ALLOWABLE LEAKAGE RATES AND RELIABILITY OF SAFETY AND POLLUTION PREVENTION EQUIPMENT

MMS Contract No. 1435-01-97-CT-30880

This study was funded by the Minerals Management Service, U.S. Department of the Interior, Washington, D.C., under Contract Number 1435-01-97-CT-30880

FINAL REPORT
SwRI Project 18-1298

Prepared for:

Minerals Management Service
U.S. Department of the Interior
381 Elden Street
Herndon, Virginia 20170-4817

May 1999

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Disclaimer:

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ACKNOWLEDGMENTS

The authors wish to acknowledge the contributions to and support for this project by Bill Hauser of the Minerals Management Service. His insight and encouragement were valuable and ensured the success of the project.

The authors also wish to acknowledge the support offered by several velocity valve manufacturers, who provided sizing programs and valves for the tests performed at SwRI. In addition, we wish to thank the staff and inspectors in three of the MMS Gulf of Mexico Districts (New Orleans, Houma, and Lafayette) for their support during the field observations, and the platform operators for their assistance and cooperation during the field observations. The field observations were a key component of the project and the honesty and concern of the inspectors helped provide a more useful end product.

Also to be thanked is the staff of the Flow Component Test Facility at SwRI for all their assistance in performing the velocity valve testing. Finally, this report could not have been produced without the skill and patience of Ms. Jackie Wishert, who prepared the report manuscript and completed the necessary revisions.

EXECUTIVE SUMMARY

Surface and subsurface safety valves installed in oil and gas production wells located in the Outer Continental Shelf (OCS) of the United States have a proven record of reliable service for over twenty years. The effectiveness of this equipment can be attributed to the development of meaningful specifications and proper installation, operation, and maintenance practices. These practices include periodic functional testing of the valves to ensure that they do not leak excessively. API Recommended Practice (RP) 14B (for subsurface safety valves) and API RP 14C (for surface safety valves) set limits on allowable leakage rates during field testing of the valves. Unfortunately, very little, if any, technical justification can be found for the leakage rates that have been established.

The goals of this program were to:

- Develop recommendations for allowable leakage rates for surface and subsurface safety valves, in particular the difference between the leakage rates specified by 30 CFR and API 14 and 6AV1.
- Draft a test method for in-field leakage testing of these valves.
- Evaluate current manufacturers' velocity valve sizing models and compare each model's prediction to laboratory test data collected at SwRI.
- Determine the reliability of non-certified surface safety valves.

Initial efforts (Task 1) of this project were focused on investigating the decision criteria behind the various allowable leakage rates. Through interviews with MMS inspectors and field operators, it was determined how the specifications are interpreted (Task 2). Several field visits were made to observe current field testing operations and identify the concerns of the field personnel who are required to perform the routine testing of the safety valves (Task 3). In addition, operational and leakage information was collected during these visits, to determine the reliability of non-certified surface safety valves. A laboratory test program was conducted to assess the sizing models of velocity valves (Task 4). A preliminary assessment was then completed in order to begin to identify the consequences of various leakage rates under typical operating conditions (Task 5). Recommendations were then developed for allowable leakage rates for surface and subsurface safety valves (Task 6). In addition, a draft test method was developed for the in-field leakage testing of these valves.

Based upon the effort of results of this study:

- There have not been any scientific studies to conclusively provide justification for leakage rates.
- It is apparent that there is no single test procedure that all MMS inspectors follow when testing SSVs and SSSVs.
- It has been determined that there is no statistically significant difference in the proportion of failures between certified and non-certified surface safety valves.
- MMS's concerns about velocity valve sizing may be valid.
- There appears to be preliminary evidence indicating that the more stringent leakage requirements specified in 30 CFR 250 may not significantly increase the level of safety when compared to the leakage rates recommended by API.

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1 INTRODUCTION

Surface and subsurface safety valves installed in oil and gas production wells located in the Outer Continental Shelf (OCS) of the United States have a proven record of reliable service for over twenty years. These valves not only protect the lives of personnel and equipment on offshore production facilities, but also protect the environment in the event of a safety incident. The effectiveness of this equipment can be attributed to the development of meaningful specifications and proper installation, operation, and maintenance practices. These practices include periodic functional testing of the valves to ensure that they do not leak excessively.

API Specification 14A for subsurface safety valves and API Specification 6AV1 (which used to be API 14D) for surface safety valves provide limits for valve leakage during the valve certification process (see Table 1). In addition, API Recommended Practice (RP) 14B (for subsurface safety valves) and API RP 14C (for surface safety valves) set limits on allowable leakage rates during field testing of the valves. The field test requirements for allowable valve leakage are less stringent than the certification requirements in recognition of the fact that the valves age and wear after several years of field service and may not seal quite as well as new valves. Nonetheless, the field allowables are still very low leakage rates. Unfortunately, very little, if any, technical justification can be found for the leakage rates that have been established.

According to the current field test method listed in API Recommended Practice 14B, the leakage test procedure is based on pressure build-up in the volume of the tubing string above the valve. This test method is relatively imprecise and leaves room for error due to inaccuracies in measuring the temperature and pressure of the process fluid. Another option for measuring leakage is to use a rotameter or flow measurement device on the well site; however, these flow meters are not often available in the field. In reality, inspections are often performed by using a more qualitative approach than the two quantitative methods outlined in API RP 14B.

Since the API Specification 14 series and API 6AV1 have wide industry acceptance and support, it has been adopted by the American National Standards Institute (ANSI) and the

Table 1. Specifications for allowable leakage rates and testing frequency.

Current standards specify inconsistent allowable leakage rates.

Standard Reference	Application	Allowable Leakage Rates		Test Frequency
		Liquid (cc/min)	Gas (SCFM)	
Subsurface Safety Valves				
API 14A, Ninth Edtion, 1994	Qualification	10	5	Not addressed
API 14B, Fourth Edtion, 1994	Field	400	15	6 months
30 CFR Chapter 11 (250.124), 1996	Field	200	5	6 months
30 CFR Chapter 11 (250.804), 1998	Field	Not addressed	Not addressed	6 months
Surface and Underwater Safety Valves				
API 14C, 1994	Field	400	15	At least annually
API 6AV1, 1996	Qualification	0	0	Not addressed
API 14H, 1994	Field	400	15	Not addressed
30 CFR Chapter 11 (250.124), 1996	Field	0	0	Each month or 6 wks
30 CFR Chapter 11 (250.804), 1998	Field	0	0	Each month or 6 wks

American Society of Mechanical Engineers (ASME) as a national standard. Also, foreign regulatory bodies, such as the Norwegian Petroleum Directorate, may require the use of equipment manufactured to these standards.

In addition to the API Specification 14 series, the Code of Federal Regulations also specifies allowable leakage rates for field tests for surface, subsurface, and underwater safety valves (see Table 1). These leakage rates, however, differ from the rates specified by the API Specification 14 series and API 6AV1.

Over the years, these various specifications and regulations have received numerous reviews and, as necessary, the documents were updated. These changes have often come about as a result of experience by the operators, manufacturers, and Southwest Research Institute (SwRI), which conducts performance tests to API Specifications 14A and 6AV1. However, these leakage rates have never been changed. Manufacturers, operators, and regulators are all in agreement that the governing standards and recommended practices must be reviewed and updated in order to provide a rational and uniform basis for setting safety valve leakage rates and practical field test procedures. Therefore, one purpose of this project is to provide this service for the oil and gas industry's benefit.

Other concerns, expressed by MMS field inspectors, relate to the reliability of:

- Subsurface-controlled subsurface safety valves (SSSV).
- Certified surface safety valves versus non-certified surface safety valves.

The subsurface-controlled SSSVs, also known as velocity valves, are designed to shut-in a well when the wellbore fluids reach a specific "velocity." The valve manufacturers have been using valve sizing models that are predominantly based on API 14BM, "Users Manual for API 14B Subsurface-Controlled Subsurface Safety Valve Sizing Computer Program," which was written in the middle 1970s. These models identify the closing velocity as a function of the products flowing through the valve. That is, the valve is sized to close at certain conditions with a mix of fluids that is specified by the operator. With time, these well conditions change to yield numerous combinations of oil, gas, and produced water over the life of the well. MMS personnel are concerned about the effect that these changing well conditions have on the closing "velocity" of the valve. Therefore, a second purpose for this project is to evaluate current manufacturers' velocity valve sizing models and compare each model's prediction to laboratory test data collected at SwRI. These data will be used to conclude the accuracy of each velocity valve sizing model.

According to information provided to MMS by the Offshore Operators Committee, about 3,000 *non-certified* surface safety valves are currently in use in Outer Continental Shelf waters. The main concern about these valves is that the designs are old, prior to 1978, and they have never been exposed to the certification process required by API 6AV1. Therefore, a third purpose for this project is to quantify the reliability of these *non-certified* valves and compare that with the reliability of *certified* surface safety valves.

2 PROGRAM GOAL AND STRATEGY

The goals of this program were to:

- Develop recommendations for allowable leakage rates for surface and subsurface safety valves, in particular the difference between the leakage rates specified by 30 CFR and API 14 and 6AV1.

- Draft a test method for in-field leakage testing of these valves.

- Evaluate current manufacturers' velocity valve sizing models and compare each model's prediction to laboratory test data collected at SwRI.

- Determine the relative reliability of non-certified surface safety valves.

These goals were accomplished by combining SwRI's available testing facilities, valve testing expertise, engineering analysis capability, knowledge of applicable safety valve standards, and relationships with regulators, standards committee members, valve manufacturers, end users, and international counterparts. The program plan (see Figure 1) was focused on first understanding the decision criteria behind the various standards currently on the books. Next, the operational experience of the valve manufacturers and end users was analyzed and evaluated. Part of this investigation included field observations of the valve testing that was intended to

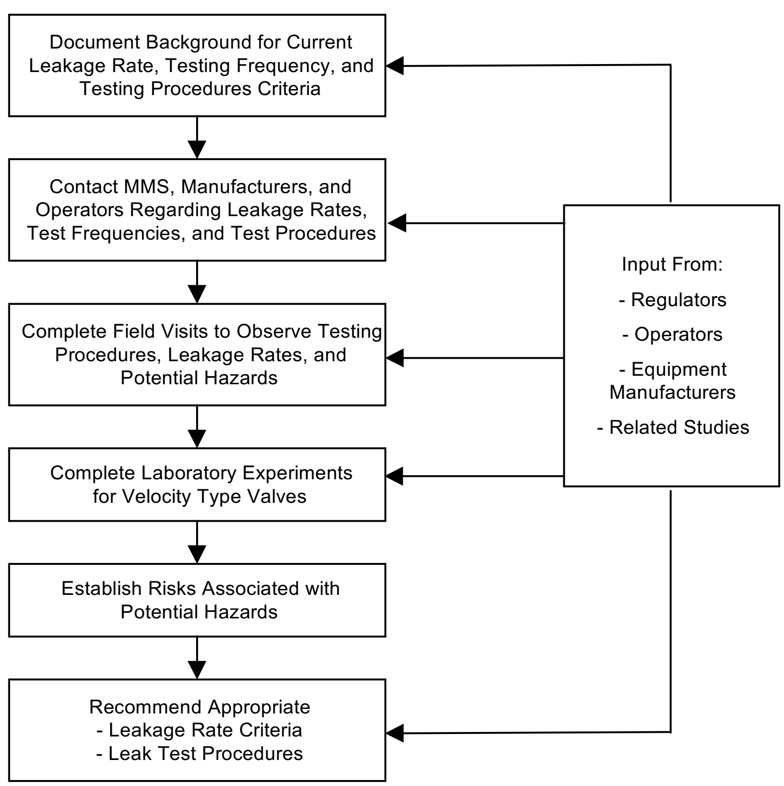

Figure 1. Overview of program plan.

The successful completion of these program elements, which included input from manufacturers, operators, and regulators, met the program goal.

meet the current specifications. The field observations were also used to gather data regarding the reliability of certified and non-certified surface safety valves, and to field test new testing procedures. Laboratory experiments were performed in order to evaluate the adequacy of current models for sizing of subsurface-controlled subsurface safety valves. The general hazards and risks associated with safety valve leakage and testing were then identified in order to define the consequences of various leakage rates under typical operating conditions. All of this information was evaluated during the development of the recommendations discussed above.

3 TECHNICAL APPROACH

As shown in Table 1, a wide range of leakage rates are currently allowed by various ruling standards, some of which give conflicting information about the same "requirement." Therefore, initial efforts (Task 1) of this project were focused on investigating the decision criteria behind the various allowable leakage rates. This was accomplished by contacting the various ruling bodies and members of standards committees to obtain their documentation on the decision criteria behind their standard.

The results of this investigation were used to form a basis for discussions with MMS personnel, valve manufacturers, and end users to determine their experience with leakage rates and testing frequencies (Task 2). The focus of the discussions was to identify how the inspectors and field operators currently interpret the "requirements," how well they follow the testing requirements, and the changes that they believe are necessary to the current standards.

In addition to the standards review and discussions mentioned above, several field visits were made to observe current field testing operations and identify the concerns of the field personnel who are required to perform the routine testing of the safety valves (Task 3). These discussions were with MMS inspectors, as well as operators' field personnel, and included identification of problems with the test procedure, concerns about the testing frequency, operational concerns about leaks and leakage rates, and the potential hazards resulting from leaks and leakage rates. In addition, operational and leakage information was collected during these visits, to determine the reliability of non-certified surface safety valves currently in use in the OCS waters.

In order to evaluate the reliability of velocity valves under changing well conditions, a laboratory program was conducted (Task 4). This program included evaluating current manufacturers' velocity valve sizing models and comparing each model's prediction to laboratory test data collected at SwRI. These data were used to conclude the accuracy of each velocity valve sizing model.

Starting from the leakage concerns identified above, the general hazards and risks were identified. A preliminary assessment was then completed in order to begin to identify the consequences of various leakage rates under typical operating conditions (Task 5). This analysis considered and addressed the various "decision criteria" identified in the review of the standards (Task 1). The hazards analysis included some modeling of the extent and concentration of discharge plumes, as a function of the operational environment, for typical leakage scenarios.

Subsequent to the collection and analysis of all of the data discussed above, recommendations were developed for allowable leakage rates for surface and subsurface safety valves (Task 6). In addition, a draft test method was developed for the in-field leakage testing of these valves. The results of each task are discussed below.

4 TASK NO. 1: CURRENT LEAKAGE RATE CRITERIA

The objective of this task was to identify and compare the decision criteria behind the various allowable leakage rates and testing frequencies identified in the U.S. National Standards in order to identify the justification of the allowable leakage rates and testing frequency. This was accomplished by reviewing the U.S. National Standards and by speaking with personnel from the American Petroleum Institute (API), the Minerals Management Service (MMS), and various members of the committees that developed these standards.

Copies of all U.S. National Standards that pertain to surface safety valves (SSV) and subsurface safety valves (SSSV) were reviewed. After discussions with MMS personnel, SwRI personnel, and API committee members, the general conclusion is that there have not been any scientific studies to conclusively provide justification for leakage rates or testing frequencies. All of these individuals have been involved over a portion of the last 20 years, in some way, on the various committees that have set the leakage rates to be included in either the MMS rules or API recommendations, and no documentation of any decision criteria was available. A detailed discussion of this may be found in Topical Report No. 1, "Current Leakage Rate Criteria," which is included as Appendix A.

5 TASK NO. 2: CURRENT LEAKAGE RATES

The objectives of this task were to:

- Identify, through interviews, how valves are currently performing, how MMS inspectors and field operators currently interpret the "requirements," how MMS inspectors perform leak checks, and how well these personnel follow the testing requirements.

- Identify locations of a range of in-service certified and non-certified surface safety valves, so that field performance tests can be witnessed.

During October 1997, SwRI sent out a questionnaire to MMS field inspectors located in all four district offices in the Gulf of Mexico Region (New Orleans, Houma, Lafayette, and Lake Jackson). Twenty-eight responses to the questionnaire were received from MMS personnel, representing a good cross section from each district office.

Based upon the results of the questionnaire, it is apparent that there was no single test procedure that all MMS inspectors follow when testing SSVs and SSSVs. The results also show that a standard test procedure would be desirable. The details of the questionnaire may be found in Topical Report No. 2, "Current Leakage Rates," which is included as Appendix B.

6 TASK NO. 3: FIELD OBSERVATIONS

The objectives of this task were to:

- Collect valve operation and leakage data for both certified and non-certified surface safety valves (SSVs) in order to determine the relative reliability of non-certified equipment.

- Identify (during the field visits) problems with current test procedures, concerns about testing frequencies, operational concerns about leaks and leakage rates, and the potential hazards resulting from leaks and leakage rates.

- Field test new safety valve test procedures.

Four field visits were conducted to three MMS Gulf of Mexico Districts (New Orleans, Houma, and Lafayette) between March 23 and June 3, 1998. Tests were conducted on 73 certified and 73 non-certified SSVs for a total of 146 tests. In order to achieve a representative sample of SSVs in operation, valves were tested from 16 different operating companies in 28 different fields in the Gulf of Mexico.

Table 2 summarizes the failure rates for certified and non-certified SSVs with respect to the requirements specified in 30 CFR Chapter 11 (250.124) (0 SCFM), API 14C (15 SCFM), and hypothetical standard that allows up to 1 SCFM. Details of the field observations may be found in Topical Report No. 3, "Field Observations", which is included as Appendix C.

Of the 146 SSVs tested, seven certified and nine non-certified SSVs failed to meet the allowable leakage rate specified in 30 CFR Chapter 11 (250.124) (0 SCFM). Based upon the test results, 9.6% of the certified SSVs and 12.3% of the non-certified SSVs tested failed. Based upon statistics, there is a 95% chance that between 3.9% and 18.8% of all certified SSVs and between 5.8% and 22.1% of all non-certified SSVs will fail to meet these leakage requirements.

All 73 certified SSVs passed the leakage requirements specified in API 14C (15 SCFM). Of the 73 non-certified SSVs tested, three non-certified SSVs failed to meet the allowable leakage rate specified in API 14C. Based upon the test results, 0.0% of the certified SSVs and 4.1% of the non-certified SSVs tested failed. Based upon statistics, there is a 95% chance that between 0% and 4.0% of all certified SSVs and between 0.9% and 14.1% of all non-certified SSVs will fail to meet these leakage requirements.

Table 2. Failure rates for certified and non-certified surface safety valves.

Based upon the data collected, there is not a statistical difference between the failure rates of certified and non-certified surface safety valves.

		30 CFR 250		API 14C		1 SCFM	
	Tests	Failures	95% Confidence Interval (%)	Failures	95% Confidence Interval (%)	Failures	95% Confidence Interval (%)
Certified	73	7	3.9 - 18.8	0	0 - 4.0	3	0.3 - 9.6
Non-Certified	73	9	5.8 - 22.1	3	0.9 - 14.1	5	2.3 - 15.3

In addition to quantifying the failure rates with respect to the two previously mentioned standards, the failure rates were also quantified with respect to a hypothetical standard that would allow for up to 1 SCFM leakage. Of the 146 SSVs tested, two certified and five non-certified SSVs had a leakage rate greater than 1 SCFM. Based upon statistics, there is a 95% chance that between 0.3% and 9.6% of all certified SSVs and between 2.3% and 15.3% of all non certified SSVs will fail to meet these leakage requirements.

Even though there were fewer failures for the non-certified valves, there is not enough data to show that certified valves perform better than non-certified valves. The overlapping confidence intervals for the certified and non-certified valves show that there is no statistical difference between the two valve groups. More data could be collected to reduce the confidence intervals, but it is unlikely that enough data could be collected to show a statistical difference between the two groups. If it is assumed that the same failure rate would occur throughout future testing, more than 1000 valves of each type would have to be tested in order to reduce the confidence intervals enough to show a statistical difference.

During the field visits, many of the operating company personnel were interviewed to gain an understanding of the operators' concerns regarding SSV testing. The following is a summary of the questions asked and operators' responses.

What concerns do you have about safety valve leakage rates, testing frequency, and test procedures?

Most of the operators felt that the 30 CFR 250 requirement of zero leakage was too strict, and they felt that some leakage should be allowed. In general, they would not have any real concerns about hazards if the SSVs were allowed to leak no more than 1 SCFM; however, there was no sound technical basis for this leakage rate. All the personnel who were interviewed felt that the one-month testing frequency was appropriate.

What test procedures do you use to check safety valve leakage?

In general, all the operators used the same basic test procedure that was used in the study. Many operators test the flow safety valve and the surface safety valve at the same time. Only a few of the operators had any type of flow meter to accurately measure leakage rates.

What are the typical results of leakage tests currently being conducted by your perso n-nel?

Most of the operators stated that between 90% and 95% of their surface safety valves pass the leakage requirements specified in 30 CFR Chapter 11 (250.124).

What safety valve related problems do you encounter during leakage tests?

The major problems that the operators encountered that caused safety valve failures were high water producing wells, high temperature wells, and wells that produce paraffin and sand.

Based upon the results obtained during this field observation phase, it has been determined that there is no statistically significant difference in the proportion of failures between certified and non-certified surface safety valves. Other factors, such as valve maintenance, well conditions, and environmental conditions, may have a greater impact upon a particular valve's ability to meet the leakage requirements specified in 30 CFR Chapter 11 (250.124).

7 TASK NO. 4: VELOCITY-TYPE VALVES

Subsurface Safety Valves (SSSV) are required in all offshore producing oil and gas wells located in OCS waters that fall under the jurisdiction of the Minerals Management Service. The purpose of these valves is to shut off well flow in the production tubing below the mudline in the event of emergencies, such as a fire or production tubing separation. One type of SSSV that is used in offshore wells is actuated by a differential pressure created by the well fluid flow through the valve. These valves, called Subsurface-Controlled Safety Valves (SSCSV) or velocity valves, are sized or configured to close when the loss of tubing back pressure from a disaster causes the well to flow in excess of its normal production rates. Velocity valves are sized using programs developed by the valve manufacturers that predict the closing flow rates for a given valve configuration and well conditions. Concerns have been raised by MMS personnel about the accuracy of these sizing programs to size the appropriate valve for current well conditions and about the reliability of these valves after well conditions change. This study was conducted to address these concerns.

Testing was conducted on valves from two different SSSV manufacturers. Each valve was tested with 5 different choke and spring/spacer combinations. Specific details of the valve characteristics will not be provided in this report to protect the proprietary elements of the manufacturers' valve designs. Each configuration was tested with both single-phase and multiphase conditions with nitrogen and water as the test media. The single-phase tests were conducted by pressurizing the system and then increasing the gas flow rate slowly until the valve closed. For the multiphase tests, a water flow rate was established and then the gas flow rate was increased until the valve closed. For each test point, the water and gas flow rates, static pressure, temperature, and valve differential pressure were recorded.

The manufacturers' models were assessed by comparing the model predictions and the test closing points for each manufacturers' respective valves. For each test point, the modified models were exercised to obtain a predicted closing rate for each flowing condition. In multiphase flow, velocity valves close at an infinite combination of liquid and gas flow rates. The prediction error for the multiphase points was calculated separately for the liquid rate and the gas rates. Figure 2 illustrates how the errors were calculated.

The water flow rate error was calculated by determining the point on the prediction curve at that the gas flow rate matched the measured test gas flow rate and by then subtracting the measured water flow rate from the predicted water flow rate at that point on the curve. The gas flow rate error was calculated by determining the point on the prediction curve at that the water flow rate matched the measured test water flow rate and by then subtracting the measured gas flow rate from the predicted gas flow rate at that point on the curve.

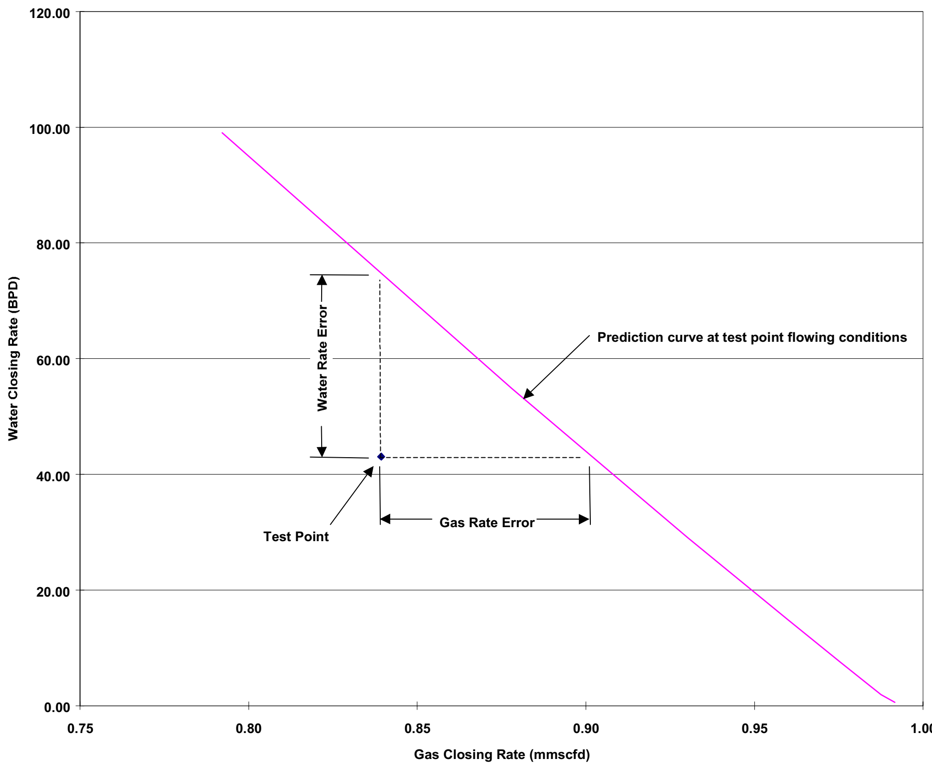

Figure 2. Illustration of the prediction error calculation on an example velocity valve prediction curve and test point.

This example shows that the model over-predicted the closing point.

For the single-phase test points, the error was calculated by simply subtracting the measured gas rate from the predicted gas rate. In this study, the errors were expressed as percentages by dividing the errors by the measured rates and multiplying by 100.

A summary of the test results are presented in Tables 3 and 4. These summary results show a good indication of the accuracy of each manufacturer's models in predicting the closing rates of their valves. A detailed discussion of the test facility, test procedure and test results may be found in Topical Report No. 4, "Velocity-Type Valves," that may be found in Appendix D.

Manufacturer A uses one model to predict the closing rates for both oil and gas wells. Manufacturer B uses one model for oil wells, that it defines as having gas-oil ratios less than 40,000 cubic feet per barrel, and another model for gas wells, that it defines as having gas-oil ratios greater than 10,000 cubic feet per barrel.

Table 3 shows the results for Manufacturer A's model and valve. The average predicted liquid error varied from –31.9 to 373.6%, and the average predicted gas error varied from –3.3 to 33.7%. Negative errors indicate that the model under-predicted the closing flow rates; the valve actually closed at rates greater than the predicted rates. From an operational and safety standpoint, these negative errors are more serious than positive errors. If a valve is sized with a model

Table 3. Summary of results for Manufacturer A's sizing model and velocity valve.
For the first and last two valve configurations, the manufacturer's model over-predicted the closing rates. For the second and third configurations, the manufacturer's model under-predicted the closing rates.

Choke/Spacer Configuration	Average Predicted Liquid Error (%)	Average Predicted Gas Error (%)	Number of Test Points
Choke A, Spacer C	177.7	19.1	10
Choke B, Spacer A	-11.7	-0.7	15
Choke B, Spacer B	-31.9	-3.3	19
Choke B, Spacer C	243.7	24.5	13
Choke C, Spacer A	373.6	33.7	9

that under-predicts the closing flow rates, the installed valve may not close because the well may not be capable of flowing enough fluid to close the valve.

Table 4 shows the results for Manufacturer B's model and valve. The errors are all negative, indicating that the model under-predicted the valve closing rates. The liquid errors for both the oil and gas well programs are -100%. This is because the gas flow rate of the test points were higher than the highest gas rate that the model predicted, that was with no water flow. When the errors were calculated as described in the previous section, the predicted water rate for each test point was zero, so the errors were -100%. See Figure 3 for an illustration. The gas flow rate errors were fairly consistent, varying between 23.3% and –28.0% for both the oil and gas well programs. The errors between the gas and oil well programs showed little significant difference.

The SSCSV sizing procedure recommended in API Recommended Practice *14B (Design, Installation, Repair and Operation of Subsurface Safety Valve Systems*) can be used to put the magnitude of these errors into perspective. In section 4.4, 14B recommends that velocity valve "closure rates should be no greater than 150 percent but no less than 110 percent of the well test rate." If a midpoint closure rate were selected of 130 percent, a ±20 percent window is left to remain within the recommendation. Many of the sizing errors shown in these tests would cause the valves to fall outside the 14B recommendation (see Figure 4).

Table 4. Summary of results for Manufacturer B's sizing model and velocity valve.
For all five valve configurations, the manufacturer's model under-predicted the closing rates.

	Oil Well Program		Gas Well Program		
Choke/Spacer Configuration	Average Predicted Liquid Error (%)	Average Predicted Gas Error (%)	Average Predicted Liquid Error (%)	Average Predicted Gas Error (%)	Number of Test Points
Choke A, Spacer A	-100*	-25.4	-100*	-23.7	18
Choke A, Spacer B	-100*	-27.4	-100*	-28.3	19
Choke A, Spacer C	-100*	-25.2	-100*	-25.2	30
Choke B, Spacer A	-100*	-23.3	-100*	-26.0	18
Choke B, Spacer B	-100*	-24.4	-100*	-28.0	22

* Note: The –100% errors for the water indicate that the model did not predict any water flow at each test point's corresponding gas rate. See Figure 3 for an illustration.

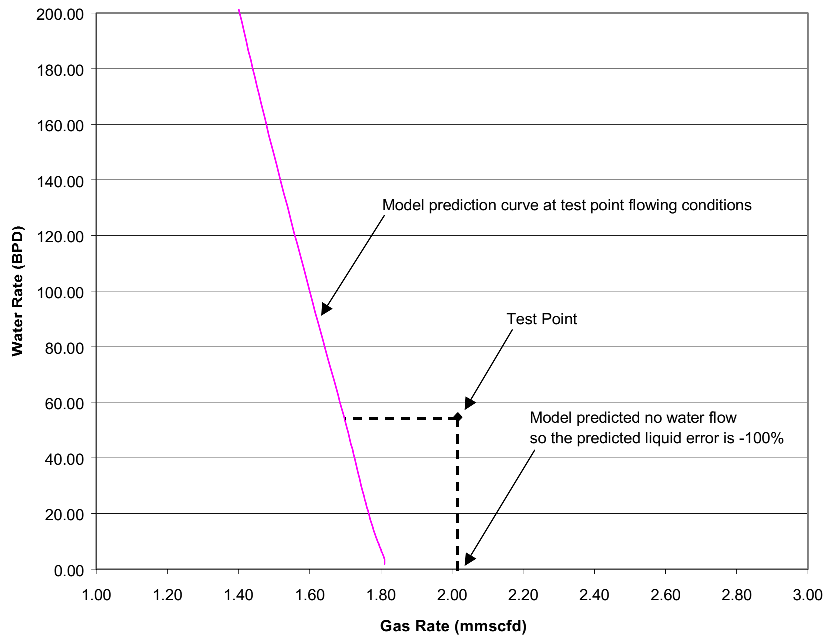

Figure 3. Example illustrating how the -100% liquid errors were calculated for Manufacturer B's results.

The gas flow rate of the test point was higher than the highest gas rate that the model predicted, that was with no water flow. When the error was calculated as described in the previous section, the predicted water rate for each test point was zero, so the e rrors were -100%.

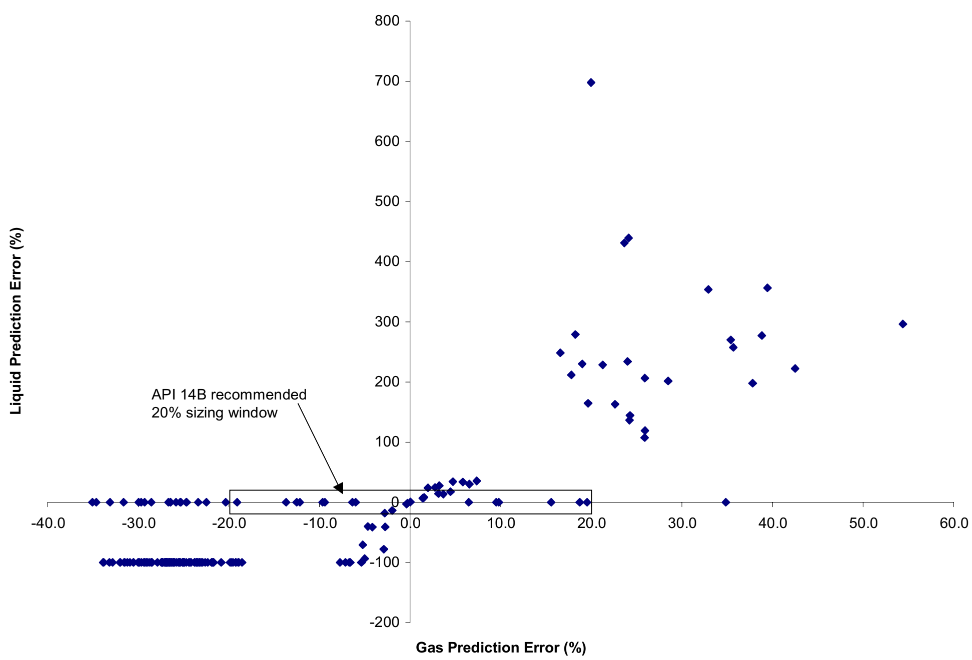

Figure 4. Plot of the percent error for each test point.

The ±20% sizing window recommended by API 14B is indicated inside the boxed area. Most of the test points fall outside this wi ndow.

In addition, actual sizing model errors can be expected to be higher than the errors shown in these results. These results only show the inaccuracy of the correlations used to calculate the valve closing differential pressure and calculate the multiphase pressure drop across the valve choke. The fluid (nitrogen and water) properties are known, and the flowing static pressure and temperature at the valve are measured. In real applications of these models, additional errors would be introduced because fluid composition and properties are not known precisely, and the flowing static pressure and temperature are estimated from the conditions at the well head and the desired closing flow rate.

One other result that can be gathered from the test data is an indication of valve repeatability. Valve repeatability is the ability of the valve to consistently close at approximately the same flow rates for a given set of flowing conditions. The closing differential pressure for each valve configuration is primarily a function of the choke size and spring/spacer combination. For this testing, the differential pressure was measured across the valve. Since, in subcritical flow, the differential pressure is proportional to the flow rate, the differential pressure measured when the valves close is a good indication of the valve repeatability. Tables 5 and 6 show the coefficient of variation of the closing differential pressures for all the tested valve configurations. The coefficient of variation is the ratio of the standard deviation of the measured closing differential pressure to the mean of the measured closing differential pressure expressed as a percentage; this dimensionless value gives an indication of the amount of variation of the valve closings.

Table 5. Manufacturer A's valve closing repeatability.

(The coefficient of variation is the ratio of the standard deviation to the mean of the measured closing differential pressures.)

Valve configuration	Coefficient of variation for the measured closing differential pressures (%)
Choke A, Spacer C	1.96
Choke B, Spacer A	3.10
Choke B, Spacer B	3.96
Choke B, Spacer C	4.56
Choke C, Spacer A	4.83

Table 6. Manufacturer B's valve closing repeatability.

(The coefficient of variation is the ratio of the standard deviation to the mean of the measured closing differential pressures.)

Valve configuration	Coefficient of variation for the measured closing differential pressures (%)
Choke A, Spacer A	8.89
Choke A, Spacer B	5.89
Choke A, Spacer C	7.14
Choke B, Spacer A	9.59
Choke B, Spacer B	9.32

Manufacturer A's valve showed less variation than Manufacturer B's valve, with coefficients of variation ranging from 1.96 to 4.83% compared to 5.89 to 9.59% for Manufacturer B's valve. Since the differential pressure is proportional to the flow rate, these results indicate that the closing flow rates would vary by approximately these same percentages. The magnitude of these variations in repeatability does not seem too large; however, when these variations are combined with the errors associated with predicting the closing rates, the overall error is substantial.

The findings of this study indicate that MMS's concerns about the validity of the current sizing models are justified. In order for MMS to have confidence that velocity valves installed in oil and gas wells in OCS waters will provide adequate protection, a number of options exist. The options identified include:

- Update existing manufacturers' models or develop new models
- Test each velocity valve in the lab before it is installed
- Test each velocity valve periodically in the well
- Terminate the use of velocity valves

Update Existing Models or Developing New Models

The literature search conducted for this study showed that there are no currently available correlations that would accurately predict the multiphase pressure drop in velocity valves. Currently available empirical correlations predicting the multiphase flow pressure drop through chokes were developed for a specific valve size and geometry, and a relatively small range of multiphase flow patterns. Extensive experimental data would be required to validate (or redevelop) the correlations for different size chokes, different valve geometries, and a wider range of multiphase flow patterns.

Currently available theoretical correlations predicting the multiphase flow pressure drop through chokes were developed for relatively small-diameter chokes, where the pressure drop is dominated by the acceleration of the fluids through the choke. These correlations are not applicable for the range of choke sizes typically found in velocity valves. Extensive experimental data would be required to develop theoretical correlations to predict the multiphase flow pressure drop through chokes in velocity valves.

Even if an accurate model could be developed to predict the flow rate at that velocity valves close, sizing models still may prove to be inaccurate. Accuracy would be limited by the quality of the model inputs. Existing correlations to estimate the well in-flow performance, downhole flowing temperature and pressure, and solution gas-oil ratio all contain inaccuracies. The sizing model would only be as good as the combined errors of these correlations. In addition, the repeatability of the velocity valve would add additional uncertainty. At this point, updating existing valve closure models or developing new models does not appear to be a practical solution because the developed sizing model is likely to still have errors in excess of ±40%.

Test Each Velocity Valve in the Lab

Manufacturers' existing models could be utilized to select a velocity valve size and preliminary configuration (choke and spacer set). The valve could then be tested in the lab to determine the actual flow rates at that the valve closes. Once this information is obtained, the valve could then be installed in the oil and gas well with the confidence that the closure flow rates are known with a little more accuracy. Unfortunately, unless real fluids are used (not nitrogen and water) at the pressures and temperatures expected at the location the valve will be installed, additional uncertainties will arise. Testing each valve in the lab would be expensive and would add additional delivery time to a product that may be needed on short notice.

With this method, each valve would be tested for the current well conditions in that the valve is to be installed. The method would not address the problem of changing well conditions unless the valve was retested periodically with the new well conditions to either ensure that the current valve configuration is appropriate or to resize the valve for the new conditions. This problem could be addressed by testing the valves with a number of configurations to provide a family of closing curves that could be used to size the valve for any well conditions. This may be cost-prohibitive because each valve would have to be tested with several bean and spring/spacer configurations with a number of different flowing conditions. At this point, lab testing each velocity valve to obtain proper valve sizing does not appear to be a cost-effective solution.

Test Each Velocity Valve in the Well

Manufacturers' existing models could be utilized to select a velocity valve size and preliminary configuration (choke and spacer set). The valve could then be tested in the well to determine the actual flow rates at that the valve closes. Unfortunately, this option would also be extremely expensive and inconvenient since additional equipment may have to be available on the platform to handle the increased production rate. In addition to the inconvenience and cost, allowing the well to flow at such high flow rates could be dangerous and possibly cause damage to the reservoir. Testing each velocity valve in the well does not appear to be a safe, practical, or cost-effective solution.

Terminate the Use of Velocity Valves

Unless MMS can have some confidence that the velocity valves installed in oil and gas wells will close at the desired flow rates, they may be required to terminate the use of these valves in OCS waters. At this point, only one velocity valve, from two different valve manufacturers, has been tested. It would be inappropriate to terminate the use of velocity valves based on this limited test data. Additional testing should be conducted to fully assess the accuracy of the current sizing models. Further testing should include several different valve sizes and models from each manufacturer, as well as numerous choke and spacer combinations for each valve. If the results are similar to those found in this study, terminating the use of velocity valves in OCS waters should be considered.

Recommendation

The results and conclusions drawn from this study indicate that MMS's concerns about velocity valve sizing may be valid. At this point, it does not appear that updating or developing new models, lab testing, or field testing are cost-effective or practical solutions to address these concerns. Because only two valves were tested in this study, the results are not conclusive, and it is not appropriate to make a decision about whether to terminate the use of velocity valves in OCS waters. Further testing should be conducted to gain enough information to make a clear judgment about the continued use of velocity valves.

Testing should include several different valve models from all the manufacturers that sell valves for use in the Gulf of Mexico. Each valve should be tested with a number of different bean and spring/spacer combinations with a number of different flowing conditions. Sufficient results could be gained by testing with nitrogen and water as the test fluids. Nitrogen and water should give a less stringent test than with real production fluids. If the manufacturer's sizing models show significant errors with the nitrogen and water tests, then it can reasonably be assumed that results for real production fluid testing would be worse. In this case, no further testing would be required. If the nitrogen and water tests are not conclusive, then further testing with real production fluids may be required. The expected result from this more extensive testing should be enough information to confidently make a clear judgment about whether to terminate the use of velocity valves in OCS waters.

8 TASK NO. 5: ESTABLISH RISKS

Within the areas of OCS waters where offshore oil and gas production platforms fall under the jurisdiction of the Minerals Management Service, each production string must be equipped with a subsurface safety valve (SSSV). In addition, each well head must be equipped with a surface safety valve (SSV). These valves are designed to close automatically when certain types of accidents occur, thereby stopping the flow of produced fluids. They can also be manually closed for accident prevention or maintenance operations. Ideally, there should be no fluid flowing through a closed SSV or SSSV. However, these valves are not always 100% effective in preventing the flow of produced fluids.

The objective of this task was to provide a technical basis for the selection of appropriate leakage rates for SSVs and SSSVs, especially comparing the leakage rates recommended by API and allowed by 30 CFR 250. The study accomplished this by:

- Computing the extent and gravity of hazards that could be posed to the environment, equipment, and personnel as a result of continued leakage of oil or gas through closed SSVs and SSSVs.

- Illustrating how the through-valve leakage rate could affect the extent and severity of these hazards.

The following hazards were considered in the study.

For gas releases:

- Toxic hazards (inhalation of gas containing hydrogen sulfide)
- Flash fire hazards (personnel burns from ignited flammable clouds)
- Torch fire hazards (damage to equipment and personnel from ignited vapor jet releases)
- Vapor cloud explosion hazards (damage to equipment and personnel from overpressures generated by the explosion of a flammable vapor cloud)
- Environmental impact (damage to the environment from natural gas releases)

For liquid releases:

- Flash fire hazards (personnel burns from ignited flammable clouds)
- Pool fire hazards (damage to equipment and personnel from heat radiating from ignited liquid pools)
- Vapor cloud explosion hazards (damage to equipment and personnel from overpressures generated by the explosion of a flammable vapor cloud)
- Environmental impact (damage to the environment from hydrocarbon liquid releases)

A summary of the results of the analysis is included below. The full report detailing the analysis and results may be found in Topical Report No. 5, "Establish Risks," and is included as Appendix E.

8.1 Gas Leakage

The rate at that gas is leaking through a closed SSSV is of concern only for accidents that involve a failure of the production tubing between the SSSV and the SSV. When considering personnel safety, such a leak is of primary concern if the gas is released into a working space on the platform. For equipment, any release that occurs above sea level could be of concern.

The rate at that gas is leaking through a closed SSV is of concern only for accidents that involve a failure of piping or production equipment downstream of the SSV. All such leaks are expected to release gas into the workspace on the platform. As a result, all such releases may be of concern to personnel and equipment.

Regardless of the type of hazard (fire, toxic, or environmental), the effects of the accident that triggers closing of the safety valves are likely to exceed the hazards posed by a 15 SCFM (API) release of gas through a closed SSSV or SSV.

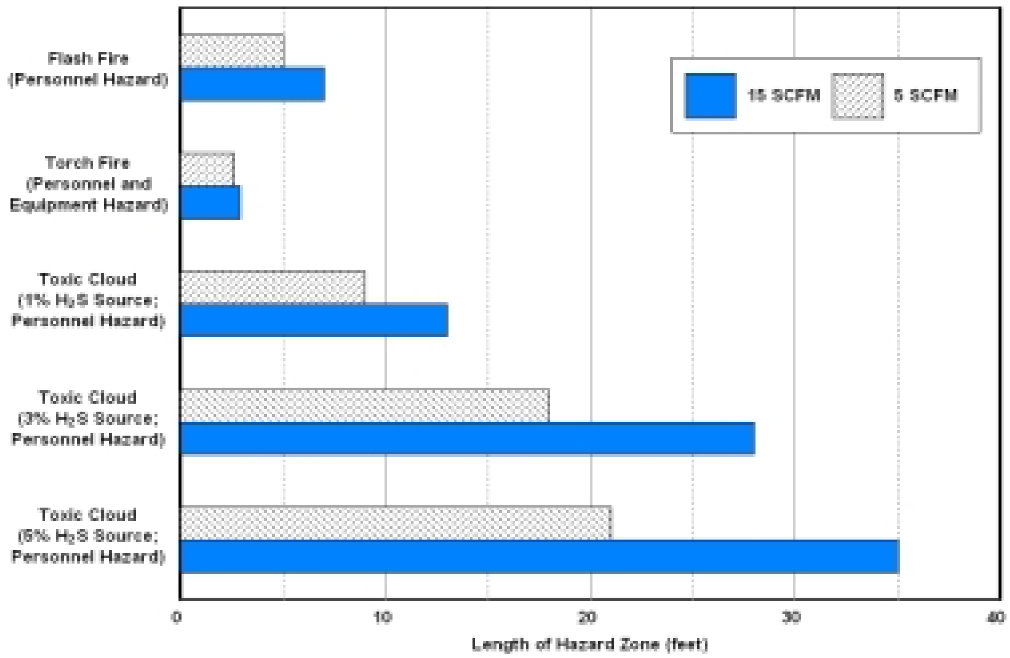

Figure 5. Comparison of flash fire, torch fire, and toxic hazard zones for gas releases of 5 SCFM and 15 SCFM.

8.1.1 Fire Hazard Zones

The flash fire and torch fire hazard zones for the leakage rates of interest for SSSVs, 5 SCFM (MMS) and 15 SCFM (API), are compared to one another in Figure 5. For both types of fire hazards, the hazard zones are short (less than 10 feet in length) and are only weakly affected by an increase in leakage (release) rate.

In contrast, the lengths of fire hazard zones associated with a gas release at the maximum SSV leakage rate allowed by the MMS should be zero, since MMS regulations do not allow any gas leakage through a closed SSV. However, even after the SSV is closed, gas might continue to be released into the environment until such time as the gas inventory in piping or process equipment has been depleted. Thus, fire hazard zones can exist after the SSV is closed, even if no gas is passing through the SSV. In most cases, the fire hazard zones created by a continuing release of gas inventory could exceed the fire hazard zones associated with a release of gas at 15 SCFM. In addition, the effects of the accident that triggers closing of the safety valves are likely to exceed the hazards posed by a 15 SCFM release of gas through a closed SSV. Therefore, it could be argued that the MMS requirement of zero gas leakage through a closed SSV does not necessarily provide a significant increase in safety.

Based on this analysis, it would be difficult to use these fire hazard zones as a basis for selecting one maximum allowable leakage rate in preference to the other for either SSVs or SSSVs.

8.1.2 Toxic Hazard Zones

The toxic hazard zones for the leakage rates of interest for SSSVs, 5 SCFM (MMS) and 15 SCFM (API), are compared to one another in Figure 5. Since there is no toxic hazard when there is no leakage, the toxic hazard zones for the leakage rates of interest for SSVs, 0 SCFM (MMS) and 15 SCFM (API), are also compared in Figure 5. The figure illustrates how the percentage difference between the toxic hazard zones produced by 5 SCFM (MMS) and 15 SCFM (API) is relatively unaffected by the amount of H_2S in the gas being released, but the absolute difference increases as the amount of H_2S in the source increases. Thus, the relative importance of the difference in maximum allowable leakage rate increases as the mole % of H_2S in the gas increases.

Personnel who work on platforms that produce gas that contains H_2S, or who would respond following an accident on such a platform, are aware of the dangers of H_2S and would have appropriate personal protective equipment (such as self-contained breathing apparatus - SCBAs) available to them. They would be expected to properly employ this equipment before approaching the point of release, even if they believe the release has been stopped. Thus, the presence or absence of a toxic vapor cloud would make little difference in how personnel would respond to the accident. Once protected by appropriate personal protective equipment, the presence of a vapor cloud containing H_2S resulting from a leaking SSV of SSSV would not significantly affect personnel safety.

8.1.3 Vapor Cloud Explosions

For the leakage rates of interest for SSVs and SSSVs, 15 SCFM or less, the amount of flammable gas within a flammable vapor cloud will be so small that vapor cloud explosions are not considered a credible occurrence.

8.1.4 Environmental Impact

For the leakage rates of interest for SSVs and SSSVs, a release of natural gas at 15 SCFM or less is expected to have a negligible environmental impact, even if the release continues for several hours. If the leakage continues for several days, it may become a concern.

8.2 Liquid Leakage

The rate at that hydrocarbon liquid is leaking through a closed SSSV or SSV is of concern to personnel and equipment only if the liquid is released into a drip tray or onto a solid deck where it can form a pool. The environmental impact is expected to be nearly independent of the location of the release, assuming the liquid ultimately reaches the water. Regardless of the type of hazard (fire or environmental), the effects of the accident that triggers closing of the safety valves are likely to exceed the hazards posed by a 400 cc/min (API) release of liquid through a closed SSV or SSSV.

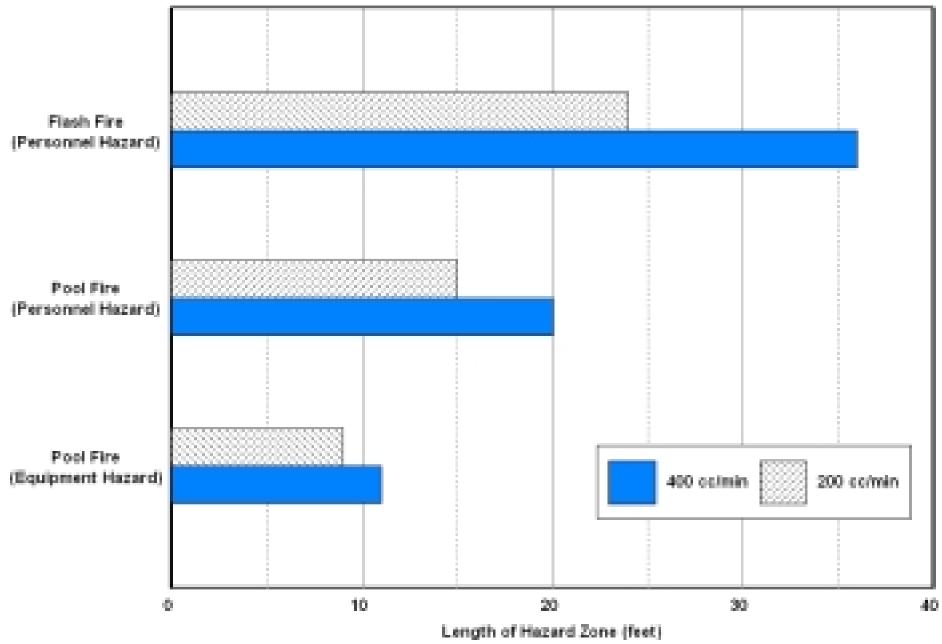

Figure 6. Comparison of flash fire and pool fire hazard zones for liquid releases of 200 cc/min and 400 cc/min, based on spills of 60-minute duration prior to ignition.

8.2.1 Fire Hazard Zones

The flash fire and pool fire hazard zones for the leakage rates of interest for SSSVs, 200 cc/min (MMS) and 400 cc/min (API), are compared to one another in Figure 6. Since there is no flash fire and pool fire hazard when there is no leakage, the toxic hazard zones for the leakage rates of interest for SSVs, 0 cc/min (MMS) and 400 cc/min (API), are also compared in Figure 6. The fire hazard zone lengths illustrated in Figure 6 are all based on the assumption that the release continues for 60 minutes before the flammable vapor cloud or the liquid pool is ignited. If ignition occurs earlier, the hazard zone lengths would be shorter. Figure 6 shows that the hazard zones associated with flash fires and pool fires are only weakly affected by an increase in leakage (release) rate (i.e., doubling the release rate from 200 to 400 cc/min causes the flash fire hazard zone length to increase by only 50%, and the effect on the length of the pool fire hazard zones is even less).

According to MMS statistics, there are approximately 3900 active offshore platforms in the Gulf of Mexico, and approximately 3300 producing oil wells. During the 10-year period from 1981 through 1990, the MMS recorded 329 spills of more than 1 bbl of liquid pollutants in the Gulf of Mexico Region—an average of 33 spills per year. These spills included releases of diesel fuel and other liquid pollutants, in addition to releases of crude oil and condensate. They also included releases from sources other than offshore platforms, such as pipelines and workboats. Thus, the annual number of accidents that release crude oil or condensate into the workspace of a platform, and that allow formation of a liquid pool in a drip tray or on a solid deck, is expected to be much smaller than 33—the average number of liquid releases of 1 bbl or more per year.

There is a low probability of occurrence of accidents in that liquid leakage through an SSSV or SSV might be an important factor, and a high probability that the effects of the accident that triggers closing of the safety valves will exceed the hazards posed by a 400 cc/min (API) release of liquid through a closed safety valve. Therefore, it could be argued that the MMS requirement of zero liquid leakage through a closed SSV does not necessarily provide a significant increase in safety.

Based on the low probability of accidents in that liquid leakage rate through a closed safety valve might be an important factor, and the weak influence of leakage rate on fire hazard zone length, it would be difficult to use fire hazard zones as a basis for selecting one maximum allowable leakage rate in preference to the other for either SSVs or SSSVs.

8.2.2 Vapor Cloud Explosions

For the leakage rates of interest for SSVs and SSSVs, 400 cc/min or less, the amount of flammable gas within a flammable vapor cloud will be so small that vapor cloud explosions are not considered a credible occurrence.

8.2.3 Environmental Impact

Unlike the flash fire and pool fire hazard zones, the environmental impact is directly related to the release rate (i.e., for a release of given duration, doubling the allowable leakage rate from 200 to 400 cc/min results in twice as much liquid entering the water). Thus, the difference between 0 cc/min (MMS for SSVs), 200 cc/min (MMS for SSSVs), and 400 cc/min (API) appears to be significant. However, MMS records show that 42,534 bbl of liquid pollutants were released into the Gulf of Mexico during the 10-year period from 1981 through 1990, as a result of accidents involving offshore platforms, associated pipelines, workboats, etc. This is an average of 4253 bbl per year. Thus, when compared to the amount of hydrocarbon liquid that could be released as a result of the accident that triggers closing of the safety valves, or from other sources that are present in the Gulf, it is difficult to argue that a limited duration release of liquid hydrocarbon at 400 cc/min is a significant source of pollution.

Leakage of oil or gas through a closed SSSV or SSV can result in oil or gas being released into the environment only if some piece of equipment (such as a pipe, gasket, pump body, vessel, etc.) has failed in such a way that oil or gas has already been released into the environment. The hazard zones and environmental impact of oil and gas releases associated with releases at the maximum allowable leakage rates specified by the MMS are smaller than those associated with releases at rates allowed by the API. However, if the leakage rates through closed safety valves are limited to the maximum allowable leakage rates specified by either the MMS or the API, the fire, toxic, and environmental hazards associated with the accident that triggers closing of the safety valves are likely to exceed the hazards posed by the low-rate release of gas or liquid through a closed safety valve. Thus, differences between the hazards posed by releases of oil or gas at rates allowed by the MMS or at the higher rates allowed by the API are likely to be overshadowed by the hazards associated with the accident that occurred prior to closing the safety valves.

9 TASK NO. 6: RECOMMENDATIONS

The objectives of this task were to develop recommendations, based on the efforts completed during this project, for:

- Safety valve allowable leakage rates
- Test procedures (for both SSVs and SSSVs)

Based on the study conducted in Task No. 5, there appears to be preliminary evidence indicating that the more stringent leakage requirements specified in 30 CFR 250 may not significantly increase the level of safety when compared to the leakage rates recommended by API. However, a complete hazards analysis should be conducted, and industry safety experts should be consulted. As a minimum, the analysis should include:

- A study to determine whether a small leak through an SSV or SSSV is likely to further damage the valve and lead to a much larger leak and, if so, over what time frame.
- A study to determine what the risk is to shut-in a well to replace a leaking SSV or SSSV. (Is there a higher risk involved in remediation than allowing a slight safety valve leak?)
- A detailed cost-benefit analysis, that would likely include an analysis of the cost to maintain the equipment with various levels of allowable leakage rates.
- A detailed risk analysis conducted by personnel knowledgeable in the daily operations on an oil and gas production platform in the Gulf of Mexico.

Details of this task may be found in Topical Report No. 6, "Recommendations," that can be found in Appendix F.

According to 30 CFR Chapter 11 (250.124), operators are required to "test each SSV for operation and leakage once each calendar month, but at no time shall more than 6 weeks elapse between tests." In addition, SSSVs "shall be tested in place for proper operation when installed or reinstalled and thereafter at intervals not exceeding 6 months." In order for these tests to be consistent between various operators and MMS inspectors, it is important to adopt a test procedure by that all testing is performed.

During the "Field Observation" phase of this project, 146 surface safety valves (SSVs) and 9 surface-controlled subsurface safety valves (SCSSVs) were tested for operation and leakage. To ensure that the leakage data collected was not affected by the test method, test procedures were developed and followed during each valve test. The test procedures consisted of closing the valve to be tested, isolating and venting the downstream piping, and measuring the

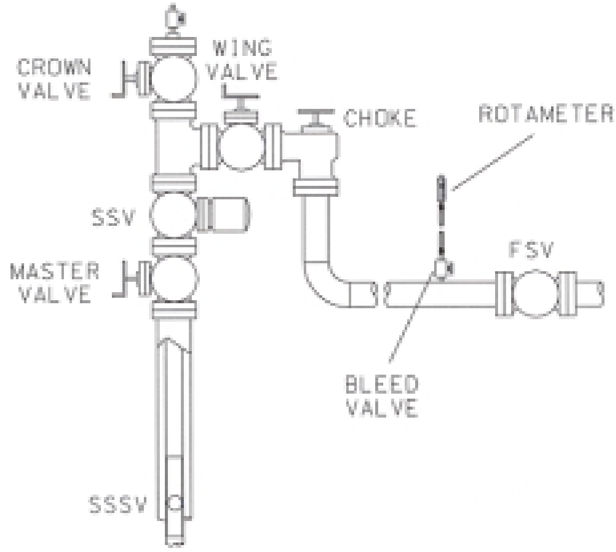

Figure 7. Leakage rate measurement equipment.

Based upon the bias error introduced by the unknown gas temperature and specific gravity, the actual flow rate can be measured to within approximately ±15%, if the temperature of the gas is between 30°F and 110°F, and the specific gravity is b etween 0.6 and 0.9.

leakage rate using a commercially available variable area gas flow meter (rotameter). A copy of the test procedures for both SSVs and SCSSVs may be found in Appendix F.

In general, most of the operators responsible for the routine testing of the safety valves on a platform used the same basic test procedure that was used during the Field Observation phase. However, most operators and MMS inspectors used audible techniques to "measure" leakage rates. Only a few of the operators had any type of flow meter to accurately measure the leakage rates. Figure 7 shows a schematic of the leakage rate measurement equipment, that was used during the field testing, as it would be connected during a test.

The rotameter, used to quantify the leakage rates, proved to be extremely useful and well accepted by both the MMS inspectors involved in the field testing and the operators. Table 7 lists the equipment used for measuring the leakage rate, including the model number and approximate cost of each component.

Table 7. Equipment used for measuring the leakage rate.

Item	Quantity	Manufacturer	Model No.	Cost
Rotameter	1	Cole-Parmer	H-03279-56	$38
Hose Barb	2	Grainger	6X411	$2
Plastic Hose	2-ft	Ryan Herco	0001-135	$4
Hose Clamp	2	Ryan Herco	0950-006	$3

10 CONCLUSIONS

Based upon discussions with MMS personnel, SwRI personnel, and API committee members, the general conclusion is that there have not been any scientific studies to conclusively provide justification for leakage rates or testing frequencies. All of these individuals have been involved over a portion of the last 20 years, in some way, on the various committees that have set the leakage rates to be included in either the MMS rules or API recommendations.

Based upon the results of the questionnaire, it is apparent that there was no single test procedure that all MMS inspectors follow when testing SSVs and SSSVs. The results also show that a standard test procedure would be desirable.

Based upon the results obtained during this field observation phase, it has been determined that there is no statistically significant difference in the proportion of failures between certified and non-certified surface safety valves. Other factors, such as valve maintenance, well conditions, and environmental conditions, may have a greater impact upon a particular valve's ability to meet the leakage requirements specified in 30 CFR Chapter 11 (250.124).

The results and conclusions drawn from this study indicate that MMS's concerns about velocity valve sizing may be valid. At this point, it does not appear that updating or developing new models, lab testing, or field testing are cost-effective or practical solutions to address these concerns. Because only two valves were tested in this study, the results are not conclusive, and it is not appropriate to make a decision about whether to terminate the use of velocity valves in OCS waters. Further testing should be conducted to gain enough information to make a clear judgment about the continued use of velocity valves.

Testing should include several different valve models from all the manufacturers that sell valves for use in OCS waters. Each valve should be tested with a number of different bean and spring/spacer combinations with a number of different flowing conditions. Sufficient results could be gained by testing with nitrogen and water as the test fluids. Nitrogen and water should give a less stringent test than with real production fluids. If the manufacturer's sizing models show significant errors with the nitrogen and water tests, then it can reasonably assumed that results for real production fluid testing would be worse. In this case, no further testing would be required. If the nitrogen and water tests are not conclusive, then further testing with real production fluids may be required. The expected result from this more extensive testing should be enough information to confidently make a clear judgment about whether to terminate the use of velocity valves in OCS waters.

Leakage of oil or gas through a closed SSSV or SSV can result in oil or gas being released into the environment only if some piece of equipment (such as a pipe, gasket, pump body, vessel, etc.) has failed in such a way that oil or gas has already been released into the environment. The hazard zones and environmental impact of oil and gas releases associated with releases at the maximum allowable leakage rates specified by the MMS are smaller than those associated with releases at rates allowed by the API. However, if the leakage rates through closed safety valves are limited to the maximum allowable leakage rates specified by either the MMS or the API, the fire, toxic, and environmental hazards associated with the accident that triggers closing of the safety valves are likely to exceed the hazards posed by the low-rate release of gas or liquid through a closed safety valve. Thus, differences between the hazards posed by releases of oil or gas at rates allowed by the MMS or at the higher rates allowed by the API are likely to be overshadowed by the hazards associated with the accident that occurred prior to closing the safety valves.

Based on the study conducted in Task No. 5, there appears to be preliminary evidence indicating that the more stringent leakage requirements specified in 30 CFR 250 may not significantly increase the level of safety when compared to the leakage rates recommended by API. However, a complete hazards analysis should be conducted, and industry safety experts should be consulted. As a minimum, the analysis should include:

- A study to determine whether a small leak through an SSV or SSSV is likely to further damage the valve and lead to a much larger leak and, if so, over what time frame.

- A study to determine what the risk is to shut-in a well to replace a leaking SSV or SSSV. (Is there a higher risk involved in remediation than allowing a slight safety valve leak?)

- A detailed cost-benefit analysis, that would likely include an analysis of the cost to maintain the equipment with various levels of allowable leakage rates.

- A detailed risk analysis conducted by personnel knowledgeable in the daily operations on an oil and gas production platform in OCS waters.

Regardless of what through-valve leakage is allowed by MMS, a standardized test procedure, such as the one recommended in this study, should be adopted by all operators and MMS inspectors. This test procedure should include a means for measuring the leakage rate.

APPENDIX A

Topical Report 1
Current Leakage Rate Criteria

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TOPICAL REPORT NO. 1
CURRENT LEAKAGE RATE CRITERIA

Introduction

The objective of this task was to identify and compare the decision criteria behind the various allowable leakage rates and testing frequencies identified in the U.S. National Standards in order to identify the justification of the allowable leakage rates and testing frequency. This was accomplished by reviewing the U.S. National Standards and by speaking with personnel from the American Petroleum Institute (API), the Minerals Management Service (MMS), and various members of the committees that developed these standards. In addition, similar studies being conducted in other countries were identified.

Current U.S. National Standards

Copies of all U.S. National Standards which pertain to surface safety valves (SSV) and subsurface safety valves (SSSV) were reviewed. A brief summary of each standard is provided below.

- *API 14A: Specifications for Subsurface Safety Valve Equipment. Ninth Edition, December 1994.*

  API 14A provides the minimum acceptable requirements for subsurface safety valve (SSSV) equipment. Of interest to this study are the acceptable leakage rates for qualification testing. These rates are 10 cc/min liquid and 5 standard cubic feet/min (SCFM) gas.

- *API RP 14B: Design, Installation, Repair and Operation of Subsurface Safety Valve Systems. Fourth Edition, July 1994.*

  API RP 14B provides design, installation, repair, and operation recommendations for both surface controlled subsurface safety valve (SCSSV) and subsurface controlled subsurface safety valve (SSCSV) systems. Of interest to this study are the sizing procedures for velocity type SSCSV's and the guidelines for testing SCSSV's. The sizing procedure gives a brief outline of the important parameters and calculations that need to be considered but does not give any specifics about how the calculations should be performed. The testing guidelines provide a basic field test procedure and explain what should be measured. The details of how these measurements should be performed are not discussed. The guidelines give a recommended test frequency of six months and an allowable leakage rate of 400 cc/min liquid and 15 SCFM gas. The document states that the testing of SSCSV's in the well is not recommended; however, these valves should be inspected at least every year.

- *API RP 14C: Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms. Fifth Edition, March 1994.*

This standard outlines API's recommendations for the design, installation, and testing of the surface safety systems on offshore production platforms. Of interest to this study are the recommended testing guidelines for SSV's and underwater safety valves (USV). These guidelines provide operation and leakage testing procedures and state a recommended maximum allowable leakage rate of 400 cc/min liquid and 15 SCFM gas.

- *API 14D: Specifications for Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service. Ninth Edition, June 1994. API 6AV1 : Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service. First Edition, June 1995.*

  The purpose of these specifications is to establish requirements for the verification of performance of wellhead SSV's and USV's. Of interest to this study are the qualification testing guidelines for SSV's and USV's and the requirement for zero leakage of both liquid and gas.

- *API RP 14H: Use of Surface Safety Valves and Underwater Safety Valves Offshore. Fourth Edition, July 1994.*

  The purpose of API RP 14H is to provide guidance for inspecting, installing, operating, maintaining and testing SSV's and USV's. Of interest to this study are the recommended field testing procedures for these valves. The document provides the same guidelines for SSV's and USV's testing that are contained in RP 14C. The acceptable leakage rates for field testing of both valve types are 400 cc/min liquid and 15 SCFM gas.

- *CFR Chapter 11 (250.121-250.124): Subsurface Safety Devices. 1996.*

  These regulations are concerned with oil and gas production safety systems. Of interest to this study are the testing requirements for SSSV's, SSV's, and USV's. These regulations state that the SSSV's should be tested according to API RP 14B with a testing interval of no more than six months and a maximum leakage rate of 200 cc/min liquid and 5 SCFM gas. For SSV's and USV's, testing should be performed according to API RP 14H with a test interval of once per calendar month but no more than 6 weeks and no allowable fluid leakage.

- *OCS Order 5: Production Safety Systems. 1980. (Has been changed to 30 CFR Chapter 11 (250.804), 1998.)*

  This document concerning production safety systems in the Gulf of Mexico region is a product of the U.S. Geological Survey. This Order is a supplement to the 30 CFR 250 regulations regarding production safety systems. The document further addresses the testing requirements of SSSV's, USV's, and SSV's but maintains the same regulations regarding leakage rates and test frequencies. The document provides the following information: Testing of surface-controlled SSSV's should be performed at intervals not exceeding 6 months. No maximum leakage rate is specified. Subsurface-controlled safety valves should be removed, inspected, and repaired or replaced, if necessary, at intervals not exceeding 6 months for valves without landing nipples and 12 months for valves with landing nipples.

SSV's and USV's should be tested each calendar month, or not exceeding six weeks with no allowable fluid leakage.

Table 1 provides a summary of the allowable leakage rate, testing frequency, and application for each specification.

Table 1. Specifications for Allowable Leakage Rates and Testing Frequency

Standard Reference	Application	Allowable Leakage Rates		Test Frequency
		Liquid (cc/min)	Gas (SCFM)	
Subsurface Safety Valves				
API 14A, Ninth Addition, 1994	Qualification	10	5	NA
API 14B, Fourth Addition, 1994	Field	400	15	6 months
30 CFR Chapter 11 (250.124), 1996	Field	200	5	6 months
OCS Order 5, 1980	Field	NA	NA	6 months
Surface and Underwater Safety Valves				
API 14C,1994	Field	400	15	At least annually
API 14D,1994	Qualification	0	0	NA
API 14H,1994	Field	400	15	NA
30 CFR Chapter 11 (250.124), 1996	Field	0	0	Each month or 6 wks
OCS Order 5, 1980	Field	0	0	Each month or 6 wks

Decision Criteria for Current U.S. National Standards

After discussions with MMS personnel, SwRI personnel, and API committee members, the general conclusion is that there have not been any scientific studies to conclusively provide justification for leakage rates or testing frequencies. All of these individuals have been involved, over a portion of the last 20 years, in some way on the various committees that have set the leakage rates to be included in either the MMS rules or API recommendations. More details about these discussions are provided below.

During the 1980s, the MMS held internal meetings to discuss the rationale for liquid and gas leakage rates for surface and subsurface safety valves. There was a contingent of this group that felt strongly that zero leakage was appropriate for surface safety valves. This contingent presented a compelling argument, based more on "logic" than on any specific studies, and convinced the members to agree with this recommendation. Likewise, for subsurface safety valves, there was a contingent that felt strongly that zero leakage was also appropriate. However, in an effort to compromise with the more generous API recommendations, the group decided to split the difference between zero leakage and the rates in the API documents. Therefore, these decisions were not based on engineering studies of potential consequences, nor were there any specific discussions on how the leakages were to be measured.

Some discussions have indicated that the original API recommendations for gas leakage might have been determined by identifying a leakage that, if ignited, would be able to be extinguished by a hand held fire extinguisher. However, this story has been hard to conclusively corroborate. During the 1980s, the API conducted a series of projects with SwRI. One of the objectives of these studies was to investigate the flammable boundaries for various gas leakage rates, in various atmospheric conditions. Additionally, fires were ignited on leaking lines in 1 scfm increments up to 12 scfm. The video tapes of these fires were shown to members of the API committees, who decided that these flames would have been easily extinguished by a single person with a standard, portable fire extinguisher. The results presented in the API project reports were not utilized to modify the current API standards.

In an effort to avoid duplication of effort, the API project results will be reviewed during the efforts on this project to establish the risks of various gas leakage rates. It is important to note that liquid leakage rates were not studied during the API study. Therefore, liquid leakage may require extra attention during the MMS project.

International Studies

A comprehensive literature search was conducted to determine if any international studies exist regarding leakage rates of production safety valves. The search was conducted with a database containing scientific and technical data dating back to 1970. The search did not produce any information directly related to leakage rates, but it did find that SINTEF in Norway recently completed several comprehensive studies on the reliability of subsurface safety valves in the North Sea. SINTEF's study included three phases which investigated the failure mode frequencies of several different SCSSV's. This information may be useful in the evaluation of testing frequencies (Task 6) and may possibly provide some necessary data to evaluate the reliability of certified versus non-certified valves.

Conclusions

It is apparent the allowable leakage rates and testing frequencies for SSV's, and SSSV's specified in the API Recommendations and the Code of Federal Regulations (CFR), were not based upon any verifiable engineering studies of potential consequences. Therefore, it is important that this project provide an engineering basis for the MMS to set allowable leakage rates and testing frequencies for SSV's and SSSV's. The results of the projects conducted by SwRI for API during the 1980's will be reviewed to determine if they can assist in providing an engineering basis for setting allowable leakage rates for SSV's and SSSV's. In addition, the results of the SINTEF studies will be reviewed to determine if they can assist in providing an engineering basis for setting the testing frequencies for SSV's and SSSV's.

APPENDIX B

Topical Report 2
Current Leakage Rates

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TOPICAL REPORT NO. 2
CURRENT LEAKAGE RATES

Introduction

The objectives of this task were to:

- Identify, through interviews, how valves are currently performing, how MMS inspectors and field operators currently interpret the "requirements," and how well these personnel follow the testing requirements.

- Identify locations of a range of in-service, non-certified and certified surface safety valves, so that field performance tests can be witnessed.

MMS Questionnaire

During October 1997, SwRI sent out a questionnaire to MMS field inspectors located in all four district offices in the Gulf of Mexico Region (New Orleans, Houma, Lafayette, and Lake Jackson). Twenty-eight responses to the questionnaire were received from MMS personnel, representing a good cross section from each district office.

Based upon the results of the questionnaire, it is apparent that there is no single test procedure that all MMS inspectors follow when testing surface safety valves (SSV) and subsurface safety valves (SSSV). The results also show that a standard test procedure would be desirable. The compiled results of the questionnaire may be found in Attachment 1.

In addition to the information gathered from MMS personnel, operators will be asked similar questions. Information from operators will be gathered during the field visit phase of this project (Task 3).

Field Observations

Field visits will be conducted to collect valve operation and leakage data for certified and non-certified surface safety valves. This data will provide the information necessary to determine the relative reliability of non-certified surface safety valves. In order to collect this data, test procedures must be developed, and specific valves must be selected for testing.

In order to ensure that the leakage data collected during the field observations are not affected by the test procedure, it is important that all valves be tested following the same test procedure. Separate test procedures have been developed for testing SSVs which are installed on oil wells and on gas wells. A copy of these test procedures may be found in Attachment 2.

In order to ensure a representative cross section of the surface safety valves, both certified and non-certified, located on the Outer Continental Shelf, valve data from a variety of operating companies were reviewed. Valve data from thirteen operating companies, representing approximately 2,500 certified surface safety valves and 1,000 non-certified surface safety valves, were reviewed. Of the approximately 3,500 valves reviewed, 86 certified and 55 non-certified surface safety valves were selected as candidates to be included in the leakage testing to determine their relative reliability. Of these candidates, 29 certified and 29 non-certified valves will be selected for leakage testing. This list of valves (Attachment 3 to this report) was forwarded to the MMS District Office in New Orleans, where the trip logistics will be worked out. When identifying the trip logistics, the following criteria will be kept in mind:

- Platforms from each company listed should be visited.
- Large platforms as well as small platforms should be visited.
- "Easy to get to" platforms as well as "difficult to get to" platforms should be visited.
- Sites should be chosen so that at least one valve from each manufacturer is tested.
- If possible, a variety of different size surface safety valves should be tested.

The field visits are currently scheduled to begin the week of March 23, 1998, and are expected to be completed during 3 one-week trips to the Gulf of Mexico.

Conclusions

Based upon the results of the questionnaire, it is apparent that there is no single test procedure that all MMS inspectors follow when testing surface safety valves and subsurface safety valves. The results also show that a standard test procedure would be desirable. A standard test procedure has been developed, and will be utilized during the field observation phase of this project where leakage testing of certified and non-certified surface safety valves will be witnessed. The field visit phase will provide an excellent opportunity to prove the viability of this test procedure, and provide important feedback which will be used to modify the test procedure if necessary.

Attachment 1

MMS Questionnaire Results

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Safety Valve Questionnaire Response
(28 Responses)

Over the years, the various specifications and regulations dealing with safety valve acceptance, leakage rates, and testing frequency have received numerous reviews and, if necessary, the documents were updated. These changes have often come about as a result of experience by operators, manufacturers, and Southwest Research Institute (SwRI), which conducts performance tests to API Specifications 14A and 14D. However, to our knowledge, these leakage rates have never been reviewed or changed. Manufacturers, operators, and regulators are all in agreement that the governing standards and recommended practices must be reviewed and updated in order to provide a rational and uniform basis for setting safety valve leakage rates, testing frequencies, and practical field test procedures. Therefore, one purpose of this project and, in particular, this questionnaire, is to provide this service for the oil and gas industry's benefit.

1. What concerns do you have about safety valve leakage rates, testing frequency, and test procedures?

   a) None. Leave the leakage rates, the testing frequency and test procedure as it is. However, the leakage rate for USV's needs to be addressed by MMS.
   b) The current procedures seem to be doing the job.
   c) Should all wells be bled to zero and hold.
   d) Some operators are unsure about a methodical test procedure, especially for SCSSV's, how much pressure to bleed off, how long to leave well shut in, etc. Also, how is leakage rate determined.
   e) Zero leakage is too strict.
   f) Should have "0" leakage; test according to 30 CFR 250.
   g) Enforce "0" leakage with monthly inspection.
   h) It is very important, but operator doesn't record how they do leakage test.
   i) Test frequency does not change when safety valves are found to be sand cut or otherwise damaged.
   j) Some leakage for SSV's should be allowed. Testing frequencies for SCSSV's operators need to be aware of CFR.
   k) SSV's should be "0" leakage, and SCSSV's should be allowed a small leak. The test frequency and procedures we are using now are O.K.
   l) Method to determine leakage rate.
   m) Zero allowable leakage is appropriate to prevent overpressuring downstream, unless Industry and MMS feel that secondary protection (PSV) is adequate, then an allowable leakage rate would be acceptable. For preventing pollution, only full isolation is acceptable. (SSV)
   n) Continued monthly testing suggested. (SSV)
   o) Allowable leakage rates for SSSV and SSV seem a little contradictory. Primary isolation of the wellbore flow is being performed by the SSSV which has an allowable leakage rate, while the SSV has no allowable leakage rate. Therefore, in effect, our regulations

are saying that prevention of overpressure and pollution events require the SSV have no leakage at the wellhead, but at the same time a satellite well flowing into a pipeline to a mother structure could be damaged and the only isolation of the wellbore flow is the SSSV which is allowed leakage and could possible cause a pollution or fire event. (SSSV)

p) A simple procedure and mathematical formula should be devised which would be agreeable to both Industry and MMS for universal use as it applies to the testing procedures and formulation of leakage rates. (SSSV).
q) Would use guidelines set by the valve manufacturers. (leakage rates)
r) Would eliminate bleed down to 20% SITP as a standard. (test procedure)
s) 30 CFR 250.124 (a) (4) for SSV leakage rates states "if any fluid flow is observed…". The word "fluid" should be removed because gas and oil are both fluids. It should read "if any flow is observed."
t) The test frequencies for SSSV's need to be reworded for consistency to semi-annually not to exceed 7 months and annually not to exceed 13 months.
u) I believe a SSV should be held for a minimum of 15 minutes. I believe 3 months would be okay for testing frequency. The SSV should be bled to 0 psi to ensure a good test.
v) None

2. Which standards do you follow regarding allowable leakage?
   (a) Subsurface safety valve
   30 CFR 250.124
   API 14B

   (b) Surface safety valve
   30 CFR 250.124
   API 14H

3. Which standards do you follow regarding testing frequency?
   (a) Subsurface safety valve
   - 30 CFR 250
   - SCSSV, 6 months or SSCSV, 6 months or 1 year
   - Storm choke, once every year if in a nipple
   - Biannually

   (b) Surface safety valve
   - 30 CFR 250
   - Each month
   - Once a month, not to exceed 6 weeks

4. What improvements should be made to these standards?

    a) None, the standards are good as is, leave them alone.
    b) Allow minimum leakage.
    c) Allow 5 SCFM for SSV's also if 2nd SSV or wing valve on well if it holds. Do not shut in well on INC.
    d) Standardize method of determining leakage rates - must be user-friendly.
    e) The testing frequency for SSSV's should be changed to semi-annually not to exceed 7 months and annually not to exceed 13 months. Using the 6 calendar month policy alone allows some wells almost 7 months without an INC and other wells slightly over 6 months receive a penalty.
    f) Let's all do the same thing (consistently).
    g) Testing of leakage rates when allowed a leakage rate.
    h) Differentiate between subsea and surface.

5. What test procedures do you use during their field visits? (Attach test procedure if applicable)

    a) For SSV's, API 14C-Table D2 (M).
    b) For SCSSV's and SSCSV's, API 14B and API 14C.
    c) SCSSV operator test records.
    d) Bleed to 0 psig and hold for 5 minutes, or bleed off 500 psig and hold for 5 minutes.
    e) Shut in well and bleed downstream side of valve to atmosphere and check for leakage.
    f) Shut in well for 30 minutes or until maximum SITP is achieved, close SCSSV (leave SSV open), bleed off 100 psi from SITP, monitor for 30 minutes (if no pressure builds up, valve holds).
    g) Bleed to 0 psi and test record.
    h) Back of hand.
    i) Shut well in and bleed to atmosphere, make sure no leakage.
    j) SSSV records, unless selected on sampling inspection.
    k) API 14B Appendix G.
    l) Shut in and check for leakage.
    m) National PINC List and Guidelines along with API 14C Table D2.
    n) API 14H Sec 4, Table 2.
    o) 30 CFR 250.124 (API 14C, API 14B, API 14F) as applicable. If Operator is using a variation of these test procedures which he feels is questionable, he will notify the Chief Inspector or Production Engineer for further guidance.
    p) Shut SSV, bleed of downstream, check for holding.
    q) Shut SSSV, bleed tubing down, check for buildup using leakage rate table.
    r) Leakage rate table (Table 1 "Maximum Allowable Subsurface Valve/Plug Build-up Rate").
    s) Some operators have their own computer programs.
    t) See Appendix 8 and Appendix 9.
    u) National PINC List and Guidelines along with API Bulletin.

v) No response.

6. What improvements should be made to these test procedures?

a) These test procedures have stood the test of time and are good as is.
b) I don't work with them enough to make a sound decision.
c) Apply API and SPPE Standards for testing SSV's and SCSSV's.
d) A simple procedure and mathematical formula should be devised which would be agreeable to both Industry and MMS for universal use as it applies to the testing procedures and formulation of leakage rates. (SSSV)
e) The word "fluid" should be removed in Appendix 8 after the CFR is corrected.
f) Let's all do the same thing (consistently).
g) How do I measure allowable leakage.
h) Length of time valve is tested. 15 min. for low pressure, 30 min. for high pressure.
i) Subsea SSCSV's should be flow tested instead of being pulled, inspected, and returned. Operators should review design parameters and compare to well test and attest that the current design will close.
j) None.

7. What are the typical results of the leakage tests currently being conducted by MMS personnel?

a) About 90% - 95% of valves pass the field test that are conducted by MMS.
b) Some SSV's leakage and write INC and operator repair, few SCSSV's leak.
c) SSV's, about 10% fail, SCSSV's not many fail.
d) INC if it fails test.
e) Haven't conducted any leakage test yet that have failed.
f) INC and Repair.
g) 95% pass, 5% fail.
h) No leakage majority of time.
i) Leakage rate test not being done.
j) Most hold.
k) About 1% of valves leak.
l) Majority of SCSSV's hold and meet requirements, but have experienced a higher failure rate with SSSV's (tubing plugs) and SSV's.
m) Very few valves have any leakage.
n) SSV and SCSSV both hold.
o) No response.

8. What safety valve related problems do you encounter during the field visits?

a) Cut gates and cut seats. SSV's freeze up and fail to close. Ruptured diaphragms.
b) SSV leakage due to worn gates and seats.
c) In the way the different companies check the valves.

d) Valve leaks, isolated needle valve at well or panel going to SCSSV.
e) Mostly leaks.
f) If the tree has two auto valves, most times SSV#2 closes first. SSV#1 usually has no flow across it, have to flush SSV#1 often.
g) Plug leaking, SSV leaking and downhole valves control bypassed.
h) Leakage of SSV's and SCSSV's, and inspection frequency not kept with SCSSV's.
i) With reference to SSV's, the most common problems are flow cutting and sand cutting. A problem encountered every so often with the SSV failing the holding test requirements has to do with high temperature, high velocity wells. If the well is shut in and the SSV is allowed to cool, the SSV will meet the holding test requirements of no leakage.
j) With reference to SSSV's (tubing plugs) the most common problem encountered has to do with plugs which are run on slip type mandrels and set in the tubing as opposed to those plugs set in a nipple profile.
k) Valve gates and seats cut by sand, water and formation debris.
l) "O" ring cut, deposits on the flappers, and sand/flow cut seats.
m) Seat and trim being cut, causing leakage.
n) SSCSV storm chokes are a problem to field test.
o) None.

9. Do you have any suggestions for cooperative operator contacts that would be helpful in defining current safety valve leakage, testing frequencies, and test procedures?

a) Not allowing operators to just put "H" on inspection form, and making them fill out a test form.
b) Follow the rules and regulations.
c) MMS notice to operators clearly stating leakage tolerances, testing frequencies, and a step-by-step test procedure.
d) Exxon, Chevron, and Texaco.
e) Bob Stafford with Camco, Lafayette.
f) Halliburton, Camco, and Cardinal.
g) To publish a standard that the inspectors would use.
h) None,

10. Do you have any suggestions for field visits, either with MMS personnel or operators, that would be particularly instructive for this project?

a) Visit platforms and check SSV's for holding, select wells with two auto valves.
b) When testing SSV's, close the bottom master first.
c) Observation for personnel knowledge.
d) Use a team consisting of a Production Engineer, Inspector, Operator and Service Person who specializes in SCSSV, SSCSV, and tubular and wireline retrieval. Our standards of testing as inspectors, Gulf wide are not standard. Have team do field test, study and report back.
e) None.

11. Are you aware of any field leakage test results (such as an accurate database) that could be made available to SwRI for use during the project?

    a) Yes.
    b) Check with Exxon, Chevron, and Texaco.
    c) Check with Union Oil.
    d) Companies are required to keep records for 2 years.
    e) None.

12. What other relevant information do you have to offer that will ensure the success of this project?

    a) SwRI committee should be composed of representatives from MMS, the OOC, valve companies, and someone from the Safety Valve Quality Assurance Program.
    b) Don't approach this project with the thought or idea that all changes that will be made will only benefit the operators. Safety or personnel, environment, and equipment should be taken into consideration.
    c) How can an inspector determine 5 SCFM during inspection of SSSV.
    d) Allow the inspectors to SAC wing SSV/SDV when they are no longer needed.
    e) The requirement for all SSV and USV as being certified as opposed to SDV which are not required to be certified. Does certification really enhance and provide better protection as opposed to non-certified equipment?
    f) Suggest that the manufacturers be included in the information gathering process as well.
    g) Certified or non-certified is irrelevant. Valve should be operational and able to hold pressure.
    h) I was not aware this was a big problem or a priority.
    i) None.

Attachment 2

Test Procedures

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TEST PROCEDURE FOR SSV/USV IN OIL WELLS

ALLOWABLE LEAKAGE RATES AND RELIABILTIY
OF SAFETY AND POLLUTION PREVENTION EQUIPMENT
SwRI PROJECT 04-1298

1. Close the valve to be tested.
2. Position valve(s) as required to permit pressure to bleed off downstream of the SSV/USV, and bleed off downstream pressure.
3. Close the bleed valve.
4. Attach hose barb and plastic tubing to the bleed valve.
5. Place end of plastic tubing in graduated cylinder.
6. With pressure on the upstream side of the SSV/USV, slowly open the bleed valve downstream of the test valve.
7. Monitor leakage for five minutes and record the average leakage rate at the end of five minutes. (Leakage rate to be recorded to determine if there is any difference in failure rate between SSV/USV tested in accordance with 30 CFR Chapter 11 (250.124) and API 14C, which has an allowable leakage rate of 400 cc/min.)
8. Close the bleed valve.
9. Disconnect hose barb and plastic tubing from the bleed valve.
10. Return the SSV/USV to service.

MAXIMUM ALLOWABLE LEAKAGE: No liquid leakage allowed.

TEST PROCEDURE FOR SSV/USV IN GAS WELLS

ALLOWABLE LEAKAGE RATES AND RELIABILTIY
OF SAFETY AND POLLUTION PREVENTION EQUIPMENT
SwRI PROJECT 04-1298

1. Close the valve to be tested.
2. Position valve(s) as required to permit pressure to bleed off downstream of the SSV/USV, and bleed off downstream pressure.
3. Close the bleed valve.
4. Attach the inlet of the rotameter to the bleed valve using hose barb and plastic tubing.
5. Attach the rotameter to nearby piping in the vertical position.
6. Open the valve on the downstream side of the rotameter.
7. With pressure on the upstream side of the SSV/USV, slowly open the bleed valve downstream of the test valve and record the leakage rate. (Leakage rate to be recorded to determine if there is any difference in failure rate between SSV/USV tested in accordance with 30 CFR Chapter 11 (250.124) and API 14C, which has an allowable leakage rate of 15 SCFM*).
8. Close the bleed valve.
9. Remove the rotameter from the piping and disconnect hose barb and plastic tubing from the bleed valve.
10. Return the SSV/USV to service.

MAXIMUM ALLOWABLE LEAKAGE: No gas leakage allowed.

Attachment 3

List of Potential Site Visits

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CERTIFIED VALVES									
Operator	**Field**	**Lease**	**Well**	**Manufacturer**	**Model**	**Size**	**Serial No.**	**Year Inst.**	**Actuator Manuf.**
Chevron USA (Mid Shelf)		SP78B	B-9	AXELSON	A20	2 9/16			
Chevron USA (Mid Shelf)		SP78B	B-16	WKM	M	2 9/16			
Santa Fe	HIGH ISLAND 134	OCS-G 6158	A-3	NATIONAL	H407477		V-90A140	93	AXELSON
Santa Fe	HIGH ISLAND 134	OCS-G 6158	A-1	WKM	M		K000761-1-1	93	WKM
OXY USA	MAIN PASS 296 B PLATFORM	OCS-G 1673	B-1	MCEVOY		2 9/16			
OXY USA	MAIN PASS 296 B PLATFORM	OCS-G 1674	B-12	MCEVOY		3 1/8			
OXY USA	MAIN PASS 296 B PLATFORM	OCS-G 1675	B-14	CAMERON		2 9/16			
OXY USA	SOUTH PASS 45	OCS-G 4479	A-1	FMC		2 9/16			
OXY USA	SOUTH PASS 45	OCS-G 4479	A-3	WKM		2 9/16			
Exxon	MISSISSIPPI CANYON 281	OCS-G 3818 A	1	AX					
Exxon	MISSISSIPPI CANYON 281	OCS-G 3818 A	5	AX					
Exxon	MISSISSIPPI CANYON 281	OCS-G 3818 A	8	MY					
Exxon	MISSISSIPPI CANYON 281	OCS-G 3818 A	12	WH					
Exxon	MISSISSIPPI CANYON 281	OCS-G 3818 A	16D	IC					
Exxon	MISSISSIPPI CANYON 281	OCS-G 3818 A	43	WKM					
Exxon	MISSISSIPPI CANYON 281	OCS-G 3818 A	45	OR					
Exxon	GRAND ISLE 16	SL 799 BB	1	AX					
Exxon	GRAND ISLE 16	SL 799 BB	2	MY					
Exxon	GRAND ISLE 16	SL 799 BB	7	IC					
Exxon	GRAND ISLE 16	SL 799 BB	10	FC					
Exxon	GRAND ISLE 16	OCS-G 31 P	25	AX					
Exxon	GRAND ISLE 16	OCS-G 31 P	27	MY					
Exxon	GRAND ISLE 16	OCS-G 31 P	29	MY					
Exxon	GRAND ISLE 16	OCS-G 34 T	33	CN					
Exxon	GRAND ISLE 16	OCS-G 34 T	35	FS					
Exxon	SOUTH PASS 89	OCS-G 1619 A	6	AX					
Exxon	SOUTH PASS 89	OCS-G 1619 A	8	FC					
Exxon	SOUTH PASS 89	OCS-G 1619 A	18	WK					
Exxon	SOUTH PASS 89	OCS-G 1619 A	24	FM					
Exxon	SOUTH PASS 89	OCS-G 1619 A	30	MY					
Exxon	WEST DELTA 30	OCS-G 16 L	10	AX					
Exxon	WEST DELTA 30	OCS-G 16 L	20	MY					
Exxon	WEST DELTA 30	OCS-G 16 N	21	WK					
Exxon	WEST DELTA 30	OCS-G 16 N	23	IC					
Chevron USA (Central)	BAY MARCHAND 2	OCS-0369	W 5A	AXELSON	A-50		14681-1	85	AXELSON
Chevron USA (Central)	BAY MARCHAND 2	OCS-0386	S 1	WKM	M/M		452563-1	87	AXELSON
Chevron USA (Central)	BAY MARCHAND 2	OCS-0387	U 5	AXELSON	A-40		17654-1	87	AXELSON
Texaco		WD 109A	A-32	NATIONAL		3 1/8			
Texaco		WD 109A	A-42	CACTUS		3 1/16			

CERTIFIED VALVES									
Operator	**Field**	**Lease**	**Well**	**Manufacturer**	**Model**	**Size**	**Serial No.**	**Year Inst.**	**Actuator Manuf.**
Ocean Energy	SOUTH PASS 27/28	0694	99D	CCV	MM	2 1/16	0596M00010		
Ocean Energy	SOUTH PASS 27/28	0353	55	AXELSON	40535	2 1/16	21076-1		
Ocean Energy	SOUTH PASS 27/28	0353	261	CCV	MM	2 1/16	803475		
Ocean Energy	SOUTH PASS 27/28	0694	122D	CCV	MM	2 1/16	789138-1		
CYX	EUGENE ISLAND 257	PLATFORM C	14HG	CACTUS	215WRF	2.0625	16913	92	BAKER
CYX	EUGENE ISLAND 257	PLATFORM C	16HG	CACTUS	205R DUAL	2.0625	K52384	92	BAKER
?? (CAP)	EUGENE ISLAND 330		A-1#1	INGRAM CACTUS		2 9/16	K127167	95	BAKER
?? (CAP)	EUGENE ISLAND 330		A-6 #1	FOSTER		2 1/16	29367A	94	BAKER
?? (CAP)	EUGENE ISLAND 330		A-8-D #1	GRAY		3 1/8	44145	88	COOPER
?? (CAP)	EUGENE ISLAND 330		A-23 #1	COOPER		2 9/16	188867	85	OTIS
?? (CAP)	EUGENE ISLAND 330		B-25 #1	COOPER		3 1/8	190884	94	AXELSON
?? (CAP)	GRAND ISLE 16		BB-1 #1	COOPER		3 1/16	784639-1	93	COOPER
?? (CAP)	GRAND ISLE 16		BB-7 #1	INGRAM CACTUS		3 1/16	K-73521	94	BAKER
?? (CAP)	GRAND ISLE 16		BB-10 #1	FMC		2 9/16	94-0978-H	95	BAKER
?? (CAP)	GRAND ISLE 16		K-19 #1	AXELSON		3 1/8	14662-1	85	AXELSON
?? (CAP)	GRAND ISLE 16		P-31 #1	GRAY		3 1/16	34977	88	AXELSON
?? (CAP)	GRAND ISLE 16		P-38 #1	COOPER		3 1/16	187746	94	BAKER
?? (CAP)	GRAND ISLE 16		T-36 #1	CAMERON		3 1/16	T43654	97	AXELSON
?? (CAP)	GRAND ISLE 16		T-48 #1	CAMERON		3 1/8	KA011023	97	CAMERON
?? (CAP)	GRAND ISLE 16		T-49 #1	FMC		2 1/16	94-03370-H	95	BAKER
?? (CAP)	GRAND ISLE 16		W-32 #1	INGRAM CACTUS		4 1/16	K102602	96	INGRAM CACTUS
?? (CAP)	MISSISSIPPI CANYON 280		A-1	INGRAM CACTUS		2 1/16	KEF95581	96	INGRAM CACTUS
?? (CAP)	MISSISSIPPI CANYON 280		A-10 #1	AXELSON		3 1/8	14349-1	85	AXELSON
?? (CAP)	MISSISSIPPI CANYON 280		A-22	WKM		2 1/16	783522-3-1	96	WKM
?? (CAP)	MISSISSIPPI CANYON 280		A-30 #1	COOPER		2 1/16	886MS0005B	86	COOPER
?? (CAP)	MISSISSIPPI CANYON 280		A-39 #1	COOPER		3 1/8	187778	96	AXELSON
Amoco	EI 196	OCS-G 0802	H-4	WKM			K002009-1		
Amoco	EI 208	OCS-G 0572	A-6	CAMERON	CG		CG29780	85	
Amoco	EI 208	OCS-G 0578	B-1	WKM	IDV		0486KS0007-1-1	85	
Amoco	EI 208	OCS-G 0578	C-15	AXELSON	A-20		1185KS0005-1		
Amoco	EI 208	OCS-G 0578	C-5D	WKM	M		K00488-1	82	
Amoco	EI224	OCS-G 5504	A-1	CAMERON			K002462-3		
Amoco	EI224	OCS-G 5504	A-3	CAMERON			JP2877		
Amoco	EI273	OCS-G 0987	B-3ST	CAMCO	TRDP 4E		HMS-258	96	
Amoco	EI273	OCS-G 0987	B-11	WKM	M		433483-1	81	
Amoco	EI273	OCS-G 0987	C-2	WKM	M		K000195-1	82	
Amoco	EI322	OCS-G 2113	A-5	AXELSON			6159-1		
Mobil	DELTA 6A	1365	5	CIW	F	2	SG2286	84	AXELSON
Mobil	DELTA 6A	1366	10B	AXELSON	5292H79	2.5	21260-1	91	AXELSON
Mobil	DELTA 6A	1499	03E	WKM	T23	2	0590MS0038		USI

CERTIFIED VALVES									
Operator	**Field**	**Lease**	**Well**	**Manufacturer**	**Model**	**Size**	**Serial No.**	**Year Inst.**	**Actuator Manuf.**
Mobil	DELTA 6A	1500	8	WKM	M	2	0488MS0007-1	88	AXELSON
Mobil	DELTA 6A	1627	06A	NATIONAL		2	S85C03	86	AXELSON
Shell	SP27	0353	42	COOPER	MM		0891MS0017		COOPER
Shell	SP27	0694	177	AXELSON	41185		20170-1		AXELSON
Shell	EI188	G0423	B 28C	GRAY	CN089		B-6584		BAKER
Shell	EI188	0423	B 10	CAMERON	4490004K1		CG-13548		BAKER
Shell	EI188	0423	8B	OTIS	FL		JP2873		OTIS
Shell	EI188	0443	C8	CAMERON	FL		JP 2973		OTIS

NON-CERTIFIED VALVES									
Operator	Field	Lease	Well	Manufacturer	Model	Size	Serial No.	Year Inst.	Actuator Manuf.
OXY USA	MAIN PASS 296 A PLATFORM	OCS-G 1673	#A-1	MCEVOY		2 1/16			
OXY USA	MAIN PASS 296 A PLATFORM	OCS-G 1673	#A-2	MCEVOY		2 1/16			
OXY USA	MAIN PASS 296 A PLATFORM	OCS-G 1673	#A-6	MCEVOY		2 1/16			
OXY USA	MAIN PASS 296 A PLATFORM	OCS-G 1673	#A-11	MCEVOY		2 1/16			
OXY USA	MAIN PASS 296 A PLATFORM	OCS-G 1673	#A-17	MCEVOY		2 1/16			
Chevron USA (Central)	BAY MARCHAND 2	OCS-G 0387	U 10	WKM			A164660	88	OTIS
Chevron USA (Central)	BAY MARCHAND 2	OCS-G 0392	Z 8	MCEVOY	M/B		43407	71	AXELSON
Chevron USA (Central)	BAY MARCHAND 2	OCS-G 0386	SC20	WKM			140191-1	78	OTIS
Chevron USA (Central)	BAY MARCHAND 2	OCS-G 0166	CC14	WKM	M/B		K00704-1	86	WKM
Chevron USA (Central)	SOUTH TIMBAILER 21	OCS-G 0263	84	WKM	M/B		334571-1-1	65	OTIS
Chevron USA (Central)	SOUTH TIMBAILER 21	OCS-G 0263	91	WKM	C		291765-1-1	71	OTIS
Chevron USA (Central)	SOUTH TIMBAILER 36	OCS-G 2624	B11	GRAY	15M		166813	80	GRAY
Chevron USA (Central)	SOUTH TIMBAILER 36	OCS-G 2624	B16	WKM	15M		79-400973	81	BAKER
Ocean Energy	SOUTH PASS 27/28	0694	172D	CCV	MM	2 1/16	86989		
Ocean Energy	SOUTH PASS 27/28	0353	57	CCV	MM	2 1/16	2739998-1		
Ocean Energy	SOUTH PASS 27/28	0353	116D	CCV	MM	2 1/16			
Ocean Energy	SOUTH PASS 27/28	0694	109	CCV	MM	2 1/16			
Ocean Energy	SOUTH PASS 27/28	0694	164	AXELSON		2 1/16			
Ocean Energy	SOUTH PASS 27/28	0694	201D	AXELSON		2 1/16	6A17-UBB2-2-0590		
CYX	EUGENE ISLAND 258	PLATFORM A	10HG	CAMERON	F	2 1/16		71	OTIS
CYX	EUGENE ISLAND 258	PLATFORM A	9JB	CAMERON	F	2 1/16		71	OTIS
CYX	EUGENE ISLAND 257	PLATFORM C	4GB	WKM	T-26	2 1/16	2376-1	73	USI
CYX	EUGENE ISLAND 257	PLATFORM C	8HG	WKM	T-26	2	O669	74	USI
CYX	EUGENE ISLAND 257	PLATFORM E	3JD	OCT	30	2 9/16	8901042	81	BAKER
CYX	EUGENE ISLAND 257	PLATFORM E	7FL	WKM	SAF-T-SEAL	2 9/16	90418D	81	WKM
Amoco	EI208	OCS-G 0572	A-1	WKM				80	AXELSON
Amoco	EI208	OCS-G 0572	A-4	WKM			373586-1-1	80	AXELSON
Amoco	EI208	OCS-G 0578	B-2	WKM	M		394730-1	80	AXELSON
Amoco	EI208	OCS-G 0578	B-4	WKM	M		Z488012-1	78	AXELSON
Amoco	EI273	OCS-G 0987	B-4	WKM	M		369222-1	71	AXELSON
Amoco	EI273	OCS-G 0987	B-5	WKM	M		Z450749-1	76	AXELSON
Amoco	SMI260	OCS-G 2305	A-2	CAMERON	FL		18222-10	79	WKM
Amoco	SMI260	OCS-G 2305	A-7	WKM	M		604337-1	79	AXELSON
Amoco	ST161	OCS-G 1248	A-7	CAMERON	M			80	AXELSON
Amoco	ST161	OCS-G 1248	B-8	AXELSON			1034-1	90	AXELSON
Amoco	ST161	OCS-G 1248	D-2	NELSON	FL		21224-1	79	AXELSON
Amoco	WD73	OCS-G 1085	D-10	CAMERON	FL		18266-10	80	AXELSON
Amoco	WD73	OCS-G 1085	D-11D	MCEVOY	C		C103804	80	AXELSON

NON-CERTIFIED VALVES									
Operator	**Field**	**Lease**	**Well**	**Manufacturer**	**Model**	**Size**	**Serial No.**	**Year Inst.**	**Actuator Manuf.**
Amoco	WD73	OCS-G 1085	D-16	MCEVOY	C			80	AXELSON
Amoco	WD73	OCS-G 1085	D-2D	MCEVOY	TRIPLE COMPL		C105760	80	AXELSON
Amoco	WD73	OCS-G 1085	D-9	MCEVOY	TRIPLE COMPL		4012	80	AXELSON
Mobil	DELTA 6A	1366	01	WKM	M	2	373387-1		AXELSON
Mobil	DELTA 6A	1366	03	CIW	F	2	CP4933	88	AXELSON
Mobil	DELTA 6A	1366	08D	WKM	M	2			AXELSON
Mobil	DELTA 6A	1366	05E	CIW	F	2	C7703		AXELSON
Mobil	DELTA 6A	1366	01D	WKM	L	2			AXELSON
Mobil	DELTA 73	3417	A01A	WKM	M-T-26	2 1/2			AXELSON
Mobil	DELTA 73	3417	B02D	GRAY	M	2 1/2		81	AXELSON
Mobil	DELTA 73	3417	B04C	GRAY	M	2 1/2		81	AXELSON
Mobil	DELTA 73	3417	B13B	GRAY	M	3		82	AXELSON
Shell	EI188	0423	B9	CAMERON	F				OTIS
Shell	EI188	0423	12	CAMERON	F				OTIS
Shell	EI188	0423	14D	CAMERON	F				CAMERON
Shell	EI188	0423	9	OTIS	F				OTIS
Shell	EI188	0443	A 2	MCEVOY	30855				OTIS
Shell	EI188	0443	A 4	MCEVOY	30855				OTIS

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APPENDIX C

Topical Report 3
Field Observations

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TOPICAL REPORT NO. 3
FIELD OBSERVATIONS

Introduction

The objectives of this task were to:

- Collect valve operation and leakage data for both certified and non-certified surface safety valves (SSVs) in order to determine the relative reliability of non-certified equipment.
- During the field visits, identify problems with current test procedures, concerns about testing frequencies, operational concerns about leaks and leakage rates, and the potential hazards resulting from leaks and leakage rates.

SSV Field Testing

Four field visits were conducted to three MMS Gulf of Mexico Districts (New Orleans, Houma, and Lafayette) between March 23 and June 3, 1998. Tests were conducted on 73 certified and 73 non-certified SSVs for a total of 146 tests. In order to achieve a representative sample of SSVs in operation, valves were tested from 16 different operating companies in 28 different fields in the Gulf of Mexico.

To ensure that the leakage data collected during the test was not affected by the test method, a test procedure was developed and followed during each valve test. This test procedure is included in Attachment 1. A variable area flow meter (rotameter) was used to measure the gas leakage rate during the tests. This leakage rate data was valuable for determining the failure rates when the SSV is tested in accordance with both 30 CFR Chapter 11 (250.124), which does not allow any leakage, and API 14C which allows a leakage rate of 15 SCFM.

SSV Field Test Results

Of the 146 SSVs tested, seven certified and nine non-certified SSVs failed to meet the allowable leakage rate specified in 30 CFR Chapter 11 (250.124). Based upon the test results, 9.6% of the certified SSVs tested failed. There is a 5% chance that less than 3.9% or greater than 18.8% of the true population of certified SSVs will fail to meet these leakage requirements. Based upon the test results, 12.3% of the non-certified SSVs tested failed. There is a 5% chance that less than 5.8% or greater than 22.1% of the true population of non-certified SSVs will fail to meet these leakage requirements.

All 73 certified SSVs passed the leakage requirements specified in API 14C (15 SCFM). Of the 73 non-certified SSVs tested, three non-certified SSVs failed to meet the allowable leakage rate specified in API 14C. Based upon the test results, 0.0% of the certified SSVs tested failed. There is a 5% chance that greater than 4.0% of the true population of certified SSVs will fail to meet these leakage requirements. Based upon the test results, 4.1% of the non-certified SSVs tested failed. There is a 5% chance that less than 0.9% or greater than 14.1% of the true population of non-certified SSVs will fail to meet these leakage requirements.

In addition to quantifying the failure rates with respect to the two previously mentioned standards, the failure rates were also quantified with respect to a hypothetical standard which would allow for up to 1 SCFM leakage. Of the 146 SSVs tested, two certified and five non-certified SSVs had a leakage rate greater than 1 SCFM. Based upon the test results, 2.7% of the certified SSVs tested failed to meet this leakage requirement. There is a 5% chance that less than 0.3% or greater than 9.6% of the true population of certified SSVs will fail. Based upon the test results, 6.8% of the non-certified SSVs tested had a leakage rate greater than 1 SCFM. There is a 5% chance that less than 2.3% or greater than 15.3% of the true population of non-certified SSVs will fail.

The following table summarizes the failure rates for certified and non-certified SSVs with respect to the requirements specified in 30 CFR Chapter 11 (250.124) (0 SCFM), API 14C (15 SCFM), and hypothetical standard which allows up to 1 SCFM. A complete listing of the results of all 146 valve tests is included in Attachment 2.

Table 1: Failure Rates for Certified and Non-certified Surface Safety Valves.

		30 CFR 250		API 14C		1 SCFM	
	Tests	Failures	Confidence Interval (%)	Failures	Confidence Interval (%)	Failures	Confidence Interval (%)
Certified	73	7	3.9 - 18.8	0	0 - 4.0	3	0.3 - 9.6
Non-Certified	73	9	5.8 - 22.1	3	0.9 - 14.1	5	2.3 - 15.3

Even though there were less failures for the non-certified valves, there is not enough data to show that certified valves perform better than non-certified valves. The overlapping confidence intervals for the certified and non-certified valves show that there is no statistical difference between the two valve groups. More data could be collected to reduce the confidence intervals, but it is unlikely that enough data could be collected to show a statistical difference between the two groups. If it is assumed that the same failure rate would occur throughout future testing, more than 1000 valves of each type would have to be tested in order to reduce the confidence intervals enough to show a statistical difference.

The test results also show that there is a significant difference for failure rates between SSVs which are tested in accordance with 30 CFR 250 and SSVs which are tested in accordance with API 14C. With the rotameter used for testing, any leakage below approximately 1 SCFM was not measurable. The 1 SCFM results in the table represent all the valve failures that were not measurable by the meter. This information gives an indication of the relative magnitudes of the failures. Approximately half of the valve failures were under 1 SCFM.

These results may be skewed by the difference in age between the certified and non-certified valves. As a result of 30 CFR 250.126, which requires that wells put into service after 1988 must have certified SSVs, the general age of non-certified SSVs is older than that of certified valve. The fact that the non-certified valves have been in service longer may influence the slight difference in failure rates. Other observations made during the field testing indicate that there are many other factors that affect the reliability of SSVs. These factors include, but are not limited to: well characteristics (temperature, water, sand, paraffin, gas vs. oil, etc.), operator maintenance, and environmental conditions.

Operator Interviews

During the field visits, many of the operating company personnel were interviewed to gain an understanding of the operators' concerns regarding SSV testing. The following is a summary of the questions asked and operators' responses.

What concerns do you have about safety valve leakage rates, testing frequency, and test procedures?

Most of the operators felt that the 30 CFR 250 requirement of zero leakage was too strict and they felt that some leakage should be allowed. In general, they would not have any real concerns about hazards if the SSVs were allowed to leak no more than 1 SCFM; however, there was no sound technical basis for this leakage rate. All the personnel that were interviewed felt that the one-month testing frequency was appropriate.

What test procedures do you use to check safety valve leakage?

In general, all the operators used the same basic test procedure that was used in the study. Many operators test the flow safety valve and the surface safety valve at the same time. Only a few of the operators had any type of flow meter to accurately measure leakage rates.

What are the typical results of leakage tests currently being conducted by your perso nnel?

Most of the operators stated that between 90% and 95% of their surface safety valves pass the leakage requirements specified in 30 CFR Chapter 11 (250.124).

What safety valve related problems do you encounter during leakage tests?

The major problems that the operators had that caused safety valve failures were high water producing wells, high temperature wells, and wells that produce paraffin and sand.

Conclusions

Based upon the results obtained during this field observation phase, it has been determined that there is no statistically significant difference in the proportion of failures between certified and non-certified surface safety valves. Other factors such as valve maintenance, well conditions, and environmental conditions may have a greater impact upon a particular valve's ability to meet the leakage requirements specified in 30 CFR Chapter 11 (250.124).

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Attachment 1

Test Procedure for SSV

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TEST PROCEDURE FOR SSV

ALLOWABLE LEAKAGE RATES AND RELIABILTIY
OF SAFETY AND POLLUTION PREVENTION EQUIPMENT
SwRI PROJECT 04-1298

1. Close the valve to be tested.
2. Position valve(s) as required to permit pressure to bleed off downstream of the SSV, and bleed off downstream pressure.
3. Close the bleed valve.
4. Attach the inlet of the rotameter to the bleed valve using hose barb and plastic tubing.
5. Attach the rotameter to nearby piping in the vertical position.
6. With pressure on the upstream side of the SSV, slowly open the bleed valve downstream of the test valve and record the leakage rate. Use the chart on the back of the rotameter to convert from air flow rate to natural gas flow rate. (Leakage rate to be recorded to determine if there is any difference in failure rate between SSV tested in accordance with 30 CFR Chapter 11 (250.124) and API 14C, which has an allowable leakage rate of 15 SCFM*).
7. If leakage occurs, verify that the SSV is actually leaking, and not the FSV (Flow Safety Valve), wing valve or gas trapped in the crown valve.
8. Close the bleed valve.
9. Remove the rotameter from the piping and disconnect hose barb and plastic tubing from the bleed valve.
10. Return the SSV to service.

MAXIMUM ALLOWABLE LEAKAGE: No gas leakage allowed.

* Based upon the bias error introduced by the unknown gas temperature and specific gravity, the actual flow rate can be measured to within approximately ±15%, if the temperature of the gas is between 30°F and 110°F, and the specific gravity is between 0.6 and 0.9.

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Attachment 2

Access Database

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ID	ValveNo	Operator	Field	Lease	Platform	Well	ValveMan	ValveModel	Size
1	C001	EXXON	MISS. CANYON 281	OCS-G 3205	LENA	A-1	INGRAM CACTUS		
2	C002	EXXON	MISS. CANYON 281	OCS-G 3205	LENA	A-30	COOPER		
3	C003	EXXON	MISS. CANYON 280	OCS-G 3818 A	LENA	A-5	AXELSON		
4	C004	EXXON	MISS. CANYON 281	OCS-G 3205	LENA	A-39	COOPER		
5	C005	EXXON	MISS. CANYON 280	OCS-G 3818 A	LENA	A-8			
6	C006	EXXON	MISS. CANYON 280	OCS-G 3818 A	LENA	A-12			
7	C007	EXXON	MISS. CANYON 280	OCS-G 3818 A	LENA	A-16 D	INGRAM CACTUS		
8	C008	EXXON	MISS. CANYON 280	OCS-G 3818 A	LENA	A-43	WKM		
9	C009	OCEAN ENERGY	SOUTH PASS 28			160	WKM		
10	C010	OCEAN ENERGY	SOUTH PASS 27			42	COOPER		
11	C011	OCEAN ENERGY	SOUTH PASS 28			158	AXELSON		2 1/16
12	C012	OCEAN ENERGY	SOUTH PASS 28	OCS-G 0694		99 D	WKM		2 1/16
13	C013	OCEAN ENERGY	SOUTH PASS 28	OCS-G 0353		261	WKM		
14	C014	OCEAN ENERGY	SOUTH PASS 28	OCS-G 0694		109	WKM		2 1/16
15	C015	OCEAN ENERGY	SOUTH PASS 28	OCS-G 0694		109 D	WKM	MM	2 1/16
16	C016	OXY	MAIN PASS 296	OCS-G 1673	B	B-15	MCEVOY		
17	C017	OXY	MAIN PASS 296	OCS-G 1673	B	B-1	WKM		3 1/8
18	C018	OXY	MAIN PASS 296	OCS-G 1673	B	B-14	CAMERON		
19	C019	AMOCO	WEST DELTA 90	OCS-G 1085	B	B-26	WKM		3 1/8
20	C020	AMOCO	WEST DELTA 90	OCS-G 1085	B	B-21	WKM		
21	C021	AMOCO	WEST DELTA 90	OCS-G 1085	B	B-23	AXELSON		
22	C022	AMOCO	WEST DELTA 90	OCS-G 1085	B	B-24	WKM		
23	C023	MOBIL	GRAND ISLE 94	OCS-G 2629	B	B3D	WKM		
24	C024	MOBIL	GRAND ISLE 94	OCS-G 2163	B	B1C	WKM		
25	C025	MOBIL	GRAND ISLE 94	OCS-G 2164	B	B-11 BC	WKM		
26	C026	MOBIL	GRAND ISLE 94	OCS-G 2163	B	B-7D	WKM		

ID	SerialNo	YearInstall	ActMan	ActModel	LeakageRate	WellType	Pass30CF	PassAPI14	DualString	WellProblem
1	KEF95581	96	INGRAM CACTUS		0	OIL W/ GL	Y	Y	N	N
2	886MS005B	86	COOPER		0	OIL	Y	Y	N	N
3					< 1 SCFM	OIL	N	Y	N	PARAFFIN
4	187778	96	AXELSON		0	OIL W/ GL	Y	Y	N	N
5					3.5 SCFM	OIL	N	Y	N	PARAFFIN
6					0	OIL	Y	Y	N	N
7					0	OIL	Y	Y	Y	N
8					0	OIL	Y	Y	N	N
9					0	OIL	Y	Y	N	N
10			COOPER		0	OIL W/ GL	Y	Y	N	N
11					0	GAS	Y	Y	N	N
12	793421-1				0	GAS	Y	Y	Y	N
13					0	GAS	Y	Y	N	N
14	793608				0	OIL W/ GL	Y	Y	Y	N
15	793609				0	OIL W/ GL	Y	Y	Y	N
16					0	OIL W/ GL	Y	Y	N	N
17			OTIS		0	OIL W/ ESP	Y	Y	N	N
18					< 1 SCFM	OIL W/ ESP	N	Y	N	PARAFFIN
19			COOPER		0	OIL W/ GL	Y	Y	N	N
20			AXELSON		0	OIL W/ GL	Y	Y	N	N
21			AXELSON		0	OIL W/ GL	Y	Y	N	Y
22			AXELSON		0	OIL W/ GL	Y	Y	N	N
23			AXELSON		0	OIL	Y	Y	N	INTERMITAN T FLOW
24			WKM		0	OIL	Y	Y	N	N
25			WKM		0	OIL	Y	Y	N	SAND
26			AXELSON		0	OIL	Y	Y	N	N

ID	ValveNo	Operator	Field	Lease	Platform	Well	ValveMan	ValveModel	Size
27	C027	SHELL	EUGENE ISLAND 189	OCS-G 0423	B	B-27	GRAY TOOL		
28	C028	ELF EXPLORATION	MAIN PASS 30	OCS-G 4903	A	A-8	WKM		2 9/16
29	C029	ELF EXPLORATION	MAIN PASS 30	OCS-G 4903	A	A-6	WKM		2 9/16
30	C030	ELF EXPLORATION	MAIN PASS 30	OCS-G 4903	A	A-1	AXELSON		
31	C031	ELF EXPLORATION	MAIN PASS 30	OCS-G 4903	A	A-3	CACTUS		2 9/16
32	C032	ELF EXPLORATION	MAIN PASS 30	OCS-G 4903	A	A-4	AXELSON		2 9/16
33	C033	EXXON	EUGENE ISLAND 314	OCS-G 2111	A	A-1 ST	INGRAM	205	2 9/16
34	C034	EXXON	EUGENE ISLAND 314	OCS-G 2111	A	A-6D	FOSTER	M505C	2 1/16
35	C035	EXXON	EUGENE ISLAND 314	OCS-G 2111	B	B-25	MCEVOY		3 1/8
36	C036	EXXON	EUGENE ISLAND 314	OCS-G 2111	B	B-7	MCEVOY		3 1/8
37	C037	FOREST	EUGENE ISLAND 309	OCS-G 0997	G	G-1	WKM		
38	C038	FOREST	EUGENE ISLAND 309	OCS-G 0997	G	G-9	WKM		2 1/16
39	C039	FOREST	EUGENE ISLAND 292	OCS-G 0994	B	B-9A	WKM		2 1/16
40	C040	FOREST	EUGENE ISLAND 292	OCS-G 0994	B	B-9E	WKM		2 1/16
41	C041	CNG	EUGENE ISLAND 314	OCS-G 1981	F	F9 S-4	NATIONAL		2 9/16
42	C042	CNG	SHIP SHOAL 246	OCS-G 1027	A	A-19	WKM		2 9/16
43	C043	CNG	SHIP SHOAL 246	OCS-G 1027	A	A-11	WKM		2 9/16
44	C044	CNG	SHIP SHOAL 246	OCS-G 1027	A	A-9	FMC	120	2 9/16
45	C045	MURPHY	SHIP SHOAL 224	OCS-G 1023	E	E1C	INGRAM CACTUS		2 1/2
46	C046	MURPHY	SHIP SHOAL 224	OCS-G 1526	E	E-15	WKM		2 1/2
47	C047	MURPHY	SHIP SHOAL 223	OCS-G 1526	B	B-2A	INGRAM		2 9/16
48	C048	MURPHY	SHIP SHOAL 223	OCS-G 1526	B	B-3A	INGRAM		2 9/16
49	C049	MURPHY	SHIP SHOAL 223	OCS-G 1526	B	B-5E	INGRAM		2 9/16
50	C050	UNION PACIFIC	EUGENE ISLAND 306	OCS-G 2109	B	B-8	FMC		
51	C051	UNION PACIFIC	EUGENE ISLAND 306	OCS-G 2109	B	B-15	FMC		
52	N001	OCEAN ENERGY	SOUTH PASS 28	OCS-G 0353		57	WKM	MM	

ID	SerialNo	YearInstall	ActMan	ActModel	LeakageRate	WellType	Pass30CFR	PassAPI14C	DualString	WellProblem
27			GRAY TOOL		0	OIL W/ GL	Y	Y	N	WATER
28			CAMERON		0	OIL	Y	Y	N	WATER
29			AXELSON		0	OIL W/ GL	Y	Y	N	WATER
30					0	OIL W/ GL	Y	Y	N	PARAFFIN
31			CACTUS		0	OIL W/ GL	Y	Y	N	PARAFFIN
32			AXELSON		0	OIL W/ GL	Y	Y	N	PARAFFIN
33	K127167	95	BAKER		0	OIL	Y	Y	N	N
34	29367B	94	BAKER		0	OIL	Y	Y	Y	N
35	190884	94	AXELSON		0	OIL	Y	Y	N	N
36	186631	94	BAKER		< 1 SCFM	OIL	N	Y	N	N
37			WKM		0	OIL W/ GL	Y	Y	N	N
38			WKM		0	OIL W/ GL	Y	Y	N	N
39			WKM		0	GAS	Y	Y	Y	N
40			WKM		0	GAS	Y	Y	Y	N
41			AXELSON		0	OIL	Y	Y	N	N
42			WKM		0	GAS	Y	Y	N	N
43			WKM		0	OIL W/ GL	Y	Y	N	N
44	69920920		AXELSON		0	GAS	Y	Y	N	N
45			INGRAM		0	OIL	Y	Y	N	WATER
46			OTIS		0	GAS	Y	Y	N	N
47			OTIS		0	OIL	Y	Y	N	N
48			HALLIBURTON		0	OIL	Y	Y	N	N
49			OTIS		0	GAS	Y	Y	N	N
50			BAKER		0	GAS	Y	Y	N	N
51			BAKER		0	GAS	Y	Y	N	N
52	2739998-1				0	OIL W/ GL	Y	Y	N	N

ID	ValveNo	Operator	Field	Lease	Platform	Well	ValveMan	ValveModel	Size
53	N002	OCEAN ENERGY	SOUTH PASS 28	OCS-G 0353		116D	WKM		
54	N003	OCEAN ENERGY	SOUTH PASS 28	OCS-G 0694		201D	AXELSON		
55	N004	OCEAN ENERGY	SOUTH PASS 28	OCS-G 0694		164	AXELSON		
56	N005	OXY	MAIN PASS 296	OCS-G 1673	A	A-5D	MCEVOY		2 1/16
57	N006	OXY	MAIN PASS 296	OCS-G 1673	A	A-6	MCEVOY		
58	N007	OXY	MAIN PASS 296	OCS-G 1673	A	A-11D	MCEVOY		
59	N008	OXY	MAIN PASS 296	OCS-G 1673	A	A-18	MCEVOY		2 1/16
60	N009	OXY	MAIN PASS 296	OCS-G 1673	A	A-1	MCEVOY		
61	N010	AMOCO	EUGENE ISLAND 215	OCS-G 0578	C	C-21	WKM		2 3/16
62	N011	CXY	EUGENE ISLAND 257	OCS-G 2103	C	C3HG	WKM	T-26	
63	N012	CXY	EUGENE ISLAND 259	OCS-G 0985	C	C26B	CAMERON		
64	N013	CXY	EUGENE ISLAND 257	OCS-G 2103	C	1	WKM	T-26	2 1/16
65	N014	SHELL	EUGENE ISLAND 189	OCS-G 0423	B	B-26	CAMERON		
66	N015	CXY	EUGENE ISLAND 259	OCS-G 0985	A	A-2			
67	N016	CXY	EUGENE ISLAND 259	OCS-G 0985	A	A-5			
68	N017	EXXON	EUGENE ISLAND 314	OCS-G 2111	B	B-18	MCEVOY		
69	N018	EXXON	EUGENE ISLAND 314	OCS-G 2111	B	B-19	MCEVOY	B-300	
70	N019	CNG	EUGENE ISLAND 314	OCS-G 1981	F	F5-D3	INGRAM		
71	N020	CNG	EUGENE ISLAND 314	OCS-G 1981	F	F5-D2	INGRAM		
72	N021	CNG	EUGENE ISLAND 314	OCS-G 1981	F	F6-D5	WKM		
73	N022	FOREST	EUGENE ISLAND 309	OCS-G 1981	G	G6	WKM		2 1/2
74	N023	FOREST	EUGENE ISLAND 309	OCS-G 0997	G	G7	WKM		2 1/2
75	N024	FOREST	EUGENE ISLAND 309	OCS-G 1981	G	G3	WKM		2 1/2
76	N025	FOREST	EUGENE ISLAND 309	OCS-G 0997	G	G4	WKM		
77	N026	FOREST	EUGENE ISLAND 292		B	B-10D			
78	N027	CNG	SHIP SHOAL 246	OCS-G 1027	A	A-14	WKM		2 3/16

ID	SerialNo	YearInstall	ActMan	ActModel	LeakageRate	WellType	Pass30CFR	PassAPI14C	DualString	WellProblem
53					0	OIL W/ GL	Y	Y	Y	N
54	6A17-UBB2-				0	GAS	Y	Y	Y	N
55					1 SCFM	OIL W/ GL	N	Y	N	N
56					0	OIL W/ GL	Y	Y	N	N
57					< 1 SCFM	OIL W/ GL	N	Y	N	WATER
58					> 20 SCFM	OIL	N	N	Y	WATER
59					0	OIL W/ GL	Y	Y	N	N
60					0	OIL W/ GL	Y	Y	N	N
61					0	OIL W/ GL	Y	Y	N	PARAFFIN
62			USI	MHA	0	GAS	Y	Y	N	N
63			OTIS		0	GAS	Y	Y	N	N
64	425525-3	74	USI	MHA	> 15 SCFM	GAS	N	N	N	N
65					0	OIL W/ GL	Y	Y	N	N
66					0	GAS	Y	Y	N	N
67					0	GAS	Y	Y	N	N
68		74	AXELSON		< 1 SCFM	OIL W/ GL	N	Y	N	N
69		74	AXELSON		< 1 SCFM	OIL W/ GL	N	Y	N	N
70			BAKER		0	OIL	Y	Y	N	N
71			BAKER		< 1 SCFM	OIL	N	Y	N	N
72			AXELSON		0	OIL W/ GL	Y	Y	N	N
73			AXELSON		0	OIL W/ GL	Y	Y	N	N
74			WKM		0	OIL W/ GL	Y	Y	N	N
75		76	AXELSON		0	GAS W/	Y	Y	N	N
76			WKM		0	OIL W/ GL	Y	Y	N	N
77			AXELSON		0	GAS	Y	Y	Y	N
78			WKM		0	GAS	Y	Y	N	N

ID	ValveNo	Operator	Field	Lease	Platform	Well	ValveMan	ValveModel	Size
79	N028	CNG	SHIP SHOAL 246	OCS-G 1027	A	A-20	WKM		2 1/2
80	N029	CNG	SHIP SHOAL 246	OCS-G 1027	A	A-6	WKM		2 3/16
81	N030	MURPHY	SHIP SHOAL 224	OCS-G 1023	E	E-7	WKM		2
82	N031	MURPHY	SHIP SHOAL 224	OCS-G 1023	PP	PP-7	WKM		1 15/16
83	N032	CNG	SHIP SHOAL 248	OCS-G 1029	D	D-11-S1	WKM		2 9/16
84	N033	CNG	SHIP SHOAL 248	OCS-G 1029	D	D-5	OTIS		
85	N034	MURPHY	SHIP SHOAL 224	OCS-G 1023	PP	PP-2B	WKM		1 15/16
86	N035	CNG	SHIP SHOAL 248	OCS-G 1029	D	D-18-S1	WKM		2 1/4
87	N036	MURPHY	SHIP SHOAL 223	OCS-G 1526	B	B-6B	WKM		2 1/16
88	N037	MURPHY	SHIP SHOAL 223	OCS-G 1526	B	B-6A	WKM		2 1/16
89	N038	MURPHY	SHIP SHOAL 224	OCS-G 1023	A	A-10	CAMERON		
90	N039	UNION PACIFIC RESOURCES	SHIP SHOAL 207	OCS-G 1523	A	A-23B	WKM	ACF	
91	N040	UNION PACIFIC RESOURCES	SHIP SHOAL 207	OCS-G 1523	A	A-24	WKM		
92	N041	UNION PACIFIC RESOURCES	SHIP SHOAL 207	OCS-G 1523	A	A-22-ST	WKM		2 1/2
93	N042	UNION PACIFIC RESOURCES	SHIP SHOAL 207	OCS-G 1523	A	A-16-ST	WKM		2 9/16
94	N043	UNION PACIFIC RESOURCES	SHIP SHOAL 207	OCS-G 1523	A	A-15	FMC		2 9/16
95	N044	UNION PACIFIC RESOURCES	SHIP SHOAL 207	OCS-G 1523	A	A-10D	WKM	ACF	
96	N045	UNION PACIFIC RESOURCES	SHIP SHOAL 207	OCS-G 1523	A	A-4	FMC		2 9/16
97	N046	UNION PACIFIC RESOURCES	EUGENE ISLAND 306	OCS-G 2109	A	A-23D	WKM		
98	N047	UNION PACIFIC RESOURCES	EUGENE ISLAND 306	OCS-G 2109	A	A-22	WKM		
99	N048	UNION PACIFIC RESOURCES	EUGENE ISLAND 306	OCS-G 2109	A	A-19	WKM		
100	N049	UNION PACIFIC RESOURCES	EUGENE ISLAND 306	OCS-G 2109	A	A-7	WKM		2 1/2
101	N050	UNION PACIFIC RESOURCES	EUGENE ISLAND 306	OCS-G 2109	A	A-5	WKM		2 1/2
102	N051	UNION PACIFIC RESOURCES	EUGENE ISLAND 306	OCS-G 2109	B	B-13	WKM		
103	N052	UNION PACIFIC RESOURCES	EUGENE ISLAND 306	OCS-G 2109	B	B-10	WKM		
104	N053	UNION PACIFIC RESOURCES	EUGENE ISLAND 306	OCS-G 2109	B	B-2	WKM		2 9/16

ID	SerialNo	YearInstall	ActMan	ActModel	LeakageRate	WellType	Pass30CFR	PassAPI14C	DualString	WellProblem
79			WKM		0	OIL	Y	Y	N	N
80			WKM		0	OIL	Y	Y	N	N
81			OTIS		0	OIL	Y	Y	Y	N
82			OTIS		0	OIL	Y	Y	N	WATER
83			WKM		0	GAS	Y	Y	N	N
84			OTIS		0	GAS	Y	Y	N	INTERMITANT FLOW
85			WKM		0	OIL	Y	Y	N	N
86			WKM		0	GAS	Y	Y	N	N
87			INGRAM		0	GAS	Y	Y	Y	N
88			INGRAM		0	OIL	Y	Y	Y	N
89			OTIS		0	OIL	Y	Y	N	N
90			OTIS		0	OIL W/ GL	Y	Y	Y	N
91			WKM		0	OIL W/ GL	Y	Y	N	N
92			WKM		0	OIL W/ GL	Y	Y	N	N
93			AXELSON		0	OIL	Y	Y	N	N
94			OTIS		0	OIL W/ GL	Y	Y	N	N
95			WKM		0	OIL W/ GL	Y	Y	Y	N
96			BAKER		0	OIL W/ GL	Y	Y	N	WATER
97			OTIS		0	OIL	Y	Y	Y	N
98			OTIS		0	GAS	Y	Y	N	N
99			WKM		0	GAS	Y	Y	N	N
100			WKM		0	OIL	Y	Y	Y	N
101			WKM		0	OIL	Y	Y	N	N
102			WKM		0	OIL	Y	Y	N	N
103			WKM		0	OIL	Y	Y	N	N
104					0	OIL	Y	Y	N	N

ID	ValveNo	Operator	Field	Lease	Platform	Well	ValveMan	ValveModel	Size
105	N054	UNION PACIFIC RESOURCES	EUGENE ISLAND 296	OCS-G 2105	B	B-9B	WKM		2 1/2
106	N055	UNION PACIFIC RESOURCES	EUGENE ISLAND 296	OCS-G 2105	B	B-18	WKM		2 1/2
107	N056	UNION PACIFIC RESOURCES	EUGENE ISLAND 306	OCS-G 2109	A	A-25	WKM		
108	N057	UNION PACIFIC RESOURCES	SHIP SHOAL 207	OCS-G 1523	A	A-29	WKM		2 9/16
109	C052	TAYLOR ENERGY	S. MARSH ISLAND 69	OCS-G-1205	B	B-29	AXELSON		2 9/16
110	C053	TAYLOR ENERGY	S. MARSH ISLAND 69	OCS-G-1205	B	B-28	MCEVOY		3
111	C054	TAYLOR ENERGY	S. MARSH ISLAND 69	OCS-G-1201	B	30	MCEVOY		
112	C055	FORCENERGY	S. MARSH ISLAND 6	OCS-G-1177		24	WKM		3
113	C056	FORCENERGY	S. MARSH ISLAND 6	OCS-G-1177		26	WKM		2 1/2
114	C057	SHELL	S. MARSH ISLAND 130	OCS-G-2280	D	D-20	CAMERON		2 9/16
115	C058	SHELL	S. MARSH ISLAND 130	OCS-G-2281	D	D-26	CAMERON		2 9/16
116	C059	SHELL	S. MARSH ISLAND 130	OCS-G-2280	D	D-6	CAMERON		2 1/2
117	C060	SHELL	S. MARSH ISLAND 130	OCS-G-2280	D	D-12			
119	C061	SHELL	S. MARSH ISLAND 130	OCS-G-2280	C	C-40	CAMERON		
120	C062	SHELL	S. MARSH ISLAND 130	OCS-G-2280	C	C-3	CAMERON		
121	C063	UNOCAL	VERMILLION 39	OCS-206	D	2	AXELSON		3 1/8
122	C064	UNOCAL	VERMILLION 39	OCS-206	D	3	WKM		2 9/16
123	C065	TEXACO	TIGER SHOAL 218	OCS-310		74	CAMERON		2 9/16
124	C066	TEXACO	TIGER SHOAL 218	OCS-310		36	WKM		3 1/8
125	C067	TEXACO	TIGER SHOAL 218	OCS-310		1	WKM		3 1/8
126	C068	TEXACO	TIGER SHOAL 218	OCS-310		79	WKM		2 9/16
127	C069	TEXACO	TIGER SHOAL 217	OCS-310		53	WKM		3 1/8
128	C070	TEXACO	TIGER SHOAL 217	OCS-310		4	AXELSON		3 1/8
129	C071	TEXACO	TIGER SHOAL 217	OCS-310		8	AXELSON		3 1/8
130	C072	TEXACO	TIGER SHOAL 217	OCS-310		5	AXELSON		
131	C073	TEXACO	TIGER SHOAL 217	OCS-310		72	COOPER		2 1/16

ID	SerialNo	YearInstall	ActMan	ActModel	LeakageRate	WellType	Pass30CFR	PassAPI14C	DualString	WellProblem
105					0	OIL	Y	Y	N	N
106			OTIS		0	OIL	Y	Y	N	WATER
107			OTIS		0	OIL	Y	Y	N	N
108			WKM		0	OIL W/ GL	Y	Y	N	N
109			AXELSON		0	OIL W/ GL	Y	Y	N	N
110			AXELSON		0	OIL W/ GL	Y	Y	N	N
111			AXELSON		0	OIL W/ GL	Y	Y	N	N
112					0	GAS	Y	Y	N	N
113					< 1 SCFM	OIL	N	Y	N	N
114			OTIS		0	OIL W/ GL	Y	Y	N	N
115			OTIS		< 1 SCFM	OIL	N	Y	N	N
116			OTIS		0	OIL	Y	Y	N	N
117					0	OIL	Y	Y	N	N
119			OTIS		10 SCFM	OIL	N	N	N	N
120			OTIS		0	OIL	Y	Y	N	N
121			AXELSON		0	GAS	Y	Y	N	SAND
122					0	GAS	Y	Y	N	N
123			AXELSON		0	GAS	Y	Y	N	N
124			WKM		0	GAS	Y	Y	N	N
125			WKM		0	GAS	Y	Y	N	N
126			WKM		0	GAS	Y	Y	N	N
127			AXELSON		0	GAS	Y	Y	N	N
128			AXELSON		0	GAS	Y	Y	N	N
129			AXELSON		0	GAS	Y	Y	N	N
130					0	GAS	Y	Y	N	N
131			WKM		0	OIL W/ GL	Y	Y	N	N

ID	ValveNo	Operator	Field	Lease	Platform	Well	ValveMan	ValveModel	Size
132	N058	SHELL	S. MARSH ISLAND 130	OCS-G-2280	C	C-26	CAMERON		2 9/16
133	N059	SHELL	S. MARSH ISLAND 130	OCS-G-2280	C	C-27	CAMERON		2 9/16
134	N060	SHELL	S. MARSH ISLAND 130	OCS-G-2280	D	D-21	OTIS		
135	N061	SHELL	S. MARSH ISLAND 130	OCS-G-2280	D	D-33	OTIS		2 9/16
136	N062	TEXACO	TIGER SHOAL 217	OCS-310		7	AXELSON		
137	N063	TEXACO	TIGER SHOAL 217	OCS-310		63			
138	N064	TEXACO	TIGER SHOAL 217	OCS-310		63D			
139	N065	TEXACO	TIGER SHOAL 217	OCS-310		62	NATIONAL OIL		2 9/16
140	N066	TEXACO	TIGER SHOAL 217	OCS-310		17	CACTUS		3 1/8
141	N067	TEXACO	TIGER SHOAL 218	OCS-310		94	NATIONAL OIL		3 1/8
142	N068	TEXACO	TIGER SHOAL 218	OCS-310		51D#2	OCT		2 1/2
143	N069	TEXACO	TIGER SHOAL 218	OCS-310		51D#1	OCT		2 1/2
144	N070	TEXACO	TIGER SHOAL 218	OCS-310		49D#2	OCT		2 1/2
145	N071	TEXACO	TIGER SHOAL 218	OCS-310		49D#1	OCT		2 1/2
146	N072	TEXACO	TIGER SHOAL 217	OCS-310		27	WKM		3 1/8
147	N073	TEXACO	TIGER SHOAL 217	OCS-310		48	BAKER		3

ID	SerialNo	YearInstall	ActMan	ActModel	LeakageRate	WellType	Pass30CFR	PassAPI14C	DualString	WellProblem
132			OTIS		0	OIL	Y	Y	N	N
133			OTIS		0	OIL	Y	Y	N	N
134			CAMERON		0	OIL	Y	Y	N	N
135			OTIS		0	OIL W/ GL	Y	Y	N	N
136			CACTUS		0	GAS	Y	Y	N	N
137					0	GAS	Y	Y	Y	N
138					4.5 SCFM	GAS	N	Y	Y	N
139			AXELSON		0	GAS	Y	Y	N	N
140			AXELSON		0	GAS	Y	Y	N	N
141			AXELSON		0	GAS	Y	Y	N	N
142			AXELSON		0	GAS	Y	Y	Y	N
143			AXELSON		>20 SCFM	GAS	N	N	Y	N
144			AXELSON		0	GAS	Y	Y	N	N
145			AXELSON		0	GAS	Y	Y	N	N
146			AXELSON		0	GAS	Y	Y	N	N
147			BAKER		0	GAS	Y	Y	N	N

APPENDIX D

Topical Report 4
Velocity-Type Valves

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TOPICAL REPORT NUMBER 4
VELOCITY-TYPE VALVES

INTRODUCTION

Subsurface Safety Valves (SSSV) are required in all offshore producing oil and gas wells located in Outer Continental Shelf (OCS) waters that fall under the jurisdiction of the Minerals Management Service. The purpose of these valves is to shut off well flow in the production tubing below the mudline in the event of emergencies, such as a fire or production tubing separation. One type of SSSV that is used in offshore wells is actuated by a differential pressure created by the well fluid flow through the valve. These valves, called Subsurface Controlled Safety Valves (SSCSV) or velocity valves, are sized or configured to close when the loss of tubing back pressure from a disaster causes the well to flow in excess of its normal production rates. Velocity valves are sized using programs developed by the valve manufacturers that predict the closing flow rates for a given valve configuration and well conditions. Concerns have been raised by MMS personnel about the accuracy of these sizing programs to size the appropriate valve for current well conditions and about the reliability of these valves after well conditions change. This study was conducted to address these concerns.

Velocity valve sizing models. Velocity valves operate on a simple force balance principle. The valves utilize a choke to create a differential pressure when fluid is flowing through the valve. The differential pressure is used to overcome a spring force to actuate the valve to the closed position. Velocity valves are configured to close at a certain differential pressure by changing the valve's choke size and spring force. By changing the valve configuration, the flow rate at which the valve closes is changed, because in subcritical flow the differential pressure is proportional to the well flow rate.

Properly sizing a velocity valve for an oil well is a difficult procedure requiring information about the well's maximum flowing potential, knowledge of the valve's differential closing pressure, and an estimation of the differential pressure created by the desired closing flow rate. The consequences of incorrect valve sizing are either premature closures that result in the need to drop production to lower than desired rates to keep the valve open, or loss of protection from using a valve that will not close because the valve's closing flow rate is higher than the flow rate corresponding to an upstream tubing or equipment failure.

The sizing model may be broken down into three main correlations. One correlation is needed to estimate the downhole flowing conditions to determine the fluid properties at the valve. The second correlation is needed to predict the required differential pressure across the valve to overcome the spring and friction forces that keep the valve in the open position. The third correlation is needed to calculate the differential pressure across the valve as a function of the liquid and gas flow rates and fluid properties. The valve should close when the calculated differential pressure developed by the flow exceeds the calculated differential pressure required to close the valve. Each of these correlations are complicated calculations and can contribute to significant errors in the sizing models.

Valve sizing is further complicated by the fact that the well characteristics including inflow performance and gas-oil ratio change over the lifetime of the well. To clarify, a valve that is sized correctly when the valve is installed may not close after the well's production characteristics change.

Velocity valve manufacturers have independently developed sizing models. Many of these models are based on the procedures outlined in API *14BM (Users manual for API 14B Subsurface-Controlled Subsurface Safety Valve Sizing Computer Program*) which was last published in 1978. There are significant concerns about the validity of these models and whether well performance changes have caused many velocity valves to become inoperative since their installation.

Project Scope. The original purpose of this study was to quantify the effects of changing well conditions on closing flow rates for installed velocity valves and to provide an improved model for MMS to estimate these closing flow rates with current well conditions. In the preliminary stages of this study, SwRI conducted a literature survey to assess API 14BM and to find newer multiphase pressure drop correlations to be utilized in the SwRI sizing model.

The results of the literature search raised a number of concerns about developing a sizing model. Some of the major concerns were a lack of valve closing repeatability, the lack of accurate multiphase pressure drop correlations, and the lack of accurate models to predict the valve closing differential pressure. The review showed that when the uncertainty of current models for closure differential pressure and flowing differential pressure are combined, the cumulative uncertainty in the closure flow rate could be in excess of ±40%. As a result, the study was refocused to the scope of the current study, which is to further access the accuracy of current manufacturer sizing models. Attachment 1 includes a letter to MMS dated December 1, 1997, summarizing the literature search results, with a further explanation of the reason for a change in scope. Also included in Attachment 1 is the updated task outline that was provided in Monthly Report No. 3. The results of this current study provide more information about the state of current valve sizing models and whether and how to proceed with developing better sizing procedures.

Two manufacturers' models were assessed by conducting single-phase and multiphase flow testing on a valve from each manufacturer. Tests were conducted under single-phase gas conditions with nitrogen and multiphase conditions with nitrogen and water. The manufacturers' models were then exercised to obtain the predicted closing rates for the test conditions. The predicted and measured rates were compared to assess the accuracy of each code. The following report presents a general overview of the manufacturers' models, a description of the experimental approach and setup, the experimental results, and the study's conclusions and recommendations.

EXPERIMENTAL APPROACH

Testing was conducted on valves from two different SSSV manufacturers. Each valve was tested with 5 different choke and spring/spacer combinations. Specific details of the valve characteristics will not be provided in this report to protect the proprietary elements of the manufacturers' valve designs. Each configuration was tested with both single-phase and multiphase conditions with nitrogen and water as the test media. The single-phase tests were conducted by pressurizing the system and then increasing the gas flow rate slowly until the valve closed. For the multiphase tests, a water flow rate was established and then the gas flow rate was increased until the valve closed. For each test point, the water and gas flow rates, static pressure, temperature, and valve differential pressure were recorded.

Test Facility. SwRI's Flowing Gas Test Facility was modified to accommodate multiphase flow for this testing. A schematic of the test facility is shown in Figure 1. A 500 ft^3 pressure vessel provided nitrogen gas flow that was measured with a 3-inch orifice meter. Water was injected into the gas flow line at approximately 50 diameters upstream of the velocity valve using a triplex positive displacement pump. The water flow rate was controlled with a three-way bypass valve arrangement. The water flow rate was measured with a ½-inch turbine meter. The multiphase flow rate was controlled with a flow control valve located downstream of the velocity valve. The test section discharged to atmospheric conditions. A balance line valve was used to equalize the pressure across the valve to open the valve after it was closed. The temperature and pressure upstream of the valve and the differential pressure across the valve were recorded to obtain the flowing conditions at the velocity valve.

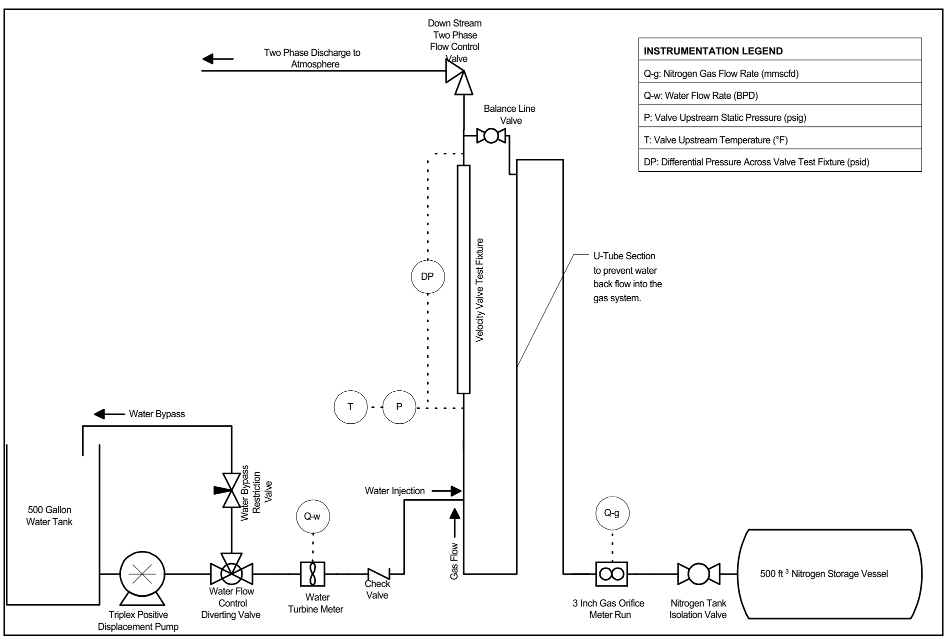

Figure 1. Schematic of multiphase flow test facility. *The facility can accommodate both single-phase nitrogen gas and multiphase nitrogen and water flow testing. The facility's flowing capacities are 10 mmscfd nitrogen gas and 1000 bpd water. The pressure rating is 1440 psig.*

The differential pressure measurement was taken across the manufacturer's valve test section. Velocity valves are actuated by the differential pressure across the choke inside of the valve. The choke differential pressure could not be obtained without affecting the performance of the valve. The differential pressure measured across the test section cannot be used to gain information about the pressure drop acting on the choke, but it does provide useful information about the repeatability of the closing points and aids in selection of the closing points from the test data.

Test Procedure. The experimental procedure involved flowing through the velocity valves with either single-phase nitrogen gas or multiphase nitrogen and water at rates sufficient to close the velocity valve. Detailed test procedures are provided below.

Single-phase nitrogen gas tests.

1. With the downstream flow control valve and the balance line valve closed, pressurize the test section to the pressure in the nitrogen storage vessel.
2. Turn on the computer data acquisition system to record the test data.
3. Slowly open the downstream flow control valve to start the gas flow.
4. Increase the gas rate smoothly until the velocity valve closes.
5. Shut the downstream flow control valve.
6. Open the balance line, and equalize the pressure across the velocity valve to reopen the valve.
7. Repeat steps 3-6 to repeat the single-phase test or continue with the multiphase testing with step 3 of the following procedure.

Multiphase nitrogen and water tests.

1. With the downstream flow control valve and the balance line valve closed, pressurize the test section to the pressure in the nitrogen storage vessel.
2. Turn on the computer data acquisition system to record the test data.
3. Slowly open the downstream flow control valve to start the gas flow.
4. With the water pump running, inject water into the test section by actuating the water flow control valve. Slowly increase the water rate to the desired rate.
5. Increase the gas rate smoothly until the velocity valve closes.
6. Shut off the water injection.
7. Shut the downstream flow control valve.

8. Open the balance line, and equalize the pressure across the velocity valve to reopen the valve.

9. Repeat steps 3-8 to perform additional multiphase tests.

Manufacturer sizing model modifications. Both manufacturers' models had to be modified to match the experimental test conditions. Both of the models were developed for natural gas, oil, and water while the testing media was nitrogen and water. One of the problems with using the manufacturers' models "as-is" for this study was the error in calculating the gas density. The models calculate the gas density at the flowing temperature and pressure using compressibility factors (z) for a generic natural gas. Since nitrogen was used for the testing, using the manufacturers' codes would create a bias error because the compressibility factors are significantly different for natural gas and nitrogen. The codes were modified to accommodate nitrogen as the test gas media. For this testing, these modifications should be more favorable to the code because the true properties for nitrogen were used for the modified code. The manufacturers' codes contain some inherent error because they use the properties for a generic natural gas, while actual produced natural gas can vary widely in composition and, thus, vary widely in fluid properties.

One other problem with using the manufacturers' models "as-is" for this study was the lack of fluid shrinkage of the test fluids. Well flow rates are input into the models in terms of stock tank barrels (STB) and standard cubic feet of gas (scf). In oil and natural gas systems, a certain amount of the gas dissolves into the oil at the elevated temperature and pressure of the downhole environment. As the produced oil is brought to stock tank conditions, the gas evolves from the oil and the oil's volume decreases. This phenomena, commonly called shrinkage, is accounted for in the manufacturer models by the use of solution gas-oil ratio or oil formation volume factor correlations. Shrinkage does not occur with nitrogen and water, so the models were modified to remove these correlations. Again, these modifications should be more favorable to the code because, by removing these correlations, the errors associated with calculating the oil shrinkage are eliminated.

Error calculations. The manufacturers' models were assessed by comparing the model predictions and the test closing points for each manufacturers' respective valves. For each test point the modified models were exercised to obtain a predicted closing rate for each flowing condition. In multiphase flow, velocity valves close at an infinite combination of liquid and gas flow rates. The prediction error for the multiphase points was calculated separately for the liquid rate and the gas rates. Figure 2 illustrates how the errors were calculated.

The water flow rate error was calculated by determining the point on the prediction curve at which the gas flow rate matched the measured test gas flow rate and by then subtracting the measured water flow rate from the predicted water flow rate at that point on the curve. The gas flow rate error was calculated by determining the point on the prediction curve at which the water flow rate matched the measured test water flow rate and by then subtracting the measured gas flow rate from the predicted gas flow rate at that point on the curve.

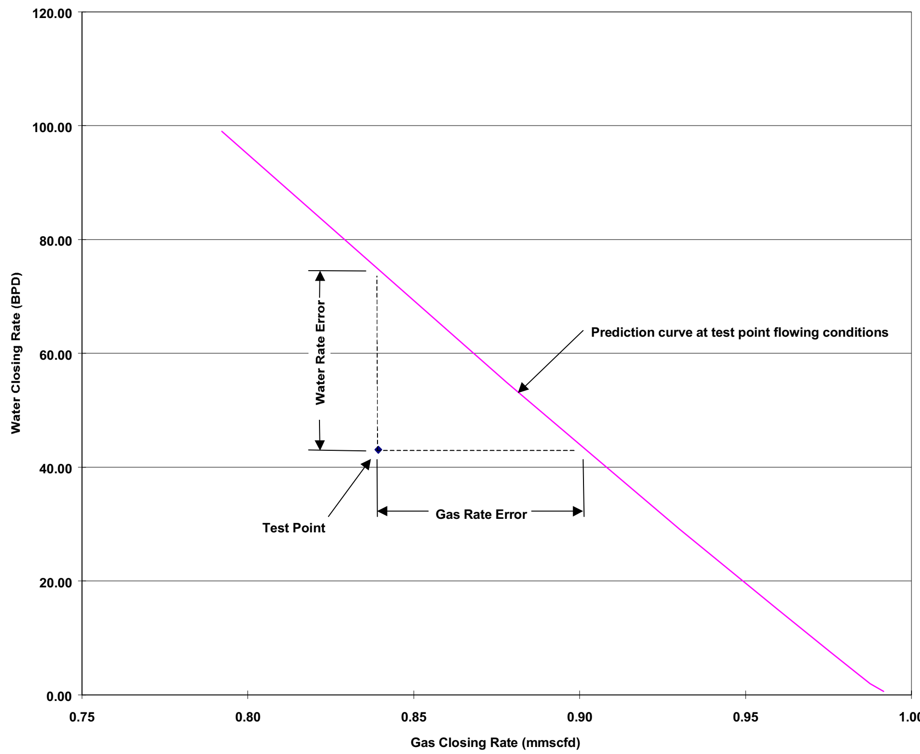

Figure 2. Illustration of the prediction error calculation on an example velocity valve prediction curve and test point. *This example shows that the model over-predicted the closing point.*

For the single-phase test points, the error was calculated by simply subtracting the measured gas rate from the predicted gas rate. In this study, the errors were expressed as percentages by dividing the errors by the measured rates and multiplying by 100.

TEST RESULTS

A summary of the test results are presented in Tables 1 and 2. These summary results show a good indication of the accuracy of each manufacturer's models in predicting the closing rates of their valves.

Manufacturer A uses one model to predict the closing rates for both oil and gas wells. Manufacturer B uses one model for oil wells, which it defines as having gas-oil ratios less than 40,000 cubic feet per barrel, and another model for gas wells, which it defines as having gas-oil ratios greater than 10,000 cubic feet per barrel.

Table 1. Summary of results for Manufacturer A's sizing model and velocity valve. *For the first and last two valve configurations, the manufacturer's model over-predicted the closing rates. For the second and third configurations, the manufacturer's model under-predicted the closing rates.*

Choke/Spacer Configuration	Average Predicted Liquid Error (%)	Average Predicted Gas Error (%)	Number of Test Points
Choke A, Spacer C	177.7	19.1	10
Choke B, Spacer A	-11.7	-0.7	15
Choke B, Spacer B	-31.9	-3.3	19
Choke B, Spacer C	243.7	24.5	13
Choke C, Spacer A	373.6	33.7	9

Table 2. Summary of results for Manufacturer B's sizing model and velocity valve. *For all five valve configurations, the manufacturer's model under-predicted the closing rates.*

	Oil Well Program		Gas Well Program		
Choke/Spacer Configuration	Average Predicted Liquid Error (%)	Average Predicted Gas Error (%)	Average Predicted Liquid Error (%)	Average Predicted Gas Error (%)	Number of Test Points
Choke A, Spacer A	-100*	-25.4	-100*	-23.7	18
Choke A, Spacer B	-100*	-27.4	-100*	-28.3	19
Choke A, Spacer C	-100*	-25.2	-100*	-25.2	30
Choke B, Spacer A	-100*	-23.3	-100*	-26.0	18
Choke B, Spacer B	-100*	-24.4	-100*	-28.0	22

* Note: The –100% errors for the water indicate that the model did not predict any water flow at each test point's corresponding gas rate. See Figure 3 for an illustration.

Table 1 shows the for Manufacturer A's model and valve. The average predicted liquid error varied from –31.9 to 373.6%, and the average predicted gas error varied from –3.3 to 33.7%. Negative errors indicate that the model under-predicted the closing flow rates; the valve actually closed at rates greater than the predicted rates. From an operational and safety standpoint, these negative errors are more serious than positive errors. If a valve is sized with a model that under-predicts the closing flow rates, the installed valve may not close because the well may not be capable of flowing enough fluid to close the valve.

Table 2 shows the results for Manufacturer B's model and valve. The errors are all negative, indicating that the model under-predicted the valve closing rates. The liquid errors for both the oil and gas well programs are -100%. This is because the gas flow rate of the test points were higher than the highest gas rate that the model predicted, which was with no water flow. When the errors were calculated as described in the previous section, the predicted water rate for each test point was zero so the errors were -100%. See Figure 3 for an illustration. The gas flow rate errors were fairly consistent, varying between 23.3% and –28.0% for both the oil and gas well programs. The errors between the gas and oil well programs showed little significant difference.

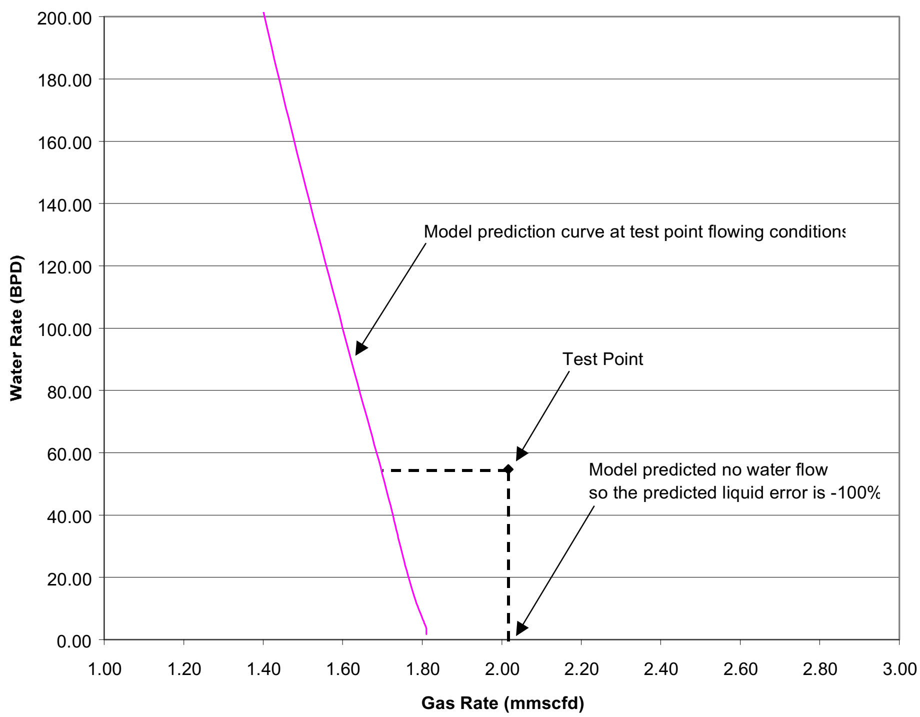

Figure 3. Example illustrating how the -100% liquid errors were calculated for Manufacturer B's results. *The gas flow rate of the test point was higher than the highest gas rate that the model predicted, which was with no water flow. When the error was calculated as described in the previous section, the predicted water rate for each test point was zero so the errors were -100%.*

The SSCSV sizing procedure recommended in API Recommended Practice *14B (Design, Installation, Repair and Operation of Subsurface Safety Valve Systems*) can be used to put the magnitude of these errors into perspective. In section 4.4, 14B recommends that velocity valve "closure rates should be no greater than 150 percent but no less than 110 percent of the well test rate." If a midpoint closure rate were selected of 130 percent, a ±20 percent window is left to remain within the recommendation. Many of the sizing errors shown in these tests would cause the valves to fall outside the 14B recommendation (see Figure 4).

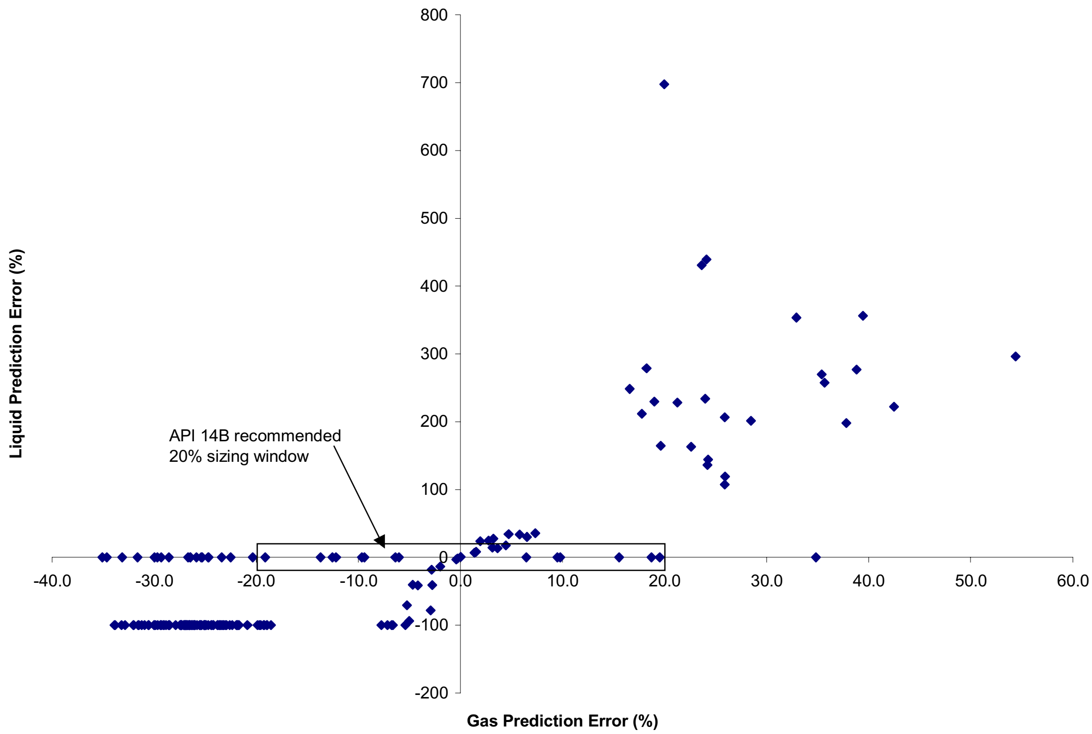

Figure 4. Plot of the percent error for each test point. *The shaded box represents the ±20% sizing window recommended by API 14B. Most of the test points fall outside this wi ndow.*

In addition, actual sizing model errors can be expected to be higher than the errors shown in these results. These results only show the inaccuracy of the correlations used to calculate the valve closing differential pressure and calculate the multiphase pressure drop across the valve choke. The fluid (nitrogen and water) properties are known, and the flowing static pressure and temperature at the valve are measured. In real applications of these models, additional errors would be introduced because fluid composition and properties are not known precisely, and the flowing static pressure and temperature are estimated from the conditions at the well head and the desired closing flow rate.

One other result that can be gathered from the test data is an indication of valve repeatability. Valve repeatability is the ability of the valve to consistently close at approximately the same flow rates for a given set of flowing conditions. The closing differential pressure for each valve configuration is primarily a function of the choke size and spring/spacer combination. For this testing the differential pressure was measured across the valve. Since, in subcritical flow, the differential pressure is proportional to the flow rate, the differential pressure measured when the valves close is a good indication of the valve repeatability. Tables 3 and 4 show the coefficient of variation of the closing differential pressures for all the tested valve configurations. The coefficient of variation is the ratio of the standard deviation of the measured closing differential pressure to the mean of the measured closing differential pressure expressed as a percentage; this dimensionless value gives an indication of the amount of variation of the valve closings.

Table 3. Manufacturer A's valve closing repeatability. *(The coefficient of variation is the ratio of the standard deviation to the mean of the measured closing differential pre ssures.)*

Valve Configuration	Coefficient of variation for the measured closing differential pressures (%)
Choke A, Spacer C	1.96
Choke B, Spacer A	3.10
Choke B, Spacer B	3.96
Choke B, Spacer C	4.56
Choke C, Spacer A	4.83

Table 4. Manufacturer B's valve closing repeatability. *(The coefficient of variation is the ratio of the standard deviation to the mean of the measured closing differential pre ssures.)*

Valve Configuration	Coefficient of variation for the measured closing differential pressures (%)
Choke A, Spacer A	8.89
Choke A, Spacer B	5.89
Choke A, Spacer C	7.14
Choke B, Spacer A	9.59
Choke B, Spacer B	9.32

Manufacturer A's valve showed less variation than Manufacturer B's valve with coefficients of variation ranging from 1.96 to 4.83% compared to 5.89 to 9.59% for Manufacturer B's valve. Since the differential pressure is proportional to the flow rate, these results indicate that the closing flow rates would vary by approximately these same percentages. The magnitude of these variations in repeatability do not seem too large; however, when these variations are combined with the errors associated with predicting the closing rates, the overall error is substantial.

CONCLUSIONS/RECOMMENDATIONS

The test program conducted during this phase consisted of testing a velocity valve from two different manufacturers with five different choke and spring/spacer combinations each. Each configuration was tested under a variety of single-phase gas conditions using nitrogen, and a variety of multiphase conditions using nitrogen and water. The manufacturers' sizing models were assessed by comparing the model predictions and the test closing points for each manufacturer's respective valves. For each single-phase gas test point, the modified models were exercised to obtain a predicted closing rate for each flowing condition. The prediction error for each multiphase test point was calculated separately for the liquid flow rate and the gas flow rate. Table 5 shows the magnitude and range of each manufacturer's model prediction errors, and the number of tests conducted.

Table 5. Summary of predicted errors. *The negative errors indicate that the model under-predicted the closing flow rate. If the model under-predicts the closing flow rate, the possibility exists that the reservoir may not be capable of flowing enough fluid to close the valve, thus making the valve ineffective.*

Manufacturer	Range of Average Predicted Liquid Error	Range of Average Predicted Gas Error	Number of Test Points
A	-31.9% to 373.6 %	-3.3% to 33.7%	66
B	-100%*	-23.3% to –28.0%	107

* Note: The –100% errors for the water indicate that the model did not predict any water flow at each test point's corresponding gas flow rate.

Regardless of the models' capability to predict the closing flow rates, the valve's repeatability needs to be addressed. Valve repeatability is the ability of the valve to consistently close at approximately the same flow rates for a given set of flowing conditions. The closing differential pressure for each valve configuration is primarily a function of the choke size and spring/spacer combination. For this testing, the differential pressure was measured across the test valve. Since, in subcritical flow, the differential pressure is proportional to the flow rate, the differential pressure measured when the valve closes is a good indication of the valve's repeatability. Table 6 shows a measure of the repeatability for each valve tested.

Table 6. Valve closing repeatability. *The coefficient of variation is the ratio of the standard deviation of the measured closing differential pressure to the mean of the measured closing differential pressure, expressed as a percentage.*

Manufacturer	Average Coefficient of Variation	Number of Test Points
A	3.7%	66
B	8.2%	107

The magnitude of these variations are not extremely large; however, when these variations are combined with the errors associated with predicting the closing rates, the overall error is substantial.

The findings of this study indicate that MMS's concerns about the validity of the current sizing models are justified. In order for MMS to have confidence that velocity valves installed in oil and gas wells in OCS waters will provide adequate protection, a number of options exist. The options identified include:

- Update existing manufacturers' models or develop new models

- Test each velocity valve in the lab before it is installed
- Test each velocity valve periodically in the well
- Terminate the use of velocity valves

Update Existing Models or Developing New Models

The literature search conducted for this study (summarized in Appendix A) showed that there are no currently available correlations that would accurately predict the multiphase pressure drop in velocity valves. Currently available empirical correlations predicting the multiphase flow pressure drop through chokes were developed for a specific valve size and geometry, and a relatively small range of multiphase flow patterns. Extensive experimental data would be required to validate (or redevelop) the correlations for different size chokes, different valve geometries, and a wider range of multiphase flow patterns.

Currently available theoretical correlations predicting the multiphase flow pressure drop through chokes were developed for relatively small diameter chokes, where the pressure drop is dominated by the acceleration of the fluids through the choke. These correlations are not applicable for the range of choke sizes typically found in velocity valves. Extensive experimental data would be required to develop theoretical correlations to predict the multiphase flow pressure drop through chokes in velocity valves.

Even if an accurate model could be developed to predict the flow rate at which velocity valves close, sizing models still may prove to be inaccurate. Accuracy would be limited by the quality of the model inputs. Existing correlations to estimate the well in-flow performance, downhole flowing temperature and pressure, and solution gas-oil ratio all contain inaccuracies. The sizing model would only be as good as the combined errors of these correlations. In addition, the repeatability of the velocity valve would add additional uncertainty. At this point, updating existing valve closure models or developing new models does not appear to be a practical solution because the developed sizing model is likely to still have errors in excess of ±40%.

Test Each Velocity Valve in the Lab

Manufacturers' existing models could be utilized to select a velocity valve size and preliminary configuration (choke and spacer set). The valve could then be tested in the lab to determine the actual flow rates at which the valve closes. Once this information is obtained, the valve could then be installed in the oil and gas well with the confidence that the closure flow rates are known with a little more accuracy. Unfortunately, unless real fluids are used (not nitrogen and water) at the pressures and temperatures expected at the location the valve will be installed, additional uncertainties will arise. Testing each valve in the lab would be expensive and would add additional delivery time to a product that may be needed on short notice.

With this method, each valve would be tested for the current well conditions in which the valve is to be installed. The method would not address the problem of changing well conditions unless the valve was retested periodically with the new well conditions to either ensure that the current valve configuration is appropriate or to resize the valve for the new conditions. This problem could be addressed by testing the valves with a number of configurations to provide a family of closing curves that could be used to size the valve for any well conditions. This may be cost-prohibitive because each valve would have to be tested with several bean and spring/spacer configurations with a number of different flowing conditions. At this point, lab testing each velocity valve to obtain proper valve sizing does not appear to be a cost-effective solution.

Test Each Velocity Valve in the Well

Manufacturers' existing models could be utilized to select a velocity valve size and preliminary configuration (choke and spacer set). The valve could then be tested in the well to determine the actual flow rates at which the valve closes. Unfortunately, this option would also be extremely expensive and inconvenient since additional equipment may have to be available on the platform to handle the increased production rate. In addition to the inconvenience and cost, allowing the well to flow at such high flow rates could be dangerous and possibly cause damage to the reservoir. Testing each velocity valve in the well does not appear to be a safe, practical, or cost-effective solution.

Terminate the Use of Velocity Valves

Unless MMS can have some confidence that the velocity valves installed in oil and gas wells will close at the desired flow rates, they may be required to terminate the use of these valves in OCS waters. At this point, only one velocity valve, from two different valve manufacturers, has been tested. It would be inappropriate to terminate the use of velocity valves based on this limited test data. Additional testing should be conducted to fully assess the accuracy of the current sizing models. Further testing should include several different valve sizes and models from each manufacturer, as well as numerous choke and spacer combinations for each valve. If the results are similar to those found in this study, terminating the use of velocity valves in the Gulf of Mexico should be considered.

Recommendation

The results and conclusions drawn from this study indicate that MMS's concerns about velocity valve sizing may be valid. At this point, it does not appear that updating or developing new models, lab testing, or field testing are cost-effective or practical solutions to address these concerns. Because only two valves were tested in this study, the results are not conclusive and it is not appropriate to make a decision about whether to terminate the use of velocity valves in OCS waters. Further testing should be conducted to gain enough information to make a clear judgment about the continued use of velocity valves.

Testing should include several different valve models from all the manufacturers that sell valves for use in OCS waters. Each valve should be tested with a number of different bean and spring/spacer combinations with a number of different flowing conditions. Sufficient results could be gained by testing with nitrogen and water as the test fluids. Nitrogen and water should give a less stringent test than with real production fluids. If the manufacturer's sizing models show significant errors with the nitrogen and water tests, than it can reasonably assumed that results for real production fluid testing would be worse. In this case, no further testing would be required. If the nitrogen and water tests are not conclusive, then further testing with real production fluids may be required. The expected result from this more extensive testing should be enough information to confidently make a clear judgment about whether to terminate the use of velocity valves in OCS waters.

Attachment 1

Update on Velocity Valve Performance (Letter Dated December 1, 1997)

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Department of Fluids Engineering
December 1, 1997

Mr. William S. Hauser
Minerals Management Service
Engineering and Standards Branch
Mail Stop 4700
381 Elden Street
Herndon, VA 22070

Reference: SwRI Project 04-1298, "Allowable Leakage Rates and Reliability of Safety and Pollution Prevention Equipment;" MMS Contract No. 1435-01-97-CT-30866

Subject: Update on Velocity Valve Performance Model

Dear Bill:

The purpose of this letter is to update you on the progress of the development of a model to predict the performance of velocity-type subsurface controlled subsurface safety valves (SSCSV). The model development may be broken down into two main correlations. One correlation is needed to predict the required differential pressure across the valve to overcome all forces tending to keep the valve in the open position, mainly the spring force. The other correlation is needed to calculated the differential pressure across the valve as a function of the liquid and gas flow rates, and fluid properties. The valve should close when the calculated differential pressure based upon the flow rate is equal to or exceeds the calculated differential pressure required to close the valve. Thus far, a number of papers pertaining to velocity valves and multiphase flow pressure drops through chokes have been reviewed. A number of issues that concern us regarding the development of a velocity valve performance model have been uncovered during this review. The following is a list these concerns:

- Based upon work done by Beggs et al. ("Pressure Drop and Closure Forces in Velocity-Type Subsurface Safety Valves," published in the 1977 API Annual Meeting Papers, Production Department) and SwRI testing experience, it has become evident that velocity valves are not very repeatable. Multiphase flow data collected by Beggs et al. showed that the velocity valves tested were not very repeatable under similar test conditions. SwRI testing experience leads us to believe that the repeatability will be further affected by varying operating conditions such as temperature. There is no evidence to suggest that the repeatability of velocity valves has significantly improved over the past twenty years.

- Initially, it was thought that a simple force balance model would suffice to calculate the differential pressure (acting across the bean surface perpendicular to the flow) required to overcome the spring force in order to close the valve. Based upon work done by Beggs et al., it has become apparent that experimental data will be required to develop correlations to predict the differential pressure required to close the velocity valve. Furthermore, experimental data will be required for various valve models, sizes, choke sizes, and number of spacers. Based on data collected by Beggs et al., two correlations were developed to predict the differential pressure required to close the valve. One correlation was for a 2-3/8 inch nominal Otis J valve, and the other was for a 2-3/8 inch nominal Camco A-3 valve. The estimated uncertainty of the correlation for the Otis valve was approximately ±15%, while the estimated uncertainty of the correlation for the Camco valve was approximately ±20%. If experimental data is not used to develop similar correlations for other valves, uncertainties in the prediction of the differential pressure required to close the valve are expected to be much greater than ±20%. Based upon previous test data and SwRI testing experience, we feel that with extensive testing, the uncertainty will be no better than ±15% to ±20% because of the non-repeatability of valve designs in different operating environments and conditions.

- Currently available empirical correlations predicting the multiphase flow pressure drop through chokes were developed for a specific valve size and geometry, and a relatively small range of multiphase flow patterns. Experimental data will be required to validate (or redevelop) the correlations for different size chokes, different valve geometries, and a wider range of multiphase flow patterns.

- Currently available theoretical correlations predicting the multiphase flow pressure drop through chokes were developed for relatively small diameter chokes, where the pressure drop is dominated by the acceleration of the fluids through the choke. These correlations are not applicable for the range of choke sizes typically found in velocity valves. The multiphase flow data (collected by Beggs et al. for the measured pressure drop required to close the valve) revealed that there was no definite trend toward larger differential pressures as the choke size increased. This indicates that the flow induced forces acting on the flow tube resulted from both the differential pressure due to accelerating the fluids through the choke and the frictional losses through the entire flow tube. To our knowledge, there are currently no theoretical correlations available that are applicable to multiphase flow through a velocity-type valve.

- API 14BM evaluates the pressure drop across the choke based upon the following assumptions:

    a) Liquid flow through the bean is described by the equation for an incompressible fluid through an orifice.

b) Subcritical gas flow through the bean is adiabatic and is described by the equation for compressible fluid flow through an orifice.
c) Subcritical, two-phase, compressible flow through the bean is described by interpolating between the results from the compressible and incompressible orifice flow equations in proportion to the volumetric fraction of free gas in the stream approaching the orifice.

API 14BM is simply an interpolation between single-phase liquid and gas models. Industry experience has shown that this type of correlation does not work well for multiphase flow.

In summary, our review of the current methods available for predicting velocity valve closure indicates that an adequate model does not exist. When the uncertainty of the current models for closure differential pressure and flowing differential pressure are combined, the cumulative uncertainty in the closure flow rate could be in excess of ±40%. In order to provide MMS with a useful velocity valve prediction tool, we feel it will be necessary to refocus this phase of the project. The following is a list of possible options of how to proceed.

Multiphase Flow Correlations:

1. Develop New Empirical Correlation

Advantages:

a. If enough data is collected, this correlation should be more accurate than existing correlations.

Disadvantages:

a. Expensive and time consuming.

2. Use Ashford and Pierce Empirical Correlation (1975)

Advantages:

a. Correlation should account for both acceleration and frictional losses.

Disadvantages:

a. Data used for correlation development comes from a single valve, and will most likely not work well for other valve geometries.

b. Data used for correlation development did not represent a wide range of multiphase flow patterns or fluid properties, and will most likely not work well for a wide variety of multiphase flow patterns or fluid properties.

3. Use Beggs, Brill, Proaño, and Roman-Lazo Empirical Correlation (1977)

Advantages:

a. Correlation should account for both acceleration and frictional losses.

Disadvantages:

a. Data used for correlation development comes from a single valve, and will most likely not work well for other valve geometries.
b. Data used for correlation development did not represent a wide range of multiphase flow patterns or fluid properties, and will most likely not work well for a wide variety of multiphase flow patterns or fluid properties.

4. Use Sachdeva, Schmidt, Brill and Blais Theoretical Correlation (1986)

Advantages:

a. Theoretical model.

Disadvantages:

a. Correlation will not work well with choke sizes typically found in velocity valves.
b. Does not include frictional losses, which would limit the model's accuracy.

5. Use API 14BM Correlation

Advantages:

a. Simple model.

Disadvantages:

a. Industry experience has shown that this correlation does not work well for multiphase flow.

Differential Pressure Closure Correlation

1. Determine Experimentally for Each Valve

Advantages:

a. Would provide the most accurate data.

Disadvantages:

a. Expensive and time consuming.
b. May not be able to obtain every model and size from the valve manufacturers.
c. Based on data collected by Beggs et al., uncertainty of closure differential pressure on the order of ±15% to ±20% can be expected.

2. Predict Closure Differential Pressure Based on Static Force Balance

Advantages:

a. No experimental data required, just valve dimensional data and spring rates.

Disadvantages:

a. Does not account for spring binding and seal gripping forces.
b. Uncertainty of the closure differential pressure much greater than ±20% can be expected.

SwRI would like to schedule a teleconference with MMS to discuss these options, and to determine how to proceed with the model development in light of the new information found. Please call me at (210) 522-3307 at your earliest convenience so that a teleconference can be scheduled.

Sincerely,

J. Christopher Buckingham
Project Manager

JCB:*jw*

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cc: A. Barajas, D. Walter, P. Spencer

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Attachment 2

Task 140 Description

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TASK 140. VELOCITY-TYPE VALVES

Objective: The objective of this task is to evaluate current manufacturers' velocity valve sizing models and compare each model's prediction to laboratory test data collected at Southwest Research Institute (SwRI). These data will be used to conclude the accuracy of each velocity valve sizing models.

Approach:

1. A copy of the velocity valve sizing programs from the manufacturers.
2. Based upon sizing information from these models and SwRI equipment capabilities, a velocity valve size will be selected for testing from each manufacturer.
3. An abbreviated test matrix will be developed to help evaluate the manufacturers' velocity valve sizing models under single-phase gas conditions and a limited number of valve configurations. The testing will be conducted in the existing SwRI Flowing Gas Test Facility.
4. Tests will be conducted to determine the closure flow rate for each valve under the flowing gas conditions and valve configurations defined in the test matrix.
5. Each velocity valve sizing model will be exercised under each test condition and valve configuration to determine how well the model predicts the velocity valve closure flow rate noted during testing.
6. Based upon the results of the single-phase testing, a decision will be made to either terminate the testing or continue with multiphase flow testing. If single-phase results show that the models are not accurate for single-phase, we may jointly decide to conclude that the models will not be accurate for multiphase flow and testing may be terminated. If the results are inconclusive or the models appear to work, we most likely will agree that multiphase flow testing will be performed.
7. If multiphase flow testing is desirable, a test matrix will be developed to help evaluate the manufacturers' velocity valve sizing models under a range of multiphase flow conditions and valve configurations.
8. Based upon the expected closure flow rates of the velocity valves to be tested, modifications to SwRI facilities will be made to allow multiphase flow testing of the three valves.
9. Tests will be conducted to determine the closure flow rate for each valve under the various multiphase flow conditions and valve configurations defined in the test matrix.
10. Each velocity valve sizing model will be exercised under each test condition and valve configuration to determine how well the models predict the velocity valve closure flow rate noted during testing.
11. The results of how each model predicted the actual test data will be reported.

Deliverable: Topical report describing the test stand, test procedure, and test results.

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APPENDIX E

Topical Report 5
Establish Risks

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CONSEQUENCES AND RELATIVE ENVIRONMENTAL IMPACT OF VARYING OFFSHORE SAFETY VALVE LEAK RATES

Prepared For

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March 5, 1999
99-02-6355

CONSEQUENCES AND RELATIVE ENVIRONMENTAL IMPACT OF VARYING OFFSHORE SAFETY VALVE LEAK RATES

INTRODUCTION

Within those areas of the Outer Continental Shelf (OCS) where offshore oil and gas production platforms fall under the jurisdiction of the Minerals Management Service, each production string (a.k.a. production tubing or wellhead riser) must be equipped with a subsurface safety valve (SSSV) and each flowline downstream of each wellhead must be equipped with a surface safety valve (SSV). (Figure 1 illustrates the general locations of these valves.) These valves are designed to close automatically when certain types of accidents occur, thereby stopping the flow of produced fluids (oil, gas, water). Ideally, there should be no fluid flowing through a closed SSSV or SSV. However, these valves are not always 100% effective at preventing the flow of produced fluids. The resulting flow of fluid through a closed valve is generally referred to as internal leaking.

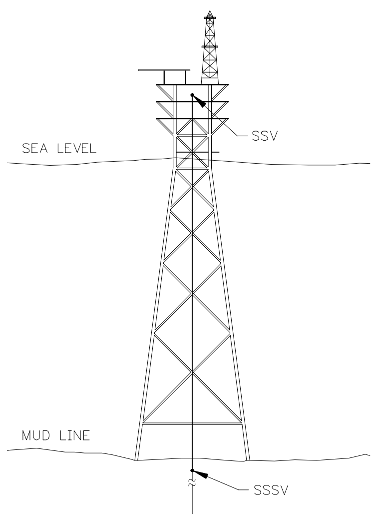

Figure 1. Locations of Surface Safety Valves and Subsurface Safety Valves.

If an SSSV and/or an SSV has been closed as a result of an accident that released oil or gas to the environment, the leakage of oil or gas through closed safety valves could pose a hazard to the environment, to equipment on the platform, and to personnel who respond to the accident or are charged with repairing affected equipment. The extent or severity of the hazard may depend on the rate at which oil and/or gas continues to flow through the closed valve(s) and the duration of the continued leakage. The American Petroleum Institute (API) and the Minerals Management Service (MMS) have established maximum allowable leakage rates for SSSVs and SSVs, but, as shown in Table 1, the maximum leakage rates allowed by the MMS (30 CFR 250) [Ref. 1] are lower than the corresponding leakage rates recommended by the API (API 14B and 14C) [Ref. 2 and 3]. Operators of offshore production platforms in OCS waters are currently required, by law, to periodically test the leakage rates of SSSVs and SSVs, and repair or replace those valves that do not meet the more stringent leakage requirements of the MMS.

Table 1. Specifications for Maximum Allowable Leakage Rates from Surface and Subsurface Safety Valves.

Valve Type	Standard Reference	Maximum Allowable Leakage Rates	
		Liquid (cc/min)	Gas (SCFM)
Subsurface Safety Valves	API 14B	400	15
	30 CFR 250.804	200	5
Surface Safety Valves	API 14C	400	15
	30 CFR 250.804	0	0

The purpose of this study is to provide a technical basis for the selection of appropriate leakage rates for SSSVs and SSVs, especially comparing the leakage rates allowed by API and 30 CFR. This study accomplishes this by:

- computing the extent and gravity of hazards that could be posed to the environment, equipment, and personnel as a result of continued leakage of oil or gas through closed SSSVs and SSVs, and
- illustrating how through-valve leakage rate could affect the extent and severity of these hazards.

RELEASE SCENARIOS AND HAZARDS

In the operation of an offshore oil and gas platform, there are a number of different scenarios in which a surface safety valve and subsurface safety valve will be required to close. In order to identify the potential hazards of leaking valves, these scenarios were defined as follows:

- The emergency shutdown system (ESD) may be activated either manually or automatically for a number of reasons. Once the ESD system is activated, both the SSV and the SSSV are closed.
- A ruptured hydraulic control line will cause the SSV and the SSSV to close.
- In the event that the production tubing is sheared or ruptured between the SSSV and the SSV, the SSSV will close, but the SSV will either be gone or it will have little effect upon the leakage from the ruptured section.
- In the event that the piping downstream of the SSV is ruptured, both the SSV and the SSSV will be closed.

The consequences associated with each of these scenarios, for conditions when the valves are leaking or not leaking, are shown in Table 2. The purpose of this table is to identify the potential hazards that are associated with these closure scenarios (that is, the type of material that would be released and in what location). For an ESD system activation or hydraulic control line rupture (with no production piping rupture), there will be no consequences if other wells in the header system are on-line and the leakage does not cause pressure buildup downstream of the SSV. If pressure downstream of the SSV is allowed to build up, a limited amount of gas will be flared after the pressure relief valve is activated.

Table 2. Consequences of Various Leakage Scenarios.

Scenario	Closed SSV		Closed SSSV		Consequence
	Leaking	Not Leaking	Leaking	Not Leaking	
1) Emergency Shutdown System Activated		✓		✓	None
		✓	✓		None
2) Hydraulic Control Line Ruptured	✓			✓	None, if other wells are on-line Limited gas to flare after relief valve is activated
	✓		✓		None, if other wells are on-line Limited gas to flare after relief valve is activated
3) Tubing Sheared or Ruptured Between SSSV and SSV	n/a	n/a		✓	None (except for the loss of inventory between SSSV and SSV)
	n/a	n/a	✓		Gas and oil released into the water or workspace
4) Rupture Downstream of SSV		✓		✓	None (except for the loss of inventory downstream of SSV)
		✓	✓		None (except for the loss of inventory downstream of SSV)
	✓			✓	Limited inventory of gas and oil released into workspace
	✓		✓		Gas and oil released into workspace

n/a indicates consequences are not affected by the condition of the SSV.

The consequences of ruptured tubing between the SSSV and the SSV depend upon where the rupture occurs. If the rupture occurs on the platform, then oil and gas may be released into the workspace. If the rupture occurs above sea level but below the platform, it is unlikely that the oil and gas will be released in the workspace. If the rupture occurs at or below sea level, then the oil and gas will be released into the water. In the event that the rupture occurs downstream of the SSV, a limited inventory of oil and gas may be released into the workspace. In most instances, the inventory of oil and gas released as a result of a rupture would far exceed the inventory of oil and gas allowed to leak past the SSSV or the SSV.

Based upon the consequences of the various scenarios, the following hazards were considered in this study:

For gas releases:

- toxic hazards (inhalation of gas containing H2S)
- flash fire hazards (personnel burns from ignited flammable clouds)
- torch fire hazards (damage to equipment and personnel from ignited vapor jet releases)
- vapor cloud explosion hazards (damage to equipment and personnel from overpressures generated by the explosion of a flammable vapor cloud)
- environmental impact (damage to the environment from natural gas releases)

For liquid releases:

- flash fire hazards (personnel burns from ignited flammable clouds)
- pool fire hazards (damage to equipment and personnel from heat radiating from ignited liquid pools)
- vapor cloud explosion hazards (damage to equipment and personnel from overpressures generated by the explosion of a flammable vapor cloud)
- environmental impact (damage to the environment from hydrocarbon liquid releases)

STUDY PARAMETERS AND RESULTS

To complete this study, the CANARY by Quest® consequence analysis package was used to model gas and liquid releases at varying leak rates. This package contains a set of complex models that calculate release conditions, initial dilution of the vapor (dependent upon release characteristics), the subsequent dispersion of the vapor introduced into the atmosphere, radiation from ignited jets or pools, and overpressures from exploding vapor clouds. The models contain algorithms that account for thermodynamics, mixture behavior, transient release rates, gas cloud density relative to air, initial velocity of the released material, and heat transfer effects from the surrounding air and the substrate. The release and dispersion models contained in the QuestFOCUS package (the predecessor to CANARY by Quest) were reviewed in a United States Environmental Protection Agency (EPA) sponsored study [Ref. 4] and an American Petroleum Institute (API) study [Ref. 5]. In both studies, the QuestFOCUS software was evaluated on technical merit (appropriateness of models for specific applications) and on model predictions for specific releases. In addition, all of the models contained in CANARY by Quest have been extensively reviewed. The release parameters and assumptions used for this modeling are given below.

<u>Gas Releases</u>

Gas releases were constrained by the following assumptions. The released material was treated as methane at 66°C (150°F) containing from 1 to 5 mole % H_2S, leaking from a 0.5-inch diameter hole. All releases were assumed to be horizontal and leaking at a regulated rate that was varied from 1 SCFM to 40 SCFM. A low wind speed (1.5 m/s or 3.4 mph) and stable atmosphere (Pasquil F) were assumed when modeling the extent of toxic and fire hazard zones.

Toxic Hazards

For the purposes of this study, the toxic hazard zone was defined as the maximum distance at which the airborne concentration of H_2S had been reduced to 100 ppmv, which is the IDLH (Immediately Dangerous to Life or Health) value established by NIOSH [Ref. 6]. (IDLH is defined as the maximum airborne concentration of toxic gas to which a person could be exposed for up to thirty minutes without suffering any escape-impairing symptoms or irreversible health effects.) Results of the toxic hazard zone calculations are shown in Figure 2. Examination of Figure 2 reveals that, for a release of gas containing 1 mole % H_2S, the toxic hazard zone varies from about 4 feet at a leak rate of 1 SCFM to about 18 feet at 40 SCFM. If the gas contains 5 mole % H_2S, the corresponding hazard distances increase to about 11 feet and 52 feet at leak rates of 1 SCFM and 40 SCFM, respectively. The lengths of toxic hazard zones produced by gas releases that equal the maximum leakage rates allowed by the MMS (30 CFR 250) and API (14B and 14C) are listed in Table 3.

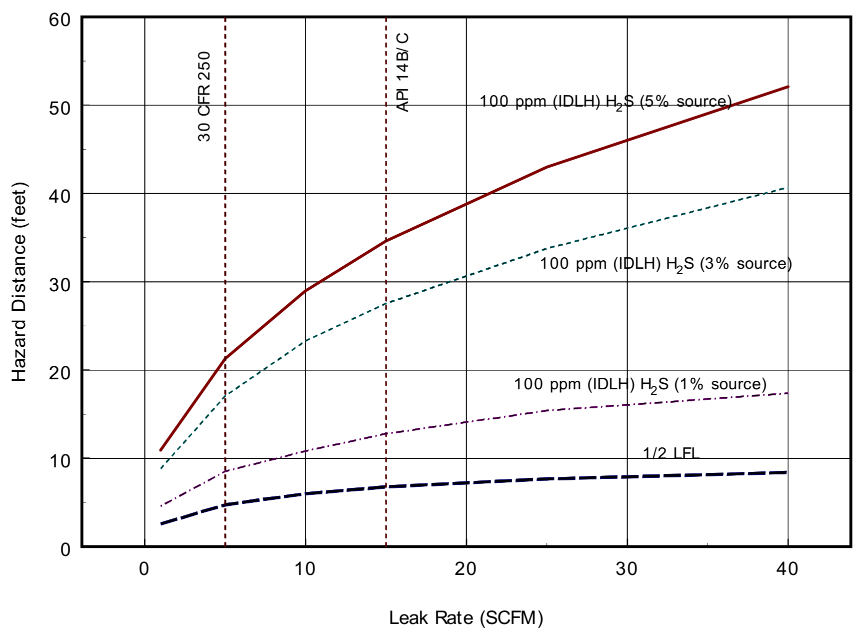

Figure 2. Flammable and Toxic Hazard Distances for Various Gas Leak Rates.

Flash Fire Hazards

Any release of flammable gas into the air will result in the formation of a flammable vapor cloud. If this cloud of flammable gas and air is ignited, one possible result is a flash fire, which simply means the flammable vapor in the cloud is consumed in a short period of time as the flame passes through the cloud. In the case of a gas release, the flash fire will typically be followed by a torch fire, which is discussed later in this section. Flash fires present a hazard to personnel only if a person comes into direct contact with the flame. Due to the short duration of a flash fire, it does not present a hazard to equipment. Flash fires present a hazard to personnel only if a person comes into direct contact with the flame. Due to the short duration of a flash fire, it does not present a hazard to equipment.

Table 3a. Length of Hazard Zones for Gas Releases – Subsurface Safety Valves.

Hazard Type	Subject of Hazard	Hazard End-point	Length of Hazard Zone (feet)	
			Leak Rate = 5 SCFM	Leak Rate =15 SCFM
Flash Fire	Personnel	1/2 LFL	5	7
Torch Fire	Personnel	Flame Length	<3	<3
Torch Fire	Equipment	Flame Length	<3	<3
Toxic Cloud				
1 mole % H_2S	Personnel	100 ppmv	9	13
3 mole % H_2S	Personnel	100 ppmv	18	28
5 mole % H_2S	Personnel	100 ppmv	21	35

Table 3b. Length of Hazard Zones for Gas Releases – Surface Safety Valves.

Hazard Type	Subject of Hazard	Hazard End-point	Length of Hazard Zone (feet)	
			Leak Rate = 0 SCFM	Leak Rate = 15 SCFM
Flash Fire	Personnel	1/2 LFL	0	7
Torch Fire	Personnel	Flame Length	0	<3
Torch Fire	Equipment	Flame Length	0	<3
Toxic Cloud				
1 mole % H_2S	Personnel	100 ppmv	0	13
3 mole % H_2S	Personnel	100 ppmv	0	28
5 mole % H_2S	Personnel	100 ppmv	0	35

A flammable vapor cloud is analogous to the toxic vapor cloud previously discussed, but the extent of the flammable cloud is based on the lower flammable limit of the gas mixture being released. When modeling flammable vapor clouds, the length of the flash fire hazard zone is often defined as the maximum distance at which the airborne concentration of the flammable gas has been reduced to one-half the lower flammable limit (1/2 LFL). Using the 1/2 LFL concentration rather than LFL introduces some conservatism into the analysis, which is generally warranted since a flammable vapor cloud might, for a brief period of time, extend beyond the time-averaged LFL boundary predicted by vapor dispersion models.

Results of the flash fire hazard zone calculations are shown in Figure 2. Examination of Figure 2 reveals that the flash fire hazard zones are quite short, varying from about 2 feet from the point of release at a leak rate of 1 SCFM to about 9 feet at 40 SCFM. The lengths of flash fire hazard zones produced by gas releases that equal the maximum leakage rates allowed by the MMS (30 CFR 250) and API (14B and 14C) are listed in Table 3.

Torch Fire Hazards

A torch fire can result from immediate ignition of a release of gas from a pressurized source, or from delayed ignition of a similar release, in which case it is preceded by a flash fire. The duration of a torch fire is limited only by the supply of fuel in the system, unless someone extinguishes the fire or the flow of fuel to the fire is stopped. Thus, it can present a hazard to personnel and to equipment. The extent of a torch fire hazard zone is typically defined as the maximum distance at which the thermal radiation emitted by the flame is of sufficient intensity to cause an undesirable effect. For personnel, a thermal radiation level of 1600 $Btu/hr{\cdot}ft^2$ is often used to define the hazard zone. At this intensity, unprotected skin might receive second degree skin burns after 30 seconds of exposure [Ref. 7]. For equipment, API RP 521 recommends limiting the radiation intensity to 5000 $Btu/hr{\cdot}ft^2$ [Ref. 8].

The torch fires that could result from ignition of gas being released at rates from 1 SCFM to 40 SCFM are quite short (ranging from about 2 feet to about 4.5 feet) and very narrow (less than 2 feet in diameter). The thermal radiation hazard zones produced by such fires are only marginally larger than the fires themselves. Thus, the torch fires included in this analysis present a hazard to equipment only if the equipment is in contact with the flame, and personnel could move out of the injury zone simply by moving one or two steps from the torch fire. Therefore, the calculated flame lengths are reported as the torch fire hazard zones. Flame length is plotted as a function of release rate in Figure 3. Examination of Figure 3 reveals that the torch fire hazard zones are quite short, varying from about 2 feet from the point of release at a leak rate of 1 SCFM to about 4.5 feet at 40 SCFM. The lengths of torch fire hazard zones produced by gas releases that equal the maximum leakage rates allowed by the MMS (30 CFR 250) and API (14B and 14C) are listed in Table 3.

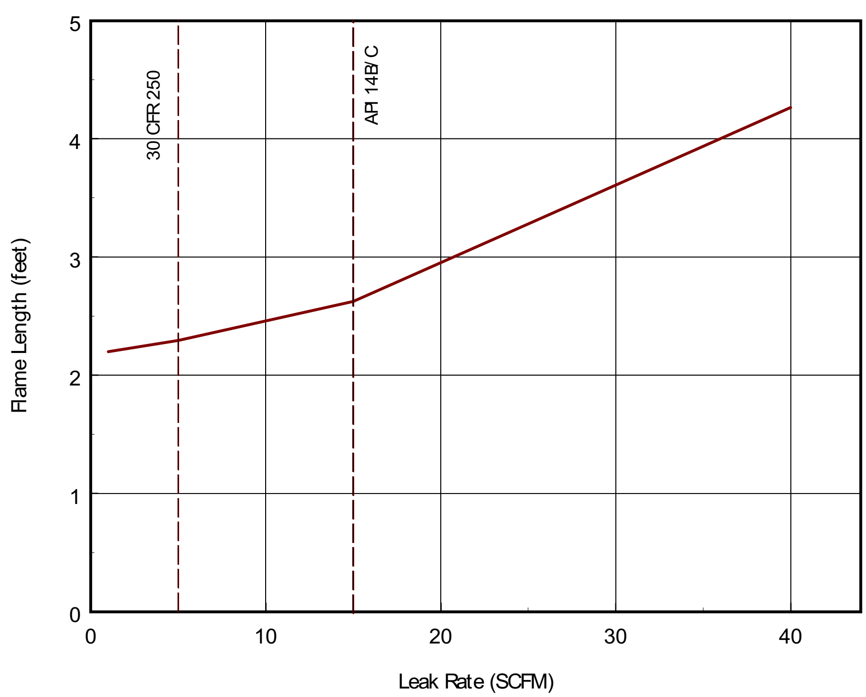

Figure 3. Effect of Gas Leak Rate on Flame Length.

Vapor Cloud Explosion Hazards

Under certain circumstances, a flammable vapor cloud might explode if ignited. Such behavior is not expected for the releases that are the subject of this study. All gas releases included in this study are small (maximum release rate of 40 SCFM) and produce small flammable vapor clouds (less than 10 feet in length) that contain only small amounts of flammable gas. API RP 750 suggests that vapor cloud explosions need not be modeled unless the process equipment is capable of releasing "5 tons of flammable gas or vapor in a period of a few minutes" [Ref. 9]. Although such a release might be possible on an offshore production platform, the releases that are the subject of this study are much too small to meet this criterion. Therefore, vapor cloud explosion hazard zones were not modeled.

Environmental Impact

Methane is the major constituent in the mixture of gases produced by most oil and gas wells. If the gas is burned, one of the products of combustion will be carbon dioxide. Both of these gases, methane and carbon dioxide, are greenhouse gases that are at the forefront of global warming discussions. In addition, if the gas contains H_2S, some oxides of sulfur will be produced if the gas is burned. Such compounds have been linked to acid rain. However, because the allowable leakage rates through SSSVs and SSVs are small and are expected to occur only rarely, these releases should present no significant environmental impacts. To illustrate this point, consider that one well-fed bovine cow or steer will emit as much as 85 kilograms of methane per year [Ref. 10]. Assuming a leakage rate of 5 SCFM through an SSSV, the release would need to continue for more than 12 hours to release the same amount of methane as one steer releases in one year.

Summary of Gas Release Results

Flash fires that could result from gas releases at rates up to 40 SCFM have the potential to cause burn injuries to persons who are not wearing protective clothing, but only if they are within about 10 feet or less of the point of release. Flash fires of the sizes included in this study do not pose a hazard to equipment or the environment.

Torch fires resulting from gas releases at rates up to 40 SCFM have the potential to cause burn injuries to persons or damage to pieces of equipment, but only if they are located within about 5 feet or less of the point of release. Torch fires of the sizes included in this study do not pose a hazard to the environment.

Unignited gas releases do not pose a hazard to equipment or the environment, but can be hazardous to persons if the gas contains H_2S. For gas that contains 1 mole % H_2S, the toxic hazard extends no more than 15 feet from the point of release if the release rate is limited to 15 SCFM (API 14B and 14C), or less than 10 feet if the release rate is limited to 5 SCFM (MMS maximum for SSSVs). For gas that contains 5 mole % H_2S, the toxic hazard extends no more than 35 feet from the point of release if the release rate is limited to 15 SCFM (API 14B and 14C), or less than 21 feet if the release rate is limited to 5 SCFM (MMS maximum for SSSVs).

These results indicate that toxic hazard zones can be larger than flash fire or torch fire hazard zones, but only if the gas contains more than about 1/2 mole % of H_2S.

Liquid Releases

For liquid releases, the released material was treated as heptane at 27°C (80°F). Heptane was chosen because it has volatility and flammability characteristics similar to those of condensate. Crude oil is typically less volatile and less flammable. Thus, using heptane to represent both condensate and crude oil provides some conservatism in the hazards analysis.

Release rates were varied from 10 cc/min to 1000 cc/min. A low wind speed (1.5 m/s or 3.4 mph) and stable atmosphere (Pasquil F) were assumed when modeling the extent of fire hazard zones.

Liquid releases that occur below the surface of the water will enter the water directly. For those that occur above the surface of the water, there are three possibilities.

1. The liquid might fall directly onto the surface of the water.
2. The liquid might fall onto a platform deck that is constructed of open grating, in which case the liquid will then fall onto the water.
3. The liquid might fall into a drip tray below a vessel or onto some part of a platform deck that is constructed of solid metal sheeting, in which case the liquid will form a pool on the platform.

Which of these three possibilities will apply to a given spill depends on the actual location of the leak and, to some extent, the construction of the platform. In order to be conservative, fire hazard calculations are based on the assumption that the liquid falls into a drip tray or onto solid decking, thereby allowing the creation of a liquid pool at least a few centimeters deep. Conversely, when considering environmental impacts, it was assumed that the liquid was released into or onto the water.

Flash Fire Hazards

Vapor generated by vaporization of a pool of flammable hydrocarbons may create a flammable vapor cloud as the flammable hydrocarbon vapor is diluted with air. If the flammable cloud is ignited, one possible result is a flash fire, which simply means the flammable vapor in the cloud is consumed as the flame passes through the cloud. Because the source of the vapor in the cloud is a pool of liquid, the flash fire will typically be followed by a pool fire, which is discussed later in this section. Flash fires present a hazard to personnel only if a person comes into direct contact with the flame. Due to the short duration of flash fires, they do not present a hazard to equipment.

The extent of a flash fire hazard zone is directly related to the size of the flammable vapor cloud at the time of ignition. In keeping with common practice, the length of the flash fire hazard zone was defined as the maximum distance at which the airborne concentration of the flammable gas has been reduced to one-half the lower flammable limit (1/2 LFL). Using the 1/2 LFL concentration rather than the LFL introduces some conservatism into the analysis, which is generally warranted since a flammable vapor cloud might, for a brief period of time, extend beyond the time-averaged LFL boundary predicted by vapor dispersion models.

The size of the flammable cloud created by a release of liquid hydrocarbons depends primarily on the rate of vaporization of the liquid (i.e., the volatility and temperature of the liquid), the area of the liquid pool that is the source for the cloud, and the weather conditions. For the purposes of this study, it was assumed that all liquid pools had a depth of 3.4 centimeters (which corresponds to the depth of a pool of heptane that will burn completely in 5 minutes). Each pool was assumed to be circular with a radius based on the assumed pool depth (3.4 cm) and the total amount of liquid spilled (i.e., the spill rate and duration). As a result, the maximum downwind extent of the flash fire hazard zone is a function of the release rate and duration, as illustrated in Figure 4.

Examination of Figure 4 reveals that spill volumes of less than 1000 cc produce flash fire hazard zones less than 1 foot in length. As spill volume increases from 1000 cc to 50,000 cc (50 liters), the flash fire hazard zone increases from about 1 foot to more than 50 feet.

Pool Fire Hazards

The primary hazard posed by a pool fire is thermal radiation. The distance from the center of a burning pool to the point at which the thermal radiation is no longer capable of causing injuries to persons or damage to equipment is primarily a function of the material that is burning, the size (area) of the pool,

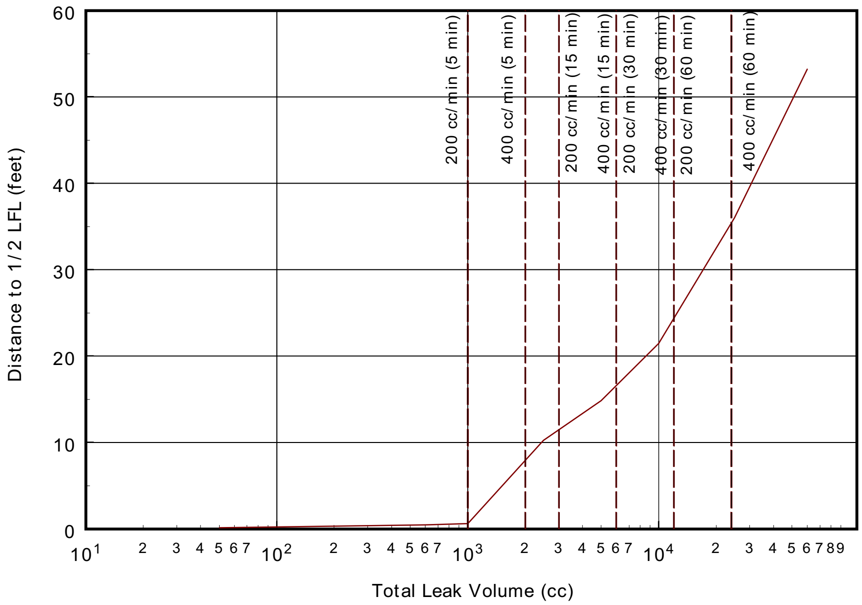

Figure 4. Flammable Hazard Distances Associated with Liquid Leak Volumes.

and weather conditions. For the purposes of this study, pool sizes were determined as previously described in the discussion of flash fire hazard zones.

The extent of a pool fire hazard zone is typically defined as the maximum distance at which the thermal radiation emitted by the flame is of sufficient intensity to cause an undesirable effect. For personnel, a thermal radiation level of 1600 Btu/hr·ft^2 is often used to define the hazard zone. At this intensity, unprotected skin might receive second degree skin burns after 30 seconds of exposure [Ref. 7]. For equipment, API RP 521 recommends limiting the radiation intensity to 5000 Btu/hr·ft^2 [Ref. 8]. Results of the pool fire hazard zone modeling are presented in Figure 5 and Table 4. Examination of Figure 5 reveals that

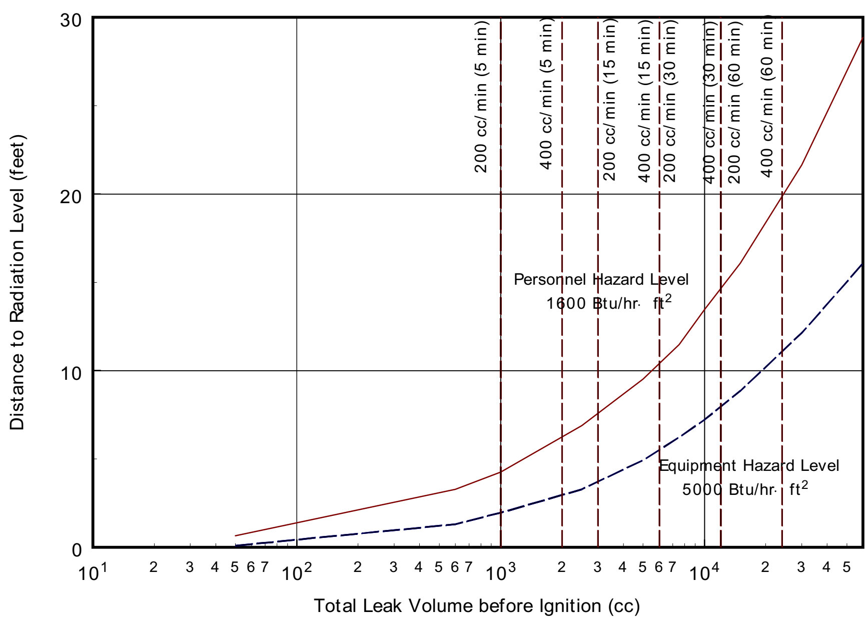

Figure 5. Effect of Liquid Volume on Distance to Radiant Heat Levels.
Table 4a. Length of Hazard Zones for Liquid Leaks from Subsurface Safety Valves.

Leak Duration/ Hazard Type	Subject of Hazard	Hazard Endpoint	Length of Hazard Zone (feet)	
			Leak Rate = 200 cc/min	Leak Rate = 400 cc/min
5 minutes				
Flash Fire	Personnel	1/2 LFL	1	8
Pool Fire	Personnel	1600 Btu/hr·ft^2	4	6
Pool Fire	Equipment	5000 Btu/hr·ft^2	2	3
15 minutes				
Flash Fire	Personnel	1/2 LFL	12	17
Pool Fire	Personnel	1600 Btu/hr·ft^2	8	11
Pool Fire	Equipment	5000 Btu/hr·ft^2	4	6
30 minutes				
Flash Fire	Personnel	1/2 LFL	17	24
Pool Fire	Personnel	1600 Btu/hr·ft^2	11	15
Pool Fire	Equipment	5000 Btu/hr·ft^2	6	8
60 minutes				
Flash Fire	Personnel	1/2 LFL	24	36
Pool Fire	Personnel	1600 Btu/hr·ft^2	15	20
Pool Fire	Equipment	5000 Btu/hr·ft^2	9	11

the pool fire hazard zones for equipment range from less than 1 foot for leaks of short duration, to about 16 feet for a spill volume of 50,000 cc (50 liters), which corresponds to 400 cc/min (API 14B and 14C) for about 2 hours or 200 cc/min (MMS maximum for SSSVs) for about 4 hours. The pool fire hazard zones for persons range from less than 1 foot for leaks of short duration, to about 29 feet for a spill volume of 50,000 cc (50 liters).

Vapor Cloud Explosion Hazards

Under certain circumstances, a flammable vapor cloud might explode if ignited. Such behavior is not expected for the releases that are the subject of this study. All liquid releases included in this study are small (maximum release rate of 1000 cc/min) and produce flammable vapor clouds that contain small amounts of flammable gas. API RP 750 suggests that vapor cloud explosions need not be modeled unless the process equipment is capable of releasing "5 tons of flammable gas or vapor in a period of a few minutes" [Ref. 9]. Although such a release might be possible on an offshore production platform, the releases that are the subject of this study are much too small to meet this criterion. Therefore, vapor cloud explosion hazard zones were not modeled.

Table 4b. Length of Hazard Zones for Liquid Leaks from Surface Safety Valves.

Leak Duration/ Hazard Type	Subject of Hazard	Hazard Endpoint	Length of Hazard Zone (feet)	
			Leak Rate = 0 cc/min	Leak Rate = 400 cc/min
5 minutes				
Flash Fire	Personnel	1/2 LFL	0	8
Pool Fire	Personnel	1600 Btu/hr·ft^2	0	6
Pool Fire	Equipment	5000 Btu/hr·ft^2	0	3
15 minutes				
Flash Fire	Personnel	1/2 LFL	0	17
Pool Fire	Personnel	1600 Btu/hr·ft^2	0	11
Pool Fire	Equipment	5000 Btu/hr·ft^2	0	6
30 minutes				
Flash Fire	Personnel	1/2 LFL	0	24
Pool Fire	Personnel	1600 Btu/hr·ft^2	0	15
Pool Fire	Equipment	5000 Btu/hr·ft^2	0	8
60 minutes				
Flash Fire	Personnel	1/2 LFL	0	36
Pool Fire	Personnel	1600 Btu/hr·ft^2	0	20
Pool Fire	Equipment	5000 Btu/hr·ft^2	0	11

Environmental Impact

It is difficult to state the environmental impact of small releases of hydrocarbon liquid in absolute terms. Therefore, this part of the study looked at the relative environmental impact of small releases by comparing such releases to other potential sources of liquid hydrocarbon pollutants. For example, if the production tubing between the SSSV and the SSV were to rupture, the inventory of hydrocarbons between these two valves could be released into the sea. Assuming the tubing has a diameter of 2 7/8 inches and the distance between valves is 300 feet, a rupture of the tubing could result in the release of 2.4 bbl of hydrocarbon. A second example would be a failure of a three-phase (oil/gas/water) separator on the platform. Assuming the separator is 8 feet in diameter and 12 feet long and 25% of its volume is occupied by hydrocarbon liquid, a failure of the separator could result in the release of 26.8 bbl of hydrocarbon onto the sea. In order to release the same amount of liquid as the production tubing example (2.4 bbl), a leak of 200 cc/min would need to continue for about 30 hours, or a leak of 400 cc/min would need to continue for about 15 hours. To release the same amount of liquid as the separator example (26.8 bbl), a leak of 200 cc/min would need to continue for about 2 weeks, or a leak of 400 cc/min would need to continue for about 1 week. This is illustrated in Figure 6.

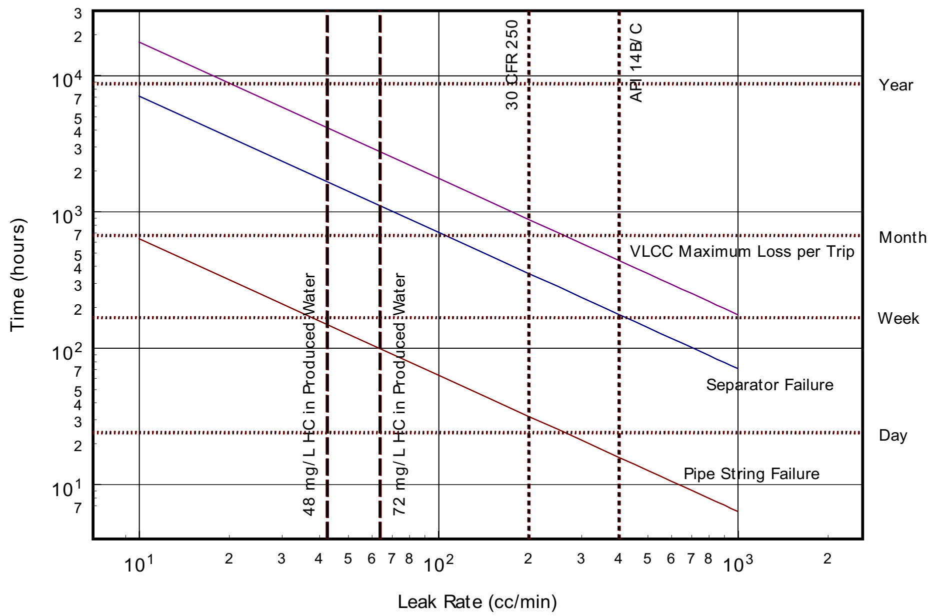

Figure 6. Liquid Leak Rate versus Time to Equal Volume of Various Events.

Crude oil tankers are another possible source of liquid hydrocarbon pollutants. According to MARPOL 1973/1978, one-thirty-thousandth (1/30,000) of the total cargo volume of a crude oil tanker is the maximum allowable release volume per ballast voyage [Ref. 11]. Thus, for a VLCC (very large crude carrier) with a cargo capacity of two million barrels, the maximum allowable release per ballast voyage is 66.7 bbl. To release this same amount of liquid (66.7 bbl), a leak of 200 cc/min would need to continue for more than one month, or a leak of 400 cc/min would need to continue for more than 2 weeks. This is illustrated in Figure 6.

Another source of liquid hydrocarbon pollutants is produced water (i.e., water that comes from the producing formation along with the oil and gas). In most of the Gulf of Mexico, government regulations allow produced water to be released into the sea, but only after nearly all hydrocarbons have been removed from the water. According to 40 CFR 435.12, the maximum 30-day average concentration of hydrocarbons in produced water is 48 mg/liter, and the daily maximum is 72 mg/liter [Ref. 12]. A platform that produces 10,000 bbl of oil per day might produce about 8,000 bbl of water per day. If this produced water contains 48 mg of hydrocarbons per liter of water (the maximum allowable 30-day average concentration), the discharge of 8,000 bbl of produced water per day would include the discharge of approximately 1/2 bbl of oil per day. This rate, 1/2 bbl per day, is roughly equal to 50 cc/min, which is about 1/4 of the 200 cc/min allowable valve leakage rate, or 1/8 of the 400 cc/min allowable valve leakage rate. Thus, in one month (31 days), a platform that produces 8,000 bbl of water per day could legally discharge the same amount of hydrocarbon liquid as a 200 cc/min leak would release in about 8 days, or a 400 cc/min leak would release in about 4 days.

Summary of Liquid Release Results

The liquid releases that are the subject of this study (i.e., low rate releases of hydrocarbon liquid) have the potential to produce one or more of the following hazards: flash fire, pool fire, environmental impact. For a release that results in a flash fire and/or a pool fire, the extent of the hazard zone depends not only on the release rate, but also on the duration of the release. The degree of environmental impact also depends on release rate (valve leakage rate) and the duration of the release. For a given valve leakage rate, such as 200 cc/min, the potential flash fire and pool fire hazard zones and the degree of environmental impact all increase as the duration of the release increases. Thus, it is difficult to compare the effects of liquid releases of varying leakage rates unless all releases are assumed to have the same duration. Therefore, the following discussion of results is based on the assumption that a liquid release will either be ignited within the first hour of its existence or it never ignites.

Based on the assumptions made during this study, a flash fire that occurs after liquid has been released at a rate of 200 cc/min for one hour would have the potential to cause burn injuries to persons within about 25 feet of the liquid pool. If the release (valve leakage) rate is increased to 400 cc/min, the hazard zone increases to about 36 feet. (In both cases, it is assumed that the persons are not wearing protective clothing.)

Based on the assumptions made during this study, a pool fire that occurs after liquid has been released at a rate of 200 cc/min for one hour would have the potential to cause burn injuries to persons within about 15 feet of the liquid pool. If the release (valve leakage) rate is increased to 400 cc/min, the hazard zone increases to about 20 feet. (In both cases, it is assumed that the persons are not wearing protective clothing.) Equipment hazard zones resulting from these same two releases would extend about 8 feet from the liquid pool if the leakage rate is 200 cc/min, or about 11 feet if the leakage rate is 400 cc/min.

When comparing the environmental impact of liquid hydrocarbon being released into or onto the water, it is easy to see that, for a given leak duration, the amount of liquid hydrocarbon released is a linear function of the release rate. Thus, over a given period of time, a 400 cc/min release will put twice as much liquid in the water as a 200 cc/min release. However, since both of these leakage rates are small, it is more instructive to look at the length of time each of these releases would need to continue in order to release the same amount of liquid as could be released from other sources. As shown in Table 2, accidents that involve a release of liquid hydrocarbon from either the production tubing between the SSSV and the SSV or from some piece of production equipment downstream of the SSV are the only two scenarios in which a leaking SSSV or SSV is likely to result in a release of liquid hydrocarbons. Therefore, these two accident scenarios are probably the best sources of liquid hydrocarbon pollutants for use in such a comparison.

In order to release the same amount of liquid (2.4 bbl) as the production tubing example previously discussed, a leak of 200 cc/min would need to continue for about 30 hours, or a leak of 400 cc/min would need to continue for about 15 hours. To release the same amount of liquid (26.8 bbl) as the separator example previously discussed, a leak of 200 cc/min would need to continue for about 2 weeks, or a leak of 400 cc/min would need to continue for about 1 week. Thus, it is quite likely that the accident that triggers closing of the SSSV and/or the SSV will release more hydrocarbon liquid than would be allowed to leak through these valves in one day, or maybe even one week, following the accident.

CONCLUSIONS

The information presented in Table 2 demonstrates that a leaking SSSV or SSV can result in oil or gas being released into the environment only if some piece of equipment (such as a pipe, gasket, pump body, vessel, etc.) has failed in such a way that oil or gas has already been released into the environment. Therefore, when discussing the relative severity of hazardous conditions that could result from continued leakage through an SSSV or SSV, there are two questions that need to be addressed.

1. How are the hazard zones affected by the through-valve leakage rate?

2. How do the hazard zones associated with through-valve leakage compare to the hazard zones associated with the release prior to closing the safety valves?

The answers to these two questions depend on the type of material being released (gas or oil); the location of the release (under water, above sea level but below the lowest working level of the platform, or on one of the working levels); platform-specific details (such as the use of solid decks or open-grating decks); and the type of hazard being evaluated (fire, toxicity, or environmental impact).

Gas Leakage Through SSSVs and SSVs

The rate at which gas is leaking through a closed SSSV is of concern only for accidents that involve a failure of the production tubing between the SSSV and the SSV. When considering personnel safety, such a leak is of primary concern if the gas is released into a working space on the platform. For equipment, any release that occurs above sea level could be of concern.

The rate at which gas is leaking through a closed SSV is of concern only for accidents that involve a failure of piping or production equipment downstream of the SSV. All such leaks are expected to release gas into the workspace on the platform. As a result, all such releases may be of concern to personnel and equipment.

Regardless of the type of hazard (fire, toxic, or environmental), the effects of the accident that triggers closing of the safety valves are likely to exceed the hazards posed by a 15 SCFM (API) release of gas through a closed SSSV or SSV.

Fire Hazard Zones
The flash fire and torch fire hazard zones for the leakage rates of interest for SSSVs, 5 SCFM (MMS) and 15 SCFM (API), are compared to one another in Figure 7. For both types of fire hazards, the hazard zones are short (less than 10 feet in length) and are only weakly affected by an increase in leakage (release) rate.

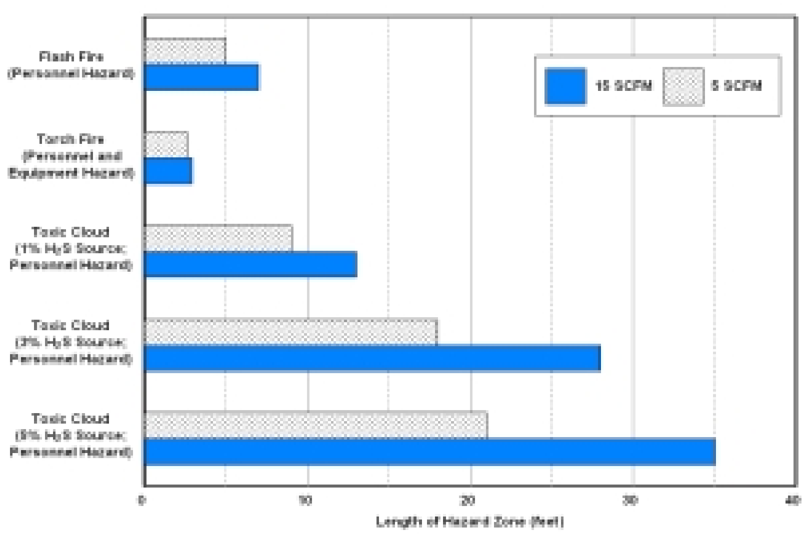

Figure 7. Comparison of Flash Fire, Torch Fire, and Toxic Hazard Zones for Gas Releases of 5 SCFM and 15 SCFM.

In contrast, the lengths of fire hazard zones associated with a gas release at the maximum SSV leakage rate allowed by the MMS should be zero since MMS regulations do not allow any gas leakage through a closed SSV. However, even after the SSV is closed, gas might continue to be released into the environment until such time as the gas inventory in piping or process equipment has been depleted. Thus, fire hazard zones can exist after the SSV is closed, even if no gas is passing through the SSV. In most cases, the fire hazard zones created by a continuing release of gas inventory could exceed the fire hazard zones associated with a release of gas at 15 SCFM. In addition, the effects of the accident that triggers closing of the safety valves are likely to exceed the hazards posed by a 15 SCFM release of gas through a closed SSV. Therefore, it could be argued that the MMS requirement of zero gas leakage through a closed SSV does not necessarily provide a significant increase in safety.

Based on this analysis, it would be difficult to use these fire hazard zones as a basis for selecting one maximum allowable leakage rate in preference to the other for either SSVs or SSSVs.

Toxic Hazard Zones

The toxic hazard zones for the leakage rates of interest for SSSVs, 5 SCFM (MMS) and 15 SCFM (API), are compared to one another in Figure 7. Since there is no toxic hazard when there is no leakage, the toxic hazard zones for the leakage rates of interest for SSVs, 0 SCFM (MMS) and 15 SCFM (API), are also compared in Figure 7. The figure illustrates how the percentage difference between the toxic hazard zones produced by 5 SCFM (MMS) and 15 SCFM (API) is relatively unaffected by the amount of H_2S in the gas being released, but the absolute difference increases as the amount of H_2S in the source increases. Thus, the relative importance of the difference in maximum allowable leakage rate increases as the mole % of H_2S in the gas increases.

Personnel who work on platforms that produce gas that contains H_2S, or who would respond following an accident on such a platform, are aware of the dangers of H_2S and would have appropriate personal protective equipment (such as self-contained breathing apparatus - SCBAs) available to them. They would be expected to employ this equipment before approaching the point of release, even if they believe the release has been stopped. Thus, the presence or absence of a toxic vapor cloud would make little difference in how personnel would respond to the accident. Once protected by appropriate personal protective equipment, the presence of a vapor cloud containing H_2S resulting from a leaking SSV of SSSV would not significantly affect personnel safety.

Vapor Cloud Explosions

For the leakage rates of interest for SSVs and SSSVs, 15 SCFM or less, the amount of flammable gas within a flammable vapor cloud will be so small that vapor cloud explosions are not considered a credible occurrence.

Environmental Impact

For the leakage rates of interest for SSVs and SSSVs, a release of natural gas at 15 SCFM or less is expected to have a negligible environmental impact, even if the release continues for several hours. If the leakage continues for several days, it may become a concern.

Liquid Leakage Through SSSVs and SSVs

The rate at which hydrocarbon liquid is leaking through a closed SSSV or SSV is of concern to personnel and equipment only if the liquid is released into a drip tray or onto a solid deck where it can form a pool.

The environmental impact is expected to be nearly independent of the location of the release, assuming the liquid ultimately reaches the water. Regardless of the type of hazard (fire or environmental), the effects of the accident that triggers closing of the safety valves are likely to exceed the hazards posed by a 400 cc/min (API) release of liquid through a closed SSV or SSSV.

Fire Hazard Zones
The flash fire and pool fire hazard zones for the leakage rates of interest for SSSVs, 200 cc/min (MMS) and 400 cc/min (API), are compared to one another in Figure 8. Since there is no flash fire and pool fire hazard when there is no leakage, the toxic hazard zones for the leakage rates of interest for SSVs, 0 cc/min (MMS) and 400 cc/min (API), are also compared in Figure 8. The fire hazard zone lengths illustrated in Figure 8 are all based on the assumption that the release continues for 60 minutes before the flammable vapor cloud or the liquid pool is ignited. If ignition occurs earlier, the hazard zone lengths would be shorter (see Table 4 and Figures 4 and 5). Figure 8 shows that the hazard zones associated with flash fires and pool fires are only weakly affected by an increase in leakage (release) rate

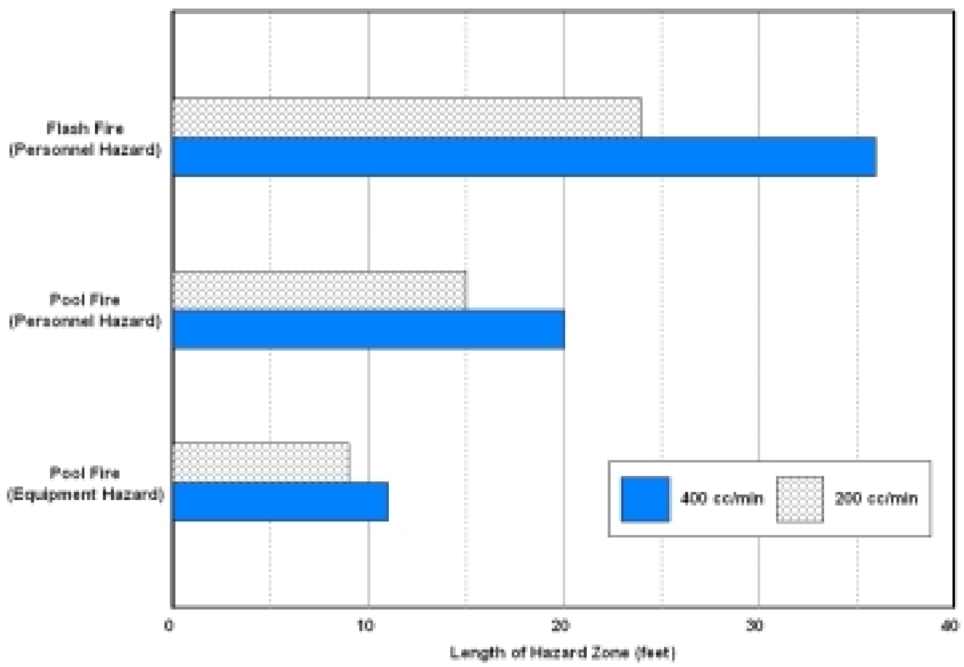

Figure 8. Comparison of Flash Fire and Pool Fire Hazard Zones for Liquid Releases of 200 cc/min and 400 cc/min, Based on Spills of 60 Minutes Duration Prior to Ignition.

(i.e., doubling the release rate from 200 to 400 cc/min causes the flash fire hazard zone length to increase by only 50%, and the effect on the length of the pool fire hazard zones is even less).

According to MMS statistics, there are approximately 3900 active offshore platforms in the Gulf of Mexico, and approximately 3300 producing oil wells [Ref. 13]. During the 10-year period from 1981 through 1990, the MMS recorded 329 spills of more than 1 bbl of liquid pollutants in the Gulf of Mexico Region; an average of 33 spills per year [Ref. 14]. These spills included releases of diesel fuel and other liquid pollutants, in addition to releases of crude oil and condensate. They also included releases from sources other than offshore platforms, such as pipelines and workboats. Thus, the annual number of accidents that release crude oil or condensate into the workspace of a platform, and that allow formation of a liquid pool in a drip tray or on a solid deck, is expected to be much smaller than 33—the average number of liquid releases of 1 bbl or more per year.

There is a low probability of occurrence of accidents in which liquid leakage through an SSSV or SSV might be an important factor, and a high probability that the effects of the accident that triggers closing of the safety valves will exceed the hazards posed by a 400 cc/min (API) release of liquid through a closed safety valve. Therefore, it could be argued that the MMS requirement of zero liquid leakage through a closed SSV does not necessarily provide a significant increase in safety.

Based on the low probability of accidents in which liquid leakage rate through a closed safety valve might be an important factor, and the weak influence of leakage rate on fire hazard zone length, it would be difficult to use fire hazard zones as a basis for selecting one maximum allowable leakage rate in preference to the other for either SSVs or SSSVs.

Vapor Cloud Explosions
For the leakage rates of interest for SSVs and SSSVs, 400 cc/min or less, the amount of flammable gas within a flammable vapor cloud will be so small that vapor cloud explosions are not considered a credible occurrence.

Environmental Impact
Unlike the flash fire and pool fire hazard zones, the environmental impact is directly related to the release rate (i.e., for a release of given duration, doubling the allowable leakage rate from 200 to 400 cc/min results in twice as much liquid entering the water). Thus, the difference between 0 cc/min (MMS for SSVs), 200 cc/min (MMS for SSSVs), and 400 cc/min (API) appears to be significant. However, MMS records show that 42,534 bbl of liquid pollutants were released into the Gulf of Mexico during the 10-year period from 1981 through 1990, as a result of accidents involving offshore platforms, associated pipelines, workboats, etc. [Ref. 14]. This is an average of 4253 bbl per year. Thus, when compared to the amount of hydrocarbon liquid that could be released as a result of the accident that triggers closing of the safety valves, or from other sources that are present in the Gulf, it is difficult to argue that a limited duration release of liquid hydrocarbon at 400 cc/min is a significant source of pollution.

Summary of Conclusions

Leakage of oil or gas through a closed SSSV or SSV can result in oil or gas being released into the environment only if some piece of equipment (such as a pipe, gasket, pump body, vessel, etc.) has failed in such a way that oil or gas has already been released into the environment. The hazard zones and environmental impact of oil and gas releases associated with releases at the maximum allowable leakage rates specified by the MMS are smaller than those associated with releases at rates allowed by the API. However, if the leakage rates through closed safety valves are limited to the maximum allowable leakage rates specified by either the MMS or the API, the fire, toxic, and environmental hazards associated with the accident that triggers closing of the safety valves are likely to exceed the hazards posed by the low-rate release of gas or liquid through a closed safety valve. Thus, differences between the hazards posed by releases of oil or gas at rates allowed by the MMS or at the higher rates allowed by the API are likely to be overshadowed by the hazards associated with the accident that occurred prior to closing the safety valves.

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APPENDIX F

Topical Report 6
Recommendations

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TOPICAL REPORT NO. 6
RECOMMENDATIONS

INTRODUCTION

Within the areas of the Outer Continental Shelf (OCS) where offshore oil and gas production platforms fall under the jurisdiction of the Mineral Management Service, each production string must be equipped with a subsurface safety valve (SSSV). In addition, each well head must be equipped with a surface safety valve (SSV). These valves are designed to close automatically when certain types of accidents occur, thereby stopping the flow of produced fluids. They can also be manually closed for accident prevention or maintenance operations. Ideally, there should be no fluid flowing through a closed SSV or SSSV. However, these valves are not always 100% effective in preventing the flow of produced fluids.

The American Petroleum Institute (API) and the Minerals Management Service (MMS) have established maximum allowable leakage rates for SSVs and SSSVs. As shown in Table 1, the maximum leakage rates allowed by MMS (30 CFR 250) are lower than the corresponding leakage rates recommended by API (API 14B and 14C). Operators of offshore production platforms in the Gulf of Mexico are currently required, by law, to periodically test the leakage rates of SSVs and SSSVs and repair or replace those valves that do not meet the requirements of 30 CFR 250.

The objectives of this task were to develop recommendations, based on the efforts completed during this project, for:

- Safety valve allowable leakage rates
- Test procedures (for both SSVs and SSSVs).

Table 1. Specifications for maximum allowable leakage rates for surface and subsurface safety valves.

Valve Type	Standard Reference	Maximum Allowable Leakage Rates	
		Liquid (cc/min)	Gas (SCFM)
Subsurface Safety Valves	API 14B	400	15
	30 CFR 250.804	200	5
Surface Safety Valves	API 14C	400	15
	30 CFR 250.804	0	0

ALLOWABLE LEAKAGE RATES

During the "Establish Risks" phase of this project, a study was conducted that identified the risks associated with varying leakage through SSVs and SSSVs. The purpose of the study was to provide a technical basis for the selection of appropriate leakage rates for SSVs and SSSVs, especially comparing the leakage rates recommended by API and allowed by 30 CFR 250. The study accomplished this by:

- Computing the extent and gravity of hazards that could be posed to the environment, equipment, and personnel as a result of continued leakage of oil or gas through closed SSVs and SSSVs.

- Illustrating how the through-valve leakage rate could affect the extent and severity of these hazards.

The following hazards were considered in the study:

For gas releases:

- Toxic hazardous (inhalation of gas containing hydrogen sulfide)

- Flash fire hazards (personnel burns from ignited flammable clouds)

- Torch fire hazards (damage to equipment and personnel from ignited vapor jet releases)

- Vapor cloud explosion hazards (damage to equipment and personnel from overpressures generated by the explosion of a flammable vapor cloud)

- Environmental impact (damage to the environment from natural gas releases)

For liquid releases:

- Flash fire hazards (personnel burns from ignited flammable clouds)

- Pool fire hazards (damage to equipment and personnel from heat radiating from ignited liquid pools)

- Vapor cloud explosion hazards (damage to equipment and personnel from overpressures generated by the explosion of a flammable vapor cloud)

- Environmental impact (damage to the environment from hydrocarbon liquid releases)

A summary of the results of the analysis is included below. The full report detailing the analysis and results may be found in Appendix E, Topical Report No. 5.

Gas Leakage

The rate at which gas is leaking through a closed SSSV is of concern only for accidents that involve a failure of the production tubing between the SSSV and the SSV. When considering personnel safety, such a leak is of primary concern if the gas is released into a working space on the platform. For equipment, any release that occurs above sea level could be of concern.

The rate at which gas is leaking through a closed SSV is of concern only for accidents that involve a failure of piping or production equipment downstream of the SSV. All such leaks are expected to release gas into the workspace on the platform. As a result, all such releases may be of concern to personnel and equipment.

Regardless of the type of hazard (fire, toxic, or environmental), the effects of the accident that triggers closing of the safety valves are likely to exceed the hazards posed by a 15 SCFM (API) release of gas through a closed SSSV or SSV.

Fire Hazard Zones

The flash fire and torch fire hazard zones for the leakage rates of interest for SSSVs, 5 SCFM (MMS) and 15 SCFM (API), are compared to one another in Figure 1. For both types of fire hazards, the hazard zones are short (less than 10 feet in length) and are only weakly affected by an increase in leakage (release) rate.

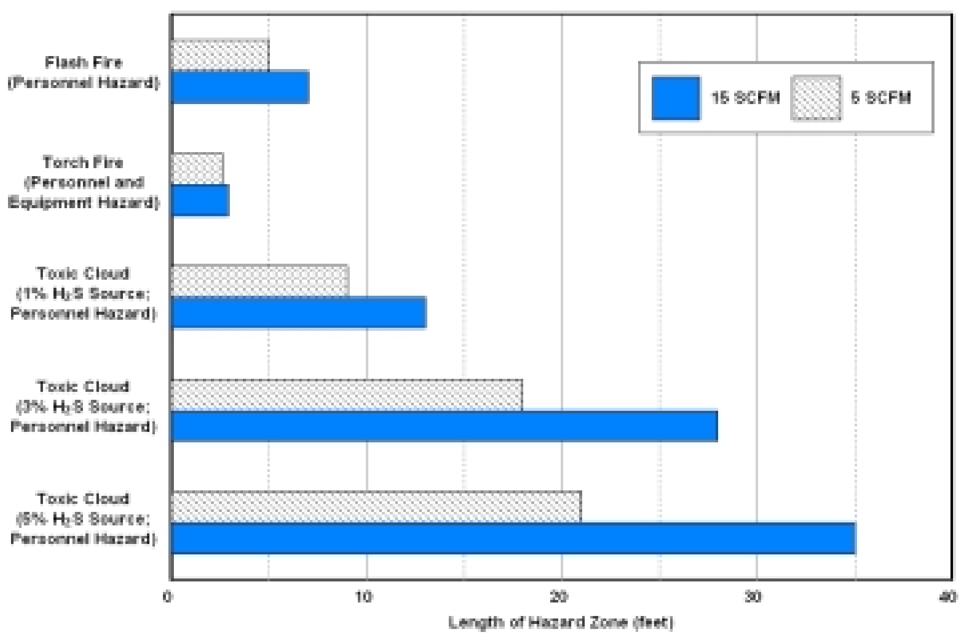

Figure 1. Comparison of flash fire, torch fire, and toxic hazard zones for gas releases of 5 SCFM and 15 SCFM.

In contrast, the lengths of fire hazard zones associated with a gas release at the maximum SSV leakage rate allowed by the MMS should be zero since MMS regulations do not allow any gas leakage through a closed SSV. However, even after the SSV is closed, gas might continue to be released into the environment until such time as the gas inventory in piping or process equipment has been depleted. Thus, fire hazard zones can exist after the SSV is closed, even if no gas is passing through the SSV. In most cases, the fire hazard zones created by a continuing release of gas inventory could exceed the fire hazard zones associated with a release of gas at 15 SCFM. In addition, the effects of the accident that triggers closing of the safety valves are likely to exceed the hazards posed by a 15 SCFM release of gas through a closed SSV. Therefore, it could be argued that the MMS requirement of zero gas leakage through a closed SSV does not necessarily provide a significant increase in safety.

Based on this analysis, it would be difficult to use these fire hazard zones as a basis for selecting one maximum allowable leakage rate in preference to the other for either SSVs or SSSVs.

Toxic Hazard Zones

The toxic hazard zones for the leakage rates of interest for SSSVs, 5 SCFM (MMS) and 15 SCFM (API), are compared to one another in Figure 1. Since there is no toxic hazard when there is no leakage, the toxic hazard zones for the leakage rates of interest for SSVs, 0 SCFM (MMS) and 15 SCFM (API), are also compared in Figure 1. The figure illustrates how the percentage difference between the toxic hazard zones produced by 5 SCFM (MMS) and 15 SCFM (API) is relatively unaffected by the amount of H_2S in the gas being released, but the absolute difference increases as the amount of H_2S in the source increases. Thus, the relative importance of the difference in maximum allowable leakage rate increases as the mole % of H_2S in the gas increases.

Personnel who work on platforms that produce gas that contains H_2S, or who would respond following an accident on such a platform, are aware of the dangers of H_2S and would have appropriate personal protective equipment (such as self-contained breathing apparatus - SCBAs) available to them. They would be expected to properly employ this equipment before approaching the point of release, even if they believe the release has been stopped. Thus, the presence or absence of a toxic vapor cloud would make little difference in how personnel would respond to the accident. Once protected by appropriate personal protective equipment, the presence of a vapor cloud containing H_2S resulting from a leaking SSV of SSSV would not significantly affect personnel safety.

Vapor Cloud Explosions

For the leakage rates of interest for SSVs and SSSVs, 15 SCFM or less, the amount of flammable gas within a flammable vapor cloud will be so small that vapor cloud explosions are not considered a credible occurrence.

Environmental Impact

For the leakage rates of interest for SSVs and SSSVs, a release of natural gas at 15 SCFM or less is expected to have a negligible environmental impact, even if the release continues for several hours. If the leakage continues for several days, it may become a concern.

Liquid Leakage

The rate at which hydrocarbon liquid is leaking through a closed SSSV or SSV is of concern to personnel and equipment only if the liquid is released into a drip tray or onto a solid deck where it can form a pool. The environmental impact is expected to be nearly independent of the location of the release, assuming the liquid ultimately reaches the water. Regardless of the type of hazard (fire or environmental), the effects of the accident that triggers closing of the safety valves are likely to exceed the hazards posed by a 400 cc/min (API) release of liquid through a closed SSV or SSSV.

Fire Hazard Zones

The flash fire and pool fire hazard zones for the leakage rates of interest for SSSVs, 200 cc/min (MMS) and 400 cc/min (API), are compared to one another in Figure 2. Since there is no flash fire and pool fire hazard when there is no leakage, the toxic hazard zones for the leakage rates of interest for SSVs, 0 cc/min (MMS) and 400 cc/min (API), are also compared in Figure 2. The fire hazard zone lengths illustrated in Figure 2 are all based on the assumption that the release continues for 60 minutes before the flammable vapor cloud or the liquid pool is ignited. If ignition occurs earlier, the hazard zone lengths would be shorter. Figure 2 shows that the hazard zones associated with flash fires and pool fires are only weakly affected by an increase in leakage (release) rate (i.e., doubling the release rate from 200 to 400 cc/min causes the flash fire hazard zone length to increase by only 50%, and the effect on the length of the pool fire hazard zones is even less).

According to MMS statistics, there are approximately 3900 active offshore platforms in the Gulf of Mexico, and approximately 3300 producing oil wells. During the 10-year period from 1981 through 1990, the MMS recorded 329 spills of more than 1 bbl of liquid pollutants in the Gulf of Mexico Region—an average of 33 spills per year. These spills included releases of diesel fuel and other liquid pollutants, in addition to releases of crude oil and condensate. They also included releases from sources other than offshore platforms, such as pipelines and workboats. Thus, the annual number of accidents that release crude oil or condensate into the workspace of a platform, and that allow formation of a liquid pool in a drip tray or on a solid deck, is expected to be much smaller than 33—the average number of liquid releases of 1 bbl or more per year.

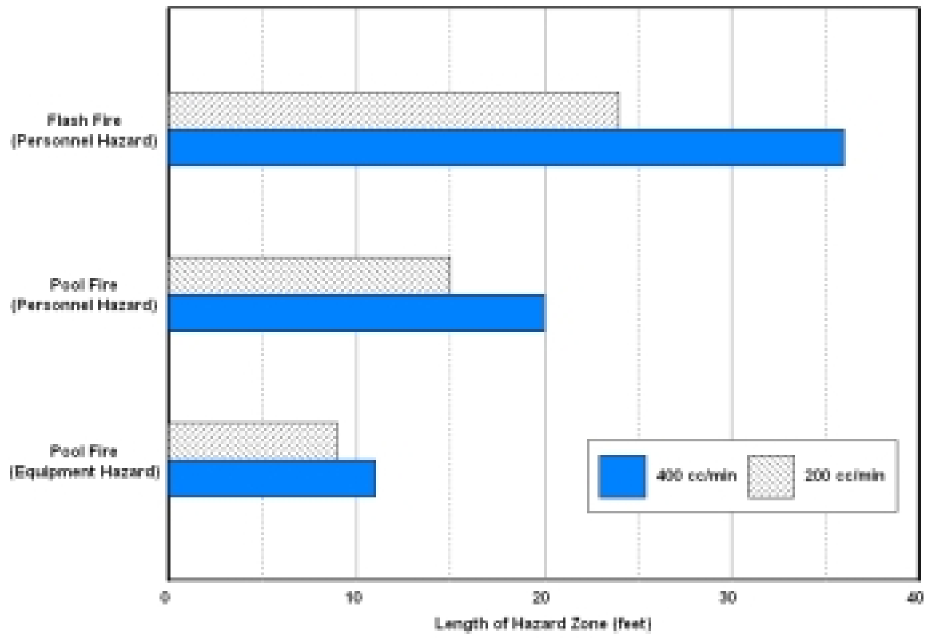

Figure 2. Comparison of flash fire and pool fire hazard zones for liquid releases of 200 cc/min and 400 cc/min, based on spills of 60-minute duration prior to ignition.

There is a low probability of occurrence of accidents in which liquid leakage through an SSSV or SSV might be an important factor, and a high probability that the effects of the accident that triggers closing of the safety valves will exceed the hazards posed by a 400 cc/min (API) release of liquid through a closed safety valve. Therefore, it could be argued that the MMS requirement of zero liquid leakage through a closed SSV does not necessarily provide a significant increase in safety.

Based on the low probability of accidents in which liquid leakage rate through a closed safety valve might be an important factor, and the weak influence of leakage rate on fire hazard zone length, it would be difficult to use fire hazard zones as a basis for selecting one maximum allowable leakage rate in preference to the other for either SSVs or SSSVs.

Vapor Cloud Explosions

For the leakage rates of interest for SSVs and SSSVs, 400 cc/min or less, the amount of flammable gas within a flammable vapor cloud will be so small that vapor cloud explosions are not considered a credible occurrence.

Environmental Impact

Unlike the flash fire and pool fire hazard zones, the environmental impact is directly related to the release rate (i.e., for a release of given duration, doubling the allowable leakage rate from 200 to 400 cc/min results in twice as much liquid entering the water). Thus, the difference between 0 cc/min (MMS for SSVs), 200 cc/min (MMS for SSSVs), and 400 cc/min (API) appears to be significant. However, MMS records show that 42,534 bbl of liquid pollutants were released into the Gulf of Mexico during the 10-year period from 1981 through 1990, as a result of accidents involving offshore platforms, associated pipelines, workboats, etc. This is an average of 4253 bbl per year. Thus, when compared to the amount of hydrocarbon liquid that could be released as a result of the accident that triggers closing of the safety valves, or from other sources that are present in the Gulf, it is difficult to argue that the a limited duration release of liquid hydrocarbon at 400 cc/min is a significant source of pollution.

Based on this study, there appears to be preliminary evidence indicating that the more stringent leakage requirements specified in 30 CFR 250 may not significantly increase the level of safety when compared to the leakage rates recommended by API. However, a complete hazards analysis should be conducted, and industry safety experts should be consulted. As a minimum, the analysis should include:

- A study to determine whether a small leak through a SSV or SSSV is likely to further damage the valve and lead to a much larger leak, and if so over what time frame.
- A study to determine what the risk is to shut in a well to replace a leaking SSV or SSSV (Is there a higher risk involved in remediation than allowing a slight safety valve leak?).
- A detailed cost-benefit analysis, which would likely include an analysis of the cost to maintain the equipment with various levels of allowable leakage rates.
- A detailed risk analysis conducted by personnel knowledgeable in the daily operations on an oil and gas production platform in the Gulf of Mexico.

TEST PROCEDURE

According to 30 CFR Chapter 11 (250.124), operators are required to "test each SSV for operation and leakage once each calendar month, but at no time shall more than 6 weeks elapse between tests." In addition, SSSVs "shall be tested in place for proper operation when installed or reinstalled and thereafter at intervals not exceeding 6 months." In order for these tests to be consistent between various operators and MMS inspectors, it is important to adopt a test procedure by which all testing is performed.

During the "Field Observation" phase of this project, 146 surface safety valves (SSVs) and 9 surface controlled subsurface safety valves (SCSSVs) were tested for operation and leakage. To ensure that the leakage data collected was not affected by the test method, test procedures were developed and followed during each valve test. The test procedures consisted of closing the valve to be tested, isolating and venting the downstream piping, and measuring the leakage rate using a commercially available variable area gas flow meter (rotameter). A copy of the test procedures for both SSVs and SCSSVs may be found in Attachment 1.

In general, most of the operators responsible for the routine testing of the safety valves on a platform used the same basic test procedure that is included in Attachment 1. However, most operators and MMS inspectors used audible techniques to "measure" leakage rates. Only a few of the operators had any type of flow meter to accurately measure the leakage rates. Figure 3 shows a schematic of the leakage rate measurement equipment, which was used during the field testing, as it would be connected during a test.

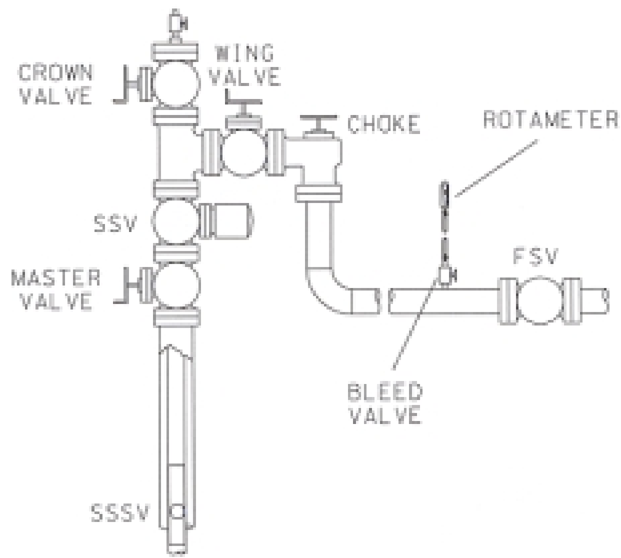

Figure 3. Leakage rate measurement equipment. *Based upon the bias error introduced by the unknown gas temperature and specific gravity, the actual flow rate can be measured to within approx i-mately ±15%, if the temperature of the gas is between 30°F and 110°F, and the specific gravity is b e-tween 0.6 and 0.9.*

The rotameter, used to quantify the leakage rates, proved to be extremely useful and well accepted by both the MMS inspectors involved in the field testing and the operators. Table 2 lists the equipment used for measuring the leakage rate, including the model number and approximate cost of each component.

Table 2. Equipment used for measuring the leakage rate.

Item	**Quantity**	*Manufacturer*	**Model No.**	**Cost**
Rotameter	1	Cole-Parmer	H-03279-56	$38
Hose Barb	2	Grainger	6X411	$2
Plastic Hose	2-ft	Ryan Herco	0001-135	$4
Hose Clamp	2	Ryan Herco	0950-006	$3

CONCLUSIONS

Based on the risk assessment study conducted, there appears to be preliminary evidence indicating that the more stringent leakage requirements specified in 30 CFR 250 may not significantly increase the level of safety when compared to the leakage rates recommended by API. However, a complete hazards analysis should be conducted, and industry safety experts should be consulted. As a minimum, the analysis should include:

- A study to determine whether a small leak through a SSV or SSSV is likely to lead to a much larger leak, and if so over what time frame.
- A study to determine what the risk is to shut in a well to replace a leaking SSV or SSSV. (Is there a higher risk involved in remediation or a slight safety valve leakage?)
- A detailed cost-benefit analysis.
- A detailed risk analysis conducted by personnel knowledgeable in the daily operations on an oil and gas production platform in the Gulf of Mexico.

Regardless of what through-valve leakage is allowed by MMS, a standardized test procedure, such as the procedure included in Attachment 1, should be adopted by all operators and MMS inspectors. This test procedure should include a means for measuring the leakage rate.

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Attachment 1

Test Procedures

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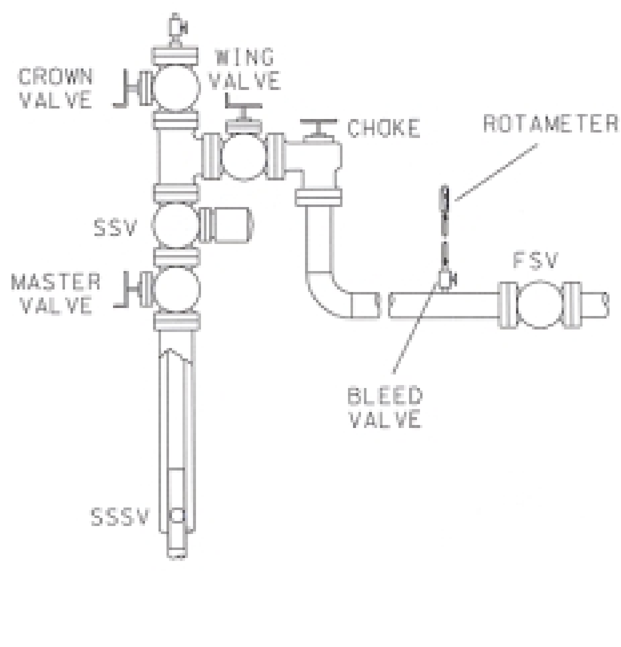
TEST PROCEDURE FOR SSV

ALLOWABLE LEAKAGE RATES AND RELIABILTIY
OF SAFETY AND POLLUTION PREVENTION EQUIPMENT
SwRI PROJECT 18-1298

1. Close the SSV to be tested.
2. Position valve(s) as required to permit pressure to bleed off downstream of the SSV, and bleed off downstream pressure.
3. Close the bleed valve.
4. Attach the inlet of the rotameter to the bleed valve using hose barb and plastic tubing and keep rotameter in the vertical position.
5. With pressure on the upstream side of the SSV, slowly open the bleed valve downstream of the SSV and record the leakage rate. Use the chart on the back of the rotameter to convert from air flow rate to natural gas flow rate*.
6. If leakage occurs, verify that the SSV is actually leaking, and not the FSV, wing valve or gas trapped in the crown valve.
7. Close the bleed valve.
8. Disconnect hose barb and plastic tubing from the bleed valve.
9. Return the SSV to service.

MAXIMUM ALLOWABLE LEAKAGE: No gas leakage allowed.



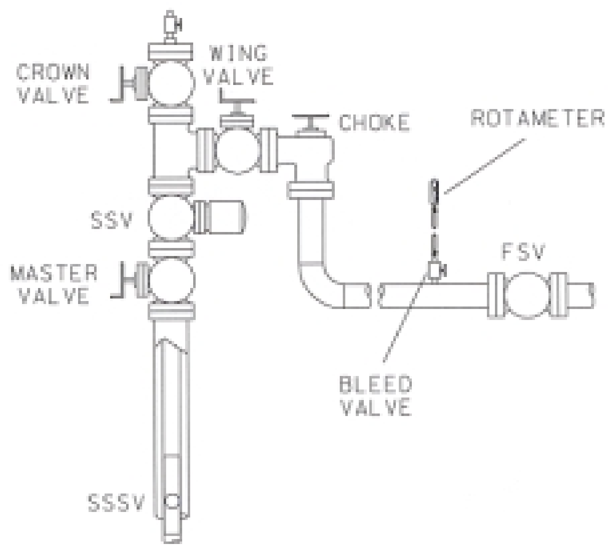
* Based upon the bias error introduced by the unknown gas temperature and specific gravity, the actual flow rate can be measured to within approximately ±15%, if the temperature of the gas is between 30°F and 110°F and the specific gravity is between 0.6 and 0.9.

TEST PROCEDURE FOR SCSSV

ALLOWABLE LEAKAGE RATES AND RELIABILTIY
OF SAFETY AND POLLUTION PREVENTION EQUIPMENT
SwRI PROJECT 18-1298

1. Close the SCSSV to be tested.
2. Position valve(s) as required to permit pressure to bleed off downstream of the SCSSV, and bleed off downstream pressure.
3. Close the bleed valve.
4. Attach the inlet of the rotameter to the bleed valve using hose barb and plastic tubing and keep rotameter in the vertical position.
5. With pressure on the upstream side of the SCSSV, slowly open the bleed valve downstream of the SCSSV and record the leakage rate. Use the chart on the back of the rotameter to convert from air flow rate to natural gas flow rate*.
6. If leakage occurs, verify that the SCSSV is actually leaking, and not the FSV, wing valve or gas trapped in the crown valve.
7. Close the bleed valve.
8. Disconnect hose barb and plastic tubing from the bleed valve.
9. Return the SCSSV to service.

MAXIMUM ALLOWABLE LEAKAGE: 5 SCFM.



* Based upon the bias error introduced by the unknown gas temperature and specific gravity, the actual flow rate can be measured to within approximately ±15%, if the temperature of the gas is between 30°F and 110°F and the specific gravity is between 0.6 and 0.9.