12 months.	0	0	0	1
P-283*	Tubing plug not tested for leakage every 6 months.	0	0	0	1
P-307	SSV was not tested monthly	1	2	0	2
P-319	BSDV was not tested monthly	0	1	1	4
P-366	Departing subsea gaslift line equipped with GLSDV	0	0	2	0
P-412	SSV, USV, or BSDV had internal leakage	38	13	22	21
	Total	**88**	**44**	**48**	**61**

NOTE: * Safety valve leaks were mentioned in the description for these INCs.
SOURCE: U.S. Department of Transportation, Bureau of Transportation Statistics, SafeOCS.

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.

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 the calendar year. 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. 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). 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 9: SPPE Failure Rates in the Gulf of Mexico, 2019-2022

		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
	2022	90	7	1	41	3	1	143
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
	2022	5105	176	30	4751	464	805	11,331
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	34,560 - 63,684	2184	312	9738	497 - 994	2876	N/A
	2022	35,757 - 61,260	2112	360	9502	464 - 928	3220	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% - 0.34%	0.64%	2.24%	0.48%	0.40% - 0.80%	0.10%	N/A
	2022	0.15% - 0.25%	0.33%	0.28%	0.43%	0.32% - 0.65%	0.03%	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-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 SSSVs identified only in OGOR-A data.

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

Appendix F: Typical SPPE Valve Components

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

Table 10: Typical SPPE Valve Components

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

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

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. See also BSEE HSE incident reporting requirements at 30 CFR 250.188, 30 CFR 254.46, and NTL No. 2019-N05.

- 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 >1 barrel

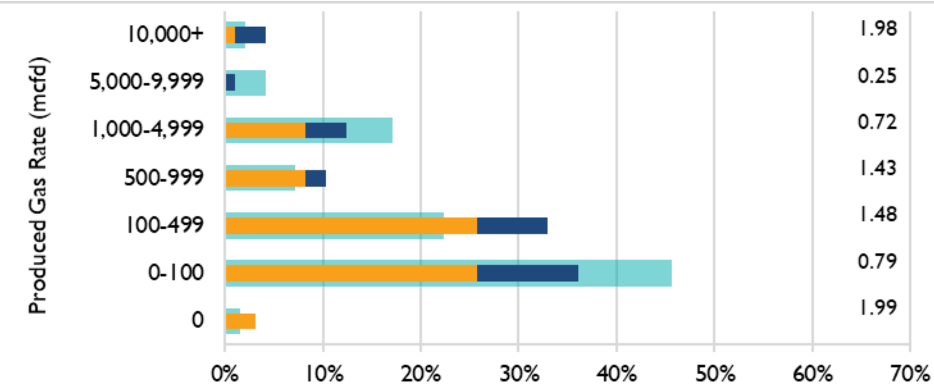
APPENDIX H: ADDITIONAL TABLES AND FIGURES

The following charts are provided for 2022 failures to allow comparison to the 2021 annual report. The charts include failures where the production rates near the time of the failure were known and exclude failures that could not have been related to the production fluids or contaminants within those fluids. The producing well population includes only the 2,445 active wells that produced in 2022.

Produced Gas Rate

Figure 34 shows the failures in each gas rate group compared to the producing well population. Almost half (45.6 percent) of the producing well population had a gas rate between zero and 100 mcfd, and many of the failures (36.1 percent) occurred on wells within that same gas rate group. The 100-499 mcfd group and the 500-999 mcfd group had some of the highest actual to expected failure ratios (1.48 and 1.43, respectively), indicating that more failures occurred on wells in these groups compared to the population of wells in those two groups.

Figure 34: SPPE Failures and Active Wells by Gas Rate Group, 2022



	0	0-100	100-499	500-999	1,000-4,999	5,000-9,999	10,000+
Well Population	1.6%	45.6%	22.3%	7.2%	17.1%	4.1%	2.1%
Surface Valve Failures	3.1%	25.8%	25.8%	8.2%	8.2%	0.0%	1.0%
Subsurface Valve Failures	0.0%	10.3%	7.2%	2.1%	4.1%	1.0%	3.1%

NOTES:

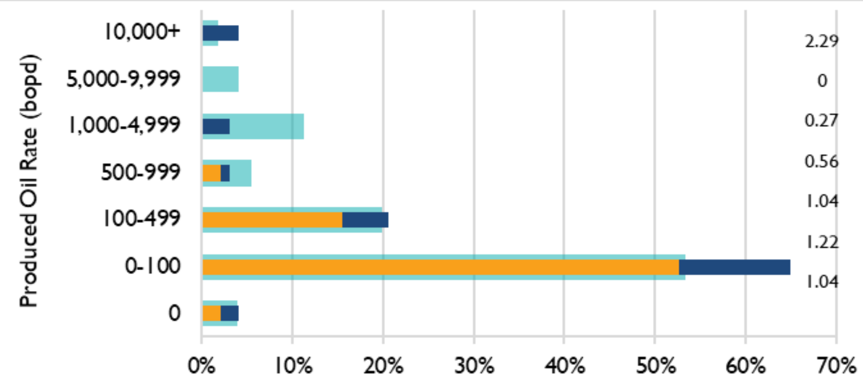
1. Active wells: n=2,445. Includes producing wells only. Rate is taken from 2022 annual average.
2. Wells with SPPE failure: n=97. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates indicated the well produced in the month prior to the failure. 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.

Produced Oil Rate

Figure 35 shows the failures in each oil rate group compared to the producing well population. Most of the producing well population (53.4 percent) had an oil rate between zero and 100 bopd, and nearly two thirds (65 percent) of the failures occurred on wells within that same oil rate group. More failures occurred on wells in the highest bopd group (> 10,000 bopd) relative to other oil rate groups, as indicated by its higher actual to expected failure ratio.

Figure 35: SPPE Failures and Active Wells by Oil Rate Group, 2022



	0	0-100	100-499	500-999	1,000-4,999	5,000-9,999	10,000+
Well Population	4.0%	53.4%	19.9%	5.5%	11.3%	4.1%	1.8%
Surface Valve Failures	2.1%	52.6%	15.5%	2.1%	0.0%	0.0%	0.0%
Subsurface Valve Failures	2.1%	12.4%	5.2%	1.0%	3.1%	0.0%	4.1%

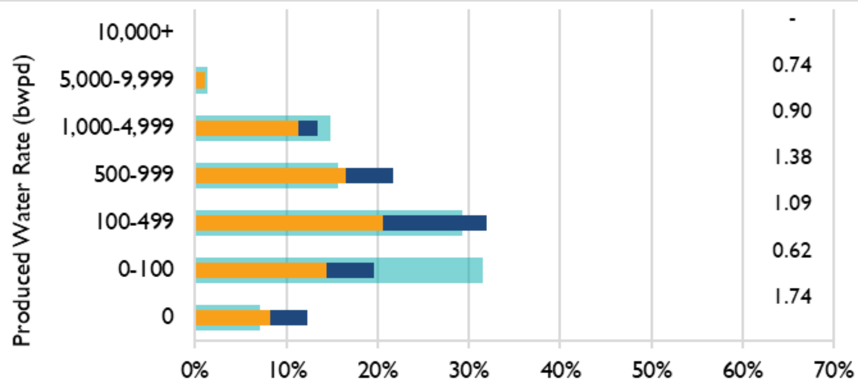
NOTES:
1. Active wells: n=2,445. Includes producing wells only. Rate is taken from 2022 annual average.
2. Wells with SPPE failure: n=97. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates indicated the well produced in the month prior to 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.

Produced Water Rate

Figure 36 shows the failures in each water rate group as compared to the producing well population. Most of the producing well population (60.9 percent) had a water rate between zero and 500 bwpd; however, the water rate groups with higher failure ratios were the 500 –999 bwpd group and the wells with zero water production (1.38 and 1.74 respectively).

Figure 36: SPPE Failures and Active Wells by Water Rate Group, 2022



	0	0-100	100-499	500-999	1,000-4,999	5,000-9,999	10,000+
Well Population	7.1%	31.6%	29.3%	15.7%	14.8%	1.4%	0.1%
Surface Valve Failures	8.2%	14.4%	20.6%	16.5%	11.3%	1.0%	0.0%
Subsurface Valve Failures	4.1%	5.2%	11.3%	5.2%	2.1%	0.0%	0.0%

NOTES:

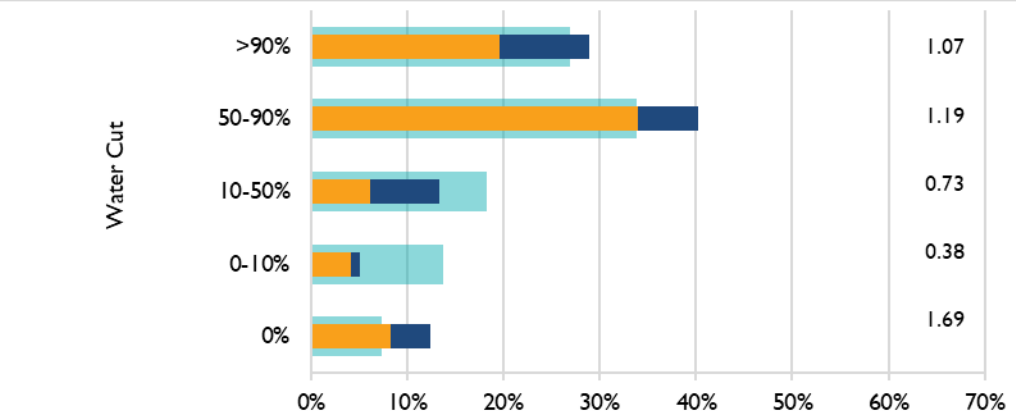
1. Active wells: n=2,445. Includes producing wells only. Rate is taken from 2022 annual average.
2. Wells with SPPE failure: n=97. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates were indicated the well produced in the month prior to the 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.

Water Cut Range

A well's water cut is its ratio of produced water to total produced liquids (oil plus water). Figure 37 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 failure ratios were not as high as the zero water cut group.

Figure 37: SPPE Failures and Active Wells by Water Cut Range, 2022



	0%	0-10%	10-50%	50-90%	>90%
Well Population	7.3%	13.7%	18.2%	33.8%	26.9%
Surface Valve Failures	8.2%	4.1%	6.2%	34.0%	19.6%
Subsurface Valve Failures	4.1%	1.0%	7.2%	6.2%	9.3%

NOTES:

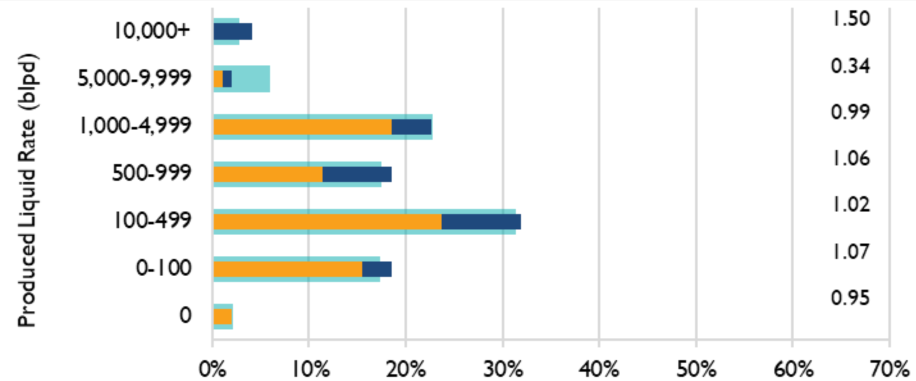
1. Active wells: n=2,445. Includes producing wells only. Rate is taken from 2022 annual average.
2. Wells with SPPE failure: n=97. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates indicated the well produced in the month prior to the failure. 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.

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 38 shows the failures in each liquid rate group as compared to the producing well population. Although the highest failure ratio (1.5) was in the greater than 10,000 blpd group, this group had one of the fewest number of wells (2.7 percent). Most of the failure ratios were near 1.0 indicating that the failures generally followed the population of wells when grouped by the total produced liquid rate.

Figure 38: SPPE Failures and Active Wells by Total Liquid Rate, 2022



	0	0-100	100-499	500-999	1,000-4,999	5,000-9,999	10,000+
Well Population	2.2%	17.3%	31.4%	17.5%	22.8%	6.0%	2.7%
Surface Valve Failures	2.1%	15.5%	23.7%	11.3%	18.6%	1.0%	0.0%
Subsurface Valve Failures	0.0%	3.1%	8.2%	7.2%	4.1%	1.0%	4.1%

NOTES:

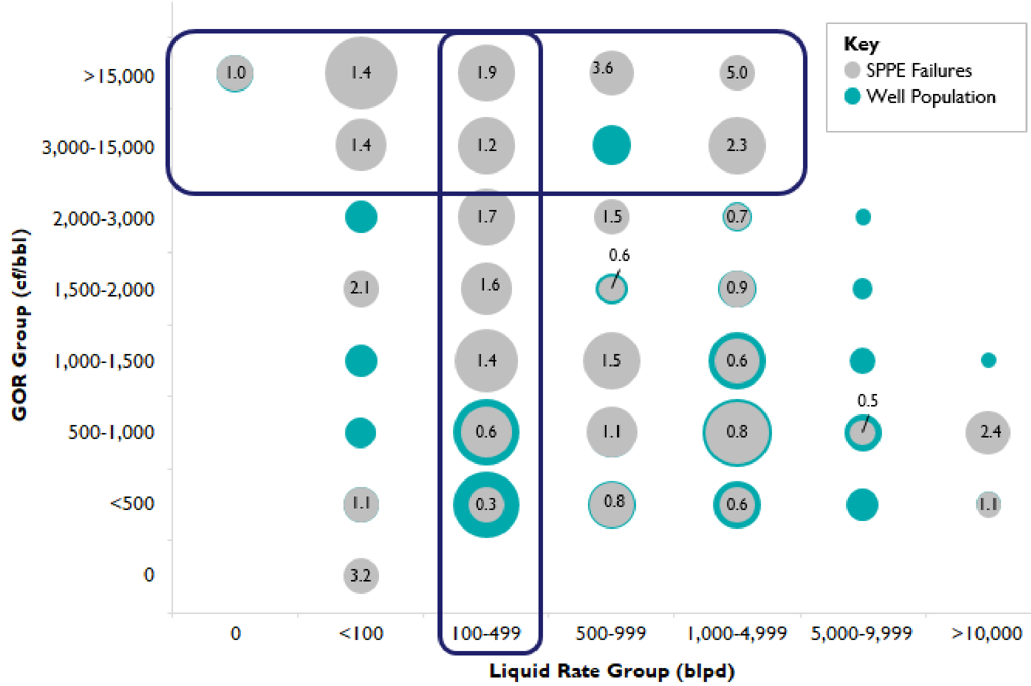
1. Active wells: n=2,445. Includes producing wells only. Rate is taken from 2022 annual average.
2. Wells with SPPE failure: n=97. Includes failures on producing wells where produced fluids could have been a factor in the failure and well rates indicated the well produced in the month prior to the failure. 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.

Figure 39 and Figure 40 compare two well rate variables to the incidence of SPPE failure. Both the failures and the active wells are divided into rate groups as a percentage, and then compared to one another (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.

Plotting the GOR group against the total liquid rate group (Figure 39) indicates that the higher GOR groups have the higher failure ratios regardless of total liquid rate. The highest failure ratio is the 5.0 on the group that produces 1,000 – 4,999 blpd with a GOR > 15,000 cf/bbl.

Figure 39: GOR versus Liquid Rate, 2022



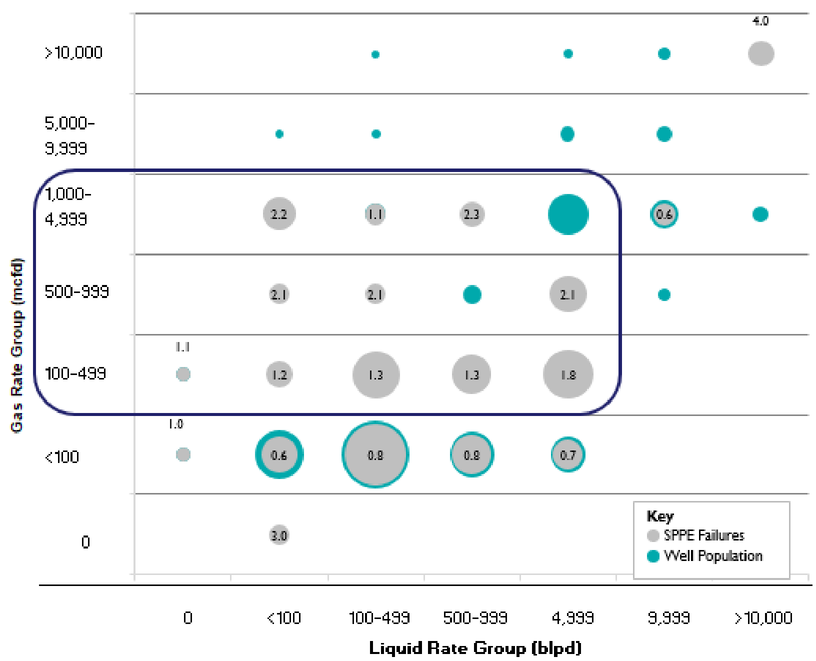
NOTES:

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=2,445. Includes producing wells only. Rates are taken from 2022 annual average.
4. Wells with SPPE failure: n=91. 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.

In Figure 40, the gas rate group is plotted against the total liquid rate group for the failures and the producing well population. 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.

Figure 40: Gas Rate versus Liquid Rate, 2022



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=2,445. Includes producing wells only. Rates are taken from 2022 annual average.
4. Wells with SPPE failure: n=96. 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.